2.0 EXPLORATION AND PRODUCTION ACTIVITIES

The C-NLOPB's regulatory role includes the issuing of approvals and authorizations pertaining to offshore exploration and production activities. The C-NLOPB is designated a Federal Authority and acts as the designated Federal Environmental Assessment Coordinator for offshore seismic surveys, geophysical surveys and drilling environmental assessments under the *Canadian Environmental Assessment Act* (CEAA). All offshore seismic surveys, geophysical surveys and exploration drilling programs on the East Coast are subject to a site-specific environmental assessment under CEAA.

Several other federal agencies have an advisory role in the environmental assessment process with respect to offshore explorations and production activities. DFO is responsible for the protection of fish and fish habitat under the *Fisheries Act*. Environment Canada is responsible for the protection of migratory birds under the *Migratory Birds Convention Act*, as well as discharges to the marine environment under Section 36 of the *Fisheries Act*. Transport Canada is responsible for provision of safe navigation (under the *Navigable Waters Protection Act*) and discharge of pollutants at sea (under the *Canada Shipping Act and Regulations* such as the *Pollutant Discharge Reporting Regulations*, 1995 and the *Guidelines for the Control of Ballast Water Discharge from Ships in Waters Under Canadian Jurisdiction*).

2.1 Exploration and Production Platforms

Exploration and delineation activities consist of:

- seismic survey-use of seismic to map rock layers and properties through the detection of differing reflections of sound passing through geological formations;
- geotechnical survey - taking samples (cores) of the substrate prior to positioning a drilling rig over a potential exploration/delineation wellsite to ensure the substrate will pose no hazard to the drilling rig;
- drilling a well - the primary activity of exploration/delineation drilling, this activity penetrates the substrate to an oil- or gas-containing formation; the primary discharge related to this activity is drill cuttings. Water-based muds (WBMs) are usually used for the top sections of the well, with synthetic-based muds (SBMs) used for deeper sections of the well and horizontal wells where borehole stability and integrity can be an issue.

2.1.1 Seismic Surveys

Seismic surveys are non-invasive techniques (2-D and 3-D seismic mapping) used to map rock layers and properties through the use of sound propagation and related echo mapping. Typical seismic surveys are able to map rock layers over 10 km deep (Cook 2006). A typical seismic survey vessel is provided in Figure 2.1.

Figure 2.1 Typical Seismic Survey Vessel

Source: http://www.fugro.no/portal/alias__Rainbow/lang__en-US/tabID__3498/DesktopDefault.aspx

A seismic survey is used to map hydrothermal porosity development via 2-D seismic, 3-D seismic and VSPs. A geotechnical program must be conducted to ensure the substrate is suitable for positioning the jack-up rig as a drilling platform. The purpose of such a survey is to demonstrate that drilling activities can be conducted in a manner that does not endanger personnel or the environment. The C-NLOPB conducts an assessment of any proposed geotechnical program in accordance with the *Accord Acts* and as per the *Geophysical, Geological, Environmental and Geotechnical Program Guidelines, Newfoundland Offshore Area*, April 2004.

2.1.2 Geohazard Surveys

A geohazard can be defined as:

> a geological state, which represents or has the potential to develop further into a situation leading to damage or uncontrolled risk (NGI 2006).

The focus on offshore geohazards has increased as offshore oil and gas activities move into increasingly deep waters and a larger proportion of field installations are placed directly on the seabed.

A wellsite/geohazard survey is required to detect hazards or potential hazards in the immediate vicinity of the proposed well locations. The survey will also ensure suitable subsea conditions for drilling purposes.

The purpose of the survey is to demonstrate that drilling activities can be conducted in a manner that does not endanger personnel or the environment.

Typical offshore geohazards include:

- slope stability;
- shallow gas;
- gas hydrates;
- shallow waterflow;
- mud diapirism and volcanism;
- gas and fluid venting forming seafloor, rockmarks; and
- seismicity.

An example of a typical vessel used for geohazard surveys in Newfoundland and Labrador is the *Anticosti* (Figure 2.2). This vessel has accommodation for 30 (10 marine crew plus 20 survey crew).

Figure 2.2 Typical Geohazard Survey Vessel

Source: Cape Harrison Marine Group n.d. (www.capeharrison.com).

2.2 Drilling Activities

Seismic surveys and geological knowledge can provide information that a location may have the potential for hydrocarbon resources. Exploration and delineation wells are drilled to confirm the presence or define the extent of petroleum resources in specific locations as the actual geological properties and confirmation of hydrocarbon resources can only be determined by exploratory drilling programs. Drilling activities (both exploration and production) are undertaken by the offshore oil and gas industry to:

- confirm the presence of petroleum hydrocarbons;
- delineate the resource; and
- to increase the accessibility to the resource during production.

Regardless whether the drilling activity is carried out for exploration or production, equipment and related operational effects are essentially the same.

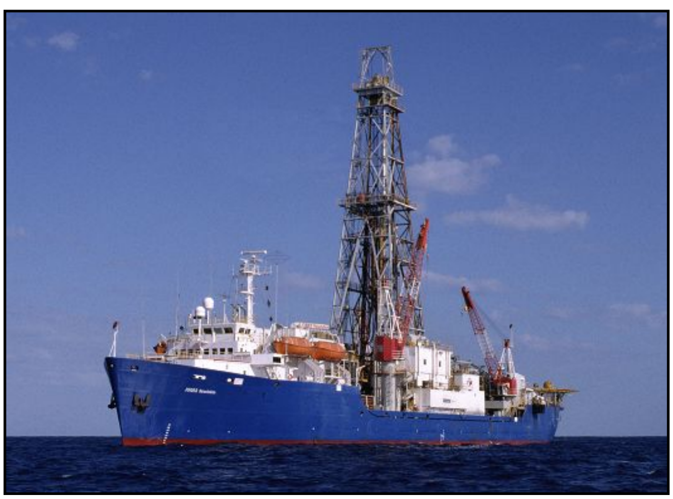
2.2.1 Drilling Platforms

Typically, drilling operations on the Canadian East Coast are conducted from several types of platforms, including a jack-up rig, a semi-submersible or a drillship (Figure 2.3). The type of rig chosen is based on the characteristics of the well site physical environment, well site water depth, expected drilling depth and the mobility required based on well site weather and ice conditions (Canadian Association of Petroleum Producers (CAPP) 2001).

Figure 2.3 Typical Drilling Platforms

Jack-up Rig

Semi-submersible Drilling Unit



Drillship

The offshore drill rig is a complex platform housing the drill equipment and working and living quarters, while supported by supply vessels and helicopters. There are two basic types of offshore drill rigs; mobile and permanent. Mobile platforms are typically used for exploration drilling while permanent platforms are used for production.

Typical offshore mobile platforms are jack-up rigs, semi-submersible rigs and drill ships. There are a wide variety of permanent drilling platforms; the actual platform used is dependant upon water depth, proximity to land, nature of the resource and physical environmental conditions such as weather and ice conditions.

A jack-up drilling rig is one in which the hull of the vessel is suspended above the surface of the ocean by means of legs which jack down through the hull to the sea floor. As the legs are jacked down, the hull is jacked up to the desired distance above the water - the air gap. A jack-up is therefore bottom-founded and is limited to water depths within the length of its legs. Used in water depth of less than 120 m, these rigs cannot move under their own impetus and units are towed to the drill site (CAPP 2001).

Drilling in deeper waters is usually conducted from a semi-submersible drilling unit. Semi-submersibles are also used in areas where increased mobility is required (i.e., areas prone to incursions of sea ice and icebergs). The drilling platform sits atop steel pontoons that are filled with water so that the unit floats with the main deck above water and the remainder below the water surface. The semi-submersibles are towed to the drilling site and are either moored to the bottom (with a series of 8 to 12 anchors (which may extend up to 1 km from the rig)) or are kept on station using a dynamic positioning system (computer-controlled thrusters) in deeper waters (1,000 to 2,000 m). As a semi-submersible is not bottom-founded, it can work in much greater water depths than a jack-up. The maximum water depth is a function of the length of the rig's riser, a bundle of utility tubes through which drilling fluids and other material are conducted, enclosed in an outer tube, suspended to the seafloor. A semi-submersible can usually operate in rougher seas than a drillship (CAPP 2001). A summary of key features of a typical jack-up rig and semi-submersible are provided in Table 2.1.

Table 2.1 Summary of Key Features of a Jack-up Rig and Semi-submersible

Item	***Rowan Gorilla VI***	***Grand Banks***
Type	Self-elevating	Semi-submersible
Year Built	2000	1984
Maximum Water Depth	121.92 m	457.2 m
Maximum Drilling Depth	10,660 m	7,620 m
Maximum Variable Load (drilling)	13,767 kips	12,564 kips
Derrick Capacity	1,133,980 kg	589,670 kg
Liquid Mud Storage Capacity	841.66 m^3	391.73 m^3
Bulk Material Storage Capacity	566.32 m^3	563.49 m^3

Drillships are generally used in areas of relatively deep water. Drill ships are typically anchored to the bottom in water depths of approximately 200 to 1,000 m, and are kept on station using a dynamic positioning system in waters up to 3,000 m deep. A moon pool in the centre of the vessel provides access for a derrick from the deck surface through the centre of the ship to the water column (CAPP 2001).

All of these mobile drilling platforms (jack-up rig, semi-submersible rig and drill ship) are self-contained units, with derrick and drilling equipment, a moon pool or some other form of access to the water surface, a helicopter pad, fire and rescue equipment and crew quarters. The operations and discharges are similar for all three drilling platforms. Typically, one to three vessels provide support to the drilling platforms.

While there are differences between platform types with respect to capabilities, treatment facilities and effluent discharge depths; the characteristics volumes and types of wastes streams are similar among drill platform (mobile and permanent).

It is probable that future parcels with the SEA Area may border portions of the southern coast of Newfoundland and Labrador. In this event, directional drilling from land may be a relevant scenario and/or option. This technology has currently been used on the West Coast of Newfoundland and Labrador on the Port au Port Peninsula.

2.2.2 Exclusion Zones

A fisheries exclusion zone (FEZ) is a temporary exclusion zone typically established around a drilling platform for the duration of the 40- to 60-day drilling program. The FEZ around drilling operations are relatively small (0.5 km^2). If the drilling platform is an anchored rig (such as a semi-submersible), then the FEZ typically extends 500 m beyond the anchor points (which can extend up to approximately 1,000 m from the centre of the drilling platform). If the drilling platform is not anchored, then the FEZ is established 500 m from the edge of the platform. Information on the FEZ is usually provided via the *Fisheries Broadcast* and through the *Notice to Mariners*.

2.2.3 Support Vessels

Support for offshore oil and gas exploration activities is provided by offshore supply vessels, which provide transportation services to offshore drilling rigs. The main services provided are the delivery of essential supplies, including food and water, personnel transport, touring operations and the provision of safety and emergency response.

2.2.4 Air Support

Additional support for offshore oil and gas exploration activities is provided by helicopter. The main services provided are employee transport, delivery of smaller essential supplies and safety and emergency support.

2.3 Production Platforms

Permanent (production) drill platforms will only occur within the SEA Area in the event that commercially viable oil and/or gas deposits are discovered and all applicable permits and approvals required by the Accord Acts and CEAA are in place. The permanent platform type that might be used will be dependant upon current available technologies at the time of development and the regulatory regime at the time of development; as well as the type, quantity and location of the resource. Given the length of time from discovery to project sanction and approval (current estimates are 10+ years), general information with respect to potential permanent platforms is provided.

Current production platforms in use on the East Coast include the gravity based structure (GBS) at Hibernia; floating production, storage and offloading vessels (FPSO) at Terra Nova and Whiterose; and leg or jacket structures at Sable.

The potential production platforms types that may occur within the SEA Area in the event that a commercial viable deposit has been sanctioned and approved may include:

- Gravity-base Structure (GBS) - A stand-alone production facility that includes a concrete GBS with topsides. A GBS and topsides is usually constructed separately and then mated at an inshore site prior to towing and installation of the platform at the offshore site.
- Wellhead GBS (WHGBS) - A concept that includes wells drilled from a concrete mono-tower WHGBS using a mobile offshore drilling unit (MODU) in a tender assist mode. All wells (producers, water injectors and gas injector) could be drilled from the WHGBS. A WHGBS has limited storage capability, so the crude would need to be offloaded on a regular basis.
- Floating Production, Storage and Offloading (FPSO) facility - A FPSO (a concept that usually includes subsea satellite wells) would entail subsea wells drilled using a MODU. Production fluids are typically transferred to a FPSO via flowlines and flexible risers. The two existing FPSOs operating on the Grand Banks (the *Terra Nova* and the *SeaRose*) are double-hulled and double-bottomed for protection from sea ice and icebergs. An FPSO would include storage and would house the oil treatment, gas compression, gas lift, water injection and utility equipment, including power generation. It would also include quarters to house all necessary operation and maintenance personnel.

2.4 Sound and Sound Effects Associated with Exploration and Production Activities

2.4.1 Underwater Sound

Underwater sounds will result from vessel and drilling platform operations, as well as seismic, geohazard and VSP activities.

2.4.2 In-Air Sound

In-air sounds will result from aircraft operations during exploration and from equipment on ships and platforms located above the waterline. The primary noise source will likely be helicopters. Aircraft noise is discussed in Section 2.3.4.3.

2.4.3 Ambient Sound

2.4.3.1 Ambient Noise Levels

The Laurentian Channel runs from the Scotian Shelf between Cape Breton Island and the Southwestern coast of Newfoundland. A few arms of the channel reach into Sydney Basin, and so acoustic characteristics of the Laurentian Channel are assumed to be similar to those of Sydney Basin. Buoys deployed in the Laurentian Channel measured a mean (average of noise levels measured at each 18 one-third octave frequency band centered between 20 and 1000 Hz) noise level of approximately 90 decibels (dB) re 1 $\mu Pa^2/Hz$; the maximum noise level was 104.6 dB re 1 $\mu Pa^2/Hz$ measured at 20 Hz and minimum noise level was 81.6 dB re 1 $\mu Pa^2/Hz$ measured at 1,000 Hz (Desharnais and Collision 2001).

The Grand Banks are located off Southern Newfoundland and are the same approximate depth as the upper SEA Area. Measurements of ambient noise on the Grand Banks for average annual wind speed of 4.83 m/s between frequencies of 30 and 900 Hz were between 77.9 and 68.0 dB re $\mu Pa^2/Hz$ (Zakarauskas et al. 1990).

Many sources contribute to ambient noise in the ocean, from marine mammals and ocean life to anthropogenic noise.

2.4.3.2 Marine Mammal Noise

The SEA Area is home to a diverse ecological community. Many of the species who inhabit or migrate through the SEA Area contribute to ambient noise levels via acoustic communication and echolocation techniques. Cetaceans are common in the SEA Area, especially in the summer months, when whales, porpoises and dolphins migrate north through the area. Cetaceans use sound for communication, navigation and hunting. The acoustic characteristics of SEA Area cetaceans are summarized in Table 2.2.

Table 2.2 Regional Cetacean Acoustic Characteristics

Species	Season/Time Spent in Region[A]	Frequency range of acoustic communication (kHz)[3]	Intensity of Acoustic Communication
Beluga whale	Occasional migration to NL coast from Arctic[1]	0.26 to 20	
Bottlenose whale	Occasional migration to NL coast from Labrador coast[1]	3 to 26	
Blue whale	Summer and Fall month[4]	0.012 to 31	Source level: ~150 dB re 1 µPa at 1 m
Long-finned Pilot Whale	Follows squid migrations[2], summer and winter month	1 to 18	
Minke whale	Summer months, attracted by capelin[2]	0.060 to 20	Source level: ~160 dB re 1 µPa at 1 m
Humpback whale	Primarily Summer months;[2] sighted throughout year in SEA Area	0.020 to 8.20	Source level: ~175 dB re 1 µPa at 1 m
Sperm whale	Primarily Summer months;[2] sighted throughout year in SEA Area	0.1 to 30	Source level: ~170 dB re 1 µPa at 1 m
Fin whale	Primarily Summer months;[2] sighted throughout year in SEA Area	0.010 to 28	Source level: ~170 dB re 1 µPa at 1 m
Harbour Porpoise	Primarily Summer months;[2] sighted throughout year in SEA Area	0.0020	Source level: ~100 dB re 1 µPa at 1 m
Dolphins (white-sided and white-beaked)	Primarily Summer months;[2] sighted throughout year in SEA Area	0.0060 to 0.015	

Source:
1. Guerrero 2006.
2. DFO 1993.
3. Richardson et al. 1995.
4. DFO Data

Note: Greatest abundances tend to occur in the summer, all species may occur within the SEA Area at anytime during the year.

2.4.3.3 Shipping Traffic and Anthropogenic Noise

Traffic noise is the combined effects on ambient noise levels of all shipping at long ranges and dominates the ambient noise in the 20 to 300 Hz frequency range. Noise from distant fishing vessels also contribute to ambient noise, peaking at 300 Hz (Richardson et al. 1995). The inshore area of SEA Area is a popular ecotourism area. Ecotourism boats also contribute to ambient noise and are included in the fishing vessel category. Noise from whale-watching boats has been estimated at 145 to 169 dB re 1 µPa @ 1m (Erbe 2002).

The Marine Atlantic ferry from Sydney, Nova Scotia, to Port Aux Basques, Newfoundland and Labrador, crosses over the western-most tip of the SEA Area, and the ferry to Argentia passes over the southern-most part of the SEA Area (Marine Atlantic 2006). Major shipping routes pass over the middle and southern part of the SEA Area. Commercial cruise lines increasingly frequent ports such as Sydney, Nova Scotia, Charlottetown, Prince Edward Island and Corner Brook and St. John's, Newfoundland and Labrador. Desharnais and Collision (2001) report approximately 95-dB re 1μPa^2/Hz peak at 80 Hz due to shipping in the Laurentian Channel and state that shipping noise is restricted to the 60 to 80 Hz frequency range.

2.4.3.4 Wind- and Wave-generated Sound

Meteorological conditions such as wind and precipitation can make measurable contributions to ambient noise. Noise produced by wind is in the range of approximately 100 Hz to 50 kHz, noise produced by large surface waves occurs in the 1 to 20 Hz range and noise produced by precipitation occurs at frequencies above 500 Hz (Wenz 1962, Figure 5.3). Observed noise levels for the Laurentian Channel in the wind-noise dominated band (1,000 Hz) were 81.6 dB re 1μPa^2/Hz (Desharnais and Collision 2001), observations consistent with those of Piggot.

2.4.3.5 Comparison of Noise Levels

A comparison of natural and potential exploration-related noise levels is provided in Table 2.3.

Table 2.3 Comparison of Natural and Potential Exploration-related Noise Levels

Source	Noise Level (dB re 1μPa)	Noise Frequency (Hz)	Notes
Ambient Noise			
Calm Seas	60	-	
Modern Waves/surf	102	100 to 700	
Fin whales	160 to 186	20	Fin whales produce series of one to five second noise pulses across 3 to 4 Hz around the 20 Hz level.
Seismic Exploration			
Small Single Airgun	216	10 to 5,000	0 to peak
Medium Single Airgun	225	10 to 5,000	0 to peak
Large Single Airgun	232	10 to 5,000	0 to peak
GSC 7900 Array	259	10 to 5,000	0 to peak
ARCO 4000 Array	255	10 to 5,000	0 to peak
GECO 3100 Array	252	10 to 5,000	0 to peak
Drilling-related Noise			
Jack-up Drilling Rigs	119 to 127	5	
Moored Semi-submersibles	154	-	Overall broadband sound level did not exceed ambient beyond about 1 km; received levels at 100 m would be approximately 114 dB re 1 μPA.
Moored Drillships	174 to185	45 to 7,070	Noise is predicted to attenuate to 115 to 120 dB at distances of 1 to 10 km.
Supply boats	170 to 180	100	
Other Industrial Noise			
Fishing trawlers	158	At 100	
Commercial freighter	172	-	
Supertanker *Chevron London*	190	dominant tone of 6.8 Hz	
Helicopter (Sikorsky @ 305 m above water)	105	-	
Pile-driving (1 km distance)	131 to 135	-	
Source: Richardson et al. 1997, in Hurley and Ellis 2004; Lawson et al. 2000 in Hurley and Ellis 2004; Thompson et al. 2000, in Hurley and Ellis 2004.			

2.4.4 Offshore Oil and Gas Industrial Sounds

Petroleum-related activities that may occur offshore, if exploration licenses are issued, include:

- exploring, drilling and testing for petroleum;
- development activities to produce petroleum; and
- production.

Activities associated with the above may include drilling of wells (either exploration or delineation wells), in addition to seismic and other geophysical surveys. The process of extracting oil and gas from the marine environment involves activities on many different times, spatial and acoustic scales. These include rig transportation to the site, platform installation, operational noise and sound associated with support vessels and aircraft.

2.4.4.1 Exploratory and Delineation Drilling

Underwater drilling noise from a variety of offshore platforms, artificial islands and drillships has been studied extensively, especially in Arctic environments. Gales (1982) surveyed underwater noise from drilling and production operations in locations from California to Alaska to the Atlantic, for both platforms and artificial islands. Greene (1987) studied the underwater drilling sound from drillships and a caisson-retained island in the Beaufort Sea, along with noise from vessels related to platform installation. A number of other studies can be found referenced and summarized in Richardson et al. (1995).

Drilling noise results from multiple processes; aside from the rotation of the drill string and the associated movement of pipe as it is fed through, there is the operation of generators, pumps, hydraulic equipment and other machinery in direct support of drilling. This noise is generally confined to the low frequency end of the spectrum, below 1 kiloHertz (kHz). A relatively strong infrasonic component around 1.5 Hertz (Hz), corresponding to the rotation rate of the drilling turntable, was measured by Hall and Francine (1991) for the Glomar CIDS (Concrete Island Drilling System) drilling caisson; however, such low frequencies would attenuate rapidly in water shallower than a few tens of metres and are not transmitted into the water by all caisson rigs.

Drilling can produce maximum broadband (10 Hz to 10 kHz) energy of approximately 190 dB re 1μPa @ 1m. Drillship noise comes from both the drilling machinery and the propellers and thrusters used for station-keeping. Drilling generates ancillary noise from the movements of supply boats and support helicopters. Emplacement of drilling platforms creates localized noise for brief time periods. Powerful support vessels are used to transport these large structures.

Deep-water drilling has the potential to generate greater noise than shallow-water drilling, owing to the use of drill ships. This noise may be more easily coupled into the deep sound channel for long-range propagation. The level of drilling noise from any platform will on occasion increase temporarily when operations such as tripping (extracting the drill string to change the bit and reinserting it afterwards) are performed; no references to quantitative measurements of these variations have been found.

2.4.4.2 Production

Additional noise is generated during oil production activities, which include borehole casing, cementing, perforating, pumping and ship and helicopter support. Production activities can generate source levels as high as 135 dB re 1μPa @ 1km from the source (Greene and Moore 1995), which suggests as much as 195 dB re 1μPa @ 1m with peak levels at 40 to 100 Hz.

Production machinery on board platforms will generate noise in addition to that created by drilling operations. Very little data exist in the literature in terms of non-drilling noise levels from platforms; Richardson et al. (1995) summarize a few reported measurements that generally point to very modest noise levels, but a quantitative acoustic characterization of such activities would require considerably more data and a more standardized monitoring approach. Measurements of noise from fixed production platform showed the strongest tones between 4.5 and 38 Hz, measured at ranges 9 to 61 m, peak sound spectrum levels at 50 to 200 Hz. Production machinery is generally located above the water, so sound transferred to the water column is not important.

2.4.4.3 Vessel Traffic and Aircraft Operations

Various supply vessels will be involved in the support of exploration; they will serve a variety of roles, ranging from personnel transport to re-provisioning to inspection and maintenance work. In addition to marine vessel traffic, helicopters will fill a vital role especially in the transport of personnel to and from ships and platforms. All of these sources of noise will contribute to the overall acoustic environment of the area.

Underwater noise due to vessels and aircraft associated with the installation and operation of oil and gas platforms can be attributed primarily to dredgers, tugs and barges, icebreakers, supply ships, small vessels and helicopters.

Vessels discussed in this section can be characterized essentially as continuous noise sources, though, as discussed below, helicopter overflight is considered a transient noise source due to the limited angle of propagation of the airborne sound into the water column. The vessels involved in offshore oil and gas operations span a wide range of sizes, power ratings and applications and, consequently, generate widely different levels of underwater sound. Vessel and helicopter noise are a combination of tonal and broadband sounds, which in the case of vessels, is dependent on their size, design and speed (Richardson et al. 1995).

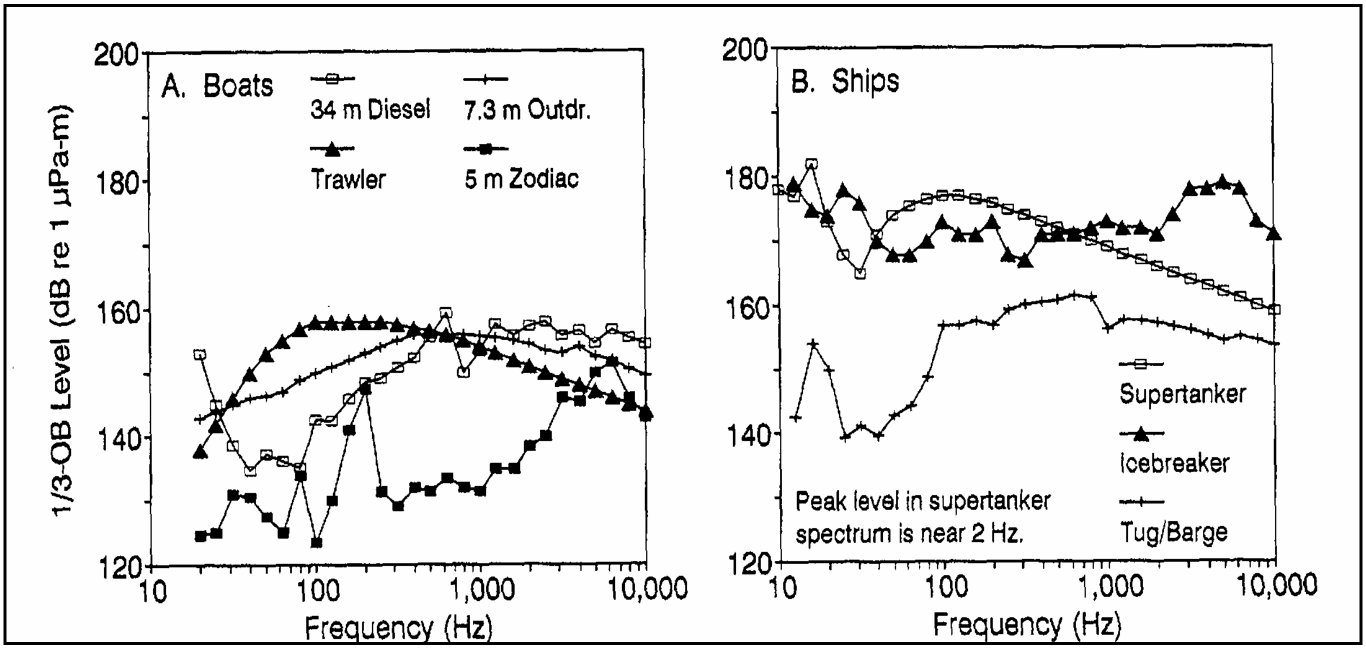
Boat and ship noise is attributable mainly to propeller cavitation, propeller singing, propulsion engines (noise transmitted through the vessel's hull) or other machinery. Noise from any of these sources can be exacerbated given any damage or improper operation. Cavitation is usually the dominant noise source according to Ross (1976, in Richardson et al. 1995). The frequency spectrum of cavitation noise has been observed to be a broadband noise consisting of sharp pulses that correspond with the propeller rotation frequency times the number of blades (Erbe and Farmer 2000). Noise from older, medium to high-speed diesel engines built with simple connecting rods is strong enough to potentially overshadow cavitation (Ross 1976). Modern diesels built with articulated connecting rods (mostly found in tankers, freighters and container ships) are slow speed (<250 rpm) and relatively quiet, with cavitation being the dominant noise source (Richardson et al. 1995).

Generally, the larger the vessel, the greater the level and lower the frequency of sound emitted. A comparison of one-third octave bands associated with both small and medium to large vessels is provided in Figure 2.4. In an operation involving diverse vessel sizes, noise will be mainly due to medium and large vessels. When operating at relatively close range, small vessels with outboard engines, such as Zodiacs, may also contribute considerable underwater noise levels.

Airborne sound waves only penetrate effectively into the ocean environment within a 13° cone off the vertical; much of the noise outside this cone does not penetrate the water surface. Because of the conical acceptance volume, aircraft are audible in the water column for longer periods when flying at higher altitudes. Furthermore, the duration of audibility is greater for shallow receiver depths (Urick 1972; Greene 1985).

Propellers or rotors generate the primary source of aircraft noise. Blade rotation produces tones with fundamental frequencies dependant on the number of blades and rate of rotation. An increase in the number of blades also produces a corresponding increase in the fundamental frequency for a given rotation rate (Richardson et al. 1995). Generally, noise spectra are below 500 Hz, with dominant tones produced as harmonics of the blade rates of the main and tail rotors (Richardson et al. 1995). Tones associated with the engines and other rotating parts may also be present, resulting in a potentially large number of less prominent tones at many frequencies.

Figure 2.4 Estimated One-third Octave Sound Levels of Underwater Noise at 1 m for A) Boats; and B) Ships



Source: Richardson et al. 1995.

Note: The icebreaker noise is from the *Robert Lemeur* (studied by Greene 1987) pushing on ice at full power (7.2 MW) and zero speed. This is estimated to be louder than that generated by an ocean-going tug pulling a load at low speed.

2.4.4.4 Two-dimensional and Three-dimensional Seismic Surveys

Two-dimensional and three-dimensional seismic surveys are most commonly carried out using airguns. The length of time a seismic survey continues depends on the area in question, but usually ranges from a week to a month. A typical seismic survey lasts two to three weeks and covers a range of approximately 555 to 1,110 km. The ship towing the array is typically 60 to 90 m long and moves through the water at speeds usually in the range of 8 to 10 km/h (4.5 to 5.5 knots).

Acoustic propagation and received sound levels in the Sydney Basin marine environment will vary as a function of depth, range and environmental properties (oceanographic and geoacoustic). The most important environmental parameters needed to give accurate predictions are the sound speed profile, the bathymetry and the bottom loss. The sound speed profile will vary with temperature and salinity, hence will vary seasonally and with depth.

Airguns

Hydrophone (airgun) assemblies are towed as "streamers" behind a vessel, with between 6 to 10 streamers towed in typical 3-D surveys. A smaller number of streamers are towed in a typical 2-D survey.

Airguns and arrays of airguns are towed approximately 50 to 250 m behind a ship and "release" compressed air every 6 to 10 seconds for a duration of 10 to 30 milliseconds per shot. Hydrophone assemblies in the form of a cable (500 m to 8 km in length) are towed behind the airgun arrays to record the reflected sound waves. The arrays and hydrophones are usually towed several metres below the sea surface. The arrays may consist of 10 to 70 airguns (Richardson et al. 1995).

The noise associated with airguns can range between approximately 215 and 235 dB re 1 µPa-m for a single airgun and approximately 235 to 260 dB re 1 µPa-m for arrays (Richardson et al. 1995). The downward pressure pulse or source strength ranges between 1 and 8 (12 and 174) bar-m for a single gun (array) (Richardson et al. 1995); frequencies range between 10 and 300 Hz. For an airgun with sound intensity of 250 dB at the source, noise levels over 30 km away can be as high as 117 dB.

Airgun Operating Principles

An airgun is a pneumatic sound source that creates low-frequency acoustic impulses by generating bubbles of compressed air in water. The rapid release of highly compressed air (typically at pressures of approximately 2,000 psi) from the airgun chamber creates an oscillating air bubble in the water. The expansion and oscillation of this air bubble generates a strongly-peaked, high-amplitude acoustic impulse that is useful for seismic profiling. The main features of the pressure signal generated by an airgun, as shown in Figure 2.5, are the strong initial peak and the subsequent bubble pulses. The amplitude of the initial peak depends primarily on the firing pressure and chamber volume of the airgun, whereas the period and amplitude of the bubble pulse depends on the volume and firing depth of the airgun (Figure 2.5).

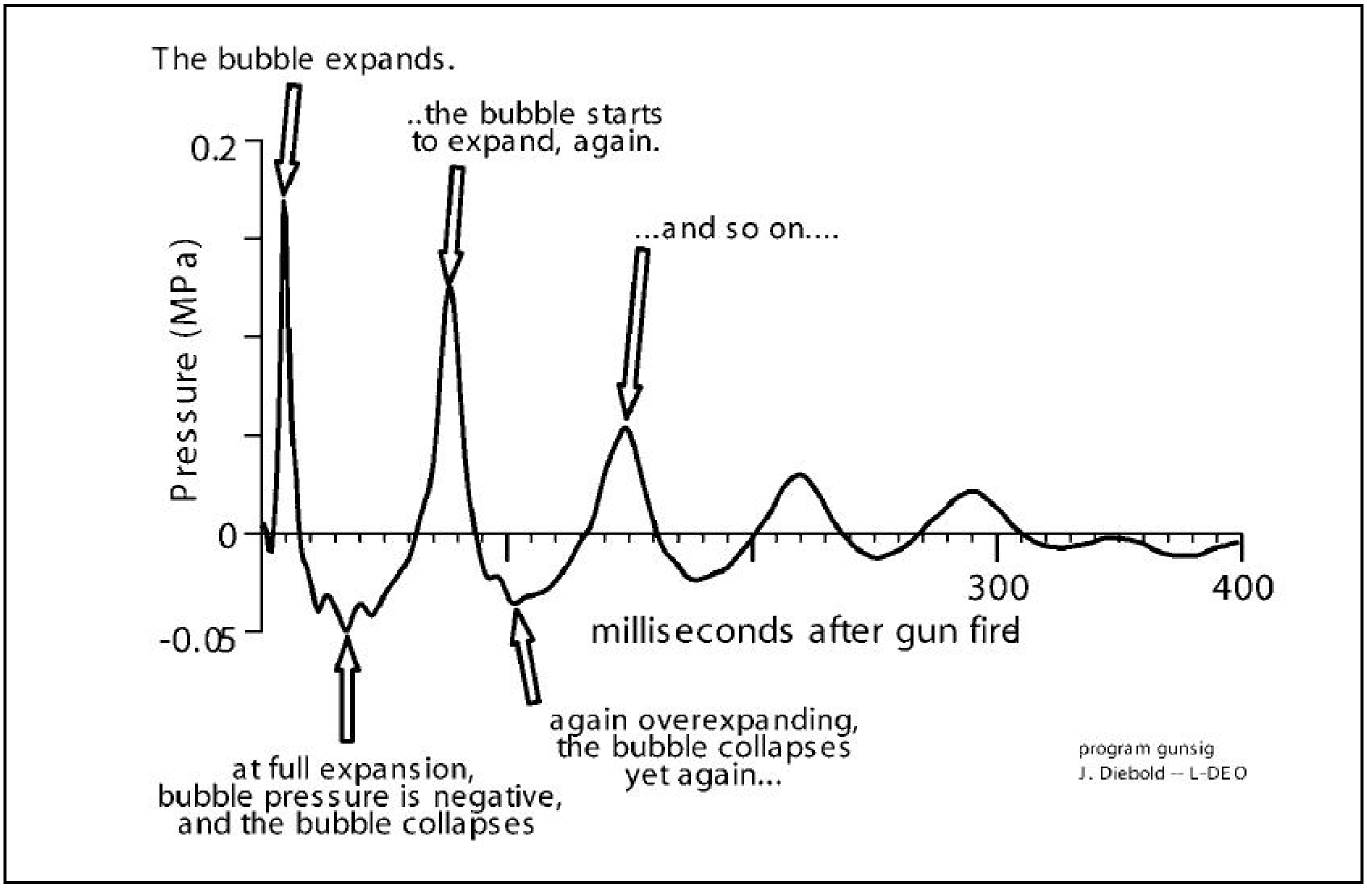
Airguns are designed to generate most of their acoustic energy at frequencies less than approximately 200 Hz, which is the frequency range most useful for seismic penetration beneath surficial seabed sediment layers. In general, the frequency output of an airgun depends on its volume: larger airguns generate lower-frequency impulses. However, due to the pulsive nature of the source, airguns inevitably generate sound energy at higher frequencies, above 200 Hz, although the energy output at these frequencies is substantially less than at low frequencies.

Zero-to-peak source levels for lone airguns are typically between 220 and 230 dB re µPa•m, with larger airguns generating higher peak pressures than smaller ones. However, the peak pressure of an airgun only increases with the cubic root of the chamber volume. Furthermore, the amplitude of the bubble pulse also increases with the volume of the airgun and for the geophysicist, the bubble pulse is an undesirable feature of the airgun signal, since it smears out sub-bottom reflections. Therefore, in order to increase the pulse amplitude (to see deeper into the Earth), geophysicists generally combine multiple airguns together into arrays. Airgun arrays provide several advantages over single airguns for deep geophysical surveying:

- the peak pressure of an airgun array in the vertical direction increases nearly linearly with the number of airguns;
- airgun arrays are designed to project maximum peak levels toward the seabed (i.e., directly downward); and

- by using airguns of several different volumes, airgun arrays may be "tuned" to increase the amplitude of the primary peak and simultaneously decrease the relative amplitude of the bubble pulse.

Figure 2.5 Air Pressure Signature



Airgun Array Source Levels

The far-field pressure generated by a seismic airgun array is substantially greater than that of an individual airgun. An array of 30 guns, for example, may have a zero-to-peak source level of 255 dB re µPa•m in the vertical direction. This apparently high value for the source level can lead to erroneous conclusions about the effect on marine mammals and fish for the following reasons:

- peak source levels for seismic survey sources are usually quoted relative to the vertical direction; however, due to the directional dependence of the radiated sound field, source levels off to the sides of the array are generally lower; and/or
- far-field source levels do not apply in the near-field of the array where the individual airguns do not add coherently; sound levels in the near-field are, in fact, lower than would be expected from far-field estimates.

Airgun energy levels generally decrease, and signal duration increases, with increasing range. In shallow water, higher frequencies (approximately 200 Hz) usually arrive before lower frequencies (approximately 70 Hz) at ranges of several kilometres. This results in a downward sweeping "chirp"-like sound. Although the arrays direct as much energy as possible downward, strong sound pulses propagate horizontally, even in shallow water.

Greene and Richardson (1988) made recordings using open bottom gas guns in water 9 to 11 m depth, hydrophone depth 8 m, ranges 0.9 to 14.8 km. Received levels ranged from 177 dB re 1µPa at range 0.9 km to 123 dB at 14.8 km.

The acoustic source level of a seismic airgun array varies considerably in both the horizontal and vertical directions, due to the complex configuration of guns composing the array. This variability must be accounted for in order to correctly predict the sound field generated by an airgun array. If the source signatures of the individual airguns are known, then it is possible to accurately compute the source level of an array in any direction by summing up the contributions of the array elements with the appropriate time delays, according to their relative positions.

Geohazard Surveys

Several tools exist for geoscientists to get an idea of what the bottom of the ocean looks like and determine if hazards to oil and gas activities are present. Active sonar is the most common tool for undertaking geohazard surveys. Types of sonar include simple depth sounders, multibeam sonar and side-scan sonar.

Depth sounders and multibeam sonar work by transmitting a ping of noise (signal) through the water column and measuring the time the sound takes to return to the receiver; the distance to the bottom or object of interest can be calculated this way. Multibeam sonar sends a fan-shaped swath of pings to the bottom, so that enough depth information can be gathered to get a very detailed image of the bathymetry, including any marine geohazards present.

Side-scan sonar is similar to multibeam sonar except instead of measuring the time for a signal to return to the transmitter, it measures the strength of the return signal. This creates an image of the ocean bottom where objects that protrude from the bottom create a dark image (strong return) and shadows from these objects are light areas (little or no return). No information on the water depth can be gained using this method. A sidescan is usually towed behind a vessel.

Side-scan Sonar System for Seabed Imagining

Side-scan sonar builds up a 2-D picture of the seabed, together with any targets on the seabed, using a combination of an asymmetrical transducer and the motion of the sonar platform through the water. Typical side scan sonar uses a simultaneous dual frequency (105 kHz and 390 kHz) system. It has peak to peak source levels of 228 dB re 1µPa @ 1m for 105 kHz and 222 dB re 1µPa @ 1m for 390 kHz. The side scan firing rate is 3.3 times per second (300 msec firing rate) at 200 m range. Side-scan horizontal beamwidths are 1.2 degrees at 105 kHz and 0.5 degrees at 390 kHz. Both sweep over an arc (perpendicular to transect) of 50 degrees.

Sub-bottom Profiler

Sub-bottom profiling operations use a Deep Tow System (DTS) deployed from the stern of the survey vessel, through an "A" Frame. The system is towed approximately 150 m behind the survey vessel (dependent on cable deployed, water depth and vessel speed), and approximately 20 to 40 m above the seabed.

The DTS uses a broadband acoustic source with frequency bandwidth from 500 Hz to 6 kHz. Power output is typically 500 Joules, but may be increased to 1 kJ if necessary. Rise time of the pulse is less than 0.1 millisecond. The boomer derived pulse is primarily restricted to a 60-degree cone. Maximum peak to peak amplitude is 221 dB relative to 1 µPa at 1 metre. The system uses an internal and external hydrophone to record the return signal. Vertical resolution is approximately 10 cm, with penetration of 40 m in sands and 100 m in soft sediment. The option exists to use a sparker source, instead of the boomer, if seabed conditions and data quality warrant it. This system is more omni-directional, and provides similar output power at a lower frequency.

Echo-Sounder

Geophysical surveying operations may employ either a dual frequency single beam sounder or a multibeam echo-sounder. A typical single beam echo-sounder (SBES), which is dual frequency capable, operates at 24 kHz and 200 kHz. SBES source levels are 219 dB re 1µPa @ 1m for 24 kHz, and 215 dB re 1µPa @ 1m for 200 kHz (peak to peak). The SBES firing rate is typically two times per second. Conical beamwidths are 9 degrees (200 kHz) and 24 degrees (24 kHz). A multibeam echo sounder (MBES) operates 240 kHz, with a source level of 213 dB re 1µPa @ 1m (peak to peak). Its firing rate is approximately four to six times per second, with a beam width of 1.5 degrees per beam. To cover a 150 degree arc, 101 beams are used perpendicular to the transect direction.

2.4.4.5 Vertical Seismic Profiles

VSPs are a collection of well bore measurements (seismograms) developed by means of geophones inside the wellbore and sound sources at the surface near the well. The seismic data can be gathered while the borehole is being drilled or afterwards. These measurements are used to correlate with surface seismic data, for obtaining images of higher resolution than surface seismic images and for looking ahead of the drill bit.

Standard surface seismic surveys use a seismic source on or near the Earth surface that emits energy that reflects at subsurface interfaces and is recorded by a set of receivers also located on or near the surface. VSPs, also known as borehole seismic surveys, differ in that receiver locations are restricted to the confines of a borehole. While this constraint limits the image volume, it also confers several advantages to seismic surveys in the borehole. For example, waves that travel from a surface source, reflect off a subsurface reflector and then arrive at a borehole receiver are less attenuated by shallow low-velocity layers, having traversed them only once, instead of the two times traveled by surface seismic waves.

The borehole usually is a quieter environment than the surface, so receivers can collect data with higher signal-to-noise ratio. Receivers clamped in the borehole record multiple components of seismic energy in the form of converted shear and direct compressional waveforms, whereas towed marine seismic and standard land seismic acquisition methods record a single component of data that is processed to enhance only compressional arrivals.

Borehole receivers can record direct downgoing airwaves, and/or signals that have been reflected from subsurface geology adjacent to the receivers. Changes in the direct signal recorded at multiple calibrated borehole receivers help determine the attenuation properties of overburden layers. Knowledge of attenuation properties helps restore portions of signal lost during transmission of both borehole and surface seismic waves. Receivers can be positioned accurately at specified depths in the borehole, allowing geophysicists to derive a profile of layer velocities at the well location. This helps convert time-indexed surface seismic data to depth, so seismic images can be tied to well-log data and drill-bit positions can be tracked on seismic sections.

There are numerous methods for acquiring VSPs. VSPs include the zero-offset VSP, offset VSP and walkaway VSPs. Zero-offset VSPs have sources close to the wellbore directly above receivers. Offset

VSPs have sources some distance from the receivers in the wellbore. An offset VSP uses a source located at an offset from the drilling rig during acquisition to allow imaging to some distance away from the wellbore. In a walkaway VSP, the source is moved to progressively farther offset at the surface and receivers are held in a fixed location, effectively providing a mini 2-D seismic line that can be of higher resolution than surface seismic data and provides more continuous coverage than an offset VSP. Three-dimensional walkaways, using a surface grid of source positions, provide 3-D images in areas where the surface seismic data do not provide an adequate image due to near-surface effects or surface obstructions.

With a zero-offset VSP, a seismic source array is deployed over the side of the drilling platform. A typical VSP source array would be comprised of four 150-cubic inch airguns and four 40-cubic inch airguns with a calibrated peak vertical source level of 242.5 dB re 1µPa @ 1m. The source is activated three to five times to create a sonic wave that is picked up by the geophones in the borehole.

A typical zero-offset compressional source signal has a 12 s linear sweep covering the frequency band 10 to 200 Hz. Frequency content for other VSPs include 10 to 100 Hz for an offset compressional source and 10 to 50 Hz for a zero offset shear source (Mi et al. 1999).

2.5 Discharges Associated with Exploration and Production Activities

Discharges associated with the exploration and production activities may include: drill muds; bilge water; deck drainage; ballast water; storage displacement water; cooling water (semi-submersible only); produced water; garbage; miscellaneous waste discharges (such as BOP fluid and cement slurry); and air emissions. All discharges will be required to comply with applicable limits as set forth in the *Offshore Waste Treatment Guidelines* (OWTG) (National Energy Board (NEB) et al. 2002). In addition to waste discharges; noise, light and accidental events are a consideration associated with exploration and production activities. As a result of the potential environmental effects associated with noise and accidental events, these issues are presented separately in Sections 2.3 and 2.6.

2.5.1 Drill Muds

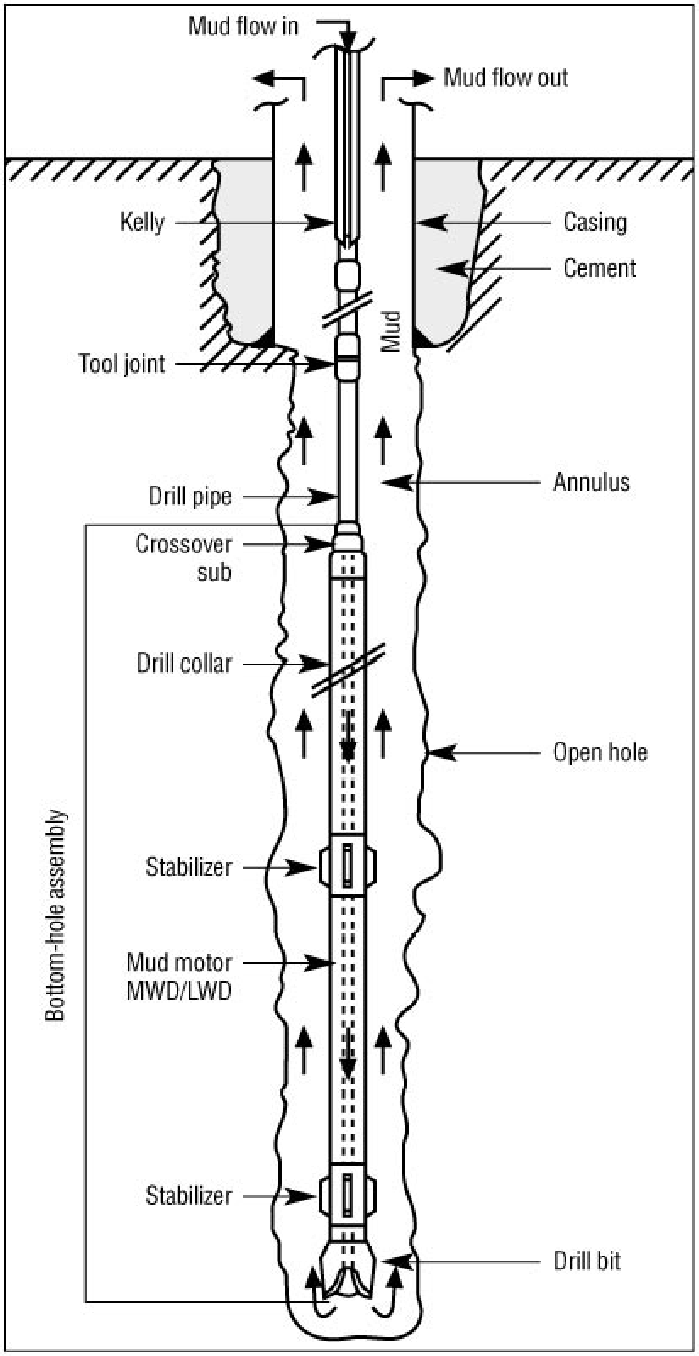
Drill muds are a complex mixture of clays, chemical additives and water that are pumped down the drill pipe to lubricate and cool the drill bit, flush out cuttings, control formation pressures, seal permeable formations and maintain well bore stability. Drill muds also help to minimize damage to reservoirs, percent the formation of gas hydrates, assist in the transition of hydraulic energy to drill tools, assist in formation evaluation via logging equipment, controls corrosion and facilitates casing cementing (CAPP 2001).

Drill solids (or cuttings) are the particles that are generated by drilling activities and are returned to the surface with drill muds. Drill solids associated with WBMs may be discharged. Drill solids associated with oil-based mud (OBM) are not permitted to be discharged. Drill solids associated with SBMs and enhanced mineral oil-based mud (EMOBM) are either reinjected or, when reinjection is not technically feasible, the SBM and EMOBM must be treated to achieve a concentration of 6.9 g/100 g or less oil on wet solids prior to discharge (NEB et al. 2002).

All exploration and production drilling on the East Coast has been conducted using WBMs or SBMs. Hibernia reinjects approximately 95 percent of their cuttings but this approach is not presently feasible for mobile platforms that are used in exploration drilling activities. The feasibility of cuttings reinjection is dependant on a variety of factors that include drill platform type and site-specific geography, resulting in cuttings reinjection being more feasible for fixed platforms than for floating platforms.

The drill bit cuts the formation rock, producing drill cuttings, resulting in the creation of the well bore. Drill mud is circulated through the drill pipe and out through small jets or holes in the drill bit. The velocity and viscosity of the mud flushes drilled cuttings away from the bit, transporting them to the surface through the annulus, as illustrated in Figure 2.6 (CAPP 2001).

Figure 2.6 Drill String Components Illustrating Drill Mud Circulation



Source: CAPP 2001.

At predetermined intervals, steel casing is cemented into the well hole, thereby providing a conduit that returns muds and cuttings to the drill platform for treatment and discharge. Drill mud is expensive and, as much as possible, is recovered for reuse. However, some mud will remain on the drill cuttings and be discharged. Discharged drill cuttings are required to meet the drill solids requirements outlined in the OWTG (NEB et al. 2002) prior to disposal via discharge or reinjection.

The muds and the cuttings are dispersed in the water column and settle to the seabed, with heavier cuttings and particles near the hole and the fines dispersed at increasing distances from the drill rig. The dispersion pattern for muds and cuttings is irregular, with a majority of muds and cuttings initially deposited with 1,000 m from source (National Research Council (NRC) 1983). Depending upon bottom energy, the deposited muds and cuttings may persist as discharged or undergo rapid or prolonged dispersion (Neff 1987). Drill, mud and cuttings and their potential effects have been discussed in several recent studies (Husky 2000; 2001; CAPP 2001; Hurley and Ellis 2004) and all confirm that small scale drilling has no measureable effect on the marine environment.

2.5.1.1 Water-based Muds

WBMs employ fresh or saltwater as the continuous liquid phase. WBMs muds are generally used in the earliest sections of a well, including shallow exploratory wells. Muds generally are composed of barite, bentonite or other clays, silicates, lignite, caustic soda, sodium carbonate/bicarbonate, inorganic salts, surfactants, corrosion inhibitors, lubricants and other additives for unique drilling problems (Thomas et al. 1984; GESAMP 1993). The constituents of muds are screened via the *Offshore Chemical Screening Selection Guidelines* (NEB et al. 1999). Composition of an example of a typical WBM formulation is presented in Table 2.4.

Table 2.4 Typical Drill Mud Components and Drill Cuttings Discharge Volume for a Grand Banks Discharge Well

	Unit	Casting Strings		
		Conductor	**Surface**	**Production**
Hole Section	inch	36	16	12¼
DF System		Gel/SW	Gel/SW	WBM
Depth (See Note 4)	metre (brt)	220	1,200	3,600
Volume Usage	Bbl	897	4,199	5,246
Wash Out	%	50	30	10
Products				
Barite	MT	-	58	115
Bentonite	MT	16	65	-
Calcium Carbonate	kg	-	-	-
Caustic	kg	116	482	138
Fluid Loss Agent	kg	-	-	2,385
Inhibitor	kg	-	-	4,769
Fluid Loss Agent	kg	-	-	9,538
Potassium Chloride	kg	-	-	100,153
Lime	kg	116	482	-
Glycol Inhibitor	L	-	-	25,024
Soda Ash	kg	116	482	238
Viscosifier	kg	-	-	3,577
Biocide	L	-	-	72
Drilled Cuttings	kg	192,032	429,562	521,786
Volume of Cuttings	m^3	74	165	201

Source: Husky 2003, in LGL 2005a.
Notes:
1. Three scenarios were taken into account. The 310-mm (12¼") hole section varies in depth with each scenario.
2. 900-mm (36-inch) and 400-mm (16-inch) hold section - near seabed discharge.
3. WBM used for complete well.
4. All depths are measured below rotary table (brt). The rotary table is 145 m above the seafloor.

Spent and excess WBMs may be discharged on-site from offshore installations without treatment (NEB et al. 2002). Operators should have procedures that reduce the need for the bulk disposal of these muds following either a drilling mud changeover or a drilling program completion.

2.5.1.2 Synthetic-based Muds

SBM refers to a water-in-oil emulsion whose continuous phase is composed of one or more fluids produced by the reaction of a specific purified chemical feedstock, rather than the physical separation processes such as fractionation, distillation and minor chemical reactions. Synthetic-based fluids (SBFs) typically have a total PAH concentration of less than 10 mg/kg (<0.001 percent) and are non-acutely toxic in most or all marine toxicity tests. Examples of synthetics include C_{16}-C_{18} internal olefins, poly-alpha olefins, linear-alpha olefins, esters and low viscosity esters, as well as other SBFs such as paraffinic fluids (i.e., saturated hydrocarbons or alkanes). SBMs are produced to duplicate favorable properties of both WBMs and OBMs.

One of the drilling muds used on the Grand Banks is Paradril-IA3, which is a SBM with PureDrill IA-35 as the base oil, together with weighting agents, wetting agents, emulsifiers and other additives. PureDrill IA-35 synthetic drilling fluid is classified as a high purity synthetic alkane consisting of isoalkanes and cycloalkanes (Williams et al. 2002). PureDrill IA-35 is a clean, colourless, odourless fluid that is safe to handle (Williams et al. 2002). It has an aromatic content of < 0.01 percent and a PAH content of < 0.001 ppm. It is non-toxic to human, plant and marine life.

PureDrill IA-35 had undergone an evaluation using the Offshore Chemical Management System (OCMS). The fluid was screened from a facility, human health and environmental perspective (Williams et al. 2002). PureDrill IA-35 base oil is a component of a whole mud system called ParaDrill that received a Group E classification by the OCNS classification system employed in the United Kingdom. The Group E classification is the best rating achievable under the OCNS system and is assigned to chemicals that have relatively low toxicity and/or does not bioaccumulate or readily biodegrades. The formulation of ParaDrill-IA, a commonly used SBM on the Grand Banks, is presented in Table 2.5.

Table 2.5 Composition of ParaDrill-IA

Component	Purpose
PureDrill IA-35	Base Fluid
NOVAMULL L	Primary Emulsifier
NOVAMOD L	Rheology Modifier
NOVATHIN L	Thinner
MI-157	Wetting Agent
HRP	Rheology Modifier
TRUVIS	Viscosity
VERSATROL	Filtration Control
ECOTROL	Filtration Control (Alternative)
Lime	Alkalinity
Calcium Chloride	Salinity
Water	Internal Phase
Barite	Density
Source: Williams et al. 2002, in LGL 2005a.	

The toxicity data for PureDrill IA-35 (Harris 1998) are:

- mysid shrimp 96-hour LC50 of >500,000 ppm;
- rainbow trout 96-hour LC50 of >400,000 ppm;

- amphipod (*Corophium volutator*) 10-day LC50 of 2,633 mg/L;
- *Macoma* 20-day LC50 of >50,000 mg/L;
- echinoid fertilization (*Lytechinius pictus*) IC50 (20 minutes) of >100 percent; and
- bacterial bioluminescence (Microtox test using *Vibrio fischeri*) EC50 of >100 percent.

Toxicity studies conducted by DFO using American plaice (*Hippoglossoides plastessoides*) and the amphipod *Rhepoxynius abronius* on Hibernia drill cuttings found:

- no acute toxicity in juvenile American plaice exposed for 30 days to Hibernia cuttings, approximating hydrocarbon concentrations found 200 to 500 m from rigs in the North Sea (Payne et al. 2001a); and
- in a dose response study using amphipods a toxic response at 5,000 ppm hydrocarbon concentration only. The cuttings demonstrated a low acutely toxicity potential and extrapolations have been carried out to determine possible size of toxic zones. The extrapolations indicate little or no risk of toxicity as close as 1,000 m or less from the rig (Payne et al. 2001b).

SBMs were developed as a replacement to OBMs, which were toxic and were partially responsible for the longevity of cuttings piles. SBMs are typically used for long reach (i.e., onshore to offshore) drilling, directional drilling and in deep waters where hole stability and integrity are critical. The SBFs used in the preparation of SBMs are water insoluble and, as such, the SBM does not disperse in water in the same manner as a WBM (Hurley and Ellis 2004). Therefore, as SBMs tend to sink to the sea bed, research has focused on toxicity in the sedimentary phase as opposed to the aqueous phase.

The OWTG (NEB et al. 2002) require that SBM and EMOBM (if approved for use by the Chief Conservation Officer), be recovered and recycled, reinjected down-hole, or transferred to shore for approved disposal (NEB et al. 2002). The discharge of whole SBM and EMOBM is not allowed.

2.6 Routine Discharges (including air emissions)

They are a variety of routine discharges associated with offshore exploration and production activities. They included the cement slurries, BOP fluid, produced water, air emissions, storage displacement water, bilge and ballast water, deck drainage, cooling water and sewage and food wastes.

2.6.1 Cement Slurry and Blowout Preventer Fluid

The upper reaches of a well (60 to 1,200 m) may be drilled into sediments with no casing by a process referred to as spudding. The drill string is removed and a pipe (casing) is inserted and cemented into place. Based on experience with previous exploratory wells (Husky 2000), excess cement may be released to the environment.

BOP fluid, a glycol-water mixture, is used in the BOP during drilling. Periodic testing of the BOP fluid is required, resulting in the release of small amounts of glycol (LGL 2002).

2.6.2 Produced Water

During exploration drilling activities, if produced water is encountered during flow testing, then it is either treated prior to discharge or atomized in the flare.

Produced water is created through the injection of seawater into the formation to provide necessary pressure to access oil as the reservoir is drawn down during the life of a project. Produced water includes formation water, injection water and process water that is extracted along with oil and gas during petroleum production. Produced water is usually discharged back into the marine environment (although it is reinjected in some fields). It is warmer that the receiving environment and contains residual oil from the formation.

Current OWTG (NEB et al. 2002) require produced water to be treated to 30 mg/L oil in discharged produced water. Produced water may also contain a range of trace metals. The typical chemical composition of produced water is provided in Table 2.6.

Table 2.6 Chemical Composition of Produced Water from Norwegian North Sea Platforms

Compound	Unit	Statfjord	Gullfaks	Ekofisk 2/4B-K	Ekofisk 2/4B	Tor	Ula
TOC	mg/L	850	61	180	-	85.5	71
THC	mg/L	15	35	-	-	-	50
Sum Aromatics	mg/L	6	9.56	5.67	66.95	-	15
BTX	µg/L	4	5	5.41	66.90	1.1	12
Naphthalenes	mg/L	0.942	2.16	0.247	0.052	0.597	-
Naphthalene		0.261	0.398	0.157	0.038	0.073	-
C1-naph	mg/L	0.35	0.628	0.062	0.012	0.17	-
C2-naph	mg/L	0.199	0.584	0.018	0.002	0.204	-
C3-naph	mg/L	0.132	0.55	0.010	0.0005	0.155	-
Phenanthrenes	mg/L	45	90	6.26	0.28	135	-
Phenanthrene	mg/L	-	-	2.09	0.08	-	-
C1-phenanthrene	mg/L	-	-	2.43	0.12	-	-
C2-phenanthrene	mg/L	-	-	1.74	0.08	-	-
C3-phenanthrene	mg/L	-	-	n.d.	n.d.	-	-
Dibenzothiophenes	µg/L	8.6	22.7	1.39	0.15	10	-
Dibenzothiophene	µg/L	-	-	n.d.	n.d.	-	-
C1-Dibenzothiophene	µg/L	-	-	1.39	0.03	-	-
C2-Dibenzothiophene	µg/L	-	-	n.d.	0.12	-	-
C3-Dibenzothiophene	µg/L	-	-	n.d.	n.d.	-	-
Sum NPD	µg/L	1	2.27	0.254	0.055	0.74	-
Acenaphytlene	µg/L	-	-	0.89	0.02	-	-
Acenaphthene	µg/L	0.001	0.001	n.d.	0.04	0	-
Fluorene	µg/L	12	11.3	n.d.	0.33	8.1	-
Fluoranthene	µg/L	0.0854	0.195	n.d.	n.d.	0.24	--
Pyrene	µg/L	0.0894	0.194	n.d.	0.08	0.42	-
Chrysene	µg/L	0.226	0.398	-	-	0	-
Benz(a)anthracene	µg/L	0.0193	0.311	n.d.	n.d.	0.23	-
Benzo(a)pyrene	µg/L	0.001	0.001	n.d.	n.d.	0	-
Benzo(ghi)perylene	µg/L	0.001	0.001	n.d.	n.d.	1.35	-
Benzo(k)fluoanthene	µg/L	0.0197	0.0528	n.d.	n.d.	0.016	-
Sum PAH 3-6 Ring	µg/L	66.04	125.15	0.89	0.47	155.36	-
Sum Phenol	mg/L	8.3	2.7	1.03	2.56	3.62	0.09
Phenol	mg/L	5.1	0.8	0.61	0.97	2.19	0.033
C1-phenol	mg/L	2.5	0.86	0.19	0.83	1.1	0.028
C2-phenol	mg/L	0.4	0.6	0.14	0.57	0.254	0.02
C3-phenol	mg/L	0.13	0.18	0.06	0.26	0.0316	0.0006
C4-phenol	mg/L	0.026	0.1	0.03	0.02	-	-
C5-phenol	mg/L	0.016	0.065	n.d.	n.d.	-	-
C6-phenol	mg/L	0.013	0.11	n.d.	n.d.	-	-
C7-phenol	mg/L	0.005	0.012	n.d.	n.d.	-	-
Sum Organic Acids	mg/L	895	55	323	577	234	-
Formic Acid	mg/L	-	-	148	275	-	-
Acetic Acid	mg/L	732	15.6	132	267	104	9.5

Compound	Unit	Statfjord	Gullfaks	Ekofisk 2/4B-K	Ekofisk 2/4B	Tor	Ula
Propionic Acid	mg/L	106	8.9	35.2	27.4	10	1.2
Butylic Acid	mg/L	39	14.1	6.35	5.18	-	1.5
Valeric Acid	mg/L	18	8.2	1.61	2.17	-	0.6
Carioic Acid	mg/L	9	8.2	n.d.	0.09	-	-
Organic Acids > C6	mg/L	-	-	n.d.	n.d.	-	-
Methanol	mg/L	-	-	6.3	33.9	-	-
Salinity Cl-	mg/L	-	-	30,400	-	90,500	40,400
Ammonium	mg/L	24.5	26.9	-	-	-	0.1
Lead	µg/L	50	50	n.d	-	80	270
Copper	µg/L	2	2	20	-	600	20
Iron	mg/L	-	-	4	-	8.9	23
Barium	mg/L	-	-	28.2	--	42.1	12
CS-VI	µg/L	10	10	6	-	0.08	40
Mercury	µg/L	1.9	1.9	n.d.	-	-	9
Zinc	µg/L	6.8	13	13	-	200	0.26
Cadmium	mg/L	10	10	n.d.	-	-	0.02
H_2S	mg/L	0.12	0.17	-	-	--	-
Total Radioactivity	Bql	-	-	-	-	-	-
40K	Bql	-	-	-	-	-	-
226Ra	Bql	-	-	-	-	-	-
Source: Røe and Johnsen 1996, in LGL 2005b.							

The scientific literature indicates that toxicity of produced water is related to the produced water's chemical composition and so varies widely, ranging from non-toxic to toxic. The causative agents of the observed toxicity in produced waters are not known. However, it has been theorized that the toxic responses may be related to extremely high dissolved solids (salinity) concentrations, altered ratios of seawater ions, elevated ammonia (Moffitt et al. 1992), hydrocarbons, hydrogen sulphide and volatile compounds (Sauer et al. 1992).

2.6.3 Air Emissions

Exploration installations are usually in an area for a short duration (e.g., exploration drilling usually takes 40 to 90 days, depending on the water and well depths to be drilled) and, as such, they do not usually cause a measurable environmental effect. Air emissions for production activities originate from flaring, generator exhaust, support vessels exhaust, helicopter exhaust, fugitive emissions from storage tanks and other related exhaust associated with production activities. Although, air emissions have been of limited concern to date, increasing societal focus on greenhouse gases and climate change issues, air emissions may be subject to a greater focus within the SEA Area than for previous offshore exploration and production activities to date.

Operators should estimate of the annual quantities of greenhouse gases (GHG) that would be emitted from its offshore installation(s), provide a description of potential means for their reduction and reporting and calculate and report the GHG emitted from the installation on an annual basis as per the requirements of the OWTG (NEB et al. 2002). Operators of a drilling or production installation should determine the type and significance of volatile organic compound (VOC) emissions and report them in accordance with existing best management practices for oil and gas operations in Canada.

2.6.4 Storage Displacement Water

Storage displacement water is seawater that is pumped into and out of oil storage chambers (either through mechanical or natural (gravity) means) on certain types of production installations (GBS) during oil production and off-loading operations. Storage displacement water that is discharged should be treated to reduce its oil concentration to 15 mg/L or less (NEB et al. 2002).

2.6.5 Bilge and Ballast Water

Bilge water is seawater that may seep or flow into the structure from various points in the offshore installation. Ballast water is water used to maintain the stability of an offshore facility. If present, oil concentrations in discharged bilge and ballast water should be treated to levels of 15 mg/L or less before discharge.

2.6.6 Deck Drainage

The deck of an offshore installation may come in contact with water from a number of sources, including precipitation, sea spray or washdown and fire drill operations. Offshore facilities often have separate systems for areas where deck drainage may be contaminated with oil. Deck drainage that has the potential to be contaminated with oil must be treated to 15 mg/L or less prior to discharge into the marine environment as per the OWTG (NEB et al. 2002).

2.6.7 Cooling Water

Cooling water is seawater (usually treated with chlorine to prohibit organic marine growth) that is used to remove heat from production systems; upon discharge it is warmer than the receiving environment. The Chief Conservation Officer may impose residual chlorine level limits for any discharged cooling water (NEB et al. 2002). The Chief Conservation Officer must also approve any other biocide agent.

2.6.8 Sewage and Food Wastes

Sewage and domestic waste originates from 10 to approximately 200 personnel depending upon the type of originating platform (mobile or permanent). Sewage and food wastes should be reduced through maceration to a particle size of 6 mm or less prior to discharge.

2.7 Accidental Events

2.7.1 Blowout and Spill Probabilities

Blowout and accidental spill events during drilling operations are considered in this section. Operational discharges of other oil and waste products, such as produced water, are generally excluded here since they are not included in spill incident reports.

2.7.1.1 Blowout and Spill Probabilities

When such an incident occurs, formation fluids begin to flow into the wellbore and up the annulus and/or inside the drill pipe and is commonly called a kick. A kick can quickly escalate into a blowout when the formation fluids reach the surface, especially when the fluid is a gas, which rapidly expands as it flow up the wellbore and accelerates to near supersonic speeds. Blowouts can cause considerable damage to drilling rigs and injuries or fatalities to rig personnel.

Hydrocarbon spills may occur as a result of equipment malfunction and/or a failure in properly implementing procedures. Most incidents involve everyday operations and duties; unsafe acts may also cause a worker to lose their life so that safety is paramount. Spill incidents sometimes occur during, or are exacerbated by, poor weather and sea conditions.

2.7.1.2 Spill History of the Offshore Oil and Gas Industry

Several sources and statistics are available to characterize and quantify the relative proportion of petroleum sources released into the marine environment. United States sources are quoted due to the long reporting interval, back to 1964, with frequent updates since then on the statistical compilations and high standard of reporting and analyses completed. As well, the proximity of the US operations to offshore Atlantic Canada and generally similar drilling equipment and practices employed render these data relevant and informative.

The US National Academy of Sciences (NAS) (2003) report *Oil in the Sea III* indicated that approximately 3 percent of the oil in the world's marine environment is the result of offshore oil and gas operations, and that production and transportation from the US Outer Continental Shelf (OCS) contributes less than 0.01 percent of the oil in the world's marine waters. The primary source of oil in marine waters is natural seepage, which introduces approximately 50 times more oil than OCS oil and gas activities Minerals Management Service ((MMS) 2006a). This 3 percent annual figure comprises approximately 0.86 thousand tonnes from platforms, 1.3 thousand tonnes from atmospheric deposition and 1.3 thousand tonnes from produced waters. Natural seepage is the largest single source of petroleum input to the world's marine environment, contributing over 4 million barrels per year (MMbbl), or 47 percent of the total inputs. Transportation of petroleum, including pipelines, tank vessel spills, operational discharges, coastal facilities and atmospheric deposition, account for approximately 12 percent, while consumption of petroleum, with largest contributions from land-based (river and runoff) and operational discharges sources, being responsible for approximately 37 percent of world-wide petroleum inputs.

In Canada, the C-NLOPB and Canada-Nova Scotia Offshore Petroleum Board (C-NSOPB) report spill incidents for activities offshore Newfoundland and Labrador and Nova Scotia, respectively. Details include numbers of incidents, spill volumes, spilled product, spill size and description of the incident. Exploration and production hydrocarbon spill information for Newfoundland and Labrador Offshore Areas can be reviewed on the C-NLOPB web site following the links for Statistics and Environmental Statistics (C-NLOPB 2006c). C-NLOPB present reported spills for the Newfoundland and Labrador Offshore Area, tabulated by exploration and development drilling for synthetic-based drilling fluids and all other hydrocarbons, with some incident counts annotated with additional details of the spill, such as a breakdown of the spill materials and actual volumes.

Selected spill and volume statistics from Newfoundland and Labrador and Nova Scotia are presented in Table 2.7 and Figures 2.7 and 2.8.

The Anderson and LaBelle (2000) study provides an update to published rates calculated by the authors through 1992. The revisions, which employ data up to 1999, indicate estimates for US OCS platform occurrence rates continue to decline, primarily because no spills of magnitude greater than 1,000 barrels (bbl) have occurred since 1980. Compared with rates calculated for the historical record, the most recent 15-year estimates for 1985 to 1999 show that rates for US OCS platforms, tankers and barges continued to decline. The 15-year rate was chosen since it appeared to represent how the rates have changed while still maintaining a significant portion of the record.

Table 2.7 Spill Incidents, Offshore Newfoundland and Labrador and Nova Scotia, 1997 to 2005

Spill Location	1997	1998	1999	2000	2001	2002	2003	2004	2005	Total	Average / Year
Offshore NL Cumulative Production (MMbbl)	1.272	23.799	36.391	52.798	54.288	104.334	122.963	114.78	111.269	621.894	69.1
NL, # Exploration Wells[1]	2	1	7	4	0	3	4	0	3	24	2.7
NL, # Spill Incidents, Exploration	1	4	24	1	0	1	4	0	0	35	3.9
NL, # Spill Incidents, Production	10	24	23	9	16	25	21	56	40	224	24.9
NL, # Spill Incidents, Total	11	28	47	10	16	26	25	56	40	259	28.8
Spill Volume, Exploration (L)	40	3,195	1,965	160	0	1	4,547	0	0	9908	1,101
Spill Volume, Production (L)	1,691	2,597	8,270	4,763	5,732	12,280	26,868 [6]	274,008 [7]	4,220	340,429	37,825
Spill Volume, Total (L)	1,731	5,792	10,235	4,923	5,732	12,281	31,415	274,008	4,220	350,337	38,926
NS, # Exploration Wells			2	4	5	7	5	2	10	35	3.9
NS, # Spill Incidents, > 150 L			1 [2]	2 [3]	1 [4]	3 [4]	6	2 [5]	1	16	1.8
NS, # Spill Incidents, Total			26	18	24	25	28	7	11	139	15.4

Source: C-NLOPB 2006c; C-NSOPB 2006.

Notes:

1. Exploration and Delineation.
2. Emission of 370 kg of freon gas.
3. 350 L diesel, 250 L kerosene.
4. MEG: mono ethylene glycol.
5. Release of 354 m^3 of SBM at seabed = 2,067 m, due to equipment failure during well abandonment, also 4 m^3 of diesel fuel spill at North Triumph, cracked fuel filter.
6. 2003 includes a release of approximately 23,000 L of SBM at Hibernia.
7. 2004 includes the November 2004 spill of 165,000 L at Terra Nova due to equipment and procedural failure.

Historic spill rates estimated from Anderson and LaBelle (2000) for OCS Platform and, for comparison, UCS Pipeline and Worldwide Tanker sources, are presented in Table 2.8. Spill rates are given as occurrence per billion barrels (Bbbl) handled.

Based on the most recent historic period (Table 2.8), one might consider the rates for spills greater than or equal to 1,000 bbl for OCS platforms as 0.13 per Bbbl, and for spills greater than or equal to 1,000 bbl for OCS platforms as 0.05 per Bbbl.

The MMS OCS-related incidents web page (MMS 2006b) presents a count of spills greater than or equal to 50 bbl (approximately 7,900 L) from 1964 through 2006 for Gulf of Mexico (GOM) and Pacific (PAC) operations. A link for each year's entry provides details for each incident, including location, cause, amount of pollution and remarks. As with the C-NLOPB (2006c) and C-NSOPB (2006) incident databases, this is an excellent resource for historical spill information.

As Anderson and LaBelle (2000) note, there are many unknown factors that affect the likelihood of an oil spill occurring during the life of the "lease sale" activities. These include timing of exploration and development, volume of production, mode of product transportation, weather and other external factors. Data limitations such as these may preclude using elaborate spill-prediction techniques, although some tangible spill assessment activities can generally be conducted as details of a particular drilling program become available.

Figure 2.7 Exploration Well and Spill Incidents, Offshore Newfoundland and Labrador (1997 to 2005)

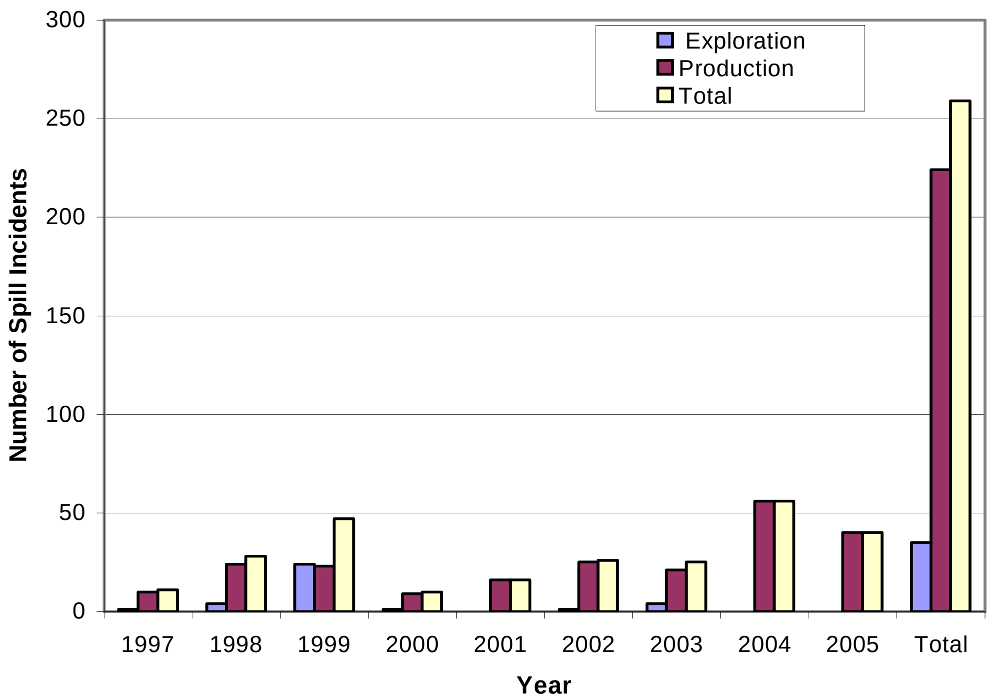


Figure 2.8 Exploration and Production Spill Volumes, Offshore Newfoundland and Labrador (1997 to 2005)

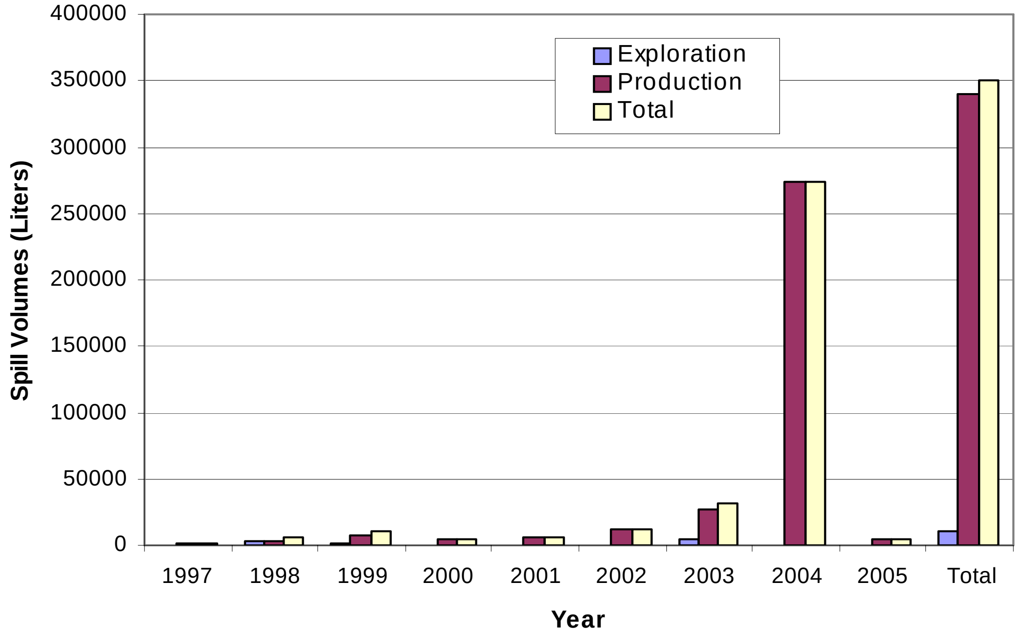


Table 2.8 United States Outer Continental Shelf Historic Spill Rates

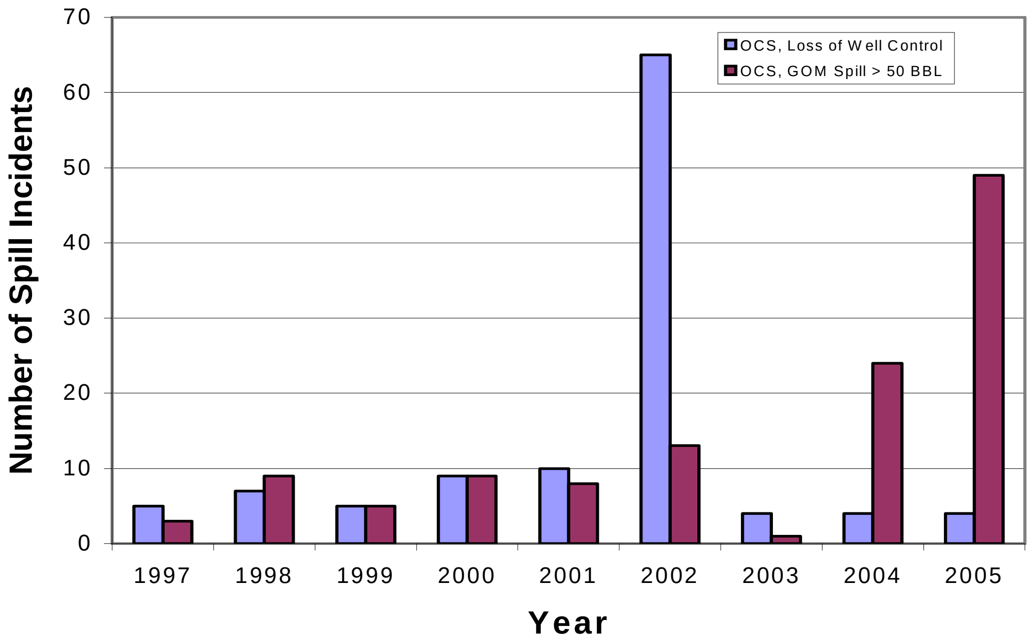
Spill Source	Time Period	Spills ≥1,000 bbl per Bbbl	Spills ≥10,000 bbl per Bbbl
OCS Platforms	1985-1999	0.13 [1]	0.05 [2]
	1964-1999	0.32	0.12 [3]
	1964-1992	0.45	0.16
OCS Pipelines	1985-1999	1.38	0.34
	1964-1999	1.33	0.33
	1964-1992	1.32	0.44
Tankers Worldwide	1985-1999	0.82	0.37
	1964-1999	1.16	0.59
	1964-1992	1.30	0.72

Source: Anderson and LaBelle 2000.
Notes:
1. There were no platform spills since 1980, which implies the 1985 to 1999 calculated rate would be “zero”, which is best not to use. Instead, it is proposed that the 15-year (1985 to 1999) spill rate is less than the 20-year (1980 to 1999) spill rate of 0.13. Last platform spill of 1,456 bbl in November 1980 at High Island 206.
2. Zero spills since 1980, zero spills ≥10,000 bbl since 1970. Last 15-year (1985-1999) spill rate less than 0.05 spills/Bbbl.
3. Equal to four-elevenths of the rate for spills ≥1,000 bbl. This is a conservative estimate, since four of the eleven spills greater than 1,000 bbl were greater than 10,000 bbl over the entire history; none of the three spills that occurred in their recent trend or production corresponding to this interval were less than or equal to 10,000 bbl.

In general, continued efforts by the oil and gas industry in conjunction with research, inspection and appropriate enforcement programs by offshore regulators are expected to contribute to minimizing the amount of oil and related materials into the marine environment. Ongoing efforts for inspecting safety devices and systems, conducting oil spill exercises and accident investigations are key factors for success. Operators should be required to use the best and safest technologies on all new and where practical, existing operations.

The MMS OCS-related incidents record (MMS 2006b) is updated as incidents occur. The most recent (1997 to 2005) statistics for spills greater than 50 bbl and for loss of well control incidents are shown in Figure 2.9. The number of deep (generally water depths greater than 1,000 m) and shallow wells drilled (shown scaled down by a factor of 100 to facilitate comparison with number of incidents) are shown for illustration of level of drilling activity.

Figure 2.9 United States Outer Continental Shelf-Related Incidents, Gulf of Mexico (1997 to 2005)



2.7.1.3 Spill Sizes

For Offshore Newfoundland and Labrador, since 1997, mean and maximum spill sizes are provided in Table 2.9.

Table 2.9 Offshore Newfoundland and Labrador Spill Sizes, 1997 to 2005

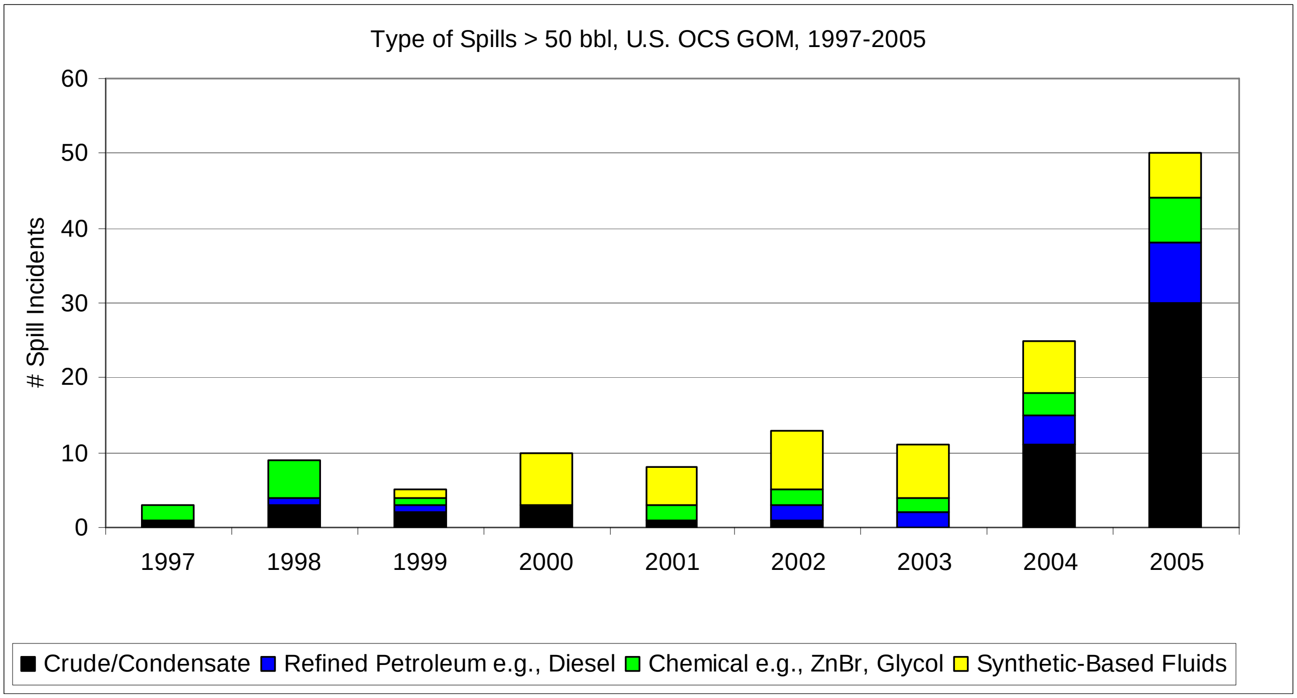
	Mean (L)	Maximum (L)
Exploration Drilling		
Synthetic Oils/Fluids	4,400	4,400
Crude or Refined Petroleum	162	< 3,195 (total from four incidents in Q1, 1998)
Development Drilling and Production		
Synthetic Oils/Fluids	5,334	96,000
Crude or Refined Petroleum	884	165,000

In terms of further discrimination of material types, from the exploration drilling spill incidents from 1997 to 2004, 44 percent of the spilled volume was synthetic oils and fluids, 27 percent crude, 27 percent diesel, 1 percent hydraulic and lubricating oils and 1 percent other oils.

Corresponding spills by volume for development drilling and production (1997 to 2005) were approximately 50 percent synthetic oils and fluids, 48.5 percent crude and the smaller remaining volume comprised of diesel, hydraulic and lubricating oils, other oils and condensate

The spill product associated with each spill incident for the US OCS is shown in Figure 2.10.

Figure 2.10 Type of Spills Greater than 50 Barrels, United States Outer Continental Shelf Gulf of Mexico, 1997 to 2005



2.7.1.4 Spill Probabilities for Offshore Newfoundland and Labrador

For Offshore Newfoundland and Labrador, the production rates from 1997 to 2005 from Hibernia (since 1997), Terra Nova (since 2002) and White Rose (since 2005) total 622 MMbbl of oil (C-NLOPB 2006c).

Together with the one spill of 1,000 bbl spill from the Terra Nova FPSO in November 2004, due to equipment and procedural failure, from 1997 to 2005 data, a Newfoundland occurrence rate of 1.6 spills (greater than or equal to 1,000 bbl) per Bbbl oil production (=one spill / 662 MMbbl) could be predicted. While this 1.6 value could be compared to the US OCS Platform rate of 0.13, it is difficult to make a direct comparison due to differences in the sample databases.

Considering spill incidents of any size, from Table 2.9 one could also estimate the following for Offshore Newfoundland and Labrador:

Predicted number of spill incidents (exploration):

= 1.44 per exploration well (3.9 incidents per year / 2.7 wells per year)

Predicted number of spill incidents (production):

= 0.36 per 1 MMbbl production (24.9 incidents per year / 69.1 MMbbl production per year)

2.7.2 Fate and Behaviour

It should be noted that in preparing for a drilling program, the environmental assessment will require a detailed spill trajectory analysis. For the SEA Area, environmental conditions will change over the course of the year, the wind, current and wave magnitudes and directions and sea and air temperatures in summer will be different from those one might encounter in the fall and winter. These conditions directly determine the fate and transport of an oil spill. Particular times of year may introduce severe weather and sea conditions that might increase the chance of an accident occurring and could compound spill response.

The actual proposed drilling location would be fundamental to any spill assessment and trajectory analysis, as would the time of year for proposed exploration, and such study should be carried out once those particulars are known and prior to any drilling activity. Locations in the SEA Area will have varying proximity to coastlines, and each location will be subject to different wind and current regimes, so that the range of possible transport and fate scenarios and shorelines potentially at risk and actual times to shoreline impact may, be unique in each instance.

As a first order approximation, it may be instructive to consider several hypothetical scenarios in the SEA Area. More accurate estimates of time-to-shore scenarios can only be accomplished via site specific oil spill trajectory analysis.

Estimates of time to shore for several scenarios based on a macro view of several physical parameters affecting spill trajectories is provided in Table 2.10, with transport calculated at a rate 3 percent of wind speed summed with 100 percent of the current speed. For each scenario, a "near" and "far" distance to shore in the SEA Area, a current and wind speed and estimated time to shore are presented. A mean and winter maximum wind speed is considered. A current speed of 30 cm/s (or 1 km/h or 0.6 knots) is considered. Four sensitivities are given where the wind and current speeds are reduced and also increased slightly to see how sensitive predictions might be to changes in the wind or current. From the simple scenarios considered, a nearshore location may be affected by an accidental oil spill within 0.5 days under strong gale or storm force wind conditions to approximately 24 to 36 hours for a range of wind and current conditions. For locations farther a-field, times of four days or longer might be expected.

Table 2.10 Hypothetical Spill "Time to Shore" Scenarios within the Strategic Environmental Assessment Area

Sensitivity	Speed-Distance	Distance to Shore (km)	Wind Speed (m/s)	Wind Scaling	Scaled Wind (km/h)	Current Speed (cm/s)	Current Scaling	Scaled Current (km/h)	"Time to Shore" (h)
Base Case	Mean-Near	50	8	1.0	28.8	30	1.0	1.1	26
Base Case	Mean-Far	200	8	1.0	28.8	30	1.0	1.1	103
Base Case	Winter Max-Near	50	26	1.0	93.6	30	1.0	1.1	13
Base Case	Winter Max-Far	200	26	1.0	93.6	30	1.0	1.1	51
Increased Wind	Mean-Near	50	8	1.2	34.6	30	1.0	1.1	24
Reduced Wind	Mean-Near	50	8	0.8	23.0	30	1.0	1.1	28
Increased Current	Mean-Near	50	8	1.0	28.8	30	1.5	1.6	20
Reduced Current	Mean-Near	50	8	1.0	28.8	30	0.5	0.5	36
Note: These are all estimates and are for illustration only.									

In terms of direction, while winds from all directions are possible during the year, the winds in summer over the SEA Area are predominantly from south through southwest, and in winter from the west through northwest. Based on the general ocean circulation, the general current flow might be expected to be to the northwest where offshore, and to the west directly along the south coast of Newfoundland. This flow is somewhat counter to a windward component of a spill trajectory and may have the effect of slowing the time to shoreline contact slightly and also adding a bit of a westerly bias to the drift direction. For example, for similar wind conditions at a time of spill, and distance to shore, a spill location in the western portion of the SEA Area might be more likely to reach Cape Breton, than a spill to the east on the St. Pierre Bank west of St. Pierre et Miquelon where, on average, the circulation may tend to move things to the northwest.

Current directions and speeds vary considerably over the SEA Area and from offshore to onshore (e.g., from a location at 47°N, under southerly winds, north to the south Newfoundland coast). These would be additional determining factors in any actual spill; this could be modeled as part of a spill assessment for a given proposed drilling location.

The open ocean affected during a spill and the potential areas at risk from transport of the oil and the possible marine life resources at risk should be considered. Again, once a more specific potential drilling location is identified, the resources that would be potentially at risk in the event of a spill could be identified with come certainty.

2.7.3 Spill Modelling and Response Planning

The exact trajectory (where, when and how much will reach shore) from an oil spill in the SEA Area is unknown. Site-specific oil spill trajectory modelling will be required for any proposed exploration drilling project that may occur in the SEA Area.

It will be a requirement for any operator to prepare and implement an appropriate and approved Oil Spill Emergency Response Plan, one that recognizes the range of possible accidental events associated with the proposed drilling activities, establishes procedures for notification and response in the event of an incident and identifies locations of trained personnel and nearest equipment.

Considerable experience has been gained from oil and gas exploration and development activities on the Grand Banks, as well as elsewhere in the world, and this body of knowledge should well serve any operators in spill response planning preparations. One consideration would be possible remoteness and access to response equipment depending on how far the location is from shore bases such as St. John’s, Marystown, Sydney, Halifax, or from other operators drilling offshore.

One element of spill response planning is hypothetical spill scenarios that could occur. This will assist in determining possible environmental or economic resources at risk downstream from a spill and be one means of gauging the appropriateness of the spill response plan. The spill assessment results are appropriate supporting information for any spill response strategy developed.

It is appropriate to review available information on shorelines potentially at risk downstream of a spill. In concert with the human and ecological resources in these regions, the physical characterization of shoreline type for example or oil residence index may help one assess the type and level of response that might be in order in the event of cleanup activities. In some instances, local perceptions of what is at risk and should be protected will be factors. And in some cases, for example if natural removal rates of stranded oil are high, it may be better to allow natural recovery of an affected shoreline and the decision to have limited or no cleanup, which may delay natural recovery in areas, may have merits as well (Owens 1999). As much information as possible regarding human and ecological factors for different parts of the SEA Area should be considered in developing a response strategy that will be of greatness effectiveness.

Essential to note are the possible variations in wind and current speed and direction that individual trajectories can assume. Of inherent importance as well are the primary fate-determining environmental conditions. In particular, wind and sea surface temperature, at the time of a potential spill, should be key considerations in any response strategy formulation.

The type and quantity of spilled product should be considered if there are to be any considerations of weathering processes, although at least in the pre-drilling assessment period and prior to much information on possible well formations its properties may not be known. Evaporation, the conversion of liquid oil into a gaseous component, and natural dispersion, the breakup of an oil slick into small droplets that are mixed into the sea by wave action, are two important weathering processes that typically occur over the first five days following a spill and act to remove oil from the sea surface. Consideration of the amounts lost due to these processes yields an estimate of the remaining amount of oil. Empirical relations exist for evaporation of many fuel types (usually a function of sea temperature and time). Similarly, vertical dispersion can be estimated from winds and waves. The type of oil will also determine the nature of damage or possible damage following an accident (e.g., risks of fire or explosion, and contamination and mortality to marine life and shoreline resources and costs for possible cleanup).

2.8 Well Abandonment and Decommissioning

Following completion of exploration (and production) activities, exploration and production well abandonment will be conducted in accordance with *Guidelines Respecting Drilling Programs in the Newfoundland Offshore Area* (C-NLOPB 2000) and the *Newfoundland Offshore Petroleum Drilling Regulations*. It should be noted that explosives are sometimes used for difficult wellhead removal, but only if mechanical severance fails. It is a requirement that operators have authorization from C-NLOPB before explosives are used.

2.9 Ice Management

2.9.1 Summary

Ice management is a required element of physical environmental programs for drilling operations taking place in regions in which sea ice and/or icebergs can occur. Sea ice and icebergs are not expected to be a frequent occurrence for locations in the SEA Area (Section 3.5). Nevertheless, some discussion of some of the generally accepted elements and considerations of ice management are presented together with some observations that can be made for possible operations in the SEA Area.

2.9.2 Ice Management Plan

Operators are typically required to submit an ice management plan as per the C-NLOPB guidelines (NEB et al. 1994). The guidelines clearly indicate all reporting requirements associated with the plan.

The Operator would prepare and implement an ice management plan appropriate for the planned operations. Since ice conditions can vary greatly from area to area, and season-to-season, or year-to-year within an area, the ice management plan should be tailored to the region, period, and nature of the operation. For example, ice management is generally of particular importance for operations on the Grand Banks or West Greenland, where iceberg severity can be high.

The Ice Management Program shall describe:

- ice detection;
- surveillance;
- data collection;
- reporting;
- forecasting; and
- avoidance or deflection.

The ice management plan should be simple, functional and provide guidance and a plan for action. The plan should address to some appropriate level of detail the following critical factors:

- operations plan and operating environment;
- ice management principles, strategy and approach;
- regional strategic surveillance;
- local tactical surveillance and observation;
- reporting and information management;
- determination of risk;
- response;
- joint ice management; and
- ice reports.

Further detail is provided in the following sections.

2.9.3 Operation Plan and Operating Environment

Description of physical environment conditions including sea ice, icebergs, marine climatology, physical oceanography should be provided in a project-specific environmental assessment. The essential elements to describe are historical sea ice and iceberg conditions.