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Nordic Electricity Congestion's Arrangement as a Model for Europe: Physical Constraints or Operators' Opportunity

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"*Nordic electricity congestion's arrangement as a model for Europe:*

Physical constraints or operators' opportunism?"

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Abstract

Congestion on power grids seems a physical reality, a "hard" fact easy to check. Our paper models a different idea: congestion signal may be distorted by transmission system operators (TSOs), which puts the European integrated electricity market at risk. 1° when the TSOs share the revenue produced by congestion's pricing they have an incentive in distorting data. 2° because congestion signals are not physical data but "home made" conventions, TSOs could be able distorting them. 3° when congestion appears on cross border lines that link several countries with their own regulatory mechanisms, the settlement of this incentive's problem necessitates a high degree of coordination. Congestion puts undoubtedly the threat of a collapse on interconnected grids. The "capacity constrained situations" have therefore to be avoided. Congestion signalling depends on norms set by TSOs and a signal is given when the power flows attain the "secure" limits set by TSOs. These security norms are not stable and invariable because some flexibility is needed by the very nature of the power flows and because lines physical capacity limits are not constant. Therefore TSOs are defining the congestion signal on a variable, complex and non transparent constraint and may manipulate it for their own interests. In Nordic countries the "Light Handed Regulation" makes this opportunistic behaviour more likely. We need a more effective congestion regulatory mechanism.

Key Words: Externalities; Information; Measurement; Incentives; Opportunism

JEL Classification: D23 – H23 – K23 – L5 – L94

We presented our paper at the ISNIE International Conference at the MIT in Boston on September 29th 2002. We thank the chairman of our session Paul Joskow and other participants for their comments. Unfortunately all remaining errors or confusion are really ours….

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I. Introduction

Natural monopoly activities are one of the main targets of competitive electricity reforms. To help introducing competition in generating and selling of electricity, these reforms have to separate and regulate accordingly the network activities[1]. In Europe, the pioneering model of such a reform appeared in England as soon as 1990. Transmission assets and operation were separated from the generation business and the selling of electricity to consumers. This unbundling of ownership and operation suppressed incentives for the transmission system operator (TSO) to collude with a given competitor against other competitors [2]/[3]. Nevertheless the regulation of transmission operation remains necessary as long as it stays a natural monopoly. The British regulator implemented it by price caps as well as by structuring incentives for reducing the costs, such as those of congestion, that are directly charged to customers. In Nordic electricity reforms like in Norway and Sweden, parts of the British transmission reform (like Legal Unbundling and Independent Regulator) were adopted at the start. These two Nordic countries went further than Britain in using market-based rules and submitted the management of cross border congestion to a market mechanism. The price of congestion is set in the Nordic wholesale market by market participants bidding for energy on each side of the grid's constraints. This extension of "market-based" arrangements explains why European Commission reports and papers[4] congratulate Nordic reforms and could use it as an example for the rest of Europe.

[1] Joskow P. & Schmalensee R. (1983); Joskow P. (1996), (2002).
[2] Kleindorfer P.R. (1998).
[3] Glachant J-M (2002); Glachant J-M., Finon D. (2002).
[4] Commission of the European Communities (2002).

This is this kind of optimistic view on market based congestion arrangements that we want to challenge in our paper. Obviously, legal unbundling of transmission creates a good ex ante incentives' alignment for the TSOs behaviour and relying on competitive market pricing ensures that the congestion pricing mechanism is transparent and non discriminatory for the users of the grid. But a key issue of this institutional arrangement for congestion management still waits for a review. It is an externality measurement problem[5]: namely the measurement of the scarcity constraint by the congestion signal emitted by TSOs. Is this signalling the hard but transparent diamond of physical constraints or the golden token ring of operators' opportunism?

Since congestion puts the risk of a collapse of interconnected electricity grids, the "capacity constrained situations" have to be avoided by TSOs, but the congestion signalling depends on norms directly set by them. Congestion is therefore defined as a situation where the power flows exceed the "regulated" limits set by TSOs. These norms are not stable and invariable because flexibility is needed by the very nature of the electric power flows on the grid and because the capacity limits of the lines are not constant. Therefore TSOs define the congestion signal on a variable, complex and non transparent constraint that they may manipulate to benefit from the congestion management's revenues or for any other personal agenda. The "Light Handed Regulation" in Nordic countries makes this strategy even more likely. While Norway is a typical light handed regulation country, the Swedish regulatory model is still lighter. It is an actual "ex post regulation"[6] system where the Swedish TSO is the authority setting the conditions for accessing and using the power grid.

[5] Barzel Y. (1990); Williamson O. (1996) & (2002).
[6] Commission of the European Communities (2002).

In a nutshell TSOs are appointed to generate a signal in order to avoid the collapse of the grid. Such TSOs have to be appointed because the conflicting private interests of generators, sellers and consumers would face too many difficulties in managing themselves the grid externalities in a frame of incomplete and asymmetric information[7]. Nevertheless we advocate here that the methods chosen by these TSOs to generate this congestion signal aren't neutral and may be manipulated by TSOs. This opportunism is all the more tempting as the externalities existing on power grids make it difficult to detect. It therefore appears that a pioneering and innovative institutional arrangement for congestion management, like the Nordic market-based mechanism, stays far for "workable perfection". Part II of our paper explains how congestion signalling works on electricity grids and Part III what is the congestion management in Nordic wholesale markets. Part IV presents our modelling of congestion signalling opportunism. Part V emphasizes that we need a more effective congestion regulatory mechanism. Part VI concludes.

II. How does congestion signalling work on electricity grids?

The electricity flows on the grid are governed by the laws of physics, namely Kirchhoff's laws. These laws show the relationships between the injections and withdrawals of power in the grid. These relationships aren't simple and except in the case of two nodes linked with only one direct line, there are several paths for the flows to go from one node to another. The path actually chosen by electricity depends on the characteristics of the lines and of the flows.

II-1 In an electric power grid we may distinguish roughly two kinds of capacity limits of power lines: the thermal limits and the stability limits.

[7] Libecap G. (2002); Glachant J-M (2002); Stoft S. (2002).

The thermal limits are closely linked with the losses of power. Some of the flowing power is converted into heat and the amount of power thus lost is proportional to the resistance of the line and to the square of the quantity of power transmitted. These losses increase the temperature of the line, causing the line to sag. At a higher temperature, the line risks breaking. Because of Kirchhoff's laws, the break of a line automatically entails a spread of its power on the remaining lines. This transfer of power brings about an increase of power, and as a consequence of losses, on these lines. Then the risk is obviously the collapse of the interconnected grid. The thermal limits of a line thus refer indirectly[8] to a physical limit on the power that can be transmitted on this line. They depends on the "real" power, that is to say, the "useful" power, but also on the reactive power, that flows back and forth automatically during power transmission, while supplying no "real" energy. The reactive power flows do also entail real power losses and take part in the transformation of power into heat. The thermal limits equally depend on the ambient temperature that contributes to increase or decrease the temperature of the lines.

The stability limits also constrain the flow of real power than can be transmitted on the lines. They refer nevertheless to more complex technical issues. They result indeed from the voltage difference between the generation and the load and this difference increases with the withdrawals of electric power. The fundamental constraining factor is the phase angle between the generation and withdrawal nodes. Eventually the voltage may drop rapidly entailing a deterioration of the grid. Unlike the thermal limits, the stability limits also depend on the length of the lines and the longer the lines, the lower the stability limit.

To sum up, congestion on an electric power grid is due to the amount of real and reactive power, the latter being by definition highly variable, as well as on the ambient temperature. For sure it puts the risk of a complete collapse of the interconnected electricity system that the transmission

[8] The fundamental limiting factor is the losses entailed by the flow of electrical current on the line.

system operators have to avoid. They thus have to devise and implement *ex ante* congestion management methods.

II-2 In order to understand how the transmission system operators may relieve capacity constrained situations, we have to recall at least two features of the electric power flows. These features are mainly the consequences of Kirchhoff's laws and highlight the specificity of the electric power grid compared with the motorway or the railway. Joskow[9] and Wilson[10] point out that these features make property rights on electric power difficult to enforce.

- The flows are not traceable in the grid, that is to say that it is impossible to impose a specific course on the electric power flows. A supply contract between a generator and a consumer, even if they are connected by a direct line within the network, can modify the flows of power in several other lines of the grid. In an alternating current (AC) power grid, the flows on each line are indeed given by a system of non linear and non independent equations that show that if the resistance of the lines and the voltage at the nodes are given, then the flows depend only on the amount and on the spatial distribution of the injections and withdrawals of electricity.
- The compensation of the flows has to be considered. Given two flows going in opposite directions on a line, that is to say, one is going from node A to node B and the other is going from node B to node A, the physical result isn't a superimposition but a compensation of the flows. It implies that only the net of the electric power flows will actually be transmitted on the line. A decrease in the actual power flows on a line, and the resulting relief of the congested path, may therefore result from creating "more" flows: namely the creation of "counter flows".

[9]Joskow P. (1996), (2002).
[10] Wilson R. (2001).

II-3 Knowing these characteristics, the only ways to avoid capacity constraints are the power cut for some customers, which is a rather crude method, or a change in the spatial distribution of the injection and withdrawal sets. An emergency signal has to be transmitted by the system operator to the market participants stating that the injection and withdrawal sets should be modified before the capacity limit is reached. That is why the system operators have to devise transmission contingency limits, lower than the physical capacity limits precisely because their goal is to warn of “almost capacity constrained” situations. The relevant capacity limit to trigger congestion management methods is therefore a norm that depends on a whole set of assumptions:

- assumptions concerning the actual injections and withdrawals,
- temperature forecasts,
- and security rules.

II-4 We have indeed noticed that the thermal and stability limits are highly dependant on the injections and withdrawals of real and reactive power on an alternating current transmission network. The capacity limits used to trigger congestion management mechanisms rely therefore on a schedule concerning the use of the grid that is used as a reference scenario to assess the risk of congestion. But the way this schedule is fixed is highly variable according to the congestion management method used. Simply phrased, this schedule may be based on the expected trades between generators and consumers, with a frequent updating of the schedule according to the changes in the trades. It enables a rather effective adjustment of the capacity limit based on the actual use of the grid in the whole area[11]. On the contrary, a system of physical transmission

[11] It is for instance the kind of approaches used in PJM where the data to compute the flows on the lines are brought up to date every 5 minutes.

rights[12]/[13] based on the assessment of transmission capacities currently used in Europe for some cross border lines entails assumptions for base case exchanges between an "exporting" area and an "importing" area[14] with less frequently updated assumptions. As stated in Boucher and Smeers (2001), "[…] in order to compute the maximal use of the network, one needs to make assumptions on the use of the network", and we may expect that the cruder the assessment of the power flows, the more conservative the assumptions on the use of the grid[15].

Since the temperature is also one of the main drivers of the transmission capacity limits, contingency limits have to take temperature forecasts in account. Typically, the non binding Net Transfer Capacities published *ex ante* by the European Transmission System Operators are based on a winter and summer scenario[16].

The difference between the "real" capacity limit and the "contingency" capacity limit is eventually partly due to the security rules applied by the TSO. One of the most widely applied security rules is the (n-1) criterion that implies the fixation of contingency limits such that the security of the grid is maintained even if one transmission line breaks. Nevertheless, other criteria may be applied, and the criterion used up to now to assess the contingency limit at the French-Italian cross border line has been the (n-2) criterion…

Obviously, congestion management let some flexibility in the measurement of the capacity constraint by the TSOs, and the choice of a congestion pricing method may increase or decrease this flexibility level.

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[12] The separate auctioning refers to the allocation of transmission capacities on a specific line considered in isolation from the rest of the grid.
[13] Inside each area, this method ignores the interdependencies between the uses of the grid.
[14] Exporting and importing areas don't refer systematically to an international exchange. Norway is for instance split in two areas.
[15] Hogan W. (1992), (2002).
[16] To have a closer look to this Net Transfer Capacity, see the following website: www.etso-net.org.

To sum up, the transmission system operators have to transmit a signal on a variable, non transparent [17] and complex constraint to the market participants, and this signal is more or less precise according to the home made conventions of the TSOs [18] and the congestion pricing method chosen.

III. Congestion management in the Nordic electricity markets

We currently assist to the creation of large electricity markets in several parts of the world. Obviously, congestion management at the interfaces between different control areas[19] is of high importance concerning this movement. We don't however assist to the standardization of the rules inside these regional markets. In Europe, the principle of "subsidiarity" for the Member States policies dominates in the European electricity law adopted in 1996 (European Directive 96-92) and introduces *de facto* a great deal of diversity in the market-based mechanisms implemented[20]. Even in the Nordic wholesale electricity market (voluntarily made up of Norway, Sweden, Denmark and Finland and that dates back to 1996)[21], different transmission rules coexist without standardization in spite of years of debates. These debates have mainly been motivated by complaints concerning congestion management.

[17] Non transparent at least for the market participants that don't share the same information as the TSO for the description of the grid and the exchanges announced by the generators and consumers.
[18] The French regulator acknowledged last Winter he didn't know how the congestion signal is set on the French-German border.
[19] A control area refers to a zone of the grid controlled by a single TSO. In Europe, the borders between control areas are mainly the political borders of each country except for some cases: Denmark (2 zones), Germany (6 zones) and Great-Britain (3 zones). In the United States too, the borders may be the ones of the states or of utilities.
[20] Hancher L. (1997); Glachant J-M, Finon D. (2002).
[21] At least, the Swedish-Norwegian wholesale market dates back to 1996; Finland has joined this market since 1998, West Denmark since 1999 and East Denmark since 2000. These moves are voluntary and not imposed by the European Law.

III-1 Two methods are currently used to manage "almost capacity constrained" situations in the Nordic market: market-splitting, based on a zonal pricing of electricity[22] and counter-trading, based on a dedicated adjustment market[23]. We will focus on Norway and Sweden.

Market-splitting is closely related to the operation of the physical day-ahead wholesale electricity market named Nord Pool. Nord Pool is a voluntary Pool, which means that the trading of wholesale electricity outside the Pool is free. But Nord Pool, owned by the Swedish and Norwegian transmission operators Svenska Kraftnät and Statnett, remains the central coordination mechanism for allocating access to congested interconnection between the Nordic control areas. When a cross border congestion signal is given the bids on this wholesale market are bids for electric power per "congestion area" that corresponds to the national areas except for Norway that currently has two congestion areas. Every bid and offer is therefore related to a given congestion area, that is mainly delimited by political borders. Nord Pool regularly publishes transmission capacity constraints for the cross border lines[24].

In fact the physical wholesale market is firstly cleared for the whole Nordic system while ignoring the grid constraints; it results in the Nordic "system price". The flows resulting from these expected exchanges are then simulated. If no constraint appears, the "system price" is used to settle the transactions in the whole Nordic region. But if a risk of constraint appears then the formal rule is to use market-splitting for a constraint on a cross border line and counter-trading for a constraint that appears only inside one of the pre-defined congestion areas. Market-splitting entails the partition of nodes into different pre-defined pricing areas on either side of the constraint. New market prices are determined, one for each area, taking in account the initial bids on the day ahead physical market and the physical transfer capacity of the cross border line

[22] Also named « zonal pricing ».
[23] Bjorndal M. (2000); Bjorndal M., Jornsten K. (2001).
[24] The cross border lines refer here to the lines that link two congestion areas.

determined by the transmission system operators. Considering the case of two zones (Norway / Sweden) and compared with the unconstrained system price, market-splitting results in a higher price in the area with a deficit of cheap generation and a lower price in the area with a surplus. As for the market operator Nord Pool, it “buys” power in the low price area (usually Norway) and “sells” it in the high price area (usually Sweden) for an amount equal to the capacity limit set for the cross border interconnection. The resulting profit is then equally split between the Norwegian TSO (Statnett) and the Swedish TSO (Svenska Kraftnät).

III-2 The management of congestion by counter-trading is completely different. Indeed, counter-trading doesn’t ask for a direct modification of the equilibrium in quantity and price of the day-ahead physical wholesale market. The counter-trading mechanism is in fact implemented through a separated voluntary market where generators bid for adjustments, upward or downward, in their day-ahead generation schedule[25]. The principle of counter-trading is thus a buy-back principle which consists in replacing the generation of one generator “ill-placed” on the grid as regards the congestion by the generation of one “better-placed” producer. The sole buyer on this adjustment market is the transmission network operator that directly bears the costs of increasing and reducing generation. These costs, or a part of them, are then charged to the national network users through the transmission tariff, depending on the regulatory model applied by the regulatory authority.

Whereas counter-trading and market-splitting have the same goal, the relief of a capacity constraint, they nevertheless differ in their trading process and in the resulting financial flows. We support the idea that the coordinated use of these two congestion management methods, with

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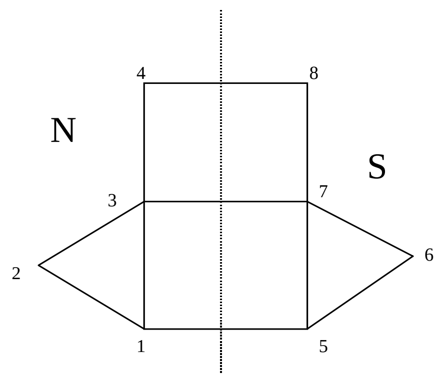
[25] In the Nordic area, consumers also are allowed to bid on this market; nevertheless their participation appears to be very low.

highly differentiated distributional consequences, gives an incentive to distort data concerning the capacity limits in order to use a specific method rather than the other. Phrased differently, the transmission system operators may benefit from the high level of flexibility in the assessment of the externalities that result from the uses of the grid and in the design of their security norms.

IV. Simulation of Congestion Signalling Opportunism

We have simulated market-splitting and counter-trading on a stylised example in order to highlight the potential benefits of the TSOs'opportunism.



Our simulation of congestion signalling opportunism focuses on the Norwegian and Swedish interconnected grid that we represent as a eight nodes grid, four located in market N (nodes 1,2,3 and 4) and four located in market S (nodes 5,6,7 and 8). There are three cross border lines (lines (1,5), (3,7) and (4,8)) that corresponds quite well to the Nordic reality. In both countries, the electric power grid is almost linear in the North whereas it's much more developed and meshed in the Centre and in the South.

IV-1 We model Kirchhoff's current law and voltage law and the law of conservation of energy[26] to stand for the power flow equations and we assume the linear lossless direct current (DC) approximation[27]/[28][29]. We also assume generation and consumption parameters, with each node being simultaneously consumer and supplier of electric power. We have attempted to reflect the main demand and cost features of the Swedish and Norwegian systems[30]. We assume linear supply and demand curves[31] at each node i:

$$p_i = a_i - b_i q_i^d$$

$$p_i = c_i q_i^s$$

Because of the presence of big electricity consumers in the Nordic countries, like the pulp and paper industry, we assume price elasticity for the electric power demand. We also consider a level of demand that can't be reduced.

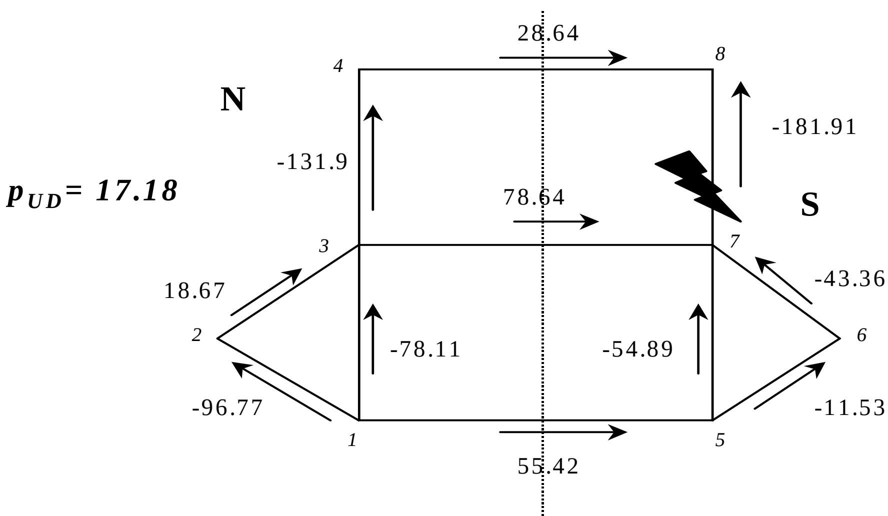
[26] For a mathematical expression of these laws, let's refer to the appendix 1.
[27] The « DC » approximation of the power flows equations is frequently used when analysing the constraints on the grid; it enables to get linear equations.
[28] To make it simple, the current law mirrors the nature of "flow" of electricity: electric power is a flow, a non storable good that is spread on the lines met. It states that the net injection in a node is equal to the current flowing out of it on each directly connected line. The voltage law makes explicit the way electric power is spread on the lines of a loop, stating that the sum of the potential differences across all components around any cycle in a grid is zero. And the law of conservation of energy simply states the equality between demand and supply (we ignore the losses with the DC approximation). These laws appear as constraints in our optimisation programs.
[29] A similar model may be found in Bjorndal et al. [2001]
[30] Norway is mainly hydroelectric with the biggest units located in the North and in the West; they largely represent the base load generation units, which run continuously. Some fossil thermal power plants are also located in the South East of the country and are used mainly to meet peak demand or during dry periods. In Sweden, the big nuclear and hydro power plants are located in the North of the country while there are some fossil thermal power plants nearer from consumption in the South and Centre. In steady operational conditions the nuclear power plants are the marginal one, that is to say are the last units to be retained by the market operator in order to produce. But depending on the rainfall, the hydro as well as the fossil thermal power plants may be the marginal generation units.
[31] Obviously, these curves are highly simplified and we should notice that a precise assessment of the generating costs of electric power is a hard task that implies to consider the start-up costs, the no load costs, the ramping rates… that also contribute to assess the productive efficiency of a generation unit.

Table 1 : Costs and demand parameters

Node	Generation	Consumption	
	c_i	a_i	b_i
1	0.8	20	0.02
2	0.1	20	0.05
3	0.5	20	0.1
4	0.1	20	0.25
5	0.9	20	0.02
6	0.7	20	0.05
7	0.3	20	0.02
8	0.2	20	0.25

The first step of the simulation consists in computing the market equilibrium that maximises the total social surplus, computed as the sum of the nodal social surplus revealed by the demand and supply bids, while taking in account the network interdependencies. We don't consider market power for the generators and assume that they bid their marginal costs. At this stage, we also don't consider the capacity constraints of the grid.

Figure 1: Unconstrained Dispatch



The results are the following unconstrained flows on each line and equilibrium price.

Throughout this paper, the arrows on the figures go from the lower to a higher node number. The number next to each arrow stands for the amount of electricity flowing on the line; a negative number means that the electricity flows in the opposite direction. Binding capacity limits are symbolized by a lightning.

Table 2: Generation and consumption per node in the unconstrained case

Node	Generation	Consumption
1	21.48	140.93
2	171.81	56.37
3	34.36	28.19
4	171.81	11.27
5	19.09	140.93
6	24.54	56.37
7	57.27	140.93
8	85.91	11.28

IV-2 Let us consider a capacity limit of 140 units on line (7,8). As noticed in the 2001 report from the Swedish National Energy Administration, "the connection from North to South include certain limitations known as "constraints". The most important bottleneck in Sweden today is […] between Northern and Central Sweden and limits the power that can be transmitted to between 6.700 and 7.000 MW". Here, the flows resulting from the day-ahead market clearing entail a binding transmission constraint and a congestion management mechanism has to be used. It should be counter-trading since the congestion appears internally in market S.

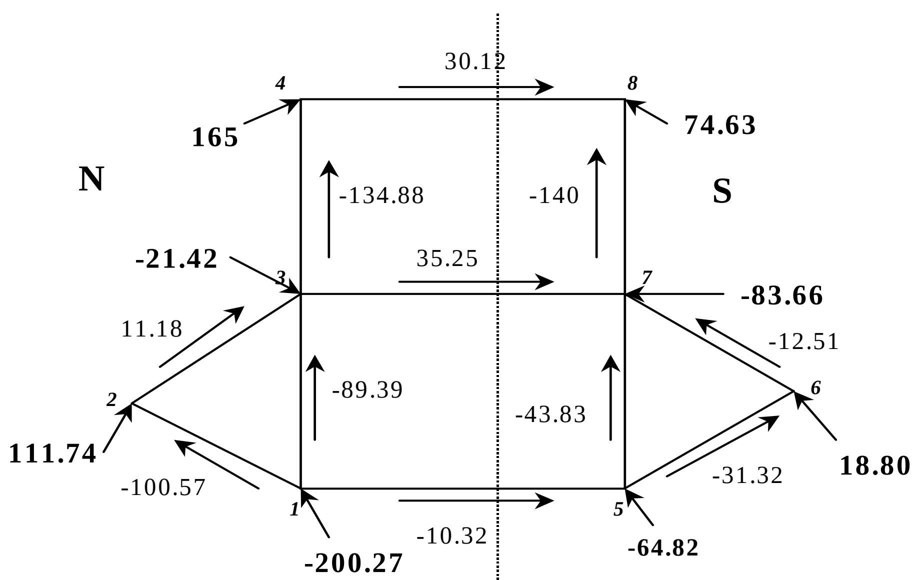
As already noticed, this mechanism entails the use of the adjustment market, where generators bid for increases or decreases in their generation schedules resulting from the spot market. Adjusting its generation level a few hours before delivery isn't costless for a producer and these costs are all the higher as the generation technology isn't flexible. Therefore, it will be easier for a hydro or a fossil thermal plant than for a nuclear one. Hence, we take into account this flexibility in a rather crude but also quite simple way: we make the assumption that the nuclear power stations don't take part in the adjustment market[32]/[33]. The generation levels are therefore

[32] A hydroelectric plant presents another kind of problem that relates mainly to water storage. The precise assessment of every component of the cost function of an electric power producer is however a difficult task.
[33] As for the consumers, they may be allowed to participate in the adjustment market but the empirical experience shows that their participation is very low. In our simplified example, the consumption level is considered to be fixed to the level resulting from the unconstrained dispatch and has to be met whatever the problems on the grid.

fixed in nodes 7 and 8 at their unconstrained levels. Besides, a generation capacity limit is fixed at 175 units in node 4, since it is already a big energy provider at the unconstrained stage.

With counter-trading, the TSO pays for the increases in generation and is paid for the decreases in generation as compared with the unconstrained equilibrium. Because of the rules applied to fix the prices on the adjustment market (the marginal bid) and of the lack of flexibility of some low-cost generation technologies, it results in congestion costs for the grid operator even if we consider that the generators truthfully reveal their costs. The goal of the adjustment market is therefore to minimize the costs resulting from the generation adjustments, while respecting the transmission capacity limit and meeting the consumption level that results from the spot market. It gives the following flows on each line of the grid.

Figure 2: counter-trading with constraint on (7,8)



The net injections for each node are displayed in bold on figure 2.

Table 3: Generation and consumption per node with counter-trading

Node	Generation	Consumption
1	19.51	219.78
2	170.58	58.84
3	29.76	51.18
4	175	10
5	20.33	85.15
6	27.92	9.12
7	57.27	140.93
8	85.91	11.27

With counter-trading, the market clearing price resulting from the day-ahead physical market is used to pay the producers and charge the consumers. In addition the generators that are retained to increase their generation on the basis of their bids on the adjustment market are paid for their additional output the marginal price for an upward adjustment. This price is settled according to the marginal bid, that is to say the bid of the most expensive generator retained in the adjustment market. Simultaneously, a few generators are selected to "buy back" some of their generation. They therefore decrease their production compared with spot market result and pay the marginal price for a downward adjustment.

Table 4: Equilibrium Prices on the Adjustment Market

Upward Price	**Downward Price**
19.54	**14.88**

The sole buyer on the adjustment market is the TSO that bears the costs of the adjustments. In our example, it results in a cost equal to:

$$\textit{TSO costs} = (G_{AU} - G_{SU}) * p_{AU} - (G_{SD} - G_{AD}) * p_{AD} = 36.34 \textit{ MU (Monetary Units)}$$

Where G_{AU} is the adjusted generation level for upward generators,
G_{SU} is the spot generation level for upward generators,
p_{AU} is the market price for an upward adjustment,
G_{SD} is the spot generation level for downward generators,
G_{AD} is the adjusted generation level for downward generators,
and p_{AD} is the market price for a downward adjustment.

IV-3 We now consider that the TSOs announce a fake transmission capacity limit of 30 units on the cross border line (3,7). The day-ahead clearing seems to constrain line (3,7) since it entails a power flow of 78.64 units. These constraints should be managed through market-splitting. We therefore compute the optimal generation set that maximizes the social surplus and doesn't violate the announced capacity limit of 30 units.

Figure 3: market-splitting with constraint on (3,7)

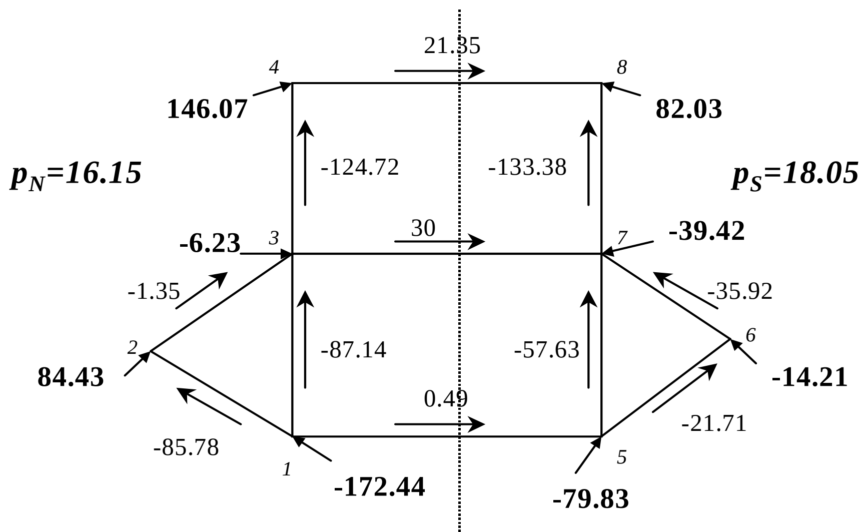


Table 5: Generation and consumption per node with market-splitting

Node	Generation	Consumption
1	20.18	192.62
2	161.48	77.05
3	32.29	38.52
4	161.48	15.41
5	20	99.83
6	25.72	39.93
7	60.01	99.83
8	90.02	7.99

It appears that the use of market-splitting to manage the constraint on line (3,7) enables simultaneously to deal with the real transmission constraint on line (7,8). Thus, putting a capacity limit of 30 units on line (3,7) can solve the internal constraint in sub-market S thanks to the high level of interdependencies in the electricity network. If the TSOs "move" the transmission constraint from the internal line to the cross border one, they succeed in relieving the internal congestion without having to resort to counter-trading… and therefore without having to pay for the generation adjustments. They even get a profit since their market operation buys the "exported" electric power units at the low zonal price and sells them at the high zonal price.

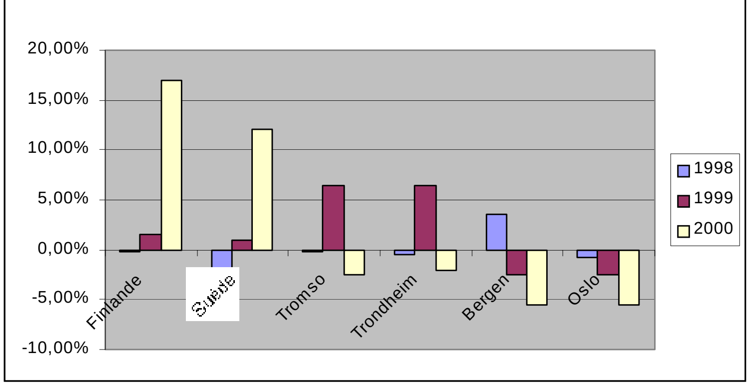
*TSOben = CBF * (*p_{HZ}*-*p_{LZ}*) = 98.50 MU (Monetary Units),*

where *CBF* stands for the net amount of cross-border flows,
p_{HZ} and p_{LZ} are respectively the energy price for the high priced area and for the low priced area.

This income is equally shared between the Nord Pool's owners that is to say the Swedish and Norwegian TSOs.

IV-4 We have therefore shown in this paper that the signal of capacity constraint emitted by the TSOs isn't neutral and may be manipulated. Obviously, the physical characteristics of the electric power grid make the detection of opportunism difficult. It seems however that the possibility of some opportunism is being taken more and more into account in the Nordic countries. The division of Nord Pool in several zones is actually far from being exceptional. The hourly Nord Pool prices are now divided into zones 40% to 50% of the yearly time. Beyond the frequency of the division in different price areas, an interesting point lies in the gap in the zonal prices. A study[34] based on Nord Pool data, reports the differences in zonal prices in 1998, 1999 and 2000. It clearly appears that the gap between them increases.

[34] Prospex (2001).



Graph 1: Price Divergences from the System Prices

This graph is based on yearly averages of hourly prices. In fact a temporary 100% price difference between the areas may happen. Obviously, this huge increase in the price differences triggers the dissatisfaction of some market participants and some Nordic companies asked courts to review TSOs behaviours. Nordel, the reliability council of Nordic TSOs, has launched an investigation on the rationale for changing the congestion management methods.

V. And so what? We need a more effective congestion regulatory mechanism!

The transmission system operators are very central entities in the competitive electricity markets. They do have privileged information regarding the power trades between generators and consumers and regarding the physical characteristics of the power system. But even more, they also have to get this privileged information: their function is indeed to coordinate the results of the competitive market with the security of the power system.

This central position of the transmission system operator puts obviously the question of their incentives at the core of the deregulation process for “making competition work in electricity”[35]. How are the incentives of the TSOs structured? Do the actual market-based congestion management mechanisms give an incentive to the TSOs to facilitate the trades of power across

[35] Hunt (2002).

theirs systems or do they give them an incentive to intervene in the market at their own benefits? We have seen that the choice of the congestion management method used is not neutral:

- On the one hand, the methods based on the adjustment of the generation and consumption schedules entail costs for the transmission system operator. The TSO is the sole buyer on this market and directly bears the congestion's cost through the cost of adjustments. On the other hand, the users of the grid pay the average cost of the congestion and are not incited to an efficient use of the grid.
- At the opposite, the methods based on the market separation, through a zonal and even a nodal pricing, entail electric power prices that reflect the impact of each use of the grid on the capacity constraint. They therefore convey good signals to the users of the grid but result in a profit for the TSO that benefits from the differences in electric power prices.

Do TSOs really manipulate the data to benefit from the congestion on the grid? At least, we have shown on a simple numerical example that such a behaviour could be highly profitable and would necessitate only a slight manipulation of the data. Besides, the use of zonal pricing as compared with nodal pricing makes this kind of opportunistic behaviour really tempting. Zonal pricing relies indeed on a transmission capacity assessment on cross border lines based on reference scenarios infrequently updated. Since the reference scenarios may be different from the actual use, we can expect that higher security margins will be taken in account in the computation of the physical transmission capacity.

The possible conflict of interest that could result from incentives rooted in the congestion management mechanism has to be taken into account seriously. Giving the good incentives to the users of the grid settles one side of the problem, but it doesn't give necessarily good incentives to the TSOs. The TSOs' central position in the competitive electricity markets may turn it into a danger for the success of the deregulation process. We therefore need regulatory mechanisms that ensure that the TSOs benefit by reducing congestion and are hurt by increasing it.

In a single country, England and Wales, the regulatory authority has implemented such a regulatory scheme since 1995. National Grid Company has an energy uplift's target and is allowed to keep the benefit resulting from actual costs below this target; at the opposite, NGC isn't allowed to charge the supplementary costs above the target to the users of the grid and must bear them in its own accounts. The result has been 87% decrease in the energy uplift[36] costs in 2000 as compared with 1994. [37] It seems worthwhile to tackle with this combined "information and incentive's" problem of the transmission system operator through an appropriate regulatory mechanism.

At the international level we have raised another layer of problems in this paper, the layer of the coordination between different countries, that is to say between different TSOs and different regulatory authorities. On the one hand, the mechanism adopted in the Nordic countries seems appealing. Zonal pricing of electric power through the use of market splitting to manage the seams between countries is both "market based" and "institutionally friendly". It creates a regional market with limited harmonization of the countries internal electricity arrangements. On the other hand, this mechanism lets a high degree of flexibility in the measurement of the capacity constraint by the TSOs. TSOs are not incited to reduce congestion on the cross border lines and stay in two different countries with different regulatory authorities and light regulatory rules. This coordination layer obviously raises the question of an effective multi-country regulatory mechanism. We are still far from it in the European electricity ''single'' market…

[36] In the former England and Wales Pool, energy uplift consisted in the costs of congestion and system's balancing.
[37] This result is all the more impressive as NGC has relied on an adjustment mechanism similar to the one used in Sweden to deal with congestion whose costs were passed to the users of the grid through the transmission tariff.

VI. Conclusion

Nordic market-based cross border congestion management appears as a model for Europe when reading European Commission reports or the European association of TSOs' (ETSO) proposals. For sure the Nordic congestion market-splitting is a market-based mechanism and it relies on a transparent and non discriminatory pricing. Furthermore, this mechanism is "European countries subsidiarity friendly" by coordinating several control areas such that each area may keep its own rules to manage its internal problems. It seems as a consequence that this method is suited to the European institutional environment characterized by the country subsidiarity principle. Nevertheless our paper showed that the Nordic institutional arrangement for congestion management doesn't solve the incentives problem in coordinating TSOs. This arrangement, with differentiated distributional consequences, may give TSOs an incentive to be opportunistic and distort the signal emitted. It may be all the more tempting as the network interdependencies make the detection of opportunism difficult and as the European TSOs are regulated only at the national level, either ex ante by newly born national regulators or ex post like in Sweden and Germany.

In a system with market separation (and more generally nodal pricing), the system operator has a lot of discretion to determine capacity/security constraints and then to affect prices for energy. The system operator can potentially profit from increasing congestion charges (difference in zonal or nodal prices) by manipulating network constraint management. If the market is organized so that the system operator can in fact profit in this way then we can expect that its behaviour will be affected accordingly as it takes advantage of the profit opportunities. We need a regulatory mechanism (probably multi-country) that ensures that the system operator benefits by reducing congestion economically and is hurt by increasing it. This is what they have tried to do since 1995 in the UK.

Appendix 1

In our 8 nodes grid, the Kirchhoff's current and voltage laws and the law of conservation of energy have the following expression:

Kirchhoff's current law ('nodal' law):

$X_1 = X_{12}+X_{13}+X_{15}$
$X_2 = X_{21}+X_{23}$
$X_3 = X_{31}+X_{32}+X_{34}+X_{37}$
$X_4 = X_{43}+X_{48}$
$X_5 = X_{51}+X_{56}+X_{57}$
$X_6 = X_{65}+X_{67}$
$X_7 = X_{75}+X_{76}+X_{78}$

Kirchhoff's voltage law ('loop' law):

$X_{13}-X_{12}-X_{23} = 0$
$X_{57}-X_{56}-X_{67} = 0$
$X_{13}+X_{37}-X_{15}-X_{57} = 0$
$X_{34}+X_{48}-X_{37}-X_{78} = 0$

Law of conservation of energy (we ignore the losses with the DC approximation):

$$\sum_i X_i = \sum_i (G_i - D_i) = 0 .$$

Where:
X_i is the net injection (positive or negative) for node i,
X_{ij} stands for the electric power flow on the line that connects node i to node j,
G_i is the power generation in node i,
and D_i is the power consumption in node i.

In the optimisation programs, these laws appear as constraints to take in account the way electric power is transmitted in the grid.

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