Electricity Merger Policy in the Shadow of Regulation

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Abstract

Electricity mergers pose distinctive challenges for competition policy - in market definition and for modelling price impacts in markets with no storage, inelastic short-run demand and transmission constraints. FERC's pivotal supply test for screening mergers is an improvement on market shares, but still potentially misleading. We counter-propose competitive residual demand analysis. The EU is poorly placed to deal with domestic mergers that impact external energy flows. The paper argues that vertical (convergent) mergers between electricity and gas raise particular concerns, given current EU gas market power, exemplified by the E.On-Ruhrgas merger. The form of the Emissions Trading System amplifies these concerns.

Key words: merger policy, electricity, gas, convergent mergers, vertical integration, emissions trading

JEL classification G34, L22, L94, L95, Q5

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1. Introduction

Electricity mergers pose distinct challenges for competition policy. A merger of electricity suppliers can affect prices in a very large number of relevant antitrust markets corresponding to different points in time and different geographic regions. Following the approach to antitrust market definition in the DOJ/FTC Horizontal Merger Guidelines, a separate relevant product market exists if a hypothetical monopolist that is the sole supplier of the product would profitably increase its price above the pre-merger level.[1] A region is a separate relevant geographic market if a hypothetical monopolist that is the sole supplier of the product in the region would profitably increase its price above the pre-merger level.[2] Demand for electricity is highly inelastic and electricity is not easily stored, hence separate antitrust product markets can exist even at very close points in time. Furthermore, separate geographic markets can exist at points that are not distant from each other if transmission constraints limit the ability of a consumer to substitute electricity from a different location.

The Pennsylvania-New Jersey-Maryland (PJM) electricity wholesale power pool and other power pools operate markets for electricity in which generators submit day-ahead bids for electricity supplies for each hour of the next day. The PJM also solicits real-time bids to balance supply and demand in each hour of the day. A merger could raise competition concerns in any of these hourly markets. A thorough analysis of the competitive effects of a merger in the PJM region should consider price impacts in 8,760 day-ahead markets and another 8,760 real-time markets for each year. Changes in supply and demand conditions can affect prices in any of these markets.

In addition to these 17,520 annual product markets, transmission constraints can create separate geographic markets, each of which can have 17,520 separate product markets per year. If transmission capacity limits the flow of electricity into a region, or if transmission losses impose significant costs on electricity flows, then the existence of competitive electricity producers in one region may not suffice to limit the ability of a hypothetical monopolist in another region to increase prices above pre-merger levels.

For these reasons the analysis of mergers of electricity suppliers is often a daunting exercise. We discuss some of the approaches that may be used to evaluate the risk of price increases from electricity mergers and some shortcuts to simplify the analysis. Our focus in this discussion is on estimation of wholesale prices for electricity energy. Implicit in our discussion

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[1] "Absent price discrimination, the Agency will delineate the product market to be a product or group of products such that a hypothetical profit-maximizing firm that was the only present and future seller of those products ("monopolist") likely would impose at least a "small but significant and nontransitory" increase in price." DOJ/FTC 1992 Horizontal Merger Guidelines at §1.11.

[2] *Ibid.* at §1.21.

is the existence of markets for wholesale electricity in which suppliers make bid offers to a central pool. To simplify matters we ignore markets for capacity and transmission capacity and for other ancillary services such as voltage stability and spinning reserves, all of which add additional possible relevant markets that could be affected by a merger in the electricity industry.

2. Approaches to Electricity Merger Analysis

A sophisticated approach to evaluate possible price impacts from an electricity merger is to estimate an equilibrium model of price formation for each relevant wholesale market. If generators submit hourly bids to a centralised pool, then an equilibrium model would estimate each supplier's bid price and quantity for each hour. The estimated equilibrium bids have the Nash property that each supplier's bid maximises its expected profit given the bids that are optimal for all other suppliers. Such Supply Function Equilibrium models were developed by Green and Newbery (1992) to compare alternative market structures of the England and Wales generation market that were potential alternative choices facing the UK Government when restructuring the Central Electricity Generating Board before privatisation. Hortacsu and Puller (2006) construct a supply function model for the Texas ERCOT wholesale electricity market. They estimate a bid function for each supplier that determines the supplier's optimal bid price conditional on expected bids by other suppliers, using as data the actual demand and observed bids supplied to the System Operator.

The advantage of this approach is that it is firmly grounded in price theory. It is a model in which each supplier is doing all it can to maximise its profit given the behaviour of other suppliers. The approach, however, has a number of disadvantages. It is complex, because it requires an estimation of optimal bids for each relevant product market and a computational search for bids that are best responses to all other bids. More troubling, there may be a continuum of equilibrium bids, so that observing that one set of bids is an equilibrium does not tightly constrain possible future equilibria if circumstances change, as they would with a merger.[3] The approach is static; bid strategies do not account for the possibility that current bids may affect future bidding behaviour.

A key variable for the analysis of market power is the extent of forward contracting, which has a potentially very significant impact on spot market bids.[4] If a producer is completely hedged (i.e. he has sold as much power forward as he expects to generate) then his optimal spot bid is marginal cost, regardless of other bids. If the spot price is less than his short-run marginal cost, he is better off reducing output and buying in the spot market to meet his contractual obligations, avoiding the higher marginal cost of generation, and vice versa. If he has sold forward more than his expected generation, he has an incentive to drive the spot price below marginal cost, as he will be a net buyer in the spot market to discharge his contract position. Only if he is under-contracted does he have an incentive to drive the spot

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[3] There are various ways of reducing the set of possible equilibria, most directly by assuming that incumbents are restrained by the threat of entry (Newbery, 1998). However, entry in electricity markets can be difficult to predict and may not be effective in the short to medium run.

[4] Most spot markets are actually cleared some time before supply and demand are realised (either day-ahead or within the day at least an hour before "gate closure").

price above marginal cost, and his profit is limited to the difference between output and contract position. If this is small, then the incentive to exercise market power is also small. Hortacsu and Puller (2006) estimate current contract positions from the point of intersection of bids with marginal costs.[5]

It is possible to estimate dynamic bidding strategies, but these add additional layers of complexity. Allaz and Vila (1993) model the choice of forward sales in a Cournot duopoly model, and show that the extent of forward cover depends on the number of contract rounds, assuming full disclosure of contract positions after each round. In the limit as the number of rounds increases, market power diminishes to zero. If contract positions are not revealed, then market power remains. It is possible to extend this model to any number of firms. In the symmetric case with constant costs and linear demand, when contract positions are not revealed, the contract cover will be $1\text{-}H$, where H is the Herfindal Hirshman Index (HHI) expressed as a fraction.[6] A further complication is that in repeated games (and electricity markets are repeated at high frequency) contract positions can be used to support collusive behaviour (Green and Le Coq, 2006). In merger analysis the problem is even more complex, as the aim is not just to understand past price-setting behaviour, but to predict the future with and without the merger, to determine the potential price-raising effect of the merger. One would expect contract cover to change and with it the incentive to bid above marginal cost. In the simple static Allaz and Vila model contract cover would fall from $1\text{-}H_0$ to $1\text{-}H_1$ where H_0 is the pre-merger HHI and H_1 the post-merger HHI. Thus if the pre-merger HHI were 1,667 and post-merger were 2,000, the predicted contract cover would fall from 83% to 80%. The effect on the predicted price-cost margin of ignoring the change in contact cover would be to understate the margin by 14% (Newbery, 2006).

Predicting market behaviour in the presence of market surveillance adds a further level of complexity. In the EU, firms may be (and all too often are) allowed to acquire potential market power through mergers, but Article 82 of the Treaty of Rome makes abusing that market power illegal (as described more fully in section IV). It is unusual for analysts to explicitly model the constraints of anti-trust agencies, which are relevant if the firms are subject to competition laws, that prohibit the abuse of single or joint market dominance. The interpretations of the EU competition laws (especially Article 82) give a list of facilitating conditions that give rise to the potential for joint market dominance, almost all of which are satisfied in many EU electricity markets. Consequently, generating companies must be somewhat cautious in their exercise of market power, but how cautious is unclear.

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[5] Yet another complication is that most spot markets require bids and offers to take the form of a ladder or step function, rather than a smooth curve from which optimal bids are most readily derived. Hortacsu and Puller (2006) smooth the step function to derive differentiable curves, but there are concerns that this may not produce optimal bids. This problem can be handled once it is accepted that market participants bid in expectation of the realised residual demand schedule, but the econometrics are considerably more demanding, as Wolak (2003) shows.

[6] The HHI is normally measured as the sum of the squared market shares of the firms in the market, with a maximum value of 10,000 for a monopoly. Here the market shares are taken as a fraction, with the monopoly value =1, and for n firms $H=1/n$.

Specifically, the short-run elasticity of demand can be very low in the short periods during which scarcity can arise (because of an outage, or extreme demand conditions) and the market clearing price can reach very high levels (certainly well above 1000 Euros/MWh). Just how high it is acceptable to allow prices to reach, given the need to cover fixed costs from a small number of very profitable hours, is a matter for the firms to judge and may vary across jurisdictions with differing attitudes to anti-trust enforcement.

Sophisticated equilibrium bidding models have a mixed record in tracking actual bidding behaviour in real markets. Hortacsu and Puller (2006) found that the bids of smaller firms in the ERCOT wholesale market differed significantly from the theoretical benchmark of static profit-maximisation in their bidding model. For this and other more conceptual reasons (such as non-uniqueness) simpler models have often been preferred in merger analysis, of which the leading example is the Cournot model.[7] This work-horse of Industrial Organisation economics assumes that each supplier chooses its output level (in each hour) to maximise its profits given the residual demand it faces (total demand *less* net imports and the outputs of other suppliers) assuming that other suppliers are simultaneously and independently determining their output levels. The obvious objection to this assumption is that suppliers actually offer to supply amounts at various *prices*, and leave the market to determine how much of their offer to accept. One way of finessing this mismatch between the strategy choices assumed and observed is to suppose that suppliers offer amounts at prices (which might be variable costs or a mark-up on these to cover various fixed costs) up to a fixed amount that they determine.

This maximum amount offered to the market would be the key short-run decision variable for strategic suppliers, and would be the total available capacity for the competitive fringe. Given the marginal cost function of each supplier, the strategies would then be levels of maximum output to offer in each hour, and this would determine the market-clearing price MCP). Contracting affects the equilibrium profoundly by shifting the residual demand schedule facing each strategic supplier, and can be either specified (based on observations) or determined as another strategic variable (the Allaz and Vila approach discussed above). The attraction of Cournot modelling is that it readily lends itself to merger analysis, and can also be used to define the relevant markets in the presence of transmission constraints.

All of these modelling approaches suffer from the additional disadvantage that they are not particularly transparent when properly calibrated to replicate the complexities of plant and markets, which limits their value in a regulatory proceeding or a court of law. The models generate point estimates of market prices and do not explain why a firm chooses a particular price or why a merger may lead the merged firm to choose a higher price. The answers to these questions lie deep within the apparatus of the model; the reasons for the price do not emerge as part of the output of the model.

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[7] A recent example of the use of such models in potential merger analysis is Moselle, Newbery and Harris (2006), undertaken for the Dutch Competition Authority, NMa. An earlier example applied to California is given in Borenstein et al. (2002).

At the other end of the spectrum of complexity for analysis of electricity mergers is the screen approach adopted by the U.S. Federal Energy Regulatory Commission (FERC) to assess generator market power.[8] The screen consists of two tests: a market share test and the pivotal supplier test. An applicant passes the market share test if its uncommitted capacity is less than 20 percent of the total uncommitted capacity of the relevant market.[9] An applicant passes the pivotal supplier test if its uncommitted capacity is less than the uncommitted capacity reserve margin, equal to the difference between the annual peak wholesale load and uncommitted installed capacity.[10] In a merger context, the merger passes the pivotal supplier test if, assuming the merged firm is removed from the market, the remaining suppliers have sufficient capacity to meet the market demand. If an applicant fails the pivotal supplier test, the applicant can demand a price above the competitive price and be assured of making some sales.

If an applicant passes both tests, the FERC makes a rebuttable presumption that the applicant does not possess significant market power in generation.[11] If an applicant fails either the market share or the pivotal supplier screen, it can rebut a presumption of market power by offering evidence based on a delivered price test or filing a mitigation proposal that would eliminate the ability to exercise market power, or the applicant can forego market-based pricing authority and accept cost-based rates.[12]

The advantage of the FERC market power screen is that it is relatively easy to apply for regulators, courts and the merging parties. The analysis merely requires an estimate of demand and load commitments, and a list of the capacities of generating plants that can serve the demand. The disadvantage with the FERC market power screen is that it can easily produce both type I and type II errors. Mergers that pose little risk of higher prices can fail the test, and mergers that may increase prices can pass the test.

It is easy to see why a merger that poses little risk of higher prices may fail the pivotal supplier test. Suppose two firms, each with a negligible share of generating capacity, merge. The merged firm also has a negligible share of capacity and is unlikely to exercise any significant market power. However, the merger would fail the pivotal supplier test if the difference between the peak wholesale demand and total uncommitted capacity is less than

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[8] See United States of America Federal Regulatory Commission, 107 FERC ¶61,018, Order on Rehearing and Modifying Interim Generation Market Power Analysis and Mitigation Policy, April 14, 2004.

[9] Uncommitted capacity is determined by adding total nameplate capacity plus capacity owned or controlled through long-term contracts, and subtracting operating reserves, native load commitments and long-term firm non-requirements sales. *Ibid.* at 38.

[10] The annual peak wholesale load is defined as the annual peak load (the needle peak) less the average of the daily native load peaks during the month in which the annual peak load day occurs. *Ibid.* at 39.

[11] *Ibid.*, at 15.

[12] The delivered price test performs market share, market concentration, and pivotal supplier analyses for different season/load conditions using economic capacity and available economic capacity. Economic capacity includes only supply that is competitive for the season/load condition. Available economic capacity accounts for native load obligations. *Ibid.*, at 43-44.

the sum of the uncommitted capacities of the two largest suppliers. When this condition holds, a merger a merger would pass the market share test, but it would fail the pivotal supplier test, which is sufficient to create a rebuttable presumption of market power.

To see why a merger may pass the FERC market power screen yet still pose a risk of higher prices, consider the following hypothetical. Firms A and B propose to merge. Firm A has 500MW of uncommitted low-cost base load capacity. Firm B has 200 MW of uncommitted capacity with a higher marginal generation cost. Peak wholesale demand is 5,000 MW and total uncommitted industry capacity is 6,300 MW. The merger passes the pivotal supplier test. The uncommitted wholesale market has a reserve margin of 1,300 MW, which exceeds the combined uncommitted capacities of the merging firms (700 MW). The merger also passes the market share test; the merged firm's share of uncommitted capacity is only 11.1 percent.

Despite the fact that the proposed merger passes the FERC market power screen, there is a risk that the merger would result in higher prices. Figure 1 illustrates why. The figure shows the industry marginal cost curves for uncommitted capacity before and after the merger, along with market demand, which is assumed to be inelastic. If the industry acts competitively before the merger, the market price would be $35/MHr. This is the point at which the industry marginal cost curve intersects demand, shown as the vertical line at 5,000 MW. Suppose that after the merger the merged firm reduces its output by 300 MW. The reduction in output shifts the industry marginal cost curve to the left by 300 MW. Assuming that all other firms continue to act competitively, the new price that equates supply and demand is $45/MHr, an increase of 29 percent compared to the pre-merger price.

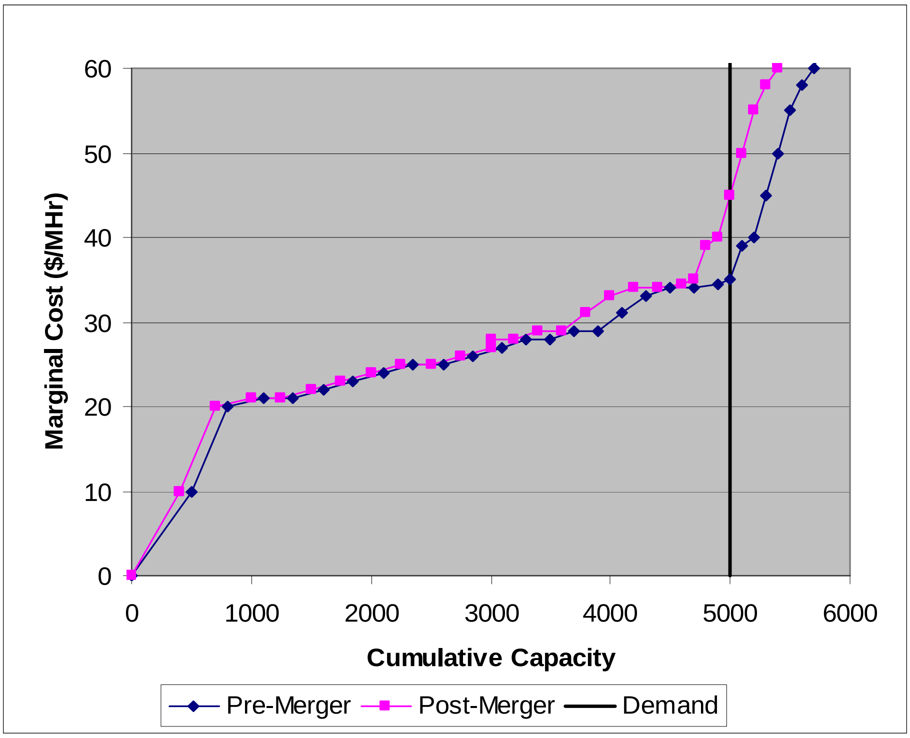

Figure 1. Marginal cost pre and post-merger and industry demand.

Figure 1 shows that the merged firm could increase the wholesale price of electricity by a substantial amount, but the figure does not tell us if the price increase would be likely because it is profitable for the merged firm. To answer this question we propose a simulation method that we call the competitive residual demand (CRD) analysis. The CRD analysis examines the residual demand facing the merging firms pre and post-merger and computes whether the merged firm has an incentive to reduce output and raise prices relative to pre-merger levels. The residual demand is the wholesale market demand less the aggregate uncommitted supply from all other firms, computed at each price chosen by the merging firms. As a further simplification, the market demand is assumed to be perfectly inelastic. The market demand is then independent of prices, but will differ at different points in time.[13]

The aggregate supply of all firms depends on their conduct, specifically whether they act competitively or reduce their outputs below competitive levels in order to benefit from higher prices. The CRD approach assumes that all other firms act competitively, in which case the supply of each firm is the output that equates the firm's marginal cost to the market price. The assumption of competitive conduct for all other firms is not unreasonable when other firms are small and are unlikely to have significant market power. An alternative approach could assume that other firms add a bid margin to their marginal costs. Because our focus is on the likely price increase from a merger, the assumption of a bid margin need not significantly change the predicted price increase because it would elevate both pre-merger and post-merger prices. Non-competitive bidding by all other firms would change the merger predictions relative to the assumption of perfectly competitive behaviour only if the departure from marginal cost pricing differed significantly before and after the merger. To the extent that bid margins are higher after the merger, the competitive residual demand analysis would underestimate the likely price increase from the merger.[14]

The CRD analysis computes the market clearing price and the merged firm's profits under different demand assumptions for different levels of output by the merged firm. Given the industry marginal cost schedule in Figure 1 and a merger of firms A and B, Table 1 shows the market-clearing price, the percentage increase in the price and the percentage increase in the merged firm's profit for different levels of output by the merged firm relative to no supply restriction. Table 1 assumes a market demand of 5,000 MW.

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[13] Baker and Bresnahan (1988) estimate the slope of the residual demand faced by firms selling differentiated products before and after a merger. Their focus is on estimation of supply and firm-specific demand functions with limited cost information. The competitive residual demand approach assumes that demand is fixed at any point in time and uses known industry marginal costs to estimate residual demands for the merging firms and to compute profit-maximizing prices before and after a merger.

[14] Intuitively this seems plausible, although under Cournot competition, other firms would increase output in response to any reduction in output of the merged firm, and this would tend to depress prices. Against that, the degree of contract cover would fall post-merger, tending to increase prices.

Table 1. Market-clearing price and merged firm's profit for different output levels

Merged Firm's Supply (MW)	700	600	500	400	300	200	100	0
Market-clearing price ($/MWh)	35	39	40	45	50	55	58	60
Increase in price (%)	0	11	14	29	43	57	66	71
Increase in merged firm's profit (%)	0	12	8	1	-14	-35	-65	-100

Reductions in supply by the merged firm increase the market-clearing price and are profitable for the merged firm if the supply reduction is no more than 300 MW. The level of supply that maximises the merged firm's profit is 600 MW, corresponding to a reduction of 100 MW from the perfectly competitive level. At this level of supply the market-clearing price is 11 percent higher than the perfectly competitive level (corresponding to 700 MW of output by the merged firm). Although other supply reductions lead to higher prices and are profitable for the merged firm, they are not as profitable as a supply reduction of 100 MW and therefore are not as likely to be chosen by the merged firm.

Table 1 suggests that the merger would raise price above the perfectly competitive level, but the analysis does not prove that the merger would raise price above the pre-merger level. To gain a better understanding of the risk of a price increase, the CRD analysis repeats the type of calculations shown in Table 1 separately for Firms A and B before the merger. Given that all other firms act competitively, one can show that in this example Firm A does not have a unilateral incentive to reduce its output. However, Firm B has a unilateral incentive to reduce its output by 100 MW when all other firms act competitively.[15] This would raise the market-clearing price to $39/MHr. The analysis should then investigate whether Firm A has a unilateral incentive to reduce its output given that Firm B cuts its output by 100 MW. In this example, Firm A does not have an incentive for further output reduction. If it did, the analysis should iterate the unilateral profit maximisation for Firms A and B until neither firm has a further unilateral incentive to reduce its output.

The competitive residual demand analysis estimates that the market price after the merger would be $39/MWh, under the assumption that all other firms act competitively. This is also the CRD estimate of the market price before the merger. Thus, in this example, the CRD analysis does not demonstrate a likely increase in prices from the merger when the total market demand is 5,000 MW. Although in this example the CRD analysis and the FERC market power screen both reach the same conclusion, namely that the merger would not raise prices, it is not difficult to find other examples that lead to different conclusions.

Computationally, the competitive residual demand analysis is considerably easier than a full equilibrium analysis. Moreover, it can be repeated to estimate price increases from the merger in many different time periods, corresponding to different demand states. The analysis also can be repeated to reflect supply conditions in different geographic markets. The CRD prediction of the total expected price increase from a merger in a geographic market is the price

[15] Firm A does not have an incentive to reduce its output, despite having a larger capacity than Firm B, because it has a much lower marginal cost.

increase estimated by the CRD analysis for each level of demand times the probability of that state of demand.

The competitive residual demand analysis has its deficiencies. It is not an equilibrium analysis; the CRD approach estimates only the unilateral incentive of the merging firms to raise price above the competitive level. The CRD analysis assumes perfectly competitive behaviour by all firms other than the merging firms, which may not be a good assumption. As noted above, this need not be a major flaw for predicting price increases from the merger, unless departures from perfectly competitive pricing differ significantly pre-merger and post-merger. A more serious concern is that the competitive residual demand analysis may understate the likely equilibrium post-merger price, because it does not take into account a possible reaction by all other firms to higher prices by the merged firms. If the supplies of the firms in the market are strategic complements,[16] then other firms would react to a price increase by the merged firm by raising their own prices above pre-merger levels. This, in turn, would give the merged firm an incentive to raise its price still further. The residual demand analysis examines only the first stage of this process: the incentive of the merged firm to raise its price given the pre-merger prices for all other firms.

The first-stage analysis is sufficient if either all firms other than the merging parties are perfectly competitive or if the analysis suggests that the merged firm does not have an incentive to increase price above the pre-merger prices of the merging firms and firms choose prices as strategic complements. If the other firms act competitively, then their prices are completely determined by their marginal costs and they would not react to a higher price by the merged firm. If the merged firm would not increase its price in the first stage, then other firms would not react by raising their prices. The first-stage analysis also can be sufficient to guide merger policy if it indicates an anticompetitive price increase from the merger, because reactions by other firms are likely to result in even higher prices.

A difficulty with the CRD analysis is that the pre-merger prices corresponding to optimal unilateral behaviour by the merging parties can differ. In our example, the pre-merger market clearing price when Firm A acts unilaterally to maximise its profit could differ from the pre-merger market clearing price when Firm B acts unilaterally to maximise its profit. If that is the case, then the analyst has to choose which price best represents the pre-merger price. A conservative choice, in this sense that it is least likely to result in a merger challenge, is the higher of the two prices.

3. Market Power Mitigation in the U.S.

Even a thorough approach to analysis of the potential for market power in electricity markets can overlook possibilities for firms to exploit market power in some scenarios. Demand may increase more than expected. Supply outages can occur. Transmission constraints can isolate geographic regions from external sources of supplies, allowing generators with access to the

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[16] The products of the firms are strategic complements if an increase in the price chosen by one of the firms increases the optimal prices chosen by other firms.

region to increase prices. Well-designed electricity markets should have regulatory measures to mitigate market power if situations arise that give firms excessive market power.

The ill-fated deregulated California wholesale electricity market did not provide for market mitigation measures. Not long after deregulation, a combination of increases in demand, inadequate supply, retail price controls, and market manipulation led to dramatic price increases. Over a period of about six months, average monthly prices surged from about $30/MWh to over $300/MWh. Absent formal market mitigation measures, California state regulators turned to the Federal Energy Regulatory Commission for help. The FERC, however, declined to intervene. California eventually resolved the crisis by entering into long-term contracts for additional supplies at great expense.

California regulators and ratepayers also attempted to use the antitrust laws to address the market power issues that arose in the deregulated California electricity market. These efforts were generally fruitless. The mere exercise of market power, when market power is lawfully obtained, absent conduct that excludes competition, is not a violation of the U.S. Sherman Act. Courts also rejected attempts to apply California business law to conduct in the deregulated electricity market, under the principle that the FERC had jurisdiction over California wholesale electricity rates even though the FERC chose not to intervene in the California market.[17]

Other wholesale electricity markets have formal procedures for intervention when generators have unanticipated market power. The market monitor for the PJM electricity power pool has rules for capping offer prices when conditions on a transmission system create a structurally non-competitive local market. The PJM applies a three-pivotal supplier test to determine when a local market is structurally non-competitive.[18] Under this test, the offer price for a unit may be capped if total available generation is not sufficient to relieve a binding transmission constraint after excluding supply by the owner of the unit and the two other largest suppliers.[19] In making this assessment the PJM includes as available capacity only units available at an effective cost no greater than 150% of the cost-based market-clearing price for the region affected by the transmission constraint.[20] Units that are offer-capped more than 80 percent of their run hours are capped at a price equal to either incremental cost plus 10% or incremental cost plus $40/MWh, or an agreed upon price.[21]

The PJM test for a structurally non-competitive market is more rigorous than the FERC market power screen. It extends the FERC pivotal supplier test to encompass the two largest suppliers in the market in addition to the applicant. The PJM test limits available capacity to

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[17] The court concluded that the "Filed Rate Doctrine" applied to California market-based rates, under which authority and jurisdiction for rate setting lies with the FERC. The court reached this conclusion even though the California rates were not actually filed with the FERC.

[18] See Amended and Restated Operating Agreement of PJM Interconnection, L.L.C., Schedule 1 at Section 6.4.

[19] See PJM Market Implementation Committee, 3-Pivotal Supplier Test Overview and Implementation Timeline, February 27, 2006.

[20] PJM Interconnection, L.L.C., Explanatory Statement before the FERC, Docket Number EL-03-236-006 and EL-04-121-000 at 6.

[21] *Ibid.*

suppliers with units that can supply electricity at a price that is not more than 50 percent greater than the cost-based market-clearing price. Furthermore, the PJM market power test applies to any region affected by a binding transmission constraint at any time of the year.

The PJM market monitor applies the three-pivotal supplier test to evaluate the likelihood that a firm may exercise market power when transmission lines are constrained, although the test could be applied to evaluate the potential for a merger to increase market power. We can apply the three-pivotal supplier test to evaluate the merger of Firms A and B in the hypothetical electricity market considered above. In our example the next two largest suppliers each have 250 MW of uncommitted capacity. The hypothetical merger (barely) passes the PJM three-pivotal supplier test. Our competitive residual demand analysis shows that the merged firm has an incentive to raise price above perfectly competitive levels. However, the CRD analysis also suggests that the merger is unlikely to raise prices significantly, because the profit-maximising price after the merger is the same as the profit-maximising price before the merger.

4. Market Power Mitigation in the European Union

The United States and the European Union appear to approach the exercise of market power in quite different ways. In the US, provided a firm acquires a dominant position legally (by innovation, superior efficiency or foresight) and does not act to exclude competition or leverage its market power into other markets, it is free to exercise that market power. In the EU in contrast, it is illegal for firms with a dominant position (exercised either singly or collectively) to abuse their market power.[22] Specifically, such firms are not allowed to charge consumers prices that are excessive. Proving that prices are excessive would require evidence that the margin of prices above costs were well above the normal commercial range for competitive firms producing the same product (not an easy test to apply in any market, let alone electricity markets, as explained below).[23]

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[22] "The concept of abuse is an objective concept relating to the behaviour of an undertaking in a dominant position which is such as to influence the structure of a market where, as a result of the very presence of the undertaking in question, the degree of competition is weakened and which, through recourse to methods different from those which condition normal competition in products or services on the basis of the transactions of commercial operators, has the effect of hindering the maintenance of the degree of competition still existing in the market or the growth of that competition." (Judgment of the Court of 13 February 1979. - Hoffmann-La Roche & Co. AG v Commission of the European Communities. - Dominant position. - Case 85/76 at http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=CELEX:61976J0085:EN:HTML

[23] The European Commission has found it difficult to sustain charges of excessive pricing. The first such case, *United Brands* (Case 27/76 [1978] ECR 207: 1 CMLR 429) was rejected by the Court as lacking sufficiently strong evidence, specifically a detailed cost analysis. In 1995 the Commission issued a formal statement of objections to Belgacom (the Belgian telecommunications operator) claiming that the prices Belgacom charged directory publishers for access to its data were abusive. In response, Belgacom dropped the charge from 200 BEF per line of data to 67 BEF/line and the Commission reached a settlement in 1997 (EC, 1997). The UK has been more energetic in pursuing such cases, where the Competition Act 1998 transposes Arts 81 and 82 into UK law. The Office of Fair Trading successfully brought a case of excessive pricing against Napp Pharmaceuticals (see *Napp*

On the other hand, the United States is clearer than the EU about the duties of regulators when liberalising. Under the Federal Power Act 1935, The Federal Energy Regulatory Commission, FERC, has a statutory obligation to ensure that wholesale prices are "just and reasonable". If an electric utility wishes to sell at market-determined wholesale prices, this will be only allowed providing "the seller (and each of its affiliates) does not have, or has adequately mitigated, market power in generation and transmission and cannot erect other barriers to entry."[24] FERC therefore assumes that market pricing is "just and reasonable" so long as it is competitive. A reason for its concern to ensure that markets are competitive when they are liberalised is that any FERC-approved form of pricing greatly restricts the competition authorities from intervening. At the same time, as noted above, existing antitrust laws are relatively powerless to prevent excessive pricing, absent other anticompetitive conduct. "Antitrust remedies are thus not well-suited to address problems of market power in the electric power industry that result from existing high levels of concentration in generation." (DOE, 2000).

If anti-trust remedies are ill-suited, the Federal Power Act appears to fill that gap, as it would appear that the authority to sell at market-determined prices can be withdrawn and replaced by regulated prices if there is "any change in status that would reflect a departure from the characteristics the Commission has relied upon in approving market-based pricing."[25] The most immediate test of this doctrine came with the Californian meltdown in late 2000, where Wolak, a member of the California Market Surveillance Committee, offered a harsh judgement: "It is difficult to see how the market melt down … could have occurred without a significant lapse in wholesale-market regulatory oversight and several ill-conceived responses …by the Federal Energy Regulatory Commission (FERC)." (Griffin and Puller, 2005, p.145.)

The obvious problem is that even competitive electricity prices occasionally have to reach high levels if they are to cover the costs of peaking generators that may only be required for a few hours each year. Distinguishing between necessarily high but remunerative and competitive prices and those emerging from the unjustifiable exercise of market power is likely to be difficult, particularly if these scarcity prices only occur in a small fraction of years. If FERC has a duty to intervene whenever prices appear unjust and unreasonable, then many of the apparent advantages of liberalisation may be lost. Indeed, Wolak reaches the conclusion that "FERC must regulate, rather than simply monitor, wholesale electricity markets" (p.178), which would seem to defeat the purpose of liberalisation.

This suggests a further contrast on the two sides of the Atlantic, reflecting the prior histories of the electricity industry on the two continents. Deregulation in the United States was in principle a cautious relaxation of regulatory control over prices, with considerable awareness

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Pharmaceutical Holdings Ltd v *Director General of Fair Trading* [2002] CAT 1). See Slot and Johnstone (2006).

[24] *Heartland Energy Services, Inc*, 68 FERC. 61,223, at 62,060 (1994), cited by Bogorad and Penn (2001). Experience with the deregulated California market suggests, however, that the FERC might apply a high threshold for intervention in the presence of market power.

[25] *Heartland* 68 FERC at 62,066, cited as above.

of the potential problems of market power. Electricity restructuring in Europe has tended to overlook issues of market power, and instead has concentrated on introducing wholesale and often retail markets in the expectation that they will be naturally competitive. In part this reflects the political dynamics of liberalisation, where Britain was an enthusiastic proponent first of privatisation, and then, somewhat belatedly, of competition to restrain the privatised monopolies. Most Continental countries were happy with their existing energy structures, and would only accept EU Energy Directives that allowed them to retain their existing market structures with minimal change. If the Commission had followed the US approach of allowing liberalisation only after any concerns about potential market power had been addressed, then it is doubtful that energy market liberalisation would have occurred in more than a few countries, and probably would have faltered at the first sign of trouble (e.g. after the California crisis).

The Commission may have been prepared to accept the consequential failure to create competitive structures because of the power of Article 82, which allows the possession, but not the abuse, of market power. In that respect they may have been unduly sanguine about the ability or willingness of member states to detect and address abuses. Figure 2 shows that most Continental markets remain highly concentrated, whether measured by concentration ratios or HHI. These measures may overstate or understate market power as they ignore import capacity and other factors that affect equilibrium prices. Nonetheless, the numbers raise potential concerns about the possible exercise of market power in most Continental electricity markets.

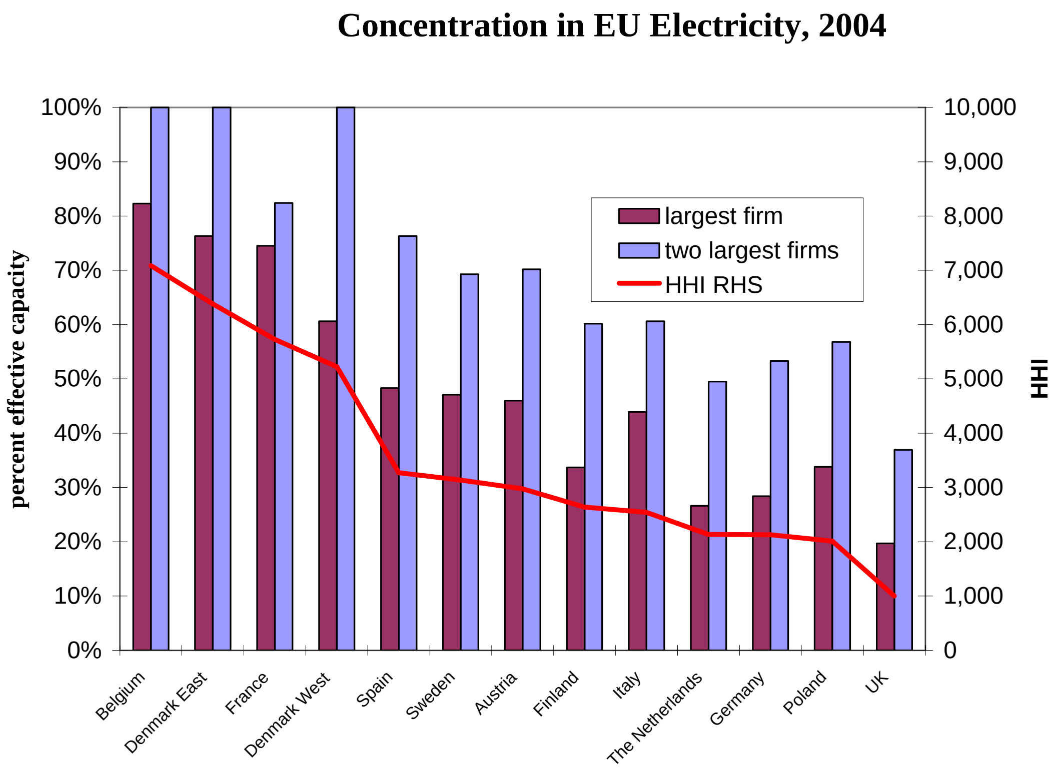

Figure 2 Most Continental electricity wholesale markets are highly concentrated
Source: EC (2006)

Many EU countries appear to lack the necessary powers and institutions to ensure that generation becomes adequately competitive. National regulators often lack the right to automatically receive the kind of information that would allow them to detect the abuse of market power.[26] Instead, they often have to collect circumstantial evidence (from price spikes or industry complaints) before they can refer a company or sector (e.g. generation) for investigation by the national competition authorities that have the legal power to collect such information.

Perhaps because liberalisation was unwillingly accepted by some member states, the member states have not been pro-active in creating more competitive markets by restructuring in the way that FERC and U.S. state regulators obliged those wishing to liberalise in the US. Most countries resisted breaking up state-owned companies at privatisation, leaving them in dominant domestic positions, with some countries (Spain) merging existing separate companies to create national champions. In the Netherlands the Government's original intention was to merge the four large electricity companies to create a national champion, but this failed as the parties could not agree to satisfactory terms (van Damme, 2005). The European Commission continues to resist the notion of national champions as fundamentally incompatible with the concept of the Single Market, but is limited (to date) in its powers to intervene in merger cases where the parties have more than two-thirds of their sales within the member state. The two recent examples that highlighted the weakness of the Commission (and of industry experts within the countries) were the E.On-Ruhrgas merger in 2002,[27] and the attempted take-over of Endesa by Gas Natural in 2005,[28] although the latter bid was apparently trumped by E.On in May 2006 (and on this cross-border bid the Commission did have jurisdiction).

Perhaps the widespread concern over the E.On-Ruhrgas merger caused the Commission to reconsider its views about growing concentration in energy markets, although the start of carbon trading under the European Emissions Trading System in January 2005, coinciding with a sharp rise in the price of gas, produced both high energy prices and high energy company profits that stimulated consumer complaints in early 2005. That provided the impetus for the Commission to launch a Sector Inquiry into the energy industries in June 2005. The European Commission had been concerned for some time that the Internal Electricity Market suffered from a range of structural problems, exacerbated by inadequate interconnections between member states that limit the number of competing generation and supply companies that can

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[26] The EC's Sector Inquiry found that there was a serious problem with a lack of transparency in electricity markets (EC, 2006).

[27] The Federal Cartel Office (Bundeskartellampt) prohibited the merger on 21 Jan 2002, (see http://www.bundeskartellamt.de/wEnglisch/News/Archiv/ArchivNews2002/2002_01_21.shtml) and the Monopolies Commission argued against the merger on competition and public interest grounds, but the Government then approved the merger in August 2002.

[28] The regulatory authority, CNE was divided in its judgment of this case, although the European Competition Commissioner, Neelie Kroes, considered that the case justified a change in EC merger rules to permit the Commission to examine such mergers (*European Power Daily*, 16 Nov 2005). This represents a change in the Commission's stance compared with the earlier Ruhrgas merger, where the Commission was less active in contesting the merger even though it had considerably larger impacts on other member states, given the central role of Germany in cross-border trade in both electricity and gas.

access customers. The Sector Inquiry was described as "a competition investigation based on Article 17 of Regulation 1/2003, which assesses the competition conditions on European gas and electricity markets and examines whether current indications of market malfunctioning result from breaches of competition law" (European Commission, 2006). This Regulation is recent (coming into effect on 1 May 2004), and appears to offer a strengthened approach to dealing with the exercise of market power.[29]

Thus the Commission can propose structural remedies for current or past abuses and these would appear to be particularly relevant in dealing with market power in energy markets. Article 7 of the Regulation states that "Where the Commission, acting on a complaint or on its own initiative, finds that there is an infringement of Article 81 or of Article 82 of the Treaty, it may by decision require the undertakings and associations of undertakings concerned to bring such infringement to an end. For this purpose, it may impose on them any behavioural or structural remedies that are proportionate to the infringement committed and necessary to bring the infringement effectively to an end. Structural remedies can only be imposed either where there is no equally effective behavioural remedy or where any equally effective behavioural remedy would be more burdensome for the undertaking concerned than the structural remedy. If the Commission has a legitimate interest in doing so, it may also find that an infringement has been committed in the past." (European Commission, 2004).

An optimistic interpretation would be that the Commission will eventually be able to follow the British model, in which liberalisation is interpreted to mean that market solutions are to be preferred where feasible, and regulation confined to natural monopoly components (and only so long as they remain natural monopolies).[30] If the unregulated sectors are to function efficiently, their ability to abuse market power needs to be restrained, either by regulation (behavioural remedies) or by structural remedies. The US experience of the workings of the Federal Power Act suggest that regulation to inhibit market power is likely to involve continuous monitoring of deregulated electricity markets. Such monitoring incurs a risk of intrusive intervention – such as price or bid caps -- that then prevents peaking plants

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[29] Article 17 of the Regulation deals with Article 81 and 82 infringements (Investigations into sectors of the economy and into types of agreements). Where the trend of trade between Member States, the rigidity of prices or other circumstances suggest that competition may be restricted or distorted within the common market, the Commission may conduct its inquiry into a particular sector of the economy or into a particular type of agreements across various sectors. In the course of that inquiry, the Commission may request the undertakings or associations of undertakings concerned to supply the information necessary for giving effect to Articles 81 and 82 of the Treaty and may carry out any inspections necessary for that purpose. The Commission may in particular request the undertakings or associations of undertakings concerned to communicate to it all agreements, decisions and concerted practices. (European Commission, 2004).

[30] Thus in telecommunications, the Communications Directives require National Regulatory Authorities to conduct market reviews and to determine which markets shall be deemed to be effectively competitive, and which markets are susceptible to *ex ante* regulation. The cumulative effect of these Directives is to limit regulation to those markets where competition law would be inadequate, and then further to restrict the scope of regulation to the minimum justifiable level.

from covering their fixed costs. That in turn may precipitate a regulatory solution in the form of capacity obligations, that experience suggests have to be carefully defined (to be able to deliver power to the entity holding the obligation when needed). Wolak's pessimistic assessment cited above then suggests that there may be little difference between the old regulatory framework and the new one (except perhaps to open the prospect of more jurisdictional disputes between State Utility Commissioners and the FERC).

The Californian evidence might suggest that any behavioural remedy to address the abuse of market power in deregulated electricity markets "would be more burdensome for the undertaking concerned than the structural remedy" (EC, 2004), opening the prospect of (gradually) restructuring the EU energy sectors to create sufficiently numerous competing firms in each market that their pursuit of profits did not amount to market abuse. The model would be the British electricity market that finally reached a satisfactory structure by 2000, shortly before the start of the New Electricity Trading Arrangements (Newbery, 2005a).

Whether this new activism will lead to a more rigorous and sceptical treatment of energy sector mergers, either by member Competition Authorities concerned that favourable treatment of domestic mergers would be overturned by another sector inquiry, or directly by the Commission for cross-border mergers, remains to be seen. Whilst there is growing agreement about the appropriate techniques to employ for analysing horizontal electricity sector mergers, that is not true for cross-fuel mergers involving an input fuel, gas into the electricity sector (exemplified by both the E.On-Ruhrgas and Gas Natural-Endesa bids).

5. Vertical mergers involving gas and electricity

Gas is increasingly an important input into electricity generation and a final energy source that competes with electricity in the retail market. When global power generation orders peaked at over 180 GW in 2001, 150 GW were for gas turbines and more than half of all orders since 1990 have been for gas turbines (OECD 2003). Liberalisation (particularly when associated with privatisation and unbundling) opens the prospect of gas and electricity companies entering each other's markets for the final product (gas or electricity supply) and acquiring firms in the other fuel market. Such mergers can be viewed as vertical integration (upstream gas and downstream electricity) or as convergence mergers (extending the company's reach from one energy source into two and reducing the difference between gas and electricity suppliers). The opportunity has clearly been attractive. Hunger (2003) cites 22 gas/electricity mergers with an asset value greater than $500 million counted by the US Energy Information Agency between 1997 and 2000.[31] Recently mega-mergers such as E.On-Ruhrgas in 2002, and the attempted take-over of Endesa by Gas Natural in 2005, have

[31] An example is the merger of Enova and Pacific Enterprises to form Sempra Energy in 1998. Enova was a supplier of electricity and a net purchaser of natural gas in southern California. Pacific Enterprises was the largest supplier of intrastate natural gas transport and storage in the region. The U.S. Federal Energy Commission approved the merger with nondiscrimination conditions on gas sales. The U.S. Department of Justice required divestiture of about two-thirds of Enova's electricity generating capacity and imposed limits of the reacquisition of electricity generation (see U.S. Department of Justice Competitive Impact Statement, available at http://www.usdoj.gov/atr/cases/f1700/1789.htm, accessed September 11, 2006.)

awakened concerns both about the ability of the European Commission to rule on such mergers and to prevent mergers that are likely to be anticompetitive.

The standard argument for believing that vertical mergers are benign is that by reducing the inefficiency of transactions between up and downstream they lower costs and hence lower prices in the final market. Further, if the upstream (gas) company has market power, it can only extract monopoly profits once, and has no additional market power through ownership of the downstream (electricity) company. Indeed, if the upstream market power involved mark-ups on marginal cost in selling to the downstream firm, to the extent that these were eliminated by the merger, electricity prices would fall, not rise. In contrast to a horizontal merger that removes competitors, vertical mergers do not remove competitors. However, the conditions under which these arguments can be rigorously established are stringent and, as with horizontal mergers, vertical mergers require careful scrutiny to assess their welfare effects.[32] Vertical integration may make it profitable for the upstream firm to raise downstream rivals' costs (Salinger, 1988; Ordover, Saloner and Salop, 1990), although Perry (1989) argues that the damage is likely to be limited.

This is not the place to rehearse the debates on the anti-competitive effects of vertical integration in general, but to see whether one should be particularly concerned with gas-electricity mergers. The first point to note is that many European countries still suffer from considerable incumbency concentration in both electricity and gas markets (as figure 2 demonstrated for electricity and which would be even more true for gas). Electricity and gas are actual and potential competitors in a broader market for energy services. In the medium run, the best placed potential entrant into the electricity market is a gas supplier, who has access to the fuel needed for combined cycle gas turbines (the natural choice for entrants), and who can (partially) hedge gas price risk by selling gas directly or as electricity. If that potential entrant merges with an electricity supplier, a major entry threat is reduced.

Next, and following the same line of reasoning as section II above, if the gas company has market power and takes over an electricity company, and if it raises the price of gas, then whenever gas is the marginal fuel in electricity, the price of electricity will rise. This will increase the inframarginal profits of the plants now under the control of the vertically merged company. The electricity part of the merged firm will have increased profits, *additional* to the normal monopoly profits of the gas part of the merged firm (and which were presumably already being maximised). Thus although the merger offers no additional *opportunities* to raise gas prices, it provides an additional *incentive* so to do.[33]

The natural way to examine this incentive is similar to the horizontal electricity merger analysis set out in section II. The competitive supply schedule for the electricity industry can be computed for the pre-merger price of gas, and then for successive increases in the price of gas sold by the upstream (gas) part of the merged firm, taking account of the ability of electricity

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[32] For example, fixed coefficients in input proportions by the downstream firms. If these are relaxed the results become ambiguous (see e.g. Church, 2004).

[33] As noted below, a higher gas price lowers the firm's profits from its gas operations, but this is a second-order effect for a small deviation in the price of gas from its stand-alone profit maximizing level.

companies to buy gas from other gas suppliers. If the gas market is imperfectly competitive, then one can assume that the pre-merger gas price-cost margin reflects the pre-merger market power of the gas company – the (residual) elasticity of demand facing the gas company will be the pre-merger inverse Lerner Index.[34] That should allow the impact of raising the gas price on gas profits to be computed (they should fall slightly), while the impact of raising gas prices on the merged firm's electricity profits can also be computed (and these should be positive whenever gas is at the margin).

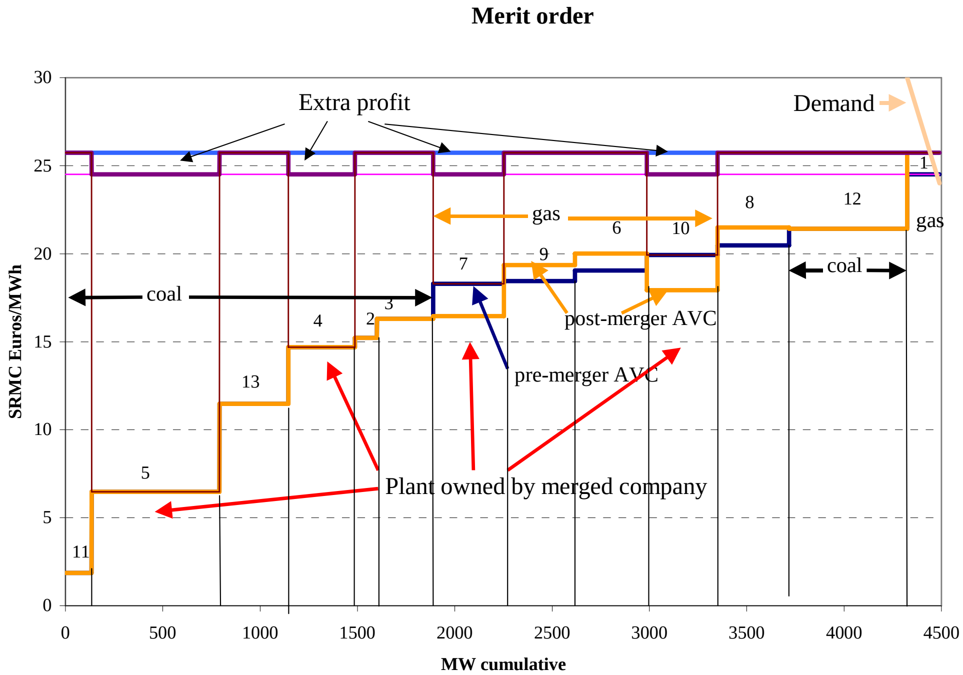

Figure 3. Effect on company profits of raising the market price of gas by 5%

Figure 3 shows the application of this technique to a market in which company A (the vertically merged gas-electricity company) owns plants 5, 4, 7 and 10 (the plant numbers are indicated above the steps in the figure). The base-load plants 11, 5 13, 4, 2 and 3 are coal-fired, the rest, except for coal-fired plant 12, are gas-fired. Before the merger the average variable costs (i.e. the short-run marginal costs) are shown by the heavy stepped line, with price set by the marginal (gas-fired) plant 1, not owned by firm A. After the merger company A now internalises the price of gas as the true marginal cost and so SRMC falls (by an assumed 10%) for gas-fired plants 7 and 10, but if the price of gas sold to other power companies rises by 5% then so does the SRMC from other gas-fired plant (but not from coal-fired plant 12). The marginal (gas-fired) plant 1 continues to set the price and A's extra electricity profit from increasing the price of gas is shown by the (arrowed) rectangles between the old price line and the new price line. The extra profit while plant 1 sets the price is company A's total capacity times the change in the electricity price shown. If other firms' gas-fired plant continued to set the

[34] The Lerner Index is (price-MC)/price, and is equal to the inverse of the residual demand elasticity facing the firm in a static non-collusive equilibrium.

price as demand varied, it would be straightforward to quantify the incentives to raise the gas price, as follows.

Suppose that demand for A's gas by the other electricity generators before the merger is $G(g)$ where g is the sales price of gas to the ESI.[35] In order to raise the price of gas, A reduces sales by ΔG, and if no other gas company increases output this raises the gas price by $\Delta g = g\Delta G/(\varepsilon G)$, where ε is the firm-specific residual elasticity of demand for gas (as a positive number). The change in profits from gas sales caused by the reduction in A's gas supply will be $G.\Delta g + (g\text{-}c)\Delta G$, where c is the cost of the gas. This can be written as $(1 - \varepsilon L)G\Delta g$, where L is the Lerner Index for A's sales of gas to these firms. Pre-merger, this is zero for a small change in the gas price from the conditions of profit maximisation (and $L = (g - c)/\text{g} = 1/\varepsilon$). If the marginal plant is owned by another company and is gas-fired with heat rate, h_m, then the change in electricity price $\Delta p = h_m \Delta g$. If company A has fraction α of total electricity sales Q and the gas consumption of the remaining generators is $G = (1 - \alpha)\beta h_a Q$ (where h_a is the average heat rate of the gas plants and β is the share of gas in their electricity capacity), then the change in gas profits is $(1 - \alpha)\beta h_a Q(1 - \varepsilon L)\ \Delta g$

The extra profit to company A from electricity sales is $\alpha Q\Delta p = \alpha Q h_m \Delta g$. The change in profits of merged company A is then

$$\Delta\Pi = [\alpha h_m + (1 - \alpha)\beta h_a(1 - \varepsilon L)]Q\Delta g, \qquad (1)$$

assuming that the demand for electricity is insensitive to its price (which has increased by Δp). In the pre-merger equilibrium, $L = 1/\varepsilon$, but after increasing the gas price $L > 1/\varepsilon$, so the second term is initially zero and decreasing but effectively second order, while the first term is positive and first order.[36] The incentive to raise the price of gas (assuming that this is possible) therefore increases with the merger, and the post-merger mark-up for A's gas sales will be maximised for a value of L that equates (1) to zero (i.e. when $d\Pi/dg = 0$):

$$\varepsilon L = 1 + \frac{\alpha\, h_m}{(1\text{-}\alpha)\beta\, h_a}. \qquad (2)$$

If the elasticity of residual gas demand, ε, is constant, then the pre-merger gas mark-up would be $L = 1/\varepsilon$, so the ratio of the post- to pre-merger gas mark-up is then the right-hand side of (2).

In general, as demand varies the marginal plant is unlikely to always be another firm's gas-fired plant (and the merit order may change – here if A bids SRMC plant 10 would move down to just above plant 7, but could stay where it is if A prices up to the bids of other firms). If another firm's gas plant is only at the margin a fraction γ of the time, then A's electricity expected profit will only rise by $\gamma\alpha Q h_m \Delta g$, and the ratio of the expected post- to pre-merger gas mark-up will be

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35 This assumes that gas suppliers price discriminate between the ESI and other sectors, otherwise the analysis would need to deal with the loss in profits elsewhere from any price rise.

36 Local concavity of the profit function, which is required for profit-maximization, implies that $L(p)\varepsilon(p)$ is increasing in p. Hence, $L > 1/\varepsilon$ after a small increase in the gas price above the pre-merger profit-maximizing level.

$$1+\frac{\alpha\gamma\, h_m}{(1-\alpha)\beta\, h_a}. \qquad (3)$$

If some of the time A's gas-fired plant sets the price, then matters become more complicated, as the merger allows A to consider the opportunity cost of gas as its marginal cost, not the marked-up price of gas sold to the electricity sector by an independent gas supplier. On the one hand, A has an incentive to lower its bid price for its gas-fired plant and steal market share from its rivals, at the expense of a lower (gas) profit on its gas-fired plant, while on the other it can choose to limit price at the (marked-up) electricity price of its rivals. Without computing the optimal strategy it is hard to say exactly what the outcome will be.

Hunger (2003) illustrates this type of analysis while Henriksson (2005) applies Hunger's approach to the E.On-Ruhrgas merger and argues that it gives rise to anti-competitive concerns. Ruhrgas controlled (directly or indirectly through cross shareholdings) 80% of sales of gas to the ESI, while E.On had cross shareholdings of a further 3% in the gas market, giving the merged firm control over 83% of gas sold to the ESI. Ruhrgas' control over pipelines meant that only Wingas (market share 11%) could supply gas to generators served by Ruhrgas (Henriksson, 2005, p55). Ruhrgas likely had significant market power in sales of gas to the ESI, particularly given its control over access.

E.On supplied α = 27% of the German electricity market, but its control over its German grid, and ownership of generation in neighbouring countries provided increased market power. The other German electricity companies had 20% of their capacity gas-fired (β = 20%), but in 2004 the load factor for gas-fired plant was only 25% (Brunekreeft and Twelemann, 2005), so that the estimated shares of gas-fired generation in the total were E.On 1.4%, others 5.8%,[37] so γ may have been quite low, possibly as low as 20%. If E.On priced its gas plant to retain its position in the (new) merit order, and if h_m/h_a = 1.2, then the factor in equation (3) is 1.44, which is not insignificant. Of course, if the gas market is competitive, the original mark-up will be small (or zero) and the vertical merger will have no adverse effects. If entry is reasonably unimpeded then the effects will be transitory (until entry drives down the mark-up over the supply price). If, for example, it is possible to build new LNG import capacity easily in Spain, and if the pipeline system and storage and balancing services are unbundled from other gas suppliers (notably Gas Natural), then the incentive of Gas Natural to raise gas prices to the ESI will be limited to the period before new LNG terminals can be built and sourced. Contracts would further limit the incentive to exercise market power.

These calculations suggest that the merged firm has an incentive to increase gas prices above their pre-merger levels. The analysis, however, does not demonstrate that the merger would necessarily have an adverse impact on electricity consumers. The reason is that, as noted above, the merger eliminates the mark-up on gas that would occur when an unintegrated electricity supplier purchases gas. The lower mark-up is a potential benefit from the merger when gas is the marginal electric plant, which could more than compensate for a higher natural gas price. However, as argued above, such beneficial effects are less likely when the merged company has little gas-fired generation setting the price, or when the merged company chooses to price up to the level of its rival's gas-fired plant, and where this is often at the margin.

Empirical studies of markets that have experienced vertical mergers do not provide substantial evidence that such mergers are anticompetitive.[38] The empirical record is, however, quite thin and much more analysis is needed to better assess the potential risks to competition from vertical mergers involving natural gas and electricity.

5.1 The impact of free allocations under the Emissions Trading System

The European Emissions Trading Scheme (ETS) limits CO_2 emissions from covered sectors, especially electricity (accounting for about 56% of the total). In order to persuade companies and governments to agree to the ETS, companies, especially generating companies, were given free allocations of EU Emission Allowance (EUAs) for about 95% of their baseline emissions. As economists predicted, the market price of allowances is reflected in electricity prices, which have increased above the cost of marginal fuel by the cost of the allowances required for the marginal plant. That means the generating companies make a windfall profit roughly equal to the value of the original allocation (with some variation depending on the change in merit order between coal and gas-fired plant).

Newbery (2005b) shows that the price of EUAs is increasing in the price of gas, for the following simple reason. If gas prices increase, then electricity generators switch out of gas-fired plant into coal-fired plant, as shown in figure 4. This increases the demand for EUAs as coal-fired plant requires almost twice the number of EUAs per MWh generated as modern gas plant. The increased demand with a fixed total supply increases the EUA price, and thus increases the windfall profit of incumbent electricity companies from their free allocation. This in turn greatly enhances the attraction for gas suppliers with market power (and able to raise the price of gas to electricity) to vertically integrate into generation.

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[37] These numbers are estimated from the TWh generated by fuel given the data in Brunekreeft and Twelemann, (2005), for which E.On-Ruhrgas would appear to have generated 7.1 TWh from gas and the remaining firms 28.5 TWh out of total generation of 494 TWh.

[38] Hastings and Gilbert (2005) show modest increases in wholesale prices from a vertical merger in the gasoline industry, but do not provide evidence of effects on retail prices. Hortacsu and Syverson (2005) show no adverse effects on retail prices from vertical mergers in cement and concrete. Chipty (2001) offers evidence that cable companies integrated into premium television services exclude rival services, but also sell more total services.

Weekday moving 24 hr av coal and gas generation Britain 1 Oct-9 Dec 05

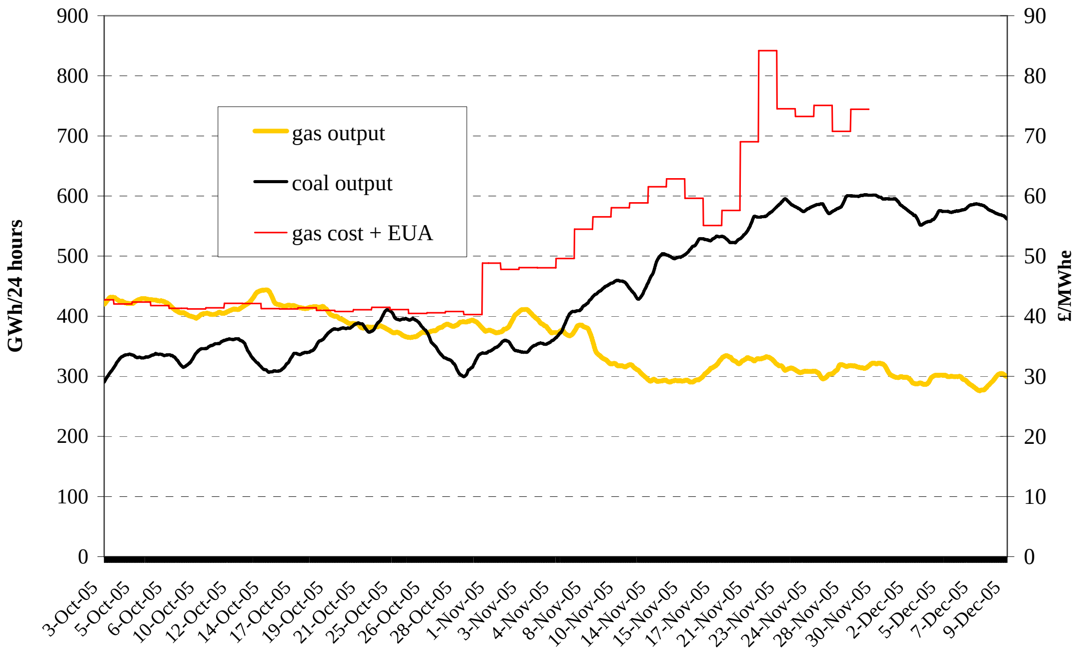

Figure 4 Impact of gas price increases on gas demand in the British ESI

Thus in addition to concerns about removing potential competitors to over-concentrated incumbent generators, vertical gas-electricity mergers amplify the market power that gas suppliers already have, both by giving them a stake in raising the price of electricity and in raising the price of EUAs. Both of these amplify potential inefficiency (and the costs of inefficiency rise as the *square* of the price mark-ups).

6. Conclusions

European electricity and, even more so, gas markets are concentrated at the country level, with inadequate interconnection between countries outside Scandinavia to import competition. Electricity has special features that make the exercise of market power particularly likely, as short-run demand elasticities are very low, supply cannot be stored, and even competitive wholesale markets are naturally highly volatile, making the distinction between efficient peak-load pricing and abusive pricing problematic. Companies with modest market shares have both the ability and incentive to raise prices when markets are tight and suppliers pivotal, rendering standard tests of market power (HHI or market shares) less effective. This complicates the analysis of mergers, which we argue should be based on a more careful model of electricity supply, screening via a pivotal supply test, and a more thorough analysis using competitive residual demand analysis. Fortunately the cost data for such analysis is (reasonably) readily available and can be obtained by competition authorities.

Vertical mergers between electricity companies and gas companies with market power in the gas market (often secured through their control over the pipeline network and storage and balancing services) are also problematic, as the incentive to raise gas prices may be enhanced through ownership of electricity generation. When gas-fired generation is at the margin, raising gas prices increases inframarginal rents, and by driving up the price of EUAs, enhances the value of the grandfathered free allocation of EUAs.

The implication is that competition authorities must be particularly vigilant in scrutinising mergers in the electricity and gas sectors, at least until the gas markets are workably competitive, and they must be willing to adopt more sophisticated methods of analysis constructing variable cost curves (although the data for this are readily to hand).

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