Nodal Pricing of Electricity:

How much does it cost to get it wrong? *

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Economists know how to calculate optimal prices for electricity transmission. These are rarely applied in practice. This paper develops a thirteen node model of the transmission system in England and Wales, incorporating losses and transmission constraints. It is solved with optimal prices, and with uniform prices for demand and for generation, re-dispatching when needed to take account of transmission constraints. Moving from uniform prices to optimal nodal prices could raise welfare by 1.3% of the generators' revenues, and would be less vulnerable to market power. It would also send better investment signals, but create politically sensitive regional gains and losses.

Keywords: Electricity Transmission Pricing, Welfare Losses, Market Power

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1. INTRODUCTION

For more than twenty years, economists have known how to calculate the optimal locational prices for electricity. That knowledge seems to have been ignored by the designers of many electricity markets. Chile, New Zealand and some US markets have adopted the optimal system of nodal spot pricing, but all the electricity markets in Europe have adopted much simpler systems, and several have no locational pricing at all. This paper asks how far welfare is reduced by the choice of such simpler pricing rules. In a simplified model of England and Wales, representing the industry in 1996/7, it compares prices, profits and consumer welfare under a system of nodal prices, uniform prices, and a hybrid in which generators face nodal prices but consumers face a uniform price.

The first-best price of electricity at each point on a network (node) equals the marginal cost of providing electricity at that node. The electricity must not only be generated, but it must also be delivered to that node, taking account of transmission constraints and electrical losses. If transmission constraints are binding, so that the amount of power flowing through a line is at the limit which safety allows, then cheap but distant generation may have to be replaced with more expensive local generation, in order to reduce power flows. In the constrained area, the optimal price of electricity rises to the marginal cost of the local generation, or to the level needed to ration demand to the amount of electricity available. Even if there are no constraints, some power will be lost in the transmission system (dissipated as heat), and prices should reflect the fact that it is more expensive to provide electricity at the far end of a heavily loaded line than close to a power station. Transmission

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Congestion Contracts (Hogan, 1992) could be used to hedge spatial price differentials, and to help co-ordinate investment.

These principles are well-known, but few electricity systems have adopted them. Chile, New Zealand and a small number of US power pools have markets which are based upon nodal spot prices, which was also proposed in the Federal Energy Regulation Commission's Standard Market Design, but almost every other country in the world uses a simplified system of transmission pricing. Nodes may be grouped together into zones, and the price differentials between zones are calculated from simplified models. Other systems still see transmission as an "overhead" cost, and use simple "wheeling rates" to calculate payments if one company imports power from a second over the lines of a third. These payments are typically based upon the volume of the flow and the length of its contracted route (the MW-mile approach), and frequently ignore the fact that any transaction in an interconnected system will affect power flows on all the other networks in that system. Green (1997) discusses the pricing rules then adopted in eight electricity systems, assessing them against economic and political criteria. One common theme was that these rules tended to produce lower price differentials than would be associated with optimal spot prices.

How important are the differences between the relatively simple rules adopted in practice, and the prices which an optimal system would produce? One of the main economic functions of a price system is to signal the opportunity cost of alternative courses of action. On the demand side, an agent should buy something if it is valued at more than its price, while a supplier should produce it if this can be done for less than its price. If buyers and suppliers face the same prices, their independent decisions will ensure that the value of output at the margin is just equal to its marginal cost, which is optimal. If prices are above marginal costs, then too little of a good will be consumed and produced, while too much will be

produced if prices are below marginal costs.¹ The wrong prices can also lead to inefficient “bypass” as agents have an incentive to leave the market, and arrange deals at prices closer to their costs.²

This paper takes a simplified model of the electrical system in England and Wales, calculates optimal prices and quantities, and compares the outcomes with those that simpler rules would produce. The model has thirteen nodes, with demand at every node and generation at most of them. It is solved for different levels of demand, and of generator availability, and a weighted sum of the results is used to give the impact over a year as a whole. In particular, we measure average prices, generators’ profits, and the change in consumer surplus relative to the first-best case. We also look at way in which the geographical pattern of prices responds to the pricing rules.

Green (1994) used a similar model to examine changes in the total cost of generation once transmission losses were reflected in the dispatch, but ignored transmission constraints. Bialek *et al.* (2003) report on a similar study undertaken for the UK Department of Trade and Industry on the impact of introducing zonal losses charging across Great Britain. Macatangay (1998) takes account of constraints (but not losses) and calculates the price for each zone on the NGC system as the dual value in a power flow optimization. Ilic *et al* (1997) use a detailed model of New England to show how the payments for seven hypothetical wheeling transactions would change between three different cost allocation rules. None of these papers studies the impact of spatial pricing on demand. This paper incorporates demand responses in a model which takes account of both losses and transmission constraints. An earlier

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¹ This is a slight simplification. When there are several goods, slightly too much of one good may be produced, even though its price is *above* marginal cost, because other prices are further away from costs.

² We will return to this issue in the conclusions.

version carried out a similar study (Green, 1998), but reported the results only for representative hours.

This paper also studies the interaction of market power and transmission pricing. In electricity networks, the exercise of market power can take counter-intuitive forms: it may involve *increasing* output at some locations, in order to tighten a transmission constraint and raise prices elsewhere (Cardell *et al.* (1997)). Borenstein *et al* (2000) show how small increases in transmission capacity can lead to significant reductions in market power, once congesting a link becomes unattractive. Oren (1997) suggests that actively traded contracts could reduce the incentives for this kind of behavior. Joskow and Tirole (2000) show how generators' holdings of transmission contracts affect their behavior, and that these can worsen market power. For example, a generator in an importing region could hold transmission contracts that increase its exposure to the local price, enhancing its incentive to raise that price. Gilbert, Neuhoff and Newbery (2004) show that the impact of transmission contracts depends on the design of the markets in which they are traded – generators will not obtain contracts that worsen their market power in a uniform price auction, but may do so in a discriminatory auction, for example. Ehrenmann and Neuhoff (2003) simulate the market in Belgium and the Netherlands and obtain lower prices when the markets are integrated than when rights to use the cross-border interconnectors are traded before the energy markets open.

This paper does not examine the impact of contracts, but does allow the two largest generators to act strategically. One of these generators sometimes reduces output to create an import constraint into an area where it owns most of the local generation, allowing it to raise prices well above their level in the rest of the country. Under one pricing rule, it also tries to raise its output in a second area, which is subject to an export constraint, in order to increase the compensation that it obtains for reducing output back to the feasible level.

The next section of the paper gives a brief outline of the theory of transmission pricing. Section 3 describes the model. Section 4 describes the three pricing rules that are compared. Section 5 shows how welfare changes with these rules. Welfare is highest when the model is solved with optimal prices (one for each node), and lowest with one uniform price for demand and one for generation. The uniform-price system is based upon that used in the Electricity Pool of England and Wales from 1990 to 2001, and very similar to the New Electricity Trading Arrangements (NETA) which followed it. Initial trading took place without regard to transmission constraints, and when generators were made to change their outputs in order to ensure a feasible dispatch, they were compensated for the opportunity costs of doing so.³ Since political considerations sometimes dictate that consumers should face a uniform price, even if locational pricing would be acceptable for generators, the model is also solved with varying prices for generators, but a uniform price (in each time period) for demand. Section 6 considers the impact of market power. Section 7 concludes.

2. OPTIMAL TRANSMISSION PRICING

The theory of spot pricing is set in detail out by Schweppe *et al* (1988). The interested reader should refer to that book, or the shorter exposition given by Hsu (1997) for details, for this

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³ The Pool provided this compensation through an algorithm that calculated payments for generators that changed their output relative to the original schedule. Under NETA, the system operator trades with the generators to ensure feasibility, but if the market is competitive, the prices for these trades will be opportunity costs. A referee has pointed out that the system operator could go further than simply creating a feasible dispatch, buying output from well-placed generators and selling power back to those in areas with high marginal transmission costs, until it achieves the same dispatch as with a locational pricing system. This is correct in theory, but many market participants would regard it as unacceptable in practice, given a long history of opposition to either locational pricing or energy trading on the part of the National Grid Company.

section will merely state their key formula for the spot price at any point on a network, and concentrate on giving the underlying intuition for it.

The optimal prices for electricity transmission can be seen as arising from the problem of maximizing the net welfare obtained from electricity consumption, subject to a number of constraints. This net welfare is equal to the benefit from consuming electricity, less the cost of generating it. For simplicity, we will ignore any variable costs which are not manifested in a need for increased generation.⁴ The constraints to be met are that total generation must equal total demand, plus losses, and that the flow along each transmission line must be less than the capacity of that line. The flows depend on the levels of generation and demand at each node. For practical applications, they are derived from a load flow model such as the DC load flow model, which is outlined below. We can write a simplified version of the problem:

$$\begin{aligned}
& \underset{\underline{d}, \underline{g}}{\text{minimise}} && \sum_j C(g_j) - \sum_k B(d_k) && (1) \\
& \text{subject to} && \sum_k d_k + l - \sum_j g_j = 0 && (\text{energy balance constraint } (\mu_e)) \\
& && -z_i^{\max} \leq \sum_j \phi_{ij} g_j - \sum_k \phi_{ik} d_k \leq z_i^{\max} && (\text{line flow constraints } (\mu_i^{QS}))
\end{aligned}$$

where d_k represents the demand at node k , g_j represents the generation at node j , and losses in transmission are equal to l . The maximum flow allowed on line i is given by $z_i^{\max}$. In the DC load flow model, the flow on line i is the sum over all the nodes of the products of the net export at each node and the power transfer distribution factor for that node and that line, ϕ_{ij} . The Lagrangean multiplier on the energy balance constraint is μ_e , while the multiplier on the

flow constraint for line i is μ_i^{QS} . The first-order conditions to this problem can be manipulated to give the price at node k :

$$p_k = \mu_e \left[1 + \frac{\partial l}{\partial d_k} \right] - \sum_i \mu_i^{QS} \phi_{ik} \quad (2)$$

The multiplier on the energy balance constraint can be interpreted as the marginal cost of generation at the “swing bus”, the location of the marginal generator - this would be the cost of providing another unit of electricity in a system unaffected by losses or constraints. In practice, however, some electricity is lost in transmission, and so more or less than 1 MW will have to be generated in order to deliver 1 MW. If an increase in demand at node k leads to an increase in flows, losses will increase. Taking the simplest possible example, of a two-node system (figure 1), we might have:

Figure 1: A Two Node network

The average loss on this line is 5% of the power delivered, but the loss is proportional to the flow squared, and so the marginal loss will be 10%, twice the average. If the marginal cost of generation (which should be the price at the generation node) is £20/MWh, then the price at the demand node should be £22/MWh. It is possible for an increase in demand to reduce system losses, however, if it reduces the flows along some lines. In the example below (figure 2), 100 MW of demand at the left-hand node is met by an extra 100 MW of generation

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⁴ In other words, we assume that the cost of transmission maintenance, for example, does not depend on the

at the central node, and the flow along the left-hand line decreases. The price at the left-hand node should be less than at the central node, reflecting this.

Figure 2: A Three Node Network

The final term in equation (2) concerns the cost of constraints. Returning to the two-node network, if the line between the nodes was operating at its maximum capacity, then any further demand at the right-hand node would have to be met by generation at that node. If the marginal cost of generation at that node was £30/MWh, this should be the price of electricity at that node. A 1 MW increase in the capacity of the link would allow another MW of power to be delivered from the left-hand node at a cost of £22/MWh, so that the shadow price of the constraint is £8/MWh. Each 1 MW increase in demand causes a 1 MW increase in the flow across the constrained link, and so the power transfer distribution factor ϕ_{ik} would equal -1 in this example. In this simple example, the price at each node is equal to the marginal cost of the generation at that node, and the price equation is basically a way of decomposing the difference between them into the cost of losses and the cost of the constraint.

To solve more complicated examples, we must be able to derive the power flows in a “meshed” network, in which there is more than one route between some pairs of points. The

DC Load Flow model used in this paper is an approximation, but a reasonable one for our purposes. The model is discussed in the appendix, but the key equation is

$$\underline{z} = R^{-1} A \left(A^T R^{-1} A \right)^{-1} \underline{y} \quad (3)$$

where $\underline{z}$ is the vector of power flows along the L lines and $\underline{y}$ is the vector of net injections at the $N-1$ nodes excluding the swing bus. R is an $L \times L$ diagonal matrix of the resistances (or strictly speaking, impedances) on each line, and A an $L \times N-1$ matrix showing the connections between lines and nodes, known as the network incidence matrix. The key results from the model (or any other realistic model of line flows) are that power flows between two nodes will be shared among all the lines connecting those nodes, directly or indirectly, but that the distribution of the flow between any two routes will be inversely proportional to the relative resistance of those routes.

In the example below (figure 3), in which all three lines have the same resistance, two-thirds of the power generated at node A will flow through line 1, and one-third through lines 2 and 3. Two-thirds of the power generated at node B will flow through line 3, and one-third through lines 1 and 2. Since flows on line 2 are defined to be from A to B, (as shown by the arrow) the output from B which is flowing towards A will actually be measured as a negative flow (or, equivalently, a reduction in the flow from A to B).

Figure 3: A Three Node Meshed Network

Assume that there are no losses, to keep the example straightforward. If there were no constraints, and sufficient capacity at node A, the price of electricity would be £20/MWh at all three nodes. If there is a binding transmission constraint on line 1, however, then a 1 MW increase in demand at node C can only be met by *reducing* generation at A by 1 MW, and increasing generation at B by 2 MW. The additional output from B would cause $\frac{2}{3}$ MW to flow through line 1 ($\frac{1}{3}$ of the extra output), but the reduction in output from A would decrease the flow along the congested line by $\frac{2}{3}$ MW. The marginal cost of meeting the demand is £40/MWh - (2 MWh from B at £30 each, but saving 1 MWh from A which would have cost £20).⁵ This example shows that the cost of delivering 1 MW to some points on the network could be greater than the marginal cost of generation at any individual node - other examples could be constructed in which the delivered cost of power is negative. Since dealing properly with constraints can produce such strong price signals, studying the cost of ignoring them should be a worthwhile project.

3. THE MODEL

This paper studies the impact of different transmission pricing schemes on a simple model, but one which represents the main flows over the national grid system in England and Wales.

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⁵ This price (£40/MWh) could also be decomposed as in equation (2). The marginal cost at node A is £20/MWh, which is equal to μ_e . Adding 1 MW of capacity to line 1 would allow us to replace 3 MWh of generation at B (costing £90) with 3 MWh of generation at A (costing £60), a saving of £30, giving us the value of μ_i^{QS} . (The reduction at B reduces the flow on line 1 by 1 MW, which allows half of the increase caused by the extra generation at A - the other half comes from the new capacity). Increasing demand at C by 1 MW will increase the flow on line 1 by $\frac{2}{3}$ MW. We get $\text{£}40 = \text{£}20 + \text{£}30 \times \frac{2}{3}$.

That system has 14,000 km of 275 kV and 400 kV transmission lines, in 400 circuits which connect 200 substations. The (winter) peak demand on the system is presently around 50 GW. The main power flows are from power stations in the north of England and the Midlands to the south, although there are several large power stations in the south-east, near the Thames Estuary.

The National Grid Company (NGC) has divided its system into a number of zones for charging generators: the boundaries of the zones generally coincide with groups of circuits which are heavily loaded and might be constrained under some operating conditions. Our model is based upon the zones used in the mid-1990s, and uses one node to represent each zone. The exceptions are that the northernmost zone is split into two, and that two southern zones with no generation are combined with their neighbors. Twenty-one lines link our thirteen nodes, so that all zones which were directly connected are linked.

The model is based upon projections for the summer and winter of 1996/97, made by NGC in April 1996. The company publishes a seven-year projection of demand and capacity each year, together with data on the transmission system. Table 1 shows the distribution of generation and demand at the winter peak in 1996/7, together with demand at the summer peak. Generation in zones 0 and 1 includes 0.6 GW of imports from Scotland in each zone, while generation in zone 9 includes 2 GW of imports from France. The table also gives NGC's zonal predictions of the marginal losses from extra generation in 2002/3 (the only year for which the figures were given): these were used as a guide when calibrating the model, although it was not possible to replicate them exactly.

Table 1 about here

Table 2 gives more information on the generation which is located at each node. Two types are identified: must-run and variable. Both nuclear and combined-cycle gas turbine stations are classed as must-run plants, submitting very low bids and running as often as they are available. This reflects the way in which the earlier gas turbine stations were bid into the Pool, partly determined by their contracts; later stations have been more flexible. The variable stations are assumed to have a linear marginal cost function: the most expensive capacity has a marginal cost of £60/MWh.⁶ Figure 4 shows the assumed marginal cost function for zone 9.

Figure 4: Generation Marginal Costs

Table 2 about here

This form of marginal cost function is a simplification, because the marginal cost function for any one power station would be roughly horizontal, while a node with several stations would have a step function. This would imply that small changes in prices would frequently have no effect on the pattern of generation, but that a change would occasionally have a discontinuous impact as one station became cheaper than another.⁷ In the presence of

⁶ At low levels of demand, the marginal cost of output is reduced by the benefit of avoiding shut-downs and subsequent start-up costs, while start-up costs raise marginal costs above “steady state” running costs. The range of marginal costs shown here is therefore greater than the range of steady state costs.

⁷ This could lead to further complications, if the new distribution of generation affected power flows and the associated prices. In practice, the price at each of several nodes might be set to equal the marginal cost of a

discontinuities, the cost of a distortion may be very sensitive to the size of that distortion, since small distortions will be costless. Our formulation gives more opportunities for adjusting generation in response to prices. Generation availability was de-rated to 90% of the raw figure in winter, and 70% in summer, to reflect outages for maintenance (mostly forced in winter, with planned maintenance concentrated in the summer).

Demand is price sensitive, with a constant elasticity of -0.15 at each node, representing a “medium-term”, rather than a “short-term”, response. This is the elasticity with respect to the price of generation: the implied elasticity with respect to the final price will be approximately double this. The resulting elasticity of -0.3 is the one used by the regulator in appraising the impact of its policies (Ofgem, 2003), and other values are used for sensitivity tests later. There are ten sets of demand curves in each season, representing different load levels. Each set is obtained by scaling down the regional peak demands by a common factor, chosen to match points on the seasonal load-duration curve.⁸ The demand curves are anchored so that these quantities are demanded at the (uniform national) prices which the Pool pricing system, as used in the 1990s, would have produced. Figure 5 shows how the network of lines links the thirteen nodes in the model. With two exceptions, electricity flows from a lower to a higher numbered zone: the reverse flows are from zone 1 (the western half of NGC’s zone 1) to zone 0, and from zone 12 to zone 10.

Figure 5 about here

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station at that node, and the output from each station would then have to be adjusted until the resulting power flows meant that the selected prices were the correct spot prices, given the power flows.

⁸ For example, the winter peak demands are created by scaling the peak demand by 1.0, 0.9, 0.8, 0.76, .073, 0.71, 0.68, 0.64, 0.6 and 0.54. In practice, the figures in table 1 were first reduced by 1.8% to take account of transmission losses, which are not separately identified in this table of the NGC source document.

Table 3 describes the lines which link these zones: the resistances have been chosen so that the flows between zones, and the marginal losses incurred on demand in each zone, are close to those given in NGC (1996). These losses are only published for the final year of the projection, and so the network model was initially calibrated for 2002/3, using demand and generation figures for that year. One adjustment was then made to represent the system in 1996/7. NGC planned to double the capacity of the lines between zone 1 and zone 2 before 2002, and so the resistance between those zones was doubled to reflect the state of the system before this investment.⁹

Table 3 about here

The transmission system in England and Wales suffers from a number of constraints. Some of these are local and cannot be modeled at the lower level of detail in this paper: a particular station is required to run to make the adjoining lower-voltage system more reliable. Other constraints relate to the flows across a number of heavily loaded boundaries: although NGC uses a different methodology to define its charging zones, their boundaries generally coincide with some of these critical system boundaries. Constraints may be caused by thermal limits on the amount of active power that can flow through a line, or by voltage limits that also depend on reactive power flows. NGC reports the main boundary limits in terms of

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⁹ This paper is slightly unconventional in using a DC model, which generally assumes no losses, to estimate the power flows, and then estimating losses on the basis of these flows, but its aim is to consider both constraints and losses within a tractable approximation of reality.

active power flows. Table 4 shows these constrained circuits and their maximum ratings.¹⁰ Since the DC load flow model used in this paper does not include reactive power, it is possible that the extent of constraints is under-estimated, should there be times when reactive power flows are high relative to active flows. While constraints 2 and 12 were occasionally binding, with small impacts on prices, the most important constraints for our purposes were numbers 1 and 6. Constraint 1 separates the North from the rest of the market, while constraint 6 isolates the South of Wales and the South-West of England. These two constraints are shown in Figure 2.

Table 4 about here

This small-scale model cannot be a fully accurate representation of the NGC system, but it will behave in similar ways in response to small changes in generation or demand. The aim of this paper is to consider whether different transmission pricing systems are likely to have an important practical impact on the electricity industry. This is a wider question than calculating prices in particular locations at particular times, although we need to do that before we can come to an answer. To answer the wider question, however, we do not need an exact representation of any one system, as long as our model incorporates the kind of responses which would be found in a real system.

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¹⁰ The boundary ratings are set so that the system can absorb the loss of any circuit without overloading the remaining lines. It is usual for a few lines to be unavailable, reducing the system's capacity to take further outages, and hence the safe boundary flows. Circuit ratings were accordingly reduced (by more in summer than winter) to raise constraint costs to the level seen in the mid-1990s.

4. THE PRICING RULES

The model was solved for a range of demand levels under “summer” and “winter” conditions (plant and transmission availability), and the results aggregated to give figures for the year as a whole. Three pricing rules were used. The first was optimal pricing: a single price at each node, for both generation and demand. The second pricing rule had separate prices at each node for generation, but a uniform national price for demand. The third pricing rule is effectively that used in England and Wales from 1990 to the present day: one national price for generation, and one price for demand. Under the Pool, this was achieved through the market rules, and while it is not imposed by the New Electricity Trading Arrangements, we should expect all traders to come close to achieving the best price possible, and hence to uniformity, if the market is efficient.

If there are constraints, however, the generators’ responses to the national prices would be infeasible, and “counter-trading” was used to manage constraints. Generation was reduced at nodes on the “export” side of a constraint, and increased at the others, in proportion to the amount of “variable” capacity at each node, reducing the flows to acceptable levels. While normal generation is paid for at the national price, constrained on generation is paid its cost (higher than the national price). Generation which is constrained off is also sold back to the generator at cost, (it must be sold back, since it had already been “paid for” under the rules used in England and Wales, both with the Pool and with NETA). If the generator had been bidding its marginal cost, it would neither gain nor lose from this transaction. If necessary, “must-run” generation could also be reduced to ensure that net exports from a node were within acceptable limits. (Similar reductions were sometimes needed with the second pricing rule, in cases when net exports were excessive, even with a local generation price of zero.) We will continue to use $g_j(p_j)$ to represent the generation that would be offered at node

j at a price of p_j , and add c_j for changes in output due to constraints. The total output at node j is thus $g_j(p_j) + c_j$.

The pricing rules can be related to the welfare problem stated in section II. The first rule, optimal pricing, is simply the solution to equation (1). The second rule is the solution to the closely related problem below. The additional constraint relates to the “merchandising surplus” which the transmission company makes with the optimal pricing rule. On average, demand exceeds generation at the higher-priced nodes, and the resulting surplus (R) can be put towards the fixed costs of the transmission network. The remaining costs are recovered through (distorting) tariffs. As long as the regulator takes the surplus from optimal pricing into account when setting limits on those tariffs, they will be lower than if all the costs of the transmission system had to be recovered through them. In order to compare welfare on a like with like basis, we want the transmission company to have to recover the same amount of revenue from its main network tariffs (not modeled here) under each pricing rule. Keeping the distortions from those tariffs constant should imply that the same adjustment would be made to each of the welfare calculations here, were we to take them into account. If we required the transmission company to raise more money from its network tariffs when it does not adopt optimal pricing, but did not take this into account, we would be biasing our results against the optimal pricing rule. For a sensitivity analysis, however, we run one simulation in which we set R to zero.

$$\begin{aligned}
& \underset{p, p_j}{\text{minimise}} && \sum_j C(g_j(p_j) + c_j) - \sum_k B(d_k(p)) && (4) \\
& \text{subject to} && \sum_k d_k + \text{losses} - \sum_j g_j + c_j = 0 && \text{(energy balance constraint)} \\
& && -z_i^{\max} \leq \sum_j \phi_{ij} g_j - \sum_k \phi_{ik} d_k \leq z_i^{\max} && \text{(line flow constraints)} \\
& && \sum_k p d_k(p) - \sum_j p_j g_j(p_j) - R = 0 && \text{(total transmission surplus equal to } R) \\
& && p_j c_j \geq 0 && \text{(generation only constrained off at zero price)}
\end{aligned}$$

Applying the third pricing rule cannot be based on an optimization that maximizes welfare, since the solver would use counter-trading to equalize the marginal cost of generation in each zone, taking us back to the results of the second rule.¹¹ Instead, the solver was instructed to balance generation and demand, earning the same transmission surplus as with optimal pricing, and counter-trading only where a constraint would otherwise be breached. Generation on the two sides of a constraint was increased or decreased in proportion to the amount of variable capacity. In other words, if output had to be reduced by 0.4 GW to the

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¹¹ An anonymous referee suggested that NGC could do exactly this when balancing the system under NETA, since each station is paid its own offered price, and NGC is fully aware of every unit's location and technical characteristics. The company could scale every offer to take account of the unit's marginal transmission losses and choose to accept the lowest scaled offers. Furthermore, some spatial arbitrage, buying electricity in the south and selling back slightly more in the north, could be profitable even when there are no constraints. NGC does not trade in this way, however. It dispatches generators to meet a total generation requirement (the sum of demand plus losses) and calls bids and offers in price order without any adjustment, as long as the units are capable of responding in time and are in the right location relative to any constraints. (Telephone conversation with NGC Wokingham, 3 January 2006.) The algorithm used here captures the essentials of NGC's behavior under both the Pool and NETA.

north of a constraint, and half of the variable generation to the north of that constraint was in a given zone, then output in that zone would be reduced by 0.2 GW. In the absence of losses, this would minimize the cost of the adjustments, which is NGC's objective. The payment for the adjustment is equal to the production cost of the adjusted generation, less the production cost of the unadjusted generation. The constraints to be met were thus:

$$\sum_k d_k(p_d) + \text{losses} - \sum_j g_j(p_g) + c_j = 0 \quad (\text{energy balance constraint})$$

$$-z_i^{\max} \leq \sum_j \phi_{ij} g_j - \sum_k \phi_{ik} d_k \leq z_i^{\max} \quad (\text{line flow constraints})$$

$$\begin{aligned} \sum_k p_d d_k(p_d) - \sum_j p_g g_j(p_g) & \quad (\text{total transmission surplus equal to } R) \\ - \sum_j C(g_j(p_g) + c_j) - C(g_j(p_g)) & = R \end{aligned}$$

The two prices, p_d for demand and p_g for generation, and the constrained outputs in each zone, were adjusted to ensure that these constraints were met.

5. RESULTS

Table 5 gives the results for our central case, with marginal cost bidding and a demand elasticity of 0.15 (relative to the wholesale price). The average revenue is lowest, and the total output highest, with optimal pricing, while the Pool system of uniform pricing has the highest average revenue and lowest level of output. Despite the lower levels of output, generation costs are higher with the two sub-optimal pricing systems. Under the Pool system, it is possible to identify the cost of constraints, as represented by NGC's counter-trading payments. The other pricing systems do not allow us to calculate a similar figure, although the extent of constraints can be seen in the coefficient of variation in generation prices. The

first row is based on calculating the coefficient of variation across the zones for each demand level, and then taking the average of these coefficients. By construction, there is no variation under the Pool system, whereas the other two systems involve significant regional variations in prices. Much of this variation comes from a binding export constraint covering the two northernmost zones, and the rest from transmission losses. The variations (in the generators' prices) are greater when consumers face a uniform price, as the only way to reduce net exports from the north is to reduce generation. In many hours, the price has to drop to zero to achieve this. When the consumers' price varies as well, the reduction increases demand, reducing net exports and allowing equilibrium to be reached at a higher price. The second set of coefficients of variation shows that there is significant variation over time as well.

Table 5 about here

Welfare, defined as the un-weighted sum of consumer surplus and profits, is £93 million per year lower with a uniform price for demand than with optimal pricing. This is equal to 1.2% of the revenue from optimal pricing. With uniform prices for both generation and demand, welfare is lower by £100 million, or 1.3% of the revenue from optimal pricing. This implies that most of the gains from spatially differentiated transmission prices come from the demand side, at least in this market at this time. On the generation side, transmission constraints have to be respected by the final pattern of outputs, whatever the pricing system. Furthermore, the adjustments made for transmission constraints have the side-effect of reducing losses, since the generators subject to the northern export constraint have the highest marginal transmission losses. For these reasons, changing the pricing rule for generators has little impact on the production cost of electricity. Changing the pricing rule for consumers, however, reduces demand in areas where the price would have been above

marginal cost, and increases demand where the price was below marginal cost, allowing much larger welfare gains.

The welfare gains are not uniformly distributed. Generators are (collectively) worse off when consumers (only) pay a uniform price, in part because the northern export constraint means that some generation is bought at a very low price – the demand response under optimal pricing allows a higher price in this area. Northern consumers similarly lose from the move to a uniform price, and while other consumers see lower prices, consumer surplus falls overall. When both consumers and generators face uniform prices, however, generators are better off than with optimal pricing. One reason for this is that generators in export-constrained areas are paid the national price for the output that they do sell (instead of a lower zonal price), and receive “lost profit” payments for the output that is constrained off (they sell it at the national price and buy it back at their marginal production cost). The average revenue is higher, and consumers are worse off.

Table 6 and table 7 present results using two other values of the demand elasticity, as a sensitivity analysis. With a lower elasticity of -0.05 , the optimal prices vary more, as demand is less responsive to changes in price. (When the price to consumers is uniform, however, the spatial variation of generation prices is very insensitive to the demand elasticity.) Although the efficient level of price variation is greater, the welfare impact of moving away from this system is smaller, as moving to a uniform price for demand reduces welfare by 0.9% of revenue. Adopting a uniform price for generation as well reduces welfare by a further £6 million a year, almost identical to the figure for the middle elasticity case. With uniform prices for demand alone, consumers collectively lose by more and generators by less than in the base case. With uniform prices for demand and for generation, the welfare effects for both groups are larger than in the base case.

Table 6 about here

With a higher elasticity of -0.25, the optimal spatial variation in prices falls, and the welfare loss from the other pricing rules increases. A uniform price for demand alone reduces welfare by 1.4% of the wholesale market revenues with optimal pricing, and imposing a uniform price for generation costs a further £7 million a year. The impact of the generators' pricing rule therefore seems not to vary with the demand elasticity, whereas the consumers' pricing rule has an impact which is non-linear in the elasticity. Collectively, consumers are slightly better off if they (only) face uniform prices, while generators suffer more from the change than in the base case. With two uniform prices, however, the collective welfare impacts are in the same direction as in the base case, but smaller.

Table 7 here

The simulations for the two non-optimal rules assume that the demand prices have to raise the same amount of revenue for the transmission company as the merchandising surplus that it automatically obtains from optimal pricing. This is on the assumption that the surplus would be used to reduce the transmission company's other charges, and that if this money was not available, it would have to be raised from some other, distorting, charge. An alternative assumption is that the surplus would simply raise the transmission company's profits, and that a better counter-factual would not require the company to make any surplus with the two non-optimal rules. Using the base case elasticity, this would reduce the average revenue by around £0.7/MWh, and increase consumers' surplus by about £200 million a year. Overall welfare, however, would rise by just £0.3 million with one uniform price (comparing that pricing system with and without the need to recover this surplus), and £1.3 million with

two. This is trivial in comparison with the welfare losses caused by shifting away from optimal pricing.

6. MARKET POWER

It is well-known that electricity markets are vulnerable to market power. Does the choice of transmission pricing system affect this vulnerability? A full-blown simulation of an oligopolistic market is beyond the scope of this paper, but this section investigates the impact of abusive behaviour by the two largest companies in the market. In 1996/7, National Power and PowerGen each owned about one quarter of the industry's capacity, as shown in table 8. While the rest of the industry continues to bid at marginal cost, we will allow these generators to vary the slope of the bid functions that they submit for their "variable" capacity. The market operator will follow the same pricing rules as before, treating these submitted bid functions as true measures of the companies' costs – the correct (original) cost functions will of course be used when calculating the actual level of welfare.

Table 8 around here

A grid search was used to find the generators' profit-maximizing strategies. In general, the companies did not gain significantly from using different mark-ups in different zones, and so common mark-ups were used for all of PowerGen's stations. National Power, however, has a high proportion of the capacity in two regions that might be the subject of transmission constraints. Zone 1, in the north-east, was always export-constrained, implying relatively low prices, while an import constraint could be created in zones 8, 12, and 13. National Power owned all the variable capacity in these south-western zones, and by

submitting high bids at times of peak demand, could ensure that some of it had to be used, despite the high prices. To give the company the chance to exploit these concentrations of plant, it was allowed to submit a different mark-up for plant in zone 1, and in zones 8 and 12. The regulator had investigated the generators' behavior when bidding stations likely to be constrained on, however, and had severely criticized some of the tactics used by PowerGen (Offer, 1992), without taking action at that time. To reflect the risk of provoking regulatory action, National Power's bids were restricted to be no more than ten times its true costs.

In the northern zone, the uniform pricing rule gives National Power the opportunity to play what has become known as the "DEC game", following from its abuse in California. If the company submits low bids for stations located behind an export constraint, they will be scheduled to run, earning the uniform national price. This output cannot be accommodated, however, and the system controller has to sell it back to the company. Under the Pool rules used in this simulation, the price is the company's own bid, which might be close to zero but would have to be positive – other market rules might allow the company to demand payment for not generating. In California, there were occasional doubts whether the power scheduled in a DEC game could have been generated, but in this simulation, the amounts involved were limited to the generator's capacity in the export-constrained zone.

Table 9 shows the results. Prices are, unsurprisingly, higher and quantities lower. The variation of prices over space does not increase by much, but their variation over time does – the peak prices are relatively much higher in the presence of market power. The highest average prices come when there is a uniform price for demand, but zonal prices for generation. This is due to the way in which transmission constraints interact with market power. National Power can create an import constraint into the South-West at peak times, and receive a higher price for all the generation it has in this zone. With optimal pricing, the full impact of this price increase is felt by the local demand, which will fall. With a uniform

price for demand, the demand-side impact of a higher generation price on one side of a constraint is spread over the entire market. This effectively makes the local demand less elastic, which would raise the profit-maximizing price, considering the area in isolation. The corollary, however, is that raising the price in one area will reduce generators' profits in the rest of the country, since the demand price will rise and sales will fall. Power flows cannot change to offset these effects, since the boundaries are already constrained.

Table 9 about here

If the generators' capacity was evenly distributed across the country, the distinction between zonal and uniform pricing might well be unimportant, for the greater gains inside a constraint would be offset by the effects outside it. In practice, however, National Power has such a high proportion of the capacity to the South-West of boundary 6 that with uniform demand pricing, the company finds it profitable to create the constraint for the two highest winter demand levels. With optimal pricing, creating the constraint is only profitable for the highest demand level. PowerGen has no plant in either the North or the South-West, and similarly gains more from raising the generation price in the central zone when there is a uniform demand price, since the part of the response that comes on the other side of the two constraints has no impact on its profits.

With uniform pricing for both generation and demand, we get an intermediate average price, even though this rule gave the highest prices in the absence of market power. The price received for most generation is not affected by transmission constraints, which reduces the incentive to exploit them and their impact on the demand price – only the incremental output receives a higher price. A lower demand price at the very peak period is responsible for much of the difference in average revenue between the two pricing rules. In the North, National

Power can exploit the export constraint by playing the DEC game – it bids all its capacity at close to zero, which is therefore scheduled to run, and receives the difference between the market price and this bid in return for not running it. This strategy will tend to reduce the price received for generation, even though the constrained-off payments will raise the margin between the generation price and the price paid by demand. Collectively, the generators' profits are lowest with this pricing rule, but National Power makes almost the same profits as with optimal pricing, implying that it is playing the DEC game at the expense of the other generators. Note that the profits shown in table 9 are variable profits, before deducting any fixed costs.

The welfare difference between optimal pricing and a uniform price for demand has now doubled, while the additional impact of a uniform price for generation has risen ten-fold. Taking market power as a given, adopting a uniform price for demand is bad for consumers and good for generators, who can exploit constraints more effectively, as described above. Using two uniform prices is worse than optimal pricing for both generators and consumers, although consumers do better than if they alone face a uniform price.

The bottom part of table 9 compares the impact of market power under the different pricing rules. Welfare is reduced by between £424 million and £569 million, or by between 5.4% and 7.2% of the industry's revenues under optimal pricing and perfect competition. The smallest loss comes with optimal pricing, and the greatest with two uniform prices. Consumer welfare falls by around £5 billion, and generators' profits rise by more than £4 billion. The change in consumer welfare from market power is least with two uniform prices and biggest with a uniform price for demand alone, but consumers still achieve their highest level of welfare (for the base elasticity) with optimal pricing, whether or not there is market power.

To conclude this section, it is worth pointing out that the market in England and Wales has become significantly more competitive since 1996/7, and so the impact of market power would be much smaller today. Even in 1996/7, our simulations have slightly overstated the impact of market power, by allowing the generators to choose different mark-ups for each level of demand. In practice, their bids had to last for a whole day, reducing their ability to exploit transmission constraints of shorter durations – a bid that would be profitable while the constraint lasted might lose money over the day as a whole. Under NETA, however, generators can change their bids in every trading period, potentially increasing their ability to exploit transmission constraints.

7. CONCLUSIONS

This paper has illustrated the benefits of applying optimal spot prices in a simple model of an electricity network based on England and Wales in 1996/97. Looking at operating costs alone, and taking nodal spot pricing as the optimum, welfare would fall by 1.2% of wholesale revenues if a uniform demand price were applied, and by slightly more if uniform prices for both demand and generation were adopted. In the presence of market power, the cost of sub-optimal pricing rises to 2.3% and 3.1% of revenues, respectively. These may seem like small numbers, but they can be compared to Newbery and Pollitt's (1997) estimate of the net benefits from privatizing the Central Electricity Generating Board, which was equal to 5% of the Board's costs. "Throwing away" a quarter or more of the benefits of that exercise might sound rather more significant.

It must be remembered, however, that introducing optimal prices will often involve transfers between agents that are much greater than the net welfare gain. That is likely to make them hard to introduce from a political point of view. The attempt to introduce

transmission loss factors in Great Britain, which would reduce prices in the north, and increase them in the south, is a good example of this. The resulting prices would provide better economic signals than the present system, and the issue was identified as one for future review when the market was first restructured, in 1990. Companies which stood to lose from the change used the industry's processes (including two unsuccessful appeals to the regulator) and legal action to stop it. Changes to the market's governance when the New Electricity Trading Arrangements were introduced allowed the regulator to press ahead with the change in England and Wales, but when the government extended the market to Scotland, it overruled the regulator and decreed that prices would continue to be uniform.

The gains from optimal prices will be greater once we consider their effect as investment signals to generators.¹² In the short term, moving towards optimal prices increases the output from stations in "good" locations, but since all the stations with low operating costs would have been dispatched under uniform pricing in any case, the stations where output rises must have relatively high operating costs, which limits the gain. Consider a long, heavily loaded line with a station at each end, and marginal transmission losses of 10%. If the marginal costs of the station at the "right" end of the line are 5% higher than at the other station, the saving from reallocating generation between the stations is only 5%. When considering investment, however, we can save the full 10% by placing the new station at the right end of the line, and the saving applies to capital as well as operating costs.

We have assumed that the system can be successfully dispatched without the use of optimal prices, and thus ignored the issue of bypass. When prices are not equal to marginal costs, some agents may wish to leave the main market and deal independently, reducing its efficiency. Hogan (1998) describes a failed experiment in the Pennsylvania-New Jersey-

Maryland (PJM) Interconnection in 1997. Customers faced a price based on an unconstrained system, but transmission constraints meant that some generators were forced not to run. They received no compensation for this, and had a strong incentive to arrange a bilateral transaction with a customer at a price between their marginal cost and the unconstrained price. Once these generators had done so, their output could not be reduced, and the system operator had to constrain some other generators instead. These then had an incentive to act in the same way, and the system operator was forced to ban bilateral trading before it ran out of dispatchable generation. A revised market mechanism uses spot prices, and is not threatened by bilateral trading. Hogan argues that any move to use zonal prices instead of nodal spot prices would create similar perverse incentives if used as a means of system co-ordination, and would be unlikely to simplify the calculation or interpretation of those prices.

One way to get round the problem of bypass is to ban bilateral trading from the start, as was done in England and Wales under the Pool system. Another is to arrange compensation payments for constrained generators, funded by all consumers, so that no-one has an incentive to leave the market, but this reduces the incentive to avoid congested locations. There are ways to make an electricity market work without nodal spot pricing.

The important question is whether nodal spot pricing would make the market work better. This paper estimates that moving from uniform pricing to nodal pricing could have raised welfare by 1.3% of the generators' revenues in a particular competitive market, and would be less vulnerable to the exercise of market power than alternative pricing systems. They would also improve the investment signals sent to generators. The size of the gains is almost certainly market-specific, and other studies would be needed to calculate the impact of

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¹² Spot prices are not the only way to send investment signals, however. In England and Wales, the National Grid Company has regionally differentiated capacity-based charges, encouraging investment in the south.

changing the pricing rule in other markets. Nothing in this study, however, suggests that gains would not exist elsewhere. They are worth pursuing.

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Appendix: The DC Load Flow Model.

The DC Load flow equations are a simple planning tool which may be used to provide an approximate relationship between generation and demand at each point on a network, and the power flows along each line. They depend upon a number of approximations which make them inadequate for detailed system planning, but should be adequate to illustrate the possibilities of unit transmission charges. The full equations are derived in appendix D of Schweppe et al, (1988); this appendix presents only their most simple form.

The network consists of N nodes which are linked by L lines. The net power injection (generation minus demand) at node j is denoted by y_j . The sum of the net injections must equal the transmission losses (l) on the system, under the energy balance constraint. In the DC equations, this means that one of the nodes is not explicitly modeled, and its net injection is effectively treated as a residual, determined by this constraint. The other $N-1$ injections form a vector $\underline{y}$. The flow along line i is denoted by z_i , and $\underline{z}$ is the N -vector of these flows. The network incidence matrix, $\tilde{A}$, shows which buses are connected by each line. A simple example is given below, in which all power is assumed to flow from the lower to the higher numbered node. The node from which power flows is given an entry of +1, and the node to which power flows is given an entry of -1. If the power actually flows in the opposite direction to that assumed, then z_i will be negative. Because $\tilde{A}$ is singular, we remove the column corresponding to the swing bus to create a non-singular $N * (N - 1)$ matrix A . In this example, node number 2 is the swing bus, and so we delete the second column of $\tilde{A}$ to create A .

$\tilde{A}$	<i>node</i>	
	1 2 3 4	
<i>line</i>	i	$\begin{pmatrix} 1 & -1 & 0 & 0 \end{pmatrix}$
	ii	$\begin{pmatrix} 0 & 1 & 0 & -1 \end{pmatrix}$
	iii	$\begin{pmatrix} 0 & 1 & -1 & 0 \end{pmatrix}$
	iv	$\begin{pmatrix} 0 & 1 & 1 & -1 \end{pmatrix}$

A	<i>node</i>	
	1 3 4	
<i>line</i>	i	$\begin{pmatrix} 1 & 0 & 0 \end{pmatrix}$
	ii	$\begin{pmatrix} 0 & 0 & -1 \end{pmatrix}$
	iii	$\begin{pmatrix} 0 & -1 & 0 \end{pmatrix}$
	iv	$\begin{pmatrix} 0 & 1 & -1 \end{pmatrix}$

R is a $N \times N$ diagonal matrix, with the resistance of line i as the ii -th element, and zeros elsewhere. The three DC load flow equations are:

$$\underline{z} = R^{-1} A \left(A^T R^{-1} A \right)^{-1} \underline{y} \quad (\text{line flow equation})$$

$$l = \underline{z}^T R \underline{z} \quad (\text{transmission losses})$$

$$\sum_{j=1}^N y_j - l = 0 \quad (\text{energy balance constraint})$$

The energy balance constraint has been written to ensure that a given set of N net injections are consistent. An alternative is to rewrite the equation with the injection at the swing bus on the left hand side, solving for this as the residual from $N-1$ predetermined injections. This effectively assumes that the marginal generator will be located at the swing bus. In practice, the merit order determines the location of the marginal generator, which is unlikely to be at a pre-defined swing bus, and the energy balance constraint as written here is used to ensure that its output (a choice variable) is consistent with electrical equilibrium.

Table 1: Zones, Generation and Demand (GW)

Zone	Name	Generation	Peak Demand		Marginal
		(Winter)	(Winter)	(Summer)	Loss
0	North [-Western]	0.6	0.3	0.2	
1	North [-Eastern]	4.3	2.4	1.7	+ 5%
2	Yorkshire	9.4	5.6	3.9	+ 3%
3	N Wales and W Lancs	7.8	4.2	3.0	+ 3%
4	E Lancashire	0.0	2.8	2.0	+ 1%
5	Nottinghamshire	4.1	0.5	0.4	+ 1%
6	West Midlands	4.5	7.0	4.9	- 1%
7	East Anglia	3.0	4.8	3.3	- 3%
8	West and Wales	3.8	4.5	3.2	- 6%
9	[Thames] Estuary	8.5	2.5	1.8	- 5%
10	London [Inner and Outer]	2.0	8.7	6.1	- 5%
12	South Coast	0.5	3.8	2.6	- 9%
13	Wessex and Peninsula	1.6	2.8	1.9	- 9%

Source: NGC, (1996)

Table 2: Generation Capacity (GW)

Zone	Name	Must-run	Variable	Total
0	North [Western]	0.6	0.0	0.6
1	North [Eastern]	3.9	1.1	5.0
2	Yorkshire	3.5	8.0	11.4
3	N Wales and W Lancs	5.9	4.1	10.0
4	E Lancashire	0.0	0.0	0.0
5	Nottinghamshire	0.0	4.9	4.9
6	West Midlands	0.2	5.2	5.4
7	East Anglia	3.6	0.0	3.6
8	West and Wales	1.1	3.5	4.6
9	[Thames] Estuary	4.5	5.4	9.9
10	London [Inner and Outer]	1.7	0.9	2.6
12	South Coast	0.0	0.7	0.7
13	Wessex and Peninsula	1.7	0.2	1.9
		26.8	33.9	60.7

Source: NGC (1996) Figures do not sum to totals due to rounding

Table 3: Lines and Flows

Line	From Zone	to Zone	Resistance ($\times 1000$)	Flow (GW)
1	1	0	8.775	0.4
2	1	2	9.000	2.5
3	0	3	9.000	1.2
4	3	4	2.025	2.9
5	2	4	3.450	2.6
6	2	5	2.250	5.1
7	3	6	8.325	2.1
8	4	6	4.500	2.6
9	5	6	3.900	2.4
10	5	7	2.250	7.5
11	6	7	3.675	2.1
12	6	8	9.075	2.5
13	7	8	7.500	2.0
14	7	10	8.625	4.7
15	7	9	16.125	1.6
16	9	10	4.875	3.0
17	9	12	5.925	2.2
18	12	10	8.250	0.2
19	8	12	8.250	2.8
20	8	13	32.250	0.8
21	12	13	3.375	0.7

Table 4: Constraints on the NGC system

Boundary	Lines	Zones affected		Max rating (GW)
1	2,3	Exports from	0,1	2.1
2	6,7,8	Exports from	0 – 4	9.2
3	10,11,12	Exports from	0 – 6	11.0
4	17,-18,19,20	Imports to	12,13	7.7
5	3,5,6	Exports from	0,1,2	6.8
6	12,13,17,-18	Imports to	8,12,13	7.8
7	20,21	Imports to	13	4.0
8	14,16,18	Imports to	10	10.5
9	-15,16,17	Exports from	9	8.5
10	1,2	Exports from	1	2.0
11	7,8,9,-11,-12	Imports to	6	6.0
12	3,5,9,10	Exports from	0,1,2,5	11.5

Source: NGC (1996)

Table 5: Base case results

Pricing System	Optimal	Zonal (for Generators)	Uniform
Demand (TWh)	289.8	286.3	285.4
Losses (TWh)	1.55	1.58	1.59
Total Revenue (£m)	7872	7842	8050
Average Revenue (£/MWh)	27.17	27.39	28.21
Cost of counter-trading (£m)			142
Coefficient of Variation of prices:			
Within hours	0.34	0.42	0.00
Across and within hours	0.59	0.65	0.50
Changes relative to optimal pricing:			
Welfare (£m)		-93	-100
(% of revenue)		-1.2%	-1.3%
Consumer surplus (£m)		-19	-265
(% of revenue)		-0.2%	-3.4%
Generator profit (£m)		-73	166
(% of revenue)		-0.9%	2.1%
Cost of generation (£m)		44	13
(% of revenue)		0.6%	0.2%

Table 6: Low elasticity results

Pricing System	Optimal	Zonal (for Generators)	Uniform
Demand (TWh)	289.5	285.7	285.4
Losses (TWh)	1.57	1.57	1.59
Total Revenue (£m)	7815	7820	8099
Average Revenue (£/MWh)	26.99	27.37	28.38
Cost of counter-trading (£m)			142
Coefficient of Variation of prices:			
Within hours	0.49	0.42	0.00
Across and within hours	0.63	0.65	0.50
Changes relative to optimal pricing:			
Welfare (£m)		-67	-73
(% of revenue)		-0.9%	-0.9%
Consumer surplus (£m)		-54	-349
(% of revenue)		-0.7%	-4.5%
Generator profit (£m)		-8	275
(% of revenue)		-0.1%	3.5%
Cost of generation (£m)		18	8
(% of revenue)		0.2%	0.1%

Table 7: High elasticity results

Pricing System	Optimal	Zonal (for Generators)	Uniform
Demand (TWh)	289.9	286.9	285.6
Losses (TWh)	1.53	1.58	1.59
Total Revenue (£m)	7922	7871	8030
Average Revenue (£/MWh)	27.32	27.43	28.12
Cost of counter-trading (£m)			142
Coefficient of Variation of prices:			
Within hours	0.28	0.42	0.00
Across and within hours	0.56	0.66	0.50
Changes relative to optimal pricing:			
Welfare (£m)		-111	-118
(% of revenue)		-1.4%	-1.5%
Consumer surplus (£m)		7	-207
(% of revenue)		0.1%	-2.6%
Generator profit (£m)		-117	89
(% of revenue)		-1.5%	1.1%
Cost of generation (£m)		67	19
(% of revenue)		0.8%	0.2%

Table 8: Generation Capacity of National Power and PowerGen (GW)

Zone	Name	National Power		PowerGen		Industry
		Must-run	Variable	Must-run	Variable	Total
0	North [Western]	0.0	0.0	0.0	0.0	0.6
1	North [Eastern]	0.0	1.1	0.0	0.0	5.0
2	Yorkshire	0.7	5.9	0.9	2.0	11.3
3	N Wales and W Lancs	0.5	0.0	1.5	2.0	10.0
4	E Lancashire	0.0	0.0	0.0	0.0	0.0
5	Nottinghamshire	0.0	0.0	0.0	2.0	4.9
6	West Midlands	0.0	0.4	0.0	2.0	5.6
7	East Anglia	0.7	0.0	0.0	0.0	3.5
8	West and Wales	0.7	3.5	0.0	0.0	4.6
9	[Thames] Estuary	0.0	1.4	0.0	4.0	9.9
10	London	0.0	0.8	0.7	0.1	2.6
12	South Coast	0.0	0.7	0.0	0.0	0.7
13	Wessex and Peninsula	0.0	0.0	0.0	0.0	1.9
		2.6	13.7	3.2	12.2	60.7

Source: NGC (1996) Figures do not sum to totals due to rounding

Table 9: The impact of market power

Pricing System	Optimal	Zonal (for Generators)	Uniform
Demand (TWh)	272.9	267.9	269.5
Losses (TWh)	1.47	1.52	1.59
Total Revenue (£m)	12200	12565	12198
National Power's profit (£m)	1932	2074	1930
PowerGen's profit (£m)	2018	2097	1757
Average Revenue (£/MWh)	44.70	46.90	45.25
Cost of counter-trading (£m)			359
Coefficient of Variation of prices:			
Within hours	0.36	0.43	0.00
Across and within hours	0.85	0.94	0.75
Changes relative to optimal pricing:			
Welfare (£m)		-182	-245
(% of revenue)		-2.3%	-3.1%
Consumer surplus (£m)		-517	-82
(% of revenue)		-6.6%	-1.0%
Generator profit (£m)		337	-162
(% of revenue)		4.3%	-2.1%
Cost of generation (£m)		30	160
(% of revenue)		0.4%	2.0%
Changes relative to marginal cost bidding:			
Welfare (£m)	-424	-512	-569
Consumer surplus (£m)	-5091	-5589	-4908
Generator profit (£m)	4448	4858	4120
Transmission surplus (£m)	219	219	219

Figure 5: Simplified Version of the Transmission System in England and Wales