

*The Brattle Group*

# Transmission Investment Trends and Planning Challenges

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**EEl Transmission and Wholesale  
Markets School**

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# In this presentation

- 1. Transmission Investment Trends**
- 2. Planning and Cost Allocation Challenges**
- 3. FERC Order 1000**
- 4. Planning Frameworks to Analyze Transmission**
- 5. Common Tools, Metrics, and Their Limitations**

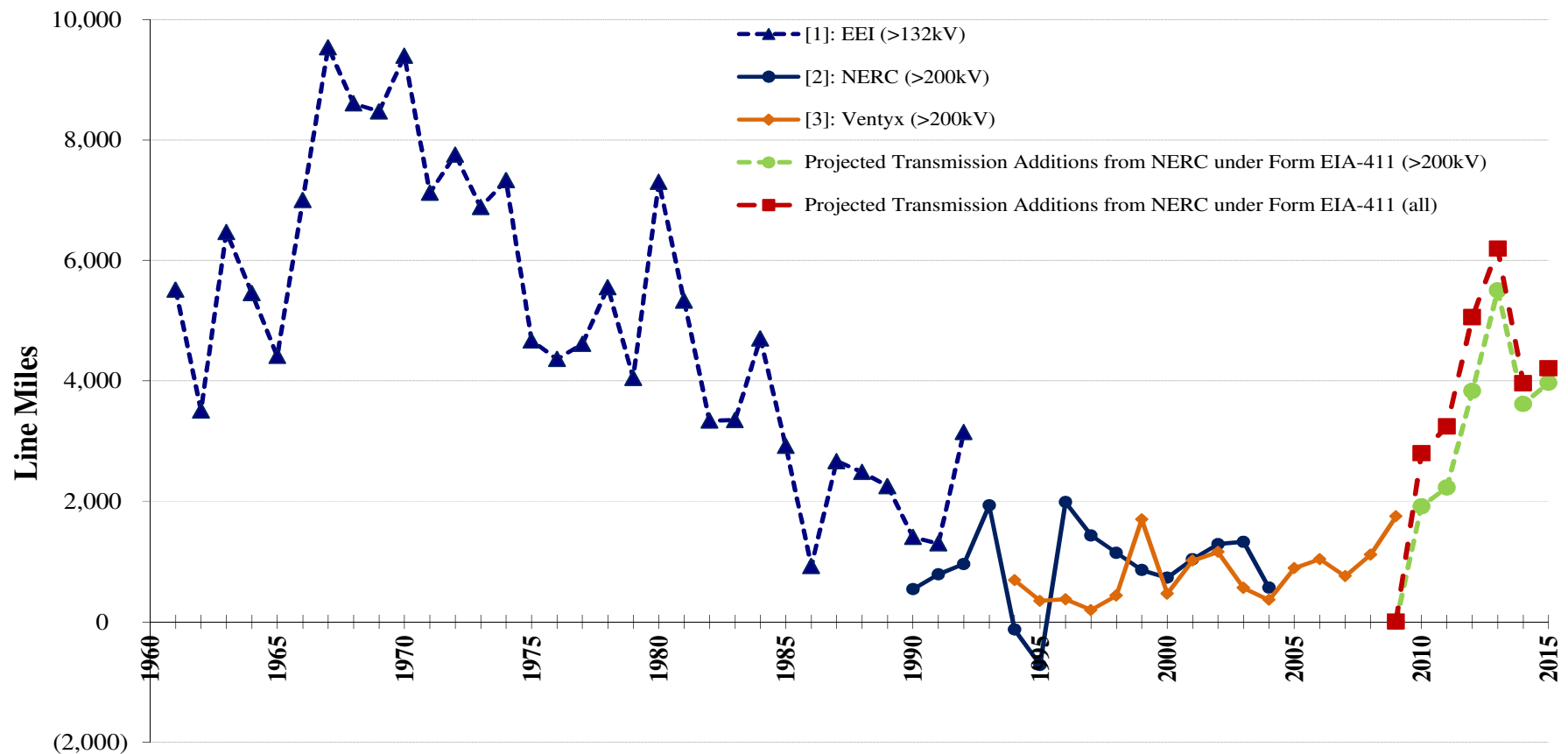
**Appendix A: Difficult-to-Quantify Benefits**

**Appendix B: Cost Allocation Methodologies**

**Additional Reading / About Brattle / Contact Info**

# U.S. Historical Transmission Addition – Line Miles

**Significant recent and projected transmission additions are still well below additions made 40-50 years ago when much of the current grid was built**



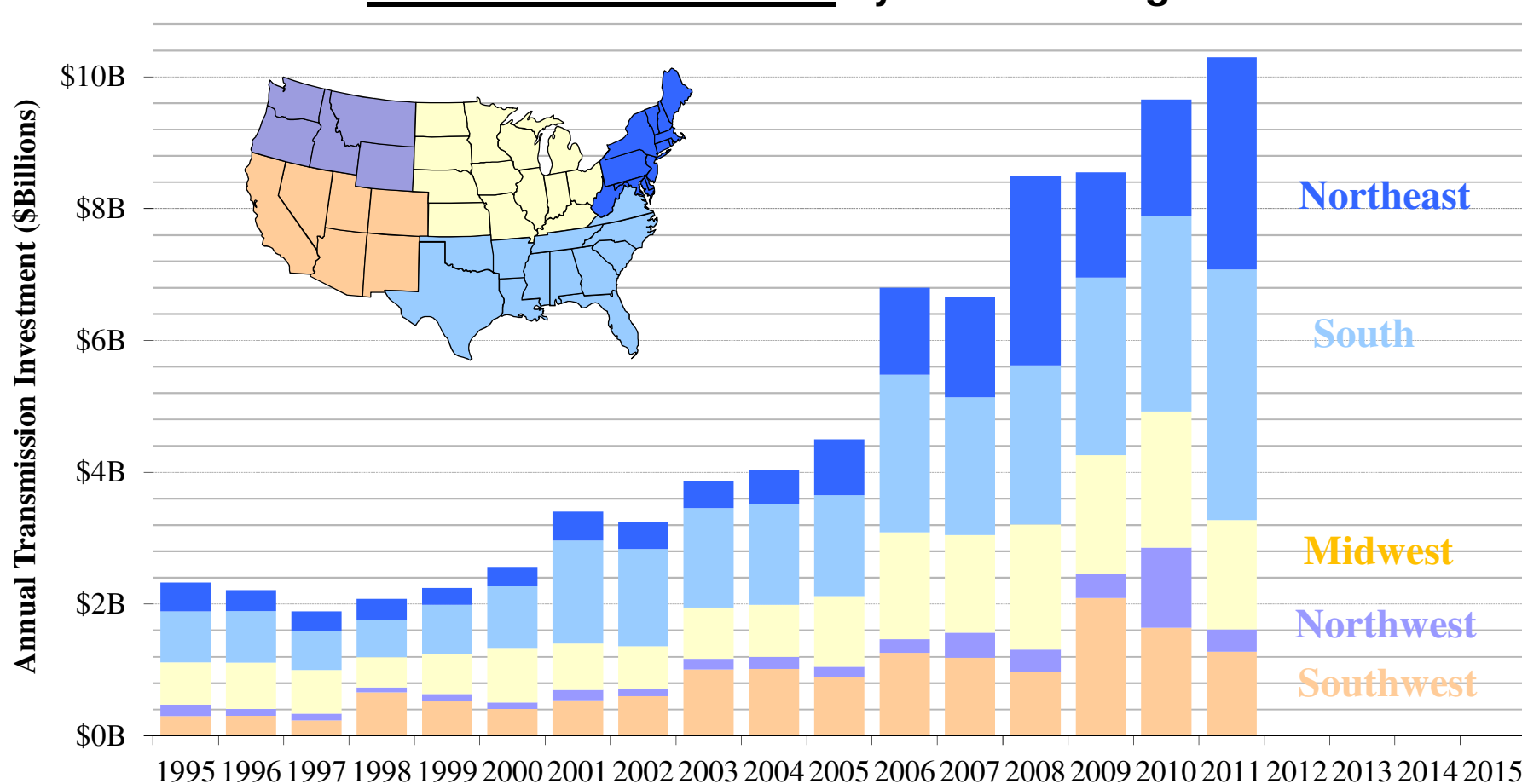
[1]: Circuit miles of overhead electric lines from EEI's Historical Statistical Yearbook. Data excludes REA cooperatives.

[2]: Courtesy of the North American Electric Reliability Corporation. NERC data is only available for lines 200kV and above. Note: transmission line additions are calculated as the difference in existing transmission between the current and prior year (i.e. 2003 additions = 2003 miles - 2002 miles).

[3]: Ventyx Suite.

# Historical Transmission Additions – Investments

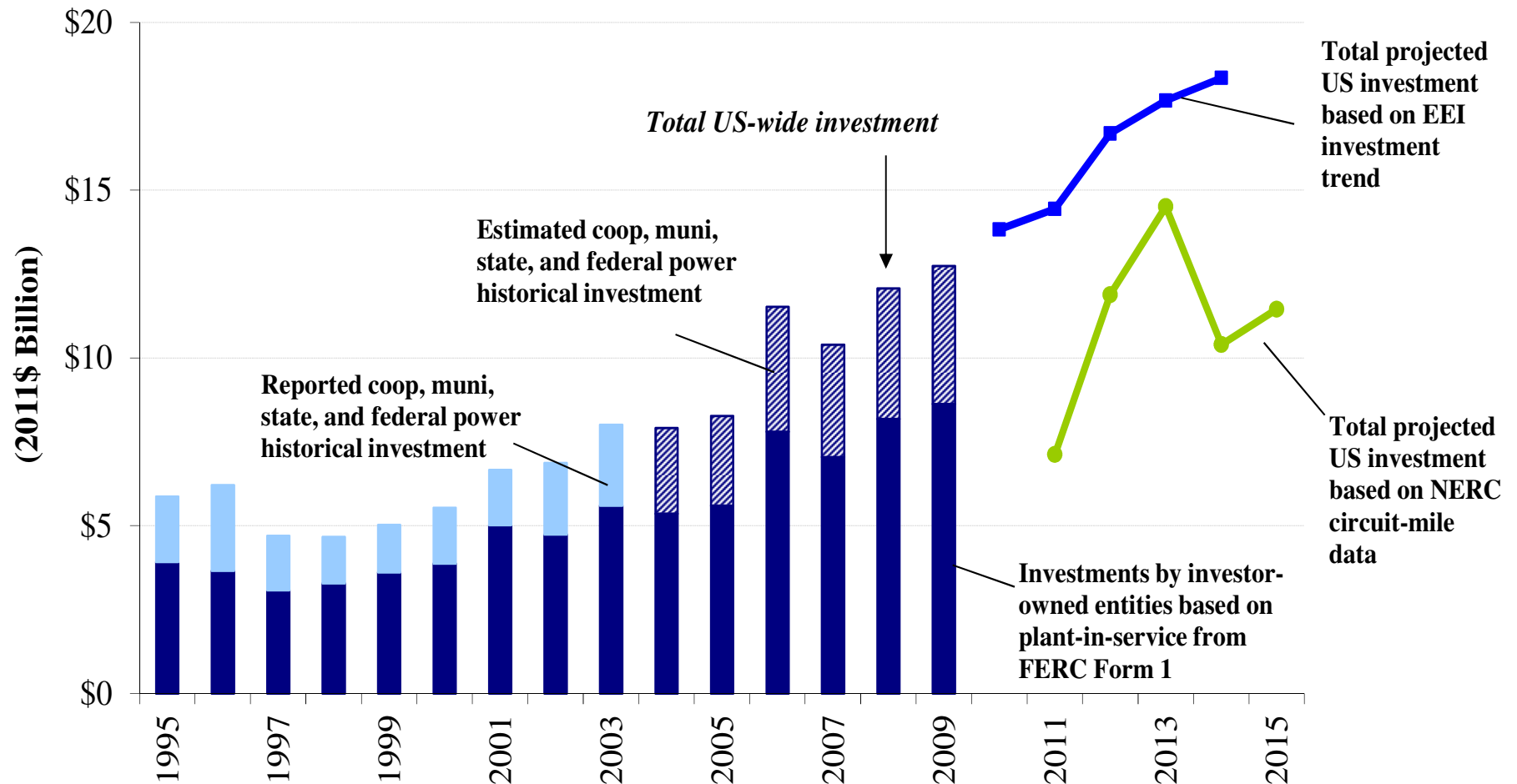
## Annual Transmission Investment of Investor-Owned Utilities by FERC Subregion



Source: The Brattle Group's analysis of FERC Form 1 data compiled in Ventyx's Velocity Suite.

# U.S. Transmission Investments – through 2015

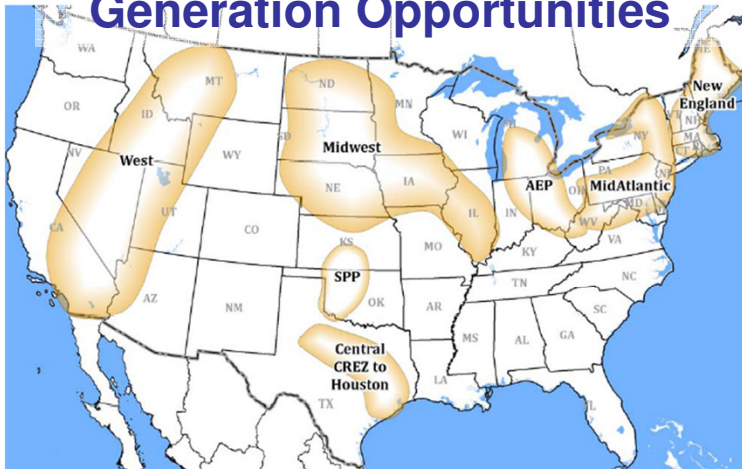
**\$60-80 billion in projected (2011\$) investment for 2011-15**



*Sources and Notes: The Brattle Group © 2012. The Brattle Group, Employment and Economic Benefits of Transmission Infrastructure Investment in the U.S. and Canada, prepared by J. Pfeifenberger and D. Hou for WIRES, May 2011.*

# Renewables Drive Significant Investment Activity

## Main Regions with Wind Generation Opportunities

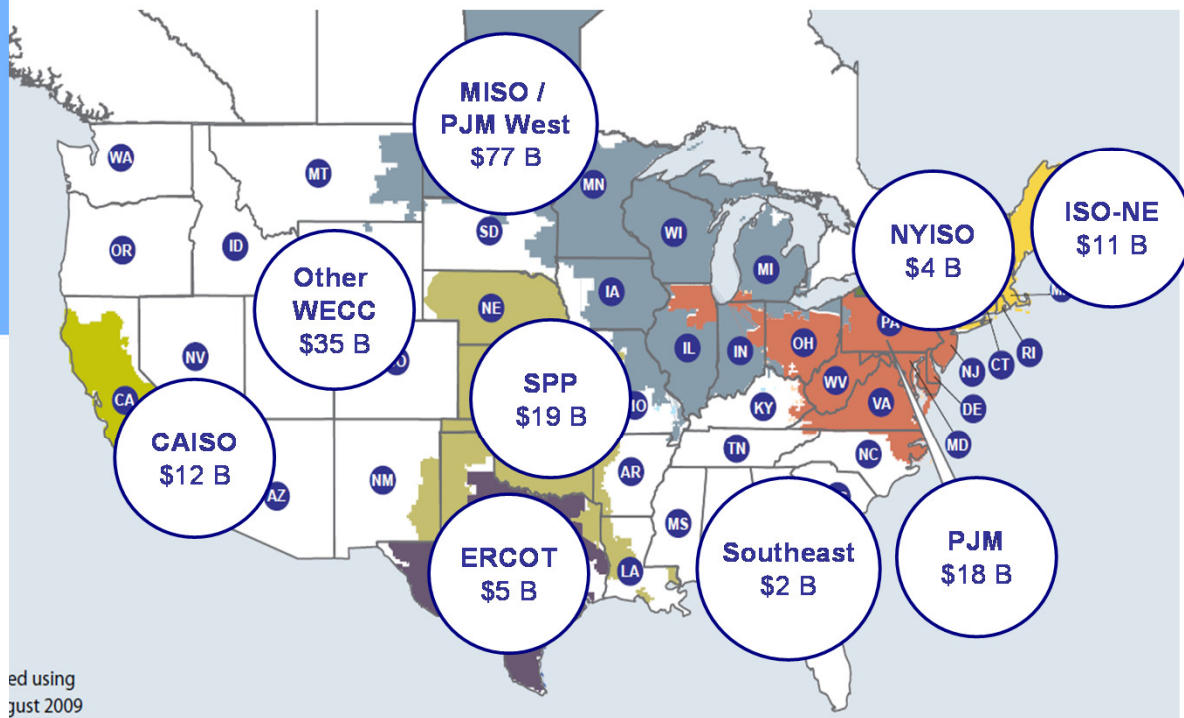


**Approx. 130 mostly conceptual and often overlapping projects (>\$100 million each) for a total of over \$180 billion**

**1/3 to 1/2 of these regional projects unlikely to be realized.**

**A significant portion of these proposed and often highly conceptual projects (many not yet part of regional planning efforts by RTOs) are driven by large-scale renewables integration**

## \$180 Billion of Planned and Still Conceptual Transmission Projects as of 2010



# U.S. Transmission Investment: 20-year Outlook

Brattle database for \$180 billion of major projects

\$30 billion ... already in RTO-approved plans

\$80 billion ... additionally proposed (non-overlapping)

\$50-100 billion in US-wide incremental transmission needed to integrate renewables:

- ◆ To satisfy existing state-level RPS requirements

\$40-70 billion

- ◆ For higher of existing state and 20% federal RPS

\$80-130 billion

\$240-320 billion in investments through 2030 (in 2011\$)

- ◆ Major reliability, economic, and renewables projects
- ◆ Local baseline investments, including lower voltages and facilities replacements



# Mostly “Regulated” Transmission

## **Transmission largely infrastructure investments based on state or regional planning with cost recovery at regulated rates**

- ◆ Public goods aspect of transmission:
  - Benefits broad in scope, wide-spread geographically, diverse in impacts on market participants, and occurring over many decades
  - Owners generally unable to capture sufficient portion of benefits
  - Will tend to lead to under-investment and over-use
- ◆ Some merchant transmission projects and competition for developing regulated transmission
  - Out-of-footprint investments by established transmission owners
  - Independent transmission developers
  - Elimination of “Right of First Refusal” of incumbent transmission owners for new builds approved in regional transmission plans
  - Merchant opportunities for HVDC lines in or between regions with sustained price differentials



# Emerging Non-Incumbent Business Models

**While focusing primarily on regulated investments, non-incumbent transmission developers have become increasingly active. We identified 10 distinct business models:**

Strategy	
1	Transmission partnerships with incumbents
2	Public-Private Partnerships
3	Independent transmission company (new build)
4	Merchant transmission
5	Transmission bundled with renewables
6	Transmission subsidiaries
7	Spin-off of transmission into quasi-ITC
8	Independent transmission company (acquisition)
9	Passive investment
10	Buy/invest in developer



1. Transmission Investment Trends

**2. Planning and Cost Allocation Challenges**

3. FERC Order 1000

4. Planning Frameworks to Analyze Transmission

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Appendix A: Difficult-to-Quantify Benefits

Appendix B: Cost Allocation Methodologies

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# Barriers to U.S. Transmission Investments

## **Numerous barriers reduce transmission investment below optimal levels:**

- ◆ Siting and permitting barriers
- ◆ Planning barriers (particularly for multi-state and inter-regional projects)
  - Planning focused on reliability projects, some “economic” or “congestion relief” projects
  - Only starting to learn how to plan for “public policy” (renewables) projects
- ◆ Cost recovery barriers
  - Issue most acute for multi-state, inter-regional, and multi-purpose projects
- ◆ Opposition based on economic and competitive impacts
  - By state regulators and load serving entities if increased export capability might increase wholesale power prices
  - By generators (including transmission owners with affiliated generation) if increased import capability would decrease wholesale power prices
  - By established transmission owners to third-party transmission development within their footprint

## **FERC “incentives” help overcome but do not actually reduce key barriers**

# Challenge: Wide-spread Benefits

**Wide-spread nature of transmission benefits creates both planning and cost allocation challenges**

▪ <b>Broad in scope</b>	<ul style="list-style-type: none"><li>• Increased reliability and operational flexibility</li><li>• Reduced congestion, dispatch costs, and losses</li><li>• Lower capacity needs and generation costs</li><li>• Increased competition and market liquidity</li><li>• Renewables integration and environmental benefits</li><li>• Insurance and risk mitigation benefits</li><li>• Fuel diversification and fuel market benefits</li><li>• Economic development from G&amp;T investments</li></ul>
▪ <b>Wide-spread geographically</b>	<ul style="list-style-type: none"><li>• Multiple transmissions service areas</li><li>• <b><u>Multiple states</u></b> or regions</li></ul>
▪ <b>Diverse in their effects on market participants</b>	<ul style="list-style-type: none"><li>• <b><u>Customers, generators, transmission owners</u></b> in regulated and/or deregulated markets</li><li>• Individual market participants may capture one set of benefits but not others</li></ul>
▪ <b>Occur and change over long periods of time</b>	<ul style="list-style-type: none"><li>• Several decades</li><li>• Changing with system conditions and future generation and transmission additions</li><li>• Individual market participants may capture different types of benefits at different times</li></ul>

# Planning & Cost Allocation: What Works?

## Existing transmission planning and cost recovery processes have varying degrees of effectiveness

- ♦ **Works well**: traditional single-utility, single-state projects built to satisfy reliability needs
- ♦ **Mostly works**: reliability-driven regional projects and *conventional* generator interconnection requests at the RTO level
  - Some unintended consequences of existing RTO cost allocation framework
  - MISO's assignment of wind integration costs illustrates difficulties
- ♦ **Still “work in progress”**: all other types of regional and inter-regional projects, including “economic” projects, renewable integration projects, EHV overlay projects, and any multi-purpose projects
  - ERCOT and CAISO (two single-state ISOs) first resolved planning and cost recovery for multi-utility, multi-purpose, and renewable integration projects
  - SPP (ITP plus highway/byway) and Midwest ISO (MPV plus postage stamp) now have planning and cost recovery for regional projects (approved by FERC in June and December 2010)
  - Other RTOs and regions have only started to address this issue; Order 1000 compliance filings may be helpful

# Cost Allocation: A Barrier for Regional Projects

## **Planning, permitting, and cost allocation process is “easier” (and more sequential) for single-state projects:**

- ◆ Planning determines need (e.g., overall benefits in excess of total project costs)
- ◆ State permitting/regulatory process confirms need and approves project
- ◆ Approved projects receive cost recovery from customers within state
- ◆ Still, some challenges for in-state projects with regional benefits (e.g., Brookings line in MN)

## **Interaction between cost allocation and permitting creates barrier for many multi-TO, multi-state projects:**

- ◆ Permitting processes primarily focused on costs and benefits to individual states and utilities: share of benefit in excess of allocated share of costs
- ◆ “Beneficiary pays” framework helpful but also creates incentives to dismiss difficult-to-quantify benefits to achieve lower cost allocations
- ◆ Result: projects beneficial to region often do not appear to be beneficial to individual states or utilities based on their shares of costs and benefits

# Cost Allocation: Fight Over “Measurable” Benefits

## CAISO, SPP, MISO and ERCOT:

- ◆ Postage stamp allocation for policy-driven regional projects based on showing (or belief) that **benefits broadly accrue to region** as a whole

## FERC Order No. 1000:

- ◆ Allocation should be based on “cost causation” or “beneficiary” principles
- ◆ Should be “**at least roughly commensurate with estimated benefits**”; those that receive no benefit must not be allocated costs involuntarily
- ◆ Postage stamp may be appropriate if all customers tend to benefit from class or group of facilities or if distribution of benefits is likely to vary over long life of facilities

## Various efforts at proposed new legislation (Corker et al.)

- ◆ “...no rate...shall be considered just and reasonable unless...based on an allocation of costs...reasonably proportionate to **measurable economic or reliability benefits [to] 1 or more persons** that pay the rate...”





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# Order 1000: Overview

**Jurisdictional transmission owners are required to participate in regional and inter-regional planning efforts that produce:**

- ◆ Regional transmission plans
  - ◆ Regional cost allocations
  - ◆ Interregional planning process (but no plans)
  - ◆ Interregional cost allocation methods
- } October 2012
- } April 2013

## **What is a “Region”?**

- ◆ Existing regions as the starting point
- ◆ Defining different regions will require showing of reasonableness
- ◆ A region must cover more than one utility (holding company)

**The rule applies only to “new” transmission facilities**

# Order 1000: Regional Planning

## The regional transmission planning process must:

- ◆ Satisfy and build on Order 890, but otherwise up to each “region”
- ◆ Be transparent and open to all interested market participants
- ◆ Explain how the region will identify and evaluate what it plan
- ◆ Consider needs driven by **public policy requirements**
  - But no mandate to include any specific requirement
  - How and for which requirements is up to each region
- ◆ Provide opportunities for stakeholder participation in identification and evaluation of regional solutions
- ◆ Include a regional process for transmission project submission, evaluation and selection
- ◆ Produce regional plans and associated cost allocation

# Order 1000: Interregional Planning

## **Interregional transmission planning requirements:**

- ◆ Each pair of neighboring regions must coordinate planning
  - Share data
  - Specify process to identify interregional projects that may offer more efficient or cost-effective solutions
  - Specify type of study and evaluation process that will be used for interregional projects
- ◆ No requirement to produce actual interregional plans (but must include process for interregional cost allocation method)

## **What is an interregional project?**

- ◆ Facilities physically located in two or more neighboring regions
- ◆ Does not include facilities solely located in one region, even if they affect another region (e.g., certain flowgates)

# Order 1000: Cost Allocation Principles

**Each regional planning process must include both regional and interregional cost-allocation methods**

◆ 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 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
- ◆ Must also specify interregional cost allocation methodology
  - Methods can differ across different pairs of neighboring regions
  - Facilities must also be selected in each entity's regional plans
- ◆ If a region can't decide on cost allocation, then FERC will decide based on record

# Order 1000: Nonincumbent Participation

## **Regional and interregional planning must facilitate non-incumbent participation:**

- ◆ Eliminate provisions that establish a federal Right of First Refusal
  - Does not affect state laws and regulation, including state-level ROFR
  - Applies only to facilities selected in regional plans for purpose of cost allocation
  - Does not apply to upgrades of existing facilities
  - Allows but does not require competitive bidding
- ◆ Specify non-incumbent participation process:
  - Criteria to determine an entity's eligibility to propose a transmission project (e.g., financial resources and technical expertise)
  - Project submission requirements
  - Project evaluation procedures
  - Same eligibility for cost allocation





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# Reliability vs. Economic Planning Processes

## **Well-established process for reliability-driven transmission planning:**

- ◆ Engineering analyses based on well-defined cases to first identify and then address reliability violations, usually so-called N-1 criteria violations
- ◆ Clear criteria (reliability standards) and well-honed (formulaic) evaluation processes
- ◆ Established analytical tools (load flow analyses, stability analyses)
- ◆ “Economics” limited to estimation and comparison of project costs (though economic value increasingly explored for large projects)

## **Several eastern RTOs developed similar process for economic and public policy projects**

- ◆ Formulaic production cost analyses and benefit-cost thresholds
- ◆ Unintended consequence: rejection of essentially all economic projects
- ◆ Narrowly-defined processes unworkable for public policy projects

## **Frameworks similar to reliability planning process not effective for “economic” and “public policy” projects**

# The “Business Case” for Transmission

## Effective planning for economic and public-policy projects requires developing a “compelling business case”

- ◆ A challenge in any industry, but more difficult here due to complexity of challenges and often inadequate economics and policy orientation
- ◆ Essentially an “integrated resource planning” effort to choose among alternative generation and transmission investment options
- ◆ Requires iterations of economic and engineering analyses
- ◆ Challenges not faced in reliability planning:
  - ◆ Projects are “optional” – often different projects (with different benefits and costs) can meet the same objective
  - ◆ Many projects are unique, serve different purposes, and offer very different types of benefits that require different analytical approaches
  - ◆ Tools that capture only a portion of economic benefits
  - ◆ Lack of established evaluation processes to estimate economic value of many types of transmission benefits

**Necessary to gain the multi-jurisdictional support needed to obtain approvals, permits, and cost recovery**

# Many Economic Benefits are Difficult to Quantify

**Economic planning needs to recognize that many transmission benefits are difficult to quantify**

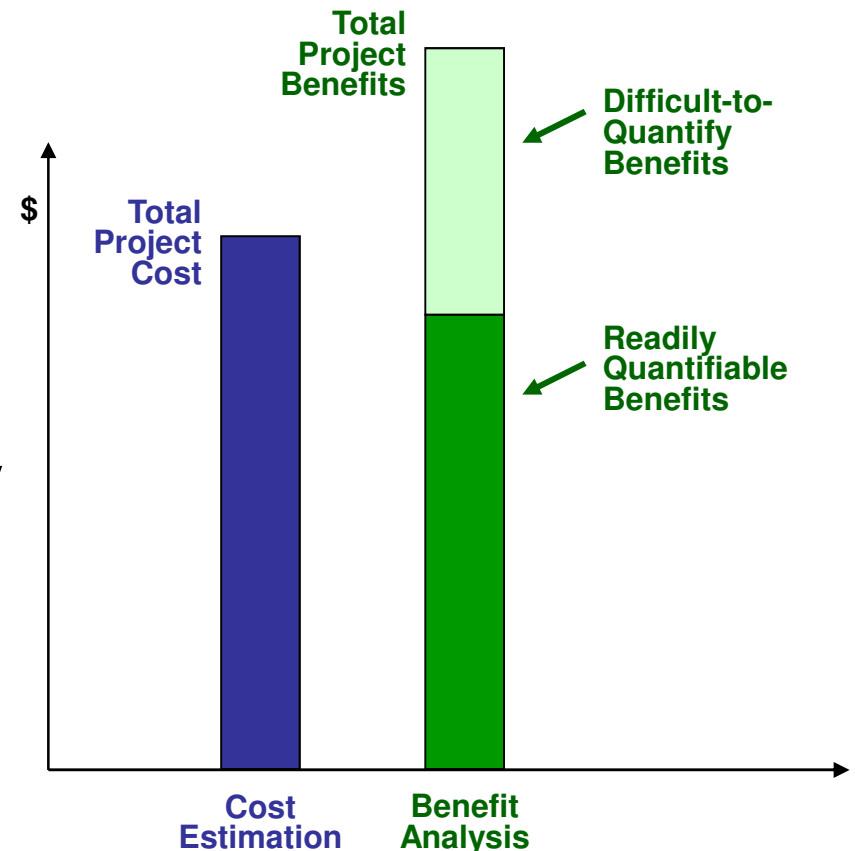
- ◆ There are no “unquantifiable” or “intangible” benefits
- ◆ Difficult-to-quantify benefits need to be explored at least qualitatively
- ◆ Standard economic analysis tools (e.g., production cost models) capture only a portion of total benefits

**Failure to consider difficult-to-quantify benefits can lead to rejection of desirable projects:**

- ◆ Total benefits > Costs
- ◆ Quantified benefits < Costs

**Additional Challenge:** Sum of benefits for individual projects will be less than benefits for an entire group of projects

*Illustrative Example*



# Total Benefits vs. Benefits that Can be Allocated

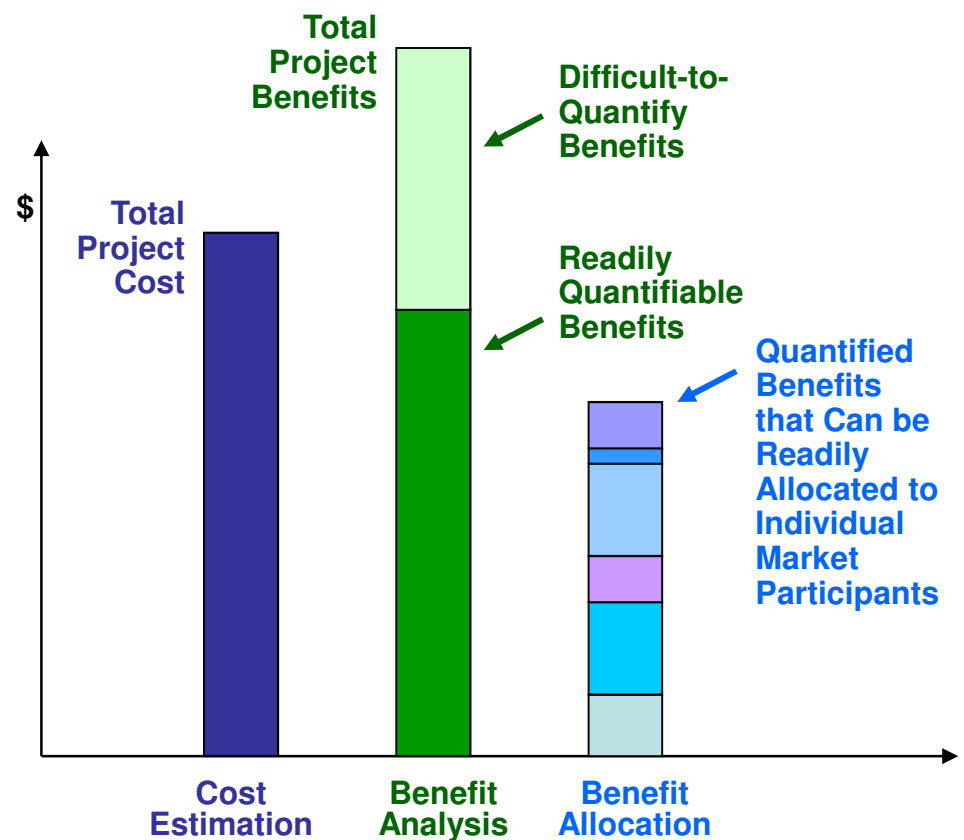
**Benefits of transmission projects should be analyzed prior to and separate from analyses to determine how costs should be allocated**

## **Recommend 2-step approach:**

1. Determine whether projects are beneficial to the region
2. Evaluate how the cost of beneficial projects should be allocated

## **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 overall project economics would result in rejection of some desirable projects



# Economic Benefits: Compared to What?

## The evaluation of economic benefits of transmission projects requires a comparison of two or more cases

- ◆ Benefits measured by comparing total system costs and benefits for:
  1. A future with the project (“change” or “project” case); to
  2. A future without the project (“comparison” or “base” case)
- ◆ Both the change case and base case may be evaluated for:
  - ◆ Different futures (different load and fuel price forecasts, environmental regulations, generating plant retirements and additions, etc.)
  - ◆ A range of scenarios and sensitivities that meaningfully reflect the uncertainties (and correlations) of key input variables
- ◆ Different change cases to explore costs and benefits for different project configurations, project alternatives, or market responses
- ◆ Change case may need to differ from base case by more than the project (e.g., by the project’s effect on future generation additions or retirements)

**Comparison cases need to be fully specified before meaningful economic analyses can be undertaken**

# Market Efficiency vs. Public Policy Projects

**Market efficiency projects are targeted to reduce overall costs while public policy projects are a means to achieve policy objectives at reasonably low (if not lowest possible) overall costs.**

- ♦ Evaluation of “market efficiency” projects typically compares a project or group of projects (possibly project alternatives) to a base case without it:

Total Costs and Benefits of  
System with Project(s)  
 (“change case”)

<Compared to>

Total Costs and Benefits of  
System w/o Project(s)  
 (“base case”)

- ♦ In contrast, the evaluation of “public policy” projects, such as renewables overlays, often requires the comparison of the proposed project(s) to one or more alternative means of satisfying the same policy requirement:

Total Costs and Benefits of  
System with Project(s)  
 (“project case”)

<Compared to>

Total Costs and Benefits of  
System with Alternative 1

Total Costs and Benefits of  
System with Alternative 2



# Lowest Cost vs. Highest Value

## **Planning often attempts to achieve specific goals at lowest costs:**

- ◆ Lowest-cost option to address reliability requirement, reduce identified congestion, or integrate a new generation facility
- ◆ Lowest cost of combined renewable generation and transmission investments to satisfy RPS requirements

## **Lowest-cost solution to address one goal not always offers highest value and lowest overall costs in long run:**

- ◆ Up-sizing reliability projects may capture additional economic benefits (market efficiencies, reduced transmission losses, etc.)
- ◆ Up-sizing market efficiency projects may reduce costs of future projects (renewables overlay, reliability upgrades, plant interconnection, etc.)
- ◆ More expensive renewable overlay may allow integration of lower-cost renewable resources and reduce wind balancing cost, losses, etc.
- ◆ Additional investments may create option value of increased flexibility to respond to changing market and system conditions

**State policy makers, regulatory commissions, and market participants need to be involved in choice between lowest cost and highest value**

# Production Costs vs. Long-Term Resource Costs

**Majority of economic planning processes measure only short-term dispatch cost savings without an evaluation of long-term resource cost impacts. For example, they:**

- ◆ Over-rely on “production costs” and LMP impacts quantified with dispatch simulation models – which measure only fuel, variable O&M, and emission costs, thus ignoring investment costs and fixed O&M cost of generation
- ◆ Evaluate a “snap shot” of the system without considering how market will respond to transmission project over time (e.g., reduction in market prices will tend to speed up retirements and delay new generation investments)
- ◆ May assume same amount of generation is built (e.g., wind) and retained in same locations with and without the transmission investment

**Capturing long-term benefits of transmission investments requires processes more akin to integrated resource planning**

- ◆ Assess long-term impacts of transmission projects on total (T&G) system costs
- ◆ Evaluate “long-term resource cost” benefits such as ability to build new generation in lower-cost locations
- ◆ Find lower-cost (or higher-value) combination of transmission and generation investments to satisfy policy requirements, such as RPS

# Benefits of Projects vs. Regional Plans

## **Estimation of benefits frequently unworkable (or not even meaningful) on a project-by-project basis**

- Sum of benefits of individual projects can be significantly less than the overall benefits of a comprehensive regional plan → resulting in rejection of desirable projects


## **Benefits distributed more uniformly for regional plans than individual projects, facilitating cost allocation**

- Estimated benefits will be more uniform across region for regional plan than for individual projects → allocation that is “roughly commensurate with estimated benefits” will be more uniform
- Portfolio of projects in regional plans allows consideration different types of benefits to different types of stakeholders → makes it easier to achieve multi-state agreements

# Inter-regional Planning and Cost Allocation

## **A number of efforts are underway to improve inter-regional planning:**

- ◆ Effort by Regional State Committee of Southwest Power Pool
  - ◆ Pfeifenberger and Hou, "Seams Cost Allocation: A Flexible Framework to Support Interregional Transmission Planning," April 2012
  - ◆ Framework recommends and specifies bilateral inter-regional planning agreements that clearly specify (1) transmission planning processes, (2) benefits considered by each of the neighboring system operators, (3) additional benefits provided by inter-regional transmission links, and (4) principles to facilitate cost sharing for interties across the seam
- ◆ Inter-regional planning and cost allocation requirements of FERC Order 1000
- ◆ Multi-regional efforts to develop inter-regional transmission plans
  - ◆ Eastern Interconnection Planning Collaborative (EIPC)
  - ◆ WECC's Regional Transmission Expansion Planning (RTEP)
  - ◆ European Ten-Year Network Development Plans (TYNDP)
- ◆ Continued efforts by Canadian suppliers to increase interties with U.S.

- 
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# Common Tools Supporting Economic Analysis

**Several types of standard modeling tools provide relevant inputs to economic analyses of transmission projects**

**Custom analyses frequently needed for certain transmission benefits (e.g., ancillary service costs of balancing intermittent resources)**

Category	Purpose	Relevant Metrics	Frequently Used Models
Production Cost Models	<b>Used to estimate production costs and market prices (LMPs or zonal).</b> Simulation of security-constrained economic dispatch, used to calculate production cost, congestion relief, and market price benefits	<ul style="list-style-type: none"> <li>APC</li> <li>Load LMPs</li> <li>Emissions</li> </ul>	<ul style="list-style-type: none"> <li><u>Nodal</u>: PROMOD, GE-MAPS, Dayzer, UPLAN, GridView, PowerWorld</li> <li><u>Zonal</u>: MarketSym, Aurora</li> </ul>
Power Flow Models	<b>Used mostly for reliability studies</b> (thermal overloads and voltage violations under N-1 or N-2 contingencies); provides inputs for economic analysis of transfer capabilities and transmission losses.	<ul style="list-style-type: none"> <li>System losses</li> <li>FCITC</li> </ul>	<ul style="list-style-type: none"> <li>PSS/E, PSLF, MUST, POM, PowerWorld</li> </ul>
Capacity Expansion Models	<b>Used to estimate approx. impact of change in transmission capabilities (between zones) on generation additions and retirements.</b> Based on least cost and user defined parameters, these models retire existing and “build” additional capacity over 20 - 40 years. Typically used in long-term resource planning exercises.	<ul style="list-style-type: none"> <li>Total generation costs (investments and operations)</li> <li>Plant additions and retirements</li> </ul>	<ul style="list-style-type: none"> <li>Aurora, EGEAS, Strategist (public)</li> <li>IPM, NEEM, RECAP (proprietary)</li> </ul>
Reliability Assessment Models	<b>Used to estimate loss-of-load-expectation and expected unserved energy</b>	<ul style="list-style-type: none"> <li>LOLE, LOLP, UNE, required reserve margins</li> </ul>	<ul style="list-style-type: none"> <li>GE MARS, SERVIM</li> </ul>

# Production Cost Models

**Security-constrained dispatch simulation models or “production cost models” are the most widely-used tool used to assess the economic benefits of transmission projects.**

## **Production cost models:**

- ◆ Measure changes in production costs, power flows, LMP, and congestion
- ◆ Allow for different definitions of “benefits,” reporting of different “metrics,” but provides incomplete picture of total transmission-related value

## **Limits of production cost models are easily overlooked:**

- ◆ Despite fancy modeling tools, results often driven by assumptions and simplifications (no long-term effects; no transmission outages; no transmission losses; contracts often ignored)
- ◆ Different (often simplistic) benefit metrics can produce very different results
- ◆ Limited number of scenarios/cases does not capture disproportional benefits under stressed market conditions and extreme contingencies
- ◆ Production cost modeling does not capture investment cost impacts (e.g., generation retirement and additions; access to lower-cost generation)
- ◆ Many “other” transmission benefits not captured in modeling efforts



# Interpretation of Model Results Can Differ Widely

**Predefined benefit-cost metrics from production cost models rely on specific interpretations of simulation results**

- ◆ Benefits to whom?
  - ◆ Societal vs. customers vs. generators vs. transmission owner
  - ◆ System wide vs. zonal impacts
  - ◆ Market-based or cost-of-service-based generation
- ◆ What types of benefits?
  - ◆ Production costs vs. market prices
  - ◆ Dispatch costs vs. total resource costs
  - ◆ Congestion charges, FTR allocations, and losses
- ◆ How do benefits vary over time and market conditions?
  - ◆ Disproportional impact under stressed market conditions and extreme contingencies
  - ◆ Extrapolate short-term results of dispatch models or fully evaluate long-term investment and resource cost impacts

# Benefit-Cost “Metrics”

**Results of production cost modeling (and analysis of other benefits) are summarized through a range of different benefit-cost metrics:**

- ◆ **Most commonly-used metrics (e.g., in PJM, MISO, NYISO, ISO-NE, SPP)**
  - ◆ **Adjusted Production Cost (APC)**
  - ◆ Load LMP (LLMP) and combined metrics (70% APC + 30% LLMP)
- ◆ **Impact on “utility cost of service” (developed for ATC)**
  - + Production costs of utility-owned generation assets
  - + Market purchase costs less off-system sales revenues
  - + Congestion charges and marginal losses
  - Revenues from allocated FTRs and marginal loss refunds
  - + Separate quantification of “other” transmission-related benefits
- ◆ **CAISO TEAM methodology**
  - ◆ Simulation-based Consumer, Producer, and Transmission Owner benefits combined into WECC Societal, WECC Modified Societal, CAISO Ratepayer, and CAISO Participant perspectives
  - ◆ Quantifies expected benefits over a wide range of uncertainties
  - ◆ Separate quantification of “other” transmission-related benefits
- ◆ **SPP ITP and MISO MVP processes that now also include “other” benefits**

# Common Metric: “Adjusted Production Costs”

**Adjusted Production Costs (APC) is the most widely-used summary metric for market simulations (e.g., from PROMOD). Meant to capture the cost of producing power within an area net of imports/exports:**

♦ **Adjusted Production Costs (APC) =**

- + **Production costs** (fuel, variable O&M, emission costs of generation within area)
- + **Cost of hourly net purchases** (valued at the area-internal load LMP)
- **Revenues from hourly net sales** (valued at the area-internal generation LMP)

♦ **Limitations:**

- ♦ Sum of APCs across areas can differ significantly from regional APC
- ♦ Ignores congestion and marginal loss revenues from exchanges between areas
- ♦ Does not capture extent to which a utility can buy or sell at the “outside” price (assumes none of import-related congestion is hedged with allocated FTRs and there are no marginal loss refunds)
- ♦ For simplicity, APC are typically only quantified for well-behaved base cases:
  - ♦ No transmission outages (every element assumed 100% available all the time)
  - ♦ No unusual weather conditions (normalized peak loads and energy everywhere)
  - ♦ No extreme contingencies (no multiple generation and transmission outages)
  - ♦ No consideration of wind generation uncertainty, change in A/S needs, or cost/reliability implications of increased unit cycling

# Often Overlooked “Other” Transmission Benefits

**Important transmission benefits (some listed below) are often overlooked because of production cost model limitations and the complexity involved in quantifying these benefits:**

- |   |   |                                       |
|---|---|---------------------------------------|
| 1. Enhanced market competitiveness                | } | Additional market benefits            |
| 2. Enhanced market liquidity                      |   |                                       |
| 3. Economic value of reliability benefits         | } | Reliability/operational benefits      |
| 4. Added operational and A/S benefits             |   |                                       |
| 5. Insurance and risk mitigation benefits         |   |                                       |
| 6. Capacity benefits                              | } | Investment and resource cost benefits |
| 7. Long-term resource cost advantage              |   |                                       |
| 8. Synergies with other transmission projects     |   |                                       |
| 9. Impacts on fuel markets                        | } | External benefits                     |
| 10. Environmental and renewable access benefits   |   |                                       |
| 11. Economic benefits from construction and taxes |   |                                       |

**See Appendix A. These benefits can double benefits quantified in typical production cost studies.**

# RTOs Increasingly Address these “Other” 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<sub>2</sub> 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

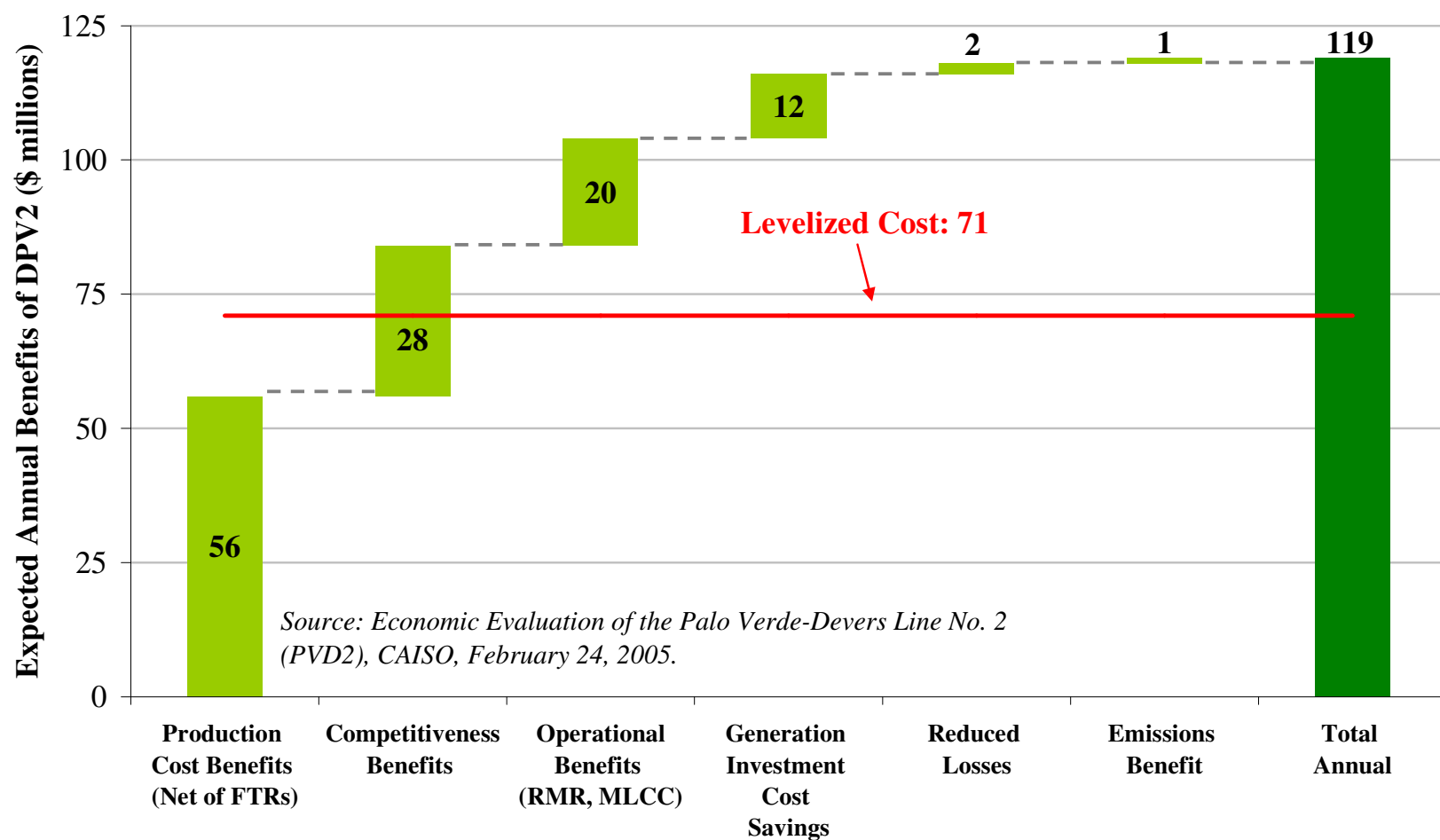
### Not quantified

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))

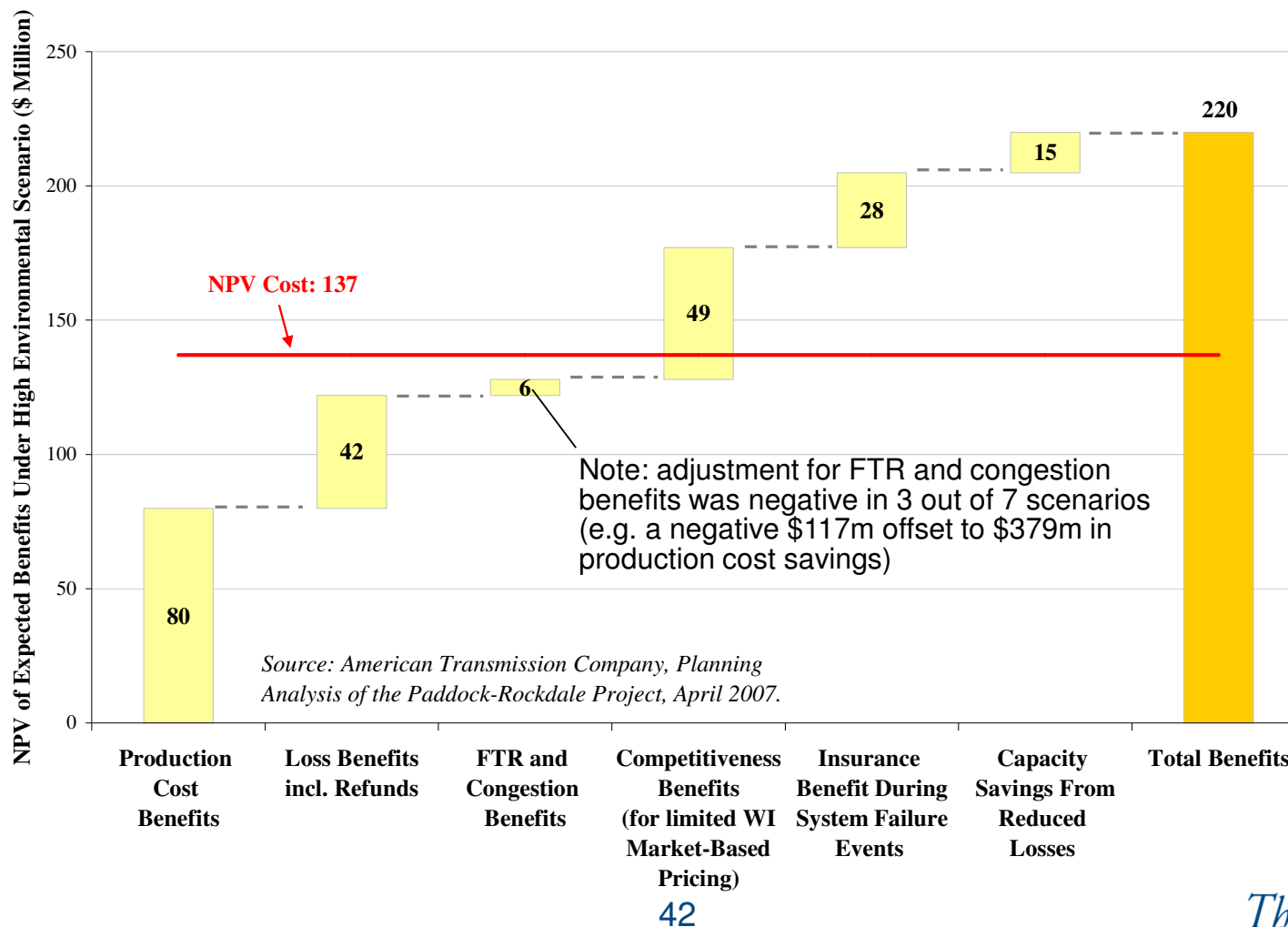
# Example: Electricity Market Benefits vs. Costs


**Total electricity market benefits of SCE's DPV2 project in CAISO exceeded project costs by more than 50%**



# Example: Electricity Market Benefits vs. Costs

**ATC's Paddock-Rockdale study: Significant net benefits (production cost savings alone exceeded costs in some scenarios)**



- 
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#### **Appendix A: Difficult-to-Quantify Benefits**

#### **Appendix B: Cost Allocation Methodologies**

**Additional Reading / About Brattle / Contact Info**



# 1. Market Competitiveness Benefits

- ◆ **New transmission enhances competition (especially in load pockets) by broadening set of suppliers**
  - Impacts structural measures of market concentration (HHI, PSI)
  - Various approaches are available to translate improvements in these structural measures into potential changes in market prices
  - Size of impact differs in restructured and non-restructured markets
- ◆ **Can substantially reduce market prices during tight market conditions**
  - Competitiveness benefits can range from very small to multiples of the production cost savings, depending on
    1. Fraction of load served by cost-of-service generation
    2. Generation mix and load obligations of market-based suppliers
  - CAISO estimated competitiveness benefits can average up to 50% to 100% of project cost (for DPV2 and Path 26 Upgrade), with wide range (5% to 500%) depending on future market conditions
  - We estimated competitiveness benefits ranging from 10% to 40% for ATC's Paddock-Rockdale project, as approved by Wisconsin PSC

## 2. Market Liquidity Benefits

- ◆ **Limited power market liquidity is costly to participants in both restructured and non-restructured markets**
- ◆ **Added transmission can increase liquidity of trading hubs or allow access to more liquid trading hubs**
  - Lower bid-ask spreads
  - Increased pricing transparency, reduced risk of overpaying
  - Improved risk management
  - Improved long-term planning, contracting, and investment decisions
- ◆ **Quantification is challenging but benefit can be sizeable**
  - Bid-ask spreads for bilateral contracts at less liquid hubs are 50 cents to \$1.50 per MWh higher than at more liquid hubs
  - At transaction volumes of 10 to 100 million MWh per quarter at each of 30+ trading hubs, even a 10 cent reduction of bid-ask spreads saves \$4 to \$40 million per year and trading hub

### 3. Reliability Benefits

#### ◆ Reliability has economic value

- Average value of lost load easily exceed \$5,000 to \$10,000 per MWh

***Reliability cost = (expected unserved energy) x (value of lost load)***

- About 24 outages per year with curtailments in 100-1,000 MW range, 5 in 1,000-10,000 MW range, and 0.25 in 10,000+ MW range

#### ◆ Even “economic” projects tend to improve reliability

- Increases options for recovering from supply disruptions and transmission outages
- For example, DPV2 was estimated to reduce load drop requirements of certain extreme contingencies by 2300 MW (i.e., \$10-\$100 million benefit for each avoided event)

#### ◆ Production cost models understate unserved energy

- EUE/LOLP models often consider only generation reliability, not probability of transmission outages
- Dispatch models do not cover full range of possible outcomes; generally also ignore transmission outages and voltage constraints

## 4. Added Operational Benefits

- ◆ **New transmission projects can reduce certain reliability-related operating costs**
  - Examples are out-of-merit dispatch costs, reliability-must-run costs, unit commitment costs (RMR, MLCC, RSG, etc.), which can be a multiple of total congestion charges
  - Added transmission can also reduce costs by increasing flexibility for maintenance outages, switching, and protection arrangements
  - Ancillary service benefits, particularly when balancing renewable resources over a larger regional footprint
- ◆ **Dispatch models do not generally capture these costs**
  - RMR costs not explicitly considered
  - Ancillary services modeled only incompletely
  - Transmission outages (planned or forced) not generally modeled
  - Uncertainty of intermittent resources not captured in production cost simulations
- ◆ **Benefits can be significant:**
  - CAISO estimated operational benefit of DPV2 would add 35% to energy cost savings
  - Reduced balancing costs for intermittent renewable generation can offset 10% of regional transmission overlay

## 5. Insurance and Risk Mitigation Benefits

- ◆ **Even if a range of “scenarios” is simulated in economic analysis, new transmission can offer additional “insurance” benefits**
  - Helps avoid high cost of infrequent but extreme contingencies (generation or transmission) not considered in scenarios
  - Incur premium to diversify resource mix to address risk aversion of customers and regulators
- ◆ **Insurance and risk mitigation value can be quantified:**
  - Calculate probability-weighted market price and production cost benefits through dispatch simulation of extreme events
  - Additional reliability value (EUE x VOLL)
  - Potential additional risk mitigation value if project diversifies resource mix and reduces the cost variances across scenarios
- ◆ **In ATC case, value of insurance against high energy costs during extreme events (even ignoring reliability value and risk premium) added as much as 25% to production cost savings, offsetting 20% of project costs**

## 6. Capacity Benefits

- ◆ **New transmission can reduce installed capacity and reserve requirements**
  - ***Reduced losses during peak load*** reduces installed capacity requirement
    - In recent cases, loss-related capacity benefits on average added 5% to 10% to production cost savings
    - Combined energy and capacity value of loss reduction can offset up to 30-50% of project costs
  - ***Added transfer capabilities*** improves LOLE
    - Allows reduction in local reserve margin requirements or satisfy requirement by improving deliverability of resources
    - Reduced reserve margin or resource adequacy requirements often difficult to attribute to individual transmission projects, but benefits can be large in local resource adequacy zones
  - ***Diversification of renewable generation*** over a larger regional footprint can increase capacity value of intermittent resources
    - Can amount to 5% of nameplate renewables capacity

## 7. Long-term Resource Cost Advantage

- ◆ **Impact of transmission on total resource costs (capital and operating) often not captured in modeling efforts**
  - Simulations with and without the transmission project, but generally for fixed generation system
  - Dispatch models do not capture capital costs of resources nor the facilitation of unique low-cost generating options
- ◆ **Additional transmission can lower total resource costs**
  - Make feasible physical delivery from generation in remote locations that may offer a variety of cost advantages:
    - Better capacity factors (e.g., renewables from wind-rich areas: 10% gain in wind capacity factor worth \$600/kW of additional transmission)
    - Lower fuel costs (e.g., mine mouth coal plants)
    - Lower land, construction, and labor costs
    - Access to valuable unique resources (e.g., pumped storage)
    - Lower environmental costs (e.g., carbon sequestration options)
- ◆ **Transmission provides additional resource planning flexibility**
  - E.g., to address currently unexpected shift in fuel costs, changes in public policy objectives, or uncertainties in the location and amount of future generation additions and retirements

## 8. Synergies with Other Transmission Projects

- ◆ **Individual transmission projects can provide significant benefits through synergies with other transmission investments**
  - For example, construction of DPV2 to Palo Verde would have improved the economics and feasibility of other transmission projects (e.g., SunZia or High Plains Express)
    - Transmission to access renewables in Southwest may be uneconomic if California markets cannot be reached
  - Construction of the Tehachapi transmission project (to access 4,500 MW of wind resources) allows low-cost upgrade of Path 26 and provides additional options for future transmission expansions
  - Regional “multi-value” overlay in Midwest (e.g., RGOS, SMART) reduces costs of state-specific wind integration network upgrades
- ◆ **Economically justified transmission projects may avoid or delay the need for (or reduce the cost of) future reliability projects**



## 9. Impacts on Fuel Markets

### ◆ **Transmission can reduce fuel demand and prices**

- Through dispatch of more efficient plants
- Through integration of resources that don't use the particular fuel
  - Western transmission projects (Tehachapi, Frontier, TransWest Express) each have the potential to reduce Southwestern natural gas demand by several percent through additional renewable or clean coal generation
  - SPP estimated natural gas price reduction of Priority Projects' wind integration benefit worth approx. one third of project costs

### ◆ **As a substitute to transporting fuel, transmission projects can benefit fuel transportation markets**

- “Coal by wire” can help reduce railroad rates (e.g., in the West)
- Accessing generation on the unconstrained side of pipelines

### ◆ **Increased fuel diversity through larger regional footprint**

### ◆ **Fuel market benefits can be wide-spread**


- Additional reductions in generation costs and power prices if fuel is on the margin (e.g., natural gas in the Southwest and East Coast)
- All fuel users outside the electric power industry benefit as well

## 10. Environmental and Renewable Access Benefits

- ◆ **New transmission can reduce emissions by avoiding dispatch of high-cost, inefficient generation**
  - Can reduce SO<sub>2</sub>, NO<sub>x</sub>, particulates, mercury, and CO<sub>2</sub> emissions by allowing dispatch of more efficient or renewable generation
    - DPV2 estimated to reduce WECC-wide NO<sub>x</sub> emissions from power plants by 390 tons and natural gas use by 6 million MMBtu or 360,000 tons CO<sub>2</sub> per year (worth \$1-10 million/yr)
    - Tehachapi transmission project to access 4,500 MW of renewable (wind) generation
  - Can also be environmentally neutral or even result in displacement of cleaner but more expensive generation (e.g., gas-fired)
- ◆ **Local-only or regional/national benefits?**
  - Reduction in local emissions may be valuable (e.g., reduced ozone and particles) irrespective of regional/national impact
  - May not reduce regional/national emissions due to cap and trade, but may reduce the cost of allowances and renewable energy credits
- ◆ **Additional economic benefits of facilitating renewables development**

# 11. Economic Benefits from Construction & Taxes

- ◆ **Comprehensive impact analyses may warrant quantification of direct and indirect economic stimulus benefits (jobs and taxes):**
  - Economic stimulus from construction activities and plant operations
  - Increased taxes for states and counties
  - Economic value of facilitating renewables development and other industrial activity
- ◆ **These benefits can be important to state policy makers and entities along transmission path**
  - For example, we estimated that over a 5-10 year construction and 20 year operations period SPP's \$1.1 billion Priority Projects and associated 3,200 MW wind investments will stimulate at least:
    - 38,000 FTE-years of employment and \$1.5 billion in earnings by these employees, which is supported by (and paid from) over \$4.4 billion in increased economic activity in states within SPP footprint
    - Economic stimulus benefits further increase by 40-80% with increasing in-region manufacturing of wind plant and transmission equipment
    - Transmission construction alone estimated to stimulate \$40 million in additional local tax revenue (on top of any property taxes and right-of-way lease payments directly paid by the transmission owners)

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Appendix A: Difficult-to-Quantify Benefits

**Appendix B: Cost Allocation Methodologies**

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# Basic Cost Allocation and Recovery Approaches

## 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.

# Summary of Current Cost Allocation Methodologies

LP = License Plate Tariffs; PS = Postage Stamp Tariffs or Postage Stamp Allocation; M = Merchant Lines; GI = Generation Interconnection Tariffs;  
 • = workable approach; n/a = workable approach not yet available

RTO/ Region	General Tariff Methodology	Reliability	“Economic” Projects	Renewables	Regional/Overlay Projects
CAISO	PS 100% ≥200kV; otherwise LP or M	✓	✓	✓ GI and location-constrained resource tariff (Tehachapi)	✓ Not specifically discussed, but 100% PS of all network facilities
ERCOT	PS or M	✓	✓	✓ CREZ (100% PS)	✓ Not specifically discussed, but 100% PS of all network facilities
SPP	PS 33% ≥60kV reliability projects; PS allocation for balanced portfolio; otherwise LP or M	✓	✓ “Balanced Portfolio” allocation	✓ GI; Highway/Byway PS treatment	✓ Highway/Byway PS treatment
Southeast	LP (utility specific tariffs)	✓	n/a	n/a (GI only)	n/a
ISO-NE	PS 100% ≥115kV; otherwise LP or M	✓	too narrowly defined	n/a (GI only)	n/a
PJM	PS sharing 100% ≥500kV; otherwise LP allocation (beneficiary pays) or M	✓	too narrowly defined	n/a (GI only)	n/a
MISO	PS sharing 20% ≥345kV; rest LP allocation (beneficiary pays) or M; pending MVP approach	✓	too narrowly defined	✓ Multi Value Project (“MVP”) PS treatment	✓ MVP PS treatment (
PJM-MISO	Sharing of reliability project based on net flows/beneficiaries	✓	too narrowly defined	n/a	n/a
NYISO	LP allocation (based on beneficiary pays) or M	✓	too narrowly defined	n/a (GI only)	n/a
WECC (non-CA)	LP; often with cost allocation based on co-ownership	✓	✓ (differs across WECC subregions)	✓ GI (e.g., BPA open season); under discussion in WREZ	n/a – under discussion in WREZ

# New Tariff-Based Cost Recovery Approaches

## New OATT-based approaches:

- ◆ CAISO:
  - Postage stamp for all network upgrades  $\geq 200\text{kV}$
  - 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:
  - \$1.1 billion Priority 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

# Non-Tariff-Based Cost Recovery Options

## New cost recovery options 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 LLC)
- ◆ 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: Zephyr and Chinook 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



# Additional Reading

- Johannes P. Pfeifenberger and Delphine Hou, "Seams Cost Allocation: A Flexible Framework to Support Interregional Transmission Planning," April 2012.
- Pfeifenberger, Hou, *Transmission's True Value: Adding up the Benefits of Infrastructure Investments*, Public Utilities Fortnightly, February 2012.
- Pfeifenberger, Hou, *Employment and Economic Benefits of Transmission Infrastructure Investment in the U.S. and Canada*, on behalf of WIRES, May 2011.
- Pfeifenberger, *Easier Said Than Done: The Continuing Saga of Transmission Cost Allocation*, Harvard Electricity Policy Group meeting, Los Angeles, February 24, 2011.
- Pfeifenberger, Newell, *Direct testimony on behalf of The AWC Companies re: the Public Policy, Reliability, Congestion Relief, and Economic Benefits of the Atlantic Wind Connection Project*, filed December 20, 2010 in FERC Docket No. EL11-13.
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- "Comments of Peter Fox-Penner, Johannes Pfeifenberger, and Delphine Hou," in response to FERC's Notice of Request for Comments on Transmission Planning and Cost Allocation (Docket AD09-8).
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- Pfeifenberger, "Assessing the Benefits of Transmission Investments," presented at the Working Group for Investment in Reliable and Economic Electric Systems (WIRES) meeting, Washington, DC, February 14, 2008.
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- Pfeifenberger, Testimony on behalf of Southern California Edison Company re: economic impacts of the proposed Devers-Palo Verde No. 2 transmission line, before the Arizona Power Plant and Transmission Line Siting Committee, Docket No. L-00000A-06-0295-00130, Case No. 130, September and October, 2006.

# About *The Brattle Group* / Contact Information

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

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Transmission

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