Commissioner Primer

Transmission Investment

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Joe McGarvey
Research Associate

EXECUTIVE SUMMARY

Public concern over the reliability and affordability of electricity has brought renewed attention from legislators and regulators to the country's electrical transmission system. In the Energy Policy Act of 2005, Congress paid particular attention to transmission, including increasing the amount of investment in transmission, which has lagged behind investment in generation.

This primer offers an overview of the issues related to transmission investment and provides information relevant to public utility commissioners on upcoming challenges in facilitating a reliable, functional, and affordable transmission system. This primer highlights recent trends in transmission investment. It summarizes the division of jurisdictional authority over transmission and presents four alternative models for transmission ownership. This report explores the basic regulatory issues that affect transmission investment including alternative funding and pricing mechanisms, as well as state and regional planning efforts.

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The electric transmission system provides critical access to an affordable and reliable supply of electricity, but policymakers face many challenges in ensuring that the transmission system continues to satisfy the power needs of the country.

Annual investment in transmission declined for most of the last 30 years, resulting in decreasing transmission capacity relative to the demand placed on the system.

INTRODUCTION

Reliable and reasonably priced electricity is an essential component of wellbeing for people and businesses in the United States. The tendency to take access to affordable electricity for granted is an indirect tribute to the companies and governing institutions that are responsible for the country's electricity service. The electricity sector is now undergoing dramatic change, particularly electricity transmission. The transmission system connects power generators across distances to the local distribution lines that serve the end customers. The transmission system thereby provides critical access to an affordable and reliable supply of electricity, but policymakers face many challenges in ensuring that the transmission system continues to satisfy the power needs of the country.

The last decade of restructuring in the electricity industry has resulted in substantial challenges for ensuring the adequacy of the transmission network and has underscored existing trends in the transmission business. While the amount of power delivered has doubled in the last 30 years, annual investment in new transmission declined for most years over that same period, resulting in decreasing transmission capacity relative to the demand placed on the system.[1] In response to this situation, Congress took several steps in the Energy Policy Act of 2005 (EPAct 2005) to promote investment in the transmission grid, and the Federal Energy Regulatory Commission (FERC) has been acting to fulfill its mandates under the Act. At the same time, state public utility commissions (PUCs), regional transmission organizations, regional state governance organizations, and industry participants are also working to craft policies intended to build a robust transmission system. This primer offers an overview of the issues related to transmission investment and provides information relevant to public utility commissioners on upcoming challenges in facilitating a reliable, functional, and affordable transmission system.

BACKGROUND

The transmission system was not originally designed with a national wholesale market in mind. The national system was built to connect utilities which were often the sole providers of electricity in a given service territory. Under this approach, transmission lines allowed a given utility the ability to supplement its generation capacity by drawing from neighboring utilities under bilateral agreements. Two facts stand out about this arrangement: 1) By contemporary standards, the movement of electricity across long distances ("wheeling") to other service providers was conducted on a small scale; and 2) transmission planning and investment were conducted by the utility as part of its overall service effort, subject to applicable state and federal regulation.

The opening of wholesale electricity markets under FERC Order 888 in 1996 led to more sales taking place over the transmission lines and also more congestion on those lines. With electricity generation load served roughly doubling in the last 30 years, there is reduced capacity in every North American Electric Reliability Council (NERC) region. For example, PJM Interconnection (PJM), which manages the grid in ten Mid-Atlantic and Midwestern states, reported congestion costs of $2.09 billion in 2005, representing 9 percent of its total billings and a 179 percent increase from the previous year.[2] Another measure of congestion is offered by transmission loading relief (TLR) procedures, in which requests for transmission service have to be turned down in order to avoid congestion. According to NERC, such requests have risen from 50 in 1997 to 2,397 in 2005.[3] At the same time, transmission investment amounts declined from 1975 to 1998, and 2003 levels are still below those of 1975 at around $4 billion per year.[4] There has been an upturn in the number of planned transmission projects, estimated to rise to $7 billion per year over the next decade according to preliminary industry surveys.[5] To place such levels of investment in context, in the last decade generation attracted $200 billion in investment, compared to approximately $40 billion for transmission over the same time.[6]

It is difficult to project exactly how much transmission investment will be needed in the coming years and whether that investment will be forthcoming. At a cost that can range from $150,000 to nearly $2 million per mile depending on size of line, the location, and the terrain, transmission is a highly capital-intensive venture.[7]

Transmission has the potential to be an appealing investment, offering limited profit but a guaranteed return in a regulated environment. But uncertainty over long-term ownership of assets, uncertainty over future returns, competition for capital with generation, a lack of experience with transmission as a separate business, and the ability of current owners of transmission to benefit from the high-congestion status quo are all factors that could undermine development of an optimal level of transmission from the public's point of view. Settled regulatory rules and certainty over future costs and returns can make transmission a more attractive investment.[8] In this way, decisions made by state and federal regulators as well as in regional planning groups have a strong influence on transmission investment.

JURISDICTIONAL AUTHORITY OVER TRANSMISSION

Jurisdiction over transmission is exercised by both the states and the federal government. In states that have restructured their electricity markets, state authority is centered on the transmission siting process. States that have traditional regulation featuring retail rates that bundle transmission, generation, and distribution charges may set the rates, terms, and conditions of transmission. All wholesale and unbundled retail rates are under FERC jurisdiction. Table 1 presents a delineation of federal and state authority over transmission. For purposes of comparison, authority over

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TABLE 1
FEDERAL AND STATE JURISDICTION OVER ELECTRICITY

Authority	Transmission	Generation	Distribution	Retail Customer Interface
Federal	• Rates, terms, conditions for wholesale and unbundled retail interstate transmission • Transmission reliability rules • Siting in national interest corridors (one year after filing)	• Wholesale sales • Ancillary services • Merger authority • No authority over facilities	• N/A	• N/A
State-traditionally regulated	• Rates, terms, conditions of bundled retail transmission or purely intrastate transmission • Siting	• Rate-based facilities • Adequacy of generation • Reserve margins • Siting	• Retail rates • Terms • Conditions • Service quality • Outage mgmt. • Outage indices • Portfolio standards	• Billing • Collection • Disconnection policy • Metering • Demand-side mgmt.
State-restructured	• Siting • Unless purely intrastate, all transmission is unbundled, and so is under FERC authority	• Siting	• Same authority as traditionally regulated states, plus: • Standard offer service (a.k.a. provider of last resort)	• Same authority as traditionally regulated states
Regional Transmission Organizations and Independent System Operators (RTOs/ISOs) [under authority delegated from FERC]	• Operational authority over transmission in a region • Maintain short term reliability • Administer own tariff and pricing system • Manage congestion • Plan and coordinate transmission upgrades and additions • Market monitoring • Operate computerized system for sharing available capacity • Serve as supplier of last resort for ancillary services • Address parallel path flow issues	• N/A	• N/A	• N/A

Source: Author's construct.

TABLE 2
MAJOR FERC ORDERS AFFECTING TRANSMISSION (1996-2006)

FERC Order (Year)	Action
888 (1996)	Established open access in transmission, requires functional unbundling of wholesale transmission and generation by utilities
889 (1996)	Required public utilities to participate in an electronic system (Open Access Same-time Information System) for posting available transfer capacity (ATC)
2000 (2000)	Provides for, but does not require, RTOs.
Mandatory Reliability Standards (ongoing)	National Electric Reliability Organization and regional reliability entities will develop mandatory reliability standards. This could establish the need for new transmission deemed necessary to meet the new standards.
Open Access Transmission Tariff – Proposed Rulemaking (May, 2006)	Would adjust Orders 888/889 to 1) set standards for calculations of ATC, 2) require an open transmission planning process, 3) reform pricing for energy and generator imbalances, 4) require providers to offer hourly firm point-to-point service, and 5) allow customers right of first refusal to rollover their transmission contracts of greater than five years.

Source: Author's construct.

generation, distribution, and customer service is included as well.

Table 2 highlights the most significant FERC orders affecting transmission investment in the last decade.

Vertically integrated utilities own and operate transmission, along with generation and local distribution lines, in a given service area. FERC's Order 888 mandates that all utilities provide open access to the use of their own transmission lines to others (e.g., other vertical utilities, independent power producers, or other generators) on the same terms and rates as it gives itself. Order 888 also requires utilities to functionally unbundle their rates for wholesale generation and transmission service.[9] Orders 888 and 2000 did not require utilities to spin off their transmission assets into independent companies. However, under Order 2000, utilities wishing to join an RTO must give the RTO operational control over its transmission lines. Although FERC sought to make RTO membership mandatory with its proposed Standard Market Design rulemaking, it withdrew the proposal in 2005.

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ALTERNATIVE MODELS FOR OWNERSHIP AND CONTROL OF TRANSMISSION

There are many possible arrangements of transmission as a business. It is important to note that, due to the fact that transmission is a costly enterprise with a long lead-time before the investment can begin to be recouped, there are substantial barriers to entry to the transmission business. Transmission was traditionally considered a monopoly asset since it was

TABLE 3
ALTERNATIVE MODELS FOR TRANSMISSION OWNERSHIP AND CONTROL

Business Model	Ownership	Control	Relationship between Ownership and Control
ITC (e.g, National Grid)	Transmission-only private entity (for profit), or ITC	ITC (may belong to an RTO)	Joint
Public Enterprise (e.g., Western Area Power Authority (WAPA))	Transmission-only pubic entity (non-profit)	Pubic entity	Joint
Regional Transmission Organization (RTO) (e.g., PJM, Midwest ISO (MISO), ISO-New England ISO (ISO-NE))	Utilities (for profit)	Independent non-profit company or partnership (ISO)	Separated
Vertical Utility	Utilities (for profit)	Utilities	Joint

Source: Author's construct.

FERC has been working to encourage further development of ITCs, establishing standards for judging independence of ownership and operation and proposing special rate incentives.

prohibitively expensive for another firm to build a competing line to serve customers already served by an existing line. In contemporary markets, transmission can be seen as competing with distributed generation located close to the customer load, as well as energy efficiency programs and demand response programs that might reduce overall demand for electricity. But in the short term, especially in constrained markets, transmission ownership could allow the owner to discriminate in favor of any generation assets that it might control.

There are four usual solutions to this problem, summarized in Table 3. First, regulators could insist that transmission be owned by a transmission-only business (either for profit, or not). In this case, the company would have no incentive to discriminate amongst generators, but regulation would still be required to ensure just and reasonable rates given its ability to otherwise charge monopoly rates. Such companies are known as independent transmission companies (ITCs) or Transcos, and feature ownership and control of transmission by the same entity.[10] Most existing ITCs have been spun off from utilities. Although the majority of transmission assets are still owned by utilities, FERC has been working to encourage further development of this business model, establishing standards for judging independence of ownership and operation and proposing special rate incentives for Transcos.[11] Most utilities have not spun off their transmission assets and FERC has not forced them to do so.

In a second instance of such joint ownership and control, all transmission assets may be owned by a public entity, which is not-for-profit and operated in the public interest. The WAPA is an example of this approach.

A third solution is offered by separating transmission ownership from control and operation of transmission. This is the approach used in the existing

RTOs, in which utilities maintain ownership of their transmission assets, but cede control over the use of the lines to an ISO, which is independently owned, although the governing board may be composed of stakeholders (as in the Electric Reliability Council of Texas (ERCOT)). The ISO is expected to ensure fair use of the region's transmission lines.

The fourth solution is that of the traditionally regulated vertical utility, in which FERC sets the rates, terms, and conditions for wholesale and unbundled retail transmission sales, while states regulate transmission that is bundled into customers' retail rates. In traditionally regulated vertical utilities that are not members of RTOs or ISOs, there is joint ownership and control of transmission.

TRANSMISSION FUNDING AND PRICING

Transmission funding refers to the substantial up-front investment to be made in new or upgraded assets. Transmission pricing refers to the manner in which the costs for the transmission may be recouped over time by those who made the up-front investment.

Alternative Funding Methods

Under traditional rate-of-return regulation, the incumbent utility in a service area makes an investment that is added to its rate base and it receives a rate of return established by a PUC and assumed to be sufficient to cover prudent costs. The utility recoups the expenses through retail sales. Revenue from wholesale sales is treated differently – the revenue may be kept or used to offset retail sales to customers, sometimes using an explicit sharing formula.

An alternative source of funding could be from net generation savings. If a commission or RTO is able to determine how much customers would save from avoided generation costs, those savings could be given to the transmission owner. Similarly, a split savings arrangement could be employed, in which a portion of costs of generation that would be offset by transmission lines are invested into transmission. Generation costs make up the bulk of customers' bills, so opening up averted generation costs as a source of revenue could generate more interest in transmission investment than standard cost of service regulation.[12]

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<u>RTO Methods for Funding Transmission Projects</u>

RTOs currently rely on two funding methods for transmission projects: participant funding or socialization of funding. Under a participant funding method, the RTO (or other applicable authority) identifies which parties (e.g., independent generator, utility) will benefit from the project, and those parties are responsible for paying for it. This method is currently used in the PJM, Southwest Power Pool, and MISO Regions.[13] Other parties may use the lines as well, but they must pay compensation to pay back those who originally funded the project. EPAct 2005 specifies that RTO membership is not required to use participant fund-

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ing, which should help encourage merchant transmission. Merchant transmission relies on securing service contracts, rather than a regulated return. It has not yet developed into a major source of new transmission investment.

Socialization of funding is used in ISO-NE and ERCOT. This funding method reflects a decision that most transmission investments benefit everyone in a given region (and not just a particular generator) because they increase the reliability of the regional system as a whole.[14] Socialization of funding should make it easier to build new projects, but the ongoing difficulty in the ISO-NE region to obtain sufficient transmission may challenge that assumption. Socialization of funding may shift some of the burden for funding a transmission project onto customers who do not directly benefit from it.

Pricing models for transmission include:

- *postage stamp*
- *license plate*
- *pancaked rates*
- *distance-sensitive pricing*

Alternative Methods of Pricing

There are several different pricing models for the owners of transmission lines to charge for use of their transmission lines.

- *Postage stamp*: Once a generator pays the price, it can send power anywhere within the region (e.g., the area covered by an RTO). This approach allows sales of electricity across any distance of an RTO at a set price. It is left to RTOs to determine which parties should get compensated. This pricing system may be easily combined with socialized funding.
- *License plate*: When a generator pays a fee to the transmission owner, it is then able to send power across the rest of the regional system. This option has been chosen when starting off an RTO in order to pay utilities for their embedded costs. Over time, the transmission owner pays off the costs in its rate base. However, once an RTO develops and ends its internal wheeling charges, FERC regards license plate pricing as unfair since it shifts costs onto transmission providers who previously received high revenue from wheeling and thereby discourages new investment. Under this reasoning, license plate funding can be phased out and replaced with postage stamp pricing.
- *Pancaked rates*: Under this system, a power producer pays a fee each time the electricity crosses a utility's boundary. The accumulation of fees for crossing a number of utilities' territories raises the cost of long-distance transactions compared to the preceding two methods. This approach is typically present where there is no RTO. Pancaked rates, rates piled on top of each other, may also come into play for transactions across RTO boundaries; agreements (known as seams agreements) are used to set the rates for transactions across RTO boundaries.
- *Distance-sensitive pricing*: Used in ERCOT, this system sets rates according to the kilowatts per mile involved in the transaction. Under this method, distance is assumed to be a major factor in transmission

cost, so longer transactions have a correspondingly higher price. However, FERC does not support this method, contending that distance-sensitive pricing limits transactions and puts a premium on generation location that might allow generators to exercise market power over other generators.[15]

The fixed cost of transmission is indeed strongly related to distance. However if distance were the only factor taken into account in pricing, then the costs of congestion would not be taken into account, and the large economies of scale present in transmission could potentially go unrealized. However, it is hard to measure congestion costs. It remains a challenging question for regulators to determine how costs should be allocated if the objective is to relieve congestion to maximize throughput.

FERC Treatment of Transmission Rates and Pricing

FERC is charged with approving the rates for transmission service in interstate commerce, including transmission associated with wholesale sales and the unbundled component of retail transmission in applicable states. EPAct 2005 directed FERC to implement rules for incentive-based rates for transmission under its jurisdiction.[16] The purpose of the incentive rates is to attract new transmission investment in order to improve reliability and reduce congestion. Incentive-based rates can supplement or replace traditional cost of service rates (which are intended to serve as a proxy for competition), relying on explicit financial incentives. Examples of incentive rate mechanisms include:

- Return sharing between customers and shareholders
- Wholesale price caps, under which the firm may operate with greater flexibility
- Performance-based rates -- firms receive higher rates if they exceed certain pre-specified performance measures (e.g., reduce congestion, lower rates or costs). Beyond providing incentives for new investment, such rates can be used to penalize poor performance. FERC is seeking to develop standards that should be used for performance-based rate mechanisms.

In November 2005, FERC issued a notice of proposed rulemaking on transmission pricing rules that would boost rates by allowing return on equity (ROE) "adders" for:

- Utilities and independent Transcos that join RTOs (as required by EPAct 2005)
- New investments intended to reduce congestion if part of a regional planning process (but not necessarily in an RTO)
- Formation of a new Transco

Other proposed FERC transmission pricing changes to attract new investment include:

- Accelerated depreciation
- Cost recovery for projects cancelled for reasons outside of utilities control

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Locational marginal pricing is intended to work as a congestion management mechanism to balance supply and demand within an area, but it may also influence transmission investment decisions.

Under LMP, the price bid by the last generator selected is the price that is paid to all the generators whose bids are accepted, even though that final price is higher than the bids of all but one of the generators.

- Deferral of cost recovery for utilities under a rate freeze
- Current expensing (not capitalization) of pre-commercial costs for permitting
- Rate base recovery of all prudent construction work in progress, instead of allowance for funds used during construction.

Locational Marginal Pricing

Locational marginal pricing (LMP) is a method for determining the price of power in a given area, and so it is distinct from the transmission-only pricing methods discussed above.[17] LMP is intended to work as a congestion management mechanism to balance supply and demand within an area, but it may also influence transmission investment decisions. In basic form, a market operator (such as an RTO) collects expected demand from retail sales along with bids from generators to sell an amount of electricity at a specified price. The market operator arranges the bids by price and accepts all of the lower cost bids necessary to meet the expected demand, an approach known as least-cost dispatch. The price bid by the last generator selected is the price that is paid to all the generators whose bids are accepted, even though that final price is higher than the bids of all but one of the generators. The geographic area is broken down into locations referred to as "nodes," and the market operator can observe when the price differs between different locations in the spot market. When such price differences emerge, the market operator can assess a congestion charge to transmission users. The organized markets (i.e., RTOs and ISOs) using LMP offer Financial Transmission Rights (FTRs) to protect against the risk of congestion charges, a topic covered in more detail below. In short, LMP refers to the cost of providing the next megawatt of power to a specific location in the least-cost manner given transmission constraints.

Areas that have low generation compared to demand often exhibit transmission congestion, and so become "load pockets" separated from the rest of the market due to lack of transmission access. If transmission congestion blocks access to generation outside the area, then the market operator will have to dispatch the generation from within the area. If a generator's output is required to satisfy demand within the load pocket, then it would be able to exercise market power by either raising its bid price or, if it owns multiple generation assets, by physically withholding a portion of its generation from the market.

Under a LMP pricing system, each location suffering from congestion will have its own market clearing price that reflects the cost of congestion. Although the short term goals of LMP are to maintain reliability of the system and achieve least-cost dispatch of generation for wholesale electricity, a longer term goal is to send clear signals about which areas feature higher prices and thereby indicate where new generation and transmission facilities could receive a higher price in the market. LMP is a new pricing model and its ability to attract generation and transmission investment to higher-priced locations will have to be determined over time.

Financial Transmission Rights

Transmission congestion fees can exceed the amount that firms in RTOs are paid for supplying electricity to congested areas. In organized markets with LMP, FTRs may be used to compensate owners of transmission and help users of transmission minimize price volatility arising from transmission congestion.[18] FTRs are financial instruments used to hedge against the risk of congestion and gain certainty about price for delivering energy. The congestion fees arise when congestion on the lines forces higher cost generators to come online. The fees are collected by the RTO and then paid out to the holders of the FTRs. Unlike firm transmission rights, which guarantee the holder access to uninterruptible transmission service on a set schedule, FTRs are <u>not</u> a right to delivery of power. FTRs are typically offered with terms of a year or less[19], and may be obtained in several ways:

- RTO may arrange an initial allocation of FTRs to load-serving entities
- RTO may also use an annual auction of its entire capacity
- Purchased or traded in a secondary market
- Awarded for new transmission service or upgrades

In addition to maintaining the short term reliability of the system, the most immediate task that faces RTOs is the need to clear static markets, and FTRs are designed to address these two issues. However, FTRs could create a new problem to the extent that they reduce the incentive to invest in future transmission. Holders are entitled to a share of congestion fees, and so could reward over-utilization of existing lines. FTRs lose value if congestion is relieved by the addition of new transmission lines. This could encourage underinvestment in transmission, in that transmission owners have an incentive to build just enough transmission to maintain the system but not greater amounts that would allow a more efficient system from the public's perspective.

TRANSMISSION PLANNING

When effective, transmission planning can increase reliability of the electrical system, reduce congestion, allow fuel diversity in generation, and encourage development of functional regional markets where desired.

Before restructuring, transmission planning was conducted by utilities under the oversight of the PUCs. Typically, PUC efforts only needed to cover a geographic area that was served by a small number of utilities. The coordination of reliability of the grid as a whole was left to the voluntary NERC regional reliability councils.[20] Under the traditional arrangement, the authority and the reasonability for transmission planning were closely matched up. However, open access and functional separation of generation and transmission under FERC Order 888 have introduced uncertainty into the planning process. Region-wide

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Regional State Committees (RSCs) provide forums for state commissioners to consider transmission siting, pricing rules, resource adequacy and planning, and funding allocation rules.

RTOs have a new responsibility to plan, but they do not have any new authorities to ensure that they achieve those plans.

planning is necessary to reflect the realities of regional markets, whether organized or not. Where there are no RTOs, authority to conduct regional planning is not in any regional group's hands. Regional EROs should be able to examine plans, but only for reliability purposes; it is beyond their purview to design market rules for other objectives such as fuel diversity or cost reduction.

FERC Order 2000 specifies that RTOs should conduct transmission expansion planning, and RTOs and ISOs are becoming more involved in planning.[21] However, an RTO's regional planning efforts can be overshadowed by more immediate objectives of short-term reliability and current market operation. RTO engineers can identify where congestion is taking place, but there still needs to be an effort to engage in the system-wide planning, combined with funding and pricing mechanisms that will enable those parties considering investment in needed transmission to do so with confidence.

Even in the areas where RTOs are present, they are not in a position to replicate the regulatory oversight responsibilities of PUCs. One effort to address transmission planning is the creation of Regional State Committees (RSCs). Originally proposed as part of FERC's Standard Market Design in 2002, RSCs exercise authority delegated by FERC. Current examples include the Organization of MISO States (OMS) and the Organization of PJM States, Inc. (OPSI). Two other regional state groups, the New England State Committee on Electricity, and the Western Interconnection Regional Advisory Board, have been petitioned to FERC but have not yet been approved. The purpose of the RSCs is to provide a regional forum for state commissioners to consider transmission siting, pricing rules, resource adequacy and planning, and funding allocation rules. In regions where an RTO is in operation, the RSC provides a forum for state authorities from around the region to interact with the RTO.

RSCs offer the potential to infuse the regional transmission planning process with a larger sense of the public interest. RTOs cannot order utilities to build. In this regard, RTOs have a new responsibility to plan, but they do not have any new authorities to ensure that they achieve those plans. RSCs could serve to coordinate state efforts to oversee utilities, even in regions with states featuring differing levels of electricity restructuring.[22]

Section 1221 of EPAct 2005 allows for the creation of interstate compacts for addressing regional siting issues. Siting decisions arrived at by the compacts are not subject to the federal siting authority that can otherwise come into play if a state fails to issue a siting permit within one year of the filing for a transmission project in an area that has been designated by the Department of Energy as a National Interest Transmission Corridor.[23] However, the jurisdiction of the compacts is limited; FERC is allowed to step in with its siting authority if the members of the compact cannot reach a decision within that one year period.[24] Nonetheless, an RSC might be able to qualify as an interstate compact for the purposes of EPAct 2005, and such authority might help the RSC establish a robust regional planning process.

CONCLUSION

Electricity is not a standard market commodity. This is due not only to its unique physical properties, but also the vital importance that it plays in people's lives. The electricity industry is in the midst of a period of enormous change, and that is especially true of the transmission sector. The rules for the markets and the authority structures underlying those markets are being written in this period. State commissions will have an ongoing opportunity to shape and influence those rules in a way that advances their responsibility to serve the public interest of their states.

Regulators have no interest in encouraging unnecessary transmission projects that boost expenses that are ultimately borne by consumers. At the same time, however, transmission offers large economies of scale to the rest of the electricity system in that tight supply rapidly escalates the total price of energy. A short-term focus could result in an effort to "exact-size" the transmission system that misses out on the economies of scale and ends up raising the total costs paid by the public. Regulators are faced with the challenge of creating a planning process, funding mechanism, and associated pricing method that rewards investment in appropriate levels of carrying capacity.

Notes

[1] Federal Energy Regulatory Commission (FERC), *Promoting Investment Through Pricing Reform*, Notice of Proposed Rulemaking, Docket No. RM06-4-000, 113 FERC ¶ 61,182 (Nov. 17, 2005).

[2] PJM Interconnection (PJM), *2005 State of the Market Report*, p. 290, available at http://www.pjm.com/markets/market-monitor/downloads/mmu-reports/20060411-som-web-4.pdf. For purposes of comparison controlling for the increasing size of PJM, congestion costs represented 7 percent of total billings in 2003 and 9 percent in 2004.

[3] North American Electric Reliability Council data available at ftp://www.nerc.com/pub/sys/all_updl/oc/scs/logs/trends.htm.

[4] Eric Hirst. 2004. *U.S. Transmission Capacity: Present Status and Future Prospects*. Washington, D.C.: Edison Electric Institute (EEI), August.

[5] Energy Security Analysis, Inc. 2005. *Meeting U.S. Transmission Needs*. Washington, DC: EEI, July. Available at http://www.eei.org/industry_issues/energy_infrastructure/transmission/meeting_trans_needs.pdf.

[6] Ibid. The preceding decade was characterized by the addition of a large number of natural-gas fired generation plants. To the extent that generation is sited close to the load centers to be served, the demand for transmission capacity is reduced.

[7] Costs for underground cable are about four times higher. Estimates presented here are drawn from http://www.eia.doe.gov/cneaf/pubs_html/feat_trans_capacity/table2.html, with the 1995 data updated to 2004 prices using a Consumer Price Index inflator. See also Michael H. Brown and Richard P. Sedano, 2004, *Electricity Transmission, A Primer,* National Council on Electricity Policy, June, p. 15 for similar estimates. AEP estimates the price of a 550 mile 765 kV line from West Virginia to New Jersey at $3 billion; see Bruce W. Radford, 2006, "Growing the Grid: The models and motives behind tomorrow's transmission expansion," Public Utilities Fortnightly, April, p. 42.

[8] For example, the prospective owner of a new generation plant cannot currently obtain transmission rights longer than one year, so the owner has little idea of transmission costs over the life of the plant. In the past,

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a generation owner would have been able to obtain commitment from a transmission provider for the life of the plant at cost-of-service rates that would rise over time in a predictable manner.

[9] The electricity restructuring laws passed by some states in the 1990s required utilities to divest their generation assets, but did not in most cases (except Michigan) mandate transmission as an independent company; in such states the companies could remain as transmission and distribution utilities.

[10] FERC regulates all transmission rates, but non-utility transmission owners, also known as merchant transmission owners, do not earn a regulated return. Instead, they negotiate contracts with interested power producers. Transcos are transmission utilities that are stand-alone companies selling at wholesale or unbundled retail. Transcos are public utilities, and may be either independent or passively owned by affiliated (vertically integrated) utilities.

[11] See FERC, *Policy Statement Regarding Evaluation of Independent Ownership and Operation of Transmission*, 111 FERC ¶ 61,473 (2005) (Transco Independence Policy Statement), and *Promoting Investment Through Pricing Reform*, Notice of Proposed Rulemaking, Docket No. RM06-4-000, 113 FERC ¶ 61,182 (Nov. 17, 2005).

[12] See Robert E. Burns and Mark Eifert. 1994. *A Cooperative Approach Toward Resolving Transmission Jurisdictional Disputes.* Columbus, OH: National Regulatory Research Institute, NRRI No. 94-06, June, available at http://www.nrri.ohio-state.edu/dspace/handle/2068/317.

[13] For example, in February 2006, FERC approved Midwest Independent System Operator's (MISO) cost allocation method for baseline reliability transmission projects. The project must qualify as a baseline reliability project in the MISO Transmission Expansion Plan. If below 345 kV, cost recovered 100 percent sub-regionally. If above 345 kV, 80 percent sub-regionally and 20 percent based on load ratio share (i.e., postage stamp). For generator interconnection projects, the generator must secure at least one year of contracts for its output, and it is then eligible to have 50 percent of the interconnection costs reimbursed at the sub-regional level.

[14] The sharing of transmission costs in these Regional Transmission Organizations (RTOs) has certain limits. ISO-New England may determine if certain portions of the funding should be localized if the locality caused the increased costs, and Electric Reliability Council of Texas requires generators to cover all costs to the interconnection (http://www.puc.state.tx.us/rules/subrules/electric/25.195/25.195.pdf).

[15] See, for example, FERC, *Final Order Directing Transmission Services*, Docket No. ER94-1395-000, 69 FERC ¶ 61,269 (Dec. 1, 1994).

[16] Section 201(f) of the Federal Power Act specifies that governmental and certain electric cooperative entities are not subject to FERC jurisdiction.

[17] For a more detailed examination of LMP, see Karl Meussen and R. Scott Potter, 2004, *Commissioner Primer: Locational Marginal Pricing*, Columbus, Ohio: National Regulatory Research Institute, NRRI 04-16, November, available at http://www.nrri.ohio-state.edu/dspace/handle/2068/3.

[18] FTRs may also be referred to as "congestion revenue rights" or "transmission congestion contracts."

[19] Under section 1233b of EPAct 2005, FERC must ensure that load-serving entities in organized markets are able to secure long-term firm transmission rights or equivalent financial rights (i.e., FTRs). Such rights would be of a greater length of time than the current one-year term of FTRs. FERC issued a notice of proposed rulemaking on this issue. See 114 FERC ¶ 61,097 (Feb. 2, 2006), available at http://www.ferc.gov/whats-new/comm-meet/020206/E-3.pdf. It could be argued that since FTRs are renewable that they already serve the long term needs of existing generators, but they still do not necessarily provide for allocation of rights for new generation. Users of transmission in unorganized markets operating FERC's Open Access Transmission Tariff are able to obtain long term contracts for both network and firm point-to-point service, resulting in less price volatility.

[20] Section 1211 of EPAct 2005 mandated the creation, under FERC, of a National Electric Reliability Organization with mandatory and enforceable reliability standards.

[21] For a detailed examination of current RTO and ISO planning processes, see ISO/RTO Planning Committee, *ISO/RTO Electric System Planning: Current Practices, Expansion Plans, and Planning Issues*, issued March 20, 2006, and available at http://www.ercot.com/news/presentations/2006/IRC_PC_Planning_Report_Final_02_06_06.pdf.
[22] For example, MISO combines both restructured and traditionally regulated states.
[23] Under section 1221(b) of EPAct 2005, FERC may issue siting permits for projects located in National Interest Transmission Corridors designated by the Department of Energy if 1) a state does not have siting authority or authority to consider the interstate benefits of transmission, 2) the applicant does not qualify for a permit in a state because it does not serve end use customers in the state, 3) the state takes longer than one year after filing to act, or 4) the state conditions its approval in such a way that the proposed project will not reduce interstate transmission congestion or is not economically feasible.
[24] If the Interstate Compact is not able to reach a decision, siting authority would fall back to FERC.

The National Regulatory Research Institute
1080 Carmack Road
Columbus, Ohio 43210-1002
Phone: 614-292-9404
Fax: 614-292-7196
www.nrri.ohio-state.edu

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