POLITECNICO DI MILANO

Scuola di Ingegneria Industriale

Corso di Laurea
Ingegneria Energetica orientamento Idrocarburi

Arctic Drilling Technologies:
Challenges, State of Art, Riser analysis on Scarabeo8

Relatore: Prof. Ing. Giovanni LOZZA

Co relatore: Dott. Germana GALLINO

Tesi di Laurea di:

Lorenzo PEZZOLA Matr. 782680

Anno Accademico 2012 - 2013.

Ringraziamenti

Giunto alla conclusione di questo documento, volgendo lo sguardo ai mesi passati, comprendo l'importanza di persone che han condiviso forza, conoscenze ed esperienze. Queste poche righe sono il ringraziamento più sentito a tutti voi al raggiungimento di quest'obiettivo che termina gli importanti anni passati al Politecnico di Milano.
Per prima vorrei ringraziare il mio tutor aziendale, Germana Gallino, per la sua pazienza e disponibilità dimostrata nei miei confronti in questi mesi di lavoro.
Grazie a Davide M. Gaviraghi e Nicola Carini che han saputo condividere il sapere e insegnare il fare nel breve tempo a nostra disposizione creando un clima lavorativo accogliente, giovanile e stimolante.
Un ringraziamento speciale a Marco Pezzola, che oltre a essere mio fratello, è un buon insegnante, capace di correggermi e aiutarmi con grandissima disponibilità e competenza.
Grazie a chi in questi mesi mi ha consigliato ed aiutato nella ricerca e scrittura di questo documento.
Il più grande ringraziamento è per coloro che hanno creduto in me, permettendomi di intraprendere questo arduo percorso: i miei genitori Angela ed Ezio. Il vostro supporto e la vostra esperienza mi han donato forza in ogni mia scelta permettendomi di scolpire il mio essere.
Un grazie speciale a Monica che ascolta con amore le mie note e condivide ogni giorno i suoi colori.
Per ultimo, un grazie a tutti i miei amici che in questi anni hanno partecipato alle mie avventure e difficoltà e che ogni giorno mi donano una parte dei loro universi.

Index

List of figures

List of tables

SOMMARIO

Risultati di studi recentemente promossi dall'agenzia USGS (United States Geological Survey) affermano che le formazioni delle regioni artiche imprigionino una quantità pari al 13-14% del totale del risorse petrolifere e più del 30% delle risorse di gas naturale ancora da scoprire nel globo. Una grande quantità di queste, corrispondente all'80%, è stimata in formazioni offshore.

Questa grande quantità di potenziale di risorse idrocarburiche, unitamente al continuo aumento dei prezzi del petrolio e la progressiva diminuzione dell'estensione media della superficie del ghiaccio perenne dovuto al surriscaldamento globale, ha causato recentemente forte interesse da parte dell'industria globale del petrolio.

L'unicità dell'ambiente Artico è rappresentata da condizioni ambientali estreme con temperature medie invernali inferiori a -40°C e da ecosistemi estremamente fragili, che richiedono grandi investimenti in grado di riempire le lacune tecnologiche che consentano di sviluppare pozzi petroliferi e impianti di produzione in sicurezza per l'ambiente e per il personale.

Dopo un'introduzione storica, il documento caratterizza l'area artica da un punto di vista geografico, ambientale e biologico, approfondendo la questione dello scioglimento dei ghiacci a causa del surriscaldamento globale.

Successivamente vengono delineate sei zone artiche principali delle quali vengono analizzate le caratteristiche fondamentali, il potenziale idrocarburico e i competitors maggiormente impegnati al loro sviluppo.

Vengono delineate le maggiori criticità legate allo sviluppo artico e lo stato dell'arte delle soluzione tecniche associate viene proposto sottolineandone peculiarità e criticità.

La seconda parte del documento riporta il processo di *riser analysis* che è stato applicato al semisommergibile Scarabeo8 operante nel settore norvegese nel mare di Barents, associato al giacimento Goliat, utilizzando il software DeepWater.

Dopo una caratterizzazione dell'ambiente e un'introduzione alla tecnologia riser, l'analisi confronta differenti configurazioni di colonne riser e ne analizza il comportamento in condizioni di perforazione e in condizioni di distacco in emergenza.

La migliore configurazione viene successivamente sottoposta a un'analisi di sensitività variando le condizioni marine a cui è sottoposto il sistema vascello-riser.

Per ultimo considerazioni tecniche vengono effettuate unitamente a un’analisi della risposta in frequenza del sistema e vengono riportate le condizioni marine critiche che portano a instabilità il sistema.

PAROLE CHIAVE: Artico; Criticità e soluzioni; Stato dell’arte perforazione; Riser analysis; Scarabeo 8.

ABSTRACT

Surveys from the USGS (United States Geological Survey), geology based and probabilistic analyses have assessed that the 13-14% of the world’s undiscovered oil and about the 30% world’s undiscovered natural gas are held in the Arctic region and more than 80% of the resources are estimated to be offshore. This great amount of hydrocarbon potential combined with the continuing Increase of oil price and the drastic melting of glaciers due to global warming, have recently moved the interest of the global petroleum industry on this region. The unique characteristics of this area require great investment in new technologies that will allow drilling in its harsh conditions.
In fact, the Arctic environment is one of the most challenging of the world and it is featured by an extremely sensitive environment that would not allow any fluid spill into it.
This document analyses the main challenges related to the development of the Arctic and the possible solution proposed by the technology state of art.
Different sites are defined and technical solutions are proposed to face safely the challenging conditions.
In the second part of the paper, the Scarabeo 8 semisubmersible is deeply analysed and a riser analysis is performed in the water of the Barents Sea on field Goliat. This document describes the riser technology and shows a riser string configurations comparison. Once the best designed string is found, a Sensitivity analysis is modelled in order to define the environmental limits in the Norwegian Arctic that would allow safe drilling according to the API standards.

KEYWORDS: Arctic; Challenges and solutions; Drilling state of art; Riser analysis; Scarabeo8.

1. INTRODUCTION

The Arctic Region is most generally defined by the Arctic Circle, which in 2012 is at 66 degrees, 33 minutes, and 44 seconds North. It is the southernmost latitude where the sun remains above the horizon for 24 hours during the summer in the Northern Hemisphere. This latitude is not fixed due to the axial tilt of the Earth, which can vary by as much as 2 degrees over a periodicity of about 40,000 years. Additional parameters and characteristics are required to gain a broader understanding of the Arctic Region and its physical, chemical, biological, social, and political aspects. An average monthly isotherm of 10 degrees °C for air temperature at 2 m above ground level is a convenient and practical Arctic determinant.

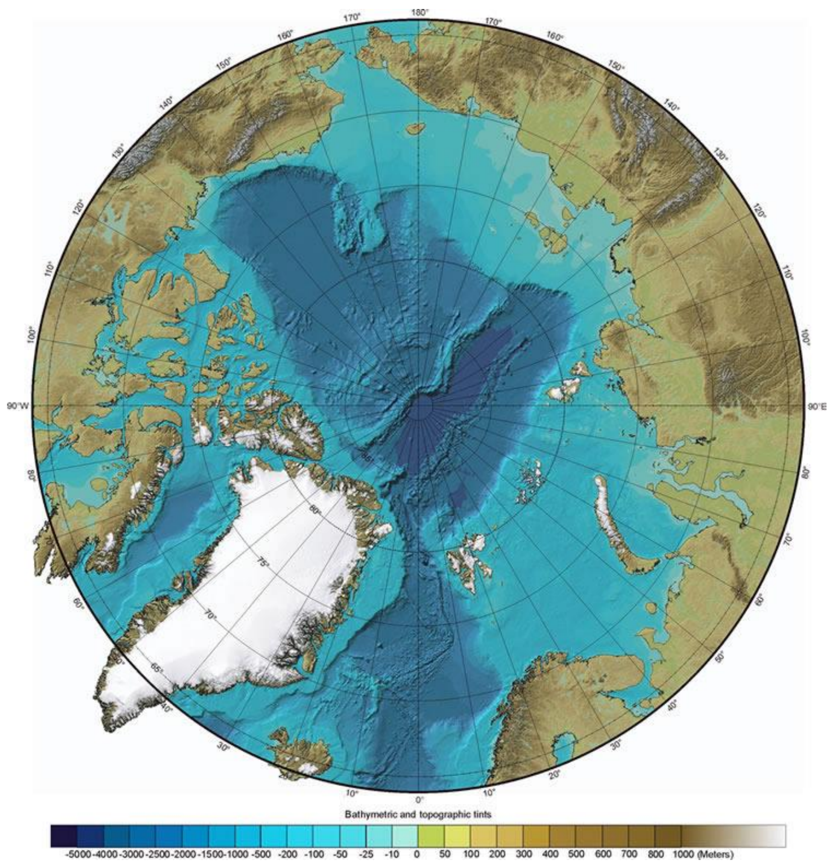


Figure 1.1-Arctic Circle map (www.geology.com)

According to some astronomical calculations the Arctic Circle is currently moving northward at about 15m per year.

It's proven that important oil and gas resources occur within the Arctic Region. It has been calculated that about 13-14% of the world's undiscovered oil may lie within this area, and a significantly higher estimate is obtained when the areas immediately adjacent to the region are included to the South, in the North Temperate Zone. However, the USGS and other estimators have indicated that there is an obvious lack of high quality data for huge areas within the Arctic. A 2008 United States Geological Survey estimates that areas north of the Arctic Circle have 90 billion barrels (1.4×1010 m^3) of undiscovered, technically recoverable oil and 44 billion barrels (7.0×109 m^3) of natural gas liquids in 25 geologically defined areas thought to have potential for petroleum.

Combined with this hydrocarbon abundance there are several complications. First of all the fierce weather conditions and the darkness predominate half of the year, second of all the oil and gas resources will be considerably more expensive and risky compared to all the conventional deposit of the world.

The last issue is the highly sensitive arctic environment that must be imperatively preserved and any risk of oil spill must be minimized or eliminated. [1]

2. GEOGRAPHICAL & GEOLOGICAL ASPECTS

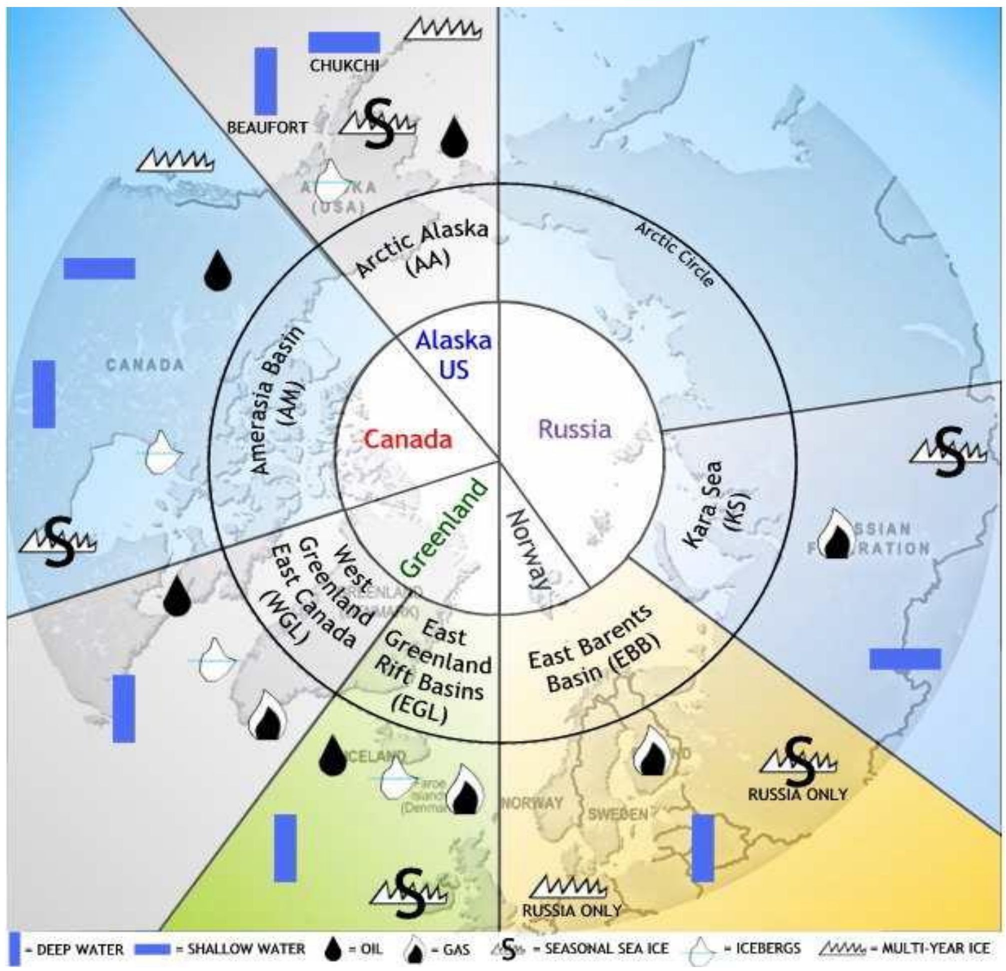


Figure 2.1-Regional hydrocarbon potential

2.1. INTRODUCTION & HYSTORY

The Arctic is variously defined in the E&P industry.

Its geographic definition covers territories north of the Arctic Circle, at latitudes greater than 66°33'44" N. Other definitions include any regions with Arctic-like conditions, such as a particularly cold climate, or with permafrost, floating ice and

icebergs. These extended definitions encompass vast areas—such as West Siberia and Sakhalin, Russia; northern Canada; and Alaska (USA) and Caspian sea —with rich hydrocarbon exploration and production histories.
The indigenous Inuit people of Alaska had long known about oil seeps on the Arctic coastal plain. Russia owned the Alaskan territory until 1867, and Russian settlers were the first westerners to report oil shows on the Alaska Peninsula. The late 19th to early 20th century saw the first successful exploration and production efforts in Alaska, but the first major commercial oil and gas fields there were discovered only as recently as the late 1950s. However, all of these successes were achieved in southern Alaska. The discovery of the first true Arctic commercial hydrocarbon field in Alaska occurred a decade later. [2]

On March 12, 1968, ARCO and Standard Oil Company of New Jersey drilled a well that tapped North America's largest oil field and the 18th largest in the world—the Prudhoe Bay field on Alaska's North Slope that was later confirmed by British Petroleum. The estimate for the field is 4.0 billion m^3 [25 billion bl] of original oil in place (OOIP), 52,5% (2.1 billion m^3 [13 billion bl]) of oil can be recovered with existing technologies. The amount of gas in place is 1.3 trillion m^3 [46 Tcf] of which about 57%(736 billion m3 [26 Tcf]) are classified as recoverable.
Moving Prudhoe Bay oil to market required the operators to solve a variety of problems, from climatic and technological to environmental and legal. Completion of the Trans Alaska Pipeline from Prudhoe Bay to Valdez, Alaska, constructed between 1974 and 1977, allowed oil production in the field to begin . [2]

In the Canadian Arctic, east of Alaska, indigenous people had also been aware of oil seeps for centuries and had even used hydrocarbon pitch to seal seams on canoes. Oil seeping along the banks of the Mackenzie River was first reported by westerners in 1789. Some subarctic fields were discovered in the 1920s. But the first purely Arctic hydrocarbon field in Canada, discovered in 1969 by Panarctic Oils, was the Drake Point gas field on Melville Island in the Canadian Arctic Archipelago. The current estimated gas reserves of the field are 153 billion m^3 [5.4 Tcf]. In 1974, Panarctic Oils discovered the first Canadian Arctic oil field—the Bent Horn field on Cameron Island. Although relatively small, this is the only Canadian Arctic oil field that has been commercially produced. The field was abandoned in 1997, but produced 453.16 thousand m^3 [2.85 million bl] of crude oil from 1985 to 1996. Today, natural gas is considered the most promising hydrocarbon reserve in the Canadian Arctic, and the highest gas potential is expected from the Mackenzie Delta–Beaufort Sea basin and basins of the Arctic Archipelago. [2]

The petroleum potential of Greenland—east of Canada and a self-governing territory of Denmark—has not been extensively explored. Much of Greenland's territory lies north of the Arctic Circle. About 80% of the island is covered by the Greenland ice sheet—an ice body generally more than 2,000 m [6,600 ft] thick—which complicates exploration activities considerably. It was not until the early 1970s, the time of a dramatic rise in oil prices, that the first large seismic surveys were carried out offshore West Greenland, mostly within the Arctic Circle. This exploration period lasted until 1978, with no discoveries. Five exploratory wells were also drilled in 1976 and 1977—all dry holes. Exploration resumed in the early 1990s, with the first oil seeps in Greenland's waters found in 1992. The Marraat-1 well, drilled in 1993, demonstrated substantial oil leakage from cores. Since then, seismic and airborne geophysical surveys have been commissioned, and a few more offshore and onshore wells have been drilled. Some structures with hydrocarbon potential have been identified, and onshore oil seeps and offshore slicks have been observed. However, to date, no oil or gas fields of any commercial significance have been discovered in Greenland. [2]

Iceland, Greenland's neighbour, may also have some Arctic petroleum potential. In 1981, Iceland and Norway agreed on a partition of the Continental Shelf in the area between Iceland and Jan Mayen Island and on a joint project to map the subsea resources of the Jan Mayen Ridge. A 1985 seismic survey and subsequent surveys identified two areas of the Icelandic shelf that are thought to have potential for commercial accumulation of oil and gas. In the Dreki area, east and northeast of Iceland, the thick continental crust potentially includes Jurassic and Cretaceous source rocks and is geologically similar to hydrocarbon basins in Norway and Gammur, on the northern insular shelf of Iceland, is a relatively young sedimentary basin of about 9 million years, from which gas escapes have been reported. In 2009, Iceland held the first licensing round for exploration and production licenses in the Dreki area, and the second round opens in 2011. However, existing surveys estimate the probability of hydrocarbon discovery as low. [2]

Norway, conversely, is one of the world's largest petroleum producers and exporters.

All of Norway's petroleum reserves are located on the Norwegian Continental Shelf in three marine regions: the North, Norwegian and Barents seas, but only the Barents Sea has Arctic petroleum production. Seismic surveying began in the region in the early 1970s, followed by exploratory drilling in 1980, when the Norwegian parliament permitted drilling north of the 62nd parallel. In 1984, Statoil discovered the Askeladd, Albatross and Snøhvit fields, which are collectively called the Snøhvit development. The Snøhvit development is now the world's northernmost offshore gas field, and its estimated recoverable reserves are 194 billion m^3 [6.8 Tcf] of natural gas, 18 million m^3 [113 million bl] of condensate and 5.1 million metric tons [53 million bl] of natural gas liquids.

Figure 2.2-Norway (www.grida.no)

Elsewhere in the Barents Sea, exploration activities continue, and this region is considered a promising area for hydrocarbon production not only by Norway but also by Russia.

The Kara Sea, the Barents Sea and its southeastern part, the Pechora Sea, are now the most explored areas of the Russian Arctic. The first offshore Russian Arctic field—the Murmanskoe gas field—was discovered in 1983 in the Barents Sea. The recoverable gas reserves of this field are estimated at 122 billion m^3 [4.3 Tcf]. In 1986, the first Russian Arctic offshore oil was discovered at the Severo-Gulyaevskoe oil and gas condensate field with estimated recoverable oil reserves of 11.4 million metric tons [84 million bl]. Fifteen hydrocarbon fields have been discovered to date in the Kara, Barents and Pechora seas, including three supergiant fields—Shtokman, Rusanovskoe and Leningradskoe— but none are producing yet. The Prirazlomnoe oil field estimated recoverable reserves are 58.6 million metric tons [430 million bl]. Offshore regions farther east—the Laptev, East Siberian and Chukchi seas—are less explored but promising. Almost all of the developed Russian oil and gas fields are located onshore, and many important ones, including giant fields, are north of the Arctic Circle. The Yamburg oil and gas condensate field, for example, is the world's third-largest gas field with estimated reserves of 4 trillion m^3 [141 Tcf]. Explorationists first investigated this remote area in 1943, during World War II, when the country was in acute need of hydrocarbons. These endeavors were suspended, and it was not until 1959 that exploration activities resumed. Discovered in 1962 near the Taz Estuary in the northern area of West Siberia, the Tazovskoe gas field was the first discovery in the Russian Arctic. The field has estimated gas reserves of about 200 billion m^3 [7.06 Tcf]. The Zapolyarnoe oil, gas and condensate field, discovered in 1965, was the first Russian Arctic oil field. This is also the world's sixth-largest gas field with 2.7 trillion m^3 [95 Tcf] of recoverable gas. However, the time from discovery to production may sometimes take decades in this challenging region. Although it was discovered 45 years ago, this field produced its first gas only in 2001 [2]

2.2. PHYSICAL ENVIRONMENT

The Arctic ice coverage has been declining, generally more rapidly than most models predict. The following is the current sea ice coverage as monitored by satellite and reported in quasi real-time by the National Snow and Ice Data Centre, Boulder, Colorado, USA.

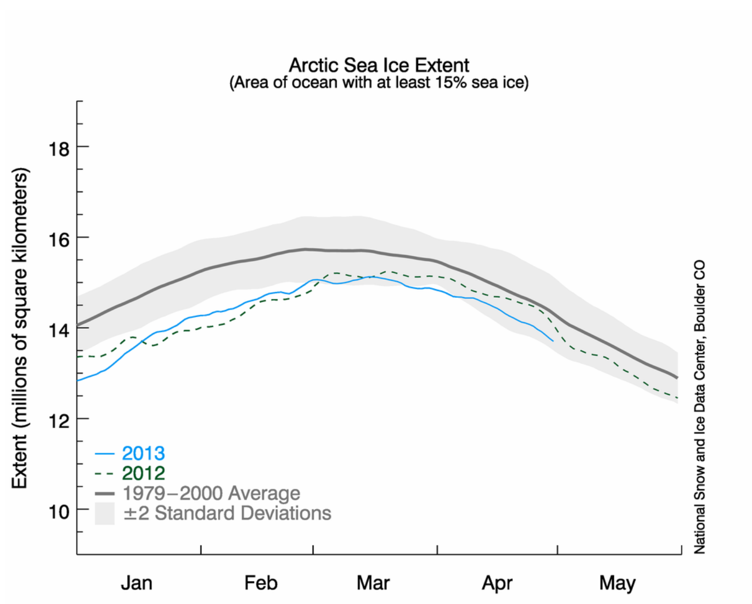


Figure 2.3- Arctic sea ice extent (I). Source: NSIDC

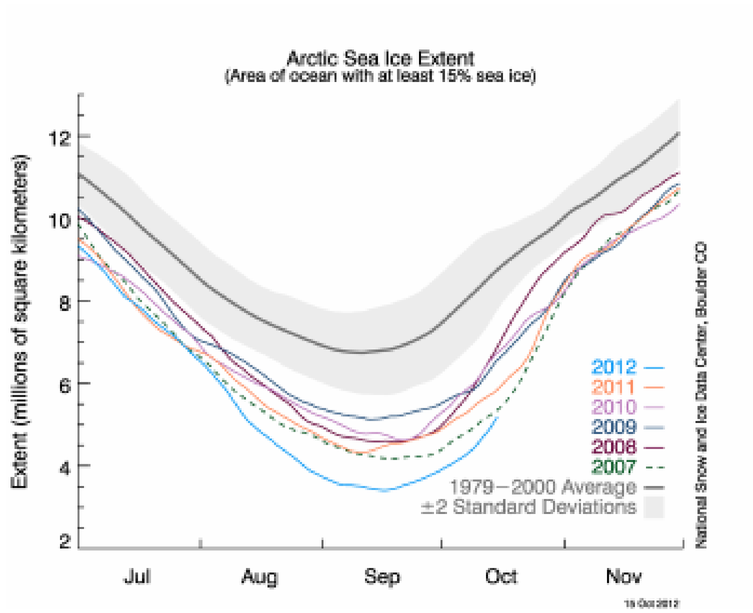


Figure 2.4- Arctic sea ice extent (II). Source: NSIDC

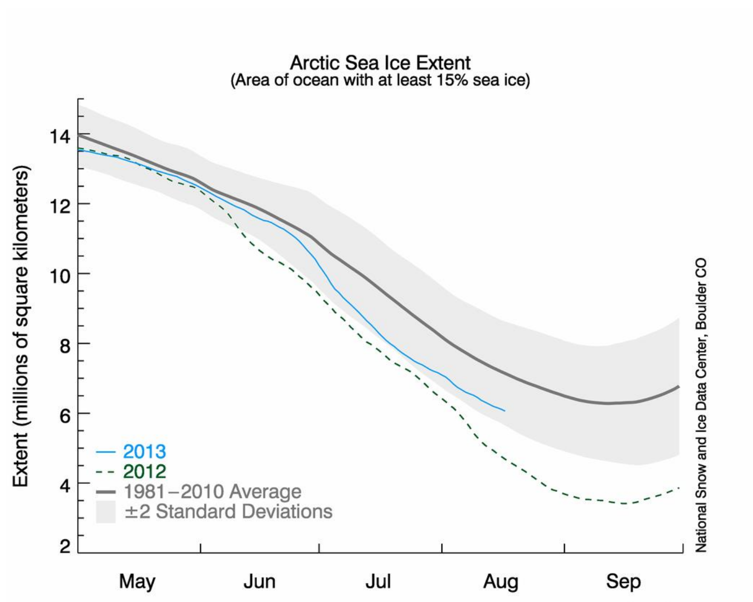


Figure 2.5- Arctic sea ice extent (III). Source: NSIDC

This current extent of sea ice is plotted in Figure 2.3, Figure 2.4, Figure 2.5, Figure 2.6, Figure 2.7 and compared to the historical median. Note that the recession of ice along the northern Russian coast is of high interest due to the

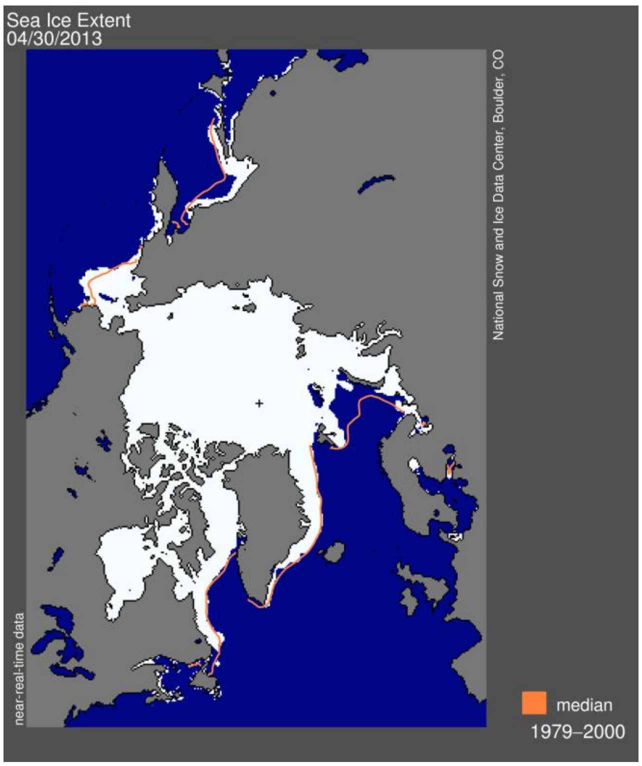


Figure 2.6- Arctic sea ice extent (IV). Source: NSIDC

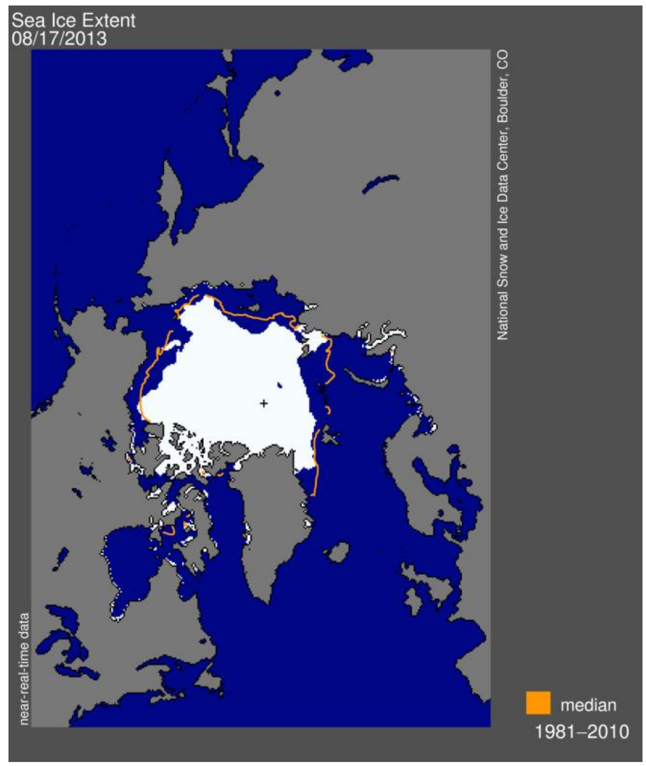


Figure 2.7- Arctic sea ice extent (V). Source: NSIDC

exploration, and rig deployment. Physical environmental changes in the Arctic can be very obvious such as the extent of the ice cover, but also very subtle, such as induced changes in ocean circulation and changes in weather patterns. These types of linkages require detailed analyses and much more data than are currently being collected. Satellite monitoring of the Polar Regions has proven to be extremely valuable. On site monitoring (on, in, or under the ice) is limited, expensive, and without adequate spatial coverage. Each new expedition into the Arctic brings new and interesting data, which are often quite remarkable. Warming of the Arctic also causes changes in the physical environment of the near-shore and onshore regions. Melting of permafrost of the Arctic Region and development of thermokarst erosion poses major obstacles to development of the entire region. The physical integrity of the land to sustain roads, laydown areas, building sites, foundations, and other infrastructure is compromised with accelerated thermokarst. The formation of thermokarst can accelerate the melting of the permafrost and result in significant increases in methanogenesis, release of the trapped methane from the subsurface. Methane is roughly 23 times more potent as a greenhouse gas as compared to carbon dioxide. One can start to appreciate some of the important linkages that exist in Arctic between physical, chemical, biological, and ultimately, social components. Recent investigations of orbital climate forcing based upon high-density dendrochronology raise interesting discussion points with respect to global climate change that will require substantial interdisciplinary evaluation and assessment. [3]

2.3. CHEMICAL ENVIRONMENT

The chemical environment of the Arctic is of high interest. Air quality, water quality, marine geochemistry, methanogenesis (production of methane from permafrost and the seabed), chemical pollution, and nuclear waste disposal have all taken their turn as issues of the day with respect to chemistry of the Arctic. Complex depositional histories of materials in the Arctic environment are being studied through detailed sedimentological coring. This information is used as a basis for understanding past climates and historical oceanographic behaviour and events. A recent oceanographic cruise found that there were undiscovered and widespread methane sources emanating from the Arctic seabed, a significant concern as methane is much more potent as a greenhouse gas than carbon dioxide. The conversion of gas hydrates at the seafloor was ostensibly the source, but much more research will need to be conducted to assess the relative impact of these methane sources. An excellent review of methanogenesis from permafrost was completed by Rivkina et al. (2007) which indicated that methane formingarchaea can produce biogenic CH_4 gas at temperatures as low as -16.5 °C. Thermokarst erosion and the degradation of permafrost layers which can extend to depths of 600m or more is of concern. Thermal coastal abrasion that affects permafrost in the cryolithosphere has the potential to release large amounts of CH_4. Linkages between meteorology, ocean temperature, coastal dynamics, permafrost, and methanogenesis obviously is a good example of the need for interdisciplinary scientific approaches.

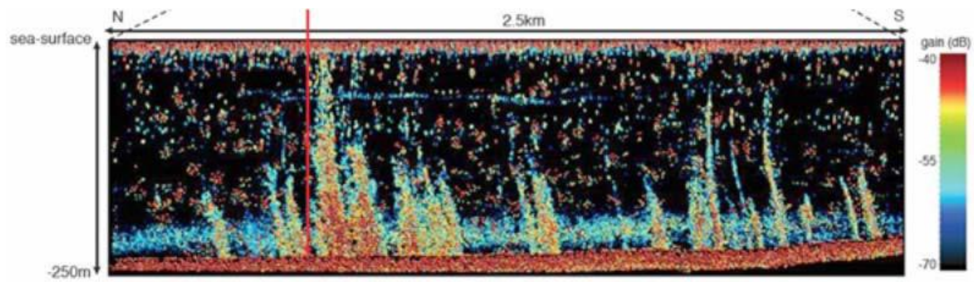


Figure 2.8- Plot of methane plumes emanating from gas hydrates on the Arctic seabed. From Marine Geochemistry Group, National Oceanography Center, Southampton, UK, 2012.

Another area of chemical concern is natural and anthropogenic radionuclides. There has been a long history of nuclear contamination of the Russian Arctic. The Soviet Union utilized the Arctic as a dumping ground for nuclear and radionuclide contaminated wastes for many years. A limited amount of monitoring has been conducted by joint research groups, but the coverage has been quite limited. Oil and gas exploration and production will need to consider both naturally occurring and anthropogenic radionuclides throughout the Russian Arctic. [3]

2.4. BIOLOGICAL ENVIRONMENT

The Arctic food web has been the focus of substantial investigation mainly from the perspective of predator/prey relationships. Biodiversity programs continue to expand in scope and complexity, to include more than just threatened and endangered species, and to include important niches previously little studied or understood.
Recent investigations at the microscopic level of plankton, algae, and diatoms has resulted in rather profound new discoveries, such as finding massive algal blooms under ice which have been

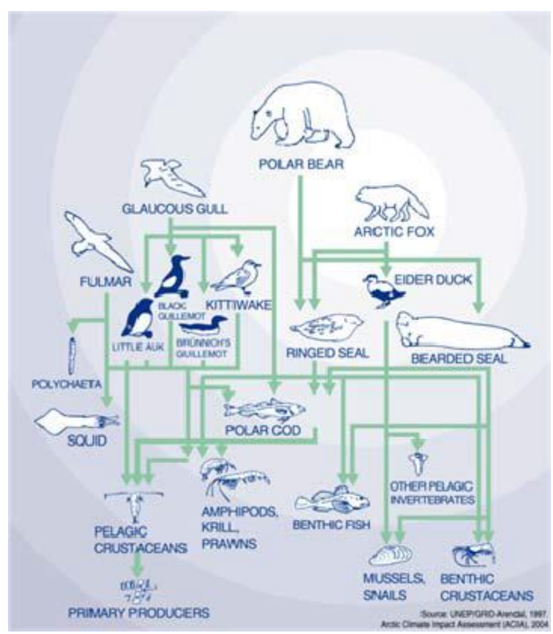


Figure 2.9-Example of an Arctic food chain

linked to alternations in the development of "polynyas"1, ice free lenses that occur in the Arctic ice pack. The analysis of the Arctic food web, both in the ocean and on land, needs to expand to include the physical, chemical, and social components. For example, changes in nutrient levels and timing of algal bloom sequences in the Arctic Ocean has the potential to change zooplankton dynamics, which, in turn, can affect fisheries production and even whale food (krill are a mainstay of many baleen whales). The Arctic food web is one area where there is a very clear need for interdisciplinary activity, linking physical oceanography to water chemistry and nutrients, linking plankton with invertebrates, and then following the food web from fish to birds and marine mammals. The dynamic nature of the Arctic food web demands that more understanding of the interactions be a high priority. Changes in the ice have already been shown to change distribution of animals, from very small scales (ice algae, phytoplankton) to very large scales (walrus and polar bears). Large walrus "haul outs" are now reported up to a month early in unusual locations. The scale factor is one of immense interest and opportunity for interdisciplinary studies and analysis. The interrelationship of runoff from the major Arctic rivers and the Arctic Ocean is poorly understood. Near-shore coastal dynamics, permafrost, thermokarst, and sedimentology are all very important aspects of oil and gas exploration in the Arctic, and all are poorly understood in most areas.

Marine mammal impacts are of high concern in the Arctic environment. The increase of human activities, especially ocean going vessels, offshore drill rigs, oil tankers, aviation, and subsea installations brings with it many new interactions with marine fauna. One of the leading concerns (in addition to potential for oil spill impacts) is noise. According to Hildebrand (2002), "Expanding use of the sea for commercial shipping and advanced warfare has resulted in noise levels at least 10 times higher today than they were a few decades ago." Changes in noise environment have been studied in detail at only a few locations around the world. There will be required much more information on the relationship of marine fauna to noise in the future. One of the very first introductory studies conducted on marine mammals, noise, and the oil and gas industry was conducted 30 years ago. In 2007, the Marine Mammal Commission prepared a report to Congress outlining the cooperative recommendations for furthering understanding of this important consideration. Various joint industry programs have been convened over the years to address issues surrounding noise and oil and gas exploration. A new era of ocean noise monitoring and surveillance, coupled with impact assessment and mitigation capabilities has arrived, based upon the deployment of new, more sophisticated devices, including high-frequency acoustic recording packages (HARP).

Comprehensive noise management programs will be required to include acute, chronic, fixed, mobile, aviation, ocean going, and miscellaneous noise sources from oil and gas exploration and production. New more stringent regulations are being promulgated for the Arctic and Subarctic region.

The interdisciplinary linkage between the physics of noise in the ocean with marine mammal ecology and, ultimately, with mitigation and operational constraints to oil and gas exploration and production is evident in this example. [3]

Figure 2.10-Beluga Whale

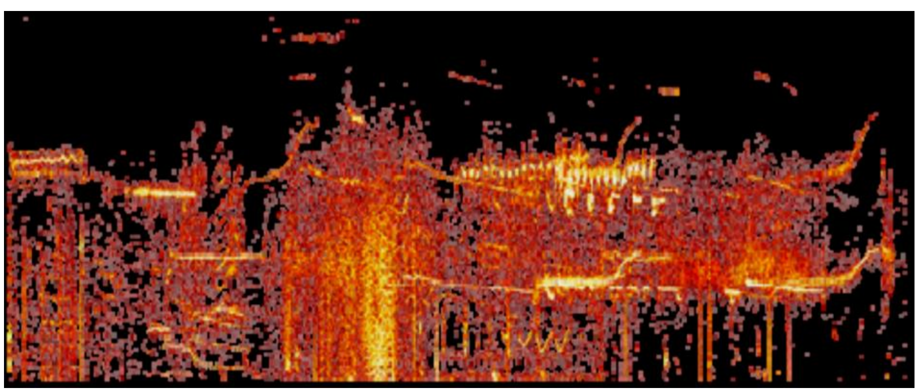


Figure 2.11-Beluga Whale Sonogram – Scripps Institution of Oceanography – Whale Sound Lab, 2012

2.5. SITE CARACHTERIZATION & COMPETITORS

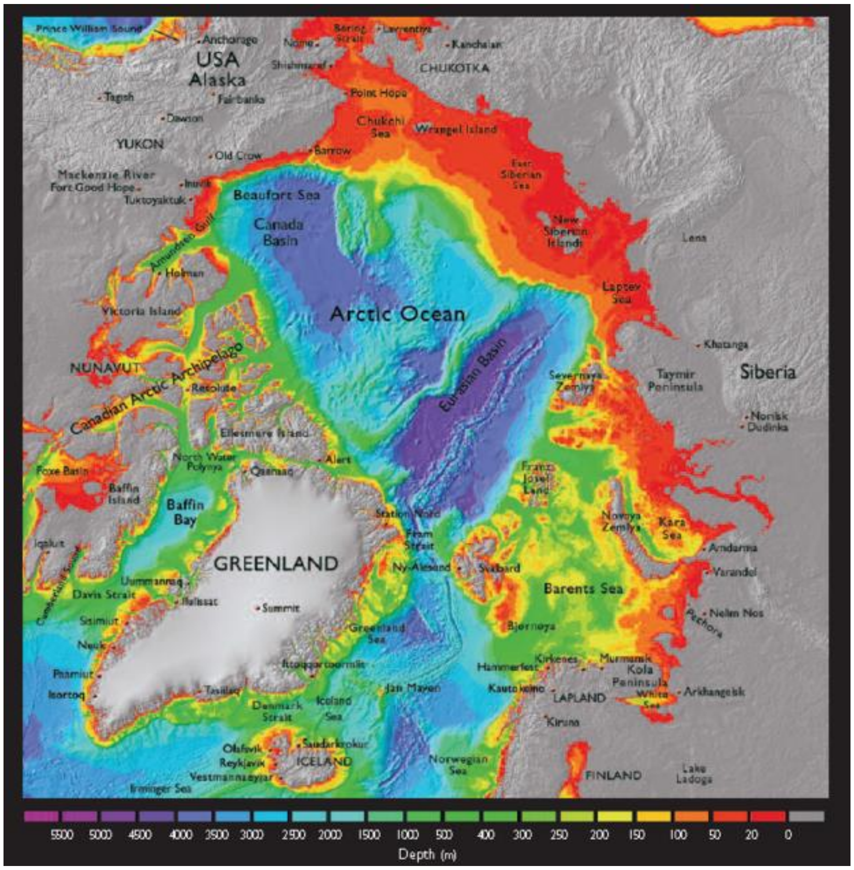


Figure 2.12- Arctic water depth. Source: www.eoearth.org

Arctic environment is composed by inhomogeneous topography both on and offshore. What is given in this paper is just a general description with some examples. It is understandable that any project must be supported by a deep analysis of the surrounding environment.

About 84% of the estimated undiscovered resources are expected to occur offshore. At the state of art this should not be a problem even in deep-water fields but several problems occurs that will be discussed deeply later on. Deep-water operations are not as complicated as shallow-water ones because of the ice masses that may impact the seabed. The main fields under deep-water are located mainly around Greenland and in the Beaufort Sea as shone in Figure 2.12.

Several arctic areas around the globe are considered “attractive” for oil and gas industry as shown in Figure 2.13.

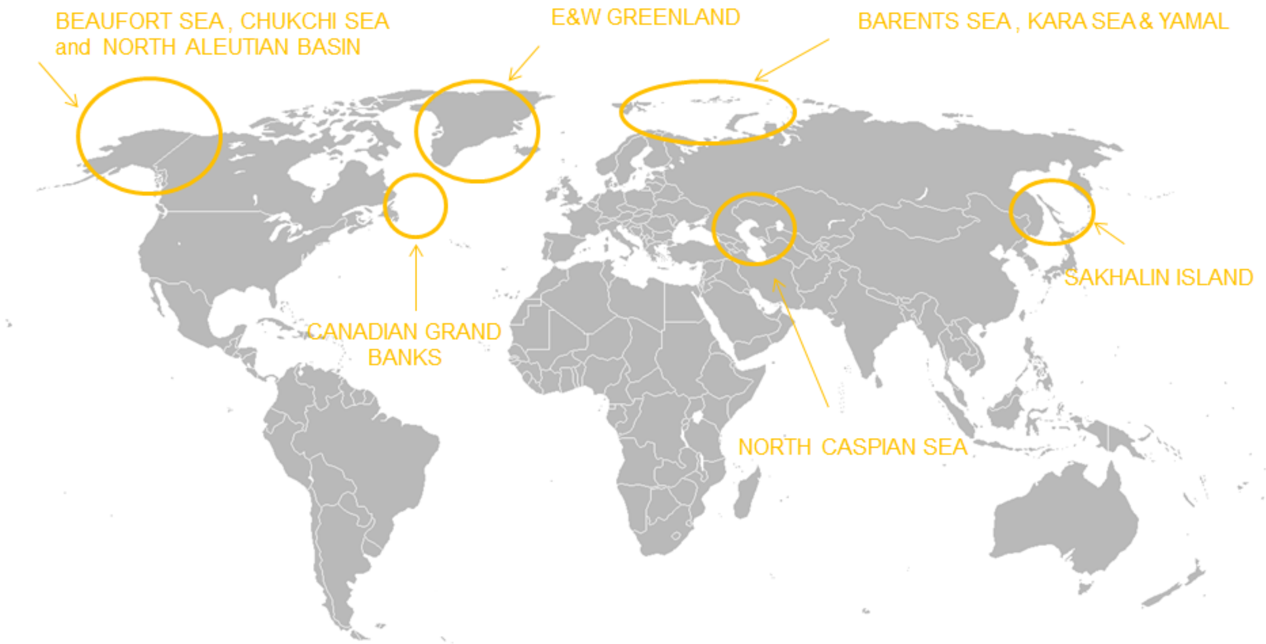


Figure 2.13- Arctic areas

2.5.1. West & East Greenland

Licensing rounds have been made approximately every second year and have resulted in a boom in oil exploration .More than 200.000 km^2 offshore West Greenland are now covered by exploration licenses. Nowadays only 6 wells in West Greenland are productive in the Baffin Bay area, that is overall about three times the size of the North Sea. [4]
Several survey explorations have been made during the 2012 and 2013 in Eastern Greenland area in the Greenland Sea in an area with an extension of 50.00 km^2 split in 19 blocks.
The licensing round for all the Northeast Greenland sea will end the15th October 2013. [5]
USGS P50 estimate for Greenland’s hydrocarbon potential is 50 billion BOE circa.

A list of the current licenses is given in Figure 2.14.

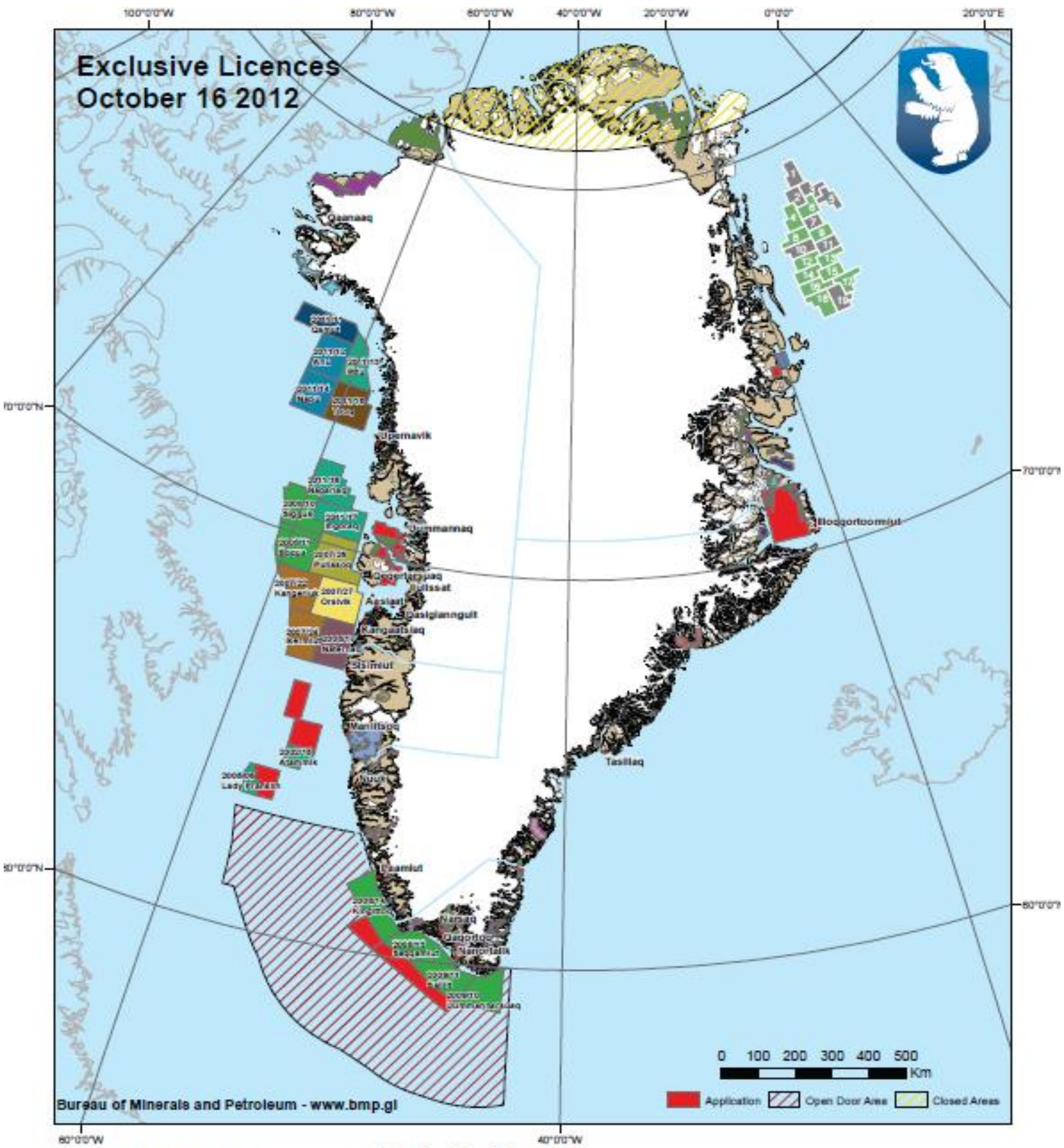


Figure 2.14- Greenland licenses map

2.5.2. Beaufort, Chukchi Sea and north Aleutian basin

Figure 2.15- Alaska. Source: Northern Economics

In the early 1980s active leasing and exploration in the Alaska Outer Continental Shelf (OCS) was driven by rapidly increasing crude oil prices and access to new, high potential areas. However, after some disappointing failures (Mukluk) and declining oil prices in 1986, the industry retreated from the

Alaska OCS and focused on lower risk projects elsewhere. Increasing petroleum prices and acreage availability in the past five years have created renewed interest in exploring for oil and gas in Alaska OCS areas. The Minerals Management Service's (MMS) Beaufort Lease Sale 195 was the most successful (tracts and high bids) Beaufort Sale since 1988. The MMS Chukchi Lease Sale 193 held in February 2008, collected $2.66 billion in high bids for 488 tracts. Sale 193 was the biggest lease sale (onshore or offshore) in Alaska's history. More lease sales are planned in the Beaufort Sea, Chukchi

Sea, and the North Aleutian Basin as part of MMS's 5-Year Lease Plan for the 2007-2012 period (MMS 2007)

MMS estimates that the OCS areas of the Beaufort Sea, Chukchi Sea, and the North Aleutian Basin have undiscovered technically recoverable resources (UTRR) in the range of 2.8 to 65.8 billion barrels

of oil (BBO) and 11.4 to 305 trillion cubic feet (TCF) of natural gas. MMS also estimates that the three OCS areas have undiscovered economically recoverable resources (UERR) ranging from 1 to 46 billion barrels of oil and 3.8 to 175.1 TCF of gas.

Economically recoverable resources represent the portion of the undiscovered technically recoverable resources that can be explored, developed and commercially produced at given costs and price considerations. [6]

Up to date it is important to underline that no oil companies are drilling in this OCS areas described above because of the extremely harsh environment of The Alaskan OCS.

In fact, in the first months of 2013 three major oil companies have abandoned drilling plans in Alaska and have suspended indefinitely exploratory efforts. Royal Dutch shell started the trend on February 27th because of equipment problems. Immediately after, Norwegian conglomerate, Statoil communicated that all drilling activities are suspended for all 2013. As last on April 10th ConocoPhillips announced that it was suspending its plans to drill exploratory wells off Alaska's arctic coasts in 2014 [7].

The first step made by Shell was connected to concerns that have been fueled by a string of malfunctions and misfortunes that Shell suffered over the course of 2012. The company had to suspend its first stab at the ocean floor in summer 2012 about 24 hours after beginning to drill, because of an ice floe that got within striking range.

Equipment damage followed, including the rupture of a spill-containment system as it was being tested for deployment back in Washington State. Then a drill rig broke loose in the Chukchi Sea and had to be towed to a remote island on December 31 *(Kulluk)*. [7]

Figure 2.16- Kulluk. Source: progerissivealaska.blogspot.com

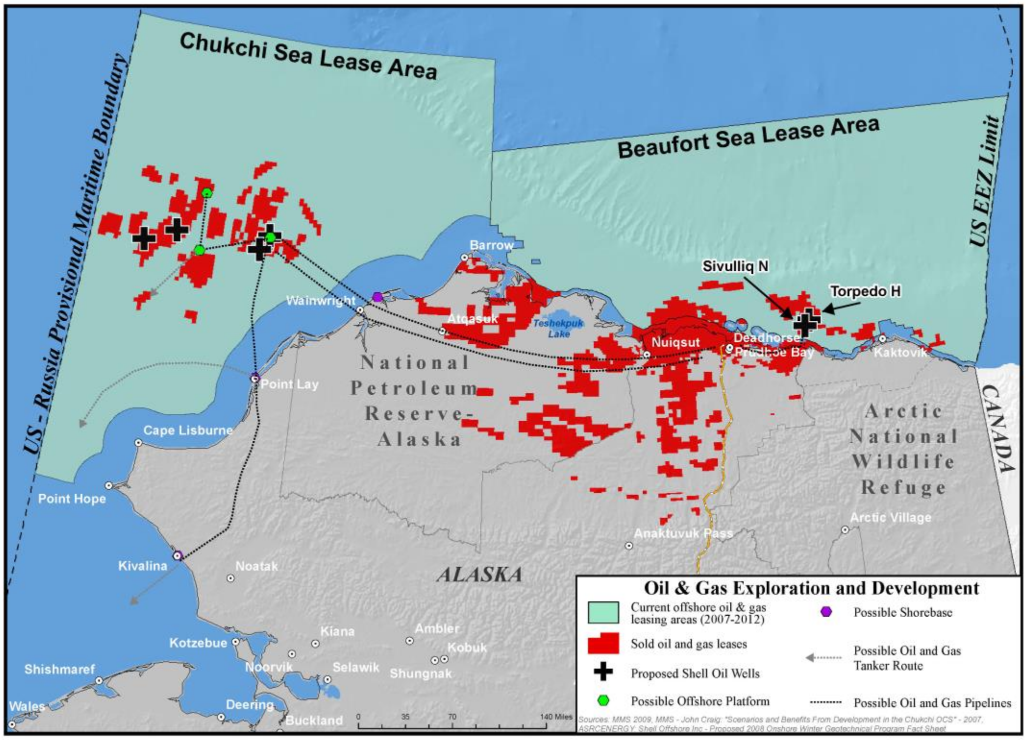


Figure 2.17-Arctic ocean oil leases 2011

Another important aspect that must be taken under evaluation is the massive presence of gas hydrates trapped on shore in Alaska on the Alaska North Slope (ANS). Assessments produced by the U.S. Geological Survey (USGS) have estimated that 85 trillion cubic feet (tcf) of undiscovered, technically recoverable gas resources exist within gas hydrates in northern Alaska. Past USGS assessments indicated 40 tcf of the resource may exist within hydrate deposits below existing oil and gas production facilities. In 2001, BP Exploration Alaska Inc. proposed a state-of-the-art 3-D seismic survey over its Milne Point production unit to provide a starting point for a full evaluation of the feasibility of commercial production from Arctic hydrates.

Hydrates presence could be either positive, under the prospective of a future technology development that will permit the utilization of this resources, either negative because hydrates could release methane under thermal or pressure stimulation during conventional perforation, causing safety and environmental problems.

The sedimentary methane hydrate reservoirs probably contain 2-10 times the currently known reserves of conventional natural gas and this makes such a kind of reservoir really interesting for a future development.

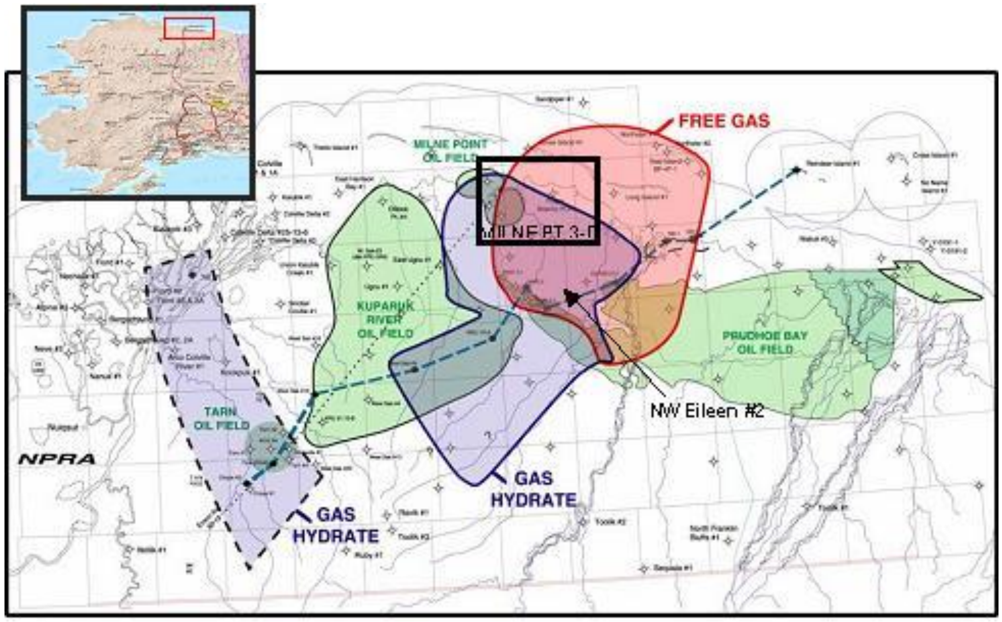


Figure 2.18- Map of gas hydrates, freegas and oil fields in Alaska North Slope

2.5.3. Barents Sea, Svalbard & Yamal

In 2008, the U.S. Geological Survey (USGS) completed an assessment of potential undiscovered, technically recoverable crude oil, natural gas, and natural gas liquid resources in the Barents Sea Shelf. These resources are assumed to be recoverable regardless of the presence of sea ice or depth of water. The ice coverage is absent in the Norwegian OCS, because of the gulf stream, and starts to increase from the Russian Barents sea. As with other areas assessed in the USGS Circum-Arctic Oil and Gas Resource Appraisal, this area shares important characteristics with many Arctic basins, such as sparse data, high geologic uncertainty, substantial petroleum-resource potential, and technical barriers that impede exploration and development. The Barents Sea Shelf, which lies entirely north of the Arctic Circle, contains an area of approximately 1,760,000 square kilometres between longs 0º

and 80ºE. Most of this area offshore northern Norway and the Russian Federation lies under less than 500 meters of water.
Thanks to the specific its characteristic this artic area is one of the most developed of the world for E&P industries with more than 100 wells drilled up to date.

The USGS assessed undiscovered conventional, technically recoverable petroleum (discovered reserves not included), resulting in the estimated mean volumes of a probability distribution of approximately 11 billion barrels (1,750 million cubic meters, equivalent to 1,500 million metric tons) of crude oil, 380 trillion cubic feet (11 trillion cubic meters) of natural gas, and 2 billion barrels (320 million cubic meters, equivalent to 270 million metric tons) of natural gas liquids. Most undiscovered petroleum is estimated to be in the East Barents Basins Province.(USGS)

There is a big list of competitors working in the Norwegian OCS as Statoil, ConocoPhillips, ExxonMobil, BP, Norske Shell, Eni Norge, Total,..

The Russian oil Industry, instead, is dominated by a very small number of oil companies. The reason for this oligarchy goes beyond politics. The distribution of oil fields within Russia favours only a small number of firms and the benefits of economies of scale. By 2003, over 80% of Russian supply came from five major private companies. These companies are Lukoil, Gazprom Neft, TNK-BP, Surgutneftegaz, and Rosneft. These major producers were complimented by major regional producers Tatneftand Bahneft. [1]

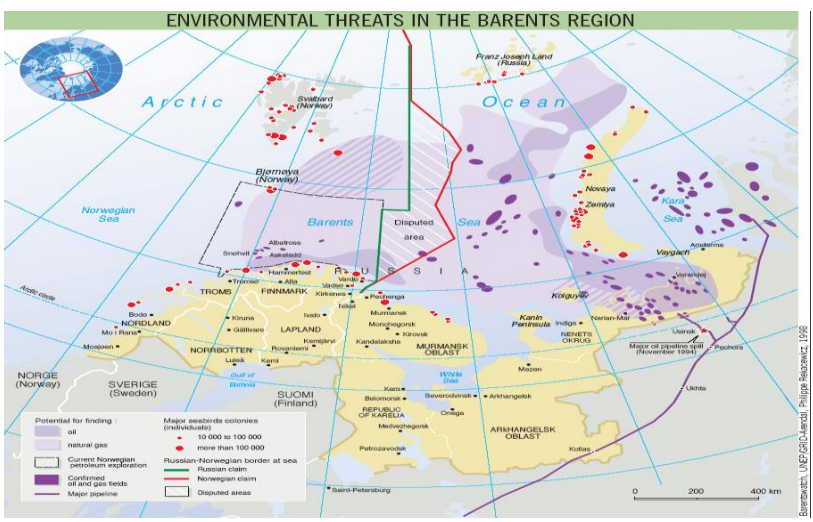


Figure 2.19-Barents region. Source: Unep

2.5.4. Canadian Grand Banks

The Grand banks area is composed by four major oil & gas fields: White rose, Hibernia, Hebron and Terranova.

The White Rose field is located 350km east of Newfoundland, approximately 50km from both the Terra Nova and Hibernia fields. It is operated by Husky Energy Operations Ltd. (72.5%) with partnership of Suncor energy (27.5%).

Figure 2.20- Canadian Grand Banks. Source:cbc.ca

The **White Rose** oilfield development involves recovering an estimated 70 million cubic metres circa (440 million barrels) of 30° API oil from an area of approximately 40km².

The first discoveries were made in 1984 and production started in November 2005. White Rose is the second harsh environment development in North America to use a FPSO (Floating Production Storage and Offloading) vessel. (Wikipedia)

The White Rose field has been developed from three or four drill centres on the seafloor, with production and water and gas injection wells located at each centre. These drill centres are located in excavated glory holes that lie below the seabed to protect the wells from iceberg scour.

On-going development plans envisage up to 10 to 14 production wells eventually. An additional eight to eleven gas and water injection wells have been drilled for resource conservation and to maintain reservoir pressure. The wells have been drilled in phases to bring White Rose satellite fields into production in late 2009 or early 2010.

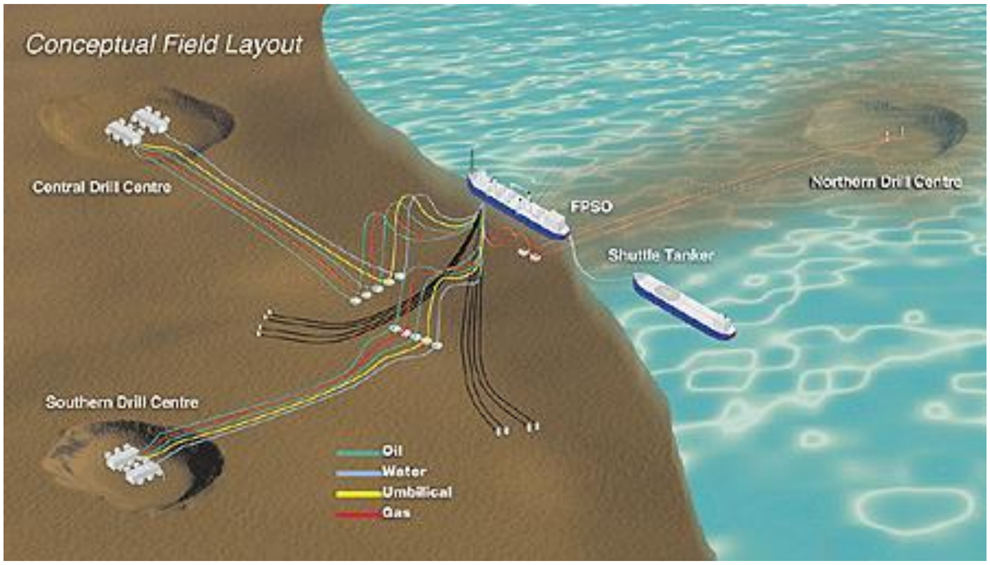


Figure 2.21-White Rose conceptual field production layout. Source:ceaa.gc.ca

The production sites are equipped with FPSO facility. In fact the drill centres are connected to a ship-shaped floating production, storage and offloading (FPSO) facility, the Sea Rose, with flexible flow-lines and risers. The FPSO's turret is designed to allow the facility to disconnect from the subsea drill centres and move in the event of an emergency. *[8]*

Hibernia field is located approximately 315 km east-southeast of St. John's, Newfoundland, Canada. The Hibernia offshore oil field is owned jointly by ExxonMobil Canada (33.125%), Chevron Canada Resources (26.875%), Suncor (20%), Canada Hibernia Holding Corporation (8.5%), Murphy Oil (6.5%) and StatoilHydro Canada Ltd (5%). The field has a EOP (Estimated Oil In Place) of 1,395 Billion barrel with 0,504% of recoverable oil.

Figure 2.22- Hibernia platform. Source: heritage.nf.ca

Explorations started in 1960s and continued till 1980s and started production in November 1997.

As the Hibernia field was located in an inhospitable and very harsh environment engineering analyses determined that the most appropriate drilling and production platform would be in the form of a gravity base structure (GBS).

The Hibernia GBS sits on the ocean floor approximately 80 m (260 ft) depth with its topsides extending approximately 50 m (160 ft) out of the water. The platform acts as a small concrete island with serrated outer edges designed to counter icebergs. The GBS contains production storage tanks and the remainder of the void space is filled with magnetite ballast with the entire structure weighing in at 1,200,000 t (1,300,000 short tons). *[1]*

Hebron is a heavy-oil field that was the first discovered in 1980 and the estimated recoverable oil is more than 700 million barrel of 18-25° API oil .

Figure 2.23-Hebron platform. Source: dcnonl.com

The field is operated by ExxonMobil, which has a 36% interest in the project. ExxonMobil took control of the project from Chevron in October 2008. The joint venture partners in the field development are Chevron Canada Resources (26.7%), Petro-Canada (22.7%), Statoil-Hydro (9.7%) and the public sector company Energy Corporation of Newfoundland and Labrador (ECNL, 4.9%).

Production is expected in 2017 by using a stand-alone concrete gravity based structure (GBS). The GBS will consist of a reinforced concrete structure designed to withstand sea ice, icebergs and meteorological and oceanographic conditions. It is designed to store approximately 1.2 million barrels of crude oil. *[9]*

Terra Nova was first discovered in in 1984 by Petro-Canada and it is the second largest off Canada's East Coast. Terra Nova is the first harsh environment development in North America to use a Floating Production Storage and Offloading (FPSO) vessel, the Terra Nova FPSO. Production from the field began in January 2002. The reservoir has an expected life of 15-17 years and the estimated oil in place is 406 million of barrels. The working interest partners are ExxonMobil Canada (22%), Suncor Energy (33,99%), Statoil(15%), Husky energy Operation Ltd (12,51%), Murphy Oil Company Ltd. (10,475%), Mosbacher Operating Ltd. (3,5%), Chevron Canada Resources (1%). *[1]*

Terra Nova is the first harsh-environment development in North America to use an FPSO vessel along with subsea production and injection. Relying on iceberg management technology that ExxonMobil helped develop during the Hibernia exploration phase, the Terra Nova FPSO is designed to handle the impact of small icebergs moving at average speeds, while being able to disconnect and move away from unmanageable ones. Subsea wells are protected from iceberg scouring by being placed in seafloor excavations. *[10]*

2.5.5. Sakhalin Island

Estimates of volumes of undiscovered technically recoverable, conventional oil and gas resources for the North Sakhalin Basin Province are about 5,345 million barrels (MMB) of crude oil, 43,807 billion cubic feet (BCF) of natural gas (18,874 BCF of associated and dissolved natural gas and 24,933 BCF of non-associated natural gas), and 757 MMB of natural gas liquids (202 MMB of natural gas liquids in oil accumulations and 555 MMB of total liquids in non-associated gas accumulations). [11]

Figure 2.24- ORLAN Platform and ice ridges. Source: exxonmobil.com

The water depths, in the range of 10-50 m, in this region allow the construction of GBS for exploration and productions during all year long. International consortia have entered into production sharing agreements (PSAs) to develop the resources. Even though all of the consortia have extensive export plans (including to the United States) via LNG terminals and export pipelines to the mainland, there has been little progress except on the first two parts of Sakhalin Island: Sakhalin 1 and Sakhalin2.

The project of **Sakhalin I** is managed and operated by Exxon Neftegas Limited (ENL). ENL is composed as following: Exxon Mobil (30%); Sakhalin Oil & Gas Development Co. Ltd. (30%); ONGC Videsh Ltd (20%); Sakhalinmorneftgas, Rosnef (11,5%); RN-Astra, Rosnef (8,5%).
The Estimated oil in place is 2,3 billions of barrels and the natural gas is 480 billion m^3 (17 trillion ft^3). The current production of oil is 250 x 10^3 bl/day. (Wikipedia)
The first well was drilled in 2003 and in 2007 ExxonMobil reached a production rate of 250000 barrels/day and 140 million ft^3/day.
Nowadays the field Chayvo development is the only one complete and two others are scheduled.
The Chayvo facilities consist of the Yastreb onshore extended-reach drilling rig, the Orlan offshore platform, and an onshore production facility. Oil and gas are then pumped via a 226-km pipeline running southwest across Sakhalin Island and the Tatar Strait to the DeKastri export terminal in mainland Russia's Khabarovsk Region.

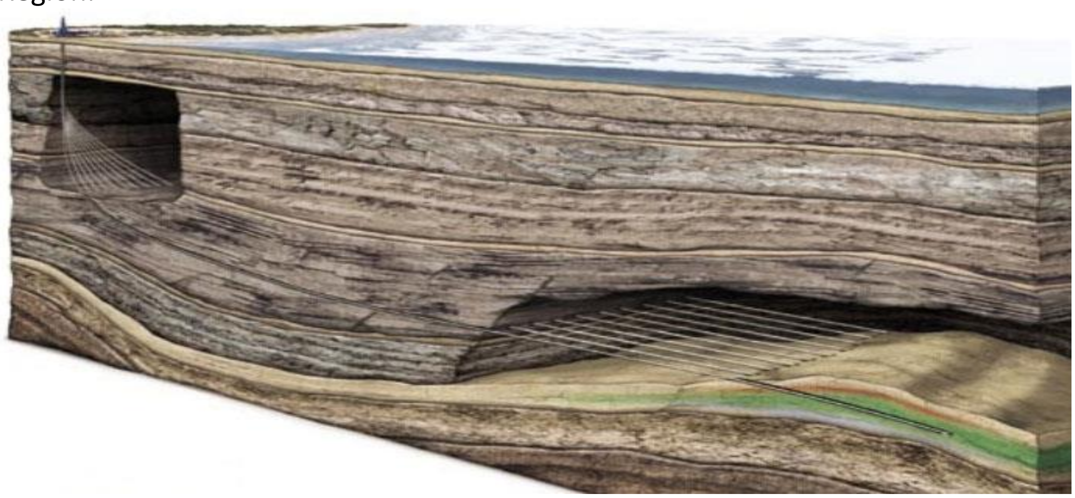


Figure 2.25- YASTREB rig and horizontal wells. Source: jalopnik.com.br

The project of **Sakhalin II** is managed and operated by Sakhalin Energy Investment Company Ltd. (Sakhalin Energy): Gazprom (50%+1); Shell (27,5%); Mitsui (12,5%); Diamond Gas (10%).

Sakhalin-2 includes the first liquefied natural gas plant in Russia. Therefore, the project is of vital importance to Russia's energy policy. This was seen as a reason why the foreign owners of the development were forced to sell a majority stake in the project to Russian gas company Gazprom. [1]

Figure 2.26-LUN-A platform. Source: Wikipedia

The Estimated oil in place is 1200 millions of barrels and the natural gas is 500 billion m^3 (18 trillion ft^3). The current production of oil is 395000 bl/day and of natural gas is 53 million m^3/day (1,9 billion ft^3/day). [1]

The Sakhalin project includes 3 production platforms; Onshore processing facilities; TransSakhalin pipelines (Sakhalin–Khabarovsk–Vladivostok); Oil export terminal; LNG plant.

The LNG plant is the first of its kind in Russia and is designed with a capacity of 9,6 million of tons of LNG per year . [1]

Sakhalin II will supply natural gas to the United States, Japan and South Korea. In late 2004, Sakhalin Energy signed a contract with Coral Energy to supply 1,800 billion cubic feet (bcf) of LNG over 20 years to a power plant on the border of California and Mexico. The LNG will be delivered via tanker to the Energia Costa Azul terminal being constructed in Baja California, Mexico. In March 2004, Sakhalin II announced the sale of 300,000 tons of LNG per year to Japan's Tokyo Gas and Tokyo Electric Power (TEPCO) starting in summer 2008. In July 2005, the project operators announced a 20-year sales agreement of 1.6 million tons per year of LNG to Korea Natural Gas (KOGAS). [12]

Sakhalin III field contains 5,1 billion of barrel of crude oil and 46 trillion ft^3 of natural gas. Chevron Corporation, ExxonMobil and Rosnefts have the license to operate under a production sharing agreement of 1993.

	Oil reserves(bbl)	Nat gas reserves(tcf))
Sakhalin I	2,3	17
Sakhalin II	1,2	50
Sakhalin III	5,1	46
Sakhalin IV	0,9	19
Sakhalin V	4,4	15
Sakhalin VI	0,6	N/A

Table 2.1- estimated oil & gas reserves in Sakhalin Island. Source: Petroleum Economist, Wikipedia

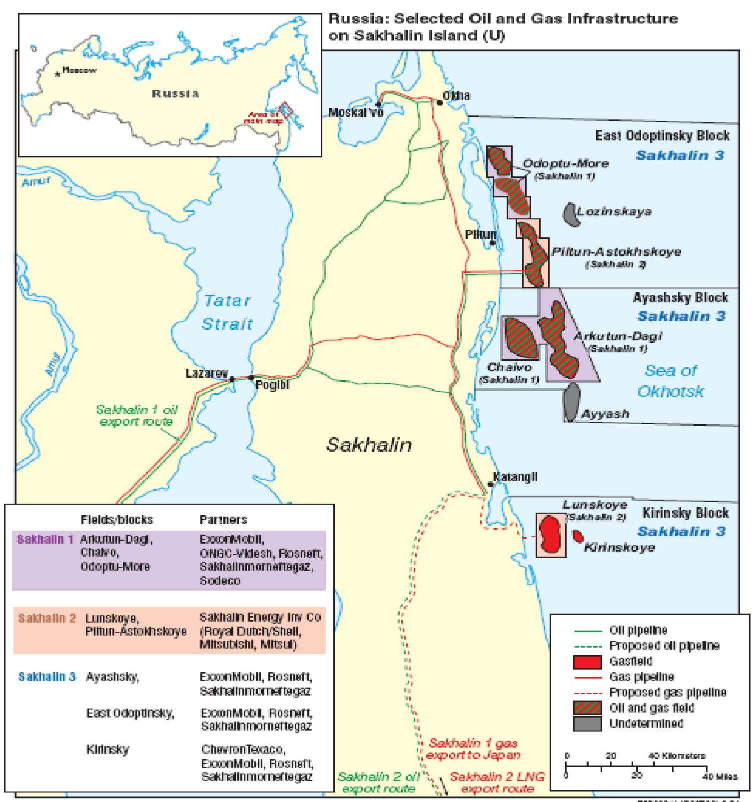


Figure 2.27- Sakhalin Island. Source: Live Journal

2.5.6. North Caspian Sea

The recently announced super giant Kashagan discovery in the Kazakhstan sector of the North Caspian Sea is the world's largest discovery in three decades. Kashagan, located in shallow water, is an analog to the onshore Tengiz field located approximately 130 to 150 km (85 miles) to the southeast.

Kashagan and Tengiz are the two largest fields in Kazakhstan, their oil reserves alone rival the United States 22 Billion barrels of oil, yet they have hardly begun to produce. Tengiz in 10 years of production has produced less than 10% of its recoverable reserves. The development costs are approximately ten billions of

Figure 2.28-North Caspian fields. Source: impex.co.jp

dollars but revenues to the Contractor and the Kazakhstan Government could exceed one trillion dollars.

The Kashagan prospect, named after the great Kazakh poet, was identified by the Soviets in the early 1970s. Although the extremely promising prospect, the field is located in an environmentally sensitive and high cost environment.

The discovery is rated at 6.4 to 100 billion barrels. Although it is likely that a good working range might be somewhere on the order of 6.4 to 20 billion barrels of recoverable oil reserves, only three wells have been drilled. With 20 Billion barrels Kashagan would be the 5th largest oil field in the world and the only one of the five outside the Arabian/Persian Gulf region.

Tengiz is the twin of Kashagan. They have the same reservoir rocks with similar fluid properties, pressure gradients, reservoir depths and sulphur content. Recoverable reserves are rated at 6 to 9 Billion barrels of light oil (out of 24 Billion barrels in-place) with associated gas reserves of 64 TCF.

As recently as 1999, 2/3rds of the Tengiz production went out by rail— around 160,000 out of 250,000 BOPD. The Caspian Pipeline Consortium (CPC) leased 10,000 tank cars sending up to 6 trains per day to Russian ports on the Black Sea. This is one of the most expensive means of transportation. Transporting oil to the Black sea costs around $6/BL with so much of the production going by rail. Transportation cost on the CPC pipeline from Tengiz to the Russian Black Sea port of Novorossisk which started up in August, 2001 is estimated at $3/BL. The $2.6 Billion, 950 mile CPC line has an initial capacity of 560,000 BOPD. Ultimate capacity for this line is 1.5 MMBOPD. Kashagan crude will have to find its own way out.

But there is movement on that front. While ChevronTexaco is negotiating with SOCAR the Azerbaijan national oil company to purchase a share in the $2.4 billion Baku-Tbilishi-Ceyhan (BTC) pipeline project, Agip-ENI has already purchased a 5% share. [13]

This landlocked region is characterized by extreme weather with summer high temperatures on the order of 44º C (110º F) and winter lows of -40º C (-40º F), that's why is defined as "arctic". It is the same latitude as Billings, Montana but 100 feet below sea level. Ice problems are expected in winter but yearround-drilling is planned. Infrastructure in this remote part of the world is weak for the world-class development contemplated for Kashagan even with Tengiz nearby. However, with reserves like these, even a large world-class pipeline like the BTC project at $2.4 Billion (capital costs) becomes feasible. [13]

The depth of the reservoir rocks ranges from 13,000 feet (4,000 m) to over 15,000 feet (4,500 m).Pressures throughout the Caspian region are nearly twice that of normal hydrostatic pressure and sometimes more. Tengiz is famous for its high temperature and pressure. Temperatures are nearly 200° F and pressures are among the highest in the world at 0.82 pounds per square inch per foot (PSI/ft) or more, almost twice normal hydrostatic pressure of 0.433 to 0.465 PSI/ft.

A pressure gradient like this can easily add over $10 MM per well for drilling fluids (mud) alone and with the kind of mud weights required (over 16 pounds per gallon) drilling can go slow. The reported cost for the first two Kashagan wells is US$ 100 MM not including the cost of the initial 110,000 square kilometres

3-D seismic data acquisition program that preceded drilling. This does not sound unreasonable. High temperatures and pressures, sour (hydrogen sulphide bearing) gas, high gas oil ratios (GOR), and poor infrastructure in a hostile—environmentally sensitive region all add up. [13]

CONTRACT AREA	VENTURE COMPANY	INTEREST OWNED
Offshore North Caspian Sea	INPEX North Caspian Sea Ltd.	INPEX N.C.S 7,56%
		Eni 16,81%
		ExxonMobil 16,81%
		KGM 16,81%
		Shell 16,81%
		Total 16,81%
		ConocoPhillips 8,4 %

Table 2.2- Kashagan operators as of June 30, 2012

2.6 RESERVOIR'S ESTIMATION AND COSTS

Table 2.1 shows the summary of the hydrocarbon potential of the different regions stated in 2.5.

Location	GREENLAND	BEAUFORT, CHUKCHI and NORTH ALEUTIAN	BARENTS, KARA and YAMAL	GRAND BANKS	SHAKALIN	NORTH CASPIAN
ESTIMATED HYDROCARBON POTENTIAL [billion BOE]	50	60	65	4	13	50

Table 2.3-Summary of hydrocarbon potential

The harsh environment and the reservoirs characteristics that require deepwater-drilling and ice management, make the Arctic oil & gas quietly expensive and investment demanding. [14]

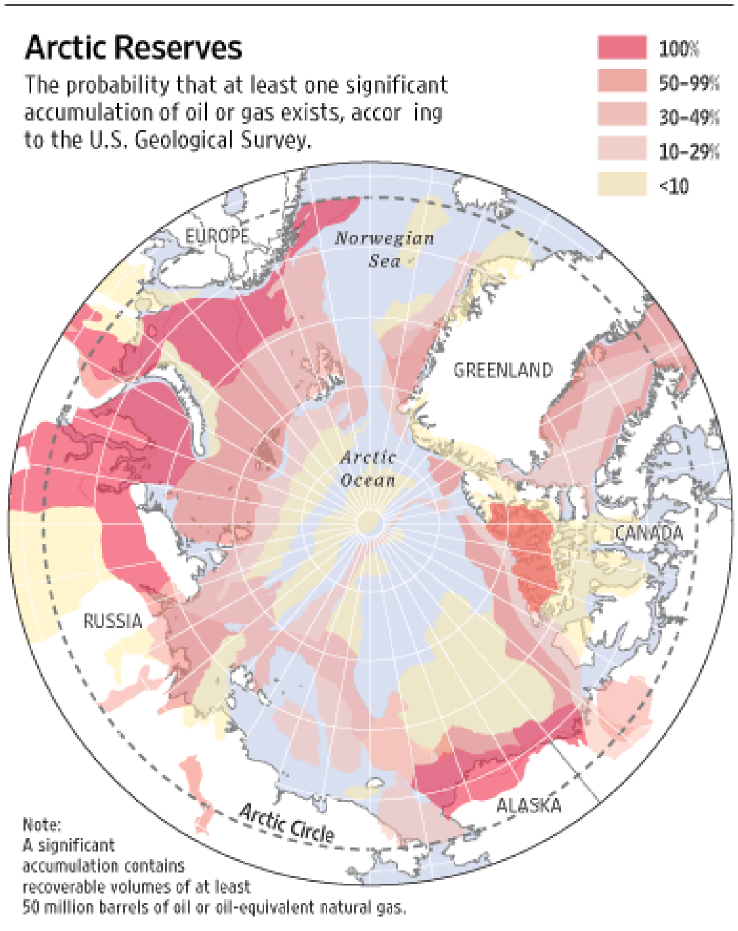


Figure 2.29- Arctic reserves. Source: USGS

It's important to underline that Arctic field development is allowed in an global scenario were many of the old big fields are seriously depleted.

In fact 2/3 of the current production will need to be replaced in the next 20 years to stop global production falling that follows the general average trend of 6,5% per annum. [15]

The economic scenario, in order to permit Arctic oil & gas evolution must provide hydrocarbon price high enough to allow the massive arctic investment that otherwise would not be economical effective.

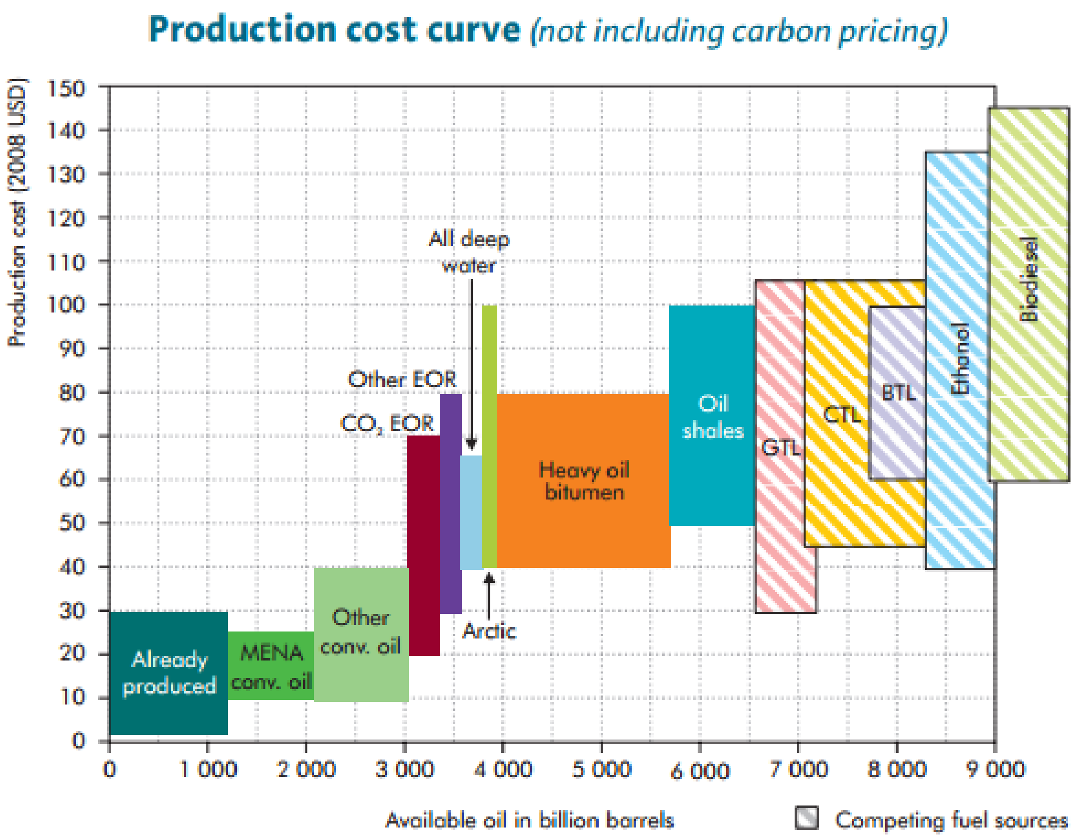


Figure 2.30.Production cost curve in function of cumulative available resource. Source: USGS

The area of the north of the Arctic Circle accounts for 13% of the global undiscovered oil that corresponds of 90 billion barrels circa of undiscovered technically recoverable oil in a geological environment of more than 25 sedimentary basins with the potential for petroleum.
Moreover the area north of the Arctic Circle has estimated more than 50 Trillion cubic meters of gas.
The arctic resources accounts therefore 30% of the undiscovered natural gas resources (this not include gas hydrates and shale gas) that correspond to 27 years of world supply.
Key areas of the North Slope are Alaska, the Barents Sea and Yamal Peninsula. [4]

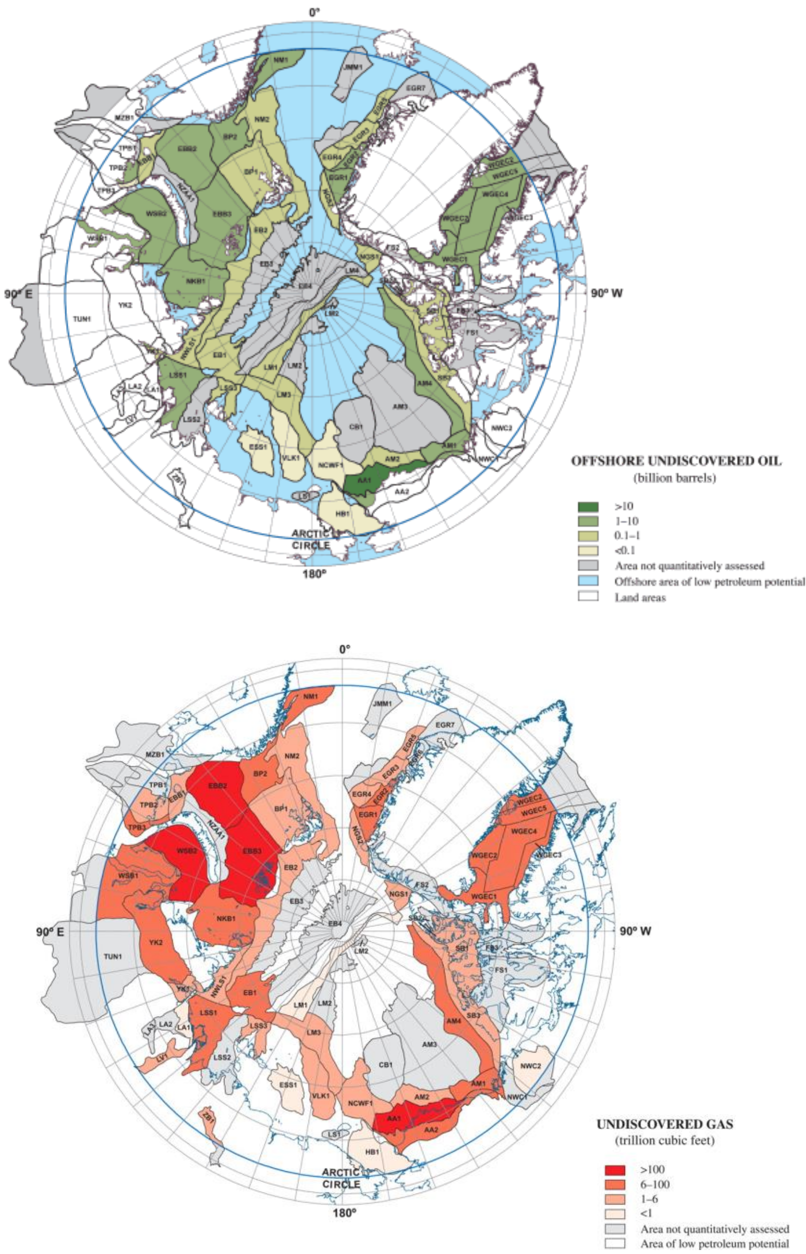


Figure 2.31-Undiscovered Oil & Gas resources map. Source: USGS

3. CHALLENGES & STATE OF ART

The purpose of this chapter is to define the main challenges regarding the arctic drilling and summarize the key existing scientific information delineated by consulting several scientific papers.
As a result of this study the state of art of technologies concerning arctic drilling is determined and the science technologies gap is outlined.
The greatest issues regarding Arctic drilling are here summarized:

- *Arctic environment & Climate change*. Global warming is impacting physical, biological and social conditions in Arctic, affecting all resource-management strategies. Especially in the last 20 years climate conditions have been undergoing remarkable changes. Climate models predictions show pronounced warming that will drive Arctic environment to change and especially the mean ice covered sea surface to decrease. Under a specific point of view this conditions could be seen as a positive element for the development of the Arctic drilling campaigns.
  Especially under this great changes the Arctic environment is extremely sensitive and its biological equilibrium of great fragility. All the efforts must be done in order to minimize the human impact on this unique environment.
- *Oil spill risk assessment, preparedness and response*. There have been significant advances in spill risk evaluation and response knowledge but still concern remains because of insufficient inputs to spill models and to quantitative data. Further, the applicability of laboratory and mesoscale studies to full field conditions remains largely untested, although international efforts are improving this foundation. Both the *Exxon Valdez* and the *Deepwater Horizon* oil spills demonstrate that spill contingency planning and a suite of spill response tools must be available and effective. Significant questions exist about the scientific and technical information needed for contingency planning and prompt emergency response (response gap) in the Arctic, which are potentially complicated by a changing climate.
  Development of new and more analytical approaches to cumulative analyses would likely benefit the overall decision making on oil and gas development options. Tools like SDM (Structured Decision Making) must be developed in cooperation with different companies and authorities.

- *Logistic and safety.* The remoteness of the arctic areas and the harsh weather conditions require to develop logistic and safety plans to guarantee the safety of all the human operations.
- *Drill sites options and ice management* should be carefully analysed and new features realized. Thus, the presence of the ice is one of the most critical elements for Arctic offshore drilling development. In this chapter the state of art of drill site technologies is summarized in connection with drilling depth and ice conditions and ice management technologies are described.

3.1. ENVIRONMENTAL IMPACT

In order to better understand the oil spill impact is here given a brief description of the ice offshore regimes that characterize the arctic environment.

The arctic ice environment can be divided in different zone depending on the ice condition and the season.

- Fast ice: area where the ice is anchored to land or seafloor. During the summer season the margin of this zone retreat towards the seashore. It can be dived into two further classes. The first is bottom fast area, were the ice is strictly connected with the seabed, and the floating fast ice where it is anchored by a complex zone of partially grounded ridge system.
- Shear zone: transition area between Fast ice and pack ice, characterized by ridging and rubble formations. The extension is very variable in seasons.
- Pack ice: area where the ice is completely free from anchoring. It can be Seasonal pack, mainly first year ice that clears during the summer, and Polar pack ice made by multiyear ice

It's notable that generally drilling takes place in the open water region between the fast and the pack ice, in a region that during the summer is sufficiently free clear of ice. [16]
It's notable that generally drilling takes place in the open water region between the fast and the pack ice, in a region that during the summer is sufficiently free clear of ice.
The ice coverage runs a leading role in influencing oil spill response and planning for offshore operation.

Over the challenging issues involved with arctic condition that will be discussed later, some aspects of the cold environment can have a positive influence and mitigation on oil spill recovery and mitigation: [17]

- Viscosity is inversely proportional to the temperature, this bring crude viscosities and the increase of the equilibrium thickness of an oil slick in case of oil spill. Under this condition the afflicted are by an oil spill can significantly reduce and furthermore the removal of the oil is far easier with mechanical and burning techniques.
- Evaporation rate is minimized under chemical equilibrium in cold temperatures. This increase the window where the more volatile elements remain with the bulk oil enhancing ignition for in-situ combustion.
- Minimal turbulence by damping of wave by ice.
- Ice can serve as natural accumulation of oil maximizing the effect of the skimming and in-situ combustion.
- Ice can help short booms and skimmers containing the oil that can easily be recovered.
- Vertical mitigation of oil under ice rapidly traps oil within the solid ice, providing insulation from organism and sea plants.

3.1.1. BLOW OUT & OIL SPILL

Care of the environment must be taken as the most relevant aspect during fields development. In fact the high sensitivity of the nature in Arctic area won't allow any risk or mistake.

The biggest care and highest concern is focused on the dramatic eventuality of Arctic oil spills.

Different opinions have been expressed about this event in correlation with the cold temperatures. Some of those sustain that not enough knowledge and oil spill response technologies are available now. On the other hand it is possible that cold temperature and low solubility of the Arctic can improve the performance of certain oil spill technologies. [3]

Recently advanced oil spill management plan for the Arctic has incorporated new technologies, including modern well blowout control, satellite and airborne detection using synthetic aperture radar, modern sorbents and dispersants, a

comprehensive ice management program, and a host of onsite inspectors and monitors.
Evaluation of risk, trajectory, weathering, and impact of a on & off shore oil spill require interdisciplinary evaluation and simulation software utilization like those implemented by DMI and SINTEF for the environmental reports of BMP.
Oil spill response in the Arctic is especially challenging in winter, when cold and darkness hamper even basic observations. Use of incineration, dispersants, and collection booms are some of the types of oil spill responses that have gained attention and have been tested.
Obviously prevention has to be the primary focus of any oil spill control plan, as once oil is released to the Arctic environment, the problem of interception, recovery, and clean up face many difficult challenges, especially in winter months and during broken ice conditions. Recent legal challenges to Oil Spill Response Plans (OSRPs) for oil and gas exploration drilling in the Alaskan Arctic have been brought by coalitions of nongovernmental organizations. The purpose is to make sure that plans and procedures are tested and validated under Arctic conditions, an activity which will require interdisciplinary planning and analysis. Much more real world testing, method development, and efficacy evaluation, especially during broken ice conditions, will be required. The interdisciplinary approach will be required to link performance, risk, trajectory, weathering, clean up, and impact assessment. [3]

3.1.2. ON SHORE IMPACT

The onshore impact of an oil spill has been studied years ago but the real effect on the fauna & flora is still not completely known.
As an example study on the effect and containment, the Jameson Land environmental impact assessment (scientific report from DCE) is here analysed in order to better understand the issue.
A large oil spill is considered the most relevant treat to the on shore environment from oil activities.
Oil spill can occur both during exploration and drilling phase and during exploitation and transport for example under a pipeline rupture.
Has been reported that terrestrial oil spill have limited impact potential compared to the marine oil spill that can affect very large areas and contaminate coastlines for many hundreds of kilometres.

However, onshore oil spill would be confined in a limited area unless the spill makes its way to wetlands and watercourses that will facilitate the spreading of the crude oil.
Oil trapped in snow in wintertime would also be able to spread with the melting snow in spring.
Poorly maintained pipeline represent a significant source of terrestrial oil spill. In fact, the largest terrestrial oil spill in history occurred in the Komi Republic (Russia) in 1994, when a pipeline failed in several points along 18 km and leaked more than 100,000 tons of crude oil to tundra, wetlands and rivers. The chemical afflicted area has been evaluated to be between 21 km^2 and 70 km^2 [18]. No information were spread about the ecological effect and toxicity but the enormous impact on fauna like fishes and the connected fishery market is well known.
Terrestrial oil spills have also occurred in Alaska, but of much smaller scale than the Komi-spill.
Crude oil on land may seriously affect vegetation and accumulates in soils were it will be preserved for many years due to low temperatures. There are examples of oil penetrating the permafrost layer. If oil reaches watercourses, fish resources will be impacted over long sections. If concentrations are high, fish and other limnic fauna may be killed [19], but low concentrations would cause tainting, making fish useless for consumption. Since rivers and streams tend to melt upstream first, frozen areas downstream might work as blocks, forcing oil contaminated water out of the river and onto the land causing impact on vegetation [20]. Birds living on and near oil contaminated water may also be fouled with oil, usually with detrimental effect [21]. Larger mammals would probably avoid oil contaminated areas [22], while small mammals probably would die in heavily contaminated areas.

Accidental oil spills are mitigated by keeping the highest HSE (health, safety & environment) and technical standards (BEP, BAT), and by strict regulation and careful planning, for example avoiding unstable areas for pipeline construction and by constructing berms around well sites and tanks in order to control spilled oil and preventing it from moving into watercourses and wetlands. In an area like Jameson Land (Greenland), with many rivers and few lakes, it will be essential to keep spilled oil away from the rivers, because the distance to the sea is short. Snow can also absorb and contain spilled oil. If removed before spring thaw, such spills would tend to give less environmental impacts compared with spills in snow free areas.

Oil spill concentrated just on land areas may deeply affect the vegetation that will accuse the toxic environment for years and therefore the revegetation may take decades.
Berms and dikes are required to limit the impact area and to restrict it to the drill site and the close surroundings.
AS shown in different experiment and evaluation like in Jameson Land area, drilling would have to take place on cliff ground and gravel banks where oil would run off and assemble in depressions and potentially also make its way to water courses. This event will represent a huge risk of marine contamination through rivers and the spill effect will result devastating for sensitive marine ecological elements such as seabird and coastal inhabitants.
Accidental spills may also include chemicals from the various processes related to oil exploration and exploitation that may cause uncontrolled fires that can cover extensive areas.
Accident of any kind must be mitigated respecting the HSE-regulation and by applying the BAT and BEP principles.
Experiments with spilled oil have been carried out in Jameson Land. As part of the background studies carried out in the 1980s an oil spill experiment was set up near Mestersvig in 1982 [23]. Crude and diesel oil was spilled on five different plant communities, with 10 L/m2. Vegetation communities included wet marsh, grassland, and three different dwarf shrub heaths. The effects were monitored over the subsequent three seasons. Shortly after the experiment was initiated, plants in the study sites started to loose chlorophyll, both those treated with crude oil and those treated with diesel. Already the first year, the number of vascular plants decreased significantly and the total plant cover decreased to less than 5 % of the original cover [24].
Even after eleven years Woody species, herbs and graminoids had recovered less than 1 % representing the long effect of this terrible event.

3.1.3. OFF SHORE IMPACT

As obvious, this chapter covers the main issue of environmental concern for marine and coastal Artic environment especially in ice-covered waters.
The Impact of a large marine oil spill is extremely effective because of several circumstances:

- Arctic extremely low temperature minimize the natural oil degradation under chemical kinetics maximizing the time-effectiveness.

- The presence of ice layers during most of the year can compromise distribution and oil conservation in tanks. More over ice presence obstacles oil spill response making all the precaution inefficient.
- Complete absence of infrastructure in major part of the artic area especially in those area were the oil & gas development is still under planning.

All the mentioned circumstances are even more effective under drilling in deep(>600 m according to Norwegian standards) and ultra-deep waters(>1524;5000 ft according to US authorities).
In fact deep & ultra-deep water increase the risk for a long and lasting oil spill due to the high pressure connected with the well and the difficult conditions in such an extreme environment.
The water depth was one of the major factor that contributed to the persistence of the oil spill (circa 3 month) of the Macondo well in 2010 [25].

According to the AMAP (2007), oil and gas assessment tankers are the main potential spill source. Another potential risk is oil spill from a blowout during drilling, which may be continuous and last for many days. Blowouts can have their origin on the platform or at the wellhead on the seafloor (subsea blowout).
Respecting the HSE –regulation and by applying the BAT and BEP principles it is possible to minimize the risk of a large oil spill. Unfortunately, the risk cannot be completely because of the new eliminated working areas and the lack of experience in this environment.
In relation to the better known area of the Barents sea it has been calculated that statistically a blowout between10,000 and 50,000 tons would happen once every 4600 years in a small scale development scenario and once every 1700 years in an intensive development scenario [26].
As already mentioned, the probability of an oil spill from a tanker ship is higher than the one of a blowout because of the extremely harsh environment.
There are even other sources of risk like for example a German trawler/weather ship, ‘Sachsen’ that sink during the Second World War in Hansa Bugt off Sabine in 1943. The wreck is still there with an estimated 60 tons of fuel oil in the tanks, which could rupture and cause a significant oil spill in a very sensitive area [27].

The fate a marine oil spill may vary considerably depending on different chemical and physical properties of the oil such viscosity and density, location and modality of the oil spill and environmental condition such temperature, currents and wind.

Oil spill in open water spreads fast in a large area that will be covered by a thick layer between 0,1 and 1 mm in the first days.
The presence of the wind will drive the oil mass at a velocity of approximately 3% of the driving force and the presence of turbulence will drive the oil to spread also in the vertical direction occupying generally the first 10 m layer. [28]
Different simulations were performed especially in the sea surrounding Greenland in order to better understand the oil behaviour under different scenarios. Simulations of oil spill trajectories in West Greenland waters have previously been performed by Christensen et al.(1993) using the SAW model, and by SINTEF [28] using the OSCAR model in preparation for the Statoil drilling in the Fylla area in 2000. When the Disko West area was assessed, DMI simulated oil spill drift and fate [29].
As part of this SEIA of oil activities in the assessment area, DMI has prepared a number oil drift and fate simulations for hypothetical oil spills in the assessment area [29] .
In the case of ice free water and surface oil spill the results accord that the slick area after 10 days was on the average 100–110 km², equivalent to a disc with a radius of about 5–6 km in the case of a continuous spill, and the slick typically covers an area of 1400–1500 km² of very irregular shape after 30 days.
Off course this results must be consider as a general event because they were applied to specific environmental condition that drove some areas to be afflicted and other not.
Under the hypothesis of ice coverage the model show that an general oil slick of 1 cm of a spill of 15000 m3 will cover only an area of approximately 1,5 km below the ice.
This could seem positive but the effect would be disastrous because of the extremely hight concentration of hydrocarbon under the ice for prolonged periods. Fauna under the ice or in leads and cracks may therefore risk exposure to highly toxic hydrocarbon levels.
Under the hypothesis of subsea blowout, the results underlined a higher concentration of oil in the water column in a restricted area depending again on the oil and environment characteristics.
In fact, because of the light oil that was selected in the model, the hydrocarbon accumulation will rise quickly to the surface forming a surface spill.
Another model of subsea blowout was assessed in relation to the exploration drilling in 2000 near Fyllas Bank in Davis Strait [28]. Here it was estimated that oil would not reach the surface at all, but rather form a subsea plume at a depth of

300–500 m. High total hydrocarbon concentrations (>100 ppb by weight) were estimated in a restricted area close to the outflow.

The oil concentration in water is defined by a combination of the surface slick and the concentration of the droplet dispersed in the water. The dissolution of different hydrocarbon in water depends mainly on the amount of WSF (water soluble fraction) in the original crude oil, the rate of dispersion and the surrounding temperature that modify the solubility. The highest polyaromatic hydrocarbon concentration found in the water column in Prince William Sound within a six-week period after the Exxon Valdez spill was 1.59 ppb, at a 5 m depth. This is well below levels considered to be acutely toxic to marine fauna [30]. SINTEF reviewed available standardized toxicity studies, found acute toxicity down to 0.9 mg oil /l (0.9 ppm or 900ppb), and applied a safety factor of 10 to reach a PNEC (Predicted No Effect Concentration) of 90 ppb oil for 96-hour exposure. [28]

WSC could leak from oil that has been encapsulated in ice. Experiments with oil encapsulated in first year ice for up to 5 months have been performed for Svalbard, Norway [31]. The results show that the concentration of water-soluble components in the ice decreases with ice depth, according to the diffusive layer model, but that the components could be quantified even in the bottom ice core.
A concentration gradient as a function of time was also observed, indicating migration of water-soluble components through the porous ice and out into the water through the brine channels.
This drove the concentration of water-soluble components in the bottom 20 cm ice core from 30 ppb to 6 ppb in the experimental period. This might indicate that the ice fauna are exposed to a substantial dose of toxic water-soluble components for a period of at least 5 months. Leakage of water-soluble components to the ice is of special interest, because of a high bioavailability to marine organisms, relevant both in connection with accidental oil spills and release of produced water [32].

3.1.4. H2S AND ARCTIC CONDITION

It has been reported that sour condition in arctic are as prevalent as in conventional environmental condition.
The presence of both arctic condition and H2S bring to several complications that must be taken under account:

- H2S and low temperature increase the probability of brittle fracture on surface facilities.
- Cold temperature requires the winterization of the rig and this causes a lack of ventilation with a consequent accumulation of H2S [16]

3.1.5. RECOVERY AND CLEAN UP

The conventional recovery system in the occurrence of an offshore oil spill is the utilization of containment boom and skimmers.
This technology is considered to be the most effective and less impacting recovery system. This system can be successfully operated in up to 10% ice condition and therefore is strictly connected to ice season in local conditions. Support vessel can help to improve this system effectiveness by deflecting ice away from the cleaning area but with the increasing of the floating ice masses up to 30% all the conventional recovery systems become ineffective because of the numerous interruptions.

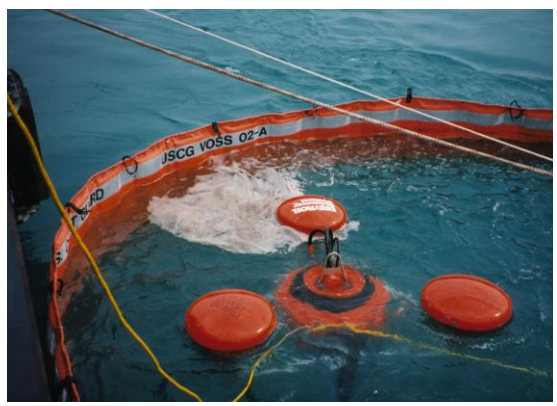


Figure 3.1- Booms. Source: eoearth.org

Ice presence can represent both a helpful element, creating natural oil pool and segregation that can be easily removed with the skimmer technology system , and most the time a problem source by incorporate ice that will require different approach involving in-situ combustion.

A study of conventional recovery in arctic condition was driven by S.L. Ross Environmental Research Ltd, 1998.
By defining the effectiveness as a percentage of total spilled oil recovered, they found results that are in Table 3.1 summarized:

	Ice coverage during freese up			Ice coverage during breack up		
	30%	50%	70%	30%	50%	70%
Conventional recovery syst.	5,9	2,2	0,6	18	12	4,4
Dispersant	4,2	0	0	0	0	0
In-situ burning on water	3,4	2,2	6,4	0	14	7,1
In-situ burning on ice	0	0	0	15	25	33
Well ignition	99	99	99	74	74	74

Table 3.1-Recovery technique effectiveness

Note:

1) In-situ burning (ISB) on-water effectiveness is for comparison with existing containment and recovery effectiveness;
ISB on-ice effectiveness would be additional to either containment and recovery or ISB on-water effectiveness.
2) This study assumed Pt McIntyre Oil which has an a-typical viscosity rendering dispersants less effective than with other
Arctic oils.

In presence of high iced seas recovery efforts need to account the on or under ice scenario. In this case, recovery techniques would be different in case of a surface oil spill or a subsea one.

- Surface oil spill: ice presence would have the effect of suspend part of the spilled oil and, in case the surface ice mass gets to 70%, make the recovery boom completely ineffective.
- Subsea oil spill: the ice will partially trap the oil under the ice layer making it impossible to recover with conventional systems.

- SURFACE OIL SPILL

In the case of surface oil spill the clean-up will be made on the ice. The most effective cleaning system is in-situ-burning that will melt part of the superior ice layer. The liquid water that would appear will accumulate in natural pool and create an insulating layer between the burning oil and the oil free ice under it. The stable oil will be free to burn with approximately 80% of removal factor.

The effectiveness of this method is compromised in the presence of snow that will induce burning oil in pits, because of its the decreasing density, minimizing the burn effectiveness. The overall efficiency in this condition was found to be 70% [33]. Moreover the presence of a snowfall will create a oil-ice slurry that is very difficult to ignite but easy to remove by mechanical techniques.

Ignition of an oil silk is a function of various elements:

- Slick thickness that will provide insulation between oil and cold ice surface
- Fire size whose heat creates hydrocarbon vapours that will maintain a correct concentration for a stable flame.
- Oil type, that must be rich of light elements
- Ambient conditions as descripted above

The presence of broken ice is a relevant limit to burning effectiveness and requires specific measures.
These conditions have been studied by SL.Ross Environmental Research Ltd, 1989 during a test in the Prudhoe bay. The general criteria for burning with presence of thin slicks on brash and slush with broken ice are as follows [17]:

  - Minimum ignition oil thickness is double than in open water (A thickness of 0.08 – 0.12 in. could result in 50-70% removal efficiency. At 0.4 in. thickness typically achieved with oil collected in a boom or wind herded against ice or shoreline, 90% removal efficiency can be achieved). Therefore, the oil slick thickness must be maximized.
  - The burn rate is halved that in analogue conventional conditions.
  - Oil to be ignited should not exceed an emulsification of 25% circa of water in oil
  - Wind rate over 20 mph will create ignition problems.

The natural decomposition of the hydrocarbon has a leading role between oil and ice interaction.
The decomposition rate is low thanks to the cold environment but the chemical equilibrium will drive the hydrocarbon evolution to free the lighter elements that are the main key for in-situ-burning .This separation drives the density of the oil to increase and finally to deplete the buoyance forces causing the sinking of the oil.

- SUBSEA OIL SPILL

In the circumstance of subsea blowout ice can significantly immobilize oil and therefore reduce the environmental impact. In a general case without high under ice current the radium of containment is between 100 and 400 meters from the spill source even in case of massive blowout. Moreover the variable thickness of the layer can create stable under-ice accumulation of oil under the thinner zones under the hypothesis of light oil.

The state of art detection technologies for under ice trapped oil are:

- GPR system (Ground penetrating Radar) operating at 500 MHZ. It is capable of penetrating at least 0,65m of ice mass and identifies a oil film up to 1-3 cm under ice.
- Acoustic imaging

After the oil detection, the cleaning phase will be strictly connected with natural vertical migration.
In the study of Dickins, et al. (2006) was observed that the behaviour of oil under ice is driven by temperature gradient and variations in melt point associated with salinity.
In fact during the freeze up the water releases the salt contained in the sea-water solution.
The increasing in salinity bring a part of the water brine pockets to melt and to migrate towards higher temperatures. This movement is usually from the cold surface to warmer ice layers lower down in the ice. Oil spilled under ice rapidly penetrates the lower warmer portions and buoyancy forces in combination with the brine movement result in vertical oil migration. Therefore, during warmer conditions during spring or summer, oil will migrate quickly to the ice surface and form melt pools.
Oil migration to the surface will allow in-situ burning and so the preferred Arctic clean up method can be deployed even for oil spilled under ice. [16]

3.1.6. WASTE MANAGEMENT

Waste management is one of the biggest issues for environmental impact and it must be taken under great consideration.
It's therefore essential to follow the regulation of every different location were the well will be drilled that are generally defined by local environmental department.

Most of the Oil Companies are constantly researching technologies which allow reconcile their activities with the protection of the environment and ecosystems, where they operate. Ecologically sustainable hydrocarbons exploration and production must take into account, on one hand, the constantly growing number of restrictions decided by global environmental policies and, on the other hand, the need to protect biodiversity in particularly fragile environments.

3.1.6.1. ZERO HARMFUL DISCHARGE

Zero harmful discharge policy represents the state of art of waste management adopted in Norwegian OCS drilling performances.
The zero environmentally harmful discharges policy was introduced in Norway in Report no 58 (1996-97) to the Storting (parliament) on environmental policy for sustainable development.
Concerning legislation, the zero harmful discharges policy was introduced in addition to the OSPAR (Oslo-Paris convention) requirements for discharges to the marine environment. The main objective is to focus on the harmful components and not only on oil and thereby reduce discharges associated with offshore oil and gas activities to a non-harmful level for the marine environment in line with the long term ambition in the OSPAR guideline. This policy relies on the possibility to identify the main harmful components of the discharges at an early stage and to assess their effects on the environment. It concerns both naturally occurring compounds and man-made compounds added during the operations. For drilling operations, it also includes physical impact to the sediments caused by e.g. sedimentation of cuttings and mud, oxygen depletion, and change of grain size distribution and general physical disturbance of sea bottom by e.g. anchors. [34]

The Policy objective involves the following restrictions on chemical usage:
- no discharges of toxic or environmentally harmful chemicals
- no discharges of other chemicals which could cause environmental harm
- no or minimal discharges of substances which rank as pollutants in chemicals.

The following restrictions are also imposed on discharges of hydrocarbons and other natural substances produced together with oil and gas:
- no or minimal discharges of environmental toxins
- no discharges of other substances which could cause environmental harm.

Special rules applied in the Lofoten/Barents Sea areas include zero discharges of produced water from normal operation.
The zero discharge goal has contributed to a stronger focus on the substitution or phasing-out of chemicals with environmentally harmful properties.
None of the substances in the red and black categories defined by the Norwegian Climate and Pollution Agency (Klif) may be released to the sea (Table 3.2)
Discharges of environmentally harmful chemicals have declined by 99.5 % since 1997 *[35]*

Note: OSPAR: Oslo-Paris convention

Category	Properties
Black - not allowed	Prioritized list of White Paper No. 21 (2004-2005)
	OSPAR List of Chemicals for Priority Action (Strategy with regard to Hazardous Substances)
	Low biodegradability (BOD28 <20%) and high bioaccumulation potential (log Pow =5)
	Low biodegradability (BOD28<20%) and high acute toxicity (EC50 or LC50=10 mg/l)
	Detrimental in a mutagenic or reproductive way (log Pow = octanol–water partition coefficient)
Red - to be replaced	Inorganic substances which are acute toxic (EC50 or LC50= 1 mg/l)
	Organic substances with a low biodegradability (BOD28<20%)
	Two of the three following criteria:
	Biodegradability equivalent to BOD28<60%
	Bioaccumulation potential equivalent to log Pow=3 and molecular weight < 700 or
	Acute toxicity of EC50 or LC50=10 mg/l
Yellow	Not categorized as red or black, and that are not defined as PLONOR substances
PLONOR	OSPAR PLONOR list (Pose Little or No Risk to the Environment)

Table 3.2 - OSPAR zero harmful discharge categories

3.1.6.2. ZERO DISCHARGE

Zero discharge policy means that no wastes are disposed of at sea. It consists in the injection of liquid and solid waste underground in depleted formations or in specific storage areas trough depleted well or annulus.

This policy requires special containers to be used on-board platforms to store the cuttings separated by shale shakers and by the other solid control equipment, while the liquid phase, which cannot be reused, is collected in dedicated tanks. At regular intervals, the tanks containing the cuttings are transferred onto supply vessels and the mud is pumped into pits on board the same vessel and transported ashore. Once ashore, both solid and liquid wastes are taken to authorized treatment sites, where the processes to render them compatible with their final destination take place. Oil-based muds (and sometimes water-based muds, if of special composition) are collected in land-based treatment plants where they are regenerated for reuse in other or future offshore drilling operations.
This waste management is hardly applicable to the arctic environment due to the absence of infrastructures onshore and the ice management issue.

An alternative to this option is represented by the reinjection of the wastes produced offshore into deep geological formations. Reinjection is carried out by pumping the whole drilling fluid or a cutting-containing slurry through the annulus of two intermediate casing strings of the same well under drilling or in a dedicated well. In the case of cuttings, the process involves collecting this solid waste from the various sources, grinding it down to a suitable grain size (usually below 300 µm), optimizing its rheology and, finally, injecting it into the hosting formation; the required properties can be achieved by adding to the cuttings about 20-50% of water.
Exhausted drilling fluids are injected separately or mixed with the cuttings, if the resulting rheological properties are considered acceptable.

The reinjection of cuttings and mud usually takes place under hydraulic fracturing conditions; the success of such an operation depends largely on careful planning and execution. Clearly, the first aspect to consider is the choice of the formation into which the waste has to be pumped; this is a vital point, because of an incorrect choice may result in Authorities refusing to give permission for the operation. The formation selected must be suitable to contain all the expected volume and ensure lasting and efficient containment of the waste so that to avoid its migration with the risks to contaminate any nearby aquifers. (ENI drilling fluid engineers book)

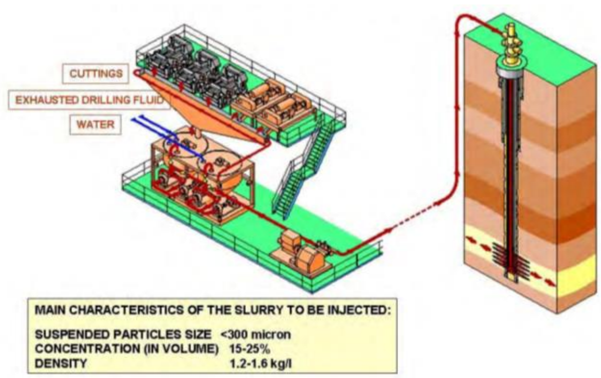


Figure 3.2- Cutting reinjection scheme; Source: ENI

This option can be chosen in the arctic environment by storing safely the wastes under the permafrost.

Abou - Sayed et al. 1989 made some tests in order to better understand the process of injection and the formation of fracture for safely contain the wasted. The test was conducted by injecting different fluids at different rate below the permafrost at 2000 ft (656m). The different fluid used were crude oil, sludge, acid, stimulation gels etc. The result of this experiment was the creation localized horizontal fracture of the dimension of 9 to 18 ft (3-6 m) radially from the wellbore. The result appeared to be a stable formation and no penetration of wastes was registered in close wells.
The injection can be done by grinding the wastes in fine particles in a vibrating ball mill that can reach the capacity of 80tons/hour. The next step is mixing them with mud or fluid in order to obtain a pompable slurry. The slurry is then injected into dedicated disposal wells or down the annulus of an existing well into formation below the permafrost.
Typical injection rates are 3 bpm (0,5 m^3/min)restricted to manage erosion of wellhead and valves.

Another way of cutting disposal is use below-grade freeze-back, a technology for onshore waste disposal.
This practice is regulated for example in the Solid Waste Management Regulations of the Alaska Department of Environmental Conservation.
All the wastes must be buried and permanently frozen at least 2 ft (0,6m) below the seasonal active layer. Continuous thermal tests and samples must be analyzed using a thermistor string to monitor the temperature in the pit and in around it. Monitoring must be conducted the following five summers if the well is abandoned and the surface revegetation must be conducted.
The total disposal management cost can reach 2,5% of total well cost. [16]
Injection of contaminated oil is a part of a typical zero discharged policy that has been used for example in North Sea. To be effective it requires using water to fracture the formation. Fracture mechanics have been analysed by Willson et al (1993). Typical slurry injected is composed by 72% water, 15% solids and 13% oil by volumes. The viscosity range is 70 to 90 cP with density between 9,8 and 11,9 ppg (997,8 to 1187,34 kg/m^3).

Another aspect of the zero discharged policy is the waste recycling: pilot programs to minimize drilling waste and recycle gravel and sand from the upper part of wells have shown the feasibility of reclaiming construction grade materials.

The test reported by Scumacher , et al gives the results of processing cuttings from two wells for use as construction material for roads and pads.
Recycling the cuttings is a useful and modern way that helps to minimize the waste that have to be processed with other more energy demanding technologies. The conclusion of this test was optimistic with the recycling of the 50% of all the solid waste generated in the well.

3.1.7. EXHAUST MANAGMENT

Exhaust gas emission comes from different combustion process as the one connected to the vessels propulsion system and the one that drives all the integrate system for equipment mobilization or fluid compression.
Nowadays most of the icebreaker and vessels are equipped with diesel or Nuclear engine and they can be divided in three groups:

- Diesel-electric
- Nuclear-electric
- Diesel-gear

Nuclear engine does not emit any polluting gas and therefore doesn't impact on the Arctic environment. The main problem is that their unique power sources create nuclear wastes that are highly toxic and the collocation after the utilization is still a big problem in any country.
The description below is focused on "conventional" diesel power and the comparison between the different technologies is out of this analysis purpose.

The Polluting gas emission is a function of the engines efficiency and the fuel quality.
The most relevant polluting gasses are Sulphur dioxide ($S0_2$), Nitrogen oxides ($N0_x$), Carbon dioxide (CO_2) and monoxide(CO) ,Particulate matter (PM).

Sulphur dioxide is a major air pollutant and has significant impacts upon human health. In addition, the concentration of sulphur dioxide in the atmosphere can influence the habitat suitability for plant communities as well as animal life. Sulphur dioxide emissions are a precursor to acid rain and atmospheric particulates.

Concerning our case, it is mostly contained in diesel fuel that is the most common power supplier for the vessel of C3 class (Big vessel as defined by United States Maritime Commission (MARCOM)). [1]
The most effective way for reducing its emission is to produce fuel with a low content of sulphur.
For example, EPA (environmental protection agency) adopted changes to the diesel fuel program to allow for the production and sale of diesel fuel with up to 1,000 ppm sulphur for use in Category 3 marine vessels. The regulations generally forbid production and sale of fuels with more than 1,000 ppm sulphur for use in most U.S. waters, unless operators achieve equivalent emission reductions in other ways. [36]

Nitrogen oxides are toxic by inhalation and its production happens in any kind of combustion. It can be minimized primarily by optimizing the air-fuel ratio during combustion and controlling the ignition temperature. The secondary abatement system on ships is the SCR (selective catalytic redactor) converter.
The process consumes urea for about the6-9 % of the fuel consumption. The efficiency of this abatement system is very high up to90-95 %.
The first icebreaker that was equipped with a SCR system was the Swedish ATLE owned by the Swedish Maritime Administration in 1974.
Ships engines can be designed to a significant reduction of NOx content in the exhaust gas by reducing the combustion pressure and temperature without SCR converters. The efficiency of those engines is not optimized which means that fuel consumption is higher, giving higher contents of carbon dioxide in the exhaust gas emissions. All efforts to reduce NOx means increased cost for investment, urea and the lack of pay load but the reduction is exceedingly good. [37]
Carbon monoxide is a colourless, odourless, and tasteless gas that is slightly lighter than air. It is toxic to humans and animals when encountered in higher concentrations. In the atmosphere it is spatially variable, short lived, having a role in the formation of ground-level ozone.
As a result of uncompleted combustion, its emission can be minimized by optimizing pressure, temperature and air-fuel ration in combustion chamber. There is trade of between NO_x and CO production that respectively are massively produced with high temperature and low temperature and therefore the engine project is a complex optimization between the polluting gas emission.

Carbon dioxide is an important greenhouse gas, warming the Earth's surface to a higher temperature by reducing outward radiation. Burning of carbon-based fuels since the industrial revolution has rapidly increased concentrations of atmospheric carbon dioxide, increasing the rate of global warming and causing anthropogenic climate change. It is also a major source of ocean acidification since it dissolves in water to form carbonic acid, which is a weak acid as its ionization in water is incomplete. [1]
Carbon dioxide formation is impossible to eliminate during combustion as it's the primer combustion product and therefore the only way to minimize its emission is to decrease the fuel consumption by adopting more efficient engines.

The Particulate matter emission is again dependent on fuel quality and it can be drastically minimized by installing filters of specific dimension on the exhaust flow.

3.1.8. IMPACT OF THE POTENTIAL ROUTINE ATIVITIES

Several activities of the oil and gas industry involve impact of different entities on the environment. In the analysis reported below the activities have been divided following the field development history and focusing on the offshore conditions.

Exploration activities are in general temporary and can last up to few years if no commercial discoveries are made. The seasons that permit this kind of activities must guarantee almost ice free sea in offshore areas and therefore in most of the cases are summer and spring.
The main issue that involve environmental impact during this periods are:

- Noise from seismic surveys and drilling;
- Cuttings, mud and chemical disposal; [38]

Sound waves generated by air guns during seismic surveys have the main potential impact on fish and marine mammals. They can cause physical damage, to tissue and auditory system, and can alter behaviours by disturbing underwater communication between mammals. Studies have reported that the impact of the seismic waves is of medium entity and no irreversible harm to environment was reported. However short time impact such mammals migration was observed.
Furthermore the impact on fishes is well-known and the disturbance of some shoal of fish as been registered more than 10 km away from the sites of intensive seismic activities. [26]

The studies quoted above indicate that behavioural and physiological reactions to seismic sounds among fish may vary between species (for example, according to whether they are territorial or pelagic) and also according to the seismic equipment used. Generalizations should therefore be interpreted with caution.
Mitigation suggested to minimize seismic waves recommend to:

- Adopt a soft ramp up of air gun array each time a new survey line is initiated [39].
- Bring skilled marine mammal observers on board during surveys in order to detect whales and to keep the minimal distance of 500 m. Hydrophones can be used to help detecting the mammals.
- Close certain area from surveys in sensitive periods.
- Respect local regulations and inform authorities and hunters organizations between any seismic activities.

Another source of noise and environmental impact is the drilling phase that involves:

- Noise from drilling process the propellers used to keep vessels/rig position and the noises will be continuous. The most impacting facility for noises is the drilling ship, followed by the semi-submersible platform ending with jack up structure (that is hardly usable in the arctic territories because of the depths and the hazard risk from iceberg and drift ice). [32]
- Drilling mud and cuttings that usually have been deposited on the seafloor beneath the drilling rig changing the physical and chemical composition of the substrate. [40]

  The liquid base could be either oil, eater or synthetic fluids (ethers, esters, olefins, etc.). As verified during the Norwegian field development, the OBM creates a widespread and severe effect on benthic animals, SBM have a faster degradation period resulting in a severe and shorter impact on the fauna.(Breuer et al. 2004).To minimize the severe impact caused by cuttings and mud discharging is recommended to use WBM combined with cleaning of the cuttings.

Any mud recycling on shore has to be considered hardly possible as previously analysed.

Development and production phase implies long and lasting activities depending on the amount of hydrocarbons in place and the production rate.
Again the potential effects on environment are:

- Solid and fluid waste material disposal;
- Noise from construction and activities (already described in the exploration activities);
- Air emission

During exploration several waste-fluid are produced as already mentioned before. In the production phase the most relevant is the produced water, typically connected more with oil field than in gas ones.
Generally, the production water is not really impacting because of the dilution but the effect of the toxic elements and the radioactive components creates big concern. [41]
In fact, even though oil concentration in produced water is low, oil sheen may occur on water surface in the absence of big waves and ripples, impacting on seabird or fishes such as polar cod.
More over the under ice storage is very impacting because with degradation and evaporation the sensitive under ice ecosystem will be dramatically exposed. [42]

During the productive life of a field, a large amount of greenhouse gasses is released in the air. For example literature report the case of Statfjord in Norway which in 2003 emitted 643000 tonnes of CO_2 that is about twice the total Greenland CO_2 emissions [43]. The most effective greenhouse gas is CH_4 that together with VOCs, from produced oil, is released in small amounts during trans-shipment. Emission of SO_2 and NO_x contribute, as previously reported, to acidification of precipitation that will impact particularly nutrient-poor vegetation on land. Again the Stafjord emissions of NO_x have been reported to be 4.000 tonnes in 1999. [43] [38]
The mitigation impact guidelines emitted by the Arctic council recommend that:

- Zero discharge policy of drilling waste and produced water must be adopted. This can be also obtained using new technologies as CRI (cutting re-injection) as previously analysed.
- Sound environmental management has to be in place.
- All the precaution must respect the Precautionary Principle; Best Available Techniques (BAT) and Best Environmental Practice (BEP) [44].

Disturbance can be mitigated by carefully planning the noisy activities in specific periods.
For example, effort is given for onshore or close to shore activities in order to not impact with bear life. Therefore, winter activities should be minimized and performed when bears naturally enter dens. In any case activities must avoid bear dens by at least 1 km.

Decommissioning activities Impacts with noise and traffic. The activities period is estimated to be short-term and low impacting. It's assumed that all the facilities will be decommissioned and no wastes will be left on the sites. As in the other phases al the activities must be careful planned and adopt BAT and BEP.

3.2. ICE MANAGEMENT

3.2.1. OFFSHORE

Ice Management (IM) is essential for Arctic operations, as it plays a vital role in enabling the movement of vessels through heavy ice conditions and in reducing the likelihood and severity of ice-structure interactions.
IM must be achieved by combining three different ways to guarantee lower loads from a modified ice environment:

- Remote active IM by using support and polar class vessels;
- Remote passive by measurement and tracking;
- Active IM on the structure.

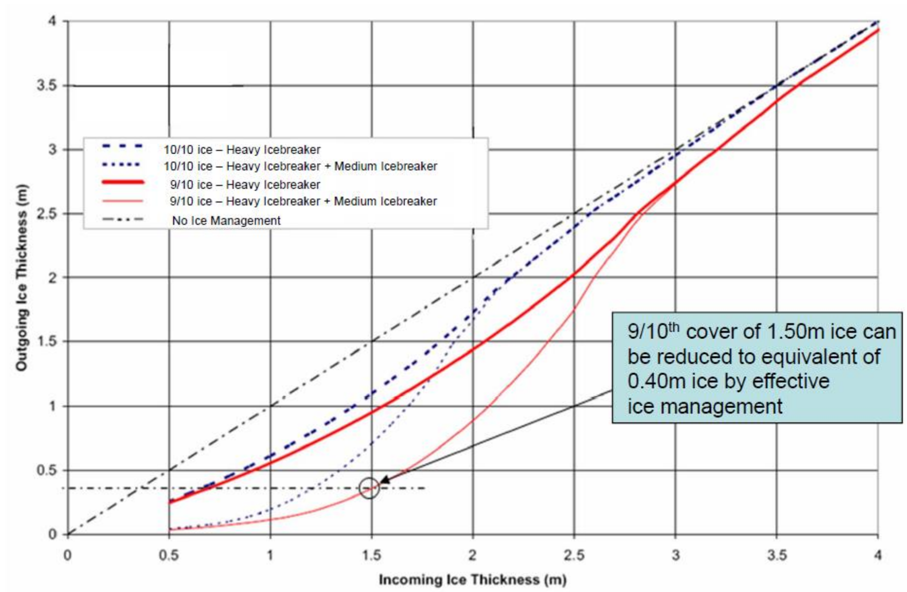


Figure 3.3-Developing ice management strategies. Source: Noble associates llc; PETER G. NOBLE

There are three basic components need to develop an ice management plan:

- Definition of hazardous ice condition in the operational area which is a function of the system and phase of operation.
- Ice observation, monitoring and forecast on a climatological and tactical scale.
- Active IM with ice breakers and other assets. [45]

Literature shows that the best ice management plan available, as shown in the figure below, is divided in three warning zone:

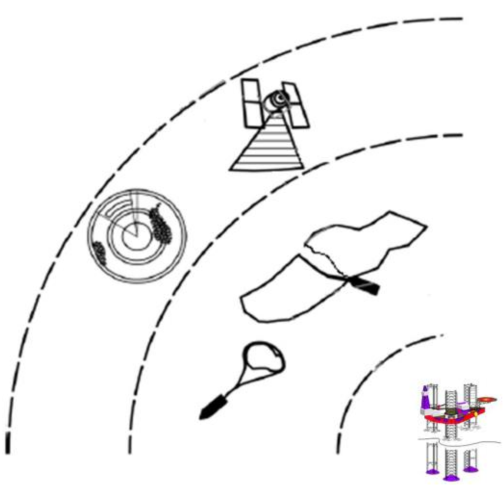


Figure 3.4- Ice management warning areas. Source: Noble associates llc; PETER G. NOBLE

- The First zone is the observation zone with remote detection systems as marine and satellites radars. After this first detection, a threat evaluation must take place.
- The second zone is considered the management zone where the physical management of the ice masses takes place by the support vessels.
- The last zone is the critical one that, in case of penetration of ice

masses, must drive the drilling unit to a well secure process and disconnection.

3.2.1.1. Ice measurement and control

An ice management plan is strictly required and it must be very detailed to ensure that hazardous ice conditions will be detected. The basic components of the management system are:

- SAR (synthetic aperture radar) to monitor ice floe speed and direction.
- Thickness measurement using ULS(upward looking sonars), based on the sea bed or autonomous underwater vehicle, and Electromagnetic impulses from aircraft or unmanned aerial vehicle.
- Ice management vessels. [46]

SAR will be the primary method for tracking ice floes. Images can cover a wide area and are available almost real time with up to six images per day. Extensive SAR work has been done in the Chukchi Sea and Canadian Beaufort Sea in tracking ice floes over several months.
Technology to determine ice thickness and tracking is advancing rapidly. ConocoPhillips has an extensive technology program in THE Chukchi Sea area connected to the study of various Arctic development concepts [47].

In order to conduct oil and gas exploration and production activities in the arctic seas, several environmental factors that can greatly affect the operations must be considered and numerous challenges must be overcome [48]. Those are mainly sea ice, ridges and icebergs, fog, gusty winds, long periods of darkness and very cold temperatures.
A fundamental objective is the ability and necessity to maintain position over the drill site or production site to recover oil and gas in harsh weather with temperatures near or below 32°F (0°C) and waters covered with ice floes and icebergs floating towards the drilling vessel or the production facilities.
Station keeping during exploration and drilling operations can be performed in three different configurations:

- Operational drilling mode,
- Non-operational with marine drilling riser connected to the blow-out preventer (BOP)

- Riser completely disconnected from the BOP.

During production phase similarly, three modes can be distinguished:
- operational production mode,
- Non-operational with production risers connected to the turret and with the production vessel,
- Production vessel disconnected from the turret.

Therefore, in order to maintain position in this harsh ice environment, ice management is commonly used as an efficient way of controlling ice floes and icebergs drifting in the vicinity, usually a mile radius, of the offshore drilling or production structure and allowing to extend, in some cases, the drilling season to year-round operations [49].
The ice management operating procedures follow an active approach
Normative ISO 19906, 2009 gives all the directive to be followed during ice management operating procedures following the step of the scientific drilling expedition 302 conducted by the International Ocean Drilling Program in 2004 [50].

As shown in figure below, the ice management system can be performed during both drilling and production phases. Support of one or more icebreakers, depending on ice condition and project size, is required and they should be positioned at a distance ranging between 0,5 and 2 miles (0,8-3,22 km) upstream from the drill site.
This vessel must be equipped with the technologies stated before in this chapter for monitoring weather and ice conditions. These technologies may also include notably visual observations, helicopter reconnaissance, airborne radar and satellite imageries [50].
Once the ice hazards are detected, the first icebreaker will intervene and will break the large ice floes in smaller pieces. Then, the second smaller and more mobile icebreaker can continue the breaking work till reaching acceptable floes dimensions in order to let the ice flow towards the drilling structure.
In addition, one or several smaller vessels using synthetic lines can be used for open sea season when towing icebergs or ice ridges is needed [51].
This global ice management configuration enable, under non-extreme conditions, the dynamically positioned drilling vessel (having at least four thrusters: two in the

bow and two in the stern) to keep a fixed position and to conduct exploratory or development drilling but also production operations minimizing the risk due to ice floes or icebergs impact.

In certain condition support vessel can push extreme features away from the rig by using steel towing as shown in figure below.

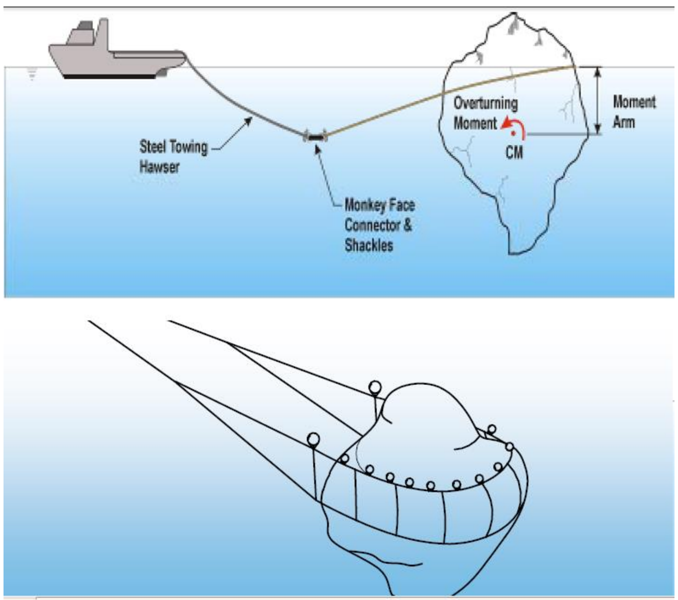


Figure 3.5- Ice towing

Finally, in the case where ice conditions would become too difficult to manage for the icebreaker fleet and towing boats, the drilling riser would be disconnected, the drill pipe retrieved (tripping pipe speed ≈ 1,000 feet per hour) and the drilling vessel would move away from the drilling site till the ice mass has transited. When the risk will be acceptable again the drilling vessel can return on position and resume operations. [52]

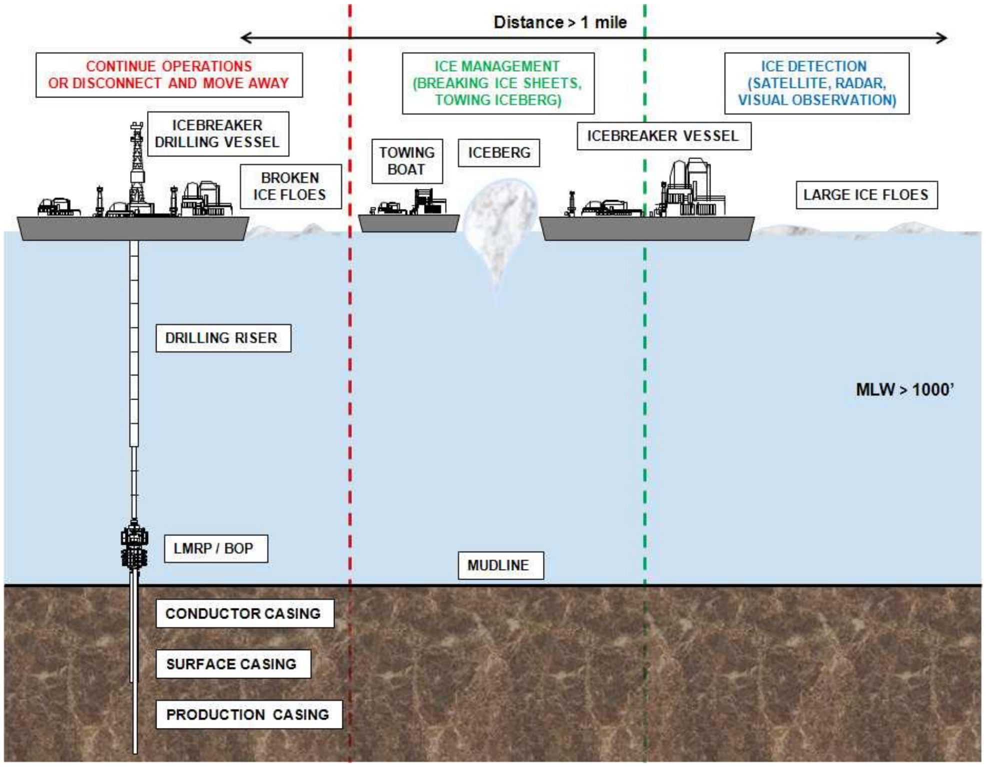


Figure 3.6 -Ice management warning areas. Source: Blade

In addition, to ensure that the vessel will stay in position even in the most difficult ice and weather conditions, recent technologies such as azimuth propulsion should be implemented on board the winterized drilling structure.

3.2.1.2. Ice breakers and POLAR CLASS

As many time mentioned, polar class and ice breakers are a key parameter as a service vessel for the Ice management and also as cargo vessel during production. Here a description of types and requirements is given.

Offshore ice conditions in arctic can be defined as follows [53]:

- Level ice/rafted ice,
- Multi-year ice,
- Ice pressure ridge/rubble fields,

- Floe ice/pack ice,
- Channels of different types,
- Iceberg presence.

Figure 3.7- Ice ridge

Varying with the expected ice condition, the vessels must have different requirements for the ship design and operation.

Figure 3.8- Floe ice

The IACS (international association of classification societies) created a list of unified requirment for polar ship to apply to vessel constructed of steel and intended for navigation in ice-infested polar waters.
Here stands a requirments Polar Class description:

Figure 3.9- Ice rubble

- PC1 (Polar class1): for year-round operation in all polar waters
- PC2 (Polar class2): for year-round operation in moderate multi-year ice conditions.
- PC3 (Polar class3): for year-round operation in second-year ice wich may include multi-year ice inclusion.
- PC4 (Polar class4): for year-round operation in thick first-year ice wich may include old ice inclusion.
- PC5 (Polar class5): for year-round operation in medium first-year ice wich may include old ice inclusion.
- PC6 (Polar class6): for summer/autumn operation in medium first-year ice wich may include old ice inclusion
- PC7 (Polar class7): for summer/autumn operation in thin first-year ice wich may include old ice inclusion.

Ship that are also to recive “Icebreaker” notation may have additional requirments and are to receive special consideration. In fact, Icebreaker refers to any ship having an operational profile that includes escort or ice management functions, having powering and dimension that allow it to undertake aggressive operation in ice-covered waters and having a class certificate endorsed with this notation. [54]

During Artic development phase the maximum interest is given to offshore Service vessels that allow to extend the drilling and exploration season from “ice free” season to “extended” season.
The main innovation demand is focused on:

- Icebreaking supply vessels;
- Icebreaking standby vessels;
- Icebreaking anchor handling vessels;
- Ice management vessels;
- Oil recovery vessels;
- Storage facilities;

3.2.2. ONSHORE

As it’s obvious temperature in Arctic onshore areas are for most of the years below the zero but they may rise significantly during the summer period. In fact the average temperature in summer are above freezing in all arctic area except in the central arctic basin and interior Greenland.
As reported the average Arctic winter temperature is –34°C [–30°F], while the average Arctic summer temperature is 3°C to 12°C [37°F to 54°F]. [55]
In the warmer areas, when temperatures are most comfortable for humans and suitable for machines, the ground is free of snow and ice and unfrozen to varying depths. But the result is that northern taiga, forest-tundra and tundra become almost impassable wetlands during the warm season.
Because of this almost impenetrable landscape the construction of permanent roads is impossible or uneconomical. This is the main reason why the only applicable period for onshore exploration and production activities, in contrast with offshore, is winter.
In fact, once the temperature drops down to at least -20°C [-4°F], the ground would be frozen enough to support the weight of the heavy trucks and equipment. Most of the time the ice roads is necessary and therefore water from beneath the rivers and lakes in the proximity is pumped and poured on the surface.

Figure 3.10-The danger of thin ice. A Super-B-Train truck hauling diesel fuel broke through the Mackenzie River ice crossing near Fort Providence, Northwest Territories, Canada. Source: CBC news

There are special requirements for the thickness and strength of the ice roads, as well as driving and safety requirements for vehicle operators. In addition, ice bridges are built to cross frozen rivers and ponds, and sea-ice roads are constructed on the frozen sea.

All these types of ice routes are used for example by Schlumberger in the Northwest Territories, Canada, to connect its base in Inuvik to locations in the Mackenzie Delta–Beaufort Sea basin.

Another solution adopted against high impact on the environment and ice fragility is the rubber-tracked, low ground pressure vehicle introduced for example by WesternGeco. These vehicles have wide rubber treaded tracks and an innovative driving system that minimize the damage caused by creeping on ice, reducing potential damage to the soil.

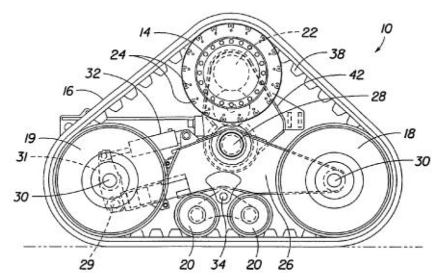


Figure 3.11-Low ground pressure vehicle

3.3. ARCTIC DRILL SITE SELECTION

Selection of drill site and rig type are highly dependent to the chosen onshore or offshore location, the local environment, the presence of infrastructures or facilities, kind of reservoir, economics and several other factors. Different onshore and offshore drill site options are in this section analysed and summarized.

3.3.1. ON SHORE drill system option

When selecting and designing an onshore drilling system in arctic regions several factors have to be carefully considered:

- Mobilization & Demobilization and moving time connected with the chosen technology and the relatives drilling seasonal costs. Maximization and optimization of the number of wells that can be drilled with the selected rig is required.
- Flexibility is a required quality because drill sites can be very diverse (multi-lateral, extended-reach, closed spaced infill wells, shallow, deep, etc…).
- Lightness and compactness of the rig that must be transported through the tundra with the minimal environmental impact. [16]

The mobilization of the equipment can be performed in mainly two ways. The first is transport the rig and the different equipment using track and constructing, as previously mentioned, ice roads when the existing gravel roads are far from the site. This technology is considered to be affordable for light-medium remoteness and the cut off distance for feasibility is around 50 miles (80,5 km).
For bigger distance, in order to minimize the impact on the local tundra, the large tire all-terrain vehicles are required (see cap 3.2.2).
The second transport technology is represented by helicopters or airplane that can be use to transport both personnel and equipment that must be packed in 10 x 10 x 50 ft packages [56]. An example of suitable aircraft is the Hercules C130.

3.3.2. OFF SHORE drill site options

Offshore site selection is strictly governed by the ice conditions and the water depth in the selected location.

Different site options are:

- Man-made islands;
- GBS (Gravity Based Systems);
- Jack-up drilling rigs;
- TLP (Tension-leg platform);
- Spar platform;
- Semi-submersible vessels ;
- Arctic circular drilling platform;
- Hybrid Semi-sub-circular platform;
- Drilling ships (monohulls);
- Unmanned seasbed rig.

3.3.2.1. Gravel Island

The first kind of artificial island analysed is the Gravel islands. This solution is suitable for shallow water (5-50 feet ; 1,5-15 m) and is built by loading trucks with gravel and unloading them into the water until mean water level is reached. After the planned elevation is reached the island slopes are graded using bags filled with gravel and finally cloths are spread on the base for ice damage protection during open water season. [57]

Figure 3.12 - Gravel island

Gravel islands are usually more expensive than ice islands and from mid-1990's they are rarely constructed in the North Slope because of the long-time environmental impact as compared with ice islands. [58].

3.3.2.2. Ice Islands

The first ice island has been successfully developed at Prudhoe Bay in Alaska in the late 1970's [59].

The technology used for ice island construction consists in drilling a hole through the sea ice and then pumping the water and spraying it over a circular area of 100-200 feet (circa 30- 60 m) using a light all-terrain vehicle(figure 46).
The water will take some time to freeze and, after this window, is possible to apply another water layer. Sometimes the water is mixed with snow to accelerate the freezing process.

Figure 3.13- Ice island construction. Source: Blade

Studies reported that the optimal air temperature to obtain a very good ice quality is between -15°F and -30°F(-26°C to -34°C circa) , therefore The construction period takes place generally from the end of October to the early December [60] [61].
Ice islands and ice roads have the enormous advantage of leaving zero impact to the environment once thawing starts during the spring season.

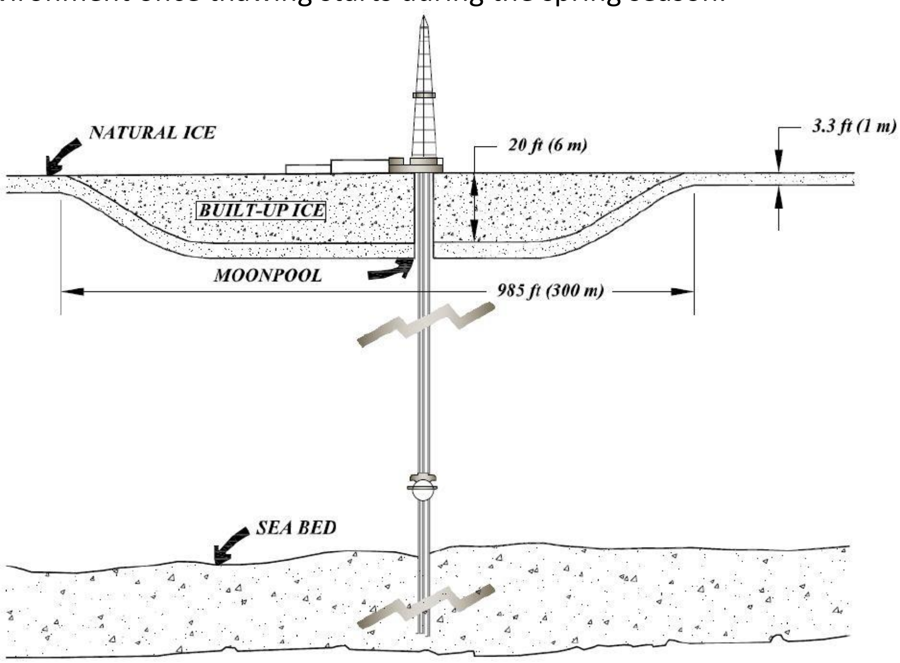


Figure 3.14- Ice island prospect. Source: Masterson et al 1987

The typical size of the island is 500 ft x 500 ft x 0,7 ft and take only one week for its construction if the temperature remains around 5 °F (-15°C). [62](Stanley & Hazen, 1996)
The medium temperature range in arctic is from -60°F(-51°C) during the winter time to 80°F(26.7°C) in the summer season. For this reason special building technologies are required in order not to have problems connected with the spring thawing as for example the pre-fabrication of insulation panels that, once installed over the ice-pad, enable the pad to remain frozen and to keep the drilling rig in loco for the next drilling season. [62]

3.3.2.3. GBS (gravity based system)

Gravity based system are designed for depth in the range of 150-200 m and are built on concrete or steel legs, or both, anchored directly onto the seabed, supporting a deck with space for drilling rigs, production facilities and crew quarters. Such platforms are, by virtue of their immobility, designed for year round drilling activities.
The world's largest GBS oil platform for arctic environment is the Hibernia platform located on the Grand Banks in 260 feet (80 m circa) of water and is operated by ExxonMobil.

Figure 3.15- Hibernia platform. Sources: freerepublic.com

The platform acts as a small concrete island with serrated outer edges designed to counter icebergs. [1]
The structure design is represented by a long cylindrical concrete caisson that extends from the seabed to 5 m above the mean sea level. The topside is supported by four shaft to 102 feet (31 m) above the waterline. [63]

3.3.2.4. Jackup rig

A **jack-up rig** or a self-elevating unit is a mobile platform that consists of a buoyant hull fitted with a number of movable legs, capable of raising its hull over the surface of sea. The buoyant hull enables transportation of the unit and all the drilling facilities to a desired location. Once on location the hull is raised to the required elevation above the sea surface on its legs supported by the seabed. Generally, Jackup rigs are not self-propelled and rely on tugs or heavy lift ships for transportation.

Jack up platforms are used as exploratory drilling platforms and. Jackup platforms have been the most popular and numerous of various mobile types in existence. Total number of Jackup 'Drilling' rigs alone in operation shall be about 540 by the end of 2013. *[1]*. Because of its nature, the Jackup rigs can only be placed in relatively shallow waters, generally less than 400 feet (120 m) of water. However, a specialized class of Jackup rigs known as premium or ultra-premium Jackups are known to have operational capability in water depths ranging from 500 to 625 feet (about *150-190 m)*

Figure 3.16- Jack up. Source: footage.shutterstock.com

The Jackup is not recommendable for those areas where ice may impact with the legs or those waters infested by icebergs. Its design is not stable enough to resist to the massive tangential stress caused by the ice impact.

3.3.2.5. TLP

A Tension-leg platform (TLP) is a vertically moored floating structure normally used for the offshore production of oil or gas, and is particularly suited for water depths greater than 300 meters (about 1000 ft) and less than 1500 meters (about 4900 ft).

Figure 3.17- TLP. Source: modec.com

The platform is permanently moored by means of tethers or tendons grouped at each of the structure's corners. A group of tethers is a tension leg. A feature of the design of the tethers is the relatively high axial-stiffness (low elasticity), such that virtually all vertical motion of the platform is damped. This allows the platform to have the wellheads on deck (connected directly to the subsea wells by rigid risers), instead of on the seafloor. This allows a simpler well completion and gives better control over the production from the oil or gas reservoir, and easier access for down hole intervention operations. [1]

On the other hand, in an Arctic environment, its rigid layout does not allow the TLP to move from the rig during the winter season or to move in case of ice-management failure. This solution is not recommendable for those waters infested by icebergs or with one/multi years ice.

3.3.2.6. Spar

Spar is a floating platform that can support drilling, production and storage operation. It consists of a large vertical cylinder bearing topsides with equipment. Similar to an iceberg, the majority of a spar facility is located beneath the water's surface, providing the facility increased stability.

Originally designed as a floating buoy to acquire oceanographic information, the main component of a spar facility is the deep-draft floating chamber, or hollow cylindrical hull. Characteristically, the hull is encircled with spiraling strakes to add stability. Additionally, the bottom of the cylinder includes a ballasting section with material that weighs more than water, ensuring the centre of gravity is located below the centre of buoyancy.

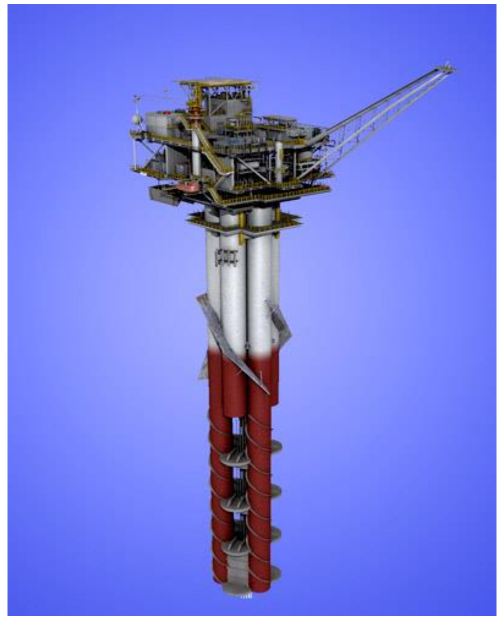


Figure 3.18- Spar. Source: anadarko.com

The deep-draft design makes the spar less affected by wind, wave and currents, enabling the facility to support both subsea and dry tree developments. Additionally, the enclosed cylinder acts as protection for risers and equipment, making spars an ideal choice for deep-water developments. Furthermore, the hull can provide storage for produced oil or gas.

Atop the spar hull sits the topsides, which can be comprised of drilling equipment, production facilities and living quarters. Drilling is performed from the topsides through the hollow cylinder hull; and drilling, import/export and production risers are passed through the enclosed hull, as well. The whole spar facility is then moored to the seafloor. [64]

The Spar, as the Jackup and the TLP, is not recommendable for those areas where ice may impact with the structures or those waters infested by icebergs. Its design is not stable enough to resist to the massive tangential stress caused by the ice impact.

3.3.2.7. Semi-submersible rig

A semi-submersible and is a specialized marine vessel that can be used both for drilling applications or oil production. They are designed with good stability and sea keeping characteristics by optimizing the RAO during the vessel design. The **response amplitude operator** (**RAO**) is an engineering statistic, or set of such statistics, that are used to determine the likely behaviour of a ship when operating at sea comparing the wave frequency with semi-sub own frequency. [1]

Offshore drilling in water depth greater than around 520 meters requires that operations be carried out from a floating vessel, as fixed structures are not

practical. A semi-submersible obtains its buoyancy from ballasted, watertight pontoons located below the ocean surface and wave action. The operating deck can be located high above the sea level due to the good stability of the design, and therefore the operating deck is kept well away from the waves. Structural columns connect the pontoons and operating deck.
With its hull structure submerged at a deep draft, the semi-submersible is less affected by wave loadings than a normal ship. With a small water-plane area, however, the semi-submersible is sensitive to load changes, and therefore must be carefully trimmed to maintain stability. Unlike a submarine or submersible, during normal operations, a semi-submersible vessel is never entirely underwater.
A semi-submersible vessel is able to transform from a deep to a shallow draft by deballasting (removing ballast water from the hull), and thereby become a surface vessel. The heavy lift vessels use this capability to submerge the majority of their structure, locate beneath another floating vessel, and then deballast to pick up the other vessel as a cargo. *[1]*

The floating nature of this vessel makes it suitable for arctic deepwater but its operability is nowadays limited to summer season because it's still impossible to guarantee station keeping in harsh ice conditions.

One example of state-of-art operating Arctic semi-sub is Scarabeo 8 owned by Saipem. It operates for ENI Norge at the Goliat field in the Barents Sea and the operation started at the beginning of 2012 and will last up to at least 2017. The rig hull was built at the Sevmash yard in Russia and the rig superstructure was partly constructed in Palermo, Italy. The rig was then towed to Westcon in Ølen, for further construction and completion. The rig will be capable of operating under harsh environmental conditions and is constructed especially for this purpose. The rig is equipped with a dynamic positioning (DP) system, allowing drilling at extreme water depths. It is a 6th generation rig, with a double derrick, designed to offer enhanced operating capacity and performance. This

Figure 3.19- Scarabeo 8 semisubmersible. Source: Saipem

particular rig has a long, bright and busy future ahead in Norwegian waters. Scarabeo 8 is due to be fully manned by the end of 2011, with a fixed complement of 207 persons. *[65]*
The upper deck is fully winterized ensuring a sustainable working environment in the cold Barents sea.
More about the Scarabeo 8 is stated in the further chapters.

3.3.2.8. Monohull Drlling ship

The mono-hull drill ship is commonly used for deepwater drilling but can also be used for well maintenance and completion. The great advantage of this drilling vessel is the ability to drill in wather depths of more than 2500 m and gthe extreme flexibility to easly sail between oilfields worldwide. [1]
Unfortunately this technology is mostly used in arctic condition just for summer season and open water drilling campain.

Figure 3.20- Monohull drillship. Source: Stena

In order to fit the Arctic requirments, a great concern is given to the following topics:

- **Off season availability**: the ship must as self sufficent as possible by carrying the maxim amount of fuel, fluids, drilling consumables, spare parts, equipment. All these requirment are connected to the difficult logistical support and the lack of infrastructure in the arctic environment. (OTC 19954; agoal based solution to offshore drilling challenges in arctic environment; Rod Allan et al 2009)

- **Polar class requirments**: according to the definition stated in the previous chapters, the hull must be able tu resist to different ice tickness and conditions. Some risk assessment have been diven and they agree on the fact that it is not recommendable to unify the icebreaker concept to the drill ship.

In fact the potential for damage and the fact that icebreaker escort would be needed for ice management suggest to separate the drillship design from the icebraker support vessel.

- Efficient open water transit : it is guarantee by an efficient hull design and a ice breaker/ ice management support.

- **Mooring and DP**: new designs have shown a new mooring solution for arctic shallow water drilling. The presence of ice combine with the hull performance require the ship to rotate around a mooring turret situated on the same axis of the moon pool. In this way the effect of wind, wave, current and ice is minimized allowing the riser operability. Moreover the Dynamic Positioning (DP) requires propulsion equipment without compromise to the additional Arctic mission. The unmoored DP station keeping performance is still a critical point, as shown by preliminary models test, because of the extreme sensitivity to any significant ice load.

Figure 3.21 - Mooring system. Source: intsok.com

- **Winterization measures**; As the drilship is designed to work from early Arctic summer to late autumn, all trhge working areas of the piope racks, riser hold, drill floor, moonpool and turret must be fully enclosed and temperature controlled.
- **Drlling riser disconnection system** (conventional technology)**;** Must be available for expected and planned disconnectio as those during well finishing but also for unexpected but planned disconnection. These can be either long term (days) for ice forecast, short term (hours) for ice management failure of super-short (minute) for emergency response.

3.3.2.9. Arctic circular drilling platform

Floating circular e&p structures are technologie designed for deep and ultradeep arctic drilling and production development (depth>500m). So far they have been used very little in arctic areas because of the critical ice management activities related. In fact this technology borders the marging of technical feasibility in arctic environment even with continuous ice management. (MMS,2008) .
The round shape is designed to be supported by a mooring system in order to resist to the high ice forces typical of the Arcit environment.

One example of working drill circular barge is the Kulluk owned by Royal Dutch shell. The Kulluk was specifically designed and constructed for extended season drilling operation in arctic waters. It is rated to work in weather conditions historically occurring throughout the oper water season (July-October) and rarely in the extended season.
Kulluk was buliutl in 1983 and purchased by Shell in 2005, up untili October 2012 the Kulluk has worked in the Beaufort sea off the Alaskan north slope. An accident occurred on 31 December when Kulluk ran aground off Sitkalidak Island in the Gulf of Alaska. It was being towed to its winter home in Seattle when it encountered a storm, and the incident occurred. The US Coast Guard evacuated its 18-man crew on 29 December. On New Year's Eve, tug crews were ordered by the US Coast Guard to cut the rig loose, leading to its grounding (Figure 3.22). [1]

Figure 3.22- Kulluk vessel. Source: Shell

3.3.2.10. Hybrid Semi-sub-circular platform

Semi-sub- circular platform is an innovative technology that is still under development. One example of company that is running over this solution is Huisman.

The idea is driven by the combination of the high stability in waves draft and the excellent sea keeping performance of the semi-submersible vessel and the superior ice resistance of the circular drilling platform. [66]

Figure 3.23- Cylindrique type Unit. Source: JBF

With the assistance of the mooring system it has been proved (Saint Petersburg 22.12.2010; Krylov shipbuilding research institute) that this solution can withstand ice up to 3.0 m at low drift speed.

3.3.2.11. Unmanned seabed rig

This innovative technology is still under development and represents a very attractive solution for arctic drilling. The Norwegian company Seabed Rig AS has developed an autonomous robotic drilling rig for unmanned drilling operations. The system (Robotic Drilling System™) sets new standards with increased safety and cost-effective planning and drilling, and can be implemented on existing as well as new drilling structures both offshore and on land.

The unmanned system utilizes autonomous robotic working operations that can be

Figure 3.24- Unmanned seabed rig. Source:rds.no

remotely controlled from an interactive 3D interface.
Robotic drilling system will also be incorporated with the submerged patented encapsulated and pressure compensated Seabed Rig for exploration drilling in harsh areas such as arctic or ultra deep waters.
The Seabed submerged rig is connected to the vessel through an umbilical with power, control and mudflow. All functions on the rig are remotely controlled from a control room on the surface vessel or from land. The rig is made up of modules that can be lowered through standard moon pool inside the surface vessel and guided in place by means of guide wires. The rig is filled with water, pressure compensated and encapsulated in order to avoid contamination of the surrounding environment.
The project is leaded by Robot Drilling System As (RDS), (ex Seabed Rig AS) and is supported by Statoil, the Norwegian Research Council (Petromaks and DEMO2000) and Innovasjon Norge. [67]

3.3.2.12. Comparison between technologies

A Boston Square Matrix (BSM) is plotted in Figure 3.25 to rank the drill site. The plot includes capital cost on the x axis, easiness the construct, mobilize and maintain on the y axis, environmental risk and footprint using five levels of colour ranging from green for 'minimal impact' to red for 'considerable impact', and technology maturity using four different circle sizes ranging from small for 'innovative' to large for 'very mature'. [16]

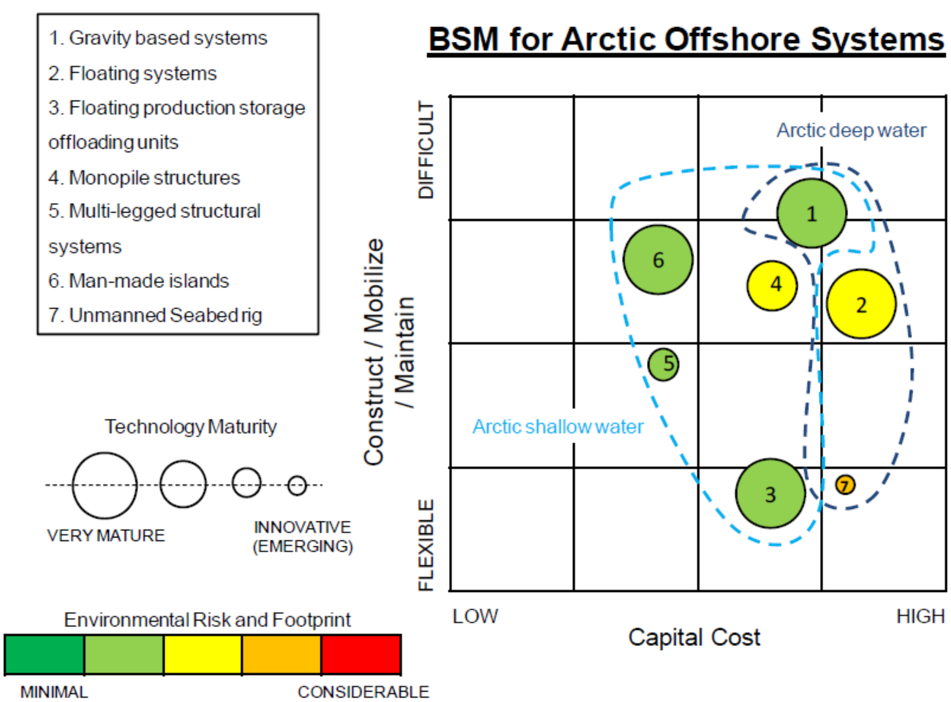


Figure 3.25- Boston Square Matrix. Source: Blade

The Table 3.3 states a summary and comparison between of all the available technologies and states of art.

SITE OPTION	ADVANTAGES	RESTRICTION WHILE CONSTRUCTING/ EXPLOITATION	MAIN DISADVANTAGES
Gravel Islands	Use of local cheap material(sand, gravel)	It is necessary to use dredging machines and cranes with small draft.	Not mobile, Ecological problems, log time material consolidation, expensive, problems during demolition
Ice islands	Availability, low cost, easy erection.	Must be no ice movement during drilling period	Usable only once, not mobile, low efficiency (one well per season),
GBS	Perfect stability and high ice resistance	water depth must be less than 150 m.	Not flexible structures, not mobile, expensive, long time project, strong visual impact.
Jack up	very flexible, high mobility	Water depth must be less than 120 m	Low stability, usable just in absence of ice. NOT RECOMMENDED FOR ARCTIC ENVIRONMENT
TLP/Spar	Flexible, usable for deep-water.	Not self-propelled.	Expensive, long time project, not fastly movable, Usable just in absence of ice. NOT RECOMMENDED FOR ARCTIC ENVIRONMENT
Drillship	Extremely flexible, Good for deep/ultra-deep water	Need ice management	Drilling possible just in absence of ice and in acceptable seawater condition
Semisubmersible	Extremely flexible, Good for deep/ultra-deep water, improved stability thanks to square hull shape	Need ice management	Drilling possible just in absence of ice and in acceptable seawater condition

unmanned seabed rig	Usable in presence of ice some on seawater surface, No riser needed, More independence from meteorological conditions.	New technology, complicate technology, not total independence because is flexibly connected to the support vessel.	Ice scouring effected, expensive, immature

Table 3.3- Summary and comparison between available technologies

3.3.2.2 ICE REGIMES

The ISO standard FDIS 19906, as previously mentioned, has been completed in 2009 and it's focused on the design of the offshore structural system. As a starting point for an offshore project the ice regime corresponding to the selected area must be identified. In the standard 8 different ice regime classes are defined as shown in the (Table 3.4).

Zone	Regional ice regime	Regions	
1	Mainly multi-year ice: 5/10 concentration	Beaufort Sea Southern Chukchi Sea Baffin Bay	Labrador Laptev Sea
2	Mainly multi-year ice: 3/10 concentration	Beaufort Sea NE Greenland	Northern Chukchi Sea Arctic Islands
3	First-year ridges	Sakhalin Cook Inlet	Sea of Okhotsk Kara Sea
4	Partially first-year ridges	Barents Sea	Bering Sea
5	First-year level ice	Caspian Sea Baltic Sea	Bohai Bay
6	Icebergs Low hazard	Barents Sea	
7	Icebergs Medium hazard	Grand Banks	
8	Icebergs Severe hazard	Labrador Baffin Bay	NE Greenland

Table 3.4 - Ice regimes. Source: Blade

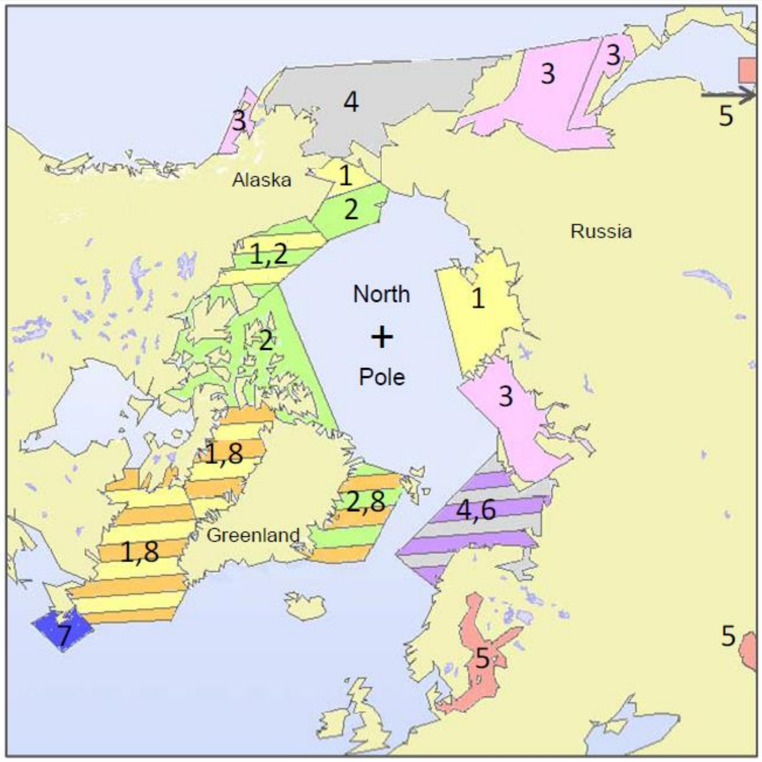


Figure 3.26 - Geographical description based on ice regimes. Source: Blade

As shown in the Figure 3.26 different ice regimes and iceberg hazard can subsist in the same region depending on the season and the weather condition. Obviously the design must allow resistance in the harsher condition.

The sea ice is categorized, as stated above, from age:

- First Year ice: forms during one winter freezing process and melts during summer. The thickness is in the range of 0 - 2 meters.

- Second year ice: survives the first summer melting and its thickness is between 0,5 - 3 meters.

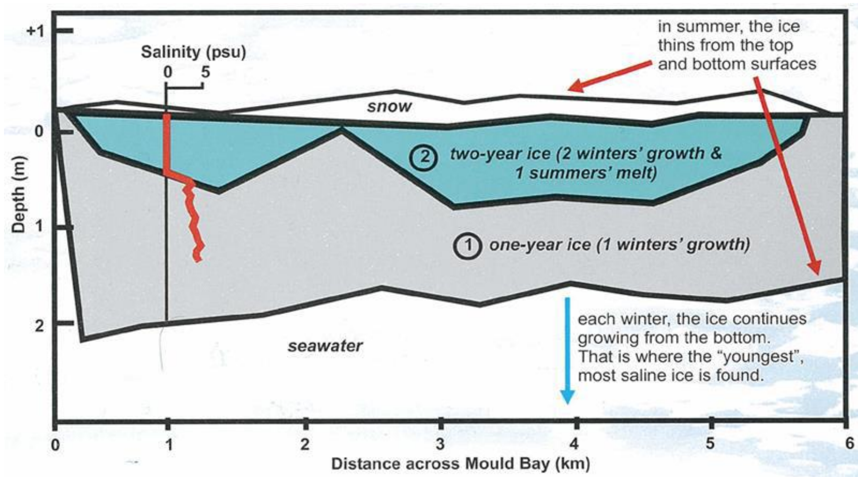


Figure 3.27- second year ice. Source DMI

- Multiyear ice: survives several years of melting. The thickness is generally more than 3 meters.

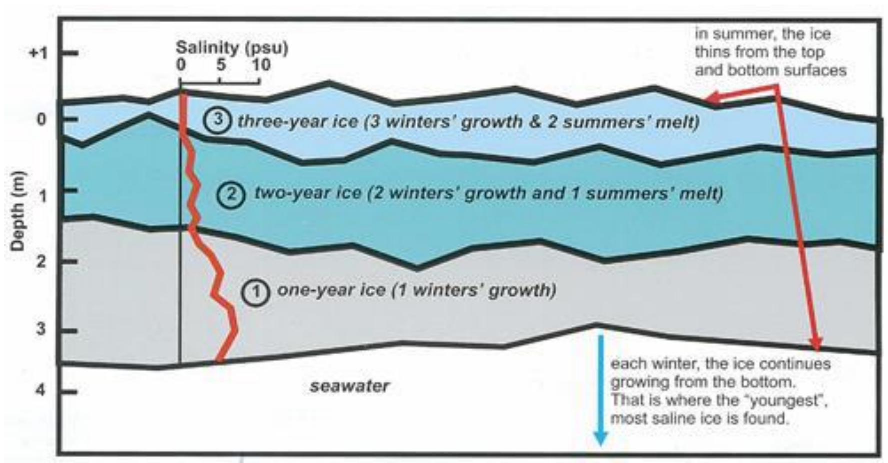


Figure 3.28- Multiyear ice. Source DMI

An international panel of experts was formed to investigate which structural concept have been used or can been used in specific ice regimes according to the ISO 19906 standards. [68](**Errore. L'autoriferimento non è valido per un segnalibro.**)

REGION	Greenland (WEST)	AK Beaufort Sea	Bearing Sea	Chukchi Sea	Cook Inlet	CA beufort Sea	CA Great Banks	Barents Sea	Kara Sea	Pechora Sea	Sakhalin island	Caspian Sea
BOTTOM-FOUNDED & FIXED TYPE STRUCTURES												
GBS		X	X	X		X	X		X	X	X	
Mobile Bottom Founded		X				X			X			
Jacket/Monopod			X		X		X					
Barge			X			X						
Jack.Up			X		X		X					
Gravel Islands		X				X						X
Ice Islands		X				X						
FLOATING STRUCTURES												
SPAR	X						X	X				
TLP	X						X	X				
Semi-Sub			X		X		X	X				
Circular Platform		X		X								
Drillship		X		X	X		X	X				

Table 3.5- Arctic installed structures

3.4. *HYDRATE'S DISCUSSION*

Methane clathrate ($CH_4 \bullet 5.75H_2O$[), also called methane hydrate or natural gas hydrate, is a solid clathrate compound in which a large amount of methane is trapped within a crystal structure of water, forming a solid similar to ice.

Methane clathrates are common constituents of the shallow marine geosphere, and they occur both in deep sedimentary structures, and formoutcrops on the ocean floor. Methane hydrates are believed to form by migration of gas from depth along geological faults, followed by precipitation, or crystallization, on contact of the rising gas stream with cold sea water. Methane clathrates are also present in deep Antarctic ice cores, and record a history of atmospheric methane concentrations, dating to 800,000 years ago.] The ice-core methane clathrate record is a primary source of data for global warming research, along with oxygen and carbon dioxide. *[1]*

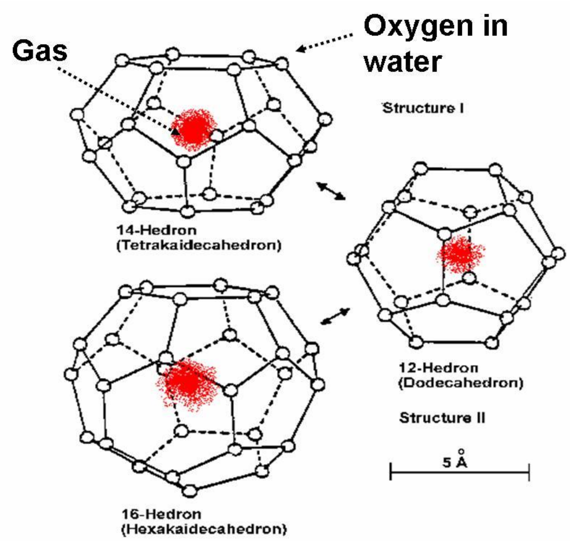


Figure 3.29- Hydrate structure. Source: sps.esd.ornl.gov

Geoscientists agree that hydrate occur in multiple areas of the Artic zone, as previously stated, in the north slope of Alaska.

Figure 3.30- Hydrate on fire. Source: dco.gl.ciw.edu

Formation and presence of hydrates is dependent upon three major variables: Temperature, Pressure, Salinity and water percentage.

Salinity has an effect on the compound characteristics, on the ability of water to link with methane. Pressure and Temperature have indeed a strong influence on the mixture behaviour as depicted in the Phase envelope diagram (Figure 3.31).

Hydrates bearing formations usually take place from immediately below the permafrost to 2000 ft (610 m) below it. They are trapped into formations typically of sandstone or siltstone characterized by a high porosity and permeability.

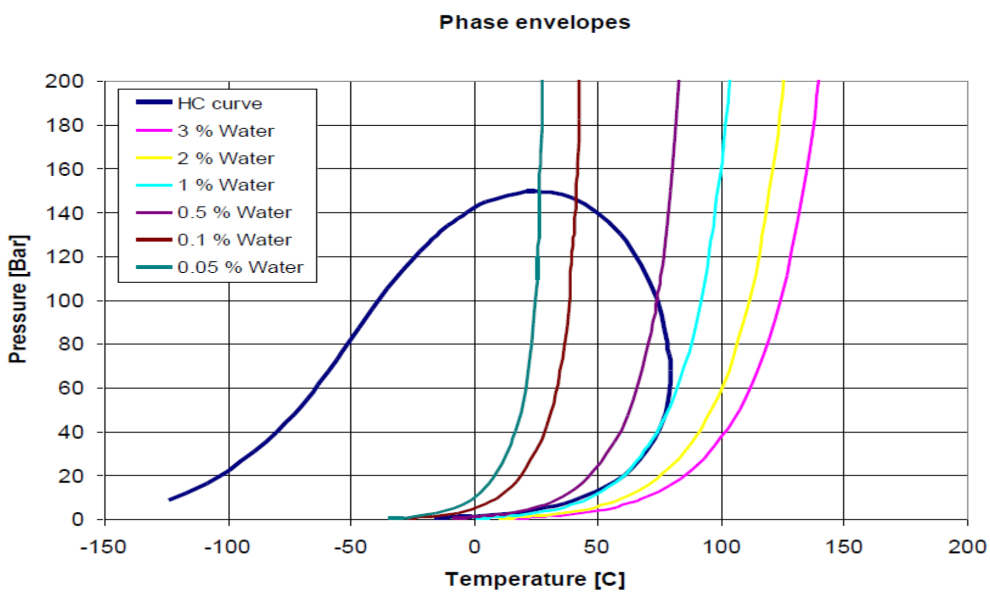


Figure 3.31- Hydrocarbon phase envelope and hydrates equilibrium curves.

Hydrates must be taken under great consideration in those permafrost region were may subsist drilling operations. In fact several steps may occur to drive the system into a not controlled well situation:

- Lack of adequate compressive strength due to the organic composition that may drive to hole instability and problems concerning wellbore integrity during the thawing process. Moreover, sufficient thawed hydrates near the surface can drive to subsidence. If large volume of dissociation occurs the wellbore can slough, causing stuck pipes.
- During phase change the volume of gas tend to increase its volume by a factor of 160 in the gas phase. The rapid expansion creates a pressure increasing that drives the gas throughout the formation by the most permeable flow path towards the warmer wellbore direction. If this event is not detected, with correct pressure driving forces, it can turn into a dangerous kick.
- During circulation the gas phase will pass through the cold upper annular section. It is highly possible to form hydrates again while circulating out gas kicks and this can dramatically increase the danger to lose the well control.

Hydrates formation and circulation requires nowadays more and more precautions because of the increasing of drilling depths. With the increasing of the sensibility to the environment by the oil companies, water based drilling fluids are often more desirable than oil based fluids, especially in offshore exploration. Unfortunately this technology in deep water offshore drilling can bring to the formation of gas hydrates in the event of a gas kick.

In deep-water drilling, the hydrostatic pressure of the column of drilling fluid and the relatively low seabed temperature could provide suitable thermodynamic conditions for the formation of hydrates in the event of a gas kick. This can cause serious well safety and control problems during the containment of the kick. Hydrate formation incidents during deep-water drilling are rarely reported in the literature, partly because they are not recognized.

The formation of gas hydrates in water based drilling fluids could cause problems in at least two ways:

- Gas hydrates could form in the riser drill string, blow-out preventer (BOP) stack, choke and kill line. This could result in potentially hazardous conditions, i.e., flow blockage, hindrance to drill string movement, loss of circulation, and even abandonment of the well.
  To prevent this hazardous condition generally the riser sting is provided with a glycol line that recirculates the organic compound preventing hydrates formation.

- As gas hydrates consist of more than 85 % water, their formation could remove significant amounts of water from the drilling fluids, changing the properties of the fluid. This could result in salt precipitation, an increase in fluid weight, or the formation of a solid plug. [69]

The hydrate formation condition of a kick depends on the composition of the kick gas as well as the pressure and temperature of the system, as shown in the figure above. As a rule of thumb, the inhibition effect of a saturated saline solution would not be adequate for avoiding hydrate formation in water depth greater than 1000 m. Therefore, a combination of salts and chemical inhibitors, which could provide the required inhibition, could be used to avoid hydrate formation. The main inhibition system is the Ethylene glycol injection.

In a glycol injection system, glycol is injected into a gas stream at a point upstream of hydrate prone areas such as high pressure or low temperature regions. The glycol present in the gas stream prevents hydrate forming conditions by absorbing the free water in the system. The glycol and water mixture may be separated by regeneration, allowing the glycol to be recycled. MEG (Monoethylen glycol) Ethylene glycol is generally preferred to DEG (Diethylene glycol) or TEG (Trietylene glycol) for this type of operation due to its low solubility in hydrocarbons. EG also possesses a low viscosity and is more effective on a weight basis for hydrate inhibition (Kohl, 1985).

The effect of the content of MEG in a water-hydrocarbon compound is shown in the equilibrium curve in the figure 66.

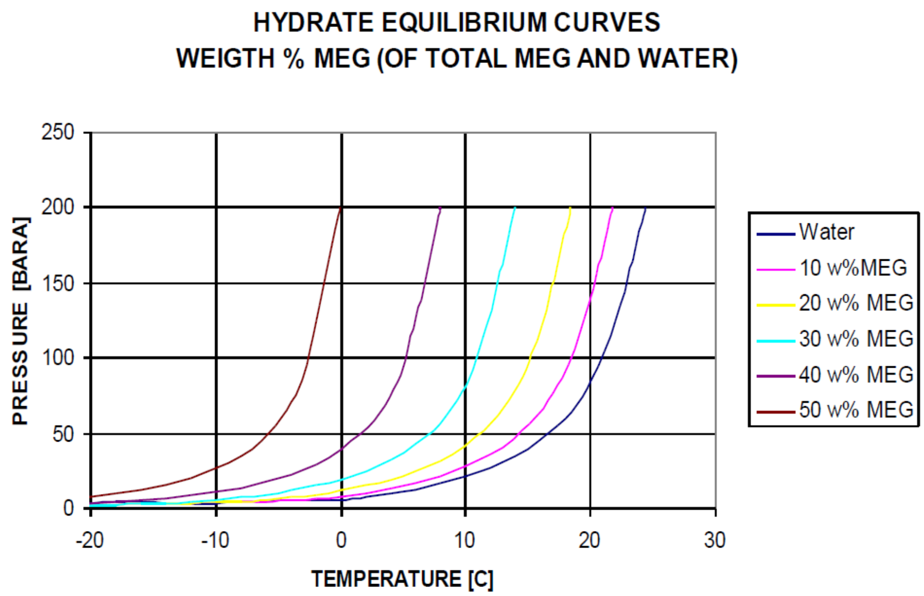


Figure 3.32- Hydrates equilibrium curves in function of MEG concentration

During drilling and exploration phase a typical area of concern is multiphase transfer lines from well-head to the production platform where low seabed temperatures and high operation pressures increase the risk of blockage due to gas hydrate formation. (Figure 3.33)

Figure 3.33- Hydrate plug. Source: pet.hw.ac.uk

Different methods are currently in use for reducing hydrate problems in hydrocarbon transfer lines and process facilities. The most practical methods are:

- At fixed pressure, operating at temperatures above the hydrate formation temperature. This can be achieved by insulation or heating of the equipment.
- At fixed temperature, operating at pressures below hydrate formation pressure.
- Dehydration, i.e., reducing water concentration to an extent of avoiding hydrate formation.
- Inhibition of the hydrate formation conditions by using chemicals such as methanol and salts.
- Changing the feed composition by reducing the hydrate forming compounds or adding non hydrate forming compounds.
- Preventing, or delaying hydrate formation by adding kinetic inhibitors.
- Preventing hydrate clustering by using hydrate growth modifiers or coating of working surfaces with hydrophobic substances.
- Preventing, or delaying hydrate formation by adding kinetic inhibitors. [70]

3.5. DEEPWATER/ULTRADEEP CHALLAGES

As previously stated, the offshore Arctic field development has gained a relevant importance due to the potential for very large reservoirs increasing their commercial viability. Some of the most important areas has been identified to be deep-water or ultra-deep-water: Barents Sea; offshore Norway and Russia; orphan basin; offshore Newfoundland; offshore Greenland and Iceland. The water depth may vary from 300 to 3000 m.
As stated previously the decreasing ice mass have increased open water and open shipping routes which provide new opportunities for field developing. [71]
Several fields are stated in depth of water that exceeds the practical limits for using a GBS or a bottom founded structure, thus the choice of floating structure is considered the most suitable solution.

The challenges in the development of deep-water Arctic are represented by:

- Remoteness of the fields from the onshore facilities or existing development;
- Danger of ice impact;
- Lack of infrastructure in the close regions;

- Long time development and multi-year drilling required;
- Lack of reliable ice& iceberg data over long periods.

The environment conditions bring the presence of massive ice features that requires solutions as detachable risers, station-keeping systems and ability of towing away from iceberg paths. Thus floating systems designs proven in deep-water over past years could provide commercially viable solutions for development of Arctic deep-water fields. [71]

Mainly three floating drilling units are suitable for deepwater arctic conditions:

- Floating Structures;
- Drill arctic ships;
- Semi-submersible rig
- Seabed Drilling rig

The first three solutions require fast connecting/disconnecting raiser system and surface ice management. Moreover, they have to be designed to operate in DP3 station keeping.

The alternative hybrid solution, that has been previously adopted in 2009 on the Chinese continental shelf [72], is the Atlantis Artificial Buoyant Seabed . This concept requires a buoy positioned at shallow water depth (250-400 m) below the sea surface to create an artificial seabed where the wellhead and the BOP is positioned above the buoy. The buoy is proposed to be anchored to the seabed by means of casing, which is connected to the wellhead located on the seabed. The design reduces the length of drilling riser that need to be retracted upon disconnection of the drilling rig. [71]

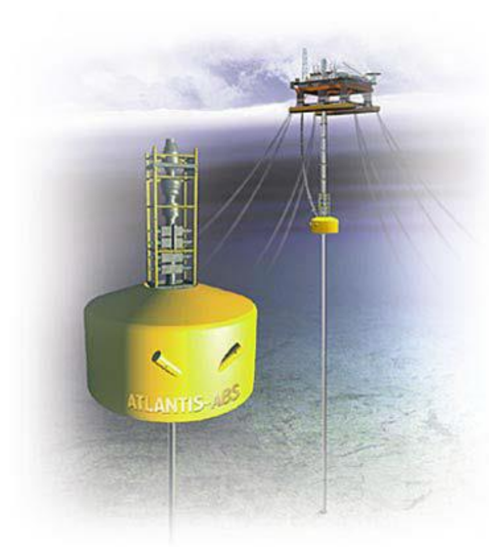


Figure 3.34- Atlantis deep-water technology. Source: Holding AS

Great concern is given on production in such a harsh environment. There are two main technical solutions:

- **Floating production platform with subsea wells**. This solution requires detachment of floating hull to safeguard against an approaching large ice event or iceberg. Therefore the wellhead (WH) will be on the seabed or located on artificial buoyant seabed.
  The transport of crude from remote fields would be by shuttle tankers, thus the floating unit must store oil till the open water condition will allow the shuttle to come.
- **Subsea to shore production using multiphase pipelines**. This solution is suitable to those fields that are close to shore with existing shore-based facilities. The technology required is high such advanced boosting systems or glycol recirculation in order to avoid hydrates. An example of application is the Snohvit field (Norway) located 232 km (145 miles) from the shore facility. [71]

Typical requirements for deepwater field production are:

- Large topside facilities for high production rate;
- Large numbers of risers and mooring lines;
- Glory holes on the seabed for ice features protection;
- Pre-drilling by floating rig or seabed rig with multi-year drilling program;
- Long step out distance form well to platform;
- High storage capability;
- Winterization on topside structures;
- Ice management;
- Detachment capability (not in case of subsea to shore production)

3.5.1 Deep-offshore impact experience: Macondo blowout

Drilling and production in extreme environment as deep/ultra-deep water represent a relative new technology that has become feasible during the oil price rising in 2007 /2008 and therefore very little information is available to support environmental impact assessment.

In this scenario could be interesting to review and understand what happened in the Macondo well in gulf of Mexico in 2010. Under severe environmental condition, located over approximately 5,100 feet (1,600 m) of water, the Deep-water Horizon drilling rig on 20 April 2010 exploded and sank.
The reason is high-pressure methane gas from the well expanded into the drilling riser and rose into the drilling rig, where it ignited and exploded, engulfing the platform.(Graham et al. 2011)
The effect of this accident is 11 fatalities, many injured and the biggest amount of oil dispersed in water in history. Approximately at 1500 m depth for 84 days 840000 tons of oil were released in the ocean. [73].
The estimated effect has been estimated to be 25% of oil removed by emergency response operation, 25% op oil evaporated, 28% dispersed or aied by chemicals and 22% formed slick and ended up on the sea bottom or reached the shore. [74]
The amount of wasted natural gas is about 6,6 x 105-1,2 x 106 kg/day [75]. The Dispersant Corexit 9500 was injected in the quantity of 2900000 l on wellhead and 4059854 l on the sea surface. [76]

By 21 June, 143 spill exposure cases had been reported to the Louisiana Department of Health and Hospitals (DHH); 108 of those cases involved workers in the clean-up efforts, while 35 were reported by gulf residents. Chemicals from the oil and dispersant are believed to be the cause of these illnesses as the addition of dispersants created an even more toxic substance (PAHs) when mixed with crude oil. Mike Robicheux, a Louisiana physician who has been treating people sick from exposure to toxic chemicals, described it as the biggest public health crisis from a chemical poisoning in the history the USA. In addition, the increased risk of mental disorders and stress-related health problems were noted shortly after the spill. [1]

The greatest impact was on marine species. The spill area hosted 8,332 species, including more than 1,200 fish, 200 birds, 1,400 mollusks, 1,500 crustaceans, 4 sea turtles and 29 marine mammals. In addition to the 14 species under federal protection, the spill threatened 39 more ranging from "whale sharks to sea grass" Damage to the ocean floor especially endangered the Louisiana pancake batfish whose range is entirely contained within the spill-affected area. The oil contained approximately 40% methane by weight, compared to about 5% found in typical oil deposits.[Methane can potentially suffocate marine life and create "dead zones" where oxygen is depleted. During a January 2013 flyover, former NASA physicist Bonny Schumaker noted a "dearth of marine life" in a radius 30 to 50 miles (48 to

80 km) around the well. In March 2012, a definitive link was found between the death of a Gulf coral community and the spill. [1]

3.6. ARCTIC CEMENTING

Cementing casing through the permafrost zone requests specific slurry design for high performance at low temperature conditions. The main differences between permafrost cement and conventional cement are:

- Setting temperature below 0 °C;
- Setting takes place without freezing;
- Low hydration heat request to prevent permafrost melting around the wellbore;
- Adequate compressive strength at low setting temperature;
- Stability during thaw and freeze cycles. [16]

Conventional Portland cement system cannot be used in arctic condition because they will freeze before the stable settlement has come. It is possible to add freeze-depressing materials to the mixed waters but the effect on the set cement quality will be negative.
Moreover care must be taken to prevent contamination with high alumina cement with Portland since it can cause flash setting of the alumina one.
A common practice in Arctic condition is to use heated mix water with additives as NaCl that will accelerate setting times and suppress the freezing temperature.

Two different type of cement have been created to suit arctic condition:

- Lumnite and Ciment Fondu. This is a calcium aluminate cement with fly ash cement to reduces the heat of hydration. Its best quality is the ability of gaining strength rapidly al low temperature while setting.
  It has been reported by Cunningngham, et al,m 1972 that between 70 and 75 °F(21,1-23,8 °C) this cement goes through a phase change with a decrease in compressive strength and an increase in permeability.
  This cement is therefore not suitable for production wells or any kind of well where the temperature may increase because of the inner flow.
- Permafrost cement. It is a blend of Portland cement with addiction of gypsum that sets first and prevent the slower Portland setting from freezing. After 12-

24 hours of setting the slurry gains a sufficient strength and a long term durability. [16]

3.7. ARCTIC WELL CONTROL

Well control is a critical aspect in any wellbore development for any region worldwide. Well known techniques have been developed and refined during years to meet the increasing requirements of safe well control and formation influx removal.
Well control in arctic areas encompasses all the traditional aspect of conventional well control.

The analysis must take into different consideration the offshore location to the on-shore one.

ONSHORE
The main concerns are connected to the on-shore well development and control.
Additional risk from a conventional drilling performance on shore is added mainly by the reduced geothermal gradient and the low surface temperature.

The reduction in geothermal gradient creates two distinct and potentially dangerous conditions:

- Potential for encountering formations containing in-situ hydrates and the potential for the creation of hydrates within the wellbore during kill operations. Hydrate laden formations are normally encountered in the upper section of the wellbore where formation temperatures are cool.
- Hydrates formation may involve a traditional well control kick, which contains a significant gas volume and associated water. [16]

For these reasons, the following conclusions have been drafted:

- Hydrates occur in two different conditions: in-situ and formed during wellbore operations.
- In situ hydrates formation takes place in the zone immediately below the permafrost region and can extend 2000 ft (610m) below it.

- Formation of hydrates plug takes place in the upper section of the wellbore during flowing or circulating operation when cooler condition are encountered.
- Reduced temperatures, resulting in cooler operating condition, for circulating and well control equipment can result in either failure to function or impaired ability to safely remove formation influxes during a well control problem.
- Well design must take into account the thermal change of both formation and equipment by selecting carefully the materials for casings, cements as well as drilling hydraulics and fluid selection. [16]

OFFSHORE

The pressure and temperature conditions encountered typically during drilling operation in depth over 500m are severe enough to allow hydrates formation even in non-arctic locations and therefore this issue is well recognized as a potential drilling hazard.

Thus, this is the most complicate well control situation in a “conventional” environment and doesn’t have any difference in the arctic environment.

As previously described one of the biggest issue is hydrate control. To prevent hydrates in BOP stack and in the riser string the glycol injection line had been developed. In fact the risers are provided with an additional line that inject glycol in the more sensitive areas of the BOP stack and recirculate it to the surface.

The well control is achieved by pressure managing during perforation. There are three main control techniques:

- Primary well control: This is the maintenance of sufficient hydrostatic head of fluid in the wellbore to balance the pressure exerted by the fluids in the formation being drilled. The hydrostatic pressure must be controlled and kept greater than the formation pressure (pressure of the fluids in the formation being drilled), but less than the formation fracture pressure. It uses the mud weight to provide sufficient pressure to prevent an influx of formation fluid into the wellbore. If hydrostatic pressure is less than formation pressure, then formation fluids will enter the wellbore. If the hydrostatic pressure of the fluid in the wellbore exceeds the fracture pressure of the formation, then the drilling fluid could be lost. In an extreme case of lost circulation, the formation pressure may exceed hydrostatic pressure, allowing formation fluids to enter into the well (kick). *[1]*

- Secondary well control: Performed once the primary well control has failed, it is composed by a backup system of mechanically operated ‘bridges’ and valves to safely contain a well influx and additionally provide a means of recovery effectively from an incoming well influx. The secondary well control is performed by acting on the BOP electronically or physically.

- Tertiary well control: Once the other systems have failed a underground blowout situation occurs. Different techniques can be performed to restore the well control such as drill a relief well, pumping heavy weighting agents, rapid pump of heavy mud, plug the wellbore by pumping cement.

3.8. SAFETY: EXCAPE EVALUATION AND RECOVERY

Evacuation due to a well control accident in Arctic environment is challenging even in mild weather operations.
The safely removal of personnel from an arctic rig is made so challenging by the reduced visibility, frigid condition, remoteness and darkness.
Emergency evacuation systems have already been development for any industry operations but arctic operations require additional measures to provide a reliable and readily available method of evacuation. Traditional use of standby vessels may not be adequate when ice and sea states restrict the movement of the vessel. For any rig operation, the primary means of evacuation should be formed around an “all weather system”. If an all-weather system cannot be developed, a method suitable for each restrictive condition must be developed. The key component that must be development is the decision tree for transitioning from one evacuation method to the other comprehensive evacuation plan in order to maximize the success probability.
Critical components of the decision tree will include:

- Weather conditions,
- Number of personnel involved,
- Reliability of evacuation method,
- Time required to implement the evacuation,
- Survivability of personnel due to exposure.

Common methods of offshore-evacuation are:

- Marine Rescue– Includes all support vessels, work boats, crew boats and standby rescue vessels. This rescue technique is limited by the ice prohibition for boat approaching and the severe wave action. In some areas the tidal effect on water depth represents another restriction for the rescue boat to approach the rig.
- Life-Boat– Includes fully enclosed self-contained self-propelled vessels, Davit rafts:
  The limiting Factors are again the ice presence, the wave action and the extremely cold temperature.
- Aviation Rescue– For offshore operations, helicopters, fixed wing sea planes, fixed wing shuttle aircraft. The main problems with this solution are the obscured visibility, fuel limitations, icing condition, distance or flight time and restricted payload.
- Direct Water Entry – Assumes all personnel equipped with exposure suits. In this case the personnel have to fight with low temperature and the difficulty to retrieve them from water. This must be considered as the last resort in case of rig evacuation.

When may be not possible to evacuate in safe condition because of the weather conditions, it may be necessary to suspend critical operations while waiting on more favourable weather conditions. [16]

Exposure to the harsh condition is the key parameter to evaluate the best rescue technique. The human body cannot handle long duration exposure to cold conditions without protection. Unprotected, survivable exposure time is estimated to be between 10 and 30 minutes in a 0°C dry, 0 wind condition. The time is significantly reduced when immersed in cold water or unprotected from cold wind. Methods of increasing the survivable time involve preservation of body heat through protective clothing and separation from the elements either through physical containment such as a lifeboat.

The most important aspects of survival in cold conditions are:

- Insuring personnel are physically capable of enduring the exposure. Physical ailments such as cardiac or respiratory conditions severely reduce survivability. Physical examinations should be administered for all personnel.

- Water survival training should be required for all personnel including a review of the specific steps contained in the approved evacuation plan for the facility.
- Insure cold weather protective equipment is available in the event of an immersion. Floatation or Full Immersion suits are a must for each person on board. Redundant supply for all personnel should be available at muster stations for personnel that are unable to retrieve their issued suits.
- Adequate compliment of life boats.
- Limiting exposure time.
- Adequate system for recovery of evacuated personnel.

3.9. LOGISTIC & WINTERIZATION

The platforms in the Arctic and Sub-Arctic require special considerations in the designs of topsides and hull to reduce the impact of very low temperatures. The primary goal of winterization is to make operations by humans comfortable while working on the platforms for a very long period compared to operations in non-Arctic regions. In addition the safety and operability of all equipment and facilities within the hull is required.

The examples of variations in topside and hull designs for winterization includes: enclosed topside modules to perform all work inside, varying designs of topside modules to reduce ice accretion, weather protection enclosures, increased automation, heating of hull compartments. Winterization considerations are also required in other systems to maintain flow in risers, flow-lines, and exposed pipes. Alternative material grades and coatings are also considered than those used in other regions. [77] [71]

Heat loss takes place mainly for three reasons:

- Conduction to air in absence of wind as a function of the temperature gradient. This unavoidable heat loss is caused by the extremely low air temperature that can reach -40° C. The only way to minimize this

Figure 3.35- Frozen deck. Source: Termon

loss is by reducing the surface area during the facility design.

- Convection caused by wind. This heat loss is much more effective that conduction and must be minimized by reducing the air velocity in the boundary layer during the design process.
- Heat losses due to added cold masses. These masses can act as surface enlargers and therefore must be protected from the wind and heated to preserve their mechanical and functional purpose.

In order to minimize the energy consumption and obtain an effective winterization some practical solutions adopted consist in:

- Heated deck equipment, pipes and cables;
- Ventilators and fun for air temperature control;
- Heated doors, stairs, escape tracks and handrails;

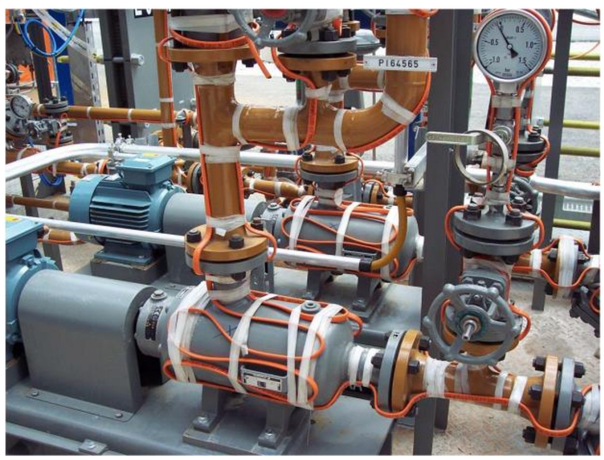


Figure 3.36- Heating equipment system

4. CASE STUDY: SCARABEO 8 IN BARENTS SEA, A RISER ANALYSIS IN ARCTIC CONDITIONS

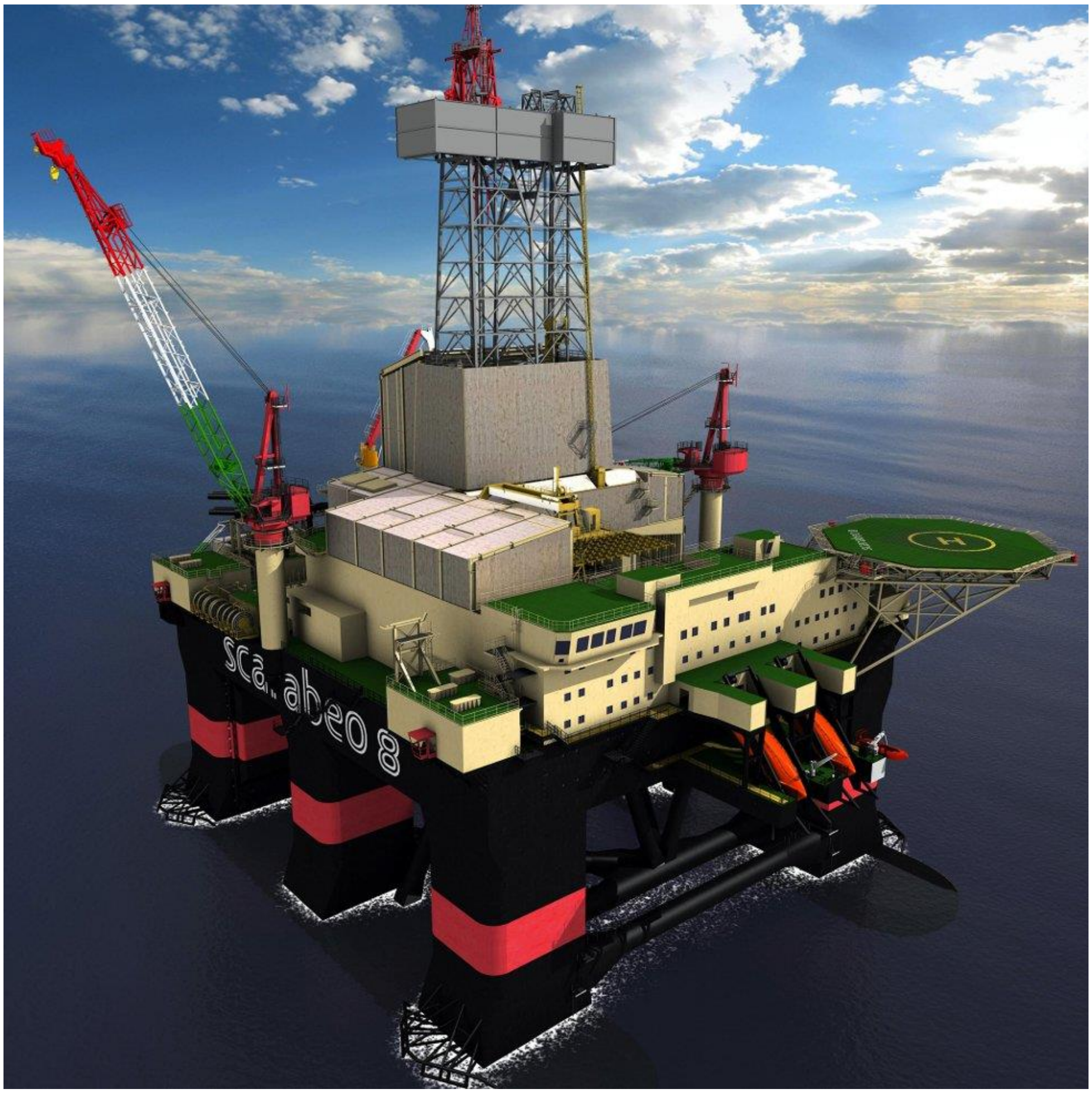


Figure 4.1- Scarabeo 8

4.1 VESSEL DESCRIPTION

The Scarabeo 8 is a semisubmersible vessel and is designed for operation, Year Round, World Wide including Barents Sea, in hash environment with a design temperature down to –20 °C. The rig is provided by an extensive cladding and heating system to improve the working environment and preserve the machinery, which are all designed for temperature to – 20 °C. The rig is heat traced on the fluid piping exposed to the weather and in the working areas walkways. All the escape ways are heat traced. [78]
The Unit consists of the upper hull, two pontoons, six stabilizing columns, four horizontal transverse trusses, four horizontal diagonal trusses and twelve vertical diagonal trusses. The upper hull or topside consists of a double bottom with main deck. The accommodation module is placed above the main deck forward and is divided in six levels. The helicopter deck is located on top of the accommodation module on the port side. [78]
Concerning operations, the main features of Scarabeo 8 are the following:

- Double derrick, which includes a substructure with drill floor, located at the main deck.
- Class 3 Dynamic Positioning combined with an Automated Thrusters Assisted Mooring.
- Acceptable Deck Load Capacity at Operation, Survival and Transit Draft.
- Vertical marine riser racking system is located on main deck forward of the drill floor.
- Vertical racking of the drill pipes and casing is arranged on main deck aft of the drill floor.
- Pipe deck and casing deck storage area located at upper deck.
- The corner columns contain some ballast tanks and machineries at the top levels. The access to pontoons, via thruster's room is granted only by the four corner columns. Each corner column is provided by an elevator.
- The central columns contain bulk mud, bulk cement and slop tanks
- The pontoons accommodate tanks for ballast water, diesel oil, drill water, potable water, mud, brine, base oil, mooring chain lockers and rooms for machinery (pump rooms and thruster's rooms)
- Eight thrusters of azimuth type, under-water de-mountable, fitted underneath the pontoons ensure the Dynamic Positioning capability of the Unit and will

allow a transit speed in calm waters of approximately 8 knots between locations when at light transit draft. [78]

4.1.1 Technical characteristics

- **Geometry:** The Dimensions and particulars of the vessel are below summarized:

UPPER HULL		
Length of the deck	83,2	m
Breadth of the deck	72,72	m
Height to drill floor	57,15	m
Design draft at operation	21,5-23,5	m
Design draft at survival	21,5	m

Table 4.1- Geometrical characterization of Scarabeo 8(I)

PORTOONS		
Length	118,56	m
Breadth	17,73	m
Depth	10,15	m
Portoons spacing	59,28	m

Table 4.2- Geometrical characterization of Scarabeo 8(II)

SPONSONS		
Length	72,24	m
Breadth	2,5	m
Depth	10,15	m

Table 4.3 - Geometrical characterization of Scarabeo 8(III)

DISPLACEMENT		
Operational Draught	23,5	m
Operational Displacement	62692,3	ton
Survival Draught	21,5	m
Survival Displacement	60319,6	ton
Transit Draught	10	m
Transit Displacement	40001	ton

Table 4.4 - Geometrical characterization of Scarabeo 8(IV)

- **Wind:** The vessel wind design follows:

SUSTAINED WINDS		
Period (sec)	V10(m/s)	highs(m)
60	55	10
30	70	10

Table 4.5- Wind design of Scarabeo 8

- **Wave:** The design sea states in survival condition allow, according to Class rules, maximum wave heights of 32 m based on 100-years sea states. The wave period range is from 3 to 30 second according to the Class recommendation.
- **Fatigue:** The hull is designed to support a fatigue life of 20 years.
- **Drilling Depth**: The maximum drilling depth (including the water depth) is designed to be 10660 m (35000 ft).
- **Positioning system:** Positioning is performed with thrusters assisted mooring system for depth in the range of 70-600 m and with DP (dynamic positioning) for depth between 250-3000m.
- **Vessel Motions and operational limits:**

Operation	Pitch/Roll MAX deg. sigle amplitude	Max heave Double amplitude [m]	Wind [m/s] (10 min average)	Current [m/s] (10 min average)
BOP(LMRP handling	3	3	20	n/a
XT handling	3	3	20	n/a
Running and retrieving riser	3	3	20	0,6
Disconnect LMRP	6,5	9	n/a	n/a
Reconnect LMRP	2,5	2	20	0,6
Land BOP	2,5	2	20	0,6
Disconnect BOP	3	2,5	20	0,6
Running casing	3	3	15	0,5 (n/a in riser)
Riserless drilling	5	6	25	0,6
Drilling through riser	5	6	25	0,7

Table 4.6- Vessel motion characterization

- **Tanks capabilities:**

Ballast in pontoons and columns		
Fuel oil tanks	3313	m^3
Potable water	775	m^3
Drill water tanks	1522	m^3
Brine tanks	841,2	m^3
Base oil tank	254,7	m^3
Liquid mud	1097	m^3

Table 4.7- Tanks capabilities

- **Positioning system:** The mooring system is composed by 8 chains with anchors 2400 m long. The thruster's systems is composed by 8 Wärtsilä/Lips LMT steerable thrusters. The control is provided by the Kongsberg Maritime K-POS-DPM 32 triple redundant dynamic positioning and position mooring system.
- **Drilling systems:**
  - -Dual derrick dynamic type 52 m highs with a dynamic hook load of 1000 t
  - - Bop stack by Cameron. Inner diameter 18 ¾", nominal pressure 15.000 psi.
  - -Riser system by Cameron Iron Works. Riser joints: Type LK 21" 75 ft x 21" OD w/buoyancy modules Telescopic Joint: 60' stroke.
- **Winterization:** Scarabeo 8 is fully winterized according what is required by NMD and by Norwegian standard NORSOK 002for winter operation in the Barents Sea.

4.2 *ENVIRONMENT DESCRIPTION*

The analysis has been developed on the base of the position and environment where Scarabeo 8 is nowadays drilling.

The drilled field is Goliath in the Norwegian sector of Barents sea and the water depth is 321 m (1053 ft). It is

Figure 4.2- Scarabeo 8 actual position. Source: Marinetraffic

located 85 km (53 miles) northwest of Hammerfest. The license owned by Eni Norge AS (operator, 65%) and Statoil Petroleum AS (35%). It was awarded in 1997 and firstly the oil was discovered in 2000 [79]. The field development concept was approved by the Government of Norway on 8 May 2009 [80].
The project for the field production shows that the field will be developed by using Goliat FPSO, a floating production storage and offloading unit.
Goliat field has two main formations (Kobbe and Realgrunnen) and two minor formations (Snadd and Klappmyss) [81].
Recoverable reserves are estimated to be 174 million barrels (27.7×10^6 m^3) [79] .
The production is expected to start in 2013 and will continue for 10–15 years. The associated gas will be reinjected to increase oil recovery or will be transported to the processing plant at Melkøya where the most important European LNG production plant is located. [82]

Met-ocean conditions are given in ref (Saipem Energy service, Met-ocean design parameter for Goliath field). These are composed by the wave condition and the current profile in function of depth. (Table 4.8, Table 4.9).
In all the models random wave analysis is used for all the wave condition with the exception of the sensitive analysis that has been made on both regular and random wave analysis.
The wave spectral density is modelled by means of the three parameter JONSWAP spectrum (i.e. H_S and T_P). The description of the Jonswap spectrum is beyond this paper purpose but more can be found in the Appendix A: JONSWAP spectrum.

1-yearCurrent					
Depth below mean water line [m]	Velocity [m/s]	Direction [deg]	Depth below mean water line [ft]	Velocity [ft/s]	Direction [deg]
0	0,60	0,00	0	1,97	0,00
1,5	0,6	0,00	4,921245	1,97	0,00
54	0,57	0,00	177,16482	1,87	0,00
134	0,56	0,00	439,63122	1,84	0,00
214	0,53	0,00	702,09762	1,74	0,00
294	0,5	0,00	964,56402	1,64	0,00
321	0,46	0,00	1053,14643	1,51	0,00

10-yearCurrent					
Depth below mean water line [m]	Velocity [m/s]	Direction [deg]	Depth below mean water line [ft]	Velocity [ft/s]	Direction [deg]
0	0,75	0,00	0	2,46	0,00
1,5	0,75	0,00	4,921245	2,46	0,00
54	0,63	0,00	177,16482	2,07	0,00
134	0,62	0,00	439,63122	2,03	0,00
214	0,59	0,00	702,09762	1,94	0,00
294	0,57	0,00	964,56402	1,87	0,00
321	0,56	0,00	1053,14643	1,84	0,00

Table 4.8- Marine current profiles

1-yearWave			
Amplitude (Hs) [m]	Period (Tp) [s]	Amplitude (Hs) [ft]	Period (Tp) [s]
10,6	14,40	34,776798	14,40
11,5	9,5	37,729545	9,50
10-yearWave			
Amplitude (Hs) [m]	Period (Tp) [s]	Amplitude (Hs) [ft]	Period (Tp) [s]
13,1	15,90	42,978873	15,90
12,5	10,5	41,010375	10,50
100-yearWave			
Amplitude (Hs) [m]	Period (Tp) [s]	Amplitude (Hs) [ft]	Period (Tp) [s]
15,6	17,20	51,180948	17,20

Table 4.9- Wave conditions; Jonswap spectrum

4.3 RISER DESCRIPTION

The riser is a key element for offshore drilling. A drilling riser is a conduit that provides a temporary extension of a subsea oil well to a surface drilling facility. Drilling risers are categorized into two types: marine drilling risers used with subsea blowout preventer (BOP) and generally used by floating drilling vessels; and tie-back drilling risers used with a surface BOP and generally deployed from fixed platforms or very stable floating platforms like a spar or tension leg platform (TLP). [1]

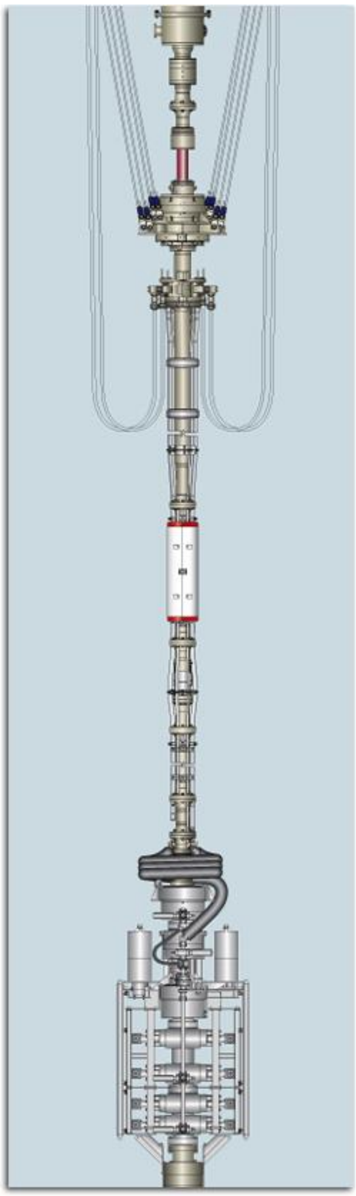


Figure 4.3 -Riser model. Source: drillqiuip.com

The main functions of a riser string are:

- Provides a fluid communication between the wellbore and the drilling vessel. The communication is obtained through the riser annulus during normal drilling operation and through the choke and kills line under well control operations.
- Guide the pipes, tools and casings in the well.
- Support the auxiliary line for BOP electrical and hydraulic supplying. [83]

The riser is composed by different elements and joints:

- **Diverter**: it is an annular preventer with a large piping system underneath and it is utilized to divert the kick from the rig. The large diameter pipe typically has two directions diverting the wellbore fluid out of the rig. In offshore applications it is located above the water line on the hydrostatic mud line.
- **Telescopic joint**: this is a key tool to guarantee riser stability; in fact it decouples the vessels fluctuation caused by the surface waves with the riser string. Moreover the telescopic joint’s outer barrel provides structural resistance for riser tensioner loads.

- **Tensioners**: used to apply vertical force to the riser in order to control its internal stresses, that must be always positive (traction stress), and its displacement. The tensioners are placed under the diverter connected with the slip ring on the telescopic joint.

- **Flex joints:** allow misalignment between the riser and the vessel and between the riser and the BOP thereby reducing the bending moment on the string. They are characterized by the rotation stiffness that is a non-linear function of the angle and generally is in the range of 10.000-30.000 ft-lb/deg (13,5- 40,7 kNm/deg)

- **Riser joints:** a riser joint is the riser main tube with a large diameter and a high strength that can be seamless or electric welded. During the riser string deployment the joints are coupled till the achievement of the seabed level.

- **Buoyant joints**: the number of buoyant joint is strictly dependent on the water depth and therefore they can be from the 40% up to 90% of the riser string. They are used to reduce the amount of tension required to maintain stability of the riser to make the riser close to neutrally buoyant when submerged.

- **Pup joints**: shorter joints of variable length that must be available to accommodate riser length and space-out according to the water depth and the operational draft.

- **Auxiliary lines:** mainly choke/ kill hydraulic and optical lines that on most of the risers pass through the riser support shoulder.

  -Choke & kill lines are used to provide well control when the blow out preventer stack is closed.

  -Mud boost line is a conduit line for drilling fluid that is

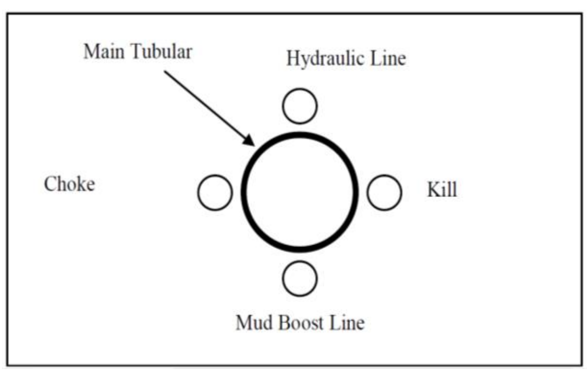


Figure 4.4- Auxiliary lines layout

pumped above the BOP stack to increase the fluid circulation.
-Hydraulic supply to control the subsea valves and the BOP shears.

- **LMRP** (low marine riser package): it is an assemblage that generally includes riser connectors, lower flex joint, subsea control pods, hydraulic accumulators, lower and upper annular preventers and a connector with the BOP. The LMRP provides a releasable connection with the BOP stack and controls the hydraulic systems through the control pods.

- **BOP stack** (blow out preventer): it is a large assemblage that is positioned between the LMRP and the wellhead connector. It is generally composed by hydraulic lines and blind rams.
  Together with the LMRP it forms the BOP system that are used to monitor and control oil and gas well fluid pressure, confine well fluids to the wellbore, centre and hang off the drill string in the wellbore and shut in the well in case of disconnection or of a kick. BOP is a critical element to the safety of crew, the rig, the environment and the well integrity. [84]

4.4 DESIGN ACCEPTANCE CRITERIA (API 16 Q)

The riser analysis was driven in accordance with design code suggested in API 16Q and has been divided in three macro-steps: Model and Data input in the software, Simulation running, output interpretation and stability & safety parameters control.

4.4.1 Data input in DeepRiser software.

The riser modelling is divided in *geometrical and physical elements characterization* by consulting the user manual of the riser and BOP constructor and *physical working parameters input* defined with specific calculation suggested by the regulations.
The working parameters calculated are the *riser string length* that defines the telescopic stroke and the *working tension* to be applied to the tensioner in order to have stability.

a. **Telescopic stroke -** the length of the riser string was calculated guaranteeing the maximum safety at the telescopic joint. The Effective stroke in condition of zero-waves has been set to be 27,97 ft (8,53 m) that corresponds to the 50,85 % of the maximum stroke guaranteed by the constructor. This parameters choice allows the vessel to keep on drilling mode for equal conditions on wave-peak or wave-downstream when forced by sea movements.

b. **Riser tensioner limits –** the tension limits are calculated respecting the minimum (T_{min}) and maximum (T_{max}) allowable tension. The limit tensions are based on the capacity limits described below:

I. **T_{min}** must respect the following criteria:

- No compression strain is allowed in the riser string. This is connected to the riser stability that under compression loads may fail and as beam fall into Buckling instability.
- The Minimum over-pull must be on a virtual level below the LMRP and BOP connection. This condition must fulfil the Hang-off design criteria and guarantee a minimum tension able to support the riser string and LMRP weight load during a quick disconnection.
- One of the six direct tensioners may fail. In this situation all the other tensioners must support all the loads without exceeding the LFJ or UPJ limits and guaranteeing a positive tension to the string.

The minimum top tension T_{min} is determined by: Formula 1,2,3

$$T_{min} = \frac{T_{SRmin} \times N}{RF \times (N-n)} \tag{1}$$

$$T_{SRmin} = W_s f_{wt} - B_n f_{bt} + W_{m-w} \tag{2}$$

$$W_{m-w} = A_i (d_m H_m - d_w H_w) \tag{3}$$

T_{min}	Minimum top tension
T_{SRmin}	Minimum slip ring tension
N	Number of tensioner supporting the riser

n	Number of tensioners subject to sudden failure
RF	Reduction factor relating vertical tension at the slip ring to tensioner setting to account for fleet angle and mechanical efficiency (0.9-0.95)
W_s	Weight of submerged riser
f_{wt}	Submerged weight tolerance factor (min=1.05)
B_n	Net lift of buoyancy material
f_{bt}	Buoyancy loss and tolerance factor resulting from elastic compression, long term water absorption and manufacturing tolerance (max=0.96)
W_{m-w}	Weight of submerged mud
A_i	Internal cross sectional area of riser including choke and kill
lines	
d_m	Mud density
H_m	Mud column to point of consideration
d_w	Sea water density
H_w	Sea water column to point of consideration

II. $\mathbf{T_{max}}$ must respect the following criteria:

- Maximum tensioner capacity 3500 kips (1587,6 tonnes) cannot be exceeded.
- API maximum allowable tension =0,9*DTL=0,9*3500 kips=3150 kips (1428,8 tonnes)
- The wellhead tension must be negative (compression strain) $T_{belowBOP} \leq 0$ in order to guarantee a stable connection between the BOP and the wellhead through the connector.

4.4.2 Simulation running.

Three different simulation modes are performed: *static*, *dynamic without waves and dynamic with waves*.

The *static* mode performs a simulation neglecting the waves and marine current interaction with the vessel and the riser string. This simulation performs a weight analysis and gives as output the relation between the minimum tension for stability and the mud density both for a working or disconnect scenario. The results given by the software have been compared with the calculated parameters in order to check the solidity of the model.

Dynamic without waves mode performs a simulation considering the riser-current interaction. This first step simulation is useful to understand the riser string solidity in a steady state condition.

Dynamic with waves is the most complete analysis and considers also the wave-vessel interaction. Because of its transient nature the software performs it in a time domain analysis. The first exploits a classic finite element method with time and space variables, the second uses instead Fourier transformations for both periodic or non-periodic waves. A comparison between the two analyses shows a considerable time performance of the second solution that instead cannot be represented by a video-simulation because of its frequency dimension.

4.4.3 Software output interpretation and key parameters control:

As suggested by the standards the key parameters to be controlled are the riser stress, the lower and upper flex joint angles both in a working and disconnect scenario.

In order to understand the riser condition three different operating modes are generally analysed:

a. **Drilling mode** – it can be performed when the environmental load cases and well condition allow a safe drilling respecting the design limits.

b. **Connected non drilling mode** –this mode is the first alert situation and the only operation allowed are circulating and tripping out drill pipes. Any rotation must be avoided and the riser may be displaced with seawater and prepared to disconnection after the well shut in if necessary. Under this circumstance the riser is filled with seawater and therefore the loads change by changing the inner fluid density. The tensioner must be able to support the weight changes during this phase.

c. Disconnected mode – performed when environmental conditions exceed the limit for safe operation. It this case the riser and the LMRP must be disconnected to avoid any possible damage to subsea or surface equipment. A possible example of the scenario is the failure of all the ice-management control systems during an arctic drilling performance.

The Table 4.10 explains the design and operating guidelines.

DESIGN PARAMETERS	RISER CONNECTED		RISER DISCONNECTED
	DRILLING	NON DRILLING	HANG OFF
Mean flexjoint angle (upr&lwr)	2 .0 deg	N/A	N/A
Max flexjoint angle (upr&lwr)	4.0 deg	90% available	90% available
Allowable stress	0,4*σ_{YS}	0,67*σ_{YS}	0,67*σ_{YS}
Minimum top tension	Tmin	Tmin	N/A
Dynamic tension limit	DTL	DTL	N/A
Max tension setting	90% DTL	90% DTL	N/A

Table 4.10- API design criteria

4.5 RISER ANALISYS

4.5.1 DEEPRISER SOFTWARE DESCRIPTION

The riser analysis has been conducted using DeepRiser software.
DeepRiser is designed as an integrated software suite for design and analysis of deepwater drilling risers and spar and TLP top-tensioned risers (TTRs).
The program has been designed as a specialized engineering tool based on a finite element analysis package. It combines analytical capabilities with a simplified GUI (Graphical User Interface). Data is input in a classic riser design form and the software automates many of the tasks associated with generating the finite element mesh , running analyses, including multiple load cases, and obtaining results in a report-ready format.
DeepRiser models are composed of building blocks known as components. Components are used to store all project data, including riser data, vessel data, environmental data and analysis data. Components are designed to be as modular as possible and higher-level components generally reference lower-level components.

Figure 4.5 shows the possible component hierarchy for a drilling riser analysis. [85]

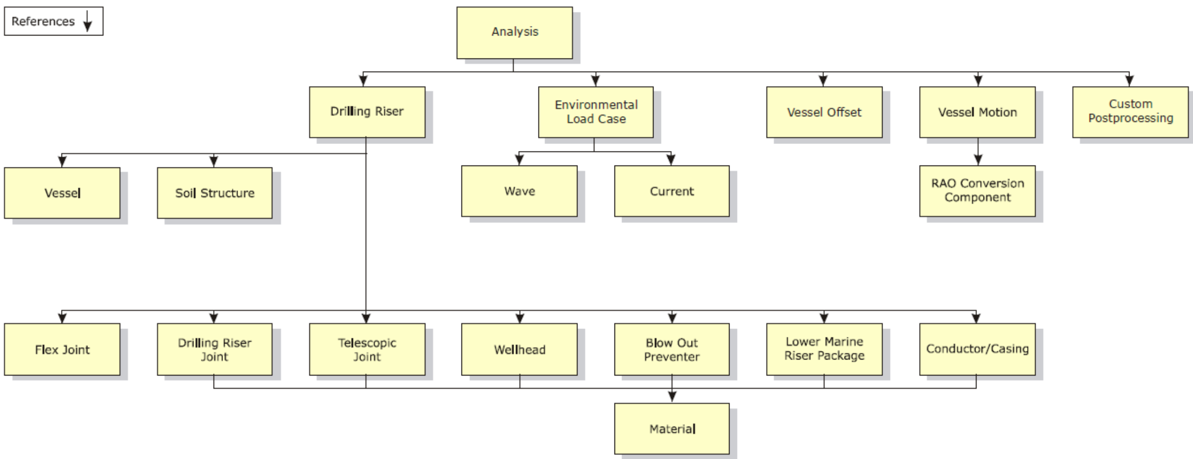


Figure 4.5- DeepRiser hierarchy

The available components that must be fully defined as boundaries conditions to run the drilling riser analysis are:

- Drilling riser joints
- Telescopic joints
- BOP
- LMRP (Lower marine riser package)
- Wellhead Connector
- Tensioner
- Subsea tree
- Seabed connection
- Environmental conditions and soil structure
- Vessel characteristics (RAO) and motion [85]

4.6 SYSTEM DESCRIPTION

The analysis describes the results of a drilling riser analysis for semisubmersible drilling rig Scarabeo 8 for the Goliath campaign.
Riser component geometry and properties are given by Cameron and vessel, environmental and fluids data are given by Saipem.

The analysis is based on the following steps:

- Five different riser string configurations were modelled with different mechanical and buoyant characteristics. The tensioner system was adapted to the different load cases in order to respect the limits suggested by API 16 Q.
- The Static analysis was run for each case and the key parameters described above (UFJ, LFJ, VM, Top tension) were compared in order to define the best riser configuration with minimum UFJ/LFJ angles or minimum Von Mises stress. A trade-off between these two behaviours is well known; therefore two of the best strings were considered the best configurations.
- The dynamic analysis was run for the best configuration in a dynamic drilling mode and in a hard hang off mode.
- A sensitivity analysis was run on the most stable configuration elected to be the best in every environmental condition.
  The Sensitivity has described the string and vessel behaviour by modelling the waves changing two parameters: wave's characteristic height (H_S) and wave's characteristic period (T).

4.6.1 VESSEL MOTION MODELING

The vessel behaviour modelling is based on the RAO (Response on Amplitude Operator) that is used to determine the likely behaviour of a ship when subject to external marine forces.
The RAO are usually experimentally obtained from models of proposed ship design tested in a model basin or from running specialized CFD (Computational Fluid Dynamics) computer simulators.
RAOs are effectively transfer functions used to determine the effect that a sea state will have upon the motion of a ship and its stability.
In Figure 4.6 the six degrees of freedom of a vessel are represented.

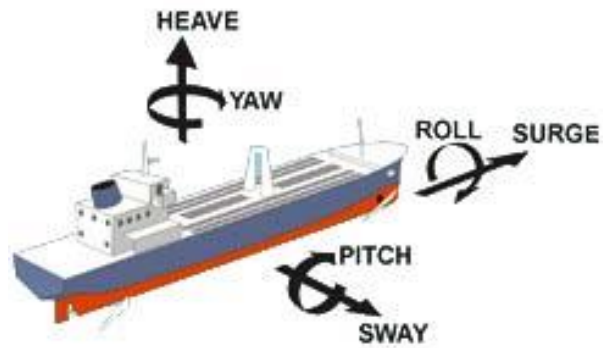


Figure 4.6- Vessel degrees of freedom. Source: km.kongsberg.com

The RAOs plots are divided in amplitude and phase plot. They show the behaviour of the studied vessel subject to a unitary force (or normalized on the force module).

These plots are particularly useful because they show the critical period of the external force that may drive the system to instability.

It is notable that a semisubmersible vessel has peculiar stability properties with a wave's stream that impacts the vessel with a head of 90° because of its squared shape that uniforms the vessel stability for every wave's head.

Scarabeo 8 RAOs are plotted in figure from Figure 4.7 to Figure 4.18.

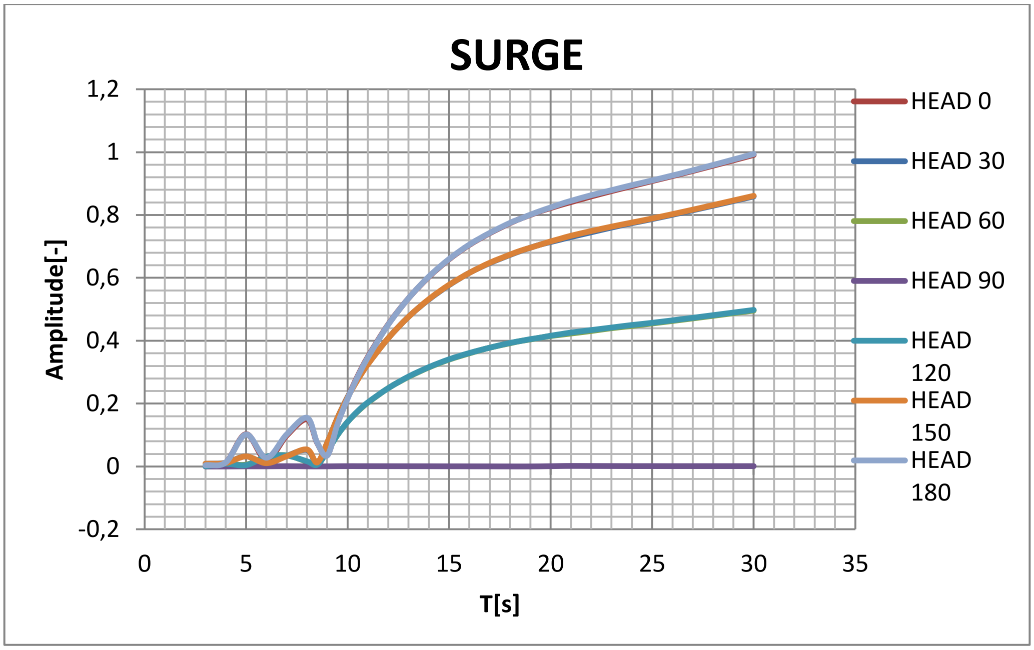


Figure 4.7- SURGE frequency response amplitude

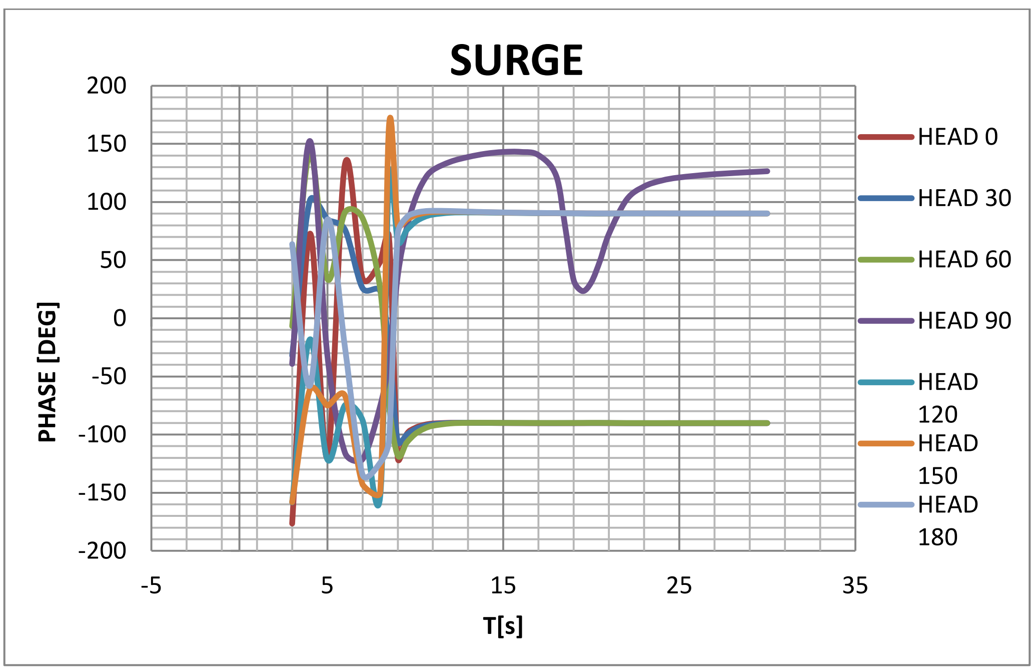


Figure 4.8- SURGE frequency response phase

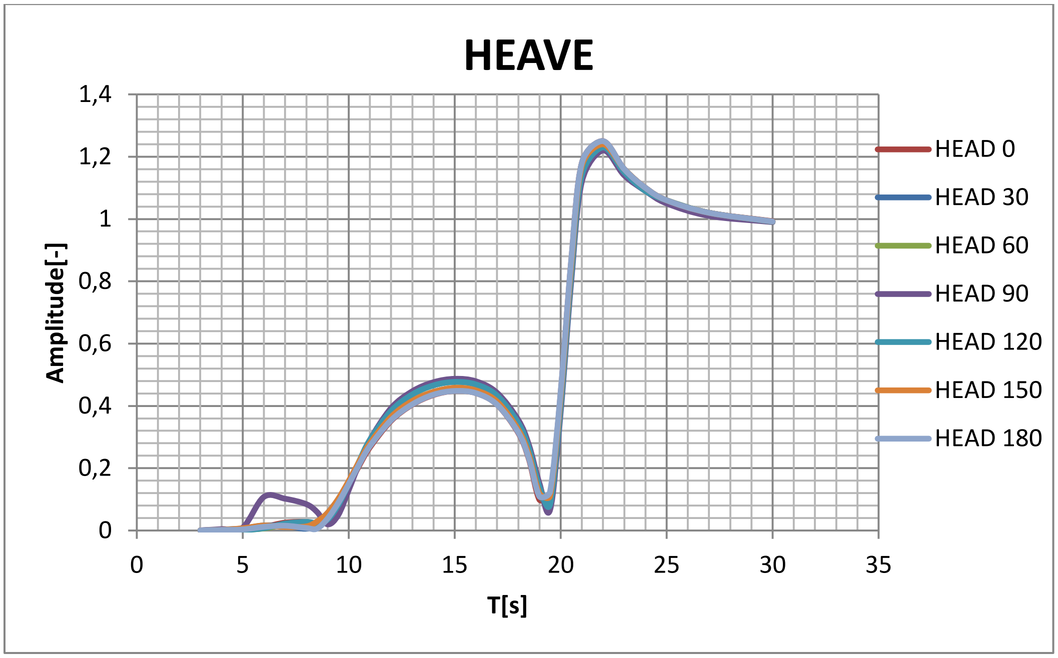


Figure 4.9 - HEAVE frequency response amplitude

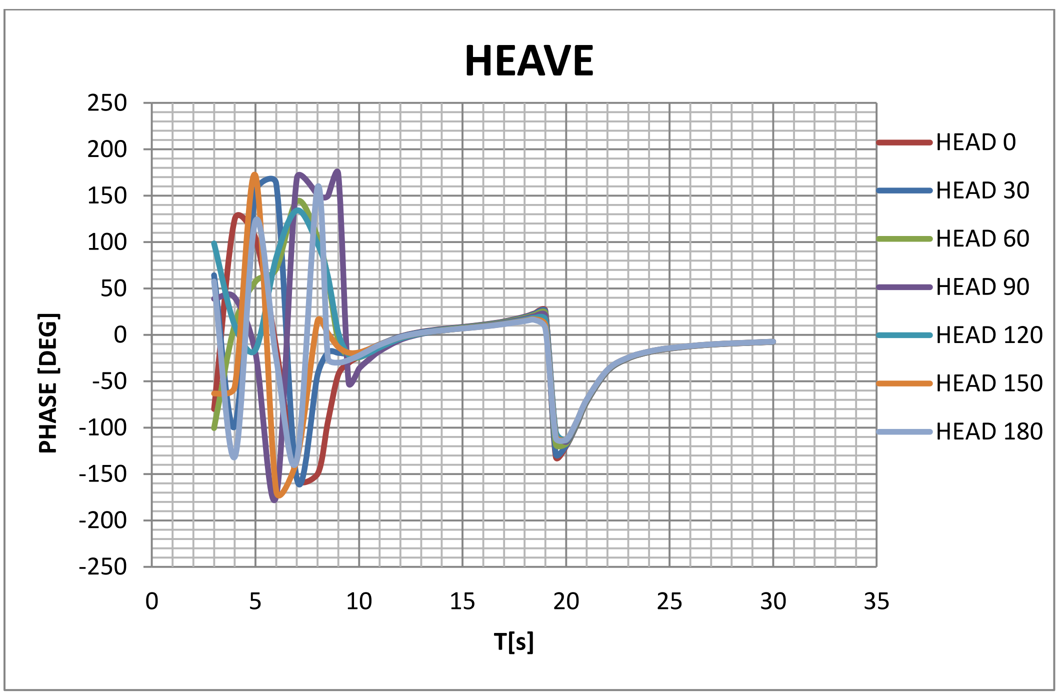


Figure 4.10- HEAVE frequency response phase

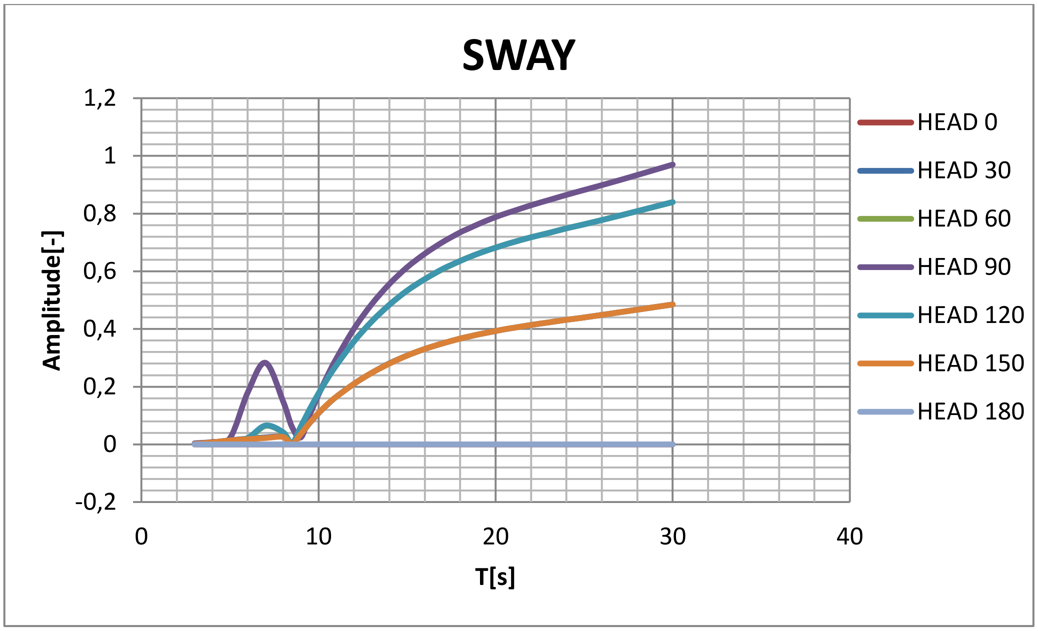


Figure 4.11 - SWAY frequency response amplitude

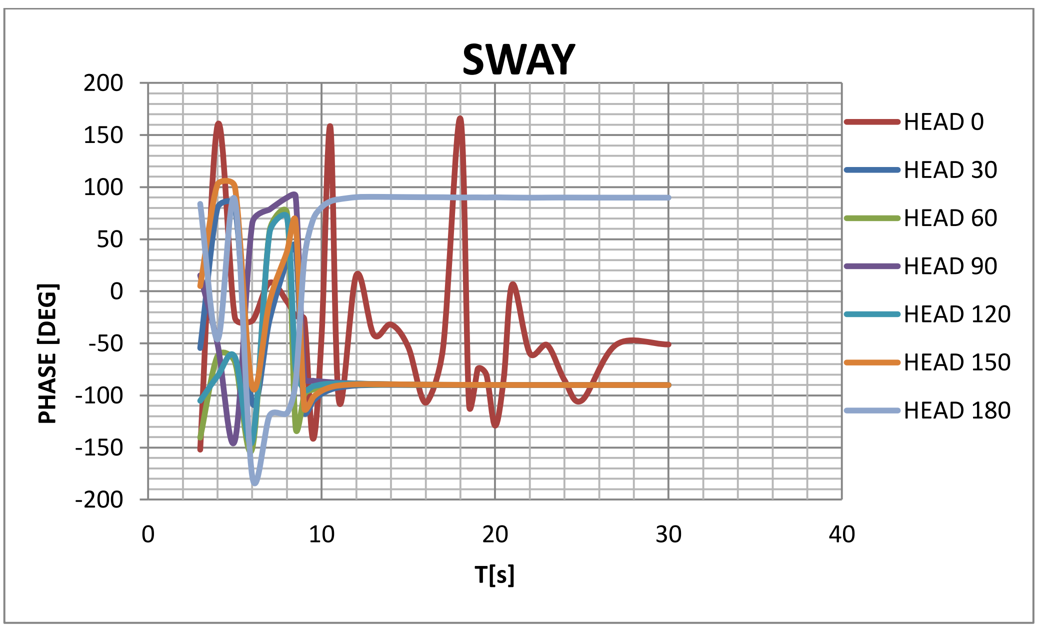


Figure 4.12- SWAY frequency response phase

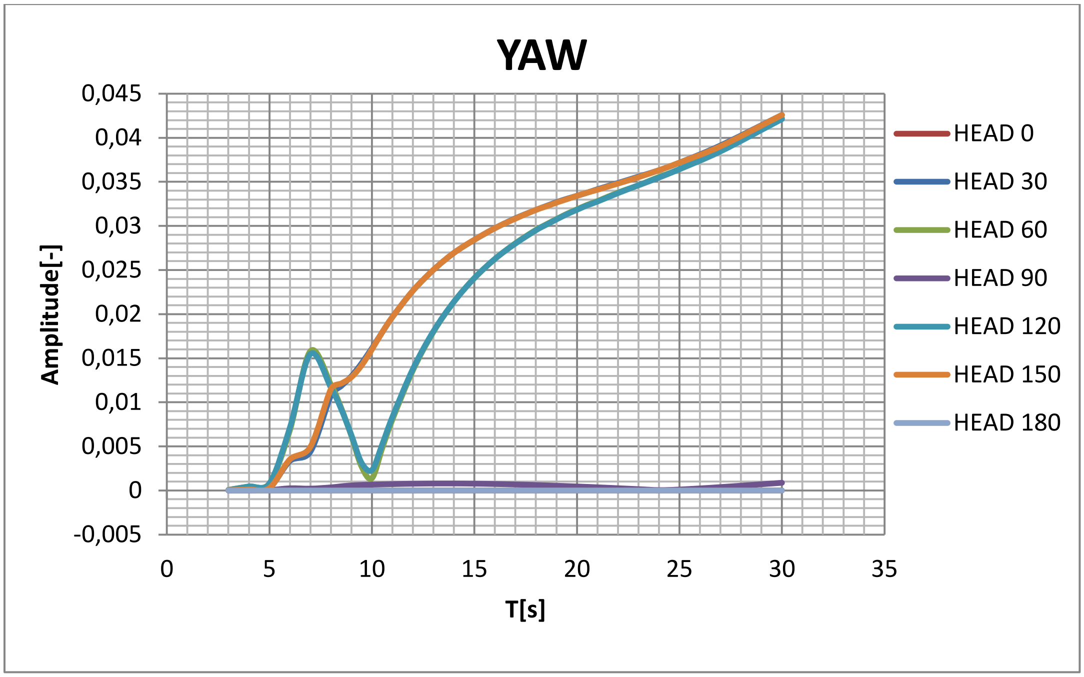


Figure 4.13- YAW frequency response amplitude

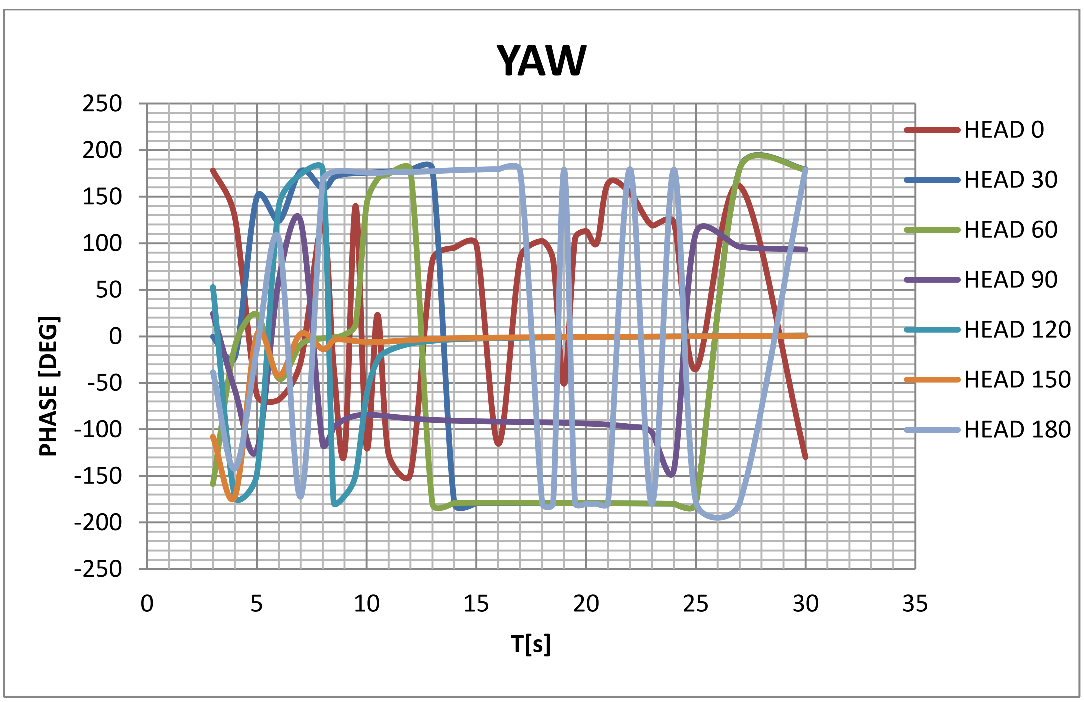


Figure 4.14- YAW frequency response phase

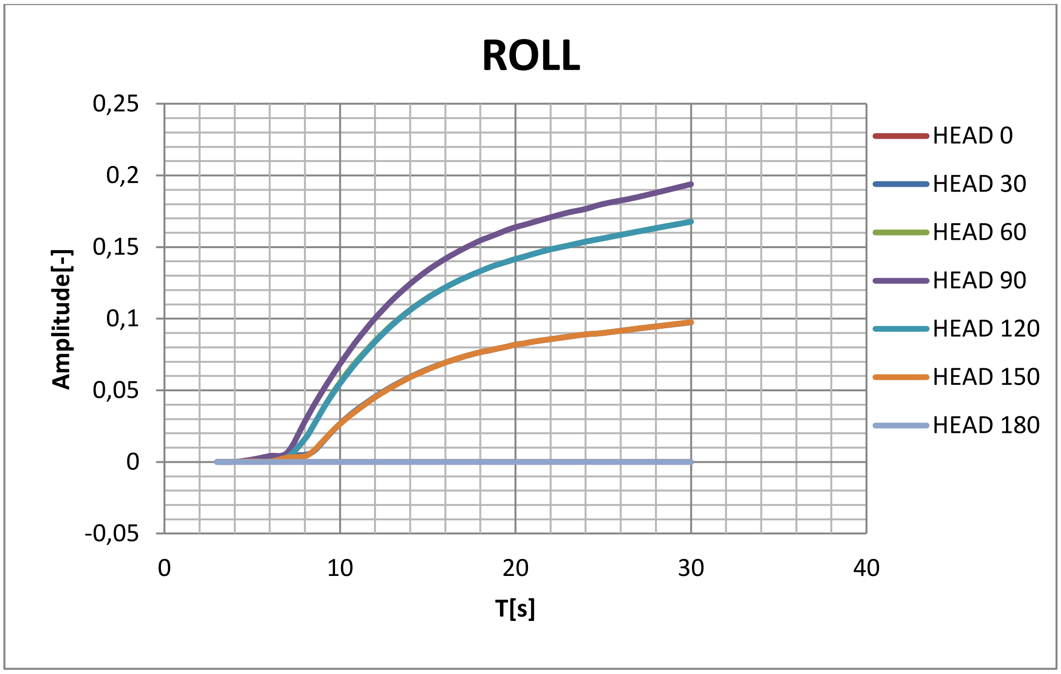


Figure 4.15- ROLL frequency response amplitude

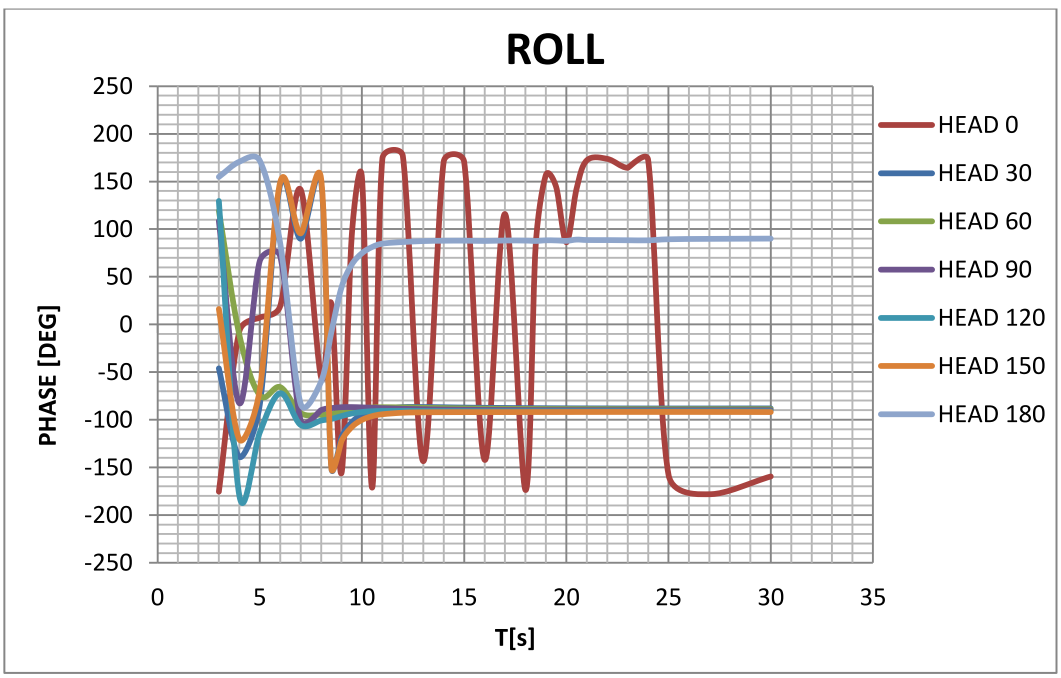


Figure 4.16- ROLL frequency response phase

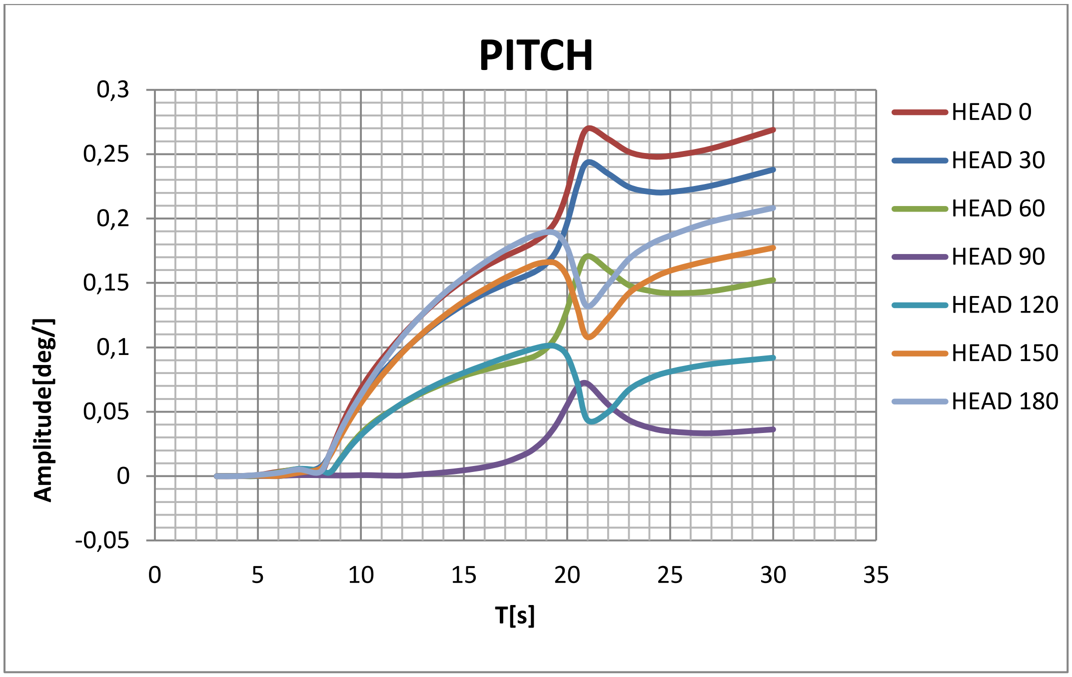


Figure 4.17-PITCH frequency response amplitude

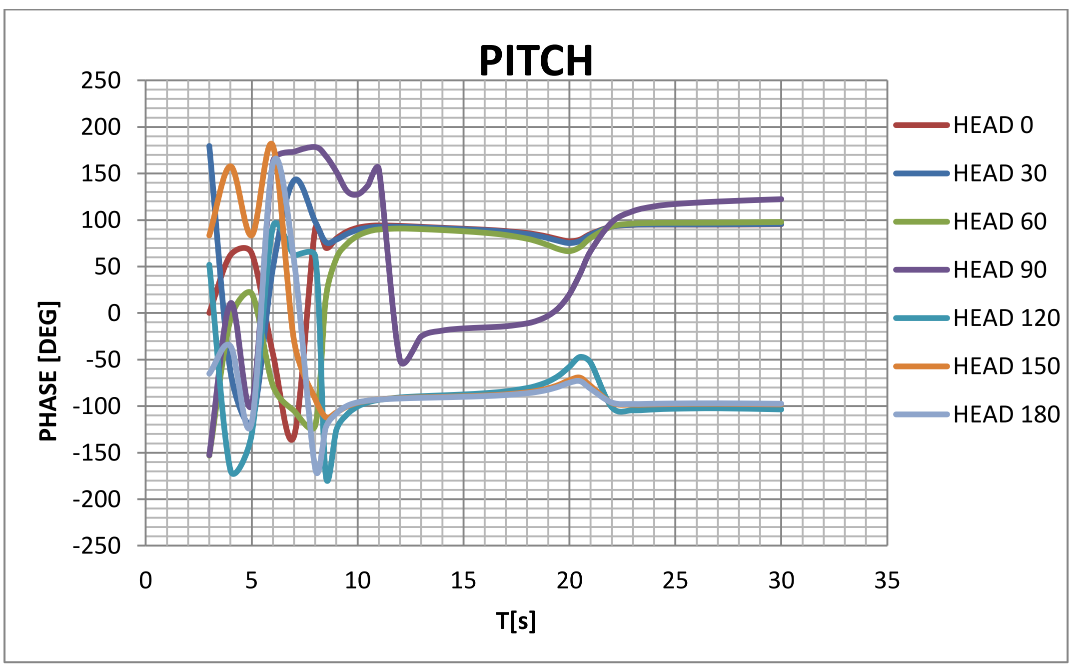


Figure 4.18- PITCH frequency response phase

4.6.2 RISER MODELING

Five riser make-up configurations are modelled to check what the main concern between vessel motion, load cases and riser stability during drilling at these depths is.

- **N°1 Configuration**: it is characterized by the presence of 10 blue buoyancy (usable till 3000’) joints in the middle and 4 slick thin joints. The design was modelled to decrease the load applied to the tensioner and the string itself.
  The main string features are reported in the Table 4.11

Riser Stack-Up & Particulars

Joint Name	No.	Main Tube Inner Diameter (in)	Joint Length (ft)	Elevation to Bottom of Joint (ft)	Dry Weight of Section (kips)	Wet Weight of Section (kips)
BOP	1	18.75	28.78	3.00	393.27	343.16
LMRP	1	18.75	14.64	31.78	190.18	165.95
Lower Flex Joint	1	0.00	10.65	46.42	30.00	26.18
PUP JOINT 25'	1	19.50	25.00	57.07	17.38	15.16
PUP JOINT 5'	1	19.50	5.00	82.07	5.68	4.95
Drilling Riser Joint 1 - SLICK (THIN)	2	19.50	75.00	162.07	61.08	53.30
Drilling Riser Joint 3 - BLUE 3000'	10	19.50	75.00	912.07	823.26	-129.67
Drilling Riser Joint 1 - SLICK (THIN)	2	19.50	75.00	1062.07	61.08	53.30
Telescopic Joint_OB	1	22.75	70.00	1137.07	84.04	73.33
Telescopic Joint_IB	1	19.75	60.00	1207.07	4.59	4.00
Upper Flex Joint	1	0.00	8.31	1240.04	11.50	10.03

Table 4.11- N°1 riser configuration layout

- **N°2 Configuration:** it is similar to the first string with the difference that the solidity was increased by using 10 thin slick joints with guards. This particular layout is connected with the special artic environment were the vessel may work. The presence of a harsh environment and the relative small water depth has driven the designer to choose a guard protection instead of buoyancy.
  The main riser features are reported in the Table 4.12.

Riser Stack-Up & Particulars

Joint Name	No.	Main Tube Inner Diameter (in)	Joint Length (ft)	Elevation to Bottom of Joint (ft)	Dry Weight of Section (kips)	Wet Weight of Section (kips)
BOP	1	18.75	28.78	3.00	393.27	343.16
LMRP	1	18.75	14.64	31.78	190.18	165.95
Lower Flex Joint	1	0.00	10.65	46.42	30.00	26.18
PUP JOINT 25'	1	19.50	25.00	57.07	17.38	15.16
PUP JOINT 10'	1	19.50	10.00	82.07	9.00	7.86
Drilling Riser Joint 1 - SLICK (THIN)	4	19.50	75.00	317.07	122.16	106.60
Drilling Riser Joint 1 - SLICK (THIN)+ GUARD	6	19.50	75.00	767.07	230.04	159.75
Drilling Riser Joint 1 - SLICK (THIN)	4	19.50	75.00	1067.07	122.16	106.60
Telescopic Joint_OB	1	22.75	70.00	1142.07	84.04	73.33
Telescopic Joint_IB	1	19.75	60.00	1212.07	4.59	4.00
Upper Flex Joint	1	0.00	8.31	1240.04	11.50	10.03

Table 4.12- N°2 riser configuration layout

- **N°3 Configuration:** it is designed as the first string but all its joints are thick. This choice increases the solidity of the joints and minimizes the VM-stress along the string. The trade-off bring the string to be more heavy and this will influence on the top tension and the UFJ/LFJ angles.
  The main riser features are reported in the Table 4.13.

Riser Stack-Up & Particulars

Joint Name	No.	Main Tube Inner Diameter (in)	Joint Length (ft)	Elevation to Bottom of Joint (ft)	Dry Weight of Section (kips)	Wet Weight of Section (kips)
BOP	1	18.75	28.78	3.00	393.27	343.16
LMRP	1	18.75	14.64	31.78	190.18	165.95
Lower Flex Joint	1	0.00	10.65	46.42	30.00	26.18
PUP JOINT 25'	1	19.50	25.00	57.07	17.38	15.16
PUP JOINT 5'	1	19.50	5.00	82.07	5.68	4.95
Drilling Riser Joint 1 - SLICK (THIN)	2	19.50	75.00	162.07	61.08	53.30
Drilling Riser Joint 3 - BLUE 3000'	10	19.50	75.00	912.07	823.26	-129.67
Drilling Riser Joint 1 - SLICK (THICK)	2	19.50	75.00	1062.07	63.28	54.02
Telescopic Joint_OB	1	22.75	70.00	1137.07	84.04	73.33
Telescopic Joint_IB	1	19.75	60.00	1207.07	4.59	4.00
Upper Flex Joint	1	0.00	8.31	1240.04	11.50	10.03

Table 4.13- N°3 riser configuration layout

- **N°4 Configuration:** It is designed with the same purpose of the string N°2. It is similar to string N°3 but the buoyancy joints are replaced with buoyancy with guards.
  The main riser features are reported in Table 4.14.

Riser Stack-Up & Particulars

Joint Name	No.	Main Tube Inner Diameter (in)	Joint Length (ft)	Elevation to Bottom of Joint (ft)	Dry Weight of Section (kips)	Wet Weight of Section (kips)
BOP	1	18.75	28.78	3.00	393.27	343.16
LMRP	1	18.75	14.64	31.78	190.18	165.95
Lower Flex Joint	1	0.00	10.65	46.42	30.00	26.18
PUP JOINT 25'	1	19.50	25.00	57.07	17.38	15.16
PUP JOINT 5'	1	19.50	5.00	82.07	5.68	4.95
Drilling Riser Joint 1 - SLICK (THIN)	4	19.50	75.00	312.07	122.16	106.60
Drilling Riser Joint 1 - SLICK (THICK) + GUARD	6	19.50	75.00	762.07	236.62	165.48
Drilling Riser Joint 1 - SLICK (THICK)	4	19.50	75.00	1062.07	126.56	108.04
Telescopic Joint_OB	1	22.75	70.00	1137.07	84.04	73.33
Telescopic Joint_IB	1	19.75	60.00	1207.07	4.59	4.00
Upper Flex Joint	1	0.00	8.31	1240.04	11.50	10.03

Table 4.14- N°4 riser configuration layout

- **N°5 Configuration:** it is the most particular string and was designed as last with experience of the other simulations. The main features are the thick slick joints on the top and bottom of the riser and 6 thin joints with guard in the central

part of it. The configuration was designed by adding solidity to the upper part of the riser that is subject to the maximum tensile strain and bending moment and lower part of the string subject to bog bending moment.
The main riser features are reported in the Table 4.15.

Riser Stack-Up & Particulars

Joint Name	No.	Main Tube Inner Diameter (in)	Joint Length (ft)	Elevation to Bottom of Joint (ft)	Dry Weight of Section (kips)	Wet Weight of Section (kips)
BOP	1	18.75	28.78	3.00	393.27	343.16
LMRP	1	18.75	14.64	31.78	190.18	165.95
Lower Flex Joint	1	0.00	10.65	46.42	30.00	26.18
Drilling Riser Joint 1 - SLICK (THICK)	4	19.50	75.00	282.07	126.56	108.04
Drilling Riser Joint 1 - SLICK (THIN)+ GUARD	6	19.50	75.00	732.07	230.04	159.75
Drilling Riser Joint 1 - SLICK (THICK)	4	19.50	75.00	1032.07	126.56	108.04
PUP JOINT 25'	1	19.50	25.00	1107.07	17.38	15.16
PUP JOINT 5'	1	19.50	5.00	1132.07	5.68	4.95
Telescopic Joint_OB	1	22.75	70.00	1137.07	84.04	73.33
Telescopic Joint_IB	1	19.75	60.00	1207.07	4.59	4.00
Upper Flex Joint	1	0.00	8.31	1240.04	11.50	10.03

Table 4.15- N°5 riser configuration layout

4.7 *STATIC ANALYSIS*

Two different load cases are considered in the static analysis:

- LOAD CASE N°1 – 10 YEARS CURRENT
- LOAD CASE N°2 – 1 YEAR CURRENT

The Tension to apply to the tensioner was calculated considering to different conditions and then choosing the most conservative between the two results.
The two tension scenarios are:

- Minimum stability tension suggested by API 16Q (see formulas cap 4.4.1)
- Minimum tension for a disconnect scenario. This value of tension is calculated neglecting the possible failure of one of the tensioners and neglecting the reduction and tolerance factors (see formulas cap 4.4.1).This scenario instead add a value of overload tension to the T_{SRmin} (Minimum slip ring tension).(see formula cap 4.4.1)
  The overload was calculated by including the 30% of the total weight of the BOP stack to the tensioner load and it has two main features:

- Enhance the safety coefficient during the drilling mode increasing the stability of the string
- Shift the neutral line of stress close the LMRP-BOP connection and guarantee a fast and safe disconnection in case of emergency.

The results of the Design tension in function of the mud density are plotted below (from Figure 4.19 to Figure 4.23).

- N°1 Configuration:

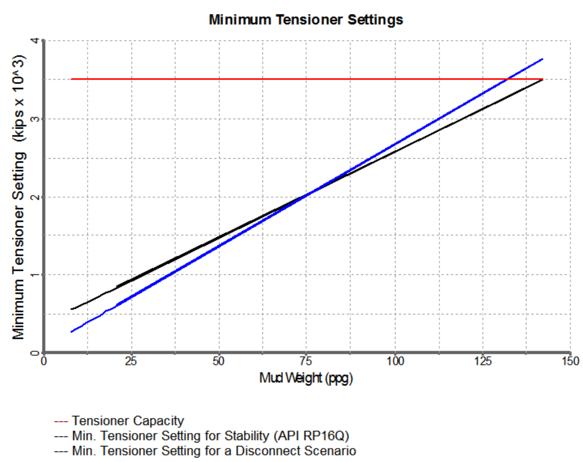


Figure 4.19 – Minimum tensioner setting curves for N°1 riser configuration

- N°2 Configuration:

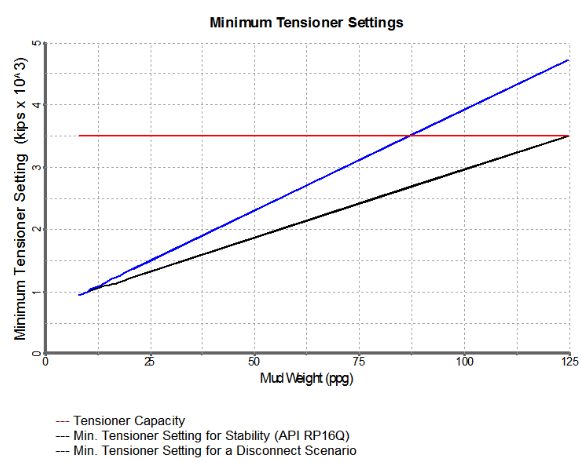


Figure 4.20– Minimum tensioner setting curves for N°2 riser configuration

- N°3 Configuration:

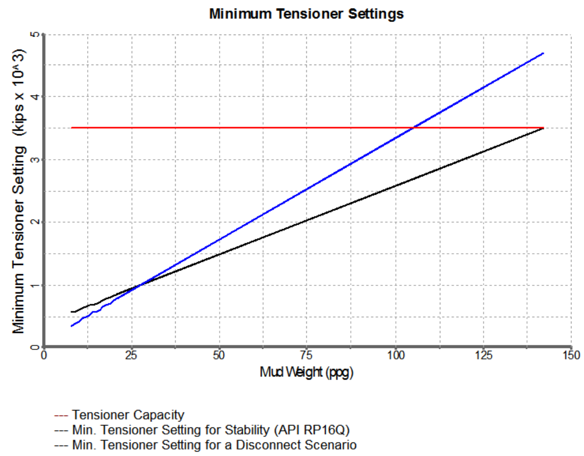


Figure 4.21– Minimum tensioner setting curves for N°3 riser configuration

- N°4 Configuration:

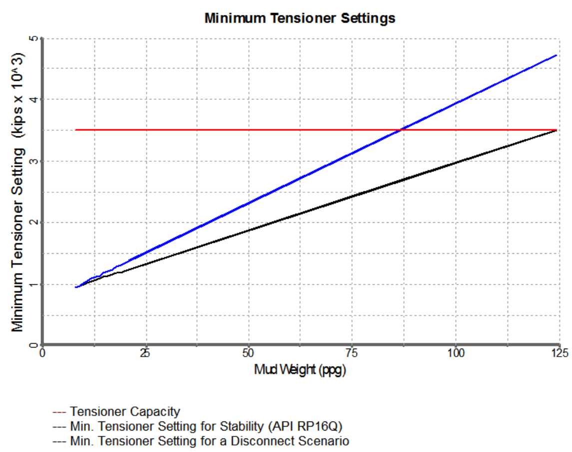


Figure 4.22– Minimum tensioner setting curves for N°4 riser configuration

- N°5 Configuration:

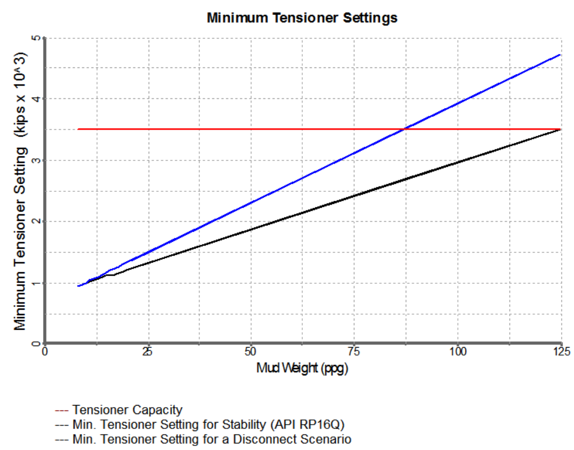


Figure 4.23– Minimum tensioner setting curves for N°5 riser configuration

It is notable that in most of the cases tension suggested by the API 16 Q is enough conservative to overcome T_{SRmin} plus the $T_{overload}$.

The static condition is analysed as a mud filled condition. The maximum mud density used in this field is 11ppg (1332.5 kg/m^3) and therefore the top tension designed is calculated by filling the riser string with this mud. Lower mud weight is less critical and is not taken into consideration in these simulations.
The results of the five simulations are in the Table 4.17 reported.

STATIC DRILLING					
TALLY	LOAD CASE	UFJ rotation (mean)[deg]	LFJ rotation (mean)[deg]	VM [kips]	Min eff. Tension (kips)
1	1	0,675	1,024	11,25	370,76
1	2	0,527	0,819	10,948	370,734
2	1	0,397	0,735	18,556	377,623
2	2	0,312	0,588	18,445	377,607
3	1	0,675	1,022	10,761	371,45
3	2	0,527	0,818	10,587	371,425
4	1	0,395	0,732	17,17	381,047
4	2	0,31	0,585	17,068	381,034
5	1	0,395	0,754	16,324	377,483
5	2	0,31	0,603	16,256	377,469

Table 4.16-Static analysis results (I)

	RESULT			
TALLY	αUFJ/αapi	αLFJ/αapi	VM/Yieald stress	T/Tmax
1	0,3375	0,512	0,140625	0,105931
1	0,2635	0,4095	0,13685	0,105924
2	0,1985	0,3675	0,23195	0,107892
2	0,156	0,294	0,230563	0,107888
3	0,3375	0,511	0,134513	0,106129
3	0,2635	0,409	0,132338	0,106121
4	0,1975	0,366	0,214625	0,108871
4	0,155	0,2925	0,21335	0,108867
5	0,1975	0,377	0,20405	0,107852
5	0,155	0,3015	0,2032	0,107848

Table 4.17- Static analysis normalized results (II)

Analysing these results is clear that the most notable strings are the N°3 and N°5. It is now possible to mark the trade-off between the UFJ/LFJ angle and the stress along the risers.

- The string N°3 shows off the lowest values of stress with a maximum value of 13,4% of the Yield stress. This positive result is due to the thick walls of the risers wall and to the buoyancy that were designed on this string.

- The string N°5 shows off the lowest values of UFJ and LFJ angle. The positive behaviour is due to the solidity of the string in the most stressed sections and of the absence of any buoyancy that enhance the movement of the riser in the current stream.

These two string have resulted to be the best designed and therefore the further analyses are performed neglecting the others strings.

4.8 *DYNAMIC ANALYSIS & OPERATIVE CONDITIONS*

Two different load cases are defined in these simulations:

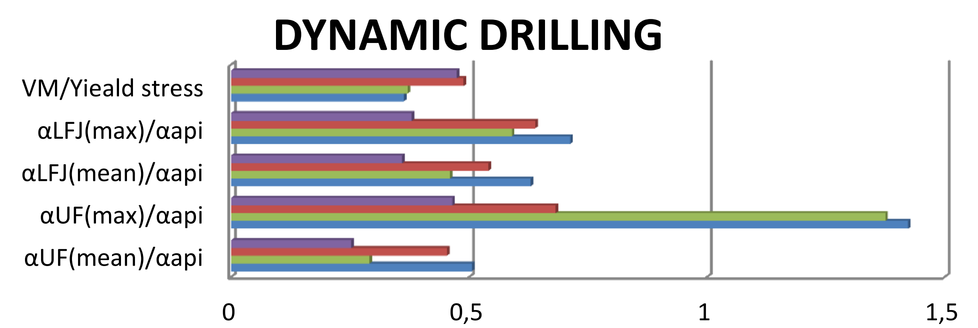
- LOAD CASE N°1 – 100 YEARS WAVES; 10 YEARS CURRENT
- LOAD CASE N°2 – 1 YEAR WAVES; 1 YEAR CURRENT

Note: the load case N°1 is very conservative and not probable; instead the load case N°2 is likely to happen.

4.8.1 Connected

The connected mode simulation is the closest to the real drilling conditions and therefore represents a useful tool to run before any campaign.
Simulations were performed in a Time Domain analysis with random sea based on the Jonswap (appendix A) spectrum of the load cases.
The Tension applied to the tensioners is the same descripted by the static analysis of the cap 4.7.
As in the static conditions the drilling fluid id Mud with a density of 11 ppg (1332.5 kg/m3).

The results of the simulation are in the Table 4.18 reported.



	αUF(mean)/αapi	αUF(max)/αapi	αLFJ(mean)/αapi	αLFJ(max)/αapi	VM/Yieald stress
Tally 5: LOAD CASE 2	0,253	0,465	0,3595	0,38	0,4745625
Tally 3: LOAD CASE 2	0,4535	0,682	0,5405	0,639	0,4888
Tally 5: LOAD CASE 1	0,291	1,37525	0,4595	0,59	0,3708375
Tally 3: LOAD CASE 1	0,506	1,42325	0,6295	0,71275	0,3629875

Table 4.18- Dynamic drilling simulation results

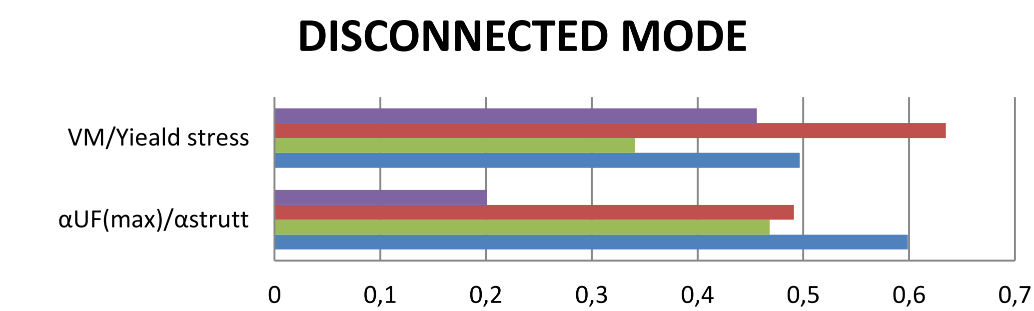
The results show a in every environmental case a better performance of the Riser String N°5 than the N°3. This solution establishes that in this specific drilling environment, characterized by a relatively small water depth, a riser solution composed by thin reinforced slick joints in the central part and slick joints in the

flex-joint-area is the optimal configuration. The buoyant joints under severe condition have a negative effect on the riser stability in this condition.
Moreover the strings in the Load case N°1 show their limits and their weak point represented by the angle deflection of the upper flex joint that exceeds the drilling limit imposed by the API 16 Q that, as shown (in table drilling-non drilling limits), is 4 deg.

4.8.2 Disconnected

Disconnected Hard Hang Off mode is the scenario that might happen when the mechanical characteristics of the riser cannot sustain the environmental conditions.
In Arctic drilling performance this could happen when the first and the second ice management devices have failed.
During disconnection the riser is first filled with seawater. This event changes completely the riser response to the external loads.
Simulations were performed in a Time Domain analysis with random sea based on the Jonswap (appendix A) spectrum of the load cases.
The Tension applied to the are now recalculated from the static analysis by filling the string with seawater with a density of 8,54 ppg (1023 kg/m3).

The results of the simulation are in the Table 4.19 reported.



	αUF(max)/αstrutt	VM/Yieald stress
Tally 5: LOAD CASE 2	0,2008	0,456025
Tally 3: LOAD CASE 2	0,4912	0,634725
Tally 5: LOAD CASE 1	0,468066667	0,340775
Tally 3: LOAD CASE 1	0,5988	0,4965875

Table 4.19- Disconnected mode simulation results

Again, also in disconnected condition scenario, the String N°5 has a better performance even in the internal stress distribution point of view.

The conclusion of the dynamic and disconnected mode simulation is that the String N°5 is the best designed and therefore a sensitivity analysis is driven on it neglecting all the other strings.

4.9 SENSITIVITY ANALYSIS

As previously described, the surrounding environment is modelled in the software with variables as wave's conditions, water depth, and water current.
The only one of them that interacts both with the vessel and the riser is the sea wave condition and moreover is the most stressing external force for the dynamic response of the vessel-riser configuration.
The sensitivity analysis is driven by choosing this parameter and by creating a matrix a between Wave amplitude in the range of 10-55 ft and Peak period in the range of 5-25,5 s. Again the waves are modelled following the Jonswap spectrum model.

The parameters analysed as results are the upper flex joint rotation and the maximum Von Mises stress.
The Table 4.20; Table 4.21 and Figure 4.24; Figure 4.25 show the results.

UFJ rotation (max)[deg]											
		Hs[ft]									
		10	15	20	25	30	35	40	45	50	55
T[s]	5	0,513	0,633	0,766	0,916	1,083	1,266	1,467	1,682	1,913	2,157
	7,5	0,585	0,744	0,911	1,089	1,281	1,484	1,7	1,928	2,168	2,42
	10	0,696	0,903	1,095	1,259	1,463	1,657	1,853	2,051	2,252	2,455
	12,5	0,895	1,192	1,5	1,862	2,214	2,54	2,876	3,2	3,51	3,83
	15	1,069	1,443	1,825	2,208	2,6	3,1	3,6	4,05	4,48	4,9
	17,5	1,16	1,6	2,02	2,45	2,879	3,31	3,74	4,307	4,87	5,406
	20	1,28	1,66	2,114	2,569	3,025	3,48	3,936	4,391	4,847	5,336
	22,5	1,25	1,721	2,2	2,67	3,145	3,621	4,097	4,573	5,049	5,525
	25	1,255	1,731	2,208	2,686	3,165	3,646	4,127	4,608	5,09	5,572
	27,5	1,239	1,707	2,176	2,647	3,12	3,6	4,07	4,55	5,023	5,5

Table 4.20- Upper Flex Joint Maximum rotation

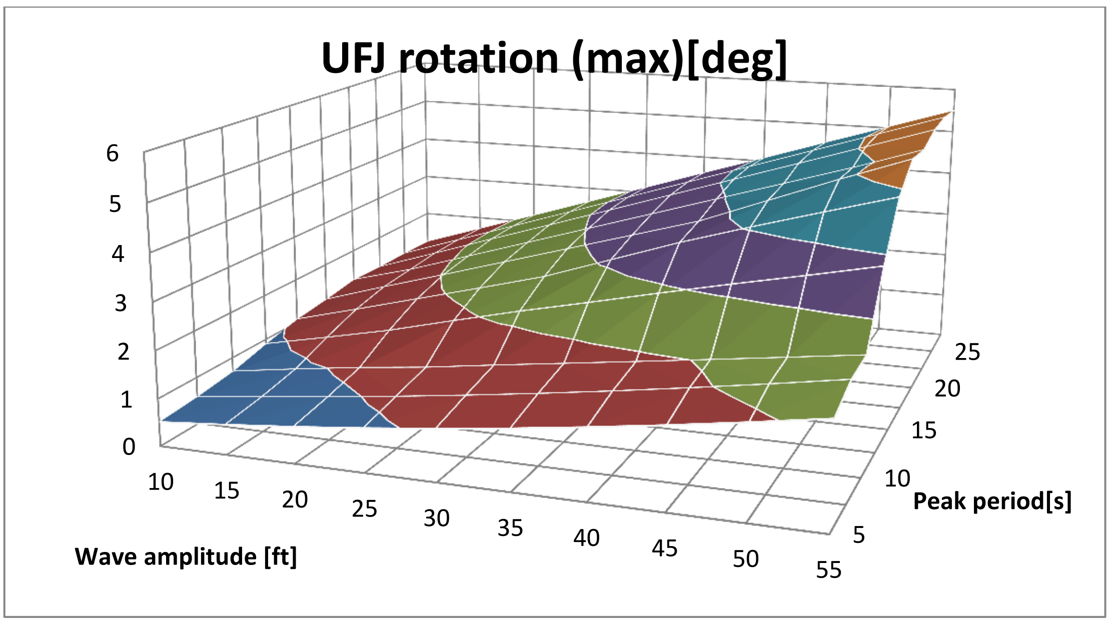


Figure 4.24- Upper Flex Joint rotation

It is important to remember that the limit for keep on drilling safely is a maximum upper flex joint deflection on 4 deg.
There is a sensible overcoming of the limits for waves with a specific amplitude greater than **40 ft** with a peak period greater than **22,5** s.

The reason of this dynamic behaviour is connected with the vessel's RAO that have a Heave resonance on 22 s and a Pitch resonance on 21 s.

VM-max [ksi]											
		Hs[ft]									
		10	15	20	25	30	35	40	45	50	55
T[s]	5	18,2	19,3	20,4	21,7	23,1	25,05	27,27	29,7	32,38	35,3
	7,5	18,298	20,198	22,335	24,79	27,57	30,66	34,049	37,732	41,696	45,936
	10	17,719	19,114	20,5	21,76	23,79	26	28,37	31	33,82	36,86
	12,5	17,476	18,22	19,43	20,6	21,665	22,683	23,882	25,582	27,427	29,4
	15	17,509	18,136	18,765	19,406	20,48	21,54	22,5	23,4	24,3	25,113
	17,5	17,5	18,09	18,7	19,3	19,9	20,551	21,2	22,1	22,99	23,8
	20	17,4	18	18,58	19,163	19,747	20,331	20,917	21,503	22,1	22,75
	22,5	17,35	17,89	18,44	18,987	19,535	20,083	20,632	21,182	21,732	22,506
	25	17,273	17,78	18,3	18,8	19,31	19,82	20,333	20,846	21,36	22,136
	27,5	17,19	17,663	18,134	18,6	19,1	19,552	20,027	20,5	20,98	21,664

Table 4.21- Von Mises stress distribution

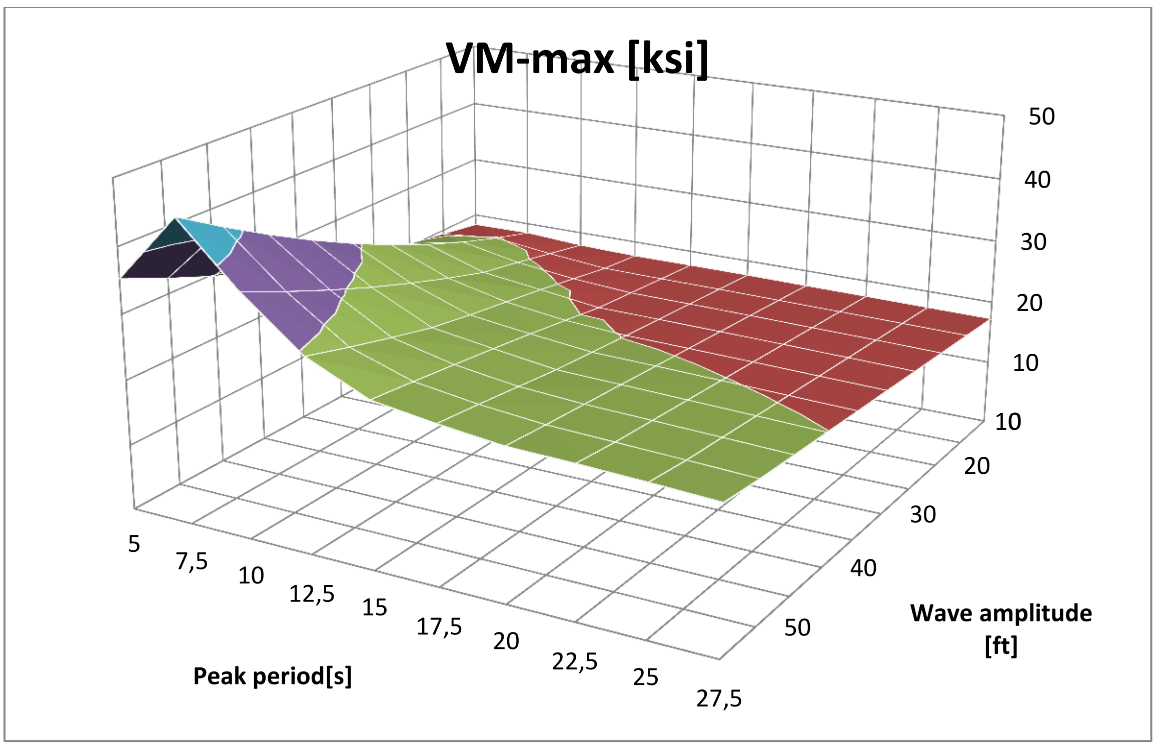


Figure 4.25- Von Mises stress

The limit for keep on drilling is a maximum Von Mises stress of 32 kips.
It is notable an outlier peak that overcomes the safe limits on a period of **7,5s** .The dynamic reason is a interaction of the waves with the riser.
In fact, as notable from the RAOs of the vessel, at this excitation period the vessel shows a vibration mode with negligible amplitude in every degree of freedom.
The reason of the instability is therefore connected just with the riser vibration modes.
A FEM (Finite Element Method) was used to understand the dynamic behaviour of the riser under a harmonic excitation.
The Figure 4.26, Figure 4.27 and Figure 4.28 show the results of the simulation and the three main vibration mode of the riser.

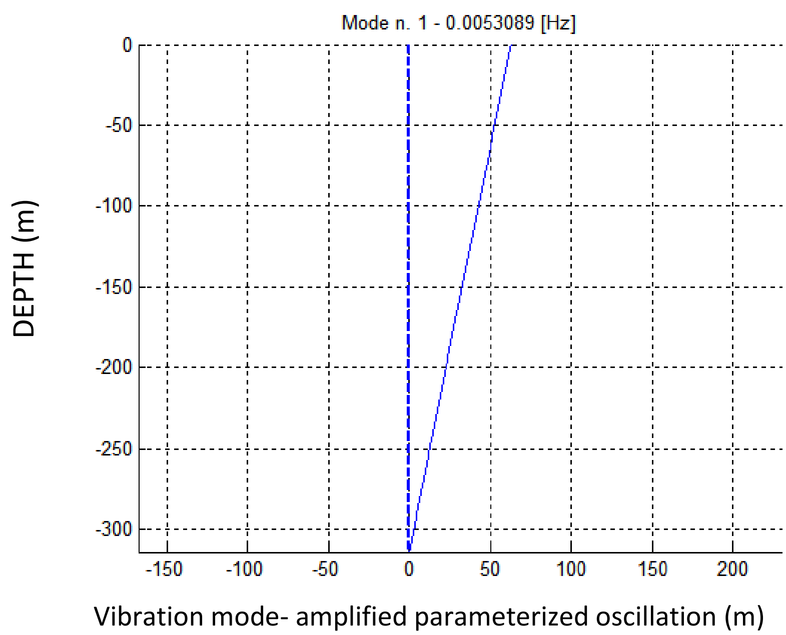


Figure 4.26- Riser first vibration mode

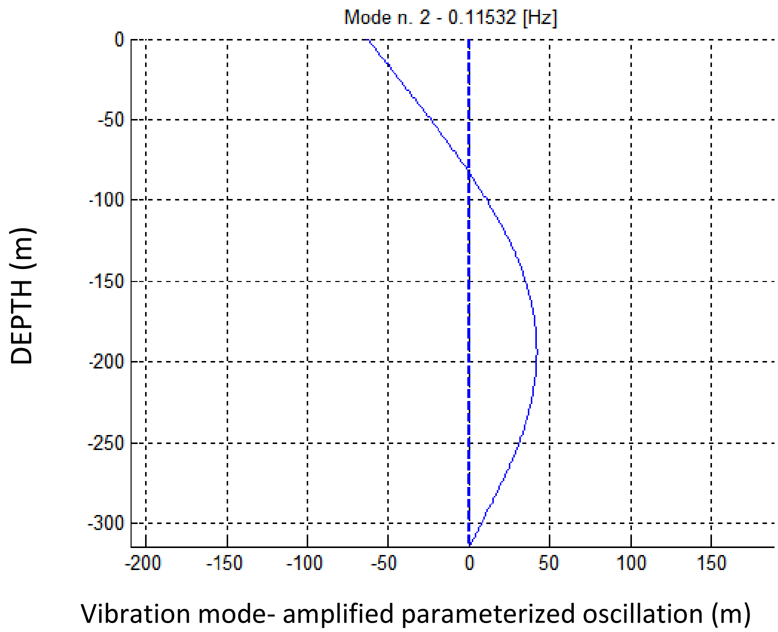


Figure 4.27- Riser second vibration mode

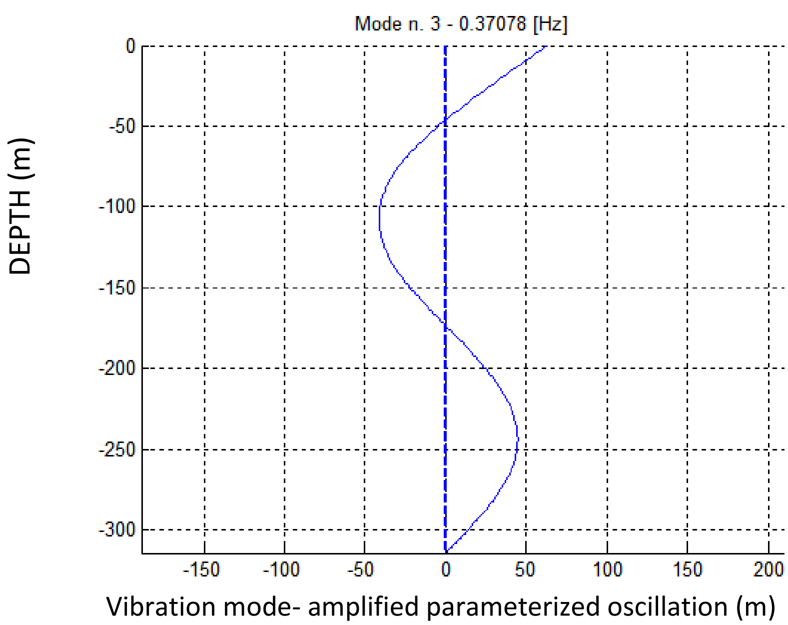


Figure 4.28- Riser third vibration mode

It is notable (Figure 4.27) that the second vibration mode is characterized by a frequency of 0,115 Hz (T= 8,6 s).
The analytical method shows the validity of the hypothesis and confirms that the riser dynamic system is characterized by a resonance at a frequency of circa **0,125 Hz** that corresponds to a critical period of **T=8s.**

4.10 CONCLUSIONS

The riser analysis has proven to be a powerful device. It is crucial for the riser string design and should be performed in any new project circumstance.
This simulation drove the author to define the following conclusions:

- Under the environmental condition described above and with riser configuration obtained in the riser configuration optimization, the system vessel- riser show instability with harmonic waves with a period T of **22,5 s** and **8 s** that are respectively one of the vibrating mode of the vessel and the riser.
  Particular care must be taken when the sea condition shows this characteristic frequency and disconnection procedure must be taken under account.
- Riser's technology can be easily adapted to arctic condition. Ice Management Systems is strictly required because no riser can resist to an ice layer or mass impact. Once the Ice Management have proven to be reliable the riser technology can start to be used in arctic seas.
- New regulations are required in order to ensure safe disconnection process during Arctic drilling performances. New standard will be developed upgrading the current regulations with new experiences.
- DeepRiser software is a valid, user friendly simulator that can model any depth or marine condition. The weak point is the massive data input required to run any kind of simulation.
  Moreover new features are needed in order to adapt DeepRiser to arctic condition as for example Ice Modelling as software input.
- Sensitivity analyses are a powerful device that should be performed in any new design condition that drives the system to different dynamic behaviour ad likely be upgraded to Real Time Simulation.

Appendix A: JONSWAP spectrum [86]

The JONSWAP (Joint North Sea Wave Project) spectra is an empirical relationship that defines the distribution of energy with frequency within the ocean.
The JONSWAP spectrum is effectively a fetch-limited version of the Pierson-Moskowitz spectrum, except that the wave spectrum is never fully developed and may continue to develop due to non-linear wave-wave interactions for a very long time. Therefore in the JONSWAP spectrum, waves continues to grow with distance (or time) as specified by the α (*alpha*) term, and the peak in the spectrum is more pronounced, as specified by the γ (*gamma*) term. Hasselmann (1966) found the latter to be particularly important as it lead to enhanced non-linear interactions.
The underlying equation describes the wave's distribution of energy:

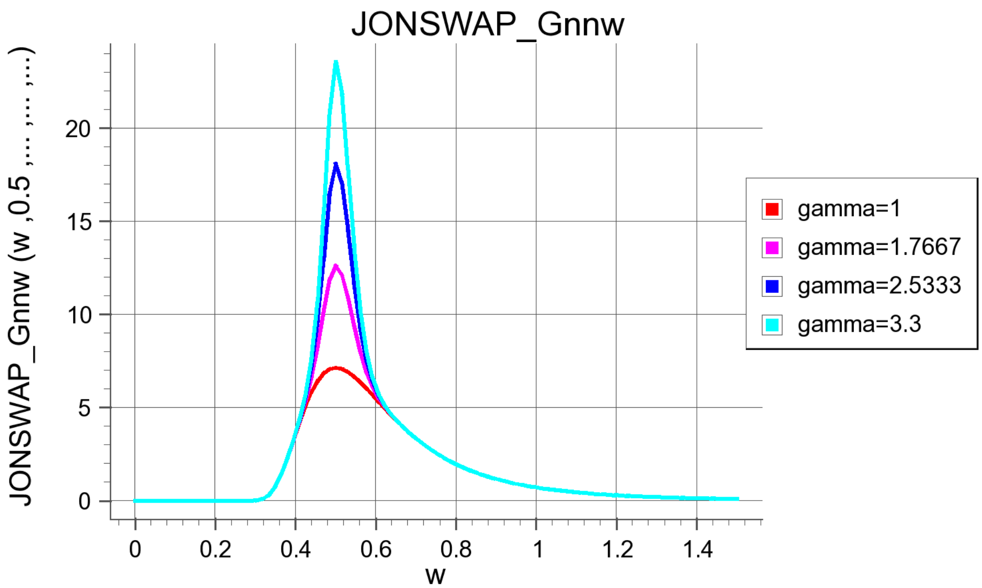
$$S(\omega) = \frac{\alpha g^2}{\omega^5} \exp\left[-\beta \frac{\omega_p^4}{\omega^4}\right] \gamma^{\alpha}$$

Where:

- $\alpha = \exp\left[-\frac{(\omega-\omega_p)^2}{2\omega_p^2\sigma^2}\right]$
- $\sigma = \begin{cases} 0{,}07 \ if \ \omega \leq \omega_p \\ 0{,}09 \ if \ \omega \geq \omega_p \end{cases}$
- $\beta = \frac{5}{4}$
- α is a constant that relates to the wind speed and fetch length, see below. Typical values in the northern north sea are in the range of 0.0081 to 0.01
- ω is the wave frequency
- ω_p is the peak wave-frequency

However if a particular wind speed and fetch length are known, then α and ω_p can be estimated using the subsequent two functions.

For a range of typical north sea conditions (where α =0.0081 and $\omega_p = \frac{2\pi}{12,4} = 0,5$)but with varying peak enhancements the JONSWAP spectra has the form described in the figure below.



The peak of the JONSWAP spectrum is empirically define by the formula

$$\omega_p = 2,84 g^{0,7} L_f^{-0,3} U_W^{-0,4}$$

Where:

- U_W is the wind speed at 10m above the sea surface
- L_f is the fetch length.

JONSWAP Alpha:

The overall energy within the JONSWAP spectrum is controlled by the α constant and is related to wind speed and the peak frequency by:

$$\alpha = 0,033 \left(\frac{\omega_p U_W}{g}\right)^{\frac{2}{3}}$$

Where:

- U_W is the wind speed at 10m above the sea surface
- ω_p is the peak frequency calculated using equation

Appendix A

Appendix B: Riser description and Analyses reports

MCSK DeepRiser Static Calculations Report File

DeepRiser Version: 3.1.1
Location: San Donato Milanese
Drilling Rig: Scarabeo 8
Riser Name: Tally 5-THICK;GUARD; NO BUOYANCY (2)
Date: 25/07/2013
Time: 10:43:43 Local
10:43:43 GMT

General Information

Parameter	Value
Water Depth	1053.15 ft
Drilling Riser Name	Tally 5-THICK;GUARD; NO BUOYANCY (2)

Riser Stack-Up & Particulars

Joint Name	No.	Main Tube Inner Diameter (in)	Joint Length (ft)	Elevation to Bottom of Joint (ft)	Dry Weight of Section (kips)	Wet Weight of Section (kips)
BOP	1	18.75	28.78	3.00	393.27	343.16
LMRP	1	18.75	14.64	31.78	190.18	165.95
Lower Flex Joint	1	0.00	10.65	46.42	30.00	26.18
Drilling Riser Joint 1 - SLICK (THICK)	4	19.50	75.00	282.07	126.56	108.04
Drilling Riser Joint 1 - SLICK (THIN)+ GUARD	6	19.50	75.00	732.07	230.04	159.75
Drilling Riser Joint 1 - SLICK (THICK)	4	19.50	75.00	1032.07	126.56	108.04
PUP JOINT 25'	1	19.50	25.00	1107.07	17.38	15.16
PUP JOINT 5'	1	19.50	5.00	1132.07	5.68	4.95
Telescopic Joint_OB	1	22.75	70.00	1137.07	84.04	73.33
Telescopic Joint_IB	1	19.75	60.00	1207.07	4.59	4.00
Upper Flex Joint	1	0.00	8.31	1240.04	11.50	10.03

Auxiliary Line Data

Line Name	Inner Diameter (in)	External Diameter (in)

Choke	4.5	6.75
Kill	4.5	6.75
Mud Booster	4.5	5.25
Hydraulic	2	2.63

Additional Information

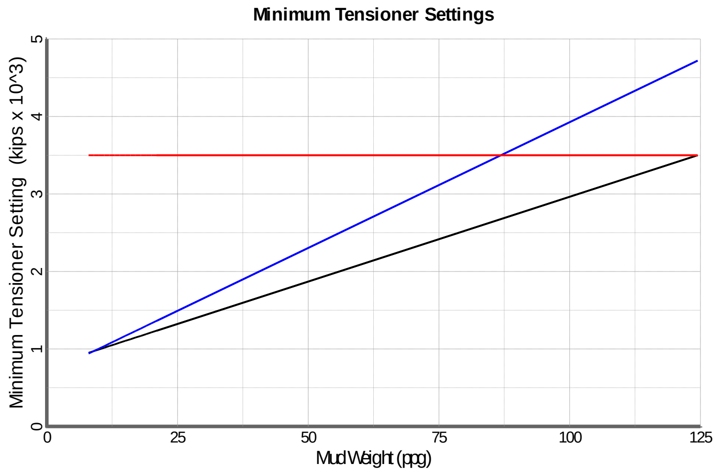
Parameter	Value	Units
Tensioner Efficiency	1.00	
Riser Steel Weight Factor	1.05	
Required Over Pull	150.00	kips
Riser Buoyancy Loss Factor	0.96	
Riser Tensioner Capacity	3500.00	kips
Number of Riser Tensioners Installed	6	
Number of Riser Tensioners Subject to Failure	2	
Number of CT Tensioners Installed	0	
Number of CT Tensioners Subject to Failure	0	
Gravitational Constant	32.19	ft/s²

Minimum Tensioner Setting for Stability (API RP16Q)

Mud Density For Stability (ppg)	Minimum Tension (kips)
8.00	941.21
9.00	973.66
10.00	1006.11
11.00	1038.56
12.00	1071.02
13.00	1103.47
14.00	1135.92
15.00	1168.37
16.00	1200.83
17.00	1233.28
18.00	1265.73
19.00	1298.18
20.00	1330.63
86.85	3500.00

Minimum Tensioner Setting for a Disconnect Scenario

Mud Density (ppg)	Minimum Disconnect Tension (kips)
8.00	951.58
9.00	973.46
10.00	995.35
11.00	1017.23
12.00	1039.11
13.00	1060.99
14.00	1082.87
15.00	1104.75
16.00	1126.63
17.00	1148.51
18.00	1170.39
19.00	1192.28
20.00	1214.16
124.47	3500.00



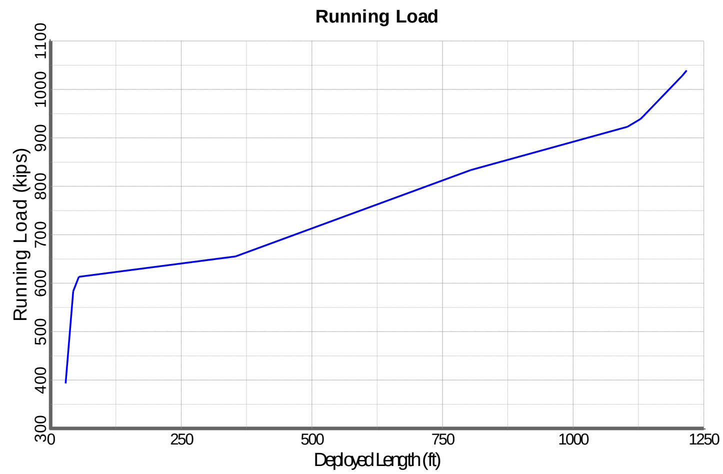
--- Tensioner Capacity
--- Min. Tensioner Setting for Stability (API RP16Q)
--- Min. Tensioner Setting for a Disconnect Scenario

Weights In Water

Configuration (kips)	Weights In Water
Riser + LMRP	782.15
Riser + LMRP/BOP	1142.48

Riser Running Load Calculations

Name Of Joint Being Run Deployed (ft)	Length of Joint (ft)	Length of Riser (kips)	Running Load
BOP	28.78	28.78	393.27
LMRP	14.64	43.42	583.44
Lower Flex Joint	10.65	54.07	613.44
Drilling Riser Joint 1 - SLICK (THICK)	75.00	354.07	655.38
Drilling Riser Joint 1 - SLICK (THIN)+ GUARD	75.00	804.07	833.57
Drilling Riser Joint 1 - SLICK (THICK)	75.00	1104.07	923.17
PUP JOINT 25'	25.00	1129.07	939.01
PUP JOINT 5'	5.00	1134.07	944.38
Telescopic Joint	75.00	1209.07	1028.37
Upper Flex Joint	8.31	1217.38	1039.36



--- Running Load

MCSK DeepRiser Static Calculations Report File

DeepRiser Version: 3.1.1
Location: San Donato Milanese
Drilling Rig: Scarabeo 8
Riser Name: Tally 3-THICK; BUOYANCY; NO GUARD
Date: 25/07/2013
Time: 10:41:03 Local
10:41:03 GMT

General Information

Parameter	Value
Water Depth	1053.15 ft
Drilling Riser Name	Tally 3-THICK; BUOYANCY; NO GUARD

Riser Stack-Up & Particulars

Joint Name **No.** **Main Tube** **Joint** **Elevation** **Dry Weight** **Wet**
Weight
Inner **Length** **to Bottom** **of Section** **of Section**

Diameter		of Joint				
(in)	(ft)	(ft)	(kips)	(kips)		
BOP	1	18.75	28.78	3.00	393.27	343.16
LMRP	1	18.75	14.64	31.78	190.18	165.95
Lower Flex Joint	1	0.00	10.65	46.42	30.00	26.18
PUP JOINT 25'	1	19.50	25.00	57.07	17.38	15.16
PUP JOINT 5'	1	19.50	5.00	82.07	5.68	4.95
Drilling Riser Joint 1 - SLICK (THIN)	2	19.50	75.00	162.07	61.08	53.30
Drilling Riser Joint 3 - BLUE 3000'	10	19.50	75.00	912.07	823.26	-129.67
Drilling Riser Joint 1 - SLICK (THICK)	2	19.50	75.00	1062.07	63.28	54.02
Telescopic Joint_OB	1	22.75	70.00	1137.07	84.04	73.33
Telescopic Joint_IB	1	19.75	60.00	1207.07	4.59	4.00
Upper Flex Joint	1	0.00	8.31	1240.04	11.50	10.03

Auxiliary Line Data

Line Name	Inner	External
Diameter	Diameter	
(in)	(in)	
Choke	4.5	6.75
Kill	4.5	6.75
Mud Booster	4.5	5.25
Hydraulic	2	2.63

Additional Information

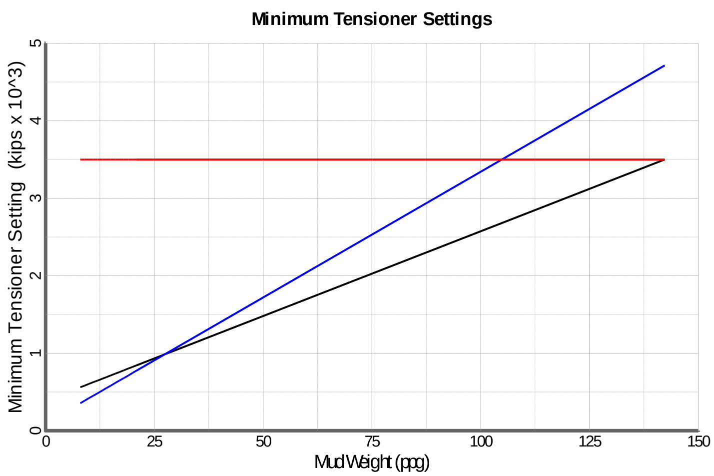
Parameter	Value	Units
Tensioner Efficiency	1.00	
Riser Steel Weight Factor	1.05	
Required Over Pull	150.00	kips
Riser Buoyancy Loss Factor	0.96	
Riser Tensioner Capacity	3500.00	kips
Number of Riser Tensioners Installed	6	
Number of Riser Tensioners Subject to Failure	2	
Number of CT Tensioners Installed	0	
Number of CT Tensioners Subject to Failure	0	
Gravitational Constant	32.19	ft/s²

Minimum Tensioner Setting for Stability (API RP16Q)

Mud Density	Minimum Tension
For Stability	
(ppg)	(kips)
8.00	356.52
9.00	388.98
10.00	421.43
11.00	453.88
12.00	486.33
13.00	518.78
14.00	551.24
15.00	583.69
16.00	616.14
17.00	648.59
18.00	681.05
19.00	713.50
20.00	745.95
104.86	3500.00

Minimum Tensioner Setting for a Disconnect Scenario

Mud Density	Minimum Disconnect
Tension	
(ppg)	(kips)
8.00	561.79
9.00	583.67
10.00	605.56
11.00	627.44
12.00	649.32
13.00	671.20
14.00	693.08
15.00	714.96
16.00	736.84
17.00	758.72
18.00	780.60
19.00	802.49
20.00	824.37
142.28	3500.00



--- Tensioner Capacity
--- Min. Tensioner Setting for Stability (API RP16Q)
--- Min. Tensioner Setting for a Disconnect Scenario

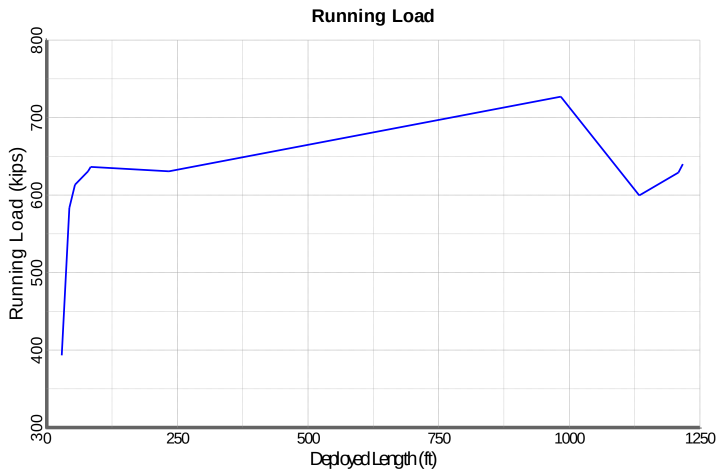
Weights In Water

Configuration	Weights In Water
(kips)	
Riser + LMRP	392.36
Riser + LMRP/BOP	752.69

Riser Running Load Calculations

Name Of Joint Being Run Deployed	Length of Joint	Length of Riser	Running Load

(ft)	(ft)	(kips)	
BOP	28.78	28.78	393.27
LMRP	14.64	43.42	583.44
Lower Flex Joint	10.65	54.07	613.44
PUP JOINT 25'	25.00	79.07	630.82
PUP JOINT 5'	5.00	84.07	636.50
Drilling Riser Joint 1 - SLICK (THIN)	75.00	234.07	630.78
Drilling Riser Joint 3 - BLUE 3000'	75.00	984.07	727.05
Drilling Riser Joint 1 - SLICK (THICK)	75.00	1134.07	599.74
Telescopic Joint	75.00	1209.07	629.10
Upper Flex Joint	8.31	1217.38	640.08



--- Running Load

DeepRiser Version 3.1 Analysis Report

Project Title: SCA8 BARENTS
Analysis Title: Analysis DYNAMIC tally 5
Load Case Title: Load Case 1
Engineer(s): SUBSY
Location: San Donato Milanese
Date: 02/07/2013

Time: 10:00

Automated Postprocessing

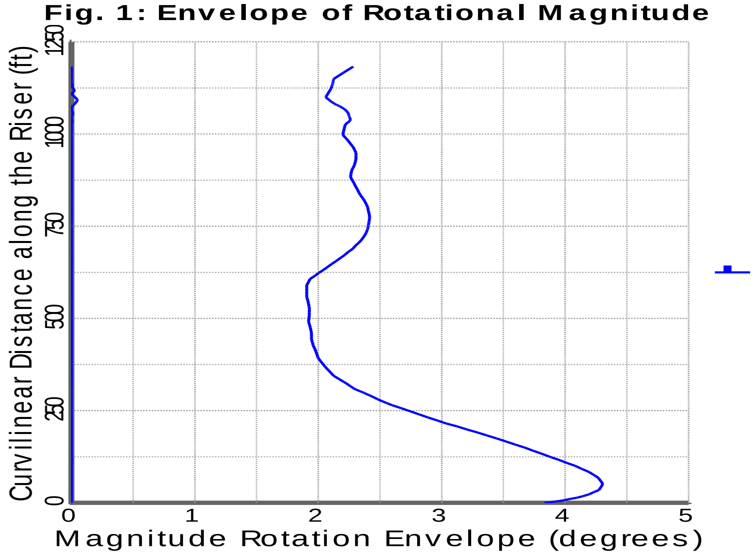


Fig. 2: Envelope of Effective Tension

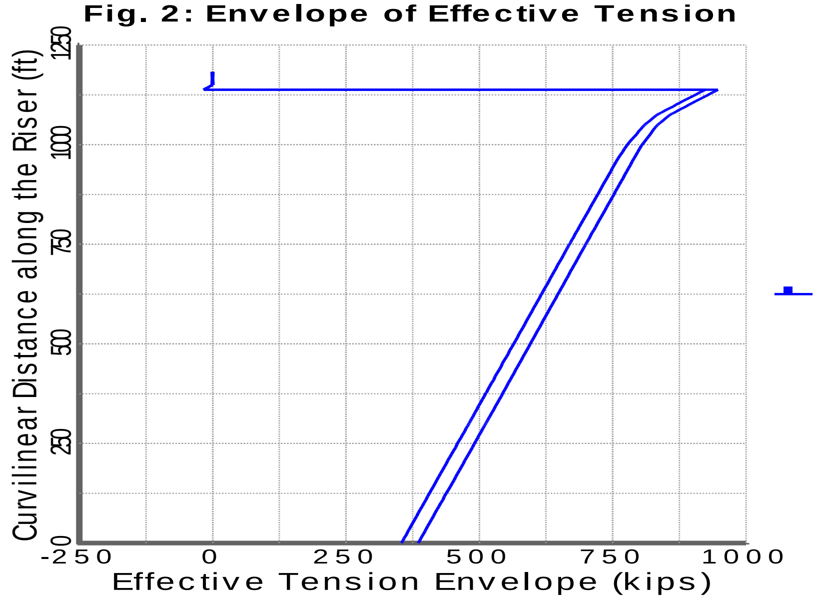
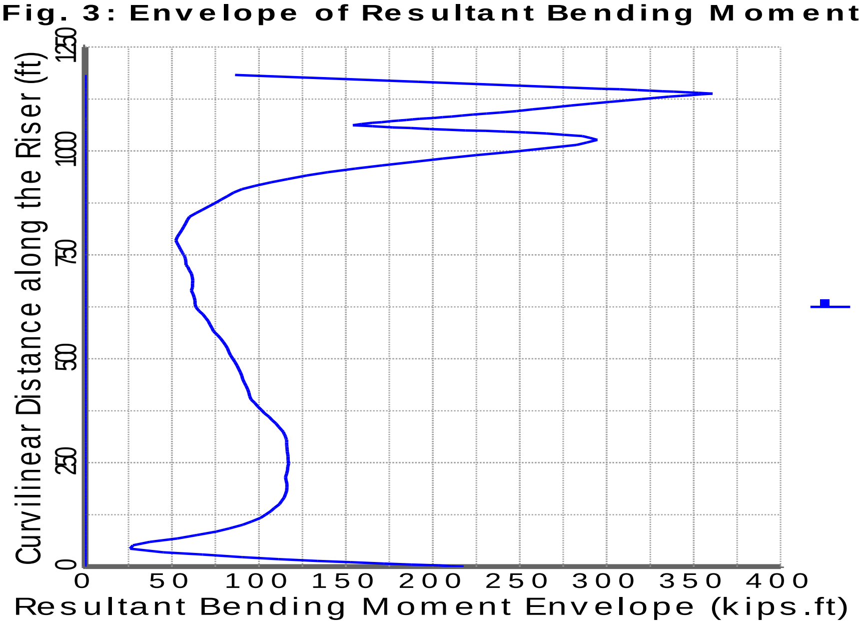
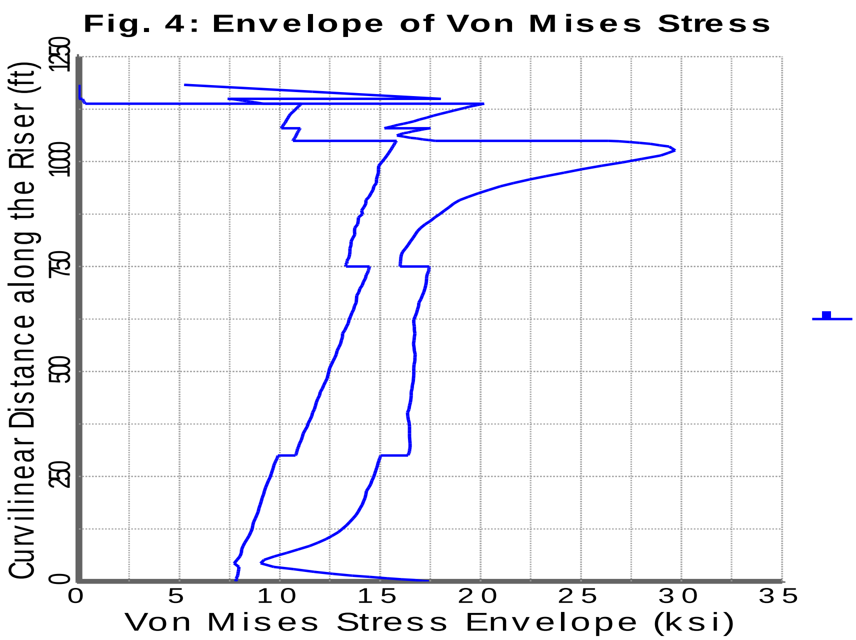


Fig. 3: Envelope of Resultant Bending Moment





mcs kenny DeepRiser Version 3.1 Analysis Report

Project Title: SCA8 BARENTS
Analysis Title: Analysis DYNAMIC tally 5
Load Case Title: Load Case 2
Engineer(s): SUBSY
Location: San Donato Milanese
Date: 02/07/2013
Time: 10:06

Automated Postprocessing

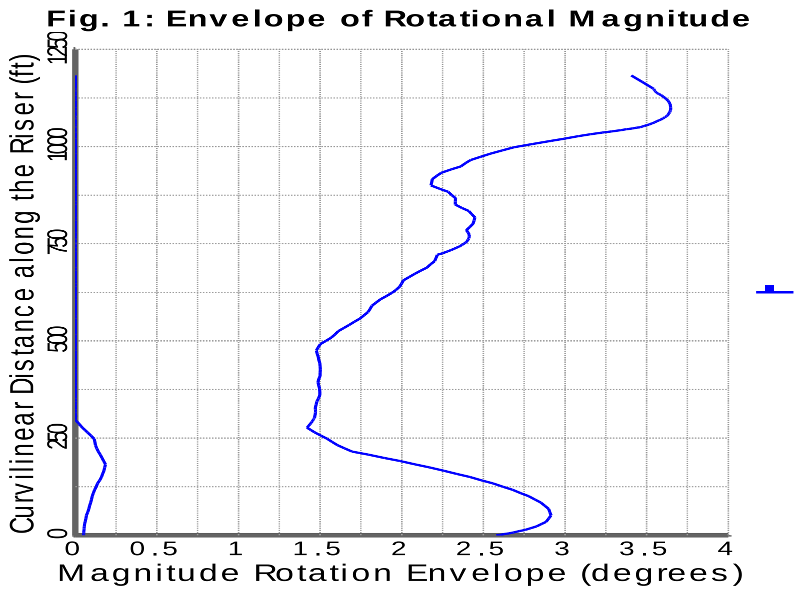


Fig. 1: Envelope of Rotational Magnitude
Curvilinear Distance along the Riser (ft)
0
250
500
750
1000
1250
0
0.5
1
1.5
2
2.5
3
3.5
4
Magnitude Rotation Envelope (degrees)

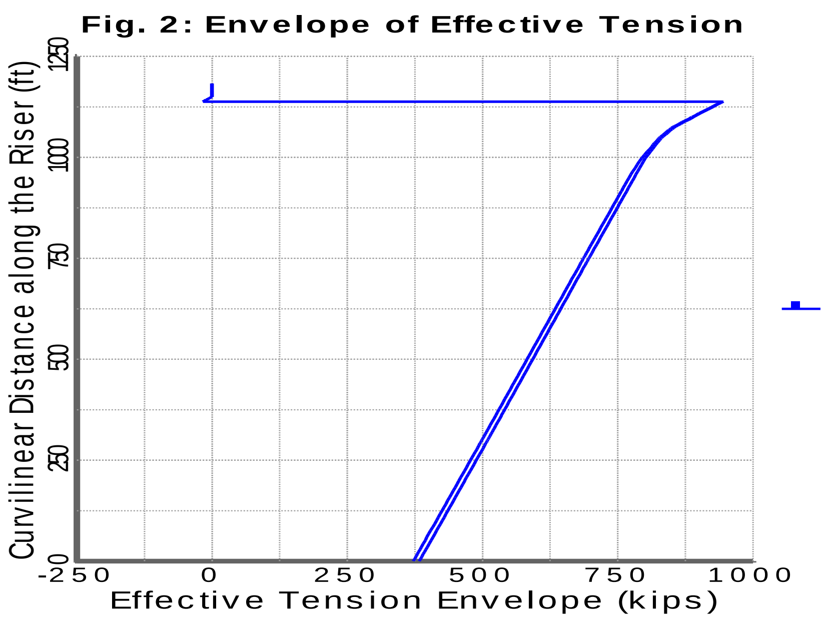


Fig. 2: Envelope of Effective Tension
Curvilinear Distance along the Riser (ft)
0
250
500
750
1000
1250
-250
0
250
500
750
1000
Effective Tension Envelope (kips)

Fig. 3: Envelope of Resultant Bending Moment

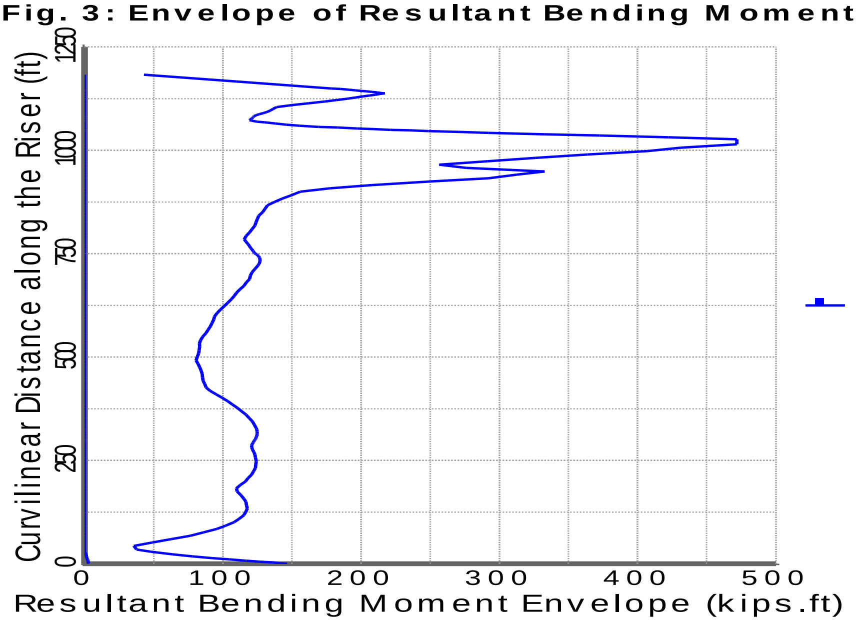
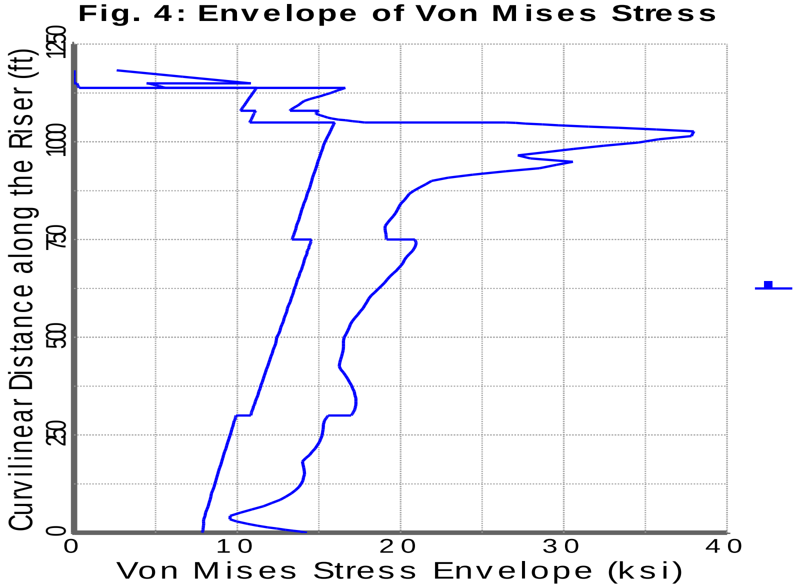


Fig. 4: Envelope of Von Mises Stress



DeepRiser Version 3.1 Analysis Report

Project Title: SCA8 BARENTS
Analysis Title: Analysis DYNAMIC tally 3
Load Case Title: Load Case 1
Engineer(s): SUBSY
Location: San Donato Milanese
Date: 01/07/2013
Time: 16:20

Automated Postprocessing

Fig. 1: Envelope of Rotational Magnitude

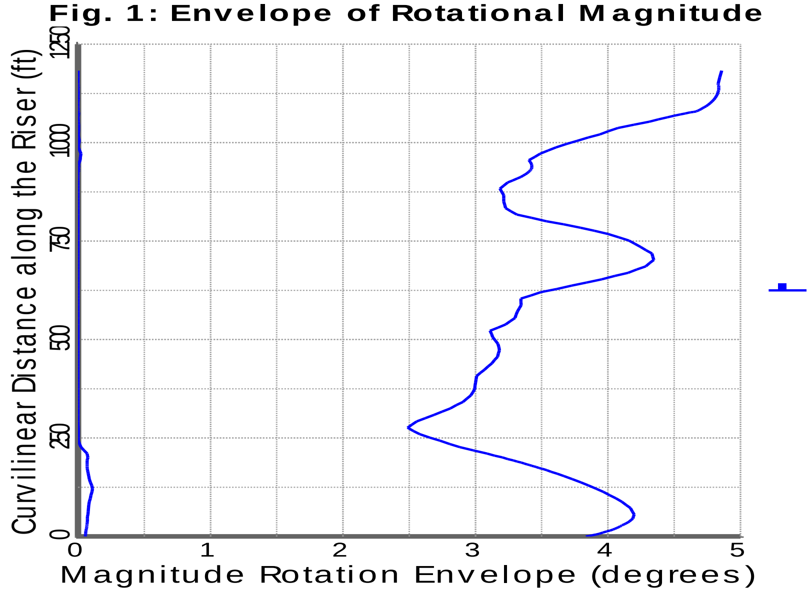
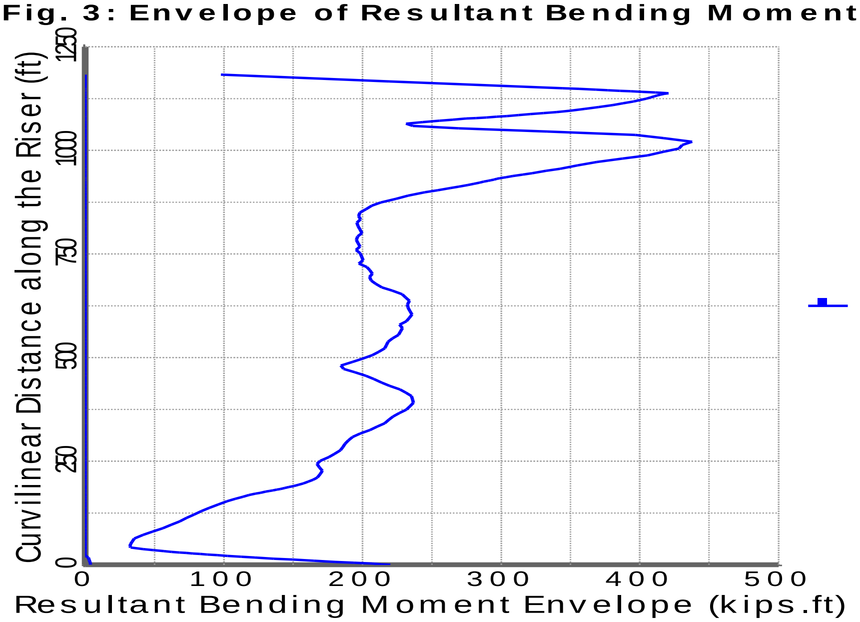
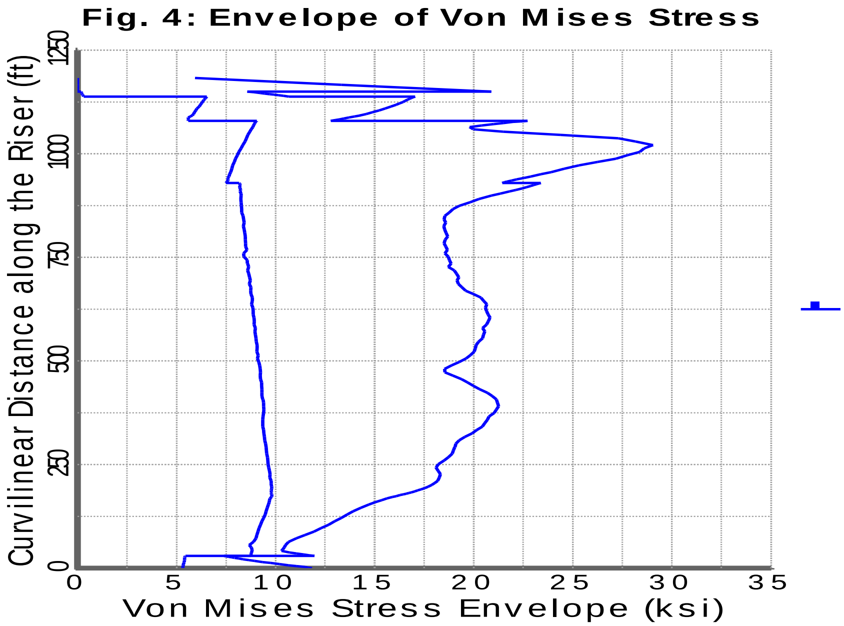


Fig. 2: Envelope of Effective Tension

Fig. 3: Envelope of Resultant Bending Moment





mcs kenny DeepRiser Version 3.1 Analysis Report

Project Title: SCA8 BARENTS
Analysis Title: Analysis DYNAMIC tally 3
Load Case Title: Load Case 2
Engineer(s): SUBSY
Location: San Donato Milanese
Date: 01/07/2013
Time: 16:25

Automated Postprocessing

Fig. 1: Envelope of Rotational Magnitude

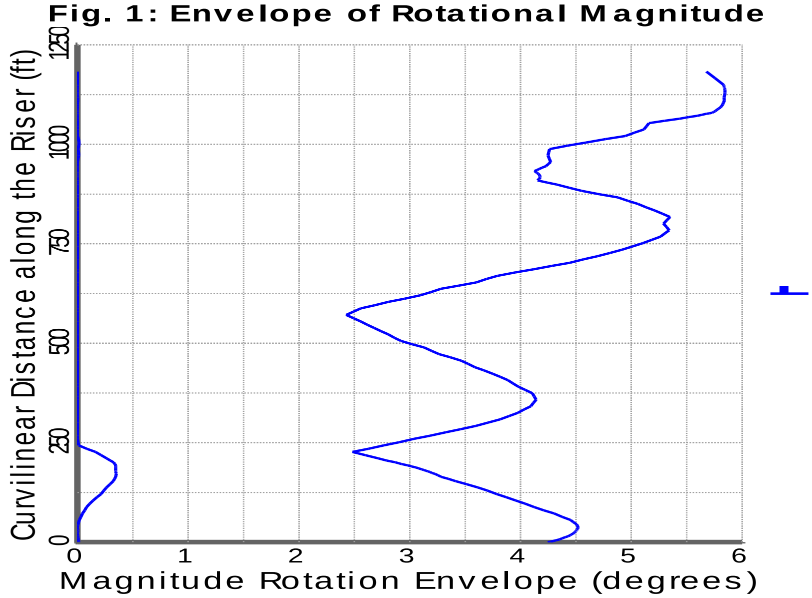
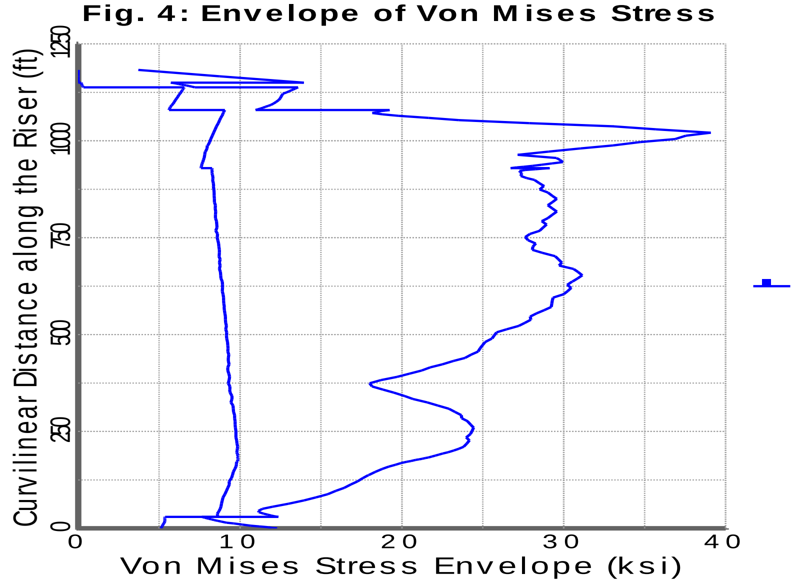


Fig. 2: Envelope of Effective Tension

Fig. 3: Envelope of Resultant Bending Moment

Fig. 4: Envelope of Von Mises Stress



DeepRiser Version 3.1 Analysis Report

Project Title: SCA8 BARENTS
Analysis Title: Analysis DISCONNECTED tally 5
Load Case Title: Load Case 1
Engineer(s): SUBSY
Location: San Donato Milanese
Date: 02/07/2013
Time: 10:21

Automated Postprocessing

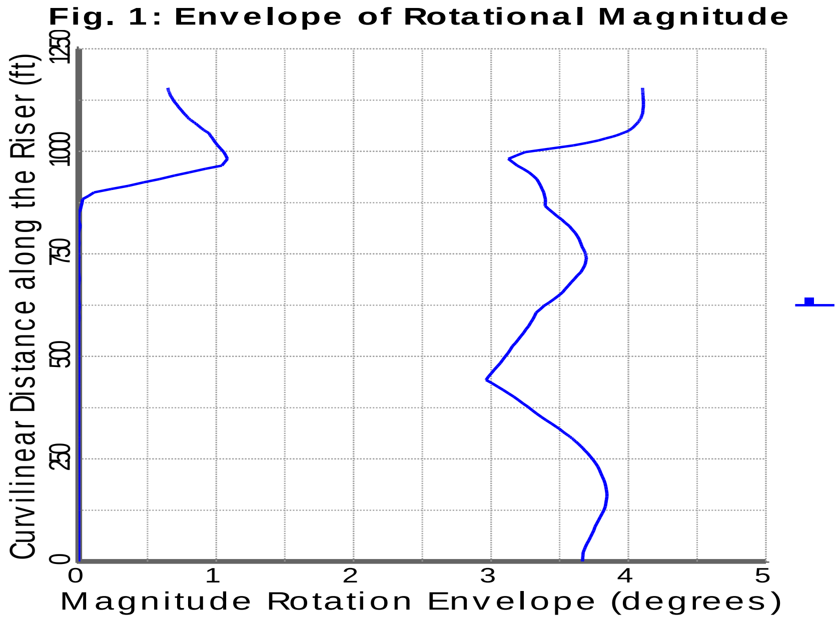


Fig. 2: Envelope of Horizontal-Y Displacement

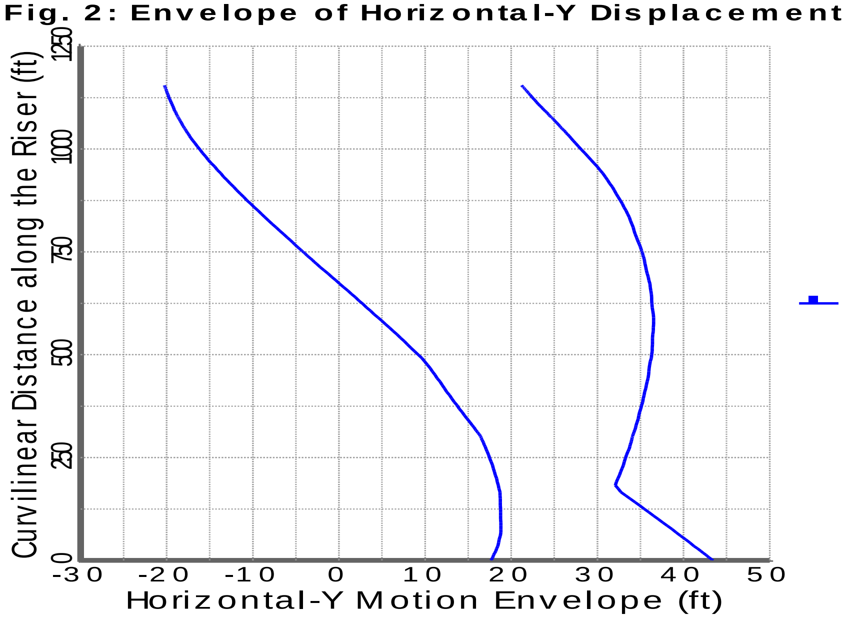
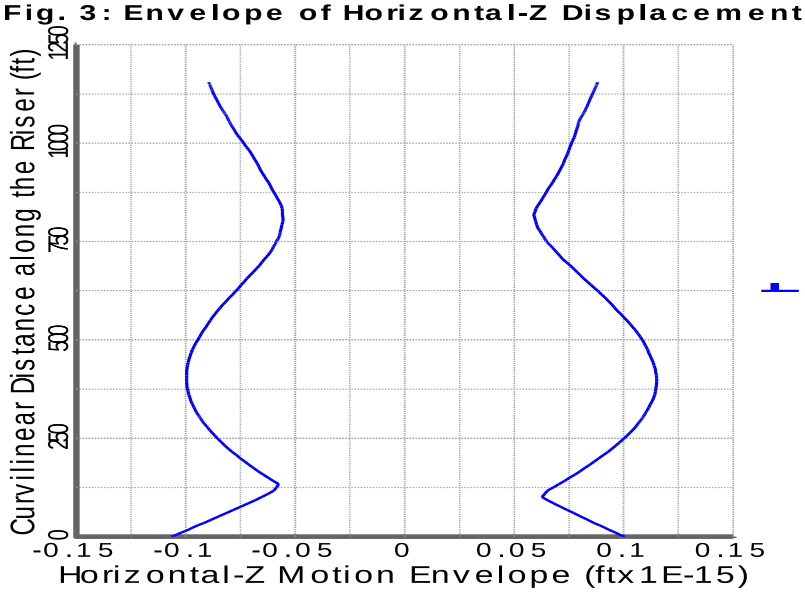


Fig. 3: Envelope of Horizontal-Z Displacement



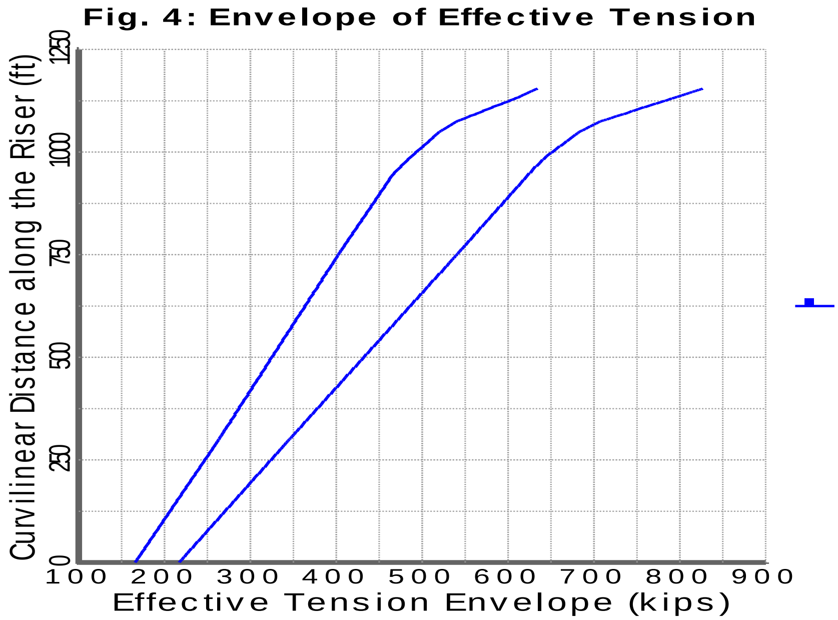


Fig. 4: Envelope of Effective Tension
Curvilinear Distance along the Riser (ft)
0
250
500
750
1000
1250
100 200 300 400 500 600 700 800 900
Effective Tension Envelope (kips)

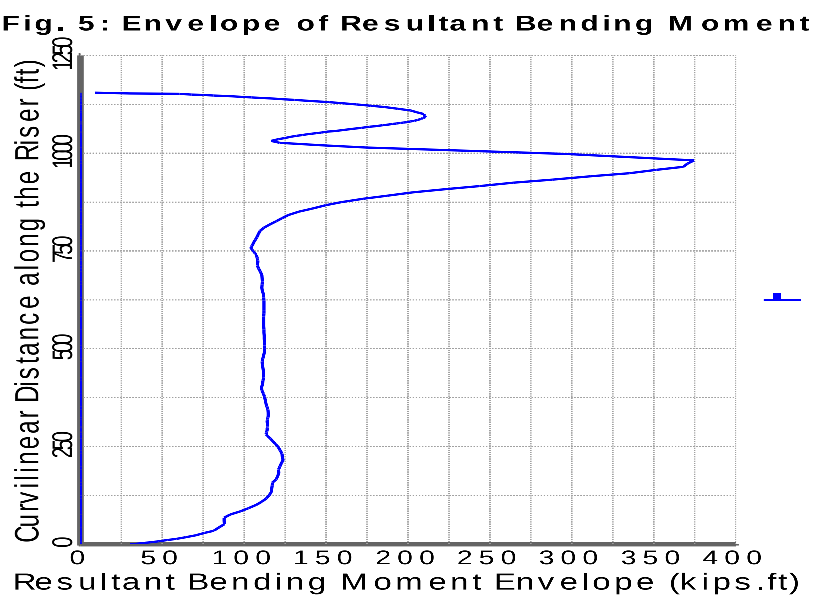
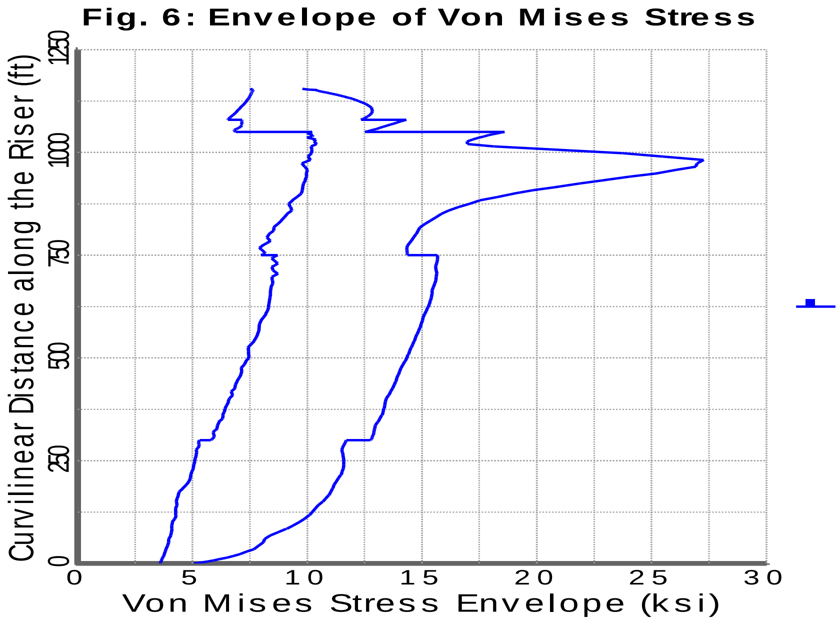


Fig. 5: Envelope of Resultant Bending Moment
Curvilinear Distance along the Riser (ft)
0
250
500
750
1000
1250
0 50 100 150 200 250 300 350 400
Resultant Bending Moment Envelope (kips.ft)



DeepRiser Version 3.1 Analysis Report

Project Title: SCA8 BARENTS
Analysis Title: Analysis DISCONNECTED tally 5
Load Case Title: Load Case 2
Engineer(s): SUBSY
Location: San Donato Milanese
Date: 02/07/2013
Time: 10:26

Automated Postprocessing

Fig. 1: Envelope of Rotational Magnitude

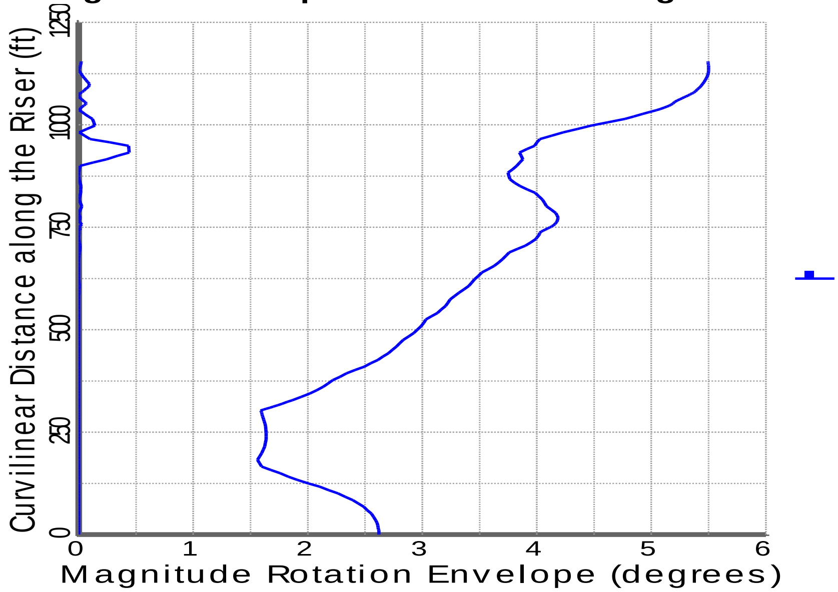
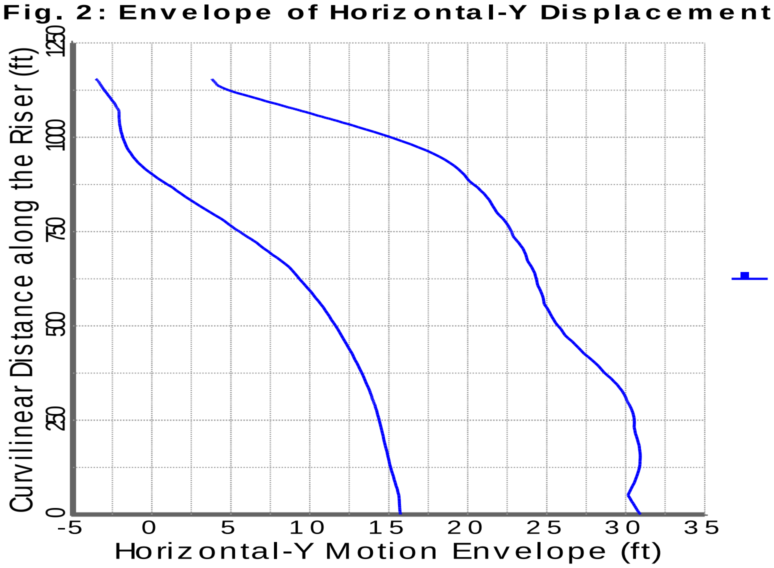


Fig. 2: Envelope of Horizontal-Y Displacement



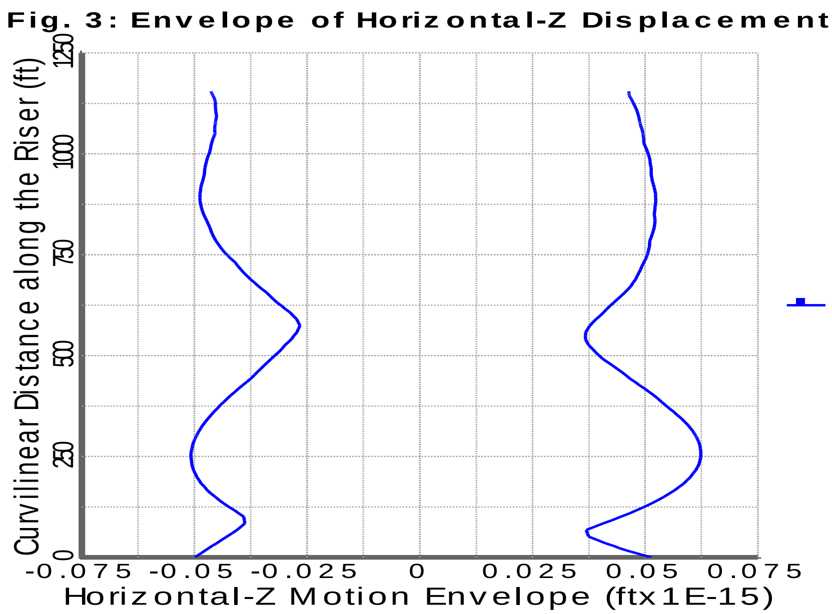


Fig. 3: Envelope of Horizontal-Z Displacement
Curvilinear Distance along the Riser (ft)
1250
1000
750
500
250
0
-0.075 -0.05 -0.025 0 0.025 0.05 0.075
Horizontal-Z Motion Envelope (ftx1E-15)

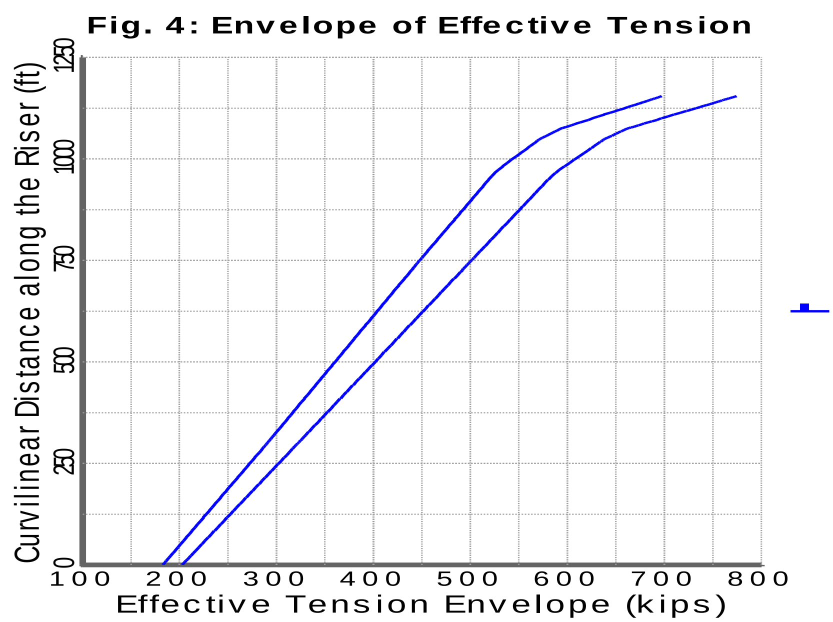


Fig. 4: Envelope of Effective Tension
Curvilinear Distance along the Riser (ft)
1250
1000
750
500
250
0
100 200 300 400 500 600 700 800
Effective Tension Envelope (kips)

Fig. 5: Envelope of Resultant Bending Moment

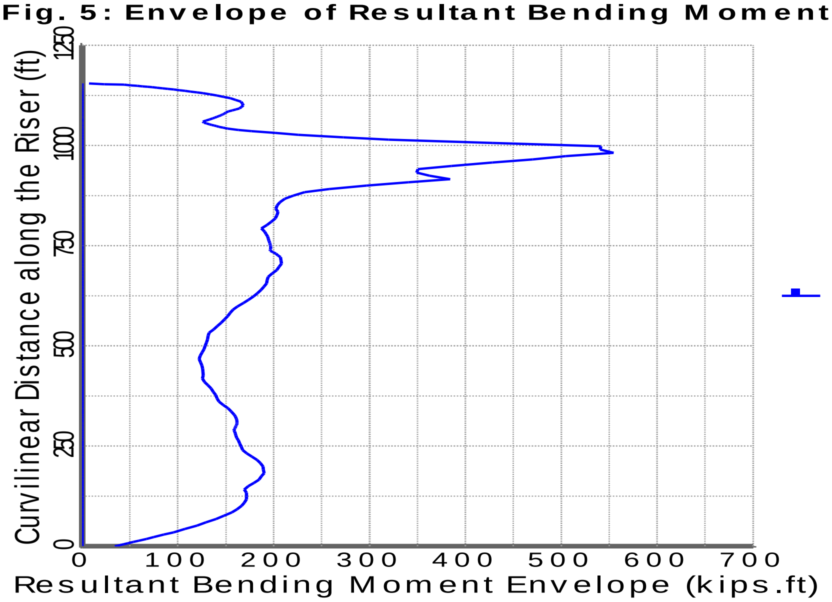
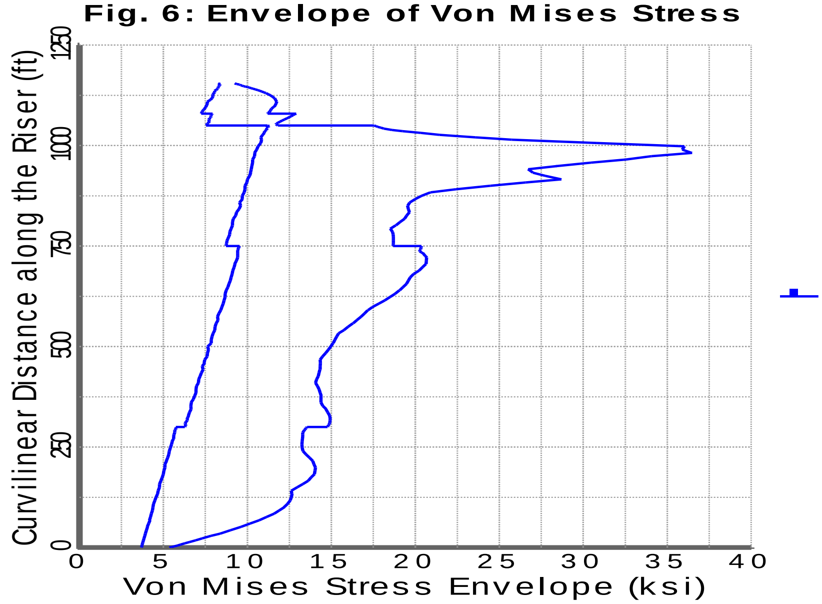


Fig. 6: Envelope of Von Mises Stress



DeepRiser Version 3.1 Analysis Report

Project Title: SCA8 BARENTS
Analysis Title: Analysis DISCONNECTED tally 3
Load Case Title: Load Case 1
Engineer(s): SUBSY
Location: San Donato Milanese
Date: 02/07/2013
Time: 10:02

Automated Postprocessing

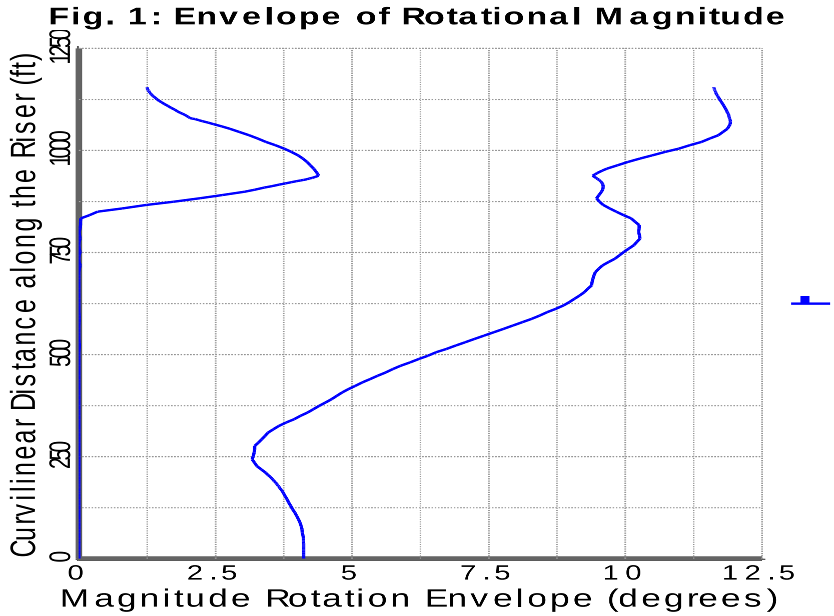


Fig. 2: Envelope of Horizontal-Y Displacement

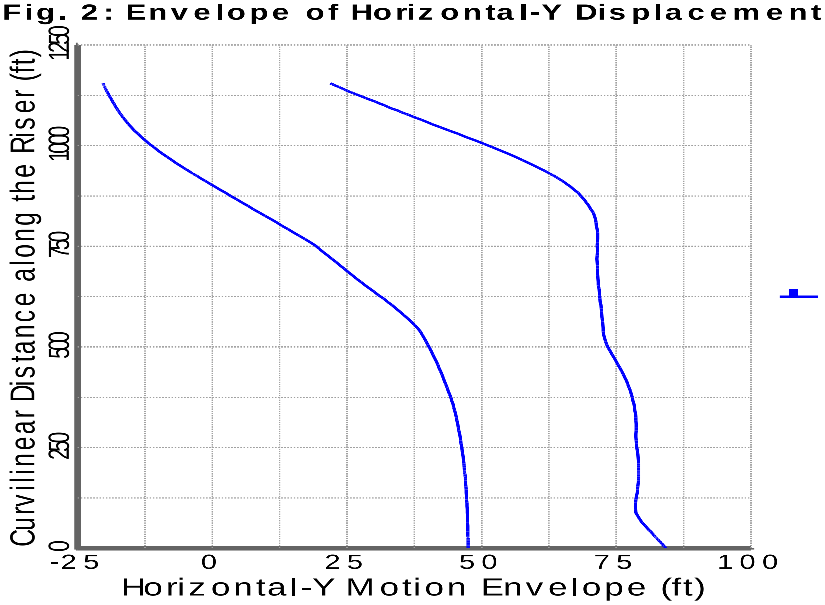


Fig. 3: Envelope of Horizontal-Z Displacement

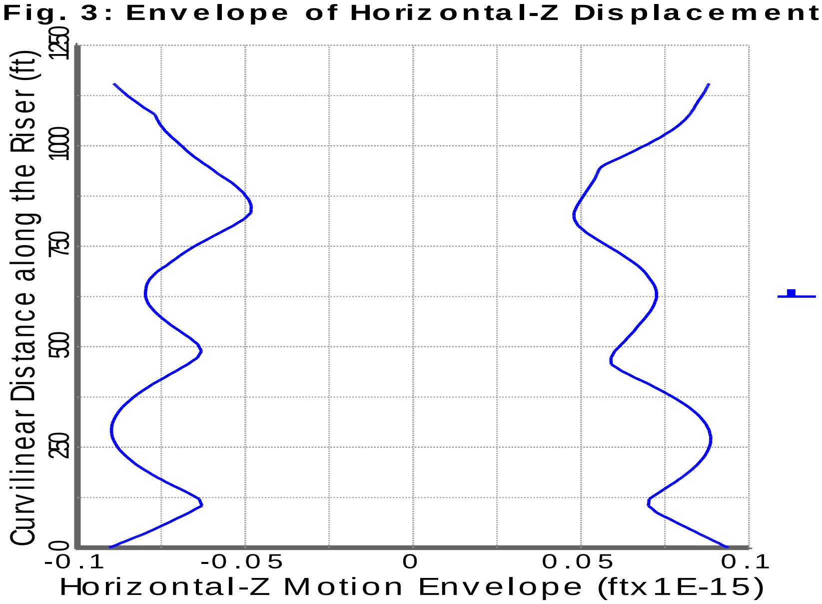


Fig. 4: Envelope of Effective Tension

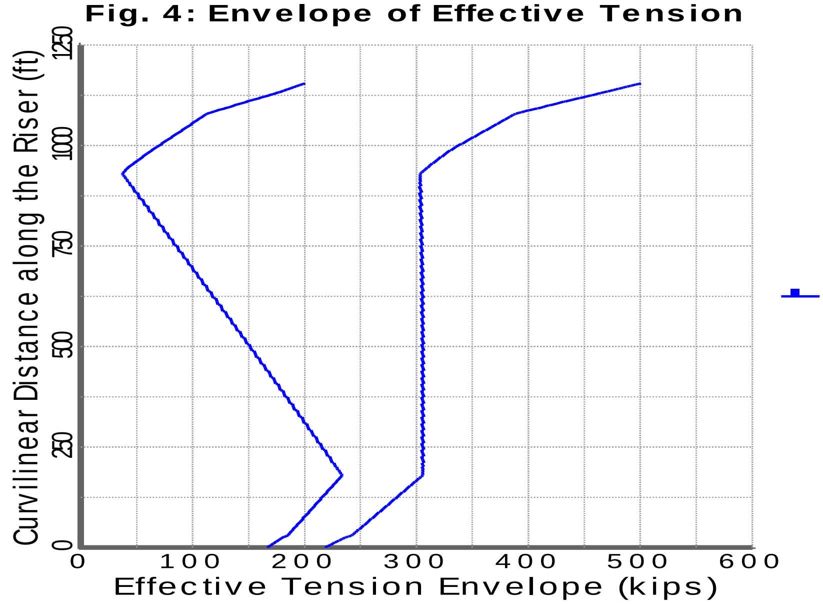
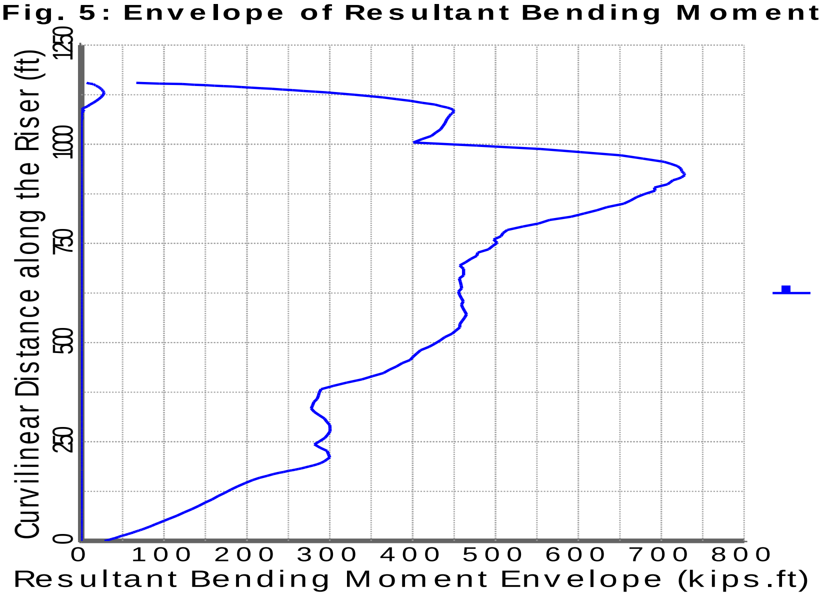
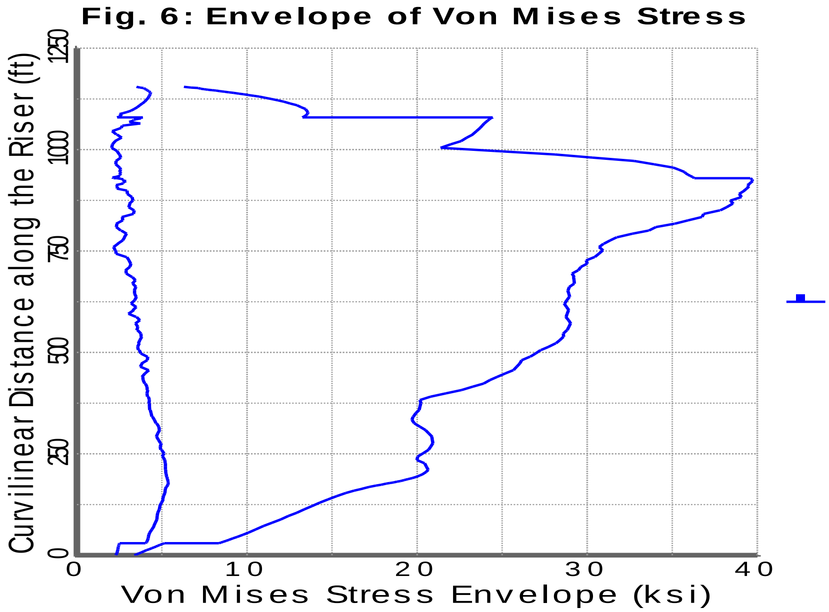


Fig. 5: Envelope of Resultant Bending Moment





mcs kenny DeepRiser Version 3.1 Analysis Report

Project Title: SCA8 BARENTS
Analysis Title: Analysis DISCONNECTED tally 3
Load Case Title: Load Case 2
Engineer(s): SUBSY
Location: San Donato Milanese
Date: 02/07/2013
Time: 10:08

Automated Postprocessing

Fig. 1: Envelope of Rotational Magnitude

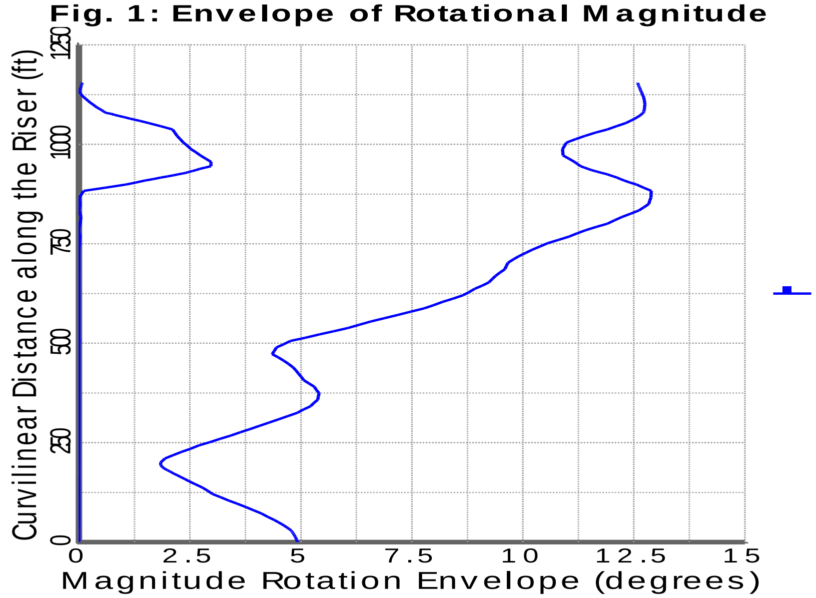


Fig. 2: Envelope of Horizontal-Y Displacement

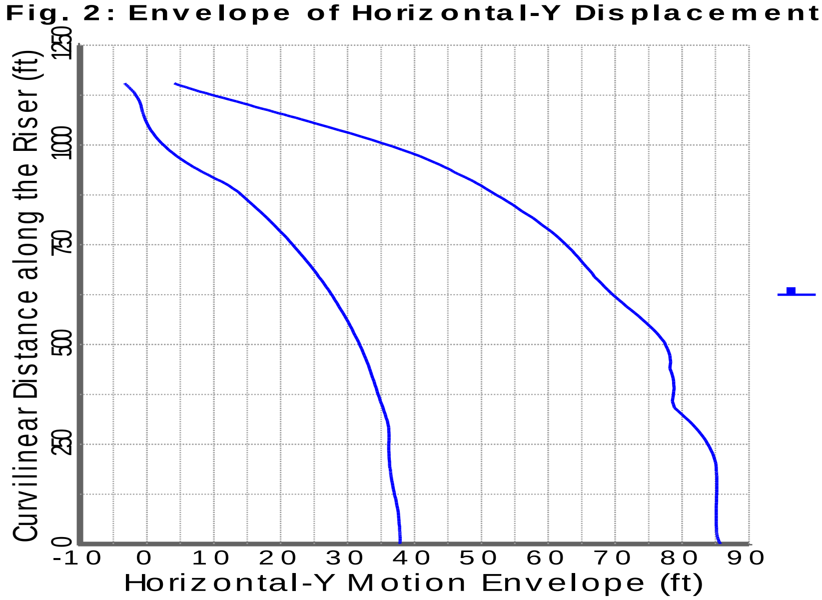


Fig. 3: Envelope of Horizontal-Z Displacement

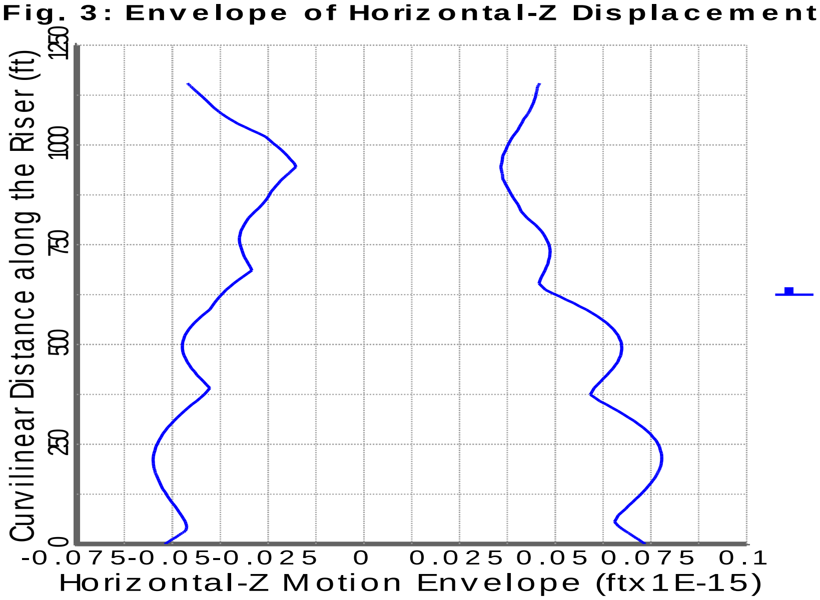


Fig. 4: Envelope of Effective Tension

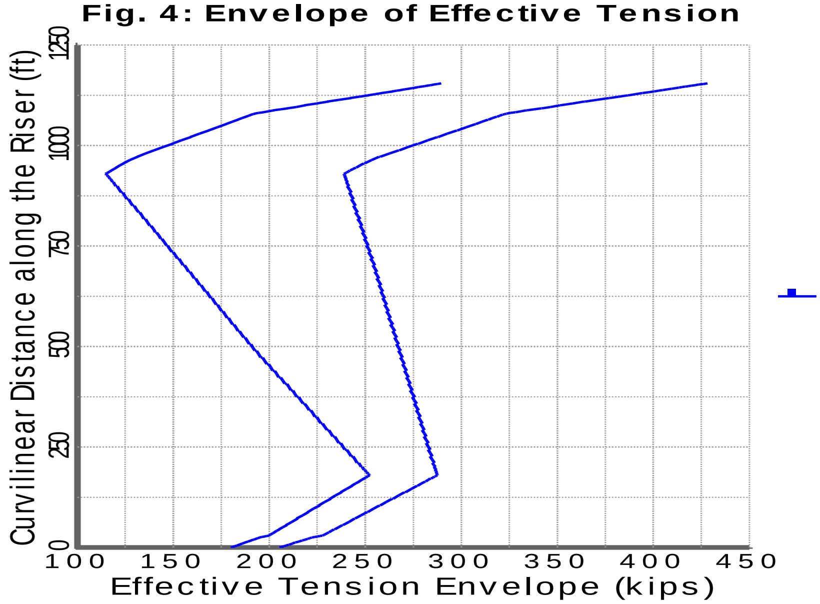


Fig. 5: Envelope of Resultant Bending Moment

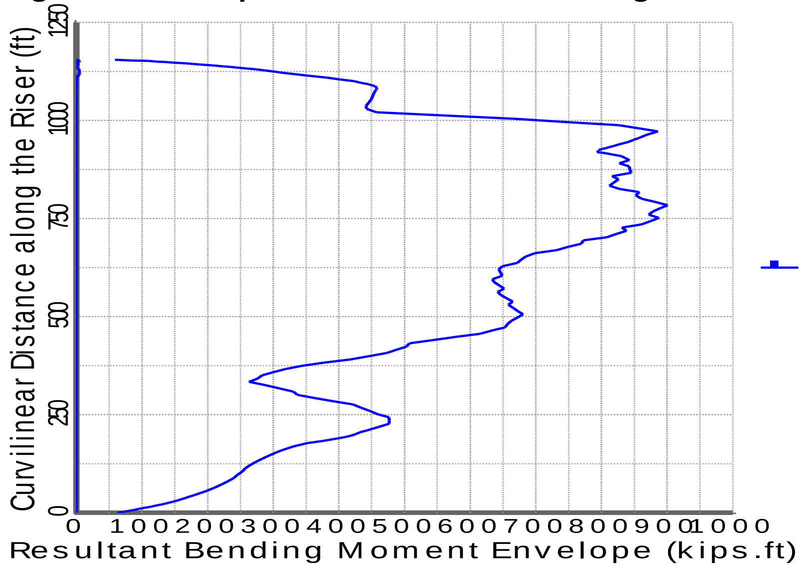
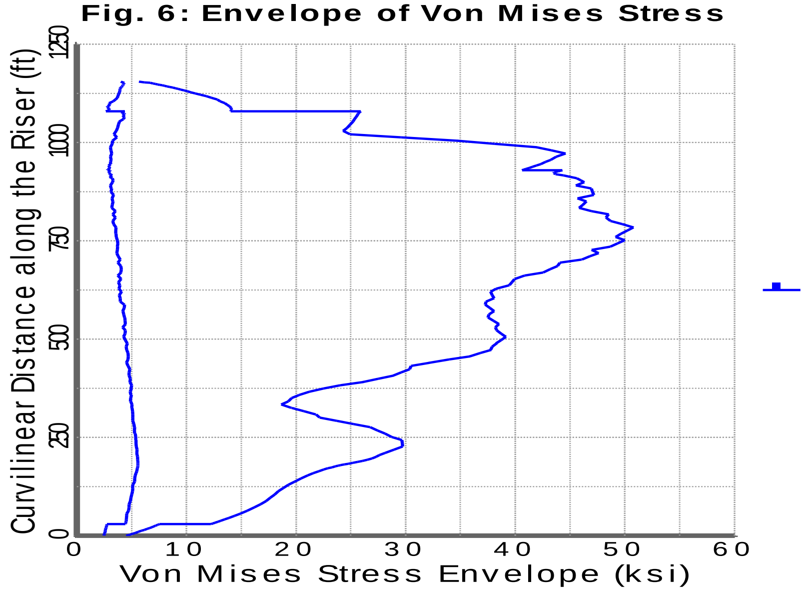


Fig. 6: Envelope of Von Mises Stress



Bibliography

[1] “Wikipedia,” [Online].

[2] C. B. e. a. Andrew Bishop, “Petroleum potential of arctic: challenges and solutions”.

[3] “SPE 157472 Achieving International Standards in the Arctic: The Need for Modern Interdisciplinary Technical and Management Approaches”.

[4] M. K. DNV, “Arctic oil & gas”.

[5] B. o. m. a. petroleum.

[6] “Economic Analysis of Future Offshore Oil and Gas Development: Beaufort Sea, Chukchi Sea, and North Aleutian Basin”.

[7] “indiancountry today media network.com,” [Online].

[8] [Online]. Available: http://www.offshore-technology.com.

[9] [Online]. Available: www.hebronproject.com.

[10] [Online]. Available: exxonmobil.com.

[11] USGS. [Online].

[12] Live Journal, [Online].

[13] “Kashagan and Tengiz – Castor and Pollux Daniel Johnston5 & Co., Inc”.

[14] IEA, “World energy outlook 2009”.

[15] U. Nerc.

[16] BLADE, “Overview of Drilling and completion activities 2010”.

[17] 2. Dickins & Allen.

[18] “NAS 2003, AMAP 2010”.

[19] “Giessing et al. 2002;Mosbech 2002”.

[20] “e.g. Collins et al. 1994”.

[21] “Mosbech 2002”.

[22] “Boertmann & Aastrup 2002”.

[23] “Holt 1987”.

[24] “Bay 1997”.

[25] “Graham et al.2011”.

[26] “Anonymous 2003”.

[27] M. E. p. comm.
[28] “Johansen et al. 2003”.
[29] “Nielsen et al. 2006”.
[30] “Short and Harris 1996”.
[31] “Faksness &Brandvik 2005”.
[32] “THE WESTERN GREENLAND SEA, David Boertmann, Anders Mosbech et al”.
[33] “McMinn, 1973”.
[34] “Zero Harmful Impact From Drilling Discharges: Where are the Limits? U.E. Moltu and L. Pinturier, Total E&P Norge”.
[35] [Online]. Available: http://www.norskoljeoggass.no.
[36] [Online]. Available: www.epa.gov.
[37] “OTC 22107 Green Management;Anders Backman, et al”.
[38] “The western Greenland Sea; National environmental research institute; David Boertmann, et al”.
[39] “Compton et al.2008”.
[40] “Breuer et al. 2008”.
[41] “Rye et al, 2003”.
[42] “Skjoldal et al, 2007”.
[43] “Illerup et al 2005”.
[44] “ PAME 2002”.
[45] “developing ice management strategies ;noble associates llc;PETER G. NOBLE”.
[46] “SPE/Iadc 163429; bais of design and specif for hallow water arctic modu;R.S shafer et al”.
[47] “Sayed 2012, Iyerusalimskiy 2012,Vachon 2012”.
[48] “Walsh et al,2004”.
[49] “Keener et al, 2009”.
[50] “Backman et al, 2006”.
[51] “Crocker et al, 1998”.
[52] “OTC 22092, Deepwater drilling for arctic oil and gas resource development; N Pilisi, Blade energy partners, et al”.

[53] “Technical and operational development of icebreaker; Goran Wilhelm et al”.
[54] “IACS; requirment concerning Polar Class 2011”.
[55] “Petroleum potential of the Arctic;Andrew bishop et al”.
[56] 1. Holley.
[57] “Agerton, 1983”.
[58] “Stanley &hazen,1996”.
[59] “Prodanovic,1986”.
[60] “Masterson et al, 2008”.
[61] “Angell, et all,1991”.
[62] “Stanley &hazen,1996”.
[63] “Hoff ,et al, 1994”.
[64] [Online]. Available: www.rigzone.com.
[65] Saipem. [Online].
[66] “Alexei Bereznitski; Huisman equipment B.V:;March 2012”.
[67] S. r. AS.
[68] “Maes,2009”.
[69] [Online]. Available: http://www.pet.hw.ac.uk.
[70] [Online]. Available: http://www.pet.hw.ac.uk.
[71] “OTC 22155; Deep-water Arctic .technical challenge and solutions; Rajiv Aggarwad and Richard D’Souza”.
[72] “Vervik,2009”.
[73] “Camili et al.2010, Crone & Tolstoy 2010”.
[74] “Schrope 2011”.
[75] “Kessler at al.2011”.
[76] “Hemmer et al. 2011”.
[77] “Conachey et al, 2007”.
[78] “Scarabeo 8 Operation manual Vessel description; Eni-Saipem; E.Pallotto”.
[79] “Status updates for offshore field development project: Goliat”. Subseal Q. Bishop interactive”.
[80] ““Eni approved for goliath development, first oil field in barets sea”. Rigzone”.
[81]

[82] “Goliat, Norway, offshore technologies.Net resources international”.

[83] [Online]. Available: www.drillquip.com.

[84] A. 1. Q.

[85] “DeepRiser; version 3.1; user manual”.

[86] unknown.

[87] “JAMESON LAND; Jannik Hansen, Gert Asmund et al.”.

[88] “SL.Ross Environmental Research Ltd, 1989”.

[89] “Agerton, 1983”.

[90] “OTC 19954; agoal based solution to offshore drilling challenges in arctic environment; Rod Allan et al 2009”.