# Proactive, Multi-Value Transmission Planning

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# Presentation Outline

I. **The Need for Improved Transmission Planning**

II. **Planning Process Improvements**

III. **Quantifying Transmission Benefits**

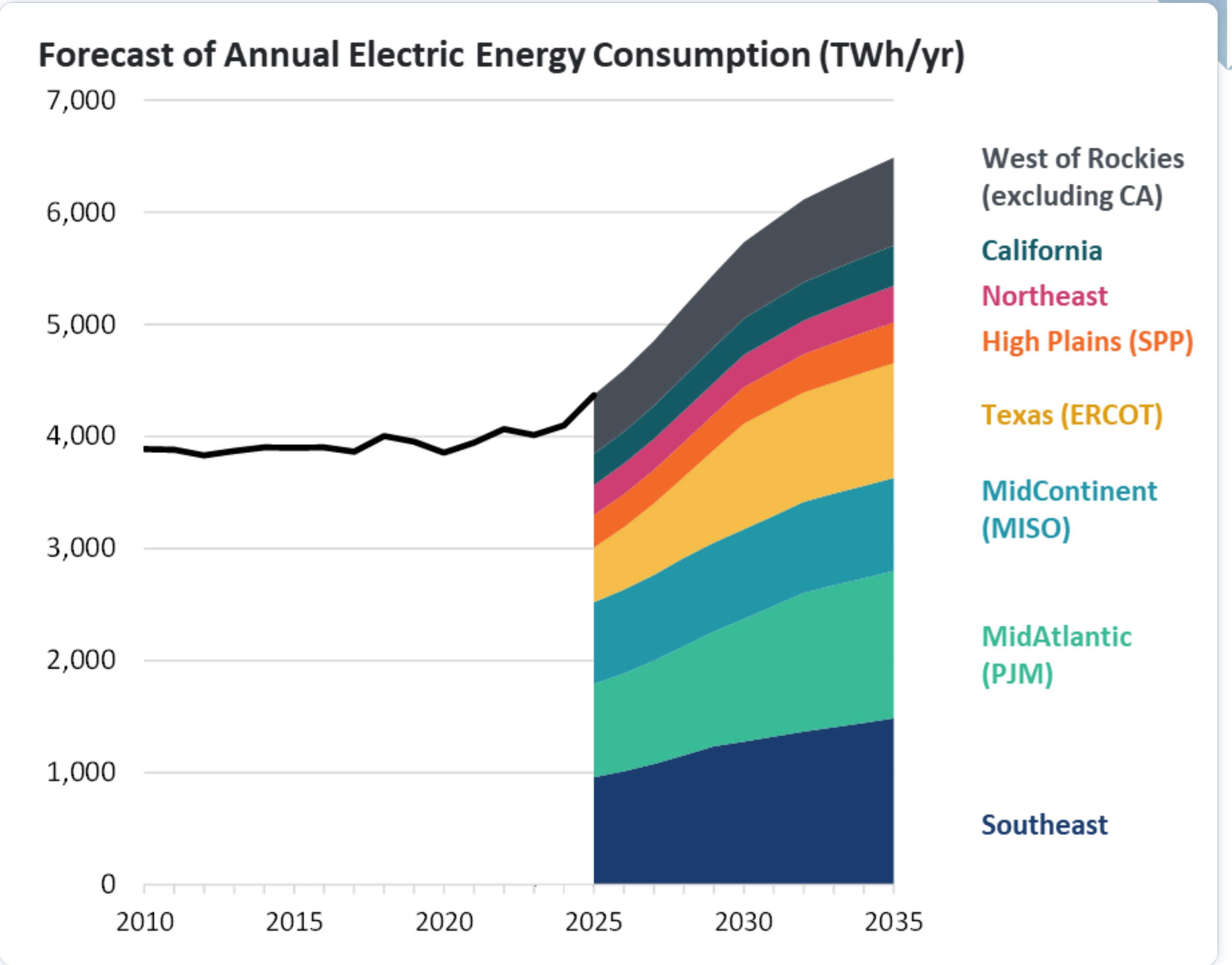
IV. **FERC Order No. 1920 is a Launch Point**

# I. The Need for Improved Transmission Planning

# The Electricity Industry is Undergoing Fundamental Changes, Which Will Require Improved Planning Processes

As the industry deals with rapidly increasing load growth projections – combined with a shift in the generation mix towards **decarbonization**, **decentralization**, and **digitalization** – fundamental changes in grid planning and operations are necessary.

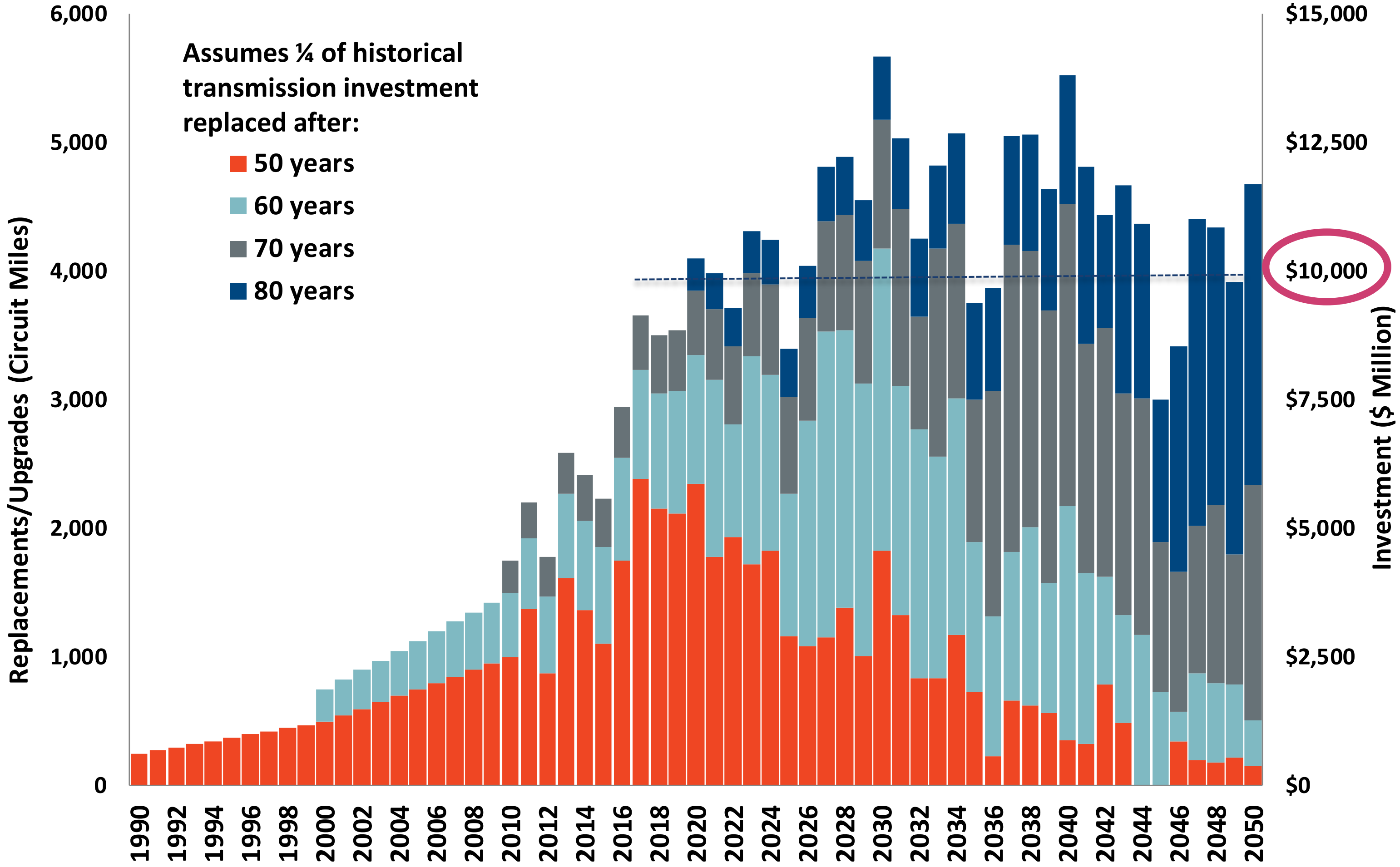
Additionally, the projected increase in frequency and severity of extreme weather events drive a **need for added grid resiliency**.




Source: The Brattle Group, based on aggregation of individual RTOs' and utilities' most recent forecasts.

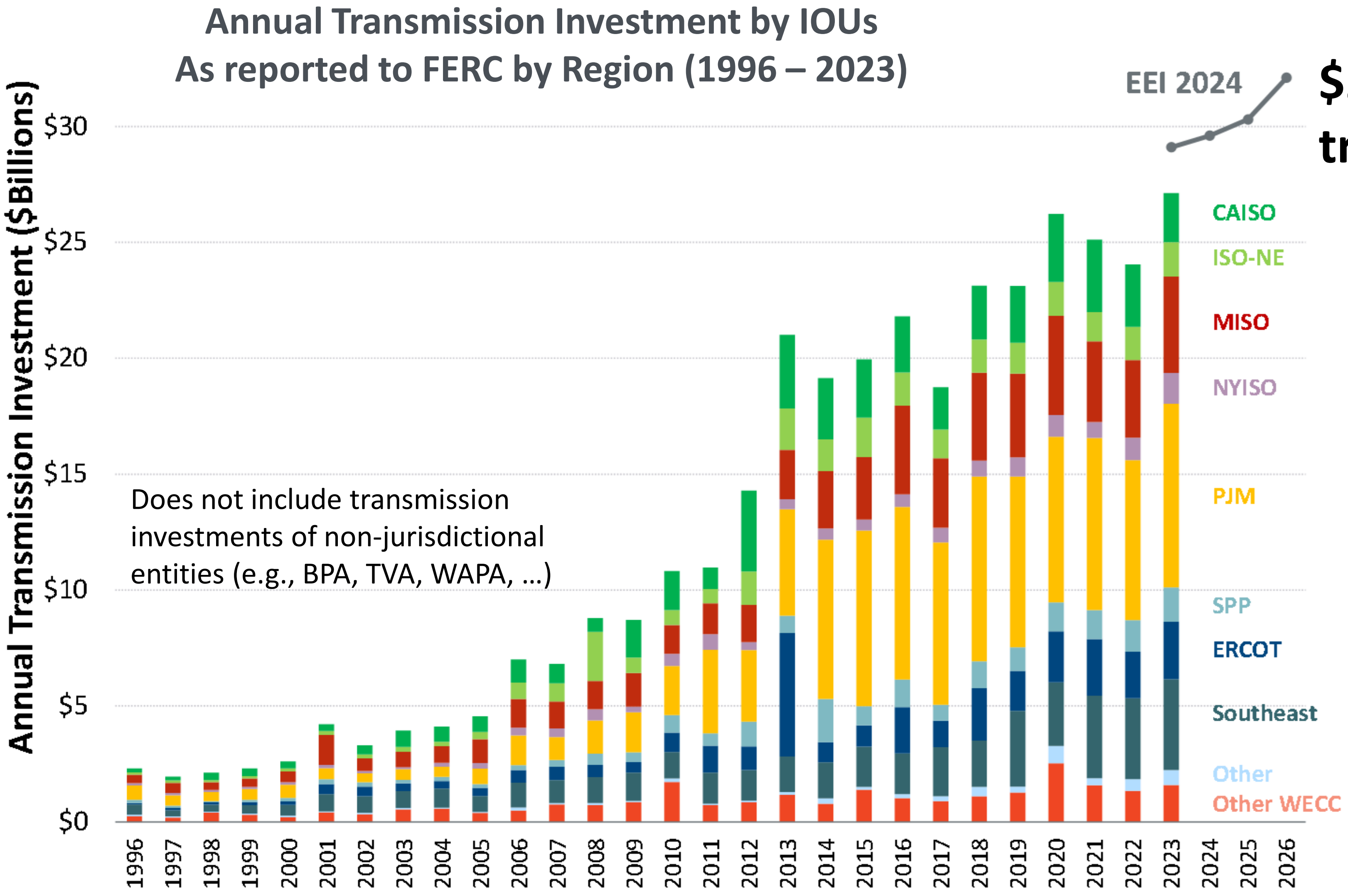
# Challenge and Opportunity: Aging U.S. Transmission Infrastructure

- 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
- 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 circuit mile costs equal to those of new lines.

# Transmission Investment is at Historically High Levels

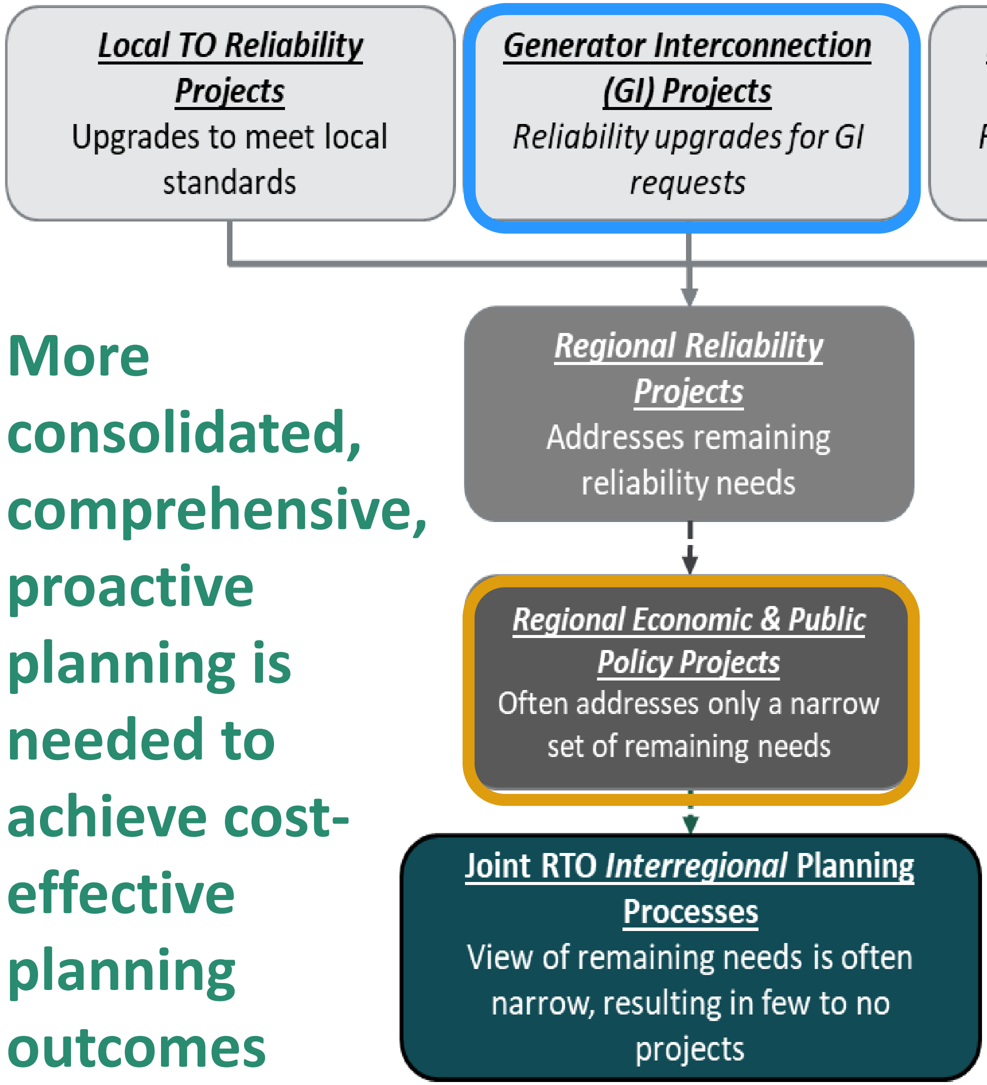



Source: The Brattle Group analysis of FERC Form 1 Data; EEI "Historical and Projected Transmission Investment" report.

**$20-25 billion in annual U.S. transmission investment, but:**

- More than 90% of it justified solely based on reliability needs without benefit-cost analysis
  - About 50% solely based on “local” utility criteria (without going through regional planning processes)
  - The rest justified by regional reliability and generation interconnection needs
- While significant experience with transmission benefit-cost analyses exists, very few projects are justified based on economics and overall cost savings

# Current US Transmission Planning is Focused Almost Entirely on Reliability




**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 generator interconnection processes are not able to achieve the most cost-effective outcomes**

**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.

# II. Planning Process Improvements

# What is a Proactive, Scenario-Based, Multi-Value Planning Framework?

**Needs Assessment**
Identify transmission needs from a variety of drivers across multiple future scenarios

**Solutions Development**
In addition to new transmission, rely on <u>advanced transmission technologies</u>, <u>upsizing opportunities</u>, and <u>flexible solutions</u> to address identified needs and enhance the grid

**Cost-Benefit Analysis**
Use multi-value processes to address near- and long-term needs, considering a future with "least regrets"

**Cost Allocation**
Utilize <u>pragmatic cost allocations</u> that are roughly commensurate with (but not formulaically based on) benefits received

**Portfolio Approval**
Approve portfolio of projects

# Develop Multiple Future Scenarios

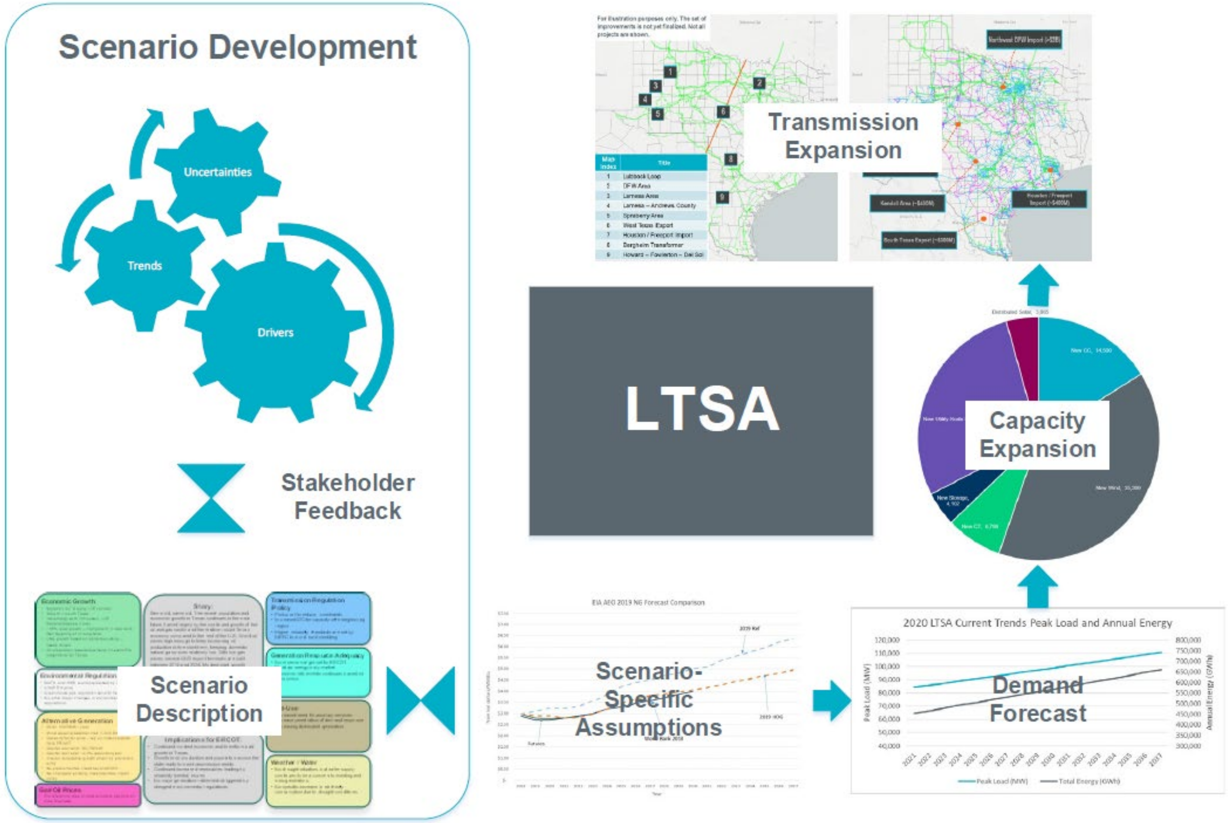
Scenario-based planning is a process first developed in the 1940s and 1950s as a tool for **integrating uncertainties into long-term strategic planning**.

Assists planners to think, in advance, about the many ways the future may unfold and how to respond effectively *and with flexibility*

Examples of scenario-based planning approaches used in regional transmission planning include:

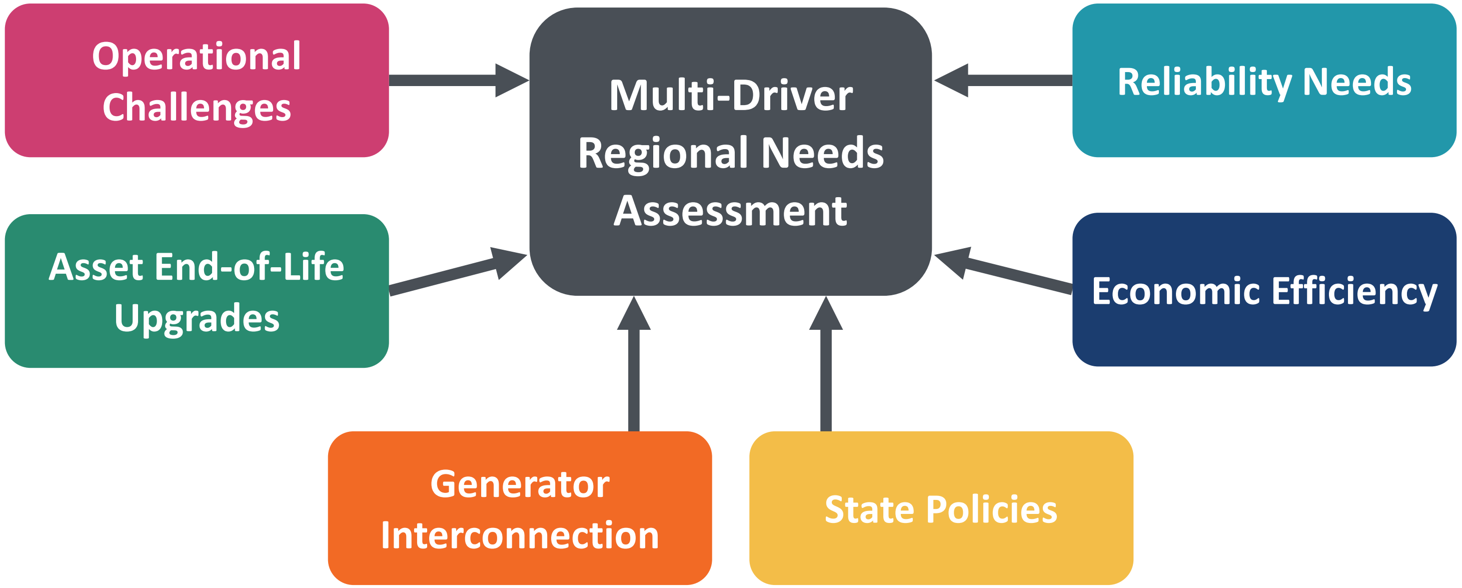
- ERCOT's Long-Term System Assessment Process (LTSA)
- MISO's Long Range Transmission Planning (LTRP)
- SPP's recent Integrated Transmission Plan (ITP)

**ERCOT LTSA Process**



# Consolidated, Multi-Driver Needs Assessment to Identify Solutions

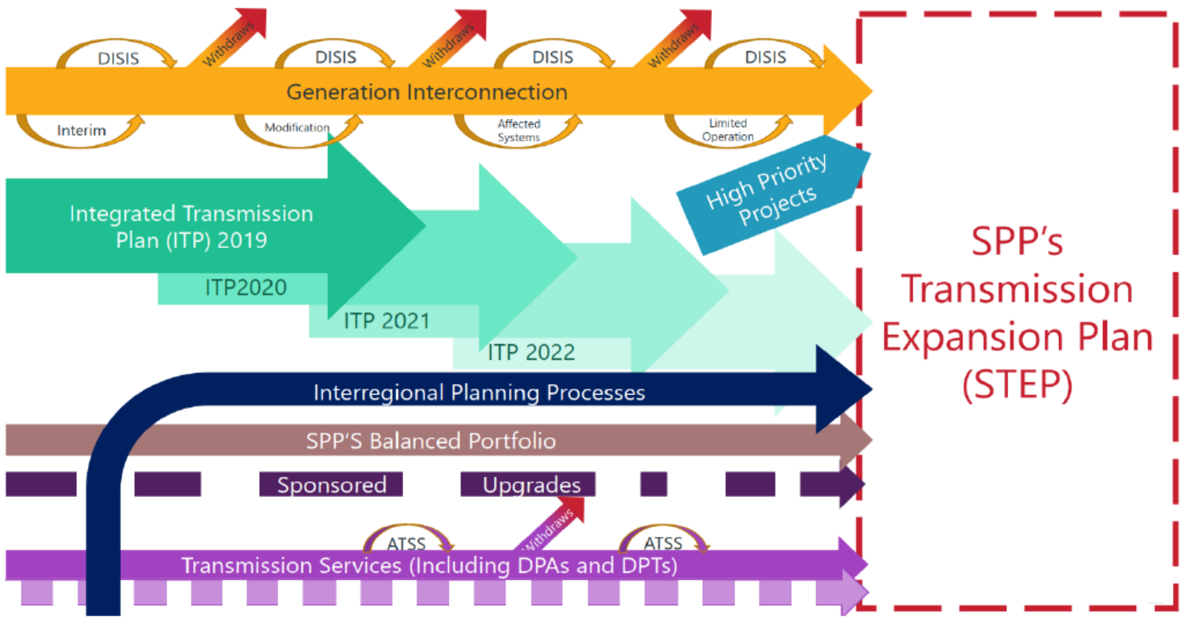
Implementing a multi-driver approach to identify regional transmission needs will allow regional transmission planners to identify overlapping concerns and develop cost-effective, right-sized solutions that can provide a broad range of benefits.



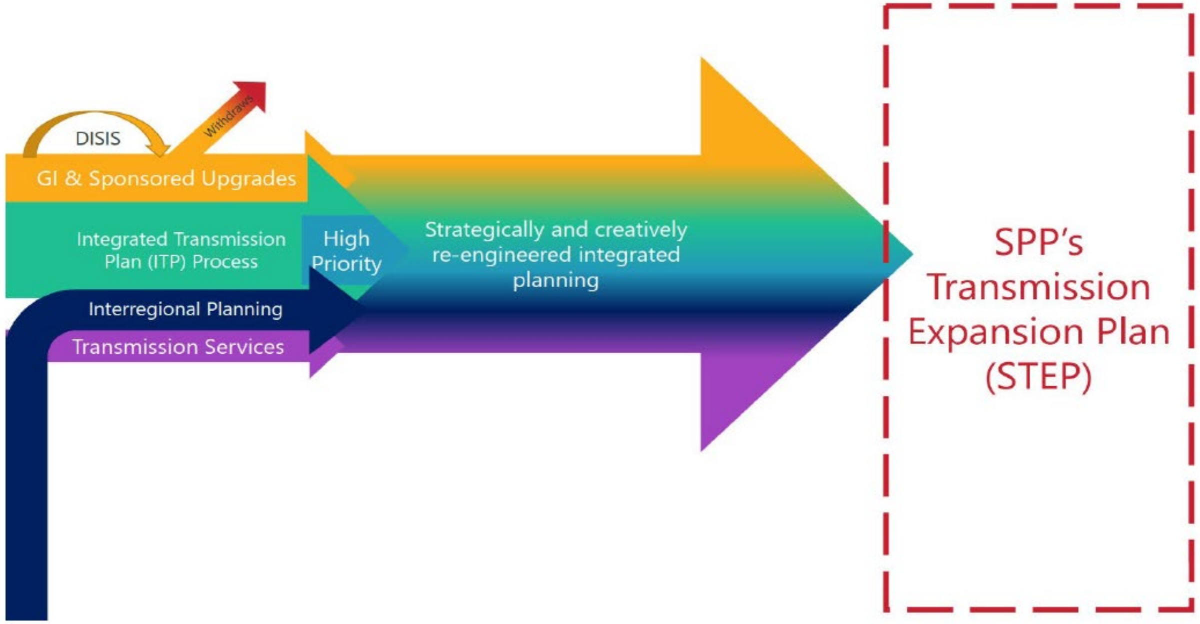
# Example: SPP's proposed Consolidated Planning Process (CPP)

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

# Expand Scope of Solutions

## 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

# Select Solutions Based on Comprehensive Cost-Benefit Analysis

The wide-spread nature of transmission benefits creates challenges in estimating benefits and how they accrue to different users, which also complicates cost allocation.

**Wide-spread geographically**

**Occur and change over long periods of time**

**Diverse in their effects on market participants**

**Broad in scope, providing many different types of benefits**

# 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:**

- **"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

## Australian Energy Market Operator (AEMO) Example:

Table 15 Calculating the weighted regret cost ($m) and ranking of Candidate Development Paths via LWWR

| | Weighted regrets | | | | Worst weighted regret ($m) | Ranking |
|---|---|---|---|---|---|---|
| | Scenario A | Scenario B | Scenario C | Scenario D | | |
| **Weighting** | 40% | 25% | 25% | 10% | | |
| **CDP1** | 0 * 40% = 0 | 40 * 25% = 10 | 70 * 25% = 18 | 0 * 10% = 0 | 18 | 5 |
| **CDP2** | 36 * 40% = 14 | 0 * 25% = 0 | 36 * 25% = 9 | 50 * 10% = 5 | 14 | 3 |
| **CDP3** | 78 * 40% = 31 | 35 * 25% = 9 | 0 * 25% = 0 | 28 * 10% = 3 | 31 | 6 |
| **CDP4** | 8 * 40% = 3 | 0 * 25% = 0 | 36 * 25% = 9 | 8 * 10% = 1 | 9 | 2 |
| **CDP5** | 29 * 40% = 12 | 137 * 25% = 34 | 45 * 25% = 11 | 9 * 10% = 1 | 34 | 7 |
| **CDP6** | 37 * 40% = 15 | 35 * 25% = 9 | 0 * 25% = 0 | 17 * 10% = 2 | 15 | 4 |
| **CDP7** | 18 * 40% = 7 | 17 * 25% = 4 | 26 * 25% = 7 | 7 * 10% = 1 | **7** | **1** |

Source: AEMO ISP Methodology

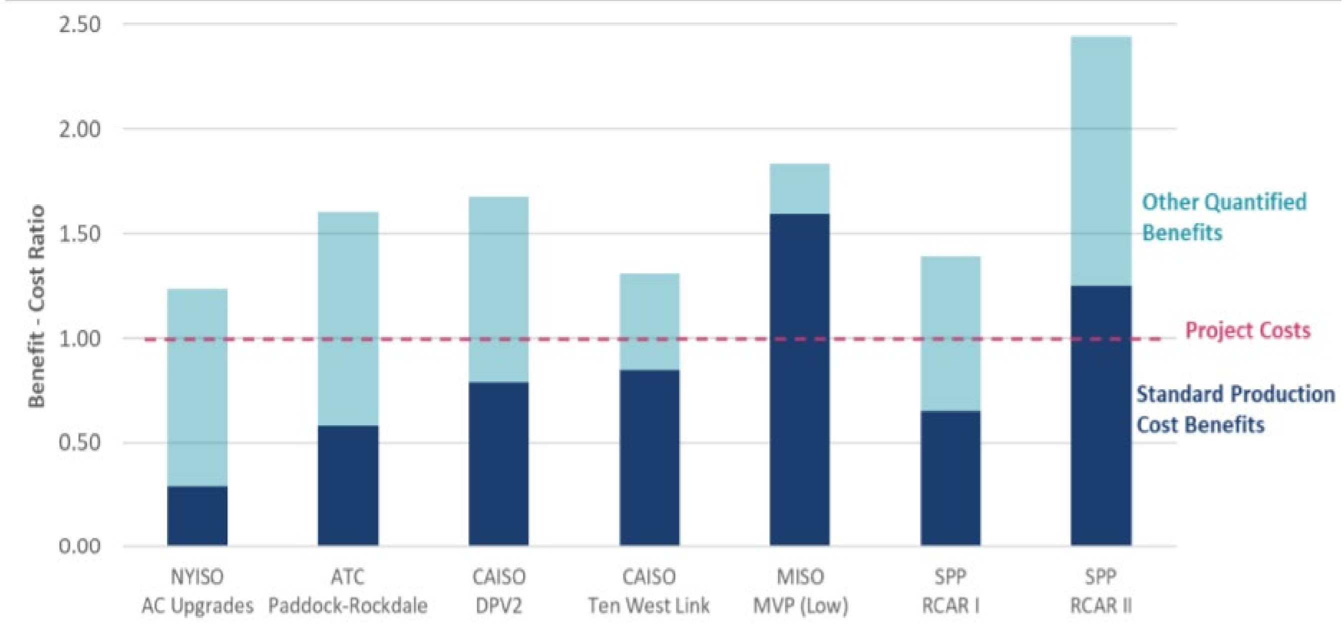
# III. Quantifying Transmission Benefits

# Quantifying Benefits Beyond “Production Cost” Savings

**Relying on solely on traditionally-quantified <u>Adjusted Production Cost</u> (APC) Savings may result in the rejection of beneficial transmission projects.**

- While the *actual* value of congestion relief alone may be enough to justify transmission investments, it is difficult to capture the actual levels of congestion that will occur through simulations and projections.
- 50% of congestion happens in 5% of the hours, but nearly all models use weather-normalized data that fails to capture this high value
- Additional benefits can and should be considered when evaluating potential transmission solutions.

FIGURE 5. BENEFIT-COST RATIOS OF TRANSMISSION PROJECTS WITH AND WITHOUT A BROAD SCOPE OF BENEFITS




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

# "Checklist" of Transmission Benefits With Proven Practices for Quantifying Them

**As we have documented in our recent report (cited widely in Order 1920) available proven practices:**

1. Consider for each project (or synergistic portfolio of projects) the full set of benefits transmission can provide (see table)
2. Identify the benefits that plausibly exist and may be significant for that particular project or portfolio; then
3. Focus on quantifying those benefits

(See Appendix D of our 2021 report with Grid Strategies for a summary of quantification practices)

| 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 |

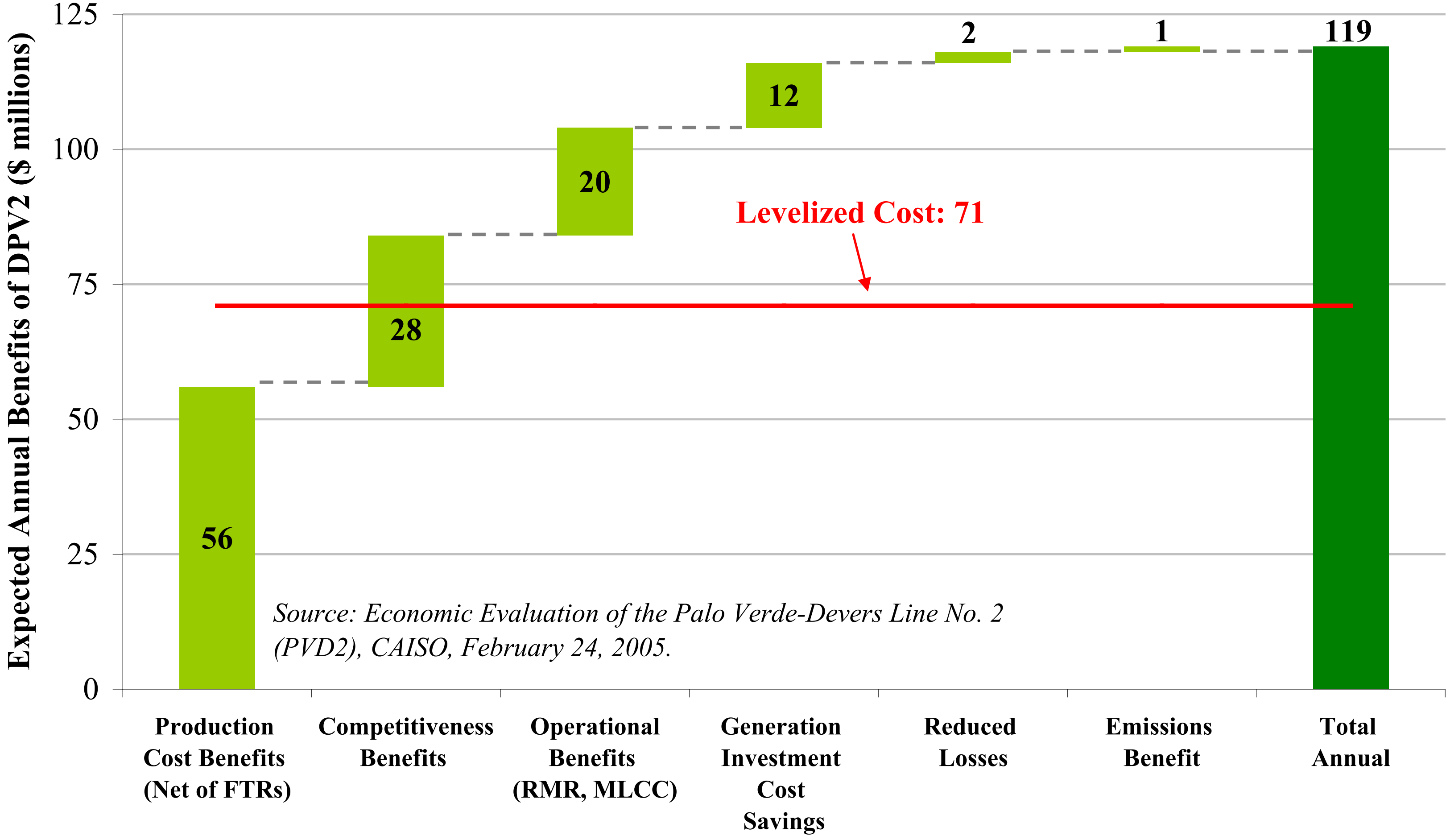
# Planners Have Approved Upgrades Based on Expanded Cost Savings

| | SPP 2016 RCAR, 2013 MTF | MISO MVP Analysis | CAISO TEAM DPV2 Analysis | NYISO AC Upgrades Analysis |
|---|---|---|---|---|
| Quantified | 1. **Production cost savings***<br>• Value of reduced emissions<br>• Reduced ancillary service costs<br>2. Avoided transmission project costs<br>3. Reduced transmission losses provide capacity and energy benefit*<br>4. Lower transmission outage costs<br>5. Value of reliability projects<br>6. Value of mtg public policy goals<br>7. Increased wheeling revenues | 1. **Production cost savings***<br>2. Reduced operating reserves<br>3. Reduced planning reserves<br>4. Reduced transmission losses*<br>5. Reduced renewable generation investment costs<br>6. Reduced future transmission investment costs | 1. **Production cost savings*** and reduced energy prices from societal and customer perspective<br>2. Mitigation of market power<br>3. Insurance value for high-impact low-probability events<br>4. Capacity benefits due to reduced gen investment costs<br>5. Operational benefits (RMR)<br>6. Reduced transmission losses*<br>7. Emissions benefit | 1. **Production cost savings*** (includes savings not captured by normalized simulations)<br>2. Capacity resource cost savings<br>3. Reduced refurbishment costs for aging transmission<br>4. Reduced costs of achieving renewable and climate policy goals |
| Not Quantified | 8. Reduced cost of extreme events<br>9. Reduced reserve margin<br>10. Reduced loss of load probability<br>11. Increased competition/liquidity<br>12. Improved congestion hedging<br>13. Mitigation of uncertainty<br>14. Reduced plant cycling costs<br>15. Societal economic benefits | 7. Enhanced generation policy flexibility<br>8. Increased system robustness<br>9. Decreased natural gas price risk<br>10. Decreased CO2 emissions output<br>11. Decreased wind generation volatility<br>12. Increased local investment and job creation | 8. Facilitation of the retirement of aging power plants<br>9. Encouraging fuel diversity<br>10. Improved reserve sharing<br>11. Increased voltage support<br><br>(CPUC Decision 07-01-040, January 25, 2007, Opinion Granting a Certificate of Public Convenience and Necessity) | 5. Protection against extreme market conditions<br>6. Increased competition and liquidity<br>7. Storm hardening and resilience<br>8. Expandability benefits<br><br>(Newell, et al., Benefit-Cost Analysis of Proposed New York AC Transmission Upgrades, September 15, 2015) |
| | (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.) | (Proposed Multi Value Project Portfolio, Technical Study Task Force and Business Case Workshop August 22, 2011) | | |

* Fairly consistent across RTOs

# Example: CAISO Transmission Project Benefits vs. Costs

Total benefits of CAISO's PVD2 project exceeded project costs by more than 50%, but only if multiple benefits are quantified



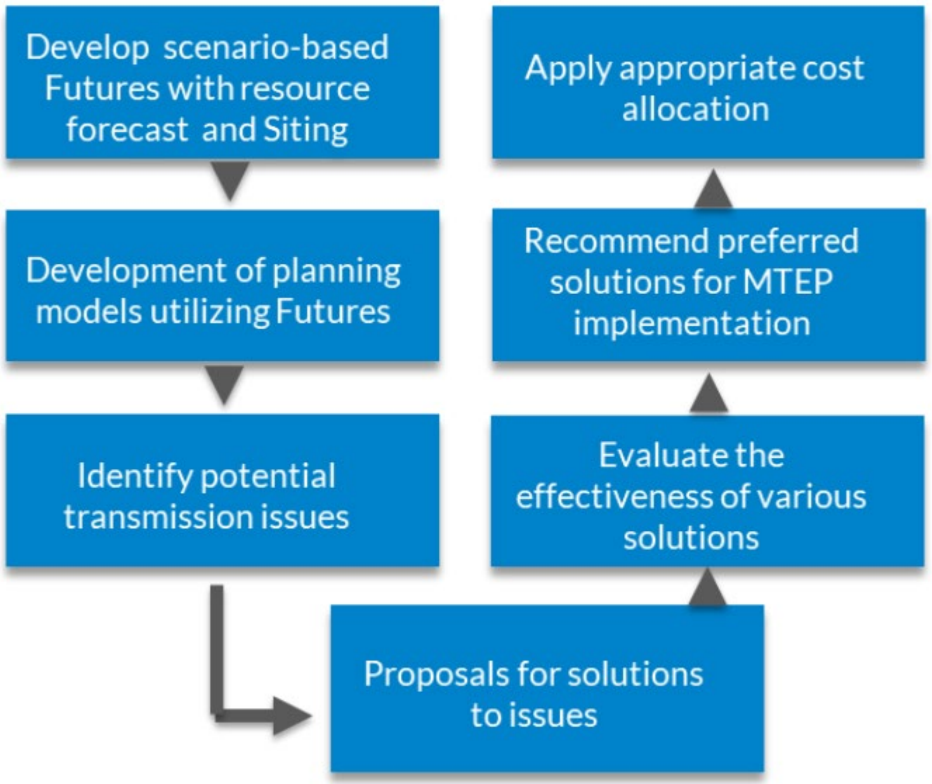



Source: Economic Evaluation of the Palo Verde-Devers Line No. 2 (PVD2), CAISO, February 24, 2005, pp. 2 (PDF 301 of 428).

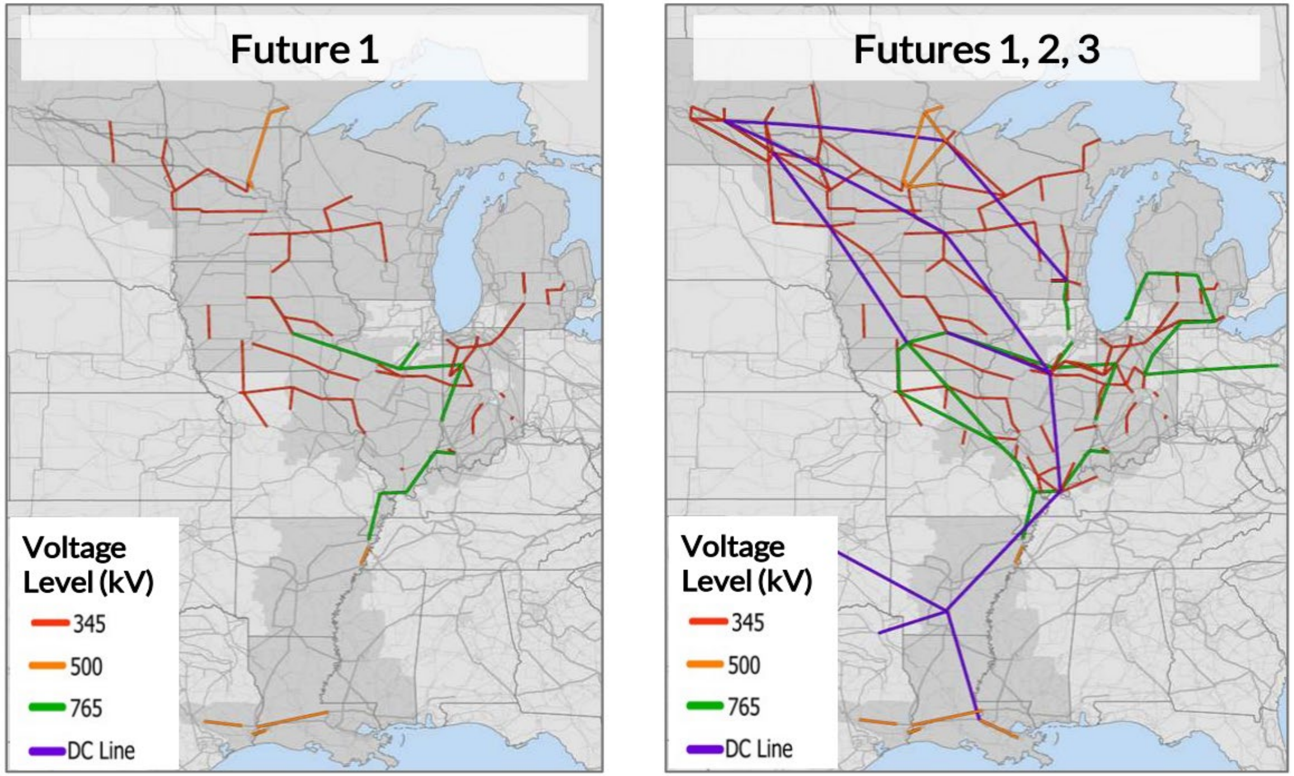
# MISO Long Range Transmission Planning Process

MISO’s LRTP Tranche 1 and Tranche 2.1 evaluated 20-year reliability, economic, and policy needs for three plausible “Futures” scenarios that accounted for uncertainty in load growth and generation.

### MISO’ LRTP Process




### MISO’s Identified Long-Term Transmission Needs



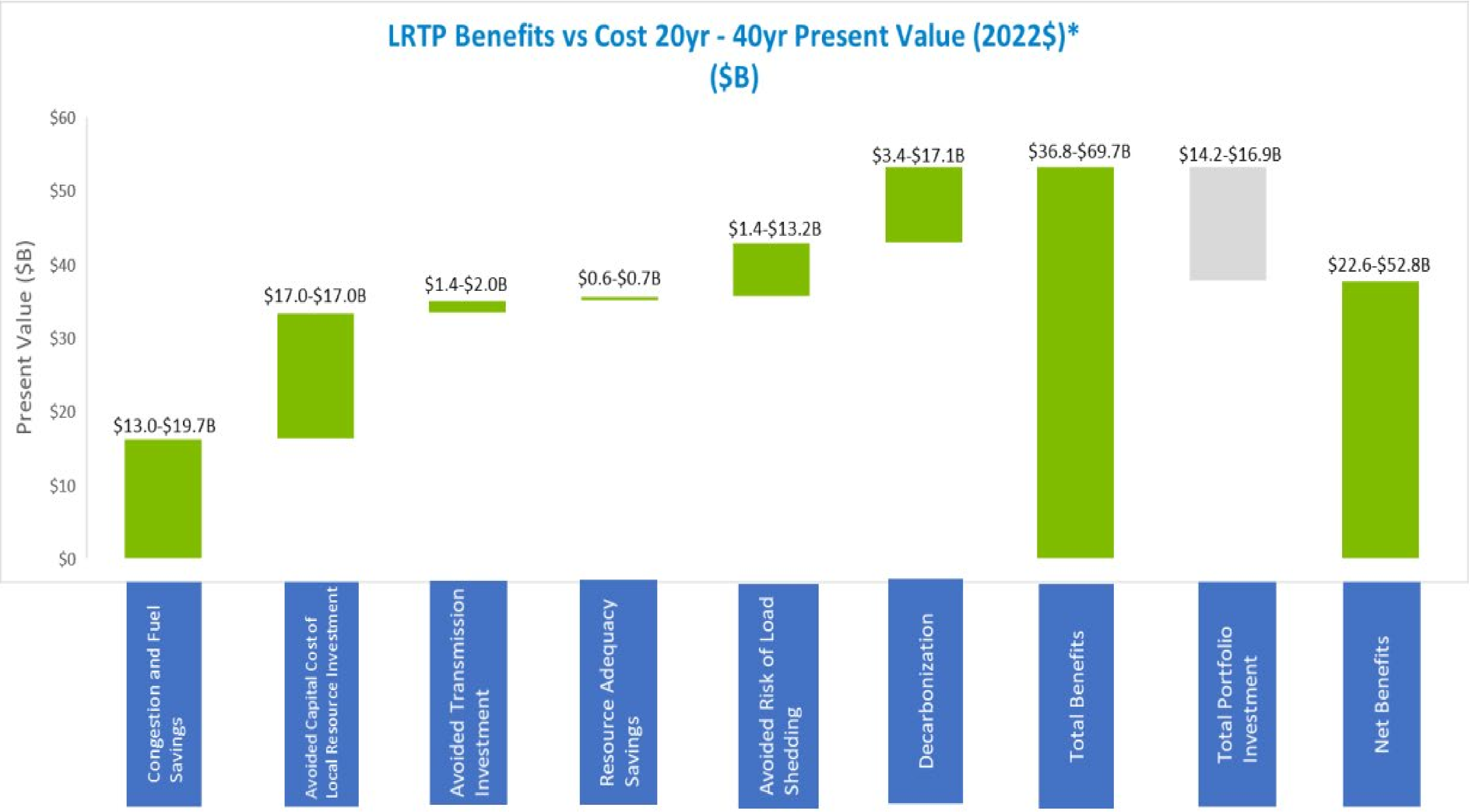

Source: MISO LRTP Roadmap March 2021

# Example: MISO Long-Term Transmission Planning (LRTP)

## 20-40-year PV of benefits ($37-$70b) substantially exceeds PV of TRR ($14-17b)

**B-C analysis based on multiple benefit metrics:**

1. Congestion and fuel savings
2. Avoided capital costs of local resource investments
3. Avoided transmission investment
4. Reduced resource adequacy requirements
5. Avoided risk of load shedding
6. Decarbonization value
7. Reliability issues addressed by LRTP
8. Other qualitative and indirect benefits

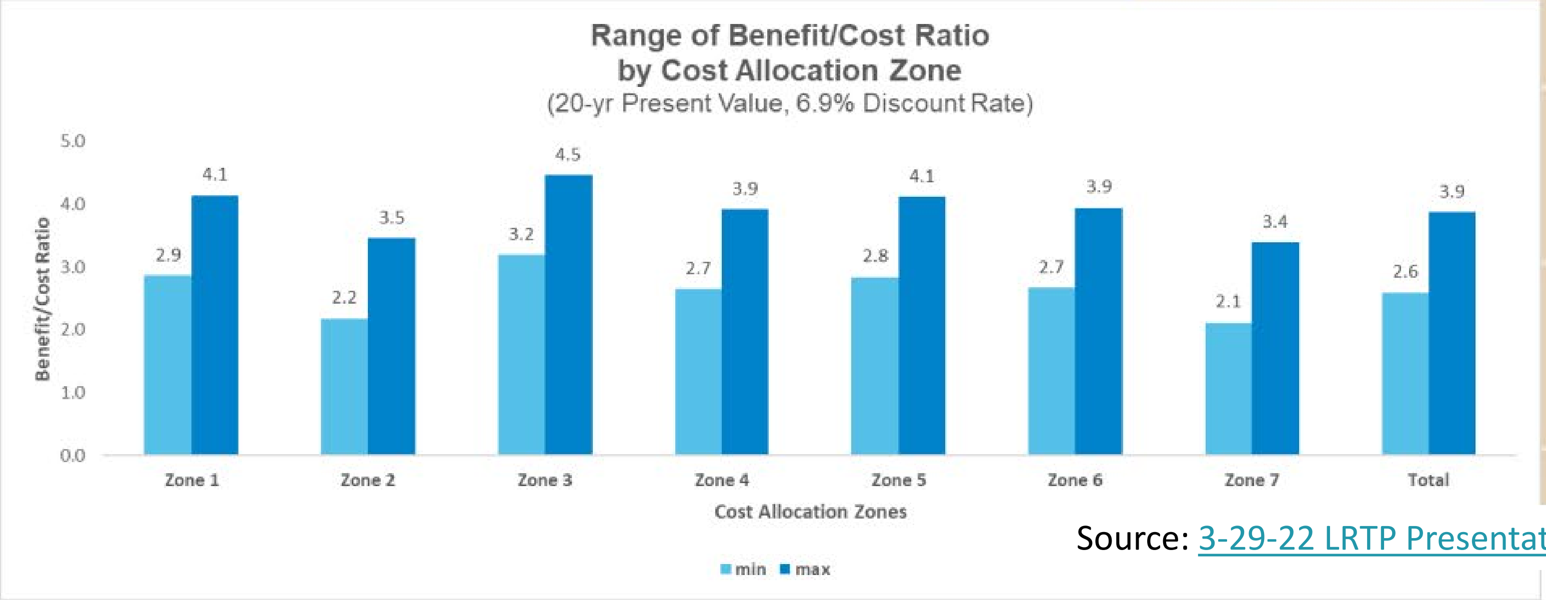


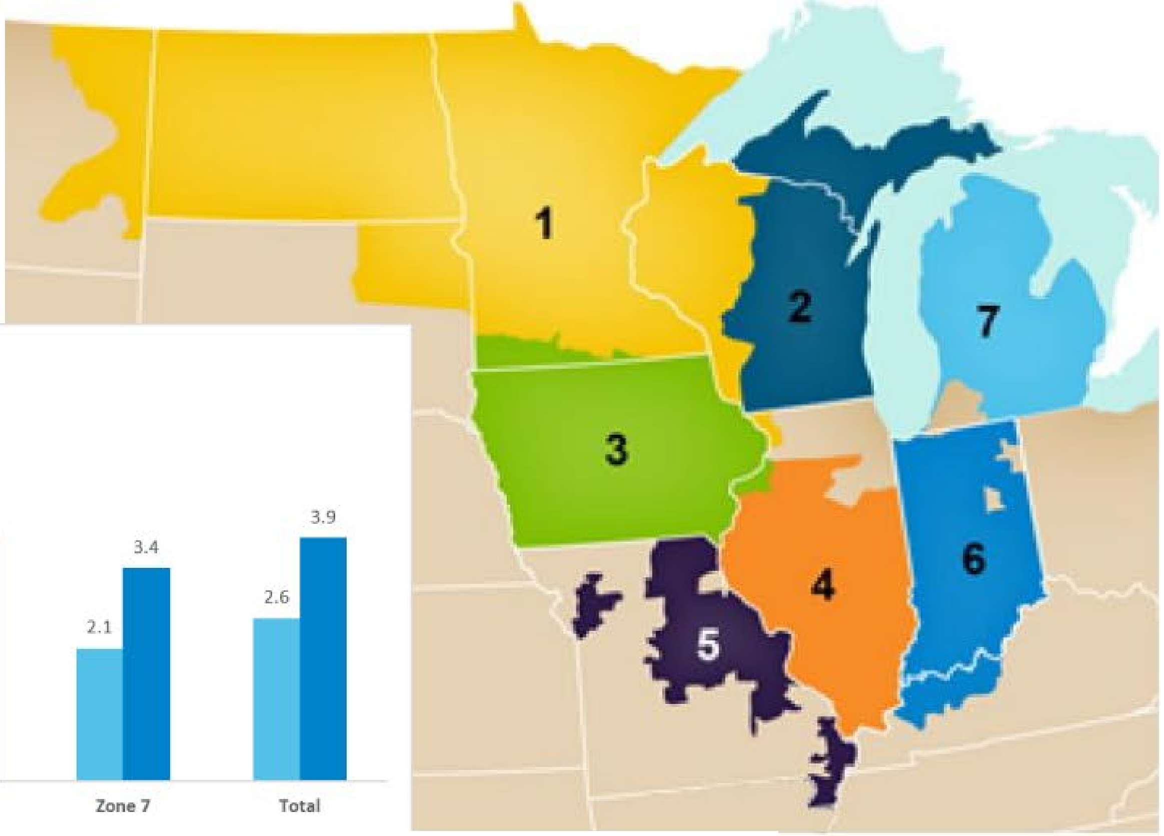

Source: [3-29-22 LRTP Presentation (misoenergy.org)]

# Example: MISO Long-Term Transmission Planning (LRTP)

**Postage-stamp within MISO's Midwest Subregion results in allocated costs that are roughly commensurate with benefits received:**

- Each Zone's benefits are at least 2.1-3.4 times higher than allocated costs
- B-C ratios vary across zones, scenarios, and study assumptions
- No costs allocated to MISO's South Subregion due to disproportionately small benefits received




Source: [3-29-22 LRTP Presentation (misoenergy.org)]

# CTPC/Duke Multi-Value Strategic Transmission (MVST) Study

Carolinas Transmission Planning Collaborative (CTPC) completes local transmission planning for utilities in North and South Carolina, including Duke Energy (DEC/DEP), ElectriCities, and NCEMC

**$503 million of Public Policy upgrades** in its 2023 Annual Plan to support solar additions

CTPC added to its local planning process a **proactive, scenario-based, multi-driver process to identify Multi-Value Strategic Transmission (MVST) projects;** implementing its first MVST study in 2024–2025.

### Key Aspects of CTPC Multi-Value Strategic Transmission Process

| IRP-based Scenarios | Alternative Solutions | Portfolio Evaluation | Benefits Analysis |
|---|---|---|---|
| Identify reliability and economic needs for future scenarios based on Duke's projected load and IRP-developed generation portfolios | Consider GETs, advanced conductors, Remedial Action Schemes (RAS), and storage as potential solutions as well as existing lines upgrades and greenfield transmission | Evaluate a portfolio of transmission solutions over the life of the assets to resolve identified needs | Quantify (**1**) avoided capacity costs, (**2**&**3**) capacity cost and energy cost savings from reduced losses, (**4**) congestion and fuel cost savings, (**5**) avoided customer outages, and (**6**) avoided transmission costs |

# IV. FERC Order No. 1920 is a Launch Point

# Experience with Proactive & Comprehensive Planning Processes

**Although still rarely used, significant experience exists with successful proactive, multi-value, scenario- and portfolio-based transmission planning efforts:**

| | 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] | ✓ | ✓ | ✓ | ✓ | ✓ |

Source: Brattle & Grid Strategies, Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs


brattle.com | 25

# Actual Planning Processes Used

**Current planning processes do not (yet) take advantage of experience with proactive, multi-value, scenario- and portfolio-based transmission planning efforts**

| | Proactive Generation & Load | Multi-Value | Scenario-Based | Portfolio-Based[30] | Joint Interregional Planning |
|---|---|---|---|---|---|
| ISO-NE[31] | ✗ | ✗ | ✗ | ✓ | ✗ |
| NYISO[32,33] | ✗ | ✗ | ✗ | ✗ | ✗ |
| – PPTPP only | ✓ | ✓ | ✓ | ✓ | ✗ |
| PJM[34,35] | ✗ | ✗ | ✗ | ✗ | ✗ |
| Florida | ✗ | ✗ | ✗ | ✗ | ✗ |
| Southeastern Regional | ✗ | ✗ | ✗ | ✗ | ✗ |
| South Carolina Regional | ✗ | ✗ | ✗ | ✗ | ✗ |
| MISO (excl. MVP, RIIA)[36] | ✗ | ✗ | ✗ | ✗ | ✗ |
| SPP (ITP)[37,38] | ✗ | ✓ | ✗ | ✓ | ✗ |
| CAISO[39,40] | ✓ | ✗ | ✓ | ✗ | ✓ |
| – TEAM only | ✓ | ✓ | ✓ | ✓ | ✓ |
| WestConnect | ✗ | ✗ | ✗ | ✗ | ✗ |
| NorthernGrid[41] | ✗ | ✗ | ✗ | ✗ | ✗ |

Source: Brattle & Grid Strategies, Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs

# FERC Order 1920 presents a unique opportunity…

**We are encouraged by FERC's effort to better align regional transmission planning with best practices for comprehensively assessing long-term transmission values**

## Key Order 1920 Planning Requirements

*Comprehensive long-term planning*

- 5-year cycle for plan refresh (minimum)
- 20-year evaluation horizon (minimum)
- For at least 7 drivers of transmission needs, asset refurbishments, and generator interconnection

*Scenario-based*

- *At least* three *plausible* and *diverse* scenarios, and *at least* one "stress test" extreme weather sensitivity for each scenario

*At least 7 benefits metrics*

*Broader set of solutions:* GETs, upsizing

*Cost allocations*: default or state sponsored

Better *interregional coordination* and transparency

## Possible Impacts & Opportunities

- RTOs have opportunity to **adopt best practices**
  - New transmission planning processes may require additional expertise and new tools
- Requirements, especially the explicit treatment of uncertainty, could spur **more robust planning frameworks and modeling approaches**
- Minimum standards for scenarios and benefits analysis have potential to **improve consistency of planning and the development of solutions that reduce long-term costs**
- Opportunity to **consolidate siloed existing planning processes** (local and asset refurbishment, regional reliability, economic, public policy, generator interconnection)

**Order 1920 requires selection criteria for potential inclusion of projects in transmission plans but does not mandate the selection of any projects (see Order 1920 Explainer)**

# …but leaves room for concerns and improvements

**Order 1920 creates a new long-term planning process, but does not require modifications to existing processes or the selection of near-term projects**

- There is a risk that existing processes result in transmission solutions (to address near term needs) that continue to preempt more efficient, more comprehensive, long-term solutions

**Effectiveness of 1920 will depend on how ISOs/RTOs implement it**

- Will scenario planning be comprehensive and used broadly to inform transmission plans, near- and long-term?
- Will “least regrets” planning (not required) be used evaluate at the risks of both over- and under-building?
- Will planners develop flexible/expandable solutions that reduce costs and mitigate risks of long-term uncertainties?
- What additional benefits metrics will ISO/RTOs elect to include beyond the mandated seven?
  - **Diversification of weather & load uncertainty; deferred generation investments; access to lower-cost generation**

**Even under the best possible circumstances, we don’t expect Order 1920 processes to identify new transmission for 5 years and expand transmission not for another decade!**

**1920 does not require *inter*regional transmission planning**

- Increased coordination requirement and process to consider project proposals will help.  But unlikely leads to systematic exploration for opportunities to reduce costs and maintain reliability/resilience more cost-effectively through interregional projects

# State Commissions and Energy Agencies Should Be Involved

## SPP Regional State Committee (RSC)

- Comprised of state commissioners from 12 states within SPP
- **RSC maintains Federal Power Act 205 rights** to file proposals with FERC to modify rules and tariffs
- Decision making is shared between SPP Board and RSC; RSC has primary responsibility for resource adequacy and cost allocation

## Organization of PJM State Inc. (OPSI)

- Collaborative body representing 14 regulatory agencies within PJM
- Facilitates communication and coordination among members, **allowing states to collectively address** PJM operations and market rules
- Ensures that **state interests and policies are considered** in regional decision-making processes

## NorthernGrid Enrolled Parties and States Committee (EPSC)

- Participate in development of regional study scope and provide comments on draft regional plans
- Enables **state agencies to participate actively in transmission planning** and **ensures that state-specific concerns and objectives are addressed** within the regional planning framework

Other state organizations participating in regional planning include Organization of MISO States (OMS) and New England States Committee (NESCOE). The California Public Utilities Commission and New York Public Service Commission play an active role in regional planning within their respective single-state RTOs.

# About the Speaker


## Peter Heller

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**Peter Heller, an energy research associate at The Brattle Group, specializes in design and implementation strategies for policy, regulation, and market design related to the energy transition.**

Peter has worked on the modernization of transmission planning processes in the Southeast US and Canada. He works with independent system operators, utilities, trade associations, renewable associations, and regulatory agencies across the US.

While pursuing his graduate degree at MIT, he focused on developing novel methods for measuring energy poverty across the United States and designing statutory and implementation changes to existing federal programs to enhance resource allocation.

Prior to MIT, his work at the Colorado State Senate relied on meaningful stakeholder engagement and technical research to produce policy proposals related to decarbonizing the electric grid and moving the Western US towards an organized wholesale market for electricity.

# Brattle Reports on Transmission Planning

**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
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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
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November 30, 2021

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

**Link: Brattle Grid Strategies**

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OCTOBER 2021

Brattle
GRID STRATEGIES LLC

Summarizes proven approaches to quantifying various benefits

# Brattle Group Publications on Transmission


Pfeifenberger, Ensuring Cost Effective Transmission to Support Affordable State Electricity Policies, Presented at the 2024 NARUC Annual Meeting, November 13, 2024.
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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.
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# About Brattle

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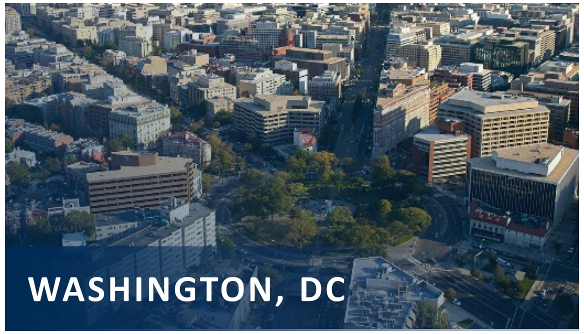


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# Additional Slides

# Proactive, Scenario-Based, Multi-Value Planning Framework

**The benefits (and overall cost savings) of transmission planning increase for 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

# Proactive Planning Can Also Streamline Generation Interconnection

Improving generation interconnection requires addressing all five elements of the GI process (with most current reform discussions focused mostly on Nos. 1 and 5):

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 through regional transmission planning?
3. **GI Study Approach and Criteria:** study assumptions, modeling approaches, and specific criteria differ significantly across regions (e.g., ERIS vs. NRIS study differences, injection levels studied, are market-based redispatch opportunities 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, are not typically considered or accepted
5. **Cost Allocation:** most 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

# Further Improvements to the Generation Interconnection Process

Reducing the scope of upgrades triggered by generation interconnection processes likely would both accelerate and lower the cost of renewable interconnection:

- Attractive: UK "Connect and Manage" (replaced prior "Invest and Connect")
  - Similar to ERCOT; reduced lead times by 5 years; network constraints addressed later (e.g., with congestion management) https://www.gov.uk/guidance/electricity-network-delivery-and-access#connect-and-manage
- ERCOT's generation interconnection process is perhaps most effective in the U.S.
  - Efficient handoff of study roles by ERCOT and Transmission Owners limits restudy needs
  - Projects can be developed and interconnected within 2-3 years; in other regions, the interconnection study process itself may take longer than that
  - Upgrades focused only on local interconnection needs and are recovered through postage stamp
  - Network constraints managed through market dispatch – which imposes high congestion and curtailment risks on interconnecting generators … in part due to ERCOT's insufficiently proactive multi-value grid planning
  - See working-paper.pdf (enelgreenpower.com) [Note: Brattle was not involved]

**Generation interconnection based on "<u>connect and manage</u>" when <u>combined with proactive transmission planning</u> offers more timely and cost-effective solutions**

# What is an "economic need" for transmission?

**Broadly speaking, an economic transmission "need" is a "business case" for a transmission solution that distinguishes itself from others by offering incremental benefits that exceed incremental costs (with or without addressing reliability needs)**

- Requires an analysis of annual (e.g., 8760 hour) benefits over the useful life of the solution
  - In contrast to reliability needs, which only requires a 5-10 year look-ahead (sufficient to permit and construct the solution by the time the reliability need arises)
- Requires analyzing the difference between (a) a clearly specified "change case" (with this solution) and (b) a "base case" (of what would be done in the absence of the particular solution)
  - Base case may include no transmission investment, an alternative transmission solution (e.g., one that narrowly addresses only a reliability need)

**Examples:**

1. Adding grid enhancing technologies (GETs) or building new transmission to reduce (but not necessarily eliminate all) congestion and generation curtailments
2. Upsizing an aging transmission line (e.g., with high-performance conductors, at higher voltage level) that would need to be refurbished now or in the future
3. Pre-building infrastructure (e.g., to generation or industrial development zones) to allow for interconnection of lower-cost or higher-value generation and loads

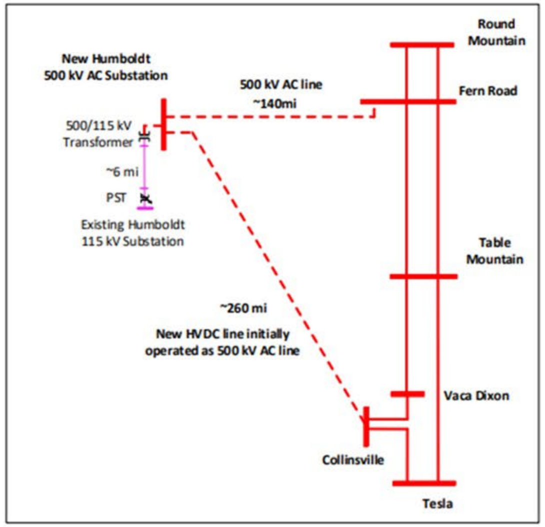
# Reduce costs and mitigate risk through more flexible solutions

**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:

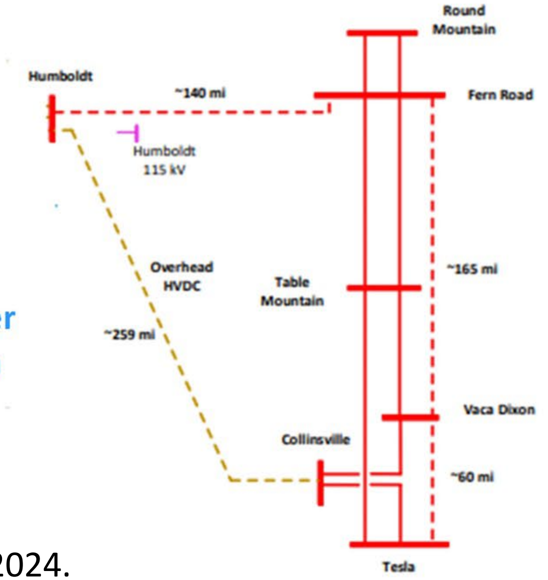
Two new 500kV lines, of which one is "HVDC-ready"

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



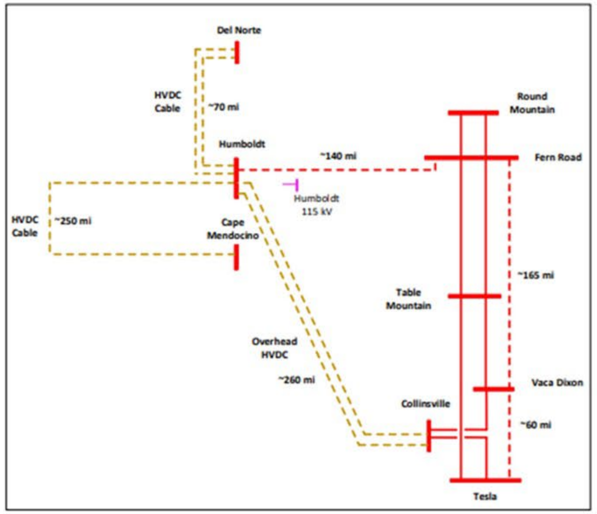

Add DC converter stations to each end of the line

### 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.

# Prioritize Projects Based on Cost and Impact

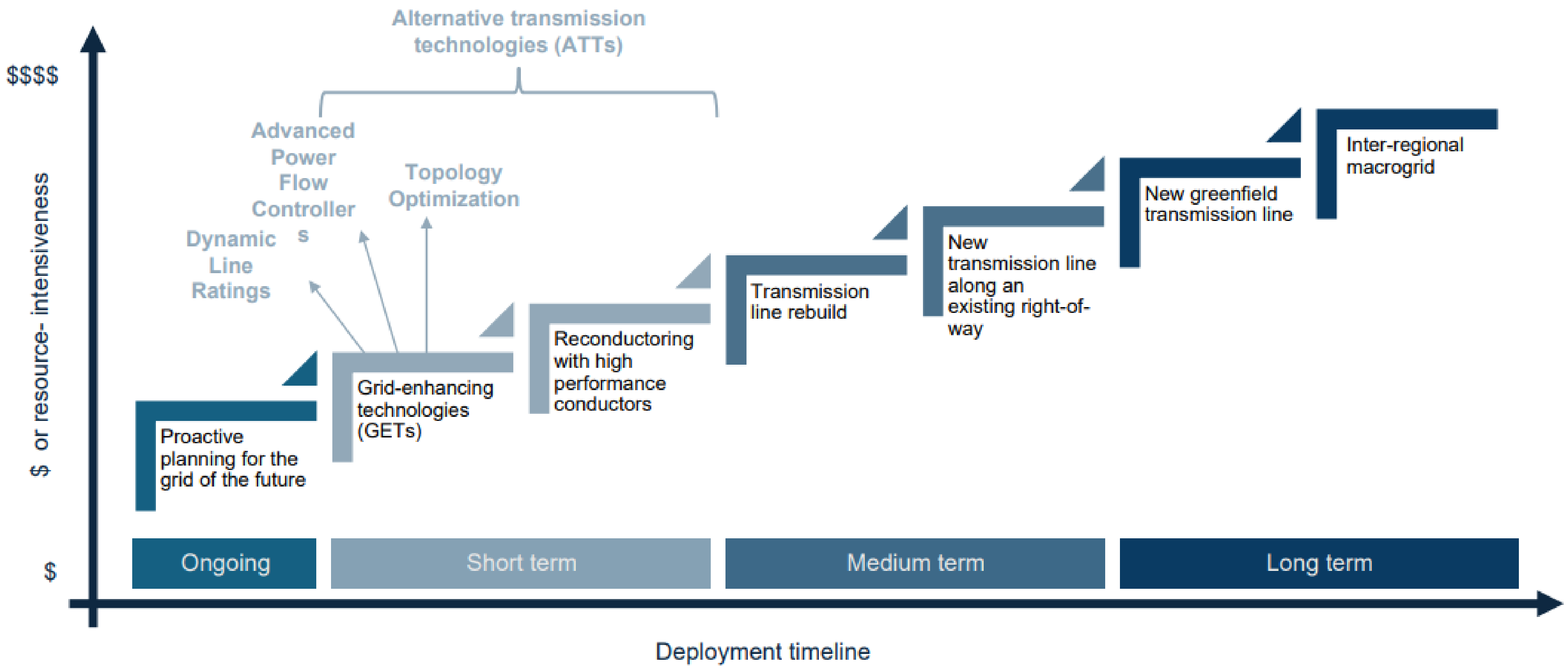
Allows planners the flexibility to prioritize short-term reliability projects; Planners can “stack” solutions by estimated cost and schedule to identify the most beneficial solutions to providing a reliable and efficient grid.

## Optimize existing grid
## → Upsize Existing lines
## → Add new lines

**Examples:**

- Duke’s MVST will consider GETs, advanced conductors, RAS, and battery storage as well as greenfield transmission and ROW optimization
- CAISO use of RAS to create 15 GW of headroom

**Proposed Transmission Solution Loading Order**

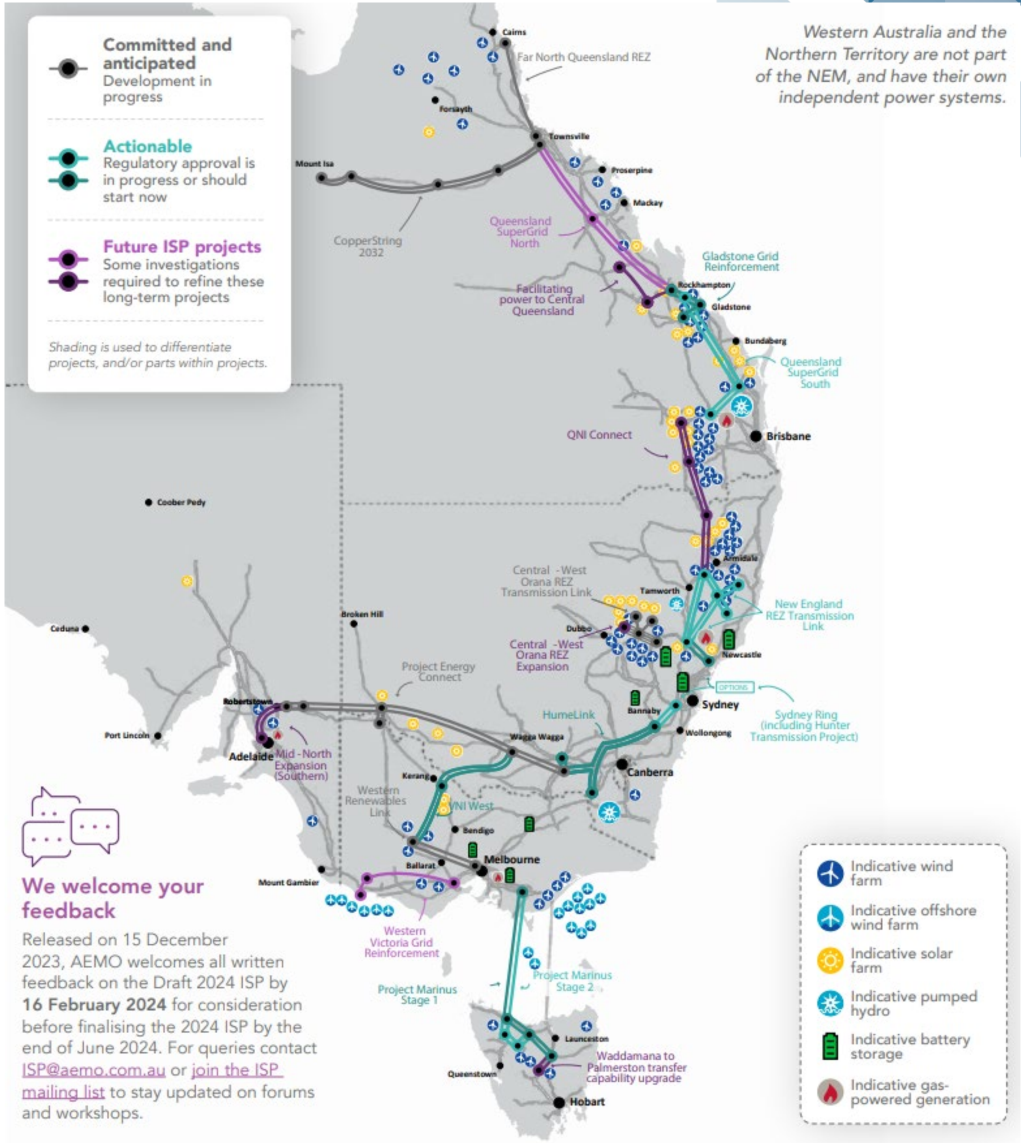



*Source*: Sarah Toth (RMI), Alternative Transmission Technologies in Order 1920 and PJM, September 6, 2024.

# Example: Australian Integrated System Plan (ISP)

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

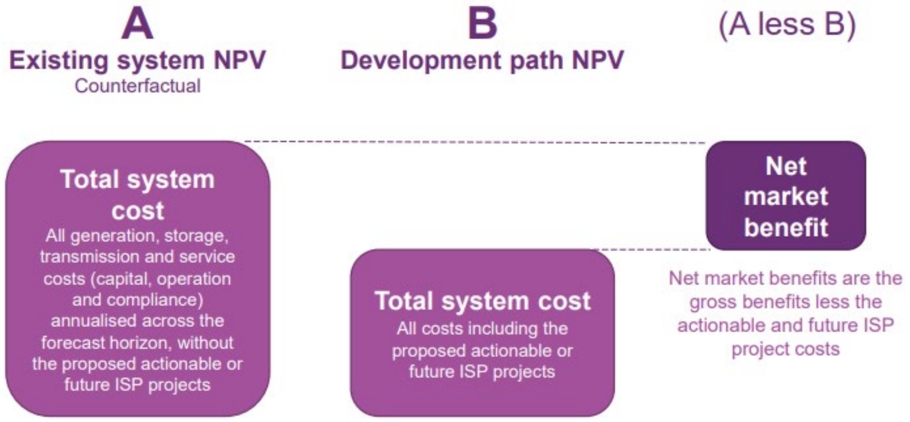
- Clearly-specified methodology (link) produces updated plans every two years with extensive stakeholder consultations (see Draft 2024 ISP)
  - Scenario-based analysis explicitly considers long-term uncertainties and risk mitigation over next 30 years (link)
  - Plans distinguish: (1) actionable projects 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

# Example: AEMO ISP Flexible Benefit Guidelines

AEMO quantifies market benefits set out in the Australian Energy Regulator's (AER) that *must* be considered. AEMO can quantify other classes of benefits that it determines to be relevant, and the AER has agreed to in writing. AEMO ***cannot*** consider: (1) the transfer in surplus between consumers and producers, (2) competition benefits already accounted for in other elements, and (3) any market benefit (except changes in GHG emissions) which cannot be measured as a benefit to generators, DNSPs, TNSPs, and consumers of electricity.




**Benefits Related to Development and Operational Costs of Generation & Storage**

- Changes in fuel consumption arising through different patterns of generation dispatch
- Changes in costs for parties due to timing of new plants, differences in capital costs, and differences in operating and maintenance costs

**Development and Operational Costs of Transmission Assets**

- Differences in the timing of expenditure
- Differences in operating and maintenance costs

**Costs Associated with Demand Reduction**

- Changes in voluntary load curtailments (through DSP)
- Changes in involuntary load shedding costs, valued at the value of customer reliability (VCR)

**Additional Benefit Categories**

- Changes in network losses
- Additional option value
- Changes in ancillary services costs
- Competition benefits
  - Increased economic efficiency from improved competitive behaviors

# Disagreements on Cost-Allocation Creates Barriers Even for Clearly-Beneficial Projects

**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 pay for transmission that benefit other states

**Hardest**: share costs of projects that provide broad regional economic or public-policy benefits:

- Fundamentally different future views of the world
  - Planners and policy makers may disagree on the outlook of natural gas costs but they agree the cost exists; not so with carbon or other policy-related benefits, which create disagreements and are often ignored
- Large regional projects for environmental policies pit states that have them (often 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 direct local jobs

**Almost Impossible**: cost allocation for interregional projects; but mostly hypothetical because no significant interregional projects have been planned in the last decade

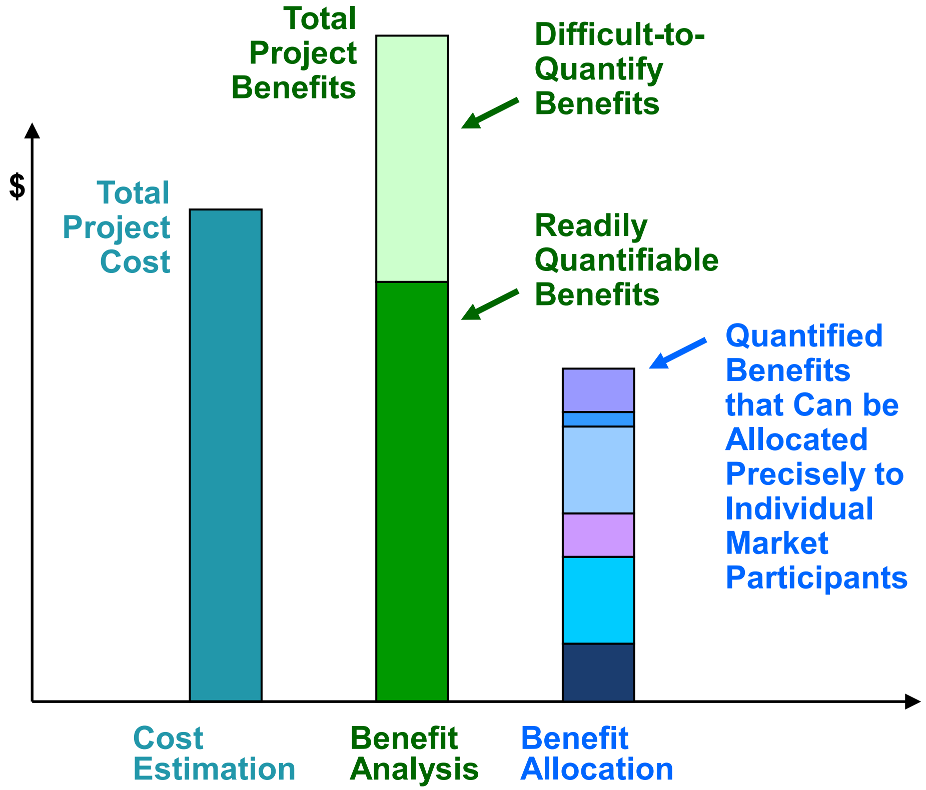
# Basic Cost Allocation and Recovery Mechanisms

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 Stamp:** transmission costs are recovered uniformly from all loads in a defined market area
   - RTO-wide examples: ERCOT, >200kV in CAISO, >115kV in ISO-NE, MVPs in MISO
   - Highway/Byway in SPP: postage stamp for all ITP 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 allocated project costs uniformly 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 associated with generation interconnection or other transmission service requests are fully or partially assigned to requesting entity.
   - Innovative variance: Tehachapi LCRI (up-front shared funding, later charged back to generators)
5) **Merchant Cost Recovery:** the project sponsors recover the cost of the investment outside regulated tariffs (e.g., via negotiated rates with specific customers); largely possible only with HVDC lines where transmission use can be controlled.
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)

# 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 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



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

Order 1000 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