Transmission Planning: Economic vs. Reliability Projects

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Agenda

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5. Common Tools, Metrics, and their Limitations

Appendix: Estimating Difficult-to-Quantify Benefits
Transmission expansion under way for utility-specific and regional reliability investments:

- $2b/year in 1990s
- $8b/year in 2008-09

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

Additional regional upgrades now driven by state renewables requirements

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

Many of these regional projects will not get realized due to:
- Overlaps with competing projects
- Planning and cost allocation challenge
- High costs

Large portion of these proposed projects are driven by regional renewables integration.

$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.

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Introduction: How Much “Economic” Transmission?

Of the $180 billion of individual projects identified earlier:

- $30 billion … in RTO-approved plans (incl. reliability)
- $80 billion … additionally proposed (non-overlapping)

Estimated US-wide incremental transmission needed to integrate renewables through 2025:

- To satisfy **existing state-level RPS** requirements
  - $40-70 billion
- For **higher of existing state and 20% federal RPS**
  - $80-130 billion

Additional baseline reliability and generation interconnection investments
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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
♦ 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
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 chose 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-state support needed to obtain approvals, permits, and cost recovery**
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The benefits of many transmission projects are:

| Broad in scope | 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 | Multiple transmissions service areas  
|                 | **Multiple states** or regions  
| Diverse in their effects on market participants | Customers, generators, transmission owners in regulated and/or deregulated markets  
|                 | Individual market participants may capture one set of benefits but not others  
| Occur and change over long periods of time | Several decades  
|                 | Changing with system conditions and future generation and transmission additions  
|                 | Individual market participants may different types of benefits at different times  

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 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 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 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
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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**

- **Cost Estimation**
- **Benefit Analysis**
  - **Total Project Benefits**
  - **Difficult-to-Quantify Benefits**
  - **Readily Quantifiable Benefits**
Overall Project Benefits vs. Cost Allocation

Analyze overall project benefits prior to and separate from analyses to determine cost allocation

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

[Diagram showing cost estimation, benefit analysis, and benefit allocation]
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.

![Bar chart showing expected annual benefits of DPV2 project.]

- Production Cost Benefits (Net of FTRs): $56 million
- Competitiveness Benefits: $28 million
- Operational Benefits (RMR, MLCC): $20 million
- Generation Investment Cost Savings: $12 million
- Reduced Losses: $2 million
- Emissions Benefit: $1 million
- Total Annual: $119 million

Levelized Cost: 71

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)

![Graph showing NPV of Benefits]


Note: adjustment for FTR and congestion benefits was negative in 3 out of 7 scenarios (e.g. a negative $117m offset to $379m in production cost savings)
The Magnitude of “Other” Benefits Can Be Large

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

Additional benefits discussed only qualitatively:
1. Enabling future “day 2” markets
2. Storm hardening
3. Improving operating practices/maintenance schedules
4. Lowering reliability margins
5. Improving dynamic performance and grid stability

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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)

<table>
<thead>
<tr>
<th>Category</th>
<th>Purpose</th>
<th>Relevant Metrics</th>
<th>Frequently Used Models</th>
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| 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 | ▪ APC  
▪ Load LMPs  
▪ Emissions | ▪ Nodal: PROMOD, GE-MAPS, Dayzer, UPLAN, GridView, PowerWorld  
▪ Zonal: 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. | ▪ System losses  
▪ FCITC                                     | ▪ 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. | ▪ Total generation costs (investments and operations)  
▪ Plant additions and retirements | ▪ Aurora, EGEAS, Strategist (public)  
▪ IPM, NEEM, RECAP (proprietary) |
| Reliability Assessment Models | **Used to estimate loss-of-load-expectation and expected unserved energy** | ▪ LOLE, LOLP, UNE, required reserve margins | ▪ GE MARS, SERVM |
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
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 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)
  ♦ 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
“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
  ♦ Ensure modeled losses actually change with transmission investments
  ♦ Calculate marginal losses and loss refunds from LMP components
  ♦ 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%
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
2. Enhanced market liquidity
3. Economic value of reliability benefits
4. Added operational and A/S benefits
5. Insurance and risk mitigation benefits
6. Capacity benefits
7. Long-term resource cost advantage
8. Synergies with other transmission projects
9. Impacts on fuel markets
10. Environmental and renewable access benefits
11. Economic benefits from construction and taxes

See Appendix. These benefits can double benefits quantified in production cost studies.
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5. Common tools, metrics, and their limitations

Appendix: Estimating Difficult-to-Quantify Benefits
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

\[
\text{Reliability cost} = (\text{expected unserved energy}) \times (\text{value of lost load})
\]
  • 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-weighed 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, NOx, particulates, mercury, and CO2 emissions by allowing dispatch of more efficient or renewable generation
    ■ DPV2 estimated to reduce WECC-wide NOx 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)
Additional Reading

“Comments of Johannes Pfeifenberger, Peter Fox-Penner and Delphine Hou,” in response to FERC’s Notice of Proposed Rulemaking on Transmission Planning and Cost Allocation (Docket RM10-23-000).


“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).


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.
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