GUIDANCE ON THE CONTENT OF OFFSHORE OIL AND GAS FIELD DEVELOPMENT PLANS

Appendices

1. Introduction

The development of and production from oil and gas fields on the land territory of Great Britain, in the United Kingdom's territorial waters and on the United Kingdom Continental Shelf (UKCS) is subject to a licensing regime overseen by the Licensing, Exploration and Development Branch (LED) which is part of the Energy Development Unit (EDU) of the Department of Energy and Climate Change (DECC). These Guidance Notes seek to make clear to Licensees preparing to develop an offshore field the purpose and practical application of the relevant model clauses incorporated into their petroleum production licences (see Appendix 2). They also cover the preparation of Field Development Plans for offshore oil and gas fields, reporting requirements for fields in production and applications for changes of operatorship and for Cessation of Production. The Guidance Notes also explain the arrangements for dealing with fields which cross licence boundaries and the Department's approach where field operations are undertaken by a contractor on behalf of Licensees. They are intended as a working guide and not as a definitive explanation of the requirements of the model clauses or of the Secretary of State for Energy and Climate Change's powers under them.

The powers of the Secretary of State in relation to the development of and production from oil and gas fields were first set out in full in model clauses scheduled to the Petroleum and Submarine Pipe-lines Act 1975. Similar clauses are incorporated into every production licence and relevant extracts can be found in Appendix 2. The licences prevent licence holders from installing facilities or producing hydrocarbons without the authorisation of the Secretary of State. When considering whether to authorise a proposal, the Secretary of State will take into account whether the proposed project accords with the Government's policy objectives (see Section 2) and whether the methods proposed to be used comply with good oilfield practice (see Section 3). The processes described in these Guidance Notes are summarised in flow-chart form in Appendix 1.

Further information on the regulation of oil and gas developments, including the current version of these Guidance Notes, can be found on the DECC Website at.

https://www.gov.uk/oil-and-gas-fields-and-field-development#process-for-oil-and-gas-field-development-plans

2. Policy objectives

2.1 Key objectives

In reviewing Field Development Plans, the Department's **overall aim** is to maximise the economic benefit to the UK of its oil and gas resources, taking into account the environmental impact of hydrocarbon development and the need to ensure secure, diverse and sustainable supplies of energy to UK businesses and consumers at competitive prices.

The Secretary of State will consider this aim in assessing proposals and, more specifically, will consider the following **policy objectives**:

a. ensuring the recovery of all economic hydrocarbon reserves;

b. ensuring adequate and competitive provision of pipelines and facilities; and

c. taking proper account of environmental impacts and the interests of other users of the sea.

The Department also seeks wherever possible to facilitate communication and cooperation between Licensees. These policy objectives represent the current Departmental objectives applicable to the majority of field developments. No single objective routinely takes precedence and, where a conflict arises, the relative merits of each will be viewed in the light of the particular facts of the proposal. Circumstances may arise where the Department needs to be able to take into account wider issues or policies in other areas of Government.

2.2 Ensuring the recovery of all economic hydrocarbon reserves

The Department will work with Licensees to ensure that the development option agreed is that which is most likely to secure the full recovery of economic reserves. **Economic reserves** are those reserves which have a (pre-tax) market value greater than the (pre-tax) resource cost of their extraction, where costs include both capital and operating costs but exclude sunk costs and costs (like interest charges) which do not reflect current use of resources. In bringing costs and revenues to a common point for comparative purposes, the Department currently uses a 10% real discount rate.

In most cases there will be alignment between the outcome of the pursuit of commercial objectives and the objective that all reserves whose value exceeds their costs of production are made available to the market. The Department will need to be satisfied, however, that proposals address all the recoverable reserves of a field and do so over a long enough time period. It will also endeavour to ensure that, in selecting their preferred option, Licensees take into account implications for other developments in the area. A more detailed discussion of the Department's approach to maximising economic recovery is provided in Appendix 3.

2.2.1 Gas flaring

It is recognised that during the appraisal, commissioning and production phases of a development, the flaring or venting of some gas is unavoidable. The Department requires that this flaring or venting should be kept to the minimum that is technically and economically justified. Flaring and venting is undesirable on both conservation of resource and environmental grounds.

Licensees are required to apply for consent to flare and/or vent gas emitted at their oil and gas fields. The main purpose of this requirement is to ensure that gas is conserved where possible by avoiding unnecessary wastage during the production of hydrocarbons.

Further detailed guidance is available here:

https://www.gov.uk/oil-and-gas-fields-and-field-development#flare-and-vent-source-categories

2.3 Ensuring adequate and competitive provision of pipelines and facilities

The provision of infrastructure (processing facilities and pipelines) is crucial to maximising economic recovery, particularly for gas. Many UKCS fields do not contain sufficient reserves to justify their own infrastructure, but are economic as satellite developments utilising existing facilities. There is, therefore, a national interest in ensuring there is sufficient infrastructure constructed; for example, it may maximise national income to oversize pipelines beyond the immediate needs of the fields concerned to create the capacity for future tie-in developments. The Department is often in the best position to assess this, because it has a right of access to all the companies' information, whereas individual companies have only their own data and may, therefore, not be able to assess future potential correctly.

2.3.1 Pipeline provision

In reviewing Field Development Plans which have implications for future pipeline applications, the Department will seek to:

a) Avoid the unnecessary proliferation of oil and gas pipelines. An additional pipeline may interfere with the rights or established practices of other users of the sea on the pipeline's route and may also have an impact on the environment. On the other hand, new pipelines, particularly those interconnecting with existing systems, may enhance competition, the security of supply and the pace of development;

b) Aid, where feasible, future field developments, including those outside the licence area. The Department's role will normally be to advise and encourage interested parties to co-operate in constructing and sizing lines according to future potential and making provision for tie-ins and risers for their mutual benefit. Licensees are also encouraged to consider the needs of the onshore petrochemicals industry when evaluating development options; and

c) Ensure that those building and operating pipelines and other infrastructure compete on a level playing field and that the marketing of gas and oil reinforces the Government's efforts to promote open and competitive markets.

Subject to these aims, ***the evacuation route and destination of petroleum are essentially matters for the commercial judgement of the Licensees***. Where oil or gas is to be exported to another country by means of a new pipeline, the pipeline will be subject to the negotiation of appropriate agreements between the Governments concerned.

2.3.2 Third party access to offshore infrastructure

The investment required to build the infrastructure needed to transport gas (and oil) from offshore oil and gas fields is characterised by significant costs and irreversibility. This can lead to conflict between the efficient use of resources and the wish for greater competition. The efficient use of resources requires no unnecessary duplication of infrastructure while greater competition requires alternative pipeline systems to be available to producers. Effective regulatory action can also prevent the exploitation of local monopoly positions where competing pipelines do not exist.

The evolution of offshore infrastructure on the UKCS has been characterised by companies developing pipelines for sole usage, followed by ullage (i.e. spare capacity) progressively being made more available for use by third parties on payment of a tariff (i.e. a payment for transportation and processing services). Field-dedicated lines are economically viable when fields are relatively large but become less viable as fields get smaller. As a consequence, there is scope for gains by all parties if the development of small fields is made viable by the owners allowing access to their existing infrastructure, with the infrastructure owners gaining additional revenue from the new users. Some of these gains would be lost if monopolistic behaviour were to deter the timely development of new small fields.

The more mature areas of the Southern North Sea, with large amounts of spare capacity offer good opportunities for pipe on pipe competition. In other regions, notably the Central North Sea, there is less spare capacity and the additional complication of relatively small gas volumes associated with oil production. There is, therefore, more potential for commercial tension between the owners of infrastructure and the owners of third party fields seeking access to that infrastructure. The scope for tension between non-proliferation of infrastructure offshore and competition creates a need for regulation. If requested by a would-be user, the Secretary of State has powers, having considered the interests of all parties, to impose a solution to problems of pipeline sizing, connections or tariffs. Guidance on the use of the powers and details of the legislation can be found at:

https://www.gov.uk/oil-and-gas-infrastructure

A voluntary industry Offshore Infrastructure Code of Practice, available on Oil and Gas

UK's website at http://www.oilandgas.org.uk/issues/operations/production_icop.cfm seeks to streamline and facilitate the timely application of the processes of seeking, offering and negotiating third party access to offshore pipelines and processing facilities and onshore terminals and ensure that access is easy and fair, with terms offered on a negotiated, non-discriminatory basis.

2.4 Taking proper account of environmental issues and the interests of other users of the sea

In addition to the Petroleum Act 1998, other legislation, for example the Offshore Petroleum Production and Pipelines (Assessment of Environmental Effects) Regulations 1999 (as amended), the Offshore Marine Conservation (Natural Habitats, &c.) Regulations 2007 (as amended) and the Offshore Petroleum Activities (Oil Pollution Prevention and Control) Regulations 2005 (as amended) cover the environmental aspect of offshore oil and gas field development

Full guidance on aspects of environmental permitting can be found on the Department's website at:

https://www.gov.uk/oil-and-gas-offshore-environmental-legislation

2.4.1 Environmental impact assessments

The Offshore Petroleum Production and Pipe-lines (Assessment of Environmental Effects) Regulations 1999 (as amended) came into force on 14 March 1999 and were amended in 2007. These Regulations implement the European Council Directive on the Assessment of the Effects of Certain Public and Private Projects on the Environment (85/337/EEC) as amended by Council Directive 97/11/EC insofar as it relates to the effects on the environment of certain offshore oil and gas projects. An environmental study, known as an Environmental Impact Assessment, must be carried out to assess the likely environmental impact of the relevant activities. In the case of proposed developments that exceed the Directive's production thresholds, a document describing the study, an Environmental Statement (ES), is then submitted to the Department as a necessary part of the project authorisation process. The ES is then subject to consultation with relevant Environmental Authorities and a period of public notice. The public has the right to comment on the Environmental Statement and the Secretary of State must be satisfied that the requirements of the Regulations as to publicity and consultation have been met. Consent for the Development will not be given until the Secretary of State is satisfied with the information provided within the ES. The decision to grant consent will take account of information from the applicant and the views of consultation bodies and the public. It will also take account of whether any negative environmental effects of the development are outweighed by other (e.g. economic, social or environmental) factors.

Further details of the Offshore Petroleum Production and Pipe-lines (Assessment of Environmental Effects) Regulations 1999 (as amended) and guidance can be obtained from the Department's Website at:

https://www.gov.uk/oil-and-gas-offshore-environmental-legislation

2.4.2 Habitats assessments

Where a project might have a significant effect on the integrity of a site which is protected under the Habitats Directive or the Wild Birds Directive, an appropriate assessment will also be required under regulation 5 of the Offshore Petroleum Activities (Conservation of Habitats) Regulations 2001 [as amended]. This assessment, which has to be undertaken by DECC will focus on the impacts of the project on the protected site and the designated features and species. Where such an assessment is carried out, the Secretary of State will normally only grant consent for the project if the assessment shows that the project will have not have adverse effects on the integrity of the protected site.

Further details of the Regulations and guidance can be obtained from the Department's Website at:

https://www.gov.uk/oil-and-gas-offshore-environmental-legislation

2.4.3 Fishing

When an offshore development is planned the Department will need to be assured that adequate consultation has taken place with the appropriate Fishery Department (see Section 8.2) and with those fishery organisations which operate in the area of the development.

2.4.4 Pollution

High priority is given to the prevention of oil pollution from offshore installations, pipelines and subsea infrastructure. The Offshore Petroleum Activities (Oil Pollution Prevention and Control) Regulations 2005 (as amended) - the OPPC Regulations - regulate all emissions of 'oil' during the course of offshore operations. These Regulations introduce a more robust and effective approach to the management of oil discharges by updating the definition of oil; introducing a permitting system for oil discharges and recovering the associated costs via permit fees; and strengthening the powers to inspect and investigate oil discharges and releases. The issue of permits under these Regulations replaces the issue of exemptions under the Prevention of Oil Pollution Act 1971. The OPPC Regulations and guidance can be found on the Department's website at https://www.gov.uk/oil-and-gas-offshore-environmental-legislation

The Merchant Shipping (Oil Pollution Preparedness, Response and Co-operation Convention) Regulations 1998 require all offshore exploration and production facilities including offshore installations, oil handling facilities and pipelines to have an oil pollution emergency plan (OPEP) in place. The Offshore Installations (Emergency Pollution Control) Regulations 2002 implement the recommendations from Lord Donaldson's review into the Governments involvement into salvage and intervention in pollution incidents insofar as they relate to the oil and gas industry. The Regulations allow for the appointment of a single representative i.e. the Secretary of State's Representative (SOSREP) authorised to act on behalf of the Secretary of State for Energy and Climate Change in the event of an incident or accident involving an offshore installation where there is, or may be, a risk of significant pollution, or where an operator is failing or has failed to implement effective control and preventative operations. OPEPs must include arrangements to reflect the potential involvement of the SOSREP and his team. Further guidance on these Regulations can be found on the Department's website at:

https://www.gov.uk/oil-and-gas-offshore-emergency-response-legislation.

The Offshore Combustion Installations (Pollution Prevention and Control) Regulations 2013 (the PPC Regulations) …

transpose the relevant provisions of the Industrial Emissions Directive 2010/75/EU ("the IED") in respect of atmospheric emissions of pollutants from combustion installations on offshore oil and gas production installations.. The Regulations cover any offshore oil or gas facility where the aggregated thermal input of all the operational combustion equipment exceeds a threshold of 50 MegaWatt thermal (MW(th)). A permit is not required where the aggregated thermal input is less than 50 MW(th). Combustion equipment, as described in the Regulations, includes burning fuel in turbines, internal combustion engines ('ICE'), fired heaters used to heat any medium, inert gas generators, or other similar fired processes. New developments will require an PPC permit prior to operation. Existing facilities which undergo substantial change (as a guideline, this is taken to be changes that result in an increase in CO_2 emissions of >100,000 tonnes) may be required to apply for a new PPC permit. Applicants will need to demonstrate that they have employed Best Available Techniques (BAT) in designing and operating combustion installations. The PPC Regulations and guidance, and details of other environmental regulations, can be found on the Department's website at:

https://www.gov.uk/oil-and-gas-offshore-environmental-legislation

2.5 Facilitating communication and cooperation

The Department actively encourages co-operation between licence groups in field development where this furthers its policy goals of maximising the economic recovery of hydrocarbons, promoting efficient infrastructure and protecting the environment. The potential benefit of co-operation is a matter considered in the Department's assessment of development proposals. Accordingly, it will seek to ensure that when Licensees are planning a development they are aware of technical experience gained elsewhere, and they have reviewed with other Licensees in the area the potential for collaboration with existing or future projects. In pursuing this objective the Department will be sensitive to issues of commercial confidentiality.

2.5.1 Unitisation and co-operative development

Where a Field Development Plan is proposed for a field which extends into the area covered by a neighbouring license with different ownership, commercial and technical disputes may arise with regard to the optimum development plan. In such cases the Department needs to be satisfied that the ultimate recovery of petroleum is maximised and that unnecessary competitive drilling is avoided. The most efficient way to satisfy these requirements and therefore avoid any possible delay in the authorisation process is for the Licensees to discuss their plans with their neighbours at an early stage and propose an agreed Field Development Plan. The proposal, which could be either a unitised development or other commercial arrangement, should allow an optimum Field Development Plan and demonstrate that there would be no risk of unnecessary competitive drilling. Where such agreement is not reached or the proposed Field Development Plan does not demonstrably satisfy these requirements, the Department will wish to understand the circumstances and give all parties adequate opportunity to make representations.

The Secretary of State has powers to require a unitisation between Licensees. The grounds for the use of this power are that unitisation is needed in the national interest both in order to secure the maximum ultimate recovery of petroleum and in order to avoid unnecessary competitive drilling.

Licensees should be aware that:

a. The Secretary of State will not necessarily refuse to grant development authorisation to a particular group of Licensees who have not concluded an agreement with the Licensees of an adjacent block on the basis that they have not concluded a unitisation agreement. The Department does not consider that powers to require unitisation extend to issues of fairness and equity between groups of Licensees. The Department's position is that proprietary rights do not exist in unextracted hydrocarbons under the UKCS and ownership of hydrocarbons arises only once they have been extracted under appropriate regulatory consent.

b. The Department's acceptance or rejection of any Field Development Plan will, therefore, be on the basis of whether or not it is an optimum development in terms of maximising the economic recovery of oil and gas. If, in any intended development, there is a likelihood of claims or disagreement between adjacent licence groups related to the field's extent, the Department should be consulted at an early stage.

In order for the Licensees to understand what constitutes a Field for both Unit Development and tax purposes, the Department will issue a proposed Field Determination (see Appendix 5) at an early stage in the Field Development Plan authorisation process, utilising the geological information that is available to it at that time.

If a Unitisation and Unit Operating Agreement (UUOA) is put in place by Licensees, this will need to be submitted to the Department for approval at the same time as the Field Development Plan. (see https://www.gov.uk/oil-and-gas-petroleum-licensing-guidance#equity-interests-and-operating-agreements)

3. Considerations of good oilfield practice

Good oilfield practice relates largely to technical matters within the disciplines of geology and reservoir engineering, petroleum engineering and facilities engineering and to the impact of the development on the environment.

The Department will ensure that practices harmful to future oil or gas recovery, or which conflict with the interests of other potential users of the licensed area, are avoided at all stages of planning and development. Harmful practices which relate to the environment, including the wasteful flaring of gas and oil pollution, have been noted above. Regulation of those aspects of good practice relating to the safety of personnel is the responsibility of the Health and Safety Executive.

The Department will ensure that the Licensees have followed good practice in formulating plans for the development and management of a field. When considering what constitutes good practice, the Licensees' proposals will be compared with the practice adopted in similar, successful developments.

During the appraisal phase good practice will normally require that information needed to determine the most appropriate development has been gathered and analysed properly. This will allow all realistic options for the field and area, including the application of new or innovative technology, to be considered properly. During the production stage the Department will seek to ensure that sufficient data are gathered to test the understanding of the reservoir and resolve uncertainties which have a material effect on the success of hydrocarbon recovery. This requires the continuing application of the most appropriate analytical methods, suitable research and the timely incorporation of improved understanding or innovative technology into the management of the field.

4. The Field Development Plan process

Current legislation allows two routes for formally authorising development and production proposals. The Department may issue either a development and production consent for an authorised Field Development Plan; or a development approval for an authorised Field Development Programme. In practice, the issue of a development and production consent has been by far the most commonly used option. *Reference to Field Development Plans and development and production consents are therefore used as generic terms throughout this guidance.*

The Department may (whether or not it has already consented to development and production) direct a Licensee to submit a programme of works for approval; or serve such a programme on a Licensee, in accordance with the terms of the Licence. The

Department may do this, for example, if a Licensee is failing to carry out production for which consent has been granted. It will not normally do this where a production consent has already been granted if the Licensee is carrying out production in accordance with its Field Development Plan, or if agreement can be reached on an amendment to the Field Development Plan.

The Field Development Plan is the support document for development and production consents. Discussions with the Department prior to its submission are the process by which the Government secures its policy objectives. The aim of the process is not the detailed review of every element of the development but, rather, the identification and resolution of any aspects of the development which relate to the Department's objectives and on which the views of the Department and Licensees may diverge. These aspects will be examined more thoroughly with the Licensees with the aim of reaching mutually satisfactory conclusions. Other aspects of the development will be subject to detailed examination only on a limited audit basis where this is considered necessary. The purpose of such an audit is to confirm the quality of the underlying technical basis of the development, not to uncover new issues. The resulting Field Development Plan is not required to provide a detailed description of the field or a comprehensive account of any issues resolved prior to its submission. It should provide only a summary of the information and requirements which led to the adoption of the proposed form of development, together with a more detailed account of the actual development and the principles and objectives which will govern its management.

Licensees are jointly and severally responsible for the Field Development Plan, which should represent a single view of all the Licensees. One Licensee is usually appointed as Operator to be responsible for the production of the Field Development Plan and ensure that all necessary consents and authorisations are obtained. It is usual for the Department to conduct discussions with the operator as the representative of all the Licensees.

DECC has no financial criteria for operatorship other than those applied to an operator in its capacity as a licensee (including financial liability for potential pollution). Prior to Field Development Plan consent, the Department will request evidence from each licensee that it has access to sufficient cash resources or has in place adequate funding arrangements to finance its share of the development costs. The Department has issued separate financial guidance which may be found at:

https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/15172/4229-guidance-financial.pdf

DECC usually also requires formal written confirmation from each Licensee that they endorse the submitted Plan and have approved funding sufficient for their share of the development costs. This allows the Secretary of State to content himself that all licensees support the proposed Field Development Plan and that sufficient funding has been committed to proceed with the FDP. In these letters, each Licensee is also required to seek the formal approval by the Secretary of State of an appointed production operator for the field development.

The operator should contact the Department early in the appraisal stage of a proposed field development and a multi-disciplinary team from the Licensing, Exploration and Development Branch will be assigned to carry forward technical discussions on the field. Each team will be headed by a manager authorised to take technical decisions on behalf of the Department and to co-ordinate, where necessary, the Department's response on policy issues.

The operator should ensure that the Department is aware of the generation of development concepts and screening studies so that aspects requiring detailed consideration by the Department can be identified. Once the Licensees have provided the Department with sufficient opportunity and information to gain an understanding of the field and its conceptual development, the Department's team manager will be able to provide a formal notification of any aspects of the development where a conflict of interest is seen which is likely to prevent the authorisation of the plan. Once issues are identified the Department will seek to agree a programme of work, or review, leading to their resolution and a timetable for completion.

Licensees should not that , with effect from 17 June 2013, the Department charges for the time spent reviewing Field Development Plans and for issuing the relevant consents – separate guidance may be found at :

https://www.gov.uk/oil-and-gas-charging-regime-for-licensing-exploration-and-development

4.1 Guidance on the content of the Field Development Plan

If the process set out above is followed, only a summary of the background and justification of the adopted proposal will need to be presented in the Field Development Plan. The proposed form and management of the development will need to be described in greater detail to provide a basis for measuring performance following authorisation of the Field Development Plan. Appendix 4 sets out the approach in more detail and identifies the basic information which will need to be provided.

For small field developments, e.g. involving a subsea tie back to an existing platform, the norm for Field Development Plan documentation is a maximum of about 15 pages of text plus associated figures. More comprehensive or varied text, which some operators might for example choose to submit for partner reasons or internal preferences, will be accepted provided it covers the Department's information requirements. For larger new field developments, or developments involving more complex or challenging reservoirs, a more comprehensive document may be required. The key feature of the Field Development Plan will be an explanation of the **commitments** that the Licensees are making (in terms of facilities, number of wells, provision for IOR/EOR, provision for 3rd party access, hydrocarbon export routes etc.) to bring forward a sound development, rather than a detailed technical description of the reservoir or required infrastructure.

4.2 Trans-boundary fields

The development and operation of fields extending beyond the limits of the UKCS, or fields wholly on one or another Continental Shelf which require the development of new trans-boundary pipeline infrastructure or wells and control facilities, will require a formal agreement between the States concerned. The agreement may make part, or all, of the Field Development Plan subject to the approval of the parties to the agreement.

The issues to be addressed in any such inter-Governmental negotiations are likely to vary from project to project. However, a principal policy objective will be to seek to put in place a framework that ensures that the benefits arising from any such development are apportioned in a fair and equitable way.

Licensees are advised to seek early, specific guidance from the Department during the screening stage for any development proposal that may have trans-boundary implications. The authorisation time-scale for trans-boundary fields will depend on the level of agreement needed between the States concerned.

4.3 Satellite tie-back development

There are an increasing number of small satellite developments which are tied back to existing host facilities. In these cases it is important that the operator of the satellite development and the operator of the host facility work together to ensure an agreed plan for any necessary modification to the host facility.

The Department will require a letter of support from the host platform operator, endorsed by all co-venturers. The letter should cover the following points:

- A statement supporting the development of the satellite field(s) over the host platform and committing the host platform to provide the necessary processing services;
- A statement confirming the intent to execute the required commercial arrangements (Construction and Tie In Agreement, Transportation and Processing Agreement, etc);
- A brief summary (or bullet points) of the major new equipment / major modifications proposed to be carried out on the host platform to support development of the satellite fields based on the required plant modifications, a statement of any expected changes to plant nameplate capacities – oil, gas, water etc.; and a Process Flow Diagram to show the new topsides equipment and tie-in points to existing equipment
- An assessment of the impact of the new satellite field production on existing production.

Where the proposed modifications are substantial the Department may require a stand-alone document capturing them to be submitted by the operator of the host facility for consent. This document should be submitted to the Department at the same time as the final Field Development Plan for the satellite field. If the respective operators of the host facility and the satellite development prefer an alternative approach then this should be discussed with the Department at an early stage, especially if the host facility is leased rather than owned by the operator.

4.4 Flexible approach to development proposals

For the majority of offshore fields it is expected that the Licensees will wish to put forward a plan covering the lifetime of the development, having first acquired a reasonably detailed understanding of the extent of the field by appraisal. It is, however, recognised that there may be valid reasons for more gradual or flexible approaches to some developments stemming from geological or engineering uncertainty, infrastructure constraints or the benefits of phasing expenditure. The Department will support such approaches provided that they are required to enable a development to progress or are likely to increase ultimate economic recovery.

The alternatives commonly used, and the criteria for their consideration, are set out below.

4.4.1 Extended Well Tests (EWTs)

The Department may authorise extended periods of test production from exploration or appraisal wells prior to development authorisation if it can be demonstrated that the Licensees will thereby gain the technical understanding or confidence in the performance of the field needed to progress towards a development. The EWT should have realistic and definable appraisal objectives essential to the success of a development and not be prejudicial to ultimate recovery. There are no strict criteria governing the maximum volume to be produced or the duration of an EWT and the duration may be extended if there is a technical justification, but it should be noted that EWTs are *not* an alternative to production under an authorised Field Development Plan. There is no obligation to proceed with a development following an EWT.

The primary objective of an EWT is to obtain essential field information and it is recognised that this may necessitate the flaring of substantial quantities of gas and, possibly, oil. The test should be designed so that oil and gas flaring is kept to the minimum that is technically and economically justified and full consideration, in consultation with the Department, should be given to the potential for saving the produced oil. The Department considers any well test with a total flow duration of more than 96 hours or which produces a total of more than 2,000 tonnes of oil to be an EWT, which will require application for a specific EWT Consent. Flow duration and the volumes produced during clean-up flow periods should be included and count towards the 96 hour and 2,000 tonnes of oil thresholds. The Department may consider long clean-up flows to be an EWT, even if there is no explicit data gathering objective. Usually the Department will treat the testing of discrete well zones and sidetracks as separate well tests, although it may require an EWT consent to be applied for where it considers one is appropriate.

An EWT Consent requires a formal letter of application setting out the timetable and objectives of the test and the quantities of oil and gas to be produced saved or flared. Operators should note that if oil and gas are to be saved during the EWT, a Field Determination may be required for the field in question. A Pipeline Works Authorisation may also be required for the subsea infrastructure used to carry out the EWT.

A formal Environmental Impact Assessment (EIA) to assess the likely environmental impact of the proposed EWT will be required to support the EWT application. Operators may request a direction confirming that a full Environmental Statement (ES) is not required and may include the assessment within the Drilling Operations application for the well that will be tested (made through UK Oil Portal). However, the Department may require a full ES where an EWT is undertaken over a significant period of time or involves the flaring of a significant quantity of hydrocarbons. An ES may also be required where the EWT is to be carried out in a sensitive location e.g. close to the coast, within or adjacent to a Special Protection Area / Special Area of Conservation / Marine Conservation Zone / Marine Protected Area, or close to a median line. Further guidance can be found in the Guidance Notes on the Petroleum Production and Pipelines (Assessment of Environmental Effects) Regulations 1999 (as amended) on the Department's website at:

https://www.gov.uk/oil-and-gas-offshore-environmental-legislation

In planning EWTs, Licensees should bear in mind that should an ES be required for the EWT, this will require formal public consultation and consultation with relevant environmental authorities which can take between three and six months.

4.4.2 Phased developments

4.4.2.1 Phased development to improve confidence or understanding

For fields which do not appear to have the economic potential to sustain further appraisal, or where the best development method cannot be determined without substantial production experience, the Department will accept the phased development of a field. The form of the later phases is then dependent on the results of the earlier ones. The Licensees will need to demonstrate that phased development does not prejudice economic recovery and will need to state in the Field Development Plan the more likely forms of further phases; the criteria which will need to be met; and the time frame proposed for further appraisal or development. The production authorisation would normally be for the duration of the first phase only.

Phased developments of the type described above, like EWTs described in the previous section, have one objective in common, namely the improvement in understanding of the field. For some fields a choice must be made by the Licensees of which approach to propose. The differences between the two options which the Licensees and Department would need to consider are as follows:

- The prime purpose of an EWT is to gain reservoir understanding; little attention needs to be paid to the possible final forms of development other than to ensure that the reservoir is not being irreversibly harmed. A phased development, in contrast, will need to demonstrate at the outset how subsequent phases of development could be accomplished and how the information gathered in the first phase would be used to help determine the later phases.
- The duration of, and production from, an EWT are set primarily by its technical objectives and, for most tests, will be small in comparison to ultimate field life and recovery. Within the constraint that it should improve ultimate economic recovery, the duration and production of the first phase will be determined by the usual development objectives and are likely to be significant in terms of field life and recovery.

- For a phased development, the production facility should be optimised for the likely requirements of the field during at least the first phase. For an EWT there is no need for the facility to be optimised beyond what is required for minimising environmental emissions and for the data collection objective.

4.4.2.2 Phased development for the purpose of early production

The Department will approve early production during the period needed for the construction of permanent facilities when this is appropriate as the first phase of a development.

4.4.3 Staged development for commercial or economic benefit

For some fields, although the final form of the development is known from the outset, it may be commercially or economically advantageous to stage expenditure, development or production. The Department is willing to accept such developments provided the Licensees can demonstrate that this staging is not detrimental to ultimate economic recovery. In these cases, depending on the complexity of the field, production authorisation could be for field life and/or subject to conditions that the further stages are undertaken.

4.4.4 Flexibility in the selection of facilities option

Licensees may wish to retain flexibility in the final selection of the facilities option for a particular field in order to optimise their project schedule. Whilst the Department is prepared to indicate during the review stage which of the options may be technically acceptable, Field Development Plan consent can be given only when the final selection has been made.

In considering any proposal the Department recognises that the understanding of a field is necessarily incomplete at the time decisions are being made and that this may result in a less than optimal development. This is particularly likely to be the case where a flexible approach is being adopted. In proposing developments in these circumstances, Licensees should ensure whenever possible that reasonable provisions are made for effective recovery from a more optimistic field interpretation.

4.5 Intermediate decisions

The project planning process generally benefits if intermediate decisions can be made on technical aspects of the project before final commitment is made to the Plan. The Department wishes to aid this process and, if it is necessary, the field development team manager will confirm when agreement has been reached on a broad conceptual proposal for the development or when all questions relating to a specific discipline have been addressed and agreed. Operators should note that "Letters of Assurance" to support intermediate decisions cannot fetter the Secretary of State's discretion to authorise developments under the terms of a petroleum production licence and should not be taken as an indication that the final Field Development Plan will be consented.

4.6 Time frame

Provided that the interactive process described above has been fully implemented, the Department's aim, where there are no major unresolved issues, is to complete its review of the final submitted Field Development Plan within one month. The early review of draft sections of the Field Development Plan, as these become available, will help it to achieve this aim.

The operator should note that the Field Development Plan will not be consented to until the Environmental Impact Assessment process for the development has also been completed. The EIA and Field Development Plan should be prepared in parallel by the operator and any choice of development concept must be made giving full weight to environmental concerns. For developments with trans-boundary implications, the trans-boundary issues are likely to take substantially longer to resolve than the Department's review of the plan.

5. Agreement to the Field Development Plan

The development will be authorised (i.e. the necessary consent/approval granted pursuant to the applicable model clauses and/or EIA regulations) once the Secretary of State is satisfied of the following:

- the FDP meets the government's policy objectives (set out above)
- the Environmental Impact Assessment process has been completed successfully
- each Licensee has approved funding sufficient for their share of the development costs
- the Department has approved a Production Operator for the development

In the event that the Licensees disagree on whether a FDP can be sanctioned, the Department may be prepared to approve the FDP if the necessary pass mark has been obtained under a formal vote called under the provisions of the Joint Operating Agreement. The Department will however wish to discuss the proposal with any licensee who has not voted to support the project to understand their reasons for not doing so. Licensees should note that any FDP submission that is not supported by all the Licensees is likely to take longer to approve than a proposal that is unanimously supported

5.1 Production

The Secretary of State's authorisation will cover both the construction of the facilities and other infrastructure, and the production of hydrocarbons from the field. The duration and the levels of production allowed will always depend on the particular circumstances of the field. The general principles outlined below will, however, be applied in each case.

5.1.1 Simple oil or condensate fields and all dry gas fields

Subject to the terms of the licence, agreement will usually be given for production over the forecast lifetime of the development. Conditions may be attached to give the Department powers to require a review if performance falls outside authorised production profiles (in addition to any legislative requirement to amend the Production Consent) or if the field is found to differ from the initial perception to such an extent that there is a risk of a loss of significant economic reserves. For phased developments, agreement will normally be for the duration of the relevant phase.

5.1.2 Other fields

It is the Department's policy to provide Production Consents for as long a duration as possible, consistent with the duration of relevant licences, and the technical and investment uncertainties associated with future production. The duration of the initial period of agreed production will be proportional to the degree of understanding of the field: the more uncertain the performance, the shorter the duration. Subject to the uncertainties involved, agreement to a duration of between five years and Life-of-Field are anticipated.

For all fields both upper and lower limits to production levels will be included in the Production Consent. These will usually be based on the maximum and minimum cases as stated in the Field Development Plan.

Production should not cease permanently without justification being given in a Cessation of Production document (see Appendix 7).

5.1.3 Gas flaring and venting

The Department is committed to eliminating any unnecessary or wasteful flaring and venting of gas. For new developments the Department expects that where, over the life of the field, the value of the produced gas is higher than the costs of bringing it to the market, the Licensees will make provision for its processing and transportation to shore. In considering whether the gas should be brought to market, the Department will have regard to the overall costs and benefit; these may not reflect the commercial positions of individual Licensees.

Where the processing and transportation of gas involves the use of third party infrastructure, the distribution of value between the Licensees and the infrastructure owners is, in the first instance, a matter of commercial negotiation between the parties. Following negotiation with the infrastructure owners the Licensees may, however, apply to the Secretary of State to use his discretionary powers under the Petroleum Act 1998 to set charges or to require access to infrastructure. The Department encourages both infrastructure owners and users to adopt the principles of the industry's voluntary *Offshore Infrastructure Code of Practice* in infrastructure access negotiations. Further detailed guidance can be found at:

https://www.gov.uk/oil-and-gas-infrastructure

If it is not economic to bring the gas to shore, the Licensees should consider carefully all other options for its handling. These would include its use as fuel, as a means for improving oil recovery, for conversion to other fuels, injection for disposal, sale to a neighbouring development or flaring. As with other development alternatives, the option which maximises the economic recovery of the field would normally be selected. Where gas is to be disposed of by flaring, full consideration should be given in the design of the facility to providing for less wasteful alternatives should the economic or technical circumstances change.

For some developments flaring or venting will be necessary for safety or operational reasons. Licensees should seek to minimise this by implementing best practice at an early stage in the design of the development and continuing to improve on this during the subsequent operational phase.

During the commissioning of production facilities flaring consents will usually be restricted in duration to between one and three months and will be for a fixed quantity of gas based on an auditable programme. Once commissioning is complete and stable operating conditions have been achieved the duration of the flaring consent will be increased and will be subject to an agreed cumulative maximum for the period. Detailed guidance on the procedures for dealing with gas flaring and venting during the commissioning phase of a new development is provided in Appendix 9.

5.1.4 Extension of licence terms

Historically, licences have been issued for set periods, and this approach inevitably raises the possibility that a long-lived field may still be producing when its covering licence is set to expire. There is no general right of extension, but DECC policy is to extend such licences for such a period, and over such acreage, as is necessary to cover production, provided that the Licensee has conformed satisfactorily with the licence conditions.

The first licences to reach this point were the 1st-Round Licences, issued in 1964. The policy on extensions for 1st and 2nd Round licences was published on the web in 2009/10. Policy on later Rounds (3rd to 7th inclusive) has also been published at:

https://www.gov.uk/oil-and-gas-petroleum-licensing-guidance#licence-extensions.

5.2 The Environmental Impact Assessment process

Under the Offshore Petroleum Production and Pipe-lines (Assessment of Environmental Effects) Regulations 1999 (as amended), an Environmental Statement (ES) is mandatory for all developments where the level of oil production is intended to exceed 500 tonnes a day (3,750 barrels/day) or the level of gas production is intended to exceed 500,000 cubic metres a day, regardless of the location of the development. It is, therefore, likely that all new oil or gas developments in the UKCS will require an ES to be prepared. The Offshore Petroleum Activities (Assessment of Environmental Effects) (Amendment) Regulations 2007, which implements the Public Participation Directive, also requires production increases above the thresholds mentioned above to be subject to a further ES to assess the environmental impact of the increase in production.

Where an ES is prepared it will include details of any measures which the Licensees intend to take to mitigate the impact on the environment of the proposed development. All ESs are subject to a period of consultation during which time any person or body with an interest in the proposed development may make their views known to the Secretary of State. The Regulations require that copies of the ES are made available to certain environmental authorities and that it is subject to a 28 day public notice period.

In making his decision whether or not to authorise a proposed project, the Secretary of State will take into account the ES and any representations he has received. If the Secretary of State considers that a project would cause a significant negative impact on the environment, authorisation might be refused or conditions to mitigate or remedy any adverse effects might be imposed in the field development consent or ES approval.

The Environmental Impact Assessment process generally proceeds in parallel with the preparation of the Field Development Plan. Licensees should bear in mind that the consideration of an ES generally takes several months and can take significantly longer than this if substantial representations are made by any of the consultees or members of the public, or if insufficient information is presented within the ES.

Detailed guidelines on the ES process is given in the Department's *Guidance Notes on the Offshore Petroleum Production and Pipe-Lines (Assessment Of Environmental Effects) Regulations 1999* (as amended) which can be found on the Department’s Oil and Gas Website at:

https://www.gov.uk/oil-and-gas-offshore-environmental-legislation

6. Regulation following Field Development Plan authorisation

The focus of the Department, once a development has been agreed, will be to ensure that the Field Development Plan is being followed or modified appropriately as the understanding of the field develops, and that the field is being managed in a manner that will maximise economic recovery of hydrocarbons. The operator will be required to prepare, on behalf of all the Licensees, an annual return summarising key aspects of the field's performance (see Section 6.1). This will enable the Department to identify quickly those fields where more detailed discussions are required. The operator may also be required to prepare a more detailed document which will notify the Department of significant proposed deviations from the Field Development Plan (see Section 6.2). In particular, the operator will need to begin a detailed dialogue with the Department some years prior to permanently ceasing production from a field (see Section 6.5).

6.1 Stewardship

In 2004, a Brown Fields Work Group convened by PILOT (the joint UK Government and Oil & Gas Industry Task Force) highlighted the quality of "stewardship" as a key factor in realising the full economic potential of UK's "Brownfields". (See http://webarchive.nationalarchives.gov.uk/20101227132010/http:/www.pilottaskforce.co.uk /files/workgroup/1649.pdf.

Good stewardship comes down to two key factors:

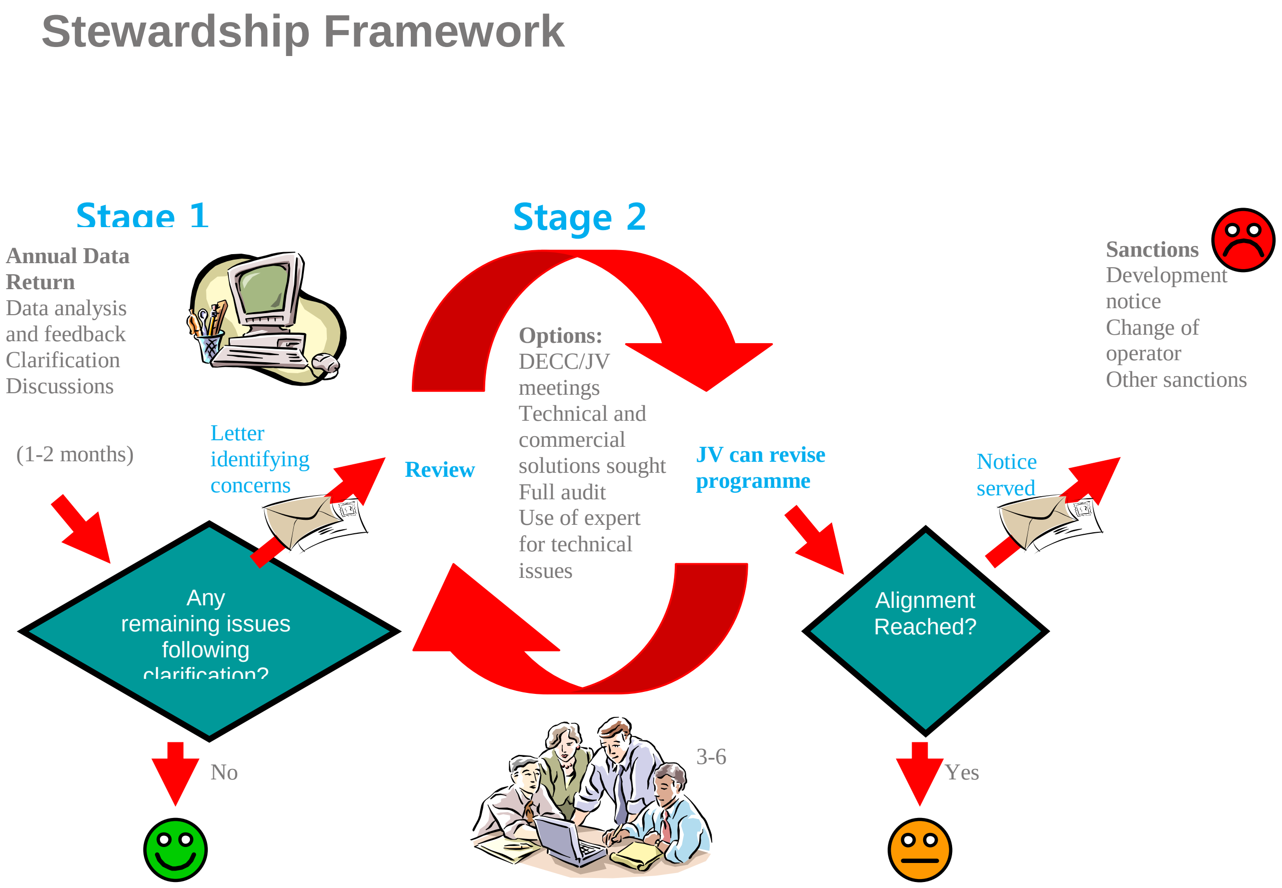
1. That asset owners consistently do the right things to identify and then exploit opportunities, and that

2. Assets are in the hands of those with the collective will, behaviours and resources to achieve this.

The Department's overall aim is to maximise the economic recovery of hydrocarbons in an environmentally sound manner, and in most cases there will be alignment between the Department's objective and the outcome of the pursuit of the Licensees' commercial objectives. The Department will need to be satisfied, however, that the Field Development Plan addresses all the recoverable reserves of a field and do so over a long enough time period. The Department will therefore carry out regular reviews of the performance of producing oil and gas fields and, where concerns over the quality of Stewardship are identified, engage the Joint Venture (JV) partners in discussions on improving their Stewardship to an acceptable level. Where a serious shortfall in stewardship is identified, the Stewardship process provides a framework for improvement including, where necessary, the use of DECC's licence powers to require the JV to undertake economic development or to require a change of operator.

This Stewardship review process is carried out annually, and consists of a number of stages (see the figure below). The process also incorporates an annual review of Production Efficiency in UKCS developments. Further information on this process can be found in Appendix 12.

Figure



In the first stage of the Stewardship review process, the operator will be required to prepare, on behalf of all the Licensees, an annual return summarising key aspects of the field's performance. This will enable the Department to identify quickly those fields where more detailed discussions are required with the Licensees on the field's performance. Guidance on the completion of this data submission is given in Appendix 11. Where significant changes to the Field Development Plan are proposed a separate submission will need to be made (see section 6.2).

If issues concerning the quality of Stewardship are identified during this first stage, then the Department will write to the operator formally notifying them of the issues. The process then goes into a second stage in which the Department engages with the operators and the other Joint Venture (JV) partners in discussions on how these issues might be resolved. These discussions may also involve audits of some aspects of field management or of the field as a whole; or the use of experts to help resolve technical issues.

If the detailed evaluation and discussion envisaged in the process does not lead to agreement between DECC and the JV, DECC will use its licence powers to require the JV to improve its Stewardship of the field - this could involve DECC specifying a work programme to require the JV to carry out economic investment; or the replacement of the operator (if the operator is shown to be the root cause of poor stewardship). Good stewardship should however equate to attractive economic investment, hence in the majority of cases it is expected that improvement can be secured by normal commercial means by the JV; perhaps by realignment, the introduction of 3rd party investment or, possibly, divestment.

6.2 Divergence from the agreed Field Development Plan

All Field Development Plans should contain an agreed Management Plan for the commissioning and production phases of the development. The Management Plan will set out the principles and objectives on which continuing technical analysis, data gathering and resulting field management decisions will be taken. In addition, the Field Development Plan itself will have objective criteria by which the successful development of the field can be judged.

The responsibility for continuing to develop the field in accordance with the Field Development Plan and Management Plan rests with the Licensees. In order that the Department can satisfy itself that this responsibility is discharged effectively the Licensees are required to inform the Department as soon as significant deviations are foreseen. The Department may request a revised Field Development Plan to be prepared which identifies deviations from the agreed plan and proposes revised approaches to field development and management. It is not anticipated that detailed Revised Field Development Plans will be required routinely, and in many cases a letter advising the Department of a deviation from the agreed plan will be sufficient. However, where a further phase of development is to be implemented with substantial alterations to the size, development strategy or understanding of the field, or where major changes to existing facilities or new facilities are required, a more formal revision to the relevant sections of the Field Development Plan will be required. General guidelines for the preparation of a revised Field Development Plan are set out in Appendix 6. Any issues will be resolved following the procedure set out in these Guidance Notes.

It is possible that a change to the authorised Field Development Plan may require Environmental Impact Assessment under the Offshore Petroleum Production and Pipe-lines (Assessment of Environmental Effects) Regulations 1999 (as amended) This will initially also need to be discussed by the Licensees with the Licensing, Exploration and Development Branch's team manager.

6.3 Reporting

Following production start-up the Department will require limited monthly production data via the Petroleum Production Reporting System (PPRS). During the construction phase, deviations from the planned facilities completion programme should be reported. The Department will also require annual production, expenditure and activity data as part of the Stewardship review (see section 6.1 and appendices 11 and 12), and data on costs, sales volumes and prices from operators twice a year (which are passed to HMRC at field level but published only in aggregate - see https://www.gov.uk/oil-and-gas-taxation#government-revenues-from-uk-oil-and-gas-production).

The Department also carries out annual reviews of the UKCS oil and gas reserves (see https://www.gov.uk/oil-and-gas-uk-field-data#uk-oil-and-gas-reserves https://www.gov.uk/oil-and-gas-uk-field-data#uk-oil-and-gas-reserves) and compiles short and medium term UKCS production forecasts approximately every 6 months based on forecasts for each separate field and for undeveloped discoveries close to development (see https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/249323/production_projections.pdf).

The Department will require updated reserves and production forecasts from the operator to assist with these exercises. In addition, Oil & Gas UK annually collect data from operators on the future production and costs of their fields and undeveloped discoveries and share the data with DECC.

Following Development Plan authorisation, the Department will also require information on the equipment to be installed to be submitted via the “Facilities Information Request” (FIR) form on the Oil and Gas Portal (*link ?*). Every two years the Department provides updated facilities information for the OSPAR inventory (see http://www.ospar.org/content/content.asp?menu=00840305340000_000000_000000), and may request input from the operator.

6.4 Auditing process

In addition to the review of issues highlighted by the Stewardship process outlined above, there may be technical audits carried out periodically either on a random basis or as a result of concerns. These audits may be of a single aspect of the field management or of the field as a whole.

6.5 Cessation of Production (CoP)

Prior to the Department agreeing that production can cease permanently from a field, Licensees will have to satisfy the Department that all economic development opportunities have been pursued. To ensure that all issues are addressed thoroughly before agreement to CoP is required, Licensees should initiate discussions with the Department in a timely manner which, in the case of a large platform-based development, may be up to five years before agreement to CoP is required. On the successful conclusion of these discussions, Licensees will submit a Cessation of Production document which will form the basis of the Department’s agreement to CoP from the field. Guidelines for the content of the CoP document are provided in Appendix 7.

The **normal economic criterion for deciding when a field's production is no longer economic** and that production should cease **is that**, taken over a reasonable period, **the value of the hydrocarbons produced no longer covers the true costs of production**. In normal circumstances this maximises the economic value of the development and is a relatively straightforward calculation (1). However, two issues, residual value and leasing costs, have given rise to complications.

If the Licensees want the **residual value** of some or all of the production facility to be considered in the calculation, they will need to demonstrate that there is a definite opportunity to realise value which, if not realised at a specific time, will be forgone.

The treatment of **leasing costs** in the establishment of the economic cut-off has proved problematic and must be agreed in principle at the time the development is authorised. In general, the Department does not consider that unavoidable costs such as capital repayment and the costs of financing are true costs of production and they should, therefore, not be considered in the definition of the economic limit for Cessation of Production. The procedure that should be adopted during the development authorisation process should be, first, for the Department and the operator to work together to identify the true economic cut-off from estimates of the underlying production profile and operating cost. The Licensees should work with the potential Lessor(s) to reach a contractual agreement which will get as close to the theoretical economic limit as practicable, taking into account the need of the operator to manage the risk of the project. In cases where the Licensees are not able to achieve this objective the Department will wish to examine the position to establish if there are any genuine economic causes for this failure. It is recognised that uncertainty in the performance of the development and other technical and economic factors may complicate this process and the Department is willing to work closely with the operator to identify these risks and encourage the development of appropriate contractual frameworks which can take account of information gained during production.

There are instances when there may be a divergence between the CoP date that maximises economic recovery and the date the Licensees would choose on commercial grounds. For example, continued production from a field might impact on production on recovery from other fields in different ownership (whether directly - e.g. if there is pressure communication or in the case of a non-unitised field spanning two or more licence blocks - or indirectly) or contract prices and current market prices might diverge significantly. The treatment of situations such as these must be agreed in principle at the time the development is authorised.

If - as is often the case - the timing or cost of decommissioning the assets associated with a field are affected by the date of CoP, the (NPV) benefit (or cost) of deferring decommissioning should be a factor in the determination of the economic limit.

6.6 Storage of field information following cessation of production

Field information will have been gathered under the terms of Petroleum Production Licences and therefore should be kept in accordance with the relevant model clauses. It is also important that sufficient information is retained after CoP to enable other interested potential operators to take a reasonably informed view about the potential for field redevelopment. Redevelopment may become feasible if, for example, new technology allows a significantly improved recovery factor.

Prior to production from the field ceasing, the operator should create a "data catalogue" of relevant information. When production ceases, the operator may either (a) elect to retain the data and maintain it in perpetuity, or (b) place the relevant data in the National Hydrocarbons Data Archive (NHDA), the only alternative to perpetual data retention and the only way in which DECC can give relief from this obligation (further information on the NHDA can be found at www.bgs.ac.uk/nhda). The NHDA option is strongly preferred by DECC and is the only way to guarantee that DECC will not carry out ongoing scrutiny of long term management plans. The amount of information that should be placed in the archive will obviously depend on field size and complexity and this should be discussed with the NHDA, who will liaise with the Department's Field Development Team on a case-by-case basis at the appropriate time. As a minimum, the operator must fulfil the obligations for well and seismic data specified in the Petroleum Operations Notice 9 (PON9) including submission of catalogues to the 'DEAL Data Registry'.

The Department also expects operators to archive (or if not, retain) the final full-field reservoir simulation model, the final geological model and copies of the Field Development Plan, Field Reports and production and injection profiles on a well-by-well basis. It is recommended that operators begin preparations to place field data in the NHDA at least 2 years prior to the expected CoP date.

6.7 Decommissioning

The Petroleum Act 1998 provides that all parties with a decommissioning liability submit a Decommissioning Programme for the Secretary of State's approval at such time as may be specified. Guidelines on the preparation of Decommissioning Programmes are available https://www.gov.uk/oil-and-gas-decommissioning-of-offshore-installations-and-pipelines#overview or can be obtained direct from the Offshore Decommissioning Unit in Atholl House, Aberdeen.

The operator should discuss his plans with the Department's Offshore Decommissioning

Unit before submitting a programme so that guidance can be given on what is likely to be acceptable. These discussions should commence well ahead of the forecast CoP date and, in the case of a large field with multiple facilities, this may need to be three years or more in advance. The onus rests with the operator to initiate these discussions.

In accordance with the UK's international obligations, all installations emplaced after 9 February 1999 must be designed to be completely removed to shore for reuse, recycling or final disposal on land. A statement to that effect should be included in the Field Development Plan.

6.8 Licence Holding post decommissioning

The Licensees should include within the CoP document a statement of their intentions on licence holding following decommissioning. The Department would usually expect licensees to relinquish the relevant parts of the licence once production has permanently ceased. If the Licensees wish to retain part of the licence following decommissioning, they should include in the CoP document their plans for further activity on the licence to ensure it does not become fallow.

7. Changes of field operators and contracting-out of field management responsibilities

7.1 Changes of field operator

There have been several changes of operator for producing fields in recent years and this seems to be an increasing trend as the North Sea matures. The Department welcomes new operators and experience has shown that the new ideas and approaches brought forward by a change in operator can lead to significant extension in field life beyond original expectation and result in increased recovery of reserves for mature reservoirs.

The North Sea is generally acknowledged to be one of most challenging areas for oil and gas production in the world. At the same time the track record of existing operators in maximising hydrocarbon recovery through technical innovation is second to none. The Department is keen to maintain this record of excellence and prospective new operators will be screened carefully to assess their ability to manage UKCS oil and gas fields to maximise economic oil recovery with due regard for the environment. The licence requires that only an approved operator may manage or supervise the exploration and production phases of an oil or gas development. The objective of this requirement is to ensure that field operations are undertaken competently. Ministers theoretically have the discretion to approve multiple operators for a field but would need compelling evidence that a field could be developed competently under such a scheme.

The degree of scrutiny of a new prospective field operator will naturally depend on their existing track-record, both in the UKCS and elsewhere, of financial, technical, management and environmental competence. Detailed guidance on the information required from a prospective operator is given in Appendix 8.

To be appointed as an operator a company will need to show that it understands the development and environmental responsibilities of the operator and that it is competent, both financially and technically, to discharge these under its agreements with its co-Licensees. The company will need to be able to demonstrate a sound management structure staffed by an established group of experienced personnel. A prospective operator would normally be expected to have a proven track record of success in the operatorship of comparable developments elsewhere and have an approach to field development compatible with the Department's objective of securing maximum economic recovery from each field. A substantial use of contracted staff would need to be justified.

7.2 Leased facilities and contracting-out of field operations

There is an increasing trend for some activities traditionally undertaken by the appointed operator to be contracted out to third parties. The Department is aware of the potential benefits of this approach but is concerned that as a result of this contracting out the appointed operator will lose the ability to discharge its responsibility for the overall supervision and management of the development. The operator must retain sufficient expertise and resources to evaluate the quality of the work of a sub-contractor and be able to form an independent view as to whether the contractor's plans or activity accord with good oilfield practice and will result in the maximum recovery of economic hydrocarbons with due regard for the environment.

If a substantive part of the drilling or production operation is contracted out, the operator will be responsible for ensuring that the contractor is obliged to work in accordance with good oilfield practice and have suitably qualified and experienced staff working under an effective management system. The operator will need to supervise the work of the contractor, identify where obligations are not being met or where they require change and put in place an effective mechanism for the enforcement or modification of the contractor's obligations and actions.

Other than for unmanned developments, it is not currently anticipated that the operator would normally be able to fulfil these expectations without having a permanent presence at the development. It is recognised, however, that on some facilities where activity is at a low level, a permanent presence might not be appropriate and it is open to operators to discuss with the Department alternative means for ensuring that they are properly supervising and managing operations.

It should be noted that matters relating to the safety of operations are covered by regulations operated by the Health and Safety Executive and are quite separate from the functions of the operator described here.

8. Organisation of oil and gas responsibilities in the Department of Energy and Climate Change

An organogram of the oil and gas responsibilities of DECC staff is available on request from the Licensing, Exploration and Development Branch at:

3 Whitehall Place,
LONDON
SW1A 2AW

or

Atholl House
86-88 Guild Street,
ABERDEEN
AB11 6AR

8.1 Energy Development Unit

The Licensing, Exploration and Development Branch of the Department’s Energy Development Unit (EDU) has responsibility for developing and co-ordinating policy on the development of the oil and gas fields on the land territory of Great Britain, in the UK's territorial waters and on the UKCS and for regulating the licence regime. Within the Branch, which has offices in London and Aberdeen, technical specialists have responsibility for the technical aspects of policy and regulation, including review of Field Development Plans.

A technical team will be assigned to each field headed by a team manager whose relationship to the Department's senior management is similar to that of the project manager to the operator's senior management. Members of these teams, which will be based either in London or Aberdeen, will be drawn from the following disciplines:

- Geology and geophysics.
- Petrophysics and reservoir engineering.
- Facilities engineering.

Others within the Branch will be directly involved in the review of specific aspects of Field Development Plans. They provide advice during the review but also have responsibility, under separate legislation, for regulation when the plan is executed. The Field Development Plan provides their initial point of contact for the execution phase.

The metering section, based in Aberdeen, is responsible for agreeing with the Licensees the method of measurement to be used for oil and gas metering. The principles are agreed during the Field Development Plan review process - reference is made to Petroleum Operations Notice 6, and to the Departments *Guidance Notes for Standards of Petroleum Measurement* (September 1997)

The Branch has, in addition to the petroleum engineering teams noted above, groups responsible for:

- Pipeline works authorisations and consents covering pipeline works start-ups and returns to use;
- Administrative requirements of the development authorisation process and the issue of production and gas flaring consents;

During the review and evaluation of a Field Development Plan the technical team will also be assisted by economists and statisticians from within the Department.

EDU also has other Branches that deal with environmental matters associated with offshore oil and gas operations, and the ultimate decommissioning of disused infrastructure and pipelines

8.2 Other government interests

DECC and a number of other Government Departments are responsible for providing a range of consents and authorisations, under a variety of legislation, during the execution phase of a Field Development Plan. Licensees should note that authorisation for a Field Development Plan, given by the Secretary of State of Energy and Climate Change under the relevant licence model clause, is given in relation to that model clause only. It does not override, or imply any commitment in respect of, any other requirement to be satisfied under any other model clause or any other provision in legislation. The operator is responsible for ensuring legal compliance including that all necessary consents and authorisations are obtained as and when required. The operator is advised to make contact with all other Government bodies at the earliest opportunity; they should not rely on the submission of the Field Development Plan to alert these bodies of their intentions or to set the time frame for their discussions.

Although the Health and Safety Executive (HSE) is not involved in the authorisation of Field Development Plans, the Safety Case for design to be submitted to the HSE will need to show how the general principles of risk evaluation and risk management have been applied from the earliest stages of design. This should include design concept selection. Operators will therefore find it beneficial to open an early dialogue with HSE in relation to concept selection and conceptual design. Appendix 10 briefly explains HSE's role in the design process and gives contact details for OSD offices.

9. References

1. *The Oil and Gas Industry Task Force, A Template for Change* (September 1999), The Department of Energy and Climate Change. [Was surely DTI not DECC!]

2. *The Petroleum Act (1998),* ISBN 0-10-541798-X, The Stationery Office.

3. *Code of Practice on Access to Upstream Oil and Gas Infrastructure on the UK Continental Shelf. January 2009. [There is a later version.] Oil & Gas UK/Department of Energy and Climate Change*.

4. *Guidance Notes on the Offshore Petroleum Production and Pipe-Lines (Assessment Of Environmental Effects) Regulations 1999 (as amended)*, The Department of Energy and Climate Change.

5. *Guidance Notes for Standards of Petroleum Measurement* (Sept. 1997-Issue 5), The Department of Energy and Climate Change.

6. *The Oil Taxation Act (1975)*, The Stationery Office.

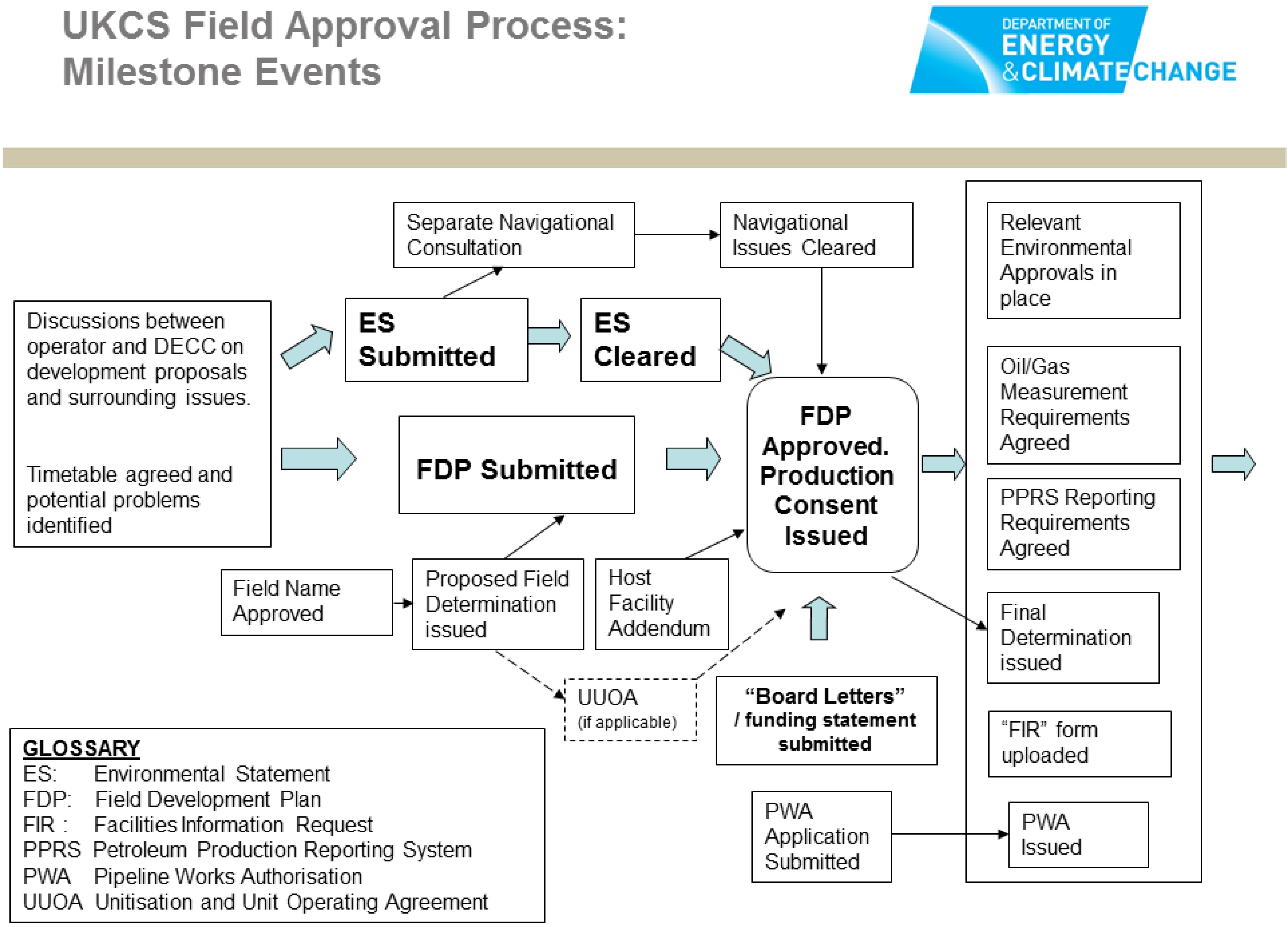
7. *The Offshore Petroleum Activities (Oil Pollution Prevention and Control) Regulations 2005 (OPPC Regulations),* The Stationery Office.

8. *Merchant Shipping (Oil Pollution Preparedness, Response and Co-operation Convention) Regulations 1998*, The Stationery Office.

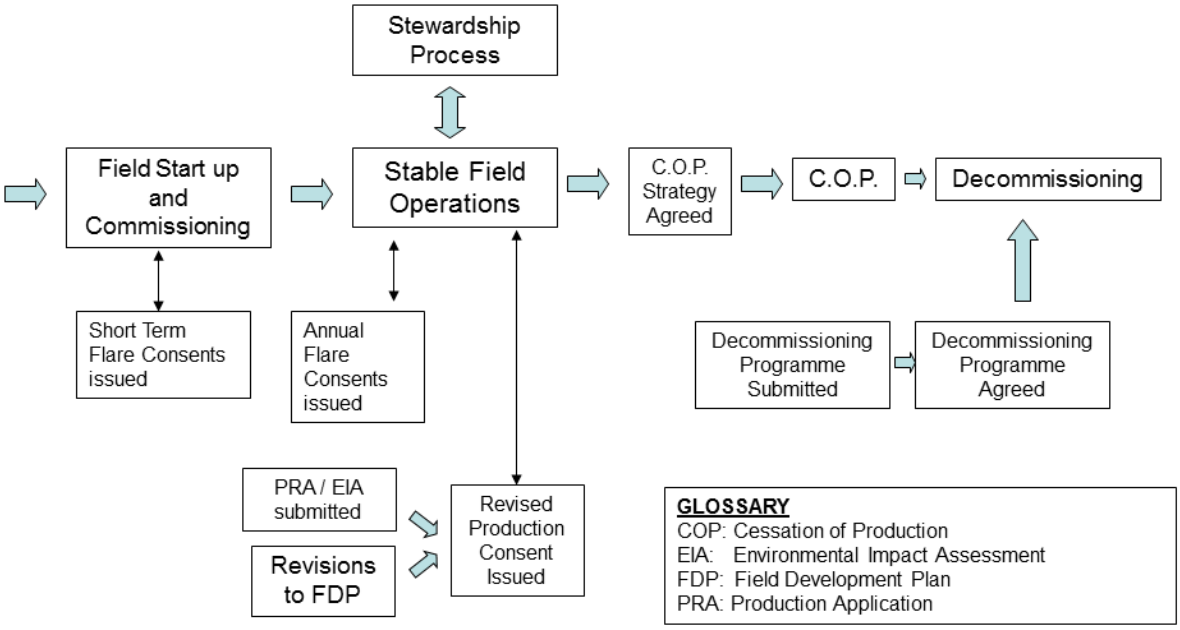
9. *Offshore Petroleum Production and Pipe-lines (Assessment of Environmental Effects) Regulations 1999 (as amended)*, The Stationery Office.

10. *Guidance Notes for Industry: Decommissioning of Offshore Installations and Pipelines under the Petroleum Act 1998*, The Department of Energy and Climate Change.

Appendix 1: Flow-chart of the field development authorisation process



UKCS Field Approval Process: Milestone Events Post Approval



Appendix 2 : Extracts from the model clauses

Set out below are extracts from the model clauses most relevant to these Guidance Notes. Model clauses covering the 1st to the 18th Rounds of Offshore Licensing are reproduced in the Petroleum (Current Model Clauses) Order 1999. The model clauses covering the 19th to the 21st Rounds are contained in SI 2004/352, and the 22nd to the 25th Rounds in SI 2008/25.

Model clause 15 (part only)

Development and production

15.- (1) The Licensee shall not-

(a) erect or carry out any relevant works, either in the licensed area or elsewhere, for the purpose of getting petroleum from that area or for the purpose of conveying to a place on land petroleum got from that area; or

(b) get petroleum from that area otherwise than in the course of searching for petroleum or drilling wells,

except with the consent in writing of the Minister or in accordance with a programme which the Minister has approved or served on the Licensee in pursuance of the following provisions of this clause.

(2) The Licensee shall prepare and submit to the Minister, in such form and by such time and in respect of such period during the term of this licence as the Minister may direct, a programme specifying-

(a) the relevant works which the Licensee proposes to erect or carry out during that period for either of the purposes mentioned in paragraph (1)(a) of this clause;

(b) the proposed locations of the works, the purposes for which it is proposed to use the works and the times at which it is proposed to begin and to complete the erection or carrying out of the works;

(c) the maximum and minimum quantities of petroleum in the form of gas and the maximum and minimum quantities of petroleum in other forms which, in each calendar year during the period aforesaid or in such other periods during that period as the Minister may specify, the Licensee proposes to get as mentioned in paragraph (1)(b) of this clause.

Model clause 21 (complete)

Avoidance

21.- (1) The Licensee shall maintain all apparatus and appliances and all wells in the licensed area which have not been abandoned and plugged as provided by working clause 17 hereof in good repair and condition and shall execute all operations in or in connection with the licensed area in a proper and workmanlike manner in accordance with methods and practice customarily used in good oilfield practice and, without prejudice to the generality of the foregoing provision the Licensee shall take all steps practicable in order-

(a) to control the flow and to prevent the escape or waste of petroleum discovered in or obtained from the licensed area;

(b) to conserve the licensed area for productive operations;

(c) to prevent damage to adjoining petroleum bearing strata;

(d) to prevent the entrance of water through wells to petroleum bearing strata except for the purposes of secondary recovery; and

(e) to prevent the escape of petroleum into any waters in or in the vicinity of the licensed area.

(2) The Licensee shall comply with any instructions from time to time given by the Minister in writing relating to any of the matters set out in the foregoing paragraph. If the Licensee objects to any such instruction on the ground that it is unreasonable he may, within fourteen days from the date upon which the same was given, refer the matter to arbitration in manner provided by clause 40 hereof.

(3) Notwithstanding anything in the preceding provisions of this clause, the Licensee shall not-

(a) flare any gas from the licensed area; or

(b) use gas for the purpose of creating or increasing the pressure by means of which petroleum is obtained from that area,

except with the consent in writing of the Minister and in accordance with the conditions, if any, of the consent.

(4) An application for consent in pursuance of paragraph (3) of this clause must be made in writing to the Minister and must specify the date on which the Licensee proposes to begin the flaring or use in question; and subject to paragraph (5) of this clause that date must not be before the expiration of the period of two years beginning with the date when the Minister receives the

application.

(5) If the Minister gives notice in writing to the Licensee stating that, in consequence of plans made by the Licensee which the Minister considers are reasonable, the Minister will entertain an application for consent in pursuance of paragraph (3) of this clause which specifies a date after the expiration of a period mentioned in the notice which is shorter than the period mentioned in paragraph (4) of this clause, an application made in consequence of the notice may specify, as the date on which the applicant proposes to begin the flaring or use in question, a date after the expiration of that shorter period.

(6) Before deciding to withhold consent or to grant it subject to conditions in pursuance of paragraph (3) of this clause, the Minister shall give the Licensee an opportunity of making representations in writing to the Minister about the technical and financial factors which the Licensee considers are relevant in connection with the case and shall consider any such representations then made to him by the Licensee.

(7) Consent in pursuance of paragraph (3) of this clause shall not be required for any flaring which, in consequence of an event which the Licensee did not foresee in time to deal with it otherwise than by flaring, is necessary in order-

(a) to remove or reduce the risk of injury to persons in the vicinity of the well in question; or

(b) to maintain a flow of petroleum from that or any other well;

but when the Licensee does any flaring which is necessary as aforesaid he shall forthwith inform the Minister that he has done it and shall, in the case of flaring to maintain a flow of petroleum, stop the flaring upon being directed by the Minister to stop it.

(8) The Licensee shall give notice to the Minister of any event causing escape or waste of petroleum, damage to petroleum bearing strata or entrance of water through wells to petroleum bearing strata except for the purposes of secondary recovery forthwith after the occurrence of that event and shall, forthwith after the occurrence of any event causing escape of petroleum into the sea, give notice of the event to the Chief Inspector of Her Majesty's Coastguard.

(9) The Licensee shall comply with any reasonable instructions from time to time given by the Minister with a view to ensuring that funds are available to discharge any liability for damage attributable to the release or escape of petroleum in the course of activities connected with the exercise of rights granted by this licence; but where the Minister proposes to give such instructions he shall

before giving them-

(a) give the Licensee particulars of the proposal and an opportunity of making representations to the Minister about the proposal; and

(b) consider any representations then made to him by the Licensee about the proposal.

Model clause 25 (part only)

Unit

25.-(1) If at any time in which this licence is in force the Minister shall be satisfied that the strata in the licensed area or any part thereof form part of a single geological petroleum structure or petroleum field (hereinafter referred to as "an oil field") other parts whereof are formed by strata in areas in respect of which other licences granted in pursuance of -

(a) the Act of 1934, or

(b) that Act as applied by the Act of 1964, or

(c) Part I of the Act of 1998,

are then in force and the Minister shall consider that it is in the national interest in order to secure the maximum ultimate recovery of petroleum and in order to avoid unnecessary competitive drilling that the oil field should be worked and developed as a unit in co-operation by all persons including the Licensee whose licences extend to or include any part thereof the following provisions of this clause shall apply.

Appendix 3: Maximising economic recovery

The very high costs of developing an oil or gas field, which can only be recovered from significant production, mean that the national interest and commercial imperatives are generally similar in relation to maximising production. However, there may be cases where they could diverge. Some examples are:

a. Where a field covers more than one block, with different owners. Attempts to gain higher shares in total output (i.e. capturing other companies' reserves) could damage reservoirs and result in needless expenditure.

b. Where production is via a floating production system. These have high operating costs, so there is an incentive to cream off high early production and move to the next location, rather than produce all the economic oil.

c. Where company capital constraints point them towards a lower cost, but less economic, development option which could leave potentially economic reserves unproduced.

d. Where severe cash constraints lead Licensees to prefer options which emphasise the need for early cash at the expense of additional recovery, or result in additional gas flaring.

e. Where partners disagree amongst themselves. Almost all licences are held jointly by a number of partners, which introduces scope for disagreement between the Licensees, though joint holding of licences is an important risk sharing device.

The approach taken by the Department is to ensure that, at the planning stage, the Licensees have examined those options which are most likely to secure the full recovery of the economic reserves of the area. In most cases the preferred commercial option will achieve this but, as explained above, cases can arise where wider UK interests and commercial interests differ. In such circumstances the Department will, in discussion with the operator, wish to obtain a full appreciation of the commercial factors and constraints involved, and explain why it believes wider UK interests are not being served by a particular option.

In examining Field Development Plans for new fields, and significant departures proposed from authorised Plans for existing fields, the Department will in particular wish to be satisfied that the approach agreed does not lead to the permanent loss of reserves which could otherwise be recovered economically. In looking at the wider picture, the Department focuses on those options which are most likely to secure maximum economic recovery of hydrocarbon reserves from the reservoir in question, taking into account other potential reserves in the area. The welfare of the UK as a whole will be highest when the net present value (NPV) of field development is maximised, taking into account the effect on recovery in other fields. This is irrespective of the division of realised value between the Licensees and the Exchequer. In ranking options the Department thus focuses on *pre-tax* NPVs calculated using an appropriate discount rate (currently, 10 per cent real).

Appendix 4: Preparation of a Field Development Plan

General approach

The approach taken by the Department to the process of field development authorisation is to establish whether there are any aspects of the proposed development which may conflict with the Department's objectives and to focus attention on resolving those aspects before the formal Field Development Plan is submitted. *Where all issues have been resolved the Field Development Plan will contain only a summary of the field and choice of development, with a more detailed description of the form of the development, its management and expected production.*

To assist this process it is expected that there will be a continuing dialogue and informal technical reviews as the description of the field and options for its development emerge during the development planning phase. There will not be routine, detailed examination of the operator's technical work unless it is established that there may be substantive issues. If issues are identified then a more detailed investigation of the elements of the development essential for the resolution of these will be made, and the Licensees will be expected to work towards justifying the plans before the Field Development Plan is submitted. For some developments it is expected that there will be no substantive issues identified and accordingly there will be no detailed examination of the Licensees technical work.

If the process outlined above is followed the Field Development Plan documentation be prepared towards the end of the development planning process, require only minor revisions to reach its final form and should be consented within one month of submission of the final document.

Audits

In addition to the process described above, there may be a technical audit carried out on elements of the development. The purpose of the audit will be to confirm the general quality of work, not to identify areas of disagreement of interpretation. It will not be necessary to prepare any technical documentation, either for inclusion in the Field Development Plan or as background support, in the expectation of an audit. It is expected however that, if required for any aspect of the development, the operator will be able to demonstrate a trail leading from uninterpreted data to statements in the Field Development Plan.

Alternative approaches

It is recognised that this approach, although favoured by the Department, may not suit Licensees wishing to use the Field Development Plan as a comprehensive reference document or who feel that the approach is unsuited to their internal organisation. In this case the submission of a different form of document, provided it covers the same issues, is acceptable. Licensees wishing to adopt an alternative approach should realise that a proposal that is not the result of a continuing dialogue with the Department will necessarily take longer to approve.

Content of the Field Development Plan

Set out below are suggested Field Development Plan section headings together with the topics which should be addressed in the Field Development Plan. The actual content of the document should be agreed with the Department's field team and will depend on the complexity of the field, the degree of interaction prior to the submission and the number of issues identified. The Field Development Plan will provide a clear explanation of the **commitments** that the Licensees are making (in terms of facilities, number of wells, provision for IOR/EOR, provision for 3rd party access hydrocarbon export routes etc.) to bring forward a sound development, rather than a detailed technical description of the subsurface reservoir description or required infrastructure. It is anticipated that, for small field developments, e.g. involving a subsea tie back to an existing platform, the norm for Field Development Plan documentation will be in the region of a maximum of 15 pages of text plus associated figures and tables. More comprehensive or varied text, which some operators might for example choose to submit for partner reasons or internal preferences, will be accepted provided it covers the Department's information requirements. For larger new field developments, or developments involving more complex or challenging reservoirs, a more comprehensive document may be required. The operator should discuss the expected scope for the FDP document with the Department's field team early in the process

Only very brief summaries will be required for reservoir description (section 2), although operators will be expected to keep their own detailed record of how the reservoir model was arrived at as part of good oilfield practice. The section should also contain sufficient information on the reservoir to enable its suitability for Enhanced Oil Recovery techniques to be assessed

The actual form of the development and the basis for field management should be described in section 3 and sufficient detail will be required to permit development and production performance to be measured. Operators are encouraged to refer to internal documents and studies in sections 2 and 3 to keep Field Development Plan documentation to a minimum.

The Field Development Plan should be submitted formally by uploading a digital copy (preferably pdf) as an attachment to the portal application for Development and Production Consent

Field determination

Field Determinations are required under Schedule 1 to the Oil Taxation Act 1975 and are based on geological grounds. The information necessary to define the structure and geological model of the field will normally be adequate for the Licensing, Exploration and Development Branch to make the Determination. A proposed Field Determination will be issued prior to the authorisation of the Field Development Plan. The final Determination will not be issued until the FDP is authorised. See Appendix 5 for further information.

A field may need to be Determined prior to an Extended Well Test if a substantial quantity of hydrocarbon is to be won and saved. This should be discussed with the Department prior to EWT consent.

Development area

The Development Area identifies that part of the field to which the development proposals refer, which may coincide with area defined by the Field Determination. Some Licensees may, however, wish to consider a phased development and the Development Area in this instance will be limited to that part of the field addressed in the detailed first phase proposals. The Development Area will be extended with subsequent phases.

Suggested contents of the Field Development Plan

1. Executive summary

The Executive Summary should state the essential features of the development including:

- A brief description of the hydrocarbon reservoirs, reserves, development strategy, facilities and pipelines.
- An outline map showing the field limits, Field Determination boundary, Development

Area boundary, contours of fluid contacts, existing and proposed wells and licence boundaries.

- A project schedule, total capital cost and a statement of licence interests.
- A central estimate of ultimate recovery, and the minimum, central and maximum hydrocarbon production profiles of:

  gas, in thousand cubic metres and billion cubic feet per year;

  oil, in thousand metric tonnes and in million US barrels per year.

- A statement of intent towards any parts of the field not addressed by the plan including any commitment to later development of that area, or to the later stages of a phased development. Any provision for the development of other hydrocarbons in the area should also be identified.
- The essential elements of the Field Management Plan.
- A statement of the provision for decommissioning and an undertaking that the field will be decommissioned in accordance with the requirements of the applicable international and domestic law in force at the time of decommissioning.

2. Field description

The purpose of this section is to present the description of the field on which the development has been based and so provide a baseline for future modifications as development proceeds.

The description should be in summary form and only a brief statement, table or map of the results provided with references to more detailed company-held data where appropriate.

Figures, diagrams and data tables

Licensees are encouraged to submit only those maps, sections and tables necessary to define the field adequately but should include at minimum a table of in-place hydrocarbon volumes, a representative cross-section and top structure maps for each reservoir. Maps should be in subsea depth at appropriate scales and include co-ordinates in degrees of latitude and longitude and the standard U.T.M. grid, stating the central meridian used and datum.

2.1 Seismic Interpretation and Structural Configuration

A brief summary of the extent and quality of the seismic survey and the structural configuration of the field should be presented using appropriate figures and maps.

2.2 Geological Interpretation and Reservoir Description

The stratigraphy of the reservoirs, facies variations, the geological correlation within the reservoir and any other relevant geological factors that may affect the reservoir parameters (both vertically and horizontally) and thereby influence reservoir continuity within the field should be described in summary form. Figures and maps should be provided where appropriate.

The geological data provided should reflect the basis of reservoir subdivision, and correlations within the reservoir, and should include the relevant reservoir maps on which the development is based , including a top structure map and cross sections showing the main reservoir units

2.3 Petrophysics and Reservoir Fluids

A brief summary of the key field petrophysical parameters should be presented incorporating log, core and well test data.

A summary of the field PVT description and fluid analyses should be included.

2.4 Hydrocarbons-In-Place

The volumetric and any material balance estimates of hydrocarbons-in-place for each reservoir unit should be stated together with a description of the cause and degree of uncertainty in these estimates.

The basis of these estimates should be available and referenced.

2.5 Well Performance

The assumptions used in the Field Development Plan for the productivity and injectivity of development wells should be stated. Where Drill Stem or Extended Well Tests have been performed the implications of these on production performance should be given. The potential for scaling, waxing, corrosion, sand production or other production problems should be noted and suitable provision made in the Field Management Plan (Section 3.7).

2.6 Reservoir Units and Modelling Approach

Where the reservoir has been subdivided for reservoir analysis into flow units and compartments the basis for division should be stated. A description of the extent and strength of any aquifer(s) should be given.

The means of representing the field, either by an analytical method, some form(s) of numerical simulation, or by a combination of these should be briefly described.

2.7 Improved and Enhanced Recovery Techniques

A summary of the alternative recovery techniques considered and the reasons for the final choice is required. Methods for targeting improved recovery (IOR) (either mechanical or operational) should be described - where none are proposed this should be justified

For all oil or condensate reservoirs the potential for application of improved recovery techniques beyond conventional methods, conventionally referred to as Enhanced Oil Recovery, should be described. Where a field demonstrates economic potential for EOR, licensees should set out their firm plans to implement this and where definite conclusions cannot be reached, a programme for addressing the outstanding issues during production should be given in the Field Management Plan (Section 3.7), and provisions made in the design of the wells and production facilities to enable it (EOR) in the future set out under Drilling and Production Facilities (Section 3.2). These provisions will include, amongst other things, weight and space for retrofitting equipment such as desalination equipment for Low Salinity Water Flooding EOR techniques, storage for chemical EOR such as Polymer/Surfactant flooding, and ensuring that both wells and production facilities are EOR ready, or can be readily made so. If the facilities are not to be made ready for EOR, then an explanation for this must be provided, including indicative costs to make facilities and wells EOR ready.

2.8 Reservoir Development and Production Technology

The chosen recovery process should be described and the optimisation method summarised, including reference to the methods used for integrated modelling of wells, flowlines and production facilities. The basic requirements for well completion design should be stated, in particular the potential for water shut off, artificial lift and stimulation should also be discussed. Progressive technology for reservoir monitoring and remote intervention (eg. intelligent wells, fibre optic across the reservoir) should also be discussed (either here or in section 2.7). The potential for scaling, waxing, corrosion, sand production or other production problems should be noted and suitable provision for mitigation made in the Field Management Plan (Section 3.7). Any limitations on recovery imposed by production technology (e.g. flow assurance issues in late field life) or by the choice of production facility or location should be indicated.

Remaining uncertainties in the physical description of the field which may have material impact on the recovery process should be described and a programme to resolve these should appear in the Field Management Plan (Section 3.7).

3. Development and management plan

The purpose of this section is to set out the form of the development, describe the facilities and infrastructure, and establish the basis for field management during the construction and production phases. For every element of the plan the description should be brief and related to the complexity of the facility or strategy concerned. Where a particular topic is not relevant to a development it should be omitted.

The general requirements for the section are set out below. Where an aspect of a development is simple the text should be correspondingly short and the entire section no more than five pages of text in length. Figures and tables should be used where appropriate and the referencing of existing documents is encouraged providing these are made available.

A statement confirming that all installations will be completely removed to shore for reuse, recycling or final disposal on land is required in accordance with the UK's international decommissioning obligations.

3.1 Preferred Development Plan, Reserves and Production Profiles

This section should describe the proposed reservoir development indicate the drilling programme, well locations, expected reservoir sweep and any provision for a better than expected geological outcome. Proposed well locations should be shown on both the maps and cross sections referred to in section 2.2

An estimate of the range of reserves for each reservoir should be given (excluding fuel and flare) with a brief explanation of how the uncertainty was determined and explicit statements of probability where appropriate. For more complex reservoirs, in particular where EOR processes need to be considered, the range of reserves for each reservoir flow unit and compartment should be given. The assumed economic cut-off should be stated.

Expected production profiles, for total liquids, oil, gas, gas usage and flare, associated gas liquids and produced water for the life of the field are required. Where fluids are to be injected, annual and cumulative injection profiles should be provided. Quantities should be provided in both metric units and in standard oil field units. Information to allow calculation of sales quantities should be provided.

The anticipated date for Cessation-of-Production, together with the underlying assumptions, should be provided.

3.2 Drilling and Production Facilities

The drilling section should briefly describe the drilling package and well workover capability,. There should be a description of the proposed well completion philosophy and figure(s) showing casing and completion, with main components' diameters and depths relative to the lithological main units and reservoir depths. A reference to a wells Basis Of Design (which is consistent with the reservoir development and management plan) should be provided

The production facilities section should describe the major equipment and infrastructure items and identify the design and operating parameters used as the basis of design. Estimated jacket and topsides weights should be provided for platform developments. A clear indication of system bottle-necks and limitations that can give rise to production constraints should also be given together with details of the contingencies available to maintain production in the event of major equipment failure(s). The scope and flexibility for future modification and expansion to address any potential for upside, incremental and satellite field development should also be identified, including any spare capacity designed-in to the facilities/pipelines to allow for future development (including the application of improved recovery techniques) or third party tie-ins. The studies forming the basis for the selection of the proposed development option should be referenced.

The section should include a diagram of the structures for the development, whether fixed, floating or subsea and should also include a description of the proposed hydrocarbon transportation system including, where appropriate, any onshore terminal facilities. Any limitations on offshore production resulting from constraints in the transportation and terminal facilities should be identified.

Where a development utilises an FPSO, a diagram of the anchor pattern should be included. If any of the anchors transgress into neighbouring licensed blocks then it must be stated that the agreement of the licensees of the adjacent block(s) has been obtained and it has been confirmed that this will not interfere with any activities proposed on the adjacent block. If, when an FDP receives authorisation, the anchor pattern is not known then a statement of commitment that such agreements will be gained should the subsequent pattern be such that they are required must be included. If the anchors are to be located on unlicensed acreage, the operator should seek clarification from DECC that this will not interfere with any proposed future licensing activities.

Where a rig is to be located for development drilling such that its anchors temporarily transgress into neighbouring licensed blocks, then it must be stated that the agreement of the licensees of the adjacent block(s) has been obtained and it has been confirmed that this will not interfere with any activities proposed on the adjacent block(s). If the pattern is not known at the time an FDP is authorised, then a statement of commitment that such agreements will be gained should the subsequent anchor pattern be such that they are required must be included. Where the anchors are to be located on unlicensed acreage, the operator should seek clarification from DECC that this will not interfere with proposed future licensing activities.

New transportation systems are often designed to service more than one development and may have a longer expected life than the originating field. In this instance a separate Field Development Plan for the transportation system may be necessary.

3.3 Process Facilities

A brief description of the operating envelope and limitations of the process plant should be provided. The use and disposal of separator gas should be described.

The section should also include:

- A summary of the main and standby capacities of major utility and service systems, together with the limitations and restrictions on operation. The design and operating philosophy for key equipment items should be discussed (eg 1st stage production separator 1 x 100% , Inlet heater to 1st stage separator 2 x 100% , Powergen sets 3 x 50%) . A Process Flow Diagram should be provided
- A summary of the method of metering hydrocarbons produced and utilised.
- A brief description of systems for collecting and treating oil, water and other discharges.

- A brief description of any fluid treatment and injection facilities.
- A brief description of the main control systems and their interconnections with other onshore or offshore facilities.

3.4 Project Planning

Commissioning plans will be discussed in greater detail as the project develops, but it should be noted that the commissioning programme will need to demonstrate a commitment to preventing the unnecessary and wasteful flaring of associated gas.

3.5 Decommissioning

A very brief description of the proposed methods of decommissioning should be included to show the basis for the decommissioning expenditure estimates. Steps taken in the design to facilitate eventual decommissioning of the production facilities should be identified.

3.6 Costs

Cost information is required by the Department to assess the economics of the development and to allow forecasting of North Sea expenditure.

Capital (Capex) and Operational (Opex) expenditure profiles are required, phased by year, to a defined monetary base in UK pounds sterling.

Capex and Opex tabulations should be subdivided into:

- Pre-Project Costs (Seismic, Exploration Drilling, Appraisal Drilling, Studies: money of the day costs are acceptable here)
- Drilling Capex.
- Facilities Capex.
- Decommissioning expenditure.
- Field Opex, excluding Tariffs.
- Tariff Opex.

A spreadsheet entitled the Common Reporting Format (CRF) is provided for operators to fill out in order to aid DECC in reviewing this data. operators should, upon completion, e-mail the CRF to DECC at mike.earp@decc.gsi.gov.uk

Details are required of the tariffing arrangements and gas contracts where applicable and if these are different to those previously notified to the Department. Where these arrangements are commercially sensitive, a limited circulation 'side letter' will be acceptable.

The information on tariffs should include:

- Total fixed and variable costs for the use of Facilities or Pipelines, phased annually.
- Base cost per barrel, escalation factors, and escalation lags.

The information on Gas Contracts should include:

- Base gas price (pence/therm), the escalation factors, the lag period, the base values for escalation factors and the contract duration.

3.7 Field Management Plan

A Field Management Plan is required that sets out clearly the principles and objectives that the Licensees will hold to when making field management decisions and conducting field operations and, in particular, how economic recovery of oil and gas will be maximised over field life.

(The plan, as described here and in different sections of the FDP, must show clear and consistent linkage between reservoir development plans, well designs and subsea facilities, and process facilities).

The rationale behind the data gathering and analysis proposed in order to resolve the existing uncertainties set out in Section 2 and understand dynamic performance of the field during both the development drilling and production phases should be outlined. The use of unmanned or subsea facilities may set restrictions on data gathering, these should be identified.

The potential for workover, re-completion, re-perforation and further drilling should be described. Where options remain for improvement to the development (eg as discussed in Sections 2.7 and 2.8) or for further phases of appraisal or development, the criteria and timetable for implementing these should be given.

Some developments will include common user facilities and may have capacity constraints; the methods to be used to set production priorities should be given. For gas reservoirs the criteria for installation of additional compression should be identified.

Appendix 5 : Determination of fields

Legislative framework

Under Schedule 1 to the Oil Taxation Act 1975 all fields are "Determined", i.e. defined, as areas of which every part is, or is part of, a licensed area. Parliamentary debate during the passage of this Act made clear that these field areas would be Determined only on the basis of geological criteria and that an oil field would be as defined in the Petroleum (Production) Act 1934, that is a single petroleum geological structure.

A Field Determination is therefore a boundary that encompasses the maximum extent of the field. This is taken as the maximum extent of all the hydrocarbons present, whether moveable or not, and regardless of whether the entire accumulation is in phase and/or pressure communication. It follows that for a hydrocarbon accumulation to be Determined as a field it must be physically separated from any other accumulations that might be present. This separation may be by means of a structural low below the lowest known hydrocarbon ("blue water") or by non-permeable rock e.g. a shale-out of the reservoir. Both structural and stratigraphic traps can therefore be Determined as fields.

However, since May 2008 licensees have been able to apply for currently unexploited parts of previously determined PRT-paying fields to be determined as new, separate fields, which would thus be "non-taxable" i.e. exempt from PRT where they can demonstrate that development is contingent on obtaining non-taxable status (see Field boundary re-determination).

The boundaries for offshore fields seaward areas (outwith the 3 nautical mile limit) east of the meridian 6 degrees west follow a latitude and longitude graticule based upon the geographical co-ordinate system ED50 (European Datum 1950).

The boundaries for offshore fields seaward areas (outwith the 3 nautical mile limit) west of the meridian 6 degrees west follow a latitude and longitude graticule based upon the geographical co-ordinate system ETRF89 (European Terrestrial Reference Frame 1989).

Onshore fields and those within the offshore landward 3 nautical mile limit, are defined in grid terms based upon the projected co-ordinate system OSGB National Grid/OSGB36.

The only exceptions to this are where a field either crosses an international boundary or extends from an offshore landward licence to areas beyond the 3 nautical mile limit.

Reference should be made to the DTI Gazette article published 21st December 1999 entitled "Co-ordinate systems for UKCS Petroleum Exploration and Production Licences" for details of the co-ordinate transformation parameters to be applied when transforming between ED50, ETRF89, OSGB36 and WGS 84.

Where fields classified as separate structures overlap vertically, they have to be defined as "volumes" with a base and/or top to the determination.

The Field Determination and Field Development Area are generally coincident although this is not mandatory.

Field determination process

A Field Determination is generally initiated by the submission of a Field Development Plan. A proposed Determination must have been issued before the Field Development Plan is authorised.

The proposed Field Determination is issued by the Department to all Licensees involved in the field together with any others whose interests appear to be affected. The recipients of the proposed Determination have 60 days from the date of receipt to make any objections they may have to it in writing. Should objections be received, the Licensees concerned are given the opportunity to put their case in more detail. All representations are considered but the final decision on the Determination rests with the Department acting on behalf of the Secretary of State. Once any objections have been resolved, a final Determination is issued, provided the Field Development Plan has been authorised. The Determination must be in place before production commences from the field.

All Fields may be re-determined at any time at the request of any party should new geological and/or geophysical data indicate that the original Determination is no longer valid. An identical procedure to that described above is followed.

As all fields are Determined, i.e. defined, as areas of which every part is, or is part of, a licensed area it follows that when such a licensed area is relinquished the field in question should be re-determined to exclude that area.

Appendix 6 : Guidance on the Preparation of a Revised Field Development Plan

These notes have been prepared to provide guidance to field operators engaged in preparing revised Field Development Plan for producing oil and gas fields. The purpose of the revised Field Development Plan is both to advise the Department of divergence from the authorised Field Development Plan and to demonstrate that the field is being managed in a manner that will maximise economic recovery of hydrocarbons. The document should be used to propose revisions to Section 3 (Development and Management Plan) of the original Field Development Plan as the understanding of the field improves. Any issues will be resolved following the procedure set out in section 4 and appendix 4 of these Guidance Notes.

For a project to qualify for a Brown Field Allowance it needs to be supported by an approved addendum to the Field Development Plan (link to general BFA guidance). All such addendums should clearly set out the scope of the proposed incremental project and state the incremental costs and the incremental reserves involved.For the guidance of operators there is a check list attached which identifies the general requirements, but operators are encouraged to agree an alternative form of document if this would be more appropriate to the individual field. Specific requirements for Brown Field Allowance FDP addenda are also set out below. Internal or partner documentation which satisfies or exceeds these requirements will also be acceptable. The revised Field Development Plan is not intended as a detailed data source or account of activities carried out during the period since Field Development Plan authorisation but should be used to identify departures from the expected performance and planned development. It is not anticipated that detailed Field Development Plan revisions will be required routinely, and operators are encouraged to discuss the level of detail required by the Department prior to preparing a revised Field Development Plan.

Check-list for the contents of a revised Field Development Plan

1. Introduction

A brief review of the field operations and performance, with divergence from the Field Development Plan noted and discussed in more detail in later sections. Any changes in licence equity should be noted.

2. Field description

2.1 Hydrocarbons initially in place and recoverable reserves
Changes in estimates of hydrocarbons initially in place and reserves should be identified by reference to the Field Development Plan base case or to the case in any previous FDP revision.

2.2 Well status and operations
A table summarising changes in well status (e.g. producer/injector, suspended/abandoned, perforated intervals, reservoir identifier, lift provision) should be included).

2.3 Geology
Where drilling, seismic re-processing or other work has had a significant impact on the reservoir model a summary of the results should be provided together with a map in subsea depth giving the current interpretation of the top structure and showing well locations and fluid contacts (by reservoir if appropriate).

2.4 Field facilities and infrastructure
A brief report on the performance of the field production facilities highlighting features that

have impeded operations and also valuable improvements. A forecast of the changes planned for the facilities, and where appropriate the related infrastructure, should be provided in Section 3.5 (see below).

3. Development and management plan

3.1 Field management
Changes in development strategy should be reviewed. Important reservoir monitoring results, reservoir monitoring limitations and specific production difficulties should be summarised. Where appropriate, plots of reservoir pressure and voidage replacement should be provided. Future Plans for reservoir monitoring should be briefly discussed.

3.2 Studies
Results and relevance of geoscience, reservoir or facilities / pipeline engineering studies completed during the reporting period should be summarised. Plans and timescale for ongoing and future studies should be discussed.

3.3 Improved Oil Recovery (IOR)
Where improved recovery has not been addressed in the Field Development Plan, the potential should be reviewed, and the results of any studies or operations discussed.

3.4 Forecasting
A comparison between the current forecast and the Field Development Plan production and injection profiles (or those agreed revisions made in earlier FDP revisions) and the current production consent should be provided, together with the current estimate of the Cessation-of-Production date.

3.5 Proposed changes to the Field Development Plan
This section provides the means for formally proposing revisions to the development and management plan set out in section 3 of the approved Field Development Plan. Proposed changes to explicit or implicit commitments or to conditions in the authorisation should be set out clearly as should plans to extend the development beyond the Development Area. The need to include other deviations should be discussed with the Licensing, Exploration and Development Branch's team manager.

Where appropriate a summary of longer term development opportunities within or around the field, including potential for recovering third party hydrocarbons, should be provided. Progress in developing opportunities already identified should also be reviewed.

Where changes in the facilities and infrastructure are planned the proposed modifications should be summarised, together with estimates of OPEX and CAPEX. Where an incremental project is planned the corresponding incremental production should be identified.

The Production Efficiency assumed for the production forecasts should be stated, and compared with the current PE for the facility. Where appropriate, measures to improve PE should be stated.Where facility modifications on a host platform are planned for a satellite development for a different operator, the proposed changes should be addressed in a revised FDP for the host field and only a cross reference provided in the FDP for the satellite field. Available topsides or pipeline capacity for any potential future tie-in developments and any associated limiting factors should be described.

3.6 Field capital and operating costs
CAPEX and OPEX profiles should be provided on an annual basis, categorised as follows:

- Drilling Capex.
- Facilities Capex.

- Decommissioning expenditure.
- Field Opex, excluding Tariffs.
- Tariff Opex.

A spreadsheet entitled the Common Reporting Format (CRF) is provided for operators to fill out in order to aid DECC in reviewing this data, (see section 3.6 of Appendix 4 Preparation of a Field Development Plan.) For incremental projects, in order to understand the impact of the incremental project the Department requires two versions of the CRF to be completed: one for the "Base Case" (no incremental development) and one for the base case plus incremental development. Operators should discuss this with the Department prior to submitting the revised FDP. operators should, upon completion, e-mail the CRF to DECC at mike.earp@decc.gsi.gov.uk.

Check-list for the contents of a Field Development Plan Addendum for Brown Field Allowance

(ie cases where an FDP addendum is being submitted solely to support an application for BFA and where an FDP addendum would not otherwise be required)

Executive summary

The field location, block(s), licence(s), licensee)(s) and their percentage interests should be stated.
A brief description of the existing development strategy / current facilities / Host platform should be provided
A summary of the scope of the incremental project, together with the “Key element(s)” of the project and timings of the main events.

Subsurface

A summary of methods used to derive incremental reserves should be provided
(eg simulation, decline curve, contacted STOIIP/GIIP x recovery factor, etc) and how incremental reserves for the water injectors have been attributed
A summary of the key uncertainties
A table of new wells , incremental reserves and costs per well should be included (For sidetracks, the donor well should be identified).
Overhead project costs (eg mobilisation/demob) and any incremental reserves from field life extension should also be indicated

Plots of production profiles – the base case and base+increment (as set out in crf) and a comparison with the current Production Consent should be provided. Water production and water injection profiles should also be included where appropriate (eg when changes to water injectors or injection facilities are being proposed as part of the incremental project).

Facilities

A brief description of any facilities changes (or confirmation there aren’t any) should be provided.

The Production Efficiency assumed for the production forecasts should be stated, and compared with the current PE for the (host) facility. Where appropriate, measures to improve PE should be stated.

The impact of the additional production from new wells , especially backout (including other fields sharing same facility) should be stated. Impact of the proposed incremental project on currently proposed or possible future third party tie backs should also be described.

Utilisation of the additional gas production should be described (export, fuel, flare). If it is to be used for fuel gas, will it replace imported gas or diesel use?

For subsea projects, methods for testing new wells should be described

A diagram showing any new subsea kit (well heads/trees/WHPSs, pipelines, umbilicals) should be included.

A Gannt chart (or similar) showing the project timetable should be provided. The impact of an PoB limitations on other potential incremental projects should be stated

Decommissioning
The incremental decommissioning cost estimate should be indicated

Appendix 7 : Guidelines for a Cessation of Production document

The amount of detail required in the Cessation of Production (CoP) Document will depend on the size and complexity of the field and its production facilities. It is recommended the operator discusses the format of the CoP document with the Department before detailed drafting begins.

The document should provide:

Executive summary
A management summary of what is in the body of the document. The summary should also contain a statement of the Licensees' intentions with regard to retention of relinquishment of the licence following decommissioning.

Field economic limit criteria
This section should include a detailed analysis of:

- Definition of economic limit.
- Determination of cut-off rates and timing.
- Cash flow over the period up to this economic limit and approximately 2 years beyond.
- It is important to include detailed information on any factors that would advance or postpone the economic limit so that the Department can form a view as to the main sensitivities and uncertainties involved.
- The costs and any revenues associated with CoP itself (capital and operating expenditures and any residual value of field assets).
- The form and costs of abandonment if these affect the timing of the economic limit.

Field life extension - options investigated
Outline of concepts and scope/timing of possible incremental activity investigated together with potential economics. Annual data for production, capital and operating costs should be provided for all projects, with summary economic indicators (Net Present Value and Internal Rate of Return) on a pre tax basis. Examples could be:

- New 3D seismic or re-processing of existing seismic data.
- Infill/additional wells (incl. coiled-tubing, multi-lateral drilling or any novel techniques).
- Re-completions.
- Development of undrained horizons/fault blocks.
- Increased gas/water/oil handling facilities.
- Increased injection facilities.
- Artificial lift.
- Gas compression.
- Gas import/export and utilisation.

- Power import/export.
- Maintenance regime.
- Reduced manning.

It is important to record for potential future operators why opportunities were not viewed as economic to pursue.

Final field status including third party-production processed/transported
A summary of the field surface layout in terms of platforms, wells, subsea wells and manifolds, intra-field flow lines, topside facilities, and transportation of products, e.g. pipelines and/or offshore loading.

Production and injection profiles together with projections through to economic limit and approximately 2 years beyond.

Brief details of any third party production that is processed and transported via the current facilities. This discussion should consider the impact of removal/alteration of platforms and subsea manifolds and the future handling of satellite and/or third party production.

Details of any remaining licence obligations.

The document should also contain appropriate reservoir maps indicating the estimated location and distribution of remaining technically recoverable oil/gas that will be undrained at the time of Cessation of Production. In addition some conception of likely changes in such distributions over time should be given for completeness of the record.

Additional developments status including third party
A summary of all nearby fields which can potentially be developed from the existing facilities and infrastructure should be listed. This should also include all third parties fields. The following information will assist in making an assessment on the viability or otherwise of potential additional development.

- Field details and status, location, exploration, appraisal etc.
- Hydrocarbon reserve estimate i.e. type oil/condensate/gas and size.
- Outline of development scheme considered or under consideration.
- Viability or otherwise of the development.
- Reasons why the development cannot proceed, i.e. requires new technology, economics, difficulty in agreeing tariff rates with third parties etc.
- Impact of life extension for the parent facilities.
- What needs to be done to promote and accelerate development.

Conceptual decommissioning plans. The decommissioning of offshore installations and pipelines are the subject of the Petroleum Act 1998. The Act provides the Secretary of State with powers to require those parties with a decommissioning liability for offshore oil and gas facilities to submit costed decommissioning programmes for his approval. This process is administered by the Department's Offshore Decommissioning Unit in Atholl House, Aberdeen. They should be contacted separately to discuss the necessary arrangements.

Such approval is separate from approval of the CoP document. It will be important, however, to include in the CoP document an indication of decommissioning plans. This should provide a general outline of the sequence of events which will take place from production cessation until complete decommissioning of wells, facilities and pipelines and include an estimate of the timetable and cost of such operations. It will be important to clarify in the CoP document that all reasonable steps will be taken during the decommissioning stage to facilitate decommissioning, whether immediately or at some time in the future, and to ensure that any requirements related to decommissioning (including environmental considerations) will not be prejudiced. This is especially important when there is a considerable time delay between CoP and actual decommissioning, e.g. a tariffing phase of operations involving the whole or part of the field facilities and pipelines.

Appendix 8 : Guidelines for application to become an oil production operator on the United Kingdom Continental Shelf (UKCS)

Purpose of these guidelines

These guidelines are provided to aid companies who wish to become production operators of oil or gas fields on the UKCS. In particular the guidelines are designed to help companies understand the information that the Department will require to consider an operatorship application.

The guidelines are applicable for the following range of operatorship transactions:

- Existing UKCS operators wishing to acquire operatorship of a new field.
- Existing Licensees in a particular field who wish to take over operatorship.
- Existing UKCS Licensees who wish to take over operatorship of a field where they currently hold no equity.
- New entrants to the UKCS who wish to become operators.
- Companies both seeking to take over operatorship of existing producing fields and acquiring new, as yet undeveloped, prospects from existing operators.

The level of detailed examination by the Department will depend on which category prospective applicants fall into with existing UKCS operators with a proven track record being subject to the least attention and new entrants to the UKCS being subject to particular scrutiny. The information that the Department will seek will in general be drawn from the Checklist attached as the Annex to this note.

The Department point-of-contact for any proposed new UKCS operatorship is the Head of Field Development and Production for the relevant Sector

Introduction

The North Sea is generally acknowledged to be one of most challenging areas for oil and gas production in the world. At the same time the track record of existing operators in maximising hydrocarbon recovery through technical innovation is second to none. The Department is keen to maintain this record of excellence and prospective new operators will be screened carefully to demonstrate their ability to manage UKCS oil and gas fields to maximise economic oil recovery with due regard for the environment and with sound finances.

The number of UKCS operatorship transfers has increased significantly over the last few years as the province matures. Several of the early large fields have changed hands as a new generation of operator emerges specialising in extending the life of fields well into the decline phase. At the same time the increasing number of small marginal pools and the success of low cost floating production vessels has attracted new niche players at this end of the market. The Department welcomes this new generation of operators who are helping to extend the life of UKCS fields far beyond original expectation.

These Guidance Notes have been written to aid potential new UKCS operators to understand the requirements of the Department in approving a new operator or a change of operatorship in an existing field. It should be noted that approval is generally on a field by field basis (i.e. blanket approvals to operate producing fields in the UKCS are not given and prospective operators must always specify the fields they wish to operate). The

Guidance Notes seek to explain the logic behind the approval process and explain clearly the information requirements in the areas of technical and environmental competence. The Annex to these notes is a checklist which should help companies in assembling the required information.

The appointment of operators is regulated by appropriate model clauses incorporated into licence conditions. Examples of the relevant model clauses are as follows:

Appointment of operators

24-(1) The Licensee shall ensure that another person (including in the case where the Licensee is two or more persons, any of those persons) does not exercise any function of organising or supervising all or any of the operations of searching or boring for or getting petroleum in pursuance of this licence unless that other person is a person approved by the Minister and the function in question is one to which the approval relates.

(2) The Minister shall not refuse to give his approval of a person in pursuance of paragraph (1) of this clause if that person is competent to exercise the function in question, but where an approved person is no longer competent to exercise that function the Minister may, by notice in writing given to the Licensee, revoke his approval.

Technical competence

The operatorship of a North Sea oil or gas field requires a very high level of technical competence with the high operating costs and large well spacing representing a harsh challenge. It is essential that prospective operators demonstrate a strong technical ability if the track record of the UKCS for successful developments is to be maintained.

The proposed technical staff structure should be described carefully with particular regard to the role of any contractors in the decision making process. The role of contractors in the day-to-day operation of North Sea facilities has grown rapidly over the last few years and the Department see this development as an aid to flexibility in field management. It is crucial, however, that operators maintain sufficient in-house staff to clearly understand and supervise the key reservoir and facilities management issues and to direct the overall field plan. It is not clear that "virtual operators" (effectively a very small shell of permanent staff surrounded by consultants who take all the major field management decisions) fit with this approach. The key technical staff (e.g. petroleum engineering manager) will be expected to have substantial North Sea operations experience.

Any operatorship experience elsewhere in the world should be described, as should any non-operated interests in the UKCS. Licensee disputes can sometimes act as drag on development of UKCS fields and the proposals for licence management should be outlined. This information is particularly important for incoming companies with no previous operating experience and in this case the management systems (e.g. proposed regularity of Operating Committee Meetings) should be explicitly spelt out.

The logic of the proposed change in operatorship needs to be clear to the Department and the forward reservoir management plan and expenditure and production profiles upon which the new operatorship is based should be supplied. We are keen to understand what the new operator feels he can add to the field management process and particularly of any firm plans to increase field lifetime and hydrocarbon recovery.

Financial capacity

A fundamental issue in any take-over of an existing mature oil field is the financial provision to continue with the authorised Field Development Plan coupled with the financial strength to cope with unexpected incidents or emergencies and to pay for eventual decommissioning of the field facilities.

DECC has no financial criteria for operatorship other than those applied to the operator in

its capacity as licensees (including financial liability for potential pollution). The financial state of the prospective licensee(s) will therefore be reviewed carefully by the Department and a forward business plan (including expected expenditure and production profiles to the end of field life) will need to be provided. DECC has issued separate financial guidance which may be found at:
Insert updated link.

One of the Department's purposes in this review is to ensure that the authorised Field Development Plan is adequately funded and that the UK taxpayer is not exposed to any risk of covering decommissioning costs that should fall due to the field Licensees.

Environmental competence

Environmental issues are extremely important in all oil and gas developments and formal Environmental Statements (ESs) are required for all new UKCS developments of any significance. It is therefore essential that any new operator in the North Sea demonstrates that he is aware of the environmental requirements, has and applies in practice a comprehensive environmental management system and is in a position to carry out a formal ES if and when required. The environmental policy of the prospective operator should be clearly explained.

Detailed information required by the Department

The Annex to this appendix provides a checklist to aid companies in providing the necessary information to the Department to process an operatorship application. In many cases only a subset of this information will be required. The following provides some additional guidance on the Checklist items.

<u>Items 1-5: Company Structure</u>: - We consider a management structure showing clear lines of responsibility and clear processes for field management to be essential. The Department will look for a strong reservoir management team with considerable North Sea experience and the minimum of vacancies in key positions. In the case of companies taking over existing producing fields it is usually advisable to have a transition period of at least 6-months during which key staff from the previous operator are available to the new operator. The key operations staff should be UK based.

<u>Item 6-7: Environmental Management</u>: - It is essential that all UKCS operations are carried out in an environmentally sensitive manner that conforms with all current environmental legislation including discharge limits. Companies seeking new operatorships in the UKCS will therefore need to demonstrate that their environmental management systems are compatible with all UKCS requirements and should have in place an independently verified environmental management system (EMS) that meets the requirements of OSPAR Recommendation 2003/5 to promote the use and implementation of EMS by the offshore industry. Companies should bear in mind that they will be required to submit an Environmental Statement in relation to field developments and certain drilling activities. We look for a proven track record of environmental awareness.

<u>Item 8-9: Management System</u>: - The responses to these items on the check-list should describe how the new operator will manage the field in practice, clearly describing the division of responsibility between the company's own staff and contractors if the latter are employed. The Department supports the growth of alliancing in the UKCS as a way of reducing the burden on operators and placing responsibility where the best expertise lies provided the essential responsibilities of the operator are maintained.

Prospective operators will need to demonstrate how they will ensure that any contractors employed have and will maintain appropriate levels of competence and standards and how the operator will manage communications and delegation of responsibility. These procedures should look to recognised management and auditing standards. The arrangements for handling emergency situations should be clearly explained.

The Department's experience shows that lack of partner Licensee alignment can seriously hinder optimal field development. New operators for producing fields should demonstrate how they will continue to involve all Licensees in the continuing field development.

Item 10 : Financial Resources :- For take-overs of existing fields, prospective operators should provide sufficient information to demonstrate the financial robustness to continue the authorised Field Development Plan and cover their share of the eventual decommissioning costs. For fields without authorised Field Development Plans, companies will need to explain how they plan to fund a development in due course.

Item 12: World-wide Operating Experience: - Companies without substantial UKCS operating experience should draw on their operating experience overseas to demonstrate a track record of effective field management.

Item 13: Companies with no Previous Operating Experience: - Companies with no previous operating experience will naturally be subject to particular scrutiny and the timetable and logic of the proposed transition to operatorship needs to be described in detail in such cases.

Item 15-17: Field Management Resources: - These items seek more detail on the technical resources available to the prospective operator. The applicants own analysis of the potential of the field should also be explained. Potential for additional recovery for fields in production should be clearly identified.

Item 18: Training Policy: - Well trained staff are considered essential for effective operatorship of a UKCS field. Any formal training standards that the applicant has adopted (e.g. "Investors in People" standard) should be noted here as well as the way in which the applicant will establish such standards in subcontractors.

Item 19-20: Reserves and Economics: - The methodology adopted by the company for reserve estimation should be outlined. North Sea operators use a wide range of reserve and production estimation methods and this information will allow the Department to place any reserves or production estimates supplied by the new operator in the correct context.

Annex : Checklist of required information for prospective new production operators

1. Charts showing the proposed management structure of the company, and the organisation, responsibilities, reporting lines and current post-holders of the proposed operating team for the development of the field(s), including their location (e.g. London, Aberdeen etc. or offshore). The location of the registered office with telephone and fax numbers should be provided. For multi-national companies the hierarchy of decision making responsibility between the UK affiliate and head-office should be clearly explained.

2. The charts should identify who is responsible for safety, emergencies, environmental matters, facilities engineering, reservoir evaluation and management, drilling, supply services, maintenance, offshore loading, monitoring progress and reporting to the Department.

3. Details of the numbers and disciplines of the personnel employed in each of the key areas of management and operating responsibility and the basis on which they are employed (e.g. permanent staff or contract).

4. Curricula vitae of executive directors and all key management and operating personnel, giving full details of their technical background, skills and previous experience and where appropriate their experience to date on the field(s).

5. If there are any current vacancies in key posts in the management structure and operating team, a statement of what action is in hand to fill them and what arrangements are being made to provide the necessary expertise pending recruitment of suitable

personnel.

6. A statement of the company's environmental management system for operating a field development, together with the overall Environmental Policy of the company (and parent company), should be supplied. This should include details of the company's intentions regarding membership of groups and schemes for dealing with oil spills and emergencies (e.g. OPOL). Details of any environmental incentive schemes and their objectives should be described. How will contractors be monitored? A discussion of the company's environmental track record to date should be provided with illustrative example cases of both good practice and cases where lessons have been learnt.

7. Details of the company's contingency arrangements for dealing with any incident on offshore installations in the field(s). This should cover both the technical and financial resources available in-house to handle such situations and the arrangements and funds available to secure assured access to expert help from outside sources. This includes a requirement to provide evidence that the risks relating to drilling operations have been appropriately assessed and that financial mechanisms are in place to meet both first party costs (well control) and third party costs (remediation and compensation). Further information can be found at https://www.gov.uk/oil-and-gas-legislation-onwmissions-and-releases.

8. An explanation of the quality management standards the company will apply in all aspects of operating the development of the field(s). How will contractors undertaking construction, maintenance and operations activities be audited? The allocation of duties between in-house and external providers of oil field management services should be clearly explained, including the chain of responsibility and decision making matrix.

9. The proposed business process (e.g. regularity of opcoms and techcoms and the procedure for dealing with Partner disputes) should be described.

10. A detailed statement of the financial resources available to each licensee to ensure that economic development of the field(s) will be maximised, including, where appropriate, a letter of support from the parent company and or major shareholders.

11. A listing of current North Sea licence interests should be provided.

12. For companies already operating oil/gas fields outside the UKCS:-

> (a) a list of oil or gas fields world-wide (onshore and offshore) which have been or are currently being operated; and
>
> (b) for each of the fields listed in 12(a), a review of the measures the company has taken to optimise recovery and a brief explanation of how these fields have performed against original expectation.

13. Companies with no previous operator experience should provide details of any other world-wide experience that they feel is relevant to becoming a North Sea operator and explain how they will manage the transition to operatorship from the previous operator if they are taking over a producing field.

14. A description of the company's in-house capabilities in the area of reservoir and facilities management, and, if these are not self-sufficient, what external resources are available/utilised to supplement these capabilities. Prospective operators should indicate the extent of their commitment to employ new or advanced technology and the company track record in introducing technology to operations.

15. A statement of the company's reservoir management philosophy. What internal audits are carried out of the reservoir development programmes and reserve calculations.

16. A forward production profile for the fields to be operated taking into account any

proposals the company has for enhancing production/reserves. It is appreciated that detailed plans may not be firmed up at this stage.

17. A statement of the facilities operations and maintenance strategy that the company would expect to adopt.

18. A statement of the company's policy towards the training of its technical staff, including formal internal or outside training programmes and other ways of ensuring that staff are kept up to date in their specialist subject(s).

19. A statement of the company's basis for field development economics, including such aspects as hurdle discount rates; oil price scenario(s), and gas flaring philosophy.

20. A statement on reserve categorisation (deterministic or probabilistic) together with a short synopsis on reserve estimation methods normally used by the company.

21. List extent of the company's current engagement with industry trade associations such as BRINDEX, Oil and Gas UK etc.

Appendix 9 : Guidelines for gas flaring and venting during facility commissioning

It is Departmental policy that on fields where associated gas is to be saved, gas flaring during commissioning should be kept to its lowest level that is consistent with the safe and efficient commissioning of oil and gas related plant. To achieve this the operator should take the initiative in keeping in close contact with the Department at all stages, from design through construction to commissioning planning, and demonstrate that all reasonable steps have been taken to keep flaring to a minimum. The following points should be noted.

Plant design: This should recognise that gas plant commissioning should begin as soon as oil stabilisation permits. If, due to very high design rates, high oil production rates will be necessary this should be discussed with the Department - whether or not a Field Development Plan has been submitted. Multi-stage systems (i.e. with separately driven casings for HP, MP and LP) should have provision for continuous testing of these stages independently if a fault in one stage would otherwise prevent testing of the rest of the train. Should the operator propose any venting of hydrocarbons, e.g. from low pressure drains, rather than disposing of them via the flare system, this should be discussed with the Department at the earliest opportunity.

Hook-up and installation planning: All gas plant must be complete, fully leak tested and otherwise tested and commissioned as far as is practicable, and able to receive gas, before first oil. A gas flaring consent will not be issued until the Department is satisfied that the system is ready to receive gas as soon as stabilised flow is achieved.

Commissioning and planning: This should be based on the assumption that, within one week of first oil, gas will be being used to commission gas handling plant. If gas plant commissioning cannot begin within two weeks of first oil, or there is a significant delay in commissioning due to plant breakdown or malfunction, the Department may need to consider limiting production until gas plant commissioning can proceed.

Commissioning gas flaring and venting consent applications: These should be submitted at least two – three months before production start-up and should contain the following (although the Department may seek earlier engagement for “complex” facilities):

a. A summary of the main points in the application.

b. A summary of the main flaring assumptions.

c. A brief overview of the field and associated main facilities.

d. A detailed description of the plant start up procedures and commissioning philosophy, including gas export line commissioning should this be applicable.

e. The commissioning schedule.

f. Flaring and/or venting calculations - on a daily basis and total quantities

g. Sketches and figures should be supplied for:

    - High level field layout.
    - Overall commissioning programme.
    - Fuel gas system.
    - Gas dehydration system.

- Gas compression system.
- Gas export system and pipeline.
- Onshore facilities.

Commissioning gas flaring consents: Initially these are short term, normally on a 28 day basis, until stable plant operation is achieved. It is a requirement of these consents that the operator shall provide weekly reports to the Department detailing the following information relating to the previous week's activity:

a. a short technical summary of the performance of the gas handling plant, highlighting any features which have affected or could affect the operation of the plant;

b. an update on commissioning activity progress and main works planned for the forthcoming period;

c. daily rates in respect of oil production, gas production, gas export, gas used for fuel and of gas flare;

d. cumulative average for production and flare; and

e. gas compression plant uptime.

It should be noted that there may also be environmental permitting requirements relating to flaring operations during the commissioning operations.

Appendix 10: Health and Safety Executive role at the installation design stage

The design notification

Regulation 6 of the Offshore Installations (Safety Case) Regulations 2005 (SI 2005/3117) (SCR) requires the operator of a production installation which is to be established on the UK Continental Shelf to prepare and submit a design notification to the Health and Safety Executive (HSE) before the completion of the design, so that the operator can take account in the design of any matters relating to health and safety raised by HSE within 3 months of the submission.

The Safety Case for design to be submitted to the HSE will need to show how the general principles of risk evaluation and risk management have been applied from the earliest stages of design, including design concept selection (reference: Assessment principles for offshore safety cases, HSG 181, HSE Books, 1998, ISBN 0 7176 12384).

In the light of experience gained in the assessment of design notifications and the earlier design safety cases, HSE strongly recommends early dialogue between the operator and the HSE so that any concerns which HSE may have regarding concept selection or conceptual design can be identified and resolved before the safety case is formally submitted.

Inspection and enforcement by the HSE

HSE Inspectors have the powers to inspect and enforce regulations which apply to design and construction aspects; for example the requirements under the Offshore Installations and Wells (Design and Construction) Regulations 1996 (DCR), and the requirements for the verification by independent and competent persons of safety-critical elements of installations under SCR (as amended by DCR).

HSE also needs to be satisfied that the duty holder has appropriate safety management arrangements in place to ensure compliance with all other relevant statutory provisions; for example those of the Offshore Installations (Prevention of Fire and Explosion and Emergency Response) Regulations 1992.

Charging for advice and guidance

Under regulation 14 of the Health and Safety (Fees) Regulations 2009 (SI 2009/515), HSE's Offshore Division is required to charge duty holders for all of its safety case assessment and inspection work to ensure compliance with the safety case in the offshore sector and the enforcement of any of the relevant statutory provisions.

General advice on, for example, the main provisions of what a safety case should contain, will not be charged for - so that in practice most requests for general advice which can be resolved quickly, for example, through a brief telephone call, are likely to be non-chargeable. However, advice in connection with the preparation of a specific safety case prior to its submission, for example, where it is to the benefit of both the duty holder and HSE to discuss how the information is to be presented within the safety case, or what specific features are, or are not, likely to be acceptable, will be chargeable. Detailed information on charging is set out in the publication "Cost Recovery for Offshore Activities: A Guide", available at

http://www.hse.gov.uk/charging/offshore/chgoffsh.htm

HSE's Offshore Division may be contacted at:-

Offshore Division

Health and Safety Executive
Lord Cullen House
Fraser Place
Aberdeen
AB25 3UB

Tel: 01224-252500

Appendix 11 Guidance on the Stewardship Process and associated data submission

This appendix provides additional guidance on the Stewardship process and data submission, and gives contacts where further assistance can be sought.

The Stewardship data submission is required annually and addresses one year of operations. The Stewardship data survey is to be completed by operators on behalf of their JV partners during February of each year. Most data requested will be for the period January to December of the previous year, with some additional data on budgets and forecasts for the following year. DECC also executes a process to review Production Efficiency of producing assets on a systematic basis across the UKCS. This process runs in parallel with the Stewardship process, and the results of the Production Efficiency review may be incorporated in the Stewardship discussions between DECC and the JV. Further information on the Production Efficiency review process can be found in Appendix 12.

Stewardship Process Timing

The annual Stewardship data survey is to be completed by operators on behalf of their JV partners during February. The data will then be collated by DECC and screened to quickly identify those fields where further discussions are required. In the screening process, DECC will initially be looking to simple, objective, performance indicators based on activity levels, well utilisation, facilities performance, investment levels, reserves replacement, production decline and remaining field life. Feedback will be provided to the JV towards May, following any clarification discussions that might be required on the data submission.

If issues concerning the quality of Stewardship are identified during this first stage, then the Department will write to the operator formally notifying them of these. The process then goes into a second stage in which the Department engages with the operators and the other Joint Venture partners in discussions on how these issues might be resolved. These discussions may also involve audits of some aspects of field management or of the field as a whole; or the use of experts to help resolve technical issues. If the detailed evaluation and discussion envisaged in the process does not lead to agreement between DECC and the JV, DECC will use its licence powers to require the JV to improve its Stewardship of the field - this could involve DECC specifying a work programme to require the JV to carry out economic investment; or the replacement of the operator (if the operator is shown to be the root cause of poor stewardship). Good stewardship should however equate to attractive economic investment, hence in the majority of cases it is expected that improvement can be secured by normal commercial means by the JV; perhaps by realignment, the introduction of 3rd party investment or, possibly, divestment.

Stewardship Data input form

Each asset team will be provided with a data submission form in Microsoft Excel format pre-populated with data from past submissions. It is important that the pre-populated form provided is used. The pre-populated forms will be placed on the DECC Oil and Gas Portal), from where nominated representatives of the operating company can download the file for completion. The completed file can then uploaded back to the Oil&Gas Portal for DECC internal use.

Further Guidance

Further guidance and definitions can be found on the data submission sheets themselves. DECC recognises that there may be a number of questions that may arise during data preparation and submission.

Enquiries on the Stewardship process and data input submission should be directed to:
Andrew Carr (Andrew.Carr@decc.gsi.gov.uk, or Tel: 01224 254071).

Appendix 12 Guidance on the Production Efficiency review process

This appendix provides additional guidance on the Production Efficiency review Process and data submission, and gives contacts where further assistance can be sought.

Production Efficiency data submission will be required annually and will address the previous calendar year of operation. The annual data survey is to be completed by operators on behalf of their JV partners during February of each year. Most data requested is for the period January to December of the previous year.

The Production Efficiency process will run in parallel with the Stewardship process, and the results of both these reviews will be incorporated into the Stewardship discussions between DECC and the JV. Further information on the overall Stewardship process and how it will be managed can be found in Appendix 11.

Production Efficiency Data input forms

Production Efficiency data will need to be collated by the operator for all producing fields. DECC has grouped fields together where it is appropriate to report the Production Efficiency of common processing facilities.

Each asset team will be provided with a data submission form in Microsoft Excel format for identified field(s) or processing facilities and this will be pre-populated with data from past submissions. It is important that the pre-populated form provided is used. The pre-populated forms will be placed on the DECC Oil and Gas Portal), from where nominated representatives of the operating company can download the file for completion. The completed file can then uploaded back to the Oil & Gas Portal for DECC internal use.

Further Guidance

Link to Guidance Notes (Power point).

Further guidance and definitions can be found on the data submission forms themselves. DECC recognises that there may be a number of questions that may arise during data preparation and submission.

Enquiries on the Production Efficiency process and data input submission should be directed to:

Robert White (robert.a.white@decc.gsi.gov.uk or Tel 0300 068 6056)
or
Willie Wilson (William.Wilson@decc.gsi.gov.uk or Tel 01224 254073)
or
Duncan Sewell (Duncan.Sewell@decc.gsi.gov.uk or Tel 01224 254060)