

The Brattle Group

Transmission Investment Needs and Cost Allocation: New Challenges and Models

Presented to:
Federal Energy Regulatory Commission Staff

Presented by:
Johannes Pfeifenberger, Peter Fox-Penner, Delphine Hou
The Brattle Group

December 1, 2009

Copyright © 2009 *The Brattle Group, Inc.*

The analysis and views contained in this report are solely those of the authors and do not necessarily reflect the views of *The Brattle Group, Inc.* or its clients.

Antitrust/Competition Commercial Damages Environmental Litigation and Regulation Forensic Economics Intellectual Property International Arbitration
International Trade Product Liability Regulatory Finance and Accounting Risk Management Securities Tax Utility Regulatory Policy and Ratemaking
Valuation Electric Power Financial Institutions Natural Gas Petroleum Pharmaceuticals, Medical Devices, and Biotechnology Telecommunications and
Media Transportation

Presentation Overview

I. Investment Trends and Transmission Needs

II. Cost Allocation and Cost Recovery

- ◆ The New Barrier to Investments
- ◆ Existing and Promising New Approaches

III. Case Studies

Appendix: “Difficult-to-Quantify” Transmission Benefits

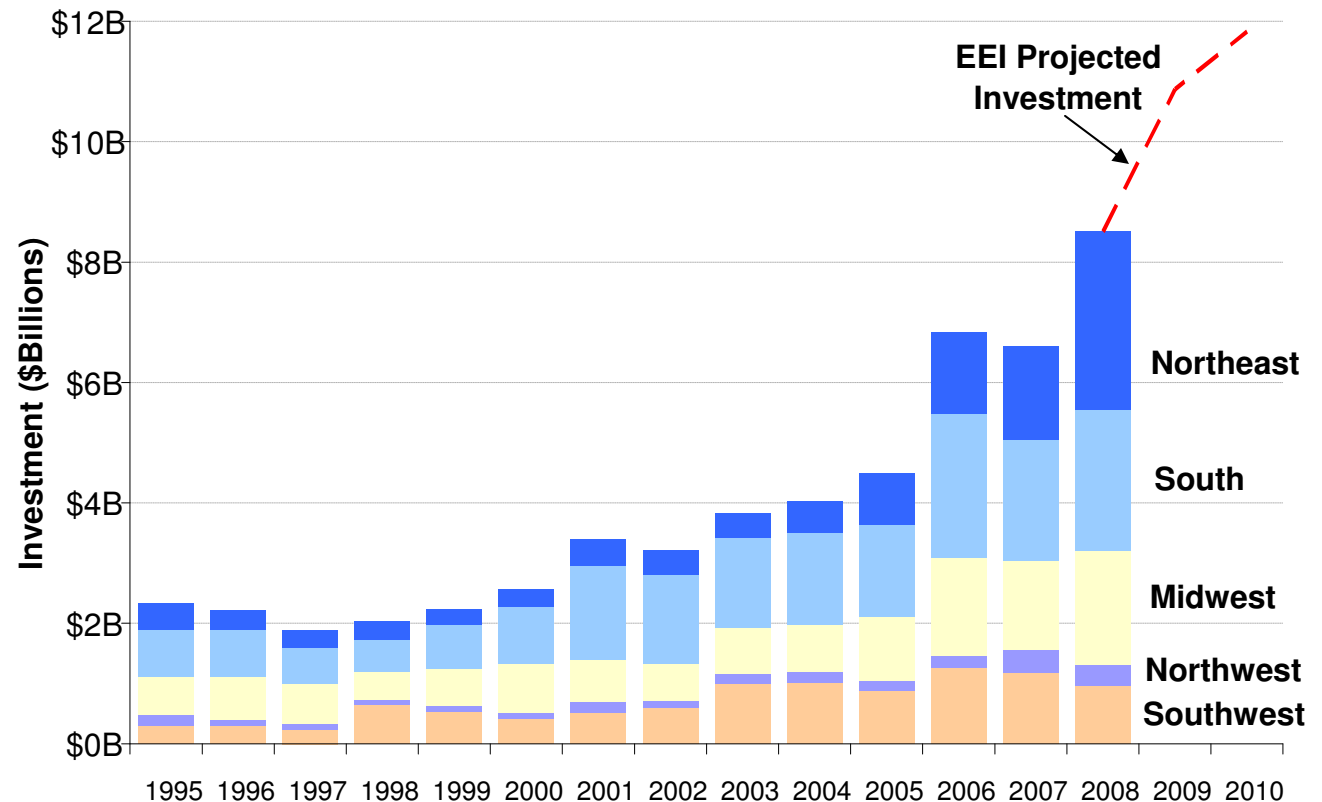
Transmission Investments are on a Strong Upward Trend

Transmission investment in 2008 is quadruple average 1990s level

Likely investment of \$10+ billion annually going forward

NERC projects transmission additions to triple from about 1,000 miles/yr in 2000-08 to 3,100 miles/yr in 2009-18

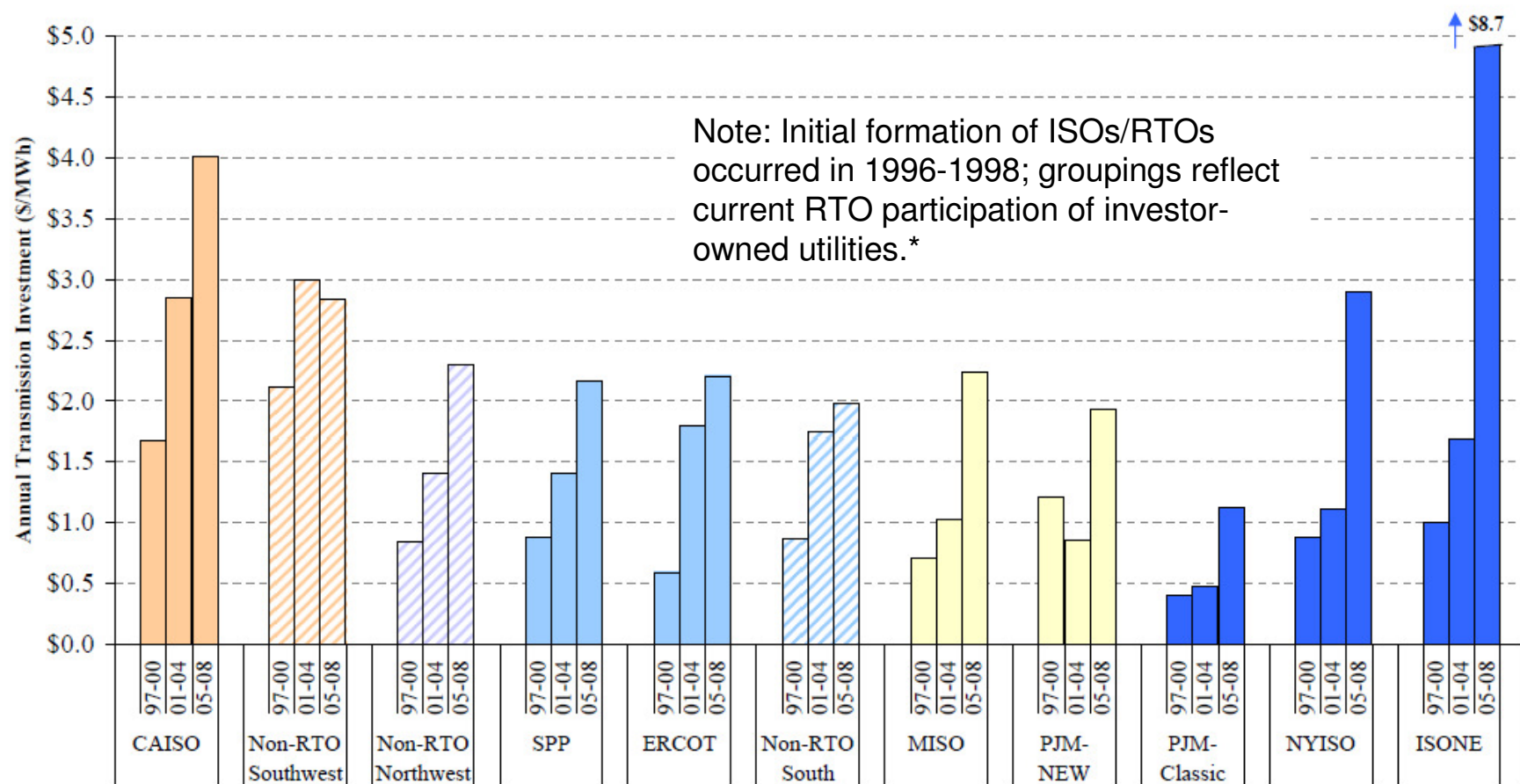
Actual Transmission Net Plant Additions By Investor-Owned Utilities



Source: The Brattle Group based on EEI survey and FERC Form 1 data compiled by Global Energy Decisions, Inc., The Velocity Suite. Investment in miles per year from NERC ES&D database and NERC 2008 Long-Term Assessment.

Transmission Investment Trends Vary by Region

Transmission Plant Additions Per MWh of Regional Load by Investor-Owned Utilities



Source: The Brattle Group based on FERC Form 1 and EIA Form 861 data compiled by Global Energy Decisions, Inc., The Velocity Suite.

*Transmission investment of investor-owned utilities; expressed as total investment dollars per MWh of retail sales.

PJM-New includes Commonwealth Edison, AEP, Dayton, Duquesne, and Dominion. PJM-Classic includes all other PJM members.

Drivers of Future Transmission Additions

- ◆ Near term load growth will be modest to flat if proposed efficiency and demand-side initiatives are implemented – minor driver in most cases
- ◆ Renewable mandates will add up to 130 GW by 2020 and be the major driver of transmission additions
- ◆ Reliability, cyber security, and old facility replacement are lesser but significant drivers
- ◆ Federal climate legislation will boost renewables but reduce demand and probably increase nuclear/CCS coal
- ◆ Better technology to increase voltage, reconductor, or add smart controls – but may ultimately lower the number of new circuit-miles
- ◆ Distributed generation – slow but steady increase
- ◆ Overall, drivers are positive

\$120 billion of New Conceptual and Planned Projects

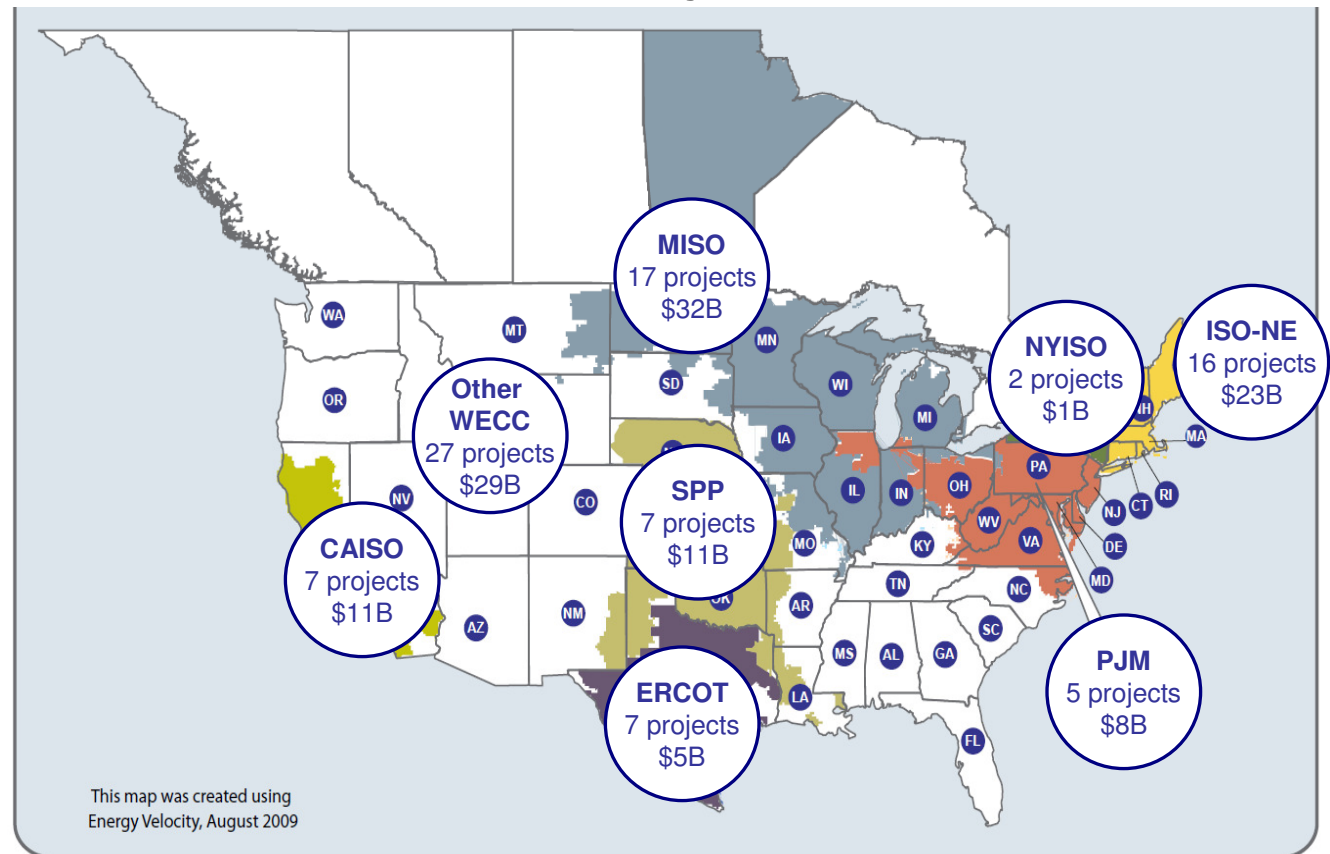
We identified approx. 90 (often overlapping) conceptual and planned projects larger than \$100 million for a total of at least \$120 billion.

Most projects will be built by incumbents.

Some opportunities for participation of transmission companies outside their traditional service areas.

Many of the projects unlikely to get built as proposed.

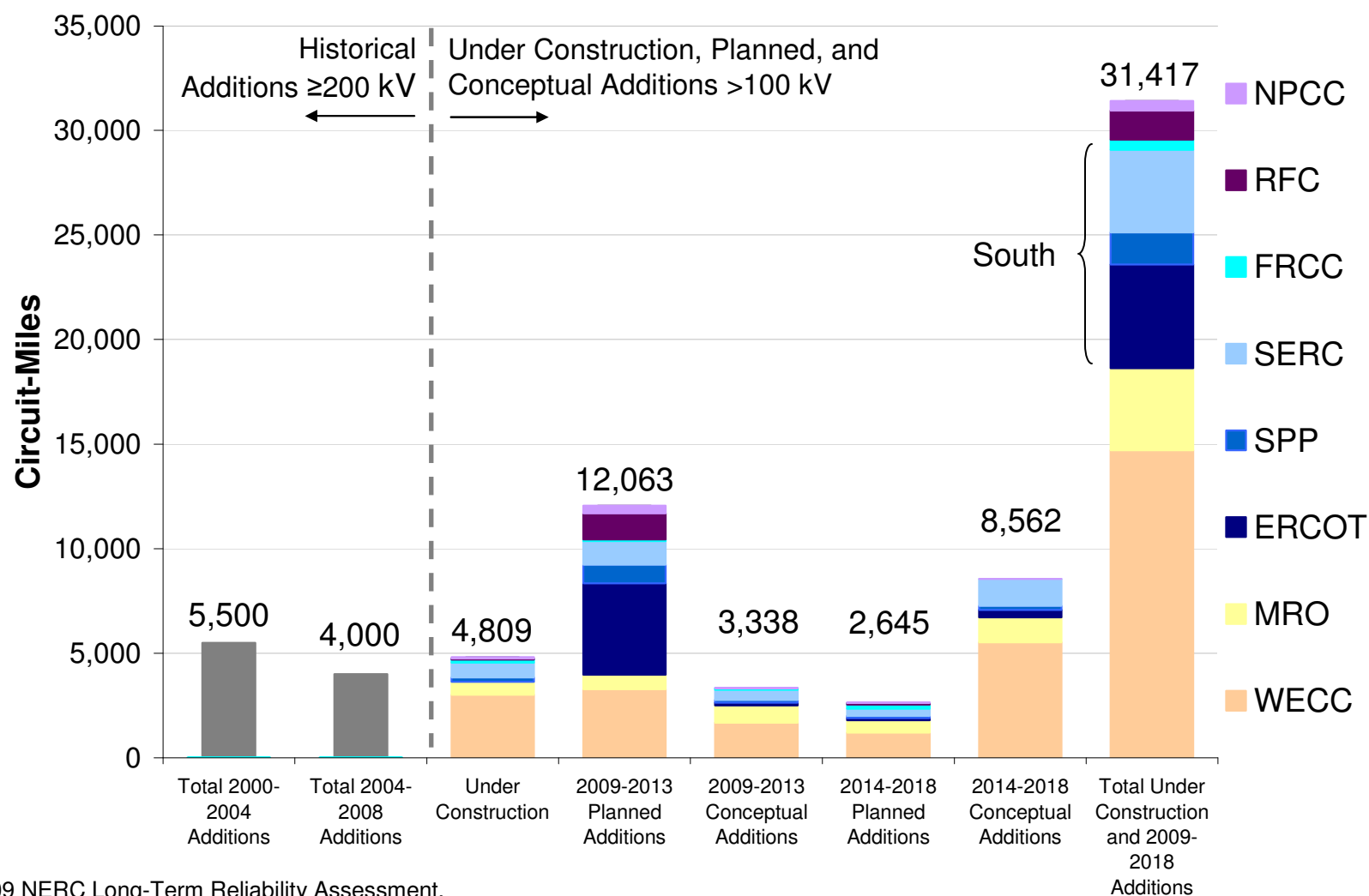
\$120 Billion in Conceptual and Planned Transmission Projects as of 9/09



Source: Map from FERC. Project data collected by The Brattle Group from multiple sources and aggregated to the regional level.

NERC: 31,000 Circuit-Miles of New Transmission by 2018

Historical and Additional Transmission Circuit-Miles by NERC Reliability Region



Source: 2009 NERC Long-Term Reliability Assessment.

How Much Transmission is Actually Needed?

The table compares various renewable overlay studies with the 2009 NERC Long-Term Reliability Assessment estimates for miles of transmission >100kV under construction, planned, and proposed from 2009-2018

Study	Description	Miles of Transmission According to Study	Miles of Transmission Projected by NERC	Transmission Cost (\$/kW wind) ³
DOE 20% by 2030	National buildout after 10% of existing transmission used to integrate 293 GW wind by 2030	12,650	31,418	\$207 [\$61bn total cost]
AEP 765kV Overlay	National 765kV Overlay to integrate 200-400 GW of wind	19,000	31,418	\$150 - \$200 [\$60bn total cost]
ISO New England	Integrate 2-15 GW of wind from New England and parts of Canada	1,015 to 5,000	438	\$1,109 - \$3,575 [\$5-\$29bn total cost]
JCSP	≥345kV overlay in parts of Eastern Interconnect to integrate 60 GW / 229 GW of wind by 2024	9,979 / 14,480	10,799	\$622 / \$259 [\$49/\$80bn total cost]
RGOS ¹	Integrate 25 GW wind in Upper Midwest	4,929 to 7,451	3,924	\$833 - \$1,000 [\$17-\$23bn total cost]
SPP EHV Overlay	765/500kV overlay to integrate ~21 GW wind in SPP by 2027	3,400 ²	1,531	\$329 [\$7bn total cost]
ERCOT CREZ	345kV overlay to integrate ~12 GW wind in ERCOT by 2013	2,376	4,970	\$427 [\$5bn total cost]

¹As of September 17, 2009. ²Estimated. ³Addition of non-wind capacity in \$/kW cost calculation will decrease the estimates for some studies.

Takeaways

Transmission construction and plans for construction are at 3x 1990s pace; expected to continue for a decade or more.

While efficiency policies are likely to constrain load growth, possibly to the point of flat sales, transmission builds will still be needed

- ◆ To integrate renewables due to state RPS and climate goals
- ◆ For reliability, cyber-security, and old facility replacement

Federal climate legislation with a RES will boost renewable and transmission needs, particularly in the Midwest and Southeast.

An unprecedented amount of new transmission is on the drawing boards, mainly point-to-point and incremental builds.

The issues are total need and execution.

I. Investment Trends and Transmission Needs

II. Cost Allocation and Cost Recovery

- ◆ The New Barrier to Investments
- ◆ Existing and Promising New Approaches

III. Case Studies

Appendix: “Difficult-to-Quantify” Transmission Benefits

The 4 “Ps” of Transmission Investments

Planning (utility, state, RTO, inter-RTO or region)

Permitting (state siting boards, state commissions, federal agencies)

- Environmental permits
- Determination of “need” (reliability, economics, ...)

Paying (tariff- and non-tariff-based cost allocation and recovery)

Proprietorship (ownership models)

- Right of first refusal by incumbent transmission owners
- Joint ownership models
- Third-party ownership
- Competitive bidding processes

This section of the presentation focuses on “paying” issues:
Cost allocation and cost recovery

Cost Allocation: What Works and What Doesn't

Existing cost allocation processes have varying degrees of effectiveness.

- ◆ Works well: cost recovery for traditional single-utility, single-state projects built to satisfy reliability needs
- ◆ Mostly works: cost allocation and recovery at the RTO level for reliability-driven regional projects and *conventional* generator interconnection requests
 - Some unintended consequences of existing RTO cost allocation framework
 - MISO's assignment of wind integration costs illustrates difficulties
- ◆ Still mostly unresolved: Cost allocation and recovery for all other types of regional projects, including “economic” projects, *renewable integration* projects, EHV overlay projects, and any multi-purpose projects
 - Only two single-state ISOs (ERCOT and CAISO) have been able to resolve cost allocation for multi-utility, multi-purpose, and renewable integration projects
 - SPP closer to resolving this issue
 - MISO and other RTOs and regions have only started to address this issue
 - Court remand of PJM postage stamp tariff creates additional uncertainty

How Cost Allocation Creates 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 each individual state: share of benefit in excess of allocated share of costs
- ◆ “Beneficiary pays” framework creates incentives to dismiss benefits to achieve lower cost allocation
- ◆ Result: projects that are beneficial to region often do not appear to be beneficial to individual states based on their shares of costs and benefits

How Cost Allocation Creates a Barrier for Regional Projects

Eastern RTOs' economic study frameworks contribute to the problem:

- ◆ Narrow focus on “production cost” simulation models that quantify short-term dispatch cost savings but cannot capture a wide range of transmission-related benefits:

“The real societal benefit from adding transmission capacity comes in the form of enhanced reliability, reduced market power, decreases in system capital and variable operating costs and changes in total demand. The benefits associated with reliability, capital costs, market power and demand are not included in this [type of] analysis.”

(SSGWI Transmission Report for WECC, Oct 2003; emphasis added)

- ◆ Narrow or unrealistic modeling assumptions and simplistic benefit metrics fail to capture full impact of transmission buildout
- ◆ Process fails to capture important (but hard to quantify) benefits of regional transmission projects

Not a single sizable “economic” project approved in MISO, PJM, NYISO, ISO-NE

Important Transmission Benefits are Often Ignored

Eastern RTO planning processes based on “production cost” studies generally do not assess important benefits:

- | | | |
|---|---|---------------------------------------|
| ◆ Enhanced market competitiveness | } | Additional market benefits |
| ◆ Enhanced market liquidity | | |
| ◆ Economic value of reliability benefits | } | Reliability/operational benefits |
| ◆ Added operational and A/S benefits | | |
| ◆ Insurance and risk mitigation benefits | | |
| ◆ Capacity benefits | } | Investment and resource cost benefits |
| ◆ Long-term resource cost advantage | | |
| ◆ Synergies with other transmission projects | | |
| ◆ Impacts on fuel markets | } | External benefits |
| ◆ Environmental and renewable access benefits | | |
| ◆ Economic benefits from construction and taxes | | |

These omitted transmission-related economic benefits, often doubling benefits from production cost studies (see Appendix), make formulaic beneficiary-pays cost allocation approaches unworkable

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 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.

So far, only TX and CA's broad application of postage stamp rates have mostly resolved cost allocation barrier to economic and multi-purpose project development

Current Cost Allocation is Complex and Incomplete

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 specific 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; developing EHV overlay and PS (H/B CARD) treatment	Developing EHV overlay and postage stamp treatment (H/B CARD to be approved)
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	✓	too narrowly defined	n/a (GI only)	n/a – under study via CARP
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 WEC subregions)	✓ GI (e.g., BPA open season); under discussion in WREZ	n/a – under discussion in WREZ

Promising New Tariff-Based Cost Recovery Approaches

Some attractive approaches (and some hopeful efforts) for allocating costs of renewable power projects within RTO tariffs:

- ◆ 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 (see [project summary](#))
- ◆ 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 (see [project summary](#))
- ◆ WECC:
 - WECC utilities often use 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
- ◆ SPP:
 - Developing EHV overlay and postage stamp recovery
- ◆ MISO's CARP:
 - 13-state (OMS) effort to design "injection-withdrawal tariff" -- regional postage stamp, subregional postage stamp, and local license plate rates charged to both load and generators
 - Decision late this year or early 2010

Non-Tariff-Based Cost Recovery Options

A number of transmission developments have successfully bypassed the RTO's tariff-based RTO cost recovery options:

- ◆ 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 (TransCanada; see project summary)
- ◆ 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 HVDC link (see project summary)
- ◆ Mostly used for HVDC lines because (by being “controllable” like pipelines) they allow owners/customers to capture more of the system benefits than AC projects.

Takeaways: Cost Allocation – The Status Quo

- ◆ Resolved only for reliability projects, conventional generation interconnections, in-state economic projects
- ◆ Despite years of effort, cost allocation remains number one barrier for multi-state, multi-utility transmission projects
 - Complicated, unworkable for most new projects
 - Slows transmission development needed for large-scale renewable integration (in particular out-of-footprint and regional overlay projects)
- ◆ TX and CA have mostly resolved issue (but much easier in single states)
- ◆ Promising efforts underway elsewhere but uncertain success
 - Outcome and timing remains uncertain (e.g., MISO CARP)
 - SPP more promising
- ◆ Some options are available to bypass of RTO cost recovery through merchant or regulated bilateral contracts

Takeaways: Options and Recommendations

- ◆ Simplify!
 - Formulaic “beneficiary pays” concepts (we’re economists) unworkable due to broad range and wide-spread nature of transmission-related benefits
 - Some forms of regional and sub-regional postage stamp tariffs (including injection-withdrawal approaches) offer hope for workable “second-best” solutions
 - CA and TX (!) arrived at similar postage stamp solutions
- ◆ Strong support from (or direct involvement by) state governors needed to achieve regional solutions
 - RTOs, transmission owners, and market unlikely to move beyond least-common denominator approaches
 - State commissions lack “political authority” to consider broader policy objectives and negotiate regional solutions
 - Even state-level solutions by CAISO and ERCOT achieved only through legislative mandates
- ◆ Threat of federal cost-allocation backstop seems necessary to achieving timely multi-state allocation agreements

Takeaways: Finding A Siting and Cost Allocation Compromise

- ◆ States are resisting a stronger federal role in mandating transmission lines or siting approval.
- ◆ Conversely, without the threat of federal action it is difficult for states to make multi-state allocation deals.
- ◆ Suggested compromise:
 - ◆ Federal government sets common regional planning process rules and region-specific policy goals
 - ◆ States must form regional planning groups (smaller than interconnection)
 - ◆ Regional plans must meet all reliability rules, renewable targets, carbon targets, and any other legislated goals at the lowest expected costs and states must site all proposed lines in plan
 - ◆ Regional plans should have proposed cost allocations for all EHV lines
 - ◆ If regions fail to provide a plan meeting the requirements, DOE or FERC can develop a plan
 - ◆ Backstop authority attaches to any lines in a federal plan
- ◆ In other words,
 - ◆ Require regional planning that meets standards and has deadlines
 - ◆ Require states to site lines in the plan and the FERC to approve cost allocation
 - ◆ Federal backstop authority expands *only* if the regions do not provide and approve a plan - - and applies to the plan, not the line

I. Investment Trends and Transmission Needs

II. Cost Allocation and Cost Recovery

- ◆ The New Barrier to Investments
- ◆ Existing and Promising New Approaches

III. Case Studies

Appendix: “Difficult-to-Quantify” Transmission Benefits

Transmission Projects: Case Studies

Significant projects are being planned across the US.

- ◆ 90 projects of over \$100 million (total \$120 billion) on the drawing boards
- ◆ Many projects are conceptual and duplicative and may be reconfigured, including owner or developer changes

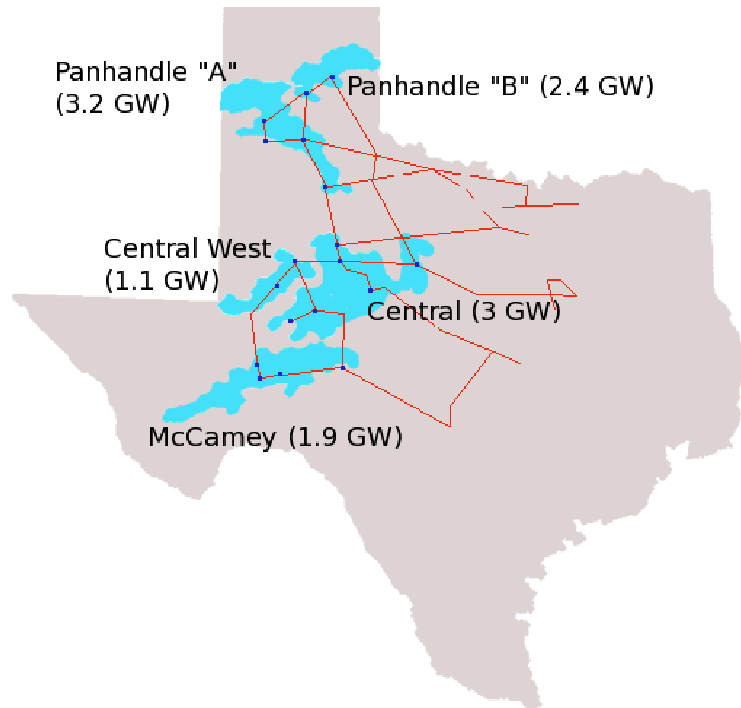
Projects mostly developed and owned by incumbents, but some opportunities for third-party investments

- ◆ HVDC lines
- ◆ Texas CREZ projects openly bid
- ◆ Other regions considering opening to non-incumbents (SPP, Alberta)

Projects and regional efforts with promising cost allocation models:

- ◆ Cost recovery in ERCOT, CAISO, and potentially SPP
- ◆ “Anchor tenant” HVDC lines and similar merchant models
- ◆ CAISO Tehachapi approach – build now, recover from generators later

ERCOT Competitive Renewable Energy Zones (CREZ)



Overview of Projects

- ◆ \$4.93B in total transmission investment, 345 kV lines
- ◆ Need: 7,100 MW of wind in ERCOT today; CREZ integrates up to 18,000MW of total wind resources to be connected to the grid
- ◆ Status: development underway; completion expected 2013-2014

Source: ERCOT and NREL

Relevance: only example of comprehensive renewable overlay open to outside bidders and close to start of construction

Establishment of CREZ spanned multiple agencies:

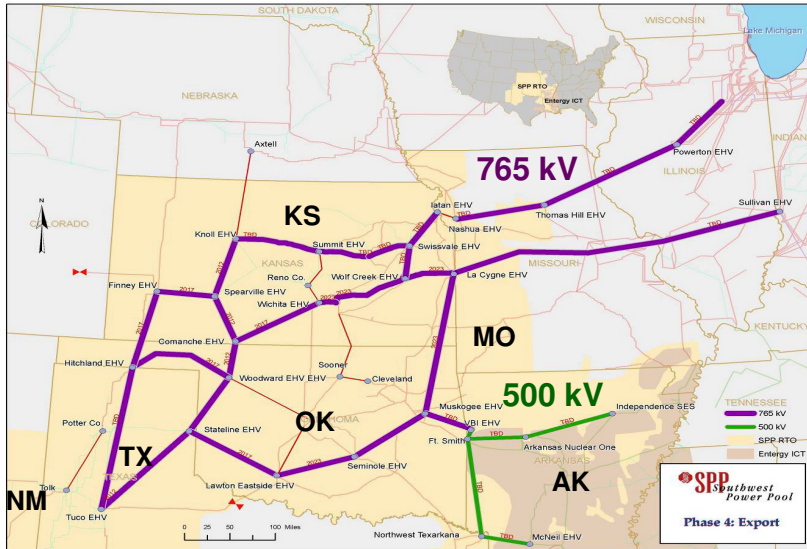
- ◆ Legislation raised RPS, mandated CREZ process to help meet the RPS, and required postage stamp cost allocation
- ◆ ERCOT identified high-potential areas for wind and potential transmission solutions
- ◆ Public Utilities Commission of Texas selected transmission options and established competitive bidding process for transmission to serve these areas

Positive results for new entrants:

- ◆ 14 companies awarded projects, including non-incumbents LS Power subsidiary, AEP-MidAmerican JV, Lower Colorado River Authority, NextEra subsidiary, Wind Energy Transmission Texas
- ◆ Postage-stamp allocation for all CREZ projects

Recent legislation passed restricting new entrants

SPP Conceptual EHV Overlay



Source: 2008 SPP Transmission Expansion Plan, p. 70

Initial EHV overlay plan:

- ◆ Ongoing system modeling and costs-benefit analysis of 2,250 miles of 500 and 765 kV overlay at cost of approx. \$8 billion
- ◆ Overlay project for 20 GW of wind in four phases through 2027

Plans scaled back to \$1.3 billion of priority projects by 2014 and integrate 7-14 GW of wind over 10 years.

Relevance: Hopeful example of multi-state planning and cost allocation

New cost allocation proposal to be developed for filing with FERC:

- ◆ Regional State Committee and SPP Board of Directors tentatively approved a “Highway / Byway” cost allocation rate design (H/B CARD):
 - “Highway projects” or transmission ≥ 300 kV, costs are shared on postage-stamp basis
 - “Byway projects” between 100 to < 300 kV have 1/3 of costs shared on postage stamp basis; 2/3 allocated to local zones
 - “Byway projects” < 100 kV costs fully allocated to local zones
- ◆ Would apply to \$1.3 billion in priority projects, some of which already face significant SPP-internal opposition over scale and cost allocation

CAISO “Tehachapi” LCRI solution



Southern California Edison Project:

- ◆ \$1.8 billion in total costs, 300 miles, 230-500kV in 3 segments
- ◆ Purpose: connect existing and potential wind resources to load centers in Southern California
- ◆ Status: multi-stage project; 1st segments online before end of 2009, final stages online in 2013

Relevance: new tariff-based cost recovery model

- ◆ Project need: over 4,000 MW of potential wind (and some solar) require new transmission
 - Segments 1 and 2 are *network* facilities to which existing postage stamp recovery applies
 - Segment 3 is location-constrained generation interconnection line for which new solution was needed
- ◆ Solution: creation of the FERC-approved Location Constrained Resources Interconnection tariff (LCRI) for Segment 3
- ◆ LCRI recovery for Segment 3: transmission owners pay upfront costs (postage stamp), but as generation comes online, generators pay pro-rata share of costs.
- ◆ Key LCRI conditions: high-voltage transmission facility, must support at least two location constrained resources, cap on total costs eligible, generators must have “demonstrated their interest” in at least 60% of the line

Project is an example of a tariff-based solution to renewable interconnection in advance of (all) generation build.

Other Promising Tariff-Based Approaches in WECC

Cost Allocation Committee (CAC) Process of Northern Tier Transmission Group (NTTG)

- NTTG is group of transmission providers and customers in Northwest and Mountain states; coordinates transmission systems operations, services, and planning.
- CAC consists of representatives from commissions, consumer advocates and public power in ID, MT, OR, UT and WY.
- Developed cost allocation principles.
- Reviews proposed regional projects and makes non-binding cost allocation recommendations based on detailed data, analyses, C-B studies, and cost allocation/ recovery proposals provided by project developers, sponsors and interested stakeholders.
- Evaluated and made recommendations for 16 projects (many “multi-use”) with cost of approx. \$10 billion.
- Mostly license plate cost recovery based on allocation of project ownership and service/reliability obligations.

BPA Network Open Season

- BPA is allowing generation interconnection customers to sign a binding agreement to take transmission service, if available, at embedded cost rates before each network open season deadline.
- BPA guarantees to provide the transmission service as long as it can do so with existing capacity or at costs no greater than its embedded rate.
- Compared to first-come, first-serve approach to clearing interconnection queue, this is hoped to better align new resource development with new transmission development, especially for wind resources.
- The first network open season began April 2008 and will be held at least annually. As of September 2009, approx. 5,500 MW of generation interconnection request (mostly wind) from 2008 network open season process.
- As a result, BPA will invest in 5 transmission projects providing 3,700 MW of new service.

Proposed Chinook and Zephyr Lines



Project proposed by TransCanada:

- ◆ Two 500kV DC lines, 3,000 MW each, \$3 billion each
- ◆ Purpose - to bring wind from Montana and Wyoming into the Southwest, help meet state RPS requirements
- ◆ Construction to begin 2012

Source: http://www.transcanada.com/company/zephyr_chinook.html.

Relevance: merchant cost recovery model based on anchor tenant and open season

- ◆ FERC granted the projects negotiated rate authority
- ◆ Project marks the first time FERC allowed an anchor tenant model for transmission rather than require a pre-construction open season
- ◆ The anchor tenants on both of the proposed lines have committed to approximately 50% of the facility capacity.
- ◆ Developers will enter into a bilateral agreement with an anchor customer for 1500 MW for 25 years and then hold an open season to subscribe the remaining 1500 MW

FERC is allowing the approach in consideration of the unique challenges facing location-constrained resources, and will consider using it for future projects on a case-by-case basis

Proposed Quebec-New Hampshire Line (NU, NSTAR, HQ)



Sponsored by Northeast Utilities (NU), NSTAR, and US subsidiary of Hydro Quebec (HQUS)

- ◆ 1,200 MW HVDC line from Quebec to New Hampshire
- ◆ Will allow for export of power from new hydro resources being developed in Quebec
- ◆ Submission for ISO technical approval expected 2011, completion in 2014

Relevance: new non-tariff, cost-based cost recovery model

FERC-approved concept:

- ◆ NU and NSTAR to charge HQUS negotiated rates capped at the cost-based rate with no open season
- ◆ In return, HQUS will receive firm transmission rights for the 1,200MW capacity of the project and sell generation into the ISO New England market via a minimum 20 year power purchase agreement.
- ◆ When completed, ISO New England will have operational control of the facility but the cost of line will not be included in the ISO tariff

Project is an example of a bilateral transmission agreement designed to avoid ISO tariffs.

About *The Brattle Group*

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

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

Our expertise in the electric utility industry includes:

- Climate Change Policy and Planning
- Cost of Capital
- Demand Forecasting and Weather Normalization
- Demand Response and Energy Efficiency
- Electricity Market Modeling
- Energy Asset Valuation
- Energy Contract Litigation
- Environmental Compliance
- Fuel and Power Procurement
- Incentive Regulation

- Rate Design, Cost Allocation, and Rate Structure
- Regulatory Strategy and Litigation Support
- Renewables
- Resource Planning
- Retail Access and Restructuring
- Risk Management
- Market-Based Rates
- Market Design and Competitive Analysis
- Mergers and Acquisitions
- Transmission

Contact Johannes Pfeifenberger, Peter Fox-Penner and Delphine Hou at
johannes.pfeifenberger@brattle.com, peter.fox-penner@brattle.com, delphine.hou@brattle.com
44 Brattle Street, Cambridge, MA 02138 1850 M Street NW, Washington, DC 20036
617-864-7900 202-955-5050



Appendix: “Difficult-to-Quantify” Transmission Benefits

(Discussion of “Other Benefits” Listed on Slide 14)

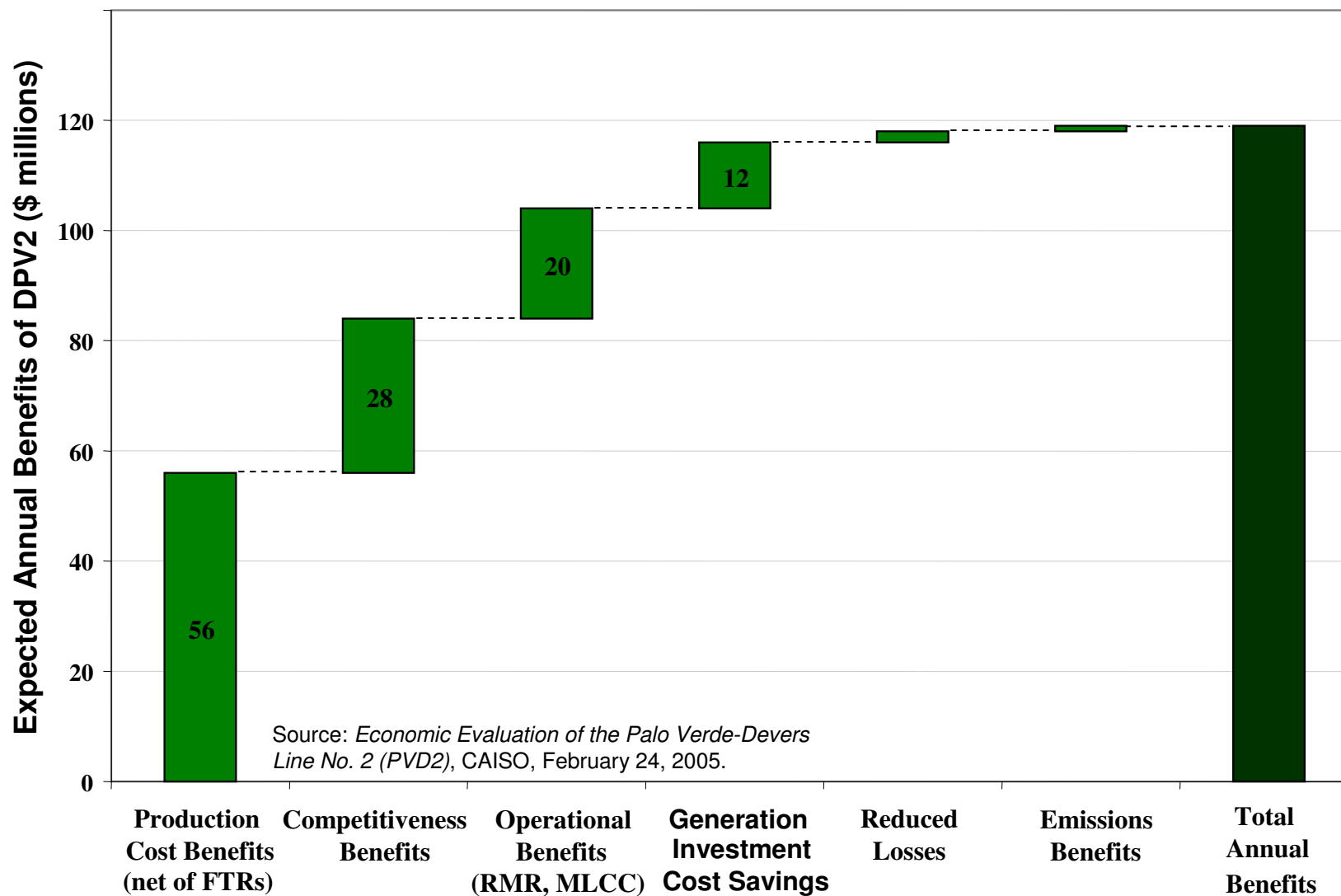
Important Transmission Benefits Often Ignored

Eastern RTO planning processes based on “production cost” studies generally do not assess important benefits:

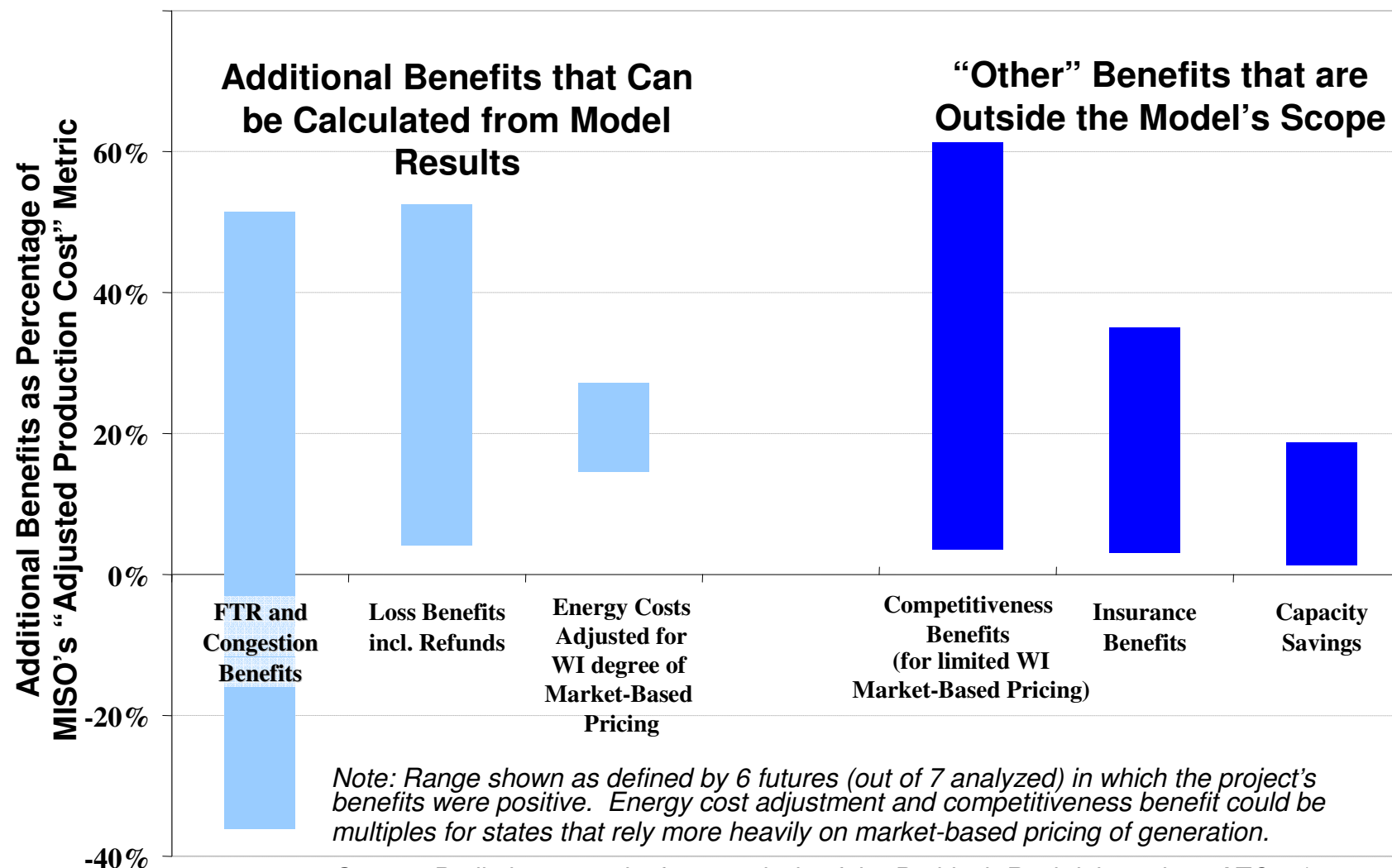
- | | | |
|---|---|---------------------------------------|
| ◆ Enhanced market competitiveness | } | Additional market benefits |
| ◆ Enhanced market liquidity | | |
| ◆ Economic value of reliability benefits | } | Reliability/operational benefits |
| ◆ Added operational and A/S benefits | | |
| ◆ Insurance and risk mitigation benefits | | |
| ◆ Capacity benefits | } | Investment and resource cost benefits |
| ◆ Long-term resource cost advantage | | |
| ◆ Synergies with other transmission projects | | |
| ◆ Impacts on fuel markets | } | External benefits |
| ◆ Environmental and renewable access benefits | | |
| ◆ Economic benefits from construction and taxes | | |

These often omitted transmission-related economic benefits can double benefits quantified in production cost studies. (Potential overlaps create risk of omissions as well as double counting.)

CAISO Example: Total Benefits of DPV2 Were More Than Double its Production Cost Benefits



Example: Adders to Production Cost Savings in Transmission Cost-Benefit Study by *Brattle* and ATC



Source: Preliminary results from analysis of the Paddock-Rockdale project, ATC, 3/07.

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**
 - We found 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. the generation mix and load obligations of market-based suppliers
 - CAISO estimated competitiveness benefits can average 50% to 100% of energy cost benefits (for DPV2 and Path 26 Upgrade), with very wide range (5% to 500%) depending on future market conditions

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

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 would reduce load drop requirements of certain extreme contingencies by 2300 MW (i.e., \$10-\$100 million benefit for each avoided event)

◆ Models tend to 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

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
- ◆ **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
- ◆ **CAISO estimated operational benefit of DPV2 would add 35% to energy cost savings**

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 recent case, value of insurance against high energy costs during extreme events (even ignoring reliability and risk premium) added as much as 25% to production cost savings

Capacity Benefits

◆ New transmission can reduce installed capacity and reserve requirements

1. *Reduced system losses during peak load* reduces installed capacity requirement

- On a recently-evaluated transmission project, loss related capacity benefits on average added 5% to 10% to production cost savings.

2. *Added import capability* may improve LOLE and, as a consequence, allow to reduce 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
- Still, benefits can be large if a project were to trigger such a reduction (e.g., \$8 million annually if Wisconsin reserve margin requirements could be reduced from 18% to 17%)

Long-term Resource Cost Advantage

- ◆ **Impact of transmission on total resource costs (capital and operating) may not be captured in simulation**
 - Simulations with and without the transmission project, but generally for fixed generation system
 - Dispatch models do not generally capture capital costs of resources nor the facilitation of unique low-cost generating options
- ◆ **New transmission can lower total resource costs**
 - Make feasible physical delivery from generation in remote locations that may offer a variety of cost advantages:
 - lower fuel costs (e.g., mine mouth coal plants)
 - better capacity factors (e.g., renewables from wind-rich areas)
 - lower land, construction, and labor costs
 - access to valuable unique resources (e.g., pumped storage)
 - lower environmental costs (e.g., carbon sequestration options)

Risk: double counting of capacity and congestion cost benefits
- ◆ **Advantage of lower-cost remote resource can exceed higher transmission-related costs (incl. congestion and losses)**

Synergies with Other Transmission Projects

- ◆ **Individual transmission projects can provide significant benefits through synergies with other transmission investments**

- For example, construction of DPV2 improves the economics and feasibility of TransWest Express and Project Zia
 - If failure to site DPV2 delays TransWest Express, each year of delay may forego \$200-300 million in low-cost imports to AZ
 - Transmission to access renewables in New Mexico (Project Zia) also 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

- ◆ **Economically justified transmission projects may avoid or delay the need for (or reduce the cost of) future reliability projects**

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.

For example, 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

◆ **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

◆ **These 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

Environmental and Renewable Access Benefits

- ◆ **New transmission can reduce emissions by avoiding dispatch of high-cost, inefficient generation**
 - Can reduce SO₂, NO_x, particulates, mercury, and CO₂ emissions by allowing dispatch of more efficient or renewable generation
 - DPV2 estimated to reduce WECC-wide NO_x emissions from power plants by 390 tons and natural gas use by 6 million MMBtu or 360,000 tons CO₂ 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 in heavily populated areas) 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 (see next slide)**

Economic Benefits from Construction and Taxes

◆ Comprehensive impact analyses may warrant quantification of direct and indirect economic benefits (jobs and taxes):

- Economic value of construction activities and plant operations
- Increased property taxes for counties
- State taxes on generator profits and natural gas use
- Economic value of facilitating renewables development

Can amount to tens of millions of dollars

◆ These benefits can be important if entities along transmission path do not receive certain other economic benefits of transmission expansion

- Constructing 1000 MW of wind generation is estimated to create direct employment of 600 FTE jobs with additional 3,000 indirect and induced FTE jobs. (55 direct and 150 indirect and induced jobs during operating years.)