

Transmission: the Critical Link

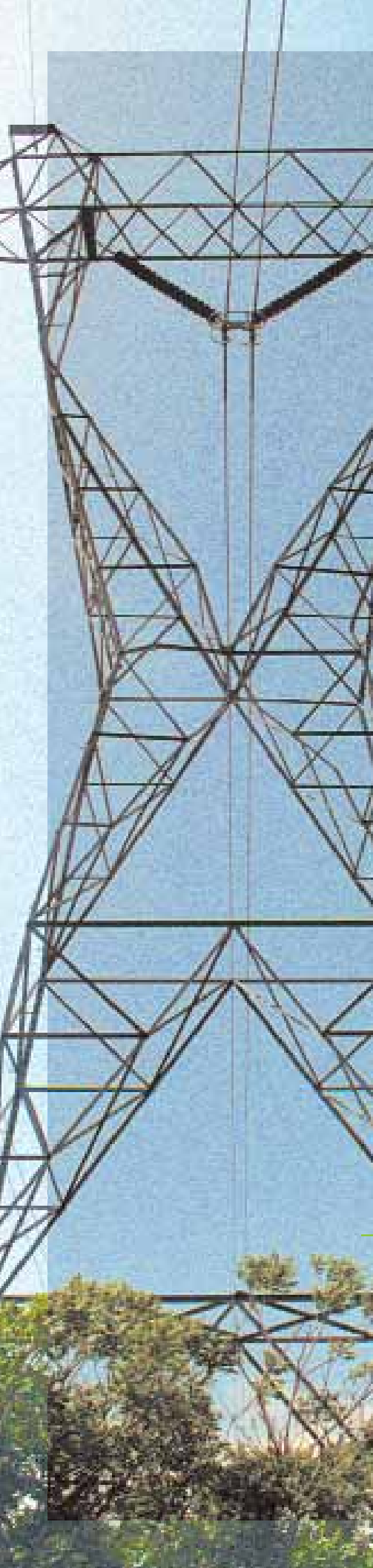
*Delivering the Promise of
Industry Restructuring to Customers*



National Grid

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Executive Summary

Over the last several years, the electric utility industry has undergone a profound transformation that has delivered real benefits to customers and has played an important role in ensuring a vibrant, growing economy for many regions of our nation. The advent of competitive electricity markets has enhanced efficiency, yielded greater choice and, in many areas, has produced lower prices for consumers. The new paradigm has spurred a vigorous and substantial increase in new generation in some states, bringing enhanced reliability and robust competition. Although the demand response sector has struggled to some degree, most stakeholders acknowledge that restructuring presents this emerging sector with opportunities for growth that would not have existed otherwise. Indeed, restructuring has produced fertile ground for innovation and efficiency not seen by the industry in decades.

Nevertheless, a number of troubling warning signs have appeared in the current industry landscape, revealing issues that must be addressed in order to complete the transition to fully competitive markets and deliver the full measure of benefits to customers that was the promise of industry restructuring. Many of these issues, such as higher wholesale prices in constrained import areas, the retention of old dirty generating plants for network reliability, limitations on competition and market power problems, and barriers to entry for new generators, arise from an inadequate transmission system. Enabling restructuring to deliver greater value to customers requires the adoption of a number of policies that support the development of a transmission network sufficient to permit competitive markets to work as intended.


This paper examines several roadblocks standing in the way of the electricity industry's transition to well-functioning competitive power markets. One overarching obstacle is the widespread lack of recognition that the transmission system is a necessary facilitator of markets, rather than a market commodity. That is, transmission is the essential infrastructure needed to support robust competitive markets. Another major obstacle is the institutional arrangement of transmission ownership and operation across the nation, particularly with respect to its fragmented nature and lack of independence from market operations. Policies need to be established that will directly address transmission investment and consolidation to enable restructuring to deliver its full benefits to customers. To be effective, such policies must move the industry in the direction of independent transmission ownership, management and operation over a wide area or region.

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Federal and state policymakers are therefore urged to embrace the following policy recommendations:

- ◆ Establish robust independent regional planning processes that identify transmission system requirements for reliability and the delivery of low-cost electricity to customers.
- ◆ Implement fair and workable cost allocation policies for new transmission investment to ensure reliability and to support competitive markets.
- ◆ Provide adequate return on equity (ROE) incentives for cost-effective new transmission investment to produce the required platform for competitive power markets.
- ◆ Provide for clear and prompt federal and state cost recovery through regulated rates for transmission investments by regulated utilities.
- ◆ Encourage the establishment of for-profit independent transmission entities to consolidate ownership and operation, and make needed investments in the transmission system.

National Grid believes that the full promise of industry restructuring is still very much achievable for the country. In this paper we describe the current state of industry restructuring and the threats to it achieving maximum benefits for customers. In doing so, we call attention to electricity markets both here and abroad that have been successful in harnessing the power of competition to provide value to customers in the form of economic, reliable delivered energy. Based on these insights, we advocate policy proposals that will better shape the industry to serve the public interest.



Customers in a number of restructured states have seen significant savings in their electricity bills.



The Rationale for Competition and Industry Restructuring

The introduction of competition in the electricity industry was envisioned as a way to reduce costs and increase product offerings to customers by giving them access to an array of competitive options while maintaining or enhancing the reliability of electric service. Policymakers, legislators, regulators and industry leaders pointed to successes associated with the introduction of competition elsewhere, particularly in the natural gas sector. The move towards a restructured industry would promote wholesale competition among generators and induce the provision of unbundled competitive services, while giving generators and customers access to regulated transport services to buy and sell power in competitive markets. This quickly created an expectation among customers that more suppliers would be battling for their business, creating more options and leading to lower prices. These expected benefits were viewed by many as more than offsetting the significant costs of transitioning to competitive markets.

These were the key pillars of restructuring. Lower prices would be offered to customers via the pressures of competitive retail and wholesale markets for electricity, and additional value would be provided by services tailored to their individual needs.

The Industry Today

The Benefits of Restructuring in the US to Date

There is ample evidence of the benefits to customers of restructuring to date. These benefits come in the form of lower prices, greater choice, environmental improvements, and enhanced efficiency.

Lower Electricity Prices

Customers in a number of restructured states have seen significant savings in their electricity bills. While some of their rate reductions were mandated as part of state restructuring legislation, savings have gone beyond those mandated levels. For example, customers of Massachusetts Electric Company currently are paying less on an inflation-adjusted basis than they were in 1997 (before the onset of restructuring), saving Massachusetts Electric customers \$1.1 billion from 1998 through 2004 compared to pre-restructuring price trends. Prices have decreased in real terms since 1998 despite a 50% increase in the price of natural gas – the fuel source for an increasing amount of generation over this same period.

Many other states that have adopted restructuring have experienced a similar decrease in the price of delivered electricity. In PJM East, fuel-adjusted

¹ The merchant transmission business model, discussed later in this paper, involves the financing of new transmission through the sale of transmission capacity at market rates.

² A later Notice of Proposed Rulemaking on Standard Market Design (July 31, 2002) proposed to standardize market design across the then existing and emerging ISO/RTOs. It met with significant opposition to which the FERC responded with its Wholesale Market Platform white paper, which more explicitly recognized regional differences. Both the Standard Market Design and the Wholesale Market Platform were efforts to broaden the accessibility and scope of power markets, thus making them more competitive.

wholesale energy prices fell 27% between 1998 and 2003.³ PJM retail customers saved \$3.2 billion in 2002 alone as a result of restructuring, representing 15% of their electric bill in that year. Savings for Pennsylvania residential customers averaged \$117 that same year.

Greater Choice

The states that have restructured have seen significant growth in electricity choices for large industrial and commercial customers. For example, in Texas (ERCOT) the market share of competitive retail suppliers has steadily increased since the opening of the markets in January 2002. Now, 18% of residential customers are served by competitive retail electric suppliers, along with 25% and 42% of commercial and industrial customers, respectively. Indeed, consumer choice has increased significantly due to the restructured markets in ERCOT, where residential customers in service territories there have at least a dozen products from which to select. In most service areas, “green” conscious consumers can shop among at least four renewable products.⁴

The Northeast also has seen an increasing number of customers choosing alternative suppliers. In 2003, over 50% of Maine’s electric load was served by competitive suppliers. In 2004, nearly half of Massachusetts’ large commercial and industrial customers were supplied by such entities.⁵ Even where electricity options have been slow to develop for smaller commercial and residential customers, there has been some activity, particularly in the area of “green” power.

Environmental Improvements

Much of the environmental benefits to customers from restructuring have been due to the development and operation of new, cleaner generation that was driven by the opportunities presented by open-access transmission and the establishment of competitive electricity markets. For example, over the past seven years, generating capacity in New England has increased 11,000 MW – of which 9,480 MW is fired by natural gas and was installed over the last five years.⁶ This is after the region *lost* a total of approximately 600 MW of generation over the same period of time before restructuring. In 2003 alone, natural gas generating capacity as a proportion of all fuel sources increased dramatically to 21% from 13% the year before.⁷ Cleaner burning generation translated into reduced emissions. Massachusetts power plants emitted 33% less SO₂ and 30% less NO_x in 2002 than such plants did in 1997. New York power plants emitted 23% less SO₂ and 18% less NO_x over the same period.⁸

The Genesis of Restructuring

In 1992, Congress passed the Energy Policy Act that set the stage for the restructuring of the electric utility industry. The Energy Policy Act sought to open wholesale electricity markets to new types of non-utility generation, enabling new players to participate in wholesale markets, bringing the benefits of competition in terms of improved efficiencies, greater technical innovation and reduced costs to customers at the wholesale level with the expectation that these benefits would also flow to retail customers. Customers, particularly large commercial and industrial customers, also clamored for retail competition. Several states enacted changes that created competitive retail markets for the purchase and sale of electricity. Transmission and distribution lines were largely viewed as common delivery infrastructure that deliver power from any generator to retail customers at regulated rates and under regulated terms and conditions.¹

Retail markets that provide benefits for customers require an effective competitive wholesale market. To further facilitate competitive wholesale markets, the Federal Energy Regulatory Commission (FERC) in 1996 issued Order 888 requiring all public utilities that own, control or operate facilities used for transmitting electric energy in interstate commerce to have on file open access nondiscriminatory transmission tariffs to facilitate market entry for competitors. Through this order, FERC encouraged the formation of Independent System Operators (ISOs) to operate and manage the transmission system and administer the open access tariffs in a nondiscriminatory manner. FERC refined its views on ISOs and market operations in Order 2000, issued December 20, 1999, outlining the requirements for Regional Transmission Organizations (RTOs) with more defined responsibilities for transmission and market operations.² ISOs and RTOs that administer markets and open access transmission have formed, or are forming, for areas covering a large part of the United States, including the Northeast (RTO-NE, NYISO, PJM), Midwest (MISO), Southwest (SPP), Texas (ERCOT), and California. Other regions, particularly in the South, have resisted the formation of RTOs/ISOs.

³ Synapse Energy Economics, Inc., “Electricity Prices in PJM: A Comparison of Wholesale Power Costs in the PJM Market to Indexed Generation Service Costs,” June, 2004.


⁴ <http://www.puc.state.tx.us/electric/reports/RptCard/rptcrd/Dec04rptcrd.pdf>.

⁵ Maine PUC and Massachusetts DTE data, respectively.

⁶ ISO-NE State of the Market Report 2004.

⁷ ISO-NE State of the Market Report 2003.

⁸ Energy Information Administration, US Department of Energy, State Electricity Profiles, 2002.



Wholesale and retail competition also has provided an unprecedented opportunity for renewable energy development, particularly wind. Driven largely by the renewable energy policies that accompanied restructuring, wind power has been able to take advantage of the market changes that have occurred.⁹

There is also evidence that competition has made generators more efficient nationwide, producing potential savings for customers. A recent study estimates that plants owned by investor-owned utilities (IOU) in restructured regimes reduced their labor and non-fuel operating expenses by about 5% relative to IOU plants in states that did not restructure.¹⁰

Further Benefits to Customers from Restructuring Are Undermined by Insufficient Transmission Investment

Though the benefits from restructured power markets have been substantial, there is a growing recognition that the realization of the full value to customers has been stalled by an inadequate transmission system that was not designed for the new demands being placed upon it. In fact, investment in the nation's electricity infrastructure has been declining for decades. Transmission investment has been falling for a quarter century at an average rate of almost \$50M a year (constant 2003 dollars), though there has been a small upturn in the last few years.¹¹ Transmission investment has not kept up with load growth or generation investment in recent years, nor has it been sufficiently expanded to accommodate the advent of regional power markets.^{12, 13}

Outlooks for future transmission development vary, with EEI data suggesting a modest upturn in expected transmission investment, and other sources forecasting a continued decline.¹⁴ Even assuming EEI's projections are realized, this level of transmission investment in the US is dwarfed in comparison to that of other international competitive electricity markets¹⁵ and is expected to lag behind demand growth.

The lack of transmission investment has led to a high (and increasing in some areas) level of congestion-related costs in many regions. For instance, total uplift¹⁶ for New England is in the \$169M/year range while locational installed capacity prices (LICAP) and reliability must run (RMR)¹⁷ charges are on the rise.¹⁸ In New York, congestion costs have increased substantially, from \$310M in 2001 to \$525M in 2002, \$688M in 2003 and \$629M in 2004.¹⁹ In PJM, congestion costs have continued to increase, even when adjusted to reflect PJM's expanding footprint into western and southern regions (see Figure 1).

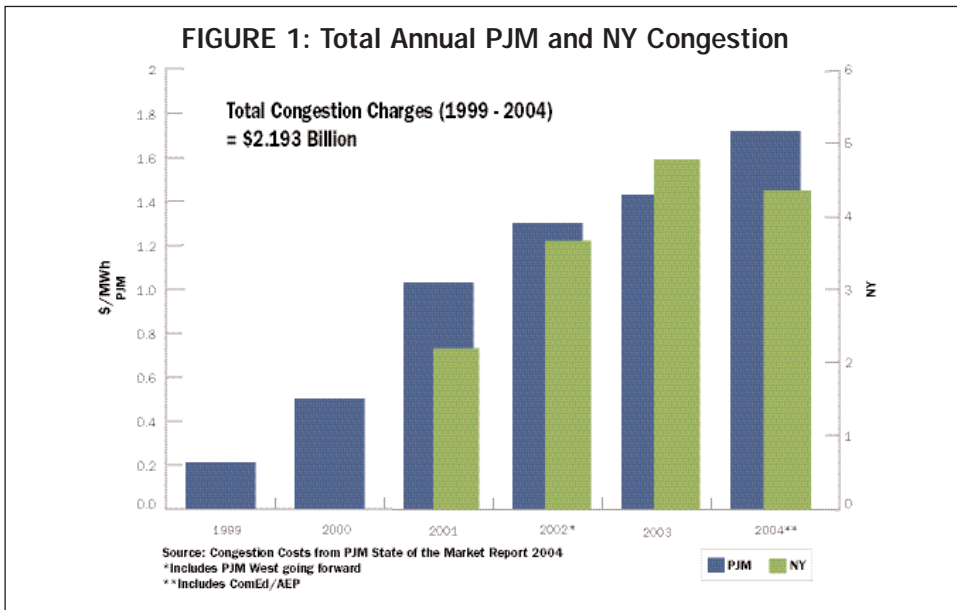
⁹ The American Wind Energy Association estimates that 350 MW of wind generation is already planned for New York State, which currently has 49 MW of generation of this type.

¹⁰ Center for the Study of Energy Markets, "Has Restructuring Improved Operating Efficiency at US Electricity Generating Plants?," July 2004.

¹¹ While it is unclear whether the increase in annual transmission investment over the last few years was driven by asset replacement or expansion of the network, EEI data show that virtually no new circuit miles have been constructed in the US for the last several years.

¹² Eric Hirst, "US Transmission System: Present Status and Future Prospects," August 2004, p.49.

¹³ In its "Post Technical Conference Comments" in RM04-7 on January 21, 2005, EEI, while asserting that there has been a recent increase in the rate of national transmission investment, acknowledged that significant new capacity is needed to support regional markets, adding that such construction would allow more economic energy to flow and reduce costs to customers.



Because regions do not currently quantify the costs of constraints in the same way, it is difficult to make direct comparisons from congestion data between regions. However, the magnitude and upward trend of available congestion cost data indicates a significant and growing problem that is increasing costs to customers.

An Inadequate Transmission System Has Led to Protected Markets and the Need for Market Intervention

Suppliers in areas with transmission constraints have the ability to exercise market power and raise electricity prices to customers during periods when high demand for electricity exceeds local generation resources. The lack of adequate transmission capacity into these areas reduces the ability of all generation to reach load. Such conditions restrict customer choice and produce markets where customers are underserved and pay higher than necessary prices.

To avoid the consequences of such market power, regulators and ISOs/RTOs have imposed market power mitigation measures, such as bid price caps and after-the-fact reductions of a generator's market revenues. While these measures may be necessary to protect customers, they also move restructuring away from the promise of enhanced customer value through competition. For example, market power mitigation in the form of price caps has been instituted in some regions in response to the opportunity for market power abuse created by an inadequate transmission network, and after the experience with manipulation of the markets in California.

LICAP Markets

Though intended to recover revenues lost by generators due to mitigation measures such as offer caps, some locational capacity market designs, if not properly structured, will be expensive for customers without achieving improved reliability. Specifically, locational designs that balkanize regional markets into small sub-zones create additional opportunities for the exercise of market power, may not ensure additional capacity, do little to address the transmission constraints that threaten reliability, and produce high and unstable pricing within the balkanized zones. An improved approach would establish a single region-wide demand curve with a deliverability requirement that is also region-wide.

¹⁴ Based on planned transmission line additions, investment in the US transmission capacity is expected to continue declining at a rate of 11% a year. Eric Hirst, "US Transmission System: Present Status and Future Prospects," August 2004, p.9.

¹⁵ See international comparisons of transmission investment later in this paper.

¹⁶ Uplift includes things like costs for reliability compensation payments to generators.

¹⁷ RMR contracts are arrangements for supply that are made between an RTO/ISO and a generator whose facility resides in an area where continued dependence on market forces alone would result in inadequate resources to maintain local reliability. Pricing of such arrangements is administratively set and is not the product of market conditions.

¹⁸ Stephen G. Whitley, ISO-NE presentation to the NEPOOL Participants Committee, May 6, 2005.

¹⁹ The PJM and NYISO congestion values are the total congestion revenues (rents) collected.



The lack of transmission investment has led to a high (and increasing in some areas) level of congestion-related costs in many regions.

While price caps may be intended to simulate market outcomes under competitive conditions, they in fact undermine the operation of and confidence in competition, and limit the opportunity to achieve market benefits by muting price signals and thus attract inefficient levels of demand response and generation investment.

In turn, price caps often lead to the need for additional intervention in electricity markets. Price caps reduce the revenues that generators can earn in the market, in some cases to the point where these generators can no longer operate economically and seek to close. To remedy the negative impact on reliability that would result from the closure of these power plants, system operators enter into costly RMR contracts with generators whose output is needed in transmission constrained areas and who seek to retire as a result of their inability to recover their costs. These RMR contract costs are ultimately passed through to customers. A generator's desire to retire plant, and the lack of adequate transmission infrastructure to provide access to generation outside the local area, can leave system operators with limited choices in the short term. RMR contracts entered into at above-market prices can serve as a disincentive to infrastructure investment that might more economically solve the problem. Meanwhile, in some areas, merchant generators facing limited access to broader regional markets due to transmission constraints have responded by canceling projects and closing plants.

The inability of some generators to recover capital costs due to price caps in energy markets has led to a significant focus on creating additional revenue streams through capacity market designs as an alternative to regulated RMR contracts. Though meant to reproduce price signals found under true market conditions and provide generators with an additional source of revenue to make up for that denied them by price caps, capacity markets are difficult to design in a manner that yields consistent and reasonable outcomes for customers. Some market mechanisms, such as the "demand curves" featured in PJM, New England and New York, while intended to reflect the value of capacity under a variety of demand and supply conditions, are susceptible to large swings in cost outcomes with even small changes in their design. These small changes can mean millions or billions of dollars in extra payments by customers without any certainty of increases in capacity, and costs can more than outweigh any savings achieved through energy price caps.²⁰

²⁰ ISO-New England estimates that the new LICAP market in its region will, over the long run, add an average of more than \$8/month to the bill of a residential customer.

Identifying Obstacles to Realizing the Benefits of Restructuring

Policies that View Transmission as Market Commodity, Rather than Market Facilitator, Only Deepen the Problem

A number of attributes of today's market inhibit the ability of customers to fully benefit from restructuring. One overarching obstacle is a widespread lack of recognition of the transmission system as a necessary facilitator of markets, rather than a market commodity itself. Transmission is, in fact, the essential infrastructure needed to support robust competitive markets.

The Underlying Theory

There is a principled view among some economists that electricity markets with locational marginal pricing (LMP)²¹ in and of themselves, especially when coupled with financial transmission rights (FTRs),²² will result in market participants voluntarily funding needed new transmission investment and in automatic management of congestion costs. In this view, regulated transmission investment (as opposed to merchant²³ or market-based) potentially interferes with energy markets because a transmission investment is seen as competing with a generation or demand-side investment to relieve congestion in an area.²⁴ This view, however, is mistaken. It does not acknowledge that LMPs do not properly reveal to customers the non-price costs of the absence of transmission (such as energy uplift and reliability actions not captured in LMPs). It also fails to recognize that transmission enables the delivery of power from remote generation which enhances competition and fuel diversity, and provides customers in that area with the opportunity of lower costs and greater choice.

The proponents of market-based mechanisms to fund transmission might acknowledge that transmission does not compete with generation and demand-side resources and yet still argue that market-funding mechanisms, such as FTRs, are sufficient to ensure adequate transmission. This is an erroneous argument because the funding of new transmission through FTRs depends on the ability of the transmission investor/owner to capture the value of relieving the constraint. However, the size of an individual

The Public Goods Nature of Transmission

The need for transmission to be treated as regulated infrastructure can be understood by considering the "common" or "public good" nature of AC transmission capacity, and that its benefits are often highly diffuse and may shift among customers over time in a dynamic market. By definition, a "common" or "public good" possesses two properties: It is non-excludable, meaning that once it is produced it is impossible (or at least very difficult) to prevent people from gaining access to the good; and it is non-rivalrous, meaning that its use by one person does not prevent it from being available to someone else, at least to a significant degree.^{25, 26} These attributes create difficulties in establishing property rights over the transmission network, undermining the ability of investors to capture the full value of their assets to the market and thus contributing to sub-optimal infrastructure where such decisions are left solely to the market.²⁷

²¹ *Locational Marginal Pricing is the cost of bringing the last unit to market (the one that balances supply and demand) in a defined area and is expressed in a central market operated by an RTO or ISO.*

²² *FTRs entitle the holder of such rights to receive revenues based on the differences in each hour between a designated set of points of injection (where output of a power plant enters the bulk power system) and withdrawal (where such output leaves the bulk power system and is consumed by load).*

²³ *The genesis of the term "merchant transmission" sprang from the proposition that such facilities would be developed and owned by investors who would construct uncontracted capacity, then bring the commodity to open market for sale as needed. It is now widely held that the predominant portion of the capacity of a proposed facility must be pre-contracted before the investment community will commit capital.*

²⁴ *In his State of the Market Report to FERC on April 13, 2005, Joe Bowring, market monitor for PJM, after remarking that PJM's Economic Planning Process "works," observed that "right now, we certainly don't have a market mechanism to incent transmission construction or even do maintenance as cost-effectively as it could be."*

²⁵ *Coase, Ronald H., (1974), "The Lighthouse in Economics," 23 Journal of Law and Economics.*

²⁶ *Attempts to price transmission use, such as transaction-based charges on power market participants for the use of the AC transmission network (e.g., on a MW-mile basis) are generally viewed by FERC and many industry observers as inefficient, unwieldy and incompatible with efforts to regionalize markets. In fact, transaction-based charges have been eliminated in all markets and are being eliminated at the seams between most markets, to allow new entries into competitive markets.*

²⁷ *It should be observed that DC interties normally do not possess non-excludable and non-rivalrous properties, making the creation and sale of property rights in the use of these facilities far less difficult than with AC facilities.*



The misplaced view of transmission as a market product has been embedded in existing regional planning and transmission pricing policies. These policies fail to acknowledge the intrinsic nature and purpose of the transmission system as a delivery infrastructure.

transmission investment project is often such that it immediately resolves the constraint, reducing the local costs of electricity to a level that will not enable the investor to recoup his costs. Other characteristics of transmission also make it extremely difficult, if not practically impossible, for transmission owners (TOs)/investors to capture the value of their investment.²⁸ Together these characteristics argue for recognizing the critical role of regulated transmission in providing the necessary infrastructure, not only to meet reliability needs but also to facilitate competitive markets. A comprehensive regional planning process, as described further below, is required to identify the need for transmission investment and ensure that the infrastructure is adequate for reliability and economic purposes.²⁹

The market-based model of transmission investment and some of the methods for allocating or assigning the costs of regulated transmission investment rely on the assumption that the beneficiaries of a particular investment can be defined over a certain period of time. However, the “common” or “public good” nature of transmission often makes it difficult to separate the benefits to the whole into individual benefits and to identify who is benefiting from moment to moment from the operation of a particular subset of transmission assets, and by how much. Moreover, customers’ perception of their benefit relative to others compounds this problem. Customers who perceive their benefit from an investment in the AC transmission system to be small will want the cost of new transmission to be paid by those whom they view as having the greater benefits. This misalignment in the way transmission customers perceive the distribution of benefits leads to cost allocation disputes, which delay and even prevent cost-effective transmission projects from moving forward. The problem of identifying beneficiaries of transmission investment is exacerbated by what economists call the “free rider” problem. Once a facility is built to benefit one entity, others can take advantage of it. This greatly diminishes the ability of transmission pricing policies based on voluntary participant-funding to deliver an adequate transmission system.³⁰ There is no impetus to volunteer to fund as long as there is the potential that someone else may.

²⁸ See sidebar on *The Public Goods Nature of Transmission*, p.9.

²⁹ Such regional planning would generally be performed by an RTO/ISO using well-defined criteria for determining whether a given proposed transmission expansion enhances the efficiency of the bulk power system or is needed to meet reliability criteria.

³⁰ Those who promote voluntary participant funding believe that market signals, such as LMP differences and FTR revenues, will elicit sufficient transmission investment from market participants or regulated transmission owners stepping forward on their own.

The Consequences in Practice

The public good nature of transmission has frustrated progress towards the development of adequate transmission infrastructure in regions that have relied greatly upon market mechanisms (and, by implication, the successful creation and sale of transmission property rights) to bring about adequate transmission investment.

The misplaced view of transmission as a market product has been embedded in existing regional planning and transmission pricing policies. These policies fail to acknowledge the intrinsic nature and purpose of the transmission system as a delivery infrastructure. In many regions, regional planning processes either do not exist or focus only on minimum reliability requirements, ignoring the competitive benefits that a robust transmission infrastructure can deliver to customers. In these regions, transmission pricing policies focus on cost recovery and allocation only for the transmission costs associated with minimum reliability upgrades, if they deal with them at all. In some regions, transmission policies do not adequately provide for fair and workable cost allocation for even regional reliability needs.

Transmission investments that serve to reduce congestion and facilitate markets, and thereby lower costs to customers, are simply not accommodated in many of today's regional planning and transmission pricing policies. This can be seen particularly in regions that rely on voluntary participant funding, an approach that depends upon beneficiaries agreeing among themselves to fund transmission upgrades. The inability of beneficiaries to agree in advance on a cost allocation and recovery process is cited as a principal obstacle to infrastructure improvements. More broadly, transmission investment is discouraged when cost recovery and allocation policies fail to recognize the system-wide benefits of that investment and instead rely on some subset of customers funding new transmission.

State Rates versus Regional Needs

The problem of aligning transmission infrastructure benefits and funding reveals itself again at the state level. Regulation that does not allow for certain and prompt recovery of costs for transmission investment to meet regional reliability and economic needs is a further obstacle to that investment. When an RTO/ISO identifies a regulated transmission solution as the appropriate response to a system need, the utility that must make the investment is faced with how it will recover its costs. There may be a regional cost recovery mechanism included in a FERC approved RTO/ISO tariff that rolls upgrade costs into a regional rate. In practice, however,

Market Response and the Role of Merchant Transmission

It is important to observe that reliance upon "market response" requires one to subscribe to the proposition that merchant transmission companies will provide the majority of new transmission assets that are needed to achieve a network adequate enough to support competition. However, the evidence demonstrates that while merchant transmission may have a niche role in supplying a portion of the necessary transmission infrastructure (e.g., DC interconnector projects between countries or regions), there is no indication to date that it can provide anywhere near the required level of capital investment, particularly in AC systems, and should not be viewed as the primary means for system expansion. The potential for vigorous growth in the merchant transmission sector has been discussed for a decade in the US and to date only a few of entities (the vast majority being DC projects) have emerged as viable contenders. Three of the largest proposed projects are either inactive or have been abandoned entirely. In the case of the Conjunction and Chesapeake Bay projects, merchant transmission developers were unable to attract adequate bids in their capacity auctions, despite the fact that their proposals were aimed at increasing supplier access to two of the most difficult load pockets in the nation, New York City and the Delmarva Peninsula.³¹

³¹ Neptune has made some progress in its efforts to extend a merchant line from PJM to Long Island, winning an RFP conducted by LIPA. Both the Neptune and TransEnergie projects to Long Island are inter-market DC links. The merchant transmission business model can prosper within this niche as flows over DC lines are controllable, thus facilitating the creation of property rights associated with the use of their capacity. Due to market barriers, differences in prices between regions are often substantial, making such merchant lines valuable.



costs often must be recovered through retail rates subject to state jurisdiction. These retail rates may be fixed for a period of time (sometimes an extended period), limiting the transmission owner's ability to recover the costs of an incremental investment. In addition, utilities have traditionally built transmission mainly for the benefit of their own customers, and regulators have allowed cost recovery based on the benefits to these customers. In many instances, retail rates generally do not reflect the incremental costs from transmission investment to support regional needs. Under these conditions, a utility would naturally resist any requirement to invest for regional needs unless state regulatory rate mechanisms allow recovery of these investments. Greater amounts of investment for regional benefit have occurred in states with flexible retail rate recovery mechanisms than in states without such flexible mechanisms.³² This flexibility aligns company and customer interests by facilitating investments to support efficient regional markets and, in the long run, leads to lower and more stable electricity prices.

Non-Profit Transmission Entities

In the face of intense opposition from some quarters, federal policymakers continue to encourage transmission owners across the nation to join RTOs. Indeed RTO/ISO formation was intended to occupy a central role in carrying forward the FERC's vision of restructuring and an extraordinary amount of effort has been expended in making this model work. While RTOs/ISOs take a step toward an independent, coordinated transmission system, it is still unclear whether they are the best long-term solution to facilitate efficient regional power markets, while ensuring reliability and delivering value to customers. RTOs/ISOs have been structured as non-profit organizations, without shareholders to absorb financial risk. Therefore, designing meaningful incentives for improved network efficiency and reliability is difficult, and raises questions as to whether rising costs for RTOs/ISOs may erode their benefits.³³ RTOs/ISOs provide incremental functionality through coordinated operations, planning and market administration (among other things), but they do not offer the synergies that are associated with combined transmission ownership and operation, such as operational consolidation and enhanced asset management. Consequently, while RTO/ISO formation may bring benefits to customers as an independent market operator and represent a preferable structure to the vertically integrated utility model, it is not the optimal or final model for transmission consolidation.

Public Authorities

Some states have created, or are considering creating, new quasi-governmental entities whose purpose is to finance, and in some cases own, new transmission facilities. These entities may play a role in facilitating

³² At the Commission's request, PJM TOs recently filed with FERC a formula rate option to recover the costs of transmission projects identified in the region's planning process. This occurred after years of fixed rate recovery in PJM, an arrangement some have blamed for stagnant transmission investment and the resultant increase in congestion costs to customers.

³³ In Order 2000, FERC estimates that RTOs would save customers up to \$5 billion annually. Though some of the costs of RTO/ISOs are due to increased scale of operation, it is generally acknowledged that RTO/ISO costs have not been offset by decreasing TO costs, and it is unlikely that RTO costs will be offset by decreasing TO costs under the current model of separation of transmission ownership and operation, and fragmented ownership of the grid.

needed transmission, though there is a concern that their transmission ownership could create further uncertainty over the appropriate role of the public sector and give rise to further fragmentation. A better approach would be to adopt the policies recommended in this paper, which should render public authority intervention unnecessary. In the meantime, however, such entities may be helpful in identifying transmission needs and facilitating solutions, provided that their focus remains facilitating (rather than competing with) private sector investment.

Transmission Adequacy – The Path to Successful Markets

Transmission as a Market Enabler

The proposition that transmission is delivery infrastructure, rather than a market product, may be understood more easily through an examination of the similarities between the construction of network upgrades and the reduction of trade barriers among nations. Load pockets are, in a sense, protected markets due to their isolation from suppliers in other areas. Adding a supplier to a protected market in a given country merely compels that supplier to compete against the least competitive among the existing suppliers who may have become inefficient under such protection. On the other hand, reducing trade barriers between nations grants customers access to multiple suppliers in unprotected markets who must compete not only with suppliers in the protected market but also each other (and anyone who later joins them) to earn customers' business.³⁴

It is easy to see from this parallel that transmission is not a market product and no more competes with generation than do the great seaports of the East Coast compete with the domestic factories that are the alternative to suppliers of international goods. Transmission enables trade routes but does not compete with the commodities that flow through them. In that sense, transmission capacity is a measure of the ability of market participants to trade freely, a policy most economists agree brings greater efficiency and increased wealth (through cost savings) to all consumers.³⁵


Customers face a choice of paying for the costs of increased transmission infrastructure or higher supply costs due to the absence of adequate transmission. In most cases, the costs of transmission are small compared to the benefits of reduced supply costs that it delivers.³⁶ Adding transmission capacity increases customer welfare by creating incentives for new supply in low-cost remote areas while producing downward pressure on the prices of protected suppliers. Transmission can also enhance non-monetary benefits to customers, particularly environmental benefits. The role of transmission in facilitating the participation of alternative (renewable) resources in power markets and the effect this has on reducing negative

³⁴ The proposition that transmission development will drive the creation of new supply and economic development in remote areas is assumed as part of the analysis of proposed economic upgrades in the MISO Transmission Expansion Plan.

³⁵ Indeed, the two major US trade agreements of the 1990s reduced trade barriers by \$36 billion/yr and, afterwards, the national annual income of the United States increased by \$52 billion-108 billion/yr, or \$1,260-\$2,040/yr for the average family of four. See <http://www.ustr.gov/new/summarydata.html> for a US Government study on trade benefits.

³⁶ A recent study of the benefits and costs of new transmission by ICF Consulting estimated that \$12 billion of improvements to the nation's antiquated transmission system would yield net savings of \$176 billion to customers between 2004 and 2030 due to reductions in congestion, operating reserve costs and economic harm as the result of outages. These numbers convert to \$60 billion in customer savings on \$8 billion of investment on an NPV basis. See http://www.icfconsulting.com/Markets/Energy/doc_files/US-transmission-grid.pdf.





environmental and economic impacts (e.g., health care costs related to poor air quality) can also be considered in assessing how transmission upgrades can improve customer (or societal) welfare.

Regional Planning Process and Transmission Pricing

Regional planning processes that focus only on reliability needs are not sufficient to ensure the infrastructure investment needed to support competitive markets. To address grid inefficiencies in the form of persistent uneconomic congestion, an independent regional entity (such as an RTO/ISO) should lead a regional planning process that identifies the economic, as well as reliability, needs of the system. This process should provide a mechanism for addressing system needs through regulated transmission upgrades to the extent that the market does not respond to meet customer needs. Stakeholders should be given sufficient opportunity for input, but the process also should contain a well-defined timeline and milestones. This is necessary so that regulated transmission proposals identified as needed and deemed to be cost-effective, may be fairly scrutinized and constructed in a timely manner. This approach allows the market to work effectively for customers but recognizes that the failure of markets to respond should not result in higher customer costs for an extended period of time when a cost-effective regulated transmission solution exists.^{37, 38} For example, the recently developed regional planning processes in PJM, New England, and ERCOT have well-defined timelines with explicit milestones and therefore provide for more efficient markets.

Certain and Prompt Recovery of Transmission Costs

Once projects are identified as needed in comprehensive regional planning processes, they should not be delayed due to uncertainty with respect to cost recovery. Doing so only continues the economic or reliability harm to customers.³⁹ Therefore, the adoption of a clear, well-defined cost allocation methodology, such as that used in New England,⁴⁰ is highly desirable as it recognizes transmission's role in supporting regional markets and that the beneficiaries of any particular upgrade may change over the life of the facility.⁴¹

To address grid inefficiencies in the form of persistent uneconomic congestion, an independent regional entity should lead a regional planning process that identifies the economic, as well as reliability, needs of the system.

³⁷ An APPA advocacy piece released last year argues that transmission should not be left to the "vagaries" of the market and, given that LMPs/FTRs do not ensure adequate transmission development, "RTOs must develop rigorous regional transmission planning and construction process that ensures the region has a robust (but not gold-plated) transmission system." The APPA paper also promotes the notion, however, that municipals and other public power entities must be permitted equity participation in transmission projects through which such companies would receive firm transmission rights. Such a proposal, if implemented, would further fragment grid ownership. Rather, an effective regional planning process should provide adequate price stability and hedging opportunities for transmission customers. "Restructuring at the Crossroads," APPA, December, 2004.

³⁸ In a July 2003 order responding to a PJM filing regarding the region's economic planning process, FERC observed that to prohibit PJM's intervention in the market in the event of market failure through the construction of regulated economic transmission upgrades "would contravene the Commission's obligation to ensure just and reasonable rates and prevent undue discrimination. The intent of the Commission's market-driven regulatory philosophy is to use the market to provide customers with just and reasonable rates; not to allow market failure to deprive customers of such rates and subject them to undue discrimination."

³⁹ Though we believe that most market solutions will not eliminate the need for additional transmission investment, we recognize that some regulators may wish to afford the market some additional period to respond, as PJM has in its Regional Transmission Expansion Planning Process (RTEP) through the provision of a market window.

⁴⁰ The New England planning process has resulted in the identification of \$2-3 billion of needed new transmission infrastructure.

Broadening Regional Markets through Wide-Area ITC Development

Broad regional markets require policies that facilitate and encourage active grid planning, management and the construction of transmission upgrades both for reliability and economic needs. A strong transmission infrastructure or network platform would allow greater fuel diversity, more stable and competitive energy prices, and the relaxation (and perhaps ultimate removal) of administrative mechanisms to mitigate market power.

A key institutional step toward an industry structure that appropriately views transmission as a facilitator of robust competitive electricity markets would be the creation of Independent Transmission Companies (ITCs) — i.e., companies that focus on investment in and operation of transmission, independent of generation interests.⁴² ITCs recognize transmission as an enabler of competitive electricity markets. Policies that provide a more prominent role for such companies would align the interests of transmission owners/operators with those of customers, permitting the development of well-designed and enduring power markets that perform the function of any market, namely, to drive the efficient allocation of resources for the benefit of customers. In its recently released policy statement, FERC reiterated its commitment to ITC formation to support improving the performance and efficiency of the grid.⁴³

ITCs offer additional benefits to customers over traditional vertically-integrated companies that build and operate both transmission and generation.⁴⁴ ITCs are not burdened with the divided interests of vertically-integrated firms that must choose between internal competing capital requirements for generation and delivery activities, and whose objective is often to “optimize the whole” by maximizing the aggregate of delivery and supply revenues. Having no interest in financial outcomes within a power market, the ITC’s goal is to deliver maximum value to customers through transmission operation and investment. With appropriate incentives, ITCs will pursue opportunities to leverage relatively small expenditures on transmission construction and management to create a healthy market and provide larger savings in the supply portion of customer’s bills. They also offer benefits over non-profit RTO/ISO models where the incentives for efficient operation and investment may be less focused.

⁴¹ In a paper released in January 2005, the Consumer Energy Council of America (CECA) acknowledges the tremendous costs to customers of an increasingly inadequate transmission network and provides a call to action for policymakers to ensure that the nation’s infrastructure is developed in a way that supports reliability and maturing markets. The recommendations include the establishment of regional processes to identify transmission to address economic and reliability needs, clearly defined cost allocation rules that are promulgated by FERC and state regulators and provide incentives for efficient operation, maintenance, and expansion of the grid. “Keeping the Power Flowing: Ensuring a Strong Transmission System to Support Consumer Needs for Cost-Effectiveness, Security and Reliability,” CECA, January 2005. See also www.cecarf.org.

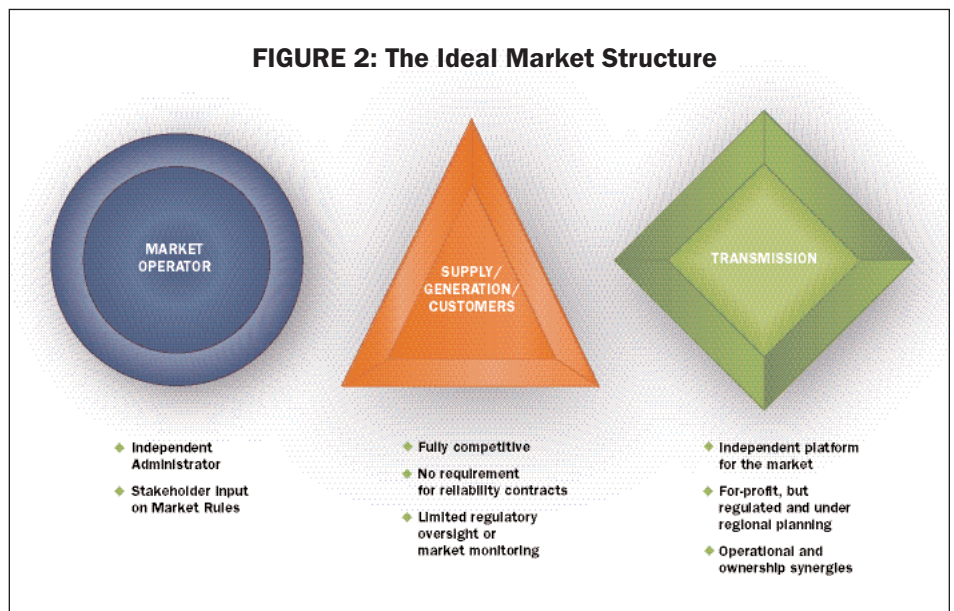
⁴² Four ITCs currently operate in the MISO region: GridAmerica, International Transmission Company (ITC), Michigan Electric Transmission Company (METC), and American Transmission Company, (ATC).

⁴³ FERC News Release, June 27, 2005 “Commission Outlines Policy to Support the Formation of Independent Transmission Companies,” Docket No. PL05-11-000.

⁴⁴ The Center for the Advancement of Energy Markets (CAEM), responding to a CATO Institute analysis, argued that vertical integration thwarts innovation and results in hundreds of millions of dollars of excess costs to customers in the form of fuel adjustments and other charges by monopolies to pay for inefficient, dirty generators. CAEM counters that the open access model has worked in other industries and is working in the electric utility industry as well. “Throwing the Baby Out with the Bathwater,” A Rebuttal to CATO’s Report “Rethinking Electricity Restructuring,” by Laura Murrell and Ken Malloy, December 16, 2004.



An ideal industry structure would permit ITCs to own, operate, and manage transmission assets over a wide area. This would allow ITCs to access economies of scale in investment, planning and operations to increase throughput and enhance reliability in the most cost-effective manner. This structure would also avoid ownership fragmentation within a single market, which is a key obstacle to the introduction of performance-based rates that benefit customers by aligning the interests of transmission companies and customers in reducing congestion. This approach to “horizontal integration” of the transmission sector under a single regulated for-profit entity is key to establishing an industry structure that recognizes transmission as a market enabler and provider of infrastructure to support effective competitive markets. Market administration would be contracted out to another (potentially non-profit) entity while generators, other suppliers, demand response providers, and Load Serving Entities (LSEs) would all compete and innovate in fully-functioning markets, delivering still increased efficiency and more choices for customers⁴⁵ (see Figure 2).



ITCs recognize transmission as an enabler of competitive electricity markets.

⁴⁵ The current delegation of transmission functions between RTOs/ISOs and ITCs was set forth in FERC's landmark 2002 Translink order. This functional split was viewed widely at the time as a starting point and as ITCs have since proven their value it would be appropriate to now revisit the delegation so as to permit for-profit independent transmission entities the ability to further leverage their expertise to deliver additional benefits to customers. Under Translink, RTOs are solely responsible for implementing congestion management, performing ATC calculations, and coordinating interregional planning and operational issues.

The consolidation of transmission ownership within ITCs will also have the salutary effect of lessening the debate over who pays – a debate often driven by the complex patchwork of TOs that cover the industry landscape. An ITC with the proper incentives will work to develop default cost allocation mechanisms for new transmission construction that recognize the broad benefits of transmission and encourage cost-effective construction, thereby avoiding a case-by-case approach that invites prolonged litigation and delays needed investment in transmission.

The integration requirement of the Public Utilities Holding Company Act (PUHCA) is a barrier to transmission ownership consolidation because it prevents registered holding companies (i.e., companies with substantial utility assets, expertise, and financial resources) from investing in electric transmission facilities that are not integrated with the holding company's other utility assets. Repeal of PUHCA will pave the way for reduced fragmentation of the grid, which would permit more economical regional investments and work to transform the patchwork of comparatively short transmission routes between generators and customers that now characterize much of the nation's transmission system.

Finally, experience to date in other countries strongly suggests that performance-based rate (PBR) mechanisms, which are important to the development of a more efficient modern grid, can be applied most effectively in wide-area ITCs that are focused on transmission, utilize substantial economies of scale in operations and management, and whose geographic coverage minimizes disputes with neighboring TOs over what actions produced which benefits. Indeed in England and Wales, Norway, and Finland, where wide-area ITCs have existed for a number of years, incentives have been created to reduce congestion costs. The results are clear: customers in England and Wales have saved at least \$700M over the period since PBR was introduced there in 1994, while retail prices in Finland have fallen by 23% in the six years after restructuring began there.⁴⁶ One estimate puts nationwide total annual US congestion costs at \$5-6 billion and the costs of ancillary service at \$8-9 billion.⁴⁷ In the event such costs were reduced through the kind of performance-based regulatory framework used successfully elsewhere in the world, it might save customers \$5 billion or more.⁴⁸

⁴⁶ See <http://www.eia.doe.gov/emeu/international/elecprh.html>.

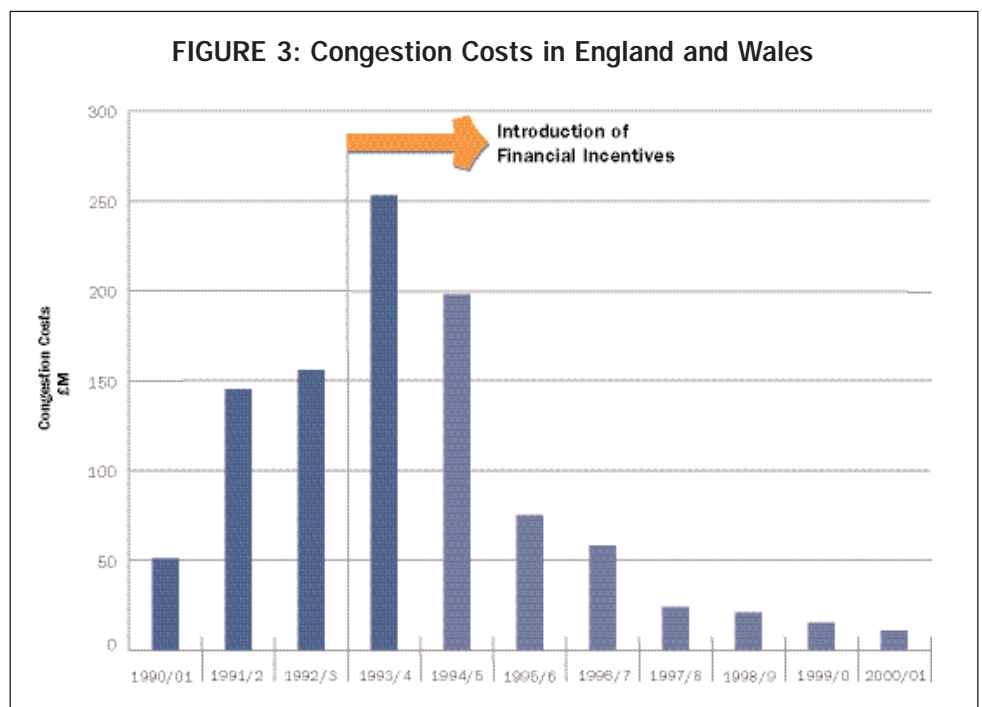
⁴⁷ Leonard S. Hyman, "Incentives and Disincentives," January 17, 2004.

⁴⁸ Leonard S. Hyman, "Incentives and Disincentives," January 17, 2004.



Success with Wide-Area ITCs

The experience in England and Wales affirms the view that independent transmission owners spend more on transmission than their vertically integrated counterparts and that this spending benefits customers. National Grid has in fact invested up to three and a half times more in high-voltage transmission (230 kV and above) in the UK than EEI's mostly vertically-integrated members in the US, adjusting for market size. This level of investment under the "Transco"⁴⁹ model in the UK has delivered reliable low-cost power to customers from the electricity market and contributed to savings of well over \$700 million in congestion costs from 1994 to 2001 when the New Energy Trading Arrangements (NETA) were implemented⁵⁰ (see Figure 3). The benefits of performance-based incentives are well documented in the case of England and Wales, where customer prices have fallen 40% since the early 1990s.



⁴⁹ The term "Transco" refers to an arrangement where the transmission system is owned, operated and developed by an entity with no market interests.

⁵⁰ Following 2001 and the adoption of NETA in the UK, the methodology for measuring congestion was altered, but annual congestion costs have stayed below \$50 million (£30 million).

The table below lists the normalized rate of investment for wide-area ITCs in other countries. To put into perspective the transmission ownership fragmentation present in the US versus other nations, each country in the table has a wide-area Transco responsible for the ownership, operation, and management of its transmission assets compared to some 450 transmission owners in the US.

Country	Investment in high voltage transmission (>230kV) Normalized by load for 2004-2008 (in \$M/GW/yr)	Number of transmission owning entities
New Zealand	22.0	1
England & Wales (NGT)	16.5	1
Denmark	12.5	2
Spain	12.3	1
Netherlands	12.0	1
Norway	9.2	1
Poland	8.6	1
Finland	7.2	1
United States	4.6 (based on representative data from EEI)	450 (69 in EEI)

Policy Recommendations

To provide the full benefits of industry restructuring to customers, transmission must be viewed as the necessary infrastructure that enables competitive markets to flourish. Moreover, the institutional obstacles to a robust and reliable transmission network capable of fully supporting competitive markets that are posed by the fragmented nature of transmission ownership and operation in the US must be addressed. We urge federal and state policymakers and legislators to embrace the following policy recommendations so that transmission can deliver the full promise of industry restructuring to customers.





Regional Planning

Policymakers should encourage the regions to develop meaningful planning processes that provide a mechanism for RTOs/ISOs to pursue regulated transmission solutions for reliability and economic needs whenever the market fails to respond or is identified as unlikely to respond. To be effective, comprehensive regional planning should include well-defined criteria and timelines for the identification and remedy of uneconomic congestion.

Cost Allocation and Cost Recovery

Regulators should support cost recovery and allocation mechanisms that recognize transmission's role in supporting regional markets and acknowledge that the benefits of transmission investment flow broadly. Allocation approaches that attempt to assign transmission costs locally may result in an under-investment in transmission facilities needed to permit regional transactions, thus balkanizing the market and leaving unfulfilled the promise of greater efficiencies that competition over a broad area can provide. Rate designs that "over localize" costs often also increase resistance to proposed transmission upgrades since such proposals are often viewed as unfairly burdensome to local customers in light of the broad and evolving nature of the benefits from many projects. Policymakers should instead encourage regional rate recovery for transmission investment that has regional benefits.

Certainty of Rate Recovery and State Cooperation

Transmission owners must be assured of certainty and adequacy in rate recovery under a regional planning process. Independently administered planning processes will assure that transmission enhancements required for reliability and market efficiency are not unduly burdening retail customers with additional costs. FERC and the states must work together to provide for certainty in rate recovery from ultimate customers through federal and state jurisdictional rates.

In addition, states should adopt siting processes that acknowledge transmission's regional role in bringing low-cost, environmentally beneficial generation to the nation's consumers. If states fail to approve in a timely manner proposed transmission facilities in a congested corridor deemed to be in the national interest⁵¹, federal backstop authority over such siting may prove critical to the development of adequate infrastructure in these areas. The U.S. House of Representatives has passed H.R. 6, the Energy Policy Act of 2005, which provides federal backstop siting authority, and the Senate has passed a similar provision in its version of a comprehensive energy bill.

⁵¹ On July 22, 2004, the Department of Energy issued a Federal Register Notice of Inquiry inviting comment on the identification, designation, and possible mitigation of "National Interest Electric Transmission Bottlenecks (NIETB). In doing so, the DOE was acting on the recommendation of its National Transmission Grid Study" (May 2002) and the "Transmission Grid Solutions Report" issued by the DOE Secretary's Electricity Advisory Board (September 2002). Together, the reports expressed concerns over the efficiency, reliability and national security impacts of the nation's most congested transmission bottlenecks.

Adequate Incentives for Cost-Effective New Transmission Investment

At a time when significant increases in transmission investment are needed, regulators should set the rate of return on transmission assets at the high end of the range of reasonableness in order to produce an adequate platform for competitive power markets. ROE adders would also encourage further construction of beneficial transmission. It is worth observing that not all incentives need to be tied to RTO/ISO participation, provided there are other factors that prevent these incentives from leading to over investment or inefficient investment (e.g., a comprehensive regional planning process with independent oversight).

Adequate Incentives for Transmission Independence and Consolidation

Such incentives must acknowledge the benefits to customers of varying degrees of transmission independence and reward them accordingly. These incentives may take the form of enhanced rates of return or other financial incentives for assets managed, operated and/or owned by an ITC. To promote the sale and consolidation of transmission assets to ITCs, tax relief should be enacted, and there should be rate allowances for the recovery of accumulated deferred income taxes (ADIT) and acquisition premiums.⁵² FERC's recently issued policy statement regarding independent ownership and operation of transmission describes several approaches to incentives including, among other things, enhanced return on equity, use of imputed capital structures, recovery of deferred income tax liabilities, and accelerated book depreciation.⁵³ We applaud FERC for reiterating its commitment to ITC formation, and urge the Commission to continue to encourage the development of specific ITC proposals for their regulatory review. Policymakers should also work diligently to repeal the integration requirement of PUHCA for transmission-only purchases, which would make the incentives described here more effective.

To Be Effective, Performance-based Rates Require Wide-Area ITCs

PBR designs will not work over the nation's current patchwork of transmission ownership and management. Transmission ownership consolidation is needed to facilitate the development of meaningful and effective incentives to increase the performance of regional transmission systems.

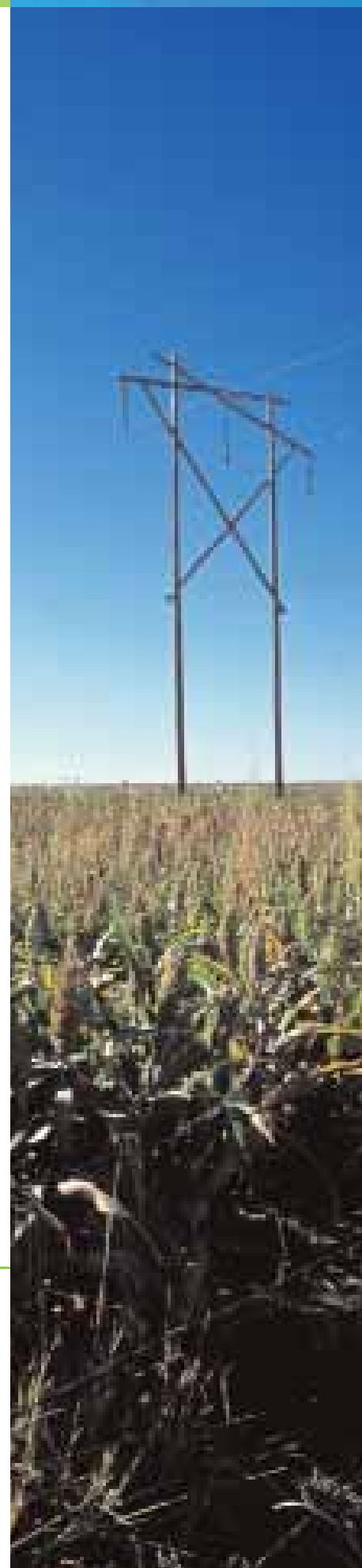
The Current Functional Delegation Between RTOs and ITCs Should Be Revisited

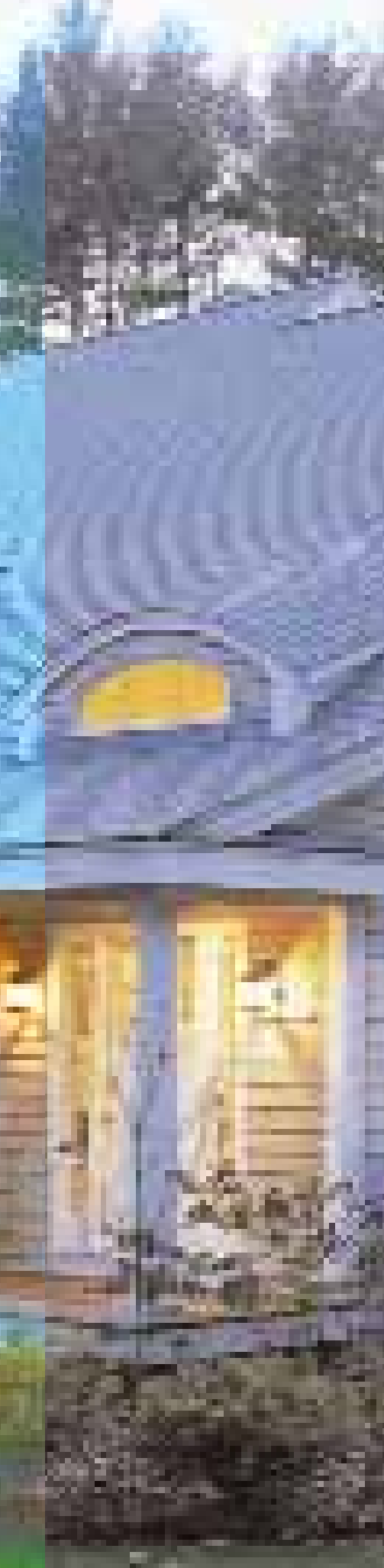
Many industry observers viewed the delegation of functions proposed by Translink⁵⁴ some years ago as a starting point for ITC functional delegation that ultimately would expand once the independent transmission business model had proven its value. The current allocation of functions limits the

⁵² Congress enacted a policy to allow entities who sell their transmission lines to ITCs to defer the tax on capital gains for eight years, provided the sellers re-invest the gains in another type of energy infrastructure. This policy is strongly supported by ITCs and it should be extended beyond its December, 2006 expiration deadline.

⁵³ FERC Policy Statement "Policy Statement Regarding Evaluation of Independent Ownership and Operation of Transmission," June 27, 2005, Docket No. PL05-11-000.

⁵⁴ Translink was an ITC that once controlled the transmission assets of three transmission owners in the MISO region. The company has since dissolved.





ability of for-profit independent entities to be innovative and otherwise take action that would bring value to customers. For instance, ITCs should be able to expand into functions associated with real-time operation as well as transmission planning and asset management. In addition, they should have access to day-ahead and real-time bid data to facilitate taking actions to minimize overall costs through innovative transmission optimization. The six-month delay in the availability of market data that exists in some RTOs/ISOs limits an ITC's ability to reduce congestion through timely and cost-effective network enhancements.

Conclusion

While electric industry restructuring has provided significant benefits to customers, there is still work to be done before it will deliver fully on its promise to those customers. At the heart of the solution is the need for a transmission system adequate to support the growing demands of developing power markets and the needs of consumers. Such a transmission system can only be realized if policymakers recognize transmission as the infrastructure that enables the effective operation of markets, and address the institutional factors that have led to the current fragmentation of transmission ownership and operation.

Policymakers and regulators should adopt the perspective that networks must be independently owned, operated, managed, and planned on a wide scale, and that the costs of establishing a system robust enough to realize the promise of competitive regional electricity markets must be allocated in a manner that reflects its far-reaching impact on customers. An underdeveloped transmission system, subject to policies that limit its potential and leave its development to the free market, has produced power markets requiring too much regulatory intervention. Regulators and policymakers must act quickly to adopt and implement transmission policies based on an understanding of the critical role that transmission plays in delivering the full scope of benefits of restructuring to customers.

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