Strategic Generation With Conjectured Transmission Price Responses in a Mixed Transmission Pricing System—Part II: Application

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***Abstract*—The conjectured transmission price response model presented in the first of this two-paper series considers the expectations of oligopolistic generators regarding how demands for transmission services affect the prices of those services. Here, the model is applied to northwest Europe, simulating a mixed transmission pricing system including export fees, a path-based auction system for between-country interfaces, and implicit congestion-based pricing of internal country constraints. The path-based system does not give credit for counterflows when calculating export capability. The application shows that this no-netting policy can exacerbate the economic inefficiencies caused by oligopolistic pricing by generators. The application also illustrates the effects of different generator conjectures regarding rival supply responses and transmission prices. If generators anticipate that their increased demand for transmission services will increase transmission prices, then competitive intensity diminishes and energy prices rise. In the example here, the effect of this anticipation is to double the price increase that results from oligopolistic (Cournot) competition among generators.**

***Index Terms*—Belgium, complementarity, electricity competition, electricity generation, France, Germany, market models, Netherlands, strategic pricing, transmission pricing.**

I. Introduction

A MODEL of oligopolistic generators who compete on a power network characterized by a mix of transmission pricing policies is presented in [12]. The mix of policies can include fixed export and access charges, path-based transmission capacity allocation based on auctions, and dc load flow-based congestion pricing. The model also allows assumptions to be made about what an individual GenCo anticipates concerning both the reactions of rival generators to changes in energy prices and how transmission prices will be affected by changes in the GenCo's demands for transmission services. The simplest assumptions are that rival generators do not react (i.e., the Cournot model) and that transmission prices are unaffected by changes in services demanded (price-taking).

However, those assumptions are not always realistic. For instance, a generator may anticipate that if it restricts sales in an effort to raise price, other generators may respond to higher prices by expanding their output. As a result, the effective demand curve facing the individual generator (which nets out other generators' sales) is more elastic than the original demand curve. This dampens the incentive to raise prices, and prices in equilibrium would be lower than Cournot levels. Empirical evidence from the U.K. market indicates that prices in the Pool system were well below the levels that would be expected in a Cournot model, and were more consistent with a model that assumes that rivals respond to price changes [19]. The model applied in this paper allows more general assumptions about the nature of rival supply responses.

An assumption that generators do not anticipate that their decisions can affect the price of transmission may also be unrealistic in many cases. This assumption too can be relaxed by our modeling framework. Large generators are sophisticated enough to know that changing the amount of transmission services they demand will likely affect congestion and the prices that result, for instance, in transmission capacity auctions. Thus, for example, a GenCo exporting through a congested interface may reduce its demand for that interface in order to decrease the price of that interface, a classic monopsonistic or oligopsonistic strategy. As a result, the price of the interface between two markets may fall to a level well below the difference in the prices in those markets.

There is evidence of this occurring in northwest Europe. For instance, Newbery and McDaniel [15] show that the price of the France–U.K. interconnector is much less than would be expected based on the relative prices of power in those two countries.

Another example could be the interface constraining flows from Belgium to The Netherlands. When this interconnector is almost or fully used, the price paid is relatively low (Fig. 1). This suggests that even though congestion is occurring, the price paid probably does not track differences in energy prices between the two countries (unfortunately, this is difficult to study empirically, as wholesale spot prices are not accurately reported in Belgium). Moreover, the day-ahead auction prices, when positive, tend to repeat themselves for many hours, which can occur if just a few market parties participate in the auctions. In other words, the low price for this interface may occur because there are one or two main users of that interface (Electrabel and EdF) who may have learned that they can lower their bids for that interface and still obtain all of the

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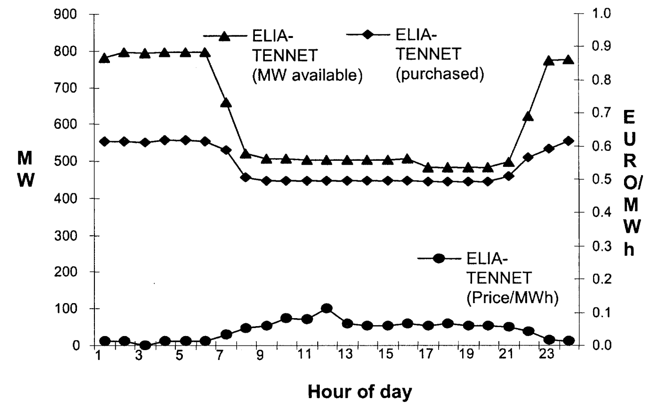

Fig. 1. Day-ahead Belgium to Netherlands interconnector availability, purchases, and prices (averages during January–July 2001). Source: [Online] http://www.tso-auction.org.

capacity. Electrabel has essentially a monopolist position in the Belgian energy market, preventing arbitragers from buying and reselling power; as a result, Electrabel may act essentially as a monopsonist with respect to transmission capacity from Belgium to The Netherlands.[1] On the other hand, the two Germany to The Netherlands interfaces, which are also used to capacity most of the time, usually get a significant price in their auctions [15]. This may be because more suppliers who desire that capacity, making that market more competitive.

The purpose of this paper is to illustrate the ability of the model in [12] to explore issues of transmission pricing and market power by applying it to the Benelux (Belgium–Netherlands–Luxembourg) market. This region is chosen as a case study because, first of all, power sector liberalization is proceeding quickly in the European Union (EU), although retail market opening and network access are more advanced in some countries than others [9], [14]. Second, one of those countries (The Netherlands) depends significantly on imports, and transmission constraints are important. Third, the region has a mix of transmission congestion management systems. Fourth, and perhaps most important, market power is a concern in this particular region, especially because mergers and acquisitions have led to consolidation in the Benelux and neighboring German markets [18]. The application shows the effects of some alternative representations of generator behavior and transmission policies and structure. In Section II, we summarize some of the assumptions made in the case study. Subsequent sections illustrate how the model can be used to examine the following issues:

- the effect of alternative GenCo expectations concerning responses of rivals and transmission prices (Section III);
- how inefficient transmission pricing that disregards counterflows can exacerbate the exercise of market power by GenCos (Section IV);
- the price impacts of dc load flow constraints compared to path-based transmission auctions (Section V);
- the interacting effects of inefficient transmission pricing and industry structure (i.e., GenCo mergers) upon prices (Section VI).

Most of these issues have not been previously addressed by oligopoly models of power markets.[2] The goal of this paper is to show the capabilities of the new modeling approach, rather than to provide an in-depth analysis of particular market design issues. Therefore, our description of assumptions and conclusions is brief and illustrative in nature, not exhaustive.

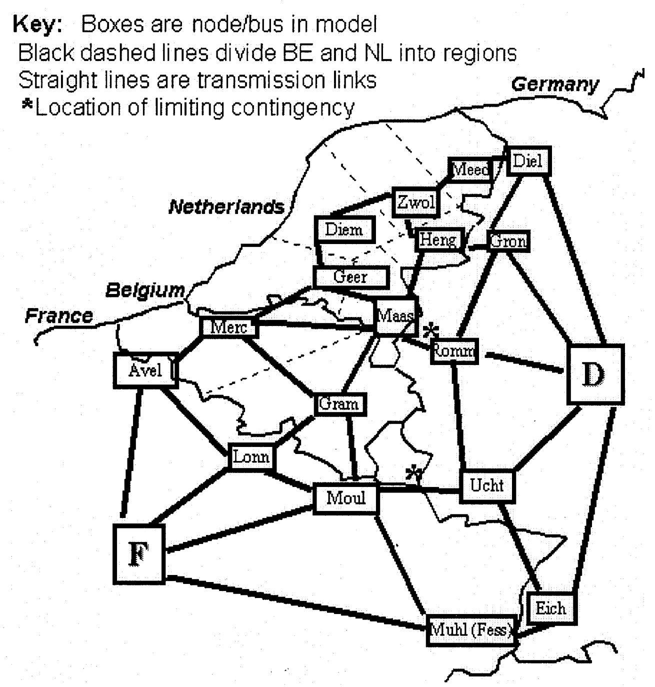

Fig. 2. Schematic of linearized dc network used in Benelux analysis.

II. Assumptions

Here, we briefly describe the assumptions made in the multiperiod version of the mixed transmission pricing model [12] applied in this case study.[3] We summarize assumptions made in the model concerning demand, imports, generation, transmission, and arbitrage. Year 2000 fuel prices and loads are used.

A. Demand and Imports

The model includes demand curves representing net wholesale loads on the high voltage grid for six network nodes in The Netherlands, two in Belgium, and one each in France and Germany (Fig. 2). Exchanges with countries outside this region are included in the net French and German loads. In addition, The Netherlands values include an estimate of the load served

[1]However, there are other possible explanations for these low interface prices. One is that individual generating companies are restricted to buying no more than 400 MW of interface capacity into The Netherlands; this can limit total demand for the interface, and thus prices. Another explanation is that since bids for the interface auction are submitted before energy prices are posted on the Amsterdam Power Exchange (APX), generators may submit very low bids for the full amount of interface capacity in order to keep open the option of using that interface if prices in The Netherlands turn out to be attractive. Further empirical analysis and better data are needed to distinguish between these possible causes of low prices for an interface that is often congested.

[2]Ref. [2] models the effect of some transmission pricing inefficiencies in the EU, but assuming perfect competition (cost-based bidding).

[3]This version is called Competition and Market Power in Electric Transmission and Energy Simulator (COMPETES).

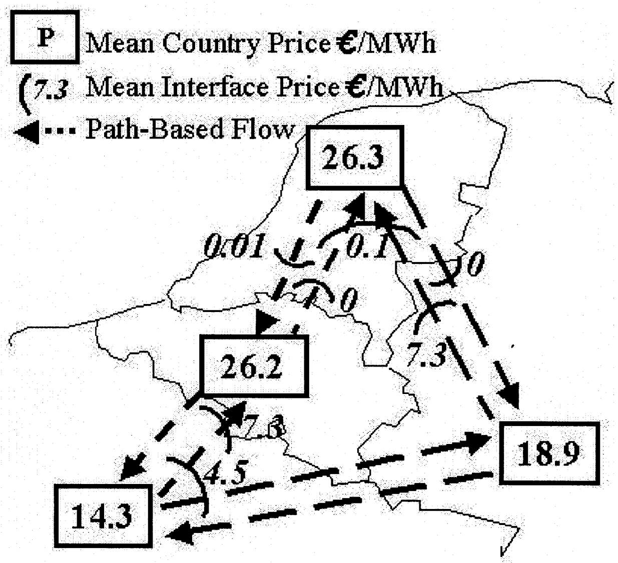

Fig. 3. Path-based transmission interface constraints, average interface prices, and country prices in competitive case.

by decentralized sources, whose capacities are included in the model. Because of its small load, Luxembourg is combined with Germany. Four demand periods for each of three seasons are defined for each node in the network. The "superpeak" period in each season consists of the 200 h with the highest sum of the loads for the four considered countries. The three other periods have equal numbers of hours and represent the rest of the seasonal load duration curve. Altogether, the 12 periods represent all 8760 h of a year. The load data are drawn from [17] and [20].

Affine demand curves are assumed for each node. Each curve is defined such there is a demand elasticity of -0.2 at the price-quantity pair for the competitive solution.

B. Generation

For each of the four countries studied, we model the few largest generation firms in each country as being strategic players ($CO_{fi} = 1$ for all i in conditions (GEN1) and (KG2) in [12]).[4] Each generating "firm" is defined as owning capacity belonging to its subsidiaries in proportion to the firm's ownership share, assuming that the firm participates in operating decisions. (Alternative assumptions are possible, see [1].) There are 13 such firms, controlling between 73% and 93% of the capacity in each of the countries. The remaining generation capacity (i.e., that not owned by the strategic companies) is incorporated in the model as a competitive fringe ($CO_{fi} = 0$).

Generating unit characteristics, including capacity and marginal operating costs, are from [13], [21]. Fuel prices are based upon a reference scenario developed by ECN [16].

C. Transmission

The model represents both the high voltage system and path-based constraints that limit flows in the Benelux region. The dc load-flow constraints are based on thermal limits for lines and other equipment within the Benelux countries and in the border regions of France and Germany. In order to better represent imports and exports from France and Germany, portions of their networks near the Benelux borders are also represented in addition to the internal Benelux network, although generation capacity and demand in France and Germany are each aggregated to a single node.

The assumed network is shown in Fig. 2. Nineteen nodes are represented, but it is possible to include many more (over 100 are considered in [11]). The thermal limits are those reported in [10] for two different critical line outage contingencies that limit flows from France and Germany to the Benelux countries. Each of these contingencies consists of a fault on one line in one of the corridors indicated in Fig. 2. Thus, two sets of power flows and thermal line limits are simulated in each period, one for each of the contingencies. Reactances used to calculate PTDFs are estimated based upon standard conductor configurations and published circuit lengths and voltages.

This application makes the simplifying assumption that the five transmission system operators (TSOs) (one each in France, Belgium, and The Netherlands, and two in Germany) operate the equivalent of a balancing market with locational prices to make sure that flows will continue to be feasible in the event of one of those contingencies. The model assumes that transmission capacity in the dc network is efficiently allocated this way (e.g., allocated to the highest bidder, as in [7]). However, as has been pointed out [5], within-country allocation in Europe is not that efficient.

Meanwhile, path-based constraints are defined using reported available transmission capabilities (ATCs) between the four countries [10]. (For instance, transactions through the French–Belgian interface are limited to about 1800 MW.) These ATCs are based on load flow studies that consider line outage contingencies and both internal and between-country constraints. The arcs shown in Fig. 3 define the location of the ATC constraints. As an example, there is a constraint on the total flow from France to Belgium/Germany (the arc shown with a price of 4.5 Euros/MWh).

Haubrich *et al.* [10] describes the shortcomings of these ATCs at some length. Generally, these constraints are very conservative, often overly so. For instance, because it is aggregate interfaces between countries that are sold rather than capacity on individual lines, worse-case assumptions are sometimes made about the locations of generation and load within the countries. As another example, thermal limits are the same in winter and summer for some lines, even though looser constraints could be used in the former season.

In the runs in which generators are price takers with respect to transmission (i.e., they do not assume that transmission prices will be affected by the amount of services they demand), we assume that scarce ATC is efficiently allocated among firms. That is, the price of each interface equals the marginal value of that transmission capacity to each GenCo; this follows from the first-order conditions for profit maximization in the TSO and GenCo models in [12] *if* price-taking behavior for transmission prices is assumed. In theory, such efficient allocation is possible through mechanisms such as the three interface auctions used to allocate capacity between The Netherlands and its neighbors.

[4] A partial exception is EdF, which we model as behaving competitively (price taking) in its home market, France. This is because if we instead model it as Cournot in that market, its dominant position would mean that it could charge monopoly prices there, which actually is impossible for political reasons.

TABLE I
RESULTS: PATH-BASED CONSTRAINTS BINDING (PRICES IN EURO/MWH, OTHER QUANTITIES IN M EURO/YR)

	Mean Annual Bulk Power Price				Genco	Consumer	Genco	Transmission	Social	Change in
Case	Netherlands	Belgium	Germany	France	Cost	Surplus	Profit	Revenue	Welfare	Welfare
Competitive	26.31	26.17	18.86	14.31	12813	51482	6708	449	58639	0
Cournot	30.38	30.25	25.37	13.87	12291	48096	9862	356	58314	-325
Conjectured Supply Function	26.90	26.67	19.94	14.23	12711	50880	7299	431	58610	-30
Cournot + Conjectured Transmission Response	33.68	33.75	26.09	14.27	12118	47016	10875	321	58212	-427
Cournot + No Netting	38.26	51.06	26.63	13.63	12175	45449	10616	1490	57554	-1085
Cournot + 1 €/MWh Tax	31.10	31.07	25.64	13.94	12235	48069	9869	360	58297	-342
Cournot + Electrabel Divest	28.88	28.88	25.29	13.87	12332	48372	9666	301	58339	-300

However, the lack of resale markets and poor coordination of timing with neighboring energy exchanges means that the observed daily interface prices are poorly correlated with daily exchange prices [10].[5]

If instead GenCos are assumed to anticipate that transmission prices will be influenced by the amount of transmission services demanded, then the marginal value of interface capacity can differ between different firms. This is because the marginal willingness to pay of a GenCo who already uses a lot of capacity is less than for smaller firms, as additional demand by the former firm will increase the price for all the service it already uses.

To start with, no export fees are imposed, and full netting of flows (crediting of counterflows) is allowed in the ATC auctions. Sensitivity analyzes consider other assumptions.

D. Arbitrage

Arbitrage is only allowed within and between The Netherlands and Germany, because the French and Belgian markets are relatively opaque and each dominated by a single large GenCo (EdF and Electrabel, respectively). Because arbitragers are assumed to buy power from one place and sell it in another if the transmission cost is less than the energy price difference, equilibrium price differences among network nodes in The Netherlands and Germany will be no more than the price of transmission (including export fees, the price of path-based interfaces, and dc load flow-based congestion prices). However, the assumed lack of arbitrager access to markets in France and Belgium means that prices there could differ from each other and from prices elsewhere by more than the difference in transmission costs.

III. COMPARISON OF GENERATOR STRATEGIES

Table I shows price results for several solutions, averaged by country and over the 12 aggregate periods. Also shown are total generator profits (equation (GEN1) in [12]), consumer surplus (equaling the sum of the integrals of the demand curves minus consumer expenditures), transmission profits [(TSO1) in [12]], and aggregate social welfare (the sum of the foregoing). Generation costs are also shown. To ease interpretation, both total welfare and change in welfare relative to the competitive case are shown. Prices are annual averages, while the other quantities represent annual totals.

The first four rows of Table I show the results for four different types of strategic behavior.

1) Perfectly competitive generators (all $CO_{fi} = 0$) (also Fig. 3) who maximize profit assuming naïvely that they cannot affect price p^*.[6]
2) Cournot competition, in which each GenCo f maximizes its profit subject to an assumption that rival sales s_{-fi} are fixed. ($CO_{fi} = 1$ for large firms, except for EdF in France, and all conjectural coefficients = 0 in conditions (GEN5)–(GEN7), (KG1)–(KG3) of the GenCo model in [12].)
3) A conjectured supply function (CSF) solution, in which each strategic GenCo f conjectures that rival sales will grow by SFC$_{-fi}$ (where SFC is the "supply function conjecture") if the price of electricity goes up 1 Euro/MWh at node i (SFC$_{-fi} > 0$ in conditions (GEN5), (KG2) of the GenCo model [12]).
4) A Cournot solution in which producers also conjecture that they can affect the cost of transmission. This is simulated by a conjecture that transmission service prices will go up if more services are demanded. (That is, WC_{fi} and WCT_{fm} can exceed 0 in conditions (GEN6)–(GEN7) and (KG1)–(KG3) of the GenCo model [12]).

Each model is solved 12 times, once for each period in the year. The same transmission network is used in every case.

For illustrative purposes, we assume in the CSF case that the values of SFC$_{-fi}$ in the Benelux Countries reflect the average slope of the aggregate marginal generation cost curve in those countries during peak periods (approximately 400 MW for each Euro/MWh price rise), which we then allocate in proportion to the peak load to each of the eight nodes in those countries. The German value of SFC$_{-fi}$ equals 2500 MW/(Euro/MWh), reflecting the fact that the marginal cost curve there is much shallower. (However, we do not define this coefficient for France because we assume that EdF is forced by regulation or political pressure to price at marginal cost in that country.)

Meanwhile, the conjectured transmission price response solution (Table I, row 4) assumes that producers believe that a 1 MW change in their demand for ATC in the path-based system will lower the cost of each interface m

[5]This lack of relationship among daily prices was also observed by Newbery and McDaniel [15]. They point out, however, that the prices of longer-term contracts for interface capacity in that market do tend to converge to average price differences between the energy exchanges in those two countries.

[6]See [11] for an explicit statement of a simple perfect competition model.

by $WCT_{fm.} = 0.0032$ Euro/MWh during super peak and peak hours for the three major congested interfaces: Germany–Netherlands, France–Belgium and France–Germany–Belgium. During off-peak and shoulder hours, WCT_{fm} for these three interfaces is set to half that value, since simulated interface prices are considerably lower during those times. These illustrative values are based on the assumption that reducing transmission capability would increase transmission prices at a rate that would cause them to roughly double if there was zero capability.[7] Meanwhile, the conjectured price response WC_{fi} for the dc congestion pricing system is zero in this case, because, as noted below, only the path-based constraints are binding in this set of solutions. Although arbitrary, use of these values of WCT_{fm} and WC_{fi} illustrates how supplier expectations about transmission prices responses might affect market outcomes.

A key result in Table I's solutions is that the path-based ATC constraints are so tight that the thermal constraints in the dc load flow [(TSO2) in [12]] never bind, even during system peaks. In reality, some intracountry congestion occurs in the Benelux countries during system peaks, but this is relatively rare; congestion between countries in the path-based system is more prevalent and economically important. Thus, the dc-based pricing system is redundant in these cases. However, if between-country ATC was to expand while load continues to grow, then within-country thermal constraints could become more important in the future.

We first compare different degrees of competitiveness among generators. First, the CSF solution (row 3 of Table I) results in prices between the competitive and Cournot extremes. This is as expected [8], since the competitive and Cournot solutions are in a sense extreme cases of the CSF model (infinite and zero response, respectively, of rival supply to price changes). The specific values of SFC_{-fi} assumed here yield CSF prices that are more similar to competitive than Cournot levels; however, lower values of SFC_{-fi} could yield prices that are closer to those of the Cournot model.

Second, the Cournot model shows that significant price increases are possible due to market power.[8] To provide perspective on the welfare loss in the Cournot case (325 M Euros/yr), this figure can be divided by the competitive demand (1097 TWh/yr), yielding a loss of 0.3 Euro per MWh of base case demand. This is about 1.6% of the average competitive price of 18 Euros/MWh.

Third, another important difference between the competitive and strategic (Cournot, CSF) scenarios is the price of transmission. The prices of the interfaces (and thus the revenue received by TSOs) are, on average, 20% less in the Cournot case. Also, strategic behavior means that interface prices no longer necessarily correspond to differences in prices between countries. For instance, even though price differences between France and elsewhere are higher in the Cournot case (because EdF is assumed to price at marginal cost in France), the cost of the interfaces with France has fallen. Thus, the cost of bringing power from France to Belgium has decreased to 9.7 Euros/MWh, even though Belgian power prices are over 16 Euros/MWh higher. This mismatch between energy and transmission prices can only persist if generators have market power and there is insufficient arbitrage (recall that we assume that arbitragers lack effective access to those two markets).

The fourth row of Table I presents the results if Cournot producers anticipate that increased demand for congested interfaces will increase the price of those interfaces. This will mostly affect large French and German producers who import into the Benelux market, by encouraging them to reduce exports in order to lower the price of the interface capacity they require. The table shows that this strategy approximately doubles the energy price increases in The Netherlands and Belgium occurring in the pure Cournot case, and lowers transmission revenues further.[9] Of course, the exact impact depends on the assumed values of WCT_{fm}. Nonetheless, this shows that strategic anticipation of how power exports affect transmission prices can significantly affect market outcomes.

These prices can be compared to actual values reported in the Amsterdam (Netherlands) and two German power exchanges. In [6], it was estimated that the average marginal power cost in the German exchanges in 2001 was 22.66 Euros/MWh, while that in the Amsterdam exchange was 29.46 Euros/MWh. These are roughly 10% above our competitive estimates (row 1, Table I), although their Dutch–German divergence is similar to ours. The disagreement between our marginal cost estimates and theirs may be due to several factors, including our use of 2000 fuel prices, and our simultaneous consideration of all markets and transmission constraints (disregarded in [6]). That reference also reports actual exchange prices averaging 24.07 Euros/MWh in Germany and 34.23 Euros/MWh in Amsterdam, thus concluding that significant market power was exercised since prices exceeded marginal costs. These prices are broadly similar to our Cournot values. Disagreements in the estimated degree of market power can arise for many reasons, including elasticities, presence of pre-existing long term contracts, and incomplete market opening in Belgium and France. Unfortunately, there were no power exchanges in Belgium or France at that time, so no comparison can be made of our simulations with prices in those regions.

IV. Effect of Inefficient Transmission Pricing

We now consider the effect of introducing inefficiencies in transmission pricing. For simplicity, only the competitive (not shown) and Cournot strategies (Table I, rows 5 and 6) are considered. The first inefficient policy is an export fee of

[7] In the competitive scenario, for instance, the German-Dutch interface has an average price of roughly 7.5 Euros/MWh (equal to the price difference between the countries, Table I). Under the assumption that this price would double if the interface capacity fell from 2500 MW (approximately its average annual value) to 0 MW results in a value of $WCT_{fm} = 7.5/2500 = 0.003$ Euro/MWh.

[8] Prices in France actually fall in the Cournot case versus the competitive simulation. This occurs because we assume that EdF prices power at marginal cost in its home market; diminished demand abroad for its power causes its marginal costs (and thus home prices) to decrease.

[9] Prices in Germany also increase, and for the same reason. With a positive WCT_{fm}, Dutch producers anticipate that the per megawatt hour payment they would receive for counterflows will diminish if they expand exports to Germany. (Recall that "netting" of flows is assumed in this solution.) This discourages those exports, dampening competition in Germany.

TABLE II
RESULTS, DC-BASED CONSTRAINTS BINDING (PRICES IN Euro/MWh, OTHER QUANTITIES IN M Euro/Yr)

	Mean Annual Bulk Power Price				Genco	Consumer	Genco	Transmission	Social	Change in
Case	Netherlands	Belgium	Germany	France	Cost	Surplus	Profit	Revenue	Welfare	Welfare
Competitive	27.70	31.10	18.88	12.72	12939	50632	6220	546	57398	0
Cournot	31.46	34.32	25.68	12.34	12383	47165	9496	420	57081	-317
Conjectured Supply Function	28.11	31.44	20.17	12.57	12821	49972	6880	518	57370	-28
Cournot + Electrabel Divest	30.69	33.61	25.40	12.40	12453	47383	9286	402	57071	-327

1 Euro/MWh (which was implemented in the EU in 2002).[10] It turns out that there is no significant impact in the competitive case; the amount raised by the fee is almost exactly offset by a decrease in equilibrium interface prices. But in the Cournot case, prices in the importing Benelux countries rise by nearly the amount of the fee, and there is some (but not a great deal of) welfare loss relative to the Cournot base case (342 M Euro/yr, 17 M Euro/yr greater than the Cournot base case).

The other inefficient policy is the disallowing of netting in ATC constraints, consistent with the policy of the Belgian-Dutch-German interface auctions. This policy is simulated by eliminating all negative values of $PTCU_{cc'm}$ in equations (GEN1), (GEN7), (A1), (MC3) of the model [12] and their associated Kuhn–Karush–Tucker (KKT) conditions. This parameter is the amount of interface constraint m consumed by a 1-MW flow from country c to country c'. As a result, for example, sales by a Dutch generator to Germany cannot be used to increase the amount of German power that can flow to The Netherlands. Further, it is then possible for an interface to bind in both directions at once (e.g., The Netherlands to Germany, and Germany to The Netherlands), as indeed often occurs in the model runs.

In the competitive case, a no-netting rule has no effect on prices, profits, transmission flows, or generation.[11] However, the effect on the Cournot solution is dramatic; prices are much higher than the Cournot solution with netting, especially in the importing countries of The Netherlands and Belgium. The welfare loss (1085 M Euro/yr, averaging about 1.0 Euros/MWh) is three times the base Cournot case. This is because in the netting cases, there are very large counterflows. These counterflows enhance competition both in receiving countries (by bringing in power from competing firms in the countries that are the source of counterflows) and sending countries (because the counterflows facilitate greater imports to the sending countries). When credit for counterflows is eliminated, the total flow in each direction decreases by factors of two or more, in effect increasing the concentration in each market. The result is more local market power and higher prices.[12]

V. DC LOAD FLOW-CONSTRAINED SOLUTIONS

The solutions in Table I reflect the fact that between country interfaces in the path-based system limit flows more than do the thermal transmission constraints in the dc load flow. To illustrate the capabilities of the model, we present a few hypothetical cases in which the path-based constraints are dropped and a tightened set of dc load-flow constraints are imposed. As a result, prices will vary among nodes within a country, unlike previous solutions.

The dc constrained solutions are obtained by first reducing the thermal capacities of the transmission lines directly connecting the four countries so that the maximum transfer capabilities between the countries approximate those assumed in the path-based system. (We calculate transfer capabilities by incrementing demand in one country and meeting it with generation in another until a transmission constraint is violated, preventing further transfer.) This reduction is made so that between-country flows would be comparable to those in Table I. For instance, the thermal capacities of lines connecting Germany to France/Netherlands were lowered by 30%.

As a result, prices become differentiated among the nodes within Belgium and Netherlands. For instance, time-averaged competitive prices vary by 28% within nodes in The Netherlands and by a similar amount in Belgium. The lowest prices

[10]This export fee was lowered to 0.5 Euro/MWh in 2003 and was eliminated in 2004. The announcement of its elimination was accompanied by the following statement by de Palacio, European Commission Vice-President in charge of Energy and Transport: "This major achievement demonstrates the commitment of the (European Electricity Regulatory) Forum to an integrated electricity market without artificial barriers to trade. Business and consumers should soon reap the benefits of this new breakthrough." Unfortunately, there remain many other artificial barriers, in the form of uncoordinated and inefficient procedures for allocating transmission capacity. As the analysis of this paper shows, the distortion resulting from this fee is likely to be much less than that due, for instance, to a no netting policy.

[11]This can be proven to be a general result that does not depend on the particular data assumptions. The reason is as follows. In the netting solution, there are many alternative competitive equilibria, characterized by different patterns of sales by individual firms, but the same prices, profits, flows, and total generation by each firm. For instance, if there are two price-taking generators A and B located on separate nodes in two-node network, one competitive equilibrium might have A selling 200 MW in B's market and B selling 110 MW in A's market. This results in a net flow of 90 MW from A to B. It can be shown that decreasing each firm's exports by, e.g., 80 MW (to 120 MW for A and 30 MW for B) and increasing sales in its own node by the same amount results in exactly the same net flow on the transmission lines $(120\ \mathrm{MW} - 30\ \mathrm{MW} = 90\ \mathrm{MW})$, the same aggregate supply to each market, and the same profit to each firm. It turns out it is possible to rearrange sales in this manner to find a competitive equilibrium in which there is no netting; in this case, by lowering each firm's exports by 110 MW (A's exports to 90 MW and B's exports to 0 MW). This is the competitive solution that would be found if no-netting is imposed as a constraint, and its prices, profits, flows, and generation will be the same as the competitive solution in the absence of such constraints.

[12]Note that we may be overstating the difference in results between the netting and no-netting systems for the following reason. A TSO operating a no-netting system might conservatively lower the net flow allowed so that contingencies involving cancellation of sales from a net importing to the net exporting side can still be handled without needing to interrupt sales in the other direction. If so, the proper comparison would then be between: 1) a netting system, but with a reduced capacity and 2) a no-netting system, but with full capacity in each direction. This could reduce the differences in results between the two systems. Therefore, our comparison can be viewed as an upper bound on the negative impact of a no-netting policy. Future research should address how TSOs might adjust ATC if they switch from no-netting to netting, and the impact of such adjustments on prices and generator behavior.

in The Netherlands occur in the north, further away from the binding thermal constraints (which tend to be lines subject to the contingencies shown in Fig. 2). Cournot prices, however, vary somewhat less because supply is restricted, resulting in less congestion. This finer price granularity also leads to some differences between the average within-country prices between Tables I and II. For instance, Belgian and Dutch prices show more differentiation. This demonstrates that the level of aggregation (four countries versus 19 nodes) can affect price results. However, a comparison of overall profit and welfare results show that the general economic impact of strategic behavior (competitive versus CSF versus Cournot) is similar in both transmission representations.

VI. Divergent Estimates of the Effects of Divestment

The last solution in each of the two tables considers a hypothetical situation in which the recent acquisition by Electrabel of generation in The Netherlands is reversed. All large generating companies, plus the spun-off company, behave as Cournot players. As a result, as the tables show, the Benelux market becomes more competitive and prices fall compared to the original Cournot cases (e.g., Dutch prices decrease from 30.4 to 28.9 in Table I, and 31.5 to 30.7 in Table II).

However, welfare under the path-based model is projected to increase (from -325 to -300, Table I), while under the dc-based model, more competition actually *decreases* welfare (from -317 to -327, Table II). That is, in the latter case, enhanced competition apparently makes society worse off, as the increase in generation costs exceed the worth of the additional consumption. Although the changes are not large, this is an example of the following surprising phenomenon, which has been observed in much simpler transmission-constrained models [3], [4]. A decrease in market concentration in a sensitive network location increases local generation. This additional output can actually exacerbate nearby congestion, enabling generators elsewhere to exercise *more* market power. The result can be worsened distortions in pricing and dispatch decisions. These results show that transmission assumptions have implications for net benefits of market changes.

VII. Conclusion

Network constraints can create opportunities to exercise market power, resulting in uneven benefits of power sector liberalization. We have extended the capabilities of complementarity-based models of strategic generator behavior on transmission networks in two ways. The first extension involves the consideration of multiple transmission pricing systems, including inefficiencies resulting from no netting of counterflows, path-based pricing, and export fees. Our application of the model to northwestern Europe shows that these inefficiencies can significantly exacerbate the effects of market power. The second extension represents how generators might expect that transmission prices will change when demands for transmission services are altered. The application illustrates that such expectations can lower revenues to transmission providers and weaken effective competition. The application also shows that distinct network representations (path-based versus dc load flows) can yield divergent conclusions about benefits of changes in market concentration.

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