A NATIONAL PERSPECTIVE

On Allocating the Costs of New Transmission Investment: Practice and Principles

A White Paper Prepared by
The Blue Ribbon Panel on Cost Allocation

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FOREWORD

This White Paper is commissioned by WIRES, a non-profit trade group composed of transmission owners, customers, technology companies, vendors, and grid management organizations, whose purpose is to raise the visibility of the transmission sector and to promote needed investment in electric transmission. (www.wiresgroup.com) This paper is nevertheless an independent study conducted by five experts in the field of electric utility operations, economics, and regulatory policy. WIRES selected the panelists – Professor Ross Baldick from The University of Texas at Austin, Mr. Ashley Brown from the Harvard Electricity Policy Group of the Kennedy School of Government at Harvard University, Dr. James Bushnell from the University of California Energy Institute, Dr. Susan Tierney from Analysis Group, and Mr. Terry Winter from American Superconductor – for their recognized expertise, diverse experience within the industry, and their ability to consider the issues objectively.

This panel was asked to prepare a White Paper on the issue of how the costs of high-voltage transmission upgrades and expansions should be fairly and efficiently allocated. Both the Blue Ribbon Panel ("Panel") and WIRES recognize that many utilities, regional transmission organizations, stakeholder groups, and members of the political community have devoted hours of debate and analysis to this question. WIRES nevertheless perceived a need for thoughtful and independent analysis of the subject, primarily because of the controversy, delay, and the substantial regulatory uncertainty surrounding the issue; the diversity of approaches adopted in organized and bilateral markets; and the growing importance but inadequacy of regional transmission planning processes within which the Federal Energy Regulatory Commission now requires cost allocation to be addressed. WIRES believes that the controversy and widely divergent approaches that currently exist create uncertainty for the industry and investors, and that this in turn inhibits investment in this key part of our domestic infrastructure.

The mandate given the Panel is to discern whether there is a widely-applicable cost allocation methodology, a set of rules or principles, or other concepts that would clarify and hopefully simplify current practice and thereby encourage and facilitate needed investment in the transmission network in all parts of the country. WIRES does not call for a single approach or a national standard but instead recognizes the need for independent expert guidance and for regulatory action that will help optimize transmission cost allocation in the context of efficient transmission planning and implementation in all regions. Finally, it should be emphasized that the views expressed herein are those of the Panel members themselves, and are not necessarily the views of WIRES, its member companies, or the employers of the Panel members. WIRES is nevertheless proud to present this analysis with the expectation that it will lead to important and timely advancements in public policy.

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Executive Summary

The United States electric system has served the nation well with decades of reliable and universal electricity service. However, there is an increasing and broad recognition that significant amounts of investment in the transmission system will be needed in the near and long term if the system is to continue to provide the kind of electricity service that Americans desire and on which the nation's economy depends.

Attracting new investment in transmission in recent years has become more complicated than in the past because of the nation's transition from a traditional era of utility regulation to a new era of national policy supporting "open access" to transmission. 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. It is the articulation of principles for that cost allocation that is the subject of this paper.

This White Paper focuses on the principles for determining the benefits of new transmission investments, and for allocating the costs efficiently and equitably among those who benefit from the enhancement. While for the most part Federal regulators have been attempting in recent years to accommodate the differences of opinion on these topics by adopting transmission cost-allocation proposals resulting from settlement discussions or negotiated agreements among stakeholders in specific geographic areas, this approach suffers from the lack of common, predictable principles supporting transmission investment for the interconnected grid that serves broad regions of the nation. While the acceptance of different regional approaches is understandable from a pragmatic point of view because such settlement processes often allow issues to be resolved with less contentiousness, that approach is inadequate to the task of creating a sustainable and viable environment for continuing attraction of capital into transmission projects. Indeed, it is unlikely that the widely divergent methods proposed and accepted for allocating transmission costs can produce a body of policies that together both meet the legal standard of just and reasonable results and also prove to be the foundation for sustainable investment for the long term, particularly when these allocations interact across regional boundaries. Finding a principled basis for cost allocation that relies on more than lowest common denominators would certainly provide a more appropriate and sustainable basis for public policy.

As a starting point for this discussion, we identify a critically important foundation, or pre-condition, for sound cost-recovery policy: clear, consistent and principled regulatory policy and oversight. Without clear and consistent regulatory policy, the process for determining cost allocation in each proposed investment in the grid becomes an opportunity for every competing interest and interest group to either reduce or eliminate its obligation to pay. While regional consensus on cost allocations may be and often is desirable for a variety of reasons, regulators cannot simply rely on consensus processes to decide how to allocate the costs of expanding the grid. Notably, absent a set of guiding principles, the achievement of a consensus is more difficult to reach and less likely to provide future guidance; such agreements are inherently *ad hoc* in nature; and the absence of consistent principles is likely to reduce the number of non-market participant players with capital to invest who will offer proposals. Clear, consistent and principled regulation is far more likely to attract investment in transmission and to increase the likelihood of informed planning and debate and greater efficiency in reaching decisions. Furthermore, in the absence of clear principles for cost allocation, debates over cost allocations may simply serve as proxies for disagreements over other issues such as siting.

Additionally, there are several important contexts for shaping sound cost-allocation principles, as fully elaborated upon below. These are: (1) establishing a credible process for deciding which transmission investment should proceed, with the process leading to such decisions being one that is inclusive and transparent; (2) assuring that regulation provides an adequate definition of the geographic footprint(s) of physical, regional electricity market(s) to be served in the transmission planning and expansion policy; (3) establishing a credible and principled "transaction chain," linking those that ultimately benefit from open-access transmission – *e.g.*, loads – with responsibility to pay for transmission investment; (4) using "rules of thumb" related to the size of the proposed transmission asset(s) as the basis for presumptions about who should pay; and (5) clarifying the regulatory jurisdiction for recovery of transmission investment costs to ensure appropriate price signals and an appropriate allocation of responsibility among Federal- and State-level jurisdictions that is consistent with national policy for non-discriminatory access to transmission and both efficiency and fairness in allocating costs.

As a starting point for developing principles of cost-allocation, we note our attempt to reconcile two quite distinct perspectives, namely that (a) to properly signal users and to assure fairness to all parties, benefits should be specifically identified and the anticipated beneficiaries should, in each instance, pay for transmission investments; and (b) because identifying specific benefits and beneficiaries is overly complex and speculative, the costs of much new transmission investment should be socialized, meaning they are spread evenly across all users in a region or market. We recognize the validity of the arguments advanced by proponents of both points of view and have endeavored to find the right balance between these two basic concepts in light of the practical realities of today's interconnected high-voltage transmission system in most parts of the country. Attempts to identify – once and forever, and with complete precision – the exact beneficiaries of specific incremental investments in the transmission system is virtually impossible. To suggest that is possible flies in the face of the realities as we understand them: the use of electric systems change over time in innumerable and very often unpredictable, unforeseen ways. Changes in the identity of beneficiaries and "cost causers" over time arising from changes in patterns of economic activity can lead to changes in the usage of the electric system. Similarly, a rigid rule that simply socializes all transmission costs can, and sometimes does, cause distortions in price signals and inequities among users that are best avoided.

This leads us to advocate transmission planning processes that are broadly inclusive, with explicit attempts to find "baskets" of investments with broad benefits accruing to regions. Such a process, we believe, tends to support relatively broad allocation of transmission costs among regional beneficiaries and – if and where appropriate – among sub-regions (or areas which due to transmission constraints operate in a relatively isolated fashion from the larger region). We think the planning process can anticipate and properly capture the likely changes in benefits and beneficiaries over time and space, without introducing impressions of precision which do not realistically reflect conditions in the real world. Our support for the "beneficiaries pay" concept does not therefore prevent us from presuming that many new transmission investments should be socialized on the basis that certain facilities in such a network industry have inherently broad public benefits, and baskets of system enhancements will, by their very nature, embody tradeoffs between various parties that provide a sound basis for socializing the costs of that portfolio of investments. Both approaches reflect consideration of who benefits.

We also propose that the cost allocations be reviewed periodically where major economic or demographic changes have occurred, in order to examine the allocation of benefits (and costs) of capital investment on a going-forward, revenue-neutral, non-retroactive basis. As we explain further below, this is consistent with the regulatory practice in most jurisdictions that places prudently incurred, used-and-useful investment into rate base but periodically examines the allocation of costs among classes of customers based on relevant studies. Such reassessment should not, as we specifically note below, be undertaken lightly or episodically, however, and any resulting shifts of cost responsibility require care in implementation.

With this as background, we endorse the following ten Principles to guide the allocation of costs of new network transmission investment[1] in all areas of the United States. We think these Principles are best considered together as a whole, as some but not necessarily all of them would lose some or all of their value if viewed in a stand-alone fashion.

- Principle 1. All viable methods of allocating the costs of new network transmission require a study of who benefits from, and who should pay for, enhancements of the grid. A sound planning process is critical to that determination.
- Principle 2. As a predicate to allocating the cost of network transmission investments, such investments should be analyzed using a single standard or unit of measure that combines reliability and economic values without distinction.
- Principle 3. The appropriate standard of measurement of the benefits of transmission is aggregate societal benefits within the geographic region being examined.
- Principle 4. Sound transmission planning (to analyze benefits and costs, and the distribution of benefits for the purpose of allocating costs) should incorporate a number of features:

  Principle 4A. Transmission planning and analysis should be done on a regional level – focusing on larger regions as a general rule. While the overall planning process must encompass a large region, the planning studies cannot lose sight of the impacts on sub-regions.

[1] We do not suggest that these Principles apply to local radial lines, including lines designed for interconnecting specific generation (narrowly defined). We make no findings here about whether any particular lines should be defined as interconnections or parts of the network. Our Principles would generally apply to network facilities.

Principle 4B. Transmission planning and analysis should include all of the demand loads (existing and reasonably anticipated) and all of the supply resources (existing and reasonably anticipated) located within the geographic region for which planning is taking place.

Principle 4C. Transmission planning should occur in a process that is open, transparent, and inclusive, and conducted by a credible entity without particular attachment to specific interests or market outcomes in the region.

- Principle 5. Transmission investments involving baskets of projects that satisfy these standards and which emerge as being a net societal benefit (to either the region or sub-regions) through the results of robust transmission planning processes should presumptively be candidates for broad, or socialized, cost recovery across the region benefiting from the project(s).
- Principle 6. As a rebuttable presumption in transmission planning exercises on a going forward basis, the larger the size of a proposed new facility, the greater its potential to serve the broadest segment of interstate commerce and therefore the larger the region that should support it.
- Principle 7. Except for interconnections of specific new generation, loads in the benefiting region should be allocated the costs of new investment.
- Principle 8. New transmission investment should be supported in Federal or other wholesale rates, as appropriate, and not be included in retail rate base subject to regulation by the various states. To the extent that existing transmission assets can be removed from retail rate base and transferred to Federal or wholesale rates in an orderly and coherent manner, it would be beneficial to do so.
- Principle 9. On a going-forward basis only and subject to constraints related to the timing, scale, and the nature of the initial allocation, cost allocations for new transmission should be subject to periodic review to determine whether beneficiaries from the investment have changed in any major ways that distort cost responsibility and appropriate pricing. Established transmission cost allocations should otherwise be rebuttably presumed to be just and reasonable.
- Principle 10. Free entry of transmission investment should be permitted, to the extent that the proponents are willing to bear the costs for such investment and

that such investment does not adversely impact the network in ways that are not appropriately addressed by the proponents.

In identifying these ten Principles and their appropriate context, we have attempted to focus squarely and appropriately on the best means to allocate transmission costs at all levels and in all markets and regions. It is necessary to identify beneficial transmission enhancements through thorough and open planning, to provide credible (if not precise) determinations of who benefits from one or another investment, and to adhere to these Principles for allocating costs while serving distinctly regional needs irrespective of conflicting stakeholder interests or the political environment surrounding a specific project.

We expect that one implication of such an approach is to make more transparent the basis of the controversies surrounding the allocation of transmission costs, which we expect are less about who should pay for the incremental costs of transmission expansion and more about other issues, which are largely collateral to allocating transmission costs. These other issues include concerns voiced by those protecting consumers' generation-related prices in regions with bottled up low-cost generation, as they fear that transmission investment (even when determined to be net beneficial to those who benefit from and will pay for it) will cause generation-related prices to equalize over larger geographic regions. Our approach will lessen the litigation and process impediments that impede investment in such net-beneficial transmission, but we are realistic enough to believe that it will not completely overcome fights that will continue to spring from desires to protect constrained-in low-cost generation as well as from siting issues.

I. Introduction

The U.S. electric system has served the nation well with decades of reliable and universal electricity service. However, there is an increasing and broad recognition that significant amounts of investment in the transmission system will be needed in the near and long term if the system is to continue to provide the kind of electricity service that Americans desire and on which the nation's economy depends. In 2007, U.S. investor-owned transmission companies plan to spend approximately $8 billion[2] on transmission construction, with planned investments (as of January 2007) expected to amount to $31.5 billion for the 2006-2009 period.[3] While new funding levels are roughly double the annual investment levels at the start of the 21st century, there is a broad consensus that the U.S. has for years been under-investing in the transmission system[4] and there are many who suggest that much higher levels of investment are required to keep up with the nation's growing demands.[5]

Part of the problem in attracting investment in transmission in recent years stems from the state of transition from the old regime of vertically integrated monopolies which planned and built for their own needs, to the current regime of disaggregated management, if not actual ownership, of transmission. Under the old industry structure, the utilities planned and built transmission to link their load centers to often distant generators in order to serve captive customers in geographically defined monopoly service territories. While the companies may have considered other energy suppliers for reliability or economical power purchases, they were not obliged to consider them for purposes of planning transmission services. Indeed, transmission owners, prior to the passage of the Energy Policy Act of 1992, were not obliged to provide transmission access to competing generators. The old regime was essentially a highly

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2 Edison Electric Institute, "Why Are Electricity Prices Increasing? New Investments for Transmission and Distribution Systems Are Needed," September 2006, page 2.

3 Edison Electric Institute, "Transmission Projects: At a Glance," January 2007.

4 *See*, for example, the report prepared by Brattle Group at the request of the Edison Foundation: "Transmission investment declined steadily for approximately 25 years, increasing only over the last few years.[fn] Between 1975 and 1999, nominal investment for investor-owned utilities (IOUs) fell at an average rate of $83 million per year. The trend reversed itself from 1999 to 2003 as nominal transmission investment increased by an average of $286 million per year and totaled nearly $18 billion over this period.…[T]ransmission mileage has not dramatically increased in recent years, relative to growth in load. "Normalized" transmission capacity, or the number of transmission line miles per unit of demand, declined by almost 19 percent between 1992 and 2002." (footnote omitted) Gregory Basheda, et al. (The Brattle Group), "Why Are Electricity Prices Increasing? An Industry-Wide Perspective," Prepared for the Edison Foundation (June 2006), p. 52.

5 The electric industry, for example, estimates that "All told, investment in the transmission system is projected to add more than 7,122 miles of new transmission through 2009, and nearly 12,484 miles added during the 2005-2014 time period." Edison Electric Institute, "New Investments for Transmission and Distribution Systems Are Needed," September 2006.

balkanized system of utilities physically linked to one another primarily for reliability purposes, although opportunity energy sales or capacity sharing were not uncommon. Under the new, competitive market structure, the balkanized regime of neighboring, largely self-sufficient utilities has given way to industry structures that also involve broad regional markets crossing both service territories and state boundaries.[6] To enable those markets to flourish and grow, open access in transmission is needed, and transmission owners are required to provide non-preferential treatment to anyone including their affiliates.[7]

While the wholesale market has changed fundamentally, the framework for enabling investment to enhance the grid required to serve the 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 the old regime of simply putting new investment into individual utility monopoly rate base no longer seems appropriate, new principles governing the allocation of cost responsibility for new transmission investment have yet to be fully articulated and implemented. Cost allocation is the subject of this paper.[8]

In the industry at large, there has been a lack of consensus about who should pay for transmission, especially where benefits are either in dispute or accrue to parties other than the traditional customers of the transmission company that would need to make the investment. Many have pointed to this lack of consensus as a cause of underinvestment in the grid. The problem stems – in part at least – from a mismatch between jurisdictional boundaries and market realities.[9] Because of the industry's historical evolution, transmission planning remains largely a local (usually state-level) process. Yet in today's highly interconnected electric system, power transactions and power flows pay no attention to boundaries of individual utility service territories or states, or, for that matter, to international borders. Electricity consumers in one area depend upon resources and reserves located in others. The transmission system serves as the vehicle for helping ensure reliable service at reasonable cost over broad regions.

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6 While only about half of the states have opened up their retail markets to competition, the wholesale generation market is competitive by virtue of the explicit policy contained in both acts of Congress and subsequent regulatory actions, and because the wholesale use of the grid is, by law, open access.

7 Institutionally, open access is provided in different ways, reflecting the regional differences in industry structure and wholesale markets that exist across the country.

8 The assignment given to this panel was to discuss and, if possible, make recommendations for allocating the cost of transmission. Where relevant to these topics, we discuss other issues, but we do not attempt to address all important transmission issues in this paper.

9 Another root of the problem is that we do not have well-defined property rights for transmission. For this and other reasons, there is no currently implementable investment model that would allow a market to work for transmission.

Given the dynamic nature of changes in the electric system over time, the benefits of transmission are constantly shifting. Transmission built by one utility for its own consumers' needs may deliver larger benefits to customers of another utility at a later time. There are classic cases where a region that appeared to have plenty of generating resources found itself relying regularly on imports from neighboring regions.[10] Such shifts in benefits occur routinely over a wide area where generating resource additions are large relative to annual demand growth. This interdependency among users, suppliers, and transmitters results not only from the physical nature of the interconnected grid as it changes over time, but also from the now decade-old Federal policy supporting open access to transmission as a means to encourage development of competitive wholesale markets on the interstate grid. The need for better integration of the nation's electric grids and a more reality-based model of cost allocation is closely linked to policies promoting open access to those grids.

Even with open access firmly in place as national policy, there continue to be conflicts over the uses and effects of, as well as financial support for, transmission capacity. For example, large facilities proposed in order to connect resources and consumers in different states may be opposed by one intervening state or another. Sometimes it is concerns over the prospect of environmental and land-use impacts that lead to opposition, as when most of the benefits of the new lines in one state are identified as flowing to consumers in another state. In other instances, the concerns focus on the question of how to best allocate the cost of new investment when it is perceived as being incremental to the requirements of local electricity users who have been supporting, in their electricity rates, all (or most) of the costs associated with the local utility's transmission investment. In still other cases, the concerns focus on one state resisting a proposed transmission line when policy makers in the state perceive that their residents' electricity rates will rise when previously bottled-up cheap power supplies may find a new market once the new line is built. Such "us-versus-them" issues even arise within states where there are transmission bottlenecks that separate a region with surplus low-cost power from a higher-cost region in another part of the state.[11]

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[10] We describe such situations in a later section of this report on Federal/State issues in transmission that affect cost-allocation.

[11] We note here that the unbundled transmission is subject to Federal jurisdiction under the Federal Power Act even in situations where there are intra-state disputes over the redistribution of such benefits and costs. Except in the Electric Reliability Council of Texas ("ERCOT") power region (which has an electric transmission system not AC inter-connected with other states), virtually all unbundled transmission is presumed to operate in interstate commerce and is thus subject to the Federal jurisdiction,

Factors such as these – and others – often encourage load-serving utilities and their State regulators to not treat the electric grid as an integrated system, with economic and reliability benefits shifting in one direction or another at various points in time. State authority over utilities is therefore often exercised in ways that discourage investment in or the siting of needed new transmission assets. Even when the need for a particular transmission project has been established (*e.g.*, through a State or regional planning process), questions over who benefits and who pays remain perennial sources of dispute. Disputes over these types of issues often chill investment that might otherwise provide broad-based benefits to a large region over time. The uncertainty – and frequent disputes, procedural delays, and fights over cost recovery – has this chilling effect by raising the risk and uncertainty of transmission investment.

This White Paper focuses on the principles for determining the benefits of new transmission investments, and for allocating the costs of those that provide net benefits to various users of the electric system. While Federal regulators have been attempting in recent years to accommodate the differences of opinion on these topics by adopting transmission cost-allocation methodologies rooted in settlement discussions or negotiated agreements among stakeholders in local areas, this approach suffers from lack of common principles supporting transmission investment for the interconnected grid that serves broad regions of the nation. On one hand, the desire for different regional approaches is understandable from a pragmatic point of view; settlement processes often allow issues to be resolved, removing local uncertainty. On the other hand, the question of whether the widely divergent methods proposed and accepted for allocating transmission costs produce a body of policies that together both meet the legal standard of just and reasonable result and prove to be sustainable and investment-friendly for the long term, is unclear, particularly when these allocations interact across regional boundaries.

The Federal Energy Regulatory Commission ("FERC") has essentially relied less on policy formulation and more on informal, local consensus-oriented processes beyond its control and supervision to determine cost allocation proposals, while plainly acknowledging that approaches other than those it approved could work as well or better. Too often, the settled approaches reflect much more than regulatory compromises and arise more from various "political" dynamics than sound principles of economics, physics, or engineering. At the end of

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primarily under the oversight of the Federal Energy Regulatory Commission. This paper takes no position on strict matters of jurisdiction. But, *see* footnote 82, below.

the day, the main principle that is common to the array of approved approaches is the simple, stark fact that each has been approved as just and reasonable by FERC. Finding a principled basis for cost allocation that relies on more than lowest common denominators would certainly provide a more appropriate and sustainable basis for public policy.

Transmission investment and the allocation of the costs of those investments are complex issues, encompassing difficult modeling, environmental, economic, equity, and engineering questions. While the full panoply of issues merits thorough consideration, our mandate is more narrow. We focus primarily on the question of cost allocation. However, cost allocation is inextricably linked to these other issues. Often the challenge of cost-allocation is very real, but sometimes it serves as a pretext or proxy for other concerns.[12] Because of these facts, we will also discuss some of the economic, modeling, ratemaking, equity, and governance questions that influence the process of transmission planning and cost allocation.

In Section II, we begin by defining many of the common concepts and phrases that have frequently been used, and sometimes misused, in discussions about transmission planning. In Section III, we discuss some of the modeling issues confronted by transmission planners as they seek to understand the power system and the question of how changes in it affect the distribution of benefits among various sub-regions. In Section IV, we explore the exercise of State and Federal jurisdictions over transmission, and describe some of the difficulties that can be created by these overlapping authorities. In Section V, we discuss the concepts underlying the current planning process in various regions, and how they relate to cost-allocation issues and approaches. In Section VI, we conclude with our recommendations for a set of framing considerations and Principles we feel should guide the design of a planning and cost-allocation in order to best achieve the continued development of the nation's electric network in an efficient and reliable manner.

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12 One of the reasons why the articulation and implementation of guiding principles for cost allocation is necessary is to make transparent which concerns about cost allocation are real and which are simply a pretext. The use of principles imposes a level of discipline on cost allocation debates that make it far more difficult to use cost allocation as a pretext for something else.

II. Definitions and Foundational Concepts

One of the many difficulties with discussing who should pay for transmission expansion is the surprising lack of a common language for conveying the critical underlying concepts. Important words such as “benefits” and “beneficiaries”, and phrases such as “economic upgrades” and “participant funding” are too often used in radically different ways by different parties. At best, the meanings intended by some speakers are not transparent, and different meanings are inferred by different listeners. At worst, the same words have opposite meanings to different people.

Therefore, before examining some general principles for assigning support for transmission investment, we discuss how we define some of the key phrases and concepts that are often used in the debates about investment. To the extent possible, we have tried to adopt definitions consistent with common practice, but which also illuminate the discussion. However, some phrases, such as “participant funding” are so fraught with disagreement that we will seek alternative phrases to stand for the associated concepts.

Critical to the issues we address here, though, is our view that some concepts that were shaped and perfected in an era before the nation adopted a policy of non-discriminatory access to transmission are no longer adequate in today’s environment. For example, transmission planning practices and approaches historically evolved in times when vertically integrated utilities had responsibility for planning both generation and transmission for their “native load” and for those served under long-term supply agreements. From the point of view of ensuring system reliability, this practice was codified in North American Reliability Council (“NERC”) standards and NERC-defined concepts. While many companies remain vertically integrated in some parts of the nation, the expectations for those entities with transmission planning responsibilities have changed dramatically over time virtually everywhere in the country. Other conditions have changed in many respects, and the future reliability of supply for loads affected by developments and events on one system are affected by developments and events on others. As we argue below, we believe reliability and economic upgrades should be considered together in a unified framework. In light of this, some of our discussion suggests the need for re-interpretation of these concepts and the development of new tools to support the analysis; however, explicit discussion along these lines is beyond the scope of this paper.

A. *Reliability versus Economic Upgrades*

Among the most important concepts in the process of transmission planning and expansion are the benefits transmission projects provide to users of the network. We will describe our notion of benefits in more detail below, but we first begin with a discussion of what we believe is the outdated and no-longer-useful distinction that has been applied to transmission projects, namely, the distinction between reliability and economic upgrades. This distinction was always problematic, but it has become more so with the advent of regional electricity markets and open-access transmission in the U.S.

Traditionally, *reliability* upgrades have been defined as those projects necessary to ensure that demand – in particular, the forecasted peak demand of "native load" served in the franchise area of a vertically integrated utility – can be met with high probability over some time horizon and under a reasonable range of contingencies. A typical framework for analyzing transmission requirements starts with the configuration of the current network. At a minimum, it then makes an assessment of future demand growth coupled with projections of resource development for some future study period or periods, usually focusing on peak demand. If, given the assumptions of the study, there is a non-trivial chance that electricity loads would have to be shed involuntarily and to a degree inconsistent with reliability standards, an upgrade can be justified under reliability grounds.

In contrast, an *economic* upgrade in that same analytic framework might be one that is not necessary to prevent black-outs but, rather, would lower costs to supply the needs of consumers by allowing for lower-cost generation to displace higher-cost generation. For example, a project connecting lower-cost power from a distant generator into a system with higher-cost local generation would be framed as economic. Conceptually, an economic upgrade would have net benefits if the cost of the transmission upgrade plus the cost of the remote resource is lower than the cost of existing resources, when assessed over a suitable time horizon.[13]

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[13] A third type of transmission upgrade is a radial interconnection, to connect specific new generation directly to the existing network. Conceptually, such transmission upgrades are generally viewed as part of the generation facility itself, enabling it to become connected into the system and thus capable of delivering power to it. Because there is near universal understanding of these as the responsibility of that generation facility, we put these upgrades into a separate category and only parenthetically discuss such upgrades.

The distinction between reliability and economic upgrades arose in the era before open-access transmission. For example, in the context of a new remote generating facility jointly owned by a number of utilities and requiring a transmission upgrade to enable its power to be delivered to loads served by those utilities, a new transmission facility might have been considered to provide economic benefits, or to meet both economic and reliability objectives.[14] As another example, transmission upgrades proposed to support an inter-utility trade arrangement might similarly have been justified based on such economic benefits. That said, many if not most upgrades were justified on reliability grounds. In an era of competitive wholesale markets – whether centrally organized or bilateral in nature – the potential for such "economic upgrades" has grown with the advent of increased wholesale trading.

Conceptually, the problem with distinguishing between "reliability upgrades" and "economic upgrades" is that it injects an artificial dividing line between two things that are both fundamentally economic concepts. The distinction assumes that a new, or otherwise unexploited, supply option falls into the domain of something "economic," whereas every new increment of demand is not associated with an economic assessment. In other words, this conceptual framework treats every net increase in load – whether from a new appliance from an existing customer or a new home or factory or hospital constructed within a local system – as a fixed electrical requirement that must be met for reliability purposes and not for economic purposes. However, it is just as appropriate to think about incremental demand – again, conceptually – as something that has the option of being served economically, or not. To make the point more vividly, it might not be "economical" to meet the reliability-related requirements of incremental load by adding transmission upgrades when the reliability problem could be satisfied at lower cost through, say, locationally targeted demand response, optimally distributed generation, or other means of assuring reliable electric service to both existing and incremental loads. The focus in "reliability" upgrades on a fixed forecast demand ignores price-responsiveness of demand and the value to consumers of incremental demand.

Another practical difficulty with traditional distinctions between "reliability" and "economic" upgrades is the fact that almost all transmission projects in effect serve both

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[14] During this era, the distinction made by State regulators between reliability and economic upgrades also came to involve the extent to which the transmission facilities would be used to serve native load as opposed to facilitate regional trade. We further discuss the interaction of State and Federal regulatory policies in Section VI.

purposes. At any point in time – and even more so over time – almost any project will lower the risks of interruptions by some degree, and almost every upgrade justified for reliability concerns will inevitably yield at least some economic benefits as well.

Furthermore, because transmission exhibits large *economies of scale* and high transaction costs – that is to say, as a general proposition larger capacity projects have much lower per-megawatt ("MW") costs – it usually makes sense to accommodate both reliability and economic opportunities within a single project rather than piece-meal. Finally, because transmission assets are extremely long-lived, lines that are unnecessary for meeting forecasted peak demand *today* will become part of the portfolio of assets maintaining supply demand balance far into the future.

With this in mind, then, we observe that today's approach of treating incremental demand as needing to be satisfied – in effect, at any cost – is problematic from a "conceptual framing" point of view.[15] We understand its origins may reside in important notions of utility franchises and an obligation to serve. But changing market conditions require us to think of reliability differently. In the current era of transmission open access and regional markets, there are multiple strategies available to assure reliable service at just and reasonable rates. In today's industry, it is appropriate to recognize that both increases in demand and increases in supply share equally the burden, and benefit, of being labeled "economic" phenomena.[16] Supply and demand cannot be treated in isolation when considering either the reliability or economic impacts of transmission projects. Both create costs and benefits for an integrated system that must be considered as whole.[17]

As a foundational concept, therefore, we think it is important to consider demand as a value to be incorporated into system planning in the same manner as supply, through explicit and transparent attempts to trade-off the costs of demand-side actions against supply-side resources in an integrated transmission expansion planning framework. If we explicitly attach some

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15 We observe that this is symptomatic of a broader problem that has long affected the electric industry. Because retail pricing traditions too rarely lead to signals to customers about the true costs of serving their demand at any given moment, regulators, operators, and planners do not think of prices as reflective of value to consumers of the electricity they consume. Unlike for most other goods where prices are conceived of as a tool for balancing supply and demand, in the traditional electric industry, prices have been considered instead as a means for recovering costs. In light of the genuinely costly nature of electric service, we think there are important values associated with thinking of prices as more than just that. And, as part of transmission system planning, it is useful to think of both demand and supply as economic constructs.

16 It is important to recognize that the concept of reliability in the context of transmission planning is driven to a large extent by the policies of NERC and the regional reliability councils. Any effort to rethink the definitions of reliability and economic upgrades must therefore involve coordination with these institutions as well.

17 As we discuss later in our paper, for practical reasons we advocate that the costs of new network transmission investment be allocated to loads, even though we see both supply and demand as equally relevant for planning purposes.

(finite) value to serving load, such as an estimated value of lost load ("VOLL") or a willingness-to-pay exhibited by demand in the market, then the prevention of interruptions becomes an economic benefit that we can integrate within an overall assessment. That is, the benefits of reliability and economic upgrades would be commensurable. This is a concept we will return to below.

In practice, it appears the notion of reliability upgrades has survived in part because projects are more likely to overcome their inevitable opposition if they are linked to reliability.[18] Advocacy for projects is based on a mantra of "reliability," without a clear articulation of what "reliability" might mean, entail, or cost. However, the lack of an economic framework prevents the discussion of the economic value of reliability upgrades, necessitating appeal to the implicit bogeyman of blackouts as the main justification for construction of transmission facilities. While this approach may be expedient given opposition to transmission siting and investment, it is likely that projects with large, tangible economic value may not be built. In the end, we do not oppose the concept that indeed transmission upgrades support reliability of the grid. But we do think the attempt to distinguish some upgrades as more worthy because they offer reliability benefits to particular "new" loads (*i.e.*, those of old and new customers of a particular utility), while other upgrades (*e.g.*, those designed to serve the economic interests of customers of a neighboring, interconnected region) as less so seems inappropriate in an era of open, non-discriminatory access to transmission.

This problem is exacerbated by the realities of today's competitive power generation market. Today, there remain many situations in which the entity performing transmission analyses (and largely responsible for upgrades flowing from them) has generating assets which stand to benefit or lose financially if some transmission upgrades are undertaken to allow for

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[18] Another source of the persistence of an artificial distinction between reliability and economic upgrades is the differing focus of traditional analysis of the two types of upgrades. Reliability planning focuses on meeting a forecast of peak loads (or multiple peak loads). Related transmission planning and assessment tools focus, in part due to the computational complexity of the analysis, on peak conditions or only on a selection of conditions and contingencies under assumed generation commitment and dispatch conditions. In fact, the cost of running an electric system is strongly influenced by conditions in all hours, and the relationship of those conditions to each other. Economic upgrade planning, therefore, considers costs integrated over time, usually with detailed consideration of generation commitment and dispatch. These economic models typically ignore many details of transmission assessment. Moving these two forms of analysis onto a comparable plane, with treatment of incremental loads and incremental supplies on analytically similar frameworks, would further support treatment of all uses of transmission on a non-discriminatory basis. Doing so will require tools that can assess transmission issues in a simultaneous consideration of transmission and generation expansion, commitment, and dispatch. These tools are beginning to be developed by vendors. *E.g.*, Baldwin Lam, "Assessing the reliability of modern day transmission systems," Presentation, August 2007, Siemens Power Transmission and Distribution, Inc. Schenectady, New York. *See also*, *IEEE Power and Energy Magazine*, special issue on transmission planning, September/October 2007 at 24-78.

wider markets. The lack of a sensible policy rationale for the distinction between reliability and economic upgrades is also manifest when a low-cost region with bottled-up economic generation will support "reliability upgrades" to meet the growth-related needs of its own customers but not the needs of outsiders who may seek reliable access to those same low-cost resources. Without knowing *a priori* whether either of those upgrades would be economic in a broader sense, it seems to us unfair – in the era of national policy for non-discriminatory open access to transmission – to cloak the former with the reliability mantel but to condemn the latter with the burden of being an "economic" upgrade. It seems obvious to us that the distinction overestimates the reliability *and* economic value of the former, and underestimates the reliability *and* economic value of the latter.

B. *Benefits of Transmission Upgrades*

We now broaden the question of reliability versus economic benefits to consider the meaning of the term *benefit* in general. Clearly transmission lines provide a diverse set of benefits (as well as costs) to a broad range of constituents. Although it can seem daunting to compile these diverse effects into a single measure of benefit, economists have in practice utilized the concept of *social welfare* for such purposes. This concept is important in part because it distinguishes between changes that make a group better off in aggregate from those that result in simply a *transfer* of benefits (*e.g.*, money or some other value) from one group to another. Therefore, we will focus on the concept of welfare-improving projects as those that merit consideration. In the context of transmission planning, improvements in welfare are usually associated with reductions in the production costs

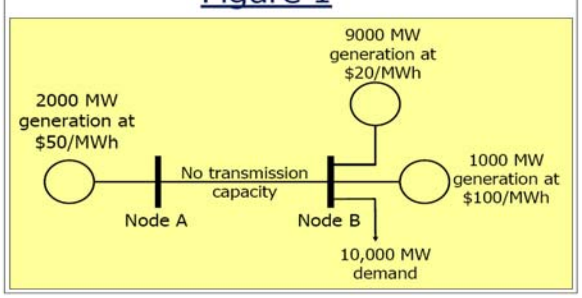
Extended Example:

Explaining key concepts and definitions

Here we utilize a simple model network to develop several examples of the different definitions we are discussing. There are two regions ("Nodes") in the network. Relative to its local load, Node A has 2,000 MW of surplus generation with production costs $50/MWh. Node B has 9000 MW of low production cost ($20/MWh) generation and 1000 MW of expensive production cost ($100/MWh) generation. For now we will assume that all of the demand is at Node B, and that demand is fixed at 10,000 MW every hour over a time horizon of consideration. (See Figure 1.) At the starting point of this example, Node B cannot utilize Node A's generation due to transmission constraints. The production cost to meet demand at Node B is $280,000 per hour.

Using this basic hypothetical example, we illustrate various concepts in more detail in five other text boxes below (**Illustrations 1** to **5**).

Figure 1



of serving demand, or with the ability to serve growing demand, or both. We will first focus on serving demand ignoring demand growth. From an economic perspective, if the savings in production over the time horizon due to access to cheaper power exceeded the cost of building the transmission line, then it would provide net benefits and should be built. Since this prescription is based on production costs, it does not depend on the structure of the market. For example, it would apply in a market using marginal-cost based prices or in a market utilizing average cost based prices.[19]

> **Illustration 1:**
>
> **Welfare Improvements**
>
> A transmission project is proposed to import power into the constrained region (Node B). With the addition of this project, the utilization of expensive local power plants ($100/MWh) is reduced and this supply is replaced by less expensive distant plants ($50/MWh) from Node A. Since the demand at Node B could be met prior to the transmission expansion in the relevant time horizon, this transmission expansion provides access to lower cost power and would be deemed an "economic" upgrade under the traditional definition. If 1000 MW of transmission were built between Node A and Node B and 1000 MW of generation is replaced in this way, there is an overall savings in production costs of $50,000 ($50/MWh x 1000 MW) every hour from the transmission project.

The market structure may have important implications for the costs and revenues from the sale of power, however. If a transmission project eliminates congestion into an expensive region, for example, it could also lower prices there. The amount of price reduction that merely reflects a change in payments from one party to another is called a *transfer*.

The transfer reflects neither a reduction in production costs nor an increase in beneficial consumption, but rather a reallocation of funds from one group to another. Naturally, transfers are very important to the groups involved, but for policymakers to weigh transfers in their decisions they are implicitly (or even explicitly) making a decision about who they feel deserves the money. In the context of investment in transmission designed to support both a reliable grid and a regional wholesale market consistent with national policy, this is a very slippery slope.[20]

A focus on energy *prices* in transmission planning can often lead to an important role for transfers in the final decision. In ISO-New England ("ISO-NE"), for example, the economic benefits of transmission projects are measured in terms of their impact on bulk power system purchase prices (on a net-present-value basis), after taking into account transmission addition or upgrade costs. The focus on the purchased price of power in ISO-NE planning therefore treats

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19 We recognize that the structure of the market may affect the incentives for bringing about such transmission construction.

20 We discuss the relationship between Federal and State regulatory jurisdictions in a later section.

transfers from generators to buyers with the same weight as fuel-cost savings. The transfer issues are somewhat different in markets that remain vertically integrated and regulated, even though the fundamental economic decision remains the same. If regulated rates are based upon the costs of serving demand, including production costs, then there will be a more direct relationship between social benefits and rates than in markets where prices are based upon the market price of supplying demand.

The question of transfers becomes more complicated in the presence of less than perfect competition (*i.e.*, when market power exists). First, prices in the importing region could be inefficiently high to the extent that they reflect market power[21] and not a true scarcity of supply or transmission capacity. Such prices would also most likely not be considered just and reasonable, and most markets in the U.S. have market power mitigation schemes in place to combat these problems. Still, to the extent that transmission investments serve to increase competition, the ensuing benefits to consumers in diminishing the severity of

Illustration 2:

Transfers

If the project eliminates congestion into the expensive region, it could also lower prices there. For example, in a wholesale clearing-price market, this price change could apply to all 10,000 MWs in each hour. (If long-term contracts for energy trade were in place before the line was constructed, the price impact would be reduced, at least in the short-term, since less volume would be affected by the reduction in the spot price.) From the perspective of consumers at Node B in this case, the transmission line provides savings in the purchase price of power well beyond the fuel cost savings from the substitution of 1000 MWs of the \$50/MWh power for the \$100/MWh power in each hour. Conversely, owners of high-cost generation at Node B lose revenues from no longer being dispatched at all, the low-cost generators at Node B also lose revenues from the reduction in the price at Node B (from \$100/MWh to \$50/MWh), and the exporters/sellers from Node A increase their revenues from zero to \$50/MWh.

The change in revenue to the low-cost generator in a clearing-price market, equal to \$450,000 every hour (\$50/MWh × 9000 MW) is a transfer from producers to consumers in the wholesale market at Node B. It reflects neither a reduction in production costs nor an increase in beneficial consumption, but rather a reallocation of funds from one group to another.

Note that the transfer issues are somewhat different in markets that remain vertically integrated, even though the fundamental economic decision remains the same. If, in our example, a single integrated firm was responsible for serving load *and* owned all the generation at Node B, then the transfers noted above are all internal to the firm. If the integrated firm is regulated under cost-of-service regulation, then retail prices at Node B would reflect the average of the low-cost and high-cost (or imported) generation (together with the investment costs for generation and transmission). For example, before the line was built, prices at B would be the average of local generation costs (9000 × \$20/MWh + 1000 × \$100/MWh)/10,000 = \$28/MWh (plus an assessment of generation investment costs). After the line is added, prices would adjust only to reflect the displacement of the high-cost local generation and would equal (9000 × \$20/MWh + 1000 × \$50/MWh)/10,000 = \$23/MWh (plus an assessment of generation and transmission investment costs.) In this case, because prices are based upon the average costs of production, the change in *regulated* prices also reflects the true cost savings in production. It is important to recognize that this is different from a change in the locational marginal prices ("LMPs"), which are based upon the *marginal* costs of production.

[21] Market power often is present in markets that are of insufficient scope or that are not highly contestable (i.e., markets where barriers to entry permit producers to charge above their marginal costs over the long term).

market power could be taken into account in decisions about whether to approve a project, even if it only acts to improve consumer, but not societal, welfare. Second, where market power is present, the measurement of the efficiency impacts can be very difficult. Lines that do not carry much power can still enhance efficiency if, through the threat of competition, they reduce supplier market power and limit the need for more intrusive market power mitigation rules. Projects that substantially reduce local market power will also likely have a dramatic impact on prices in a constrained region. Therefore it is also reasonable for the modeling of project benefits to consider the potential for market power, and not just model scenarios where all suppliers are assumed to be operating as "price-taking," perfectly competitive, suppliers. Traditional production cost models in effect assume such perfectly competitive behavior and can therefore understate both the efficiency and consumer price benefits of certain projects.

In some regions, the "benefits" of transmission projects are measured at least partly in terms of their impacts of congestion as opposed to their effect on welfare alone. As with energy prices, this can at times give misleading signals as to the social benefits of a project. The network *congestion rents* are defined as the difference between the payments by customers for energy sales minus the payment to generators for energy purchases of their power injected into the network. Because locational marginal prices ("LMPs") are ideally based upon the marginal costs and benefits of producing and consuming electricity, defining transmission benefits in terms of congestion rents will capture both the transfers as well as the true social benefits in the valuation of projects. An alternative but related concept, total *congestion cost* is more closely related to our definition of social benefits. Total *congestion costs* are defined simply as the difference between

Illustration 3:

Congestion Rents

Returning to our example, assume that the added transmission capability between Nodes A and B were only 900 MW and that wholesale prices are based on LMPs. Because some of the expensive generation would be needed at Node B, the LMP at B would be $100/MWh, while the LMP at Node A would be $50/MWh. In this case there is a net injection of 900 MW at $50/MWh into Node A and a net withdrawal of 900 MW at $100/MWh at Node B. (In this case, the congestion rents also equal the flow of power (900 MW) from Node A to Node B times the price difference between the two nodes ($50/MWh). In a meshed network of many nodes, tracing flows is complicated and it is more useful to define congestion rents in terms of injections and withdrawals.) The congestion rents are $45,000 per hour. The addition of another 100+ MW of transmission capacity would then eliminate all congestion rents. In other words the transmission expansion by another 100+ MW would "save" $45,000 an hour in congestion rents. The true savings of the additional 100+ MW of transmission capacity, in terms of reduced generation costs, are, however, only $5,000 an hour. The difference between the congestion rents and the social costs represents a transfer of $40,000 per hour.

the costs of serving demand, given actual transmission capacity, minus the costs of serving the demand assuming unlimited transmission capacity on each component of the network.

C. *Planning for Transmission*

An important issue which arises here is transmission planning cannot take place in the absence of a specification of generation and other resources. The concept of coordinating grid investments with those of other resources has been called *integrated planning*.[22] We observe that regardless of how one views open access and non-utility generation, it is hard to escape the conclusion that competitive wholesale markets have rendered the transmission planning process more complex and difficult than it was in the past. A particularly thorny issue in light of open access transmission is that transmission planning and generation investments are supposed to be carried out by different entities. These entities are precluded from the type of coordination that was inherently a part of planning in vertically integrated systems prior to the open access era. Referring to the example in the adjacent text box, if incremental resources were expected to be available at another Node C and not at Node A, then transmission planning would need this information in order to be able to meet the demand at Node B. That is, just as with "economic" upgrades, "reliability" upgrades need access to generation plans and alternatives.

Illustration 4:

Impact of Demand Growth

Now we consider incremental demand growth and its value. Suppose that demand is expected to grow so that peak demand will increase to 10,500 MW. Following the previous discussion of demand variation, we first suppose that an economic upgrade of at least 500 MW had been completed. In this case, and assuming that none of the local generation had retired, the existing system, including imports, is able to meet the 10,500 MW demand. This illustrates the case where an initially "economic" upgrade becomes used for "reliability."

If the "economic" transmission upgrade had not been made, however, and the demand was forecast to grow to 10,500 MW then, under the traditional definition of "reliability" upgrades and given no other generation options, the upgrade would presumably be required for reliability reasons. In the traditional expansion framework, the costs of "reliability" and "economic" upgrades may be allocated to different participants, despite the logical difficulty in distinguishing these upgrades and despite the fact that the economic upgrade may even become necessary for "reliability."

Because the peak demand of 10,500 MW would exceed the available generation, under the traditional reliability framework, additional resources and transmission would be planned. Assume that the generation at Node A has been identified as incremental resource. In the "reliability" framework, new transmission would be built from Node A to Node B to accommodate the demand growth.

22 We distinguish this from integrated resource planning, which is a process that is typically viewed as attempting to optimize a configuration of demand-side, generation, and transmission resources to meet the requirements of a given set of customers. We use the phrase "integrated planning" simply to describe a process of planning for transmission that takes into account the loads and resources interconnected to the system.

In some cases, such as the designation of wind power zones, it may be possible to predict transmission needs in advance of specific generation plants. However, in most cases, coherent transmission planning requires a specification of incremental generation resources. These resources need to be specified by a load serving entity or other party. To the extent that the transmission costs vary significantly with generation plans, this is problematic because coordination is then necessary between transmission and generation planning in order to achieve the lowest overall costs. For example, the transmission costs to access generation from Node A may be vastly different to that from Node C.

A further issue arises in a restructured market. In such a market, the notion of a fixed forecast is not completely meaningful. In a market with active demand participation, the amount of demand on-peak will in part be determined by the on-peak prices. From a planning perspective, the value to consumers of demand at peak may be reflected in on-peak forward contract prices, possibly on the order of hundreds of dollars per megawatt-hour ("MWh"). Even in a restructured market without active demand participation, the value of incremental demand is reflective of involuntary curtailment or VOLL, possibly on the order of thousands of dollars per MWh. In a traditional "reliability" framework, generation and transmission would always be built to meet that incremental demand. In a net benefits framework, incremental demand would not be

Illustration 5:

Impact of Demand Variation

We now consider variation in demand over the time horizon. For example, suppose that the demand varies over the time horizon between 5000 MW to 10,000 MW with an equal probability for each level of demand. The discussion of transmission planning for peak demand ignores the distribution of demand growth over the hours of the year and therefore does not consider the economic value of meeting the incremental demand. We now consider the distribution of demand over the time horizon and again consider the benefit of building a line, returning to the assumed starting condition where there is no capability from Node A to Node B. In this case, since there is 9,000 MW of low-production-cost generation at Node B, the line would only be used during the 20% of time when demand is above 9,000 MW. Given any particular proposed expansion capacity, the expected savings of displacing expensive generation could be calculated over the time horizon and compared to the cost of transmission.

Conceptually, as the proposed amount of transmission expansion increases, the marginal value of that capacity, in terms of displaced expensive generation, would decrease. For example, consider the benefits of an expansion by 990 MW and the benefits of an expansion by 991 MW. The difference between the benefits of these two expansions is due to displacing one more megawatt of expensive power for a relatively small fraction of time. Depending on the cost of transmission, it might be the case that an upgrade of less than 1000 MW was optimal in the sense of maximizing net benefits. For example, it might be the case that an upgrade of 500 MW yielded the greatest net benefits.

When demand growth is being considered, both the variation and the growth have an impact. For example, suppose that the demand is forecast to grow such that the demand will be uniformly distributed between 5,500 MW and 10,500 MW over the time horizon. Again, in a transmission planning context, we need to consider the benefits of various levels of transmission expansion.

accommodated if serving it did not yield net positive benefits. In most cases, we would expect the value of incremental demand would justify such upgrades; however, it is important to explicitly consider the value in order to consider the trade-offs between various supply and demand alternatives.

D. *Participants and Beneficiaries*

Most discussions of the allocation of transmission costs involve a discussion about who the participants in the project might be, and who the beneficiaries are. In this regulatory context, the two terms have been treated almost as synonymous. The phrase, *participant funding,* has come to define a process of identifying the immediate beneficiaries or cost-causers of a specific project (possibly on the basis that they are the proposers of the project), and allocating the project cost only to them.[23] On the other hand, when costs are *socialized*, costs are allocated on some pro-rata basis to all customers within a given region. In fact, there is a spectrum, with some effort in participant funding approaches to distinguish specifically "who benefits" from those who do not, and with much less effort to directly do so in instances where socialized funding support occurs. The latter approach, for example, tends to incorporate situations where all of the consumers of a utility pay for transmission investment. In that sense, we have always socialized costs – sometimes over all customers in a common voltage class, or sometimes over other broad categories for spreading costs to other categories of customers.

When one considers the demographic or geographic size of the region over which costs are being spread, the lack of a clear distinction between participant funding and socialization becomes apparent. In essence, socialization is also a form of beneficiary determination. It simply defines the participants or beneficiaries as everyone within a given region or sharing the services of the wide transmission network and allocates the costs uniformly based on some usage measure. If the size of that defined region is small but it is integrated with a larger region, it is very likely that those paying for the projects will not be the only ones affected by it or benefiting from it. In fact, any allocation scheme that does not consider impacts on an entire electrically connected region, such as the Western Electricity Coordinating Council ("WECC"), would likely miss at least some important impacts. The integrated nature of most high voltage transmission

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[23] In response to companies advocating "participant funding" as an exclusive approach, Section 1242 of the Energy Policy Act of 2005 clarifies that FERC may in its discretion approve "participant funding" with respect to funding new interconnections or transmission upgrades, consistent with the FPA.

predisposes us to prefer, if not advocate, allocation of the costs of major facilities and upgrades on a broader, rather than narrower, basis because the beneficiaries will generally be dispersed regionally and not always specifically identifiable with any degree of precision or permanence. Therefore, although socialization is sometimes considered the opposite of participant funding, it too is in fact a variant of beneficiaries pay, but where benefits are defined by demographic or regulatory boundaries rather than by a quantitative analysis of the system or a subset of the system.[24]

As a legacy of the historical planning approach, where needs were framed in terms of meeting the system's needs in the face of incremental growth in demand, transmission has been treated as something that benefits consumers and, in particular, the "native load." Costs have therefore traditionally been recovered solely from consumers, through either local rates or grid usage charges.

One last point to make with regard to benefits is that many transmission projects will not benefit everyone – at least in the short run – and can in fact negatively impact some network users due to the impact on energy prices. In the discussion above, for example, we focused on a local generator who is harmed by a decrease in local prices. There are also circumstances where an exporting region could experience an increase in prices. This would benefit producers and cost consumers in the exporting region. These impacts are transfers, but do represent a real cost to the generators or consumers involved, and therefore can raise opposition to individual projects based upon local interests.[25]

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[24] In fact, the traditional rate basing of transmission assets within the context of a vertically integrated utility followed a very similar model of cost allocation in which it was assumed that all customers of the utility benefited from the expansion of the system and the costs were, therefore, spread across all customers. While some states socialized costs evenly and others made class-based cost allocations, there was little effort to identify specific beneficiaries to whom cost responsibility should be allocated. It was the breakdown in the vertically integrated model and the emergence of competition that has led to demands for more precise definition of beneficiaries and cost causers. Because of the existence of competing corporate and financial interests, socializing costs across defined geographic footprints has become far more controversial and contentious than was historically the case.

[25] See discussion in Section IV on Federal/State jurisdictional issues.

III. Measurement Approaches and Concerns

We now turn to the question of how benefits can be estimated, and the practical difficulties that arise when trying to measure them. It must be noted that some measurement of benefits is necessary for any transmission planning process. Thus, arguments that the modeling of transmission benefits is a fruitless undertaking miss the broader point that a decision to invest in a transmission project is hopefully rooted in an assessment that its benefits outweigh its costs. A key question is whether one can accurately model the *distribution* of those benefits for purposes of cost allocation, in addition to estimating the overall level of the benefits.

Transmission benefits can be modeled as part of a planning process with optimal power flow models. These models assess the impact of the addition of a specific project or projects. Technically, the calculations are similar to those used to calculate locational marginal prices in an offer-based market. The critical difference being that the planning models rely upon longer-term forecasts and assumptions of future system conditions, whereas LMP calculations for offer-based markets utilize current or forecasted next-day system conditions and market offers. Given our ability to model transmission networks, calculations of the social benefits of transmission can be made. If we assume that demand is not price responsive, but has a fixed value of lost load, models can calculate the costs of serving (or not serving) demand given a certain configuration of the network. This can produce a measure of the cost savings from adding or enhancing transmission facilities.

Therefore, the impacts and benefits of transmission projects could be reliably and accurately measured *if* several critical aspects of future market conditions, such as the location of future generation and load growth, were known with certainty, and if the markets were perfectly competitive. In practice, however, none of these assumptions hold. Nevertheless, production cost simulation in an expected welfare framework can, in principle, estimate the benefits if reasonable assumptions about the probability of various outcomes can be made. Even the effect of the uncertainty itself can be incorporated in various ways into such a framework by considering the risk aversion of the participants.

The assumption of known probability distributions is reasonable in some cases for which we have historical data, for example for generation and transmission outages. However, there are many uncertainties for which probabilities are not known. Such uncertainties are not directly amenable to this approach and, consequently, related benefits can be hard to quantify. There are many aspects of the future about which we do not know what we do not know.

In transmission planning today, there is often a disconnect between the need for a line and the development of generation.[26] Clearly the two are closely related. The value of many transmission projects depends upon an assumption that generation will be developed to utilize the new facilities. Yet transmission planning models do not usually consider the prospect that transmission can *cause* generation to be built. The traditional approach is to assume that generation would be built and, if it is, to consider how much value would be lost without the transmission to use the new generation. This is currently particularly acute in the context of transmission to access renewable energy such as wind. Clearly the development of transmission infrastructure can stimulate the construction of assets to use that infrastructure. In other words, transmission can stimulate economic development. But quantifying how much transmission development is needed, and more importantly *who benefits* from this development, is very difficult.

In markets that have not been restructured, considering the interaction between generation and transmission may be less challenging. In a monopoly market, the single firm can trade off the benefits of, for example, new local generation against new transmission and remote generation. Assumptions about who will build generation are less of a concern, since the monopolist is doing both the transmission and generation investment. However, embracing this viewpoint also means embracing the notion that the monopoly firm will *remain* the monopoly in its area into the future. In this sense, integrated planning by a vertically integrated monopoly can perpetuate its monopoly and discourage the development of non-utility resources. More transmission infrastructure can facilitate entry of competition, with profound long-term benefits that are hard to quantify in a production cost model.

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[26] One of the most difficult uncertainties affecting the realities of today's transmission planning is that there are multiple owners of generation, many of whom have no corporate relationship with the transmission planning entity. This is a classic chicken-and-egg problem. Do you start with generation, and then plan transmission for it? Or do you plan transmission, having it lead to the siting of generation?

IV. Federal/State Issues: Their Impacts on Cost Allocation for Transmission

An entirely separate set of issues springs from the differences among State and Federal regulatory treatments of transmission. This section describes these tensions by examining the norms of cost recovery for investment in transmission, and how contradictions, gaps, and overlaps in cost recovery policy arise from these norms. These divergences are exacerbated and accentuated by siting practices for transmission.

A. *Effects of Transmission Investment Being in State-Regulated Rate Base*

As a general rule, when State regulated investor-owned companies invest in transmission assets, the dollars associated with the investment typically go into the State-jurisdictional rate base subject to retail regulation. That is, retail consumers' rates are set to recover the entirety of the investment over time.[27] These costs are charged to different types of customers according to some combination of MWh-usage-based and/or MW-load-based rates. In practice all of these utility costs are lumped together in rate base and customer rates.

This State-level ratemaking, based on a paradigm of cost-recovery for a utility with an obligation to serve its captive ratepayers, can often overlap with Federal transmission tariffs that are based upon a paradigm of open-access network owners selling services to all qualified users. When the transmission company's system is used by, and compensation is received from, others besides its own native load customers, these third-party uses are subject to Federally-regulated open access tariffs. The revenues associated with those other uses are typically credited back to offset the transmission revenue requirement, subject to retail ratemaking practice and to the vicissitudes of regulatory lag. While the practices of the states vary, in general the offset serves to lower transmission revenue obligations embedded in retail rates. In the discussion that follows, we observe that this overall structure of transmission cost recovery constitutes a "dual pricing regime," since it is affected by ratemaking practices of both State and Federal regulators.

The existence of the dual-pricing regime enormously complicates the appropriate allocation of the costs for new transmission. Federal regulators not only have to consider allocation of costs among different generators and load, but also have to deal with the reflection

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[27] This is done explicitly in most states. In some restructured states with rate freezes of one form or another, it may be less explicit, but is most likely embedded in the original rates that were the basis for the frozen rates.

of those costs in retail rates, a matter over which they may possess little, if any, influence. It will also mean that cost allocations and incentives may often not work as intended. Moreover, the practice of including transmission costs in retail rate base casts a large shadow over the transmission siting and certification process. Finally, the expectation that retail ratepayers support the "residual" cost of investment in transmission seems increasingly inappropriate given the evolution of national policy supporting the opening up of transmission on a comparable, non-discriminatory basis.[28]

To fully comprehend the situation, a little historical perspective is in order. Prior to the era of open-access transmission, most investor-owned utilities, as well as some government and cooperatively owned ones, were vertically integrated, in many cases, self-sufficient entities regulated primarily by State public service commissions. Utilities made investments in generation, transmission, and distribution assets to meet the needs of their native load customers. Once it was determined that the assets were intended and/or being used for serving retail native load, the investments were put into retail rate base and customers were obliged to pay for them through bundled tariffs. The system was justified by virtue of the fact that single, vertically integrated utilities built transmission to link their generating resources to distant loads. To the extent that a utility was able to make off-system sales of transmission capacity not immediately required to meet retail obligations, the revenues from those transactions were credited back to the native load customers.[29] In that way, residual revenue responsibility for the utility's investment in transmission was imposed as a means of ensuring 100% cost recovery on a discrete subset of users of the grid, namely the native load customers of the transmission owners. Traditionally, third-party users' payments would offset the level of revenue responsibility imposed on native load customers, but if third-party uses did not occur, investment recovery was accomplished

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[28] For purposes of this discussion, the term "residual" refers to the obligation that retail customers bear for ensuring that all costs incurred in investing in new transmission are recovered. The default condition in this concept – common in practice – is that all prudently incurred transmission investment costs are included in the utility's revenue requirement for recovery from native load customers. Whatever use of the system is made by others is considered "extra," in the sense that the costs are already picked up by the native load customers of the utility. In short, the retail customers have imposed on them the responsibility of assuring that no residue of costs goes unrecovered.

[29] Most native load customers are retail customers whose service is subject to State regulation, but some are municipal or cooperative utilities whose transmission tariffs were set by Federal regulation. Most, if not all, of the Federal regulatory treatment of transmission has changed so that there are few, if any, residual revenue responsibilities left in Federal rate base, other than perhaps in the form of contracts grandfathered from the pre-open access regime.

through retail tariffs.[30] Despite the emergence of federally mandated open access transmission, that same basic regime persists today in most states.

It is important to note exactly how the dual pricing regime works in practice. In general, when a State-regulated utility adds transmission assets, it seeks to add that investment to its rate base. When inclusion in rate base is approved by State regulators, all of the revenue responsibilities for paying for the assets are imposed on the jurisdictional customers in the state.[31] The result is the transmission owners are assured of recovering the entirety of their investment. That is, of course, reassuring to investors, and provides them a level of comfort. In that sense, it could be argued that the regime provides a meaningful incentive to invest. The problem, however, is that the practice distorts fundamental principles of both ratemaking and cost allocation.

In terms of ratemaking, the inclusion of all transmission investment in State-regulated rate base puts all of the risks of effective transmission management and usage on captive retail consumers and effectively eliminates incentives for productivity. The risk is imposed on native load customers because they assume 100 percent of the residual revenue responsibility for investments in the grid. If a utility sells transmission services to a non-native load, as noted, the revenues derived from such transactions are credited back to the customers as an offset to the revenue responsibility they bear. That practice creates a perverse cycle which dilutes meaningful incentives for transmission owners and operators (particularly in those regions where no Regional Transmission Organization ("RTO") exists).[32] Given the "lumpy" nature of transmission investment, there are often ample opportunities to make "off-system" sales.

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30 In fact, prior to the advent of open access tariffs, it was common practice for transmission owning utilities to use the systems of neighboring companies, either deliberately because of mutual reliability protocols or inadvertently because of loop or parallel flows. Transmission owners, as a general rule, with some notable exceptions where the practice led to intolerable levels of disruption or interference, tolerated such practices and never explicitly assessed charges for the use. The failure to charge was for two basic reasons. The first was the assumption that the flows were mutually advantageous in the sense that some companies benefited on some occasions while others did at different times. The second reason no charges were assessed was that 100 percent of the transmission revenue requirement was being met by each company's native load ratepayers regardless, and that any attempt to assign costs to other users would only reallocate costs among users without any meaningful effect on the company's bottom line.

31 In the case of multi-state utilities, 100 percent of the costs are allocated to native load customers, but those costs are allocated in some way among the jurisdictions being served.

32 In those regions where there is an RTO, of course, the effective day to day use and marketing of transmission assets is really not within the control of the transmission owner but, rather, rests with the RTO, so the perverse incentives are not as pronounced. In those regions without an RTO, however, the incentives are even more perverse today than they were in the pre-open access regime. Not only is the disincentive for managing and marketing efficiently still present, but economic incentives for vertically integrated, State-regulated utilities are powerfully aligned against providing the type of open access required by law. Thus, FERC is left with the unenviable task of trying to enforce a legal requirement that runs contrary to the economic incentives of a vertically integrated utility in a region without an RTO.

Transmission companies that do so efficiently gain nothing from doing so because, subject only to the vicissitudes of regulatory lag, the benefits from doing so are simply credited back to those customers who bear the residual revenue responsibility. Those companies that do not seize sales opportunities lose nothing by their poor performance because they are, nonetheless, made whole by their native load customers. It is important to note in that regard, that FERC initiatives to provide higher rates of return or other incentives to encourage investment in transmission can be of little effect for investors whose revenues from "off system" sales are simply returned to consumers.

Stated succinctly, the current regime de-links what ought to be inextricably tied -- performance and financial incentives. This is an arrangement that defies economic logic. Poor performance is insulated from risk while good management is precluded from gain for its performance. While poor performance can be remedied, in terms of what consumers pay, by prudence disallowances, the fact is that few, if any, state regulatory bodies have undertaken such an effort in regard to transmission and, if one did, it would be a difficult undertaking to ascertain precisely what opportunities were disregarded or overlooked and what the revenues from those foregone opportunities would have been. The point is not that the State regulators have been wrongheaded; in fact, the current regime probably justifies their actions. The problem is that the dual pricing regime inherently misaligns utility incentives, State interests, and the national policy of open-access transmission to all users on a non-discriminatory basis.

In regard to cost allocation, the problem is, to some degree, similar to that encountered in ratemaking. If 100 percent of the revenue requirement is imposed on captive ratepayers, then effectively allocating costs to beneficiaries, or fully implementing participant funding, is impaired in significant ways. First, all the costs have been fully allocated to the rates of the local customers, and it sets up a framework in which the local consumers bear the burden of funding the investment, so other users seem subordinate. Allowing others to use and contribute to paying for facilities on a usage basis simply creates an offset to the revenue responsibility imposed on native load customers. While it is certainly true that State regulators could disallow the inclusion of new investment, or a substantial part of it, in rate base,[33] they have not done so in regard to

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[33] For example, to the extent that a state determined that a company's transmission investment is made for the purpose of satisfying Federal open-access transmission responsibilities for others, the state could allocate to retail rate base only the portion of the investment costs that the state determines to be for the direct benefit of native load customers' use. The Federal transmission tariff would include recovery of this investment made in support of open-access obligations. NARUC, in a 1992

transmission in the past. That is true largely for one of two reasons: (1) The capital outlay is dwarfed by other capital expenditures, notably in generation; and, more importantly, (2) State regulators have the upfront option of simply rejecting the siting application for the line.

Thus, rather than looking to which customers, sub-regions, or region might benefit from the costs of a line, the State rate basing regime simply looks to the benefits bestowed on native load. Anything the FERC may do to implement "participant funding" or assess who generally benefits is purely secondary to the initial allocation of all costs to the native load customers of the utility making the transmission investment. While any assignment of costs to the cost causer, by offsetting the revenue responsibility of native load customers, can be made to work to some degree, it is nonetheless diluted by regulatory lag caused by the timing of rate cases, the test periods used in determining rates, the existence of rate freezes, cost allocations among different classes of retail customers, and other such issues.

Another key cost allocation consideration is that State inclusion of transmission in retail rate base renders the task of allocating costs for expanding facilities more complex and more multi-dimensional. The debate over participant funding has largely related to transmission investment in support of new generators or perhaps, in some isolated cases, to specific large loads. Concern regarding participant funding and allocating costs stems from an array of sources. Some relate to traditional regulatory considerations such as making causers pay for the costs they impose on the system and allocating costs in proportion to benefits obtained. Some, quite frankly, relate to competitive considerations where some market participants fear that others are obtaining transmission services and access on more favorable terms.

The State inclusion of transmission in rate base entails the additional concern that native load customers are being asked to subsidize expansion that they themselves do not require because new users are coming on the scene and demanding service, or because the growth of the larger regional market beyond the local utility service territory has necessitated construction within the local area. Historically, in the monopoly regime, such worries did not arise, because transmission costs were socialized across the entire utility service territory. There might have

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resolution, noted the problems associated with a failure of FERC to do so through its regime for pricing transmission. Some in the utility industry have argued against this form of ratemaking, calling it "trapped" costs or describing the outcome as a "regulatory gap," where the full investment may not be recovered through this combination of partial assignment of costs to retail rate base charged to captive consumers and recovery of other transmission costs through a tariff charged to others who are not captive and whose use of the system may not fully recover this remaining investment.

been some logic to simply extending the same approach, at least in regard to capital expenditures,[34] across the larger RTO or regional market footprint, since those markets are the contemporary functional equivalent to what the utility service territory was in the previous market structure. That is difficult for all of the reasons cited above, but even more importantly, because the socialization of costs among multi-jurisdictional rate bases is extremely contentious and, while it has been achieved in a few cases, it has never been easy and in most cases, particularly in the case of the former registered holding companies, it required FERC to intervene and impose a cost allocation regime. Simply stated, the practice of State rate basing of transmission turns a debate over cost allocation between various market participants into a multi-dimensional, highly contentious argument not only among participants but among regulatory jurisdictions. This can easily lead to stranded costs, interminable regulatory proceedings, or other consequences that strongly discourage, if not preclude, needed investment in the grid. It can also produce regulatory incentives to channel investment into equipment such as phase angle regulators, which serve to "protect" certain control areas against flows from other control areas, but may have the overall effect of limiting the robustness of regional markets.

Another effect of the State rate basing of transmission for State-regulated companies is the lag in recovering the costs of investment in transmission. In most if not all states, capital expenditures are only recoverable in rate cases. From a utility perspective, there are a variety of factors that drive a decision to seek a change in rates. Certainly, significant new capital investment is one such factor. Because transmission has typically been such a small percentage of the overall capital investment of a vertically integrated company, however, transmission investment alone is often insufficient, in and of itself, to lead a regulated utility to file a rate case. The result is that many transmission investments have the effect of impairing earnings of companies between rate cases. As a consequence, there are strong disincentives for companies to make transmission investments other than in conjunction with other investments, so that the overall magnitude of the capital investment will justify seeking a rate adjustment. Thus, unless a company is a stand-alone transmission company with strong incentives to make timely

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[34] The discussion of cost socialization, for purposes of this paragraph, is limited to capital cost allocation. Congestion costs and use of LMP or redispatch mechanisms of various types is an additional, very important issue, but beyond the scope of this discussion. It might also be noted that the same issue of socialization of costs versus participant funding existed prior to mandated open access, in the sense that every expansion was disproportionate in terms of beneficiaries and non-beneficiaries. Where in the past the issue was simply "swept under the rug," today the issue is a more transparent one, as it should be.

investments in the grid, a likely if inadvertent effect of including transmission in State rate base is to reduce the timeliness and/or adequacy of capital investment in the grid.

State laws regarding rate basing of new transmission facilities are fundamentally linked to a vertically integrated paradigm for the industry that no longer exists in many places. In numerous parts of the country today, competition is the prevailing paradigm, at least at the wholesale if not at the retail level. Moreover, even in those regions where monopoly power lingers, open transmission access is nonetheless required by Federal law and regulation. Thus, one key argument expressed in the past in support of rate basing transmission -- namely that native load customers had priority access to the grid in times of constraint -- is no longer applicable. It is that "regulatory bargain" that underlies much of the purported distinction, made historically at least, between "reliability" and "economic" upgrades.[35] That "bargain," however, has been relegated to the trash bin of history by the advent of transmission open access, which evolved from the Energy Policy Act of 1992. Open access, of course, precluded discrimination in access to the grid, thereby removing any priority claim to access by native load customers of transmission owners.

Sometimes proponents of including transmission investment in State rate base contend it insulates retail customers from the uncertainties associated with locational marginal cost ("LMP") pricing, or any other FERC transmission pricing regime. However, inclusion in rate base addresses investment costs, and LMP pricing regimes address congestion. Also, avoiding LMP does not necessarily ensure net benefits for retail customers. We believe that running LMP models, even without applying the pricing, is a very effective way of at least making dispatch far more transparent by exposing inefficiencies, anti-competitive practices, and unwarranted, either intended or unintended, biases in protocols and practice.[36] Without such transparency, there is no way to ascertain that retail customers are getting any value in exchange for having the residual revenue responsibility for transmission imposed upon them. The question of what

[35] As mentioned in Section II, reliability upgrades were traditionally identified as those necessary to serve (typically) incremental demand of native load customers while economic upgrades were those that were not necessary to serve incremental demand. Such economic upgrades are most contentious when they advantage non-native load users. While there were reliability protocols which provided criteria for determining when a "reliability" upgrade was needed, those protocols were largely derived by ascertaining what transmission owning utilities required to serve their native load.

[36] The complaint filed at the FERC within the last year by the Arkansas Public Service Commission against Entergy bears witness to the fact that at least some State commissions have serious concerns regarding the efficiency of the grid operations of the utilities over which they have regulatory oversight.

value, if any, native load customers derive for bearing the residual revenue responsibility of transmission enhancements is at best unclear and, at worse, non-existent.

B. *Siting and Cost Allocation*[37]

Linkage to the old paradigm is perhaps even more pronounced in regard to siting new transmission facilities, which has important collateral impacts on cost allocation. With the exception of the Federal backstop authority and some marginal Federal agency-specific powers newly acquired under the Energy Policy Act of 2005, siting new transmission lines is exclusively a State matter. Of those states that have siting laws – and only a slight majority do – the process is generally composed of two steps. The first step is to determine the need for the line. That step is designed to do two things: to protect consumers from having to pay for capacity that is not needed to serve them, and to decide upon a physical location for the project.

The concept of "need" is often, but not always, a reliability-based concept, but in some cases, it has also been expanded to incorporate reviews of economic benefits. The assessment of need is critical to many siting officials because the determination of need is usually seen as determinative of the reasonableness of the investment as well, thereby precluding subsequent challenges to the retail rate impact on prudence grounds. Regulators, of course, are also concerned that the project produce benefits which exceed environmental or other detriments caused. The second step, once the need is established, is to determine the precise route the facility will follow. While it is well beyond the scope of this paper to examine the overall efficacy of the substantive, jurisdictional, and other legal aspects of siting, it is important to examine the impact the siting process has on cost allocation.

The process for determining "need" is where the issue of cost allocation intersects with the siting process. Most state laws define "need" in terms of "in-state" need, while a very small minority of states reference regional needs in statute. In practice, the degree of parochialism in

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[37] We know that transmission facility siting issues are often as much about "who pays" as they are about other issues, such as whose needs are being met by the proposed facility, what environmental impacts will occur, and so forth. In this discussion, we focus on questions of "who pays" in light of "who benefits" from the proposed facility. Additionally, we focus on issues at the intersection of siting and investment recovery, even though we recognize that some similar issues may apply to instances where a transmission company seeks to obtain approval to use eminent domain as part of the process of development, construction, and operation of the transmission facility. Like facility-siting processes, eminent domain processes are typically a matter of State regulation for electric transmission facilities.

the application of State siting laws varies widely from state to state.[38] What is clear is that most State siting laws were originally enacted with vertically integrated, largely self-sufficient utilities in mind. The growth of competitive regional markets with multiple suppliers and multiple buyers has led to some siting law changes, but surprisingly little. Thus, we are left with a siting paradigm rooted in an industry structure that is very different from, and perhaps "out of sync" with, today's electricity market. This circumstance has inevitable effects on cost allocation in transmission.

In examining the question of need, siting agencies will inevitably consider the question of whose need is being addressed by the proposed project, but also the question of the costs to be borne by consumers in their own state.[39] Thus, the allocation of costs[40] to the ratepayers of the jurisdiction where the line is being proposed is a very significant factor in determining the outcome of an application. If the costs of the line are to be put in rate base of a jurisdictional utility, thus imposing 100 percent of the residual revenue responsibility on the state's ratepayers, the cost/benefit analysis is almost certain to be weighed differently than if the ultimate revenue

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[38] For a fuller discussion of the effect of local interests on State siting decisions and practices see: Ashley Brown and Damon Daniels, "Vision Without Site; Site Without Vision." *The Electricity Journal*. October, 2003. Vol. 16, Issue 8, pp. 23-24. This paper describes a classic example where parochialism stymied the siting process for the Cross Sound Cable transmission facility, a merchant, direct-current transmission facility designed to cross Long Island Sound and to interconnect Connecticut and Long Island's electric systems. Connecticut is part of the six-state regional power system previously organized as the New England Power Pool and now administered by the ISO-NE. In Connecticut, outages at three large nuclear power generating units (Millstone Units 1, 2, and 3) took place simultaneously and endured over a several-year period during the mid- to late-1990s. During this period, Connecticut consumers' power and reliability requirements were met to a large degree by imports from generating stations located out of state. Subsequently (after two of the three nuclear units eventually returned to service), Connecticut considered whether to approve the proposed siting of the new Cross Sound Cable, connecting Connecticut to Long Island and proposed to be paid for by consumers of the Long Island Power Authority. During the permitting process for the line, Connecticut raised significant concerns about a line proposed primarily to provide power supplies from Connecticut to electricity consumers in New York. After a lengthy permitting process, the facility was constructed but commercial operation was halted after Connecticut legislators effectively bypassed the regulatory process and reversed the formal decision by the state's own siting agency by enacting a one-year moratorium blocking new power projects in Long Island Sound. Eventually, the line was energized only after the U.S. Department of Energy ordered the line be powered under the emergency conditions resulting from the Northeast blackout of 2003. The line is in operation today and provides for exchanges between New England and New York. More recently, in July 2007, another underwater transmission line (the Neptune Regional Transmission System), connecting Long Island to New Jersey has just entered operation, and may eventually allow the possibility of power exchange between New Jersey, New York and Connecticut – a circumstance never envisioned at the time that Connecticut relied on out-of-state resources during the lengthy Millstone outages or when Connecticut was permitting – and resisting – the interconnection to New York.

[39] Siting authority is vested in different agencies in different states. For purposes of this paper it is sufficient to note that siting powers are vested in utility regulatory bodies in some states, but other states place that power elsewhere. In fact, a number of states have no siting agency at all.

[40] The costs taken into consideration by the siting authorities, of course, are both economic and non-economic. It is important to note that the non-economic costs for a specific jurisdiction may often outweigh the economic benefits on a jurisdiction-specific basis, where the anticipated benefits are regional and not local. That is a fundamental problem in the current siting regime, because where the benefits of new transmission benefits are regional but the non-economic costs are local, and local authorities possess final say, the barriers to obtaining approval of the facility are not insubstantial. That issue, however, is well beyond the scope of this paper. Thus, for purposes of this paper, the discussion will be limited to the economic issues as they relate to cost allocation.

responsibility were spread more widely across the multi-state region whose needs are to be served.[41] In short, the State rate basing of transmission creates policy, legal, and economic biases, in even the fairest and most substantive of siting processes, against approving new transmission facilities whose benefits are regional in nature.[42] It also provides a powerful incentive for a state to disapprove the siting of a line that it believes benefits other states more than itself.

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41 In regions where LMP is used, the local impact on congestion and nodal prices is also a highly probable consideration.

42 Also somewhat beyond the scope of this paper, but relevant because it further skews the siting process is the possibility, indeed, perhaps the likelihood that state siting authorities will consider not only transmission costs in determining transmission siting applications, but the impact of the new facility on the price of electricity in the jurisdiction from whom siting approval is sought. That is, transfers are considered in the assessment of whether or not to build a line. Many have argued that such considerations have influenced siting battles in Connecticut and Maine. In the recent Arizona decision to reject the Palo Verde II to Devers Power Line, the cost of which was to be borne entirely by California ratepayers, Arizona regulators appear to have been heavily influenced by such considerations. As the Arizona Commission noted in its own press release on the Palo Verde decision: "Much of the controversy surrounding the line centered on who stands to benefit from its construction. Commission staff member estimated that the line would end up costing Arizona ratepayers as much as $242 million while providing California utility customers with access to cheaper power generated here in Arizona."

V. Decision Making / Planning Process Issues for System Investment and Expansion

Transmission investments result from processes in which transmission providers analyze (over different time periods) the capabilities of the system to meet the present and future demands of consumers reliably and economically. Those planning processes have evolved over the years on a number of dimensions. Changes include the geographic footprint of the area being analyzed, the sophistication of the tools and information brought to bear in the planning process, the time period in which studies examined future conditions, the technologies considered for solving problems, the entities allowed to participate in the processes for identifying assumptions and selecting scenarios to examine, the stage of the process in which any outsiders have been invited to participate, and so forth. To this day, transmission planning is conducted in various parts of the country in ways that differ, at least in detail. Moreover, even within individual transmission regions, there are short-term, medium-term, long-term, and very-long-term planning processes that vary considerably along many of these dimensions.

Transmission planning is inherently complex with studies relying on a large number of assumptions about uncertain patterns, conditions, and locations of electrical flows on the system. These uncertainties and assumptions affect how one looks ahead to determine what, if any, new investments or operating approaches are required to satisfy system requirements in the future. This is true in virtually all transmission planning exercises – whether one that leads to a proposal to construct a new 345-kV transmission line on an entirely new right of way that will take years, if not decades, to plan, permit and construct, or a plan to modify an existing line to increase its capacity either through higher voltage, increased ampacity or both, or an outcome in which no new transmission enhancements are deemed to be needed.

We have discussed some of the relevant uncertainties above. For example, we identified as a key issue the assumptions made about changes in level of demand in different hours in different years in different locations (nodes) on the system. Such assumptions clearly affect the results of reliability analyses. Also important are assumptions about changes in generating resources installed on the system (*e.g.*, retirements, derating, and capacity additions), and performance characteristics of these facilities (*e.g.*, start-up and ramp times of power plants) or loads (*e.g.*, temporal variation). These are affected, in turn, by an array of uncertain trends, including economic trends, appliance-adoption and efficiency trends, siting and investment conditions in the area, technological capabilities of generation, delivery and demand-side resources, and so forth. Planning for uncertainties such as these involves considerable value judgments, even when informed by the best and most relevant information available. These complex studies and analyses may reach very different plans and recommended investments, depending in part on the quality of those sources of information, tools of analysis, and judgments.

There is nothing particularly new about this situation; it has been such for many decades. Over the most recent decades, however, transmission planning, siting, and investment-recovery proceedings have been increasingly contested, with disputes over the content of these analyses, plans, and investment decisions, and the processes leading up to them. Moreover, changes in the recent past – notably since the adoption of non-discriminatory transmission open access as a matter of national policy in the 1990s – have led to new demands on these processes while, at the same time, the proceedings have proven increasingly contentious.

In Order No. 888, its first seminal order on non-discriminatory access to transmission, FERC in 1996 established a number of principles and requirements for transmission providers. For example, they had to carry out transmission plans for and upgrades to their transmission systems to provide comparable open access transmission service for their transmission customers.[43] Different planning and transmission expansion requirements applied to customers seeking network[44] as opposed to firm- or non-firm point-to-point service.[45] Three years later, FERC's Order No. 2000 further identified transmission planning and expansion as one of the eight minimum functions of an RTO, and stated that RTOs should have the ultimate responsibility for both of these activities within an RTO region.[46]

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43 *See* 18 CFR Parts 35 and 37. In Order No. 888-A, FERC encouraged utilities to work with other utilities and customers to carry out planning and to participate in facility studies. FERC Stats. & Regs. ¶ 31,048 (1997). Order No. 888 was recently updated by FERC. *Preventing Undue Discrimination and Preference in Transmission Service*, *Order No. 890*, FERC Stats. & Regs. ¶ 31,241 (2007) ("Order No. 890").

44 Among the elements of the pro forma Open Access Transmission Tariff ("OATT") are those requiring transmission providers to "plan, construct, operate and maintain" their systems to provide network customers with service over the transmission provider's system and to do so on a basis comparable to the transmission provider's native load. (See section 28.2 of the *pro forma* OATT per Order No. 888, Appendix D).

45 For long-term firm point-to-point customers, the pro forma OATT requires the transmission provider construct facilities to meet service requests, and to consider "redispatch of the system to relieve any constraints that are inhibiting a transmission customer's point-to-point service if it is economical to do so; but if redispatch is not economical, the transmission provider is obligated to expand or upgrade its system." (Sections 13.5 and 15.4 of the OATT.)

46 Order No. 2000 stated that the "rationale for this requirement is that a single entity must coordinate these actions to ensure a least cost outcome that maintains or improves existing reliability levels. In the absence of a single entity performing these functions, there is a danger that separate transmission investments will work at cross purposes and possibly even hurt

Since the issuance of Order No. 2000 at the end of 1999, FERC has indeed allowed "considerable flexibility" to transmission providers in various regions – both with and without RTOs – in designing and carrying out their planning for transmission expansions. Through a number of decisions, FERC has authorized system planning approaches for the organized markets administered by RTOs or Independent System Operators: California ISO ("CAISO"), PJM Interconnection ("PJM"), New York ISO ("NYISO"), ISO-NE, Midwest ISO ("MISO"), and Southwest Power Pool ("SPP"). FERC has also approved a planning process as part of its approval of various third-party operators of transmission in other regions.[47]

Given this background, there currently exist many contexts in which transmission assessment and planning occurs, with many differing ways in which questions about the adequacy of transmission and the cost-effectiveness of certain transmission expansions are asked and answered. Implicitly and sometimes even explicitly, these approaches provide information to shed light on who benefits and, therefore, who might be appropriate to pay for transmission. Following are a few examples of the variety of transmission planning approaches:

- An RTO in a region with a significant share of vertically integrated utilities, with considerable transmission under state rate base regulation, with a strong state-dominated mechanism for cost allocation for particular projects. One such example is SPP's process, which has a series of planning overlays for mid-term, long-term (10 year) and longer-term time frames, as well as a regional state committee that determines cost-allocation decisions for each.[48] This approach aligns State positions on policy for cost-recovery for individual projects, with the investments of utilities in their states and the state's facility-siting decisions on such projects. We understand that in practice, this process tends to place a high

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reliability. We also recognize that the RTO's implementation of this general standard requires addressing many specific design questions, including who decides which projects should be built and how the costs and benefits of the project should be allocated." *Regional Transmission Organizations, Order No. 2000*, FERC Stats & Regs ¶ 31,089 (1999) at 31,164. To accomplish these purposes, FERC gave RTOs several years to comply and indicated that it would allow "considerable flexibility in designing a planning and expansion process that works best for its region. It is both inevitable and desirable that the specific features of this process "should take account of and accommodate existing institutions and physical characteristics of the region."" *Id.*

47 For example, *see Entergy Services*, Inc., 110 FERC ¶ 61,295 (2005*), Order on Petition for Declaratory Order* [Guidance Order]; *Entergy Services, Inc*., 111 FERC ¶ 61,222 (2005), *Order on Clarification*; *Entergy Services, Inc.*, 115 FERC ¶ 61,095 (2006), *Order Conditionally Approving Independent Coordinator of Transmission,* (collectively ICT Orders); *Duke Power*, 113 FERC ¶ 61,288 (2005), *Order Accepting Independent Entity and Transmission Monitoring Plan*.

48 108 FERC ¶ 61,003 (July 2, 2004); 109 FERC ¶ 61,010 (October 1, 2004); 112 FERC ¶ 61,319, Sept 20, 2005, including discussion of SPP's Aggregate Facilities Study Process, and the cost recovery provisions.

premium on approving projects that meet the net benefit test for *each* and every state. For example, even if the overall net benefits are high, if not all individual states are receiving net benefits then project proposals are sent back to the drawing board to find more projects to bring each state up to a positive net benefit. We further understand that at least some member states in the SPP region are leaning toward having the SPP planning process serve as an independent, "credible" entity to run simulations of the grid under various assumptions, to see the extent to which new transmission enhancements would be cost-justified on the basis of lowering system-wide production costs. This role would move the SPP process more squarely into the domain of analyzing so-called "economic upgrades" in addition to "reliability upgrades."

- An RTO in a centrally "organized" market with locational marginal prices, financial transmission rights, and congestion prices, with periodic stakeholder-based "regional transmission planning" processes for identifying both "economic" and "reliability" upgrades. Typically, RTOs draw distinctions between those transmission upgrades they identify as needed for reliability versus those designed to produce energy savings. There are some contrasts among the RTOs' planning processes for different types of projects. The processes used in New England and California are examples --
  - The process employed by ISO-NE involves stakeholder participation in the following aspects of the annual planning process: identification of planning assumptions; modeling of patterns of growth and areas of congestion; analysis of instances where the system would fail to meet reliability standards; identification of "system expansion projects" that qualify for broadly socialized costs; identification of discrete categories of upgrades with prime beneficiaries for which costs are more directly assigned, market-participant-determined rules for cost-recovery of new investment; and so forth. A notable feature of ISO-NE's process is that it includes analysis of both demand and supply options to meet a given projection of load growth. The overall "Regional System Plan" ("RSP") is developed in a relatively open, transparent, and inclusive process. But like all areas of the country, it treats

projected load growth as a given (rather than an inherently economic concept), while it treats anticipated supply additions, retirements or demand-response as means to meet that projected load growth. ISO-NE's policies marry cost-allocation principles to this planning approach. Transmission project costs are allocated according to categories of upgrades. Regional Benefit Upgrades ("RBUs") including transmission upgrades for the 115 kV and higher voltage system are included in the RSP.[49] The costs associated with upgrades classified during the RSP process[50] as either Reliability[51] or Market Efficiency[52] Transmission Upgrades are recovered through (by being rolled-into) the regional rate and assigned to loads on the basis of their ratio to total load.[53] By contrast, Local Benefit Upgrades ("LBUs")[54] involve a number of other types of upgrades whose costs are in the local rather than the regional rate.[55] Additionally, there are some "participant-funded costs" for specific types of upgrades.[56]

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49 ISO New England Inc., FERC Electric Tariff No. 3, Section II.1.118, Sheet No. 446 (April 1, 2005).

50 *Id*. at Section II -- Attachment N, Sheet Nos. 6618-23 (February 1, 2005).

51 Reliability Transmission Upgrades are those necessary to ensure the continued reliability of the NE transmission system (taking into account load growth and resources changes), but may also provide collateral market efficiency benefits. Costs are rolled into the regional rate. *Id*., and Section II.1.126, Sheet Nos. 448-9 (April 1, 2005).

52 Market Efficiency Transmission Upgrades are upgrades designed primarily to provide a net reduction in total production cost to supply the system load. Proposed Market Efficiency Transmission Upgrades shall be identified by the ISO where the net present value of the net reduction in total cost to supply the system load, as determined by the ISO, exceeds the net present value of the carrying cost of the identified transmission upgrade. (Attachment N of ISO-NE OATT) Economic analysis includes energy and capacity costs; costs of supplying total operating reserve; system losses; load growth; fuel costs and availability; generator availability; present worth factors for each project specific to the owner of the project (period not to exceed 10 years); and project costs. The costs of economic upgrades are either (a) rolled into the regional rate if net benefit to the region (i.e., categorized as RBU) or (b) charged locally where benefits accrue to a locality (i.e., categorized as LBU).

53 *Id*. at Section II – Schedule 12.B.5, Sheet No. 776 (February 1, 2005).

54 Localized Costs (***Id.*** at Section II.1.63, Sheet No. 435 (February 1, 2005) include incremental costs that are identified as exceeding requirements deemed reasonable and consistent with Good Utility Practice and current engineering design and construction practices (***Id.*** at Section II – Schedule 12C, Sheet No. 791 (February 1, 2005) (e.g., local siting requirements, such as undergrounding). Costs are not included in the regional tariff, but are rather charged to entity(ies) causing or subject to such costs.

55 (***Id.*** at Section II.1.51, Sheet No. 432 (February 1, 2005). For example, these include upgrades, modifications or additions to the NE transmission system and rated below 115kV; or that are rated 115kV or above and do not meet non-voltage criteria for regional facility classification. See cost schedule: ***Id.*** at Section II – Schedule 12.B.6, Sheet No. 776 (February 1, 2005).

56 Typically, those upgrades that are Participant Funded are: (a) A generator interconnection related upgrade, unless the ISO determines that it "benefits the system as a whole" in which case it will be treated a Reliability Benefit Upgrade; (b) Merchant transmission facilities costs (including the costs of interconnection); or (c) an elective transmission upgrade is one that is participant-funded (*Id*. at Section II.1.20, Sheet Nos. 423-24 (February 1, 2005) - i.e., voluntarily funded by an entity or entities that have agreed to pay for all of the costs of such upgrade (e.g., acceleration of projects ahead of schedule in regional system plan).

- The process of the California ISO ("CAISO") is an example of an RTO that plans in advance for transmission for resources in particular "resource-rich" geographic locations. CAISO adopted the recently approved transmission planning process for renewable resources (*i.e.*, wind), a novel approach to planning and cost recovery for transmission upgrades to support development of certain types of "location-constrained" resources.[57] In this context, "location-constrained" resources are defined as "generation resources that are typically constrained as a result of their location, relative size and the immobility of their fuel source."[58] CAISO had requested a ruling from FERC on whether the proposal to support transmission expansion connecting resources in these "location-constrained" areas would violate FERC's policy on assigning the costs of interconnecting generation resources to the developers of such projects. CAISO's proposal, with its notable financing mechanism for transmission between the grid and the "location-constrained area," initially rolls in the costs of such facilities into the transmission revenue requirement of the transmission owner constructing the project. "These costs

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57 *See* 119 FERC ¶ 61,061 (2007). *Order Granting Petition for Declaratory Order*, issued April 19, 2007 ("CAISO Order"). As described in FERC's order, CAISO's approach includes the following eligibility criteria for the proposed rate treatment for the interconnection facilities:

> "(1) The costs of the interconnection facility – which is a non-network facility – would not otherwise be eligible for inclusion in the CAISO's TAC [transmission access charge];
>
> (2) The project must provide access to an "energy resource area" in which the potential exists for the development of a significant amount of location-constrained energy resources;
>
> (3) The project must be turned over to the CAISO's operational control;
>
> (4) The project must be a high-voltage facility designed primarily to serve multiple location-constrained resources that will be developed over a period of time;
>
> (5) To be eligible for this financing treatment, a project would have to be evaluated and approved by the CAISO in the context of a CAISO transmission planning process, thereby ensuring that the project will result in a cost effective and efficient interconnection of resources to the grid;
>
> (6) To limit the cost impact of the proposal on ratepayers, there would be an aggregate cap on the total dollars associated with the multi-user interconnection facilities that could be included in TAC rates at any one time (referred to herein as a rate impact cap). Specifically, the total investment in the interconnection facilities that can be included in TRRs and the TAC cannot exceed 15 percent of the sum total of the net high-voltage transmission plant of all PTOs, as reflected in their TRRs and in the TAC; and
>
> (7) To limit the risk of stranded costs due to abandoned investment, the project must demonstrate adequate commercial interest by satisfying the following two-prong test before actual construction can commence: (a) a minimum percentage of the capacity of the new interconnection facilities – an order of magnitude of 25 to 30 percent – must be subscribed through executed Large Generator Interconnection Agreements (LGIAs); and (b) there must be a tangible demonstration of additional interest in/support for the project – an order of magnitude of 25 to 35 percent – above and beyond the capacity covered by LGIAs." (footnotes omitted)

58 CAISO Order, at n.1.

then would be reflected in the CAISO Transmission Access Charge ("TAC"), which is assessed on a gross load basis. Each generator that interconnects would be responsible for paying its *pro rata* share of the going-forward costs of using the line. Until the line is fully subscribed, all users of the grid would pay the cost of the unsubscribed portion of the line, through its inclusion in the TAC. Once the facilities are constructed, generators of any fuel type would be eligible to interconnect and contract for unsubscribed capacity."[59] In April 2007, FERC approved CAISO's proposal, stating that it "strikes a reasonable balance that addresses the barriers to development of location-constrained resources and includes appropriate ratepayer protections to ensure that rates remain just and reasonable," "includes several features that ensure that benefits will accrue to users of the CAISO grid and that limit the cost impact on ratepayers, including a rate impact cap and capacity subscription requirements" and that CAISO's evaluation and approval of such transmission facilities occurs in the "context of a CAISO transmission planning process, thereby ensuring that the project will result in a cost effective and efficient interconnection of resources to the grid."[60]

- A long-term regional planning process occurring outside the context of an organized RTO and that looks at an expansive geographic region, identifies reliability and economic options, considers demand and supply options, etc. An example is the Bonneville Power Administration's ("BPA") planning process (the so-called "Non-Wires Solution Roundtable"). BPA now uses an approach to transmission planning that includes consideration of "non-wires" alternatives to new line construction, such as targeted demand response, distributed generation, conservation measures, and generation siting strategies. BPA has used detailed assessments of alternative routes, along with an analysis of the potential to cost-effectively defer the project using non-wires solutions, including demand-side

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59 *Id*. at P 2.

60 *Id*. at P 3

management, demand response and direct load control, distributed generation, and large-scale generation.[61]

- A less structured "planning" process is carried out in more practical and more routine ways as part of the Open Access Same-Time Information System ("OASIS") process of individual companies and RTOs under FERC's Order No. 889 and as part of either a transmission interconnection request (with its associated system impact studies and facility studies), or a request for point-to-point or network service or other transmission service, or some other type of request for service from the OASIS provider. This type of forward-looking system analysis is not usually called planning, but is considered more an "impact analysis," with impacts (and related costs) driven by the introduction of a single changed element into the network (*e.g.*, a new power plant, or a request for new service relating to an existing one). These studies tend to treat incremental load growth of all those customers holding existing transmission service (*e.g.*, network service) as a given, and the new request is incremental to that growth. In these types of studies, costs are typically assigned to the applicant for incremental service, under a "beneficiaries pay" concept and assuming a situation where the new request for service is incremental (or subordinate to) growth of loads in the region seeking to be able to have access to generating resources in all parts of the network.

These various examples highlight the differences in today's forms of transmission planning, as well as in the relationship between these approaches and the ways in which investment recovery is treated in various places in the U.S.

Quite recently, FERC has weighed in on the need for greater consistency in transmission planning conducted by all transmission providers under the open access tariffs. In Order No. 890, issued in February 2007, FERC stated its concerns that the non-discrimination provisions previously established in Order No. 888 do not eliminate the incentive or opportunity to discriminate that certain transmission providers have in decisions about expanding the grid.[62]

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[61] *See*, "Siting Critical Energy Infrastructure: An Overview of Needs and Challenges," White Paper prepared by Staff, National Commission on Energy Policy, June 20, 2006, at 19.

[62] "Although many transmission providers have an incentive to expand the grid to meet their state-imposed obligations to serve, they can have a disincentive to remedy transmission congestion when doing so reduces the value of their generation or

Order No. 890 requires all jurisdictional transmission providers to file proposals for a coordinated and regional planning process that complies with various requirements, including eight planning principles and a cost-recovery principle: coordination; openness; transparency; information exchange; comparability; dispute resolution; regional participation (including regional scope, existing institutions, existing regional planning processes in various parts of the country); economic planning studies; and cost allocation relating to new projects "that do not fit under the existing structure, such as regional projects involving several transmission owners or economic projects that are identified through the study process described above, rather than through individual requests for service."[63] In a White Paper issued in August 2007, FERC Staff provided additional guidance on what it would like to see in terms of regional planning.[64]

Although it did not prescribe a particular cost-allocation approach, FERC for the first time provided "overall guidance" on this issue:

> Our decisions regarding transmission cost allocation reflect the premise that "[a]llocation of costs is not a matter for the slide-rule. It involves judgment on a myriad of facts. It has no claim to an exact science." We therefore allow regional flexibility in cost allocation and, when considering a dispute over cost allocation, exercise our judgment by weighing several factors. First, we

otherwise stimulates new entry or greater competition in their area." FERC Order No. 890, at 238. FERC noted that in Order Nos. 888 and 888-A, requirements for system studies (tied to transmission requests) "did not, however, require that transmission providers coordinate with either their network or point-to-point customers in transmission planning or otherwise publish the criteria, assumptions, or data underlying their transmission plans. The Commission also did not require joint planning between transmission providers and their customers or between transmission providers in a given region. The only section of the existing pro forma OATT that directly speaks to joint planning is section 30.9, which provides that a network customer must receive credit when facilities constructed by the customer are jointly planned and installed in coordination with the transmission provider." *Id*. at P 120 (footnotes omitted). For example, a transmission provider does not have an incentive to relieve local congestion that restricts the output of a competing merchant generator if doing so will make the transmission provider's own generation less competitive. A transmission provider also does not have an incentive to increase the import or export capacity of its transmission system if doing so would allow cheaper power to displace its higher cost generation or otherwise make new entry more profitable by facilitating exports. As the Commission explained in Order No. 888, "[i]t is in the economic self interest of transmission monopolists, particularly those with high-cost generation assets, to deny transmission or to offer transmission on a basis that is inferior to that which they provide themselves." Order No. 890, at P 423. "The existing pro forma OATT does not counteract these incentives in the planning area because there are no clear criteria regarding the transmission provider's planning obligation. Although the pro forma OATT contains a general obligation to plan for the needs of their network customers and to expand their systems to provide service to point to-point customers, there is no requirement that the overall transmission planning process be open to customers, competitors, and state commissions. Rather, transmission providers may develop transmission plans with limited or no input from customers or other stakeholders. There also is no requirement that the key assumptions and data that underlie transmission plans be made available to customers. …Taken together, this lack of coordination, openness, and transparency results in opportunities for undue discrimination in transmission planning." Order No. 890, at PP 424-5.

63 Order No. 890, at P 558.

64 Order No. 890, Transmission Planning Process, FERC Staff White Paper, August 2, 2007. Available at http://www.ferc.gov/industries/electric/indus-act/oatt-reform/order-890/white-paper.pdf.

consider whether a cost allocation proposal fairly assigns costs among participants, including those who cause them to be incurred and those who otherwise benefit from them. Second, we consider whether a cost allocation proposal provides adequate incentives to construct new transmission. Third, we consider whether the proposal is generally supported by state authorities and participants across the region….

These factors are particularly important as applied to the economic upgrades discussed above – *e.g.*, upgrades to reduce congestion or enable groups of customers to access new generation. As a general matter, we believe that the beneficiaries of any such project should agree to support the costs of such projects. However, we recognize there are free rider problems associated with new transmission investment, such that customers who do not agree to support a particular project may nonetheless receive substantial benefits from it. In the past, different regions have attempted to address such issues in a variety of ways, such as by assigning transmission rights only to those who financially support a project or spreading a portion of the cost of certain high-voltage projects more broadly than the immediate beneficiary/supporters of the project. We believe that a range of solutions to this problem are available. We therefore continue to believe that regional solutions that garner the support of stakeholders, including affected state authorities, are preferable. Moreover, it is important that each region address these issues up front, at least in principle, rather than having them relitigated each time a project is proposed. Participants seeking to support new transmission investment need some degree of certainty regarding cost allocation to pursue such investments.[65]

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65 Order No. 890, at PP 559, 561 (footnote omitted).

With these new changes, there are many pieces of the transmission planning framework that we think support a reasonable set of cost-allocation principles. The transmission planning process should be open, transparent and inclusive, with planning and its outcomes tied to the issue of cost allocation. That said, we think these general guidelines would be enhanced by analytic methods and approaches that look at both incremental load and incremental generation (and transmission) as economic in their essence. Moreover, we think the "beneficiaries pay" concept must be applied more broadly to take account of network integration and expanding markets, than what is now in place in most parts of the country. We discuss these issues in the context of specific Principles to apply.

VI. Recommended Regulatory Policies for Allocating the Cost of New Transmission Investment: Practice and Principles

In this final section, we set out the Principles we recommend as appropriate for guiding decisions on allocating the costs of new transmission investment. We begin by setting out some conceptual issues for framing the discussion on cost-allocation, based on some of the themes set forth in prior sections of this paper. As a starting point for this discussion, we identify the critically important foundation for any sound cost-allocation policy. From there, we discuss five concepts that have guided our thinking about appropriate cost allocation issues in an era of transmission open access. We offer our ten recommended Principles to guide cost allocation for new transmission investment. Last, we conclude with an example of how we envision our recommended cost-allocation framework operating in practice.

A. *Conceptual Foundation and Contexts for Our Recommendations*

1. The Foundation for Sound Cost-Allocation Policy: Clear, Consistent, and Principled Regulatory Policy and Oversight

An essential building block, or critical pre-condition, for sensible cost-allocation policy is that the regulatory policy for allocating costs of new transmission investment should be clear, predictable, based on sound principles, and to the extent possible, consistently applied. Without clear, consistent and principled regulatory policy, the process for determining cost allocation in each proposed investment in the grid becomes an opportunity for every competing interest and interest group to either reduce or eliminate its obligation to pay a reasonable share of the costs of this shared infrastructure network. The problem is not that competing groups do not have legitimate interests to protect, but rather that absent clear policy, the jockeying can be neither fully informed nor focused, and is therefore unnecessarily protracted, and disruptive to the orderly evolution of the grid and of the market it enables. The issue of cost allocation needs to be resolved in the course of the planning process described elsewhere in this paper, where all parties are duly informed of the applicable principles that will determine the outcome.

While regional consensus on cost allocations may be and often is desirable, for a variety of reasons regulators cannot simply rely on consensus processes to decide how to allocate the costs of expanding the grid. The first and, perhaps most important, reason for not waiting for consensus to emerge is that, absent a set of guiding principles, the achievement of a consensus is more difficult to reach and less likely to provide consistent planning and investment going forward. Second, absent a clear set of principles, such agreements are inherently ad hoc in nature. They may provide a means of deciding how to divvy up responsibility for paying for a specific expansion of the grid, but they rarely provide enduring and principled guidance for all future disputes. Third, the absence of consistent principles is likely to reduce the number of non-market participants willing to offer proposals to invest their available capital. Large national investors are far less likely to be active in the transmission sector where the principles governing cost allocation and cost recovery vary widely from region to region. The field will be more likely left to regional players who possess local expertise but may well lack the economies of scale or access to less costly capital than larger players may possess. More important, many of the regional costs for new transmission investment can be allocated among players who may well be vertically integrated entities with interests and investment strategies more likely to be driven by achieving desirable outcomes in the generation market than by a transmission-specific focus.

Finally, settlements in regulatory forums almost always reflect a balance of interests of those ably represented "in the room." It is also almost always the case that not all interests are (or literally can be) present and adequately represented in settlement discussions, and it is often those unrepresented interests that pay the biggest prices in regulatory settlements. It is an obvious course of least resistance for the parties who are represented. Because regulators are charged with protecting the overall public interest, they should closely scrutinize any settlement that benefits those who participated in the negotiations and/or penalizes those who did not or could not participate (*e.g.*, future customers or other future market participants) so that its overall and long term effects are understood before approval. In short, it is anything but certain that the course of least political resistance, namely accepting an offered settlement, is the same as acting in the long term public interest.

There can be no substitute for strong regulatory oversight through the articulation and application of clear guiding principles for cost allocation and close scrutiny of settlements that are offered up. Strong regulation of that type is far more likely to attract investment in transmission and to increase the likelihood of informed planning and debate and greater efficiency in reaching decisions. Ironically, that type of regulatory oversight is also the best way to allow for informed negotiations between parties and ensuring any settlements reached will be consistent with the public interest. Failure to set forth such principles will constitute default to a most unsatisfactory status quo. Those principles are to be fully understood in five contexts.

2. The First Context -- Decision Making

Critical to the credibility and acceptability of the cost allocation process is the question of who decides whether a transmission investment is warranted, and on whose behalf do the decision makers serve. In the era of open-access transmission, it is critical not only that the decision maker is independent and neutral, but that it is also responsive to and accountable to stakeholders and, ultimately, to the FERC (or the appropriate wholesale market regulator). Because we think that there will be many situations that warrant having broad socialization of costs (because of broadly dispersed social benefits), we think having a fully independent decision-making process (or governance) for transmission will provide greater legitimacy and credibility when such an entity determines that indeed such broad-based situations exist. This legitimacy and credibility is critical when consumers are being asked to pay for transmission service. For example, if shareholders of a transmission company were alone to bear the risk of paying for transmission investment, then there would be no need or requirement for an inclusive decision-making process regarding the transmission investment. Conversely, the more the investment is to be repaid by captive users, the more the investment needs the involvement, if not the blessing, of the customers or their proxy (*e.g.*, regulators).

In our framework, we address the decision making issue in a number of ways. In light of our view that beneficiaries should pay, we propose Principles leading to: (a) an inclusive process for identifying and determining the types of facilities needed to address stakeholders' needs; (b) a strong, if not conclusive, bias towards socializing the costs of broadly beneficial facilities and bundles of facilities; and (c) approval of projects that are not supported broadly on the condition that the proponents bear the costs of the project in order for it to proceed, provided the project does no injury to the system as a whole not remedied by the proponents. In short, the inclusiveness of the decision making process concerning a project or set of projects should be aligned with the scope of the obligation to pay.

3. The Second Context – The Geographic Footprint

A critical element of clear and consistent regulatory oversight is an adequate definition of the geographic footprint(s) of electricity market(s) to be served in the transmission planning and expansion policy. While power markets tend to expand and evolve geographically over time and, therefore, require a larger geographic footprint to be contemplated for transmission purposes, regulatory definitions of what constitutes a market and criteria for defining it ought to remain relatively constant. The criteria for what constitutes a "region" should remain relatively stable, although FERC should periodically revisit the application of these criteria to different regions to determine whether "the planning region" should be modified or redefined consistent with changes in conditions, practices, and market scope. The basic definition of the market should be reflective of trading realities and foreseeable possibilities and not be constrained by such relics of the old monopoly paradigm such as service territory, native load obligations, or state boundaries.[66] While the obligation to serve should certainly not be abrogated or reduced where it exists, its existence should not be permitted to constrain facilitation and growth of regional wholesale markets. The planning process for transmission expansion should be enabling for all market participants, transmission owners, and investors. It is critical that all identifiable sellers and buyers within that defined footprint have their requirements taken into account in planning the growth of the grid. Conversely, transmission costs for all interests being served should be allocated equitably among all of those who benefit from new investment in the entire market being served.

4. The Third Context – The Transaction Chain[67]

Cost allocation decisions are obviously about who pays. It is important, however, to decide not only who benefits, but also where in the transaction chain the costs should be assigned. Do they get assigned at the consumption (load or sink) end of the chain, or should they be allocated at the upstream production (generation or origination) end of the chain? Certainly, much of the 2005 legislative debate over "participant funding" of new transmission had to do with various generating interests seeking competitive advantage or defenses through allocation

[66] The relevant geographic footprint in the traditional monopoly utility setting, of course, was the service territory, a specifically identified geographic region within which the utility had an open-ended obligation to serve all customers, current and prospective, under terms and conditions defined by law and regulation. The way obligations are defined within the relevant market footprint is conceptually the same, with the obvious exception that the obligation is not, as in the old paradigm, for all electricity requirements, but rather for transmission services only.

[67] This section is addressed solely to what are commonly called reliability/economic upgrades. As noted earlier in the paper, the authors regard all upgrades as inherently economic in nature. Radial expansion, built to connect specific generators to the grid, however, is a separate subject and is not being addressed in this section. The case for allocating the costs of a radial line to the generator for whom it was built as a connection to the grid seems compelling and sets that circumstance apart from the issues discussed in this section.

of transmission costs. Many companies owning existing generators contend that new entrants should have to bear a larger percentage of the costs of new transmission since their appearance on the scene necessitated otherwise unforeseeable transmission expansions. The new generators obviously argued, to the contrary, that they were simply seeking to serve normal demand growth, so their entry into the market was nothing more than meeting reliability requirements for load growth. Nor were new generators the only "participants" wanting to get on the grid. Markets require both sellers and buyers and all are "participants" and eligible for consideration as the participants who benefit from and should bear the costs of system expansion.

There are pros and cons to assigning costs to each end of the transaction chain – that is, to loads versus to suppliers, or to both. Assigning costs at the generation end of the transaction chain, as the debate over participant funding has demonstrated, almost inevitably leads to continuing battles between generators over who should pay and how much with respect to every expansion of the grid. Such cost allocation battles, of course, will make planning and building new transmission more contentious, more protracted, and more likely to discourage transmission investors. And, while deterring a particular project for land use or other reasons may be a desired outcome in specific instances, processes that lead to disinvestment across the board are ill-advised from the point of view of the nation's economic goals. Reliance on generators for transmission cost recovery may also prove less reliable as a revenue stream than funds derived from load. That is simply the result of the fact that specific generators go in and out of service or may experience insolvency or other financial or technical ailments that cause them to default or fall short on financial obligations to transmitters. That uncertainty could make transmission expansion more difficult to finance, or more likely, will cause the cost of capital to increase. Finally, assigning transmission expansion costs to specific generators based on their contribution to capital cost requirements is considerably less than a scientifically precise exercise, the outcome of which can have a significant impact on marketplace outcomes.[68] While planners and regulators can make educated guesses as to which generator is causing which expansion to be

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[68] Deciding which generator caused which capital costs to be incurred is quite different than assigning responsibility for congestion costs. The latter, in LMP markets, are assigned based on real time operations and their after the fact review. Assigning capital cost responsibility up front for transmission expansion costs is based on assumptions of the future use of the grid, assumptions that we know from experience are flawed at best. As has been noted countless times in the past, there is virtually no transmission asset that has ever been built that has not been used in ways its planners and builders never anticipated.

built, those calculations are, at best, snapshots in time that almost inevitably turn out to be quite different over the course of the asset's lifetime.[69]

Assigning capital cost recovery responsibility to load is a preferable course to follow. However, this does place a burden on planners to set up an economic framework that demonstrates they are acting in the interests of loads. (To our knowledge, this is the approach used in most, if not all, RTO-administered OATTs; therefore, the need to resolve this question of assignment of cost responsibility for new transmission investment to "load-versus-generator" is still critically important for regions without RTOs.) While there is likely to be jockeying for position among customers and customer groups to obtain favorable cost allocations, similar to that noted in regard to generators, the outcomes of cost allocations to consumers would appear to have less effect on the overall competitiveness of the market than would allocation among generators. Perhaps more importantly, the revenue to support transmission investment will come ultimately from consumers even if the immediate cost allocation is to generators. Given that they are the ultimate source of revenues and given that the revenue stream they provide is, for reasons noted above, more reliable and stable than a stream from generators, it would seem to follow logically that costs should be allocated to them in the first instance. In fact, allocating costs to customers is also consistent with practice in some RTOs which use license plate prices; namely having the license plate rate determined at the sink rather than the point of origination of energy.

Another consideration in favor of assigning cost allocation to load is the "chicken or egg" dilemma in transmission planning. In a nutshell, do we build lines to connect loads only to known sources of generation, or do we build transmission to potential sites and hope that generators eventually develop? Do generators come and then we build, or do we build first and hope generators will come? This has become a particular thorny challenge in the open access era, particularly when utilities stopped carrying out combined generation and transmission planning and moved to an era in which Federal policy required the separation of generation planning from transmission planning. California's policy challenges regarding transmission for

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[69] Advocates for allocating transmission expansion costs to new generators suggest that the uncertainties over future use of the assets can be resolved by assigning property rights in the form of FTR's to those who pay for the expansion. While that may have the effect of somewhat mitigating a payer's revenue responsibility over a long period of time, it does little to mitigate the short term competitive disadvantage of paying for the line, and may well be of dubious value entirely in those regions that lack an LMP market.

wind power, discussed earlier in the paper, illustrates this type of problem. Texas is developing a conceptually similar program in order to facilitate the development of wind resources in areas with significant resources but far from load centers. These approaches – supporting up-front transmission investment that in turn stimulates investment in generation – work conceptually well with allocating costs to load rather than to generation since they allow for socializing the risks of infrastructure development (at least to a well-defined and tolerable degree) that in turn facilitates the development of a socially desirable resource. In sum, allocating risk to load provides a somewhat increased opportunity to promote socially and economically desirable ends in regards to the development of generation. While cost socialization poses risks of diluting price signals, skewing competition, and allowing waste and inefficiency, it also presents opportunities for diversifying society's resource base. In order to achieve the positive result and avoid the negative one, strong regulatory policy and oversight in regard to defining acceptable levels of cost socialization is necessary.

One argument sometimes advanced in favor of allocating costs to generators is that such cost allocations allow for better locational signals for siting new plants. While the argument has merit, it does not mean that allocating costs to load dilutes that signal. It simply means buyers will take the location of generators, and their economic distance from loads, into account when they plan their energy and capacity purchases. In markets with LMPs, there will still be signals to generators provided by locational prices. In markets without LMPs and in which the load plans for and procures generation resources at different distances, transmission-related costs will be part of the analysis of the relative attractiveness of different resource options, albeit with signals attenuated due to spreading transmission costs across various loads. Moreover, where the location of a specific new generator imposes significant, otherwise avoidable costs, on the network, there is a high probability that the transmission investment required to interconnect that facility will be deemed a "radial" connection, the costs of which we have specifically excluded from this paper. Thus the allocation of transmission costs (and attended rights) to load does not do material injustice to proper locational pricing signals in either system.

5. The Fourth Context – Asset Size

In allocating the costs for new transmission assets, we will start with the assumption that traditional regulatory concepts, such as "cost-causers pay" or "beneficiaries pay," should provide guidance for determining who pays for what. However, determining to any degree of certainty who the "cost causers" or "beneficiaries" are and to what degree they meet that characterization is a complex and potentially litigious exercise. As noted earlier, the type of protracted decisionmaking often expended to reach a degree of up-front precision in allocating costs is almost certain to delay decisions, especially if done on a case-by-case basis. This makes timely investment difficult and, at worst, discourages it entirely. Accordingly, it makes sense to develop ways to expedite such determinations.

One way of doing so is primarily by generic policymaking that relies on the size and scale of assets being contemplated as criteria for generic action on cost allocation. For example, in general, a larger load footprint will be served by a 750 kV or 500kV line than by a 345 kV or 230kV line because of the greater capacity of the 750 kV or 500 kV line. As a general proposition, the larger the facility, the larger the region benefited by the investment in that facility. However, there are differences among regions in terms of what size constitutes a "big" line. In a region with a small geographic footprint like New England where there are no 750 kV or 500 kV AC transmission lines, a 345 kV addition tends to be large; that size may be "sub-regional," however, in parts of the country (like the MidWest and Plains states) where there are already parts of the system reinforced with 745 kV lines and where proposals for new ones are in play. Therefore, while it might be hard to set an across-the-board size standard applicable to all new transmission investment across all regions of the country, its might be possible, on a going forward basis, to apply the standard of "size" in a way that matches the infrastructure and resource characteristics of regional markets.

6. The Fifth Context -- State and Federal Jurisdictional Overlap

There is, as noted previously, a very serious question as to whether retail ratepayers derive a benefit sufficient to warrant them assuming 100 percent of the residual revenue responsibility for new transmission assets put in retail rate base. The public policy question raised by the practice is whether the benefits to ratepayers and investors outweigh the skewing of economic incentives, meaningful allocation of costs, price signals, and siting processes in the ways described. It is clear to us that State and Federal regulators need to consider this issue very carefully and commence meaningful dialogue on it. To the extent that transmission cost allocation and pricing could be applied on a more seamless and consistent basis, both the market and all of its participants would be better off. Thus, it seems important to align the regulatory jurisdiction over the recovery of transmission investment costs in a way that ensures appropriate price signals, appropriately allocates costs among all users, and is consistent with national policy for non-discriminatory access to transmission and both efficiency and fairness in allocating costs. Jurisdiction ought to follow the market and its evolution, not to mention the physical operation of the transmission system itself, all of which are, with one notable exception, multi-state in nature.

B. *Ten Principles of Cost Allocation*

In light of these foundational concepts as well as the other relevant issues we discussed previously,[70] we propose to FERC and transmission stakeholders the following Principles as essential elements of a sound cost-allocation framework. Such Principles assist in determining when transmission investment provides value and for shaping cost-allocation principles relating to them. Since many of these issues are tied to definitional issues, analytic/measurement issues, jurisdictional and planning process considerations we describe previously, these Principles need to be read as linked to the discussions in the other parts of this paper.

As a starting point, we first elucidate two key propositions about cost allocation that, at first blush, seem contradictory but to which, on a very balanced basis, we subscribe: (1) beneficiaries should pay for transmission investments and (2) the costs of much new transmission investment should be socialized. These two foundational concepts reflect the practical realities of today's interconnected high-voltage transmission system in most parts of the country. To implement these Principles in practice, it is highly preferable that a planning process looks at "baskets" of system enhancements rather than individual projects on a case by case basis, and that there exists an opportunity to periodically look back at who has actually benefited from the use of the approved assets and then, if analytically justified and administratively feasible, revisit the existing cost allocation accordingly on a revenue neutral, going forward basis.

As we explain in the Principles below, we believe that attempts to precisely identify – once and forever at the planning stages of a project who will benefit from specific incremental investments in a transmission facility in 10, 20, or 30 years is, to understate the point, a speculative exercise at best. To suggest that it is possible to understand the future of the grid with such precision flies in the face of the realities as we understand them: that the use to which

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[70] We refer here to the prior sections' discussion of definitional issues (Section II), methodological concerns (Section III), Federal/State jurisdictional issues on transmission cost-recovery and allocation (Section IV), and transmission planning considerations (Section V).

electric systems are put over time will inevitably change in innumerable and not completely predictable ways. Such changes will almost certainly lead to shifts in the identity of beneficiaries and "cost causers." Changes in patterns of economic activity over space and time are reflected in changes of the flows on the system. In light of this, embracing rigid and highly detailed principles for allocation of the costs of transmission is simply not desirable.

As we explain below, this consideration reinforces our belief that transmission planning processes that are broadly inclusive, with explicit attempts to find baskets of investments with benefits accruing to a broad array of users across regions, or sub-regions if justified, offers the prospect of more sustainable outcomes. Such a process tends to support relatively broad socialization of transmission investments among beneficiaries, in our view. We also think this will properly capture the likely changes in benefits over time and space, without trying to assert a level of precision that is simply not attainable in the real world of transmission planning. By deliberately assembling broadly beneficial bundles of investments as part of regional planning processes, we think there is likely to be less overall error in assigning costs than would tend to occur in an attempt to identify the specific beneficiaries of specific projects and then quantify the degree to which they benefit compared to other system users. This allows us to support the "beneficiaries pay" concept while also endorsing the presumption of socialization for most new transmission investments.[71]

With this as background, we endorse the following Principles to guide the allocation of costs of new transmission investment.

- **PRINCIPLE 1. All viable methods of allocating the costs of new transmission require a study of who benefits from, and who should pay for enhancements of the grid. Sound transmission planning is integral to that determination.**

In order to analyze whether proposed transmission enhancements or bundles of investments provide net positive benefits to the system being analyzed, it is necessary to

[71] This observation is not conceptually different than the way in which transmission costs were allocated in the vertically integrated monopoly model. Transmission costs were simply socialized across the customer base of vertically integrated utilities. While some states made efforts to allocate transmission costs on a customer-class basis, most did not, and few, if any, state or Federal regulator, other than in the context of a radial line, ever attempted to assign costs on the basis of specific beneficiaries. The difference in today's market is simply that access to the grid has been opened to all, including generators and users outside of the historical service territories of specific transmission owners, and that the geographic footprint of the region for which transmission must be planned is larger and more diverse in terms of competing interests than it was previously.

carry out appropriate planning studies. The credibility and soundness of cost allocation decisions are inextricably tied to the quality of planning assumptions, processes, methods and approaches used to analyze transmission investments. While there are components of various existing transmission planning processes that satisfy this Principle, it is remarkably rare to find a process that fully satisfies the full array of needed elements.[72] This is why we start with this seemingly obvious Principle – that open, participative, and fully transparent transmission planning well grounded in sound economics is an essential precondition to sensible cost-allocation outcomes. This is not to say, however, that (consistent with Principle 6) cost allocations cannot be decided generically or founded on certain presumptions, if fairly based on evidence of how types or classes of projects are likely to affect the grid or groups of customers.

■ **<u>PRINCIPLE 2</u>. As a predicate to allocating the cost of transmission investments, such investments should be analyzed using a single standard or unit of measure that combines reliability and economic values without distinction.**

Value of Lost Load is one option, but there may be others that capture economic value to consumers. This is consistent with our view of traditional "reliability studies" as being fundamentally inconsistent with open access transmission policy. Those studies presume to plan for some load growth as a "given", and then look at what is needed to meet that growth without service interruption and without regard to cost consideration (or the value of lost load) and treat other loads as incremental to the planned-for load growth. Some notion of the value of incremental demand or of the value of lost load should be utilized to jointly evaluate the costs and benefits of expansions. Appropriate measures of "benefit" or "social welfare" should be developed and applied, as a single standard combining reliability and economic expansions or upgrades without distinction. These could include, for example, metrics that incorporate the value of insurance against low probability events, reflecting value of risk-avoidance rather than simple expected benefits and the costs of varying generation resources. The level of risk aversion implicit in such

[72] We interpret FERC's Order No. 890 as pointing in this same direction, and we note explicitly that a "sound" transmission planning process would incorporate the relevant attributes implicit in the Principles we set forth below.

an assessment requires explicit and transparent assumptions and economic input. It is essential to recognize that there is no reliability upgrade devoid of economics and no economic upgrade without reliability implications. To attempt to distinguish between the two is a metaphysical exercise with no practical meaning in modern electricity markets.

■ **PRINCIPLE 3. An appropriate standard of measurement of the benefits of transmission is aggregate societal benefits within the geographic region or market being examined.**

This is the same concept that economists use when they describe "social welfare." It focuses on the question of whether a particular upgrade or set of transmission enhancements provide net positive benefits to the system being analyzed. It does not focus on who, within that system, benefits or loses from a particular investment. (Economists call these "distributional" impacts, or economic transfers from one group to another within the system being analyzed.) Certainly, economic transfers (including energy price effects pre- and post-introduction of a new transmission element in the system) can be considered as part of the analysis guiding allocation of costs, but these should be secondary to considerations of whether there are net benefits if the project is built in the first place.[73]

■ **PRINCIPLE 4. Sound transmission planning (to analyze benefits and costs, and the distribution of benefits for the purpose of allocating costs) should incorporate a number of features**:

PRINCIPLE 4A. Transmission planning and analysis should be done on a regional level – focusing on larger regions as a general rule. While the overall planning process must encompass a large region, the planning studies cannot lose sight of the specific impacts on identifiable sub-regions as well.

We agree with FERC's conclusion in Order No. 890 that "greater coordination and openness in transmission planning is required, on both a local and regional level, to

[73] Many utility regulators will be familiar with this distinction between (a) societal benefits, and (b) ratepayer impacts, in light of the traditions in many states that examine the economic efficiency of investments in demand-side measures. Many states examine the cost-effectiveness of efficiency investments first by examining them from a societal economic test, and then examine as a secondary question the benefits and costs from ratepayers' point of view – taking into account the effects on all customers' rates of reallocating the costs of lost revenues from reduced sales resulting from efficiency actions.

remedy undue discrimination. The coordination of planning on a regional basis will also increase efficiency through the coordination of transmission upgrades that have region-wide benefits, as opposed to pursuing transmission expansion on a piecemeal basis. The specific features of the regional planning effort should take account of and accommodate, where appropriate, existing institutions, as well as physical characteristics of the region and historical practices."[74] We understand FERC's deferring its determinations about the appropriate geographic scope of particular planning regions until it sees and reviews the filings for particular regions.[75] That said, it is critical that FERC ensure that regions are defined with sufficient clarity that seamlessness within markets can be achieved and sustained. Anything less would be tantamount to erecting barriers to the existence of a robust marketplace.

In terms of defining a region, we strongly believe that at a minimum, "region" in the context of planning means a wider area than planning on an individual control area basis. It also means planning for all users in the defined region, not simply for generation owned by, or under contract to, a transmission owner. Regional plans for large interconnected areas must parallel and be connected to, planning for sub-regions as well. Additionally, "region" should reflect the reality of transactions in markets and the potential growth or changes in the geographic reach of such transactions that might be accommodated by new transmission investments. This concept of a region therefore involves more than the physical interconnections but also the patterns of actual and potential commerce enabled by existing and potentially new transmission infrastructure. Restricting assessments of the need for transmission to small sub-regions is likely to lead to sub-optimal transmission upgrades or expansions and thus limit the possible value of new transmission. That is, planning over small sub-regions means that the full range of potential projects cannot be considered. Moreover, the smaller the sub-region over which planning is being done, the less likely it is that benefits will be fully captured in the welfare of the region's participants. In other words, benefits of projects will almost

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74 Order No. 890 at P 524.

75 Order No. 890 at P 526.

certainly be mis-measured if impacts on neighboring sub-regions are not taken into account contemporaneously.

The absence of full regional coordination of operations contributes to loop flow problems and prevents the full consideration of appropriate transmission projects. In particular, if transmission planning and allocation of costs is performed by sub-regions that are too small, then transmission investments may not deliver benefits to such sub-regions if (unpriced) loop flow allows others to free-ride on those investments.[76] That said, these various studies are designed to assess whether individual and baskets of projects afford net benefits to the region as a whole, or to individual sub-regions within it. Such an analysis will also provide at least a snapshot in time of who the foreseeable beneficiaries will be.

PRINCIPLE 4B. Transmission planning and analysis should include all of the demand loads (existing and reasonably anticipated) and all of the supply resources[77] (existing and reasonably anticipated) located within the geographic region for which planning is taking place.

By "existing" we mean all power plants and loads interconnected to the network, regardless of their ownership or contractual commitments. In fact, we believe transmission planning processes that exclude existing and known resources should be impermissible as they would be inconsistent with the Federal open-access transmission regime. By "anticipated" we mean some notion of loads (*e.g.*, load growth or load reduction) and resources (*e.g.*, new proposed projects) that has met some standardized

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[76] In fact, the existence of uncompensated loop flows are a good indicator of the lack of comprehensive transmission planning and cost allocation on a full regional basis. In such a regime of localized planning, investments (like phase shifters) may be undertaken simply to correct for the lack of regional coordination, rather than to improve the full potential efficiency of the system. The presence of such equipment in today's markets are likely indicators of perverse incentives.

[77] Certainly, too, transmission planning and analyses should include consideration of both anticipated supply-side and demand-side resources as alternatives to transmission investments in determining the optimal net benefits. Traditionally, system planners and analysts have focused on supply-side resources in meeting reliability/economic requirements for electric networks. That is not to say that every type of generating resource is equivalent to all other generating resources in serving different functions, just as it is the case that not all demand-side measures are either equivalent to each other or to generating resources. But conceptually, all of these types of resources need to be included with economic data in transmission studies, to assure that they are robust and provide meaningful and relevant information for identifying which transmission investments are net beneficial. By this we do not mean that transmission planning should morph into integrated resource planning, with the transmission providers being put in the position of determining some optimal mix of hypothetical resources for the region in question. We view the role of the transmission provider as providing a rich platform of information to market participants and policy makers about implications for the transmission infrastructure of anticipated developments in generation and demand-response resources, but not some generation optimization process on its own.

criteria or development threshold for inclusion in the planning studies. Criteria might include, for example, all proposed projects that have satisfied some bright line standard (*e.g.*, filed application for interconnection, or submitted an indication of interest in a periodic "open season" process tied to the transmission planning exercise), which would be applied on an objective and non-discriminatory way by the transmission provider in determining what resources are "in" or "out" of the study. Consistent with open access policy and frameworks, the loads and supply resources included should not vary by considerations of who owns, controls or is responsible to serve the resources and loads. From the point of view of the need to understand how the network does and may perform under current and future states, it is essential to include an expansive list of affected elements on the system. Clearly, this includes the loads and generating resources connected to the network, regardless of ownership, contracts, and other forms of obligations that may exist at a particular point in time.

PRINCIPLE 4C. Transmission planning should occur in a process that is open, transparent, and inclusive, and conducted by a credible entity without particular attachment to interests or particular market outcomes in the region.[78]

The process needs to function in a way that optimizes meaningful participation of both traditional market participants (*e.g.*, transmission owners, generation owners, suppliers to retail loads) as well as non-traditional players (*e.g.*, state regulatory officials, consumer interests, suppliers of demand-side equipment). The entity conducting the analysis needs to be sufficiently disinterested in the "who wins" and "who loses" from different system configurations, outcomes, plans, and so forth, that its analyses can be credible in informing decisions about whether identified investments are indeed cost-beneficial from the point of view of the region as a whole. This foundation is essential to having the planning process be the foundation for transmission plans that identify

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78 Note that we are informed by the paper of Richard Sedano (Regulatory Assistance Project), "Dimensions of Reliability: A Paper on Electric System Reliability For Elected Officials," prepared for The Electric Industry Restructuring Series of The National Council on Competition and the Electric Industry, October 2001. In the context of discussing "rates and rules for transmission companies," Mr. Sedano describes the features of successful transmission planning, and the indicators of a successful siting process: "Transparent (open, inclusive, early) planning process; broad array of alternatives considered in answer to a reliability problem; clear criteria for approval, including what 'need' means; clear time frames for considering completed applications; accounting for all project benefits and costs, regardless of state boundaries." Pages 44-45.

projects (or bundles of projects) that are net beneficial to either a region or a sub-region or both, and therefore for supporting the results that drive cost-allocation outcomes.

- **<u>PRINCIPLE 5</u>. Transmission investments involving baskets of projects that satisfy these standards and which emerge as being net beneficial (to either to the region or sub-regions) through the results of robust transmission planning processes should presumptively be candidates for broad, or socialized, cost recovery across the region benefiting from the project(s)**.

Projects that are broadly beneficial to the region, or more narrowly beneficial to a sub-region, should have their costs allocated accordingly. In essence, such investments are socially beneficial, and should be supported broadly by all users who benefit from it.

- **<u>PRINCIPLE 6</u>. As a rebuttable presumption in transmission planning exercises on a going-forward basis, the larger the size of a proposed new facility, the greater its potential to serve the broadest segment of interstate commerce and therefore the larger the region that should support it**.

In establishing this rebuttable presumption, our aim is to simplify the process, but it is also consistent with the view that in the overall economics of supply and efficient delivery of electricity to consumers, transmission investment makes up a small portion of the overall price paid by consumers for electricity. While we believe, as a general principle, beneficiaries and cost causers should pay, and that appropriate pricing is needed to send the correct signals, we also believe spending significant social resources to fight about the measurement of benefits is wasteful, counter-productive, and often misleading in result. These battles over benefits are very likely to end up in very inefficient hair-splitting which will delay and deter investment that might otherwise be beneficial for the system.[79]

Because of the essential role that we see transmission playing in enabling large, open regional markets, with benefits for reducing the potential for, and exercise of, market power, we think there is potentially significant value in simplifying the cost-

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[79] We note, too, that the electric industry has many forms of cross-subsidies and imperfect cost-allocation approaches, and a persistent focus on fighting over this particular one is counterproductive to a large degree, given that benefits and beneficiaries switch over time in dynamic and interconnected systems like electric systems today.

recovery and cost-allocation principles. This Principle also suggests several issues relating to implementation and application of the overall point in the context of real planning and cost-allocation exercises. First, the concept of "large" would likely vary by region, given the different geographical footprints of different regional markets with interconnected infrastructure and the character of the infrastructure in the different regions. A 345 kV line may be large in one region of smallish size, but mid-sized in regional market having a much larger physical footprint. Second, it suggests that within a region, there may be different tariff overlays that charge different users for different batches of new infrastructure investment. One overlay for investments benefiting the entire region may be charged to all users on a "postage stamp basis;" another overlay would differentiate charges to users on a "license plate" basis, with different rates for different sub-regions that depend upon the allocation of costs for different bundles of investments to those specific sub-regions. This approach (having a rebuttal presumption for allocating the costs of facilities of a certain size to differently sized regions) would allow for more efficient decision making because it provides a degree of discipline within which debates over cost allocation take place, while at the same time indicating a reasonable degree of tolerance for imprecision in the allocation that will allow for a more efficient and timely decision making process. Finally, given the level of uncertainty about the going-forward benefits of any project, the presumption ought to be a rebuttable one. Thus, one would have the opportunity to make a case that the size of the proposed asset was not reflective of the geographic or temporal scope of benefits.

- **PRINCIPLE 7. Except for interconnections of specific new generation, loads in the benefiting region (or sub-region) should be allocated the costs of new transmission investment.**[80]

In the final analysis, transmission is a system to enable commerce between buyers and sellers. Ultimately, the revenue to support transmission investment will come from consumers even if the initial allocation of investment costs were to generators. As between assigning costs to suppliers versus to loads, assigning capital cost recovery

[80] As we have stated previously, we intend for our Principles to apply to network transmission enhancements, not transmission interconnections. We do not make findings here about whether any particular line would qualify as an interconnection or part of the network.

responsibility to load seems the more desirable course to follow. The outcomes of cost allocations to consumers appear to have less effect on the overall competitiveness of the market than would allocation among generators, since the revenue to support transmission investment will come ultimately from consumers even if the immediate cost allocation is to generators. Given that customers (*i.e.*, buyers) are the ultimate source of revenues, and given that the revenue stream they provide is more reliable and stable than a stream from generators, it would seem to follow logically that costs should be allocated to them in the first instance. In fact, allocating costs to customers is also consistent with practice in some RTO's which use license plate prices; namely having the license plate rate determined at the sink rather than the point of origination of energy. This also ameliorates the "chicken or egg" dilemma in transmission planning and its spill-over into investment risk. While cost socialization poses risks of diluting price signals, skewing competition, and allowing waste and inefficiency, it also presents opportunities for diversifying society's resource base. In order to achieve the positive result and avoid the negative one, strong regulator policy and oversight in regard to defining acceptable levels of cost socialization is necessary.

- **PRINCIPLE 8. New transmission investment should be supported in Federal or other wholesale rates, as appropriate, and not included in retail rate base subject to regulation by the various States. To the extent that existing transmission assets can be moved from retail rate base and transferred to Federal rates in an orderly and coherent manner, it would be useful to do so**.

Prospectively, new transmission investment should be incorporated into Federal transmission tariffs, paid for by the customers using transmission, regardless of whether those customers take bundled or unbundled retail electricity service. This is entirely consistent with national policy supporting non-discriminatory open access to transmission in which all users of transmission pay FERC-approved rates for such service. We recognize that the Electric Reliability Council of Texas is an exception to

FERC jurisdiction in relevant respects, although its transmission access and competition policies at the wholesale level are generally consistent with our approach.[81]

In regard to existing transmission embedded in retail rate base, we strongly urge State and Federal regulators to find an effective, non-disruptive way in which to move transmission out of retail rate base and into FERC tariffs.[82] While we are mindful of the difficulty of doing so from an economic, political, and equity standpoint, the benefits of doing so are very real and will require national leadership, support and accommodation from the states to accomplish. We hope that the states can work together with national leaders to find a way to advance this movement of transmission dollars from State to Federal rate base. For one thing, it will allow for all users of the grid, and not just the retail customers of a particular utility that invests in transmission, to support that investment.

The fractured jurisdiction over transmission, as explained above, has made meaningful cost allocation, effectuating incentives for transmission investment, devising meaningful price signals, and facilitation of transmission planning over wide market regions much more difficult than necessary. The fact is that transmission networks should be planned and operated to facilitate the movement of energy across broad regions and accommodate regional markets. Those energy flows that constitute the geographic scope of the market and not political boundaries should define the scope of the footprint within which transmission expansion is planned, price signals are sent, and costs

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81 We note too that our Principles are intended to apply to investor-owned utilities whose transmission is regulated by FERC, although we recognize that others, such as Federal power agencies, such as the Bonneville Power Administration and Tennessee Valley Authority, are also large providers of transmission. We would encourage such entities to adopt appropriate principles in line with those we set forth in this paper.

82 We note with approval the comment of Linda G. Stuntz, former Deputy Secretary of the U.S. Department of Energy, at the FERC Conference on Competition in Wholesale Power Markets, February 27, 2007: "FERC should exercise its rate authority over transmission in interstate commerce as confirmed in *New York v. FERC* [*New York, et al. v. FERC*, 535 U.S. 1 (2002)] for the transmission component of bundled retail sales. All users of transmission in interstate commerce should pay the FERC-approved rates for that transmission, regardless of whether transmission and electricity sales are bundled or not. Electricity transmission costs should be a passthrough item in retail customer rates, just as interstate gas pipeline transportation costs are in retail natural gas rates. This simple step will divorce transmission rates and cost recovery from State retail rate freezes and will provide encouragement for investment in transmission that now is lacking. If we continue to tolerate a system in which 90% of the revenue requirement for FERC jurisdictional transmission is subject to State rate determinations (as it is with a majority of integrated utilities), the Commission's efforts to encourage transmission investment, including deployment of new technology, can have no more effect than trying to wag the dog with the tip of his tail." Comments at p. 6-7.

allocated. In short, markets and not political borders should be the basis for cost allocation for transmission.[83]

- **<u>PRINCIPLE 9</u>. On a going-forward basis only and subject to constraints related to the timing, scale, and nature of the initial allocation, cost allocation for new transmission should be subject to periodic review to determine whether beneficiaries from the investment have changed in any major ways that distort cost responsibility and appropriate pricing. Established transmission cost allocations should otherwise be presumed to be just and reasonable.**

We believe having a process that offers an opportunity to reexamine and possibly readjust cost allocations should ameliorate the apprehensions surrounding initial allocations, since the process would be a built-in safety valve for ascertaining whether changes in the system's flows (and benefits) warrant new patterns of beneficiaries (and therefore payers). Because any settled cost allocation should be presumed just and reasonable, a review pursuant to this Principle should be tempered by the following considerations.

First, any request to re-open an established transmission cost allocation, especially involving socialization of costs resulting from tradeoffs between beneficiaries of a larger basket of grid enhancements, should be held to a high standard. Revisiting cost allocations should, as a general principle, be confined to those situations where, contrary to the initial allocation of costs to identified beneficiaries or classes of beneficiaries, the benefits of the transmission investment now substantially accrue to other parties and/or the costs continue to be borne by parties who are no longer beneficiaries as originally anticipated. This would most likely be a case where forecasts of supply or demand at the time of the original cost-allocation proved to be wrong in some significant fashion.

[83] It is very important to note that in suggesting the unbundling of retail transmission, we do not propose or even suggest that states be required to open up their retail markets to competition. That is an entirely separate question from unbundling transmission. Our suggestion here is simply that transmission costs be put into a FERC tariff and the costs reflected therein simply be passed on to retail customers by the load serving entity regardless of whether the LSE is a monopoly or competitive supplier (that status would remain a question for each state to decide for itself. Incidentally, the rate impact on consumers of such a change will, in many cases, be a decrease because in many cases the residual revenue burden borne by retail customers is greater than the costs they would have to bear in a volumetric based pass through of costs reflecting their actual use rather than a residual revenue burden.

Second, we do not propose to reopen the decisions regarding overall revenue requirements, and, in fact, strongly advise against doing so because that issue needs to remain settled in order to avoid chilling investment in transmission.

Third, we do not recommend opening "the floodgates" for repeated complaints to be filed seeking cost reallocations. Rather, we suggest that reallocation be considered only at significant time intervals identified by the FERC[84] and only in connection with larger proceedings such as rate cases or regular planning exercises. We do suggest, however, within those three constraints, that for new transmission built after the date at which a new cost-allocation policy is adopted (i.e., the new transmission for which "notice" of adoption of such a policy as this had been given), the question of "who benefits" could be reexamined periodically to allow for possible realignment between support for an investment in rates and the benefits derived from such investment, if relevant factors indicate such reexamination is warranted. Regulators would have to determine (1) what constitutes a significant material change that calls a prior allocation into question, warranting a review; (2) whether there is a material deviation from the equitable and economic justifications of the allocation that requires a readjustment in the allocation of costs; and (3) what the appropriate reallocation of costs should be on a going-forward basis.

■ **<u>PRINCIPLE 10</u>. Free entry of transmission investment should be permitted, to the extent that the proponents are willing to bear the costs for such investment and that such investment does not adversely impact the network in ways that are not appropriately addressed by the proponents.**

If specific projects are rejected through a planning process, such as we have described above, by those who would bear the costs under our socialization Principles, alternative funding options should be allowed. In short, the process should allow for "voluntary participant funding." If individual forms or groups of firms are willing to pay for transmission investments themselves, those investments should be allowed as long as they do not harm existing capability of the grid. While we understand from a siting

[84] Perhaps an appropriate period for which such recalibration would occur would be the period during which long-term transmission rights to a new investment had been made available to those paying for that investment.

perspective that there may still be scrutiny as to "need" and non-economic issues in such cases, the threshold for approval of such voluntary investments during the planning process should be lower, and more limited to technical and reliability concerns. The operative principle should be "do no harm" to others, and if parties willing to pay all the project costs, including the costs of remedying any costs imposed upon the network, are allowed to proceed with the facility, then the presumption is that they should be willing to proceed. This, for example, would be a sensible way to address radial transmission facilities.

C. *Example: How Our Recommended Cost-Allocation/Planning Framework Should Operate in Practice*

Although we wish to stress the Principles we believe should underlie a sound transmission planning and cost-allocation process, rather than dictate the specifics of such a process itself, it is useful to consider how these Principles could be combined in practice. The following describes just such a "meta-process." It is one that incorporates our Principles into a framework of regional planning and rate-making for transmission investment.

We envision a sequence of periodic planning cycles – for example "5-year plans" – that would operate in an open and transparent venue and bring together all of the relevant interested parties to a transmission planning process. Ideally these plans would operate on a large regional level, with NERC regions being a natural starting point (although some NERC regions, particularly in the Midwest, can be considered subsets of broader integrated markets themselves). The planning process would consider at least two broad classes of future market conditions:

o Specific generation and load forecasts or additional uses of the grid expected (or highly probable) to materialize. These would include generation projects that are at some specific point in the generation and siting process.

o The potential for regional resource and economic development. Potential transmission projects would not necessarily be tied to specific generation plants or load growth, but would rather be targeted at resource rich or high-need regions with the hope of stimulating further economic development.

This information would be combined into a regional analysis that would attempt to quantify the benefits of specific transmission projects. Obviously, analysis of the "development" projects would have to make stronger assumptions about the nature of the new resources, along with their benefits. The analysis would include estimates of the net social benefits (welfare enhancements) of specific projects and would also, where possible, estimate the distribution of those benefits amongst relatively large sub-regions.[85] The sub-regional analysis could be limited to cases of lower-voltage projects, with the rebuttable presumption that large voltage projects would provide benefits to the entire region.

The potential projects would be reviewed by representatives from a broad set of stakeholders and regional representatives and a “short-list” of projects for the five-year plan would be developed. This list would include a bundle of projects that we envision would be intended to balance regional interests. That is to say, if one project is viewed qualitatively as providing disproportionate benefits to one sub-region, it could be bundled with a project that is viewed to provide more benefits to other regions.

The planning process would establish some form of governing board or equivalent decision-making body that would be chosen in a way that promotes balanced, independent, and non-discriminatory decision making. Various potential models for developing such bodies exist, with examples that can be drawn from various ISO, RTO, or other regional governing bodies.

This decision-making body would consider the bundle of projects resulting from the planning process and make a decision to approve or reject the bundle. Depending upon circumstances, the body could approve subsets of the bundle, although this would dilute the regional balancing benefits of assembling the bundle. If the bundle is approved, the default cost-allocation option would be the socialization of the capital costs of projects, at least those above a certain voltage level. If specific projects are viewed broadly as clearly benefiting one sub-region substantially more than others, socialization of costs within that smaller sub-region could be applied. These costs would be applied to load, ideally through a federally administered transmission tariff.

The specific decision-making criterion applied by the panel is the net societal benefits to the region as a whole. The impacts of projects on the distribution of those benefits, such as regional impacts on prices, or on the relative benefits of projects to producers versus consumers, would receive much less weight in those deliberations. In particular, a project that is viewed to improve efficiency for a broad region should not be rejected because it could raise prices in a specific sub-region by, for example, creating broader regional customer access to “bottled up”

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[85] The Commission could generically identify a group or size of projects for a specific cost allocation approach, especially socialization. Such projects would be less likely to need a review of beneficiaries.

existing or potential generation resources. Nevertheless, costs would be allocated to the loads in the sub-regions where load was a beneficiary.

Even if the bundle is rejected, individual project sponsors could still elect to proceed with specific projects if they assemble a coalition that is willing to fund those projects. The decision-making criterion for such "voluntary participant funded" projects would be limited to engineering-based reliability considerations. In particular, a finding of increasing net social benefits would not be necessary for a project that has this kind of self-funding, although evidence that a project decreases net social benefits to the region as a whole could be considered as grounds for rejecting such a project.

Because the prospective analysis of the benefits of transmission projects are wrought with uncertainty, the planning process could also include the periodic review of the benefits of projects approved under previous plans. This review would not consider altering the level of the revenue requirement from past investments; presumably the amount residing in rate base would remain in rate base. Rather, the review would limit itself to the question of the distribution of the allocation of those costs. This is similar to the practice today in rate cases where the allocation of investment costs among customer classes is recalibrated based on changes that have occurred between rate cases. In particular, the benefits of development projects that were based upon rough estimates of potential resources rather than specific commitments by load or generation, could ex-post turn out to benefit specific sub-regions in ways that were not anticipated in advance. This review process could allow for a re-allocation in those circumstances where it is fairly obvious that the benefits are accruing to a sub-region.[86]

That said, a fairly high threshold for changing the allocation could be set for the allocation of costs for projects that were adopted as part of a bundle of projects whose costs were broadly socialized. In such cases, the packaging of projects together into a bundle whose elements together provide broad benefits should not be subject to situations later on where a particular party seeks to allocate the costs of one or another element of the package to one or

[86] We think that in general, this process of reviewing projects' benefits over time should help support the acceptability of the decisions emanating from the process. Representatives of sub-regions that are skeptical of the assumptions used behind the original plan should be reassured by the knowledge that if those assumptions turn out to be wrong, the costs of the projects could be shifted to better reflect the reality that emerges, rather than the expectations of the forecasts. In this way, many "battles" over cost-allocation could be shifted to an arena that, while still allowing for a full airing of competing views, would be less likely to impede the investment in the facilities in the first place.

another group of the market participants. The costs of projects bundled as a basket should enjoy a higher burden of proof when subsequent attempts are made to reallocate costs over time.

D. *Conclusion*

In identifying these ten Principles, we have attempted to focus squarely and appropriately on the best means to identify beneficial transmission enhancements, to provide credible "rough justice" determinations of who benefits from one or another investment, and to create a principled basis to support the allocation of cost for such transmission. We expect that one of the implications of such an approach is to make more transparent that some of the disputes about cost-allocation of transmission costs *per se* are less about who should pay for the incremental costs of transmission expansion, and more about other collateral issues. These other issues include concerns of those protecting consumers' generation-related prices in regions with bottled up low-cost generation, as they fear that transmission investment (even when determined to be net beneficial to those who benefit from and will pay for it) will cause generation-related prices to equalize over larger geographic regions. Our approach would lessen the litigation and process impediments that impede investment in such net-beneficial transmission, but we are realistic enough to believe that it will not completely overcome the strong disagreements that will continue to spring from desires to protect constrained-in low-cost generation and from sensitive local issues associated with siting major facilities, however needed from the perspective of an entire region.

APPENDIX

BIOGRAPHIES OF THE BLUE RIBBON PANEL

ROSS BALDICK

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Professor Baldick is a noted scholar of electric utility operations. An electrical engineer by training, Professor Baldick teaches courses at The University of Texas at Austin and for professional associations and regulators on power systems analysis and planning, energy auctions, transmission contracts, pricing, probability, and other issues that bear on infrastructure and administration of the grid.

Current Position:

Professor, Leland Barclay Fellow,
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Education:

The University of California at Berkeley
Ph.D. (Electrical Engineering and Computer Science), 1990
M.S. (Electrical Engineering and Computer Science), 1988

University of Sydney, Australia
B.E., 1985
B.Sc. (Mathematics and Physics), 1983

Professional Experience and Affiliations:

Boston Pacific Company
Transmission consultant, 2004-present

Competitive Power Advocates
Technical consultant on restructuring of the ERCOT electricity market, 2003-present

Federal Energy Regulatory Commission (sponsor)
Formulated and developed approaches to transmission contracts and energy auctions, 2003-2004

PSACE Committee of the IEEE Power Engineering Society
Chairman of the System Economics Sub-Committee

Publications and Presentations:

Applied Optimization: Formulation and Algorithms for Engineering Systems, Cambridge University Press, 2006.

(With Sergey Kolos, and Stathis Tompaidis), "Interruptible Electricity Contracts from an Electricity Retailer's Point of View: Valuation and Optimal Interruption," *Operations Research*, 54(4):627-642, July-August 2006.

(With John Ning Jiang), "Distinguishing Design Flaws From Misconduct: A New Approach to Electricity Market Analysis," *IEEE Transactions on Power Systems*, 20(3):1257-1265, August 2005.

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(With Ryan Grant and Edward Kahn), "Theory and Application of Linear Supply Function Equilibrium in Electricity Markets," *Journal of Regulatory Economics*, 25(2):143-167, March 2004.

Recent Projects:

"Reducing the Vulnerability of Electric Power Grids to Terrorist Attacks," U.S. Department of Energy grant, July 2005-June 2008.

"Transmission Constrained Supply Function Equilibrium Analysis of Electric Power Markets," National Science Foundation grant, September 2004-August 2007.

ASHLEY C. BROWN

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Ashley Brown, an attorney and former Commissioner of the Public Utility Commission of Ohio (1983-1993), heads a leading electric policy think tank. He focuses on matters related to electricity restructuring, regulation, and market formation. Mr. Brown is an instructor in Harvard's Executive program on "Infrastructure in a Market Economy" and Of Counsel to the law firm of LeBoeuf, Lamb, Greene and MacRae. His expertise is often called upon by domestic and foreign companies and governments.

Current Position:

Executive Director of Harvard Electricity Policy Group,
John F. Kennedy School of Government,
Harvard University, Cambridge, MA

Education:

University of Dayton School of Law, Dayton, OH
J.D., 1977
Doctoral Studies (all but dissertation)
New York University, New York, NY

University of Cincinnati, Cincinnati, OH
M.A., 1971

Bowling Green State University, Bowling Green, OH
B.S., 1968

Professional Experience and Affiliations:

Entegra Power Group
Member, Board of Directors, 2005-present

Consultant to the Government of Equatorial Guinea
Assisting in writing the country's electricity law, 2007

Town of Belmont (MA) Municipal Light Advisory Board
Chairman, 2004-present

The Electricity Journal
Member, Editorial Advisory Board, 1988-present

Electric Light and Power
Member, Editorial Advisory Board

Oglethorpe Power Corporation, Tucker, GA
Member, Board of Directors, 2000

The Keystone Center Energy Advisory Committee
Member, 1988-1994

National Association of Regulatory Utility Commissioners
Member, 1983-1993

The Government of Guinea-Bissau
Consultant, Training Government and Industry Personnel on Infrastructure Regulation, 2005

The Government of Mozambique
Consultant, Assisted Re-Establishment of the Electricity Regulatory Agency, 2006-2007

Eksom, South Africa
Consultant, Advisor on Restructuring of South African Electric Distribution Sector, 2004-2005

World Bank
Consultant, Prepared Report and Lecture on Regulatory Issues in proposed New Market Design of Russian Power Sector, and Attraction of Private Capital, 2004-2005

Selected Publications and Presentations:

(With Jon Stern and Bernard Tenenbaum), Handbook for Evaluating Infrastructure Regulatory Systems. Washington, DC: World Bank Publications, 2006.

Epilogue to *Keeping the Lights On: Power Sector Reform in Latin America* (Millan, Jaime, and Nils-Henrick M. von der Fehr, editors), Inter-American Development Bank (ISBN 1-931003-55-6).

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"The Duty of Regulators to Have Ex Parte Communications," The Electricity Journal (March 2002): 10-14.

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Dr. Bushnell directs research and teaches at the University of California. He is widely recognized for his expertise on regulation, organization, and the competitiveness of energy markets. In addition to his principal responsibilities, Dr. Bushnell is co-director of the Center for the Study of Energy Markets at UC-Berkeley. He has written widely on electricity operations and markets and has testified before State and Federal agencies on a range of regulatory and competition policy matters.

Current Position:

Director of Research, University of California Energy Institute, and Professor, Haas School of Business, University of California, Berkeley

Education:

University of California at Berkeley
Ph.D. Industrial Engineering and Operations Research, December 1993
M.S. Operations Research, May 1990

University of Wisconsin – Madison
B.S. Economics and Industrial Engineering (Double Major), May 1989

Professional Experience and Affiliations:

California Independent System Operator (Folsom, CA)
Member, Market Surveillance Committee, 2002-present

California Power Exchange (Pasadena, CA)
Member, Market Monitoring Committee, 1999-2001

California Independent System Operator (Folsom, CA)
Advisor to the Market Surveillance Committee, 1998

Selected Publications and Presentations:

(With Erin Mansur and Celeste Saravia), "Vertical Arrangements, Market Structure and Competition: An analysis of Restructured U.S. Electricity Markets." *American Economic Review*. Forthcoming.

"Oligopoly Equilibria in Electricity Contract Markets," *Journal of Regulatory Economics*. Forthcoming.

(With Severin Borenstein, Chris Knittel, and Catherine Wolfram), "Inefficiencies and Market Power in Financial Arbitrage: A Study of California's Electricity Markets," *Journal of Industrial Economics*. Forthcoming.

(With Catherine Wolfram), "Electricity Markets," *New Palgrave Dictionary of Economics and the Law*. Forthcoming.

"Electricity Resource Adequacy: Matching Policies and Goals," *The Electricity Journal*. September, 2005.

"Looking for Trouble: Competition Policy in the U.S. Electricity Industry," Chapter 6 in *Electricity Restructuring: Choices and Challenges*. Puller and Griffen, Eds. University of Chicago Press. 2005.

(With Erin Mansur), "Consumption under noisy price signals: a study of electricity retail rate deregulation in San Diego." *Journal of Industrial Economics*. Vol. 53, No. 4, December 2005.

"California's Electricity Crisis: A Market Apart?" *Energy Policy*. Vol. 32, No. 9, June 2004.

"A Mixed Complementarity Model of Hydro-Thermal Competition in the Western U.S." *Operations Research*. Vol. 51, No. 1, January-February 2003.

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(With Severin Borenstein and Steven Stoft), "The Competitive Effects of Transmission Capacity in A Deregulated Electricity Industry." *Rand Journal of Economics*. Vol. 31, No. 2, Summer 2000.

Recent Projects:

"The Use of Oligopoly Models in Economic and Policy Applications," European School of New Institutional Economics (ESNIE). Corsica, France, May 2007.

"Cap and Trade Mechanisms: Lessons for California's Greenhouse Gas Policies," California Public Utilities Commission. May 2007.

"Greenhouse Gas Policies and the Western Power Market," Presentation to the Western Power Trading Forum, New York, NY. March 2007.

"California's Greenhouse Gas Policies: Local Solutions to Global Problems?", POWER conference on electricity restructuring. UC Berkeley, March 2007.

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Dr. Tierney conducts a wide-ranging business consultancy, policy advisory and arbitration practice from her position at Analysis Group in Boston. A former Assistant Secretary of Energy in Washington, she is an acknowledged expert on economics, regulation, and electric and natural gas policy. Dr. Tierney focuses on industry restructuring, market analysis, wholesale and retail market design, contract issues, resource planning and analysis, asset valuations, regional transmission organizations, and the siting of electric transmission and generation.

Current Position:

Managing Principal, Analysis Group, Boston, MA

Education:

Cornell University
Ph.D. Regional Planning, Public Policy, 1980
Dissertation: Congressional policy making on energy policy issues
M.A. Regional Planning, Public Policy, 1976

Scripps College
B.A., Art History, 1973

Professional Experience and Affiliations:

Energy Foundation
Chairman of the Board, 2000-present

Catalytica Energy Systems Inc.
Director, 2001-present

Northeast States Clean Air Foundation
Director, 1998-present

Climate Policy Center
Director, 2001-present

National Renewable Energy Laboratory
Member, Advisory Council, 2006-present

Massachusetts Renewable Energy Trust Advisory Council
Member, 2002-present

Environmental Advisory Council of the New York Independent System Operator
Member, 2004-present

China Sustainable Energy Program's
Policy Advisory Council
Member, 1999-present

Lexecon, Inc.
Senior Vice President, 1999-2003

Clean Air – Cool Planet
Board Member, 1999-present

Economics Resource Group, Inc. (Cambridge, MA)
Principal and Managing Consultant, 1995-1999

U.S. Department of Energy (Washington, DC)
Assistant Secretary for Policy, 1993-1995

Commonwealth of Massachusetts, Executive
Office of Environmental Affairs (Boston, MA)
Secretary of Environmental Affairs
Chairman of the Board of Directors
of the Massachusetts Water Resources
Authority, 1991-1993

Commonwealth of Massachusetts,
Department of Public Utilities (Boston, MA)
Commissioner, 1988-1991

Commonwealth of Massachusetts,
Energy Facilities Siting Council, (Boston, MA)
Executive Director, 1984-1988

Recent Publications and Presentations:

"Adaptation and the Energy Sector," National Summit on Coping with Climate Change, University of Michigan, Ann Arbor, May 8-10, 2007.

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"Recollections of a State Regulator," NRRI 30th Anniversary, *Journal of Applied Regulation*, Volume 4, December 2006.

(With Matthew Barmack, Edward Kahn, and Charles Goldman), "A Regional Approach to Market Monitoring in the West," Prepared the Western Interstate Energy Board Committee on Regional Electric Power Cooperation and Office of Electricity Delivery and Energy Reliability, Department of Energy, LBNL-61313, October 2006.

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Mr. Winter is a nationally recognized power industry expert. His utility operational background is extensive in transmission planning, power operations and project management. He has had extensive operational and management experience within the vertically integrated utility environment and overseeing the implementation of regional power markets as head of a major regional transmission organization ("RTO") in the West. Mr. Winter now focuses on technology development for the electricity delivery business including information technology. At Superconductor, he is in charge of human resources, audits, data systems, and facilities operations.

Current Position:

Executive Vice President, Advanced Grid Solutions,
American Superconductor

Education:

University of Idaho
B.S., Electrical Engineering, 1964

Professional Experience and Affiliations:

California Independent System Operator
President and Chief Executive Officer, 1999-2004

California Independent System Operator
Chief Operating Officer, 1997-1999

San Diego Gas and Electric Company
Division Manager, Power Operations,
Transmission Engineering,
and Project Management, 1976-1996

Trans-Elect
Member, Board of Directors, 2006-2007

InfraSource Services, Inc.
Member, Board of Directors, 2005-2006

Consortium for Electric Reliability Technology Solutions (CERTS)
Member, Industry Advisory Board