Chapter 4 Transmission Adequacy

Transmission lines are the critical link between the point of electricity generation and consumers. The U.S. transmission grid infrastructure is owned and operated by approximately 3,000 distribution utilities and 500 transmission owners. This structure presents a distinct set of challenges in transmission planning, siting, cost allocation, grid operations and management, technological innovation, financing and construction. The development and deployment of a national strategy on transmission that meets the needs of all parties is extremely complex; however, a solution is desperately needed.

The existing grid is strained by a rising demand for electricity, an aging and congested delivery infrastructure, and a growing interest in Smart Grid technologies and the integration of renewable-resource driven generation. Upgrading the transmission grid is essential to support future electricity delivery for two main reasons. First, increasing transmission capability will help ensure a reliable electric supply and provide greater access to economically priced power. Second, the growth in renewable energy development, stimulated in part by state-adopted renewable portfolio standards (RPS) and the possibility of a national RPS, will require significant new transmission to bring these resources, which are often remotely located, to consumer load centers. According to Rick Sergel, President and Chief Executive Officer of the North American Electric Reliability Corporation (NERC), expedited transmission development is key to addressing both of these issues: "We need more transmission resources to maintain reliability and achieve environmental goals. Transmission lines are the critical link between new generation and consumers, yet we continue to see transmission development lag behind generation additions. Faster siting, permitting, and construction of transmission resources will be vital to keeping the lights on in the coming years."[1]

4.1 Trends and Drivers

Today's aging transmission grid is a hodge-podge of individual regional systems costing consumers billions of dollars in congestion annually and limiting interconnection of low-carbon resources. While there are signs of advancing grid development, challenges remain with dated processes and methods for planning, permitting, and cost allocation.

Historical Evolution of the Grid

The existing interstate electric transmission network resulted from vertically integrated utilities building generation and transmission to serve their consumers' electricity demands, to provide for the wholesale purchase and sale of electricity

[1] North American Electric Reliability Corporation, "Ten Year Outlook for Electric Reliability Highlights Environmental Initiatives, Transmission among Key Concerns," October 23, 2008, http://www.nerc.com/news_pr.php?npr=186.

with neighboring utilities, and to share generating capacity reserves to minimize installed capacity reserves. As the system grew, progressively higher voltages were developed to improve delivery efficiency. This system is now at an age and condition that requires significant upgrading or replacement of portions of original infrastructure and the addition of new infrastructure to support the United States' projected electricity future. The planning of the current system did not address the goals of broad-scale regional and interregional planning and meeting larger national needs. However, this grid system is being called on to meet the needs of wholesale markets that have evolved in response to the passage of the Energy Policy Act of 1992 (EPAct 1992) and the growing need to integrate remote sources of renewable energy generation.

State and Regional Progress in Planning and Policy

Federal Energy Regulatory Commission (FERC) Order No. 890 calls for all transmission providers to participate in open, transparent regional planning processes. States and regional entities appear to recognize the need for broader planning. In fact, many states have been very proactive in planning for their energy future, advancing well beyond national efforts. Regional Transmission Organizations (RTOs) have also been proactive within their regions. For example, in the eastern United States, the Joint Coordinated System Plan (JCSP) study is currently examining transmission infrastructure development plans that would facilitate the integration of a large amount of wind power energy.[2] The Midwestern Governors' Association (MGA) in 2007 published a greenhouse gas (GHG) reduction platform that calls for increased attention to transmission, and more recently, the Upper Midwest Transmission Development Initiative (UMTDI) was formed to identify wind power generation resources and transmission infrastructure to support those resources in a cost effective manner.[3] In the western United States, the U.S. Department of Energy (DOE) and the Western Governors Association (WGA) are leading the Western Renewable Energy Zone (WREZ) transmission planning process so that the Western Electricity Coordinating Council (WECC) can better identify and plan for renewable-related transmission needs.[4] In addition, WECC's Transmission Expansion Policy Planning Committee (TEPPC) has aided regional planning by performing economic analyses and guiding transmission planning processes in the western United States. Several states are also addressing "across the seams" planning and cost-allocation efforts by creating transmission authorities to stimulate the construction of high voltage transmission lines (e.g., Wyoming and Kansas).[5,6]

Some states have also succeeded in the implementation of energy policy supporting construction of transmission. A good example is the Competitive Renewable Energy Zone (CREZ) initiative within the Electric Reliability Council of Texas (ERCOT). While it should be noted that ERCOT is unique in that it is a separate interconnection entirely within one state (none of the other contiguous 48 states is similarly situated), the CREZ effort represents the effectiveness of

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[2] Joint Coordinated System Plan study, http://www.jcspstudy.org.

[3] Midwestern Governors Association, "MGA Energy Initiatives," http://www.midwesterngovernors.org/EnergyInitiatives.htm (accessed November 12, 2008); Office of the Governor & Lt. Governor of Iowa, "Five Midwestern States Announce Transmission Planning Initiative," September 18,2008, http://www.governor.iowa.gov/news/2008/09/18_2.php (accessed November 12, 2008).

[4] Western Governors' Association, "Western Renewable Energy Zones," http://www.westgov.org/wga/initiatives/wrez/index.htm.

[5] Wyoming Infrastructure Authority, "Wyoming Infrastructure Authority," http://www.wyia.org.

[6] Kansas Electric Transmission Authority, "Kansas Electric Transmission Society," http://www.kansas.gov/keta.

interconnection-wide planning for the development of interstate extra-high voltage (EHV) transmission (at voltages 345 kV and above).

Climate Change's Uncertain Impact on Transmission Planning

Government's response to climate change will further confound transmission planning and estimation of future needs. Compliance with applicable renewable portfolio standards (RPS), the trend toward electrified transportation, and overall pressure on industrial sectors to reduce GHG emissions could result in a tremendous additional demand on existing transmission infrastructure. Areas with high-quality renewable energy resources, such as wind power, solar power, and geothermal energy, tend to be located at significant distances from population centers. This fact is highlighted in DOE's *20% Wind Energy by 2030* report.[7] Accessing these resources and providing adequate capacity to facilitate new electrification initiatives will require expanded use of the transmission grid. Government at various levels, many utilities, and nongovernmental organizations are also working to develop and deploy Smart Grid options. These and other demand-side and distributed generation options will help offset a portion of the growing electricity demand and further reduce GHG emissions, but they will not obviate the need for significant new transmission.

Grid Congestion

The U.S. electric grid is highly congested in some areas, as DOE has noted in its 2006 congestion study.[8] New products and services could allow for more efficient use of existing transmission infrastructure. Because the location of transmission congestion changes depending on outage conditions, seasonal variation, and other factors, opportunities exist for transmission consumers to use spare transmission capacity during uncongested periods. Recent FERC rules put in place conditional firm transmission and generation re-dispatch services to address unanticipated transmission constraints. However, these new products and services cannot alleviate the need for transmission expansion.

The Rise of Smart Grid and Increasing Use of Plug-In Vehicles

Implementation of Smart Grid concepts will change the grid by enabling demand response/load management and other resources to be dispatched as generators are dispatched today. Plug-in hybrid electric vehicles (PHEVs) attached to the grid using Smart Grid technology also have significant potential to provide demand-side flexibility in the future, although the penetration of PHEVs would also increase overall electric load. Other energy storage technologies may also become cost-effective sources of system flexibility in the future. The interaction of these technologies with the transmission system, and the role transmission can play in better leveraging such technologies, will be an important component in the development of future plans. (See a detailed discussion of grid impacts of energy storage technologies and PHEVs in the EAC report, *Bottling Electricity: Storage as a Strategic Tool for Managing Variability and Capacity Concerns in the Modern Grid*, December 2008).

Increasing Investor Interest in Transmission Projects

Perhaps more so than at any point in the electric industry's history, new entrants stand poised to have a significant impact on

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[7] U.S. Department of Energy, *20% Wind Energy by 2030: Increasing Wind Energy's Contribution to U.S. Electricity Supply* (Washington, D.C.: U.S. Department of Energy, 2008), http://www.20percentwind power.org/20percent_wind power_energy_report_revOct08.pdf.

[8]

the country's transmission infrastructure. While there have been less than a dozen new regulated utilities formed over the past 40 years, interest in the transmission sector is exceptionally high. Public power and rural electric cooperative utilities that use the transmission systems of neighboring utilities to move power supplies to their retail customers are increasingly expressing interest in transmission ownership. In addition, a number of companies are exploring opportunities in the merchant transmission business. Most of these potential new entrants are drawn to the electric delivery business because of the obvious need for capital and the fact that a "21st century grid" will require new thinking, new technologies, and new business approaches, which help level the playing field with traditional utilities and provide multiple opportunities for growth.

In recent years, tens of billions of dollars of equity have been raised by infrastructure funds looking for opportunities to deploy their capital in regulated or unregulated projects. These new players have lower return expectations than traditional private equity funds, and their time horizons for holding investments may be longer. In addition, commercial and investment banks have favored lending to utility projects, as they provide greater cash flow certainty during a period of economic unease.

Rising Global Demand for Equipment and Labor

The development of a more robust electricity transmission grid will certainly require more equipment, material, and labor resources at a time when there is a growing global demand limiting supply. Current financial conditions may ease the availability of these resources in the short term, as limited access to capital and the high cost of capital may delay transmission plans somewhat. However, when financial conditions ease, capital will again be attracted to transmission investment, driven by national imperatives to connect low-carbon resources to the grid. While global market forces may create better supply in the long term, the availability of equipment, material, and labor may be limited and more expensive in the short term.

4.2 BARRIERS

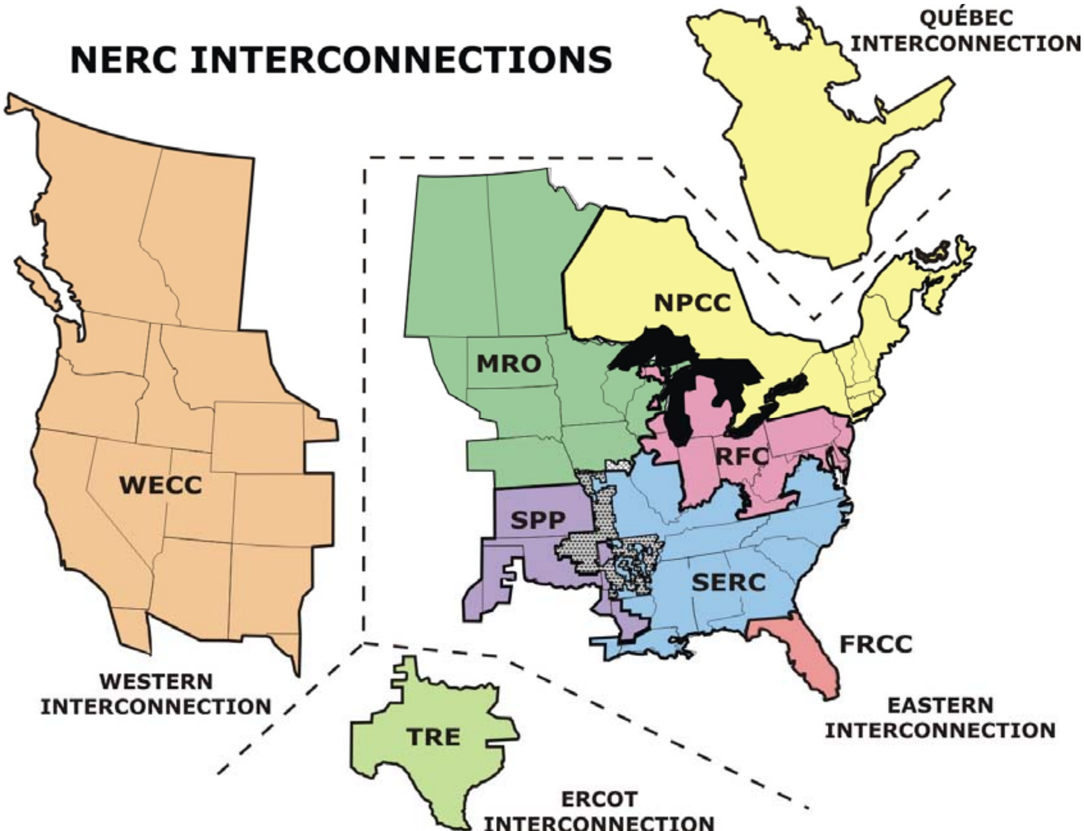
The greatest barriers to transmission development have been: 1) what project? (planning), 2) whose backyard? (siting /permitting), and 3) who pays? (cost allocation / timely recovery).

Inadequate Interregional and Long-Term Transmission Planning

Currently, interregional planning within the eastern and western U.S. Interconnections is inadequate, but it can be improved. (See Figure 4-1 for a map of NERC reliability regions and the four North American Interconnections) For example, the "lake effect" phenomenon, a power flow problem around the eastern Great Lakes, particularly Lake Erie, has existed for decades. This phenomenon, which has yet to be resolved, may have been a contributor to the spreading of the 2003 blackout in the eastern United States. Although system controls, procedures, and compliance with mandatory reliability standards were put in place to mitigate the circulating power flows, relatively little coordinated transmission investment has been made. The area surrounding Lake Erie is comprised of three RTOs in the United States and an independent system operator (ISO) in Ontario, Canada. RTOs (and ISOs) are responsible for transmission planning within their respective footprints, but they are not adequately addressing transmission planning challenges jointly with neighboring regions.

Coordinating transmission projects across the seams between RTOs and utility control areas is increasingly important to bring renewable energy to consumer loads, as well

Figure 4-1. Map of NERC reliability regions within the four North American Interconnections.



Source: [9]

as to improve overall grid robustness and the acquisition of lower cost electricity. Often, however, there is no mechanism for approval, cost allocation, and/or selection of owners for projects that cross these seams.

Lack of Unified Structure to Support Efficient Permitting of EHV Transmission Lines

The permitting of transmission facilities is highly fragmented by the federal government, states, and local authorities. These fragmented processes were not established to develop interstate EHV transmission lines or facilitate access to remote renewable energy resources, nor do they provide proper consideration for crossing federal lands. Currently, state and federal agencies are responsible for siting and permitting transmission lines in their respective jurisdictions. The siting of EHV transmission projects often involves multiple entities with varied processes.

Even relatively short transmission lines frequently require permits from various federal agencies that control the crossing of parks, agricultural lands, and rivers. Examples include the United States Fish and Wildlife Service (USFWS) and the Bureau of Land Management (BLM). In the western United States, almost all significant transmission projects require federal land or resource agency permits. While it should be noted that the western states and the affected federal land management agencies agreed to a regional transmission siting protocol in 2003 that handles multistate transmission projects,[10] this protocol has not yet been tested on an actual project. Recent experience in California suggests that the federal permit process can be extremely cumbersome and time-consuming, even for the construction of transmission to access renewable energy resources.[11]

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11 Comments of Southern California Edison on DOE 216(h) rulemaking.

Each state and federal agency typically has its own permitting rules and processes, which are rarely consistent with each other. In addition, each state and federal agency also views the costs, benefits, and environmental impacts of transmission differently. Layered on top of these permitting arrangements may be RTOs that have planning and scheduling authority in some, but not all, parts of the country. In addition, NERC and its regional entities enforce compliance with reliability standards that affect transmission operations and development. The uncoordinated participation of this wide spectrum of interested parties, and the nature of interstate EHV transmission crossing jurisdictional boundaries, complicates and impedes the planning, approval, and permitting processes. This can further delay the already lengthy siting process, add to the cost of transmission projects, and increase the financial risk to the transmission company.

A "poster child" example of this problem is American Electric Power's Jacksons Ferry - Wyoming, 765 kV transmission line. It required 16 years to complete, and nearly 14 of those years and $50 million was spent on siting activities. A portion of the siting problems that plagued the project was simply the mismatch between an interstate project and the non-integrated permitting processes of Virginia, West Virginia, and several federal agencies. Each set of rules and regulations was reasonable on its own, but when the project was revised to comply with requirements in one jurisdiction, filings needed to be amended in each of the other jurisdictions, extending the review time. This mode of permitting proved time-consuming, inefficient, and costly for consumers.

The Energy Policy Act of 2005 (EPAct 2005) recognized the impediments to interstate transmission development and sought to address them in two ways. First, it provided for FERC “backstop” siting authority within National Interest Electric Transmission Corridors (NIETCs). These have proven to be controversial, both too broad in the view of some and too narrow in the view of others. Because NIETCs are based solely on congestion, the current designated corridors are limited in scope and do not take into consideration other needs such as access to renewable resources. Second, EPAct 2005 called for DOE to act as the lead agency for coordinating federal authorizations and environmental reviews for transmission. More than three years later, DOE has published a proposed rulemaking regarding its lead agency designation, but the DOE as structured and with current resources is not well positioned to carry out the coordination duties pursuant to section 216(h) of the Federal Power Act. DOE should allocate proper focus and resources to this task, or this responsibility should be transferred to FERC, which has greater siting and National Environmental Policy Act (NEPA) expertise.

Lack of Clear Cost Allocation Policies Deters Transmission Projects

The difficulty in determining who should pay for transmission that benefits many users across multiple jurisdictions, for a variety of purposes, and over a long time, is a serious obstacle to transmission development. As Nicholas Brown, President and Chief Executive Officer of Southwest Power Pool (SPP) contributes: "Our industry desperately needs national leadership on allocating costs for the expansion of the bulk transmission system. We have planned regionally and interregionally for over a decade, but ideas remain on paper due to lack of needed cost allocation."[12] FERC has approved unique regional cost allocation approaches where RTOs have authority. In other regions, the task of cost allocation is delegated to individual states or utilities. In these areas, the lack of approved region-wide cost

[12] NERC, "Special Report: Electric Industry Concerns On The Reliability Impacts of Climate Change Initiatives," November 2008 at p. 17.

allocation methodologies and agreements can complicate and delay the planning and approval of interstate projects, thus at times creating a higher level of uncertainty and risk for investors. Moreover, a lack of cost-allocation mechanisms can complicate projects that span multiple RTOs or RTO and non-RTO regions. Cost allocation policy can determine whether a project moves forward, especially because the construction of large-scale projects can extend over a number of years and require a large capital investment.

EHV transmission projects involve the large-scale transport of electricity, usually across long distances. Higher voltage increases the transmission efficiency and decreases the amount of electricity otherwise lost. Thus, the nature of EHV transmission generally means that its benefits are provided across wide areas, possibly spanning jurisdictional boundaries. For these types of projects, it is difficult to determine particular beneficiaries over the life of the projects. In addition, benefits are often categorized into "reliability" or "economic" benefits, and the allocation methodologies frequently differ between these categories. However, interstate transmission projects generally serve multiple purposes, with benefits that can vary over time and with changing system conditions. Attempting to assign costs for these types of projects to any particular group is often met with resistance from the group, causing delays. By contrast, in some jurisdictions transmission costs are shared across all load-serving entities in the footprint based on load ratio. In this way, major backbone EHV infrastructure projects can be planned based on the needs of the entire region. This promotes projects that are designed to deliver maximum benefits to multiple stakeholders, minimizes the cost impact to any individual consumer group, and avoids disagreements that occur under “beneficiary pays” or “participant funding” approaches.

Without clear cost allocation policies, developing large-scale transmission projects is virtually impossible. In cases in which a potential transmission line crosses dissimilar cost allocation areas or RTOs, the project may be delayed to reconcile the cost allocation methodologies and determine who pays. Cost allocation disagreements can also impact transmission siting; therefore, resolution of these two issues must be linked. Indeed, many EAC members believe that cost allocation is the single largest impediment to any transmission development, especially across multiple RTOs or across RTO and non-RTO regions.

Uncertainty Regarding Cost Recovery From Retail Customers for Transmission Projects

In addition to cost allocation, uncertainty with respect to cost recovery has a profound effect on decisions to build large-scale, EHV transmission. The timely recovery of transmission investment is a vital component in attracting sufficient investment, particularly for projects with timelines that extend across many years. Since FERC issued its transmission incentive rule (Order No. 679), a number of transmission projects have been proposed. However, for most transmission builders (builders other than independent transmission companies, whose rates are entirely FERC-regulated), recovery of FERC-approved transmission costs must be approved at the state level, potentially resulting in “trapped costs.”

State utility regulators representing retail consumers want to ensure that transmission projects approved on economic grounds do not result in costs that exceed the benefits. Further, they seek to avoid the use of financial incentives that encourage utilities to propose "unnecessary" infrastructure investments to increase their rate bases, or transmission projects that are more expensive than alternatives. Thus, some state regulators and consumers remain concerned about the costs of many proposed large-scale transmission projects and whether the cost of installed transmission projects may exceed their original estimates.

Formula rates and "pass-through" rates (state-approved mechanisms to allow for automatic recovery of FERC-approved investments) help provide the certainty needed to stimulate major transmission investment. However, the reconciliation of federal and state cost recovery mechanisms to address both developer and consumer concerns is necessary to encourage the construction of the transmission grid that is required to achieve the nation's goals of energy security, electricity adequacy, and environmental protection.

A Growing Need to Optimize Grid Operation for Renewable Energy Resources

Optimization of renewable energy resources in concert with the operation of the grid is needed. Historically, the dispatching of resources depended on demand and the cost-effectiveness of nearby generating plants. Today, congestion, weather (for renewable energy), and other factors often affect the dispatching of resources. Much higher renewable resource penetration will require an efficient and responsive fleet of traditional resources, new energy storage devices, and demand response/load management resources to fill the gaps created by the inherent variability of renewable energy resources. Potential operating restrictions related to air and water quality may impact the ability of existing traditional generation sources to help integrate renewable energy and could lead to complex operational issues. In addition, the growing complexities and more intensive use of the grid, the long distances to renewable energy resources, and the continued addition of power electronics and computers will make control of the grid will be even more challenging for its operators.

Inadequate Grid Controls and Communication Systems

Better wide-area monitoring and controls are needed for proper protection and efficient operation of the transmission system. Much of the grid's existing capability is the result of well-engineered controls and communication systems. Without them, the ability of the grid to reliably transfer significant amounts of power would be greatly diminished. However, NERC has determined that mis-operation of protection devices and controls are causing a growing percentage of bulk transmission outages.[13] More sophisticated detection and control capabilities are needed and could be achieved with Smart Grid initiatives. This includes situational awareness tools for system operators to allow them to identify and implement timely control actions or to enable automatic control actions.

Limited Development and Deployment of New Technologies

There is a tremendous need for leadership in the area of research and development (R&D). The industry is highly fragmented and R&D expenditures that total less than 1% of revenues.

The costs and risks to develop and implement a new technology can be substantial. FERC has encouraged development of advanced technology through incentives under EPAct 2005 to recognize these risks and reward "first adopters." However, more can be done to encourage the development of potentially beneficial technology and ensuring recovery of investments in innovation. In, particular, there is a need to ensure recovery of investments in promising technologies in

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[13] North American Electric Reliability Corporation, "2008 Long-Term Reliability Assessment: 2008-2017" (Princeton, NJ: North American Electric Reliability Corporation, October 2008), http://www.nerc.com/files/LTRA2008.pdf.

situations where the benefits might not be seen for several years.

Resistance to Entry of New Companies

New entrants and new investors stand poised to enter the transmission industry. While many observers view this interest as proof that new companies and new capital will flow into the industry over the coming years, the reality is much less certain, as there are actually very few success stories. In some instances, the potential new entrant has proposed an uneconomic or unnecessary project, or made other mistakes, sometimes based on lack of experience. In others, utilities have fought bitter political battles at the state level to stop new entrants, or regulatory reviews have stymied projects.

Today, many incumbent electric utilities have a legal right of first refusal to construct, or arrange for construction of, any transmission project within their service territory. Reliability projects are generally completed expeditiously because improvements are required to meet NERC reliability standards. By contrast, transmission dependent utilities (TDUs) and consumer advocates frequently express concerns that incumbent utilities can continue to exercise transmission and/or generation market power by delaying "economic" projects by requesting repeated feasibility and cost-benefit studies and using other delaying tactics. Some TDUs have also expressed interest in participating jointly with incumbent utilities and other transmission owners in new transmission projects or significant upgrades, contributing their own capital, but those expressions of interest have not been reciprocated in many cases.

4.3 KEY CONSIDERATIONS

Perhaps the most important consideration for the development of the grid is our nation's developing vision for addressing climate change. Transmission can enable our electricity future by removing barriers for low-carbon resources and improving the delivery efficiency and effectiveness of the grid.

Addressing Climate Change

Transmission planning and development must be done in the context of comprehensive demand and resource analysis to ensure that demand-side resources and environmentally desirable supply-side resource options (such as Smart Grid options at the consumer and distribution level) are fully considered and pursued. Such planning must also account for the likelihood of further demand growth caused by increased electrification of the transportation sector and industrial processes as the United States pursues strategies to reduce society's impact on climate and the environment overall. The nation needs a broad vision for a transmission system that supports a national energy policy to meet the goals of energy security, electricity adequacy, and environmental protection. Collaboration among the many various stakeholders will be necessary to make this vision a reality.

Broadened planning efforts should allow for consideration of new technologies that maximize both cost benefits and system efficiencies while minimizing environmental impacts. For example, where appropriate and cost-justified, such efforts may encourage greater use of higher voltage or EHV transmission lines, including complementary high voltage direct current (HVDC) connections for transferring electricity from the nation's available sources of low-carbon energy to load centers, particularly where need for the lines is well established and corridors are limited or environmental impacts are a concern. These high-capacity lines enable the most prudent use of scarce corridors and can be effectively integrated to form a more efficient, expanded interstate transmission grid that will serve long-term needs.

Progressive planning efforts should also consider using advanced conductor materials and integrating more efficient equipment to minimize system losses and further reduce GHG emissions. Planning the transmission system of tomorrow is not only about building additional lines; it also is about designing a smarter, superior system. This approach may not be considered least-cost over short-time horizons, but it will provide significant benefits to consumers over longer periods going forward. To ensure lower prices and a higher-quality system for consumers, these broader planning efforts should consider environmental and cost-benefit analyses, including the effects of all cost-effective demand-side options, the deployment of Smart Grid, and distributed generation systems.

Recognizing the Need for Longer-Term Planning for Transmission Infrastructure

Developing a robust electricity transmission network that enables the nation's electricity future requires longer-term regional (e.g., within or among neighboring states, RTO areas, or across multiple utilities) and interregional planning (e.g., within the eastern or western U.S. Interconnections). The exception is the ERCOT Interconnection, where interconnection-wide planning has been more progressive, facilitated by its single-state jurisdiction. Such planning must take into account not only traditional transmission planning issues, such as interconnection queues, estimating demand-side program impacts, regional seams issues, and "just in time" short-term transmission development, but also broader national goals.

Because the siting and construction of transmission infrastructure can take several years to complete, long-range planning must have the flexibility required to accommodate multiple scenarios. The full range of fuel sources, demand options, and transmission solutions must be thoroughly examined, and planning must occur with a greater geographic scope and longer timeframe than ever before. Modeling the grid, particularly with respect to less-certain generation and load scenarios, needs to be enhanced. In many ways, adapting to today's energy landscape requires a fundamental shift in long-term and large-scale transmission system planning and construction. Regardless of geographic location, transmission must be viewed as a critical enabler of an adequate electricity future for the United States and planned with this in mind.

Supporting Effective Methods of Sharing Costs for Regional Transmission Projects

At the consumer level, sharing costs as broadly as possible reduces the rate impact while enabling the infrastructure that that will reduce congestion and lower delivered energy costs. A study conducted by CRA International, for example, estimates that a $2.7–3.5 billion investment in the western portion of SPP for 1,200 miles of 765 kV transmission (the first two loops of the proposed SPP EHV Overlay) would result in an annual net benefit to the SPP region of $628–728 million, not including the added benefits of economic development and reduced carbon dioxide (CO_2) emissions. This means that the cost of the added transmission would be fully offset within five years. This portion of the SPP EHV Overlay plan also enables the development of 14 gigawatts (GW) of wind power generation in the region. SPP's leadership and the CRA International study results demonstrate how regional transmission development can benefit the region with stabilized electricity costs and encourage renewable energy development.[14]

[14] CRA International, First Two Loops of SPP EHV Overlay Transmission Expansion: Analysis of Benefits and Costs (CRA International, September 22, 2008), PowerPoint slides, http://www.spp.org/publications/ETA_OGE_WESTAR_Preliminary_Cost_Benefit_Analysis%20_from_CRA.pdf.

Ensuring Affordability for Consumers

Electricity must remain reasonably priced for consumers. Failure to keep electricity rates reasonable will have a damaging impact on the nation's economy and the quality of life for many Americans. While transmission is only a small part of the average consumer's electricity bill today (typically less than 10%),[15] the construction of a major new line can cost over a billion dollars. The planned project must accordingly be assessed to ensure need, benefits, and minimal environmental impact. A properly planned and developed transmission system can facilitate lower overall costs for utilities and ultimately for consumers by creating better delivery efficiencies, greater market reach, and reduced market power for energy suppliers.

Advancing Automated Grid Control

Improved automated grid control can be achieved, in part, by accelerating the work underway to develop and deploy precise time-synchronized measurements on an interconnection-wide basis. This development effort is known as the North American SynchroPhasor Initiative (NASPI).[16] Time-synchronized phasor measurement units (PMUs) are often described as "diagnostic MRI" for the electric grid, providing continuous control and synchronized real-time data. The PMU concept should be further developed to provide automatic control of a modern grid by enabling the power system to adjust quickly to serious loss of transmission, generation, or load. As recommended in the final report on the U.S.-Canada Power System Outage Task Force Report on the 2003 blackout, such control would improve the reliability of the grid and its capability to move power and could possibly prevent or mitigate the effects of a widespread blackout.[17]

Relieving Grid Congestion

Grid congestion increases costs to customers and is a direct result of inadequate infrastructure to facilitate safe and reliable electricity deliveries. In addition to needed transmission expansion, technologies are available to improve utilization of existing infrastructure that may help reduce congestion and ensure reliable system operation.

It is possible to dynamically rate transmission lines for ambient weather conditions, which may allow more electricity to be transmitted over lines when air temperatures are lower than more conservative assumptions typically used for line rating. However, this will require transmission operators to know more about the system in near real-time than is generally the case today. Making such options available to transmission consumers, including variable-output renewable energy generation sources, can allow more efficient use of the existing infrastructure, more accurately calculate available transmission capacity, and significantly reduce the cost of reliably integrating new generation into the grid.

New devices can also help to enhance the controllability of the grid. For example, flexible alternating current transmission systems (FACTS) can provide control and voltage support to improve grid reliability and throughput. In addition, the use of HVDC to complement the EHV AC network the United States has today can also help control the network, provide additional

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[15] Energy Information Administration, "Coal Forecast," *Annual Energy Outlook 2008 with Projections to 2030* (Energy Information Administration, 2008): 131, http://www.eia.doe.gov/oiaf/aeo/pdf/0383 (2008).pdf.

[16] Pacific Northwest National Laboratory, "North American SynchroPhasor Initiative," http://www.naspi.org (accessed November 12, 2008).

[17] U.S.-Canada Power System Outage Task Force," Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations," April 2004.

interregional connectivity to improve grid stability, and mitigate the spread of blackouts.

A number of operational actions were recommended in the U.S.-Canada Power System Outage Task Force Report on the 2003 blackout. These recommendations are at various stages of development, and DOE is encouraged to ensure that ongoing activities are carried out. In addition, operation of the grid both now and in the future requires strict compliance with mandatory standards established and enforced by FERC and NERC. In addition, making the grid "smarter" must recognize that the grid must remain secure in all aspects, including cyber security.

Enhancing Grid Reliability through Actual or "Virtual" Consolidation of Balancing Areas

To make better use of renewable energy and share other resources, including demand response/load management, a wider geographic scope for energy "balancing areas" may make it easier to operate the electric grid reliably. Widening the geographic scope could provide more opportunity for excess generation in one region to be offset by reduced generation in another region. However, the benefit of larger balancing areas is generally more pronounced for wind power energy than for other renewable energy resources, because total wind power output is less variable over larger geographic regions and more resources are available to respond to this variability. More flexible dispatch, shorter-term dispatch schedules (reduced to five- or ten-minute intervals), better energy storage capability, and demand response/load management over larger geographic regions may enable the reliable integration of even more renewable energy generation and reduce the need for additional capacity. Solutions can take many forms, including consolidation of existing balancing areas into larger ones, as is the case in some RTOs, or "virtual" consolidation through coordination agreements. Nevertheless, these solutions remain dependent upon interstate transmission as well.

Cost responsibilities must be equitable and fair for operational and reliability impacts from any generation of any type, including wind power, being added to a balancing area. In addition, the balancing authority must be able to maintain compliance with NERC reliability standards after a generator has been added. DOE should consider recommendations from current efforts to mitigate the variability of wind power energy, including the NERC Planning Committee's Integration of Variable Generation Task Force Study and Electric Power Research Institute studies of variable resource (e.g., wind energy) integration.

4.4 RECOMMENDATIONS

State, regional, and national priorities, including grid reliability, economic energy supply, energy security, and climate change can all be addressed through the development of a robust transmission system. The benefits of a robust grid include:

- Access to new generation technologies and the ability to share the benefits of demand response/load management and Smart Grid initiatives across broad regions.
- Improved system resource adequacy, by allowing greater sharing of resources and less dependence on local generation and constrained fuel supplies.
- Enhanced system reliability, security, and efficiency.
- Increased market competition that will benefit consumers by eliminating grid bottlenecks, which inflate costs by blocking supply.

- Lower and more stable rates for consumers over the long term through increased access to lower-cost resources and a more diverse portfolio of energy sources.
- Access to renewable energy and other low-carbon resources to meet RPS requirements and GHG emission reduction goals.
- Enables realization of environmental policy objectives.

To achieve these benefits and support future electricity delivery, the EAC recommends that DOE pursue the following.

1. Lead expedited completion of comprehensive, long-term eastern and western Interconnection planning efforts to develop high-level backbone EHV transmission plans. Identify "best practices" for planning that encompasses demand- and supply-side options, "technology neutral" analyses, adequate assessment of environmental impacts (including GHG emissions), full support for the development of renewable and other preferred technology generation, robust planning horizons, and full consideration of the electrification of transportation elements and industrial processes for the nation's energy future.

DOE must support the establishment of long-term interconnection-wide planning efforts and models with broad stakeholder participation.

However, this "top-down" approach must be paired with a "bottom-up" approach that takes into account local needs and issues. DOE must link local, state, and regional efforts with national priorities to ensure a robust transmission system that provides large fractions of the population with increased access to the energy sources they need, including renewable energy resources. As stated in the conclusion of the Electricity Advisory Board's 2002 *Transmission Grid Solutions Report*, "The importance of working cooperatively on the federal and state level to improve our transmission infrastructure cannot be overstated."[18] DOE needs to convene regional efforts with RTOs, state public utility commissions, and regional planning councils. These collaborative efforts should examine system reliability, congestion, interconnection, and integration of low-carbon resources, and should create plans and protocols for transmission development between regions to ensure better interconnection-wide transmission development. Key activities should include:

- Establish eastern and western Interconnection-wide planning efforts that mitigate seams issues and incorporate broad stakeholder participation. These comprehensive planning studies, encompassing each of the eastern and western U.S. Interconnections, should be undertaken to develop high-level backbone EHV transmission plans. These studies, tailored to each Interconnection while supporting common national goals, will serve to provide consistency and harmonization among regional plans. These efforts should be integrated with DOE's national transmission congestion studies.

[18] Transmission Grid Solutions Report, DOE Electricity Advisory Committee, September 2002.

- Identify "best practices" that encompass demand- and supply-side options, "technology neutral" analyses, adequate assessment of environmental impacts (including GHG emissions), full support for the development of renewable and other preferred technology generation, robust planning horizons, and full consideration of the electrification of transportation elements and industrial processes for the nation's energy future. Widely distribute such "best practice" information to planning entities and governmental authorities.

2. Improve siting of transmission facilities, including potential federal siting authority for backbone EHV transmission lines. Address siting issues by taking a strong lead federal role. In the absence of FERC siting authority, support state, local, and federal "best practices," and coordination of multi-agency permitting activities and potentially expand NIETC's and FERC backstop authority to address reliability as well as interconnection and integration of low-carbon resources.

While opinions of the current siting processes and recommended course of action vary, most members of the EAC agree that the status quo for transmission siting is unacceptable. Most members of the Committee advocate that DOE support FERC siting authority for transmission projects 345 kV and higher that address national priorities such as bulk power system reliability, significant congestion, or interconnection and integration of low-carbon resources as recommended through regional and interconnection-wide planning efforts. In addition, federal intervention may be needed for 345 kV facilities that support these national priorities. EAC members also agree that DOE must also take a strong lead federal role for expeditious siting of all transmission over federal lands, allocating proper focus and resources to this task or delegating this responsibility to FERC.

However, urging passage of new legislation to provide for federal siting for all new EHV lines is not a unanimous recommendation of the EAC. Some EAC members do not recommend urging the Secretary of Energy to focus on passing new federal legislation that broadly preempts existing transmission siting laws in the absence of a federal energy policy and national renewable standard. These EAC members recommend increased multi-state collaboration, and better coordination of the federal agencies responsible for transmission line permitting. Other EAC members assert that NIETCs and FERC backstop siting authority should expand beyond congestion to address reliability as well as interconnection and integration of low-carbon resources. Still others contend that all transmission siting should be under FERC jurisdiction, similar to the rules and processes for interstate natural gas pipelines.

The key driver of policies in this area and others will be the development of a comprehensive national energy policy for the nation's electricity future. DOE should:

- Address siting issues by taking a strong lead federal role for expeditious siting of all transmission over federal land or delegate this responsibility to FERC.
- Support FERC siting authority for transmission above 345 kV as recommended through regional and interconnection-wide planning efforts that address national priorities such as

bulk power system reliability, significant congestion, or interconnection and integration of low-carbon resource. Consider possible federal intervention for facilities 345 kV and below that are needed to support these national priorities.

- If direct federal siting is not pursued, DOE should address siting issues by identifying and supporting state, local, and federal "best practices," supporting coordination of multi-agency permitting activities, and, as mentioned above, taking a strong lead in federal land use agency permitting or delegating this responsibility to FERC. For multistate lines that have been recommended through state-supported public regional siting efforts, that provide a recognized regional benefit for reliability and/or reducing congestion, and that enhance compliance with both federal and state clean energy policies, DOE should support enhanced federal siting authority, with full public participation, if state and or regional siting authorities are likely to delay approval in a timely fashion. NIETCs and FERC backstop authority may need to be expanded to address reliability as well as interconnection and integration of low-carbon resources.

3. Engage stakeholders to develop broad cost allocation for EHV transmission projects. Advise FERC to continue the use of formula rates and encourage "pass-through" rates, and work with FERC to provide broad cost-benefit analysis.

Broad cost allocation for backbone transmission facilities approved by regional and interconnection-wide planning processes must be developed and applied in a predictable fashion. This approach will support the development of transmission projects with widespread benefits and should include the following key DOE activities:

- Engage RTOs, transmission providers in non-RTO areas, and state and federal policymakers to develop broad cost allocation methodologies for EHV transmission facilities approved by regional and interconnection-wide planning authorities.
- Advise FERC to continue the use of formula rates and encourage "pass-through" rates (state-approved mechanisms to allow for automatic recovery of FERC-approved investments).
- Working with FERC, provide broad cost-benefit analyses that aid the industry in informing regulators and consumers about the need for transmission to lower electricity costs.

4. Enhance grid operations and control by expanding research and exploring new technologies. Encourage coordination/consolidation of balancing areas when deemed economical and reliable, for example to enhance operation of variable generation. Ensure the implementation of ongoing recommendations from the U.S.-Canada Power System Outage Task Force Report on the 2003 blackout.

The construction of a robust transmission network is a critical part of addressing the challenges of electric grid reliability, load growth, transmission congestion, access to lower-cost generation, and integration of renewable (and other low-carbon) generation. However, a number of steps can also be taken to operate the existing grid more efficiently, effectively, and reliably. While grid operation has a number of challenges, there are solutions available that should be developed in conjunction with transmission expansion. These solutions should include the following key DOE activities:

- Expand research into the following: (i) wide-area monitoring and control initiatives; (ii) network integration of renewable energy resources, including the development of tools to improve generation dispatch and system flexibility; and (iii) control center enhancements needed for grid security and the nation's energy future.
- Explore technologies that will improve the integration of variable renewable energy resources into the grid. Consider recommendations from NERC and EPRI efforts in this area. In addition, further investigate the benefits of Smart Grid technologies and demand response/load management while taking steps to ensure that the grid remains secure in all aspects, including cyber security.
- To improve the integration of variable renewable energy resources and further the benefits of Smart Grid technologies and demand response/load management, encourage coordination/consolidation of balancing areas when the benefits are shown to be greater than the costs, any operational and reliability cost impacts are equitably allocated, and NERC reliability standards are followed.
- Ensure the implementation of ongoing recommendations from the U.S.-Canada Power System Outage Task Force Report on the 2003 blackout and direct actions if these recommendations are not successfully implemented. Integrate recommendations from the prior and forthcoming DOE transmission congestion studies into these efforts as well.

5. Lead technological innovation, providing additional funding and engaging willing participants in joint efforts to develop and/or demonstrate new technologies. Advise FERC to support continued incentives and encourage state regulatory bodies to support cost recovery of appropriate transmission R&D investment.

In transmission, R&D efforts are needed in five broad areas: (i) achieving more effective use of existing rights-of-way, (ii) application of improved controls and diagnostics necessary for grid security and the nation’s energy future, (iii) enhancing asset reliability and flexibility with lower lifetime costs, (iv) reducing environmental and climate change impacts, and (v) advancing Smart Grid concepts to facilitate a self-healing grid and demand response/load management options.

As aging transmission facilities are upgraded and replaced, and as new facilities are designed and built, pursuing the R&D efforts listed above will support the application of technology solutions that maximize the capability and reliability of the transmission network while minimizing investment in unnecessary infrastructure and reducing environmental impacts.

DOE can provide leadership in the introduction of novel technologies through collaboration with industry and entities such as EPRI. Elements of a futuristic grid have been articulated through various industry initiatives, including the DOE Smart Grid Task Force, EPRI IntelliGrid™ and National Energy Technology Laboratory (NETL) Modern Grid Initiative. In addition, countries in Europe have successfully integrated over 50 GW of wind power. Through the study of European experiences with wind power resources, DOE can facilitate the U.S. electric power industry's understanding of how to address the variability of wind power resources and the technical requirements for reliably interconnecting them to the grid. However, the current DOE Office of Electricity Delivery and Energy Reliability (OE) R&D budget is far lower than that of any other energy research area. An increase in R&D funding from DOE is needed to further grid modernization efforts. If the economy of the United States depends on the energy future of the United States, and a robust and technologically advanced interstate grid will enable that future, then funding levels need to support strong federal leadership. DOE should:

- Formulate an R&D roadmap, build an R&D portfolio, provide seed funding, and engage willing participants in joint efforts to develop and/or demonstrate new technologies.
- Increase federal funding for transmission R&D and provide leadership at the federal level. Increase participation by national laboratories.
- Advise FERC to support continued incentives for beneficial technology development and encourage state regulatory bodies to support cost recovery of appropriate transmission R&D investment.
- Collaborate with EPRI and other private and public organizations to leverage R&D resources.

6. Reduce barriers to financing and construction of transmission by supporting new transmission ownership structures and advising FERC to encourage expedited timeliness for construction economic projects, provide opportunities for other industry participants, and encourage sound agreements for operations, maintenance, restoration, and reliability compliance where joint ownership is present.

While policymakers and utility executives must become more engaged in defining the nation’s energy priorities, immediate benefits can accrue from a more robust high voltage electric transmission system. Resolution of impediments to the construction and integration of such transmission infrastructures into the present and envisioned regional and national grids is imperative.

A broader universe of entities should be encouraged to invest in transmission facilities, through vehicles such as joint ownership. When ownership and investment is shared, risks associated with large capital investments are reduced. Such arrangements might also reduce difficulties in accessing capital for large transmission projects, which could well be adversely affected in the next few years by the current economic downturn. Facilitating investments in transmission projects by a variety of entities with different business models (i.e., publicly and cooperatively owned, as well as shareholder-owned) can also dispel the public's concerns that utilities are proposing such major transmission additions solely or largely to increase their rate bases and enhance shareholder profits.[19]

While increased participation is encouraged, jointly owned transmission projects must be supported through agreements that address operation, maintenance, restoration, and compliance with reliability standards. Incumbent utilities should not be looked upon as operator, maintainer, and restorer of last resort and have reliability compliance responsibilities without compensation, unless they have agreed to be responsible for such activities.

In addition, FERC and RTOs should be encouraged to develop processes for dealing with "across the seams" projects and facilitate independent transmission company participation and utility partnerships in "bidding" for construction rights. Key activities should include the following:

- Support reduced barriers for transmission investors and new transmission ownership structures, while ensuring that reliability is not jeopardized (DOE and FERC).
- Advise FERC to encourage states and RTOs to develop expedited timelines whereby utilities must commit to either constructing (or contracting for the construction of) economic projects and provide opportunities for other industry participants interested in contributing capital investments.
- Advise FERC to encourage sound agreements for operations, maintenance, restoration and reliability compliance where joint ownership is present.

[19] One example of such joint transmission development and ownership is the Cap X 2020 project in the Upper Midwestern United States: CapX2020, "Delivering Electricity you can rely on," http://www.capx2020.com.