GUIDANCE NOTES FOR ONSHORE FIELD DEVELOPMENT PLANS, FDP ADDENDUMS AND CESSATION OF PRODUCTION

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These notes outline the OGA's requirements for oil and gas Field Development Plans (FDP), later FDP Addendums and cessation of production for those field developments that are wholly onshore. They intended as a working guide and not as a definitive explanation of the requirements of the model clauses or of the OGA's powers under them. If you have any questions or comments on these notes please contact Toni Harvey (toni.harvey@oga.gsi.gov.uk).

OPERATORSHIP AND LICENSEE REQUIREMENTS

Information about regulatory requirements for Operator Competency and Financial Viability and Capacity requirements are covered in other guidance, and these will also be considered before granting consent for production.

THE REGULATORY FRAMEWORK AND DEPARTMENTAL POLICY

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 and similar clauses are incorporated into every onshore licence. The Petroleum Licensing (Exploration and Production) (Landward Areas) Regulations 2014 are available **here**. 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 and whether the methods proposed comply with good oilfield practice. When considering what constitutes good practice, the Licensees proposals will be compared with the practice adopted in similar, successful developments.

In reviewing Field Development Plans, the Department's overall aim is to maximise the economic recovery of UK oil and gas resources and to ensure security of gas supplies. The Department fully recognises the difficult operating environment faced by the onshore oil and gas industry and is always willing to be as flexible as possible in its requirements whilst ensuring that oil and gas developments meet its objectives.

The Department recognises that during the appraisal, commissioning and production phases of a development, the flaring and/or venting of some gas may be unavoidable. However, this flaring or venting must be kept to the minimum that is technically and economically justified. The Department controls gas emissions by requiring Licensees to apply for consent to flare or vent gas emitted by their fields. The main purpose of this requirement is to ensure that gas is conserved where possible by avoiding unnecessary wastage. The EA considers the environmental impact of emissions.

Where a Field Development Plan is proposed for a field which extends into the area covered by a neighbouring licence operated by different company the Department needs to be satisfied that the ultimate economic 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 Licensees to discuss their plans with their neighbours at an early stage and propose an agreed Field Development Plan.

In cases where the Licensees have not reached an agreement the Secretary of State has powers to require a unitisation between Licensees. However, Licensees should be aware that the Secretary of State will not necessarily refuse to authorise development 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 and ownership of hydrocarbons arises only once they have been extracted under appropriate regulatory consent. The Department's acceptance or rejection of any Field Development Plan will, therefore, be on the basis of whether or not it is the 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.

Field Determination Area

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 at an early stage in the Field Development Plan authorisation process, utilising the geological information that is available to it at that time.

For Abandoned Mine Methane fields, this will be a 1km square around the vent or mines gas well, rather than the workings expected to be drained by the development because of the uncertainty and complexity of many abandoned workings.

For Coalbed Methane (CBM) fields the area will generally be defined by the areal limits of the coal seams to accessed by the proposed development. In the case of a phased project this might mean that the field will need to be redefined as further blocks of coal are drilled.

Shale fields will also be defined by the extent of the area likely to be accessed by the planned development and if there are decision points to expand the development later in a phased project, the field determination will change incrementally as more information is known.

In situations where a proposed field does not include stacked other prospectivity, the field determination may include a depth cutoff.

The Department may authorise extended periods of test production (Extended Well Tests) from exploration or appraisal wells prior to development approval 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, although the duration of an EWT normally is 90 days. 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 approved Field Development Plan. There is no obligation to proceed with a development following an EWT. 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 and saved or flared/vented. Guidance on EWT's is found **here**. Throughout the duration of the test the operator should submit monthly oil, gas and water production figures to OGA. These should be e-mailed at the end of each month to david.roberts@oga.gsi.gov.uk.

Environmental management of onshore hydrocarbon developments does not come within the jurisdiction of the Department. Environmental legislation is implemented by DEFRA, the Environment Agency in England and Natural Resource Wales (NRW), Scottish Environment Protection Agency (SEPA) and the relevant local authorities. Any oil and gas development must have the relevant consent(s) from these authorities for both construction and operations. The Department will require proof of local authority consents before consenting to any development and check with the environmental regulator that there are no unresolved issues.

The Field Development Plan is the support document for development and production authorisations and should provide a brief description of the technical information on which the development is based. Normally the document should be no longer than 20 pages of text plus associated figures and tables although more details may be required for fields with many wells or for shale development. The document should provide a summary of the operator's understanding of the field although any background information should be available should the Department require more detail. Operators are encouraged to contact the Department early, and discuss drafting decisions before submitting a Field Development Plan in order to expedite the process.

Licensees are jointly and severally responsible for the Development Plan, which must represent a single view of all the Licensees. An operator is usually appointed to be responsible for the production of the Development Plan and to 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.

In addition, a copy of the relevant planning permission(s) must be supplied together with a letter from each licensee confirming that that they support the development plan and have the necessary funds available. This "Board Letter" should also include a statement confirming that the Department's licensee residence requirements have been met.

The Department is committed to releasing as much data as possible and will publish Development Plans six years after submission. However, any representations regarding the release of a Development Plan would be considered.

THE FIELD DEVELOPMENT PLAN CONTENT

The following are suggested section headings together with the topics that should be addressed, but can be modified as needed. Please contact Toni Harvey (toni.harvey@oga.gsi.gov.uk) or Mark Quint (mark.quint@oga.gsi.gov.uk) to arrange a technical review or provide a draft document for comment at an early stage.

1. EXECUTIVE SUMMARY

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

- A brief description of the hydrocarbon reservoirs, hydrocarbon (API, GOR, BTU, etc.), estimated reserves, development strategy, facilities and pipelines.
- An outline map showing the field limits, Field Determination boundary, contours of fluid contacts, existing and proposed wells, with Unitary Authority 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 metric tonnes 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.
- A map with the Field Determination boundary and location of any nearby protected area: National Parks, Areas of Outstanding Natural Beauty, World Heritage Sites, Groundwater Source Protection zones and any European Sites of Scientific Interest.
- The essential elements of the Field Management Plan and key decision points.
- A statement regarding the planning permission and environmental permits.
- A statement undertaking that the field will be decommissioned in accordance with the requirements of the applicable planning approval.

2. FIELD DESCRIPTION

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. A brief history of the field, referencing the discovery well and significant appraisal wells is useful. 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 the United Kingdom National Grid.

2.1 Seismic Interpretation and Structural Configuration

A brief summary of the extent, vintage and quality of the seismic data and key mapping horizons noted. The structural configuration of the field should be presented using appropriate figures and maps (e.g. dip and strike seismic lines, depth structure map of target horizon and schematic cross section)

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 (eg stratigraphic column, CPI of key log, or log cross section). 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.

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 should be included.

For CBM fields, this may include describe Net coal (ft), Nr. Seams >= 3ft thick, Coal rank (HVol Bit), gas content (*in situ* scf/t or cm3/g), gas saturation (%),permeability (mD), gas composition (% inert gas), moisture content (%) and Volatile matter (%). For shale fields, this might include gross shale and target horizon thicknesses (ft), porosity (%), Sw (%), TOC(%), permeability (mD), Gas yield (scf/ton), extent of overpressure and the mineralogy of target horizons.

Fluid and gas characteristics should be summarised.

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 briefly 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.

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 Recovery Techniques

A summary of the alternative recovery techniques considered and the reasons for the final choice is required.

2.8 Reservoir Development and Production Technology

The chosen recovery process should be described and the optimisation method summarised, including reference to the potential for artificial lift and stimulation. Plans for hydraulic fracturing and other stimulation should be summarised and reference the agreed Hydraulic Fracture Plan for details.

Any limitations on recovery imposed by production technology or by the choice of production facility or location should be indicated. Remaining uncertainties in the physical description of the field that may have material impact on the recovery process should be described and a programme to resolve these should appear in the Field Management Plan.

3. DEVELOPMENT AND MANAGEMENT PLAN

The purpose of this section is to briefly set out the form of the development, describe the facilities and infrastructure, and establish the basis for field management during production. Where a particular topic is not relevant to a development it should be omitted.

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. 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. The assumed economic cut-off should be stated. Expected production profiles per well, 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 re-injected, annual and cumulative injection profiles should be provided. Quantities can be provided in either metric units or in standard oil field units (but with conversions to metric equivalents provided). Information to allow calculation of sales quantities should be provided.

3.2 Drilling and Production Facilities

The drilling section should briefly describe the drilling package and well workover capability, and should include a description of the proposed well completion.

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.
- 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 facilities.
- A statement regarding the planning consent and environmental permissions.
- Description of export route.

3.4 Costs

Cost information is not required at present.

3.5 Field Management Plan

A brief review 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 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 potential for workover, re-completion, re-perforation, re-hydraulic fracturing and further drilling should be described. Where options remain for improvement to the development or for further phases of appraisal or development, the criteria and timetable for implementing these should be given and described in phases if appropriate.

3.6 Other Attachments:

- A copy of the relevant planning consent(s).
- If the project involving the exploitation of coal seams, proof of the agreement of the Coal Authority.
- Letter from each licensee confirming that that they support the development plan and have the necessary funds available. This “Board Letter” should also include a statement confirming that the Department’s licensee residence requirements have been met.
- OS plat of surface location of planned and existing infrastructure.

DEVELOPMENT PLAN AUTHORISATION AND PRODUCTION CONSENTS

The development will be authorised once the Secretary of State is satisfied that the Development Plan meets the Government's policy objectives as set out above.

The Secretary of State's consent will cover both the construction of the facilities and other infrastructure, and the production of hydrocarbons from the field. Subject to the terms of the licence, agreement will usually be given for production over the forecast lifetime of the development with wide tolerances in the levels to be produced. Conditions may be attached to give the Department powers to require a review if performance falls outside these tolerances 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.

If production consent is issued for a duration that is less than the anticipated life of the field it is the responsibility of the operator to apply for renewed consent to allow production to continue, and an updated Field Development Addendum may be required at that time.

Departmental consent is also required for flaring or venting operations. For onshore fields, as amounts tend to be small, we are willing to consider longer term applications for flare and vent consents.

The Department has an electronic consents system - the UK Oil Portal Field Consents system. The Secretary of State's consent will be given in the form of production consent through this system, and the Field Development Plan needs to be uploaded in the application. Online applications can only be applied for using the Portal so all applicants should ensure they have access rights. Separate applications for production, flare and vent consents will need to be completed as appropriate.

Users who do not have UK Oil Portal accounts should send an email to ukop@oga.gsi.gov.uk requesting an account and including the reason: 'to gain access to the UK Oil Portal Field Consents system'. The following information should be supplied: Forename, Surname, Organisation Name (Employer), Job Title, Work Telephone Number & Email Address.

Users who already have UK Oil Portal accounts should check that they know their login details and password and that details held about them on the Portal are correct - by logging in to the Portal here.

If, either at the time of the authorisation of a Development Plan or during the period of production, it appears that production is likely to continue beyond the term of the licence(s) involved, it is the responsibility of the operator to apply for an extension to the licence, and this extension will be subject to the continuing satisfactory performance of obligations under the licence.

FIELD DEVELOPMENT PLAN ADDENDUM

The focus of the Department, once a development has been authorised, will be to ensure that the Development Plan is being followed or modified appropriately as the understanding of the field develops. The operator will be required to prepare Field Development Plan Addendums upon request which inform the Department to proposed deviations from, or alterations to, the agreed Management Plan within the Field Development Plan.

A Field Development Plan Addendum (FDPA) will be requested when an extension of long term production consent is requested, and should be uploaded to the PORTAL consent application and a copy emailed to Toni Harvey. The Department is committed to releasing as much data as possible and would intend to publish FDPA six years after submission. However, any representations against the release of a FDPA would be considered.

Suggested headings and content of the report are as follows:

1. INTRODUCTION

A brief review of the field operations and export route with any divergence from the Development Plan should be summarised. Any changes in licence equity or Operator should be given. A map showing the field extent and licence boundaries should be provided.

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 Development Plan base case and to the case in any previous FDPA.

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 and should note any well operations carried out during the reporting period (e.g. drilling, workovers, data gathering, perforating, stimulation). And significant gap in field production should be explained. A chart of individual well historic production rates (and water cut %, if relevant) should be provided. Cumulative production chart by well is also requested.

2.3 Geology and geophysics

A brief summary of the reservoir geology and hydrocarbon type and sample CPI log should be included. A detailed depth structure map for key productive horizons with annotation of the max extent (e.g. GDT or OWC) and well paths from the surface to top horizon is required along with an interpreted seismic line across the field and if available, a schematic cross section. 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.

2.4 Field Facilities and Infrastructure

An OS plat which shows the location of all field facilities is required. A brief report on the performance of the field production facilities highlighting features that have impeded operations and also valuable improvements should be added. Describe any changes to export route.

3. DEVELOPMENT AND MANAGEMENT PLAN

3.1 Field Management

Any 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. Plans for reservoir monitoring in the coming year should be briefly discussed.

3.2 Studies

The results and relevance of any 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 briefly discussed.

3.3 Improved Oil Recovery (IOR)

Where appropriate the potential for IOR should be reviewed and the results of any studies or operations discussed.

3.4 Forecasting

A table of the forecasted production, vent and flare volumes and injection profiles should be provided, together with the current estimate of the Cessation-of-Production date. Summary of the initial estimate STOIIP or GIIP, cumulative production and recovery factor (if relevent), remaining reserves and field EUR should be provided.

3.5 Proposed Changes to the Development Plan

Proposed changes to commitments or to conditions in the development consent 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 OGA. Where appropriate a summary of exploration targets or longer term development opportunities within or around the field should be provided.

3.6 Field Operating Costs

CAPEX and OPEX are not required at this time.

3.7 Other Regulatory issues

A summary of the status of other regulatory consents and permissions should be provided; including the term of the planning consent and environmental permiting (e.g. W Sussex Council planning permission for field operations is in place until 2017, status of EA permits if re-starting production is proposed).

CESSATION OF PRODUCTION

OGA expect to be aware when production is anticipated to cease. Please contact Toni Harvey (toni.harvey@oga.gsi.gov.uk) or Mark Quint (mark.quint@oga.gsi.gov.uk) to arrange a technical review. A report is required. The amount of detail to be included in the report will depend on whether options to extend field life have been appropriately covered in previous field reports. OGA expect the PEDL licence to be relinquished when there is no future production planned from the field. The Cessation of Production report can be combined with the licence Relinquishment Report, but in addition should cover:

- Definition of economic limit and determination of cut-off rates and timing.
- Cash flow over the period up to this economic limit and approximately 2 years beyond.
- The costs and any revenues associated with cessation of production 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.
- Possible options for extending field life.
- Production and injection profiles together with projections through to economic limit and approximately 2 years beyond.
- Details of any remaining licence obligations.
- 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.
- Confirmation that all abandonment requirements in the relevant planning consents will be met and details of what is involved

It is important that sufficient information is retained after the cessation of production 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. For this reason, the COP or Relinquishment Report documents will be released once the licence(s) involved are relinquished.

The OGA is responsible for consent to sealing of the wells. HSE must be satisfied that the following regulations are compiled with; the Borehole Sites and Operations Regulations 1995; and the land-based requirements of the Offshore Installations and Wells (Design & Construction etc) Regulations 1996; and under which an operator is required to appoint an independent well examiner for well abandonment (and well suspension) designs and operations.

At the end of the EA permit, the Operator will need to produce a surrender Site Condition Report (SCR), which will review the original SCR and all the data collected throughout the life of the permit, to demonstrate that the land and groundwater have been protected during the lifetime of the site, an assessment of potential fugitive emissions to land and water and that there has been no significant deterioration in the condition of the site during the lifetime of the permit compared to the baseline condition, which was assessed when the permit was issued.

If the land or groundwater aren’t in a satisfactory state, or the Environment Agency has cause to consider that there is an ongoing risk to the environment, the application to surrender an environmental permit may not be accepted and further site remediation and/or post-decommissioning monitoring may be required. See the EA Onshore Oil and Gas Sector Guidance.

The Local Planning Authority is responsible for the site reclamation.

Annual Field Returns

Annual Field Returns are not required at this time but please do contact (toni.harvey@oga.gsi.gov.uk) or Mark Quint (mark.quint@oga.gsi.gov.uk) if production does not fall within the consented range or the geotechnical understanding or economic recoverable resource potential changes significantly.