UPSTREAM OIL AND GAS AGREEMENTS

With Precedents

Edited by
Martyn R. David

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THE PRECEDENTS ARE CONTAINED ON THE DISK

PREFACE

In the summer of 1975 my then employer, Occidental Petroleum Corporation, which had just begun the construction of the Piper/Claymore/Flotta system, informed me that I was to be in charge of their North Sea legal activities. I had previously been working on international upstream matters, but I was delighted to have the opportunity to work in such an interesting new area. Many of the agreements which I encountered or which were being developed were quite new to me, and I recall listening with awe to the City lawyers expounding upon the energy finance and gas banking deals they were involved in, and their views on the Labour Party's plans to bring in new petroleum legislation, and other similarly lofty matters. The scales quickly fell from my eyes, however, when it dawned on me that they were only a couple of months further up the learning curve than I was—at that time very few non-U.S. lawyers had any broadly-based experience of upstream oil and gas deals and the precedents we worked from were almost without exception based on U.S. practice.

It quickly became apparent, however, that the simple model-forms used for U.S. onshore drilling, which basically allowed the operator to do whatever he wanted, were wholly inappropriate to the big-money, high-risk environment of the North Sea, where inter-consortium wrangling was commonplace as operators in the early days consistently overran their budgets. The creation by the Labour government of the state-owned British National Oil Corporation and the policy of forcing participation in licences by BNOC had one positive outcome—the creation at the time of the Fifth Round of Licensing of a model-form Joint Operating Agreement. This document became a North Sea standard and remains in use in modified form today. It is interesting to speculate whether the industry would ever have agreed upon a model-form JOA had one not been forced upon it.

The 20 years that have elapsed since those early days have seen the North Sea evolve into an oilfield province which is as advanced as anywhere else in the world, not only in technological terms but in the sophistication of its commercial agreements, which are now commonly employed as international precedents.

It is interesting to note, however, that although the precedents in the second volume of this book are in as close to "standard" forms as possible, so as to be of practical use to practitioners in the energy business, with the exceptions of the DTI's "Model Deed of Licence Assignment" which is appended to the Farmout Agreement precedent, none of them takes the form of a model-form which parties can take down from a shelf, fill in the blanks and sign—oilfield deals are hardly ever that straightforward.

Even those documents which have become partially standardised, such as the Joint Operating Agreement, are subject to pressure for change—in the case of the JOA for example the changing role of the non-operators, who have more to contribute than in earlier days and who wish to participate more directly in operations, will change the form of the agreements—at the other end of the spectrum gas contracts, which invariably occupied the best part of a year to negotiate with British Gas when it was a monopoly, can now be straightforward documents whose basic format is accepted by both parties. A couple of the agreements covered in the book—offshore loading agreements and abandonment agreements—were only vaguely contemplated when the United Kingdom offshore industry was young.

I confidently predict, therefore, that the concerns expressed in the chapters of the next edition of this book, and the precedents that accompany them, will have moved on from those published here, but the two volumes of this book represent the thoughts and practice of the offshore industry as of 1996, and we hope they will be of assistance to in-house practitioners and external lawyers and advisors.

Please note that no precedents are included in respect of Chapters Four and Ten on PSA's and Floating Production Units, in both cases because the possible range of agreements is too broad to make the inclusion of a single precedent appropriate.

Martyn R. David
Editor

Also, please note that the Chapters in this book were all written in mid-1996 and are correct only as of that date.

1.

Joint Bidding Agreements

Alison Huxtable, Head of Legal and Commercial,
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USES OF JOINT VENTURE ARRANGEMENTS

It is worth noting at the outset that in constructing an effective legal framework to support the future operational success of a North Sea joint venture one will need:

(1) a real understanding of the internal and external perceptions of the proposed joint venture and to be aware of the need to address issues which arise in the course of the negotiating process, as a result of differing corporate cultures;
(2) to allocate responsibilities, obligations and liabilities to each participant;
(3) to build in some flexibility to meet changing priorities and economic fluctuations that may affect the operational timeframe;
(4) to define the manner in which the joint ventures objectives will be achieved.

What, then, are these joint objectives? In making their joint application for licence acreage the parties to the Joint Bidding Agreement are seeking to reduce their individual levels of risk, *i.e.* that the risks and liabilities and financial commitments of entering into a licensing round and obtaining licences may be borne in agreed proportions within a small group of like-minded companies with similar aims and objectives. They are also seeking to share the not inconsiderable application costs and to firmly establish their preferred principles of joint venture. We shall presently look in much more detail at these issues when we consider the formation of joint bidding groups.

UNITED KINGDOM PETROLEUM PRODUCTION LICENSING

The system of award of licenses in the United Kingdom was formerly made up on a purely discretionary basis. There is, however, an opportunity for companies to influence at least the choice of blocks on offer in a forthcoming licensing round, since the DTI will formally solicit the views of the companies upon the blocks which they would wish to see feature in the Round. The most recent licensing rounds are that of the 16th and 17th Rounds jointly announced on November 23, 1994 and governed by the Petroleum (Production) (Seaward Areas) Regulations 1988 as amended by the Petroleum (Production) Seaward Area) (Amendment) Regulations 1992.

In June 1995 the DTI announced the introduction of Regulations to implement the EU Hydrocarbons Licensing Directive (the "EU Directive"). The Hydrocarbon Licensing Directive Regulations 1995, the Petroleum (Production) (Seaward Areas) (Amendment) Regulations 1995 and the Petroleum (Production) (Landward Areas) Regulations 1995 which came into force on June 30, 1995 are designed expressly to extend to the United Kingdom the principles of transparency and non-discrimination to the award of licences for oil and gas exploration as set out in the EU Directive.

THE HYDROCARBONS LICENSING DIRECTIVE REGULATIONS 1995

These Regulations establish criteria upon which every licence application after June 30, 1995 will be determined. Previously the practice was for the criteria to be published in the Gazette Notice announcing the licensing round in question. In former times much useful, general information could be gleaned from the Gazette Notices in relation to the licensing round. Applicants would be judged against the background of a continuing need for expeditious, thorough, efficient and safe exploration to identify oil and gas resources of the UKCS, with due regard to environmental considerations. Applicants who already held licences would have their records on exploration and exploitation taken into account.

The criteria now to be applied by the Secretary of State are:

(1) the technical and financial capability of the applicant;
(2) the way in which the applicant proposes to carry out the relevant activities;
(3) in a case where tenders are invited, the price the applicant is prepared to pay in order to obtain the licence; and

(4) in the case of existing licences, any lack of efficiency and responsibility so far displayed by the applicant in operations under the licence.

In instances where two applicants for the same block are perceived to be of equal merit, the Secretary of State may rely on other unspecified relevant criteria to determine which application should be granted.

By the above means it is intended that greater transparency of the licence award process will be assured and likewise by the right of unsuccessful applicants to request to be informed of the reasons for the refusal of their application.

Notices calling for applications for production licences will be published in the Official Journal of the European Communities ("the OJ").

The Regulations go on to address the scope and application of terms and conditions for granting licences, which must be justified upon the grounds of:

(1) ensuring proper performance;
(2) providing payment; or
(3) national security, public safety, public health, security of transport, protection of the environment, protection of biological resources and of national treasures possessing artistic, historic or archaeological value, safety of installations and of works, the planned management of hydrocarbon resources and the need to secure tax revenues.

It follows that all the above terms and conditions must be applied in a non-discriminatory manner.

THE PETROLEUM (PRODUCTION) (SEAWARD AREAS) (AMENDMENT) REGULATIONS 1995 (THE "1995 REGULATIONS")

The EU Directive required a number of detailed revisions to The Petroleum (Production) (Seaward Areas) Regulations 1988 (the "1988 Regulations").

Model Clauses in respect of future licences will omit reference to procedures for uninvited licence applications since this method of award has been deemed anti-competitive within the framework of the EU Directive.

Notices advertising applications for production licences in the O.J. must now specify the date on which applications must be submitted and the date or period within which any licence will be granted. The Regulations also introduce a procedure whereby a licensee may apply for a licence for acreage contiguous to the area held under an existing licence if such can be justified on geological or production-related considerations.

The right of the Secretary of State to seek physical delivery of petroleum in lieu of royalties and the requirement that petroleum be delivered onshore United Kingdom (respectively Model Clauses 13 and 30 of the 1988 Regulations) no longer apply. Both changes confirm recent Government practice and fulfil undertakings given in support of the United Kingdom's application for exemption from the E.C. Utilities Directive.

The 1995 Regulations add to the information required from an applicant. Details to be given now include the place from which any commercial activities connected to the licence operations will be directed and controlled. A corresponding amendment is made to the Model Clause 42 of the 1988 Regulations, which empowers the Secretary of State to revoke a licence where the licensee ceases to direct and control commercial activities connected with licence operations from within the United Kingdom.

FORMATION OF A JOINT BIDDING GROUP

Well in advance of the announcement of the forthcoming round of licensing, the industry will already have begun tentative discussions within loose groupings of prospective candidates for a joint bidding application.

What qualities should be sought in an ideal co-venturer in a joint bidding application?

Doubtless the primary consideration from the exploration department's perspective will be a similarity, in terms of the group's overall strategy and in terms of activity levels. Allied to this will be a wish for a co-venturer's strong technical capability and a prospective co-venturer will be viewed particularly favourably where there is a demonstrable technical knowledge of the group's chosen geographical area of interest and previous success in acquiring licence acreage in the vicinity.

More prosaic, though of equal importance, is a need for financial capability and stability in a co-venturer. This is relatively easy to check through annual accounts though, whilst making interesting reading, they do not truly reflect a potential co-venturer's financial position either necessarily directly before or shortly after the accounts' closing date.

It should also be argued strongly for some consideration to be given to a prospective co-venturer's purely commercial abilities, by which is meant the known ability of the prospective co-venturer, through flexibility and business agility, to respond quickly to changed circumstances and to think creatively to address those changes.

Finally, though it is not suggested that it is quite so important in the North Sea, the question of political capability in a prospective co-venturer should also be briefly mentioned. This refers to political capability in the sense of absence from any pressure from the prospective co-venturer's national government being brought to bear in an attempt to influence decisions or in

some other manner restrict the actions of the co-venturer inconsistent with the agreed objectives of the co-venturing group as a whole.

Further information will need to be obtained from the exploration department before embarking upon the drafting of the Joint Bidding Agreement documentation. The following matters will probably already have been discussed as between the explorationists and some measure of understanding reached as to the best means of progressing. They concern:

Data

Have all the proposed parties to the Joint Bidding Agreement agreed to exchange technical information and, if they have, has a Confidentiality Agreement been signed? It is fair to say that data acquisition has changed over the later Rounds and the exchange of information has become less of an imperative for many companies. This is probably simply a function of the growth in their own data bases over time. 3D seismic is just beginning to make an impact on trading activity and the companies shooting speculative surveys will doubtless in time be responsible for providing 3D surveys of all prospective open acreage. Also, it is worth mentioning that greater levels of co-operation now exist between groups owning adjacent licence acreage which has resulted in a more ready sharing of information to the benefit of the data bases of both groups.

There remains a view that it is important to exchange information under a separate Confidentiality Agreement for the simple reason that there is a possibility that the formal licence application may not be made and the bidding agreement negotiations are left unconcluded and thus the disclosed data left unprotected.

What are to be the agreed percentages of participation in the licence application? It is these proportions which determine, for the future of the joint venture arrangements, the proportions in which expenditure, liability, benefit and risk are going to be borne as between the parties. It is frequently the case that the co-venturer be nominated as operator will hold the largest percentage interest share. The agreed percentage interests will not be separately identified in the licence as eventually issued by the Department of Trade and Industry for the licence simply establishes a joint entitlement on the part of the licensees as a group, but notes that "any obligations which are to be observed and performed by the licensee shall at any time at which the licensee is more than one person be joint and several obligations".

Work Programme and Budget

It is the responsibility of the operator to produce a work programme and budget for the evaluation and application process and, through the voting passmark, it will be determined what level of approval the parties consider to be appropriate for the making of all decisions connected with the licence application.

Area of Mutual Interest

As this may cover a number of blocks, one needs to reach agreement upon the operatorship for each of the blocks were any of them subsequently to become the subject of an award of a licence. It is perfectly practicable to nominate different operators for different blocks, for example, where acreage borders existing licensed acreage which may be said to be more within one co-venturer's area of expertise than another's.

When sufficient clarity of purpose emerges in response to questions upon any proposed joint bidding application, it is then appropriate to commence work upon the detailed drafting of the Joint Bidding Agreement. In the past the AMI Agreements have covered an area of mutual agreement which does not expressly relate to a specific licence round. Instead the agreement was kept in continuing effect as between the original signatory parties, so that whenever acreage, within the widely delineated area of mutual interest, was offered under a licensing round, then the signatories to the AMI would review the acreage upon offer and assess whether they wished to make an application in respect of any of the blocks.

However, the current and preferred practice is to provide for a bidding agreement to apply only for the purposes of the then current round of licensing, though this is not to discount the importance of existing AMI arrangements, which it may be necessary to research and which may dispense with any need to develop a Joint Bidding Agreement.

THE JOINT BIDDING AGREEMENT

At the outset the Agreement will set forth the numerous definitions that will be employed throughout the text of the Agreement. These will include a clear representation (whether pictorially or by co-ordinates) of the Area of Mutual Interest. Other terms to be defined will be the meaning of Affiliate, Application, Block, Closing Date, JOA, Joint Account, Licence, Operator, participating Interest, Secretary of State, Wilful Misconduct and a host of lesser items.

The Agreement will then set out a list of participating parties, together with a note of their respective participating interests, which, as we have mentioned, reflects the proportions in which each of the parties will bear the expenditures under the application arrangements and further in which each will hold a participating interest in the subsequent JOA in the event of a licence being awarded.

Early in the Agreement the parties will provide not to apply with other groups or alone for a block within the defined area of mutual interest. Occasionally the insertion of an express warranty is seen, given by each party that it is not party to any other agreement governing the area of mutual interest, which limits their freedom to enter into the joint bidding arrangements now under consideration.

Commonly there follows a provision which names the operator. However, it is also necessary to provide for the circumstances where the nominated operator declines to participate in the formal application and the responsibilities of the operatorship must then devolve to another participating party who does support the chosen application.

Provision will be required to be made for the length/duration of the Agreement. Frequently this is addressed by reference to a date that is the later of:

- (i) the date when it is agreed that no applications are to be made by members of the joint bidding group for a licence;
- (ii) the date on which the joint bidding group is notified by the Secretary of State that their application has been unsuccessful;
- (iii) the date on which the block(s), in respect of which the joint bidding group made an application, is awarded to a third party in the licensing round; and
- (iv) the signature of a Joint Operating Agreement in the event of a licence award.

It is worth mentioning at this point that the Joint Bidding Agreement, pending the signature of a Joint Operating Agreement, will frequently represent the only formal agreement between the parties governing licence operations following the award of a licence and remain in existence for some considerable period of time. The Joint Bidding Agreement should recognise, through appropriate drafting, the reality of this state of affairs, seeking to provide text of sufficient detail to assist those charged with the implementation of its terms for limited licence activities which will legitimately take place in the first years following the award of any licence.

In order to promote workable processes and systems for the conduct of early operations upon the licence acreage, a formally enshrined management forum is required, comprising a representative of each participating party empowered to make all decisions with regard to the conduct of joint operations. Each party will have a vote in accordance with its participating interest. The manner in which the decisions will be made is determined by the agreed voting passmark. As a general rule, a considerable measure of consensus will be necessary and it is desirable to optimise the opportunities for a successful award of a licence. Almost certainly, a 100 per cent affirmative vote will be necessary to support the decision for eventual application for the hoped-for block(s).

The central core of the joint bidding agreement is the application itself and the process of elimination by which that stage is reached.

All the parties, having undertaken a measure of their own evaluation work, will meet to consider the work programme for the group. In broad outline the technical evaluation process could be described as exhibiting frenetic activity at the earliest meetings; thereafter, a middle stage where the meetings are fruitful, more relaxed and relatively free from anxiety. By the final stages the difficulties may become apparent, in that every participant in the group may want to apply for some block(s), but that no two participants agree to apply for the same block(s), and the final stage when this attitude/resistance is overcome and eventual selection of a preferred block(s) is made, accompanied by general feelings of relief.

As we have indicated, the principal difficulties experienced in the practical sense stem from proposals put forward as to preferred blocks and the work programme, be it merely seismic and/or the drilling of wells (whether contingent or obligatory), meeting with less than unanimous support. If there is less than unanimous support for any proposals made at a meeting, then a vote will be taken to determine which of the proposals carries the greatest support amongst the group as a whole. In the event that both proposals carry equal support, then it is normally the proposal which would represent the most financially onerous obligation upon the group that will be selected. Quite what constitutes "financially onerous" can itself create problems. For example, assume that, one party proposes two shallow wells and some seismic and another proposes one shallow well and one deep well. It may be that the true issue is whose estimate of the financial consequences is to prevail—provision may need to be made for this.

Having identified the proposal which commands the most support, then any dissenting party will have to elect either to join the application or to withdraw. Should the dissenter decide to withdraw, then his interest must either be absorbed by the participants wishing to continue or, if they are not willing to increase their level of exposure, then a "third party" will have to be found to meet the shortfall.

In these circumstances, the legal advisor will want:

(i) to ensure that the new party joining the group at this juncture will do so on the basis that it accepts the terms of the Joint Bidding Agreement as (hopefully) agreed by all the parties without the introduction of new or varied documentary requirements.

(ii) there will be a wish to see this new entrant bound to pay a proportion of the costs incurred by the parties prior to the date of its entry in respect of the block covered by the application. However, particularly where the substitutions are very late in the proceedings, this may not be a very realistic proposition.

If a party decides to withdraw from the Joint Bidding Agreement, then that party has clearly been privy to the exchange of information and data, and

thus it will be necessary to provide that it will not be permitted to make a competing application for the same block either by itself, through an affiliate or with another group. It is not uncommon, with the approach of the closing deadline for applications, for a number of groups to break up, unable to agree upon an application.

The drafting of all of the above provisions varies both as to length and relative complexity, but neither length nor complexity is any substitute for the goodwill of the parties to the application which plays a large part in a successful venture if a licence is subsequently awarded.

Following the submission of an application to the DTI, groups of potential licensees are called in for interview—the "call-in meetings". The operator will give a technical presentation of the acreage applied for and so ensure the understanding of the overall regional geology. These meetings are considered to be well-organised, there is a genuine dialogue with DTI representatives and a better continuity of staffing at the DTI than formerly, which contributes to increased understanding. It is at the call-in meetings that the DTI, where appropriate, may seek to persuade parties to increase the level of licence activity indicated upon their application to obtain a licence. In anticipation of such a move, a more sophisticated bidding agreement may make provision to agree upon a level of work obligation slightly above that offered in the formal application papers and which may be held "in reserve" for use in the call-in meeting. However, it may be that the requirements of the DTI by way of work programme exceed the willingness of a party or parties to secure the block in question. In the event it is merely one party who cannot meet any increased obligation, then the remaining group members may be prepared to absorb the additional commitment in the event of that party withdrawing, since it will not be practicable to obtain a new entrant to the group at that juncture.

If the group are fortunate and secure a licence award, there will be a need to negotiate a joint operating agreement. This process may be assisted by setting out in the Bidding Agreement a few key principles for subsequent inclusion in any joint operating agreement.

Occasionally, in the past, parties did negotiate joint operating agreements in advance of the award of a licence. My own view is that this approach is impracticable and amounts to a tremendous waste of resource in the event the application is unsuccessful. However, inclusion of a limited number of agreed matters for use in the subsequent joint operating agreement, is beneficial. It is suggested that the following issues should be tackled:

(i) Removal of operator—either on the unanimous vote of the non-operators or only where the operator is in material breach of its obligations.

(ii) Contractual thresholds above which the operator must obtain competitive tenders and also obtain operating committee approval for the letting of contracts.

(iii) Voting passmark in the joint operating agreement, together with any provision as to whether any one party should have a right of veto.
(iv) Whether to permit any party to non-consent on any non-obligatory work programme and budget at the AFE stage.
(v) Whether deemed approvals of AFEs are to be permitted, which, whilst of great administrative benefit to the operator, can create difficulty for companies anxious to control cash flow.
(vi) Pre-emption rights. An opportunity to decide whether the parties are willing to allow freedom of assignment or whether pre-emption rights are appropriate to the particular circumstances of the group.

This list is not exhaustive, but the difficulties one might encounter in seeking to agree its terms are probably indicative of the difficulties to be experienced in concluding the joint operating agreement at a later stage.

The Joint Bidding Agreement must also provide for circumstances where one of the parties fails to meet its proper share of the costs, and this will usually mean that the other parties must be obliged to make up the shortfall brought about by the defaulter's regrettable lapse. Further, after an agreed time the defaulting party must lose its participating interest.

Remaining clauses will include a confidentiality provision to apply to all data acquired during the joint operations contemplated under the Agreement. Freedom of disclosure will frequently be permitted to affiliates, consultants and banks, provided they, too, agree to be bound by the undertaking of confidentiality.

Finally there will be a shortened form of a force majeure clause providing relief in certain circumstances, a Notices clause and a governing law clause.

Attachments to the Agreement will be:

(i) An illustration of the area of mutual interest.
(ii) A statement of costs anticipated to be incurred until the closing of the round.
(iii) A short-form Accounting Procedure.

CONCLUSION

This chapter has examined the use of the joint venture arrangement to meet the needs of North Sea co-venturers and has touched upon the United Kingdom petroleum licensing regime. It has considered the attributes of the ideal partner and drawn the outline of the agreement needed should those ideal partners be found.

The Joint Bidding Agreements are important agreements developed at the formative stage of a relationship with chosen co-venturers. Time spent on

crafting a strong but flexible Joint Bidding Agreement will be amply rewarded in the first year of licence activity and possibly thereafter, in the absence of an agreed Joint Operating Agreement.

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Joint Operating Agreements

Sandy Shaw, Legal and Commercial Manager, Lasmo North Sea

INTRODUCTION

If the Joint Operating Agreement forms an alliance similar to a marriage, it is likely to have 16 parties: four richer, four poorer, four better and four worse. Operating Committee meetings are likely to be more like a nightmare than a honeymoon!

This chapter will deal with the nature and content of the Joint Operating Agreement (or JOA). Whereas the Licence sets forth the rights and obligations of the parties *vis-à-vis* the Government, the JOA sets out the rights and obligations of the parties amongst themselves. It is the bedrock of operations as it sets forth the framework and detailed rules upon which the Joint Venture will operate.

All of us in the oil and gas industry are, or must be, familiar with the concept, contents and operations of and under Joint Operating Agreements. We recognise that, not only may we be charged with negotiating JOAs at the start of the Joint Venture's life, but that we are then responsible for living with the consequences and within the confines. Unlike many documents which are executed and then consigned to a shelf, the JOA is in constant use.

The JOA itself can be compared to a form of marriage. The partners agree to "have and to hold in accordance with the terms of the JOA until termination, withdrawal, assignment or default do us part." Much like a marriage the arrangement is consensual. Gone are the days of the shot-gun marriage to BNOC (and its successor the OPA). The parties enter the agreement to work towards joint ends. They bring with them conceptions (sometimes differing) of the way in which the marriage will be conducted. Unlike most marriages, however, the parties to a JOA write down the rules of conduct they wish to apply. These rules must last for a very long time—the life of the licence—and apply to a wide scope of activities. It is, therefore, surprising that JOAs are, compared to the average gas sales or transportation agreement, relatively short. This may be attributable to the fact that, whilst a JOA is intended to be comprehensive, it cannot cover all issues and should, therefore, be a flexible, interactive framework that allows for evolution.

Having said all of that, if JOAs are so necessary and so common, why doesn't the industry adopt standard agreements and forgo the necessity of long and difficult negotiations between the parties? There is a lot to be said for standardisation. It would cut down on legal and commercial costs early in the formation of the joint venture. It would lead to agreed standards of operations and known interpretations of complex clauses. However, it would not necessarily cater for the various needs of the parties in differing circumstances, the differing (and often antagonistic) concerns of the parties and the desired balance of powers between the players.

In practice, standardised formats are (and have been) used as a basis for negotiation in the industry. The BNOC proforma is one (and perhaps the major) historic basis. However, a JOA which completely conforms to its terms is unlikely to be bound, especially as, being quite an old document, it has now been superseded in complexity. Today, there is also (*inter alia*) the International Model Form Operating Agreement (which is not much used in the United Kingdom), and each major operating company (and even some of the smaller companies) will also have their own standard document. So, if only initially JOA negotiations will continue to be a challenge.

Rather than rattle through Articles 1 to 30 (plus) of a standard JOA, this chapter will focus upon several main areas of the JOA conceptually, without regard for where or how they are necessarily expressed within the document itself. First, the scope of the agreement and relationship of the parties will be considered; then the administrative and procedural aspects of the document which provide for the protection of operational interests, the protection of the equities of the parties will be reviewed and finally the remaining provisions covering miscellaneous issues.

SCOPE OF AGREEMENT AND RELATIONSHIP OF THE PARTIES

The Duration and Scope of the JOA

The JOA takes effect after the Licence is awarded. In most cases, the bidding Agreement between the parties will have included "heads" or key points to be included in the JOA if the bid were to be successful. In some cases, the parties will have also agreed to the JOA format, perhaps having participated in other licences together. Where the parties proceed to negotiate the fully termed JOA after Licence award, there may be myriad problems and delays. The Bidding Agreement is not appropriate for confirmed operating activities and it is therefore ideal that execution of the JOA occurs quite quickly after

Licence award, with an effective date at or closely following the date of the Licence.

The intended scope of the JOA is to cover all joint activities from the Licence award to the termination or surrender of the Licence and the abandonment of all joint property. It, therefore, formally creates the Joint Venture, sets up the Joint Account, enables joint exploration, appraisal and development of acreage and provides for the satisfaction of licence obligations. It deals with production and liftings entitlement and (usually) enables joint transportation and processing efforts.

The JOA scope may be wide enough to enable use of joint property for third party services (such as transportation and processing) and may include detailed provisions for abandonment of facilities. The scope clause is usually widely drafted to allow the parties to pursue joint operations to mutual aims and benefits.

The JOA will not deal with:

(i) Joint sales of production: this is the making of the ultimate profit and is left for the individual participants unless other agreements are entered into. This is so, even where the parties enter into parallel gas sales agreements, and the like.

(ii) Unitisation: this again is subject to further agreements with other parties and is the subject of a separate chapter in this book.

(iii) Onshore facilities: especially in relation to ownership or leasing of land, terminal facilities and the like, although this can be catered for by supplemental agreements where the development is necessary to the field development and is to be owned as joint property.

Relationship of the Parties to the JOA

1. *The Joint Venture Concept*

The JOA creates a joint venture between parties acting in concert for mutual benefit. "Joint venture" is not an English term of art. In form and intent it resembles a partnership, but specifically by the terms of a JOA it is invariably clearly stated that no partnership is created. Much has been written about the differing nature of the joint venture and the partnership. The significance of the difference has legal consequences as well as possible tax effects and can also affect the concept of the fiduciary relationship between the parties. Suffice it to say, the weight of argument and industry belief is that a joint venture does not create a partnership.

2. *The Interests of the Parties*

Unlike the licence, which does not segregate any percentage interest and is joint and several in nature, the JOA's first and prime function is to distinguish the varying interests of the parties. The percentage interests will determine each party's entitlement to ownership and benefits, and liability to cost, expense and risk. It will also determine its right to vote which is critical in the day to day running of Joint Operations.

3. *Liabilities of the Parties*

The premise of the Joint Venture is to share liabilities and benefits in accordance with each party's interest share. In certain cases, as in default, that liability can be increased pro rata to the interest share.

The liability will be clearly stated. The norm is that liability is several and not joint. This of course applies in relation to the parties themselves and cannot affect dealings with third parties and under the Licence in which the obligations of the parties will almost invariably be joint or joint and several at Law.

The sharing of liabilities will be backed up by indemnities in which the parties undertake to indemnify and hold harmless each other for claims, liabilities, (etc.), to the extent of their percentage equity interest. The intent of these clauses is to ensure that each party is fully and legally liable for its percentage interest share—and only its percentage interest share.

4. *The Operator*

In order to run the joint venture efficiently, the parties will appoint an Operator to act on their behalf. The Operator will take on the role on the basis that it reaps no gain or reward and suffers no loss in doing so. There are, however, intrinsic benefits to being the Operating party. The Operator will be the motivating party in taking the work forward by proposing budgets and plans and running meetings. It will also act as the agent of the parties in relation to third parties, including government liaison with the consent of the other parties.

The Operator is usually a party to the Licence (although this is not required) and is usually the party with the largest interest in the Block at the time of appointment, although this is also not a requirement. Despite the DTI's limitation (in the Licence) of appointing an Operator for the exploration phase only, the Operator is usually appointed for the duration of the JOA and must, of course, be approved by the Secretary of State for Trade and Industry.

There will be provisions in the JOA for removal of the Operator and this

is one area in which the views of the parties during negotiations are likely to differ. The Operator will want to limit removal provisions to those requiring cause, *i.e.* default or wilful misconduct, and will want any vote for removal to be unanimous (or as close as possible thereto) amongst the other parties. The other parties on the other hand may seek to be able to remove the Operator for no reason and/or on notice, thus avoiding default arguments and gaining flexibility and bargaining strength.

There will also be provisions for Operator resignation and selection of a replacement Operator, handover, payment of costs and the like. Common industry practice is that the reasonable cost of handover between Operators is charged to the Joint Account, although it is beneficial to clarify this within the document.

There is a growing trend in delegating major operating functions to contractors in an effort to reduce operating costs and overheads. At present, JOAs do not tend to deal in any detail with contractor-operator situations. In cases where contractors' services are used for day to day operations, the parties will expect to be fully consulted and consent to such arrangements and to any JOA amendments that may be required.

5. *Operator's Additional Liabilities*

As a party to the JOA, the Operator has the same liabilities as the other parties; *i.e.*, its percentage interest share of joint obligations. The Operator, however, also acts as the agent of the JOA parties and according to the JOA will owe a duty of care to the other parties in its capacity as Operator. The duty is usually defined as that of a Reasonable and Prudent Operator: a term which is defined within the JOA. Providing that the Operator acts in accordance with this standard and since the Operator does not seek to make a profit or charge a fee for performing as the parties' agent, it is generally accepted that it should be individually responsible only in two situations:

(i) "Wilful Misconduct": This concept is not known in English law and must therefore be defined within the JOA. There are numerous well-used definitions which universally include intentional, conscious or reckless (but not generally negligent) acts, but much negotiation will be had around the fringes, *i.e.* whether or not or to what extent prudence, foresight and prevention must be applied.

(ii) Failure to maintain insurances which are required by the Operating Committee in accordance with the JOA: a situation which is seen to put the joint property at risk and is considered to be entirely within the Operator's control (although this could be debated in certain instances). It is also generally accepted that the Operator will not be liable for consequential losses such as loss of production or profit.

ADMINISTRATION AND PROCEDURE: PROTECTION OF OPERATIONAL INTERESTS

Having determined the relationship of the parties, their relative interests and the appointment of the Operator to act on their behalf, the next major JOA concern is administrative provisions for the handling of operations and for the protection of the parties' ongoing interests.

Supervision of Operator

One major means of controlling operations is by supervision of the Operator. Administratively and operationally, as already indicated, the Operator is the moving force in most JOA activities in so far as it is obliged to present budgets and plans, to call and chair meetings and to act on behalf of the parties. Its authorities are, however, limited by the split of powers between it and the Operating Committee pursuant to the terms of the JOA.

The Operating Committee is comprised of members from each of the parties. Representation is equal regardless of the percentage interest held by the parties. Usually there is one primary Operating Committee Representative and his/her alternate, but members can invite other attendees. The Operating Committee will appoint sub-committees to deal with specific subject areas and address issues in more detail. Examples are Technical, Commercial or Reservoir Sub-Committees. Much of the real work of operational decision making is done at sub-committee level and ratified at Operating Committee level.

The Operating Committee has the overall responsibility for supervising and controlling JOA activities; making decisions on policy; agreeing programmes and budgets and drilling proposals. A list of the Operating Committee's powers and duties will usually be listed in the JOA along with a "catch all" or two to ensure that everything is covered.

The Operating Committee will act in accordance with the passmark for voting. Passmark is another area where the parties' views will differ during negotiation. The party with a large percentage interest may seek a high passmark to ensure that its vote is necessary to gain approval of or can be used to block any decision. If that cannot be achieved, it may seek a lower passmark in which its interest is critical to achieving a successful vote. The other parties, especially if they have small interests, may seek some protection to ensure that one or two parties can neither prevent nor require action.

Passmarks may also differ for different phases of the work, requiring lower passmarks for exploration and appraisal than developments, for example, especially where the exploration work may relate to licence obligations. Also, some decisions, like relinquishment of Licence can only be made unanimously

and for critical decisions, like surrender of parts of the Licence Area, fall back provisions may be necessary to ensure that the decision can be reached.

To enable the Operating Committee to make decisions, the Operator must keep the Operating Committee fully informed, for example by providing Operating Committee representatives with relevant reports and data. To protect the right to information, the parties also reserve rights of inspection and access to joint facilities. Of course, for major decisions the Operator will liaise with the Operating Committee, with one exception, the Operator will have unlimited authority to take any necessary actions in emergency situations, subject to justifying these to partners thereafter.

Control of Expenditure

Another major means of controlling operations is by control on expenditure. To revert to my comparison to a marriage, the JOA parties will have covenanted to share "all their worldly goods", at least in relation to the Joint Venture. The parties will each be liable for payment of their respective percentage interest share into the Joint Account of all sums which may properly be payable under the Licence, the JOA or any relevant law.

Whilst this does not apply to royalties (where royalties may still be applicable) it applies to the remainder of all Joint Operation funding and, as in a marriage, is an area for negotiation of control.

1. *Programmes, Budgets and Approvals for Expenditure (AFEs)*

Control of expenditure is achieved through the procedures established to agree programmes and budgets, and subsequent release of approved funds. The Operator will have the delegated authority to implement all agreed programmes and budgets. Hence, the approval of programmes and budgets is of key importance to partners in controlling operations and their exposure to costs.

Programmes and budgets are usually agreed annually. Different provisions will often apply to exploration, appraisal, development and production phases of the work and this is worth a quick explanation.

(i) In relation to the exploration phase, for example, the budget and plan is usually proposed on an annual basis only and fall-back provisions will be included in case the parties are in deadlock and unable to reach agreement regarding the completion of licence obligations within the requisite Licence time frame.

(ii) Development budgets and plans on the other hand are proposed for the entirety of the development; the plan determining the duration for the development.

(iii) Appraisal programmes fall in between these as in practice all appraisal necessary before development will not be agreed in one programme.

(iv) Production programmes revert to the annual pattern.

The budget in each case usually comprises two sections: the capital budget, *e.g.* for drilling or development costs, and the operating budget, *e.g.* for manpower and overheads. It is common to acknowledge that both the budget and the programme may require amendment.

Another level of cost control is also incorporated: the concept of the AFE. Once a budget has been approved, approval of the Operating Committee by way of AFE of specific activities and/or major commitments may be required. For each of the different budgets, the anticipated expenditure level at which Operating Committee consultation is required may vary. As the budget is very much a forecast of spending, the ability to review expenditure by way of the AFE is of value to the non-operators in controlling the way in which available funds are committed and limiting the Operator's discretion. On the other hand, the non-operators should not be allowed to delay or prevent operations pursuant to an agreed programme and budget by unreasonably manipulating the AFE procedure. Hence, the requirements for AFE approvals etc. is another area of negotiation. In most JOAs approval of the AFE is subject to the same passmark as the original programme and budget, although some JOAs provide for deeming of approvals unless a specified percentage of negative votes is received.

2. *Further Limits on the Operator: Contracting Approvals*

In addition to the budget and AFE limitations, the Operator will usually be required to conform to specified requirements regarding contracting. This can include a requirement that the Operator seeks competitive tenders and sealed bids, does not use its affiliates to perform operations without Operating Committee consent, liaises with the Operating Committee on terms of contracting and choice of contractors, etc. Specific monetary levels will also be set above which the Operating Committee may be required to agree contract award. Again this is an area of difference between the Operator, who will want to have a large amount of flexibility and a high enough limit for contracting to enable it to "get on with the work" and the other parties, who will want to maintain a degree of input and control over contracting both in respect of contract terms and contractor selection.

With the trend towards multi-venture contracting, shared facilities and the contracting-out of traditional operator services, the more usual provisions on contracting may not be sufficient. In negotiating new JOAs or in going forward with changes in methods of operations, one should be aware of how the contracting provisions will apply and whether the non-operators will be sufficiently protected and informed.

3. *The Accounting Procedure and Rights of Audit*

Control is also exercised over operations through the use of the Accounting Procedure, which will form a part of the JOA. It is a critical facet of the JOA and will demand as much time in negotiation as other key aspects. The purpose of the Accounting Procedure is to establish and detail the workings of the Joint Account, determine what costs the Operator may charge to the Joint Account and how they are calculated and to ensure that generally accepted accounting procedures are adhered to. The intent is that the Operator should neither gain nor lose by reason of its acting as Operator and running the Joint Account. Areas of contention include level of contingencies to be built into budgets, overheads (generally) and parent company overhead (or PCO), redundancy costs, etc. The parties should attempt to clarify the nature and type of items that can be legitimately included, especially in relation to extraordinary items like bonus, share schemes and office relocations. Other areas that should be covered include record-keeping, reporting, and inventories.

The right to audit will be preserved within the main JOA provisions and is an important longer term protection for partners. The Accounting Procedure will generally secure the audit right and provide details on the handling of the audits and any resulting claims.

Consideration should be given here to the use and handling of multi-venture audits, which have become fairly common. Those audits may uncover questions and claims that affect several joint ventures, with allocation of costs and benefits as well as the administration of bringing and enforcing claims being more complex.

Insurance and Litigation

Moving away from cost control, the JOA also provides other operational protections in securing the joint venture and protecting it—the insurance and litigation provisions.

There are two categories of insurances which are the subject of the JOA: those required by law and those which are desired by the joint venture.

1. *Insurances required by Law*

The Operator will be obliged to carry insurances required by any Act, by the Licence or by applicable law. Generally, legally required insurances apply only in relation to employee-related insurances held by the Operator and reimbursed by the joint account. Also, all Operators are required by the DTI to become party to the Offshore Pollution Liability Agreement (OPOL) which provides for liability in the event of pollution damage and clean-up. The JOA will, therefore, also deal with the Operator's obligations as to membership and compliance, and with the non-Operator undertakings, the handling of claims, etc.

2. *Optional Insurances*

The Operating Committee may also agree to carry certain other insurance cover for the benefit of all or some of the parties. This may be so, for example, in relation to drilling, construction or production insurances. The most usual insurance to be carried jointly by the parties is Construction All Risk (CAR) to cover the construction and installation of joint developments from design and installation through the warranty period. Most companies will carry their own general business cover, but will be required under the JOA to evidence that cover in lieu of participating in joint insurance programmes.

The litigation provisions of most JOAs are usually fairly straightforward. The Operator is required to notify the parties of any incidents which could give rise to litigation and of any claim, litigation, lien or demand, etc. The Operator is usually given a mandate to settle claims and litigation to a pre-agreed limit (generally at a fairly low level) and to take any steps to prevent a judgment being entered in default or to contest jurisdiction.

There may also be provisions specifically ensuring that in relation to contractors, so as to avoid multiplicity of litigation, claims are only made by or through the Operator and (as part of the contractual terms) against the Operator.

Where the joint venture wishes to take a matter to litigation (as opposed to defending a claim) the parties will invariably have to be consulted and may or may not seek to have the Operator represent them.

Non-Consent and Sole Risk

The last area which may be considered as protection of operational interests, is that of non-consent and sole risk.

As has been noted, the main method of control of operational interests is through the Operating Committee, which controls the direction of activities by passmark vote. The passmark, however, cannot protect all the varying interests. Parties with small percentage interests will not want to be voted into activities which they may not support or may not be able to fund, whereas parties with significant interests in the block may not want to be prevented from developing the asset because they cannot pass the voting hurdle. Two methods by which the parties can protect their interests further are by the use of a Non-Consent clause and/or a Sole Risk Clause.

It is not unusual to find both of these provisions in a JOA. Both allow, in

certain circumstances, for activities to be undertaken by some (and not all) of the parties, thereby splitting the interests of the group in relation to the acreage. The main difference between the two is the measure of support a proposal has received at the Operating Committee; parties can non-consent only after a proposal has been passed whereas a proposal giving rise to a sole risk will not have received passmark approval.

1. *Non-Consent*

Non-consent is usually a protection for small parties. Where a non-consent clause is included, the form of the clause will depend much on the passmark agreed and the relationship of the parties. The lower the passmark and the more disagreement anticipated between the parties, the more likely that the smaller percentage holders will seek non-consent provisions.

However, as non-consent clauses act contrary to the base premise of the JOA—majority rule—they are not universally accepted for inclusion in JOAs. There is no clear "standard" in use and hence the drafting of the clauses varies widely. Non-consent provisions will almost invariably *not* apply to licence obligations, which the parties implicitly accept by acceptance of the Licence. There may also be limitations on the types of projects to which non-consent applies and to the timing and consequences of a non-consent decision. Invariably, there will be penalties attached if the non-consenting party wishes to re-join the joint development at a later time, similar to the sole risk arrangements to which it may cross-relate.

1. *Sole Risk*

Sole risk provisions on the other hand, are fairly universally accepted. They recognise that a proposal (drilling, appraisal or development) may be considered worthwhile by some parties but may not meet the "majority" passmark hurdle. To allow the parties to proceed to develop their asset they may do so at their sole risk.

Sole risk provisions have been used in the industry in various forms for quite some time (and were included in the BNOC Proforma). They have developed into quite lengthy, complex and cumbersome clauses which do not always work effectively in practice.

However, as they are common provisions (and there are several examples of sole risk projects undertaken in the North Sea) several aspects of the sole risk clause should be noted.

(i) The projects to which the sole risk applies will be limited and strictly defined. Close attention will have to be paid to the drafting of the clauses and the technical references to which they relate, for

example in relation to geological closures, etc., where mapping may vary.

(ii) Preconditions for notices and timing will be set in the JOA and must be strictly adhered to. Where the time set for notices is very long, it may actually act to frustrate the parties' ability to undertake a desired project and a balance should be sought to ensure that the other parties have sufficient time to consider the sole risk proposal but not such a long time so as to frustrate it *per se*.

(iii) Provisions will delineate the shared interests of the sole-risk parties, operations of the sole risk project and whether, and on what basis existing joint property may be utilised.

(iv) The Operator will usually operate the sole risk project, whether or not it participates as a sole risk party, if joint property is used.

(v) There will also invariably be penalties for participation by non-sole-risk parties at a later time. These penalties are usually based on a multiple (commonly of 10 to 20 times) the original cost of the project, since the later participants do not face the same risk as the sole-risk parties.

(vi) The methods of repayment range from production pay-backs to cash payments to carries for future costs; all of which have different tax and capital consequences, as between the parties and (given the changing face of tax legislation) over time.

(vii) The sole risk area will form a separate area within the JOA/Licence area, which may cause some difficulties in dealing with the asset, both within a group and in relation to third parties.

Thankfully, in practice, sole risk is used more as a threat to bring other parties along in support of a proposal, than it is a means of alternative operations. However, as more and more North Sea discoveries are developed as satellite fields and as infrastructure is more likely to be used to accommodate third party usage, the economics of any given proposal are unlikely to be equivalent to all partners. It may therefore be desirable for more thought to be given to simplifying and rationalising sole risk provisions to enable them to be more easily understood and used in future.

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section in terms or fault/default and consensual separation.

In default, a party may be forced to leave the joint venture whereas parties may consensually seek to leave the joint venture by way of assignment or withdrawal.

Fault/Default

The JOA will specifically provide for cases of default. This is defined as the failure by a party to the JOA to pay its share of cash calls within the time set for payment. The terms will deal with notice and remedying default as well as the procedure for seeking recompense and ultimate removal of the defaulting party.

Terms usually provide that after notice and a set period (a short time such as six to 12 days) the defaulting party will forfeit rights under the JOA, including access to information, attendance at meetings and rights to petroleum produced. The non-defaulting parties are required to pay (in pro-rata shares) the amount outstanding (as it is not the Operator's obligation to fund the joint venture). The defaulting party is given the right to remedy the default at any time prior to forfeiture, subject to payment of interest (at penalty rate) on the overdue amount.

If the default continues for a further set period (usually 60 days) the defaulting party may be obliged to forfeit its interests in the JOA and under the Licence. The non-defaulting parties have the right to acquire the defaulter's interest in pro-rata shares or, as otherwise agreed between them, subject of course to the consent of the DTI. If the non-defaulting parties do not wish to acquire the defaulter's interests, then the Licence may have to be relinquished.

In any event, the question of liability for abandonment remains: it should not be open to a party to withdraw from the JOA by way of defaulting on its obligations and escape abandonment liability. Modern JOA's usually provide for this ongoing liability, much the same as in the withdrawal provisions, set forth below.

One area of difficulty in the drafting of default provisions is that the party in default (or its receiver or liquidator) is not likely to co-operate in signing documents for the transfer of its interests to non-defaulting parties in the case of a forfeiture. Some JOAs will, therefore, include provisions for a power of attorney, given at the outset of the agreement, enabling the Operator (or other party) to execute documentation.

Default in payment is actually quite rare, other than short term errors in administration or disputes between the parties on specific billings. Hence, it has not been questioned seriously as to whether the default and forfeiture provisions would be enforceable in litigation or whether they would be considered penalties and hence unenforceable. It is worth remembering that

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The JOA will specifically provide for cases of default. This is defined as the failure by a party to the JOA to pay its share of cash calls within the time set for payment. The terms will deal with notice and remedying default as well as the procedure for seeking recompense and ultimate removal of the defaulting party.

Terms usually provide that after notice and a set period (a short time such as six to 12 days) the defaulting party will forfeit rights under the JOA, including access to information, attendance at meetings and rights to petroleum produced. The non-defaulting parties are required to pay (in pro-rata shares) the amount outstanding (as it is not the Operator's obligation to fund the joint venture). The defaulting party is given the right to remedy the default at any time prior to forfeiture, subject to payment of interest (at penalty rate) on the overdue amount.

If the default continues for a further set period (usually 60 days) the defaulting party may be obliged to forfeit its interests in the JOA and under the Licence. The non-defaulting parties have the right to acquire the defaulter's interest in pro-rata shares or, as otherwise agreed between them, subject of course to the consent of the DTI. If the non-defaulting parties do not wish to acquire the defaulter's interests, then the Licence may have to be relinquished.

In any event, the question of liability for abandonment remains: it should not be open to a party to withdraw from the JOA by way of defaulting on its obligations and escape abandonment liability. Modern JOA's usually provide for this ongoing liability, much the same as in the withdrawal provisions, set forth below.

One area of difficulty in the drafting of default provisions is that the party in default (or its receiver or liquidator) is not likely to co-operate in signing documents for the transfer of its interests to non-defaulting parties in the case of a forfeiture. Some JOAs will, therefore, include provisions for a power of attorney, given at the outset of the agreement, enabling the Operator (or other party) to execute documentation.

Default in payment is actually quite rare, other than short term errors in administration or disputes between the parties on specific billings. Hence, it has not been questioned seriously as to whether the default and forfeiture provisions would be enforceable in litigation or whether they would be considered penalties and hence unenforceable. It is worth remembering that

forfeiture of production is only of value to the parties where the asset is producing, at which time the value of any forfeited production may well exceed the quantum of the breach!

Assignment and Pre-Emption

Where parties seek to leave the joint venture by way of transfer of their interests (sale, swap or otherwise) they will be required to conform to various rules and limitations. Primarily, the assignment of rights under the Licence will require the consent of the DTI. Additionally, the JOA will also deal with rights to and limitations on assignment. There are two main (and conflicting) trains of thought in relation to assignment rights: on the one hand that the Licence is an asset and should be, therefore, freely tradable and, on the other hand, that the Joint Venture is a group relationship that should be protected. The JOA will seek to balance these concerns.

1. *Limitations on Assignment*

(i) The Undivided Interest

Virtually all JOAs only allow a transfer of an "undivided" interest. This does not mean that a party holding a 20 per cent interest can only transfer the whole of its 20 per cent: it means that a party cannot transfer some or all of the rights attaching to a percentage interest without transferring the corresponding obligations. Special arrangements are usually made between the parties in the case of illustrative agreements between affiliates or where specified financing arrangements are to be put in place.

(ii) Consent of Parties

Virtually all JOAs will require that the other parties consent to the proposed transferee, particularly if the incoming party is new to the JOA. This is not unreasonable, since, similar to a partnership, a joint venture requires co-operation of the parties. Often, however, the consent is limited: it usually must at least be "reasonable" and in some cases can only be based on the financial capability of the transferee. The right to consent can be particularly useful to the parties as it can enable them to seek additional security from a smaller, less financially secure, new party as a condition of consent.

(iii) Minimum Interest

Less commonly, some JOAs limit the minimum interest that a party can hold, so that a party cannot transfer an interest to a new party which is

below the minimum or which would result in the transferee holding an interest below the minimum.

(iv) Inter-Affiliate Transfers

Usually, transfers between affiliates are dealt with more favourably (*i.e.* with less restrictions) under JOAs. A transfer to an affiliate may not require consent, particularly if the transferor remains secondarily liable. However, some JOAs may require a re-transfer in the event that a Affiliate is disassociated from the original Licensee. This is beneficial to protect circumvention of pre-emption rights by sale of a company, but can, in effect, put a greater restriction on transfer of an asset.

(v) Pre-Emption Rights

More importantly, transfers of interests can be restrained by rights of pre-emption. In order to protect their interests in a joint venture, the parties may seek to include various rights of "first option". These range from fairly simple requirements to pre-notify an intended disposal thereby allowing the other parties to propose offers which may (or may not) be accepted by the party proposing an assignment, to full blown rights to pre-empt (or take over) a negotiated transaction with a third party.

There are numerous concerns with the drafting and application of pre-emption clauses. One should consider if inter-party transfers will be subject to pre-emption (as the group underlying the joint venture is preserved in such case). Also, to be considered is whether the transferring party will be required to state a cash value where the consideration for the disposal is non-cash, *i.e.* a swap or farm-in. Will the drafting allow for "equivalent" terms to apply where a transaction cannot exactly be pre-empted, *i.e.* where an asset is packaged with other assets in a complex sale and purchase?

There is little case law on interpretation of pre-emption clauses, but in the unreported *Texas Eastern* litigation in 1989, in respect of a Bidding Agreement the Court showed its willingness to interpret a clause widely in seeking to protect partner pre-emption rights. Therefore one cannot be dismissive of JOA provisions in structuring asset transactions. The value of the right to pre-empt by non-transferring parties is not so much a "protection" as an opportunity to gain. Pre-emption clauses undoubtedly cause difficulties for parties wishing to transfer their assets. In some cases, they cause undue delay even where the other parties do not wish to exercise pre-emption. In other cases, they may prevent or distort multi-asset deals where pre-emption applies only in part. Perhaps this underpins the current tendency to omit pre-emption provisions from new JOAs. After all, while it is difficult to predict one's company's future position in relation to its assets, in the shrinking scope of

North Sea activity, restructuring of holdings is common. It may well be that the trend is to allow easier transfers in future.

Withdrawal

While, as indicated above, a party can leave the joint venture marriage voluntarily, subject to certain consents and rights of the other parties, by providing a "new" marriage partner, *i.e.* by assigning its interests, this, of course, presumes that there is a market of some sort for the asset. Without any other provision, the parties would otherwise be in the joint venture marriage until "death", *i.e.* upon termination or surrender of the Licence. Hence JOAs will provide another means of leaving by way of withdrawal.

Withdrawal allows parties to leave the Licence and JOA in certain circumstances. Similar in rationale to non-consent, withdrawal is never likely to apply before all licence obligations have been satisfied. Withdrawal may also be prohibited in the critical final months of the initial term when the parties are trying to determine whether to continue the Licence and, if so, which acreage is to be surrendered. Due to the financial commitments entered into by the parties, withdrawal is also likely to be prohibited until a development programme approved by the DTI has been completed.

Most importantly, the non-withdrawing parties must agree to take up the equity being surrendered by the withdrawing party. Partners are not likely to want to accept the additional equity if it has been encumbered, for example by way of over-riding royalties or net production interests. This is particularly important as the withdrawing parties (and possibly remaining partners) are not likely to see much value in the block.

If the remaining parties do not accept the withdrawing party's interests, or if all the parties opt to join in the withdrawal, the Licence will be relinquished. Hence, withdrawal should be linked with clauses on abandonment liabilities and most JOAs will (or should) provide for a withdrawing party to remain liable for its share of such costs, to prevent strategic withdrawal when, for example, field revenue declines and abandonment nears. This will not be of great concern on undeveloped acreage, but can raise interesting questions on developed acreage where abandonment is not foreseen for some time. It may not be reasonable or practical to hold a withdrawing party liable for unquantifiable sums over an indefinite time, then there is also the question of security for the liability, whereas the release of the liability at an agreed value may put the remaining parties at some risk.

Abandonment

The JOA will usually, at minimum, include an obligation for the parties to agree terms for security of abandonment. The terms will recognise that the

parties are jointly and severally liable for abandonment under the Licence and seek to ensure that the parties are liable for their pro-rata share; no more, no less. Abandonment is often the subject of separate and intense negotiations, more usually, before a development is taken forward. This is discussed in detail in another chapter.

MISCELLANEOUS PROVISIONS

The remaining JOA provisions may not clearly fit into the scope of protections, set forth above, but are no less important.

Confidentiality, Public Announcements and Trading Rights

The information generated by the Joint Venture is undoubtedly one of the assets of that venture and, hence, should be protected. Confidentiality provisions will, therefore, invariably be included in any JOA. The drafting of those provisions will vary and consideration should be given to exclusions to confidentiality as well as to the scope of the protection offered.

The JOA will usually protect as confidential the JOA itself, as well as information exchanged between the parties, both in relation to the JOA, the partners' corporate businesses and all information and data generated pursuant to joint operations, including, but obviously not limited to, technical data. Usual exclusions may include:

(i) information already in the possession of the receiving party (as shown by its written records and which is not otherwise bound by confidentiality obligations);
(ii) information which becomes generally available to the public other than by breach of the JOA;
(iii) information required to be disclosed by law, pursuant to the Licence, or by court order, or by a governmental or other body having jurisdiction;
(iv) information required to be disclosed to stock exchanges (realising that some exchanges, such as that in Australia, require a considerably greater amount of disclosure than most English companies are used to);
(v) disclosure to affiliates, subject to confidentiality restrictions;
(vi) disclosure to banks and finance houses to obtain financing subject to confidentiality restrictions;
(vii) disclosure to consultants and agents, on a need to know basis and subject to confidentiality restrictions; and
(viii) disclosure to bona fide intending purchasers of the asset, subject to confidentiality restrictions (although the whole of this provision is

optional and is sometimes subject to notice periods or is purposefully omitted where first option/pre-emption rights apply so that partners have early warning of intended disposals).

Confidentiality provisions will generally provide for applicability to a party even after it ceases to be a party to the JOA. These are arguably ineffective, however, unless the assignment/novation documents amending the JOA upon the transfer of interests formalise the continuing confidentiality undertaking.

As between the parties to the JOA, the JOA information is to be held confidential for a set period, usually the life of the JOA plus a given number of years, five being fairly common.

Akin to the general confidentiality provisions will be specific prohibitions on public announcements unless such announcements are approved by all parties. This applies both to announcements on behalf of the Joint Venture, which will be proposed by the Operator, and to individual partner announcements (unless they are required by law or Stock Exchange regulation).

Although it may seem somewhat anomalous to the obligation of confidentiality, most JOAs provide for trading rights. This is the right of the Operator, with the consent of the Operating Committee, to exchange technical data with third parties. In practice, this is useful to obtain information on areas surrounding the Licence and/or with similar geological or geophysical properties. All partners must be provided with information received in the trade and JOA parties are usually prohibited from preventing an exchange approved by the other parties merely because they already own (or have otherwise received) the data as a party to another Licence.

Lifting of Petroleum

The production and disposal of petroleum (being crude oil, gas and related liquids as defined in the Licence) is, of course, at the heart of the Joint Venture. The lifting of one's percentage interest share of such production is obviously a right. It is also an obligation: the failure to lift a percentage share can prejudice the liftings and entitlements of others. As part of the joint operations, the parties agree production and lifting schedules (usually the subject of separate and detailed agreements) and, therefore, individual parties cannot separately determine lifting programmes, conveniently using the reservoir to store their production. Hence, any production not lifted, will usually be deemed not to have been produced and to remain in the reservoir for the benefit of all of the JOA parties.

Force Majeure

Common to most JOAs is a force majeure clause. Force majeure excuses non-performance and suspends performance under contract where the failure to

perform is due to circumstances outwith the control of the defaulting party. Drafting of these clauses may be simply a widely drawn sweeping exoneration and/or may include a non-exhaustive list of circumstances and events. The clauses do not tend to be contentious. It is now fairly well accepted that a lack of funds is not considered force majeure. Similarly, it is usually accepted that labour disputes do constitute force majeure, and notwithstanding that settlement is within the control of a party, there is no obligation to settle them on unacceptable terms.

Applicable Law and Notices

It is important in the drafting of Notices Clauses to ensure that the parties have the correct information (and are kept informed of any changes to) the address/addressee for delivery, and to specify how notices should be delivered and when delivery is deemed to occur. The point is also of particular importance in advising on the day-to-day handling of JOA issues. This seems very mundane, but will not be amusing when a partner refuses to accept a misdirected or inappropriate form of notice and re-service is required to start the running of, for example, a long pre-emption period.

Similarly mundane is the Laws Clause. Why should it be necessary, one asks, to state that a North Sea JOA is subject to English law? In answer, one would note that the laws of Scotland would be equally appropriate. Either must be preferable to some of the early United Kingdom JOAs which were subject to the laws of, for example, Texas or California.

Definitions and Interpretations

Of all the JOA provisions, these are arguably the most critical and will undoubtedly take the draughtsperson the most amount of time. They cannot be overlooked in negotiation or later in reviewing JOA provisions and giving advice, as they underlie the meaning and intent of the substantive provisions.

A good JOA will have all of its defined terms listed alphabetically in an easy to find place either at the front or back of the document. Terms will be concisely defined and well thought through. It is unusual, but not unheard of, to have substantive provisions included in the definitions, although it is not desirable.

Coupled with a good (and correct) Index, proper page numbers and a consistent clause numbering system, and with a precise record of Amendments, Supplements and Novations thrown in for good measure, the industry could be at risk of having JOAs that are user-friendly. Almost as frightening as the partners in a marriage actually understanding each other!

3.

Exploration, Appraisal and Development Farmout Agreements

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INTRODUCTION AND MOTIVATION

The term "Farmout", in common with almost all the "terms of art" used in international petroleum industry agreements, has its origin in the United States. Apparently it originally referred to a practice prevalent in the last century whereby share croppers could earn a share in the proceeds of farmers' crops by working on the farmers' land.

In the oil and gas industry, the term is normally applied to the situation where one or more parties acquire an interest in a licence or concession in return for performing work which would otherwise be done by the party or parties disposing of the interest. It may involve the disposing party giving up all its interest, but more commonly that party will retain part of its interest in the licence or concession.

In deference to United States practice the party disposing of the interest will be described in this chapter as the "Farmor" and the party acquiring the interest as the "Farmee".

Oil and gas companies enter into these agreements for a variety of reasons, such as the following:

(i) In countries where new acreage is dispensed by host governments in licensing "rounds" farmouts are a means of managing asset portfolios outside these rounds.

(ii) the cost-to-risk ratio of further exploration, appraisal or development of acreage may be significantly improved if the risks of the initial drilling can be transferred to another party.

(iii) funds may not be sufficient to complete all the work one might wish to, or which one might be obliged to perform within a given time-frame.

(iv) the tax positions of the parties may differ. Many farmin wells were drilled in the United States prior to the Economic Recovery Tax Act of 1981 by independent companies who had better tax breaks than the majors.

Whatever the reasons, in mature oil provinces where farmout agreements are permitted, there will usually be a large number of farmout proposals, generated by companies which wish to attract farmees, "doing the rounds" of exploration departments at any given time.

PROMOTE LEVELS

This chapter will attempt to cover all the features normally encountered in farmout agreements, but negotiations, especially in the early stages, tend to revolve around two key points; how much interest is to be assigned and what will be the exact nature of the work to be performed? A phrase commonly heard during the comparative evaluation of farmout opportunities is "promote level".

What is meant by this is simply the ratio between expenditure and interest earned—an arrangement whereby a party reimburses past costs, or pays for exploration work and then takes all the farmor's interest, is referred to as a "ground floor" deal, but if the farmee only earns, say, half the farmor's interest in return for paying all the cost of the work then that would be described as a "two for one promote". If the farmee had only earned a 25 per cent interest the deal would be described as a "four for one promote". In the course of negotiation promote deals often become more complex; for example it is quite common to see one type of expenditure on a "ground floor" level and others at a two for one level within the same farmout agreement.

FARMOUT OBLIGATIONS—PERFORMANCE

Promote levels are really part of the commercial negotiations which precede the farmout agreement itself; most of the problems and disputes which arise during the currency of such agreements are the consequence of inexact drafting of that part of the agreement dealing with the activities to be performed by the farmee. There is a broad range of possibilities, ranging from seismic options through multiple-well commitments to the full development carries discussed later in this chapter.

Seismic Options

Under a seismic option the farmee conducts seismic work or acquires the data from others, his work or expenditure normally being capped at an agreed

level. The farmee then has time to evaluate the data. If he then decides not to drill a well he earns no interest in the acreage; if he drills he will earn interest in accordance with the promote level that has been agreed.

Multiple Well Agreements

Some multiple well agreements are similar to seismic options in that the first well earns no interest; only the second (and subsequent wells, if any) trigger assignment of interest.

Alternatively the first well might earn a certain percentage and the second a different one.

Substitute Wells

Substitute (or alternative) well provisions give rise to much wrangling during the negotiation of farmout agreements. The need for such a provision springs from the fairly common circumstance that the operator drilling the well is unable, either through his own technical incompetence or factors outwith his control, to reach the agreed target depth of the farmin well. The interests of the parties are pretty much opposed over this issue; the farmor expects his prospect to be proved or otherwise, otherwise the farmout is useless to him, and this can normally be achieved only by drilling to the target formation.

The farmee will take the view that having spent the money on drilling the well, and particularly if the problems are outwith his control, he should be permitted to earn. The problem is compounded by a further potential complication—the farmee could experience the same problems all over again with his substitute well, and find himself in the position of having spent at least twice as much as originally envisaged without having earned any interest.

It is suggested that the problem may be resolved by the establishment of a financial cap—when the farmee has spent that capped amount on drilling he is deemed to have earned his farmin interest.

Where especially deep wells are the subject of farmins, and there is a possibility that the well will encounter potentially productive horizons before reaching target depth, it can be provided that some lesser interest may be earned by the farmee should it be unable to achieve target depth.

Earn-ins

Practitioners in the United Kingdom will occasionally find themselves involved in "earn-in agreements". An "earn-in" differs from a normal farmin only in the timing of a governmental approval, which is given only when Licence work obligations are complete.

The "Earn-in" is the child of the United Kingdom Department of Trade and Industry's moral repugnance at trading in licences before work obligations have been completed—the theory being that since licensees in the United Kingdom "bid" for licences in the Rounds by offering work programmes rather than cash, they ought to see those programmes completed before using the licences as part of their asset portfolios for trading purposes. The DTI on the other hand does not wish to discourage exploration work, hence the evolution of the "earn-in", which serves to protect the respectability of all concerned, but nevertheless increases the farmee's risk since it introduces a considerable potential delay between date of its execution and the formalising of the transfer of interest.

Operatorship and "Contracting"

A farmin may well be drilled by the farmee, if he is a qualified operator and permitted to do so by local legislation, or by the operator under the Joint Operating Agreement applicable to the Licence. The most common arrangement in the United Kingdom is for the farmee to drill the farmin well, and for this reason operators see many more farmin opportunities than non-operators. Quite often the farmee will take over as operator of the licence. Where the farmee is a non-operator the issue arises of his rights to influence the drilling operations and the farmor's voting in the Operating Committee, during the period prior to assignment of interest. Where the farmor is not itself the operator the farmee will also need to take care that its obligations *vis-à-vis* the farmor are the mirror of the obligations assumed by the operator under the Joint Operating Agreement—if the farmee's obligations under the farmout agreement are more onerous than the operator's to its co-venturers the farmee will be at risk.

A common solution to the problem of the farmee's rights where he is not to operate (or cannot) is for the farmee to be given specific rights by the farmor within the framework of the farmout agreement.

These rights would normally include provision for the farmee to be consulted about voting decisions in the Operating Committee established under the Joint Operating Agreement for the licence, and may give the farmee the right to withdraw from the farmout agreement if the farmor does not vote in accordance with the farmee's wishes.

Further complications may arise if the farmee is to drill the well himself but is not to become the operator under the Joint Operating Agreement and the licence. In this case, rather than see the official operatorship of the licence leapfrogging from one party to the other, the Department of Trade and Industry in the United Kingdom will prefer the farmee to be a contractor to the licence group for the duration of the farmout obligations. The farmee will assume the same liabilities he would have undertaken had he been the official operator.

One final complication which is often encountered in the performance area is that of "drilling groups". Quite frequently a farmin opportunity will be shared by several oil companies, and in this case they will be obliged to form a group for the purpose of drilling the farmin well or wells, their conduct, default mechanism and decision-making process being governed by a "drilling group agreement", and they will appoint one of their number to be operator.

Whatever the mode of performance agreed among the parties, it is vital for the draftsman to ensure that a farmout agreement is very clear as to the precise nature of the obligations assumed by the farmee and as to their timing.

A farmout agreement will normally identify the farmin well or wells by geographical location and by depth, although the actual depth drilled is less important than the evaluation of the target formation, so the clause will commonly provide that the well be drilled to an agreed depth or to a depth which permits evaluation of the target horizon, whichever is the shallower.

The timing of the drilling may be out of the hands of the parties to the farmout agreement, especially where the well has been agreed by the parties to the Joint Operating Agreement as part of an approved work programme, but where the parties control timing of drilling it will be important for the farmor to specify a date by which the obligations must be complete, and to provide a mechanism for extensions of that date, such as force majeure circumstances.

ASSIGNMENT OF INTEREST

Pre-emption

Before addressing the issues of methodology and timing of interest assignment, it is worth first considering a feature of many joint operating agreements which may act to prevent the farmout happening at all: pre-emption.

This is not the place to debate whether pre-emption clauses result in parties fettering their rights to freely trade their assets, or permit the entrenched oil companies in a petroleum province to resist entry by newcomers, but they have certainly become "lawyers' playgrounds" as attempts to avoid them and the resulting counter-measures become ever more elaborate.

Pre-emption clauses only really matter to farmees—the farmor will successfully dispose of or dilute his interest whether the farmee or an existing co-venturer performs the work for him. Farmees detest them and often attempt to defeat them, normally by obscuring the nature of the consideration by cross-farmouts, where an interest in a licence is exchanged for another.

Some recent pre-emption clauses attempt to prevent this happening by requiring the farmor to state the cash value of the consideration, but clearly the value of a chance to drill a wildcat well is very difficult to quantify—a banker might well assign it a negative value, whereas explorationists will always scent the next "company-maker".

The period during which co-venturers may consider whether or not to exercise their pre-emption rights is normally 30 or 60 days, although these periods are frequently waived where a co-venturer knows it has no intention of pre-empting.

Timing of Assignment

There are two basic options as to the timing of interest assignment under a farmout agreement; it may take place when the earning obligation has been fulfilled, or at an earlier point with provision for reassignment if the earning obligation is not fulfilled.

The latter arrangement, which prima facie seems absurdly risky for the farmor, was nevertheless common in the United Kingdom and is still standard practice in some other countries.

OTHER PROVISIONS OF FARMOUT AGREEMENTS

Promote levels, mode of performance and timing assignment are the principal commercial points to be negotiated in a farmout deal, but the agreements will contain a number of other clauses requiring drafting and negotiation, such as the following:

Access to Data

The farmout agreement will provide that the parties will keep one another fully informed as to the progress of the earning obligations, but there is a further issue arising which may cause problems if not addressed in the farmout agreement. Joint Operating Agreements do not normally address the issue of the data access rights of parties coming in to the agreement through the novation process.

It is therefore useful to cover this in the farmout agreement and to provide that the farmee has rights to all the data associated with the licence and generated under the Joint Operating Agreement, whether prior to the date of interest assignment or after.

Representations and Warranties

A farmout is, in essence, no more than the disposal of an asset, so it is hardly surprising that farmout agreements contain much the same provisions

concerning representations and warranties as are contained in the acquisition agreements discussed elsewhere in this book, albeit in somewhat more basic and abbreviated form. The normal headings are:

(i) Affirmation that the licence is valid and subsisting and not about to be revoked. The farmor should be able to confirm that the work obligations under the licence have been performed or otherwise.

(ii) Affirmation that no party, to the knowledge of the farmor is in breach of the operating agreement and that it has not been materially amended since the farmee last saw it.

(iii) A statement that there are no liens or encumbrances on the interest to be assigned, and that the farmor is the sole and beneficial owner of that interest.

(iv) A statement that the farmor has no knowledge of any actual, threatened or pending litigation, arbitration, disputes or judgments or awards relating to the licence or the operating agreement.

Disputes over the representations and warranties tend to revolve around the farmee's attempts to oblige the farmor to give undertakings concerning the performance of its co-venturers. If the farmee is only acquiring an interest in, say, one block of a multi-block licence, representations regarding breach by co-venturers on other blocks in which the farmor himself may have no interest are very difficult to give.

Turnkey Farmouts

Practioners in the oil and gas business will occasionally come across the term "turnkey farmout". This simply refers to a normal farmout incorporating a turnkey drilling agreement. Under a turnkey agreement a lump sum (or "turnkey") price is agreed with a drilling contractor, including all materials, equipment and services. The price is paid once the well reaches its target depth, or in the case of a subsequent drill stem test, after liner has been run and cemented.

This agreement, which involves the drilling contractor assuming drilling risks normally borne by an oil company, will usually be more costly for the farmee than if it had drilled the well in the conventional manner, but introduces a cost cap, the benefit of which is shared by the farmor.

DEVELOPMENT FARMOUTS

It is possible to look at the variety of farmouts as a spectrum of risk: from wildcat farmouts through appraisal farmouts to development farmouts, and it is at the latter stage that the risk becomes sufficiently low for the banks to enter the picture. An oil or gas company which has an upcoming development and cannot finance it out of cashflow or by raising fresh equity therefore has two choices: to approach the banks, who will probably be prepared to finance some or all of the development costs against the security of the "proven" reserves of the field; or to seek a partner prepared to enter into a development farmout arrangement; normally another oil company attracted by the development and possessing the requisite capital, or access to it.

The oil or gas company, while expecting a lower return than the banks on the funds it has in effect loaned, will wish to take equity in the field.

The arrangement commonly adopted is that the farmor assigns part of its interest to the farmee, who thenceforth assumes all associated liabilities and benefits. The farmee then "loans" the farmor the funds required to pay for its share of development costs until first production. This is sometimes referred to as a "development carry".

This "loan" is then repaid not in cash, but by the farmee taking some (usually most) of the farmor's oil or gas entitlement, until the value thereof equals the farmee's contribution to the farmor's share of development costs plus an additional share equating to the interest on the "loan". Thereafter shares in the hydrocarbon streams are taken by the farmor and farmee in their post-farmout equity percentages.

The economic effects of the equity splits and the respective shares of production are simple to calculate, but two imponderables remain—the strength of the farmee's covenant and the development cost risk. The latter risk may be covered to some degree by allowing the farmee to exercise influence over the farmor's vote in the operating committee.

DOCUMENTATION ASSOCIATED WITH FARMOUT AGREEMENTS

Documentation required to give effect to the terms of a farmout agreement will differ from country to country, depending on the regulatory and fiscal regimes of the host government, but will generally include an assignment of the licence interest and a novation of the relevant operating agreement.

Assignment of Licence Interest

This document has now become standardised in the United Kingdom and the form as approved by the Department of Trade and Industry is included in the precedents.

Operating Agreement Novation

This document makes the farmee a party to the operating agreement, and amends participating interests of the parties. The more hard-bitten in-house lawyers welcome these documents, since they provide a convenient opportunity to incorporate other amendments to the operating agreement which have been agreed but which have been awaiting formal incorporation by the parties. The process of circulating documents of this type round a large consortium is tedious in the extreme, as may be imagined.

Interest Assignment

Obviously the assignment of the farmor's interest could be accomplished in the farmout agreement or in the operating agreement novation, and indeed this used to be the case in the United Kingdom but a separate document has been deemed appropriate for United Kingdom Stamp Duty avoidance reasons.

The interest assignment (and often the operating agreement as well) is normally executed, and the originals are held, outside the United Kingdom for the same reason.

Trust Deed

Trust deeds (also referred to as Umbrella Agreements and Cross-Indemnity Agreements) will be necessary in the United Kingdom where the farmee is farming-in to less than all the blocks of a multi-block licence.

Under United Kingdom law the farmee will become a licensee of the entire licence notwithstanding its partial beneficial interest. It will then be required to hold that part of the licence in which it does not have an interest in trust for the other licensees, and to help them in the following ways:

(i) to help a party who wishes to assign the licence, provided the incoming licensee covenants with the parties to the Trust Deed to the effect that it will be bound by the Trust Deed.

(ii) to act in accordance with the desires of the other licensees in respect of the blocks in which it holds no interest.

(iii) to refrain from committing any acts which might prejudice the licence.

Execution Agreement

Execution agreements are believed to be specific to the United Kingdom where the consent of the Department of Trade and Industry is technically required to the entire text of the farmout agreement and all its associated documentation. The DTI will not accept farmouts containing a condition precedent that the agreement will have no effect until DTI consent is obtained and therefore the practice has arisen of entering into "execution agreements" whereby the parties agree to enter into the farmout agreement, which has been negotiated and is an attachment to the execution agreement once the necessary approval to the farmout is forthcoming. It is difficult to see any significant legal difference between a condition precedent and an execution agreement, and the practice is of largely cosmetic effect.

4.

Production Sharing Agreements in Principle and in Practice

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Oil companies require for their activities either an *exclusive licence* or a *contract of work*. Exclusive licences are granted to an applicant possessing the necessary qualifications by the owner of the petroleum *in situ*. In most countries, ownership of petroleum *in situ* is vested in the State or the Crown represented by its government. Exceptionally such ownership is vested in the private or public owner of the land overlying the petroleum accumulation. An exclusive licence grants the holder thereof the right to extract the petroleum from its place of accumulation. Ownership of such petroleum is transferred to the licensee as from the moment it flows into a well drilled for that purpose by the latter within the boundaries of his licence area. A contract of work is a contractual relationship between a foreign oil company (referred to as contractor) and a national state oil enterprise specifically authorised for the purpose (referred to as state party).

The state party is in possession of a specific exclusive exploration and/or production licence or an exclusive general authority to undertake petroleum operations covering the whole territory of the country. Contracts or work may be categorised into risk contracts and non-risk contracts. Oil companies work under risk contracts, but if forced by circumstances oil companies may exceptionally accept non-risk contracts. A risk contract requires the contractor to supply the funds needed for the authorised petroleum exploration, development and production operations. A risk contractor receives his compensation and reward either in cash or in a share of the oil and gas production resulting from his operations. If compensation and reward is agreed to be made in cash, the amount thereof is made dependent on and linked to the aforesaid oil and gas production. Any risk contractor accepts and bears the risk of losing his investments, if he does not succeed in producing oil and/or gas. Risk contracts under which contractor's compensation and reward are expressed and paid in deliveries that the agreement will have no effect until DTI consent is obtained and therefore the practice has arisen of entering into "execution agreements" whereby the parties agree to enter into the farmout agreement, which has been negotiated and is an attachment to the execution agreement once the necessary approval to the farmout is forthcoming. It is difficult to see any significant legal difference between a condition precedent and an execution agreement, and the practice is of largely cosmetic effect.

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Generally, oil companies prefer exclusive licences to risk contracts and production sharing agreements to other types of risk contract. In practice, oil companies have no choice in the matter, the choices are made by the host governments. From the beginning of the petroleum industry, governments of Western industrialised countries (OECD Member States) have settled on a petroleum régime based on licensing and on public or private ownership of petroleum *in situ*. In contrast, developing countries prefer to engage foreign oil companies on the basis of risk contracts, almost exclusively in the form of production sharing agreements. Their example has in recent years been followed by countries undergoing a transition from a state controlled economy to a market economy, such as most of the East European countries, the Russian Federation and other member States of the CIS.

The production sharing agreement (PSA) is the oldest form of risk contract. World-wide, production sharing agreements have now been applied for more than 25 years and they still remain the type of risk contract most widely adopted and accepted. Other types of risk contracts have been developed at a later stage. Most bear a close resemblance to the PSA. Particularly so, if the contractor is allowed to purchase from the state party a portion of contract oil production at market value and to be paid with the cash reward to which the contractor is entitled under the terms of the contract.

The other types of risk contracts can be categorised as:

- (i) contracts covering special petroleum development projects where no preceding exploration and appraisal work is involved. Each such contract is unique in the sense that it is tailor-made for a particular oil or gas development project;
- (ii) association contracts as applicable in Columbia. These contracts, which are made between a foreign oil company and Ecopetrol, the state enterprise and exclusive licence holder, are in substance very similar to a state participation agreement, in the sense that investments and production are proportionally shared between contractor and Ecopetrol;
- (iii) risk-bearing service contracts as practised in some other Latin-American countries, such as Ecuador, Peru, Brazil and Argentina.

THE CONCEPT

A production sharing agreement is a contractual arrangement made between a foreign oil company (contractor) and a designated state enterprise (state party), authorising the contractor to conduct petroleum exploration and exploitation within a certain area (contract area) in accordance with the rules of the agreement. The authority of the state party is either based on the possession of a specific exclusive licence granted under the rules of the

prevailing petroleum legislation, in which case the area of the agreement coincides with the area of the licence, or on a general exclusive authorisation (and duty) to undertake petroleum operations covering the whole country without specific obligations attached thereto.

In the case where the state party has been given a general authorisation, the contract area is the area as specifically described in the production sharing agreement. The contractor is responsible for the funding of the exploration and exploitation work, albeit a contract may give the state party an option to contribute to the costs of the development of particular commercial discoveries. All operations have to be carried out in accordance with annual work programmes and corresponding budgets, which need the approval of a supervisory body, which in most instances is the state party itself. If a discovery is declared commercial, contractor has to prepare a plan for developing such discovery (development plan) and submit this plan to the state party for approval. Development work and production operations have to be conducted in accordance with the approved plan. The oil and gas production becoming available at the point of delivery (as defined and described in the agreement) is divided between the host State, the state party and contractor.

As understood herein oil and gas production means the liquid and gaseous products derived from the petroleum after the latter's treatment and include crude oil, condensate and natural gas. From suitable natural gas (referred to as rich or wet gas) certain liquid hydrocarbons (NGLs) may be recovered in a gas plant. Crude oil, condensate and possible natural gas liquids are hereinafter individually and collectively referred to as oil. The host State receives at the delivery point a certain percentage portion of the available production (a percentage portion that may increase at higher levels of daily production), such portion being referred to as royalty oil or royalty gas (in the context of the production sharing system "oil" shall hereinafter be understood to include "natural gas").

The total portion, to which a contractor is entitled, consists of two components. The first component (cost recovery oil) is a percentage portion reserved for the contractor to compensate the latter for the costs incurred by him in carrying out the authorised operations. In contracts as applicable in certain countries a third portion is provided for representing the monetary value of the income tax which the state party and the contractor are liable to pay. Production remaining after royalty oil, cost oil and possibly tax oil, in this order, is shared between state party and contractor in a simple proportion or, as is more often the case, in complex proportions. Complex proportions are intended to make the division of remaining oil, usually referred to as profit oil, more favourable to the state party at higher levels of production performance, as measured in terms of cumulative production, or, alternatively, in terms of daily production.

A contractor is liable to pay income tax on his income realised from the sale of his total share of the production. In fact, contractor's taxable income consists of the sales proceeds of his cost oil and his share of the profit oil, less deductible costs. If cost recovery is efficient and complete and the contractual meaning of "recoverable costs" is about the same as the fiscal meaning of "deductible costs", the contractor's taxable income amounts to the market value of the contractor's share of the profit oil. Originally, production sharing was seen as a substitute for paying income tax and contractor's income tax was considered to be included in the profit oil share to which the state party was entitled. Consequently, the state party was obliged to pay the contractor's income taxes on the contractor's behalf. Under some types of PSA the original system is still maintained.

Initially, the major oil companies viewed the emergence of the production sharing agreement with suspicion. There were two reasons for their attitude. Until the early 1970s, oil companies were accustomed world-wide to operate by virtue of exclusive licences. (An exclusive licence gives the holder the ownership of any petroleum that flows into his wells). In contrast, the PSA is a contractual arrangement and as such it does not give the contractor any public law title to petroleum as such, but instead it gives the contractor a contractual right to being delivered a portion of the oil and gas production that becomes available (after treatment and processing of the petroleum) at the point of transfer. Summarising the difference between a PSA and an exclusive licence is a matter of (1) lacking title to petroleum as produced, and (2) being only entitled to a part of the total oil and gas production.

It is not a matter of a difference in government take in the sense that operating under a PSA would be more onerous and less profitable than operating under an exclusive licence, apart from the reduced access to production. As a matter of fact, any desired level of government take in a monetary sense can be expressed in the context of a PSA as easily as this can be done in the context of an exclusive licence. There is only this difference that the PSA offers a greater choice of parameters (fiscal and non-fiscal) in which to express government take, such as the terms of production sharing, extra charges on profit oil barrels, export duties and contractor's income taxes and which collectively allow more flexibility and more response to variations in profitability.

In contrast, an exclusive licence offers a more limited number of parameters which are all of a fiscal nature, such as royalty, net profit shares, gross profit shares, levies on excess profits and general and/or special petroleum income taxes. In practice, the production sharing parameters available are made dependent on production performance. In this manner government take is made to increase in relative terms (percentages) as production performance (as measured in terms of levels of cumulative production or daily production) improves. Tacitly, it is thereby assumed that if production performance improves, profitability also improves. This does not necessarily have to be the case. For instance, in a case where production can only be boosted by

drilling more wells, costs will increase commensurately and the project's profitability, despite increased production, may well remain the same.

CONTENTS AND STRUCTURE

A production sharing agreement contains many more rules and procedures than those covering the manner in which the production should be divided between the respective parties and how contractor's income taxes should be assessed and paid.

At the time of adopting the concept of production sharing agreements a host State may be a mature petroleum country, *i.e.* a country in which in the preceding period petroleum exploration and exploitation has been undertaken with varying rates of success, or a pioneer country, *i.e.* a country of which the petroleum potential had still to be established and which has chosen the PSA as a means to build up a domestic industry with help of foreign oil companies. A mature host State may or may not have enacted in the preceding period adequate petroleum legislation (law and regulations). If so, the production sharing agreement does not have to be an elaborate and extensive document and, as is further discussed below, the rules and regulations of the preceding legal regime can be made applicable to contractor's operations. If not, the production sharing agreement should contain all the necessary rules otherwise found in adequate petroleum legislation.

The developing countries, that over the years have embraced the concept of production sharing agreements, were for the most part pioneer oil countries. At the time of opening up their territory for petroleum exploration and offering PSAs to interested foreign oil companies, pioneer countries generally did not possess adequate petroleum legislation. Therefore, a production sharing agreement has to provide for all the necessary operational rules and procedures in order to give contractor the necessary guidance in exercising his right to conduct petroleum operations. In addition, considering that the petroleum operations and their funding had to take place in developing countries, which are characterised by a weak economic environment and correspondingly weak currency, a production sharing agreement was and still is required to contain appropriate financial and foreign currency exchange provisions as well as provisions that are aimed at improving the economic position of the host State in general (the latter are known as national economic interest provisions).

After taking the decision to adopt the concept of production sharing agreements, governments of host States started with and further developed their own version of such agreements in order to meet the demands and requirements of their particular economic, legal and other relevant circumstances. In exceptional cases, a host country was satisfied with simply copying the contract style of another host country (e.g. Syria took over the

Egyptian style). Major influence on the shaping of a style typically for a host country can be ascribed to (a) the status and scope of the prevailing petroleum legislation, (b) the organisation of the host country's economy (free market, mixed or state controlled economy) and to (c) the degree of experience with petroleum operations (relatively mature host country versus pioneer country). In case mature host countries (for political reasons) opt for embracing the concept of production sharing agreements, these countries make a switch from either a regime of (exclusive) licensing (which also means concession agreements) or from a regime of state planning and control. If adequate petroleum legislation is in existence at the time of making the switch, the new contractual concept must be embedded in and integrated with the prevailing legislation.

Integration should secure that the body of the existing legislation would be applicable to contractor and contractor's conduct of the operations. The easiest way in which to achieve the desired integration is to grant the designated state enterprise one or more specific exclusive licences as may be granted under the prevailing petroleum legislation and to authorise the new licensee to enter into a production sharing agreement in respect of its licence(s). In this situation, the area of the PSA coincides with the area of the licence(s). The state party/licensee is responsible for keeping the licences in good standing and for fulfilling the conditions and exercising the rights attached thereto. In this context the state party/licensee has to observe the area relinquishment obligations and is *inter alia* responsible for converting exploration licences into production licences when a commercial discovery is made. As will be discussed later, Nigeria offers an example of how production sharing agreements can be reconciled and integrated with an existing petroleum legislation based on a regime of (exclusive) licensing.

In most instances, where a mature host country makes a switch to production sharing, the new agreements exist side by side with exclusive licences or state controlled ventures originating from the preceding period. Examples of host countries, that after years of petroleum exploration and development within the framework of a licence system, made a complete or partial switch to production sharing agreements are Egypt, Indonesia, Libya, Malaysia, Nigeria, Oman, and Abu Dhabi. Of these countries only Libya, Malaysia and Nigeria possessed at the time of introduction adequate petroleum legislation. Consequently, the respective governments were faced with a reconciliation and integration problem. Examples of mature host countries that introduced the concept of production sharing within a framework of state planning and control are China, East European countries, the Russian Federation and other member states of the CIS.

Between contracts there exist also differences in the matter of government take provisions. Distinction must be made between differences in structure (the various portions of production and the use of production tranches) and differences in the actual absolute and percentage figures. Differences in

structure are found between contracts applicable in different host countries. These differences belong to the differences in contract style. Differences in actual figures completing the structure are found between contracts applicable in one and the same host country. These figures are settled in negotiations with applicants. The finally agreed values are influenced by competition between applicants, by the individual applicant's estimate of the petroleum prospects of the particular contract area applied for, by its assessment of the available legal and physical infrastructure and the technical difficulties and risks involved. Furthermore, the individual applicant's attitude will be influenced by its assessment of the political risks represented by a particular host country. (As understood herein, political risk represent the risk that an oil company must abandon its venture for internal or external political circumstances affecting or caused by the host country).

In practice, host countries having decided to switch to and adopt the concept of production sharing agreements sooner or later produce a model agreement with a number of blank provisions, to be completed in negotiations with applicants. The usual subjects to be filled in concern size and location of the contract area, obligatory exploration work and expenditure commitments, and the absolute and percentage values of the production sharing parameters. Systematically, the contents of any model or actual production sharing agreement may be considered to be composed of five Parts. (The systematic approach is followed for the purpose of reviewing the contents of a PSA. In practice provisions are arranged more haphazardly).

THE PSA'S CONSTITUENTS

Part I (regulatory provisions)

Contains rules and procedures regulating the right of the contractor to conduct petroleum operations. It contains the description or identification of the contract area, an area relinquishment scheme, duration of the contract, possible sub-divisions of this period into an exploration period, a development period and a production period, and an obligatory exploration programme and exploration expenditure commitments. If a production sharing agreement is integrated in a specific exclusive licence granted to the state party the provisions regarding area, area relinquishment, duration and exploration commitments should be identified by a reference to the corresponding conditions attached to the licence concerned.

Depending on whether or not substantial petroleum or other relevant legislation is applicable, Part I contains rules about the way and manner contractor has to conduct his operations (application of good oil field practices, safe abandonment of fields and installations when production is terminated, taking measures for the conservation and protection of the environment and for the avoidance of causing pollution). More typically, in Part I rules are found about the protection and promotion of the national economic interest. The national economic interest is served by provisions about transfer of technology, training of contractor's national employees and state party's personnel and about giving preference to locally manufactured goods and to local supplies and services.

Finally, Part I may contain rules concerning exploitation of straddling petroleum reservoirs by which are meant petroleum reservoirs that extend across the boundary of the contract area into the area of another petroleum right.

Part II (financial provisions and disposition of production

Contains provisions which reflect the fact that the authorised petroleum operations have to be carried out in countries with a weak economy and an equally weak currency. The usual provisions include the contractor's production disposal rights (right to export and right to keep the proceeds of export sales abroad in so far as not needed to satisfy tax and other local financial liabilities), finance matters (funding in U.S. dollars), banking, foreign currency exchange and transfer of funds abroad, insurance matters.

Part III (cost recovery, production sharing and taxes on income and profits)

Contains the rules and procedures concerning production sharing (involving contractor's compensation and reward) and contractor's income taxes. In Part III the government's and the contractor's take are determined. Part III determines how the oil and gas production is divided among and between the host State, state party and contractor, the implementation of the procedures regarding the recovery of costs out of cost oil, contractor's liability for income taxes, the assessment of the contractor's taxable income and whose responsibility it is actually to pay these taxes. Part III may also contain provisions regarding the economic stabilisation of the contract. To Part III should also be reckoned to belong any rules about opportunities and options given to a state party to contribute to investments in the development of commercial discoveries. From the point of view of the contractor, the terms of Part III determine the economic viability of his venture.

Part IV (organisational and co-operative aspects)

Contains rules and procedures concerning or involving the co-operation between state party and contractor. Part IV contains rules about supervision, operatorship and co-operation between contractor and state party. Part IV

concerns the control over and decision taking with regard to investments, operational matters and work programmes and corresponding budgets, in so far as these investments, programmes and budgets have not been made obligatory, declarations of commercial discovery and preparation of plans to develop such discoveries (development plans). Exceptionally, a contract may provide for state participation on the side of contractor. In such a situation, the designated state participant shares the rights and obligations of contractor and becomes a co-contractor.

Part V (legal and non-operational matters)

Contains provisions dealing with matters more of a legal than an operational nature. To mention a few: the contractor's obligation to provide parent company guarantees or bank guarantees with respect to the fulfilment of the obligatory exploration work programme and/or exploration expenditure commitments or even with respect to the contractor's performance generally; the contractor's liability *vis-à-vis* third parties and the government's for damages caused by the execution of the authorised petroleum operations; the contractor's obligation to keep government and state party harmless against claims from third parties in connection with the authorised operations; the state party's acquisition of the ownership of land, fixed or movable assets; internal or external assignment of interest in the contractor's side of the contract; matters concerning amendment, termination and ratification or government approval of the contract; applicable law; settlement of disputes.

CO-OPERATIVE ASPECTS

A production sharing agreement has a dual character. On the one hand a PSA represents a petroleum right since it authorises the contractor to undertake petroleum exploration and exploitation within the contract area. On the other a PSA embodies a contractual form of co-operation between the contractor and state party. It is not the same co-operation as exists and is practised between participants in a joint venture, whereby rights and obligations are shared between the participants on a proportional basis. Under a production sharing agreement state party and contractor have the same objective, *i.e.* the optimum development of the petroleum resources of the contract area, but have different rights and obligations.

Nevertheless, because of striving to attain the same objective, they have to exercise their (different) rights and perform their (different) obligations in a co-operative manner. This means that state party and contractor should try to behave as if actually they were participants in a joint venture. Such joint venture co-operation is impossible if in the PSA the state party is exclusively seen as a supervising authority wishing to control and use the contractor's funds for conducting petroleum operations which serve foremost its and the host State's particular interests. Whether the state party and its contractor succeed in effectively co-operating with one another does not only depend on how their co-operation is described in the agreement but essentially on the existence of a spirit of mutual trust and understanding between the parties.

ECONOMIC ASPECTS

An oil company acting as contractor is running its business for profit and will therefore only decide to make an investment if the company foresees a profitable outcome taking into account its own particular economic standards and methods of calculation (*e.g.* applying the discounted cash flow method). Although a state party shares with its contractor the same objective (that of finding and extracting petroleum in an optimum manner) it does not share the contractor's economic constraints, since it is not compelled (although it may have the option) to make and risk investments. Furthermore, in judging investments, it may and usually does apply economic yardsticks different from those applied by its contractor. A state party may, for instance, be interested in further and additional exploration work solely for the purpose of completing the inventory of the host country's petroleum potential, despite the fact that in the contractor's opinion the area of the contract has been conclusively investigated making any additional exploration work superfluous.

A state party may have economic opportunities or obligations which are not available to or do not apply to its contractor. This may lead to disagreement between the parties when they have to make a decision whether or not to develop a petroleum discovery. For example, disagreement may arise if a state party is interested for reasons of its government's social policies to develop a petroleum discovery which in accordance with a contractor's economic yardsticks should not or at least not yet be developed, or if a state party is interested in the context of national energy supply policies to develop a natural gas discovery which is too small for an export project but large enough for supplying the local gas market (*e.g.* supply of gas to a power station or industry located near the gas field).

In particular in the latter case disagreement may arise if the state party is obliged to sell the gas on non-commercial conditions (*e.g.* at prices below the market value and payable in the national currency). Such preferential conditions render the proposed gas development of no commercial interest to a contractor (unless of course with respect to a contractor's share of the natural gas production concessions are made that remove the aforementioned financial obstacles). As will be discussed later, it is essential that a production sharing agreement should provide for a sole risk and account development option in

favour of the state party, which should allow the latter to proceed with a development project on its own.

LEGAL AND POLITICAL BACKGROUND

Developing countries, recently joined by East European countries, the Russian Federation and other member States of the CIS, prefer to enter with foreign oil companies into risk contracts in general and production sharing contracts in particular rather than granting to these companies exclusive licences as is the standard legal practice in the western industrialised countries. The following commentary on the legal and political background of global exploration and exploitation of petroleum will explain the reasons for their preference.

During the first 100 years of the existence of the extractive petroleum industry, whose beginning is traditionally set in 1859, the year in which "Colonel" Drake drilled his first well at Titusville, Pennsylvania, oil companies were accustomed to and were only prepared to carry out their operations on the basis of exclusive licences granted to them by the authority who was or claimed to be the owner of the petroleum *in situ*. In the American Union States this authority was and is the landowner, which in many cases proved to be the Federal Government in as much the Federal Government owned vast stretches of land in the American Union States. Anywhere else (including the continental shelf of the United States but with the exception of the land territory of respectively the Netherlands and the German Federal Republic), the ownership of the petroleum *in situ* is vested in the national State or Federation or Crown represented by its government.

While state sovereignty over natural resources was generally accepted in international law (as demonstrated by the adoption of the 1958 Convention on the Continental Shelf) developing countries raised during the 1960s and 1970s within the General Assembly of the United Nations the question of whether this sovereignty was permanent and inalienable and, if so, what the legal and economic consequences are of such permanent sovereignty.

Preliminary work by the United Nations on the concept of permanent sovereignty started with the establishment of a Commission on Permanent Sovereignty over Natural Resources (GA resolution 1314 (XIII) of December 12, 1958). On December 14, 1962 the General Assembly adopted, without significant changes to the text that was prepared by the aforesaid Commission, GA Resolution 1803 (XVII). The text of this resolution mentions permanent sovereignty but failed to explain this expression. For the extractive petroleum industry the resolution contained an important message with respect to the much feared nationalisation measures with which this industry was confronted and threatened from time to time. The relevant paragraph reads as follows:

"4. Nationalisation, expropriation or requisitioning shall be based on grounds or reasons of public utility, security or the national interest which are recognised as overriding purely individual or private interests, both domestic and foreign. In such cases the owner shall be paid appropriate compensation in accordance with the rules in force in the State taking such measures in the exercise of its sovereignty and in accordance with international law."

Developing countries were not satisfied with this state of affairs. Although it was appreciated that foreign companies, whose assets and rights were about to be nationalised, could not rely on or invoke diplomatic protection from their home governments, developing countries did not agree to the reference to international law that at the insistence of the western industrialised countries had been included in the paragraph quoted above. They felt that, if nationalisation measures would be brought within the scope of international law and had to be judged on the basis of those principles, they would be hampered in pursuing a policy of nationalisation with respect to the assets of the multinational corporations exploiting natural resources within their territories. In the host countries' view matters pertaining to nationalisation measures, such as their justification and the compensation that should be paid should be judged solely on the basis of the rules of domestic law and domestic policy objectives.

The debate on the extent and scope of state sovereignty over natural resources and on the applicability of principles of international law in nationalisation matters culminated in 1974. In that year the General Assembly adopted three important resolutions, namely a Declaration and a Programme of Action on the establishment of a New International Economic Order (Resolutions 3201 and 3202 of May 1, 1974) and a Charter of Economic Rights and Duties of States (Resolution 3281 of December 12, 1974).

In the 1974 Charter some fundamental principles were stated which greatly affected the way in which the relationship between multi-national oil companies and developing host countries further developed. Without any overstatement, the 1974 Charter can be considered to contain and express the legal foundation and justification of the production sharing agreement. As will be shown, the concept of the production sharing agreement, as explained above, perfectly satisfies the declaratory provisions of the Charter. However this may be, it should be pointed out that before the Charter came into existence a few developing countries had already for some years worked with production sharing agreements.

Chapter II, Article 2 of the Charter reads (as far as relevant for the subject under discussion) as follows:

"1. Every State has and shall freely exercise full permanent sovereignty,

including possession, use and disposal, over all its wealth, natural resources and economic activities.

2. Each State has the right:

(a) To regulate and exercise authority over foreign investment within its national jurisdiction in accordance with its laws and regulations and in conformity with its national objectives and priorities. No State shall be compelled to grant preferential treatment to foreign investment;

(b) To regulate and supervise the activities of transnational corporations within its national jurisdiction and take measures to ensure that such activities comply with its laws, rules and regulations and conform with its economic and social policies. Transnational corporations shall not intervene in the internal affairs of a host State. Every State should, with full regard for its sovereign rights, co-operate with other States in the exercise of the right set forth in this subparagraph;

(c) To nationalise, expropriate or transfer ownership of foreign property, in which case appropriate compensation should be paid by the State adopting such measures, taking into account its relevant laws and regulations and all circumstances that the State considers pertinent. In any case, where the question of compensation gives rise to a controversy, it shall be settled under the domestic law of the nationalising State and by its tribunals, unless it is freely and mutually agreed by all States concerned that other peaceful means be sought on the basis of sovereign equality of States and in accordance with the principle of free choice of means."

The 1974 Charter notwithstanding, many developing countries have, since then, entered with western industrialised countries into bi-lateral agreements for the promotion and protection of reciprocal investments. These bilateral agreements display a remarkable blending of western rules of international law with provisions of the Charter concerning the possibilities of nationalising foreign assets. Taking for example the United Kingdom/People's Republic of China Agreement of May 15, 1986 ("concerning the Promotion and Reciprocal Protection of Investments"), foreign investments may not be nationalised, except for an internal public or social purpose and against a reasonable compensation, such compensation to be based on the real value of the investment expropriated, to include payment of interest, be made without undue delay, be effectively realisable and be freely transferable. The company affected must have the right under the law of the host State making the expropriation, to prompt review by a judicial or other independent authority of that State, of its case and of the valuation of its investment. It will be clear that in this manner the applicability of domestic law is acknowledged but at the same time the principles of international law are now incorporated in the domestic law by means of the investment protection treaty.

The extent and scope of a State's sovereign powers over natural resources and the modalities of nationalisation measures have been further developed and "the state of the art" in this matter is represented in the text of 1994 European Energy Charter Treaty, namely in article 18 (Sovereignty over Energy Resources) and article 13 (Expropriation). The state of the art reflects not only the situation in the Member States of the OECD, but most importantly also the situation in East European countries and the Member States of the CIS, all of which are Contracting Parties of the Treaty. The text of article 13 is very similar to the text of article 5 (Expropriation) of the aforesaid United Kingdom/China Agreement of May 15, 1986. However, the article on sovereignty (article 18) differs greatly from the corresponding article in the 1974 Charter. State sovereignty is recognised but is not described as being "permanent". Because of its importance the text of this article is quoted in full:

> "(1) The Contracting Parties recognise state sovereignty and sovereign rights over energy resources. They reaffirm that these must be exercised in accordance with and subject to the rules of international law.
> (2) Without affecting the objectives of promoting access to energy resources and exploration and development thereof on a commercial basis, the Treaty shall in no way prejudice the rules in Contracting Parties governing the system of property ownership of energy resources.
> (3) Each State continues to hold in particular the rights to decide the geographical areas within the area under its jurisdiction to be made available for exploration and development of its energy resources and the rate at which they may be depleted or otherwise exploited, to specify and enjoy any taxes, royalties and other financial payments payable by virtue of such exploration and exploitation and to regulate the resource conservation and the environmental and safety aspects of such exploration, development and reclamation within the area under its jurisdiction, and to participate in such exploration and exploitation, inter alia, through direct participation by the government or through state enterprises.
> (4) The Contracting Parties undertake to facilitate access to energy resources inter alia by allocating in a non-discriminatory manner on the basis of published criteria authorisations, licences, concessions and contracts to prospect and explore for or to exploit or extract energy resources."

It should be noted that in paragraph (2) any rule of law vesting the ownership of minerals *in situ* in the owner of the land overlying the mineral deposit is respected. The reference in paragraph (3) to state participation reflects the fact that in some oil and gas producing West European countries and in the Member States of the CIS state participation is a common practice. As to paragraph (4), the reference to "contracts" as an alternative to licences and concessions accommodates the position of the East European countries

and the Member States of the CIS. Those States, given their background and past history of state ownership and state control and planning with regard to the exploitation of natural resources, have a "natural" preference for production sharing agreements which preference they share with the developing countries.

In the light of these developments (*i.e.* the proliferation of bi-lateral investment protection agreements and the emergence of the European Energy Charter Treaty) it may be concluded that the pertinent provisions of the 1974 Charter have lost their sharp edges and should be interpreted in a less strict fashion. Nevertheless the developing countries' satisfaction with the risk contract in general and the production sharing agreement in particular is beyond dispute and as briefly indicated above the acceptance of and interest in the PSA has recently spread to countries which are in a process of converting their centrally planned economies into a market economy, such as a number of the East European countries, the Russian Federation and some other Member States of the CIS. It should be noted that they have been preceded in this matter by the People's Republic of China.

From the description of the concept of a production sharing agreement (see above) it follows that a production sharing agreement fully respects the permanent sovereignty of the State over its natural resources, in this case petroleum. It achieves this in a manner that could never be achieved by the granting of exclusive licences or concessions. As a matter of fact, a PSA can be viewed as a production sales agreement whereby the state party sells a portion of the oil and gas production by delivering such portion to the contractor in exchange for the latter rendering operational services and funding the ensuing operations.

The breakthrough of the production sharing agreement came in the first half of the 1970s at the time when the traditional concessions and other licences in the Member States of OPEC (with the exception of Iran and Indonesia) were either nationalised, terminated, completely taken-over or ended with a 60 per cent state participation. The various actions and measures taken by the OPEC Member States were explained and justified by pointing to the need to introduce the New International Economic Order (Solemn Declaration of Sovereigns and Heads of State, Algiers, March 4 to 6, 1975). These events strengthened the need for a type of petroleum right that could be reconciled with the principles of the 1974 Charter but at the same time would not obstruct the flow of the much needed foreign investments.

One most practical aspect should not be overlooked. The enthusiasm for the production sharing contract as shown by developing countries should not only be ascribed to the fact that state sovereignty is upheld and maintained. For developing countries the fact that the state party is not primarily responsible for the funding of the petroleum operations (at most it may have been given the option to contribute to development expenditure) is of great practical importance. A production sharing agreement offers developing countries lacking the financial resources and technical experience to build up a domestic petroleum industry on their own the possibility to engage foreign oil companies and make use of the latter's financial and technical capabilities and resources for this purpose without having to make concessions in the matter of sovereignty over their domestic petroleum resources, *i.e.* without having to grant exclusive licences to these companies and running the risk of foreign domination over their petroleum sector.

It should be added that in the context of the nationalisation, termination or complete take-over of the traditional concessions in the Middle East Gulf States and the concessions in Venezuela the former concessionaires were offered non-risk service contracts accompanied by long term oil purchase contracts. This type of contract of work is only suitable for major oil producing States with a mature domestic petroleum industry within their jurisdiction.

HISTORICAL DEVELOPMENT

Indonesia

Indonesia was the first petroleum producing country to embrace production sharing agreements as the legal instrument for permitting foreign oil enterprises to undertake petroleum operations within its territory. PSAs were adopted in replacement of the exclusive licence agreements that had been terminated by virtue of Government Decree No. 44 of October 26, 1960.

The origin of the concept can be traced back to the Netherlands-Indies Mining Law of 1899, as amended in 1919. In accordance with article 5a of this Law, the competent minister could be authorised by special law to enter into contracts with an oil enterprise granting the latter (the contractor) the exclusive right to search for and produce petroleum within a certain territory and for a certain number of years. A contractor was obliged to pay a royalty and a proportional part of the gross profit (revenues less costs and losses carried forwards). The proportion was related to the annual capital expenditures. The government had the right to demand the royalty and profit share be paid in oil or oil products, provided the oil or oil products so received would be used by the government for its own needs. Clearly, it is only a small step from this type of contract to the PSA.

Government Decree No.44 of October 26, 1960 determined that oil and gas are part of the national riches under the control of the State. The exploration and exploitation were declared to be the responsibility of the State which for this purpose could delegate this responsibility to national state enterprises. These enterprises had to be established by law. Such law established their authority to undertake the exploration and exploitation of petroleum. The Decree authorised the competent minister to designate enterprises which

should assist the national state enterprise in fulfilling its task, if so needed. Then existing licence agreements had in fact been nationalised and the former concessionaires were only allowed to continue exercising their rights for a period as short as possible and to be determined by government regulation. The affected concessionaires were accorded a preferential right in obtaining a contract of work with the designated state enterprise in respect to the area of their former (and suspended) petroleum agreement.

The present designated state oil enterprise is Perusahaan Pertambangan Minyak dan Gas Bumi Negara (Pertamina). Pertamina was established by Law No. 8 of 1971, in replacement of the state enterprise P.N. Pertamina which dated from 1968 and was now liquidated. In the words of the Law No. 8 of 1971 (article 5) the objective of Pertamina was to develop and carry out the exploitation of oil and natural gas in the widest sense of the word for the maximum prosperity of the People and the State as well as for creating National strength.

Pertamina's tasks are described in article 13 as follows: to carry out oil and natural gas exploitation for the acquisition of maximum prosperity for the People and the State (repeating Pertamina's objective) and to supply and serve the domestic demand for oil and natural gas, the implementation of which shall be regulated by government regulation. Pursuant to article 12: (a) Pertamina may co-operate with another party in the form of a "Production Sharing Contract"; (b) the terms and conditions of such co-operation shall be regulated by a government regulation; and (c) the production sharing contract shall become effective as of the moment of approval by the President. In the "Elucidation" annexed to the Law it is stated that in this co-operation the most favourable terms for the State have to be sought. Furthermore it is stated that every production sharing contract which has been approved by the President will be notified to Parliament.

It is noteworthy that from the earliest contracts onwards an element of mandatory state participation can be detected. Pursuant to the relevant condition, Pertamina was entitled to require a foreign contractor to offer (within three months after the first declaration of commercial discovery) a five per cent, later increased to 10 per cent participating interest in his contract to an Indonesian enterprise designated by Pertamina (according to later contracts Pertamina could also designate itself). If contractor's offer is accepted, the ensuing co-operation between contractor and the Indonesian participant is governed by the rules of an agreement of co-operation, the main principles of which are attached to the production sharing agreement concerned.

Initially the production sharing agreements were seen as income tax but the contractor's income taxes were considered to be part of Pertamina's share of the profit oil and the latter was responsible for payment. In order to satisfy all formalities a contractor received tax receipts from the tax authorities enabling contractor to demonstrate (mainly *vis-à-vis* the tax authorities of his home country) that he not only had been subject to income tax but that the tax had also been paid. In the 1980s the Indonesian government was persuaded to change the income tax paying procedure and to accept direct payment of income taxes by the contractor, due to the difficulties which U.S. oil companies experienced (in their dealings with the U.S. Internal Revenue Service) in getting the tax payments made by Pertamina on behalf of the contractor accepted and recognised for the purpose of the foreign tax credit. The IRS considered and treated the Indonesian production sharing agreements as royalty paying agreements in respect of which no income tax in the sense as understood under U.S. fiscal rules was paid. All Indonesian contracts were amended providing for a revised share of profit oil in favour of contractor and bringing cost recovery rules in line with cost deduction schedules as applicable under customary western style income tax legislation.

Indonesia offers an example of a country where nationalisation of foreign petroleum rights was not intended as a means of establishing a state controlled and managed domestic petroleum industry (as was the purpose of the nationalisations that took place in Mexico in 1938 and in Iran in 1951) but rather as the first step (together with the establishment of national state enterprises) in opening the way for awarding risk contracts instead of exclusive licences.

Egypt and Syria

The next country to adopt the concept of production sharing contracts was Egypt. As late as 1969, state participation in concession agreements still belonged to the "Preference Items for Concessions in the U.A.R." as published by the Egyptian Government. However, soon thereafter the concept was considered of merging the principle of state participation with the more exotic principle of production sharing known from Indonesia. In May 1970 a typical Indonesian style PSA was concluded between the Egyptian General Petroleum Corporation (EGPC) and the North Sumatra Oil Development Corporation (NOSODECO), a Japanese company. As of July 1973, EGPC has concluded a great number of agreements on this new pattern, in which some features of the preceding state participation agreements were retained.

At the same time the more important of the earlier participation agreements (e.g. the participation agreement under which the prolific Morgan field was produced) were converted into a PSA.

As from the time PSAs became generally applied in Egypt, the PSA was adopted in Syria in almost identical form. The Syrian government was assisted by officials from EGPC's concession department. There was however a difference introduced. This concerned a variation in the payment of royalty. Under the Egyptian PSAs royalty was due but EGPC was responsible for paying this royalty from its own resources. Under the Syrian PSAs the royalty

took the form of setting aside a part of the production for delivery to the State, thereby reducing the production on which contractor and state party could lay a claim by way of cost oil and profit oil.

Peru

In 1971 a simple form of production sharing was introduced in Peru. It had been the international petroleum industry itself (in this case Occidental Petroleum Corporation) which acquainted the country with the concept. Under the terms of the Peruvian contract the production made available by the contractor was divided in two equal shares between Petroperu, the Peruvian national state oil company, and the contractor. The latter was liable to pay income tax. As of 1985, PSAs were replaced by a different type of contract, the so named risk bearing service agreements. Under the rules of this type of agreement the contractor is paid a fee expressed in U.S. dollars per barrel produced.

The Philippines

By Presidential Decree of December 22, 1972 "on the promotion of petroleum exploration and production in the Philippines" new conditions for service contracts were published. The service contracts appeared to be similar to the Indonesian style production sharing agreements but with proceeds sharing instead of production sharing, *i.e.* in essence, total production is sold by contractor and the sales proceeds are shared between the parties in the same way as production would have been shared between them. The contracts are made between a foreign oil company (contractor) and the Petroleum Board (state party) and their main features are the following: contractor undertakes, manages and execute petroleum operations, and meets all costs thereof; up to a maximum of 70 per cent of the gross proceeds from production may be used by contractor in repayment of costs incurred; the Petroleum Board receives 60 per cent of the net proceeds defined as gross proceeds less cost incurred within the 70 per cent limit and less the Philippino Participation Incentive Allowance (PPIA), if applicable. The PPIA is expressed as a discount off sales price and is granted to the contractor with Philippino participation.

An incentive is granted if a contractor agrees to set up a joint venture with a Philippino partner. In the case of Indonesia a contractor has to make an offer for five per cent or 10 per cent national participation without receiving any compensation therefor.

The contractor receives 40 per cent of the net proceeds plus the PPIA, if applicable. Further terms and conditions include: valuation of crude oil for determining gross proceeds to be based as to exported crude oil on the posted price, which is the f.o.b. price as established by the contractor in consultation with the Petroleum Board, and as to local sales on the price realised in arm's length deals; all foreign currency earned by export sales may be kept abroad except foreign currency needed for payments to the Petroleum Board and for covering costs incurred in local currency; the contractor to be subject only to income tax, but all income tax including any tax on distribution of income to shareholders to be assumed and paid by the Petroleum Board on behalf of the contractor.

Sales proceeds sharing instead of production sharing comes very close, albeit more in substance than in form, to the holding of an exclusive licence.

Libya

In Libya production sharing contracts were applied as of 1974. The same oil company, that had been instrumental in introducing the concept in Peru, signed on February 7, 1974 the first contract of this type with the Libyan National Oil Corporation, NOC. This corporation had been established in 1970. Up to that time exclusive petroleum rights had been granted in the form of concessions under the terms of the Petroleum Law of 1955. Upon the introduction of PSAs, the Petroleum Law was not abolished but its scope was restricted to the activities of NOC. Exclusive oil rights were reserved for and only granted to NOC. The latter became authorised to enter into PSAs with interested foreign oil companies, provided any proposed and negotiated agreement was submitted to the governmental authorities (the General People's Committee) for approval.

The pattern of the Libyan contract was rather similar to that of the Peruvian contract but there were some important differences. For instance the production was not divided into two equal parts but in proportions much more favourable to NOC, such for instance 81/19 or 85/15. Because of this disproportionate division the Libyan contractor was exempted from having to pay any income taxes (nor royalties for that matter). There was also a difference in the matter of development work. After a commercial discovery in a block was made NOC would contribute to the operating costs and development costs to be incurred up to the date of export. These costs would be shared between NOC and the contractor in the same proportion as the production would be shared, say 81/19 or 85/15. Initially, NOC's contributions to development expenditure were treated as loans which had to be paid back by the contractor over a number of years, repayment to start when a certain level of production had been reached or a certain quantity of petroleum had been produced.

To take an example: as soon as the cumulative production, all blocks taken together, would have reached the level of 100 million barrels, the contractor concerned was obliged to start repayment of NOC's contributions at a rate of five per cent per year. In other contracts, in particular those concerning

non-associated natural gas, no repayment is required. In the course of time the terms concerning the production sharing proportions, NOC's contributions to development expenditure and repayment obligations, if any, were varied to make contracts economically favourable or less favourable, depending on whether non-associated gas or crude oil was involved, on the prospects of finding petroleum in particular contract area and on the level or expected level of the international oil price, but the pattern of the original 1974 contracts has always been maintained.

A peculiar feature of the early Libyan contracts was that supervision over operations was exercised not by NOC but by a management committee consisting of two members representing the Libyan State and one member from the contractor. In fact, the management committee established by the nationalisation decree of September 1, 1973 acted as management committee for the purposes of the production sharing agreements. Later this was changed in the sense that two Libyan members were appointed by NOC. Decisions are taken by simple majority, hence NOC is in firm control as it would have been if itself would have been the supervisory body.

Malaysia

In Malaysia the ground work for the adoption of PSAs was laid by the Petroleum Development Act 1974 which came into force on October 1, 1974. By virtue of this Act:

(i) all existing petroleum agreements were cancelled as of April 1, 1975, and

(ii) the ownership in and the exclusive right of exploring for, exploiting, winning and obtaining petroleum was vested into a state-owned Corporation, which was named Petroleum Nasional Berhad ("Petronas"). Petronas was granted complete freedom to design and the form, terms and conditions of any new petroleum contracts, including those that were meant to replace the agreements that had been cancelled by the Act.

Petronas was and is under no obligation to submit finally agreed terms to its government for approval. This means that only Petronas is involved in the making of the new agreements. As a consequence, changes and amendments to the agreements can be arranged between and among Petronas and a contractor in mutual agreement without the intervention of any state authority or of the legislature. Following the example given by Indonesia in 1971, Petronas chose the concept of production sharing as the standard for new agreements, but, in contrast with the Indonesia example, the sharing of production between state party and contractor was from the outset not seen as an income tax replacing or tax absorbing arrangement and was not meant to exhaust the methods to determine government take. As a matter of fact, the already existing Petroleum (Income Tax) Act 1967, which imposed a tax on income from petroleum operations, was maintained albeit the Act in several aspects had to be amended in order to cater for the peculiarities of the new arrangements. The first PSAs were signed on November 30, 1976.

Special features of the Malaysian contracts include a special levy (cash payment) on profit oil barrels (at current prices inoperative) and by the imposition of an export duty on the profit oil barrels exported. Furthermore recent contracts provide for state participation (through a Carigali, a subsidiary of Petronas) in the contractor's side of the contract.

Angola

The State of Angola became independent in November 1975. In petroleum policy matters the government was guided by the example of Malaysia. In 1978 a new petroleum law (Law 13/78 of August 26, 1978) was enacted. It clearly showed that the makers were inspired by the principles of the 1974 Charter. The Law, which is a framework law leaving details to be filled in by subsidiary legislation (government regulations), declared all onshore and offshore petroleum deposits to be the property of the People of Angola and all the exploration and exploitation rights to be transferred to Sonangol, the Angolan state oil agency.

Sonangol was not authorised to alienate its mining rights, neither partially nor totally. As from the moment the Law would come into force all then existing petroleum rights would be considered as void and deemed to have been transferred to Sonangol. Any foreign company possessing the necessary technical capabilities and financial capacities and wishing to explore within the national territory was permitted to do so but only in association with Sonangol and within the areas comprised in the licences granted to Sonangol. This association could be in the form of a 51/49 joint venture (this possibility was restricted to the onshore) or a production sharing contract (this possibility was available for both the onshore and the offshore).

At the end of 1979 the terms of the envisaged production sharing contracts were made public. The terms appeared to follow the Egyptian style, except that an operating committee fulfils the role of the board of directors of the Egyptian joint operating company and except that the payment of an excess profit tax was required per barrel profit oil. The levy equalled the difference between the barrel's market value and a certain indexed base price. In 1984 the price cap amounted to US$22.70. The excess profit tax reflected the Angolan government's preoccupation with creaming off excess profits generated by the high price level prevailing in the early 1980s.

The People's Republic of China

In August 1982, China invited foreign oil enterprises to apply for production sharing agreements with respect to the Chinese part of the continental shelf. The basis for the contracts was laid down in the *Regulations of the People's Republic of China on Exploitation of Offshore Petroleum Resources in Co-operation with Foreign Enterprises* which had been made public on January 30, 1982. The new Regulations followed the by now classic Indonesian approach: the ownership of petroleum *in situ* on the continental shelf was vested in the State. The Chinese National Offshore Oil Corporation (CNOOC), which had been established at the same time, was given the exclusive right to search for and exploit such petroleum. CNOOC should undertake the licensed activities in co-operation with foreign oil enterprises.

The Regulations contained the main principles on the basis of which the co-operation should take place. The standard chosen appeared to be production sharing characterised by two special features: the production sharing concept is applied to each individual field and CNOOC is given the option to participate in the development of any such field with a share of up to 51 per cent. Development cost oil as generated by a particular field is divided between contractor and CNOOC in proportion to both parties' individual contributions to the costs of development. Remaining oil (*i.e.* oil remaining after royalty oil (12.5 per cent), tax oil (5 per cent) and cost oil (up to 50 per cent of production) is divided between the contractor and CNOOC as participant on the one hand (X per cent) and CNOOC as state party on the other 1-X per cent). The X-factor is determined on the basis of successive tranches of levels of daily production, each tranche having its own X-factor. X-factors were fixed in negotiations with applicants.

Nigeria

Shortly after Nigeria became a member State of OPEC (July 1971) OPEC's conference (extra-ordinary meeting of September 22, 1971) adopted a resolution calling upon the members to start negotiations with their respective concessionaires and licence holders on the acquisition of a state interest in the traditional concessions in the Middle East Gulf area and in other licences. Nigeria did not actively participate in these negotiations, but was satisfied with implementing the results thereof with respect to the licences and oil mining leases under its jurisdiction. By means of an agreement signed on June 11, 1973 with the concessionaire the Nigerian government acquired a 35 per cent interest in those petroleum rights. Later, in two successive steps, this initial interest was increased to 60 per cent. Through nationalisation of a 50 per cent foreign shareholding in the major concessionaire the government further increased state participation to 80 per cent. Later again, this share was reduced to 60 per cent.

The government's interest in OPEC style state participating had been focused on its main producing areas. For new exploration acreage the government had shown to be prepared to experiment with the concept of production sharing. In 1972 a production sharing agreement was concluded with an American oil company. At that time, Egypt had already decided to switch to the concept and was negotiating and signing a great number of production sharing agreements. Undoubtedly, the Egyptian contracts had stood model for the Nigerian agreement. Nevertheless there were three important deviations from the Egyptian example.

First, the Nigerian agreement did not have an autonomous contract area. Instead, the contract area coincided with the area of two oil prospecting licences granted to and held by the state party (in this case the Nigerian National Petroleum Corporation, NNPC). Being the licence holder made NNPC responsible for maintaining the licences in good standing, for fulfilling any area relinquishment obligations and also responsible for the conversion of the prospecting licences into oil mining leases after commercial discovery, all in accordance with the applicable petroleum legislation.

Secondly, the Nigerian agreement provided for setting aside a portion of the production (a portion referred to as tax oil) for the payment of the special Petroleum Profits Tax. Profit oil therefore amounted to what remained of the production after deduction of cost oil (a fixed 40 per cent) and tax oil (55 per cent of the production remaining after cost oil, the percentage figure represented the then prevailing rate of the Petroleum Profits Tax). The so remaining profit oil portion is divided between NNPC and the contractor in proportions of 65/35 (lower tranche, up to and including 50,000 b/d) and 70/30 (upper tranche, in excess of 50,000 b/d).

Not only the cost oil allocation (a fixed 40 per cent) but also the division of the profit oil was very similar to the production sharing envisaged under the Egyptian NOSODECO contract signed in May 1970. Lower tranche, up to and including 50,000 b/d, profit oil is shared 69.5/31.5, second tranche, in excess of 50,000 b/d, profit oil is shared 75/25. On the other hand, under the rules of the Egyptian contract delivery of tax oil was not envisaged. Contractor was subject to Egyptian income taxes but contractor's income taxes were paid by EGPC on the former's behalf out of EGPC's share of profit oil.

Thirdly, the contractor remained throughout the duration of the contract responsible for carrying out the operations, no joint operating company was established (after making a commercial discovery) as was and still is the practice under Egyptian contracts. The agreement of 1972 remained an isolated event. Not before the early 1990s did the Nigerian government again offer oil companies the opportunity to enter into production sharing agreements with NNPC. This change in policy took place in connection with opening up the Nigerian exclusive economic zone, including its continental shelf, for

exploration. In fact prospecting licences were on offer to be formally acquired by NNPC.

Oil companies interested in starting an exploration venture could apply or make a bid for a production sharing agreement with respect to NNPC's licences covering the exploration acreage of their choice. As licensee, NNPC is responsible for keeping the licences in good standing and, in case of commercial discovery, for timely converting the prospecting licences in oil mining leases. The contractor has to work within the rules provided for in the licences, possible future oil mining leases and the applicable petroleum legislation. A portion of oil (royalty oil) is reserved for NNPC in order to allow the latter to pay the royalty due to the State under the terms of any offshore oil mining lease (rates depend on water depth and are ranging between 20 per cent (shallow water) and 0.0 per cent (water depth in excess of 1000 metres). A further portion of production is allocated to the contractor for recovery of the operating and capital costs incurred by him in accordance with the rules of accounting incorporated in the agreement.

The next portion, referred to as tax oil, is allocated to NNPC in order to allow the latter to pay on behalf of itself and contractor the petroleum income tax due in accordance with the Petroleum Profits Tax Act (PPT). In this case, taxable income consists of the difference between the proceeds and deductible costs of the total venture, as calculated in accordance with the rules of the PPT. However this may be, contractor must be seen (*vis-à-vis* the tax authorities of his home country) as having been subject to the PPT and as having actually paid its share of the PPT imposed. Therefore the PPT paid by NNPC to the government is allocated between the parties on the basis of actual proceeds received and actual costs incurred. The remaining production is divided between NNPC and contractor in proportions depending on levels of cumulative production.

Other countries

Many more developing countries, when opening up their territory for exploration to foreign oil companies, have opted for adopting the concept of production sharing as the vehicle to engage and co-operate with the latter. To mention a few: Yemen, Myanmar, Vietnam, Ivory Coast, Ghana, Tanzania. Apart from Nigeria, other non-western, major petroleum producing countries, such as Oman (1975) and other Gulf States, similarly experimented with the production sharing concept but its application remained restricted to new exploration ventures situated outside their main producing areas. The latter remain state controlled or governed by concessions or licences with majority state participation. Since the 1990s, East European countries, the Russian Federation, Kazakhstan and some other member States of the CIS have followed their example.

THE ORIGINAL INDONESIAN MODEL

Indonesia was the first host country where the production sharing agreement was adopted and applied. For Indonesia the concept was not something radically new. As mentioned before, the origins of the concept can be traced back to the colonial mining legislation of the former Netherlands Indies. The early Indonesian production sharing agreements stood at the basis of the concept's further development and evolution that took place not only in Indonesia itself but also in all other countries that followed Indonesia's example and made the concept the centre piece of their petroleum regime. The original model is summarised in Pertamina's *Summary of Indonesian Oil Contracts*, (2nd ed. 1972), in which the data of all contracts concluded between 1969 and 1971 are represented.

The broad principles are the following:

(i) Duration of contract 30 years including a period of 10 years for exploration;

(ii) Contract is automatically terminated if within the 10 year exploration period contractor does not succeed in discovering petroleum;

(iii) During the 10 year exploration period, at regular intervals, parts of the contract area have to be relinquished;

(iv) Pertamina is responsible for the management of the operations. The contractor is responsible to Pertamina for the execution of the operations and provides the necessary funds therefor;

(v) If petroleum is discovered which in the judgment of Pertamina and the contractor (alternatively: in the judgment of the contractor after consultation with Pertamina) can be produced commercially then the contractor will commence development;

(vi) The contractor is responsible for the preparation of annual work programmes and corresponding budgets. Any such programme and budget are submitted for approval to Pertamina. (*Note*: in an actual contract it is stated that when considering work programmes and budgets proposed by contractor, Pertamina will give due consideration to the fact that the contractor carries the risk of and provides the necessary funds for the petroleum operations). Pertamina's agreement to a proposed work programme shall not be unreasonably withheld;

(vii) If Pertamina wishes to propose a revision as to certain specific features of the submitted work programme and budget Pertamina and the contractor shall meet and endeavour to agree on the revisions proposed by Pertamina. In any event, any part of the work programme as to which Pertamina has not proposed a revision shall in so far as possible be carried out as prescribed therein;

(viii) It is recognised by both parties that the details of a work programme may require changes in the light of changing circumstances. The contractor is authorised to make such changes provided they do not change the general objective of the work programme;

(ix) Pertamina shall periodically consult with the contractor with a view to the fact that the contractor is responsible for carrying out the work programme adopted pursuant to the contract;

(x) The contractor is obliged to execute a work programme in a workmanlike manner and by any appropriate scientific methods;

(xi) Up to a maximum of 40 per cent of available crude oil production may be taken by the contractor in repayment of costs incurred. In this context and for this purpose "costs" mean expenditures as paid, without application of depreciation or amortisation rules, even when the purchase or acquisition of capital assets is concerned;

(xii) The balance of crude oil remaining after the contractor has taken his entitlement to cost oil (at least 60 per cent of total production) is split 60 per cent to Pertamina and 40 per cent to the contractor (main producing areas) or 65 per cent to Pertamina and 35 per cent to the contractor.

After the dramatic increase of the international oil price at the end of 1973, beginning 1974, contracts were amended and a system of successive daily production tranches was introduced. Each daily production tranche was divided into cost oil (tied to a maximum of 40 per cent of the tranche) and profit oil. For each tranche higher in the series the split of the profit oil portion became more favourable to Pertamina. In fact the original profit oil split of 65/35 was under the new system only applicable up to 75,000 b/d (the bottom tranche); the profit oil in the next tranche, which ranged from 75,000 b/d to 200,000 b/d, was divided 67.5/32.5; and profit oil in the upper tranche, *i.e.* that part of the production in excess of 200,000 b/d, was divided 70/30. In addition, an excess profit charge was introduced payable in cash with respect to each barrel of net profit oil. In this context, net profit oil meant the profit oil remaining after satisfying the domestic supply obligation.

The excess profit charge amounted to a certain percentage of the difference between the selling price and a base price which was fixed at US$5 per barrel. The intention was to replace the respective 65/35; 67.5/32.5 and 70/30 proportions, in which net profit oil was divided, by a new 85/15 proportion but only in respect of the aforementioned price difference. As a result the amount of the excess profit charge payable per barrel net profit oil in respect of the bottom tranche can be calculated as: (.35 − .15) × ($12 − $5) = $1.40 (assuming a selling price of $12 per barrel). For the next tranche it would be (.325 − .15) × ($12 − $5) = $1.225.

(xiii) Up to 25 per cent of total crude oil production had to be supplied to the domestic market. The actual amount that had to be delivered within the said 25 per cent limit was a certain fraction of the Indonesian domestic consumption. This fraction was found by dividing total contract production by total Indonesian production (all dividing total contract production by total Indonesian production (all contract areas taken together). The domestic supply obligation was shared between Pertamina and the contractor in the same proportions as profit oil was divided between them. If the system of dividing daily production in tranches was applicable, up to 25 per cent of each tranche had to be delivered to the domestic market. The contractor received US$0.20 per barrel for crude oil delivered to the domestic market.

(xiv) Pertamina is fully entitled to take its share of profit oil in kind. If Pertamina elects to take any part thereof, it shall so advise the contractor not less than 90 days prior to the commencement of each semester of each year provided that such election shall not interfere with the proper performance of any crude oil sales agreement which the contractor has executed prior to the notice of such election. If Pertamina does not take its share of the profit oil in kind the contractor is obliged to market Pertamina's share to the best of his abilities. If however Pertamina can realise a better price for the contractor's cost oil, it can exercise an option to market this portion of the production itself.

(xv) The contractor is entitled to retain abroad the proceeds of the sale of all crude oil from the venture, except for the proceeds of Pertamina's share of the profit oil sold by the contractor.

(xvi) Valuation of the crude oil production for the purpose of the contract is based on realised prices f.o.b. point of export in Indonesia as paid by third parties, or, if there are no such third party sales and prices, as price shall be derived from prices paid by third parties for crude oil of similar type and quality.

(xvii) The contractor is subject to Indonesian income taxes and all other taxes, including all dividend withholding taxes or taxes imposed on the distribution or remittance of income or profit by contractor. However, all such present and future taxes are to be paid and assumed by Pertamina out of its share of the profit oil. The contractor will receive from the tax authorities official receipts evidencing that all taxes due by him had been paid.

(xviii) If associated natural gas cannot be commercially exploited it has

to be flared or put at the disposal of Pertamina for the latter's account. If natural gas can be commercially exploited, Pertamina and the contractor may decide to participate in a gas project. Costs and revenues will then be treated on the same basis as in the case of crude oil. (*Note:* as was customary in the early contracts there are no specific provisions made for natural gas; in those days markets for natural gas had still to be developed).

(xix) Pertamina is entitled to request the contractor to offer a 5 per cent undivided interest in contractor's side of the contract to an Indonesian enterprise (Indonesian participant) to be designated by Pertamina. Pertamina should make its request within three months after the contractor's first declaration of commercial discovery. The Indonesian participant must repay five per cent of the costs incurred by the contractor up to that moment. Repayment should be made in cash or kind. If in kind, 50 per cent of the Indonesian participant's share of production would be reserved for that purpose and the amount to be repaid would be increased by 50 per cent.

Systematically, the contents of any production sharing agreement may be thought to be made up of five distinct Parts. Each Part will now be examined in more detail.

PART I: REGULATORY PROVISIONS

Parties

Parties are on the one part an authorised state enterprise (state party) and on the other one or more oil companies. In some host countries *e.g.* Egypt, Syria) the government is also a party and will co-sign the agreement. If the government is a party it takes the place of the state party in matters of approving assignments and termination of the contract. If there is more than one oil company, the latter constitutes collectively the contractor.

Authority

When entering into a production sharing agreement, a state party is either acting pursuant to a general authority granted by a basic or special petroleum law or acting as the holder of a specific exclusive exploration and/or production licence granted in conformity with the terms and conditions of the applicable petroleum law. An extreme example of conferring a general authority is presented by the Malaysian Petroleum Development Act 1974. By virtue of this Act all then existing petroleum agreements were cancelled with effect from a April 1975 and the ownership in and the exclusive right of exploring for, exploiting, winning and obtaining petroleum, whether onshore or offshore, was vested into a state owned corporation which was named Petronas. In consideration for having received the ownership and these exclusive rights Petronas is liable to pay royalties to the Federal Government and any State government. Petronas was granted complete freedom to set the form, terms and conditions of any new agreements, including those that were meant to replace the ones that were cancelled. Petronas was and is under no obligation to submit finally agreed terms to its government for approval.

In contrast, the freedom and status of Indonesia's state oil enterprise Pertamina are more restricted. In Indonesia the ownership of petroleum is vested in the State which has also been declared responsible for exploration and exploitation. The Indonesian State could delegate this responsibility to national state enterprises. Such delegation was effectuated by Law No. 8 of 1971 establishing the aforesaid Pertamina. As described before, Pertamina was permitted to co-operate with another party in the form of a production sharing agreement but any finally agreed production sharing contract required the approval of the President before the agreement would become effective. It will be recalled that in the "Elucidation" annexed to the aforementioned Law it is stated that in this co-operation the most favourable terms for the State have to be sought and that every production sharing contract which has been approved by the President will be notified to parliament for information.

In the People's Republic of China the ownership of petroleum *in situ* is vested in the State. The ministry of petroleum affairs is declared to be the competent authority in charge of offshore petroleum exploitation in co-operation with foreign oil companies. The forms of co-operation and the demarcation of offshore areas for such co-operation belongs to the competence of the ministry. The actual conduct of operations and co-operation with foreign oil companies is entrusted to the Chinese National Offshore Oil Corporation (CNOOC) under supervision of the ministry. It belongs to the competence of CNOOC to call for bids and to enter into contracts with foreign oil companies with respect to the demarcated areas.

In Egypt, the ownership of petroleum *in situ* is vested in the State and EGPC, the designated state oil enterprise, has been granted an exclusive concession for the exploration and exploitation of petroleum throughout the country. In accordance with Law No. 86 of 1956 a production sharing contract negotiated between EGPC and a foreign oil company becomes only binding until a special law is being issued authorising the responsible minister to sign the contract. By this procedure the contract is given the full force and effect of law.

In Syria a comparable situation obtains. Law No. 7 of 1953 declares all minerals to be the property of the government. The state owned Syrian Petroleum Company (SPC) was established by Legislative Decree No. 9 of 1974. Pursuant to this Decree, SPC is authorised to carry out all petroleum operations in the country. Whenever a foreign oil company expresses the wish

to work for SPC as a contractor and should the government agree with this request, it shall authorise the responsible minister to enter into a contract with SPC and the oil company as contractor. The contract is declared not to be binding unless and until a law is published approving and ratifying the contract and giving the latter full force and effect of law.

Some East European countries and Member States of the CIS, where a domestic petroleum industry still has to be built up (earlier described as pioneer countries), have followed the example given by the People's Republic of China *i.e.* a basic petroleum law declares petroleum *in situ* to be the property of the State and the government to have the exclusive authority to undertake petroleum exploration and exploitation within the territory of the State. A state owned enterprise is established or a special government or state agency (sometimes called Authority or Directorate) appointed to which the petroleum authority is transferred. The state agency or state enterprise is authorised to enter into contracts (in the contracts described as production sharing agreements) with foreign oil companies. The contracts become effective on the date the agreement is approved by the government.

Although not a pioneer country, the Russian Federation is developing a petroleum mining regime along the same lines. By the Law on the Use of the Subsoil of July 15 1992 a system of licensing was introduced. At the same time, the federal government had to make a decision on the legal basis on which foreign oil companies could be given access to petroleum and petroleum operations within the territory of the Federation. The state authority authorised to issue licences has the choice between granting exclusive licences either to joint venture companies owned and established by a foreign oil company and a particular state enterprise or to state enterprises alone. In the latter case it was the intention that the state enterprise/licensee should enter with foreign oil companies into production sharing agreements containing pre-established terms and conditions (*i.e.* terms and conditions as set forth in government regulations).

In developing countries, where at the time of introduction of the production sharing agreements a well developed regime of petroleum licensing is in existence and being applied, governments usually wish to uphold the existing petroleum legislation. This calls for an integration of the production sharing agreement within a licensing system. To this end a government issues exclusive licences (or concessions) to a state owned oil enterprise in conformity with the existing petroleum legislation and authorises the state enterprise/licensee to enter into contracts with foreign oil companies to undertake petroleum operations within the area of the licences concerned. Examples of developing countries where this approach has been and still is followed are Libya, Nigeria and Tanzania.

Where production sharing agreements have been integrated into a licensing regime they have to be implemented within the framework of the underlying licence. This means that a contractor should operate in such a manner that the state party/licensee can fulfil the conditions and procedures imposed by the licence. In this context it should be recognised that the state party/licensee is responsible for keeping the licence in good standing, for timely fulfilling the area relinquishment schedule, for fulfilling the obligatory exploration work programme and financial commitments, and for paying royalties.

Description of the Contract Area

In practice, exploration acreage on offer is divided into blocks on the basis of a geographical grid system. A contract may comprise one or more of such blocks. Alternatively, if the production sharing agreement is integrated into a licence, the contract area coincides with the area of the underlying licence.

Duration of the Contract and Area Relinquishment

Generally, distinction is made between an exploration phase and a development/production phase. The exploration phase is usually divided into sub-periods of two or three years. Parts of the original contract area may have to be surrendered at the end of the each sub-period. A contract will be terminated if within the duration of the exploration phase no commercial discovery is made. Under these circumstances a contractor will have lost his total investment. If at the end of the total exploration period commercial discoveries have been established the demarcated area of these discoveries may be retained, the area outside the demarcated areas must be surrendered. Total duration of a contract may be fixed at a specified number of years (*e.g.* 30 years). If so fixed, all petroleum discoveries declared to be commercial have to be developed and produced within this period. If at the end of the fixed contract period there are still fields being produced the contract usually provides for the possibility of an extension of the contract. Such provision should clarify whether the extension will be granted on the same conditions or whether conditions have to be renegotiated.

Generally, with respect to each commercial discovery a development area of sub-block comprising the discovery has to be demarcated. Within such area or sub-block development and production operations may be carried out for a period of a fixed number of years (say 15 to 20 years plus possible extensions). Alternatively, development work should take place within a specified development period, say two to three years, after which the development area is converted into a production area. Within a production area production operations may be undertaken again for a specified number of years, say 15 or 20 years, with the possibility of extension. The overall duration of the contract should comprise the successive development and/or production periods (plus possible extensions) and, if so needed, be extended accordingly. Alternatively, if the production sharing agreement is integrated

into an exclusive licence, the provisions of the licence regarded duration, area relinquishment and conversion, if applicable, apply.

Obligatory Exploration and Evaluation Work, Declaration of Commercial Discovery

With respect to each sub-period of the exploration phase a contractor usually is obliged to carry out a minimum amount of U.S. dollars on exploration work.

After making a discovery, a contractor is obliged to carry out a programme of evaluation work in order to decide whether the discovery is commercial.

Only discoveries declared by contractor to be commercial and so approved by the state party may be developed and produced in accordance with the rules of the contract.

Any contract should provide for the state party having an option to develop a discovery not declared to be commercial for its sole risk and account. If a state party would be interested in a sole risk and account development, it may have to use the services and facilities of contractor. To protect the interests of contractor, it should be agreed that costs hereby incurred by contractor are immediately recoverable from cost oil.

National Economic Interest Provisions

Developing countries, opening up their territory to foreign oil companies for exploration and exploitation of petroleum, will try to make use of the presence of the foreign oil companies and the latter's operations for the purpose of bolstering and supporting their domestic industry generally. To this end governments will insist on incorporating in their production sharing agreements clauses aiming to promote the national economic interest. These clauses consist of obligations imposed on contractor, concerning training of personnel, transfer of technology, use of locally manufactured goods, use of local services and local sub-contractors and giving preference to employing citizens of the country. The required training of personnel involve the training of contractor's national personnel as well as the raining of the state party's personnel and may take place within the host country or abroad using the facilities of any one of contractor's foreign affiliated companies. The cost of the training may or may not be partially or wholly recoverable from cost oil. If not, it ranks as a payment of a bonus by contractor.

The required transfer of technology is meant for the benefit of the state party and is expected to enable the latter to perform more efficiently the functions assigned to it under the rules of the agreement, such as acting as the supervisory body or participating in the activities of a management committee or in those of the board of directors of a joint operating company.

The contracts applicable in the People's Republic of China are characterised by the attention paid to and the emphasis put on transfer of technology. In these contracts transfer of technology is understood to mean and involve the application and use of contractor's or rather contractor's affiliated companies' technology to and for the benefit of the authorised petroleum operations. The use and application of contractor's technology include giving training to personnel in handling such technology.

Being obliged to give preference to the employment of nationals, to the use of locally manufactured goods and to the supply and other services offered by local enterprises (sub-contractors) puts a contractor and his operations at risk. The available nationals may not have the required skills, the required goods and services may not be available at the time they are actually required or too expensive or not meeting international standards. Having to use non-qualified personnel, sub-standard goods or incompetent sub-contractors or having to cope with long delivery times will harm and endanger contractor's operations. Hence contractors generally insist that these obligations are qualified in the sense that a contractor may purchase abroad and import any goods required for his operations, may employ foreign personnel, and may use the services of foreign sub-contractors (*e.g.* foreign drilling contractors), if nationals do not possess the necessary skills, if local goods and services are not available at all or, if they can be made available, are not competitive in terms of quality, price and terms of delivery. As a sanction against using foreign personnel, goods and services unnecessarily, a contract may provide that costs made in this respect (*e.g.* salaries paid to foreign personnel) are not recoverable from cost oil. Whether or not much attention is paid to national economic interest provisions depends on the status of the economic development of the host country concerned and the aspirations of its government in this regard. In particular in contracts applicable in Malaysia and the People's Republic of China a strong emphasis is put on incorporating national economic interest provisions.

PART II: FINANCIAL PROVISIONS AND DISPOSITION OF PRODUCTION

Financial Provisions

Generally, a contractor is responsible for funding authorised operations. But there are types of contract which provide for an option on the part of the state party to share in the funding of the development phase of any particular field as soon as the decision is taken to develop such field (as for instance envisaged by contracts applicable in China and Tanzania) or even for a commitment on the part of the state party to make such contributions (as

envisaged under Libyan contracts). Without exception however the funding of exploration work is the sole and exclusive responsibility of a contractor. If this work does not result in a commercial discovery, the contractor will receive no compensation and will have lost his investments.

A foreign contractor is obliged to provide the funds for the operations in convertible foreign currency (usually U.S. dollars are stipulated). Since production sharing contracts are mainly used and practised in countries with a weak and non-convertible currency and an economy prone to a serious measure of inflation, any contract should contain clauses providing the contractor some privileges in the matter of foreign currency exchange and U.S. dollar accounting.

An essential requirement for a foreign contractor is to be allowed to keep the proceeds of his export sales abroad, at least to the extent that any local payment obligations, such as payment of local taxes and locally incurred costs, have been fulfilled. This means that the foreign contractor should be exempted from the generally applicable obligation to surrender foreign currency proceeds to the central bank of the host country (in exchange for local currency), except as needed to satisfy liabilities expressed in local currency. Furthermore a contractor should be and usually is allowed to hold bank accounts in convertible foreign currency, to repatriate any surplus foreign exchange and to keep the books of account in US dollars.

Disposition of Production

Generally, a contractor is allowed freely to export his combined share of the crude oil production, *i.e.* the total of cost oil and contractor's share of the profit oil, albeit this freedom might be restricted by the imposition of an obligation to supply the domestic market other than and apart from a case of national emergency. With respect to the disposal of natural gas and NGL's special arrangements are made. Such special arrangements may involve a LNG-export project.

Unless the contractor is paid a realistic market price in freely convertible currency, supply to the domestic market has a negative impact on the contractor's venture economics. In contracts applicable in Egypt, under which EGPC has been given the preferential right to purchase a portion of the contractor's crude oil for the supply of the domestic market, the contractor's interests are protected in that EGPC must pay the price which is established as the value of cost oil. This value is derived from the market value. According to contracts applicable in Malaysia the state party (Petronas) has the right to purchase for domestic supply purposes from contractors up to 50 per cent of the quarterly volume of cost oil at a price equal to the cost oil value. According to contracts applicable in Indonesia contractors are obliged to supply a portion of their profit oil to the domestic market. In fact, a maximum of 25 per cent of the total crude oil production is reserved for the domestic market and the actual portion to be delivered is shared between Pertamina and any particular contractor in the same proportion as the profit oil is shared between them. According to recent contracts contractors receive for crude oil supplied by them 10 per cent of the cost oil value, albeit during the first five years of field production contractors are paid a price equal to the full cost oil value. According to a model contract recently proposed by the government of an East European country the state party is given an option to buy from the contractor the latter's total share of production subject to a mutually satisfactory purchase contract being agreed between the parties. The price to be paid by the state part, if it exercises this option, would be the price the contractor would have received in an arm's length transaction with a non-affiliated third party on world markets.

Arrangements for natural gas, which may include a scheme aiming to sell the gas produced on the domestic gas market, will generally only be made after a discovery of non-associated gas has been established and the possibilities of development and marketing, either locally or abroad, have been studied and evaluated. However in recent production sharing agreements as applicable in Egypt the disposal of natural gas production received more attention. As in the case of crude oil, priority must be given to meeting the requirements of the domestic market. If gas is to be disposed on this market, EGPC shall be the buyer under a long-term gas sales agreement. The parties shall consult together whether to build a gas plant to extract liquid petroleum gases (LPG, defined in the contract as a mixture of propane and butane) from gas produced under the contract. The costs of such a gas plant are recoverable from cost recovery petroleum, unless the minister agrees to accelerated recovery. EGPC has the option to pay for the gas purchased under any long-term gas sales agreement and for the LPG bought from the gas plant either in cash or in crude oil. If in the absence of a long-term gas sales agreement, gas or LPG is exported contractor may retain abroad the proceeds from exporting contractor's share thereof.

PART III: COST RECOVERY, PRODUCTION SHARING AND TAXES ON INCOME AND PROFITS

Cost Recovery

For the recovery of the cost incurred by him, a contractor is dependent on the volume of cost petroleum that the rules of a particular contract put at his disposal.

Generally, distinction is made between exploration, capital development

and operating costs. These costs may be recovered from the available cost petroleum in accordance with rules of amortisation and depreciation along the lines of the calculation of taxable income pursuant to income tax laws, but which will be different under different contracts. Cost recovery operates on a quarterly basis *i.e.* costs incurred in any quarter are recovered from the cost oil available in any such quarter. In case of under-recovery costs are carried forward t the next quarter.

Furthermore, distinction is made between recoverable costs and non-recoverable costs. Non-recoverable costs are costs made by a contractor in deviation from the rules of the contract. In particular, those costs are excluded which have been incurred in non-authorised work or do not appear in an approved budget. In some types of contract criteria are laid down for judging whether costs are acceptable for cost recovery. Unjustifiable costs or excessive costs, *i.e.* costs in excess of international prices, are not allowed to be recovered. These criteria will be applied by the state party when making use of its right to audit the cost. The audit exceptions raised by the state party will be discussed with the contractor. When agreement is reached between the parties the cost recovery may have to be retro-actively adjusted. To forestall problems in the audit phase, the state party will be involved in the process of awarding contracts. Usually the operator is required to award major contracts only on the basis of international tendering. The terms of the tendering will have to be approved by the state party. In the contracts applicable in Malaysia costs incurred without Petronas' prior approval in respect of hiring of equipment, plant and machinery are not recoverable.

It is of decisive importance from the point of view of a contractor's (discounted) cash flow economics (in which the factor time plays a decisive role) that the procedures allow contractor's costs to be recovered as soon after they have been made taking into account the applicable depreciation and amortisation schedules prescribed, and subject to the availability of cost oil. Generally speaking, a state party has an interest in limiting its contractor's claim on cost oil because any claim diminishes automatically the availability of profit oil and the state party's portion thereof, albeit some types of PSA provide for a percentage limitation on production volumes that can be used as cost oil. A state party's first concern lies in preventing that contractor recovering cost that under the rules of the PSA are not allowed to be recovered. In this regard, a state party will be inclined to request a prior approval procedure, *i.e.* a procedure under which no cost oil is assigned to expenditures incurred before the state party has given its approval (for their recovery). According to such a procedure cost oil may only be claimed for approved costs. It will be clear that such prior approval procedure, if conceded, may quite possibly delay the recovery of costs for a considerable time and hence have a detrimental effect on the contractor's (discounted) cash flow economics.

However this may be, it cannot be denied that control over costs made by the contractor is a legitimate concern of the state party. As a rule, PSAs provide for an auditing procedure, whereby in a later stage expenditures made are investigated and judged against the depreciation rules and the criteria described in the PSA. If the state party raises sustainable objections and the contractor agrees thereto, corrections to the cost recovery will be made and the calculations reversed. Depending on the circumstances such corrections may result in the contractor having to settle quantities of cost oil that were overlifted. It will be clear that an auditing procedure does not prevent costs being recovered which under the rules of the PSA should not have been recovered. A state party's concern in this respect can be met by providing for a pre-auditing procedure. The latter procedure should allow proposed expenditure to be scrutinised and judged against the auditing criteria of the PSA before these expenditures are actually made. Obviously such pre-auditing should take place in the shortest time possible in order to prevent that the operations by lack of funding have to be stopped.

An example of a superficially similar procedure is found in a recently made production sharing agreement concerning development of certain oil fields in a member State of the CIS. This agreement provides for the establishment of the contractor of Authority for Expenditure (AFE) procedures in accordance with standards of the petroleum industry for controlling major projects. The AFE-procedures prepared by the contractor have to be reviewed and approved by the management committee. Under this particular agreement the management committee is the supervisory body of the venture (see below). The contractor is obliged in his reporting to the management committee to report on the progress of each AFE. The management committee to report on the progress of each AFE. The contractor has the right to issue and approve AFE's within the limits of the work programmes and budgets as approved by the management committee and must submit copies of all AFE's issued to its members. It is clear that the procedure which is different from a pre-auditing procedure involving the state party. Nevertheless, it should go a long way in removing the concerns of a state party.

The operation of the accounting rules plus the differentiation into recoverable and non-recoverable costs result in the determination of the amount of the recoverable costs per quarter. If cost oil is limited to a certain percentage of the available quarterly production, the recovery can be made more complex by dividing production into successive tranches with each tranche higher in the series being assigned a lower cost oil percentage. In contrast herewith, some types of contract do not recognise or impose any volume restriction on the cost oil portion. This means that the total available production, after deduction of royalty petroleum, is available for recovery of the recoverable costs (as specified).

In order to provide incentives meant to help contractors faced with high cost operations, special cost related deductions may be allowed. Such allowances are expressed as a percentage of the capital development costs incurred and are recoverable in the same manner as costs actually incurred.

It should also be noted that a liberal depreciation schedule is in itself also an important incentive.

An important element of the cost recovery process is the evaluation of the oil or gas production. If the price used for the determination of this value is higher than the objective market value, the cost recovery remains incomplete to the disadvantage of the contractor. For this reason parties will strive to include in the contract an acceptable definition of the market value of the oil or gas that is hopefully going to be produced. Where oil is concerned, it is always difficult to give proper weight to gravity and quality characteristics, but if objective criteria are used (*e.g.* f.o.b.-prices as published in internationally recognised trade journals) it is possible to arrive at formulae that are acceptable to both parties.

Production Sharing Methods

The manner in which the production is shared between the State, state party and contractor depends on the rules of the individual contract. Contracts that are applicable in the same host country share the structure of the production sharing method but differ as far as absolute numbers and percentage figures are concerned. The actual figures are arrived at after negotiations with applicants and depend on competition and the particular circumstances of the contract and contract area.

With only a few exceptions, the total production is divided into three or four unequal portions. The first portion is destined for the State and is referred to as royalty oil (as mentioned before in this context oil includes gas). Where a contract provides for royalty oil the applicable percentage varies between 10 per cent and 15 per cent, usually made dependent on the level of daily production. A series of successive production slices or tranches may be defined whereby with respect to each tranche higher in the series a higher royalty percentage is applicable.

The second portion, referred to as cost recovery oil or cost oil, is assigned to the contractor for the purpose of recovering the costs incurred by him.

In some countries (*e.g.* Nigeria) contracts provide for a separate portion referred to as tax oil. The value of this portion represents the income tax that has to be paid by the state party and contractor collectively.

The third or fourth portion (*i.e.* if there is a tax oil portion) is referred to as remaining oil or profit oil and is shared in complex proportions between state party and contractor. A common method uses a series of successive daily production tranches and assigns to each tranche higher in the series a sharing proportion that is more in favour of the state party. The sharing itself concerns the profit oil part of each individual production tranche, *i.e.* each tranche has first to be divided in royalty oil, cost oil and profit oil before the sharing percentages can be applied.

A closely related method consists in dividing cumulative production in successive tranches and assigning to each tranche a different profit oil split. Over time, as cumulative production increases, the profit oil split will become more favourable to the state party. As provided for in some recent contracts (e.g. the Libyan model contract of April 15, 1989, discussed below) a relation is made between the sharing proportions and the status or completeness of the cost recovery. Under such relationship the sharing proportion becomes more in favour of the state party depending on whether "pay-out" has been achieved or depending on the continuously changing value of a factor representing the ratio between contractor's cumulative cash-in (*i.e.* the proceeds from the sale of cost oil and contractor's share of profit oil) and contractor's cumulative cash-out. It will be clear that until production starts the value of this factor is zero and that at pay-out time the factor equals one.

As previously remarked, when governments organise a bidding round for contracts in the context of opening up new exploration acreage they will make a model agreement available to applicants. In such model agreement only the structure of the production sharing is indicated leaving it to the applicants to make suggestions for the actual absolute numbers and percentages to be filled in.

Initially, the contracts adopted in Libya represented the simplest form of production sharing. The (crude oil) production was divided in two unequal parts, the largest part (81 or 85 per cent was commonly used) was destined for the state party (in this case the National Oil Corporation (NOC), which was established in 1970). Such a simple split has many advantages: it avoids discussions about the implementation of a cost recovery procedure (non-recoverable costs, disputed costs, reasonable cost oil values). It also avoids discussions about the implementation of complex profit oil sharing mechanism. The disproportionate split was accompanied by an exemption of income tax and royalties which added to the simplicity of the concept. This simplicity however was partly undone by the introduction of complex arrangements regarding NOC's contributions to development expenditures. Initially, NOC was committed to contribute its percentage production share (say 81 or 85 per cent) to development expenditures. The contributions were made in the form of loans to be repaid by the contractor at a rate of five per cent per year starting from the moment cumulative export would exceed 100 million barrels.

Later this financing arrangement was made more complex (exemption of repayment, partial repayment, payment with or without interest) in order to take account of different circumstances. Nevertheless, it appeared that a relationship with the actual amount of costs incurred by contractor could not be missed. A model contract dated April 15, 1989 contains the following rules as applicable to crude oil production. Division of production is implemented per individual block. The sharing proportions are fixed (say X per cent is assigned to NOC and (1-X) per cent is assigned to the contractor) until the

value of the contractor's share of cumulative block production equals the cumulative amount of the contractor's block expenditures. As from that moment (pay out time) the (1-X) per cent portion (now called net crude oil) is divided between NOC and contractor according to the formula: (Base Factor) × (A Factor) × (1-X). The base factor is determined on the basis of levels of daily production and the A factor is nothing else than the ratio between the two aforesaid cumulative amounts of respectively contractor's revenues and costs.

A more traditional method of production sharing is contained in the model production sharing contract attached to the 1989 Australia/Republic of Indonesia Agreement. Under this model contract the role of the state party is assumed by a Joint Authority established under the Agreement to administer a certain Zone of Co-operation in the area of which the petroleum operations have to take place.

According to the model contract distinction is made between first tranche production and second tranche production. First tranche production (10 per cent of total production during the initial five years of production, 20 per cent thereafter) is shared between the Joint Authority and contractor in a 50/50 proportion for natural gas and in escalating proportions for oil. The oil proportions escalate from 50/50, 60/40 to 70/30 depending on a series of three successive daily production tranches (0 to 50,000 b/d; 50,001 to 150,000 b/d; and more than 150,000 b/d). The second tranche production (90 or 80 per cent of total production) is in the first place reserved for cost recovery purposes. The recoverable costs consists in investments credits for exploration and capital expenditure (equal in value to 127 per cent of these costs) and operating costs (defined as the sum of exploration costs, non-capital costs and depreciation of capital costs). The investment credits have to be recovered from the second tranche production by priority. Income taxes have to be paid, but in cash and not in kind. Therefore there is not a tax oil portion. Any part of the second tranche production remaining after cost recovery is shared between the Joint Authority and contractor in the same proportions as the first tranche is shared between them.

It should not come as a surprise that this production sharing mechanism is very similar to that applicable under the most recent Indonesian contracts albeit these Indonesian contracts never leave out a domestic supply obligation (DSO) at 10 per cent of the export price with a 60 months of production DSO-holiday.

In practice, endless variations on the theme of production sharing are possible and indeed being applied in order to meet the circumstances of the individual case.

Recent Indonesian contracts offer a good example of adapting production sharing to the individual circumstances of a venture. Contractor's profit oil shares are increased for certain categories of production. In this context distinction is made between production obtained from frontier areas, from marginal fields (small producers), from special types of reservoirs where enhanced oil recovery methods are applied, or from fields located in deep water.

Taxation of Income and Levies on Excess Profits

Generally, the contractor and state party are both subject to any law of the host country that imposes tax on income or profit. In most cases this is the common income tax law, but it could also be special petroleum income tax law is the case in Malaysia and Nigeria. Usually the contractor has to pay any imposed tax in cash in the same manner as any other commercial enterprise subject to income tax but in Nigeria the petroleum tax has to be paid in kind (tax oil).

Under some contracts the government may choose whether the contractor should pay the tax levied on his income in kind or cash. Exceptionally, contracts applicable in Egypt and Syria require the state party to pay the contractor's income taxes on his behalf. The contractor will receive the proper tax receipts from the tax authorities. Said contracts define what constitutes the contractor's taxable income. This taxable income consists of petroleum revenues (Note: possible other revenues are apparently excluded) less recoverable costs plus the amount of income tax for which the contractor is liable. The addition of payable income tax to the contractor's taxable income is due to the fact that the contractor's tax is paid by the state party on behalf of the contractor. Consequently, the tax so paid forms part of the contractor's taxable income. This clarification is important for the domestic tax position of a foreign contractor (*e.g.* the foreign tax credit arrangement from which U.S. oil companies may benefit). It is also provided that the tax to be paid on behalf of the contractor should be paid out of the state party's share of the profit oil. In cases where the combined rate of the various applicable income taxes exceed 50 per cent, it causes contractor's taxable income and thereby the amount of tax payable to become an unrealistically large amount which cannot be accommodated within the monetary value of the state party's share of profit oil. To cope with such discrepancy (as occurs in Syria where the combined rate of various applicable income taxes is about 85 per cent) a limit has been put on the amount of tax payable by eliminating the addition of tax payable to contractor's taxable income.

The system of obliging the state party to pay for the contractor's income taxes had been copied from the earlier versions of the Indonesian contracts. In Indonesia itself the system had been discarded in the 1980s at the insistence of the U.S. companies operating in that country.

Libyan contracts exempt the contractor completely from paying any income tax (and royalties for that matter). Such exemption may put a foreign contractor within the orbit of the income tax laws of his home country. Having been exempted from paying income tax in the host country, could

result in a contractor having to pay income tax in his home country with respect to the tax-exempted income.

The payment of income tax, the delivery of royalty petroleum and the sharing of profit petroleum form part of the government take which brings into focus the matter of stability of conditions determining this take. The volume of royalty petroleum and the share of profit petroleum are contractual payments that have been agreed and accepted against the background of the payments due under the income tax law(s) as prevailing at the time the contract was negotiated and entered into and are assumed to remain the same during the validity of the contract.

An (petroleum) income tax paying contractor has however no guarantee that the (petroleum) income tax will similarly remain unchanged during that period.

Generally, there are two methods to achieve the desired stability of the government take:

(i) to freeze the rate of the applicable (petroleum) income tax; or
(ii) to adjust the contractual payments, such as the sharing of profit oil, in order to counter-balance any negative effects on the profitability caused by a future adverse change of the applicable income tax.

Applying the first method, a contract will provide that income tax will be levied at the rate existing on the effective date of the contract. Future changes to the rate of the income tax would then not be applicable to income derived from the contract. Such protection against future changes of the tax rate can only be offered by a contract that is a law in itself (*e.g.* contracts as applicable in Egypt and Syria).

An example of the method of contractual adjustment is provided by Malaysian contracts. Contractors are subject to the Petroleum (Income Tax) Act 1967, as amended with effect from April 1, 1975. It is stated in the contracts that if income tax were changed or new taxes specially meant for the petroleum industry were introduced in such a manner that the burden of taxation was significantly increased or decreased, Petronas and the contractor would mutually agree on an arrangement which was directed at restoring the original economic position of the parties. It should be noted that a stability provision in this form works both ways: if the burden of taxation were decreased, *e.g.* if a lower rate for the income tax were introduced, a contractor is, in principle, not supposed to benefit from such relief.

Another example of a so called economic stabilisation clause is provided by a 1992 model contract made available by an East European country. The relevant clause states that if the State (or the government) amends any existing tax rates or enacts any new tax as to adversely affect the economic benefit that contractor will derive from his contract then the parties will amend the contract as to effectively eliminate such adverse economic effects. It is added that the foregoing notwithstanding changes in laws and regulations regarding the protection of the environment and employment which are applicable to marginal fields (small producers), from special types of reservoirs where enhanced oil recovery methods are applied, or from fields located in deep water.

Taxation of Income and Levies on Excess Profits

Generally, the contractor and state party are both subject to any law of the host country that imposes tax on income or profit. In most cases this is the common income tax law, but it could also be special petroleum income tax law is the case in Malaysia and Nigeria. Usually the contractor has to pay any imposed tax in cash in the same manner as any other commercial enterprise subject to income tax but in Nigeria the petroleum tax has to be paid in kind (tax oil).

Under some contracts the government may choose whether the contractor should pay the tax levied on his income in kind or cash. Exceptionally, contracts applicable in Egypt and Syria require the state party to pay the contractor's income taxes on his behalf. The contractor will receive the proper tax receipts from the tax authorities. Said contracts define what constitutes the contractor's taxable income. This taxable income consists of petroleum revenues (Note: possible other revenues are apparently excluded) less recoverable costs plus the amount of income tax for which the contractor is liable. The addition of payable income tax to the contractor's taxable income is due to the fact that the contractor's tax is paid by the state party on behalf of the contractor. Consequently, the tax so paid forms part of the contractor's taxable income. This clarification is important for the domestic tax position of a foreign contractor (*e.g.* the foreign tax credit arrangement from which U.S. oil companies may benefit). It is also provided that the tax to be paid on behalf of the contractor should be paid out of the state party's share of the profit oil. In cases where the combined rate of the various applicable income taxes exceed 50 per cent, it causes contractor's taxable income and thereby the amount of tax payable to become an unrealistically large amount which cannot be accommodated within the monetary value of the state party's share of profit oil. To cope with such discrepancy (as occurs in Syria where the combined rate of various applicable income taxes is about 85 per cent) a limit has been put on the amount of tax payable by eliminating the addition of tax payable to contractor's taxable income.

The system of obliging the state party to pay for the contractor's income taxes had been copied from the earlier versions of the Indonesian contracts. In Indonesia itself the system had been discarded in the 1980s at the insistence of the U.S. companies operating in that country.

Libyan contracts exempt the contractor completely from paying any income tax (and royalties for that matter). Such exemption may put a foreign contractor within the orbit of the income tax laws of his home country. Having been exempted from paying income tax in the host country, could

result in a contractor having to pay income tax in his home country with respect to the tax-exempted income.

The payment of income tax, the delivery of royalty petroleum and the sharing of profit petroleum form part of the government take which brings into focus the matter of stability of conditions determining this take. The volume of royalty petroleum and the share of profit petroleum are contractual payments that have been agreed and accepted against the background of the payments due under the income tax law(s) as prevailing at the time the contract was negotiated and entered into and are assumed to remain the same during the validity of the contract.

An (petroleum) income tax paying contractor has however no guarantee that the (petroleum) income tax will similarly remain unchanged during that period.

Generally, there are two methods to achieve the desired stability of the government take:

(i) to freeze the rate of the applicable (petroleum) income tax; or

(ii) to adjust the contractual payments, such as the sharing of profit oil, in order to counter-balance any negative effects on the profitability caused by a future adverse change of the applicable income tax.

Applying the first method, a contract will provide that income tax will be levied at the rate existing on the effective date of the contract. Future changes to the rate of the income tax would then not be applicable to income derived from the contract. Such protection against future changes of the tax rate can only be offered by a contract that is a law in itself (*e.g.* contracts as applicable in Egypt and Syria).

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Obviously, if a contractor has been exempted from paying income tax or if the income tax, which he is liable to pay, is actually paid on his behalf by the state party concerned the rate of the tax or any change thereof in the future has no consequences for the contractor or the economics of his venture.

In addition to income tax some types of contract provide for the payment in cash of a special levy on profit oil barrels. This levy is calculated on the difference between market value (or cost oil value) and an indexed base price (as under early Indonesia, Malaysian and Angolan contracts). These arrangements have lost their significance at today's international price levels.

PART IV: ORGANISATIONAL AND CO-OPERATIVE ASPECTS

Operatorship

Generally, the contractor is the operator and as such responsible for and in charge of carrying out the operations authorised by and under the contract. During the exploration phase of the contract contractor is responsible for fulfilling the minimum exploration work programme and to spend the minimum expenditure commitments. Departures from this general pattern occur.

According to contracts applicable in Egypt and Syria a joint non-profit operating company (having the contractor and the state party as its shareholders) is established as soon as a commercial discovery has been declared. This joint operating company is responsible for carrying out the development and production operations and any further exploration work.

The operating company does not own any title to petroleum produced or any other asset or property obtained or used for the authorised operations. It carries no responsibility of its own. Any of the company's decisions is understood to be a decision of state party, contractor or state party and contractor as may be required under the contract. The operating company is funded by the contractor. Upon request (*i.e.* upon making cash calls) the operator shall receive in advance all the cash it needs for the operations. The company has a board of directors in which state party and contractor are equally represented. The contractor designates the general manager who shall also be a managing director. EGPC designates the chairman who shall also be a managing director. Hence there are two managing directors and one general manager. The establishment of a jointly owned operating company for the purpose of operating the venture as soon as it has become clear that commercial exploitation of petroleum is a possibility is a typical feature of

the Egyptian (and Syrian) contracts. Its incorporation in the contract can be explained by the circumstance that the Egyptian contracts have been developed against the background of state participation agreements in the context of which a joint operating company had to be formed after making the first commercial discovery.

Under other types of contract the contractor may be left in charge of the operations until the state party exercises its option to become operator with respect to any individual discovery or field. This approach is followed in contracts applicable in the People's Republic of China. The state party (in this case the Chinese National Offshore Oil Corporation (CNOOC)) has the option to take over the role of operator with respect to any field that has been brought into production. Such option may be exercised as from the moment all development costs incurred with respect to the field concerned have been recovered from cost oil generated by the field in question.

Generally speaking, the entity acting as operator, be it a jointly owned operating company or contractor himself, is responsible for preparing the annual work programmes and corresponding budgets and any specific plan for evaluation of a discovery and development thereof if commercially warranted. Subsequently, the operator is responsible for the execution of these programmes and plans (after the latter have been approved by the supervisory body) in accordance with the rules of the contract and any applicable petroleum and other relevant legislation in so far as such legislation is in existence. If relevant legislation is absent the necessary operational rules must be found in the contract. These rules (Part I provisions) are formulated as duties of the operator

Important duties include the operator's obligation to carry out petroleum operations in a proper and workmanlike manner and in accordance with good oil field practice, to prevent pollution of the environment, pay for the costs associated with clean-up of any pollution caused, to take appropriate abandonment measures upon termination of the contract, and to fulfil any of the national economic interest provisions. Standard duties of the operator include submitting to the state party copies of all relevant data and information obtained in the course of the operations, such as geological, geophysical and any type of well data, providing all personnel, financial and technical resources required for a proper performance of the operations.

If the contractor is the operator, he shall not be able to fulfil his duties without receiving the technical, financial and personnel support of an affiliated company and/or a parent company. How the contractor is organised and on whether or not the contractor belongs to a globally operating group of companies structured around a parent company and intermediate holding companies in their turn controlling service companies and numerous operating subsidiaries amongst which is the contractor. If a joint company is the operator, it will need the assistance of its contractor/shareholder, which in its turns needs to get the benefit of internal services. Consequently, when a joint operating company is the operator, the contractor is no more of a conduit for conveying services. An important task of the operator consists in organising the procedures to be followed in the awarding of major contracts. Usually the operator is required to award contracts exceeding certain financial limits by international tender. Exceptions may have to be made with respect to local services and the acquisition of locally manufactured goods.

Supervision of operations

The authorised operations are supervised by the state party directly or, exceptionally, by a management committee, consisting of representatives of state party and contractor.

In Indonesian or Indonesian style contracts supervision is called management. From the earliest Indonesian contracts onwards the relationship between Pertamina and the contractor is described as follows: "*Pertamina shall have and be responsible for the management of the operations. The contractor shall be responsible to Pertamina for the execution of the operations.*" This approach is also followed in the model production sharing agreement annexed to the Treaty between Australia and the Republic of Indonesia of December 10, 1989 (discussed above). In this model contract it is stated that the contract is subject to the Treaty, including the Petroleum Mining Code. The Joint Authority is responsible for the management of the operations contemplated under the contract in accordance with its management functions defined under the Treaty including the Petroleum Mining Code. The contractor is responsible to the Joint Authority for the execution of petroleum operations in accordance with the provisions of the contract and is hereby appointed as the exclusive corporation to conduct petroleum operations. The contractor is obliged to provide all human, financial and technical resources required for the performance of the petroleum operations authorised by the contract; is recognised to have an economic interest in the development of the petroleum pools in the contract area and to be entitled to a share in petroleum produced from the contract area in accordance with the relevant provisions of the contract.

The supervisory body (state party or management committee) performs its task by reviewing and approving, in the form as prepared and submitted by the operator, annual programmes of work and corresponding budgets, any declaration of commercial discovery and any plans to develop such a discovery and the award of major contracts. The supervisory body may propose changes to the submitted work programmes. The contractor may wish to change an approved programme in order to adapt the latter to changed circumstances. The supervisory body may wish to change an approved programme. Each type of contract contains different solutions for these problems.

To take the 1989 Australian/Indonesian model contract (again) as an

example, it is stated in that model contract that should the Joint Authority wish to propose a revision to specified aspects of the work programme and budget, the Joint Operating Authority shall specify its reasons for its request but shall not require the operator to undertake more petroleum operations than the minimum work programme and expenditure commitment specified in the contract. The parties must agree on any changes before they become effective. It is recognised by the Joint Authority that the details of the work programme and budget and the development plan may require changes in the light of existing circumstances and nothing in the contract shall limit the rights of the operator to make such changes provided they do not change the general objective, quantity and quality of the petroleum operations.

In a production sharing agreement applicable in Oman dated May 14, 1975 it is stipulated that as soon as possible after contractor shall have received the management committee's proposed revisions contractor shall either notify the management committee that the work programme and budget has been revised as proposed by the management committee or call for an extraordinary meeting of the management committee for the adoption of a work programme and budget by majority vote.

A similar approach is followed in a recent production sharing contract for development of certain petroleum reservoirs in one of the member States of the CIS. Under that development contract the contractor is obliged to prepare and present to the management committee for its approval a comprehensive plan for development of the oil fields concerned. Furthermore, the contractor is obliged to prepare and submit to the committee for its approval annual work programmes and corresponding budgets. The management committee shall consider and review any proposed plan for development and either approve as presented or any representative may propose such revisions as to specific points contained therein as may be deemed advisable from the point of view of internationally recognised oil field practice. As soon as possible after receipt of the committee's proposed revisions or amendments. The contractor must either notify the management committee that the plan of development has been revised as proposed by the committee or call for a meeting of the committee for the purpose of arriving at a mutually acceptable plan for development. The affirmative vote of all members of the management committee shall be required for approval of such plan of development. If a plan of development supported by the contractor has not been approved within six months of the submission of such plan to the committee, the contractor has the right to retain on behalf of the state party and himself an internationally recognised, independent Western petroleum engineering firm approved by the committee for the purpose of reviewing the contractor's plan of development. If following such review the firm agrees that the contractor's plan is reasonable and economically feasible, then such plan shall be deemed approved by the committee. It should be added that in this particular case the management committee consist of six members three of which appointed by the contractor and the other three by the state party. Each member has one vote. Decisions are reached by majority of votes cast with the contractor having a tie-breaking vote. However, decisions in certain important matters requiring unanimity include approval of the annual work programmes and budgets, approval of the annual allowable production and approval of the plan for development, any proposal for amendment of the contract, and the election of an internationally recognised independent auditor.

Under contracts applicable in Malaysia the contractor is allowed to change any approved work programme and budget without the approval of Petronas, provided the estimated costs do not change by more than 10 per cent. Similarly, Petronas is allowed to revise any approved work programme and budget provided the agreed annual budget would thereby not be changed by more than 10 per cent.

The requirement that work programmes, budgets, declaration of commercial discovery and corresponding development plan and the award of major contracts should obtain the approval of the supervisory body is an essential condition of a contract because, as usually stipulated therein, the operator is only allowed to execute work programmes and development plans and incur costs in connection therewith if these programmes and plans and corresponding budgets and contracts have been so approved. To reinforce this requirement, it is generally expressly stated that no compensation for or reimbursement of costs are given if these costs have been incurred in doing work that was not part of an approved work programme or have been incurred on the basis of a non-approved contract.

Of crucial importance are the procedures regarding a declaration of commercial discovery and the plan to develop such discovery. Generally, contracts require agreement between the supervisory body and the contractor about the existence of a commercial discovery and the overall development plan. The underlying thought is that a contractor should not be forced to develop a discovery which in his opinion (using his own economic yardsticks) is not commercial.

Such an approach is described in the 1989 Australian/Indonesian model contract. In this model contract it is stipulated that if petroleum is discovered in the contract area which the Joint authority and contractor agree can be produced commercially based on the consideration of all pertinent operating and financial data, then the Joint Authority shall declare a discovery area and the contractor shall commence development. A similar approach is followed in a 1992 model contract made available to the industry by a East European country. In this model contract it is stated that when in the contractor's opinion a discovery is commercial he must present his declaration accompanied by supporting documentation, including a development plan, estimated expenditures and an estimated production schedule, to the state party for the latter's written approval and agreement thereon. After reviewing the documentation the state party may present to the contractor alternatives for development

work and production schedule. The state party and the contractor will meet and discuss the alternatives. The contractor is obliged not to refuse unreasonably the state party's alternatives. After this discussion the state party will communicate its decision concerning the declaration of commerciality. If the state party fails to provide its written comments regarding the contractor's declaration of commerciality then the contractor's determination that there is a commercial discovery shall be deemed approved by the state party.

In some countries the applicable contracts provide for a sole risk right on the part of the state party in case the contractor is of the opinion that the discovery that has been made is not commercial. Such sole risk option is provided for by the contracts applicable in Egypt, Syria and Libya (see below).

If the supervisory body is a management committee, in which both parties are represented, the voting requirements for reaching binding decisions merit attention. Generally speaking, where a management committee takes the place of the state party in its role of supervisory body, the contractor may not expect to be accorded in such committee a position of equal voting strength with the state party. This aspect is reflected by the Libyan model contract dated April 15, 1989. The model contract provides for a supervisory management committee consisting of three members. Two members including the chairman are appointed by NOC, the Libyan state party. The third member is appointed by the contractor. The committee reaches its decisions by a majority vote. The powers of the committee are unusually extensive. It may revise as it sees fit any proposal (work programmes and budgets, development plans, contract awards) submitted to it by the contractor for its approval. Work programmes approved by the committee have to be carried out by the contractor within the framework of the corresponding budget subject to some flexibility in this regard. The management committee decides on the commerciality of a discovery based on evaluation reports prepared by the contractor. If the management committee declares a commercial discovery, a plan of development must be prepared and submitted to the committee for its approval. Any development plan approved by the committee must be carried out by the contractor. If the contractor cannot support a development plan because development of the discovery would not be economically justified for him, the contractor has the right to withdraw from such development. However NOC may develop the discovery for its own risk and account and may thereby request the operational services of the contractor.

Co-operation between Contractor and State Party

Depending on the type of contract, the contractor and state party will co-operate in the context of either a jointly owned operating company or a management committee, in which both parties are represented.

If according to the contract a joint operating company has to be formed (which must take place upon the first declaration of a commercial discovery) this company will take over as operator. The charter of the joint operating company is attached to the contract and is considered to be an integral part of it. The company has a board of directors in which the contractor and the state party are represented with an equal number of directors. Two of the directors will be appointed as managing directors and one of them will be the general manager of the company. The work and planning is done by the general manager and his staff. Plans, work programmes and budgets have to be approved by the board of directors (before being submitted to the state party for approval). The board takes its decisions by a majority of votes. As mentioned before the contractor/shareholder is obliged to render financial, technical and personnel services in order to make sure that the company can be an efficient operator.

Contracts that do not envisage the formation of a joint operating company may provide for the setting up of a management committee. In this situation the contractor remains the operator. Such a management committee is intended either as an advisory committee or as a supervisory committee (see above). When a management committee acts as an advisory committee its task consists in discussing and reviewing any proposal prepared by the operator before they are submitted to the supervisory body, in this case the state party, for approval.

Contracts applicable with respect to the continental shelf of the People's Republic of China contain an elaborate system of operatorship, supervision and co-operation. Parties are CNOOC (see above) and a foreign oil company as contractor. As mentioned before, the contractor is the operator but CNOOC is entitled to take over the operatorship with respect to any field that is brought into production. CNOOC may exercise this right at the moment the field development costs have been recovered from cost oil. A joint management committee is established in which CNOOC and contractor are equally represented. Decisions of the committee are taken in unanimity. Before annual work programmes and corresponding budgets are submitted by contractor to CNOOC for its approval they will be reviewed by the committee. Any discovery must be notified to the committee. If the committee or the contractor is of the opinion that the discovery should be evaluated a relevant plan will be prepared by the contractor and submitted to the committee. If the discovery is considered to be commercial (by the committee or by the contractor) the plan of development will be submitted by the committee to CNOOC. In its turn CNOOC shall submit the plan to the ministry for approval. If either party (*i.e.* CNOOC or contractor) considers the discovery not to be commercial, the other party may develop such discovery for its sole risk and account. The joint management committee has also its own responsibilities. It is responsible for approving the acquisition of goods and services within the limits of an approved budget.

State Participation

Although from a political and economic point of view production sharing contracts may be considered to the (poor) developing countries' alternative to obligatory state participation, elements of state participation have been introduced in the contracts. As a matter of fact, state participation has manifested itself in three different forms, namely in the form of an option (or even commitment) for the state party to contribute to and share development expenditure (as exemplified by contracts applicable in Tanzania, Libya and the People's Republic of China); in the form of establishing a jointly owned operating company (as exemplified by contracts applicable in Egypt and Syria); and by the participation on a proportional basis of the state party itself, a subsidiary of the state party or a national enterprise designated by the state party, in the rights and obligations of the contractor (as exemplified by contracts applicable in Indonesia and Malaysia).

PART V: LEGAL AND NON-OPERATIONAL MATTERS

Guarantees

Host governments will insist on being given financial guarantees (say, bank guarantees expressed in U.S. dollars) with respect to the fulfilment of the obligatory exploration work programme and/or the exploration expenditure commitment. Sometimes governments insist on a general performance guarantee to be issued by the parent company of the contractor guaranteeing the fulfilment by the contractor of his obligations under the contract.

Liabilities

Generally, a contractor shall be required to indemnify and keep the State and state party harmless against all claims from third parties for loss or damage to property or injury to persons caused by or resulting from contractor's operations. Excepted are loss, damage and injury caused by any action of the personnel of the state party or the State (or, alternatively, caused by the proven negligence and wilful default of the state party). In some contracts it is additionally provided that the state party concerned shall hold the contractor harmless from any claim brought against the contractor by the employees of the state party for their personal injury or damage to personal property due to the fulfilment or non-fulfilment of the contract.

If the contractor consists of more than one oil company, each such contractor-company is jointly and severally liable for the performance of all obligations of contractor.

Assignment of Interests

Distinction can be made between external assignments and internal assignments: If the contractor consists of more than one oil company and anyone of the contractor-companies wishes to assign its interest in the contract to the others such assignment is an internal assignment. If the contractor or any one contractor-company wishes to assign its interest in the contract to an affiliated company or to a third party such assignment is an external assignment.

Generally, any assignment needs the prior written consent of the state party or the government in case the government has signed the contract or if the contract had been subject to the latter's approval.

Title to Movable and Fixed Assets

Under most types of contracts all movable and fixed assets acquired by the contractor for the authorised operations become the property of the state party. The contractor retains the right to use the assets for the operations and of course the right to recover the cost of acquisition out of cost oil in accordance with the rules of the contract.

Under Egyptian contracts, land becomes the property of EGPC as soon as purchased. Title to fixed and movable assets is transferred from the contractor to EGPC gradually as the costs thereof is being recovered by the contractor out of cost oil, provided that a complete transfer takes place at the termination of the contract.

In the light of this kind of provision, land and buildings are rented and use is made of subcontractors for drilling and other operations, and, where possible, equipment and installations are leased rather than purchased.

Confidentiality of Information

Contractors are required to keep data and information obtained pursuant to the contract confidential and are not allowed to disclose such data and information to third parties without the prior written consent of the state party. It should be recalled that these data and information are the property of the state party.

Settlement of Disputes

Generally, a contract will provide for binding and final international commercial arbitration for resolving disputes arising between the state enterprise and the contractor in connection with the interpretation of the contract or with the operations carried out thereunder.

The arbitration systems commonly adopted under the contracts are arbitration in accordance with the rules of the International Chamber of Commerce (ICC-arbitration), the arbitration in accordance with the rules of the International Centre for the Settlement of Investment Disputes (ICSID), set up under the Convention on the Settlement of Investment Disputes between States and Nationals of other States October 14, 1966), and the arbitration procedure set up by the United Nations Committee on International Trade Law (UNCITRAL Arbitration Rules). Some types of contract, in which the government appears as a party, refer to the possibility of a dispute arising between the government on the one hand and the state party and the contractor together on the other. Such disputes have to be submitted to the domestic courts of law which are competent in those matters.

Amendment of the Contract

It is generally stipulated that the contract can only be amended by mutual agreement of the parties but where the original contract had been subject to the approval of the government any agreed amendment is likewise subject to the approval of the government. If a contract has the status of law any amendment needs to be approved by law and will involve the legislature.

Termination of the Contract

A contract will be terminated in accordance with its rules. These rules envisage the right of contractor to terminate the contract at any time (without being entitled to any compensation and subject to take the appropriate abandonment measures; obligatory termination if not commercial discovery of petroleum has been made during the exploration phase of the contract; and termination by the government if the contractor is in breach of any material provision on the contract or of the contractor is declared to be bankrupt.

Applicable Law

Without exception, a contract is governed and construed in accordance with the laws of the host country. To these laws should also reckoned to belong any relevant provision of an international treaty or agreement to which the host country is a party (*e.g.* bilateral agreements for the protection of reciprocal investments).

Approval and Ratification

With a few exceptions, production sharing agreements need the approval of the host government before they become effective. In some instances (*e.g.* Egypt and Syria), where the government itself is a party to the contract, together with the state party, a law has to be passed authorising the minister responsible for petroleum affairs to sign the contract, thereby approving and ratifying the contract and giving it full force and effect of law.

5.

Unitisation Agreements

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INTRODUCTION

Definition of Unitisation Agreement

The Unitisation Agreement is an agreement by the owners of a single oil field which extends into more than one licence area to develop that field as a single unit. Usually entitled a Unitisation and Unit Operating Agreement, the Unitisation Agreement normally includes all of the provisions of an ordinary JOA, together with additional ones which are intended to establish the rights of the respective parties to production from the field. It is perfectly possible to have separate agreements for unitisation and operating purposes, and this is common in the United States, but in UKCS practice the two tend to be combined. This chapter deals only with the parts of such an agreement specific to the unitisation of the field and refers to the statutory regime in force in the United Kingdom.

Typically, a Unitisation Agreement will provide that:

> "all rights and interests of the Parties under the Licences are hereby unitised in accordance with the provisions of this Agreement insofar as such rights and interests pertain to the Unitised Zone and each of the Parties shall own all Unit Property and Unitised Petroleum in undivided shares in proportion to its Unit Equity."

It can be seen from this that from wherever in the reservoir Unitised Petroleum actually comes, and in whichever licence block the platforms are in fact located, the owners will own them in their unitised proportions. It is the Unitisation Agreement which formalises this as between the various licensees, and, as with ordinary JOAs, sets out the framework and rules within which the joint venture will be conducted.

Reasons for Unitising

Unitisation of an oil field (which is defined by Model Clause 28(1) as "a single geological petroleum structure or petroleum field" and which therefore includes both gas and condensate fields) is only necessary where that field underlies more than one licensed block. In the early days of oil exploration and production in the United States, there were no provisions for unitisation and as the law of capture[1] applied to oil a highly competitive atmosphere existed in which lease owners would attempt to drill and produce their own oil as quickly as possible in the hope of then producing oil which had migrated from neighbouring areas into their wells. Wells would be drilled along the very edge of the lease line to achieve this and such competitive drilling, although no doubt profitable for those who were able to get in first, often resulted in unnecessary duplication of expenditure and less than optimum development, leading to reduced total ultimate recovery from the field. This would not fall within the definition of good oil field practice. Accordingly, most petroleum producing states in the United States have adopted legislation which provides powers to require unitisation, although this is still not the case in Texas.

When the United Kingdom and Norwegian governments were first framing regulatory regimes for the North Sea they were able to profit from the United States experience and adopt powers to require unitisation *ab initio* and to prevent competitive drilling—for example Model Clause 20 requires that no well shall be drilled within 125 metres of any of the block boundaries. There are good grounds for arguing that the rule of capture applies in the United Kingdom. Although the Petroleum Act 1934 vests all petroleum rights in the Crown, licences granted under the Act, as extended by the Continental Shelf Act 1964, give the licensee an "exclusive licence and liberty ... to search and bore for, and get, petroleum ... under (the licensed area)". This should be read as meaning petroleum under the licensed area at any time, not just at the time the licence was granted, so if it has migrated from an adjoining block, it can be produced. This is not the view of the DTI, but in theory at least it could apply. In practice, operation of the Model Clauses renders the point academic.

[1] Capture is defined as "a taking, an arrest, a seizure. Capture is in some cases a mode of acquiring property. Thus, everyone may, as a general rule, on his own land, as on the sea, capture any wild animal, and acquire a qualified ownership in it by confining it, or absolute ownership by killing it." *Jowitts Dictionary of English Law.*

LEGAL BASIS

Model Clauses

All references to Model Clauses are to The Petroleum (Production) (Seaward Areas) Regulations 1988, as amended by The Petroleum (Production) (Seaward Areas) (Amendment) Regulations 1995.

Model Clause 17 provides for government control of all development and production programmes, not just unitisations.

17.—(1) provides that

"the Licensee shall not—

(a) erect or carry out any relevant works, either in the licensed area or elsewhere, for the purpose of getting petroleum from that area ...; or

(b) get petroleum from that area ...,

Except with the consent in writing of the Minister or in accordance with the programme which the Minister has approved..."

This plainly gives the Minister, acting through the Department of Trade and Industry (DTI), wide powers to approve any development plan (commonly known as the Annex B) prior to any physical development work being carried out on a field, whether unitised or not. The stated policy of the DTI is to ensure the maximum recovery of economic oil from the nation's resource base and they will seek to achieve this by ensuring that the development option agreed is that which is most likely to exploit fully the recovery of economic reserves. This includes developing such reserves under a single development plan. Plainly therefore, when an Annex B is submitted to the DTI for approval, if an oil field extends into another block or blocks licensed to different companies, the DTI will wish to be satisfied that the development plan covers the oil in *all* relevant blocks and that therefore agreement to the development has been obtained from the licensees of those blocks.

Such agreement will normally be obtained by bringing the licensees of the relevant blocks into the Unit from the start. However, if the value of the accumulation is insignificant, perhaps worth less than the cost of a well to prove it up, they may be prepared to give a waiver, which is quite acceptable to the DTI and indeed will be encouraged if this will avoid competitive drilling. The waiver will usually contain the condition that if such block is subsequently found to have a greater share of the field reserves, its licensees will have the right to reopen the question of unitisation.

An alternative would be to purchase the adjoining block, or the relevant part containing the extension, which will be discussed later. If the adjacent block is unlicensed, the opportunity exists to make an out of round application for a licence, which, if granted, will avoid all the problems which a unitisation tends to bring.

Model Clause 28—(1) allows the Minister to *require* unitisation if he considers "that it is in the national interest in order to secure the maximum ultimate recovery of petroleum and in order to avoid unnecessary competitive drilling that the oil field should be worked and developed as a unit." No notice under this Model Clause has actually been served—like so many of the Model Clauses its mere existence is enough to ensure that licensees take the appropriate steps which the Clause requires.

It is therefore in the interests of all of the licensees of an oil field to ensure that unitisation discussions have commenced at a sufficiently early date to enable the Annex B to be granted within the project timetable constraints. The DTI is not concerned as to how the oil is shared out amongst the difference licensees, although Model Clause 28—(4) does allow the Minister to prepare a development scheme which shall be "fair and equitable to the licensee and all other licensees" if he does not approve the scheme originally submitted, and in practice the DTI interprets this requirement of fairness to cover all unitisations. It can be seen from this that whatever scheme is submitted should be reasonable, but so long as the development plan provides for the maximum recovery of the reserves the national interest will be served.

Transmedian Fields

Model Clause 29 deals with oil fields across national boundaries and gives the Minister very wide powers to give such directions as he may think fit to the licensees as to the manner in which the rights conferred by the licence should be exercised. The reasons why the government should have a greater interest in unitisation of a field across the median line are obvious. In the case of a field wholly within the UKCS it should be immaterial to the government who produces the petroleum as long as it is produced. Where a field is partly in United Kingdom waters and partly in those of another country the interest of the government in obtaining the maximum equity share in the field becomes similar to that of the United Kingdom licensees so as to ensure its maximum take in the form of tax and/or royalties. So far, there have been four transmedian fields in the North Sea: Frigg, Statfjord and Murchison, all of which are unitised with Norwegian companies and the Markham field which is partly in United Kingdom waters and partly in Dutch. In each case a separate treaty has been entered into between HMG and either the Norwegian or Dutch governments which sets out some detail provisions relating to the field and the agreements applying to it. In addition to a number of the topics which are also covered in the Unitisation Agreement, such as appointment of the operator and extension of the Unit Area, they reserve to the governments rights to approve the initial determination and re-

determinations, deal with such matters as applicable law and arbitration, health and safety, communications systems, free movement of personnel across the international median line, continuation of production after expiry, surrender or revocation of a licence, transportation of production, and taxation issues. The Treaty is between Governments and so does not apply directly to the Licensees, but its provisions will be given effect by virtue of the Model Clauses. During negotiation of the Treaty, the Governments may keep their Licensees informed, and even consult them, but will always reserve to themselves the right to conclude the final terms.

PRELIMINARY AGREEMENTS

Data Exchange

Before one gets to the point of negotiating a Unitisation Agreement there will be at least one, and probably several, preliminary agreements into which the parties will enter during the early phases of evaluation of a field. Once the licence group which has made the initial discovery has established that it does not fall wholly within the boundaries of their own licence block they will need to determine what proportion of the reserves lie in the adjoining block or blocks. They will have some indication of this from their own data, but this will vary depending upon a number of factors including the quality of the data and the size of the extension. Once they have decided that there are some economic reserves in the adjoining block, if it is already licensed contact will have to be made with its licensees to exchange data to see whether a unitisation is likely to be necessary in the event of development. In such circumstances, ownership of the data will invariably remain with the parties who acquired it and they will wish to ensure that although disclosed to the adjoining block owners, it goes no further. Thus the first agreement to be entered into will be in respect of the confidentiality of this data.

Joint Well/Bottom Hole Contributions

Following this exchange of information there may well be a further intermediate stage which will relate to the acquisition of new information rather than the sharing of that which already exists. Such information might be new seismic, drilling a new well or studies carried out by or on behalf of the block owners. A joint well or joint studies agreement would therefore be entered into to cover these situations, or possibly a bottom hole contribution might be negotiated in respect of a well to be drilled on one of the blocks. In the case of joint well and joint studies agreements, the scope of these will almost certainly fall outside the ambit of the block JOA and, unless some voting mechanism is incorporated, all decisions will require unanimous approval.

Considering that licensees of two or even more blocks could well be involved in such agreements the reaching of decisions unanimously could cause real delays to the project and some form of voting mechanism is therefore highly recommended. At such an early stage in the project this is more likely to be acceptable if it is by way of voting under the respective block JOAs rather than a simple passmark of all the parties involved. In other words, the parties to each block JOA will vote on a proposal and when they have reached a decision the operator will cast a vote on behalf of the licence group.

The operator of the well will generally be the operator of the block on which it is situated and it will therefore be that company's accounting procedure which is used. Even at this early stage in a project considerable time can be expended on negotiating such aspects as covered by the preceding Chapter.

Pre-Unitisation Agreements

These initial agreements are steps along the way towards unitisation, the penultimate step normally being a pre unitisation agreement (or PUA).

THE UNITISATION AGREEMENT

Timing

The Unitisation Agreement will probably be signed at the time of Annex B approval, and will normally supersede the PUA entirely.

Where the development plan has been prepared by the licensees, (as has always been the case so far on the UKCS), the DTI's interest is to secure maximum ultimate recovery of petroleum, to avoid unnecessary competitive drilling and to ensure that the field should be worked and developed in co-operation by all persons. The DTI will also wish to be satisfied that no company is seeking an unfair advantage, but only to obtain what it rightfully should obtain. Based on previous experience, the Department rightly takes the view that there are different opportunities to apply pressure to the licensees of the adjoining block or blocks (or even to co-venturers in the same block) at different times during the field development. If a Unitisation Agreement is not finalised until at or near first production there is considerable scope for applying pressure in equity negotiations, particularly where some of the parties have already carried the main burden of development costs. This could in turn lead to a delay in first production which would not be in the national interest, and the DTI therefore require that the Unitisation Agreement is signed (or at worst is in final form) prior to the granting of Annex B so that they have the comfort of knowing that this aspect at least will not cause future problems. As will be discussed later, the process of establishing the

first provisional Tract Participations and then the initial determination also requires that the relevant provisions have already been set out in the Unitisation Agreement. Furthermore the DTI's current practice is not to grant an Annex B unless it is satisfied that there are appropriate arrangements in place to deal with abandonment, including the financial or security provisions between the parties. These arrangements are normally included in the relevant JOA or Unitisation Agreement.

Because of the value of the petroleum reserves it will be apparent that each of the licensee companies has an interest in maximising its share of those reserves, in contrast to a field which is found wholly within one block, where such shares will have been fixed by agreement at the time of applying for the licence (although possibly changed by subsequent assignments). This of course leads to considerable difficulties in negotiating particular provisions of the Unitisation Agreement—notably the technical sections which determine how the reserves are calculated and shared between the licence blocks. It is usually easier to negotiate such matters early in the life of the development, rather than later. Even so, because no real discussions can take place until some knowledge has been acquired, they will inevitably be protracted as each side seeks to maximise its own position.

Passmark

The question of the Operating Committee passmark tends to be contentious in any Operating Agreement negotiation. On the one hand you have the operator and any party with a large interest who do not wish their operations to be held up by a veto in the hands of a small interest owner, whilst the latter does not want to be steam-rollered into decisions which will cost it money, but with which it does not agree. Such considerations apply equally in a unitisation, with the additional layer of licence block concerns as well as individual company ones. The passmark will generally therefore be negotiated in such a way as to ensure that no individual licence group can be forced into a decision by the vote of others unless such group's overall interest is minimal. This can be done by either setting the passmark at a sufficiently high level, or by incorporating a requirement that for a Unit Operating Committee decision to be valid it requires the vote in favour by at least one party from each licence. This is probably preferable to the setting of a passmark on its own which can of course be affected by the change of interests following a re-determination. Where there is only a single determination and no re-determinations, a traditional passmark without further qualifications would be the better solution.

UNIT AREA

The Unitisation Agreement is required to cover the development, operation and abandonment of the field. Accordingly it will contain a definition of the Unit Area by reference to a two-dimensional map and co-ordinates. This definition is much more precise than that found in an ordinary JOA. However, the field to which it applies is a three-dimensional entity and a further definition is therefore required which is normally made by reference to named formations which underlie the Unit Area and which are encountered by specified wells between certain measured depths (the "Unitised Zone"). Thus although any activities carried out within the Unit Area will be subject to the provisions of the Unitisation Agreement, it is only concerned with the production of petroleum from the formations contained within the Unitised Zone. As will be shown later, activities carried out within the Unit area but outside the Unitised Zone count as Non Unit operations.

Extension of Unit

Unitisation Agreements frequently include provisions allowing for extension of the Unit, although such extension will only be allowed if new formations can be shown to be in communication with hydrocarbons in the Unitised Zone. Normally, the technical provisions for determining Tract Participations will apply to any extension, possibly modified to take account of different characteristics, if these are already known. If the parties leave the agreement of such provisions until an extension is found, it is likely to involve further protracted negotiations. Some agreements also provide for the reduction of the Unit Areas in appropriate circumstances.

Having established the Unit Area and Unitised Zone, the principal parts of the Unitisation Agreement which will not be found in a standard JOA relate to the calculation and sharing of the reserves between the licensees of the various blocks in which the field lies.

INITIAL DETERMINATION

Tract Participations

The share of the reserves allocated to each of the licence blocks in which a unitised field lies are known as the Tract Participations. In the very early stages of the appraisal and development of the field there will not be sufficient technical understanding of it to calculate precisely the share of reserves. They will therefore be allocated on a provisional basis between the relevant blocks. This will probably have been negotiated in the Pre-Unitisation Agreement,

and this allocation may either be maintained until the first determination, or adjusted on signature of the Unitisation Agreement. In any event, this will be a negotiated rather than technically-determined figure, albeit based on the available technical knowledge at that time.

Unit Interests

The individual interests of the respective block licensees (commonly known as Unit Equities) will be calculated by reference to their pre-existing interests under their respective JOAs, multiplied by the Tract Participation. The initial Unit Equities will be agreed prior to Annex B and it will be on the basis of these that each unit owner will pay its respective share of development costs. Given that during the development phase heavy expenditure is required, with no income to offset it, the parties will not want to pay more than they have to, but equally will not want to have less than their appropriate share of production once this starts. Ideally, they will pay as little as they can of the development costs, and get as much of the production as they can. Since they are all trying to achieve the same thing, however, the provisional shares which will have been agreed during negotiation of the Unitisation Agreement should be based on what they believe their respective shares of the reserves to be.

Technical Basis of Determination

As the development proceeds and wells are drilled, the technical understanding of the reservoirs will increase so that by the time of first production all the parties will have a much better idea of what their share should in fact be. The Unitisation Agreement normally contains detailed technical rules on how to establish both the total volume of reserves and their location. These rules will be applied during the development phase with the intent that at first production date the first technically-based determination (as opposed to the earlier negotiated one) can take place. At this point there will be a recalculation of the shares of capital expenditures which should have been made and those who have overpaid will receive a refund from those who have underpaid. In a field which has cost £1 billion to develop, each one per cent share is worth £10 million, so it can be seen that even small swings can have a significant impact on a company's finances.

There is a variety of bases used for determining the petroleum in the Unitised Zone. Examples of these include hydrocarbon pore volume (HCPV), hydrocarbons initially in place (HCIIP), moveable hydrocarbons initially in place (MHCIIP), initial recoverable reserves (IRRES), and economically recoverable reserves (ERRES). Each of these has its advantages and disadvantages, but as the methods become progressively more complicated they will in theory become more equitable, but there will also be greater scope for disagreement. There tends therefore to be a preference within the industry for opting for one of the more straight forward methods, provided that it will give an equitable result. In general, only one of these bases will be used in UKCS unitisations, although a combination of two or even more is quite possible. Given the nature and history of unitisations and re-determinations it is perhaps not surprising that the industry has not agreed a standard set of parameters or procedures, however desirable that might be.

A great deal depends upon the type of hydrocarbons present, and on the quality of the reservoir: if one part contains more gas and less oil than another, some form of compensation will be required to account for the difference in value of the respective products. Equally, if one part of the reservoir is less permeable than another, requiring more wells to produce the same quantity of petroleum, an "x" factor might well be built in to compensate for the difference in the cost of producing the same volume of petroleum.

RE-DETERMINATIONS

As has already been stated, the further into the life of the field one goes, the more one knows about it. It is therefore logical that at certain stages in the field life that knowledge should be used to re-establish Tract Participations and hence unit equities. Nevertheless, it is well known that re-determinations are never easy, taking up on a great deal of time and money, frequently resulting in disputes and often in litigation. Indeed, unitisations are one of the very few areas where upstream oil companies are prepared to go to court with one another. Cases involving the Balmoral, Fulmar, Scott and Nelson fields have ended up in court, with the parties seeking orders regarding the interpretation of Unitisation Agreements. All of these have involved the expert provisions in the re-determination part of the agreement.

Number and Timing

There is no standard as to the number of re-determinations and their timing which are to some extent dependent upon the size of the field. Larger fields with an anticipated long production life can be expected to require more re-determinations than small fields. However, because re-determinations inevitably lead to the polarising of the positions of respective licence groups and probably also because of the smaller size of the new fields on the UKCS, there has been a move in recent years to both minimise the number of re-determinations and to include ways to discourage the calling of them. Many agreements opt for a compulsory determination at first production and one optional re-determination to take place at a specified time, for example, two years after commencement of production, or on completion of drilling of the

last development well. Others will have only a single technical determination whilst yet more (mainly older agreements) provide for several re-determinations according to a timetable, some or all of which will be compulsory (unless, of course, otherwise unanimously agreed). One point to bear in mind is that re-determinations should not take place too near the end of field life, for reasons which will be discussed shortly.

Decision Making

All decisions relating to unitisation matters in UKCS agreements are made unanimously, as opposed to the normal issues to be decided by the Operating Committee, for which a passmark will have been negotiated in the usual way. This is not the case in United States agreements, where a higher passmark than that used for normal operating committee votes is frequently employed for equity matters. However, the cost and value of offshore developments being so high, the companies involved are not prepared to allow themselves to be voted into anything. This of course can (and usually does) add to the delays. To ensure that this does not lead to deadlock, the normal procedure is to appoint an expert.

Procedure

The Unitisation Agreement will contain the detailed technical procedures to be followed in carrying out a re-determination. One of two approaches is normally adopted: the more popular is a highly detailed procedure (often known as the Cook Book) which describes at great length the technical rules starting with common and agreed data bases and stipulates steps to be carried out in calculating the new Tract Participations; the alternative is a set of general guidelines establishing the ground rules but giving greater freedom to work out the detail at the time. Either method will include a data cut-off point, after which time no new data will be included in the current re-determination exercise, otherwise the whole process would be constantly restarting as new information becomes available. Whilst it is possible to provide that the operator carries out all the work and presents it to the unit owners, in practice the commercial interests of the parties are such that they require to be involved throughout the process. There will generally be several sub-committees, each comprising representatives of all the parties and dealing with one area of expertise—*e.g.* geology, geophysics, petrophysics, reservoir engineering—all under the overall control of an equity committee responsible for the whole re-determination. Whichever method is adopted, it is important to set some form of timetable and a way of resolving dead-locked items, otherwise the entire process can grind to a halt. Because the process of re-determination naturally falls into a sequence of events it is relatively easy to establish milestones at which decisions must be taken. If agreement cannot be reached, reference can be either made to the expert, left to the operator to decide, or the decision of the majority in favour can be taken. In either of the latter two cases the dissenting party will have its objections noted and has the right to bring such objections back onto the agenda at the time of the final decision. The idea of this is to protect such party's position without allowing it to cause the process to seize up completely, with the hope that the objection may have lessened by the end of the process. If it has not, recourse will be made to the expert.

It is important to remember that these procedures will be written by technical experts rather than lawyers, but it is vital that they are carefully checked from a legal perspective, as it is likely to be this part of the Agreement which ends by being scrutinised by the Courts. To do this properly, the lawyers need to sit down with the authors to ensure that the former thoroughly understand at least the intent, if not the content, of the procedures. Unfortunately, this seldom occurs, or, if it does, is seldom carried out properly.

Hurdles

It is very hard to calculate the cost of carrying out a re-determination, but estimates vary from between £1 million to more than £2 million per exercise for the Operator plus expert. In addition, each party will have its own costs and the whole process can cost up to £10 million in all. In the majority of UKCS fields which are likely to be unitised in the foreseeable future, the potential advantage to be gained by a change in equity is unlikely to be much greater in value, given the decreasing size of new UKCS fields. Apart from this financial cost there is the very real cost to the joint venture of parties pulling in different directions in order to maintain what they perceive as being their essential commercial interests. A number of ways have been dreamt up to avoid or at least minimise the disruption to the real business of producing the petroleum, and these include a requirement that *all* of the licensees of one of the blocks, and not just one of them, must agree to call for a re-determination, a requirement that if the change in Tract Participations is less than a certain percentage, perhaps two or three, the party or parties calling for the re-determination will bear all the costs of it, and/or a proviso that if the minimum percentage is not reached, that no change in Tract Participations will take place.

ROLE OF THE EXPERT

Because of the commercial interests of the parties in the outcome of the determination and any re-determinations, it has always been recognised that

there is a strong possibility that they will be unable to reach agreement among themselves and that reference to a third party will be necessary. Accordingly, Unitisation Agreements invariably provide for referral to an expert in such a case. It would in fact be possible to hand the entire re-determination process to an expert *ab initio* and abide by his decision, but few, if any, companies are prepared to allow a third party such complete control. Although we refer to "the expert", and usually to "him" it will in fact almost certainly be an independent company with the necessary resources and expertise to carry out the work.

The expert is almost invariably appointed to act as an expert and not as an arbitrator. Strictly speaking however, his role falls somewhere between the traditional one of an expert, which is to provide an opinion by which the parties will agree to abide, thereby preventing any dispute from arising, and that of an arbitrator who has to decide the respective merits of two competing claims when the dispute had already arisen. It can be taken as read that in a re-determination, the dispute has already arisen. The purpose of this is to avoid the application of the Arbitration Acts to the expert's role. These Acts provide a framework and set of legal rules for the conduct of arbitrations and also allow appeal to the Courts from the arbitrator's decision in certain limited circumstances. A formal arbitration can be even more lengthy and expensive than taking an action through the Courts, and although a re-determination can take a considerable period of time it is nothing compared to fullscale litigation either in front of an arbitrator or in Court. Nevertheless, as mentioned above the Courts have been involved on at least four occasions regarding some part of the expert process.

Selection

The Unitisation Agreement will contain procedures for selection of the expert. It is probably better to make the choice at the start of the process rather than waiting until the expert is needed, by which time positions will most likely have become entrenched and reaching agreement on anything, including choice of the expert, has become extremely difficult. At the time of negotiating the Unitisation Agreement or at the latest the start of the re-determination, parties ought to be able to take a reasonable position. Selection is generally carried out by each licence group or unit owner submitting a list of experts ranked in order of preference. Points will be awarded depending on the placings and it is to be hoped that this will result in one final choice. This however does not always happen, in which case a decision might be made by casting lots where there is a tie, or trusting the selection to an independent third party such as the President of the Institute of Petroleum. The terms of reference for the expert should be annexed to the Unitisation Agreement, once again to avoid delay and also to ensure that these are agreed before any contentious issues have arisen. If they are not clear and comprehensive, the Courts allow the expert considerable latitude to, for example, revise figures when he considers it necessary in order to correlate data. The terms of reference will also include provisions to ensure that the expert has no conflict of interest, such as having already carried out work on the subject matter of the re-determination for one of the parties.

Method of Referral

As noted above, an expert might be called in at various stages throughout the re-determination process, or not until the final stage. Alternatively, the expert might deal with the whole re-determination on his own, or be involved in all the discussions of the unit owners. This latter method, known as the "guided owners process", has been used in two recent unitisation agreements. Its purpose is to seek to prevent the parties taking an extreme position during the negotiations between themselves, in the knowledge that they can then make a more moderate submission to the expert. As the expert will have observed all the discussions and negotiations, he will be aware of the positions taken by each of the parties and if one which had taken an unreasonable stance subsequently makes a very reasonable submission it is likely to lack credibility. It is possible to have different experts at different times during a re-determination, for example, one dealing with issues which arise as it proceeds, and another at the end. This is undesirable, not least because of the need for the expert to acquire all the relevant information, something which would have to be duplicated if different experts were used.

Once the matter is in the hands of the expert he may be asked to consider submissions from each licence group or from each of the parties (although the latter is not to be recommended) and may be asked either to choose one of the submissions (a pendulum determination) or reach his own decision. The former again is intended to prevent parties from taking too extreme a position but really only works where only two submissions are made, whilst the latter has the disadvantage that a great deal of time and work is necessary to bring the expert up to the same level of understanding of the reservoir as that of the parties. A variation on this is to ask the expert to carry out his own work, and then choose whichever of the parties' submission is closest to it. Having completed his work and reached a decision, the expert may be asked to calculate the Tract Participations or this may be done by the operator.

ADJUSTMENTS

Assuming that agreement is finally reached on new Tract Participations, there will be "winners" and "losers" amongst the unit owners. Those who have gained equity will have to repay part of the original development costs to those who have lost, whilst in any re-determination after first production date the latter will have to repay to the former the share of petroleum which they have overlifted by virtue of having had a larger Unit Equity than they should have done.

Capital Expenditure

Repayment of capital expenditure normally takes place on completion of the re-determination. It is based on the original cash calls made during the development phase and is therefore easy to establish. It may or may not include the pre-development costs dealt with by, or incurred under, the PUA. Because those payments were made over a period of several years the refund is normally inflated by RPI or a similar index. The question of whether interest should also be payable appears at first sight to be straightforward: since those parties were effectively lending money to the others it does not seem unreasonable that they should be paid interest on the "loan". However, interest is more usually not included, originally because in the days when oil prices were on an upward trend the increased production which the gainers would obtain was expected to have a higher value and they would therefore be compensated by this. Furthermore, interest would have to be paid net of tax and to achieve a fair result for the gainer might unfairly penalise the loser. Repayment of capex is normally done by a single payment within, say, 30 days of fixing the new Tract Participations. It is unusual to spread payments out, although this could be done to match the makeup of petroleum.

Production

The licence group which has ceded equity will also have to cede part of its petroleum production to the other group to refund the volume which has been overlifted. Thus if the Tract Participation in the "losing" block has been reduced from, say, 45 per cent to 40 per cent, in the first year or so after completion of the re-determination, the licensees of this block would in fact lift less than 40 per cent (somewhere between 20 per cent and 30 per cent) leaving the balance (known as "make up oil") to be lifted by the "winning" licence group to recoup the production deficit. Limits must be set on the amount available to protect the losers from forfeiting all of their production for a period of time. If however the re-determination has taken place towards the end of field life it may be necessary for them to give up their whole entitlement in order to refund the other group. This is another reason for minimising the number of re-determinations and seeking to ensure that they take place early in the production phase rather than later.

The concept of make up is quite straightforward where the field produces oil or condensate, which tend to be sold on a spot rather than term basis. Equally, where the production is gas which is sold to a single purchaser, there should be no problem. However, the present trend is to sell gas to several different purchasers and as gas is still generally sold on a term basis the relevant agreements will need to take account of this, both as between seller and buyer and as between all the sellers.

This balancing process tends to be done on a pure volume for volume basis without taking into account changes in the value of the petroleum, either pre or post-tax. For PRT-paying fields, production during the safeguard period is plainly more profitable than that produced afterwards. Nevertheless this aspect is ignored, probably because it would be too difficult to devise an equitable solution. For tax reasons, a cash equivalent is not attractive, quite apart from the difficulties of assigning a value to the production.

Because the purpose of re-determination is to put the parties in the position in which they would have been had they had the necessary knowledge of the reservoir at the outset, no tax is levied on either the repayment of Capex or make-up of petroleum. Interest, however, does attract tax. Past Opex is generally not adjusted, because it is linked to the levels of production, and therefore should re-balance in line with over/underlifted petroleum. Again, if a re-determination takes place too near the end of field life, opex on a unit per barrel basis will be higher than during the plateaux period, so this may not be the case in practice. Another reason not to leave it too long.

LICENCE ISSUES

Maintenance of Licences

When entering into the Unit Agreement each party will normally warrant that its licence is valid and subsisting and that they will continue to maintain it and they will indemnify the other parties in respect of any breach of such warranties. It is more than likely that the licences for the different blocks in which the unitised field lies were awarded at different times. In such a case, it is possible that one of the licences might expire before the end of field life. Under the provisions of The Hydrocarbons Licensing Directive Regulations 1995, the Secretary of State may extend the term of the licence for a field which has not yet reached the end of its life, provided that the licensees have performed their obligations in accordance with its terms and conditions, but the licensees of the adjoining block will seek to ensure that the licensees of the expiring licence will indeed request an extension. Because this is bound

to be towards the end of field life it is not necessarily the case that they would wish to do so when abandonment costs are starting to loom large on the horizon.

Relationship to Underlying JOAs

The JOAs applying to the underlying licence blocks will continue in existence, notwithstanding the Unitisation Agreement. The latter will normally contain a provision such as:

> "All other agreements previously entered into by and between some or all of the Parties which contain provisions conflicting with the provisions of this Agreement are, as between such Parties, deemed amended to the extent necessary to eliminate such conflict but, as deemed amended, shall remain in full force and effect."

As can be readily appreciated, this allows the underlying JOAs to continue in existence so that, for example, any pre-emption provisions will continue to apply to the parties to it, even if the Unitisation Agreement has none. The voting rules might also be required, depending on how Unitisation Agreement deals with this issue, as well as the default clause.

Default

Because of the nature of the unitisation, the normal default provisions in a JOA are not generally carried through to the Unitisation Agreement. If a party defaults under the latter, its share of costs will normally be picked up by its co-licensees and they in turn will seek their remedies under their own JOA. As this generally provides for forfeiture they can exercise their rights under their JOA and obtain the defaulter's interest in the licence. This avoids the problems of assignment of the defaulter's share in its licence having to be made to all of the other unit owners, including those not on that licence. This however is not always the case and some Unitisation Agreements contain a traditional form of default clause. A further problem which can arise in those circumstances where there is a single gas purchaser is the necessity to ensure that 100 per cent of the gas sold under the agreement continues to be delivered to the purchaser. This requires pre-signed letters of authority from each of the unit owners to the gas purchaser confirming that upon receipt of a notice from the unit operator (or another party in the unit operator's case) the proceeds of sale of the defaulter's share should be paid to those other parties which are paying its share of field costs.

Assignment

Unitisation Agreements normally do not provide for pre-emption, again because of the two (or more) licences. Nevertheless the underlying JOAs may well have a pre-emption clause, in which case that will continue to apply as between the parties to that JOA.

NON UNIT OPERATIONS

As mentioned earlier, the Unitisation Agreement applies to all activities within the Unit Area, but only the Unitised Zone is to be exploited jointly. Thus if the members of one of the licence groups wish to drill an exploration well to a different horizon than that of the Unitised Zone, but within the Unit Area, it may be possible to use unit facilities for this purpose, under the control of the unit operator, as a Non Unit Operation. The Unitisation Agreement will normally provide for this.

In addition, one or more of the unit owners may wish to utilise any spare capacity in the Unit Facilities for the production or transportation of hydrocarbons from an adjoining field in which it has an interest (or indeed from an accumulation discovered as a result of drilling carried out as a Non Unit Operation). Provided that such spare capacity exists and subject to the absolute precedence of Unit Operations, it does not seem unreasonable to allow this, although the interests of the other parties must of course be preserved. One approach would be to argue that as the party has already contributed its full share of the capital expenditure relating to such facilities it should merely be charged the incremental operating cost, together with the cost of any modifications. The alternatives are either to require that the terms of such use are the same as would be obtained at arms length, or merely to leave the decision to the Unit Operating Committee to make if and when necessary. In any of these cases, agreement will have to be reached as to how to calculate spare capacity, and whether a unit owner is entitled to use only its percentage share of such capacity, or has the right to rent the shares of the others. There is no reason why such a clause should not be included in an ordinary JOA, but almost invariably it is not.

Sole Risk Drilling

The sole risk clause in a standard JOA is normally used (if at all) during the exploration and appraisal phases. The scope for sole risk drilling during development and production is much more limited, but it may be appropriate to include such a clause to enable one licence group to prove an equity point prior to a re-determination by drilling a well at its own cost. If such well is

subsequently adopted by the Unit, the cost would be reimbursed, though normally without the penalty common for exploration/appraisal wells. The downside of this is yet again the likelihood that such activity will have a negative effect on the cohesiveness of the joint venture.

ALTERNATIVES TO UNITISATION

Re-determinations tend to be lengthy, difficult, divisive, contentious and expensive. There has been a trend in recent years to seek ways of avoiding these problems including the following:–

Purchase

Where there are extensions into adjoining blocks it may be feasible to purchase these rather than unitise. This however is only likely to be an attractive option if the extension is a small one, mainly because of the cost to the purchasers, but also because if it is sizeable, the licensees will probably want to engage in a full unitisation.

Fixed Interests

If agreement cannot be reached on the value to purchase, a further method would be to agree that the percentage interest is fixed at the outset. This can be the case for small interests on the edge of a field or, in cases like Forties, where BP sold a number of small fixed interests, with limited rights to the purchasers. There are at least two major fields in the North Sea where it was agreed to fix the interests for all time thus avoiding the need for either an initial technical determination or any re-determinations. For this to be successful however the parties need to be sure of the technical parameters without the benefit of having drilled any development wells, which may require something of a leap of faith.

Cross Licence Assignments

If agreement can be reached for the licensees of one licence to take an assignment of the other licence and vice versa so that their percentage interests are the same on both sides, determinations and re-determinations are again obviated. Once again the problem is one of reaching agreement on the split of reserves between the two blocks to enable the appropriate shares to be calculated and like the fixed interest option is effectively a one-off determination. Nevertheless, this approach has been used for more than one UKCS field.

All of these options are most likely to be carried out very early in the field's development.

6.

Gas Transportation Agreements

Jeremy Deeley, Managing Counsel of Mobil North Sea Ltd

OVERVIEW

The offshore transportation of oil and gas is, arguably, the most significant aspect involved in bringing the production of hydrocarbons to the industrial and domestic market of the United Kingdom. It is certainly one of the most complicated functions, with the vast majority of all United Kingdom hydrocarbons produced offshore in the Northern, Central and Southern sectors of the North Sea, with only relatively small amounts produced on the United Kingdom mainland.

Most of this production is transported to shore through pipelines, although there are notable exceptions to this situation where offshore storage combined with tanker loading facilities enables fleets of tankers to ship crude oil to the markets. The oil production from the Mobil operated Beryl field is a good example of this type of system in operation and, indeed, these types of arrangements are being proposed for the recently discovered giant oil fields in the deep water West of Shetlands area: for example the Foinaven field will use a floating production system with offshore loading.

Some of these pipelines connect with fields hundreds of miles out in the northern part of the North Sea. For example, gas from the Brent field is transported for 281 miles before it reaches the St Fergus Terminal north of Aberdeen in Scotland. Not only can the distances involved be vast, the extent and diversity of the current system to transport oil and gas is extraordinary, based on the continuous development and investment which has taken place over the last 28 years.

In December 1965 the first significant discovery of gas in United Kingdom waters was announced: the West Sole Field, off the Humberside coast in the United Kingdom Southern Basin. This led to the first export pipeline being commissioned in the United Kingdom Sector of the North Sea. In 1967 this 42 mile pipeline, operated by BP, commenced transportation of gas production from the West Sole Field to Easington Terminal on Humberside.

From these small beginnings we have today an offshore pipeline network of over 5,000 miles, ranging in pipe size from 36 inches down to less than six inches.

In the early days, pipeline systems were relatively straightforward with pipelines being dedicated to individual fields. For example, for oil production, there were developed in the 1970s three major trunk pipeline systems (Forties, Brent and Piper, to Cruden Bay, Sullom Voe and Flotta respectively). These were big, long-distance lines: the Forties–Cruden Bay line was 106 miles long and had a diameter of 36 inches. In the last decade, however, considerable expansion has taken place as the system has become more sophisticated. Not only has the aggregate length of pipeline in the United Kingdom Sector trebled, the whole system has become increasingly complex as smaller accumulations of hydrocarbons are being produced due to the proximity of pipelines to previously uncommercial or marginally economic discoveries. What now exists is a widespread network of interfield and trunk pipelines and other facilities on the bed of the North Sea, picking up production from fields along their way, commingling production streams, treating, separating and measuring throughput, and ultimately depositing their charge at receiving terminals on the mainland. This complexity is fully reflected in the legal agreements which support such arrangements.

The heroic scale of these arrangements is reflected on the mainland. All the major receiving terminals (Sullom Voe, Flotta, St Fergus, Theddlethorpe, Bacton, Easington and the rest) are large, complicated and expensive facilities. For instance, the Mobil operated Scottish Area Gas Evacuation System (the "SAGE System"), is based upon a 200-mile long, 30-inch gas pipeline from the Beryl field, picking up Scott and Brae gas along the way, and a Processing Terminal at St Fergus, all of which has cost over £640 million to construct.

Finally, mention must be made of the huge volumes of oil and gas handled by this system. Last year, on average, the United Kingdom produced over 2.7 million barrels of oil a day and over 6.7 billion cubic feet of gas a day. This has to be transported safely and efficiently either through the transportation system or via tanker to the mainland where it can be processed, accounted for and delivered for ongoing transportation by the right party, at the right delivery specification and at the right time. That this in fact happens is in no small part due to the web of legal arrangements and documentation at the core of such transportation arrangements which reflect in their detail and sophistication the complexity of the business of bringing oil and gas of the North Sea into the mainland of the United Kingdom.

From a lawyer's perspective, the offshore oil and gas industry is tightly controlled, not just by legislation and regulation but also by the detailed legal agreements which govern the conduct of business in the North Sea. Given increasing concerns regarding the environment and safety and, not least of all, the increasing role that the legislation of the European Union is set to

play (of which more later), the trend is to increase, not decrease, the level of legislative control. A good example is the relatively recent application of the responsibilities of the Health and Safety Executive to the offshore industry in the form of the Offshore Safety Act 1992. This has resulted in the need to prepare and submit what is known as a "written safety case" for all offshore installations, of which pipelines form a part.

LOCATION AND CONSTRUCTION OF PIPELINES

It is useful to look at the primary legislation concerning offshore pipelines (see Appendix for a list of statutes, statutory instruments and other regulations relevant to oil and gas transportation) as well as the agreements relating to the pipeline. These are all relevant to a number of practical issues which will need to be addressed in bringing a gas discovery onshore: (this discovery can be assumed to be a gas discovery of one trillion cubic feet (1Tcf) of relatively dry gas, somewhere north-east of the Forties field).

Legislation and Regulatory Matters

1. *Petroleum and Submarine Pipeline Act 1975*

The first practical issue will be to determine the proximity of a pipeline system of sufficient size and available capacity to offer a viable export route for the (1 Tcf) gas discovery assumed above. Now it may be that after a look at the map, it is quickly determined there is neither a gas pipeline in existence nor one under construction with adequate capacity to handle the volumes of gas involved. Otherwise it could be that the company's preference is to build its own dedicated pipeline, thinking perhaps that it would be good business to construct an oversized pipe, transport third party gas and secure a generous stream of tariff income for the privilege, in addition to transporting its own gas.

Under section 20 of the Petroleum and Submarine Pipeline Act of 1975 (the "PSPA"), no person shall execute under any controlled waters any works for the construction of a pipeline or use a pipeline unless he is authorised in writing by the Secretary of State to do so and the works are or the use is in accordance with the terms of the authorisation.

Furthermore under section 21 of the PSPA, any authorisation issued pursuant to section 20 may contain such terms as the Secretary of State thinks appropriate including terms as to the persons who are authorised to lay and use the pipeline, the route, the design and the capacity of the pipeline, and steps to be taken to avoid or reduce interference by the pipeline with fishing and other sea activities.

In broad terms, the Government has the power under these provisions to control practically every aspect of an offshore pipeline system. This it will do for the purpose of ensuring the development of a coherent, safe and efficient system of transportation.

The main criterion applied by the Government in deciding to authorise the construction and use of a new pipeline under the PSPA is whether or not it is necessary. The cost of laying and operating pipelines is amortised for various tax purposes which means, in practical terms, that the Government is making a significant contribution towards these costs. The general policy of the Government is therefore that there should be no unnecessary proliferation of pipelines.

To implement this policy, the Government may resort to the extensive powers in the PSPA. For example under section 22, where it appears to the Secretary of State (on the application of a person other than the owner of a pipeline) that the capacity of a planned pipeline should be increased, or that a junction should be installed in it through which another pipeline may be connected to it, then, after giving the owner of the pipeline an opportunity of being heard about the matter, the Secretary of State may require the owner to make any necessary modifications. Similarly, under section 23 the Secretary of State may require the owner of a pipeline to transport third party production, provided that to do so would not affect the ability of the owner to transport its own production through the pipeline.

In this respect, there is little doubt the Government has properly exercised its powers under the PSPA to avoid unnecessary proliferation of lines, requiring companies to share and size pipelines in ways they might have preferred not to have done. A well known example concerns the use of the gas pipeline constructed for the Mobil operated Beryl field which forms part of the SAGE System where the Government applied pressure upon the Beryl Group and the Brae Group to use just one pipeline for the export of gas from the Beryl and Brae fields. As Wood Mackenzie state in their North Sea commentary service "the Department of Energy informed both parties that only one line would be sanctioned and that any unreasonable negotiating positions held by the groups could harm the companies' longer term relationship with the Government".

Despite these overtones of coercion, perhaps the measure of success of the Government in implementing this policy is the fact that there exists today an efficient transportation system in this country without a history of bitterly fought court cases.

2. *Crown Estate Commissioners*

Eventually all pipeline crossing agreements will be in place, and as the pipeline in the above example approaches the outer edge of territorial waters (12

nautical miles, from base lines drawn by reference to the Territorial Waters Order in Council 1964), the Crown Estate Commissioners will need to be approached.

The Crown owns the seabed lying under territorial water and the Crown Estate Commissioners administer these rights. Under the Crown Estate Act 1961, the Commissioners are obliged not to

- "sell, lease or otherwise dispose of ... the Crown Estate or any right ... in relation to [it] except for the best consideration ... which in their opinion can reasonably be obtained ... but excluding any element of monopoly reasonably attributable to the extent of the Crown's ownership of comparable land".

Negotiations will therefore take place with the Commissioners for a right to lay the proposed pipeline over the seabed within territorial waters and payment will have to be made to the Commissioners for such right, probably by reference to a formula agreed in 1990 between the Commissioners and the UK Offshore Operators Association ("UKOOA"). In 1987, when the territorial waters limit was extended from 3 to 12 nautical miles, the Commissioners changed the basis for calculating rents for new pipelines. Instead of a linear basis, rents were to be based on matters such as throughput, value, capacity of pipeline, field reserves, anticipated production levels, etc. These subjective tests were seen as inequitable, so UKOOA negotiated an agreement for 15 years from 1990. Under this agreement, rental levels were fixed, subject to indexation. UKOOA members may choose to adopt this basis for new pipelines or for existing leases lease at rent review.

3. *Environmental Regulation*

Once the pipeline arrives at the high water mark on the beach, appropriate arrangements will need to be made with the owners of land over which the pipeline will need to travel, and consents will be required from the local planning authorities. This aspect will involve the commissioning of an environmental impact study as part of the planning process.

As a result of the Environmental Protection Act 1990, much consideration will be given to environmental damage and clean-up liability provisions. At its most extreme, a transporter may be confronted with demands for unlimited indemnities, open-ended as to time and amount, in respect of environmental liabilities.

Agreements

1. *Pipeline Crossing/Pipeline Proximity Agreements*

In addition to legislation, a suite of detailed legal agreements will need to be considered, some of which will depend on whether or not a dedicated pipeline is being built to one of the established gas receiving terminals on the east coast of the United Kingdom. Currently there are four: Bacton, Theddlethorpe, Easington and St Fergus (five if the Teeside reception facilities are counted).

In the example of the 1 Tcf dry gas discovery, it is now assumed that a decision has been made to build a dedicated pipeline to shore, with a delivery point at St Fergus, 50 miles north of Aberdeen in Scotland. As it works its way westwards to the coast, the proposed pipeline will cross a significant number of blocks which have been licensed, and at least four (probably more) pipelines which are either in place or approved. This raises the need to prepare and agree pipeline crossing agreements.

While most in the industry now accept there is no need to obtain agreement from licence groups to cross their blocks, most feel pipeline crossing agreements are useful; provided they are practical and to the point. These are likely to contain provisions requiring the parties to keep each other fully informed, allow them to observe operations, carefully control (and in some respects restrict) operations within a defined Work Control Area, and make provision as to who will be liable in the event of an accident. The main legal issue in such agreements will usually concern the level of indemnity which will apply to any loss or damage caused to the existing pipeline with consequential loss of or interruption to production. This indemnity will be set at a level of tens of millions of pounds. The main practical issue will concern the definition of the Work Control Area, within which the owners of an existing pipeline will seek to have an element of control and a maximum information flow in relation to all operations to be carried out in relation to the new pipeline.

2. *Tie-In and Construction Agreements*

Finally, the pipeline will require to be connected to the reception and processing facilities at the Processing Terminal. This will require the negotiation of a Tie-In and Construction Agreement with the terminal owners. Again it is usually the level of indemnity which becomes the biggest issue, between the pipeline owners and the terminal owners, with the latter seeking as large a sum as possible in the form of an indemnity against any loss or damage to the Terminal or its business arising as a result of any incident during tie-in operations. Because of the need to ensure compatibility with the existing Terminal facilities, these agreements assume that all works are

sanctioned by the Terminal Operator, who will usually be deeply involved in such operations, even to the extent of being engaged to carry out the work itself on behalf of the pipeline owners. Control over such works is therefore very tight with full observation, inspection and survey rights being provided.

TRANSPORTATION AND PROCESSING

Having touched upon issues relating to the physical location, construction and connections of the pipeline, it is appropriate to look at how that pipeline may be used and what rights can be secured for the transportation and processing of gas in the relevant offshore and onshore infrastructure, of which the pipeline forms a part.

Transportation and Processing Agreements

In general terms, a Transportation and Processing Agreement will now need to be put in place under which: (i) gas can be commingled with other gas in the pipeline; (ii) the commingled gas stream can be transported to the receiving terminal; (iii) the commingled stream can be processed so that the liquids and impurities are stripped out of it, leaving a gas which is of a specification which will enable it to be sold (whether to British Gas or otherwise); (iv) natural gas liquids (NGL) separated out of the gas are transported away from the terminal; (v) each party will receive a share of the various product streams which equates in some way to their production; and (vi) tariffs, processing and other fees payable for the provision of transportation and processing services are established.

There are many legal issues involved in the transportation and processing of the gas stream in the example above, some of which depend on whether we are providing or seeking transportation rights. Key issues are as follows:

1. *Capacity Rights*

One major area of complexity concerns capacity rights within the pipeline. Here there is a distinction to be drawn between shippers who have their gas transported on a purely third party basis, and those persons who own the pipeline and use it to transport their own gas. In the third party situation the transporting system will set aside a stated amount of capacity for the duration of the life of the field in accordance with the profile for such gas provided by the shippers. This profile will be one of the most important provisions of the Transportation and Processing Agreement and the capacity booked for such gas will be available on a firm basis for the life of the field profile. Typically, as the field goes into decline, the profile will reduce and the amount of firm capacity will reduce accordingly.

As any unutilised capacity in a pipeline can be sold to a new gas stream and is therefore precious to a transporter, a shipper can expect to be subject to detailed restrictions on its ability to vary its capacity nominations within the profile and its gas deliveries pursuant to such nominations. Typically a shipper will not be permitted to increase its firm gas deliveries if that would exceed the nomination level seen in the previous year. The transporter is interested in having as precise a view as possible of the profile of any gas to be transported over the life of the field until full depletion and to minimise the flexibility of a shipper to increase nominations and the amount of firm capacity it can use.

An exception to this typically rigid approach is, however, seen where the gas stream is subject to a "blowdown" at the end of the field life. A typical example would be an associated gas field, say in the Central or Northern North Sea, where gas is produced in conjunction with oil production. In such a situation, gas will be produced or even reinjected with the main purpose of maintaining sufficient pressure in the reservoir so as to maximise oil production. At the end of economic oil production, gas production can be maximised, with a consequent requirement to increase the profile and step up the amount of firm capacity. This will lead to complex and detailed arrangements on when blowdown can be notified and triggered, duration of a second plateau period, alteration to send or pay requirements, etc. Perhaps the most difficult aspect will concern the ability or the willingness of a transporter to offer the flexibility to accommodate deeply uncertain arrangements at the end of a profile which could be some 20 years away and provide substantial amounts of fixed capacity which it would rather commit elsewhere.

Other complexities arise where the owners of a pipeline use it to transport their own production. In the earlier example of the company building its own pipeline, it was assumed that such company was the sole licensee of the licence in which the new field had been discovered, and that the discovery lay wholly within the block covered by the licence; in other words with a single company owning and operating its own pipeline. It is likely, however, that the new pipeline will be developed, owned and operated jointly by a group of licensees or by a group of companies within a unit owning the field. As an alternative, the ownership of the pipeline could belong to those companies who from time to time use the pipeline to transport their own production, with ownership changing constantly through time as new fields come on stream and old fields are abandoned.

Ownership of the pipeline will not, however, necessarily have anything to do with rights to capacity in the pipeline. Clearly it is not possible physically to identify which part of a pipeline belongs to which member of the group owning it, and therefore each owner will have an undivided interest in the pipeline as a whole. However, each owner of the group is likely to have

something akin to an individual ownership interest in a portion of the throughput capacity of the pipeline. It will be as if it has its own notional pipe through which it will wish to transport its own equity gas and any share of third party gas.

Issues concerning the ownership of the pipeline itself are unlikely to be difficult or contentious. However, issues concerning entitlement to capacity are likely to involve much discussion. In essence, those who contribute to the pipeline's costs (both capital and operating costs) will wish to claim a proportionate share of the capacity of the system, and the right to use that share of the capacity for any purpose they choose. Other members of the group may however feel they have certain entitlements to unutilised capacity, or at least priority to use any such unused capacity over third parties who have no interest in the pipeline.

A detailed agreement will therefore need to be entered into between all those who from time to time have an ownership interest in the pipeline. Often called an "Operating Agreement", this agreement will need to address with absolute precision whatever is agreed concerning ownership interests in the pipeline and entitlements to capacity. In addition it will need to address all the basic issues that are found in field operating agreements, including those relating to the operator, the equivalent of a joint operating committee, budgets, provisions to handle the abandonment of the system, and the consequences of default.

2. *Liabilities*

This leads on to the area where perhaps more legal energy is spent than in any other area: liabilities. Although the pipeline network transporting production from the UK Sector of the North Sea to the mainland has been developed down the years to high technical levels and has been operated to high levels of safety, the transportation of hydrocarbons in vast quantities does present scope for things to go expensively wrong.

(i) Standard Liability Regime

Given the value of the hydrocarbons and the revenues they generate, all transporters seek to limit their liability to the owners of production streams. At the same time, shippers do not wish to be exposed to the potentially vast cost consequences of damaging the transportation system. To reflect this balance of interests, the general practice has evolved of agreeing a "mutual hold harmless" regime of liability. Typically, this will involve each group protecting the other group from loss or damage to its physical property and facilities, claims for personal injury or death caused to its employees and also against third party claims resulting from its acts or omissions.

(ii) Contractors

Within the general structure of the traditional "mutual hold harmless" liability regime in North Sea agreements, the issue of how to provide for liability in relation to contractors is becoming more contentious. The position often now being argued is that although a company will indemnify and hold the other contracting party harmless against loss, damage or injury caused to its employees, it will not accept that such arrangements apply to contractors, particularly its own contractors.

This situation derives from the major oil companies adjusting and responding to a lower price and the resultant streamlining and restructuring of their operations and use of man power. One of the keynotes of this process is a large scale move to outsourcing in all areas of the business to contractors, who are being used in positions of greater authority and responsibility.

The result of all this is that companies, as part of a cost saving measure and also to reduce the exposure to claims under relevant insurance policies, now no longer make automatic provision for the coverage of their own contractors with their insurance arrangements. So in contract negotiations, a transporter or shipper will often be seen to take the position of declining to accept liability for injury or death to or loss or damage to the property of its contractors. More significantly from a legal view, liability provisions are being proposed which make no reference to contractors or their explicit position in relation to the general liability regime.

This represents a significant departure from the traditional, all-embracing "mutual hold harmless" regime described above. In legal terms, all clauses relating to liability, particularly the definition of Wilful Misconduct, should be given the greatest attention in order explicitly to provide for the position of contractors within the liability regime. If this is not done, a significant area of liability exposure will open up, which will rely upon the extent to which contractors have any or sufficient insurances in place and the willingness of a company to enter into direct contract negotiations with the contractors of the other contracting party on this particular issue.

(iii) Pollution I—Marine Pollution

An ever-present feature of all oil and gas production and transportation agreements are the provisions dealing with pollution.

The primary concern is marine pollution. The main legislation is to be found in the Prevention of Oil Pollution Act of 1971 and the Merchant Shipping (Oil Pollution) Act 1971. As a response to this legislation and also the search for some form of international agreement on compensation for pollution from offshore operations, in September 1974, the major oil companies entered into a voluntary arrangement to accept liability for oil pollution damage, known as the Offshore Pollution Liability Agreement, or better

known by the acronym OPOL, references to which you will find in all transportation agreements.

The essence of the OPOL arrangements is that each operator contracts with all other operators to accept liability for costs arising from pollution from his offshore facilities up to pre-agreed limits and also to contribute to the guarantee fund set up under the Agreement. Liability under OPOL is strict and does not depend upon fault upon the part of the operator. The maximum liability for pollution damage and remedial, clean-up measures is currently set at $100 million.

The benefits of these arrangements can be seen when it comes to addressing the complex and lengthy liability and indemnity provisions in a transportation agreement. Because the OPOL arrangements are accepted as an industry norm, liability for environmental pollution is in fact one of the least contentious discussion areas, with a standard form approach and wording invariably being adopted.

Different but equivalent compensation arrangements exist under the Merchant Shipping legislation in respect of cargoes of oil.

(iv) Pollution II—Off Specification Gas

The most contentious area within the general liability regime will concern the treatment of contract losses and penalties incurred by shippers as a result of the commingled gas stream going "off-specification".

The issue here is described in the phrase "polluter pays". This concerns the delivery of off-specification gas from a particular field or pipeline entry point into the commingled stream, causing the main pipeline gas stream and hence the gas of the other users of the transportation system at that time to become "polluted". This is pollution in the sense that the processing terminal cannot easily or at all process and clean up the gas to meet the various sales gas nominations in force at such time. If the processing terminal cannot deliver the quantities of gas required under the various gas sales agreements, contract losses in the form of shortfall penalties will be incurred by shippers to their buyers of gas. With certain fields where the gas is associated with the main oil field, the problem of loss can become more acute due to the fact that if gas production is shut in, which may only be a small fraction of overall production in any event, the oil field also has to be shut in. The loss of revenues can therefore potentially be huge.

In this situation, there are a number of conflicting issues to be resolved:

(i) if there is no fault on the part of the transporter/processor, it will seek to exclude all liability for such losses and, more importantly, any involvement in the arguments likely to take place between shippers as to causation and apportionment of liability for the consequences of the delivery of off-specification gas into the transportation system.

(ii) even if there is fault on the part of the transporter/processor, a shipper may have to establish that Wilful Misconduct has occurred rather than the lesser test of negligence under English common law. In any event, a shipper will be asked to accept a limitation of liability on the part of the transporter on the basis that the potential exposure to the revenue streams is so large and the rewards of transportation income are so small in comparison, it is entirely usual and reasonable for liability to be restricted in such a way.

(iii) a shipper will wish to secure limitations of liability *vis-à-vis* all other users of the transportation system if it delivers off-specification gas into the commingled gas stream, with the potential for causing all sales gas to go off-specification and the other users to incur losses and penalties to their purchasers.

(iv) conversely, a shipper, unable to deliver sales gas to its purchaser due to off-specification gas from another user, will wish to pass on to such person on an unlimited basis the full amount of the contract losses and penalties it has incurred to its purchaser.

In the previous old-style arrangements in the North Sea, these issues were controlled by the monopoly purchaser of gas, British Gas, dictating the terms of gas quality delivered into and from any transportation system. This was done through an "Allocation Agreement" whereby British Gas obliged all users delivering gas into a particular system to comply with a uniform and relatively narrow range of gas qualities. With British Gas acting as a party to all gas allocation and sales arrangements and obliging all users to comply with standard-form requirements, the potential for inter-user liabilities was minimised.

In the new-style arrangements currently seen in the North Sea, however, British Gas are no longer a monopoly purchaser and are no longer party to all gas allocation and sales arrangements. Transporters/processors therefore seek to impose their own requirements, which differ from system to system, and exclude purchasers from transportation, processing and, in particular, processing arrangements.

In general terms, a transporter will exclude liability for any losses incurred by a gas purchaser where another shipper is at fault. To achieve this they will insist upon complete indemnification from the polluter and will attempt to put in place an inter-user agreement, whereby shippers are liable to each other for the consequences of their off-specification deliveries without reference to the transporter.

Legal difficulties may arise in the absence of an inter-user agreement, where one shipper wishes to claim compensation from a polluter for the contract losses it has suffered, but it can only gain recourse to the polluter through the transporter through whatever indemnity and liability provisions are in place between the transporter and the polluting shipper. The shipper who is seeking recovery of his losses will have no direct contractual relationship with

the polluter. The interesting question then arises: to what extent can such a shipper enforce the liability provisions in the separate contractual agreements between the polluter and the transporter even though it is not a party to such contract. In English law, the general principle is that there is no privity of contract in such a situation and the shipper suffering loss has no recourse against the polluter.

Elaborate and detailed legal agreements will be seen in relation to all transportation arrangements dealing with this problem. As allocation agreements are disappearing, new legal formats are being developed to take their place. Much attention is also given to the question of limitation of liability for off-specification gas, particularly in the larger, expanded transportation systems where there will be a multitude of third party users each with the potential to incur substantial contract losses and penalties. In this respect the old approach of "polluter pays", namely a shipper paying for whatever loss it causes, is being restricted to take account of the reality of the expansion of the North Sea gas business.

(v) Force Majeure

Aside from the "mutual hold harmless" liability regime, a favourite vehicle for claiming relief from liability is by claiming that a force majeure event has occurred. The essence of force majeure is to suspend performance of the terms of a contract, thereby releasing the affected party from its obligations for the duration of the force majeure event to the extent it is unable to perform them because of events beyond its reasonable control which are unforeseeable or, if foreseeable cannot be prevented or overcome by the taking of reasonable steps.

Such clauses need to be approached with care. Contrary to popular opinion, English law does not recognise a doctrine of force majeure in the way in which do many Civil law jurisdictions (for example France). Because of its effect of suspending the performance of the contract and therefore limiting or excluding liability, a force majeure clause will be subjected to the closest scrutiny and will be given a narrow construction by the English courts. Therefore, the events which the parties want to be recognised by the courts as being events of force majeure need to be defined very precisely to avoid the relevant provisions being void for uncertainty.

Since the Piper Alpha disaster where the most tragic and cataclysmic sequence of force majeure events occurred, there has been a willingness in transportation agreements to develop force majeure clauses to include more flexibility regarding extensions of time, temporary de-dedication of an oil or gas field to a specific export route and eventual termination if performance remains impossible beyond a certain time. In other words, a more constructive approach is being applied to these clauses, rather than simply looking at them as the first expedient to provide short-term relief in the event that something goes wrong.

3. *Abandonment*

Abandonment is becoming an increasingly important consideration given that the design life of offshore pipelines is only in the region of 20–30 years and that more and more producing fields are in decline and will be abandoned before the end of this century.

It is also seen as involving extremely sensitive environmental issues, as the recent events connected with the disposal of the Brent Spar offshore oil storage facility have demonstrated. Under the Petroleum Act 1987 a programme of abandonment has to be submitted in respect of all offshore installations, including submarine pipelines, upon notice from the Secretary of State. Although primarily the responsibility of an operator, all persons holding ownership rights in the relevant installation will be affected. Given the magnitude of abandonment costs, great attention will need to be given by operating companies as to how abandonment liabilities are handled and what form of security will be required to be put in place in respect of these liabilities. Will it be a cash fund; a guarantee or some other form of enforceable financial instrument, or will an operator simply agree that payment need only be made when the actual expenditures are incurred?

Abandonment is also an extremely important issue for a shipper because if a transporter announces that it is exercising his right to abandon because it is no longer economical for it to continue to operate the system, the shipper may well be faced with the prospect of acquiring the system in order to maintain production or face termination of the transportation arrangements. Currently these issues seem a long way off but they will come gradually more and more to the fore over the next decade and the legal provisions and provisions in this area can be expected to become more and more detailed and complex over time.

Legislation and Regulatory Matters

Until very recently, the regulatory powers of the Department of Trade and Industry only covered offshore infrastructure. The scope of the Petroleum and Submarine Pipelines Act 1975 related to the production facilities and the transportation systems located in United Kingdom waters. They did not extend to beach terminals and onshore processing facilities. These areas were unregulated and were therefore the subject of fierce and bruising negotiations on every occasion when processing services were sought from onshore terminals. This has now all changed as a result of the Gas Act 1995.

Gas Act 1995

On November 8, 1995, Royal Assent was given to the Gas Act 1995, which extends the powers of the Secretary of State for Trade and Industry to determine terms of access and to regulate tariffs for gas processing facilities, onshore and offshore.

Section 12(1) of the Act provides that a person may apply to the Secretary of State for directions to secure a right to have gas processed by a gas processing facility. Under section 12(3), after due consideration of any such application, and where he is satisfied that the efficient operation of a facility and the processing of existing quantities of gas would not be prejudiced, the Secretary of State can issue directions

- (i) specifying the terms on which the Secretary considers the owner of a facility should enter into an agreement with the applicant;
- (ii) securing processing rights for specific quantities and kinds of gas;
- (iii) ensuring that the right of access to such rights is not impeded;
- (iv) regulating tariff charges;
- (v) securing pipeline connection rights to a facility;
- (vi) specifying sums to be paid for processing rights;
- (vii) requiring the owner of a facility to enter into an agreement;
- (viii) generally any other rights considered to be necessary as expedient.

In other words, the wide ranging, extensive powers previously applicable offshore are now applicable onshore. All aspects of the transportation and processing chain prior to entry to the National Transmission System are now fully regulated.

Code of Practice—Access to Offshore Infrastructure

The provisions in the Gas Act 1995 represent the culmination of dissatisfaction with the terms offered by owners of infrastructure for the provision of gas transportation and processing services; the pressure to reduce the costs of bringing oil and gas ashore via the CRINE initiative ("Cost Reduction in the New Era") and increase competitiveness; the push to liberalise the United Kingdom gas market out of the monopoly hands of British Gas; and a desire to improve access to infrastructure and eliminate discriminatory business practices.

In October 1994, the DTI issued a Consultation Document entitled "UKCS Competitiveness—Infrastructure", the preface to which states

> "A number of companies have already expressed their concern directly to the Minister that gaining access to UK offshore infrastructure was unnecessarily complicated, time consuming and that simplification was required if the next generation of smaller fields, particularly gas, were to be developed efficiently. Some of these companies also indicated to the

Minister that the terms on offer for access went beyond what could reasonably be considered fair commercial terms."

The purpose of this Document was to establish a Steering Group "charged with the responsibility of developing a Code of Practice incorporating, as far as practicable, standardised contractual terms for infrastructure systems".

During the past 12 months, much discussion has taken place between the various companies representing owners and users of infrastructure, the Steering Group (known as the d'Ancona Committee), the UK Offshore Operators Association Limited (UKOOA) and the DTI. As a result, a Code of Practice for Offshore Infrastructure Access has emerged. It is still in draft form, but is close to final acceptance and implementation.

The Code

"provides a frame work which, it is intended, all parties should follow during the processes of seeking, offering and negotiating access to offshore pipelines and processing facilities and onshore terminals. The purpose is to streamline and facilitate the timely application of the processes and ensure that access is easy and fair, with terms offered on a negotiated non-discriminatory basis".

It establishes general principles to guide the processes of seeking, offering and negotiating access, together with a set of actual procedures intended to ensure that the principles are followed and applied.

The main features of the Code are:

(i) It applies to all existing and future UKCS oil and gas infrastructure and to users, infrastructure owners, and owners of capacity rights in infrastructure systems.

(ii) Access to infrastructure should be available on a non-discriminatory negotiated basis. This means that infrastructure owners should be obliged to consider all requests for the use of capacity without favouring any particular company or client, and should negotiate in good faith to endeavour to reach timely agreement with the party requesting capacity.

(iii) In the event of a dispute, infrastructure owners may need to justify their positions to the DTI.

(iv) Where capacity is not available within existing infrastructure an owner is expected to provide the incremental capacity with the user being responsible to fund the necessary investment.

(v) All contractual arrangements at terminals are to be transparent to buyers and sellers using such facilities. This means that the priorities of use within any terminal, together with the allocation systems applicable are to be made freely available to all potential bonafide users.

(vi) Where there is a supply "chain" of services provided, the Code requires those services to be separated so that each significant component can be separately priced and provided. This is the principal of "unbundling". This is to enable a potential user to separate out commercial terms to identify price and conditions for any component of a total package of services.

(vii) There is to be transparency of pricing information. Indicative terms, including price and other key commercial aspects such as ship or pay, tariff escalation, etc will be made available by the infrastructure owner.

(viii) Every six months, infrastructure owners will inform the DTI of their indicative prices quoted during that period. These prices will then be published in Energy Trends, but with a time lag of at least eight weeks after such indicative prices have been offered.

(ix) Standardisation of contract terms should be introduced.

(x) All commercial negotiations should proceed in a timely fashion. The aim of the Code is to avoid delay. It contemplates set periods of time for all phases of contract negotiations eg. following an application an infrastructure owner will, within 10 working days, provide its indicative terms for the business in question, including an indicative tariff.

The DTI will be responsible for maintaining the Code and for ensuring its relevance and application to future users and infrastructure owners. It will therefore apply the detailed framework for all future commercial negotiations relating to use of offshore pipelines and onshore terminals. In such a way, the Code can be seen as the external expression of the Gas Act which will underpin all matters relating to the application and enforcement of the Code given the extensive powers of the Secretary of State for Trade and Industry. Indeed it is expressly stated that nothing in the Code is intended to fetter the discretion of the Secretary either under the Petroleum and Submarine Pipelines Act 1975 or the Gas 1995.

EUROPE

There will undoubtedly be an increasingly European dimension to any legal developments and changes affecting the transportation of oil and gas in the United Kingdom. For the past 30 years, the offshore industry in the United Kingdom has regarded itself as being subject only to United Kingdom law. The legislation of what is now the European Union has left it largely untouched. There are, however, developments afoot which could fundamentally change this position.

The European Commission has been considering for some time, draft Directives for improving access to natural gas and electricity infrastructure.

This is seen as part of the creation in the Union of a single energy market within an overall single internal market. Proposals were put forward in 1993, the core of which is the principle that "Member States shall take necessary measures to ensure that what are described as natural gas undertakings, and producers and suppliers of natural gas, are able to conclude supply contracts and supply their customers by means of the interconnected system, subject to conclusion of Agreements with the relevant transmission companies and distribution systems operators."

Although it is unclear whether these proposals are intended to apply to offshore infrastructure, they raise the issue of enforcement of rights of access to infrastructure across trans-national borders.

This can be seen in the context and as an expansion, of the intention behind the European Union Directive, dated May 31, 1991 (91/296), known as the "Transit Directive", on the transit of natural gas through grids and the trade in natural gas between the high-pressure gas transmission grids of the various Member States. The idea behind this Directive is open access to gas transmitted through one grid to any other grid where the necessary connections exist.

Article 3.2 provides: "the conditions of transit shall, pursuant to the rules of the Treaty, be non-discriminatory and fair for all concerned, shall not include unfair clauses or unjustified restrictions and shall not endanger security of supply nor quality of service."

Until now, however, the Transit Directive has never been used to gain access to any Member State's grid. Also it only applies to high-pressure gas transmission systems, not low pressure systems and it does not apply to distributors of gas.

The other significant development in the context of European legislation is the current project known as the Interconnector, under which a 38 inch, 150 mile-long pipeline between Bacton in England and Zeebrugge in Belgium will link mainland Europe to the United Kingdom for the first time.

On the basis that this connection means that there is the potential to affect business between member states, there is every likelihood that the whole of the United Kingdom offshore oil and gas industry will, if the European Commission has the political will to expand its jurisdiction, become explicitly subject to Articles 85 and 86 of the European Community Treaty of Rome where the principle of the effect on trade between Member States would need to be considered. This could mean that transportation systems run the risk of being regarded as "dominant undertakings" under European competition legislation, with the need for transportation deals requiring reference to the Commission for clearance prior to finalisation. Perhaps the biggest problem in this scenario will be the practice of discriminatory tariffing, where different tariffs are applied as between owners and third party shippers. This is precisely the point at which the European competition legislation takes effect. Infrastructure owners may find themselves obliged to allow competitors access

to their facilities on terms no less favourable than those they give to their own services.

CONCLUSION

In view of the legislative developments in the United Kingdom represented by the Gas Act 1995 and the offshore Infrastructure Access Code, together with the import of European legislation, it would seem that the commercial and legal free-for-all which has characterised the United Kingdom oil and gas transportation and processing industry is soon to become a thing of the past. Regard must now be paid to legislative provisions and Code provisions as the means of conducting any future transportation and processing business. It remains to be seen, however, whether the essentially non-standard nature of the business, with differing qualities and quantities of gas lends itself to a new standardised and transparent environment.

MAIN UK LEGISLATION AND REGULATIONS

Offshore Installations

Petroleum Act 1987
Mineral Workings (Offshore Installations) Act 1971
Offshore Installations (Safety Zone) Regulations 1987 (S.I. 1987 No. 1331)
Offshore Installations (Inspectors and Casualties) Regulations 1973 (S.I. 1973 No. 1842 and S.I. 1991 No. 679)
Offshore Installations (Safety Case) Regulations 1992 (S.I. 1992 No. 2885)
Offshore Installations and Pipeline Works (Management and Administration) Regulations 1995 (S.I. 1995 No. 738)
Offshore Installations (Prevention of Fire and Exploration and Emergency Response) Regulations 1995 (S.I. 1995 No. 743)

Pipelines

Pipelines Act 1962
Petroleum and Submarine Pipelines Act 1975
Oil and Gas (Enterprise) Act 1982
Submarine Pipelines Safety Regulations 1982 (S.I. 1982 No. 1513 and S.I. 1991 No. 680)
Offshore Installations (Emergency Pipeline Value) Regulations 1989 (S.I. 1989 No. 1029)
Submarine Pipelines (Inspectors and Casualties) Regulations 1987 (S.I. 1977 No. 835 and S.I. 1991 No. 680)

Submarine Pipelines (Designated Owners) Orders 1992 (S.I.s 518–522)
Gas Act 1995

Safety

Offshore Safety Act 1992
Offshore Installations (Safety Case) Regulations 1992 (S.I. 1992 No. 2885)
Offshore Installations (Safety Zones) Orders 1991 and 1992

Marine Pollution

Prevention of Oil Pollution Act 1971
Merchant Shipping (Oil Pollution) Act 1971
Merchant Shipping Act 1974
Offshore Pollution Liability Agreement (September 1974)
Merchant Shipping Act 1979
Merchant Shipping Act 1984
Merchant Shipping (Prevention of Oil Pollution) Regulations 1983 (S.I. 1983 No. 1398; S.I. 1991 No. 2885 and S.I. 1992 No. 98)
Merchant Shipping (Control of Pollution by Noxious Liquid Substances in Bulk) Regulations 1987 (S.I. 1987 No. 551 and S.I. 1990 No. 2604)
Merchant Shipping (Reporting of Pollution Incidents) Regulations 1987 (S.I. 1987 No. 586)

Abandonment

Health and Safety at Work Act 1974
Food and Environmental Protection Act 1985
Petroleum Act 1987
Radioactive Substances Act 1993

7.

Oil and Gas Financing Agreements

David Winfield, Partner, Freshfields

INTRODUCTION

Costs of hydrocarbon exploration and development are immense. It has been estimated that funding requirements for the global oil and gas industry over the next five years will be in excess of $300 billion. Treasury departments of multinationals and small independents alike are faced with the challenge of ensuring that their companies are able to raise capital on suitable terms, so as to enable strategic objectives to be achieved at the desired levels of profitability. This chapter examines the principal debt funding techniques that are available to producers and focuses on "non-recourse" or "project" financing techniques.

The chapter is written from the perspective of an Anglo-Saxon lawyer. To a degree that is appropriate: most oil and gas financing techniques were devised first by United States lawyers (particularly in Texas), then developed by English lawyers during the early years of North Sea development; and the loan documentation (though perhaps not the security documentation) used on these deals tends to be English or New York law governed. But the legal regime in the jurisdiction in which the development is carried out will always need to be considered and will frequently determine the structure.

Sources of Finance

Expenditure can be financed from internally generated funds, to the extent they are available. Where large developments are concerned, however, all but the largest producers will have to raise capital from external sources to fund expenditure. Capital can be raised, broadly, by way of equity or debt. The decision as to whether to raise debt or equity for a particular purpose will be determined in part by the perceived appropriate level of gearing for the company in question. Most companies choose to maintain a certain level of debt on their balance sheet, since this enables them to leverage their return on existing equity capital and to benefit from tax deductibility of interest payments.

The returns to a lender are, however, modest when compared with those of a successful equity investor. A typical syndicated loan to an oil and gas multinational will yield a margin to the lender of less than half a per cent per annum. This should be borne in mind in the forthcoming pages, since it determines the risk threshold of the banker and explains the banker's attitude to risk allocation and security.

1. *Equity*

Significant producers are likely to have a listing on one of the major stock exchanges. They will therefore have access to additional equity capital, subject to market conditions and other factors which will not be considered here.

2. *Debt*

The principal forms of borrowings that are likely to be raised by producers are considered below.

(i) Public Bond Issues, Medium Term Notes and Commercial Paper

Larger producers will have access to the international capital markets and so will be able to raise debt by way of bonds, MTNs and CP. Typically, this provides access to low cost fixed rate funds in substantial amounts (*i.e.* in excess of $100 million). In the past some oil companies have issued oil production stocks. These securities have characteristics in common with public loan stocks generally, except that the stockholder has a right to receive periodic payments related to the value of production from a relevant field, rather than a right to interest at a fixed rate.

(ii) Bank Debt

Much debt raised by producers will be by way of bank debt. This can be on a bilateral basis, at least in the case of smaller facilities (say of $30 million or less, but this will depend upon the identity of the lender and the borrower). Larger amounts (typically of up to $100 million or so, but possibly much more) can be raised on a syndicated basis.

(iii) Lease Finance

Debt finance can also be raised by way of lease finance. In the United Kingdom context, the finance lease involves the financier acquiring title to the asset and leasing it to the lessee long-term, probably for the useful life of the asset. The arrangements will be structured in a way that results in all of the risks and

rewards of ownership being transferred to the lessee, so that conceptually the arrangement is virtually identical to a secured loan. (In most jurisdictions, accounting rules require finance leases to be shown as borrowings.)

Finance leases are used because they allow the lessor, as owner of the equipment, to utilise depreciation or similar allowances for tax purposes so as to reduce its liability to tax. Part of this benefit can be passed back to the lessee, with the result that the interest rate implicit in the rental is lower than would be charged on a straightforward secured loan. The lessee is therefore assured of the indirect benefit of depreciation allowances on the equipment throughout its life, regardless of its own tax position and ability to use those allowances.

3. *Industry Finance*

The third main source of funding employed by oil producers can be called "industry finance" and involves transactions between producers, rather than between producers and financiers. The three most common are the farm-in, the carried interest (or the carry) and the net profits interest (or the "NPI").

A farm-in involves a transferor selling part of its interest in a particular field, usually before the commencement of development. The interest is sold on terms that the transferor agrees to fund all or part of the cost of developing the transferor's retained interest.

A carry involves one consortium member funding the development expenditure of a second, on terms that the first will retain a specified share of the future production entitlement of the second. The specified share will, essentially, enable the funder to recover the development costs incurred in respect of the carried interest plus a financing charge.

An NPI involves a sale (usually for a lump sum) of petroleum yet to be won from a field. The sale is on terms that the transferor receives a future income stream determined by reference to the future performance of the field. A similar vehicle is an Overriding Royalty Interest. In this case there is no interest in the future production, only a contractual right to payment. (The distinction can be of importance in terms of whether consent is required from the licensor government.)

PROJECT DEBT

The remainder of this chapter will focus on project finance transactions, with particular reference to the terms that will be found in project finance loan agreements.

Project Finance for this purpose means debt that is lent:

(i) for the development of a single project (for example, a particular field development, or construction of a floating platform, pipeline or transportation facilities); and

(ii) on the basis that the lenders will be entitled to look solely to cashflows (or disposal proceeds) from the relevant project or asset as their means of repayment.

The main characteristics of full recourse corporate debt and of project debt are set out below:

	Full Recourse Corporate Debt (public bonds or bank debt)	Project Debt (syndicated loan)
Purpose:	typically can be applied for general working capital purposes	to fund development of a particular project
Pricing:	if large corporate borrower, low margins	high margins
Security:	likely to be unsecured (this will depend on the identity of the borrower)	secured on all project assets and often also on sale or usage contracts
Financial Covenants:	may include financial covenants (depending on the strength of the borrower). If so, these will be predominantly balance sheet rather than cashflow based (*i.e.* tangible net worth/ gearing), though an interest cover test may be included	will include detailed cash-flow based financial covenants e.g. debt service cover ratio/loan life cover ratio. No balance sheet type tests will be included
Recourse:	full recourse to the borrower/issuer— may include guarantees from principal operating companies or parent	non or limited recourse (so banks take project risk)
Repayment profile:	bullet repayment or amortising repayment profile	amortising repayment profile, matching project cash flows
Control through contractual provisions:	representations, undertakings and events of default, whilst detailed, should not unduly impair the ability of the borrowing group to carry on its business	representations, undertakings and events of default will enable the banks closely to control and monitor the borrower's activities in relation to the project

Advantages/Disadvantages of project finance

A number of points come out of the above. From the sponsor's point of view, a project finance loan, because of its limited or non-recourse nature, enables third party capital (rather than the sponsor's capital) to be put at risk in the development of a particular project. (The banks will, however, typically require the sponsor to contribute some capital to the project. This is important for the banks because it provides a cushion of equity that will protect the banks in the event that the project does not progress as anticipated. It is also important from the banks' perspective for the sponsor of the project to demonstrate a financial commitment to it, even though the project loan is made without recourse to the sponsor.)

Another benefit of the project loan for the producer is that, because it is amortised out of cash flow, it enables the sponsor to match cash receipts with outflows, reducing the danger of liquidity difficulties.

But the bank's willingness to take the risk on the project comes at a cost. First, margins are high (frequently in excess of 1 per cent and possibly far higher, well in excess of the margin that would be paid by a multinational for an unsecured full recourse loan). And there will be other significant costs, some hidden, which result from financing a development on a project finance basis. First, banks' up-front fees and advisers' fees will be substantial and must be factored into the financing costs. Secondly, the costs of the sponsor's management time in structuring and negotiating a project financing deal should not be underestimated. But equally significant, from the point of view of the sponsor, is the fact that the decision to borrow on a project finance basis can materially affect the economics of the project. This is because of the banks' general aversion to risk.

An example of this is as follows. It may be useful to consider an example. If the project involves the development of a gas field, there may be a long-term gas sales agreement with an offtaker. The banks will consider the principal terms of the gas sales agreement (*i.e.* as to quantity, term and price) in great detail, since they will be looking to the payments arising under the gas sales agreement to amortise their loan. The gas sales agreement will contain buyer and seller force majeure provisions which will determine the circumstances in which the buyer or the seller may be temporarily excused from the obligation to deliver or take gas by reason of force majeure. The banks will clearly argue for a wider definition of seller force majeure then would be usual and will want buyer force majeure to be narrowly defined. The sponsor may be content with a particular level of risk on force majeure, but the banks may have a lower threshold to the risk, reflecting the fact that the sponsor is anticipating equity returns and the banks are receiving banking margins. It is likely that the banks will (at least to a degree) be successful in their meddling with the gas sales agreement, but this may have an effect on pricing. In the context of a project, a number of issues of this type will arise.

The issues that are likely to be sensitive, from the point of view of the banks are set out below under the heading "Risk Allocation".

This issue needs to be taken into account by producers who are considering whether or not to employ project finance. The risks from which the banks are seeking to protect themselves (or the project) may be risks that the sponsor would ordinarily be content for the project to bear. The effect of the banks' involvement, therefore, may be to alter (perhaps materially) the commercial terms of the development in a way that might reduce the sponsor's return on equity.

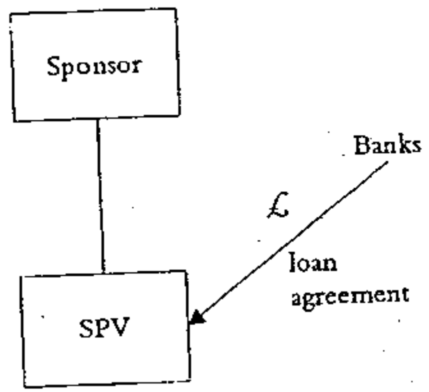
Recourse

The recurring theme in any discussion of project finance is recourse. It is often said that there is no such thing as a truly non-recourse financing. Invariably, the sponsor of the project is required to give warranties in relation to certain aspects of a project, on which it will be contingently liable. As noted above, the sponsor is likely to be required to inject a certain level of equity into the project vehicle, possibly contemporaneously with the making of advances by the bank. And the sponsor may agree to cover (by further equity contribution or the making of subordinated loans) certain cost overruns in relation to the project.

From a legal perspective, limitation of recourse can be achieved in a number of ways. The cleanest can be referred to as "structural non-recourse", so called because the limitation of recourse to the sponsor flows from the structure of the deal rather than the specific provisions of the relevant contract.

In this situation, the banks lend to a special purpose vehicle (SPV), which will undertake the project. All of the project assets and contracts will be vested in the SPV. The critical point (from the sponsor's point of view) is that the sponsor gives no guarantee of the SPV's obligations and that the SPV is a limited liability company. The loan is therefore non-recourse to the sponsor, simply because the banks have no rights against the sponsor under the relevant documentation. If the loan goes into default, the banks can sue the SPV, enforce security over the SPV's assets and even petition for a winding up of the SPV. But they would have no recourse to the operating company.

The structural method is effective because of the distinct legal personality of a company. It is a fundamental principle of English company law (and the laws of most—but not all—other jurisdictions) that companies have distinct legal personalities and are not liable for the obligations of their limited liability subsidiaries or other affiliates. There are certain exceptions to this rule. If for example the banks were able to show that the SPV entered into the financing as agent for the sponsor, the sponsor could be liable on the loan. But the English courts are extremely reluctant to accept (in the absence of special circumstances) that a special purpose vehicle should be treated as



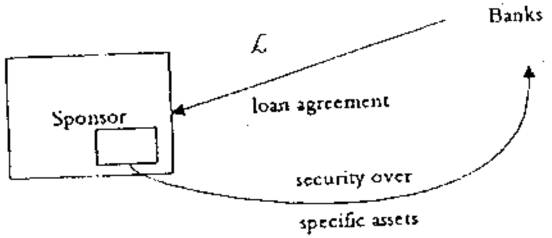
Banks have covenant of SPV but no guarantee of Sponsor.

Diagram 1

the agent of its parent in this situation. Where structured limited recourse protection is proposed in any jurisdiction, detailed legal advice should be taken as to the circumstances in which the veil of incorporation may be lifted under relevant applicable law.

The second example is the contractual method.

In this example, the banks lend directly to the sponsor on a secured basis. But the financing documents between the bank and the sponsor provide that the banks are only entitled to make recovery from the sponsor to the extent



Banks lend to Sponsor but agree contractually that their rights to recovery are limited to sums recovered/rights under the security documents.

Diagram 2

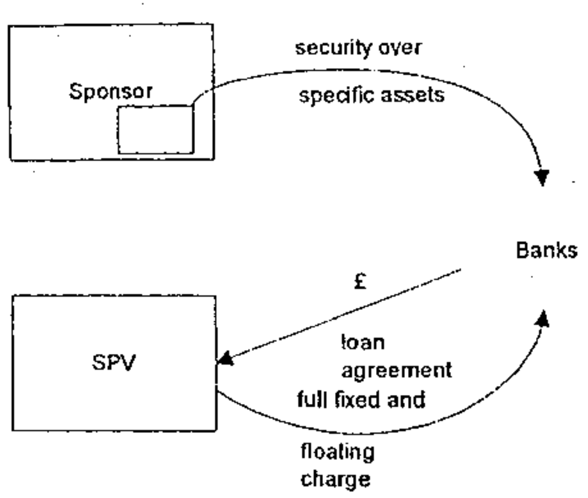
of the security provided. Concerns have been expressed to the efficacy of contractual limited resource provisions under English law. The author does not share these concerns, though it is clearly crucial from the point of view of the sponsor that the limited resource provisions are drafted with considerable care.

Whilst the techniques described above are the most common and straight forward, other variants exist as in the example shown below.

In this example, the loan is made to a special purpose vehicle. The sponsor gives security over certain assets (for example, a bank account or certain assets to the project) as security for the obligations of the SPV under the loan. Provided no full guarantee is given, the extent of the banks' recourse to the sponsor will (under English law) be limited to the assets which are given as security.

As to which of these techniques should be used, there is no doubt that the structural route using an SPV is cleaner. The following considerations will apply:

(i) assets and contracts relating to the project may already be vested in the sponsor. They may be difficult to novate or may be incapable of assignment. For example, concessions may have been granted to



Banks have full recourse to SPV and its assets, but recourse to Sponsor only to the extent of assets charged.

Diagram 3

operating companies and may be non-transferable. If this is the case, the structural route will not be possible;

(ii) commercial counterparties (contractors, offtakers) may be unwilling to deal with a special purpose vehicle—they may want the covenant of the sponsor. (This issue can normally be resolved by the provision of a guarantee, though this will clearly defeat the sponsor's aim to develop the project on an entirely non-recourse basis.);

(iii) there may be tax considerations as to which route should be followed particularly if the SPV is not wholly-owned by the sponsor;

(iv) from an internal management, operational and accounting point of view, it will frequently be desirable to develop the project in a special purpose vehicle, particularly if several co-venturers are borrowing jointly;

(v) contractual restrictions in operating companies (for example negative pledges and limitations on borrowings in other financial documentation) may require the borrowings to be taken in a special purpose and possibly off-balance sheet vehicle;

(vi) there may be balance sheet considerations. In particular, if the SPV is not wholly-owned by the sponsor, it may be possible to keep the project debt off the sponsor's balance sheet.

Consortium/individual developments

The capital intensive nature of oil and gas developments has resulted in most major developments being carried out by consortia, rather than individual producers. In the context of a consortium development, project finance can be used to finance the development expenditure of one member of a consortium, or the expenditure of the entire consortium. Some consortium projects are specifically structured in such a way as to enable non-recourse funds to be borrowed, sometimes because certain members of the consortium are not readily able to finance their share of development expenditure by other means.

Different issues will arise, particularly from the banks' perspective, if an individual consortium member's expenditure is being financed. In particular:

(i) concessions are often granted on a joint and several basis with a right to revoke following breach by any licensee;

(ii) consortium documentation may provide for liens to arise in certain circumstances in favour of other consortium members over the interest that is financed. (The banks' security will be subject to any such matters);

(iii) the banks' ability to dispose of the financed interest on enforcement may be restricted (for example, by restrictions on assignment of interests under operating agreements); and

(iv) the bank is unlikely to have any direct control over the assets that have been developed (unless the interest that has been financed is a controlling interest in the field).

These issues need not be fatal to proposals to raise project finance, but if banks are unduly concerned about the creditworthiness or identity of a particular member of the consortium, this might cause difficulties.

Field Development: Risk Allocation in Project Finance

The risks to which a particular development are subject can be wide-ranging. Lending banks will be willing to accept certain of these, but not others. The principal risks which arise in the context of a field development are listed below. It will be important in the context of any project finance transaction to ascertain how these and any other risks that are identified will be apportioned, in particular whether they will:

(i) fall on the banks;
(ii) fall on the project vehicle (and therefore indirectly on the banks, if there is insufficient equity in the vehicle to absorb the risk); or
(iii) fall on the sponsor, insurers or other third parties.

Environmental/Legal Liability

Risk of environmental or other legal liability is of particular concern to a banker, because it represents potential exposure over and above monies lent. Lender liability issues have in recent years been the source of considerable concern for banks, as a result of case law in the United States which led bankers to believe that they could be held liable for environmental damage solely by reason of being a secured creditor. These concerns appear to have been overstated, but the banker's sensitivity to these issues is in part justified because of the tendency of litigators to look for a "deep pocket". In any case, in the unlikely event they were to enforce their security and take over the operation of a project, there is little doubt that they would have exposure for environmental and other legal liabilities.

The banks will require liability insurances to be in place and sponsors will typically have no objection to this. There may however be some debate as to the appropriate levels of cover and deductible.

Construction Risk

If banks lend prior to completion of the construction phase, they will need to evaluate the construction risk. Construction risk has several elements:

Contractor's Credit: the banks will need to be content with the identity of the contractor from a credit point of view. Insolvency of the contractor will

probably lead to increased costs. It will definitely lead to delay and (as noted above) timing of completion of the project will be critical to the project economics. The banks will need to be satisfied that the contractor is financially sound. If there is concern, performance bonds and/or completion guarantees may be required;

Contractor Force Majeure: the banks will consider carefully the force majeure provisions in the construction contract to ensure that these are acceptable;

Technology Risk: if the technology to be employed in construction is tried and tested, the banks will have less concern on construction risk generally. If innovative techniques are involved in construction, banks may be unwilling to accept completion risk. (If completion risk is not accepted by the banks, this may involve the sponsor giving guarantees of the bank debt that expire once completion certificates have been delivered. Alternatively, the sponsor could finance the project during the construction phase and refinance at project completion).

If the construction arrangements are on a cost plus fee or similar basis, the financiers would also be exposed to the risk of cost overruns. Typically they will not accept this risk—they will either require a fixed cost (or "turnkey") contract or will require the sponsor to agree to cover cost overruns.

The recent cost cutting initiatives relating to North Sea developments have resulted in increased use of "partnering" or "alliance" arrangements between contractors and engineering and design specialists. These arrangements are structured to provide an incentive to all concerned to contain costs and so should lead to more profitable development from the point of view of the sponsor. However, the absence of a fixed cost element in the construction phase will need to be addressed from the point of view of the banks (probably by sponsor support), if the construction is to be financed on a project basis.

Operating Risk

The profitability of the field will to a degree turn on the effectiveness of the operator. Where the operator is a major, banks are not likely to view operator risk as a serious consideration. If the proposed operator is a smaller company with no track record, the banks' position may be different.

Offtaker risk/market price risk

In the context of a gas development, there is likely to be a long-term gas sales agreement which the banks will see as their primary source of repayment. The cash flows arising under that contract will determine the level of debt that can be raised to finance the project. The banks will assess the value of the covenant of the offtaker. Frequently, the offtaker will be a State (or recently privatised) utilities entity, but where this is not the case the bank's evaluation of the offtaker's creditworthiness will form a significant part of the credit assessment in relation to the project.

In the case of an oil field development it is likely that no long-term offtake contract will be in place. The project will therefore be exposed to fluctuations in the oil price. This risk could, at a price, be managed by the purchase of oil derivative contracts and the banks and the sponsor will consider the project economics to ascertain the sensitivities to market price fluctuations. If the banks are satisfied that possible oil price fluctuations do not threaten project economics to the detriment of the debt (for example because there is sufficient sponsor equity in place), the banks will be content for no commodity hedging strategy to be put in place. In a highly-leveraged situation, the banks may require commodity hedging arrangements to be in place.

This can give rise to commercial difficulties, since the sponsor is likely to handle its commodity price risk management on a consolidated basis and may be reluctant for derivatives contracts to be purchased in connection with a particular development. One solution in such cases is for the project vehicle to enter into derivatives contracts with the sponsor, rather than with the market.

Political Risk

Political risk and project finance is an enormous topic. Frequently, political risk is an all-or-nothing issue for the banks, in that banks will simply refuse to fund projects in certain jurisdictions on a true project finance (*i.e.* non-recourse) basis, largely because the expropriation risk is unacceptably high. As a result it remains virtually impossible to raise conventional project finance for transactions in certain parts of the world (for example, the former Soviet Union). Transactions can be done, for example, by obtaining political risk insurance cover, but the costs may be prohibitive. The non-recourse financings that take place in these jurisdictions invariably rely on multilateral agency or ECA support.

A lower level of political risk frequently arises. This could relate, for example, to exposure to changes in the petroleum royalty regime which might adversely affect the project vehicle, or in relation to discretions and powers that sovereigns retain in relation to concession agreements. The question whether the banks will take the risk of discretions being exercised to the banks' detriment will depend upon which State is involved and upon the experience of lenders in that State. In the early days of North Sea financings detailed agreements were entered into between HM Government and project lenders so as to cover issues of concern to lenders. But practice has changed and detailed assurances are no longer required by lenders. But in many States it is common for lenders to require host governments to give undertakings to

cover issues of concern, though there is often doubt as to the binding nature of these undertakings.

(There have in the past been loans relating to developments in the Norwegian sector of the North Sea in which all aspects of production risk have been borne by sponsors, and in which the banks accepted certain political risk, principally in relation to change of tax and royalty regime and in relation to expropriation. Arrangements of this type are not common.)

Tax risk

Tax risk can be regarded as a sub-category of political risk. There are two aspects to tax risk. First, the host government might change the tax regime in a manner that renders the project company unable to service and repay its debt. This could happen if, for example, deductibility of interest were restricted or eliminated. The second more specific aspect of tax risk concerns the ability of the project company to pay interest to lenders without making withholding on account of tax. As between the banks and the project company, these risks will rest with the project company. Its obligations to make payments to the banks will not be qualified by reference to its own tax position, and it will be obliged to gross up payments to the banks if withholding is required. In the context of financings in most jurisdictions, the banks will be content for the project to bear tax risk (so that insurance/sponsor support would not be required).

Reservoir Risk

Perhaps the most fundamental risk associated with the project, and one to which the banks are generally exposed, is reservoir risk. The ability of geologists and petroleum consultants accurately to predict reservoir reserves and recoverability is limited. In accepting this risk, banks will be willing only to lend against proven reserves and in assessing the level of debt that a particular development can sustain, banks will take into account the uncertainties that are inherent in reserves estimation and predictions of reservoir performance.

Financial Risks

The project will be exposed to fluctuations in interest rates and possibly to foreign exchange fluctuations. The banks will require these risks to be eliminated by way of derivative contracts, though if the sponsor wishes to manage these risks on a consolidated basis, the counterparty to these contracts could be the sponsor.

Risk on sponsor

As indicated above, the sponsor is likely to have a number of obligations to the project company in its capacity as sponsor. It may have undertaken to provide additional equity in certain circumstances, or it could have entered into contracts with the project company so as to cover risks which the banks are not willing to allow the project company to bear. The banks will evaluate the sponsor's covenant, as they will that of any other counterparty to contracts with the project vehicle. If the banks are reluctant to take the risk of sponsor default, this may (depending upon the proposed role of the sponsor in relation to the project) be fatal to the functioning. Alternatively, letters of credit or performance guarantees might be required.

Consortium Risk

As indicated above, where the banks are financing the expenditure of one member of a consortium, the banks will have regard to the identity of the other consortium members. The particular concern from the banks' point of view is that other members of the consortium might fail to meet their obligations to provide funds for development.

Legal Risks

Finally, the banks will have to assess the legal risks inherent in the transaction. To a degree, these can be assessed. The banks' lawyers will undertake due diligence in relation to the capacity of the sponsor and project company to enter into the transaction and opinions in relation to the enforceability of the various documents will be obtained. But there will inevitably be uncertainties. These are likely to relate primarily to security issues. These uncertainties can arise in jurisdictions in which rules relating to financing transactions are highly developed as well as those in which such transactions are less common. For example, under English law rules governing priorities of competing security interests can be uncertain, and there can be doubt as to whether a particular security interest takes effect as a fixed or a floating charge, a matter that can be important in determining the ranking of the security interest on an insolvency. But more fundamental issues arise in jurisdictions where secured financing techniques are less tried and tested, for example the former Soviet Union. The concerns can be fundamental. They might for example relate to the ability of the project company to create security over a particular asset. Where fundamental issues do arise, it may be impossible to devise a bankable security package. Where the issues are not fundamental, they may nevertheless result in additional sponsor support being required.

Security and Related Issues

Why is security taken?

It is sometimes argued (at least by borrowers) that because of the particular nature of a project vehicle (it typically has only one third party lender) and because it is most unlikely that the banks would actually enforce their security, that it is not critical for project finance banks to take security. But project finance banks will invariably require security, for the following reasons:

(i) on a winding up of the project company there will be numerous unsecured creditors (these could include suppliers of equipment and services, employees and offtakers). The banks will wish to rank ahead of these claimants in any winding up of the project vehicle, to the extent that there is value in the project assets.

(ii) if the project is unsuccessful, the bank will ideally want the right to sell the entire project assets to a third party. This can only be achieved if the bank has security over all of the project assets. (As a practical matter in the context of an oil and gas development, if the project fails the project assets are likely to represent a liability rather than an asset. But if the asset that is financed can be adapted for use in other fields (for example if it is a floating production vessel), it could be of significant value to the banks.)

(iii) where project assets are fixed and cannot be adapted for alternative use, it is still possible to envisage circumstances in which banks might wish to enforce security. The sponsor might become insolvent, for example, and the banks may need to take control of the project pending sale to a third party.

It is however the case that banks will be extremely reluctant to enforce security over oil and gas project assets. If a project runs into difficulties, the sponsor and the banks will have community of interest to a large extent, and the banks will (by virtue of financing documentation) have a high degree of contractual control over the continued management of the project. But if the project ultimately proves not to be viable, the position is unlikely to be improved if it is the banks (or a receiver) rather than a sponsor in control. The banks will be further discouraged from enforcing security by the liability issues referred to above and by potential liability for abandonment costs: even if enforcement is through a receiver (for whose actions the banks should not be liable—at least under English law) the banks would probably be required to indemnify the receiver against liabilities in connection with the project.

The Security Package

It is likely that the banks will wish to have security over all assets of the project vehicle, as follows:

(i) security interests over all property and fixed assets (equipment etc.) which are vested in the project vehicle;

(ii) assignments or charges of contractual rights including under any construction or offtake contract and (in the case of consortium developments) interests under joint operating agreements;

(iii) charges of licence interests (in many jurisdictions, producers will resist charging licence interests, particularly if there are other fields within the licence that covers the project field);

(iv) charges over receivables and cash accounts.

In addition, the bank may require a charge over the shares in the project vehicle.

Typically the project vehicle will also be required to give a full fixed and floating charge over all of its assets (though these will for the most be caught by (i)–(iv) above).

Direct Agreements

The banks may also want to obtain direct contractual undertakings from third parties who have dealings with the project vehicle, in particular contractors and offtakers. The main reason for this is that, under basic principles of contract law, if the project vehicle were to commit a repudiatory breach of, for example, the offtake contract, this might release the offtaker from its future obligations. The banks will be unwilling to accept the risk of the project vehicle losing its rights against the offtaker. The offtaker will therefore be required to agree with the banks that, if the project company were to breach its obligations under the offtake contract, the offtaker would inform the banks and allow the banks to "step in" and cure the breach within a specified time period.

Government Consent/Direct Agreement

As discussed above, there may be aspects of political risk in relation to which direct comfort is sought from host governments. So the banks may for example require a specific undertaking from the government that royalty payments will not be increased, or that any right to terminate the licence on receivership of a licensee would not be invoked. The contents of these agreements will vary from jurisdiction to jurisdiction and, as indicated above, banks taking security over United Kingdom production licences now take a relaxed view on these issues. But it is however still necessary in the United Kingdom to obtain the Secretary of State's consent to the charging of the licence.

Other third party undertakings

Other contractual counterparties will be given notice of the creation of security and may be required to give certain undertakings directly to the banks. For example, commercial banks with which project bank accounts are held will be required to confirm to the lending banks that no rights of set off will be exercised and that no previous notices of assignment have been received, in relation to the project accounts. Similar comfort may be required from other counterparties.

Subordination

The sponsor will probably enter into a series of contractual agreements with the project vehicle. Capital may have been provided by way of loan, for example, and various services (including management services) may be provided by the sponsor to the vehicle. Given the security that the banks have over the assets of the project vehicle, the sponsor's claims against the project vehicle under these arrangements are in effect subordinated to the banks' claims. But the banks will probably require the sponsor to enter into a subordination agreement with the banks.

A simplified security structure for development of a gas field might be as follows:

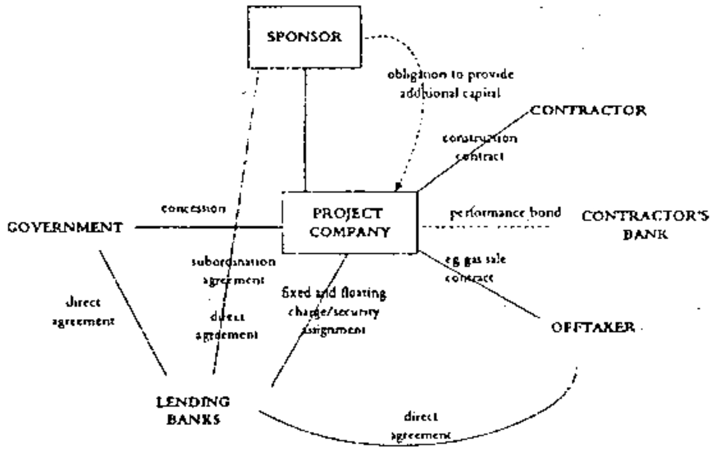


Diagram 4

Technical Points on Security

Governing and proper laws: under conflicts of law principles, the relevant (or "proper") law for the purpose of determining the nature and effect of an interest created by a security document will, in the case of security over real property and equipment, be the *lex situs*, or place where the asset is located. It is therefore important to distinguish between the *governing law* of the security agreement (*i.e.* the law which the parties agree should be applied in construing the agreement) and the *proper law* (*i.e.* the law that will under conflicts of laws principles be relevant in ascertaining the substantive effect of the charging provisions in the document). Difficult legal issues can arise if different governing and proper laws apply (for example if an English law charge is executed in relation to property in, say Russia). Where possible, this practice should be avoided.

Conflicts of law rules differ from jurisdiction to jurisdiction and a detailed analysis will not be set out here. But it follows from the significance of the *lex situs* that, whatever the intention of the banks and the chargor, if the rules of the jurisdiction in which the relevant assets are located are not sufficiently clear or robust as regards the creation and enforcement of first ranking security interests, it will not be possible to devise a viable security package on a non-recourse basis.

Different rules apply where contractual rights are concerned. If rights under a contract are assigned by way of security by a project vehicle to a bank, the governing law of the assignment will (under English conflicts of law principles) be relevant in determining the effect of the assignment as between assignor and assignee. But the assignability of the contract and the relationship between the counterparty and the assignee will be determined by the law governing the underlying contract.

Conflict of law issues need careful consideration in the context of offshore developments. Assets secured may comprise contractual rights against third parties, rights granted by a State under a licence to exploit the continental shelf and equipment located on the high seas. Contractual rights will be governed by the rules stated above. The granting of security over a concession is, most likely, governed by the laws of the State granting the concession. When equipment located outside territorial waters is secured, the parties may have a degree of choice as to the proper law of the security. The legal analysis may be complex, because conflicts rules applied by the courts of different States vary. The approach taken will, however, depend on practical considerations. In particular, the parties will have regard to the jurisdiction in which the security is likely to be enforced and will consider the likely approach of the courts in that jurisdiction. But given the lawyer's caution, it is quite usual to have the same offshore asset subject to two or even three sets of security documents, each with a different governing law. Security over assets in the Scottish sector

of the United Kingdom continental shelf are, for example, invariably subject both to English and Scots law charges, in an attempt to reserve the extensive benefits of an English law charge but to ensure that, if Scots law is found to be the proper law, the charge is effective.

Perfection: once created in accordance with the relevant proper law, security needs to be perfected in accordance with all applicable laws. This may require registrations to be made in the jurisdiction of incorporation of the chargor and, in the case of security over land or equipment, in the jurisdiction of location of the assets. Where contractual rights are assigned, the security interest may need to be perfected by the giving of notice to contractual counterparties.

Title to assets: If security is taken over an asset such as a vessel or platform during construction, it will be important to consider at what stage title to the asset passes to the project vehicle. If, for example, title to the asset were to remain with the contractor pending completion, the banks would be taking a risk on the contractor during the construction phase.

THE PROJECT FINANCE SYNDICATED LOAN AGREEMENT

A project finance loan agreement will be based closely on the form of syndicated loan agreement that is commonly used in the eurocurrency markets. Emphasis is given below to those provisions that are specific to project finance transactions relating to oil or gas field developments.

Financial Model

Prior to considering the terms of the loan agreement, it is worth briefly considering the economic and technical evaluation that the banks will undertake prior to committing to lend. The arranger will, together with its technical advisers, consider in detail the project economics so as to be in a position to model the likely cashflows arising in the project vehicle during the course of the project. Assuming that the banks lend during the construction phase, this will involve consideration of: the costs of construction and the dates of construction expenditure; the likely completion date; ongoing operating and management costs; date of first petroleum; rate and period of recovery of petroleum; future price of petroleum; the tax regime to which the vehicle is subject; and financing costs. The financial model will demonstrate how much debt the vehicle could safely carry and the banks will run variants to the model to ascertain the project sensitivities to various contingencies (change of tax rate, for example, or delay of completion date).

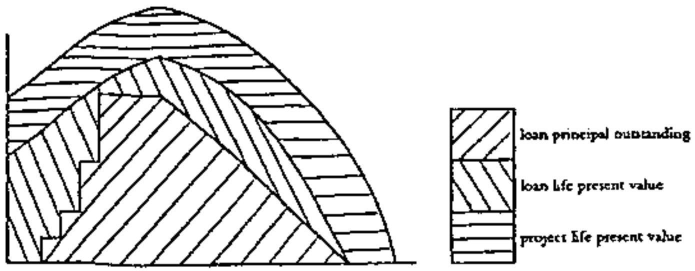


Diagram 5

The model will enable the banks to determine what will be regarded as the key ratio during the project life, the loan life cover ration (*LLCR*). The LLCR is, broadly, the ratio at any time of (i) the peak debt amount at or after such time to (ii) the present value of future cash flows which will be generated by the project during the term of the loan. The ratio therefore indicates the extent to which the banks are collateralised by those cash flows at any time. The banks may also consider the project life cover ratio which takes into account the present value of projected reserves after the maturity date of the loan.

Another ratio that will be significant to the banks is the debt service cover ration (*DSCR*). The DSCR is the ratio, during a given future period, of: (i) the cash flows that will be generated during that period to (ii) the financing costs during that period. The ratio therefore indicates whether the project is expected to generate sufficient cash flows during each relevant period to avoid a payment default. Other ratios may be relevant, but these key ratios will form a vital component of the credit decision and are likely to be reflected in the loan agreement.

Loan Agreement

Parties

The parties will include the project vehicle, as *borrower*, and each of the *banks*. In addition, a financial institution (quite likely the arranger of the transaction) will be party to the agreement as *facility agent*. The facility agent acts as agent for the banks and performs an administrative role so as to avoid the requirement for bilateral dealings between the borrowers and each of the banks, for example in relation to payments and delivery of information.

Additional parties will include the *arranger*. The arranger is the financial institution which has arranged the transaction for the borrower. Once the

transaction has been arranged, the arranger will have few if any obligations in respect of the loan, but it will be party to the agreement so as to take the benefit of certain warranties and indemnities. There is also likely to be a *technical bank*, which also acts as agent for the banks, and which will be qualified and required to make decisions on behalf of the banks (in consultation with appropriate experts) on technical matters relating to the field and its development. Finally, the *sponsor* of the project may be party to the document, perhaps because it gives a guarantee of certain obligations of the borrower or because it gives certain warranties or undertakings relating to the project to the banks, for example in relation to the injection of equity into the project vehicle.

Purpose

The purpose of the loan will be stated. It is likely to be for the funding of development expenditure in accordance with a development plan that is subject to approval by the banks. If the loan is made after certain expenditure has been incurred, part of the loan may be capable of being applied in refinancing that expenditure.

Conditions Precedent/Advances

There will be a number of standard conditions precedent to advances relating, for example, to execution of security documents, compliance with obligations and to there being no event of default. The borrower may also be required to satisfy the technical bank in relation to any particular drawing that all cover ratios referred to in the document will be satisfied after the making of the drawing. (This will give the banks the right to decline to increase their exposure if the development is not proceeding as planned.) Advances are likely to be made on dates on which project expenditure is required to be funded by the vehicle.

Repayment/Prepayment

The repayment provisions will require final repayment by a specified date. The loan will amortise, once the project becomes cash generating, and cash generated from the project will be required to be applied in repayment of the loan in accordance with an agreed repayment schedule. It is also possible that excess cash flow in the project vehicle (*i.e.* cash flow that is not required for ongoing project expenditure or scheduled debt service) will be required to be applied in prepayment. If this is the case and the project performs better than anticipated, the banks will receive early repayment.

The project company should negotiate a right to prepay, in some circumstances change and it can fund itself more cheaply from other sources. In certain circumstances the project company will be required to prepay the loan, for example if there is a total loss of the project assets and insurances proceeds are paid or if assets are requisitioned and compensation is received.

Operation of project accounts

The banks will exercise close control over the project vehicle's cash. Project accounts will in any event be subject to the bank's security, but the banks will allow cash to be applied only for purposes approved by the banks.

Budgets

The agreement will (if the field is not a consortium development) require the project company to prepare budgets for approval by the banks. These budgets will determine what expenditure may be incurred by the project company.

Information/Reports

The project company will be required to deliver detailed information and forecasts to the banks in relation to the project, and to permit the technical bank and various consultants to the banks (e.g. the reserves consultant) to prepare reports relating to the project and its progress. The information contained in the reports of the technical bank and reserves consultant will be used to calculate the various cover ratios required to be maintained. The information will be fed into the model referred to above and the model will from time to time be updated to reflect changes to the various assumptions on which it is prepared (for example as to the tax rates).

Representations and warranties, undertakings and events of default

An example of the representations that might be found in a facility agreement relating to an oil or gas development is set out in the appendix to this chapter. Many of these are common to all syndicated loan transactions, but the ones that are of particular interest are as follows:

Warranties

Consents: the project vehicle will warrant that all consents necessary for the validity of the loan agreement and related security have been obtained. As noted above, governmental consent may be required, particularly in relation to the charging of licence interests;

Environmental matters: warranties as to environmental compliance will be required, whether or not the project company is the operator of the field;

Project agreements: all agreements and contracts relating to the project vehicle's interest in the project will need to be made available to the banks and will be subject to warranties by the project vehicle as to completeness and validity;

Undertakings

Information: as noted above, detailed information relating to all aspects of the project will be required to be delivered to the facility agent and technical bank;

Disposals: the project vehicle will covenant not to dispose of any of its interest in the project or project assets;

Project agreements: the project vehicle will undertake not to vary any of the contracts to which it is party relating to the project. The manner of exercise of voting rights at (for example) operating committee meetings may be subject to control by the banks. For example, the vehicle might be required to agree not to vote in favour of abandonment or a change of operator. The project vehicle will also be required to undertake not to vote in favour of any arrangement for unitisation or redetermination of the project field.

Accounts: the project vehicle will undertake to operate its accounts in the manner prescribed in the loan agreement. This will leave the vehicle with little discretion as to the application of cash.

Insurance: The project company will be subject to detailed undertakings concerning insurances.

Transactions with affiliates: the ability of the project vehicle to enter into transactions with affiliates and to pay dividends will be restricted.

Events of default

Cross default: the facility will cross default if other indebtedness of the project vehicle goes into default, though this is not likely to be of relevance since the vehicle is unlikely to have other financial creditors. A question will arise as to whether the facility should cross default on a default relating to debt of the sponsor. The banks' position on this point is likely to depend upon the degree of sponsor support.

Others: in addition, the following events are likely to constitute events of default:

(i) damage to a significant part of the project assets;
(ii) expropriation of project assets;

(iii) (possibly) a breach by any person of the joint operating agreement (or similar contract);
(iv) (possibly) a change of operator;
(v) a change of control of the project company or (possibly) the sponsor;
(vi) a failure to satisfy the project cover ratios;
(vii) (if funds are lent prior to completion) a failure to achieve completion or certain "milestones" during the completion phase by prescribed dates.

All of the above events will entitle the banks to accelerate the loan and enforce their security. It should be noted that a default may be of considerable significance for the sponsor, since if the project vehicle is wholly-owned by the sponsor, a default in relation to the project debt could cause cross default throughout the sponsor's group. Whilst the facility agent may have a right to call a default without a bank direction, it is likely that a direction from a specified percentage of banks (*e.g.* 66 per cent or 75 per cent) would be required.

OTHER FINANCING AND SECURITY TECHNIQUES

Finally, it is important to mention certain alternative financing and security arrangements that are used in connection with oil and gas development.

Pipeline financing: throughput agreement

Throughput financing agreements typically involve a group of suppliers of oil or gas setting up a special purpose vehicle (SPV) to borrow from financiers in order to construct a pipeline. The sponsors will agree in advance to utilise the pipeline capacity in agreed proportions and to pay a tariff for the use of the pipeline. The tariff payments will, typically, be calculated so as to cover pipeline operating costs, the SPV's debt service obligations and an agreed equity return for the SPV.

The crucial aspect of the sponsor's obligation to pay tariff is that payments are required to be made in all circumstances. (Provisions giving effect to such obligations are, for obvious reasons, commonly referred to as "hell or high water" provisions.)

An example of such a provision is as follows:

> "regardless of whether or not the pipeline company is at fault and regardless of the extent to which the pipeline is constructed, the obligations of the shipper under this agreement shall not be affected or invalidated in any circumstances including but not limited to the failure,

> impossibility or impracticability to have product shipped through the pipeline for any reason whatsoever including but not limited to the total destruction, damage, non functioning or change in ownership or control of the pipeline or any other installations, determination or non-enforceability for any reason of the pipeline company's right to have products transported through the pipeline force majeure or any circumstances whatsoever arising, including the institution of bankruptcy proceedings with regard to the property of the pipeline company which operate or but for this provision would operate to frustrate or terminate this agreement or to permit the shippers to rescind this agreement or release them from their obligations hereunder."

The obligation to make tariff payments is therefore unconditional, and this forms the basis of the throughput financing structure: the suppliers' obligations to the SPV are assigned by way of security to the lenders to the SPV. The lenders can (because of the unconditional nature of those obligations) look to the suppliers for repayment of the loan to the SPV.

The structure essentially gives the lenders a guarantee from the suppliers. But because the obligation of the supplier is to pay tariff or availability fee and is not a financial guarantee, suppliers have (at least in the past) been able to avoid accounting for the obligation as financial indebtedness.

The enforceability of the tariff payment in a throughput structure has been much debated, as has the "take or pay obligation" often found in a sponsors' offtake contract. It is the author's view that, if properly drafted, such arrangements should be enforceable, at least if governed by English law.

Production payments

Production payments have been extensively used in the United States to enable companies to raise finance on a non-recourse basis. These transactions involve a payment by financier or group of financiers to an oil producer in exchange for a right either to a specified amount of production recovered from the relevant field or to a specified amount of the proceeds of sale of that production, free from costs of production, so as to enable the financier to recover its "loan" plus financing charges. Under United States jurisprudence, it is considered that the production payment confers on the bank a proprietary right to the petroleum or money in question, and this (at least previously) led to these transactions being treated as a sale of an asset rather than a loan in the accounts of the producer, and gave rise to favourable tax treatment.

The fact that, under United Kingdom licences, producers have no proprietary right to oil until recovered means that it is not possible to grant a proprietary interest in unrecovered reserves. But it is possible to dispose of a right to receive in the future proceeds of sale of petroleum (provided the right is, by its terms, capable of assignment).

Forward purchase/advance sale arrangements

A forward purchase or advance sale arrangement involves a financier (or purchaser) making an advance payment to a producer (to be used to finance field development) against an undertaking by the producer to deliver a specified quantity of oil or gas in the future. The arrangement differs from the production payment in that, usually, no proprietary right is vested in the financier or purchaser.

In the United States arrangements of this type have been entered into between gas producers and gas suppliers to enable gas suppliers to obtain dedicated reserves, often at competitive prices.

Multifield Facility

Loan facilities can be secured on a borrower's interest in a number of fields. Facilities of this type can be put in place to finance the development of some or all of the fields on which they are secured. Alternatively they could be arranged to provide funds for other purposes. A common feature of such arrangements will be provisions setting out the method of calculating the "borrowing base" which in turn will determine the amount that can be outstanding from time to time. The means of calculating the borrowing base is likely to be similar to that described above in relation to the calculation of cover ratios.

Offshore Trust Arrangements

Bankers' concerns regarding political risks can be addressed by the use of offshore trust arrangements. These involve the establishment of a trust into which the proceeds of sale of oil or gas from a particular field or series of fields are paid. Lenders who advance funds for development purposes or to refinance development costs are designated beneficiaries of the trust, with the result that they can require the trustee to make disbursement from the trust accounts in order to service and repay debt due to them. The trust arrangements will be structured so as to ensure that the proceed of sale held by the trustee will at all times be sufficient to cover the amounts outstanding to beneficiaries. These arrangements are commonly used in connection with developments in African countries.

SPECIALIST LENDERS

Finally, it is important to be aware of the role of multilateral agencies and the export credit agencies in oil and gas development.

International Bank for Reconstruction and Development

The IBRD (part of the World Bank) was formed to assist in the reconstruction and development of its member states. World Bank finance is frequently used to assist oil and gas development in countries where political risk deters commercial lenders. The World Bank lends to member states and their national oil companies, financing exploration and development either by itself or in conjunction with other multilateral agencies. More recently, guarantees have been issued by the Multilateral Investment Guarantee Agency (established by the World Bank) to encourage commercial banks to fund developments.

The European Bank for Reconstruction and Development (*EBRD*)

The EBRD's function is to promote the mobilisation of capital and investment (by both public and private sector) in economically viable projects, principally in Central and Eastern Europe. The EBRD may collaborate on projects with the World Bank, International Monetary Fund and other agencies. The EBRD provides finance and technical assistance in circumstances where it would not be available from other resources. It has participated extensively in oil and gas related projects in Central and Eastern Europe.

European Investment Bank (*EIB*)

The EIB is primarily charged with the development of the member nations of the EEC. Its capital is subscribed by member states and loans are made to the private sector. The scope of the EIB is not limited to sponsoring development within the EEC and a number of African projects have been completed with EIB financing. The EIB works together with other lenders and aid agencies to enable the development of a variety of industrial and energy projects.

Other multilateral agencies frequently involved in oil and gas development are the International Finance Corporation (also part of the World Bank) and the Overseas Private Investment Corporation (*OPIC*).

Export Credit Agencies

The export credit agencies (*ECAs*) also perform an important role in international financing transactions, particularly where asset finance is involved. The principal agencies are as follows:

Export-Import Bank of the United States (*Ex-Im Bank*)
The Export-Import Bank of Japan (*JEXIM*)
Hermes Versichnungs AG (*Hermes*)

Companie Francaise d'Assurance pour le Commerce Extèrieure (*COFACE*)

The function of these agencies is to encourage international trade, in particular by facilitating exports from the State in which they are established. The financing techniques and requirements of the various agencies differ, but they are commonly involved in providing finance or guarantees (to exporters or purchasers) thereby directly or indirectly financing a portion of the development costs of a project. As with finance provided by the multilateral institutions, export credit finance is frequently a prerequisite to developments in States in which levels of political risk are perceived by commercial bankers to be unacceptably high.

8.

Gas Sales Agreements

Niall Trimble, Director, The Energy Contract Company Ltd

INTRODUCTION

In the past gas was always sold on long-term contracts, often on a depletion contract basis. That is, all the gas was dedicated to a single buyer. Over the last few years the gas industry in Great Britain has changed dramatically and so has the contract format. Now gas is bought on a variety of contract lengths from a few days upwards and many of the agreements are now on a supply rather than a depletion basis. This paper describes the fundamental elements in gas contracts and is divided into three sections: The first of these covers the main non-price terms. It then goes on to review the various methods by which the price of gas can be established under a sales agreement. The terms set out in this paper generally all occur in medium and long-term agreements, but some of the shorter-term contracts may not include all of the provisions described. In the final section the paper will show how the shorter term agreements differ from the long-term versions.

PRINCIPAL TERMS IN GAS SALES CONTRACT—NON-PRICE

Agreement for Sale and Purchase

Although it can be very short, the Agreement for Sale and Purchase of Gas is the cornerstone of a gas sales contract. This is a short clause which simply says that the Seller agrees to sell gas and the Buyer agrees to buy gas, on the terms set out in the contract.

Quantities

One of the two most important elements in the gas sales contract are the quantities provisions, which govern the amount of gas to be supplied on any one day. The main elements are:

(i) The DCQ—the Daily Contract Quantity, or DCQ is generally meant to represent the average daily flow of gas during any year. It is of no great significance in itself, but it is a reference point from which several other vital terms are calculated;

(ii) the Plateau DCQ—in a depletion contract the agreement will specify a fixed DCQ for the early years of the contract, the Plateau DCQ. This can last for a fixed period of time, for example, for the first six years after the start of deliveries. Alternatively, the Plateau DCQ can continue until a fixed proportion of reserves on the field have been produced. This period is known as the Plateau Period. In a Supply Contract, the DCQ for the whole contract period will be specified in the contract;

(iii) Decline DCQ—after the end of the Plateau Period, a Depletion Contract will enter the Decline Period. At this time, the DCQ will be reset each year according to the production capacity remaining on the field. The DCQ will generally be the maximum the field can sustain throughout the whole of the year concerned, bearing in mind the Buyer's rights to nominate under the contract. The Seller will nominate a Decline DCQ to the Buyer each year, using a specified notice period laid down in the contract. If the Buyer and the Seller are unable to determine an appropriate DCQ, then the matter may be referred to an independent expert for resolution. There is no Decline Period in a Supply Contract;

(iv) delivery Capacity—the Delivery Capacity, which is used in both Depletion and Supply Contracts, is the maximum daily amount that the Buyer can nominate and which the Seller is obliged to deliver. It is generally set at a fixed percentage of the DCQ, for example 150 per cent of the DCQ. As a result, when the DCQ starts to go down in the Decline Period, the Delivery Capacity will decline pro-rata. Although this percentage relationship remains constant throughout the life of the contract, it is possible to introduce a standard seasonal variation which is constant from year to year. For example, the Delivery Capacity could be 150 per cent of the DCQ in the months of October to March and 130 per cent in the months April to September. This is possible because gas demand is an inverse function of temperature, and is lower in the summer;

(v) minimum Nomination and Zero Nomination—as gas-field production equipment does not always work well at very low levels, it is customary for there to be a minimum quantity that the Buyer can nominate for delivery on any day. This can be set either as a percentage of the DCQ or as a fixed daily production rate. Although most gas sales contracts do allow the Buyer to nominate zero, the Buyer will not be allowed to nominate quantities between zero and the minimum nomination level;

(vi) obligation to Deliver—the Contract will generally oblige the Seller to delivery any Quantity of gas nominated by the Buyer, so long as nomination lies between the Minimum Nomination level and the Delivery Capacity. The Seller will be relieved from this obligation to deliver only by circumstances which constitute force majeure.

(vii) excess Gas—although the Seller's obligation is to deliver gas up to the Delivery Capacity level, the Buyer will generally have some rights to request greater volumes, known as Excess Gas. However, the obligations on the Seller to deliver such Excess Gas will be less onerous, generally reasonable endeavours or something similar. Excess gas will normally be paid for at a premium to the normal contract price;

(viii) nomination Procedure—the Contract will also lay down a procedure for the time when the daily or weekly nomination of gas volumes should be made by the Buyer. It will also specify the Buyer's rights to vary the nomination at short notice and the speed with which the Seller must respond to such changes.

Under-Deliveries

A gas sales contract will not only lay down the quantities of gas the Buyer is entitled to nominate on a day, it will also deal with a failure to deliver. This is known as an under-delivery, and the consequences will depend on the circumstances which lead to the failure. If the Seller was prevented from producing or delivering gas as a result of circumstances beyond his reasonable control, then he will be relieved from his obligations by a concept known as force majeure. Under these circumstances, the only consequence will be that the Buyer's Take or Pay Obligation (described in the following section) will be reduced by the amount of gas that the Seller failed to deliver.

If on the other hand, the Seller is unable to claim force majeure relief, then not only will there be an equivalent reduction from the Take or Pay Obligation, but the Buyer will also have the alternative of imposing one of two further sanctions. Firstly, he could sue the Seller for damages in the Courts. If, for example, the Seller failed to deliver gas worth one million pounds and the Buyer had to purchase alternative supplies, which cost one-and-a-half million pounds, then he could go to court to claim damages for the extra half-a-million pounds. Alternatively, the Buyer could classify the under-delivery as

Shortfall Gas. This will mean that the Seller then has to deliver an equivalent quantity of gas to the Buyer in the future at a discount to normal contract price. The Shortfall Price is generally between 50 and 100 per cent of the normal price.

Take or Pay

Originally gas was contracted almost exclusively on a long-term basis and there was little market for gas outside the confines of these agreements. In order to justify the heavy expenditure needed for gas field development, the Take or Pay concept emerged. This guaranteed the seller a minimum income level, regardless of the buyer's take. Despite the recent changes in some parts of the European gas market, especially in Britain, the popularity of Take or Pay remains unchanged. In the contract the parties will agree a guaranteed minimum quantity for each year, the Take or Pay Amount. If the Buyer takes less than this amount, he will pay for the balance not taken. The Take or Pay amount will generally be related to the amount of capacity provided by the Seller under the contract. The Annual Contract Quantity (ACQ) is generally the sum of the DCQs in effect throughout the year and the Take or Pay Amount will be set basically as a percentage of the ACQ, typically between 70 per cent and 100 per cent. However, there are some adjustments to this basic quantity, to arrive at the Take or Pay amount:

Take or Pay Amount:

(X) per cent of the ACQ less:

- (i) Underdeliveries by the Sellers.
- (ii) Quantities of Gas that the Buyer was unable to accept for reasons of Force-Majeure.
- (iii) Accumulated Carry-Forward (a credit for previous overtakes, to be explained in the following section).

If in any year, the Buyer takes less than the Take or Pay Amount, then after the end of that year he will pay for the amount of gas not taken. The amount due is normally the amount of gas not taken, multiplied by the average gas price for that year.

Make-Up/Carry Forward

As it would be very harsh on a Buyer to continually pay for gas not taken without any means of recovery, most gas sales contracts will contain Make-Up and Carry-Forward provisions. These allow a Buyer's Take or Pay obligations to be averaged out over the life of the contract. Once a Buyer has made a Take or Pay payment, then these volumes will go into a Make-Up bank. If at some point in a future year, the Buyer has taken the Take or Pay

Amount for that year, before the year end, he can then start to take gas free of charge, up to the amount of Make-Up outstanding.

The Carry-Forward provisions work in a similar fashion. If the Buyer takes more than the Take or Pay Amount in any year, then he will receive a credit for the overtake. This is aggregated with all overtake credits from previous years as a Carry Forward Balance. Thereafter, if the Buyer takes less than the Take or Pay Amount, then he can reduce his Take or Pay Liability by the amount of the Carry Forward Balance.

The way in which these two systems work can be illustrated as follows. Throughout the period illustrated, the Take or Pay Amount or obligation is 100 units. In year one, the actual take is only 90 units, so a Take or Pay payment of 10 has to be made. This means the Buyer enters year two with 10 units of Make-Up. In year two, take is equal to the Take or Pay obligation and so the Make-up Balance is taken forward unchanged into year three. In year three, take exceeds the obligation by five units so these are taken free of charge and a reduced Make-Up Balance of five goes forward to year four. In year four, take again exceeds the obligation by five units. These are also free of charge, thereby eliminating the Make-Up Balance. In contrast in year five, gas take is 20 units above the minimum level and so this goes into a Carry Forward Balance for year six. In this final year, the Buyer undertakes by twenty units but does not have to make a Take or Pay payment, as it is exactly covered by the Carry Forward Balance.

Contract Length/Termination

In a Supply Contract, the contract length is fixed at the outset and at the close of the period, the contract will end. The position for Depletion Contracts is a little more complex. There will still be a fixed contract period, but there will also be a right of early termination for the Seller and it is generally expected that the contract will terminate through this mechanism. Traditionally, in the United Kingdom this right of early termination has only been available to Sellers. In a depletion contract linked to a single field, declining field production means that there will inevitably come a point in the later years, at which continued production will become uneconomic. The term "uneconomic" is normally very strictly defined and in making this calculation the Seller is only allowed to include those costs which would be saved if the field went out of production, that is operating costs rather than depreciation on capital expenditure. The contrast will also specify the period over which the calculation of field economics must be made, generally one year. An early termination clause will also specify the notice period that the Seller must give when serving an early termination notice. This is normally around one or two years. Finally, there may also be a couple of restrictions on the use of the clause. First, early termination may not be allowed if the cost or revenues in this period, are abnormal or untypical. Secondly, this right may not be made available to the Seller until a predetermined number of years after the start of production.

GAS PRICE FORMULAE

Introduction

The aim of the pricing mechanism is to try and reconcile the very differing interests of the Buyer and the Seller in the longer term and to produce a price which shares the risks in an equitable fashion. For the Seller the aim is two-fold. First, to have a price which reflects the value of the gas in the market place from time to time. Secondly, the price mechanism should provide the gas producers with the confidence to make the substantial investments needed to develop offshore gas-fields. From the point of view of the Buyer, if it is a gas marketing company, it is essential that the change in price of gas matches both that of the other fuels with which gas has to compete in the marketplace and the price of gas available to its competitors where there is gas to gas competition. Overall, a buyer's aim in setting price provisions is to ensure that the gas can be sold at an acceptable profit throughout the lifetime of the contract. If the Buyer is a power generator then it will need a gas price which generates an acceptable rate of return on the Power project and whose escalation matches that in the electricity sales agreement.

Multiplicative Formulae

For short-term sales covering one year or less, gas is generally sold on a fixed price basis. However, for periods longer than this, the price is generally re-calculated on a regular basis by means of a price formula. For sales in the United Kingdom, this is basically a multiplicative formula of the type shown below. This is simply an illustration, the actual escalators and weights used will vary considerably from contract to contract.

$$P = Po \times \left(0.2 \times \frac{GO}{GOo} + 0.3 \times \frac{FO}{FOo} + 0.5 \times \frac{PPI}{PPIo}\right)$$

In this example, a Base Price (Po) is multiplied by the changes in the value of the escalators over time. The current price of Gas-Oil (GO) is divided by the historic price of Gas-Oil (GOo) and the resultant number is multiplied by the percentage weighing assigned to that indicator, 30 per cent in the case of Gas-Oil. This process is repeated for each of the indicators. The results of the individual calculations are then summed and multiplied by the Base Price (Po) to generate the price itself (P).

Additive Price Formulae

Although the Multiplicative Formula is the norm in Britain, throughout the rest of Western Europe an Additive Formula is more common.

$$P = Po + (0.5 \times F1 \times GO - GOo) + (0.5 \times F2 \times LSFO - LSFOo)$$

In this case, the Historical Gas-Oil price (GOo) is deducted from the Current Gas-Oil price (GO). A proportion of this, determined by the pass through factor (F1), is then multiplied by the percentage weight assigned to Gas-Oil, 0.5. This process is repeated for the other indicators such as Low Sulphur Fuel-Oil (LSFO) and the total set of price-changes are aggregated and added to the Base Price (Po) in order to generate the gas price (P).

THE MECHANICS OF GAS PRICE FORMULAE

Clearly when very large sums of money are involved, the details of gas pricing clauses need to be very carefully defined.

Frequency of Escalation

The contract will define the times at which the price under the contract will be re-calculated using new data. In the United Kingdom this has generally been done on a yearly basis in the first month of the Contract Year. This review frequency is a matter for discussion between Buyer and Seller. In the rest of Western Europe, re-calculation in the first month of each quarter is fairly standard. There are a couple of key issues which underlie the frequency of re-calculation. If both Buyer and Seller are concerned that the price of gas should as closely as possible reflect the price of competing fuels in the market place, then ideally the price should be re-calculated as frequently as possible. However, if the price is re-calculated on a quarterly or monthly basis, then the average price payable over the life of the contract will be slightly higher than if yearly price escalation was used. This assumes that the indicators used in price escalation rise, rather than fall over the lifetime of the project.

For example, if we have indicators rising at one per cent per quarter, then the quarterly price escalations will produce prices which are one-and-a-half per cent higher than those for yearly price escalation. Therefore, for Buyers who do not mind the possibility of a competitive disadvantage for short periods when prices have dropped, infrequent price escalation will probably result in slightly lower gas prices on balance over the life of the contract. Conversely, it is generally in the interest of gas sellers to review prices as frequently as possible.

Base Period and Review Period

(i) It is also necessary to define exactly what data should be used when the prices are re-calculated. In our pricing formula the denominator volumes, *i.e.* GOo, PPIo, etc., are taken from a period known as the Base Period, which is generally the period immediately prior to the period to which the Base Price applies.

(ii) The choice of Base Period is once again purely a matter of negotiation between Buyer and Seller, however, it is essential that the period chosen should be one for which price data to be used has already been published. Otherwise there will be no certainty as to what price has actually been agreed.

(iii) The numerator values in the price equation, GO, PPI and FO, etc., will be taken from what is known as the Review Period. Each contract will define a period in relation to the date on which the price is re-calculated. Often this relationship will involve a slight time-lag in order to allow time for price data to be published. A fairly common Review-Period in the United Kingdom is 12 months data ending three months prior to the review date. On the Continent a period of six months ending one month prior to the review date is often used.

(iv) As the aim of the pricing mechanism is to reflect the change in the value of indicators over time, it is important that the period of price growth used each year exactly matches the number of years since the price was first calculated, or the price will either include too much of the change in the value of the indicators or too little. Therefore, the relationship between the period to which the Base-price initially applies and the Base Period, should be identical to the relationship between the period to which the new price applies and the Review Period.

(v) One final word of warning on Base Periods. Many price escalators, notably the oil market ones, can vary a great deal from the long-term trends in the short-term. If you pick a Base Period where the indicators were below trend then gas prices will in future be above the expected levels and vice-versa. For example, in the winter of 1990/91, prices of most oil products rose following the Iraqi invasion of Kuwait. In the 12 months to June 1991 the Gas-Oil price in Britain was £158/tonne. In the following 12 months, it dropped to £135/tonne. If we had a gas price of 13p, 100 per cent escalated with Gas-Oil and if the level of Gas-Oil prices in the Review Period reached say £200/tonne, a gas price formula with a base-period in 90/91 would yield a price of 16.5p/therm but a contract based in the following year would mean a price of 19.3/therm. For a field producing 100 mmcfd, this could mean a difference in revenue of

£10.4 millions per year. Although the Base-Price itself is the key determinant of gas prices in the future, the Base Period values can also exert a significant influence.

POSSIBLE GAS PRICE ESCALATORS

Probably the most difficult issue in gas contract negotiations is what indicators to include in the price escalation formula. In the past this was relatively straight forward. The price was escalated with the price of the other fuels with which gas competed; gas-oil, fuel oil perhaps a little electricity and coal. In most of Western Europe this is still the case. However, in countries where gas to gas competition has emerged, for example in Britain, a completely different approach may be necessary. In this section we will analyse the various indicators showing the advantages and disadvantages from the point of view of both buyer and seller:–

Oil Products—Rotterdam Market

There are two basic markets for oil products. The Rotterdam market is essentially a wholesale market in which the oil companies trade products between themselves. The gas sellers in most of Western Europe often favour the use of Rotterdam price series for Gas-Oil and Low Sulphur Fuel-Oil because these are a good indicator of the market value of gas and because Rotterdam prices are unregulated and free of government controls. Sellers in the United Kingdom used to be enthusiastic about the use of Rotterdam prices, but the volatility of all oil prices in recent years has reduced the attraction of these indicators considerably. The reaction of buyers varies from country to country. In many countries on the Continent, especially in the Netherlands and Belgium, the prices at which fuel-oil and gas-oil are sold to end users follow the Rotterdam market fairly closely. As a result, gas utilities such as Gasunie have little problem with using these indicators for price escalation. As natural gas is regarded as a high quality clean premium fuel, High Sulphur Fuel-Oil is generally not perceived as a competitor and is rarely used in gas price escalation. In the United Kingdom gas buyers were always sceptical about the use of Rotterdam prices, as the link to end-user gas prices in this country was rather tenuous. The advent of gas to gas competition has meant that escalation with any non-gas indicator now poses a high degree of risk for the buyer.

Oil Products—Inland Markets

Prices in inland markets mean the prices at which oil products are sold to end users in countries such as Great Britain and Germany. The price of both Gas Oil and Fuel Oil in such markets are amongst the most popular of all escalators in gas pricing clauses, especially outside the United Kingdom. From the buyers standpoint, these are the products with which gas actually competes in the marketplace. However, in Britain, the advent of gas to gas competition means this is no longer true. Once again if gas competes with gas rather than oil products, oil product escalation will not necessarily produce a price at which the buyer can compete successfully with other gas marketeers. In most European markets the sellers also like oil products because they are an accurate reflection of the market value of their gas. Of the two, Gas-Oil is more popular with the sellers than Fuel-Oil because the markets for the latter are in decline. There is a concern that in the long term, its price might decline relative to those of other oil products. In the United Kingdom in recent years the volatility of all oil prices has notably reduced the gas sellers preference for oil, in favour of inflation type indicators such as PPI.

Electricity

In some gas markets such as Great Britain and France, the principal competitor to gas in the domestic market is electricity. From the point of view of gas utilities such as British Gas, domestic electricity used to be a very attractive component in the price escalation basket. However, now that the domestic market for gas is about to be opened up to competition, this argument has lost most of its validity. The sellers tend not to find electricity very attractive partly through lack of familiarity. They also have a fear that electricity prices, which are often closely regulated by governments, may not fully reflect market conditions.

Coal

Coal does not compete to a limited extent in some markets with gas, notably in steam-raising and low-grade heat markets, so it is of some interest to gas utility buyers. However, the buyers who find coal most attractive as an escalator are the power producers. The sellers tend to be very much against the inclusion of coal as an escalator of gas prices. It is perceived as a low quality fuel with considerable environmental problems, which can only compete with gas if is sold at a significant discount. It is therefore likely to grow less in price than other fuels in the long run. In addition, the price series for coal seem to be less reliable than those for other fuels such as Fuel-Oil and Gas-Oil.

Gas Prices to End-Users

It is of course perfectly possible to escalate the beach price of gas with the sales prices for gas sold in industrial and commercial markets. However, in the past both buyers and sellers have tended to shy away from its direct use in pricing formulae because of the fear that it would be circular and might lead to price instability. If gas prices at the beach were determined by gas prices to end-users, there might be an inflationary price spiral with rising sales prices pushing up beach prices which, in turn, might exert upward pressure on sales prices. The same process might also operate in reverse. The sellers still retain this dislike for gas as an escalator. However, many buyers in markets where there is gas to gas competitions, such as Great Britain, now feel that the gas sales prices are a more appropriate element in an escalation basket than the more traditional choice of gas oil. This choice is a particularly significant one for the independent gas-marketers in Great Britain. As they compete purely with other gas sellers, it makes sense in theory to escalate their purchases of gas with the same indicator.

Gas Prices at the Beach

In the last six months gas marketing companies in Britain have become acutely aware of the risks involved in price escalation. The oversupply of gas to the British market has meant a collapse in gas prices at the beach. It is now possible to buy gas on a short-term contract at prices well below those in long-term contracts signed only one to two years ago. As a result the gas marketers who signed long-term commitments are losing market share to those who kept their commitments shorter-term. As a result buyers have become very wary about signing long-term contracts unless they become uncompetitive *vis-à-vis* other gas marketers. It may well be that the only way sellers can sell gas on a long-term basis in the future is if the price escalation provisions are linked to the price in short-term gas purchase agreements at the beach. At the moment all of these prices are confidential and no such index exists. However, the need for this type of indicator is so acute that it seems highly likely that one will emerge in the future. Another alternative would be a link to spot-gas prices. At the moment no such market exists, although one may well develop in the United Kingdom in the near future. Spot gas prices may well turn out to be highly volatile and may thus form a less than ideal escalator for long-term contracts.

Inflation

So far, all of the escalators outlined are energy prices of one sort or another. The final option is the only exception to this rule. Although it is not used very often in the rest of Europe, one of the most common price escalators in the United Kingdom in recent years has been the Producer Price Index (PPI). (This is a measure of inflation for companies rather than individuals). The sellers view PPI-based escalation favourably because of its predictability and because it forms a very useful hedge against collapsing oil prices. If a company needs to raise finance from banks to cover field developments costs for new gas fields, escalation of gas-prices with PPI can make the project significantly more attractive to lenders. Once again the lack of any link to the prices at which gas or other fuels are sold by competitors means that anything more than a token element of PPI escalation poses substantial risks for gas buyers. Over the medium/long term PPI linked prices could diverge dramatically from the cost of alternative sources of gas.

VARIANTS ON THE BASIC GAS PRICE FORMULA

Any gas price formula, no matter how carefully constructed is going to pose risks for both buyer and seller in the long-term. Market conditions can vary substantially over 10 or 15 years and a formula which works well initially could pose great difficulties later on, particularly for Buyers. For this reason, it is often desirable to have a means of modifying price formulae over time.

Price Break Clauses

1. *What are they?*

The most common of these pricing variants is the Price-Break Clause or Price Review Mechanism. This is extremely common on the Continent. The pricing clauses contain a normal pricing formula but this is subject to review at regular intervals, say, every two or three years after the start of deliveries. Review is open either to buyers or sellers who can demonstrate that the price is no longer appropriate in the light of current market conditions. The key concept involved is defining the set of circumstances under which prices can be changed. In the event that the parties are unable to agree on the new price, then the dispute will be referred to an independent expert or arbitrator who will determine the new price or formula.

For most Western European gas utilities, the definition and use of a Price-Break clause is relatively easy. They tend to use a net-back approach to determine the price they pay for gas. This starts with the price obtainable from end-users, deducts their "non-gas" costs and a fixed profit margin and the balance goes to the gas producer. At the specified interval the net-back calculation is repeated. If it produces a different price to that from the price-formula, then the base-price is adjusted accordingly.

2. *Prospective rather than Retrospective Price Break Clauses*

To date most price break mechanisms have been retrospective. That is the parties examine the market data over the past three years to see if the price needs to be adjusted. In order to provide the sensitivity needed in highly competitive markets, with gas to gas competition, these clauses may need to be prospective as well as retrospective. That is they will need to anticipate likely changes in the market place. If one party can demonstrate that forecast changes in the market are likely to cause problems for buyer or seller this would also be grounds for change.

3. *Changes in Indicators*

The degree of volatility in countries such as Great Britain is now so great that future price reviews will almost certainly need to cover changes in the indicators themselves as well as changes in the base price.

4. *Advantages and Disadvantages of Price Break Clauses*

The great advantage of this type of contract provision is that it does allow the parties to adjust the pricing provisions over time and protects both sides against the risk of losing money in the long-term. The disadvantages are that these clauses are extremely complex and difficult to draft and negotiate and may noticeably complicate the negotiation process. If they are invoked by one of the parties, then they could lead to prolonged and extensive disputes, and may require a great deal of senior management time on both sides to resolve.

Hardship Clauses

A Hardship Clause allows either the buyer or the seller to require the other party to re-negotiate the price, if they can demonstrate that they are suffering hardship as a result of the existing price level. It is generally wise to define what is meant by hardship for both sides, for example, if the rate of return for the Seller has fallen below a pre-defined threshold level or if the Buyer is unable to re-sell the gas to final consumers at a pre-defined profit level. Once again, if the Parties are unable to agree on whether hardship exists at some point in the future, then the contract will normally provide for the dispute to be resolved by an independent expert.

A Hardship Clause bears many similarities to a price-break clause although it does not operate on a regular basis and it has broadly the same advantages and disadvantages.

SHORT-TERM GAS CONTRACTS

Until very recently, virtually all gas delivered in Europe was sold on a long-term contract basis. However, in recent years a small but growing portion of the market in Great Britain is covered by short-term contracts lasting a year or even less. Indeed, since the price collapse in the second quarter of 1995, most of the new gas being purchased at the beach has been sold on monthly contracts.

How do short-term contracts differ from longer term ones? The first thing to notice is that although the short-term contracts are shorter and simpler than the longer-term versions, the majority of terms are very similar. The point at which the contracts start to diverge is at a contract length of around one to two years. For contracts of one year or less, then some of the terms described in this paper disappear:–

(i) The biggest difference is in price escalation. As monthly/quarterly/ contracts are so short, there is no need to adjust their value over time. The gas is generally sold on a fixed price basis and all of the price escalation provisions are absent from the contract. To date the one-year contracts done in Britain have also been on a fixed price basis. However, if the market continues to be volatile it is easy to see that a day may come when these contracts are escalated on a monthly or quarterly basis, possibly with other short-term gas prices.

(ii) Although Take or Pay continues to be very much a part of shorter-term contracts, the Make-Up and Carry Forward provisions are redundant. Within a short-contract period, which coincides with the period over which take or pay is calculated, there is no chance to recover the payments made for gas not taken. However, even here there are exceptions. Some of the more recent one-year contracts done in the British market, allow for Make-Up to be recovered after the end of the contract period, generally in the following summer.

9.

Mobile Production Unit Commercial Agreements

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INTRODUCTION

The rapid emergence of Mobile Production Units (MPU) as a more attractive option for developing certain types of oil fields, in particular marginal oil fields, is owed as much to a revolution in commercial thinking as it is to the technological advances. Technical innovation, particularly with respect to Floating Production Storage and Offtake vessels (FPSOs) has ensured that MPUs are reliable, safe and are economically viable. Technical advancement will continue to bring down the costs of such systems thus ensuring their place in offshore developments. Without commercial innovation, however, the potential which such systems evidently have would not have been realised. The providers of the facilities (the contractors) and the concession owners (the oil companies) have, by entering into more constructive relationships, made it possible to develop fields which were previously thought to be beyond reach.

In the past the contractor was required to build and sell to the oil companies facilities fit for purpose and specified by the oil companies. Although in some cases this remains the preferred option, even in relation to MPUs, the new commercial environment alluded to above allows the contractor to extend his relationship with the oil company past construction and installation and through to production and abandonment.

This chapter provides insights into the agreement between the contractors and oil companies which facilitates the development of offshore discoveries where the contractor and oil company continue their relationship beyond the build and installation stage.

MOBILE PRODUCTION UNITS

Before discussing aspects of the agreement it is worthwhile reviewing the types of facilities which fall under the category of MPUs.

MPUs are facilities which can be rapidly mobilised and demobilised at low costs. They generally fall into three categories:

Jack Ups

Jack Up Rigs represent a small proportion of the overall MPU market. They are "fixed" platforms in the sense that they must be supported on the sea bed and can only be located in water depths of nominally less than three hundred feet.

Semis

Semisubmersible drilling or accommodation rigs have formed the basis for a number of conversions into MPUs. The topsides are stripped of their original drilling equipment and replaced with production and process facilities. Unlike a Jack Up the semi can operate in a wider range of depths and environmental conditions as it is a floating facility.

Floating Production Storage and Offtake (FPSO)

Like semis FPSOs are floating facilities. FPSOs are typically either conversions of tankers or purpose build monohulls. With integrated storage and increasingly lower capital cost designs the FPSOs are currently the most popular of the MPUs.

Other categories of MPUs such as barge based systems are likely to be introduced through innovation and advances in technology.

SHARING OF RISK AND REWARD

The highly mobile nature of MPUs lends them to a new way of thinking in the commercial forum. In particular, there is now a range of possibilities with respect to the contractors' involvement in a development. On the one extreme, the old contractor/company relationship, the contractor builds a facility and sells it to the oil company. Under this scenario the contractor assumes none of the risks associated with the start up and development of the oil field.

In this new era the contractor can increase its exposure to the risk and reward of developing an oil field in a number of ways. The contractor could own the facility and bareboat charter the facility on a fixed period. In this

manner the contractor would probably be accepting the capital risk of the facility by way of initial cost overruns and possible obsolescence.

The contractor could further its exposure in a number of ways such as by providing topsides and crew, accepting payment terms based on the performance of the field or by allowing the contract to terminate with little or no recourse when the field reaches its economic abandonment date.

Ultimately the contractor could take an equity position in the field possibly by farming into the facility and accepting its share of all the risks including, amongst others, the product price risk.

BUY OR LEASE

The mobility of MPUs readily lends itself to a leasing arrangement whereby the contractor can own the facilities and lease them sequentially to a series of oil companies. The factors which influence the oil companies decision whether to buy and operate versus lease with crew are:

(i) Desire to minimise upfront capital costs. Leasing a facility places the requirement to raise the funds on the contractor, leaving the oil company free to allocate such funds elsewhere.

(ii) Tax regime of host country. Leaving Financing Leases aside (as we are normally referring only to an Operating Lease) the fiscal regime of the host country may not be neutral with respect to which entity provides the capital, incurs the operating costs and receives revenue.

(iii) Field Life. The closer in duration the field life is to the facility life the less incentive there is to lease the facilities. An oil company with a short duration field and no other field to subsequently develop would need to sell the facility after the abandonment of the field to preserve the economic value of the investment. A third party such as a contractor is better placed to market the facility as a service and ensure full employment.

(iv) Reservoir Risk. Closely related to (iii) above, it may be preferable to lease a facility for a field which has a long expected field life but an unacceptably high possibility of early abandonment.

(v) Operating Synergies and Competence. In many cases the contractor has already in place sufficient resources, logistics support and inhouse expertise (particularly with respect to marine operations) to provide a more cost effective operation than that which an oil company would be able to provide.

LEASE AND OPERATION AGREEMENT

Assuming the decision by the oil company is to lease a facility then an agreement between the contractor and oil company is required. The following discussion outlines the issues which must be covered in such an agreement. For completeness the full range of services provided by the contractors including topsides and provision of crew has been considered.

SCOPE OF WORK

Prior to Production Commencement

It is extremely important to define the interface between contractor and oil company in such an involved and long term relationship. A systematic and thorough approach will ensure that all contingencies are accounted for. Issues to consider include:

(i) Provision of equipment—a detailed list is required of each party with respect to the equipment they will be providing. Just as important is to clearly state at each interface which party has responsibility, *i.e.* the oil company may be providing the wellheads and tree and the contractor the control system. The interface for the design and provision of equipment in relation to the control systems on the tree must be clearly understood.

(ii) Provision and Co-ordination of Services—Similar to the above services such as drilling, modifications, mobilisation and installation and their interfaces must be clearly understood between the parties.

(iii) Regulatory Requirements—There are many approvals required for the construction, installation and operation of a facility and an oil field. Although the two parties may both be required to provide their input into various certifications it is important to establish which party has ultimate responsibility for each one.

Responsibilities After Production Start Up

The two parties must agree on which party is responsible for such things as crew, consumables, communications, weather forecasting equipment, metering, tug boats, supply vessels, stand by vessels, ROVs, onshore warehouse and logistics, fuel and bunker, helicopter operations, oil spill response and safety management systems as well as shuttle arrangements.

Each host country may have different regulations specifying which party must be responsible for certain issues. This is particularly true for issues such as oil spill response, Safety Management Systems and certification.

In addition it may not be possible to request that the contractor accepts responsibilities which are beyond their control or highly variable such as supply of production consumables, fuel and bunkers for shuttle tankers and helicopter operations. The parties could agree, however, that the contractor manages these services and passes the cost onto the oil company.

SETTING THE PRODUCTION DATE

Historically the contractor was paid on the basis of percentage completion of the facility and had a contractual responsibility to complete the facility at a prearranged date. In this respect the actual commencement of production was not a concern to the contractor. In this new relationship the contractor may only be paid on the basis of production and is therefore much more concerned that both parties meet the start date.

A windows procedure which, over time, narrows down the production commencement date is usually employed. Each party has the ability to change the final date through ever-decreasing margins until a final date is set. There is usually a financial penalty on the unavailable party for failure to meet the final date.

The constraints which each party must keep in mind when they are committing to a windows procedure depend on what they are bringing to the alliance. The oil company must accommodate the drilling and completion schedule, partner agreements and approvals and the government and regulatory approvals which are the responsibility of the oil company.

The Contractor must keep in mind all previous commitments if any part of their facility is being used elsewhere, the modification schedules and the government and regulatory approvals which fall to the contractor.

WARRANTIES

Each party will provide warranties to the other party which, if not adhered to, could result in financial penalties and/or termination. Warranties are an efficient means of ensuring each party completes their scope of work satisfactorily without the need to have it overseen by the other party.

Contractor warranties may include any of the following:

(i) contractor will act as a good and prudent operator;

(ii) contractor's equipment is in good condition, suitable for use and meets the overall production and capacity performance criteria agreed by both parties;

(iii) all of Contractor's personnel are fully qualified, trained, competent and fit for assignment;

(iv) contractor has met all necessary laws and regulations;

(v) contractor will maintain sufficient liquidity to meet its obligations.
Company warranties may include points (iv) and (v) above.

TARIFF STRUCTURE

The tariff structure typically has either a day rate element, a per barrel rate element or a combination of the two. In addition a mechanism can be added which relates return to the contractor to oil price. In addition to a Normal Operating tariff the parties may also wish to discuss a Force Majeure tariff, a Planned Shutdown tariff, an Unplanned Shutdown requested by contractor tariff, an Unplanned Shutdown requested by company tariff and/or a Weather downtime tariff.

The contractor's tariff will depend on the recovery of costs that the contractor requires over the expected field life which, in turn, is a function of the contractor's initial costs plus any financing charges, operating expenses, contractor's expected downtime and their required profit element less whatever residual value they believe the facilities may have either in terms of a sale price or further employment.

TERMINATION

Other than planned termination such as a prearranged date, or upon reaching a cumulative production target or at economic field abandonment there are also other reasons for terminating the agreement by either party including inability to make the production commencement date after an agreed period, breach of warranties, force majeure, liquidation, catastrophe and even voluntarily (without reason).

Each of the above reasons for terminating may be linked to some recourse by either party such as:

(i) Recapture of costs. The contractor, for example, may be able to recoup some or all of the facilities costs from the oil company should the oil company be unable to meet the production date, be in breach of its warranties or voluntarily terminate the agreement.

(ii) Take over of Facilities. The oil company may, for example, take over the facilities in the event of contractor's breach of warranties or liquidation.

(iii) Financial Penalties. The oil company may, for example, impose penalties on the contractor for breach of warranties or failure to meet the production commencement date.

POLLUTION

Pollution is an important topic which unlike other terms and conditions of the agreement is, for the most part, already set out by the relevant authorities. Taking a rather complex subject and making a number of simplifications a summary is provided below.

The oil company is responsible for oil pollution from the production facility under OPOL. Oil Pollution from the export tankers is more complicated and is covered under conventions and voluntary agreements. These conventions and agreements allow for efficient prevention and clean up of crude spillage or threatened crude spillage with no fault and no litigation access by claimants to funds in exchange for limited liability.

In the event of a spill claimants would normally refer to:

(i) CLC (International Convention on Civil Liability for Oil Pollution Damage, 1969). Payment limit varies with ship size (maximum of $19.1mm) and is provided by the P&I club of the tanker owner.

(ii) Convention Fund (International Convention on the establishment of an International Fund for Compensation of Oil Pollution Damage, 1971). Allows for additional payments if CLC coverage is not adequate and also varies with ship size (maximum of $81.8mm). The payment from this fund is provided by levy on oil imports.

(iii) TOVALOP (Tanker Owners Voluntary Agreement Concerning Liability for Oil Pollution). Payment limit is set at $70mm and is provided by the P&I club of the tanker owner. It allows for payment where CLC and Fund is non existent or lacking.

(iv) CRISTAL (Contract Regarding a Supplement to Tanker Liability for Oil Pollution). Allows for additional payments where TOVALOP coverage is not adequate and varies with ship size (maximum $135mm). The payment from this fund is provided by annual subscriptions from cargo owners.

Payment levels are not additive and claimants may still be able to seek damages in court from tanker owners, charterers and cargo owners.

OFFTAKE ARRANGEMENTS

The discussion to this point has only concerned itself with the floating production agreement. There will be a requirement for an offloading agreement which will address either export through a pipeline or by export tankers.

A pipeline transportation agreement is relatively straightforward and will encompass issues such as firm capacity volumes, send or pay provisions, ability to alter firm capacity, ability to access additional capacity, warranties, liabilities and tariff.

The more usual case for export of crude oil is through export tankers. These tankers usually have higher specifications than VLCCs with such modifications as bow thrusters, dynamic positioning and controllable pitch propellers.

Assuming the oil company does not have its own export tankers the company will enter into typically one of three types of agreements:

Time Charter where the oil company locks in a particular vessel for a fixed length of time. A Time Charter is most applicable for high usage such as prolific fields and/or fields with no storage.

Contract of Affreightment where the export tanker owner charges per lift. The contract is not vessel specific but the export tanker owner guarantees availability through size of fleet. COAs are most applicable for lower frequency use such as liftings from field with storage.

Finally there is a Voyage Charter which is similar to COA but the contract is vessel specific.

Each of these arrangements have fairly standard terms which can be obtained from the vessel charterers.

CONCLUSIONS

The emergence of highly mobile production systems such as FPSOs have created an exciting environment where contractor and oil company can redefine their relationship. Aside from issues dealing with pollution and other regulatory areas the contractor and the oil company have complete freedom to determine the manner in which an oil field can be developed.

In general there are a range of possibilities from adapting the more historical approach to field development where the contractor builds and delivers a facility to an oil company's specifications through to an alliance and finally to an equity partnership with the oil companies. In the event that the contractor assumes either the role of owner of the facility, alliance partner or equity holder in the oil field development there will be a requirement to enter into an agreement with the field owners. This chapter has provided an overview of the issues which should be considered in such an agreement.

Because there is such a diverse range of possible relationships and risk/reward sharing opportunities between the oil company and the contractor with respect to the employment of an MPU it is not possible to provide a model form of agreement.

10.

Oil and Gas Acquisition Agreements

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INTRODUCTION

This chapter on Oil and Gas Acquisition Agreements is divided into two parts. The first part addresses the important preparatory work involved in an acquisition; the second part focuses on the Acquisition Agreement itself. The reason for this is simple—the preparatory work on any acquisition of oil and gas assets is as important, if not more so, than the negotiation of the Acquisition Agreement. Incomplete or inadequate preparatory work can, as will be shown in this chapter, jeopardise the success of an acquisition. Hence the time devoted to it.

This chapter concentrates principally on privately negotiated acquisitions of oil and gas assets (or the shares in the corporate entity holding those assets) in the United Kingdom sector of the North Sea. Many of the principles are, however, applicable to acquisitions of oil and gas assets generally.

PRELIMINARY ISSUES

The target assets in any oil and gas acquisition, and some of the reasons why the Buyer and Seller are likely to want to do a deal, are set out below.

Target Assets

For offshore interests, the principal target assets on any acquisition will be interests in the relevant petroleum production licences. Onshore they will be exploration, appraisal and development licences or, since the new Landward Areas Regulations, the single Petroleum Exploration and Development Licence.

The assets will generally also include the relevant working interests under the governing joint operating agreements (and possibly also under relevant bidding agreements and unitisation agreements), and there may be associated assets such as rights and obligations under sales, transportation and other field agreements, technical data, tax losses, employees and other assets depending on the nature of the deal.

Reasons for Acquisition or Disposal

Why does the Seller want to sell, and why does the Buyer want to buy? The rationale is likely to be a combination of factors, some of which may be as follows:–

(i) The Seller may no longer regard the North Sea as an attractive area in which to operate and may be looking to invest its money elsewhere. The Seller may also be looking to dispose of interests outside certain core areas on which it is focusing investment, or may be seeking to dispose of small holdings which are time consuming to administer in proportion to their value.

(ii) The Buyer may be planning to enter the North Sea for the first time by acquiring existing licence interests (rather than participating in bidding rounds) or it may be looking to increase its percentage interest in licences in which it already has an interest. The Buyer may alternatively be looking to acquire production to finance exploration commitments, or it may have interests in adjoining areas and may know more about the overall geology of the area and hence have better information as to the prospective value of the assets. Finally, the Buyer may be interested in acquiring associated assets and rights, such as valuable data or operatorships.

BASIC ACQUISITION STRUCTURES

There are two principal methods of acquiring oil and gas assets—the asset deal and the share deal:–

Asset Deal

The asset deal involves a direct acquisition of the licence interests and associated assets from the company or companies which hold them. In the case of an asset deal the Seller will be the company or companies which hold the assets.

Share Deal

The share deal involves an acquisition by the Buyer of some or all of the shares in the company or companies which hold the licence interests. In the case of a share deal the Seller will be the shareholder or shareholders of the licence owning company or companies. A share deal will take the form either of an agreed or contested takeover (in the case of a public target company) or a privately negotiated acquisition (in the case of a private target company). Public takeovers are beyond the scope of this chapter which focuses on the privately negotiated acquisition.

Swap/Farm-In/Earn-In

Swaps, farm-ins and earn-ins are all variations of the asset deal, and the principles are essentially those which apply to an asset deal, although there are particular considerations which apply in each case. These variations are covered in other chapters of this book, and this chapter concentrates on the straight asset deal.

ASSETS VS SHARES

Before addressing the issues that arise in planning and structuring an acquisition, it is worth focusing briefly on the principal advantages and disadvantages, in an oil and gas context, of an acquisition of assets as opposed to an acquisition of shares. These issues may have a significant bearing on the way in which the deal is structured.

Asset Deal—Advantages

1. *Clean Cut-Off*

The principal advantage of an asset deal from the Buyer's point of view is that it should be possible to achieve a clean cut-off between the Buyer and the Seller. Liabilities which relate to the period before the sale will remain with the Seller, and the Buyer should start with a clean sheet, or at worst take only liabilities of which it is aware and which have been taken into account in the purchase price. This is generally a significant attraction for any buyer doing an asset deal.

2. *Simpler Due Diligence*

As a result of the ability to achieve a clean cut-off between the Buyer and the Seller, it is likely that the due diligence which the Buyer will want to carry out, and the warranties and indemnities which it will be seeking, will be simpler. The Acquisition Agreement will identify the assets and liabilities being acquired, and the Buyer will focus its investigation on those assets and liabilities without being overly concerned about the Seller's other assets and liabilities.

As a general rule, an asset deal is likely to be simpler for a deal involving, for example, a small number of interests. It is also likely to be preferable where there are no pre-emption rights involved, where there is no transfer of the operatorship involved, and where the interests involved are not producing interests. If there is a large portfolio of interests and/or pre-emption rights and/or a transfer of operatorship and/or producing interests, the asset deal becomes more complicated, and this is addressed below.

Asset Deal—Disadvantages

1. *Pre-Emption*

The principal disadvantage of an asset deal is that if pre-emption rights exist in the governing contractual documents, it is likely to trigger them. This will mean at the very least that the question of the application of the pre-emption rights will need to be addressed and, if the deal is to go ahead, a waiver of the partners' rights to acquire the interests in priority to the Buyer will need to be obtained. At worst, of course, it may mean that the Buyer is prevented from acquiring some or all of the assets which it wishes to acquire.

2. *Consents*

Even if there are no pre-emption rights, or the partners are prepared to waive them, an asset deal is still likely to give rise to a requirement to obtain consents to the assignment of the interests both from the relevant JOA partners and, possibly, other third parties (in addition to the Secretary of State for Trade and Industry). Partner consents may of themselves give rise to issues which will need to be resolved, and these are addressed in more detail below. Depending on the nature of the deal, the number of third party consents may be significant—if the field is in production, there will be field agreements to be novated, and if a transfer of operatorship is involved, novations of the contracts entered into by the Seller as operator will be needed. In each case this is likely to require the agreement of the other contracting party or parties to each such contract. Accordingly, even if there

are no pre-emption rights, there could still be a significant number of third party consents required.

3. *Operatorship*

If the Buyer wishes to assume operatorship of any particular licence, on an asset deal this will almost certainly require the approval of the partners to the relevant joint operating agreement. The Seller will cease to be the operator and the Buyer will (subject to partner and DTI approval) become the new operator. There may be reasons why some or all of the partners are reluctant to give their approval to the Buyer, and they may be able to frustrate the Buyer's ambitions.

4. *Documents*

One aspect of the asset deal which is often overlooked, but which can be significant, is the sheer volume of documentation involved, particularly if the deal involves a portfolio of interests and/or operatorship and/or assets at the production stage. There may be a significant number of novation agreements which need to be drafted and then negotiated with different parties who will all have different comments and raise different issues. The handling and management of this documentation can be a time consuming and labour intensive job, sometimes involving hundreds of different novation agreements all with different parties and on different terms.

5. *Tax Losses*

Corporation tax losses will not pass to a Buyer on an asset deal.

In an asset deal, the more complex the deal, the greater the reliance on the co-operation of third parties—those third parties may have no particular incentive to co-operate and may not respond as quickly or helpfully as the Buyer and Seller would like. This will have an impact on the timetable for the acquisition, and it may take longer than the Buyer and Seller envisage to obtain the necessary consents and reach agreement with the relevant third parties.

If one or more of the factors outlined above is significant in any particular transaction, the Buyer and Seller may want to examine alternative structures.

Share Deal—Advantages

The obvious alternative to an asset deal is for the Buyer to acquire the shares in the company or companies which hold the assets. This has a number of advantages

1. *No Pre-Emption*

First, pre-emption is unlikely to be a problem—most United Kingdom joint operating agreements do not extend the application of pre-emption rights to a transfer of the shares in the licence-owning company. It is likely that the shares, and hence the underlying assets, can be transferred to the Seller without the partners having an opportunity to pre-empt. Clearly this depends on the wording of the particular joint operating agreement, and there are some which do catch a sale of shares; but the majority do not.

2. *Simpler Implementation*

Secondly, the transfer mechanics and the documentation for a share deal are likely to be less complex—the principal documents will be the Acquisition Agreement, the Disclosure Letter and the Tax Indemnity. There will be a number of supplementary documents such as board minutes, stock transfer forms and resignation letters. But because the corporate entity remains the same, there is no need to transfer across to the Buyer all the relevant joint operating agreements, sales agreements, transportation agreements and other contracts, and for this reason the deal can generally be implemented without the potential mountain of novation agreements which may be required to complete an asset deal.

3. *Fewer Consents*

As a share sale involves the transfer of the corporate entity, rather than an individual transfer of each asset, there are generally fewer third party consents required. There is correspondingly less reliance on third parties than in an asset deal, although consents may be required under contracts which have a "change of control" clause. However, as a general rule a share deal can be effected with less involvement of or reliance on third parties, and this is an advantage both in terms of logistics and timing.

4. *Operatorship*

If the Buyer is hoping to secure or retain operatorship in the target licences on a share deal (depending on the particular wording of the relevant joint operating agreement) the partners may have no right to object, as the identity of the operator will remain the same, the only change being the change of ownership of the licence-owning company. The Buyer can in this way retain the operatorship in its newly acquired subsidiary without needing to obtain partner approval.

5. *Tax Losses*

If Corporation tax losses are important to the Buyer, it should be possible on a share deal to ensure these remain in the target company and are available to set against profits.

As a general principle a share deal is likely to be preferable where there is a large portfolio of interests being transferred, and where to do an asset deal would potentially give rise to difficulties with pre-emption rights, consents and third party co-operation.

Share Deal—Disadvantages

1. *Unwanted Assets and Liabilities*

One significant downside of a share deal is that the corporate entity which holds the licence interests also comes with all its other assets and liabilities, including historic tax liabilities. Assuming that the Buyer wishes to acquire only specified licence interests, the parties will have to address what is to be done with the unwanted assets and liabilities. They may agree that those assets and liabilities should be transferred out of the target company before sale. However, that can be a complex procedure, and indeed there may be liabilities such as those relating to tax which cannot be stripped out and in relation to which the Buyer will have to rely on an indemnity from the Seller. The question of the unwanted assets and liabilities in the target company will give rise to the following issues:

- (i) First, how easily can they be transferred out? Depending on the nature of the assets and liabilities in question, there may be a number of third party consents which will need to be obtained if those assets are to be stripped out. This is addressed in more detail later. It is in any event unlikely that the Seller will be able to strip out all the assets and liabilities to create an entirely clean company owning only the assets and liabilities which the Buyer is prepared to take.
- (ii) Secondly, because of the unwanted assets and liabilities, the Buyer will need to carry out additional due diligence to ascertain what is there, what needs to be stripped out, and what it requires indemnification against. The due diligence process and the warranties sought are therefore likely to be more comprehensive. The Buyer will also seek a comprehensive indemnity against any unexpected liabilities left in the target company, and to back up the additional obligations of the Seller under the warranties and indemnities, the Buyer may require additional security (for example by way of parent company or bank guarantee), bearing in mind that claims under the indemnities may not arise for a number of years.

Cleaning up a company for sale can be a complex process, and the time and work involved should not be underestimated. An alternative structure may be to transfer the target licences into a new, clean company and sell the shares in that company. This is addressed in more detail below.

INITIAL CONSIDERATIONS

Some of the particular issues which need to be addressed in looking at the planning and structure of any oil and gas deal are set out below.

Assets and Governing Contractual Documents

First, what assets are comprised in the deal, and what are the governing contractual documents? It is essential at an early stage to have sight of complete, up-to-date and executed copies of the relevant licence and working interest documents. These will set out the terms on which the assets are held and will, for example, enable the parties to ascertain whether there are applicable pre-emption rights.

Disclosure of Information

One of the first tasks of the Seller in contemplating any disposal should be to review the relevant joint operating agreements to ensure that information relating to the licences and the licence operations may be disclosed to interested third parties. Joint operating agreements invariably contain confidentiality provisions restricting disclosure of information, and permission may be required before information can be made available to potential buyers. Many joint operating agreements permit disclosure without consent (subject to execution of a suitable confidentiality undertaking) to a "bona fide intending purchaser" of the assets. Under this and similarly worded provisions disclosure may therefore be permitted without consent, but the Seller will need to be satisfied that the party to whom disclosure is to be made is a bona fide intended purchaser (or whatever words are used) of the assets. Depending on the wording, the exclusion may not apply on proposed sale of shares.

Approvals and Consents

It is essential at an early stage to identify precisely what approvals and consents will be needed for the transaction. These are addressed in more detail later, but will always include the consent or clearance of the Secretary of State for Trade and Industry. On an asset deal, approvals and consents will be required from the partners on the licences in question. There may be

other approvals and consents, for example shareholders' approval, the approval of lending banks, and overseas Governmental consents if international assets are involved. Third party approvals and consents almost invariably have an impact on the timetable, and the earlier they can be identified and applied for, the better.

Pre-Emption

Another issue that merits consideration at an early stage is the question of pre-emption: are there pre-emption rights in the relevant joint operating agreements, will they apply to the proposed transaction, and is there a realistic possibility that they might be exercised? It is important to analyse the necessary joint operating agreements and the relevant partner groups at an early stage to ascertain both the legal and commercial position on pre-emption. If there are pre-emption rights and there is a risk that they will be exercised, this means at best that there may need to be discussions and negotiations with the relevant partners, and at worst it could mean that the deal is not viable from the point of view of the Buyer. In analysing the pre-emption rights, a key point for which to watch is what action triggers the pre-emption rights. Some pre-emption provisions cut in at an early stage and may, for example, be triggered by the execution of heads of agreement between the Seller and proposed Buyer.

Timing

The planning and structuring of any deal must take account of any particular factors which require the deal to be done by a certain time—there may be commercial, tax, accounting and other reasons why it is essential for the deal to be done by a specified time, and this may have an impact on the way in which the deal is structured. If there is a timing constraint, it is important to understand what the implications are if that deadline cannot be met: does the deal fall away, does there need to be an adjustment to the price or other terms of the deal or is there some other consequence? In addition, it is critical to identify the point at which the deal is "done" for the purposes of any timing constraint—is this when an execution agreement is signed or a conditional or unconditional acquisition agreement is signed, or is it in fact not until final completion of the deal? Many transactions are done using a prior "effective date"; however, while this is useful in determining financial adjustments between Buyer and Seller, it is not effective to pre-date the deal for tax or legal purposes.

Commercial Priorities

One of the most important issues to identify at an early stage in planning any oil and gas deal is what the commercial priorities of the parties are and how much importance they attach to them. Clearly in any normal deal the Seller wants to sell and the Buyer wants to buy, but there are usually a number of other commercial objectives—for example the Buyer may be particularly interested in certain specified assets, and may want to structure the deal to secure those; the Buyer may also want to acquire tax losses to take over key employees, and may want operatorship in certain blocks. In order to structure the deal, it is important to identify how important each of these additional objectives is on the part of the Buyer or the Seller, and to understand whether the relevant party is willing to go ahead with the deal if one or more of them cannot be achieved. If they are so important that the deal is not worth doing for the Buyer without them, then the structure and planning will need to take that into account.

Tax Planning

Finally, the planning of the deal must obviously take into account at an early stage any tax planning that is desirable on the part of either party, and again, it is essential to understand the extent to which that tax planning is important in the context of the deal. The tax issues on acquisitions can be complex, and are beyond the scope of this chapter. However, because oil and gas acquisitions can give rise to complex legal and tax issues, there is always a danger of the "tax and legal tail wagging the commercial dog". It is important that a proper control is kept over the legal and tax planning aspects so that the structure of the deal does not become unnecessarily complicated, putting at risk the main commercial priorities, in order to achieve an objective which is of peripheral importance or *de minimis* in the context of the deal as a whole.

It is important to identify the answers to all these questions at the earliest stage—the answers will drive the structure.

PRE-ACQUISITION ISSUES

The previous section addressed some of the general issues which arise in planning and structuring an oil and gas acquisition. This section focuses on specific issues, including the questions of due diligence, consents and approvals, and pre-emption rights.

Due Diligence

On a private acquisition, it is generally accepted that as part of the pre-sale process, the Buyer will conduct extensive investigations into the affairs of the Seller in relation to those assets to be acquired. These investigations will focus principally upon financial, commercial and legal issues, and it has become commonplace in the oil and gas industry for the due diligence material to be assembled in a data room by the Seller, so that the Buyer can enter and review it at an early stage.

The value (to both Buyer and Seller) of a data room will depend to a significant degree on how well organised it is, and the accuracy of the information contained in it. The scope of the due diligence exercise can be as wide or as narrow as the Buyer wants to make it and the Seller is prepared to accept, but the principal legal issues which should be the subject of any due diligence investigation are as follows:

1. *Investigation of Title*

The Buyer will wish to satisfy itself that the Seller has good title to the assets being sold. In the context of licence interests, this involves not only ensuring that the Seller is a party to the licence and the JOA, and that the percentage equity share under the JOA is correct, but also ensuring that the chain of title by which the Seller derived those rights is correct. It is surprising how often that is not the case (or at least is not apparent on the face of the documents) and that remedial work needs to be done to rectify the situation.

2. *Encumbrances, Royalties, etc.*

As part of the investigation of title, the Buyer will want to ensure that the assets being acquired are free of encumbrances, charges and other third party rights, and in particular, in the context of oil and gas assets, overriding royalties. Although it will not provide a complete answer, the Buyer should always carry out a search against the Seller with the Registrar of Companies, as this will show charges registered under section 395 of the Companies Act 1985.

3. *JOAs, etc.*

Part of the Buyer's legal investigation will be to carry out a review of the relevant joint operating agreements, bidding agreements, unitisation agreements, and any other agreements from which the Seller's interests, rights and obligations are derived. The purpose of this will be to ensure not only that the interests being acquired validly exist, but also that those agreements properly grant to the Seller the rights which the buyer wishes to acquire, and that there are no unduly onerous obligations under those agreements which might result in the Buyer finding that it has inherited liabilities which were not anticipated. The review will also include ensuring that such matters as the voting pass mark for operating committee meetings is acceptable in the context of the interest to be acquired.

4. *Field Agreements*

If the interests to be acquired are producing interests, the Buyer will also wish to review the relevant field agreements for the sale, transportation and lifting of the oil or gas, and any other agreements relating to the production which the Buyer will assume. Again, the principal objective in reviewing these agreements will be to ensure that they contain all the necessary rights and do not impose any excessive obligations with which the Buyer would not wish to be burdened following Completion.

5. *Pre-Emption Rights*

In reviewing the joint operating and other agreements from which the Seller's interests are derived, one of the main areas at which the Buyer will wish to look is the question of pre-emption rights, so as to ascertain at an early stage whether there are pre-emption rights, and if so whether they apply to the proposed deal. It is essential to analyse the wording of any pre-emption provisions with care, in order to identify the point and circumstances in which they cut in, and what action needs to be taken when they do cut in.

6. *Assignment/Change of Control*

Again, in reviewing the joint operating and other agreements, as well as the field agreements, the Buyer will wish to check for any restrictions on assignment of those agreements (in the case of an asset deal) or change of control (in the case of a share deal). Restrictions on assignment may take a number of forms, but in most cases it is likely that the consent of the relevant third party will be needed to the assignment of the agreement in question. Even if the benefit of the agreement can be assigned without the consent of the third party, it would be most unusual for the obligations under the agreement to be assignable without such consent, and it is unlikely that the Seller would be willing to proceed with the acquisition without having obtained the contracting party's consent to the assumption by the Buyer of the obligations under the agreement (effectively through a novation of the agreement). In the case of a share deal, the provisions for which the buyer will be watching will be change of control restrictions which provide that, in

the event of ownership of the Seller changing, the agreement in question is terminable or variable or, in extreme cases, terminates automatically. While change of control provisions are less commonly found than restrictions on assignment, if they do exist, the result may be that an asset which the Buyer thinks it is acquiring is not in fact available following the sale.

7. *Abandonment*

One of the most important aspects of legal due diligence will be an investigation into the abandonment arrangements for the relevant assets, and the associated abandonment security provisions. This will entail reviewing the obligations with regard to the licence interests under the Petroleum Act 1987 and reviewing the abandonment security provisions in the relevant joint operating agreement. The principal objectives of such a review will be to identify: what those security arrangements are; what the Buyer will need to put in place; how much this will cost the Buyer on an annual basis; and what the Buyer's eventual estimated abandonment costs are going to be. The Buyer will also need to look carefully at the availability of relevant tax reliefs. It is essential to address these issues early, not least because many abandonment security arrangements require that before any assignment of the interest can be completed, the Buyer must enter into substitute arrangements. These may involve entering into a trust arrangement or providing a letter of credit, and as this is likely to involve banks and trust corporations, they may take time to set up.

8. *Contingent Liabilities*

Finally, the Buyer will look carefully at what contingent liabilities or commitments exist in relation to the interests to be acquired. For example, there may be financial commitments to upgrade the operations to comply with updated health and safety or environmental requirements.

The scope of any legal due diligence is up to the Buyer to determine. However, the results of due diligence are only as good as the information provided, and if the Seller provides inaccurate or incomplete information, the due diligence exercise will at best be of limited value. In the absence of contractual warranties there may be no legal redress against the Seller if the due diligence information is wrong, and for this reason it is normal for the Seller to give specific warranties in addition to warranting that the information provided is complete and accurate. The question of warranties is addressed below.

DTI Approvals and Consents

Any acquisition, whether of assets or shares, requires the approval of the Secretary of State for Trade and Industry. The approvals required take different forms depending on the type of transaction. The various types of approval are briefly reviewed below. The Model Clause references are to the Petroleum (Production) (Seaward Areas) Regulations 1988, which apply to offshore licences awarded in the 11th round and later. Different regulations apply to other licences (depending on when they were awarded), but the principles are essentially the same. In recent years, the procedures have been considerably simplified, and the new procedures are covered in more detail below.

1. *Approval in Principle*

This is not strictly necessary, but in most cases it is helpful to seek the "in principle" approval of the Department of Trade and Industry to the proposed deal at an early stage. This is particularly important in a deal where they may be aspects which will give the DTI difficulty or where there is some doubt as to whether it will actually be approved. If any issues can be addressed at an early stage, it may enable them to be resolved in a manner satisfactory to the DTI. Approval in principle is normally obtained by writing to the DTI setting out briefly the basis of the deal, and following that up, if necessary, with a visit to discuss and explain it.

2. *Approval of Documents*

Prior to 1994, the principal documents on the deal needed to be approved by the DTI under Model Clause 41(3). However, under new Guidance Notes issued in September 1994 the procedures have been considerably simplified. The DTI now relies on a system of check-lists, and in most cases no draft legal documents need be submitted to the DTI for approval (though the DTI reserves the right to require this if it thinks appropriate).

3. *Consent to Assignment*

On an asset deal, the consent of the Secretary of State will be required to the assignment of the licence and working interest under Model Clause 41(1). This will be so even where the Buyer is already a party to the licence in question and is merely increasing its interest, and also where the assignment is to an affiliated company.

4. *Change of Operator*

On an asset deal, if the Buyer is proposing to take over the operatorship, this will require the approval not only of the joint venture partners (depending on the terms of the JOA), but also of the Secretary of State. Under Model Clause 24, any operator is required to be approved in writing by the Secretary of State, and that approval is required even if the Buyer is a well known operator of other licences. On a share deal, there is no change in the identity of the operator, and strictly no approval is required from the DTI. However Model Clause 24(2) does provide that where an approved person is no longer competent to exercise that function, the Secretary of State may by notice in writing given to the Licensee, revoke his approval. It is possible that, as a result of any change of control of the operator, the Secretary of State could take the view that the operator is no longer competent to exercise the relevant function. Accordingly, on a share sale, if the target company is an operator, it would be prudent to obtain confirmation from the DTI that the Secretary of State would not propose to exercise his powers under Model Clause 24(2) as a result of the change of control.

5. *"Ten-on-a-Licence Rule"*

If the proposed transaction will result in there being more than 10 licensees on any particular licence, the Secretary may raise an objection to the assignment on the grounds of the so-called "ten-on-a-licence" rule. This rule was originally introduced in 1984, and was updated in 1990. The general principle is that the Secretary of State seeks to limit the number of licensees on any licence to 10, and while this is only a guideline as opposed to a binding rule, exceptions are likely to be made only in exceptional circumstances or if good reason can be shown why it should be disregarded.

6. *Change of Control Pre-Clearance*

On a share deal, it is not strictly necessary to obtain the prior approval of the Secretary of State to the transaction itself. Model Clause 42(3) merely provides that the Secretary of State may revoke the licence if, following a change of control in the licensee the Secretary of State has served notice stating that he proposes to revoke the licence unless there is a further change of control within a period of three months, *and* that further change of control does not take place. The Secretary of State therefore has the power to revoke any licence following a change of control, unless within three months there is a further change of control as specified by the Secretary of State. The practical implication is that the parties would normally apply to the Department of Trade and Industry in advance of a share acquisition seeking confirmation from the Secretary of State that it would not be his intention to exercise his powers under Model Clause 42(3) as a result of the proposed change of control. While such confirmation is not expressed to be legally binding, it usually gives sufficient comfort to enable the Buyer to proceed with the deal. It should be noted that for the purposes of Model Clause 42(3) a change of control is defined by reference to the Income and Corporation Taxes Act 1988 and effectively catches a change of control of one third or more of the voting rights in the target company. It does not have to be a 51 per cent change.

7. *Release of Abandonment Notice*

If a notice has been served on the Seller in respect of the licence interest in question under section 1 of the Petroleum Act 1987, the Seller will wish to ensure that, having disposed of its interest, it is released from its obligations under the section 1 notice. This is normally done by making application to the Department of Trade and Industry for a release under section 3 of the Petroleum Act 1987, although it should be noted that such a release is unlikely to be granted until the deal has been completed and the Buyer has acquired the interest in question.

8. *Assignments by way of Security*

Finally, if the proposed acquisition is being financed by lending secured on the target assets, the Secretary of State's consent will be required to any assignment of the licence interest(s) by way of security. This will normally be achieved through a "government consent agreement" under which the necessary consent is granted (though the Secretary of State will normally require a further consent before the security can be enforced).

The new procedures for Government approvals to interest assignments introduced in 1994 are changes to administrative arrangements only. There is no change in the criteria applied in determining whether consent or approval should be given. Nor do they apply to proposals for a change of operator or where the incoming company has no existing United Kingdom licence interests. Briefly, the revised procedures involve the submission of a request for consent providing the following information:

(i) Licence No./block(s)
(ii) Outline of proposed transaction including
- name of new/withdrawing licensee
- terms of interests assignment
- existing/revised interests of all parties

(iii) Rationale for the transaction
(iv) Contribution of new licensee

(v) Progress on work programme
(vi) Proposed change of operator (if relevant)
(vii) Proposed effective date and timetable

If the proposal is acceptable, a consent letter will be given, on the condition that the Licence Assignment is in the form of the Deed approved by the Secretary of State. This is a standard form deed which the DTI expects to be used unless there are good reasons for departing from it.

If there is no new licensee coming in, but the existing licensees are simply changing their respective equity shares, less information is required and again, no draft legal documents need be submitted.

Finally, the executed documents are still required to be submitted to the DTI after execution.

These new procedures have simplified the approval process. Nevertheless, it is important that clear and complete information is given to the Department of Trade and Industry. The officials who handle the approvals are invariably helpful, but if additional or corrective information has to be provided it is likely to delay the granting of the necessary clearances.

Pre-Emption Rights

There is no defined meaning of the term "pre-emption right", but in essence a pre-emption right is a contractual right for each joint venture partner to acquire a proportionate part of the licence interest in priority to any third party. The question of pre-emption rights is dealt with in the chapter on joint operating agreements, and the comments in this chapter focus on their practical and legal implications in the context of any proposed acquisition.

1. *Form*

Pre-emption rights vary from JOA to JOA, but they generally take one of two forms: either an obligation on the Seller to offer the interest in question to its partners first (*i.e.* a right of first refusal), or an obligation on the Seller to offer to the partners the deal that has been negotiated with the Buyer. With the right of first refusal, the trigger point requiring the Seller to offer the interest to its partners may arise at an early stage (perhaps even before the Buyer and Seller have agreed to a deal in principle). It is therefore important for the Seller to analyse the relevant JOAs before commencing discussions with the Buyer, to ensure that the pre-emption rights are not inadvertently triggered before their implications have been addressed. It is also possible that there may be more than one set of potentially applicable pre-emption provisions. For example, in addition to those in any relevant JOA, they may also be contained in a unitisation agreement. In these circumstances the interrelationship and applicability of the provisions will need to be assessed.

2. *Application*

The application of pre-emption rights in any particular case will depend first on the terms and structure of the deal in question, and secondly upon the wording of the particular pre-emption provisions. Most pre-emption provisions are drafted to apply to any asset deal for cash, but they may not catch a share deal and it may not be clear whether they catch variations on an asset deal, for example a swap. If there are pre-emption rights in the relevant joint operating agreements, a proper analysis should be carried out with a view to identifying whether they apply to the proposed transaction.

3. *Relevance to Deal*

If the pre-emption rights do apply on the face of it, the parties will need to assess first their importance from the Buyer's and Seller's perspective and secondly whether there is a real risk of the partners exercising their pre-emption rights. The Seller may not mind whether it sells to the partners or the proposed Buyer, provided there is a deal. However the Buyer will not want to spend time and effort negotiating and documenting a deal with the Seller, only to find that partners pre-empt. Where there is more than one licence interest involved it is important to establish whether, in the Buyer's eyes, the deal is an all or nothing deal (*i.e.* whether the Buyer is prepared to go ahead with the rest of the deal notwithstanding that it may be pre-empted on one or more of the assets in question). If, from the Buyer's perspective, it is an all or nothing deal, the Buyer and Seller will need to analyse the partner groups to try to form a view as to whether there is a realistic risk of the partners exercising their pre-emption rights.

If pre-emption rights exist, and there appears to be a real risk of partners exercising them, the parties may wish to structure the transaction so as to bring it outside the scope of the pre-emption provisions.

Pre-Emption Avoidance

Depending upon the wording of any particular set of pre-emption provisions, there may be ways in which a transaction can legitimately be structured so as to fall outside them. The view is sometimes expressed that pre-emption rights are not worth the paper they are written on because they can always be circumvented by anyone with a creative mind. That is not necessarily the case, and it is perfectly possible to draft pre-emption provisions which do not permit avoidance. However, for as long as pre-emption rights exist, people

will try to find ways around them, and the pre-emption provisions which have traditionally been negotiated in North Sea JOAs have tended to leave the door open for certain types of transactions. It is therefore often possible to bring any particular transaction outside their scope. There are a number of structures which are used:

1. *Non-Cash Consideration/Indivisible Package Deal*

Where the pre-emption rights entitle the partners to match the deal done with the Buyer, one argument commonly put forward is that if the deal can be structured in such a way that the partners cannot physically match it, this defeats the pre-emption rights. The usual examples are where the consideration offered by the Buyer is non-cash consideration which the partners do not have (*e.g.* an interest in another field, equity, loan notes, etc.), and cannot therefore match, and secondly where the deal between the Buyer and the Seller is structured as an indivisible package deal involving a package of interests which cannot be split. Each particular case would depend on the facts of the case and the wording of the pre-emption provision in question, and some JOAs do now incorporate provisions specifically designed to defeat arguments such as these.

2. *Acquisition of Shares*

A sale of the shares in the licence owning company may well be effective to transfer ownership of the assets without risk of pre-emption—most United Kingdom JOAs do not extend the application of pre-emption rights to a share sale; however it is essential nevertheless to check the specific wording in each case because there are certainly some which do.

3. *Hive-Up/Affiliate Route*

If the share sale route is not attractive to the parties (and as previously mentioned there are a number of reasons why this may be the case), an alternative is to look at the "hive-up" or "affiliate" route. This involves the Seller transferring the assets in question to an affiliated company (usually newly formed) and the Buyer then acquiring the share capital of that affiliated company. It is a more complex structure, and is examined below.

Structuring a Hive-Up/Affiliate Transaction

Most United Kingdom JOAs permit the transfer of a working interest to a company which is an affiliate of an existing partner (usually subject to a financial capability test). Equally most United Kingdom JOAs do not extend the application of pre-emption rights to a share sale. Hence it can be seen that at each stage of the hive-up process (*i.e.* the transfer to an affiliate and the sale of shares in that affiliate), the pre-emption provisions may not apply. The effectiveness of this route is entirely dependent upon the wording of the particular pre-emption provisions, and these would need to be carefully reviewed because there are certainly some JOAs which specifically prohibit such a transaction, while there are others which, while not specifically prohibiting the transaction, contain wording which makes it difficult to carry out effectively. For example some JOAs, while permitting a transfer to an affiliate, also provide that if the Seller and the affiliate cease to be under common control the assets will be retransferred.

Assuming the wording does not block the hive-up route, how else could the transaction be attacked by the partners seeking to pre-empt? There are likely to be a number of possible arguments, and partners will look carefully at the timing of any transfer to an affiliate so as to ascertain whether it was a true affiliate at the time of the transfer:-

(i) Under most United Kingdom JOAs the transfer by the Seller to its affiliated company will be permitted free of pre-emption rights *only* if the Seller and the affiliated company are true affiliates at the point at which the assets are transferred.

(ii) The assets should therefore be transferred to the affiliated company *before* any action is taken which could be said to break the group relationship between the Seller and the affiliated company. It should be noted that in many United Kingdom JOAs the affiliate definition is by reference to section 736 of the Companies Act 1985, and section 736(4) specifically permits beneficial ownership to be taken into account in determining whether one company is affiliated with another.

(iii) Accordingly, if, at the time the assets are transferred from the Seller to the affiliated company, any action has been taken which changes, or could be argued to have changed, the beneficial ownership of the Seller or the affiliated company, there may be a risk of attack. Any arrangement, whether binding or not and whether in writing or not, between the Buyer and the Seller (or the affiliated company) with respect to the proposed sale of the assets or the shares in the affiliated company will expose the parties to this risk. Clearly the stronger the arrangement the more likely it is that the transaction can be successfully attacked.

If the hive up route is to be effective, the Seller must transfer the assets to its affiliated company *before* any arrangement which breaks the affiliate relationship is made with the Buyer for the acquisition of those assets or the shares in the affiliated company. This may present a dilemma for the Seller, which will not wish to go to some lengths to rearrange its group structure and to transfer assets out unless there is some certainty of a deal with the

Buyer (unless the Seller has decided in any event to package the assets into a company for sale). However, obtaining that certainty is likely to jeopardise the group relationship (and therefore the effectiveness of the hive-up route). The Seller may therefore have to take a decision as to which is the more important. It may not be possible to achieve both objectives.

Depending on the structure of the transaction and the wording of the pre-emption provisions, there may be other reasons why a hive-up may not succeed. The *Texas Eastern* 1989, unreported) case indicated that the courts are willing to go to some lengths to imply terms into commercial agreements to give effect to what they believe was intended. If a deal is to be legitimately structured to fall outside the pre-emption provisions it must therefore truly do so in compliance with the provisions. If it does not comply with the provisions it will be open to attack.

Partner Consents and Approvals

If there are no pre-emption rights (or no partners who wish to exercise pre-emption rights), the consent of the joint venture partners to the assignment of the working interests will nevertheless almost certainly need to be obtained.

JOA consent provisions generally take one of three forms. In each case the consent of the partners will be required, but one or more of the following provisions may apply:–

(i) consent can be withheld only on grounds of financial or technical capability; or

(ii) consent must not be unreasonably withheld; or

(iii) consent can be withheld absolutely and without giving grounds.

The absolute right to withhold consent is more commonly found where the partners' relationship is governed by a bidding agreement and the full joint operating agreement has not yet been negotiated.

As with pre-emption rights, the parties should address the question of consents at an early stage and analyse the relevant partner groups with a view to identifying any potential problem areas. There may be a variety of reasons why the partners, or any one of them, may seek to withhold consent: they may not be satisfied with the proposed assignee's financial standing, and insist on the support of a parent company guarantee; the Buyer or Seller may have an unconnected dispute with one of the partners; or the partners may see it as an opportunity to extract something in return, and may seek to impose conditions to their consent (for example a change to the voting passmark).

The extent to which consents can be withheld will depend on the wording of the particular JOA or bidding agreement, but if potential consent problems can be anticipated in advance and dealt with at an early stage this will save delay and difficulty later on, when there may be less time and more commercial pressure.

Pre-Sale Clean-Up

If the corporate entity which owns the oil and gas interests is to be sold, and the Buyer wants only those interests and nothing else, it may be necessary for the Seller to clean up the target company prior to the sale. That company may own a variety of other assets, and have a number of other obligations and liabilities, in addition to those which the Buyer wishes to acquire, and the parties may agree that unwanted assets and liabilities will be transferred out of the target company before the Buyer acquires the shares. A clean-up can be a complex process and should not be undertaken lightly. It may give rise to tax and legal issues which are beyond the scope of this chapter. However, there are two issues in this context which merit mention—first the practicalities involved (as they may impact on the timetable), and secondly the price paid (or not paid) for the unwanted assets.

1. *Practicalities*

The parties will need to identify what assets and liabilities exist, and what needs to be moved out. In the time that is likely to be available, it is unlikely to be feasible to identify all the assets and all the liabilities, particularly historic or contingent liabilities. In any event, it will not be possible in practice to strip out a number of liabilities such as those relating to tax. The Buyer must therefore accept that, however thorough the clean-up exercise, thee may be residual liabilities left behind for which reliance will have to be placed on an indemnity from the Seller. Having identified the principal assets and liabilities, the parties will need to ascertain what is involved in moving them out, and this may involve obtaining third party consents, for example from the DTI, other partners, landlords, banks, employees, and third party contractors. That may of itself be a time-consuming process and may militate against the commercial desirability of doing the share deal in the first place. For that reason it is important that the practicalities of transferring out the assets and liabilities are analysed.

2. *Price*

It may suit both Buyer and Seller for the assets to be transferred out of the target company for nominal value or book value or in any event for something less than market value. If the assets are proposed to be transferred out at anything less than market value, there are a number of serious implications:–

(i) Financial Assistance: any transfer of assets or other transaction by the target company in connection with the acquisition of its shares, at less than market value, is likely to constitute financial assistance given by that company for the acquisition of its own shares in breach of section 151 of the Companies Act 1985. A breach of section 151 is a criminal offence punishable for the directors by imprisonment. There are exemptions, and there is a whitewash procedure for private companies, but that procedure involves obtaining an auditor's report and will take time to get in place. So it is essential if financial assistance is an issue to address it early.

(ii) Directors' duties: any sale by a company of its assets at less than market value will, on the face of it, constitute a breach by the directors of that company of their duty to act at all times in the best interests of that company. Unless the company is solvent *and* its shareholders agree to the transaction (see the *Rolled Steel* case[1] the directors will be personally exposed to attack if they authorise such a transaction.

(iii) Unlawful Distribution: finally, even if there is no financial assistance and no breach of directors' duties, a transfer of assets at under value to an associated company may constitute an unlawful distribution in breach of the Companies Act 1985. The *Aveling Barford*[2] case involved a transfer by one company to a sister subsidiary of assets at less than market value. It was held by the court that the difference between the transfer price and the market value of the assets constituted a distribution by the transferring company of the amount of that difference, and as the transferring company did not have distributable reserves of that amount, the distribution was held to be unlawful and in breach of the Companies Act.

In summary: if, as part of a clean-up, assets are to be transferred out at anything other than market value, there are potentially serious implications for the directors and care will need to be taken to ensure that they are not open to attack.

Depending on its complexity, and depending on the extent to which reliance needs to be placed on the co-operation of third parties to give consents, the clean-up may involve significant work and potential delay before the deal can be completed. The parties should therefore assess at the outset whether the benefits to be obtained from acquiring the shares in the target company outweigh the associated difficulties with cleaning it up. They may not.

[1] *Rolled Steel Products Limited v. BSC* [1985] 3 All E.R. 52.
[2] *Aveling Barford Ltd v. Perion Ltd* [1989] BCLC 626.

Financing

If the acquisition is to be financed on a non-or limited-recourse basis which involves creating security over the licence interests, it is likely that a number of additional consents will be required and this will need to be factored into the timetable. The principal consents are likely to be as follows:

(i) From the Secretary of State, to the assignment of the relevant licence interest by way of security.

(ii) From the other joint venture partners to the assignment of the licensee's rights under the relevant joint operating agreement—this will depend on the wording of the JOA, and it may permit the creation of a fixed charge or an assignment by way of security without consent being required.

(iii) From the counter-party to any relevant field agreements if there are producing assets involved.

Obtaining the necessary consents may involve lengthy negotiation between the banks, the potential purchaser, the joint venture parties and the parties to field agreements, and the time involved will need to be factored into the overall timetable for the acquisition.

OUTLINE STEPS

Set out below is an example of the outline steps of a typical acquisition. Clearly, each deal is different, and the steps in each deal will be different, but any deal is likely to involve some or all of the following:

- Seller's preparatory work—analyse JOAs, other relevant issues, commercial priorities, pre-emption.
- Obtain consents from partners to disclosure of data (if relevant).
- Buyer to execute confidentiality undertaking.
- Initial disclosure of information.
- Agree terms in principle.
- Finalise structure.
- Obtain clearance in principle from DTI.
- Buyer's detailed due diligence exercise.
- Negotiate Acquisition Agreement, and associated documents.
- Submit formal application for approval to DTI.
- Circulate draft novations to partners/third parties (asset deal).
- Obtain formal approval from DTI.
- Execute conditional Acquisition Agreement.
- Period to completion
  - satisfaction of conditions

  - agree forms of novations with partners/other third parties (asset deal);
  - obtain formal approval from DTI (if not already through)
  - partner consents/waiver of pre-emption;
  - other third party consents;
  - transfer out of unwanted assets/liabilities (share deal);
  - finalise financing; and
  - other condition *e.g.* shareholder consents.
- Completion of Acquisition Agreement, execution of novations etc.
- Copies of relevant documents to partners, DTI.

THE ACQUISITION AGREEMENT

The first part of this chapter focuses on the pre-acquisition issues. If the pre-acquisition work is properly done, the negotiation of the Acquisition Agreement is likely to give rise to fewer issues. The basic shape and principles of the acquisition agreement for an oil and gas deal are no different from any other acquisition agreement (whether assets sale or share sale) and this section therefore addresses those areas of particular relevance in the context of an oil and gas deal.

The Target Assets

1. *Share Deal*

In a share deal, the assets are the shares in the licence-owning company or companies. They are transferred by the execution and delivery of stock transfer forms.

2. *Asset Deal*

The assets in this case are more complex, comprising principally the licenses in question and the working interests under the joint operating and other relevant agreements. With producing assets, there will also be the rights under the relevant field agreements. In addition, the assets will probably also comprise data, and, in the case of any transfer of operatorship, the rights and assets held by the Seller in his capacity as operator. There may be other assets, for example physical inventory of stock.

Identifying the assets and dealing with them in the agreement should not be contentious, but it is critical that proper details of the licence interests, the percentage shares and the underlying agreements should be clearly set out in the agreement, or in schedules to the agreement. This will avoid subsequent disputes as to what interests were acquired and what the underlying agreements were.

Price

The Acquisition Agreement will set out clearly what the consideration for the deal is. Again, once the consideration is agreed, it should be neither contentious nor difficult to set out the terms in the Acquisition Agreement. The consideration is likely to consist of one or more of the following elements:–

1. *Cash*

This may be straight cash with no adjustments, or may involve a post-completion adjustment for items such as stocks, physical inventory, and the lifting position on producing assets. If there are post-completion adjustments, there are two essential elements: first, the basis upon which those adjustments are to be made (which may include applicable accounting principles) should be clearly stated. Secondly, there should be a clear mechanism and time-scale for the parties to reach agreement on the adjustments, failing which there will be a right for either party to refer the matter to independent arbitration.

2. *Swap*

This will normally involve consideration in the form of licence interests of the Buyer (possibly overseas assets), and may be a straight swap or involve a cash adjustment. The advantage of a swap deal in terms of negotiating the contract is that because both parties are wearing different hats, there may be a mutuality of interest in what are normally "Buyer's points" and "Seller's points".

3. *Other Non-Cash Assets*

The consideration may consist of other assets, such as equity or loan notes issued by the Buyer, or a carry arrangement whereby the Buyer agrees to carry the Seller for certain costs.

4. *Deferred Consideration*

It is possible that some or all of the consideration will be deferred, to be paid or satisfied at a later date. If that is the case, the Seller will be concerned to ensure that the Acquisition Agreement sets out clearly the Buyer's obligations in respect of payment or satisfaction of the deferred consideration, both as

regards timing and quantum. In addition, the Seller will wish to address the possibility of the Buyer going into receivership or liquidation before the consideration has been satisfied in full, and whether it is appropriate to negotiate early trigger points for specified events of default, and security arrangements to protect the Seller in the event of non-payment.

Conditions

Completion of the Acquisition Agreement may be subject to a number of different conditions, and there will be a period between signing and completion in which those conditions have to be fulfilled. The length of that period will depend upon the nature of the conditions, but they may involve the co-operation of third parties and accordingly be outside the control of the Buyer and Seller. In those circumstances, the time allowed for fulfilment of the conditions is important. While it is always open to the parties to agree to extend the time limit, if too short a period is agreed, and intervening events cause one party to wish to get out of the deal, a time limit that is too short may give that party the opportunity to extend the process with the result that the conditions are not met within the time limit and the deal falls away. There would normally be an obligation on both parties to use reasonable endeavours to procure fulfilment of the relevant conditions, and this may give an action against a party who delays.

The conditions on an acquisition of oil and gas assets are likely to consist of one or more of the following:–

1. *DTI Consents and Approvals*

This will comprise either approval of the assignment of the licence interests (in the case of an asset deal) or pre-clearance of the deal (in the case of a share deal), and any other approvals applicable to the particular transaction.

2. *Waiver of Pre-Emption Rights*

If there are pre-emption rights in the relevant joint operating agreements, the Buyer and Seller may agree that, if those pre-emption rights are exercised in respect of some, but not all, of the interests to be transferred, this will not affect the sale of the remaining interests. Failing that, it will be a condition of the deal that the parties to the relevant joint operating agreements waive their rights to pre-empt or that the period for exercising those pre-emption rights has expired without any such exercise.

3. *Partner Consents*

Even if there are no pre-emption rights, the deal will normally need to be conditional upon the necessary consents to the assignment of the working interests having been obtained in a specific provision in the novation agreement which transfers the rights and obligations under the relevant joint operating agreement from the Seller to the Buyer.

4. *Completion of Novations*

On an asset deal, completion of the transaction will normally be conditional upon novations of all the relevant joint operating and other material agreements having been completed. It is preferable for the completion of the novations to be effected simultaneously with completion of the transaction itself, and this can sometimes be achieved by executing the novation agreements in agreed form in escrow to be held pending completion of the full transaction, when the novation agreements will automatically be released from escrow upon execution by the Buyer and Seller, dated and completed.

5. *Clean Up*

On a share deal, completion may be conditional upon the clean-up of unwanted assets and liabilities having been achieved, if not in its entirety, to a significant degree. As this can be a complex process, and perfection is unlikely to be achievable (certainly in any realistic timescale), the parties may agree the extent to which the clean-up should be completed before the deal goes ahead, and include provisions for continuing to handle it following completion. The Buyer will, to the extent that the liabilities are removed prior to completion, rely on indemnification from the Seller.

There may be other conditions, such as shareholder approvals, bank consents, and financing.

The Seller (in an asset deal) will also wish to address the question of obtaining release from obligations under any notices issued by the Secretary of State under Section 1 of the Petroleum Act 1987 with regard the abandonment of relevant installations. This will require discussion with the Department of Trade and Industry and the Department of Trade and Industry may not release the Seller until the transaction has been completed. It may not therefore be appropriate for such release to be a condition to completion, and unless alternative arrangements can be agreed with the DTI, it should be a post-completion event.

Period to Completion

If the Acquisition Agreement is subject to fulfilment of conditions, there will be a handover period between the signing of the Acquisition Agreement and its completion. During that period the assets will continue to be owned and operated by the Seller, but the Buyer will wish to ensure that the assets acquired at completion are the same assets as envisaged when the Acquisition Agreement was signed, and that nothing has been done which materially alters those assets or the nature of the commercial deal between the parties. The parties will therefore normally agree contractual protections for the Buyer which will ensure first that the Buyer knows what is going on and is kept informed in relation to the assets in question, and secondly that the Seller cannot do things which would materially prejudice the Buyer's position in relation to those assets. There is a balance to be struck here between including sufficient protection to give the Buyer the necessary information and comfort, while not tying the Seller's hands so completely as to make proper and efficient continuing operation impossible.

The scope of the contractual obligations and the restrictions which are placed on the Seller in respect of the period between signing and completion will depend both upon the nature of the assets and the length of the period up to completion, and upon the respective bargaining powers of the parties. Clearly, the longer the period between signing and completion, the greater the risk for the buyer and the greater the comfort that may be required.

The principal areas in which the Buyer is likely to look for protection are as follows:–

1. *Consultation*

The Buyer will want to be kept fully informed and consulted on any issues relating to the assets, other than those which might be regarded as day to day issues. Any such information and consultation will need to be in compliance with applicable confidentiality provisions under the JOAs.

2. *Ordinary Course*

The Buyer is likely to require that, as a minimum, the Seller carries on the operations in relation to the assets in the ordinary course of business and in accordance with good and prudent oilfield practice.

3. *Disposal/Charging*

The Seller should not be permitted to dispose of, charge or otherwise encumber the assets in question.

4. *Preservation of Assets*

In addition to a negative covenant not to dispose of or charge the assets, the Buyer will normally also seek a positive obligation on the Seller to take all necessary steps to preserve and protect the licence interests.

5. *Insurance*

The Seller should keep in place all existing insurance policies, and it may be prudent for the Buyer's interest to be noted on those policies.

6. *Material Amendments*

The Buyer will not want the Seller to agree any material amendments to any of the joint operating agreements, field agreements or other relevant agreements without the Buyer's consent—the Buyer will be inheriting these agreements which are fundamental to the assets being acquired, and changes to them could materially prejudice the Buyer's position.

7. *Voting*

Ideally, the Buyer would want to ensure that the Seller voted in accordance with the Buyer's directions at meetings of the relevant operating committees, but that give rise to problems in practice:

(i) First, such an arrangement is generally considered to constitute a breach of Model Clause 41 and as such to require the approval of the Department of Trade and Industry. In addition, it is likely to require the approval of the partners under the relevant joint operating agreement, and they may not be willing to accept that an outside third party can be involved in their decision-making.

(ii) Secondly, the Seller will not wish to find that, if the deal falls through, the Buyer has voted in favour of matters at meetings of the operating committee which the Seller would not otherwise have voted for.

For these reasons, it is commonly agreed that while the Seller will consult with and take account of the Buyer's representations in considering how to cast his vote, the Seller is not obliged to vote in accordance with the Buyer's directions. Again, the question of confidentiality should be borne in mind.

8. *Consistency with Warranties*

The Buyer may seek a general undertaking that in respect of the period between signing and completion the Seller will act in a manner consistent

with the warranties. The warranties set out the contractual assumptions upon which the Buyer's decision to acquire the assets is based, and the Buyer should be entitled to assume that those assumptions are true not only at signing but also at completion of the deal, at least in so far as it is within the power of the Seller to ensure that such is the case. The question of whether warranties should be given only at signing or also at completion (and if they are repeated at completion in what form they should be repeated and whether additional disclosure should be permitted) will be negotiated between the Buyer and Seller. The issues to which this gives rise are common to all acquisitions with a gap between signing and completion, and are beyond the scope of this chapter. It is ultimately a question as to which party will bear what risk when.

Depending on the nature of the deal, there may be other restrictions and undertakings in respect of the period between signing and completion.

Data

On an oil and gas deal, a particularly important area is the question of transfer of data. The geological and other data relating to the working interests to be acquired is a valuable asset, and the Buyer will wish to ensure that it will acquire and be entitled to use that data after completion. There are two principal areas which need to be addressed:—

1. *Identification*

The Acquisition Agreement should clearly identify which data is transferred to the Buyer and which is retained by the Seller. In many cases, this will be clear, because certain data will relate only to a particular asset. However the Seller may have data which has been independently obtained, and which relates to a number of blocks some of which are included in the sale and some of which are not. It may not be clear whether that data is included in the sale. This is a matter for commercial negotiation, and the Buyer will wish to make sure that it is getting all relevant data or, if it is not, that the commercial terms reflect this. Equally, this Seller will not wish to find that it has inadvertently agreed to hand over data relevant to its ongoing operations.

2. *Seismic Data*

One aspect of the data transfer which requires particular attention is the question of speculative seismic data licences. In many cases, these agreements will have been entered into by the operator on behalf of the licence group, and the Seller itself may not be a party to them. In other cases, there may be a separate agreement between the Seller (or licence company) and the owner of the data. The Seller's entitlement to the data licensed under those agreements is derived from those agreements and if that data is to be passed on to the Buyer the terms of those agreements are relevant. Many of them contain restrictions on the data being passed to any third party (and this sometimes includes a change of control), and many of them provide for escalation fees to be paid if the data is passed to a third party. At worst, there may be provisions for termination of the licence if there is an assignment or change of control, with the result that the data may have to be returned unless a deal can be negotiated with the owner. It is worth noting that these agreements often do not differentiate between intra-group transactions and transactions with third parties, so that, for example, on the hive up structure described above, there may be restrictions and/or fees which apply *both* on the transfer of the assets to an affiliated company (even though it is intra-group) *and* subsequently on the sale of the shares in that company. It is apparent that there may be a cost involved in transferring data on the acquisition, and the parties will need to agree between them how this should be borne.

Liabilities and Indemnities

Whether the deal is an asset deal or a share deal, one critical area will be the split of liabilities between the Buyer and the Seller, and the issue of which party is responsible for what liabilities. The Buyer will generally wish to acquire the assets clean, or at worst with only those liabilities which are known and quantified and which have been taken into account in the price. As a general rule, the Seller will be responsible for liabilities in respect of the period prior to completion, and the Buyer will be responsible for liabilities in respect of the period after completion (or the effective date if different). An area of difficulty relates to liabilities which arise after completion but which could be said to be attributable in whole or part to activities that took place before completion. These may give rise to questions of causation, and if possible it is preferable to identify the potential liabilities in advance and deal with them specifically. If the Buyer has negotiated appropriate warranties, such contingent liabilities should become apparent through the disclosure exercise, or, if they are not and were known of before signing, may give the Buyer a warranty claim. However, from the Buyer's point of view it is preferable to identify the issues and deal with them on an indemnity basis, than to have to pursue a warranty claim through the courts.

It is important that both parties are clear as to who is responsible for which liabilities and potential liabilities, and it is important to bear in mind on an asset deal that the split of liabilities in the novation agreements with joint venture partners should be consistent with what is agreed between the principal parties.

Warranties

The warranties on any deal serve two principal purposes. The first is to require the Seller to disclose all relevant information against the warranties, so that before entering into the deal the Buyer has a full picture of the assets and liabilities he is taking on. The second purpose is to give the Buyer a remedy against the Seller for breach of contract if the warranties given by the Seller prove to be untrue and the Buyer suffers loss as a result (by having paid too much for the assets).

The warranties set out the legal and commercial assumptions made by the Buyer in agreeing to acquire the assets for the price agreed. In the context of an oil and gas deal, the principles underlying the warranties are no different from those in any other deal, but the subject matter of the warranties will be specific to the oil and gas assets in question. The scope of the warranties will be largely dependent on the nature of the target assets, and, ultimately, the negotiating strength of the respective parties. However, some of the areas which would normally be covered in the context of an oil and gas deal are as follows:–

(i) Title: Fundamental to any deal is the Seller's title to the assets, and its freedom to sell free from encumbrances, royalties and other third party rights.

(ii) Defaults: The Buyer will wish to be assured that the Seller has not breached and is not in default of the relevant licences, joint operating agreements and field agreements.

(iii) Withdrawal, Revocation, Surrender: The Buyer will wish to know that the Seller has not given any notice of withdrawal to the partners in respect of its interests, that nothing has occurred which might cause the licence to be revoked, and that no action has been taken by the partners to surrender the licence.

(iv) Sole Risk/Non Consent: The Buyer will want details of any sole risk or non-consent operations (both ongoing and historic) as these may give rise to different equity interests in different parts of the block.

(v) Accuracy of Information: The Buyer will seek confirmation that the joint operating agreements and other material agreements which underlie the assets are complete and up to date in the form provided (see page ?). The Buyer will normally also seek to require the Seller to warrant that all information provided to the Buyer in respect of the assets is complete and accurate and that all documents which affect the Seller's title and the interests in question have been disclosed.

(vi) Assignment/Change of Control: The Buyer will want assurance that the position with regard to assignment of material contracts and (in the case of a share sale) change of control has been fully disclosed and that there are no restrictions on assignment or change of control which might trigger adverse consequences for the Buyer.

(vii) Litigation, etc: The Buyer will want to be satisfied that there is no ongoing litigation, arbitration, third party claims or disputes relating to the assets to be acquiring, and that there are no facts likely to give rise to such matters.

(viii) Suspended/Abandoned Wells: If the assets being acquired include wells that have been suspended or abandoned, the Buyer will want to be satisfied that the work on those wells has been carried out properly, and in accordance with good and prudent oilfield practice.

(ix) Accrued Obligations: The Buyer will want to be assured that the Seller has performed all accrued obligations, and has discharged all liabilities in respect of the period prior to completion (including the payment of all cash calls due).

(x) Committed Expenditure/Obligations: The Buyer will wish to ensure that it has been correctly informed as to the state of the current work programs and budgets (*i.e.* as to what stage of the approval process they have reached, and whether they have been adopted), so that any contingent liabilities can be factored into the relevant financial models. The Buyer will also want to be assured that there are no binding undisclosed commitments, for example in relation to long term contracts.

(xi) Others: Depending on the nature of the deal there may be many other areas covered by the warranties, including:–
- — environmental matters;
- — status of records, accounts etc;
- — ownership, completeness, accuracy and transferability of technical data;
- — tax position and liabilities;
- — abandonment and security arrangements.

The warranties on a share deal are likely to be more extensive than on an asset deal because the target company comes with all historic and current assets and liabilities.

It is usual to exclude specifically any warranty or representation in respect of reservoir volume or performance—these will be a matter for the Buyer's technical experts to assess.

As mentioned, the scope of the warranties on any deal will depend on the nature of the assets and the negotiating strengths of the respective parties. From the Buyer's point of view, it is critical to ensure that the fundamental assumptions which underpin the Buyer's decision to acquire the assets at the price agreed are properly reflected in the warranties. Slavish adherence to "standard form warranties" may mean that many irrelevant areas are covered but the most important assumptions are omitted.

Finally, the warranties will be qualified by matters disclosed in the Disclosure

Letter, and the Acquisition Agreement will normally contain specific limitations on the Seller's liability under the warranties. These issues are common to any acquisition agreement, and again are beyond the scope of this chapter, but like warranties the form and content of the limitations and disclosures negotiated will ultimately reflect the negotiating strength of the parties.

Outstanding Tax Affairs

On most deals there will be a need for the Buyer and the Seller to liaise and co-operate with each other after completion in relation to the preparation, submission and agreement of outstanding tax returns, and for this reason it is helpful to set out in the Acquisition Agreement who is responsible for handling those returns. On an asset deal, the Buyer stands in the Seller's shoes for the purposes of petroleum revenue tax, and the reliefs to which the Buyer is entitled will depend on the Seller's expenditure position. The Buyer will therefore have a vested interest in ensuring that the Seller gets those returns in promptly so that they can be agreed and the relief made available.

On a share deal, the Buyer may well be able to take advantage of the target company's corporation tax losses, and again, the Buyer and Seller will need to agree how the submission of the relevant returns and the agreement of the loss position with the Inland Revenue is handled. The Seller's corporation tax losses will not be available to the Buyer on an asset deal.

If the Acquisition Agreement contains a clear allocation of responsibilities and an agreed procedure for handling the administration of tax affairs, this should ensure that following completion they are dealt with in the most effective and efficient manner.

PRACTICAL TIPS

Finally, experience shows that there are certain practical steps on oil and gas acquisitions which can both facilitate the process and increase the chance of reaching a successful closing.

Preparation and Structure

An early assessment of the issues involved on any acquisition, such as pre-emption, tax, financing and third party consents will ensure first that the material issues are addressed and factored into the planning, and secondly that the best structure for the deal is settled at the outset. This should avoid problems further down the road.

Financing

If the deal is being financed by bank or other borrowings, the lenders will be as concerned as the Buyer to ensure that the Acquisition Agreement and other agreements are in an acceptable form. The negotiation of the financing should take place alongside the negotiation of the main commercial documents. In particular, obtaining the necessary consents for the granting of security may take time, and if not started early will delay the deal.

Commercial Objectives

There is always a risk on complex oil and gas deals of tax, legal and regulatory issues overshadowing the parties' commercial objectives. While they are important, they need to be kept in perspective, the objective should always be to get the deal done within whatever tax, legal and regulatory constraints apply.

Information

If clear, accurate and complete information is provided to the Department of Trade and Industry and partners at the earliest practicable stage, it will save time. If information has to be changed, supplemented or clarified, this will almost certainly cause delay.

JOA Novations

These follow a generally accepted format, and there is little point in reinventing the wheel. It often helps to use the form of novation which was last used for the licence in question, as it will be a form with which the partners will be familiar and on which they will relatively recently have signed off.

Other Novations

If the deal involves a number of non-JOA novations with, for example, service companies and contractors which are not familiar with the standard JOA novation format, it is often preferable to use a letter form of novation which has the same effect but is more user friendly. If it is properly drafted to achieve the necessary objective without being overly legalistic or complicated, much time and effort can be saved.

CONCLUSIONS

Oil and gas acquisitions have to be negotiated within the framework of the regulatory and contractual rules under which licence interests are held. They require a disciplined, structured approach. Legal, regulatory and commercial hurdles can, with imagination and foresight, nearly always be overcome, provided the issues are identified and addressed at an early stage. For this reason the successful negotiation of oil and gas acquisition agreements requires, on the part of the participants and their advisers: a detailed understanding of the legal, regulatory and contractual framework; an ability to identify the critical issues and factor them into the best overall structure; and a determination and ability to find creative solutions to problems.

11.

Abandonment Agreements

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A few years ago, operators and joint venturers of North Sea oil and gas properties gave relatively little thought to what would happen when their interests ceased production. That situation has changed rapidly in the last few years with the passing of the Petroleum Act 1987 and with many producing North Sea fields coming to the end of their economic lives. Until recently the only significant facility to have been abandoned was Piper Alpha.

The last year or so has seen some significant developments. By early 1995, the DTI had approved eight relatively straightforward abandonment programmes. There have been a number of reports into abandonment and a proposed relaxation of the United Kingdom requirements. These will be examined in more detail later. Unfortunately, a legal analysis of the Brent Spar is beyond the scope of this chapter. Nevertheless, a brief summary of developments is included for the sake of completeness.

This chapter is divided into two sections. The first section will examine the meaning of abandonment and what rules and regulations apply primarily in respect of North Sea platforms. The second section will outline some of the principles and clauses found in many abandonment agreements. The example abandonment agreement which is included is indicative only of certain issues which may be relevant. It could not be used for any particular set of circumstances without considered revision. It does not, for example, contain detailed provisions on how abandonment liabilities or any liability fund may be apportioned if a field interest is sold by a participant prior to abandonment. The agreement is also styled a "decommissioning agreement" for reasons given below.

PART I

Meaning and Legal Framework

The first point to make is that, the term "abandonment" is misleading. The word "abandonment" has connotations of the surrender of ownership rights or of leaving behind one's obligations. The word preferred by the industı and by Government is "decommissioning".

What Then Does Abandonment or Decommissioning Entail?

A 1991 House of Commons Report (*House of Commons Energy Committe Fourth Report—Decommissioning of Oil and Gas Fields—March 20, 199:* indicates four alternatives which could be considered when decommissionin or "abandoning" disused facilities.

These are:

(i) leaving the facilities in place;
(ii) partial removal and toppling of the facilities;
(iii) wholly or partially removing the facilities and then dumping thei in deep water; and,
(iv) wholly or partially removing the facilities and taking them on-shor

Obviously the option chosen for decommissioning will depend on a numbe of factors and will attempt to balance environmental, safety and cost concern: A very useful analysis of the process required for abandonment plans can b found in the DTI consultative document *Guidance Notes for Industry—Abandonment of Offshore Installation and Pipelines under the Petroleum A 1987*—May 4, 1995.

What Could It All Cost?

In 1988 the United Kingdom Offshore Operators' Association ("UKOOA' estimated that the cost of removing all offshore United Kingdom Continent Shelf ("UKCS") facilities would range from £4.4 billion to £2.9 billio depending on whether total or partial removal was required. Arthur Anderse estimated that the total cost of United Kingdom abandonments was £7 billio in their 1994 survey of the UKCS.

In 1993 a Norwegian expert (Torbjoern Lorentzen) estimated in a repoı commissioned by the Norwegian environment ministry that if all the 50 c so existing installations on Norway's Shelf are removed and broken up, a fields are depleted, the total cost could reach Kr50bn (at 1993 values) ($7.3bn This is Kr12bn more than the Norwegian Petroleum Directorate's estimate c what removal alone would cost.

Norwegian field abandonments work out as more expensive at approx mately £70M per facility against £30M per facility for the UKCS.

In addition to the platforms, over 3,500 miles of pipelines have been lai of which approximately 60 per cent are of 30" diameter or greater.

There is an obvious desire to contain decommissioning costs given the sum involved and widely differing estimates for different removal methods. Th Government also has a major interest. Following 1993 tax changes in th

United Kingdom, it is estimated that, in the case of PRT paying fields, 66.5 per cent of abandonment costs can normally be expected to fall upon the Exchequer or taxpayers in the form of tax relief. This figure reduces to about 33 per cent in the case of non-PRT paying fields.

Taxation

The combined effect of royalty, Petroleum Revenue Tax ("PRT") and corporation Tax has historically imposed a high rate of taxation on oil and gas revenues. The loss of Government revenue resulting from tax reliefs available for abandonment expenditure has been of major concern to the Government and is likely to have a continuing influence in determining its approach to cases of abandonment.

The oil industry is still seeking improvements in the regime for abandonment tax reliefs despite a number of important changes brought about in the last few years.

As a general rule, abandonment costs can be offset in calculating income for royalty purposes and can be relieved against income for the purposes of PRT.

The major concern for the oil industry is that (despite lobbying) payments into abandonment trust funds are still not allowable expenses for tax purposes.

Before the 1993 Budget changes, oil companies were generally able to set off a significant proportion of abandonment costs against their PRT bill. In effect, this meant that the Government (or the taxpayers) could be paying 75 per cent of those costs. Under the new PRT regime (*i.e.* 50 per cent for existing fields and zero for new fields) a far larger proportion of abandonment costs may now have to be met by the oil companies. As stated above, roughly 66.5 per cent of abandonment costs will fall on the Exchequer in respect of PRT paying fields. The figure for non-PRT paying fields is roughly 33 per cent.

What then are Companies Operating on the UKCS Actually Obliged to do by way of Removal Obligations?

The United Kingdom is party to a number of international Conventions which provide some degree of guidance in respect of domestic obligations concerning abandonment. For a more detailed analysis of International Law obligations see "Abandonment of Energy Sites and Structures: Relevant International Law": Rosalyn Higgins, Q.C., *Journal of Energy & Natural Resources Law*, February 1993.

What international law there is remains in conflict.

The 1958 Geneva Convention on the Continental Shelf states (in Article 5(5)) that facilities should be "entirely" removed. There is some debate on whether this requirement is of any legal effect or whether it has become obsolete by virtue of non-observance. There is a generally held view that Article 5(5) does not now reflect customary international law.

The United Nations Convention on the Law of the Sea ("UNCLOS") (1982) speaks broadly of "ensuring the safety of navigation", and of giving proper publicity to structures "not entirely removed". Note the difference in emphasis between total and partial removal within the Geneva Convention and UNCLOS. UNCLOS was ratified by its 60th state (Guyana) on November 16, 1993 and so came into force on November 16, 1994.

Despite the United Kingdom not being a party to UNCLOS (it is a party to the earlier 1958 convention) it still believes that UNCLOS reflects customary international law.

In 1990 the United Kingdom Government declared that removal of "abandoned" facilities should comply with International Maritime Organisation ("IMO") Guidelines. These stipulate the entire removal of structures in low water (meaning less than 75 metres in depth) and weighing less than 4,000 Tonnes in air (exclusive of the deck and superstructure since these will require removal in any event). There should be at least partial removal in deeper waters provided that there is 55 metres of clear water above any submerged remains. The Government has increased this to 75 metres for the northern part of the North Sea on grounds of safer navigation for naval submarines. The Government has, however, announced recently that this requirement will shortly revert back to 55 metres. All installations placed on the seabed after January 1, 1998 standing in less than 100m of water and weighing less than 4,000 Tonnes will require total removal. Structures placed after January 1, 1998 will need to be of a design such that entire abandonment or permanent disuse is feasible. Adherence to these criteria would have meant as at March 1990 removing 111 of the 155 fixed installations on the UKCS.

Another factor to bear in mind when looking at decommissioning obligations is that toppling an oil platform and/or disposing of it in the sea could constitute "dumping". The London, Paris and Oslo Conventions on dumping should be borne in mind in relation to the dumping on site of offshore installations. The London and Oslo Conventions of 1972 are shortly to be subsumed by a new OSPAR Convention. It is unlikely, however, that pipelines would be subject to the Dumping Conventions. A permit may be required from the relevant coastal state. Deep sea dumping is likely to be an exception and only allowed where it is the best practicable environmental option and consistent with international obligations.

As for Norway, many of the fixed installations on Norway's Continental Shelf may be left in place following their useful lives as it would be too costly and difficult to remove them. The Petroleum Act Committee of Norway reported in June 1993 that, among other things, oil companies should make greater use of floating production units. Generally, field operators in Norwegian waters should submit an abandonment plan to the authorities at

least two years before the field is due to be shut down. The Committee recommends that pipelines be left in place provided fishing interests are protected. Norway's procedures are similar to those of the United Kingdom with the relevant Norwegian statute being the Petroleum Act 1985. Recently, however, the Norwegians have been discussing total removal of facilities as the environmental debate has intensified.

The Petroleum Act 1987 ("The Act")

The most important piece of domestic legislation which has acted as a catalyst (and was probably meant to) in the formulation of abandonment agreements is the Petroleum Act 1987. The Act provides that the Secretary of State for Energy (now Trade and Industry) ("the Secretary") may call for an "abandonment programme" from owners of an interest in a platform or a pipeline and may, ultimately, impose an abandonment programme if the owners default or if the Secretary is dissatisfied with their proposals.

A bank will not be an owner of an interest for these purposes by reason of holding an interest in an installation or pipeline by way of security for a loan (sections 2(1)(d) and 2(2)(b) of the Act).

The abandonment programme should stipulate the costs of abandonment and the timing of operations. The Act is so drafted that the Secretary may execute works and seek reimbursement. The Secretary may also call upon any one party to fulfil the obligations of all interested parties in a facility and may call upon holding or subsidiary companies of that party to do likewise. The idea of the parties being jointly and severally liable for their facilities and for this extending broadly within groups of companies is to encourage the oil companies to procure that each of their joint venture partners makes valid and binding security arrangements to protect against one of them defaulting or going into liquidation. Section 3 of the Act enshrines this by making it clear that if the Secretary is and continues to be satisfied with abandonment obligations already in place (including financial arrangements) then he will only look to the owners of a facility (broadly the JOA or unit partners) and not their associated companies.

To provide further incentives, failure to comply with any notice given by the Secretary is a criminal offence. Any breach of the Act by a Company can also bring liability for its directors, secretary or managers if there is "consent", "connivance" or "neglect".

Provision is also made to ensure that the owners of the installation will be able to fund their obligations. If the Secretary is not satisfied of this he may by notice require the relevant person to take such action as he may specify. This power is wide enough for the Secretary to require the owners of the installation to enter into security agreements for abandonment.

Part III of the Act establishes a security zone of 500 metres around each installation. The Act makes it an offence for any vessel to enter this safety zone and provides that, in such event, both owner and master shall be guilty of an offence.

By way of an opening shot in exercising his powers under the Act, section 1 Notices have been served on the owners of United Kingdom installations giving preliminary notice that they should submit an abandonment programme by such date as may later be directed by the Secretary. No further action has yet been taken on this. Section 11 of the Act allows the Department of Energy to promulgate regulations for the abandonment of offshore installations. The consensus appears to be that whilst the Department will publish guidelines, actual regulations are unlikely to be forthcoming.

Safety Provisions

Following the Piper Alpha disaster some of the recommendations of the Cullen Report have been given statutory effect by the Offshore Safety Act 1992. The Health & Safety Executive now has the statutory power to carry out a wide-ranging programme of revising and updating the existing offshore safety regime including the functions of securing the safety, health and welfare of persons on offshore installations or engaged in associated pipeline work, the safety of the installations and pipelines and their construction and dismantling. Existing legislation on those matters may now be enforced by the Health & Safety Executive which has the power to enlarge or modify those provisions by regulations made under the Health and Safety At Work, etc., Act 1974.

Operators will now be required to submit a Safety Case for each installation which will have to be accepted by the Health & Safety Executive. This Safety Case will have to be formally updated for each major modification during the life of an installation and this will include the abandonment stage. Consequently, in developing an abandonment programme a Safety Case will be required to be submitted to the Health & Safety Executive.

United Kingdom Approval Framework

Under the United Kingdom framework a number of approvals need to be obtained before a facility can be decommissioned or abandoned. In summary the approvals required are as follows:

(i) the abandonment programme is to be approved under The Petroleum Act 1987;

(ii) any abandonment of a well is to be approved under the relevant licence governing the oil and gas field. This will be a requirement of the Model Clauses of the relevant licence. This function is

currently carried out by the Health and Safety Executive on behalf of the DTI;

(iii) a Safety Case for the safe working of the abandonment will need to be approved under the Offshore Installations (Safety Case) Regulations 1992;

(iv) confirmation will be required that the provisions of the Coast Protection Act 1949 have been met. These require DOT approval as to the safety of navigation;

(v) if there is to be partial or total disposal onshore then the applicant will need to comply with the requirements of the Environmental Protection Act 1990. Particular regard will need to be paid to the "duty of care" provisions of section 34 EPA;

(vi) if there is to be total or partial disposal at sea then there will need to be a licence under the Food and Environment Protection Act 1985 which will require consultation with the MAFF or its Scottish equivalent—SOAFD or, in Northern Ireland—DENI;

(vii) in certain circumstances an authority may be required under the Radioactive Substances Act 1993. This will require consultation with HMIP and HMIPI (to become the Environment Agency and the Scottish Environment Protection Agency).

Residual Liabilities

Another area to be considered when looking at abandonment is who is responsible for any remains of facilities once they have been "abandoned". This is where the term "abandonment" is perhaps most confusing.

The general consensus is that the theoretical risk of liability on the original JOA or unit partners for "residues" remains even after the relevant facilities have been decommissioned. The Government feels that this risk is remote in any event on the basis that complying with a proper abandonment programme and clearly marking any residues of facilities on marine charts (given that there should be a mandatory 500 metre exclusion zone) would discharge any duty of care to potential plaintiffs. The logic here is that the master and owner of the vessel would be negligent by being in a position (*i.e.* within the exclusion zone) to collide with the partially abandoned facilities in the first place. However, the theoretical risk remains and abandonment agreements should also legislate for the potential of future liability from debris or pollution following decommissioning.

In Practice

The submission of an abandonment plan and the various approvals to be sought should be through the DTI in Aberdeen whose intention is to operate as a "one stop shop". This means, in effect, that they will co-ordinate the various consultations and approvals required. The relevant field operator will discuss the plan with the DTI in Aberdeen up to three years in advance of actual decommissioning. The programme will provide options, comparative assessments and preferences. The content of the plan will include an inventory of what is to be decommissioned and a timetable. The abandonment plan must have regard to the "precautionary principle", best available techniques, best environmental practice, health and safety and also pay due regard to other users of the sea. Full details are to be provided to the Department of Trade and Industry, Oil and Gas Division, Atholl House, 86–88 Guild Street, Aberdeen AB9 1DR (Tel: 01224 254022).

The Brent Spar

An analysis of the implications of the Brent Spar episode is beyond the scope of this chapter. For further information see "Abandonment: Headline News": Mark Saunders [1995] 8 OGLTR 287. Suffice it to say that political, environmental and PR concerns will have greater prominence when considering decommissioning in the future.

PART II

Abandonment Agreements

Historically, most early JOAs said very little about abandonment. An "abandonment" clause in a JOA would commonly merely provide that if the parties decided to abandon any joint property, the operator should try to recover and dispose of whatever may be economically and reasonably recovered (or which the law requires to be recovered) and the net costs or proceeds should be debited or credited to the joint venture parties as appropriate.

The following clauses were typical and are still often seen:

"Disposal and Abandonment

1. If the Operator shall consider that any item of the Joint Property is no longer needed or suitable for the Joint Operations the Operator shall, subject to the provisions of the Accounting Procedure, dispose of the same.
2. If the Participants shall decide to abandon the Joint Operations, or any part thereof, the Operator shall recover and endeavour to dispose of as much of the Joint Property as may be determined can economically and reasonably be recovered or as may be required to be recovered under the Acts, the Licence or any other applicable law, and the net cost or net proceeds therefrom shall be charged or credited to the Joint Account."

Some JOAs went a little further than this. They provided that the parties would agree an abandonment agreement to deal, among other things, with "an equitable sharing of liabilities between the Participants" and the "provision of security therefor". To the extent that this is an agreement to agree it may be of little binding effect. The relevant clause would commonly run as follows:

> "3. Without prejudice to Clause 2 above it is agreed that following any proposal made to the Joint Operating Committee for the Operator to prepare a development programme and budget for a particular discovery the Participants will before submission of an Annex 'B' to the Department of Energy agree the terms of an Abandonment Agreement which should, inter alia, include an equitable sharing of liabilities between the Participants and the provision of security therefor provided that in the event of failure to obtain unanimous agreement of the Participants to the terms of such Abandonment Agreement the provisions of this Clause 3 shall be deemed to have been satisfied for the purpose of enabling the submission of an Annex 'B' if the Participants who have agreed the terms of such Abandonment Agreement hold in aggregate a Percentage Interest not less than that specified in Clause (*Pass Mark Clause*) and provided further that in such event the Participants shall use all reasonable endeavours to obtain unanimous agreement to the terms of the abandonment Agreement as soon as practicable after such submission."

The recent trend is for the parties to agree a fully blown abandonment agreement which may be contained within the JOAs or even included as an annex to a joint bidding agreement. Like any agreement, these will vary according to the circumstances but certain features should be common. Please note that the following information is indicative only. Each field and the profile of its participants will require different legal solutions.

Common Features in Abandonment Agreements

The recent trend is for a separate abandonment agreement to be put in place or incorporated as part of the JOA.

The JOA has to be approved by the Department of Trade and Industry and the abandonment clauses or annex contained within it are capable of forming an approved abandonment arrangement under section 3(2)(3) of the Petroleum Act thus preventing associates of the JOA parties from being required to submit an abandonment programme. Abandonment agreements will vary according to the circumstances but certain features should be common. They should seek to deal with how to agree the terms and costs of an abandonment programme and how to provide security for abandonment costs.

1. *The Abandonment Programme & Budget*

A formal procedure is needed to determine what abandonment operations are to be carried out and for the costs to be budgeted.

Some JOAs adopt provisions for abandonment as part of the annual budget procedures. On this basis the operator would be authorised prior to the financial year in which he considered that first abandonment is likely to occur, to submit to the operating committee a proposed abandonment programme budget for approval. The operator would then be required in each succeeding year to submit an update of that programme and budget with details of any new costs. The annual programme and budget would need to be approved by the operating committee by the start of each year. Once approved, the operator should be authorised to submit the abandonment programme and budget to the Secretary for approval under the Act.

Since there may well be problems in all JOA parties reaching agreement on a particular abandonment programme and budget some JOA parties might prefer to provide for abandonment programmes and budgets to be prepared prior to first commercial production of petroleum from the field.

Whatever the timing arrangements in the JOA for agreeing abandonment programmes these may be upset by a section 1 notice under the Act. If the Secretary requires an abandonment programme to be submitted prior to the operating committee reaching agreement, the operator may need further powers in the JOA. The operator might have to be given authority to prepare an abandonment programme and budget and submit it to the Secretary without prior operating committee approval. This could be submitted by the operator alone or by the JOA partners on a specified pass mark vote (see specimen Clause 3 above). Revisions could then be proposed by the JOA parties after submission of the abandonment programme.

The JOA should provide that all parties must pay their share of costs of the abandonment programme whether it is an approved programme or one imposed by the Secretary.

2. *Security for Abandonment Costs*

Security is rightly perceived by the industry as of vital importance. The costs of abandonment will be considerable. The concept of joint and several liability under the Act means that parties to a facility must be sure that if any of their number defaults there will be adequate security to fund the defaulter's liabilities.

The time-honoured JOA remedy of forfeiture, *i.e.* losing your share of revenues if you default, will probably not be appropriate here. By the time abandonments is an issue the field will probably be in decline and the defaulter's future revenues could well be less than its share of abandonment costs.

So What Forms of Security Are There?

The types of security for abandonment costs seen in practice are:—

(i) Parent Company Guarantee.
(ii) Bank Guarantee or Letter of Credit.
(iii) Performance Bond.
(iv) Trust Fund.

The following is a very simple guide to what these terms mean.

1. *Guarantee*

A guarantee generally imposes a secondary liability to pay on the default of the primary obligor. The evidence required to prove an entitlement to payment under a guarantee varies according to the guarantee. The only difference between a parent company guarantee and a bank guarantee is the strength of the guarantor. In most cases a clearing bank's guarantee is better than a parent company's. Certain companies do, however, have a better credit rating than some banks.

2. *Letter of Credit/Documentary Credit*

This is a promise by a bank of immediate or future payment against the presentation of documents to the bank or its agent. There are a couple of types of letters of credit which may be referred to in abandonment agreements.

(i) Standby Letter of Credit

This is a form of documentary credit where the obligation to pay is enforceable once specified documents have been presented in accordance with the terms of the letter. The presentation of the documents within a specified time limit is the *only* condition of payment by the issuing bank. A standby letter of credit performs the function of a guarantee and is commonly used where the giving of a guarantee by a bank is prohibited. A letter of credit differs from a guarantee in that it is *not* contingent on the default of the primary obligor and is usually conditional only the presentation of a written demand by the beneficiary—*i.e.* it is independent of the underlying transaction.

(ii) Irrevocable Letter of Credit

Provided the document is presented to the issuing bank (by way of written demand) within a stated time, it is exactly that. An irrevocable standby letter of credit should generally be stronger for a beneficiary than a guarantee.

3. *Performance Bond*

Usually a performance bond will be of a first demand type *i.e.* money is payable effectively on the beneficiary's say-so, although it is also possible for the bank to require evidence that the primary party is in default. In this case, this could be more onerous for the beneficiary than a guarantee. An unconditional performance bond (payable on demand) is as good as a standby letter of credit.

Summary of Terms

In practice there may be little difference between a bond, a credit and a guarantee. All are basically undertakings to pay; it is the degree of conditionality to that undertaking which varies between them.

It is worth remembering that a parent company guarantee (even a bank guarantee) has the attendant risk that the parent (or the bank) may not itself be good for the money. Most agreements therefore provide that any guarantor must have a defined credit rating. By way of example, the abandonment agreement may stipulate a credit rating of "AA—or better by Standard & Poors Corporation" or an "Aa rating (whether graded 1, 2 or 3 or otherwise qualified) or better by Moody's Investors Service Inc".

Even if this type of provision applies, it should be remembered that a past rating is no guide to the future performance of the relevant parent company or bank. If, as is increasingly the case, renewable letters of credit are used to provide security, the stipulated credit rating can be made to apply on each renewal.

BRINDEX (British Independent Oil Exploration Companies) recently concluded that (i) the payment of cash into a trust fund or (ii) bank guarantees are the only "totally secure" methods of providing security for abandonment.

As always, security arrangements are not such good news for the smaller companies. A parent company guarantee requires a high credit rating of the parent; a standby letter of credit can cost between 0.1 per cent and 0.5 per cent of the security amount per annum. This leaves the abandonment trust fund as the only viable option and even that will swallow up valuable cash flow.

Timing of Security

One should ideally provide security for abandonment costs at the beginning of the field's life. Since most companies are usually not willing or far-sighted enough to commit early to future expenditure, a practice has developed of providing such security at a critical or "trigger" point in the field's life.

UKOOA believes that this trigger point, requiring security for abandonment costs, should come into play when the "discounted cost of abandonment exceeds a pre-determined proportion of the discounted value of the remaining reserves (*typically* 50 per cent–75 per cent)".

In most abandonment agreements the security requirement is generally "triggered" when the net remaining value of the field is equal to or below 150 per cent or 135 per cent of the projected cost of abandonment.

To determine when this trigger is reached requires constant monitoring. It also requires provision for expert determination if values cannot be agreed between the joint venture partners.

Once the trigger has been reached the relevant field will have entered its "run down period" and each year thereafter the parties will need to determine the value of security required from them.

So How Does the Trust Fund Fit In?

JOA parties will not wish to tie up part of their cash flow by paying into a trust fund. In addition to this, whilst tax relief is available for the costs of maintaining guarantees and letters of credit such relief is not available for cash payments into an abandonment fund to provide for future costs.

A typical abandonment agreement will therefore commit the parties to maintain adequate security usually by way of guarantees or letters of credit and provide that if this security becomes inadequate or is not renewed, cash payments will only *then* be made into an abandonment trust fund or such amount as together with any ongoing security is equal to that party's share of the estimated costs.

In order to provide for a regular payment basis for those JOA parties required to pay into the abandonment trust fund, the operator may estimate each year the remaining field production and the cost of abandonment to determine a unit cost per barrel of production.

The abandonment agreement would typically provide that any surplus following the completion of the abandonment programme would be held on resulting trust and distributed pro rata according to contributions.

Since the effect of tax will vary for each party, calculation of field interests and abandonment costs should be on an after tax basis or should disregard tax reliefs.

Forfeiture of a participant's interest is not considered appropriate as a sanction for not maintaining the required security in view of the risk that the value of the defaulter's interest is approaching its share of abandonment costs. Also forfeiture is likely to be resisted by JOA parties with a smaller interest since they could be overruled on decisions as to acceptability of their security. It is for these reasons that the trust fund with a requirement to make cash payments is seen as the most effective way of dealing with security defaults. Failure to make a cash call to the trust fund would have to be treated as any other cash default under the JOA.

If a trust fund is provided for, the trust document is often contained in an annex to the abandonment agreement. Normal trust law considerations will apply. The purpose of the trust will need to be defined for example "to pay for the costs of abandonment of Field X". There will need to be a trustee (which can be a trust corporation). There should also be provisions concerning the permitted types of investments for funds paid into the trust fund.

Some abandonment agreements do not go into the complexities of a trust fund. They merely stipulate that the security for abandonment costs will be a guarantee or an irrevocable standby letter of credit of the appropriate credit rating. Any default in providing such security would then be dealt with under the standard JOA default provisions.

By way of illustration only there follow some sample clause headings for abandonment agreements. Two examples are given. The first deals with a trust fund option, the second deals with a simpler agreement (standby letter of credit only). Clearly any working document would require substantial revision to meet the particular circumstances of the field and its participants.

Sample Clauses 1: Abandonment Agreement with Trigger Provisions and an Annexed Trust Fund Option

"Definitions"

Definitions will usually be required of, among other things, the following: "Abandonment", "Acceptable Securities", "Net Cost" and "Net Value", "Qualifying Surety" and "Trust Fund".

"Object"

To provide for the costs of abandonment.

"Determination of Abandonment Estimates"

Typically this will provide that the operator estimates, for example, the date of commencement of abandonment, the net cost (the estimate of abandonment costs), the net value (the discounted value of future revenues) and the run-

down period (that is the date when the trigger point has been reached). There will need to be provision for expert determination of any disputes.

"Trust Fund"

This will state that within an agreed period prior to the run-down period, the parties will each establish a trust fund (usually in accordance with an annexed pro forma) to meet its share of abandonment. This share could be calculated as follows:

$$A = B - \frac{C}{1.5} - D$$

Where: A = the party's share of the portion of the net cost allocated for the following year (*i.e.* the amount it actually needs to make available);

B = the party's share of the net cost calculated as at the end of the following year;

C = the party's share of the net value calculated as at the end of the following year; and,

D = the amount already in the party's trust fund less any expected cash calls during the next year, plus interest on the balance, net of tax.

The figure 1.5 (in the above formula) could read 1.35 or any other figure depending on the agreed "trigger". In the above formula you have an agreed "trigger" ratio of two-thirds of net value to net cost.

The above formula may be reduced to a cost per barrel for the next year such amount to be cash called monthly and to be paid into the relevant trust fund. If the operating committee determines that security is insufficient or that there will be a short-fall then further cash calls will be required.

"Alternative Security"

This will detail acceptable alternatives to the trust fund (with the trust fund to become effective if these alternatives are no longer appropriate or they become insufficient). If an alternative security is in place then this could constitute item "D" in the equation above. This clause will also deal with the formalities of various securities; for example, board approval should there be a parent company guarantee and/or lawyers' opinions of the competency of any company to give its guarantee.

"Default"

This will specify that in the event of non-payment of a cash call or a party's security becoming insufficient and not being remedied within a short period, then the operator can take steps to enforce any security.

"Payments"

This will regulate how cash calls should be made and where they should be made from. This may well be pursuant to agreed pro forma notices which will also be annexed to the abandonment agreement.

"Assignment and Withdrawal"

This will deal with the formalities where one of the parties to the facilities transfers or otherwise disposes of its interest. There may, for example, be a corresponding transfer of a share of any abandonment fund or an extinguishing of part or all of an exiting guarantee. This could lead to complex estimations of share of fund against share of liability involving the type of issues commonly encountered when valuing pension funds in corporate or asset disposals.

Appendices to the Abandonment Agreement

Could be as follows:

1. *Trust Deed*

This will commonly detail the purpose of the trust and state that monies will be paid to the trustee. There will be details on how monies are to be held and invested—"Acceptable Securities". There will also be standard trust law provisions—for example, that the trustee can charge fees, take professional advice, exercise its absolute discretion and be indemnified for its liabilities and expenses.

2. *Bond*

A *pro forma* bond providing, for example, a maturity date and the issuer's liability amount. There may also be pro forma letters of demand in respect of the bond.

3. *Letter of Credit*

There may be alternatives given depending on whether there is one bank or a syndicate of banks providing this. In the latter case, percentage obligations may be stipulated. In each case, the bank will agree to pay a (capped) amount if a demand notice is served (commonly in the form of an annexed pro forma).

Sample Clauses 2: "Simpler" Abandonment Agreement providing Standby Letter of Credit only as Security—No Trust Fund

The "simpler" form agreement would not require sample appendices.

"Definitions"

"Abandonment Costs", "Abandonment Plan"—to be revised from time to time as the Department of Trade and Industry or the law requires, "Defaulting Party"—(defined in accordance with the underlying JOA) "Joint Facilities", "Security"—an irrevocable standby letter of credit: to be issued by a "qualifying" bank to the "Security Holder" (usually the operator) and to be issued annually for a minimum one-year period.

"Introduction and Changes in Legislation"

Each party agrees to provide security for its share of abandonment costs paying regard to changes in law and taxation from time to time.

"Scope"

To provide for the abandonment costs of field X.

"Abandonment Plan"

This will provide that the operator will prepare an Abandonment Plan. This will be revised annually and deal, among other things, with a geological/reservoir review of the relevant Block(s), the formulation of an abandonment trigger date and updated Abandonment Costs. This plan shall be agreed by the operating committee.

"Abandonment Costs"

This will provide that the Abandonment Costs (and the costs of the Abandonment Plan) shall be borne by the parties according to their JOA Percentage Interests. This clause may stipulate the operator's estimate of Abandonment Costs (which the parties agree) shall be updated annually.

"Provision of Security"

Each party will provide Security for its share of Abandonment Costs on execution of the Agreement and no less than 14 days before each anniversary.

"Security Holder"

Will provide that the operator holds the securities (with the operator's security to be held by the party with the next largest Percentage Interest). Any default will entitle the Security Holder to call on the Security. Default could mean default in providing the Security or in paying an abandonment cash call. There will be provisions dealing with placing monies on deposit and accounting back to the defaulting party for any surplus monies remaining.

"Change in Rating"

This will provide for substitute Security if any bank issuing Security should fall below the stipulated rating.

"Default"

Any default (to the extent not satisfied by Security) shall be dealt with as would a JOA default.

"New Entrants/Further Development"

Merely a declaratory statement that the Agreement will be reviewed if the Licence Parties change of if the field life is extended.

Miscellaneous Clauses

"Assignment"

Not to be permitted save pursuant to the JOA.

"Operating Committee Decisions"

To be pursuant to the JOA "pass mark".

"Conflict"

This Agreement to prevail over the JOA.

"Applicable Law"

Dealing with governing law and (possibly) submission to jurisdiction.