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COMPLYING WITH ENERGY AND NATURAL RESOURCES REGULATIONS

LEADING LAWYERS ON US ENERGY MARKETS AND REGULATORS' ATTEMPTS TO PROVIDE OVERSIGHT

ASPATORE

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The Millennial Revolution in Electric Transmission: From Monopoly to the Marketplace

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Introduction

Factually, this chapter is about an ongoing revolution in the development and financing of this country's electric power grid. This revolution has led to a breakdown in the control of local utility monopolies with absolute authority over all aspects of the generation, transmission, and distribution of electricity in their service territories, as well as over the captive customers in that territory. It is a revolution that continues to transform the business model profoundly. It is a story of the piecemeal destruction of those monopolies and their replacement with emerging new relationships among generators, power deliverers, and their joint customers. Much like the destruction of the telecom monopoly of the Bell system, the process of replacement of a monopoly with the marketplace has unleashed the energy and genius of entrepreneurship with its wild successes and spectacular failures. However, because we are in the early days of this transformation in the electric power sector, it is very difficult to step back and look at the process from a distance. For the authors, gaining any sort of perspective is even more challenging since we have been very active participants in the revolution. My own story is illustrative.

In 1975, when I left the staff of the United States House of Representatives, and joined a law firm in Washington, all I knew about electricity was that you flipped the light switch and the lights went on. Virtually my entire practice for its first twenty-five years was focused on representing national sponsors with projects in thirty-five states in the ever-growing senior living industry. Originally based in Washington, DC, our family moved to Portland, Maine in 1982, with virtually no change in my practice.

In 1999, a group of regulatory lawyers in my former firm asked me to help with some early project finance aspects of an idea they had been working on with a group of engineers, an energy economist, and Canadian government affairs consultants. The idea was to generate electricity from newly discovered gas fields off the coast of Nova Scotia, and then to transmit the electric power via subsea cable to southern New England and New York. I provided some marginally useful financing advice as the project was far, far away from reality. By the year 2000, this marginal interest had morphed into drafting memorandums of understanding (MOUs) for a six-figure investment by a third party and much more than a casual relationship to what had become known as the Neptune Project. The first leg of the Neptune Project was a subsea high-voltage direct current (HVDC) cable linking the electric power grid in New Jersey with that of Long Island, New York. By 2001, I was working much of my time on the project; by 2002, I was its general counsel; and from 2003 to 2005, I was totally committed to it. By the time the project closed on its financing, I was Ahab hunting for the white whale—I would land it or die trying.

Cable Laying Vessel Julio Verne during Hudson Project

Image courtesy of the Hudson Project

Since that time, I have worked on another Neptune-sized project called the Hudson Transmission project, which is now transmitting power from the PJM grid directly into ConEd's West 49th Street substation and a number of other projects in development. Clearly, the center of gravity of my practice has shifted to independent transmission.[1] Now at least I know why the lights go on when you flip the switch.

Our firm is now advising the state of Hawaii energy office on the development of inter-island HVDC grid ties, as well as Vermont's Transco on a project under Lake Champlain connecting New York state wind power to the southern New England grid. The firm is also advising developers of independent transmission projects in Maine, Massachusetts, New York, and New Jersey, as well as in the emerging area of offshore wind.

[1] In 2011, I joined Bernstein Shur, a 110-lawyer firm with significant depth in the energy space on behalf of non-utility participants.

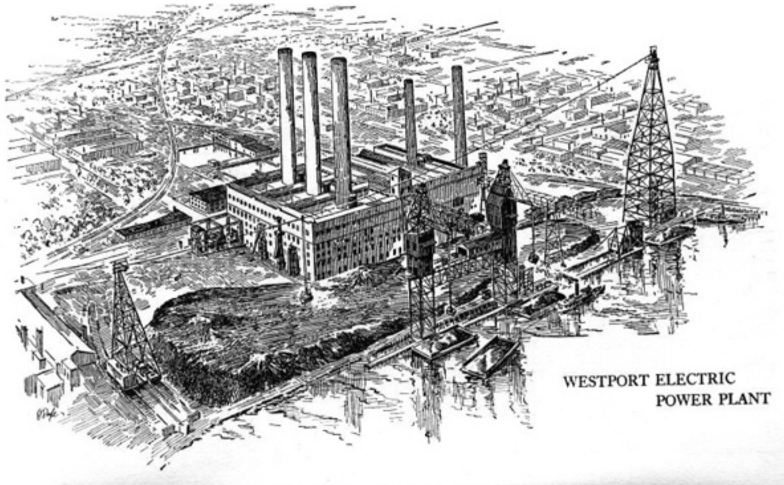
Given this background and experience, this chapter must be more than a scholarly examination of the first decade of independent transmission. I have not tried to detach my own experiences in subsea HVDV cable projects from our drafting process. While it is my hope that this chapter, being written fourteen years after my entry into this field, will have enough "up close and personal" recounting of events to give the reader the flavor of the time and a window into this exciting and new area of law practice, I also hope that it is combined with enough distance in time and perspective to offer the reader insights that a pure documentary history could never do. Please forgive selected war stories. They illustrate the incredible difficulty when an existing paradigm in a long-entrenched industry is challenged. They demonstrate how complicated such a process can be when political, economic, environmental, and other forces clash. They are included to provide texture and context to larger themes, but then again I may not be able to see beyond my own outstretched hand.

The Electric Public Utility in America: The Vertically Integrated Monopoly Model

Establishing the Vertically Integrated State-Regulated Monopoly

It was not long after Thomas Edison's first demonstration of the light bulb in the late 1870s that the first utilities were formed in the United States—producing and selling electric power to consumers. In the early years, local municipal control through exclusive franchise agreements was the only regulatory structure. The unregulated mishmash of wires sprouting like spider webs around our cities was untenable as a model. Municipalities began to grant exclusive franchises to utility companies to sell power within a defined geographical service territory in exchange for an agreement to provide reliable service to all customers in the service territory and at regulated prices. Thus the regulated utility monopoly system was born.[2]

[2] There were a number of models that utilities followed including investor ownership (IOU), municipal ownership, and federally sponsored public power authorities. Regulation of electric utilities was founded on a long Anglo-American tradition of economic regulation stretching back to seventeenth century England. The United States Supreme Court affirmed the states' right to regulate private property where it is "affected with a public interest." *Munn v. Illinois*, 94 U.S. 113, 126 (1886) (declaring an Illinois law regulating grain warehouses constitutional). Quoting an 1810 English opinion, the



Westport Electric Power Plant

As an infrastructure and capital-intensive industry, electric utilities were traditionally considered natural monopolies. Duplicative infrastructure was seen as economically wasteful, and larger, centralized generating plants offered higher efficiencies and lower costs. Thus, the electric power industry soon organized itself into vertically integrated utilities, controlling the entire supply chain from power generation to the delivery of electric service to the end user. This was the prevailing model in America for almost a century.[3]

US Supreme Court reiterated the more than 200-year-old principle of a government regulated monopoly:

> There is no doubt that the general principle is favored, both in law and justice, that every man may fix what price he pleases upon his own property, or the use of it; but if for a particular purpose the public have a right to resort to his premises and make use of them, and he have a monopoly in them for that purpose, if he will take the benefit of that monopoly, he must, as an equivalent, perform the duty attached to it on reasonable terms.

Munn v. Illinois, 94 U.S. 113, 127-28 (1886) (quoting *Allnutt* v. *Inglis,* King's Bench 1810 [12 East, 527, 537]).

[3] Vertically integrated utility companies remained the predominant utility structure through the 1970s when they controlled over 95 percent of generation in the United States. Electric Energy Mkt. Competition Task Force, FERC, Report to Congress, *Competition in Wholesale and Retail Markets for Electric Energy: Pursuant to Section*

Poles being set, early 1900s

As the United States entered into the twentieth century, electricity was becoming commonplace and utilities were quickly merging, consolidating, and expanding their territories. With utilities growing to serve entire states, local regulation at the municipal level had clearly become inadequate. The first statewide utility commissions were created in 1907 in New York, Wisconsin, and Georgia, with many other states close on their heels.[4] State commissions developed more comprehensive systems of regulation than the initial municipal franchise agreements. State commissions exercised oversight of utility financing and investment, the quality of service provided, and the rates charged to consumers. State commissions sought to ensure that utility expenditures and rates were "just and reasonable." In exchange, utilities were effectively guaranteed a "reasonable" rate of return of and on their investments from ratepayers.

1815 of the Energy Policy Act of 2005, at 10, (2006), http://www.ferc.gov/legal/fed-sta/ene-pol-act/epact-final-rpt.pdf (hereinafter "Task Force Report").

[4] Energy Info. Admin., *The Changing Structure of the Electric Power Industry 2000: An Update*, at 5, http://www.eia.doe.gov/cneaf/electricity/chg_stru_update/update2000.html.

The reasonable return on investment drove an explosion in private investor-owned utilities in the early decades of the century. By 1921, 94 percent of all electricity generated in the United States came from privately owned utilities.[5] Utility holding companies sprang up, purchasing state-based utilities in numerous states, further consolidating the industry. By 1932, 73 percent of US generating capacity was controlled by just eight utility holding companies.[6] On the other hand, the guaranteed return also stifled innovation—a no-risk culture arose driven by this highly regulated system.

With the rise of utility holding companies that operated outside the state-by-state regulatory structure, it became clear that a federal regulatory system was needed. Indeed, the US Supreme Court in *Public Utilities Commission of Rhode Island v. Attleboro Steam & Electric Co.*[7] ruled that state utility commissions were prohibited by the Commerce Clause from regulating electricity sold across state lines. In response, and at the urging of newly elected President Franklin D. Roosevelt, Congress passed the Public Utilities Act of 1935, which included Title I—the Public Utilities Holding Company Act of 1935 (PUHCA),[8] and Title II—the Federal Power Act of 1935 (FPA).[9] Pursuant to PUHCA, holding companies were required to register with the Securities and Exchange Commission (SEC),[10] to be limited to a single integrated public-utility system,[11] and were generally subjected to strict regulatory requirements. The FPA, in turn, established exclusive jurisdiction in the Federal Power Commission (FPC), later to become the Federal Energy Regulatory Commission (FERC), over interstate transmission of electric energy and the sale of electricity at wholesale prices in interstate commerce. Thus, the modern federal regulatory system was created.

Throughout these early decades, the energy lawyer's opportunities were limited. With the dominance of vertically integrated utilities, a single company controlled the electricity industry in most jurisdictions. Utilities were highly prized clients with multi-faceted legal needs. In addition, the

[5] *Id*.
[6] Task Force Report, *supra* note 4, at 18.
[7] *Pub. Utilities Comm'n of R.I. v. Attleboro Steam & Elec. Co.,* 273 U.S. 83 (1927).
[8] Codified at 15 U.S.C. §§ 79a *et seq.* (West).
[9] Codified at 16 U.S.C. §§ 824 *et seq.* (West).
[10] PUHCA, Section 5 (15 U.S.C. § 79e).
[11] PUHCA, Section 11 (15 U.S.C. § 79k).

relative stability and long lifespan of utilities made utility clients career makers. With federal regulation following the FPA, a new practice area evolved, but the industry remained highly concentrated.

A Chink in the Monopoly Armor

There are four main components comprising the electricity industry: generation, transmission, distribution, and customer service. Simply put, power was produced at utility-owned generating facilities and then flowed through utility-owned transmission lines to reach utility-owned end-user distribution systems where the power was ultimately directed to the customer. The utility was the exclusive interface with its customers to provide billing and other administrative services. The customers really had no other options and became known in later years in the public policy debate as "captive customers." For decades, these four components were all controlled by vertically integrated utilities, and the prevailing wisdom was that all four components were part and parcel of the natural utility monopoly.

This system was secure as long as rates continued to decline with ever-increasing economies of scale and demand growth. Increasing costs and slowing growth beginning in the 1960s, however, heralded a major shift in the utility industry. The late 1960s and 1970s saw tightening regulation of system reliability[12] and power plant emissions after passage of the Clean Air Act in 1970. In addition, the 1973-1974 Arab Oil Embargo added fuel to the slow-burning fire of rising prices, resulting in significant price spikes as the oil-dominated utility generating facilities faced skyrocketing fuel prices. Additionally, huge cost overruns on nuclear and other new utility-owned generation plants led to ever-increasing electric rates as regulators passed these costs through to the utility's customers.

With the myth of ever-decreasing rates shattered, the monopoly model itself was questioned, and the concept of wholesale competition took seed. In 1978, Congress passed the Public Utility Regulatory Policies Act of 1978

[12] System reliability became a greater concern to state and federal regulators following the 1965 Northeast Blackout, which affected an estimated 30 million consumers in the United States and Canada. *See* Federal Power Commission, *Prevention of Power Failures: A Report to the President by the Federal Power Commission* (July 1967), Vol. I at 8, http://blackout.gmu.edu/archive/pdf/ fpc_67_v1.pdf.

(PURPA)[13] to promote energy conservation and alternative energy generation to reduce the industry's reliance on Middle Eastern oil. PURPA sought to encourage new efficient and alternative fuel generating facilities by requiring utilities to purchase power from, and interconnect with, small, independent power producers that met certain statutory requirements. These non-utility plants were designated qualifying facilities (QFs). Many QFs were able to demonstrate efficiencies in operation unprecedented among many utility plants.

PURPA created a new market for independent power producers that were guaranteed interconnection and power purchase by the incumbent utility at the utility's avoided cost. Avoided cost was the cost to the utility of building the next power plant to meet the marginal need of growing demand. Suddenly, utilities were not the only game in town. As non-utility generation began to develop and successfully integrate with the electric grid, it became clear that the vertically integrated utility model was not the only option and that, at least in certain instances, the injection of competition on the generation portion of the supply chain made economic sense.

PURPA also opened up the energy lawyer's options. Independent power producers became a new source of clients for energy lawyers. No longer did the utilities completely dominate the field, though they remained the big fish.

Wholesale Competition: The Beginning of the End for Vertically Integrated Utilities

Through the 1980s, free markets and deregulation were hot button issues, and Congress began to further open up wholesale competition with passage of the Energy Policy Act of 1992 (EPACT 1992).[14] Where PURPA had allowed qualifying facilities to produce power and sell it to utilities at a regulated rate, EPACT 1992 created a new class of merchant power companies known as exempt wholesale generators (EWGs). Like QFs, EWGs were non-utility entities permitted to sell power at wholesale. EWGs, however, were not limited to charging the utility's avoided cost and could charge market rates for their power. Thus, the industry moved closer to true wholesale competition.

[13] Codified at 16 U.S.C. §§ 2601 *et seq.* (West).
[14] Pub. L. No. 102-486, 106 Stat. 2776.

While there was growing competition, the utilities' control of the balance of the electric system created barriers to entry and barriers to competition. For example, utility-owned generators routinely received priority in the interconnection process, as well as cost breaks, while non-utility generators had difficulty getting interconnected due to roadblocks, such as utility refusals to grant access easements across utility properties needed to interconnect a generator lead line. Additionally, the generation dispatch system controlled by utilities was not always based on price.

Following EPACT 1992, FERC issued a series of orders in an effort to encourage wholesale competition. In 1996, FERC issued Orders 888[15] and 889[16] to "remove impediments to competition in the wholesale bulk power marketplace and to bring more efficient, lower cost power to the nation's electricity consumers."[17] In Order 888, FERC required utilities to adopt open access transmission tariffs (OATTs) that established non-discriminatory terms and conditions of service, and to unbundle transmission and wholesale power service such that rates charged for transmission services would be equal between utility and non-utility wholesale power. Order 889 required utilities to adopt a common, open-access system for communication of transmission system information to transmission customers to end the preferential information access of the utilities. Thus, open access same-time information systems (OASIS) were mandated for all transmission-owning utilities.

The impact of these orders was to advance the drive for wholesale competition by leveling the playing field between non-utility generators and utility-owned generation. By requiring non-discriminatory access to transmission system information and transmission service, non-utility generators were better able to compete with utilities to wheel power to end-users. Unregulated wholesale competition was alive and well, leading to the development of interstate bulk power sales and the creation of a new market for energy trading. Free from the constraints of the highly regulated

[15] Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities, Order No. 888, 61 Fed. Reg. 21,540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 (1996) (hereinafter "Order 888").

[16] Open Access Same-Time Information System (formerly Real-Time Information Networks) and Standards of Conduct, Order No. 889, 61 FR 21,737 (May 10, 1996), FERC Stats. & Regs. ¶ 31,035 (1996) (hereinafter "Order 889").

[17] Order 888, *supra* n. 16, introduction/summary at 21,737.

utility monopoly, wholesale power became a commodity, giving rise to trading companies specializing in trading bulk power and transmission rights. Once again, the evolving energy industry opened new opportunities for the legal practitioner with more complexity, more transactions, and many new potential clients.

Through the 1990s, the concept of deregulation or restructuring of the electric industry caught hold in states with relatively high electricity prices. The success of non-utility power plants in the wholesale markets demonstrated that the traditional vertically integrated utility was not, in fact, a natural monopoly. Policymakers began to consider avenues to expand the wholesale markets to retail customers by taking utilities out of the power production business and providing retail customers with the ability to choose from whom they purchased their power. Where utility rates were above comparative market rates, state legislatures and utility commissions took action to restructure the utility system in the hopes of driving down the retail cost of electricity.

California was the first major state to attempt to restructure its utility regulatory system. In 1996, the California Legislature passed AB 1890, enacting a complex electricity market and retail choice system that had initially been developed and proposed by the California Public Utilities Commission after years of study.[18] Other states were quick to follow. For example, Maine, faced with skyrocketing energy prices, in part due to heavy utility investment in nuclear plants that had massive cost overruns, enacted a comprehensive restructuring act in 1997 that mandated that every incumbent utility must divest all their generation facilities by 2000.[19] The utilities would thereafter operate the "wires" delivering the power to retail customers produced by independent generators. Other states incentivized or required divestiture through commission orders rather than by legislation. By 2000, twenty-four states had initiated some form of restructuring.[20]

The collapse of the California wholesale market in 2001, however, following rolling blackouts and massive price spikes, sent shockwaves through the

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[18] C. Blumstein, L.S. Friedman, R.J. Green, *The History of Electricity Restructuring in California*, Uni. of Cali. Energy Institute, Center for the Study of Energy Markets, Working Paper 103 (August 2002) at 6-11.
[19] Me. Rev. Stat. Ann. §§ 3204 *et seq.* (West).
[20] Task Force Report, *supra* n. 4, at 26.

restructuring movement, resulting in suspended or diminished restructuring efforts in many states. For example, the New Hampshire Public Utilities Commission had implemented a restructuring plan, based on 1996 legislation,[21] that initially contemplated full divestiture of utility generation. In the wake of the California energy crisis, however, the legislature and the Commission pulled back, allowing the state's largest utility to retain a significant portion of its generating assets until at least 2006.[22] This partial restructuring allowed retail choice, but left a vertically integrated utility in the mix as one source of "competitive" electric supply. Other states, such as Nevada, repealed their restructuring legislation entirely.[23]

Regional Transmission Organizations and the Dawn of Merchant Transmission

Despite the development of wholesale, and in some states, retail markets and divestiture of utility generation, the utilities' grasp over transmission was still strong, providing opportunities for discriminatory practices. Recognizing that Orders 888 and 889 had not fully accomplished their intended market transformation, in 1999, FERC issued Order 2000,[24] continuing its push to transform the electric industry and foster greater competition. Order 2000 required public utilities to investigate participation in regional transmission organizations (RTOs) operated by independent companies not affiliated with the utilities. Order 2000 built on a purely voluntary program initiated in Order 888, pressuring utility participation in a shift that had already begun in some regions under independent system operators (ISOs).

RTOs/ISOs manage regional transmission systems and operate competitive regional energy markets to determine the dispatch of power into the system and the price paid to participating generators for their power. RTOs/ISOs are generally multistate organizations (with exceptions such as New York and California, and, of course, Texas) and have established markets for power, ancillary services, and transmission rights. Some RTO/ISO organized markets such as PJM are extremely sophisticated, conducting

[21] N.H. Rev. Stat. Ann. §§ 374-F:1, *et seq.* (West).
[22] N.H. Rev. Stat. Ann. § 369-B:3-a (2003).
[23] Task Force Report, *supra* n. 4, at 28, Fig. 1-2.
[24] Regional Transmission Organizations, Order No. 2000, 65 Fed. Reg. 809 (Jan. 6, 2000), FERC Stats. & Regs. ¶ 31,089 (1999).

capacity as well as energy markets on a month ahead, week ahead, day ahead, and real-time basis. Their control of dispatch of generators follows a merit order protocol with accommodation for "must run" base load units that cannot be turned on and off at will, such as nuclear or run of the river hydroelectric generators. The market for ancillary services, such as spinning reserve and black start, puts a market price on these critical aspects of a reliable electrical grid and allows participants to make rational investment decisions on the deployment of their capital resources.

In 2005, Congress passed comprehensive energy legislation that further solidified the control of RTOs/ISOs over regional electric markets and continued to erode utility control over transmission. The Energy Policy Act of 2005 (EPACT 2005) covered a host of energy-related issues from ethanol production to daylight savings time.[25] Relevant to utilities, EPACT 2005 contained three major adjustments affecting utility control of transmission.

First, EPACT 2005 tightened reliability standards, making them mandatory and enforceable.[26] This resulted in a greater focus on transmission development to improve reliability and indirectly gave the RTOs/ISOs more power to order transmission system upgrades. Second, EPACT 2005 created incentives for investment in transmission infrastructure to attract additional capital investment in transmission.[27] Third, EPACT 2005 granted FERC the power to designate "National Interest Electric Transmission Corridors" in areas of congestion and to preempt state control and grant eminent domain powers and construction permits where state authorities either do not or cannot approve transmission projects necessary to meet reliability standards.[28] The intent of these provisions was to incentivize and facilitate additional transmission development by utilities, as well as non-utility transmission companies that could capitalize on inter-state connections.

The twentieth century saw tremendous change in the electric power industry. From a burgeoning technology was born massive vertically integrated, regulated utilities that dominated the industry for half a

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[25] 42 U.S.C. §§ 13201 *et seq.* (West).
[26] 16 U.S.C. § 824o (2006).
[27] 16 U.S.C. § 824s (2006).
[28] 42 U.S.C. § 824p (2006). We are not aware of FERC ever issuing such an order pre-empting state control.

century without challenge. Yet change came with consumer price shocks that the system could not mitigate, as well as with new technologies, new markets, and eventually new regulations pushing the industry toward competition. By the end of the century, competitive markets were thriving at the wholesale level, and retail competition was becoming a real possibility as restructuring efforts created retail choice in many states. Moreover, the utilities' control over transmission also was slipping as RTOs and ISOs took over regional transmission planning responsibility, and the allocation of construction responsibility to the various incumbent rate-based utilities in their service territories. Finally, merchant transmission companies had begun to appear. As the millennium turned, the utilities' transmission function began to change rapidly.

The Millennium: Thirteen Years In

In the 1990s, Enron was a god-like company exploding with new ideas, new financial structures, and new ways to trade energy-related commodities. An entire industry of energy traders soon grew up in a very lightly regulated marketplace. The market capitalization of the energy trading industry led by Enron was enormous and growing every day. There was money flooding the market. Failure was not even a concept to be discussed. In this environment, non-utility merchant transmission projects, led by private developers and private equity had their beginnings. Since the early 1990s, FERC tried to open the transmission grid to independent transmission companies. In the words of one respected commentator, "Up to about 1990 the grid was essentially run by regional oligarchies of large and small utilities, some overseen by state regulators, others co-opting state regulators."[29]

In those years, merchant or independent transmission meant developing and financing projects without the protection of a governmentally approved tariff rate or even a contract with a load serving entity (LSE). The "Field of Dreams" mantra—if you build it they will come—was alive and well. Energy traders were willing to make a bet, and that bet was that in the right markets, ownership of transmission capacity between two

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[29] Krapels, *Busting Transmission Trusts*, PUB. UTIL. FORTNIGHTLY, Feb. 2013, http://www.fortnightly.com/fortnightly/2013/02/busting-transmission-trusts?/.

points standing alone, without customers signed up, was sufficient. The key to the castle was market-based rate authority granted by FERC.[30]

In exchange, the potential merchant transmission developers had to be willing to take all the risks of development. There was no guarantee of a return of and on invested capital. There was no recovery of development costs for projects that did not succeed. Initially, no incumbent utility was willing to make such a bet, but they were more than willing to fight the development of such independent proposals with every weapon at their disposal. Discussion of some examples of these battles will be discussed later in this chapter.

Many of the early opportunities for independent transmission involved bridging control areas. Contrary to common belief that the United States is made up of one large electrical grid, the reality is a hodgepodge of state and regional grids whose interconnections have been, to say the least, uncoordinated. It is not by accident that the first three major completed independent subsea transmission projects have involved interconnection between New York and its neighbors, each belonging to a different electric control area. The resulting increases in grid reliability and substantial reductions in delivered power costs to ratepayers is compelling and will be discussed in the case studies below.

Transmission infrastructure finance had historically been based on the regulatory compact guaranteeing a reasonable return of and on equity. The common stock of utility companies and their bonds were held very broadly in conservative portfolios. Released from the low fixed returns of these sorts of portfolios, private equity funds started looking at the independent generation sector for the stability of transmission investment at much higher IRRs. The story of independent transmission in the millennium has provided a number of examples of such forays.

Until recent years, there had been very little attention given by FERC to inter-control area or interregional planning and cost allocation matters. In the early millennial period, a number of specific attempts to bridge

[30] Neptune Regional Transmission System, LLC 96 FERC 61,147(2001). This Order authorized Neptune, then a project that existed essentially on the back of the proverbial envelope, to operate under the imprimatur of FERC as a merchant transmission owner and to sell its transmission capacity pursuant to a non-discriminatory open-season process.

the policy gulf were successful, but only in the context of ad hoc decisions being made to answer questions raised by the development of several inter-control area merchant grid ties. For all practical purposes, the New York City metropolitan area includes northern New Jersey, southeastern Connecticut, as well as New York City and Long Island. Yet New Jersey, only hundreds of yards across the Hudson, is part of the PJM grid and electrically might as well have been light years away. Efforts by FERC in the early 2000s to create one regional RTO for the northeastern states went down in flames under the weight of hundreds of lawyers protecting the fiefdoms of their clients and for lack of any basic federal policy guidance that would have facilitated such a region-wide solution.

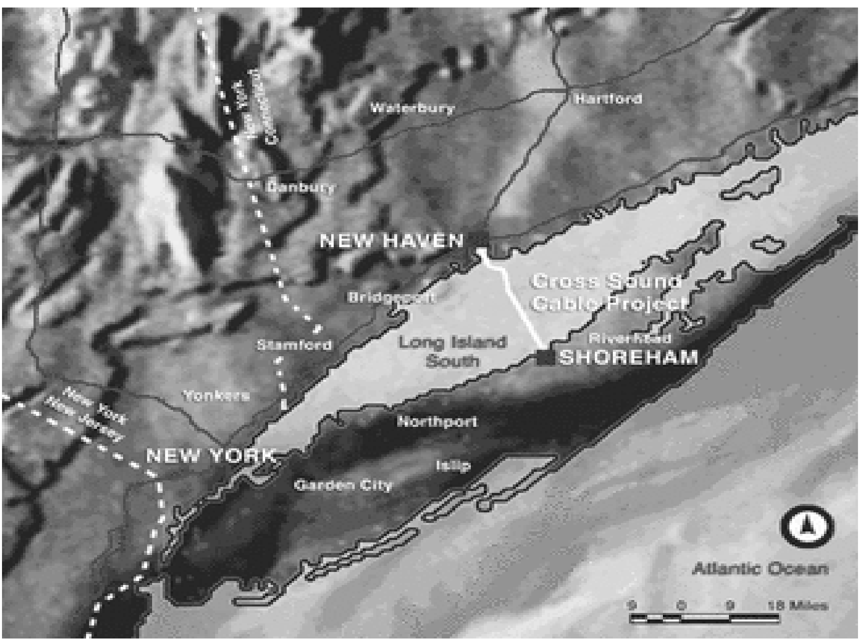
The most obviously advantageous market condition for the development of a merchant tie is a substantial and enduring price spread between adjacent control areas. For example, if the locational marginal price (LMP) of a MWh of power at the generator node is $40, and the delivered price in the sink or consumption market is $120, then the spread is $80. If the cost of transmission between the source and the sink is $10 per MWh, then the net savings to the sink market is $70. When a spread is that large it suggests a very large and diverse source market with substantial surplus generating capacity, a strong control area grid, and relative ease of entry for new generation. On the other hand, the cost of $120 at the sink suggests a highly urban, generation- and transmission-constrained market with fairly high barriers to increases in domestic generation capacity as well as transmission constraints. The key economic driver of almost all subsequent independent transmission proposals was the savings to customers that could be achieved in the sink market if electric power can be delivered from the source market at a price that is lower than the spread.

2000 – 2013: The Response

The case studies we will describe below illustrate these market conditions and other market parameters that led to the development of four significant subsea HVDC projects in the first thirteen years of the millennium. In providing these case studies, we will describe the project basics and rationale, and then focus in greater or lesser detail on the applicable regulatory structure and development issues and solutions.

Cross Sound Cable

Cross Sound Cable, a venture originally sponsored by Hydro Quebec's wholly owned US subsidiary Trans Energie, US (TransE), is a 330 MW HVDC underwater electric cable project using ABB Voltage Source Converter (VSC) technology. It connects ISO-New England from a United Illuminating substation in New Haven, Connecticut, twenty-five miles under Long Island Sound to the Long Island Power Authority (LIPA) substation on the site of the now closed Shoreham nuclear power plant. Development began in 1999, construction commenced in 2002, and the cable was completed in 2003 but did not go into regular service until late 2004 as a result of a settlement between Connecticut and New York brokered by FERC. The project was sold to Babcock and Brown in 2006, and then was later acquired by Brookfield Energy.



Cross Sound Cable Project

The need for the Cross Sound Cable was based on grid reliability, system stability, and ancillary service benefits to the project, as well as some price benefit to Long Island. Unfortunately, the project was never able to make a compelling case for economic benefit with Connecticut stakeholders.

Energy Parochialism Meets Developer Hubris

On June 9, 2000, TransE filed for a Certificate of Environmental Compatibility and Public Need with the Connecticut Siting Council, the Connecticut statutory body tasked with issuance of this most critical of state permits for its project.[31] Starting from New Haven Harbor, the proposed cable route abutted the federal channel or the anchorage for about two miles. Both areas were heavily trafficked areas. The Commission held nine public hearings on the proposal. Interveners in opposition included the Connecticut public advocate, the Connecticut attorney general, as well as fishing (oysters) and business interests and the environmental community in general. The board of alderman of the city of New Haven, the project's host city, unanimously opposed the project.

On July 27, 2000, the Commission issued its order denying the certificate, basing its decision on environmental concerns and lack of a clear electric reliability benefit, finding that:

(i) information on the effects of the proposed project on shellfish resources within New Haven Harbor, obtained during the proceedings, has raised concerns from both municipal and State officials, legislators, and the public" that New Haven Harbor is a "primary oyster habitat and that the shellfish beds within New Haven Harbor are an irreplaceable resource," and questioned how the proposed restoration efforts after trenching within the oyster beds would benefit the oyster industry; and stated
(ii) the proposed project would have a substantial benefit to Long Island, but it would at best provide only incremental benefits to Connecticut and the region, that may not be realized for several years.[32]

The project route was rejected unanimously.

The developers adjusted the route, avoiding the oyster beds, and reapplied for an alternate site on July 24, 2001. After thirteen public

[31] Connecticut Siting Council Docket No. 197 *available at* http://www.ct.gov/csc/cwp/view.asp?a=958&Q=247616.
[32] *Id*.

hearings and despite the continuing strong opposition of Connecticut's attorney general Richard Blumenthal, the siting board approved the project by a vote of 8-1 on January 3, 2002.

Attorney General Blumenthal took the unusual step of appealing the siting board ruling to the Superior Court of Connecticut while his office was simultaneously defending an agency action of the siting board pursuant to the statutory role of the attorney general. The decision in the case[33] allowed the attorney general's appeal while raising serious ethical misgivings about the attorney general's office appearing on both sides of the litigation. Agreeing to a "Chinese Wall" within the attorney general's office as a cure for this ethical issue, the court first granted standing to the Attorney General and then promptly dismissed his appeal on the merits. Blumenthal's opposition did not end after this setback in Superior Court.

The cable also required other state permits, particularly a permit from the state Department of Environmental Protection and permits issued by the Army Corps of Engineers. These permits were issued in March 2002 and construction of the cable portion of the project began soon thereafter. In relevant part, these permits authorized cable burial only during certain months of the year to avoid harm to spawning fish species, and required a fixed burial depth outside the federal channel and a different and deeper depth inside the channel. The permits provided such work could be done in subsequent years if not completed during the initial permitted burial campaign window.

At the end of the first burial campaign, however, seven locations along the twenty-four-mile length of cable were not buried to the legally mandated burial depth, some for fairly long distances. Connecticut agencies immediately began tough enforcement actions, ultimately preventing the Cross Sound Cable from going into commercial operation—even though it was technically and mechanically able to do so. After seeking and obtaining a legal opinion from Attorney General Blumenthal that would effectively prevent the developer from correcting the permit violations by reburying the cable to its authorized depth, the legislature enacted two one-year moratoria on any further subsea burial/remediation.[34]

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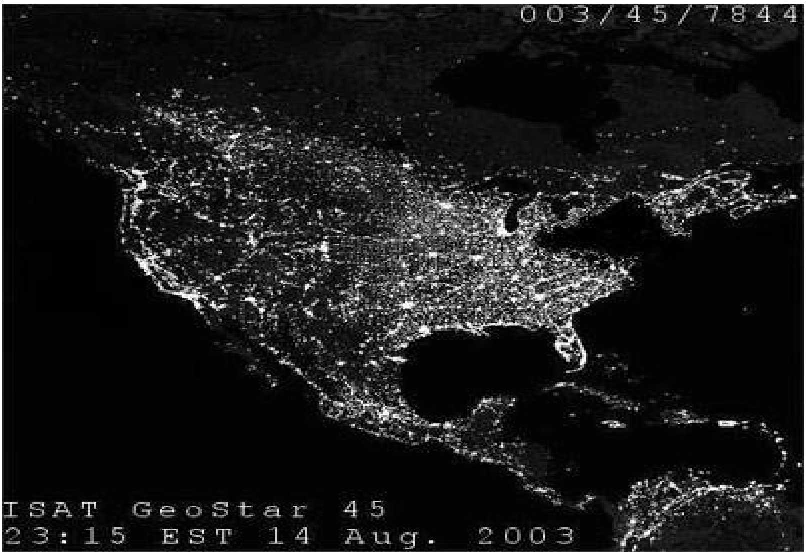
[33] *City of New Haven v. Connecticut Siting Council*, CV0205513195S, 2002 WL 31126293 (Conn Super. Ct. Aug. 21, 2002).

[34] *See* Attorney General's Opinion (Gov. Rowland), April 17, 2002.

And so it stood until August 14, 2003, when a massive blackout in the northeast and other parts of the United States and Canada occurred. Citing his emergency powers and notwithstanding the non-compliance with the permits and approvals that had allowed the state of Connecticut to prevent the cable from operating, US Department of Energy Secretary Spencer Abraham ordered the cable activated to stabilize the grid and prevent rolling blackouts as the grid was being restored to full operation.[35] That order was extended indefinitely on August 28, 2003, and the cable operated under that order until that order was lifted on May 8, 2004 and the cable was again shut down.



Satellite Image: Northeast Blackout, August 2003

A Congressional hearing followed with a battle of the titans—Attorney General Blumenthal in one corner and New York Attorney General Spitzer in the other.[36] Finally, FERC took the bull by the horns and brought the warring parties together for discussions with little effect until an ultimatum was issued and FERC promised to issue an order without the consent of the parties. Under this threat, a deal was made and the cable was re-energized and continues to operate under its third owner today.

[35] Department of Energy Order No. 202-03-2 (August 28, 2003).

[36] *See* Hearing Before the SubCommittee on Energy and Air Quality of the Committee on Energy and Commerce of the US House of Representatives, May 19, 2004.

Cross Sound Lessons Learned

Cross Sound has become a guide to those who have come after on how *not* to do things, and is stark evidence of how developing and permitting done without sufficient regard for local interest combined with the parochial interests in opposition led by a powerful public figure willing to push to the limit, can lead to the perfect storm that was Cross Sound. Here are just three specific lessons learned:

Due Diligence. Pre-installation subsea surveys have the clear technical capability of identifying most of the bottom conditions, and that, in turn, will determine the final cable route. Whether that survey work was done and the conditions were not known, or whether the developer or contractor chose to ignore the data, and take a chance that nobody would notice, is not known.

Fishing Interests. Whether they deal with fish swimming in the sea or oysters lying in the sand on the sea bottom, fishing interests are fierce when it comes to protecting their resources from what they perceive as threats. This is true throughout New England, and developers who take these folks on do so at their own risk.

Community and State Benefit. Both need to exist, and to be palpable. Both require early identification of stakeholders, understanding of the project's impacts on them and clear ways to mitigate those impacts. Attorney General Blumenthal sued an agency his office represented, opined that legislation preventing repairs to be done was constitutional, litigated at every available turn. The argument that brought allies to his cause was his claim that the state's scarce energy resources were being diverted to the benefit of another state, while forcing Connecticut consumers' electric bills higher.

Energy Parochialism

All politics are local and energy politics particularly so. After waging the long battle, the project is up and operating, almost always in export mode for Connecticut generation for import to LIPA. An editorial by Dr. Robert Peltier, Platts energy editor in chief, stated:

> So for Connecticut, the bottom line of its opposition to operating the Cross Island Cable is this: There's nothing in

it for us. Mr. Blumenthal put it this way, "We will be vigilant against new projects that seek to exploit any transmission facility, siphon power from Connecticut to Long Island, raise prices for our consumers, or harm our economy."

In my view, Dr. Peltier continued, the Cross Sound Cable is a model for future transmission development. It is privately owned and imposes no cost on Connecticut ratepayers (unlike other local electric transmission lines). (What is) more, its impact on regional transmission planning is undeniably positive because it serves as another vehicle for moving power during emergencies. In fact, a recent test run proved that the cable can move power from New Haven to Norwalk via Long Island, giving Connecticut the ability to route power around one of the worst transmission bottlenecks in the country.

Mr. Blumenthal's interference with the Cross Sound Cable is a prime example of all that can go wrong when local politicians—for their own political gain—take stands against projects that will benefit millions of people. Ultimately, Mr. Blumenthal will lose for two reasons: A larger national interest is at stake, and the public's tolerance for unconstructive interference in electricity transmission is at its lowest level in years. This is just the kind of test case that will force congressional preemption of interstate transmission disputes and diminish state involvement in future planning decisions. And (we will) all have Mr. Blumenthal to thank for that.

Neptune Regional Transmission System

The Neptune Regional Transmission System was originally conceived of in the late 1990s as a means to bring "gas by wire" from newly discovered offshore natural gas fields in Nova Scotia to markets in Boston and New York via a multi- leg project extending hundreds of miles. It wound up as one part of a sixty-one mile subsea HVDC link using Siemens technology and Pirelli (now Prysmian) cables. The project connects the PJM RTO at

Sayreville, New Jersey, subsea to Jones Beach, Long Island and then is buried along the Wantaugh Parkway using direct current (DC) to a converter station and then back under the Parkway by alternating current (AC) line to the LIPA Newbridge Road substation. It has a transfer capacity of 660 MW and provides over 20 percent of the power needs of Long Island. The development process began in 1999 with initial closing and the start of construction on July 15, 2005. It was completed early and under budget and went into commercial operation on June 30, 2007.

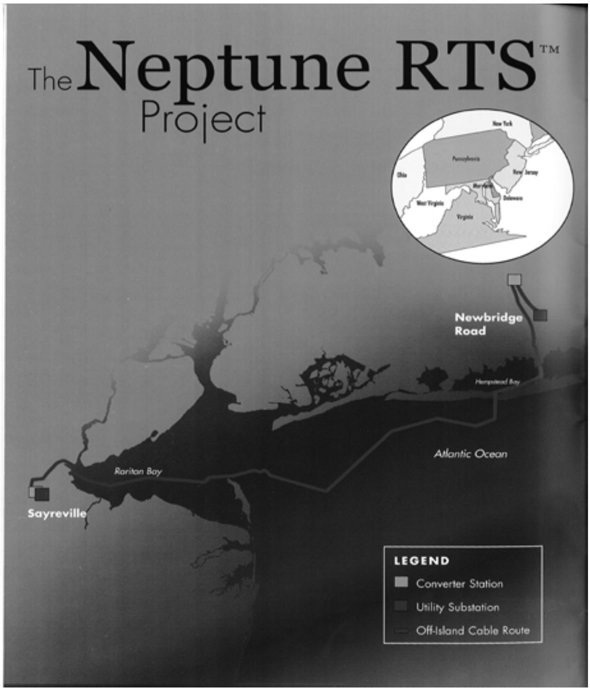
The project rationale was straightforward. The price spread between PJM at the Sayreville node and the LIPA Newbridge Road substation was profound and enduring, according to energy economists. When selecting Neptune in an RFP, LIPA projected ratepayer savings of over $1.5 billion during the twenty-year term of the contract for use of the cable.

Generation resources in PJM are abundant and diverse within all or part of thirteen states encompassed within it, from New Jersey, to Illinois, to the west, and Virginia to the south. PJM has an aggregate installed capacity of over 157,000 MW in its control area. There are few barriers to entry for new generation in appropriate locations within PJM. The PJM grid's deliverability standard is to plan, construct, and maintain the grid to permit the deliverability of energy from any point to any other point within the PJM footprint at all times and under all conditions. Transmission congestion exists, but is not substantial and is dealt with using nodal pricing mechanisms to charge higher prices to transmit from constrained regions.

In effect, LIPA and its customers took out a long-term lease on a node that came out of the ground in Sayreville, New Jersey and allowed LIPA to buy energy and capacity for delivery over the Neptune line under long-term supply contracts with a particular generator bidding on power in the day ahead or even real time markets. In the first summer of operation in 2007 alone, LIPA reported savings of over $20 million.

<u>Permitting and Development Issues: FERC Market-Based Rate Authority</u>

The New Jersey to Long Island leg of the Neptune Project was the first of its kind to propose to connect the PJM and NYISO grids, but the first approval sought was much more broadly based. It sought approval for the entire proposed network, including imported energy from Atlantic Canada. On May 23, 2001, Neptune filed an application with FERC for approval of a merchant-based tariff intended to allow prices to be set along the nodes of the Neptune Regional Transmission System by negotiation and open seasons.[37]



The Neptune RTS™ Project

The filing described the Neptune project as a submarine HVDC system that will consist of "several thousand miles of undersea high voltage direct current (HVDC) transmission that will connect capacity rich regions of Maine, New Brunswick, and Nova Scotia with capacity constrained markets in Boston, New York City, Long Island, and Connecticut. The Neptune project will also create new interconnections between NEPOOL, New York Power Pool, and PJM Regions, and when fully completed will create system benefits, including improving regional reliability and increases in the transfer capability of existing transmission lines in these regions."[38]

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[37] Order Approving Proposal with Conditions (July 27, 2001) Docket No. ER01-2099 also cited at 96 FERC 61,147.

[38] *Id*.

Neptune Thrystor Valve Hall

Courtesy Neptune Regional Transmission System.

The filing went on to describe the specific links being proposed in the first phase as the interregional links from PJM to New York (Manhattan and Long Island) totaling 1200 MW and the benefits of these links. The initial links were intended to further the Commission's goal of eliminating seams between these regions. In addition, the Neptune interconnections would significantly aid inter-pool trading and provide the basis for an integrated northeastern RTO that would be one of the deepest and most liquid power markets in the world. The filing suggested that "no one should pay more for Neptune Project capacity under the proposed rate structure than the difference in the price of power at the delivery and receipt." This previously discussed enduring spread was the foundational assumption for the project upon which the developers were willing to stand or fall.

There were interveners in this proceeding from every element of the energy sector including the incumbent utilities serving load throughout the northeast (LIPA, BGE, PSEG, GPU/PECO, ConEd, NStar, NU, CMP), energy traders (Enron, TXU Trading, Dynegy, El Paso Merchant Energy, and Mirant), the RTO/ISOs (NEPool, NY ISO, PJM), the New York Public Service Commission, and others.

A mere sixty-five days after the filing, FERC issued a unanimous order granting market-based rate authority to Neptune and granting Neptune the authority to issue securities and assume obligations or liabilities.[39] FERC did not, as several protestors had demanded, require a full evidentiary hearing on the matters at issue in the request. FERC required Neptune to join the applicable RTO, in this case either NY ISO or PJM, and to proceed under their tariff structure, including the ability to be paid as other participants for system benefits it might provide.

It is hard to overstate the impact that this order had on the viability of this project. Before the order, Neptune was a group of developers, none of whom were affiliated with any incumbent utility with an idea and some specific ways to implement it. Neptune had no rights in any of the real estate or submerged land leases or rights of way needed to construct any of the legs of the project. It had no contracts with a technology provider to design and build the project. It had performed no system impact studies, obtained no rights to interconnect to either the PJM system or the LIPA or Con Ed systems, and it had very little external financing.[40]

What this order did do was to provide the legal framework around which Neptune could test its concept and thus its viability in the marketplace. FERC was truly going to let the market decide whether the project would go forward or not. It gave Neptune the right to take what existed and what was planned, which in reality was very little more than an idea, and see what, if anything, anybody was willing to pay for these rights. It gave federal authority to issue securities and to enter into binding agreements. It made Neptune real or at least gave it a real chance to take the next step.

FERC Approved Open Season and the 9/11 Attacks

Pursuant to the FERC Market Based Rate Authority, the open season began in early September 2001, seeking to award phase one contracts on November 21, 2001. There were sixty-two registered bidders for the open season, including many from the energy trading sector, incumbent utilities

[39] 96 FERC ¶ 61,147 (July 27, 2001).

[40] The developers of the Cross Sound Cable, a subsidiary of Hydro Quebec, kept loose tabs on the development of Neptune, not as a meaningful competitor but as a joke—they called it Neptoon, as in “cartoon.”

and their trading subsidiaries, bankers, energy equity funds, and players in the gas transmission space. The Neptune team road show visited Houston, Halifax, and New York City. The investment bankers, regulatory counsel, energy economists, and technology providers spoke, and the audience asked a lot of questions.

Firm bids on phase 1 were due on October 22, 2001 and indicative bids on later phases were due on October 31, 2001. While there were many short-term indicative bids on later phases between Nova Scotia or New Brunswick and Boston and New York, none was robust enough nor had a long enough term to be economically viable. With respect to phase 1, however, a major player in the natural gas pipeline space made bids on the New Jersey to Long Island leg as well as the New Jersey to Manhattan leg at rates far above our most optimistic projections for a term of twenty-five years. For a company seeking to finance the project on the strength of a highly rated counterparty, the prospects looked bright.

On September 11, 2001, the attacks on the World Trade Center, the Pentagon, and the aborted attack on the Capitol itself changed everything. Not only were we now at war, but the belief that the economy had nowhere to go but up was shaken when Enron, the paragon of the new energy era, filed for bankruptcy protection on December 2, 2001. Ultimately, this led to the collapse of the energy trading sector. By the end of 2002, the entire energy trading sector had lost 95 percent of its market capitalization. Even so, the economic engine rolled on . . . for a while.[41]

Negotiations for a transmission scheduling rights agreement began almost immediately after the open season. Negotiation went slowly with a counterparty steeped in gas transmission law and experience, and the

[41] One of the realities that loomed over this process was the fact that as developers the Neptune partners did not have sufficient development capital to pay for the development process on a current basis. An initial injection of $500,000 had been pretty much depleted by mid-2002. The search for development capital partners was critical, as was the management of any development capital that was available. On July 31, 2002, a large energy firm stepped up with a substantial development loan of an amount sufficient to bring the project to financial closing. By December 2002, however, its non-utility subsidiaries were struggling along with the rest of the energy trading sector, and after disbursing approximately half of the committed funds the company pulled the rest of its funding. A subsequent settlement brought the total to about three-quarters of the original promised sum, so development continued, although always with an eye on costs.

permitting process underway, many regulatory unknowns remained. While progress was slow, progress was made. In early March of 2002, it seemed that the off-take agreement was ready for execution by the parties, only to have the final negotiating session postponed by the counterparty at the last minute.

The cause of the postponement and ultimately the complete breakdown of the negotiations were totally extrinsic to the deal. The bankruptcy of Enron the previous December had begun a cascade of reactions in the accounting world and serious re-evaluation of long-held principles and procedures. Now the deal just seemed too risky. The capital lease concept and value at risk disclosure rules effectively would have required this counterparty to book all the payments due under the contract for its entire twenty-five-year term as an expense on the first day of the contract without allowance for any offsetting asset to be booked. That balance sheet impact was profoundly negative. The winning bidder withdrew.

The cascading losses in the energy space, the serial collapse of the entire industry, the loss of its development capital investor, and the loss of its counterparty for its off-take agreement all led the Neptune developers to the inescapable conclusion that the time of the merchant project had ended. The only customers for the transmission service being offered were the load serving utilities in the service territories that Neptune could reach. From triple digit possible customers in the market, Neptune's customer base was reduced effectively to two—Consolidated Edison (ConEd) in New York City and the LIPA.

Wandering in the Desert: Fifty First Meetings

While development capital had gotten tight, permitting and site acquisition continued. A series of one-on-one meetings began with the load serving entities. ConEd had never before seriously considered a cable importing power from another control area and was generally committed to meeting New York City's power needs with more in-city generation. The Neptune team would meet with ten people, all of whom nodded politely and said it was an interesting idea and left. A month or so later, a follow-up meeting would be scheduled, a new and different group of ten people would come to the meeting, and then promptly left. The only common denominator was that these meetings were scheduled for lunch time, and I am sure many people came for the free lunch.

During the same time period the Neptune team met with officials at LIPA who, because of their continuing Cross Sound Cable battle with Connecticut's Attorney General Richard Blumenthal, were interested but very cautious. The LIPA team was relatively stable, in that mostly the same people came to the meetings, and as progress in the development of the Neptune Cable continued to be reported, their interest seemed to grow. In the spring of 2003, it became evident that LIPA was seriously considering a cable, and it then informed the Neptune team that state procurement law prevented them from engaging in sole source negotiations but that LIPA would soon issue an RFP for energy and capacity for on-island generation or off-island generation to be delivered by a cable with a commercial operations date no later than the summer peak of 2007. The RFP was issued on May 30, 2003 for between 250 and 600 MW of base load supply. ConEd efforts were effectively put on hold.

While continuing the site control, permitting, interconnection, and financing process, which will be described in some detail below, Neptune prepared and filed its proposal in response to the RFP.[42]

Neptune was one of fourteen responders to the LIPA RFP. Once filed, the process with LIPA was surprisingly interactive, with numerous requests for clarification and updates on development progress. On May 27, 2004,

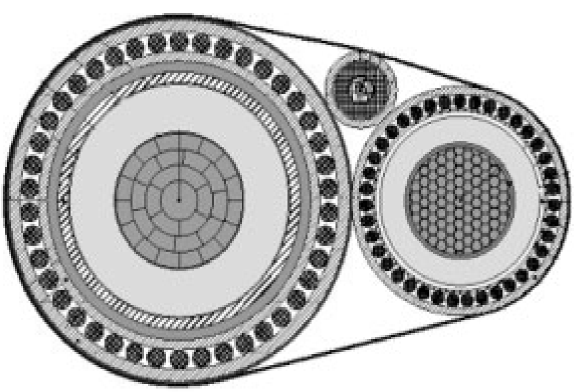
[42] Neptune faced substantial challenges on the technology side of the project. Agreements with the original proposed technology provider were not renewed and agreements were made with Siemens, one of the pioneers of HVDC thyristor valve technology. Siemens neither manufactures nor installs subsea cable; thus, Siemens proposed a cable partner to work with it to provide that portion of the scope of the work under an Engineer, Procure and Construct (EPC) contract. Each HVDC cable is manufactured specifically to meet the needs of a particular project. There is no such thing as an-off-the shelf, sixty-seven-mile-long roll of subsea HVDV cable for purchase. The optimum voltage for the cable in this case was 500 kV. At this voltage, and over the distance of this cable line, losses would be mitigated and more of the power injected into the point of receipt would be delivered to the point of delivery with substantial positive economic implications. Such 500 kV cables existed and had been type tested; however, the selected cable provider had not yet type tested their proprietary design. After a six-month process including two failed type tests, it became clear that the proposed cable provider could not perform and had to be replaced. Another cable manufacturer—Pirelli—with a 500 kV type tested cable joined the Siemens consortium.

almost a year to the day after the RFP was issued, LIPA selected two projects: a 326 MW combined cycle gas turbine generation project in Bellport, Long Island, and the 600 MW[43] nameplate Neptune Project.

In its press release announcing the decision LIPA said:

> The Neptune cable project which can link Long Island to a diverse source of [energy] supply from markets southwest of the region [PJM], emerged as the off-island resource with the greatest long-term benefits for Long Island.
>
> The sixty-seven-mile-long Neptune cable will be capable of transporting some 660 MWs of supply, and will open up an energy corridor [for Long Island] from the mid-Atlantic state through Long Island and on into New England and Canada.

The press release went on to announce its intention to issue another RFP to supply LIPA with power over the Neptune line. LIPA further stated that "[s]eeking energy purchase contracts with suppliers in Pennsylvania, New Jersey, and Maryland will provide LIPA with the opportunity to gain access to a more diverse, cost-effective supply source which will help contain future electricity costs on Long Island."



Neptune Cable Schematic
Courtesy Neptune Regional Transmission System

[43] 660 MW is the actual capacity of the line.

The Multi-Track Run-Up to Financing

During the period from May 27, 2004 until financial closing on July 15, 2005, the Neptune project was moving faster and faster along three parallel tracks.

Track A involved the negotiation of

1. The off-take agreement with Neptune's counterparty LIPA, known as the Firm Transmission Capacity Purchase Agreement (FTCPA) (the FTCPA was executed on October 4, 2004, subject to subsequent approval by the New York State Comptroller);
2. The EPC Contract with a consortium of Siemens and Pirelli; and
3. The project insurance package, which was primarily in the London Market ("Lloyd's").[44]

These two agreements and the related insurance package are joined in this analysis because the obligations of Neptune to a counterparty and sole customer had to be backstopped by obligations of the EPC contractor or by insurance to ensure the risk profile of the project was sufficiently secure to successfully navigate the private equity and debt markets in which a raise of almost $800 million would be required.

Track B involved the filing, negotiation, and issuance of all pre-financial closing permits,[45] the most complex of which was the New York Article

[44] Pirelli, the largest manufacturer of electric cable, was acquired by Goldman Sachs and renamed Prysmian.

[45] List of key pre-closing permits: **Federal**: Neptune Regional Transmission System LLC (hereinafter "NRTS") 96 FERC ¶ 61,147 (2001), order on reh'g 96 FERC 61,326 (2001); 98 FERC ¶ 61,140 (2002) order modifying and clarifying prior order; 103 FERC ¶ 61,213 (2003) (clarifying prior order, 103 FERC Neptune Regional Transmission System LLC Docket No. ER01-2009-003, Letter Order); December 23, 2004 (letter order accepting for filing Neptune's report on the open season) (Taken together, the "Authorization Orders."); **US Army Corps of Engineers**: Rivers & Harbor Act of 1899 permit and Section 404 of the Clean Water Act; **New Jersey**: New Jersey Department of Environmental Protection Waterfront Development Permit/Water Quality Certificate/Acceptable Use Determination. No. 1219-02-005.2 WFD 040001, December 14, 2004; New Jersey Department of Environmental Protection GP-11 Wetlands Permit, Stormwater Runoff Permit, June 14, 2005; New Jersey Department of Environmental Protection VRAP MOU, April 14, 2005; **New York**: Article VII Certificate of Environmental Compatibility and Public Need, as amended (included Section 401 of Clean Water Act Water Quality Certification) October 28, 2004.

VII Order from the New York Public Service Commission and the related US Army Corps of Engineers permits that covered the allowed windows for the subsea cable laying campaigns and the burial depth requirements of the cable in New Jersey, as well as a plethora of local and county permits.

Track C involved the completion of the interconnection processes that included filing with FERC Interconnection Service Agreement and Construction Service Agreements in the NY ISO and the PJM territories, tariff changes in both control areas, and the development of Common Operating Instructions. This track gave rise to a good bit of FERC administrative litigation on a very fast track.

Much of the mid 2004 to 2005 time period was consumed in a six dimensional game of chess. These six dimensions—FTCPA/EPC/insurance/permits/interconnection and financing—had to stand on their own and meet their own requirements, no portion of which could be mutually inconsistent with any of the other dimensions.[46]

Track A

Several subjects were emblematic of the Track A elements process. The first was the overhang of the Cross Sound experience of LIPA on the permitting and financing process. The equity investors, the lenders, and LIPA all had to be comfortable that the problems incurred by Cross Sound would not be repeated in Neptune. A specific subgroup of the development team made up mostly of lawyers and engineers were tasked with identifying any aspects of the cross sound suite of permits that would need attention. This resulted in two major changes in the permits issued for Neptune. The first was that burial depth was a "target" burial depth. If it was not achieved, there was a defined protocol to go back and attempt to rebury or to use pre-approved protection mechanisms if such reburial was not practicable. Second, the

[46] Several ancillary structural matters needed to take advantage of state or local tax requirements could be handled separately to a great extent but still needed the coordination function. These included the Urban Renewal structure required in New Jersey and the sale lease back structure with Nassau County Development authority, both of which reduced substantial recording changes, allowed for sales tax exemptions on the construction contract and provided the framework for payment in lieu of taxes (PILOT) agreements with the host municipalities. Also included in this category were the host community benefit agreements.

permits specifically provided that failure of a good faith effort to meet target burial depth was not a basis for refusing to allow the cable to commence or to continue operations. Finally, an allocation of the risk and costs of these reburial efforts was agreed to between Neptune and the EPC contractor, with insurance covering much of the unallocated risk.

Second was the relationship between the FTCPA and EPC in terms of price, currency risk, time for performance, warranties, change order risk, and liquidated damages or other penalties for delay. Normally one seeks to tie down at least one of these agreements to ensure that the other critical project agreements can provide a backstop. But when negotiating all these agreements simultaneously, the ability to perfectly cover all of these risks was always at issue. The biggest problem that appeared to have the chance of derailing the negotiations was the necessity of proposing a price increase above that which was bid in the RFP caused by the delay in the bid award.[47]

Cable Carousels aboard Cable Laying Vessel Julio Verne

Courtesy of Hudson Transmission Project

Third was the issue of insurance.[48] The cable provider required a form of insurance not generally issued in the US market and only issued in the London market at a very high premium. The London market, and even then only a small number of syndicates at Lloyds, had had very bad experiences with subsea communications cable that had generated huge losses, since a fiber optic cable is really just a strand of glass. A long time

[47] It is my belief that the savings to LIPA ratepayers even with the price increase brought the two parties together on this issue.

[48] Insurance requirements were set forth in Schedule 9.04 of the Institutional Loan and Letter of Credit Facility Agreement (confidential).

was spent differentiating the market risk, hiring insurance risk evaluators to distinguish between fiber optic and the Neptune armored copper cable. That all being said, the Lloyds syndicates knew we needed the coverage and that there was, apparently, no one else willing to step up, so the price held. Having the benefit of a world-class insurance broker, Marsh, we asked them to see if they could make a market in the US to counterbalance the London market's intransigence. They did, and the insurance was placed with a London/New York consortium put together by Marsh at a substantial discount from the initial quoted price.

Track B

Track B involved multiple permits at the local, county, state, and federal level. A representative sample of each is listed in the footnotes above.

<u>NY Article VII</u>

The most deserving state permit of mention is the New York "Article VII" Certificate of Environmental Compatibility and Public Need. This permit is a one-stop, New York State permit run by the New York Public Service Commission involving multiple parties, and New York state and federal agencies included the Section 401 Water Quality Certification required by the Federal Clean Water Act. It is followed by a set of implementing Orders (Environmental Management and Construction Plans [EM&CP]) that approved detailed construction approvals. In this case, the project was approved based on a negotiated stipulation among all the parties, meaning that all the underlying issues had been worked through and the Commission did not need to perform a judicial function in a formal adversarial hearing. In this project, the Article VII effectively ends the NY PSC's active participation in the operation and regulation of the Neptune project as there are no rate proceedings that would come before the PSC.

<u>Army Corps of Engineers Permits</u>

The most critical federal environmental permit is the Army Corps of Engineers (ACOE) permit under Section 10 of the Rivers and Harbors Act of 1899. Section 404 of the Clean Water Act was submitted to the ACOE on January 2003, the process remained active and ongoing with a series of public notices and subsequent agency consultation in July and August of 2004, leading to the issuance of the permit on February 16, 2005. The time and expense of this process was enormous, as were the stakes. As previously discussed, the need to tailor conditions in the permit to avoid Cross Sound-like circumstances was paramount and, ultimately, successful. Burial depth was a target, remediation efforts and processes were described, and the continuation of operations during any such remediation process was adopted.

In addition to burial depth, the impact on species inhabiting the area of sea floor in and around the cable route and in the related water column was the primary concern of the Federal Fish and Wildlife Service, a consulting federal agency. The burial process for the cable was by jet plow, a small four-wheeled vehicle placed on the sea bottom, looking much like the Martian rover with a long tooth called a stinger. With the cable routed through the jet plow, it followed the surveyed cable route using GPS guidance for its controllers on the surface using high pressure water, and emulsified the sea bottom along the route followed by the stinger to shape the excavation to the proper depth, thus allowing the cable to immediately slide into the disturbed area.

Within twenty-four hours, the sediments had generally resettled and the area restored naturally to its pre-installation condition.[49] The specific benthic studies required by the Fish and Wildlife staff involved analysis of the particulates that were suspended in the water column and sediments before and after the jet plow run and chemical analysis of such disturbed sedimentation. Given the known historically serious pollution upstream in the Hudson caused by toxic discharges, this concern was not without basis, although no such pollution was found by the studies. The concerns for life forms living on or under the sea bottom were related to clams and flounder. The concern was that the installation would disturb the spawning season of winter flounder and that clams in the area would be stressed. Clam stress was measured by density of clams in the area, but not known was how many mating-impeding headaches were induced in flounder by the cable laying campaign. However, in both cases post-installation surveys showed no adverse impacts on these populations.

[49] The cable was installed to its target depth in over 99 percent of the route with a few small areas that were remediated as provided in the permit.

Track C (Interconnection Agreements)

The interconnection process turned out to be the most challenging part of the pre-approval process. The first impediment arose because of opposition of the owner of the land underlying a substation adjacent to the Neptune converter station in Sayreville, New Jersey and its refusal to grant an access easement across the land to the substation bus bar. The second impediment was due to the two interconnecting utilities on the New Jersey side of the cable project, PSE&G and First Energy's affiliate JCP&L, who opposed the initial market-based rate authority ruling and whose opposition was unremitting up until the financial closing and start of construction.

The interconnection process in New York and in PJM differ slightly, but in essence their tariffs provided an opportunity to interconnect with their system by filing an interconnection request followed by a series of technical studies, designed to determine at a very preliminary level: (1) the reliability impacts of such a new interconnection (feasibility study); (2) to determine the system upgrades that would be necessary to mitigate those impacts (system impact study; and (3) to determine the specific costs and specifications of such upgrades. These studies are paid for by the developer and any "but for" upgrades to the system as well as direct connection expenses are allocated to the developer.

Reliant ROW Issue

New Jersey permits required a complete route map with right, title, and interest along the entire route and an owner's consent. The Neptune converter station in Sayreville abuts the JCP&L Raritan substation, the intended point of interconnection. The Raritan substation itself is owned by JCP&L, but has easements for the operation maintenance modification and expansion of the substation from Reliant Resources, a PJM and NY ISO generator with interests in eighty-one power plants in New York. Negotiations for an easement across this property and the owner's consent were suddenly halted, and I was advised by the Reliant official that Reliant's "commercial folks" had ended the negotiations. He said, "Well, the news is not good. There was a discussion with me on the phone involving [John, NFI] and a couple of other commercial folks. The bottom line is they (cannot) see how anything you could offer will offset the impact on the in-city energy and capacity market if the project moves forward."[50]

With this evidence of an explicit use of market power to prevent a competitor from interconnecting to the PJM system, a complaint was filed at FERC on April 4, 2003, Reliant reversed its position on April 22, 2003, and signed the proffered agreement, and the FERC complaint was dismissed on May 3, 2003.

Study, Re-Study, Re-Re-Study, *Ad Nauseam*

One of the biggest variables in the interconnection process was the projected topology of the power system when the proposed interconnection was scheduled to occur and what would be the impact on that projected system. The primary determinant of that topology was the retirement of existing generators, many of which were utility owned. The process of retirement allowed a notice of retirement to be withdrawn without penalty.

Spare Transformer at Duffy Street Station, Neptune Project
Courtesy Jack Montgomery

[50] Broder Affidavit, ¶ 19, *Neptune v. Reliant New Jersey Holdings*, FERC Docket No. EL03-115-000 (April 8, 2003).

Generally, the result of a generator withdrawal on the interconnection studies was to substantially increase the amount of system reliability upgrades that were needed in the form of more transmission to bring power into the area to offset the generation that had disappeared. The opportunity for mischief was legion, however, and in a flurry of proposed retirements and un-retirements it became almost impossible for PJM to conduct its studies and to develop a baseline topology of its system.

Ultimately, on December 21, 2004, Neptune brought this issue to FERC for resolution in a complaint to FERC.[51] The case was brought on a set of facts stipulated by PJM so that an answer on policy grounds that was being sought could be obtained in a timely manner. Prior to the requested decision date, FERC granted the Neptune Complaint.[52] The result was issuance of interconnection agreements and construction service agreements with both PSE&G and JCP&L, which they refused to sign. The unsigned agreements were filed by PJM with FERC and were accepted for filing.[53]

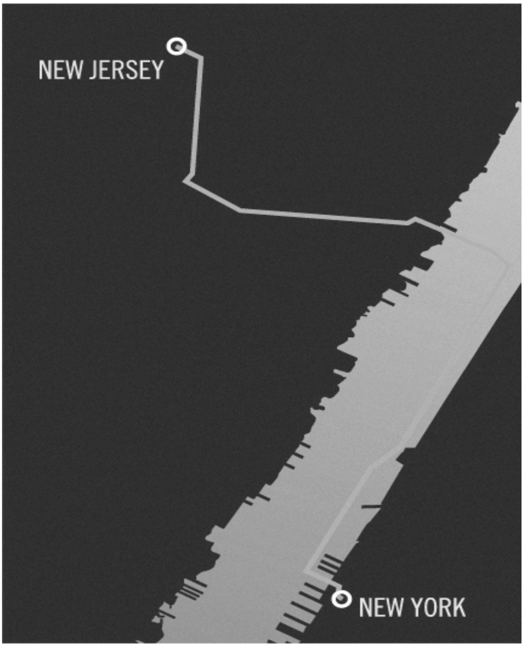
Simultaneously, the project team and an army of outside counsel were working through the selection of equity participants and the negotiation of terms with them, the raising of debt, the coordination of terms, and the due diligence from both debt and equity to meet each investor's or lender's unique requirements. Once all required permits, consents, and approvals were obtained, the closing happened very quickly and on July 15, 2005, financing was closed and a Notice to Proceed was given to the EPC contractor. Slightly less than two years later on June 30, 2007, Neptune reached COD and has been operational, delivering power with very few interruptions ever since. As noted earlier, Neptune provides over 20 percent of the power needs of Long Island. It was awarded the distinction of *Project Finance Magazine* 2005 Deal of the Year.

Hudson Transmission Project

Hudson was developed by three of the five original Neptune partners in response to an RFP from the New York Power Authority (NYPA). It runs from a PSE&G substation in northern New Jersey under the

[51] *NRTS v. PJM*, FERC Docket N0. EL05-48.
[52] *NRTS v. PJM*, 110 FERC 61, 61,098 (2005) order on reh'g 111 FERC 61455 (2005).
[53] *PJM*, 111 FERC 61,456 (2005).

Hudson River interconnecting to the Con Ed system at its West 49th Street substation. NYPA, in turn, was providing this transmission cable to essentially serve the power needs of its government agency customers, such as the Metropolitan Transit Authority and the New York City Housing Authority. Given the costs of real estate on Manhattan, the project was designed with back-to-back converter stations in New Jersey, delivering A/C power via an eight-mile cable.



The Hudson Transmission Project

The need for cheaper and reliable power for NYPA's customers pushed the issuance of the RFP and the award to Hudson. The state and local permitting, and FERC approvals, were essentially copies of the Neptune process, and do not need a lengthy recounting here.

The development team initially believed that because of the groundbreaking nature of the Neptune efforts, development of Hudson would be much shorter. However, there were two major issues that drove a development process that took eight years, even longer than Neptune. These were the New York Article VII process and the Interconnection Agreement in *PJM*. In each case, it was extrinsic matters that caused the delay.

Article VII

The Article VII process for Neptune was previously described as one that was resolved through a negotiated settlement with the stakeholders and did not require the NY PSC to be the arbiter. The Hudson project, however, required a fully litigated process and order. The reason for the difference was that the interests of several stakeholders could not be resolved by anything other than failure of the project. That is a result that cannot be negotiated.

Recalling the concerns expressed in 2003 by Reliant Resources in seeking to stop Neptune because of its impact on the New York non-utility generators they owned, in the case of Hudson, the injection of up to 660 MW of cheaper energy imported from PJM into the heart of the constrained load pocket of Manhattan was going to have an adverse effect and a potentially existential impact on those and other generators that were part of the Independent Power Producers of New York (IPPNY), as their place in the dispatch curve would most certainly be reduced. Secondly, this new injection of power had the potential of providing a substitute for nuclear power from Entergy's Indian Point plant up the Hudson. The mere existence of an alternate supply fueled Governor Cuomo's efforts to close Indian Point, which in turn would mitigate the prospect of blackouts in New York City if the nuclear plant were to close.

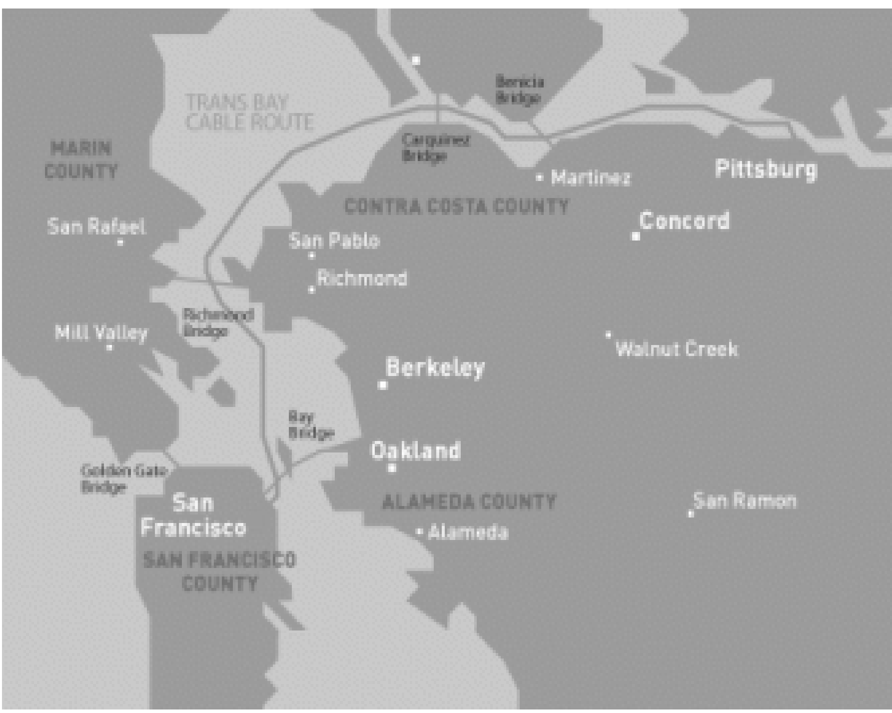
Interconnection and Upgrade Costs in PJM

Timing is everything when seeking to interconnect to any transmission system. The capacity of a system is inherently lumpy, meaning upgrades required to support one interconnecting party often leads to unused interconnection capacity in the system not used up by the new interconnecting party. This "headroom" gives another later interconnecting party a much reduced "but for" cost responsibility. Neptune came along in 2003-2005, when there was some headroom in the system that resulted in a direct interconnection and system upgrade cost responsibility of approximately $15 million. The initial feasibility and system impact studies for Hudson yielded staggering upgrade costs just shy of $600 million, an increase of 4,000 percent. An over-two-year process ensued as studies were critically examined, technical parameters were changed, and the request for export capacity reduced, leaving the final interconnection number in excess of $175 million still the largest interconnection cost assessment ever levied in PJM. It is a testament to the enduring value of the project that such a cost could be paid with the project still being viable.

The Hudson Project reached COD in June 2013 ahead of schedule and on budget and has been operating at an availability percentage of over 99 percent ever since.

Trans Bay Cable

Developed by Babcock & Brown, this underwater HVDC Project with a transfer capacity of 400 MW connects the City of San Francisco with the City of Pittsburg, California via a subsea cable. It was completed in November 2010. The transmission development arm of Babcock & Brown has reformed as Pattern Energy and is active in other subsea cable development projects, including Hawaii.



Trans Bay Project

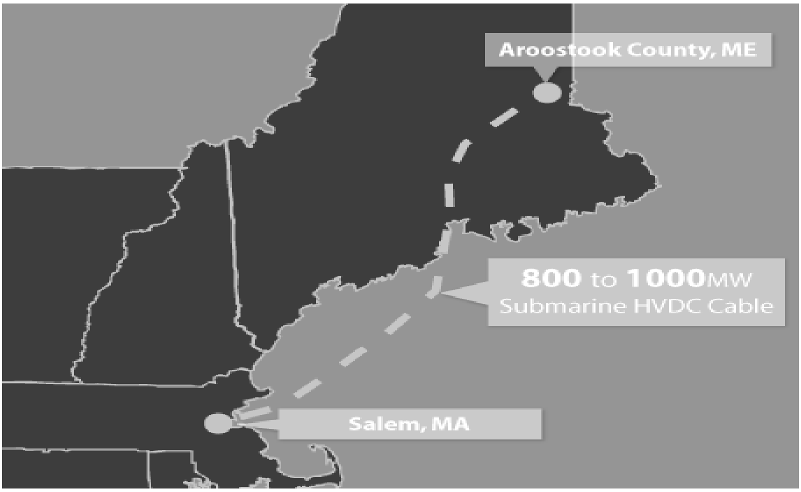
The project now provides 40 percent of the power to San Francisco, injecting its power right into the heart of the city and avoiding an almost impossible task of building terrestrial transmission in this highly urban setting, once again showing the efficacy of subsea cable routes in serving such isolated load pockets.

Utilizing available California legal structures, the project was the first large intra-state HVDC project to be developed on a rate-based rather than merchant or contracted model. This model may well become a model for future development. The state of Hawaii, for instance, has enacted its own statute based on the California model and efforts are now underway to develop an inter-island grid tie using this approach.

New Project Proposals, New Players, and the Emergence of Regional RFPS

In the last several years, additional HVDC projects with subsea components have begun development. These include:

1. The Green Line with a point of receipt in Aroostook County, Maine, to Searsport, Maine via an already purchased right-of-way and then into the water to a point of delivery in the Boston region's North Shore;
2. The Poseidon project connecting central New Jersey with Long Island along a route similar to the Neptune Project,
3. West Point, a project buried in the Hudson from the Albany area to the general area of the existing infrastructure of the Indian Point substation,
4. The Grand Isle Intertie, connecting renewable generation in New York State that is constrained by lack of terrestrial transmission capacity to downstate, across Lake Champlain and then into southern New England and perhaps even back into New York via existing transmission corridors;
5. A project sponsored by NextEra seeking to rate base a project from the Seabrook nuclear plant's adjacent substation to Salem station, north of Boston; and
6. The Oahu/Maui proposed HVDC grid tie in Hawaii.



The Green Line

With a combined transmission capacity of over 2250 MW, these projects will continue to meet the needs of urban areas where terrestrial options through suburbs and the cities themselves have proven impractical, or where inter-island cables are the only way to connect separate island grids. By comparison, other north-south, strictly terrestrial project proposals seeking to connect Canadian Hydro Power and other renewables to southern New England and New York markets, buried all the way along a turnpike route or through rural Vermont or New Hampshire, have engendered cost challenges and stakeholder opposition political acceptance.

The makeup of the development teams for these projects has changed dramatically. The prominence of private equity as a player in the development process is much lower as the industry's apparent tolerance for delay and for risk diminished. While several projects have made very healthy returns from cash flow and from sales of interests, many have failed to thrive, leading to large losses and the decision to stop funding at a much earlier point in the development process. Significant industry rather than financial players are moving into this space alongside and in joint ventures with developers or entirely on their own accounts. These parties, to name only a few, include NextEra, National Grid and Exelon, and several regional or large in-state transmission utilities. Additionally, traditional investors in energy funds, such as retirement funds, are starting to make direct investments in this space.[54] Whether such industry players, used to a rate-based development process with recovery of investments for abandoned development, will choose to walk the high wire without a net has yet to be determined by events.

Finally, there seems to be a trend toward use of regional RFPs on behalf of states and incumbent LSEs to solicit generation solutions (through long-term energy purchase agreements) as well as for transmission solutions.[55] Also in the works is a possible RFP by the New England States Council on Energy (NESCOE) for transmission-only solutions to bring renewable generation to southern New England to meet state renewable mandates. Each of these RFPs is likely to offer fully contracted or rate based reimbursement. The state of Hawaii is in the process of studying the feasibility of an inter-island grid tie between Oahu and Maui. Once the PUC has made such a determination, an RFP will be issued under the state's new certified cable company law that will permit such a cable to be rate- based.

But as significant as these developments may seem, they are but a small sampling of the structural changes to come.

The Emerging New Order: FERC Order 1000

Background

It is hard to fully appreciate just how significantly the current electrical regulatory structure has evolved since the early 1990s. In that short time, the industry has implemented FERC Order 888's[56] mandating of open access to transmission facilities to remedy undue discrimination and encourage the development of efficient, lower cost power, and FERC Order 890's[57] coordinated, open, and transparent regional planning process to further remedy undue discrimination—just to name a few. Entire utilities are now vertically divested, leaving them with a transmission and

[54] CalPers' purchase of a large stake from Arclight in the Neptune project and other retirement funds direct investments is in development as well.

[55] NYPA/RFP of May 2013 for generation and transmission solutions to mitigate the possible loss of the Indian Point Nuclear Plant.

[56] Order No. 888, *supra* n. 17.

[57] Preventing Undue Discrimination and Preference in Transmission Service, Order No. 890, 72 Fed. Reg. 12266, ¶ 3 (Mar. 15, 2007), FERC Stats. & Regs. ¶ 31,241 (2007).

distribution function and a non-exclusive relationship with their customers. The once captive customers are now set free to select a power provider in an increasingly robust retail market.

Although a customer's bill may look quite similar to how it did before electrical deregulation, often the utility is a mere paying agent for its competitors. The clear thrust of such developments is to do more than rearrange deck chairs, but to continue to restructure the operation, planning, and participation in the electrical industry. As discussed above, the first decade of the millennium gave rise to an emerging merchant transmission business model where point-to-point transmission links within and across control areas were developed by developers with no-load serving obligations and who, in exchange for taking all the risks associated with such development, were able to charge a market-based rate for their transmission service. The merchant transmission's customers, who were by and large the LSEs at the point of delivery, created a competitive process to secure such transmission capacity, a process that often involved an RFP in which transmission and generation solutions directly competed with one another.[58] In the case of the Trans Bay project, for instance, the solution was a rate-based rather than market-based transmission solution, moving the independent transmission model one major step further along in its evolution.

For all intents and purposes, the projects discussed above were developed outside the ambit of an existing and well-trod pathway set forth in federal energy policy. Projects moved forward because they made economic sense and were proposed by developers and capital willing to take the risk. But make no mistake, FERC and the RTO/ISO community touched each of these projects, be it through authorizing interconnections or granting market-based rate authority. By 2013, at least four major independent transmission links, one connecting ISO-New England and NYISO, two connecting PJM and NY ISO, and one intra CALISO project, were in operation and proving a very significant proportion of lower cost power to transmission and generation constrained urban load pockets.

In a related development, but occurring during the same time period, many states and regions developed Renewable Portfolio Standards seeking to

[58] The tension between transmission solutions and generation solutions during the lengthy request for proposal process associated with the Neptune and Hudson projects described above are but two examples.

promote (some say force) the development of renewable generation in their jurisdictions. Maine, for example, now requires that a portion of all electricity used to supply Maine consumers must come from *new* renewable resources. The required percentage started at 1 percent in 2008 and will climb to 10 percent by 2017.[59] A bit to the south, New York requires a renewable target of 30 percent of state consumption by 2015, of which around 20 percent is derived from existing generation sources and the remainder from eligible incrementally increasing new renewable resources and customer-sited resources.[60] In the most aggressive jurisdiction in the country, the state of Hawaii requires that 40 percent of all net electrical consumption must come from renewable resources by 2030.[61] Together with federal tax incentives, state renewable polices such as these have and will continue to lead to a remarkable growth in the development of new renewable resources.

Yet as is often the case, renewal generation resources are quite distant from load, and therefore, transmission becomes a key issue in meeting RPS goals. Notwithstanding the lofty state RPS goals, the responsibility to solve the resulting transmission problem often fell to generators, who were forced to construct long and expensive “generator ties” to the nearest transmission node. Rate-based treatment of transmission expense was generally unavailable unless the transmission upgrade mitigated a system reliability concern. It was inevitable that a regulatory change was in order.

Order 1000 and the New Battleground

Based on these realities, FERC began a stakeholder process, starting with three regional technical conferences in September 2009, a lengthy request for comment in October 2009, and a Proposed Rule in June 2010.[62] Then in 2011, at the conclusion of a multi-year drafting and commenting process, FERC issued Order 1000[63]—an order that will, in some dramatic and some

[59] Me. Rev. Stat. Ann. 35-A § 3210 (West).
[60] *See, e.g.*, State of New York Public Service Commission, Case 03-E-0188, Renewable Portfolio Standard (RPS), Order Establishing New RPS Goal and Resolving Main Tier Issues (issued Jan. 8, 2010).
[61] Haw. Rev. Stat. §§ 269-91 *et seq.* (West).
[62] Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, Order No. 1000, 76 Fed. Reg. 49842 (Aug. 11, 2011), 136 FERC Stats. & Regs. ¶ 61,051 (2011) , ¶¶ 23-30 (hereafter “Order 1000”).
[63] Order 1000, *supra* n. 62.

halting steps, lead to the creation of a policy that will bring independent transmission into the policy and regulatory framework, and potentially alter the landscape for future transmission development in the United States. As the Public Utility Regulatory Policies Act of 1978[64] led to a restructuring of the electrical industry and the growth of independent, non-incumbent utility renewable generation, Order 1000 and its progeny will have the potential to restructure the current electrical industry, spur new development in independent and non-incumbent transmission, support the growth of renewable power generation and state-based renewable energy policies, and work to place incumbent and non-incumbent utility transmission developers on a more balanced regulatory footing.

Notwithstanding its apparent and daunting complexity, Order 1000 generally focuses on three primary areas of reform: (1) non-incumbent developer rights (2) inclusion of public policy considerations in the planning process, and (3) inter-regional planning and cost allocation reforms. Of its various provisions, it is the inclusion of state policies into a regional transmission planning process and the elimination of the federal right of first refusal (ROFR) in certain circumstances that will most significantly affect the relationship between incumbent and non-incumbent transmission utilities for decades to come.

One must not, however, underestimate the power and influence of the incumbent utility sector as they fight to protect their one remaining monopoly.

Although it has become clear that independent and non-incumbent transmission providers will play an increasingly important role in the overhaul of our country's electrical grid and the country's rapidly evolving transmission needs, one cannot minimize the forces of the status quo and their ability to delay what they view as an existential threat. As FERC marches toward implementation, the battleground will be in compliance filings, the amendment of FERC-approved Open Access Transmission Tariffs (OATTs), and in the courts, where the incumbent utilities are expected to fight long and hard all the way to the US Supreme Court to protect their perceived constitutionally protected "natural monopoly." Until this issue is resolved, full implementation of Order 1000 will not occur.

[64] 16 U.S.C. § 824a-3.

Legitimizing the Non-incumbent Transmission Development Community: Non-incumbent Developer Requirements

Of the various components, Order 1000's efforts to promote competition in regional transmission planning processes is arguably the most significant challenge to the incumbent transmission public utility—and likely will be the most strenuously opposed by the incumbent transmission public utilities. Order 1000 requires the "removal from Commission-jurisdiction tariffs and agreements . . . provisions that grant federal right of first refusal to construct transmission facilities selected in a regional transmission plan for purposes of cost allocation."[65] The federally approved ROFR provided the incumbent public utility transmission provider with a right to construct, own, and recover the cost of transmission infrastructure located within the incumbent's service territory and subject to a transmission plan created according to the standards outlined in Order 890. This is an existential challenge to the utilities' core business.

Under the new regulatory structure, any non-incumbent developer of a transmission facility[66] that is selected as part of a regional transmission plan now must be provided "an opportunity comparable to that of an incumbent transmission developer to allocate costs of such transmission facility through a regional cost allocation method or methods."[67] The termination of the ROFR only applies to *new* transmission facilities that were selected under the regional transmission plan for purposes of cost allocation, with four important conditions:

- The ROFR elimination does not apply to a transmission facility that was not selected for cost allocation under the regional transmission plan;
- The ROFR elimination does not apply to any upgrading of transmission facilities, including tower change outs or re-conductoring;

[65] Order 1000, *supra* n. 62 at ¶ 225.

[66] A "non-incumbent transmission developer" means "(1) a transmission developer that does not have a retail distribution service territory or footprint; and (2) a public utility transmission provider that proposes a transmission project outside of its existing retail distribution service territory or footprint, where it is not the incumbent for purposes of that project." Order 1000, ¶ 225|. An "incumbent transmission developer/provider" is "an entity that develops a transmission project within its own retail distribution service territory or footprint." *Id*.

[67] Order 1000, *supra* n. 62 at ¶ 225.

- The rule permits but does not mandate the use of competitive bidding to procure transmission projects or project developments; and
- The rule does not affect state or local laws and regulations governing the construction of transmission facilities, including local and state siting and permitting.[68]

As expected, the public utilities have already begun to protect their "natural monopoly" and have initiated challenges to implementation of the cost allocation provision as ISO/RTOs make various compliance filings and amend FERC-approved OATTs.[69] Lengthy court challenges will continue to delay development of the cost allocation methodology. Given the influence of incumbent utilities within their service areas, one can equally imagine efforts to limit the rights of non-incumbents under this provision in state legislatures.

For instance, when ISO-New England submitted its compliance filing for Order 1000,[70] various incumbent utilities and other parties reasserted their right to monopoly status and challenged the legality of the proposed elimination of the ROFR under the *Mobile-Sierra* doctrine, a longstanding and incumbent-favored doctrine that prevents the unilateral amendment of a contractual term unless a failure to amend the contractual term would seriously harm the public interest. In again rejecting the challenge, FERC reasoned that the doctrine did not apply to a Transmission Operating Agreement because the TOA was only "of general applicability" rather than a specific contract, and that the rationale articulated in Order 1000 regarding the changing electrical landscape supported the change.

Notwithstanding the strenuous opposition by incumbent utilities, FERC's commitment to removal of the federal ROFR is steadfast, and any major policy retreat by FERC is unlikely. As FERC stated, failure to remove the federal ROFR "would leave in place practices that have the potential to undermine the identification and evaluation of more efficient or cost-effective solutions to regional transmission needs, which in turn can result

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[68] Order 1000, *supra* n. 62 at ¶ 319.

[69] For a summary of compliance filings by region made, *see* FERC, Order No. 1000 – Compliance Filings & Orders, http://www.ferc.gov/industries/electric/indus-act/trans-plan/filings.asp.

[70] ISO New England Inc., 143 FERC ¶ 61,150 (2013).

in rates for Commission-jurisdictional services that are unjust and unreasonable or otherwise result in undue discrimination by public utility transmission providers."[71]

Reliability Plus: The New Transmission Planning Process

For decades the primary, if not the only, justification for development of new transmission infrastructure has been to ensure the reliability of the electrical system; in other words, to prevent blackouts and other less dramatic service interruptions. Other important state and federal policies, including encouraging the development of new renewable resources, played virtually no role in the reliability-based transmission analysis. It had heretofore been unthinkable that an RTO/ISO would order a rate-based pool transmission facility to be built and rate-based to interconnect a rural wind farm without a reliability rationale.

Order 1000 takes the first steps to change this traditional planning module by requiring that the local and regional transmission planning process must include consideration of state and local policies, statutes, and regulations, including renewable portfolio standards. The order also provides that the procedures adopted by "public utility transmission providers . . . must allow all stakeholders to bring forth any transmission needs they believe are driven by public policy requirements, those procedures must also establish a just and reasonable and not unduly discriminatory process through which public utility transmission providers will identify, out of this larger set of needs, those needs for which transmission solutions will be evaluated."[72] The independent and non-incumbent public utility went from not having a voice, to having a seat at the table. At the same time, the transmission developer has only one seat among many and while evaluation of alternate solutions is required, approval is not.

Yet the inclusion of public policy considerations into the regional transmission planning process is important. Renewable generators are often located away from existing infrastructure and require new transmission development. To date, there had been no established federal policy mechanism through the OATT process with respect to the development

[71] Order 1000, *supra* n. 62 at ¶ 253.
[72] Order 1000, *supra* n. 62 at ¶ 209 (emphasis added).

and integration of renewable generation. Order 1000 now requires consideration of state and federal public policy in the planning process. Public utility transmission providers must now identify such policies, and then evaluate proposed transmission solutions according to those criteria. To further ensure that proposed solutions are "reviewed in a fair and non-discriminatory manner," public utility transmission providers must post on their websites an explanation of what transmission needs will be driven by public policy, how proposed solutions will be evaluated in the local or regional transmission process, and why other suggested transmissions will not be evaluated.

FERC will presumably carefully evaluate the compliance filings for the creation of procedures to add consideration of public policy to the planning process and will seek strict compliance with the resulting FERC-approved OATT tariff changes. This requirement, however, could just as easily become mere window dressing, for while FERC tends to work using such guidance, that guidance often, years later, yields a mandate.

Cross-Regional Planning and Cost Allocation

While there may be no requirement to produce an interregional transmission plan or cost allocation process, or otherwise proceed toward formal interconnection planning, Order 1000 clearly moves the ball toward development of a cross-region transmission planning process. Order 1000 recognizes that many transmission solutions involve crossing regional control areas ("seams projects"), thus requiring transmission providers to explore cross-region transmission solutions and to work jointly with neighboring regions on planning protocols. Each neighboring transmission planning region is also required to have a common interregional cost allocation method for new interregional transmission facilities selected by the region. In one recent example, a proposed project designed to bring transmission constrained wind power from New York State north of the Adirondacks under Lake Champlain and down through Vermont into southern New England (and New York City) was delayed because the planning protocols in operation in ISO-New England and NYSIO were neither compatible or complimentary, nor did they provide any cost allocation guidance for this interregional proposal. In a recent series of cases before FERC, the Midwest ISO (MISO) and PJM worked out substantial seams protocols.

One anticipates that for the moment non-incumbent transmission developers will avail themselves of FERC proceedings to provide a declaratory order dealing only with the facts at issue in their particular project and on an ad hoc basis obtain FERC consent to move forward with projects between control areas. One expects the non-incumbent to do so even without a fully baked plan promulgated by the applicable RTO/ISO. Order 1000 also requires cost allocation to be "roughly commensurate" with estimated benefits, and allows wide discretion for each region to develop an allocation methodology. In other words, those who benefit from a new transmission facility should roughly be the ones who pay for its increased costs. Yet by linking the transmission planning and cost allocation in the transmission planning process, FERC seeks to "increase the likelihood that transmission facilities in regional transmission plans are actually constructed."[73] And given that those facilities must not necessarily be constructed by an incumbent transmission provider, substantial opportunities abound for the independent transmission developer.

Order 1000 and Beyond

As the RTOs and participating transmission owners begin the lengthy process of submitting compliance filings outlining proposed regional transmission planning processes and removal of the ROFR from FERC-jurisdictional tariffs, the "winners" and "losers" under the new regulatory scheme will become increasingly clear. Although the non-incumbent transmission provider may urge for additional reforms on the ground that Order 1000 has not gone far enough to spur a competitive market for transmission development, it is increasingly clear that the electric industry landscape has and will continue to rapidly erode the traditional monopoly power of the incumbent public utility transmission provider.

Predictably, those incumbent transmission public utilities have long sought to protect their monopoly status against the growing independent and non-incumbent transmission movement, inspired and empowered by cable transmission projects such as the Cross Sound, Neptune, Hudson, and Trans Bay cable projects previously discussed. The new battle lines are drawn, yet as compliance filings and the question of Order 1000's legality continues to move through FERC and the federal courts, it is apparent that change is coming.

[73] Order 1000, *supra* n. 62 at ¶ 501.

The first battles for independent transmission companies being fought are in the courts and through the compliance filings and approval process at FERC. Without winning this fight public policy based transmission lines will simply not occur. That having been said, planning for "collector" transmission lines designed to transmit power from a number of renewable generation projects in renewable rich region, (for example on shore or off shore wind) have begun in earnest in anticipation of the day when such a project will be ordered built and included in rate base by an RTO.

Conclusion

It is not by chance that the case studies in this chapter have focused on subsea cable projects and not primarily terrestrial projects. Like any new participant seeking market entry, one looks for the least fortified point of entry, and in these cases that was in the water. It was not clear in whose service territory the water was between PJM and NYISO or between NYISO and ISO New England, so whose job was it to defend that territory? Very few seams projects between control areas using water borders had been attempted, yet the economic benefits, as previously described, are substantial. In retrospect, the approach seems natural.

Another reason for a non-incumbent without eminent domain power to approach a subsea route is that such submerged land within the three-mile limit are state waters, and states have been permitting cables in state waters for decades. Cables in federal waters are also available, provided the requirements of federal law are met. In all four case studies cited, the vast majority of the right of way needed for the project was obtained under existing authority from state and federal agencies.

Fish do not vote, but people do, as anyone who tries to build terrestrial transmissions anywhere learns. Whether those transmissions go through dense urban and suburban places or rural areas, residents will fight to protect their land or their views. If one stays out of oyster beds, does not stress too many clams, nor disturb too many winter spawning flounder, and avoids whale sanctuaries and shipping channels, a well-surveyed and planned route is likely to be approved with much public storm and stress. The installation of a subsea cable affects a long and narrow strip of sea bottom and such impacts are temporary and benign. A buried cable does not bother anyone, in contrast to high voltage terrestrial transmission corridors.

Yet, as described in detail in the body of this chapter, the difficulty of paradigm change is profound. Such change is an existential threat to many powerful stakeholders, whether they are utilities in their own service territories or merchant generators seeking to keep their market share and price position. One would not expect anything less than opposition using all available means. The entirety of FERC Orders has not entirely leveled the playing field, leaving many artifacts of the monopoly past un-reformed. Also, we must remember that much of the nation is not a part of organized markets under the RTO/ISO model.

At the end of the day, whatever the mechanism, whatever the protocol, whatever the structure, the unbending truth of the electricity industry has been that "load pays." Under this construct, the ratepayers are the ultimate beneficiary because when they turn on the switch the light comes on. That too may be changing.

FERC's regulatory approach as illustrated by Order 1000 suggests that the universe of beneficiaries may in fact be broader than ratepayers to include everyone who breathes the air, and wants to live free of air pollution, and toxic substances in our land and our water. By including "public policy" considerations into the planning model of electric transmission and doing it on an interregional basis, we essentially change the equation. No longer is the question of ordering the construction of a new transmission line only to ensure that the lights stay on for a certain subset of customer, but whether a line to a wind-rich resource area far from load can be ordered built and paid for to allow wind developers to build their wind farms with a guaranteed pathway to market. The question that will arise is whether that universe includes ratepayers or taxpayers in general.

Revolutions are not neat and tidy and they are not linear in nature. They look more like the outside of a paint can after the paint inside is used up and the drips of paint have dried in irregular patterns all along the outside of the can. A robust marketplace powered by the need to keep the lights on and to meet a wide array of public policy goals at the national and state level is the future that FERC has chosen. Getting there will not be neat and linear either, as the enormous machine known as the power grid is built out and changed in accordance with this broader vision. The definition of utility lawyer has been forever changed and broadened. This having been said, legal practitioners in this space on any side of the transaction are well advised to learn as much about the needs and imperatives of the other parties in a proposed transaction as these needs may not always be obvious or linear.

Key Takeaways

- Seeking declaratory relief at the FERC: The transmission space is in the process of a dynamic process of radical change. Once a new policy has been put in place by FERC, compliance filings and court challenges can hold up implementation for years. Filing a complaint at FERC seeking declaratory relief for an implementation step in the context of a policy compliant new project can move the policy implementation process along more rapidly, and is a strategy to be seriously considered.
- New market entrants: After a period where new independent transmission projects had been financed by private equity, we are entering a period where insurance companies and pension funds are making direct investments in such projects, and new projects are being co-developed and financed by the non-regulated subsidiaries of large public utilities operating outside of their regulatory footprint
- Reliability plus: Order 1000 now requires consideration of state and federal public policy in the planning process. Public utility transmission providers must now identify such policies, and then evaluate proposed transmission solutions according to those criteria. Opportunities for advocacy on behalf of stakeholders whose interests in transmission beyond the concept of reliability are legion and create a whole new body of empowered stakeholders needing competent counsel.

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