CHAPTER 4

Unitisation and Redetermination—Sean Rush

INTRODUCTION

Nature ignores the boundaries within which rights are conferred by landowners or regulatory authorities to explore for and to extract petroleum. Indeed, it is often the case that a petroleum reservoir straddles two or more defined exploration areas (held under concessions), wherein the rights of exploration and extraction are accordingly held by multiple consortia. To ensure the orderly development and production from the shared reservoir the parties to the various consortia will often enter (whether voluntarily or as a regulatory requirement) into a unitisation and unit operating agreement (UUOA) or, into a separate unitisation agreement (UA) and unit operating agreement (UOA).[1] The UUOA provides for the joint development of a common reservoir by merging the ownership interests of the different consortia into an identified "unit", defined according to the proportion of how much of the common reservoir extends into the area of their respective concessions. It will contain detailed provisions whereby each unit party's share is "redetermined" periodically on the advice of an expert appointed by the parties. This process ensures that each unit party ultimately pays for and receives an equitable share of the shared petroleum resource. **4–01**

This chapter considers the nature of petroleum, the manner of the ownership of petroleum and the case for unitisation, the use of preliminary agreements, the key contractual terms used within a unitisation and unit operating agreement, the redetermination process, the management of UUOA disputes, alternatives to redetermination, and cross border development options. **4–02**

THE NATURE OF PETROLEUM

Petroleum is a "migratory" mineral—meaning that it moves through sub-surface conditions according to prevailing pressure systems applying to the strata in which it is found. That pressure is often released by natural occurrences, such as earthquakes, or where the rock formations between the petroleum and the surface have sufficient porosity and permeability that the petroleum simply migrates to **4–03**

[1] The reasons why a UUOA might be split into separate UA and UOAs are dealt with in detail at para.4.19 below. A model form UUOA was issued by the Association of International Petroleum Negotiators (AIPN) in 2005, available at *www.aipn.org* [Accessed 25 April 2016] (and currently undergoing revision).

the surface and evaporates into the atmosphere or seeps into the ocean or onto land. In either case, the petroleum moves to the point of least pressure until it either makes its way to the surface or until it can go no further and is trapped and sealed within a stratigraphic trap.

4–04 It is these traps that are of most interest to oil and gas exploration and production (E&P) companies. Once a trap has been identified the pressure within it is released by drilling a well, causing petroleum to flow towards it and ultimately to the surface. Once the petroleum is extracted it is processed and shared between the consortium which is made up of E&P companies that had the rights to extract it, usually according to their joint operating agreement (JOA)—see Ch.3.

4–05 The JOA is ill-equipped to address the competing ownership and development rights that arise where the stratigraphic trap—the reservoir—straddles multiple properties whose extraction rights are owned by different consortia, through different concession interests, and which are adjacent to the well. Each consortium has an equal right (and sometimes also an obligation) in law to access the common reservoir underlying the areas of its respective concession and yet if each consortium did so then the capital investment needed would be unnecessarily duplicated. Similarly it is often optimal to employ secondary recovery techniques, such as gas or water injection, into the bottom of the reservoir from wells located in an adjacent concession area in order to fully flush the reservoir so that production recovery can be maximised from the existing production wells. Furthermore, an uncoordinated approach to producing the common reservoir may irreparably damage it, thereby reducing the maximum economic recovery of the interest petroleum reserves. These challenges may be overcome by aligning all interested parties under one coordinating agreement, the UUOA, which would thereby enable the maximum economic recovery of reserves from the common reservoir in accordance with good oilfield practice.

THE OWNERSHIP OF PETROLEUM AND THE CASE FOR UNITISATION

4–06 Before examining the mechanics of the UUOA, it is worthwhile revisiting the principles of ownership that are relevant in petroleum exploration and production operations in order to understand the issues that unitisation attempts to solve:

(i) *Ad coelom*—under the doctrine of *ad coelom*, a landowner owns both the rights to the land's surface and everything above and below it as well. This includes any minerals beneath the surface of a parcel of land. In many countries however, such as the UK, the doctrine of *ad coelom* has been modified in respect of petroleum deposits so that the rights to petroleum existing beneath the surface are vested in and owned by the state and are not capable of being owned by a private landowner.

(ii) *The law of capture*—oil and gas are migratory minerals—they move underground depending on pressure changes—and they can be extracted from an adjacent parcel of land if a well relieves pressure and causes the natural and unprompted movement of petroleum towards it. In the US, ownership of such migratory minerals has followed the same rule applying to that of wild animals—the "law of capture" whereby a surface owner acquired property rights in an animal that strayed onto his land when it was reduced to his possession and "captured."[2] The law of capture has been said to apply to water rights[3] under English law and it has been argued that the rule must apply to petroleum underlying the United Kingdom Continental Shelf (UKCS) due to the nature of mineral ownership thereunder, as determined by international law.[4] However, whilst some doubt will remain over the application of the law of capture under English law, until the question is put fully to the English courts then it is sensible to structure commercial arrangements applicable to a field assuming that it does so apply.[5]

(iii) *Rights of extraction*—an owner of land may permit another to enter onto his property and remove the mineral resources. Such rights are known as "profits à prendre". The US continues to adhere to the principle of *ad coelom* and surface owners commonly lease their land to E & P companies and permit production activities in exchange for the payment of a royalty. In combination with the law of capture, this led to competitive drilling as one landowner tried to out-drill his neighbour and to deplete as much of the underlying resource as he could before his neighbour thought about doing the same. In most other countries the state is the owner of underground petroleum deposits in situ and may award exploration and production rights pursuant to some form of concession, typically a licensing or production sharing regime.[6] These areas are usually much larger than the parcels of land individual landowners might lease to E&P companies in the US and so the capacity for a single reservoir to straddle the boundary of multiple concessions is somewhat reduced.

Nevertheless, where a reservoir straddles multiple concessions then in the absence of an alternate legal construct the common law may apply the rule of capture.[7] As noted above, in the US this rule incentivised a landowner to drill as **4–07**

[2] The law of capture was first determined under US law in *Westmoreland & Cambria Natural Gas Co v De Witt*, 18 A. 724 (Pa. 1889). See also M.P.G Taylor, T.P. Winsor, S.M. Tyne, *Joint Operating Agreements*, 2nd edn (London: Longman, 1992), p.66 for a discussion on the application of the law of capture in the US and UK; Rick D. Chamberlain commentary on the law of capture in, *A New Dimension in the Rateable Taking of Natural Gas in Oklahoma: Enrolled House Bill* 1221, (1984) 20 Tulsa L.J. 77.

[3] See T. Daintith et al., *United Kingdom Oil and Gas Law*, edited by A. Hill, 3rd edn (London: Sweet & Maxwell, 2003), para.1–723.

[4] M. Hammerson, *Upstream Oil and Gas: Cases, Materials and Commentary* (London: Globe Business Publishing Ltd, 2011), paras 3.27–3.2.10.

[5] This suggestion is particularly applicable to long term gas sale "depletion" contracts which were prevalent in the UK until late 1990s. Is gas from a licence area subject to such a depletion contract if it migrated from outside the licence area but was nevertheless produced from it? This was a real issue for British Gas in the mid-1990s as the spot price for gas plummeted and it found itself bound to continue purchasing gas under depletion contracts at over three times the spot price.

[6] In this article the generic "concession" is used to describe the rights to extract and produce petroleum from an area whether it be a lease, licence or production sharing contract. The detail of these concession arrangements is considered in Ch.1.

[7] "Capture" is defined in *Jowitt's Dictionary of English Law*, 3rd edn (London: Sweet & Maxwell, 2010) as "a taking, a seizure. Capture is in some cases a mode of acquiring property. Thus, everyone

many wells on its land and to pump out as much oil and gas as fast as possible before his neighbours drained the common reservoir. This wasteful activity did not accord with good oilfield practice and led to the duplication of capital spend, poor reservoir management, no secondary recovery and ultimately less petroleum being extracted. The increased production also led to the over-supply of oil and gas in the region of operations, reducing the regional market price for oil and gas products, and accelerating the early abandonment of wells. In all, this wasteful activity, although incentivising the fast-track development of the early petroleum industry, ultimately led to sub-optimal developments and a reduction in total ultimate recovery from a field—with a consequential reduction in revenue to the landowner and to the state authorities.

4–08 To ameliorate the problem many oil producing states regulated the amount of space between each well leading to "pooling." Pooling differs from unitisation as owners who cannot meet the regulatory spacing threshold to drill a well can combine with others to do so. However, the "pool" is an aggregation of surface land and subsurface extraction rights and therefore not limited to one common reservoir meaning drilling may target multiple geologic structures.[8] Unitisation on the other hand applies strictly to one common reservoir. The UK, whose petroleum licence areas covered vast tracts of the North Sea, provided as a licence condition that drilling could not take place within 125m of the licence boundary, which incentivised adjacent owners to undertake commercial discussions where a reservoir may straddle the concession boundary. However, more often than not such discussions led to unitisation, because it constrained the extent of the aggregated area, leaving the potential for large undiscovered structures that could exist wholly within the unexplored areas of the licences, to the relevant concession holders and not the "pool". In addition, the UK Government may require unitisation where in the national interest to do so and it is now a standard power that most governments reserve for themselves should competitive production activity undermine the maximum economic recovery of reserves.[9]

4–09 It is perhaps worth noting at this point that in addition to the regulatory differences noted above, the practical differences between a unitised field onshore in, for example, Texas, and offshore on the UKCS, complicates any generic analysis of unitisation. This is because the differences in the commercial environment within which each field is situated, means that commercial structures that work in one area will not necessarily work well, or at all, or be

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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".

[8] "Pooling" has been defined as: "a pool or a pooled unit is the joining together or a combination of small tracts or portions of tracts for the purpose of having sufficient acreage to receive a well drilling permit under the relevant State spacing laws and regulations, and for the purpose of sharing production by interest owners in such a pooled unit" (Bruce M. Kramer & Patrick H. Martin, *The Law of Pooling and Unitization*, 3rd edn (Matthew Bender, 2006)).

[9] See Asmus et al., "Unitizing Oil and Gas Fields Around the World: A Comparative Analysis of National Laws and Private Contracts" (2006) 28 *Houston Journal of International Law* 3, 24–25 where the authors note that most countries in their study had legislation dealing with unitisation and compulsory unitisation where agreement between owners cannot be reached. The paper is available without charge at University of Houston Law Center's Public Law & Legal Theory Series On the Social Science Research Network web site at *http://papers.ssrn.com/sol3/papers.cfm?abstract_id=900645* [Accessed 25 April 2016] .

needed in the other. The key differences are in cost, schedule and the availability of production and evacuation facilities. Onshore wells are almost invariably cheaper, less technically complex and of shorter duration. Drilling an onshore well in a shallow gas reservoir may take a mere half day to drill with a land based rig that is easily trucked to and from the well site. The ease of logistics and comparatively small cost provides ample opportunity for individual E & P companies, who believe the common reservoir extends further into their tract (see 4–20 (xii) below), to fund their own drilling to prove up their claim (although, often times it is the reverse that happens). In fact, it has been observed that in North America unitisation, whether compulsory or voluntary, usually only takes place after the commencement of production and when secondary recovery methods need to be employed.[10] Conversely, drilling an offshore well is far more expensive and logistically challenging. A UKCS well programme may take a year or more to plan, over a month to drill, if suitable rigs are available, and at a cost (at least until recently) of up to US $500,000 a day. If there is a platform from which the well can be drilled its use will be limited in terms of bed space and well "slots" by which to accommodate a participant's desire to prove up its own tract (and this will be exacerbated where the interests of the unit operator (see below) are not served by the drilling of such a well). Secondary recovery techniques will form part of the early thinking for end of field life production and, with the potential for disaffected licence holders to appeal to the regulator, it is considered better to attempt to land an agreement. As such, the commercial dynamics of an onshore versus offshore unit development are very different and these significant differences must be kept in mind when the UUOA is being negotiated and the redetermination process is being fleshed out. For the purposes of this chapter, the analysis which it contains is primarily directed at an offshore conventional unit development, although many of the principles will apply to onshore developments, especially where the state owns the resource and awards one form of petroleum exploration and/or production concession or another to an E&P company.

The aspiration that is common to any type of unitisation is that by applying the **4–10**
principles of unitisation (and of any subsequent redetermination) the participating consortia will become commercially aligned by sharing risks and rewards equitably, thereby facilitating the optimal technical development and production of the petroleum resource. How well this aspiration is realised in practice will depend upon how well the UUOA is drafted, negotiated and applied in practice.

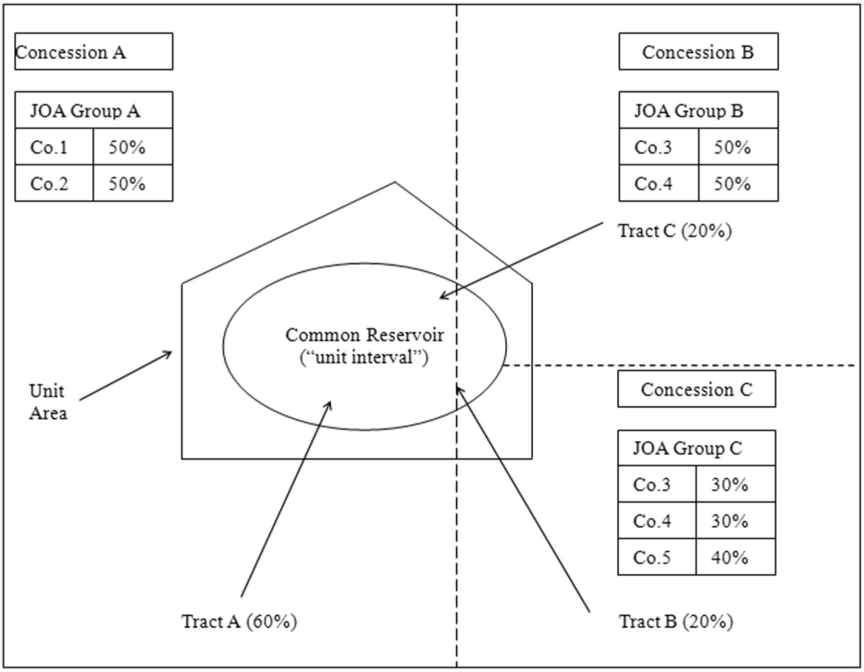
THE USE OF PRELIMINARY AGREEMENTS

In the simplest of terms, the UUOA is a form of JOA but whose application **4–11**
applies across two or more adjacent concession areas. The unitisation process involves the owners establishing the extent of the common reservoir (the "unit interval") and then ascribing a proportion of that unit to each of the underlying concession groups, thereby creating each concession group's "tract"[11] with the

[10] See Taylor et al., *Joint Operating Agreements* (1992).

[11] As defined in the AIPN model form UUOA and also see the Petroleum Joint Venture Association Model form Unit Agreement available in O'Brien's *Encyclopaedia of Forms*, Ch.42.

resultant proportion that the tract bears to the total common reservoir being the concession group's "tract participation".[12] The tract participation is then multiplied by each of the concession group owners' participating interests (as recorded in each underlying JOA) to give each owner's share in the tract. A unit owner's ownership interest in the unitised common reservoir (its "unit interest") is the aggregate of that owner's interests in the various tracts that make up the unit. It is each owner's unit interest share that defines its contribution to capital and operating costs as well as its share of the resultant production. Figure 1 illustrates the methodology for determining unit interests.



Company	Concession A	Concession B	Concession C	Total Unit Interest
Co. 1	50 x 60/100 = 30	-	-	30%
Co. 2	50 x 60/100 = 30	-	-	30%
Co. 3	-	50 x 20/100 = 10	30 x 20/100 = 6	16%
Co. 4	-	50 x 20/100 = 10	30 x 20/100 = 6	16%
Co. 5	-		40 x 20/100 = 8	8%

Figure 1: Calculation of Unit Interests

4–12 Once established, the unit interests are then typically fixed for a period of time but because the initial analysis which underpinned the unitisation will have been

[12] As defined in the AIPN model form UUOA and also see the Petroleum Joint Venture Association Model form Unit Agreement available in O'Brien's *Encyclopaedia of Forms*, Ch.42.

based on very limited data, it is common for the unit interests to be revised between the participating consortia using the redetermination process after a period of commercial production. The redetermination process is complex, requiring a multi-disciplinary team approach involving economists, geologists, geophysicists, reservoir engineers, petroleum engineers and lawyers. The change of even a one percent unit interest in a large field through the redetermination process can be worth tens and even hundreds of millions of dollars of petroleum production costs and revenues. Accordingly, it is important that the correct ground work to allocate ownership rights is put in place from the very beginning.

Before the question of unitisation can be contemplated, evidence must be acquired suggesting that a geological structure, with petroleum bearing potential, might straddle a concession boundary. In order to better understand the structure, the two or more concession groups will incrementally learn more about the structural extent and distribution of petroleum, if any, to establish if the structure is a common reservoir. The first step is for each group to disclose the data they each have collected relating to the possible joint structure and consider the potential for the presence of a common structure that might merit unitisation. Such data might include seismic or well data from analogue or offset (parametric) wells[13] that has been acquired by the individual consortium pursuant to its JOA. The exchange would normally be handled under a data exchange agreement that provides for mutual obligations of confidentiality. **4–13**

If the potential for a common structure is identified the next step is for the participating consortia to jointly acquire additional data under a joint cost sharing agreement or, if drilling a well, pursuant to a joint well agreement. Because these joint activities involve third parties and activities outside the concession area of at least one of the consortia, they will be outside the scope of the underlying JOAs—hence the need for an additional agreement, wherein special rules relating to decision making and ownership of acquired property will be incorporated, as well as administrative matters relating to cash calls and defaults. Often the completion of a joint well will be sufficient to satisfy any well commitment a consortium may owe to the government under its relevant concession and accordingly the opportunity to share costs and complete minimum work obligations with another consortium is often attractive. **4–14**

Where work completed under these preliminary agreements confirms a commercial discovery straddling a concession boundary then a pre-unitisation agreement (PUA) will often be negotiated. The scope of a PUA may vary from project to project depending on the alignment of the parties, the appraisal work needed and the range of options for field development. Older fields in the UK often relied upon an extensive and detailed document that was entered into in order to give the participants contractual certainty of their initial unit interests prior to the commencement of significant appraisal spending. **4–15**

The PUA will define the unit and provide for the preparation of a field development plan (FDP) that will set out how the parties propose to develop the reservoir and evacuate production from the unit to market. It will convene an operating committee with rules for decision making. In this regard it contains many provisions that are common to JOAs but at some point, usually prior to the **4–16**

[13] Offset (parametric) well data is derived from wells that may have targeted or drilled through the target geological formation but in an area that is distinct from the unit.

first point of petroleum production, will be superseded by the UUOA.[14] However, the PUA is usually targeted solely at what is needed to prepare and execute the FDP and accordingly the PUA is often silent on other exploration, production or decommissioning work programmes and budgets, offtake rights and the redetermination process. FDP execution and subsequent production is often therefore outside the scope of a PUA and must commence under the UUOA. As such the UUOA is structured so as to supersede the PUA so that any work commenced under the PUA can transition to the UUOA, which is fully equipped to deal with matters within the scope of the PUA and also the resultant development, production and subsequent decommissioning work programmes.

4–17 The key issues a PUA might address (at least on an initial basis, before being finalised in a UUOA) will include the following:

(i) *Appointment of the pre-unit operator*—the PUA will appoint a pre-unit operator to conduct the activities envisaged under the PUA. Although that operatorship is usually awarded to the operator who has the highest unit interest this may not always be the case if another operator is strong technically, in regards to the likely FDP requirements. The role of the operator (appointed principally under the PUA and then progressing to the UUOA) is similar to that under a JOA. Consequently, the party appointed as unit operator will have considerable influence with regard to the FDP, the best downstream gas or oil evacuation routes, where wells are to be drilled and other data collection processes that will be payable by the unit account. Additionally, under the UUOA the unit operator will be charged with the development of a reservoir simulation model[15] depicting the unit operator's view of the reservoir, including its shape, projected flow rates, porosity, permeability, oil/gas in place and the estimated distribution of both across the common reservoir. Tract participants who share their tract with the unit operator can therefore take comfort that the unit operator will seek to promote a FDP that proves up reserves in the unit operator's tract, provided it can be justified as complying with good oilfield practice. Conversely, owners who are not aligned with the unit operator need to take certain steps to protect their interests so that when a final assessment of unit interest is undertaken, they are able to present sufficient information to counter the unit operator's assertions of petroleum volumes and distribution across the common reservoir.

(ii) *Convening of pre-unit operating committee*—the PUA will convene a pre-unit operating committee to oversee the work of the pre-unit operator and also to convene sub-committees to advance the technical, legal and commercial negotiations needed in developing the FDP for submission to the regulator and advancing the UUOA draft to execution. The PUA may also document those matters that the parties have already agreed will be

[14] Often when the FDP (formerly known in the UK as the "Annex B") is approved. See W. English, "Unitisation and Unit Operating Agreements" in M. David (ed.), *Upstream Oil and Gas Agreements* (London: Sweet and Maxwell, 1996), p.102.

[15] Typically this will be a computer generated 3D dynamic simulation model that takes account of well and production data in "real" time in the sense that the model is constantly validated by the operator against daily production or well data which over time is known as a "history matched" model.

included in the UUOA such as voting passmarks, historic costs to be shared, the basis for redetermination and principles that might apply.

(iii) *The unit interval*—having discovered the common reservoir it will be necessary for the purposes of the FDP to define its extent. This is usually done on a three dimensional basis whereby areal latitude and longitude coordinates are bounded by specified depths, usually defined by reference to geological formations at the top and bottom of the strata in which the reservoir is contained. The resulting three-dimensional map is known as the "unit interval".

It is important that the unit interval represents the best view available on the existing data because petroleum that falls within it, or otherwise migrates to it, belongs to the unit participants as "unit substances" and are subject to the UUOA. If the unit interval is too small then petroleum that falls outside it may be extracted by the consortium that holds the rights within the relevant area, potentially draining the common reservoir. Conversely, if the unit interval is too large then it may capture petroleum that is not properly in pressure communication with the common reservoir and may therefore fall wholly within one concession and be for the relevant concession group's individual benefit.

(iv) *The unit area*—the unit area will be defined by reference to longitude and latitude coordinates. The unit area is the aggregate of the contiguous area of each concession group's concession within which unit operations targeting the unit interval may take place under the UUOA. It will include the unit interval with an additional buffer to accommodate an increase in the unit interval should it be warranted. Whilst it may be bounded by the bottom of the unit reservoir, it is not constrained by an upper level as unit operations will take place between the unit interval and the land or sea surface. Except for non-unit operations (see below at para.4–20) all activities undertaken within the unit area will be subject to the UUOA, whose governance processes will supersede the underlying JOAs.

(v) *Preparation of the field development plan*—the PUA will provide for the decision making mechanisms by which the party appointed to be the PUA operator will develop the FDP and will submit it to the host government for approval. In the UK guidance in regards to unitisation is given in the regulator's *Guidance on the Content of Offshore Oil and Gas Field Development Plan* which makes clear that the regulator expects any adjacent concession groups to have been consulted in regards to a field development proposed for a field extending into a neighbouring license and, ideally, for the FDP to be submitted in an agreed form.[16]

(vi) *Historic costs*—agreeing which historic costs were incurred by each concession group for the benefit of the common reservoir will feature prominently. Historic costs expended solely by one concession group but which are agreed should be shared will be the subject of a rebate to the consortia that funded them initially. The agreed costs to be shared may be repeated and supplemented in the UUOA.

[16] Paragraph 2.5.1, available at *https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/265842/FDP_guidance_notes_November_2013_web.pdf* [Accessed 8 June 2016].

THE UNITISATION AND UNIT OPERATING AGREEMENT – KEY CONTRACTUAL TERMS

4–18 A UUOA will contain terms that, not surprisingly, deal with: (i) "unitisation", i.e. the merging of ownership interests in the common reservoir, that are held under two or more concessions, into a single unit and a process for how those interests may be altered over time; and (ii) "operations" which deal with how the common reservoir will be developed and petroleum will be produced, including the governance applying to such operations. A publicly available UUOA based on the AIPN model form can be found on the SEC website.[17] Many of the operational aspects of a UUOA do not differ materially from those applying to a regular JOA and so will not be addressed in this chapter.

4–19 An initial issue of form will need to be resolved by the parties. Should the UUOA be separated into a UA and a UOA, as is the norm in the US and Canada, or should it be kept together as a UUOA, as is the practice in the North Sea? Splitting might be considered appropriate if the host government requires the unitisation of a reservoir to be approved by the regulator, sometimes by tabling in the local Parliament or equivalent. Two issues arise that splitting the UUOA is intended to address: (a) the time taken for a fulsome review and approval by the regulator is likely to be shortened if the document submitted for approval contains only the minimum required to comply with the legislation; and (b) in the event that a document is submitted to the regulator it may fall within the scope of Freedom of Information Act legislation enabling disclosure to the public and potentially revealing confidential aspects of the agreement to other competitor companies and regulators. This risk is particularly heightened where the document is tabled in Parliament. Similarly, the UUOA may be required by the rules of an applicable stock exchange to be disclosed for fund raising purposes. As such, it may be particularly desirable for a unit operator to preserve the confidentiality of the UOA aspects where thorny issues, such as full liability for its wilful misconduct, have been conceded and where publication of such could undermine a negotiating position elsewhere. Accordingly, if the full document is likely to be subject to public disclosure then paring it back to the minimum, through splitting the document into discrete parts, might be desirable.

4–20 The timing for completing the UUOA is a matter to be agreed. A host government may require, as a condition of approving the FDP, that the UUOA is in place in order to ensure commercial negotiations do not delay the technical execution of the FDP.[18] Many of the provisions agreed to in the PUA, including those summarised above, will feature in the UUOA although some terms may be given greater attention and will consequently be refined in the final form UUOA. Other common terms applying to unitisation are as follows:

(i) *Unitisation*—the key difference between the JOA and UUOA is the commitment by the differing consortia to pool their interests, as they apply to the common reservoir, and so to "unitise" their interests. A typical formulation of a "unitisation" clause reads as follows:

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[17] See *http://www.sec.gov/Archives/edgar/data/1509991/000104746911001716/a2201620zex-10_6.htm* [Accessed 25 April 2016].

[18] This is the practice in the UK.

> "all rights and interests of the Parties under the [concessions] are hereby unitised in accordance with the provisions of this Agreement insofar as such rights and interests pertain to the Unitised Interval and each of the Parties shall own all Unit Property and Unit Substances in proportion to its Unit Interest"[19]

This mutual commitment is the written embodiment of the aspiration to align all commercial interests in the common reservoir in order that development can be undertaken coherently with the intent of maximising the economic recoverability of petroleum. Once the unitisation takes effect the parties are (or ought to be) indifferent to the point where the production is extracted or where facilities might be located.

(ii) *Supremacy of* the *UUOA*—provision is usually made for the terms of the UUOA to take precedence over any JOA (or other agreement) that might otherwise apply to a part of the unit area. This is important so that it is clear that decision making and the conduct of operations is determined by the UUOA. The JOA, will continue to apply outside the unit area and to any work undertaken by one group within the unit area as a "non-unit" operation (see below para.4–20 (viii)).

Similarly the UUOA will supersede the PUA, and work that may have commenced under the PUA may transition to and be completed under the UUOA. It is often the case that the effective date of the UUOA is stated to be the date of the PUA (or when the first significant cash call was issued thereunder) so that the unit interests and cost shares under the UUOA apply retrospectively to work completed under the PUA.

(iii) *Tract participations and unit interests*—as illustrated in fig.1, the UUOA will allocate a proportion of the common reservoir (the unit interval) to each consortium as its tract participation. Each tract participation is then allocated amongst the members of each consortium according to its participating interest in each underlying JOA. The aggregate of each party's share in each tract will be that party's unit interest.

(iv) *Decision making*—like a JOA, a UUOA will provide for the establishment of an operating committee made up of representatives of the parties (the unit operating committee (UOC)) and will define the process by which decisions with regard to unit operation are to be made. Because operational decisions, such as where to locate a production well, might either advantage or disadvantage one concession group over another in a redetermination, voting passmarks often require at least one member from each concession group to vote affirmatively in addition to the usual passmark threshold required under the underlying JOAs.

(v) *Work programmes*—the PUA will provide for exploration and appraisal activity needed for the preparation of the FDP but implementing it may not be within its scope, necessitating the need for the UUOA to be concluded. Unlike a JOA, it would be unusual for a UUOA to include an exploration and appraisal programme as exploration is dealt with under the preliminary agreements with appraisal under the PUA. This is because once a discovery has been made and the unit interval delineated, there is no need for further exploration or appraisal as any production in pressure communication with

[19] Paraphrased from English, "Unitisation and Unit Operating Agreements" in David (ed.), *Upstream Oil and Gas Agreements* (1996), p.97.

petroleum in the unit interval will automatically be subject to the UUOA. Petroleum that is not in pressure communication is normally outside the scope of the UUOA. However, whilst separate reservoirs that are not in communication with the unit interval are likely to have a different distribution of petroleum than in the unit interval, the unit parties may wish to include a new reservoir in the unit in order to gain access to the facilities and a petroleum evacuation route. Strictly speaking, this would require an amendment to the UUOA because only substances within pressure communication of the unit interval are within its scope and "unitised."

As such, for example, where a UUOA does not provide for a "floor" for the unit area, so that the unit area includes all depths, then the parties to the unit will be able to conduct deeper exploration operations below the unit interval. However, if a resultant discovery is made whereby production is shared according to the extant unit interests then the agreement could more properly be classified as a "pooling" agreement although the distinction is less clear (and somewhat irrelevant) if the new volumes can be considered in a subsequent redetermination of the unit interests.

(vi) *Disposition of production*—another differentiator of the UUOA from the JOA is that the UUOA is negotiated in the context of a known discovery and a draft FDP, with identified oil and gas lifting and transportation options. Accordingly, the "agreement to agree" language in regards to gas "special arrangements" and oil lifting "principles" that are common to many JOA forms are replaced in a UUOA by detailed and specified arrangements that integrate the production rights with the offtake arrangements envisaged in the FDP. In addition, there is often a provision declaring that, regardless of which concession the production originated from, it shall be deemed to have been extracted from the recipient's concession area so that the fiscal terms applicable to the recipient's concession area will apply to production received.

(vii) *Sole risk*—sole risk is often omitted from UUOAs because the common reservoir includes all petroleum in pressure communication with the unit interval and is already the property of all the unit owners and should therefore be capable of being produced from the production wells envisaged in the FDP. Undiscovered or un-appraised reservoirs that are separate from the unit interval and that might be targeted under a sole risk operation are not usually included in a UUOA. Where sole risk is included it is more likely to be used by a unit party to prove up reserves in its part of the tract, through the drilling of a parametric well, and thereby increase its unit interest during a redetermination. If the well is successful then it may be "adopted" by the unit parties together who will pay for the well costs but usually without the uplift that is typical of the sole risk buy-back provisions under many JOAs.

(viii) *Non-unit operations*—non-unit operations are usually more extensively documented in the UUOA as opposed to a JOA for two reasons: (a) because the FDP will have been developed it is a more realistic possibility that, in the event of a new discovery in one of the concession areas, it will be most economic to tie the new well back to the unit facilities and produce through them. As such, it is common for more detailed arrangements setting out the terms of use of unit facilities for non-unit operations to be included, including the use of well slots and processing capacity; and (b) often a concession group will wish to undertake activities within the unit area that targets a formation other than the unit interval. In such a case, the unit operating committee will need to be informed and grant consent, which may be withheld if such non-unit operations interfere with planned unit operations. Often such operations are undertaken by the unit operator in order to ensure the unit operations are not compromised. Furthermore, should the non-unit operation involve drilling through the unit interval, an indemnity for damage to the unit interval is often required. Data recovered in regards to the unit interval will usually be contributed, on a no-charge basis, to the unit.

(ix) *Decommissioning*—most JOAs, historically, have left the thorny issue of decommissioning (and security therefor) until after a discovery has been made. However, with a UUOA, a discovery will often have been made before the process of unitisation gets underway so it is clear that production facilities will be constructed and will accordingly need to be decommissioned and removed. Due to the enormous costs involved in offshore decommissioning, the UK regulator has required UUOAs to contain detailed decommissioning security provisions to ensure that funds will be on hand to pay for decommissioning after production has ceased and this has become standard in UUOAs elsewhere.[20]

(x) *Default*—the consequences of a unit party's failure to pay cash calls are broadly the same under a UUOA as they are under a JOA. The key difference however is that the unit operator may initially seek immediate payment by way of cash call from the concession group in which the defaulting unit party participates. This cash call then triggers a similar call under the JOA, whereby the failure to pay then commences the process by which a defaulting party loses its vote, its entitlement and ultimately its participating interest, including its unit interest, under the JOA. In the event each member of the defaulting party's group also fails to pay the outstanding cash call then the process by which they lose their voting rights, rights to production and ultimately unit interest might also apply under the UUOA.

(xi) *Transfer*—any unit interest transfer by a unit party will necessitate the transfer of the underlying interest in the JOA, meaning that any criteria thereunder, such as the technical and financial capacity of the assignee, will need to be met to the satisfaction of the remaining JOA parties as well as the other unit parties. Similarly, although the use of pre-emption clauses are common in UUOAs, if pre-emption rights apply under the JOA then the members of the transferring party's concession group will normally be able to exercise such pre-emption rights in priority to the other parties to the UUOA.

(xii) *Redetermination*—the initial tract participations, and consequential unit interests, are commonly adjusted according to a redetermination procedure. This is a key part of the UUOA and is explained in detail below. However, one difference between the UK offshore model and the North American

[20] For example see art.12 of the AIPN model form UUOA.

onshore model will need to be considered. In the UK, redetermination is usually done on a concession group to concession group basis, with the respective JOA operators leading the analysis and submissions for their group as part of the joint operations under the JOA. Unit owners who are members of two or more concession groups will be conflicted out from participating in all but the concession group in which they hold the highest participating interest. Similar rules apply to operators under multiple JOAs whereby a "redetermination operator" will be appointed from the non-conflicted parties. This structure is desirable to ensure that the concession's geological interpretation, as approved under the underlying JOA, is considered and not an individual unit party's view that will have been constructed outside the scope of the JOA, without the approval or support of the relevant JOA operating committee and which is almost certain to be self-serving. Conversely, in North America it is standard for each unit party to have its own voice in the redetermination process and be able to present its individually created geological model, in competition to not only that of the unit operator but also to the operator under the underlying JOA to which it is a party. As discussed above, an onshore unitised field presents fewer logistical challenges and costs when compared to an offshore field, and so there is little reason why a party to an onshore unit would delegate the preparation of its redetermination case to an operator whose role will have diminished considerably given the smaller concession areas prevalent onshore. For North Sea fields it is much less practicable for a unit party to develop a geological model that can credibly compete with that of the unit operator's as well as that of the operator under the relevant JOA who will likely continue to analyse other exploration opportunities within areas subject to the JOA other than the unit interval. An expert is likely to lend more weight to a model developed by an operator pursuant to a JOA for the concession's area, including the unit interval, which is then approved for submission to the expert for and on behalf of the JOA parties.

REDETERMINATION

4–21 "Redetermination" is a process whereby the unit owners agree that at one or more dates certain[21] in the future they will agree to revisit the unit interests in the light of information received from new wells or production data and, where appropriate, will adjust the tract participations to reflect the proportion of the reservoir and associated petroleum that the new data now suggests underlies each tract. In the absence of agreement an "expert" will be appointed to determine the revised unit interests.

4–22 The basis of, and the methodology for, the calculation of petroleum volumes is a matter for agreement in the UUOA. A number of methods are available:

[21] Commonly set at a certain number of years after the commencement of production, or the drilling of the last well or after a certain percentage of estimated recoverable reserves have been produced.

(i) *Stock tank oil originally in place (STOOIP) or its gas corollary gas initially gas in place (GIIP)*—a STOOIP/GIIP approach requires a calculation of the volume of petroleum in the reservoir, as measured in a "stock tank", i.e. at surface atmospheric pressure, without correction to account for other variables such as recovery rates, quality or the timing of development costs. It is thought that most North Sea unitized fields utilise a STOOIP approach due to its simplicity and ability to calculate early field life.[22] STOOIP is simple but is unsuitable for more complicated reservoirs where the petroleum recovery factor per unit of volume of rock may vary across the reservoir.

(ii) *Moveable oil originally in place (MOOIP)*—MOOIP is STOOIP less the estimated oil left in the reservoir at abandonment. Its simplicity makes it attractive but it can only be calculated with certainty at end of field life and needs to accommodate the inaccuracies associated with estimating STOOIP.

(iii) *Economically recoverable reserves*—this requires assessing the maximum economically recoverable reserves, i.e. what will actually be produced over field life. This is attractive for more complex reservoirs with differing recovery rates but can be problematic because the recoverable reserves may change depending on petroleum prices due to their influence on the economics of secondary or tertiary recovery expenditure.

The timing and the mechanism for calling a redetermination is important. **4–23** Once the field is in production a reasonable database will have accumulated including well data, which gives the best information of the characteristics of the unit interval, and production data from which the unit operator can test its view of the subsurface by "history matching" its reservoir simulation model outputs against historic production data. The more unit well data available, the better the data set. As such the redetermination provisions will often require all wells envisaged in the FDP to have been drilled and be in production before a unit party may call for a redetermination of unit interests. Usually the final redetermination is called no later than when two thirds of the field's estimated recoverable reserves have been produced, but more often than not a redetermination will be called earlier.

The data set will be added to over time as more information is gathered from **4–24** unit operations and will be maintained by the unit operator as the "Common Database."[23] Some commentators consider that the Common Database is strictly for use in redeterminations but in practice the information is (or should be) used by the unit operator to produce the field in accordance with good oilfield practice. However, once a redetermination has been triggered the unit operator will then collate the Common Database for delivery to each unit party and the expert.

A typical redetermination process might proceed in accordance with the **4–25** following sequence:

[22] See Daintith et al., *United Kingdom Oil and Gas Law* (2003), p.1184, para.1–742 and also Taylor et al., *Joint Operating Agreements* (1992), p.67.

[23] As defined in the AIPN model form UUOA.

(i) One unit party calling for a redetermination in accordance with the time prescribed in the UUOA (usually after completion of the final well or after a period of commercial production) or when an agreed number of reserves have been produced).
(ii) Each unit party submitting its view (often known as their "Final Offer") of the revised unit interests, based on the Common Database, for consideration by a technical sub-committee convened by the unit operating committee and made up of representatives of the unit parties.
(iii) Consideration of the Final Offers by the unit operating committee and unanimous determination of the redetermined unit interests. Failing unanimity, the opportunity for any unit party to refer the redetermination to an expert for determination.
(iv) The selection of an expert and conclusion of the expert's contract to assess the technical merits of each Final Offer.
(v) The delivery of the Common Database by the unit operator to the expert and, if agreed, the presentation of the unit operator's reservoir simulation model.
(vi) A process by which the expert may meet with all the unit parties to discuss and agree preliminary issues and matters of process.
(vii) The delivery by each unit party (or each concession group) of a written submission and presentation thereof to the expert setting out the competing model and consequential unit interest allocation.
(viii) The delivery by each unit party of written rebuttal to the other unit parties' cases.
(ix) The delivery of a preliminary report from the expert setting out its initial findings as to tract participation and unit interests, duly supported by reference to technical analysis from the Common Database.
(x) The opportunity for any unit party to challenge the expert's preliminary findings based on manifest error or compliance with the expert's instructions.
(xi) The delivery of the final determination and implementation of the redetermined unit interests thereafter.

4–26 Three key aspects of the redetermination process as outlined are therefore: (i) the Common Database; (ii) the expert determination; and (iii) the implementation of the redetermined unit interests. These are considered further below:

(i) *The Common Database*—the scope of the Common Database is often a matter for extensive negotiation. The non-contentious data for inclusion is the data collected and charged to the unit account. This includes exploration and appraisal data that may have originally been collected under a JOA and contributed to the development of the unit under the PUA, along with data collected by the unit operator during the development and production phase. It is this data that is used by the unit operator to build its reservoir simulation model that models the subsurface characteristics of rock porosity, permeability, pressure, petroleum/water distribution across the common reservoir and ultimately is the key tool for forecasting production rates and estimating the ultimately recoverable reserves. The simulation model is likely to be the best available model dealing with the reservoir and is a fundamental tool for reservoir management during operations and for redetermination. In order for any unit owner to credibly persuade an expert that the unit operator's model is incorrect and that reserves that are not accounted for in the unit operator's model lie in its own tract, that unit owner will need to have a full and cohesive comprehension of the unit operator's model. As such, it will be important that the unit operator be required to produce the reservoir simulation model in a non-proprietary software format and in a timely manner, so that a unit owner is able to assess and challenge the model or to adapt it to meet its own purposes.

Including non-unit data is more contentious and usually resisted by the unit operator and those aligned with it. However, because the redetermination is based purely on what is in the Common Database it will be important for those unit owners that are not aligned with the unit operator to be able to contribute well or other data proving reserves in their tract that may not be otherwise included in the Common Database due to that data being obtained outside of unit operations. Unless good oilfield practice incentivises the unit operator otherwise, the unit operator itself is unlikely to pursue any operations that may have the effect of proving up reserves in a tract in which it has little or no interest and it would be difficult for it to justify doing so anyway if it conflicted with its own reservoir simulation model. Not only might such activity reduce the unit operator's unit interest but the unit operator would have to pay its unit interest share of the associated costs. As a result, it will be important that rights in the UUOA are included allowing the submission to the Common Database of data collected independently by a unit party or concession group under their JOA or by virtue of the sole risk provisions in the UUOA (as described above, para.4–20 (vii)).

That said, it will be important that rules constraining the submission of non–unit data are agreed so that that the Common Database is not populated with a huge amount of irrelevant data as a redetermination approaches. One mechanism is to limit the contribution of non-unit data to data that supports a model that has been previously presented, at least in outline, to the unit operating committee, but rejected. Limiting the Common Database to non-unit data that supports such an alternate model could be one constraint that provides a unit party with the tools it needs to mount a credible challenge to the unit operator's model without unfairly requiring the other unit parties to sift through an enormous amount of new and irrelevant data while preparing their own case or rebuttal.

Usually the UUOA provides for a "data cut-off" point after which no new data is added to the Common Database. This can present difficulties, especially where the redetermination process occurs over an extended period of time when new, and potentially significant, data is acquired (e.g. the unexpected watering out of a production well). To address the potential for an inequitable outcome, the parties may agree a later data cut-off date for data collected from unit operations that will be acquired in a predictable manner and readily digested.

(ii) *Expert determination*—if the unit operating committee is unable to agree to the redetermined unit interests recommended by the unit operator, the matter is [24] referred to a third party expert that is typically a reservoir management service company. The expert will usually be selected by the vote of the unit operating committee. The UUOA will incorporate the procedure to be followed by the expert. The procedures commonly used include the: (a) "shot gun" approach, where the expert receives submissions as to what the unit interests should be but delivers its own decision; (b) the "pendulum" (or "baseball" as it is known in the US) approach, where the expert must select one of the unit owners' suggested redetermination of unit interests; and (c) the "guided expert" approach,[25] where the expert sits with the technical team as an observer throughout the process and is then called upon to decide selected issues that cannot be agreed between the unit parties.[26]

To ensure that local arbitral legislation will not apply to the agreed process, it is important that the UUOA confirms that the expert is to have no judicial function. The resultant decision is then delivered to the unit owners as a final and binding decision (subject to fraud or manifest error). However, due to the significant values involved and complexities of the subject matter, challenges to an expert's decision have often resulted in lengthy and costly court actions.[27]

When drafting the expert redetermination procedure, considerable thought should be given to how long it may take. Whilst it may be attractive to provide for a lengthy period, such as a year or more, to ensure the expert has sufficient time to deliver a robust determination, once the battle lines are drawn operating decisions are considered in the context of how they may look in front of an expert and so it is often the case that decisions during a redetermination are difficult to achieve leading to stagnation of decision making and, potentially, to a loss of value. For example, a decision to approve the acquisition of new seismic data or to drill a further producing well in one area might be interpreted as tacit support for the prospectivity of that area and so is unlikely to be approved while the redetermination is ongoing. The flip side is for unit parties deferring such activity until after the redetermination in case the data proves up reserves in an area in which they hold limited equity. If decisions are compromised in this manner then it could compromise the maximum economic recovery of petroleum in accordance with good oilfield practice and the unit's ongoing viability. Either a shorter process should be adopted or the parties could have an unqualified statement included in the UUOA

[24] See Asmus et al., "Unitizing Oil and Gas Fields Around the World: A Comparative Analysis of National Laws and Private Contracts" (2006) 28 *Houston Journal of International Law* 3, 88.

[25] See Daintith et al., *United Kingdom Oil and Gas Law* (2003), p.1184, para.1–742,

[26] As used in the Nelson field's redetermination and described in *Shell v Enterprise* [1999] All E.R. (D) 561.

[27] For a discussion of the narrow range of how an expert's decision may be challenged under the common law see Freedman and Farrell, *Kendall on Expert Determination* (London: Sweet & Maxwell, 2014), p.14.

that decisions made by the unit operating committee cannot be used as evidence of support for one geological model over another in a redetermination.

(iii) *Implementation of the redetermined unit interest*—in addition to changing the allocation of costs and production on a go forward basis to align with the adjusted unit interests, the UUOA will provide a mechanism to reapportion historic capital costs and production that were allocated to one tract or other in accordance with the former unit interests. The methodology is a form of banking system with production and cost "credits" and "debits" being identified, although, until redetermination occurs the unit owners can never be sure how much debt they have accumulated or exactly when it must be settled. The key variables and mechanisms for such an adjustment are as follows:

- *Production*—historic production that was allocated to unit owners in accordance with the former unit interests is commonly adjusted by allocating a proportion of production from the unit owners whose unit interests have been reduced to the unit owners whose unit interests have been increased for a set period until the volumes that were wrongly allocated have been repaid or "made up". It will be important that any redetermination is held far enough away from estimated end of field life to ensure that there are sufficient volumes available for make up. No account is ordinarily taken of differentials in commodity prices which can lead to windfalls depending on the difference in value of the volumes when originally produced and the same volumes when produced and re-allocated as "make up".
- *Capital costs*—historic capital costs and pre-production operating expenses are typically adjusted by a lump sum cash transfer from one unit owner or tract group to another, with an interest component, but even this seemingly simple process may not be without difficulty. In one unusual case of redetermination involving the Balmoral field[28] on the UKCS the capital costs were so great and the associated make up worth so little, that the unit owners were understood to be litigating to have their unit interests reduced rather than increased, such was the failure of that field's performance.
- *Operating costs*—operating costs after production commencement associated with producing the volumes originally are not subject to reallocation on the basis that such costs will be self-adjusting by attaching to the equivalent make up volumes. This presupposes that operating costs on a per barrel basis remain the same throughout field life, which may not always be the case.
- *Alternates to "make up"*—an alternative approach is for the unit owners to agree that compensation for production, capital and operating costs wrongly allocated will be effected by a lump sum cash settlement whereby the constituent value of each element of production or cost, as and when it was incurred or produced, is assessed and reconciled with a resultant cash settlement. However, due to the potentially high volume of production that may be lifted

[28] See discussion by J. Ross, *Industry Practice in Equity Redeterminations*, TDM 2 (2004).

between determinations and its associated value, a very small percentage change in unit interests can result in the cash transfer of many tens or even hundreds of millions of dollars between unit owners. With the more recent volatility in oil prices, a redetermination that is prescribed to be made up in cash is open to all manner of wind-falls or inequities depending on what the oil price happens to be doing at the time of redetermination. Issues relating to the movement in foreign exchange rates and the tax treatment of a cash settlement will also complicate this method of compensation.

THE MANAGEMENT OF UNITISATION DISPUTES

4–27 The uncertainties associated with adopting redetermination mechanisms when signing the UUOA is at a time so far removed from the time for make up or cash settlement provides one reason why redeterminations have been so litigious. Whilst most organisations will respect the principle that each unit party should receive its fair entitlement of production, the timing for any make up and cash settlements can be inconvenient. In times where cash has more value in the bank and credit is difficult to come by, any transfer of significant sums is likely to be resisted. Similarly, organisations providing make up volumes will be reluctant to do so in a high petroleum price environment. To minimise potentially large swings in unit interests the UUOA can provide for unit resets in addition to several redeterminations. Unit resets are a "mini-redetermination" process by which the unit operator may reset the unit interests periodically after a streamlined process that does not involve an expert. A unit reset may be contested where manifest error is involved and they may also be overturned by an expert in a subsequent redetermination. The intention of the unit reset is to enable the unit operator to make a judgment call based on what it is seeing in the field with a view to estimating the most accurate apportionment of unit interests as possible, using the most recent production data. It is thought that with the possibility of a unit reset being over-turned for manifest error or by a subsequent expert, the commercial incentive for a unit operator to favour its own interests are minimised. The unit reset process thus seeks to adjust the unit interests according to real time data. This in turn should mean that adjustments arising from a subsequent redetermination are minimised, thereby reducing the risk that its implementation will be excessively burdensome for some unit parties and so reducing the likelihood of an extended legal challenge.

4–28 It is commonplace for agreed settlements of disagreements relating to redeterminations to be difficult to achieve as unit owners optimise the process in an attempt to ensure that cash settlements or production reallocations occur at a more convenient time. Disagreements that would normally form the subject of an amicable settlement become protracted and often litigious, as unit owners digest the redetermination's value proposition.

4–29 Fundamentally, redeterminations are a technical evaluation and so, in theory, should not involve lawyers. However, for the reasons set out above, it is common for lawyers to take on a role that is excessively disproportionate to the volume of legal material, which is actually put before an expert. There is much anecdotal evidence of experts arriving to hear technical submissions from a party, only to find lawyers on hand, transcribing the exchanges, cautioning their clients and even video-recording the proceedings. Such conduct can backfire as undue reliance on legal process may be viewed as a sure sign that the relevant party's technical case is weak.

Acting as counsel for a unit operator in a contentious redetermination requires a fine balancing act between attempting to ensure each unit party has a fair chance to produce its preferred model but keeping within the redetermination rules (that are often no more than guidelines), so that no unit party is unduly advantaged. A golden rule worth bearing in mind is that the process is meant to determine the best technical case and that, failing manifest error or the expert acting outside the terms of its agreed contractual authority to act, a court will be reluctant to overturn an expert's decision. As such, to the extent the unit operator or the expert is required to exercise a discretion during the course of the redetermination then the safest and most defensible approach will be the one that allows the expert to do its job to the greatest possible extent. **4–30**

A unit operator's aspiration should be to allow the expert to make its decision, for each unit party to have a fair opportunity to present its case and for each unit party to dutifully implement the outcome. To avoid as many debates over process as possible it is advisable to provide for the development of a prescriptive timetable, commencing with the date that a unit party refers the unit interests to redetermination, and thereafter going through all the steps and agreed timetable until the expert delivers its final decision. **4–31**

As noted above, with the values involved it is almost impossible for at least the risk of court proceedings to be avoided but at least a unit operator can minimise the number of potentially valid claims against it by acting impartially and in accordance with the procedure. The expert's conduct, on the other hand, is somewhat out of the unit operator's control and the English courts have, over the years, been kept busy because experts have acted outside the scope of their agreed remit. For example, in the leading English law case on this subject, the expert used a mapping software programme other than that prescribed in its expert contract, which lead to a material change in the unit interest apportionment. The consequent expert determination was accordingly overturned.[29] **4–32**

Nevertheless, some steps can be taken in drafting the expert redetermination procedure to minimise the possibility of an appeal to the courts later being made by a disgruntled unit party: **4–33**

(i) Provide that the decision of the expert will be final and not subject to appeal, than where fraud or manifest error are apparent.
(ii) Eliminate the misuse of the court process to defer implementation of the expert's decision by requiring the expert's decision to be implemented as soon as practicable after its delivery, regardless of whether a court process may, or has, commenced, albeit with the proviso that the implementation can be reversed if the court so orders.

[29] *Shell UK Ltd v Enterprise Oil Plc* [1999] All E.R. (D) 561.

(iii) Provide terms that facilitate inter-party settlement so that a unit party (or concession group) may either combine with another at any time or withdraw from the process, thereby narrowing the areas of dispute for consideration by the expert.
(iv) Give the expert a broad scope to set its own process and make its decision for its own reasons, within the agreed timetable. This should include empowering the expert to determine all technical matters even if doing so requires it to make a legal interpretation of the expert's contract. Alternatively, if the unit parties cannot agree to such, then provide for a short-form reference to an independent legal expert to resolve the issue.
(v) Provide an opportunity for the unit parties to review the preliminary decision and identify any manifest errors, but leave the expert to decide whether to incorporate any consequential amendments in the final decision.
(vi) Respect the golden rule—redetermination is a technical process whereby the unit parties have agreed that the best technical case should prevail. Adhere to a process that best facilitates this outcome.

ALTERNATIVES TO REDETERMINATION

4–34 The cost, distraction and (often) stagnation of decision making which is generated by the redetermination process has led to certain alternatives to be considered.[30] The unit reset option (considered at para.6–26 above) has already been considered as such an alternative.

4–35 It may be argued that a unitisation process is no different to any other acquisition process where a willing seller acquires a fixed interest in an appraised field for a fixed sum. In such a case there is usually no post-sale adjustment of consideration if the field should subsequently prove to be bigger or smaller. As such, the reserves risk in an appraised field are a common risk borne by E&P companies as part of their day-to-day business. Consequently, it is arguable that the unitisation of a field poses no more or less risk and so companies should be comfortable in agreeing to fix equities once and for all, regardless of the final output of the field. The drawback, of course, is that where further information comes to light that demonstrates that the initial unit interests were not accurately allocated then it would be inequitable to leave the unit interests unaltered.

4–36 Where a discovered reservoir extends into an adjacent concession area the regulator, as part of the FDP approval process, may want confirmation that the owners of such concession have been consulted and have agreed to the proposed development.[31] In the absence of a UUOA there are three main contractual options by which this requirement may be satisfied:

[30] The Prudhoe Bay redetermination was reported to cost between US $50 million and US $100 million. See Asmus et al., "Unitizing Oil and Gas Fields Around the World: A Comparative Analysis of National Laws and Private Contracts" (2006) 28 *Houston Journal of International Law* 3, 84.

[31] This is the case in the UK. See the UK's *Guidance on the Content of Offshore Oil and Gas Field Development Plans*, para.2.5.1 available at *https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/265842/FDP_guidance_notes_November_2013_web.pdf* [Accessed 25 April 2016].

(i) *Purchase*—often an extension into an adjacent concession is small and of minimal interest to the concession holders. Nevertheless, to preclude the possibility of a competitive development, the owners wishing to develop the common reservoir may offer to acquire the interest in the extension. The purchase can be structured along traditional lines where the area of the concession containing the extension is carved out and the extraction rights transferred or as a one off payment in exchange for a commitment that the parties having rights to the extension will not drill into the common reservoir and extract petroleum therefrom.

Purchasing is often secured where the extension is demonstrably small. A purchase price is more complicated to agree where the extension is larger and the range of possible reserves more uncertain.

(ii) *Fixed interests*—where agreement cannot be landed on the purchase price an alternative is to enter into a UUOA but to fix equities from the outset so that there are no redeterminations. In principle, this is similar to the US practice of "pooling" where multiple leaseholders with interests in one or more tracts "pool" their interests together, fixing their interests, in order to receive regulatory consent—in the case of US oil producing states, to drill in compliance with local spacing regulations, but elsewhere to proceed with a development. This avoids the issues associated with redetermination as outlined above but enables the owners of the extension to participate in the development.

Parties may agree to fix interests where the extension is small or where the owners of the extension hold similar interests in the concession area in which the discovery has been made, both of which militate against entering into the complications of redetermination.

(iii) *Cross assignment*—if agreement can landed between two or more concession holders on the distribution of reserves across the respective concession areas, then they may enter into a cross assignment whereby the interests of each participant is "equalised" across all concession areas, thereby fixing the interests in, not only the common reservoir, but across the concessions.

An example of a cross-assignment is the UK's current largest producing field, Buzzard, which straddles two production licences (P.928(S) and P.986) and, as such, could have been unitised. However, the two concession groups had, similar if not identical, owners and a common operator. This undoubtedly facilitated an agreement to fix equities across both licences (and not just the common reservoir) prior to FDP approval when recoverable reserves from Buzzard were estimated at ~400 million barrels and plateau production forecast at 80,000 boe/day.[32] However, the record shows that Buzzard plateaued at 220,000 boe/day (which at the time of writing it continues to produce at) with recoverable reserves of 775 million bbls.[33] These new reserves will almost certainly be distributed across the two licence areas disproportionately to the fixed equity interests. Whilst the

[32] See Buzzard field development plan press release at *https://www.encana.com/news-stories/news-releases/details.html?release=615219* [Accessed 25 April 2016].

[33] See Buzzard field owner, Oranje-Nassau Energie's public statement at *http://www.onebv.com/Buzzard* [Accessed 25 April 2016].

merits of fixing the Buzzard interests will remain confidential to the owners, it provides both a good example of the potential for a common reservoir to expand beyond expectations as further information is accumulated from production operations and a caution to fixing equities early.

CROSS-BORDER DEVELOPMENT OPTIONS

4–37 Like the unitisation of domestic fields, a petroleum reservoir could straddle the onshore or offshore border between two or more sovereign states. In such a situation the process of unitisation is complicated by the need for the relevant states to agree to the unitisation framework before the process of negotiating the UUOA between the participating E&P companies can commence (and particularly so where there are ongoing disagreements between those states relating to their territorial or maritime boundary lines). In the North Sea these inter-state agreements have been the subject of field to field treaties[34] although more recently the UK Government has agreed framework terms with the Governments of Norway and Northern Ireland.[35]

4–38 The commercial dynamics which apply to the negotiation of the terms of such a Treaty should be fairly similar to the negotiations which take place between the participating E&P companies but with some added nuances reflecting the respective governments' wider public interest mandate. Each state will wish to obtain the maximum equity position for the participants on its side of the boundary so as to maximise its take from royalty, tax or other fiscal benefits. The location of the production station (onshore) or platform (offshore) will also be a key matter as it will likely determine the regulatory framework applicable such as health and safety legislation, employment law and the fiscal terms that apply to opex, capex and decommissioning. The evacuation route for produced petroleum will also be important as the landing point for petroleum will trigger a significant uplift in local economic activity, including jobs and downstream processing operations, such as petrochemical plants and power generation, as well as improving the landing state's energy security.

4–39 A cross-border unitisation should not be confused with a joint development zone (JDZ) arrangement. The terms which govern the establishment of a JDZ like the terms of a cross-border unitisation, are settled between states but typically apply in respect to a disputed geographical area that may or may not hold discovered reserves. The relevant states form a joint management committee that supervises operations within the JDZ which at least allows petroleum exploration

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[34] See Taylor et al., *Joint Operating Agreements* (1992), p.71 and English p.100. The Frigg Field Reservoir Agreement between the Governments of the UK and Norway available online at *https://treaties.un.org/doc/Publication/UNTS/Volume%201098/volume-1098-I-16878-English.pdf* [Accessed 25 April 2016].

[35] See the Framework Agreement between the Government of the United Kingdom of Great Britain and Northern Ireland and the Government of the Kingdom of Norway concerning Cross-Boundary Petroleum Co-operation (effective 10 July 2007) available at *https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/243184/7206.pdf* [Accessed 25 April 2016]. And neither is cross-border unitisation a uniquely European phenomenon: see, for example, the agreements between the governments of Australia and Timor Leste relating to the unitisation of the Sunrise and Troubadour fields in the Timor Sea.

(and even production) operations to commence, notwithstanding that sovereignty over the area is claimed (and disputed) by two or more states. If a petroleum discovery is made then, no matter where it lies in relation to the claimed borders, each state will share in the resultant production according to defined terms, usually equally.

JDZs exist, for example, between Nigeria and São Tomé and Principe in the Gulf of Guinea, between Kuwait and Saudi Arabia and between Malaysia, Thailand and Vietnam. **4–40**

CONCLUSION

Unitisation (and redetermination) remains the oil and gas industry's best mechanism to manage the unknown distribution of petroleum in a common reservoir. It seeks to identify the size and distribution of reserves held in a common reservoir by creating a production and cost banking type of arrangement that can be revisited as more geological information provides better and more accurate assessments. The process is inherently flawed because geological uncertainty can never be completely resolved until the end of field life. Whilst the flaws are inherent, understanding the redetermination process from the inception will provide some comfort that unit owners receive as fair a distribution of cost and production as is possible. **4–41**