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An Unintended Consequence of Emissions Trading

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Improving Electricity Resource-Planning Processes by Considering the Strategic Benefits of Transmission

Current methods of evaluating the economic impacts of new electricity transmission projects fail to capture the many strategic benefits of these projects, such as those resulting from their long life, dynamic changes to the system, access to diverse fuels, and advancement of public policy goals to integrate renewable-energy resources and reduce greenhouse gas emissions.

Vikram S. Budhraja, Fred Mobasheri, John Ballance, Jim Dyer, Alison Silverstein and Joseph H. Eto

> Not everything that counts can be counted, and not everything that can be counted counts.
> —Albert Einstein

Methods of evaluating the economic impacts of new electricity transmission projects generally rely on production-cost simulation models to estimate project benefits, expected-value approaches to assess key uncertainties, and a utility's cost of capital to determine the present worth of future impacts. These methods do not capture the many strategic benefits of high-voltage electricity transmission projects, such as those resulting from the long life of projects, dynamic changes to the system, access to diverse fuels, mitigation of risks as a form of insurance against extreme events, and advancement of public policy goals to integrate renewable-energy resources and reduce greenhouse gas emissions. Incorporating more formal evaluations of these important

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benefits will enable public policymakers and stakeholders to make better-informed decisions about building new transmission and will contribute to equitable recovery of project costs.

Our research has identified several approaches for enhancing existing methods to account for the strategic benefits of transmission projects[1]:

- Use a social discount rate rather than a utility's cost of capital to evaluate the present value of future impacts;
- Take fuel diversity benefits into account using the price elasticity of natural gas;
- Formally consider the dynamic impacts of new transmission to enable later generation additions for local and export uses;
- Apply portfolio analysis methods from the financial services industry to evaluate the overall risk of a combined collection of energy assets, rather than only the risk associated with individual projects;
- Develop model-based techniques to quantify benefits from reductions in extreme events, e.g., reduce impact of blackouts and volatility of markets; and
- Until these techniques are developed, incorporate Delphi and other stakeholder consensus-building techniques to recognize and quantify the benefits of mitigating low-probability, high-societal-impact events such as major blackouts and market dysfunctions.

I. Introduction

There is general consensus that new transmission projects are needed to advance the policy objectives of renewable-energy integration, reliability management, efficient market operations, interconnection of new load and generators, reduction of transmission congestion and bottlenecks, and expansion of access to regional power markets.

Approval of major regional transmission projects in this new environment has proven challenging.

Historically, major transmission projects were sponsored and owned by vertically integrated utilities and were generally proposed in connection with new power plant development. Today, the landscape has changed dramatically with the separation of generation and transmission assets, the separation of transmission operations and ownership, and the shifting of responsibility for transmission operations and planning from utilities to independent system operators/regional transmission operators in many areas. Approval of major regional transmission projects in this new environment has proven challenging, as evidenced by the difficulty in moving forward with major transmission projects.

It is especially difficult to advance major regional transmission projects that involve multiple jurisdictions and utilities and that are planned to integrate remote resources, reduce costs, improve market operations, provide long-term strategic benefits, or improve operating flexibility. These projects cannot go forward without certainty about cost recovery, which requires allocation of costs through tariffs or contracts. Achieving this certainty requires consensus among stakeholders and policymakers regarding benefits, costs, and their allocation.

These challenges were recognized in a September 2007 report prepared by The Blue Ribbon Panel on Cost Allocation.[2]

> While the wholesale electricity market has changed fundamentally, the framework for enabling and encouraging investment that will better enable the grid to serve growing competitive markets has not yet fully emerged. One area still largely unresolved is how the costs incurred in transmission expansion will be allocated among users. While it is clear that many traditional cost-allocation approaches are no longer appropriate, new principles governing the allocation of cost responsibility for new transmission investment have yet to be fully articulated and implemented.

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This article seeks to improve decisions regarding new transmission projects by recommending adoption of methods to incorporate strategic benefits of transmission, which are either ignored or are not well-accounted for by current transmission evaluation methods. We submit that it will be easier to make decisions about future large transmission projects, including how to allocate their costs, if the benefits of these projects are better understood.

II. Traditional Evaluation Methods Do Not Account for Many of the Economic Impacts of Transmission

The economic impacts of proposed new transmission projects have traditionally been estimated using production-cost simulation models that analyze two scenarios: one with and another without the proposed project. Many commercial production-simulation models are available, such as PROSYM, GEMAPS, PROMOD, and PLEXOS. These models simulate production from a fleet of available generation resources and associated fuel consumption and emissions with least-cost dispatch algorithms. Using forecast estimates of fuel prices, costs of various emissions, and variable operations and maintenance (O&M) costs, the models calculate total production costs over time for a given load forecast and associated load shape. The gross benefit for the new transmission project is estimated to equal the difference between the total production costs from the two simulations (with and without the new transmission project). The net benefit of the transmission project is then calculated by subtracting the capital and annual O&M costs of the project from the estimated gross benefit.

It will be easier to make decisions about future large transmission projects if their benefits are better understood.

Benefit-cost ratios and internal rates of return can then be calculated based on annual production, capital, and O&M costs of the project.

Sensitivity analyses are used to understand the impacts of uncertainty in key assumptions such as fuel costs, load forecasts, and the capital costs of a transmission project. If the analyst can assign probabilities to the different uncertainties (e.g., the likelihood that natural gas prices will be below \$5/MMBtu, equal \$7/MMBtu, or be above \$9/MMBtu), and can estimate a project's expected value of benefits.

We conclude that current methods used to quantify transmission project benefits:

- Are data-intensive and require many assumptions and judgments about the future fleet of generation, fuel prices, and transmission network;
- Understate the benefits of long-lived (50-year or more) assets by using high discount rates based on a utilities' cost of capital to estimate the present worth of the future impacts of transmission;
- Minimize or ignore the impact of new transmission in reducing the likelihood or severity of high-impact but low-probability events, such as blackouts and extreme market volatility, which have been very costly in the last two decades, and
- Are static, assuming that once a new transmission project is built it will not support any additional generation, when in fact transmission systems are dynamic and new lines added to the system can facilitate new generation and inter-regional power transfers.

The shortcomings of these methods of analyzing transmission projects have been recognized in a report prepared by the Western Interconnection Seams Steering Group,[3] which noted that:

> 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

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costs and changes in total demand. The benefits associated with reliability, capital costs, market power and demand are not included in this [type of production cost] analysis.

Because the above transmission benefits are unrecognized or are underestimated by current analysis methods, stakeholders and policymakers cannot accurately weigh the costs versus the benefits of a proposed transmission project, and will make less effective decisions about grid expansion options.

Our research identified several ways to improve transmission benefit quantification to better represent the full range of transmission project impacts. These methods are discussed in detail below.

A. Use a social discount rate

Transmission projects are long-lived assets that produce societal benefits over many years, including the ability to reduce the likelihood and severity of extreme market volatility and multiple-contingency events, which are costly and risky to society. Two important criteria for defining a public good are: (1) consumption by one party does not foreclose consumption by another party; and, (2) owners cannot prevent consumption by others. Electricity transmission facilities fit these criteria. Use of transmission facilities is subject to open access rules. That is, transmission is a common carrier, so transmission owners cannot reserve transmission for their own exclusive use. Other examples of public goods are greenhouse gas reduction, air pollution reduction, flood control, and highway systems.[4]

Because transmission is a public good, a social discount rate rather than the (higher) utility cost of capital should be used for calculating the present worth of future benefits from new transmission projects. Use of a social discount rate has long been advocated for economic evaluation of public projects in sectors such as transportation, agriculture, water resources, land use, and lately, global warming mitigation projects.[5] More broadly, a variety of economic studies have recommended social discount rates ranging from 1 to 3 percent, with a few estimates as high as 4 and 7 percent.[6]

Our research identified several ways to improve transmission benefit quantification to better represent the full range of impacts.

In a recent article,[7] former California Energy Commissioner John Geesman notes that the ''...discount rate is set to approximate the cost of capital of the real party at interest in the decision, the belief being that such a rate should fully capture the value attached to a choice between today and tomorrow.'' However, he observes, ''The construct doesn't work quite as seamlessly with decisions affecting broad swathes of the public, or society at large, so the 'cost of capital' is transformed into a 'social discount rate.''' Geesman notes that the Bush Administration directed ''...its agency heads in 2003 to use both a 7 percent real cost of capital and a 3 percent real social discount rate in conducting regulatory evaluations.''

California Energy Commission (CEC) staff in a 2004 draft white paper[8] on upgrading of the California electricity transmission system echoed this view, concluding that high-voltage transmission infrastructure in a restructured market has increasingly become a public good. The CEC recommended using a social discount rate comparable to that used for CEC buildings and appliance standards when evaluating the costs and benefits of transmission investments.

Application of a social discount rate does not require any change in benefit-cost analysis methodology, other than to insist on the use of a social discount rate.[9] The impact of using the discount rate choice on the present value of benefits from long-lived projects is significant. For a project with uniform (equal) benefits over 50 years of economic life, the use of

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a 5 percent (societal) rather than 10 percent (private utility) discount rate increases the present value of benefits by 60 percent or more over the 50-year evaluation period.

B. Estimate fuel diversity benefits

In most regions, the marginal fuel for electricity generation is natural gas. Addition of large amounts of renewables and associated transmission will displace baseload coal (in some regions) and natural gas-fired electricity generation. Reduced natural gas consumption, in turn, will affect the price of natural gas and, as a result, the cost of power (and other activities) that relies on burning natural gas. These benefits can be quantified and should be credited, at least in part, to large regional transmission projects that enable interconnection of major new renewable resource developments.

To determine the fuel diversity benefit of a transmission project, it is necessary to quantify the amount of natural gas (or coal) used regionally, with and without the transmission project. The degree to which the project would decrease the price of the natural gas can be forecasted by taking into account both the price elasticity of natural gas and the decrease in the amount of natural gas that would be used as a result of the new project.

For example, the Tehachapi Transmission Project in southern California is being developed to interconnect approximately 4,500 MW of wind generation. Assuming an average 35-percent capacity factor, the annual production from this new wind power will be 13.3 billion kWh. In 2006, approximately 107 billion kWh was produced from natural gas in California.[10] Therefore, the Tehachapi Transmission Project could reduce the amount of natural gas consumed for power production by 12.4 percent,[11] which would mean a total reduction in California's natural gas use of 4.8 percent (**Figure 1**).

A recent study by Wiser *et al.* estimates the price elasticity for natural gas at 0.8 to 2.0 percent.[12] Assuming that each 1 percent drop in natural gas demand drives natural gas prices down by 1 percent, for the 4,500 MW Tehachapi wind and transmission line development, the 4.8-percent reduction in natural gas consumption could reduce the price for natural gas in California by 4.8 percent. If natural gas is priced at $6/MMBtu, that elasticity reduction could equal $0.29/MMBtu.

With the Tehachapi project's wind power providing 13 billion kWh of electricity to California consumers (and assuming no other changes to the system), the electricity produced from natural gas could decrease from 107 billion kWh to 94 billion kWh. Assuming a heat rate of 9,000 BTU/kWh, the $0.29/MMBtu price reduction translates to annual savings of about $250 million. Since the total cost of the Tehachapi transmission line is estimated to be $1.8 billion, a single year of natural gas savings for electricity production alone equals about 14 percent of the cost

Example of Fuel Diversity Benefit Calculation

▪ Integrate 4,500 MW of renewables (e.g., Tehachapi Wind)	
▪ Estimated annual production	≃ 13 Billion KWh (approximately 35% CF)
▪ Electricity production Using Gas in California	
– Base case	≃ 107 Billion KWh
– With Renewables	≃ 94 Billion KWh
▪ Reduction in Gas for Power Plants	≃ 12 %
▪ Price elasticity of natural gas	1% demand reduction equals 0.8 – 2% price reduction*
▪ Gas for electric production as a % of CA gas consumption	≃ 40 %
▪ % Reduction in gas usage	= .12 * .4 ≃ 4.8%
▪ Gas Price Reduction (assume 1% for 1% reduction)	= 4.8%
▪ Gas Price	
– Base Case	$6/M²BTU
– With Renewables	$5.70/M²BTU
▪ Cost Savings for remaining 94 Billion KWh assuming average 9,000 BTU/KWh	= 94 Billion KWh * 9,000 BTU/KWh X $0.30/M²BTU ≃ $250 Million/year

Note: Including price impact on non-electric sector, benefit will be 2.5 times, or $625 million. Illustration ignores timing and present value for simplicity.

*Wiser, Bolinger, and St. Clair, January 2005, Easing the Natural Gas Crisis: Reducing Natural Gas Prices through Increased Deployment of Renewable Energy and Energy Efficiency

Figure 1: Example of Fuel Diversity Benefit Calculation

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of the transmission line. While it can be debated how much of these savings should be attributed to the wind project versus the transmission line itself, the fact remains that without the line the fuel diversity benefits cannot be realized at all, so the line should receive some portion of the fuel diversity benefit.

C. Formally consider dynamic impacts

Major new transmission projects are undertaken to connect expected new remote generation with loads. Once built, many new major transmission lines enable additional new generation construction (that was not assumed in the original transmission plan) that will also seek to serve these loads. Dynamic analysis should be used to evaluate such changing benefit streams over the life a transmission asset. These benefits could be estimated based on past experience with the construction of older transmission projects and their impacts on generation expansion and inter-regional power trading.

Estimating dynamic planning benefits of new transmission projects is a form of scenario analysis. It entails:

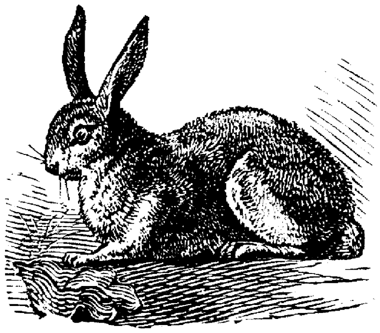
a. Defining a base case (the transmission project and associated initial generation);

b. Estimating benefits from the proposed transmission project;

c. Modifying future-year base cases to reflect dynamic impacts, for example new generation capacity construction;

d. Estimating changes in benefits over time from the new transmission uses, and

e. Assessing other dynamic factors (such as unanticipated benefits) either individually or using scenarios and weights.



D. Apply portfolio analysis methods

Portfolio analysis is commonly used in the financial industry to identify groups of investments that perform well under a variety of scenarios. When building a financial portfolio, managers use diversification and allocation of assets among different investment categories to limit risk correlation between asset classes, to create a portfolio that maximizes risk-adjusted returns.

In the electricity industry, diversification of supply resources has long been an important element in planning for uncertainty. Resource diversification mitigates and reduces the consequences of fuel price uncertainty, load uncertainty, generation resource performance variations, major generation failure, and natural events such as fire, earthquake, etc. Instead of concentrating on one or two types of supply resources such as coal, oil, and gas, today's utilities typically use a portfolio of resources that can include demand-side resources, nuclear, coal, hydro, gas, and renewable energy, combining resources that may be local and distant, self-owned and purchased. Portfolio diversification has been mandated through policy mandates such as renewable portfolio standards or energy efficiency goals.

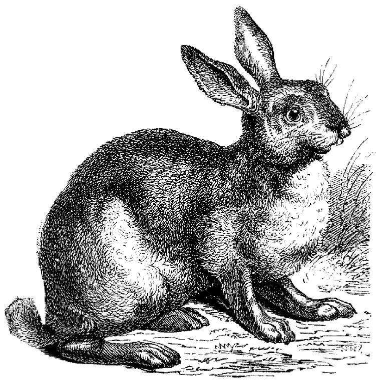
Electric system planners can plan for uncertainty using tools that include scenario planning, sensitivity analysis, decision analysis, and probabilistic production-simulation models. However, most new transmission and generation projects have been evaluated using benefit-cost analysis on a project-by-project basis, rather than as part of a portfolio of projects.

High-voltage transmission is a system resource much like new generation. Transmission enables utilities to import a significant portion of the power they need from other utilities and/or merchant plants, enabling geographic, technology, ownership, financial and fuel source diversification. Many utilities enjoy the diversification benefit of seasonal power exchanges, which exploit the differing load and resource patterns of importing and exporting regions.

More research is needed to determine how to use modern portfolio management techniques to identify effective, robust, risk-reducing combinations of energy system resources. Appropriate allocation among different types of resources – supply and demand, local and regional, fossil and non-fossil, generation and transmission – may be more important than precise quantification of the benefit-cost of individual projects in limiting the overall risk of decisions. Given the amount of capital investment already in place in utility systems, electric system planners and policymakers may want to seek new assets that improve diversification and reduce overall system risk, rather than seeking only those assets that have the highest benefit-cost ratio. In many cases, new transmission could be a risk-reducing asset that enhances overall electricity portfolios.

E. Develop model-based techniques to quantify benefits from reductions in extreme events

Power systems are generally designed to meet N-1 (one contingency) or N-2 (two contingencies) reliability criteria. However, extreme events, such as the August 2003 Northeastern U.S. and Canada blackout and the 1996 Western Interconnection blackout, are typically multiple-contingency events. Additional transmission capacity could help mitigate the magnitude, duration, and footprint of blackouts resulting from these types of extreme events.



Volatile market prices can also become extreme events and society has little tolerance for runaway market prices or market dysfunction. Additional transmission capacity can help mitigate market dysfunction and vulnerability to runaway market prices by reducing local scarcity of electricity supplies and allowing access to additional suppliers that can check high local power costs.

Regional power flow analyses can simulate the degree to which new transmission projects could reduce the likelihood, severity, or footprint of a power system blackout. Similarly, production simulation models can be used to estimate the impact of new transmission upon congestion and market price volatility.

Focusing on reliability, calculating the benefit from reduced vulnerability to extreme events entails[13]:

a. Developing a base model that includes loads, resources, and transmission;

b. Simulating an extreme event with the base-case model to estimate load-shedding and customer loss due to service interruptions or blackouts from extreme events;

c. Changing the base case by adding major new transmission lines (one, two, or three);

d. Re-running the revised base case with new transmission lines for the same extreme event as in Step c above;

e. Estimating the blackout footprint in terms of load-shedding and customer loss, and

f. Calculating the benefit of the proposed new transmission in terms of *Economic Value of Load Loss* multiplied by *Reduction in Load Loss*.

This approach to quantifying extreme event mitigation focuses on network carrying capacity under multiple contingencies with and without a new transmission project and the resulting impact of an extreme event in terms of blackout footprint. The modeling for such quantification is an ambitious effort requiring significant engineering expertise, data, and resources.

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F. Incorporate difficult-to-quantify benefits

Although it is generally agreed that transmission projects have strategic benefits, such as insurance against contingencies, these benefits are not easily quantified. It will take time to develop and gain acceptance for utilization of these methods. While this process moves forward, Delphi or other methods can be used to develop consensus on a level of strategic benefits that could be assigned to transmission projects as an adder or percentage of total project cost.

Experts in the management science and decision analysis fields have studied ways to quantify difficult-to-quantify variables. One approach is the Delphi methodology, which relies on a panel of experts to assign weights and worth to different decision criteria or variables. The panel shares their results and iterates through several cycles of weighting and evaluation, with the goal of achieving consensus on an agreed set of weights and values for each variable. Generally, two to four iterations are sufficient for the panel members' views to converge.

The Delphi approach could be adapted to incorporate societal or strategic benefits. Stakeholders or constituent groups could assign values to different benefit categories for a new transmission project, evaluating transmission's strategic impact on fuel diversity, reliability and market volatility.

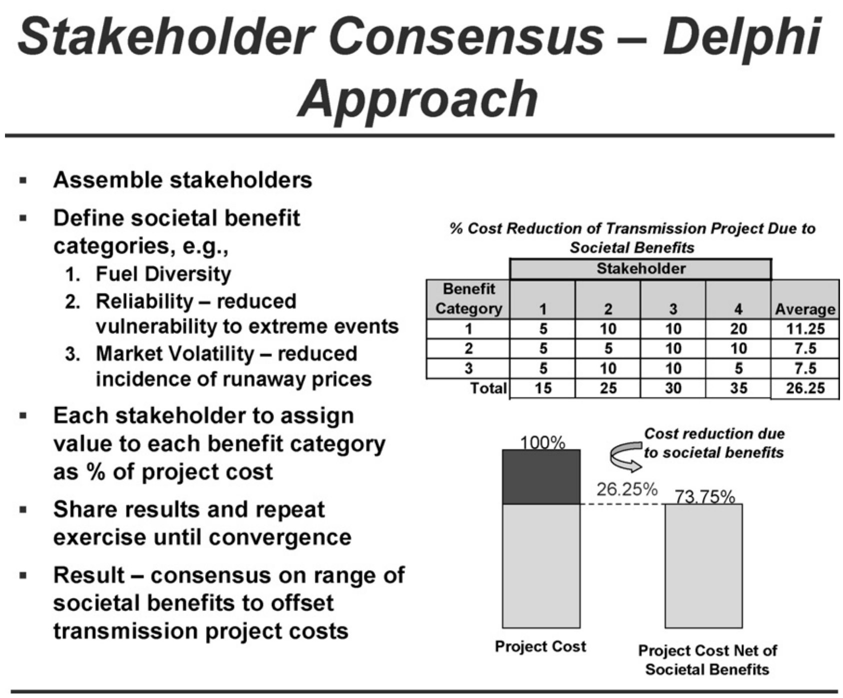

Figure 2: Stakeholder Consensus — Delphi Approach

Figure 2 illustrates the application of the Delphi stakeholder-consensus approach to assess a new transmission project. In this example, there is consensus that societal benefits for the project under consideration should be valued at 26.25 percent of the project cost. Therefore, the primary quantifiable benefits from the project have to be equal or larger than 73.75 percent of the project cost for this project to be economical and cost-effective.

III. Conclusions

Improved quantification of benefits from new electricity transmission projects, as described in this article and summarized below, can be useful for:

- Calculating the distribution of benefits among project participants and jurisdictions;
- Providing a basis for sharing benefits among direct and indirect participants and critical stakeholders;
- Enabling each utility or jurisdiction to analyze benefits of projects (or a package of projects);
- Assisting in determining cost allocation among multiple participants and jurisdictions, and
- Selecting a cost-recovery methodology.

In summary, current transmission planning methods should be augmented as follows to recognize strategic benefits that are not accounted for in current analysis approaches that are currently used:

a. Public Good

– Use of a social discount rate to calculate the present value of benefits from a proposed new transmission project.

◦ Fuel Diversity

– Incorporating the benefit from a potential decrease of natural gas price resulting from the construction of a new transmission project that integrates a significant number of new renewable resources, which would reduce natural gas consumption and emissions.

◦ Low-Probability, High-Impact Events

– Incorporating risk-mitigation benefit to society for low-probability, high-impact market events and extreme multiple-contingency events; this would entail analysis of event scenarios or use of the Delphi or other methods to obtain stakeholder consensus on the value of the risk mitigated by the project.

Additional research is needed to improve the quantification of transmission benefits. Research areas include:

◦ Dynamic Analysis

– Quantification of transmission project benefits should recognize the impact of new transmission projects on the construction of new generation capacity in exporting regions.

◦ Portfolio Analysis

– Portfolio analysis methods utilized in the financial industry should be adapted to transmission electric system planning, i.e., portfolios of energy resources could be constructed and assessed for overall risk. These portfolios should include resources such as demand response, new generation (renewable and fuel based), new transmission, and energy conservation.

◦ Extreme-Event Benefits (Insurance Value)

– Methods should be developed to quantify extreme event mitigation benefits of proposed transmission projects for:

Reliability – the benefit of new transmission in reducing the likelihood and footprint of future blackouts (in

Methods should be developed to quantify extreme event mitigation benefits.

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particular, extreme (N-x) events), and

Market Volatility – the benefit of new transmission in reducing market volatility due to extreme events and the societal value of reduced vulnerability to runaway market prices.

Appendix A.

Supplementary data

Supplementary data associated with this article can be found, in the online version, at doi:10.1016/j.tej.2009.01.004.

Endnotes:

1. The material used to prepare this article is derived from V. Budhraja, J. Ballance, J. Dyer, F. Mobasheri, A. Silverstein, and J. Eto. 2008, *Transmission Benefit Quantification, Cost Allocation and Cost Recovery*, California Energy Commission, Energy Research and Development Division.

2. The Blue Ribbon Panel on Cost Allocation, *A National Perspective on Allocating the Costs of New Transmission Investment: Practice and Principles*, Sept. 2007.

3. Western Interconnection Seams Steering Group (SSG-WI), *Framework for Expansion of the Western Interconnection Transmission System*, 2003.

4. Costs of public good projects are spread over all potential users and beneficiaries. This is the case for highways, dams, flood control, and other public-good projects.

5. The concept of a social discount rate has been discussed by economists and philosophers for decades. F. Ramsey wrote in 1928 that ''policymakers should be more patient than private citizens'' and that it was ethically indefensible to discount the future. F. Ramsey, *A Mathematical Theory of Saving*, ECON. J., 1928. M. Dobb wrote in 1960 that to discount future enjoyment implies a ''weakness of imagination'' and that labor productivity rate

should be used as the discount rate. M. DOBB, ESSAY ON ECONOMIC GROWTH (Long, 1960).

6. W. Nordhaus in *The Stern Review: The Economics of Climate Change in 2006*, recommends a 3-percent social rate of discount. H. Lopez, in *The Social Discount Rate: Estimates for Nine Latin American Countries*. Policy Research Working Paper, The World Bank, Latin America and the Caribbean Region, Office of the Chief Economist, June 2008, estimates that the social rate of discount for Latin American countries in the 3- to 4-percent range. D. Evans and H. Sezer, in *The Elasticity of Marginal Utility of Consumption: Estimates for 20 OECD Countries*, FISCAL STUDIES, 26 (2):197–224, 2005, estimate it at between 1.3 and 1.7 percent in six developed countries. D. Evans, in *Social Discount Rates for Six Major Countries*, APPLIED ECONOMIC LETTERS, 11:557–560, 2004, finds an average social discount rate of 1.4 percent in 20 Organization for Economic Cooperation and Development (OECD) countries.

7. J. Geesman, *Discount Rates: The Divine Right of Economists*, GREEN ENERGY WAR, Aug. 13, 2008.

8. California Energy Commission (CEC). *Upgrading California's Electric Transmission System: Issues and Actions for 2004 and Beyond*, 2004, CEC-100-04-004.

9. Transmission project benefits could be calculated using both a social discount rate and a traditional cost of capital to indicate the sensitivity of calculated benefits (and costs) to the choice of discount rate.

10. 2006 Net System Power Report, April 12, 2007, California Energy Commission Publication CEC-300-2007-007.

11. For the sake of simplicity, this calculation ignores the fact that there will not be a one-for-one displacement of renewable for gas-fired generation, and that some amount of gas-fired generation will be needed to provide ancillary services and firming for the intermittent renewable generation.

12. R. Wiser, M. Bolinger and M. St. Clair, *Easing the Natural Gas Crisis: Reducing Natural Gas Prices through Increased Development of Renewable Energy and Energy Efficiency*, Berkeley CA: Ernest Orlando Lawrence Berkeley National Laboratory Report LBNL-56756, Jan. 2005.

13. The analysis methodology for estimating a new transmission project's benefits in mitigating market volatility is conceptually similar to the methodology outlined for quantifying the benefits of mitigating extreme-event impacts on system reliability.