Improving Transmission Planning: Benefits, Risks, and Cost Allocation

PRESENTED TO

Midwestern Governors Association
& Organization of MISO States

PRESENTED BY

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Content

I. Background

- Transmission investment trends
- Main drivers of transmission development
- The need for improved transmission planning
- Promising progress

II. Key Challenges in Transmission Planning

- Wide range of benefits that change over time
- Risk-mitigation and option value of transmission that can avoid high-cost outcomes
- Divisive regional cost recovery
- Ineffective inter-regional planning
- Investments too focused on reliability and local needs

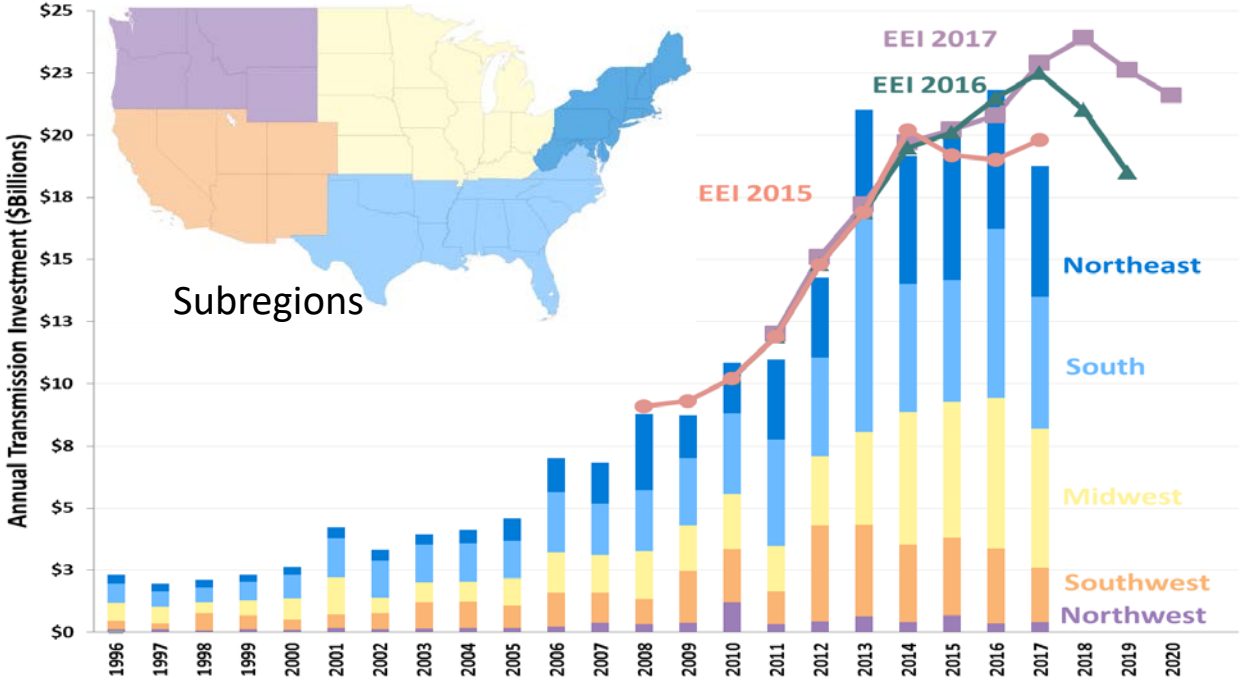
III. Recommendations

Appendix: Cost Allocation and FERC Order 1000

Transmission Investment Have Grown Significantly

U.S. transmission investment is at about $20 billion/year in the past five years after steadily rising since 2000. Mostly to address reliability and local needs.

Historical and Projected U.S. Transmission Investments
(FERC-jurisdictional entities only)



Sources and Notes: The Brattle Group, © 2018. Regional Investment based on FERC Form 1 investment compiled in Ventyx's Velocity Suite, except for ERCOT for years 2010 - 2017, which are based on ERCOT TPIT reports. Based on EIA data available through 2003, FERC-jurisdictional transmission owners estimated to account for 80% of transmission assets in the Eastern interconnection and 60% in WECC. Facilities >300kV estimated to account for 60-80% of shown investments. EEI annual transmission expenditures updated December 2017 shown (2011 -2020) based on prior year's actual investment through 2016 and planned investments thereafter.

Main Drivers of Transmission Needs

- **Serve growing load**
- **Generation interconnections**
- **Local and regional reliability**
- **Need to replace aging infrastructure**

Traditional Drivers

- **Regional economic and public policy needs**
  (Congestion relief; access to low-cost clean energy resources)
- **Capture value of resource and load diversity**
- **Mitigate risks and create options valuable to proactively address future uncertainties**
- **Cost reductions offered by better interregional planning**

New Drivers

Transmission Planning Processes Need Urgent Improvements to be "Future Ready"

Efforts to improve planning processes are urgently needed to fully realize the potential future savings for at least three reasons:

- Transmission projects require at least 5–10 years to plan, develop, and construct; as a result, **planning has to start early to more cost-effectively meet the challenges** of changing market fundamentals and the nation's public policy goals in the 2020–2030 timeframe
- A continued reliance on traditional transmission planning that is primarily focused on **reliability and local needs leads to piecemeal solutions** instead of developing integrated and flexible transmission solutions that enable the system to meet public policy goals more cost effectively in the long run
- U.S. is in the midst of an investment cycle to replace **aging existing transmission** infrastructure, mostly constructed in the 1960s and 70s; this provides unique **opportunities** to create a more modern and robust electricity grid at lower incremental costs and with more **efficient use of existing rights-of-way** for transmission

Substantial recent transmission investments focused too narrowly on reliability and local needs have resulted in missed opportunities

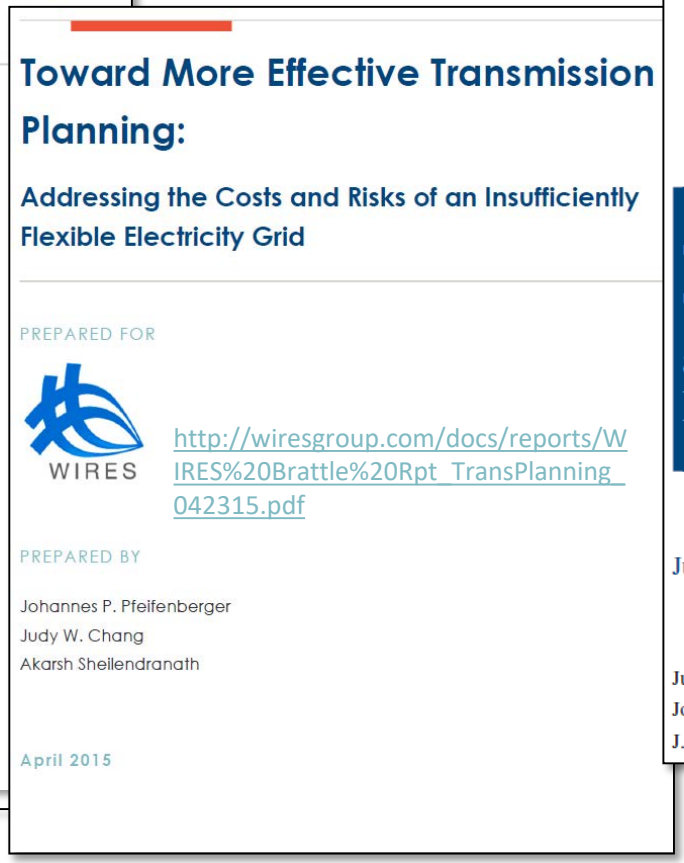
Key Challenges in U.S. Transmission Planning

Current planning processes do not yield the most valuable transmission infrastructure. Key barriers to doing so are:

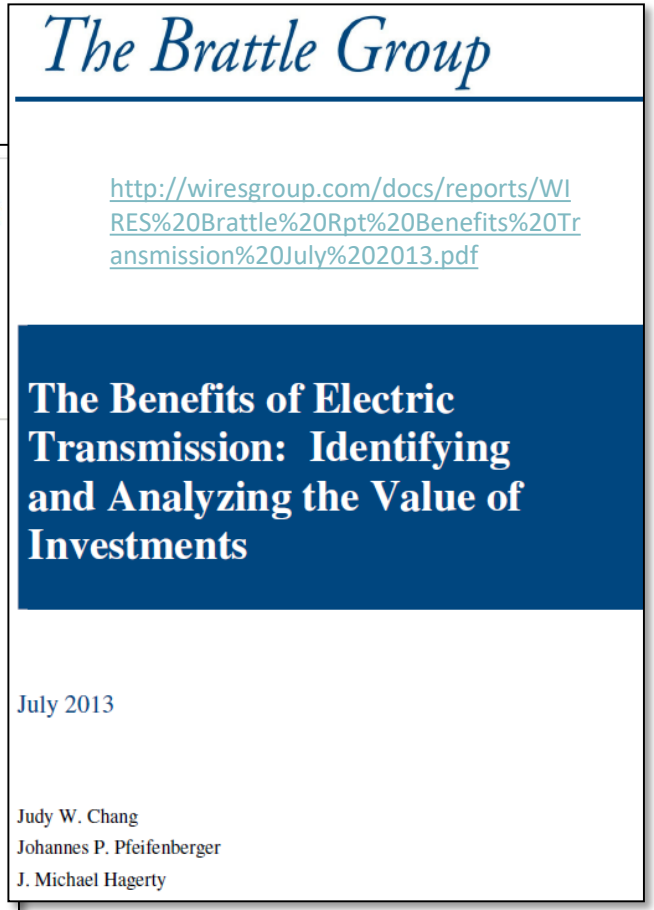
1. Planners and policy makers **do not consider the full range of benefits** that transmission investments can provide, understating the expected value of such projects and how these **values change over time**
2. Planners and policy makers do not account for the **risk-mitigation and option value of transmission** infrastructure that can avoid the potentially high future costs of an insufficiently-robust and insufficiently-flexible transmission grid
3. Shared **regional cost recovery** is overly divisive, particularly when applied on a project-by-project (rather than portfolio- or grid-wide) basis
4. Ineffective **Interregional planning processes** are generally unable to identify valuable transmission investments that would benefit two or more regions
5. Substantial recent investments solely for **reliability and local needs** make it more difficult to justify even beneficial new transmission

Brattle Reports on Transmission Planning and Benefit-Cost Analyses

http://wiresgroup.com/docs/reports/WIRES%20Brattle%20Report_TransmissionPlanning_June2016.pdf



http://wiresgroup.com/docs/reports/WIRES%20Brattle%20Rpt_TransPlanning_042315.pdf



http://wiresgroup.com/docs/reports/WIRES%20Brattle%20Rpt%20Benefits%20Transmission%20July%202013.pdf

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Transmission Planning for Reliability vs. Economic and Public Policy Needs

Well-established transmission planning and approval processes exist for both regional and local reliability needs:

- Clear criteria (reliability standards) and well-honed (formulaic) evaluation processes
  - Based on clear, uncontroversial NERC reliability standards, supplemented by region-specific reliability planning practices (such as for metro-area import analyses)
- Established engineering-based analytical tools (load flow analyses, stability analyses) widely-used both in regional and local planning

For economic and public policy needs, similarly well-established tools and criteria are not yet as established

- Lack of universally-accepted analytical tools and frameworks
- Limited experience in quantifying certain transmission-related economic and public policy benefits
- For approval, "need" not as clearly defined as for reliability

Promising Progress in Planning for Economic and Public-Policy Needs

Supportive policies and transmission-development efforts include:

- **ERCOT (CREZ) and CAISO (Tehachapi)**: successful HVAC transmission overlay to access low-cost wind and solar resources
- **MISO Multi-Value Projects** (MVPs): achieving regional consensus for $6 billion portfolio within MISO-north footprint benefit-cost ratio of 2.6-3.9; but yielded only one set of projects in 2011
- **New York:** Public Policy Planning Process considering wide range of benefits (and using competitive solicitations to find innovative solutions at lower costs)
- **SPP value of transmission**: planning process uses advanced approach to estimating multiple benefits of transmission investments; retrospective analysis shows $3.4 billion in transmission investments provide $12 billion in savings

Other on-going efforts:

- **California's "RETI 2.0":** Second round of Renewable Energy Transmission Initiative to identify zones for transmission to connect high levels of renewable energy resources
- **NREL-SPP Interconnection Seams study** on expanding HVDC interties between Western and Eastern U.S. grids

Challenge: Quantifying Economic and Public Policy Benefits

The wide-spread nature of transmission benefits creates challenges in estimating benefits and how they accrue to different users

▪ **Broad in scope, providing many different types of benefits**	• Increased reliability and operational flexibility • Reduced congestion, dispatch costs, and losses • Lower capacity needs and generation costs • Increased competition and market liquidity • Renewables integration and environmental benefits • Insurance and risk mitigation benefits • Fuel diversification and fuel market benefits • Economic development from G&T investments
▪ **Wide-spread geographically**	• Multiple transmissions service areas • **Multiple states** or regions
▪ **Diverse in their effects on market participants**	• **Customers**, **generators**, **transmission owners** in regulated and/or deregulated markets • Individual market participants may capture one set of benefits but not others
▪ **Occur and change over long periods of time**	• Several decades • Changing with system conditions and future generation and transmission additions • Individual market participants may capture different types of benefits at different times

Regional Planners Are Getting Better at Identifying Broad Range of Benefits

SPP ITP analysis:

Quantified

1. production cost savings*
2. reduced transmission losses*
3. wind revenue impacts
4. natural gas market benefits
5. reliability benefits
6. economic stimulus benefits of transmission and wind generation construction

Not quantified

7. enabling future markets
8. storm hardening
9. improving operating practices/maintenance schedules
10. lowering reliability margins
11. improving dynamic performance and grid stability during extreme events
12. societal economic benefits

(SPP Priority Projects Phase II Final Report, SPP Board Approved April 27, 2010; see also 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)

* Fairly consistent across RTOs

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

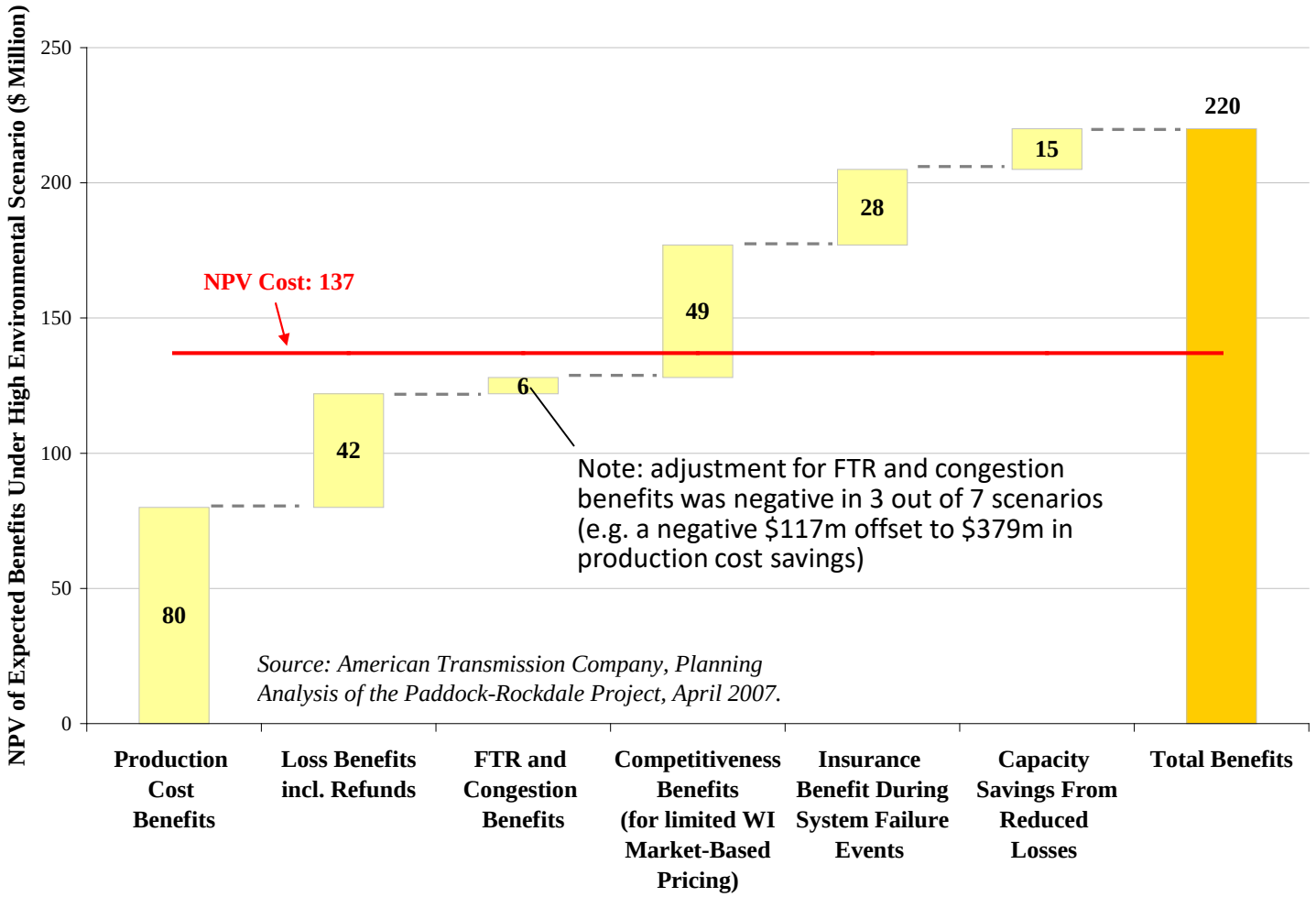
(CPUC Decision 07-01-040, January 25, 2007 (Opinion Granting a Certificate of Public Convenience and Necessity)

Brattle Study Documenting Best Practices for Quantifying Transmission Benefits

Benefit Category	**Transmission Benefit** (see 2013 WIRES paper)
Traditional Production Cost Savings	Production cost savings as currently estimated in most planning processes
1. Additional Production Cost Savings	a. Impact of generation outages and A/S unit designations
	b. Reduced transmission energy losses
	c. Reduced congestion due to transmission outages
	d. Mitigation of extreme events and system contingencies
	e. Mitigation of weather and load uncertainty
	f. Reduced cost due to imperfect foresight of real-time system conditions
	g. Reduced cost of cycling power plants
	h. Reduced amounts and costs of operating reserves and other ancillary services
	i. Mitigation of reliability-must-run (RMR) conditions
	j. More realistic "Day 1" market representation
2. Reliability and Resource Adequacy Benefits	a. Avoided/deferred reliability projects
	b. Reduced loss of load probability or c. reduced planning reserve margin
3. Generation Capacity Cost Savings	a. Capacity cost benefits from reduced peak energy losses
	b. Deferred generation capacity investments
	d. Access to lower-cost generation resources
4. Market Benefits	a. Increased competition
	b. Increased market liquidity
5. Environmental Benefits	a. Reduced emissions of air pollutants
	b. Improved utilization of transmission corridors
6. Public Policy Benefits	Reduced cost of meeting public policy goals
7. Employment and Economic Stimulus Benefits	Increased employment and economic activity; Increased tax revenues
8. Other Project-Specific Benefits	Examples: storm hardening, fuel diversity, flexibility, reducing the cost of future transmission needs, wheeling revenues, HVDC operational benefits

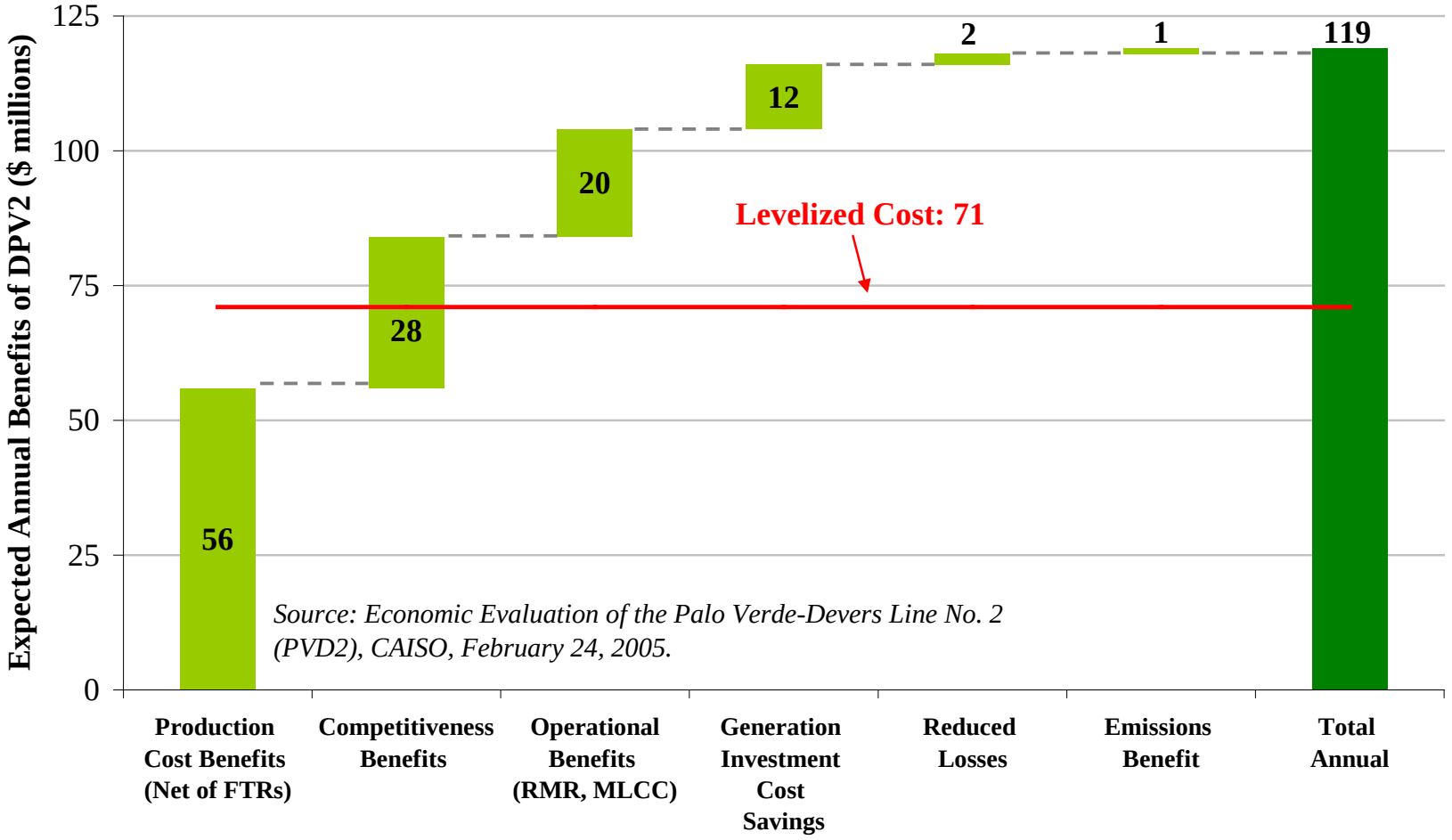
Example: ATC Transmission Project Benefits vs. Costs in Wisconsin

ATC's Paddock-Rockdale study: Significant total benefits



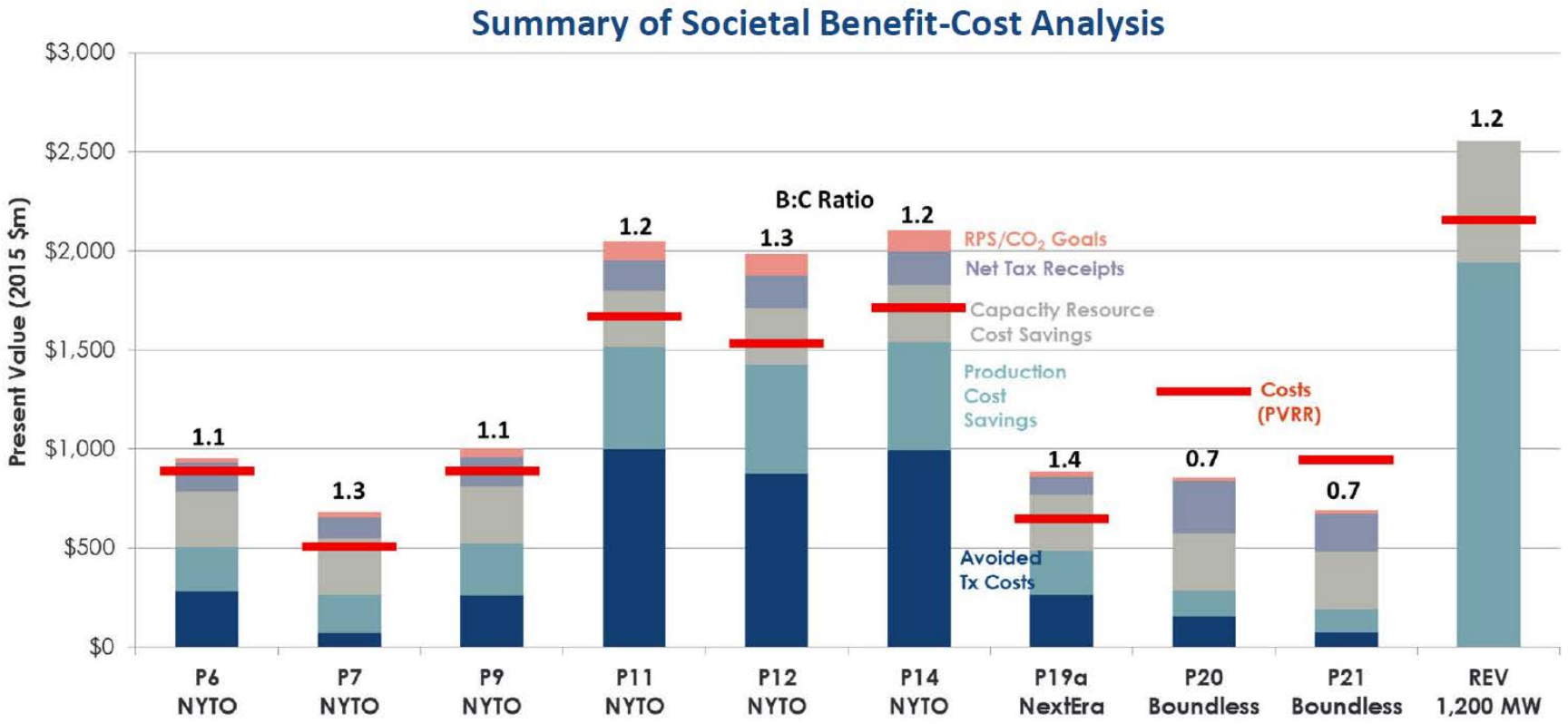
Example: CAISO Transmission Project Benefits vs. Costs

Total electricity market benefits of CAISO's DPV2 project exceeded project costs by more than 50%, but only if multiple benefits are quantified



Example: New York's "Public Policy" Transmission Planning Process

New York recently modified its "public policy" transmission planning process by mandating that the full set of benefits (as listed in Brattle report) be considered. Resulted in approval and competitive solicitation of two major upgrades to the New York transmission infrastructure



Source: Comparative Evaluation of Alternating Current Transmission Upgrade Alternatives, NYPSC Trial Staff Final Report, Cases 12-T-0502 , 13-E-0488, 13-T-0454, 13-T-0455, 13-T-0456, 13-M-0457, and 13-T-0461, September 22, 2015.

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The "Insurance Value" of a More Robust and More Flexible Grid

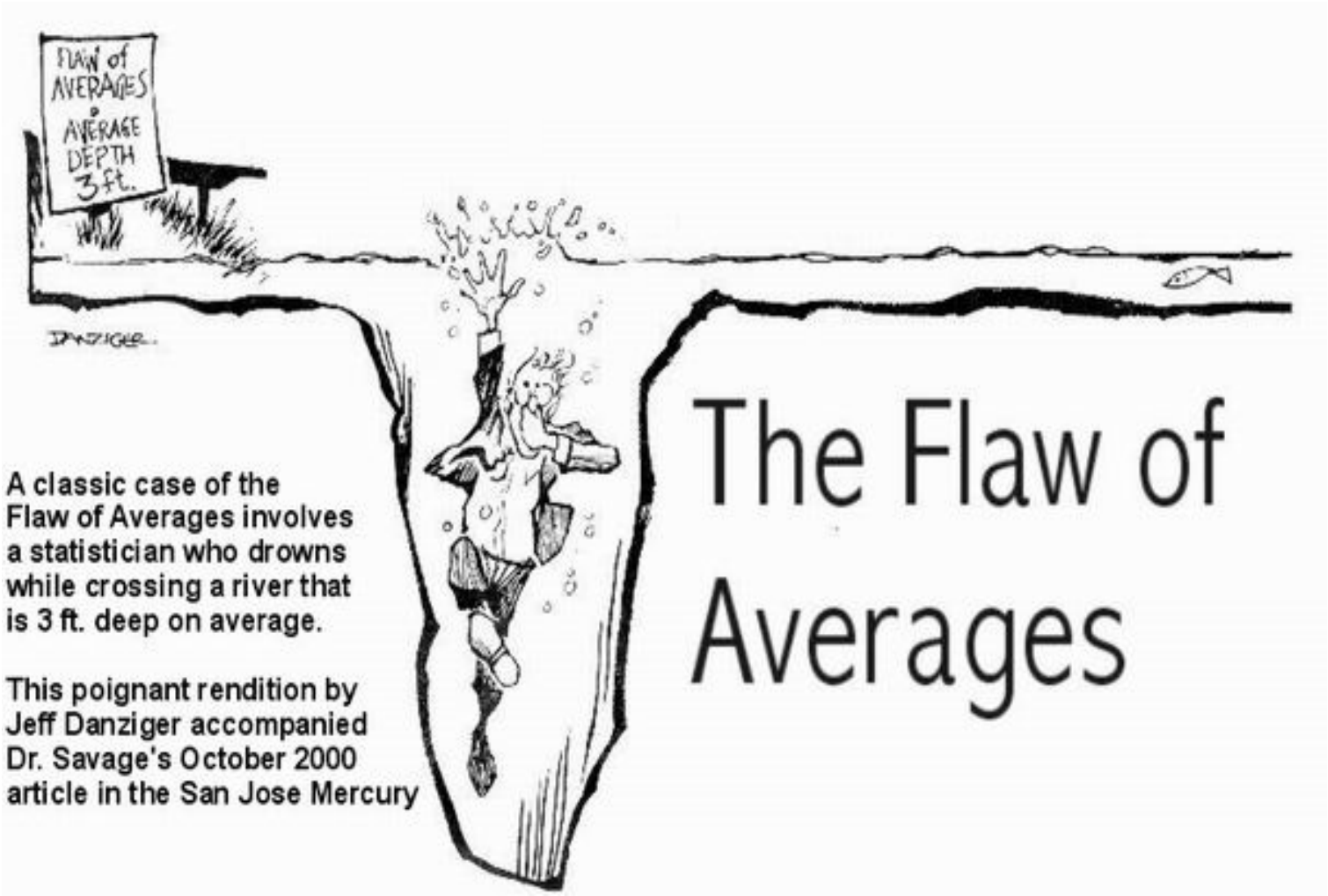
What do auto insurance and new transmission have in common?

Answer:
Both are expensive to get,
but it can be much more expensive to not have them when they are needed

Example:
CAISO's "Path 15" constraint was a major factor in CA power crisis.
The upgrade would have paid for itself in just one year!

Source: Herman K. Trabish, "3 serious failures in transmission planning and how to fix them: Planners need to think of the cost of not building new lines, a new study urges," Utility Dive, May 4, 2015.
http://www.utilitydive.com/news/3-serious-failures-in-transmission-planning-and-how-to-fix-them/391504/

Planning for "Average" Conditions Misses the Risk and High Cost of Extreme Outcomes



- For details and examples on why we underestimate risks at the face of uncertainty see:
  http://web.stanford.edu/~savage/flaw/Article.htm
  http://flawofaverages.com/

Inadequate Transmission Creates High Risks of Costly Outcomes

Most transmission planning efforts do not adequately account for short- and long-term risks and uncertainties affecting power markets

- **Short-Term Risks:** transmission planning generally evaluates only "normal" system conditions
  - Planning process typically ignores the high cost of **short-term challenges and extreme market conditions** triggered by high-impact-low-probability ("HILP") events due to weather, outages, fuel supply disruption, or unexpected load changes associated with economic booms/busts
- **Long-Term Risks:** Planning does not adequately consider the full range of long-term scenarios
  - Does not capture the extent to which a less robust and flexible transmission infrastructure will help reduce the **risk of high-costs incurred under different (long-term) future market fundamentals**

A more flexible and robust grid provides "insurance value" by reducing the risk of high-cost (short- and long-term) outcomes due to inadequate transmission

- Costs of inadequate infrastructure (typically are not quantified) can be much greater than the costs of the transmission investment

Examples of Short-Term and Long-Term Risks that Create "Insurance Value"

Short-Term Risks & Uncertainties

High-Impact Low-Probability Events:

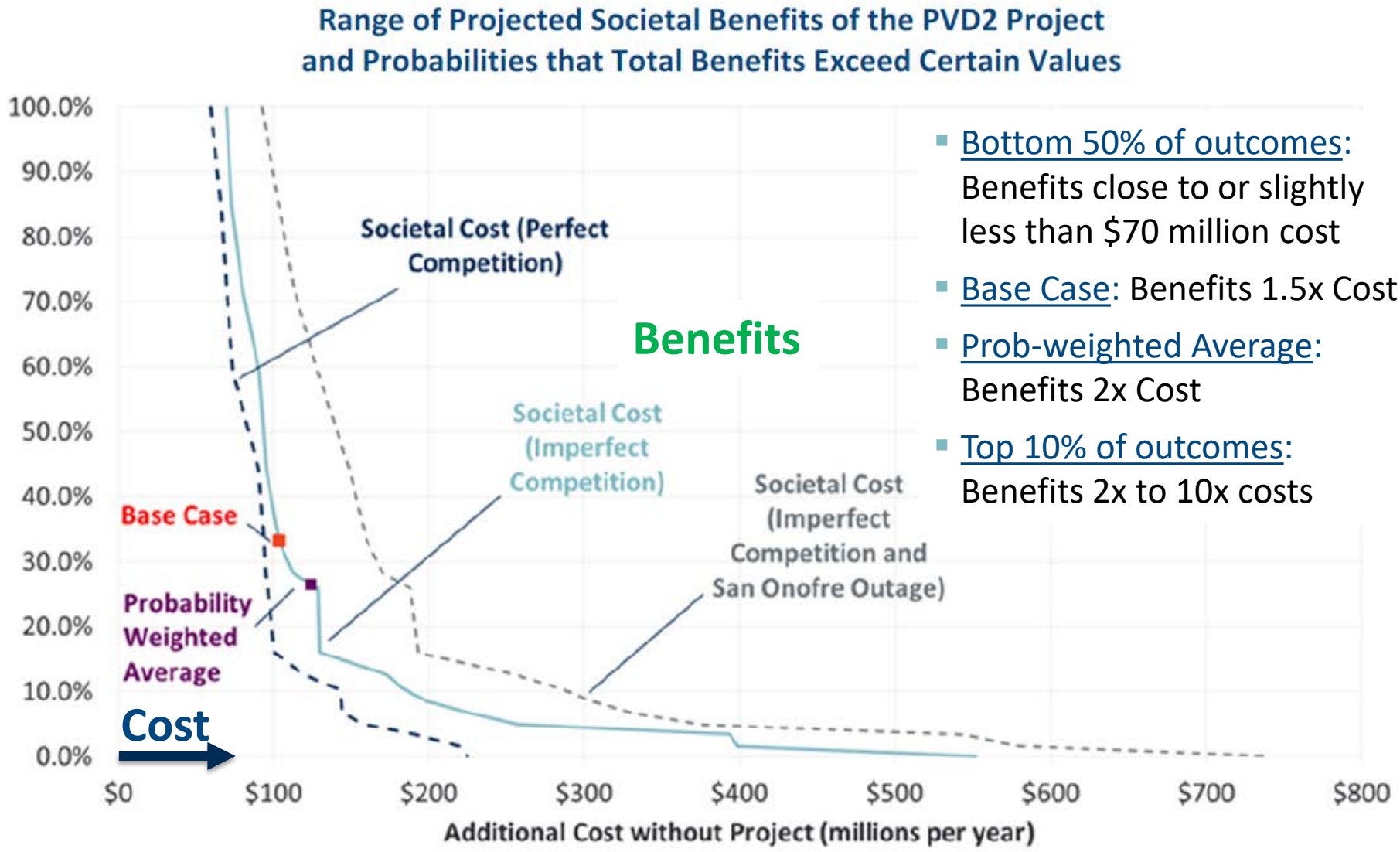
- Extreme weather affecting loads and resources (heat waves, cold snaps, droughts)
- Major transmission outages (e.g., due to storms or bush fires)
- Major generation outages
- Price spikes in fuel cost
- Unexpectedly-high renewable generation variances (e.g., low wind year)

Long-Term Risks & Uncertainties

Different Future Outcomes:

- Rapid region-wide load growth (e.g., due to electrification)
- Rapid local load growth (e.g., due to urban migration, local mining expansion)
- High environmental constraints (e.g., stringent climate policies)
- New technologies and technology cost reductions
- Substantial long-term shifts in fuel costs
- Various other public policies

CAISO Example: Quantifying the Risk of High Costs Without the Transmission Project



- Bottom 50% of outcomes: Benefits close to or slightly less than $70 million cost
- Base Case: Benefits 1.5x Cost
- Prob-weighted Average: Benefits 2x Cost
- Top 10% of outcomes: Benefits 2x to 10x costs

ATC Example: Long-term Insurance Value

In this planning study, ATC evaluated the long-term value of a wide range of benefits that the project would provide under **seven plausible futures**:

- The 40-year PV of customer benefits fell short of the $136 million PV of the project's annual cost in the "Slow Growth" future
- The 40-year PV of potential benefits substantially exceeded the PV of costs in six other futures scenarios analyzed by:
  - Approx. $100 million in the "High Environmental" future
  - Approx. $400 million in the "Robust Economy" and "High Growth" futures
  - Reaching up to approx. $700 million under the "Fuel Supply Disruption" and "High Plant Retirements" futures

Thus, not investing saves customers money in one future, but would leave customers $400-700 million worse off in four out of seven plausible futures

- Shows that understanding the impact of projects across a range of plausible futures is necessary for assessing the long-term risk mitigation benefit of a more robust, more flexible transmission grid

Source: http://wiresgroup.com/docs/reports/WIRES%20Brattle%20Report_TransmissionPlanning_June2016.pdf, page 18.

Consideration for Risk Mitigation Through Transmission Investments

Additional considerations regarding the risk mitigation and insurance value of transmission infrastructure

- Given that it can take a decade to develop new transmission, delaying investment can easily **limit future options** and result in a **higher-cost, higher-risk** overall outcomes
  - "Wait and see" approaches limit options, so can be costly in the long term
  - The industry needs to plan for both short- and long-term uncertainties more proactively – and develop "anticipatory planning" processes
- **"Least regrets" planning** too often only focuses on identifying those projects that are beneficial under most circumstances
  - Does not consider the many potentially "regrettable circumstances" that could result in very high-cost outcomes
  - Focuses too much on the cost of insurance without considering the cost of not having insurance when it is needed
- **Probabilistic weighting assumes risk neutrality** and does not distinguish between investment options with very different risk distributions

Example: Better "Least-Regrets" Planning

"Least Regrets" analysis can help planners avoid decisions that reduce flexibility to respond to changing future market conditions

- The "least-regrets" option may not be "least cost" in any future (nor have the lowest cost on a probability-weighted average basis)

Total Cost to Customers of 3 Options in 4 Futures (Option 1 can be not building)

	Future 1	Future 2	Future 3	Future 4	Average
Option 1	$100m	$120m	$125m	$144m	**$122m**
Option 2	$105m	$121m	$128m	$134m	**$122m**
Option 3	$110m	$121m	$128m	$130m	**$122m**

Difference Between Lowest-Cost Option and Maximum Regret of Each Option

	Future 1	Future 2	Future 3	Future 4	Max Regret
Option 1	--	--	--	$14m	$14m
Option 2	$5m	$1m	$3m	$4m	$5m
Option 3	$10m	$1m	$3m	--	$10m

https://nicholasinstitute.duke.edu/sites/default/files/publications/ni_wp_13-05.pdf

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

Easiest: develop "needed" regional and local transmission projects that do not involve cost sharing (now majority in many regions)

Harder: regionally share costs of transmission projects "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 transmission 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 are often ignored
- Large regional and inter-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

Benefit-Cost Analysis of Projects Should be Separate from Cost-Allocation Analysis

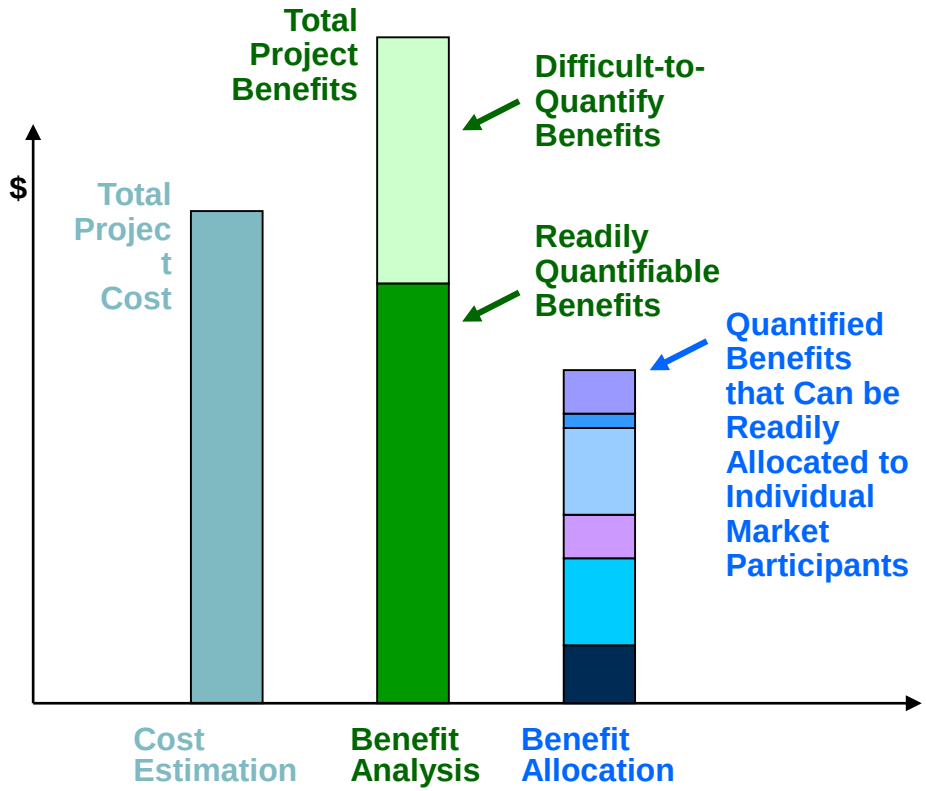
Benefits of transmission projects need to be analyzed prior to and separate from analyses to determine how costs should be allocated

Recommend 2-step approach:

1. Determine whether projects are beneficial overall
2. Evaluate how the cost of a portfolio of beneficial projects should be allocated based on distribution of benefits

Because:

- Benefits that can be allocated readily or accurately tend to be only a subset of readily-quantifiable benefits
- Relying on allocated benefits to assess individual projects would result in rejection of many desirable projects
- Individual projects create synergies with other projects. Benefits of a portfolio of projects will tend to be more stable and distributed more uniformly



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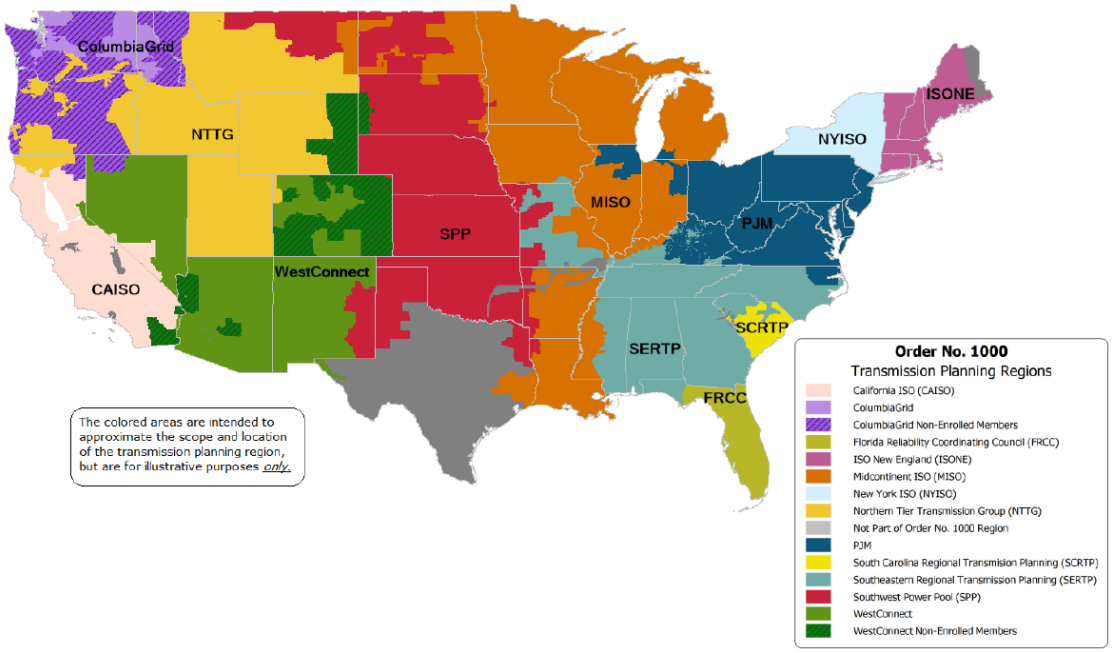
Interregional Transmission: Numerous Studies Show Potential for Significant Cost Savings

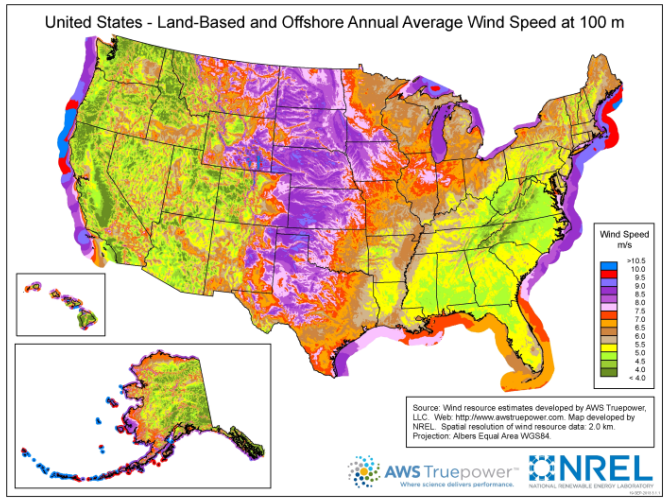
- **Eastern Interconnection States Planning Council (2013):** Multi-stage anticipatory planning can reduce total generation costs by $150 billion by increasing interregional transmission investments by $60 billion, with overall system-wide savings of $90 billion
- **Eastern Interconnection Planning Collaborative (2015):** Combination of interregional environmental policy compliance and interregional transmission may offer net savings of up to $100 billion in a future with stringent environmental policy goals
- **Brattle (2016):** Providing access to areas with lower-cost renewable generation that will meet RPS and clean energy needs through 2030 has the potential to reduce the combined generation and transmission investment needs by $30–70 billion
- **MacDonald, Clack *et al.* (2016):** Building more robust transmission grid would enable reducing U.S. carbon emissions from electricity sector by 80%, saving consumers $47 billion/year at benefit-to-cost ratio of almost 3-to-1.
- **North American Supergrid (2017):** National HVDC overlay (mostly underground) would provide net benefits through access to cheap renewables (but we have concerns about possibly under-stated costs)
- **SPP/NREL Interconnection Seams Study (2018):** Savings 2-3 times larger than costs in a carbon-policy future (and better break-even without carbon policies)
- A number of interregional planning studies of the **European grid** yield very similar results

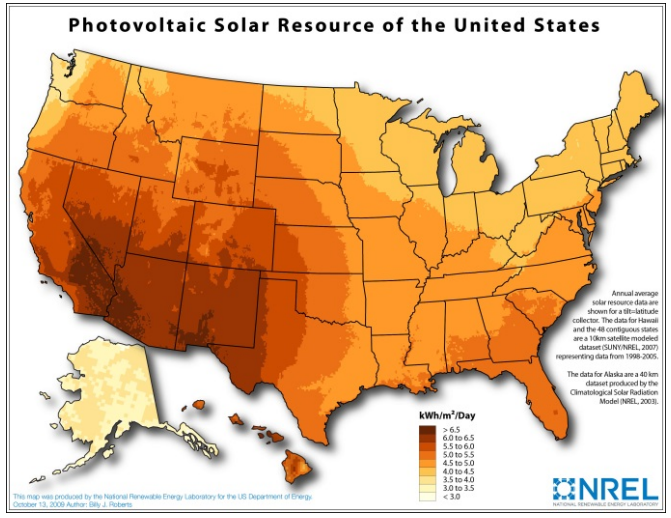
Challenge: Absence of Effective Inter-Regional Planning

The U.S. is split into 15 transmission planning regions

- Even within these 15 regions, there are many layers of less aggregated transmission planning efforts
- Planning regions (1) do not capture interregional load diversity and (2) do not align with low-cost renewables
- Many interregional transmission studies, but mostly conceptual with few decision-making implications







Source: FERC, Transmission Planning Regions

Challenges Faced in Developing Interregional Transmission Infrastructure

Large inter-regional transmission projects are extremely difficult to plan, as values are poorly understood and no mechanism for cost recovery exists

- Inter-regional planning is a voluntary and ad-hoc process
- Reliability needs (the main driver of regional planning) rarely apply to interregional projects and economic benefits of interregional transmission are not well understood, rarely quantified, or inconsistently analyzed by regions
- Cost recovery (cost allocation) high contentious and not specified for interregional projects

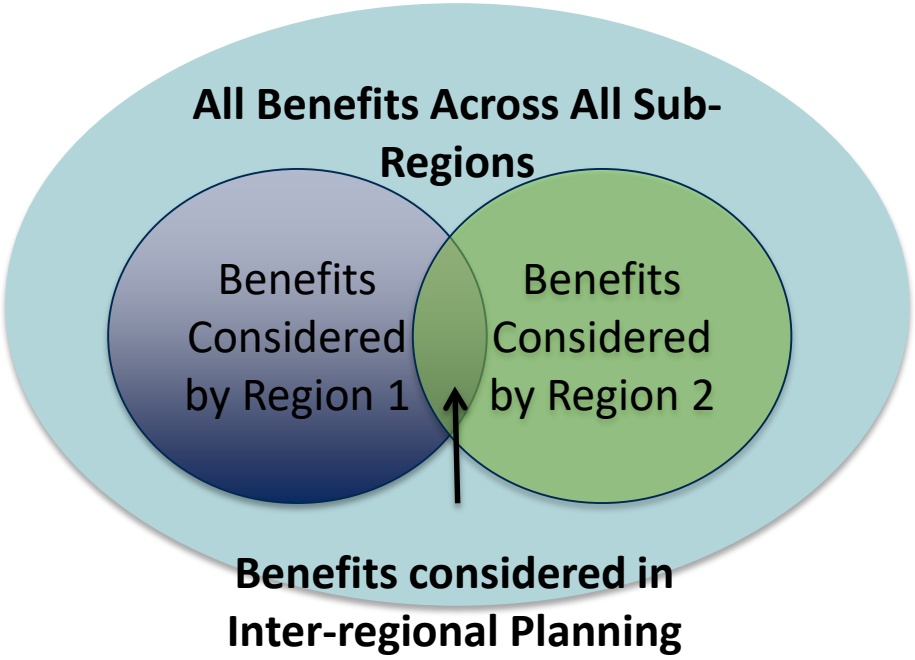
Unlike transmission planning for vertically-integrated utilities and some regional planning efforts, inter-regional transmission planning is not coordinated with long-term generation planning

- Long-term transmission and generation planning tend to be disconnected, both in process and in analytical approach
- Many inter-regional renewable integration studies focus on renewable generation investments, but tend to use generic public-policy and transmission assumptions with limited credibility, not reflecting regional and state-level differences

Ineffective Interregional Planning: Understated Transmission Benefits

Divergent criteria result in "least-common-denominator" planning approaches create significant barriers for transmission between regions

- Experience in the parts of the U.S. shows that very few (if any) inter-regional projects will be found to be cost effective under this approach
- Multiple threshold tests create additional inter-regional hurdles

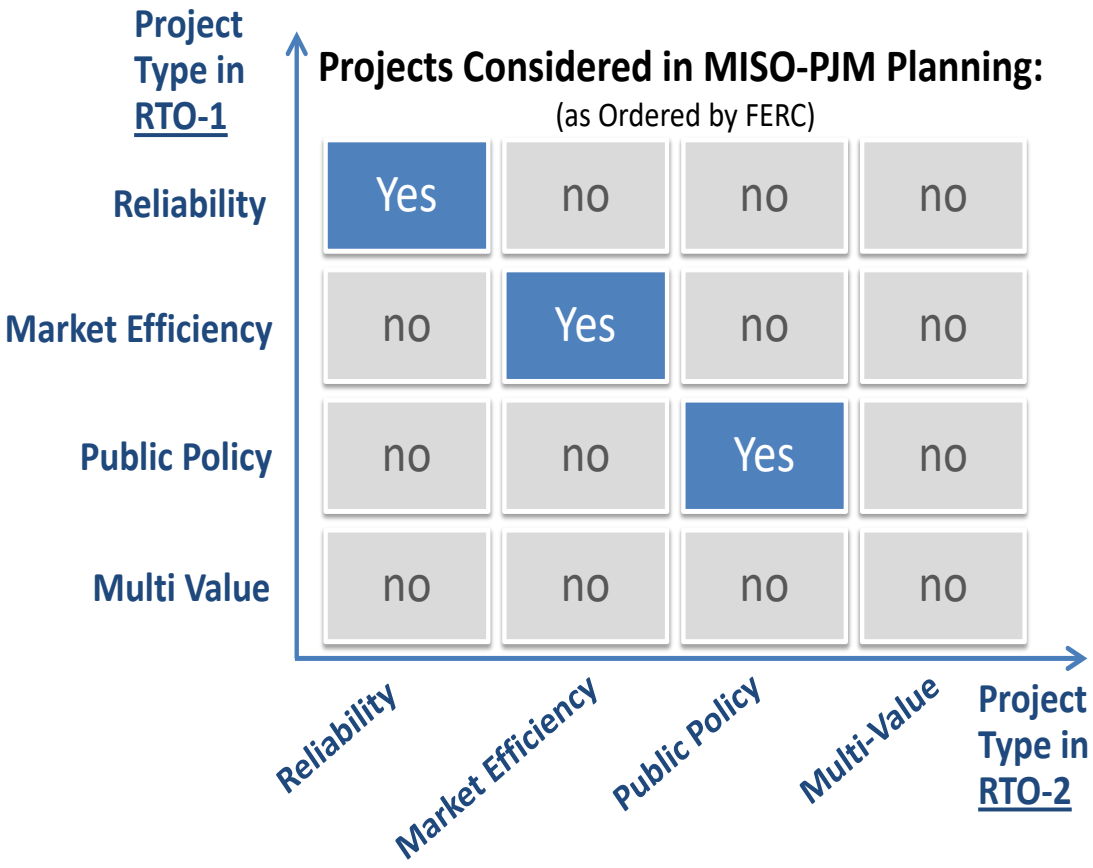


Planning processes currently use "least common denominator" approach and do not evaluate interregional projects based on their combined benefits across all regions

Recent proposal to only utilize each region's benefits framework will be helpful, but insufficient

Ineffective Interregional Planning: "Compartmentalized" Benefits

Experience from the Eastern regions shows that most planning processes compartmentalize needs into "reliability," "market efficiency," "public policy," and "multi-value" projects – which in turn fails to identify valuable projects.



- Compartmentalizing creates additional barriers at the inter-regional level by limiting projects to be of the same type in neighboring regions (see MISO-PJM example).
- It eliminates many projects from consideration simply because they don't fit into the existing planning "buckets."

I. Background

- Transmission investment trends
- Main drivers of transmission development
- The need for improved transmission planning
- Promising progress

II. Key Challenges in Transmission Planning

- Wide range of benefits that change over time
- Risk-mitigation and option value of transmission that can avoid high-cost outcomes
- Divisive regional cost recovery
- Ineffective inter-regional planning
- **Investments too focused on reliability and local needs**

III. Recommendations

Too Much Focus on Addressing Reliability and Local Needs at Lowest Cost

Transmission planning often is too focused on addressing reliability and local needs at lowest costs; risks building the "wrong" projects

- For example: what is the lowest-cost option to address a specific reliability need based on current forecasts? What is the lowest cost to replace an aging facility?

The least-cost transmission solution to address specific need does not always offer highest-value, lowest total costs to customers:

- Up-sizing projects may capture additional economic benefits (market efficiencies, reduced transmission losses, reduced costs of future projects such as renewables overlay, reliability upgrades, plant interconnection, etc.)
- More expensive transmission overlay may allow integration of lower-cost renewable resources and reduce balancing cost, losses, etc.
- Modest additional investments may create option value of increased flexibility to respond to changing market and system conditions (e.g., single circuits on double circuit towers)
- Least-cost replacement of aging existing facilities may be lost opportunities to better utilize scarce rights of way
- More robust and flexible solutions that mitigate short- and long-term risks

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Recommendations

20th Century approaches to transmission planning are ill-suited to address 21st Century challenges. We need:

- More fully consider broad range of reliability, economic, and public-policy benefits, including experience gained though:
  - SPP value of transmission and benefits metrics for regional cost allocation review
  - NYISO consideration of broad set of benefits for public policy projects
  - MISO MVPs and occasional CAISO economic and public policy projects
- Improve anticipatory planning for "known and unknown" uncertainties to create options, increase flexibility and mitigate risk of high-cost outcomes
- Reduce divisiveness of regional cost sharing by (1) recognizing broad range of benefits and (2) focusing on larger portfolios of transmission projects
- Recognize benefits of expanded interregional transmission infrastructure and better integrate interregional projects into regional planning and cost allocation processes
- Focus less narrowly on addressing near-term reliability and local needs with least-cost transmission solutions, but more on infrastructure that provides flexibility and higher long-term value at lower total cost

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Note:

The views expressed in this presentation are strictly those of the presenter and do not necessarily state or reflect the views of *The Brattle Group, Inc*.

Johannes (Hannes) Pfeifenberger is an economist with a background in power engineering and over 20 years of experience in the areas of public utility economics and finance. He has published widely, assisted clients and stakeholder groups in the formulation of business and regulatory strategy, and submitted expert testimony to the U.S. Congress, courts, state and federal regulatory agencies, and in arbitration proceedings.

Hannes has extensive experience in the economic analyses of wholesale power markets and transmission systems. His recent experience includes the analysis of transmission benefits, reviews of RTO capacity market and resource adequacy designs, testimony in contract disputes, cost allocation, and rate design. He has performed market assessments, market design reviews, asset valuations, and cost-benefit studies for investor-owned utilities, independent system operators, transmission companies, regulatory agencies, public power companies, and generators across North America.

Hannes received an M.A. in Economics and Finance from Brandeis University and an M.S. in Power Engineering and Energy Economics from the University of Technology in Vienna, Austria.

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About The Brattle Group

The Brattle Group provides consulting and expert testimony in economics, finance, and regulation to corporations, law firms, and governmental agencies worldwide.

We combine in-depth industry experience and rigorous analyses to help clients answer complex economic and financial questions in litigation and regulation, develop strategies for changing markets, and make critical business decisions.

Our services to the electric power industry include:

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- Cost of Capital
- Demand Forecasting Methodology
- Demand Response and Energy Efficiency
- Electricity Market Modeling
- Energy Asset Valuation
- Energy Contract Litigation
- Environmental Compliance
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Appendix
Cost Allocation Approaches and Order 1000 Requirements

Basic Cost Allocation and Recovery Mechanisms

Five widely-used methodologies to allocate and recover costs from transmission customers:

1) **License plate (LP):** each utility recovers the costs of its own transmission investments (usually located within its footprint).
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 LP tariffs from own customers.
3) **Postage stamp (PS):** transmission costs are recovered uniformly from all loads in a defined market area (e.g., RTO-wide in ERCOT and CAISO).

   In some cases (e.g., SPP, MISO, PJM) cost of certain project types are allocated uniformly to TOs, who then recover these allocated costs in their LP tariffs.
4) **Direct assignment:** transmission costs associated with generation interconnection or other transmission service requests are fully or partially assigned to requesting entity.
5) **Merchant cost recovery (M):** the project sponsors recover the cost of the investment outside regulated tariffs (e.g., via negotiated rates with specific customers); largely applies to DC lines where transmission use can be controlled.

Examples of Tariff-Based Cost Allocation Mechanisms

Examples of tariff-based broad cost-sharing approaches:

- CAISO:
  - Postage stamp for all network upgrades ≥200kV
  - *Tehachapi LCRI* approach: up-front postage stamp funding of project, later charged back to interconnecting generators, thereby solving chicken-egg problem
- ERCOT:
  - Postage stamp for all *CREZ* transmission being built to integrate 18,000 MW of new wind; build-out awarded to a diverse set of 7 transmission companies
- SPP:
  - Priority and ITP Projects under FERC-approved postage stamp ("highway/byway") recovery
- MISO:
  - "Multi Value Project" postage stamp recovery
- WECC:
  - Co-ownership of lines (within and out of footprint) based on contractual allocations of point-to-point capability to resolve cost allocation issue
  - BPA open season approach for >5,500 MW renewable generator interconnections
  - Northern Tier's multi-state cost allocation committee

Examples of Non-Tariff-Based Cost Recovery Mechanisms

Cost recovery examples that bypass the RTO's OATTs:

- Long-term merchant PPAs:
  - HVDC cable from PJM to LIPA financed with long-term PPA for capacity
  - Example: Neptune (independent transmission company)
- Merchant anchor tenant with open season:
  - Anchor tenant signs up for large portion of capacity, open season for rest
  - Standard model used for new pipelines
  - Example: some proposed HVDC lines
- Regulated PPA with ISO operational control:
  - Utilities own transmission, sold bilaterally to generator at state regulated rates, buy bundled long-term PPA
  - Project under RTO operational control but bypasses RTO cost recovery
  - Example: NU-NSTAR-HQ Northern Pass HVDC link
- Participant funding with cost-based rates for transmission service:
  - Stand-alone transmission company to construct and own AC collector system and charge cost-based rates for long-term transmission, balancing, and firming service
  - Mostly used for HVDC lines because (by being "controllable" like pipelines) they allow owners/customers to capture more of the benefits than with HVAC projects

FERC Order 1000: Cost Allocation Principles

Each regional planning process must include cost-allocation methods. These cost allocation methods must satisfy six principles:

1. Costs allocated must be "at least roughly commensurate" with estimated benefits
2. Those that receive no benefit must not be allocated costs involuntarily
3. Benefit-to-cost ratios thresholds, if used, cannot be greater than 1.25 unless justified by the region and approved by FERC
4. No allocation of costs outside a region unless other region agrees
5. Transparency of cost allocation method and identification of beneficiaries
6. Different cost allocation methods can apply to different types of transmission projects (*e.g.,* reliability, economic, public policy, existing vs. new)

Order 1000: Cost Allocation Requirements

- Participant funding permitted, but not as sole cost allocation method
- Cost allocation can vary for different types of transmission projects (e.g., reliability, economic, public policy)
- "Postage stamp" (load ratio share) for regional cost recovery may be appropriate and consistent with cost allocation principles if:
  - All customers tend to benefit from class or group of facilities
  - Distribution of benefits likely to vary over long life of facilities
- Regions must also specify inter-regional cost allocation methodology
  - Methods can differ across different pairs of neighboring regions
  - Inter-regional facilities must also be selected in each entity's regional plans
- If a region cannot decide on cost allocation, then FERC will decide based on record