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PRIME MINISTER

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You are well aware of the present weakness in the oil market and the difficulties which OPEC are having in agreeing cuts in their production. There is the risk of renewed pressure on North Sea producer governments to help by cutting production. BP and Shell have taken action temporarily to reduce production on their own initiative. There may however be pressure on the United Kingdom Government to reduce UKCS output in the following ways:

(i) by imposing production cuts;

(ii) by "banking royalty oil" ie by asking companies to reduce production by the 12½% royalty, saving it up to be produced for the Government at some later date.

For your information a background note on production controls is attached at Annex A. At Annex B there is a copy of a note prepared last year discussing a proposal made by Shell at the time for short-term royalty banking; Shell have recently revived this proposal (see interview with Mr Holmes in the Daily Telegraph for 1 July).

Action on either basis would be limited in scope. Production controls might make it possible to cut back output to the extent of something less than 360,000 bd, 13% of current production. But formally at least 6 months' notice is required, although the licensees might be persuaded to waive this. Royalty banking could be more immediate in effect but its effect on production would be limited to a maximum of 250,000 bd and would need the co-operation of the licensees for its implementation. But although the effect on the amount of oil entering world markets would be marginal, the financial effects for the Exchequer would be substantial. A 13% reduction in output through production controls would cost the Exchequer about £2 billion. Royalty banking up to 250,000 bd would also cost about £2 billion.

Peter Walker
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10 July 1985

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ANNEX A

PRODUCTION CONTROLS

Background Note

1. Under the terms of petroleum production licences oil can be produced only with the consent of the Secretary of State for Energy. A production profile is negotiated as part of the development plan. The Department insists on a stringent interpretation of the requirements of "good oilfield practice" ie minimising risks of damage to the reservoir or of reducing ultimate economic recovery. Operators often seek production increases as development work improves knowledge of the reservoir characteristics, but this is not always agreed; sometimes the consent level is reduced. Consent levels are averages for the period, and there are no controls on daily or monthly production as such. But production has on occasion had to be reduced or shut in in order to remain within the consent.

2. About half of UK production comes from fields covered by short term consents, usually of 6 months' validity. These cannot be varied during their term without the licensees' agreement. Other fields have longer term approvals or consents. In most cases these can be varied after an initial period of immunity, but 6 months' notice must be given, cuts are limited to 20% at most and the SoS must consider any representation made by the licensees on relevant technical or financial matters. A few small fields have long term consents which cannot be varied.

3. In addition to legal constraints, Ministerial assurances have been given on the possible incidence of production cuts. These limit cuts to 20% at most, even where that is not a legal requirement. In some fields, even 20% might damage long term recovery and would not be attainable in practice. Also, all fields are assured of an initial immunity period, typically 4-5 years.

4. Overall it should be possible to impose cuts, on 6 months' notice, to the extent of something less than 360,000 b/d (13% of current production). This might be increased by something less than 60,000 b/d by the end of 1986. The constraints are essentially legal, and are only marginally increased by the assurances.

5. It may, however, be possible to reach agreement with the companies (who have an interest in avoiding large price falls) to accept cutbacks much sooner than 6 months. In particular they may be willing to agree to a deal whereby they accept, say, a 10% cut immediately rather than a 20% cut after 6 months. At this stage, it is only surmise that they may be prepared to agree to such a deal.

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ANNEX B

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ROYALTY BANKING

The Shell Proposal

1. Shell have suggested that HMG implement short-term royalty banking, in order to take some oil off the market to reduce current pressures. They have worked out how this might be done in respect of their own fields, on which the current level of royalty is around 80,000 b/d. They would propose to cut production in the Brent field by 75,000 b/d in August (relative to the consent level: production will be about 60,000 b/d down in any case for maintenance) and by 85,000 b/d in September. Repayment could be obtained by increasing production above the consent level by 27,000 b/d for the succeeding six months, or 53,000 b/d for the last quarter of 1984 only.

2. This note assesses the technical and administrative feasibility of the proposal, and touches on the implications of extending the approach to other UKCS fields and licences. The objections to royalty banking more generally, which would include longer-term banking arrangements where the period of repayment was not necessarily known in advance, were mentioned in the Government memorandum on depletion policy (Select Committee on Energy: July 1982). Royalty banking, it noted, involved certain costs and potential risks for the Government, associated with the lack of incentive for companies to recover the banked oil when fields are in decline; it was not, therefore, an acceptable option.

Technical Aspects

3. Shell are confident that even the higher production rate required for the shorter of the two possible cycles (two months' banking, three months' payback) is within the capacity of the Brent field, topside facilities and pipelines; and that there would be insignificant risk of damage to the reservoir or to long-term recovery. PED agree. The swing in production would also affect gas production from Brent, but Shell have checked that the variation is within the range allowed by their contract with BGC.

4. Shell believe that there is more limited scope to increase production in Fulmar and perhaps North Cormorant, if this were needed because of unexpected problems with Brent. They prefer to accomplish the whole swing in Brent, but the Fulmar and Cormorant possibilities give additional assurance that any banked oil could be recovered.

5. PED have made a preliminary assessment of whether similar swings would be possible in /the other major fields. The general conclusion, which may be slightly modified by the separate examination of BP's proposal to swing Forties and Magnus,

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is that that degree of flexibility is not available in most cases. Maintenance apart, all these fields are planned to produce at or near consent levels for the next 6-9 months, and close to technical capacity. Increases in production to achieve repayment of banked oil would not be possible. (Magnus, which figures in the BP proposal, was not included in this assessment). I suspect that PED have, properly, erred on the side of caution, and detailed discussion with the operators might uncover some more limited scope. But there would be serious objections to production increases in at least three major fields (Ninian, Claymore and Thistle) and there is less scope in Forties, now off plateau and declining, than in Brent. (Shell have said that the present flexibility in Brent will be gone in a couple of years time).

6. It seems safe to conclude that the maximum technical scope on the UKCS, outside Shell/Esso production pivoting on Brent, will be well short of the possibility of banking royalty for two weeks, even if six months are allowed for recovery.

Administrative and Legal Aspects

7. Administrative and legal problems would be minimised in Shell's proposal by swinging only one field, within a single chargeable period, and by the fact that only two companies need be consulted. Except BP (in respect of Magnus and perhaps Forties) any other case would be more complicated.

8. The main administrative problem however does apply to Brent. This is the need to suspend or modify the effects of parts of the model clauses, relating to the taking of royalty. The technically correct form for this is a deed of variation, but Legal Branch advise that an exchange of letters is acceptable, providing it is clear and comprehensive. The problem is that there would be little time to set up these arrangements. We could not be absolutely sure that the alternative arrangements were truly comprehensive, or even that they could be unambiguously interpreted, and we should have to depend on the co-operation of the companies to solve the many practical problems that might be expected to arise. Full commitment of the company to the success of the exercise would be essential, so that we do not run excessive risks of the exercise floundering in disputes or at worst even litigation.

9. In the Shell proposal, we should have to be assured of Esso's commitment, which is lacking at present. But Shell, as promotors of the idea, ought to be committed.

10. If royalty banking were sought from fields more diversely owned, or simply more divided, it would be progressively more difficult to attain a reasonable assurance of the necessary degree of commitment. The extreme would be Claymore with 17 licences ranging from Texaco to Pict, all of whom have some

say in the field. (In Forties the farmors have no effective voice). The risks of relying, even in part, on informal co-operation must be greatly increased in such a field. A similar problem with different overtones arises in Murchison because of the participation of Norwegian licences.

11. In the Shell proposal, all the swings are within a single consent period, so no variation of the consent is needed (the consent is to average production over the period, and there are no explicit controls on the rate for shorter periods). If in other cases the repayment period runs into that of the next consent, there is no obvious difficulty in varying the new consent level suitably (and, where necessary, any flaring consent).

12. Other than in Brent, it might not be acceptable to recover the banked oil in as short a time as three months, and the repayment period would extend into the next chargeable period. This would require still more radical suspension or amendment of the current effects of the model clauses. We have not identified any obviously serious problems in this, but the number of detailed points on which we would have to rely on informal co-operation would be increased, and likewise the risks of divergent approaches or dispute.

13. Shell have an administrative problem of their own. There is a computer programme (BOLS) which allocates lifting rights at Sullom Voe between the Brent system participants. The main programme can cope with royalty banking, but subsidiary programmes, which produce reports on profile of entitlement, royalty schedules and other matters, will not. Quite a lot of manual amendment and re-drafting would be required. It seems more an inconvenience than an obstacle; Shell accept this.

Financial Aspects

14. The main financial impact is on HMG, and appears as extra interest costs through delayed receipt of royalty oil. Shell's proposal is actually royalty banking in Brent, coupled with a production swing in Brent which offsets the volume of RIK taken from their other fields. Shell might propose compensation for the production swing. But they were planning maintenance work in August anyway which would have cut production by an amount conveniently equal to the production swing, and we should certainly refuse compensation for that. If the genuinely incremental cut were taken as being all royalty, the interest cost to HMG is about £1½ m over the five months (average) until the oil is recovered.

15. There are other costs which the companies might seek. HMG pays the companies delivery and treatment costs on RIK, which average around 10% of the value of the oil, and these

are paid pretty promptly on lifting. Shell have suggested that we continue to pay D & T costs even if we bank the oil, as these are largely (80%) fixed costs which they continue to incur. So far as Shell alone is concerned, this could probably be rejected. Since they have suggested that HMG makes a major sacrifice, it is hardly unreasonable to ask them to bear a small part of the cost (around £75,000 extra interest charges). But since Esso are less than enthusiastic, it might be necessary to swallow this additional cost in order to obtain their co-operation; and we should then have to concede to Shell also. This would apply more widely if we seek banking in other fields.

16. As well as bearing most of the cost, HMG would bear most of the risk that the oil price falls and the banked oil is worth less when it comes to be sold. As an abstract possiblity, the time exchange of royalty oil could be made as an exchange of value rather than volume; and Shell expressed anxiety that we would require more barrels if the price fell. The administrative problems would be multiplied many times if we did. As the companies, not HMG, would then bear the price risk, we should certainly lose Shell's co-operation and disputes would be almost inevitable. I think we would have to accept that HMG would take the price risk on the banked royalty.

17. In suggesting royalty banking, Shell were assuming that it could be implemented industry-wide. If, as seems likely from the above, there are only a few cases, including Shell/Esso, where it is technically and administratively acceptable, Shell and the other "possible" companies would be nervous about finding themselves meshed into a different set of legal and contractual relationships with HMG from the companies outside the net. If royalty banking in Brent were regarded as an alternative, for Shell/Esso only, to storage, it would probably be necessary to offer nominal storage charges as well as D & T costs, notwithstanding that the banked oil is less flexible and less certain than the stored oil.

18. If we were to seek implementation of royalty banking on an immediate basis, BNOC would have to unwind its forward commitments on the oil in question (typically six weeks ahead). On Brent, this is not a serious problem, since the oil should be sold to Shell anyway, as RIK sale-back. In other cases, BNOC's practical flexiblity in scheduling liftings should absorb much of the problem but BNOC might in some cases have to repurchase oil, with some risk of additional losses if the market had firmed. There is also a risk of demurrage charges if tankers are rescheduled and miss the appointed slot. The extent of these costs can only be estimated after discussion with BNOC.

Conclusions

19. There are no technical objections to Shell's proposal. Many administrative problems are simplified by the shorter

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of the two repayment schedules proposed. The need to rely at least in part on the co-operation and commitment of the companies involved could be acceptable in this context, providing we have reasonable assurances of co-operation from Esso.

20. Other than Brent, there are few, if any, large fields where the necessary degree or production swing is technically acceptable for short-term banking of this kind. The total scope on the UKCS will fall well short of uniform application of royalty banking, probably much nearer 100,000 b/d than the total RIK flow of 250,000 b/d at present.

21. Even where technically acceptable, royalty banking even on a short-term basis may be administratively unacceptable because the complexity of the licence holding, diversity of interests of the licence holders, or presence of foreign licensees make it impossible to be confident of a sufficient commitment to co-operation and the solving of practical problems. Selective implementation of royalty banking might be unwelcome to the companies in the few cases where it might be acceptable to us.

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