

The Brattle Group

Transmission Planning and Cost Benefit Analysis

Presented at:
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Agenda

Introduction

Topic 1: The Changing Role of Economic Analysis and Cost-Benefit Assessments in Transmission Planning

Topic 2: Frameworks for the Economic Analysis of Transmission Benefits

Topic 3: Understanding Standard Economic Analysis Tools for Transmission and Their Limitations

Topic 4: “Other” Transmission Benefits Commonly Overlooked or Not Quantified

Additional Reading

Speaker Bios and Contact Information

About *The Brattle Group*

Introduction: Presentation Overview

- ◆ FERC transmission policies, such as the recent Notice of Proposed Rulemaking (NOPR), are revising the existing planning processes for reliability upgrades, generation interconnection, and often narrowly-focused “economic” or “market efficiency” projects by adding **planning for “public policy” requirements.**
- ◆ This presentation will:
 - Describe the role of economic analysis and cost-benefit assessments in transmission planning
 - Present frameworks for the economic analysis of transmission benefits
 - Explain and highlight the limitations of standard economic analysis tools such as production cost modeling
 - Explore often overlooked transmission-related benefits and how to quantify them

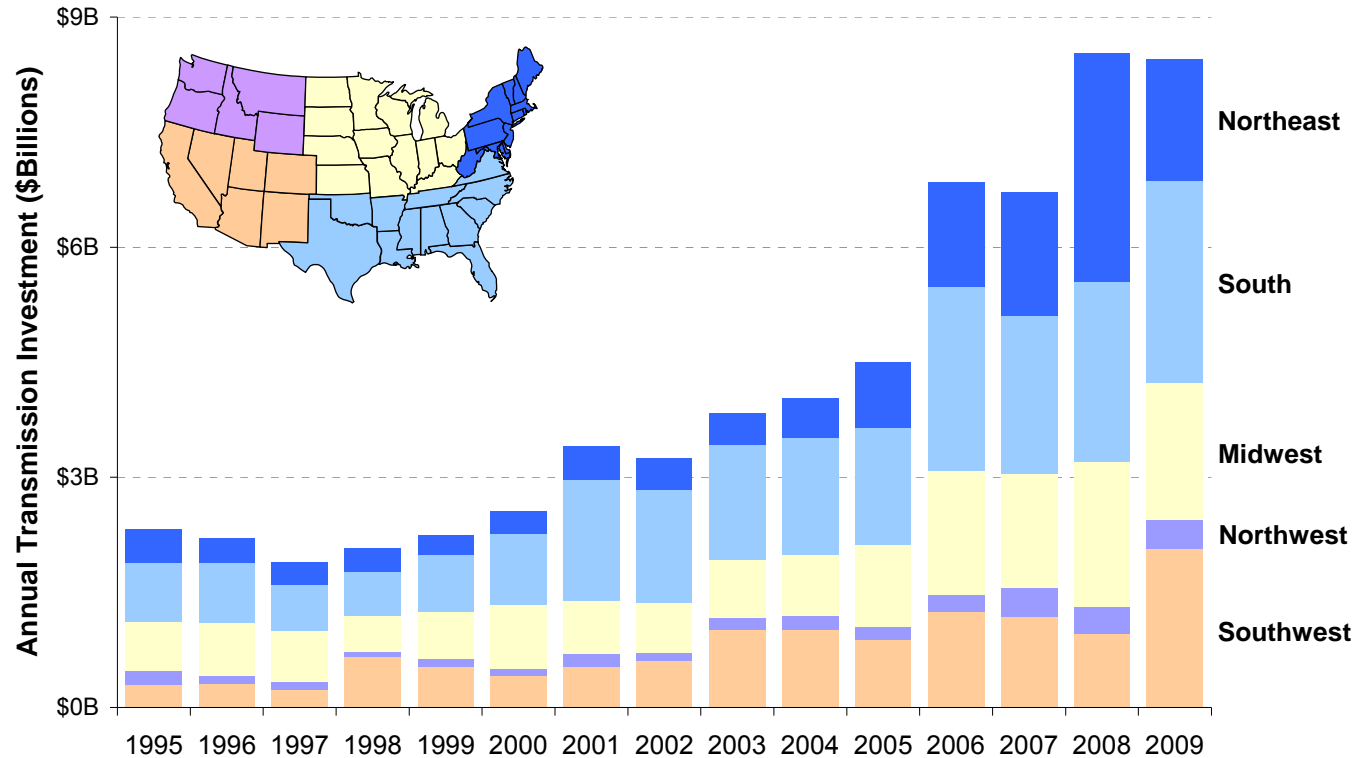
Introduction: Increasing Transmission Investments

Rapid increase in transmission investments from \$2b/year in 1990s to \$8b/year in 2008-09

NERC predicts investment to triple from about 1,000 miles/yr in 2000-08 to 3,000 miles/yr for 2009-2017 (mostly reliability and generation inter-connection projects)

Larger regional upgrades now driven by renewables buildout to meet RPS policy requirements

Annual Transmission Investment of Investor-Owned Utilities by FERC Subregion



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

Introduction: \$180 Billion of Proposed Projects

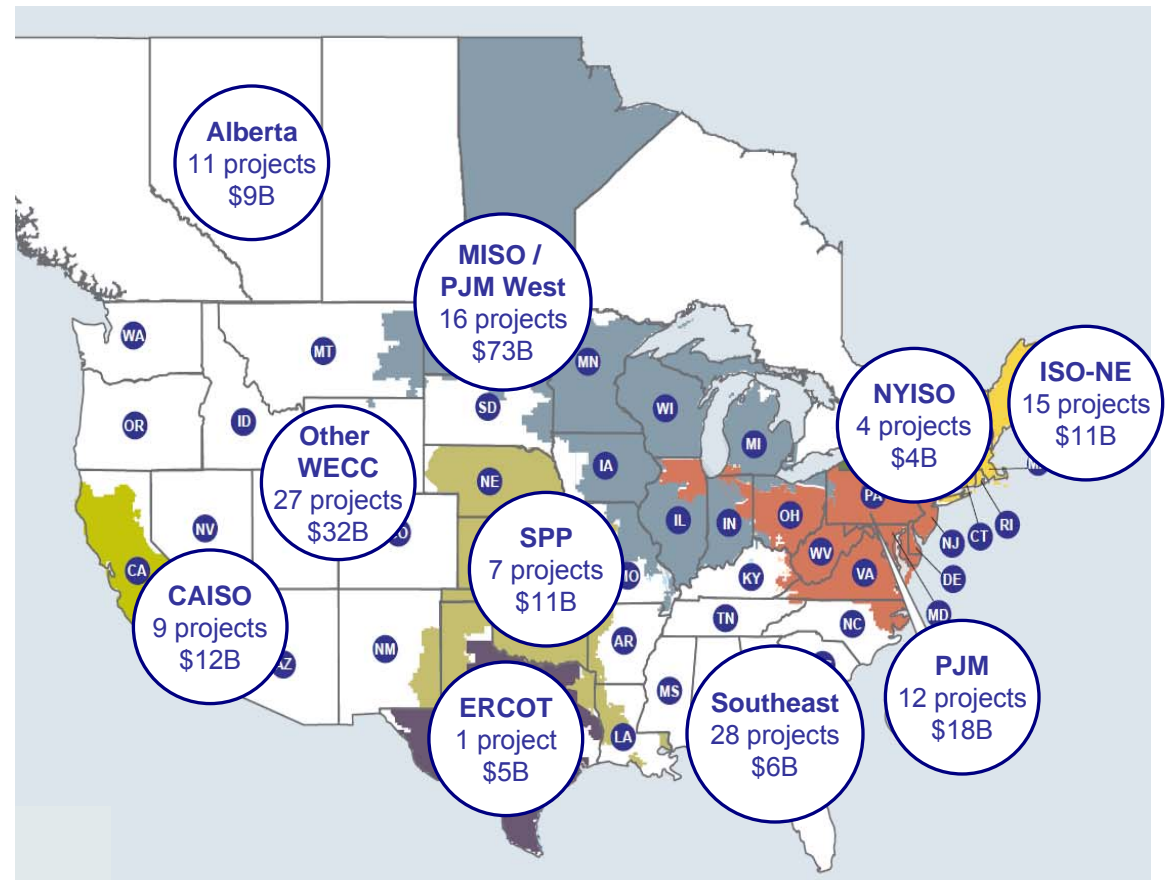
We identified approx. 130 most conceptual and often overlapping planned projects >\$100 million each for a total of over \$180 billion

Many projects driven by large-scale renewable integration but also reliability and congestion relief

A large portion of these projects will not get realized due to overlaps and planning/benefit-cost challenges

Nevertheless, \$60-90 billion likely over next 10-20 years (plus additional baseline reliability and local generation interconnection needs)

\$180 Billion of Planned and Conceptual Transmission Projects as of 9/10



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

Introduction

- Topic 1:** **The Changing Role of Economic Analysis and Cost-Benefit Assessments in Transmission Planning**
- Topic 2:** **Frameworks for the Economic Analysis of Transmission Benefits**
- Topic 3:** **Understanding Standard Economic Analysis Tools for Transmission and Their Limitations**
- Topic 4:** **“Other” Transmission Benefits Commonly Overlooked or Not Quantified**

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Topic 1 – Changing Role of Economic Analyses

In this section we discuss the changing role of economic analyses in transmission planning, some of the challenges the industry faces in planning for economic and public policy projects, and how FERC is attempting to address them.

We will cover:

- ◆ The challenges of planning for and allocating costs of economic and public policy-driven projects
- ◆ FERC's NOPR on transmission planning and cost allocation and recent orders that try to address these challenges
- ◆ Building a “business case” for economic and public policy-driven projects
- ◆ Planning implications of difficult-to-quantify economic impacts
- ◆ The difference between analyses to assess project benefits and analyses for cost allocation

Industry Challenges Leading to FERC NOPR on Transmission Planning and Cost Allocation

- ◆ Examples of challenges of planning for economic (i.e., congestion relief) and public policy-driven (e.g., state mandated renewable portfolio standards or RPS) projects:
 - ◆ PJM – believes that without explicit direction, it may not consider public policy-driven projects under the current tariff
 - ◆ ISO New England, NYISO – public policy-driven projects are evaluated using the same procedures as “economic” projects with narrow benefit definitions and difficult to overcome benefit-cost ratios
- ◆ Some regions (e.g., CAISO, ERCOT, SPP, and Midwest ISO) have implemented or filed mechanisms to consider public policy mandates using a broader transmission planning framework and region-wide cost allocation
- ◆ In the non-RTO WECC, multi-purpose projects are often considered; history of transmission co-ownership (participant funding) and ability of transmission owners to charge for wheeling has helped fund projects
 - ◆ Traditional participant funding approach may start to be unworkable for large new project with wide-spread benefits
- ◆ Given the challenges that still remain (especially for Eastern RTOs or non-RTO regions), the FERC NOPR specifically addresses consideration of public policy goals, intra-and inter-regional planning, and cost allocation

FERC's NOPR on Transmission Planning

FERC's NOPR has significant implications for economic analyses and cost-benefit assessments of projects. It addresses:

- ◆ Public policy consideration – transmission planning must consider public policy requirements established by state or federal laws or regulations
- ◆ Mandatory regional transmission plans – regions must develop and file actual transmission plans
- ◆ Inter-regional planning process – neighboring regions must coordinate and have a transmission planning process that considers reliability, economic, and public policy projects that span both regions
- ◆ Cost allocation – regional and inter-regional plans must include cost allocation for reliability, economic, and public policy-driven projects
- ◆ Right of First Refusal – **Not covered in our presentation**
 - ◆ Remove ROFR from FERC-approved tariffs, but does not preempt state-specific rules
 - ◆ Add process for independent developers seeking tariff-based cost recovery and participation in regional plans

Details on Specific FERC NOPR Components

◆ Planning for public policy requirements

- ◆ Example: state-mandated Renewable Portfolio Standards (RPS)
- ◆ Even if one state in the region has RPS requirement, the regional transmission plan will have to consider it
- ◆ Need to be considered in transmission planning in the same manner that reliability and congestion relief would be considered by a “prudent” utility

◆ Regional cost allocation principles

- ◆ Allocation should be based on “cost causation” or “beneficiary” principles
- ◆ Costs allocated should be “at least roughly commensurate with estimated benefits”
- ◆ Costs can only be allocated to regions in which the facility is located
- ◆ Those that receive no benefit must not be involuntarily allocated costs
- ◆ Facilities located entirely within one transmission owner’s service area do not require (but can be granted) regional allocation
- ◆ Postage stamp may be appropriate:
 - ◆ If all customers tend to benefit from class or group of facilities
 - ◆ If distribution of benefits likely to vary over long life of facilities
- ◆ FERC will use backstop cost-allocation authority if no agreement is reached amongst regional stakeholders

Details on Specific FERC NOPR Components

◆ Interregional Planning and Cost Allocation

- ◆ Regions need to share plans and coordinate planning processes
- ◆ Requires cost allocation methodology for projects spanning both regions
- ◆ Cost of facilities located solely in one region cannot be allocated to neighboring region (unless voluntarily/with agreement)

◆ Scope of Benefits

- ◆ Broad set of transmission related benefits can be considered
- ◆ Benefits from individual facilities or group of facilities
- ◆ Present and likely future benefits:
 - ◆ Explicitly recognizes that benefits (and beneficiaries) may change over the life of facility due to “changing power flows, fuel prices, population pattern, and local economic development”
- ◆ Specified that individual categories of benefits can include (but are not limited to):
 - ◆ Reliability
 - ◆ Reserve sharing
 - ◆ Production cost savings and congestion relief
 - ◆ Meeting public policy goals
- ◆ If benefit-to-cost ratios are used they “must not be so high that facilities with significant positive net benefits are excluded” (e.g., not higher than 1.25)

The “Business Case” for Transmission Projects

Effective planning for “economic” or “public policy goals” differs significantly from traditional transmission planning

- ◆ Traditional transmission planning:
 - ◆ Oriented toward avoiding reliability violations (and interconnecting large individual generation resources without reliability violations)
 - ◆ Clear criteria (reliability standards)
 - ◆ Well-honed (formulaic) evaluation process and established tools
- ◆ Planning for economic and public policy projects:
 - ◆ Akin to developing a “compelling business case” (a challenge in any industry)
 - ◆ 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
 - ◆ Lack of established evaluation processes and tools for many types of benefits
 - ◆ Often requires an “integrated resource planning” effort to choose among alternative and determine optimal combination of generation and transmission investments

Without developing a compelling “business case” or resource plan, economic and public-policy projects may fail to gain the broad policy-maker and multi-state support needed for approvals, permits, and cost recovery

Implications of “Difficult to Quantify” Benefits

Planning processes need to recognize that many transmission benefits are difficult to quantify

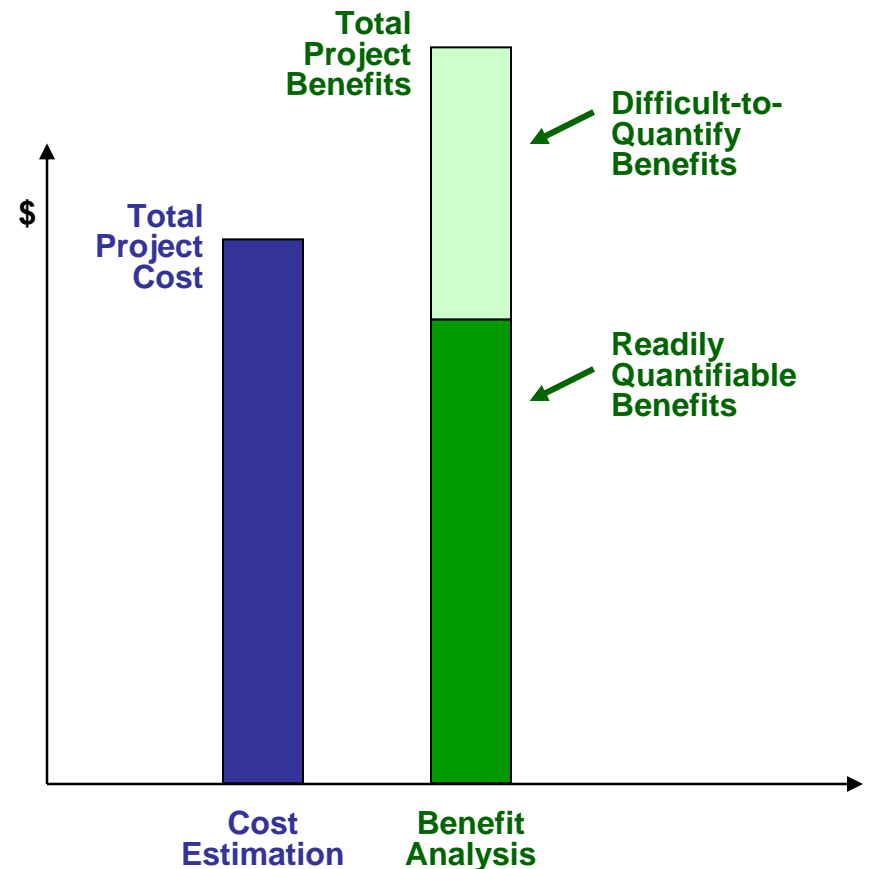
- ◆ There are no “unquantifiable” or “intangible” benefits
- ◆ Difficult-to-quantify benefits need to be explored and considered at least qualitatively
- ◆ Standard economic analysis tools (e.g., production cost models) capture only a portion of transmission-related benefits

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 also generally be less than benefits for an entire group of projects

Illustrative Example



Implications of “Difficult to Quantify” Benefits (cont’d)

FERC noted in its recent approval of SPP’s “Highway/Byway” cost allocation methodology, that most benefit-cost analyses:

- ◆ Do not evaluate many difficult-to quantify benefits provided by EHV facilities, including for example:
 - ◆ Congestion reduction and enhanced reliability by reducing loading on existing lines; increased ability to withstand emergencies
 - ◆ Access to a wider range of generation resources
 - ◆ Flexibility to adjust to additional federal and state energy policies
- ◆ Analyze benefits as of only one point in time and do not consider how the function and benefits of facilities change over time with system conditions and future generation and transmission expansions

FERC’s NOPR and SPP orders underscore that projects with wide range of benefits may not pass target benefit-cost ratios because:

- ◆ Certain benefits are not considered under current narrow tariff language
- ◆ Some benefits are difficult to quantify and are often overlooked
- ◆ Some benefits are subjective and need to be weighed against a set of realistic alternatives, especially for public policy-driven projects
 - ◆ Key state-level policy makers will need to be involved

Overall Project Benefits vs. Cost Allocation

Analysis of overall project benefits should be done prior to and separate from analyses to determine how costs should be allocated

Recommend 2-step approach:

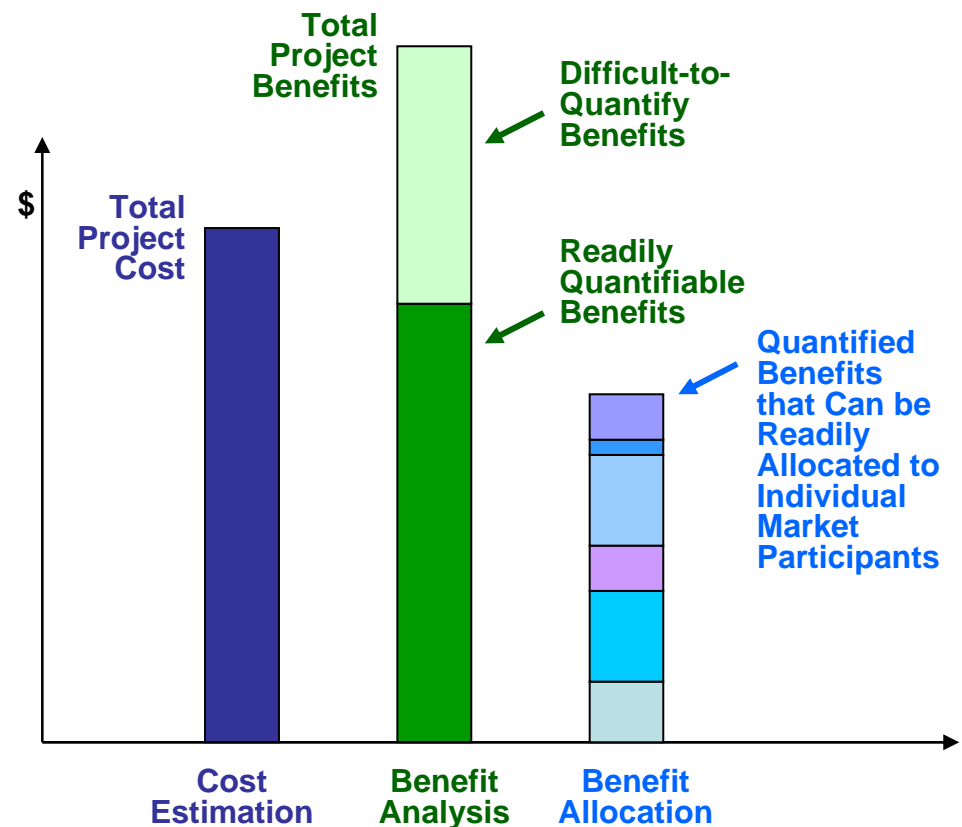
1. Determine whether a project is beneficial to the region
2. Evaluate how the cost of beneficial projects should be allocated

Because:

- ◆ Relying on allocated benefits to assess overall project economics would result in rejection of some desirable projects
- ◆ Benefits that can be allocated readily or accurately tend to be only a subset of readily-quantifiable benefits

Example: NYISO economic project evaluation and cost allocation based only on narrowly-defined, readily-quantifiable benefits (not helpful that cost allocation allows qualitative consideration of other benefits)

Illustrative Example



Overall Project Benefits vs. Cost Allocation (cont'd)

The recently FERC-approved SPP “Highway/Byway” cost allocation methodology provides helpful guidance

- ◆ SPP’s methodology (postage stamp for facilities $\geq 300\text{kV}$) was developed by Regional State Committee in context of evaluating an actual set of “Priority Projects”
- ◆ SPP approved projects considering many different benefits types of benefits
 - ◆ Adjusted production costs insufficient, but 1.78 benefit-cost ratio overall after considering other benefits (value of reduced losses, wind revenue impact, gas price impact, reliability value, economic development value)
- ◆ In a separate analyses, SPP supported postage stamp cost allocation
 - ◆ Engineering analysis to show that EHV facilities $\geq 300\text{ kV}$ are largely used for region-wide energy transfers and therefore should have region-wide cost allocation
 - ◆ No state-level benefit-cost tests were performed, but economic analyses show most benefits are wide-spread and each state benefits in one way or another
- ◆ SPP Priority Projects and “balanced portfolio” projects also show that benefits of a group of projects will tend to be more-evenly-distributed than the benefits offered by individual projects (similar experience in ISO-NE)

Overall Project Benefits vs. Cost Allocation (cont'd)

FERC approved SPP's Highway/Byway (postage-stamp) cost allocation methodology noting that it is roughly commensurate with benefits

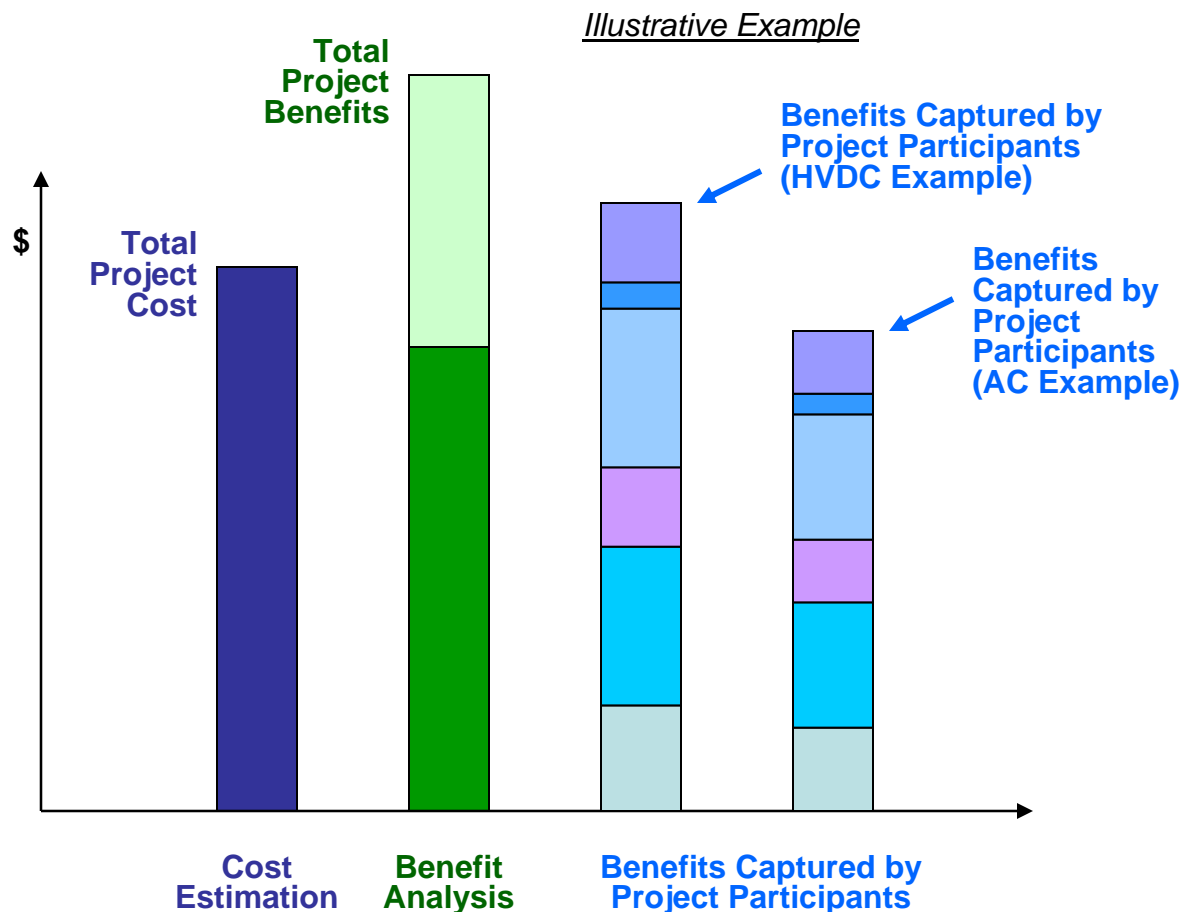
- ◆ Users change over time and availability of system for use itself is a benefit to users as a whole
- ◆ Production cost savings are not the only metric relevant in considering whether costs are roughly commensurate with benefits
- ◆ Sole reliance on quantitative analysis to support cost allocation not required because:
 - ◆ Quantitative analyses may not accurately reflect true beneficiaries
 - ◆ Often do not consider “qualitative (less tangible)” regional benefits inherently provided by the EHV transmission network
 - ◆ Do not consider how function and benefits of individual facilities changes over time with system conditions and future generation and transmission expansions
 - ◆ Often do not capture how different customers realize different types of benefits at different times

Overall Project Benefits vs. Cost Allocation (cont'd)

Tension between overall project benefits and cost allocation also an issue for participant-funded (incl. merchant) transmission projects

- ◆ Overall project benefits more easily captured for HVDC projects that allow control of power flows and access
 - ◆ First choice for many merchant projects
- ◆ AC project benefits generally more wide-spread, allowing more non-participants to “free ride” on regional project benefits

Participants may or may not capture enough of overall benefits to be willing to pay for desirable projects



Introduction

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Topic 2: **Frameworks for the Economic Analysis of Transmission Benefits**

Topic 3: Understanding Standard Economic Analysis Tools for Transmission and Their Limitations

Topic 4: “Other” Transmission Benefits Commonly Overlooked or Not Quantified

Additional Reading

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Topic 2 – Economic Analysis Frameworks

In this section we discuss some of the challenges in specifying an effective framework for the economic analysis of transmission benefits.

We will cover:

- ◆ Benefits to whom and when? – the challenge of applying analyses with limited accuracy and foresight to long-lived assets
- ◆ Benefits compared to what? – the need for correct comparison cases
- ◆ Differences between analyzing market efficiency and public-policy projects
- ◆ Short-term production cost savings vs. long-term resource costs
- ◆ The tension between lowest cost and highest value

Benefits to Whom and When?

The benefits of many transmission projects are:

Broad in scope	<ul style="list-style-type: none"> ▪ Dispatch cost savings ▪ Regional reliability benefits ▪ Fuel diversification and fuel market benefits ▪ Renewable power for RPS ▪ Economic development ▪ FTR allocations ▪ Reduction in system losses
Wide-spread geographically	<ul style="list-style-type: none"> ▪ Multiple transmissions service areas ▪ <u>Multiple states</u> or regions
Diverse in their effects on market participants	<ul style="list-style-type: none"> ▪ <u>Customers, generators, transmission owners</u> in regulated and/or deregulated markets ▪ Individual market participants may capture one set of benefits but not others
Occur and change over long periods of time	<ul style="list-style-type: none"> ▪ Several decades ▪ Changing with system conditions and future generation and transmission additions ▪ Individual market participants may different types of benefits at different times

Benefits Compared to What?

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

- ◆ Benefits are 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 (e.g., different load and fuel price forecasts, different environmental regulations, different 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 may explore costs and benefits for different project configurations, project alternatives, or market responses to the project
- ◆ For most sizeable projects, the change case may need to differ from the base case by more than the project itself (e.g., the project will often affect future generation additions or retirements)

Comparison cases need to be fully specified before compelling economic (or often even reliability) 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. This has important implications for their analysis:

- ◆ 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 transmission overlays that can integrate renewables needed to meet RPS, often requires the comparison of the proposed project(s) to one or more alternative means of satisfying the requirements:

**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**

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 participants will respond to impact of 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 public policy requirements, such as RPS

Lowest Cost vs. Highest Value

- ◆ Many current planning frameworks attempt to achieve project 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 will not always offer the highest value and lowest system-wide costs in long run
 - ◆ Up-sizing reliability project may capture additional economic benefits (market efficiencies, reduced transmission losses, etc.)
 - ◆ Up-sizing market efficiency project 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

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Topic 3 – Tools and their Limitations

In this section we discuss some of standard economic analysis tools used to evaluate transmission benefits.

We will cover:

- ◆ Tools commonly used to analyze economic impacts of transmission
- ◆ The transmission-related benefits they can estimate
- ◆ What are “adjusted production costs” and “load LMP” metrics
- ◆ Which impacts these metrics capture and what they miss

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	Used to estimate production costs and market prices (LMPs or zonal). Simulation of security-constrained economic dispatch, used to calculate production cost, congestion relief, and market price benefits	<ul style="list-style-type: none"> ▪ APC ▪ Load LMPs ▪ Emissions 	<ul style="list-style-type: none"> ▪ <u>Nodal</u>: PROMOD, GE-MAPS, Dayzer, UPLAN, GridView, PowerWorld ▪ <u>Zonal</u>: MarketSym, Aurora
Power Flow Models	Used mostly for reliability studies (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"> ▪ System losses ▪ FCITC 	<ul style="list-style-type: none"> ▪ PSS/E, PSLF, MUST, POM, PowerWorld
Capacity Expansion Models	Used to estimate approx. impact of change in transmission capabilities (between zones) on generation additions and retirements. 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"> ▪ Total generation costs (investments and operations) ▪ Plant additions and retirements 	<ul style="list-style-type: none"> ▪ Aurora, EGEAS, Strategist (public) ▪ IPM, NEEM, RECAP (proprietary)
Reliability Assessment Models	Used to estimate loss-of-load-expectation and expected unserved energy	<ul style="list-style-type: none"> ▪ LOLE, LOLP, UNE, required reserve margins 	<ul style="list-style-type: none"> ▪ GE MARS, SERVM

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 remain assumptions-driven (simplifications; short-term vs. long-term; contracts often ignored)
- ◆ Different benefit metrics can produce very different results
- ◆ Limited number of 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)
- ◆ Many “other 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)**
 - ◆ Combined metric: 70% APC + 30% LLMP
- ◆ **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
- ◆ **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

Common Metrics: “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 net imports** (valued at the area-internal load LMP)

– **Revenues from net exports** (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 area
- ◆ 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)
- ◆ Does not factor in the extent to which additional transmission capacity could make additional FTRs available to load serving entities in the zone or region
- ◆ Does not capture FTR payments and loss refunds in RTO environments (assumes area-internal congestion is fully hedged with FTRs without marginal loss charges)
- ◆ Does not consider the extent to which utilities in an area are buying or selling off system; overstates or understates customer benefits by not distinguishing between regulated and merchant generation within the area

Common Metrics: “Load LMP”

“Load LMP” (LLMP) meant to capture the power purchase costs for utilities without cost-of-service-regulated generation or long-term contracts (e.g., in restructured retail markets):

- ◆ **Load LMP (LLMP) =**

- Purchase power costs incurred if all load within an area were supplied at nodal spot-market prices** (i.e., no load supplied with cost-of-service generation or long-term contracts)

- ◆ *Limitations:*

- ◆ Meaningful measure of customer impacts only if 100% of the area’s load is supplied through wholesale market purchases and long-term contracts expire in near term
 - ◆ Assumes allocated FTRs are unavailable to load serving entities; also ignores marginal loss refunds
 - ◆ Generally not meaningful metric in a cost-of-service environment; will confuse benefits and costs if the utility is a net seller in wholesale power market
 - ◆ Also ignores extent to which congestion and loss reduction impacts generation
 - ◆ 70% APC-30%LLMP metric roughly approximates impact on utility with 70% cost of service generation and 30% market-based purchases; but metric suffers from both APC and LLMP limitations

Post-Processing of Simulation Results

Some of the limitations of APC and LLMP metrics can be addressed by post-processing detailed simulation data output

- ◆ **Congestion and FTR impacts**

- ◆ Expansions reduce congestion and add feasible FTRs
- ◆ Benefits also depend on extent to which congestion is hedged through existing allocations of FTRs
- ◆ Our ATC work shows this can add or subtract 50% depending on market conditions, metric (e.g., APC vs. LLMP), and treatment of imports

- ◆ **Transmission loss reduction**

- ◆ Do modeled losses actually change with transmission investments?
- ◆ Are marginal losses and loss refunds considered?
- ◆ Can add 25% to production cost savings (subtract 5-10% from Load LMP savings) plus capacity value of reduced peak load; total energy and capacity value of loss reduction can offset up to 30-50% of project costs!

- ◆ **Customer benefits under cost-of-service vs. market-based generation**

- ◆ Market structure matters!
- ◆ Can change utility and customer impact by 50%

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Topic 4 – “Other” Benefits

In this section we discuss some of the “other” transmission-related benefits that are commonly overlooked or not quantified.

We will cover:

- ◆ Why these benefits are frequently overlooked
- ◆ The specific types of benefits commonly overlooked and not quantified
- ◆ The potential magnitude of these benefits
- ◆ The individual benefits and how they can be evaluated

Often Overlooked “Other” Transmission Benefits

Many planning processes (e.g., by eastern RTOs) are based solely on production cost simulations (APC, LLMP metrics), which quantify short-term dispatch cost savings and LMP impacts but do not 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 limitations of simulations and benefit metrics fail to capture full impact of transmission buildout, especially of regional transmission projects

- ◆ Frequent outcome is that quantified benefits do not exceed project costs
- ◆ Perhaps not surprisingly, not a single sizable “economic” or “market efficiency” project has been approved in MISO, PJM, NYISO, ISO-NE

Often Overlooked “Other” Transmission Benefits

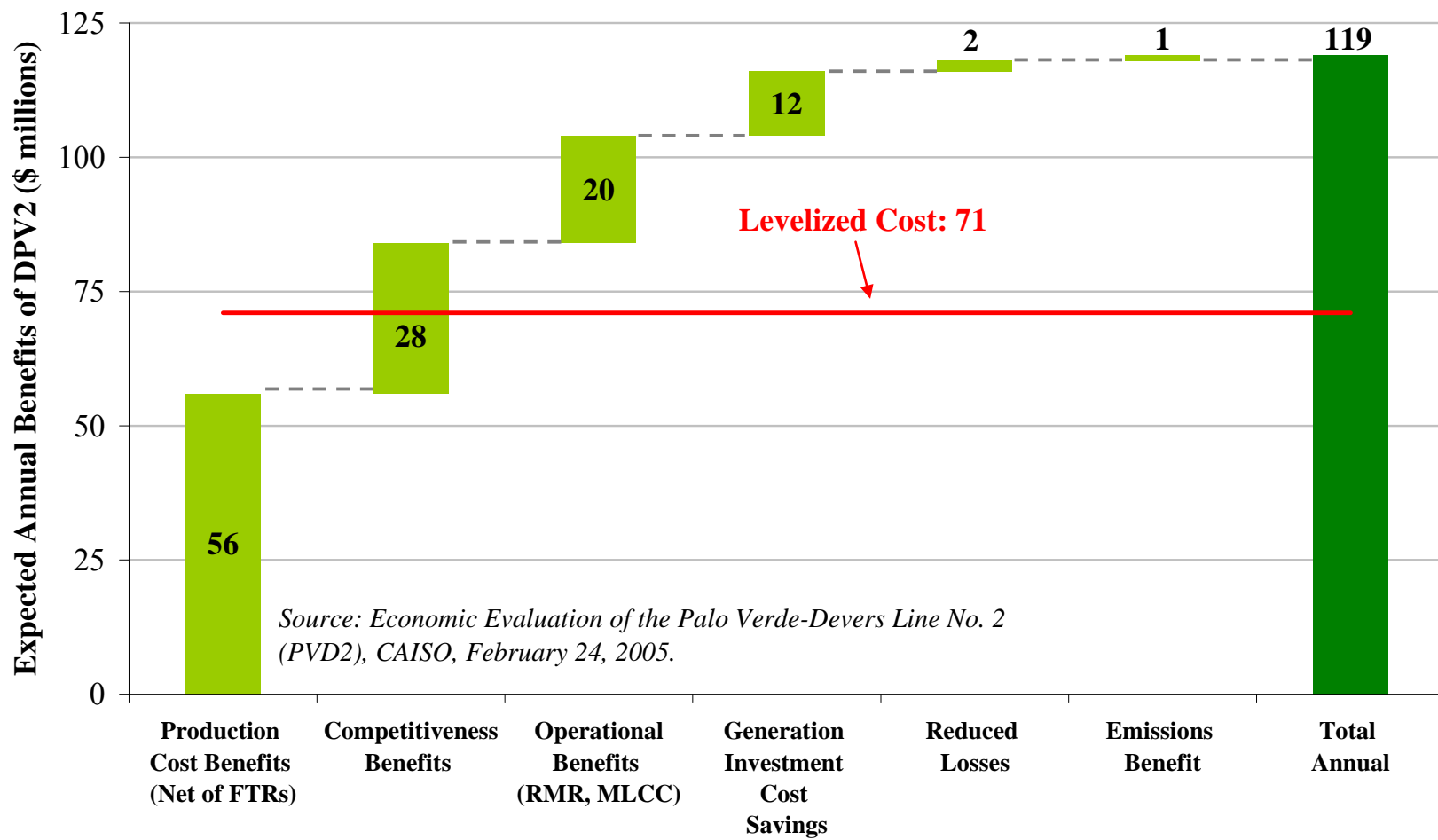
Important transmission benefits, some of which are listed below, are often overlooked because of production cost model limitations and the complexity involved in quantifying these benefits

- | | | |
|---|---|---------------------------------------|
| 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 | | |

These benefits can double benefits quantified in production cost studies and offset a substantial portion of project costs

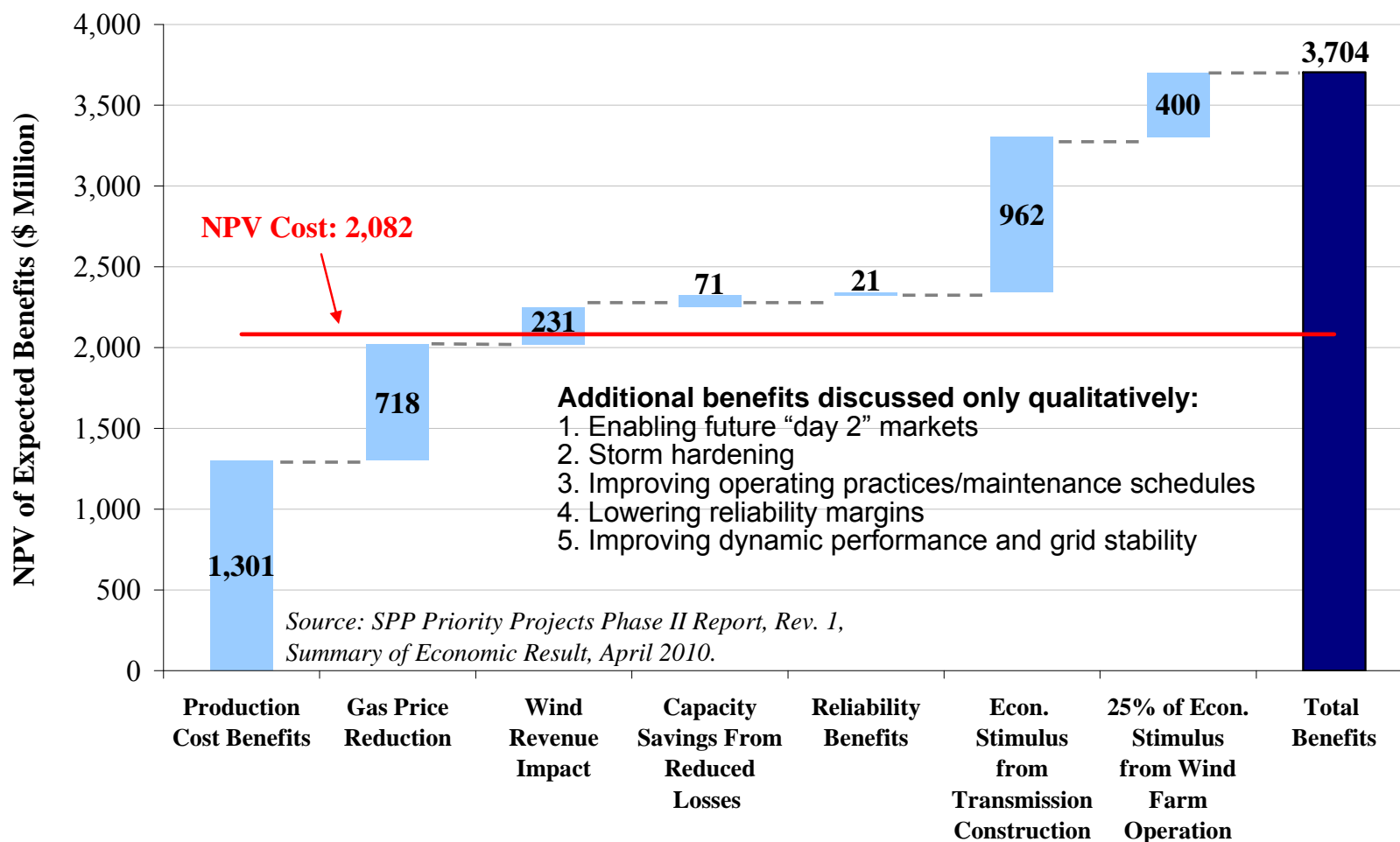
The Magnitude of “Other” Benefits Can Be Large

Example: Total benefits of SCE’s DPV2 project in CAISO were more than double its production cost benefits



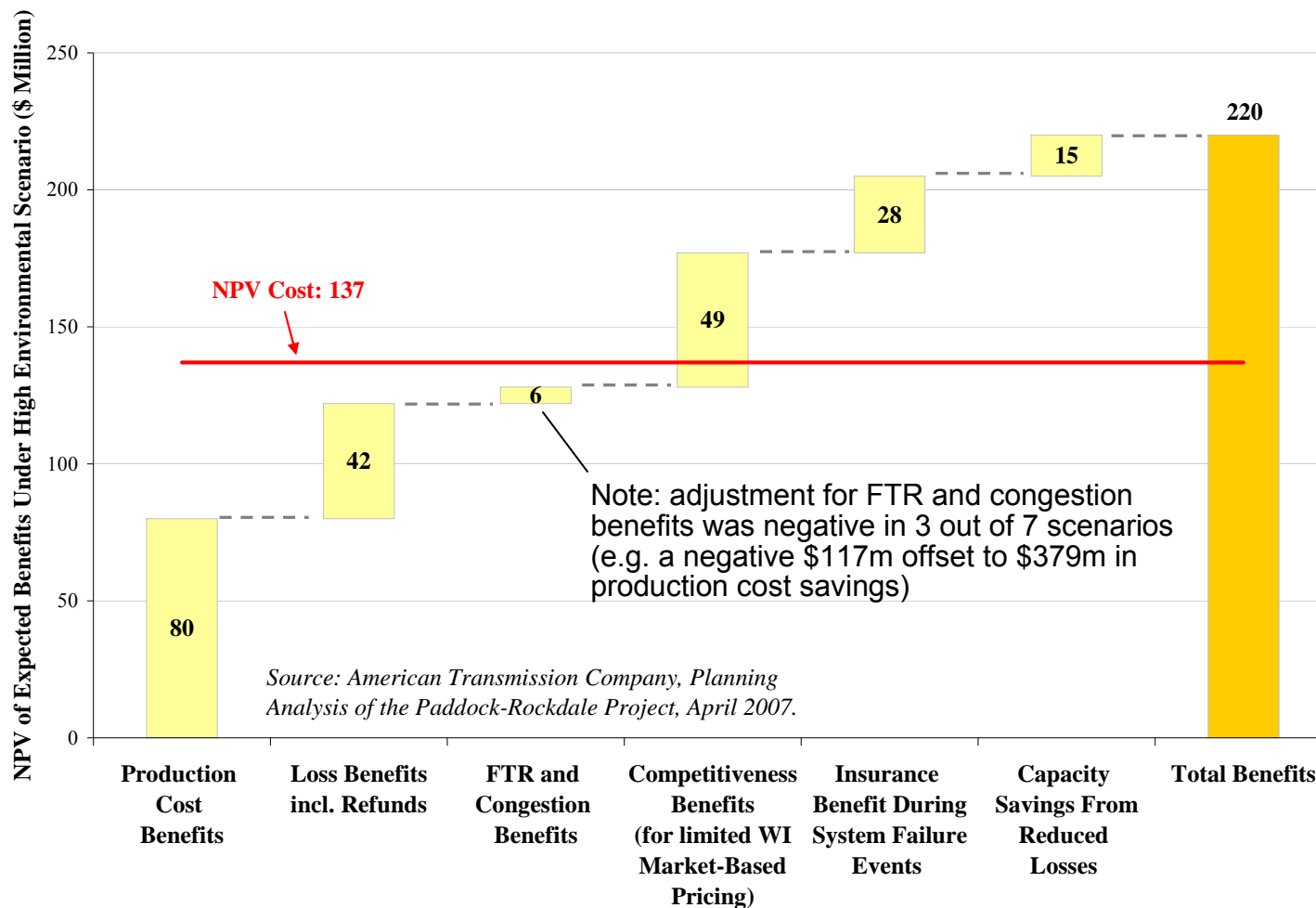
The Magnitude of “Other” Benefits Can Be Large

Example: Total benefits quantified for SPP’s Priority Projects were three times production cost benefits



The Magnitude of “Other” Benefits Can Be Large

Example: Production cost savings were insufficient in some scenarios of ATC’s Paddock-Rockdale study (though sufficient 5 out of 7)



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 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) 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)

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
- ◆ **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)

Introduction

- Topic 1:** **The Changing Role of Economic Analysis and Cost-Benefit Assessments in Transmission Planning**
- Topic 2:** **Frameworks for the Economic Analysis of Transmission Benefits**
- Topic 3:** **Understanding Standard Economic Analysis Tools for Transmission and Their Limitations**
- Topic 4:** **“Other” Transmission Benefits Commonly Overlooked or Not Quantified**

Additional Reading

Speaker Bios and Contact Information

About The Brattle Group

Additional Reading

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Johannes (Hannes) Pfeifenberger is a principal of The Brattle Group and leads the firm's utility practice area. He is an economist with a background in power engineering and over 20 years of experience in the areas of public utility economics and finance. He has submitted numerous filings with the FERC and given testimony before state commissions regarding planning, cost recovery, and the economic benefits of regional and inter-regional transmission projects. He has helped transmission owners, developers, and ISOs in both western and eastern US power markets analyze project benefits and has worked with the CAISO and Midwest ISO on developing regional transmission cost recovery methodologies.



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Delphine Hou is an associate of The Brattle Group and specializes in transmission issues and has assisted electric utilities, independent power producers, transmission-only market participants, regulators, and industry organizations on matters involving transmission benefits, cost allocation, market analysis, and a range of financial and regulatory issues. Ms. Hou also has experience with proprietary and industry-standard electricity market optimization and production cost models.

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