Cambridge Working Papers in Economics CWPE 0454

UNIVERSITY OF
CAMBRIDGE
Department of
Applied Economics

Transmission Policy in the United States

Paul Joskow

The
Cambridge-MIT
Institute

Massachusetts Institute of Technology
Center for Energy and
Environmental Policy Research

CMI Working Paper 54

Cambridge Working Papers in Economics

UNIVERSITY OF
CAMBRIDGE
Department of
Applied Economics

Not to be quoted without permission

Massachusetts Institute of Technology
Center for Energy and
Environmental Policy Research

CMI Working Paper

October 7, 2004

TRANSMISSION POLICY IN THE UNITED STATES

Paul L. Joskow[1]

ABSTRACT

This paper provides an overview of the development of electric power transmission access, pricing and investment policies in the U.S. over the last 15 years and evaluates the current state of those policies. Pre-liberalization transmission access and pricing policies are reviewed since more recent policies have evolved from them. FERC's efforts to ensure that transmission owning utilities provide non-discriminatory access and pricing to wholesale transmission customers, culminating in Order 888 and 889 are discussed. These rules did not respond to problems created by a highly balkanized transmission system and only partially responded to problems caused by common ownership and operation of transmission networks with generating and marketing businesses in the same regions. These problems motivated FERC to seek to create Regional Transmission Organizations (RTO) meeting a long list of criteria related to governance, network consolidation, network operations, transmission pricing and investment as reflected in Order 2000. The slow pace of "voluntary" reform following Order 2000 led FERC to issue a proposed Standard Market Design Rule (SMD) which provided more detailed prescriptions for wholesale market design, network operations, regional planning, resource adequacy, and transmission investment. The SMD rule confronted enormous resistance from groups of utilities and states that have not embraced an electricity sector liberalization agenda. However, many of the provisions of the SMD are being implemented by the RTOs and ISOs in the Northeast and Midwest. PJM's market rules and transmission pricing, planning and investment policies are reviewed as an articulation of FERC's RTO and SMD visions.

JEL: L94, L51, K2

[1] Elizabeth and James Killian Professor of Economics and Management, Massachusetts Institute of Technology (MIT) and Director of the MIT Center for Energy and Environmental Policy Research (CEEPR). I am grateful for research support from the Cambridge-MIT Institute and the CEEPR and to comments from Gert Brunekreeft and an anonymous referee.

October 7, 2004

TRANSMISSION POLICY IN THE UNITED STATES

Paul L. Joskow[1]

INTRODUCTION

This paper provides an overview of the development of electric power transmission access, pricing and investment policies in the U.S. over the last 15 years and evaluates the current state of those policies. The intended audience for the paper is primarily non-U.S. scholars and policy-makers interested in understanding U.S. electric power transmission policies and what can be learned from them. However, the paper may also be of interest to U.S. scholars and policymakers who are unfamiliar with the historical evolution of U.S. transmission policies.

It is difficult to write a paper about U.S. transmission policy. This is the case for several reasons. First, transmission policy in the U.S. has been in a constant state of change for the last decade. It has been evolving from policies developed following the passage of the Federal Power Act in 1935 to support very modest volumes of unbundled wholesale power transactions in an industry dominated by vertically integrated investor-owned utilities to more recent policies designed to support the expansion of competitive wholesale and retail markets for power. To understand what these policies are today and why they take the forms that they do, it is necessary to understand their historical evolution from policies developed during the pre-liberalization era. Second, the legal responsibilities for important aspects of transmission policy are split between the federal government and the states and reflect the legacy of vertically integrated utilities regulated

[1] Elizabeth and James Killian Professor of Economics and Management, Massachusetts Institute of Technology (MIT) and Director of the MIT Center for Energy and Environmental Policy Research (CEEPR). I am grateful for research support from the Cambridge-MIT Institute and the CEEPR.

primarily by the states. Third, different states have taken very different approaches to liberalization of the electricity sector. Some states have embraced wholesale and retail competition as well as restructuring and regulatory reform initiatives to support a successful transition to competitive power markets. Other states have rejected liberalization and resisted efforts to expand competitive wholesale markets. Still others have accepted some aspects of liberalization (e.g. requiring utilities to look to the market for incremental power supply needs) and rejected others (e.g. retail competition, unbundling, and separation of generation, transmission and distribution). No federal laws have been enacted clearly and definitively to promote wholesale and retail competition or the changes in supporting institutions required to ensure that these competitive initiatives provide long-term benefits to consumers. The path to competition in the U.S. electric power sector has been slow and difficult and the absence of necessary supporting transmission institutions is both a part of the problem and a symptom of the lack of a clear and definitive U.S. electric policy (Joskow 2004, forthcoming).

This paper discusses the evolution of U.S. transmission policy from where it started prior to the major liberalization initiatives in the mid-1990s to where it stands now. There is a clear linkage between some aspects of current transmission policies and those that existed prior to the 1990s. I describe this evolution below. Perhaps more importantly, there are significant differences across the regions of the U.S. The states of the Northeastern U.S. have largely embraced a wholesale and retail market liberalization agenda and have moved forward to adopt wholesale market designs and transmission institutions that reflect the goals of federal policymakers. Accordingly, I focus my discussion on the transmission and associated wholesale market institutions that federal

regulators would like to see applied across the U.S. and their implementation in the Northeast with particular emphasis on PJM.

THE U.S. INSTITUTIONAL CONTEXT

The transformation of the U.S. electricity sector from one built upon regulated vertically integrated geographic monopolies to one that supports efficient wholesale and retail competition for power generally has been a significant challenge.[2] Creating the necessary transmission policies and institutions to support this transformation has been complicated by a number of institutional, legacy investment and political factors that many other countries have been able to avoid.

First, the U.S. industry has been characterized by an unusually large number of private vertically integrated utilities of widely varying sizes that own and control generation, transmission, and distribution facilities in or near their distribution franchise areas. Many of these vertically integrated utilities are control area operators (about 140 separate U.S. control areas in 1995) that were, and in many cases still are, responsible for operating portions of one of the three synchronized AC networks in the U.S., subject to rules established by the regional reliability councils and a variety of bilateral and multilateral operating agreements. Only in the Northeast did multi-utility power pools emerge during the 1960s and 1970s to centrally dispatch generation resources on a least cost basis and to manage the operation of transmission networks with different owners of individual pieces.

This legacy industry structure was not conducive to creating well functioning competitive wholesale and retail markets (Joskow and Schmalensee, 1983; Joskow 2000).

[2] See Joskow (2004 forthcoming) for a more detailed discussion of the transition to competitive electricity markets in the U.S.

Ideally, a restructuring program would have separated competitive generation and marketing functions from regulated transmission and distribution activities. Generation ownership would have been further decentralized in geographic areas where ownership concentration created significant additional market power problems. Horizontal integration of transmission assets would have taken place to create regional transmission companies to own and operate transmission networks spanning large geographic areas. However, in a country that supports private property rights, it is very difficult to force private incumbent utilities to implement vertical and horizontal ownership restructuring initiatives of this kind. In several other countries, the restructuring and competition program was implemented in conjunction with the privatization of state-owned assets so that they did not have to confront issues associated with government takings of private property, an opportunity that did not present itself in the U.S.

Second, the electric power industry in the U.S. has historically been regulated primarily by the states. The states have a variety of different views on the desirability of transitioning to competitive wholesale and retail electricity markets and restructuring the utilities in their states to do so. Unlike most other countries that have gone down this path, the U.S. has no clear and coherent national laws that adopt a competitive wholesale and retail market model as national policy and that give federal authorities the tools to do the necessary restructuring and wholesale market design work required to make it work. Instead, the U.S. has relied largely on individual state initiatives, supporting actions by federal regulators (primarily the Federal Energy Regulatory Commission --- FERC --- with some support from the Department of Energy --- DOE) to use limited existing statutory authority to cajole and encourage the states and their utilities to create

competitive wholesale markets and supporting transmission institutions, based largely on decades old statutory authorities which FERC has endeavored to use creatively to support its pro-competition agenda. It is hard to force states to adopt policies they don't like, especially when the regulated utilities in these states don't like them either. As a result, to make progress, FERC has had to rely on a variety of alternative regulatory and institutional arrangements, and various regulatory carrots and sticks to provide incentives for cooperation, to compensate for its inability to require the kind of restructuring program that can most effectively support wholesale and retail competition.

Third, the combination of many relatively small vertically integrated utilities, many operating small control areas, combined with state regulation, has had the effect historically of limiting investments in transmission capacity that would have created strong linkages between generating facilities that are dispersed over large geographic areas. Moreover, the configuration of the control areas' internal networks typically reflected a century of evolution of the utilities that began supplying electricity early in the 20th century, with generating plants first located in or near urban load centers and then gradually expanding as more remote generating sites became necessary to accommodate larger generating stations and the growth of suburban areas. Interconnections with neighboring utilities were built primarily for reliability purposes rather to gain access to lower cost power supplies located remotely from the utility's franchise area. The legacy transmission networks generally have weak interconnections with their neighbors and therefore represent potentially serious limitations on the geographic expanse of effective competition as wholesale power markets are deregulated.

The structure of the U.S. industry and the primary role of the states in economic regulation also created challenges for exploiting the benefits of large-scale integrated AC electric power networks and their reliable physical operation. The U.S. has three synchronized AC transmission networks: the Eastern Interconnection, the Western Interconnection, and the Electric Reliability Council of Texas (ERCOT) network. See Figure 1. The Eastern Interconnection covers the transmission facilities in the states East of the Rocky Mountains plus portions of Eastern Canada. The Western Interconnection covers the Rocky Mountain states, the states west of the Rocky mountains, Alberta, British Columbia and portions of Northern Mexico. ERCOT covers most of the more populated areas of Texas. Each of the three synchronized AC networks has multiple control area operators, primarily private (investor-owned utilities – IOUs) vertically integrated utilities, which are responsible for balancing supply and demand in real time to meet operating reliability criteria within their control areas and coordinating scheduled and unscheduled flows of power and associated reliability criteria that apply to flows between control areas.

The three AC networks covering the U.S., Canada and Northern Mexico are divided into ten Regional Reliability Councils (Figure 2). These reliability organizations in turn are divided into about 24 sub-regional reliability organizations (Figure 3). The activities of these regional and sub-regional reliability organizations are coordinated by the North American Electric Reliability Council (NERC). The reliability organizations were created during the 1960s to develop and apply "voluntary" operating reliability criteria and to coordinate long term planning activities of individual utilities as groups of utilities (as in New England, PJM, New York and elsewhere). At the very least, these

organizations define criteria for operating reserves, frequency, scheduling, inadvertent flows, reactive power support, contingency criteria for defining effective transmission capacity, black start capability, etc. and assist with the evaluation of the impacts of new proposed generation and transmission projects. They have also served as an early warning system for identifying potential shortages of generating or transmission criteria using traditional long-term planning criteria for reserve margins and loss of load probabilities. The regional reliability councils have also designated "security coordinators" who are responsible for monitoring portions of the network in real time to identify potential overloads of transmission capacity, as well as other operating reliability problems, and to order curtailments of schedules or loads (e.g. transmission line relief actions) to bring the system into conformity with operating reliability criteria.

The reliability rules and supporting activities of the reliability councils were (and are) voluntary. Utilities did not have to adhere to them, though most did under the general obligation to behave in accordance with "good utility practice" and with the support of state regulators and FERC. The reliability councils had no long term planning authority but did publish annual forecasts that aggregated the forecasts of demand and investment prepared by individual utilities, groups of utilities, and state regulators. For example, NERC had no authority to require or provide financial incentives to utilities to make investments to meet certain planning reserve margins, though many utilities employed long term planning criteria to support new investments and to justify their investments with state regulators. Only a few states (this is often forgotten today) had established formal investment planning criteria or operated a formal investment planning

process, relying instead on utilities to do so under the general legal obligation to provide safe, reliable and economic service to retail consumers.

The reliability rules and the role of the regional reliability councils and NERC were largely left in place and unchanged as liberalization of wholesale and retail markets proceeded forward in the mid-1990s. Little thought was given to whether and how these rules should change as liberalization proceeded or much attention given to the interaction between evolving wholesale market mechanisms and traditional reliability rules. Most economic research on competitive wholesale markets ignored traditional reliability considerations, whether or not they were consistent with the assumptions underlying wholesale markets, and how reliability and market behavior and performance could be integrated constructively. Little progress on these fronts has been made to date.

These institutional, legacy investment, and political realities have significantly complicated the successful liberalization of the U.S. electricity sector. Implementing effective transmission policies has proven to be especially challenging. As a result, while wholesale and retail market reforms have moved forward at different paces across the country and over time, transmission congestion and the barriers to needed transmission investment have been a growing problem. Transmission Line Relief actions (TLRs) in the Eastern Interconnection have grown by a factor of 5 since 1998. Congestion charges in PJM have grown by a factor of 10 since 1998. Congestion charges in the New York ISO have more than doubled since 2001. Congestion has grown rapidly in Texas (ERCOT), California and New England. At the same time, investment in new transmission capacity has lagged the growth in electricity demand and the growth in new generating capacity (Hirst, 2004). Policymakers are increasingly concerned about

reliability problems and reliability considerations are playing an increasingly important role at the interface of wholesale market design, transmission pricing, and transmission investment policies.

PRE-LIBERALIZATION TRANSMISSION ACCESS AND PRICING POLICIES

To meet their obligations to their franchise customers in the pre-liberalization regime, vertically integrated utilities acquired and operated generation (G), transmission (T) and distribution assets (D). State regulatory agencies set the prices at which electricity was sold to retail consumers, evaluated the reasonableness of the costs incurred by the utilities they regulated, which in turn were used to determine retail prices, and defined and monitored other service obligations (e.g. service quality, resource adequacy, etc.). Regulated (bundled) retail prices were based on the utility's overall (G+T+D) accounting cost of service, where a utility's cost of service or "revenue requirement" was defined as:

$$R = OC_d + OC_G + O_t + (r + d)[K_d + K_G + K_T + \sum d_{-t}] + T$$

OC_i = operating costs of distribution, generation and transmission facilities

K_i = original cost of capital investments in distribution, generation and transmission facilities

r = allowed rate of return on capital investment

d = annual depreciation rate

$\sum d_{-t}$ = accumulated historical depreciation of distribution, generation and transmission facilities based on original cost

T = income and property taxes

Using today's language, retail prices "bundled" generation, transmission and distribution costs together, though concepts of bundling and unbundling evolved long after these pricing procedures were defined.[3] The aggregate revenue requirement R was then allocated to various customer classes (residential, commercial, industrial) based on the voltage level at which they took power, load factors, peak demand and other considerations to come up with a set of price schedules or "tariffs" that specified the bundled retail price for electricity service. No separate price for transmission service was either visible or calculated by state regulators, though there was an implicit price defined by the transmission capital and operating cost components of the overall cost of service that determined regulated retail prices.

Since the passage of the Federal Power Act in 1935, the Federal Energy Regulatory Commission ("FERC" – formerly the Federal Power Commission) has had jurisdiction over the prices and terms and conditions of service for "interstate" transmission service. However, this authority did not apply[4] to "bundled" transmission service provided by the transmission facilities that a vertically integrated utility owned and operated to provide retail service to its franchise customers subject to state regulatory

[3] These cost-of-service formulas were only used from time to time to reset retail prices and were not applied continuously or with ex post adjustments. Once prices were set in a regulatory proceeding they were generally fixed (except perhaps for automatic adjustments for fuel price changes) until a subsequent price review. The period of "regulatory lag" between price reviews could be quite long (Joskow 1974) and the overall process was one where regulatory formulas effectively were used to set price caps with ratchets of uncertain durations (Joskow and Schmalensee 1986).

[4] Or, at least was never exercised.

jurisdiction.[5] Moreover, prior to the Energy Policy Act of 1992, FERC had no authority to require utilities to provide "unbundled" transmission service to third parties seeking to use their transmission networks to buy power from a remote generation source or to sell power to a remote load. By the 1990s, most utilities did "voluntarily" provide some unbundled transmission service to neighboring vertically integrated utilities and to municipal and cooperative distribution companies seeking power supply alternatives to the vertically integrated utility within whose network they were embedded. The prices and related terms of these unbundled transmission services were regulated by FERC.

These "voluntary" unbundled transmission arrangements took several forms:

a. *Coordination agreements*: There were transmission and power supply agreements between neighboring interconnected vertically integrated utilities. The agreements facilitated short term "economy" trades of electric energy between these utilities, allowing them to utilize their aggregate generating capacity more efficiently. To support these short-term trades of energy, the coordination agreements typically specified that the parties involved would provide supporting transmission service on a reciprocal basis. The transmission service itself was "free" and the energy trades were priced on a "split savings" basis defined by the difference between the buyer's and seller's marginal generation costs. For example, prior to restructuring in the late 1990s, the three California IOUs had coordination agreements to facilitate economy trades of energy between them. The power pooling agreements in New England,

[5] There are some who believe that FERC has always had the legal authority to require utilities to unbundled transmission service and to "buy" the service at a FERC regulated price to meet the needs of their regulated franchise customers. Whether it might have such authority or not, it has never chosen to exercise it. As long as a utility keeps the ownership and control of its transmission assets inside the utility FERC has not extended its regulatory reach to "internal" transmission service. Several utilities have voluntarily and with the support of their state regulators unbundled all transmission service in the last few years as part of their state/federal restructuring programs.

New York and PJM were coordination agreements. These agreements typically required that the participating parties make reciprocal commitments of the transmission facilities they owned and operated to support the agreements, but the visible price of the actual transmission service provided under the agreements was zero.

b. *Point-to-Point (contract path) transmission service agreements*.[6] Utilities also had "voluntary" agreements to provide point-to-point (contract path) transmission service from a particular generating station or point of interconnection with a neighboring transmission-owning utility to a particular distribution utility (typically a municipal or cooperative distribution utility that did not have its own transmission network and sought to purchase some of its power needs from a third party rather than from the local vertically integrated utilities). While FERC had no direct authority to require that such service be offered to third parties, many utilities provided unbundled transmission service "voluntarily," often in response to antitrust suits and related pressures from FERC and the Nuclear Regulatory Commission (discussed further below). When this type of voluntary unbundled transmission service was provided, the prices and related terms and conditions were regulated by FERC.

Point-to-point transmission service came in two flavors: (a) *firm transmission service* that entitled the transmission customer to a maximum Mw capacity of transfers from a defined point A to a defined point B. The service could only be curtailed on a proportionate basis when curtailment of the host utility's transmission system as a whole took place; (b) *non-firm transmission service* that entitled the

[6] There were a few network transmission service agreements either involving groups of municipal and cooperative utilities or power pooling arrangements.

transmission service customer to a maximum Mw capacity of transfers from point A to point B, but the service was provided only if the host vertically integrated utility did not need the service to meet its own *economic or reliability* needs to import/export or otherwise adjust the generator dispatch on its transmission system. Utilities were much more willing to provide non-firm service than firm transmission service to third parties.

Once unbundled transmission service was provided by a utility to an unbundled transmission service customer, the prices and other terms and conditions of the service (e.g. duration of contract) became subject to FERC jurisdiction and regulation. However, FERC played no role in planning of transmission facilities, licensing transmission facilities or evaluating the costs and reasonableness of transmission facilities owned and operated by vertically integrated utilities. Instead, FERC essentially was a free-rider on state regulation of transmission investments and costs.[7] FERC priced transmission service essentially by carving out the fraction of the vertically integrated utility's total cost of service attributable to the transmission facilities it owned and operated ($OC_t + (r + d)[K_T - \sum d_{-T}]$) and then allocated a share of these costs to unbundled transmission customers based on their proportionate "use" of the utility's transmission system. Cost allocations were based (roughly) on the contribution of third party transmission customers to the peak load on the network. So, if the peak utilization on the network was 10,000 MW and 1,000 Mw was accounted for by unbundled transmission service

[7] FERC-regulated third party transmission service revenues accounted for less than 10% of the aggregate transmission cost of service and were typically credited back against a utility's state-jurisdictional retail revenue requirements and associated retail prices. For most utilities, unbundled transmission service was a minor business supplied from transmission capacity in excess of what was needed to serve their retail franchise customers/ Effectively, state regulators set the price for "internal" transmission service while FERC set the price for unbundled "third party" transmission service but played no real role in oversight of transmission planning, operation or total costs.

agreements with third-parties, 10% of the total costs of the transmission network would be allocated to the unbundled transmission service agreements and a price per MW of transfer capacity was calculated based on these costs. In short, the regulated price of transmission service was set equal to the average total cost of a transmission-owners network per Mw of peak demand on the network. This regulated price was effectively a price cap since transmission owners were free to "discount" the price to a level that did not exceed this cost-based regulated value. FERC could free ride on state regulation of costs, facilities planning and licensing because unbundled transmission services represented a small fraction of the demand on a typical utility's network and was voluntary.

This type of point-to-point or contract path transmission service made it possible for an unbundled transmission service customer to move power from one point on a utility's network (e.g. a generating plant) to a delivery point on the utility's network (e.g. a municipal distribution system or an interconnection point with another utility's transmission network). However, if the power supply was located on another utility's network, the transmission customer would have to purchase point-to-point service separately on the networks of each intervening utility on the "contract path" as well. When two or more networks were involved, the resulting transmission service prices are generally referred to as being "pancaked" since the charges for using each transmission owner's network on the contract path had to be added together.

These pricing procedures have a number of peculiarities. A transmission service customer effectively pays (roughly) the average total cost of the transmission network per Mw of peak demand on the network it is seeking to use. The transmission customer

could buy the service for a day, a week, a year or multiple years at roughly the same price per MW-day, depending on the transmission capacity the transmission-owning utility made available. There was no differentiation in prices for peak and off-peak system conditions, congestion or the locations of the sources and sinks. As a result, the regulated price could be far above the short run marginal cost of transmission when the network was not congested. It could be far below the short run marginal cost of transmission service when the network was congested, though a vertically integrated utility was unlikely to make transmission service available under these conditions.

If multiple transmission networks had to be crossed to put together a complete contract path, these transmission pricing arrangements led to a situation in which the unbundled transmission service price for transmitting power say 300 miles over a system with a large geographic footprint and peak demand of D_T (demand of the vertically integrated transmission owner's own retail customers plus the peak demand of third-party users of the network) would be roughly 1/3 of the cost of transmitting the same power the same distance over three systems with footprints 1/3 of the larger utility's size but which together had end-to-end networks that formed a parallel contract path.

Thus, other things equal, equivalent "contract paths" over a large utility's network were much more attractive financially for a potential transmission service customer than were otherwise equivalent paths over two or more smaller utilityies' systems. See Figure 4. Moreover, except on the Western Interconnection, where each utility's physical transmission rights were reasonably well defined based on a network model that took loop-flow and related network effects into account,[8] contract path-based transmission

[8] The WSCC also developed "nomograms" to allocate transmission capacity when simultaneous import limits were inconsistent with non-simultaneous transmission rights.

services failed to account for network interdependencies, loop flow and simultaneous transmission constraints. As a result, more transmission capacity could be sold by individual utilities with parallel lines than was feasible for the network to deliver simultaneously. This, in turn, led to loop flow problems and inefficient rationing of scarce transmission capacity to maintain overall network reliability (administrative transmission line relief procedures or TLRs.)

There was very significant controversy about transmission access and pricing during the decades preceding the recent liberalization initiatives discussed in more detail below. Most of the controversy was associated with efforts by municipal and cooperative distribution utilities ("transmission dependent utilities" or TDUs) to get access to unbundled transmission service from the vertically integrated utility within whose network they were embedded. The TDUs sought this service in order to buy some of their power needs competitively from other utilities in the region with surplus generation to sell, rather than relying solely on power supplied (and regulated by FERC) by the vertically integrated utility upon whose network they depended. As already noted, the Federal Power Act did not require utilities to offer unbundled transmission service, but simply gave FERC the authority to regulate its terms and conditions when it was offered voluntarily by transmission owners. However, TDUs brought antitrust cases against vertically integrated utilities (typically under Section 2 of the Sherman Act for "monopolization") which led to court decisions or, typically, settlements that involved provision of transmission service by proximate vertically integrated utilities to these entities. In addition, the Atomic Energy Act contained licensing provisions for new nuclear power plants that involved an assessment of the effects of the proposed plant on

competition. These proceeding too were used aggressively by TDUs to extract concessions regarding the provision of unbundled transmission service.

TDUs also objected to the terms and conditions of service. They argued that FERC's pricing procedures effectively forced them to pay for a proportionate share of a vertically integrated utility's transmission network. However, they received only a point to point service and often had to pay again for each point added to the agreement. They argued that the pricing arrangements should have provided them with "network service" that would allow them to access any point on the network for a contracted maximum transfer capacity. They also objected to "pancaking" of transmission prices across multiple systems on the contract path since this could increase transmission service prices to very high levels when multiple networks were required to put a contract path together between the designated sources and sinks.

FROM PURPA TO THE ENERGY POLICY ACT OF 1992

Title II of the Public Utility Regulatory Policy Act (1978), or PURPA, played an important role in stimulating the entry of independent power producers into the electric power sector during the 1980s and helped to set the stage for the more dramatic reforms of the late 1990s. Prior to PURPA there were effectively no unintegrated independent generating companies in the U.S. PURPA required utilities to purchase power produced by certain Qualifying Facilities (QFs), primarily cogenerators and small power plants using renewable fuels. This made it possible for a large number of non-utility companies to enter the electric generation business as owners of QFs.[9] Roughly 60,000 Mw of QF capacity

[9]Utilities and public utility holding companies were allowed to own no more than a 50% interest in a QF. However, some of the most successful QF development and operating companies were subsidiaries of utility

came into the sector during the 1980s and early 1990s and eventually accounted for 10% of total U.S. generating supplies. This capacity was concentrated in New England, New York, New Jersey, Pennsylvania, California and Texas.

By 1991, the forces unleashed by PURPA and various FERC initiatives to encourage entry of independent power producers[10] that did not meet PURPA's restrictions had led those interested in exploiting the associated competitive market opportunities to seek relief from the statutory restrictions on the entry of IPPs and limitations on the availability of unbundled transmission service. In response to these pressures, the Energy Policy Act of 1992 (EPAct92) was passed by the Congress in October 1992.[11] It included provisions that removed legal barriers to utilities and non-utilities having ownership interests in independent power producers, removed restrictions on U.S. utilities owning electric utility assets in other countries, and expanded FERC's authority to order utilities to provide transmission (or "wheeling") service to support wholesale power transactions.

OPEN ACCESS TRANSMISSION OBLIGATIONS: ORDERS 888/889

After EPAct92 was passed, FERC embarked on a number of initiatives to expand transmission access opportunities for wholesale buyers and sellers of generation services. The initial focus was on creating more opportunities for IPPs to contract with utility buyers, even if they were located on another utility's transmission system; to increase opportunities for vertically integrated utilities with excess capacity to make wholesale sales to utilities

---

holding companies (an exempt holding company could retain its single state exemption and still have interests in QFs located anywhere in the U.S.).

[10]FERC had also issued regulations that reduced the administrative burdens placed on true independent power producers.

[11]P.L. 102-486, Title VII, October 24, 1992.

with whom they were not directly interconnected; and to expand power purchase opportunities for municipal distribution companies that were otherwise dependent for power supplied by the vertically integrated utility in whose network they were embedded.

However, these early initiatives focused primarily on requiring utilities to respond to transmission service requests on a case by case basis and most vertically integrated utilities responded slowly and reluctantly to these FERC initiatives. There was no general requirement for utilities to file generic transmission tariffs that specified generally available transmission service offerings and associated maximum prices. Moreover, the nature of the transmission services that transmission owners were obligated to supply, and the associated prices, remained fairly vague, and utilities defined the kinds of transmission services and the pricing principles applicable to them in a variety of different ways. Transmission service requests sometimes became lengthy negotiations. Some utilities responded to requests for transmission service by claiming that their transmission capacity was fully utilized to meet the needs of their regulated retail customers and their existing contractual obligations to sell power to municipal utilities and other IOUs.

Both FERC and transmission service customers became frustrated by the slow pace at which transmission service was being made available to support wholesale market transactions, and FERC continued to receive complaints about discriminatory terms and conditions (real or imagined) being offered for transmission service. Moreover, California's restructuring initiatives that began in April 1994 began to make it clear to FERC that its transmission access and pricing rules might have to support far more radical changes in the structure of the utility industry -- the functional separation of the generation of electricity from distribution service and the opening of retail electric service to

competition -- and deal with a variety of new issues regarding state vs. federal jurisdiction over transmission, distribution, wholesale power sales and the treatment of "above market" costs of generating capacity and QF contracts (what came to be called the "stranded cost" problem).

These considerations led FERC to initiate rulemakings on transmission service that ultimately served as the basis for two major sets of new rules issued in 1996. These rules are Order 888 -- "Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Service by Public Utilities; Recovery of Stranded Costs By Public Utilities and Transmitting Utilities,"[12] and Order 889 -- "Open Access Same-Time Information Systems" or "OASIS".[13] Despite several subsequent initiatives discussed further below, these rules now serve as the primary federal foundation for the obligations imposed on transmission owners to provide to third parties unbundled transmission service, ancillary network support services, and information about the availability of these services to support both wholesale and retail competition.

Order 888 requires all transmission owners to file with FERC pro-forma open access transmission tariffs that define the terms and conditions of the transmission services that will be made available to potential transmission customers. Order 888 specifies the types of transmission services that must be made available, the maximum cost-based prices that can be charged for these services, the definition of available transmission capacity and how it should be allocated when there is excess demand for it, the specification of ancillary services (including balancing services) that transmission

[12] Final Rule issued April 24, 1999, 75 FERC ¶ 61,080.

[13] Final Rule issued April 24, 1999, 75 FERC ¶ 61,078.

owners must provide and the associated prices, requirements for reforms to power pooling arrangements to comply with Order 888.[14] All transmission owners and power pools subsequently filed open access transmission tariffs with FERC and they are the foundation for the provision of transmission service, balancing and operating reserves to third parties in large portions on the United States today.

While Order 888 is very long, the basic principles it embodies are simple: transmission owners must provide access to third parties to use their transmission networks at cost-based maximum prices, make their best efforts to increase transmission capacity in response to requests by third parties willing to pay for the associated costs, and shall behave effectively as if they are not vertically integrated when they use their transmission systems to support wholesale market power transactions, treating third-party transaction schedules on their networks that are supported by firm transmission agreements equivalently to their own use of their transmission network. FERC did not, at that time, make a concerted effort to resolve the problems created for transmission service customers by the large number of transmission owners, all operating under separate pro forma Order 888 tariffs, which existed in many regions of the country --- the problem of pancaked transmission prices --- or other issues associated with the balkanized ownership and control of the two AC systems subject to FERC jurisdiction.[15] Moreover, since most control areas continued to be operated by vertically integrated firms, there remained concerns about the "independence" of transmission owners and the potential for discrimination against independent generators and marketers seeking to use

[14] It also contains important principles regarding stranded cost recovery. See Joskow (2000).

[15] The ERCOT system in Texas is not subject to FERC jurisdiction.

these transmission systems in terms of access, congestion management, and the costs of balancing services. To deal with this issue, FERC imposed rules restricting contacts between transmission system operators and affiliated generating and marketing departments within the firms, a weak form of functional separation.

Nor did Order 888 require complete unbundling of transmission service in the sense that most vertically integrated utilities continued to provide service for their own retail customers based on bundled cost-based rates determined by state regulatory agencies. Finally, Order 888 did not include guidance or rules related to the creation of organized spot markets for energy, capacity, ancillary services or congestion management. Vertically integrated control area operators were obligated to provide scheduling and dispatch services, operating reserves, and balancing energy, but they were not obligated to create markets for these services which otherwise were included as part of their Order 888 tariffs and sold to third party transmission customers at average accounting cost-based prices. Basically, Order 888 adopted the contract path model, assumed that wholesale markets would be governed by bilateral transactions, and assumed that transmission owners and operators would continue to be vertically integrated firms.

Order 889, issued at the same time as Order 888, requires each public utility or its agent (e.g. a power pool) that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce to create or participate in an Open Access Same-time Information System (OASIS). This system must provide information, by electronic means, regarding available transmission capacity, prices, and other information that will enable transmission service customers to obtain open access non-

discriminatory transmission service in a time frame necessary to make effective use of the transmission system to support power transactions. FERC went on in subsequent proceedings to define in more detail the precise information and formats that OASIS systems must have. OASIS systems are now operating in all regions of the country and rely extensively on internet technology to transfer information. Order 889 also required public utilities to implement standards of conduct to functionally separate transmission and unregulated wholesale power merchant functions to ensure that a vertically integrated transmission owner's wholesale market transactions are not advantaged by virtue of preferential access to information about the transmission network. Utilities must also make the same terms (e.g. service price discounts) available to third parties as they do to their wholesale power marketing affiliates.[16]

It is important to recall that when the process that led to Orders 888 and 889 began, state initiatives to promote retail competition and to encourage utilities to divest generating assets and other reforms to promote retail and wholesale competition were just beginning (Joskow 2004, forthcoming).[17] Moreover, the massive expansion of development of merchant generating capacity had not yet taken place (Joskow 2004, forthcoming).[18] Orders 888 and 889 created an open access transmission platform to

[16] Importantly, Order 888 established federal principles governing the recovery of stranded costs recovery. FERC, and ultimately most state commissions that have considered the stranded cost issue, effectively sent utilities with stranded cost problems the following message: "Play ball by opening up your transmission and distribution systems and by taking actions necessary to create competitive wholesale and retail markets quickly, and regulatory policy will treat requests for reasonable provisions for stranded cost recovery favorably. Moreover, this deal may not be on the table forever." See Joskow 2000 for a discussion of stranded cost issues and how they were resolved.

[17] The first retail competition programs began in early 1998.

[18] Only about 5,000 Mw of new generating capacity was completed in the U.S. in 1997 and 1998. About 175,000 Mw of new generating capacity began operating between 2000 and the end of 2003, most of it merchant generating projects. (Joskow, 2004 forthcoming).

enhance opportunities for municipal distribution companies and vertically integrated utilities to expand their reliance on wholesale power purchased from a generating facilities located in their regions and beyond. It was expected that this in turn would create more opportunities for merchant generating companies to enter the market by making it easier for them to use the transmission network to reach all potential buyers in their regions.

REGIONAL TRANSMISSION ORGANIZATIONS (RTO): ORDER 2000

Order 888's basic regulatory framework presumed that the prevailing structure of the electric power industry would remain largely unchanged, essentially expanding the availability of traditional utility transmission services and pricing procedures. Order 888 also gave the incumbents first refusal on available transmission capacity (they had paid for it after all it was argued and needed it to supply their regulated retail or "native load" customers), and relied on administrative rationing, rather than economic rationing, to allocate limited transmission capacity. Order 888 did not require utilities to operate transparent organized day-ahead or real time markets for energy or operating reserves but rather required transmission owners to provide balancing services and operating reserves at cost-based prices. The transmission owners administering the Order 888 tariffs generally owned generating capacity and used the same network to buy and sell wholesale power as did their would-be competitors.

The three pre-existing Northeastern power pools and California took a more comprehensive approach to developing new wholesale market institutions after Order 888 was issued.[19] They created independent system operators (ISOs)[20] to schedule and

[19] FERC placed substantial pressure on them to do so.

dispatch generation and demand on transmission networks with multiple owners, to allocate scarce transmission capacity, to develop and apply fair interconnection procedures for new generators, to operate voluntary public real-time and (sometimes) day-ahead markets for energy and ancillary services, to coordinate planning for new transmission facilities, to monitor market performance in cooperation with independent market monitors, and to implement mitigation measures and market reforms when performance problems emerged. In 1998, a proposal for a Midwest ISO covering several Midwestern states had come to FERC and in 1999 restructuring legislation was passed in Texas that included the creation of an ISO for ERCOT. Several additional states either had passed or were considering restructuring legislation that required utilities to join FERC-approved ISOs during this time period. Indeed, prior to the California electricity crisis in 2000-2001, it looked like electricity sector liberalization initiatives would sweep through much of the country within a few years.

Accordingly, in May 1999[21] FERC began a rulemaking proceeding to address a number of issues that had emerged in the context of changes in the industry that had taken place since 1996 and had not been addressed adequately in Order 888. The primary goal of the proceeding was to identify new institutions to govern the operation and expansion of transmission networks that could better support the development of efficient competitive regional wholesale power markets consistent with the expansion of retail competition on a state-by-state basis and the rapid growth of merchant generating

---

[20]They effectively turned the existing power pools into ISOs that met FERC new rules regarding governance and system operator functions.

[21] This rulemaking grew out of an inquiry regarding Independent System Operators that had commenced in 1998.

capacity. The rulemaking proceeding was apparently motivated by the following post-Order 888 considerations: the growing number of state initiatives to introduce retail competition and to induce vertically integrated firms to divest some or all of their generating assets; increasing transmission congestion and growing evidence of wholesale market inefficiencies and performance problems; complaints from merchant generators and marketers about discriminatory practices regarding the availability of transmission service, congestion management, balancing and operating reserve services; complaints about discriminatory interconnection procedures and excessive costs, inconsistent allocation of scarce transmission capacity and rapidly increasing administrative rationing of power schedules to meet reliability constraints; and growing concerns about network reliability.[22] The proceeding also reflect growing regulatory burdens placed on FERC by issues arising as wholesale market and transmission institutions evolved and FERC's desire to devolve (de facto) the administration of some of its regulatory responsibilities to independent system operators or other regional entities, including increased reliance on alternative dispute resolution systems.[23]

In December 1999, FERC issued Order 2000 which contained a new set of regulations designed to facilitate the "voluntary" creation of large Regional Transmission Organizations (RTO) to resolve what FERC perceived to be problems created by the balkanized control of transmission networks and alleged discriminatory practices of generators and energy traders seeking to use the transmission networks of vertically

[22] *Notice of Proposed Rulemaking Regarding Regional Transmission Organizations*, Federal Energy Regulatory Commission, issued May 13, 1999, 87 FERC ¶ 61,173.

[23] Order 2000 refers to this as "light-handed regulation" but does not use the term in ways that most students of regulation would recognize.

integrated firms under Order 888 rules.[24] In order to achieve its primary goal of providing a superior regional transmission network platform to support competitive regional wholesale markets, Order 2000 articulates several specific institutional goals:

a. For all transmission owning utilities (publicly and privately owned) to transfer operation of their transmission to <u>independent</u> operating entities --- Regional Transmission Organizations (RTO) --- that would be responsible for a wide range of system operating tasks (e.g. scheduling, dispatch, congestion management, managing voluntary public spot markets for energy, capacity and ancillary services, generator interconnection, transmission planning and evaluation of transmission investment needs and proposals), regional transmission tariff administration, interconnection, and network investment planning. Order 2000 sought effectively to expand the ISO models created in New England, New York, PJM, and California to the rest of the country and, in the case of existing ISOs, to expand their geographic expanse.[25]
b. To increase the regional scope of network operations in order to reduce the adverse consequences of balkanized ownership of transmission assets, including the consolidation of control areas.
c. The clearly assign responsibilities for maintaining short-term network reliability to independent system operators.

Order 2000 required all transmission owning utilities subject to FERC jurisdiction to file plans for joining a regional transmission organization (RTO) meeting certain

[24] *Regional Transmission Organizations*, 89 FERC ¶ 61,285 (1999). Order 2000 technically makes participation in an RTO voluntary, but there are carrots and sticks available to FERC that will create significant pressure for utilities to join RTOs. Order 2000 does not mandate a particular organizational form for an RTO, however.

[25] The primary transmission network is Texas (ERCOT) is not subject to FERC jurisdiction. However, Texas adopted similar reforms for ERCOT on its own initiative.

criteria regarding independence, regional scope, operation authority, and responsibilities for short-term reliability. If they chose not to join an RTO they were required to explain what barriers precluded them from joining an RTO. Thus, FERC characterized participation in RTOs as being "voluntary," while suggesting (not too subtly) that there would be consequences for utilities that did not join an RTO in a timely manner (e.g. vertically integrated utilities losing market-based pricing authority for sales of wholesale power from their fleet of generating plants, more intense review of merger applications, etc.).

Order 2000 also specified a set of minimum functions that an independent RTO would have to assume. RTOs were to be responsible for the design and administration of regional open access transmission tariffs; for scheduling and dispatching generators on regional networks and making arrangements for the non-discriminatory provision of ancillary services (including energy balancing services); evaluating the total capacity of the network too support various trading patterns and the amount of available transmission capacity that could be sold to third parties after legacy transmission rights had been accounted for; operation of a regional OASIS system; implementation of market-based mechanisms for allocating scarce transmission capacity; monitoring generator, marketer, transmission owner behavior and market performance; coordinating maintenance performed by transmission owners; coordinating regional planning processes for new transmission facilities; and operating voluntary public spot markets (real time and day-ahead) for energy and ancillary services.

While Order 2000 suggested that considerable discretion would be left to stakeholders to propose the details of how these functions would be implemented within

each proposed RTO, some fairly clear guidance and expectations for what acceptable proposals would look like are contained in the Order. The Order made it clear that it expected conforming proposals would have the RTO pick up all Order 888 responsibilities that applied to transmission owners, including arranging for balancing services and "last resort" supplies of ancillary services, would eliminate pancaked rates within RTOs, that congestion management should be "market-based" and yield visible price signals reflecting the costs of transmission constraints. It expressed a strong preference for RTOs to developed Performance Based Ratemaking (PBR) techniques to provide transmission owners with better incentives to reduce the number and duration of outages and to optimize operating costs. Regarding transmission investment, Order 2000 expressed its desire that RTOs focus on promoting "market-based solutions" within a regional planning process that coordinates with the states in the ISO's region, while retaining the ultimate responsibility for transmission planning and coordination of both regulated and merchant transmission investment and any associated state approvals necessary for the projects to proceed. Order 2000 has a long discussion of "lessons learned" and refers favorably to the market designs then operating in PJM and New York.

Order 2000 reflected FERC's efforts to create a better platform to support wholesale and retail competition in light of the constraints created by the legacy structure the U.S. electric power industry and FERC's limited legal authority to require changes to it. FERC did not have the authority to require vertical and horizontal ownership restructuring and the reality that many states remained skeptical of the wisdom of either retail competition or restructuring actions that would effectively shift regulatory and policy authority from the states to the federal government. Order 2000 effectively takes

the existing ownership structure as a constraint and promotes the creation of new not-for-profit independent system operators (ISO, RTO, ITP, pick your favorite name) to deal with these issues.[26] However, these independent entities own no transmission assets, have no linemen or helicopters to maintain transmission lines and respond to outages, and are not directly responsible for the costs of operating, investing in, or the ultimate performance of the transmission networks they "manage." Thus. Order 2000 has set the U.S. on a path which separates system operation from the ownership, maintenance and physical operation of transmission facilities and which leaves a highly balkanized structure of ownership of state/federal regulated transmission assets in place.

FERC envisioned that utilities would make their initial filings of RTO proposals or explanations of impediments to joining an RTO by October 15, 2000, RTO start-up by December 15, 2001, implementation of market-based congestion management by December 15, 2002, and inter-RTO parallel path flow, transmission planning and expansion protocols by December 15, 2004. Recall, however, that Order 2000 was issued six months before the onset of the problems in California in June 2000 and at a period of time when the pro-competition bandwagon appeared to be moving fairly quickly through the states.

Order 2000 was very controversial when it was issued and became even more controversial as California's new wholesale and retail power markets began to melt-down in mid-2000. While utilities generally met the initial filing deadline many of the proposals were non-conforming in many dimensions. Moreover, utilities have been very

[26] Order 2000 indicates that RTOs that owned transmission assets would be permitted, though it is clear that FERC's staff was not enthusiastic about this type of Transco Model. It also envisioned independent transmission companies (ITC) under the umbrella of RTOs and subsequently started investigations and issued rules regarding the distribution of responsibilities between RTOs and ITCs.

slow to move forward with the creation of either RTOs or ISOs. Indeed, only PJM, which has expanded westward rather than integrating with New York and New England as envisioned by many at FERC in 1999, and the New England ISO have been fully certified by FERC as RTOs.[27] Although Order 2000 remains on the books and its goals remain FERC policy today, the process of moving all transmission owning utilities into RTOs has been much more difficult than was anticipated at that time.

FERC STANDARD MARKET DESIGN (SMD) PRPOPOSAL

On July 31, 2002 FERC commenced a new rulemaking proceeding to consider a proposal for a "Standard Market Design" or "SMD" that would apply to all transmission-owning utilities over which FERC had jurisdiction. This rulemaking reflected FERC's frustration with the slow speed with which Order 2000 was being implemented and it's perception that there were significant remaining inefficiencies in wholesale power markets. The California electricity crisis, the collapse of ENRON and other marketers, growing evidence of inadequate transmission infrastructure (Hirst), growing transmission congestion and concerns about network reliability indicated to FERC that a more aggressive approach to transmission and wholesale market reform was necessary. In particular that a set of stable and consistent wholesale market, transmission access and pricing, congestion management, and transmission investment rules were need to move forward more aggressively to fix the problems.

The primary features of the proposed SMD were:

1. An Independent Transmission Provided (ITP) would be required to assume operating responsibility of all transmission systems, no matter how small. RTOs

[27] SPP received conditional certification on October 1, 2004.

would qualify as ITPs, but if transmission owners did not join an RTO they would have to contract with an ITP to become the system operator for their transmission networks which would assume any control area responsibilities.

2. An LMP-based day-ahead and real time wholesale market design and congestion management system operated by the ITP, along with financial transmission rights (FTRs) --- now called Congestion Revenue Rights or CRRs in the proposal) as in PJM and New York. (The PJM model was expected to be enhanced to include marginal losses, as is now the case in New York and New England).
3. A single unbundled transmission tariff meeting all Order 888 requirements would have to be filed by the ITP and would be applicable to all transmission customers, including any distribution company affiliates of the transmission owner that supplied retail customers with power whether or not they are in states that have introduced retail competition. That is, complete unbundling of transmission service was required, including transmission service provided by vertically integrated utilities to serve their regulated "native load" customers. Transmission tariffs would adopt a "license plate" approach in which the cost of service (capital and operating costs) for network transmission assets and associated operation and maintenance costs would be assigned to Load Serving Entities (LSEs) [28] based (somehow) on the benefits they derive from the network. To the extent that a transmission network is used (net) to move power to neighboring transmission system (e.g. from AEP to PJM), an appropriate fraction of the exporting network's costs would be allocated to the LSEs in the importing area. Generators

[28] An LSE is an entity that supplies power to retail customers. Distribution companies that arrange for power supplies for retail consumers as well as competitive retail power suppliers are LSEs.

would be responsible for interconnection costs, congestion costs (which they could hedge with CRRs), marginal losses, but would not pay directly for the capital and operating costs of the network. In this way, traditional pancaked transmission rates would be eliminated.

4. Resource adequacy requirements that would obligate all LSEs to make forward commitments for generating capacity and/or demand response to meet their forecast peak demand plus a reserve margin to be determined through a regional stakeholder process
5. A regional transmission planning and expansion process would be implemented to identify transmission investment needs for interconnection, to meet reliability requirements, and that are economically justified but which are not being provided by the market.
6. Strong market monitoring and market power mitigation mechanisms would be required. A $1000/Mwh bid cap for energy and ancillary services in the day-ahead and real time markets was proposed, as well as bidding restrictions to deal with local market power problems.

The original SMD proposal envisioned that all transmission owners would have SMD tariffs in place by September 30, 2004. This is not going to happen. The SMD proposal created a firestorm of opposition in many states and regions. The California experience, the collapse of ENRON and the bankruptcy of other marketers and merchant generators, has significantly reduced interest among the states in moving forward with electricity sector liberalization. Especially in the South and the West, FERC's proposal was viewed as an ill-advised effort to take power away from state regulators and to

impose a flawed model for the electric power industry on portions of the country that did not want it. State regulators and members of Congress from these regions lobbied against it. A provision was even included in the Energy Bill passed by the Senate in 2003, but not yet passed by both houses of Congress, that would have required FERC to delay implementation of the SMD for several years.

In the face of all of this opposition, FERC retreated from the SMD proposal. To quell the mounting controversy, on April 28, 2003 FERC issued a "Wholesale Market Power Platform White Paper" to "clarify" what it expected the Final Rule coming out of the SMD proceeding would actually look like. Basically, this paper suggests that FERC will refocus its attention on moving Order 2000 forward, with the primary detailed provisions of the SMD reflected "guidance" and "ideas" rather than mandatory requirements.

TRANSMISSION PRICING AND INVESTMENT POLICIES IN PJM

It is fairly clear that the SMD proposal was intended to apply the best practices utilized by the Northeastern ISOs (PJM, New England, New York)) to the rest of the country. Despite the political difficulties FERC has faced in implementing the SMD, the basic market designs operating in the Northeast remain FERC's vision of how wholesale market and supporting transmission institutions should be organized. The California ISO and the MISO are committed to implementing wholesale market and transmission policies that embody the same basic design features. Thus, this is the future for wholesale markets and transmission institutions in a large portion of the U.S. electric power system. Accordingly, I will discuss transmission policy in PJM where

implantation is most advanced, and note some differences between PJM, New York and New England.

a. Basic PJM System Operator and Wholesale Market Design

Transmission policies are properly integrated with the broader wholesale market platform of which they are part. Accordingly, let us start with the basic wholesale market platform operating in PJM

1. PJM is an Independent system operator and has been qualified as an RTO by FERC pursuant to Order 2000. PJM is not a market participant, does not own G, T, or D assets and is not engaged in wholesale or retail marketing.[29] PJM is responsible for system operating reliability and for applying reliability rules and criteria developed by regional reliability councils (MAAC in the case of the original PJM footprint).
2. PJM operates (voluntary) day-ahead and real time (adjustment or balancing) bid-based markets for energy and ancillary services. Market participants submit bids and offers to the day-ahead and real time markets. Locational Marginal Prices (LMP) that balance supply and demand at each location on the network and the allocation of scarce transmission capacity are performed together using a least cost bid-based security constrained dispatch (state-estimator) model that incorporates the physical topology of the network and reliability constraints. The LMPs reflect equilibrium marginal energy costs, marginal losses (in New York and New England and soon in PJM), and the marginal cost of congestion at each location.

[29]In theory an independent Transco could qualify as an independent system operator RTO as well, but this would require substantial ownership restructuring in the U.S. context.

3. Congestion is priced based on the difference in LMPs between the designated delivery and receipt points of generation supplies chosen by a transmission service customer.
4. Participation in day-ahead and real time markets is voluntary in the sense that generators, loads, and marketing intermediaries may submit their own day-ahead schedules for energy and ancillary services to the RTO and can (try to) use bilateral arrangements to stay in balance in real time. However, bilateral schedules are still liable for congestion and loss charges and any residual imbalances are settled at the real time prices determined in PJM's spot market.
5. Self-supply of ancillary services is permitted, but the associated generators or demand response must be identified and under the control of PJM.

b. PJM's Transmission Pricing and Related Policies

PJM administers an open access transmission tariff that meets the requirements of Order 888 and Order 2000 discussed above. This tariff (along with the PJM Operating Agreement and the PJM Reliability Assurance Agreement which are interdependent) establishes prices for various categories of transmission service available to third party transmission users;[30] defines how the associated revenues are distributed to transmission owners (TO); specifies interconnection rules and obligations for generators, merchant transmission owners (none yet) and regulated TOs; specifies the definition, allocation

[30] The incumbent regulated transmission owners, all of whom were previously (and most of whom still are) vertically integrated utilities providing generation, distribution and transmission services to retail customers ("native load") do not actually purchase transmission service under the PJM open access transmission tariff to use their own transmission networks to serve their retail customers. Instead they provide the transmission service "internally" and the associated costs are included (recovered) in the regulated bundled prices they charge to their retail customers. However, they subject to all of the other terms and conditions of the PJM Tariff, PJM Operating Agreement and the PJM Reliability Assurance Agreement.

mechanisms, accounting and settlements for financial transmission rights (FTRs); and a establishes a process for identifying and approving regulated transmission expansion projects and the allocation of the associated costs and financial transmission rights.

The PJM transmission tariff provides for various types of transmission service using the transmission facilities owned by the TO participants in PJM.

Firm Network Integration Service: This service was designed to replicate the transmission service available to the regulated vertically integrated utilities that made up PJM at the time the new wholesale market arrangements were created in 1998. This service is designed to make it possible for any Load Serving Entity (LSE) to integrate flexibly any generating plants it owns and power supply arrangements it makes with third parties to economically serve its retails loads. Each LSE purchasing network integration service pays a transmission access charge based on its proportionate peak demand on the network in each "transmission zone" in which power is delivered to a distribution network to serve its load. A transmission zone is effectively the geographic area served by each incumbent regulated TO. The transmission access charge is FERC regulated and equal to the average total cost of capital investments (depreciation, interest, return on equity investment and taxes) plus the operating costs of the existing transmission assets included on the network. Additional charges may be assessed to cover network enhancements necessary to provide the service consistent with PJM/MAAC reliability rules. The charges are remitted to existing transmission owners to cover their regulated cost of service. The price for this service is more or less equivalent to the transmission component of the incumbent utilities' state-regulated bundled retail prices. Depending on the delivery zone on the PJM network, prices for network integration service are in the

range of $15 - $25/kw-year. The service is available on a yearly basis and prices can be adjusted over time based on regulatory cost-of-service formulas.

By paying these access charges LSEs also receive financial transmission rights (FTRs) or Auction Revenue Rights (ARR) which they can/must put up for auction in annual and monthly auctions operated by PJM. FTRs give their holders the right to a proportionate share of the annual congestion charges (difference in LMPs between delivery and receipt points times the associated Mw of transfers) associated with the points of receipt and delivery designated in their network integration transmission service agreements (or the equivalent for incumbent vertically integrated utilities). The FTRs were designed to make it possible for LSEs to hedge the annual congestion costs associated with the sources and sinks designated in the Network Integration Service agreements. When the new market system was initially established, FTRs were allocated to the incumbent TOs with native load obligations. They could sell their rights but had no obligation to do so. In 2003, the PJM tariff was changed to require that all FTRs (subject to a number of limitations that are too complicated to discuss here) be put up for auction in an annual and monthly auction process administered by PJM. Instead of FTRs, firm transmission service customers are allocated Auction Revenue Rights (ARRs) which entitle them to the revenues received when their FTRs are auctioned. Thus, firm transmission customers have a choice between hedging congestion costs forward by selling their FTRs in the annual and monthly auctions or (effectively) selling and then buying back the FTRs at in the PJM auction so that they can hedge congestion costs as they are realized. FTRs were originally “obligations” which could carry either a positive or negative value at a particular point in time depending on the sign of the difference in

LMPs between delivery and receipt points. In 2003 PJM introduced FTR "option" rights which can take on only positive values as well as peak and off-peak FTRs.

Firm-Point-To Point Transmission Service: This service is designed to support imports in, exports out, intra-PJM transactions, and transit through the PJM system between interconnected control areas to support transactions that are not otherwise covered by Network Integration Service agreements. Short-term firm point-to point service is available on a daily (peak and off peak), weekly or monthly basis. Long-term point-to-point service is available on an annual and (by agreement with the TO) longer basis. The pricing arrangements (average total cost of the transmission network per Mw of peak demand on the network) are similar to those for network integration service except confer rights to a designated set of receipt and delivery points. Firm transmission customers are subject to congestion charges and charges for losses. They are allocated FTRs/ARRs to match the firm point-to- point transmission service they have purchased.

Non-firm point-to-point transmission service. This service is a "non-firm" variant of firm point-to-point transmission service. It is availably only on a monthly, weekly, daily or hourly (peak and off-peak) basis. When there is congestion indicated on the network based on day-ahead schedules, non-firm customers' schedules are curtailed first to try to relieve the expected congestion. If congestion can be relieved by such curtailments then congestion charges are not created. Non-firm customers have the option of responding to the curtailment requests by reducing their schedules or paying any congestion charges that are realized. Pricing arrangements are otherwise similar to those for firm service, except there would be no network enhancement charges. Non-firm transmission service customers are not allocated any FTR/ARRs in return for paying for this service.

The price for each type of transmission service offered by PJM is based on traditional regulatory cost-of-service/rate-of-return formulas applied to one of more TOs in the transmission zones where delivery points are designated. In addition, the probability of and costs of congestion depend, in part, on the availability of transmission facilities. But while PJM coordinates transmission maintenance schedules, it is each of the TOs that is responsible for physically operating and maintaining the transmission facilities it owns. PJM does not own any transmission facilities, does not have maintenance personnel and equipment and cannot penalize or reward TOs for variations in the availability of their facilities. Capital, operating and maintenance costs for transmission service must be recovered by the TOs through a convoluted mix of FERC and state cost-of-service regulations. In Order 2000, FERC encouraged RTOs to develop and propose performance-based-regulation (PBR) mechanisms that would apply to owners and operators of regulated transmission assets. None of the Northeastern RTO/ISOs has developed or applied PBR mechanisms to date and no formal regulatory mechanisms are in place to encourage TOs to cut operating costs, to improve the availability of transmission equipment, or to respond quickly to especially costly unplanned equipment outages.

Generators (or merchant transmission projects interconnecting with the PJM network) do not pay a separate transmission service charge to use the PJM network. However, as discussed below, they must pay for the costs of interconnection facilities, network upgrades required to restore PJM/MAAC reliability criteria if their interconnection creates violations of these criteria, and any costs of meeting MAAC generator "deliverability" criteria if the generators want to be certified as "capacity resources," as

almost all generators do. About 70% of the regulated transmission investments identified in PJM's latest Regional Transmission Expansion Plan (November 2003) fall in one of these last two categories and are paid by new generators seeking to connect to the network. As far as PJM is concerned, generators deliver power at their point of interconnection with the network and are paid/billed based on the associated LMP. Accordingly, they are not assessed congestion charges directly. However, whether or not generators pay network congestion charges de facto depends on their agreements with buyers of power and whether it is the buyer or the seller that is providing the supporting transmission service to get the power from the point of delivery to the point of receipt.

c. PJM's Transmission Investment Policies

Transmission investment policies involve a number of interdependent questions. How are transmission investment needs identified? What entities are expected to develop the new facilities? How are the associated costs expected to be recovered through transmission charges? Which entities that make use of the network pay for its various components? Transmission investment in PJM is mediated through a regional planning process and ongoing adjustments to a baseline regional plan.

Transmission investments in PJM fall into several categories and are evaluated and approved through a comprehensive and transparent regional transmission planning process that is updated roughly every six months to reflect changes in the baseline assumptions about generation additions, generation retirements, demand, congestion patterns, and the progress of transmission projects included in the baseline plan:

Direct interconnection investments: When a new generating unit or merchant transmission projects seeks to connect to the PJM network, the TO in whose transmission zone the project will be located performs a study of the direct capital and operating costs associated with the new transmission facilities require to make the connection to the network. The proposed generating project is responsible for 100% of these direct interconnection costs. About $275 million of investments that appear in PJM's latest RTEP fall in this category.

Interconnection Network Reliability Investments: PJM and the TO in whose transmission zone the facility is located also evaluate the impact of the proposed project on network reliability. A series of engineering studies are performed to assess whether the proposed project, as an increment to the existing facilities on the network, will lead to any violations of PJM/MAAC reliability criteria. These criteria are not simple. They involve a set of assumed study conditions under various contingencies: when all facilities are operating; N-1; N-2; multiple contingencies; and delivery to load criteria. These criteria and their application have not changed since before the new PJM markets were created and take no account of the LMP mechanisms or of the associated market mechanisms for allocating scarce transmission capacity. If the engineering studies indicate that reliability criteria are violated, the expected costs of network investments required to restore the reliability parameters are identified. The proposed generator will be required to pay for these costs, though they may be shared with other generators in the construction pipeline that benefit from these network enhancements (the cost allocation mechanism is fairly complicated). The generator will receive its proportionate share of

any new FTR/ARRs created as a consequence of the network facility enhancements it is required to pay for.

It is important to note that these reliability assessments are based on a set of engineering assumptions and study conditions that may be little relationship with the way the network would actually operate if the network enhancements where not made and increased congestion were realized.

Generator Deliverability Investments: If a generator or HVDC merchant transmission project wants to qualify as a "capacity resource" under PJM's Reliability Assurance Agreement and wholesale market Operating Agreement, as is typically the case since there is significant "capacity value" in the PJM market, they must meet a final reliability criterion called "generator deliverability." Engineering studies are performed to determine whether (oversimplifying a complex process) the full power that the proposed generator can produce can be reliably delivered outside of its transmission zone under a set of engineering study conditions that assume all existing generators are dispatched first to meet load.[31] If the generator deliverability condition is not satisfied the generator must either pay for any necessary network enhancements (and receive any incremental FTR/ARRs) or purchase firm transmission service that supports deliverability from a third party. Interconnection network enhancements and deliverability network enhancements together account for about $215 of investments in PJM's latest RTEP (November 2003).

It should be noted that interconnection network investments and deliverability network investments provide potentially powerful locational incentives to new generating projects. The network upgrade costs at some locations may be zero (or even negative)

[31] New generator deliverability criteria were recently proposed.

and at other locations these costs may be substantial. New generators can reduce their investment costs by selecting a location where these network upgrade obligations are low rather than high. It is likely that these interconnection network upgrade cost obligations play a more important role in generator location decisions than do variations in LMPs.

Other reliability investments: The PJM RTEP process may indicate that one or more PJM/MAAC reliability criterion is expected to be violated for other reasons e.g. load growth or generator retirements at specific locations. PJM can direct TOs to make the necessary investments required to restore the reliability parameters. The associated costs are then recovered from charges to the load that benefits from the investments. These costs amount to about $200 million in the latest PJM RTEP.

Merchant transmission investments: The original design of the PJM system was predicated on the assumption that any "economic" transmission investments that were not required for "reliability" would be made on a merchant basis. The costs of merchant transmission projects would be borne by the developer and the developer in turn would receive the transmission rights created by the investment. The incentive for merchant investment would be the market value of the transmission rights created by the project. The associated expected value of the transmission rights created is then the expected difference between the LMPs between the affected delivery and receipt points times the incremental transmission capacity between these two points created by the investment (Joskow and Tirole 2004a). In the case of AC facilities, a merchant investor would receive any incremental FTR/ARRs resulting from the investment. HVDC merchant transmission facilities are treated like generators and effectively create physical import or export rights to the AC network.

It is important to note, however, that PJM's distinction between "reliability" and "economic" transmission investments is economically arbitrary. It appears nowhere in the economics literature on LMP, FTRs or transmission investment. Indeed, most of this literature ignores reliability and related stochastic issues completely.

Several merchant transmission projects have been proposed through the PJM interconnection and RTEP planning process. None have yet been completed. The most active projects are HVDC interconnections between PJM and New York City and Long Island. The farthest along is a project that has been awarded a long term contract for transmission between PJM and Long Island by the Long Island Power Authority (LIPA), a municipal utility which can pass the associated costs on to its regulated customers without approval of a state or federal regulatory agency. LIPA already has a long term contract for all of the 330 Mw capacity of the Cross Sound Cable connecting New England with Long Island, the only "merchant" project completed so far in the U.S. There are also two transformer projects in PJM being developed by an incumbent TO that would increase AC transfer capacity and the associated rights awarded to the merchant developer and one "behind the fence" transformer project being developed at an oil refinery site with electric generating capacity. As I understand it, the latter is in lieu of having the local TO build and operate the transformer to support an interconnection.

HVDC links to New York City and Long Island are especially attractive for a number of reasons. The LMPs in NYC and Long Island are consistently significantly higher than those in neighboring areas --- about $20/Mwh on an annualized basis. In addition, these are both very difficult places to find sites for new power plants and have extremely high construction costs. In addition, DC links from PJM and New England can be brought in

under water where NIMBY issues should be less of a problem (though this did not mute the controversy over the Cross Sound Cable process. Finally, on Long Island there is a municipal distribution utility that is willing and able to sign long term contracts for the transmission capacity developed in this way. This means that the developer does not have to rely on differences in spot market LMPs to produce the revenues for the project, reducing financing costs and opportunism problems.

Economic Planned Transmission Facilities: PJM resisted doing any analysis of "economic transmission" investment opportunities or including such potential investments in its regional transmission plan and requiring TOs to proceed with them. By "economic transmission" investment opportunities I refer to transmission investments whose expected economic benefits associated with reductions in congestion costs exceed their expected capital and operating costs (all properly discounted to present value). In fact, many network upgrade investments that are justified on "reliability" grounds could just as well be categorized as "economic" transmission investment opportunities. In many cases, if the investments were not made, the network could still be operated "reliably," but there would be more congestion and much higher prices in some areas. Many reliability investments affect the future trajectory of LMPs and incentives for generation and transmission investments. On the other hand, "economic" transmission investments can also often confer "reliability" benefits as well. Thus, in my view, at the very least, reliability and economic transmission investments are interdependent. At worst the distinction between them is analytically arbitrary.

In any case, the dream that merchant investors would come forward to make all efficient investments in response to congestion has not been matched by reality. As of

the end of 2003 no merchant transmission network investments were made in PJM (or in New England or New York), as congestion costs steadily rose. After a contentious proceeding at FERC, in 2003 PJM was required to include potential "economic" transmission investments in its planning process. PJM has now developed a process to identify "unhedgeable congestion" and to assess the benefits and costs of potential network enhancement projects that would reduce congestion. The process is complex and still evolving. To oversimplify,[32] PJM defines unhedgeable congestion as congestion which cannot be hedged with the existing portfolio of FTRs. For example, for the nine-month period August 2003-April 2004 there was $626 million of congestion charges in PJM, of which $65 million was defined as "unhedgable." Where unhedgeable congestion is identified, a set of simple cost benefit assessments associated with network upgrades that would reduce the congestion are then performed by PJM. When these assessments yield benefit/cost ratios that exceed certain specified thresholds a project is put on a list of potential regulated "economic" transmission projects. Market participants are then given a year to propose alternative "market solutions" to the identified projects. If market solutions are not forthcoming the projects are added to the PJM Regional Transmission Expansion Plan and the incumbent TOs in whose transmission zones the projects are located are directed to make the investments. The resulting costs, net of revenues from the auctioning of ARRs created by the investments, are then recoverable through the PJM Open Access Tariff from the customers of the LSEs who are expected benefit from the investments.

[32] For a detailed discussion of the procedures that were recently adopted by PJM see PJM FERC Filing in Docket Number RT-01-2-01, dated April 21, 2004. http://www.pjm.com , accessed June 15, 2004.

Roughly 34 potential economic transmission investment projects were identified during the first phase of application of this program and "market windows" are now open for merchant projects to fill these needs before regulated transmission projects are added to the RTEP.[33]

d. Differences Between PJM and Other Northeastern Markets:

In my view, PJM now has a reasonably good system in place for providing transmission service, for allocating scarce transmission capacity, for pricing of the direct and network costs of interconnection to provide good locational signals to new generators, for identifying and developing transmission investment inside PJM, and for supporting merchant transmission projects that enhance interconnection capacity between PJM and neighboring control areas. However, PJM is not typical of the U.S. as a whole.

The New York and New England ISOs now have similar wholesale spot market mechanisms that are integrated with the allocation of scarce transmission capacity. They also have similar open access transmission tariffs. They also both have capacity obligations that are placed on LSEs. However, their transmission investment policies are quite different. In New England and New York, generators are required to pay only for the direct (shallow) costs of interconnection and are not responsible for any associated reliability network upgrade costs as those are defined in PJM. Nor are their deliverability obligations for generators seeking certification as capacity resources. As a result, generators do not face the same locational incentives as they do in PJM and more of the costs of new transmission investments are "socialized" into the basic charges for

[33] PJM FERC Filing in Docket Number RT-01-2-01, Appendix 1, dated April 21, 2004. Available on the PJM web site.

transmission service reflected in their open access transmission tariffs. There is also more ongoing controversy about "who pays" for transmission investment in New York and New England than in PJM. The "shallow" interconnection charge approach has also been adopted by FERC in its recent "generic" generator interconnection rule that applies more broadly to TOs across the U.S. [34]

e. Expanding interconnection capacity between control area operators:

Transmission policies in PJM and the other Northeastern ISOs have focused primarily on "intra-network" transmission investment. Other than the opportunities for merchant investors to seek to expand inter-control area transmission facilities, there is no process in place in any of these areas systematically to evaluate opportunities to expand transmission capacity on both sides of the borders between them or to support beneficial projects with regulated transmission investments. FERC had hoped to reduce this gap by promoting the creation of large RTOs that would effectively "internalize" these investment opportunities into the intra-RTO regional planning process. FERC's goals here have not been realized. PJM showed no interest in merging with New York and New England and New York and New England faced political opposition to merging with each other. And while PJM has expanded West and (soon) South, transmission investment planning appears to continue to be balkanized across the individual PJM regions. Inadequate attention to opportunities to expand inter-control area transmission capacity, in the U.S. context of a highly balkanized grid with a large number of incumbent transmission owners and control area operators, is a continuing problem especially in light of the resistance to implementing FERC's RTO rules.

[34] FERC Order 2003, "Standardized Generator Interconnection Procedures," July 23, 2003.

CONCLUSIONS

All transmission-owning utilities in the U.S. are now required to have FERC approved open access transmission tariffs and OASIS in place. These tariffs obligate TOs to make transmission service available at traditional regulated cost-based prices on a non-discriminatory basis, while the OASIS systems are designed to provide information about transmission utilization and transmission availability to third parties. Since Orders 888/889 were issued in 1996, FERC has expressed its concerns about continuing discriminatory practices by vertically-integrated control area operators and about operating and investment inefficiencies caused by the balkanized ownership and management of the Eastern and Western Interconnections. FERC has also expressed support for integrating transparent spot energy markets with the allocation of scarce transmission capacity, LMPs, transparent markets for ancillary services provided under Order 888 tariffs and open regional transmission planning and investment procedures. However, aside from the Northeastern markets, relatively little progress beyond Orders 888/889 has been made in most regions of the country. The development of the Midwest ISO and California's program of market redesign (whose implementation was recently delayed until 2007) are proceeding on the evolutionary path that FERC envisioned. However, overall progress down this path continues to be relatively slow.

Transmission networks continue to be balkanized and arguments continue about how appropriate transmission investments should be identified, who bears the responsibility for making the investments, and who pays for the associated costs. FERC is taking responsibility for a growing share of the economic value of transmission

investments while the states retain control over transmission planning and permitting for new facilities.

Despite these problems, nearly 200,000 Mw of new merchant generating capacity entered to market in the last five years and nearly an equal amount of incumbent generation has been deregulated through divestiture or transfers to unregulated affiliated of previously regulated firms. Wholesale market transactions account for a growing fraction of the electricity delivered to retail consumers. However, along with the growth of merchant generating capacity and wholesale trade, network congestion has increased as existing transmission facilities have been used more intensively and investment in new network facilities (beyond direct interconnection facilities) has stagnated (Hirst). Transmission congestion in PJM, New York, New England, California, Texas and the Midwest continues to grow. See Figure 5 and Tables 1 and 2. Transmission investment has been slow to catch up (Hirst). Even in the Northeastern RTO/ISOs with relatively well developed transmission planning procedures, network enhancements have been slow to be realized and expansion of inter-control area transmission capacity has been virtually non-existent. Aside from the direct costs of congestion, growing concerns about "locational market power" that result from this congestion has led to more intensive market power mitigation programs that carry both potential benefits and potential costs, especially as they affect investment incentives.

In the end, one must attribute the slow pace of change to the absence of a clear and definitive federal policy toward wholesale and retail competition in the U.S. and the lack of supporting federal laws to implement such policies. This situation in turn reflects the fact that many states have not been convinced that electricity restructuring and

competition will benefit consumers and their reluctance to cede their 100+ years control over the electric power industry to the federal government. Overall, the U.S. is a country whose electricity sector is stuck somewhere between the old regime of state regulated vertically integrated monopolies and a regime of liberalized wholesale and retail markets and supporting institutions and regulatory mechanisms for supporting them efficiently. This is not a good place to be.

REFERENCES

Hirst, Eric. "U.S. Transmission Capacity: Present Status and Future Prospects," mimeo, June, 2004

Joskow, Paul L., "Inflation and Environmental Concern: Change in the Process of Public Utility Price Regulation", *Journal of Law and Economics*, October, 1974.

Joskow, Paul L., **"**Deregulation and Regulatory Reform in the U.S. Electric Power Sector," in *Deregulation of Network Industries: The Next Steps* (S. Peltzman and Clifford Winston, eds.), Brookings Press, 2000.

Joskow, Paul L. "The Difficult Transition to Competitive Electricity Markets in the U.S.," *Electricity Deregulation: Where To From Here?*, (J. Griffin and S. Puller, eds.) University of Chicago Press, forthcoming 2004. (**http://web.mit.edu/pjoskow/www/**)

Joskow, Paul L. and Jean Tirole**, "**Transmission Rights and Market Power on Electric Power Networks," *Rand Journal of Economics*, 31(3) Autumn, 2000.

Joskow, Paul L. and Jean Tirole, "Merchant Transmission Investment," *Journal of Industrial Economics*, forthcoming 2004. (http://web.mit.edu/pjoskow/www)

Joskow, Paul L. and Richard Schmalensee, *Markets for Power: An Analysis of Electric Utility Deregulation*, MIT Press, 1983.

Joskow, Paul L. and Richard Schmalensee, "Incentive Regulation for Electric Utilities", *Yale Journal on Regulation*, December, 1986.

New York Independent System Operator, *State of the Market Report*, Potomac Economics, LTD, May 2004.

North American Electric Reliability Council (NERC), Transmission Loading Relief Procedure Logs, Trend Charts, http://www.nerc.com, accessed June 15, 2004.

PJM Interconnection, *Regional Transmission Expansion Plan*, November 2003, http://www.pjm.com, accessed June 15, 2004.

PJM Interconnection, *Open Access Transmission Tariff*, updated to May 6, 2004.

PJM Interconnection, *Amended and Restated Operating Agreement*, updated to June 15, 2004

PJM Interconnection, *State of the Market Report*, March 4, 2004.

FIGURE 4
TRADITIONAL CONTRACT PATH MODEL

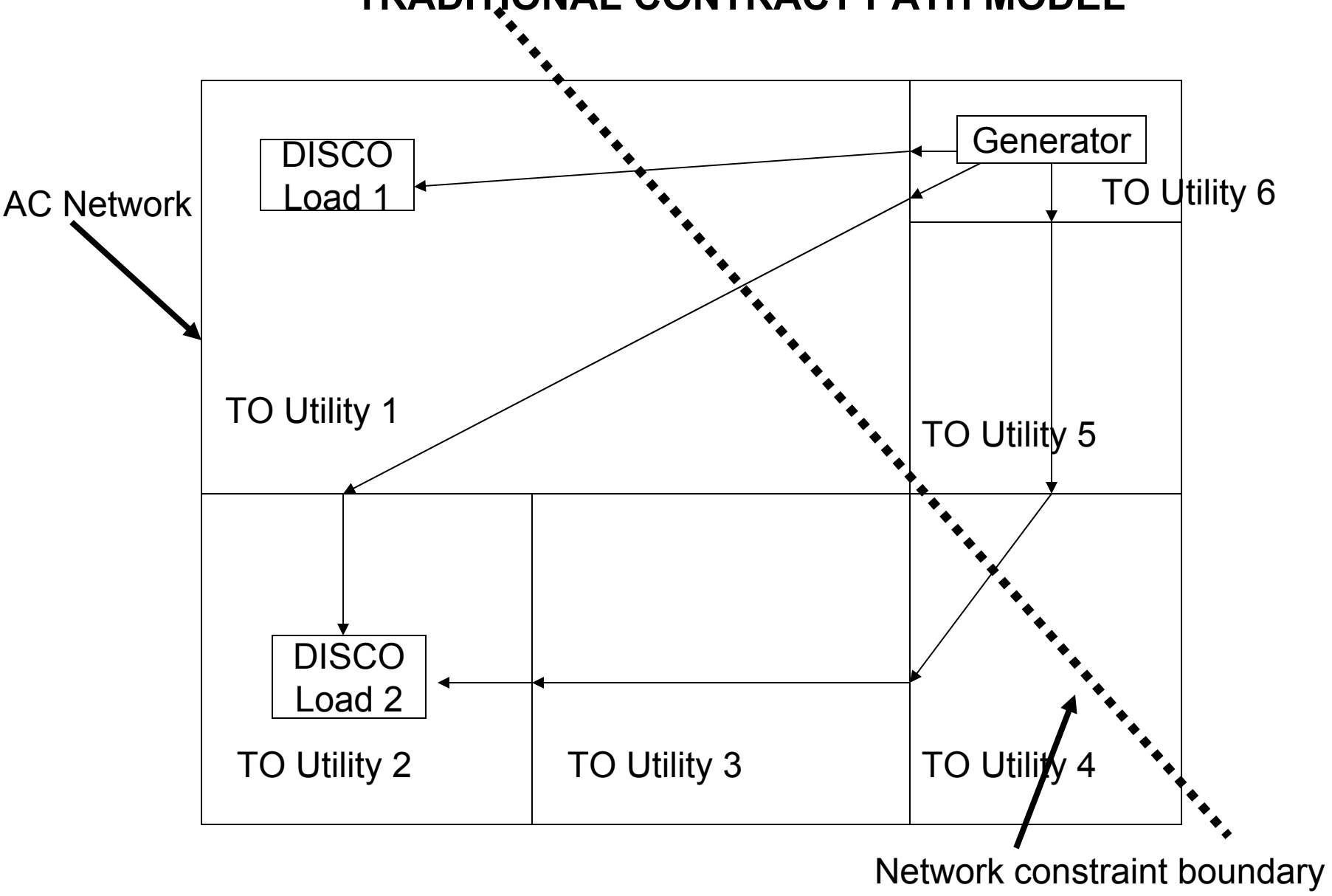


FIGURE 1

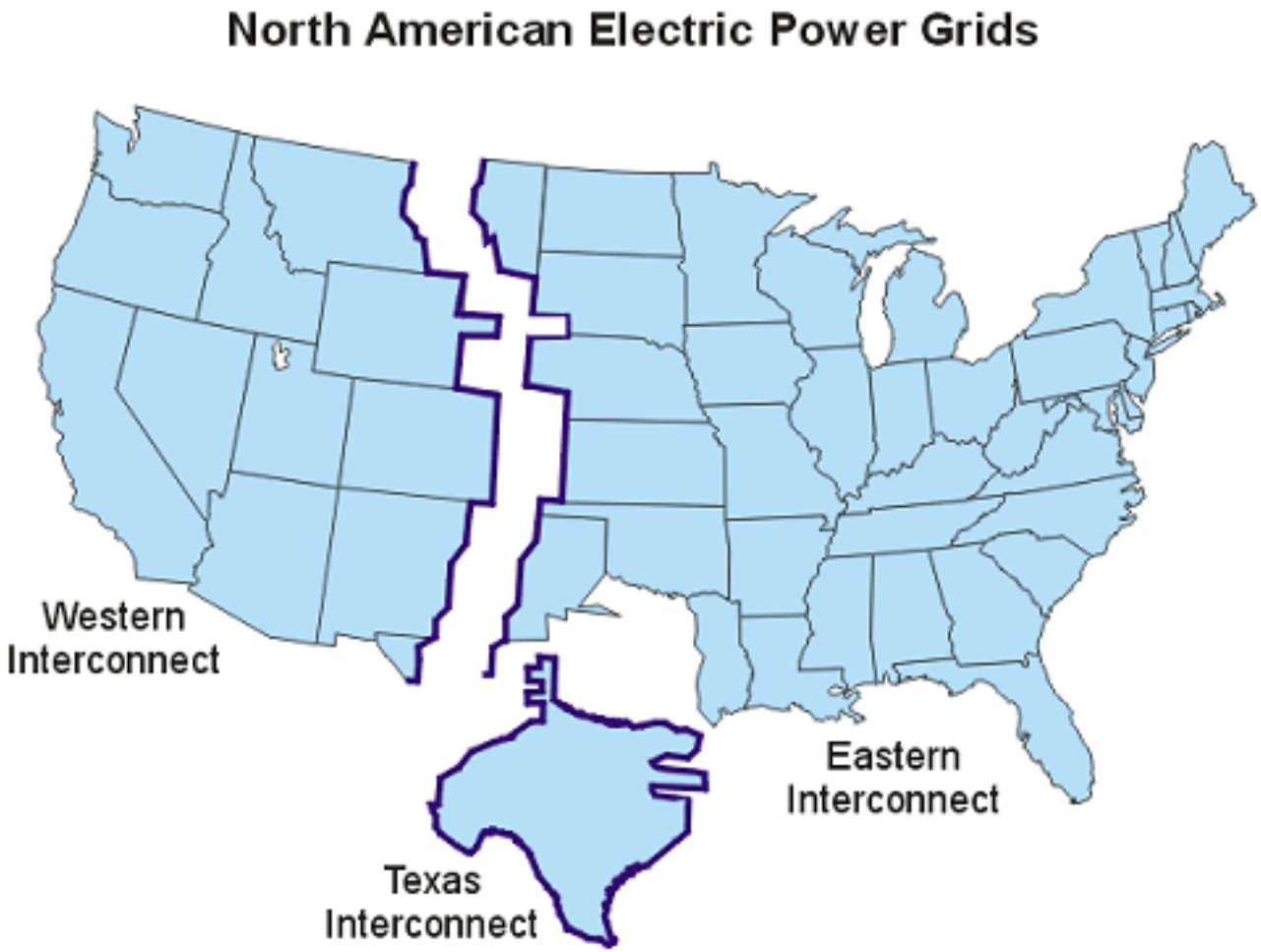
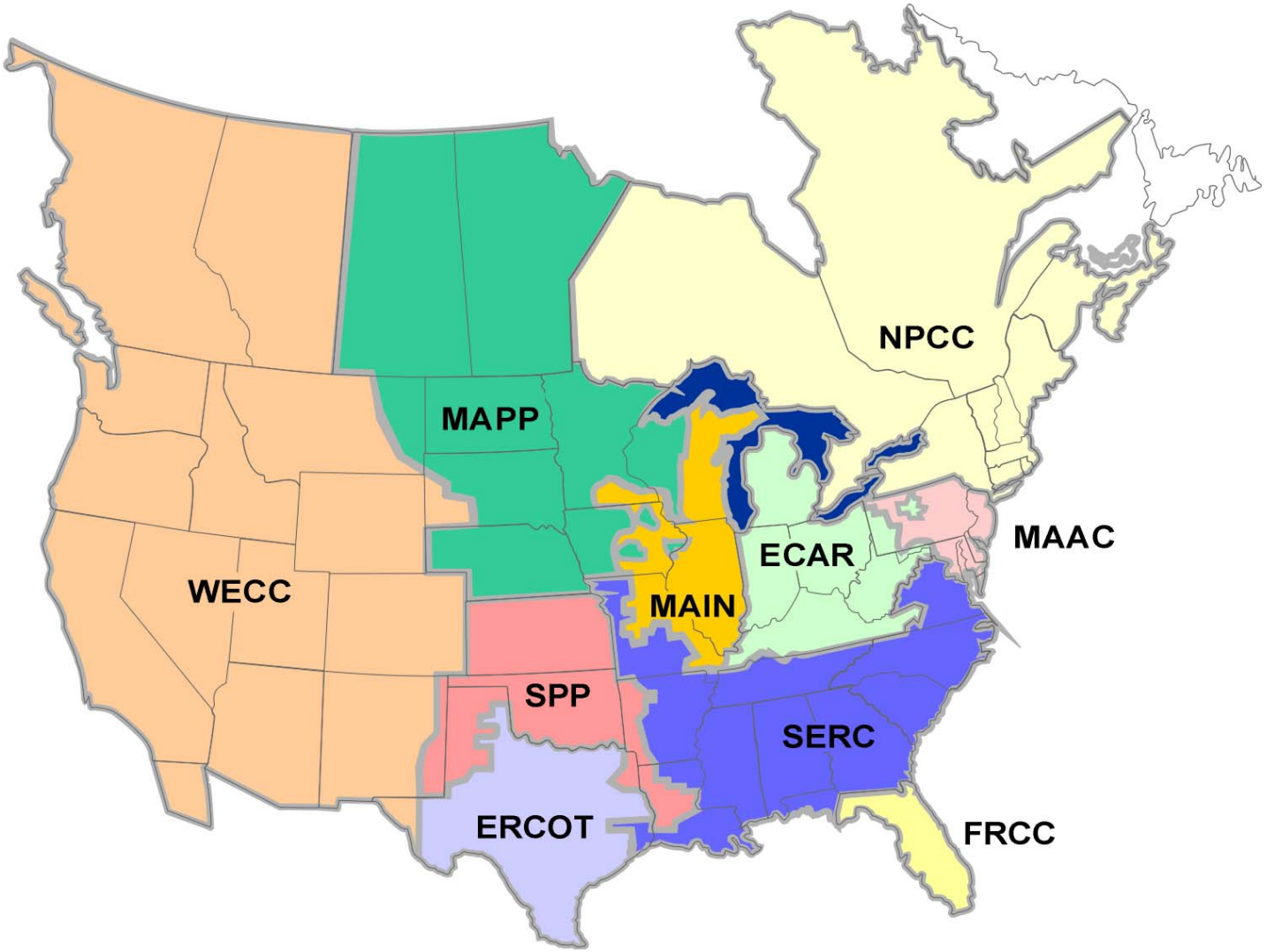
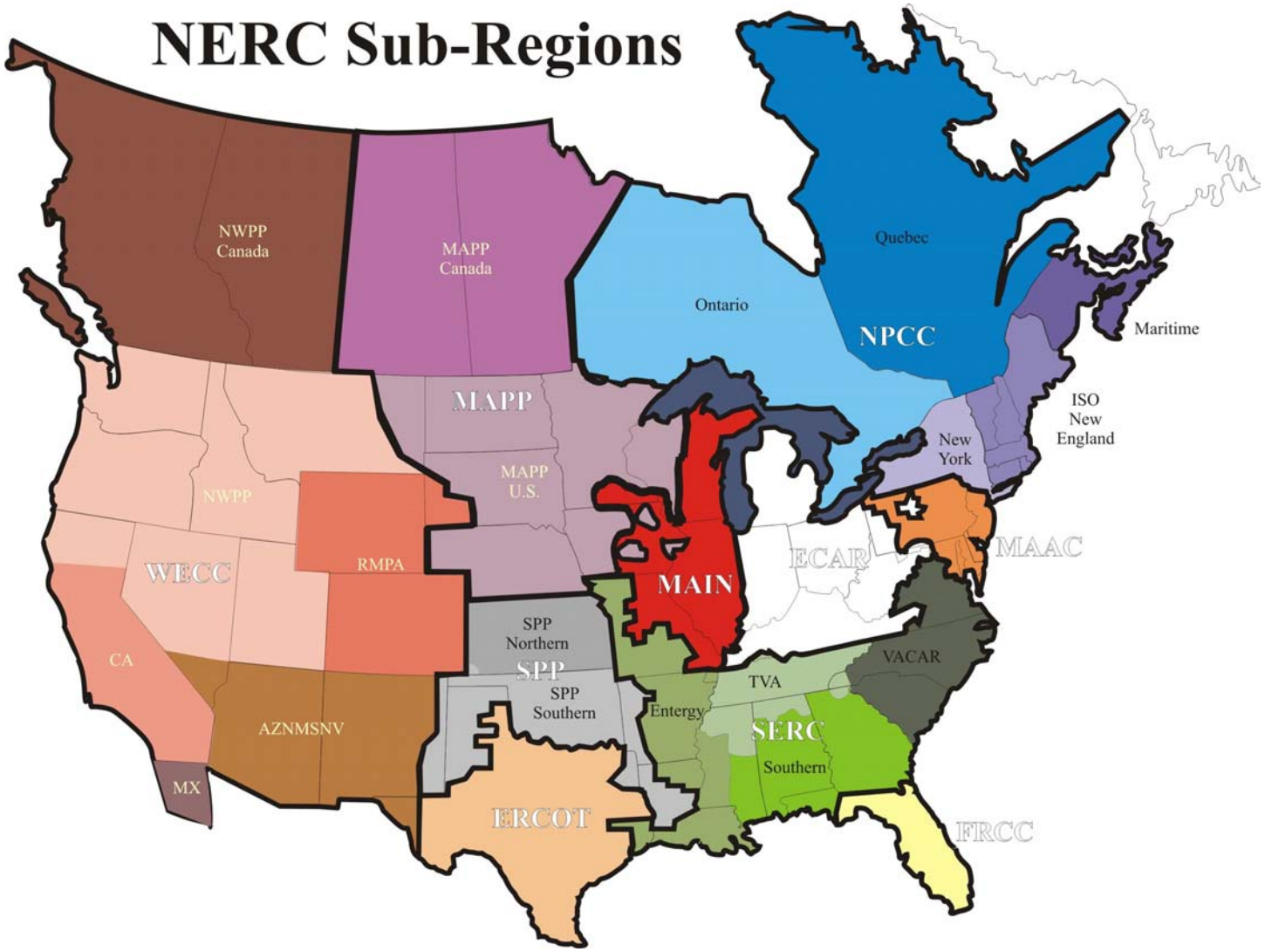

North American Electric Power Grids
Western Interconnect
Eastern Interconnect
Texas Interconnect

FIGURE 2



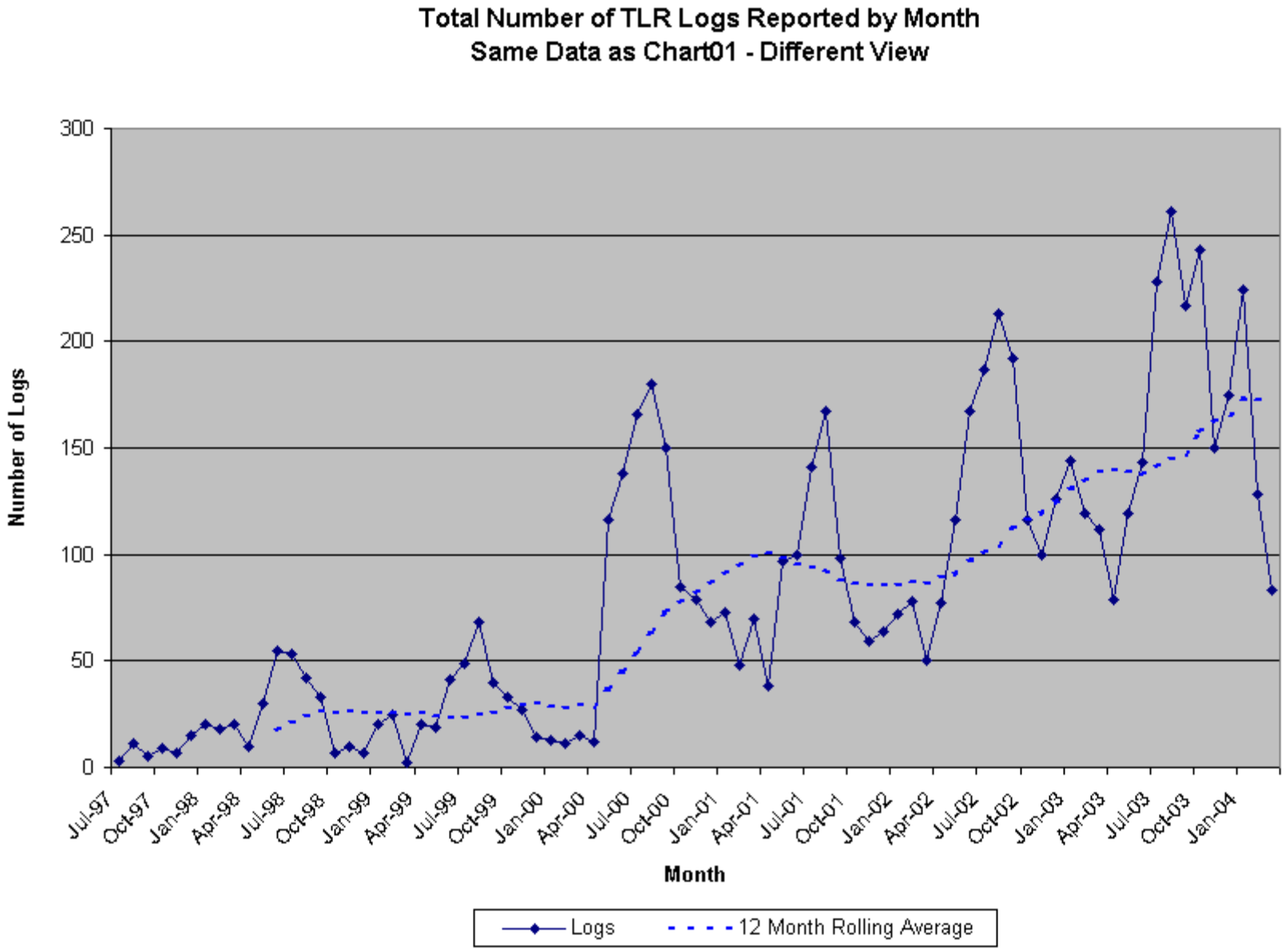
Source: NERC

FIGURE 3



Source: NERC

FIGURE 5



Source: NERC Transmission Loading Relief Logs

TABLE 1

PJM CONGESTION COSTS (RENTS)

($ millions)

1999	53
2000	132
2001	271
2002	430
2003	499

Source: PJM Interconnection, *State of the Market Report 2001, 2002 and 2003*

TABLE 2

CONGESTION COSTS IN NEW YORK

2001	$310 million
2002	$525 million
2003	$688 million

Source: New York ISO, *State of the Market Report 2003,* page 43