- the energy advisor

Preparations for awarding licences for exploration and production of hydrocarbons

Project G-1
Basic premises, possible development paths and scenarios

Iceland
Ministry of Industry

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Summary

This report has been prepared by Sagex AS as part of the Icelandic authorities' preparations for awarding licences for exploration and production of hydrocarbons. The report addresses basic premises, possible development paths and scenarios for exploitation of hydrocarbons within the 200 nm Exclusive Economic Zone at the Jan Mayen Ridge north-east of Iceland.

The development will be in an artic deep water environmentally sensitive frontier area with harsh environmental conditions that will challenge the use of technology and operational performance.

There are no technology stoppers for developing the Jan Mayen Ridge Area. Proven and cost effective technologies are presently available and may be further improved before developments offshore Iceland will be realised.

Exploitation of both oil and gas appears possible and to be commercially attractive, indicating a strong incentive to explore the Jan Mayen Ridge. The limit size for possible economic exploitation of an oil field is in the region of 10-20 million standard m^3 of oil.

Care must be taken to clarify all issues of an environmental nature prior to any offshore petroleum related activities.

The initial exploration activities can be served from existing infrastructure in the north-eastern part of Iceland without specific incentives.

This study has addressed the question of technical viability, and is neutral with regards to any possibility of petroleum discoveries in the area.

1 Introduction

1.1 Aim and Purpose

The authorities in Iceland are in the process of developing the required legal and regulatory framework including licence terms for exploration and production of potential hydrocarbon resources in the Jan Mayen area within the 200 nautical miles Exclusive Economic Zone northeast of Iceland.

The purpose of this study is to make available in a systematic fashion, background information and ideas about how exploration and production of oil or gas could be developed in the coming years.

1.2 Background

The ongoing preparations for the awarding of licences for exploration and production of oil and gas in the Jan Mayen Ridge should be based on sensible premises and assumptions regarding possible hydrocarbon resources, their potential value and the technology likely to be used in exploration drilling, field development and production.

Insight into these aspects is required to be able to assess the potential economic impact of opening the Jan Mayen Ridge area for exploration and production and make the right decisions on the kind of fiscal regime, financial licence terms, and health, safety and environmental standards to apply.

Because of the uncertainty about the existence of exploitable hydrocarbons in the area, the best way to approach this is to make informed guesses about the nature, scope and development of the exploration and production activity on the basis of different assumptions about the timing and size of discoveries covering the range from failure to success.

Although the petroleum exploration frameworks in Icelandic neighbouring countries such as the Faroes, Greenland and Ireland, in many respects are relevant for Iceland, the Norwegian experience has been used as the basic references for this study. In particular, Norwegian waters in the Norwegian Sea and Barents Sea area provide many relevant examples of field development and production conditions similar to those expected in the Jan Mayen area (geology, water depths, weather, ice conditions and waves). The Faroes and Greenland are still in the early exploration stage and have little to contribute with respect to field development and production operations.

2 Basic Area Conditions

2.1 Location of potential exploration area

The area of the Jan Mayen Ridge within the 200 nm Exclusive Economic Zone northeast of Iceland is from regional geological considerations seen as most interesting from an oil exploration point of view. The area was selected by Sagex as suitable for a seismic survey in 2001, shortly following the approval in Althingi of the Petroleum Bill. The seismic program was designed in close cooperation with Icelandic energy authorities. The survey was partly financed by GeysirPetroleum hf and acquired by the Norwegian geophysical company InSeis AS. Subsequently, GeysirPetroleum commissioned a non-exclusive interpretation of the seismic data. The results are documented in the report “Seismic interpretation and mapping-Jan Mayen 2D interpretation project - 2004” submitted to the Icelandic energy authorities (Orkustofnun) in 2005.

The map in figure 2.1 shows the outline of the area relative to the Icelandic north-eastern coastline and the 200 nm Exclusive Economic Zone. The area outlined in red in the north-eastern corner of the map is the area referred to as the Cooperation Area in the 1981 continental shelf agreement between Iceland and Norway.

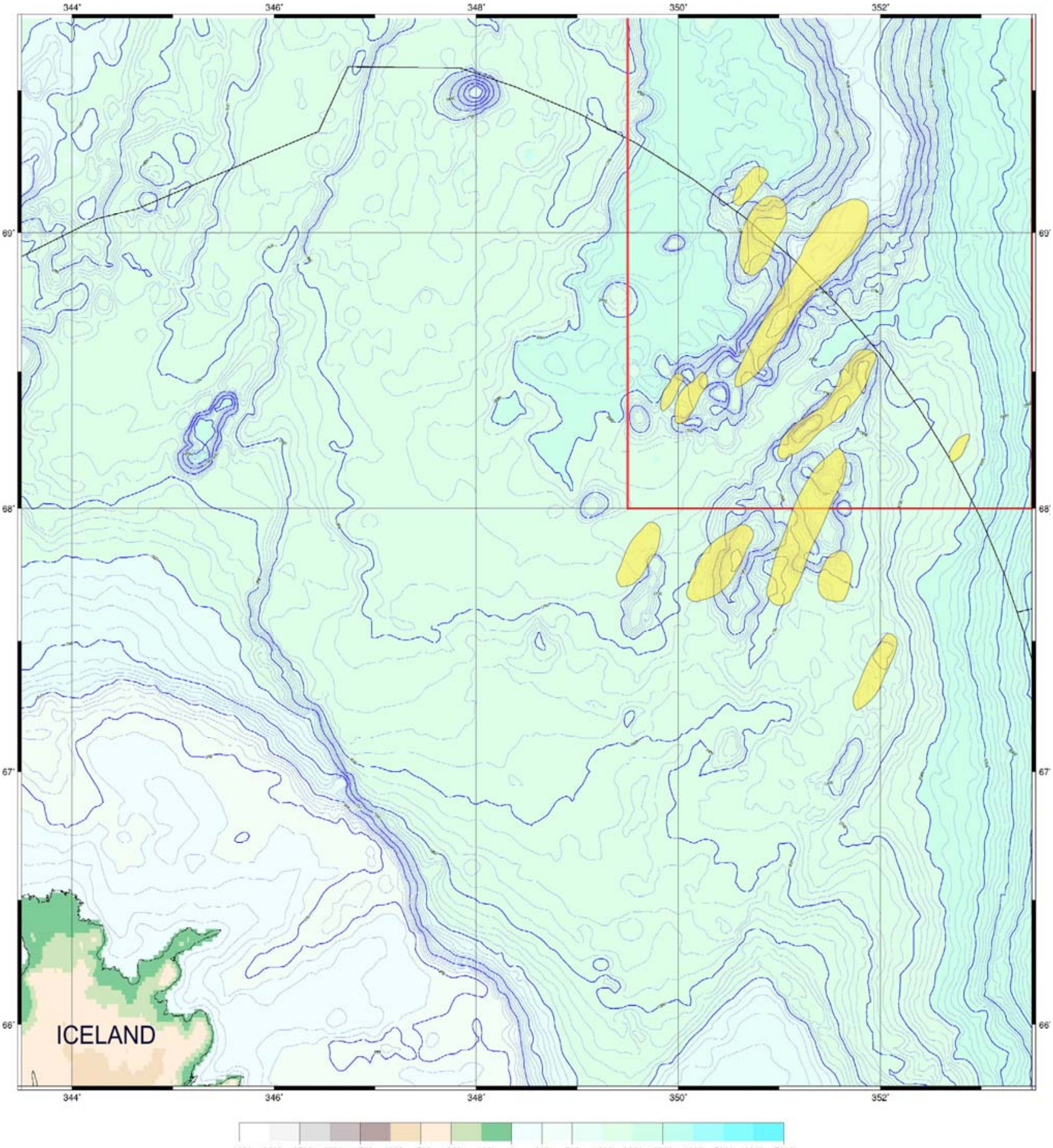

Figure 2.1 Bathymetric map of the north-eastern Icelandic waters.

The water depth in the area is in the range of 1000 m to 1500 m. Potential hydrocarbon prospects are indicated in yellow.

2.2 Potential prospects in the study area

Evaluation of the petroleum potential of the Jan Mayen Ridge is in an early stage, based on limited amounts of seismic data and geological analogues with other better know areas. However, the interpretation of the seismic data has identified basins with sediment thickness up to 8km and structural highs capable of acting as hydrocarbon traps. The crucial elements such as source rock, reservoir rock and seal rock as well as generation, migration and accumulation of hydrocarbons, see figure 2.2, are likely to be present.

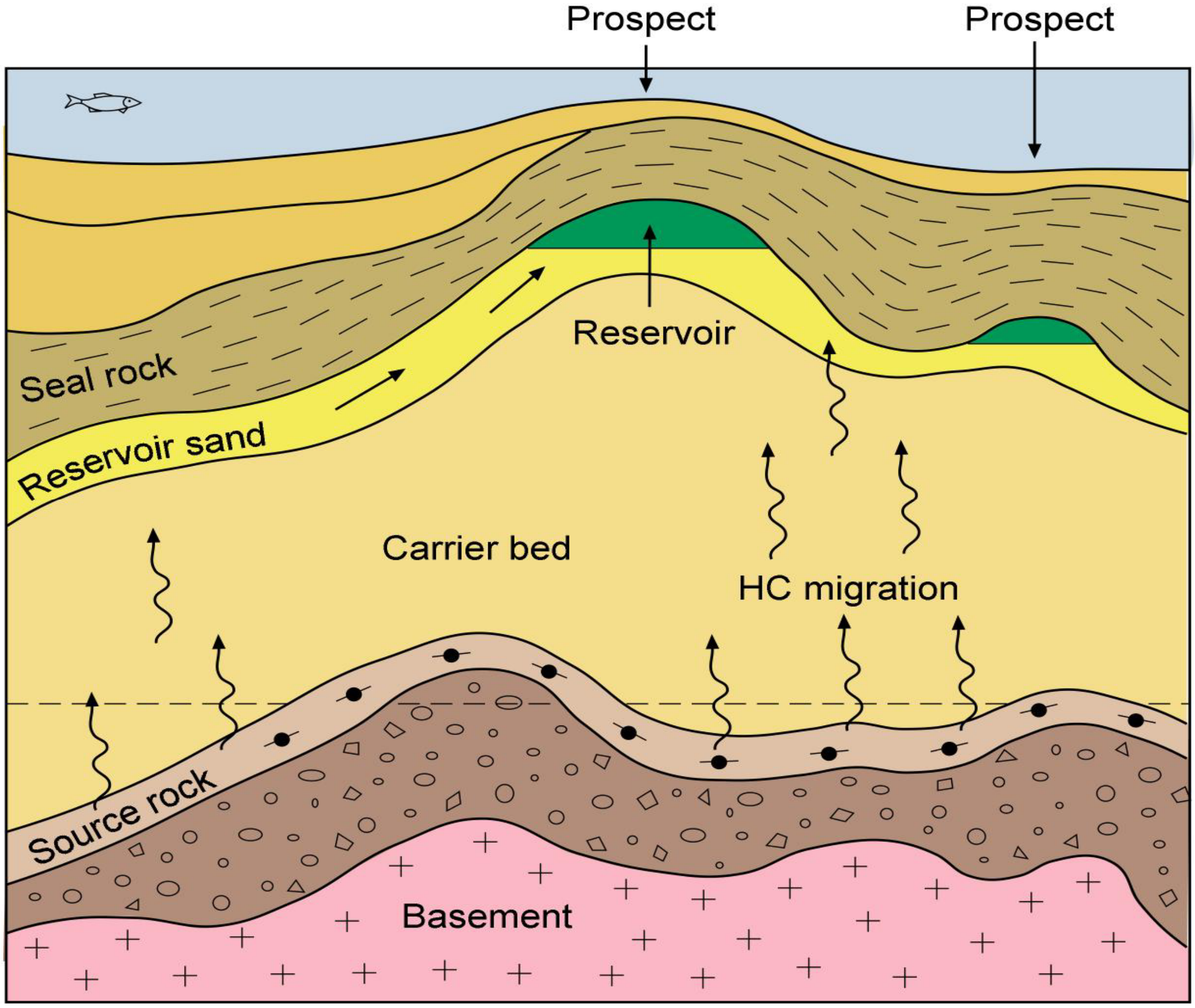

Figure 2.2: Petroleum system illustration, showing the essential elements needed for a petroleum system to generate, migrate and accumulate hydrocarbons in the subsurface.

Several prospective structural closures have been identified as potential prospects; reference is made to figure 2.3. The area extent of the closures is an estimate and will be adjusted by further interpretation and investigation of the study area.

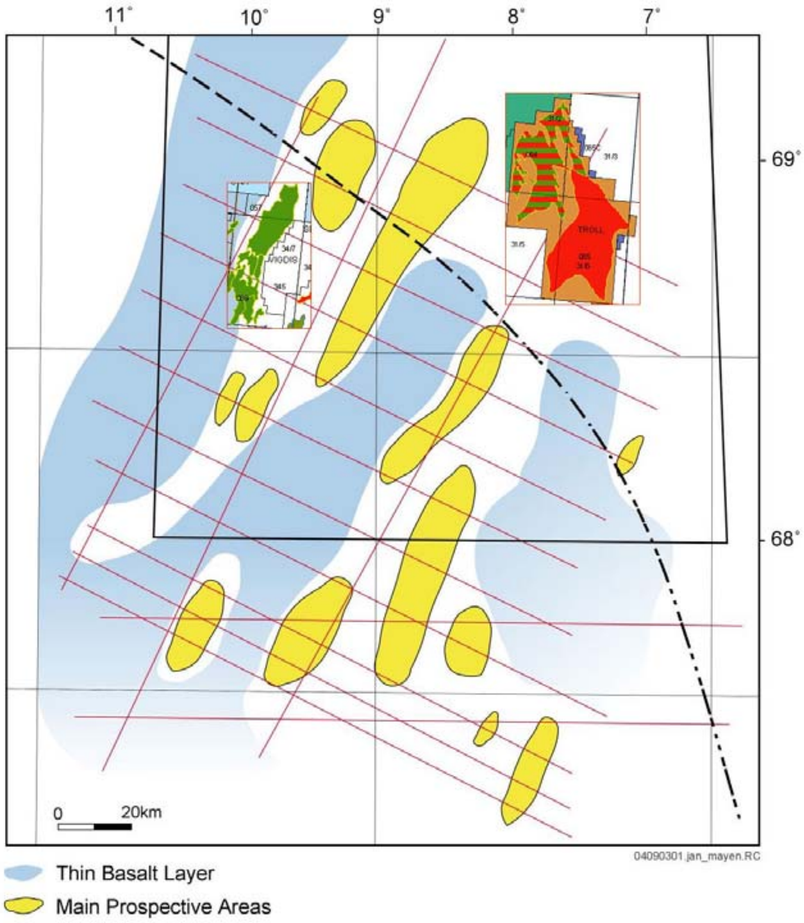

Figure 2.3 Seismically identified prospects. The red lines are the seismic lines from the 2001-2002 seismic survey.

For reference purpose the Norwegian Snorre oil field (green) and the Troll gas field (red) are superimposed on the map in figure 2.3. The Snorre field contained originally 242 million standard m^3 (MSm^3) of oil and 6.4 billion standard m^3 (GSm^3) of gas and the Troll field contained originally 233 MSm^3 of oil and 1318 GSm^3 of gas.

The average depth from the seabed to the potential reservoirs is in the range 3000 m to 3500 m.

2.3 Physical Oceanography

2.3.1 Bathymetry

The Iceland Plateau is the westerly boundary of the deep Norwegian Basin (3200m-3600m) bounded by the Norwegian Continental Slope and the Vøring Plateau to the east. The Iceland Plateau is a broad flat-floored platform between Iceland and Jan Mayen Island. The western boundary of the plateau is the Kolbeinsey Ridge, and the eastern margin drop off into the Norwegian Basin. Depths across the plateau generally range from1800m to 2000m. Associated with the Iceland Plateau is a large linear ridge (The Jan Mayen Ridge). The Jan Mayen Ridge is 275 km long and up to 110 km wide, and strikes in a nearly north-south direction. The southern part of the Jan Mayen Ridge is located within the Iceland's 200 nm Exclusive Economic Zone and is contained by the 1000 m – 1500m contours.

Reference is made to figure 2.1 for a bathymetric map of the study area north-east of Iceland.

2.3.2 Currents

The East Greenland Current is the major outlet of water from the Arctic. It flows southward mainly within 40nm off the Greenland coast.

The Jan Mayen Current branches from the East Greenland Current at about 76^0 N, travels south-easterly and passes north of Jan Mayen to join a large permanent counter-clockwise eddy in the Greenland Sea.

The East Iceland Current branches off from the East Greenland Current at about 70^0 N and flows toward northeast Iceland where it divides, part travelling southward and part travelling eastward. The east flowing branch forms the periphery of the counter clockwise eddy between Jan Mayen and Iceland. The current is weak, generally less than 0.2 kts.

2.3.3 Oceanographic fronts

The mixing of Atlantic water north into the Nordic Seas is of great importance climatologically as it the saline water that, by the process of intense winter cooling, sinks to form the dense water that is eventually recycled back over the Greenland-Iceland-Norway ridges into the Atlantic.

The South East Iceland Front is the boundary between the warm North Atlantic Current and the East Iceland Current. The median position lies at approximately 64^0 deg N across the East Iceland shelf, then north-easterly over the slope. The position is subject to both long and short term displacements; 50 nm in a 10 day period and 100nm in a season are not uncommon.

2.3.4 Waves

Larger waves occur to the south of Iceland. In an average year, 80% exceeds 1.5 m and 30% exceeds 3.7 m and during winter 10% exceeds 6 m. The frequency of moderate to high waves decreases northward and eastward to much calmer waters northwards and eastwards of Iceland. Here waves exceeding 6 m have an annual frequency of less than 1% and are exceptional occurrences from May to August. The highest waves occur between November and March.

During periods of intense cyclonic activities off Iceland the swell advances from between the south and southwest. Strong northerly winds west of Jan Mayen generate a long north-easterly swell along the northwest Iceland coast. If this occurs simultaneously with the southerly swell through the Denmark Strait, the resulting cross swell produces difficult ship conditions. It is uncertain whether such conditions can occur in the potential hydrocarbon exploration area.

On the Vøring area in the Norwegian Sea the 100 year significant wave is 16.5 m.

2.3.5 Sea Ice

The maximum limit of sea ice goes along an east-west line off the north coast of Iceland approximately at latitude 69^0 N, and turns north-east at approximately 15^0 W. The potential petroleum exploration area is outside the boundary for the maximum limit of sea ice. Reference is made to figure 2.4. Drift ice may occur in the exploration area. Design against drift ice is no problem and has very small cost effects.

Figure 2.4: Major Pattern of Ice Circulation. Source: Arctic Monitoring and Assessment Programme (AMAP)

2.4 Meteorology

2.4.1 Wind

The large-scale air circulation over the North Atlantic is determined by the Icelandic low pressure area and the high pressure areas over Greenland and the Central Arctic Basin. The prevailing winds are westerly or south-westerly between Iceland and Scandinavia, transporting warm and humid air from lower altitudes towards the Arctic.

Depressions are most frequent to the south and west of Iceland. Two main tracks dominate, one running north of and the other running south of Iceland. Few depressions pass directly over Iceland.

Winds, or more precisely differences in air pressure which causes winds, are often closely related to ocean circulation. The anti-clockwise ocean current between Iceland and Jan Mayen may have an effect on the wind.

The prevailing wind direction at the Det Norske Meteorologiske Institutt (DNMI) Jan Mayen weather station at 70^0 56' N 8^0 40' W is north-westerly between 315^0 and 345^0. The cumulative and relative wind velocity is given in table 2.1. For reference to the Norwegian Continental Shelf, the wind velocity at Sula is also given in the table. It is generally stronger winds in the Norwegian Sea off west coast of Norway compared with the meteorological station at Jan Mayen. Sula is a meteorological station at the Møre –Trøndelag coast (Haltenbanken area)

Wind velocity (BEAFORT scale)	Description	Wind Frequency			
		Jan Mayen 70 56.00 N 8 40.00 W		Sula 63 50.80 N 8.28.00 E	
		Cumulative	Relative	Cumulative	Relative
	Calm		2.21		1.69
1	Light Air	8.30	6.10	4.73	3.04
2	Light Breeze	17.24	8.94	14.32	9.52
3	Gentle Breeze	29.89	12.64	32.09	17.78
4	Moderate Breeze	52.24	22.36	54.94	22.84
5	Fresh Breeze	70.56	18.32	69.33	14.40
6	Strong Breeze	86.44	15.88	80.90	11.56
7	Near Gale	95.57	9.13	89.58	8.68
8	Gale	99.09	3.52	96.18	6.60
9	Strong Gale	99.84	0.75	98.52	2.34
10	Storm	100.0	0.16	99.69	1.17
11	Violent Storm			99.97	0.29
12	Hurricane			100.0	0.03

Table 2.1: Wind velocity at weather stations at Jan Mayen and at Sula at the Norwegian west coast (Haltenbanken area) in the 10 year period December 1987 – January 1998

2.4.2 Fog and visibility

The main cause of poor visibility is fog resulting from the flow of warm moist air over a cold surface sea.

In summer, fog is common and persistent with south-westerly winds. Around Jan Mayen, during summer, fog may last for several weeks. The ice edge is particularly foggy. In winter, fog is much less frequent and occurs mainly over the strip of cold water along the ice edge with southerly and south-westerly winds. Fog may affect the helicopter operations, but will not affect the work at the site.

2.4.3 Ice accumulation

Ice accumulation is most likely to occur between December and April. However it can occur at any time of the year to the north and west of Iceland with winds blowing from between north and east. Ice accumulation may also occur with freezing fog, freezing drizzle and rain.

2.4.4 Comparison of physical environmental conditions with other areas

The wind, waves and currents at the Jan Mayen Ridge area are generally less severe than in the Norwegian sector.

Table 2.2 shows a comparison of conditions at the Jan Mayen Ridge area with prevailing conditions in some other relevant petroleum development regions. Comparison has been made to the Norwegian Sea area and the Barents Sea area of the Norwegian Continental Shelf. These are the areas which are considered to be relative close to the Jan Mayen Ridge area and with relevant available data on hydrocarbon exploitation activities.

Conditions	Comparison with other areas/regions
Water depth	• Jan Mayen Ridge area: 1,000 – 1,500 m • Norwegian Sea, Ormen Lange subsea (under development): 1,000 m • Gulf of Mexico, Na Kika platform: 1,920 m
Weather	• Wind, waves and currents at Jan Mayen Ridge area are generally less severe than in the Norwegian sector (Norwegian Sea) • Fog may be more of a problem at Jan Mayen Ridge and offshore North-East Iceland than in the Norwegian Sea
Sea ice	• Jan Mayen Ridge expected to be comparable to the Norwegian sector of the Barents Sea; both areas are outside the normal maximum limit of sea ice • Shtokman field, Barents Sea, Russian sector (scheduled for development in 2010), will be more exposed to sea ice than the Jan Mayen Ridge area

Table 2.2 : Brief comparison of environmental conditions.

Relevant hydrocarbon exploitation areas in the arctic region are shown in figure 2.5

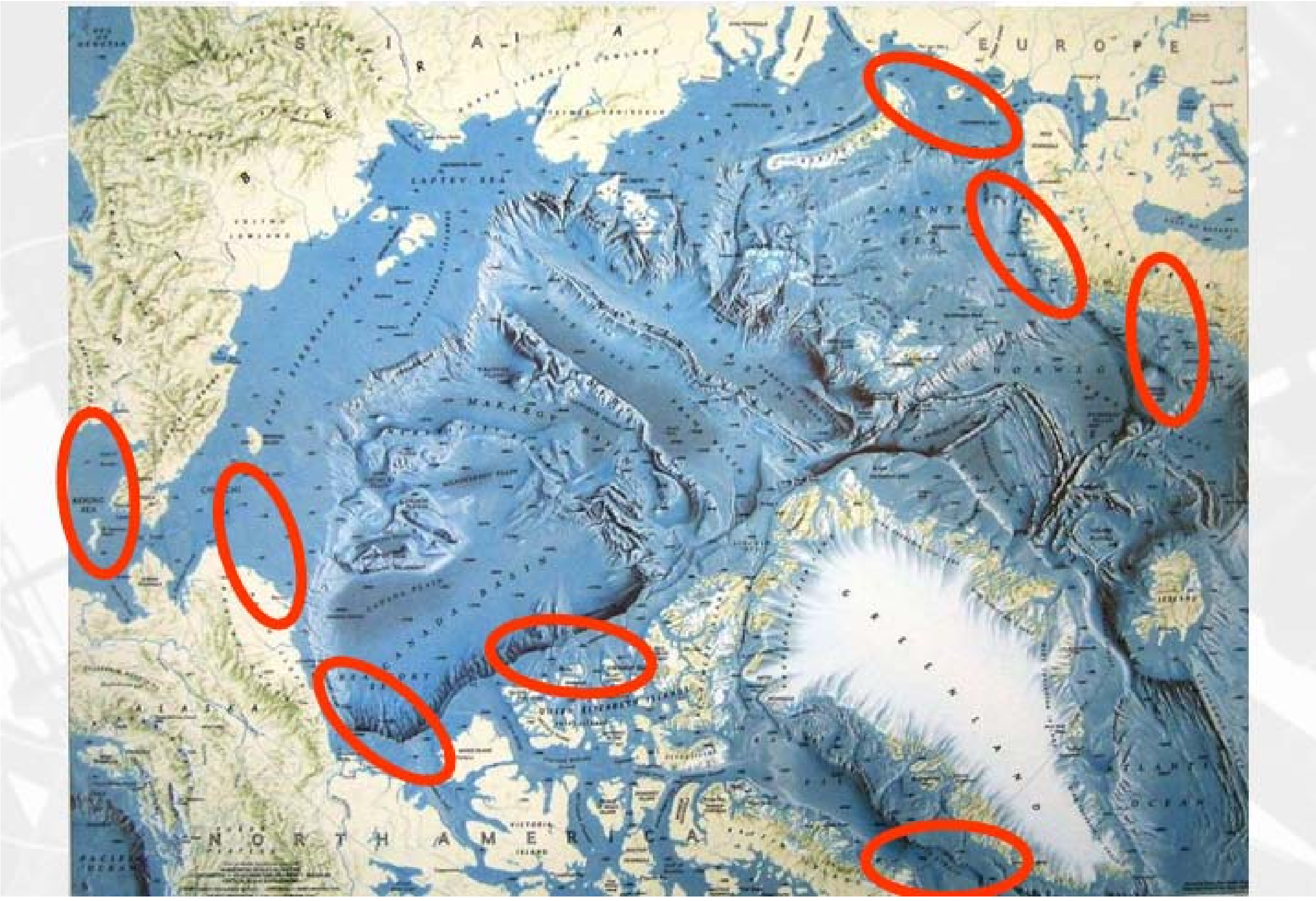

Figure 2.5 The Arctic Region with current petroleum exploration areas encircled in red

Some oil companies operating in the arctic region are in the process of establishing a common data-base including environmental conditions. Reference is made to figure 2.6 for an overview of the initiative.

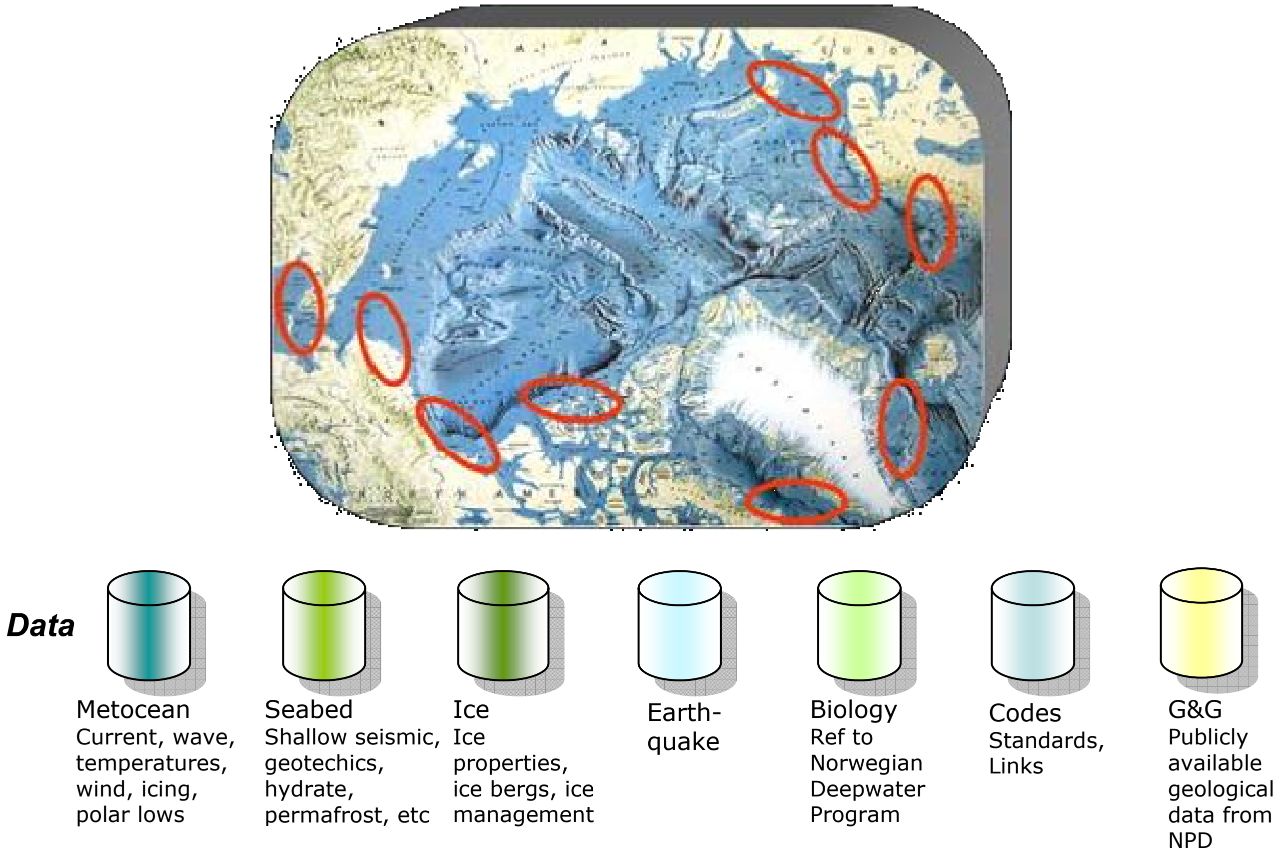

Figure 2.6 Arctic Environmental Data Collaboration Initiative

3 Basic Premises for Exploration and Field Development

3.1 Environmental Impact Assessment

To ensure that the environmental aspects are adequately considered prior to opening new areas, an Environmental Impact Assessment should be performed.

In the European Union a Directive called the Strategic Environmental Assessment (SEA) Directive sets requirements to Environmental Assessments of plans, programmes and policies that may have impact on the community at large. Opening of petroleum exploration activities in Icelandic waters are considered to be activities that requires an Environmental Assessment according to the SEA Directive

As an EEA member, Iceland has to implement the SEA Directive. The purpose of the directive is to ensure that environmental consequences of certain projects are identified and assessed during their preparation and before their adoption. The intervention in the natural surroundings including those involving extraction of mineral resources are projects identified in the Directive. The public and environmental authorities can give their opinion and all results are integrated and taken into account in the course of the planning procedure. After the adoption of the plan or programme the public is informed about the decision and the way in which it was made. In the case of likely transboundary significant effects the affected state and its public are informed and have the possibility to make comments which are also integrated into the national decision making process.

A Strategic Environmental Assessment may take up to two years from the start of the planning to the final approval in the Parliament. The process involves the following main steps;

- Preparation and approval of the SEA programme
- Investigations in the field and review of relevant reports
- The process in the Parliament

3.2 Onshore Infrastructure

3.2.1 Supply services for drilling operations

A drilling rig needs supply for drilling operations like:

- drill pipe
- tubulars
- cement,
- chemicals and other constituents for mixing of mud
- personnel for the rig-operations (Normal rig-crew is 60-80 persons)

- consumables for the personnel
- fuel
- spare parts

Onshore-services will include delivery of consumables, transport services and labour.

In addition oil spill contingency equipment is needed.

The needs during exploration drilling operations are normally served through supply services located at an existing harbour and helicopter-operations based at an existing airport.

A drilling rig operation is normally served by a supply vessel every second day and a helicopter every third day.

Countries generally stipulate that the transport of goods and services for hydrocarbon exploitation shall take place directly from the host country. Such stipulations do not violate EU-regulations related to open competitions as long as all competitors, both foreigners and domestic, are treated equally in Iceland.

Emergency preparedness has to be adapted to operations of drilling rigs. Helicopter bases as close as possible to the offshore operations are essential in the emergency preparedness of the respective areas. It is not likely that the supply service operators will choose other shore bases than in Iceland due to the long transport distance from other countries i.e The Faroes, Ireland, Scotland or Norway.

3.2.2 Helicopter operations

Sagex has reviewed helicopter operations north-east of Iceland with CHC Helicopters, a major international operator serving the offshore industry in Norway.

The European regulations for helicopter operations, JAR-OPS-3, are requirements that the helicopter operators must comply with for operations in all European countries. In Norway these regulations has been issued as BSL (Bestemmelser for Sivil Luftfart) requirements governing offshore as well as onshore operations.

Onshore helicopter base

There is a requirement to a minimum runway of 400 m for take-off. The onshore base must have infrastructure such as:

- Jet-fuel
- Maintenance facilities
- Storage for spare-parts
- Hangars
- General ground facilities (check-in, security control etc)

For logistical purposes it is recommended that the base is established as part of a regional airport in north-east Iceland. This will facilitate transportation of the passengers to and from the helicopter base.

Helicopters

The distance from potential regional airports in north-east Iceland to the exploration drilling rig operating within the 200 nm zone set requirement to the needed helicopter performance.

The distance from the regional airport in Eigilsstadir is approx. 225 nm and from Husavik 255 nm. There is a requirement that the helicopter shall carry sufficient fuel for the return to shore in case it is impossible to land on the rig due to adverse weather conditions and it must have sufficient fuel reserves for 30 min hovering. The performance range for the Sikorsky S-92 Helicopter that recently has entered operations by CHC Helicopters is 538 nm with no reserves. The actual helicopters for operations north-east of Iceland, S-92, or an equivalent helicopter from Eurocopter, is therefore on the limit when it comes to the distance that shall be served.

CHC Helicopters indicates that the range can be increased by adding an extra fuel tank in the cabin or utilize a local airport further north-east i.e. Vopnafjordur, Digranes, Torshøfn or Raufarhøfn for refuelling purposes. The adding of an extra fuel tank will reduce the number of passengers to 16 seating (normal is19 seating). CHC Helicopters has approached Sikorsky with a request to get the S-92 certified for an extra fuel tank integrated in the cabin. The Shtockman field in the Russian sector of the Barents Sea has a similar problem as the Jan Mayen Ridge with a distance from shore to the field on the helicopter operations performance range limits.

The S-92 is the latest development of Sikorsky Helicopters for Commercial Operations. It is equipped with the latest State-of-the-art Safety technology. The cabin is air-conditioned. For operations in Icelandic waters the helicopters will be equipped with anti-freeze systems for the rotor blades.

Requirements to Operations

North Sea Helicopter operations outside controlled airspace are monitored by an active GPS/Satellite monitoring system (ADS). This is a governmental requirement in Norway. Icelandic authorities should consider implementing this for future helicopter operations north-east of Iceland.

Helicopter navigation offshore outside controlled airspace is fully based on satellite navigation information.

For emergency purposes there is a requirement that there shall be one emergency preparedness helicopter in addition to the transport helicopter. These two helicopters can serve the simultaneous operation of two exploration drilling rigs. The standby emergency preparedness helicopter will normally be a part of the emergency preparedness for the drilling rig.

The transportation will normally be scheduled for the lightest part of the day. The minimum visibility requirements on the rig-site is horizontal visibility minimum 1 km and vertical visibility 60 m. Fog could be a problem in the area and it is recommended to perform a weather study to get info on the meteorological conditions in the exploration area.

A meteorological forecast service has to be established for north-east Iceland helicopter operations. Such forecasts are also necessary for the drilling rig operations.

Contract for Helicopter services

The Operating Oil Company enters into contract with the Helicopter Operations Company. In Norway there is a guideline issued by the Association of Oil Companies (OLF) that is used as reference document in such contracts in addition to international and Norwegian rules and regulations. It is recommended that Icelandic authorities review the OLF guideline for potential adaptation in Iceland.

3.2.3 Supply base serving production operations

A typical shorebase in Norway serving the Snorre Field in the Tampen area, Saga Fjordbase in Florø include the following facilities:

- Total area: 420.000 m^2
- Total paved area: 360.000m^2 of which 260.000 m^2 are for rent
- Offices: 7400m^2
- Warehouses: 15.000 m^2
- Deepwater quays (10-18m) 250 m

The Saga Fjordbase AS employs 90 people.

This base serves several oil and gas fields and a similar base on the coast in north-east Iceland could serve a large oil and gas development at the Jan Mayen Ridge.

3.3 Technology

In this section we will address whether safe, cost-effective and proven technology[1] is available for drilling, field development and production at the expected water depths in the Jan Mayen Ridge area.

Prevailing weather, sea and ice conditions are significant factors when assessing appropriate technologies for offshore exploration and development. The area at the Jan Mayen Ridge north-east of Iceland has less severe wind, wave and current conditions than the south-eastern part of the Norwegian Sea, where exploration and production activities have been ongoing for some time. The area is also located outside the maximum limit of sea ice, so the risk related to drift ice is expected to be manageable and comparable to conditions in the Norwegian sector of the Barents Sea. A residual risk of drift ice can be expected to remain, however, and will have to be taken into account in the design and planning of offshore structures and operations.

Prior to start of offshore operations, a detailed weather and ice monitoring and forecasting service will need to be established for the area. Such services are commercially available using a combination of surface, airborne and satellite technologies.

3.3.1 Exploration

In the exploration phase suitable technologies are needed to carry out seismic mapping and exploration drilling activities.

Seismic acquisition

The method of seismic acquisition can be compared with the technique of echo sounding, in which sound waves are used to obtain information about subsurface geological sequences and thus about the hydrocarbon potential of the area studied. Ref Figure 3.1

[1] For the purpose of this study we have defined "proven technology" as technology that has been applied in full-scale field developments under conditions comparable to the ones we are discussing here.

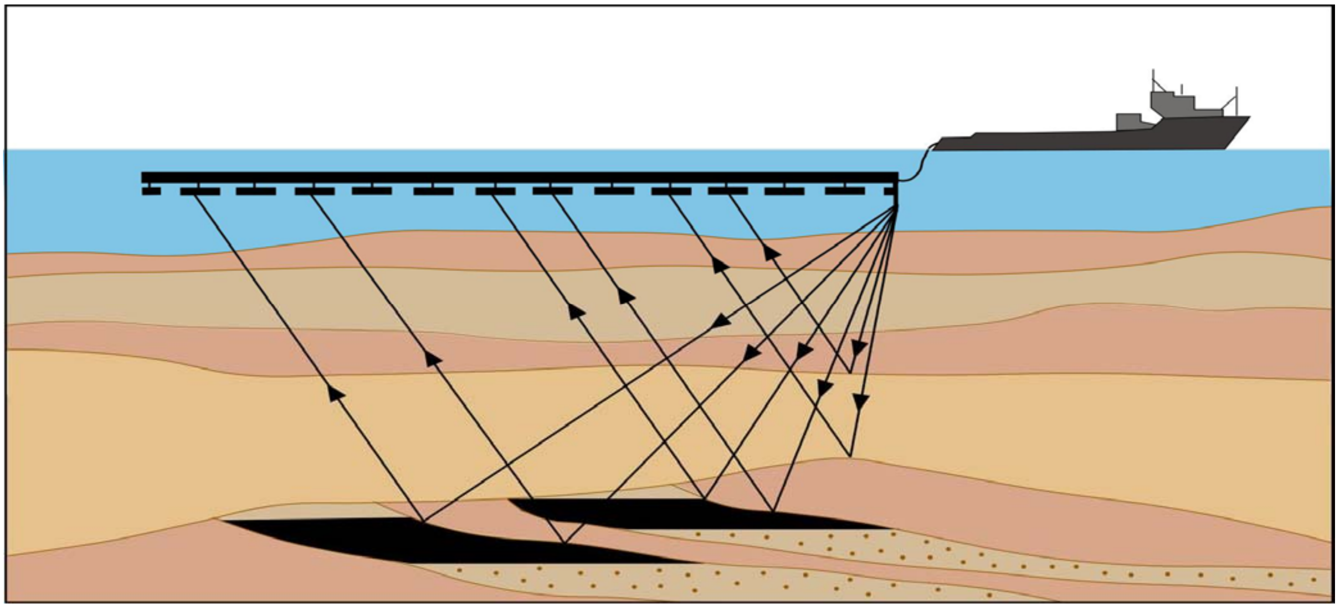

Figure 3.1 Schematic figure of seismic acquisition

The sound waves are generated by air-guns. Investigations has shown that the effects on fish are local and with no long term adverse effects.

The gathering of seismic data at the Jan Mayen Ridge area is deemed possible with fairly standard technologies and is not further discussed in this section. Reference is made to the successful seismic acquisition at the Jan Mayen Ridge performed by the S/V Polar Princess during summer 2001.

Drilling rig and supply services

As regards exploration drilling, the key factors to consider with respect to available technologies are:

- Water depth
- Weather, sea and ice conditions
- Distance to onshore infrastructure

The water depth in the area is typically between 1,000 and 1,500 m. A number of floating drilling rigs available on the market are capable of drilling at water depths up to 3,000 m in harsh environments. Of these 5th generation rigs, at least one is also fully winterized and suitable for year round operations in the North Atlantic. In addition, several 6th generation rigs are on order with the first ones scheduled for delivery in 2008. Also these rigs will be fully winterized and capable of drilling at water depths up to 3,000 m in harsh, sub-arctic environments.

Figure 3.2: Fully winterized 5th generation drilling rig “Eirik Raude”

The drilling unit will need to be supplied with equipment, consumables and manpower from a shore base, and the distance from the shore base to the drill site is a key factor here. The distance from the coast of Iceland to the target area is about 370 km (200 nm). For supply and support vessels this is not seen as a problem.

Personnel transport in offshore drilling operations is normally done by helicopter. There are at least two modern, reliable offshore support helicopters available with a range in excess of 900 km (500 nm), which should be adequate for the purpose. Reference is made to section 3.2.2 Helicopter Operations.

For data and voice communication with the offshore drilling unit, a high-bandwidth satellite link would be the logical choice. For back-up, an independent, low-bandwidth mobile satellite service or a high frequency single sideband (HF-SSB) radio system may be used. These are all commercially available services with coverage in the relevant area.

Drilling of an exploration well

Planning of the first exploration well in a frontier area like the Jan Mayen Ridge may take up to one year once the seismic data has been processed.

The drilling program for a well in 1800 m water depth offshore West-Africa is shown in Figure 3.3. The well was designed to be drilled to a total vertical depth of 3500 m from the rig floor. The 36” conductor was jetted to 90 m penetration. The 171/2” section was drilled to 2700 m and a 13 3/8” casing was runned and cemented. These first two segments were drilled riser-less and the riser and Blow Out Preventer was installed when the 17 ½” section was completed. The upper sections was drilled using seawater with high viscosity pills for hole cleaning. The 12 ¼” section was drilled to the total of 3500 m. To give the required hole stability, a mud with very light density was required. This section was therefore drilled with an oil based mud system.

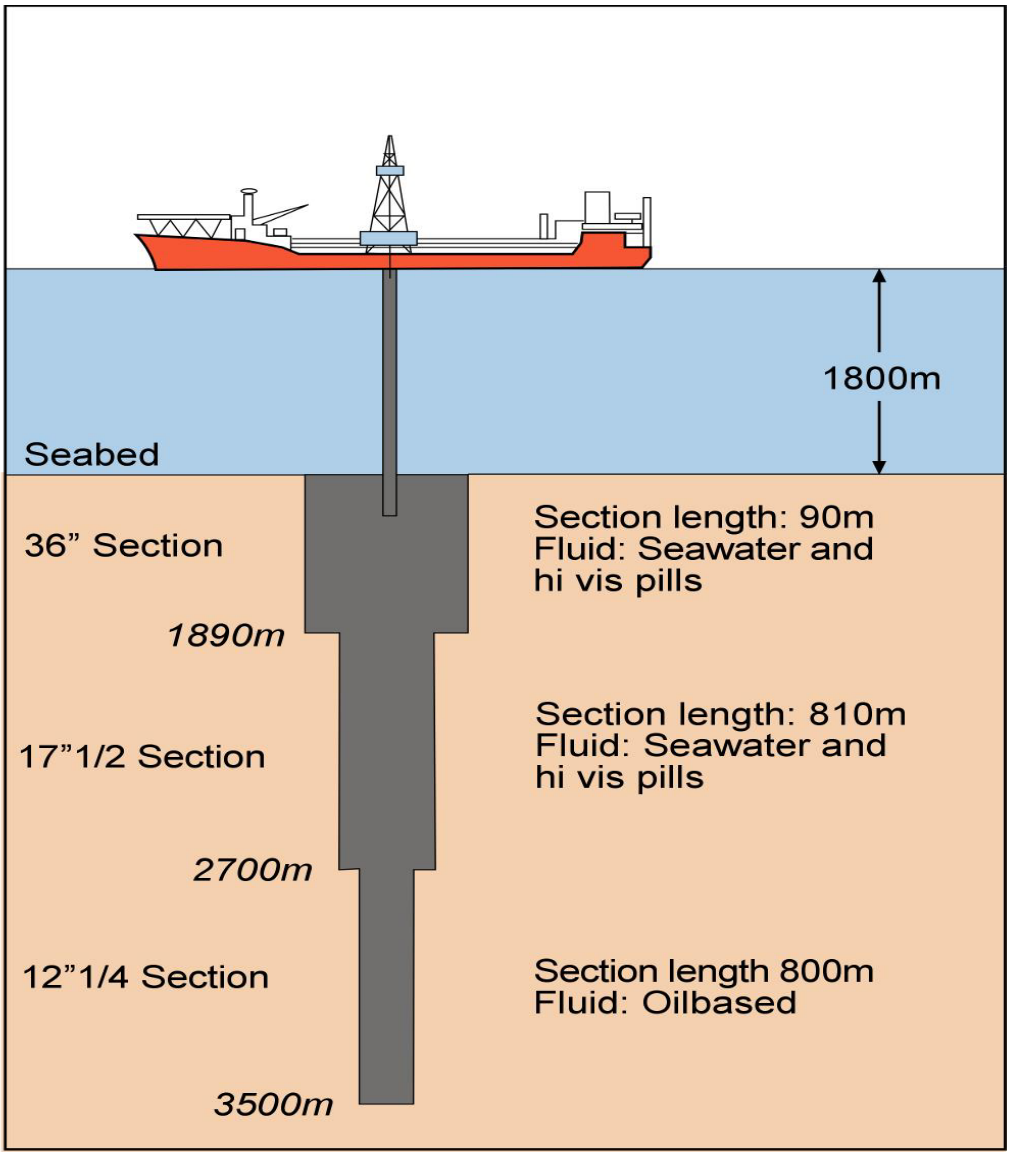

Figure 3.3 Drilling programme for deepwater exploration well offshore West-Africa.

3.3.2 *Environmental effects of drilling operations*

Figure 3.4 illustrates the main sources of discharges to sea from a production operation.

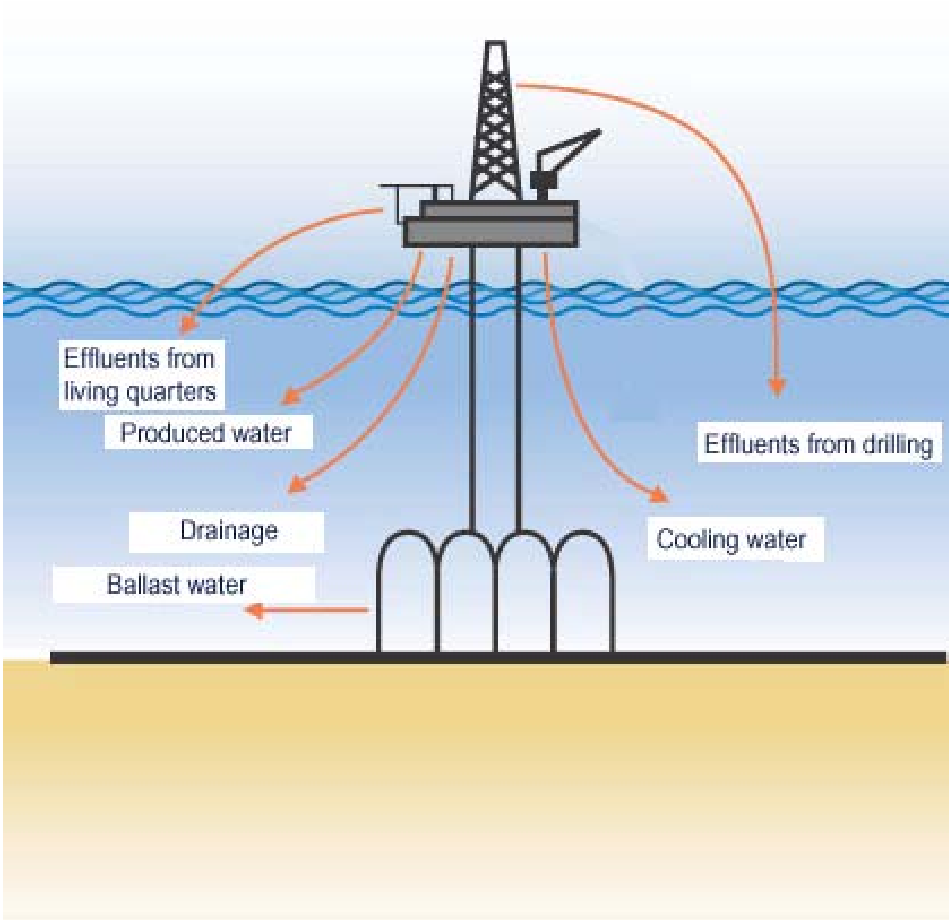

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Figure 3.4 Main sources of discharges to sea from a production operation.

The contribution from the various sources of discharges is changing during the exploration and production activities. During the later stages of production the oil content in the produced water is the dominant sources of discharged oil quantities. The trend in discharge of oil (Tons pr year) from the petroleum activities on the Norwegian Continental Shelf is shown in figure 3.5. The oil content in the discharged water is well within the limits of 40mg/l.

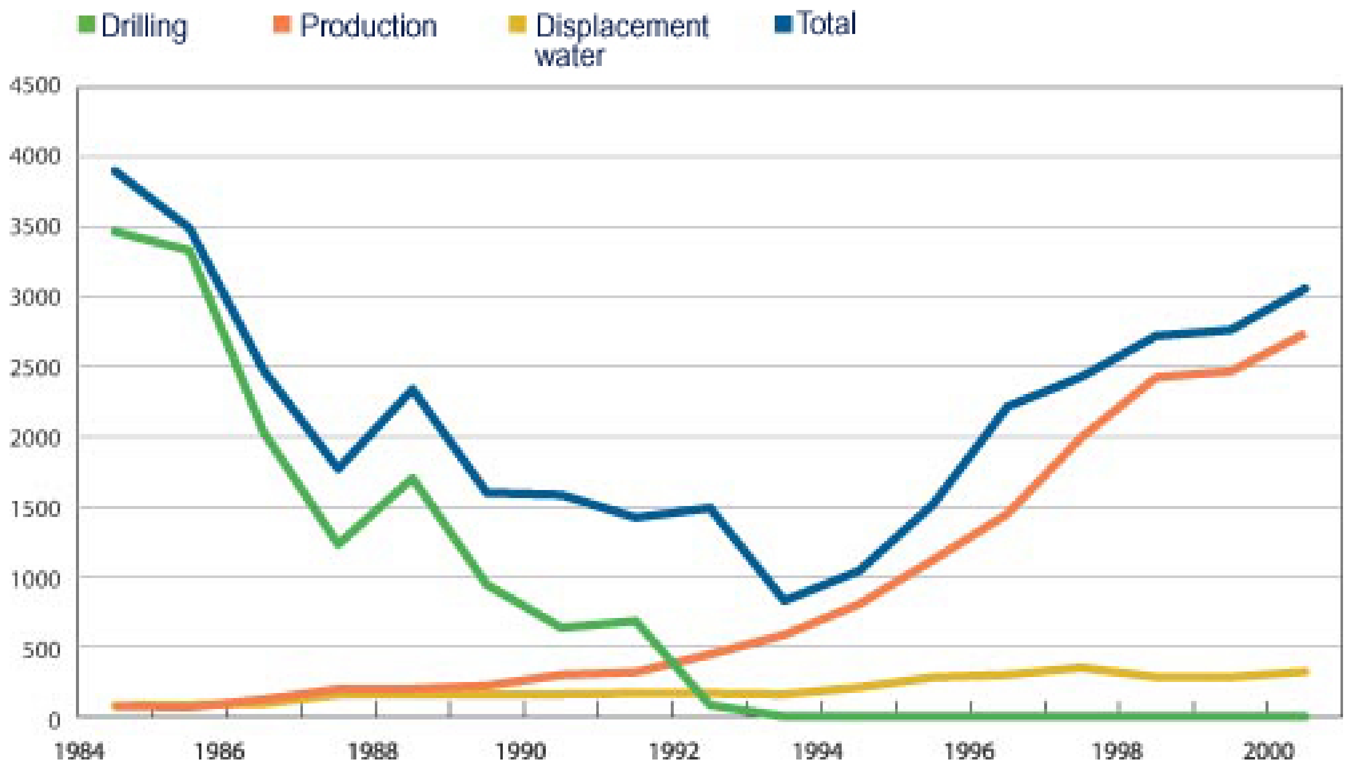

Figure 3.5 Trend in discharge of oil (Tons pr year) from the petroleum activities on the Norwegian Continental Shelf . Source State Pollution Control Authority.

3.3.3 Safety of drilling operations

The main safety risks during drilling operations are identified in the Drilling Operations Emergency Preparedness Programme as Design Basis Accidents like

- Loss of well-control that may cause blowout of oil or gas
- Loss of platform structural Integrity
- Collision with vessels
- Flight Accidents

The emergency programme describes consequence reducing measures so that the safety risks are acceptable.

3.3.4 Development and Production

Facilities

Oil and gas facilities can be divided into "upstream" and "downstream" facilities. The boundary between the two is blurred, but simplistically speaking "upstream" facilities produce reservoir liquids out of the ground and separate them into marketable crude oil, natural gas and by-products (mainly water), while "downstream" facilities refine crude oil and/or natural gas into other petroleum products such as heating oil, gasoline, LNG, etc.

We will in the ensuing sections mainly address upstream facilities. However, we will also discuss some downstream technologies which have a particular bearing on gas utilisation.

Field Installations

Typical offshore field installations consist of:

- Production and injection facilities
    - Production wells
    - Water and/or gas injection wells
    - Wellheads, equipped with a valve assembly for controlling and shutting in the well ("x-mas tree")
    - Flowlines and risers from the wells to the processing facilities

- Processing facilities, with systems for
    - Separation of the wellstream into oil, gas and water
    - Processing of the oil to meet specifications for export by shuttle tanker or pipeline
    - Processing of gas to meet specifications for export by pipeline, or re-injection into the reservoir

- Export facilities
    - Oil export pumping and metering
    - Gas compression and metering, for export and/or re-injection
    - Oil and gas export risers
    - Oil and gas export pipelines
    - Oil loading equipment, e.g. loading buoy

Various support and utility systems, such as
- Fuel gas
- Flare and drain
- Power supply
- Cooling water
- Heating medium
- Compressed air
- Insert gas
- Control systems
- Safety systems
- Living quarters
- etc.

- Decks and substructures to support the above mentioned facilities, either
    - Fixed to the seabed, or
    - Floating

The deck and the various processing and other facilities installed on it are commonly referred to as the "topsides". An offshore platform thus consists of substructure and topsides.

Development Wells

A field development may comprise production wells, water injection wells and gas injection wells, jointly referred to as development wells.

Most development wells nowadays are deviated, i.e. drilled partially sideways, to provide maximum coverage of the reservoir from as few drilling locations as possible. The wells usually have a slanted or horizontal bottom section to maximise the length of wellbore exposed to the relatively thin reservoir layers.

The wellheads and x-mas trees may be located on the fixed or floating platform ("platform-completed" wells, with "dry trees"), or directly on the seabed ("subsea-completed" wells, with "wet trees").

Subsea Technologies

Subsea-completed wells can be connected by flowlines to an offshore platform or directly to a pipeline to shore. Since the wellstream is unprocessed until it reaches the processing facility, the flow is multi-phase, i.e. a mixture of oil, water and gas (and sometimes solids).

Subsea tie-back[2] to a nearby platform is today common technology throughout the world, and has been done at water depths down to 2,300 m (Shell's Coulomb field, Gulf of Mexico). The advantage of such subsea well tie-backs is that a large geographical area can be covered from one single platform.

The advantage with subsea tie-back to shore is that all processing facilities then can be located onshore and large, costly offshore structures are avoided. Tie-back to shore is viable in some cases, depending on the distance, the properties of the reservoir fluid and other conditions. The main limiting factors are high pressure drop, liquid "slugging" and formation of solids (hydrates and wax) along the pipeline as the unprocessed well fluid is cooled by the surrounding seawater. Research and development has been ongoing for many years to place essential processing equipment such as purpose-built separators and multi-phase pumps on the seabed, known as subsea processing. The aim of this is to alleviate the problems of multi-phase transportation and thus extend the reach of subsea tie-backs. Subsea processing has not yet achieved widespread commercial acceptance.

A disadvantage of all subsea technologies is the high maintenance costs compared to similar surface technologies.

The current state-of-the-art for deepwater subsea production and multi-phase transportation technology in the Norwegian Sea is represented by the Ormen Lange field currently under development offshore Norway. Ormen Lange is located at 1,100 m water depth 114 km from shore. After the Snøhvit field in the Barent Sea (160 km) this is the longest subsea tie-back in the world. However, the water depth at Snøvhit is 250 m.

The distance from the Jan Mayen Ridge to Iceland is about 400 km. Pipeline transportation of unprocessed wellstream across such a distance in cold waters is not considered proven

[2] Tie-back: The connection of production or injection wells to a host facility, such as a platform, via flowline(s) and an "umbilical" with power supply and control signal cables and chemical injection line.

technology. Transport of unprocessed wellstream from a potential discovery at the Jan Mayen Ridge to Iceland has therefore not been considered further in this report.

For the Jan Mayen Ridge this leaves the alternative of some form of processing of the wellstream at the field. Since subsea processing is still at the Research & Development stage, surface processing on a platform or vessel is the likely solution.

Figure 3.6: Subsea production systems

Floating Production Technologies

The water depth of 1,000 - 1,500 m at the Jan Mayen Ridge area rules out any type of fixed platform. Accordingly, some form of floating unit must be considered.

The following types of floating units are relevant:

- Semi-submersible platform
- Tension Leg Platform (TLP)
- Spar platform
- Ship-shaped Floating Production, Storage and Offloading unit (FPSO)

The four types are illustrated in Figure 3.7.

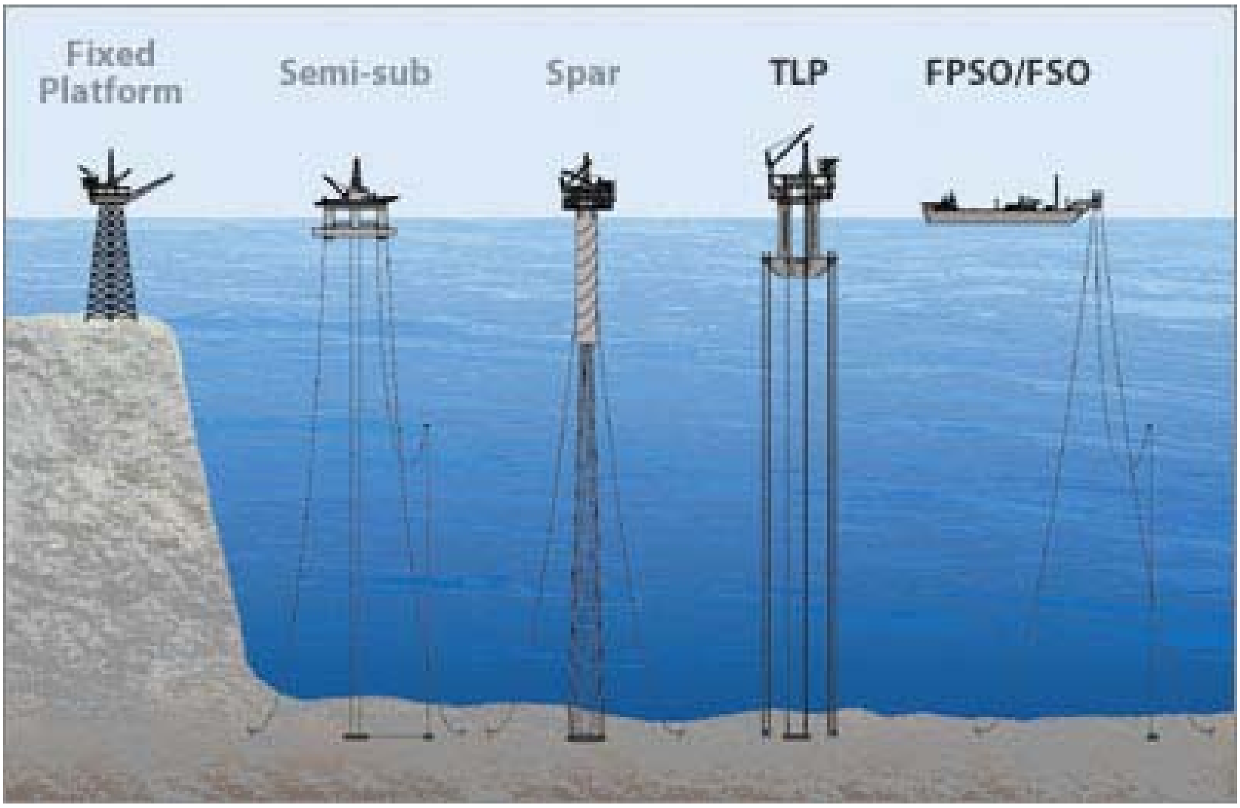

Figure 3.7: Deepwater production system types

Below we take a closer look at each of these main types.

Semi-Submersible Platforms

A semi-submersible platform has a hull consisting of pontoons with vertical columns placed on top. The deck is placed on the columns. The whole structure is anchored to the seafloor with spread mooring lines, i.e. catenary mooring lines (typically 12 or 16 of them) extending in a star-shaped pattern from the corners of the platform.

A semi-submersible gas processing platform is shown in Figure 3.8.

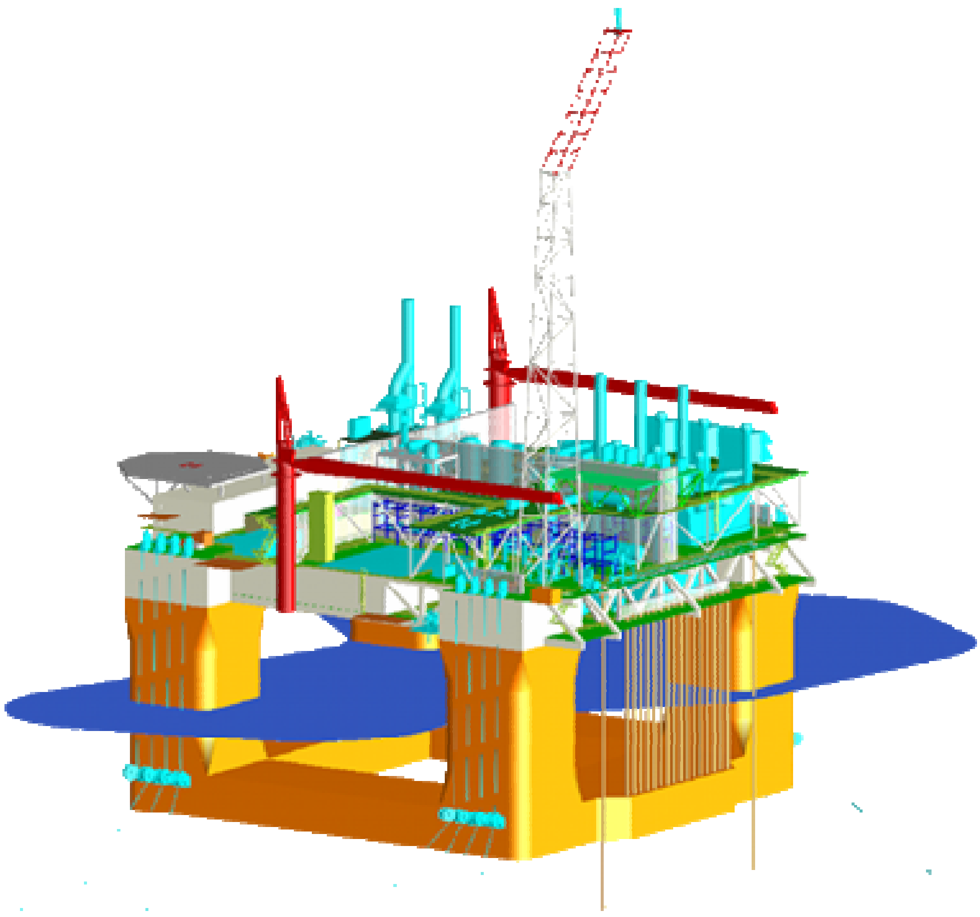

Figure 3.8: Semi-submersible platform

Tension Leg Platforms (TLPs)

A TLP is characterised by its unique mooring system. The TLP is anchored to the seabed with vertical tendons, or “tension legs”. After fixing the bottom ends of the tendons to the seabed and the top ends to the hull, a tensioning mechanism installed in the hull is used to tighten the tendons so that the floating hull is pulled slightly down in the water. The buoyancy forces will then keep the tendons constantly in tension and the platform is anchored like an “inverted pendulum”. The result is a floating platform with no vertical movement (only horizontal).

Figure 3.9 shows a new type of TLP developed for use in ultra-deepwater developments (up to 3,000 m) in the Gulf of Mexico.

Figure 3.9: SeaStar tension leg platform

Spar Platforms

A Spar platform, sometimes also referred to as a deep draft caisson vessel, consists of a large vertically floating column, often with a truss section connecting the column to a ballast tank at the bottom. The structure is anchored with a spread mooring system similar to the one used for semi-submersibles.

Figure 3.10 : Spar platform

Floating Production, Storage and Offloading Units (FPSOs)

An FPSO has a ship-shaped hull. In most cases it is moored with a so-called turret mooring system. This consists of catenary mooring lines attached to a vertical cylinder-like construction around which the whole vessel can rotate, or “weather-vane”. The mooring lines and cylinder stays in the same position, while the vessel is rotated according to the weather. The turret can be either an internal turret, located centrally in the hull, or an external turret, located in an extension to the bow of the vessel. The former is used in new-build FPSOs while the latter is used in tankers converted into FPSOs.

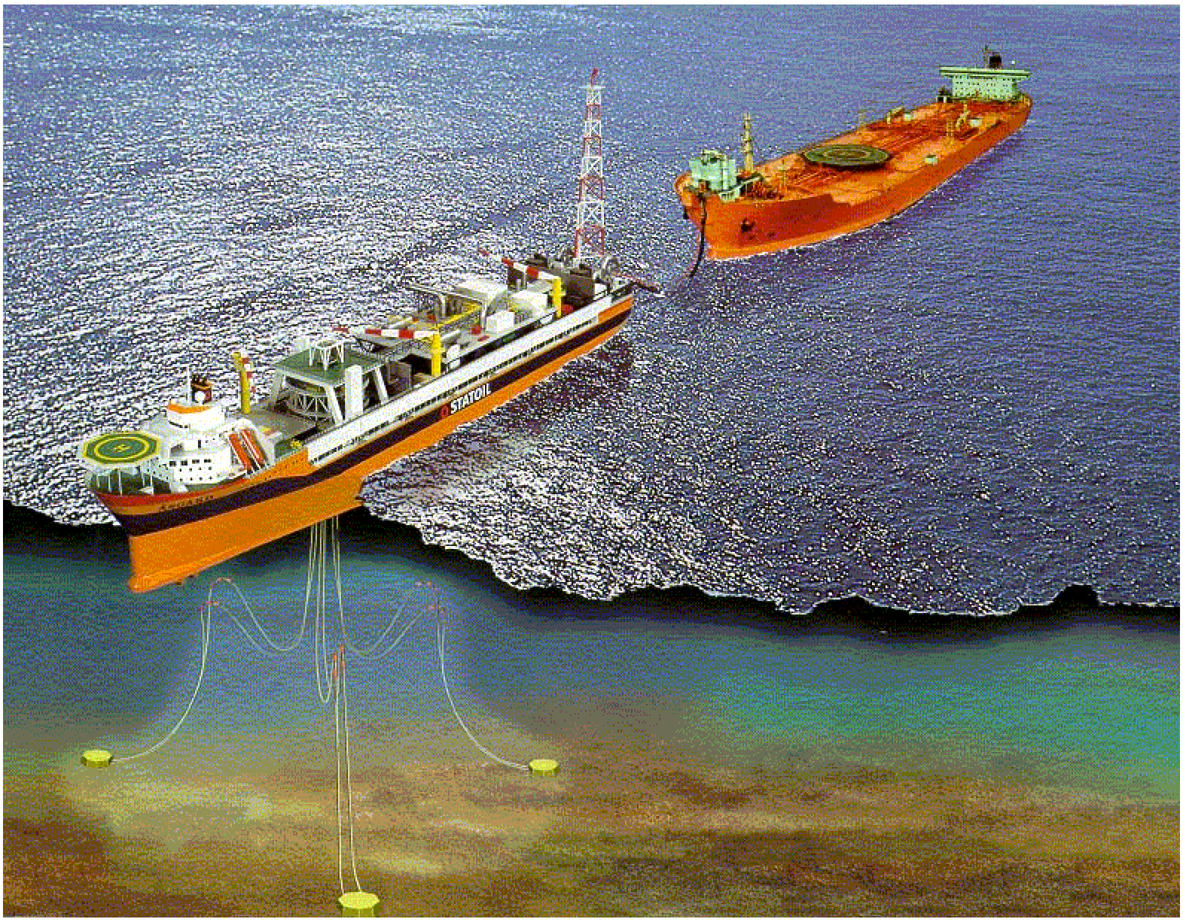

Figure 3.11: FPSO, during oil offloading to a shuttle tanker

Discussion – Field Installations

Proven drilling, completion and tie-back technologies are available both for subsea-completed and platform-completed development wells under the prevailing conditions at the Jan Mayen Ridge.

All the types of floating production units described above represent feasible solutions for the given conditions. The different types each have their own unique advantages and disadvantages, of which we have summarised the main ones in Table 3.1. The choice will in the end be governed by economics, where not only capital costs, operating costs and production, but also flexibility and ability to accommodate future extensions, will play important roles.

For smaller oil field developments a stand-alone FPSO will be the typical choice. For larger developments one of the three platform types, with their capability of supporting a greater number and size of risers, will most likely be required, in combination with either an FPSO or an FSO (Floating Storage and Offloading unit).

In moderately deep waters FPSOs normally employ flexible risers in a catenary configuration. For water depths of 1,000 - 1,500 m this system could be extended by use of a hybrid riser. In such a hybrid riser the lower part would be a vertical bundle with distributed and local buoyancy, fixed to the sea floor and extending up to just below the wave zone. At this point it is connected via a flexible riser or jumper to the FPSO. Hybrid risers have so far been utilised in floating production developments in West Africa and Gulf of Mexico, and they are currently being considered for deepwater applications in other parts of the world.

Figure 3.12: Hybrid riser

Type of floating unit	Description	Advantages	Disadvantages
Semi-submersible	Vertical columns supporting topsides and supported on large pontoons. Anchored to the seafloor with spread mooring lines	• Large number of flexible risers is possible. • The unit can be built at a ship-yard.	• Wet trees only. • Sensitive to deck payload changes. • No oil storage capacity.
TLP	Floating structure anchored to seafloor with vertical, pre-tensioned tendons	• Dry trees. • The unit can be built at a ship-yard. • Favourable motion characteristics.	• Active hull system, i.e. constant tension has to be maintained to keep the platform stable. • Tendon fatigue. • Sensitive to deck payload changes. • No oil storage capacity.
Spar	Large vertical column supporting topsides, sometimes with a bottom truss section connecting the column to a ballast tank. Anchored to the seafloor with spread mooring system	• Dry trees. • Favourable motion characteristics. • Can accommodate deck payload changes. • Oil storage capacity.	Topsides must be lifted into place at the offshore installation site with a heavy lift crane vessel.
FPSO	Ship-shaped, usually weather-vaning vessel. Turret mooring system.	• The unit can be built at a ship-yard. • High deck payload capacity. • High oil storage capacity. • Oil offloading to shuttle tankers directly from the vessel.	• Wet trees only. • Limited number of flexible risers possible. • More susceptible to weather downtime.

Table 3.1: Comparison of different floating production units

Oil and Gas Export

Due to the lack of pipeline infrastructure in the area, the logical choice for oil export is offshore loading into shuttle tankers, either from an FPSO or an FSO. The oil could either be transported to a new terminal in Iceland, or to an existing terminal in a central European port, for transfer into larger, conventional tankers.

For the produced gas, re-injection will probably be the only economically viable solution for a smaller and/or low-GOR[3] oil field scenario.

In the case of a large gas discovery, access to sufficiently large markets will be the main challenge:

- A pipeline connection to the UK, Norway or the North Sea gas grid is regarded as not economically viable in the foreseeable future.

- Gas liquefaction is a realistic alternative.

Any economically viable development of a major gas field at the Jan Mayen Ridge area is therefore likely to incorporate some form of Liquified Natural Gas (LNG) or Gas To Liquids (GTL) technology.

LNG and GTL

LNG production involves liquefying methane – the main constituent of natural gas – by cooling it down to approximately -160 ^{o}C. GTL production involves conversion of the natural gas to low-emission, synthetic transport fuels or other liquid hydrocarbon products. These technologies are proven, but due to the major investments required they are dependent on a large gas reserve base and/or high oil price scenario to be economically viable.

LNG transport and distribution relies on purpose-built tankers and receiving/regasification terminals, as well as the existence of a gas pipeline distribution grid at the receiving end. Potential LNG production in Iceland would therefore be aimed at the export markets in USA and Europe.

GTL, on the other hand, is used to make common oil products like diesel and jet fuel which can be distributed locally in Iceland through existing, conventional distribution channels. The GTL products have extremely low aromatics and sulphur contents and they are therefore more environmentally friendly than conventional diesel and jet fuels.

An LNG or GTL plant could either be located onshore in Iceland, or on a floating platform at the field. Floating LNG or GTL production and offloading for deepwater remote gas field developments has been proposed, and concepts have been developed, but no such facilities have been built and installed to date. Therefore a gas pipeline to Iceland and an onshore LNG or GTL production facility at the Icelandic coast is the most probable gas offtake solution.

[3] GOR: Gas/Oil Ratio

The water depth along most of the pipeline route is around 2,000 m, with steep gradients at the field and at the approach to the Icelandic continental shelf. Construction of a gas pipeline under these conditions will be a technological challenge, but is still deemed feasible with today's technology. Next year, 225 km of 24 inch diameter pipe is planned to be installed in some 2500 m of water to build the Independence Trail gas pipeline in the Gulf of Mexico. The vessel scheduled to lay this pipeline has recently completed installation of the Snohvit gas pipelines and part of the Ormen Lange gas pipelines offshore Norway, and is the current world record holder in deepwater pipelaying.

Figure 3.13: LNG plant in Western Australia

Figure 3.14: Shell's Bintulu GTL plant in Malaysia

4 Field Developments

4.1 Introduction

The main phases of the Exploration and Production chain are illustrated in Figure 4.1

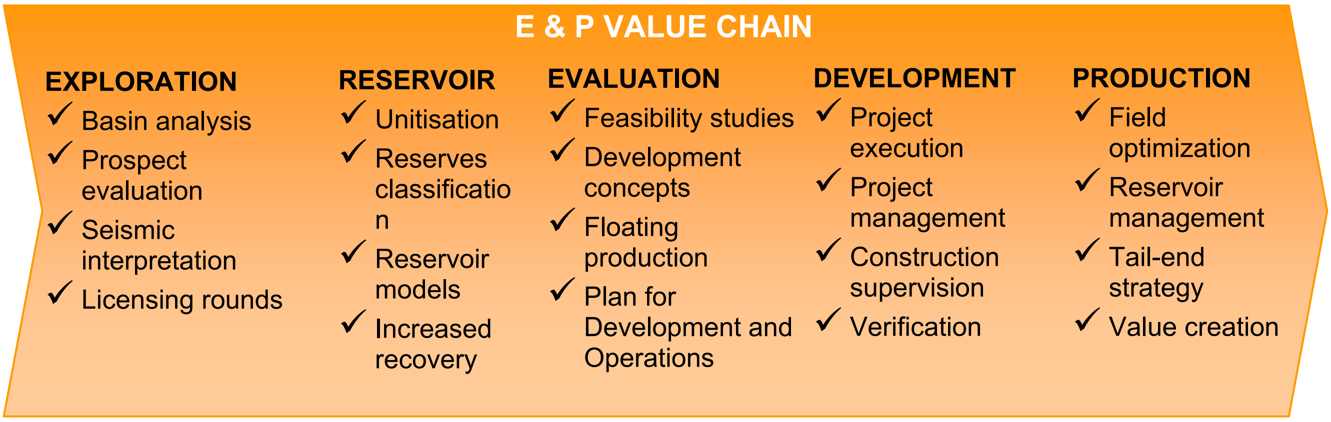

Figure 4.1 Exploration and Production value chain

Exploration and field developments at the Jan Mayen Ridge will be performed in a typical frontier area with little or no existing infrastructure for oil and gas production, limited logistic services and the need to develop emergency preparedness systems for the offshore operations.

Four generic exploration and field development scenarios including both oil and gas discoveries are presented and the event tree fig 4.2 illustrates possible paths leading to the four scenarios. The scenarios focuses solely on the selected field developments and do not include for establishing emergency preparedness, logistics services or normal onshore support functions.

Oil and gas production profiles have been constructed based on experience data from other petroleum regions and modified to suit the intent of this particular study. They do not in any respect represent any work based on geological and petrophysical data from the designated study areas at the Jan Mayen Ridge.

4.2 Objective

The objective of this scenario-based evaluation is to present some examples of typical oil and gas field development solutions that could be applicable to exploit possible petroleum resources at the Jan Mayen Ridge, illustrate the economic potential of developing moderate to small oil fields and to assess a possible potential of both oil and gas developments.

The field development solutions are based on proven technologies that currently are being applied world wide for exploitation of oil and gas resources.

The economic assessments are indicators of the viability to develop oil and gas resources at the Jan Mayen Ridge and do not intend to rank or assess field economics of the hypothetical field developments.

The associated exploration and development plans are presented to indicate a realistic time period from start of exploration to first production of oil and gas.

4.3 Basic Assumptions

4.3.1 Economics

All costs and revenues are given in real 2005 terms and does not account for tax and government take.

Oil Price

- USD 35 BOO (Barrels of Oil)
- Sensitivity USD 20 BOO

Gas Price

- NOK 1,00 Sm3 net of LNG transport
- Sensitivity NOK 0,60 Sm3 net of LNG transport

Exchange Rate- USD 1, 00 = NOK 6, 50

Discount Rate

- 12% in real terms
- Discount rates vary between oil companies. The 12% discount rate is considered to be within the range presently used by the oil and gas industry. However, the discount rate is basically a company specific or government specific choice. From a government perspective a discount rate of 7- 8% could be applicable considering that the risk adjustment is of considerably less significance to the society at large compared to an oil company.

4.3.2 Method

In order to illustrate the economic potential of oil and gas exploitation, the method of calculating the Net Present Value (NPV) of the different scenarios has been applied. The NPV method estimates all relevant cash elements from a concrete development in size and time. Cash expenditures and incomes over a relatively long period of time are made comparable through discounting, i.e. a future payment is calculated to a value of today by charging an annual “interest” to such payment. The values of today are summarised to arrive at the NPV, and a positive NPV indicates a profitable project.

The annual discount rate intend to reflect a reasonable rate of return from a specific and individual development such as a project, covering an element of free interest rate (market rate) plus an element of risk and – if relevant – an element of inflation.

Alternative methods could be simpler (pay-back time) or more advanced (real option pricing). However, in this context it is considered that the NPV method is an adequate economical indicator to consider if a development is a potential candidate for exploitation. The method is consistent with current oil industry practice and is well known also outside the oil and gas industry.

4.3.3 Development Estimates

Development cost estimates are high level coarse estimates and in general based on representative data from developments offshore Norway and are considered representative for world wide offshore developments in deep waters, harsh environments and with deep reservoirs where advanced technical solutions are required.

The investment costs (CAPEX) are based on information from current development projects. The costs are distributed according to the activities and timing of the development schedule.

The yearly operating costs (OPEX) are estimated as a percentage of CAPEX. In this report OPEX has been calculated as 3%- 5% CAPEX dependent upon the amount of subsea and above water installations.

4.3.4 Contracting of Facilities

The basic assumption is that the Oil Company (developer of the fields) invest and owns all the offshore and onshore installations except the FSO, oil shuttle tankers and LNG export tankers which are assumed to be on lease.

An alternative to ownership is to lease FPSOs and thereby free upfront investment costs and reduce the cash exposure of the investment phase.

It is assumed to rent supply base, helicopter and supply base services. The rental costs are part of the OPEX.

4.3.5 Development Schedules

An activity schedule for each scenario is the basis for distribution of cost elements and associated cash flows and economic calculations.

The development schedule in Figure 4.14 shows the main activities from exploration through field developments, and illustrates the expected time period to first oil.

4.3.6 Scenarios

For this study the prospective area has been sub-divided into Area 1 and Area 2. Area 1 has been selected to represent an oil region and Area 2 a gas and oil region. It is further considered that Area 1 is the most promising regarding a fast track development requiring a stand-alone oil solution only and that Area 2 is better suited for development when some offshore infrastructure is in place and the region is more mature. Therefore, plans for exploration start with Area 1.

For the purpose of this study only, preparation of an exploration program starts 01.07.06 and after a period of seismic and geological and geophysical (G&G) studies the first exploration well is spud in Area 1 during 2008. Considering an early discovery followed by further seismic and exploration wells, G&G and technical studies and a normal period of development planning and project execution first oil can realistically be achieved by the end of 2015.

4.4 Path of Events

The event tree illustrates the paths leading to the various scenarios. Exploration is envisaged to be phased activities that start in Area 1 and subsequently in Area 2. Timing of events will be generated by the results of each exploration well.

The four scenarios are generated from an event of dry holes only to possible substantial gas and oil reserves in two development areas.

Scenario 1 represents an alternative where the exploration activities result in no discoveries.
Theme:
- Cost exposure

Scenario 2 represents an alternative where one moderate size oil field is discovered and where further exploration leads to a discovery of two additional smaller oil fields.
Theme:
- Development of moderate and small oil fields
- Stepping stone for increased exploration

Scenario 3 represents an alternative where two oil fields are discovered in one area and three moderate size gas fields and one moderate size oil field is discovered in another area.
Theme:
- Development of moderate to large gas fields with condensate and a small oil field
- Gas export
- Common use infrastructure

Scenario 4 represents an alternative to Scenario 3 where the gas discoveries are substituted by two oil discoveries.
Theme:
- Development of oil fields
- Gas disposal of associated gas

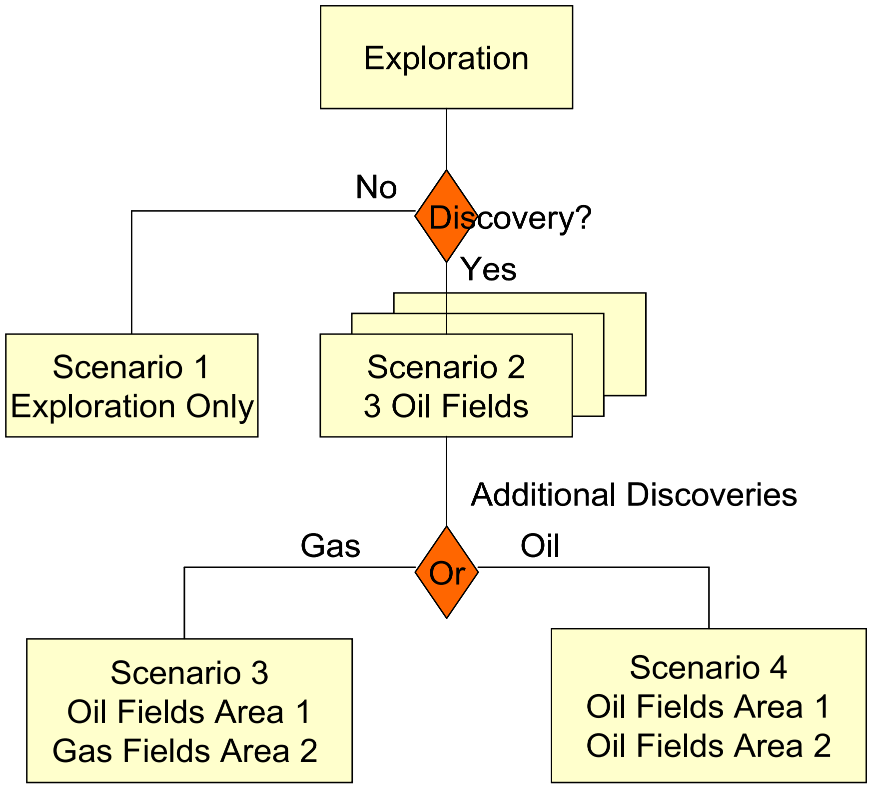

Fig 4.2 Event Tree

4.5 Scenario 1 – Exploration phase only

The exploration phase will commence by acquisition of area and infill seismic and G&G studies with the objective to identify prospects for exploration drilling. It is assumed that a total of 32000 km of seismic lines will be acquired as a basis for decision on where to position the first exploration well. Seismic acquisition and interpretation may take 1- 2 years.

Drilling of an exploration well may take from 3 to 6 months depending on drilling depth, geology, pressure, weather conditions and a possible drill stem test.

Scenario 1 represents an alternative of no discoveries and Area 1 and 2 are relinquished after a series of dry holes.

Scenario 1 is illustrated in Figure 4.3 and associated economics in Figure 4.4

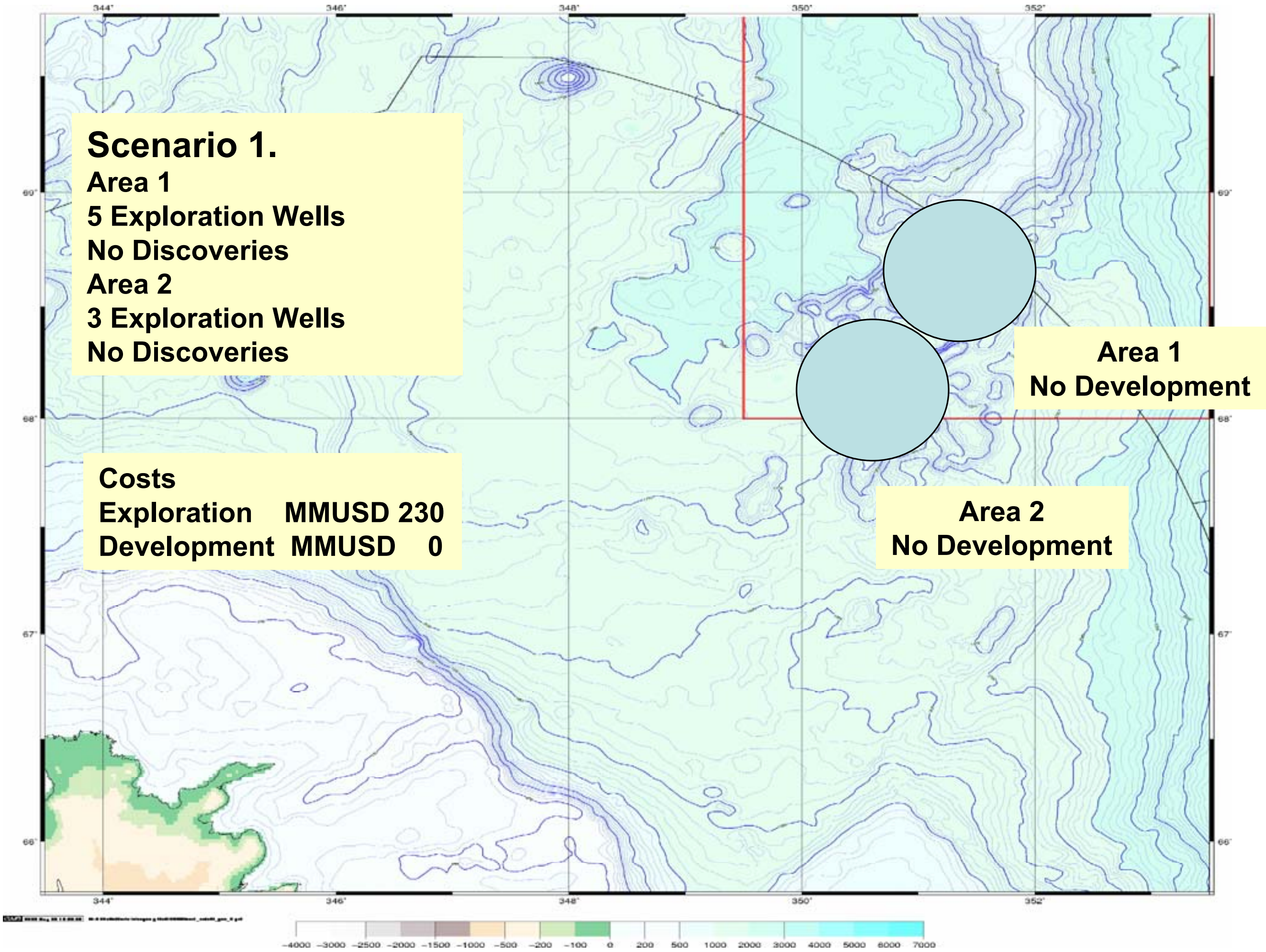

Figure 4.3 Scenario 1 – Exploration phase only

It is assumed that all services for logistics including helicopters and supply boats, and supply base are rented.

Assumed personnel requirements for Scenario 1 are 5-10 oil company employees on the drilling rig and 5-10 employees on the onshore supply base.

Estimated exploration cost is million USD 230 (MMUSD).

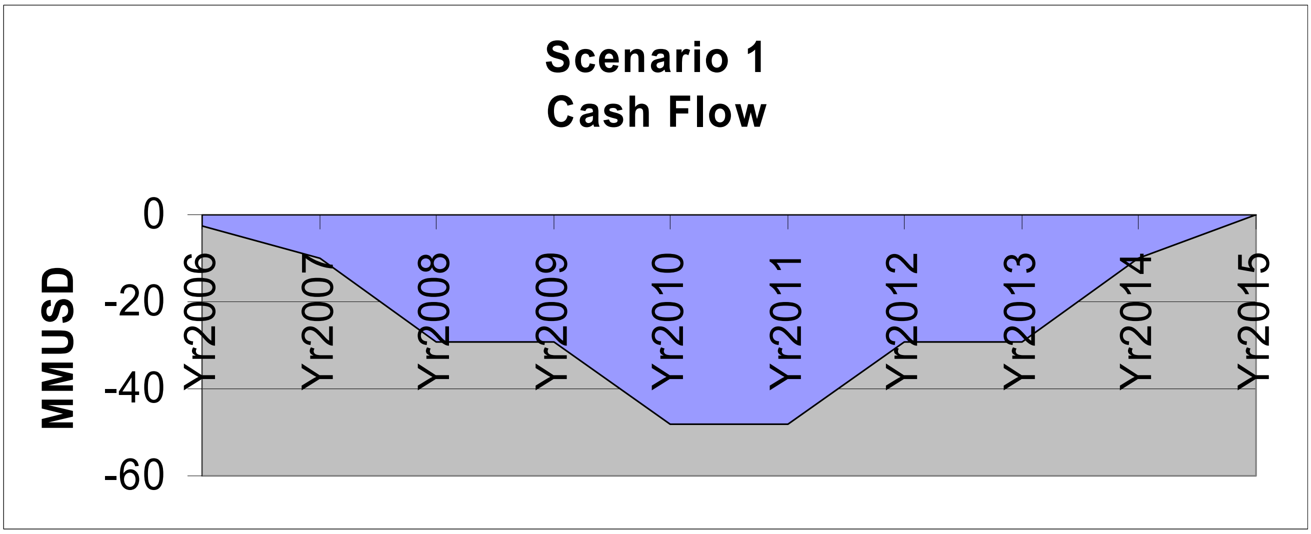

Fig 4.4 Scenario 1 Cash Flow

4.6 Scenario 2 – Oil Field Development

Scenario 2 represents an alternative with discoveries and oil developments of Area 1 whilst Area 2 is dry.

Scenario 2 will illustrate a development of small to moderate size stand alone oil developments where all direct production, storage and export of oil and gas are performed offshore. An onshore base including management, technical functions, supply base and logistics functions, will support the offshore operations.

A subsea development with floating production and storage is envisaged and with an FPSO as production centre for all developments. For each field, flowlines connect subsea wells to subsea manifolds that are connected to the FPSO by pipelines and flexible risers. The manifolds and wells are controlled from the FPSO through service umbilicals between the FPSO and each field.

The FPSO processes the multiphase well streams into oil, water and gas. The processed oil is stored in the storage tanks of the FPSO and periodically offloaded to dedicated oil shuttle tankers for export. The separated water is further processed and cleaned before it is disposed to sea. The gas is injected into the reservoir for reservoir pressure support and disposal. The gas can be considered stored in the reservoir and can be produced later if commercially attractive together with other fields that may be developed in the area. Scenario 3 illustrates such an alternative of integrated gas production.

All field installations including the wells, subsea installations and FPSO are considered as upfront CAPEX (capital expenditures) by the oil companies. Drilling of wells is performed by floating drilling units under short term for the purpose contracts. Offloading of oil by shuttle tankers are performed under long term contracts and the transport cost is included in the net oil price.

OPEX (operating expenditures) covers direct operating costs like consumables and maintenance of facilities, operators and support personnel, management and administration, supply base and logistics services.

Scenario 2 is illustrated in Figure 4.5 and the associated production profiles and economics in Figure 4.6

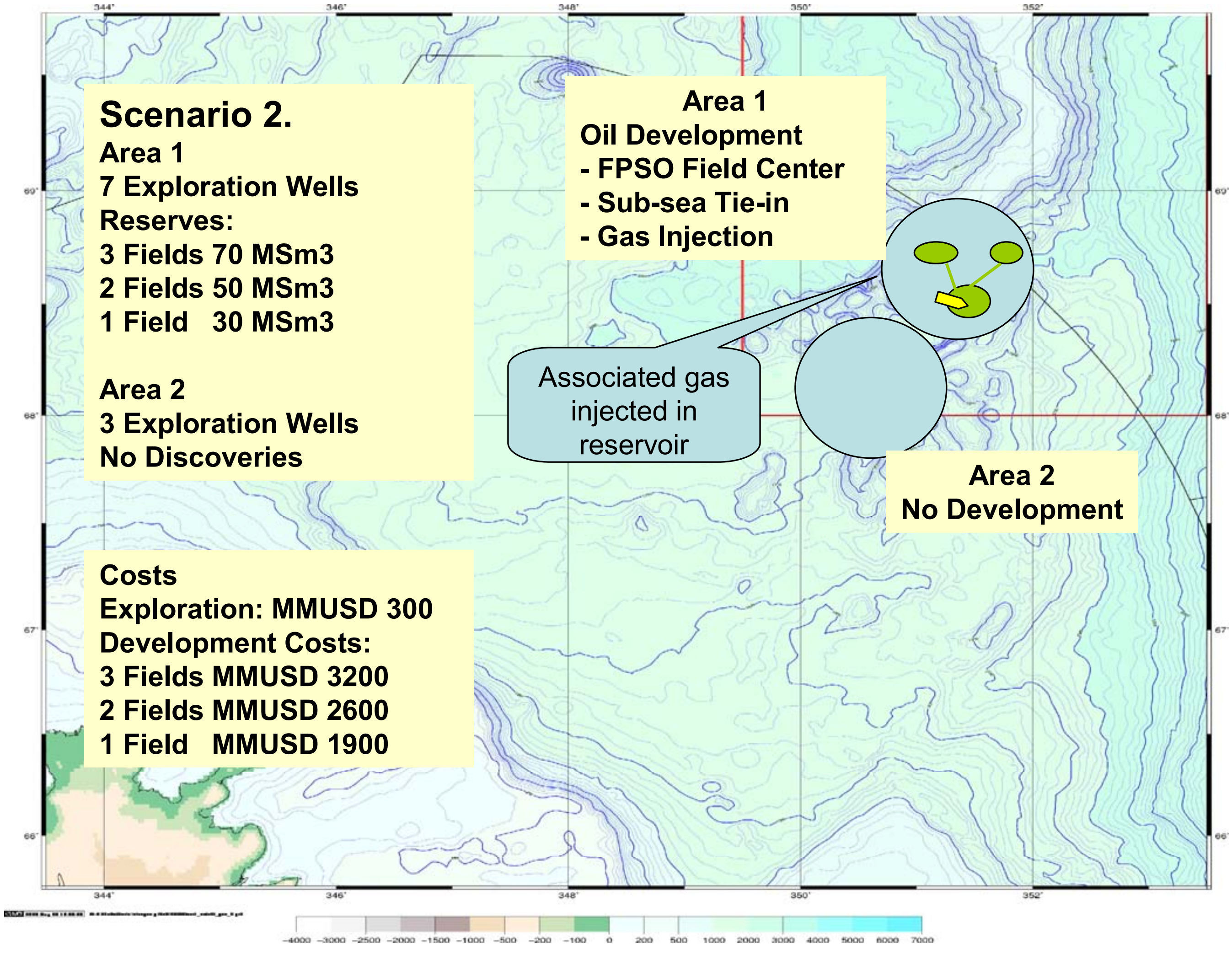

Figure 4.5 Scenario 2 – Small to Medium Oil Field Development

Estimated exploration costs are million USD 300 (MMUSD)
Estimated development costs are for:

- 3 Oil Fields million USD 3200 and max yearly operating cost million USD 100
- 2 Oil Fields million USD 2600 and max yearly operating cost million USD 80
- 1 Oil Field million USD 1900 and max yearly operating cost million USD 60
-

It is assumed that all services for logistics including helicopters and supply boats, and supply base are rented.

Assumed personnel requirements for Scenario 2

- Oil company; 10-15 employees

- Supply base and service personnel, 20-30 employees

Offshore manning 60- 100 operators, maintenance and service personnel each rotation

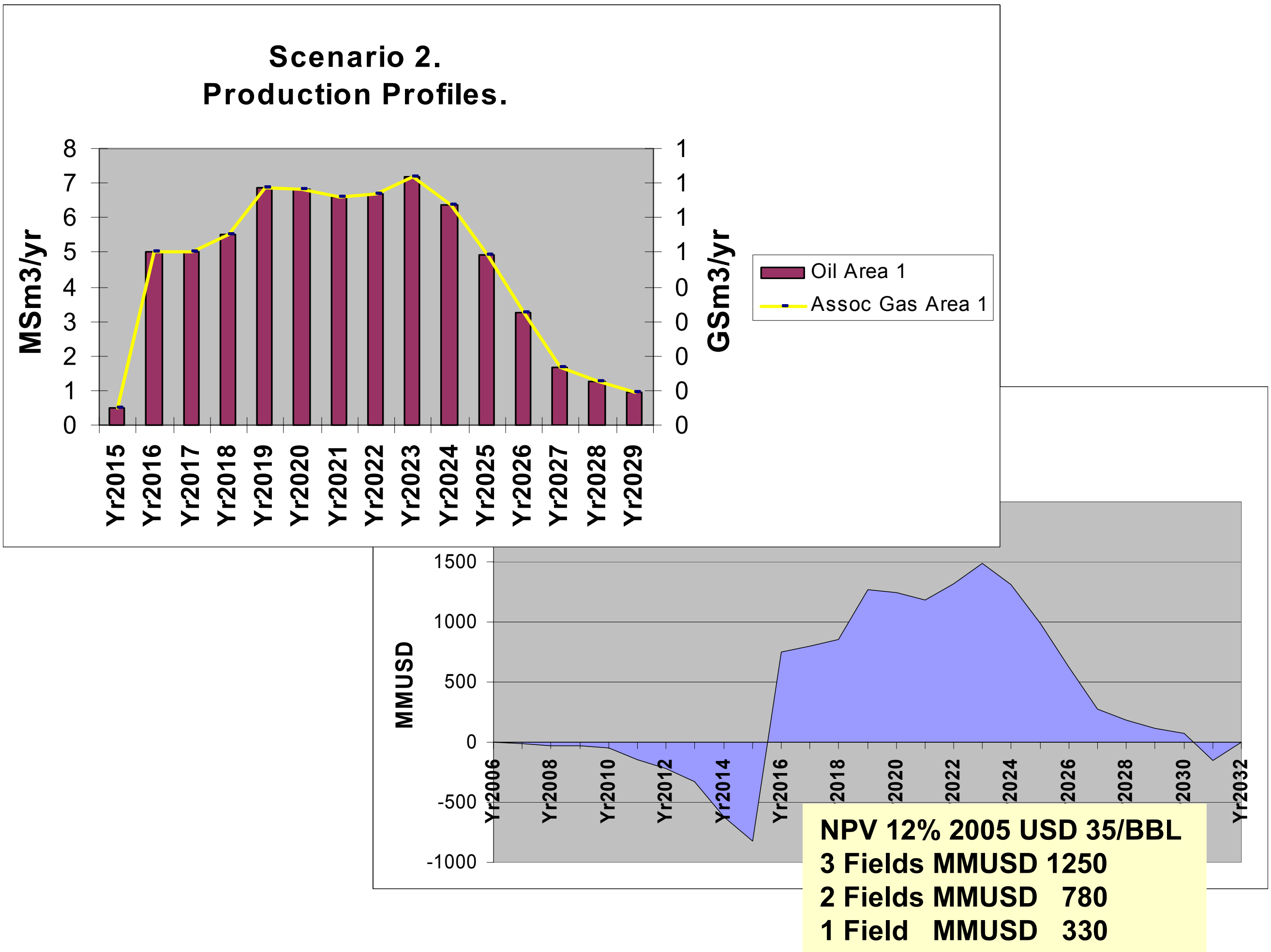

Figure 4.6 Scenario 2 – Production Profiles and Economics

Figure 4.7 FPSO with Shuttle Tanker

4.7 Scenario 3 – Oil and Gas Field Development

Scenario 3 represents an alternative with oil discoveries and oil developments of Area 1 and primarily gas and condensate discoveries and a gas/ condensate development of Area 2.

Scenario 3 will illustrate an integrated development between two areas a potential for use of common infrastructure between licensees and the potential for exploitation of gas resources at the Jan Mayen Ridge. The production of oil and gas will include all aspects of upstream oil and gas production with offshore and onshore direct production and onshore support functions.

For Area 1 a phased and integrated development of two oil fields (identical to Scenario 2 with two fields) is envisaged with a subsea development and an FPSO as field centre. The produced gas will initially be injected into the reservoir, but later produced and transferred for export through a pipeline to the processing platform in Area 2.

Area 2 is envisaged to be a phased subsea development with a floating Semi Submersible Production Platform as field centre and an FSO for storage and offloading of condensate. The area consists of several fields that are connected to the field production centre through pipelines from individual satellite field manifolds. The subsea wells are connected to the manifolds by flowlines and control of each field is maintained by means of service umbilicals.

The Semi Submersible Production Platform processes the multiphase well stream into gas, oil/condensate and water. The gas is stripped for liquids on the platform before it is compressed and transported through an export pipeline to shore, liquefied in an LNG facility and exported as liquefied gas by dedicated LNG transport tankers. The oil and condensate is transferred for storage at an FSO and periodically offloaded for export to dedicated oil shuttle tankers. The processed water is further cleaned before it is disposed to sea.

All offshore installations except the FSO are considered as up front CAPEX. The FSO is considered to be leased for the production life of the field and is considered as a part of OPEX.

OPEX costs for the offshore facilities, pipelines and onshore LNG facility include direct operating costs like consumables and maintenance, operators and support personnel, management and administration, supply base and logistics services.

Drilling of wells is performed by floating drilling units under short term for the purpose contracts. Transport of oil by crude oil shuttle tankers and of LNG by LNG tankers is considered to be performed under long term contracts and the transport costs are included in the net oil and gas prices.

Common use of infrastructure across licenses will normally be regulated by tariffs for processing, storage and transport of one party’s oil and gas by another party and in some instances the tariff regime may prohibit optimal use of infrastructure. In this scenario a tariff would be expected to be paid from Area 1 to Area 2 for processing, transport and liquefaction of associated gas. The economic assessments of this evaluation consider the developments of Area 1 and 2 as one economic entirety so that tariffs are not relevant for these evaluations.

The Scenario 3 is illustrated in Figure 4.8 and associated Production Profiles and Economics in Figure 4.9

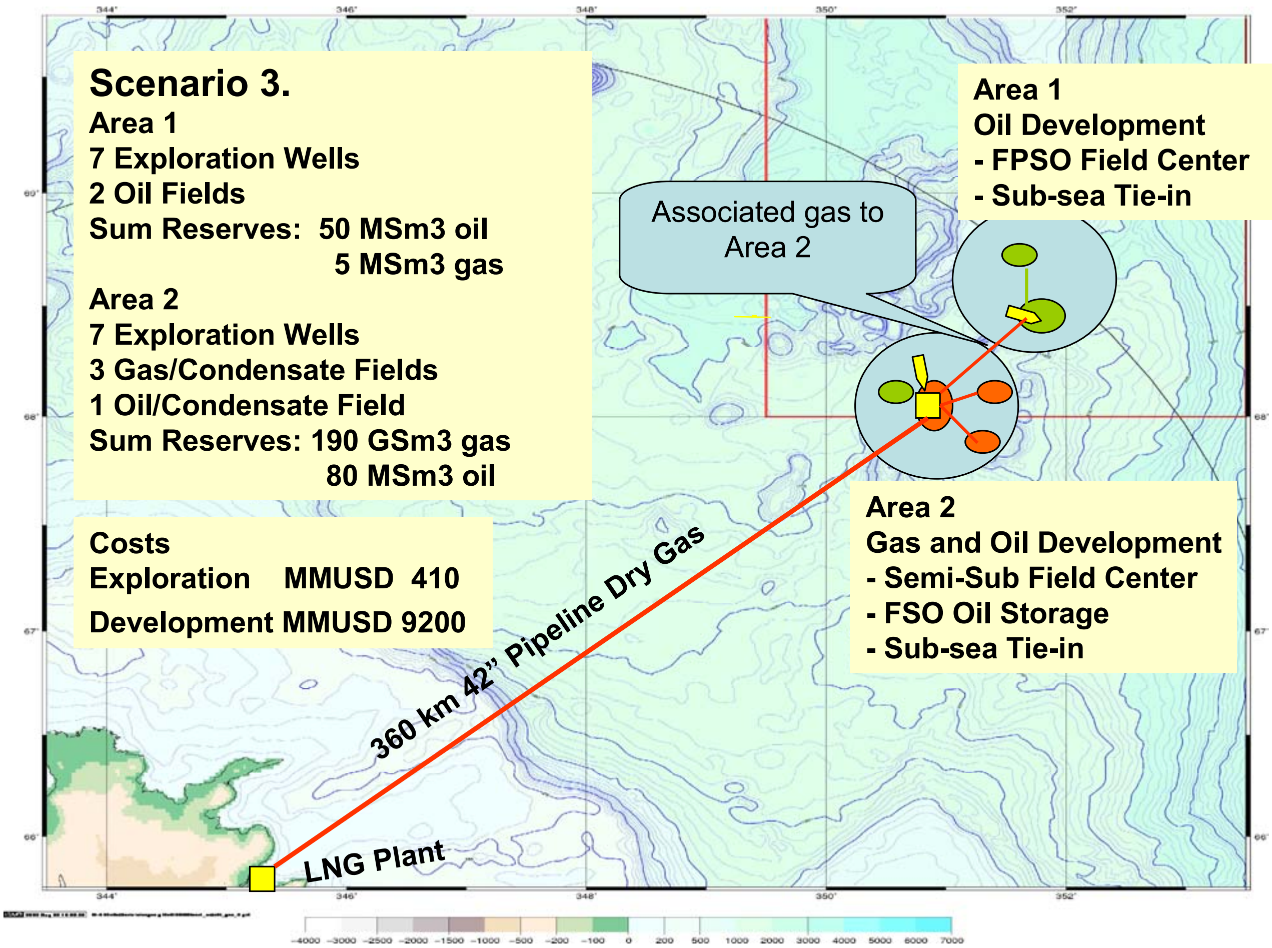

Figure 4.8 Scenario 3 – Integrated Oil and Gas Field Development.

Estimated exploration costs are million USD 410 (MMUSD)

Estimated investment costs are million USD 9200. Max yearly operating costs for Area 1 are million USD 80 and Area 2 million USD 190.

It is assumed that all services for logistics including helicopters and supply boats, and supply base are rented. Offshore storage tanker FSO is assumed to be leased.

Assumed personnel requirements for Scenario 3

- Oil Company; 30 -50 employees
- LNG facilities including operators, maintenance and service personnel 100- 150 employees
- Offshore manning 120-200 operators, maintenance and service personnel each rotation

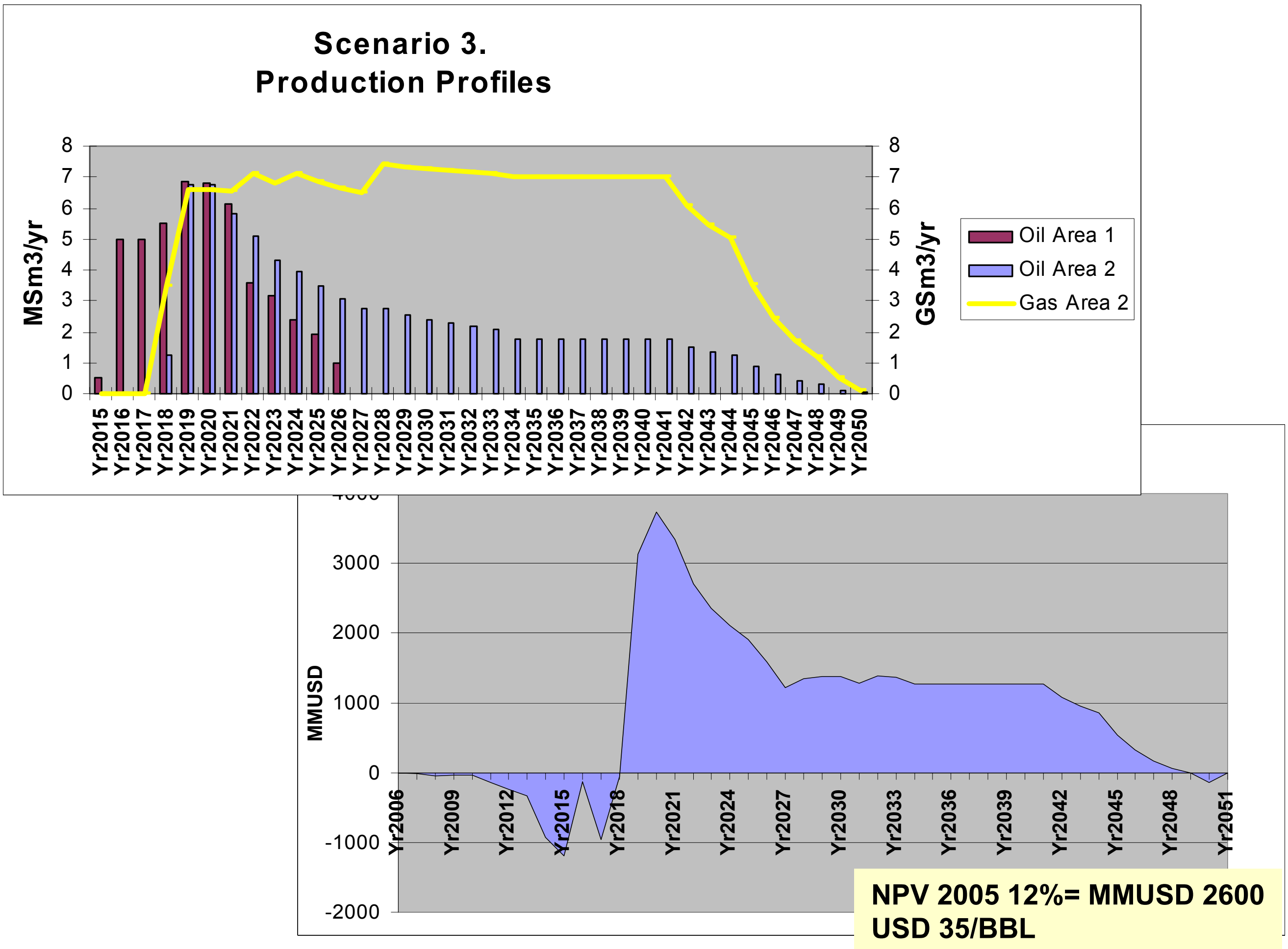

Figure 4.9 Scenario 3 – Production Profile and Economics

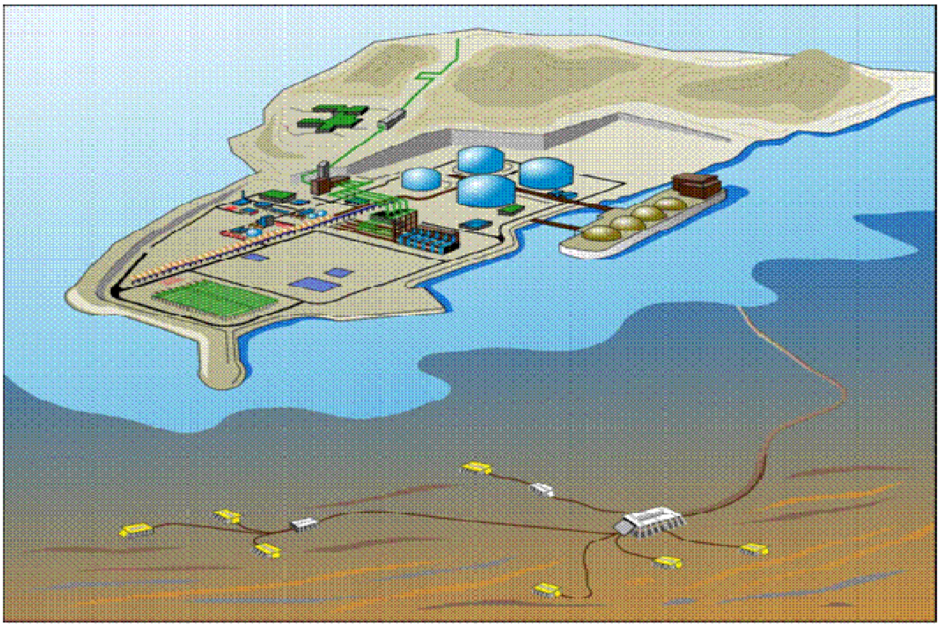

Fig 4.10 Onshore LNG Plant

4.8 Scenario 4 – Two Oil Field Developments

Scenario 4 represents an alternative to Scenario 3 with oil discoveries in Area 2 rather than gas. Oil development of Area 1 is identical to Scenario 3.

Scenario 4 will illustrate two separate developments of two oil areas and the disposal of gas in the oil reservoirs for reservoir pressure support and gas storage.

For Area 1 a phased and integrated development of two oil fields (identical to Scenario 2 with two fields) is envisaged with a subsea development and an FPSO as field centre. The produced gas will be injected into the reservoir.

Area 2 is envisaged to be a phased subsea development with a floating Semi Submersible Production Platform as field centre and an FSO for storage and offloading of oil. The area consists of two fields that are connected to the field production centre through pipelines from individual field manifolds. The subsea wells are connected to the manifolds by flowlines and control of each field is maintained by means of service umbilicals.

The Semi Submersible Production Platform processes the multiphase well streams into oil, gas and water. The oil is transferred to the FSO via a pipeline and flexible riser through the mooring buoy of the FSO for storage and offloading to dedicated shuttle tankers. The gas is stripped for liquids on the platform before it is compressed and injected into the reservoir. The processed water is further cleaned before it is disposed to sea.

Drilling of wells is performed by floating drilling units under short term for the purpose contracts. Offloading of oil by shuttle tankers are performed under long term contracts and the transport cost is included in the net oil price.

All offshore installations except the FSO are considered as up front CAPEX. The FSO is considered to be leased for the production life of the field and is considered as a part of OPEX.

OPEX costs for the offshore facilities include direct operating costs like consumables and maintenance, operators and support personnel, management and administration, supply base and logistics services.

Use of gas for reservoir pressure maintenance and gas disposal in the reservoir during oil production is often practised for offshore developments. The gas has a latent value (not assessed in this evaluation) and in many instances it will be commercially attractive to produce the gas near the end of the oil production life of the fields and to convert the oil fields to gas fields. For this scenario where the area has little or no infrastructure for gas it is considered favourable to store the gas until the area is further matured and offshore LNG processing technology is more advanced.

Scenario 4 is illustrated in Figure 4.11 and the associated Production Profiles and Economics in Figure 4.12

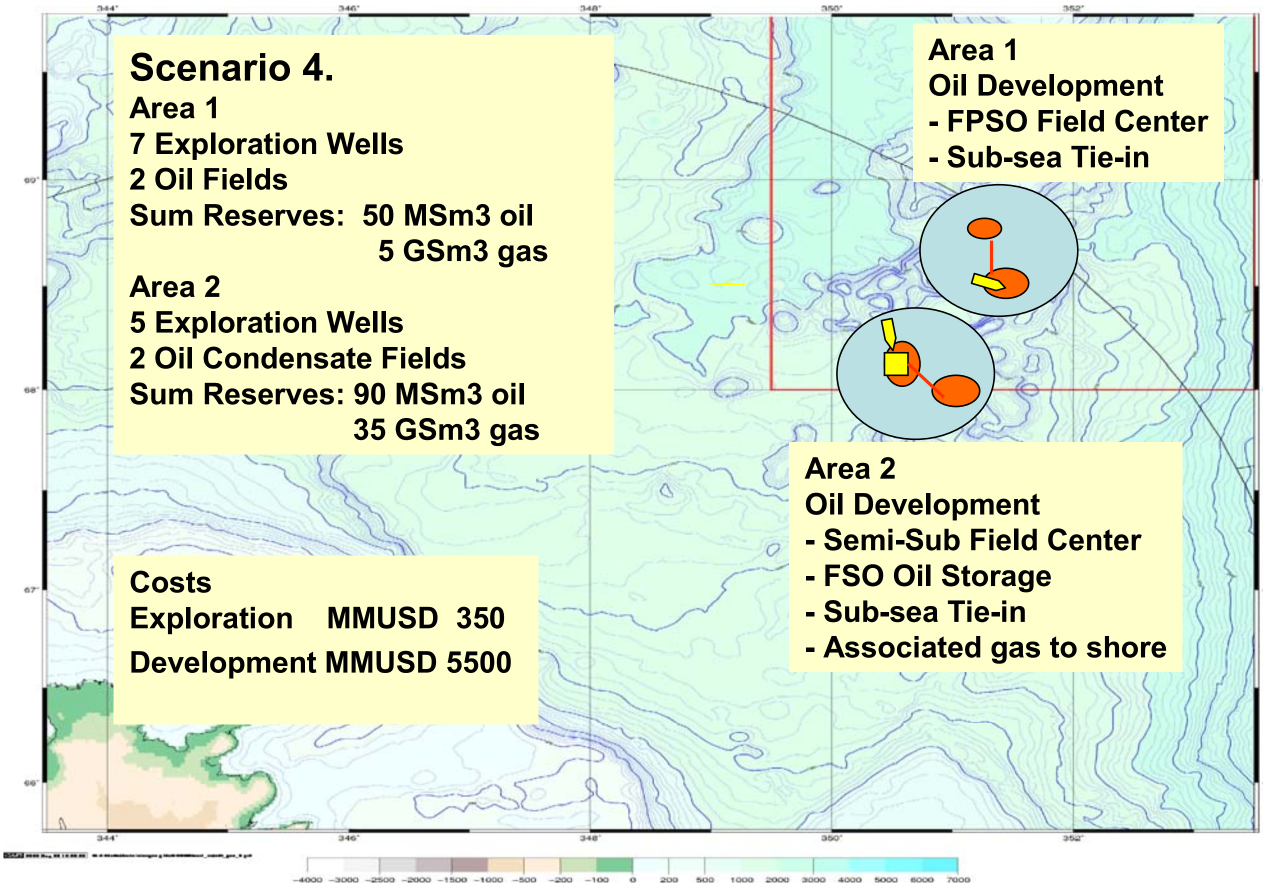

Figure 4.11 Scenario 4 – Two Oil fields with gas disposal in the reservoir

Estimated exploration costs are million USD 350 (MMUSD)

Estimated investment costs are million USD 5500 and max yearly operating costs for Area 1 are million USD 80 and Area 2 million USD 90.

It is assumed that all services for logistics including helicopters and supply boats, and supply base are rented. Offshore storage tanker FSO is assumed to be leased.

Assumed personnel requirements for Scenario 4

- Oil Company; 30 -50 employees
- Offshore manning 120-200 operators, maintenance and service personnel each rotation

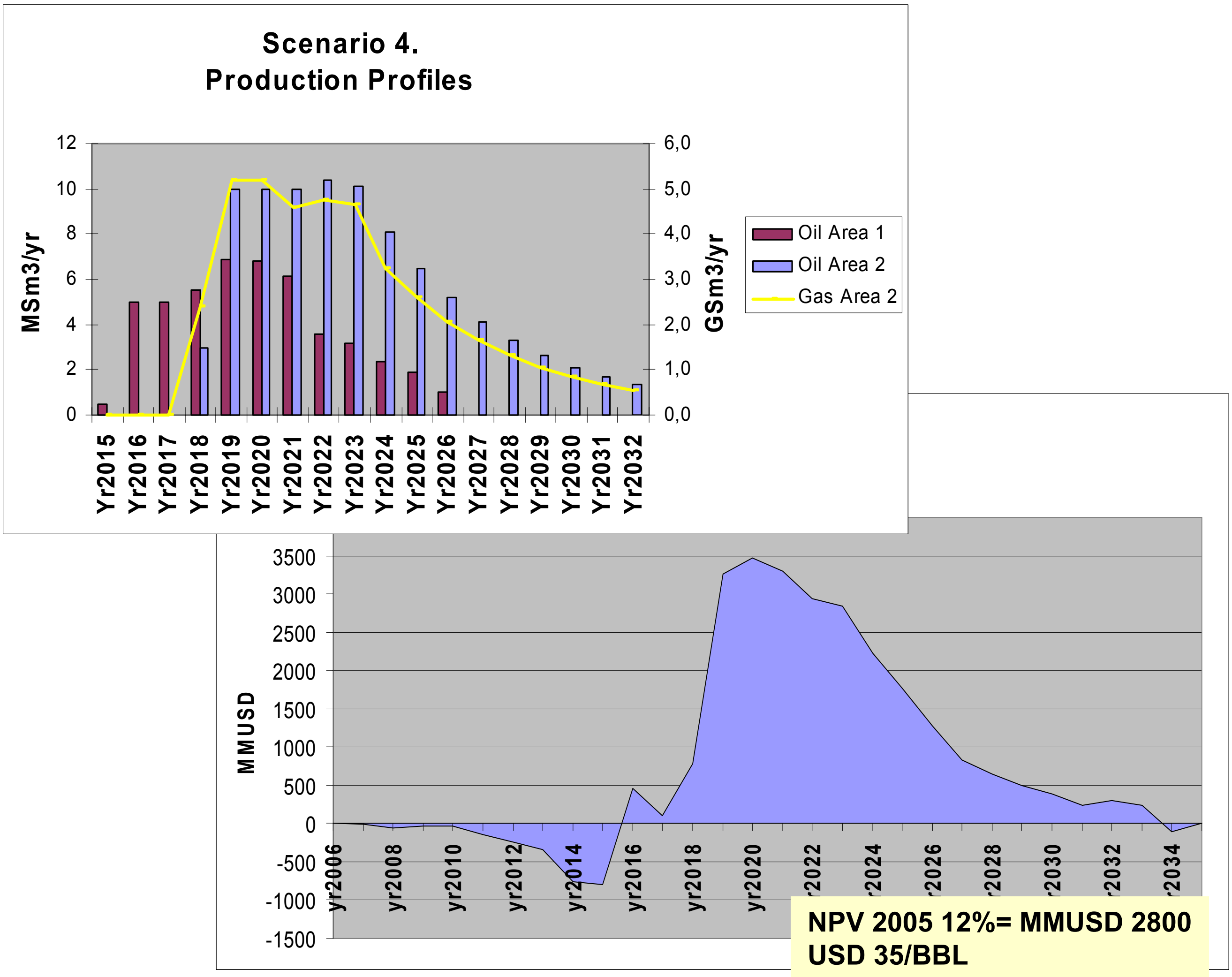

Figure 4.12: Scenario 4 – Production Profiles and Economics

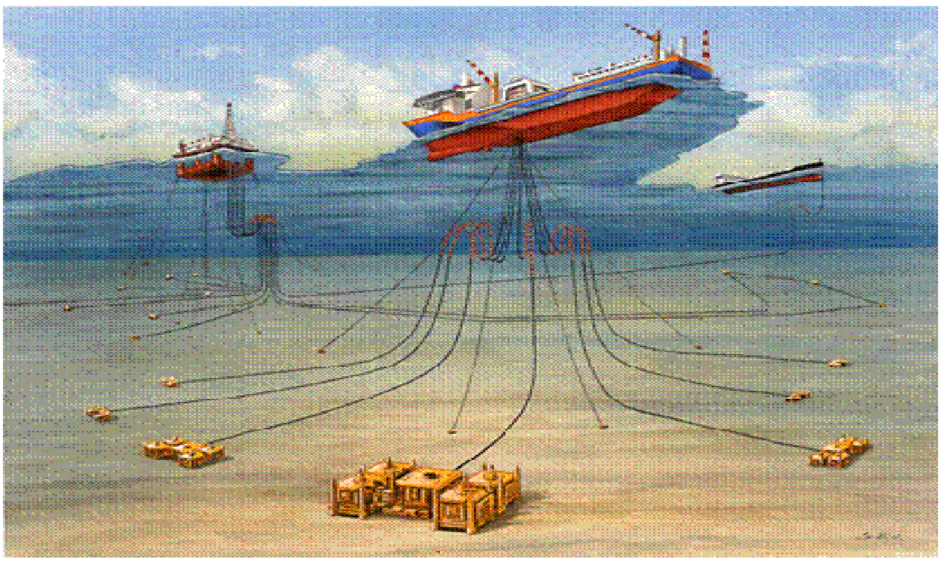

Figure 4.13 Subsea Oil and Gas production

4.9 Development Schedule

The development schedule in Figure 4.14 shows the main activities from exploration through field developments, and illustrates the expected time period to first oil.

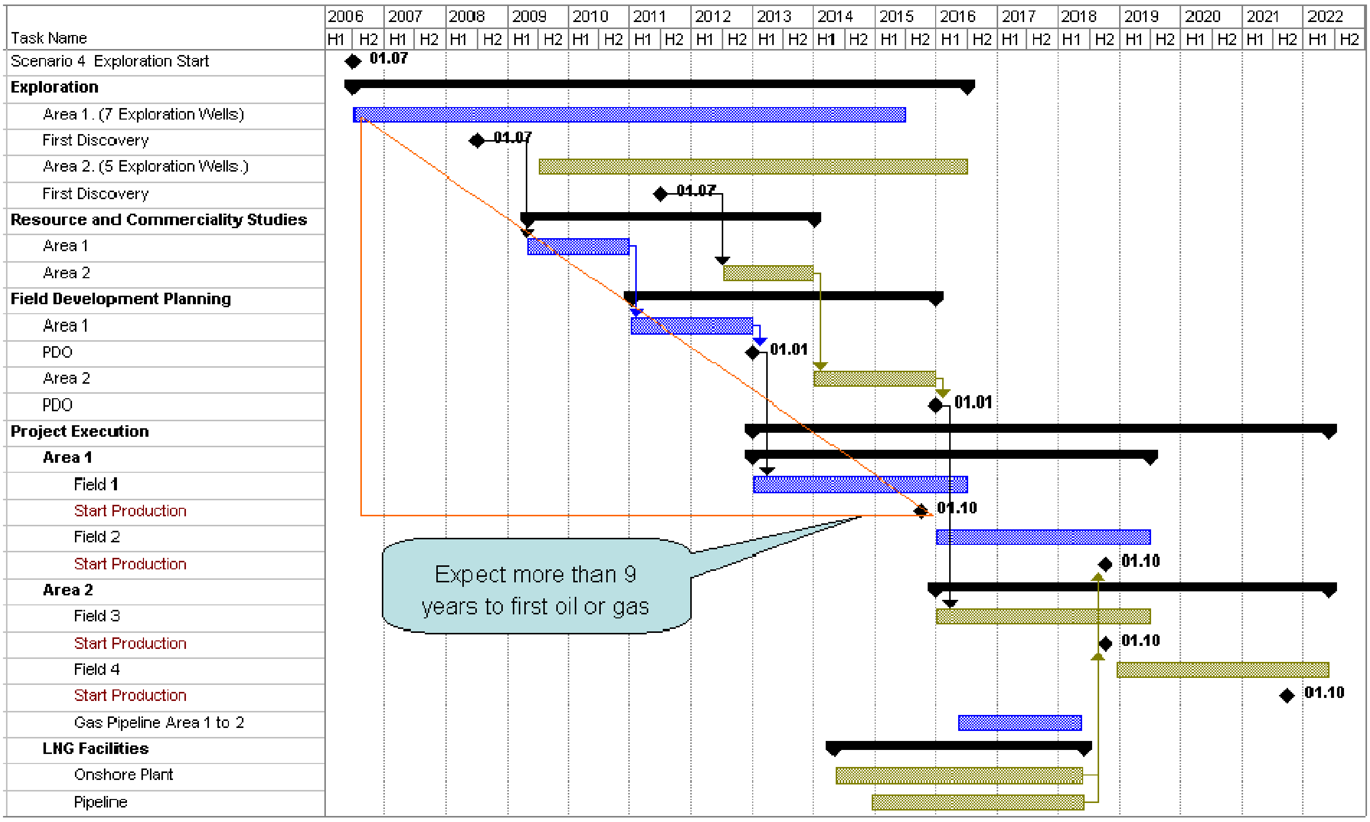

Figure 4.14: Development Schedule

4.10 Economics

4.10.1 Basic Assumptions

Oil Price
- USD 35 BOO (Barrel of Oil)
- Sensitivity USD 20 BOO

Gas Price
- NOK 1,00 Sm3 net of LNG transport
- Sensitivity NOK 0,60 Sm3 net of LNG transport

Discount Rate
- 12%

Development economy including the cost of exploration before tax and government take.

4.10.2 Economic Results

The economic results for different scenarios are shown in table 4.1 and figure 4.15 shows net present value of different scenarios at varying discount rates.

Scenario	Description	Oil Price BOO			
		USD 20		USD 35	
		NPV 12% MMUSD	IRR	NPV 12% MMUSD	IRR
1	Exploration only	(-130)	na	(-130)	Na
2	3 Oil Fields	150	15%	1250	28%
	2 Oil Fields	(-93)	10%	780	24%
	1 Oil Field	(-253)	4%	330	20%
3	Oil and Gas Area	131	13%	2600	26%
4	Two Oil Areas	775	20%	2800	33%

Table 4.1: Economic Results

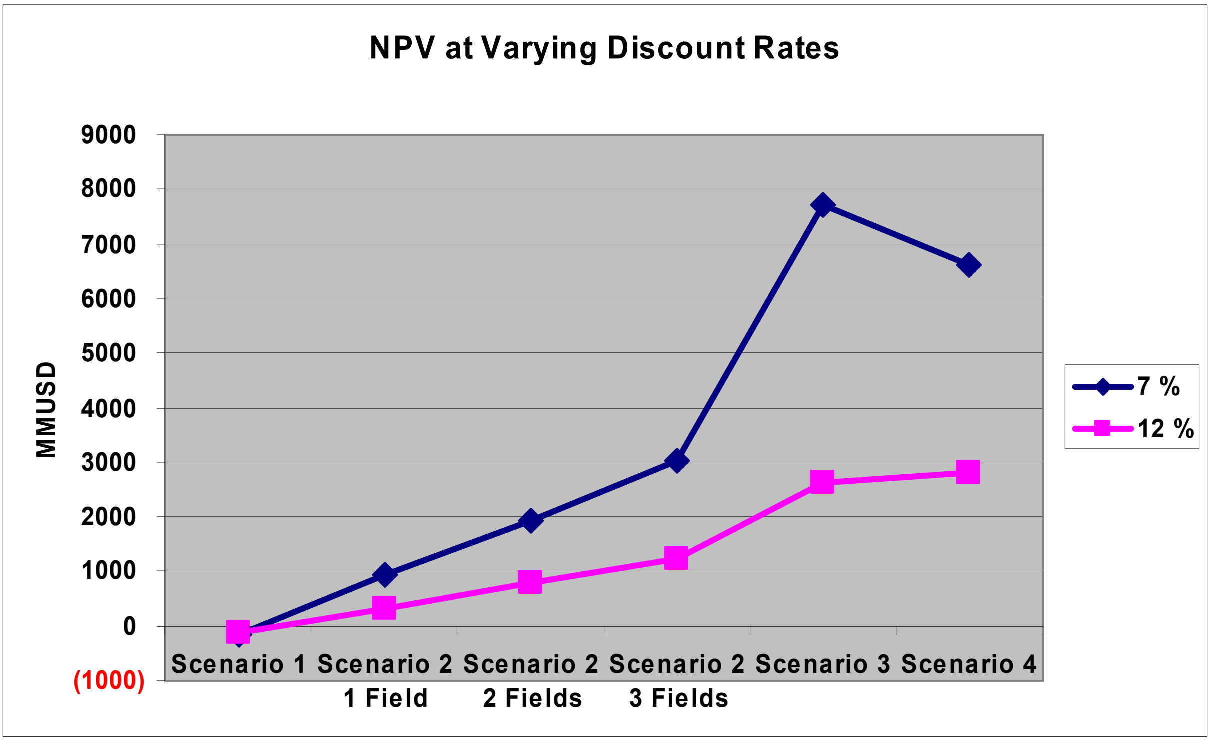

Figure 4.15 : Economics at 7% and 12% Discount Rate

The economic results indicate a strong incentive to explore the considered areas for potential oil and gas resources and the exploitation of both oil and gas has high commercial value in today's environment of high energy prices and increasing energy demand.

The results further indicate that bringing the gas to shore for liquefaction and LNG export is commercially attractive.

Sharing of infrastructure has not been evaluated at any length, but is considered to contribute positively to any development or in some instances it could be a key to make new developments possible. In this respect it should be noted that a climate and incentive for licensees to cooperate across licences should be facilitated for.

Gas disposal of associated gas in the reservoirs is possible and flaring of gas during normal operations is not a prerequisite for oil production. The economics of late recovery of injected associated gas in oil fields have not been evaluated, but could add positive value especially during late phases of production when more infrastructure has been developed.

It has not been the intent of the economics assessments to evaluate or conclude on the smallest development that could be attractive at the Jan Mayen Ridge. However, by interpolation of the economic indicators for Scenario 2, the limiting size for an oil field development could be in the range of 10- 20 MSm3 recoverable oil reserves.

5 Discussion

5.1 New Technology Development Trends

During the past 30-40 years, offshore developments have successively moved to harsher environments and deep waters. Technology is stretched and technology gaps closed. Offshore developments have moved from fixed platforms seafloor supported platforms to floating platforms, sub-sea developments and multiphase pipelines over long distances in deep waters.

The technology is international and moves forward through cooperation between regions and companies. Norway is an active participant of this technology drive together with participants in the Gulf of Mexico, offshore Brazil and Angola and in the Barents Sea.

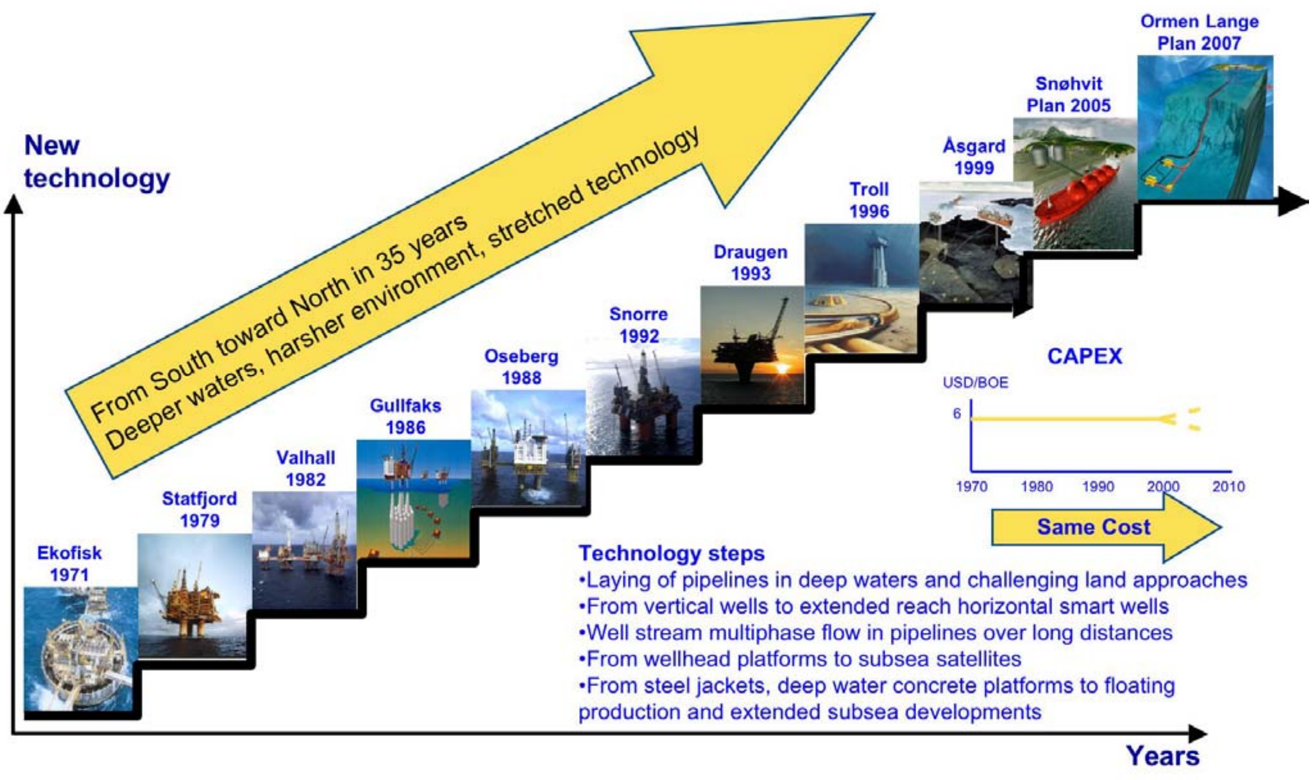

Figure 5.1 Technology Steps offshore Norway

SAGEX believes the following to be the most important drivers for technology development of interest from an Icelandic perspective:

- As the more easily accessible petroleum resources in the world are being discovered and produced, oil companies are increasingly being forced to turn their attention to remote, frontier areas to find new business.

- Increasing global, regional and local environmental concerns are forcing the oil industry to substantially cut their emissions and increase their energy efficiency.

These drivers have lead to significant developments in amongst other the following areas:

- Deepwater drilling and subsea well tie-backs
- More efficient platform designs
- Deepwater riser technology
- Deepwater pipelaying
- Pipeline transportation of unprocessed wellstream, flow assurance
- Subsea processing
- Increased Oil Recovery (IOR)
- Floating LNG and GTL production
- More efficient LNG and GTL processes
- More environmental-friendly chemicals for drilling and production
- Improved oil/water separation technologies
- Gas turbines with lower emissions and increased efficiency
- Re-injection of aqueous and gaseous effluents
- Offshore platforms powered by electricity from shore

These trends are expected to continue and mature, which will clearly benefit a future development of petroleum resources at the Jan Mayen Ridge area.

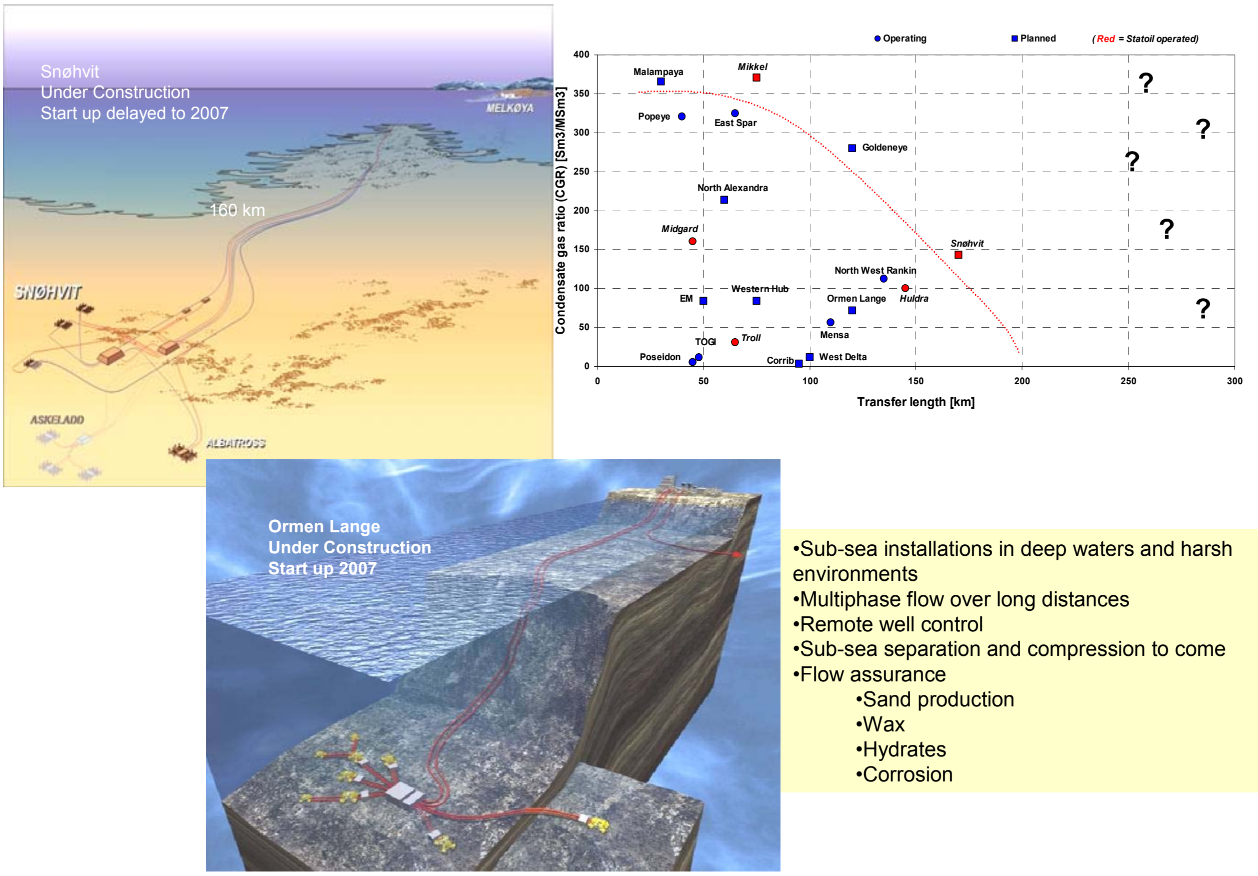

Figure 5.2 : Subsea Developments. Multiphase flow over long distances.

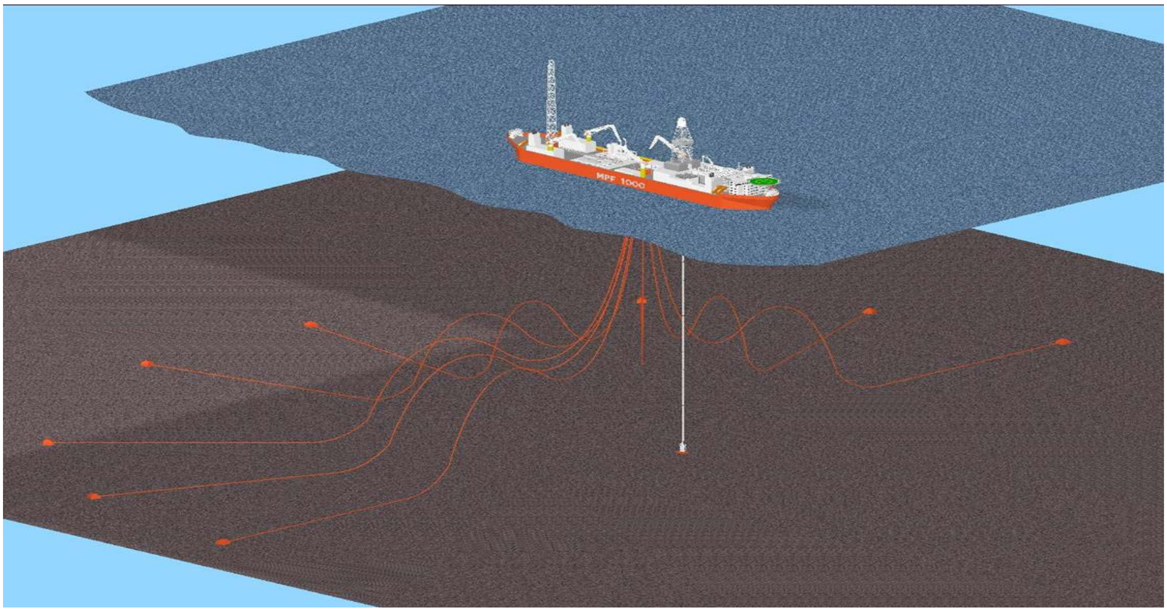

Figure 5.3 : Near-future Multipurpose Floater (MPF 1000). Simultaneous drilling, production, storage and offloading.

5.2 Oil and Gas Market

5.2.1 Global Oil Price Development

The last couple of years have seen a remarkable development in crude oil prices; see Figure 5.3. Prices have been driven by a narrowing gap between demand on the one side, and available production capacity on the other. Currently (December 2005) prices are hovering around 60 USD/barrel.

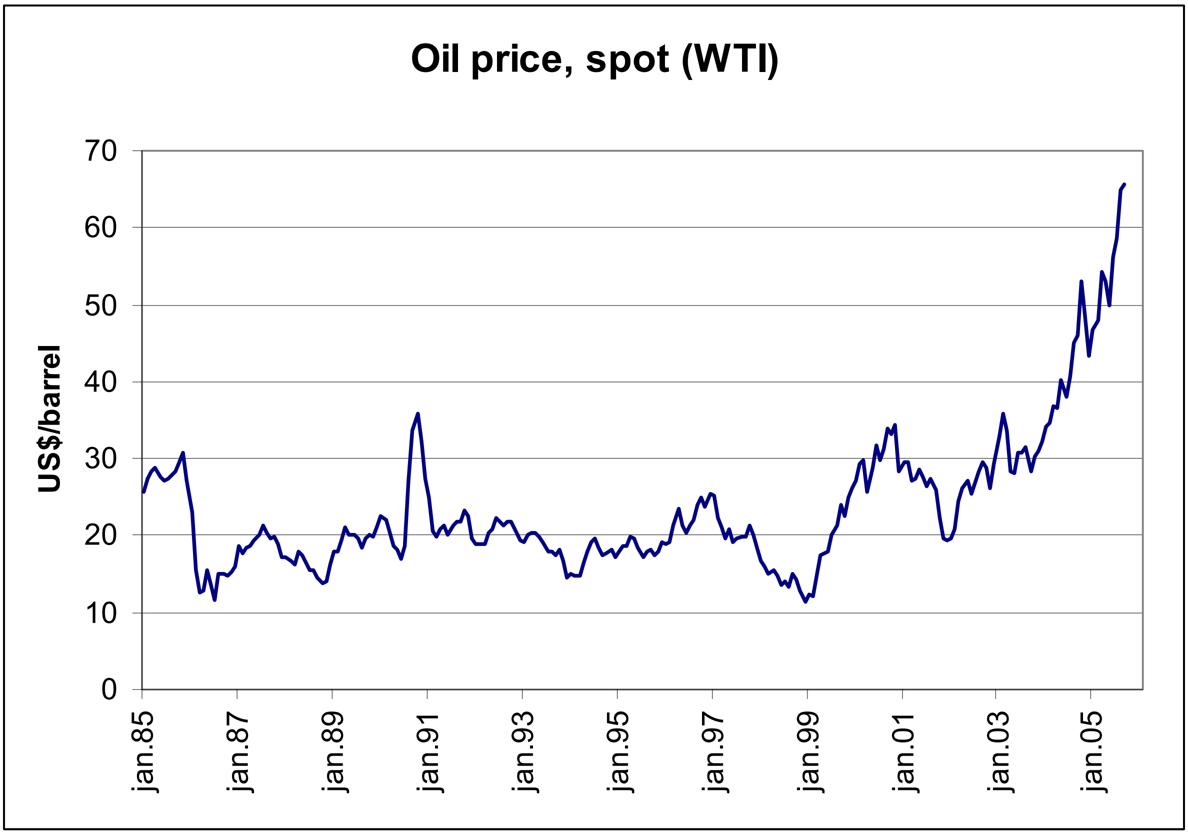

Figure 5.3: Oil price development, West Texas Intermediate (WTI) spot price January 1985 – September 2005

There are several reasons for this situation:

- Continued strong demand growth, particularly in developing countries like China.
- Low oil prices during the 1980s and 90s caused many producers not to invest in new capacity.
- OPEC no longer has sufficient spare capacity to control world prices.

Recent price levels have been further influenced by:

- The war in Iraq. Iraq's oil production is now at below pre-war levels.

- Hurricanes in Gulf of Mexico causing disruption in US supply of crude oil and refined products during second half of 2005.

It is expected that it will take many years for OPEC and non-OPEC producers to increase their production capacity to a level which can reassure the market. The current high price levels are therefore foreseen to last for several years, and might even increase further.

Most observers do predict, however, that prices will stabilise themselves on a lower level once adequate capacity has been built up. This long term price expectation is the key factor in the oil companies' decision process to invest in future capacity.

Until around 2002, estimates of long term crude oil prices typically converged in the range 18-21 USD/barrel. Long term price estimates have risen sharply over the last couple of years. The gap between low and high estimates has also widened, indicating increased uncertainty. Long term price forecasts now span from 20 to 60 USD/barrel and more, with the majority of estimates being in the range 30-50 USD/barrel. For investment planning purposes, prices of 25-30 USD/barrel have lately been quoted by several oil companies.

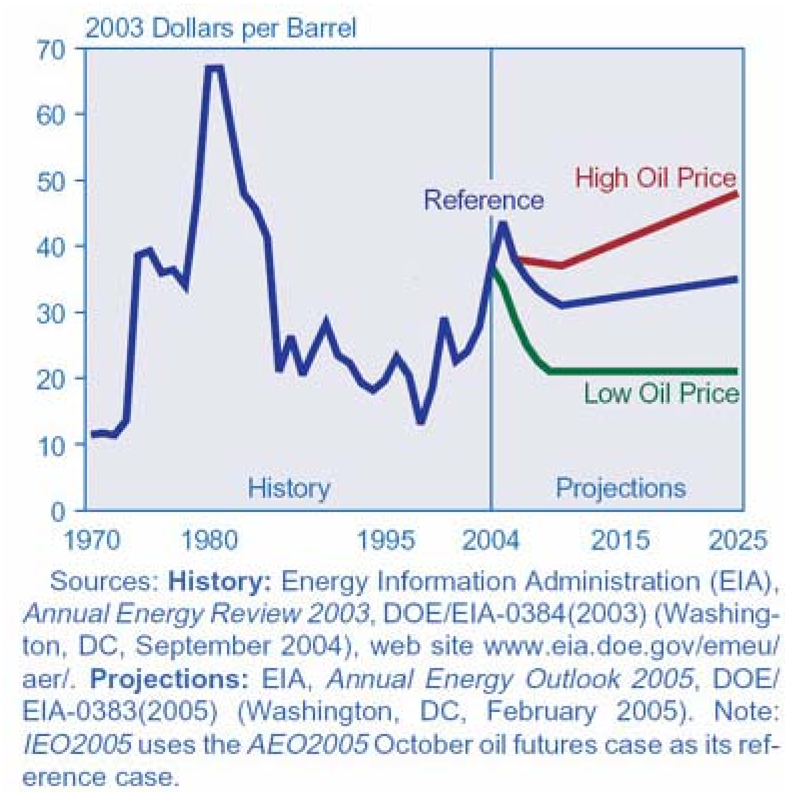

Figure 5.4: World oil prices in three cases (Source: US Energy Information Administration). Note that this forecast has already been beaten, since the average price for 2005 seems to end up at around 57 USD/barrel.

These developments indicate that petroleum exploration and production in high-cost, frontier areas such as the Jan Mayen Ridge area will be more attractive to oil companies now than just a few years ago.

5.2.2 Gas Prices and Gas Utilisation

Except for short term and seasonal fluctuations, natural gas prices will generally follow the prices of alternative energy sources, usually oil, coal, hydroelectric or nuclear power. Gas contract prices are commonly linked to indices of such alternative energy sources (mainly crude oil, fuel oil or coal). In a medium and long term perspective higher oil prices therefore means higher gas prices as well.

The Jan Mayen Ridge area is located remotely from the world's large petroleum consuming markets. This is less of problem for oil, which can easily be transported by tankers and sold on flexible contract terms or in the spot market. Gas, on the other hand, is not that easy to handle and depends on expensive infrastructure for transport and distribution. As a consequence, natural gas and LNG have traditionally been traded on long term take-or-pay contracts where the combined pre-project sales volumes had to be high enough to carry all the initial investments.

Crude oil is traded globally. In comparison, natural gas has traditionally been traded in regional markets: In USA and Europe almost all natural gas has been supplied through pipelines; in Japan LNG imports from Asian, Australian and Middle Eastern producers are predominant. The recent high oil prices and escalating world demand for gas as a cleaner alternative to coal and oil is about to change this.

The global LNG market is currently growing at a rate of about 10 % per year. In USA and Northwest Europe the percentage growth is considerably stronger, as declining supplies from indigenous gas fields make these countries increasingly dependent on imports. Since LNG is transported by tankers it can be traded both regionally and globally. LNG is thus gradually changing natural gas from a regionally traded to a globally traded commodity.

LNG eliminates the need for a gas export pipeline from the producing country to the consuming country, or countries. LNG must however be regasified before use. It therefore still requires the presence of a gas pipeline grid for distribution in the consuming countries.

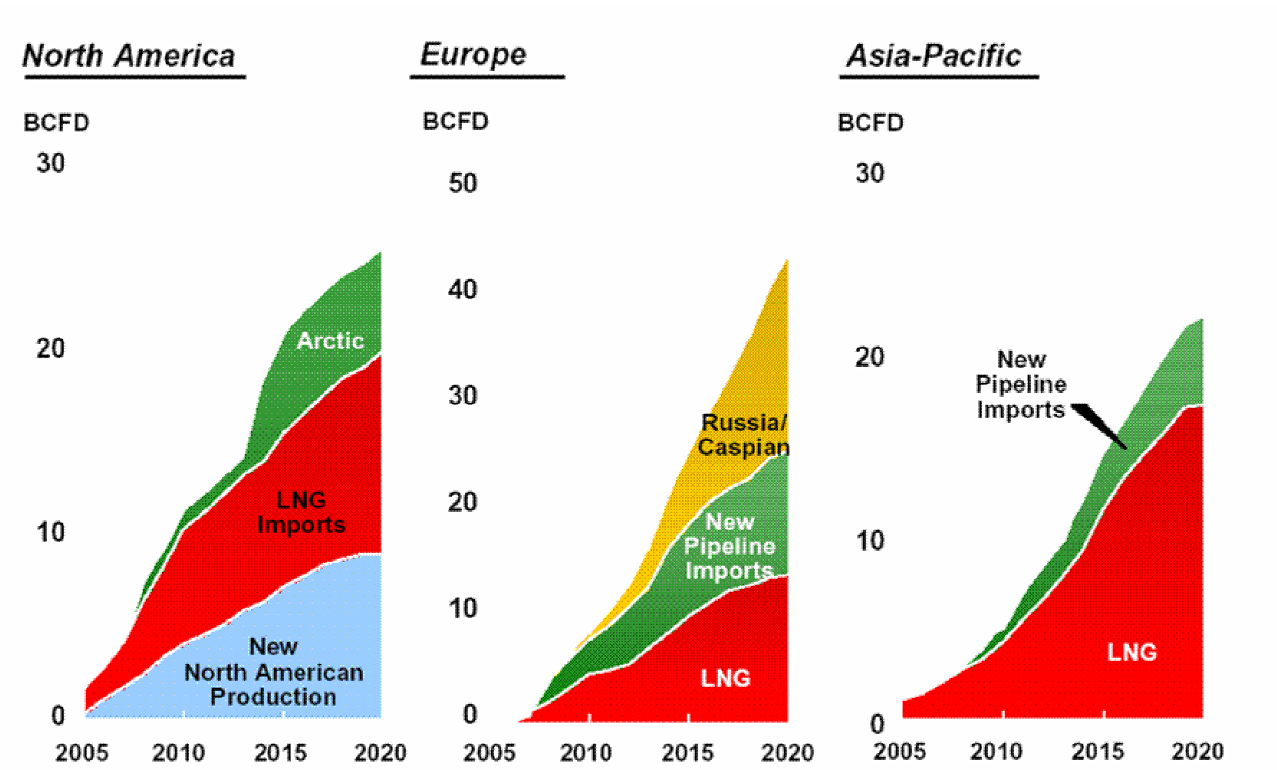

Figure 5.5: Forecast of increase in gas supply demands (Source: ExxonMobil)

GTL technology is now emerging as an alternative to LNG for gas developments in remote areas. The advantages of GTL are:

- Huge market potential (global diesel and jet fuel markets)
- Environmental advantages compared to conventional oil products
- Ease of transportation and distribution (no cryogenic tankers, regasification facilities or gas distribution grids required)
- Independence of long term sales contracts.

The demand for GTL is expected to grow rapidly in the years ahead.

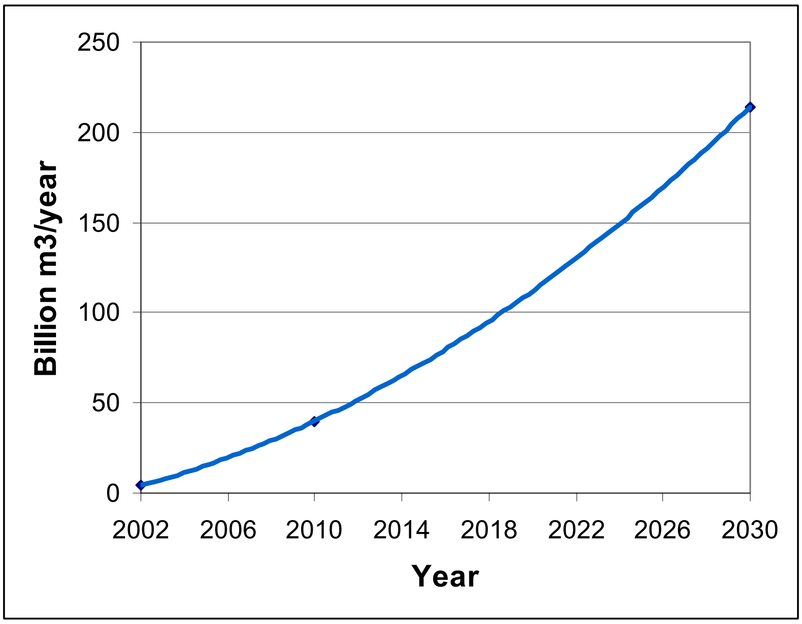

Figure 5.6: Predicted future global demand for GTL (Source: IEA)

If the global demand for LNG and GTL shall continue to grow, LNG and GTL- technologies must be competitive to the conventional alternatives. The conventional alternatives are pipeline gas and traditionally refined petroleum products. LNG requires large investments in production plant, special tankers and receiving terminals. GTL requires similarly large investments. But as more of these facilities have been constructed, the costs have come down, thus improving their competitiveness.

Iceland may be seen by oil companies as a high cost source of gas. However, Iceland has several advantages which can be actively used to attract interest in potential Icelandic gas developments, e.g.:

- A stable political and economic climate
- A predictable and well-functioning legal system
- A well-trained workforce and modern educational, business and finance institutions
- Closer location to the large markets in USA and Europe than many of its competitors

6 Conversion factors, abbreviations and references

Conversion factors

1 m^3 oil = 35.315 ft^3 = 6.2898 barrels (bbls)
1 barrel oil (BOO) = 0.159 m^3 (159 litre)
1 Nm^3 gas = 1 Sm^3 gas (1 atm and 0^0C)
1 m^3 = 33.31 ft^3
1 Nm^3 gas = 0.00679 barrels oil equivalents
1m^3 oil equivalents = 1 m^3 oil or 1,000 m^3 gas

M = 10^3 = 1 thousand (Kilo)
MM = 10^6= 1 million (Mega)
MMM= 10^9= 1 milliard (am.billion)(Giga)

List of Abbreviations

AMAP	Arctic Monitoring and Assessment Programme
BBL	Barrel
BCFD	Billion Cubic Foot pr. Day
BOO	Barrel of Oil
BOPD	Barrel of Oil pr Day
BSL	Bestemmelser for Sivil Luftfart (Norwegian Civil Aviation Authority Regulations)
CAPEX	Capital Expenditures
FPSO	Floating Production Storage and Offloading
FSO/FSU	Floating Storage and Offloading Unit
G&G	Geology and Geophysics
GI	Gas Injection
GOR	Gas Oil Ratio
GPS	Global Positioning System
GSm3	Billion Standard m3 of gas
GTL	Gas To Liquid
IEA	Energy Information Administration
IOR	Improved Oil Recovery
IRR	Internal Rate of Return
LNG	Liquefied Natural Gas
MMUSD	Million US Dollars
MSm3	Million Standard m3 of oil
NCS	Norwegian Continental Shelf
NPV	Net Present Value
OLF	Association of Oil Companies in Norway
OPEC	Organisation of Petroleum Exporting Countries
OPEX	Operational Expenditures
PDO	Plan for Development and Operation
R&D	Research and Development
SEA	Strategic Environmental Directive
TLP	Tension Leg Platform
WTI	Western Texas Intermediate (Standard quality for pricing of oil)

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