Regional Transmission Projects:

Finding Solutions

A Report by The Keystone Center

June 2005

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The Keystone Center is a neutral, nonprofit, public policy and education organization founded in 1975 and is headquartered in the Rocky Mountains at Keystone, Colorado. The primary mission of Keystone's Science and Public Policy Program is to resolve conflicts and facilitate mutual understanding and education among diverse parties on controversial public policy issues. Through the use of neutral, professionally managed processes of dialogue, mediation, and negotiation, The Keystone Center enables people with different perspectives to clarify issues in dispute, explore productive ways of dealing with those issues, and develop and document consensus recommendations for creative action by federal, state, and local government and other decision makers. The Keystone Science and Public Policy Program concentrates in three substantive areas: energy, environmental quality, and public health. More information about The Keystone Center can be found at www.keystone.org.

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Endorsements

This report is designed to be an accurate portrayal of the Dialogue group's discussions. By endorsing this report, participants agree that they are comfortable with the package of consensus recommendations in this document and with the way the issues are described. To ensure an open and candid dialogue, participants presented their personal opinions in the Dialogue deliberations and not necessarily the official positions of their organizations. Therefore, the recommendations do not represent official government or organizational position. That said, the participants agreed as part of this process to embark on a "good faith" effort to share the final recommendations with their organizations and constituents and, to the extent they can, work toward their implementation.

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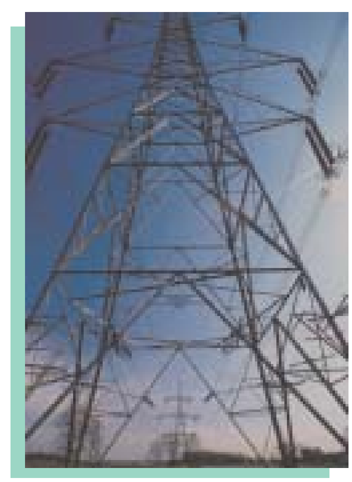
Executive Summary

The Keystone Center convened and facilitated a year-long Dialogue on "Regional Transmission Projects: Finding Solutions" to develop recommendations that will help address the difficult and contentious issues related to expansions of regional electric transmission systems that are needed for reliable and economic transmission of power within and across regions. This effort brought together a cross-section of affected stakeholders and thought leaders to address the problem with the collective wisdom of their experience and interests. Transmission owners sat at the table with consumer advocates and environmental organizations. Representatives from regional transmission organizations exchanged ideas with state and federal regulators. Generation developers explored common interests with public power suppliers. Together, the Dialogue participants developed consensus solutions about how to begin unraveling some of the more intractable issues surrounding identification of need, allocation of costs, and reaching consensus on siting—issues that can frustrate the development of regional transmission infrastructure.

Expansion of the physical transmission infrastructure is critical to ensuring a reliable and economical electricity system, as are increasing demand-side resources, adding generation capacity, improving operating procedures, and developing new transmission technologies. The Dialogue participants agreed that energy planning processes and market structures should balance all these components; however, when new regional transmission infrastructure is an important part of the solution, it can face years of delay and financial uncertainty. Sometimes no solutions to existing transmission constraints emerge because of perceived and real barriers to implementation. The Dialogue addressed this increasing gridlock, which in many cases prevents expansion of the regional bulk power transmission network where it is needed.[1]



The Dialogue participants also agreed that to maximize the value of their efforts, they should focus on the most critical challenges facing the construction of regional transmission facilities. Therefore, the first part of the Dialogue was devoted to identifying and prioritizing these issues. In addition to relying on the experience of the Dialogue participants, the group also sought input from stakeholders throughout the country who are affected by regional transmission

[1] The report does not distinguish between transmission for increased reliability and for economic reasons. Although these distinctions can be made in the short run, the Dialogue participants felt that the distinction between the two may diminish over time, and that today's problem of economic transmission congestion, if left unaddressed, may become tomorrow's reliability problem. The challenges and recommendations enumerated in this report will apply, regardless of how a given region might characterize the nature of its transmission constraints.

constraints and efforts to resolve them. Keystone interviewed more than 70 individuals in four regions of the country—the Northeast, the Midwest, the Rocky Mountain region, and California—to uncover insights on major hurdles and ideas on how to resolve them.

Building on these regional case studies and interviews, the Dialogue participants agreed that **one of the most challenging problems is the jurisdictional split in authority among state, federal, and local governments over transmission planning, cost allocation (and related ratemaking treatment), and siting.** The process for making decisions about transmission planning, cost allocation, cost recovery, and siting has not evolved in all regions of the country to reflect the regional nature of electricity markets and transmission needs to support bulk power transactions.

> *"Part of me believes that we will need a crisis to get over the hurdles to building new transmission."*
> – Industrial customer

When a transmission owner or vertically integrated utility develops plans for new transmission, it must first consider the needs of customers within its service territory, even though the boundaries seldom coincide with potential beneficiaries within the regional market. When the state issues a certificate of need for a new facility, its authority to evaluate the need and benefits typically stops at the state border. States and local governments retain authority over siting transmission on private and state land; federal land managers have jurisdiction over siting on federal lands. Yet the need for bulk power or "backbone" transmission facilities is regional in scope, covering multiple jurisdictions. Cost allocation and cost recovery decisions may be divided among state, federal, and non-jurisdictional entities (such as federal power authorities). The long-term beneficiaries of regional lines typically include most of the region's inhabitants, calling for a broader allocation of costs than emerges from any single jurisdiction. The rational development of a transmission system for the 21st century begs for a regional perspective to transmission planning.

Another issue that the Dialogue participants chose to tackle is the long-standing problem of balancing local and state concerns with regional benefits in the siting process. People who live close to proposed transmission facilities frequently have concerns about the potential impact of the facilities on their health, their quality of life, the value of their land, and the aesthetics of the area. The state, of course, has oversight of the same issues, and over broader environmental and economic impacts in the state. The lack of an effective way to balance these interests with the regional benefits of improved reliability and access to economical and diverse sources of power is a major barrier to the building of new facilities.

The Recommendations

The Dialogue participants generated and debated a wide range of possible solutions to the dilemmas they identified. In the end, they adopted a set of recommendations that they felt, as a package, could make the decision-making process on planning, allocating cost, and siting of new transmission more rational, more effective, and more closely aligned with the realities of our current electricity system. The Dialogue's consensus recommendations do not call for a complete overhaul of the current jurisdictional structure. For example, one possible solution that was considered is to invest all planning, cost allocation, and siting authority in a regional or federal government entity. Some of the participants felt strongly that this model would be preferred; others felt just as strongly that it is neither the ideal option nor politically feasible in the near term. Therefore, the Dialogue instead developed recommendations that recognize the existing separation of authority among federal, state, and local governments while trying to reduce the potential for dysfunctional outcomes for transmission construction.

Coordinating and streamlining these processes and addressing overlapping jurisdiction are the principle subjects of this report. For instance, the Dialogue participants discussed the viability of greater federal authority to site transmission in cases of a clear national interest—a proposal that has been considered in national energy legislation for the past several years. In theory, many participants agreed that there is a need for some mechanism to break the logjam when states and local governments cannot agree on need, cost recovery, or siting for new facilities; in practice, they could not agree on the best way to craft a "federal backstop" provision. The debate on this issue among Dialogue members in many ways reflected the debate that continues in Congress.

This report focuses on two main concerns:

♦ **The need for a regional approach to transmission planning, cost allocation, and siting.** In parts of the country where Regional Transmission Organizations (RTOs) or Independent System Operators (ISOs) exist, a regional focus plays a much stronger role in transmission decisions. Where they do not exist, voluntary multi-state collaborative efforts have developed in some cases to address the need for a coordinated regional focus. Recognizing the regional differences, the Dialogue's recommendations emphasized that voluntary multi-state collaborative efforts need to be strengthened and formalized as the first step toward a solution.

♦ **The need for a more coordinated, collaborative, and transparent process at every stage of the decision-making process—planning, cost allocation, and siting.** All interested stakeholders need to have access to the process, and information and analysis must be shared early and often. There needs to be a two-way conversation that includes both education of the public about the need for, and the risks and benefits of, new transmission facilities and education of policy-makers about the concerns of stakeholders who will be affected by the decisions.

To address these concerns, the Dialogue participants developed consensus over the span of a year on the following set of recommendations directed at state and federal policy-makers, transmission owners and developers, RTOs/ISOs, electricity consumers, generators, environmental advocates, and other affected stakeholders. The recommendations fall into three broad categories:

1. Recommendations on appropriate institutional arrangements and processes for achieving regional consensus on the need for new or expanded transmission infrastructure
2. Recommendations on the process for siting of transmission lines
3. Recommendations on the tools needed to support regional planning, cost allocation, and siting efforts.

1. Regional Institutions and Processes

Recommendation 1a: A regional approach to transmission needs assessment and planning is needed. This will require the creation of voluntary regional planning bodies in areas without RTOs/ISOs. Where RTOs/ISOs exist, transmission planning and needs assessment must be a core function.

Where there is an RTO/ISO, the RTO/ISO should conduct a coordinated, "bottom-up/top-down" regional transmission planning process involving all stakeholders. Bottom-up planning requires compiling information on transmission constraints and possible remedies from existing transmission owners, state officials, and other regional stakeholders. Top-down planning should be based on a "clean-slate" approach—that is, an assessment of regional transmission needs without regard to individual state or utility boundaries—and should look at ways to maximize system performance between transmission owners and between regions.

Voluntary regional efforts must have broad stakeholder support and must be developed from the bottom up if they are to succeed. The Rocky Mountain Area Transmission Study (RMATS) is an example of such an effort, which recently completed a year-long process to identify regional transmission needs for serving load within the region and exporting power.

Recommendation 1b: Regulatory authorities should extend due deference to identification of need and development of cost allocation guidelines for transmission expansion decisions that evolve from a regional planning process if it meets the following minimum criteria: (1) meets NERC reliability criteria and supports competitive wholesale electricity trade; (2) considers the roles of generation and demand-side management, as well as transmission, in meeting regional needs; (3) involves states and other regional stakeholders in the process; (4) uses an independent analysis of transmission needs; (5) results in a regional plan of sufficient geographic scope; and (6) provides opportunities for due process and fair participation.

While these criteria are broad enough to apply to regional planning efforts across the country, each region must determine how to structure the planning process to meet the criteria most effectively. If the development of a regional transmission plan is consistent with these criteria, then the Federal Energy Regulatory Commission (FERC), the states, and other regulatory authorities should extend due deference that investments made in accordance with that plan are needed, and that the costs associated with such investments are just and reasonable, pending review of the prudence of the actual construction costs.

To lend weight to these criteria, they must be adopted by FERC and the states. FERC should issue a notice of proposed rulemaking to review and adopt final criteria. Full participation by all ratemaking entities and interested stakeholders may help in developing buy-in to the final criteria, so that they will become generally accepted by the states.

Recommendation 1c: States should take a leadership role in bringing together stakeholders and forging agreement about solutions to regional transmission needs, cost allocation, and siting where RTOs/ISOs do not exist. Where RTOs/ISOs do exist, states should be actively involved in the regional planning process, in order to build a common understanding of the range and impacts of possible solutions. To enable effective state participation, adequate funding should be provided for staff time.

To be effective participants in regional planning processes, state agencies must have reasonable and predictable funding for such activities as travel to out-of-state regional planning meetings, staff time for verification of load and resource data used in regional transmission planning, participation in regional planning workgroups, and collaboration with neighboring state agencies. States could consider several sources of funding, including: existing state general funds (although the competition for state general fund appropriations would be intense and subject to potential volatility); fees assessed on regulated entities (although relying solely on fees levied to support the activities of public utility commissions would not apply to non-jurisdictional entities); or a surcharge on transmission tariffs that reflect transmission flows through control areas or as part of the ISO administrative fees recovered through the ISO tariff.

2. Siting Process

Recommendation 2a: The siting process should be inclusive and credible so that it meets the needs of all stakeholders. This should be accomplished through outreach, education, and public participation initiatives.

No matter how effective, no siting approach ensures that all parties will accept a transmission project; however, projects will have the best chance of moving forward if they are based on a thorough, objective, and open analysis. Adhering to a shared set of standards and goals can improve the credibility of the siting process and help to address stakeholder concerns. Three suggestions for process goals and recommendations for achieving them are described in more detail in this report: (1) create open and informed public processes, (2) seek broad participation, and (3) ensure fairness.

Recommendation 2b: To better inform the overall siting process, siting should be considered within the technical planning process.

In some regions, there is a disconnect between the planning and siting processes for transmission lines, which results in a less informed and potentially more conflict-ridden process. Public stakeholders in the siting process often come to the table with perspectives that were never previously considered. As a result, many transmission owners and regional planning organizations are realizing the value of stakeholder input on siting early in the planning process. Given the multitude of frameworks that exist for siting processes around the country, it is not possible to recommend a single "one-size-fits-all" process for implementing this recommendation. But the concept of integrating regional planning and state and local siting is a key element of this recommendation. As a part of its outreach and education effort, the U.S. Department of Energy (DOE) should assist with the integration of siting and planning by providing information, resources, and technical skills training.

Recommendation 2c: An improved, coordinated, and more efficient siting process should be created for consideration by policy-makers on multi-state transmission projects. Because there may be no consensus solution for all regions of the country, a range of models for implementation is offered.

To ensure environmentally, technologically, and economically sound siting processes, a project sponsor should be able to file for an application, permit, or license at a single decisional authority. As the lead entity in the process, this authority would have the task of conducting an analysis that addresses the concerns and responsibilities of the cooperating agencies, which in turn, must have the discipline to use the record established by the lead entity as the basis for their decisions. The key challenge to implementing this recommendation, particularly for multi-state transmission facilities, is identifying the proper lead agency/entity. The report outlines a number of approaches that have been tried or proposed, each of which has attempted to improve the coordination of decision-making among states. The Dialogue did not endorse one approach over another and recognized that the overall goal of consolidating decision-making could be achieved through multiple approaches, including regional cooperation among states through voluntary Memorandums of Understanding or Interstate Compacts; and increased federal jurisdiction, such as federal backstop eminent domain authority or cooperative federalism (where determination of need and permitting decisions rest with FERC but a regional forum is established to oversee the siting process).

Recommendation 2d: In regions of the country where it is feasible, a corridor identification process should be developed, together with a permit pre-filing process for transmission facilities located within such corridors.

The first element of the Dialogue's two-tiered recommendation is to identify regional corridors, based on projected need for new transmission in the future. This process is intended to mitigate stakeholder concerns before they arise by identifying corridors and, therefore, potential sites for new lines long before the siting process begins. A flexible approach would be necessary for successful implementation of this recommendation. The Dialogue recognizes that the process currently used on federal lands in the West may not be applicable in other parts of the country, such as the Northeast.

Complementary to corridor identification, a pre-filing process should be developed that provides certainty and benefits to builders who propose to site transmission lines within pre-established and designated corridors. A streamlined pre-filing permitting process will also assure skeptics and critics that corridor adjustments agreed upon (such as some undergrounding or avoiding important natural features) will be honored. The pre-filing system should be administered by the entity that maintains ultimate authority over siting within the specified region. This recommendation does not preclude traditional siting processes from taking place. Project proponents would continue to have the ability to site new transmission facilities through processes that are currently in place.

3. Tools for Planning, Cost Allocation, and Siting

Recommendation 3a: States, stakeholders, and RTOs/ISOs should develop a region-wide set of guidelines on cost allocation for new transmission facilities that limits case-by-case review of allocation decisions.

Given the difficulty of identifying the beneficiaries of new transmission and the often contentious and unpredictable nature of determining cost allocation on a case-by-case basis, there is a need for a generally accepted set of principles or guidelines to be adopted through a regional stakeholder process. Such guidelines are sometimes referred to as "default cost allocation mechanisms."

The content of such guidelines is likely to vary by region. For instance, the implementation of this approach in the PJM Interconnect relies on the use of a "but for" criterion. In ISO-NE, the same general approach is implemented through specification of the types of lines (voltage level and purpose) that fall into specific cost allocation categories. At a regional level, the states, transmission owners, and RTOs/ISOs should work with other regional stakeholders to establish the accepted allocation rules. Within RTOs/ISOs, the cost allocation agreement can be implemented through the RTO/ISO tariff filed with FERC. The existence of RTOs/ISOs that conduct independent evaluations of the need for transmission through a process that includes all affected stakeholders may improve the environment for agreement on cost allocation in advance of transmission investment, particularly if the cost allocation principles and method are developed through a transparent stakeholder process. Because of the need for regulatory approval, FERC would be an important audience.

Recognizing that reaching consensus on a broad regional cost allocation approach will be challenging and time-consuming, transmission developers need to preserve the option to negotiate with the affected parties of a proposed project and retain the flexibility to opt out of a broader regional approach. Such flexibility will allow locally affected parties to reach consensus on a sub-regional solution to cost allocation in order to ensure timely development of needed transmission infrastructure.

Recommendation 3b: Regions should use accepted economic and engineering models and develop clearly understood and accepted analytical procedures based on best practices, which (1) determine need and (2) identify costs and benefits of transmission expansion over a reasonable, near-term time period (e.g., 5 to 10 years).

Development of transmission planning models is likely to evoke considerable debate, with perceived "winners" and "losers" trying to advance their parochial interests. And the debate does not end with adoption of a generally accepted modeling platform. Equally important to the outcome of the analysis of transmission needs, costs, and benefits are the data and assumptions used. To be successful, the adoption of the most appropriate regional models, data, and assumptions must receive buy-in from the parties involved, including regional planning entities, state policy-makers and public utility commissions, transmission owners and developers, consumers and environmental advocates, generators, and load-serving entities.

FERC could help the effort by conducting regional technical conferences open to all stakeholders, where best practices in analytical tools across regions would be identified in order to ensure basic consistency while respecting legitimate regional differences. The Dialogue participants do not underestimate the time and commitment required to move beyond the selection of regional transmission planning models to implementation of a process that not only makes the model, assumptions, and data accessible and understandable but also invites debate and buy-in among the stakeholders with an interest in the analytical outcome. The balance between transparency and accuracy will need to be settled on a region-by-region basis.

Recommendation 3c: RTOs/ISOs and their participating transmission owners (TOs) should agree that TOs will construct transmission identified by RTOs/ISOs as needed when reasonable conditions are met, including sufficient assurance of cost recovery and environmental and siting approvals.

Although the Dialogue did not reach consensus on the question of whether there should be federal backstop authority on siting as envisioned in proposed national energy legislation, they did agree that some mechanism is needed to help ensure that transmission expansion identified in regional transmission plans is built. The Dialogue recommends that the RTO/ISO authority to require construction of needed transmission should be negotiated between TOs and RTOs/ISOs during the formation of the regional entities. Recognizing that RTOs/ISOs do not have the authority to guarantee cost recovery or siting approvals, TOs will need clear assurance of cost recovery from federal and state regulators and successful navigation of the siting process. Most importantly, the authority to compel construction must be based on a robust planning process that clearly identifies the need for new regional transmission.

There is a need to provide similar "backstop authority" to build in areas without RTOs/ISOs. The first step in meeting this challenge is to have a voluntary, multi-state regional planning process to establish where new facilities are needed. In regions without RTOs/ISOs, a state may be able to require construction of new transmission facilities under its authority to enforce the service obligation of regulated integrated utilities. In some cases, states are creating special state financing authorities to serve as a means to build, own, and operate new transmission, which can be exercised if TOs do not voluntarily undertake construction.

Recommendation 3d: DOE and FERC should organize a conference on best practices to provide information on the siting process and its relationship to stakeholders.

States have varied processes for siting transmission, and within the latitude of those siting requirements, transmission developers have different approaches for interacting with the affected public, regulatory agencies, and political officials. Much can be learned by looking at the successes and failures of past siting experiences and extending the lessons learned to improve siting practices in the future. Subjects to be addressed at such a conference should include, but not necessarily be limited to:

♦ A transparent siting process that provides for consultation with and input from state and local public officials, affected communities, abutters, and electricity consumers early in the siting process

♦ Giving attention to the concerns of the public, including landowners, state and local government officials, public interest groups, and other interested parties

♦ Information about electromagnetic fields (EMF)

♦ Discussions of how to assess and communicate the need to build transmission

♦ Case studies of successful and unsuccessful siting experiences

♦ Technologies available to transmission builders, including different types of overhead conductors and underground cables and their respective reliability and cost characteristics

♦ Consideration of a range of reasonable transmission solutions that are economical for consumers and technically feasible, take into account practical issues with route selection (e.g., wetland areas, historic buildings), and are within a public utility's ability to perform

♦ Discussion of the decision-making process on building transmission in both restructured markets and traditionally regulated areas

♦ Technologies to increase transfer capacity within existing rights-of-way

♦ Potential costs and benefits of mitigation measures to transmission customers and stakeholders.

Recommendation 3e: FERC should direct each RTO/ISO to work with regional stakeholders to develop workable and equitable mechanisms for providing long-term financial transmission rights or other appropriate instruments that provide transmission customers effective financial hedges against transmission congestion costs.

One challenge created by the migration to a market-based transmission system is the inability to secure financial transmission rights (FTRs) as a hedge against future transmission congestion costs for more than a few years. As a result, long-term power supply arrangements (whether wholesale power purchases or generation investments) are frustrated, because the long-term cost of congestion is unknown. Providing long-term firm transmission service at predictable prices would remove one barrier to cost-effective long-term customer power supply contracts and generation investment. Potential investors would: (1) know what rights and obligations will follow their investment; (2) have access to the information they need to evaluate the economic viability of their investment; and (3) receive the assurances needed to support financing.

The FTR allocation processes used by RTOs are linked to their planning processes to the extent that the availability of FTRs depends on the characteristics of the transmission system, which are determined by the RTOs' transmission planning processes. Thus, some industry stakeholders may wish to ensure that the RTOs' planning requirements and requirements for allocating long-term FTRs are consistent.

Adoption of this recommendation may cause disputes in some regions. For example, some parties may argue that the resulting assurances would shift costs to other users of the transmission system, especially if sufficient physical capacity is not added to the transmission system to support long-term FTRs. The Dialogue participants believe that these issues can be resolved through a FERC process or during regional deliberations among stakeholders in the development of reasonable solutions.

I. Introduction

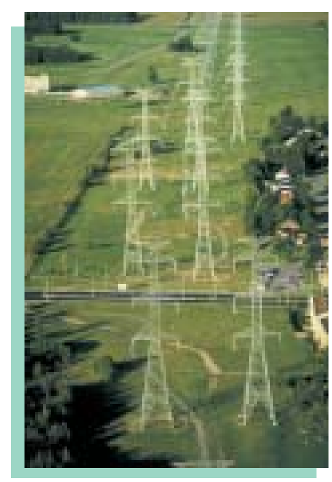
This report is the result of a year-long Policy Dialogue convened and facilitated by The Keystone Center. The purpose of the Dialogue was two-fold:

♦ To convene a balanced, representative, multi-stakeholder group to explore the challenges associated with easing constraints on the electricity transmission grid

♦ To develop recommendations for federal and state policy-makers, regional entities, and other relevant stakeholders to overcome such challenges and ensure that adequate transmission capacity will be available to provide desired benefits.

The Keystone Dialogue on "Regional Transmission Projects: Finding Solutions" brought together a diverse and high-level group of individuals to address issues related to the expansion of transmission infrastructure. Participants included individuals from consumer groups, environmental organizations, federal and state government agencies, regional transmission organizations, industry associations, transmission and generation owners, and utilities interested in the role of national and state policy in the investment, siting, and development of new transmission facilities. A complete list of the participants is provided in Appendix A.

Throughout the course of the Dialogue, participants recognized a common element of tension between the roles of the federal government and the roles of the states with regard to the development and expansion of transmission infrastructure. Participants described two different visions:



♦ **Federal Responsibility:** This approach would give the federal government the lead responsibility in regulating the need, siting, and cost recovery for transmission facilities.

♦ **Shared federal and state responsibility:** This approach reflects the current structure within which we operate, with responsibilities for transmission infrastructure development shared among the federal government, state governments, and non-regulated entities such as power market administrations (PMAs).

The Dialogue group agreed that both visions present challenges and, for the purposes of this report, recognized the need to create recommendations based on one vision. As a result, the discussion proceeded, and the recommendations in this report were formulated, within the context of the current structure of shared responsibility. Participants recognized that the shared responsibility vision is perhaps a more challenging arena for ensuring that needed transmission capacity will be built in the future; however, the model of federal responsibility faces a significant amount of tension and does not appear to be a politically feasible policy option at this time. Policy-makers should be aware that the Dialogue group made an implicit decision to craft recommendations within the complex and often controversial structure of shared responsibility.

To identify key barriers, Keystone staff, with the assistance of Dialogue participants, embarked upon a process of outreach to regional stakeholders, which was intended to provide insight from stakeholders affected by regional transmission congestion problems. Through interviews with stakeholders in four regions (Northeast, Midwest, Rocky Mountains, and California), input was sought on the common barriers that span different geographic regions and land uses, different market structures and transmission planning approaches, and different stages of project development (including projects identified within or outside a formal planning process to meet needs). Summaries of the four case studies are provided in Appendix C, and a list of the individuals interviewed is provided in Appendix E.

Armed with the input from the regional transmission case studies, the Dialogue participants agreed on a list of the most pressing problems and then worked toward consensus on the solutions. The Dialogue was based on the premise that the need for new transmission infrastructure has already been determined; however, throughout the discussions, the participants acknowledged that the process used to make decisions about need are critical to the facilitation of later decisions about siting and cost recovery. The Dialogue participants identified barriers and developed recommendations that the group felt should be addressed to ensure that reliable, economic, and adequate transmission is available to consumers.

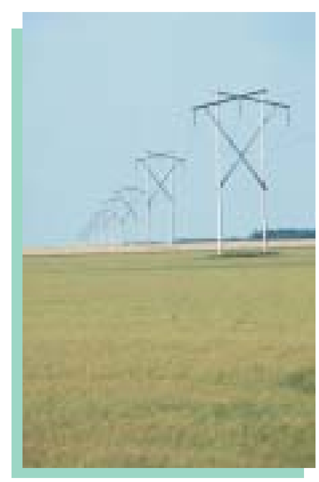
Participants in the Dialogue group devoted significant time and energy to the writing of this report. The strength of the report lies in its recommendations, which were forged by group consensus among a broad array of stakeholders. Participants hope that this report will help to inform the debate around these issues, and that the recommendations will help federal and state policy-makers as well as regional entities, such as regional transmission organizations (RTOs) and independent system operators (ISOs), more effectively address the transmission congestion problems facing all regions of the country.

II. Background

Focus of the Dialogue

The U.S. electric transmission grid includes more than 150,000 miles of high-voltage transmission lines, which cut across state and regional boundaries. In recent years, the number of transactions on the transmission grid has increased significantly to serve growing demand for power and as a result of development of competitive wholesale markets. Yet investment in new transmission facilities is lagging behind investment in new generating capacity and growth in electricity demand, in part because new generation is being built closer to load in some regions.[2] Over the past 25 years, overall investment in electric transmission nationwide has been declining at the rate of $103 million per year. In 2000, the level of transmission investment was more than $2.5 billion (in 2001 dollars) below the level of investment in 1975. Over the same period, electricity sales nearly doubled.[3] Further, according to the Energy Information Administration, electricity consumption will increase by 51 percent from 2002 to 2025.

As a result of these concerns, federal and state policy-makers are exploring ways to ensure that the right investments in both the physical and operational aspects of the transmission system will be made to achieve desired levels of reliability, market efficiency and national security. Within the past 4 years, the U.S. Department of Energy (DOE) and the Federal Energy Regulatory Commission (FERC) have completed studies of transmission bottlenecks and made recommendations for improvements.[4] Several proposals for national energy legislation have also included provisions for increasing financial incentives and mitigating jurisdictional conflicts for new transmission. Some states are collaborating to find solutions to regional transmission congestion problems,[5] and regional transmission organizations are beginning to implement multi-state transmission planning processes.



Despite these efforts, barriers still exist that prevent or delay development of new transmission capacity where it has been identified as the appropriate solution to problems involving congestion, reliability, or economic power transfers. As

[2] In the West, for instance, new load growth during the past 15 years has been met with new natural gas generation built near load centers. Now the region is looking at the need for new transmission to allow greater fuel diversity.

[3] EEI's Statistical Yearbook of the Electric Utility Industry, May 2003.

[4] US DOE, National Transmission Grid Study, May 2002; FERC, Electric Transmission Constraint Study, 2001.

[5] For example, 12 western governors and four federal agencies signed the "Protocol Governing the Siting of Interstate Transmission Lines in the West" in 2002.

documented in DOE's National Transmission Grid Study, a number of critical transmission lines have been delayed substantially, in some cases taking more than 10 years from proposal to final approval. In other cases, transmission lines have been proposed and then abandoned because of perceived risks and barriers. The barriers differ across the country, depending on market structures and land-use patterns in different regions. There is also a disincentive to build transmission that eliminates or mitigates congestion and thus reduces prices depending on which side of the constraint an entity operates. In many cases, transmission line proposals and permitting decisions have become embroiled in lengthy litigation.

It was against this backdrop that The Keystone Center Energy Board, a group of senior-level individuals representing a broad cross-section of the energy industry, consumer and environmental advocates, and policy-makers, advised Keystone to undertake a Dialogue on national policy in order to advance solutions to the challenges of regional transmission planning and expansion.

The Dialogue Process

The Keystone Center Dialogue process allows participants to articulate their experience and interests, reach a better understanding of the interests of other participants, and find areas of common ground for achieving jointly held goals. The Dialogue on "Regional Transmission Projects: Finding Solutions" was first convened in May 2004. Dialogue members were selected based on their interest in, and level of experience with, addressing transmission issues. A subgroup of participants served as a steering committee to advise Keystone on the design and scope of the Dialogue.

This report is designed to be an accurate portrayal of the Dialogue group's discussions. By endorsing this report, participants agree that they are comfortable with the package of consensus recommendations in this document and with the way the issues are described. However, to ensure an open and candid discussion, participants presented their personal opinions in the

Dialogue deliberations and not necessarily the official positions of their organizations. Therefore, the recommendations do not represent official government or organizational positions; but the participants agreed as part of this process to embark on a "good faith" effort to share the final recommendations with their organizations and constituents and, to the extent they can, work toward their implementation.

At the initial plenary meeting, the group identified key challenges to meeting infrastructure needs, exchanged information and viewpoints about additional ongoing processes to address these issues, and finally reached agreement on regions to be evaluated in more detail. Three case studies (Midwest, Northeast, and the Rocky Mountains) and one retrospective study (California Path 15) were selected to provide information about challenges and successes in addressing transmission constraints.

Following the first plenary meeting, Keystone staff and some Dialogue participants conducted a series of interviews with stakeholders from the four regions selected for study. Their goal was to identify and gather information on key barriers to the building of adequate infrastructure to meet the electricity needs of consumers. Input was sought on barriers that were common to the different geographic regions, different market structures and transmission planning approaches, and different stages of project development (including projects identified within or outside a formal planning process to meet both reliability and economic needs). Keystone staff interviewed approximately 70 stakeholders from a diverse range of perspectives, including state public utility commissioners, consumer and environmental advocates, utilities, transmission owners, generation owners, regional transmission organizations, and federal policy-makers. Work groups met to review and analyze the results of the interviews and identify commonalities among the stakeholder groups.

The second meeting of the Dialogue group was held on October 21, 2004, in Washington, DC, where, based on input from the regional stakeholder interviews, participants selected priority issues for development of Dialogue recommendations around three major issue

Dialogue by Design

The Keystone Center Dialogue Process is designed to bring diverse interests together to develop solutions to complex and often controversial public policy problems.

Three important ground rules guide Keystone Dialogues:

1. People participate in the discussions as individuals, not as formal representatives of an interest group or organization.
2. All conversations are off-the-record and not for attribution.
3. The participants agree to explore the respective interests of the other stakeholders to achieve a common understanding of the issues and develop solutions that are mutually acceptable.

The process of developing consensus involves give and take among the participants, as a better understanding of their mutual interests emerges.

areas: determination of need, cost allocation and recovery, and siting. Consensus was reached on the problem statements, and workgroups were charged with the task of creating appropriate recommendations to address the core problems. A set of criteria was used to help the workgroups identify and reach agreement on the problem statements.

The final plenary meeting was held February 24-25, 2005, in Shepherdstown, WV, at the National Conservation Training Center. Plenary participants discussed findings from the workgroups and refined their recommendations. The development of consensus on the recommendations and the suggested implementation continued after the final plenary meetings and resulted in this report.

III. Problem Statements

At the outset of the Dialogue, the participants agreed to prioritize the hurdles that currently face plans for expansion of regional transmission systems, and to focus their problem-solving efforts on issues that met the following criteria:

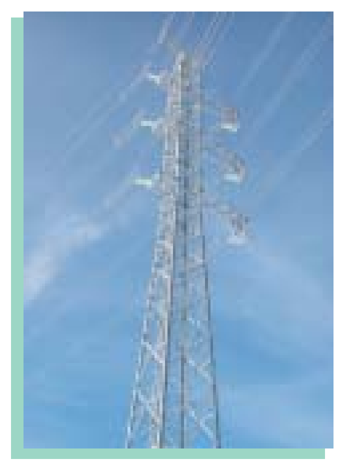
♦ Resolution of the problem would, together with the adoption of other recommendations, increase the likelihood that needed investment in regional transmission infrastructure will be made.

♦ It is a problem that is common to more than one region of the country.

♦ The problem can be addressed within the political realities of the current market structures and separation of jurisdictional authority over determination of need, cost recovery, and siting of new facilities.

During the first phase of the Dialogue, the Keystone staff and Dialogue participants conducted more than 70 interviews with stakeholders in four regions of the country to provide additional on-the-ground perspectives about the challenges of transmission expansion. (See Appendix E for a list of the individuals interviewed and a summary of the key observations from each of the regions and Appendix D for an expanded discussion of the key issues.) Based on the input from the interviews and research on the regional congestion case studies, the group agreed to the following priority problem statements:

1. Criteria to measure the regional benefits of new transmission are unclear, making it difficult to determine need and cost allocation for new regional transmission facilities; and achieving consensus in integrated networks is contentious, particularly over time.
2. Stakeholder concerns are real and growing and must be addressed, or they will adversely affect the ability to successfully site and construct needed transmission lines in a timely manner.
3. It is difficult without some form of regional planning body to deal with regional infrastructure needs.
4. The lack of an effective forum/policy for coordinating multi-state processes or resolving multi-state disagreements around siting is a barrier.



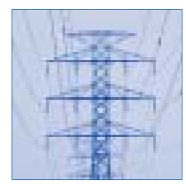
IV. Recommendations

The following recommendations addressing the Dialogue's problem statements were agreed to by consensus of the Dialogue participants. The recommendations fall into three broad categories:

1. Recommendations on appropriate institutional arrangements and processes for achieving regional consensus on the need for new or expanded transmission infrastructure
2. Recommendations on the process for siting of transmission lines
3. Recommendations on the tools needed to support regional planning, cost allocation, and siting efforts.

1. Regional Institutions and Process

Recommendation 1a: A regional approach to transmission needs assessment and planning is needed. This will require the creation of voluntary regional planning bodies in areas without RTOs/ISOs. Where RTOs/ISOs exist, transmission planning and needs assessment must be a core function.



Background

Transmission needs assessment and planning must have a regional focus, for a number of pressing reasons:

♦ As more transactions occur regionally among distant players, the interstate nature of the transmission grid and the need for regional solutions are highlighted. Increasingly, reliance on single state or single utility planning efforts is insufficient. Rather, a more region-wide focus is in order.

♦ As congestion increases on the grid, solutions to that congestion are beyond the ability of any single utility or state to effectuate. For example, a transmission problem in one state might be remedied more easily by a transmission upgrade on a neighboring system, which may be in another state.

♦ Interstate transmission projects by their very nature impact regional energy markets. Many observers believe that the existing processes are too cumbersome, particularly to sponsors of electric transmission projects. Where there is a definite need for new transmission facilities, there are fears that state processes will delay the construction due to the inability of states to adequately consider regional issues or due to parochial concerns. There are also concerns that different laws and processes along the path of an interstate line will impede investment because of

> *"California is not an island—it's part of an inter-connected grid. Consequently, if there are problems on the system, they cascade to other regions. We need to deal with the transmission system as a regional system, with coordination among many more players."*
> – Energy markets expert

the time necessary to go through the different state processes and uncertainty as to whether all the states on a route will make necessary findings.

It is critical that there be a clear means to ensure a regional, multi-state approach to planning of the transmission grid. Even if each state exercises its siting authority with the best of intentions and motives, a state-by-state determination of need can, by definition, lead to conflicting decisions among state regulators.

Implementation

Where there is an RTO/ISO,[6] the RTO/ISO should conduct a coordinated, "bottom-up/top-down" regional transmission planning process involving all stakeholders. Bottom-up planning requires compiling information on transmission constraints and possible remedies from existing transmission owners, state officials, and other regional stakeholders. Top-down planning should be based on a "clean-slate" approach, that is, an assessment of regional transmission needs without regard to individual state or utility boundaries, and should look at ways to minimize seams between transmission owners and between regions.

In regions with RTOs/ISOs, there are efforts underway to focus on regional transmission needs assessment and planning for transfer capability. These efforts should be recognized and expanded. RTOs/ISOs need to make long-term transmission planning and inducing timely investments in transmission facilities two of their core functions.

Currently, RTOs or ISOs are operating in areas that serve more than two-thirds of the U.S. population. One of the less publicized benefits of RTOs and ISOs is their role in fulfilling the requirement of FERC Order No. 2000 for RTOs and Order No. 888 for ISOs for independent regional planning. Each RTO/ISO has the ability to look at the entire transmission system within its footprint and devise solutions that meet regional needs. Moreover, due to their large footprints, the RTOs/ISOs also should provide critical information to the marketplace, such as Locational Marginal Pricing (LMP), to allow generators, transmission entities, and demand-side responders to identify where congestion exists.[7]

A number of RTOs/ISOs have evolving or established transmission planning processes. The Dialogue participants agreed that an important element of a good process is broad involvement of stakeholders, particularly, consumers and state policy-makers. Later in this report, we outline specifically the roles of regional transmission planning bodies and recommend the best process to achieve broad understanding of the need, costs and benefits, and siting alternatives and impacts of new facilities.

[6] In Order 888, FERC declared that an ISO may have a role with respect to reliability planning (Order 888, p. 282). In its Wholesale Market Platform white paper, FERC clarified that *all the characteristics and functions for RTOs would apply to ISOs, except for scope and regional configuration.* As such, it is clear that one of the functions of an ISO, as is the also the case for an RTO, is the planning and coordination of functions to eliminate "seams issues."

[7] LMP, as a short term indicator of high congestion, does not necessarily signal a need for new development, nor is it, standing alone, necessarily an incentive to build; however, the RTO/ISO or other parties can act independently to monitor high LMPs, determine whether they are caused by high levels of unhedgeable congestion, and if so, determine whether a planning process that addresses needs can relieve congestion within a region.

Regional Coordination: Three Success Stories

Rocky Mountain Area Transmission Study (RMATS): RMATS was initiated in August 2003 by Wyoming Governor Dave Freudenthal and Utah Governor Mike Leavitt as a voluntary transmission planning effort covering the states of Wyoming, Utah, Colorado, Idaho, and Montana. The objective was to identify and evaluate generation and transmission options for serving the region's electricity needs. The RMATS report, released in September 2004, outlined transmission priorities for meeting regional load and accommodating exports. Although a transmission upgrade has not yet occurred as a result of this effort, the RMATS process illustrates an innovative approach to addressing regional transmission issues. More information about RMATS is provided in Appendix C, "Case Studies of Regional Transmission Constraints."

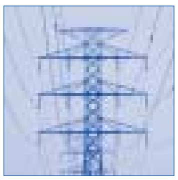
PacifiCorp Multi-state Project (MSP): MSP was a collaborative process that was established in April 2002 and concluded in July 2003. Its purpose was to enable PacifiCorp and other interested parties to investigate various issues faced by the company as a multi-state utility subject to the jurisdiction of six state regulatory commissions. The process specifically addressed environmental risks for coal-fired generation and inter-jurisdictional cost allocation issues, yet it illustrates another example of regional collaboration that could possibly be replicated for reaching agreement on cost allocation of transmission facilities. Although the process was long, challenging, and often frustrating, PacifiCorp viewed MSP as a success that contributed substantially to a mutual understanding of various parties' views and concerns. The final agreement was adopted through a state-by-state regulatory review and approval process.

Interregional Cooperation Among ISOs and RTOs: The PJM Interconnection in the Mid-Atlantic region cooperates with surrounding regions on transmission analysis and planning. PJM and the Midwest ISO (MISO) have developed a Joint Operating Agreement that covers broad coordination of the reliability, operational, planning, and market functions of each entity. The two RTOs work to identify the extent to which their respective transmission problems and solutions impact the other, and to use redispatch of generation and other market tools to resolve such issues. The regional transmission plans of the two RTOs are coordinated, and there is a commitment to extend this coordination to facilities that cross the regional boundary. In addition, seams coordination is undertaken between PJM and both the New York ISO and ISO New England. On April 22, 2005, PJM, MISO, and the Tennessee Valley Authority (TVA) entered into a Joint Coordination Reliability Agreement. As a result, over the next several years, transmission planning will be more integrated across the Midwest, Mid-Atlantic, Tennessee Valley, and Northeast regions.

In regions without approved RTOs/ISOs, voluntary, multi-state organizations should be created to assess the need for and benefits of new transmission capacity. The assessment process should be inclusive—with states, consumers, private and public utilities, merchant generators, independent transmission companies, citizens' groups, and other stakeholders all involved. While *ad hoc* initiatives can be effective in starting assessment processes, their long-term success will require sustained support and an institutional base. Such organizations would not have responsibility for transmission siting (although they could facilitate interstate compacts for transmission siting); however, their assessments would receive due deference in state siting proceedings.

Voluntary regional efforts must have broad stakeholder support and must be developed from the bottom up if they are to succeed. The

Rocky Mountain Area Transmission Study (RMATS) is an example of such an effort, which recently completed a year-long process to identify regional transmission needs to serve load within the region and to export power. In general, the Dialogue participants agreed that, in regions where an RTO/ISO exists, regional multi-state coalitions should be organized on the same geographic footprint, as has been the case for the Organization of MISO States and the New England Regional State Committee.



In regions without RTOs, the definition of the appropriate region for multi-state collaboration should consider the geographic range that encompasses all the beneficiaries of the interconnected transmission system. The difficulty lies in determining the extent of a given region's boundaries. However, where the boundaries are established may be less important than reaching agreement between transmission owners and states within the region to an associated cost allocation approach as recommended by the Dialogue.

> *"States have differing opinions and values about what need is, for instance whether conservation can meet need or transmission must be built. Determining need is not currently done in collaboration with all the affected stakeholders."*
> – Environmental advocate

Remaining Challenges

While a regional planning organization should have broad support, some stakeholders are likely to have concerns about the development of fully functional RTOs operating competitive wholesale markets. In addition, those whose economic interests could be harmed by transmission expansions might oppose the formation of such organizations. In order to avoid triggering a protracted fight over mandatory RTOs, it should be made clear that these organizations would be responsible only for assessing—through a collaborative stakeholder process—the need, costs and benefits, and proposed cost allocation methods for new transmission. In addition, stakeholders who currently object to the costs of RTOs must be assured that this recommendation will ensure efficiency and cost-effectiveness of RTOs and will not engender additional costs without commensurate benefits.

Recommendation 1b: Regulatory authorities should extend due deference to identification of need and development of cost allocation guidelines for transmission expansion decisions that evolve from a regional planning process if it meets the following minimum criteria: (1) meets NERC reliability criteria and supports competitive wholesale electricity trade; (2) considers the roles of generation and demand-side management, as well as transmission, in meeting regional needs; (3) involves states and other regional stakeholders in the process; (4) uses an independent analysis of transmission needs; (5) results in a regional plan of sufficient geographic scope; and (6) provides opportunities for due process and fair participation.

Background

Too often, the need for an independent comprehensive regional planning process has foundered over some recurring issues. In non-RTO/ISO areas, resistance has come from the perception of FERC-driven RTO/ISO formulation. Some entities have resisted such efforts even in instances where they had previously agreed voluntarily to support them. On the other hand, some regional efforts have been strictly advisory and lacked enforcement authority. Some of the most difficult issues, such as cost allocation, have been addressed only in limited ways in these efforts. Therefore, incentives are needed for states and market participants to arrive at consensus solutions on difficult issues, such as regional need determination and cost allocation.

Implementation

In order to create incentives for voluntary regional planning processes and to support strong stakeholder processes within existing RTOs/ISOs, FERC and the states should extend due deference to such regional planning processes and cost allocation recommendations that meet the six minimum criteria above. More specifically, the Dialogue proposes that regional transmission planning efforts should include the following:

1. Development of an independent regional planning process that meets NERC reliability criteria, supports the needs of all native load customers in the region, and supports a robust competitive wholesale market
2. Development of an independent regional planning process that appropriately considers the roles of generation and demand-side alternatives in addition to transmission to address needs
3. Involvement of the states and other key stakeholders in the development of regional processes to develop an independent regional transmission plan
4. Independent analysis of the need for, and costs and benefits associated with, particular investments
5. Development of a regional plan over an area of sufficient scope to reflect inter-utility power flows and include the primary beneficiaries of the transmission network
6. Opportunities for due process and fair participation by all interested stakeholders. These criteria must be embraced by all affected stakeholders in the region and implemented in a way that is perceived as not only allowing participation but also addressing concerns raised during the process. If stakeholders feel they have had adequate opportunity to be heard, they are more likely to help facilitate the implementation of the final transmission plans and the cost allocation recommendations.

While these criteria are broad enough to apply to regional planning efforts across the country, each region must determine how to structure the planning process to meet the criteria most effectively. If the development of a regional transmission plan is consistent with these criteria, then FERC, the states, and other ratemaking authorities should extend due deference that investments made in accordance with that plan are needed, and that the costs associated with such investments are just and reasonable—subject, of course, to prudence challenges concerning construction of the transmission solution.

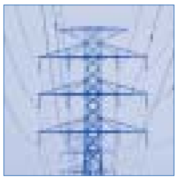
To lend weight to these criteria, they must be agreed to by FERC and the states.[8] Full participation in the development of how the criteria will be met by all ratemaking entities and interested stakeholders should help in developing buy-in to the final criteria, so that they will become generally accepted by the states. Regional planning bodies (RTOs/ISOs or voluntary multi-state entities) could hold proceedings to develop stakeholder consensus on how the criteria would be implemented in the regional planning process.

Remaining Challenges

Clearly, adoption of these criteria by FERC and the states would not limit the debate on the appropriateness of the regional process in meeting the criteria; however, transmission investment decisions subject to FERC's or a state's review that meet these criteria should be eligible for more streamlined review.

[8] The Dialogue participants were not in full agreement that this list is the exhaustive list of appropriate criteria, but they did agree that these six are at least the minimum criteria needed to support due deference.

These criteria are not intended to trump the authority of the states or FERC to review the prudence of the actual costs incurred for construction of new transmission facilities. Even if adopted by states, they would apply only to the question of whether the transmission expansion is needed. Hopefully, this would expedite the permitting processes at other stages of transmission development.



Recommendation 1c: States should take a leadership role in bringing together stakeholders and forging agreement about solutions to regional transmission needs, cost allocation, and siting where RTOs/ISOs do not exist. Where RTOs/ISOs do exist, states should be actively involved in the regional planning process, in order to build a common understanding of the range and impacts of possible solutions. To enable effective state participation, adequate funding should be provided for staff time.

Background

In regions where RTOs/ISOs exist, they have the authority and resources to lead regional planning efforts. Even within those regions, however, the participation of state regulators is critical to ensuring that later decisions about transmission siting and cost recovery are built on state buy-in and collaboration at the earliest stages of the planning process. In a number of RTO/ISO regions, states already have developed or are considering formal multi-state forums to discuss and resolve differences in electricity policy, including the assessment of need, cost allocation, and siting for transmission facilities. For example:

♦ The Organization of MISO States, Inc. (OMS), established in June 2003, is a non-profit, self-governing organization of representatives from each state with regulatory jurisdiction over entities participating in the Midwest Independent System Operator, Inc. (MISO). The purpose of OMS is to coordinate regulatory oversight among the states, including recommendations to MISO, the MISO Board of Directors, FERC, other relevant government entities, and state commissions as appropriate. Fourteen states and the province of Manitoba each appoint a member to the OMS Board of Directors. OMS has no legal authority to bind the states. It is a voluntary body established to cooperate and coordinate. To the extent that there are differences on issues, OMS attempts to determine the basis for the difference and find acceptable compromises or accommodations. OMS is funded by a surcharge on transmission revenues.[9]

♦ The New England State Committee on Electricity (NESCOE) is currently under development. As proposed, NESCOE will focus on interstate policy issues/implications and will be an active participant in New England's existing stakeholder process. The NESCOE budget will be reviewed and approved by FERC and will be included as part of ISO-NE's administrative fees.

♦ The Southwest Power Pool Regional State Committee (RSC), established on April 26, 2004, is made up of regulatory commissioners from Arkansas, Kansas, Missouri, Oklahoma, New Mexico, and Texas. Workgroups currently in place are discussing the issues of cost/benefits and cost allocation. The Southwest Power Pool (SPP) funds the RSC, with approved annual budgets of $223,000 for 2005 and 2006.[10]

♦ The Organization of PJM States (OPJMS) has been formed and is in the process of finalizing various protocols and agreements. This organization will cover a 13-state region and will include the District of Columbia.

In some parts of the country without an RTO/ISO, states have taken the lead in

[9] OMS has a current operating budget of $328,000, and its budget for 2005 is $657,300. While the Dialogue participants debated the appropriate level of funding and funded activities, they agreed that OMS's current level of funding is reasonable.

[10] EEI, RSC Backgrounder.

developing multi-state collaborative forums for transmission planning. Examples include the Committee on Regional Electric Power Cooperation (CREPC) and the Seams Steering Group – Western Interconnection Planning Working Group (SSG-WIPWG) in the Western Electric Coordinating Council (WECC) and the Rocky Mountain Area Transmission Study (RMATS).

Those voluntary multi-state transmission planning efforts with the highest level of political support have proven to be the most successful. For instance, RMATS, which was initiated by governors from Wyoming and Utah, successfully designed a broad stakeholder process and developed a 10-year regional transmission plan over the course of a year (see box on page 21). Within 6 months after completion of the plan, governors from California, Wyoming, Nevada, and Utah created a partnership through a memorandum of understanding (MOU) to facilitate implementation of one of the recommendations. The Frontier Line is expected to facilitate development of 6,000 megawatts of coal and wind resources in the RMATS region and allow the power to reach as far west as California.[11] Despite the priority established by the states, sustaining the process has been a challenge, in large part due to lack of dedicated financial resources.

Implementation

The first step in ensuring state input and leadership is to develop formal multi-state collaboratives where they do not currently exist. State regulatory commissions and energy planning organizations, such as state energy commissions and facility siting agencies, are critical agencies to include in regional transmission planning efforts. Clearly, when the participation of state agencies responsible for siting and cost recovery and for energy policies that affect deployment of alternatives to transmission is more inclusive, it is more likely that appropriate interests will be represented in the development of the plan. In New England, the state governors will appoint the individuals they want to represent their states on the NESCOE.

To be effective participants in regional planning processes, state agencies must have reasonable and predictable funding for such activities as travel to out-of-state regional planning meetings, staff time for verification of load and resource data used in regional transmission planning, participation in regional planning workgroups, and collaboration with neighboring state agencies. States could consider several sources of funding, including existing state general funds (although the competition for state general fund appropriations would be intense and subject to potential volatility), fees assessed on regulated entities (although relying solely on fees levied to support PUC activities would not apply to non-jurisdictional entities), a surcharge on transmission tariffs that reflect transmission flows through control areas or as part of the ISO administrative fees recovered through the ISO tariff as currently under consideration in the ISO-NE.

With concern over RTO funding and accountability increasing, the Dialogue participants agreed that any new mechanism to fund state participation in regional transmission planning must be subject to oversight to ensure that

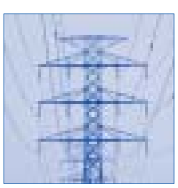
"It is still very difficult for non-utility stakeholders to participate in the transmission planning process. These are highly technical issues, but having stakeholders present is essential for buy-in. First, we need more funding at the regional planning level, and more funding for NGOs secondarily."
– Wind energy advocate

[11] Web site http://psc.state.wy.us/htdocs/subregional/home.htm.

funding levels are reasonable and funds are being used appropriately. Accountability could be provided by state regulatory commission oversight, review by governors' offices, FERC oversight, or some combination of the three. For example, funding for OMS is reviewed by the state PUCs, and FERC approves the MISO tariff that authorizes the surcharge.

Remaining Challenges

The durability of joint decisions is important to the success of multi-state collaboratives. Consensus decisions are viable only if they are carried through to implementation. Voluntary multi-state entities typically do not have authority to bind their member states to their decisions without additional contractual arrangements, such as an interstate compact or an MOU among the participating states. Interstate compacts requiring Congressional approval, while more cumbersome to implement, are binding on the signatories. Thus, compacting states are bound to observe the terms of their agreements, even if those terms are inconsistent with other state laws. Compacts are not, however, dependent solely upon the good will of the parties. Once they are enacted, Congress and the courts can compel compliance with the terms of interstate compacts. Consequently, compacts are considered the most effective means of ensuring interstate cooperation.[12]



MOUs are not necessarily binding, but they are less difficult to implement and represent agreements between parties to abide in good faith by the terms of the MOU. For example, the Western Governors Association Transmission Permitting Protocol is an MOU signed by 12 western governors, one Canadian provincial premier, and four federal agencies provides that the permitting agencies will coordinate reviews of proposed interstate transmission lines. Examples of multi-state agreements in other areas include the Emergency Management Assistance Compact, the Interstate Compact on Agricultural Grain Marketing, the New York-New Jersey Port Authority Compact, the Delaware River Basin Compact, and the PacifiCorp multi-state agreement (MOU) on cost allocation, which was subsequently submitted for regulatory approval by each state utility commission.

As stated throughout this report and addressed in detail in the following recommendation, other affected stakeholders must be brought into the multi-state transmission planning process as well, including consumers, generators, environmental and energy policy advocates, transmission owners and developers, and RTOs. As discussed below, if affected stakeholders are included in the earliest stages of the process, they can develop an understanding of the needs and benefits of expanding transmission, the alternatives, and the analysis that has been done to determine need. It is not enough for government agencies to reach agreement, if that agreement is not seen as inclusive of the needs of all the affected parties. An effective stakeholder process is likely to add time to the early stages of the process but may help to avert time-consuming opposition in the siting and cost recovery phases.

2. Siting Process

Recommendation 2a: The siting process should be inclusive and credible so that it meets the needs of all stakeholders. This should be accomplished through outreach, education, and public participation initiatives.

[12] See web site http://ssl.csg.org/compactlaws/comlistlinks.html. The Supreme Court ruled in Virginia v. Tennessee, 148 U.S. 503 (1893), that not all compacts require Congressional approval. Today, it is well established that only those compacts that affect a power delegated to the federal government or alter the political balance within the federal system require the consent of Congress.

Background

Based on stakeholder interviews and the sense of the Dialogue group, one of the key challenges identified was adequately addressing concerns of local stakeholders about the siting of potential transmission projects. (Such concerns often are referred to as "Not In My Back Yard" or NIMBY, a term that the Dialogue participants felt was polarizing and, as a result, opted not to use in this report.) The Dialogue agreed that involvement of local stakeholders at the earliest possible stages of the siting process is crucial, and that existing siting processes need to be rethought in order to create a reasonable possibility that they will not be bogged down by angry opposition. An underlying theme of this recommendation is the need to create opportunities early and frequently that will lead to a more inclusive, open, and fair process for all parties involved—one that engages local stakeholders in a two-way dialogue with project proponents, much earlier than in many of the processes in practice today.

The Dialogue participants operated under the assumption that any siting process would be based on an established determination of need. The group recognized the importance to many stakeholders of ensuring that alternative approaches to increasing transmission capacity have been adequately explored. Thus, this recommendation assumes that an adequate assessment of all the alternatives has already occurred, and that the assessment includes the input of all stakeholders.

Implementation

Outreach and education efforts by industry, regional bodies, states, and other appropriate entities would go far toward making stakeholders a more effective part of an inclusive and credible siting process. To accomplish this, information must be easily available, the process must be unrestricted and flexible, and the technical planning process must be opened up to account for concerns and objections. However, security or contractual requirements may dictate that some project information be kept confidential. None of this guarantees that siting will be done without delay or added expense, but it will help. Adhering to a shared set of standards and goals can improve the credibility of the siting process and help to address stakeholder concerns. Three suggestions for process goals and recommendations for achieving them are presented below: (1) create open and informed public processes, (2) seek broad participation, and (3) ensure fairness.

1. Create Open and Informed Public Processes by Making Information Public and Engaging in Stakeholder Outreach

Stakeholders need to feel that they are getting all relevant information at appropriate points in the public process. Despite legitimate restrictions on critical infrastructure information, much of the information in the siting process should continue to be public. It is important that the information be available, including not just the facts related to planned construction, but also the deliberative process and the schedules and milestones for decision-making on items such as system needs, alternative solutions, and project design. Nothing encourages distrust like information that is unnecessarily concealed or that is so difficult to get that it is effectively concealed. As for critical infrastructure information, there must be a resolution that makes regional planning and the rules clear to all participants. At a minimum, information about all aspects of the process must be easily accessible and promptly updated.

As a general proposition, stakeholders will more easily understand specific siting proceedings if they have a good general background. A well-supported education effort is needed to provide necessary information to the general public about how energy demand, both nationally and on a regional basis, is satisfied with a focus on the role of electric transmission infrastructure. The process for planning and siting transmission resources should be clearly explained. Such an effort should address, but not be limited to:

- Why long-term planning is necessary for meeting energy demand
- The role of the wholesale competitive market process in bringing forth solutions and new investments
- How different resource options—transmission, generation, and demand response—are examined in the planning process, including the technical limitations of each resource option
- When transmission infrastructure solutions are the best choice
- How to get more information on stakeholder issues, including an explanation of the siting process and how to participate.

More focused education efforts will be needed in some siting cases. They should be built around the content of the general education program, and they should also include fundamentals of the specific proposal and process.

The Dialogue recommends that DOE, through its Office of Electricity and Energy Assurance, should support the development of educational resources related to the siting process. First, DOE can support development of a detailed template for the stakeholder aspects of the siting process. Second, DOE is also positioned to provide information resources to states and municipalities so that they can more clearly understand the siting process and can then, in turn, identify and integrate potential demand for additional transmission infrastructure into local zoning and land-use efforts. DOE should use information on growth and development to provide feedback to local and state planning agencies. Possible avenues for dissemination of information include, but are not limited to Web-based forums, workshops conducted by local planning offices based on materials provided by DOE, and regional workshops conducted by regional DOE offices. Given that one of DOE's strategic goals is to protect our national and economic security by promoting diversified supply and delivery of reliable, affordable, and environmentally sound energy, the Dialogue suggests that DOE can provide a valuable resource by disseminating information that helps stakeholders understand the national context for regional transmission expansion.

In regions with RTOs/ISOs, those entities can also engage in the education and outreach effort that is being suggested in this recommendation. The text box on page 29 provides examples in which stakeholder involvement has led to successful implementation of new transmission infrastructure development, illustrating a process that could be complementary to the educational role recommended for DOE.

2. Seek Broad Participation

Participation is one of the keys to minimizing unnecessary opposition. Opponents may see every obstacle—meetings at inconvenient times or places, restrictive rules for comment, limits on dialogue with the managers of the siting process—as evidence of duplicity. Participants will feel part of the process if they are incorporated rather than being treated as ancillary. That demands both that the process be designed appropriately and that the process managers have the skills necessary for dealing with the inefficiencies that naturally result when concerned, non-expert participants are involved.

It will also be important to use knowledgeable third parties to provide information, answer questions and help stakeholders become involved in the siting process. Respected, objective decision leaders in the community might serve as a bridge to stakeholders with concerns about siting. Parties may include local experts, disinterested but informed opinion leaders, local government officials, FERC, RTOs/ISOs, and other

Stakeholder Outreach Initiatives: Evolving Processes in Response to Growing Stakeholder Needs

New England is in the process of developing its fifth regional plan detailing system needs and potential transmission solutions. Previously, individual utilities planned their own systems with limited sharing of data. Today, the planning process is regional. Data are collected, integrated, and shared regionally with all market participants, and stakeholders have a core role in reviewing the regional plan at all stages of development. Stakeholders may join one of six sectors in NEPOOL including an "End Users" sector. NEPOOL's Reliability Committee, which includes members from all six sectors, works closely with ISO-NE in developing the regional plan. Independent of NEPOOL, government agencies and other stakeholders may participate in a Planning Advisory Committee (PAC), which meets regularly with members of the ISO staff to review and question the regional plan in detail. Many stakeholders are members of both the NEPOOL Reliability Committee and the PAC. The focus of the regional plan is on system need and potential regulated solutions should the market not respond. Potential regulated solutions are planned at a more conceptual level rather than at a specific design and siting level.

In **Connecticut**, stakeholders have the opportunity to participate in transmission projects through the Connecticut Siting Council (CSC) process. Utilities are required to consult with affected municipalities 60 days before filing an application. The newly formed Connecticut Energy Advisory Board (CEAB) issues a mandatory request for proposals (RFP) for alternatives for each new siting application, and the CSC includes a review of the CEAB findings in its siting process. The CSC also holds hearings for stakeholders to participate, and it has granted intervener status to individuals when it felt it appropriate. The CSC process verifies need, addresses alternatives, and approves specific routes and designs.

In the **Midwest**, American Transmission Company (ATC) uses an inclusive process for the planning, routing, and siting of transmission infrastructure, involving people and agencies at many levels. In determining where transmission is needed, ATC first looks at individual issues or customer requests, then studies how those needs impact the system in a broader planning area and in the entire ATC system. In addition, ATC coordinates its planning closely with the Midwest ISO on a regional level. If identified needs change or go away, so do the corresponding transmission projects. As a standalone transmission company, ATC strives to design a portfolio of projects in which each project addresses multiple needs, so that the set of needs in total can be met as economically as possible, and overall societal impacts can be minimized.

An extension of the planning process is the public participation process. ATC proactively seeks input from local officials, landowners, and other stakeholder groups in an effort to strike the right balance between a safe and reliable system and the impact on potential costs, land use, and the environment. Public examination and discussion of transmission plans in advance of the commencement of work can enhance awareness of the need for transmission system improvements, help eliminate surprises, and improve projects by involving the perspectives of those most familiar with impacted areas. ATC's public outreach efforts may involve sharing and exchanging information about specific planned transmission work with those who may be impacted. Outreach efforts can include a variety of interactions, such as one-on-one or small group meetings with stakeholders, public open houses, newsletters, and other communication and collaborative activities.

(continued on page 30)

Stakeholder Outreach Initiatives: Evolving Processes in Response to Growing Stakeholder Needs (Continued)

When transmission infrastructure improvements or additions are required, ATC follows a careful and deliberate process that provides guidance for identifying and analyzing potential options for siting and routing of transmission facilities. Legislation passed by the Wisconsin legislature in 2003 (Wisconsin Act 89) created a general state policy on the siting of electric transmission facilities. This policy states that:

> *. . . to the greatest extent feasible consistent with economic and engineering considerations, reliability of the electric system, and protection of the environment, the following corridors should be used in the following order of priority:*
>
> - *Existing utility corridors* [such as transmission lines].
> - *Highway and railroad corridors.*
> - *Recreational trails, to the extent that the facilities may be constructed below ground and that the facilities do not significantly impact environmentally sensitive areas.*
> - *New corridors.*

Through input received from agencies, the public, and other stakeholders, ATC develops siting criteria that are applicable and appropriate for the location and issues associated with a particular project.

regional entities. (For example, local utilities in the New England area, working with ISO-NE, have formed a Reliability Operating Committee [ROC], which provided help in analyzing alternative designs and underground options for a proposed line in Connecticut. The fact that the ROC was a knowledgeable third party with ISO participation went far in meeting the concerns of stakeholders.) The press can also educate consumers about siting issues and provide the public information needed to open the process to all with concerns.

3. Make Fairness a Standard Throughout the Siting Process

Stakeholders will tend to focus on substance if they believe the process is fair. In contrast, stakeholders who believe that the siting process is unfair will be further aggrieved. The perception of unfairness can transform the siting debate into a dispute about fairness rather than the merits of siting. This both diverts the siting goal and weakens the case for siting.

Administrative processes used to decide siting disputes often assume that participants are fully equipped to follow existing rules for establishing standing, preparing filings, and arguing issues. In fact, few siting participants, including many state and local government officials, have the necessary experience, knowledge base, or skills to become engaged fully and effectively with the procedural requirements of siting processes. This strongly argues for the redesign of the process to accommodate all the stakeholders likely to be involved. Procedural requirements must respect the need to handle evidence, maintain a record, and evenhandedly produce an outcome.

Remaining Challenges

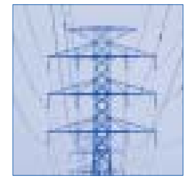
No matter how effective it may be, no siting process can ensure that all parties will accept a transmission project; however, projects will have the best chance of moving forward if they are based on the principles outlined above.

Recommendation 2b: To better inform the overall siting process, siting should be considered within the technical planning process.

Background

Oftentimes, there is a disconnect between the planning and siting processes for transmission lines, which results in a less informed and potentially more conflict-ridden process overall. The siting process should be integrated into the technical aspects of the planning process, so that stakeholder needs can be accommodated well before the siting proposal is put forward to a community. To reiterate, this recommendation is based on the assumption that need for a new transmission facility has already been determined. Siting will be only a little less painful and protracted than today if stakeholders do not see substantial evidence that resource and site alternatives were seriously considered up front. Many regional planning organizations and transmission owners are realizing the value of inclusion in their planning and siting processes, and increasingly they are shaping their processes based on stakeholder input. (See the text box on page 29 for specific examples.) This recommendation builds upon the recognition that addressing potential stakeholder concerns as early in the process as possible can lead to more acceptable outcomes.

Much of the transmission planning process requires engineering and other technical judgment. In many traditional planning processes, siting is not normally considered to be a part of the planners' responsibility, any more than they are expected to deal with financing. A natural consequence is that the results of the transmission planning process often drive the siting process, leading to the unintended result that an initial plan which is both technically optimal and least cost may not necessarily be aligned with the needs of stakeholders. In practice, a solution that planners see as suboptimal may be the one that can be most easily sited.



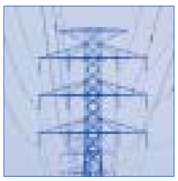
Public stakeholders in the siting process often come to the table with perspectives that were never previously considered. Planners and regulators have a well-established template for siting, which assumes that an appropriate technical process is the essential prerequisite for an acceptable project. With so many decisions already made, misunderstandings and suspicion are an understandable result. Proponents feel they have done their job the right way. Opponents inevitably see options or approaches that were not considered or were quickly rejected as inefficient.

Implementation

Given the multitude of frameworks that exist for planning and siting processes around the country, it is not possible to recommend a single "one-size-fits-all" for integrating siting concerns in the planning phase; therefore, flexibility is essential. The Dialogue participants put forth this concept as a way to encourage decision-makers to, at a minimum, consider siting issues within the technical planning process under the premise that "more information is better."

DOE should assist with the integration of siting and planning by providing information, resources, and technical skills training. Outreach and education on how to best integrate siting issues with the technical planning process could be done simultaneously with the overarching outreach and education effort referred to in recommendation 2a. Analysis of past experience, including both successes and failures, would appear to be the best indication of where planning analysis should be modified. All key parties must be directly involved, so that the requirements of the siting process will be reflected accurately in planning, and the demands placed on planners will be realistic. For example, transmission planners must be actively involved to ensure that the planning process effectively links with siting, and groups that may oppose siting must be included, so that their expectations will be clearly understood.

Routing alternatives traditionally examine costs, feasibility of construction and known obstacles. In the future, the siting process will be more successful by including analysis that directly speaks to the concerns of those who are the most likely sources of opposition. For example, stakeholders must be assured that state and regional transmission planning processes provide every opportunity for participation by generation and demand side solutions. Specifically, planners should:



- Ensure that each resource option has a fair opportunity to provide solutions to planning needs
- Ensure that different routes and sites are fully evaluated
- Retain siting options going forward, so that they will be presented to all participants in a direct comparison of costs and impacts
- Assess and present the broad impacts of different options so that, for example, opponents will be able to see that resource and siting alternatives have been effectively considered
- Discuss alternatives in terms of trade-offs.

> *"In some states, the certificate of need process regulations were written before open access and did not contemplate construction of transmission lines to serve a regional market. Some lines that are needed for the efficient operation of a wholesale market could not be permitted under the current statutes and rules."*
> – Cooperative utility

Remaining Challenges

It is not the intent of this recommendation to require the regional planning entities to duplicate the siting process. Instead, the intent is to bring forward to the planning process some of the objections and information needs that might be raised during the siting process. The hope is that if there is adequate analysis to address these concerns, it will reduce the overall time to permit and site needed transmission.

Recommendation 2c: An improved, coordinated, and more efficient siting process should be created for consideration by policy-makers on multi-state transmission projects. Because there may be no consensus solution for all regions of the country, a range of models for implementation is offered.

Background

There has been much talk of a need to create a more efficient and coordinated "one-stop process"[13] to address concerns about the coordination of multi-state processes and resolution of multi-state disagreements around siting. To ensure environmentally, technologically, and economically sound siting processes, a project sponsor should be able to file for an application, permit, or license at a single decisional authority. This authority would take the lead for analysis of siting proposals and management of the ensuing process, regardless of where jurisdiction for siting lines is vested. As the "lead entity" in the process, this authority would have the task of conducting an analysis that addresses the concerns and responsibilities of the cooperating agencies, which in turn, must have the discipline to use the record established by the lead entity as the basis for their decisions.

The primary benefit of the process would apply to facilities that support the interstate

[13]The Dialogue recognizes that, in reality, this process is not literally a "one-stop process"; however, the terminology is used to convey the concept of creating a more coordinated and efficient siting process.

market. With a one-stop process, all agencies would maintain their authority; the main thrust is that a project would follow one time line established by the lead entity, and others with decisional authority would follow that time line in producing their output. The lead entity would not dictate the outcome for other agencies, just the time limits. If an agency failed to complete its required permit action within the established time frame, the lead entity would assume that the agency approved of that permit. This would reassure the project sponsor that it would get a decision in a certain time and not be held up by the serial processing of necessary permits or licenses. The outcome(s) of the permitting authorities could be appealed; however, appeals would be based on the record established by the lead entity.

Implementation

The key challenge to implementing this recommendation is identifying the proper lead agency/entity, based on local, state, and regional needs. A number of approaches are possible. The approaches suggested below are not mutually exclusive, and they could be mixed and matched according to agreements by policy-makers.

Models Involving Regional Cooperation Among States

♦ *Voluntary Cooperation*: Nothing precludes states from joining together voluntarily to address interstate transmission issues. There are several examples of voluntary agreements where states have come together to share information and resources to meet defined goals. As in each of the examples below, states would voluntarily convene and determine who the lead agency in a one-stop process should be. A significant challenge with any voluntary approach is that it will work only to the extent that states can agree. If there is disagreement at any point, there is no legal requirement for the process to continue or for all the affected states to be a part of the process.

> *"Many times different agencies have different goals. For instance, state regulators may be more interested in getting power to population centers at the lowest price. Public land managers might look independently at other priorities such as natural resources without regard to costs."*
> – Public land manager

◊ *Organization of MISO States:* OMS is an organization of 14 state utility regulatory commissions and the province of Manitoba. OMS was organized in 2002 to establish a regional approach to energy issues. Through its Planning and Siting Workgroup, OMS recently completed a state-by-state survey of siting processes within each of its member states to serve as a basis for streamlining and coordination of siting processes. This sharing of resources does not diminish state authority, and decisions ultimately will be made on a state-by-state basis.

◊ *Western Governors' Association (WGA) Transmission Permitting Protocol:* This protocol was signed by 12 governors, a Canadian provincial premier, and 4 federal agencies. It provides for permitting agencies to coordinate reviews of proposed interstate transmission lines. The 12 governors have pledged coordination with each other in the siting of interstate lines and have signed MOUs with the federal agencies.[14]

♦ *Interstate Compacts:* An interstate compact is essentially an agreement between two or more states, entered into for the purposes of dealing with a problem that crosses state lines, which provides a formal mechanism for cooperation among the states. It is the most binding

[14] For more information on the Protocol, refer to the WGA web site at http://www.westgov.org/wieb/electric/Transmission%20Protocol/index.htm.

legal agreement possible and must be approved by the U.S. Congress. This approach presents a number of challenges, including the time and effort needed to establish the compact, its rigidity once the compact has been approved, and the fact that any revisions to the original compact must be adopted via the same Congressional path—something that Congress might be reluctant to approve.

Models Involving Federal Jurisdiction

In the debate on federal siting authority there are tensions between different factions regarding (a) whether any level of siting authority ought to be granted at the federal level, and (b) if so, to what degree and under what parameters. National energy legislation proposals put forth in the 108th Congress, and again in the 109th, provide a so-called "backstop" to states, which would have 12 months to site lines in those areas of national priority as identified by DOE, after which time FERC would be authorized to exercise federal eminent domain authority to complete the siting of the facility. This public policy debate is reflected in the discussions of the plenary group; some plenary members are strongly in favor of a federal backstop, some are adamantly opposed, and others are somewhere in the middle. Additionally, as stated in the introduction to this report, due to the multitude of challenges presented with a purely federal model for development of transmission infrastructure, the Group developed recommendations based on the existing framework of shared jurisdiction. Consequently, specific recommendations regarding the implementation of a federal role in siting—either a backstop, total federal jurisdiction, or "cooperative federalism"—were not put forward; however, brief descriptions of the three models are presented below.

> *"I don't think a regional state committee will do the trick without authority over siting. It would require an interstate compact to do that and I don't think the states will give up that right."*
> – State regulator

♦ *Federal Backstop Authority.* Implementing a federal backstop would require legislation to give the appropriate agencies jurisdictional authority. As presented in recent versions of the Federal Energy Bill, federal backstop language allows the Secretary of Energy to designate interstate congestion areas and puts the backstop into place for proposed transmission within those areas not sited by states within 12 months of a petition. Twelve months is allowed for the states to complete siting processes before transfer to the FERC, regardless of the length or complexity of the line. There is no time limitation on FERC to finish once a transfer takes place and processes begin again with hearing requirements and other reviews.

At the heart of this debate is what role the federal government should play in siting new lines (with the caveat that other alternatives have been thoroughly explored) and how such a role, if any, should be implemented. Some have indicated that, while they are not adamantly opposed to a backstop provision, the proposals that have been put forth to date essentially amount to federal preemption—a concept not widely accepted by state, environmental, or consumer advocates. Therefore, consideration of alternatives to address the issues of those opposed to the current legislative proposals might help to alleviate their concerns.

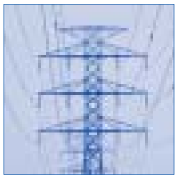
♦ *Federal Jurisdiction:* This model is based on the FERC's existing authority to site natural gas pipelines. With federal jurisdiction for siting, FERC would have jurisdiction over the siting of interstate electric transmission facilities similar to its longstanding authority to site interstate pipelines. For the purposes of a one-stop process, the predetermined federal agency (i.e., FERC) would be deemed the lead entity.

In practice, this means that, should an electric transmission company want to construct transmission facilities in interstate commerce, it would first have to obtain a certificate of public convenience and necessity from FERC. Therefore, the sponsor of a potential electric transmission project would have to submit an application containing specific information required by any future FERC regulation implementing this new authority. Information necessary for FERC to review the proposal might include information related to electric markets, project engineering, proposed rates, and accounting treatment. FERC would conduct an environmental review under the National Environmental Policy Act (NEPA), resulting in either an environmental assessment or an environmental impact statement. Other federal and state agencies would be able to participate in the proceeding. If the Commission approved the proposal, it would issue a certificate allowing the construction of the project. The FERC decision would be subject to rehearing at FERC. Parties who did not receive a favorable rehearing decision would be able to appeal to the U.S. Court of Appeals. The certificate holder would have the right to condemn land in eminent domain proceedings.

♦ *Cooperative Federalism:* As a means to implementing either of the federal options described above, the concept of "cooperative federalism" was put forth by some members of the Dialogue. If FERC were given jurisdiction over the siting of interstate lines, either outright or as a backstop, a regional board could be established as a forum for determining siting and could be utilized as a means of securing state involvement in the process. This approach is based on principles from Section 209(a) of the Federal Power Act. If given the necessary authority, FERC could use Section 209(a) to refer the determination of need and locational siting for interstate transmission facilities to a regional board, which would serve as the lead entity on siting proposals. This approach does not give the states the independence that would be possible under regional compacts, given that FERC would ultimately retain decision-making authority and set the rules for participation. However, a regional board would not have the potentially cumbersome time delays that a regional compact might have. If properly established, regional boards could provide the states a forum for land-use issues for the purposes of creating a coordinated one-stop process.

Remaining Challenges

One of the key challenges with implementation of this recommendation is determining who the lead entity will be and what, if any, legislative changes are required to ensure that a lead entity can create a consolidated record on which other agencies can rely or can be granted authority to make decisions on behalf of other agencies. The greater the authority vested in the lead agency, the more difficult it will be to get other state and local entities to implement the necessary changes to divest their regulatory authority to other agencies within or outside of the state. One of the models presented—greater federal jurisdiction—obviously requires national legislation to implement, and the history of such proposals in recent national energy legislation is a testament to the difficulty of achieving consensus on granting greater decision-making authority at the federal level. Another potential obstacle is the implementation of a statutory deadline for siting decisions coupled with a default approval if the deadline is not met. Some Dialogue participants pointed out that this proposal may create direct conflicts with other legislative requirements such as the National Environmental Policy Act (NEPA). The recommendation, however, seeks to encourage policy-makers responsible for siting decisions to consider creating the appropriate regulatory environment that will result in a more coordinated and timely overall process.



Recommendation 2d: In regions of the country where it is feasible, a corridor identification process should be developed, together with a permit pre-filing process for transmission facilities located within such corridors.

Background

Federal, state, local, and tribal governments and their agencies, as well as companies, industry associations, public interest groups, and individuals (i.e., stakeholders), should have every opportunity possible to engage in discussions about the siting of transmission facilities. The more information that is available in this regard, the better. Up-front information that links to potential areas of need and is provided long before a specific project is proposed will be helpful for long-term, regional planning.

Early stakeholder input in an inclusive and transparent process that identifies corridors appropriate for transmission siting based on a need that has been determined and verified as legitimate for the region has, in some cases, been useful in making the siting process more predictable and less costly across federal lands in the West. For example, in southern Nevada, the federal Bureau of Land Management (BLM) processed an application for a 40-mile, 230-kV transmission line starting in December 2001. The Final Environmental Impact Statement (EIS) was issued in May 2003. The proposed location for the transmission line and the alternative location that were analyzed in the EIS were located in right-of-way (ROW) corridors previously identified and designated in a BLM land-use plan. The record of decision approving the construction, operation, and maintenance of the transmission line was issued by BLM and was not appealed.

The controversies that would normally have been associated with this project were addressed during the land-use planning process and were not revisited in the site-specific EIS. In this case, the EIS process itself was more predictable and less costly because BLM could properly limit the scope of the analysis to the two alternatives previously designated as preferred locations for transmission lines during the land-use planning process. Therefore, the Dialogue group recommends that a government or government-chartered entity should work with local stakeholders to identify regional corridors for long-term land-use allocation in regions where it is feasible. In conjunction with this long-term corridor planning process, a pre-filing process for those project proponents who seek to build transmission facilities within the pre-identified corridors should be established.

Placement of ROW facilities in designated corridors minimizes the proliferation of individual ROWs and associated adverse environmental impacts. The ability to locate new ROWs in designated corridors provides industry with a level of certainty about the availability of land for such uses. The existence of designated ROW corridors provides the public with a level of certainty that other lands outside the designated corridor will not be used as locations for new ROW facilities unless traditional siting processes prevail outside the corridor identification process.

Additionally, the prompt consideration of electric transmission infrastructure through a pre-filing process for transmission will allow necessary facilities to be installed *when they are needed*, as opposed to *long after they are needed*. By including all concerned parties early on in this process, project proponents may be able to minimize concerns that some stakeholders might have with regard to such an expedited process.

A significant consideration for policymakers regarding the potential use of the corridor identification process is that concerns could potentially be raised by landowners whose land ends up being within the confines of a proposed corridor. It is conceivable that the federal government will be asked to compensate such landowners in the future. In fact, the Energy Policy Act of 2005, as passed by the House Energy and Commerce Committee on April 13, 2005, provides for compensation in an "amount equal to the full fair market value of the property taken on the date of the exercise of eminent domain authority, except that the compensation shall exceed fair market value if necessary to make the landowner whole for decreases in the value of any portion of the land not subject to eminent domain."[15] This recommendation does not specifically condemn land owned by stakeholders; however, by identifying a corridor within which future transmission infrastructure will potentially be built, it does create the potential for eminent domain issues to be raised by affected landowners. If a transmission line were built on property that lies within the corridor, compensation issues could arise.

Implementation

The proposed two-tiered solution is based on two models within the federal government: (1) BLM's Corridor Identification process for land-use allocation and (2) FERC's process for pre-filing of natural gas pipeline certificates. Appendix B provides for more detailed information on the BLM Corridor Identification process.

Corridor Identification

The first element of the Dialogue's two-tiered recommendation is to identify regional corridors, based on projected need for new transmission in the future. This process is intended to mitigate stakeholder concerns before they arise by identifying corridors and, therefore, potential new lines long before the siting process begins. A flexible approach to meeting local and regional needs would be necessary for successful implementation of this recommendation. The Dialogue recognizes that the process currently used on federal lands in the West may not be applicable in other parts of the country, such as the Northeast.

Additionally, the Dialogue would be remiss if it did not enumerate some of the potential barriers to implementation of the corridor identification process in areas beyond the open and largely federally owned lands upon which this system has worked with some success. For example, in more congested urban areas there is an increasingly prevalent concern that concentrating critical infrastructure within predetermined and well-defined areas could compromise national security efforts. Moreover, environmental impacts could be multiplied by repeated construction along the same routes for each new project. Finally, there is a need to consider the topography of regional systems, and there is also a need for flexibility to consider multiple alternatives when siting new lines, particularly within congested areas, such as the Northeast. Given these dynamics and the potential for additional steps in a process that some feel is already cumbersome, corridor identification could provide a disincentive to build, which must be noted within the context of this discussion. Nevertheless, the Dialogue chose to put forth this recommendation as a new and innovative voluntary way to approach this important and complex issue for those regions of the country where it is feasible.

A designated ROW corridor is a parcel of land with specific boundaries identified through land-use planning or another suitable public process as the preferred location for future ROW facilities. In order to be used efficiently, corridors should be identified, analyzed and designated on a regional, multi-state basis. Such designation requires intergovernmental, interagency cooperation and coordination, with full participation by all relevant government agencies and stakeholders. This recommendation is intended to apply to corridors nationwide, potentially including federal,

[15] H.R. 6, Section 1221(g).

state, and private lands, depending on local needs and interests.

Proposed Process for Corridor Identification

1. An open and transparent stakeholder process is first initiated by a public entity (the lead entity) to determine the legitimate and verifiable need for electrical power at locations within a region and potential sources of the required power. The lead entity consults often and consistently with all stakeholders during the process.
2. After the needs of the region have been determined, a similar open and transparent stakeholder process is convened (or continued) for identification of potential ROW corridors. A NEPA-type process then determines which corridors will meet the need for electrical power in the manner that is least disruptive to the social, economic, and environmental fabric of the region and provides a high degree of assurance that it can accommodate at least one additional ROW facility.
3. Finally, formal land-use allocation decisions designating the ROW corridors are made by land management and zoning agencies, based on the results of the NEPA process. Land-use decisions can include what accommodations, if any, will be offered for use of the designated corridors. Corridors are recognized as preferred locations for additional ROW facilities and should be made available to all stakeholders for their planning needs.

To ensure that long-term goals of the stakeholders are met, the determination of need for additional power and the source of that power should be made on a planning horizon of at least a 10 to 15 years, with periodic reviews of the corridor taking place to ensure that plans maintain their relevance and are updated accordingly. With allocation of sufficient resources, regional ROW corridor planning efforts can be completed in a 2-year time frame. In order to have a 2-year planning process, all stakeholders must be dedicated to the task, and adequate personnel and financial resources must be available.

Pre-Filing

Complementary to corridor identification, a pre-filing process should be developed that provides certainty and benefits to builders who propose to site within pre-established and designated corridors. A streamlined pre-filing permitting process will also assure skeptics and critics that corridor adjustments agreed upon (such as some undergrounding or avoiding important natural features) will be honored. The pre-filing system should be administered by the entity that maintains ultimate authority over siting within the specified region. This recommendation does not preclude traditional siting processes from taking place. Project proponents would continue to have the ability to site new transmission facilities through processes that are currently in place.

Proposed Process for Pre-Filing

It is recommended that pre-filing should be voluntary, based on a request by the project sponsor. As an example, FERC's NEPA Pre-filing process requires a project sponsor to identify the federal and state agencies with permitting requirements, evidence that those agencies have been made aware of the sponsor's intention to use the process, and verification that the federal agencies have agreed to participate in the process. In addition, the sponsor must identify the other interested parties and organizations that have been contacted about the project and what work has been done (e.g., contacting landowners). For an example of the FERC Pre-Filing process, see the text box on page 39.

For any transmission project of substantial impact, an extensive environmental review will need to take place, likely under NEPA. Absent conflicts between state and local agency reviews, the critical path for the analysis and determination of a transmission

FERC's NEPA Pre-Filing Process for Natural Gas Pipelines: An Example

FERC developed the NEPA Pre-Filing process for natural gas pipeline projects as a mechanism to identify and resolve issues at the earliest stages of project development by involving the participating agencies and the public earlier in the process. While the NEPA Pre-Filing process is voluntary, available at the request of the project proponent, it is subject to FERC approval. FERC strongly encourages project proponents to avail themselves of the benefits and efficiencies to be gained from increased public involvement and early resolution of issues.

An example of the NEPA Pre-Filing process was the expansion of the Kern River Gas Transmission Company's system through Wyoming, Utah, Nevada, and California. The project involved the construction of more than 700 miles of gas pipeline and 160,000 horsepower of compression, which essentially doubled the existing capacity of the system. The pre-file proposal was approved on April 2, 2001, and the pre-file period lasted for 4 months, culminating in an application filed with the Commission on August 1, 2001. After analysis, the final EIS was issued in June 2002, and an order approving the project was issued in July 2002, a little more than 11 months after it was filed. The pipeline expansion was placed into service on May 1, 2003, about 25 months after the pre-filing process commenced. The traditional processing method would have taken about 6 months longer for a project of the same size. Currently, more than one-half of the major projects for natural gas facilities (pipelines, storage facilities, and liquefied natural gas terminals) participate in the NEPA Pre-Filing process.

project will be the NEPA review. Therefore, the way to "shift" the NEPA review timeline is to begin the process before a filing or application is made at the relevant agency. That is, at the genesis of a project, the sponsor should petition the review agency to begin its NEPA review. While this does not truncate the NEPA review, it does result in some "parallel processing" rather than the usual sequential analysis followed in so many projects.

It seems reasonable to apply the same type of requirements to the sponsors of transmission projects. Here, the bottom line is getting cooperation, or at least a delineation of the issues, at the earliest possible time. In that vein, the sponsors need to involve stakeholders who would be affected, including federal, state, and local agencies that will have permitting responsibilities in connection with the project, public utility commissions, RTOs, potential builders, community members, environmental activists, landowners down to the homeowner level, and current and potential customers.

No stakeholder is bound to agree with all the proposals being made, and they would retain any rights to protest, oppose, or comment on projects when their objections cannot be ameliorated by the pre-filing process. However, the pre-filing process would allow a project sponsor to resolve issues, or if no resolution is reached, to crystallize the unresolved issues so that they can be addressed promptly and succinctly by the reviewing agency in the formal application phase of the process. Although it might not solve all the concerns of stakeholders, this approach should be viewed as a proactive tool for mitigating those concerns before they become roadblocks.

Remaining Challenges

The ultimate intent of this recommendation is to provide opportunities to stakeholders at the earliest possible stage in the overall siting process as a means of addressing concerns and providing information. Having said that, the Dialogue group recognized that there are some challenges associated with this overall recommendation.

♦ *Landowner concerns:* The potential for devaluing a landowner's property because of recognition that new transmission lines might be sited and constructed in the future presents a potential challenge with this approach. Within the existing federal program of corridor identification, this problem is addressed through comprehensive negotiations that take place with the adjacent landowners and other stakeholders during the identification and analysis stages of the land-use planning efforts. Additionally, there are anecdotal examples of situations where owners of large blocks of non-federal lands with non-intensive uses (e.g., grazing lands) adjacent to federal lands see the value of their lands increase when the adjacent federal lands are designated as corridors. In this situation the non-federal land owners can generate additional income from their lands by allowing the placement of additional transmission lines on their properties.

♦ *Potential need for legislation:* The existing federal program operates on the basis of a legislative mandate. Expanding this legislative mandate could be difficult to achieve. A pre-filing process might require federal or state legislation as well.

♦ *Development of interagency agreements:* Possible programmatic agreements would have to be developed between agencies to acknowledge "lead" agencies and to agree on cooperation. (There has been success in this approach, as exemplified by FERC's execution of such an agreement with nine other federal agencies in order to expedite the processing of natural gas projects.)

♦ *Development of voluntary agreements:* In lieu of legislation, some regions might be able to develop voluntary agreements to implement this recommendation. Although this approach might be easier to achieve, the lack of firm authority could make it a weaker proposition.

♦ *Shifting of existing roles:* Opposition to a corridor identification/pre-certification process could arise out of the need for new roles within existing planning processes (e.g., the impact on RTOs that currently engage in the planning process, or the shifting of authority for some jurisdictions in a streamlined planning process).

♦ *Applicability nationwide:* This model has proven successful in the West, where there are large areas of both federal and private land. Questions remain as to the ability to implement corridor identification in more urban and congested areas, such as the Northeast.

Despite these challenges, given the relative success of the BLM and FERC processes, it is likely that there could be support for the concept, so long as it is managed fairly and efficiently. Support could come from utilities, federal land agencies, and transmission entities who want to build lines and, on some levels, from communities and environmentalists as well. Although these last two groups tend to be supportive of corridor identification, they have a difficult time separating it from the project-by-project process, where they tend to be more strident in their opposition. Another concern is that those with traditional stakeholder concerns might feel marginalized by an expedited process; it is therefore important that the process be open and inclusive from its inception.

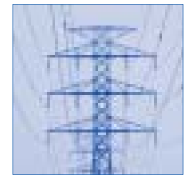
3. Tools for Planning, Cost Allocation, and Siting

Recommendation 3a: States, stakeholders, and RTOs/ISOs should develop a region-wide set of guidelines on cost allocation for new transmission facilities that limits case-by-case review of allocation decisions.

Background

Uncertainty about cost allocation at the state, regional, and federal levels discourages needed transmission investment, because it increases uncertainty about the likelihood and timeliness of cost recovery. There is often disagreement about what constitutes an appropriate cost allocation mechanism for a particular type of investment. And even if there is agreement on a method (e.g., direct assignment, beneficiaries pay, or regionalization/socialization), there can be disagreement about the application (e.g., which cost allocation method should apply to a particular investment, or who the beneficiaries of a particular investment would be).

The role of cost allocation uncertainty in inhibiting transmission investment has been cited in a variety of recent reports[16] as is the case of Path 15 in California. Upgrades to Path 15 were needed to relieve the bottleneck in Central California that was faulted for contributing to the 2001 California blackout and was considered a barrier to transport of low-cost generation. Market participants argued about who would benefit and, therefore, who should pay for the costs of the line. The lack of an agreed mechanism for allocating the costs of the upgrade contributed to a delay in its construction, even though the parties recognized that the upgrade was in fact needed. (A more detailed discussion of Path 15 is included among the case studies in Appendix C.)



Given the difficulty of identifying the beneficiaries of new transmission and the often contentious and unpredictable nature of determining cost allocation on a case-by-case basis, there is a need for a generally accepted set of principles or guidelines to be adopted through a regional stakeholder process. Such guidelines are sometimes referred to as "default cost allocation mechanisms." A cost allocation method agreed to in advance, such as the Regional Network Service (RNS)/Local Network Service (LNS) in New England or the "but for" test in PJM, have value in avoiding case-by-case litigation that can delay, discourage, and increase the cost of needed transmission investment.

Implementation

As a general principle, the Dialogue participants agreed that cost allocation methods should attempt to distribute costs to those who benefit and those who cause the costs to be incurred, but they recognize the difficulty of identifying beneficiaries. Clear guidelines are needed in this area. The content of such guidelines is likely to vary by region. For instance, the implementation of this approach in PJM relies on the use of the "but for" criterion (see box on page 42). Another approach involves distributing the costs of backbone lines (bulk power, high voltage), which provide benefits across broad regions, to everyone in the region and assigning the costs for local area transmission to local load and generation.

In ISO-NE, this general approach is implemented through specification of the types of lines (voltage level and purpose) that fall into specific cost allocation categories. While regional differences are likely to emerge, every

[16] See, for example, RMATS Transmission Study: Transmission Planning for the Rocky Mountain Sub Region, Cost Allocation and Cost Recovery Issues and Alternatives, 2004; Eric Hirst, Transmission Planning and the Need for New Capacity, December 2001; and NECA Issue Paper, Transmission and Distribution Pricing Review: Allocation of New Investment Costs, 1999.

> *"FERC needs to provide clarity on cost recovery on transmission plans, particularly on interstate lines. That will solve a lot of this debate. Once there's regulatory certainty, that gives applicants certainty."*
> – Midwest state regulator

effort should be made to address problems that arise at the seams between regions. Several regions have adopted regional cost allocation proposals to provide guidance on how costs will be treated (for examples, see the text box below).

Cost allocation guidelines could be established at the federal level if FERC set forth a uniform or standard policy but still allow for regional variation with respect to specific allocation methods. Given the current climate and the experience of the past few years, however, an attempt by FERC to establish a standardized policy on cost allocation methods is likely to be viewed negatively by some states. Therefore, a regional approach may be more acceptable to a broader range of regulators, policy-makers, and stakeholders. On the other hand, regional variations could introduce seams that would not exist under a national standardized policy.

At a regional level, the states, transmission owners, and RTO/ISOs should work with other regional stakeholders to establish the accepted allocation rules. Within RTO/ISOs, the cost allocation agreement can be implemented through the RTO/ISO tariff filed with FERC. The existence of RTOs/ISOs

Cost Allocation Methods: Definition of Terms

Uncertainty about the meaning of terms that are used to identify different cost allocation methods confuses policy discussions and impedes efforts to achieve agreement on cost allocation principles. The Dialogue participants agreed that clarifying the definitions of different cost allocation approaches would be helpful. Because the term "participant funding" has been used in the debate to describe a number of different approaches, the Dialogue group decided to avoid the use of this term altogether. Instead, the following definitions were adopted:

Direct Assignment: Under "direct assignment," one market participant or group of participants is directly assigned the cost of a transmission upgrade required for the transmission or interconnection service it has requested. The upgrade occurs only if the participant or group is willing to pay the cost. (This cost allocation method is sometimes referred to as "participant funding.")

Beneficiaries Pay: Under the "beneficiaries pay" approach to cost allocation, an attempt is made to identify the direct beneficiaries of a particular transmission upgrade and directly allocate and charge the costs of that upgrade to those benefiting consumers through rates that the customers are obligated to pay. The upgrade occurs even if the participants would prefer not to pay the costs. One application of the "beneficiaries pay" approach is the "but for" test used in PJM.[a]

Regionalization/Socialization: "Regionalization" or "socialization" of costs means allocating them broadly over all consumers in a region, or over the system of a transmission-owning utility. Socialization of costs assumes that the transmissions system and its users and consumers will benefit as a whole over time.

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[a]Applied to facilities built as the result of a generator's interconnection, the "but for" approach asks whether the upgrade would have been needed *but for* the interconnection. If the upgrade is needed solely because of the interconnection, then the interconnecting generator should pay. If not, then the costs should be allocated to a subset of customers or spread to all the customers in the region.

that conduct independent evaluations of the need for transmission through a process that includes all affected stakeholders may improve the environment for agreement on cost allocation in advance of transmission investment, particularly if the cost allocation principles and method are developed through a transparent stakeholder process. Because of the need for regulatory approval, FERC would be an important audience. State regulators would also be key, because it is unlikely that FERC would approve a cost allocation method over the objections of the majority of states in a region. This recommendation recognizes the

National Grid Company's Transmission Cost Allocation Proposal

The following excerpts are from comments by National Grid USA on FERC's Standard Market Design Notice of Proposed Rulemaking, submitted to FERC on January 10, 2003 (Docket No. RM01-12-000), p. 34-35.

"National Grid's pricing proposal . . . can perhaps best be understood by analogy to the manner in which the costs of public roads are allocated among taxpayers. Typically, a homeowner has complete dominion over his or her driveway and complete responsibility for the associated costs. Beyond the driveway is a local street, which is shared by local residents and paid for by members of the local community, including the homeowner, through their local taxes. Beyond that is a vast network of interstate highways, which presumably benefit all citizens, and which are funded predominantly by the federal government through taxes paid by all citizens.

"This analogy may serve as a basis for pricing transmission upgrades. A generator's responsibility for the leads to the substation where there is direct interconnection of facilities to the grid, just as the homeowner has sole use and responsibility for his or her driveway. Accordingly, …the cost of transmission facilities that solely or predominantly benefit a single transmission customer, such as a direct interconnection facility for the sole use of a generator or load, should be the responsibility of that customer. This is generally not a controversial issue.[a]

"Next in line are the looped transmission facilities that are used to transmit electricity to and from customers' sole use facilities in a portion of the ITP's region, but which provide little or no support to bulk transfers throughout the region. These "local" transmission facilities, which typically operate at relatively lower voltages, serve a function similar to local streets. The cost of necessary network upgrades to these local transmission facilities should be allocated to customers throughout that portion of the ITP's system though, where some customers in the sub-region derive particular benefits from the facilities, a proportionally adjusted part of the upgrade costs could be allocated to them . . . .

"Deeper into the system, where high voltage parallel system elements form a network that support bulk transfers throughout the region, it is more difficult to associate use of new network upgrades with particular transmission customers and power sources. Like the interstate highway system, the benefits and utilization of existing and new network facilities are spread much more broadly. Such upgrades (to allow movement of aggregate regional generation to aggregate regional load) could be rolled in and allocated to aggregate load within a market, or an ITP's region, when an ITP is formed. It is appropriate to generally charge the rolled-in rate to all loads within such a market or ITP unless it can be shown that certain load "islands" exclusively benefit from certain upgrades."

[a]The SMD NOPR notes that "there is general agreement that these [interconnection] facilities should be directly assigned to the interconnecting generator." NOPR at P 194.

important role that state policy-makers and regional stakeholders should play in all aspects of regional transmission planning and the development of cost allocation guidelines.

Beyond wholesale cost allocations set by FERC, transmission owners or developers and the states could enter into an MOU outlining how the costs of transmission upgrades will be recovered, similar to the PacifiCorp Multistate Agreement on allocation of costs of certain generation assets. Agreement to participate from entities that are not under FERC's primary jurisdiction would increase the scope of the participating region. This is especially important in the West, where more transmission is owned by such entities.

Recognizing that reaching consensus on a broad regional cost allocation approach will be challenging and time consuming, transmission developers need to preserve the option to negotiate with the affected parties of a proposed project and retain the flexibility to opt out of a broader regional plan. Such flexibility will allow locally affected parties to reach consensus on a sub-regional solution to cost allocation in order to ensure timely development of needed transmission infrastructure.

Remaining Challenges

The most significant barrier to development and adoption of generally accepted guidelines for cost allocation in advance of transmission investment will be achieving a consensus on allocation rules that are viewed as fair both in the short term and over the long term. The willingness of parties to agree up front to a cost allocation mechanism may be affected by their views of how likely they are to be assigned costs in the future, and

Southwest Power Pool: Proposal for Regional/Zonal Sharing of Costs for Transmission Upgrades

In a FERC filing on February 28, 2005, and a press release issued on March 1, 2005, Southwest Power Pool, Inc. (SPP) provided the following description of a proposal for allocating the costs of transmission upgrades.

"Southwest Power Pool, Inc. (SPP) filed at FERC a joint proposal with the SPP Regional State Committee (RSC) to address transmission cost allocation for transmission upgrades. This significant proposal is in compliance with the February 10, 2004 SPP RTO Order that assigned the development of this proposal to the RSC. Following more than nine months of stakeholder effort the proposal was adopted by the SPP Board of Directors on January 25, 2005.

"The proposal prescribes a regional/zonal sharing of cost for new Base Plan Upgrades that have been identified by SPP as necessary to ensure the continued reliability of the SPP transmission system . . . .

"This proposal breaks new transmission expansion projects into four categories: (1) SPP Base Plan facilities; (2) economic upgrades; (3) generation interconnection facilities; and (4) facilities required to respond to transmission requests. As to SPP Base Plan facilities, SPP will allocate one-third regionally (above a $100,000 threshold). The remaining portion will be allocated locally to zones that are determined to benefit by use of SPP's longstanding incremental MW-Mile analysis. Economic upgrades, if constructed, will be allocated in accordance with agreements reached with project sponsors. Generation interconnection facilities and facilities required to respond to transmission requests will be allocated consistent with existing provisions of the Tariff, as it may be amended, though the Cost Allocation Plan provides a mechanism for network upgrades associated with certain designated network resources to be treated the same as Base Plan facilities."

whether they or others will reap the benefits of an investment. Parties have a tendency to focus more on near-term costs and benefits than on costs and benefits over the longer term. For example, in states or regions where transmission investment will provide high cost areas with access to low-cost generation, customers in the high-cost areas will be more willing to support a cost allocation mechanism that assigns them some of the transmission investment costs. Customers in the low-cost areas may be reluctant to agree to accept any portion of the cost of transmission investment that might raise their electricity costs, particularly at the same time that they may see prices rise as their local low-cost generation takes advantage of its new access to a higher cost area. A focus on the longer term costs and benefits, combined with a reasonable transition plan to any new cost allocation methodology, may help to mitigate concerns over such near-term cost shifts.

Recommendation 3b: Regions should use accepted economic and engineering models and develop clearly understood and accepted analytical procedures based on best practices, which (1) determine need and (2) identify costs and benefits of transmission expansion over a reasonable, near-term time period (e.g., 5 to 10 years).

Background

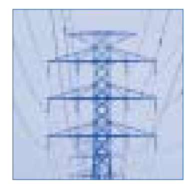
There is a need to identify current best analytical practices and make improvements where needed. There is also a need to develop broad regional buy-in for the tools that will be used. Data and analysis should be transparent, widely accepted, and publicly available (within the constraints of security and legitimate confidentially concerns). Several regions are developing models and mechanisms to assess need, including the following:

♦ The Seams Steering Group for the Western Interconnection (SSG-WI) has formed a model improvement work group to help identify and propose solutions to rectify shortcomings in existing models, such as poor modeling of hydro operations and accounting for bidding behavior (California ISO has done the most work in this area).

♦ California ISO has developed a model that looks at regional costs and benefits, as well as tradeoffs between generation sources and between transmission and generation investments. The ISO model is open to stakeholder input and used in public utility commission forums.

♦ MISO is developing a model and has looked at the California ISO, PJM, and SPP models for guidance. PJM, ISO-NE, and NYISO have models that are used to evaluate need, power system impacts, costs, and benefits of transmission expansion.

♦ In the Western Interconnection, production cost models have been used to evaluate the costs and benefits of transmission in the five-state Rocky Mountain Area Transmission Study region (Colorado, Idaho, Montana, Utah, and Wyoming), in the Southwest Transmission Expansion Plan (Arizona and Southern California), and in interconnection-wide planning by the SSG-WI. The RMATS modeling effort also relied on publicly available data to the support the analysis.

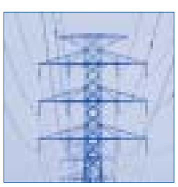


Implementation

Development of transmission planning models is likely to evoke considerable debate, with perceived "winners" and "losers" trying to advance their parochial interests. And the debate does not end with the adoption of a generally accepted modeling platform. Equally important to the outcome of the analysis of transmission needs, costs, and benefits are the data and assumptions used. To be successful, the adoption of the most appropriate regional models, the data, and the assumptions must receive buy-in from the parties involved, including regional planning entities, state policy-makers and public utility commissions, transmission owners and developers, consumers and environmental advocates, generators, and load-serving entities.

FERC could help the effort by conducting regional technical conferences open to all stakeholders, where best practices in analytical tools across regions would be identified in order to ensure basic consistency while respecting legitimate regional differences. The purpose of the technical conferences would not be to suggest a single national model, but rather to provide possible regional solutions with some level of coordination and consistency among the regions. The conferences should provide a schedule and structure for regional stakeholders to talk about the models and to learn more about the data and assumptions that go into each. Strong stakeholder involvement in this process would enhance the ultimate buy-in, and use of the resulting model(s) would have a presumption of acceptance as a result of the process that led to its adoption.

In the West, SSG-WI held one such technical conference in September 2004. It was not as broad-based as recommended here, but it did result in many suggestions for improvements to models[17] (although the status of follow-up on the ideas generated at the conference is uncertain). There is also an RTO/ISO Council that could facilitate assessment of best practices in areas with RTOs/ISOs.



In non-RTO/ISO regions or regions that contain both an RTO/ISO and TOs that are not part of the RTO/ISO, alternative hosts for such collaborative efforts would need to be identified. Possibilities include regional reliability councils that cover a large area and regional stakeholder transmission planning efforts convened by companies and/or states. DOE's Office of Electric Transmission and Distribution should play a constructive and supporting role in this effort.

Remaining Challenges

The Dialogue participants do not underestimate the time and commitment required to move beyond the selection of regional transmission planning models to implementation of a process that not only makes the model and its assumptions and data accessible and understandable but also invites debate and buy-in among stakeholders with an interest in the analytical outcome. As repeatedly emphasized throughout this report, however, an inclusive and transparent process is more likely to generate a better understanding and support of the need for transmission expansion and the long-term benefits to the region.

The Dialogue participants also debated the pros and cons of relying on publicly available data as a means of achieving greater transparency. While a number of stakeholders interviewed in the RMATS planning process stated that this was an important element in achieving buy-in to the model results, some Dialogue participants felt that the use of data that is confidential for both business and security reasons would provide more accurate results. The balance between transparency and accuracy will need to be settled on a region-by-region basis.

Recommendation 3c: RTOs/ISOs and their participating transmission owners (TOs) should agree that TOs will construct transmission identified by RTOs/ISOs as needed when reasonable conditions are met, including sufficient assurance of cost recovery and environmental and siting approvals.

Background

Although the Dialogue did not reach consensus on the question of whether there should be federal backstop authority on siting, as envisioned in proposed national energy legislation, they did agree that some mechanism is

[17] See web sites http://www.ssgwi.com/GeneralMeetingSummary.asp?mm=y&wg_id=3&mt_id=112 (for the first day of the conference) and http://www.ssgwi.com/GeneralMeetingSummary.asp?mm=y&wg_id=3&mt_id=113 (for the second day).

needed to help ensure that transmission expansion identified in regional transmission plans is built. Some of the RTOs/ISOs have the authority to order participating TOs to build transmission when it is needed either to ensure reliability, or to relieve chronic congestion, if, after a reasonable time period, transmission has not been built and other economic solutions have not been implemented. The authority is negotiated among TOs and the RTO/ISO, as was done by MISO, ISO-NE, PJM and California ISO.

In practice, some question the extent to which RTOs/ISOs actually have an ability to compel construction. There are several reasons for this perception. First, RTOs/ISOs do not have authority over siting and cost recovery for transmission facilities; therefore, they are powerless to guarantee the TOs recovery of their investment or to negotiate the siting process managed by the states or federal agencies (in the case of public lands). Second, RTOs/ ISOs are relatively new entities that have been focusing resources on near-term priorities, such as developing transmission plans and operating protocols.

Most importantly, the authority to compel construction must be based on a robust planning process that clearly identifies the need for new regional transmission. Two regional entities (PJM Interconnect and ISO-NE) have completed initial transmission plans for both reliability and economic constraints. When the plans are completed in other regions, however, each RTO/ISO must be prepared to use this authority to ensure the construction of needed transmission infrastructure.

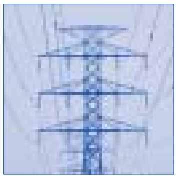
Implementation

The Dialogue recommends that the RTO/ ISO authority to require construction of needed transmission should be negotiated between TOs and RTOs/ISOs during the formation of the regional entities. The TOs will inevitably want to negotiate the conditions under which the obligation to construct new facilities can be enforced. Recognizing that RTOs/ISOs do not have the authority to guarantee cost recovery or siting approvals, TOs will need clear assurance of cost recovery from federal and state regulators and successful navigation of the siting process. For example, in the agreement between the TOs and ISO-NE, the parties agreed that the obligation to build new transmission facilities identified in the regional plan rests with the TOs, under the condition that the state and federal agencies provide just and reasonable recovery of the costs and return on the investment; local, state, and federal agencies provide any necessary siting, construction, and operating permits; necessary rights of way can be acquired; and required financing is available. If these conditions are met and a TO asserts that it is not in a position to construct needed facilities, whether for financial or other reasons, the TO should further agree to allow other means to have the project built. (For example, TOs in the Midwest incorporated such a provision in their agreement to organize the MISO, as detailed in the text box on page 48.)

Once transmission plans are developed, FERC could, on its own initiative, inquire about each RTO's use of available mechanisms to compel construction, in order to determine where it has been exercised appropriately. In addition, any party has the right to appeal to both the RTO/ISO and ultimately FERC if it believes such mechanisms are not adequately used.

Remaining Challenges

By signing an agreement on RTO/ISO authority to require construction, TOs are agreeing to raise the capital under whatever financial circumstances exist at the time, including the prevailing interest rates, regardless of whether the new facilities are consistent with the company's own strategic plans for allocating investment dollars. Therefore, the authority to compel investment in major new facilities should not be exercised without clear consensus, through the transmission planning



process, on the need for new facilities and a clear written agreement about the conditions that apply to the obligation to build. The Dialogue participants recognize that negotiating the appropriate conditions is not a simple task. For instance, the parties must agree on what constitutes "adequate time" to allow voluntary agreements to construct needed facilities. In addition, if assurance of cost recovery is needed, states may be required to provide some form of pre-approval, automatic pass-through, or other means of assurance that is not typical ratemaking policy. Finally, we recognize that even where the need for new transmission facilities has been identified, expansion may require investment in facilities that are not under the jurisdiction of an RTO/ISO or FERC.

If states outside of RTO/ISO regions would prefer to keep the obligation to build in the private sector, then a voluntary contractual agreement among TOs is required. States should play an active role in the development of these agreements, since they are integral to the cost recovery and siting decisions.

Recommendation 3d: DOE and FERC should organize a conference on best practices to provide information on the siting process and its relationship to stakeholders.

Background

States have varied processes for siting transmission, and within the latitude of those siting requirements, transmission developers have different approaches for interacting with the affected public, regulatory agencies, and political officials. Much can be learned by looking at the successes and failures of past siting experiences and extending the lessons learned to improve siting practices in the future. Drawing on and modifying workable existing models, project proponents can learn the best ways to work toward gaining community buy-in by understanding local concerns and to meet local needs with appropriate consideration of the constraints of technical acceptability and overall costs to customers.

Midwest ISO: Alternate Arrangements for Transmission Construction

The "Agreement of Transmission Facilities Owners To Organize the Midwest Independent Transmission System Operator" includes in its Appendix B ("Planning Framework") the following language concerning identification of needed transmission and the responsibility for its construction:

"If the designated Owner is financially incapable of carrying out its construction responsibilities or would suffer demonstrable financial harm from such construction, alternate construction arrangements shall be identified. Depending on the specific circumstances, such alternate arrangements shall include solicitation of other Owners or others to take on financial and/or construction responsibilities. Third-parties shall be permitted and are encouraged to participate in the financing, construction and ownership of new transmission facilities as specified in the Midwest ISO Plan. In the event interest among other Owners or other entities is not sufficient to proceed, all Owners, subject to applicable regulatory requirements, shall be responsible for sharing in the financing of the project and/or hiring of a contractor(s) to construct the needed transmission facility; provided, however, the Owners' obligations under this sentence shall be subject to the Owners being satisfied that they will be compensated fully for their investments and will not be subject to additional regulatory requirements . . . ."

State Infrastructure Financing Authorities

A number of states have legislatively created state and quasi-state financing authorities capable of issuing revenue bonds to finance and direct the construction of major infrastructure projects. In some states, such authorities are created specifically to help facilitate transmission construction (an example is the Wyoming Infrastructure Authority). In other states, they are given a broader mandate and may finance a range of projects, from wastewater treatment plants to natural gas pipelines (an example is the Kansas Development Finance Authority).

In most cases, state financing authorities have been created to act as the "last resort" source of funding when the private sector does not step forward to build needed infrastructure. In the case of pipeline infrastructure, for instance, the need for state infrastructure authority was triggered when major investors such as Dynegy and Enron faced bankruptcy, and the pipeline industry and producers were unable to fill the financial gap.

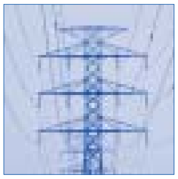
Some argue that, in areas that have not voluntarily formed RTOs/ISOs, the mere existence of these authorities, coupled with the possibility of state ownership and operation of new transmission facilities, is in itself adequate to bring forth collaborative efforts and private investment to resolve the problem. Montana, on the other hand, adopted and later repealed through a state-wide referendum a law creating the Montana Power Authority. The Montana legislature also rejected a later proposal to use state revenue bonding authority to finance coal development. Some opponents of the proposal argued that the private sector had adequate investment capability.

Implementation

FERC, in conjunction with other entities, such as DOE's Office of Electric Transmission and Distribution and Office of Energy Assurance, should organize a conference on best practices to provide information on what a good siting process entails and highlight issues that need to be considered, including discussions of specific mitigation measures. Participants should include transmission companies, state agencies, federal agencies, utilities, environmental and community organizations, local government representatives, and participants familiar with both successful and failed siting experiences.

Subjects to be addressed at such a conference should include, but not necessarily be limited to:

- ♦ A transparent siting process that provides for consultation with and input from state and local public officials, affected communities, abutters, and electricity consumers early in the siting process
- ♦ Giving attention to the concerns of the public including abutters, state and local government officials, public interest groups, and other interested parties
- ♦ Information about electromagnetic fields (EMF)
- ♦ Discussions of how to assess and communicate the need to build transmission
- ♦ Case studies of successful and unsuccessful siting experiences
- ♦ Technologies available to transmission builders, including different types of overhead conductors and underground cables and their respective reliability and cost characteristics
- ♦ Consideration of a range of reasonable transmission solutions that are economical for consumers and technically feasible, take into account practical issues with route selection



(e.g., wetland areas, historic buildings), and are within a public utility's ability to perform

♦ Discussion of the decision-making process on building transmission in both restructured markets and traditionally regulated areas

♦ Technologies to increase transfer capacity within existing rights-of-way

♦ Potential costs and benefits of mitigation measures to transmission customers and stakeholders.

Remaining Challenges

Gathering information and experience from different regions of the country through a peer exchange conference is the first step. The second and equally important step in the process is disseminating the lessons learned at such a conference beyond the attendees to other stakeholders in the region, as a way of facilitating buy-in. For this step to be effective, FERC and DOE would have to determine the best method to facilitate broader distribution and implementation of best practices emerging from such a conference.

Some might argue that the federal government may not be in the best position to organize a conference on state and local siting practices, particularly in the midst of a heated debate over the role of the federal government in transmission siting. However, FERC's experience in overseeing natural gas pipeline siting practices and DOE's interest in national transmission reliability make these agencies the natural choice to facilitate development of a consolidated information base on siting practices that states and localities can use to reevaluate their current practices in the face of ongoing change in the electricity industry.

Recommendation 3e: FERC should direct each RTO/ISO to work with regional stakeholders to develop workable and equitable mechanisms for providing long-term financial transmission rights or other appropriate instruments that provide transmission customers effective financial hedges against transmission congestion costs.

Background

Federal electricity policy is increasingly reliant on a competitive market model. One outgrowth of this policy shift is the manner in which use of the transmission system is allocated. In each of the existing RTOs and ISOs, transmission is provided on an "as needed" basis, with load-serving entities allocated financial transmission rights (FTRs)[18] to provide a financial hedge against potential cost fluctuations resulting from congestion. FTRs are allocated on the basis of historic load and usage, and issues have been raised about long-term FTRs for existing and future load. This transmission paradigm differs from the "regulated model," in which parties contracted for physical transmission rights (either short-term or long-term) at a specified price, subject to regulatory review and approval.

One challenge created by the migration to a market-based transmission system is the inability to secure FTRs for more than a few years. Currently, long-term FTRs are available in some markets for incremental transmission investments, but long-term FTRs that reasonably hedge against future congestion costs are not available currently. As a result, long-term power supply arrangements (whether wholesale power purchases

[18]An FTR is a market financial instrument that provides for a payment to the holder equal to the difference in Congestion Component of the Locational Marginal Prices between the source of the FTR and the sink of the FTR. The source of an FTR does not have to correspond to a generator and the sink of the FTR does not have to correspond to a load. As such, the FTR may not correspond to an actual physical injection of power at the source and an actual physical withdrawal of power from the system at the sink. To assure revenue adequacy of the RTO, the RTO checks that the FTRs assigned do not provide financial rights on elements of the transmission system in excess of the capacity of those elements. If the system is dispatched optimally and assuming no changes to the transmission system, theoretically the congestion rents collected will be adequate to make the FTR payments.

or generation investments) are frustrated, because the long-term cost of congestion is unknown. Providing long-term firm transmission service at predictable prices will remove one barrier to cost-effective long-term customer power supply contracts and generation investment, so that potential investors will (1) know what rights and obligations will follow their investment, (2) have access to the information they need to evaluate the economic viability of their investment, and (3) receive the assurances needed to support financing.

Adoption of this recommendation may cause disputes in some regions. For example, some parties may argue that the resulting assurances could cause cost shifting to other users of the transmission system, especially if sufficient physical capacity is not added to the transmission system to support long-term FTRs. Some parties also may argue that long-term FTRs will reduce the liquidity of the short-term financial rights markets. On the other hand, load-serving entities depend on long-term transmission service at predictable prices in order to provide reliable electric service at reasonable rates. Further, the policy goal of making long-term FTRs available could provide incentives for the construction of new transmission lines or other transmission upgrades, especially for those parties who otherwise might face cost shifts or for load-serving entities that want to ensure sufficient transmission capacity to accommodate long-term FTRs. The Dialogue participants believe that these issues can be resolved through a FERC process or during regional deliberations among stakeholders in the development of reasonable solutions.

Physical delivery capacity is determined by the RTOs' transmission planning criteria. The RTOs' FTR allocation processes are linked to their planning processes, to the extent that the availability of FTRs depends on the characteristics of the transmission system and those characteristics are determined by the RTOs' transmission planning processes. In particular, it is important to recognize that RTOs/ISOs allocate FTRs according to physical deliverability of electricity from generators to specific load centers. Issues have been raised about sufficient supply of long-term FTRs for existing and future load, primarily because RTOs' and ISOs' planning criteria do not necessarily require physical deliverability of electricity from generators to specific load centers. Instead, RTOs may plan only according to the deliverability of generation to the market instead of specific load centers. Thus, some industry stakeholders may wish to ensure that the RTOs' planning requirements and requirements for allocating long-term FTRs are consistent.

"Local opposition will always be a problem, but utilities would be better to acknowledge it rather than crush it or dismiss it."
– Consumer advocate

Implementation

Serious consideration needs to be given to the creation of transmission planning processes and FTR allocation methods that accommodate long-term FTRs in RTO/ISO regions, so that transmission customers can secure long-term FTRs in a manner that recognizes the physical limitations of the system, supports new generation investment, and provides certainty for load-serving entities seeking long-term purchase power arrangements. FERC should direct each RTO/ISO to work with regional stakeholders to develop workable and equitable mechanisms to provide transmission customers with long-term hedges against congestion costs. Potential options could include serial issuances of shorter-term FTRs with a right of first refusal, or long-term FTR allocations corresponding to investments.

Remaining Challenges

Despite some of the advantages of creating long-term FTRs, there are a number of issues that must be addressed in the design and implementation. For instance:

♦ The inherent uncertainties in the future configuration and operation of the system will decrease the certainty of the simultaneous feasibility calculation,[19] thereby making long-term FTRs more prone to a financial pro-ration sometime in the future and decreasing the certainty of the value of the FTR. Furthermore, an FTR that looks attractive today could result in assigning the holder a significant counterflow obligation[20] in the future.

♦ Alternatively, if the market rules determined that the long-term FTR would hold its electric power (megawatt) and financial value, policies would have to be developed to determine which parties should pay to make the FTR whole. This would likely be highly controversial.

♦ The mechanism may tend to create a new equivalent to a "grandfathered" agreement, as market participants may oppose any changes in the market design or transmission system configuration that could impact the value of the FTR. This could include any FTRs held for arbitrage opportunities, whose holders may oppose addition of transmission that would decrease the value of the FTR.

♦ Long-term FTRs may tend to decrease the opportunities for others to trade FTRs on a shorter-term basis to hedge congestion costs for unit outages and short-term changes in the procurement of energy.

♦ The market for long-term FTRs may prove to be illiquid, due to their uncertain value.

[19] A market test to ensure that the transmission system can support the subscribed set of financial transmission rights for a defined set of system conditions. The test models the flow according to the megawatt values of the requested financial transmission rights and calculates whether the financial transmission rights can be supported without creating a transmission system overload.

[20] A financial obligation held by a market participant that requires scheduling power to flow in a direction on a transmission facility so as to decrease the net flow on the facility. If the market participant does not schedule a transaction that decreases the flow, it is required to pay others to do so.

Appendix A
List of Participants

Charles Acquard, Executive Director, National Association of State Utility Consumer Advocates

*John Anderson, President and CEO, The Electricity Consumers Resource Council

*Larry Bruneel, Vice President of Government Affairs, International Transmission Company

*William Burlew, Manager of Federal Affairs, American Transmission Company

Edward Comer, Vice President, Edison Electric Institute

*Shelley Fidler, Principal, Van Ness Feldman

*Peter G. Flynn, Deputy General Counsel, National Grid

Arlyn Fredrick, Senior Transmission Policy Specialist, American Transmission Company

Bert Garvin, Commissioner, Wisconsin Public Service Commission

*Craig Glazer, Vice President, Governmental Policy, PJM Interconnect

*Charles Gray, Executive Director, National Association of Regulatory Utility Commissioners

Dan Griffiths, Senior Public Policy Analyst, Pennsylvania Office of Consumer Advocates

Dede Hapner, Vice President, Regulatory Relations, PG&E Corporation

*Joseph Hartsoe, Managing Director, Federal Policy, American Electric Power

Jolly Hayden, Vice President, Transmission Operations, Calpine Corp.

*Jessica Holliday, Manager, Partnership for Climate Action, Environmental Defense

Marty Kanner, President, Kanner & Associates

Will Kaul, Vice President, Transmission, Great River Energy

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Robin Kittel, Director of Market Relations, Xcel Energy

Doug Larson, Western Interstate Energy Board Member, Western Governors Association

*Larry Mansueti, Director, Electric Markets Technical Assistance Program, Office of Electric Transmission and Distribution, U.S. Department of Energy

*Bill McKinnon, Director, Transmission Business Development, Northeast Utilities

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Diane Munns, Chairperson, Iowa Utility Board

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*Beth Soholt, Director, Wind on the Wires

Julia Souder, Program Manager, Office of Electric Transmission and Distribution, U.S. Department of Energy

Dave Svanda, Principal, Svanda Consulting

*Glen Thomas, Commissioner, Pennsylvania Public Utilities Commission

David Withrow, Lead Policy Analyst, California ISO

Jeff Wright, Chief, Energy Infrastructure Policy Group, Federal Energy Regulatory Commission

* Steering Committee member.

Appendix B
BLM Process for Corridor Identification

Certain Federal public land managers in the western U.S. are currently required to identify, analyze and, where appropriate, designate corridors pursuant to existing legislative mandates. These Federal managers are conducting this planning for well over 200 million acres of public lands in the western U.S. These corridor designation efforts are part of larger comprehensive land use planning efforts and are scheduled to continue for the foreseeable future. Where these land use planning efforts are currently taking place, the great majority of the lands being considered for corridor designation have existing right-of-way uses currently on the lands. The corridor identification and analyses are primarily focused of the appropriate future widths and compatible uses of the corridors when designated. "New" lands are identified and analyzed on an as need basis when refinements to existing transmission facilities is considered an inappropriate future land use.

It is recognized that public land managing agencies do not usually have the expertise needed to identify the location and compatible uses of the corridors; therefore a wide spectrum of stakeholders are brought into the corridor identification process, including relevant Federal agencies, local utilities, and other electrical transmission line operators, State Utility Commissions (or their functional equivalents), State or Regional Siting Authorities, Tribal Governments, public interest groups and private citizens. These stakeholders provide to the public land managers what they perceive to be the best location for the corridors, the width of those corridors, land uses that will be compatible with corridor uses and those land uses that are discouraged and where possible prohibited. In determining the corridor locations, widths and compatible uses, the stakeholders are asked by the public land managers to project their needs and concerns for time periods extending 15 to 20 years in the future.

Designation of corridors on federal lands can potentially channel transmission uses onto adjacent and nearby (adjacent) non-federal lands. This potential channeling can be viewed as establishing "de-facto" corridors on the adjacent non-federal lands. For non-federal landowners who do not anticipate using their lands for siting purposes, the establishment of the de-facto corridors is seen as de-valuing their lands. This tension between designating corridors by federal agencies on federal lands when determined to be an appropriate land use allocation through their land use planning process is recognized. To meet this challenge in a way that allows the federal agencies to meet their land use planning mandates and to not potentially de-value the adjacent non-federal lands, comprehensive negotiations take place with the adjacent landowners and other stakeholders during the corridor identification and analysis stages of the land use planning efforts. However, as noted above, most of the federal lands being considered for corridor designation are currently experiencing various right-of-way uses. In many situations the adjacent non-federal lands will also be experiencing various right-of-way uses. When federal lands or adjacent non-federal lands are experiencing right-of-way uses, the potential to de-value the non-federal lands by the designation of a corridor on the federal lands may be less than where new corridors are being proposed.

When a land use planning process determines that a corridor is an appropriate use of federal land, a land use decision is made by the agency. The land use decision allocates the lands within the described corridor for transmission and other compatible uses. Conflicting land uses are strongly discouraged or prohibited as appropriate. The land use decisions are published and made available to the public in various formats. Most of these decisions are placed on agency web sites and are usually mapped. After the decisions are made and published, routine inspections of the lands help ensure that unauthorized land uses do not occur.

Appendix C
Case Studies of Regional Transmission Constraints

Purpose and Selection of Case Studies

At the first plenary meeting, Dialogue members reviewed and selected several transmission congestion corridors as case studies to help identify the primary barriers to enhancing the transmission network. These case studies were selected based on a number of criteria suggested by the steering committee, including projects that:

- Represent a range in geographic and topographic scope
- Are within different market structures
- Represent both reliability & economic congestion problems
- Are at different stages of resolution
- Demonstrate lessons learned that are transferable or provide important insights
- Involve barriers considered high priority by the Dialogue group

The purpose of the case studies was to illuminate through interviews of regional stakeholders the nature of the congestion problems, the interests of the various stakeholders affected, the challenges that need to be addressed to relieve the congestion, and any lessons learned that might be applicable on a regional or national basis.

Through a voting process, the Dialogue participants selected three current transmission congestion problems (Maine to Massachusetts, Minnesota to Wisconsin, and the Rocky Mountain area) and one case study where the congestion problem has been resolved (California Path 15). Below is a summary of the information gathered through the interview process about each of the case studies and the observations drawn from them by the Dialogue Group. Through discussion and prioritization, the Dialogue participants used the information from the case studies to identify and select the most important challenges that are the focus of recommendations contained in this report.

Over 60 stakeholders, representing state regulators, consumer advocates, regional transmission organizations, transmission owners, and environmental organizations, were interviewed in the four regional case studies. (See Appendix 5 for a list of interviews and interview questions.) The Phase I Workgroups reviewed the results of the interviews and developed their list of major barriers based on both their own experience and the information provided by the interviews.

The following pages outline the results of those stakeholder interviews. They informed the overall Dialogue, but do not represent the final recommendations of the Dialogue participants.

Results of Regional Case Studies

Case Study I: Northeast - Maine to Massachusetts

Workgroup Members

Peter Flynn, National Grid; Craig Glazer, PJM; Joe Hartsoe, AEP; Jessica Holiday, ED; Mike Jacobs, AWEA; Bill McKinnon, Northeast Utilities; Camilla Ng, FERC

Characterization of the Transmission Congestion

The problems with between Maine and Boston was described as two problems:

1. The constraint between Maine and New Hampshire prevents generation in Maine from getting to markets in southern New England. This bottled-in generation keeps LMP lower within the state than in other parts of the region. The proposed expansion of the New Brunswick, Canada to Bangor Hydro transmission intertie may provide an increased opportunity for power exports from Maine to Canada.

2. There are also constraints in transmission capacity bringing power into Boston. Several of those interviewed suggested that proposed transmission expansion south of Boston to the Rhode Island border, combined with the transmission enhancements north of Boston would relieve the most immediate reliability problems and would provide access to more economic generation in Rhode Island.

There was general agreement that the Maine to New Hampshire congestion was an economic congestion problem. The primary beneficiaries of transmission expansion in this corridor would be load centers in Massachusetts and generators in Maine (natural gas, biomass and undeveloped wind generation.) The ISO-New England (ISO-NE) 2004 Regional Transmission Expansion Plan did not identify this congestion as a reliability problem, but did provide data regarding the number of hours the region experienced higher than average LMP. Although there is data documenting the congestion, no formal proposals have been made to relieve the constraint between Maine and New Hampshire. ISO-NE has not identified it as a priority. In addition, stakeholders interviewed generally did not think the congestion problem was pressing, but a few thought it was likely to develop into a reliability problem in the future.

Market Structure & Major Players

Although not required, most utilities have divested their generation assets in New England. Current transmission owners in the region include Northeast Utilities, National Grid, Vermont Electric & Light Company, NStar, Central Maine Power, United Illuminating and Bangor Hydro. New England is also home to a merchant transmission project (Cross Sound Cable) that was built in 2003-04. Another merchant project was proposed to address Maine to Massachusetts constraints, but has not been funded or built.

ISO-NE has established a Locational Marginal Price (LMP) system, which is designed to provide market price indicators of where there are constraints in transmission. ISO-NE, formally approved in 1997, develops annual Regional Transmission Expansion Plans (RTEP). In the past, the RTEP was based primarily on consolidation of transmission owners expansion plans, but continues to evolve into more independent analysis of regional transmission need. The focus of the RTEP has been identification of reliability needs, most recently constraints in Southwest Connecticut which is being addressed by a project under development by Northeast Utility and the congestion in Vermont which will be resolved by a project proposed by VELCO.

Bulk power transmission expansion costs are recovered through a FERC-approved tariff which spreads costs among the region's load-serving entities in rough proportion to their sales. Maine and Rhode Island unsuccessfully appealed for reconsideration of the FERC approval.

Summary of Top Issues from Northeast Workgroup

NEED

Despite general recognition of a congestion problem between Maine and New Hampshire, stakeholders felt the congestion problem was not urgent enough to attract investment. This raised the question of what criteria should be applied to determine when congestion becomes a regional problem worth addressing.

While there are strong proponents of market driven investments, others questioned whether short-term LMP signals are adequate for enticing investment in regional transmission expansion. A number of those interviewed argued that market signals should be accompanied by a regional transmission needs assessment and planning process such as currently exists under the New England regional transmission expansion plan (RTEP) process

The RTEP identifies the need for transmission upgrades to maintain reliability or to relieve congestion. The market then has an opportunity to act on that information by building market-based projects, such as new generation. If the market appears unlikely to resolve the problem, however, the RTO can approve regulated transmission upgrades to maintain reliability or to relieve congestion.

COST RECOVERY

Independent System Operator - New England (ISO-NE) has a FERC-approved tariff which allocates the cost of bulk power transmission investment to all regional loads. Most stakeholders viewed this cost-recovery formula as an important factor in encouraging investment in regional transmission for reliability needs. Several stakeholders claimed that the lack of similar cost-recovery rules for non-transmission solutions created a bias toward transmission expansion. This cost-recovery approach has not yet been applied to economic upgrades in New England.

SITING & PERMITTING

Landowner sentiments to restrict new lines, and more specifically the desire by localities to have transmission buried is proving to be a major impediment in more developed areas of the country. Aesthetics, safety and environmental concerns will continue to have a place in siting decisions, but there is no policy on how to weigh these social values against the additional costs or how to allocate costs among local and regional ratepayers.

PROCESS

Unequal distribution of benefits and costs (both cost allocation and the impact of changes in LMP) of regional transmission upgrades has led to continued disagreement among states about the cost allocation for economic upgrades to transmission facilities. With siting and cost recovery authority resting with the states and local governments, and planning authority resting with the ISO-NE, there is currently no way to resolve the differences between state interests and regional need. Political leadership and buy-in from affected stakeholders is essential.

INNOVATIONS

A number of developments in the Northeast were mentioned by stakeholders interviewed as having the potential to improve the process and outcomes in efforts to address congestion in the region:

Regional State Committee (RSC). The recent proposal to develop a Regional State Committee (RSC) made up of representatives from each state to work more closely with the ISO-NE transmission planning process may be one step toward resolving disputes between the states over cost allocation. However there was not agreement that this step alone was adequate.

Cost Allocation Policies. ISO-NE's & PJM's cost allocation policies were cited as examples of regional cost allocation guidelines that recognize the broad benefits of "backbone" transmission infrastructure by spreading the costs to all electricity consumers in the region.

Legislative Proposals. Massachusetts legislation authorizing the state siting council to recognize regional need may be a model for other states that have regulatory or legislative language which restricts the state to consideration of only direct and immediate benefits for the state.

Case Study II: Midwest – Wisconsin/Minnesota Interface

Workgroup Members

Larry Bruneel, ITC; Bill Burlew, ATC; Craig Glazer, PJM; Chuck Gray, NARUC; Joe Hartsoe, AEP; Will Kaul, Great River Energy; Robin Kittel, Xcel Energy; Larry Mansueti, DOE; Diane Munns, Iowa PUC; John Procario, Cinergy; Ron Snead, Cinergy; Beth Soholt, Wind on the Wires; Glen Thomas, Pennsylvania PUC

Characterization of the Transmission Congestion:

The Midwest ISO frequently invokes Transmission Loading Relief (TLR) curtailments to scheduled transactions which cut or reduce those scheduled transactions to address congestion on constraining lines, though this is rarely for transactions for which firm transmission service has been reserved. One of the reasons that the Midwest ISO is transitioning to its so-called Day 2 market structure is that the TLR mechanism for controlling flows on network transmission lines is an inefficient instrument for congestion management, in some instances requiring hundreds of megawatts of transaction cuts to achieve tens of megawatts of line loading relief.

Market Structure & Major Players:

There are three elements of market structure in the Midwest that heavily influence transmission issues.

- **Separation of generation and transmission:** Wisconsin has allowed separation of transmission and generation ownership, other states do not. Wisconsin has a stand-alone transmission company in the American Transmission Company (ATC). ATC was created when the state legislature allowed five local utilities to divest transmission, in exchange for equity interests in the new company and positions on the board of directors. On the other hand, in surrounding states, including Minnesota, companies can have both generation and transmission. Many of those interviewed agreed that the ATC model seemed to be an effective one.
- **Arrowhead-Weston line:** One of the biggest transmission issues in the area revolves around this project. While certain parties debated the merits of the Arrowhead-Weston project, the project was approved by the Wisconsin PSC and re-approved by the PSC after new capital cost estimates proved to be well above those originally approved. The PSC concluded that no other alternative solution provided the range of benefits that the Arrowhead-Weston project did. Other alternatives may be been cheaper, but they did not provide the reliability benefits.

Characterization of the Transmission Congestion

According to many stakeholders interviewed, much of the congestion in the Midwest is the result of lack of new transmission investment in the Wisconsin-Minnesota interface, also described as part of the interface between two reliability councils, the Mid-Continent

Power Pool (MAPP) and the Mid-America Interconnected Network (MAIN).[1] The Minnesota-Wisconsin interface has often been identified as a critical congestion point in the electric grid. The construction of the Arrowhead-Weston transmission line and several other lower voltage system reinforcements on the ATC system is expected to relieve the constraint.

The main transmission element in the Wisconsin-Minnesota Interface is a 345kV line from east of Minneapolis to central Wisconsin (the King-Eau Clair-Arpin line). Given the topology of the transmission network in the Midwest, this line can constrain transactions from virtually anywhere within the MAPP region to markets south and east of the MAPP region. It is expected that many constraints will be addressed by the Arrowhead-Weston project and other ATC system reinforcements. However, completely relieving constraints in the upper Midwest will require reinforcements to the transmission system in other states besides Wisconsin.

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Market Structure & Major Players

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- **Separation of generation and transmission:** Wisconsin allows separation of transmission and generation ownership, other states do not. Wisconsin has a stand-alone transmission company in the American Transmission Company (ATC). ATC was created when the state legislature allowed five local utilities to divest transmission, in exchange for equity interests in the new company and positions on the board of directors. On the other hand, in surrounding states, including Minnesota, companies can have both generation and transmission. While the system in Wisconsin was viewed favorably, the differing structures between states and regions have made interstate expansion more difficult.
- **Midwest ISO (MISO):** Regional planning is coordinated by MISO. MISO develops the MISO Transmission Expansion Plans (MTEP), which is essentially a consolidation of transmission owners' expansion plans. However, it is building

[1] In 2005, the Midwest Reliability Organization (MRO) became operational and replaced the MAPP Regional Reliability Council of the North American Electric Reliability Council (NERC). This has resulted in a more effective and efficient reliability organization to administer and enforce reliability standards across a broader geographical region in the Midwest part of North America. For more details, see www.nerc.com/regional/mro.html.

toward more independent analysis of regional transmission need. The primary focus of the MTEP recently has been the identification of reliability projects.

- **Organization of MISO States (OMS):** Unique to this region is the Organization of MISO States, which consists of 14 state regulatory utility commissioners and the province of Manitoba, within the MISO footprint, that regulate members of the Midwest Independent System Operator (MISO). OMS was organized in 2002 to establish a voluntary regional approach to addressing energy issues.

Summary of Top Issues from Midwest Work Group

The Midwest Work Group identified a number of important issues that are potential obstacles to investment in the transmission grid.

NEED

Participants in the Midwest Workgroup and many interviewees from the region viewed the concept of a stand-alone transmission company (i.e., ATC) as an effective model for financing and implementing transmission. Independent transmission companies (hereafter "transcos") clearly define where transmission needs to be built, and where they plan to build.

Outside of ATC's transmission network, there is greater uncertainty about how the need for regional transmission will be identified and implemented. Systems in place in such states to construct new transmission are understood by individual generators and transmission companies and the respective state public utilities commissions, but are opaque to outsiders. From a regional perspective, MISO combines expansion plans from individual companies in a "bottom-up" process and combines them into a regional plan. Stakeholders interviewed suggested that the bottom-up process is inadequate to develop a truly regional plan for economic or reliability upgrades, and many suggested that a region-wide look (i.e., a "top-down" approach) might result in better decisions.

COST RECOVERY

Many stakeholders interviewed identified cost recovery is a key concern for transmission owners because approximately 90% of costs are currently recovered through after-construction, state-by-state prudence reviews and rate cases. When state regulators determine cost-recovery based on direct and immediate benefits to the state's ratepayers, there is a risk that a portion of the investment and return will not be recovered. MISO has not yet developed policies for regional cost recovery, and it may be difficult to reach consensus among the region's stakeholders.

SITING & PERMITTING

State-by-state siting authority exacerbates the risk of building regional transmission projects. The workgroup pointed out the lack of incentives for states that do not receive direct benefits to approve the necessary permits or coordinate regional siting. There was disagreement about the extent to which Federal regulators should be allowed to intervene in contentious siting issues. However, the Workgroup felt that a strong system for incorporating local input from multiple stakeholders into the process would facilitate siting issues and must be in place

PROCESS

In some states like Minnesota, there are multiple agencies addressing need, siting, and rate recovery, which results in lengthy, duplicative and costly administrative processes. There are efforts underway to streamline these process issues in Minnesota.

Many interviewees noted that MISO seemed too large a footprint for some of the planning and coordination functions. There are some efforts underway to examine whether to split MISO into three sub-regional planning functions. It was also noted that MISO as an institution is developing, and has not fully implemented its coordinating role. Many in the Workgroup felt that in time it would adequately coordinate planning functions, as in the PJM Interconnect.

INNOVATIONS

Workgroup participants and interviewees suggested several potential innovations to address some of the transmission constraints in the area.

Highway/byway tariffs. The concept of a highway/byway tariff is one that is under consideration in the Midwest. The essential idea is that high voltage (and often multi-state) transmission lines should be paid for by all potential customers within its footprint. Lower voltage lines, which essentially serve just local communities, would be paid for by the particular community. While many liked this concept, stakeholders frequently raised the concern that the "devil is in the details," for example, determining how to allocate costs of some low voltage lines that are used for long-distance transmission.

One-stop shopping. In some states, such as Minnesota, there are separate hearings for need determination, siting, and rate recovery, which lengthen the time to develop new lines. There was strong sentiment for a single state agency should have jurisdiction over siting, need and cost recovery, and it was suggested that this is under consideration within the relevant state agencies.

Sub-regional planning. There is a general sense among participants that the MISO region and the proposed consolidation with PJM will create planning regions spanning broad geographic areas which have sub-regional differences. Many noted that identification of need would be more effective if sub-regional plans on a smaller geographic scale are developed from a "bottom-up" approach, and these could be included in the "top-down" planning by the RTO. The combination of the bottom-up and top-down planning inputs would then be used to develop a single regional plan. MISO is considering a proposal to split planning into three sub regional areas.

Case Study III: Rocky Mountain Area Transmission Study (UT, WY, CO, ID, MT)

Workgroup Members

Dede Hapner, PGE; Robin Kittel, Xcel; Doug Larson, WGA WIEB; Ron Montagna, BLM; David Withrow, CA ISO

Characterization of Transmission Constraint

The main driver for expanding transmission capacity in the region is the desire to access lower cost wind and coal resources predominately found in Wyoming and Montana. This will enable fuel diversity to both meet load growth within the region and to export power to other regions.

Other transmission expansion drivers identified were 1) economic growth in the west; 2) deregulation beginning in 1994-95, which caused utilities to slow their investment given the uncertainty of cost recovery; and 3) "paper congestion," which is the appearance of congestion based on the existence of bilateral contracts and contract path scheduling that gives priority to firm transmission rights. Transmission rights are being held but not used, according to many of those interviewed. In some cases unused transmission is released at the last minute in spot markets, but there is not a liquid market for transmission. Contract path congestion was raised as a problem by a number of stakeholders, who sited studies that indicate there is less physical congestion than assumed in the Rocky Mountain Area Transmission Study (RMATS), and some of the physical congestion is loop flow which is difficult to manage given the current method for assigning rights to the transmission system. Some argued that for these reasons it has not been adequately demonstrated that the existing transmission system is being used efficiently.

Market Structure & Major Stakeholders

RMATS was initiated August 2003 by Wyoming Governor Dave Freudenthal and Utah Governor Mike Leavitt as a voluntary transmission planning effort covering the states of Wyoming, Utah, Colorado, Idaho, and Montana. The objective was to identify and evaluate the generation and transmission options for serving electricity needs of the region. The RMATS report outlining transmission priorities for meeting regional load and accommodating exports was released Sept. 2004.
(http://psc.state.wy.us/htdocs/subregional/meet.htm)

In the past, transmission investment was driven by the location of new generation and its relationship to loads. RMATS is looking at the regional benefits of an integrated approach for the first time. The preferred solutions, according to a number of those interviewed, are ones that balance generation diversity and lowest cost.

The transmission owners in the region are integrated utilities: PacifiCorp, Xcel, Western Area Power Authority (WAPA), Northwestern Energy, Bonneville Power Authority (BPA), Basin Electric, Wyoming Municipal Power Agency, Tri State Generation and Transmission (G&T) serving municipal utilities, Idaho Power, Utah Associated

Municipal Power Systems, and Deseret G&T. Cost recovery decisions regarding transmission investments are primarily handled by state utility regulators. Several states have requirements for utility Integrated Resource Planning or least cost planning of generation and transmission facilities. Few of the states have state siting agencies or committees. Permits for siting are typically issued by the local governments.

Over 50% of the land in the RMATS region is public land managed by federal land managers or tribal governments.

There is no RTO/ISO in the Rocky Mountain states. The California ISO (CA-ISO) is the only RTO-like organization in the Western states, although efforts to develop other RTOs (Grid West/ RTOWest, WestConnect) have been under consideration. Transmission scheduling is done under standards set by the Western Electricity Coordinating Council (WECC), based on contract paths, e.g., bilateral firm transmission agreements. Unused transmission capacity can be released for sale in the day ahead spot market, but sometimes is simply held off the market and goes unused. WECC also has a FERC-approved unscheduled flow mitigation plan that is used to manage congestion caused by the contract path scheduling system.

Summary of Top Issues from RMATS Workgroup

NEED

Lack of efficient use of the current transmission system because of the way transmission rights are allocated and scheduled in the RMATS region makes it difficult to identify "real" need. Opponents of transmission often argue that the constraints are "paper constraints" not physical constraints, therefore new transmission is not justified. Analytical models used in RMATS were based on the assumption of a fully competitive market and the most efficient use of the transmission system.

COST RECOVERY

Under the current market structure, participant funding is the likely method for cost recovery of multi-state regional transmission expansion, however identifying beneficiaries becomes more contentious and analytically difficult the longer and the more complex the project. Cost recovery of transmission designed to accommodate exports from the region appears to be particularly unwieldy under the participant funding model and an impediment to investment.

SITING

Siting transmission on public and tribal land was identified as a potential impediment because of the lack of coordination among the various agencies with overlapping jurisdiction, insufficient land management agency resources, and the divergence of interests among the federal land agencies, the tribes and the states. While efforts are under consideration to address this, it remains a concern.

PROCESS

There was almost unanimous agreement that the factors contributing to the progress made in the RMATS process were its "clean sheet" approach, high level political leadership and transparent and inclusive analysis. However, there is a concern about the ability to sustain a regional planning effort under this multi-state voluntary model.

Regional transmission planning and investment is hindered by several key factors: 1) the disconnect between transmission planning and generation development, 2) the difference in timeframes between transmission and generation construction, and 3) the lack of coordination between the transmission owners, load serving entities least cost planning, public land managers and the RMATS multi-state planning effort on the planning time horizons.

INNOVATIONS

- U.S. Bureau of Land Management's (BLM) Programmatic Environmental Impact Statement (PEIS) on western energy facilities corridors initiated to help consolidate and streamline the transmission construction permitting process for facilities on public lands
- RMATS "clean sheet" approach to transmission need analysis
- Wyoming Infrastructure Authority and other state financing approaches
- Western Governors Association's (WGA) Transmission Siting Protocol
- Conditional firm transmission rights proposed by wind advocates to address the dilemma of intermittent renewable resources that currently only have two options for transmission access – firm or interruptible transmission rights
- Colorado's legislation giving transmission developers the right to appeal local government decisions on transmission siting.

Retrospective Case Study IV: California – Path 15

Workgroup Members

Dede Hapner, PG&E; Bob Porter, WAPA; Jessica Holliday, Environmental Defense; David Withrow, CA-ISO

Characterization of Transmission Constraint

The constraint addressed by the Path 15 transmission project was initially considered to be economic by most of the stakeholders interviewed. The characteristics of the congestion changed over time, ultimately being viewed as a reliability problem as well. In the 1980's, the bottleneck was seen to be limiting the ability to transmit cheap hydroelectric power from the Pacific Northwest south to the load centers in Southern California. At that time, a Path 15 upgrade (an 84-mile stretch of electrical transmission lines in the Central Valley connecting Southern California with the northern part of the state) was considered in conjunction with the California-Oregon Transmission (COT) Project. However, the California Public Utilities Commission (CPUC) did not approve the participation of investor-owned utilities in the line, so the COT project ended in San Francisco.

The constraint was compounded when, as part of California's restructuring in the late 1990's, three operators (Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric) merged, with their joint transmission assets forming an "interstate highway" of electrons going down the backbone of state. Originally built as an "expressway" to serve specific generation units, Path 15 became the point on this highway system where three 500-kV lines linking northern and southern California narrowed to two lines for 84 miles through the Central Valley. The result was an exacerbation of existing constraints.

After restructuring, the bottleneck was seen primarily as preventing the transmission of available generation in southern California and the desert southwest to load in the north during periods of low hydroelectric generation availability.

In response to the CPUC's 2001 Transmission Investigation, PG&E was required to submit a Path 15 upgrade proposal. However, once the proposal was submitted, the CPUC determined that adequate economic benefits had not been demonstrated for PG&E customers and therefore, rejected the proposal. At the same time, DOE directed Western Area Power Administration (WAPA) to explore a Path 15 upgrade as a component of the President's Energy Plan. The project was eventually reconfigured with WAPA as the lead entity, in cooperation with PG&E and TransElect. With WAPA, a federal entity, leading the project, the CPUC stepped aside and the project moved forward.

The upgrade increased Path 15's south-to-north capacity from 3900 MW to 5400 MW, significantly reducing electricity costs with savings estimated at $100 million annually under normal conditions and more than $300 million during a dry year, when Path 15 helps to mitigate lack of hydro in Northern California. The project was completed under-budget and ahead of schedule, activated on December 14, 2004.

Market Structure:

California has had a deregulated wholesale energy market since 1998. California ISO, established the same year, has a mandate to act as impartial operator of the state's wholesale power grid. New transmission projects that are submitted by Participating Transmission Owners (or any other entity) are studied by CAISO to determine benefits. The CAISO Board approves projects that are deemed "necessary and cost effective." For projects developed by California investor-owned utilities requiring new rights of way, the California Public Utilities Commission (CPUC) undertakes an environmental review and permitting (siting) process. FERC reviews these determinations of need and reviews the costs expended by the transmission owner. FERC allows only those costs deemed to be prudent. These costs are recovered through the CAISO's transmission access charge (TAC). The TAC is the mechanism by which transmission owners get compensated for the maintenance and capital costs of their transmission facilities. The TAC is specified on the settlement statements for all users of the ISO grid -- essentially, load pays these costs. For transmission owners in California who are not part of the ISO grid, their costs are recovered at the whole-sale level through a similar FERC-approved transmission revenue requirement. Retail rates are paid by end-users with the approval of the CPUC.

Summary of Top Issues from Path 15 Workgroup:

The Path 15 Workgroup identified a number of key issues that contributed to delays in addressing the California bottleneck.

NEED:

Disagreement regarding the appropriate need determination methodology proved to be a major issue for Path 15, and one that continues to be unresolved in California. For the initial Path 15 proposal, the CPUC assessment took into account only benefits to the ratepayers of the sponsoring utility (PG&E). When limited to considerations of PG & E ratepayers only, a sufficient economic case could not be made, even though the upgrade would provide significant state-wide benefits. A broader approach has been developed in conjunction with CA-ISO and will be applied to need analysis for Path 26. The new methodology looks at regional need and will be considered by CPUC as a new standard for economic analysis of proposed new transmission facilities.

In addition to a broader approach to need determination, the experience with Path 15 highlighted the need for an integrated transmission planning method that considers optimum use of the western region's generation resources to ensure the lowest total cost to utility ratepayers. Currently, no planning process adequately fulfills this purpose in the West.

Another issue identified by the Path 15 Workgroup is the difference between the mission of the CPUC and the CAISO. CA-ISO is responsible for ensuring transmission system reliability, while CPUC is responsible for balancing the interest of ratepayers and utility shareholders. The CPUC barred PG&E from expanding its transmission assets because the primary benefits were to the transmission common carrier users as opposed to the power end users. CA-ISO, on the other hand, viewed the Path 15 transmission expansion as necessary to the reliable operation of the state's electricity system. Federal involvement may not have been needed if CPUC had allowed PG&E to build the common carrier facility upgrades and recover the cost through the CA-ISO transmission tariff. Similar conflicts in various state agency mandates can be seen in other regions throughout the country.

PROCESS:

Lack of coordination between various intrastate, interstate, and federal agency jurisdictions limits the ability to address serious transmission constraints, such as Path 15, in a timely manner. There is a need for collaboration among such entities to plan for future corridor needs and assess the full scope of project benefits. Individual agency processes need to be complementary and provide for comprehensive planning of common carrier lines. In the example of Path 15, the absence of either an infrastructure for such coordination or an over-arching entity to administer some form of broad-based planning led to conflict, inefficiency, and delays in addressing the bottleneck.

LESSONS LEARNED:

Path 15 cannot be used as a template for other projects because of a number of unique factors such as the role of WAPA & TransElect, the energy crisis, and Federal intervention; however, because multiple players drove the solution and the absence of any one could have precluded a successful project, the role of each of the players provides some transferable lessons learned

- FERC allowed an incentive rate of return;
- PG&E assumed the risk of taking the lead on the terminal facilities and cooperated with partner entities to ensure success of the overall project;
- The CPUC acquiesced to allow the project to move forward with WAPA as the lead entity and exhibited flexibility in considering preferred solutions to load and resource balancing;
- TransElect provided the major source of funding and took the critical first step towards financing the project;
- WAPA served as experienced project manager and honest broker, provided right of eminent domain and statutory authority to build;
- Maslonka implemented and assumed risk of construction and cut down on time and cost due to experienced workforce, use of stockpiled materials, and pre-positioning of work yards;
- DOE made a national commitment to address the constraint and provided leverage in resolving some implementation issues;
- CA-ISO provided in-state support and incorporated facilities with its other common carrier facilities and thus provided a means of cost recovery.

Appendix D
Identification of Key Issues/Problems

The second phase of the Dialogue began with a plenary session, which was held on October 21, 2004. The Keystone Center staff and plenary participants met to discuss the findings of the Work Groups on the regional stakeholder outreach process. Dialogue members found common themes among the various regions and organized them into the areas of Need, Cost Recovery, Siting, and Process.

Participants agreed on several criteria to guide the third and final phase of the project, development of recommendations for the primary barriers addressed. The most important criteria for the group were barriers that stood in the way of investment in needed transmission. The definition of "needed" differed slightly among participants, but universally applied to transmission that lowered societal costs of delivered energy and improved reliability of the overall grid. The Dialogue members also chose to focus on problems that were present in more than one region of the country. Though regional differences were apparent, the group felt that recommendations that could be generally applied to more than one region of the country would have a better chance of affecting positive change. Furthermore, the group concurred that its recommendations should be those that could result in definitive actions, including legislative, regulatory, education or voluntary process changes. In turn, this required that state and federal legislators and regulators would be receptive to these recommendations, and that the timing for implementation was ripe.

During the first screening, the Dialogue Group consolidated the findings of the stakeholder outreach Work Groups into the following set of issues:

NEED

The group identified six main obstacles related to the issue of transmission need. These included the following:

- The lack of an integrated planning system that incorporates potential transmission, generation and/or demand-side responses often favors generation at the expense of the other two options.
- Inefficient use of the current transmission system can often overstate or understate need.
- The lack of clear, effective criteria hampers the determination of economic need.
- Short-term Locational Marginal Pricing signals are inadequate to provide incentives for long-term transmission investments
- State need determinations often exclude regional considerations.
- Renewable generation sources require cost allocation and interconnect policies that facilitate their participation in the market.

COST RECOVERY

The group identified three main obstacles related to cost recovery issues:

- There is inherent conflict between individual states (cost recovery and siting requirements) and broader regional transmission needs and planning.
- It is challenging to apply participant funding to regional projects where beneficiaries are difficult to identify, especially over time.
- Lack of a regional rolled-in rate methodology to pay for transmission upgrades.

SITING

The group identified four main obstacles related to siting issues.

- The lack of an effective forum and/or policies for resolving multi-state disagreements hampers investment.
- There is a lack of a viable model to bring multiple stakeholders into the siting process early.
- Delays are caused by inadequate coordination among the multiple interests involved in siting transmission facilities on public and tribal land.
- There is a lack of a consistent framework (regional or national) for weighing aesthetics, safety, and environmental concerns.

PROCESS

The group identified two obstacles that were primarily process-oriented.

- There is a need for intrastate-agency coordination, particularly in states where siting, need, and environmental review are handled by multiple state agencies.
- Regional planning on a voluntary basis (such as the RMATS process) can be difficult to sustain if one or more of the parties decides at any time not to participate. In addition, since there is no authority to compel entities to build, a voluntary collaboration on transmission planning may still not lead to transmission expansion.

Based on discussion and application of the criteria above The Dialogue group narrowed and reframed its focus to eight key issues under three topic areas: cost recovery, siting, and need. They selected the following problem statements as appropriate for further Work Group analysis and possible recommendations:

COST RECOVERY	• Conflict between state cost recovery & siting with regional transmission needs & planning • Reaching agreement about who benefits is an impediment when beneficiaries pay • Lack of established rate design to predict revenue stream
SITING	• Lack of an effective forum/policy for resolving multi-state disagreements • Not in My Backyard (NIMBY)
NEED	• Lack of clear, effective criteria to determine economic need • Tension between market solutions and regulated solutions • How to deal with regional transmission needs in the absence of an RTO

Appendix E
List of Interviewees and Questions from Regional Stakeholder Outreach Process

Northeast

• Bobbie Kates Garnick	Keyspan Energy
• Ashok Gupta	Natural Resources Defense Council
• Mark Sinclair	Conservation Law Foundation
• Sue Jones	Natural Resources Council of ME
• Mark Sidebottom	Emera
• Tsion Messick	Conectiv
• Laura Manz	PSEG
• Beth Nagusky	ME Energy Resources Council
• Larry Dewitt	PACE Energy Project
• Peter Brandien	ISO-NE
• Craig Glazer	PJM
• Rich Sedano	Regulatory Assistance Project
• Diedre Matthews	MA Energy Facility Siting BD
• Don Downes	CT PUC
• James Connelly	MA DTE
• Tom Welch	ME PUC
• Lisa Barton, Bill McKinnon	Northeast Utilities
• Jerry Spring	VELCO
• Hariph Smith	CMP/Energy East
• Bing Young	Hydro One
• Peter Flynn	National Grid
• Mary Ellen Paravolos	National Grid
• Bob Clark	NSTAR
• Mike Jacobs	AWEA

Rocky Mountain Region

• Rick Anderson	Energy Strategies, LLC
• Jeff Burks	Utah Energy Office
• Jim Byrne	RMATS Facilitator
• Robert Dintelman	Western Electricity Coordinating Council
• Inez Dominique	Colorado Public Service Commission
• Mary Fisher	Xcel Energy
• Bryce Freeman	Wyoming Office of Consumer Advocate
• Steve Furtney	Wyoming Public Service Commission
• Roger Hamilton	Energy and Environmental Consulting
• Doug Larson	Western Interstate Energy Board
• Mark Lindberg	Montana Energy Officer for Governor Martz
• Ron Montagna	Bureau of Land Management
• John Nielsen	Western Resource Advocates
• Scott Powers	Bureau of Land Management
• Steve Waddington	PacifiCorp
• Constance White	Utah Public Service Commission

California Path 15

• Gary Ackerman	Western Power Trading Forum
• Barbara Barkovich	Barkovich & Yap, Inc.
• Kevin Coughlan	California Public Utilities Commission
• John Geesman	California Energy Commission
• Lenny Goldberg	The Utility Reform Network
• Scott Logan	Office of Ratepayer Advocates
• Bob Mitchell	TransElect
• Arthur O'Donnell	The Energy Overseer
• Jim Scarff	Office of Ratepayer Advocates
• Jan Smutny-Jones	Independent Energy Producers Association
• Wes Williams	Southern California Edison

Midwest

• Scott Barnhart	American Transmission Company
• Larry Bruneel	International Transmission Company
• Mary Fisher	Xcel Energy
• Bert Garvin	Wisconsin Public Services Commission
• Craig Glazer	PJM Interconnect
• Joe Hartsoe	American Electric Power
• Will Kaul	Great River Energy
• Jim Keller	Wisconsin Electric; Midwest ISO Advisory Committee
• Tom Kreager	Save Our Unique Lands
• Diane Munns	Iowa Utility Board; Organization of MISO States
• Dale Osborn	Midwest ISO
• John Procario	Cinergy
• Sam Randazzo	McNees Wallace & Nurick, LLC; Industrial Energy Users-Ohio
• Phyllis Reha	Minnesota Public Utilities Commission
• Bill Smith	Organization of MISO States
• Beth Soholt	Wind on the Wires
• Mike Stuart	Wisconsin Public Power
• Pat Connors	Wisconsin Public Power
• Michael Vickerman	Renew Wisconsin
• Susan Wefald	North Dakota Public Services Commission

National

• Kara Colton	National Governors Association
• Larry Dewitt	Pace Energy Project
• Joe Eto	Lawrence Berkeley National Laboratory
• Jolly Hayden	Calpine
• Eric Hirst	Consultant to U.S. Department of Energy
• Kevin Kelly	Federal Energy Regulatory Commission
• Dave Nevius	North American Electric Reliability Council
• Mark Robinson / Jeff Wright	Federal Energy Regulatory Commission

Draft Interview Questions

<u>Regional Transmission Projects: Finding Solutions</u>

Background information on the Dialogue

The Keystone Center is convening a Dialogue to explore challenges facing development of regional transmission facilities as one possible solution to improving our national electricity infrastructure. The dialogue involves a national plenary group of stakeholders, including state and federal policy makers, industry representatives and public interest groups. The work of the plenary group will be informed by evaluation of three unresolved regional transmission congestion areas and one completed transmission case study. Through conversations with you and other regional stakeholders, we hope to identify challenges that span various geographic regions, market structures, and planning approaches. Dialogue participants will use this information to develop a set of consensus recommendations for addressing these challenges, which we hope will inform the current national and state policy debate on how to best ensure adequate transmission capacity.

The goal of this conversation is to gain insight into the diverse perspectives on how to resolve transmission bottlenecks in the region. Therefore, your comments will not be for attribution, and we assume that your responses reflect your personal views as opposed to those of your organization unless you indicate otherwise. We have designed the interview to last no more than one hour.

Background information about the interviewee

1. Affiliation
2. Position within organization
3. Brief description of involvement in transmission expansion planning and implementation
4. Major interests in transmission system

Information about the specific congestion area

1. How would you characterize the electricity constraints or problems in your region? (e.g. Inadequate generation? Generation is not located near load? Inability to build generation where resources (wind/coal) are available? Aging transmission facilities? Need for increased transmission capacity? Unintended loop flows? Inadequate use of demand response or other alternative technologies?)
2. How would you rate the level of need for transmission expansion? (high to low)
    a. If you perceive the need to be low, what do you see as possible alternatives for addressing regional constraints? Are they being implemented effectively?
    b. If you see there to be a strong need, how would you characterize it (e.g. reliability / economic)? Who would be the primary beneficiaries?

3. If you do perceive problems that could be resolved with additional transmission capacity, please provide a brief history of the identified congestion areas and proposed solutions.
4. How would you describe the existing process to determine "need" for transmission expansion at the permitting, siting or cost recovery phase ? What do you see as the benefits and disadvantages of the current process (es)? Are the criteria used (e.g. Locational marginal price differences, long-term regional needs, transmission load relief (TLR) events, accommodation of new generation) consistent in all venues that consider need?
5. What improvements would you suggest for the current need-determination process?

Information about the siting and permitting process

1. Are you involved in the siting and permitting process?
   If not, do opportunities exist for you to get involved?
2. Would you describe the current process as adequate and efficient? In what ways is it effective? In what ways could it be improved?
3. How would you describe the effectiveness of federal – state coordination of permitting and siting? If you feel coordination is adequate, please describe what elements of the process ensure this, e.g. How are state and federal EIS requirements coordinated? Is there information sharing among the jurisdictional authorities?? Joint public input process?
4. What improvements in Fed/State coordination should be made?
5. Is there a forum for sharing multiple state interests? How effective is it in resolving differences in the information requirements, criteria for approval, timelines? If no such forum currently exists, how are differences between states resolved?
6. What are the primary environmental concerns in siting new transmission lines in existing right of ways? In new right of ways? How are these addressed?
7. What entities have the right of eminent domain in your region? Is this a problem or a benefit?
8. Do you perceive the need for a federal authority of eminent domain under any circumstances? If so, when?

Information about stakeholder process

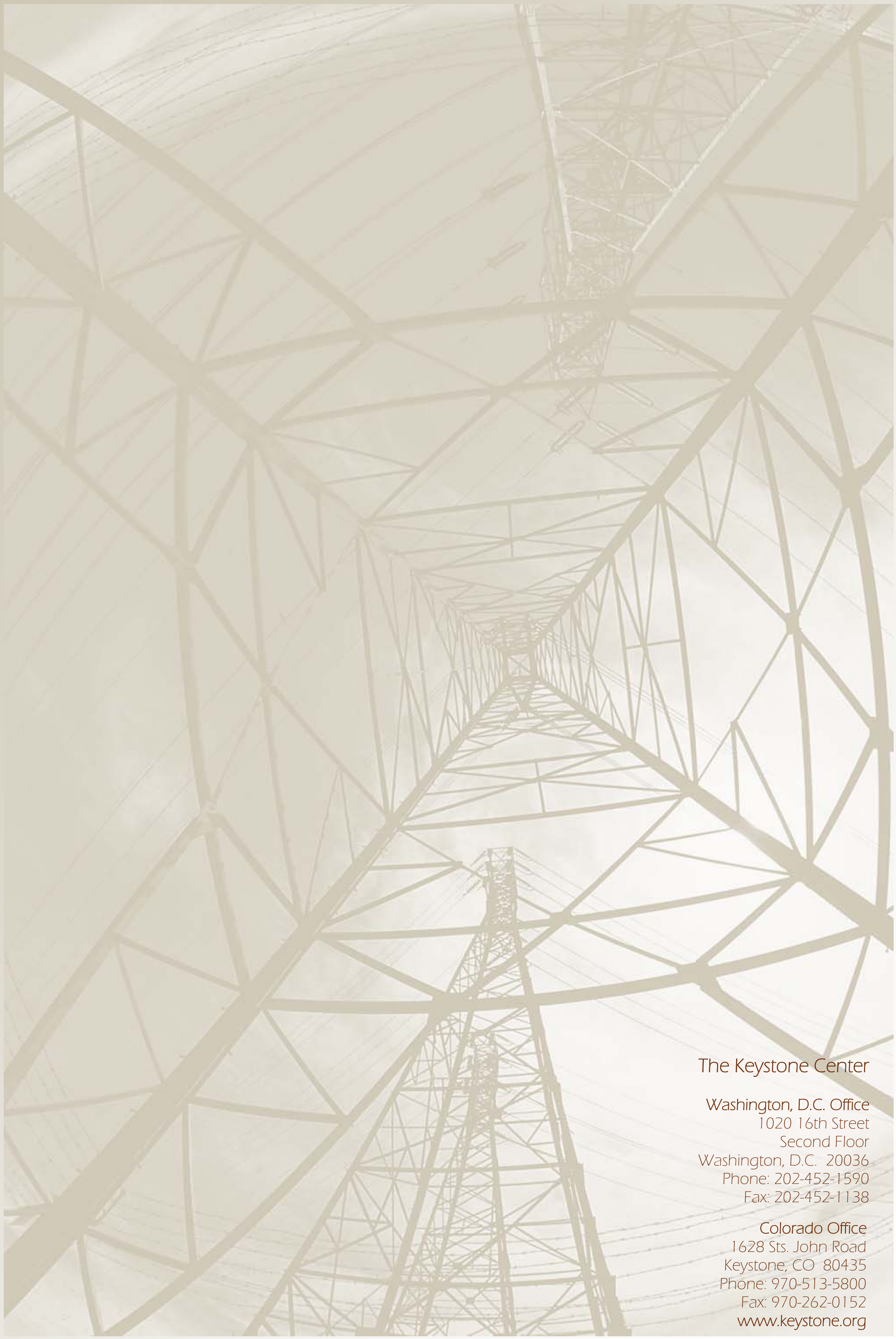
1. What are the current forums for stakeholder input?
2. How would you characterize the level of stakeholder representation and involvement in all stages of the process (planning, permitting, siting, cost-recovery, identification of transmission developer)? Do you feel it is adequate? Useful? In what ways could it be improved?
3. How is stakeholder input incorporated into the final decision? Do you see other ways it could more effectively be incorporated?

Information about the cost recovery process

1. Please explain the cost recovery process and your role (eg. Who makes the decision, what criteria are used, what is the time-frame for evaluating costs and benefits and what is the process/method for identifying beneficiaries?)
2. How do the state or regional authorities make decisions about how to balance competing goals of lowest cost and least environmental impact?
3. What criteria are used to determine when lines should be underground? How are the incremental costs of underground lines allocated?
4. How would you characterize the process in terms of its appropriateness and efficiency?
5. From your perspective, what are the primary considerations in determining who should pay for transmission expansion?
6. How do differences get addressed/ resolved among stakeholders involved in the cost-recovery decisions?
7. Is cost-recovery perceived as a significant risk by potential transmission owners/investors?

Wrap-Up Questions

1. What, in your view, are the major challenges preventing transmission expansion where it is needed? Who and/or what has affected the delays?
2. What are the key ingredients required which would help resolve apparent conflicts over the need and implementation of transmission expansion?
3. Other people we should talk to?



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