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PRICING NORTH SEA NATURAL GAS

TEACHER'S NOTE

August 1969

INDEX

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1. This note will concentrate on certain general economic principles raised by the case, since it is these rather than the mechanics of DCF and tax incorporation which are likely to be of the most relevance to students who are initiates to economics. The principle issues raised will be: price; risk; time; economic surplus; and bargaining.

Normative pricing principles

2. There are three parties to the North Sea gas pricing decision: the oil companies, the Gas Council, and the Ministry of Power. The exchange relations between them are those of a highly imperfect market. On the drilling side, although there are 23 licencees and 53 participating corporations, there are so far only nine effective drillers while the crucial negotiations involved only four groups. The Gas Council is an effective monopolist in the final market for gas, while the Ministry of Power has under its direct supervision four out of five of the energy sectors in Britain. The market structure involved in the beach-pricing of North Sea gas is thus very distant from perfect competition. It approaches that limiting case known as 'bilateral monopoly', where both buyer and seller are the sole units on their side of the market: we may conveniently characterise the situation as, in Wiles' phrase, "advanced higgling".

3. Where public bodies are involved, the principles of optimum pricing in so indeterminate a situation become particularly important. Indeed as can be seen from the case, the two parties with narrower interests than the Ministry of Power have both made different pricing principles the foundation to their arguments: that is to say, they have argued that a particular pricing principle is socially optimal not merely optimal for one of the parties. In the following paragraphs of this section we will formalise the alternatives together with other possibilities which any arbitrating body should keep in mind.

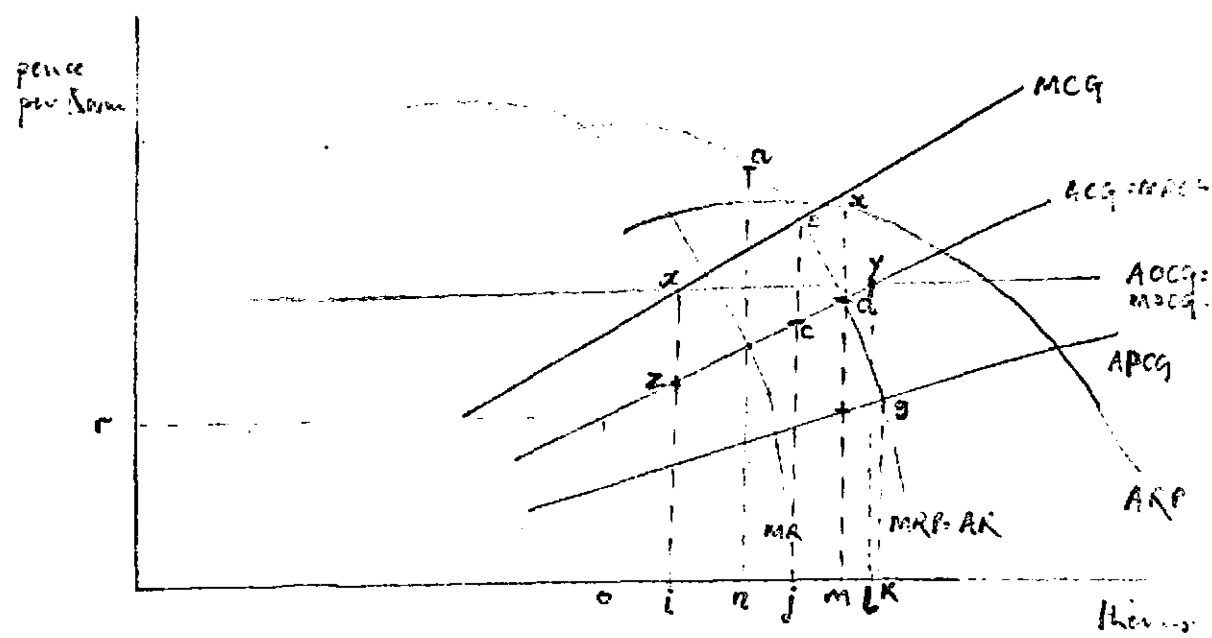
4. Monopsony. Monopsony is that market structure where there are many sellers but only one buyer. This is clearly close to the situation under discussion. The optimum price for a monopsonist is shown in Figure 1. Here ACG is the average cost of gas to the buyer. If the buyer gets delivery of m therms he must pay an average price per therm

of p. The marginal cost to the buyer of the m'th therm is composed of the average price ', plus the increased price that he will have to pay for all other therms which previously he bought for less than p. MCG traves the marginal cost for each successive therm (i.e. the <u>increase in total costs</u> which the buyer incurs as a result of n+1 rather than n therms).

5. Some confusion may surround ACG, judging from many textbooks. ACG is the supply curve, denoting the average price to be paid for the production of any quantity. It is an average from the point of view of the buyer, just as the demand curve is the average revenue from the point of view of the seller. But it should be noted that ACG is also the <u>marginal</u> cost curve of the seller. The sellers average cost curve is given by APCG, the average production cost of gas. That APCG is not the supply curve can be seen by considering price r. It might be thought that it would still be profitable to <u>supply</u> any number of therms up to quantity m at a constant price r, and indeed it would. But it would not be the position of maximum profit, for beyond point o, each successive unit would have a greater marginal cost than it yielded in marginal revenue.

6. A similar argument can be seen to apply to the demand side. In Figure 1, ARP is sometimes depicted as the derived demand curve. It signifies the average revenue which the buyer can expect from employing a certain quantity of the goods in question as part of a process of production or distribution. Thus with m therms the buyer could expect to receive an average revenue per therm of mx. His marginal revenue would be well below this, represented by the point d on the MRP curve.

Figure 1.



It is this MRP curve which constitutes the derived demand curve and the average revenue curve from the primary seller's point of view. MR is the primary seller's marginal revenue curve.

7. Under monopsony, the buyer would purchase j units at price c. Beyond that point the marginal cost of gas to him would be greater than the marginal revenue product derivable from selling the gas to a final customer: and since he is a monopsonist he can offer below e for j, since for any price c and above the drillers will deliver at least j therms of gas.

8. The curves in Figure 1 have been drawn so as to allow the clear distinction of alternative quantities and prices. Figure 2 is a more realistic depiction of the situation holding in the case of North Sea Gas at the present time. The Average Revenue Product curve and the Average Production Cost of Gas curve have been left out for the sake of simplicity. The MRP (AR) curve is drawn with a discontinuity showing the transition from domestic consumer demand to the premium industrial market. The MPCG curve is shown as steeply rising, because after a certain point additional gas can only be delivered from given reserves with (a) a more than proportionate increase in the number of initial wells; (b) the danger of well-clogging; (c) rising compression costs. The solution is identical to that shown in Figure 1 with j therms being purchased at price c per therm.

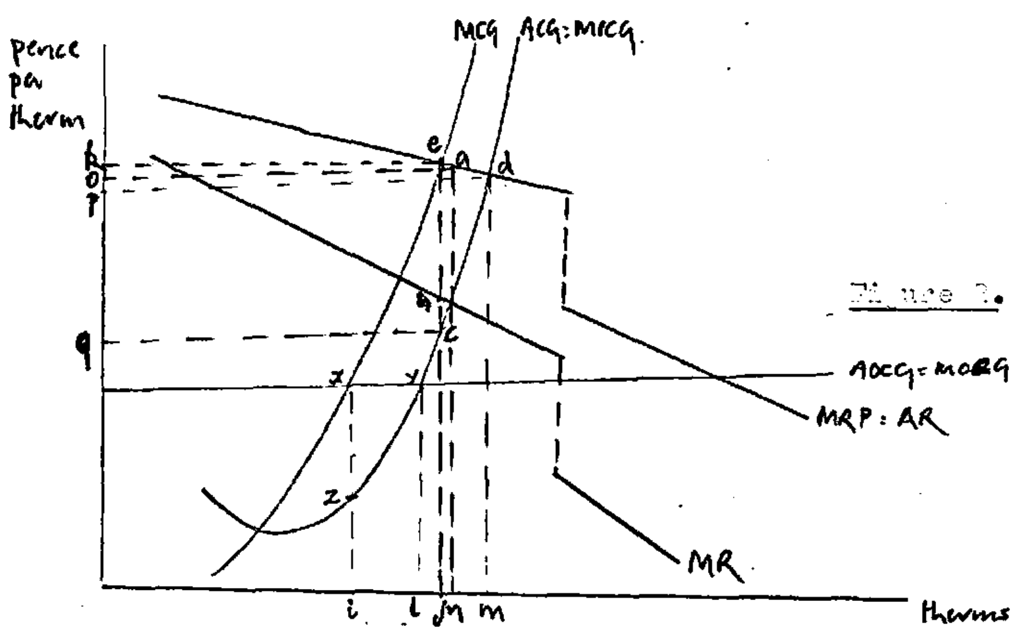


Figure 2.

9. It should be noted in passing that under monopsony there is no single demand curve, for a demand curve is a relationship between price and quantity demanded independently of supply. In the case of monopsony, the quantity demanded depends on the shape of the supply curve (that is to say it is determined by the intersection of marginal revenue and marginal cost). There cannot therefore be an independent demand curve,

just as there is no supply curve under monopoly.

10. The Gas Council have based their arguments on a principle equivalent to monopsonic pricing. We will discuss their support for this principle more fully in the section on economic surplus: it is enough at this point to note that a '<u>supply price</u>' implies a monopsonistic price - though it is often far from clearly specified. A price should be offered which is just enough to elicit the volume required by the Gas Council: the volume presumably being decided according to the point of intersection of the MRP and MCG curves.

11. <u>Cost-plus pricing</u>. A second principle which has at times been confused with that of the supply price by adherents of the Gas Council, has been that of cost-plus pricing. The principle distinction between the two is that while the supply price is based on the marginal production costs of gas, the cost plus price is based on average production costs. In the first case volume and price are interdependent through the supply curve: any price n will call forth a supply o. In the second case volume and price from the producer's point of view become independent: a price which covers average costs including an allowance for normal profit is guaranteed over a range of volumes; volumes are settled independently, in the case of Figure 1 at that point where the MRP curve cuts the APCG curve at g. k therms would be produced at price g.

12. Cost plus pricing is a different form of exchange relationship from what we may call 'arms length pricing'. With cost plus the buyer guarantees a profit, and where he is the sole buyer he determines volume as well. He in effect employs the producer as a contractor, paying him a management fee. There may be strong arguments in favour of such a pricing procedure where there is little information and in particular where risks are unknown. But as with all cost-based prices there is the difficulty of estimating the costs themselves (notably in the allocation of overheads) and on top of this the problem of providing an incentive for the producer to minimise his costs in the process of production.

13. <u>Marginal cost pricing</u>. This is the third cost-related price, and is most relevant to the Ministry of Power. It sets price at the point where the <u>marginal production cost</u> curve cuts the demand curve, that is at d in Figure 1. m therms would then be produced for a price of d pence per therm. The argument in favour of marginal cost pricing is evident from Figure 1. At production levels below m, the marginal cost of producing an extra therm will be less than the marginal benefit derived from it: at m they will be equal, while beyond m further therms will

cost more than they contribute to social welfare. The many assumptions and problems associated with these assumptions are well dealt with in J. de Graaff's Theoretical Welfare Economics, Cambridge 1957, Chapter 9.

14. In contrast to cost-based prices, the drilling companies have argued for those based on what they loosely call 'market principles', but might better be termed 'demand-based' prices. More specifically, the 1964 provisions allowed drilling companies to sell North Sea oil to the final users without any intermediate body as exists in the case of the natural gas. Spokesmen for the drillers as well as some economists have suggested that this provision should apply equally to gas, and that the drilling companies should be free to offer gas to area Gas Boards and to individual industrial users regardless of negotiations with the Gas Council. Superimposing this approach on to the structure of negotiations as they exist can lead to three possible solutions: a monopoly price; a freely competitive price, and an opportunity cost price.

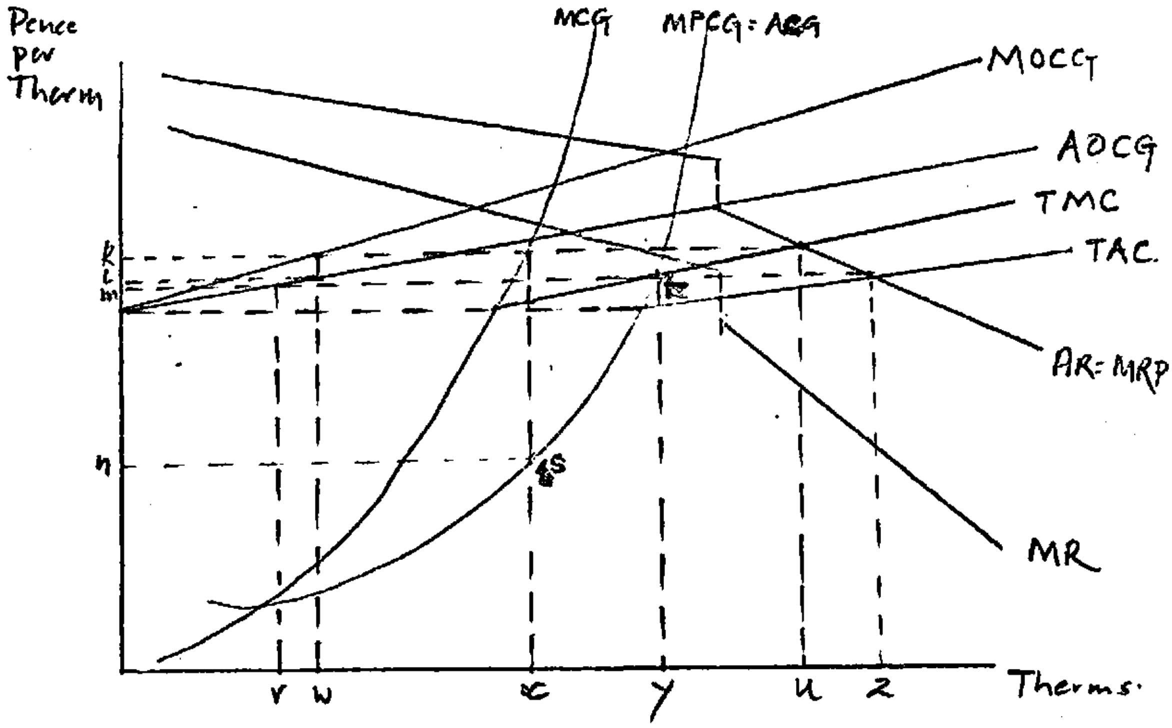
15. Monopoly price. In Figures 1 and 2 the monopoly price is shown as point a, price a pence and volume n therms. At this volume the marginal revenue to the seller equals his marginal production costs, but he charges the buyers the maximum they can pay given the marginal revenue product curve. It is interesting to note that only in the special cases where the MCG curve cut the MRP curve at a or where the MR curve cut the MPCG curve at c would the volumes produced under monopolistic and monopsonistic solutions coincide.

16. Perfectly competitive price. This basis for pricing North Sea gas has been argued most forcibly by Polanyi in his Hobart Paper 'Pricing North Sea Gas'. Price and volume would be determined under perfect competition by the point where supply equals demand, in Figures 1 and 2 at point d. m therms would be produced at price d. This is the same solution as in the case of marginal cost pricing.

17. Opportunity Cost Pricing. The opportunity cost price is determined by the price the Gas Council would have to pay for alternative supplies and could thus be assumed to represent a competitive price if the drilling companies were allowed to compete with the Gas Council for the Area Gas Board and industrial markets. The schedule of the cost of alternative supplies of gas could also be taken as the demand curve for North Sea Gas by the Gas Council, for that portion which is below the marginal revenue product curve. If the cost of alternative supplies of gas is represented by the horizontal line AOCG in Figures 1 and 2, we have two new pricing solutions: i therms at z pence for a monopsonistic situation (since beyond i the marginal cost of North Sea Gas would be above the marginal cost of gas from alternative sources). There is no monopolistic price since over

the relevant range the drillers are facing a horizontal demand curve.

18. In practice the opportunity cost schedule can be estimated to have an upward slope, representing the cheaper alternative supplies from naptha (c. 4½d see Exhibit 13 Table 6) and imported Natural Gas from either Algeria or Holland (c. 5½d. ibid.). In this case it may be profitable to combine supplies from the North Sea with those from other sources. The optimal combinations are shown in Figure 3. This is a repetition of Figure 2, save that upward sloping opportunity cost curves have been substituted for the horizontal in Figure 2. The opportunity cost curves

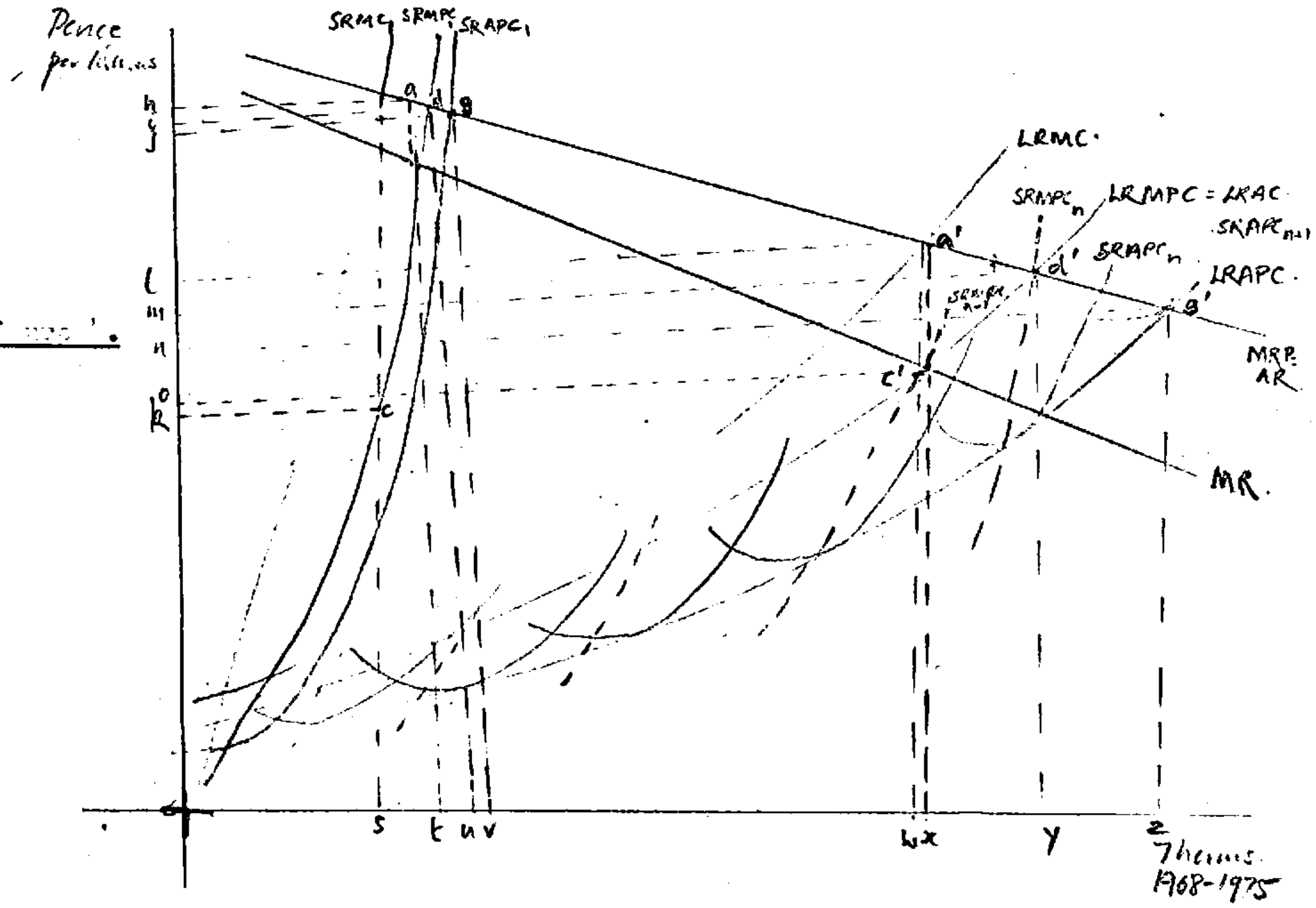


have then been added to the cost curves of North Sea gas, to produce total cost curves. In a competitive situation the optimum total output would be z therms at which point the marginal production cost of gas (the average cost to the Gas Council) would equal the marginal revenue product. Total output would be made up of y therms of North Sea gas and v therms of other types of gas, all provided at m pence per therm. In a monopsonistic situation, total output would equal u therms, composed of x therms of North Sea gas and w therms of other. In this case there would be no uniform price. For North Sea Gas the Gas Council would pay n pence, and for other gases an average of l pence. It is interesting that in the Gas Council calculations as shown in Exhibit 13 they clearly envisage some mix of the kind we have been discussing.

19. To sum up so far, we have pricing solutions shown by the following points on Figures 1 and 3 according to the following pricing principles:

c	....	monopsony
a	....	monopoly
g	....	cost plus
d	....	marginal cost & perfect competition
t,y	....	opportunity cost (perfect competition)
s,z	....	opportunity cost (monopsony).

However, these all refer to the short run: they may be transposed, as some have argued they should be transposed, to the long-run. This is done in Figure 4.



20. <u>The Long-Run</u>. Figure 4 shows the four distinct short-run solutions (excluding for the sake of simplicity the opportunity cost solutions) on the left hand side. The MRP and MR curves have been taken as not changing from the short to the long run: an unrealistic assumption since there may be expected to be an upward shift of the demand curve over time, but for the sake of the points at issue it does not alter the solutions in a substantial way. The Long run average production cost curve is the envelope of the short run ones. The Long run marginal production cost curve is the long run supply curve and the long run average cost curve for the buyer. The short-run solutions stand as in the previous analysis. The long-run ones are based on exactly the same principles and are represented by a', c', d' and g'. It should be noticed that the long-run solutions are also the optimum short term solutions: for example at point d' short-run marginal cost $_n$ = long-run marginal cost = price, the solution to the

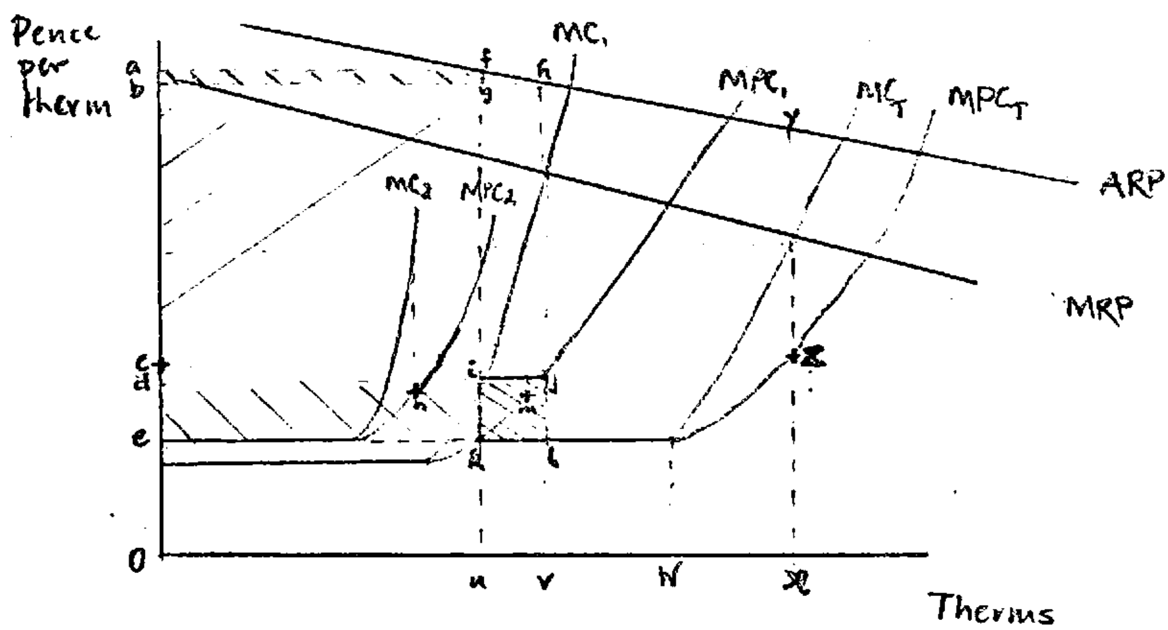
marginal cost pricing problem first proposed by Boiteaux.

21. The Long-Run and Short-Run in Pricing Analysis. The short-run is traditionally distinguished from the long-run by the fact that in the short-run capacity is fixed. There are clearly difficulties in using this criteria literally in the analysis of natural gas: the extent of reserves is not certain and the realisation of what one might think of as the capacity of the field involves fixed investment over time as can be seen from the Figures in the Appendix. Nevertheless the empirical studies of gas pricing have found the distinction useful and have based it on a distinction of the development period from the exploration period. Macevoy's study for example (Price Formation in Natural Gas Fields, Yale 1962) concentrates on testing price data for natural gas against a short-run pricing model, defining the short-run as one "within which it is not possible to establish an entirely new productive facility" (p. 9. n.19.) and taking it operationally for the purposes of measuring concentration as three years: Adelman accepts this with the proviso that it may be a little low: (cf. his The Supply and Price of Natural Gas, Blackwells, 1962, p.9. n.1.).

22. While the distinction can clearly be given an operational significance along these lines for the North Sea it is less easy to see how the alternatives suggested for pricing the gas by the two perspectives can be resolved. Macevoy found the short-term model successful in explaining field price structures. Polanyi normatively suggests a long-term solution for the short-term situation under negotiation, and this has been implicit in a number of the oil companies' arguments.

23. For the Gas Council as an effective monopsonist in the beach market for North Sea Gas, the long-run solution in Figure 4 is w therms at o pence per therm. But to pay o pence per therm for all deliveries of gas may not be to minimise cost. The point is illustrated in Figure 5. Here we assume that there are two fields, the first of which has been developed, as against the second which has not: in addition there is the unspecified possibility of the discovery of further fields. The schedules are as in previous figures, and as in Figure 3, the total cost curves are derived from adding

Figure 5.



the two individual sets of curves horizontally. If the two fields were both simultaneously available for production now the optimal solution would be a total output of x therms at a weighted price of c pence, and individual quantities m and n determined as in Figure 3. But if we assume that the first field is now ready for production, whereas the second field will not be available for production for a year, the optimal position is not clear. New fields may be discovered with supply curves below x pence. Demand may grow and so on. What then can be said of the pricing solution for the first field?

24. Clearly up to u therms, the first field's supplycurve will be continuously below that of the second. For additional amounts of at least vw this no longer holds. Under short-term maximisation, the monopsonist would buy v therms at d pence per therm: selling them at h pence, and earning a profit of bhjd. If he waited a year, however, he could purchase v - u therms at the lower price e from the new field, buying instead from the first field in the current year, u therms for e pence and selling them for a pence. This delay would be worth it if: (abgf + dike) plus the discounted value of gklh was greater than ghij. Whether this was so in fact would depend on the shapes of the schedules and the discount rate. Adding further fields complicates but in no way alters the principles of the analysis. Similar principles will also hold for competitive or monopolistic situations.

25. <u>The Supply Curve</u>. What we can trace in this way is a long-run supply curve (marginal cost curve) based on the least cost parts of a family of short-run supply curves. But there are two particular problems of using the concept of a supply curve for natural gas output: first, the problem of risk and second, the nature of the gas price. In simple analysis any price will call forward a certain quantity of output. For natural gas, however, a price and its relation to previous prices will create an expectation of future prices and this will lead to certain drilling programmes. There is no certainty at all that these programmes will produce given outputs of gas. We might depict the supply curve as rather a smudge, or a family of probability distribution, thus:

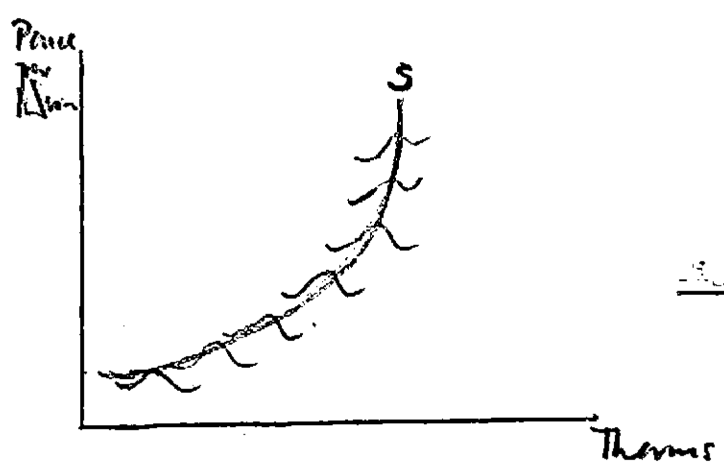


Figure [illegible].

This holds of course for demand schedules as well as supply, and for many other industries than gas drilling: but it is particularly applicable to oil and gas in spite of the improvements in survey techniques.

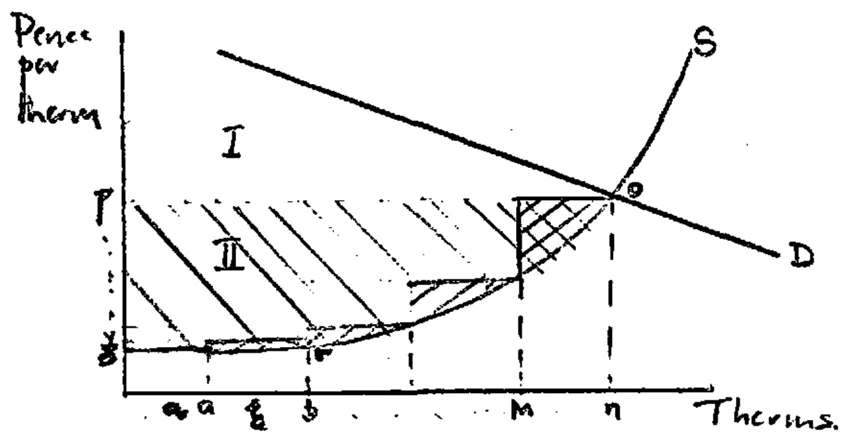
26. Secondly, any one beach price has a double component: on the one hand it has the nature of an operating price, that is to say it is a price related to output of the field under negotiation. The negotiating drillers will have to be offered a price which will cover costs and normal profit on further development and delivery of the field under offer. As can be seen from the Appendix and Exhibit 7 this will tend to be comparatively low. But added to this must be an incentive component for further drilling, if this is is desired, which we may call an incentive price. Two forms of incentive price are possible, the first being a cost plus price calculated on the pre-contract costs of the negotiating party. In this case the total price would be made up of an ex post cost-plus incentive price and an ex ante operating price. Although this might be argued to suffer from the defects of cost plus pricing metnioned above, it might nevertheless be necessary to give such a guarantee in order to encourage further drilling. Alternatively, the incentive price could be an ex ante calculation of the pre-contract costs of the next field: the Gas Council in this case would contract to pay a current negotiator an ex ante operating price relating to the field under negotiation, plus an incentive price which would cover estimated costs and normal profits of the next field under consideration. With a rising supply curve, the first form of inventive price would be lower since the costs to be covered could be expected to be lower than those of the next field. For this reason, and also because a guarantee of ex post costs may be thought to provide a greater measure of security, the Gas Council should favour the cost-plus form of incentive payment.

27. A central assumption of this argument is that both short and long-term supply curves rise in the relevant range. For the short-term the case is relatively clear. With given reserves in place, to increase recovery from say 80% - 90% will require (i) increased well drilling and/or (ii) increased compression costs. For the longer-term, three reasons are commonly suggested for the ultimate upward slope of industrial supply curves: (i) increased output from the individual units each with short-run rising supply curves; (ii) the intorduction into the productive process of increasingly inefficient units of production; (iii) the bidding up of input prices by virtue of an increase in the share of total demand for the relevant inputs as the result of expansion: (see Joan Robinson,
In the case of Gas it is the second factor which is important. One school has argued that natural gas like oil is a decreasing cost industry; that is to say that new units introduced into the productive process are likely to have lower marginal cost curves because of technological developments which serve to reduce exploration, development and delivery costs. But for

any one field, such as the North Sea, the most likely blocs near the Slocheran line received as many as eight applicants while many others received none (see Exhibit 1). We may in principle therefore expect that exploration costs will rise over time as drillers move from the more to the less likely areas in a field.

28. Producer Surplus. We may point the discussion of the last three paragraphs if we see the issue from the Gas Council's point of view in terms of how to capture the maximum producer's surplus. Producer suplus is defined in the usual sense as that revenue accruing to the producer over and above that which was necessary to induce him to supply any given amount. In Figure 7 quantity n is supplied at price p, for p must be paid to induce the production of the marginal unit ^{n}. All previous units would have been supplied at a lower price than p, but the analysis begins by assuming that price discrimination by the consumer is impossible - all units must be purchased at the same price. In certain situations, however, this assumption may be dropped - particularly where, as in the case of Gas, the supply curve extends over time. The Gas Council, as a monopsonist, may effectively divide up the supply curve into sections a, b.... n, and offer different prices z, y .... p, to each according to each one's short run supply curves. If we imagine each section to be a field, we can see how the Gas Council can appropriate a large proportion of the producer surplus, leaving

Figure 7



the cross-hatched area to accrue to the drillers.

29. The size of the steps depends on the speed with which the Gas Council wants to develop the field. If it wanted the whole of the North Sea to be explored simultaneously in order to reach output n in the shortest time, it would have to pay (under the first scheme of incentive pricing) price p. This would encourage existing drillers to bring in rigs from other areas of their international operations, and stimulate inactive holders of unlikely blocs. On the other hand if the Gas Council was willing to space out its purchases over time, it could pay z pence for a therms, y pence for b-a therms and so on.