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Financing a National Transmission Grid: What Are the Issues?

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Abstract

The United States requires a substantial investment in transmission capacity over the next several decades. This investment is needed to ensure system reliability, to accommodate growth in demand for electricity, and to allow the integration of significant amounts of renewable generating capacity. In this paper I survey the need for new transmission capacity and consider the financial and regulatory obstacles that stand in the way of this new investment.

This paper makes three points. First, the historical pace of transmission investments will not be adequate to enhance grid reliability or to allow largescale penetration of renewable generating capacity. Second, the replacement of a vertically integrated electric utility industry in many parts of the country by a more disaggregated one composed of merchant generators has added to the challenge of transmission planning and investment. Third, the focus on federal funding for grid improvements is misplaced. There is no evidence that the private sector is incapable of raising the funds needed for critical investment, provided a rationalized regulatory structure is put into place.

Making changes to our regulatory and political systems that facilitate transmission investment and siting will not be easy. But the costs of underinvesting in an improved and enlarged national transmission grid are high. Moving to a largely carbon-free economy by the middle of the century will require a transformation of the power system in this country, one that cannot be successful without a strong interstate high-voltage transmission backbone.

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I. Introduction

An integral part of the Obama administration's energy policy is the dramatic expansion of renewable electricity production. The American Clean Energy and Security Act of 2008 (H. 2454) establishes a national renewable portfolio standard mandating that 20 percent of the nation's electricity come from renewable sources by 2020.[1] Optimism about wind, in particular, runs high.

A recent U.S. Department of Energy (2008) study considered scenarios in which 20 percent of the nation's electricity is provided by wind by 2030. It concluded that this goal could be reached at an incremental cost of roughly 2 percent over baseline projections of energy costs. Reaching it would require significant incremental capital costs, including an expansion of the national transmission network by approximately $20 billion in net present value. Increased capital costs would be offset by substantial savings in fuel costs.

Enthusiasm for renewable electricity generation abounds at the state level as well. Twenty-seven states have set mandatory portfolio standards, and five others have established voluntary standards.[2] Increased penetration of renewable electricity sources would accompany what is projected to be a significant rise in overall demand for

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[1] The text for H.R. 2454 is available at http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=111_cong_bills&docid=f:h2454pcs.txt.pdf

[2] See list at http://apps1.eere.energy.gov/states/maps/renewable_portfolio_states.cfm.

electricity over coming decades. But improvements in the nation's transmission network would be needed to ensure reliability.

These various trends and policy initiatives all draw attention to the need for a major investment in the nation's interstate transmission grid. This paper investigates the infrastructure needs and the barriers that stand in the way of transmission infrastructure investment. In particular, I consider the available options to finance that investment and the role that the government should play.

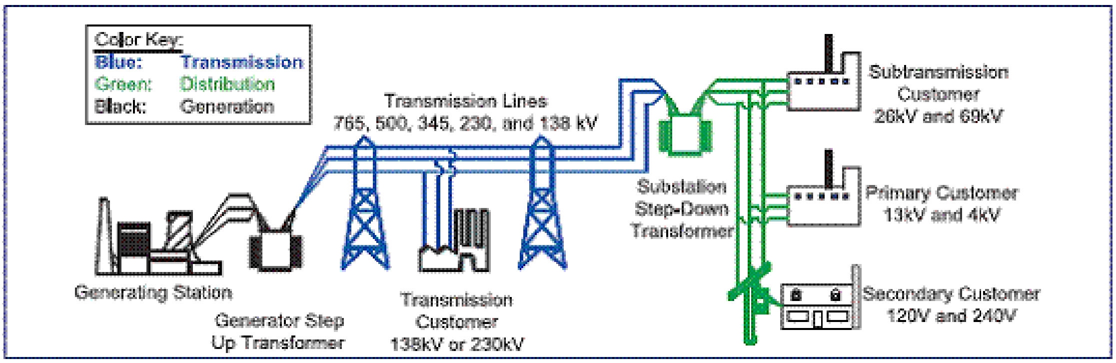
While the absolute dollar amounts that investment in interstate transmission requires are large, the costs are relatively modest when expressed as a fraction of total electricity costs. Cost is likely not a significant barrier to investment, but cost-allocation and siting issues are. Despite the call by some for federal financing of high-voltage grid infrastructure, I argue that the government would do better to focus on reducing the political and regulatory barriers to investment.

Section II of this paper reviews projected growth in electricity use and projections of needed investment in new high-voltage transmission capacity. I also provide some estimates of the costs of that investment. Section III surveys the regulatory framework and the incentives and barriers to private investment in interstate transmission capital. I turn to financing issues and options in section IV. Section V provides an assessment of key policy issues, and section VI concludes.

II. Investment Needs for a Twenty-First-Century Grid

Electricity in the United States requires generating plants, a transmission network, and local distribution. To understand the electrical transmission and distribution system, we begin with a basic description of the transmission network and a history of regulatory oversight in the United States.

Figure 1. Electricity Generation, Transmission, and Distribution



Graphic courtesy of North American Electric Reliability Corporation (NERC)

Figure 1 shows a very simple electricity network. Electricity is generated at a power station and transformed to high voltage to facilitate long-distance transmission with minimal loss in transit. The generator, for example, might be a wind farm in eastern Montana. Electricity is sent over transmission lines to load centers. Wind from Montana, for example, might be sold into power markets in the Chicago area. At the demand center, the high-voltage electricity is transformed back to voltage levels usable by industrial, commercial, and residential customers. Voltage requirements might range from 120 volts (residential appliances) to 13,000 volts or higher in industrial settings.

As of 2008, the United States had a little over 1,000 gigawatts of electricity-generating capacity (see Table 1 below).[3] Overall, capacity is expected to grow 16.8 percent between 2008 and 2035, according to the Energy Information Administration's most recent Annual Energy Outlook. In contrast, solar capacity is expected to grow by a factor of eleven, and wind capacity is expected to nearly quadruple (U.S. Energy Information Administration, 2009a).

Table 1. Net Summer Generating Capacity

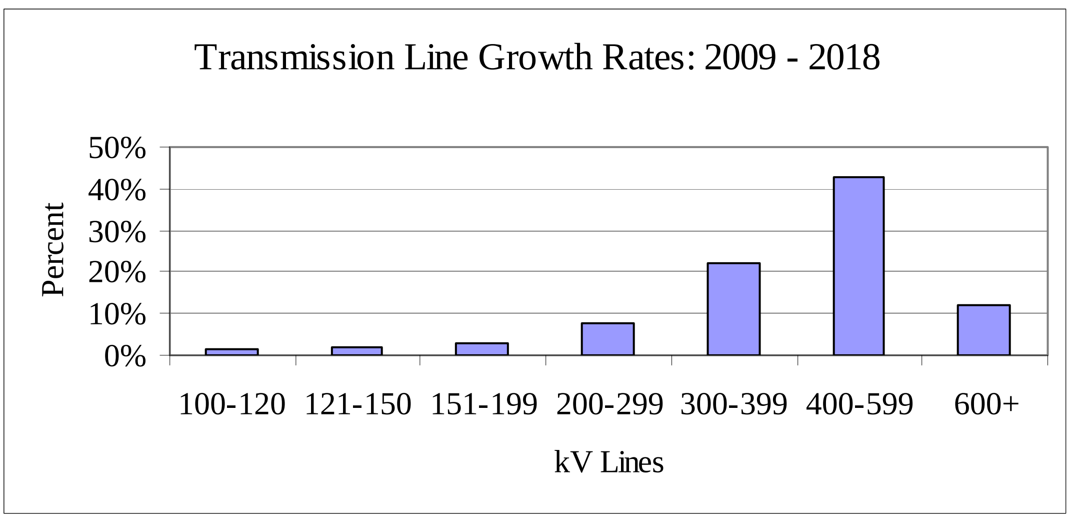
Fuel Source	**Megawatts**	**Share**
Coal	313,322	31%
Natural Gas	399,427	40%
Nuclear	100,755	10%
Petroleum	57,445	6%
Hydroelectric Conventional	77,930	8%
Other Renewables	38,493	4%
Pumped Storage	21,858	2%
All Energy Sources	**1,010,171**	

Source: U.S. Energy Information Administration, 2010. Total includes assorted other energy sources not broken out separately. Because of rounding, share numbers do not sum exactly to 100%.

[3] A gigawatt (GW) equals 1,000 megawatts (MW), which, in turn, equals 1,000 kilowatts (KW).

The rapid growth of renewable electricity, albeit starting from a very low base, presents a challenge for the nation's high-voltage transmission network. The current voltage transmission network in the United States comprises over 365,000 circuit miles of lines of at least 100 kilovolts (kV).[4] Of this amount, roughly 165,000 circuit miles are of lines 200 kV or higher. In its annual electricity supply and demand (ES&D) survey for 2009, the North American Electric Reliability Corporation (NERC) projected an 8.6 percent increase in transmission circuit lines miles between 2009 and 2018. Growth rates for lines are weighted toward the larger voltages (see Figure 2), with a growth rate of over 40 percent for lines in the 400–600 kV range.

Figure 2. Transmission Line Growth Rates: 2009–18

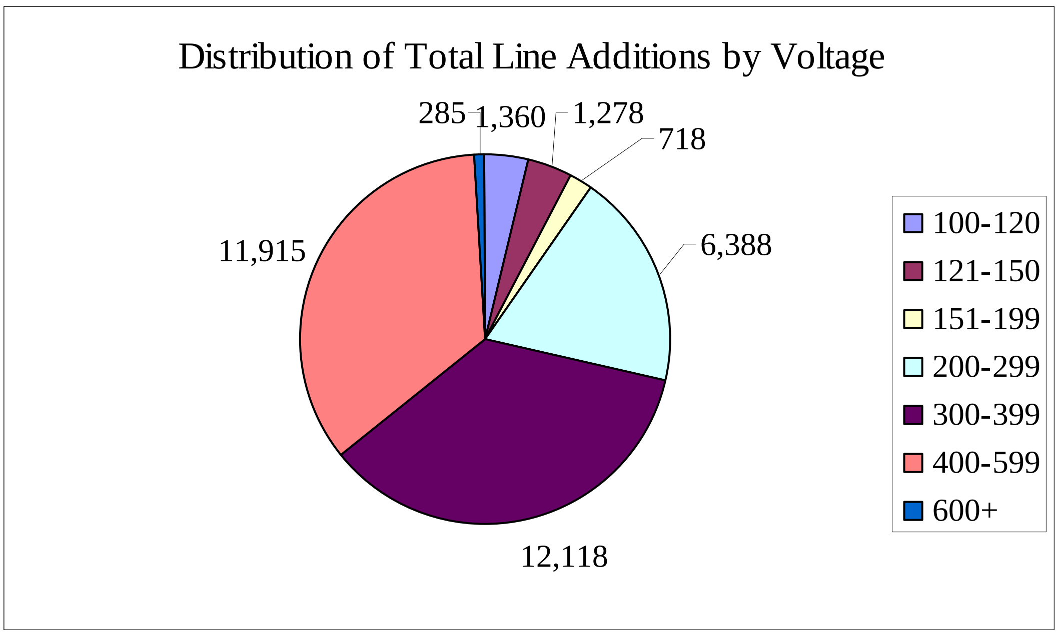


Source: NERC, 2009, ES&D data

[4] This includes 2,277 miles of DC lines, most of which are in the 400–600 kV range. The entire network in the NERC system, including parts of Canada, is nearly 450,000 circuit miles. See North American Electric Reliability Corporation, 2009, Table 6.

The bulk of the growth in total miles added (under construction, planned, or conceptual) is in the 200–600 kV range (see Figure 3). One-fifth of the growth is in the 200–300 kV range, with roughly one-third in the 300–400 kV and an equal amount in the 400–600 kV range.

Figure 3. Distribution of Total Line Additions by Voltage



Source: NERC, 2009, ES&D data

Investment patterns differ across the various interconnections. While the Eastern Interconnection anticipates a 10 percent increase in high-voltage transmission (lines of 200 kV or higher), Texas projects a 50 percent increase, according to NERC.[5] A major purpose of these increases is to improve the integration of variable-generation sources.

[5] The United States has three self-contained electricity generation, transmission, and distribution networks: the Eastern Interconnection, Texas, and the Western Interconnection. See section III.2 below for a fuller discussion of the organization of today's electricity system.

The Western Interconnection also anticipates increased transmission investment, which would improve integration of renewable generation. Growth is projected at over 20 percent for this region.

Table 2. Transmission Lines at End of 2008								
	100–120	**121–150**	**151–199**	**200–299**	**300–399**	**400–599**	**600+**	**Total**
Existing Transmission Lines	104,502	67,046	26,956	81,172	55,245	27,776	2,361	365,058
Total Line Additions	105,862	68,323	27,674	87,561	67,363	39,691	2,646	396,474
Projected Growth	1.3%	1.9%	2.7%	7.9%	21.9%	42.9%	12.1%	8.6%

Source: NERC, 2009, ES&D data

Data are for United States only. Unit of measure is a circuit mile. Total line additions include transmission lines under construction, planned, or conceptual.

NERC, in its most recent reliability assessment, expressed concern about the pace of investment in new transmission lines, stating that siting and construction will “need to significantly accelerate to maintain reliability over the coming ten years.” (NERC, 2009, p. 29). Construction has averaged around 6,000 circuit miles per five-year planning period. NERC projects a need for 16,000 circuit miles over the next five years. Finally, NERC estimates that roughly one-third of new investment in transmission lines of 200 kV or higher will be required to ensure reliability and another one-third to integrate variable renewable generation into the grid. In contrast, NERC estimates that only 7 percent of new investment will be required to integrate new fossil fuel, hydro, and nuclear generation.

Estimates of the cost of investments in the transmission grid vary. In a recent report for the Edison Foundation, Chupka et al. (2008) assign a cost of approximately $880 billion (measured in nominal dollars) for integrating renewable technology into the grid as well as for continuing to make smart grid investments over the next twenty years. The authors break this down into $300 billion for transmission investment, slightly less than one-third of which will be for 230 kV lines or larger, and $580 billion for new distribution investment. Under their “realistically achievable policy” scenario, by contrast, the authors project an investment in generation infrastructure of $505 billion over this period, assuming gains in energy efficiency and reductions in demand.

The Edison Electric Institute reports data on actual and planned investments in new transmission capacity. Table 3 shows actual investments (in 2007 dollars) for the first part of the decade ranging from $5 billion to $8 billion annually. Planned investments for the last three years of this decade, by contrast, rose to roughly $10 billion annually.

Table 3. Transmission Investment by Investor-Owned Utilities	
Year	**Investment**
2000	4.9
2001	5.1
2002	5.2
2003	5.7
2004	5.7
2005	6.8
2006	7.6
2007	7.8
2008	9.4
2009	10.4
2010	11.0
Billions of 2007 dollars. Data for 2008–10 are projected. Source: EEI	

A survey of member companies by the Edison Electric Institute (2010) identified $58 billion (nominal) in transmission projects planned for completion by 2020. EEI notes that this is not an exhaustive list, but it does identify some useful trends. The survey focuses on three types of investments:

• Transmission line and support investments

• Transmission supporting the integration of renewable resources

• Transmission-related smart grid projects

We can calibrate the EEI estimates a bit by applying cost per GW-mile estimates to the NERC line additions anticipated for the next decade. Table 4 reports estimates of unit transmission cost from Chupka et al. (2008).

Table 4. Unit Transmission Costs in 2008 Dollars

Voltage (kV)	Cost ($1,000/mile)	Capacity (MW)	Cost (Millions of Dollars per GW-Mile)
230	$2,076	500	$5.46
345	$2,539	967	$2.85
500	$4,328	2,040	$1.45
765	$6,577	5,000	$1.32

Source: Chupka et al., 2008, table 4-1

Using those unit costs, Chupka et al. (2008) estimated a cost over the 2008–15 period of $32.5 billion in nominal dollars (applying a 1.9 percent inflation rate to the 2007 unit costs) for investment in 230 kV lines or higher. Applying those unit costs to the NERC ES&D data for 2009 (covering anticipated investments between 2009 and 2018) yields an estimate of investment costs for 230 kV lines or higher of $90.8 billion in constant 2008 dollars.[6] The higher costs reflect, in part, growth in the anticipated need for investment in transmission capacity.

These numbers are significant, but it is important to keep them in perspective. Annual expenditures on electricity are projected to be about $350 billion, according to data from the most recent Annual Energy Outlook (U.S. Energy Information Administration, 2009a, table 8). The present value of those expenditures over the coming decade (discounted at a 5 percent real rate) is $2.6 trillion. Even if investments in transmission infrastructure turn out to be double the estimates made here, they would still account for only 7 percent of electricity's total retail cost. As I discuss below, cost by itself may be less of an issue than cost allocation, which is an activity with political and distributional implications.

While some of the investments that NERC anticipates will be needed over the coming decade would address the problem of low reserve margins in some NERC regions (specifically, the Midwest and western Canada), much of the investment in transmission will be needed to accommodate renewable generation capacity expected to come on line over the coming decade. NERC projects some 260 GW of new renewable capacity coming on line then, with the vast majority of that (249 GW) in the form of wind or solar.

[6] This estimate includes conceptual investments (investments identified by NERC that have been included in a transmission plan, a line required to meet a NERC TPL standard, and projected lines not under construction or planned as identified by NERC members). Eliminating the conceptual investments lowers the estimate to $53.2 billion.

The NERC analysis notes that state Renewable Portfolio Standards programs will drive much of the increase in intermittent capacity and expresses concerns about the current siting and approval process for new transmission projects. I return to this issue below. But the report identifies key siting issues that are worth listing, as they make clear the challenge facing policymakers:

> Siting of new bulk power transmission lines brings with it unique challenges due to the high visibility, their span through multiple states/provinces and, potentially, the amount of coordination/cooperation required among multiple regulating agencies and authorities. Lack of consistent and agreed-upon cost-allocation approaches, coupled with public opposition due to land-use and property valuation concerns, have *[sic]*, at times, resulted in long delays in transmission construction. When construction is delayed, special operating procedures to maintain bulk power system reliability may be needed. For example, it took the American Electric Power Company fourteen years to obtain siting approval for a 90-mile 765 kV transmission project, while it required only two to construct it.
>
> North American Electric Reliability Corporation, 2009, pp. 60–61

Presenting particular challenges to power planners are regional variable-generation "hot spots." The Southwest Power Pool (SPP), for example, has roughly 50 GW of wind in its Generation Interconnection queue, according to the NERC analysis. SPP has formed a Wind Integration Task Force to evaluate how best to integrate wind into the SPP transmission system (NERC, p. 115). The state of Texas has created

Competitive Renewable Energy Zones (CREZs) with special rules to facilitate transmission from wind-rich areas of Texas (West Texas and the Panhandle) to population and energy centers in the state. Currently, there is inadequate transmission to serve the CREZs. Finally, the Southwest Transmission Expansion Planning (STEP) group, composed of stakeholders from Arizona, New Mexico, Nevada, and California, are engaged in a multiyear effort to plan upgrades of capabilities for transmitting electricity across those four states. Three sets of upgrades were proposed to increase transmission capability by 3 GW. According to the NERC report, two sets of upgrades have been substantially completed, but the third set, the Palo Verde to Devers 500 kV transmission line, has been held up by Arizona's refusal to permit the line within its borders (NERC, 2009, p. 164).

III. The Regulatory Framework

The focus of this paper is on incentives and financing mechanisms for new transmission investment. In order to know what steps the United States should take to meet its need for new investment in transmission infrastructure, we need to understand how the electric-utility sector is regulated and how changes in regulatory procedure are altering the investment landscape. We turn to that topic now.

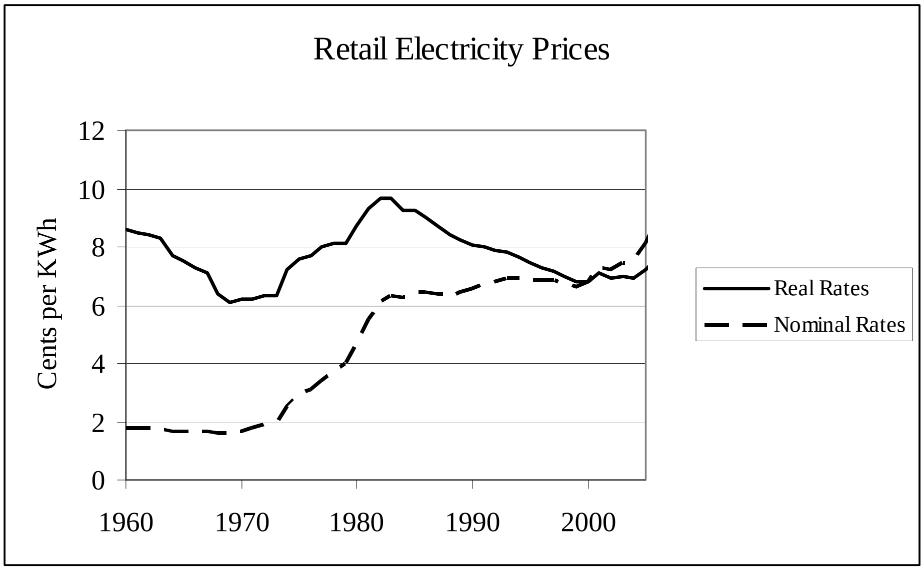
1. Utility Regulation: Old Style

Historically, electric utilities operated as vertically integrated entities in a regulated environment. The common view—borne out by historical experience—was that large economies of scale existed in generation, transmission, and distribution. A single firm providing electricity to customers in a region would avoid duplicative fixed costs and would spread the costs of large generating plants and transmission and distribution infrastructure over many customers.

In return for being granted the right to a local monopoly, electric utilities were made subject to regulation, primarily at the state level, though for projects crossing state lines as well as certain types of investment (e.g., nuclear power plants), federal regulation also came into play. Most state regulators set retail rates using rate-of-return regulation (see Viscusi et al., 2005 for a fuller discussion of regulation). In short, utilities would submit data on their costs of operation and the size of their installed capital base (rate base). After negotiation with the utility in a quasi-judicial rate proceeding, the regulator would set electric rates that were projected to raise sufficient revenue to cover allowed costs and to earn a "reasonable" rate of return on the utility's rate base. The return on the rate base was also subject to negotiation in the proceeding.

This approach worked well through the 1950s and 1960s, or as long as nominal electricity prices held firm and real prices kept falling (see Figure 4). However, the spiraling costs of nuclear power, along with sharp increases in the price of oil and natural gas, which began with the first oil shock in 1973, led inevitably to sharp increases in retail electricity prices. Nominal rates on average more than tripled, while real rates increased by roughly two-thirds between 1973 and 1982. With the accident at the Three Mile Island nuclear power plant in Pennsylvania in 1979 and the nuclear-power-related bond default by the Washington Public Power Supply System (WPPSS) in 1983, the system appeared to be unraveling.

Figure 4. U.S. Average Retail Electricity Prices



Source: U.S. Energy Information Administration, 2009b

Changes to the existing structure began with the passage of the Public Utilities Regulatory Policy Act of 1978 (PURPA), which allowed “qualifying facilities” to sell wholesale power to vertically integrated utilities. The qualifying facilities would be allowed to sell power to the regulated utilities at the latter’s avoided costs of producing power. While straightforward in concept, avoided cost was determined by regulators, who typically set high rates for it—attractive for the qualifying facilities but effectively creating incentives for a flood of high-cost capacity.

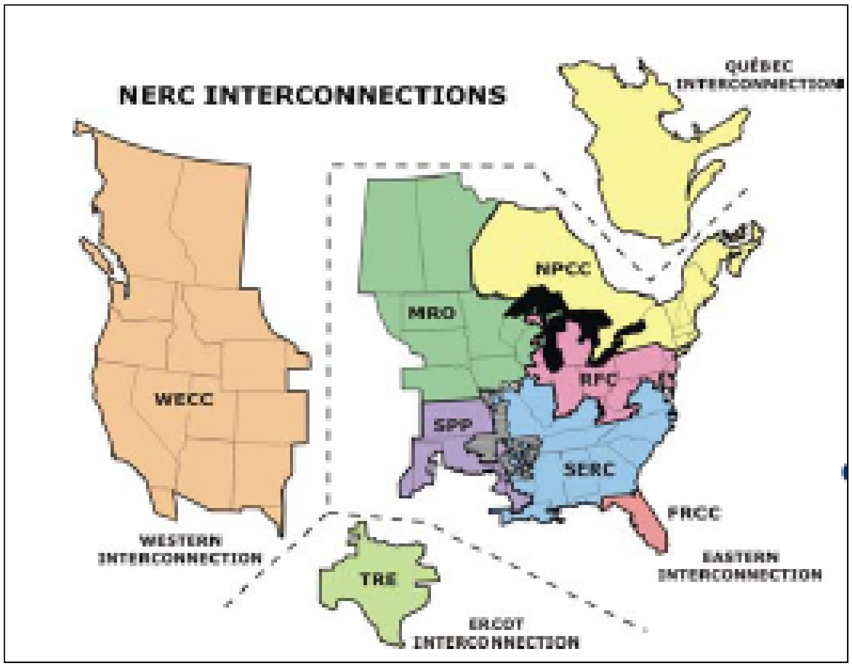
Hogan (2008) argues that spurring the movement away from regulated generation was the successful deregulation of pricing in the trucking, airline, and natural-gas industries, as well as the experience of other countries. Partial divestiture of vertically integrated utilities could allow competition to develop in the generation of electricity and provide a countervailing force to the escalating costs of construction of new power plants. While some of the appeal of restructured markets was dampened by the California electricity crisis (Borenstein, 2002 provides an excellent analysis of the crisis), restructuring has proceeded to a point where roughly half the generating capacity in the United States is operating under some form of restructuring that rests on functioning wholesale power markets (Joskow, 2006, table 1).

2. Utility Regulation: New Style

To understand the current state of regulation in the United States, it is useful to consider how electricity networks operate. The United States organizes electricity networks in a number of ways. At the most basic level, there are three interconnections in the United States: the Eastern Interconnection, the Western Interconnection, and the Texas (ERCOT) Interconnection (see Figure 5). An interconnection is a connected AC power grid all of whose lines are synchronized to the same frequency. As these three interconnections are not synchronized, AC lines cannot connect the three interconnections. DC power lines can interconnect, and currently there are a handful of DC lines that cross interconnection borders.

Within interconnection regions, NERC regional entities serve to coordinate planning and operation to ensure reliable electricity production. The eight NERC regions within the three interconnections (excluding the Quebec Interconnection) are shown in Figure 5.

Figure 5. U.S. Interconnection Regions



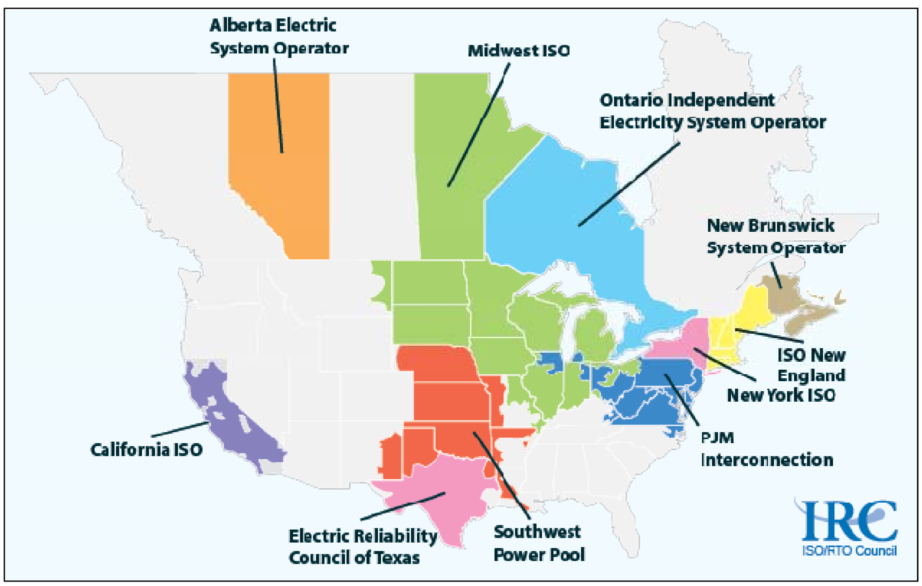
Source: NERC, 2009

Within NERC regions, electricity generation and transmission operate under a variety of regulatory frameworks. The traditional approach was one of vertical integration, whereby a single utility in a region (or state) was responsible for generating, transmitting, and distributing electricity to its customers. Certain regions of the country have restructured their utility industries to allow competition in generation and have developed power markets for day-ahead and spot trading of electricity. Since electricity generation and demand must be balanced at all times, oversight is required to ensure minute-by-minute equilibrium in markets. Responsibility for that falls to Independent System Operators (ISOs) and Regional Transmission Operators (RTOs).

The ten ISOs and RTOs in the United States and Canada serve two-thirds of electricity consumers in the United States and roughly half of the consumers in Canada, according to the ISO/RTO Council (2009) (see Figure 6). ISOs and RTOs are responsible for organizing and overseeing wholesale power markets in their region and ensuring the overall stability of electricity generation, transmission, and distribution. As such, they coordinate wholesale power markets and oversee transmission planning in their region.

For our purposes, the distinction between an RTO and an ISO is immaterial. Below I will often refer to an ISO. All comments made about ISOs apply equally to RTOs.

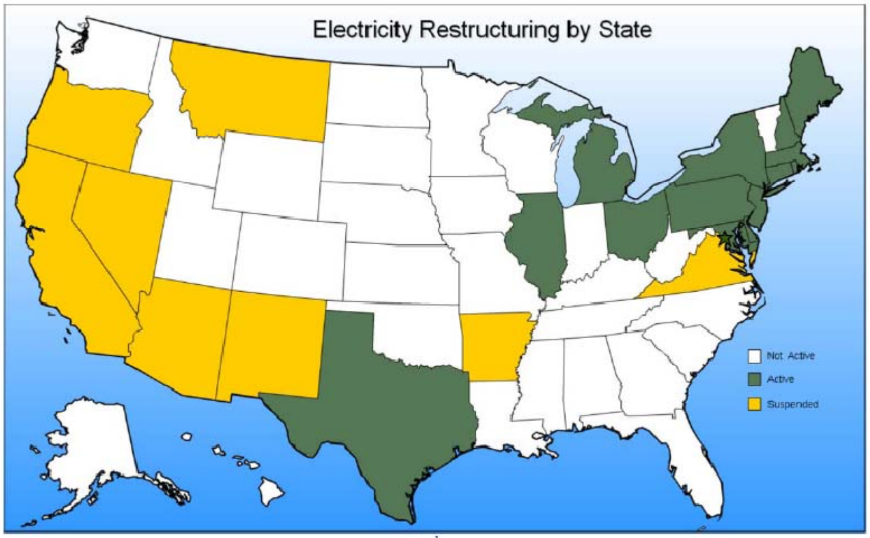
Figure 6. ISO and RTO Structure in the United States and Canada



Source: ISO/RTO Council

The ISO and RTO regions overlap states that have engaged in electricity restructuring to one degree or another (see Figure 7).

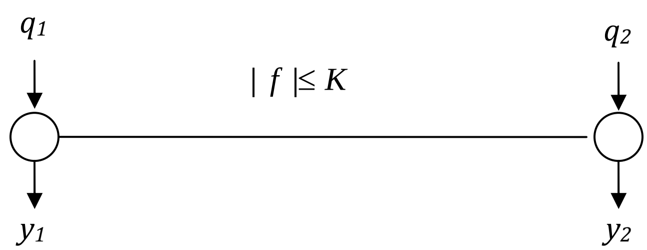
Figure 7. Electricity Restructuring as of 2010



http://www.eia.doe.gov/cneaf/electricity/page/restructuring/restructure_elect.html

As described in Hogan (2008), the ISOs developed spot markets for electricity using a "bid-based, security-constrained, economic dispatch with locational marginal prices as the market foundation and substitute for the contract-path model" (p. 12). A simple example illustrates how locational marginal pricing works. Consider a simple electrical network with two nodes and one line connecting them. A node is a location where electricity can enter (generation) or exit (load) the network.

Figure 8. A Simple Electrical Network



At the left-hand node, a generator offers to supply q_1 MWh (megawatt hours) of electricity at a price per MWh of *c1*. Demand for electricity at this node is y_1. Similarly, a generator at the right-hand node offers to supply q_2 at price *c2*. Demand at this node is y_2. With sufficient competition, generators will have an incentive to bid a price equal to their marginal cost of generation. For purposes of this discussion, I will assume perfect competition in generation.[7] The power line connecting the two nodes has a capacity limit of *K* MWs. The flow along the line from the left to the right node is measured as *f*, and negative values indicate power flowing from right to left. Since electricity generation and load must balance at all times, we have the following relationships:

$$q_1 = y_1 + f$$
$$q_2 = y_2 - f$$

These two equations plus the capacity-constraint equation, $|f| \leq K$, define the electrical network. Assuming that we have sufficient generation to satisfy load at all times, the issue for the ISO dispatcher is how to satisfy load demands at minimum cost.

[7] For evidence on market power in wholesale electricity markets, see Wolfram, 1999; Borenstein et al., 2002; and Mansur, 2008.

Assume the electricity from generator 1 is cheaper than electricity from generator 2 ($c1 < c2$). If all demand can be satisfied by generator 1, then the price paid for electricity by consumers at both nodes would be $c1$, and generator 1 would receive $c1$ per MWh sold.

This solution works so long as y_2 does not exceed K. If not, the transmission line becomes congested and the dispatcher must use generator 2. Now

$$q_1 = y_1 + K$$
$$q_2 = y_2 - K$$

With a congested network, locational marginal pricing can be used to provide the appropriate short-term pricing signals to consumers. The idea behind locational marginal pricing is to pay each generator its system marginal cost of production (as determined by the bids it offers). In the present case, with no generation capacity constraints, this comes down to paying each generator according to its marginal cost.

For consumers at y_1, an increase in demand can be satisfied by generator 1 at marginal cost c_1. Thus the price paid by consumers at y_1 would be c_1. An increase in demand by consumers at y_2 cannot be satisfied by increasing generation at generator 1 because of the capacity constraint. Instead, the marginal load would have to be served by generator 2 at cost c_2. The price of electricity at node 2 would thus be c_2. The revenue received by generator 1 will be $c_1(y_1 + K)$, while the revenue received by generator 2 will be $c_2\ (y_2 - K)$.

Note that the payment to generator 1 does not exhaust the revenue from consumers at node 2, since the load at y_2 paid c_2y_2. The difference $(c_2 - c_1)K$ is the transmission congestion rent, which would be paid to whoever has been deemed the owner of those rents. They might, for example, be owned by the developer of the transmission line and provide a source of revenue for partially defraying the construction costs of the line to be charged to network users.[8]

Pricing gets more complicated in more complex transmission networks. Indeed, it is easy to construct examples in which the marginal cost of supplying electricity to new demand at some node exceeds the marginal cost of producing the electricity by all generators.[9] The essential points to take away relate to a new disconnect between generation and load servicing. More specifically, in the transition from vertically integrated to restructured markets in many areas of the country, decisions about investment in generation might not be taking into account their impact on the transmission and distribution system. This increased separation of generation and load also elevates the importance of financing for transmission. The importance of transmission is magnified by the role that wind- and solar-generated electricity is

[8] This description abstracts from a number of important market considerations. First, I have ignored line losses. While of practical import, they can be priced in a similar fashion as load and generation with congestion. I have also ignored various financial instruments that are used by power sellers and buyers to hedge risk. Contracts for differences and transmission congestion contracts are two financial instruments available to market participants. See Hogan, 1992 and Bushnell and Stoft, 1996, among others, for discussion on this point.

[9] The marginal cost of serving demand can exceed the marginal cost of any individual generator if the marginal demand requires the cutting back of a low-cost generator due to congestion and the consequent larger increase in generation required from a higher-cost generator to serve marginal demand.

expected to play in federal and state policy in coming years. How will the investments in transmission be financed, and what role should government perform in overseeing or perhaps providing financing? I turn to these questions next.

IV. Financing Issues and Options

The simple network example above illustrates the point that congested transmission networks create rents that can be used to defray costs of the transmission infrastructure. Under what circumstances would these congestion rents be sufficient to finance new transmission investment? This is the key question underlying the idea of merchant transmission investment. If private investors can recoup their costs of investment (including an adequate return on capital), then new investment in transmission capital can be left to them, just as new generation has been. The idea that merchant transmission investors can be compensated with transmission congestion rights (rights to congestion rents) was put forward by Hogan (1992) and Bushnell and Stoft (1996, 1997). Necessary conditions include that the transmission network be optimally sized and that prices provide correct market signals to all parties.

Pérez-Arriaga et al. (1995) and Joskow and Tirole (2005) argue that the conditions under which transmission congestion rents would be sufficient to cover the full costs of transmission investment are quite restrictive and unlikely to hold in practice. One reason is that it is unlikely that the transmission investment would be of optimal size. Pérez-Arriaga et al. (1995) note that high fixed costs of transmission investment and the potential high political costs of underinvestment in transmission lead to overinvestment in anticipation of future growth. Until demand catches up with transmission investment, congestion rents would be inadequate to cover all investment costs. In addition, network design requirements to ensure reliability (N-1 or similar rules) lead to overinvestment, again making congestion rents inadequate to cover investment costs. On the basis of their experience in a diversity of power systems, Pérez-Arriaga et al. (2009) estimate that congestion rents cover only about 20 percent of total investment costs.[10]

An additional prerequisite to achieving efficiency is a congestion rent that serves as an accurate measure of the social benefits of marginal transmission investments. Joskow and Tirole (2005) provide a number of examples of market imperfections where that equality breaks down. Some involve the exercise of market power by some participant in the game. Preemption is another reason: added transmission capacity competes with new generation in a congested region. If the length of time required to site a new transmission line exceeds the time required to site new generation, the new transmission may be deterred, even if it is socially preferable to build new transmission rather than new generation capacity.

If the value of rights to transmission congestion charges is not sufficient to cover the costs of investment, additional revenues will be needed. A variety of approaches have been put forward to fund transmission costs over and above the value of transmission

[10] Hogan (personal communication, April 27, 2010) points out that the real problem facing policymakers is how to reconcile the coexistence of merchant transmission with a socialized investment model. As Hogan notes, “Developing rules for hybrid systems is a real challenge, but the first step is to recognize that regulated mandatory transmission would compete with voluntary merchant transmission and compete with voluntary choices for investments in generation capacity and demand response. How can we design the rules so that all these pieces fit together and are credible and sustainable?”

congestion charges. In general, cost allocation can be done in two ways: costs can be allocated to beneficiaries of a project; or they can be socialized across the network. The former approach has the merit of matching benefits and costs and can provide appropriate economic signals for new investment. Measuring and allocating benefits, however, is a difficult task, especially when the evolution of the transmission network changes the nature of the benefit.[11] Spreading costs over all existing users, in contrast, is much simpler and avoids what might be arbitrary assumptions and judgments about benefits. Cost socialization is appealing on the grounds of simplicity but does not provide economic price signals and may be perceived as unfair to the extent that system users are paying for transmission investments that are of no obvious value to them.

Postage-stamp allocation is the most common form of cost socialization. It spreads the cost uniformly across users on a per-megawatt or megawatt-hour basis. This approach is simple but, as noted above, may not accord with network users' notions of fairness to the extent that users differentially benefit from network expansion. Postage-stamp allocation has been commonly used in Europe and in U.S. markets.

"Beneficiary-pays" principles have been applied in instances of new transmission investment where the value of a new line can be attributed to generators and load on some basis. While reasonable in concept, this principle implies that the benefits of a line are determined by comparison with the counterfactual of the absence of a line. The counterfactual, however, may be utterly unrealistic, given the very strong likelihood that

[11] The cost of interconnecting to the grid is easily allocated to the primary beneficiary: the generator wishing to interconnect. Much of the investment in the grid is for network enhancements, however. I discuss this distinction further in the next section.

a network of some kind would have developed to handle demand. In principle – though difficult in practice, the value of a new line should be calculated by subtracting the benefits that a more evolutionary or improvised response to demand would have yielded from the benefits that a new line yields. The starting point for calculating its value should not be the complete absence of benefits that would result from the line's abrupt elimination. The latter approach exaggerates the incremental value of a new line.

Reliability standards create difficulties for the beneficiary-pays principle, since the nonoccurrence of a network failure may render a line redundant in the strictest sense. The beneficiary-pays principle would then suggest that there is no benefit to this line—and thus no one to whom costs can be allocated.

Network usage is a third approach to financing transmission costs. It can be implemented in a number of ways (marginal or average participation, contract paths, etc.). Whatever the specific approach used, the basic idea is to allocate costs on the basis of usage of the network. The main difficulty here is that a unique way to measure usage does not exist and as a result the allocation of costs is inherently arbitrary, despite apparently clear allocation rules based on usage.

So long as locational pricing is used to address short-term congestion issues, the focus of recovering transmission investment costs can be on efficiency and fairness. Ramsey pricing could be used to recover investment costs with minimal loss of efficiency. Ramsey pricing allocates the burden in inverse proportion to the elasticity of demand of users on the network. This would tend to shift costs away from large industrial customers, which are better able to adjust demand when prices are high, and toward smaller residential and commercial customers on the load end, who are more priceinelastic. Alternatively, a focus on fairness would suggest allocation schemes such as the Aumann-Shapley approach. An example of this approach applied to the Brazilian network is provided by Junqueira et al. (2007).

Different ISO regions have taken different approaches to allocating transmission investment costs. Hogan (2008) cites testimony by a former Federal Energy Regulatory Commission (FERC) chairman describing allocation procedures by the various ISOs: 100 percent socialization of costs by ISO New England, one-third socialization by the Southwest Power Pool, 20 percent by the Midwest ISO, and 100 percent for high-voltage transmission by PJM Interconnection.

The distinctions among these various approaches are probably less important than anticipatory network builds and interstate cost allocation. "Anticipatory network builds" refers to the possibility that new generation development will occur in stages within a given region (one, say, with high wind potential). But economies of scale in *transmission* investment dictate building the transmission network extension all at once, in anticipation of the full generation build-out. Who bears the costs of the network expansion in the years before full generation build-out occurs?

Cost allocation is the second area of concern. Many renewable-energy projects will require significant investments in interstate transmission capacity. A lack of clear guidance at the national level as to how cost allocation will be achieved serves as a barrier to this kind of investment. As noted in a recent Department of Energy advisory committee report, "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 investment" (Electricity Advisory Committee, 2009, p. 50).

The first issue—anticipatory network builds—has been a focus of attention for ISOs, FERC, and various states. Kaplan (2009) notes that no standard approach has been settled on. California has taken the approach of allocating to ratepayers, through a transmission access charge, a portion of the costs of new transmission of electricity from renewable energy sources that future generators will draw upon. As more generation that was anticipated by that network expansion comes on line, costs will be shifted from the general rate base to the generators that benefit from the expansion of transmission capacity (see Kaplan, n. 56).

In response to the issue of anticipatory network builds, some have called for direct investment in transmission by the federal government. For example, Governor Jon Huntsman of Colorado and Governor Brian Schweitzer of Montana, writing on behalf of the Western Governors' Association, asked House and Senate leaders in early 2009 to enact a set of policies that would ensure the construction of sufficient capacity in high-voltage transmission lines to bring large amounts of wind, solar, and geothermal electricity to market over the next several decades (Huntsman and Schweitzer, 2009). The two governors noted that staged investment in renewable generation creates the possibility of inefficiently low levels of transmission investment that will be locked in, once completed (an example of the holdup discussed in Joskow and Tirole, 2005). In particular, the association recommends that the federal government do the following:

- Enact legislation to fund the upsizing of *near-term* transmission projects proposed to serve large, geographically constrained, low-carbon resource areas.
- Enact legislation to preserve the ability to expand, to their maximum technical capabilities, *other proposed* projects to large, geographically constrained, low-carbon resource areas.
- Increase the borrowing authority and authorization for federal power marketing administrations for transmission construction to move geographically constrained, low-carbon generation.
- Provide that interest on bonds issued by or on behalf of states or local governments to finance transmission facilities in furtherance of developing geographically constrained, low-carbon resources is exempt from federal income tax.
- Redirect the implementation of Sections 1221 and 368 of the Energy Policy Act of 2005 to focus on expedited cooperative actions with states to preserve transmission corridors and ensure the timely siting and permitting of large transmission lines to move geographically constrained, low-carbon generation.

(Huntsman and Schweitzer 2009, p. 2)

The Western Governors' Association conflates two issues: federal funding for transmission projects and improved regulatory guidelines at the federal level that would facilitate regional transmission planning. If the appropriate pricing signal (e.g., a carbon tax or cap-and-trade system) or a well-designed policy that sets renewable-portfolio standards is put into place beside an appropriate regulatory cost-allocation model, the financial incentives to build transmission lines naturally follow. If an appropriate pricing signal and cost-allocation model are put into place, federal subsidization of transmission investment should not be necessary.

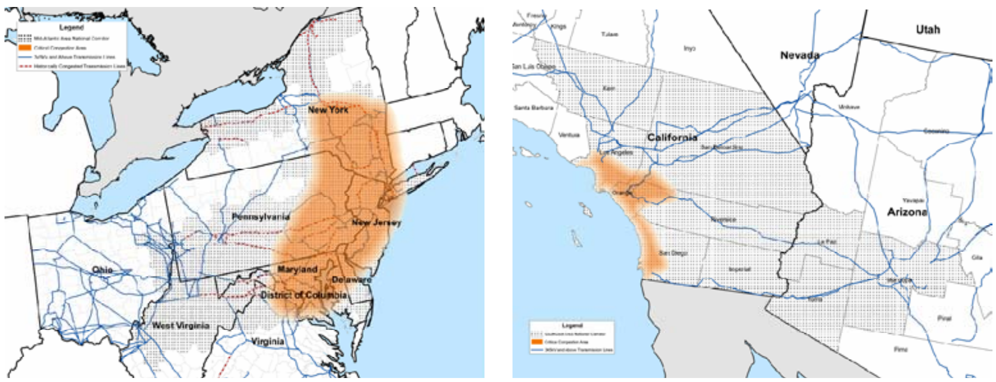
The construction of appropriate regulatory rules and procedures is essential, and here the federal government can continue to take leadership. Developing model regulatory structures to address anticipatory network builds will help address the holdup from suboptimal transmission investment in the short run. FERC's approval of CAISO's (California Independent System Operator's)proposed funding mechanism for "location-constrained" renewable resources is one example. In its April 19, 2007, decision (Docket EL07-033), FERC "found that the CAISO's proposal strikes a reasonable balance that addresses barriers impeding the development of location-constrained resources while at the same time including appropriate ratepayer productions so as to ensure that rates are just and reasonable and not unduly discriminatory" (Federal Energy Regulatory Commission, 2007).[12]

While a strong case can be made that federal funds are not required to support transmission infrastructure investment, it is less clear what principles for cost allocation will be most effective at addressing the ongoing tension between the federal desire for national transmission policy to address siting issues that transcend state boundaries and states' desire to avoid unnecessarily curtailing their prerogative to set policy within their own borders. The Energy Policy Act of 2005 attempted to address this issue by allowing for the designation of National Interest Electric Transmission Corridors. The Department of Energy was given the authority to designate certain regions as National Interest Electric Transmission Corridors where deficiencies in transmission investment adversely

[12] Available on line at http://www.caiso.com/1bee/1bee7d3b3b4d0ex.html.

affected consumer and business interests. The DOE responded by designating two such corridors in 2007: one in the mid-Atlantic states and one in the Southwest (see Figure 9).

Figure 9. National Interest Electric Transmission Corridors



The Energy Policy Act also authorizes FERC to permit investments in corridors crossing states that have withheld approval for more than one year. But in 2006, FERC promulgated rules allowing it to override states' denials of permit applications for transmission projects. FERC was taken to court over these rules, and in February 2009 the Fourth U.S. Circuit Court of Appeals held that FERC may issue a permit only in cases where states have failed to act on a permit application. It may not override states' adverse decisions.

How national policy may be furthered in the face of this decision remains to be seen. Clearly, the federal government has not yet established a planning process that transcends state boundaries and interests and moves national energy policy forward. I turn next to some ideas on what kind of process might help overcome this obstacle.

V. Assessment

As noted above, while the aggregate costs of needed transmission investment are quite high—in the many billions of dollars over the next thirty years—these costs are a small portion of the total costs of producing, transmitting, and distributing electricity. Even so, it is important to design cost-allocation schemes in an economically efficient manner, so that market mechanisms can provide the appropriate signals to potential investors and spur needed investment.

Still, the impediments to transmission investment for a twenty-first-century grid are more political than economic. Thus, Congress needs to return to the topic of National Interest Electric Transmission Corridors and craft legislation that prevents states from unilaterally holding up critical transmission projects that would relieve congestion and encourage the development of valuable renewable resources in otherwise stranded regions. While FERC has nominal responsibility for interstate transmission regulation, the large potential for extensive conflict between federal and state regulation makes transmission investment planning in an interconnected network a highly risky activity for the private sector. Regulatory oversight needs to reflect the logic of power flow on electric networks and the dictates of Kirshoff's Laws.[13]

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[13] Kirshoff's Laws describe how electricity flows in a network. Electricity cannot be directed along particular paths from source to destination but rather flows throughout the network. Thus a bilateral transaction in which electricity is generated at one node and consumed at another can have adverse effects on parts of the network at a distance from the two nodes in question.

Resolving the question of the federal structure of electricity regulation is beyond the scope of this paper. A recent white paper on governance prepared for the Working Group for Investment in Reliable and Economic Electric Systems (WIRES) by Baldick et al. (2007) makes a number of recommendations for reconciling federal interests with state and regional interests. They include open and thorough planning processes, clear principles for defining the social benefits of transmission projects, forward-looking regional planning, periodic review of cost-allocation rules, and free entry for merchant transmission where feasible (Baldick et al., 2007, pp. 57–69).

The debate over the relative merits of allocating costs to beneficiaries as against socializing them is, in large measure, counterproductive. The sums involved are simply not great enough in the overall scheme. Moreover, it is seldom possible to establish a bright line between cases where beneficiary-pays principles should apply and those where cost-socialization rules should. Transmission interconnections are one place where beneficiary-pays principles should apply and can easily be applied. A new generator, for example, clearly benefits from access to the transmission grid. Interstate-transmission trunk lines, on the other hand, are probably better suited to cost socialization. It is important, however, to design cost-allocation rules that do not place merchant transmission lines at a competitive disadvantage in cases where those lines may be cost-effective.

Given the diffuse benefits of large projects, Baldick et al. (2007) recommend a presumption of cost socialization, and then further recommend socializing these costs to load, on the grounds that the costs will ultimately be borne by consumers, in any case. Whether costs will be fully passed forward to consumers is an empirical question that depends on a number of factors, including the degree of congestion on the grid. In fact, once one allows for congestion and the possibility of market power on the part of generators, it is possible that the burden of the costs will be affected by the cost-allocation decision.[14] A fruitful area for future research might be the incidence of cost allocation in congested networks where market power comes into play.

Finally, as noted by Baldick et al. (2007), it would be desirable to remove transmission investment costs from state retail rate bases and move them to wholesale rates prospectively, to be sure, and retroactively, to the extent possible. One goal of the restructuring of wholesale electrical markets and the development of competitive merchant generation has been to shift risks from retail customers to investors. Shifting risk to investors while allowing them to earn rates of return that reflect that risk contributes to efficient capital investment in electricity infrastructure. To the extent that transmission capital costs are borne by consumers in retail rates, the consumers are the residual bearers of risk. Retail rate proceedings effectively pass the costs of poor investments on to consumers (except in egregious cases of ill-advised investments) as well as the benefits of prudent investment decisions (in the form of reduced future rates or lower rate increases). Here the open-access architecture of the wholesale transmission grid comes into conflict with a state's focus on regulating rates paid by consumers within its borders. Sale of transmission services to another utility creates revenue that the state

[14] This stands in contrast to the general principle in tax analysis that the economic incidence of a tax (the distributional impact of a tax after equilibrium adjustments in prices have occurred) is unaffected by the statutory incidence of a tax (the issue of who is legally responsible for remitting a tax payment to the government).

recognizes by reducing the rates paid by in-state customers. In effect, state retail rate-making confounds efforts to develop a national—or, at least, an interstate—wholesale market in transmission.

The bottleneck in investment in grid expansion and improvement is not lack of federal funding but rather a failure to recognize that grid investments offer benefits that transcend state boundaries, provided that they are shaped by a planning process that is open, transparent, and credible. While it is important for political and historical reasons to recognize the role that states play in electricity planning, a better coordinated federal, regional, and state approach will be needed to move projects forward.

VI. Conclusion

In this paper, I have provided an overview of issues related to investment in a national transmission network and have made the following points. First, the historical pace of transmission investments will not be adequate to enhance grid reliability—a critical necessity—or to unleash the potential for generating electricity from the wind, the sun, or the earth.

Second, the replacement of a vertically integrated electric utility industry in many parts of the country by a more disaggregated one composed of merchant generators has added to the challenge of transmission planning and investment. Under a vertically integrated structure, a single firm working with state and federal regulators could plan generation, transmission, and distribution; under a disaggregated structure, generation and load servicing are routinely handled by different entities that may be at a great geographic distance from one another. Add to that the geographic distance between load centers and regions rich in renewable resources, and the importance of an interstate transmission network becomes that much more apparent.

Third, the focus on federal funding for grid improvements is misplaced. There is no evidence that the private sector is incapable of raising the funds needed for critical investment, provided a rationalized regulatory structure is put into place. Clear protocols on transmission planning and cost recovery are essential, as is some resolution of the issue of federal and state regulatory overlap. Federal preemption of siting may be necessary to prevent state-level holdups, but it must be done in a way that respects the federal nature of the U.S. political system.

Making changes to our regulatory and political systems that facilitate transmission investment and siting will not be easy. But the costs of underinvesting in an improved and enlarged national transmission grid are high. Moving to a largely carbon-free economy by the middle of the century will require a transformation of the power system in this country, one that cannot be successful without a strong interstate high-voltage transmission backbone.

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