Falkland Islands Government

Department of Mineral Resources

FIELD DEVELOPMENT GUIDELINES

July 2025

Contents

Abbreviations

ASP	Alkali - surfactant - polymer
BBL	Barrel
CCAB	Consultative Committee of Accountancy Bodies
COP	Cessation of Production
CPI	Computer-processed interpretation
DMR	Department of Mineral Resources
DSCR	Debt Service Cover Ratio
DST	Drill Stem Test
EBITDA	Earnings before interest, taxes, depreciation and amortization
EIA	Environmental Impact Assessment
EIS	Environmental Impact Statement
EOR	Enhanced Oil Recovery
ERAP	Emissions Reduction Action Plan
ES	Environmental Statement
ESG	Environment, Social and Governance
EWT	Extended Well Test
ExCo	Executive Council
FDP	Field Development Plan
FDPA	Field Development Plan Addendum
FEED	Front-End Engineering Design
FICAD	Falkland Islands Civil Aviation Department
FID	Final Investment Decision
FIG	Falkland Islands Government
FIGAS	Falkland Islands Government Air Service
FIMA	Falkland Islands Maritime Authority
FPSO	Floating Production, Storage and Offloading (vessel)
GAAP	Generally Accepted Accounting Principles
GHG	Greenhouse Gas
IAS	International Accounting Standard
IASB	International Accounting Standards Board
IFRS	International Financial Reporting Standards
IOR	Improved Oil Recovery
ITT	Invitation to Tender
JV	Joint Venture
NPV	Net Present Value
NSTA	North Sea Transition Authority
OEE	Overall Equipment Effectiveness
OPOL	Offshore Pollution Operators' Liability (Fund)
OPEP	Oil Pollution Emergency Plan
OPOL	Offshore Pollution Liability Association
OPRED	Offshore Petroleum Regulator for Environment and Decommissioning
PE	Production efficiency
PEP	Project Execution Plan
PON	Petroleum Operations Notice
PVT	Pressure-Volume-Temperature
PWA	Pipeline Works Authorisations
RAM	Reliability, Availability and Maintainability
SCAL	Special Core Analysis
SCF	Standard cubic foot
SET	Standard Economics Templates
UKCS	United Kingdom Continental Shelf

UUOA	Unitisation and Unit Operating Agreement

Note: Where this document refers to 'FIG', it is referring to decisions taken by Executive Council.

1 Introduction

The development of, and production from, oil and gas fields in the waters of the Falkland Islands is subject to a licensing regime overseen by the Department of Mineral Resources (DMR).

DMR has historically issued production licences to oil and gas companies during licensing rounds. These licences allow the oil and gas companies to conduct exploration and appraisal activity, subject to the necessary model clauses contained within the licence when issued. If the exploration and appraisal activity identify a hydrocarbon accumulation that can be developed, then the oil and gas company may seek consent to undertake development and production operations by the submission of a development plan. Production can only occur within a licensed area of the production licence.

Licensees need DMR's consent to erect or carry out permanent works for the purpose of getting or conveying petroleum from a licensed area or to get petroleum from such an area. Such consent is referred to as a 'Development and Production Consent'.

The document submitted in support of an application for such a consent is referred to as a Field Development Plan ('FDP'). The FDP is a description of the technical, economic and emissions information on which the development is based. The FDP will also contain the initial planning for the decommissioning of the field at the end of field life.

The areal extent of the oilfield field is defined by FIG on geological grounds. The areal extent of the whole or part of the oilfield as defined by FIG, that is addressed by the development plan is proposed by the oil and gas company and agreed by FIG. One or more development plan can be proposed for differing areas of the oilfield as defined.

Independently of this FDP consenting process an Environmental Impact Statement (EIS) is submitted for any proposed development.

Duty to Maximise Economic Recovery

Petroleum discoveries must be efficiently managed and exploited to maximise economic recovery and to ensure the development of a long-term industry presence that will benefit the Islands for decades to come.

When considering whether to consent to an application, DMR will, amongst other things, assess whether the proposed project accords with the obligations set out in the Hydrocarbon Policy Principles. DMR will also consider whether the development methods proposed comply with good oilfield practice.

These guidelines complements DMR's remit within government and its functions and advisory role in respect of legal requirements and policy commitments. The evaluation of a field development plan includes: detailed technical and subsurface considerations; the scope for emissions reduction, including through energy integration opportunities; and an economics assessment to determine whether economically recoverable petroleum has been maximised, which includes the societal impact of GHG emissions.

1.1 Scope and purpose of the document

This document is intended to assist those involved in the planning of a new field development and subsequent consent to an FDP leading to production of first hydrocarbons, primarily licensees and their advisors. The guidelines covers the following:

- An overview of DMR's objectives and considerations relevant to all new field developments;
- The Assessment Phase leading to the Concept Select;

- The Authorisation Phase leading to the grant of development and production consent;
- The Execution Phase leading to the production of hydrocarbons; and
- The process for revising a previously consented to project (i.e. an FDP Addendum (‘FDPA’).

As each potential new oilfield has its own technical challenges, it is expected that the licensees of any proposed development will liaise early and often with DMR and its officials.

Please note these guidelines are not a substitute for any regulation or law and is not legal advice. It does not have binding legal effect; they are guidelines, and the overarching principle is if the operator of a proposed new development has any questions they should bring this up at an early stage.

1.2 Field Development road map

The “road map” below sets out the main phases of the field development process and the main requirements of each phase.

Although it is presented linearly, for any individual development there may be information that passes between phases in a more fluid way particularly as more knowledge about the behaviour of a field and its assets is gained.

DMR expects the Field Operator, appointed on behalf of the Licensees in terms of Model Clause 22 to undertake the development and operate the field according to the consent issued by FIG, to engage with DMR early and frequently in the planning of a proposed field development, initially to discuss development options and, subsequently, the content of the FDP prior to its submission in final form as part of the application for consent. The ‘Field Operator’ is therefore referred to in these guidelines in that context. DMR will appoint a single point of contact to coordinate all discussions relating to the FDP.

DMR will review the Field Operator’s development options in relation to matters such as: Overarching plans such as the Islands Plan; the Hydrocarbon Policy Principles, relevant ExCo decisions and any other applicable guidance published from time to time by DMR. DMR will undertake a detailed examination of the Field Operator’s decisions which may, amongst other matters, include a review of the technical, economic and emissions basis for the development. The Field Operator will be expected to provide the necessary justification of such plans or amend the draft FDP as appropriate, in a timely manner.

Appraisal Phase

To properly understand the risk and uncertainty and range of outcomes for a field, the Field Operator must:

- Understand the geology and geophysics and reservoir engineering characteristics of the reservoirs
- Understand the hydrocarbon to be developed
- Quantify the amount of hydrocarbon present in these reservoirs to try to ensure maximum economic recovery, based on the technical understanding of reservoirs to be exploited
- Understand the necessary reservoir engineering required to extract the hydrocarbon
- Carry out development well placement studies.

This phase informs the Assessment Phase of the type and complexity of the reservoir and hydrocarbon to be developed.

Assessment Phase

The purpose of the Assessment Phase is to evaluate alternative development concepts. This will involve the preparation and submission of a Concept Select Report.

The Field Operator should provide a Concept Select report to DMR that summarises:

- The full range of options considered;
- The decision criteria; and
- The steps taken to comply with the Falkland Islands Hydrocarbon Development Policy Statement.

The Assessment Phase will conclude if DMR has no objection to the Concept Select decision.

Authorisation Phase

The purpose of the Authorisation Phase is to define fully the development scope and detailed implementation plans for the chosen concept.

This phase will begin with the Licensees' initial application for consent and during this phase the Field Operator should share an early version of the FDP with DMR.

The Authorisation Phase of a project is where the Concept Select proposal is matured to secure all relevant Licensee and regulatory approvals. The Authorisation Phase should deliver all the information necessary to ensure a robust project is developed with clear scope, cost estimate, and schedule; along with a Local Content Plan.

Once the project has matured toward a decision by the Licensee to invest in the project ("Final Investment Decision" or "FID"), the Field Operator must submit the final FDP to DMR with its final form application for a Development and Production Consent for the field. This document will include a detailed account of the development and the principles and objectives which will govern its implementation throughout the full lifecycle of the project.

The Operator should discuss with DMR the duration of this consent before applying (see Section 5.19).

Execution Phase

The Execution Phase of a project is where the Field Operator will implement the project scope set out in the FDP and the Project Execution Plan ('PEP').

The purpose of the Execution Phase is to carry out all required activities (e.g., well construction, engineering, procurement, construction, commissioning/start-up etc.) and to deliver the project objectives.

Front-End Engineering Design (FEED) will be completed and Detailed Design will take place.

Operation Phase

In the Operation Phase the Field Operator will produce hydrocarbons and manage health, safety and environment risks.

The Field Operator will manage the field and facilities in line with the obligations of the FDP and associated documents, having regard for optimal health, safety and environmental performance and observing good oilfield practice and the need to maximise economic recovery. The Field Operator will carry out measurement, reservoir surveillance, maintenance, inspection, intervention and reporting activities as required.

Alongside regulatory meetings, regular Stewardship meetings will be held with the Field Operator to discuss performance, compliance, forward plans and any other expectations around competent management of the field.

Decommissioning phase

No decision taken in an earlier phase may adversely affect decommissioning. A conceptual decommissioning plan is described in the FDP.

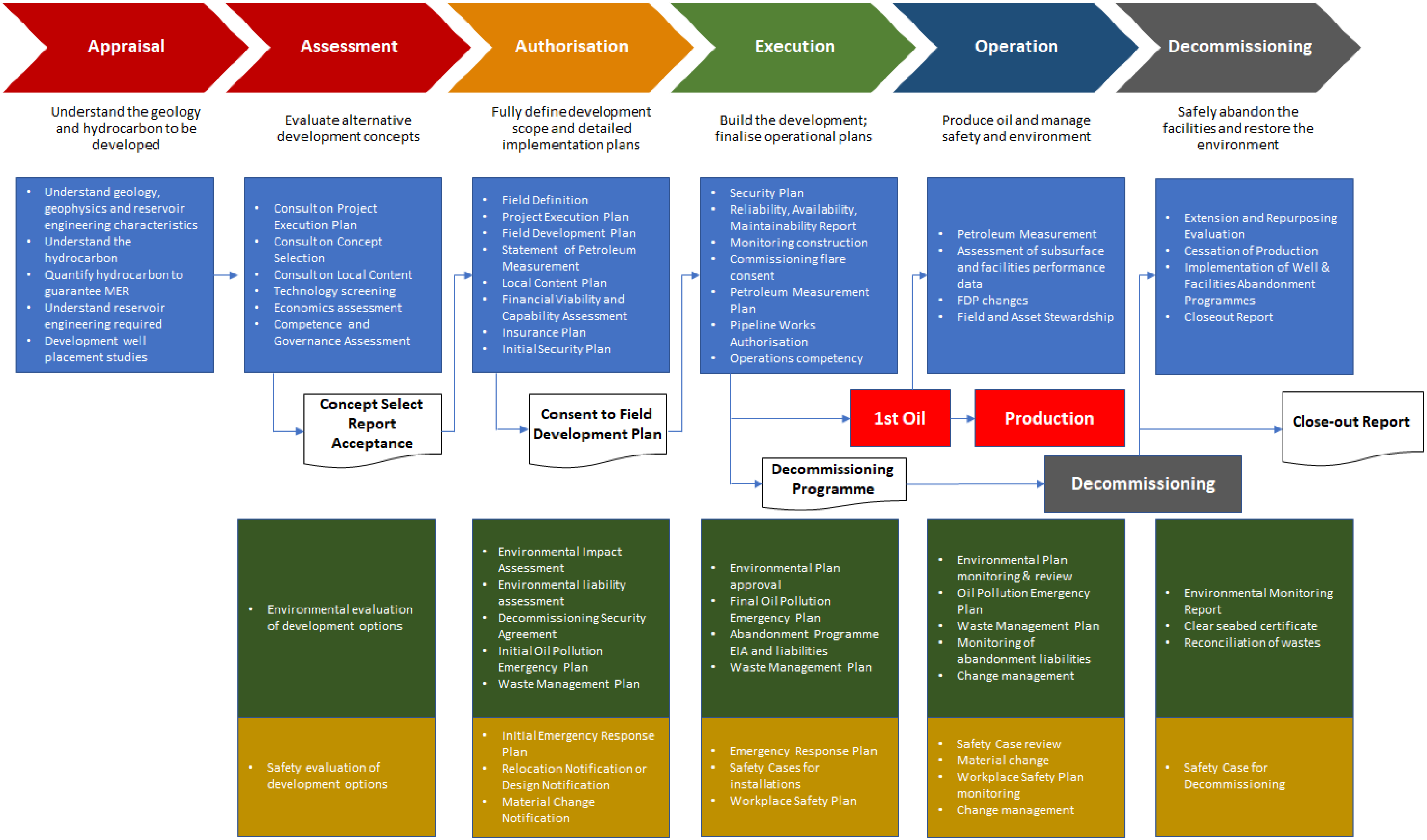

Figure 1: Field Development Road Map

1.3 Field Operator

The FDP should represent a single view of the project by the Licensees, who are jointly and severally liable for the content of the FDP and implementation of any consent given. A Field Operator (normally a licensee and approved by DMR as Field Operator, it might not be the major equity holder) is appointed to be responsible for the preparation of the FDP and to ensure that all necessary consents and authorisations are obtained, and for the execution of the project. It is usual for DMR to conduct discussions with the Field Operator as the representative of all the Licensees.

1.4 Scalability of the process

The elements in the new field development road map and the project phases described above are intended to guide industry to an efficient and timely field development. It is recognised that for smaller projects (for example a subsea tie back into existing production facilities), some elements of the road map can be simplified, however all elements of the field development road map are applicable.

At an early stage, the Field Operator should discuss with DMR its requirements for the FDP and the Development and Production Consent.

2 Key principles

2.1 Hydrocarbons Policy Principles

DMR is committed to delivering the principles of the Hydrocarbon Policy Statement on behalf of the Falkland Islands Government:

- Hydrocarbons in Falkland Islands waters belong to the people of the Falkland Islands and their exploitation must be to the benefit of the people of the Falkland Islands, both those of today and future generations.
- The Falkland Islands Government will maintain constant supervision and control over all hydrocarbon activities within the Falkland Islands Designated Area.
- Petroleum discoveries must be efficiently managed and exploited to maximise economic recovery and to ensure the development of a long-term industry presence that will benefit the Islands for decades to come.
- Development of the hydrocarbons industry must ensure the protection and conservation of the Falkland Island's environment and biodiversity.
- Development of the hydrocarbons industry must take into consideration existing commercial activity and promote the development of local business capacity.
- The exploitation of finite natural resources will be used to develop lasting benefits to society across the whole of the Falkland Islands.
- Transparency and accountability must be present throughout the hydrocarbon development process from all parties involved.

When considering whether to consent to a proposed field development or to amendments to a field development plan, DMR will evaluate whether the proposed project complies with these principles.

2.2 Ensuring third party cooperation

When reviewing proposals for exploration, appraisal and field development where there could be significant efficiencies around common infrastructure use and access to logistics, DMR will evaluate if the proposals are in accordance with the Hydrocarbon Policy Principles, which may include such considerations as, but not limited to:

- avoiding the unnecessary proliferation of oil and gas pipelines;
- avoiding the unnecessary proliferation of infrastructure which generates emissions;
- maximising use of existing infrastructure;
- allowing access to common logistics, drilling units and survey campaigns where practicable;
- aiding, where feasible, future field developments, including those outside the licence area.

Subject to the above, the evacuation route and destination of petroleum are essentially matters for the commercial judgement of the Licensees.

2.3 Systematic development process

After discovery, the development of hydrocarbon resources will proceed along systematic lines as set out in this document. This gives a stable development environment where business planning is facilitated and long-term decisions can be taken of an economic and regulatory nature. For most hydrocarbon developments, this will centre on a number of key focal points:

- Portfolio management of discoveries;
- Concept Select Report leading to the preferred development;
- Field Development Plan for the preferred development;
- Engineering Design, Execution, Commissioning and Operation;
- Decommissioning Programme and close-out.

These are described further in the following sections.

3 Field Development Process - essential requirements

The Field Development Process requires the demonstration by the Operator of the following aspects and provision of related information. This applies across all phases of the field development process.

3.1 Portfolio Management

DMR expects that discoveries should be moved through to FID, or the licence relinquished, in a timely manner. Operators are therefore expected to:

1. Demonstrate the use of a systematic process to identify and prioritise the planning and development of all licensed discoveries;
2. Present a work programme for each licensed discovery, from the start of the licence development phase (usually the Second Term) through to production startup;
3. Demonstrate how the work programme, up to consent being given to the FDP, will be resourced and funded;
4. Demonstrate how they will track and maintain delivery against the work programme and;
5. Highlight to DMR any deviations from expected progression through the licence second term.

3.2 Governance and Organisation (see also Section 8)

Operators are expected to demonstrate for each project that appropriate governance and organisation is in place, including but not limited to the following elements:

1. A governance and management structure that defines the decision makers, project owners, joint venture partners and regulators;
2. The capability and competence of key roles including project managers and project leadership;
3. Defined, documented and distributed project goals, roles and responsibilities, delegation of authority, and a management of change process; and
4. A defined organisational structure to support an integrated approach including subsurface, well operations, facilities, production operations, logistics, supply chain, commercial and finance, and joint venture partners.

3.3 Project Management

Operators are expected to demonstrate:

1. The use of a project management process to deliver the project objectives and milestones, including the decision-making process, phase-specific progression criteria and decision hold points;
2. How quality and assurance is being applied, appropriate to the size/complexity of the project;
3. Employment of a project-specific risk management process, including technical and non-technical risks; and
4. That lessons learned are incorporated to ensure continuous improvement to the business process.

3.4 Project Delivery

3.4.1 Front end preparation (assessment and authorisation phases)

DMR expects the operator to ensure that the front-end preparation will secure maximum value to the project, including by:

1. Delivery to DMR of a concept select report at the end of the 'Assessment' phase showing how options have been considered and the decision criteria adopted;
2. Demonstrating that technology and EOR assessments have been undertaken;
3. Delivering a field development plan at the end of the 'Authorisation' phase (FID) including final investment approval from operator/joint venture partners;
4. Establishment of a project execution plan (PEP), to be updated at each phase of the project. The PEP should describe how the project is intended to be carried out, including:
   - Project overview
   - Project organisation, including JV arrangements
   - Approval and assurance strategies
   - Project execution details:
     - Contracting strategy;
     - Project controls strategy;
     - Risk and opportunity management;
     - Change management processes; and
     - Safety and quality management.
5. Applying probabilistic cost estimates and sensitivity analyses to provide a view of the project's range of uncertainty either side of the base case production profiles, e.g. with respect to production rates, production efficiency, oil/gas price, drilling success, schedule delays, and other relevant parameters;
6. Finalising all commercial arrangements as far as possible with any remaining agreements included in the overall PEP;
7. Developing a Local Content Plan to demonstrate the early engagement and alignment of the supply chain to the project objectives;
8. Demonstrating that lessons learned have been incorporated prior to the commencement of the next phase of the project;
9. Developing a construction, commissioning, and handover strategy;
10. Demonstrating an assurance and approval strategy that assesses the technical and commercial readiness against minimum gate acceptance criteria; and
11. Demonstrating that benchmarking assessments have been carried out as appropriate for the scale of the project.

3.4.2 Execution Phase

Supplementary to the completion of the front-end preparation DMR expects the operator to:

1. Execute the project in line with the PEP and the consented field development plan;
2. Demonstrate the completion of all commercial arrangements for all scopes;
3. Track and show progress against initial project schedule and demonstrate how the schedule and scopes are being effectively managed;
4. Demonstrate effective cost control and present any variance from sanctioned estimate;
5. Develop and maintain a management of change process including effective decision making and cost and schedule impact; and
6. Monitor risks and opportunities in support of the project.

3.4.3 Decommissioning Phase

1. DMR will set a deadline for the operator to submit a closeout report following the completion of decommissioning including an assessment of cost, schedule and reserves against the consented FDP, and lessons learned.

3.5 Environmental Impact and Health and Safety assessments

The environmental regulation of offshore oil and gas activity is the responsibility of the Department of Mineral Resources. An EIS describing the project is required to be submitted to DMR by the Field Operator in connection with the development consent process. Where a relevant consent is in scope of the *Offshore Minerals Ordinance 1994 (as amended)* FIG's consent is required. More information is given in the Hydrocarbons Environmental Impact Assessment Guidance Note amended 2016.

Major Accident regulation is the responsibility of DMR as the Competent Authority to implement the applicable statutory and regulatory requirements on the safety of offshore oil and gas operations.

Field Operators must submit a Design Notification to the DMR at an early stage in the design process for field developments involving new installations. The design notification must be followed by submission of a safety case, for DMR's acceptance, before the installation can be operated. DMR requires a Relocation Notification if a production installation, with an existing Falkland Islands safety case, is to be moved to a new location in external waters or if a non-production installation is to be converted to a production installation. For installations that have a current safety case in another jurisdiction, the Field Operator should contact DMR at an early stage to confirm the requirements.

3.6 Decommissioning

In accordance with Falkland Islands law and good oilfield practice, wells must be plugged and abandoned and installations must be removed for reuse, recycling or final disposal on land. Subsea infrastructure is expected to be removed unless there is a strong justification for making it safe in situ. Decommissioning should be carried out in the most cost-effective way which includes reducing as far as reasonably possible in the circumstances GHG emissions from the abandonment and decommissioning of fields.

3.7 Unitisation and co-operative development

Prior to the completion of the authorisation phase, licensees should have identified if unitisation will be required for the field they are seeking to develop.

Where a field definition extends across more than one licence, DMR may require Licensees to enter into a Unitisation and Unit Operating Agreement ('**UUOA**') prior to submitting an FDP. This UUOA needs to be approved by DMR prior to development and production consent being issued.

3.8 Flexible approach to development proposals

For most offshore fields, it is expected that Licensees will put forward a plan covering the lifecycle of the development. DMR recognises that there may be valid reasons for more gradual or flexible approaches to some developments based on geological or engineering uncertainty, infrastructure constraints or the benefits of phasing expenditure. DMR will generally support such approaches where consistent with the fulfilment of the Hydrocarbon Policy Principles. The alternatives to full lifecycle developments that are commonly proposed, and the criteria for their consideration by DMR, are set out below.

3.8.1 Extended Well Tests (EWTs)

Extended Well Tests, which are well tests lasting longer than 96 hours of flowback or producing over 2,000 tonnes of oil/oil equivalent, used to gather essential field information to improve technical understanding and confidence in field performance for potential development.

DMR may consent to extended periods of test production from exploration or appraisal wells prior to field development consent. An EWT consent requires an application to DMR setting out the timetable and objectives of the test and the quantities of oil and/or gas to be produced, saved or flared/vented.

The application should demonstrate that the primary objective of the EWT is to obtain essential field information to improve technical understanding or confidence in the performance of the field to advance towards a development. The application should also demonstrate that the EWT programme is optimised to reduce emissions as far as reasonable in the circumstances. The EWT should not be prejudicial to ultimate recovery of a future development. EWTs are not an alternative to production under a Development and Production Consent. The well operator should contact DMR to ascertain whether an EIS is required to support the EWT application.

3.8.2 Phased developments

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, or to commence early production, DMR may accept a proposal for the phased development of a field. Licensees will be expected to demonstrate that such phasing does not contravene obligations to maximise the potential of hydrocarbon resources.

Licensees must submit an application and FDP for the initial phase of the project. The submission can be scaled in accordance with the phased nature of the proposed development plan and should include:

- the more likely forms of subsequent phases;
- the criteria which will need to be met to move to development of the subsequent phases;
- the time frame proposed for further appraisal or development;
- that the emission profile of such subsequent phase(s) has been minimised to a level acceptable to DMR.

3.8.3 Satellite tie-back development

In cases where a satellite field development is to be tied back to existing host facilities with different ownership, it is important that the Field Operator of the satellite development and the operator of the host facility collaborate to ensure an agreed plan for any necessary modification to the host facility.

DMR will require a letter of support from the host facility operator, on behalf of all its co-venturers, in respect of the proposal.

3.9 Considerations of Good Oilfield Practice

The licence requires that the Licensee(s) 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.

DMR considers that good oilfield practice relates largely to technical matters within the disciplines of geology, reservoir engineering, petroleum engineering and facilities engineering and to the impact of the development on the environment. In that regard, practices that are harmful to future oil or gas recovery and/or to the environment should be avoided during all phases of field development. These may include:

- practices that do not contribute to climate commitments, for example by reducing GHG emissions from sources such as flaring, venting, and power generation as far as reasonable in the circumstances; and
- practices which conflict with the interests of other potential users of the licensed area.

Licensees should ensure that they follow good oilfield practice when proposing plans for the development and management of a field.

3.10 Gas utilisation/flaring

Gas disposal by flaring or venting will not ordinarily be permitted. A detailed technical, economic and emissions assessment should be provided to DMR to justify essential flaring or venting proposed. The Licensees' full consideration should be given in the design of the facility to provide for the lowest emission solution and this must be reviewed as economic or technical circumstances change.

For new field developments, DMR 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, Licensees will make provision to do so.

The Licensees should consider carefully all options for gas handling. These may include its processing and transportation to shore, use as fuel, as a means for improving oil or gas recovery, for sale to another asset/ facility, conversion to other fuels (including electricity) or injection for disposal with a view to future recovery. Licensees should also consider ways to avoid all routine flaring and venting such as using flare gas recovery systems in accordance with good oilfield practice.

In considering which development option should be selected, DMR will, amongst other things, consider the expected overall costs and benefits including GHG emissions and associated societal carbon costs, which may not always reflect the commercial positions of individual Licensees.

3.11 Measurement of petroleum

Licensees are required under the licence to measure hydrocarbons using methods customarily used in good oilfield practice and approved by DMR. The FDP submission will include a basic statement on the proposed method of measurement for the relevant field. Prior to any production, a Petroleum Measurement Plan will be required to gain DMR's approval of their methods for petroleum measurement. Submission of such a plan in the manner, and with the details, compliant with the UK 'PON6' process will normally be accepted.

4 Assessment Phase requirements

During the Assessment Phase Licensees should provide DMR with sufficient opportunity and information to gain an understanding of the field and its conceptual development. The conclusion of the Assessment Phase will be DMR having no objection to the Concept Select decision including the considerations set out below.

4.1 Concept Select

DMR's involvement in the Assessment Phase and Concept Select is important as decisions made by licensees in this phase will likely have significant implications on their obligations.

DMR requires to be consulted on the development plan options so that matters requiring detailed consideration by DMR can be identified. Such consideration may include technical, economic and environmental evaluation of the options. DMR will generally commence its consideration in parallel with the Field Operator's concept select process but will not conclude its consideration until after the Field Operator has completed their selection process and confirmed – in its Concept Select Report – its preferred concept with the appropriate Licensee approvals. This approach will allow DMR sufficient opportunity and information to gain an understanding of the field and its conceptual development. It will also provide DMR with the opportunity to inform the Field Operator at an early enabling stage, of any aspects of the proposed development which are not aligned with the Falkland Islands Hydrocarbon Development Policy Statement or any other matters to be addressed, including decommissioning. The requirements for operators are outlined further below.

DMR will set out to the Field Operator any information required to support consideration of the development options. It is likely that the information required by DMR will be similar to that used by the Field Operator to inform the Licensees' own decision-making process. However, DMR may require further information, for example, seeking clarifications of submitted information or as a result of insights gained from the review.

The Field Operator should prepare and submit to DMR a Concept Select Report once the development concept option has been selected. DMR will then review the report and if any concerns are identified DMR may seek to agree with the Field Operator a programme of work or review, intended to lead to their resolution within an agreed timetable.

DMR having no objection to the Concept Select does not necessarily mean that the final version of the submitted FDP will be consented to, nor should this be taken to imply any agreement, consent or authorization from any government agency.

4.2 Greenhouse Gas Emissions

4.2.1 Overview

DMR considers the emissions contributions of new and incremental developments as part of the Assessment Phase. The Field Operator should demonstrate amongst other things that the following have been considered and evaluated from a technical and economic perspective:

- Alternative concepts with significantly lower GHG emissions.
- Concepts with power from renewable sources.
- A forecast of each concept's energy consumption and GHG emissions, with justification if the selected option does not have the lowest GHG emissions.
- The selection of energy efficient equipment for power generation.

- Energy efficient process design including waste heat recovery, efficient turndown, reliability, redundancy, etc.
- Zero routine flaring and venting.
- Strategy for detecting, minimising and monitoring emissions of methane throughout field life.
- Evaluation of GHG emissions impacts on selected host infrastructure.
- Gas recovery systems alternatives to gas export constraints.
- Possibilities for Energy Hubs.
- Quantification of the GHG emissions of hydrocarbon export options and mitigation strategies.
- Pre-investment in facility design to allow connection to future low carbon power and other emission reduction opportunities.
- Re-use/re-purposing of infrastructure and facilities.

This information will be documented in an Emissions Reduction Action Plan (ERAP) for each asset which is maintained throughout field life. This will follow good practice such as illustrated by the NSTA's ERAP requirements. ERAP documents will include the following information.

4.2.2 Emissions reduction philosophy

Produce an Emissions Reduction Philosophy for field development which, among other things, will summarise and assesses the applicability of available emissions abatement and emissions monitoring opportunities and technologies.

The operator should complete appropriate study work in order to present arguments for the concept put forward for assets in the Concept Select Report and the Environmental Impact Statement, where it will consider the available development options and their GHG footprint. Technical source material will be made available to share with DMR on request. The study work should include proportionate technical and economic assessments. This should be refreshed at least every two years.

4.3 Economic Assessment

DMR assesses the economics of all new and incremental field developments. Consideration is given to whether the proposed project accords with the Hydrocarbon Policy Principles.

> ***'Economically recoverable'*** *in relation to petroleum means those resources which could be recovered at an expected (pre-tax) market value greater than the expected (pre-tax) resource cost of their extraction, where costs include both capital and operating costs (including carbon costs) but exclude sunk costs and costs (such as interest charges) which do not reflect current use of resources. In bringing costs and revenues to a common point for comparative purposes a 10% real discount rate will be used.*

The social costs of carbon will be taken into account using UK Government carbon appraisal values for all greenhouse gas emissions, and will be combined with the associated real terms social discount rate. The standard social discount rate is set at 3.5% in real terms and in the longer term (beyond 30 years) declines in a series of steps to allow for future uncertainty. Apart from carbon costs, present values for all other costs of extraction and for all revenue streams should be calculated using a 10% real discount rate.

Economic welfare at national level will be highest when the pre-tax net present value ('NPV') of oil and gas resources is maximised, taking into account the effect of recovery in other fields and the societal cost of associated GHG emissions. This is irrespective of the subsequent impact of taxation on the division of realized economic value between operators and the Treasury. In the Assessment Phase, Field Operators must examine those options which are most likely to maximise economic recovery at the national level.

The preferred commercial option may achieve this, but cases may arise where wider national interests and individual commercial interests diverge.

Field Operators are therefore required to include information on all development options being considered within the Concept Select Report submitted to DMR prior to developing the preferred Field Development Plan. Corresponding data for each of the options must also be submitted in Excel workbook format using Standard Economics Templates (SET). Data required covers underlying assumptions of revenue and costs and aspects relevant to environmental and societal cost considerations, including forecast GHG emissions, energy demand, flaring/venting volumes and associated costs to the Field Operator, as well ranges on reserves and what break-even prices are in each scenario. Where the development plan for a new field or incremental development has a significant impact on another field(s), relevant data for the affected field(s) should also be provided to capture the impact of the development.

Societal carbon appraisal values are not intended as forecasts of market-based carbon prices. Operators are expected to develop their own objective view on future carbon market prices for commercial assessments of returns to new or incremental investments.

4.4 Consultation on Local Content Plan

The Local Content Code of Practice seeks to advance the stake of Falkland Islanders in the developing oil and gas industry in a sustainable manner and to ensure capacity development and employment of Falkland Islands' people, use of Falkland Islands' goods and services, transfer of technology and know-how, localisation of knowledge and ownership. This in turn seeks to create a legacy of long-term benefit and growth to the Islands economy and helps to retain as much 'value' locally as possible.

The Code encourages the integration of the oil and gas sector with the other sectors of the Falkland Islands' economy to effectively support national growth and development through the development of joint projects/facilities, joint ventures and partnerships.

The intent of the Code is to ensure that at every step of the exploration, production and marketing of the oil and gas resources as well as related businesses, maximum use shall be made of available local capacity. It will ensure that the capability of Falkland Islands' people is developed sustainably to ensure progressive increases in local content and local participation.

DMR expects all projects requiring an FDP to develop a Local Content Plan. In the Assessment Phase, the Field Operator should prepare a draft Local Content Plan prior to Concept Select and share with DMR for informal review and discussion. This should be at an early stage of the project, in advance of any project specific contract award.

Following DMR's initial review, any incomplete or unsatisfactory Plans will be returned with comments/ clarifications to be addressed. It is then expected that the Field Operator will share their progress and draft plan with the Chamber of Commerce and potentially other groups such as the Rural Business Association such as in the format of a workshop so that the approach can be discussed further and points raised by local business representatives. This will result in a workshop output that will inform the Local Content Plan that will be formally submitted in the Authorisation Phase.

It is anticipated that Local Content Plans will be developed as an ongoing process in tandem with the field development planning.

4.5 Consultation on Project Execution Plan (PEP)

The Field Operator should prepare a PEP for all phases of the project. In the Assessment Phase, the PEP should be developed in parallel with the FDP and should be recompiled and updated at each phase of the project.

The PEP should include sections comprising:

- Schedule planning, control and management
- Project organisation
- Contracting strategy (reference the Local Content Plan)
- Cost planning, control and management
- Risk and opportunity planning, control and management

Further guidance on the PEP is given in Section 5.4.

4.6 Technology and EOR screening

Field Operators should demonstrate that existing, new and emerging technologies have been considered for deployment to their optimum effect and, where appropriate, encourage the development of such technologies for the purpose of:

- meeting the obligations in the Hydrocarbon Policy Principles;
- building knowledge of the reservoir characteristics and handling of the oil types;
- building resilient development solutions;
- pre-investment in/futureproofing of facility design; and
- mitigation of climate impacts and environmental risks.

In the Assessment Phase, for all hydrocarbons developments, the potential for application of improved recovery processes beyond conventional methods should be evaluated. A summary of all the recovery processes considered and the reasons for the final choice is required in the Concept Select report. Field Operators are required to justify if EOR processes are not being/planned to be used.

Where a development demonstrates economic potential for EOR, Licensees should set out their firm plans to implement this. Where definite conclusions cannot be reached, a programme for addressing the outstanding issues during production should be given in the FDP and for ensuring that both wells and production facilities are EOR-ready or can be readily made so.

A summary of applicable technologies considered should be included in the Concept Select report. Appropriate technology should be identified during the Concept Select process and discussed in the Concept Select report. The report should identify what technologies were considered and the reason for being proposed or discounted should be provided. The likely benefits these technologies could potentially provide to the development should be stated as well as any risks associated with their deployment. Reasons for the final technology solution should be included in the report. Technologies should cover the full life cycle of the development.

4.7 Environmental Statement (ES) preparation

Section 64A requires an Environmental Impact Assessment (EIA) to be conducted, and Environmental Impact Statement (EIS) to be submitted, for each application to drill a regulated well. Section 64B requires an EIA and EIS for each application for a “relevant consent” (as defined in section 64), where it is considered that the environment might be significantly affected if the application were to be granted. An applicant may under section 67 request an exemption from certain EIA/EIS statutory requirements if they can satisfy DMR that the environment would not be significantly affected even if the application were to be granted. An applicant may also under section 67A request an exemption from certain EIA/EIS statutory requirements if already covered by a previous EIA/EIS, and if there could be no effects on the environment that would be substantially different or significantly greater than the effects mentioned in the previous EIA/EIS. Where an EIS is required to be submitted to DMR, the Field Operator should normally engage with DMR in the Assessment Phase, before Concept Select, and the choice of development concept must be made giving full weight to any environmental concerns.

Further guidance is contained in the Hydrocarbons Environmental Impact Assessment Guidance Note amended 2016. While statutory timescales are fixed, the timescale for the overall EIA process may vary from project to project particularly if there are unusual issues, a high degree of complexity or if it takes time to respond satisfactorily to representations and requests for further information.

Under the Offshore Minerals Ordinance 1994 (as amended) the EIS process must finish (demonstrably and to the satisfaction of DMR) before consent can be given by FIG to drill a regulated well or give a relevant consent.

4.8 Onshore planning, utilities and socio-economic impacts

Onshore facilities are likely to be an essential component of field developments. Strategic thought must be given to the way in which the onshore demands of a development are serviced. Given the geographic spread of industrial and residential receptors in the Falkland Islands and its environmental sensitivities, early and focussed thought must be given to the optimum way to deliver the needs of the development. Early discussions with the Planning Department and the Department of Public Works must be held to understand the issues, priorities and availability of public services.

Impacts on society also need to be considered and adequate socio-economic impact assessment will be required prior to concept select, in order to feed into the concept select process. Such assessment requires a considerable amount of research and data, sometimes over time, and the approach to building up sound socio-economic data, trends and analysis of impacts needs to begin in the assessment phase in order that the optimum development plans are subsequently formed.

The Concept Select Report must contain an appraisal of socio-economic issues relevant to each concept (and sub-option if relevant) and describe the approach to managing this topic towards and beyond consent being given to a field development proposal.

4.9 Risk Register

All of the above topics represent areas of risk to the progress of field development including commercial, technical (subsurface / facilities / logistics), safety, environmental or socio-economic risks. Some risks will be specific to the Operator, some risks will be specific to the government and some will be shared. Internal and external risks should also be identified such as market fluctuations and interference by third parties.

The Operator will demonstrate that risks have been actively identified and managed by maintaining a risk register and discussing the management of risk regularly with DMR. While the burden is on the Field Operator to demonstrate that risks are competently controlled and mitigated, it is recognised that offshore hydrocarbons development can have a strategic nature whereby some risks are better managed in cooperation with DMR.

5 Authorisation Phase requirements

During the Authorisation Phase, the Licensees are required to undertake a number of activities in support of their application to obtain consent from DMR to install facilities and produce hydrocarbons.

The issue by DMR of a Development and Production Consent for the proposed development indicates the completion of the Authorisation Phase.

5.1 Economics Assessment

As part of the Authorisation Phase, the Field Operator should submit final economics information in the SET format to account for any significant changes provided at the earlier Assessment Phase. The Field Operator should provide this information for the chosen development concept prior to internal approval of the project by Licensees.

5.2 Greenhouse Gas Evaluation

5.2.1 Overview

DMR considers the emissions contributions of new and incremental developments as part of its consideration of FDPs/FDPAs. The Field Operator must demonstrate, for example amongst other things, that the following have been considered and evaluated from an environmental, technical and/or economic perspective:

- Concepts which demonstrate significant savings in GHG emissions;
- What has been considered, incorporated or rejected to minimise emissions and maximise recovery;
- FDPs for tie backs and FDPAs should include information on emissions from power, flare, vent and total emissions, for both the remaining life of field for the host/base case 'as is' and the incremental case with the tie back or addendum;
- Data should be provided on: yearly production forecasts; emissions forecasts and emissions intensity; and life of field emissions intensity;
- Where relevant, outline the impact of potential future emissions intensity reduction opportunities;
- The means to avoid all base load flaring and venting from the development;
- Alternatives to gas export constraints;
- Quantification of the GHG emissions impact of hydrocarbon export options;
- A like for like comparison of emissions from all export options when determining the solution with the lowest carbon emissions to produce a unit of product.
- Justification must be provided to DMR if the selected option does not have lowest GHG emissions;
- Pre-investment in facility design to allow connection to future low carbon power and other emission reduction opportunities.

5.2.2 Plan of activities to reduce emissions

Once consent is given to a field development plan, an Emissions Reduction Action Plan (ERAP) will be required promptly.

Planned emissions reduction initiatives, including for logistics emissions, will be set out. For each asset, the operator will select, plan and execute, for each asset, appropriate emissions reduction and monitoring initiatives which are aimed at reducing the emissions of that asset over a reasonable timescale.

During detailed design process, the report will include further analysis of low-carbon technologies, techniques and modes of operating the field and the facilities to minimise GHG emissions. This will include analysis of Reliability, Availability and Maintainability (RAM) of the facilities.

Plans will set out, with associated budgets, the approach to deliver continuous improvements in flaring and venting. All operators should have, or work towards, credible plans to achieve zero routine flaring and venting, to be included as part of the ERAP.'

Project reporting will include activities to reduce all forms of emissions, including those associated with power generation, flaring and venting, production operations and logistics.

Operators should also maintain their own action plans within their corporate opportunity progression and work program and budget tools. Operators should be prepared to make available on request their full plans for such activities including as a minimum; estimated abatement opportunity, costs and time frame.

This plan should be updated at least annually.

5.2.3 Flare and vent management strategy

The Operator will have Flaring and Venting Management Plans incorporated as part of their ERAP and management of operations.

The operator should develop appropriate document(s) that cover the following and maintain such documents as part of their corporate management system and operational procedures:

- Projections for flaring and venting quantities and associated emissions over the life time of the installation
- Procedures for managing flaring and venting as part of ongoing operations
- Plan of improvement actions that include activities to improve understanding and performance relating to combustion efficiency.
- Maintenance of RAM assessments and performance monitoring to demonstrate that all opportunities to minimise flaring are taken and lessons learned.

5.2.4 Ultra-low carbon assessment

The operator should complete appropriate study work on options that would lead to an ultra-low carbon profile for their assets and have that work available to share with DMR on request. This should be refreshed at least every two years.

This will include assessments of, at least:

- Potential for electrification of assets from lower-carbon sources of power, onshore and offshore.
- The addition of offshore renewable power units to the asset to displace fossil fuel use.
- The means by which alternative power sources would be connected to the assets, including issues of safety, voltage conversion etc.
- The use of alternative gas and liquid fuels.
- The removal of GHGs from exhaust gases.

5.2.5 Local content issues

The sourcing of any studies and initiatives to reduce GHGs should have due regard to the Local Content obligations.

5.2.6 Implement and execute in a timely manner

The operator will demonstrate timely implementation and execution by demonstrating progression of emissions reduction activities in their annual reports and reduction in emissions reported to DMR over time.

5.3 Local Content Plan

In the Authorisation Phase, the Field Operator should submit its final Local Content Plan prior to, or along with, the submission of the FDP application.

The Local Content Plan submission should focus on the following criteria:

- Engagement - early and continued engagement with the Field Operator's supply chain regarding the specifics of the project, aimed at improving project performance. Reference to good practice will be expected such as the use of industry tool kits including those outlined in the Offshore Energies UK Supply Chain Code of Practice and Engineering Construction Industry Training Board Project Collaboration Toolkit. Environmental objectives should also be included as part of the Field Operator's initial engagement with the supply chain. Consultation with local business groups will be expected, not limited to the Chamber of Commerce and the Rural Business Association.
- Trust - demonstration of trust and empowerment throughout the project life cycle – clearly identifying functional requirements and subsequently supporting the supply chain to deliver to their contractual commitments without bespoke, restrictive or client-specific requirements.
- Innovation - encouragement and fair evaluation for the proposed use of alternative/new products, processes and/or contracting methodologies.
- Quality - demonstration that historical performance, quality, employment practice and supplier culture is appropriately valued.
- Workforce - demonstrating concrete steps are taken to develop a healthy and skilled local workforce for the future.

Once the final Local Content Plan is submitted an assessment process will be undertaken by DMR. Where DMR considers that all five of the above criteria have been satisfactorily addressed, the Plan will go to consultation with local business representatives such as the Chamber of Commerce and potentially others such as the Rural Business Association and Falkland Islands Fishing Company's Association depending on context.

The Field Operator will give an account of the consultations held, any comments received and further action taken to update the Plan. Following satisfactory incorporation of any points raised, the Local Content Plan will usually be endorsed with no further action. In cases where one or more of the elements are considered not to meet expectations, DMR will seek improvement. In cases where improvements cannot be achieved, final endorsement will be withheld pending discussion between the Field Operator and DMR.

The Local Content Plan should be submitted as a single document where possible and should normally include as a minimum the following sections with reference to Table 1.

- Executive summary;
- Company overview and contracting policy;
- Project overview;
- Evidence of engagement, trust, innovation and quality; and
- Valuing and developing the local workforce.

Table 1 - Local Content Plan Evaluation Criteria

Criterion	Below Expectations	Meets Expectations	Commendable
Engagement	ITTs issued without prior discussion with supply chain and the DMR Operators look to their own requirements that need bespoke solutions.	Pre-ITT discussion held with suppliers to present scope, expectations and contract award process.	Engagement session held with the supply chain, where functional requirements were presented and integrated solutions sought Operators openly communicate project opportunities on local networks and are receptive to solutions and ideas. They also enter contract award details and comprehensive project information.
Trust	Operator requires extensive inspection team to oversee activity. Contracting model stifles supplier incentive to deliver increased value (e.g. by claiming 100% of savings).	Operators are open to supplier initiatives to reduce cost and are willing to share in savings.	All parties are actively incentivised to benefit from successful project performance - proportionate to the level of exposed risk/responsibility. Potential win-win provision included in contract.
Innovation	ITT issued and technical non-compliance leads to disqualification. Operator not receptive to innovative ideas and solutions. Contractual terms and strategy set out clearly within ITT.	Alternative solutions requested as part of ITT process and considered where appropriate. Operator receptive to supply chain company's innovative ideas, practices, solutions and commercial methods but none adopted in this instance. Contractual terms and strategy set out clearly within the ITT with alternative proposals included for company consideration.	Suppliers encouraged to provide alternative technical / commercial solutions for discussion prior to ITT release. Operator adopts supply chain company's innovative ideas, solutions and commercial methods. Contractual terms reflect responsibility and do not penalise innovative models. Mutually beneficial contract agreement in place incentivising efficiency and value creation through project lifecycle leading to potential upside for all parties.
Quality	ITT respondent list compiled via internal approved vendor list.	Industry tool Supplier Qualification System used to develop ITT list, in addition to companies previously known to buyer. All selected vendors required to complete a supplier audit assessment.	Industry audit tool trusted to identify competent suppliers without additional prequal information.

Criterion	Below Expectations	Meets Expectations	Commendable
Workforce	ITT restricts local workforce from entering into bidding, either explicitly or by requiring skills or services unavailable locally. Work packages are combined in a way that prevents local workforce from engaging with specific scopes.	Operator has assessed local skills and pressures and engaged with local companies and bodies. Local staffing is prioritised, eligibility is flexible and upskilling is offered case-by-case. ITTs are packaged to allow local firms to compete on relevant scopes.	Operator develops a local workforce development programme to encourage and support a local workforce including upskilling opportunities and apprenticeships. Personnel are given other support such as with housing, family and welfare to form a long-term workforce.

5.4 Project Execution Plan ('PEP')

The Field Operator should provide DMR with an updated PEP covering the Authorisation Phase and prepare a PEP for the Execution Phase of the project.

5.5 Field Definitions

For reasons of good practice and administration and in line with Model Clause 6(2) of the Offshore Petroleum (Licensing) Regulations 2000, all fields must be defined by a boundary drawn around them. A Field Definition will enable the Licensees with an interest in the blocks in which the field is situated and Licensees in the adjacent blocks to understand what constitutes the field for both development and tax purposes. This is undertaken in two stages; first, DMR will issue a proposed Field Definition at an early point in the Authorisation Phase, utilising the geological information that is available to it at that time. Second, the final Field Definition will be issued when the Development and Production consent is given. Vertical data may also be required to delineate the field from other hydrocarbon-bearing strata where necessary.

5.6 Development Area

The FDP must relate to the Field Definition area, or the Field Operator, on behalf of the Licensees, may propose that the FDP covers an area (the 'Development Area') that differs from the Field Definition for the following reasons.

- Where the Field Definition is not unitised the Development Area would usually extend only to that part of the field covered by the FDP as described below.
- Where development well trajectories are outside the Definition.
- For a phased development, the Development Area may be limited to that part of the field addressed in the detailed first phase proposals. The Development Area may be extended with subsequent phases.
- Any other reason with sound justification.

The Development Area will always be agreed with DMR and documented in the FDP.

5.7 Unitisation and Unit Operating Agreements (UUOA) - Competing interests

Commercial and technical disputes may arise about the optimum development plan when an FDP is proposed for a field and the Field Definition extends into an area covered by an adjacent licence.

In such cases DMR needs to be satisfied that the Hydrocarbon Policy Principles will be met and that unnecessary competitive drilling is avoided. The most efficient way to satisfy these requirements, and avoid any possible delay in the consenting process, is for the Licensees to agree with the adjacent licensees and propose to DMR a unitised development or other commercial arrangement that facilitates a field development.

Where such agreement is not reached or the proposed field development does not demonstrably satisfy these requirements, DMR will wish to understand the circumstances and give all parties adequate opportunity to make representations.

DMR may require a field to be worked and developed as a unit in cooperation by all Licensees. The grounds for the use of this power are that DMR considers it is in the national interest in order to secure the maximum ultimate recovery of petroleum and in order to avoid unnecessary competitive drilling. If, in any intended development, there is a likelihood of claims or disagreement between adjacent licence groups related to the field's extent, DMR should be consulted at an early stage.

If a UUOA is put in place by Licensees, this should be submitted to DMR at the same time as the draft FDP. If the Licensees choose not to enter into a UUOA and propose an alternative commercial arrangement, it may be appropriate to define two or more Development Areas within the Field Definition to document different ownerships in the different parts of the field – this should be discussed with DMR at an early stage in the FDP process.

5.8 Field Operator approval

Prior to submitting the final form application (and FDP) for development and production consent, Licensees are required to appoint a Field Operator (or 'Operator') to organise and supervise the works, which requires approval by FIG under Model Clause 22.

Section 8 details expectations for such a Field Operator in order to gain the approval of FIG, and if an appointed Operator subsequently fails these standards, the appointment may be revoked. Without FIG's approval, any person nominated as Field Operator by the Licensees is not authorised to act in that capacity and may not represent the Licensees in dialogue with DMR.

A Field Operator must clearly be appointed by a Joint Operating Agreement of the Licensees prior to seeking FIG's approval for the appointment. If the Field Operator is not one of the Licensees, this will require prior discussion with DMR and the case will be critically examined. Liabilities at all times remain jointly and severally with the Licensees, and in some cases, such as the obligation to undertake a decommissioning programme, liabilities may extend to other parties.

5.9 Host facility modifications

In cases where a satellite field development is to be tied back to existing host facilities it is important that the Field 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 and evaluation of any impacts e.g. increased emissions from power generation or fluid processing.

DMR will require a letter of support from the Field Operator of the host facility, endorsed by all the facility owners. The letter should cover the following points:

- A statement supporting the development of the satellite field(s) over the host facility and committing the host facility to provide the necessary processing/transportation services

- A statement confirming the intent to execute the required commercial arrangements (e.g. construction and tie-in agreement, transportation, processing and operating services agreement etc.)
- A summary of the major new equipment/ modifications proposed to be carried out on the host facility to support development of the satellite
- An assessment of the impact of the new satellite field production on existing production and facility emissions.

Where the proposed modifications are substantial, DMR may require the operator of the host facility to submit an application for DMR's consent to such modifications, supported by a document describing the new equipment/ modifications proposed to be carried out on the host facility to support development of the satellite. This application and supporting document should be submitted to DMR at the same time as the final application/FDP for the satellite field. If the respective Field Operators of the host facility and the satellite development prefer an alternative approach to documenting the proposed host modifications then this should be discussed with DMR at an early stage, especially if the host facility is leased rather than owned by the host Field Operator.

Such modifications may also require DMR's agreement and it may require the Installation Operator of the host facility to submit a Design Notification for modifications to the host facility's Safety Case.

5.10 Environmental impacts and oil spill planning

5.10.1 Environmental Impact Statement

DMR cannot issue a Development and Production Consent until the EIA process for the development has been completed to the satisfaction of DMR including an Environmental Impact Statement process involving submission, acceptance, agreement to begin public consultation, a period of consultation, a period of response to representations and requests for further information, and a satisfactory conclusion to any matters raised resulting in an updated EIS. Should matters be raised that, in the opinion of DMR, warrant a further period of consultation, then the applicant will be notified and such further consultation shall be undertaken and any further matters resolved.

The Licensee(s) should submit an application for a Development and Production Consent to DMR and confirm that it will submit, or has submitted, a supporting EIS along with any draft FDP, usually after Concept Select. Under the Offshore Minerals Ordinance 1994, all EISs are subject to a period of public consultation during which time any person may submit representations in relation to the proposed project. Licensees should bear in mind that the consideration of an EIS can take several months and can take significantly longer than this if significant representations are made by any person, or if insufficient information is presented within the EIS.

Once DMR are satisfied the EIS process has been completed, DMR will ask ExCo to agree that this is the case and advise ExCo that a development and production consent may then be considered, subject to any conditions recommended by DMR under Section 64C(3) of the Offshore Minerals Ordinance 1994 (as amended).

Guidance on EIS content and methodology is available from DMR.

5.10.2 Environment Plan

The key project details, commitments and obligations resulting from the EIA process will be carried forward via an Environment Plan that will be a condition on the development consent. This will include:

- Project information;
- Control measures required to achieve the outcomes described in the EIS;
- Legislative compliance requirements;
- Environmental monitoring requirements;
- Record keeping and reporting; and
- Environmental management system information.

5.10.3 Offsetting

It is expected that the Operator will deliver its requirement to offset any residual impacts on the natural environment (i.e. fauna, flora, soil, water, air, climate, landscape and seascape) by making contributions to the Falkland Islands Environment Trust. Contributions will be made at quarterly intervals based on relevant emissions of CO_{2e} at a price-per-tonne value set periodically by the Governor.

Emissions in scope of this requirement include the seven direct GHGs used by the Intergovernmental Panel on Climate Change (IPCC) (CO2, CH4, N2O, HFC, PFC, SF6, NF3). A CO_2-equivalent figure is to be calculated using their global warming potential used by the UK National Atmospheric Emissions Inventory for national reporting at the time of calculation.

Relevant emissions include those related to:

- Vessels involved in construction and installation of facilities.
- Production installations.
- Drilling installations.
- Flaring and venting of hydrocarbons.
- Supply vessels.
- Standby/guard vessels.
- Helicopters and other dedicated crew transportation.
- Planned / foreseeable well interventions, pipeline interventions, maintenance, inspections and surveys.
- Carrying out seismic surveys that are essential for the project.
- Landward facilities dedicated to the project.
- Imported power emissions such as electricity.
- Workforce emissions such as accommodation or transportation where the emission sources are mainly for the purpose of delivering the project.
- Waste treatment, transportation and disposal undertaken in the Falkland Islands or its conveyance to another country.
- Decommissioning, as an inevitable effect of the project.

5.10.4 Initial Oil Pollution Emergency Plan

An initial Oil Pollution Emergency Plan (OPEP) will be required to support the EIS, since oil spills are a critical environmental issue with potentially severe environmental impacts and confidence is required in the arguments made in the EIS. While contracts with support companies may not have yet been placed, and this limits the extent to which to OPEP can be fully populated, the OPEP will be structured in line with good practice and include reliable and accurate information on:

- Organisation and communications - control centre and key locations, interface with government agencies.
- Prevention, including blowout prevention and design and operational safeguards in installations, subsea equipment and wells.

- Source control including blowout prevention (including the location and logistics of a suitable well capping device) and arresting a major FPSO or connected tanker incident.
- Relief well planning, in the event of a well blowout.
- Immediate cleanup at-sea, surveillance and sampling.
- Shoreline cleanup.
- Waste management.
- Scientific monitoring programme, short-term and long-term.

5.11 Design Notification

Where appropriate, DMR must have completed its review of the Design or Relocation Notification before DMR gives advice to ExCo on whether a Development and Production Consent may be considered. Design Notifications (or Relocation Notifications where applicable) should be submitted to DMR at an early stage of the design process as there may be significant issues that influence the design and construction of the installation. The Installation Operator should ensure that DMR has sufficient time to complete their review of the Notification prior to the formal submission of an FDP.

While three months is provided for in the regulations for DMR to raise matters with the Operator to allow the Operator to take these matters into account prior to submitting the field development plan, more time may be advisable to reduce the risk of a significant issue presenting itself later in the process. Ultimately, a satisfactory Safety Case will need to be submitted, and the more attention that is paid to the early stages of the process, the less chance there will be of a serious issue needing to be resolved later potentially after contracts have been placed.

The Field Operator should advise DMR of the outcome of the Design or Relocation Notification review, and any necessary steps needed to address DMR observations, prior to DMR making its decision whether to grant Development and Production Consent.

5.12 Insurance

5.12.1 Insurance Plan

The operator must develop an insurance plan during the authorisation phase that identifies and quantifies the insurance requirements that are required by Falkland Islands law (or may be instructed by law if they are lacking) and by good oilfield practice and principles of good governance. This will include at least the following:

- Construction All Risk;
- Machinery Breakdown;
- Terrorism and Sabotage;
- Loss of Revenues;
- Control of Well/OEE (construction/operations);
- Seepage & Pollution (clean-up & third party);
- Third Party Liability including pollution;
- FPSO Construction All Risk, Hull & Machinery and third-party liability insurance;
- FPSO Protection and Indemnity;
- Drilling Contractor Protection and Indemnity; and
- Non-owned Charters Liability/Aviation Liability.

This will be documented in an Insurance Plan that will be reviewed by DMR and other government departments. Before an application for field development is made, a finalised Insurance Plan will need to be accepted. As part of this submission, evidence will be needed from suitably qualified providers that the insurances within the plan can be provided at the time at which they are needed and that the insurances will operate in a way consistent with good oilfield practice and that they will minimise the exposure to the government and Falkland Islands economy if an insurance event occurs by having appropriate terms and mechanisms to restore injured parties, the environment and facilities speedily and efficiently. The costs of such insurances should be clearly included in the economic tables submitted to support the project.

5.12.2 Environmental Liabilities

Liabilities in the event of a serious environmental incident can be large and the event could also trigger a loss of confidence in the Operator and licensees, cause a loss of revenue, and damage the parties' ability to fund response, remediation and compensation. This section deals with issues specific to environmental liability in addition to applicable guidance given above.

The Offshore Minerals Ordinance 1994 (as amended) provides that an Operator and licensees are financially liable for the following (summarised):

a) damage to the environment of the controlled waters or of the Falkland Islands or their dependent or associated ecosystems;
b) loss or impairment of an established use;
c) loss of or damage to property of a third party or loss of life or personal injury of a third party; and
d) reimbursement of reasonable costs by whomsoever incurred relating to necessary response action, including prevention, containment and clean up and removal measures, and action taken to restore the environment.

In the consenting phase of the FDP, the Operator must provide evidence that the liabilities associated with a credible worst-case incident have been reasonably estimated and that the Operator is capable of implementing competent plans to provide financial resources to meet these liabilities including the immediate launch and uninterrupted continuation of all measures necessary for effective emergency response and subsequent remediation of any damage. Given the large uncertainties involved in estimating such liabilities, DMR may accept the estimate provided or determine that a specific level of liability cover is required.

Evidence must be provided that reputable providers of appropriate insurance or indemnity provision are willing to provide cover for the proposed development. Such arrangements must not only cover the forecast cost of credible worst-case incident, but be structured and administered in a way that allows efficient processing of claims in a way similar to schemes such as the Offshore Pollution Liability Association (OPOL) Fund.

Environmental liabilities are held jointly-and-severally by all of the licensees. At the point of consent being sought for the FDP, the manner in which the liabilities resulting would be shared among the partner licensees must be documented.

5.13 Emergency Response and Security Planning

The operator must develop an Emergency Response Plan and a Security Plan during the authorisation phase that sets out the organisation and delivery of responses to emergencies and security risks. Reference will be made to the latest versions of:

- Integrated Offshore Emergency Response Plan
- National Oil Spill Contingency Plan

The above documents will also be referenced in Oil Pollution Emergency Plans and in Safety documentation. The operator will liaise both with DMR and with other necessary local agencies in drawing up their plans including Department of Emergency Services and Island Services, Falkland Islands Maritime Association (FIMA), Falkland Islands Civil Aviation Department (FICAD), Falkland Islands Government Air Service (FIGAS), Royal Falkland Islands Police, Department of Natural Resources, Customs and Immigration and King Edward Memorial Hospital. Attention should be paid to matters such as logistics, supply lines and communications given that resources may be stretched by several different agencies during an incident.

Before an application for field development is made, a finalised Emergency Response Plan and Security Plan will need to be accepted.

5.14 Onshore planning, utilities and socio-economic impacts

As development proposals are brought forwards, detailed discussions must be had with the Planning Department and Public Works Department to ensure proposals are compatible with local requirements and infrastructure and minimise impacts on the environment and public services. It is expected that a ‘Utilities Statement’ will be prepared to accompany any onshore or coastal development that documents the demands that may be placed on water, sewerage, power, roads and transport and waste management. If harbour facilities are impacted, then consultation and agreement with FIMA will be required. If aviation solutions are required, FICAD and FIGAS must be consulted and agreements reached. It is expected that the operator will take all reasonable steps to mitigate any adverse effect on the public, environment and utilities by adopting good practice in their design, construction and operation of onshore facilities and logistics.

A socio-economic impact assessment report and a social effects monitoring programme will be required prior to an application for field development. Given the relatively small population of the Falkland Islands, it is essential that the necessary time and effort is made to gather data, consult stakeholders and conduct a full analysis of impacts, and to draw solutions into the field development. This requires a holistic approach given the majority of activity occurs offshore and there may be strategic solutions that avoid or minimise shoreside impacts.

5.15 Decommissioning security arrangements

DMR must be satisfied that appropriate financial security arrangements for decommissioning are in place. These will depend to a large degree on the financial strength of the Licensees and Installation Operator. Advice on acceptable decommissioning securities will be provided by DMR.

Consent to a Field Development and Production Programme will not be given unless there is a high degree of confidence that adequate securities can and will be obtained. Subsequent consents required to drill wells and locate and operate an Installation may not be given if these securities are not in place, and licences may be at risk if there is a failure to demonstrate competence in this matter.

5.16 Time frame

Provided that the process described in these guidelines has been fully implemented, DMR will usually aim to complete its review of the final submitted application for consent and FDP within three months, though this is highly dependent on the subject matter and justifications and it should be noted that expert opinion may well be sought. The early review by DMR of draft sections of the FDP and its associated documents as these become available will help achieve this aim.

5.17 Risk register

A Risk Register will continue to be maintained and updated by the Operator and reviewed regularly with DMR to ensure risks and mitigations are competently managed and issues and resolutions are foreseen in good time.

5.18 Content and submission of the FDP

5.18.1 Overview

The FDP should provide a comprehensive understanding by the Licensees of the field, although more information must be provided if required by DMR.

The content of the FDP should be agreed with DMR and will depend on the complexity of the field, the degree of interaction prior to the submission and the issues identified. The FDP will provide a clear explanation why the FDP concept is considered optimum from the emissions, technical and economic perspectives. It will also set out the commitments that the Licensees are making (in terms of environment, facilities, number of wells, provision for Improved Oil Recovery ('IOR') or Enhanced Oil Recovery ('EOR'), provision for third party access hydrocarbon export routes etc.) to bring forward a sound economic development, rather than a detailed technical description of the subsurface reservoir description or required infrastructure.

Field Operators are encouraged to refer to their internal documents and studies in Sections 2 and 3 of the suggested contents shown below, to keep FDP documentation to a minimum. A list of Annexes can be provided in Section 4 of the suggested contents shown below with copies of all documents provided to DMR.

The actual form of the development and the basis for field management should be described and sufficient detail will be required to permit development and production performance to be measured.

5.18.2 Submission of documents and form of application

To assist with submission of what might be a large number of documents, the Field Operator will agree at an early stage the means by which documents shall be transmitted or uploaded securely and changes tracked. Pre-application versions of the FDP and any associated documents may be communicated in this way allowing an efficient dialogue. Transmission or upload will not constitute submission in respect of Model Clause 15(2) unless a formal application is made.

A formal application will be made via an acceptable letter from the Field Operator confirming that an application for field development and production consent is made with reference to the relevant field and licences, with evidence that they have the mandate of the other licensees. Once in receipt of such a letter, DMR will promptly confirm that an application has been duly made, or explain the reasons why DMR regards that an application has not been made or why its consideration cannot yet begin.

The FDP document and any necessary annexes should be submitted formally by uploading a digital copy or copies (preferably pdf) via the agreed method and referencing these as attachments to the formal letter of application for Development and Production Consent submitted as official Field Operator correspondence.

DMR will give advice on the contents of what is considered an acceptable letter of application.

5.18.3 Suggested contents of the FDP

The suggested section headings for an FDP document are set out below. Additional details are provided in the following section of these guidelines. References to 'Section' in this subchapter are to sections of the FDP as below.

The FDP is constructed so that the executive summary forms a one-page description of the field and the sections below this form a high-level description of the subjects covered by the section. The annexes which are separate documents to the FDP are where the detailed technical descriptions and information can be found together with references to the relevant internal oil and gas company reports that have also been supplied.

Section 1. Executive Summary

Section 2. Field Description

2.1 Seismic Interpretation and Structural Configuration

2.2 Geological Interpretation and Reservoir Description

2.3 Geological Model

2.4 Petrophysics and Reservoir Fluids

2.5 Hydrocarbons Initially In Place

2.6 Reservoir Modelling Approach

2.7 Reservoir Development, Improved and Enhanced Recovery Processes

2.8 Wells Design and Production Technology

Section 3. Development and Management Plan

3.1 Preferred Development Plan, Reserves and Production Profiles

3.2 Drilling and Production Facilities

3.3 Process Facilities

3.4 Emissions Considerations

3.5 Project Planning

3.6 Decommissioning

3.7 Costs (capex and opex)

3.8 Field Management Plan

Section 4. List of Annexes

5.18.4 Maps and Diagrams

The Field Operator should ensure that all diagrams provided are of good quality. After consultation with DMR these should include (as a minimum) a location plan; a geological column, a structure map at an appropriate scale on appropriate horizon(s)); illustrative seismic sections; and illustrative geoseismic cross section(s). All figures including maps and seismic lines need to be of suitable resolution to be clearly legible in the final report. Maps and seismic examples should not be less than a full page in width.

Maps should follow standard geoscience best practices and must include as a minimum:

- Scale bar
- Suitable and legible grid coordinates
- Block outlines
- Outlines of the licence and where appropriate any Lead(s) and Prospect(s)
- Contours with legible contour labels and contour interval clearly marked

The location of cross sections should be clearly marked on a location map. The columns in any Computer-processed Interpretations ('CPIs') should be readable and any colour flags for formation/fluids should be added in a legend.

5.18.5 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, licence boundaries, Field Definition boundary, Development Area boundary (if different from the Definition), Unit Area boundary (if different from the Definition) contours of fluid contacts, existing and proposed wells and licence boundaries;
- the licence(s) involved and a statement of licence interests, or Unit interests if the field is unitised;
- a central estimate of ultimate recovery, and the low-side, base case and high-side 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;
- an explanation why the FDP concept is considered optimum from environmental, technical and economic perspectives;
- a statement describing the steps to be taken to reduce GHG emissions and to contribute towards Falkland Islands obligations;
- a statement describing the potential for reuse or re-purposing of the infrastructure for activities other than hydrocarbon production and processing;
- the essential elements of the Field Management Plan;
- a project schedule and total capital cost; and
- a statement of the provision for, and commitment to, decommissioning.

5.18.6 Field Description

The purpose of this section is to present the description of the field on which the development is proposed and thus 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 (such as subsurface modelling) provided with references to more detailed company-held data where appropriate.

In terms of 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, as a 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 coordinates in degrees of latitude and longitude and the standard UTM grid, stating the central meridian used and datum.

5.18.6.1 Seismic Interpretation and Structural Configuration

A description of the extent and quality of the seismic survey(s) used, ties to the wells and the structural configuration of the field should be presented using appropriate figures and maps. The applicant should provide considerable detail in this section and discuss this with DMR.

5.18.6.2 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. 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.

5.18.6.3 Geological Model

A description of how the seismic mapping of surfaces and faults, the reservoir subdivision and the log analysis were integrated to build a 3D geological model of the field should be provided.

5.18.6.4 Petrophysics and Reservoir Fluids

A description of the key field petrophysical parameters should be presented incorporating log, core, Special Core Analysis ('SCAL') and well test data. A summary of the field Pressure-Volume-Temperature ('PVT') description and fluid analyses should be included.

5.18.6.5 Hydrocarbons Initially In Place

The volumetric and any material balance estimates of hydrocarbons initially 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 justified, and reports be available and referenced.

5.18.6.6 Reservoir Modelling Approach

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 described briefly. Where the reservoir has been subdivided for reservoir modelling 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. Where Drill Stem ('DST's) or Extended Well Tests ('EWT's) have been performed, the implications of these on history matching and predicted production performance should be given.

5.18.6.7 Reservoir Development, Improved and Enhanced Recovery Processes

The chosen recovery process should be described (e.g. depletion, pressure maintenance, aquifer support). 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.

Methods for targeting IOR (either mechanical or operational) should be described. Where none are proposed this should be justified.

For all hydrocarbons reservoirs, the potential for application of improved recovery processes beyond conventional methods (EOR) should be described. A summary of all the recovery processes considered and the reasons for the final choice is required. There will be a requirement for operators to justify why EOR processes are not being used or are not planned to be utilised.

Where a field demonstrates economic potential for EOR, Licensees should set out their firm plans to implement this. 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 of the recommended FDP contents) and for ensuring that both wells and production facilities are EOR ready or can be readily made so. The provisions made in the design of the wells and production facilities to enable EOR in the future should be set out under Drilling and Production Facilities (Section 3.2 of the recommended FDP contents). 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/mixing/pumping for chemical EOR (such as polymer EOR, thermally activated polymer or alkali/surfactant/polymer ('ASP') flooding). Where gas (hydrocarbon or carbon dioxide) is available already or becomes available for a miscible gas EOR process to be implemented within the life of the field, then additional considerations to equipment requirements should be conducted to allow miscible gas injection to be implemented. 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 retrospectively.

5.18.6.8 Wells Design and Production Technology

The basic requirements for well-completion design should be stated, in particular the potential for water shut off, artificial lift and stimulation should be discussed. Progressive technology for reservoir monitoring and remote intervention (e.g. intelligent wells and fibre optic across the reservoir) should also be discussed (either here or in Section 2.7 of the recommended FDP contents). 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 of the recommended FDP contents). 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. A reference to a Wells Basis of Design document should be provided.

The methods used to optimise production should be summarised, including reference to the methods used for integrated modelling of wells, flowlines and production facilities.

5.18.7 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 relate 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. Figures and tables should be used where appropriate and the referencing of existing documents is encouraged, providing these are made available.

5.18.8 Preferred Development Plan, Reserves and Production Profiles

This section should describe the proposed reservoir development and 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 of the recommended FDP contents.

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 selection of cases to represent the low-side, base case and high-side cases need to be clearly defined. A base case can typically be defined probabilistically using 'P50' values for the assessment for both the total volume of production and the production profile that achieves this. For the low and high side selection, multiple different interpretations are possible in terms of the total volume of production and the variables contributing to the production profile that achieves this. For example, a profile having a short plateau and a slow decline and one with a long plateau and a rapid decline could give the same oil/gas recovery.

Judgment is required in deciding which combinations of variables are to be analysed in more detail. With an understanding of the underlying physics of the reservoir processes, sensitivities can and should be selected to get an assessment of the possible range of production profiles around the selected cases. This will necessarily involve competent experts and discussion with DMR as to the approach used to ensure that the right options, constraints and critical factors are examined for a robust case that identifies risks and opportunities.

Using such time-dependent data to assess uncertainty cannot be truly probabilistic, and therefore descriptors such as P90 and P10 for low and high cases may be misleading. The preferred range to be quoted is low and high-side cases that are defined with reference to hydrocarbons volumes and production profiles.

The language used to describe such time dependent uncertainty must be consistent across all documentation.

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 oilfield units. Information to allow calculation of sales quantities should be provided.

The anticipated date for permanent cessation of production ('COP'), together with the underlying assumptions, should be provided.

5.18.9 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, Section 2.7 and 2.8 of the recommended FDP contents) 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 bottlenecks 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 provided for in the facilities/pipelines design 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 a floating production storage and offloading vessel ('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 the final form Development and Production Consent is submitted, the anchor pattern is not known then a Statement of Commitment that such agreements will be obtained should the subsequent pattern be such that they are required, must be included.

Similarly, 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 the final form Development and Production Consent is submitted, then a Statement of Commitment that such agreements will be obtained should the subsequent anchor pattern be such that they are required must be included.

New transportation systems are often designed to service more than one development and may have a longer expected life than the originating field. In such circumstances, a separate FDP for the transportation system may be necessary.

5.18.10 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 (e.g. first-stage production separator 1 x 100%, inlet heater to first-stage separator 2 x 100%, Powergen sets 3 x 50%). A process flow diagram should be provided.
- A summary of the methods of well testing and 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 flare and vapour recovery system.
- A brief description of the main control systems and their interconnections with other onshore or offshore facilities.
- A summary of provision of space or utilities for future EOR facilities or future developments.
- A summary of expected production efficiency with reference to a Reliability, Availability and Maintainability study, maintenance and intervention plan and offloading analysis.
- A brief description of any new/emerging technologies to be deployed.

A reference to a facilities basis of design (which is consistent with the Reservoir Development and Management Plan) should be provided.

For an FPSO development, a statement on whether it is new (leased or purchased) or refurbished should be given and, if refurbished, a description of the modifications required should be provided.

5.18.11 GHG emissions Considerations

This section should describe the measures put, or to be put, in place that will contribute towards the achievement of Falkland Islands obligations with respect to climate change. Consideration should be given to:

- Concepts which demonstrate significant savings in GHG emissions.

- What has been considered, incorporated or rejected to minimise GHG emissions and maximise recovery.
- Confirmation that well data will be collected via, for example, coring of the overburden, cement bond logs etc., to evaluate the reservoir for potential repurposing of the reservoir (and wells) in the future.
- A brief information on measures taken to minimise equipment transportation and non-productive time (and, therefore, carbon footprint) during drilling operations.
- A brief description of measures taken to prevent export outages potentially leading to excess flaring should be provided.
- FDPs for tie-backs and FDPAs should include information on emissions from power, flare, vent and total emissions, for both the remaining life of field for the host/base case 'as is' and the incremental case with the tie-back or addendum.
- Outline impact of potential future GHG emissions intensity reduction opportunities.
- A brief description of the rig selection criteria including assessment of energy efficient or GHG emission reduction measures.
- A brief description of renewable energy sources or energy efficient equipment for power generation.
- A brief description of adaptability included in the asset design to allow for integration with future technologies for the reduction of GHG emissions.
- A brief description of pre-investment in facility design to allow connection to future low carbon power and other GHG emission reduction opportunities.
- A brief description of how the infrastructure can be re-used for other developments.
- A description of any measures put in place to obtain accurate measurement of flare volumes and composition.

5.18.12 Project Planning

Schedules defining key events and decision dates during the detailed design, procurement, construction and commissioning of major elements of the development should be provided.

Project Plans should be prepared systematically and submitted using suitable software using logical task connections. Plans must be of a sufficient level of detail to allow DMR to understand underlying processes and identify key regulatory inputs. It must be understood that while DMR seeks to facilitate timely progress, this may be challenging if DMR is not informed of project plans and milestones. It is in the operator's interest to ensure DMR is aware of progress to avoid a situation where DMR requires more time to process a regulatory function than is planned for, or the operator's proposals require extended discussion, for example where progress is made as a result of design or procurement decisions that subsequently are not accepted by DMR as meeting the regulatory requirements.

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 and carrying out commissioning operations in an efficient and timely manner.

5.18.13 Decommissioning

Plans for decommissioning will bet set out, including:

- The plugging and abandonment of wells;
- The removal of the Installation(s);
- The removal of subsea infrastructure, or, if justified, the making safe of difficult items by burial.

Any deviations from this will require description and justification. Estimates of expenditure for the main components of the decommissioning operations will be provided. Steps taken in the design to facilitate eventual decommissioning should be identified.

Notwithstanding the above, it is noted that there will be an evaluation of reuse potential of the infrastructure after the term of the FDP for other petroleum-related functions, or repurposing for non-petroleum uses, towards the end of field life.

5.18.14 Economics

DMR assesses the economics of all new and incremental field developments for alignment with the Falkland Islands Hydrocarbon Development Policy Statement. The approach taken by DMR aims to ensure that operators have examined those options which are most likely to maximise economic recovery.

To assist with that process, economics information should be included within the FDP documentation submitted to DMR.

Corresponding data for each of the options must also be submitted in Excel workbook format using the Standard Economics Templates ('SET').

Financial information should be presented in United States Dollars.

With reference to probabilistic assessments discussed in Section 5.18.8, the time-dependency of the production profiles along with the cost profile must be reflected in the economic assessment.

In addition, for any selected development, project economics must be submitted in spreadsheet format retaining original formulae and links that set out, at least, the following data in annual and quarterly intervals for the life of the field:

- Oil and gas production;
- Revenue;
- Royalty;
- Operating costs;
- EBITDA;
- Capital costs;
- Abandonment costs;
- Debt (if any);
- Interest (if any);
- Debt service cover ratio (DSCR)
- Tax;
- Project free cashflow; and
- Discounted free cash flow (10% discount rate).

Further metrics relating to debt and equity modifiers to the above metrics will also be included as applicable. Two scenarios will be presented: a base case and a stress case. The stress case will apply a credible and pessimistic set of circumstances such as low oil/gas price future, temporary oil/gas price shock, delay in production by six months, increase in transportation cost by 20%, capex increasing by 25%, etc.

The sheet will contain key assumptions used in the model including:

- Pricing Scenarios, including oil price, oil price inflation, oil price differential inflation, gas price, gas price inflation, general inflation;
- Oil/gas sales assumptions including crude lifting assumption, parcel size, destination;
- Abandonment assumptions;
- Include licence end date in cut-off calc;
- Financial provision for decommissioning including monies set aside and the costs of maintaining securities;
- Royalty;
- Tax assumptions, including corporation tax;
- Tax shelter if applicable;
- Depreciation timing;
- The timing of statutory payment such as tax and royalty; and
- Proposed capital structure of the project.

Sensitivity analysis will be performed on the scenarios presented including:

- High, medium and low cases: with sensitivity performed both on the total amount of oil and gas extracted and different profiles via which this extraction could be undertaken.
- Delays to capital expenditure, operational expenditure and abandonment expenditure;
- A reasonably foreseeable range of operational outcomes relating to drilling progress and production efficiency;
- Robustness to foreseeable fluctuations in oil/gas prices and expression of 'break even' oil/gas price in early stages;
- Changes to interest rates; and
- Reasonably foreseeable variations in any other financial assumptions listed above.

5.18.15 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, whilst taking the steps necessary to reduce the GHG emissions over the life of the field. The plan, as described in this section, must be reflected throughout the FDP, showing 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 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, and 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 (e.g. as discussed in FDP template 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.

5.18.16 List of Annexes

The FDP should also be supported by the following detailed technical Annexes, which may include (but are not limited to):

- Annex A Subsurface Evaluation Report
- Annex B Reservoir Management Plan
- Annex C Facilities Basis of Design
- Annex D Project Execution Plan
- Annex E Logistics and Infrastructure Plan
- Annex F Wells Basis of Design
- Annex G Telecommunications Design Philosophy
- Annex H Oil/Gas Offtake Strategy
- Annex I Flow Assurance Plan
- Annex J Subsea Operating Strategy
- Annex K Long Term Development Philosophy
- Annex L Concept Selection Report
- Annex M EOR screening study.
- Annex N Host Facility Addendum (if appropriate);

It is noted in other sections that further documents are also required to be accepted before a final form FDP application can be made, including:

- Environmental Impact Statement and initial OPEP;
- Design or Relocation Notification (if appropriate);
- Insurance Plan;
- Emergency Response Plan and Security Plan;
- Local Content Plan; and
- Socio-economic Impact Assessment and Social Effects Monitoring Plan.

5.18.17 FDP Addendum (FDPA) - Guidelines on content

This part of the guidelines has been prepared to provide guidance to Field Operators engaged in preparing a revised FDP for producing oil and gas fields. A revised FDP is often referred to as an 'FDP Addendum' or 'FDPA'. The purpose of the FDPA is both to advise DMR of divergence from the extant consented FDP and to demonstrate that the field is being managed in a manner that complies with the obligations in the Falkland Islands Hydrocarbon Development Policy Statement. The FDPA should be used to propose any revisions to Section 3 (Development and Management Plan) of the extant FDP as the understanding of the field improves, or to propose incremental development projects not included in the extant FDP.

An FDPA could be required for a larger number of wells; a significant difference in the recoverable oil and gas; a significant change in the production asset or its capacities; a different set of well trajectories or targets that mean that outcomes are materially changed or that the reasoning by which they are achieved is materially changed; a different set of environmental impacts that requires further consultation under the Offshore Minerals Ordinance, such as because the impacts are substantially different or significantly greater.

For the guidance of Field Operators, the general headings and contents expected in an FDPA are set out below but Field Operators are encouraged to discuss with DMR an alternative form of document if this would be more appropriate for the field in question. Internal or partner documentation that satisfies or exceeds these requirements will also be acceptable. The FDPA is not intended as a detailed data source or account of activities carried out during the period since the grant of Development and Production Consent, but should be used to identify departures from the expected performance and planned development. It is not anticipated that detailed FDP revisions will be required routinely, and Field Operators are encouraged to discuss the level of detail required by DMR prior to preparing an FDPA. A PEP will still be expected although the level of detail necessary will be dependent on the extent of the proposed revision.

Suggested contents of an FDPA

1. Introduction

A brief review of the field operations and performance should be set out, with divergence from the consented FDP noted and discussed in more detail in later sections. Any changes in Licensees/licence equity and/ or Field Operator 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 FDP base case or 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, etc. should be included).

2.3 Geology

Where drilling, seismic reprocessing 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 should be provided. 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, and 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/EOR)

Where improved recovery has not been addressed in the FDP, 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 FDP production, injection and GHG emission profiles (or those agreed revisions made in earlier FDPA(s)) together with the current estimate of the COP date should be included.

Where the development is a tie-back to an existing asset, information on GHG emissions, from power, flare, vent and total emissions, for the remaining life of the field for the host should be provided. The base case ‘as is’ and the incremental case with the tie-back should be provided.

Data should be provided on yearly production forecasts, emissions forecasts and emissions intensity, with a life of field emissions intensity.

3.5 Proposed changes to the FDP

The proposed revisions to the Development and Management Plan set out in Section 3 of the consented FDP should be set out here. Proposed changes to explicit or implicit commitments, or to conditions in the Development and Production Consent, should be set out clearly as should any plans to extend the development beyond the Development Area. Any other proposed revisions should first be discussed with DMR.

Where appropriate, a summary of longer-term development opportunities within or around the field, including potential for hosting third-party hydrocarbons, should be provided. Progress in developing opportunities already identified, in particular IOR or EOR, 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 (‘PE’) 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 to accommodate a satellite development for a different operator, the proposed modifications should be addressed in an FDPA 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 Economics

DMR’s SET4 should be used to aid DMR in reviewing this data. For incremental projects, in order to understand the impact of the incremental project, DMR requires two versions of the SET 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 DMR prior to submitting the FDPA.

3.7 GHG Emissions Reduction Plan

Where a Field Operator proposes amendments to an FDP, DMR will request a summary of the implementation of the current GHG emission reduction action plan, or inclusion of such a plan should one not exist. A GHG emissions reduction project 'hopper' for the field should also be described.

Where relevant, outline impact of potential future emissions intensity reduction opportunities such as the potential for and impact of future renewable power sources.

5.19 Development and Production Consent

The issuing by DMR of a Development and Production Consent for the proposed development indicates the completion of the Authorisation Phase. The Development and Production Consent will cover both the construction of the facilities and other infrastructure, and the production of hydrocarbons from the field.

DMR will generally issue a Production Consent 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 production consent will usually reflect the degree of understanding of the field: the more uncertain the performance, the shorter the duration. Subject to the uncertainties involved, DMR would normally anticipate a duration of between five years and life of field. For phased developments, the Development and Production Consent will normally be given for the duration of the relevant phase.

DMR may attach conditions to the Consent requiring the Field Operator to review the development plan with DMR if performance falls outside consented production profiles or if the field is found to differ from the assumptions made in the FDP to such an extent that there is a risk of a loss of economic reserves. As mentioned earlier, FIG may also impose conditions on its agreement to the grant of consent.

For all fields, both upper and lower limits to production levels will be set out in the Production Consent in line with the table below. These will usually be based on the maximum and minimum cases as stated in the FDP..

Table 2 - Format for production consent table

Year	OIL				GAS			
	Extracted (bbls)		Reinjected (bbls)		Extracted (mmscf)		Reinjected (mmscf)	
	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum
1								
2								
3								
4								
5								

Note: Standard Temperature and Pressure applies. One bbl = 158.9 litres. 1 scf = 0.02832 m^3.

6 Execution Phase requirements

The project scope as defined by the FDP and PEP will be implemented during the Execution Phase of the project. In this phase, the Licensees have committed to proceed with the development and FIG has issued a Development and Production Consent. The purpose of this phase is for the Field Operator to execute all required activities (e.g. well construction, engineering, procurement, construction, commissioning/start-up etc.) and to deliver the project objectives.

The end of Execution Phase will be regarded as production of first hydrocarbons. DMR's expectations during this phase are set out below.

6.1 Monitor project execution

The FDP and PEP will include a project schedule including major decision points and milestones as well as permitting requirements. As part of the PEP the Field Operator should also discuss and agree an engagement plan with DMR. During the Execution Phase, progress against the project schedule should be monitored and deviations from the planned schedule should be reported to DMR.

6.2 Confirmation of design basis

During Execution, design work will continue and key assumptions or uncertainties will be defined in greater detail. Alongside this, health, safety and environmental analysis will progress. The Field Operator will ensure that DMR is kept informed about progress on design and definition of the project and the associated safety, health and environmental issues. Consent to the FDP is predicated on the EIS and on information in other key documents and if the Field Operator wishes to change important details then these may require further consent. It is in the interest of the Field Operator and DMR to maintain dialogue so that developments are undertaken efficiently and any potential regulatory issues are identified and discussed at an early stage. The Field Operator is expected to maintain a constructive dialogue with DMR and regularly inform DMR of the refinement of project details.

For a production installation an important output will be the Reliability, Availability and Maintainability (RAM) analysis since this forms the basis of the production efficiency that underpins the project economics and is also the basis of many other aspects including GHG emissions performance and logistics. It is expected that this will be undertaken during FEED by an independent organisation and that the Field Operator will involve DMR in the scope and delivery of the analysis.

6.3 Commissioning flare consents issued

During the commissioning of production facilities, DMR may, where appropriate, issue flaring consents which 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. In the absence of Falkland Islands guidelines, the NSTA guidance on flaring and venting shall be used. Once commissioning is complete and stable operating conditions have been achieved, the Field Operator may apply for longer durations for the flaring consent subject to an agreed cumulative maximum for the duration of the consent.

The Field Operator is required to demonstrate that measures to reduce flaring and venting have been considered and, where appropriate, implemented as part of their commissioning strategy. These include for example, early commissioning of the gas compression, vapour recovery and gas injection systems using only the necessary volumes of production, to ensure these systems, which avoid the escape and waste of petroleum and greenhouse gases, are fully functional before production is ramped up.

6.4 Pipeline Works Authorisations

Pipelines are those pipes and other conduits and connectors that connect one field to a host installation that serves a different field for production (inter-field, versus intra-field), or which connect an offshore development to shore.

Pipeline Works Authorisations (‘**PWA**’) will not usually be issued until after the Development and Production Consent has been given. In the absence of specific DMR guidance, NSTA guidance on the PWA process shall be referred to and interpreted accordingly.

A PWA or variation should be in place before any pipeline or pipeline system construction or modification works begins. Before submitting a PWA application, DMR recommends that the pipeline owner (or prospective owner) informally consults DMR at the earliest possible opportunity, to discuss the proposed scheme and the applicable regulatory requirements.

Where there are no objections, it normally takes approximately four to six months from receipt of a satisfactory application to issuing the PWA. In the case of pipelines in respect of which an EIS is required, the procedure may take longer. Field Operators must therefore submit applications at least four to six months before construction begins.

6.5 Safety (major hazards) case acceptance

Before a production installation can be operated in its capacity for drilling or oil and gas production, a Safety Case must have been submitted at least 6 months before the start of the oil and gas operations and it must be accepted by DMR before operations commence. The period of 6 months is an absolute minimum to avoid delay as there may be significant issues that need to be addressed following DMR’s review of the document. It is expected that there will be an ongoing dialogue with DMR on this issue prior to the submission of a document. In the case of a production installation in particular, it is expected that either the development of a new Safety Case or a material change to an existing Safety Case will involve significant dialogue with DMR over and above the legislative requirements to facilitate the resolution of any issues and timely progression of the project.

Further information is provided in DMR’s document ‘Offshore Installations (Safety Case) Order 2008 – Guidance Notes’ (2014).

6.6 Divergence from the agreed FDP

Once a Development and Production consent has been given, it is expected that the development will proceed in accordance with the consented FDP and the PEP. The Licensee should promptly inform DMR of any deviations to the plan as they become evident.

If the Licensees wish to deviate from the consented works they may be required to submit a Field Development Plan Addendum (‘FDPA’).

It is possible that a change to the consented works may require a further EIS under the Offshore Minerals Ordinance 1994 (as amended), or that an exemption under Section 67A could be applied for on the basis that the change is covered by an earlier accepted EIS and there are no effects on the environment that are substantially different from the effects mentioned in the previous environmental impact statement, or significantly greater than those effects.

It is noted that the Ordinance requires an EIS for an application to drill a regulated well, and therefore wells may not be drilled unless an EIS for the well is produced and accepted or an exemption is requested and granted under Section 67A.

The Field Operator should contact DMR for further information.

7 Regulation following FDP Consent

7.1 Required future Consents

7.2 Development and Pipeline Works Authorisation Production Consent

If Licensees wish to continue production beyond the duration of the initial consent they may apply for an extension to the production consent. If field production performance is expected to fall outside the upper or lower limits specified in the extant Production Consent, the Field Operator may apply for a revision to these levels. A request to increase the maximum production in the FDP Consent may also require the Field Operator to apply to DMR for their associated environmental permits to be revised, and which may involve submission of an EIS or a request for an exemption.

7.3 Flaring and venting consent

Once commissioning is complete and stable operating conditions have been achieved, the duration of any flaring/ venting consent may be extended and will be subject to an agreed cumulative maximum for the consented period.

7.4 Other environmental consents or conditions

Other environmental consents will apply to the project and there may be conditions placed on consent to the FDP that place obligations relating to the environment. The Field Operator must notify DMR if any circumstances change that mean that such consents or conditions are not likely to be met, whether for planned reasons or due to unplanned situations emerging. In particular, issues that will increase emissions and/or decrease the efficiency of the operation will need to be carefully examined to ensure that commitments and obligations are being maintained. If environmental outcomes or justifications differ significantly from those on which the development programme and production consent were based, it will undermine the basis for those consents and it may be necessary to undertake a further EIS process for the changes. Therefore the Field Operator is expected to monitor this situation and raise any issues with DMR at an early stage.

7.5 Pipeline Works Authorisation

If the Operator wishes to install new pipelines or vary the original specification of a pipeline, a PWA Variation may be required. A new EIS may also be required or an exemption applied for.

7.6 Cessation or suspension of Production

If Licensees subsequently wish to cease production permanently, or if production is to be suspended from a field for an extended period, the Operator should contact DMR to discuss what notifications/ authorisations may be required.

7.7 Retention and Reporting

Licensees have a number of obligations for retention and reporting of data and information for field developments. Please refer to DMR Petroleum Operations Notices on our website for information.

7.8 Changes of Licensee and/or Field Operator

Any Licensee changes (including in a Licensee's equity interest) or changes of Field Operator following consent require the approval of DMR. A Change of Control of a Licensee should be notified to DMR.

8 Operator Competency and Governance expectations

8.1 Scope and purpose

These guidelines set out when DMR will normally consider the adequacy of a company's competency and governance arrangements and the factors that DMR will usually take into consideration when doing so.

DMR considers that good and proper standards of Licensee competence and governance are necessary to (i) deliver the legal obligations under the Licences and legislation (ii) deliver obligations assumed by the Operator on behalf of other licensees, and (iii) act in a way that enables DMR to ensure that the Hydrocarbon Policy Principles are met. This includes having a suitably high level of expertise and strength of resource, and having capable and responsible Boards who plan and deliver appropriate strategies designed to secure the successful long-term delivery of projects. It also includes being responsive to guidelines issued by DMR from time to time and complying with any notices issued by FIG or DMR in delegated role.

Many of these expectations or requirements are intrinsic to being a Licensee and an Operator. These may be reviewed at key points of licensing and development such as at the point of consent being given to an FDP, or at any other time considered appropriate by DMR, with the obvious expectation that standards are maintained at all times, noting that appointment of Operatorship may be revoked if FIG considers that the Operator is no longer competent to exercise that function (Model Clause 22(2)).

These guidelines focus on the following areas:

- Minimum levels of competency that are required to demonstrate that the Licensee or Operator understands the development, environmental and safety responsibilities and that it is competent, both financially and technically, to discharge these under its agreements with its co-licensees.
- The adoption and application by a Relevant Board of a recognised corporate governance code, suitable for the size and characteristics of the Licensee.
- The adoption and application by a Relevant Board of specific principles that are consistent with the Hydrocarbon Policy Principles.
- A commitment by the Relevant Board to take appropriate steps to assist the Falkland Islands Government in meeting climate objectives, to align to a common standard of climate reporting and to give due consideration to its corporate social responsibilities.
- How DMR will monitor compliance with these guidelines including by requiring the Relevant Board to account for how it has met, and will in future meet, these guidelines.

Where DMR makes any assessment of the competence or governance of a Licensee, this is done specifically and exclusively for DMR's own purposes.

These guidelines, and DMR's assessment, is not intended to replace all the other governance requirements with which each Licensee may have to comply. Third parties should not rely on any statement (or absence of any statement), decision, action or inaction of DMR, or rely on DMR in any other way, to satisfy themselves as to adequacy of a Licensee's governance. They will need to carry out their own due diligence on the governance of Licensees.

8.2 Operator Competency

A prospective field 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 DMR's objective of securing maximum economic recovery from each field and from the basin as a whole. A substantial use of contracted staff would need to be justified.

The level of detailed examination by DMR will depend on which category prospective applicants fall into and will be proportionate to their proven track record. The information that DMR will seek will in general be drawn from the checklist below.

It should be noted that consent is on a field-by-field basis and prospective operators must always specify the fields they wish to operate.

8.2.1 Technical competence

The operatorship of an oil or gas field requires a very high level of technical competence with the high operating costs and large well spacing representing a significant challenge. It is essential that prospective operators demonstrate a strong technical ability.

The proposed technical staff structure should be described carefully with particular regard to the role of any contractors in the decision-making process. It is crucial 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 relevant offshore operations experience.

Any operatorship experience elsewhere in the world should be described, as should any non-operated interests. Licensee disputes can sometimes act as drag on development 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.

If any change in operatorship is proposed, it needs to be clear to DMR and the forward reservoir management plan and expenditure and production profiles upon which the new operatorship is based should be supplied. DMR will be keen to understand what a new operator feels he can add to the field management process and particularly of any firm plans to increase field lifetime and hydrocarbon recovery. The same is true for any change in the licensee arrangements.

At the point of consenting for the FDP being sought, the Operator must provide the following information. This can be provided within or alongside the FDP documents; or if it has recently been provided through other channels then this may be referred to in the FDP documents along with a statement that it remains current and accurate.

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., Stanley, 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, health, emergencies, environmental matters, facilities engineering, reservoir evaluation and management, drilling, supply services,

maintenance, offshore loading, monitoring progress and reporting to DMR; who is responsible for regulatory/consenting processes , including production, flare and vent consents and well notifications).

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. 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/gas field management services should be clearly explained, including the chain of responsibility and decision-making matrix.
7. The proposed business process (e.g. regularity of opcoms and techcoms and the procedure for dealing with Partner disputes) should be described.
8. A listing of current licence interests should be provided.
9. For companies already operating oil/gas fields outside the Falkland Islands:
   (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.
10. Companies with no previous operator experience should provide details of any other world-wide experience that they feel is relevant to becoming a Field Operator and explain how they will manage the transition to operatorship from the previous operator if they are taking over a producing field.
11. 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.
12. A statement of the company's reservoir management philosophy. What internal audits are carried out of the reservoir development programmes and reserve calculations.
13. 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.
14. A statement of the facilities operations and maintenance strategy that the company would expect to adopt.
15. 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)

16. A statement of the company's basis for field development economics, including such aspects as hurdle discount rates; oil/gas price scenario(s), and gas flaring philosophy.
17. A statement on reserve categorisation (deterministic or probabilistic) together with a short synopsis on reserve estimation methods normally used by the company.
18. List extent of the company's current engagement with industry trade associations both within the Falkland Islands and in other jurisdictions.

Notes

Items 1-5: Company Structure We consider a management structure showing clear lines of responsibility and clear processes for field management to be essential. DMR 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 based in the Falkland Islands or the UK.

Item 6-7: Management System The responses to these items on the checklist 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. DMR supports the principle of 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. DMR'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 9: 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 10: 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 12-14: 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 15: 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 16-18: 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 DMR to place any reserves or production estimates supplied by the new operator in the correct context.

8.2.2 Health, Safety and Environmental Management and Performance

At the point of seeking consent for the FDP, the Operator must provide the following information. This can be provided within or alongside the FDP documents; or if it has been provided through other channels then this may be referred to in the FDP documents along with a statement that it remains current and accurate.

i. A summary of the Operator's safety, health and environmental policies.

ii. A section confirming that the Operator possesses an understanding of the relevant statutory health, safety and environmental provisions, and understands the roles and responsibilities of licensees in relation to health, safety and environmental management.
iii. A section describing the company's management structure, including details of functional responsibility for the management of health, safety and environmental matters including an organogram.
iv. A section confirming that the company has relevant safety, health and environmental management systems, or a commitment to have such systems in place prior to appointing an operator to undertake any offshore oil and gas activities.
v. A section confirming that, where a third party is appointed to manage the offshore oil and gas activities, or to manage the liabilities relating to those activities, the company will select a third party that has the capacity to adequately undertake the duties relating to the appointment, and that reasonable steps such as monitoring, audit and review will be put in place to ensure that the third party meets, and continues to meet, the relevant requirements.

Details of the Operator's health, safety and environmental performance record must be provided, including information in relation to any major accidents, including activities by a parent or affiliate company involved in offshore oil and gas operations, in any country:

i. Details of any major accidents during the last five years.
ii. Details of any failure to comply with any relevant safety or environmental legislative standards or requirements that resulted in enforcement action by the regulator during the last five years.
iii. Details of any criminal or civil action taken against the company, or pending against the company, with respect to safety or environmental issues during the last five years.
iv. Details of any conviction for breaching any safety or environmental legislation during the last five years.

8.3 Governance Principles

8.3.1 Relevant Board

DMR considers that the governance of a Licensee is the responsibility of the Relevant Board. DMR considers the "Relevant Board" to be the Board of Directors or equivalent with effective control over the Licensee. In some cases that will be the Board of that Licensee. However, DMR understands that responsibility for governance may, in some cases, be delegated to another Board in the Licensee's group, in which case DMR will regard that Board as the Relevant Board and expect that Board to apply these guidelines. Licensees should be prepared to identify and inform DMR as to the Relevant Board in the application of these guidelines. DMR notes that certain Licensees may be in groups that are organised such that it is not practical for a single Board to take responsibility for all elements of these guidelines. Therefore, it will be acceptable for responsibility to be divided between boards. DMR does not seek that the definition of Relevant Board be too restrictive, and may not be a single company board, so long as responsibilities are clear.

8.3.2 Corporate Governance

A main purpose of corporate governance is to facilitate effective, entrepreneurial and prudent management that delivers the long-term success of a company.

DMR expects all Licensees to observe a recognised corporate governance code that is appropriate for a company of its size and character.

DMR recognises that many Licensees are already observing an existing corporate governance code (or are part of a group of companies under common ownership already observing an existing corporate governance code). Provided that DMR considers that code to be appropriate for the Licensee, then DMR would not normally expect the licensee to comply with any additional code.

In its adoption and application of an existing corporate governance code, DMR will expect the Relevant Board to seek to reflect its spirit and follow a 'comply or explain' approach. It is expected that the Licensee would, if requested, provide DMR with a descriptive statement under the principle of comply or explain which should state how the Relevant Board complies with the guidelines, identify areas of noncompliance, and explain the reasons for such non-compliance by reference to their own circumstances.

The following are recognised corporate governance codes appropriate for companies of different sizes and with different characteristics:

- The UK Corporate Governance Code
- The Wates Principles of Corporate Governance
- The Quoted Companies Alliance Corporate Governance Code

The Licensee may be able to point to other codes that it considers appropriate for a company of its size and characteristics and DMR would consider that. Where the Relevant Board of a Licensee is overseas, the requirement in these guidelines to adopt a recognised corporate governance code will normally be satisfied by that Licensee group observing an appropriate governance code from that country. We will normally accept, where appropriate, and where the Licensee is part of a group of companies under common ownership, the observance of these governance requirements, by the Relevant Board, may be demonstrated primarily at national or Group level, if not independently by the Relevant Board of the licensee.

If the parent of a Licensee group which exercises effective control over a Licensee chooses not to observe an appropriate existing corporate governance code, DMR will expect the Licensee's Board of Directors or equivalent to adopt and observe an appropriate corporate governance code acceptable to DMR.

In addition to observing the principles of a corporate governance code outlined in this Corporate Governance section, DMR also expects that all Licensees, in their application of these guidelines, will observe the governance requirements set out below, which DMR considers to be essential to the delivery of the Hydrocarbon Policy Principles.

8.3.3 Purpose and Leadership, Board composition, and Director Responsibilities

In addition to fulfilling their statutory duties as directors and the principles on board composition outlined in the relevant corporate governance codes discussed above, DMR expects that a Relevant Board, and its Committees will:

- Possess appropriate senior level knowledge and experience of offshore upstream operations and of the specific requirements of the Falkland Islands, its challenges, ways of working, and all aspects of DMR hydrocarbons policies, the Falkland Islands Hydrocarbon Development Policy Statement and DMR guidelines.
- Have knowledge of and ensure compliance with DMR's requirements as to fitness of persons (legal and natural) who exercise control over the Licensee.
- Include an experienced (and normally Consultative Committee of Accountancy Bodies ("CCAB"), or equivalent, qualified) financial officer with responsibility for the internal control and risk

management systems of the Licensee or group (having regard to the unpredictable nature of the oil and gas industry) and for the integrity of the financial statements issued by the Licensee or the group.

8.3.4 Technical capability

All licensees must demonstrate their ability to meet the requirements for operations within the framework of the licence. This includes having the suitable technical and managerial ability in terms of experience and staff numbers including ensuring any operator appointed is capable of satisfactorily carrying out the functions and discharging the duties under relevant statutory provisions.

8.3.5 Fitness of licensees

The 'fitness' of existing and prospective licensees, Directors and individuals involved in the management of licensees, as well as those who control licensees, is critical to DMR's statutory duties and objectives.

The 'fitness' of existing and prospective licensees, Directors and individuals involved in the management of licensees, as well as those who control licensees, is critical to DMR's statutory duties and objectives and the public interest.

DMR will consider fitness whenever an application for a licence is made, or where a licensee intends to take on or extend a commitment or obligation, or at any other time a review is considered appropriate. This will include financial viability and capability.

The following is a non-exhaustive list of factors that DMR will normally take into account when assessing the fitness of a licensee, Director or other individual if relevant, or major shareholder of the licensee or of an entity controlling the licensee.

a) Whether the licensee, Director or other individual is bankrupt and/or associated with any corporate insolvency proceedings, or liquidation or administration;
b) Whether the licensee, Director or other individual has any unspent conviction for a relevant offence; has been the subject of any adverse finding or any settlement in civil proceedings; has been the subject of, or interviewed in the course of, any existing or previous investigation or disciplinary proceedings by other regulatory authorities, government bodies or agencies, or in criminal proceedings; has been investigated, disciplined, censured or suspended or criticised by a regulatory or professional body, a court or Tribunal, whether publicly or privately; has been notified of any potential proceedings or investigations that might lead to proceedings of a disciplinary or criminal nature; or, has been involved with any business to which the above apply;
c) Whether the licensee, Director or other individual has been candid and truthful in all their dealings, including with any regulatory body (for example, in the provision of information), and whether the person demonstrates a readiness and willingness to comply with the legal, regulatory and professional requirements and standards, and to deal with regulators in an open and cooperative way;
d) Whether the licensee, Director or other individual has been involved with a company, partnership or other organisation that has been refused registration, authorisation, membership or a licence to carry out any trade, business or profession, or has had that registration, authorisation, membership or licence revoked, withdrawn or terminated, or has been expelled by a regulatory or government body; and
e) Whether the Director or other individual has been dismissed, or asked to resign and resigned, from employment or from a position of trust, fiduciary appointment or similar.

DMR will consider all such cases on their own merits, taking into account factors which include (but are not limited to) the extent of the Director's or other individual's involvement in and responsibility for corporate acts or omissions; the causes of any insolvency, liquidation or administration; the nature and seriousness of any proceedings referred to above; the frequency of any conduct or omissions. DMR will also have regard to the scale and scope of businesses controlled by the Director or other individual, in assessing the relevance of a factor (or factors) to a particular case.

In general (other than in exceptional circumstances), DMR will raise any concerns that it has as to fitness with the relevant licensee or individual and provide them with an opportunity to comment, before making any final decisions based on such concerns.

8.3.6 Delivery of licence commitments and DMR policy principles

DMR expects a Relevant Board, and its Committees, to promote the long-term success of the Licensee. In doing so, a Relevant Board should:

- Identify opportunities to create and preserve value and establish systems of oversight to identify and mitigate risks to ensure all existing contractual liabilities and licence commitments are met.
- Consider the indirect financial risks to third parties, when allocating financial resources between projects or participating in the acquisition or disposal of licences or licensees if these actions result in a material increase in the risk of a licensee becoming insolvent or being unable to meet licence commitments. The third parties that Relevant Boards should consider include, but are not limited to, joint venture partners, investors, users and owners of shared infrastructure, regulators, employees, contractors and suppliers.
- Adopt a prudent application of appropriate company law as it applies to the issuing of dividends or other capital distributions (excluding routine capital movements within a group where these will not impact on the ability of the Licensee to meet its future liabilities and obligations), reflecting the highly cyclical nature of the industry and the subsequent impact on the licensee's ability to meet actual and contingent liabilities.

8.3.7 Audit, risk, internal control and reporting

In addition to pre-existing principles outlined in the relevant corporate governance codes discussed above, and notwithstanding the role which a range of other regulators have in this regard, DMR expects that a Relevant Board, and its Committees should:

- Ensure compliance with all applicable financial accounting principles, for example as set out within the International Financial Reporting Standards ("IFRS") and by the International Accounting Standards Board ("IASB"), and to follow the expectations set out therein.
- Ensure that the Licensee is in full and open compliance with the IASB's provision set out within International Accounting Standard ("IAS") 37 (and other relevant IFRS's) on disclosure of provisions, contingent liabilities, and contingent assets, and make reference to any other relevant accounting standards such as recommendations by FRC as part of any thematic review.
- Have a clear understanding of internal control, accountability and responsibilities to support external assurance, effective decision making and independent challenge.

8.3.8 Environmental Governance

It is essential that the industry continues its social licence to operate and develops and maintains good Environment, Social and Governance ("ESG") practices in their plans and daily operations.

The value of the environment is embedded in the culture and commitments of the Falkland Islands and is the bedrock of its economy. The Licensee must be responsive to the commitments in the Falkland Islands

Government Islands Plan, in its Environmental Charter, its participation in the United Nations Framework Convention on Climate Change and its commitments and ambitions for conservation, biodiversity, land restoration and marine environmental objectives.

Among other things Licensees must reduce, as far as reasonable in the circumstances, greenhouse gas emissions from all aspects of their upstream operations, and it must exercise influence in its supply chain and downstream processes to minimise such emissions. Further, as part of the obligations under the Offshore Minerals Ordinance 1994, reasonable measures must be taken such that the impacts of unavoidable emissions are eliminated, reduced, remedied and offset.

DMR, therefore, expects that a Relevant Board, and its Committees should seek to:

- Establish and embed a culture of greenhouse gas emission reductions in Licensee operations.
- Work towards the mitigation of the impacts of unavoidable greenhouse gas emissions whether by measure of carbon emissions, biodiversity impacts, conservation or socio-economic impacts.
- Measure, report, align, and track the Licensee's performance against relevant environmental targets set by the Falkland Islands Government and/or the oil and gas industry.
- Have due regard to the Falkland Islands Government's obligations and ambitions with regard to climate change and to any related mandatory reporting requirements.
- Secure that the Licensee considers ongoing developments in good practice to influence and promote best practice and ESG reporting.

8.4 Corporate Social Responsibility

DMR expects that a Relevant Board, and its Committees, should give due consideration to its social responsibilities attendant with the Licensee's operations and interactions with stakeholders. Whilst not binding, DMR expects the Relevant Board, and its Committees should ensure that the Licensee considers:

- Principles of diversity, equality and inclusion.
- The global conversation on energy transition.
- Local content expectations.
- Good practice in supply chain management.
- The stability and improvement of the Falkland Islands workforce, and opportunities for young people in particular.
- The importance of prompt payment.

8.5 Review of implementation

DMR will not systematically monitor compliance of Licensees with these guidelines, nor do these guidelines seek to impose a general requirement on Licensees to report on their compliance therewith.

Rather, DMR will look out for actions or behaviours that it considers may not be consistent with these guidelines. When doing so, and in particular (but without limitation), DMR will consider evidence from: (i) a stewardship review process; (ii) ongoing engagement with industry; (iii) discussions with other regulators or entities; and (iv) discussions with investors. When indications of inadequate governance are identified, DMR may address these directly with the Licensee including undertaking a review of the Licensee's governance arrangements.

DMR may also review a Licensee's governance as part of its consenting and authorisation processes. In particular, if an application to acquire a Licence interest (or the acquisition of a Licensee), or an application for a consent to undertake an activity, would, if granted, be expected to materially change the size and characteristics of the Licensee (or the group of companies under common control with the Licensee), then DMR may choose to undertake a review at that time.

As part of a DMR review, the Licensee may be required to account for how it has met, and will in future meet, these guidelines. If a DMR review was precipitated by concerns that DMR has about the actions or behaviours of a Licensee, then the Licensee should, in responding to those concerns, consider what has led to them, including whether any governance failing has played a part.

In its response to a DMR governance review, DMR would expect a Licensee to identify the corporate governance code that the Relevant Board has been observing and to evidence and explain that this is appropriate for the size and characteristics of the Licensee. It should also discuss how it has applied the Strategy specific principles and/or identify areas of noncompliance, with reasons based on their own particular circumstances. Where a change to the size and characteristics of the Licensee, or the group of companies under common control with the Licensee, is anticipated that consideration be given as to the appropriate corporate governance code for the new Licensee or group.

If through its review DMR considers a Licensee's governance to be inadequate, then the Licensee will be asked to propose changes to its governance arrangements that will address those concerns. If DMR considers that the proposed changes are inadequate or previous arrangements have not been followed, DMR may then seek to exercise its power to direct the Licensee to comply with stated governance principles and practices.

If, in DMR's view, a failure of governance amounts to a failure of competence as a Licensee or Operator, then DMR will also consider whether or not to investigate that suspected failure and apply sanctions. It is not DMR's intent to seek to impose sanctions or invoke its power to direct, until all other opportunities of interaction have been exhausted.

9 Financial Viability and Capability

9.1 Overview

Licensees or Operators will be expected to satisfy financial tests that ensure that they can

(i) deliver their commitments to work programmes and development plans;
(ii) maximise economic recovery;
(iii) absorb stress from various sources including market fluctuations, unexpected changes in the operations and responding to and remedying adverse events; and
(iv) pay for decommissioning of the field facilities.

This is necessary to satisfy several of the Hydrocarbon Policy Principles and is highly relevant to the national interest of the Falkland Islands and the requirement for good oilfield practice. Such tests may be applied at any time but will be particularly relevant at key licence steps such as consent for field development.

These guidelines set out when DMR will consider the financial capability of an entity and the factors that DMR will usually take into consideration when doing so. These factors may vary according to the circumstances and will be assessed on a case-by-case basis. These guidelines also set out the steps that entities seeking a decision from DMR should take to facilitate those considerations.

The following sections are guidance in respect of the expectations around financial viability and capability, and the entity in question should be interpreted in the relevant context, e.g. Licensee (normally meaning a group of Licensees jointly and severally), Field Operator, Installation Operator or potentially a wider set of liable parties in the case of decommissioning.

These guidelines set out details of the process that DMR will apply to assess financial capability in respect of certain licence events. It is not a substitute for any other financial assessments that may be carried out by other regulators.

From time-to-time DMR may review the financial health of an offshore or onshore licensee or infrastructure owner between licence events and may, in certain circumstances, make further information requirements of that licensee and infrastructure owner unconnected to a specific licence event.

At various points during the lifecycle of a licence DMR will be asked by licensees to make decisions on commitments and activities proposed, and DMR believes that the financial capability of the licensee is an important consideration in making those decisions. To inform those decisions DMR will usually undertake a financial assessment of the licensee.

The output of this financial assessment will normally be a risk-based assessment of the licensee’s financial capability accompanied by a recommendation to ExCo as to how to proceed. In most cases the recommendation as to the licensee’s financial capability will not be determinative as ExCo will also be advised to take into account certain other relevant factors.

The factors that DMR will consider when taking a decision or making a recommendation to ExCo on a licence event and how those factors are weighed are informed by statute and by the Hydrocarbon Policy Principles.

Other regulators are responsible for regulating various other aspects of the upstream petroleum industry offshore and onshore, including FIMA and the Planning Department.

9.2 Financial Capability

These guidelines apply to a person seeking a decision from DMR in respect of any of these activities (an "Applicant"). The Applicant will in most circumstances be the Licensees, with whom liabilities remain jointly and severally, represented by the Operator appointed to organise and supervise the works.

ExCo takes decisions in respect of various activities pertaining to the extraction and storage of petroleum in the Falkland Islands petroleum industry. Many of those decisions are based on commitments made by an Applicant to undertake certain activities in the future. DMR considers that it is important to understand the Applicant's financial capability, to be able to make a judgement as to the likelihood of that Applicant having the funds needed to meet the commitment (the "Commitment").

The following activities will possibly include the making of a Commitment, or the transfer of that Commitment from one person to another:

a) Licence award;
b) Licence assignment;
c) Licence progression;
d) Well consent;
e) Field development (including extended well tests);
f) Change of control of Licensee; and
g) Pipeline Works Authorisation.

However, the above list may not be exhaustive and DMR may also apply these guidelines in any other circumstances where a Commitment is made that will or may require material financial resources to discharge it.

Where an application is submitted on behalf of a person who would assume the Commitment to DMR, it is the person assuming the Commitment that shall be regarded as the Applicant.

Issuing a development and production consent secures a Commitment by the Operator to proceed with the development, and this Commitment will require material financial resources to discharge it. In assessing an Applicant's financial capability, DMR will assess two broad financial criteria. These are *financial viability* and *financial capacity*.

- **Financial viability** refers to an Applicant's historic, current and future solvency and provides assurance that the Applicant is currently solvent and is expected to remain so for the foreseeable future.
- **Financial capacity** refers to the Applicant's ability to meet all known and anticipated future commitments, including the Commitment, and will focus on the Applicant's financial forecasts or on financing on a project basis.

DMR may seek additional assurances from the Applicant in respect of its proposed **decommissioning obligations**. Where such assurances are sought and provided, DMR will take these into consideration in making its decision. DMR will separately guide Licensees on how it will review financial capability in respect of decommissioning liabilities.

Rather than an Applicant demonstrating that it has the financial capability to meet a Commitment on a standalone basis, the Applicant may wish to rely on a guarantee from a natural person or corporate body.

DMR will consider applications relying on guarantees, but these must be created by way of a deed that is acceptable to DMR and the guarantor must demonstrate to DMR that it has the requisite financial capability. If a guarantor meets DMR's financial capability requirements, the financial capacity tests will not be applied to the Applicant. The process by which DMR will consider an application relying on a guarantor is set out in section 9.2.1.

DMR also recognises that, increasingly, existing and proposed new licensees are exploring new sources of finance and innovative financing structures to meet their Commitments. While DMR will always need to be satisfied that these new sources and structures will meet an Applicant's Commitments, DMR does not want to discourage this innovation by setting rigid requirements of how financial capability can be demonstrated. Therefore section 9.5 sets out how DMR will generally consider certain of these funding proposals, and Applicants and potential Applicants considering using new or innovative funding models are encouraged to make early contact with DMR.

In the case of a proposed licence assignment or licensee change of control, where an existing licensee intends to retain a Commitment or Commitments after the completion of the transaction, DMR will consider the financial capability of both parties to the transaction. As such, both parties should consider themselves an 'Applicant' for the purposes of these guidelines.

DMR's assessment processes will thereby seek to ensure the transaction is not detrimental to either the new and existing licensee's capacity to meet their Commitments in their post-completion portfolios.

To assess the financial capability of an Applicant DMR will require certain information from that Applicant. The information required by DMR will vary by application type and section 9.6 sets out the information that will normally be required for different application types, along with some further details relating to the DMR's information requirements.

DMR expects the information requirements set out in section 9.6 to be addressed in any application. On occasion, DMR may accept an application without all the information required by section 9.6, but reserves the right not to do so. Given the volume of applications typically received during a licence round for example, DMR will normally only take into consideration financial information provided with the application. However, DMR always reserves the right to request further information, in addition to that outlined in section 9.6, should it be required by DMR to fully evaluate the Applicant's financial capability.

DMR's assessment of an Applicant's financial capability forms one part of the decision-making process in respect of the activities listed in paragraph 3.2 above. In taking these decisions DMR will also take into consideration other relevant factors alongside financial capability, including the technical capabilities of the Applicant and the Applicant's operational and commercial plans, these factors are not covered by these guidelines.

The output of this financial assessment will normally be a risk-based assessment of the Applicant's financial capability and a recommendation to ExCo as to how to proceed. In most cases the recommendation as to the Applicant's financial capability will not be determinative as ExCo, with advice from DMR and others, will also take into account the factors referred to above. DMR will notify the Applicant in writing of the outcome of the application but will not always be able to provide feedback on the rationale for the decision.

Any queries regarding which requirements will apply, Applicants are encouraged to direct these to DMR.

9.2.1 Guarantors

In these guidelines, the term 'Guarantor' means entity person that guarantees to fund the obligations of an Applicant, which can include a parent company. DMR will not accept a guarantee from any party rated by the international rating agencies (S&P's, Moody's and Fitch) below investment grade. Where an Applicant proposes to rely on a person as a Guarantor, the Applicant will need to provide DMR with a deed of guarantee, as set out below. This is a legally binding document requiring the Guarantor to meet the Commitments of the Applicant should the Applicant be unable to meet those Commitments itself (and if required to do so by DMR). Before DMR accepts any guarantee from a proposed Guarantor, DMR will need to be satisfied that the Guarantor has the financial capability to meet the Commitments of the Applicant. To that end, DMR will apply the same financial assessment to the Guarantor as it would to an Applicant and these guidelines will apply to the Guarantor as it does to the Applicant and, where the context allows, references in these guidelines to the term 'Applicant' should also be read as referring to a Guarantor.

Deed of guarantee templates may be based on the format of the NSTA for the following types of applications:

a) Licence award;
b) Licence assignment; and
c) Licensee change of control.

Templates can be found on the NSTA website as follows and shall be appropriately amended to suit the relevant Falkland Islands law and entities: https://www.ogauthority.co.uk/licensingconsents/licensing-system/licensee-criteria/

Any modifications must be agreed with DMR. If the Applicant proposes to rely on a Guarantor for another application type, then the Applicant should contact DMR who will advise on an acceptable template.

Where an Applicant has informed DMR of its intention to rely on a Guarantor, the Guarantor should provide the financial information, as outlined in section 9.3. The assessment of financial capability, as outlined in sections 9.3 and 9.4, will then be performed on the Guarantor. The Applicant will not be subject to a separate financial capacity assessment but it will be subject to a financial viability assessment and should provide the appropriate financial information as outlined in the following sections.

In making an application where the Applicant intends to rely on a Guarantor, or if the Applicant is uncertain whether DMR will require a Guarantor, the Applicant should provide a draft deed of guarantee, together with a letter of undertaking from the Guarantor confirming that they will execute such deed of guarantee if the application is successful.

In some cases DMR may give an Applicant the opportunity to offer a Guarantor following an initial assessment of the Applicant's financial capability. However, DMR cannot undertake to do this in every case and, by not providing the necessary documentation in the first instance, the Applicant risks causing delay to their application or the application being refused outright because it has failed to demonstrate adequate financial capability.

Where the Guarantor is a natural person, DMR expects to undertake additional assessment regarding the ability of such Guarantor to meet the guaranteed obligations and apply such additional processes as may be required to ensure the deed of guarantee is enforceable.

The deed of guarantee must be accompanied by a legal opinion from a reputable law firm authorised to act in the jurisdiction in which the Guarantor is incorporated and/or domiciled confirming, among other things, the enforceability of the guarantee against the Guarantor in such jurisdiction. If an Applicant believes that this requirement may apply they should contact DMR at the earliest opportunity.

In assessing an application, DMR will give each relevant assessment area an appropriate risk-rating and commentary as to key risks that the assessment area presents. A final recommendation will consider all risks highlighted across the relevant assessment areas.

9.3 Financial Viability Assessment

9.3.1 Overall considerations

DMR will assess the Applicant's historic and current solvency. This is intended to assure DMR that the Applicant is currently solvent and is likely to remain so for the foreseeable future. The Applicant's financial history will be reviewed, and this may be used as an indication of the Applicant's likely future performance.

For green field projects and/or newly incorporated applicants, the criteria below may not be an accurate guide to future solvency or stability. An assessment will still be made at the point of application using the information set out below, but a further assessment against the criteria listed will be undertaken at the date of confirmation that adequate funds have been raised to deliver the Commitment, or such other point as DMR sees fit to discharge its obligations in the public interest. See section 9.3.5 for more information.

In making its assessment of the Applicant's financial viability, DMR will perform a risk based financial assessment across three areas as follows.

9.3.2 Demonstrable Track Record

While past performance is not the best indicator of an Applicant's ongoing financial viability, it is DMR's view that an established company with an extended track record of solvent trading is more likely to meet future commitments than a company without such a track record. This is in part because it has demonstrated a capability of doing so and in part because it will have earned a valuable reputation that it will not want to give up cheaply. However, DMR does not wish to exclude new entrants to the industry and section 9.3.5 below sets out how DMR will assess applications from newly incorporated companies.

DMR will assess an Applicant's Demonstrable Track Record through a review of historic financial information of up to five years submitted by the Applicant and through a review of other information available about the Applicant from public sources including, but not limited to, details of any breaches of law or regulation leading to enforcement action. DMR will pay particular attention to the historic solvency and profit and cash generation of the Applicant and any qualifications or 'emphasis of matter' set out in audited accounts. If the Applicant cannot submit the information requested, the Applicant should contact DMR at the earliest opportunity.

Evidence of sustained solvent trading with sustained profitable trading and cash generation will have a positive bearing on DMR's assessment of the Applicant's Demonstrable Track Record. Indications of significant losses, difficulties generating positive cash flow and/or breaches of lending covenants may negatively impact DMR's assessment. Recent insolvency proceedings and frequent or lender imposed financial restructurings may also have a significant bearing on DMR's assessment of the Applicant's Demonstrable Track Record.

In assessing the Applicant's Demonstrable Track Record, DMR will also consider the scale of previous profits and positive cash flows set against the scale of the Commitments that the Applicant is seeking to take on through the application.

9.3.3 Current Financial Analysis

DMR will assess the Applicant's solvency as at the date of the application.

To do this DMR will calculate the Applicant's Current Ratio, Interest Cover Ratio and Net Assets on each of the three most recently audited and filed statutory accounts , and the Applicant's most recent management accounts submitted. The DMR's expectation is that these accounts will have been prepared under UK Generally Accepted Accounting Principles (GAAP), IFRS or GAAP of the jurisdiction in which the Applicant is registered. If not, the Applicant should contact DMR.

The Applicant's Current Ratio, Interest Cover Ratio and Net Assets will be calculated as follows:

Current Ratio *= (Current Assets) ÷ (Current Liabilities)*

Interest Cover Ratio *= (EBITDA) ÷ (Interest Expenses)*

Net Assets *= Total Assets - Total Liabilities*

DMR believes that together these calculations provide an insight of the current solvency and liquidity of the Applicant providing a robust, albeit historic, view and the management accounts providing a more up to date view of the Applicant's status.

The Current Ratio is an indication of the Applicant's ability to meet its obligations in the short term. DMR will interpret a low Current Ratio, particularly Current Ratio of less than one, as an indication of financial weakness of the Applicant.

Criterion: Current Ratio *of less than 1 (one) is not acceptable*

The Interest Cover Ratio indicates how easily an Applicant will be able to pay their interest expenses on outstanding debt. A lower ratio may also imply that the Applicant already has a substantial debt burden which it may find difficult to service. An Interest Cover Ratio of less than two is a sign that the Applicant may struggle to meet the Commitments.

Criterion: Interest Cover Ratio *of less than 2 (two) indicates concern*

Net Assets as calculated is a simple measure of the Applicant's balance sheet solvency. Net Assets of less than zero would be a clear sign of financial weakness. A positive Net Asset value indicates that the Applicant is balance sheet solvent but a positive Net Asset value that is significant relative to the scale of the Commitments that the Applicant is proposing to take on would be a clear positive indication of the Applicant's current financial viability.

Criterion: Net Assets *of less than 0 (zero) is not acceptable*

Note that DMR expects that any pensions liabilities of the Applicant will be fully reflected in both the Applicant's audited and management accounts. If this is not the case the Applicant should state that and provide a separate, audited, estimate of those liabilities.

9.3.4 Capital Structure

In assessing the Applicant's financial viability it is also important to understand its capital structure and DMR will calculate the Applicant's gearing ratio to aid that understanding. DMR will calculate a gearing ratio based on both the latest audited and filed statutory accounts and on the Applicant's most recent management accounts.

DMR will calculate the Applicant's gearing ratio as follows:

Gearing Ratio *= (Total Debt) ÷ (Total Debt + Equity)*

The Gearing Ratio is a measure of how the Applicant is funded, with a higher Gearing Ratio indicating that debt makes up a larger part of the Applicant's capital structure. More debt in an Applicant's capital structure carries greater risks, as debt must eventually be repaid and generally requires the borrower to make regular interest payments to the lender. A higher Gearing Ratio also implies that the Applicant will find it harder to borrow more funds, should the need arise.

Criterion: *a high* ***Gearing Ratio*** *indicates concern*

If the Gearing Ratio is high in consideration of the Commitment then DMR is more likely to be minded that the Applicant has not demonstrated sufficient financial capacity.

The Gearing Ratio calculation will be made including all debt owed by the Applicant, without reference to the identity of the lender or to any security held by the lender. Where some or all the debt on an Applicant's balance sheet is intragroup and the Applicant believes that the simple Gearing Ratio calculation outlined above would misrepresent its true capital structure, the Applicant may provide details of the intra-group debt and an explanation of why DMR should modify its view of the Applicant's solvency risk profile. In taking that additional information into consideration, DMR may also need to see relevant financial information for the intra-group lender.

9.3.5 Applicants lacking corporate track record or current financial standing

DMR recognises that persons may choose to incorporate a new company to make an application, or a company may apply that otherwise does not have a substantive corporate track record or financial standing. While not ideal, there may be merit in considering such an application on the basis that the Applicant can evidence that delivery risks are adequately managed by other means or will be managed before development proceeds, and by DMR being satisfied that the Falkland Islands is not exposed to unnecessary risks. In that case much of the analysis of financial viability of the Applicant set out in the preceding paragraphs of this section will not be meaningful, though the relevant information will be required to support DMR's assessment. Primarily, DMR will address this by placing more importance on the financial capacity assessment set out in section 9.4 below, but will also consider in detail the identity and track record of the shareholders, directors and officers of the Applicant. A further assessment against the criteria listed will be undertaken at the date of confirmation that adequate funds have been raised to deliver the Commitment, or such other point as DMR sees fit to discharge its obligations in the public interest.

An Applicant that has provided evidence of shareholders, directors and officers with a demonstrable track record of running successful, solvent businesses particularly upstream oil and gas businesses, will be considered lower risk than those that cannot provide that evidence.

9.4 Financial Capacity Assessment

9.4.1 Overall considerations

The financial capacity assessment informs DMR's judgement of the likelihood that the Applicant will, in future, have the financial resources necessary to meet the Commitment. In making this assessment DMR will consider all the Applicant's current Falkland Islands and overseas licence commitments, including the new Commitment, and its known and committed sources of funding.

However, where an application does not increase an Applicant's cumulative commitments, DMR may decide that there is no requirement for financial capacity to be demonstrated. In which case, no financial capacity assessment will be carried out.

DMR expects that Commitments will be met. Therefore, DMR will want to see evidence that the Applicant expects to have the financial capacity to meet the expected costs of the Commitment and all other commitments and obligations, but also that it will be able to withstand reasonable shocks to the costs of meeting its commitments and obligations, and to its sources of funding.

DMR considers that there are two ways that an Applicant can demonstrate that it has the financial capacity to meet the Commitment, alongside all existing commitments. In most cases, DMR will want to see clear evidence that the Applicant will have funds available as and when they are required to satisfy the Commitment by referring to the resources they will use to support a cash flow forecast, starting from the date that the application is made to the point in time when the Commitment will have been discharged.

Where the Applicant has demonstrated a strong track record and the scale of an Applicant's Net Worth relative to costs of meeting the Commitment are such that DMR can be satisfied that the Applicant will be able to meet the Commitment without the need for the Applicant to prepare and DMR to review cash flow forecasts, DMR may not require the Applicant to provide the cash flow forecast requested. Further guidance on how an Applicant's Net Worth will be assessed and when the Net Worth test may be substituted for the full cash flow analysis is set out in section 9.4.3 below.

Alternatively, in some cases DMR may be prepared to accept a high investment grade credit rating of an Applicant as evidence that the Applicant will be able to meet the Commitment. In these cases neither a review of the Applicant's cash flow forecasts nor its Net Worth will be required.

If the Applicant would prefer DMR to make its assessment based on its credit rating or on an assessment of its Net Worth, the Applicant should contact DMR prior to submission.

DMR notes that, under the terms of its licences, each licensee agrees to be jointly and severally liable to fully discharge all commitments made in that licence. Without prejudice to the joint and several nature of licence obligations, in making its assessment of the Applicant's financial capacity, DMR will normally only consider the Applicant's capacity to fund its proposed share of the Commitment. However, DMR may make exceptions to this approach where, for example, another licensee or proposed licensee is known to be in financial difficulties.

If the Applicant is uncertain how DMR will apply joint and several liability in the context of a particular application it should contact DMR at the earliest opportunity.

9.4.2 Financing on a project basis

If the field development is financed largely or wholly on a project basis with no recourse to the parent company or a guarantor for debt finance, financial capacity will be assessed on consolidated basis for the project company and its parents in respect of its ability to provide equity for the project. If for the green field development project company requires external financing, its financial capacity will be assessed only after such financing has been put in place.

Where finances are arranged on a project basis, DMR will need to review project financing proposals, agreements and final documentation to address concerns about potential reputation risk for the Falkland Islands and to safeguard the recovery of reserves and future development prospects associated with potential default.

9.4.3 Net Worth

By their nature, Commitments need to be discharged in the future, therefore, to satisfy itself that the Applicant will have the financial capacity to meet that Commitment it will normally be necessary for DMR to assess the Applicant's capacity to access the cash necessary to do so in the future; i.e. at the time the Commitment is expected to be discharged. However, some Applicants will have a Net Worth that is sufficiently high relative to the cost of discharging the Commitment that no further assessment of financial capacity is necessary.

DMR will calculate the Applicant's Net Worth as follows:

Net Worth *= Net Assets - Intangible Assets*

If, on this basis, an Applicant has demonstrated that it has a Net Worth substantially greater than the estimated cost of the Commitment then DMR will normally deem that the Applicant has demonstrated sufficient financial capacity.

Criterion: Net Worth *is substantially greater than the estimated cost of the Commitment*

If Net Worth is smaller, particularly a Net Worth less than 3.5 (three point five) times the estimated cost of all commitments, Applicants will be expected to prove their financial capacity by an analysis of their cash flow forecasts.

9.4.4 Cash Flow Forecasts

In other circumstances the Applicant's cash flow forecasts from the date of the application to the date in the future when that Commitment is fully discharged will be fundamental to DMR's assessment of the Applicant's financial capacity.

These cash flow forecasts should include details of all sources of free cash flow expected to be available to the Applicant for the period of the cash flow forecast (including full details of debt facilities), the costs of all committed projects (including but not limited to the Commitment), the costs of any uncommitted projects where cash flows from those projects are subsequently included in the cash flow forecast, and any other expenses or repayments that the Applicant will need to satisfy, in particular, repayment of debt and interest expenses.

To aid DMR's understanding of the cash flow forecasts, the Applicant should provide the output from its integrated financial model and should detail all key assumptions and methodologies underlying the cash flow forecasts, in particular, oil and gas prices, interest and inflation rates, how project costs have been estimated, any contingencies that have been applied to those costs and expectations as to timing of completion and rate of production from development activities.

At a minimum, the cash flow forecast should be provided in accordance with the Applicant's internal reporting process, e.g. annually or semi-annually, up to the point that the commitment is expected to be discharged. DMR reserves the right to ask for more detailed cash flow forecasts and for re-worked forecasts based on its own, stated assumptions and methodologies, if it believes that that would give a clearer view of the likelihood of the Applicant meeting the Commitment than the original cash flow forecasts provided. The format and structure of forecasts should be consistent with current industry practice, and DMR reserves the right to reject forecasts that are not or ask for them to be re-worked. See section 9.4.5 below for further details.

Where the information provided indicates that the Applicant is reliant on, or intends to rely on, large amounts of debt to fund its activities, DMR will consider if and to what extent the Applicant's reliance on debt increases the risk that the Applicant will not be able to meet its Commitments.

To assess the Applicant's ability to service its existing and proposed debt, DMR will perform an analysis of the Applicant's Debt Service Cover Ratio in respect of each period set out in the Applicant's cash flow forecasts. The purpose of this assessment is to ensure that the level of free cash generated by the Applicant's business once all other commitments have been met (including the Commitment) will be sufficient in each period to meet the agreed repayment schedule of its existing and any new debt, along with any regular servicing costs, such as interest.

DMR will use the following calculation to calculate the Debt Service Cover Ratio (DSCR) of an Applicant in each period:

DSCR *= (EBITDA) ÷ (Debt Repayments + Debt Service Cost)*

Criterion: DSCR *in any period of less than 2 (two) indicates concern*

DSCR less than two will highlight periods where there is a risk that the Applicant may find it difficult to meet the Commitment and all its other commitments. However, DMR will take into account the particular circumstances of that period, for example, a period in which the principal of a loan must be repaid to lenders.

Where DMR's analysis of the Applicant's Debt Service Cover Ratio indicates periods of weakness, DMR may seek clarification from the Applicant as to how it will mitigate these risks.

9.4.5 Sensitivity Analysis

A cash flow forecast based on reasonable assumptions and robust methodologies that suggest that the Applicant will always have the cash available to meet its Commitments, in addition to its other commitments, with a reasonable amount of headroom is a strong indication that the Applicant has adequate financial capacity. In this case it is unlikely that DMR would seek further clarification.

If the cash flow forecast presented by the Applicant indicates that there will be periods where there is little or no headroom and/or a low Debt Service Cover ratio and/or is based on assumptions and methodologies that appear to DMR to be optimistic, DMR may conclude that the Applicant has a high risk of not being able to meet its Commitment.

If DMR believes that to do so would give a clearer view of the likelihood of the Applicant meeting licence commitments than the original cash flow forecasts provided by the Applicant, DMR may ask for more detailed cash flow forecasts and/or for re-worked forecasts based on DMR's own stated assumptions and methodologies.

In particular (but without limitation) DMR may ask for cash flow forecasts to be re-worked based on one or more of the following sensitivities:

i. lower oil and gas prices;
ii. higher interest rates;
iii. higher inflation rates;
iv. capex overruns;
v. delays to field start-up; and
vi. lower than expected production rates.

These parameters may be varied or updated from time to time to take account of changes in prevailing market conditions or trends. Tests should be applied individually and also simultaneously with respect to the above sensitivities.

9.5 Evidential Requirements for Specific Financing Arrangements

In assessing the Applicant's financial capability, DMR will need to satisfy itself that the financing arrangements underlying the cash flow forecasts presented by Applicants are reliable. At the same time, DMR recognises the important role played by a variety of different financing arrangements in developing UK petroleum resources and is open to considering any credible financing arrangements proposed by Applicants.

To assist Applicants in submitting the best possible applications, the following paragraphs set out DMR's general expectations as to the evidence needed to demonstrate that a type of financing arrangement is, or will be, in place for as long as it is needed to ensure that the Applicant can meet the Commitment.

If an Applicant intends to use a type of funding arrangement that is not listed below, or intends to provide a different form of evidence of that funding arrangement than the form recommended, then the Applicant should contact the DMR prior to making the application.

a) Loans from banks or other financial institutions: Such loans should be evidenced by the provision of a copy of the executed loan agreement and an executive summary of key terms. Loan agreements that are conditional upon a licensing event are acceptable. Irrevocable commitments from a bank or other financial institution to provide debt finance are also acceptable, but letters of intent are not. If an Applicant will be relying on commercial debt to meet its existing and/or proposed Commitments, DMR will need assurances that the funding arrangements will remain in place long enough to fund the work programme and that the Applicant can meet the interest payments and agreed capital repayment obligations. A debt repayment schedule for the Applicant should therefore be provided along with cash flow projections clearly showing interest charges and capital repayments. If the debt repayment schedule shows any significant redemption of debt before the Commitment has been met and which cannot be met from operational cash flow, details of how the redemption will be funded should also be provided.
b) Parent company guarantee: see section 4 above.
c) Parent company loan: A copy of the executed loan agreement should be provided along with an executive summary of key terms. DMR may undertake additional assessment to ensure that such an arrangement can be satisfied.
d) Directors' loans: Details of the loan arrangement between the Applicant and director should be provided. DMR may undertake additional assessment to ensure that such an arrangement can be

satisfied. A proposal relying on a loan from a director that has previously been declared bankrupt will come under particular scrutiny.

e) Commodity-based loan: Where funding is expressly linked to a commodity (for example, reserve-based lending), the Applicant must disclose the assumptions that have been made for the provision of this funding, including anticipated commodity value and remaining reserves. Whilst DMR will consider the financial impact of specific sensitivities in its initial assessment, the overall risk assessment will also consider the operational assessment of the project. The Applicant is encouraged to share any financial assessment or other third-party reports commissioned in securing this type of funding instrument.

f) Bonds: Any existing or anticipated bond funding should be detailed in full, including the borrowed amount, quantum and timing of capital repayments and interest payments. Applicants should submit any agreements governing the bond issue, disclose details of potential penalties and any additional rights accruing to the bond holders. Applicants will also be required to detail how the bond repayment is anticipated to be financed during the term of the Commitment that is the subject of the application.

g) Deferred payments: The scenarios below highlight two of the most commonly anticipated forms of deferred payment structure that may underpin an Applicant's financial model. Any funding source that is deferred or contingent upon performance, the passing of time or other future events should be detailed by the Applicant, disclosing the key terms that govern the payment of deferred sums and anticipated impact on the Commitment if that such funding is not provided.

    i. Contingent payments: Details of cash inflow or outflow that is contingent upon future events should be detailed, including the quantum of cash flow, conditions upon which the payment is contingent and the Applicant's existing rationale for including or excluding such payments from its forecasts.

    ii. Vendor assistance: Applicants should detail any form of assistance to be provided by a vendor to the Applicant]. Whilst vendor assistance may take the form of cash payment, it extends to wider forms of assistance such as the provision of services at discount to market rates, commitment to pay or contribute to future liabilities (for example, decommissioning) and provision of equipment or staff. Details of any arrangement that allows a vendor to absorb costs or liabilities that would otherwise by met by the Applicant in the normal course of business, should be disclosed and detailed alongside other funding arrangements.

h) Contractor financing: Any discount to or deferral of payment for services to an Applicant by a contractor in exchange for equity or other financial benefit is considered to be a form of financing and should be detailed alongside other financing arrangements.

i) Issue of additional share capital: Details of the proposed (private) share issues should be provided, together with documentary evidence that (a) the funds are available and have been irrevocably committed to the share issue by the investor(s), or (b) the share issue has been guaranteed/underwritten by a recognised financial institution or stock brokerage (future share issues will not be acceptable without such evidence). Arrangements with financial institutions or stock brokerage firms in which they undertake to raise equity on a 'best efforts' basis will not be considered as adequate evidence of funding.

j) Equity Capital Markets: Whilst not practical to consider the full range of public market instruments that may be considered during a licence's life in these guidelines, the Applicant should disclose any anticipated funding to be provided via Initial Public Offering, rights issue or similar offering along with anticipated timing of such a fundraising. Where securing funding of this nature is critical to the Commitment] the level of requested information and scrutiny by DMR will be higher. Where such funding is anticipated as a future option rather than a critical source of funding, detailed disclosure of such funding is not anticipated.

k) Prepayment Facility: Where an Applicant has agreed to transfer entitlement to revenues from the future sale of petroleum to a third party in exchange for an upfront payment, DMR will expect to see this reflected in cash flow forecast. In addition, the Applicant should provide DMR with a copy of the prepayment facility agreement along with a summary of the agreement terms in advance of its execution.

l) Farm-outs and Cost Carries: Where an Applicant's Commitment will be funded or part-funded by a farm-out or by a Cost Carry Arrangement DMR will require a copy of the farm-out and/ or Cost Carry Agreement and will assess the other party's capacity to finance the Commitment in addition to the Applicant.

9.5.1 Exploration and Appraisal Well Commitments

In applications relating to the drilling of an exploration or appraisal well, DMR will expect to see evidence that an Applicant has sufficient funds to meet its share of the drilling costs, the plugging and abandonment of the well if it is proven to be "dry" or otherwise non- viable and a minimum contingency of fifty per cent (50%) for both the drilling costs and plugging and abandonment costs.

If, following a review of the financial information provided by a licensee, DMR is not satisfied with the licensee's financial capability, under Section 57 of the Offshore Minerals Ordinance 1994 (as amended) DMR may require the licensee to take further action to ensure that the licensee will be able to plug and abandon the well. This action may include, amongst other things, the creation of financial security to ensure that the requisite funds would be available for the plugging and abandonment operation. At an early stage, the Applicant should contact DMR to discuss the forms of security acceptable to DMR.

9.6 Information Requirement Matrix

Applicants should submit the information indicated in the table below relevant to the type of application being submitted; a "tick" denotes information that must be provided and a "cross" is information ordinarily not required to be provided, however, it may be requested by DMR. Where DMR considers it has not received sufficient information to enable completion of its financial assessment, further information may be sought from the Applicant which may include items indicated with an "cross" in the table below.

All information submitted to support the basis of financial assessment should be accompanied by a letter from the Applicant (or the Guarantor, as appropriate) stating that, to the best of the Applicant's (or Guarantor's) knowledge and belief, the submitted information is a fair and accurate reflection of the Applicant's (or Guarantor's) business and plans. This letter should be signed by a Director or by another individual authorised by the Applicant's (or Guarantor's) Board.

Table 3 - Financial information requirements for different licence events

Information Requirement	Application Type								
	Licence Application		Licence assignment		Licence progression	Well consent		Field Development	Change of control of licensee
	No work programme	Work programme	No work programme	Work programme	From exploration to production	Exploration or appraisal well	Development well	Field Development Plan	Direct or indirect change of ownership of any licensee
Company ownership / directors									
Details of all company directors	✓	✓	✓	✓	✓	✓	✓	✓	✓
Details of any shareholders owning >10%	✓	✓	✓	✓	✓	✓	✓	✓	✓
Details of any planned issue of additional share capital	✗	✗	✗	✗	✗	✗	✗	✗	✓
Historical financial performance									
Copies of three most recently filed audited statutory accounts	✓	✓	✓	✓	✓	✓	✓	✓	✓
Copy of most recent management accounts should be provided for the period since the period covered by the last audited accounts, including balance sheet	✓	✓	✓	✓	✓	✓	✓	✓	✓
Financing									
Commentary of funding plans specific to the future cash flow profile	✗	✓	✓	✓	✓	✓	✓	✓	✓
Breakdown of debt by funding type, lender, rates and security specifically identifying lending from shareholders and other connected parties, separately from third party lenders	✗	✓	✗	✓	✓	✓	✓	✓	✓
Provide executed loan agreements, including repayments schedules for all 3rd party, parent guarantor or director loans	✓ / ✗	✓	✗	✓	✓	✓	✓	✓	✓
Provide details where future provision of financing is contingent upon award of	✓	✓	✓	✓	✓	✓	✓	✓	✗

Information Requirement	Application Type								
	Licence Application		Licence assignment		Licence progression	Well consent		Field Development	Change of control of licensee
	No work programme	Work programme	No work programme	Work programme	From exploration to production	Exploration or appraisal well	Development well	Field Development Plan	Direct or indirect change of ownership of any licensee
licence, consented FDP or other key milestones									
Provide copy of deed of guarantee on Guarantor's corporate headed stationery	✓ / ✗	✓	✗	✓	✓	✓	✓	✓	✓
Cash Flow Projections									
An estimate of the Applicant's share of committed work programme costs	✗	✓	✗	✓	✓	✓	✓	✓	✓
The Applicant's integrated financial model including all key underlying assumptions	✗	✓	✗	✓	✓	✓	✓	✓	✓
Cash flow projections in relation to existing operations and the committed work programme costs	✗	✓	✗	✓	✓	✓	✓	✓	✓
Basis of estimate for decommissioning and funding plans	✗	✗	✓	✓	✗	✓	✓	✓	✓

Notes:

a. If published accounts are not available, pro-forma financial statements which have been certified by a director and are sufficiently detailed to enable the Financial Viability Assessment to be undertaken should be provided.

b. Where an Applicant is seeking to rely on a Guarantor, the information outlined in this table should be provided on behalf of the Guarantor in addition to the Applicant. The Applicant should also provide a group structure chart detailing the relationship between the Applicant and the Guarantor.

9.7 Decommissioning Liabilities

This section deals with issues specific to decommissioning in addition to applicable guidance given above.

While many aspects of the operations generate risks or liabilities that must be adequately provided for, there are specific challenges for liabilities relating to decommissioning, whether in a planned and orderly fashion, or triggered by an event that hastens the need for decommissioning, potentially in a situation where there might be pressure on the Operator's ability to raise or gather funds from licensees or other liable parties.

DMR expects operators, at the point at which consent for an FDP is sought, to have externally verified estimates of decommissioning liabilities and to present these in a detailed and rational form according to the activities including well plug and abandonment, removal or making safe of subsea infrastructure, and removal of installations. Further detail will be expected when an abandonment programme is required under Section 48 of the Offshore Minerals Ordinance 1994 (as amended). The liabilities will be calculated for an orderly decommissioning scenario and also for a disorderly decommissioning scenario where interim management of assets is required by a third party.

DMR will assess the ability of the Applicant and other relevant Licensees to meet decommissioning obligations under Part V of the Offshore Minerals Ordinance 1994 (as amended). DMR will place weight on the approach taken in OPRED's "Guidance Notes on the Decommissioning of Offshore Oil and Gas Installations and Pipelines" in respect of the financial capability of liable parties.