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Electricity Transmission Policy for America: Enabling a Smart Grid, End-to-End

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Electricity Transmission Policy for America: Enabling a Smart Grid, End-to-End

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Preface

This working paper has been prepared as part of the Energy Innovation Project, an interdisciplinary study of the U.S. energy innovation system that is being carried out at the MIT Industrial Performance Center. The goals of the Energy Innovation Project (EIP) are to evaluate the strengths and weaknesses of the U.S. energy innovation system and to recommend ways to improve its performance. Occasional working papers prepared by members of the EIP research team are published as a contribution to public debate. The views expressed in these papers are those of the individual authors and do not necessarily reflect the conclusions of the Project as a whole or the Industrial Performance Center.

The subject of this paper, the electric power transmission network, is a critical enabler of technological innovations in power generation and in electricity use, topics of ongoing research by other members of the EIP team. The paper contributes to the active public policy debate on the future of the nation's electric power system by laying out a set of primarily institutional recommendations for upgrading the transmission network.

Richard K. Lester
Director, Energy Innovation Project

Electricity Transmission Policy for America:

Enabling a Smart Grid, End-to-End

Executive Summary

This paper proposes a framework of policies to guide the future development of America's electric transmission grid so that the electric power industry will be able to serve more effectively the changing needs of the U.S. economy and society. The paper provides a factual overview of the American electric power industry, with a focus on high voltage transmission. The current framework of public policies affecting the electric industry and, specifically, the transmission grid are summarized, and a range of proposals for legislative and regulatory policy reform are analyzed. Finally, a set of recommendations is provided which would accelerate innovation and the evolution of an "end-to-end smart" transmission grid in America.

Conclusions

America's electric power industry is *highly fragmented*, divided among more than 3,100 separate entities, under a variety of forms of investor and public ownership. Within the investor owned sector, consolidation has been underway.

America's electric power industry, *in the aggregate*, has a stable revenue base of $250+ billion per year, and a large asset base of $800+ billion. The industry is generally not over-levered. Of the electric power industry's total asset base, power generation accounts for 60%, distribution for 30%, and high voltage transmission for 10%.

America's high voltage transmission grids are the strategic links between generation and electricity consumer loads. As America's economy and society become more digital processor and information technology driven, we are becoming more dependent on uninterrupted, high quality electric power supplies. Investor-owned utilities own 66% of America's high voltage transmission line miles, while public entities own 30%. Although they do not own transmission facilities, independent system operators manage wholesale power markets and provide transmission services for about 2/3 of America's electricity consumers.

Although annual investment in transmission declined by 35% during the 1980s and 1990s, recent increases have been spurred by the Northeast blackout in 2003 – the worst electric system failure in American history. Modernization of America's high voltage transmission grids is overdue and urgent.

Public policy oversight of America's electric power industry policy is a *hodge podge*, rooted in the federalism concept of 50 state laboratories. Although federal authority frequently overlaps, diverse state regulatory policies predominate regarding electric industry structure, generation adequacy, energy resource mix, transmission siting and cost recovery and retail electricity prices. Federal regulatory policies govern wholesale power market design and prices, and, since 2005, electric system reliability standards.

America lacks a coherent national energy policy. However, America's electric power industry can and should become the leading edge of the transition to a secure and environmentally sustainable energy future.

Recommendations

Transmission planning and siting: In legislation Congress should:

- clarify that the electric high voltage transmission planning authority of the Federal Energy Regulatory Commission (FERC) applies to all electric transmission owners, operators, and developers, and to local, state, and federal agencies with transmission planning responsibilities;
- authorize FERC to designate regional transmission planning entities within the Eastern and Western Interconnections;
- empower regional planning entities, in consultation with industry, governmental, and nongovernmental stakeholders and drawing upon available plans and proposals, to develop regional transmission plans which include an approved list of specific projects, including approved routes and cost estimates;
- authorize FERC to establish defined time lines for the completion of regional transmission planning results for FERC review, modification and approval;
- provide that FERC approval of proposed projects included in regional plans has conclusive effects in other governmental agency proceedings.

Transmission cost recovery and allocation: In legislation Congress should direct FERC to determine cost recovery for future high voltage interstate electric transmission projects and such projects affecting interstate commerce, and clearly direct that FERC's cost recovery decisions take precedence over any State cost recovery determinations. In legislation Congress may include cost allocation guidance for high voltage transmission projects. With or without statutory guidance, however, FERC should conduct a rulemaking proceeding with the aim of developing cost allocation principles appropriate for a variety of different circumstances. A key factor to consider during rule making should be that a cost allocation method, if applied to an otherwise meritorious project, should result in a project that can attract financing.

Independent system operator coverage: In legislation Congress should: direct FERC to develop and implement a plan to reduce the number of electric power balancing authorities and to establish independent system operators and organized wholesale power markets covering the northwest and southwest United States, which do not already have such coverage. Legislation should provide a 3-year transition period for this to occur.

Transmission grid modernization: U.S. Department of Energy (DOE) should, in cooperation with North American Electric Reliability Corporation and Electric Power Research Institute, develop and guide implementation of a national innovation strategy for America's electric transmission grid. The strategy should result in specific plans for all transmission owners to incorporate "best available, cost effective" technologies that will improve the operating performance of their existing transmission facilities within a defined period of years.

Smart grid: Federal smart grid standards must be developed and implemented nationwide. In parallel with national standards development, transmission system operators should develop and demonstrate, with utilities and their customers, demonstration demand response programs, enabling utility customers to participate in wholesale power markets, selling "negawatts" during peak demand periods. Demonstration projects involving distributed power generating systems and energy storage should be deployed on utility customer premises and inside utility distribution networks. Transmission system operators must be full partners in these projects. Such programs would, of course, be accompanied by utility implementation of advanced metering infrastructure enabling two-way interactions between customers and the grid operator. Depending on results of demonstration programs, state regulatory agencies should approve rules and rate designs, including dynamic pricing, appropriate for wide-scale deployments incorporating national smart grid standards.

Introduction

A persistent trend in the economies and societies of advanced nations throughout the 20th Century has been that an ever increasing fraction of the primary energy resources they use – oil, coal, natural gas, nuclear, hydro power, geothermal, wind, solar and biofuels – is consumed in the form of electricity. Forecasts generally conclude that this trend will persist for the foreseeable future. Furthermore, as modern economies and societies become more and more saturated with digital electronic processors, they have become critically dependent on uninterrupted, high quality electricity supplies. America embraces these trends.

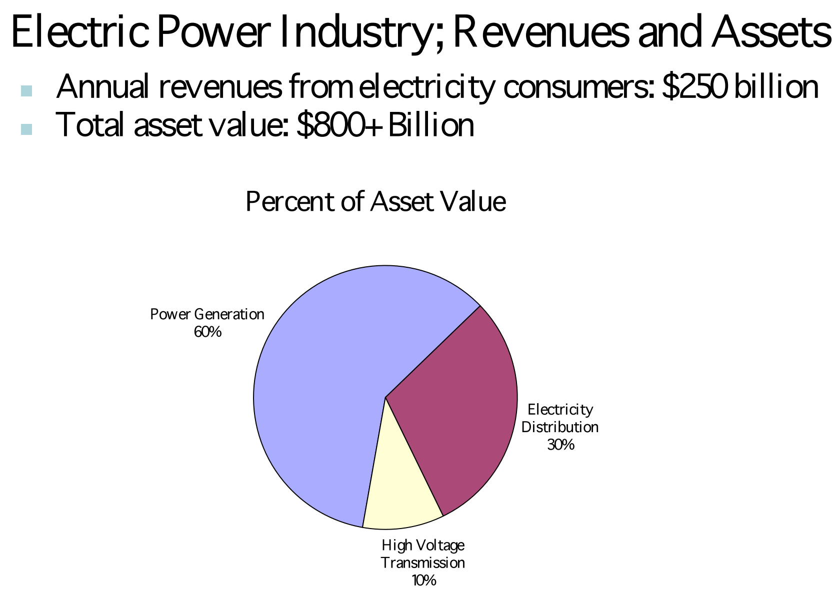
An electric power industry is composed of three basic components: generation, which converts primary energy resources into electricity; distribution, which distributes electricity to millions of consumers at home, work and play; and transmission, which connects generators to distributors. Among modern, industrially advanced nations, America's electric power industry is unique. It is largest in size, with about 1,000,000 megawatts of generating capacity, serving the largest economy in the world. It is predominantly owned by private investors. And, importantly, public policy oversight of the industry is vested primarily in America's 50 diverse states.

This working paper focuses on America's high voltage electric transmission networks or grids -- the vital links between power generators and distributors of electricity to consumers. Whereas America's transmission grid was recognized as the most important engineering feat of the 20th Century, it is now widely recognized to be in urgent need of modernization. Modernization of the grid itself will require deployment of technologies that are for the most part currently available or in advanced development, and will not depend on technological breakthroughs. Moreover, it should not require large financing from the federal government. However, modernization of America's electric grid will require public policy reforms at the federal, state and local levels. With reforms, America's electric transmission networks can become the enablers of rapid technological innovations in electric power generation, and also innovations on both sides of the meters connecting local utilities and their customers. Without electric transmission policy reform, however, these necessary innovations in power generation and electricity consumption will be stifled.

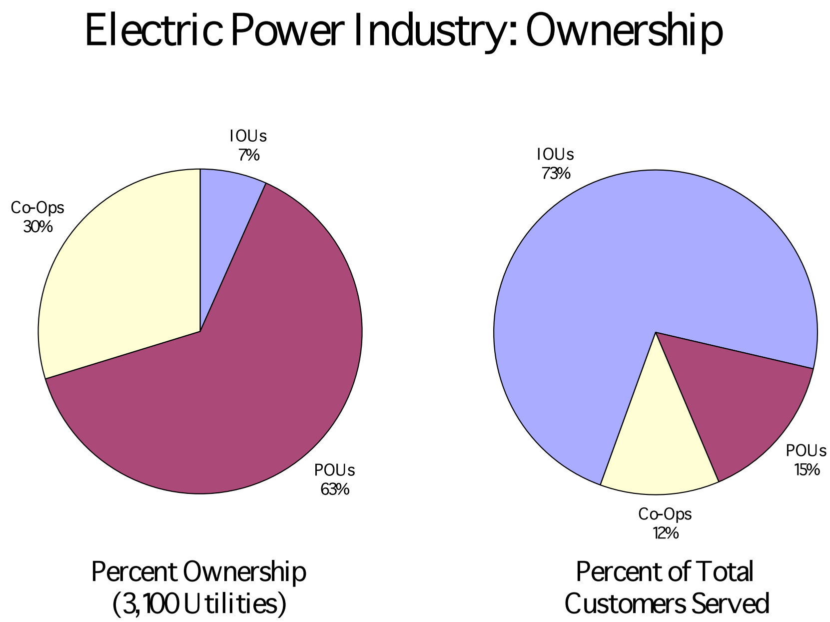
What is a framework of policies to guide future development of America's electric transmission grid so that America's electric power industry will be able to serve more effectively the changing needs of America's economy and society? In answering this question, first, we provide essential facts about the American electric power industry as a whole, and, second, we focus on high voltage transmission. Third, we summarize the existing framework of public policies affecting the electric industry and the transmission grid specifically. Having provided this foundation, we develop and analyze a variety of proposals for legislative and regulatory policy reform. And finally, based on our analysis, we provide a set of recommendations which, if implemented, could accelerate innovation and the evolution of an "end-to-end smart" electric transmission grid in America.

Several energy/climate bills are pending before the United States Congress which contain specific provisions affecting electric transmission. Any Federal legislation focused on transmission will modify, more or less, the complex matrix of existing Federal, State, and local laws and regulations affecting electric transmission, and probably related components of the electric power industry. This working paper will, we hope, make a constructive contribution to this Federal legislative process.

1. America's Electric Power Industry



America's electric power industry, *in the aggregate*, has a stable revenue base of $250+ billion per year, and a large asset base of $800+ billion. The industry is generally not over-levered, and most balance sheets are strong. Of the electric power industry's total asset base, power generation accounts for 60%, distribution for 30%, and high voltage transmission for 10%.

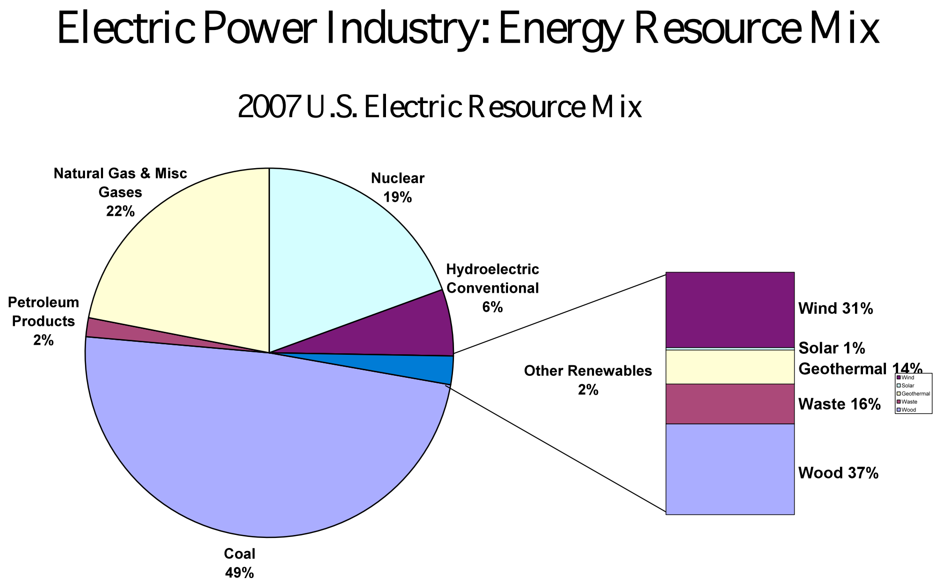


Ownership of America's electric power industry is divided among about 3100 separate entities. 213 (7%) investor owned utilities (IOUs) serve almost 75% of America's electricity customers, 2,000 (63%) public owned utilities (POUs) serve 15% of customers, and 930 (30%) cooperatives serve 12% of customers mostly in rural areas. It is also noteworthy, as discussed further below the Federal Power Marketing Authorities (Fed PMAs – Tennessee Valley Authority, Bonneville Power Authority, and Western Area Power Authority) own generation and extensive transmission systems, marketing wholesale power preferentially to POUs and others. Within the investor-owned utility (IOU) sector, consolidation has been underway, exemplified by Exelon, Duke Power, and Mid-America.

America's electric industry is, therefore, *highly fragmented*, under a variety of forms of ownership, and embedded in 50 states and the District of Columbia.

How did this happen? As the American electric utility industry expanded rapidly during the early decades of the 20th Century, financial abuses became widespread. Small local IOUs were consolidated into large, multi-state regional holding companies, with very complex corporate structures. These structures, which defied comprehension by state economic regulators, enabled holding companies to milk the equity out of their utility operating subsidiaries, leaving them debt laden. Financial collapses of utility holding companies were major cause of the1929 stock market crash.

The Public Utility Holding Company Act (PUHCA), enacted in 1934, abolished most electric utility holding companies. Most electric utility operating franchise areas were confined to a single state, subject to thorough state economic and financial regulation. In addition to state regulation of their operating companies, the remaining regional holding companies were subject to detailed federal financial regulation. PUHCA was finally repealed in 20005.



Currently, coal provides about half, and natural gas and nuclear energy each provide about one-fifth, of the primary energy required to supply America's electricity demands. Renewable resources provide only two percent.

However, driven by federal tax incentives and state renewable portfolio standards (RPS), renewable resources have recently become the most rapidly expanding part of the electric resource mix. 25 states and the District of Columbia have adopted mandatory RPS goals. For example, California has RPS goals of 20% in 2010 (which will not be achieved until 2012-13) and 33% by 2020. An additional 3 states have adopted non-binding RPS goals.

Meeting America's future needs for electricity while largely reducing greenhouse gas (GHG) emissions from power generation will require intensive development of America's regions which are rich in wind and solar resources, as well as nuclear power and coal incorporating carbon capture and sequestration (CCS) technology.

Power Generation; CO_2 Emissions: 2006

Total	*~ 5890 Million Metric Tons*
Electric Power Generation	40%
Transportation	33%
Industry	17%
Commercial	4%
Residential	6%
Electric Power Generation	*~ 2344 Million Metric Tons*
Coal	82%
Natural gas	15%
Petroleum	3%
Nuclear	0%
Hydro (conventional)	0%
Renewable energies	0%

Source: *Lawrence Livermore National Laboratory, U.S. DOE*

CO_2 emissions from use of fossil fuels – coal, petroleum and natural gas – are the largest contributors to total greenhouse gas emissions, which are an increasing worldwide threat to a sustainable environment. The table above shows that, for America, electric power generation is the largest sector contributing CO_2, 40%, with transportation contributing 33%. Of the primary energy sources for the power generation sector, coal contributes 82%, natural gas 15% and petroleum 3%. Non-carbon energy sources, which contribute 0% of CO_2, account for about 30% of power generation.

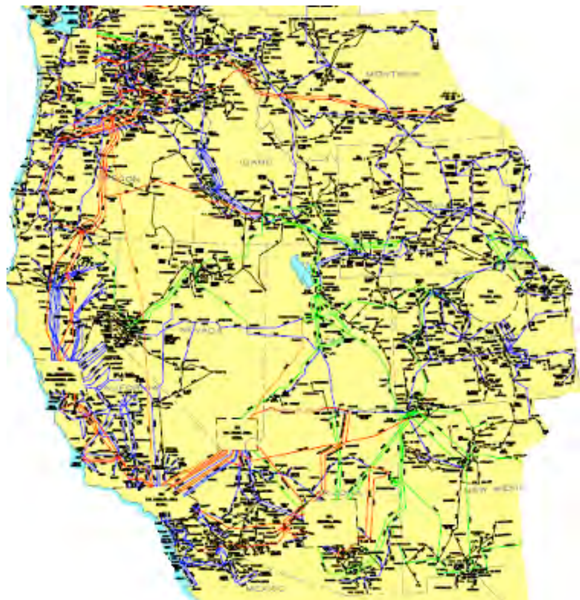
2. High Voltage Transmission

A High Voltage Transmission Corridor

With America's electric power industry in view, we now focus on electric transmission. This picture shows one high voltage transmission corridor among many. It is not a pretty picture, but it is a vital electron highway which connects power generators with consumer loads.

America's economy is becoming more digital processor, information technology driven. As a result, America is becoming more dependent on uninterrupted, high quality electric power supplies.

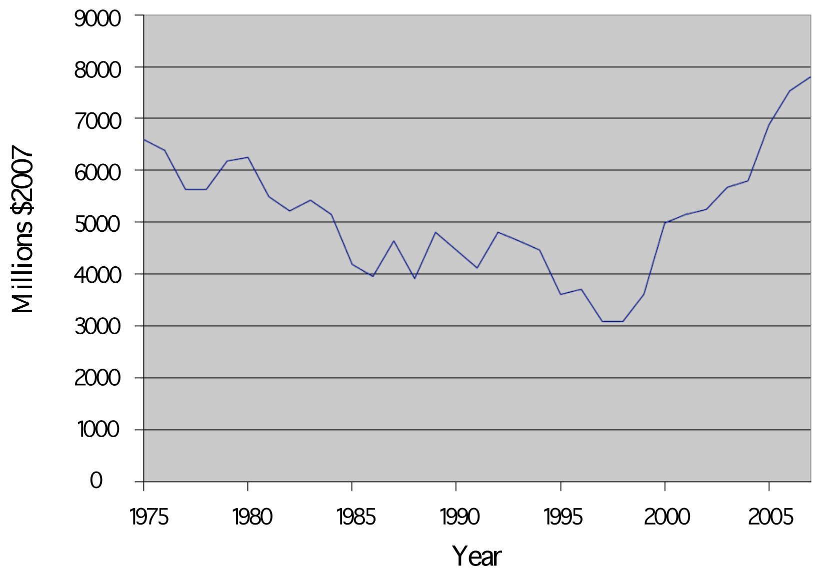
Western U.S. Transmission System



Shown above are the principal high-voltage transmission lines within the Western Electricity Coordinating Council. High-voltage electric transmission networks are sprawling, inter-connected, technologically complex networks. Power flows across these networks from power generators to utility distribution systems. Power flows are governed by physical laws, not pathways described in contracts between generators and utilities or utility customers. A comparable map of the New England or Mid-Atlantic regions would show even denser networks of lines.

Electric Transmission plays a critical role as the strategic link between generation and load. It ensures reliability by delivering en3rgy and providing reliability services such as ramping, load-follwing and regulation services. In addition, it delivers economic and environmental benefits by delivering lower cost, cleaner supplies over long distances to load centers and enabling efficient adjustments to meet balancing areas'differing seasonal needs. All of this is accomplished by a transmission system that represents a small portion of consumer electricity costs.

Electric Transmission Grid: Investment Levels, 1975-2007



The chart above shows annual investment levels in transmission ($2007). Despite its critical role in America's electric power infrastructure, annual investment in transmission declined by 35% during the 1980s and 1990s, due to uncertainty about the nature and extent of power industry restructuring. Annual investment levels have increased dramatically since 2000, spurred by the northeast blackout in 2003. Investment levels have exceeded 1970s levels since 2005.

Transmission line losses increased from 5% in 1970 to 9% in 2001, and have since returned to the 5% range. Costs of grid congestion, power outages and power quality disturbances range from $25 to $80 billion annually.

Reminder: Although transmission is the vital link between generators and load, it represents about 10% of costs consumers pay for electricity.

High Voltage Transmission by Owner and Region

Data in Miles [and Regional %] for the 48 Contiguous States for Transmission Lines of 230 kV and Higher

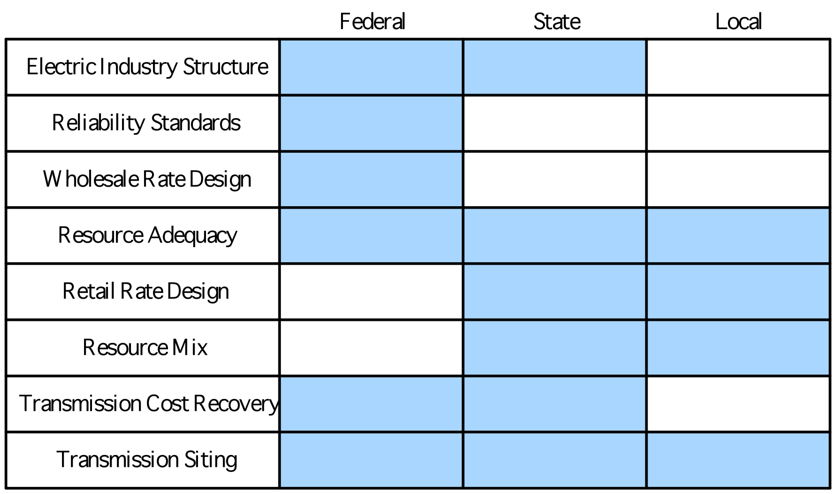
Owner Type	Northeast / Midwest	Southeast	Southwest	Upper Plains	West	U.S. Total
Federal	21 (0%)	2,768 (7%)	0 (0%)	2,541 (17%)	18,214 (27%)	23,544 (14%)
Other Public Power	964 (3%)	2,079 (5%)	731 (5%)	1,798 (12%)	5,525 (8%)	11,098 (7%)
Cooperative	0% (0%)	2,993 (8%)	387 (2%)	2,908 (20%)	4,496 (7%)	10,784 (6%)
Subtotal – All Public Power and Cooperatives	986 (3%)	7,840 (20%)	1,118 (7%)	7,247 (49%)	28,235 (42%)	45,426 (27%)
Independent Transmission Companies	4,640 (15%)	0 (0%)	351 (2%)	1,045 (7%)	0 (0%)	6,036 (4%)
Investor Owned Utilities	24,968 (81%)	31,412 (79%)	12,408 (80%)	5,402 (36%)	37,034 (56%)	111,223 (66%)
N/A	260 (1%)	264 (1%)	1,686 (11%)	1,148 (8%)	1,250 (2%)	4,609 (3%)
Total	30,853 (100%)	39,516 (100%)	15,563 (100%)	14,843 (100%)	66,519 (100%)	167,294 (100%)

Source: Stan Mark Kaplan, Electric Power Transmission: Background and Policy Issues, Congressional Research Service (2009).

The chart above shows miles of high voltage transmission lines in the 48 contiguous states by region and type of owner. Overall, IOUs and independent Transcos own 70% and POUs, Federal PMAs and cooperatives own 27% of the total miles of high voltage transmission. However, ownership patterns vary across the country. In the West and Upper Plains, public power owns more than 40%, whereas in the Northeast, Midwest and South, private power owns 80%.

3. Electric Power Industry Policy

Electric Industry Policy Oversight



Electric power industry policy is a *hodge podge*, rooted in the federalism of 50 state laboratories. There is no coherent national vision and policy.

Industry structure: There are overlapping federal and state authorities. Federal legislation (Energy Policy ACT, 1992) sanctions independent power producers (IPPs) and requires transmission owners to provide IPPs open, nondiscriminatory access to their transmission facilities and wholesale power markets. Some states have required IOUs to divest their generation assets and procure additional power supplies from IPPs. Other states, primarily in the northwest and southeast, have not required such IOU restructuring. (Further discussion follows.)

Reliability standards: Federal legislation (Energy Policy Act, 2005) mandates reliability standards for the entire American electric power industry. (Further discussion follows.)

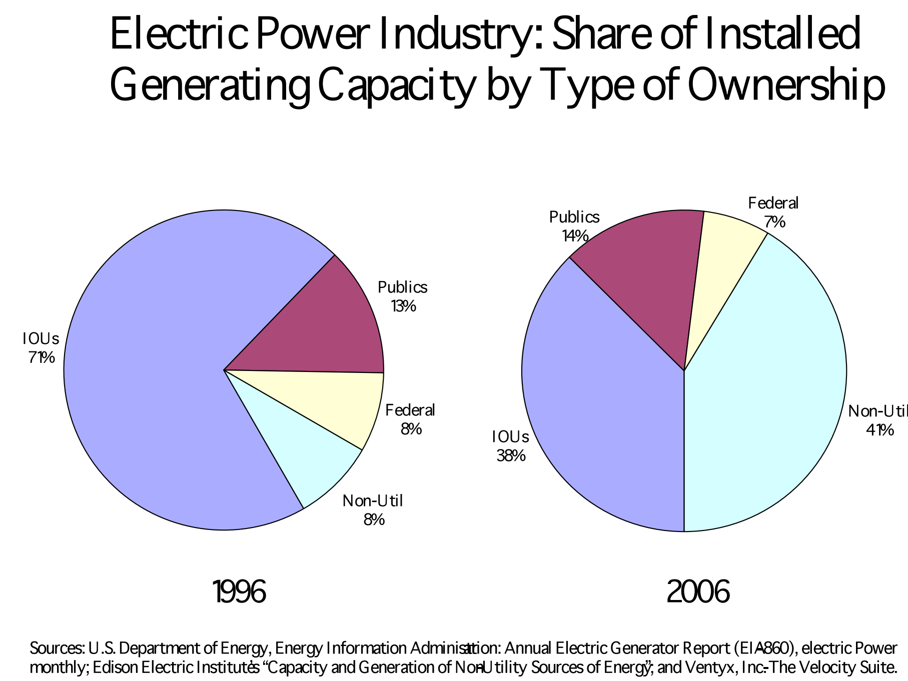
Wholesale rates: Federal Energy Regulatory Commission (FERC) approves wholesale market designs of RTO/ISOs. FERC also determines whether wholesale market prices are "just and reasonable." (Further discussion of RTO/ISOs follows.)

Resource adequacy: Whether electric power supplies are and will be adequate to meet expected demands for electricity are subject to overlapping FERC and State Public Utilities Commission (PUC) authorities, in the case of IOUs. In the case of POUs, self-governing boards determine resource adequacy.

Retail rates and energy resource mix: Electricity consumer prices and the energy resources used to generate the power are two issues of key importance to both the electric power industry and electricity consumers. Retail prices and the energy resource mix are fixed by state PUCs for IOUs, and by self-governing boards of POUs. Retail competition is also under state jurisdiction.

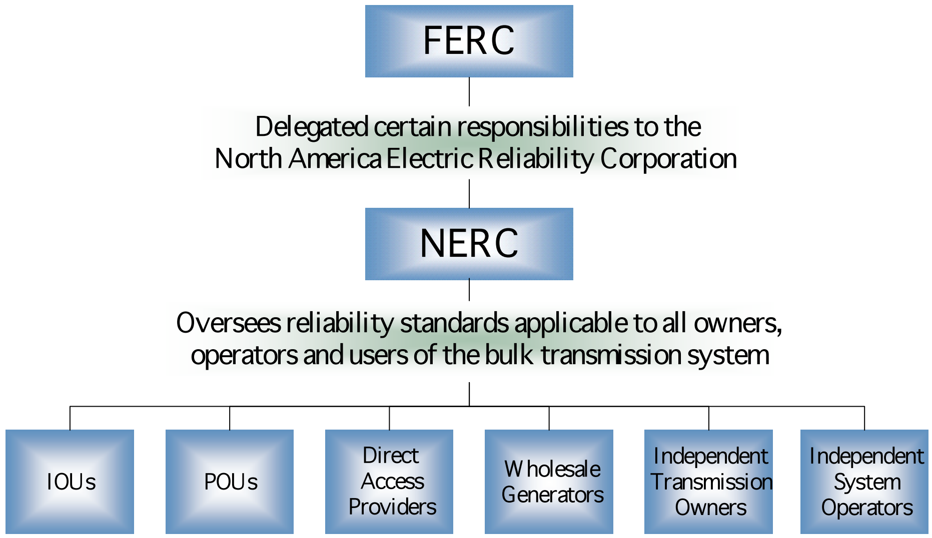
<u>Transmission cost recovery</u>: Cost recovery for transmission investments is approved by state PUCs and FERC for IOU transmission owners, by FERC alone for independent Transcos, and by self-governing boards for POUs.

<u>Transmission siting</u>: Multiple overlapping local, state and federal authorities approve the location of transmission lines and related facilities. (Further discussion follows in section 4.)



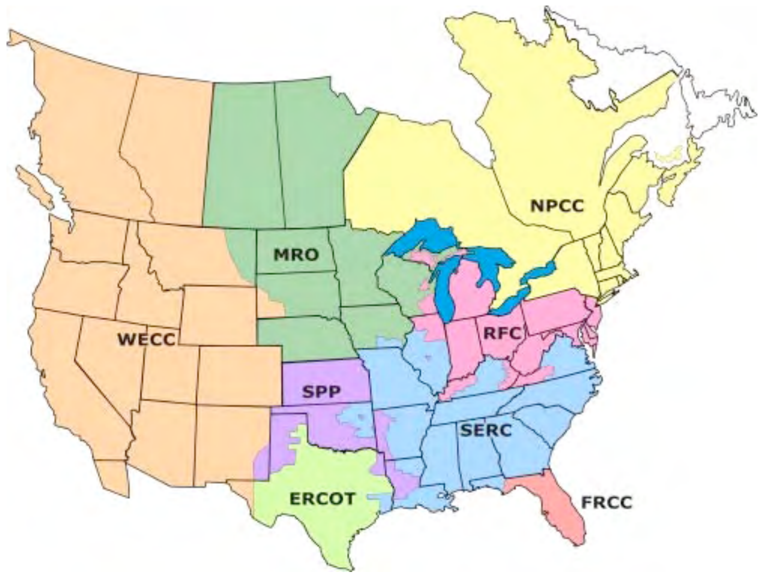
Federal and state policy initiatives related to industry restructuring have had a large impact on the ownership of power generation in America. IOU ownership of generation has shrunk from 71% of capacity in 1996 to 38% in 2006. During the same period, IPP ownership has increased from 8% to 41%. IPPs have also been major innovators, introducing and going to scale with combined cycle technology for natural gas units, and with fluidized bed combustion and selective catalytic reduction NOx control for coal units.

Federal Reliability Oversight



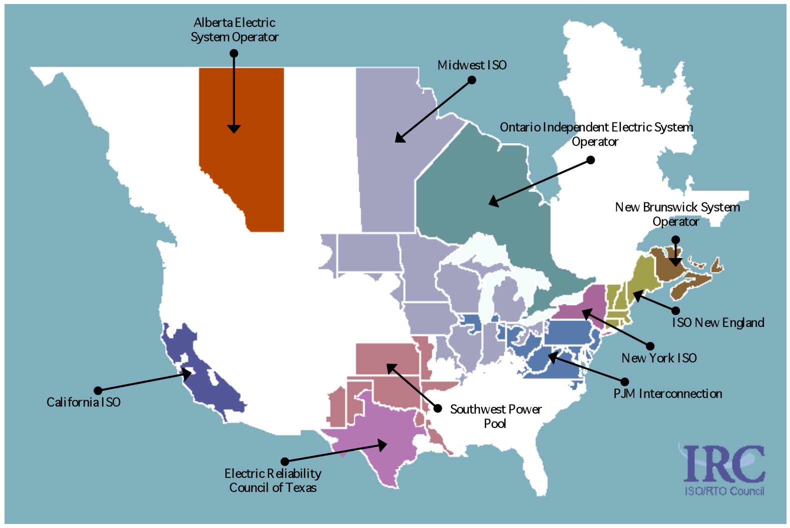
After a blackout cascaded throughout the northeast U.S. and Canada in 2003, Congress enacted the Energy Policy Act, 2005, which created a new structure for establishing and enforcing mandatory electric reliability standards. Compliance with these standards is now mandatory and enforceable for America's entire electric power industry. With a strong assertion of federal authority, IOUs, Federal PMAs and other POUs, IPPs (wholesale generators), independent Transcos, and RTO/ISOs are currently all subject to North American Electric Reliability Corporation (NERC) reliability standards and enforcement.

North American Electric Reliability Corporation



As the map above shows, with FERC approval, NERC has divided America and Canada into 8 regional electric reliability organizations for monitoring and enforcing compliance with NERC standards within their regions.

Electric Transmission Grid: RTO/ISO
Operating Responsibility



Electric Transmission Grids: Operating Responsibilities

Responsibility for *operating* America's electric transmission networks or grids is dispersed among widely divergent business models that can co-exist under the transmission open access regime established by FERC in 1996 under Order 888 and revised in 2007 under Order 890. Overall the grids are operated within a framework of about 130 control areas, which FERC now calls "balancing authorities."

Some IOUs own and operate transmission grids, and manage their balancing authorities. These are located in the Western Electricity Coordinating Council (WECC), except for California, and in the southeast U.S. Federal PMAs (TVA in the southeast, and BPA and WAPA in the west) and some POUs also own and operate their transmission grids, and manage their balancing authorities.

Other IOUs own, but do not operate transmission grids. Instead they participate in RTO/ISOs which operate transmission grids within their defined balancing authorities. Many smaller POUs also participate in the RTO/ISO in which they are embedded.

RTO/ISOs operate, but do *not* own grids. (See further discussion below.) Their territories are defined by membership. For example: CAISO operates most, but not all, of the grid in California. CAISO operates all large IOU-owned grids -- PG&E, SCE, SDG&E, and some smaller POU-owned grids – Riverside, Pasadena. However, CAISO does *not* operate some larger POU-owned grids – LADWP, SMUD, which have their balancing authorities embedded within CAISO's control area. There are other seams that have resulted from membership decisions. PJM operates ComEd territory in Illinois that is fully within the Midwest ISO boundaries.

This mosaic of transmission operating responsibilities is the result of two policy thrusts during the 1990s. State-centric regulatory policy required electric industry restructuring (generation divestment) and the introduction of retail competition in some parts of America, while restructuring was successfully resisted by incumbent electric utilities in other parts of America. Meanwhile, as noted, federal regulatory policy in the late 1990s and early 2000s championed transmission open access and the voluntary formation of competitive wholesale power markets administered by independent ISOs (defined in FERC Order 888) or RTOs (defined in Order 2000), which have been successfully established mainly in areas where state utility restructuring has been required.

Basically, American public policy compelled a transition in the electric power industry which has never been fully extended or standardized nationally (or at least throughout FERC jurisdictional entities), resulting in continued balkanization of the grid and often significant differences in ownership structures and wholesale market rules between regions. The bottom line is that RTO/ISOs provide transmission service for about 2/3 of America's electricity consumers located in the Northeast, mid-Atlantic, Midwest regions, and California. Transmission service in the Northwest and Southeast regions is provided by IOUs not participating in RTO/ISO controlled grids, Federal PMAs, POUs and cooperatives.

RTO/ISO Model

An RTO or ISO is defined as an electric utility regulated by FERC, and most are non-profit. It is funded by a grid management charge approved by FERC and paid by generators and load serving entities within the RTO/ISO's balancing authority. It operates the electric transmission facilities under its authority in compliance with NERC approved mandatory reliability standards. In so doing, it provides nondiscriminatory access to transmission services for all qualified market participants. Historically, some RTO/ISOs evolved from power pools, for example PJM, while others were created by state legislation which also mandated electric industry restructuring, for example CAISO, or through other voluntary associations, such as the Midwest ISO.

An RTO/ISO designs and administers within its balancing authority several types of auction markets, including day-ahead and real-time wholesale spot markets (including five minute dispatch) for electric energy and ancillary services, and forward markets for financial transmission rights; several also operate forward markets for capacity. These markets are characterized by transparent prices and have both ex ante and ex post rules that support workably competitive market outcomes. Importantly, both the RTO/ISO market operators and its market monitors (which may be internal or external or both) evaluate performance of its wholesale power markets, reporting evidence of possible manipulative behavior to its management and/or directly to FERC. In collaboration with its market participants and other transmission project developers, an RTO/ISO also proactively plans for transmission expansion and improvement projects to increase reliability of transmission service, reduce grid operating costs by relieving transmission congestion, and to facilitate achievement of state and (potentially) federal energy/climate policy goals.

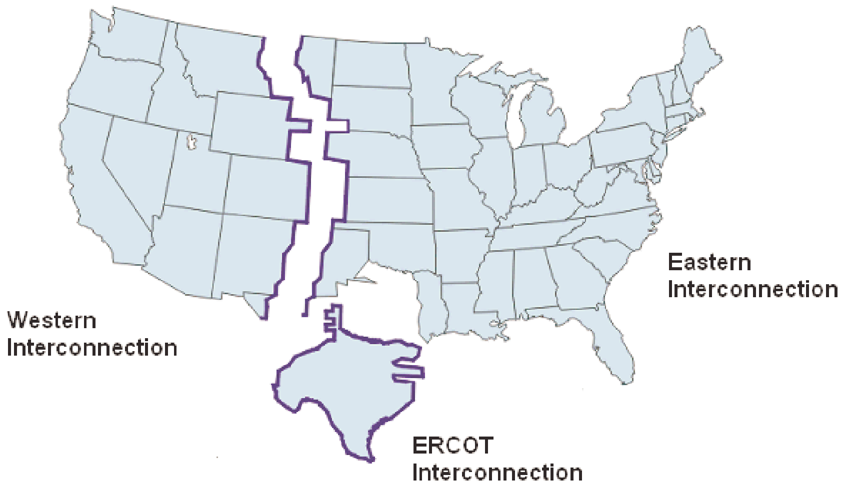
Control Room: California Independent System Operator

California Independent System Operator, CAISO, manages the transmission grid for about 80% of California and over 30% of the electric load in the entire multi-state Western Electricity Coordinating Council. Within very narrow electric frequency limits around 60 Herz, CAISO maintains a dynamic balance between electric loads (customer demands) and supplies provided by generating plants, 24 hours/day X 7 days/week X 365 days/year, except 366 days for leap year. CAISO is able to manage peak loads which exceed 50,000 MW with voluntary cooperation from its customers reducing their loads during peak periods, but without service interruptions.

Electric Power Industry: System Interconnections

With a focus on electric transmission grids, we have seen that America's electric power industry is grouped into 130 balancing authorities. These in turn are grouped into 8 regional electric reliability organizations under NERC. And 8 RTO/ISOs cover the Northeast, Mid-Atlantic and Middle West regions, California and Texas. The largest aggregations of America's electric power industry, which we now consider, are three major interconnections, which operated independently of one another. Within each separate interconnection, transmission networks are composed primarily of high voltage alternating current (AC) lines, with some direct current (DC) lines interspersed for point-to-point transmission service within the interconnection. The AC networks within an interconnection are in fact interconnected so that power can flow among the various AC networks, which must be operated synchronously. Between the interconnections, however, there a only a limited number of DC tie lines, so that each interconnection operates independently of the others.

Electric Power Industry: System Interconnections



Source: adapted from a map located on the Energy Information Administration website at http://www.eia.doe.gov/cneaf/electricity/page/fact_sheets/transmission.html.

The Eastern Interconnection includes over 750,000 MW of generating capacity. Of the three, it is the most tightly networked interconnection. Operating challenges mainly relate to thermal overloads (line sags). As noted above, in the Eastern Interconnection, RTO/ISO coverage is relatively complete in the Northeast, mid-Atlantic and Middle West regions, whereas, in the southeast, the IOUs and TVA, the largest Federal PMA, do not participate in RTO/ISOs.

The Western Interconnection includes over 125,000 MW of generating capacity. Given its large geographical expanse, it is loosely networked except around urban areas. Operating challenges focus on maintaining grid stability over long distances. In the Western Interconnection, only California is covered by an RTO/ISO.

The ERCOT Interconnection (Electric Reliability Council of Texas) includes about 50,000 MW of generating capacity, comparable to CAISO. The interconnection lies entirely within Texas, covering most of the state. ERCOT is a NERC regional reliability entity. Although not subject to FERC regulation, it operates in a manner more or less consistent with an RTO/ISO.

4. Electric Transmission Policy: Analysis and Recommendations

The preceding sections of this report provide a foundation for evaluating electric transmission policy, and a variety of alternatives proposed for improvement. We now restate the question raised at the outset of this paper: **What is a framework of policies to guide future development of America's electric transmission grid so that America's electric power industry will be able to serve in a timely and cost-effective way the changing needs of America's economy and society?** In this section, we seek an answer for this question by considering, in turn, a sequence of elements which a comprehensive transmission policy should resolve. Our sequence includes: planning, cost allocation/recovery, siting, permitting, finance, construction, operation, maintenance, and improvement/innovation. For each element, we summarize the current status (referring to material in sections 1 through 3), the major issues and alternatives, and our policy recommendations, if appropriate. Taken together, the resulting set of policies focused on America's electric transmission grid should attract investment and accelerate innovation within the grid infrastructure. Transmission grid operators should then be able to facilitate achievement of America's energy, climate and other environmental policy goals, while continuously supplying power for America's electricity dependent economy and society.

Planning

An electric transmission network is a multi-billion dollar investment in infrastructure that evolves and expands over decades as new generation is constructed and old generation is retired, and as the patterns and density of electric loads increase and alter with urban and suburban land developments. Planning for America's transmission grid should be driven by a range of requirements: enabling and maintaining overall grid reliability; relieving congestion on transmission lines; providing economic benefits through open access to transmission services and wholesale market operations; and facilitating achievement of regional and national energy and environmental policy goals.

Current status

FERC Order 890 requires all jurisdictional public utility transmission providers, including RTO/ISOs, to implement a coordinated, open, transparent planning process for all participating stakeholders – load serving entities, generator owners and developers, participating transmission owners and developers. RTO/ISO staff and stakeholders reach consensus on planning assumptions, identify locations where transmission projects may improve reliability and/or relieve congestion, may provide economic benefits, and, in states where applicable, projects to meet RPS goals. Developers propose transmission projects, staff evaluates projects and alternatives, and proposes inclusion or exclusion from the plan. Depending on project size, management or RTO/ISO board approves projects included. FERC Order 890 explicitly encourages RTO/ISOs to participate in regional planning efforts, including adjacent RTO/ISO and non-RTO areas. Current status of Interconnection-wide transmission planning is discussed separately below.

Outside RTO/ISO controlled grids, IOUs are subject to Order 890, although FERC has not required rigorous compliance. POUs and Federal PMAs are subject to self-governing board review. In promulgating Order 890, FERC did not make it applicable to POUs and Federal PMAs, However, FERC stated its expectation that such public entities would adopt and participate in comparable transmission planning processes. Thus, FERC apparently assumed it has authority to impose Order 890 planning processes on POUs, although it has refrained from doing so. FERC has recently announced a series of regional technical conferences to examine the progress and sufficiency of the Order 890 planning process.

Issues

Should FERC Order 890 apply to POU or Federal PMA controlled grids?

Yes, but this will require FERC rulemaking, which may be contentious.

Does FERC Order 890 apply to IOU controlled grids not within RTO/ISOs?

Yes, but planning by IOUs for IOU controlled grids may not, in practice, be held to the same standards of compliance as RTO/ISO planning.

What should be the effect of RTO/ISO decisions approving transmission planning projects?

Rebuttable presumption regarding "need" in state PUC Certificate of Public Convenience and Necessity (CPCN) proceedings.

- Rebuttable presumption in FERC project cost recovery proceedings.

Interconnection-wide planning

Current Status

Eastern Interconnection: Recently, an initiative to establish a regional transmission planning entity for the entire Eastern Interconnection has been launched in an effort to stay ahead of any federal legislation.

Western Interconnection: In general, Western Interconnection-wide planning is voluntary, led by WECC's Transmission Expansion Planning Policy Committee, with subregional planning groups, committees, stakeholders being formed. "WECC/TEPPC will not prescribe the exact facilities to be built, but rather provide intelligence to state and federal decision-makers about what is needed." (WECC/TEPPC report) The Western Governors Association (WGA) is also involved in regional transmission planning activities. Specifically, WGA has underway with U.S. DOE a joint initiative aimed at mapping Western Renewable Energy Zones in the Western Interconnection.

California has established the Renewable Energy Transmission Initiative (RETI). This is a collaborative planning initiative, involving representatives of CPUC, CEC, CAISO, renewable energy developers, environmental and consumer organizations, and IOUs and POUs. The goal of the RETI collaborative is to reach consensus on a list of areas which should be reserved/sanctioned for development of renewable energy resources within California, and on a rank-ordering of the list. The process has been underway for two years and has produced a draft report on Renewable Energy Zones and environmental constraints. Work on a collaborative plan is ongoing.

ERCOT Interconnection: Electric Reliability Council of Texas (ERCOT) planning is more or less consistent with FERC Order 890, with planning results approved by the PUC.

The American Recovery and Reinvestment Act (ARRA, stimulus legislation) provides DOE with $80M, in coordination with FERC, to provide funding and technical assistance to other entities enabling the formation of interconnection-based transmission plans. The Eastern initiative and WECC are applicants for support.

Issues

What should be the scope of multi-state regional transmission planning?

- Electric transmission planners inevitably accord highest priority to transmission service reliability in their analyses of projects for inclusion in their plans for future development. Most proposed transmission projects are justified because they are necessary to maintain reliability of the grid as available power supplies and electricity demands are forecast to change over time.
- Electric transmission planners also include economic analyses, in choosing among competing alternatives to fulfill a reliability need, but also to reduce the costs of transmission congestion incurred under grid operations. State PUCs focus on project costs, as well as siting, in their review of transmission projects in Certificate of Public Convenience and Necessity (CPCN) proceedings.
- In addition to reliability and economics, renewable energy policy has become a large factor, contributing to the increasing salience at all levels of government of electric transmission policy. (See summary of RPS above) Some Federal legislative proposals specify a high minimum amount of renewable energy that any transmission line authorized would be required to carry – a so called "green" line provision.
- Furthermore, the most comprehensive scope proposed for regional transmission planning includes energy efficiency measures, distributed generation systems on consumer premises, and consumer demand response programs among the alternatives to be evaluated in conjunction with transmission expansion plans. FERC Order 890 also requires consideration of these alternatives in determining the need for transmission expansion.

What is the best geographical scope for regional planning?

- The Eastern Interconnection includes 6 NERC designated regional reliability organizations. Eastern has already undergone consolidation, although further steps for planning may be desirable. Eastern has 6 RTO/ISO planning authorities that are not congruent with NERC reliability regions. An Interconnection-wide planning effort is underway, but will the southeast U.S., which lacks RTO/ISO coverage, participate fully and effectively?
- WECC is the sole regional reliability organization designated by NERC for the Western Interconnection. WECC is highly politicized. States protect access to low cost generation for their native loads, while POUs protect their preferred access to cheap hydro from Federal PMA's. California relies on imports from northwest and southwest for 20 percent of its electricity. In these circumstances, is subregional or interconnection-wide planning preferable?

What effects should transmission plans of RTO/ISOs and other planning entities have on decisions by regional planning entities? Interconnection-wide or other large-scale regional transmission planning should initially build upon and coordinate existing RTO/ISO transmission plans, and separate IOU, POU and Federal PMA plans. Large scale regional plans should recognize and include projects already included in plans of other entities, if appropriately justified.

What should be the effect of regional planning entity decisions for State decisions? Federal decisions? Regional planning "without consequences" would not accelerate construction of necessary and desirable transmission projects. Unless decisions by regional planning entities to include proposed transmission projects in regional plans have conclusive effects for all participants, regional planning entities would merely constitute an additional layer of bureaucracy that complicates, and frustrates effective and timely decision-making. Furthermore, effective planning, including analysis of alternatives to transmission, as well as transmission project alternatives, should provide a foundation for resolution of cost recovery/allocation decisions and siting decisions.

Recommendations

In legislation Congress should:

- Clarify that FERC's electric transmission planning authority applies uniformly to all entities which are electric transmission owners, operators, developers or have planning responsibilities;
- Authorize FERC to designate an appropriate number of regional transmission planning entities within the Eastern and Western Interconnections;
- Empower regional planning entities, in consultation with interested state agencies, transmission owners, operators and project developers within the respective planning regions, to collect and evaluate relevant transmission improvement and expansion plans currently available and other data, and to develop regional transmission plans which include an approved list of specific projects;
- Authorize FERC to establish defined time lines for the completion of regional transmission planning results for FERC review, modification and approval;
- Provide that FERC approval of proposed projects included in regional plans has conclusive effects in State PUC CPCN proceedings. Under FERC Order 890, as expanded, in choosing proposed projects for inclusion in regional plans, the planning entities should embrace a form of regulated competition analogous to utility competitive procurement, under state PUC oversight, of additional power generation, which results in long-term power purchase agreements.

Cost Recovery/Allocation

Current Status: Cost Recovery

<u>IOUs</u> – For integrated IOUs not participating in RTO/ISOs, recovery of costs for high voltage transmission projects they own within their utility franchise service territories may be subject to State PUC approval, inclusion in utility rate base, and recovery in bundled retail customer rates. For IOUs participating in RTO/ISOs, recovery of costs for such projects may also be subject to FERC approval, and recovery of costs through open-access tariffs based on transmission owners selling services to all qualified users. If State rate-based recovery is provided, the revenues derived from open access services should be credited

back to reduce retail utility customer rates. Wherever overlapping cost recovery regimes exist, cost allocation becomes even further complicated.

Independent Transcos – For independent Transcos owned by third parties, cost recovery for transmission projects is approved by FERC, with the possibility of incentive rates in appropriate circumstances. IOUs which have separate transmission affiliates that develop and own transmission projects outside their distribution utility franchise service areas will be subject exclusively to FERC cost recovery, the same as independent Transcos.

POUs, Federal PMAs – Cost recovery for transmission projects is approved their respective governing boards.

Current Status: Cost Allocation

General – Allocation of project costs is often the most contentious issue a proposed high voltage transmission project encounters. Difficulties increase geometrically in proportion to the number of states involved. Power flows throughout transmission networks along paths of least impedance, regardless of contractual obligations or political boundaries. Electric transmission networks evolve and expand incrementally over decades, in response to patterns of urban development and resulting electricity load growth, and to development and deployment of various technologies for power generation with increasing unit sizes in order to achieve economies of scale. Growth and shifting concentrations of electric load and power generation mean that benefits and costs of transmission service in the long-term, as well as the short-term, are likely to change over time. Local networks integrate into regional networks, which integrate into even larger interconnections spanning many states within half a continent. Incremental project additions to "high voltage" transmission networks vary in capacity from 230kV to 765kV, in distance from a few hundred yards to a few thousand miles, and in cost from less than $1 million to more than $10 billion.

Allocation methodologies -- A variety of cost allocation methodologies have been proposed and applied with varying degrees of success. "Generator pays" may be appropriate for a radial line from the bus bar to the high voltage transmission network, but not for a major network expansion even though increases in generation are a substantial cause of the expansion project. In any event, under the generator pays principle the costs would ultimately be passed through the supply chain to electricity consumers. "Beneficiary pays" may, arguably, be applied to channel the cost of most transmission projects to load serving entities, which can then pass them through to their retail consumers. However, major conflicts may arise among load serving beneficiaries regarding an economic or fair apportionment of costs among them. "Participants pay" may be appropriate, allocating a specific project's costs to the owners, assuming the economic and other merits of the specific project proposed had been independently evaluated and approved. Finally, transmission project costs may be "socialized" and distributed among load serving entities in proportion to the load each serves. It seems difficult to make meaningful distinctions in practice between beneficiary pays and cost socialization especially since the benefits of investment in new transmission are enhance reliability, economic and/or enabling achievement of energy/environmental policy goals. Moreover, in most cases the benefits will be difficult to quantify with precision and widely distributed in a regional context.

Examples --

- Interstate project, subject to multiple local PUC and FERC approvals. Cost allocation among the various states can be very contentious, and failure to agree upon cost allocation can bring a project to a halt. A recent example is Palo Verde 2, which was a proposed new transmission line from southern California to the Palo Verde substation in Arizona. Following CAISO review and approval, the CPUC approved the project because of reliability and economic benefits. Thereafter, Arizona PSC disapproved because the project benefits were deemed to flow disproportionately back to California. Prior DOE designation of the project as within a National Interest Electric Transmission Corridor was ineffectual.
- Within RTO/ISO markets, most of which have multi-state footprints. The developer transmission owner (IOU or independent Transco) can choose whether or not to recover project costs through the ISO's Transmission Access Charge (TAC). If the owner elects TAC recovery, then project costs are allocated among all load serving entities who are ISO market participants in proportion to the amount of load they serve. The financial transmission rights created by the specific project must be released and made available to all market participants through FERC-approved allocation and/or auction processes. If the owner elects not to recover project costs through TAC ("merchant transmission"), then the owner can obtain a long-term allocation of transmission rights from the ISO that reflects the incremental value of the capacity added by the project to the RTO/ISO controlled grid. This hybrid RTO/ISO cost recovery mechanism seems to be working in practice.
- Remote, location constrained, renewable energy resource areas. FERC approved an innovative tariff for CAISO which allows cost recovery of transmission facilities sized to serve the "location constrained" resource area when it is fully developed by incrementally recovering from initial resource project developers (wind, solar, geothermal) only their pro rata share of total transmission cost, while socializing the balance of costs across the entire network interconnected and served. As additional projects are developed and completed, they, too, pick up their pro rata shares of transmission costs until the renewable resource area is fully developed. Note that the risk of the location constrained area not being fully developed is also socialized. This innovative tariff is a possible precedent for other location constrained renewable resource regions.
- FERC practice. FERC has so far avoided specifying any set of general principles to guide its transmission cost allocation decisions, preferring to decide cases ad hoc. FERC may thereby believe it is encouraging the parties to reach settlements. However, the lack of sound principles to channel debate may prolong negotiations and strengthen the hands of outliers.

Issues

How should electric transmission costs be allocated between resource producing and electric consuming states when they are separated by long distances?

For example, what is an appropriate allocation of costs of a transmission line from Oklahoma to Illinois that is loaded primarily with wind power generated in Oklahoma? It would seem appropriate that costs be apportioned between Oklahoma, which derives economic benefits in the form of renewable energy investment, tax revenues and employment, and Illinois, which benefits from green power, although it may cost more than power from local sources using natural gas or coal. But what about the transit states, Kansas and Missouri? Should these states share in the costs because they may receive benefits attributable to increased system reliability, depending on how the line is configured and whether it is AC or DC? Or should they be compensated, in addition to the compensation effected landowners receive for granting the project rights-of-way, because of the line's unsightly visual impacts across the landscape? On the other hand, it would seem more appropriate to channel all costs to load serving entities receiving the power pro rata to their electric loads, recovering none of the costs – a tax – from the wind power generators.

Cost allocation can be a show-stopper for transmission projects, especially interstate projects. And, there is no established "best practice" methodology.

Who decides?

- 50 states, potentially differently? This is a prescription for paralysis.
- FERC? This is clearly the only Federal agency with the requisite expertise.

However, guidance in legislation seems desirable.

Recommendations

The issues of cost recovery and cost allocation for high voltage interstate electric transmission projects, and such projects which affect interstate commerce, should be settled at the national level.

- In legislation Congress should direct FERC to determine cost recovery for future high voltage interstate electric transmission projects and such projects affecting interstate commerce, and clearly direct that FERC's cost recovery decisions take precedence over any State cost recovery determinations.
- In legislation Congress may include may include cost allocation guidance for high voltage transmission projects. With or without statutory guidance, however, FERC should conduct a rulemaking proceeding with the aim of developing cost allocation principles appropriate for a variety of different circumstances. A key factor to consider during rule making should be that a cost allocation method, if applied to an otherwise meritorious project, should result in a project that can attract financing.

Siting

Current status

Determining the location for high voltage electric lines can be a formidable obstacle for every major transmission project. Bottoms-up, activists asserting "not in my backyard" – NIMBY-- may intervene before local, State, and Federal regulatory authorities, in series or combination. Even after all remedies before administrative agencies are exhausted, the issues may be litigated, project by project, through State and Federal court systems.

Federal PMAs have eminent domain powers to back up their siting decisions. Other transmission owners and project developers do not. However, even the exercise of eminent domain powers may be legally challenged, causing multi-year delays.

EPAct 2005 enabled DOE to establish National Interest Electric Transmission Corridors (NIETCs) and provided FERC with "backstop" authority to mandate siting of lines within a NIETC. In 2009, this Congressional mandate was deemed by the 4th Circuit Court of Appeals NOT to enable FERC to override a state decision opposed to construction of such a line.

Issues

Could Congress pass a statute that would effectively override state opposition?
Even with the commerce clause of the U.S. Constitution diminished by recent Supreme Court cases, it is quite possible to draft a statute that would override the 4th Circuit's decision and be upheld on appeal.

Could transmission project developers increase their chances of success with flexibility in precise location, taking seriously into account various local objections along the route for a major line?
Yes, if a successful outcome is paramount. Could governmental authorities encourage project developers to find "creative" solutions which involve funding local aesthetic or environmental amenities along the route, even though project costs may be raised modestly? Of course, they could. IPP project developers are familiar with these techniques, and state regulatory authorities have approved their Power Purchase Agreements with utilities.

Finally, will powers of eminent domain for certain transmission projects of national importance provide timely and constructive solutions to line location? It has been proposed that interstate electric transmission projects should be treated the same as interstate natural gas transmission projects, which are accorded "eminent domain powers."

Recommendation

Regional planning entities should be empowered to decide the siting of interstate transmission lines. Alternative routes should be identified and evaluated for all major electric transmission projects included in multi-state regional transmission plans. State and Federal agencies, as well as transmission owners and project developers, should participate in regional entities' planning processes. Legislation should provide clear preemptive backstopping authority for FERC to site a transmission project after it has been approved by a regional planning entity, and a transmission project designated NIETC by DOE. Legislation for electric transmission comparable to natural gas transmission is desirable.

Permitting

Current status

Electric transmission projects require numerous local, state, and federal permits, in addition to specific siting approval.

Issue

Whether, or how best to assist project developers through a lead agency or other coordinating mechanism to assist project developers in permitting interstate transmission projects?

Recommendation

Each state should establish a single lead agency to coordinate the local, State and Federal permitting processes for interstate electric transmission projects, with the designated regional planning entity providing a coordinating and expediting role.

Finance

Current status

The American electric power industry is, as a whole, in a strong financial condition compared to other strategic industries in the American economy. Most assets are not highly levered and projected revenues are relatively secure. Electric transmission accounts for only about 10 percent of total capital invested in the industry.

Nevertheless, the costs required to develop the multi-state transmission projects necessary for America's renewable resources to be developed will be very large. For example, the Green Power Express is a proposed 765 kV network that would deliver 12,000 MW of wind energy from the Dakotas, Minnesota and Iowa to load centers in Chicago, Minneapolis and southeast Wisconsin. The project would cost an estimated $10-12 billion. The owner would be ITC Holdings Corp, an independent Transco. PG&E has proposed a 1,000 mile transmission line that would bring 3,000 MW of new renewable power from British Columbia to northern California. It would cost $3.2 billion. CAISO has developed a *conceptual* plan for achieving California's 33% RPS in 2020 goal. The transmission required to implement the plan would cost an estimated $6 billion.

More recently, an interregional planning effort in the Eastern Interconnection has evaluated conceptual transmission plans to support access to wind resources that cross the territories of PJM, Midwest ISO, Southwest Power Pool, and other Midwestern and Southern utilities. The analysis suggests that achieving a 20 percent RPS requirement with wind resources across the Eastern Interconnection would require an investment of $80 billion in transmission, as well as a $1 trillion investment in capital costs of new generation.

Before the 2008 financial collapse, transmission expansion could be project financed. The project developer as general partner and a group of limited partners as investors would invest equity in a special purpose entity formed to hold the project assets, and lenders would provide loans secured by the project's dedicated revenue stream, as approved by FERC and backed by the value of the transmission assets. Typically, project financing might involve 15-20 percent equity and 85-80 percent debt. It is unclear whether, and the terms and conditions upon which, this kind of off-balance sheet project financing is available in current financial market conditions. What is clear is that an investor with a strong balance sheet which is willing and able to invest equity and carry its interest on its balance sheet, or the balance sheet of its wholly owned subsidiary in the transmission business, is likely to be able to attract both lenders and other equity investors. There are quite a few IOUs in this position today and some are aggressively developing transmission projects within and outside their distribution utility franchises. There are also independent Transcos with large transmission projects under development whose limited partners have deep pockets.

As long as state and federal economic regulatory agencies authorize rates sufficient to meet revenue requirements of IOUs, POUs and RTOs, the IOUs and POUs should be able to secure financing from their traditional sources in order to fund the investment required to modernize America's transmission grid. As noted above, FERC appears willing to authorize financial incentives to attract capital for transmission investment, and FERC has authority to increase those incentives if necessary. Access to federal financial assistance programs for dealing with the US financial/economic crisis should not be required.

Issues

If the private sector is ready and willing to undertake the requisite projects, should the Federal PMAs use the Federal government's balance sheet to expand their transmission networks?
ARRA increased the borrowing authorities of the Federal PMAs by $3.2 billion to finance transmission expansion. Private developers, financed by private capital, may well wish to compete for the opportunities to expand the grid.

Should renewable project developers be responsible for financing (and owning) the dedicated transmission line from generating project bus bar to transmission network interconnection?
America's high potential wind resources are off shore the coasts of northern California and Oregon (where deep water may make the costs of development prohibitive), off shore the coasts of Mid-Atlantic and New England states (where the Continental Shelf maintains relatively shallow water depths), and onshore in the central tier of states from the Dakotas to Texas. America's high potential solar resources are in the southwest desert regions of California, Nevada, Arizona, Utah and New Mexico. These regions are remote from America's large urban load centers. Renewable energy project developers may be small, thinly capitalized start-ups, compared to utility transmission owners.

The sequence of steps required to move from planning through construction may well take longer for electric transmission projects (7-10 years) than for renewable energy generation projects (2-3 years). Thus financing for transmission to reach a renewable resource area may be required before financing for specific renewable resource projects. The phasing of necessary financing should influence who should be responsible for it.

Recommendation

State and Federal regulatory agencies should continue to authorize for proposed transmission projects rates of return on capital sufficiently high to attract financing from their traditional sources. Unless capital markets freeze up again, the capital required to expand and modernize America's transmission grid may be attracted from the private sector. **This assumes, however, a rational policy framework exists for planning, cost recovery and allocation, and siting of electric transmission facilities.** American investor-owned utilities with strong balance sheets, independent Transcos with requisite financial capacity, and Federal PMAs with expanded borrowing authority should all play roles in developing, financing and owning the infrastructure.

Construction

Current status

During the current economic recession and at least early years of a recovery period, construction contracts can be negotiated with private firms on favorable terms. Now is an unusual opportunity to accelerate development and construction of major electric transmission projects already in approved transmission plans throughout America, making them "shovel ready."

Recommendation – Full speed ahead.

Operator/Operation

Current status

As summarized previously, America is currently divided into about 130 electric power balancing authorities. Most RTOs/ISOs are a single balancing authority. Hence, balancing authorities range in size from 100 MW to 100,000 MW of peak electricity demand. About 2/3 of America's electricity consumption is provided through wholesale power markets operated by RTO/ISOs. In the operational time-frame, an RTO/ISO administered market typically provides open access through self-scheduling and/or bid-based offers into its day ahead and real time markets for energy and ancillary services. The markets are based on a full network model that incorporates almost all relevant generation and transmission constraints, and results in transparent marginal prices for energy, transmission congestion and line losses at numerous locations throughout the transmission network served. The remaining 1/3 of electric consumption is provided by IOUs, Federal PMAs and POUs located primarily in the northwest and southeast of the United States. Many of the larger entities are more or less self-sufficient in power generation. FERC Order 888, which mandates open access to electric transmission, does not apply to Federal PMAs or POUs. Although Order 888 applies to IOUs outside RTO/ISOs, an IPP may find it difficult to obtain nondiscriminatory open access to an IOU owned and operated balancing authority.

Issues

Should the RTO/ISO model of independent operating companies for wholesale power markets be expanded to cover the entire nation? FERC tried to accomplish this result under Order 2000, which nevertheless left the decision to join an RTO as voluntary, and later under the proposed notice of public rulemaking for a standard market design in 2002, which would have made the establishment of an independent transmission provider and a centralized market for spot power mandatory. This federal effort to develop and implement a standard design for wholesale power markets complemented state efforts in the late 1990s to restructure the IOU industry by requiring disintegration of generation from distribution. Electric utilities in the southeast and northwest regions successfully resisted restructuring, and FERC succeeded partially, and then stalled, in its effort to propagate the RTO/ISO model. There is, as noted above, no RTO/ISO coverage for the southeast and northwest regions of America. While FERC is unlikely to initiate again a mandatory effort to expand RTO/ISOs, as discussed next, other industry developments may engender a revived interest in aspects of regional integration.

Should the number of balancing authorities be reduced, providing each with a coherent regional scope? Large footprints for transmission planning and operations, and transparent pricing for wholesale power in regional markets are increasingly important for overall reliability of service and economies of scale, and, importantly, for achievement of national energy and climate policy goals. Larger, fewer balancing authorities, coupled with coverage by the RTO/ISO operating model, which has capabilities for five-minute dispatch of the system, is especially important to enable effectively to integrate large amounts of variable renewable energy into America's electric power supplies. The appropriate boundaries should be determined by long term resource policies rather than who owns what.

Can the benefits of "smart grid" be realized if consumers do not have access to an RTO/ISO operated wholesale power market? Not fully. See further discussion below.

Recommendation

In legislation Congress should direct FERC: to develop and implement a plan to reduce the number of electric power balancing authorities and to establish RTO/ISOs to cover the northwest and southwest United States, including POUs and federal PMAs within their wholesale power markets. Legislation should provide a 3-year transition period for this to occur.

Maintenance

Current status

Maintenance of electric transmission facilities is the responsibility of the respective owners. There is no overall maintenance oversight body, and no process for leveling up "best practices" transmission maintenance standards for the industry as a whole.

CAISO, however, operates under a state legislative mandate that is unique. Under the CAISO model, a Transmission Maintenance Coordinating Committee, drawn from transmission owner stakeholders and reporting to CAISO management and board, assures "best practices" are followed throughout CAISO operated facilities.

Issues

Should CAISO's maintenance model be adopted by other RTO/ISOs?

Should oversight be provided for POU and Federal PMA owned transmission facilities?

The largest single contingency in CAISO's grid control area is a DC line from the Pacific Northwest to Los Angeles owned and operated by LADWP. CAISO does not control that line.

Recommendation

Within RTO/ISO controlled grids, and also transmission facilities not subject to RTO/ISO operation, NERC should review whether "best practices" are fully implemented for transmission maintenance. NERC already has asset management standards.

Improvement/Innovation

Current Status

Overall, America's transmission networks evolved over decades, shaped and sized to serve a huge variety of locally-franchised utility service areas from downtown Manhattan to tiny towns in high mountains and low deserts. The transmission asset base is composed of an increasing fraction of assets that have reached or exceeded their expected service lives. While annual investment levels in electric transmission declined from $6 billion to $3 billion ($2007) during the 1980s and 1990s, since 2000 there has been rapid recovery to $8 billion in 2007.

Technology is proven and commercially available for both transmission expansion and incremental improvements. There is no plan, or process to produce a coherent plan, for improving America's current transmission networks by assessing comprehensively and incorporating systematically cost-effective technological improvements.

Technologies to consider in an assessment effort may include, for example:

- Optimization of AC and DC transmission deployments, as well as AC levels (230kV - 765kV).
- Demonstrations of energy storage -- batteries, fly wheels, compressed air, pumped storage hydro -- while planning for deployments from initial commercial application through full market penetration.
- Deployment throughout transmission networks of phaser measurement units, enabling transmission lines to be reliably loaded closer to their thermal capacities.
- Deployment of flexible AC transmission system (FACTS) devices wherever cost-effective.

Issue

Is a national strategy for electric transmission R,D&D and innovation necessary? Desirable?

Recommendation

DOE Office of Electricity Delivery and Energy Reliability should, in cooperation with NERC and EPRI, develop and guide implementation of a national innovation strategy for America's electric transmission grid. The strategy should result in specific plans for all transmission owners to incorporate "best available, cost effective" technologies that will improve the operating performance of their existing transmission facilities within a defined period of years.

DOE should fund, and EPRI manage under contract with DOE, a program for electric transmission related R, D&D to support and advance technologies that have a potential to result in major improvements in the safety, reliability, and efficiency of transmission facilities and operations. Funding should be spread across applied research, development and demonstration projects leading toward certification of equipment, facilities, products and processes as "best available, cost effective."

Smart Grid

Current status

"Smart grid" is variously defined. For our purposes, it means the development and deployment of advanced communications, information, and sensor technologies throughout electricity infrastructures for two-way communications, processing and use of information that will enable large improvements in infrastructure operations. A major focus of smart grid development has been on utility deployment of advanced metering infrastructure (AMI), complemented by development and deployment of smart grid infrastructure on customer premises. This would enable electricity customers to optimize their investments in energy efficiency, distributed energy resources such as photovoltaics, and participation in demand response programs.

The Energy Independence and Security Act, 2007 (EISA) calls for the National Institute of Standards and Technology (NIST), in cooperation with DOE, to lead development of interoperability standards for smart grid components. FERC has authority to oversee electric industry implementation of NIST standards within smart grid applications. The normal NIST process for standard development is for industry participants to reach a voluntary consensus regarding the specification of a particular standard. In the past, NIST standard development has taken three to eight years.

A NIST approved process for selecting smart grid standards, currently envisioned to be a set of about 15, is targeted to be reached in Fall 2009. The first NIST sponsored workshop for smart grid standards development was attended by 700 participants.
In the meantime, a variety of smart grid demonstration projects are underway – Boulder, Colorado, UC San Diego, CAISO, etc. DOE funding is available under ARRA for additional demonstration projects to be awarded through competition. State PUCs are also conducting proceedings with a view to adopting state-based regulatory policies governing smart grid issues and deployments. Furthermore, electric utilities in a growing number of states are

deploying advanced metering infrastructure (AMI) purchased from a variety of vendors, including meters with various functional capabilities.

Issues

Can the NIST standards development process be accelerated without reducing quality of results and acceptance by consensus?
Development of a plan for standards development is underway. Whether the plan can be successfully implemented remains to be seen. FERC has an important role in monitoring and nudging the NIST process along.

Can multiple demonstration projects be deployed so that lessons learned are systematically extracted, evaluated and made widely and freely available to those interested in smart grid?
Will demonstration projects yield data for cost/benefit analyses that will provide a foundation for regulatory approvals and wide-scale deployments of smart grid technologies and packages?

Will state PUCs approve utility rate structures based on "dynamic" or real-time prices for electric energy purchased from and/or sold to transmission grid operators?
How much of the benefits of smart grid development and deployment will be lost if traditional utility cost of service regulation continues to be used to fix all or some portion of rates for all or some portion of different classes of utility customers?

Can the benefits of smart grid be realized if consumers do not have access to an RTO/ISO operated wholesale power market?
Consumers, individually or aggregated together in groups, require information about wholesale power market conditions and prices in order to optimize their electricity consumption and to participate, if they choose, in programs to reduce demand during peak periods. RTO/ISO model wholesale power markets can provide consumers with both the information they need for "smart" consumption patterns and with an opportunity to sell "negawatts" into RTO/ISO markets. It is possible that utilities not participating in RTO/ISO markets could develop comparable programs. However, the large scale of RTO/ISO markets provides them major advantages in the scope of programs they can offer integrating electricity consumers into distributed generation and demand response programs.

Intermittent renewable resources can be made less volatile, or even dispatchable, by combining solar/wind capacity with on-site storage. Besides providing operational benefits, this would also increase capacity utilization of any transmission that is built to access renewable resource areas. Furthermore, an RTO/ISO model seems desirable for the smooth integration of plug-in hybrid and electric vehicle charging/discharging facilities as America's automotive transportation fleet becomes electrified.

Recommendations

Federal smart grid standards must be developed and implemented nationwide. In parallel with national standards development, RTO/ISOs should develop and demonstrate, with utilities and their customers, demonstration demand response programs, enabling utility customers to participate in wholesale power markets, selling "negawatts" during peak demand periods and for ancillary services at other times. Demonstration projects involving distributed power generating systems and energy storage should be deployed on utility customer premises and inside utility distribution networks. Transmission system operators must be full partners in these projects. Such programs would, of course, be accompanied by utility implementation of advanced metering infrastructure enabling two-way interactions between customers and the grid operator. Depending on results of demonstration programs, State PUCs should approve rules and rate designs, including dynamic pricing, appropriate for wide-scale deployments incorporating national smart grid standards.

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From 1989 until 1994, Willrich was chief executive officer of PG&E Enterprises, the subsidiary of Pacific Gas and Electric Company for unregulated business, which he started up and grew to profitable operations with assets of $3 billion. From 1979 until 1989 he was executive vice president and in various other executive positions at Pacific Gas and Electric Company.

Prior to joining PG&E, Willrich was in academia and government. He was director of international relations of The Rockefeller Foundation from 1976 to 1979, professor of law University of Virginia from 1965 to 1979, and founder and director of the University's Center for Science, Technology and Public Policy. He was assistant general counsel, U.S. Arms Control and Disarmament Agency from 1962 to 1965. From 1955 through 1957, Willrich was as a pilot in the U.S. Air Force, including service in Strategic Air Command.

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