

Section 4

Draft Plan and alternatives

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4.1 Introduction

The IOSEA3 is a result of the Irish Government's decision to conduct a licensing round in the Rockall Basin in Q2 2009. Successful applicants will be offered Frontier Exploration Licences in Q3 2009 that will last 15 years, as detailed in the Draft Plan and summarised below. The licence period will be divided into four phases, each with work obligations as follows.

First phase	1 September 2009 to 31 August 2012 - seismic data acquisition
Second phase	1 September 2012 to 31 August 2016 - at least 1 exploration well
Third phase	1 September 2016 to 31 August 2020 - at least 1 exploration well
Fourth phase	1 September 2020 to 31 August 2024 - to be agreed with the Minister

In the first phase, the licensee must undertake a work programme that shall include at a minimum 2D or 3D seismic data acquisition. Where exploration drilling is not included in the first phase, planning for drilling in the second phase should take place and be proposed prior to the start of the second phase. The third phase should include a proposal to drill a further exploration well. Licensees will be required to undertake reasonable site-specific environmental studies as may be appropriate to the work programmes. The Licensing Terms for Offshore Oil and Gas Exploration, Development and Production, 2007 will apply to licences granted under the Round (see Section 3). The IOSEA3 covers the first and second phases only, ie the period 2009 to 2016. It is proposed that subsequent phases and licensing rounds for exploration in this area will be the subject of further SEA at a future date.

4.2 Scenarios and assumptions for Draft Plan

The scenarios being considered for the range in activity levels following licensing awards comprise the undertaking of 2D and 3D seismic data gathering from 2010 (it is unlikely that any seismic acquisition could be organized to commence in the remaining four months of 2009) to 2016 and exploratory drilling in the period 2011 to 2016. Although IOSEA3 is an assessment of exploration activities only, recognition of the possibility that a proportion of the exploration may ultimately result in development drilling taking place is also made. Estimates of maximum levels of each activity have been made by the DCENR on the basis of experience and are shown in Table 4.1.

Since all previously held licences in the area have been relinquished some time ago, there are no activities arising out of previous licensing rounds which need to be considered. Exploration activities occurring in the neighbouring Slyne/Erris/Donegal and Porcupine basins are covered by IOSEA1 and IOSEA2, respectively.

Table 4.1 Exploration activities (and potential development activity) forecast in the IOSEA3 area between 2010 and 2016 arising from the Rockall Basin licensing round

Type of activity	2010		2011		2012		2013		2014		2015		2016	
	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max
2D seismic survey (km)	-	7,000	-	7,000	-	7,000	-	7,000	-	7,000	-	7,000	-	7,000
3D seismic survey (km ²)	-	4,000	-	4,000	-	4,000	-	4,000	-	4,000	-	4,000	-	4,000
Exploration drilling (numbers of wells)	-	-	-	1	-	2	-	3	-	3	-	3	-	3
Appraisal drilling (numbers of wells)	-	-	-	-	-	-	-	1	-	1	-	1	-	1
Development drilling (numbers of wells)	-	-	-	-	-	-	-	-	-	2	-	2	-	2



4.3 Alternatives

The SEA Directive requires that the environmental report identifies and evaluates reasonable alternative strategies to the proposed plan. The available options are better understood in the context of Ireland's energy outlook.

In 2005 the Economic and Social Research Institute (ESRI) forecast that Ireland's annual energy demand would increase from 14.8 million tonnes of oil equivalent (mtoe) in 2003 to higher levels by 2020 depending on different rates of growth. In the benchmark scenario where growth would continue at then-current levels, the forecast demand was 18.6 mtoe, an increase of 25.7%. In a high growth scenario the forecast demand was 20.0 mtoe, an increase of 35.1%. In a low growth scenario the forecast demand was 16.9 mtoe, an increase of 14.2%.

In terms of Ireland's total energy requirements, there are very few indigenous resources and these provide only a small fraction of the overall requirement. Ireland has no indigenous oil, and only about 10% of its gas requirement comes from indigenous sources, ie the Kinsale and Seven Heads fields in the Celtic Sea. One of the recommendations to Ireland from the International Energy Agency is that Ireland should develop a long-term strategy for an optimal energy mix striking an appropriate balance between energy security and climate change mitigation, noting an increasing dependence on natural gas (IEA, 2007). A recent European green paper on energy set a target of 10% of the Community's requirement from alternative energy sources by the year 2012 (European Commission, 2001).

A crucial factor in the outlook for Irish energy policy is the fact that the UK, which has to date been Ireland's source of imported gas requirements, is now becoming a net importer of gas. A 2007 report quoting UK Department of Trade and Industry data showed the extent of decline of production of oil and gas predicted for the UK Continental Shelf (Sustainable Energy Ireland, 2007). One scenario based on an older rate of investment showed a decline from 4.6 millions of barrels of oil equivalent per day (mboe) in 1999 to 1.0 mboe in 2020 and to 0.4 mboe in 2030. A second scenario based on a more recent investment rate showed production declining from 4.6 (mboe) in 1999 to 2.2 mboe in 2020 and 1.4 mboe in 2030.

In the medium to long term Ireland will either have to develop its own sources or access new sources, probably in Eastern Europe. This brings issues of security of supply and price stability or volatility. The main alternative in the supply side is coal and peat, which causes greenhouse gas emissions to rise much faster than expected (IEA, 2007).

As a means of testing or assessing Ireland's offshore hydrocarbon reserves, there is no realistic alternative to the exploration activity proposed in the Draft Plan. However, alternatives within the Draft Plan to offer blocks for seismic data acquisition and exploration drilling in the Frontier Exploration Licensing Round 2007 have been identified as:

- 1) to proceed with licensing according to regulation, with no other licensing restrictions;
- 2) to proceed with the offer, subject to licensing and/or drilling conditions which may derive from the SEA process;
- 3) to award licences but restrict the extent of area licensed by withholding certain blocks;
- 4) to award licences but restrict all licences temporally;
- 5) to postpone the offer for licensing in the Rockall Basin.

This situation is recognised and accepted in the Government White Paper on Energy Policy Framework 2007-2020 titled 'Delivering a Sustainable Energy Future for Ireland', published in March 2007. Section 3.6.1 states the following: 'The overarching objective of securing our national energy supply will be a key driver in the development of Ireland's approach to hydrocarbon exploration and production. It is a key Government policy objective to encourage investment in oil and gas exploration off the Irish coast and to optimise the value of any oil and gas finds for Ireland.' The paper also states in Section 3.6.5, titled Actions: 'We will continue the practice of holding annual licensing rounds in the Atlantic basins. These licensing rounds will be underpinned by a comprehensive Strategic Environmental Assessment.'

4.4 Description of exploration scenario

This section provides a general description of the seismic and drilling operations likely to be used to undertake these activities.

4.4.1 Seismic surveys

Offshore seismic surveys are conducted by a vessel towing acoustic sound sources (air guns) that release pulses of compressed air into the water column. The air guns are towed 5 to 10 m below the sea surface and will release a bubble of compressed air at intervals of 10 to 20 s, equivalent to a spacing of approximately 12 m on the sea bed. Air guns produce loud impulsive low frequency sounds at regular intervals which are usually around 226 dB for a single air gun or 242 to 252 dB for an array.

The generated sound waves travel to the sea bottom, both penetrating and reflecting off the sea bed itself and successively deeper rock strata beneath (Figure 4.1). The reflected signals are detected by hydrophones towed in streamers behind the survey vessel. Each streamer is constructed in sections comprising a central core containing the electronics, surrounded by a layer of cable oil (a light kerosene-type oil), and enclosed in a durable outer skin. The streamer is towed at 5 or 6 m depth behind the noise source, and has a tail buoy attached which locates the furthest extent of the towed array behind the survey ship (Figure 4.1). The reflected signals picked up by the hydrophones are recorded and processed by geo-physicists and geologists using computer software to create either a 2D vertical section or a 3D picture of the seabed and underlying geological formations.

A 3D seismic survey is basically derived from a dense grid of 2D survey lines. However, the way in which it is processed and interpreted is different from that of 2D data. If enough closely-spaced seismic survey lines are sailed, the data can be used to create a 3D image of the subsurface rock by layering the 2D cross-section images side by side. This difference enables practitioners to take the data from linear (2D) to volume (3D) information. In 3D surveys, the subsurface is closely sampled in every direction, leaving no open loops or gaps in the structure or stratigraphy when it is analysed.

The greatest advantage of 3D data is that it provides the ability to map the subsurface more completely, allowing the interpreter to fill in the 'gaps' that are inherent in 2D data. Other advantages of 3D over 2D stem from the greater density of data points, leading to more accurate positioning of drilling targets through improved horizontal and vertical resolution, and a choice of viewing perspective in the software-generated 3D models.

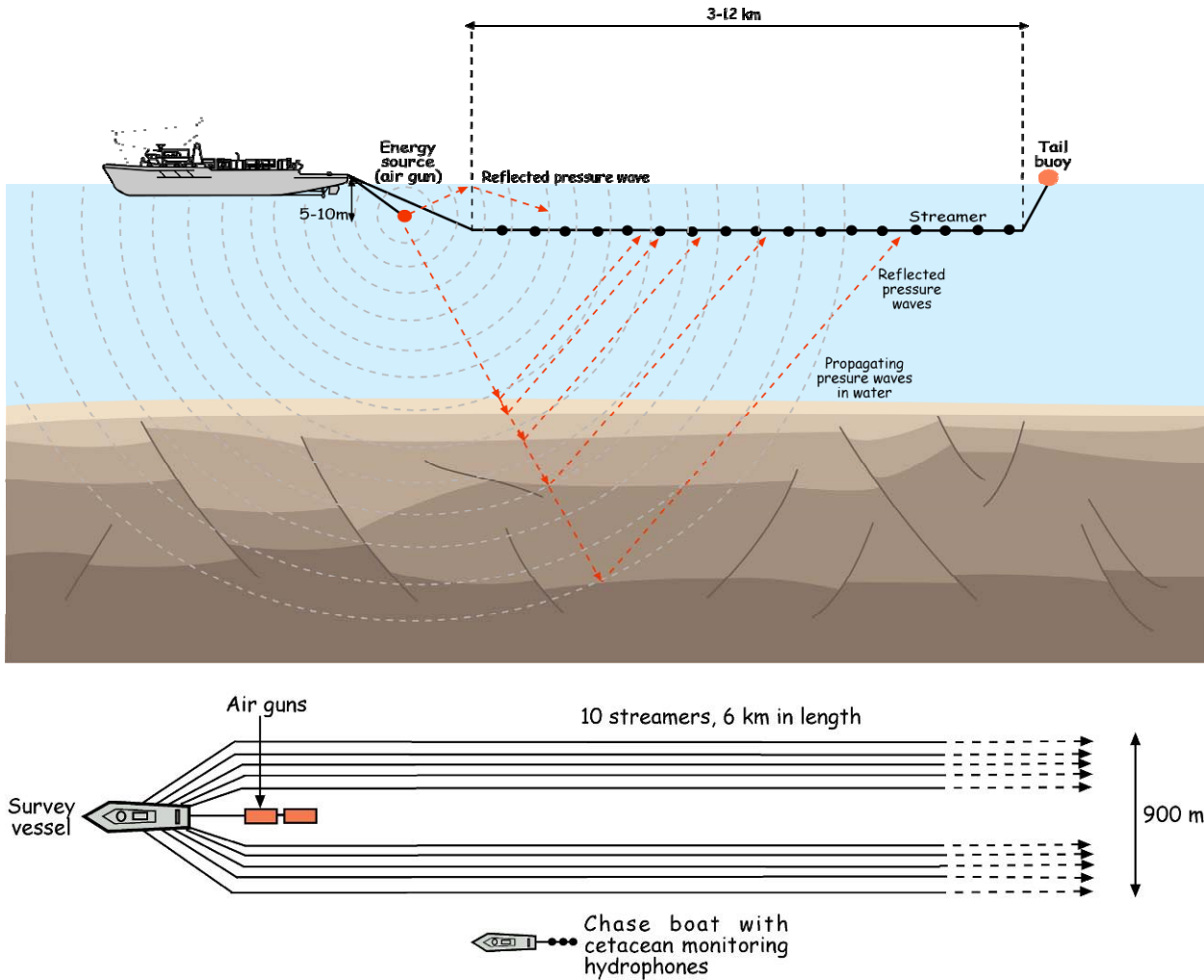
In 2D seismic surveys, one streamer with a length of 3 to 12 km is used (Figure 4.1). In 3D seismic surveys, many parallel traverses must be carried out, and it is therefore more efficient to collect swathes of data by towing six to twelve streamers, each separated by approximately 100 m from its neighbours (Figure 4.1). Ensuring that a large number of streamers remain straight and parallel to each other is difficult and 3D survey vessels rarely tow streamers that are longer than 3 km.

Normally, a seismic survey vessel travels at approximately 4.5 to 5.5 knots, or around 10 km/hour (Turnpenny & Nedwell, 1994).

Thick basalt formations have been found north of the IOSEA3 area in the UK west of Shetland province. Basalt structures tend to be opaque to traditional surface-towed seismic arrays, and if basalt layers are likely to be encountered, a different survey system making use of multiple geophones and hydrophones arranged along cables deployed on the seabed. These benthic arrays are either towed along behind the vessel (dragged array), or lifted and replaced in a new location as the survey progresses. Such surveys normally involve two vessels, one attached to and processing the data from the sensors, and one from which the source is deployed. Multi-component systems are considered to be better at penetrating basalt structures which are opaque to traditional towed seismic survey techniques. However, although basalt bodies are found in the IOSEA3 area, this method of hydrophone deployment is presently uncommon in deep water and is not usually used in initial seismic surveys.



Figure 4.1 Typical seismic survey set-up



Seismic scenario assumptions

The seismic survey effort estimated by the DCENR (Table 4.1) for the IOSEA3 area amounts to a likely maximum of 49,000 km of 2D and 28,000 km² of 3D survey. As all previously held licences in the area have been relinquished, there are no pre-existing forecasted activities to be acknowledged in the scenario assumptions. In terms of ship time at sea this amounts to approximately 1,960 days vessel time for 2D seismic over the period 2010 to 2016, and 933 days vessel time for 3D seismic over the period 2008 to 2014 (based on the experience of the DCENR and ERT).

For the purposes of impact assessment for shipping activity and fuel use in later report sections, this amounts to 2,893 days ship time over 7 years (including weather downtime and other delays), or approximately 413 days per year on average. Due to operators clubbing together or ‘piggybacking’ surveys together in order to achieve economies in vessel hire and concerns over noise contamination, it is assumed that seismic activity will be restricted to one or two vessels working over the IOSEA3 area during the summer months each year (DCENR, pers comm). In the absence of fuel consumption data specific to seismic survey vessels, a figure of 15 tonnes diesel per day has been used, which is roughly midway between that for a large tug or anchor handling vessel (ERT, unpublished information). This information is summarised in Table 4.2.

Table 4.2 Seismic survey vessel activity and fuel use in the IOSEA3 area from Rockall Basin licensing round between 2010 and 2016

Time span of activity	Coverage	Ship time (days)*	Fuel use at 15 tonnes/day
2D 2010 to 2016	49,000 km	~1,960	29,400
3D 2010 to 2016	28,000 km ²	~933	13,995
Total		~2,893 days over 7 years, or ~413 days/year	43,395 tonnes or ~6,200 tonnes/year

* Based on survey rate of 25 km/day for 2D and 30 km²/day for 3D (including weather downtime and other delays).

NB: The distances cited in the above table do not include the turning circle of the survey vessel at the end of each transect; airguns continue to fire during turns

4.4.2 Exploration drilling

The location of the IOSEA3 area requires specialised drilling equipment able to cope with the deep water and harsh weather conditions of the Atlantic Ocean. The two main options available for drilling operations under these circumstances are a semi-submersible drilling rig or a drill ship. As water depths in the IOSEA3 area are generally deeper than 200 m, not even the new ‘ultraharsh-environment jack-up rigs’ can be deployed in the area.

Semi-submersible drilling rig

A semi-submersible drilling rig, or semi-sub (Figure 4.2), is a drilling unit which is usually supported on two parallel submersible hulls that are streamlined like a ship. The hulls carry columns extending above the sea surface which between them support the main deck, superstructure and drilling rig.

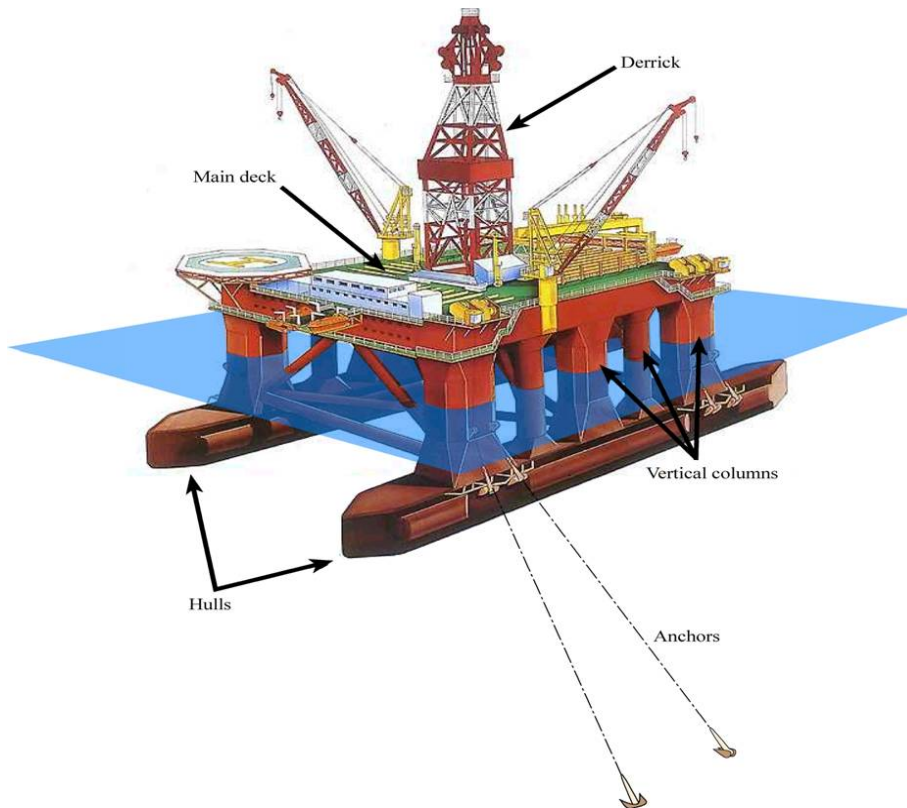
When the lower hulls are flooded they provide ballast to cause the rig to partially submerge. In this half submerged state, the rig becomes a stable work platform and is far less susceptible to wave motion, particularly rolling and pitching, than when de-ballasted and floating on the sea surface.

It is often the case that a semi-sub will have eight to twelve anchor lines set at various points around the rig to keep it in position (known as a moored semi-sub). In deeper water the anchor spread radius might extend to a few kilometres from the drilling location, with a couple of hundred metres of anchor chain resting on the sea bed. Additionally, the rig carries several thrusters (or propulsion units) as part of a dynamic positioning (DP) system. Controlled by a computer that determines the exact position of the drilling rig relative to the well, the thrusters are automatically actuated as necessary to maintain the rig precisely on station. In very deep waters, it is generally necessary to utilise a semi-sub which is controlled solely by DP, without the use of anchors.

Although this kind of drilling rig is usually capable of self propulsion, they are often towed into position. Once in place, anchor handling vessels (usually the same vessels as the tugs) place the anchors in position in order to secure the rig at the exact drilling location.



Figure 4.2 A typical semi-submersible drilling rig



Drill ship

Modern drill ships are purpose-built, featuring all the equipment normally found on board any conventional drilling rig. The main advantage of a drill ship over some semi-submersible platforms is that it can sail to and from the drilling location unassisted. Generally, modern drill ships are equipped with a DP system to maintain the vessel's position over the well site and therefore they do not depend on anchors to keep them in position.

Drilling operations

Typically the first step in the sequence of drilling activities is to drill a top hole section into the sea bed into which the conductor pipe is cemented, following which the well is drilled in successively smaller diameter sections until the hydrocarbon-bearing formation is reached. Once each well section is drilled, steel casing of appropriate diameter is inserted and cemented into place in order to provide stability and a barrier between the wellbore and surrounding formations. In addition the casing provides a firm anchorage for the blow out preventer (BOP) stack and structural integrity for subsequent drilling, testing and possible future production operations. Once the BOP is in place the marine riser, a large-diameter pipe that connects the BOP stack to the drilling rig, is installed.

The use of drilling fluid, also known as drilling mud, is intrinsic to all drilling operations. Drilling mud assists in a number of functions such as lubrication and cooling of the drilling bit, suspension and transport of rock cuttings to the surface and, most importantly, the provision of hydrostatic pressure to counterbalance formation pressure. Drilling mud consists of a liquid mixture of clay, water or oil, and other chemical additives. The most commonly used drilling fluids contain water as the fluid continuous phase, and are known as water-base muds (WBMs). However, certain borehole conditions might require a mud formulation where the continuous phase is oil or a synthetic fluid and these are known as oil-base muds (OBMs) or synthetic base muds (SBMs).

The mud is pumped down the drill stem to the drill bit, and then circulated back to the surface via the annulus (the space between the drill stem and the wall of the bore hole) and through the BOP stack and the marine riser back to the drilling rig or ship. Back onboard, these muds and cuttings pass through a mud recovery system where part of the drilling mud is recovered. Once reconditioned, this mud is often used again. However, the cuttings must be disposed of, together with any adhering mud and chemicals not removed by the cleaning system, and for this process three main alternatives are on offer:

- Overboard discharge.
- 'Skip-and-ship' ie to send the cuttings back to a shore facility for cleaning and landfill.
- Cuttings re-injection.

When using WBM the rock cuttings, and any mud remaining at the end of drilling, are usually discharged to the sea. Under the OSPAR Decision 2000/3 the discharge into the sea of cuttings contaminated with oil-base fluids at a concentration greater than 1% by weight on dry cuttings is prohibited. This option is therefore not available for oil-contaminated cuttings unless they can be cleaned offshore to meet these requirements. Although certain pilot projects are currently running in the North Sea, this option is not yet considered to be achievable in general industry practice. A more common approach for oil-contaminated cuttings is to ship them to shore where they can be cleaned and re-cycled as, for example, road aggregate, or put into landfill. Cuttings re-injection (CRI) is another disposal option, useful for contaminated cuttings, where drill cuttings are mixed into a slurry with water and pumped at high pressure down a separate injection well. CRI is slowly becoming more widespread in mature oil development areas where there are enough potential injection wells available.

The top hole section of the well has to be drilled without the conductor and BOP in place, and thus with no riser from the seabed to the drilling platform. This means that all drilling fluids, rock cuttings, and cement returns from the top section are discharged directly from the top of the well onto the sea bed. Once the marine riser is in place, the drill fluids and cuttings can be circulated from the well back up to the drilling rig where they will be treated so that the drilling mud can be re-used and the cuttings disposed off appropriately as described above.

Cementing operations

The steel casings that are run into each of the well sections will be cemented into place. When setting the conductor it is normal practice to use a certain amount of excess cement. To minimise the amount of cement being discharged it is considered good practice to have a remotely operated vehicle (ROV) present at the wellhead to observe the cement returns.

Excess cement from the deeper sections is circulated back to the drilling rig or ship through the marine riser, and treated in the same way as the cuttings (ie cleaned and discharged overboard).

Well testing

If hydrocarbons are found, a well test may be required to establish the well performance and well characteristics.

The most conventional well test method involves flowing or producing the reservoir fluids, up to the drilling unit, where they are flared off. Whilst producing the well at different flow rates, a comprehensive evaluation of the well and certain reservoir characteristics can be made which will help in evaluating whether the reservoir could be exploited commercially in the future.

Alternatively a closed chamber well test can be carried out under certain circumstances. During a closed chamber well test, the well bore itself is used to store the produced fluids whilst pressure build-up in the well bore and flow are measured downhole. After the test the oil sample of approximately 20 to 30 barrels of oil is circulated to the surface, collected into containers/tote tanks and shipped to shore for analysis and disposal of interfaces. Although not as comprehensive as a conventional well test, the data obtained, combined with log and seismic data can, in some cases, provide sufficient information to decide if any future development of the well would be viable.

Well abandonment/suspension

Depending on operational issues and the hydrocarbon reserves found, an exploration well can either be abandoned or suspended.



In case of abandonment, mechanical and cement plugs are placed along the well, plugging off all points where hydrocarbons can possibly enter the wellbore. The casing will then be mechanically cut and recovered from below the seabed.

If further development of the well in the near future might be an option, then the well may be suspended. If this is the case, the well will be left intact and a series of mechanical and/or cement plugs will be placed inside the well to prevent the escape of hydrocarbons. The conductor and casings will be sealed and left protruding approximately 1.8 m (6 ft) above the seabed.

Drilling scenario assumptions

Under the maximum drilling activity scenario in Table 4.1, a maximum of 25 wells may be drilled over the period 2010 to 2016 (0 to 15 exploration wells, 0 to 4 appraisal wells, 0 to 6 development wells). At the maximum anticipated rate over the period 2010 to 2016, with no pre-existing drilling activity, this would average out between three and four wells per year.

It is not possible to state unequivocally the distribution of hydrocarbon types within the IOSEA3 area. Evidence of oil (from seabed coring) and gas (from seismic data) has been recorded from sites throughout the Rockall Basin (PAD, 2006b). The majority of gas chimneys have been recorded from the northeast part of the licensing area. The Doosh gas condensate discovery is also situated on the northeast margin of the Rockall Basin.

For the purposes of impact assessment for drilling activities, certain assumptions will need to be made such as the length of time taken to drill a well, the fuel used by the drill rig and associated shipping and the likelihood of a well test being needed. These assumptions are made on a conservative basis, and are summarised in Table 4.3.

Table 4.3 Estimated fuel use and time span of drilling/associated activities per well (source: ERT unpublished data)

Vessel type	Time span (days)	Fuel consumption	Fuel used (tonnes)
Drilling rig (semi-sub type)	50	20 tonnes/day	1,000
Large tug	14	25 tonnes/day	350
Anchor handlers	4	25 tonnes/day	100
Standby/safety vessel	50	3 tonnes/day	150
Supply vessel	21	8 tonnes/day	168
Helicopter	9 h/week for 7 weeks	1,050 lbs/hr	30
Well test (required for 50% of wells drilled)	2	-	2 million m ³ per well

If hydrocarbons are found (including finds that turn out to be small non-commercial quantities), then a well test may be required to evaluate the potential reserves which will involve producing the hydrocarbon concerned to the surface over a period of 48 hours. In the absence of any production facilities, the produced hydrocarbon will have to be flared off. The quantity flared in this way is typically in the region of 2 million m³. However, since the scenario for the Draft Plan includes provision for appraisal and some development drilling, an overall well testing rate of 50% will be assumed, leading to 1 - 2 well tests per year based on all. It will also be assumed that the unsuccessful wells will be suspended rather than abandoned.

Again, if hydrocarbons are found, a vertical seismic profile (VSP) or checkshot survey may be carried out in order to obtain more detailed data on the formation structure. Such surveys use airguns to emit loud acoustic pulses, and hydrophones to detect the reflected sounds. The airguns used are smaller and fewer in number than those used in 2D or 3D seismic survey, but are otherwise similar. The hydrophones can be placed at various locations (including inside the wellbore or on the seabed) depending on the information that is required. The airguns may be deployed from the drilling unit or from a small survey vessel, and are fired periodically. The blast emitted from the gun is designed so that it directs most of its energy in the vertical plane to prevent noise loss into the surrounding waters. The guns fire at very close intervals so that the pulses generated cancel out the reverberation that follows the initial blast. The number of sound blasts required varies from survey to survey, depending on how much information is required, but surveys would typically be complete within 1 day. On the basis of the assumptions above for well testing, up to 2 VSP/checkshot surveys per year may be expected.