A Typical Case of Weak Institutional Complementarity in Institution Building : The Design of Transmission Network Monopoly in Competitive Electricity Markets

Jean-Michel Glachant, Vincent Rious

ISNIE Conference in Reykjavik June 2007

A typical case of weak institutional complementarity in institution building: The design of transmission network monopoly in competitive electricity markets

**Jean-Michel Glachant & **Vincent Rious*

**University Paris Sud **Electrical Engineering School Supélec in Paris*

Abstract

In a "*Weak institutional complementarity*" type of institution building it is typically the less replaceable institutional characteristic which dictates the path of change for the institution as a whole. We will show it is exactly what explains the diversity and imperfection of actual transmission monopoly designs in competitive electricity markets.

Firstly we argue that transmission monopoly in competitive electricity markets has to be analysed within an industry modular frame. Transmission is a set of several modules which have to be distinguished and separated in any design analysis and comparison. At least three modules make the core of transmission design: 1° the short run management of network externality; 2° the short run management of cross border trade; and 3° the long run management of network investment.

Second in a new-institutional economics perspective we say that 1°monopoly design in a competitive policy cannot handle these three modules irrespective of the "institutional" definition and allocation of property rights on transmission; while 2°definition and allocation of property rights on transmission cannot ignore the existing electrical industry and transmission network structure: they basically have to complement each other.

Third we apply this frame to compare PJM (USA) and NGC (UK) and we show it remarkably illuminates the reality.

JEAN-MICHEL GLACHANT is tenured professor and Head of the Department of Economics at U. Paris Sud. He has been deputy director or director of the leading French institutional economics research center in the 90' (ATOM). His research focuses on the institutional economics of competitive reforms in the European network industry, particularly the creation of a single energy market in the European Union. He is currently member of Board of ISNIE, as well as partner of the U. Cambridge energy research institute (EPRG) and of the European Energy Institute (EEI). He received his Ph.D. in Economics from La Sorbonne University.

VINCENT RIOUS is an electrical engineer with a Master Degree from the French engineering school SUPELEC. He is currently a young researcher in the economics and engineering of transmission network management both at SUPELEC and U. Paris Sud.

I. INTRODUCTION

The Transmission System Operator (TSO) is a key module in electricity markets (Wilson, 2002). In this paper, we will examine its role in managing flows of electricity, while ignoring issues related to balancing generation and consumption. When administering electricity flows, a TSO must fulfill three independent missions: (1) the short-term management of electricity flow externalities, (2) the development of the grid (Brunekreeft et al., 2005), and (3) coordinating neighboring TSOs in order to deal with border effects (Glachant et al., 2005). [2005]). The management of flows of electricity by the TSO can thus be studied with a modular approach. An ideal TSO can be construed as the set of the most efficient implementations of these three missions.

However, no ideal TSO exists in practice. Specifically, the TSOs of reference, such as PJM and NGC, are not ideal TSOs. Our assumption here is that the transmission grid's governance structure imposes compatibility constraints on the various implementations of the TSO's missions. Consequently, the governance structure of transmission explains the discrepancies between the ideal TSO and actual TSOs.

The role of managing the flows of electricity can be studied in a modular framework in which the modules are the three aforementioned interdependent missions, as well as the governance structure of the TSO. We will demonstrate that the governance structure of transmission explains the diversity in how TSOs are set up, as well as the discrepancies in their results.

Our paper is organized as follows. In Part II, we present the three missions, to wit the operational modules of TSOs, as well as the various implementations. An ideal TSO can be construed as the sum of the most efficient implementations. In Part III we define a fourth module, the governance structure of transmission, and we demonstrate that incorporating this element introduces compatibility constraints between the implementations of the TSO's operational modules. In Part IV we look at the two references TSOs, PJM in the United States and NGC in Great Britain, which feature relatively opposed characteristics.

II. MODULAR ANALYSIS OF TSO-S

The management of electricity flows by Transmission Grid Operators comprises three principal missions with durations lasting from the very short term (several minutes to several hours) to the very long term (five to twenty years). These missions can be examined in a modular analysis framework that is analogous to that developed by Wilson (2002) to study markets for electricity. The three core missions split into three different transaction domains, providing the reference modules for our analytical framework. First, in the shortest time horizon, we have the short-term management of externalities between flows of electricity. Second, over a longer horizon, we have planning the development of the transmission grid (Brunekreeft et al., 2005). Finally, since electric transmission grids are increasingly open to direct transactions between each other, a third element is the management of border effects across TSO zones (Glachant et al., 2005).

Thus, we can distinguish between the behaviors of the TSOs in the management of each of these three transmission modules by the extent to which they internalize externalities in the pricing system. Consequently, the ideal TSO is defined as the combination of optimal variants for each of the three modules. This ideal TSO could then serve as a benchmark for comparisons across existing TSOs.

We observe that the real-time balancing of supply and demand has been excluded from our modular approach. While administered by the TSO, this real-time market is much more an essential component of the market design and market sequencing (Saguan, 2007; Glachant and Saguan, 2006) than a mission inherent in the transmission system. In the new British system (NETA), operational since the closing of the Pool, management of the balancing market has, moreover, been separated from the other traditional missions of the transmitter NGC.

II. A. SHORT-TERM MANAGEMENT OF ELECTRICITY FLOWS

The principal mission of a TSO with respect to electricity flows is their short-term management, principally owing to the externalities associated with congestion on the grid and power losses. This first mission is central to system operation[1] (SO). It encompasses several variants (with varying degrees of integration) of system operation and the energy market, so as to internalize network externalities.

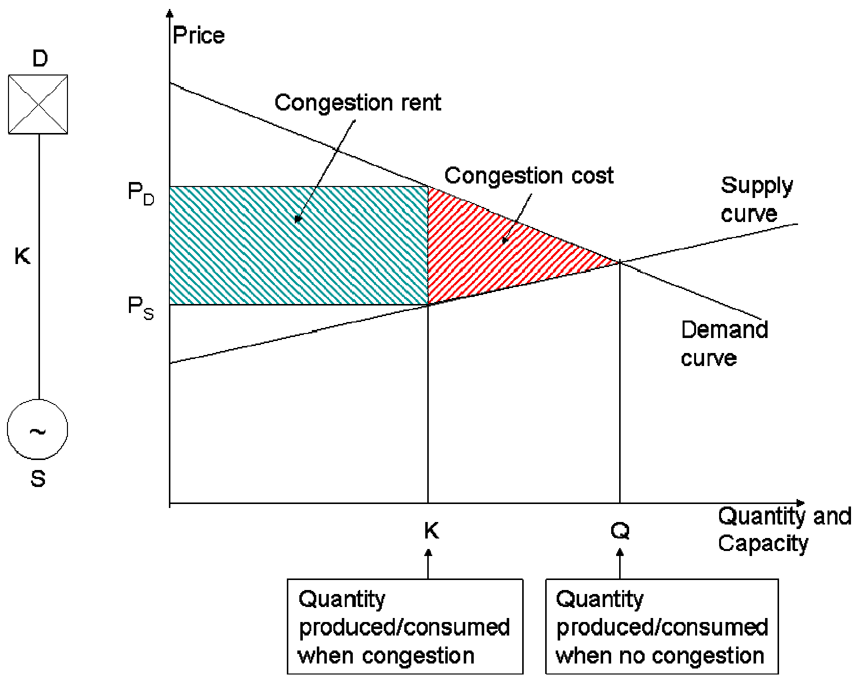
The optimal allocation of the grid's limited capacity is a well-known issue in the electrical industry. Schweppe et al. (1988) demonstrate that efficient dispatching can be obtained thanks to a system of nodal pricing, with clearing being constrained by the externalities of the grid. Theoretical analyses generally only account for congestion and losses, and rarely consider the constraint created by strain on capacity (Caramanis et al., 1982). Nodal energy pricing yields a different price at each node of the grid. These nodal prices indicate where it is preferable to generate or consume an additional megawatt, given

[1] Which also includes balancing generation and consumption in real time or near real time.

the losses and capacity constraints on the grid. The differences between nodal prices reflect the social value of the externalities on the grid. They also generate a surplus for the TSO, who is the intermediary collecting the prices demanded from users injecting power and those withdrawing power from the gird. The grid's capacity constraints limit the maximization of the social surplus. This results in a social cost, called "congestion cost" in continuous[2] current approximations for a lossless grid (cf. Figure 2).

Figure 1

Graphic representation of nodal pricing on a congested two-node grid



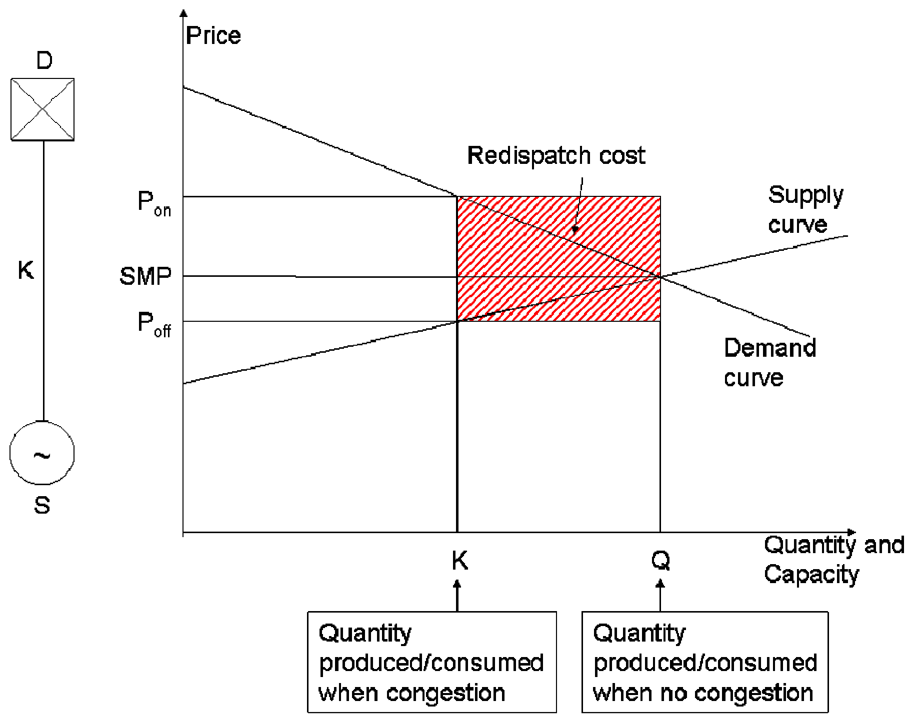
There are, however, other procedures for managing congestion on the transmission grid. Thus, on the initiative of the TSO congestion externalities can also be managed through a direct modification to the list of dispatched power plants. This is called redispatching. This procedure for managing electrical flows and their externalities thus operates outside of the electricity market (cf. Figure 2). In this other means of managing congestion, the electricity market receives no economic signal containing information on the constraints on the grid, and the market for power continues to operate as if there were no losses nor

[2] The continuous current approximation only accounts for the flow of active power and an approximation to the behavior of the grid computed from linear equations. In this case, only congestion (and losses) constrain nodal pricing.

constraints on it. All market participants pay, or are paid, a market price that is unconstrained by conditions on the grid: called the "System Marginal Price." However, some generators or consumers are called by the TSO after closing of the market for energy (outside of "Merit Order") to increase (and then paid Pon) or to decrease (and then paid Poff) to manage the externalities of flows of electricity. The ensuing redispatching cost is assumed by the TSO in the short term. However, directly or indirectly this cost is generally socialized *ex post* in the grid access fee. Thus, only the redispatched entities receive direct economic signals on the existence of constraints on the grid's transmission capacity.

Figure 2

Graphic representation of redispatching on a congested two-node grid



Each of these types of externality on the grid can thus be managed separately from the others, with either redispatching or nodal pricing. For example, nodal pricing may only internalize congestion, while losses and constraints attributable to strain on the system may remain socialized. Similarly, externalities can be managed with varying degrees of precision, depending on the strength of the economic signal transmitted to agents on the market to inform them of the state of constraints on the grid. For example, zonal pricing manages congestions by forming only two prices: the local equilibrium price for each zone, upstream and downstream, from the principal congestions. *De facto*, this zonal management procedure combines the zonal pricing and the redispatching methods (Bjørndal-Jørnsten, 2001; Ehrenmann-Smeers, 2005).[3] On one hand, the main ("structural") congestions are managed with nodal pricing of energy with the grid broken down into zones equivalent to "big nodes."[4] On the other hand, secondary (also called temporary) congestions are managed with redispatching, and their costs are directly socialized in the grid fees.

To conclude, Table 1 presents the three short-term solutions for managing transmission grid externalities, classifying them by their level of integration of system operation and electricity market, as well as by the level of socialization of the costs of externalities.

Table 1

Short-term methods for managing the externalities of electricity flows (*)

Methods for managing externalities	Level of integration between system operation and energy market	Level of socialization of the costs of externalities
Nodal pricing	High	Low
Zonal pricing	Average	Average
Redispatching	Low	High

II. B. DEVELOPMENT OF THE TRANSMISSION GRID

The second mission of the TSO is the long-term development of the electricity transmission grid. In principle, short-term management of the externalities of electricity flows can inform the TSO and network users on the constraints associated with the current state of the grid's operations. However, in the

[3] Each of the various means for managing constraints on the grid can be hostage to the more or less extensive exercise of local market power by "reliability-must-run generators." The redispatching methods is considered to be more sensitive to market power, since the cost of local congestion is socialized with it (Harvey-Hogan, 2000). However, the redispatching method also facilitates the use of standardized forward contracts on electricity markets. This can increase the liquidity of markets and limit the market power of some operators. Thus, a trade-off must be found between increasing the internalization of network externalities into the prices on electricity markets, on one hand, and limiting local market power while fostering liquidity on electricity markets, on the other hand.

[4] Hedging instruments have been designed to cover the volatility of nodal or zonal prices (Hogan, 1992). These are forward contracts, typically called "Financial Transmission Rights" (FTR) in the United States. The owner of such a contract may receive a congestion rent associated with the price differential between two nodes: a "charge" node and a "source" node.

long term, the TSO should also make efficient investments to eliminate all constraints that are economically excessive. This mission of developing the transmission grid presents two aspects to the TSO. First, we assume that the TSO is sufficiently responsible and efficient to invest in reducing the social costs imposed by network externalities or, equivalently, in maximizing the social surplus. However, we also know that the short-term signals sent by constraints on the grid are generally inadequate to effectively guide the long-term siting of economic agents on the grid. Finally, the surplus received by the TSO from short-term system operation fees does not fully cover the costs of the entire grid. The indivisibility[5] of the equipment and the economies of scale, in conjunction with the risk aversion of the engineers running the grid, are at the root of this economic inadequacy of the short-term signals (Pérez-Arriaga et al., 2005; Joskow-Tirole, 2005). Thus, short-term pricing signals must be completed by long-term siting signals, known as “grid access fees” (Green, 2003). These grid access fees allow the TSO to recover the full costs of investments in grid infrastructures (Pérez-Arriaga and Smeers, 2003).

On one hand, the TSO must account for the response of the grid's users to siting signals (short- and long-term) and the expected evolution of the consumption and generation of electricity across the network. On the other hand, the TSO must arbitrate between short-term operating costs, observed or expected on the basis of new requests for grid connections, and the costs of long-term investments in the transmission grid. All other things being constant, these computations must yield a maximization of the social surplus (Pérez-Arriaga - Smeers, 2003).

There are three broad alternative methods for allocating grid costs: deep cost, shallow cost, and zonal pricing (Hiroux, 2005). Other, intermediate methods are also possible. All these methods can be classified by the level of incentives they provide.

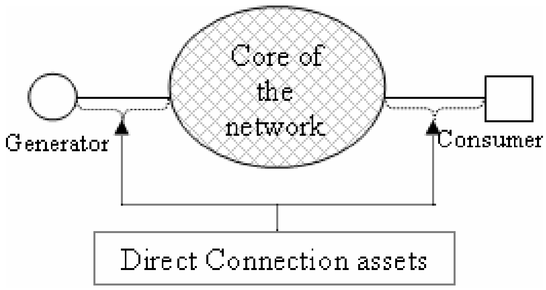
The cost of expanding the grid can be allocated as “deep cost” with a fee charged to each individual user for each new connection or significant expansion of use. In this case, the full costs of all new infrastructures will be directly imputed to network users, and new connections or changes in utilization[6] will trigger new investments from the point of view of the TSO. The billed infrastructures in this case are both the connection infrastructures themselves (attaching a user to existing equipment) and the expansion of the grid’s structure to handle the increased flows induced by new users.

[5] Indivisibility arises from the fact that some amounts can only assume discrete values. This is notably the case for electricity transmission lines, the capacity of which cannot be augmented by marginal increments.

[6] For whatever reason: a local increase in consumption, a new connection, increased generating capacity of an existing power plant, etc.

Figure 3

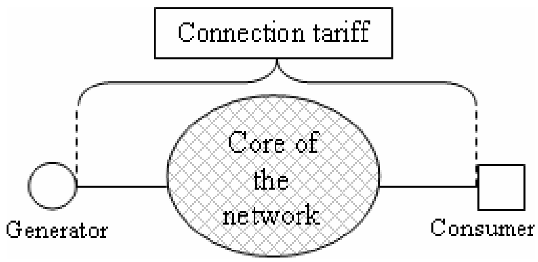
Distinction between connection lines and core of the network



This deep cost method is contestable on a theoretical basis, since it individually affects the costs of indivisible characteristics of power lines. Moreover, this method only partially internalizes the externalities of investments in the grid, as users are not compensated when their connection generates positive externalities for the grid.

Figure 4

Deep cost allocation method



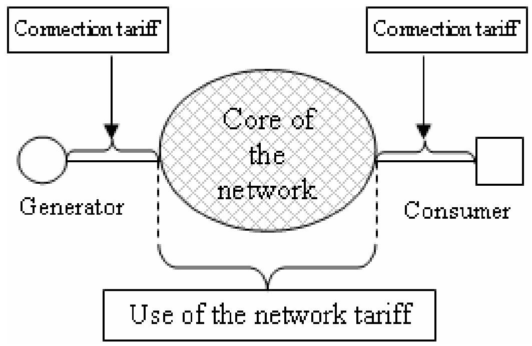
Another method for allocating costs, called the shallow cost, only charges new users, or those who increase their use of the grid, for a small portion of the cost (shallow cost) imposed on the grid. This portion only covers the price of the infrastructure necessary for connecting them. Conversely, all the required reinforcements to the grid's internal equipment (thus, to the "core of the grid") are socialized across all grid users in the general grid access fee (Use of System, or UoS tariff[7]). With this shallow cost

[7] The boundaries of the definition of the Use of System tariff varies widely with the rules of the network. Principally, this fee covers the costs of grid infrastructures and maintenance, as well as the costs of operating the system (balancing, system services, losses and congestion when they are socialized).

pricing method, new users are effectively given an incentive to connect to the grid. However, they have no incentive to account for the effective capacity of the grid's various segments to accept new connections.

Figure 5

Shallow cost allocation method



A final method, called zonal pricing, starts from the shallow cost of connecting to the grid in order to account for direct costs. However, this is completed with a grid usage fee that is differentiated by the zone of the grid. The costs of grid development are thus indirectly imputed to its users by separately signaling the structural capacity to receive connections for each zone of the grid. Many variants are possible here. From the perspective of the grid, this is an active method, since positive externalities from connections can be internalized (fully or in part) in the grid access fee.

Publication of forecasts of the transmission grid connection capacity by the TSO can contribute an additional siting signal for the users' choices. However, this information does not negate the value of the three methods presented above, since we are not limited to a binary, all or nothing, signal. Indeed, the capacity of a grid's nodes (or zones) to receive connections is its nodal (or zonal) ability to accept consumption or generating hook-ups without creating new congestion. There is thus only the grid cost allocation method to inform users how much they must pay in reinforcement costs if they decide to rely on the posted new-connection capacity.

In conclusion, we present a table with the various solutions for allocation grid development costs, classifying them by how they distribute the costs between hook-up fees and grid use fees, and by how they internalize externalities.

Table 2

Methods for allocating the costs of grid development

Allocation methods	**Connection fees [as a % of the grid's costs]**	**Usage fees [as a % of the grid's costs]**	**Externalities internalized by the method**
Deep cost	100	0	Negative externalities
Shallow cost	~0	~100	Distance to the grid
Zonal	0 < x < 100	0 < (1-x) < 100	Negative externalities; and indirectly positive externalities

II. C. COORDINATION AMONG TSO-S

The third mission of TSOs is to coordinate, in order to internalize parallel external flows and border effects.[8] This allows the TSO to make optimal use of all the resources of the interconnected grid, facilitating arbitrage and promoting the merging of the markets in their zones. Coordination between TSOs requires both coordinating the short-term management of grid externalities and coordinating developments on the grid. The problem of compensation amongst the parties to be coordinated is not considered here, and has yet to be addressed in the literature.

There are two ways to coordinate neighboring electricity markets in the context of a market for electricity: uniformization or combination (Glachant et al., 2005). As to the former, uniformization implies that both TSOs choose the same methods for short-term management of electricity flows and grid development, on each grid and at their interconnections, and that they share at least a minimum of information on the state of their networks (cf. Cadwalader et al., 1999) for the short-term coordination of externalities management in electricity flows). As to the latter, coordination by combination requires the establishment of gateways between TSOs to allow the coexistence of individual mechanisms that differ between zones and that are, by extension, more difficult to coordinate.

If we abstract from the cost of implementing coordination, uniformization is always efficient, while combination is nothing other a "second-best" solution, in the jargon of economists. Nonetheless, depending on the cost-benefit relationship of implementing the various coordination methods, coordination by combination, or sometimes even no coordination at all may be the optimal solution (Costello, 2001).

[8] Called spillover effects by Costello (2001).

Indeed, the need for coordination between neighboring TSOs and the effectiveness of the chosen method varies with the topology of the grid. The more enmeshed and interconnected the grids, the more it is efficient to coordinate to internalize border effects (Costello, 2001).

In conclusion, the various coordination solutions for managing border effects among neighboring TSOs are summarized in the following table.

Table 3

Coordination solutions at the borders between neighboring TSOs

(classified by the extent to which they internalize border effects)

Coordination at the borders between neighboring TSOs	Level of internalization of border effects
No coordination	Low
By combination	Average
By uniformization	High

II. D. AN IDEAL TSO

The optimal implementation of the three modules presented above constitutes an ideal TSO for the management of electricity flows on the transmission grid. This type of TSO sends economic signals to grid users to ensure their efficient utilization of the network. It also develops the grid efficiently and coordinates with neighboring TSOs to ensure optimal management of the border effects between their systems.

First, in this framework, grid externalities are managed by the nodal pricing of power in the short term. This permits efficient dispatching of power plants and allocation of the grid's capacity (Schweppe et al., 1988). Second, in the long term, the goal of a responsible TSO is to develop the grid to maximize the social surplus. To invest efficiently, the TSO must determine the social cost of externalities and arbitrate between this cost and that of investments in the grid. To ensure efficient siting of the users of the grid despite externalities and the indivisibility of grid investments, the preferred grid pricing method is zonal, completed by the publication of capacities to host new connections. Third, methods that send siting signals, such as nodal pricing and the deep cost allocation of network costs, are appropriate for internalizing grid externalities. They are also appropriate for internalizing border effects between several TSOs (Glachant et al., 2005), provided they exchange the information and data required for coordination (cf. Cadwalader et al., 1999, for the short-term coordination of externalities management in electricity flows).

In conclusion, an ideal TSO must combine the methods for managing its core missions as follows:

Table 4

Characteristics of an ideal TSO

Missions of the TSO	***Ideal implementation***
1 - Short-term externalities management	*Nodal pricing*
2 - Development of the grid Investments	Centralized by the TSO, minimization of social cost of externalities
Fees	Zonal and connection capacity pricing
3 - Coordination at the borders	By uninformization

III. COMPATIBILITY OF THE MODULES OF THE TSO

If we assume that the TSO is, by nature, efficient and benevolent, then there will never be a compatibility constraint between the three modules we have analyzed.

In reality, of course, there is no credible guarantee that the TSO will be benevolent. Any TSO may encounter contradictions between its own goals, influenced by its governance structure, and the ideal methods for it to exercise its missions. Moreover, the energy regulatory body may also have to deal with ambiguities in the government's energy policy and seek to reconcile contradictory goals. In reality, the most likely situation is that the TSO's governance structure will generate compatibility constraints (also called "institutional complementarity" in Pagano, 1993; and Aoki, 2001) between the operational modules of the TSO.

First, we demonstrate that the governance structure of electricity transmission principally results from the unbundling of the grid from the generation and commercialization aspects of power. Thus, unbundling the transmission grid simultaneously affects the regulation of the transmission monopoly and the market design, which is subject to the externalities of electrical flows. Subsequently, we demonstrate that governance of the transmission grid impacts on existing compatibility constraints between the various implementations of the TSO's three missions.

III. A. THE GOVERNANCE STRUCTURE OF THE ELECTRICITY TRANSMISSION GRID

The consequences of unbundling the electricity transmission grid go beyond the guarantee of free and unrestricted access to the network. The process of implementing the unbundling also constitutes the basis for the "governance of transmission" and thus delineates the compatibility constraints on the procedures for actualizing the TSO's missions.

We will first look at the elements impacting on the choice of procedure for unbundling the ownership of the transmission grid. Then we will address the consequences of the process for unbundling the governance of the TSO and its regulation. Finally, we will examine the impact of government policy, governance, and the regulation of transmission on the market design associated with the externalities on electricity flows.

III. A. 1. Unbundling the ownership of the transmission grid

Unbundling the transmission grid from generation and commercialization activities is usually considered indispensable. This unbundling always includes system operation (= managing short-term flows). However, unbundling ownership of the transmission grid[9] requires the ability to force the incumbents to cede their network assets.

Furthermore, withdrawal from system operation is easy enough for a legal authority to impose in a deregulation process. Indeed, operating the system represents a relatively low volume of investment and work, though it can be employed strategically by incumbents to impede entry by competitors.

Conversely, complete divestment of all transmission grid infrastructures can be more difficult to impose. The grid is a guaranteed and recurring source of revenues for the incumbent, and may thus play a key role in the finances and the market value of the firm. The security of income associated with transmission infrastructures is attractive in the context of cyclical uncertainty on electricity markets. Moreover, ownership of the transmission grid may allow incumbents to strategically protect their installed base of generating facilities during any major network development plans.

The choice of unbundling the grid may also be impacted by other determinants, principally technical. If the ownership and operation of a network on the scale of a continent (United States, Continental Europe) or a subcontinent (Scandinavia, South-eastern Europe) are highly fragmented between many distinct TSOs, then parallel flows of electricity create many "border effects" between these

[9] If Transmission Ownership is not integrated with System Operation, Transmission Ownership may, or may not, be bundled with another part of the power supply chain.

TSOs. If these border effects are not sufficiently internalized, they can reach values that are critical for the security of the system in the context of increased volatility associated with commercial trade in electricity. Unbundling the grid in ownership and in operation in each of the TSO's zones may not suffice to solve the characteristics problems of "border effects." One solution, then, is to withdraw the "system operator" function from the incumbents and consolidate it over a larger geographical zone encompassing several electrical zones under the direction of a new Independent System Operator (ISO) or Regional Transmission Organization (RTO). The creation of these regional system operation zones can occur without completely modifying the historical structure of the ownership of the grid infrastructures. A compromise that can be offered to the incumbents is that they retain ownership and maintenance of their grids in exchange for the creation of an independent regional operator to run them. Horizontal integration of system operation over large zones thus allows border effects between the former zones of the incumbents to be internalized (Costello, 2001; PJM, 2004b).

We can distinguish between two types of TSO here: a "heavy," and a "light," TSO. A "heavy TSO" ("TOSO") owns the grid infrastructures it operates, while a "light TSO" ("SO") does not. The term "TSO" is thus a generic term encompassing both of them.

In conclusion, it is the magnitude of the horizontal effects at the borders between zones of neighboring TSOs, as well as the effective potential for imposing vertical restructuring of assets in the electrical chain, that frame the modalities of unbundling the transmission grid.

III. A. 2. Governance and incentive regulation of transmission

The modalities of how the transmission grid is unbundled have consequences for both the governance of electricity transmission and its regulation as a monopoly.

The governance of a light TSO impacts its regulation and the industrial structure of the electricity sector. It is, in fact, difficult for a regulator to provide strong incentives to a light TSO, owing to its financial shallowness (few assets, little equity, low revenues). This is why light TSOs are usually non-profit organizations that are partly self-governing within the framework of an *ad hoc* statute, as opposed to for-profit light TSOs (Barker et al., 1997). A non-profit light TSO allows for direct or indirect participation of the network's owners and users on the assumption that there is no danger of collusion or of the organization being captured by a single interest group. This is typically the scenario of stakeholder participation in ISO governance in the United States.

Conversely, in the case of "heavy" TSOs, the regulator can impose incentive regulation on the TSO's controllable costs in order to fix the monopoly's income. In fact, in terms of assets, equity, and revenues, the potential financial risks of incentive regulation are acceptable to heavy TSOs.

III. A. 3. The governance of transmission and market design associated with the externalities of electricity flows

As the system operator, the TSO is the principal architect of the market design associated with the management of electricity flows. The governance of transmission has an impact on the design of the market that handles the externalities associated with electrical flows. Furthermore, government policy and the action of interest groups (political economy) can also act at this stage.[10]

When the system operator is a "heavy" TSO, participants in the electricity market have no direct stake in its governance. Consequently, the TSO is better placed to defend its own interests during the conception of the market design. Conversely, at the time of formulation of the market design, a light TSO is neutralized, at least in principle, by the participation of stakeholders that are assumed to be balanced. During the construction of broad regional markets, light TSOs should be less sensitive to incompatibilities between prior market designs, because their own financial interests weigh little in their mission of inter-zonal coordination.

The governance of TSOs is the product of a compromise between controlling costs, the market design associated with externalities from electricity flows, and coordination between TSOs. The capital base of heavy TSOs allows the regulator to encourage it to significantly cut its controllable costs. However, the financial stakes associated with these infrastructures may have an impact on the market associated with externalities, as well as the process of coordinating with other TSOs. Conversely, a light TSO can more easily coordinate with its neighbors, but is harder to motivate.

III. B. COMPATIBILITY CONSTRAINTS BETWEEN THE MODULES OF THE TSO

The governance of transmission defines the compatibility constraints between the implementations of the three missions of the TSO. In the terminology of Pagano (1993) and Aoki (2001), this is called "weak institutional complementarity." On one hand, there is an institutional complementarity between the TSO's three operational modules, since the implementation of some missions is constrained in advance by the governance of transmission. On the other hand, there is a weak institutional complementarity, since several combinations of the implementation are feasible.

---

[10] The regulator, in turn, must account for government policies seeking to reconcile incompatible objectives. For example, siting signals that are economically efficient from the perspective of the network may hamper the development of wind power, since wind farms are usually far from consumption centers and existing grids, thus necessitating additional investment. The regulator may also have difficulty implementing a "rational agenda" because of the cost of change that the new rules on the TSO's three modules ?…? ("political economy" in Pérez, 2002 and 2004). To conclude, the market design associated with externalities in electricity flows may be suboptimal, not only because of the unbundling of grid ownership, but also because of an inconsistent energy policy handed down from policy makers and for reasons of political economy.

We will examine the three types of constraints on compatibility that are the most significant in the context of a competitive wholesale market for electricity. First, a TSO must be sensitive to incentives, so as to ensure efficient development and operation of the grid. Second, siting signals are of real significance to users for ensuring the coordination between users and the capacity of the network to accept new connections despite the vertical unbundling of the transmission grid. Finally, coordination between TSOs must allow efficient use of all transmission grids, both between and within zones, whatever their topological enmeshment and the boundaries on ownership of the infrastructure.

III. B. 1. Compatibility constraints attributable to incentive regulation

The TSO's incentives to administer and invest in its grid vary with the combination of governance structure and the method used for short-term externalities management. According to this method, the management of these externalities can generate a rent or cost for a TSO. Moreover, we must also consider the robustness of this method in the event of market power being exercised by users of the grid, since this can lead to mistakes in investment.

Each method for managing externalities is vulnerable to the exercise of market power by one of the actors indispensable to the security of the grid. This type of behavior can lead to misguided estimates of the need for investments (Joskow-Tirole, 2005). The redispatching method is considered the most sensitive to market power, since the cost of local congestion is socialized with it (Harvey-Hogan, 2000). When users of the grid do not assume the cost of the externalities they cause, they are able to manipulate how congestion is managed and significantly bump up the social cost of externalities (Green, 2004).

Nodal pricing, for its part, leads to efficient dispatching of the grid's users and, to some extent, their choice of siting. However, as to the TSO's own investment decisions, congestion rent provides a counter-incentive signal. Indeed, nodal pricing can provide an incentive to a profit-maximizing TSO to prolong congestion (Pérez-Arriaga et al., 1995). Similarly, with zonal pricing, the TSO benefits from inter-zonal congestion but bears the cost of intra-zonal congestion (Glachant-Pignon, 2005). We conclude that a TSO that internalizes electricity flow externalities through nodal pricing should be subjected to more stringent regulation to ensure that it takes care to correlate its profit maximization with the maximization of social surplus.

The redispatching method is considered inefficient for internalizing the externalities of electricity flows. However, in its defense, it directly imposes the cost of congestions resulting from system operation on the TSO. Moreover, the TSO can extrapolate the long-term evolution of congestion from the requests for connections it receives. Consequently, the TSO can maximize profits by comparing the short-term cost of congestion with the long-term cost of investing in, and maintaining, the grid. As mentioned above (in

Section II. B), this private maximization procedure is equivalent to maximizing social surplus (Pérez-Arriaga – Smeers, 2003). In this case, the regulator itself has easy access to congestion costs through the intermediation of the TSO. Therefore, it can verify their consistency with siting decisions and the volume the TSO's investments. We also need to ensure that the balancing market (=real-time market) allows redispatching costs to be monitored to prevent the manipulation of congestion and problems related to the exercise of market power on the local market.

Whatever method is used to manage externalities, we could also force the TSO to compute the social cost of externalities. The regulator would thus have access to data formatted to provide a basis for investments in the network. This would also facilitate the detection of local market power. However, only a heavy TSO can support incentive regulation for the cost of externalities. Conversely, for a light TSO that is non-profit and partly self-regulated, nodal pricing is a better option. This type of TSO is insensitive to the amount of the congestion rent, since it does not capture this rent owing to its non-profit status. This status does not keep it from continually computing the social value of externalities.

III. B. 2. Compatibility constraints attributable to siting signals

The allocation of network costs is determinant if users are to appreciate the grid's constraints and effective connection opportunities. Investments in the grid are very expensive. Consequent, efficient siting of the grid's users may conflict with other goals. For example, promoting the establishment of wind power, facilitating the connection of new entrants, and entrenching the equalization of rates are all conducive to opting for the shallow cost method of grid cost allocation across all users.

Furthermore, whatever the method of short-term management of externalities, it cannot provide economically efficient signals in the long run, since it is constrained by regulation. Of course, nodal pricing is most appropriate short-term externalities management method for emitting long-term siting incentive signals. If the short-term management of externalities is ensured with redispatching, on the other hand, only the redispatched units are informed by the congestion. However, nodal prices do not measure the impact an expansion of the grid between two nodes has on other nodes. Therefore, these are not efficient long-term signals for the precise siting of the actors. Even when formal property rights, such as the Financial Transmission Rights (FTRs) of Hogan (19920, are created, they feature similar limitations—unless the new investor receives the algebraic sum of all the FTRs that it creates or "makes possible" (Bushnell-Stoft, 1997).

In addition, because of economies of scale, nodal pricing does not generate sufficient revenues to cover all infrastructure costs of the grid, which is exacerbated by the indivisibility of the network equipment (Pérez-Arriaga et al., 1995). Furthermore, some externalities are not internalized by nodal pricing, such as the reliability (=security) of the system. There is no method that can fully internalize the externalities and indivisibilities of investments in the grid (Joskow-Tirole, 2005, Smeers, 2005).

As a result, a locally differentiated grid access fee is always required to address problems arising from indivisibilities and externalities associated with investments in the grid. On one hand, a deep cost pricing of connections to the grid does not internalize the positive externalities of these connections. On the other hand, shallow cost pricing only encourages users to move nearer to the grid, but not to choose the best sections thereof. Only zonal pricing makes it possible to internalize the externalities of investments in the grid while simultaneously providing siting incentives to users.

In the matter of access to price signals, users of the network may have to pay *ex ante* to know whether they will be able to connect to the grid and how much it will cost. For the TSO applying shallow cost or zonal pricing, this information can be acquired cheaply. Conversely, for the TSO using the deep cost method, this same information may be very expensive and only available after a hook-up has been requested, since the TSO needs to conduct case by case network analyses subsequent to actual connection requests. Consequently, advance posting of the grid's capacity to accept new connections makes this cost allocation method the most transparent for users. Nonetheless, this type of information may be difficult to compute when the nodes' capacities for accepting new connections are interdependent and vary from one request to the next. If the capacities for new connections are available, they cannot all simultaneously be realizable.

In conclusion, price setting options on the grid seem quite limited. Whatever method is chosen to manage the externalities in the short term, an additional rate is necessary to generate a siting signal that internalizes the indivisibilities and externalities of investments in the grid. Posting the availability of capacities for new connections yield more transparency of the method for allocating costs for the users.[11]

III. B. 3. Coordination compatibility between TSOs

The governance of TSOs encompasses the methods implemented for managing externalities and for emitting long-term siting signals, whether uniformization between them or combining TSOs.

Some choices in uniformization and coordination between TSOs are preferable because they facilitate coordination and provide more information by yielding better internalization of externalities. Thus, in Cadwalader et al. (1999) we find the coordination of two systems using nodal pricing. According to Marinescu et al. (2005), it is more difficult to coordinate two systems using redispatching for their

[11] However, these price- and volume-based signals may only have a limited impact on users' siting decisions, since they are also constrained by primary energy resources, such as water, wind, coal, gas, etc.

congestions. In this case, coordination may require a gateway between the TSOs. Such mechanisms already exist for the short-term management of externalities (such as: priority given to historical contracts; first come, first served; explicit auctions; etc.). However, those methods that are best for internalizing externalities, and thus border effects, should be preferred.

Consequently, even coordination between TSOs has an institutional dimension. Since it modifies organizational structures and grandfathering arrangements, it must be supported by the respective governance structures of the different TSOs. Failing this, we cannot imagine how TSOs would be able to set up coordination mechanisms. For example, how would they exchange the required data? In addition, their modules for externalities management (congestions and losses) and grid development can also prove poorly suited to each other if they only internalize some of the border effects.

Thus, there is a need for a regulatory authority with jurisdiction over all TSOs requiring coordination. At the least, this authority would need to push for the implementation of rules for compensation associated with each step in the progression of the coordination. In the most developed version, this authority can guide coordination by combination toward coordination by unformization thanks to an implementation of appropriate new methods (Glachant et al., 2005).

IV. COMPARATIVE INSTITUTIONAL STUDY OF PJM AND NGC

We now have a framework of an ideal TSO with which to compare two real TSO case studies: PJM in the United States and NGC in England. PGM and NGC are two reference TSOs in the international experiments with competitive electricity markets, but with opposing governance structures. A comparison will shed some light on the real differences between them, in terms of both the results one would expect given their methods of operation and the results that are actually observed.

IV. A. PJM (PENNSYLVANIA-NEW JERSEY-MARYLAND) CASE STUDY

PJM is often evoked as the example to follow when creating a system operator responsible for a vast geographical zone. This zone, in fact, extends across several U.S. states. Originally: Pennsylvania, News Jersey and Maryland. Now, however, the PJM zone extends as far as Chicago and so covers an electrical region that is greater than France or Germany.

In its management of the externalities of electrical flows, PJM internalizes congestion in its nodal pricing—internalizing losses is still pending. As to development of the transmission grid, PJM does not yet apply economic investment criteria that account for all relevant externalities and allow users of the grid to easily assess *ex ante* the potential variations on their new projects for using the grid. In the matter of coordination between neighboring TSOs, this operator, covering a vast geographical zone, eliminates many border effects, and has no problems coordinating with other ISOs or similar entities.

IV. A. 1. Modular analysis of PJM

We will examine the three modules in order: short-term management of externalities from the flows, development of the grid, and coordination between TSOs.

IV. A. 1. a) Short-term management of the externalities of electricity flows

For both its congestion management and the associated financial hedging tools, PJM is the reference for the Standard Market Design of the U.S. federal regulator, the FERC.[12]

PJM's nodal pricing internalizes congestions. This method is completed by forward contracts that allow the different actors to hedge against volatility in nodal price differentials. Two variants on these forward contracts exist in the PJM zone, Financial Transmission Rights (FTRs) and Auction Revenue Rights (ARRs). FTRs are auctioned, with account being taken of the constraints of the grid (as in nodal pricing). They provide financial rights to the congestion rent associated with a price differential between a "source" node and a "load" node. APRs are allotted to distributors (Load Serving Entities) on the basis of their peak consumption, once again with account being taken of the grid's constraints. These APRs can be transformed into FTRs, yielding a right to revenues generated by at the FTR auction (PJM, 2005).[13]

Losses are not included in nodal pricing. Their volume is distributed across the grid's users as a loss rate that is temporally, but not spatially, differentiated. This socialization of losses thus does not provide information on the impact of grid users' individual behavior. There is no targeted incentive to users of the grid to reduce losses on the grid. Furthermore, the PJM governance structure also does not provide the TSO with an incentive to reduce the volume of losses on the grid, since it is not financially responsible for losses (this is equivalent to "cost pass through" in principle).

---

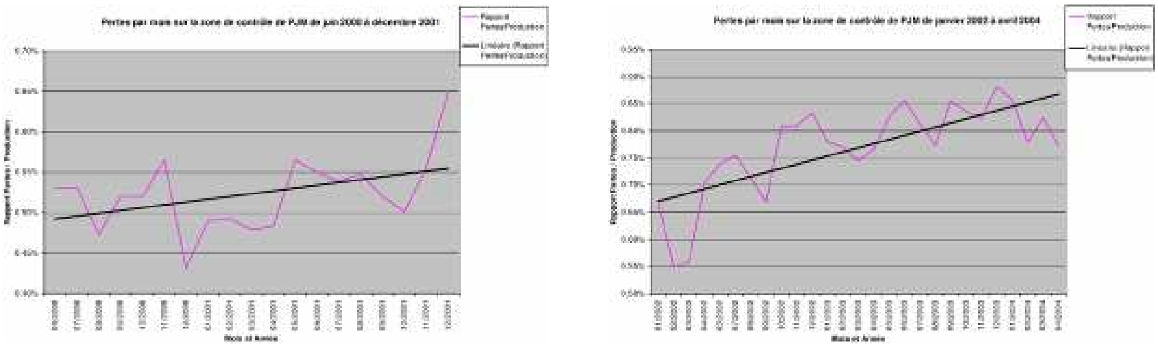
[12] However, the management of losses would need to be incorporated in PJM's nodal pricing for it to match the best practices of other RTO/ISOs.

[13] The FERC was concerned about the advantage accruing to historical transactions during FTR auctions and the allotting of APRs (PJM [2005]), since FTRs and APRs that hedge historical transactions against nodal price differentials are prioritized.

Figure 6

Evolution of trends in losses on PJM's Very High Tension grid

(relative to generation from June 2000 to December 2001 and from January 2002 to April 2004)



(computed with PJM data)

The geographical expansion of the PJM zone makes it difficult to assess the evolution of losses. However, an analysis is possible if we concentrate on periods in which the PJM zone is geographically stable (cf. **Erreur ! Source du renvoi introuvable.**). The increase in losses in this zone is striking, especially with regard to the Very High Tension grid.[14]

In conclusion, PJM is an example of an ideal TSO in terms of congestion management. A debate is ongoing at PJM as to whether to incorporate losses into nodal pricing, thus matching the best practices of other RTO/ISOs. The prioritization of grand-fathered transactions during FTR auctions and the allotment of APRs creates a problem of discrimination (PJM, 2005).

IV. A. 1. b) Development of the electricity transmission grid

As to the development of its transmission grid, even though PJM is a light TSO, some procedures allow it to determine a consistent level of investment in the grid. Several of these decision-making criteria need to be strengthened to better assess the economic efficiency and the risks associated with the investments. Moreover, long-term signals guide the siting of the grid users.

In matters of investment in the grid, the FERC has paid particular attention to the lack of any economic rationale in the associated decision-making processes in most ISO zones, especially that of PJM (FERC, 1999; PJM, 2004a). PJM, as well as other ISOs in the North-Eastern United States (such as

[14] In the case of PJM, Very High Tension includes tensions in excess of 350 kV.

NYISO[15]) are confronted by increasing congestion, which appears to be linked to inadequate investment in the grid.

In fact, congestion rent has been rising in the PJM zone since 1999. This may be attributable to the geographic expansion of the PJM zone (cf.). However, this expansion is less helpful for explaining the relative increase in congestion rents vis-à-vis consumption in the PJM zone (cf. the black bars and the left-hand scale on **Figure 7**). Prior to mid-2004, PJM only decided to invest in the grid on the basis of security of the system, ignoring economic arbitrage between the cost of externalities and the cost of investments in the grid.

Table 5

Evolution of congestion rents in the PJM zone from 1999 to 2004

(in millions of $)

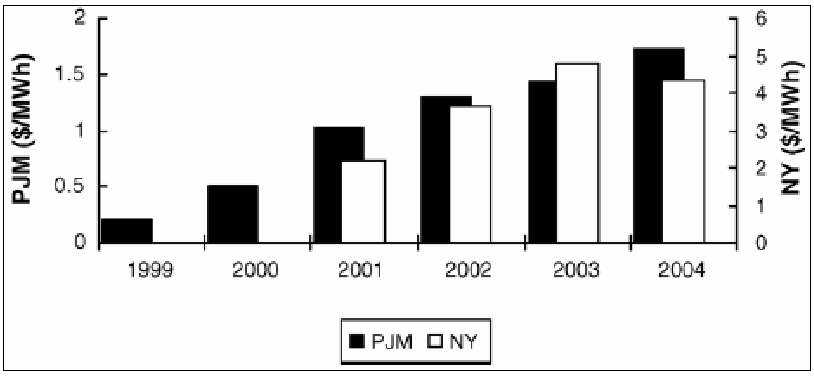
Year	Congestion rent charge (millions of $)
1999	53
2000	132
2001	271
2002	430
2003	499
2004	808

(Source PJM [2005])

Figure 7

Evolution of congestion rent in the PJM zone

(compared to energy consumption from 1999 to 2004)



(Rossignoli et al. [2005])

[15] New York ISO is the system operator in New York state.

In 2004, PJM initiated the concept of "Economic Planned Transmission Facilities." These make room for an arbitrage between the cost of congestion and the cost of investing in the grid, allowing them to account for externality costs in grid investment decisions (PJM, 2004a).

Since the implementation of the concept of Economic Planned Transmission Facilities, 34 investment decisions have been. This is a large number, even for a zone of the size of PJM. This reveals the existence of a real need for economically motivated investments, especially since the payback time associated with most of these investments is less than one year (Joskow, 2005a).

However, the economic criterion applied to investment is itself rather strange. Arbitrage between the costs associated with system operation and investments in the grid is based on estimates of the cost of congestion revealed by FTR auctions, but with no direct calculation of the cost of these congestions (Joskow, 2005a; PJM, 2004a). Furthermore, neither losses nor undistributed energy are accounted for in the decision. Finally, decisions to invest in the grid are based on instantaneous expectations of the cost of congestion and take no account of their uncertainty vis-à-vis future flows of electricity (Hogan, 2005).

Other signals, accounting for a more long-term time horizon, are required to guide the siting of the grid's users and to limit the occurrence of long-term congestion. In the PJM zone, long-term signals come from the deep cost of connecting generators and the zonal grid usage fees paid by consumers to cover the costs of other investments.

At the time of connection, generators not only pay for the hook-up but also for any reinforcement of the grid that has been made necessary. The grid's capacity to accept connections is not published. This deep cost allocation method thus lacks transparency for investors other than the incumbents, who remain keenly aware of the capacities of the networks they still own. The deep cost allocation method, in conjunction with persistent vertical integration of the grid in terms of ownership by the incumbents, may represent a barrier to entry to independent actors into the electricity market.

The costs of investments whose necessity becomes apparent outside of the context of new connections are socialized within the historical zones of the incumbents. This creates a *de facto* zonal grid usage pricing scheme. This grid usage fee is partially based on the "integrated" prices defined by local regulators for an integrated generation-transmission-commercialization service (Joskow, 2005b) in each of the states of the PJM zone. As a consequence, price differences between network owners are less a reflection of inter-zonal cost differentials than of divergent regulations, as these are not harmonized across states. However, these differences cannot be too large in absolute value, since grid usage fees only represented from 4 per cent (ComEd zone) to 7.1 per cent (Rockland zone) of energy prices in 2004. Nonetheless, some inconsistency between prices from one zone to the next, as well as in their capacity to accept new connections, is to be expected.

In conclusion, development of the PJM's transmission grid is evolving, but the criteria for investments are still far from those of an ideal TSO. The economic criteria for grid investments still fail to account for losses and uncertainty. Zonal pricing for access to the grid, which PJM defines for its entire region, allows for a better internalization of externalities in the grid's users' siting decisions. Deep cost allocation, in conjunction with persistent vertical integration of the grid in terms of ownership by the incumbents, may represent a barrier to entry to independent generators.

IV. A. 1. c) Coordination Among TSOs

PJM needs to coordinate with neighboring zones, since it is crisscrossed by numerous traversing and parallel flows, from the western Midwest to the zone of NYISA in the north-east, and the TVA[16] in the south-east (DoE, 2002). Internalizing border effects is also of some interest for PJM in terms of an efficient and secure use of its interconnections.

Border effects often create problems with security or inefficiency if they are insufficiently or inadequately internalized. The recent integration of the extended Allegheny Power zone into PJM (PJM, 2004b) demonstrates that the coordinated management of these effects can significantly alter the distribution of flows—and that PJM is adept at handling such changes. The creation of the neighboring Midwest ISO, modeled after PJM, has demonstrated that ISOs are regional coordinators and that they facilitate the creation of large regional market zones on the basis of free and unrestricted access to the transmission grids of the incumbent operators.

On one hand, PJM has also signed coordination agreements with two neighboring network operators, Midwest ISO and TVA (MISO-PJM-TVA, 2005 and MISO-PJM, 2005) in order to align the operation of their systems and their plans to develop transmission (Regional Transmission Expansion Plans). On the other hand, projects to coordinate real-time markets with New England (ISO-NE[17]) and New York (NYISO, 2003) confirm that ISOs can coordinate with relative ease.

In conclusion, we find that ISOs are able to implement efficient solutions for coordinating (economically, "first-best") by internalizing border effects, at least for the operation of their systems. As to the matter of coordinating investments, use of the shallow cost allocation method recommended by the FERC may give rise to problems with compensation between transmission zones. This is because each transmitter, in each zone, is expected to fully bear the costs of expanding its network. Nonetheless, PJM is

---

[16] The TVA (Tennessee Valley Authority) is a public body that generates and transmits electricity in the Valley of the Tennessee.

[17] ISO-NE is the system operator for the New England states.

less vulnerable to this problem, since grid investments made at the request of generators are billed at deep cost there.

IV. A. 1. d) Comparison of PJM with the ideal TSO

We compare the TSO PJM with an ideal TSO in Table 6, below.

Table 6

Comparison of PJM with the ideal TSO

Missions of the TSO	Variant implementations	Ideal TSO?	Comments
1 - Short-term externalities management Congestions	Nodal pricing, FTR/ARR	Yes	Priority of historical transactions of FTR/ARR allocation
Losses	Rate of losses (temporally differentiated)	No	In the works
2 - Development of the grid Investments	Criteria based on a congestion ceiling	No	recent principle, no cost for losses, no risk assessment
Fees	Deep cost for new generation connections Zonal pricing of grid use, paid by consumers	Partially	No publication of connection capacity
3 - Coordination at the borders	Uniformization	Yes	

IV. A. 2. Compatibility between the modules of PJM

ISOs like PJM are voluntarily created by the states, since the FERC does not have the authority to modify the vertical ownership structure of the U.S. electrical industry. These ISOs may cover vast geographical zones, frequently spanning several states (PJM, New England, MidWest) so as to internalize the many border effects between the small historical zones of the incumbents. ISOs are non-profit and partially self-regulated entities, since it is difficult to provide incentives for light TSOs. We see how the governance of transmission guides the institutional complementarity in the implementation of the base missions of the TSOs.

IV. A. 2. a) Impact of regulation

Reform of the electric industry in the United States occurs in a structure of dual regulation. The federal regulator, FERC, is only one engine in the deregulation process and has no authority over the state regulators called Public Utilities Commissions (PUC). The relationship between the FERC and the PUCs is not hierarchical, and they do not operate in the same legal or jurisdictional field. Thus, there is no unique framework for deregulation. All of these particularities render the deregulation process difficult to control and instigate by the federal authority FERC.

The jurisdiction of the FERC is limited to interconnected wholesale markets and to the problems in electricity transmission associated with them. However, the decision to begin deregulating the electricity industry falls under the exclusive purview of the public authorities of the states. Moreover, in any event local regulatory authorities, the PUCs, retain control over the retail electricity market, as well as investment and the transmission price when this function remains vertically integrated with generation in ownership.

With regard to this, the dynamics of the deregulation process in the United States is heterogeneous and subject to many border effects between its many electrical zones (Joskow, 2005b). Now, without the effective participation of the electricity transmission grids in the creation of wholesale markets for electricity, unification between the zones is not ensured.

As of 1999, the FERC (1999) has been striving to remove these obstacles with a draft regulation: "*Order 2000*." The proposal is that all transmission grid owners transfer the operation of their grid to a new regional transmission operator (= an RTO). These RTOs would be responsible for operating the system and coordinating a planning process on the regional scale. Thus, owing to its large size, PJM was classified as an RTO by the FERC in 2002. Also, even though the FERC is unable to impose divestment in terms of ownership or operation of the transmission grid in the electrical industry, it has succeeded in establishing RTOs based on unbundling of the system operation in states having liberalized the electricity industry.

IV. A. 2. b) The Governance Structure of the Electricity Transmission Grid

System operators who control vast zones are necessary in the framework of deregulation of the electrical industry in the United States because of the border effects between the many zones of the incumbent operators. In the United States, the transmission grid has historically been fragmented among 400 incumbent operators and 100 control zones (Pérez-Arriaga - Olmos, 2005). In this context, traversing and parallel flows abound. Furthermore, the volatility of the exchanges on wholesale markets make these "non-internalized" border effects increasingly critical for the security of the grid.

Transmission Load Relief (TLR) is being activated more and more often (Joskow, 2005b). This procedure allows congestions at interconnections between zones to be lightened by interrupting the bilateral contracts that cross these connections. Consequently, the FERC is necessarily interested in the creation of system operators to manage vast zones of markets, who would be capable of internalizing border effects and offering free and unrestricted access to the grid to outsiders. This trans-border interest was prioritized over the goal of divestment of grid assets by the incumbent operators exclusively within their zones and with no solution to the critical problem of border effects.

However, the constitution of ISOs and RTOs was made easier by the fact that they were light TSOs, since the owners of network assets did not lose ownership of their equipment. Since TSOs own few assets and function as non-profit clubs, they remain difficult to provide with incentives. Indeed, rigorous financial incentives from the regulator on the operation of the system would put their very survival in jeopardy, since their revenues are ensured by the set of access fees to regulated infrastructures. Nonetheless, these ISOs and RTOs are clearly monopolies that must be regulated. However, in practice these RTOs and ISOs are essentially self-regulating bodies, owing to *ad hoc* governance structures based on representation from all large stakeholder groups.

This direct representation of grid users in the ISO/RTOs is not without its detractors. Generators have been found to be overrepresented in the governance structures of the ISO/RTOs (Boyce-Hallis, 2005). Thus, they may be acting in accordance with surreptitious pressure originating from an interest group. Notably, incumbent generators prefer to keep the grid congested in order to capitalize on their local market power. The implications these pressures have for policies on investment in the grid are obvious.

In conclusion, system operators can internalize the resulting border effects. In the U.S. context of a dual regulatory structure (federal and local), the constitution of new system operators has only been possible in the form of light TSOs. Strong incentive regulation cannot be applied to these TSOs (ISO or RTO, such as PJM) to contain the costs of operating the system. Self-regulation of ISOs such as PJM may also undermine efforts to control operating costs because of the weight of generators in the governance structure.

IV. A. 2. c) Compatibility constraints between the variants of PJM's missions

The governance and regulation modalities of PJM create compatibility constraints between the variants of its missions. We will look at three types of compatibility constraints for PJM: (1) controlling costs and incentive regulation for the electricity transmission monopoly, (2) the emitting of siting and destination signals, and (3) coordination with neighboring TSOs.

(1) To begin with the network costs: In the 1990s, light TSOs in the United States managed their congestion using zonal electricity pricing. Within the zones, some congestion was managed using redispatching. Then problems with manipulating congestions appeared. As of the late 1990s, redispatching costs rose substantially in the zones. PJM set up its nodal pricing system in 1998, and was imitated by other ISOs subsequently. We have already seen that nodal pricing is the most efficient, theoretically, and also well adapted to light TSOs such as PJM. Moreover, PJM is a non-profit organization. This makes it indifferent to the fact that appropriating congestion rents through nodal pricing negatively impacts on investments in extending the grid.

Nonetheless, this recrudescence of congestion attracted the attention of the federal regulator FERC. Prior to the conception of Economic Planned Transmission Facilities in April 2004, no economic opportunity for investment in the grid was accounted for in the planning of the PJM grid. Though this concept has its drawbacks, it is a first step to inducing more efficient management of the development of transmission grids by light TSOs.

Furthermore, nodal pricing engenders a significant redistribution of benefits and costs relative to the previous situation. This redistribution underlies the strong opposition to implementing this design (Kirsch, 2000), and FTRs were allotted to minimize these effects. However, after more complaints about the pre-emption of FTRs by incumbent transactions (first come to FTR, first served FTR), they had to be put to auction, and ARRs were created (Shanker, 2003). This problem, typical of political economy, has thus evolved since the remaking of the market for FTRs. However, questions remain regarding the other priority given to grandfathered transactions (PJM, 2005) that may limit the efficiency of nodal pricing.

(2) As to the siting signals emitted, nodal pricing and the deep cost method for allocating network costs yield signals. As to short-term siting signals, integrating losses into nodal pricing was deemed of secondary importance, since PJM's efforts were focused on extending its initial zone and absorbing the zones of neighboring utilities. In the matter of long-term siting signals, as previously mentioned, the deep cost method of allocating costs does not allow the positive externalities associated with some connections to be internalized. Moreover, to the extent that the incumbent operators remain generators and network owners, this method of allocating grid costs may become a barrier to new entry. Publication of capacities for new connections on PJM's network could make the cost allocation method more transparent to new users and thus reduce this barrier to entry for independent generators.

(3) As to compatibility constraints related to coordination with neighboring TSOs, the Standard Market Design of the federal regulator FERC provides a framework for coordination by unformization

among RTOs and ISOs, at least for the system operator. The FERC's preference for a shallow cost allocation of grid costs creates issues with compensation between parties in the matter of investments in interconnections. These problems are mitigated by PJM due to its policy of deep cost pricing of generators' connections.

IV. A. 2. d) Conclusion of the PJM case

The compatibility constraints between variants on the PJM's missions and the effective efficiency are summarized in Table 13.

Table 7

Institutional complementarity of the PJM system

Institutional complementarity	Modules - affected	Implementation	Institutional complementarity constrained by
Cost control and incentive regulation	Externalities management 1. Congestions	Nodal pricing	Governance structure of light TSOs
		FTR/ARR	Political economy favoring historical transactions in allotting FTRs/ARRs
	2. Losses	Rate of losses (temporally differentiated)	Political economy, ill suited to governance structure with increasing loses, changes pending
	Grid development a) Investments	Criteria by congestion threshold	Governance structure of light TSOs
Siting signals	Externalities management	Nodal pricing	1 and 2
	Grid development b) Fees	Deep cost and Zonal price	Provision of siting signals despite government price controls Barriers to entry?
Coordination	Externalities management	1 and 2	1 and 2
	Grid development	a) and b)	a) and b)
	Coordination	Uniformization	Adapted methods with siting signals, initiatives framed by the Standard Market Design (FERC)

IV. B. NGC (NATIONAL GRID COMPANY) CASE STUDY

IV. B. 1. Modular analysis of NGC

Even though NGC's method for management externalities in the short term is theoretically flawed, its operating costs do appear to be under control. Also, investments in the grid appear satisfactory, i.e.

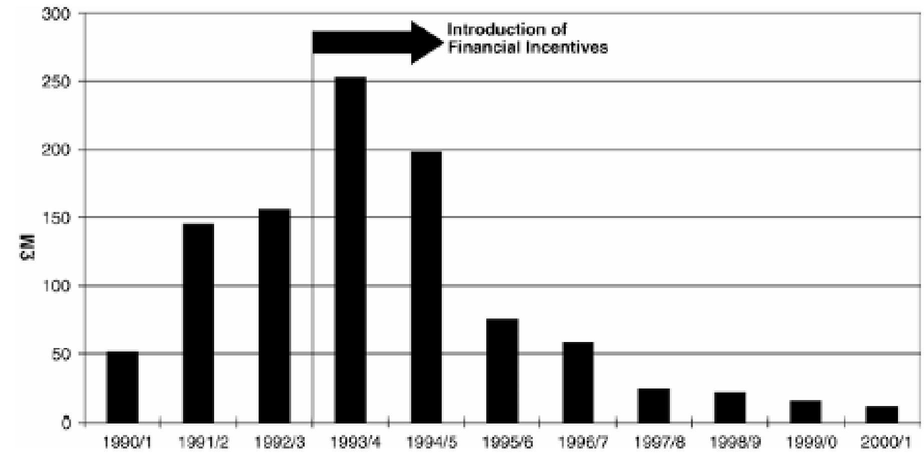
compliant with the regulation of the transmission monopoly and with the needs of the electricity wholesale market. This is true despite the fact that zonal pricing has a mixed record in its impact on users' siting decisions. Finally, coordination with neighboring TSOs remains a secondary problem, given the topology of the grid and the lack of integration of its interconnections.

IV. B. 1. a) Short-term management of the externalities of electricity flows

The methodology NGC applies to managing externalities in the short term has been criticized for its theoretical heterodoxy, while simultaneously being praised for its good results, in terms of both congestion and losses. The cost of externalities is distributed across generators and consumers on a national basis, in a ratio of 45:55, with no signal to internalize these externalities. However, at the same time NGC is encouraged to reduce costs through an incentive regulation called "System Operator regulatory scheme." This provides a financial incentive for NGC to jointly manage congestions and losses by planning of grid maintenance operations with the goal of reducing the costs of these externalities.

Figure 8

Evolution of the redispatching cost on the NGC grid



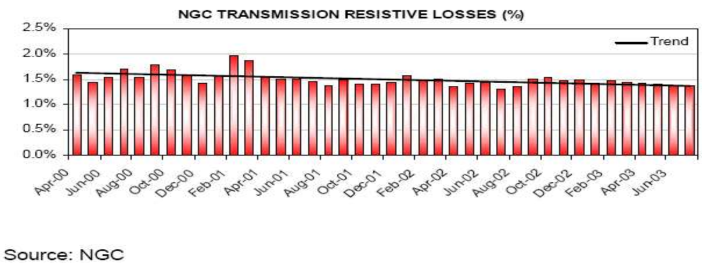
Source : (Rossignoli *et al.* [2005])

Ever since the beginning of the deregulation of the electrical industry, congestion has been managed by the redispatching method, from the Anglo-Welsh Pool to NETA (and then BETTA, its extension into Scotland). The experience of the Pool has revealed that the theoretical flaws found in this method are not limited to the theory. However, the introduction in 1994 of an incentive system that allowed NGC to arbitrate between various management methods (NGC, 2004a) (bilateral contracts, J–1 power exchanges, real-time balancing mechanism, etc.) has allowed the cost of redispatching to be reduced very significantly (cf. Figure 8).

The regulatory method consists in motivating the TSO to improve the planning of its maintenance operations with respect to the cost inherent in redispatching, as well as in curtailing problems with local market power. NGC manages congestion starting with the medium term, spanning several months. It anticipates flows on its grid in light of the availability of generating facilities. NGC can also modify the planning of its maintenance operations to arbitrate between the cost of maintenance and the cost of the redispatching necessitated by these interventions (Brunekreeft et al., 2005). NGC can also contract an option with generators that are indispensable to the reliability of the grid ("reliability-must-run generators") (NGT, 2005a) to reduce its exposure to their local market power.

Figure 9

Losses on the NGC grid, with trend



Source: NGC cité par (Joskow [2005a])

As to losses, they are uniformly prorated across all users of the grid at "Estimated Transmission Losses Adjustments rates." These ignore the actual location of users on the grid, and thus their individual impact on the losses. However, NGC has an incentive to reduce the quantity of grid losses and achieves this by optimizing the topology of its grid and its tension plan. Consequently, even though the users of the grid have no individual incentive to reduce losses, we observe a decline, or at least a stabilizing trend, in the volume of losses on the NGC grid.

In conclusion, in the matter of the short-term management of externalities, the theoretical flaws in the methods used by NGC have been mitigated in practice with incentive regulation that allows the system operator to attain an acceptable level of performance.

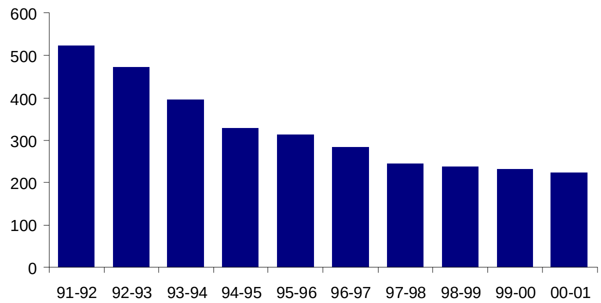
IV. B. 1. b) Development of the Transmission Grid

As to the development of the transmission grid, NGC is responsible for designing and financing investments as the owner of the facilities. However, in its role as system operator (SO) it must also guide the siting of the grid's users.

Investments in the network are limited by three complementary budget constraints that combine an incentive regulation with, or without, performance sharing and cost-of-living service regulation. On one hand, the short-term budget constraint is fixed by the regulator, OFGEM, in the framework of short-term system operation incentives (below IV. B. 1. a). This constraint encourages NGC to jointly manage externalities and the planning of maintenance operations, as well as to arbitrate between pure operating costs (short- and medium-term) and small-scale grid investments (with short payback periods). On the other hand, the medium-term budget constraint set by OFGEM establishes a budget for maintenance operations that targets productivity growth of the type "RPI[18] – X." Finally, the long-term budget constraint set by OFGEM (called the Transmission Owner regulatory scheme) computes a "normal" envelop for investments in the grid. In principle, these three budget constraints are adequate, in the context of the governance of NGC, to ensure a satisfactory level of investment in the grid (Joskow, 2006).

Figure 10

Controllable operating costs (£m) on the NGC's network



Source: (NGT [2005b])

It is remarkable that these rules yield results deemed satisfactory, even though the economic rationale for investments provided by OFGEM (2004a) remains relatively fluid. Also, NGC (2004a)

[18] Retail Price Index.

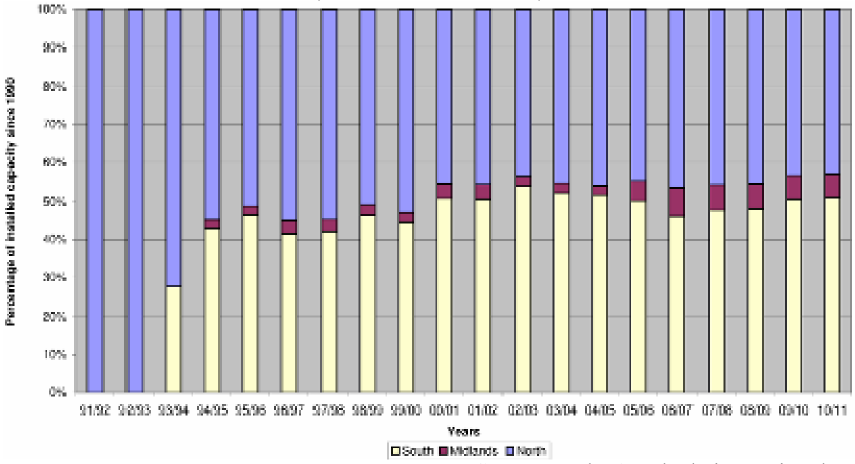
primarily justifies these investments on the basis of engineering criteria (idem OFGEM, 2004a). In fact, the operating costs of NGC are falling (Figures 8 and 9) and the investments that are made comply with regulatory contracts (OFGEM, 2004b). The value of the efficiency factor X in RPI – X regulation has, in fact, driven the performance of NGC, and efficiency gains have cut controllable costs by more than half in one decade (cf. Figure 10) and network costs by 40 per cent (NGT, 2005b).

As to long-term siting signals, zonal pricing was introduced on the grid in 1994. This was done so that, at the time of the dash for gas, generators would need to compare the costs of transmitting electricity with that of transporting gas in their investment decisions. Electricity transmission zones with negative prices are those with a local generating deficit. Thus, they compensate generators who connect new generation facilities in them.

Figure 11

Distribution of new capacities between the North, the South, and the Midlands

(cumulative since 1990)



Source : author's calculations using data from NGC [2004b]

The results of this pricing are mixed, as we see in Figure 11. Most of the connections occurred in the southern part of the NGC grid. However, there were a respectable number of connections in the northern part, despite the price differential. With a mean electricity price of 25£/MWh during this period, the maximum price differential was at most 11 per cent of the price of power to a producer. For a typical consumer, this differential reached 13 per cent.

However, according to NGC's most recent connection forecasts, the single most important component of generators' decision is the constraint on the supply of primary energy (gas and coal). Indeed, we find that since the expansion of the capacity of the underwater gas pipeline between Great

Britain and the continent most new developments, in particular CCGT, seek to built in the south (NGT, 2005) to reduce the cost of their gas supply.

In conclusion, investments in the grid are satisfactory with regard to the decline in system operating costs and the budget constraint for those investments. This is despite the fact that the economic criteria for investment decisions should be more clear and explicit for NGC to approach the ideal TSO. As to long term siting signals, the impact of zonal pricing is fairly weak beside the constraints on the supply of primary energy.

IV. B. 1. c) Coordination at the borders with neighboring TSOs

In the matter of coordinating with its neighbors, the NGC zone appears very different from PJM, since it deals with very few traversing and parallel flows. Consequently, border effects are not a priority to it.

On one hand, flows across the France-England interconnection on the southern border are easy to control on this direct current power line. This connection can be managed like any generator directly hooked into the English grid. On the other hand, on the northern border the Scottish interconnection is easy to administer because of its quasi-radial structure. Consequently, NGC has to deal with few border effects from its neighbors. And the coordination methods it uses are relatively simple. The France-England interconnection is allocated by an explicit capacity auction with price equal to the supply price of each supplier (pay-as-bid). The Scottish interconnection capacity is shared between the two integrated Scottish firms (Scottish Power and Scottish & Southern Energy). Clearly, this allocation method does not generate scarcity signals on the Scottish interconnection capacity.

In conclusion, the border effects encountered by NGC require little coordination. The current coordination methods could be improved by using more market-oriented methods, such as marginal pricing and market-linking solutions, especially on the Scottish side. Nonetheless, the cost of implementing these methods could exceed the benefits gained from coordination, since the border effects are relatively trivial.

IV. B. 1. d) Comparison of NGC with the ideal TSO

We compare NGC with the ideal TSO in Table 8

Table 8

Comparison of NGC with the ideal TSO

Missions of the TSO	Variant implementations	Ideal TSO?	Comments
1 - Short-term externalities management Congestions	*Redispatching*	No	Tendency to reduce costs with incentive regulation
Losses	Loss rate	No	
2 - Development of the grid Investments	Mostly engineering criteria Fluid economic criteria	Near	Good results thanks to incentive regulation
Fees	Zonal usage fees Zonal connection capacity	Near	
3 - Coordination at the borders	Combination	No	Little need for coordination

IV. B. 2. Compatibility of the NGC modules

The industrial structure of the Anglo-Welsh electrical industry is based on a complete separation of the transmission grid from other activities, in terms of both ownership and management. Network ownership and system operation fall under the same entity. This allows a clear incentive regulation to be applied without threatening the viability of the TSO. This incentive regulation compensates for the impact of theoretically suboptimal choices in terms of the implementation.

IV. B. 2. a) Clarity of the regulation

In England and Wales, there was little difficulty in effecting the complete separation in ownership of the grid and transmission activities. This makes free and unrestricted access to the grid possible, and also underlies the governance of electricity transmission.

Assorted entities have an impact on the regulation of NGC through a diversity of interventions. These principally include the regulator OFGEM and, to a lesser extent, the British Department of Trade and Industry. Of course, DTI must also contribute to the transposition of directives and regulations from the European Commission into domestic laws that will be applied by the regulator OFGEM. However, the subsidiarity principle is very well established here, and Great Britain generally exceeds the *minima* required by the European directives. The Anglo-Welsh electricity market is thus frequently cited as a reference for deregulation of the electrical industry, in Europe and elsewhere (Joskow, 2005a).

IV. B. 2. b) The Governance Structure of the Electricity Transmission Grid

Liberalization of the Anglo-Welsh electrical industry has led to the complete separation of the electricity transmission grid. NGC is thus a “heavy,” private, and independent TSO that owns and operates the transmission grid of England and Wales. Since NGC owns the electricity transmission grid, the regulator OFGEM can impose incentive regulation on system operation and grid maintenance.

Ownership of the network by the system operator allows the transmission grid to be developed in a satisfactory manner for three reasons. First, the revenues yielded by grid ownership ensure that potential financial losses (either from system operation or from network ownership) do not financially threaten the TSO. Also, regulation of the operation and ownership of the grid makes it possible to expect an arbitrage between short- and medium-term operating costs and investment costs of NGC (Joskow, 2005a). In this framework, incentive regulation of system operation encourages NGC to arbitrate between the operating costs of the grid and small-scale investments (with a short payback period), while the long-term budget constraint encourages NGC to arbitrate between small scale and larger investments. This is all the more relevant since the electricity transmission grid is characterized by significant economies of scale.

In conclusion, a heavy, profit-maximizing TSO can be induced to reduce investment and operating costs and under the pressure of well-designed regulations.

IV. B. 2. c) Compatibility constraints on the implementation of NGC's missions

The governance of NGC, along with regulation, create compatibility constraints on the variants of the implementation of its missions. We will look at three types of compatibility constraints for NGC: (1) controlling costs and incentive regulation for the electricity transmission monopoly, (2) the emitting of siting and destination signals, and (3) coordination at the borders with neighboring TSOs.

(1) As to compatibility constraints on the control of network costs, the "heavy TSO" governance structure of NGC makes it possible for the regulator to use incentive regulation to control system operation costs and, to a lesser extent, the costs of investing in the grid. Incentive regulation allows the theoretical flaws of suboptimal methods, such as redispatching, to be compensated for.

(2) In the matter of compatibility constraints on siting signals, nodal pricing would be more efficient (Green, 2004) for sending appropriate economic signals to market actors and for internalizing congestions. Nonetheless, at the time of the design of the market reforms in England and Wales, consumers in the south and generators in the north were wary of the redistributive effects of a more incentive-based pricing system, since the network would have received the rent associated with the internalization of externalities (Green, 1997; OXERA, 2003).

In fact, the zonal nature of the grid access fee is sometimes used to maintain a certain causality signal in the allocation of network costs and to reduce barriers to entry to those generators whose connection would necessitate significant investments in the grid (Hiroux, 2005). This cost allocation method also allows the promotion of renewable energy (OFGEM, 2003). Early during the deregulation process, it was promoted as lowering barriers to entry to new generators.

(3) In the case of NGC, no compatibility constraints have been imposed by coordination at the borders with neighboring TSOs. The topology of the NGC grid and its interconnections severely circumscribes the value of increased coordination at the borders.

As to the allocation of the France-England interconnection, it will be difficult to modify the structure of pay-as-bid auctions to attain an ideal meshing of these two markets. On one hand, this interconnection is not part of the regulated activities of NGC and is thus exempt from the oversight of OFGEM (Joskow, 2005a). On the other hand, modification of pay-as-bid auctions into a marginal price fee structure could reduce the profit NGC obtains from this activity.

As to the interconnection with Scotland, the flow is quite naturally from Scotland into England, owing to the overcapacity and generating costs of the two Scottish generators. Moreover, in light of the concentration of the Scottish electrical industry in two local monopolies, (Scottish & Southern Energy et Scottish Power), an allocation of the Scottish interconnection by the market may not be desirable. This provides a rationale for an administered allocation of the interconnection. This fact is also consistent with the new management by redispatching of the Scottish interconnection, which has been integrated into the operation of the British system by the new British Electricity Trading Arrangement (BETA).

IV. B. 2. d) Conclusion of the NGC case study

The compatibility constraints on the performance of the missions of NGC, and their efficiency, are summarized in Table 9.

Table 9

Institutional complementarity of the NGC system

Institutional complementarity	Affected modules	Implementation	Institutional complementarity constraints
Control of grid costs and incentive regulation	Externalities management 1. Congestions	*Redispatching*	Political economy (generators in the north and consumers in the south)
	2. Losses	Loss rate	
	Grid development a) Investments	Engineering criteria	Heavy TSO governance structure adapted to incentive regulation
Siting signals	Externalities management	*Redispatching*	1 and 2
	Grid development b) Fees	Zonal pricing	ENR siting and connection signals
Coordination	Externalities management	1 and 2	1 and 2
	Grid development	a) and b)	a) and b)
	Coordination	Combination	Little need A strong concentration of Scottish producers for the allocation of interconnections

IV. C. CONCLUSION OF THE COMPARISON BETWEEN PJM AND NGC

We have found two ways of diverging from an ideal TSO, and neither appears to clearly dominate the other. This is because the milieus of PJM and NGC are different. The hierarchy of the tasks of these TSOs varies with the configuration of their grids and the institutional framework given to the regulation of the transmission monopoly.

Owing to its insularity, the NGC zone is a special case. NGC is not confronted with the problem, common in continental Europe, of conflict of interest at the borders when coordination between neighboring TSOs frequently involves financial issues related to the development of domestic grids to accept transiting flows. Consequently, coordination at the borders is only a secondary issue for NGC—developing its own grid is the only priority.

ISOs in the United States, especially PJM, are regional coordinators and, until recently, development of their grid was a secondary issue. Now that work on the coordination within and between ISO zones is well advanced, the development of the grid is becoming an important consideration to prevent congestion from splintering markets (cf. the directive of the FERC, 2005, subsequent to the EPAct, 2005).

V. CONCLUSION

This modular analysis has demonstrated that the institutional framework creates compatibility constraints on the performance of the TSO's missions for managing the flows of electricity and the associated externalities. Its conclusions are more qualified than those in other studies (Boucher-Smeers, 2001; Ehrenmann-Smeers, 2005).

Some of the management methods actually implemented are markedly suboptimal relative to an ideal TSO. But these methods are good enough in the institutional context that frames their implementation. Also, regulation may curb the inefficiencies in some cases.

There are probably two reasons for this.

First, the institutional context may limit the set of methods effectively available for implementation to suboptimal solutions. Indeed, institutional constraints frame the technical-economic methods for managing electrical flows on the transmission grid.

Second, regulation of the network monopoly could complete these methods by reducing inefficiency, unexpectedly making satisfactory results possible. This may take the form of imposing *ad hoc* incentives on some selected classes of decisions, or imposing new decision criteria. Consequently, methods for managing electrical flows that diverge from the optimum must nevertheless be considered, as they may be the only ones attainable given the context. Thus, additional rules can be designed to limit the initially undesirable effects.

Naturally, optimal solutions remain a goal to strive toward when the institutional bases allow (Boucher-Smeers, 2001; Ehrenmann-Smeers, 2005), since they facilitate the creation of vast market zones. Nonetheless, in a context of subsidiarity between public authorities that are not strongly hierarchical, the feasibility of coordinated modifications to industrial structures and national technical rules is limited to short and infrequent windows of opportunity (Glachant et al., 2005). Consequently, suboptimal solutions may be destined to last and it is necessary to subject them to more exhaustive examinations (Pérez-Arriaga - Olmos, 2005; Marinescu et al., 2005; and ETSO-Europex, 2004).

REFERENCES

Aoki M. (2001), *Towards a comparative institutional analysis*, MIT Press, Cambridge

Baker J. Jr., Tenebaum B., Woolf F. [1997], “Governance and regulation of power pools and system operators. An international comparison”, Worldbank

Bjørndal M., Jørnsten K. [2001], “Zonal Pricing in a Deregulated Energy Market”, The Energy Journal, 22(1), 51-73

Boucher J., Smeers Y. [2001], “Towards a common European Electricity Market-Paths in the right direction… still far from an effective design”, Journal of Network Industries, 3(4), 375-424

Boyce J. R., Hallis A. [2005], “Governance of electricity transmission systems”, Energy Economics, 27(2), 237-255

Brunekreft G., Neuhoff K., Newbery D. [2005], “Electricity Transmission: An overview of the current debate”, Utilities Policy, 13(2), 73-93

Bushnell J., Stoft S. [1997], “Improving private incentives for electric grid investment”, Resource and Energy Economics, 19(1-2), 85-108.

Cadwalader M. D., Harvey S. M., Hogan W. W.; Pope S. L. [1999], "Coordinating congestion relief across multiple regions", http://ksghome.harvard.edu/~whogan/

Caramanis M., Bohn R., Schweppe F. [1982], "Optimal Spot Pricing: practice and theory", IEEE Transactions on Power Apparatus and Systems, 101, 3234-3245

CESI, [2003], "Implementations of short and long term locational signals on the Internal Electricity Market", report for Eurelectric, www.eurelectric.org, December

Costello K. W. [2001], "Interregional coordination versus RTO mergers: a cost-benefit perspective", The Electricity Journal, 14(2), 13-24

Department of Energy (DoE) [2002], "National Transmission Grid Study", may

Ehrenmann A., Smeers Y. [2005], "Inefficiencies in European congestion management proposals", Utilities policy, 13(2), 135-152

European Commission (EC) [2004] "Strategy paper: Medium term vision for the internal electricity market". DG Energy and Transport Working Paper, march

ETSO [2005], "The current ETSO ITC model and possible development",

ETSO-EuroPEX [2004], "Flow-based Market Coupling: A joint ETSO-EuroPEX proposal for cross-border congestion management and integration of electricity markets in Europe. Interim Report"

FERC [1999], "Regional Transmission Organizations. ORDER n° 2000, Final Rule, Docket No.RM99-2-000", www.ferc.gov

FERC [2005], "Promoting Transmission Investment through Pricing Reform, Docket No. RM06-4-000"

Glachant J-M., Lévêque F. [2005], "Electricity Internal Market in the European Union: What to do next?", CEEPR Working Paper

Glachant J-M., Pérez Y., Pignon V., Saguan M. [2005], "Un marché européen de l'électricité ou des marchés dans l'Europe ? Regards croisés : économistes et ingénieur", Droit de la régulation et l'économie, Annales de l'UMR, André TUNC, Université Paris I, May (in French)

Glachant J-M., Pignon V. [2005], "Nordic congestion's arrangement as a model for Europe? Physical constraints vs. economic incentives", Utilities Policy, 13(2), 153-162

Green R. [1997], "Transmission pricing in England and Wales", Utilities Policy, 6(3), 185-193

Green R. [2003], "Cost recovery and the efficient development of the grid", in François Lévêque (Ed.) Transport Pricing of Electricity Network, 137-153

Green R. [2004], "Electricity Transmission Pricing: How does it cost to get it wrong", CEEPR Working Paper

Harvey S., Hogan W. W. [2000], "Nodal and zonal congestion management and the exercise of market power", http://ksghome.harvard.edu/~whogan/

Hogan W. W. [1992], "Contract networks for electric power transmission", Journal of Regulatory Economics, 4(3), 211-242

Hogan W. W. [2003], "Transmission market design", Electricity Deregulation: Where to From Here? Conference at Bush Presidential Conference Center, Texas A&M University, 4 April

Hogan W. W. [2005], "Market design failures and electricity restructuring", presentation at The Economics of Electricity Markets Conference, IDEI Toulouse, 2 June 2005, http://idei.fr

Hiroux C. [2005], "The Integration of Wind Power into Competitive Electricity Market: The Case of the Transmission Grid Connection Charges", 28th annual IAEE international conference, Taipei, June 3-6

ISONE, NYISO [2003], "Virtual Regional Dispatch: concept, evaluation and proposal", Joint working paper ISO New England, Inc., New York ISO, Inc.

Joskow P. [2005a], "Patterns of transmission investment (and related issues)", Electricity Infrastructure Investment Workshop, CRE, Paris, France, March

Joskow P. [2005b], "Transmission Policy in the United States", Utilities policy, 13(2), 95-115

Joskow P. [2006], "Incentive regulation in theory and practice: electricity distribution and transmission network",

Joskow P., Tirole J. [2005], "Merchant Transmission Investment", Journal of Industrial Economics, 53(2), 233-264

Kirsch L. D. [2000], "Pricing the Grid: Comparing Transmission Rates of the U.S. ISOs". Public Utilities Fortnightly, February 15, 30-42

Marinescu B., Coulondre J-M., Tsamasphyrou P., Bourmaud J-Y. [2005], "Improving TSO's coordination for cross-border redispatch: a discussion of possible approaches in the European context", 2nd CIGRE/IEEE PES International Symposium Congestion management in a market environment, San Antonio, October 5-7

MISO-PJM [2004], "Joint Operating Agreement", www.pjm.com

MISO-PJM-TVA [2005], "Joint reliability coordination agreement", www.pjm.com

Newbery D., Green R., Neuhoff K., Twomey P. [2004], "A review of the monitoring of market power: The possible role of TSOs in monitoring for market power issues in congested transmission systems", report prepared for ETSO (www.etso-net.org)

NGC, [2004a], "Balancing Principles Statement", October

NGC, [2004b], "Seven Year Statement"

NGT [2005], "Seven Year Statement"

NGT, Carlton J. [2005a], "Investment in transmission", presentation at the Conference of Economics of Electricity Markets, IDEI Toulouse, 2 June 2005

NGT, Martin T. [2005b], "Benefit of transmission focused development", presentation at the 2005 Energy Roundtable, May 31, www.energyroundtable.org

OFGEM [2003], "Transmission Investment and Renewable Generation. Consultation Paper", October, www.ofgem.gov.uk

OFGEM, [2004a], "Planning and operating standards under BETTA, An Ofgem/DTI conclusion document Volume 2", September

OFGEM [2004b], "Extending the National Grid Company's transmission asset price control for 2006/07. Initial consultation", May

OXERA [2003], "The impact of the average zonal transmission losses applied throughout Great Britain", study for the DTI, June

Pagano U. (1993), "Organisational equilibria and institutional stability", in Bowles S., Gintis H., Gustafson B. (Eds.) *Market and Democracy*, Cambridge University Press, Cambridge

Pérez Y. [2002], "L'économie néo-institutionnelle des réformes électriques européennes, Thèse de l'Université Paris 1 Panthéon-Sorbonne", in French

Pérez Y. [2004], "L'attractivité des réformes électriques, un problème de mesure ?" in Saboly & Cailluet (Eds.) Mesure(s), Presses de l'Université de Toulouse, in French

Pérez-Arriaga I. J., Rubio F. J., Puerta J. F., Arceluz J., Marin J., [1995], "Marginal Pricing of Transmission Services: an analysis of cost recovery", IEEE Trans. on Power Systems, 10(1), 546-553

Pérez-Arriaga I., Smeers Y. [2003], "Guidelines on tariff settings", in François Lévêque (Ed.) Transport Pricing of Electricity Network, 175-203

Pérez-Arriaga I. J., Olmos L. [2005], "The plausible congestion management scheme for the internal electricity market of the European Union", Utilities policy, 13(2), 117-134

PJM [2004a], "PJM FERC Filing in Docket Number RT-01-2-01", www.pjm.com, April

PJM [2004b], "State of the Market 2003", www.pjm.com, March

PJM [2005], "State of the Market 2004", www.pjm.com, March

Rossignoli J., Paravalos M. E., Besser J. G. [2005], "Transmission: The Critical Link Delivering the Promise of Industry Restructuring to Customers," The Electricity Journal, 18(9), 18-27

Schweppe F., Caramanis M., Tabors R., Bohn R. [1988], Spot Pricing of Electricity, Kluwer Academic Publisher

Shanker Roy J., [2003], "Affidavit of Roy D. Shanker, Docket No. ER03-406-000, PJM Interconnection L.L.C.",, www.pjm.com, February

Smeers Y. [2005], "Long term locational prices and investment incentives", 4th Conference on Applied Infrastructure Research, 8 October

Wilson R. [2002], "Architecture of the power markets", Econometrica, 70(4), 1299-1344