

**PROMOTING EFFICIENT TRANSMISSION INVESTMENT:
THE ROLE OF THE MARKET IN EXPANDING
TRANSMISSION INFRASTRUCTURE**

November, 2001

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Acknowledgement

The authors would like to thank the sponsorship of TransÉnergie U.S. Ltd. for its support in writing this paper. The authors also would like to thank William W. Hogan, Roy J. Shanker and Eric J. Hirst for their review and comments on this paper. All errors and omissions, of course, remain the authors’.

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Introduction

For much of the 20th century, electric power policy occupied a small corner in American public affairs. Surely, an occasional spotlight would shine on the utility industry every few years – the result of environmental or consumer activism, for example, or of geopolitical threats to our fuel supply. But, by and large, the structure of electricity markets and regulation generated little debate. This low profile testifies to the long success of the electric power industry in delivering inexpensive and abundant electricity to America’s homes, offices and factories.

The deregulation and restructuring of the electric power industry that began in the 1990s changed all that. Not since the days of Thomas Edison, George Westinghouse and Samuel Insull has the public shown as keen an interest in electric power. By late 2000, public debate achieved unprecedented intensity when price shocks rocked California’s electricity markets. As of this writing, a newly released federal energy policy and continuing controversy in California assure, for the foreseeable future, prominent headlines for topics in electric power.

It is in this context of heightened public scrutiny that we offer this paper on transmission reform. The scope of this paper, however, ranges beyond the current, narrow debate over who should own what transmission assets how. Readers expecting a discussion of solely transmission issues may be surprised to find significant detours into the market structure and regulatory framework governing generation and distribution, the other major sectors of the electric power industry. In fact, our approach holds that ***transmission reform is the key to an efficient allocation of investment resources not only among new transmission projects, but among all available methods of providing electric power to end-users — including transmission projects, large-scale generation, distributed small-scale generation, and load management technologies.*** We propose that, if the appropriate structures in place, then markets – not regulators – can determine the efficient level and combination of investment in a wide range of electric power facilities. The result will be greater public service: fewer stranded investments, and increased availability of power and cheaper rates for the nation’s electricity users.

The intended readership of this paper, then, comprises not only players in the transmission sector, but anyone interested in current policies affecting the electric power industry as a whole.

This paper has four parts. In Part I, we review the context in which the current debate over transmission policy is taking place. We look at how previous regulatory and market actions have determined today’s transmission infrastructure. We also provide a brief timeline that identifies the milestones in the development of electric power deregulation. Readers familiar with industry regulation and technology may wish to skip this section.

In Part II, we address *merchant transmission*, a free-market approach that is tailored to the particularities of transmission technology. Unlike other regulatory models, merchant transmission requires the full risk of transmission investment to be in the hands of the owners of the transmission facility – there is no guaranteed rate of return, nor are there regulatory incentives for action.

In Part III, we discuss ways to assure reliability of electric service in a merchant transmission environment. We propose that regulators issue requests for proposals (RFPs) to satisfy transmission needs unmet in the competitive market for transmission. We describe the workings of this model – merchant transmission backstopped by a competitive solicitation – and its application in the real world.

In Part IV, we outline the benefits and drawbacks of *performance-based rate* regulation, or PBR, of transmission services – a non-market regulatory scheme currently proposed by certain market participants.

We believe that the adoption of a competitive market for transmission investment with an RFP backstop will most likely result in an economically efficient and socially beneficial transmission policy. That said, we recognize that the debate over transmission policy is far from over. Whatever its final outcome, we hope that our proposal will prove a thought-provoking and valuable contribution to the discussion.

Executive Summary

The restructuring of electric power transmission sector is now the subject of intense debate. On the one side are proponents of monopoly transmission companies and traditional regulatory regimes; on the other are proponents of competing transmission companies and a free market in new transmission investment. The stakes could not be higher: a healthy transmission sector is critical if the electric grid is to meet the nation's demand for power in the decades to come.

This paper argues in favor of a competitive market in transmission investment, backstopped by regulatory intervention when the markets fail to provide needed transmission upgrades. Our approach recognizes that a competitive market for transmission is not a perfect market; it also recognizes that traditional regulatory approaches cannot offer perfect regulation. With these observations in mind, we aim to combine the advantages of free markets with the steadying hand of regulation.

A competitive market for new transmission investment is vital to an innovative and robust transmission sector. In fact, a competitive market in transmission investment is comparable to today's competitive market in generation investment. In both transmission and generation, new technologies have opened the door to competition. In the case of generation, the success of gas-fired combined-cycle turbines and of cogeneration and independent power producers showed that, in the words of the FERC, "[b]igger was no longer better," that competition between electricity producers small and large could flourish. Comparably, new advances in transmission and other technologies are for the first time challenging the primacy of traditional steel-lattice-tower transmission facilities. Furthermore, if free to compete with legacy technologies, today's transmission technologies can complement – or even substitute for – new power plants, bringing power cheaply and easily to end users from sources previously unavailable.

A market-based approach to new transmission investment is the logical extension of the adoption of bid-based, security-constrained locational pricing for transmission service with firm transmission rights. Bid-based, security-constrained locational transmission prices accurately indicate where new transmission investment is needed by providing market-based price signals to industry participants. Firm transmission rights provide transmission developers the property rights associated with their investment, which enable the developers to finance their investments. And we know this works: in the US and abroad, power grids successfully have adopted or currently are implementing elements of this approach. In contrast, other schemes that seek to encourage transmission investment rely not on market efficiency but on regulatory incentives – the success of which is founded on the (necessarily inconsistent) skills and perspicacity of government regulators.

In cases of market failure, a competitive solicitation for new transmission investment should be issued, to assure needed transmission upgrades at the lowest possible costs to consumers. The electric power industry does not adapt to change quickly, the result of its monopoly heritage. To assuage industry concerns over potential failure of the competitive market to provide adequate transmission investment, we propose the establishment of a regulatory backstop to the competitive market. This backstop will be triggered by the judgment of an independent operator of the transmission system, that the need for a transmission upgrade is not being addressed by the competitive market. The independent system operator (ISO, RTO or otherwise) would then be authorized to issue a request for proposals or other competitive solicitation for the provision of transmission investment that satisfies the need. The competitive solicitation would be open not only to traditional steel-lattice-tower transmission technologies but new, innovative technologies. Project costs would be allocated through a cost-benefit analysis that appropriately assigns costs to those transmission customers that benefit from the project.

Unlike competitive markets for new transmission investment backstopped by a competitive solicitation process, regulation of transmission by performance-based rate incentives is not likely to provide for optimal transmission investment. While the FERC has signaled its support for competitive markets in new transmission investment, it also has kept open the door to an alternative: performance-based rate incentives. Performance-based rate regulation may be attractive to some theorists but, like many other regulatory schemes, it is difficult to apply in practice. Such a regime relies not on the market but on the heavy hand of regulation. Among its dangers: it does not provide for universal market participation but establishes a single – monopoly – market player, thereby limiting the range of solutions (including technologies) available to the electric power industry; it requires government officials to determine appropriate base revenue levels (and other cost targets) as well as levels of performance, and to measure performance against a benchmark; and it gives the regulated entity the potential to exercise undue market power in the provision of transmission services. In contrast, market-based transmission with a competitive solicitation backstop encourages industry players to compete for market-based returns – but, when there is no demand for such returns, market-based transmission with a competitive solicitation backstop encourages industry players to compete for regulation-based projects.

A competitive market in transmission investment will bring to end users new, cheaper sources of electric power. It will foster innovation not only in the transmission but also in the generation sector. A regulatory backstop will preserve reliability by addressing any potential market failures. By adopting the competitive market/regulatory backstop model, we can go a long way toward achieving the full promise of a restructured electric power industry.

Part I: The Context of the Current Debate

“The objective is to move away from governmental control as a substitute for the market and toward reliance on competition in the marketplace as a more efficient way to serve the public.”

Daniel Yergin and Joseph Stanislaw¹

“The gap between the transmission expansion need and the proposed construction of transmission is widening. To support the reliability of the bulk power system, proper incentives must be developed to encourage transmission construction.”

North American Electric Reliability Council²

The American utility system has been called the most complex machine ever created by man.³ It satisfies one-quarter of the global use of electricity.⁴ Over 1000 public and private electricity suppliers buy or sell over the system.⁵

The size of the system is reflected in the complexity of its regulation. The industry spans three national and fifty-five state, provincial and other jurisdictions.⁶ For much of the past century, the US regulated electric utilities as monopolies.⁷ As a regulated monopoly, an electric utility held an exclusive franchise to provide electric service to a specified geographic area. In return, the utility was required to provide electric service to customers at a regulated price.

The Heritage of Monopoly Regulation

The theoretical foundation for monopoly regulation lies in the concept of the *natural monopoly*. Loosely put, natural monopoly occurs when the most efficient way of organizing production is through a single firm rather than through competition among

¹ DANIEL YERGIN & JOSEPH STANISLAW, *THE COMMANDING HEIGHTS: THE BATTLE BETWEEN GOVERNMENT AND THE MARKETPLACE THAT IS REMAKING THE MODERN WORLD* 13 (1998).

² NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL, *RELIABILITY ASSESSMENT 2000–2009: THE RELIABILITY OF BULK ELECTRIC SYSTEMS IN NORTH AMERICA* 33 (2000).

³ Leonard S. Hyman, *Setting the Stage*, in *POWER SYSTEM RESTRUCTURING: ENGINEERING AND ECONOMICS* 1 (Marija Ilic et al. eds., 1998).

⁴ ENERGY INFORMATION ADMINISTRATION, *PUBLICATION NO. DOE/EIA-0219(99), INTERNATIONAL ENERGY ANNUAL 1999 92-94* (2001).

⁵ SHIMON AWERBUCH, LEONARD S. HYMAN & ANDREW VESEY, *UNLOCKING THE BENEFITS OF RESTRUCTURING: A BLUEPRINT FOR TRANSMISSION I* (1999).

⁶ Hyman, *supra* note 3.

⁷ The Public Utility Holding Company Act of 1935 restricted the activities of public utility holding companies; the Federal Power Act, also enacted in of 1935, regulated wholesale transactions and rates for electric power flowing interstate. State laws, many of which were enacted even earlier, gave state commissions the authority to set retail electric prices.

Generation is the process of creating electricity. Power plants, whatever the fuel – hydro, nuclear, gas, coal or other source – are the locus of electric generation.

Transmission is the process of moving electricity generated by power plants over long distances, in bulk, via high voltage wires (transmission lines).

Distribution is the process of moving power from transmission lines to the end user over low-voltage lines and other equipment.

multiple firms.⁸ A firm will tend to natural monopoly if it has *economies of scale* or *economies of scope*. A firm has economies of scale if its costs of production decline as it increases plant size and the amount of goods or services produced. A firm has economies of scope if costs of production decline as it increases the types of goods or services produced.

Economies of scale and scope are found in many unregulated and formerly-regulated industry sectors, including motor carriers, railroads, airlines, and telecommunications. Regulators of these industries sought efficiencies by restricting

production to a small number of firms – in other words, the government limited competition and fostered monopoly behavior. In return for freedom from competition, the government imposed *cost of service regulation* (COSR) on the rates that a monopoly could charge.

COSR sought to alleviate the dangers of *monopoly pricing*: the tendency of monopolies to create artificial scarcity and thereby induce high prices. COSR limited the rate of return monopolies could achieve to a reasonable point above the (reasonable) costs including a regulated return incurred by the monopoly and required regulated monopolies to serve all customers.

It has long been understood that electric utilities were natural monopolies.⁹ Accordingly, the guiding hand of regulation sought maximum efficiency by bundling together all aspects of electric service (generation, transmission, and distribution), creating the *vertically integrated utility* with an exclusive geographic franchise. And by subjecting electric utilities to COSR, regulators sought to prevent monopoly prices while at the same time assuring proper levels of investment and service.

The Origins of Power Industry Deregulation: Natural Gas

By the late 1970s, COSR was “effectively the only form of regulation” in the US.¹⁰ But drawbacks of COSR had become increasingly clear. Theory and empirical evidence now argued that the use of COSR resulted in many inefficiencies, among them:

⁸ See, e.g., PAUL L. JOSKOW & RICHARD SCHMALENSEE, *MARKETS FOR POWER: AN ANALYSIS OF ELECTRIC UTILITY DEREGULATION* 29 (1983); PAUL A. SAMUELSON & WILLIAM D. NORDHAUS, *ECONOMICS* 911 (12th ed., 1985).

⁹ As late as 1985, the leading college economics textbook described electric utilities as the most extreme form of natural monopoly. See SAMUELSON, *supra* note 8, at 524.

¹⁰ AWERBUCH, HYMAN & VESEY, *supra* note 5, at 147.

- minimal incentives to reduce costs;
- distorted investment and risk-taking;
- retarded innovation and stranded costs; and
- cost misallocation between outputs, including cross-subsidization.¹¹

As a result, the government's commitment to monopoly regulation began to waver. By 1980, the modern motor carrier, airline, and railroad sectors – monopolistic industries whose aggregate revenues then accounted for almost four percent of the country's gross domestic product – had been opened to competition for the first time.¹²

It is in this context that Congress and the Federal Energy Regulatory Commission (FERC) began to explore ways to deregulate the natural gas industry. The FERC had long maintained that the transportation of natural gas through pipelines created a natural monopoly. Prodded by the passage of the Natural Gas Policy Act of 1978, which provided for decontrol of natural gas prices at the wellhead, in 1985 the FERC ordered natural gas firms to open their pipeline networks to local distributors and other end users, such as industrials and gas-fired electric generators.¹³ Local distributors could now offer customers the advantages of competition at the wellhead (lower production-area prices), free from the control of pipeline owners. At the same time, many state public utility commissions began to accommodate new competition in the local distribution of natural gas, creating competitive *local* prices.

Subsequent FERC rulemaking reconfirmed that an efficient and competitive gas industry required the liberalization of pipeline markets. However, the FERC did not question the status of gas pipelines as a natural monopoly; it sought only to regulate the *market power* of pipeline owners so as to foster competitive prices:

“The Commission must create a regulatory environment in which no gas seller has a competitive advantage over another gas seller. In particular, the Commission must regulate the pipeline transportation system and pipeline sales for resale in a manner that ensures that pipeline control of the transportation system -- **a natural monopoly** -- does not give a competitive advantage to pipelines over other sellers in the sale of natural gas. This will ensure that the benefits of decontrol redound to consumers of natural gas.”¹⁴

¹¹ *Id.* at 145.

¹² Hyman, *supra* note 3, at 2.

¹³ Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, Order No. 436 [1982-1985 Transfer Binder Stats. & Regs. Preambles] Fed. Energy Reg. Comm'n Rep. (CCH) ¶ 30,665 (1985).

¹⁴ Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation; and Regulation of Natural Gas Pipelines After Wellhead Decontrol, Order No. 636 [1991-1996 Transfer

The FERC's experience deregulating the natural gas industry was to influence greatly its deregulation of another industry in the energy sector, albeit one with more than three times the annual revenue of natural gas¹⁵ – the electric power industry.

The Deregulation of Electric Power Generation

The origin of deregulation in the electric power industry owes much to political events.

The oil embargo of 1973 focused attention on the supply and use of fuel. In response, interest in conservation and alternative fuels soared. This attention resulted in the enactment of the Public Utility Regulatory Policies Act (PURPA) in 1978. PURPA required electric utilities to supplement the power that they generated with power purchased at wholesale from two energy-efficient sources. The first source included power plants that used biomass and other alternative energies as fuel. The second included power plants that produced electricity as well as steam for industrial uses, called cogeneration plants. Interest in demand-side management programs also increased. Such programs sought to reward reductions in energy use through consumer conservation and other methods.

By the late 1980s, the country again became alarmed at the rising use of fuel from foreign sources.¹⁶ The Energy Policy Act of 1992 (EPAct) permitted sales of power at wholesale by a new class of non-utility generators, called Exempt Wholesale Generators (EWGs). The EPAct opened the door to independent power producers (IPPs) not already protected by PURPA to compete with vertically integrated utilities. Unlike the alternative-fuel and cogeneration plants promoted by PURPA, these IPPs were not defined by energy efficiency; they could sell electricity at wholesale regardless of the generation process.

Both PURPA and the EPAct struck a blow against the concept of monopoly regulation of the electric power generation. Cogenerators and other non-utility power producers flourished. New technologies, particularly gas-fired combined-cycle turbines, were producing electricity in ways that were more market-friendly – in more modular and flexible quantities, and at lower cost – than the huge power plants the vertically integrated utilities had already built. In the words of the FERC, “Bigger was no longer better.”¹⁷ Vertically integrated utilities no longer possessed the economies of scale in generation that could limit competition.

Binder Stats. & Regs. Preambles] Fed. Energy Reg. Comm'n Rep. (CCH) ¶ 31,939 at 30.393 (1992) [emphasis added].

¹⁵ Hyman, *supra* note 3, at 2.

¹⁶ RICHARD F. HIRSCH, POWER LOSS: THE ORIGINS OF DEREGULATION AND RESTRUCTURING IN THE AMERICAN ELECTRIC UTILITY SYSTEM 240 (1999).

¹⁷ Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888 [1991-1996 Transfer Binder Stats. & Regs. Preambles] Fed. Energy Reg. Comm'n Rep. (CCH) ¶ 31,036 at 31,641 (1996), *order on reh'g* Order No. 888-A, Fed. Energy Reg. Comm'n Rep. (CCH) Stats. &

Economies of scope had also diminished. By the late 1960s and 1970s, improved transmission technologies and new regional interconnections enabled power plants to be built more than one thousand miles from power users.¹⁸ With a substantial amount of power now moving between regions, and between utilities within regions, the incentive to link vertically generation and transmission assets decreased. It was apparent that the economies of scale or of scope in generation no longer justified the holding that vertically integrated utilities were “natural monopolies.”

At about the same time, dissatisfaction with cost-of-service regulation of monopolies was growing as well. Utilities, it was believed, had little incentive to manage their costs under a system that allowed them to pass those costs onto consumers (although subject to regulatory approval).¹⁹ Large cost overruns occurred in the construction of nuclear power plants and other generation facilities. Furthermore, the anticipated need for such facilities did not always materialize, and advocates of change argued that a competitive market could result in wiser long-term investments and better allocation of costs among utilities and ratepayers.

In their book *MARKETS FOR POWER* (1985), Joskow and Schmalensee summed up the fundamental issues faced by policymakers at this time:

What if we are evaluating an industry that was once a natural monopoly...but where the market has grown enough that two firms can now provide output at minimum costs? Clearly the alternative to regulated franchised monopoly is not likely to be anything close to a perfectly competitive market.... In considering the natural monopoly question, it is important not to think of there being two simple extremes: natural monopoly and competition.²⁰

In other words, were inefficiencies that resulted from the imperfections in the monopoly regulation of generation greater than those that would result from imperfections in competitive markets for generation? The judgment was made: establishing competitive, though imperfect, markets for generation was superior to continuing a regime of imperfect regulation. If we required perfectly competitive markets, “we would not have

Regs. ¶ 31,048 (1997), *order on reh'g* Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g* Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom.* Transmission Access Policy Study Group v. FERC, 225 F.3d 667 (D.C. Cir. 2000), Nos. 97-1715 et al. (D.C. Cir.), *cert. granted in part* New York v. FERC, 121 S.Ct. 1185 (2001).

¹⁸ Promoting Wholesale Competition, Order No. 888, *supra* note 17, at 31,641, note 21, citing Bernard S. Black & Richard J. Pierce, Jr., *The Choice Between Markets and Central Planning in Regulating the U.S. Electricity Industry*, 93 COLUM. L. REV. 1339, 1345 (1993).

¹⁹ ALFRED E. KAHN, 2 *THE ECONOMICS OF REGULATION: PRINCIPLES AND INSTITUTIONS* 49-54 (1970-1971) (describing the Averch-Johnson-Wellisz effect).

²⁰ JOSKOW & SCHMALENSEE, *supra* note 8, at 31-32. Emphasis added.

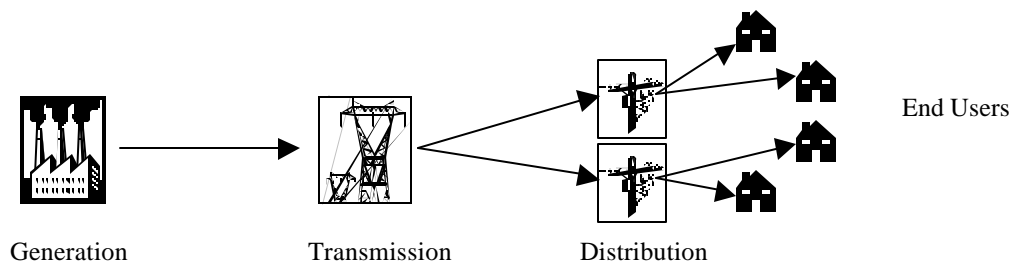
deregulated airlines, railroads, long distance telephone and many other industries.”²¹ By the mid-1990s, a competitive market for generation had become national policy.

Transmission, however, was another story. The economies of scale and scope so evident in transmission made it ‘universally accepted that ‘transmission qualifies as a classic ‘natural monopoly.’”²² While technological and structural changes swept over other industries, the transmission sector remained immune to new ideas.²³ But the impact of the competitive markets for generation presented FERC with problems even more complex than those raised by its earlier reform of the regulation of natural gas pipelines.

The Nature of Transmission

Like gas pipelines, transmission lines are highways. They connect generation facilities to one or more points of electricity demand, called *loads*. Loads are often electric distributors that pass on to end-users the power they draw from transmission lines. In this way, transmission lines constitute one step in the movement of electricity from producer to consumer.

Figure 1. Transmission as highway to distributors/end users



Transmission lines also connect generation facility to generation facility, forming an integrated network called a *power grid*. The power grid is managed by a *system operator* that *dispatches* power through the grid to assure system *adequacy* (the ability to meet

²¹ Paul L. Joskow, *Deregulation and Regulatory Reform in the U.S. Electric Power Sector* 77 (MIT Center for Energy and Env'tl. Pol'y Res., Working Paper No. WP-2000-003, 2000).

²² JOSKOW & SCHMALENSEE, *supra* note 8, at 65, quoting Leonard W. Weiss, *Antitrust in the Electric Power Industry*, in *PROMOTING COMPETITION IN REGULATED MARKETS* 144 (Almerin Phillips ed., 1975).

²³ For a recent argument that transmission should be regulated as a natural monopoly, see PA CONSULTING GROUP, *THE FUTURE OF ELECTRONIC TRANSMISSION IN THE UNITED STATES* 5-12 (2001) (“The status of transmission as a common carrier for all market participants requires that the approach must be applied primarily within a regulatory rather than a direct market competition context”); see also Joskow, *supra* note 21, at 16 (“The natural monopoly rationale for vertical and horizontal integration does not and has not relied primarily on the attributes of the costs of building and operating individual generating plants *per se*. Rather, it is the attributes of the transmission network and its ability to aggregate and facilitate the operation of generating facilities dispersed over wide geographic areas to achieve cost efficiency and reliability objectives over time frames from seconds to decades, that has played the most important role in defining the vertical and horizontal structure of this industry. It is these complementarities between generation and transmission networks that are the primary source of scale and scope economies in electricity.”)

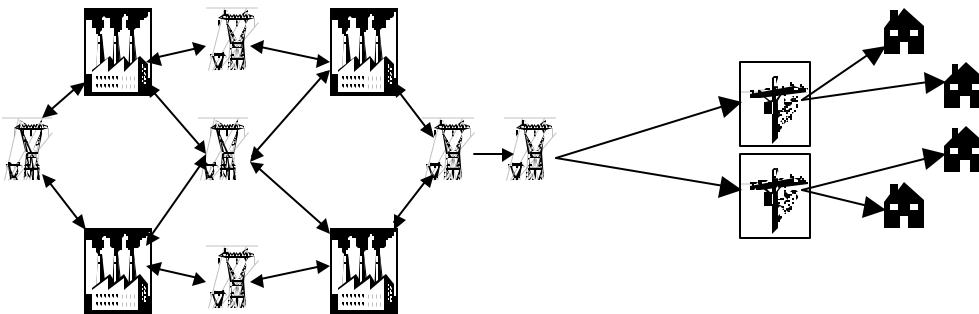
demand) and *security* (the ability to withstand sudden outages of generation or transmission components).

Because of the physical nature of electricity, however, a power grid does not send electricity from Point A to Point B. The power grid is like a pool of water: inputs are indistinguishable once they are made, and no output can be associated with any input. For the reason that electricity cannot be directed to flow through specific lines, it is said that electricity flows in *parallel paths*.

For a power grid to work correctly it must achieve the following:

- i. The total generation at any moment must be kept equal to total electricity consumption and losses on the system.
- ii. The electricity is allowed to flow through the transmission system in accordance with physical laws and cannot be directed to flow through specific lines.²⁴
- iii. The system must be designed with reserve capacity in generation and transmission to allow for uninterrupted service when contingencies occur.²⁵

Figure 2. The power grid



In North America, electric utilities have connected their power grids via transmission lines into large groups with their own system operators. These groups are themselves

²⁴ This is not true of direct current (DC) technologies, which can be directed to flow along predetermined paths from point A to point B. As we discuss below, new applications of DC technology are reshaping fundamentally the concept of the power grid.

²⁵ John Makens, *Upgrading Transmission Capacity for Wholesale Electric Power Trade*, Energy Information Administration, available at http://www.eia.doe.gov/cneaf/pubs_html/feat_trans_capacity/w_sale.html (downloaded September 7, 2001). Stated another way, the power grid has five primary tasks: (i) to meet load demand at minimum operating cost; (ii) to compensate for transmission losses (because an amount of electricity is lost as it travels over transmission lines); (iii) to compensate for the various operating constraints presented by power grid technology; (iv) to provide flexible generation to meet varying load demand in real-time (by matching the amount of power generated with load); and (v) to provide stand-by network resources in the event of an outage on the network. Marija Ilic & Frank Galiana, *Power Systems Operation: Old vs. New*, in *POWER SYSTEM RESTRUCTURING: ENGINEERING AND ECONOMICS 21* (Marija Ilic et al. eds., 1998).

networked into one of three regional areas, called *interconnections*: one for the eastern US and Canada; one for the western US, Canada, and portions of Mexico; and one for Texas. Approximately half of all generated electricity in the country is purchased and sold within these interconnections on the *bulk power market*.

Traditional Transmission Pricing

Under traditional federal monopoly regulation, the FERC regulated the price of each bulk power transaction. For “firm” transmission service,²⁶ a utility could charge rates designed to yield annual revenues that equaled the *embedded cost* of the utility’s transmission facilities – that is, a fair rate of return on the original cost (less depreciation and including operation and maintenance expenses and taxes).²⁷ It didn’t matter how much of the transmission system the electricity being purchased “used” – that is, charges could not be distance sensitive. Because of this indifference to distance, such pricing was called embedded cost, *postage stamp* pricing. If power flowed through several companies, traditional industry practice was to specify that power flows along a fictional *contract path* consisting of the transmission-owning utilities between the ultimate points of delivery and receipt.²⁸ Transmission charges across two or more utilities were added together, or *pancaked*.

For non-firm transmission service, a utility could charge rates to reflect, in addition to the variable costs of providing the service, a charge as high as the full amount of the fixed costs of providing the service.²⁹ In practice, utilities varied the charges for non-firm transmission between their variable costs and their rolled-in costs to reflect market conditions.

Transmission in a Competitive Market for Generation

As competitive markets for generation developed, regulators began to rethink the nature of transmission pricing. In 1994, the FERC issued a Pricing Policy Statement that recognized that new computer models could price transmission services in ways that were more efficient and transparent to transmission service sellers and customers.³⁰ For example, with the FERC’s permission, marginal cost pricing could now replace

²⁶ “Firm” service obligates the seller to guarantee transmission capacity, even if the buyer does not use all purchased power. PHILIPSON & WILLIS, UNDERSTANDING ELECTRIC UTILITIES AND DE-REGULATION 223 (1999).

²⁷ Inquiry Concerning the Commission’s Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act; Policy Statement [1991-1996 Transfer Binder Stats. & Regs. Preambles] Fed. Energy Reg. Comm’n Rep. (CCH) ¶ 31,005 at 31,137 note 4 (1994).

²⁸ Promoting Wholesale Competition, Order No. 888, *supra* at note 17, at 31,650 note 94, citing *Indiana Michigan Power Company*, 64 FERC ¶ 61,184 at 62,545 (1993).

²⁹ Inquiry Concerning the Commission’s Pricing Policy, *supra* note 27, at 31,137.

³⁰ *Id.* at 31,139.

embedded cost, postage stamp pricing.³¹ Distance-sensitive pricing and flow-based pricing (that is, pricing based not on an assumed contract path but on the costs of each of the parallel paths upon which the transmission flows) could be suggested. FERC announced that it would be flexible in reviewing novel pricing proposals.³²

But the industry was sidetracked by matters other than pricing. Like the natural gas industry before it, the electric industry now had a competitive wholesale market that relied on transportation facilities owned and operated by market participants. The danger: owners of transmission lines could restrict the entry of competing generation to the bulk power market by denying or inefficiently pricing rights to use the power grid. The *market power* held by transmission line owners stood in the way of a fully competitive market for generation.

And just as it had done with respect to the natural gas industry, the FERC sought to regulate the way competitively-produced generation was to be treated by the owners of transmission lines. It did this in Order 888, issued in 1996 – four years after passage of the EPAct.

Figure 3. Milestones in transmission deregulation, 1978 - 2001

1978	Natural Gas Policy Act, PURPA (promoting cogeneration)
1980	Deregulation of trucking, airlines and railroad sectors completed
1985	FERC Order 436 (promoting open access to natural gas pipelines)
1992	Energy Policy Act (promoting IPPs)
1994	FERC Pricing Policy Statement
1996	FERC Order 888 (promoting open access to transmission facilities)
1999	FERC Order 2000 (promoting RTOs)

³¹ Citing the economist Alfred Kahn, the FERC defined marginal costs as “[t]he cost of producing one more unit; it can equally be envisioned as the cost that would be saved by producing one less unit.” *Id.* at 31,143 note 27.

³² *Id.* at 31,144: “We fully intend to be flexible and to consider innovative ... pricing approaches that accommodate the changing needs of the competitive bulk power market.”

Order 888 required all electric utilities that owned or controlled transmission facilities to establish non-discriminatory access and rates for generators wanting to transmit electricity over the facilities. The order also “unbundled” transmission from generation; from then on, the transmission business of a utility could give no preference to the utility’s other businesses, including generation.

The concerns regarding possible discriminatory behavior, sometimes referred to as vertical market power, were substantial enough that some states that were in the process of restructuring retail electricity markets either required or strongly encouraged the electric utilities that they regulated to divest of some or all of their generation assets. “One of the surprising outcomes of the state reform programs has been a significant amount of ‘voluntary’ divestiture of generating facilities by incumbent vertically integrated utilities. States promoted divestiture as a means of dealing with stranded cost valuations and to alleviate market power concerns.”³³ For example, Connecticut passed legislation that mandated the divestiture of all utility generation facilities by January 1, 2004.³⁴

In addition to requiring non-discriminatory access and rates and unbundling of transmission, in Order 888 the FERC encouraged, but did not require, the creation of not-for-profit *independent system operators* (ISOs) that would manage regional power pools impartially.

As a result of Order 888, five different areas of the country organized ISOs: the California ISO, the PJM ISO, ISO New England, the New York ISO, the Midwest ISO and the ISO for the Electric Reliability Council of Texas (ERCOT). The state governments of California and Texas required the creation of ISOs in their jurisdictions; the Midwest ISO was created by utilities that otherwise would be ordered by state regulators to sell their transmission assets.

The Impetus for Further Reform

The effects of Order 888 were decidedly mixed. With respect to generation, in general Order 888 was a success – new generation was brought on-line (except in California) and many utilities spun off or sold their generation assets. Prior to Order 888, investment in generation capacity resulted from non-market, regulatory incentives; but subsequent to Order 888 the market for generation had “begun to respond in areas of capacity deficiencies.”³⁵ It is estimated that the generation capacity of merchant generators (non-utility generators selling electricity at non-guaranteed rates) will have risen from 12.6

³³ Joskow, *supra* note 21 at 50.

³⁴ Conn. Gen. Stat. §16-244e - §16-244g (2001).

³⁵ NERC, *supra* note 2 at 10.

percent of total generating capacity in 1998 to an expected one-quarter of total capacity by the end of 2001.³⁶

But transmission investment did not keep pace with the changes in generation (see Table 1 below). In December 1999, the FERC stated: “It appears that the planning and construction of transmission and transmission-related facilities may not be keeping up with increased requirements.”³⁷ The North American Electric Reliability Council (NERC) was more direct: “The gap between the transmission expansion need and the proposed construction of transmission is widening. To support the reliability of the bulk power system, proper incentives must be developed to encourage transmission construction.”³⁸

Table 1. New Transmission Investment: 230 kV and over (circuit miles)

Assessment Period	Actual Plant (pre-existing)	Planned Additions	Change in Planned Additions from Prior Year	Total Miles Anticipated
1994-2003	150,953	10,400	--	161,353
1995-2004	150,826	8,851	(15%)	159,677
1996-2005	153,782	6,818	(23%)	160,600
1997-2006	151,510	5,834	(14%)	157,344
1998-2007	150,225	5,587	(04%)	155,812
1999-2008	155,691	6,155	10%	161,508
2000-2009	157,810	7,527	22%	165,682

Source: NERC Reliability Assessments

Transmission operations fared no better. ISOs were slow to organize.³⁹ A 1998 FERC staff report observed that “better regional coordination in areas such as maintenance of transmission and generation systems and transmission planning and operation” were

³⁶ ELECTRIC POWER SUPPLY ASSOCIATION, COMPETITIVE POWER SUPPLY INDUSTRY FACTS, available at <http://www.epsa.org/competition/index.cfm?section=competition> (downloaded September 7, 2001).

³⁷ Regional Transmission Organizations, Order No. 2000, [Transfer Binder Stats. & Regs.] Fed. Energy Reg. Comm’n Rep. (CCH) ¶ 31,089 at 30,998 (1999), *order on reh’g*, Order No. 2000-A, Fed. Energy Reg. Comm’n Rep. (CCH) Stats. and Regs. ¶ 31,092 (2000), *pet. for review pending sub nom.* Public Utility District No. 1 of Snohomish County, Washington v. FERC, Nos. 00-1174, et al. (D.C. Cir.).

³⁸ NERC, *supra* note 2 at 33.

³⁹ The FERC has given various reasons which explain the difficulty in forming a voluntary, multi-state ISO, including: “‘cost shifting,’ which involve increases in rates for some parties; disagreements about sharing of ISO transmission revenues among transmission owners; difficulties in obtaining the participation of publicly-owned transmission facilities; concerns about the loss of transmission rights and prices embedded in existing transmission agreements; and the preference of certain transmission owners to sell or transfer their transmission assets to a for-profit transmission company in lieu of handing over control to a non-profit ISO.” Regional Transmission Organizations, Order No. 2000 *supra* note 37 at 31,002.

needed.⁴⁰ The NERC observed that the transmission system has “minimal operating experience” in managing the power flows and magnitudes resulting from long-distance bulk power transactions.⁴¹ It also found that the number of transmission line loading relief (TLR) procedures is rapidly increasing, tripling in each of the years 1999 and 2000.⁴² (TLR procedures are followed to when the electric load threatens to become too high for the transmission line to handle.)

Order 2000: Structuring the Transmission Entity

It was clear that something had to be done. But the call for novel transmission pricing proposals set out in the 1994 Pricing Policy Statement stimulated little industry interest. In December 1999, the FERC took action. It revised its approach to transmission operations and investment by issuing Order 2000.

At the heart of Order 2000 lies the concept of Regional Transmission Organizations (RTOs), entities that would plan and control regional transmission systems. RTOs are to be organizations responsible for eight critical transmission management functions.⁴³ RTOs must meet the following characteristics: independence; scope and regional configuration; operational authority; and short-term reliability.⁴⁴ Further, it is contemplated that operational control of transmission facilities will be ceded to RTOs by its members.⁴⁵

Other than these characteristics and responsibilities, the nature of RTOs is not restricted by Order 2000. It is common to discuss potential RTO structures as one of two

⁴⁰ STAFF OF THE FEDERAL ENERGY REGULATORY COMMISSION, STAFF REPORT TO THE FEDERAL ENERGY REGULATORY COMMISSION ON THE CAUSES OF WHOLESALE ELECTRIC PRICING ABNORMALITIES IN THE MIDWEST DURING JUNE 1998 5-8 (1998), *cited in* Regional Transmission Organizations at 31,999.

⁴¹ NERC, *supra* note 2 at 29.

⁴² See NERC, *Logs by Security Coordinator, 1998-2000*, spreadsheet, available at ftp://www.nerc.com/pub/sys/all_updl/oc/scs/logs/trends.xls (downloaded September 7, 2001).

⁴³ Tariff administration and design; congestion management; parallel path flow; ancillary services; OASIS and total transmission capability (TTC) and available transmission capability (ATC); market monitoring; planning and expansion; interregional coordination. Regional Transmission Organizations, Order No. 2000 *supra* note 36 at 30,994.

⁴⁴ *Id.* at 30,993-994.

⁴⁵ *Id.* at 31,033. As of mid-2001, ISOs, transmission owners and other stakeholders had (at FERC instigation) opened negotiations to create four large regional RTOs covering the national transmission grid. See New York Independent System Operator, Inc., et al. Order on RTO Compliance Filing, 96 FERC ¶ 61,059 (2001); see also Avista Corporation et al. Order Granting Rehearing in Part and Granting Clarification, in Part, 96 FERC ¶ 61,058 (2001); PJM Interconnection, L.L.C. and Allegheny Power Order Provisionally Approving RTO Participation Agreements and Tariff Changes, as Modified, and Deferring Consideration of Proposed Rate Changes and Disposition of Facilities, 96 FERC ¶ 61,060 (2001); PJM Interconnection, LLC, et al. Order Provisionally Granting RTO Status, 96 FERC ¶ 61,061 (2001); Southwest Power Pool, Inc. et al. Order Rejecting RTO Filings, 96 FERC ¶ 61,062 (2001); Bangor Hydro-Electric Company, et al. Order Granting, in Part, and Denying, in Part, Petition for Declaratory Order, 96 FERC ¶ 61,063 (2001); Southern Company Services, Inc. Order on Status Report, 96 FERC ¶ 61,064 (2001); GridSouth Transco LLC, et al. Order on Compliance Filing and Status Report, 96 FERC ¶ 61,067 (2001).

categories. *Transcos* are independent companies, either non-profit or for-profit, that combine ownership of the grid and responsibility for system planning and operations. *Hybrid Gridco/ISOs* are arrangements under which an independent company owns the grid but an ISO has responsibility for managing use of the grid and coordinating the spot market.⁴⁶ As used in this paper, the term *hybrid gridco/ISOs* assumes that the ISO is responsible for the transmission planning process.

Order 2000: Reinventing Transmission Pricing

In addition to addressing the structure of transmission ownership and control, the FERC in Order 2000 also addressed the pricing of transmission. Although the actual cost of transmission commonly amounts to less than 10 percent of the total cost of delivered electricity, the FERC noted that policies that encourage “efficient operating and investment decisions for both generation and transmission facilities are based in part on the price signals that flow from transmission pricing.”⁴⁷ As a result, “significant pricing reform may be needed as well” in order to ensure sufficient transmission investment and reliable transmission operations. “Indeed,” stated FERC, “... transmission pricing reform is inevitable.”⁴⁸

The FERC noted that prices should:

- eliminate regional rate pancaking;
- manage *congestion* (a state on the transmission grid that restricts or constrains the ability to add or substitute one source of power for another);
- internalize parallel path flows;
- deal effectively and fairly with transmission owning utilities that choose not to participate in RTOs; and
- provide incentives for transmission owning utilities to efficiently operate and invest in their systems.⁴⁹

The debate over optimal RTO structure and pricing methods has now begun. In Parts II and III, we consider proposals for a competitive market in transmission investment and suggest marrying merchant transmission with a regulatory backstop. In Part IV, we look at the benefits and drawbacks of *performance-based rate* (PBR) regulation, one of the regulatory regimes discussed in Order 2000.

⁴⁶ William W. Hogan, Enabling the Power of Markets, Presentation before the EEI Chief Executive Conference (January 7- 8, 1999), available at <http://ksghome.harvard.edu/~.whogan.cbg.ksgh/eei0199.pdf> (downloaded September 7, 2001). The term *Independent Transmission Company* (ITC), often used in the industry, can refer to transcos or hybrid gridco/ISOs, depending on the context.

⁴⁷ Regional Transmission Organizations, Order No. 2000 *supra* note 37 at 31,172.

⁴⁸ *Id.* at 31,173

⁴⁹ *Id.* at 31,171.

Part II: The Case for Merchant Transmission

“[Order 2000] contains a coherent framework for competitive electricity markets built on a bid-based, security-constrained economic dispatch with locational pricing and financial transmission rights (FTR). This is the simplest model that actually works.”

William W. Hogan⁵⁰

As noted earlier with respect to generation, there is no perfect market, just as there is no perfect regulation. But which should one favor when choosing between imperfect markets and imperfect regulation?

As Professor William W. Hogan has written, “The typical example of a transmission investment invokes the image of a large new transmission line, which might look to be too difficult to base solely on market decisions. As a result, the implicit assumption often is that only a regulated monopoly could manage the intended investment, and the discussion of market institutions defaults to the design of monopoly mechanisms.”⁵¹ Old habits die hard. Yet free market institutions for transmission are already in use, both in the US and abroad. Not coincidentally, the line separating the market for transmission from the markets for generation and modes of consumption has all but disappeared.

The Impact of the Substitutability of Technologies

The primary factor that is remaking the transmission sector is advances in technology. *Distributed generation (DG), demand-side solutions and next-generation transmission technologies (NGTTs)* are now viable alternatives to large power plants and steel-lattice-tower transmission facilities. This increase in the number of providers of electricity for consumption, from one (the current transmission grid) to many (distributed generation, demand-side solutions and next-generation transmission technologies), shows how far we have come from the world of natural monopoly.

DG is generation located close to the point of use and generally up to 50 megawatt capacity. Technologies used in DG include diesel engines, internal combustion engines, microturbines, fuel cells, and renewable technologies such as wind. DG is often modular – simple to build and install, small in capacity and easy to relocate. According to the US Department of Energy,

⁵⁰ William W. Hogan, *Regional Transmission Organizations: Millennium Order on Designing Market Institutions for Electric Network Systems 1* (2001), available at http://www.utilitiesproject.com/documents.asp?d_ID=144 (downloaded September 7, 2001). Professor Hogan is Lucius N. Littauer Professor of Public Policy and Administration at Harvard University’s John F. Kennedy School of Government and Research Director of the Harvard Electricity Policy Group.

⁵¹ William W. Hogan, *Market-Based Transmission Investments and Competitive Electricity Markets 2* (1999), available at <http://ksghome.harvard.edu/~.whogan.cb.gksg/tran0899.pdf> (downloaded September 7, 2001).

There is considerable interest among electricity generators in the potential use of distributed generators to cut costs by delaying, reducing, or eliminating investments in transmission and distribution equipment. In addition, the operational flexibility of distributed generators, which can either be connected to the grid or used in remote locations, may provide new system management options not available with central station units.⁵²

And not only are generation companies interested in DG technologies. Industrials already derive 22 percent of their electricity from DG, primarily in the form of cogeneration facilities.⁵³

The importance of distributed generation as an alternative to traditional transmission projects stimulated the Federal Trade Commission (FTC) to urge the FERC to be particularly alert to “the implications of the development of distributed generation.... DG has the potential to increase the substitutability between generation and transmission in relieving transmission congestion”; in fact, any incentive to favor transmission over generation to solve load demands “may present the strongest challenge to bringing the full benefits of competition to consumers.”⁵⁴ The FTC’s argument is particularly cogent in light of that agency’s mandate “to ensure that the nation’s markets function competitively, and are vigorous, efficient, and free of undue restrictions.”⁵⁵

Demand-side programs also show great promise as alternatives to traditional transmission facilities. While the track record of conventional demand-side management programs has been mixed, these programs were often undertaken by monopoly providers of electric service that had no effective incentive to reduce customer use of electricity. But the demand-side reductions effected in response to the recent California electricity price spikes and other indicators show that demand-side solutions can be a valuable way to reduce load on the transmission grid.⁵⁶ Furthermore, technological advances are poised to increase the role of demand-side investments through advances in metering and controls for appliances and other electrical equipment.

Perhaps the most important challenge to the traditional transmission grid’s status as a natural monopoly is the rise of new ways of transmitting electricity. Flexible AC Transmission System (FACTS) devices, next-generation controllable high voltage DC lines, advances in underground and submarine cables and low-impact cable installation techniques, applications of superconducting materials and other new technologies have

⁵² ENERGY INFORMATION ADMINISTRATION, PUBLICATION NO. DOE/EIA-0383 (2001), ANNUAL ENERGY OUTLOOK 2001 38 (2000).

⁵³ *Id.*

⁵⁴ Comment of the Staff of the Bureau of Economics of the Federal Trade Commission at 8, Regional Transmission Organizations, Order No. 2000 *supra* note 37.

⁵⁵ FEDERAL TRADE COMMISSION, VISION, MISSION AND GOALS, *available at* <http://www.ftc.gov/ftc/mission.htm> (downloaded September 7, 2001).

⁵⁶ *See, e.g.*, James Sterngold, *California's New Problem: Sudden Surplus of Energy*, N.Y. TIMES, July 19, 2001, at A1.

economies of scale that are substantially realized at those capacities at which they would be installed in a transmission system. For example, the capacity at which modern DC transmission projects realize economies of scale at roughly 200 to 300 megawatts, comparable to a modern combined-cycle, gas-fired generation unit. FACTS devices reach their economies-of-scale plateau at capacities of less than 100 megawatts, comparable to a modern peaking generation unit.

The realization of scale economies at such low levels undercuts the traditional notion of transmission as a natural monopoly. It is the existing, legacy transmission system that has the substantial economies of scale that justify monopoly regulation, not the more modern approaches to transmitting power to customers. While the existing, legacy transmission system may continue to exhibit the characteristics of a natural monopoly, the technological advances in transmission argue for a different treatment to be afforded to additions and expansions to the transmission system.

Because the economies of scale of today's transmission technologies are comparable to those of modern generating units, given the right structure a competitive market in transmission investment can flourish, as has the competitive market for generation investment. Deregulation of generation flowed in great part from new technologies such as combined-cycle, gas-fired turbines and regional transmission grids; so too do arguments for a competitive market in transmission flow from new approaches such as distributed generation, demand-side solutions and, most importantly, next-generation transmission technologies.

Establishing Market-Based Prices for Transmission

If the correct market structures are in place, distributed generation, demand-side solutions and next-generation transmission technologies can compete with traditional transmission facilities for customers seeking access to electric power. Because competitive markets for distributed generation facilities and demand-side solutions either currently exist or under development, we turn to the viability of competitive market for *new* transmission investments.⁵⁷

There are two requirements for a viable market for new transmission investment. First, price signals must be created to promote efficient transmission investment. Second, property rights must be granted to investors so as to give to the investors the value of their investments. These two requirements – efficiency through price signals and property rights – are satisfied with location-based marginal pricing and financial transmission rights. In fact, as we discuss herein, a competitive market for transmission investment is the logical extension of the implementation of location-based marginal pricing and financial transmission rights.

⁵⁷ We are not advocating as part of a competitive transmission market that existing transmission facilities be deregulated.

If competition is to be efficient, price signals must accurately reflect the cost of each alternative and drive investment in accordance with market needs. As the history of cost-of-service regulation has shown, the dictates of central planning, while appropriate for a vertically integrated electric utility monopoly, are not appropriate to a competitive market for electric service. Recognizing the efficiency of *market-based* incentives, the FERC has stated that it will require RTOs “to implement a market mechanism that provides all transmission customers with efficient price signals regarding the consequences of their transmission use decisions.”⁵⁸

If one is to enable a market-based, efficient choice among DG, traditional generation, demand-side solutions and transmission technologies, one must establish a market price that reflects the costs of electric power *as transmitted*. If the cost of transmission is ignored, grid users cannot make a useful comparison of the prices of any one of the four alternatives. On the other hand, if accurate transmission costs are accounted for, useful prices can be established and grid users can make an efficient choice among the alternatives.

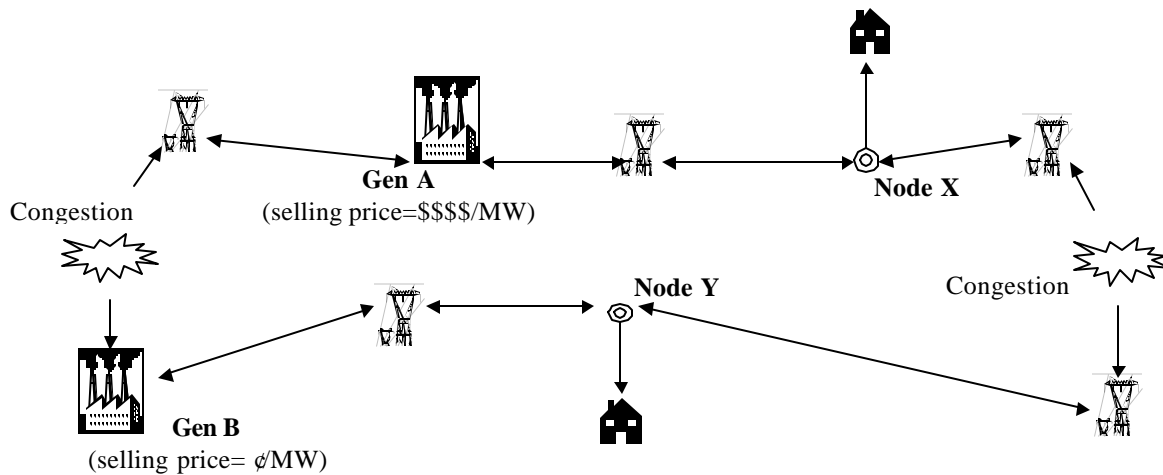
Unfortunately, the physical nature of electricity complicates the easy development of the costs of transmitting electric power. More particularly, the ability of the power grid to move electricity from sellers to buyers varies considerably from one location on the grid to another. The most significant cause of this variation is *congestion*, which restricts or constrains the ability to add or substitute one source of power for another. Congestion occurs when demand for power transmission exceeds supply, and if not managed correctly by the system operator, congestion can lead to system collapse. Philipson and Willis provide an apt analogy: “Imagine traffic congestion in a world where car engines won’t work if they get too close to too many other engines. If this is the case, overcrowding on the highway could lead to rapid and extremely disastrous traffic jams.”⁵⁹

Congestion costs vary at different points on the grid, called *nodes*. For example, in Figure 4 below congestion prevents loads at Node X but not at Node Y from accessing the less-expensive power of Generator B. The congestion costs for the loads at Node X is the difference between what loads at Node X for Generator A’s power and what they would have paid for Generator B’s power. But since traditional transmission pricing such as embedded cost, postage stamp pricing does not reflect congestion costs, loads at Node X pay the same for transmission as do loads at Node Y. The result: there are no price signals that discourage the siting of load at Node X, where it is expensive. Nor are there price signals that encourage the siting of generation at Node X, where local generation clearly is needed and may be sold profitably. The lack of market price signals promotes inefficient grid operation and investment by transmission providers, and inefficient choices by loads among transmission, generation and demand-side solutions.

⁵⁸ Regional Transmission Organizations, Order No. 2000 *supra* note 37, at 31,126.

⁵⁹ PHILIPSON & WILLIS, *supra* note 26, at 260.

Figure 4. Location-based congestion costs



Determining the cost of power at any one point on the grid (including the opportunity costs created by congestion) is called *location-based marginal costing*. Because prices based on location-based marginal costing reflect the costs of *transmitted* power at different nodes, they act as signals that allow system users to allocate such costs among themselves efficiently. In the jargon of economics, the network externalities of pricing delivered power are internalized in location-based marginal costing. For this reason, *location-based marginal pricing* has been called the “most accurate pricing method” for transmission.⁶⁰

Bid-Based, Security-Constrained Locational Pricing

Determining the location-based marginal price (LBMP) is most efficiently done through a voluntary, bid-based market.⁶¹ Loads submit to the system operator bids to purchase power at a particular node for a maximum acceptable purchase price – that is, they inform the market what they are willing to pay for electricity *as transmitted*. Generators, on the other hand, submit to the system operator offers to sell electricity – at the sale price at the point of injection into the grid but prior to transmission. The system operator then purchases and dispatches the generation in order of offered price, lowest to highest, basing the locational selling price of power at the nodes on the bid and offer prices it receives.

When congestion occurs, least-cost generation often must be passed over for purposes of system security. For this reason, this market model – where the system operator acts as a clearing agent *and* manager of system security – is called *bid-based, security-constrained*

⁶⁰ *Id.* at 258.

⁶¹ This discussion is drawn primarily from Hogan, *supra* note 51 and other writings of Professor Hogan cited at <http://ksghome.harvard.edu/~whogan.cbg.ksq/>.

*dispatch with nodal pricing.*⁶² In bid-based, security-constrained dispatch, the difference between LBMP at two nodes is the cost of transmission between the two nodes.

A variety of bid-based, security-constrained pricing models have been approved by FERC for use by ISOs, including the Pennsylvania-New Jersey-Maryland (PJM) ISO, ISO New England and the New York ISO.⁶³ The FTC is positively inclined to the model as well.⁶⁴

Financial Transmission Rights

If generators receive payment for power injected into the grid prior to transmission, and loads pay for power withdrawn from the grid subsequent to transmission, what happens to the difference in the two prices? The bid based, security-constrained nodal pricing model has an elegant answer: *financial transmission rights*, or FTRs.⁶⁵ An FTR is a financial instrument that pays the holder the price difference of power at two nodes, multiplied by the amount of power flowing between those two nodes. Like many other financial instruments, FTRs are tradable on the secondary market.

FTRs “represent exactly the financial benefit that would accrue to a market participant that owned its own line.”⁶⁶ Picture a firm that has built a new transmission line over which it has sole right to purchase power. This transmission line is designed so that it has no congestion; any power sent over the line would be free of congestion costs. The amount the firm saves by using the new transmission line equals the difference between what it pays for its “congestion-free” power delivered over the new transmission line and what it would have paid for “congested” power had the new transmission line not been built.

Remember, however, that in a typical power grid one cannot have physical rights to the flow between two locations, since no grid input or output can be identified with any one party. So the savings from the reduction of congestion are represented in an FTR, which captures the property value of transmission. Using our example in the previous paragraph: The firm that has built a new transmission line will, under an FTR regime,

⁶² Certain bid-based, security constrained pricing models price not at individual nodes but zones of nodes, purportedly for ease of administration and enhanced price liquidity.

⁶³ See Pennsylvania-New Jersey-Maryland Interconnection et al. Order Conditionally Accepting Open Access Transmission Tariff and Power Pool Agreements, Conditionally Authorizing the Establishment of an Independent System Operator and Disposition of Control Over Jurisdictional Facilities, and Denying Rehearing, 81 FERC ¶ 61,257; ISO New England, Inc., et al. Order Conditionally Accepting Congestion Management and Multi-Settlement Systems, 91 FERC ¶61,311; Central Hudson Gas & Electric Corporation et al. Order Conditionally Accepting Tariff and Market Rules, Approving Market-Based Rates and Establishing Hearing and Settlement Judge Procedures, 86 FERC ¶ 61,062;

⁶⁴ Comment of the Staff of the Bureau of Economics of the Federal Trade Commission, *supra* note 54 at 21.

⁶⁵ Also called transmission congestion contracts, fixed transmission rights, and financial congestion rights.

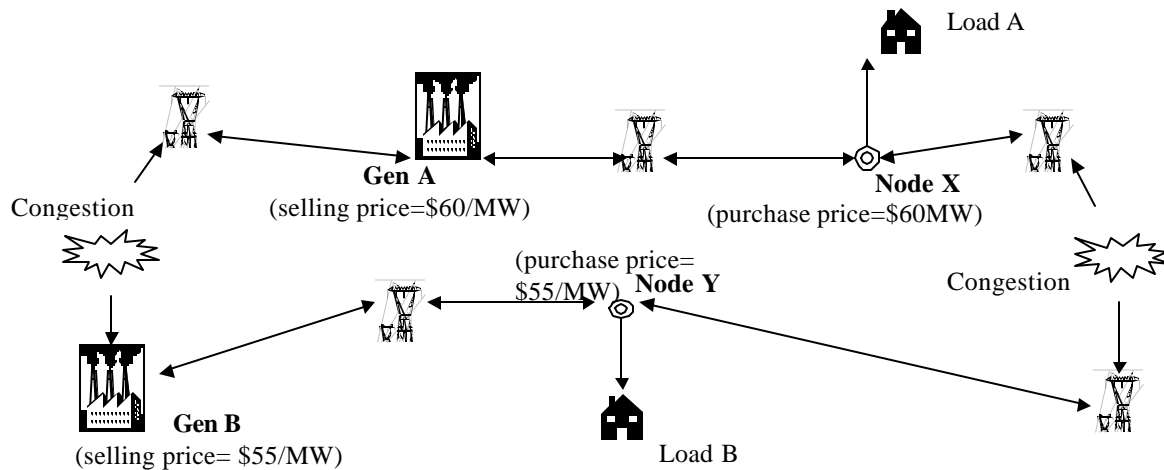
⁶⁶ Karen Lyons et al., *An Introduction to Financial Transmission Rights*, ELEC. J., December 2000 at 31, 33.

purchase power that includes congestion costs – just as if the new transmission line had not been built. However, the firm will then get paid the amount it would have saved if it purchased power at a price that did not include congestion costs. It is the right to receive the amount that it gets paid that is the FTR.

Of course, it is imperative that system operators be prohibited from holding an FTR; otherwise, they would have the incentive (as well as the means) to *increase* congestion costs, thereby increasing the value of the FTR. FTRs free grid dispatch from concerns about the market effects of congestion costs. As a result, system operators can dispatch power economically (from least to greatest cost).

FTRs are used as a hedge against congestion costs between two nodes. For example, in Figure 5 below Load B pays \$55/MW for power at Node Y, and Load A pays \$60 for the power it draws from the grid at Node X. The holder of the FTR receives the difference, or \$5. If Load A owns the FTR, it is paid \$5, so its congestion costs are covered and the effective cost of its power at Node X is \$55.

Figure 5. Financial transmission rights



Another benefit of FTRs is the incentive it provides for grid expansion. A builder of transmission facilities will be granted FTRs equal to the incremental increase in power that can be transferred over the new facilities.

It is worth noting that in New York State, which has location-based marginal pricing and FTRs, a recent trade press article reported that five transmission developers have requested interconnection studies for transmission projects with an aggregate capacity of

almost 6,000 megawatts – equivalent to approximately fifteen large combined-cycle power plants.⁶⁷

Bid-Based, Security-Constrained Locational Pricing and the Optimal Level of Transmission

Some observers contend that a competitive market for transmission expansion that is based on these price signals cannot result in the optimal level of transmission investment; they argue that, to the contrary, transmission investment is best assured by decisions made by a monopoly entity.⁶⁸ These observers fail to understand the critical link between locational pricing and transmission expansion policy. Simply put, a centralized transmission expansion policy fundamentally interferes with the market outcomes expected to occur from the implementation of locational pricing. This interference becomes fatal to efficient market outcomes when such a centralized planning regime contains a bias towards “socialization” of transmission expansion costs (that is, spreading the costs of centrally planned projects to all customers without regard to cost causation or the tracking of those who directly enjoy the benefits of such projects). Under this framework, tweaking of a locational pricing and FTR regime would not likely result in competitive, market-based alternatives to transmission expansion.

The most vocal proponents of a centralized transmission expansion policy have promoted performance-based rates (PBR), sometimes referred to as incentive-based rates, for transmission as a means to improve operations and spur new transmission investment. We discuss the use of PBR in a subsequent section. For now we address three main objections to a market-based approach to incremental transmission investments:

1. FTRs alone cannot provide sufficient investment incentives because (i) they are not consistently defined and (ii) the economies of scale in transmission investments will result in less than optimal amounts of investments even with FTRs;
2. Substantial negotiating costs will discourage transmission investment; and
3. New transmission investment would need to be monitored closely by a centralized authority in order to prevent grid modifications that may be privately profitable but negatively impact the system.⁶⁹

In response to the first objection regarding inconsistency in the definition of FTRs, we note that differences in market design and rules pertaining to many other attributes of

⁶⁷ Philip Lentz, *NY's Increasing Electric Demand Sparks Plans for New Power Lines*, CRAIN'S N.Y. BUS. September 23, 2001, at 14.

⁶⁸ See generally Lisa Cameron, *Transmission Investment: Obstacles to a Market Approach*, ELEC. J., March 2001, at 25, 25-26; Joskow, *supra* note 20.

⁶⁹ Cameron, *supra* note 67, at 36-37.

electricity markets besides the definition of FTRs often occur from one power pool to another. Yet, while these differences result in obstacles to efficient markets,⁷⁰ to date no one has argued that these differences require a monopoly entity for the purpose of making *generation* investment decisions. Similarly, any differences in the definition of FTRs should not frustrate completely the establishment of a competitive market for new transmission investment.⁷¹

Further, any differences in product definition – as well as the absence of FTRs in one region and their use in another – are being addressed. The recent FERC orders establishing four RTOs in the continental United States is clear evidence that market integration and consistency will occur.⁷² In the Northeast, for example, ISO New England has proposed to conform its market design to that of PJM.⁷³ This demonstrates that the urge to conform market practices is strong.

With regard to economies of scale, evidence demonstrates that new transmission investment does not have economies of scale necessarily greater than those possessed by generation. Because of this, it would be inconsistent to apply monopoly regulation to new transmission and not generation.⁷⁴

⁷⁰ See, e.g., New York Independent System Operator, Inc. et al., *supra* note 45, slip op. at 12: “[T]he vitality of this natural market is hampered by the balkanized set of market rules that have developed in the Northeastern ISOs since their inception. These market rules vary in numerous ways, from limits placed on ramping rates for external transactions to the manner in which transmission rights are allocated and from transaction scheduling to the type of ancillary services available in the spot market. Moreover, the divergence of these rules creates uncertainty among market participants and may discourage trade among the Northeastern ISOs. In sum, the narrow configuration of the existing Northeastern ISOs creates artificial constraints within the broader market that spans the Northeastern region.”

⁷¹ However, the FTRs contemplated for PJM and New York need to be more like true financial instruments if the existing FTR framework now in place in PJM and New York is to be more compatible with market-driven transmission investments. Among needed improvements are the development of longer term FTRs, the awarding of capacity and similar reliability-related rights to transmission expansions and the implementation of FTR options. While important details, a discussion of these improvements is beyond the scope of this article.

⁷² See New York Independent System Operator, Inc., *supra* note 45; see also Avista Corporation et al. Order Granting Rehearing in Part and Granting Clarification, in Part, 96 FERC ¶ 61,058 (2001); PJM Interconnection, L.L.C. and Allegheny Power Order Provisionally Approving RTO Participation Agreements and Tariff Changes, as Modified, and Deferring Consideration of Proposed Rate Changes and Disposition of Facilities, 96 FERC ¶ 61,060 (2001); PJM Interconnection, LLC, et al. Order Provisionally Granting RTO Status, 96 FERC ¶ 61,061 (2001); Southwest Power Pool, Inc. et al. Order Rejecting RTO Filings, 96 FERC ¶ 61,062 (2001); Bangor Hydro-Electric Company, et al. Order Granting, in Part, and Denying, in Part, Petition for Declaratory Order, 96 FERC ¶ 61,063 (2001); Southern Company Services, Inc. Order on Status Report, 96 FERC ¶ 61,064 (2001); GridSouth Transco LLC., et al. Order on Compliance Filing and Status Report, 96 FERC ¶ 61,067 (2001).

⁷³ ISO New England, Inc. et al., Order Conditionally Accepting Congestion Management and Multi-Settlement Systems, 91 FERC ¶ 61,311 (2000).

⁷⁴ Of course, merchant transmission facilities would have to satisfy the appropriate market-power criteria in order to obtain market-based rates. For FERC standards regarding market power in connection with granting market-based rates, see, e.g., Dartmouth Power Associates *Limited Partnership*, 74 FERC ¶ 61,037 (1996); USGen Power Services, LP, 73 FERC ¶ 61,302 (1995); Southern Company Services, Inc. 72 FERC ¶ 61,324 (1995); Louisville Gas and Electric Co., 62 FERC ¶ 61,016 (1993).

The second objection regards negotiation costs. Critics argue that substantial negotiation costs are associated with the creation of a long-term contract among the many beneficiaries of a given project. It is maintained that amount of these costs, along with the ability of many to free-ride (i.e., to obtain the benefits of the proposed transmission project without supporting its costs), will hinder the development of transmission projects in the competitive market.

In an economist's perfect world, there are no transaction costs. But the mere existence of transaction costs does not necessarily lead to failure of competitive markets in new transmission investment, or to less-than-optimal outcomes compared to outcomes achieved under regulation. In the context of transmission, transaction costs attract concern greatly out of proportion with their effects. The developer of a proposed merchant transmission project will not negotiate with thousands of end users; instead, it will negotiate with relevant market participants – in practice, a handful in number and largely wholesale in nature. Furthermore, many merchant transmission projects can proceed without such negotiations by requiring the transfer of all or a portion of such rights to make whole those harmed by the project. Perhaps the best evidence to counter this objection are the several market-based transmission projects world-wide that have overcome this obstacle without much difficulty, including the MurrayLink underground HVDC project interconnecting the Victoria and South Australia electricity grids, and the DirectLink underground HVDC project interconnecting the New South Wales and Queensland electricity grids.⁷⁵

The third objection to a competitive market for new transmission investment regards the complexity of the transmission grid. Critics argue that certain investments might be privately profitable but impose a high cost on society. Of course, a similar concern could be expressed with respect to models of centralized procurement, under which politically “profitable” but socially more costly investments might occur. While this objection to a competitive market for new transmission may be valid in theory, no evidence supports its validity in

Merchant Transmission in Action

On June 1, 2000, the FERC approved the creation of a transmission facility that would link the ISO New England system with the NY ISO system via an undersea, HVDC cable from coastal Connecticut to Long Island, NY. In its approval, the FERC found that the project's negotiated rate structure represented a form of “opportunity cost pricing,” effectively capping rates at customers' expectations of the locational price differential between New England and New York. The project clearly has all the characteristics of merchant transmission: its investors assume 100 percent of the financial risk of the project, foregoing any guaranteed recovery of their investment through mandatory charges to ratepayers; it will charge location-differential prices to its customers; it was not solicited or planned by an ISO or other regulatory authority, but is driven by market-based opportunities; and it will sell FTRs that are tradable on the secondary market. The project validates merchant transmission as a source of transmission investment that is a viable alternative to command-and-control regulation. See *Order approving TransEnergie US Ltd's proposal to construct a merchant transmission facility by installing an undersea high-voltage direct current cable between Connecticut & Long Island, NY, subject to conditions under ER00-1*, 91 FERC 61,230.

⁷⁵ For more information about MurrayLink, see <http://www.transenergie.com.au/MurrayLink/default.html>. For more information about DirectLink, see <http://www.transenergie.com.au/DirectLink/default.html>. It is important to note that the Australian regulatory system allows market-based providers of transmission service to take financial positions in the energy markets and trade energy over their facilities on their own account.

practice. Current institutions effectively guard against this concern. First, the reality of transmission systems is that no control area operator (ISO, RTO, or otherwise) would allow connection of a transmission project that would deteriorate the reliability and necessary operating characteristics of the transmission system. Second, the FERC would guard against the creation of market power as part of its ratemaking authority. We further propose that, as an additional safeguard, a necessary prerequisite for obtaining market-based rate authority for transmission projects should be that the subject project must not impair any entities' existing property rights to the transmission system.

We do, however, recognize that legitimate questions exist regarding the ability of market-based transmission alone to provide the optimal levels of transmission investment. While we are convinced that a market approach is the best way to achieve optimal investment in the electric industry, we recognize that electricity is a critical necessity of modern life and, as such, reliability of service must be paramount. Whether valid or not, the California experience with electricity markets have left many to doubt the ability of markets to provide for this reliability.⁷⁶ A monopoly entity, however, is quite unsuited to performing this function. Happily, policymakers need not choose between the devil and the deep blue sea. We propose a market-based transmission expansion policy that is backstopped by a regulatory process that will assure sufficient investment in transmission assets to maintain desired levels of reliability of service. We describe our proposal in the following section.

⁷⁶ *The New York Times* reported that a recent survey of state utility commissioners showed that three-quarters of the commissioners believe that events in California will slow or halt local deregulation. Neela Banerjee, *States' Plans To Deregulate Get 2nd Look*, N.Y. TIMES, May 2, 2000, at A14. See also Price C. Watts (pseudonym), *Heresy? The Case Against Deregulation of Electricity Generation*, ELEC. J., May 2001, at 19.

Part III: The Competitive Solicitation Process – A Regulatory Backstop

“Until recently, the electric utility business has been more or less like a 40-year old ... bachelor who still lives with his mother. Even after he decides that life on his own has some things to commend it, no one can be quite sure how the socialization process is going to go. Nor is Mom’s view of all this new-found independence entirely predictable, as she frets about what friends he might keep and whether he’ll eat right and wash his underwear.”

Former FERC Chairman James J. Hoecker⁷⁷

Like the mother of Hoecker’s bachelor, some industry observers are not quite sure that merchant transmission is viable in the context of the US transmission sector. It is true that market-based transmission pricing structures have been introduced successfully here and in other countries,⁷⁸ but the size and complexity of the US power grid is unmatched and the consequences of market failure would be catastrophic.

In a regulatory environment increasingly uncomfortable with the deregulation of the electric power industry,⁷⁹ we believe that we can increase the industry’s comfort level with a competitive market for transmission investment by instituting a competitive solicitation process as a backstop that could be used to correct inefficiencies that may arise in an environment of solely merchant transmission projects. In this, we follow the FERC, which recently approved the use of a request for proposals (RFP) process in coordination with merchant transmission as a way to encourage unmet transmission expansion needs.⁸⁰ By backstop, we do *not* mean that the process of transmission planning and evaluation is secondary to market investment. What we do mean is that the planning process results in the issuance of an RFP only in situations in which the market demonstrably does not provide sufficient resources to meet system needs.

⁷⁷ James J. Hoecker, *Electric Competition Revolution: The Sequel*, Remarks before the Sixth DOE/NARUC National Electricity Forum (September 17, 1998), *available at* <http://www.ferc.gov/news/speeches/commissionersstaff/houston9.pdf> (downloaded September 7, 2001), at 2.

⁷⁸ In addition to the PJM, New England and New York ISOs described at *supra* note 63, the following countries have introduced or announced market designs incorporating market-based transmission pricing structures: Australia, New Zealand, and Norway, as well as Argentina, Bolivia, Chile and Peru. William W. Hogan, *The RTO Millennium Order: Following Through or Falling Apart?* 9 (2000), *available at* <http://ksghome.harvard.edu/~.whogan.cbg.ksg/hepg1200.pdf> (downloaded September 7, 2001).

⁷⁹ N.Y. TIMES, *supra* note 75.

⁸⁰ *See, e.g.*, ISO New England, Inc. et al., Order Conditionally Accepting Congestion Management and Multi-Settlement Systems, 91 FERC ¶ 61,311 at 62,076 (2000) (“[A]ll projects in the [regional transmission] plan should be built following a competitive solicitation. We also conclude that third parties should be allowed to build merchant transmission facilities outside the context of the plan, subject to ISO review to ensure that such facilities meet technical requirements and do not reduce the overall transfer capability of the ISO’s grid”).

Our proposal involves three basic actions. First, the relevant RTO continually evaluates transmission system needs and conducts planning studies to ensure that sufficient resources exist to meet reliability planning criteria. Second, should the RTO determine that the market will not provide sufficient resources to meet anticipated needs (accounting for proposed, viable market-based projects), the RTO issues an RFP soliciting proposals that would address specific needs. Third, a winning project is selected from those proposals that are technically feasible and that meet the criteria published in the RFP.

Competitive Solicitation: Encouraging Innovation and Efficiency

The use of competitive solicitation in the US dates to the War of Independence, when Robert Morris first advertised for bids to supply food rations to the Continental Army.⁸¹ Today, suppliers compete for \$130 billion of federal contracts annually – more than twice the amount of contracts not available for competition.⁸² From the construction to the information services industry, RFPs are an accepted way to purchase products and services in a competitive manner. The electric power industry itself commonly uses the RFP process – for power supply, construction, maintenance and other contracts – as do its federal regulators the DOE and the FERC. One web-based aggregator of commercial RFPs lists approximately fifteen new electric power industry RFPs per month; in August 2001 alone such RFPs ranged from tree-trimming services to investment banking services to 250 megawatt power supply contracts.

RFPs are particularly appropriate complements to a competitive market in transmission. In contrast to requests for quotations (RFQs), which solicit bids for products or services of detailed description, RFPs solicit proposals to solve a problem or fill a need without excessively restricting the range of potential solutions: the incentive to reduce costs through all available means is the centerpiece of the RFP model. As a result, proposals responding to a backstop RFP might involve the variety of feasible solutions: AC transmission lines, FACTS devices, DC transmission facilities, demand-side management programs, generation facilities and other possible solutions. The soliciting party will have a range of cost-effective technology and market solutions from which to choose. And, most importantly, consumers can have some assurance that a competitive process has been implemented to keep rates at reasonable levels.⁸³

⁸¹ JAMES F. NAGLE, JR. A HISTORY OF GOVERNMENT CONTRACTING 49 (2d ed., 1999).

⁸² Of federal contracts with a value of \$25,000 or more. FEDERAL PROCUREMENT AGENCY, TOTAL FEDERAL SNAPSHOT REPORT, ACTIONS REPORTED INDIVIDUALLY ON SF279, FISCAL YEAR 2000 THROUGH FOURTH QUARTER, available at <http://fpds.gsa.gov/fpds/FPR2000c.pdf> (downloaded September 7, 2001).

⁸³ We are often asked whether an RFP backstop merely is another name for least-cost planning. Our answer: *no*. Least-cost planning requires a monopoly market participant to design, develop and implement least-cost solutions that satisfy a need defined by regulators; with RFPs, *all* market participants compete to satisfy a need. In addition, we are not proposing, nor do we advocate, the inclusion in the proposal evaluation process of “externalities” or other administratively determined quantifications of environmental and other external costs.

The First Step: The Needs Assessment

Planning future transmission requirements involves divining under substantial uncertainty the location of future generation and loads, the nature of future electricity demand and other variables that will affect the future capability of the power system to transfer power efficiently. Where location-based marginal prices exist, two distinct indicators identify the need for transmission upgrades. The first indicator comprises price signals at the different locations; these price signals would correspond to demand for expansion. The second indicator comprises the principles of physics and engineering – physical requirements that if violated would threaten the reliability of the system.⁸⁴ To the extent that the competitive market for transmission expansion does not satisfy the needs identified by needs assessment – whether derived from price signals or engineering principles – the RTO should issue an RFP for solutions to fill those needs.

The development of the transmission needs assessment should be limited in two ways. First, it should apply only to needs for *reliability* upgrades – upgrades that assure the technical ability of the power system to meet demand. It should not apply to needs for *economic* upgrades – those upgrades that reduce the cost of congestion more than the cost of the upgrade – except in very rare circumstances.⁸⁵ Unlike an economic analysis, reliability studies do not call for forecasts of future electricity prices – forecasts that require the use of elaborate production cost simulations relying on estimates of future fuel prices, future generation installation and retirement decisions, predictions about generator bidding behavior and the determination of an appropriate discount rate. Economic assessments are best left to private investors, who have money at risk. On the other hand, economic assessments by transmission planners risks interference with the market for delivered power that may undercut not only investments in merchant transmission but also in generation and load management. Only in cases where it can be shown clearly that, even under conservative assumptions, a market failure is preventing the market from developing an economic upgrade, should the transmission needs assessment evaluate economic upgrades.⁸⁶

Second, the development of the transmission needs assessment should be limited as to authorship. Transmission owners (incumbents and transcos as well as ISOs and RTOs that have elements of transmission ownership) have, in the words of the FERC, “the incentive and ability to bias the [needs assessment plan] in favor of their competitive

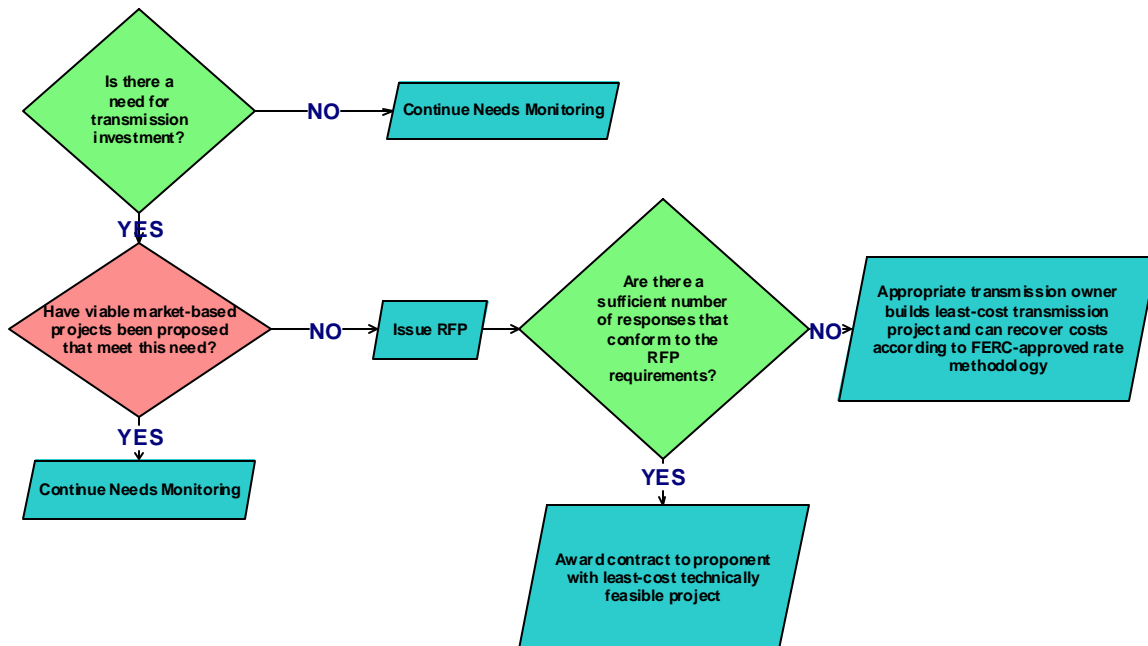
⁸⁴ Reliability criteria used in traditional transmission planning are set by engineers who seldom account for the marginal costs of reliability upgrades. This is because, under cost of service regulation, recovery of the costs of transmission upgrades is all but assured. As a result, reliability margins may be set quite high.

⁸⁵ In practice, a transmission upgrade is neither a reliability upgrade nor an economic upgrade; generally, it improves reliability *and* reduces congestion. The focus of the transmission needs assessment should, however, be on those upgrades that are needed for reliability.

⁸⁶ Even in these cases, it may be better to identify and remedy why the market failed to produce a solution, because the market failure likely indicates a problem in the structure of the market.

interest.”⁸⁷ It is imperative that an independent body – such as a truly independent RTO – develops the needs assessment and issues the related RFPs.

Figure 6. The RFP Backstop Process⁸⁸



Competitive Solicitation: Best Practices

For a competitive solicitation process to be effective, five common-sense guidelines must be followed. First, an award should be made only when a sufficient number of qualified bidders have responded to the RFP. The fewer the number of competitors, the weaker the incentive to submit the least-cost bid. The greater the number of competitors, the greater the incentive – and greater the likelihood of ever lower cost bids. Existing transmission owners should be allowed to respond to the RFP and submit a bid based on an approved ratemaking methodology (if it so desires – we do not mean to preclude incumbent transmission owners from bidding a market-based amount should they have the necessary approvals). If only two companies respond to the RFP and one of them submits a cost-of-service bid based on an approved regulatory methodology, then there is a sufficient number of bidders. By definition, a bid based on an approved ratemaking methodology is just and reasonable.

⁸⁷ ISO New England, Inc., *supra* note 79, at 62,072 (2000).

⁸⁸ For discussion in greater depth of the RFP process, see Motion to Intervene and Comments of TransÉnergie U.S. Ltd. at 11-15, New York Independent System Operator, Inc. et al. Order on RTO Compliance Filing, *supra* note 45.

Second, the RFP should permit respondents to bid innovative cost-recovery mechanisms. Fixed-price bids may not always be least-cost bids. The great attraction of the RFP lies in its incentive to reduce costs through *all* available means. Pricing models that result in the least cost to society – for example, those that most accurately match use with payment – can complement least-cost technologies, management practices and other factors in creating a bid with the overall least cost.

Third, the RFP should allow the same freedoms to RFP-based projects as to merchant transmission projects – otherwise, there would be less incentive to participate in RFPs. For example, the RFP must allow bidders to design, finance, build, own, and maintain the project that satisfies the RFP. This accords with the fundamental rationale behind the RFP process: its incentive to reduce costs through *all* available means. In particular, ownership can mitigate the overall risk of a project: the greater the ownership, the lower the risk, the lower the bid, the greater the societal benefit. Of course, to the extent that either an RFP-based project or a merchant transmission project interferes with the property rights of others or degrades the performance of the power system as a whole, then such actions and interests should be restricted.

Fourth, an RFP need not be issued for small needs. Do the costs of the RFP process outweigh the benefits to be gained by an RFP-based project? If so, other procurement methods to satisfy transmission needs may be utilized.

Fifth, the total time to review bids and select a winner should be reasonable.

Recent Transmission RFPs

RFPs in the transmission sector are an established feature of the electric power industry. For example, in June 2001 the Western Area Power Administration solicited indications of interest in the financing and co-ownership of transmission lines in central California. In April 2001, ESBI Alberta Ltd. (formerly Grid Company of Alberta) solicited bids for the construction transmission substations. Earlier, the same organization issued RFPs for facilities comparable to a planned 144 kV transmission line; the project was awarded to a distributed generation facility. Finally, in October 2001, VENCORP, the system operator for the state of Victoria, Australia, issued an RFP for the construction, ownership and operation of shunt capacitor banks to be connected to the incumbent utility's system. *See* Intent to Relieve Path 15 Transmission Constraints, 66 Fed. Reg. 31,909 (June 13, 2001); ESBI Alberta Ltd., Request for Expressions of Interest (RFI) for Providing and Operating Transmission Facilities (April 27, 2001) *available at* http://www.eal.ab.ca/ts/RfI_Final_Apr_26_2001.pdf (downloaded September 7, 2001); ESBI Alberta Ltd., Effectiveness of Procurement Process of New Transmission Facilities (December 28, 2000) *available at* <http://www.eal.ab.ca/tp/review%5Fof%5Ftransmission%5Fprocurement%5Fprocess%5Ffinal.pdf> (downloaded September 7, 2001); VENCORP, Invitation to Tender for the Provision of Network Reactive Support Services Comprising 600 MVAR of Shunt Capacitor Banks, (October 26, 2001), *available at* <http://www.vencorp.com.au/> (downloaded November 6, 2001).

Cost Allocation: The Uses of Cost Causation Methods

Payment to the winning bidder of the RFP should be allocated in accordance with a cost-benefit analysis, assigning costs to those transmission customers that benefit from the project.⁸⁹ This allocation is necessary for efficiency reasons. In some cases, the benefits will be widespread and costs should be allocated accordingly. In other cases, the benefits will accrue to a relatively small group of customers and this small group will fund the project. Any remaining costs should be recovered as part of regional transmission rates.

Allocating costs in this manner achieves two benefits. First, customers have the proper incentive to fund merchant transmission (or competing solutions such as load management and distributed generation). Customers will know that if they do not fund merchant transmission projects, they will trigger the issuance of an RFP – which they will end up funding as well.

If on the other hand, the costs of all RFP projects are socialized – that is, spread over all transmission customers in a region, regardless of who benefits – then those customers that receive a proportionally greater benefit from a proposed project than other customers would never fund a project in the market. Instead, these customers would wait until their transmission need was addressed by the needs assessment conducted by the RTO and funded by all transmission customers, not just those customers that benefit.

The second benefit achieved by allocating costs in accordance with a cost-benefit analysis is that customers have the proper incentive to fund merchant transmission (or competing solutions such as load management and distributed generation) *that is most efficient in reducing congestion*. This is because the incentive to fund such projects will be determined by location-based marginal costs, the most efficient way to identify the location and level of congestion on the grid.

Linking the cost of a transmission project to the benefits it produces is the most efficient way to finance such projects in the context of a competitive solicitation. The following example illustrates how benefit-based cost allocation is superior to socializing costs (that is, spreading costs regardless of the benefits and harms that result from the project):

Two zones within a power grid experience congestion 100 hours every year. At such times, the energy cost in Zone A is \$20/MWh, and in Zone B it is \$40/MWh. Zone A accounts for 18,000 MWh of load, or 90 percent of the system's total load, while Zone B accounts for only 2,000 MWh, or 10 percent of the system's total load. No merchant transmission projects to relieve the constraints have been planned. The system operator therefore turns to its regulatory backstop and issues an RFP for the construction of transmission facilities. As a result, transmission

⁸⁹ A portion of the project costs may be recovered by the allocation of FTRs to the winner, if the bid of the winner is so structured.

facilities have been built that reduce congestion, and the cost of energy at both Zone A and Zone B becomes \$21/MWh for the one hundred hours of congestion.

Prior to Project

	<u>Zone A</u>	<u>Zone B</u>
Load (MWh)	18,000	2,000
Price (MWh)	\$20	\$40
Annual Cost/MWh	\$ 36,000,000.00	\$ 8,000,000.00

Subsequent to Project

	<u>Zone A</u>	<u>Zone B</u>
Load (MWh)	18,000	2,000
Price (MWh)	\$21	\$21
Total Cost for the 100 Congested Hours	\$ 37,800,000.00	\$ 4,200,000

Given these figures, if the cost of the transmission project is \$1 million, who should pay for it?

Zone A will fight the project tooth and nail, because its annual costs will rise by \$1.8 million. On the other hand, Zone B should want to fund the project, since its annual costs of energy will drop by \$3.8 million. If the cost of the project is socialized according to percentage of load, Zone B will pay only 10 percent of the project cost, bringing its net savings to \$2.8 million. In this case, however, Zone A will not only be required to pay higher annual energy costs but also 90 percent of the project, or an additional \$900,000!

Clearly, Zone B will still benefit from the project if its holds Zone A harmless by paying it \$1.8 million (bringing its total cost up to \$2.8 million for a net savings of \$1 million).

Finally, assume that a merchant developer does want to develop the transmission upgrade and fund it via the market. If backstopped project costs will be socialized, Zone B will prefer the backstop because it would fund only 10 percent of the backstop project. As a result, Zone B would refuse to fund the cost of the merchant project. Obviously, Zone A will not fund the merchant project, because not only does it not benefit from the project, it will have to pay higher energy prices if the project is built.

On the other hand, if the costs of the backstop project are assigned to those that benefit, then Zone B has an incentive to fund the merchant project – and the project would get built. Zone B, in fact, would *favor* a merchant project, because it could tailor the terms and conditions of the project to meet their needs through

negotiations with the developer. This is less risky than waiting to see what results from – and then having to accept the results of – the RFP process.

Critics may argue that a cost-benefit test will delay needed transmission projects by creating endless litigation over the assumptions underlying the cost-benefit analysis. This argument ignores that the cost-benefit test that allocates costs among transmission customers *is the same analysis now used to determine whether to build an upgrade and what is required to connect and integrate such upgrade into the transmission system*. Evaluating whether a transmission need should be addressed necessarily involves identifying who will benefit by how much. In particular, the system impact and interconnection study process clearly identifies affected areas of the system and identifies any needed reinforcements to those areas. As a result, there is no greater incentive to litigate the allocation of transmission investment costs resulting from a cost-benefit analysis under an RFP regime as there is with respect to an allocation of transmission investment resulting from an upgrade analysis under more traditional transmission investment regimes.

Further, a cost-benefit test to assign costs from projects built pursuant to the RFP process will not result in more – and even may result in fewer – challenges to allocations that are socialized among all transmission customers, whether they benefit from the expansion or not. Surely, if costs are allocated among those who benefit, those who are charged may challenge the calculation of their benefit. But, if costs are socialized, those that do not benefit also may litigate – not on the basis that they do not benefit, but on the basis that the analysis that determined the need for the project was flawed. At the least, under a cost-benefit allocation those that are charged have less incentive to litigate because they have allegedly received some benefit from the project to which they contribute.

Answers to Common Questions About Merchant Transmission with an RFP Backstop

Q: How will merchant transmission projects overcome regulatory and permit requirements?

A: The regulatory and permit requirements that in the past have prevented transmission expansion will not delay the creation of merchant transmission projects, if such projects are structured correctly. In fact, many of the regulations that historically obstructed the transmission projects – primarily zoning restrictions and not in my back yard (NIMBY) activism – simply do not apply to modern transmission facilities. For example, cables using high-voltage direct current (HVDC) Light technology are smaller and easier to place underground than traditional high-voltage alternating current (AC) cables – making highways, railroads and pipelines viable locations for transmission lines, as they are for fiber optic lines. As a result, there are now opportunities for transmission construction free from the controversies over rights of way that so often have plagued the industry in the past.

Further, statutes and regulations are not static: they change in response to changing environments. The development of merchant generation stimulated a nationwide reconsideration of siting policies applicable to generation facilities;⁹⁰ there is no reason to think that such a reconsideration will not occur in the context of a newly invigorated, competitive transmission sector.

In any case, regulatory burdens faced by the transmission sector are comparable to those faced by other industry groups. Telecommunications, airlines, aerospace, banking, wholesale generation: these are but a few of the sectors that face regulatory barriers to expansion on a staggering scale. Yet competitive markets in these sectors are thriving; there is no need to think otherwise about transmission.

Q: Isn't transmission a natural monopoly that requires monopoly regulation?

A: The economies of scale that at one time may have justified monopoly regulation of both transmission and generation need to be reevaluated. Wholesale generation that developed under PURPA and the EPAct of 1992 demonstrated the viability of smaller, more nimble power plants. Transmission too has been transformed: today's transmission projects are similar to generation peaking units in both size and economies of scale. The modularity of new controllable technologies, such as HVDC and FACTS, enables incremental increases in scale, allowing grid capacity to more closely match demand.

⁹⁰ See, e.g., Andrew Caffrey, *States Encourage Utilities to Build Plants In Hopes of Avoiding an Energy Debacle*, THE WALL ST. J., June 27, 2001, at B1.

This is not to say that transmission systems lack economies of scale altogether. No market is perfectly competitive. And no regulatory approach is perfect and costless. The tradeoff is between imperfect markets and imperfect regulation.⁹¹ But if, in the words of the FTC, “the reliance on behavioral rules ... has proved to be less than ideal,”⁹² market-oriented approaches have proven their effectiveness, in the power industry and elsewhere. Again, the example of competitive generation is instructive. Generation has residual economies of scale but few now would require monopoly regulation in that sector. So too with transmission.

Q: If an optimally-sized transmission investment is built, congestion is reduced to zero and FTRs will be worthless. How can worthless FTRs incentivize transmission construction?

A: It is not necessarily the case that an optimally-sized transmission investment should reduce congestion to zero for all hours of the year. Even if this were the case, the developer can contract with load serving entities beforehand. Load serving entities should be willing to fund transmission investments up to the amount that the project reduces congestion. For example, if a project reduces expected congestion from \$100 million to zero and the cost of the project is \$80 million, then the developer and the affected load serving entities should be able to strike a deal in which the project is funded from the reduction in congestion costs.

Q: Network improvements often benefit parties that don’t pay for them, making it difficult to recapture the costs of the improvement. How does merchant transmission avoid this problem?

A: The answer has two parts: one for new transmission technologies, the other for traditional transmission technologies. First, new, controllable transmission technologies prevent free riders because transmission is directed to only paying users. These technologies include HVDC and FACTS. Second, older technologies can avoid free riders through the use of FTRs as locational hedges in the power market: grid users who attempt to free ride risk volatile prices of power, and bankruptcy.

Q: Have other countries adopted bid-based, security-constrained economic dispatch with locational prices?

A: Yes. Core elements of the model have been adopted successfully in Australia, New Zealand, and Norway, as well as Argentina, Bolivia, Chile and Peru.

⁹¹ Joskow & Schmalensee, *supra* note 8 at 31; Hogan, *supra* note 51 at 22.

⁹² Comment of the Staff of the Bureau of Economics of the Federal Trade Commission, *supra* note 54 at 32.

Q: Won't developers of merchant transmission "cherry pick" the attractive projects, leaving unattractive projects to the competitive solicitation process?

A: Merchant transmission developers and legacy transmission owners will compete for the best projects. If there is profit to be made, developers will seek it – whether in the competitive markets or as a result of an RFP. Other projects, as always, would rely on regulatory determinations of allowable cost recovery – a process that is outside of the competitive markets.

Q: What if merchant transmission doesn't work?

A: In the event that competitive markets for transmission investment fail to meet societal goals – particularly with respect to system reliability – regulators should reserve the authority to backstop the competitive market arena and promote investment through other means. They should solicit competitive bids by issuing RFPs open to any technology or other solution – central station generation, distributed generation, steel-lattice tower AC transmission systems or next-generation transmission technologies such as HVDC and FACTS – that can achieve the RFP's goals.

Part IV: Performance-Based Rates – A Proper Incentive?

“The rat must smell the cheese.”

Utility executive John Rowe, on the use of regulatory incentives to motivate corporate action⁹³

As noted in the discussion of Order 2000 above, the FERC stated that while “PBR is far from a new concept,”⁹⁴ it would consider proposals by RTOs for transmission pricing founded on PBR. In this part we will review the suitability of PBR as means to achieve the creation of a vibrant and economically efficient transmission sector. As we shall see, the premises underlying PBR are questionable in the context of today’s transmission technology and the current structure of the electric utility industry.

PBR: An Incremental Step

For participants in the electric utility industry, deregulation requires change in practices and long-held cultural beliefs. Traditional utility regulation centered on “a laborious, legalistic, highly ritualized process called rate hearings, in which – Kabuki-like – lawyers, lobbyists, corporate officials, experts, intervenors, environmentalists, consumer activists, and regulators all performed their stylized roles.”⁹⁵ This process is now challenged by new technologies and a changed economic environment. But the urge to temper reform remains strong.

A parallel to today’s attitudes toward reform can be found in the 1970s, when regulators took their first steps to free the price of natural gas. At the time, according to Betsy Moler, who was chairman of the FERC from 1993 to 1997, regulators “tried to provide transition mechanisms that would allow us to inch along the way from a regulated to a deregulated market.” Eventually, however, regulators had to take the plunge. Moler says: “once we had deregulated [we had] increasingly come to respect the power of markets. We recognize what competition can do. We’re teachable.”⁹⁶

PBR is but another transitional mechanism. PBR is intended to modify the behavior of transmission companies so as to simulate the stresses of competitive pressures, thus inching the transmission sector along from a regulated towards a deregulated market. But, like COSR, it uses the heavy hand of regulation to direct market behavior. As a result, inefficiencies and regulatory burdens similar to those present under COSR will also be present under PBR.

⁹³ Quoted in Larry Tye, *Plan to Save Power Would Put Utility in Vanguard*, THE BOSTON GLOBE, September 22, 1989, at 21.

⁹⁴ Regional Transmission Organizations, Order No. 2000 *supra* note 37 at 31,182.

⁹⁵ YERGIN & STANISLAW, *supra* note 1 at 350.

⁹⁶ *Id.* at 352, citing Cambridge Energy Research Associates, *Interview with Betsy Moler and Philip Sharp*, ELECTRIC POWER TRENDS, 1996-1997 8 (n.d.).

How PBR Works

PBR, like COSR, is founded on theories of natural monopoly. Like COSR, PBR holds that market-based incentives are inapplicable to transmission because economies of scale (or scope) stifle competition or otherwise are not suited to the market. To avoid the monopoly pricing to which natural monopolies tend, PBR (like COSR) regulates the prices a company can charge for the services that it provides. PBR (like COSR) obliges regulators to define these prices in consultation with stakeholders – such as is done in a traditional public utility commission rate case, for example.⁹⁷

Unlike COSR, PBR assumes that transmission investment and operations should be receptive to incentive pressure, preferably financial. This means that a for-profit entity such as a transco is best suited to PBR regulation, rather than a not-for-profit such as an ISO.⁹⁸

Under PBR, government regulation must try to replicate as best it can the variety of market-based incentives that in the absence of a natural monopoly would result in efficient and reliable transmission service. There are four elements to standard models of PBR:

- 1) *Price or Revenue Caps.* Unlike COSR, which ties prices that the transco may charge to cost of service, PBR simply *caps* the price that the transco may charge or, in the case of a revenue cap, the total revenues the transco may earn. The transco's allowed rate of return neither is determined nor guaranteed by regulation. Cost-savings and other efficiencies redound to the benefit of the transco; cost-overruns and other inefficiencies harm it. A simple price or revenue cap can work this way:
 - a) regulators establish a target cost for the construction and operation of a transmission facility for one year at \$1 billion, *and*
 - b) the actual cost to construction is \$750 million, *then*
 - c) the transco may recover \$1 billion from customers. If the actual cost is \$1.35 billion, the regulated firm may recover only \$1 billion and not recover the excess \$350 million.
- 2) *Constraints.* The model that caps prices (or alternatively, revenues) described in Item 1 above is *pure* – that is, prices (or revenues) are fully delinked from rates of return. PBR is usually milder: various rate of return constraints are introduced into the model

⁹⁷ In practice, COSR is a type of PBR because of regulatory lag. To illustrate: Cost-of-service-based rates are adjusted only periodically; therefore, if the utility reduces costs between rate cases, it keeps the additional profits. If, on the other hand, costs increase between rate cases (above what the rates provided for), then the utility's profits are decreased until the rates are adjusted in next rate case.

⁹⁸ PA CONSULTING GROUP, *supra* note 23 at 1-3.

to effectively maintain some link between prices (or revenues) and costs.⁹⁹ So, in the example in above Item 1, assume that a constraint on returns of 10 percent over costs exists. In that case, if the actual cost is \$750 million, then the transco could keep only \$75 million (that is, 10 percent of \$750 million) and the remainder would be allocated to price reductions for the benefit of customers.

- 3) *Performance Targets.* PBR adds an additional twist to the price cap model. In addition to cost targets and, possibly, rate of return limits, quality of service targets are established. This is because a price (or revenue) cap model may encourage a firm to meet its revenue targets by cutting back on service quality. Service levels are benchmarked on a “quality index;” if the firm exceeds particular benchmark levels, it can recover additional amounts from customer. If it fails to meet certain levels, penalties are levied and the maximum price it may charge customer is reduced. Quality of service indices may be established for many areas of service; increases in quality of service in any one may be rewarded differently from increases in others.¹⁰⁰
- 4) *Periodic Reviews.* Some PBR models call for a *ratchet* – a periodic adjustment of price caps (including any base revenue levels) and performance indices under the PBR regime. Adjustment can be made every few years as a result of cost and service quality performance reviews.¹⁰¹ In both style and substance, the reviews would look very much like rate cases under COSR.

Accounting for Inflation and Increased Productivity

Difficulties arising from the use of PBR in the transmission sector are discussed in the next section. But we pause here to discuss two major obstacles that prevent the smooth implementation of PBR irrespective of the industrial sector to which PBR is applied. Both involve problems of measurement.

The first is the measurement of inflation. Generally, PBR price or revenue caps are automatically indexed to inflation. Such indexing should be, optimally, tied to inflation in the prices of the inputs specific to the industry or company being regulated. Yet rarely do the prices of these specific inputs track the prices reflected in generally accepted inflation indices such as the Consumer Price Index.¹⁰² Despite this, many regulators use

⁹⁹ AWERBUCH, HYMAN & VESEY, *supra* note 5, at 148.

¹⁰⁰ For an overview of the basic PBR model, *see generally* Paul L. Joskow, Comments of Professor Paul L. Joskow, Regional Transmission Organizations, Order No. 2000 *supra* note 37; *see also* AWERBUCH, HYMAN & VESEY, *supra* note 5.

¹⁰¹ Joskow, *supra* note 99, at 10.

¹⁰² Addressing the applicability of common inflation indices to the utility industry in particular, a recent article argues that “empirical analysis using U.S. data has shown that utility costs are not directly tied to general inflation indices.” A.J. Goulding et al., *X Marks the Spot: How U.K. Utilities Have Fared Under Performance-Based Ratemaking*, PUB. UTIL. FORTNIGHTLY, Sept. 1, 2001, at 28, 32.

broader indices because the costs of developing industry- or company-specific measurements are seen as excessive.¹⁰³

The second obstacle that prevents the smooth implementation of PBR generally is the determination and measurement of the so-called *X factor*. The X factor is the measure of productivity which offsets, in part or in full, the automatic increases in price or revenue caps due to inflation. It is intended to account for increases in output that cannot be explained by increases in input. Establishing an X factor calls for the use of complex econometric and mathematical formulae, which is difficult enough. But, setting an X factor also relies on the use of backward-looking data and (most influentially) on the qualitative judgment of regulators. Too high an X factor can cause significant harm to company's revenue. Too low requires additional regulatory intervention that "claws back" revenue deemed excessive.¹⁰⁴ It is especially difficult to measure productivity improvements for transmission, because this industry sector does not yet represent a stand-alone industry. As a result, data for transmission-only activities simply are unavailable, most likely rolled into consolidated data as reported by integrated utilities. As we will see below, inappropriate estimates of the elements of PBR have resulted in disproportionately high benefits to regulated companies, causing political uproar and extraordinary regulatory intervention.

Difficulties of Transmission PBR

Whether supporting PBR or otherwise, arguments in favor of placing responsibility for transmission investment decisions in the hands of a monopoly entity rests on the assumption that a centralized, monopoly entity can perform the transmission expansion function more efficiently than can a competitive market for new transmission investments. Of course, if this were the case, that same entity could plan generation expansion as well. But we know from past deregulation and market liberalization efforts that centralized entities do not perform their functions efficiently. These entities have a difficult task of determining which investments are efficient and which are not, primarily because of the difficulty of making an administratively-determined process simulate market outcomes under a competitive framework. A constant in the history of regulation has been the failure of regulators to anticipate and forecast changes in the industry. Further, regulators are subject to a political process that often diminishes the probability of efficient decision-making. In the words of one writer,

[r]ight now, the key challenge that faces the industry is finding a way to provide a regulated entity with the incentive to invest efficiently.... 'No off the shelf performance-based regulation formula for [monopoly transmission providers] appears readily workable, either politically or administratively, yet neither is conventional

¹⁰³ *Id.*

¹⁰⁴ *Id.* at 34.

cost-of-service regulation sufficient.’ With regulated companies serving as the main engine for transmission investment for the foreseeable future, the issue of how to best regulate them must now become an industry priority. [note omitted]¹⁰⁵

Curiously, this quotation is from an article that *advocates* centralized authority over transmission expansion.

As attractive as this formula sounds in general, in the transmission sector its specifics are difficult to apply. Problems arise in defining base revenue levels (and other cost targets) as well as levels of performance; in measuring performance against a benchmark; in the potential exercise of undue market power; and in other areas. A brief summary of the problems of PBR in the transmission sector follows.

- ***Transco may manipulate transmission planning.*** As discussed in Part II above, transmission is only one element of the power system: others include distributed generation, new technologies, and demand-side resources. But PBR rewards a transco only for transmission solutions. This is so even if generation, distributed generation, or demand-side solutions are more efficient. As a result, innovation and investment in the most efficient solutions may be discouraged. Given that these competing resources may need to interconnect to the transmission grid, the Transco may use its interconnection standards and procedures to discriminate against its competitors. In the words of the FTC, any incentive to favor one solution over another “may present the strongest challenge to bringing the full benefits of competition to consumers.”¹⁰⁶
- ***Transco may manipulate grid operations.*** Under PBR, a transco is a regulated monopoly. Yet PBR may create incentives for a transco to participate in the market and exercise undue market power.

¹⁰⁵ Cameron, *supra* note 67, at 37, quoting Steven Stoft & Frank Graves, *PBR Designs for Transcos; Toward a Comparative Framework*, ELEC. J., August/September 2000, at 32, 32.

¹⁰⁶ Comment of the Staff of the Bureau of Economics of the Federal Trade Commission at 8, Regional Transmission Organizations, Order No. 2000 *supra* note 37.

- ***Transco may earn excessive profits as a result of regulatory lag.*** PBR's incentive to reduce cost by allocating cost savings to the transco often is balanced by constraints on the transco's rate of return. This allows customers to share in cost savings above a certain level. However, when cost-saving targets are improperly figured, or when incentive and restraint are not properly aligned (in cases, for example, when the periodic review of constraints (the *ratchet*) lags

Transmission PBR in England and Wales

Much of the precedent for PBR comes from the experience of National Grid Company, the transmission utility in England and Wales that is regulated under performance-based rates. The FERC's *Order 2000* stated that a party "that intends to propose PBR ... examine the strengths and weaknesses of the British approach."

As discussed elsewhere in the text, the experience with National Grid Company demonstrates that the company has benefited substantially from PBR but not necessarily the consumer. But putting that aside, the England and Wales experience may not be transplantable to the United States.

When evaluating National Grid's experience under PBR, one must keep in mind the fundamental differences between transmission infrastructure in the US and the UK. The physical layout and operational requirements of the England and Wales transmission grid, as well as the economic environment in which the grid operates, makes the experience of National Grid Company distinctive. As a result, the usefulness of the UK experience as the model for the US is limited.

Lack of Locational Prices and FTRs. The England and Wales system does not have locational prices and FTRs. Instead, there was one energy-clearing price for the whole grid. Congestion costs were paid via an uplift mechanism to the energy-clearing price. Under this system, it makes sense to provide PBR mechanism to the transmission operator to reduce congestion costs because load and generation had little if any incentive to take actions that would reduce congestion.

Distinctive Stakeholder Populations. The limitation to National Grid Company of ownership and control of transmission facilities in England and Wales, and the relatively few generation and distribution assets within the jurisdiction, also stands in stark contrast to the situation in the US. PBR is much more workable in an environment where there are few stakeholders, as in the UK. Because consensus regarding appropriate incentives is much easier to achieve among few stakeholders, cost and service targets are subject to less controversy and easier to establish in the UK than they would be in the US power environment, which has many stakeholders.

behind the setting of cost-saving incentives, the purpose of rate of return constraints is unsatisfied. “This result – a windfall from captive customers – appears to be what has happened in Great Britain, which instituted an incentive-type regulation scheme when its electricity industry was privatized in 1990. The National Grid Co. earned a 1994-95 pretax profit of \$ 959 million on gross revenue of \$ 2.242 billion – a return of 43 percent. In the same year, the 12 distribution companies of England and Wales jointly earned a pretax profit of only 13 percent (even so, nearly double the profit margin of five years before).... Concerned by this outcome, the U.K. regulator has begun to pay close attention to the costs and profits of these companies. PBR is beginning to look like American-style, cost-of-service regulation.”¹⁰⁷

- ***Allocation of costs and benefits will foster disputes and create a regulatory burden.*** Disputes over the appropriateness of baseline cost and performance levels will be familiar to those experienced in disputes over “allowable costs” under COSR. Under PBR, both the transco and its customers have incentives to contest regulatory determinations. If cost targets are high, the transco will easily save on costs and collect the resultant savings rather than reduce prices. If the costs targets are low, the prices that customers will be charged will be lower but the transco will have less incentive to flow through cost savings to customers. The same is true regarding performance targets. The lower the performance target, the greater the ability of the transco to meet the target and collect its “reward;” the higher the performance target, the greater effort the transco must expend to achieve its reward but the prices charged will be lower. It is clear that the exercise of regulatory discretion will breed regulatory contests expensive to the both to contestants and to the regulator.
- ***Definition and measurement of cost and performance targets will foster disputes and create a regulatory burden.*** The network externalities present on a transmission grid present significant impediments to accurate definitions and measurements of system costs and performance. As a result, cost and performance targets may not be set with sufficient accuracy to encourage appropriate transco behavior or to discourage contests by stakeholders. An example of the difficulties of defining system performance is set out by Stoft and Graves, who note that assessing the efficiency of transmission line upgrades “involves computing savings of generation costs over long time horizons. Note that these costs are external to the transco operations and accounts, immediately flagging a difficulty for designing a desirable PBR system!”¹⁰⁸ Further, congestion costs can be quite large under extreme circumstances, and they are very hard to predict accurately in advance.¹⁰⁹ One group of transmission owners

¹⁰⁷ Michael Brower, *PBR's Changing Face*, PUB. UTILITIES FORTNIGHTLY, March 15, 1996, at 7.

¹⁰⁸ Steven Stoft and Frank Graves, *PBR Designs for Transcos; Toward a Comparative Framework*, ELEC. J., August/September 2000, at 32, 35.

¹⁰⁹ *Id.*

that supports transmission performance measures proposed a four-year process “to establish a consistent performance-related database and to study available options” for a performance-based rate methodology.¹¹⁰ Four years is a long time to wait in order to set up a regulatory framework to increase the amount of transmission, which is needed now. Furthermore, during the period in which performance measures are being determined, transmission owners have the incentive to delay implementing expenditures that improve performance until the new regime is established in order to obtain the associated performance reward.

The above summary identifies serious drawbacks in the various PBR models now being proposed. Like most regulatory models, perfect regulation leads to perfect results. But the regulatory imperfections in PBR make the imperfect markets of merchant transmission that much more attractive.

Table 2. Comparison of COSR, PBR and merchant transmission

	COSR	PBR	Merchant Transmission
Regulated prices	Yes	Yes	No
Basis of prices charged	Regulatory rate of return	Regulatory cap with rate of return constraints	Competitive market
Review period	Yes	Yes	No
Rate cases	Yes	Yes	No
Industry Structure	Monopoly transco	Monopoly transco	Competitive gridcos with ISO/RTO coordination
System Management	Transco	Transco	ISO/RTO
System Expansion	Transco	Transco	Competitive gridcos with RFP backstop
System Planning	Transco	Transco	Competitive market with ISO/RTO reliability-driven planning as backstop
Congestion Management	Regulatory fiat	Financial incentive defined by regulation	Financial incentive defined by competitive market
Role of Regulator	Price setter	Price setter	Referee

Merchant transmission with an RFP backstop does not have the problems that PBR creates. With merchant transmission, market-based incentives rule, rather than regulatory incentives that seek to mimic market-based incentives. Allocations of cost and benefits among industry players, definitions of costs and performance, manipulation of transmission planning and operation, undue market power – these issues will evaporate as the self-regulatory mechanisms of competitive transmission markets create increased efficiencies. The mixed experience of UK transmission under PBR, as well as the

¹¹⁰ JEFF D. MAKHOLM, ASSESSMENT OF PJM TRANSMISSION OWNERS’ TRANSMISSION ENHANCEMENT PACKAGE, n/e/r/a mimeo, October 11, 2000, p. 4, *available at* http://www.pjm.com/documents/FERC/2000docs/Oct/101100_rto_rep.pdf (downloaded September 7, 2001).

increasing popularity of competitive-market transmission around the world, argues against PBR and for merchant transmission.

In those situations in which the regulatory backstop is needed to ensure sufficient transmission, the RFP process is the ultimate PBR – except that, instead of only having one company respond with only one type of solution, which is the case of a PBR, any number of companies proposing any variety of types of projects that meet the need compete to provide the least-cost solution.

Conclusion

Technological development is increasingly relegating the monopoly regulation of transmission investment to the dustbin of history, much as it did to the monopoly regulation of electric generation. Maintaining a regime of transmission regulation founded on theories of natural monopoly, although not likely to be the road to ruin, silences market signals that are capable of identifying opportunities for needed investment – in new transmission facilities, distributed generation or any other solutions that best can satisfy demand for power. This interference with market outcomes is fundamentally inconsistent with the move towards market-based congestion management systems and, in particular, locational-based marginal pricing. A competitive solicitation process that backstops a competitive market for transmission investment, as described above, allows market signals to flourish and, at the same time, provides comfort to those unaccustomed to the operation of competitive market forces. It is the best way to assure consumers that the electric rates they pay are reasonable and that the electric service they receive will remain reliable. The FERC has opened the door; the industry must now cross the threshold to a new, more efficient way of doing business.

Appendix I: Next-Generation Transmission Technologies

High-Voltage Direct Current Transmission (HVDC).

“HVDC lines are connected to AC systems through converter systems at each end. The power is converted from AC to DC at the sending end and back to AC at the receiving end. HVDC circuits have some advantages over AC circuits for transferring large amounts of power. HVDC circuits can be controlled to carry a specific amount of power without regard to the operation of the AC circuits to which they are connected. If HVDC lines are operating in parallel with AC lines, the outage of a parallel AC line does not overload the DC line. However, the outage of the HVDC line does increase the loading on the parallel AC lines. HVDC circuits have resistance but do not have reactance associated with AC, so they have less voltage drop than AC circuits. HVDC circuits have a major disadvantage as they require converter stations at each end of the circuit that are very expensive, making HVDC uneconomical except when power is transmitted for long distances. HVDC circuits also do not have the system instability problems that AC circuits have.” *Source: John Makens, Upgrading Transmission Capacity for Wholesale Electric Power Trade, Energy Information Administration, available at http://www.eia.doe.gov/cneaf/pubs_html/feat_trans_capacity/w_sale.html (downloaded September 7, 2001).*

Flexible AC Transmission Systems (FACTS).

“Flexible AC Transmission System, (FACTS), can be used to help mitigate current preventive system operating constraints. The FACTS concept uses new power-electronics switches and other devices to provide faster and finer controls of equipment to change the way the system power flows divide over the system under normal conditions or during contingencies. A FACTS device can be used to reduce the flow on the overloaded line and increase the utilization of the alternative paths excess capacity. This allows for increased transfer capability in existing transmission and distribution systems under normal conditions. Some FACTS applications are presently feasible and in service while others are in various stages of development.” *Source: John Makens, Upgrading Transmission Capacity for Wholesale Electric Power Trade, Energy Information Administration, available at http://www.eia.doe.gov/cneaf/pubs_html/feat_trans_capacity/w_sale.html (downloaded September 7, 2001).*

Static Compensators (STATCOMs), State Condensers (STATCONs), and Unified Power Flow Controllers (UPFCs).

“The STATCOM provides voltage support by generating or absorbing reactive power through an electronic shunt connection that can quickly dampen major power-system disturbances. The STATCOM is actually a power-electronics system having dc storage, a converter, and a transformer to hold a power line at the required voltage level by supplying, or absorbing, reactive power. Depending on the size of the energy storage, it can supply real power to the load for short periods.... Another example of the newer FACTS devices is the Unified Power Flow Controller (UPFC). It is so named because it provides control over all three power-flow parameters of voltage, line impedance, and power factor, in one device.” *Source: NAT’L INST. OF STANDARDS AND TECHNOLOGY, U.S. DEP’T OF COMMERCE, MEASUREMENT SUPPORT FOR THE U.S. ELECTRIC-POWER INDUSTRY IN THE ERA OF DEREGULATION, PUBLICATION NO. NISTIR 6007, 20 (1997).*

Appendix II: Glossary

<i>bulk power market</i>	the market in which wholesale power is traded.
<i>contract path</i>	an assumption used in transmission pricing that electricity flows from Point A to Point B.
<i>congestion</i>	a state on the transmission grid that restricts or constrains the ability to add or substitute one source of power for another.
<i>cost of service regulation</i>	a regulatory model linking a firm's costs to the firm's rate of return.
<i>demand-side solutions</i>	behavior and technologies that can reduce end-user power consumption.
<i>direct current</i>	a flow of electricity that is controllable as to direction and amount.
<i>distributed generation</i>	modular electric generation or storage located close to the point of use, including microturbines, fuel cells, photovoltaics and small wind turbines.
<i>distribution</i>	the process of moving power from transmission lines to the end user over low-voltage lines and other equipment.
<i>economic dispatch</i>	the process under which a transmission system operator connects sources of generation to the power grid, in order of least to greatest cost.
<i>economies of scale</i>	circumstances in which costs of production decline as plant size and the amount of goods or services produced increase.
<i>economies of scope</i>	circumstances in which costs of production decline as the type of goods or services produced increases.
<i>embedded cost</i>	the original cost of a transmission facility (less depreciation and including operation and maintenance expenses and taxes).

flow-based pricingtransmission pricing based not an assumed contract path but on the costs of each of the parallel paths upon which the transmission flows.

generationthe process of creating electricity. Power plants, whatever the fuel – hydro, nuclear, gas, coal or other source – are the locus of electric generation.

independent system operatora non-profit independent system operator formed in accordance with FERC Order 888 that operates a regional power pool impartially.

financial transmission rights.....a financial instrument representing the financial value of congestion costs.

load.....a point of electricity demand

parallel pathsthe flow of electricity over an AC power grid, the result of physical laws preventing electricity from flowing through specific lines in specific directions.

postage stamp pricinga transmission pricing method that is not sensitive to distance.

power gridan integrated network that connects generation facilities to each other as well as to distribution facilities.

power poolsa power grid comprising the discrete power grids of separate utilities.

regional transmission organization ...an entity responsible for certain transmission functions and meeting specified criteria in accordance with FERC Order 2000.

system operator.....a control unit responsible for managing a power grid.

system reliability.....the ability of the power system to meet demand.

system securitythe ability of the power system to withstand sudden outages of generation or transmission components.

transcoan investor-owned entity that combines operation and ownership of transmission assets driven by the same corporate and market incentives.

transmissionthe process of moving electricity generated by power plants over long distances, in bulk, via high voltage wires (transmission lines).

transmission line loading reliefprocedures that seek to prevent power outages or property damage when the electric load threatens to get to high for the transmission line to handle.

vertically integrated electric utility....an electric utility that owns and controls each element of the electric utility function: generation, transmission and distribution.

Appendix III: Acronyms Used

<i>DG</i>	Distributed Generation
<i>FACTS</i>	Flexible AC Transmission System
<i>FERC</i>	Federal Energy Regulatory Commission
<i>FTC</i>	Federal Trade Commission
<i>FTR</i>	Financial Transmission Right
<i>HVDC</i>	High Voltage Direct Current
<i>ISO</i>	Independent System Operator
<i>LBMP</i>	Location Based Marginal Pricing
<i>PBR</i>	Performance-Based Rates
<i>RFP</i>	Request for Proposal
<i>RTO</i>	Regional Transmission Organization
<i>TLR</i>	Transmission Line Loading Relief
<i>UPFC</i>	Unified Power Flow Controller