Investment Opportunities in the UK North Sea

• A guide to the mechanics of asset acquisition and divestment in the North Sea

• The promote licence and the fallow initiative – opportunities for new investment

• Employee rights in the transfer of interests

• A snapshot of the North Sea taxation regime

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INTRODUCTION
The North Sea is a mature and declining oil and gas province. With decreasing potential for exploration upside and falling rates of oil and gas production from existing fields the region may be less attractive for established producers to maintain their investments in light of diminishing returns. Consequently those producers could seek to dispose of certain assets in favour of realizing funds for higher risk and reward investment opportunities elsewhere.

For leaner, more aggressive players willing to undertake oil and gas production on tighter margins and to bring a greater focus on maximizing economic oil and gas recoveries the North Sea can however represent a very attractive investment opportunity. This correlation of interests creates an environment where existing oil and gas interests can change hands for the significant benefit of all parties involved. Recent and prospective North Sea assets sales by major companies such as BP, Shell, ExxonMobil, ConocoPhillips, Amerada and Agip in favour of independents such as Paladin Resources, Apache, Tullow Oil, Perenco, Dana Petroleum and Venture Production are indicative of this trend.

In addition to acquiring depleting producing assets there is also an increasingly attractive case for investment into hitherto undeveloped small and marginal fields in light of recent changes to the North Sea regulatory regime. The fallow initiative is designed to encourage development activity on blocks and discoveries that have not been worked as actively as might have been expected and the new promote licence has facilitated the entry of smaller companies into the North Sea by deferring some of the more stringent financial and technical requirements in applying for a new licence.

New M&A opportunities, the fallow initiative and promote licenses are key tools in the attraction of smaller oil companies to the continued development of oil and gas interests in the North Sea. This publication discusses some of the issues that investors should consider when making commercial decisions on whether to enter or expand their operations in the North Sea and whilst it is not intended as a definitive guide it may serve as a useful reminder of certain important issues. As with all transactions, specialist legal advice should be sought at the outset of any deal.

Jones Day provides a full range of legal services to existing and prospective North Sea investors and their financiers, including advising on the acquisition and disposal of equity interests and on all matters relating to exploration, development and exploitation activities. Through our offices in Dallas and Houston Jones Day also has more than thirty years of experience in advising explorers and developers in the Gulf of Mexico, a region which ten years ago underwent a similar process of transition to that facing the North Sea today.
A GUIDE TO THE MECHANICS OF ASSET ACQUISITION AND DIVESTMENT IN THE NORTH SEA

The North Sea Regulatory Regime

Legislation

The legislative framework for oil and gas exploration and production activities in the North Sea is as originally established by the Petroleum (Production) Act 1934 for onshore activities, which was extended to the UK continental shelf by the Continental Shelf Act 1964 and ultimately consolidated by Part I of the Petroleum Act 1998.

The fundamental principle of this framework is that all proprietary rights in UK oil and gas are vested in the Crown and that approved commercial enterprises are specifically licensed by the Crown (acting through the Secretary of State for Trade and Industry – in turn represented at the administrative level by the Department of Trade and Industry (DTI)) to undertake oil and gas exploration and production activities.

Licences, Blocks and Fields

The North Sea licensing regime distinguishes between:

- exploration activities (surveys and drilling); and
- production activities (appraisal, development and production),

which may be undertaken in:

- landward areas (i.e. onshore, inland waters and marine areas down to the low water mark); and
- seaward areas (i.e. the remainder of the territorial sea).

Companies require a licence from the Crown in order to be authorized to conduct exploration and exploitation activities in the North Sea. A seaward petroleum exploration licence gives the licensee a non-exclusive authority to explore for oil and gas bearing areas by way of geological surveys and limited drilling rights in any seaward area not the subject of a seaward petroleum production licence.

A seaward petroleum production licence gives the licensee the exclusive authority to “search and bore for, and get,” oil and gas in the seabed and subsoil within the block or blocks covered by the licence. A block is an area within a grid system covering the North Sea and comprises about 200 to 250 square kilometers (80 to 100 square miles). The provisions of a production licence require the licensee to “surrender” part of the licensed area after an initial period and so over time many blocks have been divided and the surrendered areas may be re-licensed by the Crown as part-blocks.

A field is defined for the purposes of a licence as strata forming part of a single geological petroleum structure or petroleum field. A field may lie within one or more blocks across one or more licence areas, and so provision is made in the UK oil and gas regime for the unitized development of such fields.

The licensee holds the legal interest conveyed by its licence over the whole of the licence area. The licence makes no provision for a licensee to hold legal title over part of the licence area only. In order to effect a transfer of interests in a block or field forming only part of the licence area the transferor will usually agree to transfer its legal title under the licence to the transferee, with the parties entering into a trust deed for the transferee to hold that legal title on trust for the transferor in respect of any section of the licence area not forming part of the block or field being transferred.

Model Clauses

The operational detail of a licence lies within model clauses which are published from time to time by the UK government in the form of a Statutory Instrument and which are incorporated by reference into the licence, except that since the 20th offshore licensing round in 2002 the model clauses that apply to a particular licence have been set out in full in the licence itself.

A new set of model clauses will not retrospectively affect an existing licence except by special application. Consequently it is necessary to identify which set of model clauses will apply to a particular licence in order to fully determine the terms of that licence.

The latest model clauses for seaward area production licences were issued in 1988 under SI 1988/1213 and amended in 1992, 1995 and 1996 and now apply to licences granted pursuant to applications for licences lodged on or after 16 December 1996.
Considerations in Structuring Acquisitions and Divestments

As with the acquisition or divestment of assets of any nature, the transferring of North Sea assets may be undertaken by way of a direct acquisition of the assets in question or the acquisition of the issued shares of the company holding those assets and all other assets and historical liabilities (if any) that come with that company. Such a transfer will be subject to the usual weighing up of the relative advantages and disadvantages of the two sale processes. The UK regulatory regime does not require a corporate group to hold different licences through separate subsidiaries and consequently some companies have organized multiple but discrete North Sea operations through one operating company, rendering a share sale transaction impractical where not all of those operations are the target assets.

Pre-emption Arrangements

Most North Sea projects are structured as unincorporated joint ventures, and the applicable joint operating agreements (JOAs) will usually have in place some provisions restricting the parties’ freedom to transfer interests, typically through pre-emption rights.

The Master Deed is an agreement between the Secretary of State and companies active in the North Sea who have signed a deed of adherence to the Master Deed and was established in 2003 following concerns that pre-emption provisions in existing JOAs were restricting new entrants into the North Sea and inhibiting the realignment of licence interests. Although adherence to the Master Deed is optional, the vast majority of companies currently operating in the North Sea are party to it.

The Master Deed sets out new pre-emption arrangements to apply in respect of existing JOAs which contain pre-emption provisions. The new arrangements will not be imported into JOAs not already containing pre-emption provisions and will not replace the existing arrangements of those JOAs that do, but the new arrangements will take priority in the event of any inconsistency with existing pre-emption terms.

Under the new arrangements, upon entering into negotiations or making a bona fide decision to transfer an interest under a JOA a party may give notice of such intention to transfer to the other JOA parties, who will have 7 business days to reserve or waive their pre-emption rights. If any of the other JOA parties do not expressly waive their pre-emption rights within the 7 day period, or if the notice of intended transfer was not given, then the transferring party must give notice to those other JOA parties upon reaching an agreement to transfer its interests. The other JOA parties will then have 30 days to exercise their rights of pre-emption.

The new pre-emption arrangements in the Master Deed are part of a drive by the DTI to remove commercial and behavioural barriers to the development of the North Sea. As part of this drive, the Secretary of State has also announced that as of the 20th offshore licensing round in 2002 new JOAs are not permitted to contain pre-emption provisions unless the contracting parties can advance a compelling case as to why they are necessary. If the DTI gives its approval to the inclusion of pre-emption provisions, only the new pre-emption arrangements set out in the Master Deed may be incorporated into the JOA.

Investors in North Sea interests will be concerned by the risk of having their acquisition pre-empted by existing JOA parties, especially once they have invested substantial sums of money in conducting due diligence into those assets. For this reason acquisitions are sometimes structured as share sales so as to avoid triggering pre-emption provisions associated with asset transfers. However, most JOAs in the North Sea extend the application of pre-emption rights to a change of control. It is often necessary therefore to create more innovative acquisition structures so as to disapply pre-emption rights. The new pre-emption arrangements under the Master Deed, for example, will not apply to transfers of JOA interests in consideration for shares or other exchanges of interests not converted into money sums. Non-monetary consideration may also make it difficult for existing JOA parties to match a purchase offer and therefore be unable to be pre-empted, and packaging multiple interests together with the target assets may serve to dissuade existing JOA parties from exercising their rights.

If the parties to the proposed transfer cannot avoid the application of the pre-emption rights they may wish to, and certainly it would be in an investor’s best interest to, seek a binding waiver of pre-emption rights from the existing JOA parties. If such a waiver were forthcoming the investor could
proceed with the certainty that its expenses in furthering
the acquisition will not be incurred in vain, although if the
waivers do not materialize then the vendor may lose the
investor’s interest and find the existing JOA parties unwilling
to make a firm bid for the assets on their own.

If an early waiver of pre-emption rights is not
forthcoming then the sale and purchase agreement will need
to provide for the eventual waiver of pre-emption rights as a
condition precedent to the sale proceeding.

**DTI Consent – Licence Transfers**

Model clause 41 requires a transferring licensee to obtain
the Secretary of State’s consent (issued through the DTI)
for any transfer of a North Sea licence interest. This
restriction applies regardless of whether the transfer is to an
affiliated or unrelated company.

Where the transfer of a licence interest is made to a
company already undertaking operations in the North Sea
then DTI’s consent can usually be obtained within about 2
weeks. Applications will take longer to process if the transfer
is more complicated or the transferee is not already active
in the North Sea. In the latter instance the DTI will require
comprehensive information regarding the company’s
financial and technical capacity and track record outside of
the North Sea. Where the transferee is a subsidiary of a
foreign parent company the DTI will generally require an
undertaking from the parent to support the transferee in its
licence operations.

If the transferor is also the operator of the licensed area
then model clause 24(1) requires the transferor to obtain
the DTI’s consent to the new operator. The DTI will
investigate whether the proposed new operator is suitable
and competent to undertake the role of operator. Again,
these investigations will be more time consuming where the
proposed operator is not already active in the North Sea,
and will be more stringent where the transfer of production
operation is at issue.

The DTI’s consent to a transfer of a licence interest will
also be conditional on the deed of assignment being made
in a form approved by the Secretary of State. The DTI has
issued a simple form model deed which if used will fulfil this
requirement. While it is open to the parties to use a different
form of deed of assignment any such deed may increase the
time taken to obtain the DTI’s consent to the transfer of the
licence interest.

The parties to a proposed transfer will not circumvent
the DTI’s approval requirements by structuring the transfer
as a share sale rather than an asset sale. Model clause 42(3)
provides that the DTI may revoke a licence if there is a change
of control of a licensee and the licensee fails to comply with
a subsequent notice from the DTI requiring a further change
of control to take place. The definition of ‘control’ is by
reference to whether the relevant person exercises, is able
to exercise or is entitled to acquire direct or indirect control
over the company’s affairs. This definition covers the transfer
of voting rights in a licensee as would occur in a transfer by
way of a share sale.

The parties to the transfer of a licence interest by way of
a share sale will usually seek prior confirmation that the DTI
does not intend to require a subsequent change of control
of the licensee if the sale proceeds. The DTI will have the
same considerations as to technical and financial
Due Diligence

The nature and extent of the due diligence to be undertaken by an investor into the particular North Sea interests which are available for sale will depend on whether the deal is structured as an asset or share purchase. As with all acquisitions, due diligence should be an easier task in an asset sale as the only assets on which due diligence needs to be performed are those which are being transferred, and other assets and liabilities of the seller, which it is retaining, can be considered differently. In a share sale the target company will be transferred together with all of its assets and liabilities. Therefore a more comprehensive due diligence will need to be undertaken to identify all assets that are being acquired, so that unwanted assets can be stripped out prior to acquisition or the purchase price adjusted accordingly, and to quantify the historical and potential liabilities that come with the target company.

Due diligence into North Sea interests is a similar undertaking to the acquisition of assets in other licence-based regimes, and the due diligence checklist will be similar in most instances. The checklist will also differ in many key respects to an investigation into assets held in an oil and gas regime organized on the basis of production sharing concessions.

There are however several due diligence issues that are particular to the North Sea that a prospective new entrant should be aware of:

Restriction on the Number of Licensees

The DTI has a policy which restricts the number of licensees on a single licence to 10. An investor should satisfy itself that the proposed sale will not breach this policy, especially where the seller is disposing of only part of its interest.

Decommissioning

Decommissioning liabilities are of critical importance for existing and potential licensees, and this will be a particularly significant issue where the investment target is a mature interest approaching the end of its life.

The Secretary of State may at any time issue a notice to require the submission by a licensee of a costed decommissioning programme for offshore installations and submarine pipelines. The programme must include an...
estimate of the cost and time schedule for decommissioning and set out continued maintenance activities if the decommissioning does not include total removal of the relevant facilities. The Secretary of State will usually initiate the requirement for a decommissioning programme to be submitted once field approval has been granted. Once the decommissioning programme has been determined by the DTI (subject to any amendments the DTI may require) then the programme will remain in force until removed by the Secretary of State.

The obligation to carry out an approved decommissioning programme is joint and several among all of the licensees, and so as part of its due diligence an investor will want to ensure that the remaining licensees have complied with, and have sufficient financial capacity to fund their share of the costs to continue complying with, the programme.

It is usual for a company disposing of North Sea interests to request the Secretary of State to exercise its discretion and remove the notice requiring the submission of the programme against that licensee and, in most cases, the notice will be withdrawn. This will not completely relieve that party from the obligation to carry out the decommissioning programme. Liability for decommissioning activities and their costs may rest not only with existing licensees but also with former licensees and those former licensees may be called upon to carry out the programme. As the persons who own the infrastructure at the time of decommissioning will normally remain the owners of any residual structures, the ongoing liability for monitoring, maintenance and liability for damages could remain with all existing and previous licensees in perpetuity. The seller will therefore seek protection from the investor against future liabilities in connection with the decommissioning programme, usually by way of an indemnity.

In response to the increased disposition of interests in North Sea licenses from large to smaller companies the UK government has developed a policy to ensure that adequate security for decommissioning costs is available in certain circumstances. Where a party selling its interests requests the Secretary of State to exercise its discretion to remove a notice the DTI will consider whether the JOA group will be weakened to an unacceptable extent by the selling party’s departure and, if so, the Secretary of State may refuse to remove the notice until the remaining JOA parties have established a satisfactory financial security arrangement for decommissioning costs. The Secretary of State may also serve notices on parents and associated companies of licensees to provide security that the costs for decommissioning will be available when needed.

**Access to Infrastructure**

In reviewing field development programmes the DTI’s policy objectives include ensuring the open, adequate and competitive provision of access to platforms, pipelines and other facilities to all prospective participants. The DTI may therefore require construction of facilities with capacity in excess of the immediate needs of the fields which are the

**THE DTI’S POLICY OBJECTIVES INCLUDE ENSURING THE OPEN, ADEQUATE AND COMPETITIVE PROVISION OF ACCESS TO PLATFORMS, PIPELINES AND OTHER FACILITIES TO ALL PROSPECTIVE PARTICIPANTS.**
subject of the development programme in order to facilitate future third party use of platforms, pipelines and other facilities.

A buyer of North Sea interests should therefore investigate whether the facilities it is acquiring are the subject of third party access arrangements, whether the development of small fields nearby may suggest third party access through the facilities in the future, and whether the licensee itself has or may in the future require access through any third party facilities.

The buyer should also ascertain whether any negotiations for third party access to infrastructure have broken down and if a request has been made to the Secretary of State to determine the access arrangements.

**New Arrangements for Asset Transfers**

In addition to introducing new mandatory pre-emption arrangements the Master Deed also introduces a new streamlined process which parties may elect to follow when transferring interests in North Sea petroleum agreements. Petroleum agreements are widely defined to include licenses and all agreements and arrangements made under, pursuant to or in relation to any licence, and will therefore include agreements such as JOAs, transportation and processing agreements, allocation, attribution and commingling agreements and agreements governing decommissioning.

As the new arrangements relate to a participant to the Master Deed disposing of its interest in the relevant agreements the arrangements are only relevant where the acquisition is structured as an asset sale, for in a share sale the agreement interests will still be held by the same participant, albeit under a different ownership structure.

Put briefly, if the seller wishes to follow the new transfer arrangements it must give notice of the intended transfer to the other agreement participants together with a full draft of the execution documents, any applicable DTI consent or approval of the transfer and other documents and information prescribed by the Master Deed. If the remaining participants agree the wording of the execution documents and do not object to the use of the streamlined transfer arrangements (which objection must be reasonable) then the transferring parties may enter into the execution documents in the agreed form and submit them to an administrator set up under the Master Deed. The administrator will then execute the execution documents as attorney for the other agreement participants.

These new arrangements should enhance efficiency in North Sea asset transfers by avoiding the often timely exercise of obtaining signatures from all agreement participants even where the transfer and form of execution agreements have been approved.

If the seller elects not to use the new transfer arrangements, or if an existing participant to an agreement reasonably objects to their use, then the transfer will need to be effected by the usual procedures.

**Asset Management Prior to Completion**

Whether a transfer is structured as an asset or a share sale, if the purchase is conditional (e.g. on obtaining a waiver of pre-emption rights from existing JOA participants) the buyer of a North Sea interest will usually seek to protect the value of the assets for the period between signing the sale agreement and taking legal title to the assets on completion of the transfer. In this respect the usual considerations will apply in connection with North Sea acquisitions as to upstream acquisitions in other jurisdictions, and the buyer will usually require the vendor to continue the normal operation of the assets and not to enter into any material contracts or make any material decisions without prior consultation with the buyer.

Parties to a transfer of North Sea interests should be aware of the potential danger in agreeing another common covenant – that the buyer is entitled to some degree of control over the seller’s voting rights on operational committees during such interim period. Model clause 41 requires a licensee to obtain the DTI’s consent before any right granted by a licence or derived from a right granted by a licence may become exercisable by or for the benefit or in accordance with the directions of another person. If the buyer has control over the seller’s voting rights at operational committees prior to receiving DTI consent to the transfer then the seller may be in breach of this prohibition.
THE PROMOTE LICENCE AND THE FALLOW INITIATIVE — OPPORTUNITIES FOR NEW INVESTMENT

The promote licence and the fallow initiative are both designed to break down barriers impeding the continued development of the North Sea and the involvement of new participants in such developments. The two initiatives are aimed at different types of barriers: the promote licence targets financial and technical impediments and the fallow initiative is aimed at modifying certain behavioural norms.

The Promote Licence

The “Promotional Seaward Production Licence” (the promote licence) was offered for the first time as part of the 21st offshore licensing round in 2003.

Promote licences are designed to facilitate the involvement of smaller companies in North Sea activities. They may be granted to companies who, at the time of making an application for a licence, lack the organizational or financial resources to carry out the type of work usually required during the initial term of a traditional Seaward Production Licence.

The promote licence does not replace the traditional licence. Companies who from the commencement of the licence will have the necessary resources to commit to a significant work programme should still apply for a traditional licence.

The Application Process

In considering applications for a promote licence the DTI will consider:

• the technical and innovative capability of the applicant to establish a viable drilling prospect within 2 years of the grant of the licence;

• the applicant’s approach to securing additional technical and financial resources to complete the substantive work programme in the third and fourth years of the licence; and

• the applicant’s previous history of operations (if any) in the North Sea.

These criteria will be judged against the background of ensuring expeditious, thorough, efficient and safe exploration with due regard to environmental considerations.

The application for a promote licence must be supported by a proposed work programme. The early stages of the work programme will be aimed at evaluating and “working up” the licence area acreage into a prospect, which will not usually include seismic or drilling activity. Accordingly such application does not need to satisfy the DTI of the applicant’s technical and financial capacity to drill a well. If the licensee wishes to undertake seismic, drilling or other substantive operations then it will still need to meet the DTI’s full competence criteria before it can obtain consent for such work.

Following submission of the application the applicant will need to demonstrate to the DTI the technical rationale for the application and the applicant’s plans to secure the additional resources to undertake the more substantive work programme in the latter phase of the initial term. The application will not need to address the financial and environmental information required by applicants for traditional licences.

Term of the Promote Licence

As with traditional licences to be granted under the 21st licensing round, a promote licence will have an initial term of 4 years with an option to extend for an additional term of 4 years and a third term of 18 years.

The less onerous work commitments to be undertaken during the first 2 years of the initial 4 year period of a promote licence enables the licensee to assess the prospectivity of the licence area and promote it to potential investors.

Continuing Beyond the Initial Period

In order to progress beyond the first 2 years of the licence the licensee must commit to drilling at least one well, or to an equivalent substantive activity, during the third and fourth years of the licence and support such commitment with evidence of the financial resources and technical and environmental expertise to carry out such work.

In assessing this the DTI will apply the more stringent financial, technical and environmental criteria that are applied to applications for traditional licences. Promote licences therefore defer for up to 2 years the need to provide the scope of information and evidence that the DTI requires
for an application for a traditional licence rather than avoiding the requirement altogether.

If the promote licence continues beyond the initial 2 year period then the licensee will essentially be subject to the same conditions as under a traditional licence.

Expiry or Termination of the Promote Licence
If no application is made for an extension of the promote licence beyond the 2 years, or if the DTI does not approve such an application, the promote licence will automatically terminate on the expiration of the initial 2 year period. The licensee may also request the termination of the promote licence at any point during the initial 2 year period on the basis that there is little or no prospectivity in the licence area. This compares favourably with the position under the traditional licence where the licensee may terminate all or part of the licence only by giving not less than 6 months notice to expire on an anniversary of the date of commencement of the licence.

Reduction in Licence Fees
An additional financial incentive for promote licences is that the licence fee is reduced for the initial 2 year period. The licence fee for the initial 2 years will be £15 for each square kilometer of licence area before increasing for the third and fourth years to the £150 per square kilometer payable each year for the initial term of a traditional licence.

The Future of Promote Licences
Promote licences were first offered as part of the 21st offshore licensing round, and applications for such licenses having closed on 8 May 2003. As no promote licences have yet been awarded and implemented, there is as yet no experience on how a licensee will progress in practice under such a licence.
**The Fallow Initiative**

The fallow initiative aims to regenerate activity in licence areas which have lain dormant for some time by encouraging existing licensees to undertake new activity or to transfer interests where a different alignment of interests may be more amenable to developing a licence area.

**Fallow Blocks**

A block within a licence area will be considered fallow if the initial term has expired and there has been no drilling activity for 4 years or dedicated seismic or other significant activity on the block for 2 years.

The DTI divides fallow blocks into two classes: class A blocks are those where technical barriers prevent the development of the block, and class B blocks have commercial barriers preventing the development of the block.

In the case of a class A block the DTI may encourage research and development to be undertaken to attempt to overcome the technical barrier. Class A blocks will be reviewed by the DTI after 2 years.

In respect of class B blocks the process is as follows:

- the DTI will request the licensee to report on whether it is feasible to undertake activity to remove the block from the fallow definition;
- after 3 months the DTI will invite those licensees who do not see a feasible way to undertake such activity to either relinquish that part of the licence containing the block or to transfer their interests to those licensees who do see such activity as feasible;
- if the block is not relinquished by all of the licensees (in which event it may be offered for re-licensing) and activity has not commenced then information regarding the block will be placed on the Licence Information for Trading (LIFT) website;
- the block will remain on LIFT for 9 months, during which time the existing licensees must use reasonable endeavours to agree on activity to remove the block from the fallow definition and have complete freedom to agree the commercial terms for a transfer of interests;
- after the 9 months have expired those licensees who do not have a firm strategy for the development of the block must transfer their interests to a licensee which does have such a strategy and which requests the transfer; and
- if after a further period of 3 months the block is not removed from the fallow definition then that part of the licence containing the block must be relinquished and will be offered for re-licensing by DTI.

**Fallow Discoveries**

The definition of fallow discoveries applies the same criteria as for fallow blocks, and the treatment of class A fallow discoveries are the same as for class A fallow blocks.

In respect of class B fallow discoveries the procedure is essentially the same as for class B fallow blocks, except that data on the fallow discovery will remain on LIFT for 18 months and, once a firm strategy for development of the discovery has been identified by the continuing licensees and any new third parties, there will be a further period of 6 months within which activity on that development must commenced before the DTI will require the discovery to be relinquished and re-licensed.

**Opportunities**

The first blocks in the fallow initiative were released on September 24, 2002. The second phase saw 40 fallow blocks and 37 fallow discoveries added to LIFT in February 2003 and the process is expected to be updated quarterly.

The fallow initiative has allowed smaller companies – both existing players and new entrants to the North Sea – access to assets which were held by, but did not fit within the investment criteria for, larger companies. For example, it has been reported that through the fallow initiative Challenger Minerals and Palace Exploration acquired the Heather field and are developing the field towards first oil in 2004.
EMPLOYEE RIGHTS IN THE TRANSFER OF INTERESTS

Most investors will be familiar with the imposition by host countries of regulations protecting employees in the event of the transfer of a business undertaking. Oil companies operating in jurisdictions as geographically and juridically diverse as the US and Indonesia have had to contend with such provisions.

Where an investor structures its acquisition of North Sea interests through an asset sale it will need to be aware of certain UK legislative provisions for the protection of employees associated with those interests contained in the Transfer of Undertakings (Protection of Employment) Regulations 1981 (TUPE).

The Application of TUPE

TUPE applies to the transfer of a business undertaking or part of a business undertaking from one organization to another where the undertaking is situated in the UK immediately before the transfer occurs.

Undertaking – there is no specific definition of an undertaking in TUPE. Decisions of competent courts and tribunals have determined that an undertaking may form the whole or part of a business as long as the undertaking constitutes a stable economic entity. UK employment tribunals may consider a wide range of factors when determining whether an undertaking has been transferred, such as whether assets or staff were transferred and whether the undertaking, post-transfer, is carried on in a similar way as before and has retained its identity. The decisions of UK employment tribunals have not necessarily been consistent in each case and if in doubt an investor should proceed on the basis that TUPE will apply.

TUPE may apply not only to the transfer of an entire business as a going concern but also in theory to the outsourcing of part of a particular undertaking (such as catering or helicopter transportation services), taking an out-sourced function in-house and the retention of a new contractor in place of an existing contractor.

This can lead to situations which might appear strange to investors unaccustomed to UK and wider EU employment regulations, and care must be taken in structuring sale and purchase arrangements accordingly.

Situated in the UK – TUPE will only apply where the transferred undertaking is situated in the UK immediately before the transfer takes place, irrespective of where the undertaking may be situated following the transfer.

Although the UK has authority to carry out certain economic activities on its continental shelf, no part of the continental shelf forms part of the UK’s territory. TUPE therefore will not apply to undertakings situated in the North Sea beyond the UK’s 12-mile territorial limit. This was the reasoning in a 1996 Industrial Tribunal decision which held that workers on mobile accommodation vessels in the North Sea were employed in an undertaking outside of the UK and therefore beyond the protection of TUPE. However, the mere fact that employees are assigned to work in the North Sea does not necessarily mean that the undertaking itself is situated outside of the UK, and this will need to be reviewed on a case-by-case basis.

Even though TUPE does not apply to undertakings situated in the North Sea, other employment-related UK legislation has been given extra-territorial effect in order that it may apply to employees working on the UK continental shelf, such as the Employment Rights Act.

Investors acquiring a North Sea undertaking should adopt a cautious approach as to whether TUPE applies to operations which prima facie appear to be located outside of the UK and should also be aware of the range of rights and obligations an employer of offshore workers has under UK legislation.

The Effects of TUPE

TUPE allows very little flexibility to the way an investor may vary the treatment of the existing employees of an undertaking which that investor has acquired.

The main provisions of TUPE are as follows:

- employees who are employed as part of the undertaking at the time such undertaking changes hands automatically become employees of the transferee on the same terms and conditions (except for certain occupational pension rights). The existing contracts of employment therefore continue with the transferee with no break, as if they were originally made with the transferee;
• the transferee inherits all rights and obligations arising out of the existing contracts of employment, other than criminal liabilities and rights and obligations relating to benefits for old age, invalidity or survivors in employee occupational pension schemes;
• the transferor and transferee must comply with statutory provisions requiring them to inform and consult with employee representatives over the transfer of the undertaking. The transferee should take steps to confirm the transferor has complied with its consulting obligations as a decision of the Employment Appeal Tribunal in March 2003 confirmed that liability for a failure by the transferor to collectively consult with its employees on the proposed transfer will pass at law to the transferee. The potential liability for a failure to comply with the consultation obligations are up to 13 weeks’ pay for each affected employee;
• the transferee takes over any collective agreements made on behalf of the employees which are in force immediately before the transfer;
• the transferee may not fundamentally amend the terms and conditions of employment to the detriment of the transferred employees (even with the employees’ consent) as a result of the transfer. An employee who has suffered a worsening of his or her terms and conditions of employment as a result of the transfer may have the right to terminate his or her contract and claim unfair dismissal (on the grounds that the actions of the new employer forced him or her to resign) if the worsening constitutes a fundamental breach of contract. In other words, the transferee may vary the terms and conditions of employment in the same manner that the transferor could have, as long as such variation does not fundamentally breach the employment contract; and
• existing employees may only be fairly dismissed in connection with the transfer on economic, technical or organizational grounds entailing changes in the workforce, and such employees may in any event be entitled to redundancy payments.

TUPE is designed to safeguard and continue the existing employment rights and obligations for the benefit of employees. However, once the existing rights validly end (for example on expiration of a fixed-term employment contract) then the transferee may be free to re-engage the relevant employee on different terms under a new employment contract.

Coping with the Effects of TUPE

The intention of TUPE is that it should apply to all relevant transfers and should not be avoided. Accordingly, any provision of any agreement (whether a contract of employment or otherwise) will be void to the extent that it would exclude or limit the rights granted under TUPE.

If the transfer of an undertaking is ostensibly governed by TUPE there are only a few options the investor may have to accommodate the effects of TUPE:

Pre-transfer Arrangements
• an employee may object to the transfer of his or her employment contract, in which case the contract of
employment will be terminated without entitlement to compensation (unless the employee can claim constructive unfair dismissal);

• employees are free to elect to remain under the employment of the transferor, in which case TUPE will not apply; and

• the transferor could effect a pre-transfer reorganization of staff to move employees out of the undertaking to a different area of the transferor’s business, although this would need to be done with caution.

Arrangements at the Time of Transfer

• the parties to the transfer may calculate and apportion the cost of the employment-related liabilities and adjust the purchase price accordingly; and

• each party will usually seek indemnities from the other against liabilities which the other party has been allocated responsibility for.

Post-transfer Arrangements

• the transferee may fairly make transfer-related dismissals where they are made for economic, technical or organizational reasons, and in compliance with the usual fairness requirements under the Employment Rights Act, although the dismissed employees may be entitled to redundancy payments;

• harmonisation of the terms and conditions of employment across the transferee’s combined workforce is not an exception to TUPE. Where the transferred employees have lower benefits than pre-existing employees the transferee may be required to improve the terms and conditions of the new employees to avoid potential discrimination claims. Where the transferred employees have greater benefits than pre-existing employees, either the rights of the pre-existing employees will need to be improved or, over time, the terms and conditions enjoyed by the transferred employees could be reduced to those held by the existing workforce, although this must be done carefully and in a manner which is compatible with TUPE requirements; and

• some time after the transfer is completed the transferee may make decisions based on standard employment law principles as to the dismissal of, and renegotiation of contracts with, employees. It is important to note that there is no time limit on the application of TUPE and, although the chain of causation for dismissals connected with TUPE weakens over time, the termination of an employment contract may still be found to be transfer-related even if it occurs years after the transfer takes place.

It is of course open to the parties to structure the transaction as a share sale, in which case TUPE shall not apply as the same corporate entity will be employing the employees. However, the transferee will still need to secure protection from the transferor against accrued liabilities it will take on as part of the undertaking and should consider seeking warranties that the transferor has complied with any information and consultation objections and that there is no matter which has or is likely to give rise to an obligation to inform and consult. A share sale structure will allow the transferee greater flexibility in dealing with employees post-transfer, although subject always to the fairness obligations under non-TUPE employment-related legislation.

The Reform of TUPE

In February 2003 the UK government announced plans to undertake a public consultation process on a draft revised form of TUPE with the aim of having a revised TUPE regime in effect in the first half of 2004.

The revisions follow a public consultation process undertaken in 2001 to improve the operation of TUPE following 20 years’ of practice. The proposed revisions are:

• to apply TUPE more comprehensively to service contracting operations involving labour-intensive services (as compared to high-level ‘professional services’) such as catering and security;

• to impose on the transferor an obligation to provide information to the transferee on the employment liabilities that will be transferred;

• to clarify the circumstances in which employers can lawfully make transfer-related dismissals and negotiate transfer-related changes to terms and conditions of employment for economic, technical or organizational reasons; and

• to improve the manner in which TUPE applies in the transfer of insolvent undertakings, to minimize the number of businesses and jobs lost.
A SNAPSHOT OF THE NORTH SEA TAXATION REGIME

The Petroleum Act 1998 consolidates the position established by the Petroleum (Production) Act 1934 that the right to explore for and exploit oil and gas vests exclusively in the Crown. The Secretary of State for Trade and Industry may grant licences to persons for such consideration as the Secretary of State may determine in order to undertake such exploration and exploitation. That consideration has traditionally been based on the payment of royalty by licensees and on the taxation of their profits.

The Current Tax Position

Over the course of 2002 and 2003 the taxation regime applicable to North Sea operations has undergone significant changes:

Corporation tax – this is levied on profits made by licensees from North Sea operations, currently at the rate of 30 per cent. Oil and gas extraction activities are ringfenced from all other trading activities so that trading losses, capital losses on the disposal of business assets and interest payments for financing arising in any other activity cannot be used to offset oil and gas trading profits and capital gains.

A supplementary charge has also applied since 17 April 2002, whereby licensees must pay a charge equal to 10 per cent. of profits on oil and gas produced from a licence area. The supplementary charge is calculated in the same manner as corporation tax, except that the licensee cannot offset financing costs against the supplementary charge.

The UK government is currently in consultation regarding further possible corporation tax reforms.

Petroleum Revenue Tax (PRT) – this is a field-based tax that is currently charged at 50 per cent. of “super-profits” from the disposal of oil and gas, tariff income and consideration received from the disposal of certain assets.

PRT is not charged on fields given development consent on or after 16 March 1993.

The 2003 Budget extends that relief with effect from 1 January 2004 so that PRT will not apply to third party tariffing businesses under contracts entered into on or after 9 April 2003 for transportation, processing and other services in relation to certain oil and gas fields. Apart from decreasing the tax burden of the owners and operators of such businesses this relief will also benefit third party licensees accessing such infrastructure, since the abolition of PRT should be reflected in lower tariffs.

Where an interest in a licence area is transferred then the buyer will, generally speaking, inherit the seller’s PRT position in respect of fields within that licence area, including unused expenditure relief, allowable losses and cumulative capital expenditure unless the parties to the transfer jointly elect for these inheritance provisions to not apply.

Capital allowances were accelerated with effect from 17 April 2002. Capital expenditure which previously qualified for a 25 per cent write down under the plant and machinery and mineral extraction allowance codes are now entitled to a 100 per cent. write down in the first year. Long-life assets, which previously attracted a 6 per cent. write down, are now eligible for a 24 per cent. first year write down before reverting to a 6 per cent. annual write down. These write down allowances are deductible against general corporation tax and the supplementary charge.

The Abolition of Royalty

Royalty was previously payable by licensees, typically at the rate of 12.5 per cent. of the gross value of oil and gas “won and saved” from a licence area, less an allowance for certain transportation, processing and storage costs. In 1983 royalty obligations were abolished for all fields given development consent on or after 1 April 1982. With effect from 1 January 2003 royalty obligations were also abolished in respect of fields given development consent prior to 1 April 1982, so that royalty is no longer applicable to North Sea operations.

Stamp Duty on Transfers

Asset sales – stamp duty is charged ad valorem on conveyances and other documents which transfer property by sale in the UK and this principle applies equally to the transfer of North Sea asset interests.

The current rates of stamp duty increase incrementally by reference to the consideration value of the transaction, with the maximum rate being 4 per cent. for consideration over £500,000.

Share sales – if a divestment is structured as a share sale then stamp duty will be payable on the transfer of shares in the target company at the rate of 0.5 per cent. of the consideration paid.
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<tr>
<td>Peter Roberts</td>
<td>Emad Khalil</td>
<td>Wesley Johnson, Jr.</td>
<td>Juan Tena</td>
</tr>
<tr>
<td>31st Floor, Edinburgh Tower</td>
<td>29-01 Prudential Tower</td>
<td>120, rue du Faubourg Saint-Honoré</td>
<td>Velázquez 51, 4th Floor</td>
</tr>
<tr>
<td>The Landmark</td>
<td>30 Cecil Street</td>
<td>75008 Paris</td>
<td>28001 Madrid</td>
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<tr>
<td>15 Queen's Road Central</td>
<td>Singapore</td>
<td>France</td>
<td>Spain</td>
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<tr>
<td>Hong Kong</td>
<td>Tel.: 65.6233.5080</td>
<td>Tel.: 33.1.56.59.39.42</td>
<td>Tel.: 34.91.520.39.42</td>
</tr>
<tr>
<td>Tel.: 852.3189.7286</td>
<td>Fax: 65.6536.3939</td>
<td>Fax: 33.1.56.59.39.38</td>
<td>Fax: 34.91.520.39.38</td>
</tr>
<tr>
<td><a href="mailto:Peterroberts@jonesday.com">Peterroberts@jonesday.com</a></td>
<td><a href="mailto:ehkhalil@jonesday.com">ehkhalil@jonesday.com</a></td>
<td><a href="mailto:wrjohnsonjr@jonesday.com">wrjohnsonjr@jonesday.com</a></td>
<td><a href="mailto:jtena@jonesday.com">jtena@jonesday.com</a></td>
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<td>Jeffrey Schlegel</td>
<td>Bradford Keithley</td>
<td>Robert A. Profusek</td>
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<tr>
<td>Chase Tower, Suite 6500</td>
<td>2727 North Harwood Street</td>
<td>222 East 41st Street</td>
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<td>600 Travis Street</td>
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<tr>
<td>United States of America</td>
<td>Tel.: 1.214.969.2920</td>
<td>Tel.: 1.212.326.3800</td>
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<tr>
<td>Tel.: 1.832.239.3728</td>
<td>Fax: 1.214.969.5100</td>
<td>Fax: 1.212.755.7306</td>
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<tr>
<td><a href="mailto:jaschlegel@jonesday.com">jaschlegel@jonesday.com</a></td>
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