EXECUTIVE SUMMARY

Objective

The objective of this study is to deliver an assessment of oil and gas technology that may be applied to cold regions of the United States Outer Continental Shelf (OCS). Advances in harsh environment offshore exploration and production technology have made it economically and technically feasible for projects to proceed in ice-covered waters.

This study assesses the current state of offshore technology in arctic and sub-arctic regions. The results of this assessment are then used to provide insight and guidance into existing/future exploration and development technologies that might be applied on the US OCS, in particular those areas in the Beaufort, Chukchi and Bering Seas.

The work covers exploration structures, bottom-founded and fixed production concepts, floating production concepts, terminals, pipelines and subsea facilities, and also touches on other technologies that might be relevant to Alaskan OCS exploration and development.

Assessment Methodology

This study draws on a review of current state-of-practice and state-of-the-art used in, or proposed for, arctic and sub-arctic offshore development areas. Assessments of exploration and production options are primarily based on technical feasibility. As appropriate, other aspects have also been considered, including constructability, capital costs, environmental considerations, operations, maintenance and repair, abandonment and decommissioning.

Given the large geographic area encompassed by the Beaufort, Chukchi and Bering Seas, location scenarios were adopted to help focus the assessments. These locations were chosen based on current and historic activity and interest (including lease sales, drilling, studies, projects, etc.) and water depths (given the general differences in offshore facilities configuration with water depths). Overall applicability of the technology to the region of interest was also considered.

Technical Feasibility

Bottom-Founded Structures

In multi-year ice areas of the Alaskan OCS, there are bottom-founded, e.g., gravity base structure (GBS), solutions that would be considered safe and economical up to around 250 ft (75 m) water depths when foundation properties are good, and up to around 200 ft (60 m) water depths when foundation properties are relatively weak.

There are no known bottom-founded platform design solutions for water depths greater than 330 ft (100 m) that could be deemed workable or proven for multi-year ice areas.

In the more southern areas, where multi-year ice is absent and only first-year consolidated ridge loadings are possible, bottom-founded solutions out to 500 ft (150 m) water depths are potentially viable.

Jacket & Jack-up Structures

The ice reinforced jacket platform was first successfully used in sea ice in the mid 1960's for Cook Inlet, Alaska developments. Previous studies have suggested that jacket structures are suitable for areas of the Bering Sea. However, these studies did not consider the vibration responses associated with the dynamic ice loading. Jacket type structures could likely be made to work in light first-year ice and in water depths less than 200 ft (60 m). However, the jacket structure's potentially poor response to dynamic loading and the need for conductor system protection are significant design issues for application in the Bering Sea.

Current design practices and understanding of jacket design make their application unsuitable for the Beaufort and Chukchi Seas.

Developments in jack-up technology and the advancement of ice maintenance programs indicate that the operating range and season of jack-up exploration could potentially be extended in the Bering Sea.

Ice Islands

Grounded ice islands have been used successfully as exploration drilling structures in nearshore areas of the US and Canadian Beaufort Sea. In practice, operational ice islands have been employed in water depths of up to 25 ft (7.6 m) in the Beaufort Sea.

Based on work sponsored by the MMS, the use of operational ice islands might be achieved in water depths of up to approximately 30 ft (9 m). The MMS Ice Island Study (2005) suggests that “incremental improvements in equipment capacity with higher productivity would allow islands to be constructed into deeper water and it is considered that 40 ft (12 m) water depth should not present a problem”.

The use of ice islands in the nearshore Chukchi would likely be infeasible due to the unstable and unreliable landfast, or contiguous, ice zone. Ice islands would be generally infeasible for Norton Sound due to its warmer and shorter winter season. However, definite conclusions can only be reached through more detailed study.

Gravel Islands

Although not a “high tech” technology, gravel islands have been successfully used in the Beaufort Sea for decades and continue to be viewed as a candidate structure for exploration and/or production in this area of the Alaskan OCS.

Since no gravel island structure has been used in the Chukchi Sea, a more detailed assessment would be required to determine feasibility. Due consideration would need to be given to the fact that the nearshore Chukchi Sea ice environment may be more dynamic than the Beaufort Sea. In the nearshore Bering Sea, gravel islands may be subject to higher waves and larger wave loads, which would need to be taken into consideration during detailed assessment.

Floating Structures

There are only a limited number of floating exploration or production structures that have been used in ice environments. Seasonal exploration can be carried out in the Alaskan OCS using drillships and drilling barges and, in areas without multi-year ice, semi-submersibles or a TLP. However, for exploration, the only location that a floating structure might be capable of staying on station year-round might be the Bering Sea under light ice conditions. A Semi-rigid Floater structure might work year-round under first-year ice conditions but would need to have the ability to disconnect and leave station in the event of potentially higher loads.

Floating production systems for the Beaufort Sea, Chukchi Sea and North Bering Sea are not considered to be technically feasible, even with continuous ice management. No floating production structures could be economically designed to stay on station with multi-year ice loads found in the Beaufort and Chukchi Seas, and possibly northern Bering Sea depending on local ice conditions. Floating systems may have some merit in southern Alaskan OCS areas, however.

Subsea Solutions

In some cases, there may not be a requirement for a production island or platform offshore. If the wellhead is located in water of sufficient depth, protection from ice would not be necessary. In areas with water depths less than the maximum ice keel depth, glory holes may need to be considered to protect the subsea facilities from ice ridge keels.

Improvements in the area of subsea facilities and processing have been made in recent years in the pursuit of resources in harsh and remote environments. As a result of these improvements, fields requiring longer, deeper subsea tiebacks are now becoming much more technically and economically feasible. Gas tiebacks have reached 105 miles (170 km) and oil tiebacks have reached 40 miles (65 km).

Subsea facilities can potentially be considered for any development on the Alaskan OCS. However, there are limitations on which technology should be or would need to be considered. Glory holes would only offer protection from gouging keels. Where active ridge building is taking place or there are grounded ridges present, there is the potential for a ridge keel to be pushed into an open glory hole as the ridge keel is being formed. Beyond the zone of active gouging, subsea facilities might be placed directly on the seabed (depending on the ice gouging regime).

Pipelines & Flowlines

Pipelines have been designed, constructed and are operational in the arctic, but these are in relatively shallow water depths and relatively close to shore. Pushing the limits to developments further offshore in deeper water will require that additional consideration is given to aspects related to design, construction and operation.

Some of the main considerations with respect to pipeline design in the arctic are strudel scour, thaw settlement of permafrost, upheaval buckling and ice gouging. It is generally felt that the first three considerations can be designed for on future projects. However, pipeline burial for protection in water depths from approximately 65 to 130 ft (20 to 40 m) will be a challenge given the more severe gouging in these water depths and the fact that the pipeline can likely not be installed from the ice in winter. While trenching from the ice to a certain water depth has been proven on projects in the nearshore Beaufort Sea, trenching and pipeline installation from floating vessels has not yet been attempted.

Export Terminals

The technical feasibility of marine terminals in arctic areas has been established through successful experience in a wide range of port facilities. A general review of experience in operation of high-latitude oil and gas marine terminals indicates that existing technology of port structures design and construction is sufficient to support operations in the Alaskan OCS.

While technically feasible, no tanker traffic has been proposed in the EIS for upcoming Beaufort or Chukchi lease sales. Regulatory requirements would require the use of pipelines (if economically feasible) rather than barging or tankering production to shore. An exception may be gas export by LNG or CNG.

Other Technologies

Advancing technologies such as extended reach drilling, well intersection method and pilot hole to pilot hole HDD installations might be considered for arctic developments.

Recommendations

It is generally agreed that environmental conditions (especially waves and ice conditions) are changing in the arctic. But no one knows definitively by how much, nor is there a compilation of current information (that the Study Team could find) that provides the information necessary to draw upon. *It has been suggested by stakeholders that the MMS might consider a future study to compile, collect and/or generate ice, metocean and meteorological information to be used by interested parties in screening studies.*

In carrying out this study, the Study Team identified additional information that would be "valuable to have" for future work. In addition, some technological areas were identified where advancements should be pursued, and these are also captured in this report.

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3D: Three Dimensional

ACEX: Arctic Coring Expedition

AGPPT: Alaska Gas Producers Pipeline Team

API: American Petroleum Institute

AZIPOD: Azimuth Thruster

BAT: Best Available Technology

Bbl: Barrel

BCF: Billion Cubic Feet

BOP: Blowout Preventer

BOPB: Barrels of Oil per Day

Bpd: Barrels per Day

BPXA: British Petroleum Exploration Alaska

CAC: Canadian Arctic Class

CALM: Catenary Anchor Leg Mooring

CANMAR: Canadian Marine Drilling Ltd.

CGB: Concrete Gravity Base

CIDS: Concrete Island Drilling System

CNG: Compressed Natural Gas

CRI: Caisson Retained Island

CSA: Canadian Standards Association

CSO: Coflexip Stena Offshore

DAT: Double Acting Tankers

DNV: Det Norske Veritas

DP: Dynamically Positioned

DP3: Class 3 Dynamic Positioning System

DWT: Deadweight Tonnage

EIS: Environmental Impact Statement

ERD: Extended Reach Drilling

FEIS: Final Environmental Impact Statement

FOIRLT: Fixed Offshore Ice Resistant Loading Terminal

FPSO: Floating Production Storage and Offloading

FS: Factor of Safety (or Safety Factor)

FSO: Floating Storage and Offloading

FSU: Floating Storage Unit

ft: Foot

GBS: Gravity Base Structure

GTM: Gas Transfer Module

HDD: Horizontal Directional Drilling

IACS: International Association of Classification Societies

IMO: International Maritime Organization

in: Inch

KBPD: Thousand Barrels per Day

kg: Kilogram

Kips: Kilopound

km: Kilometer

kPa: Kilopascal

ksf: Kilopound per Square Foot

ksi: Kilopound per Square Inch

LNG: Liquefied Natural Gas

Lun-A: Lunskoye A

m: Meter

MAC: Mobile Arctic Caisson

MAOP: Maximum Allowable Operating Pressure

MBM: Multiple Buoy Mooring

MCAD: Monocone Arctic Platform

MD: Measured Depth

mm: Millimeter

MM: Million

MMbbls: Million Barrels

MN: Meganewton

MPa: Megapascal

MMS: Minerals Management Service

MMSCF: Million Standard Cubic Feet

MMSCFD: Million Standard Cubic Feet per Day

MODU: Mobile Offshore Drilling Unit

MOU: Memorandum of Understanding

MV: Motor Vessel

MW: Megawatt

n.d.: No Date

NDT: Non-Destructive Testing

OCS: Outer Continental Shelf

OLAC: Online Accelerated Cooling

OLS: Offshore Loading System

OSER: Operational Safety and Engineering Research

OSR: Oil Spill Response

PA: Piltun-Astokhskoye

PA-A: Piltun Astokh-A

PA-B: Piltun Astokh-B

PIP: Pipe-in-Pipe

psi: Pounds per Square Inch

R&D: Research and Development

RFP: Request for Proposal

ROV: Remotely Operated Vehicle

SALM: Single Anchor Leg Mooring

SCADA: Supervisory Control and Data Acquisition

SDC: Steel Drilling Caisson

SET: Solid Expendable Tubular

SPM: Single Point Mooring

SSDC: Single-Steel Drilling Caisson

SSGB: Steel Stepped Gravity Base

STL: Submerged Turret Loading

TA&R: Technology Assessment and Research

TAPS: Trans Alaska Pipeline System

TCF: Trillion Cubic Feet

TLP: Tension Leg Platform

TLU: Tanker Loading Unit

Ton: Short Ton

Tonne: Metric Tonne

TVD: True Vertical Depth

USD: United States Dollar (Currency)

VCG: Vertical Center of Gravity

VIV: Vortex-Induced Vibration

VLCC: Very Large Crude Carrier

WIM: Well Intersection Method

W.T.: Wall Thickness

1.0 INTRODUCTION

1.1 Introduction & Overview

Offshore hydrocarbon exploration and production requires a bottom-founded platform, an artificial island, or a floating structure plus subsea equipment including pipeline/riser systems. Transportation of produced hydrocarbons to market is also an essential aspect of any development. An added complexity when hydrocarbon resources are located in arctic regions is the presence of first-year and/or multi-year ice during a significant part of the year. Global climate changes may also result in longer open water seasons in the future, which may lead to more significant storm events that must be considered in the design of full-field offshore development concepts for arctic regions.

This study has been carried out in response to the United States Department of the Interior, Minerals Management Service Request for Proposal (RFP), MMS Technology Assessment and Research (TA&R) Program, Operational Safety and Engineering Research (OSER) Broad Agency Announcement Solicitation 0106RP39786. Specifically, Objective #4, “Conduct a technology assessment for Outer Continental Shelf, Oil and Gas Operations in the Cold Regions to determine what may be technically feasible -given both ice-challenges, and also open water with large fetches and waves.”

A number of “cold regions” offshore developments have been carried out or are planned worldwide, including the east coast of Canada (Hibernia, Terra Nova, White Rose), Sakhalin Island (Russia), Kashagan (Caspian), Shtokman (Barents Sea) as well as in the Beaufort Sea (Northstar, PanArctic Drake). An understanding of these analogue projects, as well as those already operational or planned for the United States (e.g., Northstar and Oooguruk), can provide insight and guidance into potential exploration and development technologies that might be applied to cold regions of the United States Outer Continental Shelf (OCS).

1.2 Background

Principal factors governing the design of offshore exploration, production, and transportation facilities in arctic regions include:

- Environmental loads, primarily ice, with waves, currents and seismic effects also playing significant roles;

- The platform/island/structure itself (whether exploration or development), together with its functional requirements which consist of providing sufficient topsides space and the ability to be mobilized to site with significant consumables on board (as required);
- Available foundation/mooring resistance;
- Protection of pipelines and subsea equipment; and,
- Transport of produced hydrocarbons.

The combined effect of these principal factors dictates the geometry and material quantities required for exploration and production structures. Ice loads are clearly the governing design load for Beaufort and Chukchi Sea exploration and production structures. As a result of the oil and gas industry's limited arctic offshore exploration activity over the past 20 years, ice loads research has kept a low profile. Even so, through the 1990's and to the present day, there have been significant advancements in fundamental ice mechanics and analysis of full-scale ice load measurements. Beginning in the early 1990's, for example, Canadian Marine Drilling Ltd. (CANMAR) began promoting probabilistic predictive models based on the use of full-scale ice load measurements, such as the Hans Island Experiments. CANMAR's models suggested that design ice loads were some 15 times lower than the estimates of the 1980's. Other researchers have followed suit and ice loads currently developed by internationally recognized ice experts are now consistent with these lower figures. At the same time, advancements in structural steel research combined with these more realistic ice load predictions, led to improvements in economic feasibility of arctic offshore facilities.

There are also many challenges associated with the design and installation of offshore pipelines and subsea facilities in arctic environments. These include the evaluation of environmental data (such as ice gouge data), evaluation of geotechnical data, design for these environmental and geotechnical conditions, and construction or installation planning for an environment characterized by a limited construction season and harsh environmental conditions. Some unique aspects of arctic designs include environmental loadings (e.g., ice gouge, thaw settlement and strudel scour) and the effective use of limit state pipeline design for extreme loading conditions, such as those resulting from ice gouge and thaw settlement.

The transport of produced hydrocarbons from the arctic to market is also a significant consideration whether it be by pipeline, tanker or LNG/CNG carrier; each with its specific challenges.

1.3 Study Technical Objectives

The objective of this study has been to deliver an assessment of oil and gas technology that may be applied to cold regions of the United States Outer Continental Shelf (OCS). Advances in harsh environment offshore exploration and production technology have made it economically and technically feasible for similar projects to proceed in northern ice-covered waters. This study examines the current state of offshore technology in the Arctic or similar regions. These results are then used to provide insight and guidance into existing/future exploration and development technologies that might be applied on the US outer continental shelf, in particular those areas within the Beaufort, Chukchi, and Bering Seas. The work covers exploration structures, bottom founded and fixed production concepts, floating production concepts, terminals, pipelines, and subsea facilities, and also touches on some other technologies which might be relevant to Alaskan OCS exploration and development.

2.0 ARCTIC STRUCTURES

2.1 Evolution of Arctic Structures & Facilities

Exploration drilling for oil and gas in the Beaufort Sea began from gravel islands in shallow Alaskan State Waters in the late 1960's and similarly in the Canadian Beaufort Sea in the early 1970's. With time, activities progressed into deeper waters. In 1976, ice reinforced drillships were first utilized in Canadian waters, followed in 1981 by the first use of a bottom-founded caisson system. Exploration activities commenced in Beaufort OCS regions in 1982 using gravel islands, ice islands, bottom-founded structures and drillships. Examples of bottom-founded structures deployed in the Beaufort Sea are presented in Figure 2-1.

Figure 2-1: Arctic Caisson Drilling Structures

These bottom-founded structures were conceived primarily to extend the depth capability of granular islands. The caisson-retained islands were formed by building an underwater berm and then backfilling the caisson systems with a core of dredged material. Compared to conventional island-building up to that time, the amount of fill required to achieve stability was significantly reduced. As well, the effects of wave and current erosion during the open water season were reduced. However, these structures still required significant field operations to construct the berms, deploy, backfill, densify the core (Molikpaq requirement), decommission and move. Although touted as “mobile” structures, the caisson structures were not truly “MODU’s” (mobile offshore drilling units).

The SSDC was the first MODU-type structure in the Beaufort Sea, coming into service in 1982, and with the addition of the MAT remains the only active bottom-founded exploration structure in the arctic offshore.

In the early 1980’s, it was thought that an exploration (not production) structure for a 200 ft (60 m) water depth in the Beaufort Sea (Figure 2-2) had to be protected by a sand berm around 0.6 mile (1 km) in diameter and 100 ft (30 m) thick. At that time, ice features around 100 ft (30 m) thick were thought to deliver a load of about 3.3 million kips (1.5 million tonnes) to the exposed neck of a platform. These huge loads resulted from the extrapolation of small-scale tests directly to full-scale scenarios.

However, the combination of operational experience and full-scale research programs has resulted in a global design load reduction factor of around 15 (Figure 2-3). This obviously has a direct bearing on the global size and cost of arctic production structures. A reduction factor of around two for local loading on a 10.8 ft^2 (1 m^2) area has resulted primarily from using more realistic strain rates and treating the load in a probabilistic manner rather than as the absolute maximum possible crushing pressure.

The principles outlined in the technical paper *State-of-the-art of Bottom-Founded Arctic Steel Structures* (Fitzpatrick, 1994) have been used to predict the size, shape and weight of many arctic structures, including the following examples:

- The MAT base for the SDC (which carries an enormous imposed gravity load) was estimated to require 40,800 tons (37,000 tonnes) of steel. Final as-built weight was 39,700 tons (36,000 tonnes).
- The “Champ” MODU structure was estimated at 69,500 tons (63,000 tonnes) of steel. After one year’s engineering of detailed scantlings and third-party

verification, the weight takeoff from the drawings was 66,000 tons (60,000 tonnes).

- An ice-strengthened catamaran transport barge was estimated at 27,500 tons (25,000 tonnes). This was later verified by a Dutch engineering firm.
- A large GBS structure for the Grand Banks was estimated to require 93,700 tons (85,000 tonnes) of steel. After two years of finite element engineering analysis, two independent engineering firms - one in Edmonton and the other affiliated with The University of Manchester - estimated the final required steel weight at 95,900 tons (87,000 tonnes) and 92,600 tons (84,000 tonnes), respectively (see Fitzpatrick and Kennedy, 1997).

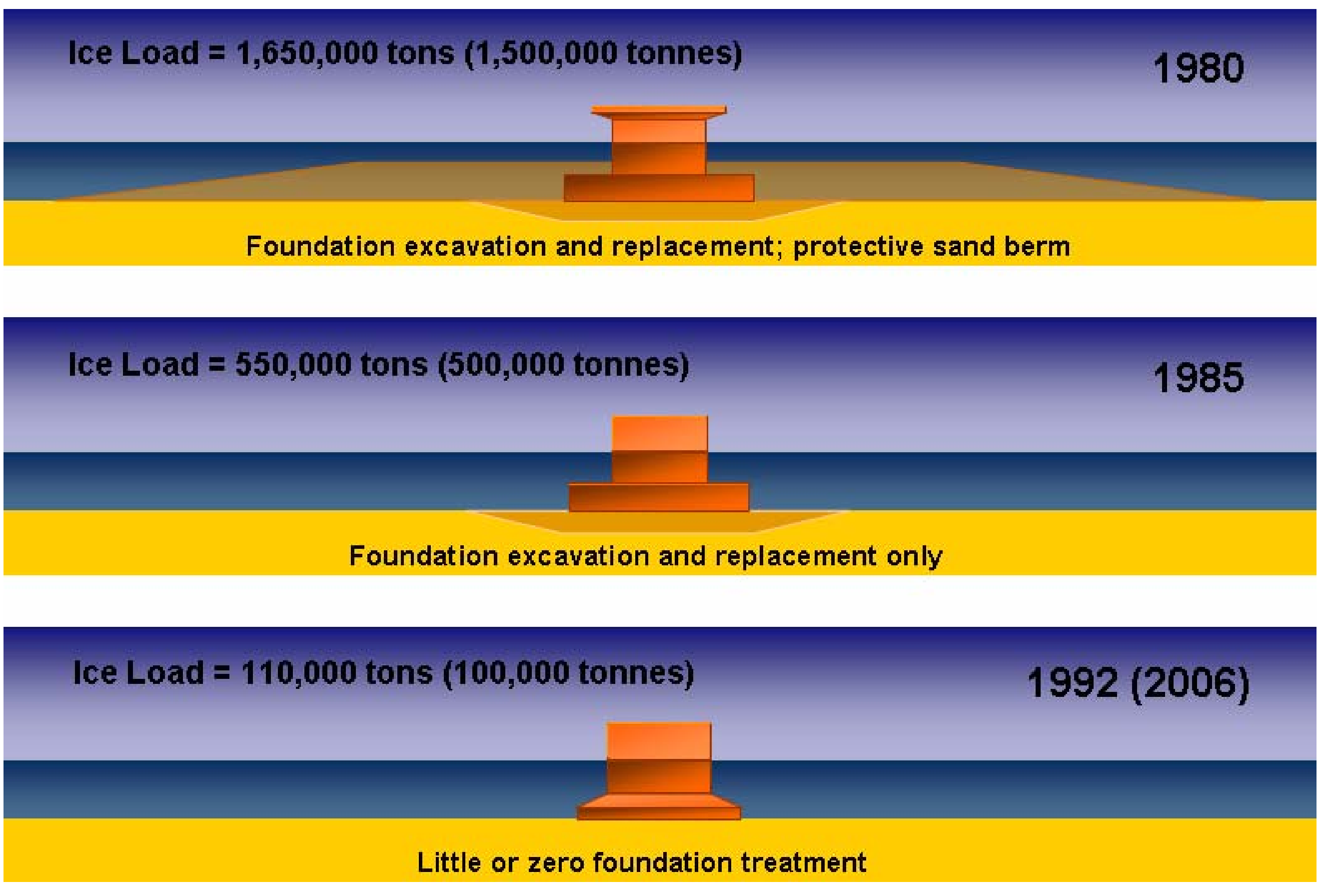

Figure 2-2: Evolution of Arctic Structure Loads and Foundation Requirements

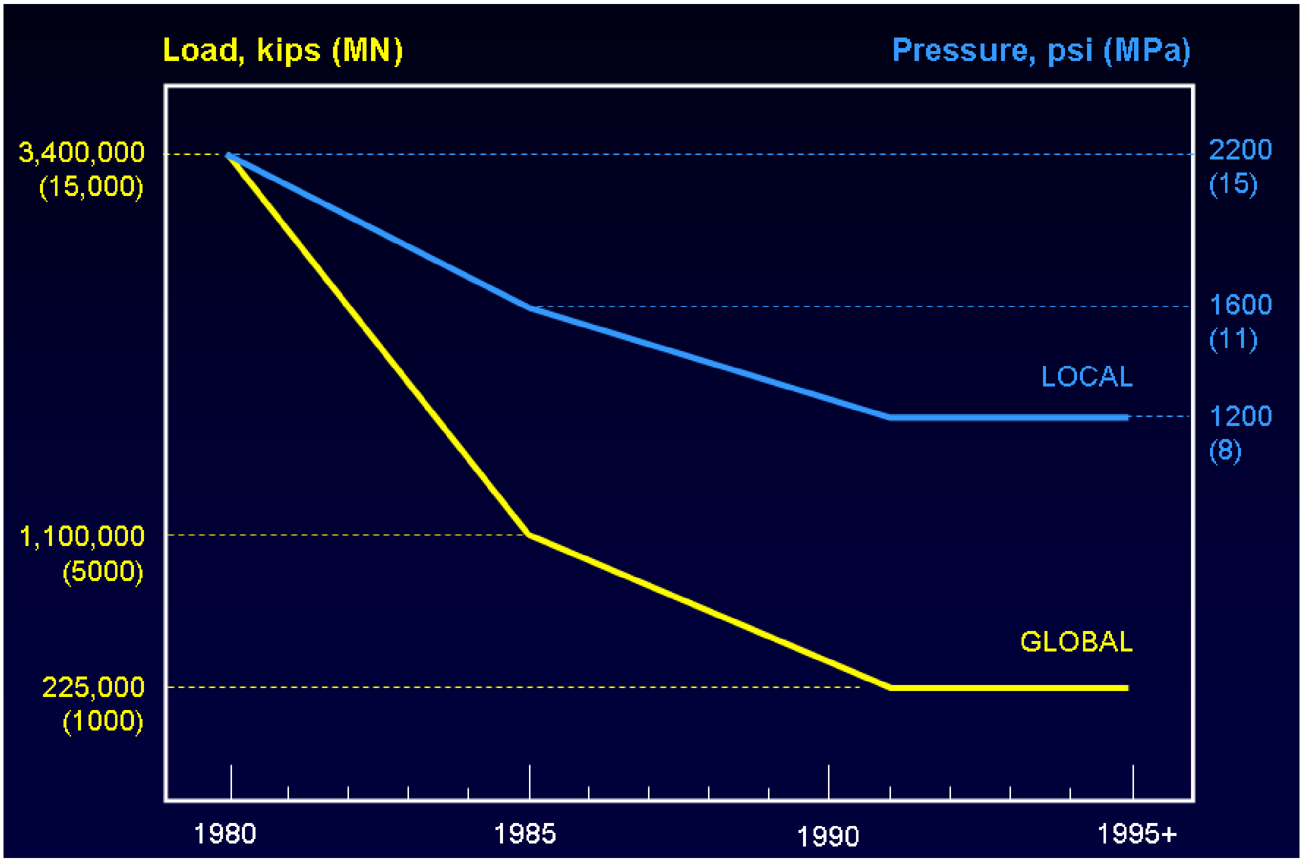

Figure 2-3: Evolution of Ice Loads on Arctic Structure

While the use of subsea pipelines in an offshore arctic or sub-arctic environment has been contemplated for several decades, only a handful of production or pilot pipeline projects have been constructed (e.g., PanArctic Drake, Northstar, Oooguruk, Sakhalin Island). In some cases, developments have been proposed without an offshore structure (e.g. PanArctic Drake). Several are planned to be constructed in coming years (e.g. North Caspian) while a number are being considered for the Beaufort Sea and other areas.

Early work considered the need to place the pipeline below the design ice gouge depth; however, it was not until the mid 1990's that there was greater recognition that soil movements and pressures transmitted through the soil to the pipeline had to be considered in design. Early projects, such as the PanArctic Drake and Polar Gas projects, explored innovative methods to protect the pipeline against ice gouging. Ongoing industry and research community work continues to progress offshore arctic pipeline design with regards to design gouge depths, subgouge deformation, and allowable pipeline strain limits.

2.2 Primary Design & Operation Considerations

2.2.1 Ice Loads

2.2.1.1 Full-Scale Ice Load Measurements

It is well-documented that extrapolating small–scale laboratory tests to full-scale scenarios greatly overestimates global ice loads on structures. This is due to the fact that ice fails non-simultaneously, and not at a uniform pressure, during an interaction. Hence, the only reliable method to determine global ice loads has been from measurements and observations of full-scale interactions. The most effective technique, and the most telling, has been monitoring the global response of the structure's foundation.

2.2.1.2 Geotechnical Monitoring

Pressure panels installed on the loaded face of an arctic structure or in the surrounding ice were a traditional method of measuring ice loads. But it is impractical and expensive to outfit the entire width of a large arctic structure with instrumentation, so only very small portions were instrumented, if at all. The "local" pressures measured on these small contact areas were often averaged across the entire contact width, which assumed that the peak pressures at the instrumented locations occurred at the same time and also between instrumented locations. This type of analysis led to overestimation of the peak global ice load in much the same manner as extrapolation to the full scale from very small-scale laboratory tests.

A more effective technique is to monitor the global response of the structure's foundation to ice loading. The global ice load can then be inferred from the measured deformation using finite element techniques. CANMAR reviewed eight (8) case histories in which foundation responses of arctic offshore structures were monitored and analyzed and, in all cases, only small (if any) foundation deformations were observed. Global ice loads interpreted from ice instrumentation were found to be 2.0 to 3.5 times higher than those interpreted from geotechnical responses (see Hewitt et al., 1994) as indicated in Table 2-1.

Determination of ice loads from the geotechnical response of arctic structures has proven to be very useful in placing an upper bound on ice loads. More importantly, it is the response of the foundation as compared to its maximum possible deformation that ultimately dictates the safety of a structure. Geotechnical response can also be useful in “ground-truthing” and discounting the apparently very high ice loads determined from small-scale ice instrumentation (Hewitt, 1994).

Table 2-1: SDC Drilling Location Ice Loads (Hewitt et al., 1994)

SDC Drilling Location	Ice Load Interpreted from Ice Instrumentation, tons (tonnes)	Ice Load Interpreted from Geotechnical Response, tons (tonnes)
Uviluk	8820 (8000)	< 3300 (< 3000)
Kogyuk	< 11,025 (< 10,000)	< 11,025 (< 10,000)
Phoenix	7715 (7000)	2200 (2000)
Aurora	7715 (7000)	< 3860 (< 3500)
Fireweed	N/A (no instrumentation)	< 1325 (< 1200)
Cabot	N/A (no instrumentation)	< 550 (< 500)

2.2.1.3 First-Year Ice Loads

First-year ice interactions with offshore structures are nominal, common loading events in the Beaufort Sea and other arctic regions. CANMAR compiled a database of measurements that included over 14,000 data points determined from re-analysis of 16 separate ice load data sets dating from as far back as 1966. Most of the data sets were collected during dedicated ice monitoring programs on Beaufort Sea structures and, in some cases, include load measurements in grounded ice rubble fields (see Blanchet and Kennedy, 1996). The advantage of using full-scale information is that natural effects such as ice temperature and the distribution of cracks and flaws are included in the data set.

An “envelope curve” was developed from these maximum data points to provide a deterministic method to estimate first-year ice loads on wide arctic structures for a variety of scenarios. The approach was used to secure drilling permits from MMS for year-round drilling operations for the SDC (formerly SSDC) in the Beaufort Sea.

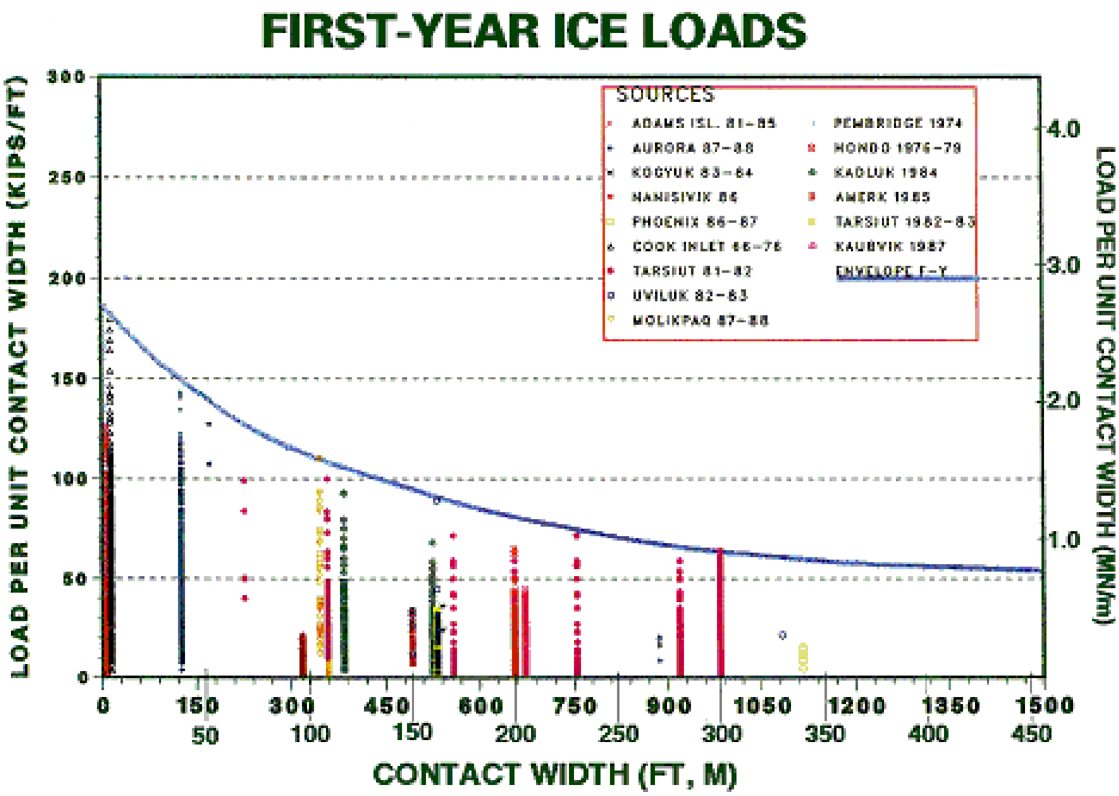

Figure 2-4: First-Year Ice Loads (Blanchet and Kennedy, 1996)

2.2.1.4 Hans Island Experiments & Multi-year Ice Impacts

Research programs have also made major contributions to the understanding of ice loads. The landmark Hans Island Multi-year Impact Experiments of the early 1980's investigated the loads generated by collisions with multi-year floes at full-scale. Results from the first Hans Island research program were initially very surprising. Global ice forces generated by high velocity impacts of 20 ft (6 m) thick multi-year floes, determined from floe deceleration, were significantly lower than anticipated.

Hans Island is a natural rock outcrop in the Kennedy Channel between Greenland and Ellesmere Island and it is impacted regularly by large ice features. The largest load recorded during the tests was during the summer of 1983 and resulted from a 20 ft (6 m) thick multi-year ice floe, several miles in diameter, moving at 4 feet per second when it hit the vertical base of the rock island. This impact was a significant milestone event in the ice engineering community. It was certainly an important event to study member John Fitzpatrick's understanding of ice-structure interaction, as he was present on Hans Island and was responsible for developing the analytical methodology for calculating the ice load.

Several methods were used to estimate the ice crushing force. The simplest, and most accurate, was to determine how the mass slowed down and then, by the use of Newton's law, the global force imparted to the island. This force proved to be about 49,500 tons (45,000 tonnes) over a contact length of about 1000 feet (3050 m). Prorating this 49,500 tons (45,000 tonnes) to a 65 ft (20 m) thick ice floe (an extreme Beaufort Sea ice feature) on a 230 ft (70 m) wide production structure would yield an ice load of 33,000 to 44,000 tons (30,000 to 40,000 tonnes).

2.2.1.5 Pipeline Considerations

Arctic offshore pipeline design issues related to ice gouging, strudel scour, frost heave / thaw settlement, upheaval buckling and sediment transport drive pipeline architecture and pipeline trenching requirements in terms of depth of cover and backfill thickness. Pipeline protection from ice in arctic environments is normally derived from both lowering the top of the pipe below the surrounding seabed (depth of cover) and burial (backfill thickness).

In sub-arctic and arctic areas, consideration must also be given to the design, installation and protection of subsea equipment such as wellheads and manifolds. Protection scenarios include placing the equipment below the maximum ice keel depth, as was the case on the Drake PanArctic pilot project (Watts and Masterson, 1979), or placement of subsea equipment in large excavated holes in the seabed (glory holes) which place equipment below the maximum ice gouge depth (McKenna, Crocker and Paulin, 1999).

2.2.2 Wave Loads

In the early 1990's, a typical maximum design wave (100-year return period) of 30 ft (9 m) was used for the Beaufort Sea (Fitzpatrick, 1994). More recently, other investigators have suggested a 40 ft (12 m) maximum wave. Functionally, the deck level for a bottom-founded production structure in the Beaufort Sea should be set to provide 9.8 ft (3 m) of clearance to green water when the structure is hit by a 40 ft (12 m) wave with a 3.3 ft (1 m) storm surge. However, for bottom-founded structures in the Beaufort, the design wave load will be very low compared to the design ice load, and will not govern the design. However, it does dictate a certain minimum freeboard above sea level which, in turn, influences the float-in stability requirements of the unit (the higher the center of gravity of the topsides, the more difficult the issue).

Wave loads are also a consideration for any floating type structure and subsea equipment, although such equipment has been designed for significant wave loads in other parts of the world.

2.2.3 Earthquake

Earthquake loads are also a consideration for bottom-founded structures and foundations. The SDC's topsides, for example, were designed for operation in the Alaskan Beaufort Sea at an acceleration of 0.25 g. It is likely that a nominal acceleration of at least this number will be required for topsides of any potential production platform concepts. This is not an overly onerous design condition, but it will be the prevailing lateral design condition for the topsides. Any shallow or "squat" platform which has the strength to resist an ice load on the order of 110,000 tons (100,000 tonnes) is not going to be affected by a moderate earthquake. However, that same platform will definitely have the ability to transfer its base accelerations up to the topsides. The question that must be asked is, "Will the structure dynamically amplify its base shears to a degree that is very onerous to the topsides?" This must be considered in the assessment of platform concepts.

Earthquake effects on pipelines and other subsea equipment (for example, seismic wave propagation) must also be considered.

2.2.4 Foundation Reaction Loads

Foundation reaction loads are sometimes trivialized and their significance often ignored. Experience has shown that even when the soils are soft, very high local pressures can build up locally against the base of an offshore structure. Such pressures are of the same order as ice load pressures, i.e., the structure base needs as much strength as the vertical sides. This is an important consideration for bottom-founded platform concepts.

Foundation capacity associated with other concepts such as floating structures and their associated mooring systems must also be properly assessed.

2.2.5 Facilities Functional Considerations

Functional considerations must also be addressed when designing/evaluating islands, platforms or other structures.

2.2.5.1 Deck Area

In the North American Arctic, re-supply is expensive during the frozen-in period. To a similar degree, other arctic areas have costly winter re-supply problems. Throughout the development phase, as production wells are being drilled, large storage areas are required in order to offset winter re-supply costs. While the amount of space required is site and project specific, many investigations over the past years result in a fairly consistent top deck requirement of about 110,000 ft^2 (10,000 m^2). For very little additional cost, this can be matched with a similar closed in deck about 16 to 26 ft (5 to 8 m) below. This 110,000 ft^2 (10,000 m^2) area, particularly in the US and Canadian Beaufort Sea, where design loads are in the 110,000 tons (100,000 tonnes) region, seems to fit quite reasonably with the structure size necessary for stability. No extensive deck cantileverage is required.

2.2.5.2 Oil Storage & Transportation

Many structures will be required to store oil in significant quantities particularly where product transportation is by ice breaking tankers. If use is made of the wet storage principle, i.e., either oil or water is present in the holding tanks at all times, and this seems to be the most preferable option, then the designer needs to be cognizant of the fact that there is a certain amount of storage capacity that is “free”, so to speak. This is because the presence of significant environmental loads requires a certain minimum size of structure for stability alone. Whether or not it achieves its weight as a result of oil or water ballast does not make a great difference (dry storage is different; there is no “free” dry storage). This minimum size structure varies a great deal according to regional location. In the Canadian sector this free storage can amount to around 2 MM bbls, and in the US typically around 1.5 MM bbls. In deep water In the Sea of Okhotsk (460 ft (140 m)) it can be as high as 3 or 4 MM bbls, while in the relatively mild Pechora Sea it is perhaps somewhat less than a few hundred thousand bbls. Defining this maximum free storage capacity is a good place to start the design of a product transportation system.

In general, the minimum storage capacity is related to the off-loading cycle time. The off-load quantity within each cycle is of course equal to the unfactored storage capacity. Where the free storage capacity is greater than this minimum, then use of this knowledge can be made to optimize further the tanker power, cycle times and carrying capacity.

2.2.5.3 Dry Storage

Where dry storage is required this adds significant expense to the basic structure. In many instances the premium can be around 30% or more of the basic platform cost. For many reasons, it should be avoided if possible.

2.2.5.4 Environmental Safety

The product storage area, for environmental reasons, should not be immediately inside the outer face. All the concepts shown have double bottoms, double tops and at least 33 ft (10 m) of plain water ballast tank between the outer face and the storage area. Approximately, this gives sufficient energy absorption capacity to resist penetration to the oil storage area by large icebreaking tanker traveling out of control at high speed.

2.2.6 Ice Gouge Effects

It is generally accepted that arctic pipelines would need to be trenched to some depth below the mudline to protect the pipeline from ice keels. Ice gouging of the seafloor is a near-shore feature for most of the northern continents where these ice keels intrude into water with depths less than the ice keel draft and form a gouge in the seafloor soils.

Early arctic offshore concepts were such that the design burial depth was sufficient to reduce the probability of ice contact with the pipeline to an acceptable level. The concept of subgouge deformation below moving ice keels in contact with the seabed was not recognized as an important design issue until the late 1980's and, therefore, does not appear to have been considered in the design of the pipelines.

A pipeline on the seafloor in such an environment may not be able to withstand the ice contact loadings and typically must be buried below the predicted extreme ice keel gouge depth for protection. As an ice keel passes over any point in the seabed, vertical and lateral stresses are applied to the soil at the keel base, resulting in some distribution of vertical and lateral soil displacements with depth beneath the ice keel. This is typically termed subgouge deformation of the seabed beneath the gouging keel (Figure 4-29). This deformation can impose forces on the pipe body and result in deformation of the pipeline.

The configuration of the pipeline after gouging, and hence the strain in the pipeline, depends on the pipeline properties, the soil characteristics, the depth of the design ice gouge, and the depth of the pipeline below the mudline. The pipe must be trenched sufficiently beneath the influence zone of soil displaced below the ice keel to limit pipeline strains to within acceptable limits. If the pipeline is trenched below the zone of significant soil movement, it will experience increased soil pressure but not high bending due to the relatively small soil displacements. If the pipeline is trenched within the zone of significant soil movement, it may experience plastic strains. Therefore, the soil displacements induced at the pipeline depth due to ice gouging and resulting strains in the pipeline must be calculated and evaluated. The effect of this soil displacement and the loading on the pipeline can be evaluated through non-linear finite element analysis.

3.0 REVIEW OF EXPLORATION & DEVELOPMENT OPTIONS

3.1 General

Offshore oil and gas exploration and production activities have been carried out and/or considered for a number of Arctic and cold ocean regions. A review of these activities may provide insight into options and technology, which are suitable for use in areas of the Alaska OCS; in particular, areas of the Beaufort, Chukchi, and Bering Seas.

As a starting point for this review, the project team identified candidate analogue areas based on experience and an initial review of Arctic and cold region exploration and production activities. Candidate areas were then studied in sufficient detail to allow screening and subsequent selection of analogue areas to carry forward in this study. In general, screening was based on area environmental (i.e. metocean and ice) conditions, water depths, and structure types / technologies considered in this study, including:

- Ice Islands
- Gravel Islands
- Bottom-Founded Structures
- Fixed Structures
- Floating Structures
- Subsea Solutions
- Pipelines & Flowlines
- Export Terminals
- Other Technologies

Discussion regarding the selection/screening of candidate areas is provided in Section 3.2. Review of the selected analogue areas is carried out in Section 3.3.

Of direct relevance to this study are those advances in exploration and production activities that have taken place in the Beaufort, Chukchi, and Bering Seas; these are reviewed below in Section 3.4. Note that the US and Canadian Beaufort Seas are typically discussed together in this report due to similarity in environments and structures/technologies used.

3.2 Analogue Area Selection

3.2.1 Selected Areas

Selected analogue areas are presented in Table 3-1. The table also highlights some of the most significant activities undertaken, or considered, in each analogue area, along with the associated structure types and technologies.

Subject areas of the Alaska OCS are included for completeness and have been reviewed in the same manner as the analogue areas. Furthermore, structures and/or technology used in one particular area of the OCS may be considered for application in another area of the OCS.

The following sub-sections provide discussion on selected analogue areas. It should be noted that metocean and ice data considered in the following sub-sections and throughout the remainder of this report can be found in Appendix A; they are generally not referenced directly in the main body.

3.2.1.1 Cook Inlet

Cook Inlet is a 180-mile (290 km) long estuary stretching southwest from Anchorage to the Gulf of Alaska. Oil was first discovered in Cook Inlet in 1963 and development commenced shortly thereafter.

Infrastructure used to develop Cook Inlet's offshore oil resources consist of fixed jacket offshore platforms connected to land based storage and distribution facilities via subsea pipelines. These structures are subject to first-year ice conditions ranging from 20 to 79 inches (0.5 to 2.0 m) thick.

Table 3-1: Analogue Areas Selected for Review

Region	Previous Exploration Program, Study, Project	Structures / Facilities
US Beaufort Sea	Northstar	Gravel Island / Pipeline
	Liberty	Gravel Island / Pipeline
	Oooguruk	Gravel Island / Pipeline
	Nikaitchuq	Gravel Island / Pipeline
Chukchi Sea	Chukchi Sea Feasibility Studies	Fixed Structures / Pipelines / Tankers
Bering Sea	Conceptual Studies	Floater, Fixed Structures, Pipeline
Cook Inlet (Alaska)	Various	Fixed Structures
Canadian Beaufort	Tarsiut/Kopanoar/Issungnak	Gravel Island / Pipeline
	Amauligak	Caisson Retained Island / Pipeline
	West Amauligak	Subsea / Pipeline
Canadian High North	Drake PanArctic	Pipeline and wellhead
	Polar Gas	Subsea manifolds / pipelines
Davis Strait/West Greenland	Conceptual Studies	Floater, Subsea & Flowlines
Canadian East Coast	Hibernia	Concrete GBS / Storage
	Terra Nova	Floater, Flowlines & Subsea
	White Rose	Floater, Flowlines & Subsea
	BP Amoco West Bonne Bay	Steel GBS / Storage
Eastern Russia	Sakhalin 1	CIDS / Pipeline
	Sakhalin 2	Molikpaq / Lunskoye / Piltun-Astokhskoye-B / Pipeline
	Sakhalin 4	Bottom-Founded, Pipeline
	Sakhalin 5	Bottom-Founded, Pipeline
Barents Sea	Shtokman	Floater, Subsea & Flowlines
Pechora Sea	Prirazlomnoye	Fixed Structure, Tankers
Karas Sea (Gulf of Ob)	Conceptual Studies	Fixed Structure, Pipelines
Baltic Seas	Kravtsovskoye	Jacket, Pipeline

3.2.1.2 Canadian High North

A limited number of projects were proposed for the Canadian High North including the Drake PanArctic gas project and the Polar Gas project. A Canadian company, PanArctic Oil Ltd., sponsored the Drake Field subsea completion which was located in the Canadian High Arctic off of Melville Island. The world's first arctic subsea flowline began transporting gas in April 1978, from a subsea wellhead to production facilities onshore (Palmer et al., 1979). The three-year program to design, fabricate and construct was part of a test program to evaluate the performance of the field development concept and demonstrate the feasibility of such an offshore arctic development.

Polar Gas was a consortium of American and Canadian companies formed in 1972 that investigated the possibility of bringing natural gas southward by pipeline from the Canadian Arctic Islands (Houlding, 1976). Considerable design work and a research program was undertaken to look at the feasibility of laying pipelines in extreme low temperatures and through the ice in the Canadian Arctic.

3.2.1.3 Canadian East Coast

The East Coast of Canada currently has several producing oil and gas fields. These fields are located off the coast of Newfoundland and Nova Scotia. Furthermore, significant exploration activity has been undertaken in these areas and on the Labrador Shelf.

The fields located offshore Newfoundland are the Grand Banks developments; Hibernia, Terra Nova, and White Rose. These developments use structures that are designed (at least to some degree) to withstand sea ice and iceberg loads.

Although the Labrador Shelf does not have a production project to date, significant exploration has been carried out on the shelf and, in recent years, consideration has once again been given to potential gas production from the area. In terms of sea ice and icebergs, the Labrador shelf is subject to a much harsher environment than the Grand Banks.

The Sable Energy Project, which lies offshore Nova Scotia (near Sable Island), experiences very little sea ice, and icebergs are rare. The likelihood of sea ice from the Gulf of St. Lawrence encroaching on the Sable development is very low; less than 1 percent based on 30 years of observations (CAEE, 2005). Furthermore, only one iceberg has been reported in the Sable development area in the last 60 years, and the probability of future iceberg occurrences is low (ExxonMobil, 2007).

3.2.1.4 Offshore Greenland

Offshore petroleum exploration has taken place off the east, north, and west coasts of Greenland; however, drilling has only been conducted offshore west Greenland. Initial exploration offshore west Greenland took place between the early to mid 1970's with extensive seismic surveys. Following this period, five wells were drilled between 1976 and 1977; however, interest in further exploration was curtailed when well results had indicated that the wells were dry (Geological Survey of Denmark and Greenland, 2005).

Throughout the 1990's, interest in offshore west Greenland began to grow and in 1997 additional processing of well data suggested that the Kangamiut-1 (drilled in 1976) showed hydrocarbons (Geological Survey of Denmark and Greenland, 2005). In 2000, the sixth exploration well (Qulleq-1) was drilled. No further exploration drilling has taken place; however, offshore exploration licenses were awarded for licensing rounds held in 2002, 2004, and 2006.

In general, a significant portion of the west coast of Greenland experiences sea ice each year during the winter and early spring and, depending on location, icebergs can be encountered frequently (Mosbech et al., 2007). Some consideration and preliminary study work with respect to potential development options has been carried out and is discussed later in this report.

3.2.1.5 Eastern Russia (Sakhalin Island)

Sakhalin Island is a large elongated island in the North Pacific, north of Japan, which is part of Russia. Projects currently producing oil offshore Sakhalin Island include Sakhalin 1 (ExxonMobil) and Sakhalin 2 (Shell) directly off the east coast of Sakhalin. These projects have been developed using retrofitted gravity base platforms from the US Beaufort (CIDS) and the Canadian Beaufort (Molikpaq). Future proposed projects include Sakhalin 5 which will be off of the northeast coast of the island.

The east coast of Sakhalin Island is an area characterized by storm winds, fog, freezing temperatures in winter, intense snowstorms, sea ice and pressure ridges, and ice gouging. Table 3-2 presents information on some of the Sakhalin Island projects currently being considered.

Table 3-2: Sakhalin Fact Sheet (source EIA, 2007)

April 2007

Sakhalin Fact Sheet

Sakhalin Island, a former penal colony located off Russia's eastern shore (see map), is home to six oil and gas projects. The five projects are currently in different stages of development, and two of the projects, Sakhalin I and Sakhalin II, aim to bring oil and natural gas production online in the near term. Both projects have targeted Asian markets. Three blocks after Sakhalin VI have not been awarded yet.

Name	Sakhalin I	Sakhalin II	Sakhalin III	Sakhalin IV	Sakhalin V	Sakhalin VI
Primary Field/Block Names	Odoptu [Northern and Southern] (onshore), Chayvo (onshore and offshore), Arkutun-Dagi	Sakhalin Energy Investment Company: Piltun-Astokskoye, Lunskoye (will provide most of the LNG, 34 kb/d of oil)	Kirinskii, Veninskaya, Vostochno-Odoptu, Aiyashkii	Pogranichny Block, Okruzhnoye fld	Kaigansko-Vasyukansk (active drilling)	Pogranichny
Oil Reserve Estimate	975 million bbl, (Source: IHS Energy)	1.0-1.2 billion bbl (Source: Shell)	Total: 4-5 billion bbl Veninsky Block: 830 million bbl (Source: IHS)	880 million bbl	4.4-5.7 billion bbl	600 million bbl
Natural Gas Reserve Estimate	11 Tcf, (Source: IHS Energy)	17.3 Tcf (Source: Shell)	Total: 27-38 Tcf Veninsky Block: 11 Tcf (Source: IHS)	19 Tcf	15.2-17.7 Tcf	n/a
Net Total Investment	Phase 1: $5 billion	Phase 1: $4.5 billion, Phase 2: $20 billion over next 4-5 yrs.	$13.5 billion expected (ExxonMobil- $80m in geological studies)	$2.6 billion expected	$3-5 billion expected	n/a
Current & Expected Prod'n Level	Max oil production from Chayvo field achieved in Feb. 2007 at 250 kb/d. Commercial gas prod'n expected in 2008	Current: 80,000 bbl/d for 6 months, Phase II: 180,000 bbl/d, year-round oil production expected in Dec. 2007, LNG prod'n expected in Summer 2008	n/a	n/a	n/a	n/a
Primary Project Developers	Exxon Neftegaz (30%), in conjunction with consortium members SODECO (30%), ONGC Videsh (20%), Rosneft (8.5%), Sakhalinmorneftegaz (11.5%), and RN Astra (8.5%)	Gazprom (50%+), Sakhalin Energy Investment Company: Shell (27.5%), Mitsui (25%), Mitsubishi (20%)	Rosneft is primary developer. Veninsky Block: Rosneft (49,8%), Chinese Sinopec (25.1%) and Sakhalinskaya Neftyanaya Kompaniya (25.1%)	BP (49%), Rosneft (51%)	Elvary Neftegaz: BP (49%), Rosneft (51%)	Petrosakh, Alfa Eco
Status/Notes	Mode of gas export still up for negotiation. Exxon prefers pipeline exports to China (cheaper). Other shareholders, Gazprom prefer piping to LNG terminal at Sakhalin II.	Oil production began in 1999; Processing terminal under construction which will have capacity of 66,000 bbl/d of oil, 1.8 bcf/d of gas	Lukoil possibly in cooperation with Gazprom will probably take part in new tenders for Kirinskii and Vostochno blocks.	Rosneft undertaking 3D seismic, to be complete by Oct. 2006.	Rosneft undertaking 3D seismic.BP/Rosneft drilled 3 successful wells during 2006.	3 blocks in Sakhalin VI have not been awarded

Source: Project Homepages (see links section), IHS Energy, Interfax, Russian Energy Monthly (www.easternblocenergy.com), FSU Oil and Gas Monitor, Pipeline & Gas Journal

3.2.1.6 Russian Arctic (Barents, Karas, Pechora, and Baltic)

Technology developments in the Russian Arctic are driven by the same challenges that exist in the American and Canadian Arctic; the hydrocarbons are to be extracted from shelf reserves which are located in areas of adverse environmental conditions, and they are to be safely delivered to markets in lower latitudes. If there is any difference, it probably manifests in conditions for transportation, and in the available infrastructure which, in the Russian case, may be more challenging.

The routes from the main Russian Arctic fields to European and American consumers are fairly long and are through remote areas both in the sea and on land. A map showing the location of the main fields of the Russian Arctic is presented in Figure 3-1 (Imayev et al., 2005). As can be seen, large offshore and oil and gas reserves are located east of Novaya Zemlya archipelago, in the Kara Sea and near the Yamal Peninsula coast. While a number of future offshore exploration projects are planned for this area, information on work carried out to date is limited. Descriptions of Arctic offshore projects included in this Section are primarily related to work that has been carried out in the Russian sector of the Barents Sea.

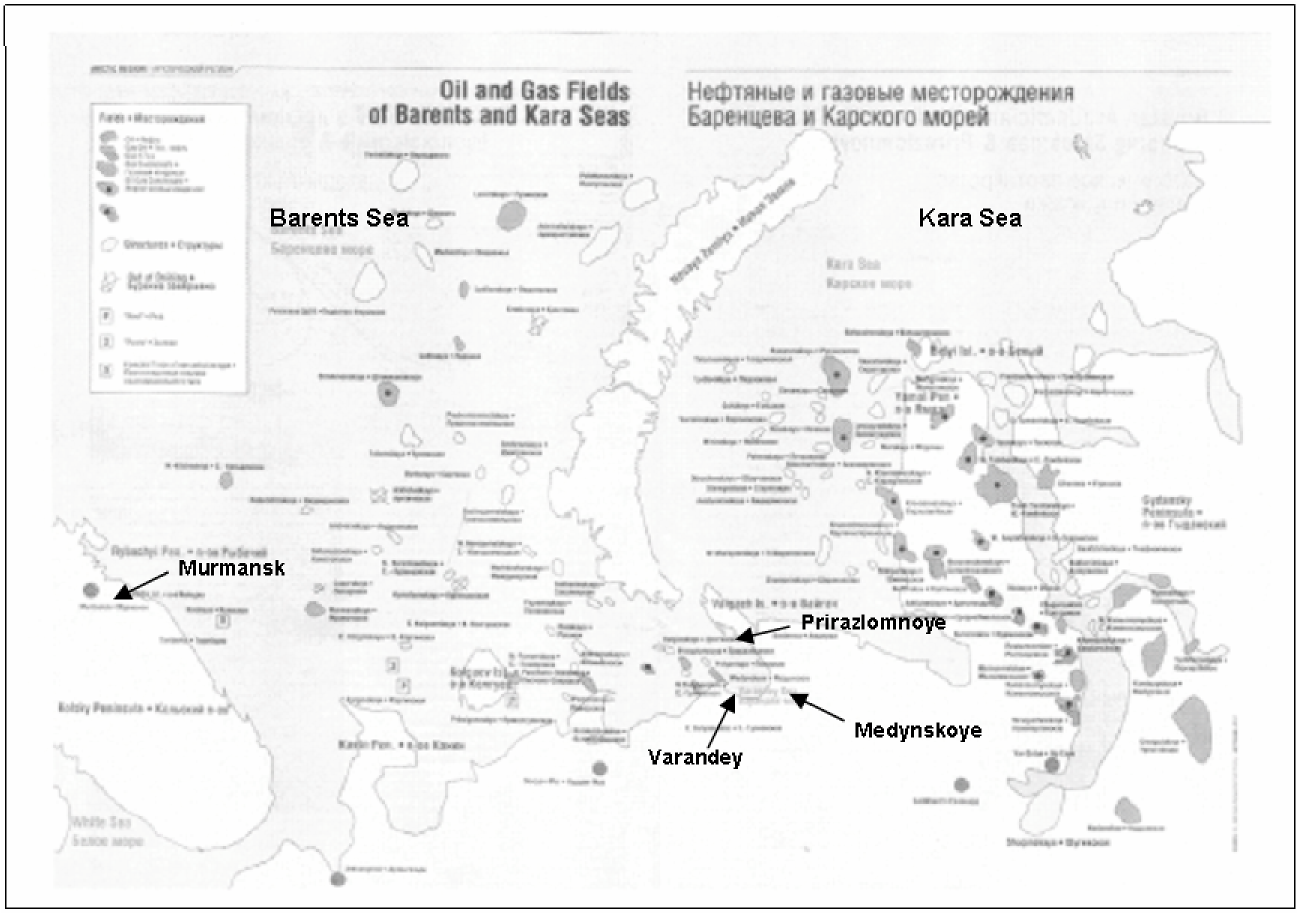

Figure 3-1: Oil and Gas Fields of Barents and Kara Seas (Imayev et al., 2005)

A significant part of the world's oil and gas reserves are believed to be in the Russian sector of the Arctic Ocean Shelf. Many of the prospective fields were discovered east of the Ural Mountains, along the Siberian coast (Ob and Taz Bays, Yamal Offshore); however, more recently activity has been progressing along the European coast (Barents Sea, Pechora Sea). According to some recent publications (Snieckus et al., 2007), questions still surround ultimate recovery calculations and what will be required to bring the gas-dominated production to the market. However, the pace of technological developments for exploration in the Russian Arctic remains high. These developments are expected to be dominated in the near future by the exploration of the giant Shtokman (or Shtokmanskoye) gas and gas condensate field in the Barents Sea. Located approximately 373 miles (600 km) offshore, in 985 to 1150 ft (300 to 350 m) of water, with ice conditions that include two-year ridges and icebergs, the Shtokman field development will apparently stay at the forefront of contemporary Arctic development technology.

Technical information on exploration in the Russian Arctic is not widely available. However, a cross-referenced search through multiple promotional briefs, news summaries and press-releases on the internet gives, in many cases, somewhat of a picture of the basic technology components planned for development projects. Some information on the general scope of the Russian Arctic technology projects was collected during an information gathering trip to Moscow and St. Petersburg in April, 2007. This information has been mainly included in Section 3.3 and within Appendix D.

The meeting with the specialists of Krylov Shipbuilding Research Institute in St. Petersburg was particularly informative. Krylov is one of the largest technological and research centers in Russia. The company has more than 2000 employees and a wide range of research installations and scientific/design groups. One of the largest areas of activities in Krylov now is development of technical means (ships, platforms and marine technology) for oil and gas exploration. The promotional manual prepared by the Institute lists over 200 projects and contains brief descriptions of approximately 75 of them (Krylov Institute, n.d.). It is interesting to note that 70 percent of these projects are directly associated with exploration on the Russian Arctic shelf. This clearly indicates the significance of Arctic development in the overall scope of oil and gas exploration technology work in Russia.

Informative discussions during the information gathering trip to Russia were also conducted with the specialists of VNIIGAZ (All-Union R&D Institute of Natural Gases) in Moscow. Presently, VNIIGAZ is a leading scientific institution of Gazprom (the largest Russian oil and gas enterprise). The technology research is conducted in the VNIIGAZ Offshore Oil and Gas Fields Center (Gazprom and VNIIGAZ, n.d.).

Information on development in the Russian Arctic is also contained in reviews prepared by foreign companies and in published results of their joint studies with Russian companies and institutions (Frantzen and Bambulyak, 2003).

A number of pipelines have been considered for the Russian Arctic, including pipelines across the Baltic Sea, Baydaratskaya Bay, the Pechora region, and the Barents Sea. Most activity currently being planned for the Barents Sea seems to be for the western part which is essentially ice free.

3.2.2 Screened Areas

In addition to the areas discussed above, the following list of areas were initially considered candidate analogues. However, upon further consideration they, along with offshore Nova Scotia, were not carried forward in this study:

- North Caspian Sea
- Greenland Sea
- Yellow Sea
- Norwegian Sea
- North Sea
- Laptev Sea
- East Siberian Sea

3.2.2.1 North Caspian

The North Caspian Sea is ice covered for 3 to 5 months per year. Level ice thickness has been observed up to 36 inches (90 cm) and the extent may reach the coastal regions as far south as Aktau. Ice movements are purely wind driven which leads to three main types of deformed ice features: rafted ice, ridges and stamukhi. Rafted ice regularly reaches over 3.3 ft (1 m) in thickness in the early ice season and has been observed locally to over 9.8 ft (3 meters). A unique aspect of Caspian rafted ice is that it has been consistently observed where it is made up of over 10 layers. Ridges and stamukhi cause pitting and gouging of the seabed across the entire northern area. Ice ride-up and pileup are also a concern for exploration and production islands.

For exploration and appraisal drilling, AKCO has used the MODU Sunkar which has water ballast onto a submerged rock berm as well as a man-made island. The shallow water depth of the North Caspian is favorable to the use of man-made islands (gravel/rock) for production facilities.

While, the Caspian has ice related problems similar to the Alaskan OCS areas, the major differences are the thickness of the ice and the water depths. Therefore, this region is not carried forward as an analogue area.

3.2.2.2 Other Areas

Baffin Bay is considered to have good potential for gas and oil (Indian and Northern Affairs Canada, 1995) as there is evidence of active oil seeps and petroleum source rocks in the area. Only one well has been drilled in Baffin Bay between 1976 and 1977, and no development concepts were discovered as part of this study, Baffin Bay is not being considered further in this study.

Ice resistant structures have been considered for the northern Yellow Sea. However, environmental conditions in that region are not considered to be analogue to those areas of interest in the Alaskan OCS. As the North Sea and Norwegian Sea are not subject to regular seasonal ice coverage or multi-year ice intrusions, they are not considered further. No significant discoveries in the Laptev and East Siberian Sea have been identified and therefore these regions are also not considered further.

3.3 Analogue Exploration & Development Options

3.3.1 Bottom-Founded & Fixed Structures

3.3.1.1 Sakhalin Island

<u>Sakhalin 1</u>

The Sakhalin 1 project acquired the Concrete Island Drilling System (CIDS) from the US Beaufort Sea (Section 3.4.1.6) and renamed it the Orlan Platform (Figure 3-2). Compared to the cost of a newbuild, the cost to purchase, refurbish and upgrade an existing structure was attractive to the project (PennWell Publishing, 2007).

The CIDS structure had been built in 1983 and was designed for year-round drilling in Arctic waters up to about 50 feet water depth. At the time of purchase, it had been mothballed off the north slope of Alaska. Refurbishment started in 2001 and included installing a wave deflector shield, and strengthening the platform base to resist earthquake effects (PennWell Publishing, 2007).

Figure 3-2: Orlan Platform off of Sakhalin (from PennWell Publishing, 2007)

Sakhalin 2

The first phase of the Sakhalin development began with the Molikpaq platform producing oil from the Astokh feature of the Piltun-Astokhskoye field back in 1999. The Molikpaq is the first offshore oil production platform in the Russian Federation. It is located on the Astokh feature of the Piltun-Astokhskoye (PA) reservoir offshore Sakhalin. Sakhalin Energy has been successfully producing oil from the Vityaz Complex since July, 1999. Up until 2007, production from a floating storage and offloading unit was limited to the summer ice-free season.

The Vityaz Complex consists of the Molikpaq production platform (Section 3.4.1.5), a single anchor leg mooring buoy (SALM) and the Okha floating storage and offloading (FSO) unit (Figure 3-3). During the ice season, following the disconnection from the Okha FSO, the SALM is ballasted down on the sea bottom thus completing preparations for the winter.

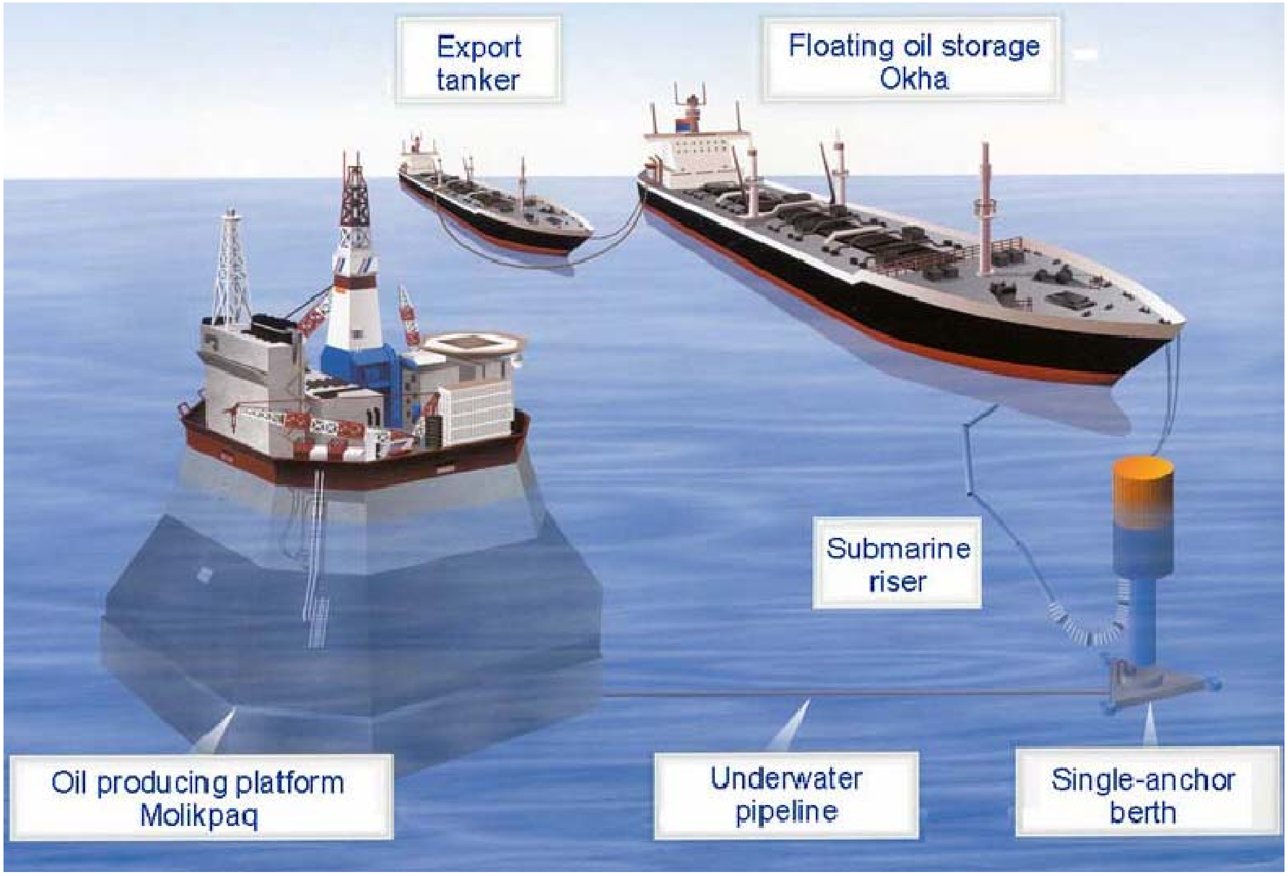

Figure 3-3: The Molikpaq Platform as part of the Vityaz Production Complex (Calitz and Mercer, n.d.)

Sakhalin Energy plans to convert the Molikpaq to a year round production cycle at year end 2007, once the platform has been connected to the new pipeline system (Phase 2).

Scheduled to begin full operations in 2008, the Sakhalin 2 Phase 2 project is the second stage in plans to develop the Piltun-Astokhskoye oil field and the Lunskoye gas field. Together, the Piltun Astokhskoye and Lunskoye fields hold more than 1 billion barrels of crude oil and more than 17.5 tcf (500 billion cubic meters) of natural gas, making them among the largest oil and gas reserves under development in the world (Sakhalin Energy, 2006b).

Once extracted, the oil and gas will be piped onshore for processing. It will then be transported via two 497 mile (800 km) pipelines to the LNG plant and oil export terminal that has been constructed in Prigorodnoye, in the south of Sakhalin Island. The sea at Prigorodnoye is nearly ice-free and allows exports all year.

The permanent offshore infrastructure installed for Sakhalin 2 includes a network of offshore pipelines and three bottom-founded production structures; the Piltun Astokh-A (PA-A) or Molikpaq, the Piltun Astokh-B (PA-B), and the Lunskoye A (Lun-A). These platforms are designed to operate in six-month frozen seas, severe storms, significant seismic loading, and a combination of sea ice, wind and wave loads.

The Sea of Okhotsk is characterized as an area with air temperatures that can reach 102°F (39°C) in the summer and -38°F (-39°C) during the winter, waves that can reach a 100-year maximum height of around 65 ft (20 m), and ice pressures of 0.6 psi (4 kN/m^2) (Snieckus, 2002).

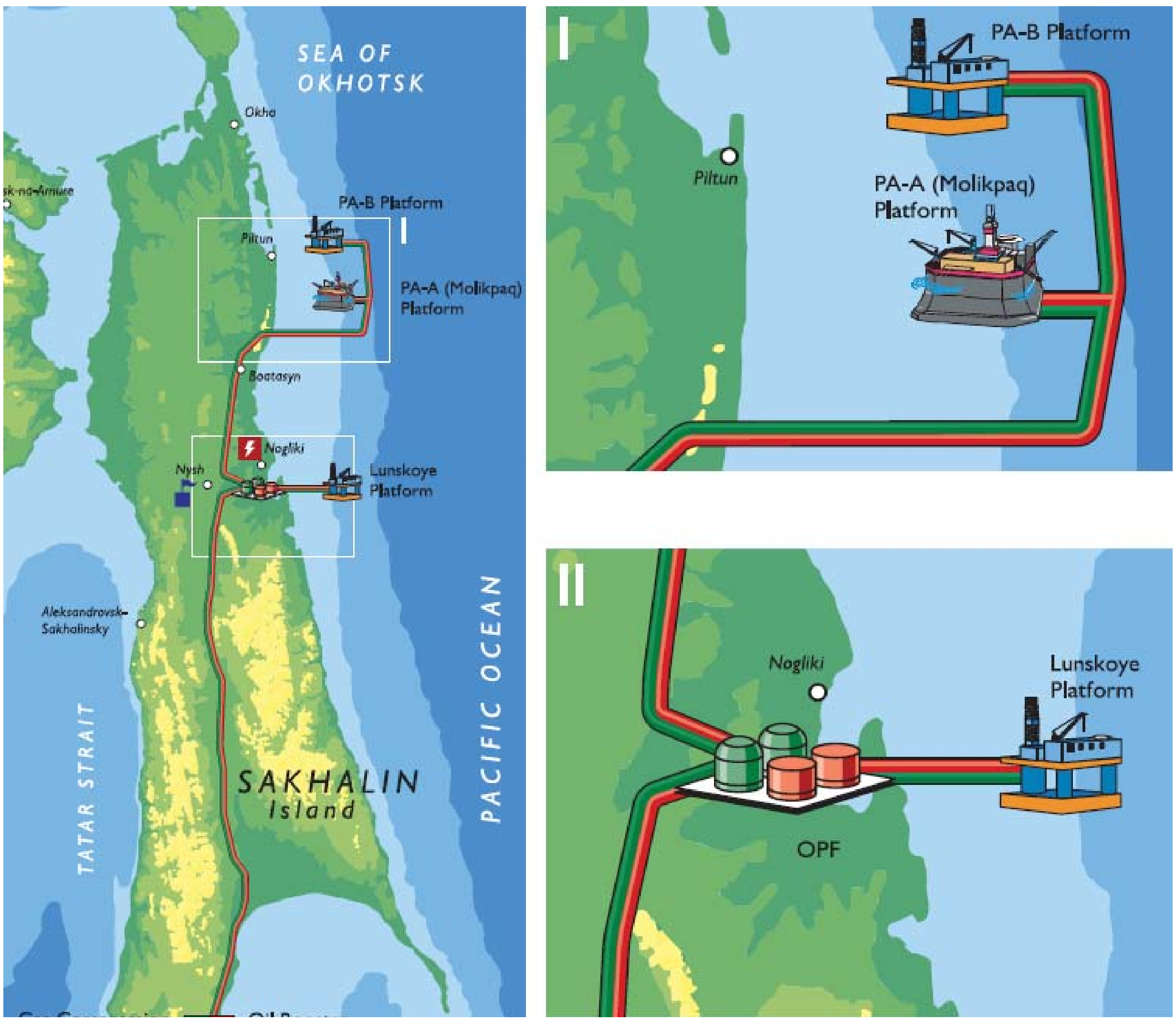

Figure 3-4: Sakhalin Island, PA-A, PA-B and Lun-A (Sakhalin Energy, 2007)

The Piltun Astokh-A

The PA-A drilling and production platform (Figure 3-5) was made from the conversion and refurbishment of the mobile bottom-founded arctic drilling rig, the Molikpaq. The Molikpaq was an octagonal-shaped steel caisson structure designed to operate in the severe ice conditions of the Canadian Beaufort Sea in water depths of 50 to 65 ft (15 to 20 m) (Offshore News, 2007).

The main conversions and refurbishments to the Molikpaq included the introduction of a 50.5 ft (15.4 m) spacer, earthquake reinforcing, and the introduction of large wave deflectors (Van Hoorn and Kim, 1999). The main purpose of the spacer is to address the deeper water depths in the Sea of Okhotsk.

At its base, the PA-A platform measures 365 x 365 ft (111 x 111 m) and reduces to 285 x 285 ft (87 x 87 m) at the top deck. The caisson supports a 240 x 240 ft (73 x 73 m) box girder deck structure, which carries the topsides and drilling facilities. The substructure has a weight of 41,362 tons (37,523 tonnes) (Hydrocarbons Technology, 2007).

The PA-A platform is ballasted with 9,820,000 ft^3 (278,000 m^3) of sand which permanently anchors it to the seabed 10 miles (16 km) off the coast of Sakhalin Island in 100 feet (30 m) of water (SPG Media Limited, 2007f).

Figure 3-5: The Piltun Astokh-A (SPG Media Limited, 2007f)

The Piltun Astokh-B (PA-B)

The PA-B platform (Figure 3-6) is slightly larger then the Lun-A platform described in the next Section; it carries topsides of 30,865 tons (28,000 tonnes) in a water depth of 105 ft (32 m) and is located 7.5 miles (12 km) offshore (SPG Media Limited, 2007f).

The PA-B concrete gravity base (CGB) consists of a caisson base and four cylindrical legs that support the topsides. It has a substructure weight of 99,210 tons (90,000 tonnes). The caisson base is 308 x 300 ft (94 x 91.5 m) and 38 ft (11.5 m) high. The diameter of each leg measures more than 79 ft (24 m) at the base and are approximately 128 ft (39 m) high. The total height of the substructure is 174 ft (53 m) (SPG Media Limited, 2007).

This platform supports drilling facilities, accommodations, processing, and power generation facilities. It has the capacity to produce 70,000 barrels of crude oil per day

(11,000 m^3) and up to 92 million standard cubic feet (2.6 million Sm^3) of gas per day (SPG Media Limited, 2007).

Figure 3-6: Installation of PA-B Platform, Sakhalin 2 (JSC Gazprom, 2007a)

The Lunskoye A (Lun-A)

The Lun-A platform (Figure 3-7) is located 9.3 miles (15 kilometers) offshore, operates in a water depth of 157 ft (48 m), carries a topsides of 24,200 tons (22,000 tonnes), and has an estimated substructure weight of 113,500 tons (103,000 tonnes) (Rigzone, 2005).

The Lun-A consists of a rectangular-shaped base caisson topped with four legs. The base caisson is 344 x 289 ft (105 x 88 m) and 44 ft (13.5 m) high. The diameter of each leg measures more than 65 ft (20 m) wide and 184 ft (56 m) high. The total height of the concrete substructure is 228 ft (69.5 m) (Rigzone, 2005). The concrete thickness ranges between 1.6 and 2.5 ft (0.5 and 0.75 m) and is steel reinforced throughout.

The Lun-A platform has a production capacity of 1.77 tcf (50 million m^3) of gas per day and 50,000 barrels of condensate per day (Sakhalin Energy, 2006).

Figure 3-7: LUN-A Platform (JSC Gazprom, 2007a)

Piltun Astokh-B (PA-B) and Lunskoye A (Lun-A) Platforms

The PA-B and the Lun-A platforms are four-legged gravity base substructures, operating in the Sea of Okhotsk. The PA-B and the Lun-A platforms were originally designed as steel structures which was later revised to concrete (Snieckus, 2002).

The PA-B and the Lun-A platforms are designed to resist a 200-year strength earthquake and a 3,000-year ductility level earthquake (Beckman, 2004). At the top of the concrete gravity base legs, friction pendulum bearings connect the topsides to the substructure. These bearings isolate the topsides from severe earthquake motions by employing the characteristics of a pendulum to lengthen the structure's natural period. When activated by a seismic shock, the convex bearing, or articulated slider, moves along the concave plate underneath, causing the topsides to move with small pendulum motions. In the event of a vertical movement, the top plate on which the topsides rest can twist, but the concave plate can also restore its own position and the topsides' equilibrium (Beckman, 2004).

PA-B and Lun-A have been constructed with an unusually large 95 ft (29 m) air gap between the deck and the substructure, which compares with 62 to 72 ft (19 to 22 m) for a typical North Sea structure (Beckman, 2004). This air gap was necessary to guard against large ice blocks that get thrown against the structure by waves during the annual melt.

Installation of these platforms was a two part process. The bases were towed to site and ballasted to the seabed in the open water season. In the subsequent open water seasons the topsides were floated to site and installed by float over.

3.3.1.2 Russian Arctic

<u>Prirazlomnoye Field</u>

Prirazlomnoye oil field is the largest natural reserve on the Russian Arctic Shelf which is presently in an advanced stage of development. Consequently, it will become the first oil producing offshore reserve on the European coast of the Arctic Ocean. The first oil production was originally planned for 2005 (Frantzen and Bambulyak, 2003), but now the field is expected to become operational in 2008 (PRINT-EXPO Co. Ltd, 2007). The various stages of Prirazlomnoye development may be traced through the series of projects executed by the Krylov institute (Krylov Institute, n.d.) and in information available on the internet from various sources (see, for example, Frantzen and Bambulyak, 2003; Luff, 2006; SPG Media Limited, 2007a; PRINT-EXPO Co. Ltd, 2007; Chernov, 2005; Madslien, 2006; Offshore Media Group, 2007; Dolphin Exhibitions Transtec Neva Exhibitions JSC, 2007).

The field, discovered in 1989, is located in the Pechora Sea (southeast Barents), 37.3 miles (60 km) offshore in a water depth of approximately 65 ft (20 m) (see Figure 3-1). The estimated oil reserves at Prirazlomnoye are 610 million barrels over an expected production life greater than 20 years. Initially, the field was planned to be developed by an international consortium with participation of Norway's Statoil and Norsk Hydro. However, in 2002, after several variations in the prospective ownership, the operational license was issued to Sevmorneftegaz, led by the conglomerate of subsidiaries of Rosneft and Gazprom (all Russian).

The operational concept for the field is based on using a single platform with 40 directional wells; 19 for production, 16 for injection and 5 reserved. The process technology to be used during operation at Prirazlomnoye is described in Chernov (2005). The Arctic engineering aspects of the project became a focus of interest and research activities of the leading

Russian organizations began more than 10 years ago. It should be noted, that while western companies are actively involved in Prirazlomnoye, from the very beginning this development was geared towards maximizing the participation of leading Russian engineering companies and fabrication (shipbuilding) facilities.

The relatively shallow water depth at the site made the possible use of a gravity caisson for the platform an obvious choice. The specialists of the Krylov institute conducted model tests of a gravity caisson for Prirazlomnoye back in 1996, long before the actual contemporary platform configuration was developed (Krylov Institute, n.d.). At that time, Krylov, on the orders from Rosshelf, were investigating the wave and ice loads on the caisson, including the ice pile-up formation at caisson walls. The work for the same client continued in 2000. By this time, Krylov researchers were interested in evaluation of scour effects generated by an AZIPOD-equipped tanker which was to be tied to the Prirazlomnoye platform.

The most recent stage of development began in 2002, when Sevmorneftegaz (final field operations license owner) purchased the Norwegian TLP Hutton platform. The concept was to use the Hutton's topsides as the Prirazlomnoye platform drilling rig (Frantzen and Bambulyak, 2003). Krylov developed temporary anchorage for Hutton in the Kolsky Bay and the support systems required for separation of the topsides from the hull and for the subsequent long-term positioning of Hutton's superstructure on two temporary barge floats (Krylov Institute, n.d.). The topsides modifications and caisson fabrication were implemented at the Sevmash and other yards in the area.

The steel caisson was assembled from four "super-blocks" (PRINT-EXPO Co. Ltd, 2007). Cast-in-place concrete was used for stiffening of the caisson structure and its ballasting. Installation of modified Hutton topsides on the caisson substructure was originally scheduled for July-August, 2006. The complete platform was planned to be towed from the Kolsky Bay to location in the South-East Barents in September, 2007 (PRINT-EXPO Co. Ltd, 2007).

The schematic view of the Prirazlomnoye platform is shown in Figure 3-8. The topsides weight is 42,990 tons (39,000 tonnes) and the weight of the caisson is 106,925 tons (97,000 tonnes) SPG Media Limited (2007a). The caisson's footprint is 413 x 413 ft (126 X 126 m). The platform has 14 oil storage tanks with the total capacity of 710,000 barrels (113,000 m^3) and 2 water tanks with the total capacity of 7,400,000 gallons (28,000 m^3). A single derrick will service 40 well slots.

The protection berm will be placed around the caisson after the initial settlement at the site. The platform will be equipped with two offloading systems with capacities up to 353,000 ft^3/hr (10,000 m^3/hr) (SPG Media Limited, 2007a). The only information available on the design ice criteria is that the Prirazlomnoye platform will be able to safely resist the ice pressure generated by the ridge with a 11.5 ft (3.5 m) thick consolidated layer (Central Design Bureau for Marine Engineering (Rubin), n.d.).

Medynskoye Field Platform

A gravity caisson platform is also considered for the Medynskoye oil field, which is located in the same general area as Prirazlomnoye (Figure 3-1). The field is closer to shore and the design water depth there is approximately 49 ft (15 m). The Medynskaya Center platform proposed for this field is an all-purpose structure (drilling, production, storage and offloading [Krylov Institute, n.d.]). The platform will have 38 wells and a storage capacity of 99,000 tons (90,000 tonnes). The DWT 44,000 tons (40,000 tonnes) tankers will be used in offloading operations. The caisson substructure is 279 x 279 ft (85 m x 85 m) at the deck, and 335 x 335 ft (102 m x 102 m) at the seabed level. The total substructure weight is 130,000 tons (118,000 tonnes). The topsides consist of seven functionally completed modules with a total weight of 15,800 tons (14,300 tonnes) (Krylov Institute, n.d.).

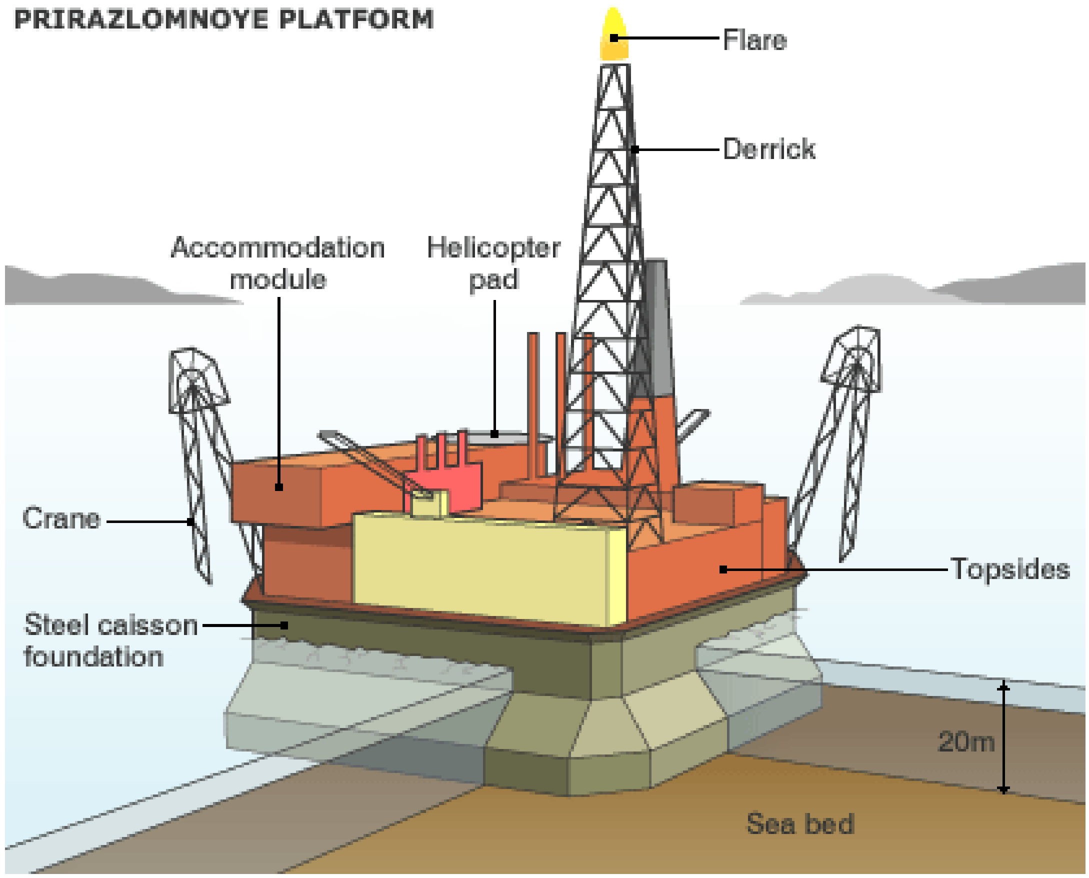

Figure 3-8: Prirazlomnoye Platform (Madslien, 2006)

3.3.1.3 Canadian East Coast

Presently, the only permanent bottom-founded structure employed offshore Newfoundland and Labrador is the Hibernia platform. However, according to recent news, the Hebron project, which will also employ a fixed structure, may soon be underway (The Telegram, 2007a; The Telegram, 2007b).

<u>Hibernia</u>

The Hibernia oil field is located approximately 196 miles (315 kilometers) east-southeast of St. John's. The field was discovered in 1979 and first oil was achieved in November 1997 (Department of Natural Resources, 2007). Current recoverable reserves for Hibernia are estimated to be 1.244 billion barrels (Department of Natural Resources, 2007). Hibernia field development capital expenditures amounted to $5.8 billion (Howell, 2007).

The Hibernia platform (Figure 3-9, Figure 3-10), a gravity base structure (GBS) equipped with topsides production and drilling facilities, was employed for field development (Department of Natural Resources, 2007). The platform has a design production capacity of approximately 230,000 bopd and has an oil storage capacity of 1.3 million barrels (HMDC, 2007). Hibernia oil is light sweet crude with a gravity of about 32°-34° API (SPG Media Limited, 2007d).

For development drilling, the Hibernia platform is equipped with two derricks, allowing the simultaneous drilling of wells (HMDC, 2007). In 2004, one of the world's longest extended reach wells, measuring 30,698 ft (9357 meters), was drilled from the Hibernia platform (Industry Canada, 2007).

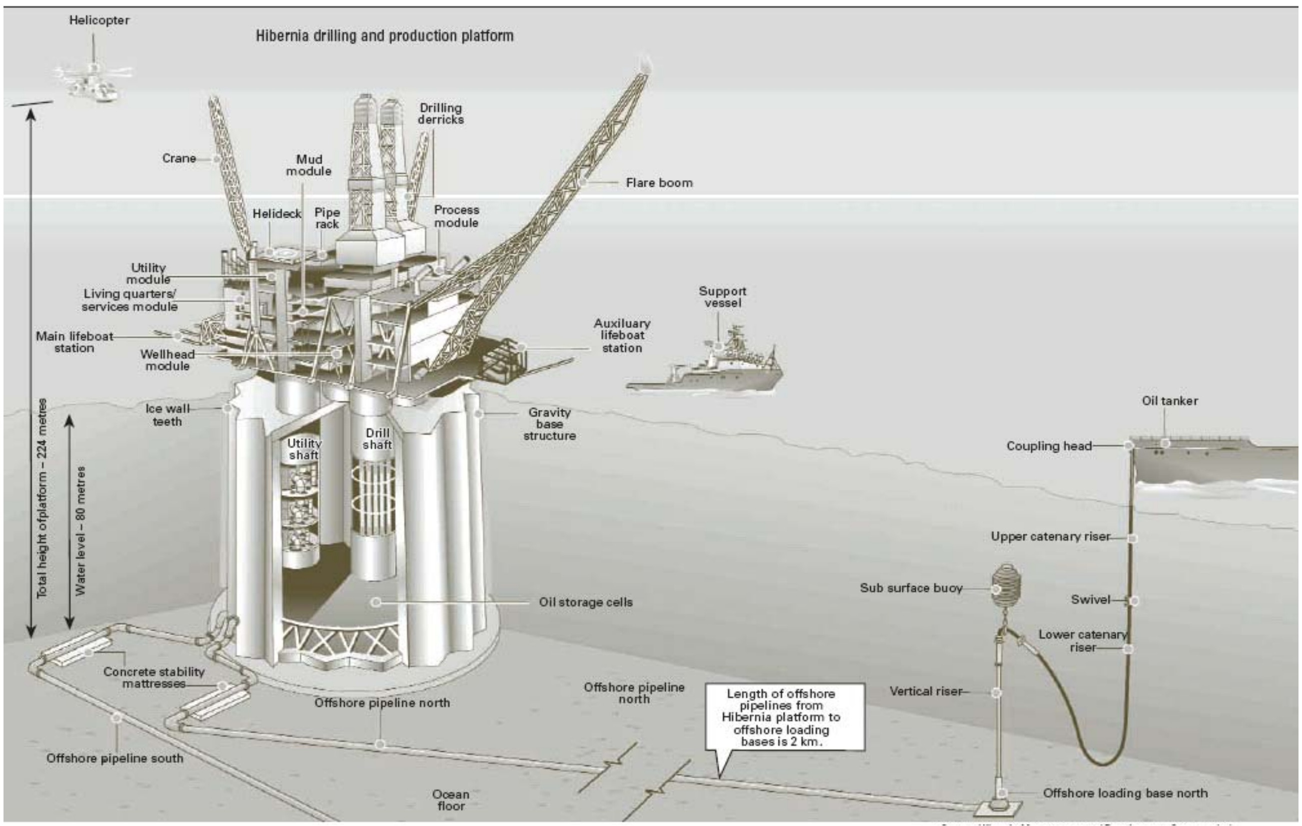

Figure 3-9: Hibernia Drilling and Production Platform with OLS (Bott, 2004)

Oil is exported from the Hibernia platform to shuttle tankers via a redundant Offshore Loading System (OLS). The OLS is comprised of a subsea pipeline, sub-surface buoy, and flexible loading hoses (HMDC, 2007). As a measure of safety, the tanker loading point is located 1.25 miles (2 kilometers) away from the platform (HMDC, 2007).

Hibernia utilizes 3 custom-built shuttle tankers for oil transport – the *Kometik, Vinland,* and *Mattea*. These shuttle tankers have storage capacities of 850,000 barrels, are double-hulled and have double bottoms with additional strengthening (particularly at the waterline). They are bow-loaded and are capable of quickly disconnecting from the OLS (HMDC, 2007).

The Hibernia platform has a total height of 735 ft (224 m) and weighs 1.32 million tons (1.2 million tonnes) (HMDC, 2007). Platform height is made up from the 279 ft (85 meter) caisson, 436 ft (133 meters) of topsides facilities, and 85 ft (26 meters) from the shafts that protrude through the GBS roof to support the topsides (HMDC, 2007). The four shafts (a utility, riser, and 2 drilling) each measure 56 ft (17 meters) in diameter (HMDC, 2007).

Figure 3-10: Hibernia Platform (HMDC, 2007)

The Hibernia GBS is a one-off design. To allow year-round production, the Hibernia platform is designed to withstand impact from sea ice and icebergs (HMDC, 2007). Specifically, the platform is capable of withstanding the impact of a 1.1 million ton (1 million tonne) iceberg (1-in-500-year event) (SPG Media Limited, 2007d), without sustaining damage, and a 6.6 million ton (6-million tonne iceberg) (1-in-10,000-year event), with repairable damage (HMDC, 2007). Although the probability of an iceberg colliding with the platform is low, Hibernia still employs an aggressive ice management strategy (HMDC, 2007).

The Hibernia GBS is constructed of high-strength reinforced and pre-stressed concrete, which is reinforced with steel (rebar) and pre-stressed tendons (SPG Media Limited, 2007d). The GBS caisson, which measures 348 ft (106 m) in diameter, consists of an exterior 4.6 ft (1.4 m) thick ice-wall with 16 teeth intended to distribute iceberg loads over the entire structure (HMDC, 2007). Furthermore, the GBS has an ice-belt, which includes the ice-wall, measuring 49 ft (15 m) thick (HMDC, 2007).

<u>Hebron</u>

The Hebron oil field, discovered in 1981, is located approximately 220 miles (350 km) offshore Newfoundland in close proximity to the Hibernia, Terra Nova, and White Rose developments.

Hebron is a heavy oil field containing an estimated 400-700 million barrels of resources (Chevron, 2007). With close-neighboring fields, Ben Nevis and West Ben Nevis, the Hebron/Ben Nevis Complex has a reserve estimate of 731 million barrels of oil (Department of Natural Resources, 2007).

Field development has not yet commenced. However, with the signing of a memorandum of understanding (MOU) in August 2007, it has been indicated that construction is expected as early as 2010 (Calgary Herald, 2007), and that the field may achieve first oil as early as 2015 (The Telegram, 2007a). A preliminary cost estimate of $4 billion to $5 billion was reported for field development (The Telegram, 2007a).

Although several options have been evaluated (subsea tieback, FPSO with subsea wells, new generation GBS, and FPSO with wellhead platform (Department of Natural Resources, 2007)), the Hebron field development will be based on the use of a GBS similar to that of Hibernia (The Telegram, 2007b). The Hebron GBS, however, will be smaller then Hibernia, requiring less concrete and being easier to build (The Telegram, 2007b).

Other Proposed Grand Banks Structures

The Steel Stepped Gravity Base (SSGB) shown in Figure 3-11 was developed for application on the Grand Banks of Newfoundland in water depths of around 330 ft (100 m) (Fitzpatrick and Kennedy, 1997). The SSGB concept represents a departure from traditional cylindrical concrete gravity base production platforms with respect to shape, material and method of construction.

Figure 3-11: Steel Stepped Gravity Base Structure

The principal criteria affecting the design of an offshore platform in the Grand Banks environment is icebergs, waves and foundation strength parameters. The design iceberg for the Grand Banks is estimated at a mass 4.4 million tons (4 million tonnes). A berg of this mass can impart a shear force of 100,000 tons (90,000 tonnes) and a moment of 23 million ton-ft (6.3 million tonne-m) into a gravity base structure. This ice load can be applied from any direction and at any elevation. A structure capable of resisting such an ice load has to be monolithic or non-wave-transparent.

Ideally the design wave load would be very close to the ice load. The SSGB achieves this by reducing the diameter of the structure as it progress upwards through the water column. The stepping process reduces the wave shear force to 110,000 tons (100,000 tonnes) and a moment of 18 million ton-ft (5 million tonne-m) which is very close to the ice load.

In specific terms, the base of the SSGB must minimally have an area capable of resisting the shear and overturning moments created by the ice or wave loads. The foundation parameters in conjunction with the wave and ice load determine the necessary base area of the structure to be 140,000 ft^2 (13,000 m^2). The SSGB has been reviewed for deployment at several locations on the Grand Banks. Parameters chosen for the foundation design are considered representative of some of the weaker strength sites. Thus, the structure base area is unlikely to increase no matter where the structure might be considered for deployment.

By optimizing the SSGB's shape the designer has been able to:

- Converge the global loads;
- Minimize material use to 93,700 tons (85,000 tonnes) of steel and a ballast weight of 220,500 tons (200,000 tonnes);
- Provide free storage capacity. The structure needs a minimum footprint and size to resist the applied loads. This minimum size provides "free space". This free space provides a storage capacity of 750,000 to 1,000,000 bbls;
- Provide hydrostatic stability. Steel structures have a low vertical center of gravity (VCG) and the VCG of a steel pyramid shape can be further lowered by the use of solid ballast. This low VCG offers stability under towing and as a result the structure can be safely towed to site when loaded with up to 33,000 tons (30,000 tonnes) of topsides; and,

- Minimize setup time. All solid ballast has been installed prior to tow out. Water ballast is added to hold the structure in place.

The SSGB provides an economical solution to the challenges of exploration and hydrocarbon production in iceberg infested waters.

3.3.1.4 Cook Inlet

To date, a total of 16 jacket structures have been installed at the Inlet using three structural concepts; the monopod, the tripod and the quadpod. The first of these structures was installed in 1964 and the last in 1986.

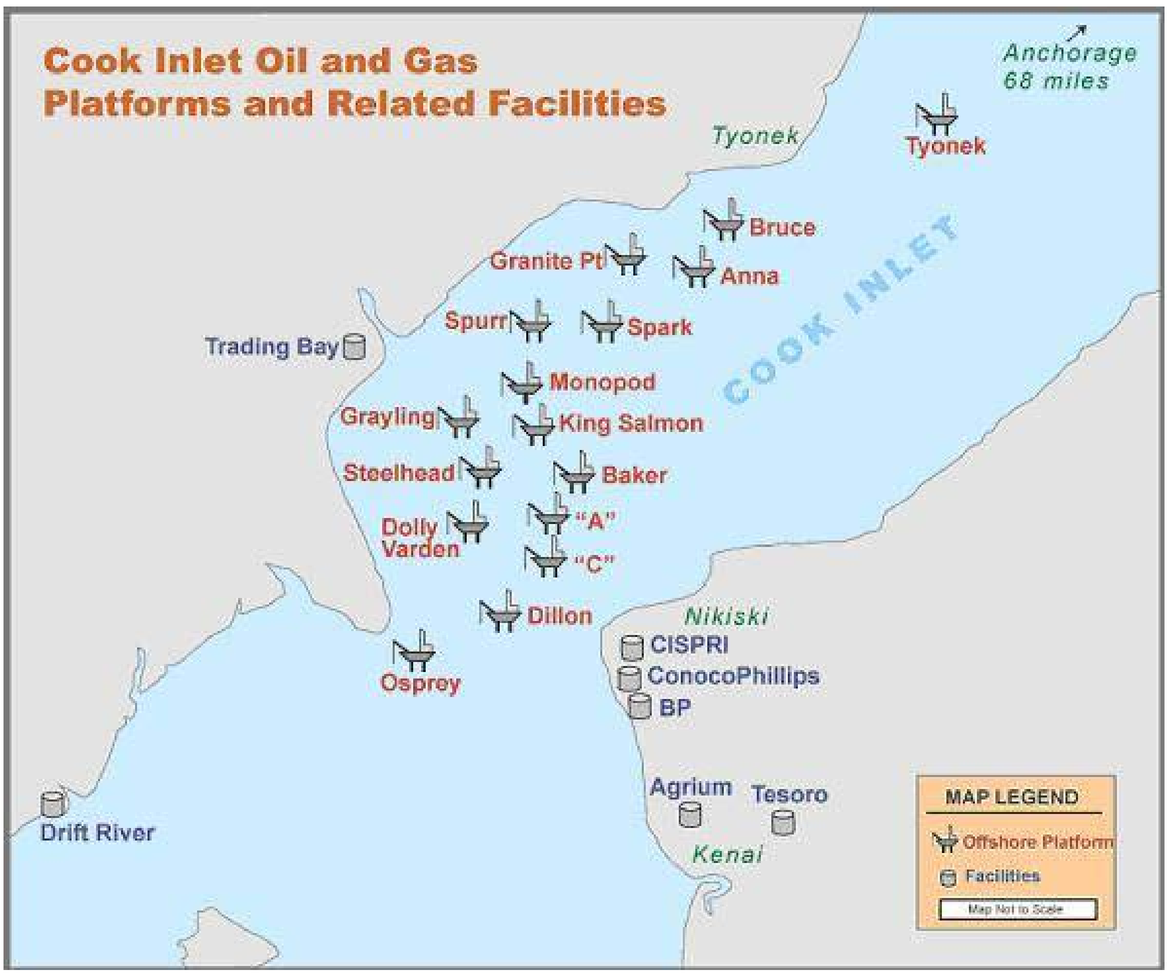

Figure 3-12: Cook Inlet Infrastructure (CIRCAC, 2007)

The fixed jacket structures designed for Cook Inlet's environment differ from conventional jacket structures in several ways:

- Partially constructed from low temperature steel;
- The jacket systems are composed of very large ice reinforced legs with diameters in excess of 14 ft (4.3 m);
- The jacket bracing is located several feet below the water line. This protects the bracing from ice impacts and prevents ice bridging; and,
- The jackets use an X-bracing system rather then K type bracing (Figure 3-13 and Figure 3-14). This provides additional load paths in the event of a member failure.

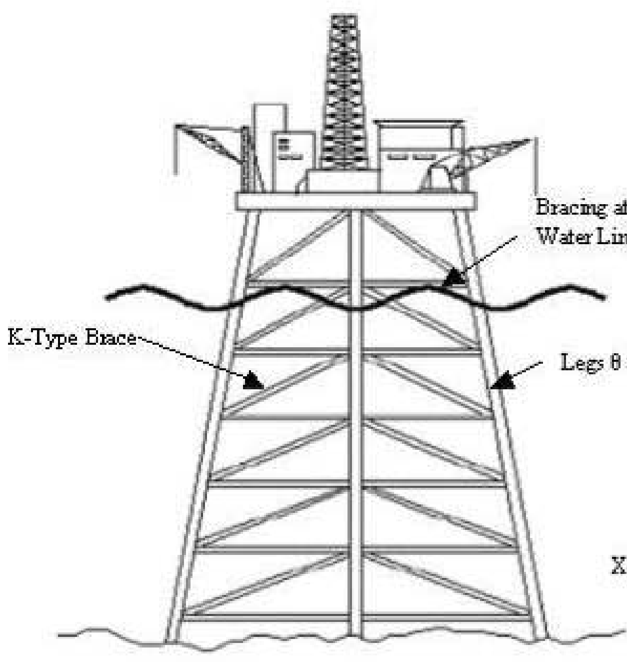

Figure 3-13: Conventional Jacket Structure (OOP, 2007)

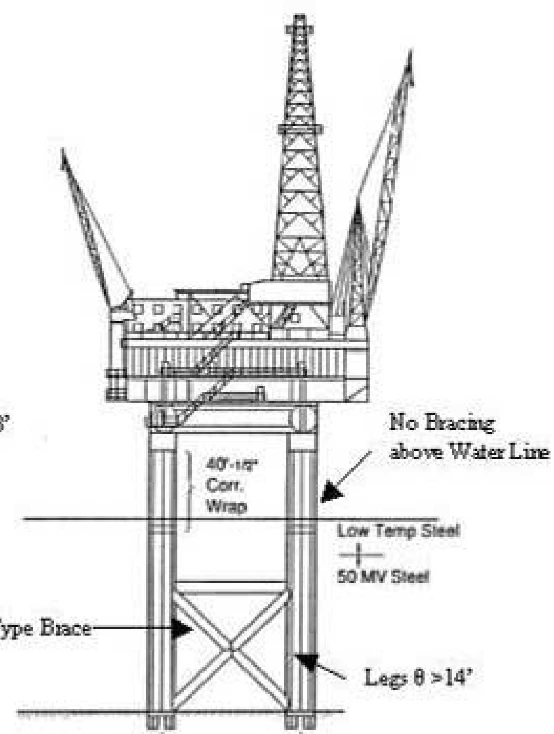

Figure 3-14: Cook Inlet Jacket Structure (CIRCAC, 2007)

The Inlet's jacket structures have been designed using a variety of ice loads, wave heights and water depths:

- Ice thickness varying from 2.8 to 6 ft (0.9 to 1.9 m) with a crushing strength of 300 psi (2.1 MPa);
- Design wave heights from 28 to 41 ft (8.5 to 12.5 m); and,
- Design depths from 62 to 183 ft (19 to 56 m).

The load variation is dependent on the structure's specific location, the designer's interpretation and application of the available metocean data, and the designer's understanding of jacket structural responses to sea ice loading. An online database of the Inlet's structures can be accessed from the Cook Inlet Regional Citizens Advisory Council website (CIRCAC, 2007).

Table 3-3: Summary of Cook Inlet Platforms (CIRCAC, 2007)

Summary of Cook Inlet Platforms													
Platform Name	Type	Design Ice Thick, ft (m)	Wave		Wind Velocity, MPH (km/h)	Earth-quake (g)	Current, ft/s (m/s)	Leg Dia., ft (m)	Water Depth, ft (m)	Year	Designer	Jacket Wt, tons (tonnes)	Deck Wt, tons (tonnes)
			Height, ft (m)	Period (Sec)									
Anna	Quadpod	2.8 (0.9)	30 (9)	9	80 (129)	0.1	10 (3)	14 (4.3)	77 (23.5)	1966	Earl & Wright	1515 (1374)	1200 (1089)
A	Quadpod	6 (1.8)	41.5 (12.6)	10.8	65 (105)	0.15	10 (3)	14.6 (4.5)	83 (25)	1964	Earl & Wright	N/A	N/A
Baker	Quadpod	2.8 (0.9)	30 (9)	9	80 (129)	0.1	10 (3)	14 (4.3)	102 (31)	1965	Earl & Wright	2533 (2298)	N/A
Bruce	Quadpod	2.8 (0.9)	30 (9)	9	80 (129)	0.1	10 (3)	14 (4.3)	62 (19)	1966	Earl & Wright	1415 (1284)	1200 (1089)
C	Quadpod	3.5 (1.1)	28 (8.5)	8.5	65 (105)	0.06	12 (3.7)	15.5 (4.7)	73 (22)	1967	Earl & Wright	N/A	N/A
Granite Point	Quadpod	5 (1.5)	28 (8.5)	N/A	N/A	N/A	13.5 (4.1)	17 (5.2)	75 (23)	1966	Brown & Root	3400 (3084)	N/A
Grayling	Quadpod	6 (1.8)	28 (8.5)	8.5	100 (161)	0.1	10 (3)	17 (5.2)	125 (38)	1967	Brown & Root	3550 (3221)	N/A
King Salmon	Quadpod	3.5 (1.1)	28 (8.5)	8.5	65 (105)	0.06	12 (3.7)	15.5 (4.7)	73 (22)	1967	Earl & Wright	1585 (1438)	1200 (1089)
Monopod	Monopod	6 (1.8)	28 (8.5)	8.5	100 (161)	0.06	10 (3)	28.5 (8.7)	66 (20)	1966	Brown & Root	6000 (5443)	N/A
Spark	Tripod	3.5 (1.1)	28 (8.5)	8.5	60 (97)	N/A	10 (3)	13 (4.0)	62 (19)	1968	McDermott	N/A	N/A
Spurr	Tripod	3.5 (1.1)	28 (8.5)	8.5	60 (97)	N/A	10 (3)	13 (4.0)	67 (20)	1968	McDermott	N/A	N/A
Steelhead	Quadpod	4.2 (1.3)	28 (8.5)	8.5	80 (129)	N/A	12.6 (3.8)	18 (5.5)	183 (56)	1986	McDermott	N/A	N/A
Tyonek	Quadpod	2.8 (0.9)	27.5 (8.4)	8.5	80 (129)	0.1	10.1 (3.1)	14 (4.3)	100 (30)	1968	McDermott	N/A	N/A
Dillion	Quadpod	2.8 (0.9)	30 (9)	9	80 (129)	0.1	10 (3)	14 (4.3)	92 (28)	1967	Earl & Wright	1585 (1438)	1200 (1089)
Dolly Varden	Quadpod	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Osprey	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
N/A Not Available													

The Inlet's current metocean data characterizes it as an area with large temperature fluctuations of 51°F (11°C). Strong 13 ft/sec (4 m/s) currents, 22 ft (7 m) spring tides, variable size first-year ice floes of 6.5 ft (2 m) thick and pressure ridges as thick as 20 ft (6 m) are common to the area. Refer to Appendix A for a summary of Cook Inlet's metocean data.

3.3.1.5 Jack-up Drilling Rigs

The jack-up rig was first introduced to the offshore industry in the mid 1950's. The jack-up rig was developed to provide a fixed base drill rig capable of operating in harsh environments (wave only) with the flexibility to relocate to alternate drilling locations.

A jack-up drilling rig consists of a hull, legs and a lifting system. A wide variety of hull styles, legs and lifting systems exist. The variation is primarily a result of the trade off the designer must make between drilling stability and buoyancy stability.

Rig installation involves a wet or dry tow to site. Wet tows usually occur over short distances. Under wet tows, the rig provides its own buoyancy. Dry tows typically occur over large distances. During dry tow, the rig is carried on a barge or on the deck of a transporter. Once on site, the rig's legs are lowered to the seabed and the hull is elevated to provide a stable work deck. The rig is now ready to begin drilling operations. Removal of the rig is the reverse of the installation.

A modern drilling jack-up is capable of working in wave heights of 79 ft (24 m), in winds of 100 knots, in water depths approaching 500 feet (152 m) and to drill depths of 35,000 ft (10,700 m) (BASS and OTD/KeppelFels, 2005). Jack-up platforms have been constructed for numerous ocean environments; yet none have been constructed to operate in sea ice conditions.

Table 3-4: LeTourneau Super Gorilla Operating Parameters (from LeTourneau Technologies, 2007)

Environmental Criteria			
504 feet of Leg, Elevated Weight of 28,550 Kips			
Water Depth Feet (Meters)	**Wind Speed Knots (Meters/Sec.)**	**Wave Height Feet (Meters)**	**Air Gap Feet (Meters)**
450*(137.2)	100*(52)	69*(21.0)	50*(15.2)
400*(121.9)	100*(52)	71*(21.6)	50*(15.2)
328 (100.0)	100 (52)	81 (24.7)	55 (16.8)
300 (91.4)	100 (52)	82 (25.0)	60 (18.3)
250 (76.2)	100 (52)	87 (26.5)	60 (18.3)
200 (61.0)	100 (52)	88 (26.8)	60 (18.3)
150 (45.7)	100 (52)	88 (26.8)	65 (19.8)
504 feet of Leg, Elevated Weight of 31,810 Kips			
Water Depth Feet (Meters)	**Wind Speed Knots (Meters/Sec.)**	**Wave Height Feet (Meters)**	**Air Gap Feet (Meters)**
328 (100.0)	100 (52)	72 (21.9)	55 (16.8)
300 (91.5)	100 (52)	73 (22.3)	60 (18.3)
250 (76.2)	100 (52)	75 (22.9)	60 (18.3)
200 (61.0)	100 (52)	76 (23.2)	60 (18.3)
*Specifications when using 604-Foot (184.1 meter) leg length. Dynamic effects included			

A study by CKJ Engineering (CKJ Engineering, 1997), the development and implementation of a jack-up drilling program on the Grand Banks of Newfoundland (Bagnel, 2007) and the anticipated construction of a new Russian ice-resistant jack-up rig are indicative that the operating range of jack-up drilling rigs can be marginally expanded to include areas of seasonal sea ice and of marginal sea ice concentration.

CKJ Engineering's study (CKJ Engineering, 1997) involved brief investigations into the structural feasibility of using jack-up Rig SX during freeze-up in Sakhalin.

The successful development and implementation of a jack-up drilling program on the Grand Banks of Newfoundland, Canada, was accomplished by the understanding of the ice-free season and implementation of an ice management program (Bagnel, 2007).

The ice-resistant jack-up rig Arkticheskaya (Figure 3-15) is under construction at the Severodvinsk Shipyard, Russia. It is being constructed to operate in Arctic water depths of up to 330 feet (100 m) and in ice flows of 1.6 feet (0.5 m) thick (MNP Global, 2007).

In light of CKJ's study, the successful implementation of a jack-up drilling program in Newfoundland, the anticipated construction of ice-resistant jack-ups and the continued development of jack-up rig technology, an extension of a traditional seasonal jack-up drilling program may be considered for the Bering Sea.

Figure 3-15: Ice Resistant Jack-up Arkticheskaya 6500 / 10-30 (JSC Gazprom, 2007b)

3.3.2 Floating Structures

3.3.2.1 Canadian East Coast

Currently there are 3 producing fields in operation offshore Newfoundland within the Grand Banks Jeanne d'Arc Basin (Figure 3-16). Two of these fields, the Terra Nova and White Rose, have employed FPSO (Floating Production Storage and Offloading) vessels for field development.

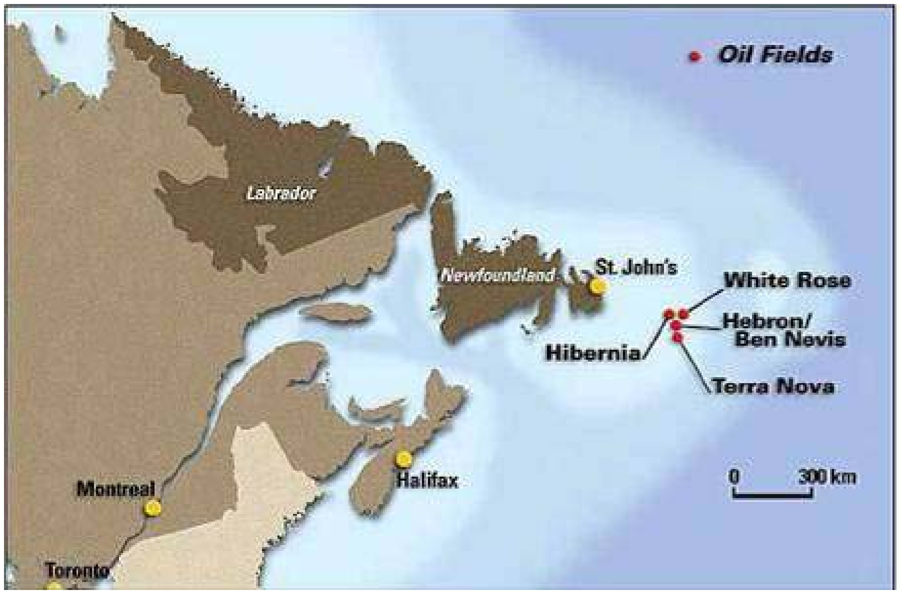

Figure 3-16: Grand Banks Field Developments (Howell, 2007)

Terra Nova

Discovered in 1984 by Petro-Canada, the Terra Nova field is currently the 2nd largest producing field off the east coast of Canada. Furthermore, the Terra Nova was the first 'harsh environment' development in North America to utilize a FPSO vessel (Petro-Canada, 2007a). The Terra Nova field is located approximately 220 miles (350 kilometers) east-southeast of St. John's. Field water depths range from 295 to 330 ft (90 to 100 meters) (SPG Media Limited, 2007e).

Production from the $2.8-billion Terra Nova project began in January, 2002 (Bott, 2004). Field recoverable oil reserves have been estimated at 440 million barrels and life of field is estimated to be 19-21 years (Petro-Canada, 2007a).

As shown in Figure 3-17, a variety of equipment, vessels, and subsea infrastructure are employed for the development and operation of the Terra Nova field.

Figure 3-17: Terra Nova Field Development (Petro-Canada, 2007a)

Through an integrated subsea and topside production system, oil is produced, stored, and subsequently offloaded to shuttle tankers. Production from subsea wells/trees is gathered by subsea manifolds and conveyed topside (to the FPSO) via flexible flowlines and risers. More then 25 miles (40 km) of flexible flowlines, control umbilicals, and dynamic risers were required for the project (Furlow, 1998). Flowline and riser inner diameters ranged between 5 and 10 inches (125 and 250 mm), while the umbilicals used were the largest ever manufactured at the time, with an outside diameter of 10.4 inches (265 mm) (Cottrill, 2000).

To protect against potential iceberg gouging, subsea equipment is located in excavated seafloor pits, called open glory holes (Figure 3-18). Glory holes used for the project are approximately 38 ft (11.5 m) deep and base dimensions range from 53 ft x 53 ft (16 m x 16 m) to 184 ft x 53 ft (56 m x 16 m) (Furlow, 1998). Excavation of the glory holes was carried out by a giant trailer suction dredger, the Queen of The Netherlands (Cottrill, 2000).

Although considered sacrificial and equipped with ‘weak links’ to protect wellhead equipment, flowlines were trenched and buried in the seabed to provide stability, insulation, and afford some measure of protection from iceberg gouging. The initial plan was to provide 5 ft (1.5 meters) of cover, however, due to trenching difficulties some flowlines were rock-dumped instead (Cottrill, 2000).

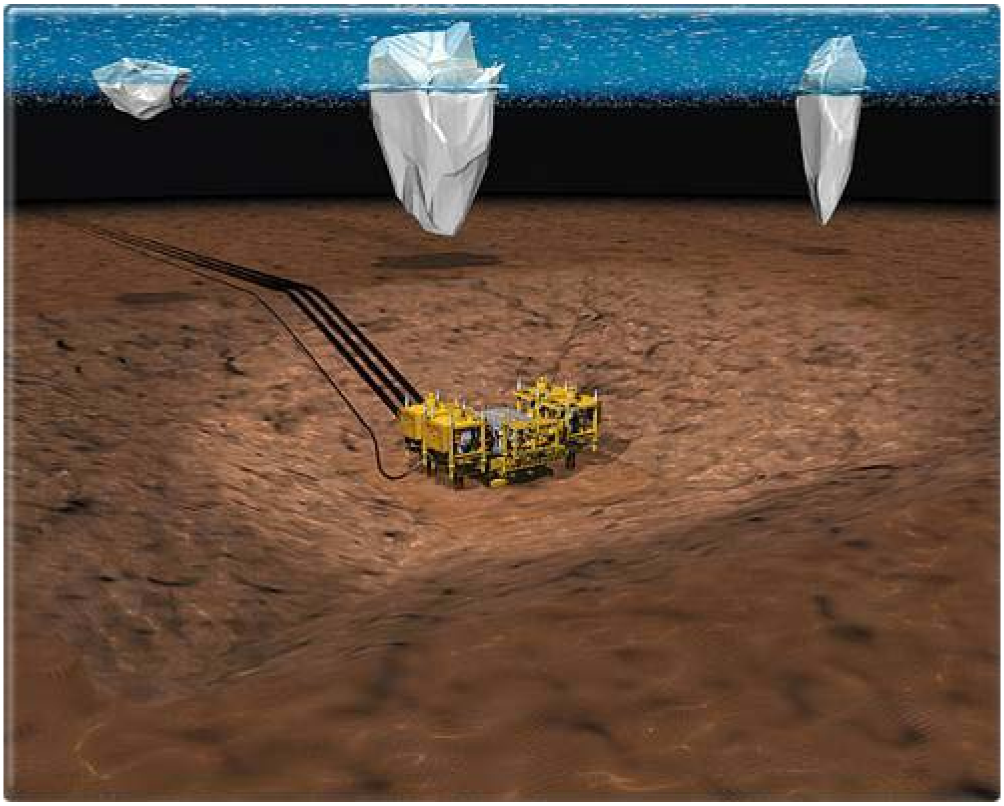

Figure 3-18: Open Glory Hole (Petro-Canada, 2007a)

To avoid icebergs and severe sea ice conditions, the Terra Nova FPSO is equipped with an internal disconnectable turret system. During a disconnect, the spider buoy, along with its attached risers and moorings, is released allowing the FPSO to move off station and sail out of harms way. Once released, the spider buoy sinks to a mid-water equilibrium depth of 115 ft (35 meters) (measured from surface to buoy top) (Cottrill, 2000).

A planned disconnect, which entails well shut-in, depressurization, flowline flushing, etc., can be executed in under 4 hours, while in an emergency situation, disconnect can be achieved in approximately 15 minutes (Sofec, 2007). Up until the final moment of disconnect (i.e. prior to mechanical connector release), the sequence is reversible (Furlow, 1998). The turret system is designed to reconnect in a matter of hours with normal operations support (Furlow, 1998). Reconnect can be accomplished in up to 7 ft (2.1 meter) significant wave heights (Cottrill, 2000).

In June 2007, the Terra Nova FPSO underwent its first planned disconnect when it left the field to undergo several months of maintenance work in the Keppel Verolme shipyard in Rotterdam, the Netherlands. The Terra Nova arrived back in the field on September 25th and was reconnected to it's moorings on October 1st (Petro-Canada, 2006).

There were a number of design challenges for the Terra Nova disconnectable turret system; severe weather and storm conditions, relatively shallow water, a large vessel, a significant number of risers, a heavy mooring system and the ability to disconnect/reconnect. At time of design, the Terra Nova turret was quoted "as the most sophisticated and complicated turret ever" to be constructed (Furlow, 1998).

At the heart of the development and production system is the Terra Nova FPSO, shown in Figure 3-19. The Terra Nova measures 959 ft (292.2 m) long by 149 ft (45.5 m) wide and more than 18 stories high from keel to helideck (Petro-Canada, 2007a). During operation, it has a draft of approximately 43 to 62 ft (13 to 19 m) and a maximum displacement of 213,000 tons (194,000 tonnes) (Fletcher and Clark, 2001). The Terra Nova has a production rate of 180,000 bpd (Howell, 2007) and an integrated storage capacity of 960,000 barrels of oil.

Figure 3-19: Terra Nova FPSO (Petro-Canada, 2007a)

The Terra Nova FPSO is purpose built for the harsh environment experienced on the Grand Banks. In addition to a disconnectable turret, the Terra Nova is equipped with a double-hull, 3,300 tons (3,000 tonnes) of additional steel to provide ice strengthening (Petro-Canada, 2007a), and a thruster-assisted mooring system (Cottrill, 2000).

As a result of ice strengthening, the Terra Nova is capable of withstanding the impact of a 110,000 ton (100,000 tonne) iceberg traveling at 1-knot (Cottrill, 2000). Furthermore, it can operate in moderate to high pack ice concentrations (5 to 8/10ths) and is capable of maintaining station in concentrations of 8 to 9/10ths (PERD, 2002).

The thruster-assisted mooring system is designed based on 100-year storm conditions; sea ice loads do not govern mooring design (Cottrill, 2000). The mooring system is comprised of a nine-leg group catenary chain with a heavy excursion limiter system (Sofec, 2007) and 5 thrusters with a combined capability of 33,500 hp (25 MW) (Cottrill, 2000). During 100-year storm conditions, thrusters are fully utilized to maintain station (Cottrill, 2000).

Figure 3-20 below (PERD, 1998) has been included to illustrate Terra Nova’s significant mooring capabilities and provide comparison to other FPSO’s as well as mooring system designs dominated by sea ice loads.

Crude oil is offloaded from the Terra Nova to ice strengthened shuttle tankers. The Terra Nova is equipped with a tandem offloading system, which is designed for connection/disconnection in up to 16 ft (5 m) significant wave heights (Furlow, 1998).

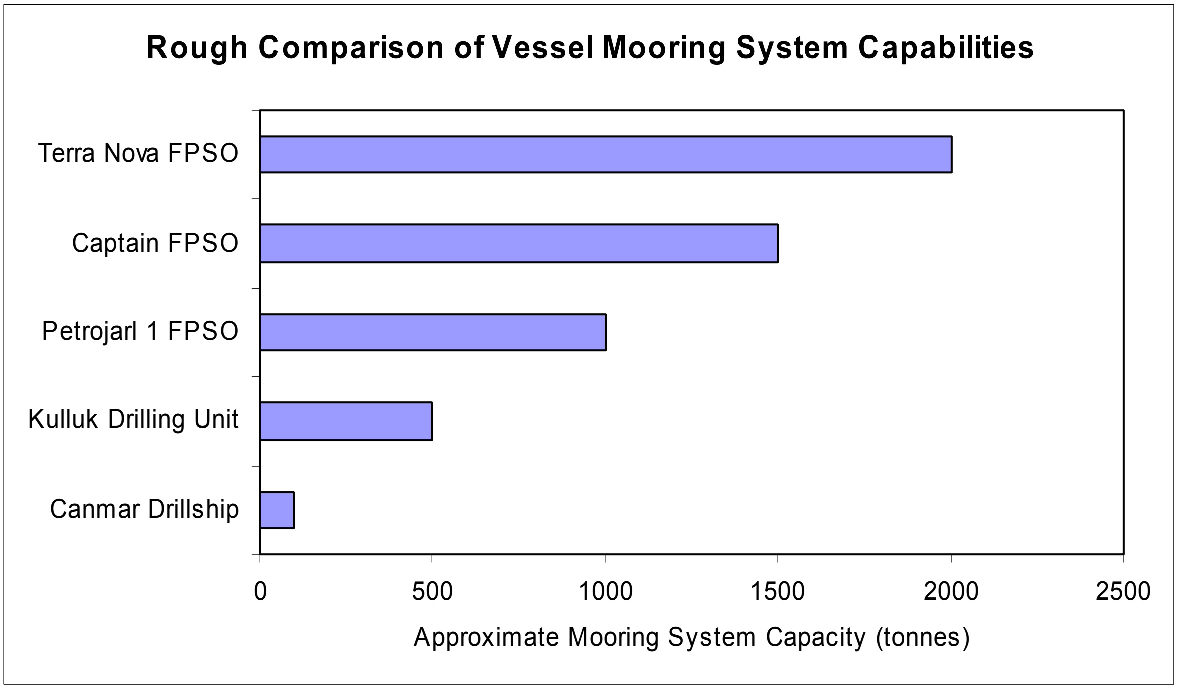

Figure 3-20: Comparison of Mooring Capabilities (from PERD, 1998)

<u>White Rose</u>

The White Rose field (Figure 3-21) is located approximately 220 miles (350 km) east of Newfoundland's Avalon Peninsula and about 31 miles (50 km) from the Terra Nova field (Clarke, 2001).

Discovered in 1984, White Rose is the third major oil field on the Grand Banks. Development commenced in 2002 and, with a pre-production cost of $2.35 billion, the field achieved first oil in November 2005 (Howell, 2007).

Current estimated oil reserves for the White Rose field are 283 million barrels (CNLOPB, 2007a), and total production life is estimated to fall between 12 and 15 years (Husky, 2007). White Rose oil quality is 30 degrees API (Husky, 2007a).

The White Rose field is situated in approximately 395 ft (120 meters) of water, and like its predecessor, the Terra Nova, field development was based on employing an integrated production system. The system is comprised of subsea wells and associated equipment, flexible flowlines, dynamic risers, and a FPSO facility (Clarke, 2001).

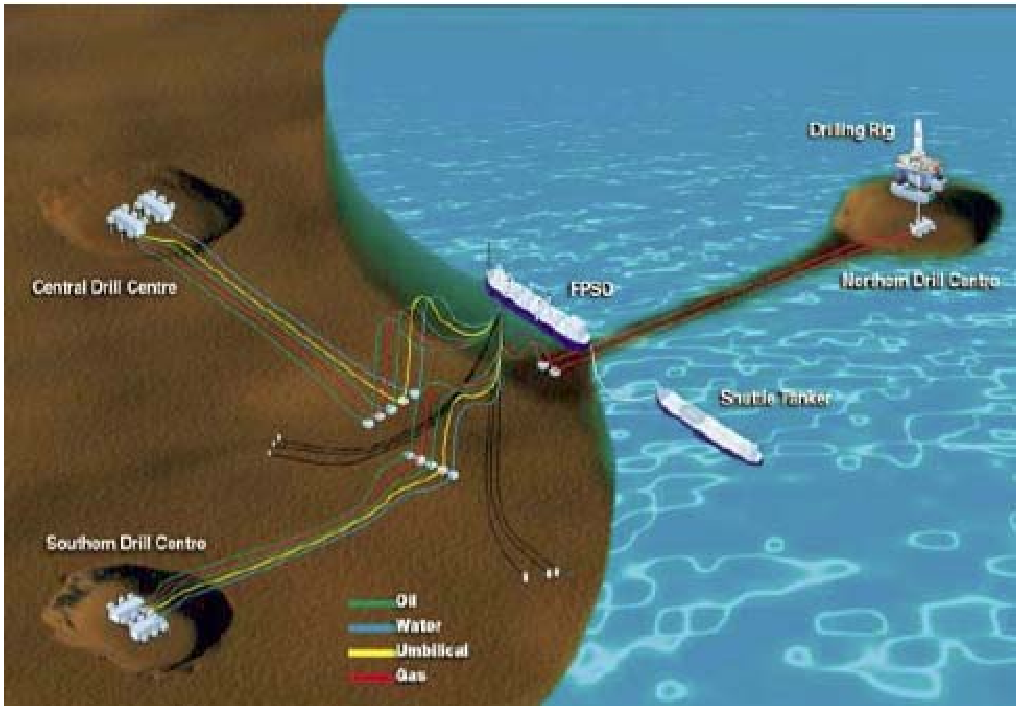

Figure 3-21: White Rose Field Development Schematic (Clarke, 2001)

At each drill center, subsea wells and equipment are clustered together and located in open glory holes to protect against potential iceberg gouging. White Rose glory holes, shown in Figure 3-22, are excavated to a maximum depth of 36 ft (11 meters) to ensure that the top of equipment (critical to well integrity) is located a minimum of 6.6 to 9.8 ft (2 to 3 meters) below the surrounding seabed (Husky, 2001a). Glory holes have been excavated by two methods; a ROV assisted grab excavation system (Boskalis Offshore bv, 2003) and a trailing suction hopper dredge (Husky, 2006).

The White Rose field uses over 25 miles (41 km) of flexible flowlines, risers, and umbilicals (Husky, 2007a). Flowlines are laid on the seafloor and are insulated for temperature maintenance (Husky, 2006). To afford a measure of iceberg protection, flowlines and umbilicals are equipped with weak link technology (Husky, 2006).

Similar to the Terra Nova, White Rose field development is centered around the FPSO facility, the SeaRose (Figure 3-23).

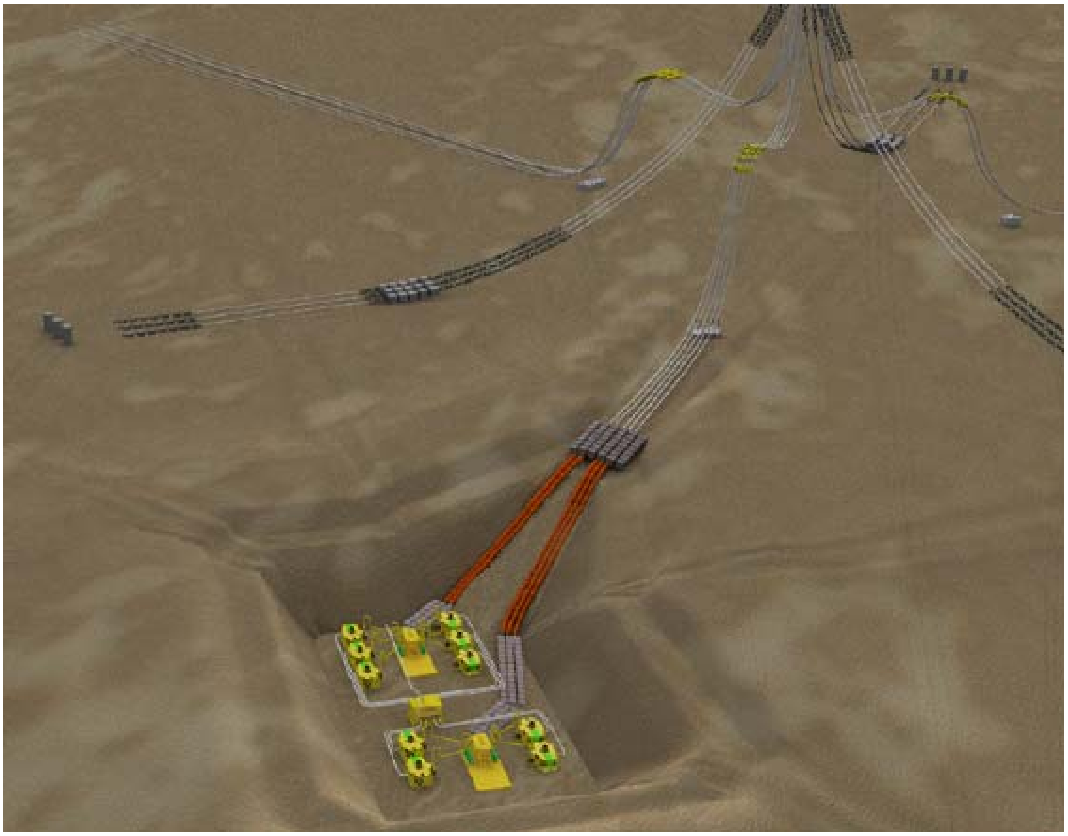

Figure 3-22: Typical White Rose Glory Hole (Lochte, 2007)

Figure 3-23: SeaRose FPSO (Husky, 2007a)

The SeaRose has a production capacity of 140,000 bopd (Husky, 2007b) and can store up to 940,000 barrels of processed oil (Husky 2007). In overall length, the SeaRose measures 876 ft (267 m). The hull measures 151 ft (46 m) in breadth and is 87 ft (26.6 m) deep (SPG Media Limited, 2007b). The SeaRose has a design draft of 59 ft (18 m) and a displacement of 206,200 tons (187,100 tonnes) (SPG Media Limited, 2007b).

The SeaRose, like the Terra Nova, is designed and purpose-built for the Grand Banks harsh environment. It is double-hulled, ice strengthened, and equipped with a disconnectable internal turret mooring system. The SeaRose hull form is based on a proven Grand Banks shuttle tanker design (SPG Media Limited, 2007b). Modifications to the tanker design included deepening the hull by 13 ft (4 m) and making changes to the bow (SPG Media Limited, 2007b).

The SeaRose hull and moorings are designed to withstand the impact of a 110,000 ton (100,000 tonne) iceberg; in the event that an (unmanageable) iceberg of greater mass approaches, the SeaRose will disconnect from its moorings (Husky, 2001a). Ice loading criteria, presented elsewhere in the White Rose development plan, also indicates that the SeaRose is likely designed to withstand the impact of such an iceberg moving at 1.6 ft/s (0.5 m/s) (Husky, 2001a). The development plan also indicates that the SeaRose is likely capable of withstanding 1 ft (0.3 m) thick pack-ice with coverage of up to 50% (Husky, 2001a).

In addition to ice strengthening, the SeaRose is designed to remain connected to its moorings during 100-year storm conditions (Clarke, 2001). Furthermore, production can be maintained during 1-year storm conditions and in moderate sea ice coverage up to 50% (Clarke, 2001).

A notable difference from the Terra Nova is that the SeaRose employs a passive mooring system; that is, thrusters are not employed for station keeping (Clarke, 2001). The SeaRose mooring system is comprised of 3 groups of chain/wire mooring lines (Clarke, 2001). In the event that the SeaRose disconnected from its moorings, it would avail of its main (ship) engines for propulsion to move off station.

Oil is offloaded from the SeaRose via a 395 ft (120 m) long, 20 inch (508 mm) diameter, flexible loading hose (SPG Media Limited, 2007b) to purpose-built double-hulled shuttle tankers (OilOnline, 2005). Shuttle tankers are bow-loaded, as shown in Figure 3-24, and can connect to the SeaRose’s mooring hawser in significant wave heights of 16 ft (5 m)

(Husky, 2001a). The hawser based mooring system has emergency disconnect capability and during the offloading hawser tension is continually monitored (Husky, 2001a).

Figure 3-24: SeaRose Offloading to Shuttle Tanker (Howell, 2007)

Labrador

From the onset of the 1970's, and continuing until 1985, the Labrador shelf experienced significant exploration activity. During this time period, 26 exploration and 2 delineation wells were drilled. Five 'significant discoveries' were made with total reserves of approximately 4.2 tcf of natural gas (120 billion m^3) (CNLOPB, 2007b) and 123 MMbbls of natural gas liquids (Wagner, 2003).

In recent years, interest and activity offshore Labrador has increased. During a seminar in 2003, *Labrador Gas Revisited: Technologies for Development*, Fluor Canada presented several options for gas production (Wagner, 2003). Based on the harsh environment characteristic of the Labrador Shelf region, the use of floating structures was considered on a seasonal basis.

Fluor indicated that a combined production option employing a FPSO with CNG carriers for gas export, or solely the use of CNG carriers (with minimum on-ship processing), would be technically feasible (Wagner, 2003). However, as a result of short production season duration (ranging from four to six months), these options may not be economically viable and further analysis would be required (Wagner, 2003). To date, although progress has been made, a commercial CNG solution has yet to emerge.

Drillships

As aforementioned, the Labrador Sea off the Canadian East Coast experienced an active drilling campaign in the 1970’s and 1980’s. Water depths ranged up to 1900 ft (580 m) and averaged around 655 to 985 ft (200 to 300 m). Wells took approximately 53 to 84 days to reach depths of 6900 to 10,500 ft (2100 to 3200 m). Frequently, wells had to be re-entered in the next drilling season to test the well or properly suspend/abandon the well. The drilling season was considered to be 110 to 120 days, at best.

During this era (circa 1970 – 1980), the dynamically positioned (DP) drillships utilized in the Labrador Sea were state-of-the-art vessels. The “Pelican”, “Pelerin”, “Petrel”, “BenOcean Lancer”, and “Neddrill 2” were all used extensively (Figure 3-25 and Figure 3-26). The “Sedco 445”, another DP drillship which drilled the Snorri J-90 well in 1975, was the first rig in the industry to operate on a well in full DP mode in 1971 offshore Brunei. One of their main advantages over moored vessels was enhanced mobility to disconnect if required and avoid icebergs or pack-ice in the early part of the Labrador drilling season.

Many of these drillships also offered reinforced hulls for protection from ice impact and large storage capacity allowed great self sufficiency in this remote location. However, advantages offered by the ship-shape design became a disadvantage in the months of October and November. It is known that ship-shape hulls are subject to poor heave, pitch, and roll motions that prevent efficient drilling/completion/testing operations. For this reason, semi-submersible designs would be best in the later months of the Labrador drilling season, from a motion standpoint.

The design of the “Pelican” series drillships has evolved over the years. The first units, “Pelican”, “Havdrill” and “Petrel” laid the foundation for the enhanced design of the next series of “Pelerin”, “Polly Bristol”, “Ben Ocean Lancer” and “Pacnorse I”. In the early 1980's the “Pelican” design was further enhanced to construct the ice-class drillships “Valentin Shashin”, “Mihail Mirchink” and “Viktor Muravlenko”.

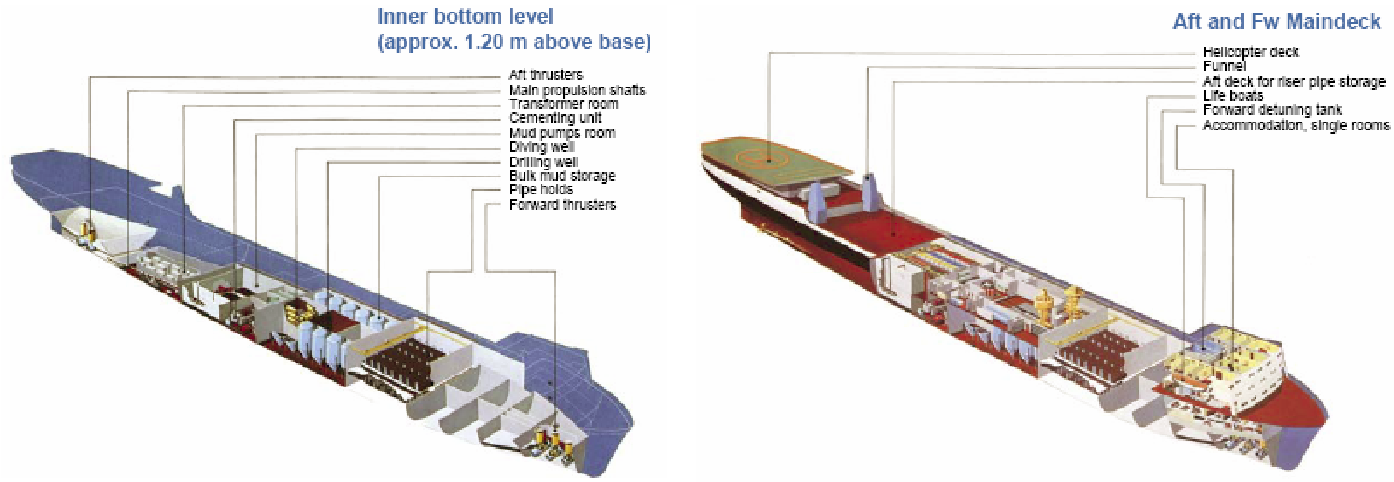

Figure 3-25: Design Concept of Drillships “Pelican”, “Pelerin”, “Petrel”, “BenOcean Lancer”, and “Neddrill 2” (GustoMSC, n.d.)

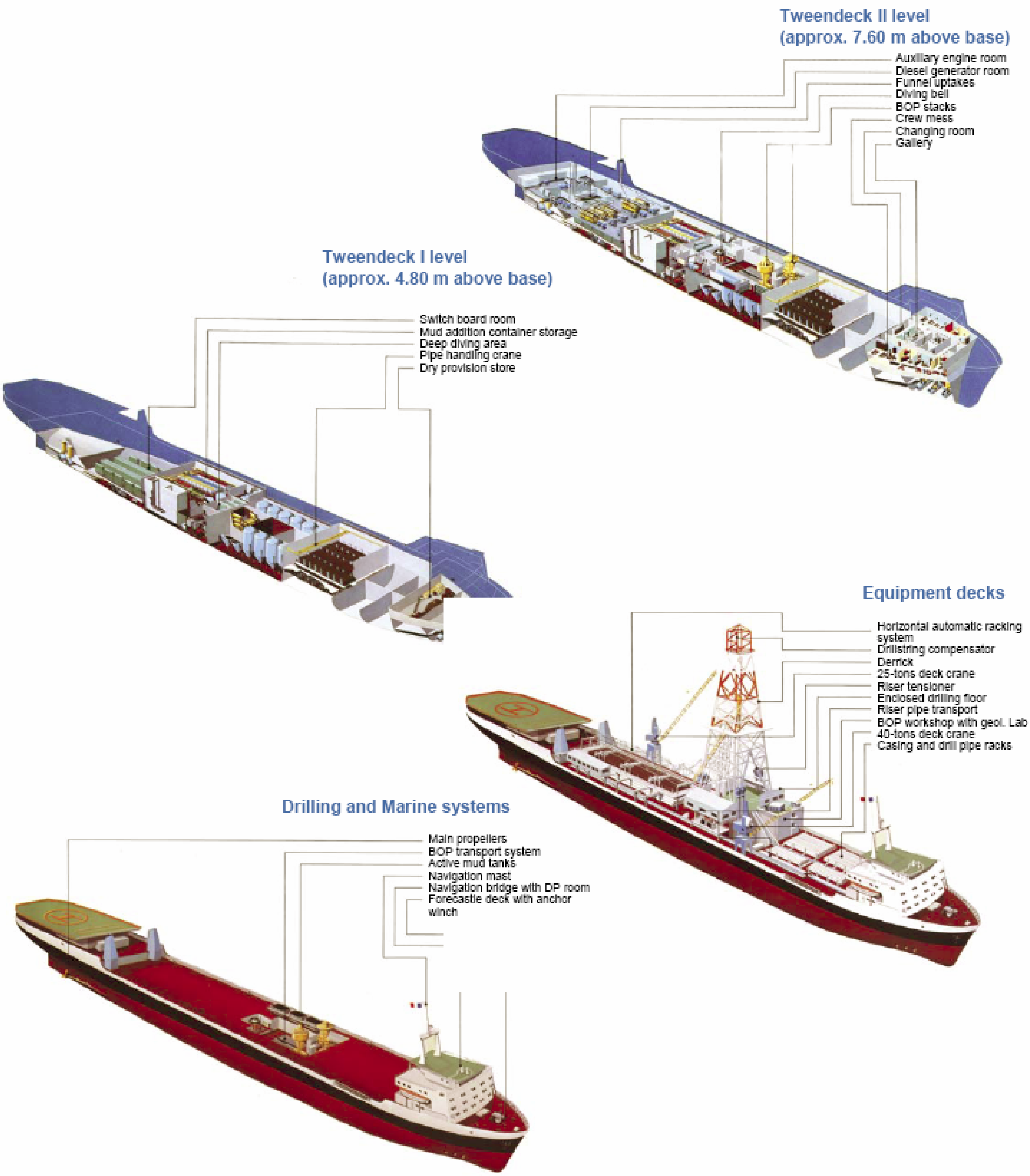

Figure 3-26: Additional Design Details of “Pelican”, “Pelerin”, “Petrel”, “BenOcean Lancer”, and “Neddrill 2” (GustoMSC, n.d.)

Orphan Basin

The use of a SPAR under ice conditions on the east coast of Canada has been proposed (Murray, 2004), albeit for deeper water conditions.

At the time, twelve SPARS had been installed with the deepest being at 5,400 ft (1645 m). Some of the features of a concrete spar were identified as being a traditional structure, 95% of the structure could be fabricated using slipforming operations, it would have a relatively fast construction time, and it was suitable for a harsh environment.

The proponents indicate that the structures can be built either out of steel or concrete. The structure can also be used for drilling and work over and can be used for oil storage. A configuration with bottom tensioned risers was proposed along with a disconnect feature (see Figure 3-27 and Figure 3-28).

The location looked at for the structure (Orphan Basin) could have a significant wave height of 52.5 ft (16 m) and potentially pack ice conditions. The disconnect feature would permit the SPAR to move off station in the event of the approach of a significant ice feature.

3.3.2.2 Canadian High Arctic

Floating Ice Drilling Pads

It should be noted that the complete Section that follows has been extracted from MMS Project No. 468 (C-CORE, 2005). Minor modifications to the text have been made.

The use of ice as a support material for offshore oil and gas exploration began in 1973 at the Hecla exploration well in the Canadian High Arctic. The floating drilling pad used artificial thickening of the natural ice sheet by flooding with seawater. Build-up rates were dictated by the time required to freeze thin layers of water, which were repeatedly added to the frozen core. Close to 40 floating ice pads were successfully used between 1973 and 1986 in the Canadian High Arctic using flooding and freezing techniques in water depths up to 1640 ft (500 m) (Masterson et al., 1987).

A total of 38 wells were drilled from floating ice pads (see Figure 3-29) between 1973 and 1986 (Masterson et al., 1987). Table 3-5 shows a chronological list of sites.

Figure 3-27: SPAR Concept for Offshore Canada (from Murray, 2004)

Figure 3-28: Disconnected SPAR (from Murray, 2004)

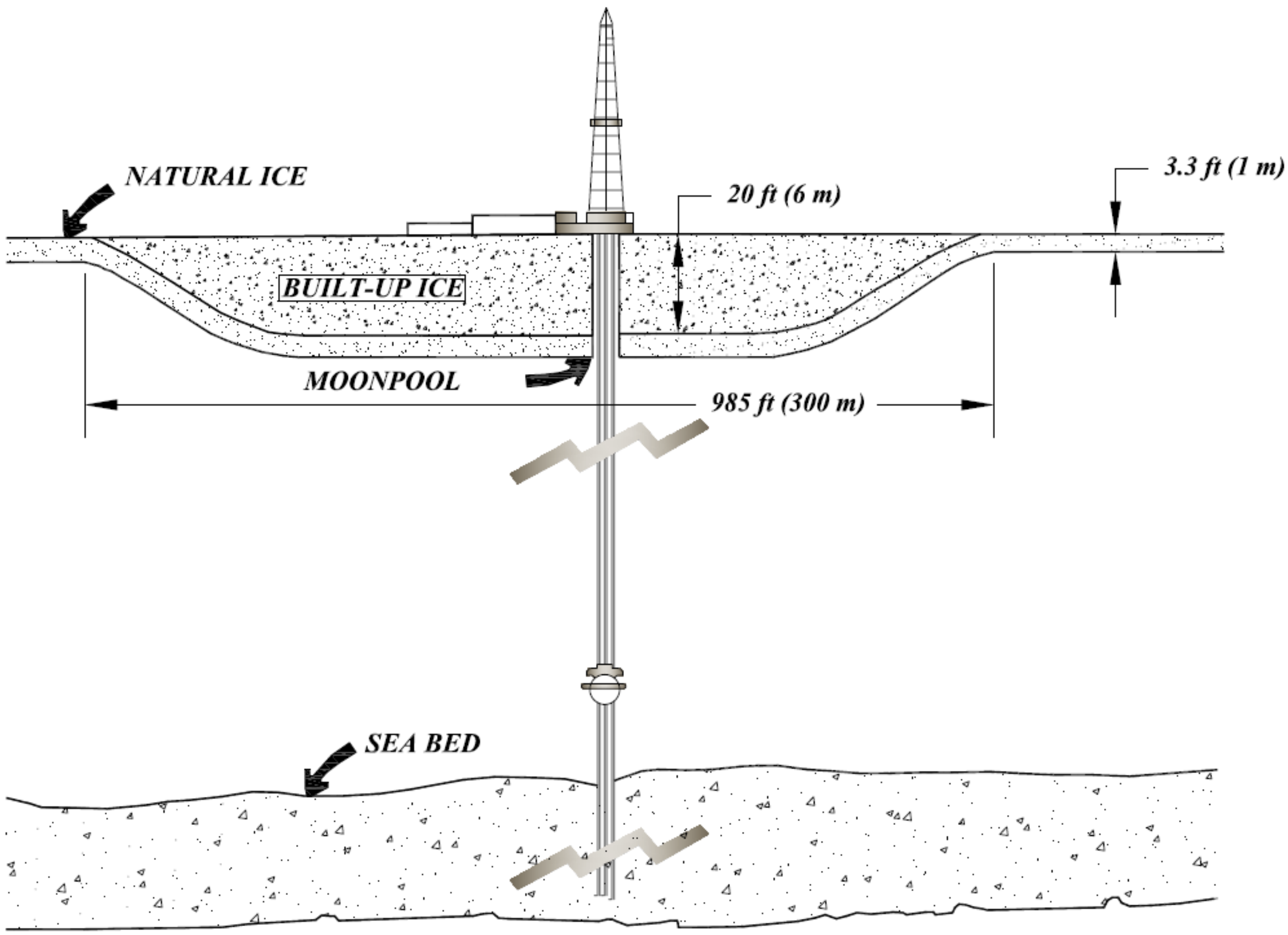

Figure 3-29: Cross-Section of Cape Alison Floating Spray Ice Pad (Masterson et al., 1987)

Table 3-5: Floating Ice Pads Constructed in the Canadian High Arctic

Structure	Dates	Original Thickness, ft m)	Design Thickness, ft (m)
Hecla N-52	1973/74	6.2 (1.9)	17.4 (5.3)
Resolute Bay Test	1974		
East Drake I-55	1974/5	6.6 (2.0)	16.4 (5.0)
NW Hecla M-25	1975/76	7.9 (2.4)	16.4 (5.0)
Jackson Bay G-16 & 16A	1975/76	3.9 (1.2)	18.0 (5.5)
W. Hecla P-62	1975/76	6.2 (1.9)	14.8 (4.5)
Drake F-76	1977/78	3.3 (1.0)	23.3 (7.1)
Roche Point O-43	1977/78	6.2 (1.9)	17.1 (5.2)
& Cape Grassy I-34	1977/78	2.95 (0.9)	17.4 (5.3)
Hazen Strait F-54	1978/79	6.9 (2.1)	21.3 (6.5)
Whitefish H-63	1978/79	20.7 (6.3)	21.0 (6.4)
Whitefish H-63A	1979/80	22.6 (6.9)	23.6 (7.2)
Char G-07	1980		
Baleana D-58	1980		
Cisco B-66	1980/81		~39.5 (~12)
MacLean I-72	1980/81		18.4 (5.6)
Cisco C-42	1982/82		18.7 (5.7)
Cape Mamen F-24	1981	15.1 (4.59)	21.0 (6.4)
Sculpin K-08	1981/82	33.1 (10.1)	33.8 (10.3)
Seal Island Floating Road	1981/82	3.6 (1.1)	9.2 (2.8)
Whitefish A-26	1981/82	21.7 (6.6)	23.3 (7.1)
Cisco K-58	1982/83		
Grenadier A-26	1982/83	4.3 (1.3)	22.6 (6.9)
Skate C-59	1982/83		20.0 (6.1)
E Drake L-06	1982/83		20.3 (6.2)
N Buckingham N-69	1982/83		21.7 (6.6)
Cisco M-22	1983/84	18.0 (5.5)	23.0 (7.0)
Cape Alison	1984/85	2.95 (0.9)	22.6 (6.9)
N Cornwall N-49	1985/86	2.95 (0.9)	23.3 (7.1)

Ice pads were constructed by pumping water onto the ice in thin layers, and allowing them to freeze in place to increase the thickness of the ice sheet at the drilling location. The majority of the drilling pads were built on level first-year ice of the order of 3.3 to 6.6 ft (1 to 2 m) thick. A number of pads were built on thick multi-year ice, for which flooding was used to provide a smooth surface rather than to increase the thickness. Construction of the platform took between 20 and 75 days, with an average build-up rate of approximately 2.8 inches/day (70 mm/day). Build-up rates varied significantly as a function of temperature, wind speed and equipment used. The platform would generally be ready to accept the rig during January or February, allowing up to 100 days of drilling.

The main structure constructed was the drilling pad to support the rig and associated equipment. Other important infrastructure included a relief pad for use in the event of blowout and an airstrip for both Twin Otter and Hercules aircraft.

Movement of the landfast ice sheet was not a great concern in the arctic islands, based on a number of years of historical data and the landlocked nature of the ice. The deep water depth provided some allowance for relative horizontal movement between the platform and seabed without over stressing the riser.

Spray ice started to be used for the construction of the floating Arctic island platforms in 1984/85 at Cape Alison and 1985/86 at North Cornwall. High pressure, high volume pumps and monitors were used to enhance the freezing rate of seawater to build up the ice platform thickness.

3.3.2.3 Russian Arctic

<u>Shtokman</u>

The Shtokman (Shtokmanskoye) gas field was discovered in 1988 and appraised between 1990 and 1995. The field is located in the Barents Sea, approximately 373 miles (600 km) offshore, in water depths of 1080 to 1150 ft (330 to 350 m) (see Figure 3-1). Detailed information on the environmental and operating conditions at Shtokman field is contained in Zubakin et al. (2004b), Naumov (2004), Buzin (2004a), Buzin (2004b), Zubakin et al. (2004c) and highlights of these publications are presented in Appendix A of this report. The summary of basic information about Shtokman is presented in Luff (2006). The Shtokman gas reserves are estimated at 112 to 116 tcf (3.2 to 3.3 trillion cubic meters), and the condensate reserves at 220 million barrels. This is the fourth largest gas field ever found. The expected production rate is 10 Bcf (283 million m^3) and more than 150 wells will be required. First production is expected in 2012, with a subsequent field life of 50 years. The estimated total development cost is USD 20 billion. It was widely expected that western oil companies would have a substantial share of the Shtokman development, but presently it is anticipated that Gazprom will be the sole operator.

Both subsea and platform development concepts have been considered for the field. The subsea development case is described further in Section 3.3.3.3.

In the platform scenario, Gazprom is considering three tension leg platforms (TLP's) with topside weights of 55,000 tons (50,000 tonnes) and a total weight of 204,000 tons (185,000 tonnes). Forty subsea wells will be required (Luff, 2006). The three-platform scenario for Shtokman is mentioned in other sources as well, for example, Gazprom and VNIIGAZ (n.d.). Several concepts are being developed for the transportation and transshipment of hydrocarbons from the field. The search for the most efficient supply base location for the Shtokman exploration and production activities is also underway (see Section 3.3.5 below for more details).

3.3.2.4 Sakhalin Island

Sakhalin 2

The Sakhalin 2 project utilizes a floating structure for offloading oil produced at the Molikpaq structure. Oil produced from the Molikpaq platform is exported via a 12-inch subsea pipeline to a Floating Storage and Offloading (FSO) vessel, the Okha supertanker, located 1.2 miles (2 km) away, and which is anchored to a Single Anchor Leg Mooring (SALM) (Figure 3-30 and Figure 3-31). Oil is then loaded onto tankers for export (Figure 3-32) (SPG Media Limited, 2007c).

Due to severe climatic conditions in the Sea of Okhotsk, Molikpaq production is currently limited to a six-month period when the sea is free of ice. In the winter months when production is shut-in, the SALM unit is lowered to the seabed and the Okha FSO is chartered out to transport oil for other parties (Rigzone, 2007a).

Figure 3-30: “Smit Sakhalin” Connected up to SALM Production Buoy Preparing for Winter Lay Down Operations (Courtesy of DC Marine)

Figure 3-31: SALM Buoy Ice Up After Storm Event (Courtesy of DC Marine)

Figure 3-32: FSO “Okha” Connected up to Production SALM Buoy, Late Season (Courtesy of DC Marine)

3.3.2.5 Offshore Greenland

Recent petroleum exploration licenses awarded offshore Greenland lie in two general areas, West of Disko Bay, and roughly West of Nuuk, the capital of Greenland.

Licenses West of Nuuk, Atammik and Lady Franklin (shown in Figure 3-33 below), are owned by EnCana and its partner Nunaoil A/S. The Atammik license is located approximately 125 miles (200 km) from shore and its water depths range from 660 to 3300 ft (200 to 1000 m) (Geological Survey of Denmark and Greenland, 2002). The Lady Franklin license lies approximately 156 miles (250 km) from shore and has water depths ranging from 2500 to 5700 ft (750 to 1750 m) (BMP, 2006).

As shown in Figure 3-34, in 2005 EnCana presented a potential development scenario which involved the use of an FPSO and integrated subsea production system (Cooper, 2005). The potential scenario was based on a location in the Eastern Davis Strait in a water depth of approximately 3800 ft (1150 m). The FPSO was an ice strengthened 250,000 DWT tanker with a production capacity of 165,000 bbls/d (Cooper, 2005).

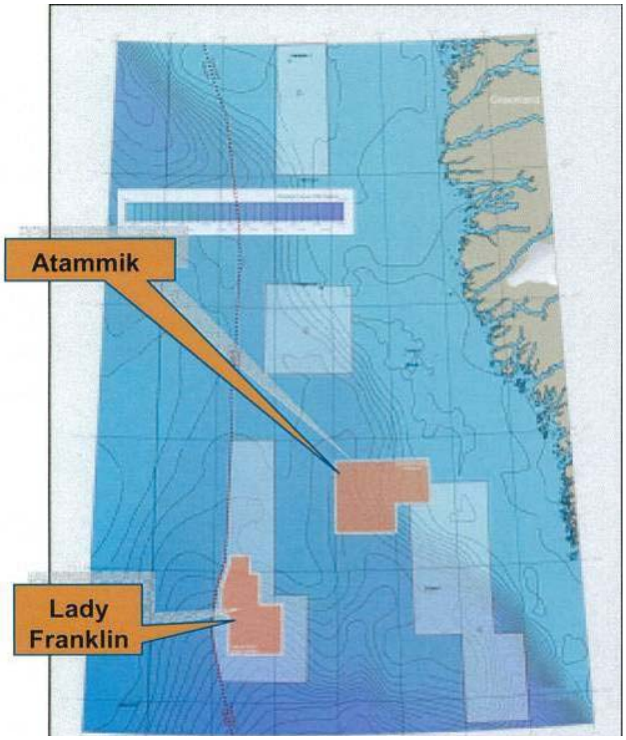

Figure 3-33: Atammik and Lady Franklin Exploration Licenses (Cooper, 2005)

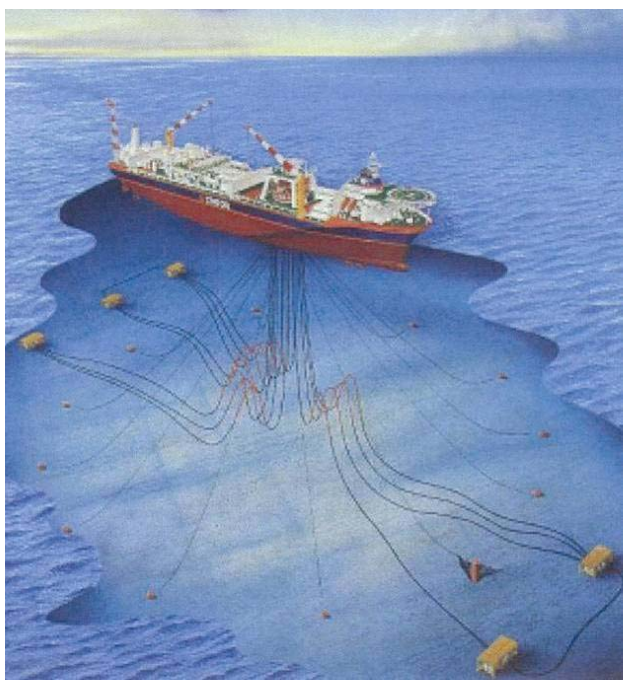

Figure 3-34: Potential Development Scenario Offshore West Greenland (Cooper, 2005)

Ice conditions in Eastern Davis Strait are fairly benign; typically only first-year ice is encountered and south of 65 to 67°N the seas are predominated by ice-free areas year round (Mosbech et al., 2007).

The aforementioned conditions are much less severe then those experienced further North in the West Disko Bay area. This area is typically covered by sea ice during the winter and early spring and icebergs are much more frequently encountered and in larger sizes then would be typically experienced south of 65 to 67°N; in Disko Bay there are always hundreds of icebergs present (Mosbech et al., 2007).

In 2003, a feasibility study carried out to assess field development concepts for the West Disko Bay area concluded that the most feasible solution would be to utilize a subsea to beach development scheme (Mosbech et al., 2007; BMP, 2006). FPSO development schemes were considered; however, the assessment indicated that they would only be able to achieve an annual uptime in the range of 40 to 65% (BMP, 2006). Husky Oil Operations, Esso Exploration Greenland, and Nunaoil A/S hold interest in exploration licenses for this area (Husky, 2007c).

3.3.2.6 Semi-rigid Floater Concept

The semi-rigid floater structure shown in Figure 3-35 was originally designed for Sakhalin Island. The structure combines the buoyancy properties of a conventional buoy with tension leg platform concepts (CKJ Engineering Ltd., 2005). The semi-rigid floater was developed primarily to provide an exploration solution for sea ice environments in water depths ranging from 260 to 1640 ft (80 to 500 m); however, depending on severity of ice conditions, it may also be considered for a year round production solution.

The structure consists of a circular floating hull, three cable groups and three anchors. The floating hull is circular and consists of a series of decks. The top deck is approximately 330 ft (100 m) in diameter with a centrally placed 49 ft (15 m) diameter moonpool. The lower deck accommodates the unit's cable and winching systems.

A procedure has been developed for the installation and relocation of the structure using the assistance of tugs. This system involves deploying and individually positioning all the anchors. When all anchors are in position, they are ballasted and the cable groups are winched in until the unit is centrally located between the anchors. Deballasting of the upper hull then commences until the force in each cable group is about 16,500 tons (15,000 tonnes). The structure is then ready to begin drilling operations.

Preparing the structure for relocation is essentially the reverse of the installation process. Depending on whether or not the unit is being moved to shallower or deeper water, the cable lengths can be adjusted as required for site-specific conditions.

The semi-rigid floater concept is designed to carry 16,500 tons (15,000 tonnes) of topsides and can operate in 16,500 tons (15,000 tonnes) of ice loading with wave heights of 49 ft (15 m) without being subject to fatigue issues. When disconnected, the structure has floating stability when its anchors are free of the sea floor in waves up to 26 ft (8 m). Stability is maintained by adjusting the amount of water ballast.

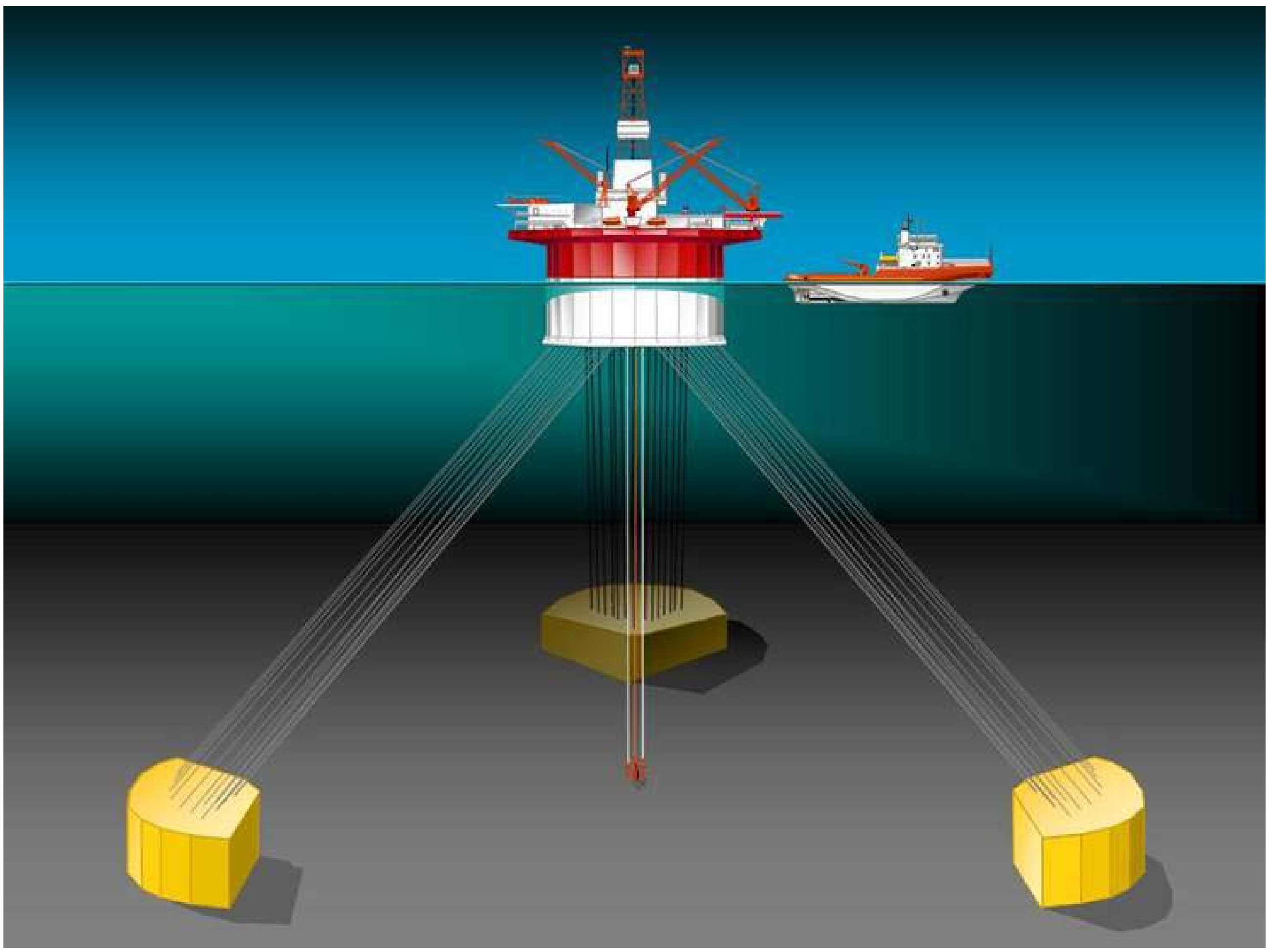

Figure 3-35: Arctic Semi-rigid Floater

3.3.2.7 Monocone Arctic Platform (MCAD)

The Monocone Arctic Platform (MCAD) was presented at the 2007 Offshore Mechanics and Arctic Engineering Conference as a solution to production and drilling in Arctic sea ice environments with water depths of up to 410 ft (125 m) (Paganie, 2007).

The MCAD is a cone-shaped floating hull consisting of an upper and lower section. The upper section provides the structure’s buoyancy and ice breaking features. The lower section consists of a heavy steel ballast that can be lowered to adjust the unit’s vertical center of gravity. The unit maintains its position by the use of a steel mooring system. The mooring system consists of 32 chains connected to 16 driven anchor piles. The 16 piles are expected to be 9.8 to 13.1 ft (3 to 4 m) in diameter with an embedment of 151 to 180 ft (46 to 55 m) (Paganie, 2007).

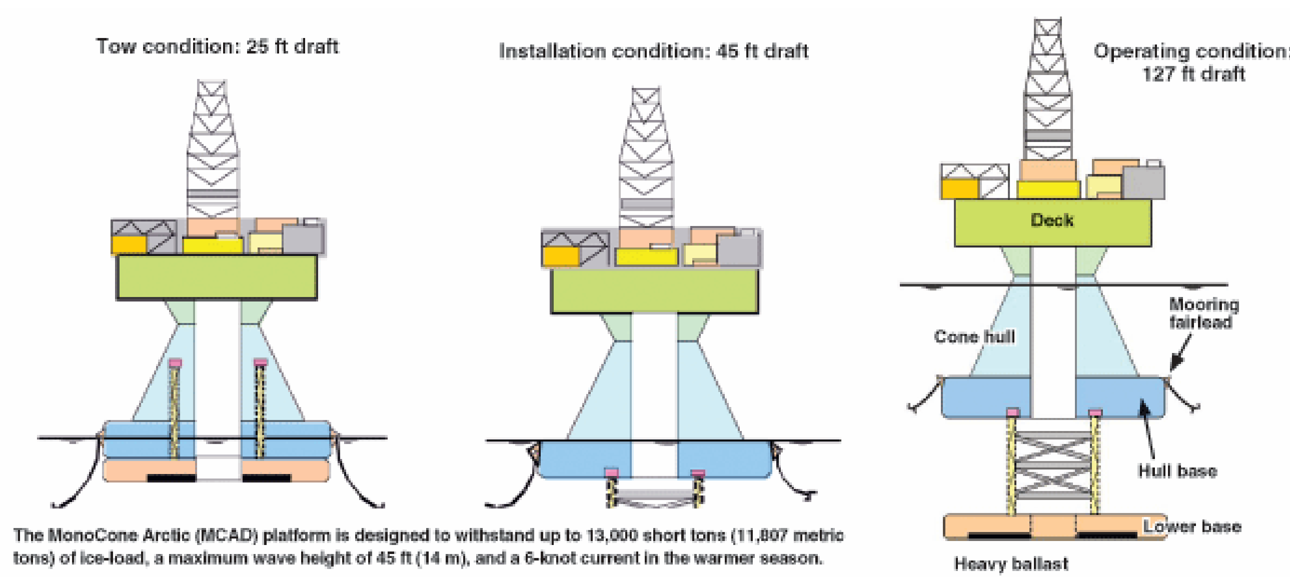

Figure 3-36: MCAD Platform (Paganie, 2007)

The installation and relocation of the unit requires the assistance of tugs and pile driving services. Anchor piles are driven at the planned drilling location prior to the unit’s arrival. Upon arrival, the unit’s mooring system is connected to the anchor piles and the ballast section is lowered. The structure is now ready to begin drilling operations. Preparing the structure for relocation is the reverse of the installation process. The MCAD’s mooring system is only partially mobile, so each installation and relocation of the unit requires the installation of new anchor piles.

The MCAD is designed to operate under ice loads of 13,200 tons (12,000 tonnes) in wave heights of 46 ft (14 m). The MCAD has capacity to carry 26,500 tons (24,000 tonnes) of topsides. The estimated construction cost of the MCAD is $500 to $600 Million USD (Paganie, 2007).

3.3.2.8 Conventional Floating Exploration Structures

Conventional floating exploration structures, drillships and semi-submersibles, have been used in areas subject to seasonal/marginal ice cover including the east coast of Canada, offshore Greenland, the Russian Arctic, and offshore Sakhalin Island. Drilling with these structures is generally carried out during summer months when seas are ice free. However, there are drilling units which are ice strengthened/classed for operation in light/managed ice cover. Furthermore, there are other drilling units, such as the Vidar Viking, which have shown that drilling in ice well beyond light/managed ice is possible.

The purpose of this section is to highlight some notable technology and drilling units employed in analogue areas.

<u>Vidar Viking</u>

The Vidar Viking is an ice breaking (Class DNV IBICE10, 4.3 ft (1.3 m) ice) anchor handling, tug and supply vessel complete with a full dynamic positioning system.

The vessel was outfitted with a moon pool and a compact drill rig for deep sea drilling in summer of 2004. This upgrade was performed to allow the Vidar Viking to serve as the drilling vessel for the Arctic Coring Expedition (ACEX) project (ALIAS, 2007). In the summer of 2004 as part of the ACEX, the Vidar Viking successfully gathered cores from under the central polar ice pack. Ocean floor core sampling was carried down to the full target depth, to bedrock on the Lomonosov ridge, at 1440 ft (438 meters) of core length (Keionen et al., 2007). Prior to this date no core drilling had taken place under the central polar ice pack.

Figure 3-37: “Vidar Viking” Equipped with Compact Drill Rig, in the Central Polar Pack (Keionen et al., 2007)

This drilling program was possible as a result of the many lessons learned in ice management, ice intelligence and evaluations, forecasting drift, risk assessments and icebreaker operations by the Sovetskiy Soyuz and Oden to defend the stationary Vidar Viking vessel in moving pack ice. This program allowed the vessel to remain on station for days at a time in difficult ice and weather conditions.

The station keeping operation had an allowable movement during operation of about 5% of water depth. The Vidar Viking was able to keep station at the central polar pack in approximately 10 tenths of 8.2 to 8.9 ft (2.5 to 2.7 m) thick multi-year ice drifting at about 0.19 knots (Keionen et al., 2007).

This accomplishment has proven that it is possible to keep a vessel in the central polar pack stationary for a significant length of time. It is likely that station keeping in thick ice can be reached beyond what has been achieved by the Vidar Viking with the application of the latest azimuth propulsion icebreaker technology.

Eirik Raude

The Eirik Raude (Figure 3-38) is a 5th generation harsh environment, dynamically positioned semi-submersible. The Eirik Raude is 390 feet long by 280 feet wide (119 m long by 85 m wide). It can handle a variable deck load of 7129 tons (6467 tonnes) in operation and 4867 tons (4415 tonnes) in transit. The platform weighs 52,552 tons (47,675 tonnes), has a lifting capacity of 1002 tons (909 tonnes), and can handle up to 32,800 feet (10,000 m) of drill pipe (Ocean Rig ASA, 2007).

Figure 3-38: Eirik Raude (Ocean Rig ASA, 2007)

The rig is operational in water depths of 230 to 10,000 ft (70 to 3050 m). In depths of 230 to 1600 ft (70 to 488 m), position is maintained by use of the mooring system. Beyond this depth, position is maintained by the class 3 dynamic positioning system (DP3) and the unit's six computer controlled thrusters (Ocean Rig ASA, 2007). This DP3 system is capable of holding the rig on position in violent storms. In the fall of 2003, the rig maintained position over a well off the east coast of Newfoundland in 120-knot (62 m/s) winds and 79 foot (24 m) waves (Goa, 2003). Furthermore, Goa (2003) indicated that the Eirik Raude encountered ice while drilling on location off the east coast of Canada.

Quick disconnect features allow the Eirik Raude to disconnect from, and secure, a well in 35 seconds. The quick disconnect feature makes it possible for the rig to operate in areas prone to icebergs (Goa, 2003).

3.3.2.9 Henry Goodrich

The Henry Goodrich (Figure 3-39) is a harsh environment 4th generation semi-submersible, and has been used year round on the Grand Banks. The Goodrich has carried out the majority of development drilling for the Terra Nova field.

Figure 3-39: Henry Goodrich (Toolpusher, 2007)

The Henry Goodrich is ice-classed and can withstand significant storm conditions (TransOcean, 2007):

- Operating Conditions: Maximum wave 45 ft (14 m), significant wave 25 ft (8 m), period 13 seconds, wind 50 knots (26 m/s), current 2 knots (1 m/s); and
- Storm Conditions: Maximum wave 105 ft (32 m), significant wave 56 ft (17 m), period 15 seconds, wind 60 knots (31 m/s), current 2.5 knots (1.3 m/s).

The Henry Goodrich's classification (by DNV) is +1A1 Column Stabilized Drilling Unit, HELDK, POSMOOR TA, DRILL N, ICE TL.

3.3.3 Subsea Solutions

Advancement in subsea technologies are allowing for faster production, longer tiebacks, deeper water solutions, and tiebacks to land without the use of offshore structures. Notable developments in non-arctic environments include Ormen Lange and Snøhvit. The Ormen Lange tieback to shore is 75 miles (120 km) long and originates at 3300 ft (1005 m) water depth. The Snøhvit project, which has recently come online, has subsea equipment in approximately 820 to 1150 ft (250 to 350 m) water depth located approximately 93 miles (150 km) offshore.

Subsea solutions (no structure) have been used and/or considered in arctic and sub-arctic type areas as described below.

3.3.3.1 Canadian East Coast

On the Grand Banks, the biggest concern with respect to subsea infrastructure is icebergs. Free floating and (seabed) gouging icebergs may pose a risk to subsea structures that extend above the seabed. If the structure is placed below the mudline, the hazards posed by free floating icebergs are eliminated. If the structure is located a sufficient distance below the mudline, the risks due to gouging ice keels are minimized.

Protection of subsea structures from gouging icebergs on the Grand Banks is achieved by placing the equipment in excavated pits known as glory holes. Alternative strategies have been looked at during previous project design; however, open glory holes were identified as the optimum solution for east coast Canada projects requiring protection. Similar issues would exist for subsea infrastructure that would be placed in water depths approximately less than approximately 1000 ft (300 m) on the Labrador Shelf.

There are only two known projects in the world which use glory holes to protect wellheads and associated equipment from potential ice impacts. Petro Canada's Terra Nova field and Husky's White Rose field located on the Grand Banks of Newfoundland (see Section 3.3.2.1). The Terra Nova development utilizes 5 glory holes in water depths ranging from approximately 312 to 330 ft (95 to 100 m) water depth while the White Rose development requires only 3 glory holes in water depths ranging from approximately 395 to 410 ft (120 to 125 m).

As an indicator of the dimensions associated with these east coast developments, Table 3-6 provides a summary of the overall glory hole dimensions.

Table 3-6: Grand Banks Canada Glory Hole Dimensions (Technip, 2001)

<table>
<tr><th>Field</th><th>Glory Hole</th><th>Base Dimensions, ft (m)</th><th>Depth, ft (m)</th><th>Side Slopes</th><th>Ramp Slope</th></tr>
<tr><td rowspan="5">Terra Nova</td><td>Southeast</td><td>82 x 82 (25 × 25)</td><td rowspan="4">32.8 (10)</td><td rowspan="5" colspan="2">1:3</td></tr>
<tr><td>Northwest</td><td>82 x 82 (25 × 25)</td></tr>
<tr><td>Northeast</td><td>147.6 x 82 (45 × 25)</td></tr>
<tr><td>Southwest</td><td>213.3 x 82 (65 × 25)</td></tr>
<tr><td>Far East</td><td>141.7 x 76.1 (43.2 × 23.2)</td><td>33.8 (10.3)</td></tr>
<tr><td>White Rose</td><td>Southern</td><td>190.3 x 145.7 (58 × 44.4)</td><td>29.5 (9)</td><td>1:1.8</td><td>1:5</td></tr>
</table>

3.3.3.2 PanArctic Drake

The world's first arctic subsea flowline began transporting gas in April 1978, from a subsea wellhead to production facilities onshore (Palmer et al., 1979). A Canadian company, PanArctic Oil Ltd., sponsored the Drake Field subsea completion which was located in the Canadian High Arctic off of Mellville Island (Figure 3-40). The three-year program to design, fabricate and construct the flowline was part of a test program to evaluate the performance of the field development concept and demonstrate the feasibility of such an offshore arctic development.

The well location was chosen such that the top of the wellhead was deep enough to avoid contact by ice keels (predominantly less than 150 feet (46 m) deep). Another requirement was that the flowline bundle length be minimized (4000 ft or 1220 m).

The water depth at the well location was 181 feet (55 m) and the well was drilled from the floating ice using an onshore rig modified for offshore drilling (Watts and Masterson, 1979). The Christmas tree assembly which was installed was equipped with diverless remote hydraulic flowline connectors which were used to tie-in the flowlines. Diverless pipeline bundle connections were made by using the deflect-to-connect method (Palmer et al., 1979).

Figure 3-40: Drake Project Location Map

3.3.3.3 Russian Arctic

Subsea solutions have been considered in the Russian Arctic, including Shtokman. In the subsea development case, subsea separation and compression technology will be used. If the subsea method is chosen, technology applied during development of the Ormen Lange field in Norway will be taken as a prototype (SPG Media Limited, 2007a). The gas will be transported from the well through a pipeline and liquefied onshore. The specialists of JSC GiproSpetsGaz (Gazprom affiliate) and VNIIGAZ, together with Norwegian companies are investigating the feasibility of this concept.

3.3.4 Pipelines

3.3.4.1 PanArctic Drake

Overview

The Drake Field subsea well test experience is instructive, since it shows the effort required for pipeline bundle construction in the arctic. The implication is that the schedule lengthens considerably over that which would be anticipated from a more conventional pipeline configuration. The gas was produced to a test flare for several months and then shut-in and, years later, the well and flowline bundle were abandoned.

Pipelines

The flowline bundle is illustrated in Figure 3-41. The flowline bundle contained two 6-inch (152 mm) flowlines with heat tracing. One flowline was insulated with a layer of expanded polyurethane foam. In addition to the flowlines, the bundle contained one 2-inch (50 mm) annulus access line and four 1-inch (25 mm) lines for methanol injection, two for hydraulic control and one spare. There were also electrical cables for strain gauging and pressure and temperature measurements. The pipes and cables were made into a bundle and enclosed in the carrier pipe, where they were held in place by aluminum spacers. In addition to a methanol injection line for hydrate control, each of the two pipelines was heat traced using different methods. An 18-inch (457 mm) carrier pipe was used to contain the bundle of seven pipelines and various cables.

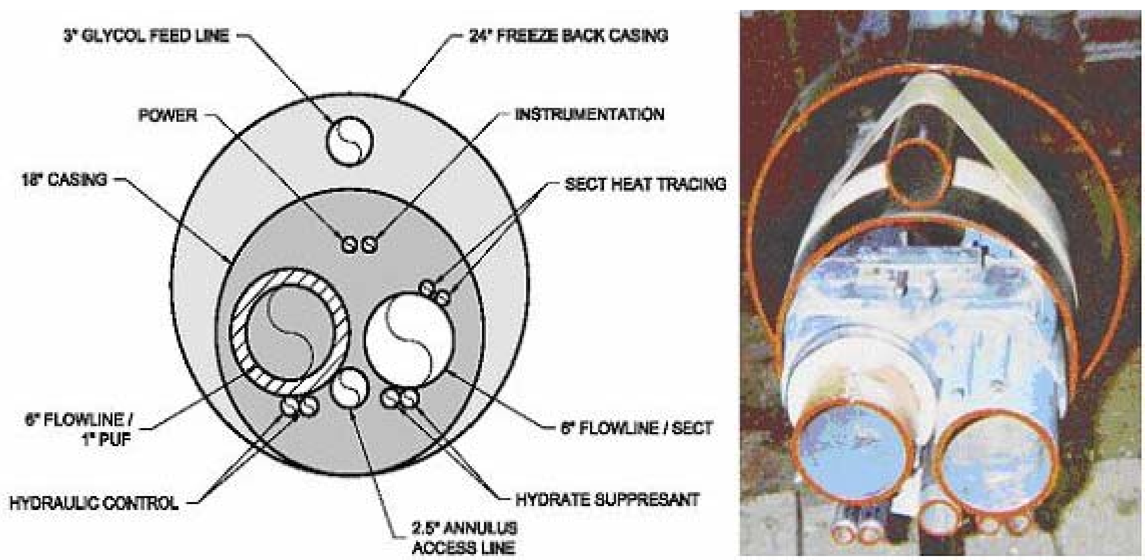

Figure 3-41: Drake Flowline Bundle (Palmer et al., 1979)

Project Design Challenges & Highlights

Ice gouging was a major concern for the flowline bundle. The deepest ice island keel depth expected for the area was 148 ft (45 m). The depth at which the wellhead was to be located was based on this maximum expected keel depth. A relatively steep shore crossing was located which would minimize the length over which the flowline would need to be protected from sea ice. The sea ice at the site was found to be a mixture of first-year and multi-year ice with average and maximum thicknesses of 9.8 ft (3 m) and 57 ft (17.4 m), respectively.

A 13 ft (4 m) deep trench backfilled with rock was initially planned to protect the pipeline. However, due to the weak characteristics of the seabed soils, it was determined that digging a trench with steep side slopes was not possible and it would collapse under its own weight.

An evaluation of alternative protection techniques was therefore carried out. The solution which was selected was to protect the pipeline with frozen soil. The pipeline would be placed in a 5 ft (1.5 m) deep trench, backfilled with gravel, and the soil frozen around the carrier pipe, thus creating a protective cylinder around the flowline system. The frozen soil would have a significantly greater strength than the surrounding soil and also increase the lateral resistance of the pipeline to movement.

The 18-inch (457 mm) casing pipe was itself put inside a 24-inch (610 mm) casing pipe. A methanol-water mixture at -22°F (-30°C) was circulated offshore through the annulus between the 18 and 24-inch (457 and 610 mm) lines and returned via a small diameter return flowline in the annulus. The system was designed to grow the frozen soil bulb to a minimum diameter of 9.8 ft (3 m) after being in operation for 40 days.

When completed and operational, the frozen soil bulb would extend from 50 ft (15 m) onshore to 919 ft (280 m) offshore at 65 ft (20 m) water depth. Additional protection was afforded the pipeline in the nearshore zone out to 16 ft (5 m) water depth through the construction of a grounded ice berm.

<u>Pipeline Construction / Construction Planning Challenges & Highlights</u>

The presence of sea ice was determined to be a significant factor in the schedule. Sea ice begins to form in the area in September, can support light equipment by November, and can support heavy equipment from January to May. Natural ice thicknesses could reach 6.6 ft (2 m). Therefore, the decision was made to artificially thicken the ice where additional thickness was needed and install the pipeline from the ice.

Nearshore, the trench was excavated by a clamshell crane supplemented by blasting through permafrost. Offshore, the 5 ft (1.5 m) deep and 820 ft (250 m) long trench was made in 30 minutes using a specially designed large trenching plow. The plow was specifically designed for the soft soils encountered and was also designed to be disassembled and air freighted to the site (Brown and Palmer, 1985).

Fabrication occurred on Melville Island during the winter of 1977 – 78. A “stove pipe” technique was employed for pipe string and bundle make-up under a temporary shelter. This necessitated a significant staging area for pipe handling. The outer jacket pipe was pulled over the inner bundle of pipes, tubing and power cables. Even though the pipeline was only 4000 feet (1220 m) long, the pipe bundle make-up lasted four and a half months, not including pipeline installation.

In the nearshore area, a plow launch hole was cut in the ice. A 1 ft (0.3 m) wide slot was cut through the ice from shore to the ice island drilling platform using an ice saw mounted on a crawler tractor. A cable connected to a winch offshore was dropped through the slot and connected to the plow. The plow was then dropped through the launch hole and pulled offshore.

The flowline bundle was to be pulled into place using the same ice-based winch. When the bundle was complete and on the onshore launchway, the subsea completion manifold was welded to the leading edge of the bundle. Once the plow created the trench and was retrieved, the cable was re-laid through the slot in the ice and the pipe pulled from shore into the trench. The pipeline was then tied into the wellhead using a diverless connection method; the deflect-to-connect method (Palmer et al., 1979). The leading sections of the flowline bundle were made positively buoyant by using floatation devices and a number of additional winches used to control the flowline bundle position during the tie-in procedure.

Logistically, PanArctic had a permanent site on Mellville Island (Rea Point) that could be reached by ship during open water season. The site was approximately 31 miles (50 km) southeast of the Drake shore crossing location. A portable camp and runway were established for the Drake work and equipment/supplies were airlifted in from Rea Point.

3.3.4.2 Polar Gas Project

<u>Overview</u>

Polar Gas was a consortium of American and Canadian companies formed in 1972 who investigated the possibility of bringing natural gas southward by pipeline from the Canadian Arctic Islands (Houlding, 1976). Considerable design work and a research program was undertaken to look at the feasibility of laying pipelines in extreme low temperatures and through the ice in the Canadian Arctic (Figure 3-42).

Pipelines

The overall pipeline system was envisioned to consist of 3100 miles (4990 km) of 48-inch (1220 mm) pipeline down the west side of Hudson Bay. Offshore pipelines were planned to be dual 36-inch (914 mm) lines. The pipelines bringing gas from the islands were planned as a phased approach. The first pipelines being considered were those running south from Melville Island. Subsequently, pipelines would be built to the islands further north.

Project Design Challenges & Highlights

Major problems associated with pipelines for the project were identified. This included the duration of the open water season as channels could remain ice covered for as much as 50 weeks/year and this could limit the use of laybarges. In addition, little was known about bathymetry, currents, and bottom conditions, and, given the ice conditions, the pipeline would need to be protected from the ice.

The conclusion with regards to ice gouging was that ice masses large enough to cause serious problems to the pipeline would not be experienced along the pipeline route due to the protection afforded by the surrounding islands and the prevailing currents. The maximum water depth for gouging from ice islands or large pieces of ice was considered to be less than 148 ft (45 m).

Pipeline Construction / Construction Planning Challenges & Highlights

The main challenge with regards to the pipelines was to install pipelines across deepwater channels between the Arctic islands. Logistics were also identified as a significant issue; 15 staging areas would be required to move almost 5.5 million tons (5 million tonnes) of equipment, materials, and supplies.

A number of channel crossing methods were looked at for the Polar Gas project, including:

- Lowering the pipeline from the surface of the ice or by conventional laybarge;
- Pulling the pipe from shore-to-shore, from the ice surface or from a vessel; and,

- Tunneling.

All were considered feasible. The primary solution was to use the ice as a working platform for installation and logistics.

A 100-day construction period would take place between February and May when daylight hours were available and the ice was thick (up to 6 feet (1.8 m)) and stable. At that time, the ice island bottom pull concept (Figure 3-43) was considered the most promising and cost effective solution where the availability of an open water season could not be guaranteed. The plan was to build up artificial ice platforms in the channel, mount large winches, and conduct a number of shore-to-shore (or ice platform to ice platform) pulls. An ice strengthened pull ship or pull barge was considered for use in areas where an open water season could be expected. One or more mid-line tie-ins could be expected during construction and would be carried out by lifting the pipeline to the surface (ice or water) and welding the pipeline segments together, or by carrying out hyperbaric welded tie-ins.

A second route was later investigated (Figure 3-42) as the result of technological advances at the time, that took the pipelines south across M’Clure Strait, over Victoria Island, and across Dolphin and Union Strait. Surveys done in these Straits in 1979 indicated these crossings to be technically feasible (Kaustinen, 1981).

The crossing location of M'Clure Strait was 75 miles (120 km) wide, extending to a depth of 1640 ft (500 m). The ice could vary from 6.6 to 40 ft (2 to 12 m) in thickness with an average natural ice thickness of approximately 9.8 ft (3 m). However, the ice did contain ridges and the ice hole method (Figure 3-44) was therefore proposed for this crossing as this technique was less dependent on having long flat ice surfaces along the pipeline right of way. Tie-ins between pipeline strings would be made at the ice surface or using a 1-atmosphere welding technique to weld the pipelines on the seabottom.

The crossing location of the Dolphin and Union Strait was 19 miles (30 km) wide and 361 ft (110 m) deep. A laybarge or pullbarge method of installing the pipe was considered to be preferable as the channel was determined to be ice-free in August and September of each year. In shallow water (less than 79 ft (24 m)) at the shore crossings of Dolphin and Union Strait, the pipelines were to be installed in tunnels to protect the pipeline from ice gouging (Figure 3-45). At M’Clure Strait, the pipelines would be installed in a tunnel to a water depth of 180 ft (55 m).

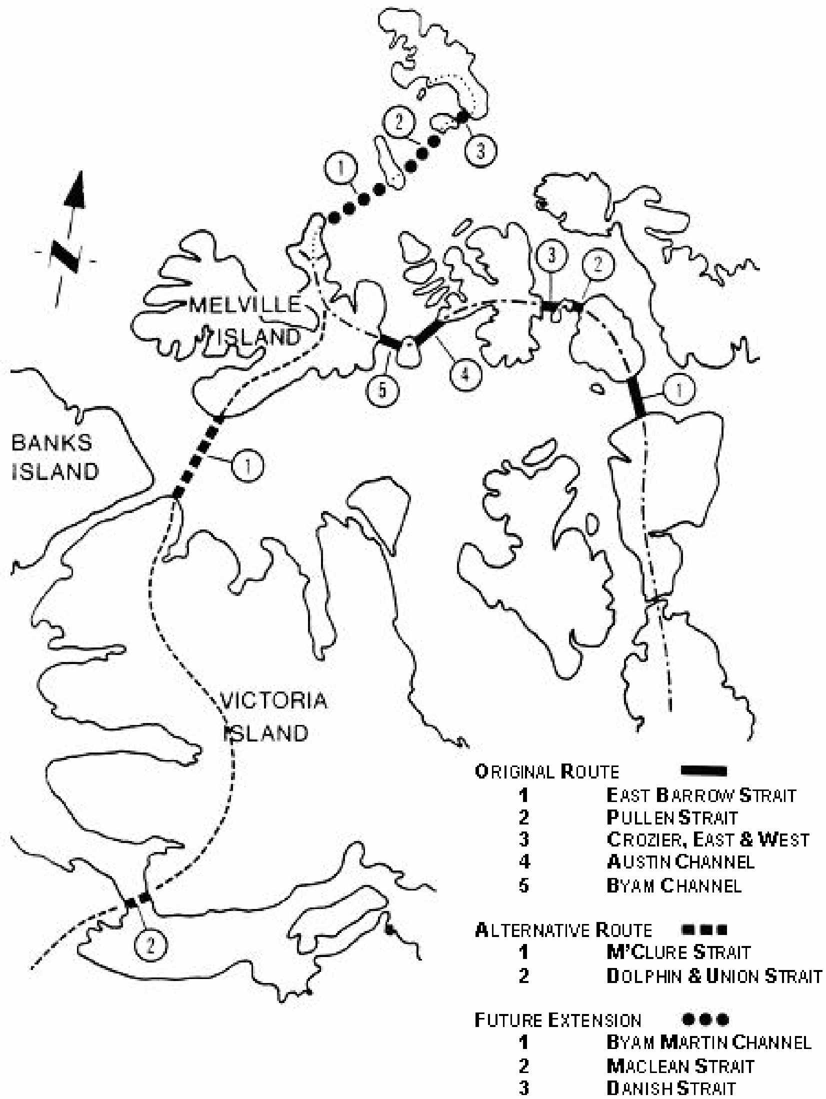

Figure 3-42: Polar Gas Channel Crossings (modified from Kaustinen, 1981)

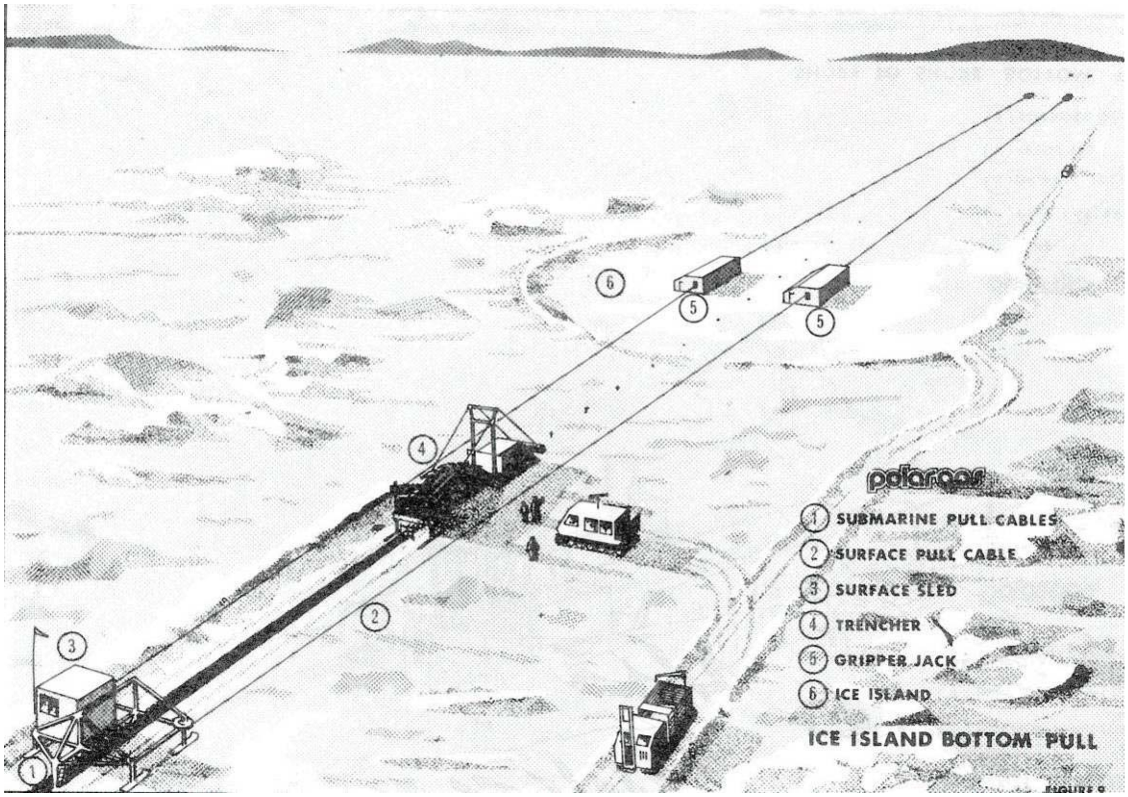

Figure 3-43: Ice Island Bottom Pull Method (from Kaustinen, 1981)

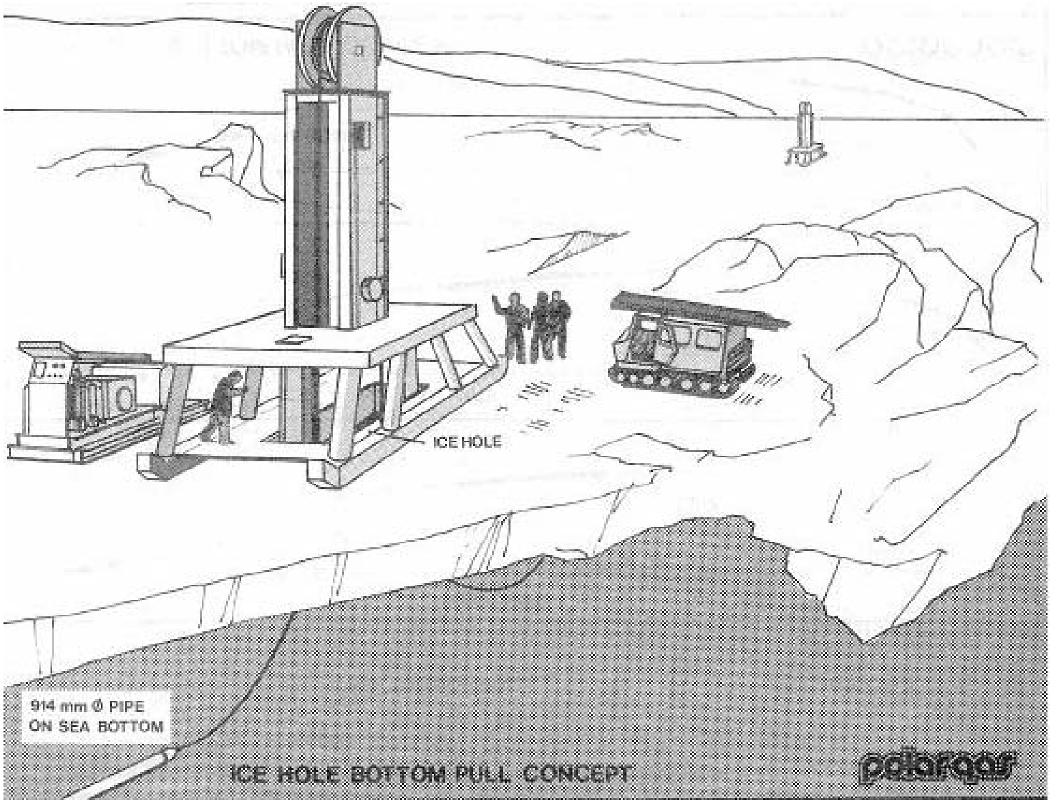

Figure 3-44: Ice Hole Bottom Pull Method (from Kaustinen, 1981)

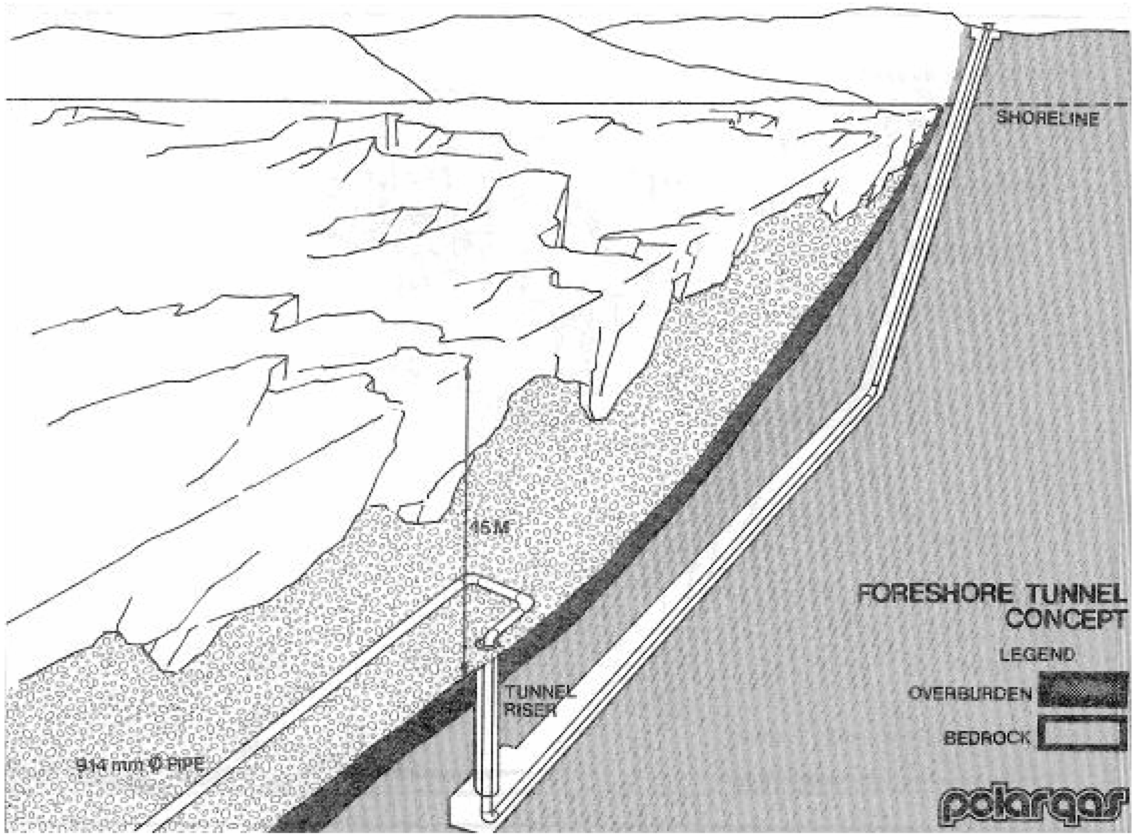

Figure 3-45: Polar Gas Foreshore Tunnel Concept (from Kaustinen, 1981)

3.3.4.3 Baydaratskaya Bay (Russia)

Gas transportation schemes from the Yamal Peninsula include pipelines crossing the Baydaratskaya Bay of the Kara Sea over a distance of approximately 37 to 44 miles (60 to 70 km). Maximum water depths across potential pipeline routes are less than 82 ft (25 m) and, therefore, ice gouging is a concern. Ice is present from approximately November to July.

Studies of ice gouging in the Baydaratskaya Bay began in the 1980's. Extreme ice gouge depths of 5 to 6.6 ft (1.5 to 2 m) have been measured. Maximum widths up to 165 ft (50 m) have been measured while widths averaged 33 ft (10 m). Such gouges have been observed to have happened over 100's of feet in length (Marchenko et al., 2007). Most of the gouges measured have been located in water depths less than 50 ft (15 m).

The presence of ice gouging of the seabed will require pipeline to be buried to resist subgouge deformations induced in the seabed by the ice keels. Early work had indicated that 6.6 to 9.8 ft (2 to 3 m) of pipeline cover might be required to protect the pipeline.

3.3.4.4 Nord Stream Pipeline (Russia)

The planned Nord Stream pipeline (Figure 3-46) will consist of two 48-inch (1220 mm) lines running 750 miles (1200 km) from Vyborg, Russia, to Germany's northeast coast (PennWell Corporation, 2007). This line, when constructed, will be the first pipeline installed in the Baltic Sea. The maximum water depth along the pipeline route will be 690 ft (210 m) and the pipeline will have wall thicknesses ranging from 1.2 to 1.8 inches (30 to 45 mm). Trenching of the pipelines will occur in the nearshore areas where there is excessive wave and current action. The pipeline will also be trenched where there is a risk of ice gouging, ship grounding, etc. At a minimum, it is expected that the pipelines shall be trenched and backfilled at the landfall points, and at shallow water at Vyborg, Russia, and at Greifswald, Germany. If the trenches required backfilling, the project will reuse native materials as much as possible (PennWell Corporation, 2007).

Figure 3-46: Proposed Pipeline Location (Nord Stream, 2007)

There will be a service platform approximately 56 miles (90 km) to the northeast of Gotland Island. The platform will be 98 x 98 ft (30 x 30 m) square and it will rise approximately 115 ft (35 m) above the water. The platform will be used for maintenance and service of the pipelines, including launch and reception of testing and diagnostic equipment, control of gas parameters, and placement of valves (Nord Stream, 2007)

The following information has been reproduced from Nord Stream (2006).

“The ice conditions in the Baltic Sea show a high degree of variance in time and space and are strongly related to the severity of the winters. During the 1980s the ice coverage varied between 13 and 98 %. The Baltic Sea is ice covered for 0 to 3 months per year. In the northern regions the ice cover usually lasts for 5 to 6 months.”

“The Bothnian Bay, the eastern part of the Gulf of Finland and some Archipelago areas are frozen over every winter. The 50% probability contour crosses the open sea in the northern Baltic proper. In the open area in the Central part of the southern Baltic proper, the probability of ice occurrence is less than 10%. The ice cover is more frequent in the coastal area. Along the coast, the 90% probability zone is covering the Finnish coast, including the Archipelago Sea and the Swedish coast (Gävle, Stockholm, Nyköbing) as far South as Västervik. The 75% probability zone covers areas as far south as Karlskrona on the Swedish Coast and the areas around Rügen (south coast of Meck-lenburger Bucht, Greifswalder Bodden, Pommerche Bucht) on the German Coast. In the areas at the entrance to the Baltic Sea (Ystad) the probability is less than 50%.”

The average ice extent during mild, normal and severe winters, respectively, is shown in Figure 3-47.

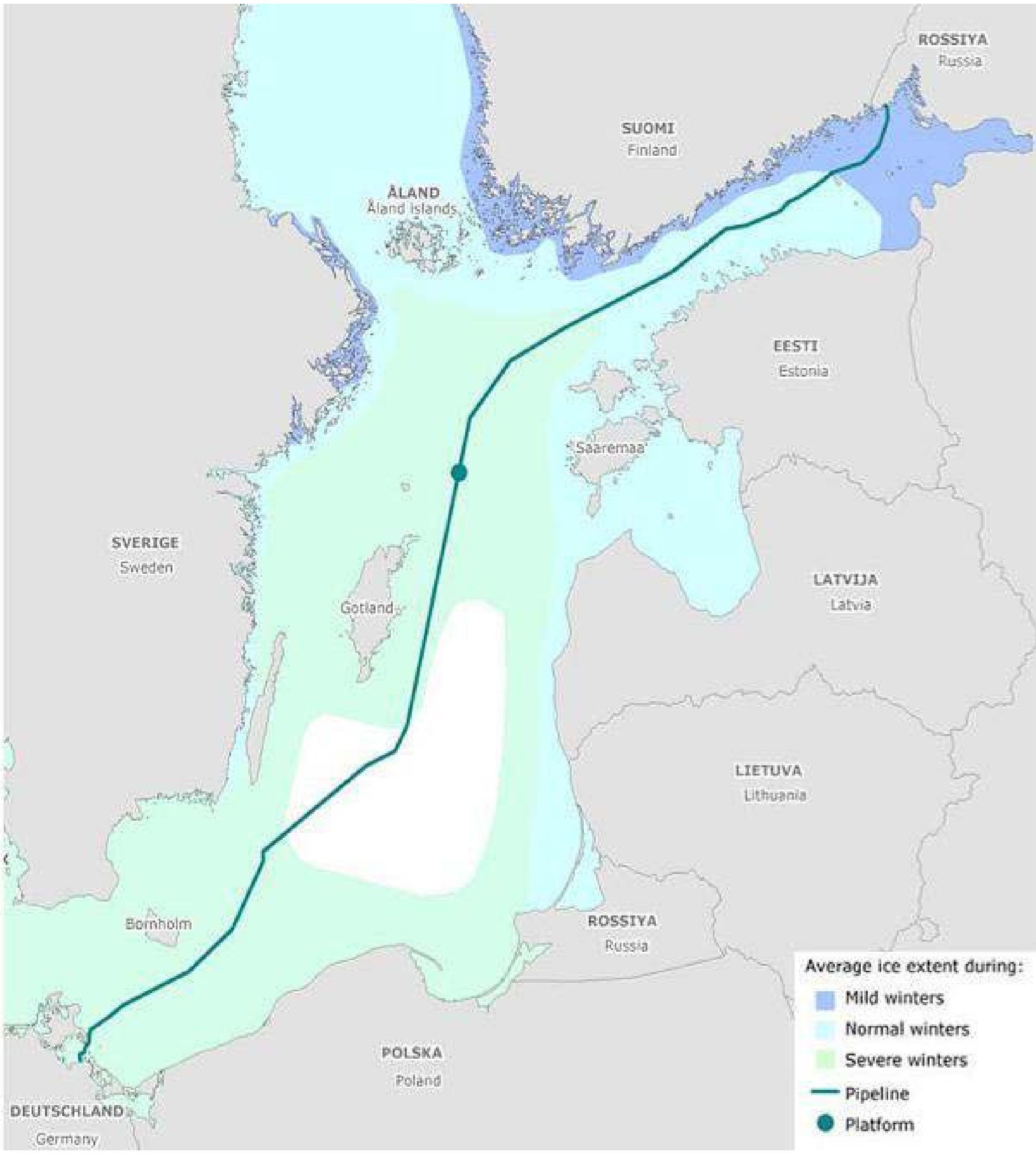

Figure 3-47: The Average Ice Extent during Mild, Normal, and Severe Winters, Respectively (Nord Stream, 2006)

3.3.4.5 Canadian East Coast Flowlines

<u>Terra Nova</u>

The Terra Nova development utilizes approximately 20 miles (33 km) of flexible flowlines and dynamic risers to convey produced hydrocarbons from the subsea wells to the riser base manifold and then to the FPSO (Petro-Canada, 2007b; Cottrill, 2000). The total installed subsea flowline length is 16 miles (26 km), with design temperatures ranging from 131 to 212°F (55 to 100°C) and design pressures ranging from 4.2 to 6.6 ksi (29 to 45.2 MPa) (Tveit et al., 2000). The flowline internal diameters range from 5 to 10 inches and are located in approximately 310 ft (95 m) water depth. The flexible flowlines enter the FPSO via a quick disconnect spider buoy which serves as the mooring point for the FPSO and the route for all produced fluids flowing between the FPSO and the reservoir (see Terra Nova of Section 3.3.2.1). The Terra Nova spider buoy is one of the largest quick disconnect turret moorings ever built (Petro-Canada, 2007b).

Technip Canada Ltd. (formerly Technip CSO Canada Ltd., formerly Coflexip Stena Offshore Newfoundland Ltd.) supplied and installed all flexible flowlines, risers, umbilicals, and jumpers for the Terra Nova development project (Technip, 2007). The flexible flowlines and risers were manufactured by Coflexip Stena Offshore Newfoundland Ltd. (CSO) in Le Trait, France (Alexander's Gas & Oil Connections, 2007a).

Terra Nova flowlines were originally planned to be trenched 5 ft (1.5 m) below the seabed using CSO's TM9 trenching machine, but difficulties in trenching the hard glacial seabed led to the use of rock dumping on some of the flowlines (Cottrill, 2000; Lever et al., 2001). Tideway's Seahorse and Van Oord ACZ's Trollness dynamically positioned fall-pipe vessels were thus used to dump some 155,000 tons (140,000 tonnes) of rock and sand for stabilization, protection against gouging icebergs, thermal insulation to reduce wax deposition, and rectification works (Tideway, 2007; Cottrill, 2000). Figure 3-48 provides a schematic of the trenched and/or rock-dumped flowlines.

In addition to these subsea protection measures, flowlines used on the Terra Nova project are considered sacrificial and contain weak-link connections to wellhead equipment (for protection of the wellhead if the flowline is impacted by a gouging ice keel) (Cottrill, 2000).

The flowline design maintains production fluid temperatures well outside of the hydrate formation region during normal operations, with predicted cool down times (to below hydrate formation temperatures) ranging from 5 to 6 hours during shutdown, depending on shut-in pressures and production fluid composition (Stephens et al., 2000).

Refer to Terra Nova of Section 3.3.2.1 of this report for further discussion of the Terra Nova development.

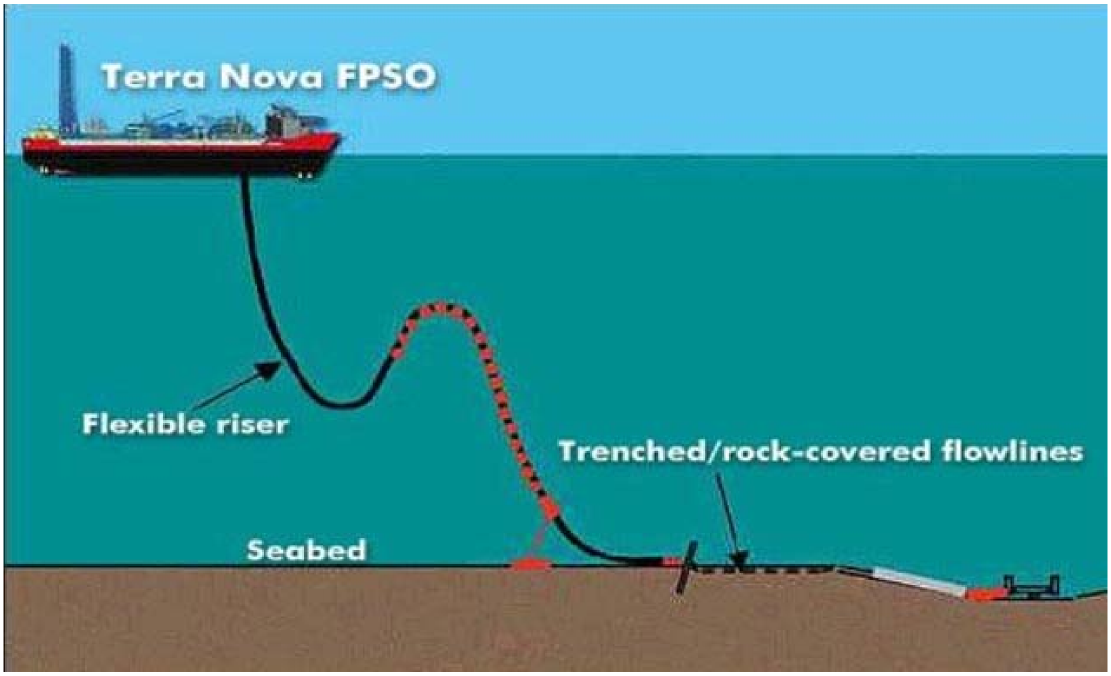

Figure 3-48: Terra Nova Flowline Protection (Courtesy of Tideway, 2007)

White Rose

Similar to the Terra Nova development, the White Rose project FPSO (the SeaRose) utilizes a disconnectable turret mooring system, as discussed in White Rose of Section 3.3.2.1 of this report. Technip Canada Ltd. supplied and installed 26 miles (42 km) of risers, flowlines, and umbilicals for the project (Technip, 2007). As with Terra Nova, the flexible flowlines were manufactured in Le Trait, France (Alexander's Gas & Oil Connections, 2007b). Subsea construction was completed by CSO's Constructor and Marianos vessels.

Flexible flowlines enter the FPSO via a riser buoy and quick disconnect geo-stationary turret which serves as the mooring point for the FPSO and the route for all produced fluids flowing between the FPSO and the reservoir (see White Rose of Section 3.3.2.1). The installed water depth ranges from 377 to 427 ft (115 to 130 m).

As with Terra Nova, flowline weak links are utilized at wellhead connections for protection of the wellhead if the flowline is impacted by a gouging ice keel (Husky, 2001a). The flowlines are designed to be fail-safe to minimize harmful environmental consequences should a flowline fail or become damaged (Husky, 2001b). Flowlines may be flushed and purged of all internal production fluids to mitigate environmental risk associated with potential ice keel impact (Husky, 2001b).

3.3.4.6 Sakhalin Island

Sakhalin 1 Pipelines

Two pipelines connect the Orlan platform located in approximately 82 ft (25 m) water depth to shore approximately 6 miles (10 km) away. From there, the lines carry on to the Chayvo Onshore Processing Facility. These pipelines are a 36-inch (914 mm) full wellstream line and a 24-inch (610 mm) gas re-injection line. Both pipelines are buried to a depth sufficient to protect them from ice gouge and long term effects of sediment transport (loss of cover).

Connecting Sakhalin Island to mainland Russia is a 24-inch (610 mm) export line. This line must go through the Tatar Strait which is covered with first-year ice in winter. Water depths range from 16 to 72 ft (5 to 22 m) through the channel and 0 to 16 ft (0 to 5 m) across the flats on either side. Given the presence of ice and ridging, and the fact that sediment transport is actively ongoing, the pipelines are buried for protection from ice keels (Baranov et al., 2007).

At the DeKastri Export Terminal, a 48-inch (1220 mm) loading line is used to transport crude offshore to the single point mooring system from which tankers are loaded. This line is buried and backfilled out to 50 ft (15 m) water depth for protection against first-year pressure ridge keels.

Sakhalin 2 Pipelines

The development of the Piltun-Astokhskoye and Lunskoye fields of the Sakhalin 2 project incorporates the use of five offshore pipeline systems that have been installed over two phases of the project.

Phase I of the offshore pipeline development involved the installation of a 12 inch (305 mm) diameter, 1.25 mile (2 km) long pipeline from the PA-A platform to a single anchor leg mooring buoy (SALM) (SEIC, 2004). This pipeline allowed seasonal production from the PA-A platform for approximately 6 months of the year.

Phase II of the offshore pipeline development connects the three offshore platforms (PA-A, PA-B and Lun-A) to onshore pipelines. Phase II also connects the export terminal to the tanker loading unit in Aniva Bay. Details of the Phase II pipelines are as follows:

- Two 14 inch (357 mm) pipelines from PA-A platform to landfall at Chayvo Bay. This line will allow year-round production from the PA-A platform.
- Two 14 inch (357 mm) pipelines from the PA-B platform to landfall at Chayvo Bay.
- Two 4.5 inch (114 mm) pipelines from Lunskoye Platform (LUN-A) to land and one 30 inch (762 mm) pipeline from LUN-A to land.
- One 30 inch (762 mm) tanker loading line from the offshore export terminal to the tanker loading unit in Aniva Bay (SPG Media Limited, n.d.).

The Sakhalin 2 offshore pipelines incorporate the state-of-the-art in design and construction of pipelines. Offshore pipelines located in less then 100 ft (30 m) of water are installed in 6.5 ft (2 m) deep trenches and backfilled to protect against gouging. Sakhalin offshore pipelines are designed with burst strengths twice the factor normally applied by industry (SEIC, 2004). This results in approximately double the pipe wall thickness used in other jurisdictions. The offshore pipelines are constructed from API 5L X52 grade steel which remains ductile at low temperatures (SEIC, 2004). Cofferdams are installed at land fall to provide protection from sea ice at the transition between offshore and onshore pipelines.

The Phase I offshore pipeline has been in seasonal operation since approximately early 2000 (approximately). Installation of over 187 miles (300 km) of offshore pipelines in water depths up to 164 feet (50 m) was completed in early 2006 (Sakhalin Energy, 2007).

3.3.5 Export Terminals

3.3.5.1 Canadian Arctic

Cameron Island is the only site in the Canadian Arctic Islands which had been developed for commercial oil production (1985-1996). Light crude was shipped from Bent Horn in the southwest of the island to Montreal via the M.V. Arctic, a double-hulled tanker. The field was abandoned in 1996 after producing a total of 2.8 million barrels of oil. The abandonment reflected the difficulties of exploiting the resource in harsh environments. After abandonment, final clean-up occurred in 1999.

3.3.5.2 Russia

Export terminals in Russia, although perhaps to a lesser degree, have harsh natural conditions analogue to areas of interest for this study. Three major geo-political and economic factors are behind the current development in the Southeast Barents and the Northeast Gulf of Finland (Baltic):

- Oil and gas development in the Southeast Barents area;
- Loss by Russia of year-round open water ports in the Baltic as a result of the disintegration of the Soviet Union; and,
- The need to create the infrastructure for the growing flow of Russian oil and gas to Western markets.

The single factor which affects all transportation ideas proposed for the Barents is that the western sector of the sea (Kolsky peninsula, Figure 3-1) is free from ice year-round. Consequently, the northern part of Kolsky peninsula, including the major commercial port of Murmansk and nearby areas, are considered convenient transshipment locations for oil from the Timan-Pechora basin and Prirazlomnoye fields (Varandey terminal in the southeast Barents is the loading point of these operations). The Kolsky peninsula is also considered to be the most probable loading point for the LNG produced from the Shtokman field reserves. An example of one of the Barents Sea oil and gas transportation concepts is presented in Figure 3-49.

A brief review of available information shows that marine transportation of hydrocarbon products is one of the main areas of development in the Russian Arctic. Major research & development and technology projects have been conducted at all levels; from global transportation concepts to the design of service fleet vessels that will be required for execution of specific tasks under the conditions of arctic oil and gas exploration. Several examples of these projects are briefly described below.

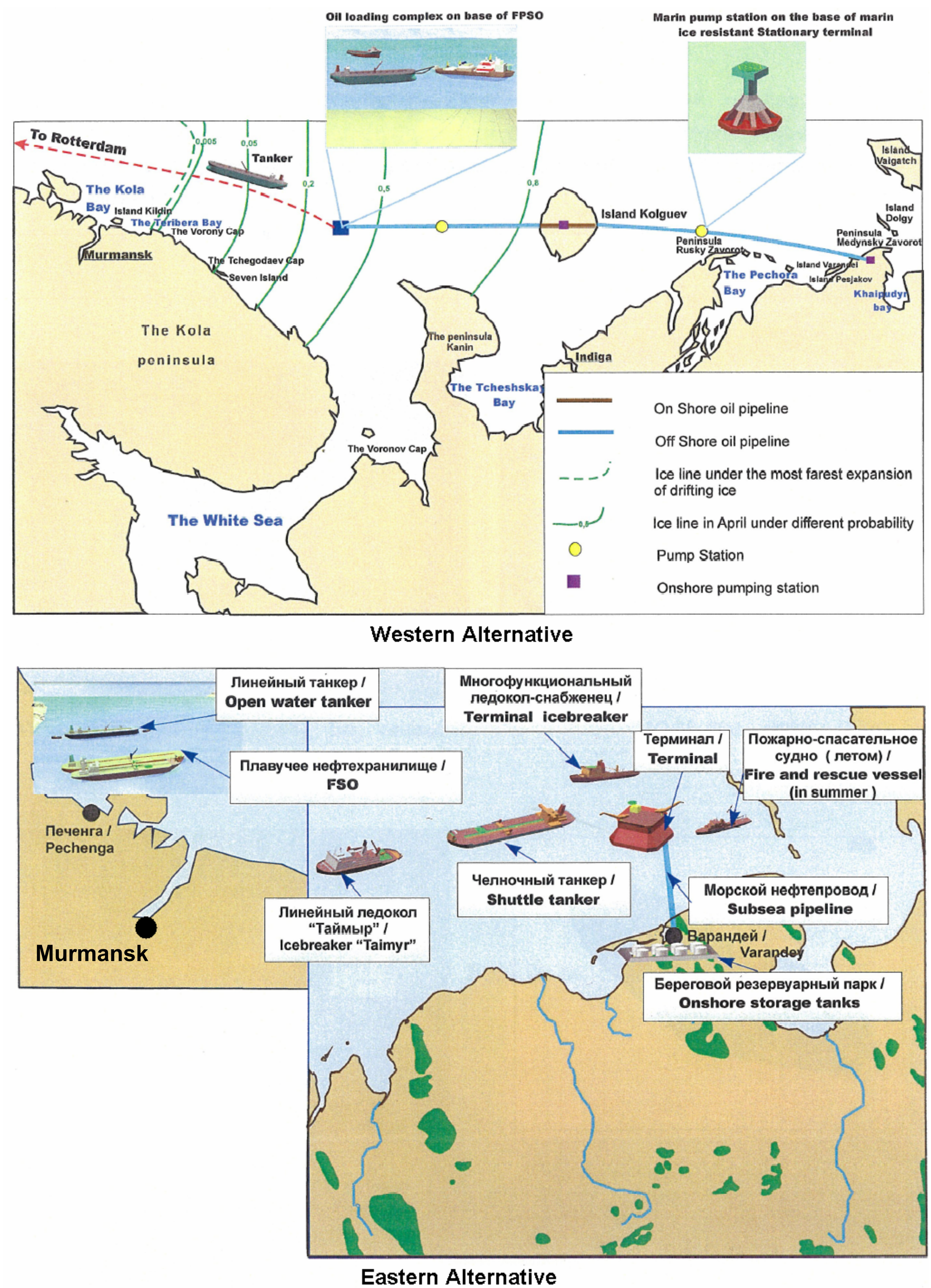

Figure 3-49: Technical and Economic Evaluation of Alternatives for Oil Transportation from Timano-Pechora Province, Krylov Institute Development (Krylov Institute, n.d.)

Southeast Barents

One of the most active projects in the Russian Arctic at this time is the development of the oil transportation link originating at the small island of Varandey, located in the southeast corner of the Barents Sea, almost directly south of Novaya Zemlya archipelago (Figure 3-1). The Varandey oil export terminal was developed to load oil recovered from the nearby Timan-Pechora fields on tankers and deliver it either across the Barents to the non-frozen Murmansk area for transshipment, or directly to Western Europe and/or the USA.

An information search regarding the Varandey project indicates that, with respect to the overall scale of plans and actual developments along the Russian coast of the Arctic Ocean, the Varandey project is only a "tip of the iceberg". Terminals are now being considered all along the European section of the coast, as well as in the Western Siberian section. A brief summary of the Varandey project is presented below, based on information included in the Krylov Institute projects catalogue as well as Falling Rain Genomics, Inc (2006), Lukoil-Kaliningradmorneft (n.d.), Advanced Production and Loading AS (2006), Russian Maritime Register of Shipping (2006), and Universal Solutions S.A.E. (2005).

At Latitude 68.82° north, Varandey is located roughly at the latitude of King William Island in the Canadian Arctic and of Point Hope in Alaska (Figure 3-1). A summary of operational conditions in general offshore areas of the Southeast Barents is presented in Appendix A of this report. No direct information on the ice thickness at the Varandey site is available, but it is reported that the landfast ice may grow down to the seabed in 5 to 6.6 ft (1.5 to 2.0 m) of water, and this may serve as some indication of the possible ice thickness at the site.

In the initial stage of the terminal development (1999 - 2000), offloading was done through a flexible hose (i.e. without loading structure) directly over the DWT 22,000 tons (20,000 tonnes) ice class tanker side manifolds. It was considered temporary (for Varandey "early oil") and intended for summer season operations only (Krylov Institute, n.d.). These loading operations were conducted approximately 2.5 miles (4 km) offshore in approximately 36 ft (11 m) of water by a subsea pipeline connected to an onshore steel storage facility. The DWT 22,000 tons (20,000 tonnes) shuttle tankers would take the oil to Murmansk for transshipment to larger DWT tankers and subsequent export out of Russia, or directly to the port of destination.

In 2000 – 2001, the loading system was upgraded for winter operations. In this case, the tanker to be loaded was tied to a specially equipped large diesel/electric icebreaker.

Besides providing safer mooring for the tanker, this icebreaker also served as the operational facility for the diving team personnel and equipment. The divers were required for handling the subsea manifold and lifting of the flexible loading hose. Another icebreaker was permanently kept in the area for ice management on an as-needed basis. Winter operations began in 2001 (Krylov Institute, n.d.). The offloading concept using a totally underwater terminal connection was considered for Varandey as well in 2005 (Krylov Institute, n.d.).

Later in 2002 the system was modified; an arctic underwater loading terminal (PLEM type) was installed on the seabed. The end of a flexible hose was equipped with a quick-releasing connection intended for operations with tankers having bow loading systems for cargo reception.

In 2001, Krylov, working together with Halliburton, performed a conceptual design of a bottom-founded terminal in Varandey for a deep water (53 to 73 ft (16 to 22 m)) operation. At that time, four alternatives were considered for the terminal (Krylov Institute, n.d.):

- Modified DWT 284,400 tons (258,000 tonnes) Very Large Crude Carrier (VLCC). The terminal was designed to provide 691,900 barrels (110,000 m^3) oil storage. The 3.3 ft (1 m) double bottom space and 6.6 ft (2 m) space between the walls of the double hull were to be filled with concrete.

- Modified Steel Drilling Caisson (SDC) platform. The conceptual sketches of the system show additional foundation sections (block) that would be twice as wide as the original platform, apparently to improve the stability of the platform/seabed interface. The platform was designed to maximum ice loading conditions of the Pechora Sea.

- TLU, Caisson Alternative. A steel caisson with a total on-site weight of 79,365 tons (72,000 tonnes) (including the sand ballast). The dimensions were 167 ft (51 m) long at water level and 203 ft (62 m) maximum width at seabed with a total height of 107 ft (32.5 m).

- TLU, Tower Alternative. The system was a bottom-founded SPM (gravity structure) with a turret. The maximum dimension of tower substructure was approximately 43 ft (13 m) at water level (stem) and 125 ft (38 m) at the seabed (base). The height (to the deck level) was 107 ft (32.5 m).

The alternative shown in Figure 3-50 is apparently the closest to that actually constructed (Krylov Institute, n.d.). Essentially, the TLU is based on the last concept described immediately above, but with some important modifications. With an apparent goal to increase the ballast weight, a wider caisson-type hull is being used. Twenty-four piles have been added to the design to ensure the on-bottom stability of the structure. The octagonal-shape TLU is 115 ft (35 m) wide at the waterline and has a 141 ft (43 m) base at the seabed. The total height is 184 ft (56 m) (131 ft (40 m) to the deck level). The design water depth is 71 ft (21.5 m). The substructure weight of the concept shown in Figure 3-50 is 14,330 tons (13,000 tonnes).

Tankers will be built to the Russian Register ice-class requirements and will be DWT 77,160 tons (70,000 tonnes) with a loaded draft of 46 ft (14 m). An AZIPOD propulsion system will allow for these tankers to operate in 5 ft (1.5 m) thick ice without an icebreaker support (Universal Solutions S.A.E., 2005).

The model tests (at 1:70 scale) were conducted in Krylov in 2005 on the orders of the TLU working documentation developer (CKB “Corall”, Ukraine) (Krylov Institute, n.d.). Both regular and irregular extreme wave conditions as well as maximum pressures that could be generated by the level and ridged ice were modeled in the tests (Krylov Institute, n.d.).

The TLU in its present configuration carries an acronym FOIRLT (Fixed Offshore Ice Resistant Loading Terminal). This project in general is also called “Varandey II”. The terminal will have a loading capacity of 13.2 million tons (12.0 million tonnes) per year. The heated oil will continuously circulate inside the “looped” underwater loading line. Loading pumps will be located onshore.

The TLU will have a turret, helipad, loading boom and accommodations for 12 people (Lukoil-Kaliningradmorneft, n.d.). The swivel stack designed for arctic conditions is reportedly supplied by APL (Advanced Production and Loading), which was their first stand-alone swivel stack delivery not part of a complete turret system (Advanced Production and Loading AS, 2006). The TLU was built at the Vyborg, Baltic and Kaliningrad shipyards and the TLU installation was scheduled for September, 2007 (Russian Maritime Register of Shipping, 2006).

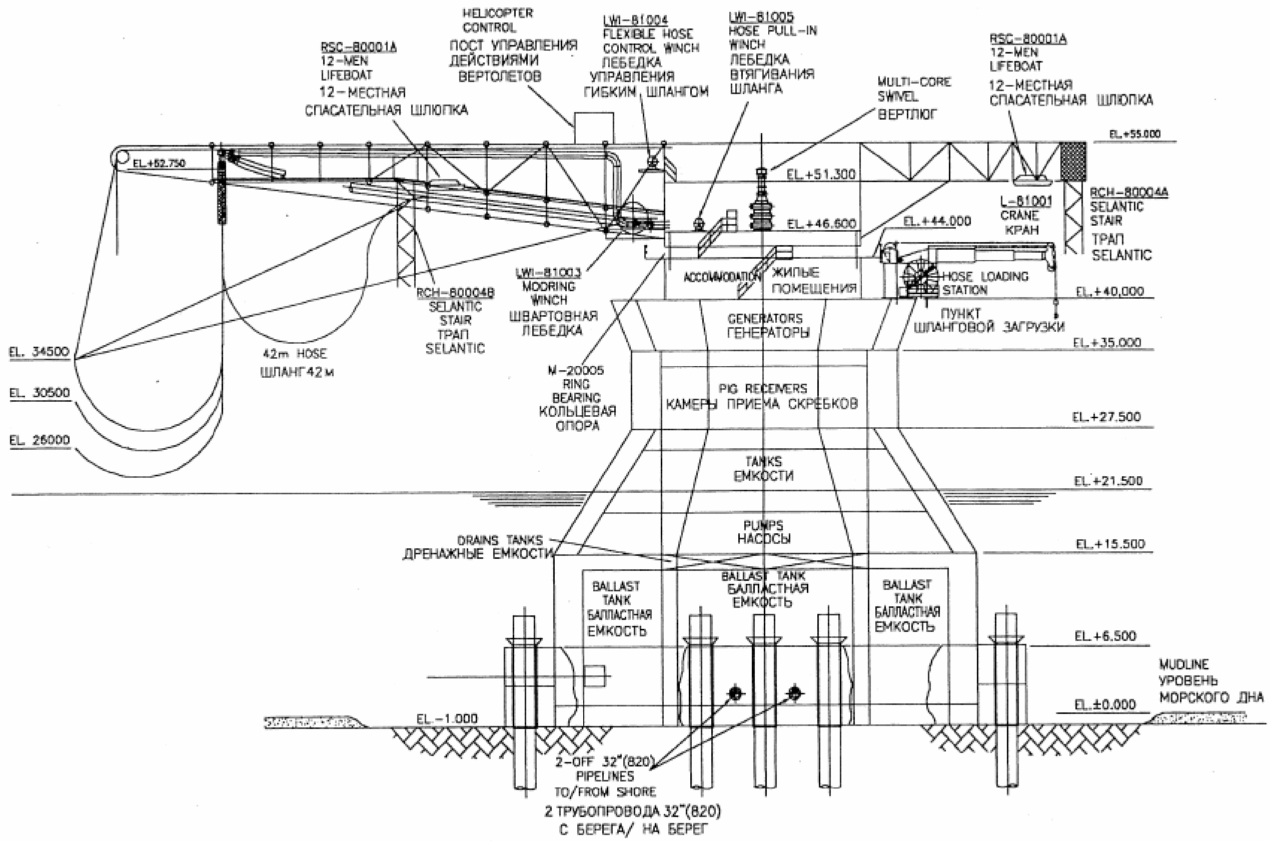

Figure 3-50: Varandey TLU, General Concept (Krylov Institute, n.d.)

<u>Gulf of Finland</u>

The loss of Estonian, Latvian and Lithuanian ports, coupled with the lack of space along the south coast of the Gulf, left only one relatively available stretch of the Russian coast in the Baltic for the direct export of oil and gas products to Europe; the Karelia Isthmus coast, specifically the northernmost part of it, near the Finnish border (Figure 3-51). A cluster of oil terminals have been built and more are being considered for the area, which include both crude and oil products terminals for conventional tankers over DWT 110,000 tons (100,000 tonnes) with ice-breaking escort. The two main locations are Primorsk (Transneft) and Vysotsk (Lukoil) with a planned capacity of 55.1 million tons per year and 16.4 million tons per year (50.0 million tonnes per year and 14.9 million tonnes per year), respectively.

The ice conditions are relatively mild compared with the Arctic; the sea is frozen up to four months each year and the average ice thickness is 1.6 ft (0.5 m). However, considering that no special ice-resistant or ice protection engineering measures are included into the terminal designs (Panin and Rode, 2003), the structural designs in these cases may be of certain interest in the current study. The weak seabed soils require piles as the only reasonable option for pier and trestle foundations in 49 to 59 ft (15 to 18 m) of water. Consequently, the main focus of the structural design in this case is the ice/pile interaction. The working concept is to conservatively assume crushing of the ice on the outside piles while this load is distributed over the remaining piles.

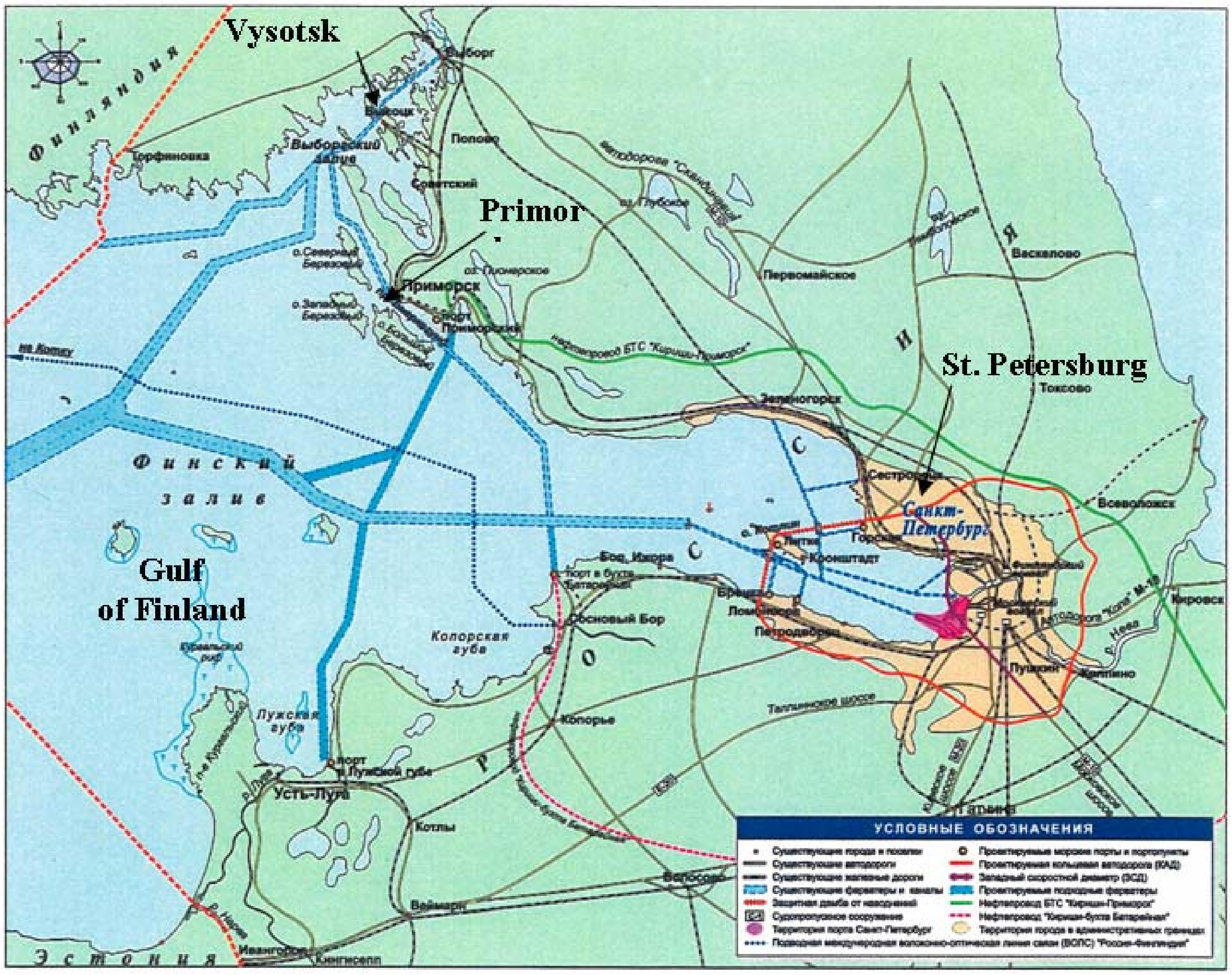

Figure 3-51: New Oil Terminals in the Gulf of Finland (Panin and Rode, 2003)

Prirazlomnoye

Substantial effort was dedicated to development of the optimal overall logistics of exploration and production at Prirazlomnoye field. According to SPG Media Limited (2007a), the supply base for the platform will be in Arkhangelsk (large port at the White Sea), which indeed is probably the closest location with well-developed infrastructure, but still approximately 621 miles (1,000 km) from the field. The oil transportation concept for Prirazlomnoye described in available information sources varies in such details as the DWT of the ice-class tankers (from 77,000 tons (70,000 tonnes) to 242,000 tons (220,000 tonnes)), and their propulsion system (AZIPOD or conventional). However, the general idea is the same; the shuttle tankers will take the oil from Prirazlomnoye platform to the non-frozen north-west fiords of the Kolsky peninsula 684 miles (1,100 km) away, and from there, the commercial tankers (DWT 165,000 to 187,000 tons (150,000 to 170,000 tonnes)) will tanker it to Western Europe and/or America. The transshipment FSO “Belokamenka” with a storage capacity of 397,000 tons (360,000 tonnes) is already operational in the Kolsky Bay (SPG Media Limited, 2007a; Madslien, 2006). It is estimated that two 21,500 hp (16 MW) line icebreakers will be required for the shuttle route, and at least one multifunctional ice breaker will be used for ice management at the platform, particularly during offloading operations (SPG Media Limited, 2007a).

3.3.6 Extended Reach Drilling

World records with respect to extended reach drilling continue to be set in harsh environments. The push to extend the capabilities of extended reach drilling is driven in part by the significant reduction in offshore facilities if wells can be drilled from shore or from existing structures to access reservoirs.

Within the last few years, the Hibernia platform off the east coast of Canada successfully drilled a 31,000 ft (9450 m) measured depth (MD) oil producing well to access a reservoir 5.9 miles (9.5 km) away (Standing, 2006). In 2007, Exxon Neftegas Limited completed a well with a measured depth of 37,016 feet (11,282 m) or more than 7 miles (11.3 km) (Abraham, 2007). The well originated onshore Sakhalin Island and was the new world record for the longest measured-depth extended reach well. This beat the previous record established by BP at Wytch Farm which accomplished 37,001 feet (11,278 m) and by Total at Tierra del Fuego at 36,693 feet (11,184 m) (Fischer and Schmidt, 2007).

3.3.7 Other Technological Advancements

3.3.7.1 Well Intersection Method

The Well Intersection Method, WIM, has not yet been utilized offshore or in arctic locations. However, it has been used once in an onshore application where it was successfully employed in 2004 by Anadarko Petroleum (Smith, 2004) in the Buckinghorse River Valley in the foothills of Northeastern British Columbia, Canada (Figure 3-52). In the Buckinghorse area, Anadarko encountered a deep river valley that prevented the connection of a number of gas wells on one side of the gorge to production facilities on the other side of the gorge. This gorge made conventional onshore pipeline construction both uneconomical and environmentally challenging. The river crossing design incorporated the drilling and intersecting of two conventional horizontal wells on both sides of the river valley. Surface well locations were approximately 1.75 miles (2.8 km) apart. Both wells utilized a 13-3/8-inch (340 mm) surface casing followed by a 9-5/8-inch (244 mm) casing string landed at 90 degrees (horizontal) at approximately 4700 ft (1433 m) TVD. An 8-3/4-inch (222 mm) hole was drilled and intersected downhole at TVD. Once connected, cased (using 7-inch (178 mm) casing) and cemented, both wells acted as a pipeline to transport gas across the river valley. Additional details on WIM can be found in Section 4.12.2.

Figure 3-52: Buckinghorse River Valley Crossing (from Smith, 2004).

3.3.7.2 Pilot Hole to Pilot Hole HDD

A relatively new development in the HDD industry has been to drill two pilot holes, from entry points at either side of the crossing, and intersect them underneath the crossing, rather than to drill a single pilot hole from entry to exit. One such pilot hole to pilot hole HDD project was completed in British Columbia, Canada in January, 2004. Two 9-7/8-inch (251 mm) pilot holes were intersected at approximately 200 ft (61 m) Total Vertical Depth (TVD) using rotating magnet ranging equipment. The crossing was slightly greater than 2600 feet (792 m). After the intersection, the hole was reamed and a pipe bundle (NPS 8, 6, and 2 in the bundle) pulled from the entry to exit point using standard HDD techniques (Osbak, 2004).

3.3.7.3 Arctic Offshore Vessels

The most advanced developments for Arctic offshore oil and gas development in Russia are associated with shipbuilding because, traditionally, a wide scientific and technological base exists in this area. For example, the following is a list of development works presented in the Krylov Institute's project catalogue (Krylov Institute, n.d.):

- Shuttle tanker, Russian ice class LU4 (3.3 ft (1.0 m) ice), DWT 154,324 tons (140,000 tonnes) for oil product transportation in the Northern areas and the Baltic, 2001;

- Shuttle tanker, German Lloyds ice class (3.3 ft (1.0 m) ice), DWT 71,650 tons (65,000 tonnes) for oil products transportation in the Northern areas and the Baltic, 2001;

- LU5 ice class port tug for service fleet operations at the Primorsk Oil Terminal (see Section 3.3.5.2), 2003;

- Icebreaker modification for services required during tanker offloading operations offshore (diving and OSR equipment units and helipad installation), 2004;

- Development of technical requirements for LNG carriers to be built for Shtokman field operations, 2005;

- 60-ton (54.4 tonne) lifting capacity hovercraft for oil and gas exploration in the Yamal swampy areas (crane, fire fighting and well services modifications), 2005;

- New generation nuclear Arctic icebreaker, DWT 26,500 tons (24,000 tonnes), 80,500 hp (60 MW), for year-round operation in 9.2 to 9.5 ft (2.8 to 2.9 m) ice, 2006;

- Mobile (Floating) Refinery Plant, 132,000 tons/year (120,000 tonnes/year) maximum oil input capacity for the on-site diesel fuel generation in the remote Arctic exploration areas, 2000; and,

- Floating LNG plant for relatively small offshore reserves, where it is required to maintain the production efficiency of on-site operations, 2006.

Another advance in Arctic Offshore vessels is the use of Double Acting Tankers (DAT). Double acting tankers are built with “highly hydrodynamic shaped bows and sides” and thus travel forward in open water as do conventional tankers; however, in conditions requiring ice breaking, they travel astern to use their reinforced stern hull-form to break ice (SPG Media Limited, 2007h). Sumitomo Heavy Industries has built the first DAT, the Tempera, as shown in Figure 3-53).

Figure 3-53: “Tempera” in Icebreaking Mode (SPG Media Limited, 2007h)

3.4 Alaska OCS Exploration & Development Options

3.4.1 Bottom-Founded & Fixed Structures

3.4.1.1 General

Exploration drilling for oil and gas in the Beaufort Sea began from gravel islands in shallow Alaskan State Waters in the late 1960's and similarly in the Canadian Beaufort Sea in the early 1970's. With time, activities progressed into deeper waters. In 1976, ice reinforced drillships were first utilized in Canadian waters, followed in 1981 by the first use of a bottom-founded caisson system. Exploration activities commenced in Beaufort OCS regions in 1982 using gravel islands, ice islands, bottom-founded structures and drillships. In the authors' view, the experience of bottom-founded exploration structures provides the best analogue to the operating conditions that will be experienced by future production structures in the Alaskan OCS. In total, five separate bottom-founded structures were deployed in the Beaufort Sea:

- Tarsiut Caisson-Retained Island or Tarsiut Caissons (concrete caissons);
- Single-Steel Drilling Caisson or SSDC (steel structure) with later addition of steel MAT;
- Caisson-Retained Island or CRI (steel caissons);
- Molikpaq Mobile Arctic Caisson or MAC (steel caisson);
- Beaufort Sea I Concrete Island Drilling System or CIDS (concrete and steel structure).

These structures were conceived primarily to extend the depth capability of granular islands. The caisson-retained islands were formed by building an underwater berm and then backfilling the caisson systems with a core of dredged material. Compared to conventional island-building up to that time, the amount of fill required to achieve stability was significantly reduced. As well, the effects of wave and current erosion during the open water season were reduced. However, these structures still required significant field operations to construct the berms, deploy, backfill, densify the core (Molikpaq requirement), decommission and move. Although touted as "mobile" structures, the caisson structures were not truly "MODU's" (mobile offshore drilling units).

The SSDC was the first MODU-type structure in the Beaufort Sea, coming into service in 1982 and with the addition of the MAT remains the only active bottom-founded exploration structure in the arctic offshore. The steel SSDC and the CIDS, a similar concrete-steel hybrid concept which is now deployed offshore Sakhalin Island, are ballasted with water.

Table 3-7 summarizes the chronological drilling history of these five structures in the Beaufort Sea. The same data has been sorted by structure name in Table 3-8.

In recent years, with additional gas discoveries in the Mackenzie Delta region and the revival of the Mackenzie Valley Pipeline, some companies have proposed constructing gas conditioning facilities supported by barge structures. These barge structures are discussed following the review of the aforementioned exploration structures.

Table 3-7: Deployments of Bottom-Founded Structures in the Beaufort Sea (by year)

Year	Drilling Unit	Location	Operator	Prospect	Water Depth (without berm), ft [m]	Notes
1981-82	Caisson-Retained Island	Canada	Gulf Canada	Tarsiut N-44	69 [21]	On berm
1982-83	SSDC	Canada	Dome/Texaco	Uviluk P-66	105 [32]	On berm
1983-84	SSDC	Canada	Gulf Canada	Kogyuk N-67	92 [28]	On berm
1983-84	CRI	Canada	Esso	Kadluk O-07	48 [14.5]	
1984	Molikpaq	Canada	Gulf Canada	Tarsiut P-45	74 [24.5]	On berm
1984-85	CRI	Canada	Esso	Amerk O-09	85 [26]	On berm
1985	CIDS	USA	Exxon	Antares	49 [15]	
1985	CIDS	USA	Exxon	Orion	50 [15]	
1985-86	Molikpaq	Canada	Gulf Canada	Amauligak I-65	105 [32]	On berm
1986	SSDC/MAT	USA	Tenneco	Phoenix	60 [18]	
1986-97	CRI	Canada	Esso/Home	Kaubvik I-43	59 [17.9]	
1987-88	SSDC/MAT	USA	Tenneco	Aurora	66 [20]	
1987-88	Molikpaq	Canada	Gulf Canada	Amauligak F-24	87 [26.5]	On berm
1989-90	Molikpaq	Canada	Esso/Gulf	Isserk I-15	38 [11.5]	
1990	SSDC/MAT	USA	Arco Alaska	Fireweed	50 [15]	
1991-92	SSDC/MAT	USA	Arco Alaska	Cabot	55 [17]	
1997	CIDS	USA	Arco Alaska	Warthog	35 [10.5]	
2002-03	SSDC/MAT (now *SDC)*	USA	EnCana	McCovey	35 [10.5]	
2005-06	SSDC/MAT (now *SDC)*	USA	Devon	Paktoa	43 [13]	

Table 3-8: Deployments of Bottom-Founded Structures in the Beaufort Sea (by name)

Drilling Unit	Year	Location	Operator	Prospect	Water Depth (without berm), ft [m]	Notes
Caisson-Retained Island	1981-82	Canada	Gulf Canada	Tarsiut N-44	69 [21]	On berm
CIDS	1985	USA	Exxon	Antares	49 [15]	
CIDS	1985	USA	Exxon	Orion	50 [15]	
CIDS	1997	USA	Arco Alaska	Warthog	35 [10.5]	
CRI	1983-84	Canada	Esso	Kadluk O-07	48 [14.5]	
CRI	1984-85	Canada	Esso	Amerk O-09	85 [26]	On berm
CRI	1986-97	Canada	Esso/Home	Kaubvik I-43	59 [17.9]	
Molikpaq	1984	Canada	Gulf Canada	Tarsiut P-45	74 [24.5]	On berm
Molikpaq	1985-86	Canada	Gulf Canada	Amauligak I-65	105 [32]	On berm
Molikpaq	1987-88	Canada	Gulf Canada	Amauligak F-24	87 [26.5]	On berm
Molikpaq	1989-90	Canada	Esso/Gulf	Isserk I-15	38 [11.5]	
SSDC	1982-83	Canada	Dome/Texaco	Uviluk P-66	105 [32]	On berm
SSDC	1983-84	Canada	Gulf Canada	Kogyuk N-67	92 [28]	On berm
SSDC/MAT	1986	USA	Tenneco	Phoenix	60 [18]	
SSDC/MAT	1987-88	USA	Tenneco	Aurora	66 [20]	
SSDC/MAT	1990	USA	Arco Alaska	Fireweed	50 [15]	
SSDC/MAT	1991-92	USA	Arco Alaska	Cabot	55 [17]	
SSDC/MAT (now *SDC)*	2005-06	USA	Devon	Paktoa	43 [13]	
SSDC/MAT (now *SDC*)	2002-03	USA	EnCana	McCovey	35 [10.5]	

3.4.1.2 Tarsiut Caissons

The industry's first caisson-retained island was installed by Canadian Marine Drilling Ltd. (CANMAR) at the Tarsiut location in the Canadian Beaufort Sea. The Tarsiut Caissons comprised four concrete caissons (see Figure 3-54) set down on an underwater sand berm in 69 ft (21 m) of water, and then infilled and backfilled with dredged material to a freeboard of +23 ft (+7 m). The structure was used only for one drilling season, 1981 – 82, although the structure did serve as an ice engineering research platform the following season. Based on the Tarsiut Caisson experience, CANMAR saw the need for a fully-mobile year-round drilling platform, which led to the development of the SSDC (see below). The Tarsiut Caissons were decommissioned near Herschel Island in the mid-1980's, where they remain.


Figure 3-54: Tarsiut Concrete Caissons during Installation and in Service

3.4.1.3 SSDC & SSDC/MAT (now SDC)

The experience with the Tarsiut Caissons led CANMAR to develop a fully-mobile, water-ballasted concept for year-round drilling. The SSDC was fabricated by modifying the forward half of a Very Large Crude Carrier (VLCC) and the name "Single-Steel Drilling Caisson" (SSDC) was adopted to differentiate it from the multiple concrete caissons used at Tarsiut. In 1986, the SSDC was modified to prepare it for deployment in the US Beaufort Sea. It was mated with a steel MAT[1] substructure to eliminate the need for foundation

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[1] The MAT structure carries the highest loads of any steel structure ever built.

preparation (subsea berms) and functioned as a single unit called the SSDC/MAT. In recent years, with a change of ownership, the structure (including MAT) has been renamed the SDC. The structure is a MODU and all drilling and topsides facilities are permanently affixed to the deck, resulting in simpler and faster mobilization for drilling operations. Of the 19 deployments of bottom-founded structures in the US and Canadian Beaufort Sea, 8 were those of the SDC.

Figure 3-55: SSDC (left), MAT Substructure (Top Right), SSDC/MAT (Bottom Right)

3.4.1.4 CRI – Caisson-Retained Island

Similar to the Tarsiut Caissons, but built with steel instead of concrete, the Caisson-Retained Island or CRI was conceived and built by Esso Resources Canada and first deployed in 1983. The CRI was developed to reduce the amount of dredged material and was comprised of eight individual hinged steel caissons placed in a ring and held together with steel wire cables. Like the Tarsiut Caissons, the core of the CRI was filled with dredged material to provide the base for drilling operations and provide resistance to wave and ice loads. The CRI was deployed three times in the Canadian Beaufort Sea from 1983 – 87. The structure has not been active since that time.

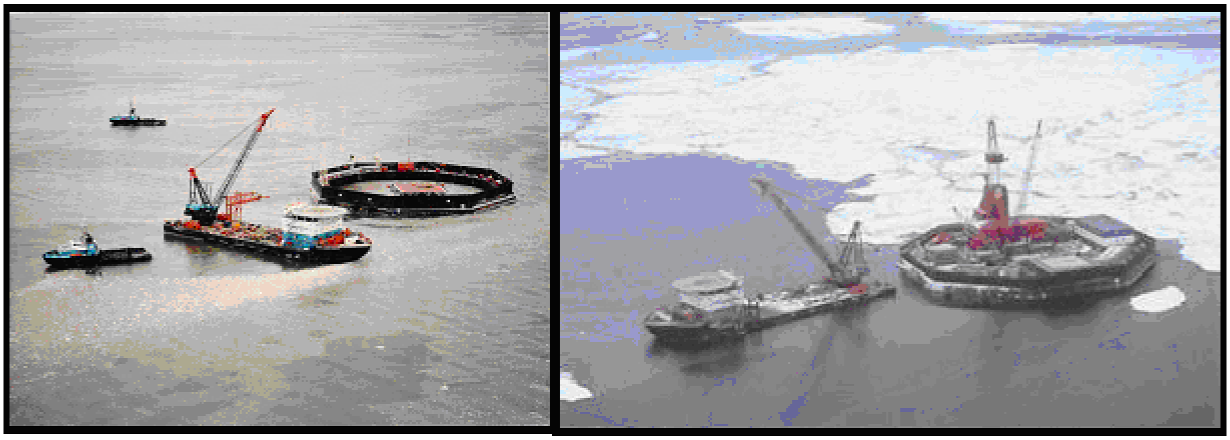


Figure 3-56: Esso's Caisson-Retained Island (CRI)

3.4.1.5 Molikpaq Mobile Arctic Caisson (MAC)

The Molikpaq, developed by Gulf Canada Resources, took the Esso steel caisson-retained island concept one step further. The structure is a monolithic, water-ballasted steel annulus with a self-contained deck for drilling and topsides facilities, but unlike the fully water-ballasted SSDC and CIDS, Molikpaq relied on a densified sand core to provide the bulk of its resistance to environmental loads. Like the Tarsiut Caissons and the CRI, Molikpaq is not a true MODU. The unit began operations in 1984 and drilled four locations in the Canadian Beaufort Sea. It was mothballed in 1990 and later modified and redeployed in 1997 as a permanent production facility in the Sea of Okhotsk off Sakhalin Island, Russia. The only Beaufort Sea production was from Amauligak with Molikpaq, when during extensive well testing they loaded a tanker and it offloaded in the south.

3.4.1.6 Concrete Island Drilling System (CIDS)

The CIDS, also known as the Glomar Beaufort Sea 1, was a steel-concrete hybrid structure consisting of a steel base topped by a concrete mid-section at the ice belt and two steel deck sections. Like the SDC, the unit was a MODU and was ballasted with water only. The CIDS was deployed at three locations in the US Beaufort Sea, the last in 1997. In 2001, the structure was towed to Russia for refurbishment and (like Molikpaq) now operates as the permanent production platform Orlan in the Sea of Okhotsk, offshore Sakhalin Island.

Figure 3-57: Molikpaq in the Beaufort Sea and as-Modified for Sakhalin

Figure 3-58: CIDS in the Beaufort and Under Tow to Sakhalin Island

3.4.1.7 Barge Structures

Niglintgak Barge

Shell Canada Ltd. has proposed to develop its Niglintgak gas field (of the Mackenzie Gas Project) using barge-mounted processing and gas conditioning facilities which will be pre-built prior to arriving on location at the Niglintgak site (Mackenzie Gas Project, 2004). The Niglintgak gas field is located within the Mackenzie Delta of the Canadian Beaufort Sea, offshore of the North West Territories.

Shell proposed that the required processing facility topsides modules be transported via marine barge through the Beaufort Sea and into the Kumak Channel, where the barge would then serve as the foundation for the modules, as shown in Figure 3-59. Placement of the barge-mounted gas conditioning facility is planned for a naturally sheltered area on the seasonal flood plane of the Little Kumak Channel, near the Kendall Island Bird Sanctuary (as shown in Figure 3-60). The barge will be grounded with minimal excavation and will not require a slip, thus minimizing permanent land deformation in the area. Easier reclamation activities are thus facilitated as the barge may be removed from the site for salvage or reuse (Mackenzie Gas Project, 2004). Several layers of naturally insulating soils are present in the area which will protect the barge from any potential permafrost. An alternate installation proposal placed the barge upon driven piles in the sheltered channel.

The preliminary design proposed that a lightweight, 180 x 361 ft (55 x 110 m), ice strengthened steel barge be constructed overseas and towed to its installation location in the Kumak Channel (Mackenzie Gas Project, 2004).

Taglu Barge

Imperial Oil Resources has also considered utilizing barge-mounted gas conditioning facilities for its Taglu field development in the Kuluarpak Channel, as shown in Figure 3-61 (Mackenzie Gas Project, 2004). Unlike the Niglintgak barge, the proposed Taglu barge would require excavation of a slip for protection against ice and fast moving water in the narrow Kuluarpak Channel. Furthermore, the soils at Kuluarpak contain permafrost, thus making thaw settlement a potential hazard to the installation. Transportation of the barge to the Taglu site was expected to be more difficult than transport of Shell's proposed Niglintgak barge due to the relatively narrow width of the Kuluarpak Channel. For these reasons, among others, a land-based facility concept was ultimately chosen for the Taglu field (Mackenzie Gas Project, 2004).

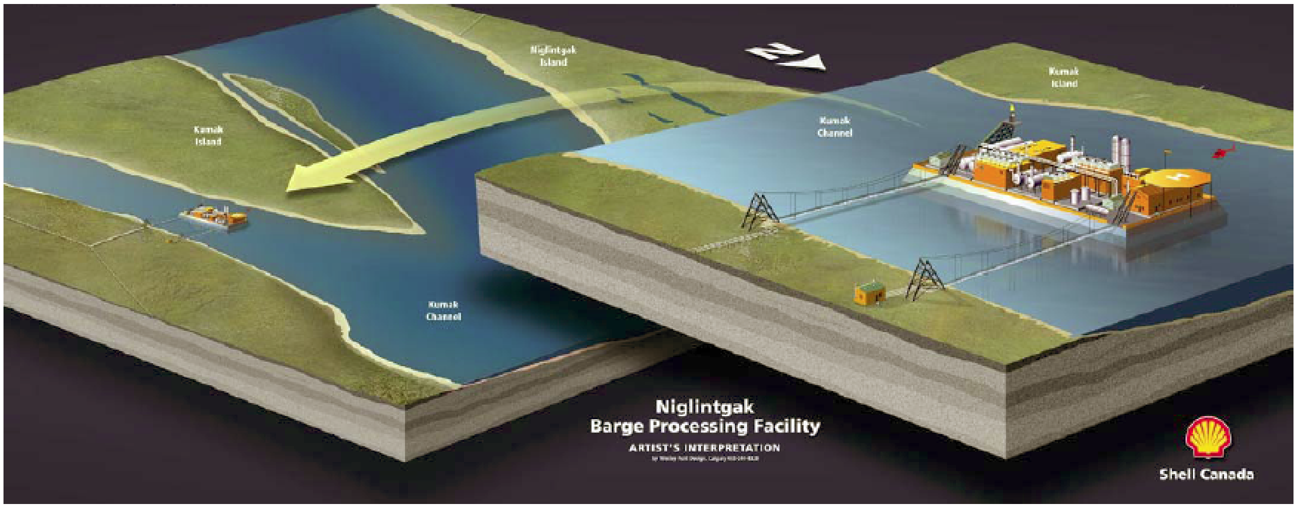


Figure 3-59: Niglintgak Barge Processing Facility (from Mackenzie Gas Project, 2004)

Figure 3-60: Proposed Placement of Niglintgak Gas Processing Facility on Seasonal Flood Plane (from Mackenzie Gas Project, 2006)

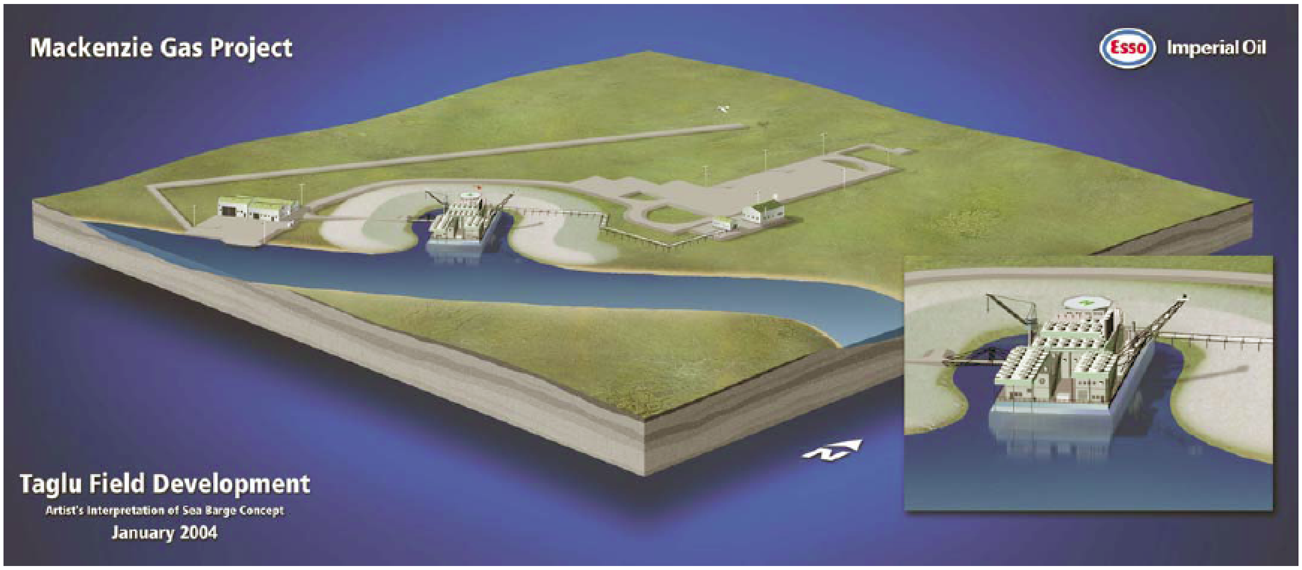


Figure 3-61: Taglu Field Development (from Mackenzie Gas Project, 2006)

Norton Sound Barge Concept

In an evaluation of structural concepts carried out for Norton Sound (Fluor Ocean Services, 1982), a concrete gravity barge structure was assessed for a water depth of 30 ft (9 m). The barge structure was of self-floating design for transportation and installation, and therefore to minimize draft light-weight concrete was to be used where possible. Ballast for the barge consisted of gravel. The barge was designed to accommodate drilling and production facilities.

3.4.1.8 GBS Structures

A number of arctic GBS structures have been considered for the Beaufort, Chukchi and Bering Seas as presented by Buslov and Krahl (1984).

In addition, PMB Systems Engineering et al. (1983) carried out a preliminary evaluation of a concrete gravity base structure for the south Bering Sea. Specific areas considered in the study were the St. George's, Navarin and North Aleutian Basins in water depths ranging from 300 to 450 feet (91 to 137 m). The concrete GBS evaluated was composed of a cellular base with a flared mat, steel skirts, and four main shafts that project from the cellular base to the deck and topsides (PMB Systems Engineering et al., 1983). The GBS evaluated is similar to the North Sea platform Statfjord C as shown in Figure 3-62.

Figure 3-62: Statfjord C under Construction (Statoil ASA, 2007)

3.4.2 Jacket Structures

Several jacket type structures have been evaluated for use in the south Bering Sea (PMB Systems Engineering et al., 1983); these being an eight leg template jacket, a four plus four template jacket, and a steel mono-tower jacket. The evaluation identified the four plus four steel template as the most suitable jacket concept for the South Bering. Area considered were the St. George's, Navarin and North Aleutian Basins in water depths ranging from 300 to 450 ft (91 to 137 m).

The four plus four template jacket as shown in Figure 3-63 has eight legs complete with skirt piles. The four end legs terminate beneath the surface giving the structure a clean water plane, which is expected to prevent ice bridging of the legs. The four double walled legs are on a spacing of 100 x 140 ft (30 x 43 m) and contain the wells and risers (PMB Systems Engineering et al., 1983).

3.4.3 Ice & Gravel Island Structures

Significant exploration drilling has been carried out from ice and gravel islands in the Beaufort Sea. Gravel islands have also been used as production structures. Due to the inherent similarity of the Alaskan and Canadian Beaufort Sea regions, with respect to environment and previous structure types used, both regions will be discussed together under this Section.

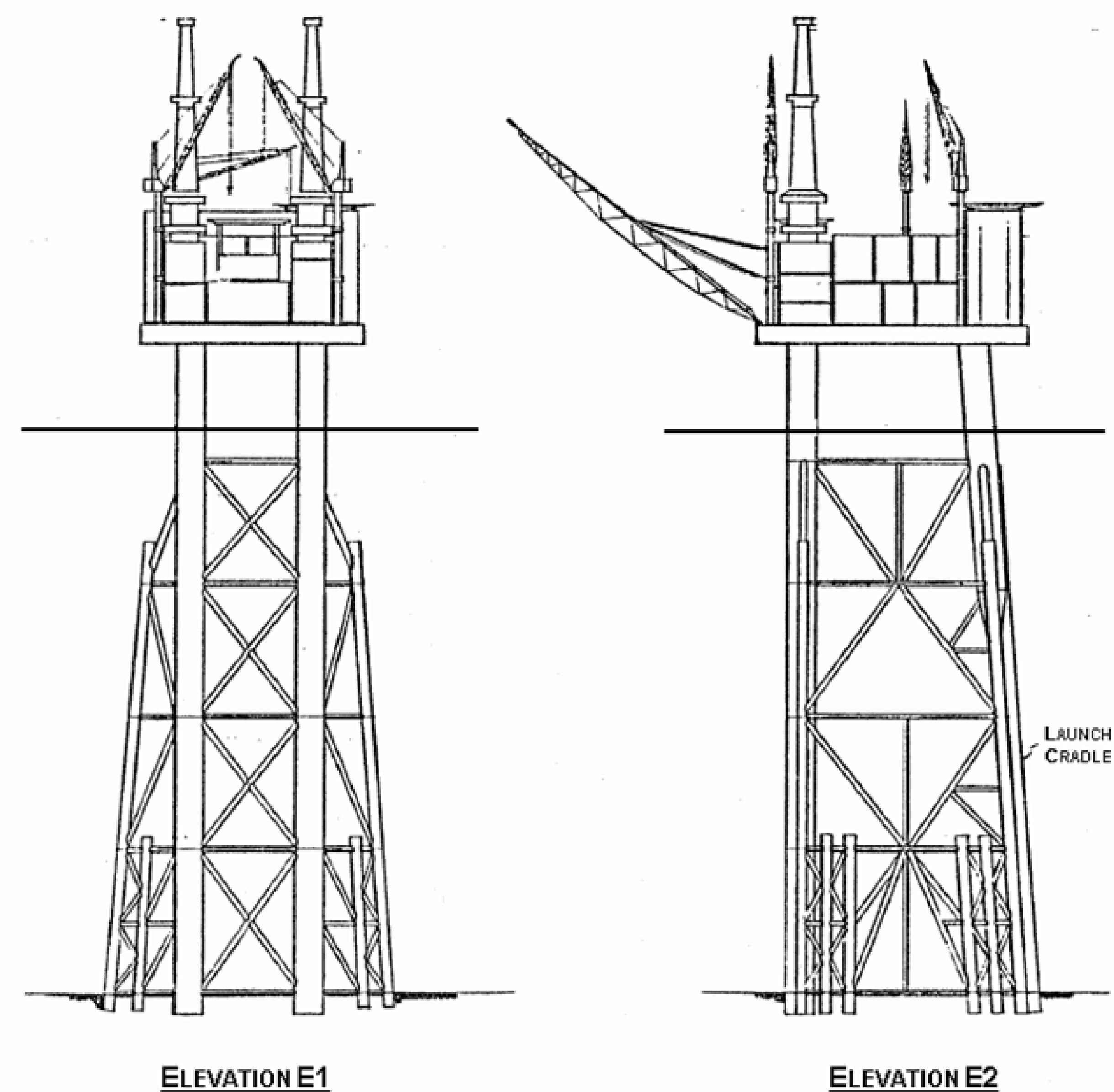


Figure 3-63: Four plus Four Template Jacket (modified from PMB Systems Engineering et al., 1983)

3.4.3.1 Grounded Artificial Ice Islands

This complete section has been extracted from the major MMS Project No. 468 (C-CORE et al., 2005). Minor modifications to the text have been made. It should be noted that floating ice drill pads were generally not considered in the Beaufort given the nature of the ice movement.

The first grounded flooded ice island was built by Union Oil in Harrison Bay, Alaska in 1976/77. Grounded ice islands have generally been constructed in less than 30 ft (9 m) water depth. The use of sprinkling and spraying on experimental and relief well pads has allowed these methods to be developed with lower risk to project schedules. Spray ice was also used to form protection structures around grounded drilling structures such as the CIDS platform offshore Alaska in the mid 1980s.

Grounded ice islands are constructed in a similar way to floating islands, in that artificial ice is built up on top of the natural ice sheet to increase its thickness until it becomes grounded on the seabed. However, since the water column is shallow, any movement of the island in relation to the seabed will damage the drill-string, and so the design requirement is to eliminate any differential movement. The island is therefore designed to withstand the horizontal force applied by the surrounding ice sheet by providing resistance through contact with the seabed. An additional requirement is to maintain the stability of the rig foundation, which will undergo creep settlement of the ice under loading.

As with floating platforms, start of construction is limited by the formation of stable ice and access to the drilling location. Generally, to date, platform design has been performed using the natural ice to support equipment and personnel during construction.

The first grounded ice island to be used for exploration drilling was constructed by Union Oil in Harrison Bay in 1977/78. It was grounded in 9.8 ft (3 m) water depth using flooding techniques by applying thin layers of seawater to the ice surface and allowing it to freeze in place. Generally, however, the relatively slow build-up rates achievable with flooded ice techniques limit the usefulness of these structures as grounded ice platforms. It is more suited to the construction of roads, which require less ice thickness.

Spray ice islands have been used to stabilize rubble fields and for potential use as relief drilling pads, such as at Tarsiut (Neth et al., 1983), Alerk (Weaver and Poplin, 1997), Kadluk (Kemp et al., 1988) and Isserk (Poplin and Weaver, 1992). Figure 3-64 shows the Tarsiut relief pad built next to the main caisson retained drilling island.

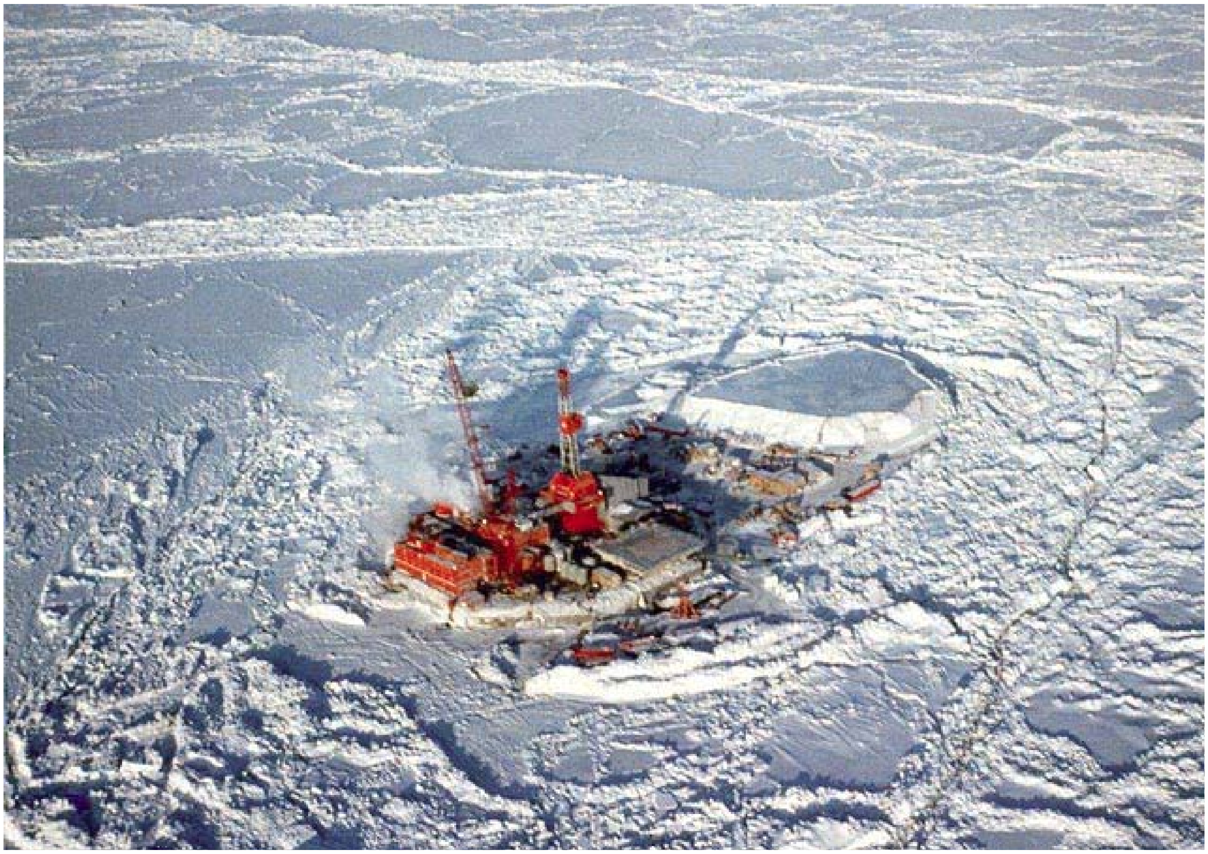


Figure 3-64: Tarsiut Relief Spray Ice Island (ICETECH, 2008)

The first use of an island built completely from spray ice for exploratory drilling was carried out by Amoco at Mars, Harrison Bay, in 1986. This island was built on the landfast first-year ice in 24.9 ft (7.6 m) water depth, to provide a completed freeboard of 24.6 ft (7.5 m). The 1083 ft (330 m) diameter platform required 4 pumps to produce 35.3 million ft^3 (1 million m^3) of ice during the 45 day construction program. Figure 3-65 shows the Mars ice island during drilling operations.

Figure 3-65: Mars Spray Ice Island (C-CORE, 2005)

The technical and financial success of this platform led to spray ice becoming the material of choice for the construction of grounded platforms in shallow water in the Beaufort Sea. Construction cost savings on the order of 50% were quoted compared to sand and gravel islands previously used, as demonstrated in Figure 3-66. The construction of another 3 exploration spray ice islands in the 1980s at Angasak, Nipterk and Karluk reinforced the advantages of spray ice construction.

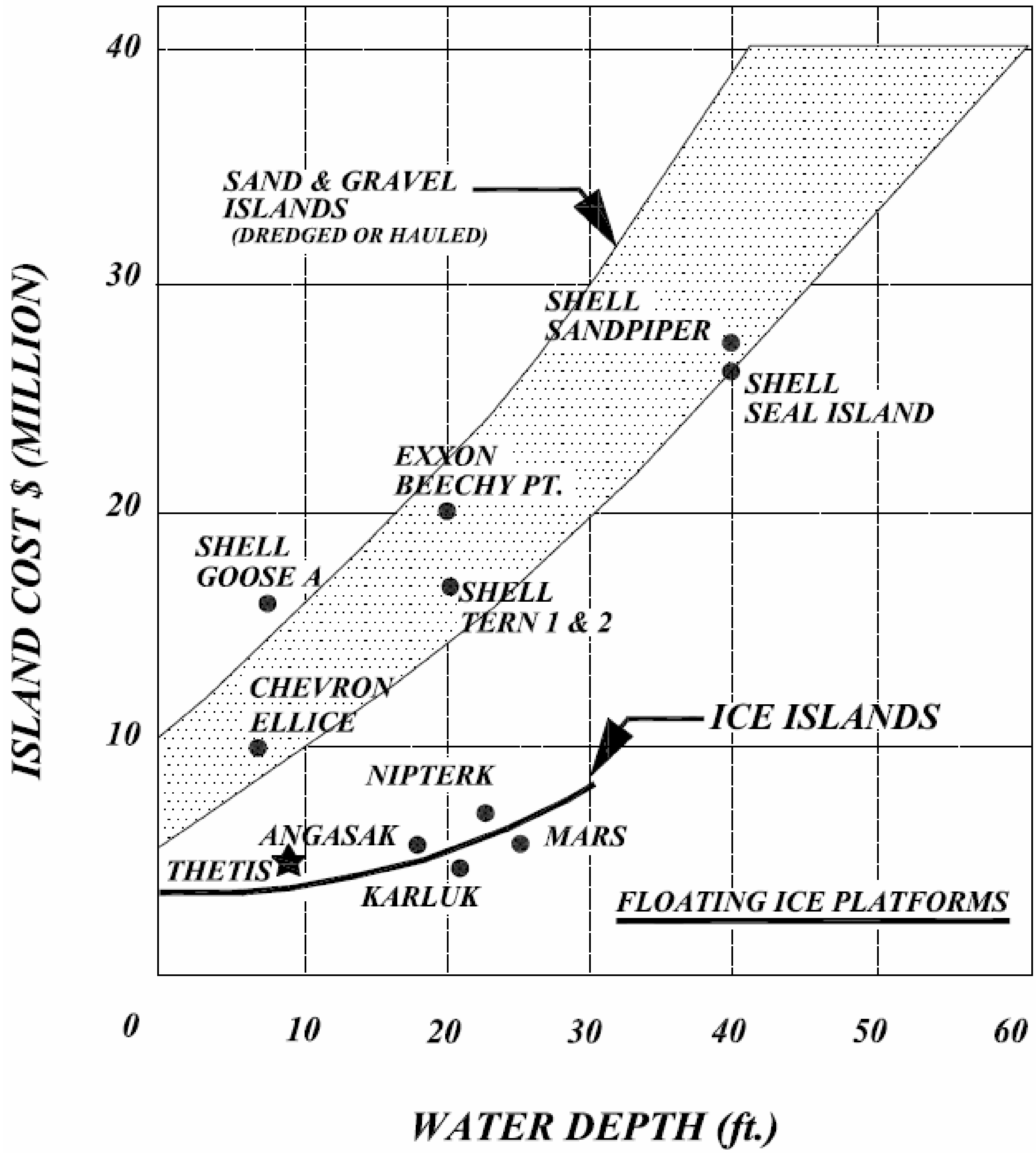


Figure 3-66: Cost Comparison between Gravel and Ice Islands (C-CORE, 2005)

Operational spray ice islands were used at the Thetis Field in 2002/03, where a number of innovative techniques were successfully used. This allowed the drilling of 2 wells using the same rig in the same season. A summary of grounded artificial ice island construction is presented in Table 3-9.

Table 3-9: Summary of Grounded Artificial Ice Island Construction

Name	Operator	Location	Technique	Use	Dates	Water Depth, ft (m)
	Union Oil	Harrison Bay, US Beaufort Sea	Flood	Experimental Island	1977/80	9.8 (3)
	Exxon	Harrison Bay, US Beaufort Sea	Flood, Spray	Experimental Island	1979	9.8 (3)
	Esso	Canadian Beaufort Sea	Spray	Experiment	1980	
Tarsiut	Gulf Canada	Canadian Beaufort Sea	Spray	Relief Pad	1981/82	63 (19.2) on Berm
Alerk island	Esso	Canadian Beaufort	Spray	Relief Pad	1982	38 (11.6)
SSDC Uviluk	CANMAR	Canadian Beaufort Sea	Spray	Experimental Protection Structure	1982/83	98 (30)
Kadluk 0-07	Esso	Canadian Beaufort Sea	Spray	Relief Pad	1983/84	44 (13.5)
Sohio Rubble Generator	Sohio	McKinley Bay, Beaufort Sea	Spray	Experimental Protection Structure	1983/84	43 (13)
Ice Island Experiment	Exxon	Canadian Beaufort Sea	Spray	Experimental Island	1983/84	45 (13.7)
Big Gun Expt., MV Kigoriak	Esso	McKinley Bay, Beaufort Sea	Spray	Experimental Protection Structure	1983/84	46 (14)
SSDC Kogyuk	CANMAR	McKinley Bay, Beaufort Sea	Spray	Experimental Protection Structure	1983/84	93 (28.4)
CIDS Antares Barrier	Exxon	Alaskan Beaufort Sea	Spray	Operational Protection Structure	1984/85	49 (14.9)
Cape Alison C-47	PanArctic	Ellef Ringnes Island, Canadian Arctic	Spray	Operational Floating Island	1984/85	259 (79)
MARS full-scale prototype	Sohio	Harrison Bay, US Beaufort Sea	Spray	Experimental Island	1984/85	30 (9.1)
Mars	Amoco	Harrison Bay, US Beaufort Sea	Spray	Operational Island	1985/86	25 (7.6)
Angasak L-03	Imperial/Esso	Canadian Beaufort	Spray	Operational Island	1986/87	18 (5.6)
Nipterk P-32	Imperial	Canadian Beaufort	Spray	Operational Island	1988/89	23 (6.9)
Karluk	Chevron	US Beaufort	Spray	Operational Island	1988/89	25 (7.6)
Isserkl-15	Imperial	Canadian Beaufort Sea	Spray	Relief Pad	1989/90	38 (11.5)
Ivik	Pioneer	Thetis, Harrison Bay, Alaska	Spray	Operational Island	2002/03	9.8 (3)
Oooguruk	Pioneer	Thetis, Harrison Bay, Alaska	Spray	Operational Island	2002/03	12 (3.7)
Natchiq	Pioneer	Thetis, Harrison Bay, Alaska	Spray	Operational Island	2002/03	7.5 (2.3)
Kashagan, Sunkar Site	Agip KCO	North Caspian Sea	Spray	Operational Protection Structure	2002/03	
Kashagan, Aktote Site	Agip KCO	North Caspian Sea	Spray	Operational Protection Structure	2003/04	
Kashagan, Kairan Site	Agip KCO	North Caspian Sea	Spray	Operational Protection Structure	2003/04	

A review of the design criteria used in practice for spray ice islands suggests that the strength of the island itself is rarely critical in determining resistance to lateral ice loads, but rather the sliding shear force developed between the island and the seafloor. The general practice has therefore been to adopt a safe, lower-bound strength profile and undertake a check that it is adequate

3.4.3.2 Gravel Islands

This section begins with an overview of gravels islands with a general focus on their use from an exploratory drilling perspective. Following this, production projects utilizing gravel islands have been highlighted; further information with respect to gravel islands can be found within the assessment section, Section 4.

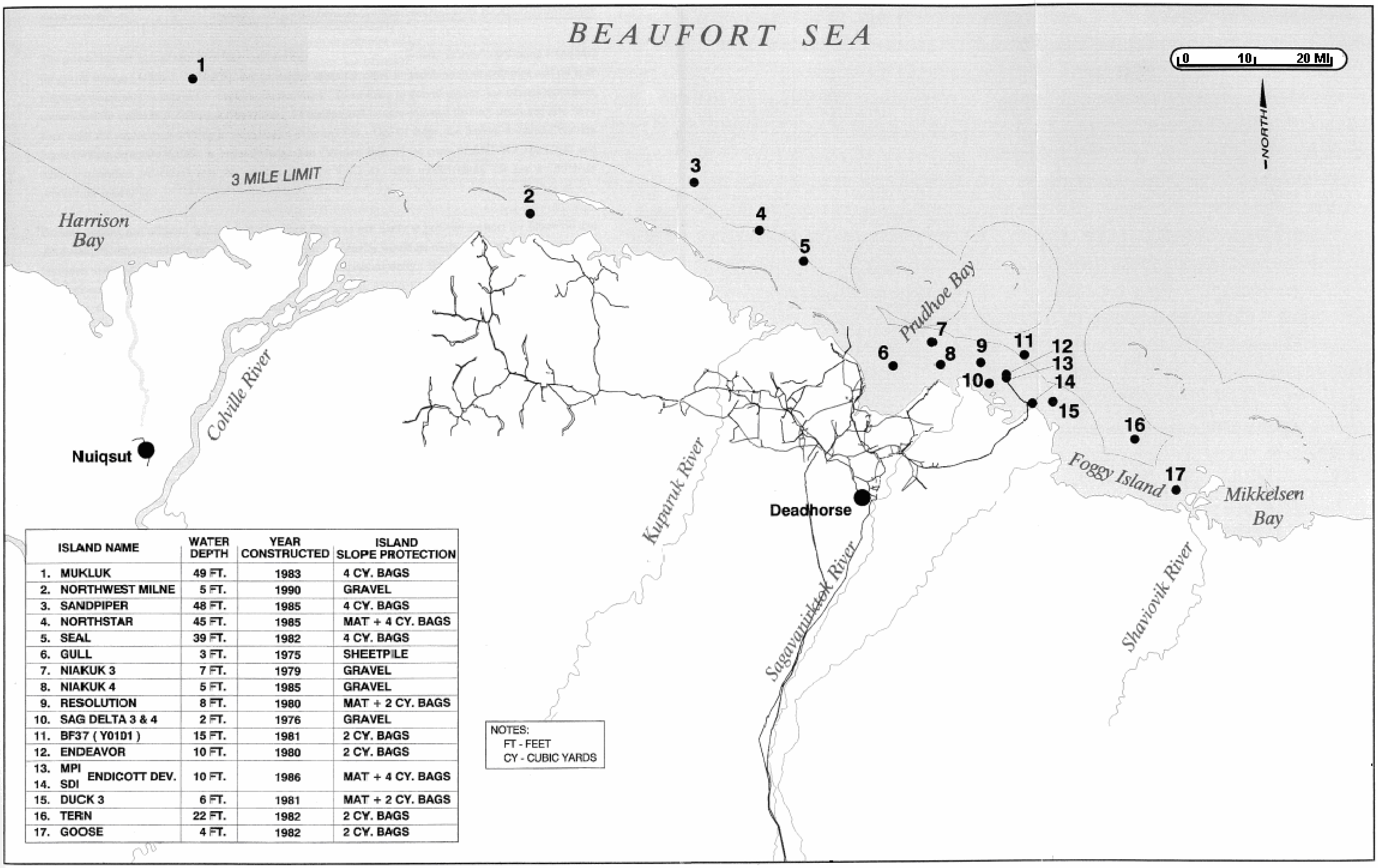
Exploratory drilling for oil and gas commenced in the Mackenzie Delta area of Northern Canada in the mid-sixties. After several years of extensive on-shore exploration, the first offshore Arctic well was drilled by Imperial Oil in the winter of 1973 - 74. This well was drilled from the artificial island, Immerk B-48, where construction had started using a cutter-suction dredge in the summer of 1972. This island was constructed at a fairly sheltered location in the offshore delta in a water depth of 43 ft (13 m). There was no drilling from the island during the first winter in order to demonstrate that the island could withstand the winter ice. This it did successfully, and after adding additional fill during the next summer, drilling commenced (Croasdale and Marcellus, 1977).

As shown below in Table 3-10, 31 artificial granular islands have been built in water depths ranging to 62 ft (19 m) in the Canadian Beaufort Sea. Note that Table 3-10 is an excerpt from Appendix Table C-2, Overview of Drilling Activity in the Canadian Beaufort Sea.

Table 3-10: Exploratory Drilling Islands used in the Canadian Beaufort Sea (from Timco, 1998)

Date	Island
1972	Roland Bay L-41
1973	Immerk B-48, Adgo F-28, Pullen E-17, Pelly B-35
1974	Unark L-24, Adgo P-25, Garry P-94
1975	Nerlerk B-44, Adgo C-15, Ikattok J-17, Nerlerk F-40
1976	Sarpik B-35, Kugmallit H-59, Unark L-24A, Arnak L-30
1977	Kannerk G-42, Isserk E-27
1978	Garry G-07
1979	Adgo J-27
1980	Issungnak 2O-61
1981	Alerk P-23
1982	Issugnak O-61, West Atkinson L-17, Itiyok I-27
1984	Adgo H-29 Nipterk L-19
1985	Nipterk L-19A Adgo G-24 Minuk I-53 Ellice L-39
1986	Arnak K-06
1987	Angasak L-03
1989	Nipterk P-32

Notation
Sacrificial beach island
Sandbag retained island
Hauled island
Spray ice island



ISLAND NAME	WATER DEPTH	YEAR CONSTRUCTED	ISLAND SLOPE PROTECTION
1. MUKLUK	49 FT.	1983	4 CY. BAGS
2. NORTHWEST MILNE	5 FT.	1990	GRAVEL
3. SANDPIPER	48 FT.	1985	4 CY. BAGS
4. NORTHSTAR	45 FT.	1985	MAT + 4 CY. BAGS
5. SEAL	39 FT.	1982	4 CY. BAGS
6. GULL	3 FT.	1975	SHEETPILE
7. NIAKUK 3	7 FT.	1979	GRAVEL
8. NIAKUK 4	5 FT.	1985	GRAVEL
9. RESOLUTION	8 FT.	1980	MAT + 2 CY. BAGS
10. SAG DELTA 3 & 4	2 FT.	1976	GRAVEL
11. BF37 (Y01D1)	15 FT.	1981	2 CY. BAGS
12. ENDEAVOR	10 FT.	1980	2 CY. BAGS
13. MPI / 14. SDI ENDICOTT DEV.	10 FT.	1986	MAT + 4 CY. BAGS
15. DUCK 3	6 FT.	1981	MAT + 2 CY. BAGS
16. TERN	22 FT.	1982	2 CY. BAGS
17. GOOSE	4 FT.	1982	2 CY. BAGS

Figure 3-67: Alaskan Beaufort Sea Manmade Islands (modified from US Army Corps of Engineers, 1999)

Between 1975 and 1990, 17 gravel islands were constructed in the Alaskan Beaufort Sea (refer to Figure 3-67). In 2001, Seal Island (known as Northstar now), initially used for exploration, was rebuilt by BPXA for the Northstar production project. Both Northstar and Endicott are production islands and will be discussed in greater detail below.

Land fast ice, ranging up to 6.6 ft (2 m) thick, covers the near-shore Beaufort Sea for about nine months of the year, and has a considerable influence on construction methods and island design. In the deeper water areas, multi-year ice incursions have to be considered. Gravel islands need sufficient sliding stability to withstand the forces generated by moving ice and the possibility of ice ride-up also has to be considered.

Artificial islands have been built either during the winter by trucking granular fill over the ice or in the short Arctic summer using dredges. Islands have been constructed of gravel, sand, silt and a mixture thereof. Slope protection has been designed to match the measured and predicted sea-state, which also influences the island freeboard needed to avoid wave over-topping. Slope protection methods for artificial islands have included anchored poly-filter cloth and sandbags, concrete units, rock fill, and sacrificial beaches. Optimum granular artificial island designs have to account for constructional constraints, working area needed, ice action, wave action and geotechnical factors.

For exploratory drilling, a stable platform is required from which to drill. Drilling operations can last from about thirty to one-hundred and sixty days. The actual time will depend on the well depth, drilling factors, and whether any testing of discovered hydrocarbons is conducted.

In the early 1970's, of the numerous offshore drilling concepts which were considered, artificial granular fill islands were selected to initiate Arctic offshore drilling. They had the advantage of short lead-time and the use of proven technology. Also they could be built to withstand the year-round environment and thus the drilling rig could stay over the well until it was completed. The main disadvantages of islands are the short period available for construction in the summer, and also the fact that in deeper water, the construction times and costs increase rapidly.

The design of artificial granular islands for ice-infested waters is normally governed by the resistance of the structure to ice loads. It is also influenced by materials and techniques available for construction as a function of location and season. Figure 3-68 shows the two basic designs utilized in the Canadian Beaufort Sea for the construction of granular fill artificial islands.

Figure 3-68 is drawn with an approximate vertical exaggeration of 3 times. The figure illustrates islands in 16 to 23 ft (5 to 7 m) water depth.

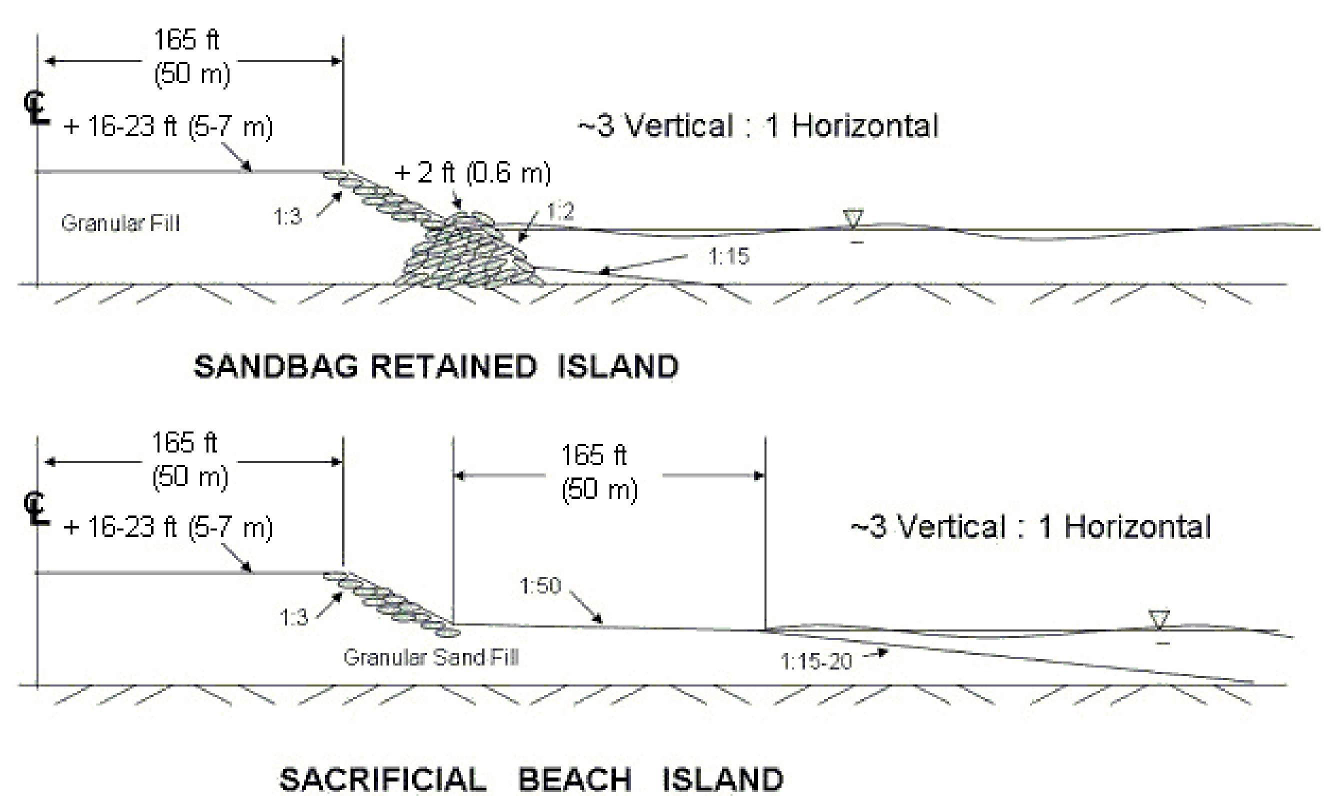


Figure 3-68: Basic Designs for Granular Fill Artificial Islands in the Canadian Beaufort

The deepest granular fill island was Issugnak O-61 in 62 ft (19 m) water depth. The island took 3 seasons to complete and required 176.6 million cubic feet (5 million cubic meters) of fill. The 1:15 – 20 sloped beach section shown for the sacrificial beach design would be approximately 3 times wider than that shown in Figure 3-68.

A photo of the first deepwater sacrificial beach island, Arnak L-30, is shown undergoing wave action in 1976 in Figure 3-69. This photo shows a large amount of redistribution of the sand from the sacrificial beach to the lee side of the island. This sediment transport behavior was a feature of the design.

Figure 3-69: Imperial Oil's Arnak L-30 September 1976 Showing Wave Action on the Sacrificial Beach Island Design (from Croasdale and Marcellus, 1977)

Referring back to Table 3-13, of the 31 islands constructed in the Canadian Beaufort Sea, 13 were Sandbag Retained Islands, 13 were Sacrificial Beach Islands, 1 (Sarpik B-35) was protected by filter-cloth with concrete units attached (which proved to be problematic) and the remaining 5 were classified as hauled islands (shallow water islands not requiring significant erosion protection). The choice of design to a large extent was based on the availability (and cost) of construction equipment.

Northstar

The Northstar oil field was discovered in the Beaufort Sea in 1983 by Shell (SPG Media Limited, 2007g). Northstar Island is a 5 acre (20,200 m^2) manmade production island which was built upon an abandoned/deteriorated exploration island, Seal Island. It was chosen to utilize Seal Island because significant cost and time savings would be realized through rebuilding (and subsequent expansion) as opposed to starting from scratch and building a new island. Furthermore, based on ERD capabilities at the time, Seal Island was able to reach 95% of the reservoir (US Army Corps of Engineers, 1999).

Northstar Island is grounded in approximately 39 feet (12 m) of water and is located about 6 miles (9.7 km) offshore. Seasonal access to the island is achieved via ice roads.

Figure 3-70: Northstar Production Island (Thomas, n.d.)

Oooguruk

The gravel island was completed in 2006 in about 4.5 feet (1.4 m) of water and stands 23 feet (7 m) above the seafloor. An equivalent of 22,000 truckloads of gravel was used to construct the island (Wright, 2006). In the summer of 2006, side slopes were constructed on the island to resist ice loads; slope protection is provided by gravel bags (8000 in total) (Quinn, 2007). Settlement of the island has been estimated as a meter or so which will require maintenance of the island. Wick drains were installed to speed up consolidation settlement from two and a half years to nine months (Knott, 2006). The project is scheduled for first oil in early 2008.

Endicott Island

Endicott Island was the first production island constructed. The Endicott oil field is located in the Beaufort Sea, about 8 miles (12.9 km) east of Prudhoe Bay. It was discovered in 1978 by the Sohio Alaska Petroleum Company and is currently operated by BP Exploration (Alaska).

This project pool has been developed from two artificial gravel islands that are located approximately 4 miles (6.4 km) offshore in 2 to 14 feet (0.6 to 4.3 m) of water. These islands are connected through a 5-mile (8 km) long gravel causeway, which supports the pipeline (shown in Figure 3-72).

The causeway was constructed in 1984-85. Endicott production began in July 1986. During the peak production years from November 1987 and October 1993, Endicott averaged about 104,250 barrels of oil per day (BOPD). Production has declined over the years to the point where during the last 8 months of 2004, production from Endicott was 17,600 BOPD.

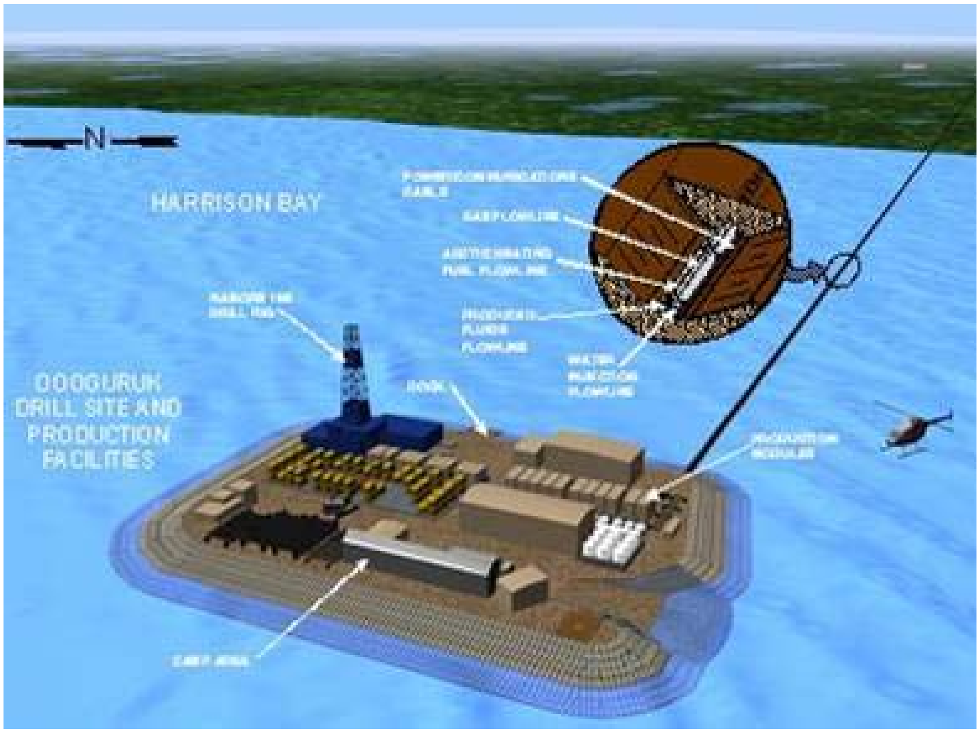


Figure 3-71: Oooguruk Production Island (INTEC, 2007)

Figure 3-72: Endicott Production Island (Thomas, n.d.)

3.4.4 Floating Structures

3.4.4.1 Drillships

The ice class drillship "Explorer II" and "Kulluk" were used in the Beaufort or Chukchi Seas for water depths in excess of 100 (30 m) in the 1980's and 1990's. To the south, in Navarin Bay and St. George Basin, semi-submersibles were used extensively due to the relatively ice-free environment for most of the year. The first drilling operations undertaken by drillships in ice prone waters were primarily intended for open water use, and normally drilled during the Beaufort or Chukchi's summer and early fall seasons. However, with icebreaker support, they soon developed the capability to maintain position in a variety of pack-ice conditions. This extended their operating season beyond the open water period, although they did not work extensively in heavy ice. The Explorer II (see Figure 3-73) is a Donheiser Marine, Super Class 1AA design. Its mooring system is an eight point wire design and had a variable load capability of 6,387 tons (5794 tonnes).

Figure 3-73: "Northern Explorer II" (formerly the CANMAR Explorer II and Explorer II) (WorldOil, 2000)

The Kulluk was designed as a second generation drilling system that was purpose built to significantly extend the open water season, by beginning drilling operations in the spring break-up period and continuing until early winter. As a result, the Kulluk operated in a greater and more difficult range of pack-ice conditions than drillships. In addition, "in-ice performance information" was systematically obtained during its operations. Because of this, the Kulluk's experience base provides the best source of data for most considerations related to moored vessel station-keeping operations in various pack-ice conditions.

Figure 3-74: Kulluk (Courtesy of DC Marine)

The Kulluk (shown in Figure 3-74) was designed with a variety of features to enhance its performance capabilities in ice. Some of the primary technical challenges that were considered and accommodated in the Kulluk's design are highlighted as follows:

- Minimizing the icebreaking and clearance forces that the vessel would experience from any direction, by providing it with an "omni-directional capability" to resist ice action;

- Developing a hull form that would “minimize” icebreaking forces, enhance ice clearance, and reduce the possibility of ice moving down the hull and under the vessel, where it could interfere with the mooring and riser systems, and enter the moonpool area;

- Providing a strong mooring system that could resist the “high” load levels associated with heavy pack-ice conditions during extended season operations, with acceptable mooring line tensions and vessel offsets;

- Developing a submerged mooring system that would “eliminate” the problem of ice entanglement with mooring lines at (or near) the waterline; and,

- Configuring an ice management system that would be capable of “protecting” the Kulluk in the more difficult ice conditions expected in the Beaufort’s extended drilling season.

Typically, the Kulluk was supported by two to four CAC 2 icebreakers during its operations in heavy pack-ice conditions. Although the vessel occasionally operated in unbroken ice, it normally worked in managed ice conditions, where the oncoming pack-ice cover had been pre-broken into relatively small fragments by the support icebreakers (shown below in Figure 3-75).

Figure 3-75: The Kulluk - Operations with Icebreaker Support (Courtesy of DC Marine)

3.4.4.2 Semi-Submersibles

Semi-submersibles are conventional floating exploration structures and have been used considerably in the south Bering Sea. Table C-1 located in Appendix C provides information on Alaska OCS drilling activity including drilling rigs employed. In general, harsh environment winterized semi-submersibles have been used.

An example of a previously used semi-submersible; the Ocean Odyssey (Figure 3-76) was an advanced super-class unit designed to operate in Arctic environments (OSTI, 2007). The Odyssey was capable of operating in winds greater than “100 knots (51.4 m/s) with its 4,500-ton (4100 tonne) deck-load without de-ballasting from its 80 ft (24.4 m) operating draft” (OSTI, 2007). Further, the Odyssey was constructed with reinforced columns and was equipped with a caged riser (Oil Rig Disasters, 2007). The Ocean Odyssey is now used as a mobile spacecraft launch platform (SPG Media Limited, 2007i).

Figure 3-76: Ocean Odyssey (NationMaster, 2005)

3.4.4.3 FPSO

To date, no floating production structure has been used in the Alaskan OCS; however, a feasibility assessment of a tanker-based FPSO system has been carried out for the southern Bering Sea (Brian Watt & Associates, 1985). A water depth of 250 ft (76 m) was used for the assessment and the FPSO concept was based on a 126,000 DWT tanker design with an ice strengthened hull. The assessment considered several mooring systems with both flexible and rigid risers. The final concept selection utilized a turret mooring system with flexible risers.

The assessment concluded that although the FPSO would require local ice strengthening, ice was not the governing global design load. Moreover, the assessment concluded that no significant advances in technology were required at the time to develop a feasible system (Brian Watt & Associates, 1985).

3.4.5 Subsea Solutions

As discussed previously in Section 3.3.3, subsea tiebacks to a platform and subsea solutions with no structure have been used/considered for ice environments. While no such production facilities have been built in the Alaskan OCS or the Canadian Beaufort, glory holes have been considered for the Arctic to house the wellhead and associated equipment during exploration.

3.4.6 Pipelines

3.4.6.1 BP Alaska Northstar

The Northstar project was the first Arctic project with a subsea oil pipeline. The Northstar project operated by BP Exploration (Alaska) Inc. included the design, construction and installation of the first offshore oil and gas production pipeline in the U.S. Arctic (Lanan et al., 2001). The Northstar Unit is located approximately 8 miles (12.9 km) northwest of Prudhoe Bay, offshore approximately 6 miles (9.7 km), in a water depth of approximately 40 feet (12 m) (Figure 3-77).

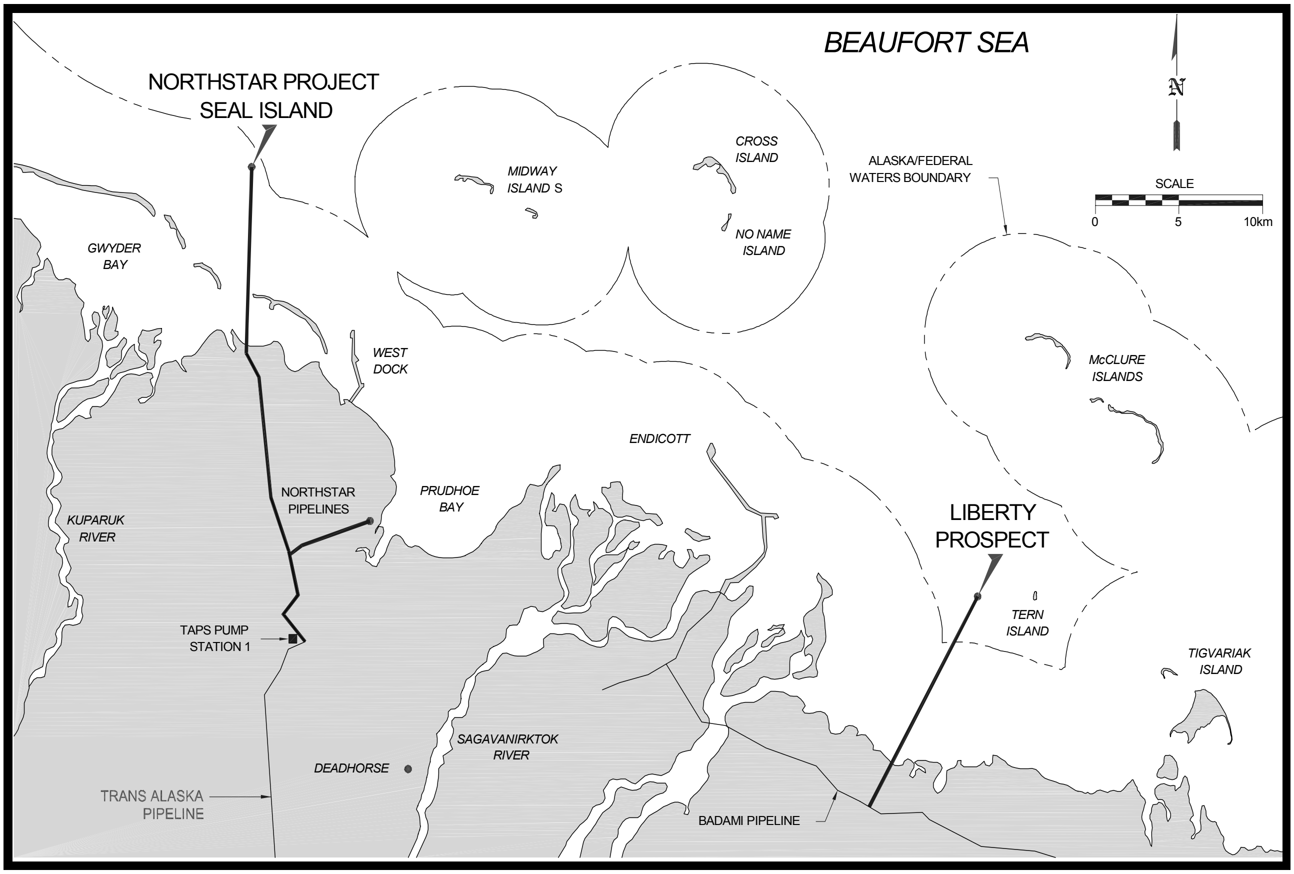


Figure 3-77: Northstar and Liberty Project Location Map (from Lanan et al., 2001)

A single drilling/production structure with pipelines to shore was selected as the development plan. Seal Island, an exploration gravel island built by Shell in 1982, was enlarged and drilling/process facilities installed for oil production. Construction of the island and the pipeline were completed in 2000. Facilities were installed on the island through the summer of 2001 and production started that fall.

Pipelines

Seal Island is approximately 6 miles (9.7 km) offshore in 37 feet (11 m) of water. Production of the 65,000 bbl/day is from the gravel island, with the oil transported to shore and then to TAPS Pump Station 1 by a 10.75-inch (273 mm) diameter pipeline. A second 10.75-inch (273 mm) diameter pipeline supplies gas from Prudhoe to the island for fuel gas and reservoir pressure maintenance.

The 10.75-inch (273 mm) crude sales oil pipeline offshore segment was a 0.594-inch (15 mm) W.T., API 5L Grade X-52 based on pipe stability requirements during installation and compatibility with potentially high operational strains (Lanan et al., 2001). The oil line is designed for a normal operating pressure of 850 psig (5860 kPa). The offshore gas pipeline has the same pipe specifications, wall thicknesses, and grade. The gas line is designed for a throughput of 100 MMSCFD (2.8 million cubic meters per day) and a normal operating pressure of 1250 psig (8620 kPa). The oil and gas pipelines were bundled together over the offshore pipeline length and incorporated within the bundle was an external leak detection system.

Several technical issues were addressed during the design phase, including route selection, landfall site selection, ice gouge protection, permafrost and strudel current loadings, and construction methodology. The pipelines have been designed to withstand 100-year return period environmental conditions. The Northstar development also utilized limit strain design criteria to meet the challenges of offshore arctic environments and marginal field economics.

<u>Project Design Challenges & Highlights</u>

Pipeline design challenges and highlights associated with the Northstar development included:

- Ice keel protection;
- Strudel scour evaluation;
- Thaw settlement of permafrost;
- Upheaval buckling; and,
- Limit strain criteria.

Ice Gouging: The Northstar pipelines were designed to avoid failure due to ice keel gouging of the seabed. The effect of sub-keel soil displacement interaction with the pipelines has been considered in establishing the required depth of cover. A number of analyses were carried out by varying the ice keel width to determine the width that induced the largest strains in the pipeline for a 100-year ice gouge depth of 3.6 ft (1.1 m). This design ice gouge depth should be considered against the maximum depth ice gouge measured from

10 years of gouge data which was determined to be 2.0 ft (0.6 m) (Lanan et al., 2001). The results indicate the pipeline bending strains due to gouging would be safely less than maximum allowable levels for the burial depth selected.

Strudel Scour: The allowable pipeline free span lengths were evaluated for pipeline strain limitations and the prevention of vortex shedding induced oscillations of the pipelines. Based on available and applicable data, the value associated with the 100-year return period maximum horizontal dimension event was found to be 122 ft (37.2 m) at the seabed. By examining side slopes of scours, a maximum scour dimension of 84 ft (25.6 m) at the base of the pipe is estimated (for an 8 ft (2.4 m) burial depth from seabed to bottom of pipe). A conservative strudel scour span dimension of 90 ft (27.4 m) was adopted for design (Paulin et al., 2002). This phenomenon has been found to not control the pipeline's wall thicknesses or depth of cover requirements.

Permafrost Thaw Settlement: Ice bonded permafrost was found to be present along the pipeline route close to shore in water depths less than approximately 5 ft (1.5 m). The maximum thaw induced settlement potential in the ice-bonded permafrost region was found to be approximately 2 ft (0.6 m) close to the onshore transition, within a few hundred meters from shore. A design value of 2 ft (0.6 m) of settlement was used for the lagoon section of the offshore route (Paulin et al., 2002). The other location where thaw settlement appeared higher was on the outside of the barrier islands, just before the top of the permafrost drops deep below the seabed under the influence of deeper water conditions. Here, the potential settlement was found to be generally less than 1.5 ft (0.46 m); a design value of 1.5 ft (0.46 m) was adopted and was assumed to be differential settlement. An operational limit state bending strain criterion was used to confirm that the pipelines would be safe under the maximum predicted differential thaw settlement.

Upheaval Buckling: Because the pipelines were operated at a temperature significantly higher than that at which they were installed, upheaval buckling was a design issue. A maximum allowable overbend vertical curvature had to be defined for pipeline construction. A maximum 2 ft (0.6 m) variation in pipeline elevation (trough to peak) over 302 ft (92 m) was considered reasonable given the pipeline trenching/installation method (see Lanan et al., 2001). The results of the analyses indicate that a minimum backfill thickness of approximately 5 ft (1.5 m) of native soil (low submerged density and uplift resistance) was required over top of the pipelines.

Limit State Design: The pipelines need to be buried deep enough to withstand these environmental forces, but not so deep as to be impossible to construct or make the project uneconomical. The pipeline design is therefore based on strain rather than stress. The criteria have been included in the design for non-cyclic pipeline displacements (e.g. thaw settlement, sub-ice keel soil deformation, and island settlement). Northstar pipelines are designed at 1.2% operating bending strain, with 1.8% strain for extreme events (Nogueira et al., 2000). Because these criteria are dependent on pipe behavior during extreme bending, full-scale bend tests were conducted to validate the limit state design methodology.

Shore and Island Approach: The design of the shore approach at the landfall point included the consideration of coastline erosion effects on the stability of the pipelines as well as ice ride-up onshore. The shore approach at Point Storkersen extends approximately 180 feet (55 m) onshore of the receding coastal bluff line after which the pipelines then transition onto a gravel pad through a casing. At Seal Island, the trench terminated at a vertically curved sheet pile slot in the island. The design accounted for the effects of potential island settlement on the pipeline.

Burial Depth: As a result of all the environmental and operational loading conditions, the required depth of cover was determined to be 7 feet (2.1 m) (original seabed to top of pipe) for water depths less than 33 feet (10 m) deep and 9 feet (2.7 m) for water depths greater than 33 feet (10 m) (Lanan et al., 2001). Depth of cover is defined on this project as the distance from top of pipeline to the top of the original undisturbed seabed. The trench was backfilled overtop of the pipelines using the trenching spoils.

Pipeline Construction / Construction Planning Challenges & Highlights

The overall construction strategy for the Northstar project was to use the winter construction season to its maximum advantage, allowing the use of conventional or adapted onshore construction equipment and techniques. The limited open water season in the Beaufort Sea combined with its remoteness and reduced accessibility with respect to mobilizing marine equipment (e.g. pipe laying vessels and ocean-going barges) makes construction significantly more expensive, extends project execution schedules, and entails some risks with respect to equipment mobilization and construction windows.

Innovative construction methods were developed for the Northstar project such as on-ice and through-ice excavation and installation (Lanan et al., 2001). Ice-based construction had been used successfully in artificial gravel island construction and, coupled with ice thickening, offered an attractive alternative to conventional marine pipeline installation methods in this area.

Construction of the offshore segment of the pipelines included construction of ice roads, thickening of the sea ice to form a bearing surface, making ice slots by cutting and removing ice blocks, excavation of an offshore trench into which the pipelines are lowered, and backfilling of the trench.

An eight-foot wide slot was cut in the ice and blocks removed using backhoes and moved to locations away from the work site to prevent excessive deflections of the ice in the working areas. Offshore trenching was conducted from the surface of the ice using modified backhoes equipped with extended reach booms.

Welding of the pipeline took place to the side of the trench, where non-destructive testing (NDT) was also performed. The welds were then coated, the cathodic protection anodes attached to the pipelines, and the pipelines strapped together to form a bundle. Sidebooms were used to lower the bundle through the slot and into the trench. All spoils were then placed back into the pipeline trench. The pipelines were hydrotested using a water-glycol mix followed by an inspection pig run. Additional information on this project can be found in: Lanan et al. (2001); Nogueira et al. (2000); Paulin et al. (2002).

3.4.6.2 Pioneer Oooguruk

<u>Overview</u>

Pioneer Natural Resources Alaska, Inc. is developing the Oooguruk Field, offshore Alaska. This field is located approximately 5.6 miles (9 km) offshore, near the mouth of the Colville River Delta, and 40 miles (64 km) west of Prudhoe Bay. The man-made gravel island is located in less than 5 ft (1.5 m) of water and stands 23 ft (7 m) in height as measured from the seabed. First oil is scheduled for early 2008; by 2010 oil production is anticipated to peak at 15,000-20,000 bpd (Knott, 2006). Produced fluids are transported to shore via a multiphase pipe-in-pipe system.

<u>Pipelines</u>

Production will be transported to shore through a 5.6 mile (9 km) multiphase pipeline which will form part of a subsea bundle, including power to the island, which will be unmanned during production operations. This line will be the first application of pipe-in-pipe (PIP) production flowline technology in the offshore Alaskan Arctic (Knott, 2006). The bundle is an open bundle rather than being enclosed in a single large pipe; individual pipes are strapped together which makes the system lighter and less complex which translates to lower cost (Knott, 2006).

The open bundle consists of four pipelines including a 12.6 inch (320 mm) diameter internal pipe within a 15.75 inch (400 mm) diameter external pipe (PIP) which transports the multiphase flow to shore. The remaining lines are a 5.9 inch (150 mm) diameter gas line, a 9.8 inch (250 mm) diameter water line and a 2 inch (50 mm) diameter diesel pipeline. The PIP system is API 5L grade X-52 materials or better. The presence of an annulus facilitates the use of an annulus vacuum monitoring or pressure monitoring system for leak detection. The annulus between the external and internal pipelines would also help contain any potential leakage in the event of an emergency.

Project Design Challenges & Highlights

A significant design issue was protection of the pipeline bundle against ice gouging. To protect the pipeline, it was trenched and backfilled. Trenches were planned to be 9 ft (2.7 m) deep affording 6.6 ft (2 m) of cover over top of the pipeline (Knott, 2006). This backfill cover would also resist upheaval buckling of the pipeline as it heats up during operations.

Another significant challenge associated with the Oooguruk pipeline was to design against the effects of strudel scour, where river overflood waters flow through holes or cracks in the ice sheet and erode the seabed. To monitor any erosion of soil cover over the pipeline, Pioneer planed to install a fiber optic temperature monitoring system with the pipeline. Such a system will detect any decrease in temperature, indicating loss of soil cover as the result of seabed erosion (Knott, 2006). Other design issues included thaw settlement of permafrost and upheaval buckling potential.

Construction was planned to be carried out from the ice. In preparation for construction planning, two 330 ft (100 m) long test trenches were excavated in 2006 (one near shore and one close to the island) to understand soil behavior during trenching (Knott, 2006). The three-phase pipe-in-pipe system was installed from the ice in the winter of 2007 (Nelson, 2007a).

3.4.6.3 Nikaitchuq

ENI is planning to develop the Nikaitchuq Field offshore the coast of the North Slope of Alaska. The site is in the Beaufort Sea, near Spy Island and approximately three miles offshore Oliktok Point.

The project calls for a production pad at Oliktok Point and offshore gravel islands inside the barrier islands, in the vicinity of Spy Island, in water depths of six to ten feet (Cashman and Nelson, 2005). The original concept called for a “pipe in pipe” design to provide secondary containment for the three-phase flow and an annular space for pipeline leak detection. Nikaitchuq will produce up to 40,000 bbls/day (OilVoice, 2007).

The pipeline was planned to be trenched from the ice in winter. Initial engineering work included pipeline concept evaluation, flow assurance, pipeline mechanical design, trenching and installation studies, and design to protect against seabed ice gouging, permafrost thaw settlement, strudel scour, upheaval buckling and channel migration (INTEC, 2007).

3.4.6.4 BP Alaska Liberty

The BP Alaska Liberty project was planned to be developed in much the same way as the Northstar project (BPXA, 2000). The proposed artificial gravel island was to be located in Foggy Island Bay east of Endicott and was to be a self-contained drilling and production facility. The island would have been constructed 6 miles (9.7 km) offshore inside the natural barrier islands in approximately 21 feet (6.4 m) of water. The facilities were to be designed for production of 65,000 bbl/day.

The 12.75-inch (324 mm) crude sales oil pipeline offshore segment design yielded a 0.688-inch W.T., API 5L Grade X-52 line based on pipe stability requirements during installation and compatibility with potentially high operational strains. The oil line was designed for a MAOP of 1415 psig (9756 kPa). The oil pipeline was designed for a maximum operating temperature (oil pipeline inlet) of 150°F (66°C) (INTEC, 1999).

Several technical issues were addressed during the design phase, including route selection, landfall site selection, upheaval buckling, ice gouge protection, permafrost and strudel current loadings, and construction methodology. The pipelines were designed to withstand 100-year return period environmental conditions and utilized limit strain design criteria to meet the challenges of offshore arctic environments.

The pipeline was designed to avoid failure due to ice keel gouging of the seabed. Analysis indicated a 100-year ice gouge depth less than 1.5 feet (0.5 m). A 3 foot (0.9 m) ice gouge depth was conservatively adopted for design.

The maximum thaw induced settlement potential in the ice-bonded permafrost region was found to be approximately 0.9 feet (27 cm). A design settlement of 1 foot (30 cm) was combined with an operational limit state bending strain criterion to confirm the pipelines were adequately designed. The Liberty pipeline was designed for a maximum 1.2% operating bending strain, with 1.8% strain for extreme events (INTEC, 1999).

INTEC (1999) prepared a conceptual engineering report to evaluate and present design alternatives for the Liberty pipeline. The report was intended to provide permitting and resource agencies information for evaluating alternatives in the Liberty Environmental Impact Statement. The report reviews four design alternatives:

- Single wall steel pipeline;
- Steel pipe-in-pipe system;
- Single wall steel pipe inside HDPE (high-density polyethylene) sleeve; and,
- Flexible pipe system.

In order to fully evaluate these alternatives, the report covered project design criteria, installation methods, construction costs, operations and maintenance issues, system reliability, and leak detection.

The Liberty pipeline design was completed in 2000 but the project was cancelled in 2002. Since then, BP has been investigating the use of extended reach drilling to develop the project from shore (Nelson, 2005).

3.4.6.5 Chukchi Sea Pipeline Studies

In 1986, joint industry studies were undertaken to investigate the feasibility and cost of hydrocarbon transportation systems for the central and northern Chukchi Sea (INTEC, 1986). The technical feasibility and costs for transportation systems including pipelines and tankers were major considerations that had to be evaluated at the time, prior to exploration for potential oil reserves in the area.

Preliminary pipeline analysis was performed to define parameters that would significantly affect the technical feasibility and the costs of offshore pipelines, including routing, hydraulics, trenching, and construction. In subsequent studies (INTEC, 1991), preliminary pipeline design requirements were established for 8 pipeline routes. These lines ranged in length from approximately 110 to 210 miles (177 to 338 km) and from 16 to 44 inches (406 to 1118 mm) in diameter.

Water depths in the study area ranged from shore to approximately 300 feet (91 m) in the northern portion. Sea ice within the study area and along potential tanker routes was identified as the dominant environmental condition affecting hydrocarbon transportation systems.

Survey data available at the time indicated that the seabed was actively exposed to ice gouging to water depths of at least 165 feet (50 m). Maximum ice gouge depths were generally observed between water depths of 115 and 165 feet (35 and 50 m). A maximum observed ice gouge depth of 15 feet (4.5 m) was recorded at a water depth between 115 and 130 feet (35 and 40 m) and no ice gouges were recorded in water depths greater than 190 feet (58 m).

As with other arctic areas, one of the primary design concerns was ice gouging. The required depths of cover derived from statistical parameters of ice gouge frequency were determined to be between 6 and 14 feet (1.8 and 4.3 m) depending on the location.

A number of construction methods were evaluated including laybarges, bottom tow, and bottom pull. For pipelines in water depths greater than 40 feet (12 m), a third generation laybarge was recommended as the method of installation. In water depths less than 40 feet (12 m), pipeline installation by bottom pull was considered practical. For nearshore loading lines and for short nearshore lines, the bottom tow method was the recommended installation method.

The recommended pipeline trenching method in the offshore areas was a trailing suction hopper dredge or a linear trencher (dredge) concept. An evaluation of these two types of dredges indicated an economic advantage for the linear trencher where the pipeline length was greater than 35 miles (56 km). In shallow water nearshore, which was not accessible by the trailing hopper suction hopper dredge, a cutter suction dredge would be used to excavate the trench.

3.4.6.6 Bering Sea

A study carried out to look at production systems for the southern Bering Sea (PMB Systems Engineering et al., 1983) investigated issues with respect to offshore drilling and production structures, topsides requirements, crude oil pipelines, and terminals. The study was carried out in advance of lease sales of the mid 1980's.

Areas investigated included the Navarin Basin, the St. George Basin and the North Aleutian Shelf which were at the southern limit of annual ice cover. Open water was described as approximately eight months of the year. Ice keels up to 10 feet (3 m) thick could be present in the Navarin Basin. Soil conditions in the area are described as silts and fine sands further offshore and sands to soft clays in the nearshore region.

Pipeline sizes ranging from 24-inches to 36-inches (610 mm to 914 mm) were adequate to transport 100 KBPD to 300 KBPD over distances of 65, 242, and 611 nautical miles (120, 448, and 1132 km) in a maximum water depth of approximately 600 feet (185 m). It appears that the D/t ratios (38 to 41) for the pipelines were selected on the basis of withstanding combined stresses in the sagbend during laying and not on the basis of environmental loadings.

Pipeline construction was not considered an issue and the longest line could be completed in two seasons. Construction in the southern Bering Sea was envisioned to be similar to the North Sea in terms of weather window for installation.

Nearshore trenching would be carried out to a water depth sufficient so that waves and currents would not affect the line. No unusual obstacles were anticipated over what might be expected for a North Sea installation.

3.4.6.7 Mackenzie Delta (Dome, Esso, Gulf Canada)

In the early 1980's, hydrocarbon discoveries in the Canadian Beaufort Sea convinced potential offshore operators to investigate offshore pipeline options for the Mackenzie Delta Region. Dome Petroleum, Esso Resources Canada, and Gulf Canada Resources evaluated pipelines and inter-island flowlines for development scenarios at the Tarsiut, Kopanoar, and Issungnak fields (Figure 3-78). The sites were envisioned to be developed using artificial islands (production and satellite) in 65 to 200 ft (20 to 60 m) water depth to produce oil and gas.

Additional details on these studies are not in the public domain.

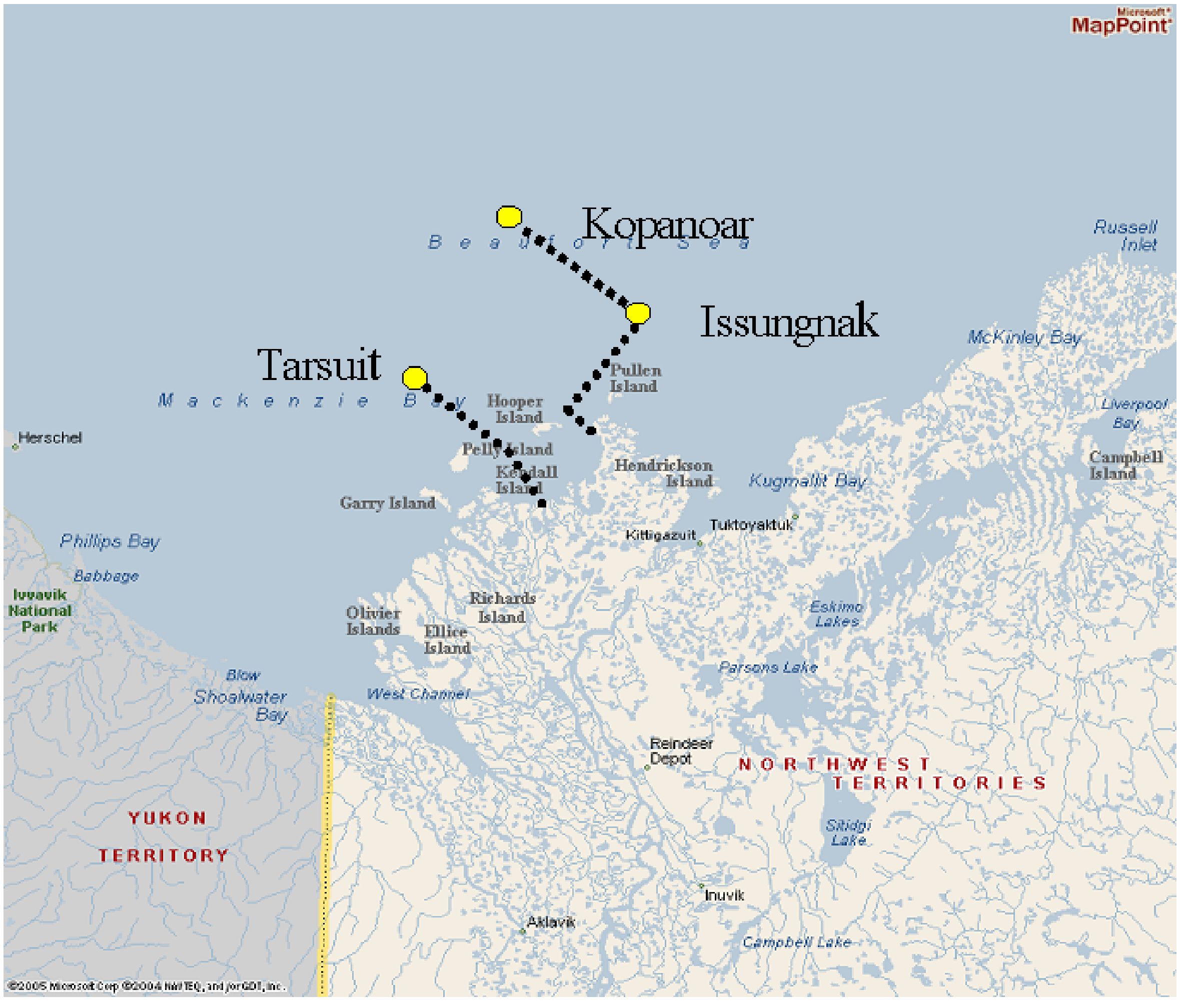


Figure 3-78: Approximate Locations, Mackenzie Delta Development

3.4.6.8 Amauligak

In 1989, Gulf Canada Resources Ltd carried out a study to progress preliminary design, develop a construction strategy, and prepare a cost estimate for the installation of two 20-inch (508 mm) pipelines from a caisson retained inland (CRI) at the Amauligak discovery to a landfall location at North Point on Richards Island in the Canadian Beaufort Sea (INTEC, 2007).

The proposed project involved the possible installation of two 30 mile (48 km) long pipelines in a common trench. These pipelines would transport crude oil from the Amauligak field to an onshore pump station. The water depth was approximately 102 ft (31

m) at Amauligak and gradually decreased towards shore, with the final ten miles in shallow water.

Additional details on this study are proprietary.

3.4.6.9 East & West Amauligak Pipelines

In the late 1980's, Gulf Canada Resources carried out studies to investigate issues related to the installation of flowline bundles from the proposed future Amauligak caisson retained island (CRI) to developments at East and West Amauligak which would be tied back into Amauligak.

Additional details on these studies are proprietary.

3.4.7 Extended Reach Drilling

Several extended reach wells have been drilled onshore Alaska, including several record breaking horizontal lengths (Alvord et al., 2007). Based on these technological developments, the potential of using ERD for wells offshore is being recognized. To maximize access to the reservoir, the Alpine field has been developed using horizontal well technology (Alvord et al., 2007).

In the early part of the decade, the Liberty prospect was proposed to be developed using a gravel island and a pipeline to shore (approximately 6 miles (9.7 km) long). The project did not progress in that form but the current production plan filed by BP proposes to use extended reach drilling that was not considered feasible 5 or 6 years ago. BP plans to drill six extended reach wells from Endicott Island which is located approximately 8 miles (12.9 km) to the west of Liberty (Fischer and Schmidt, 2007).

3.5 Summary - Exploration & Development Options Review

Based on the preceding review, a variety of exploration and development options have been employed or considered for use in the Arctic and other cold regions. Table 3-11 summarizes these options.

Table 3-11: Summary of Arctic and Cold Regions Exploration & Development Options

Region	US Beaufort Sea	Chukchi Sea	Bering Sea	Cook Inlet	Can. Beaufort Sea	Can. High North	Can. East Coast	Offshore West Greenland	Barents Sea	Kara Sea (Gulf of Ob)	Pechora Sea	Baltic Sea	Sakhalin Island
Bottom-Founded & Fixed Type Structures													
GBS	X	X	X		X		X			X	X		X
Mobile Bottom-Founded	X				X					X			
Barge			X		X								
Jacket/ Monopod			X	X			X						
Jack-up			X	X			X						X
Gravel Island	X				X								
CRI					X								X
Ice Island	X				X								
Floating Structures													
FPSO/FSO			X				X	X					
SPAR							X		X				
TLP							X		X				X
Semi			X	X			X	X					X
Drillship	X	X		X	X		X	X					
Floating Ice Pad						X							
Export and Infrastructure													
Offloading Buoy/ Terminal			X				X				X		X
Export Terminal		X	X			X	X		X		X	X	X
Pipeline	X	X	X		X	X	X		X			X	X
Subsea/ Flowlines	X	X	X		X	X	X	X	X				X

The assessments of options presented in Table 3-11 are carried out in the following section (Section 4). In addition to the options above, advancing technologies (ERD, WIM, and Pilot Hole to Pilot Hole HDD) are also assessed as they have potential Alaskan OCS applications. Several options not carried forward for assessment include Caisson Retained Islands, Barges, and Floating Ice Pads.

Caisson retained islands are a subset of gravel islands. They were developed in response to requirements associated with drilling in deeper water in the Canadian Beaufort during the early 1980's; CRI's help reduce quantities required (especially with sand islands) near the water line. However, CRI's are an expensive solution for exploration in comparison to mobile bottom-founded units and have been generally disregarded for use as production structures. In shallow water, sand bag or mat retained gravel islands are generally the most economical choice for production structures.

Barges have not been carried forward because of their similarity with other bottom-founded structures; both GBS and mobile bottom-founded structures are assessed.

Floating ice pads, like those used for exploration drilling in the Canadian High Arctic, have also been excluded from assessment. Although these are potentially economical seasonal exploration structures, the project team is unaware of a location in the OCS study areas, which would permit their use (i.e. a location with adequate water depths and stable, or non-moving, floating landfast ice).

4.0 ASSESSMENT OF OPTIONS

4.1 Approach

The results of the assessment of potential exploration and production options suitable for the northernmost regions of the Alaska OCS (the Beaufort, Bering, and Chukchi Seas) are presented in the sections that follow.

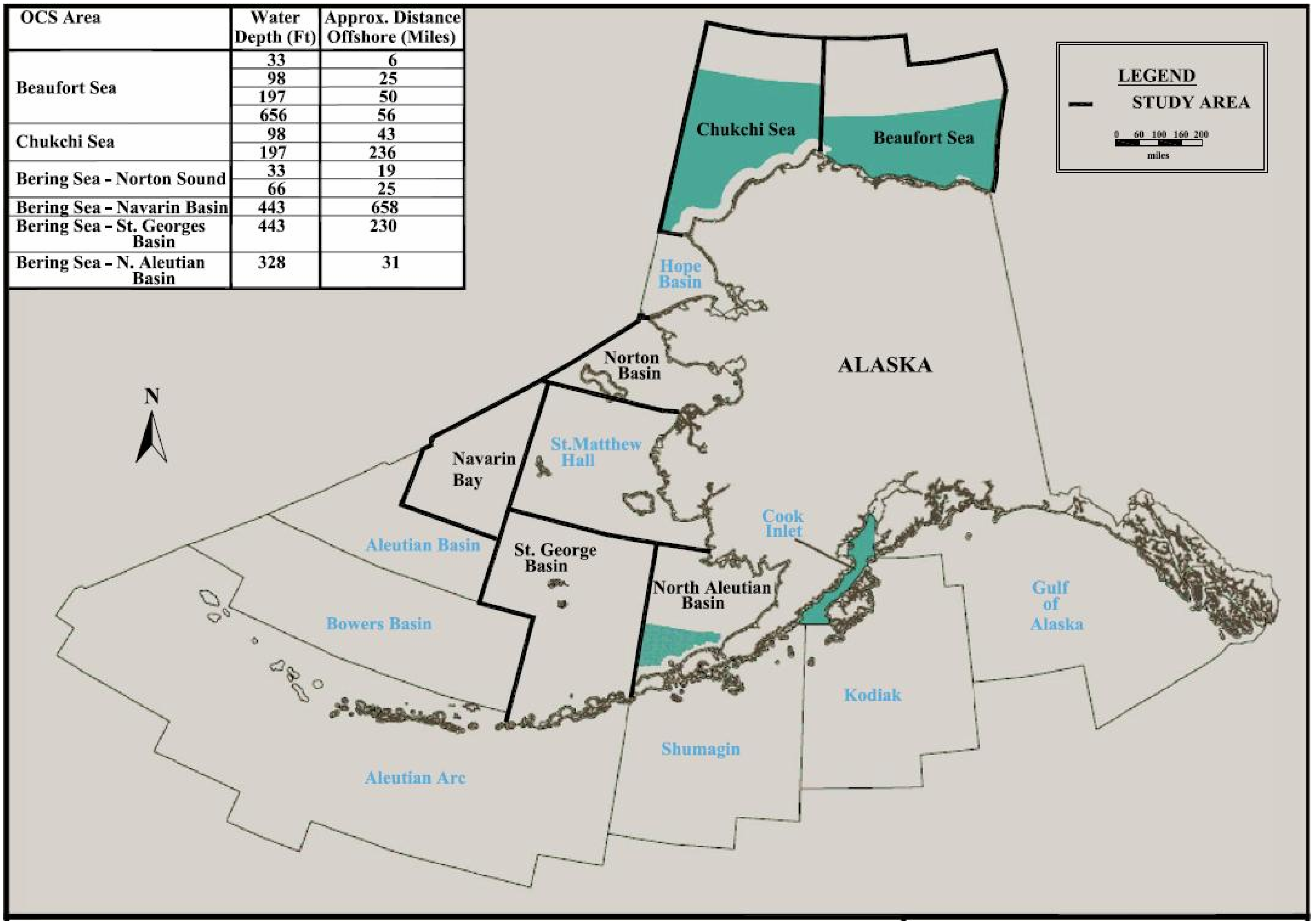
In general, the assessment draws on the review of Alaskan OCS and analogue experience, current state-of-practice and state-of-the-art. Assessments also consider bathymetry, metocean, ice and geotechnical conditions (where such data is available). This environmental data is included in Appendix A (Metocean & Ice Data) and Appendix B (Geotechnical Considerations).

Assessments of exploration and production options are primarily based on technical feasibility. As appropriate, the following other considerations are also discussed:

- Constructability;
- Capital costs;
- Environmental considerations;
- Operations;
- Maintenance and repair; and
- Abandonment and decommissioning.

4.2 OCS Scenarios

Based on the number of potential options identified, and the large geographic area encompassed by the Beaufort, Chukchi, the Bering Sea, location scenarios were created to help focus the assessments. Scenario identification also facilitated the gathering of metocean, ice and geotechnical data. Scenario locations (shown below in Figure 4-1) were chosen based on current and historic activity/interest (including lease sales, drilling, studies, projects, etc.) and water depths (given the general differences in structure types with water depths).



OCS Area	Water Depth (Ft)	Approx. Distance Offshore (Miles)
Beaufort Sea	33	6
	98	25
	197	50
	656	56
Chukchi Sea	98	43
	197	236
Bering Sea - Norton Sound	33	19
	66	25
Bering Sea - Navarin Basin	443	658
Bering Sea - St. Georges Basin	443	230
Bering Sea - N. Aleutian Basin	328	31

Figure 4-1: Assessment Study Areas with 2007-2012 Proposed Final Program Areas (modified from MMS, 2007c)

4.3 Metocean/Ice Considerations

4.3.1 Beaufort and Chukchi Seas

In coastal areas of the Beaufort and Chukchi Seas, mean monthly temperatures during the coldest month range from approximately -13°F to -23°F (-25°C to -31°C). Temperatures as low as -49°F to -50°F (-45°C to -46°C) have been observed.

Winds in the Beaufort prevail from the east, while the Chukchi Sea winds on average are from the northeast. Nearshore 1/100 year winds in the Beaufort are higher then those found for the Chukchi and range from approximately 70 knots to 98 knots (36 m/s to 50 m/s). For the Chukchi, the 1/100 year wind value is about 62 knots (32 m/s).

Differing wave height values between the Beaufort and the Chukchi are due to the increased fetch that can often exist in the Chukchi. In the Beaufort, nearshore wave heights can reach up to approximately 20 ft (6 m) (US Army Corps of Engineers, 1999). Further offshore, in water depths up to approximately 100 ft (30 m), a 30 ft (9 m) maximum wave height is plausible (Kennedy et al., 1994). For the Chukchi Sea, 1/100 year significant wave heights have been predicted at 29 ft (8.8 m) (MMS, 1986).

Ice conditions in the Chukchi and Beaufort have some similarities; however, the ice in the Chukchi is much more dynamic than in the Beaufort. In particular, Chukchi landfast ice is typically unpredictably unstable and break-outs can occur at any time (MMS, 1990; MMS, 2007b). First-year level ice thicknesses in the Beaufort and Chukchi Seas range from approximately 5.9 to 6.5 ft (180 to 200 cm), and 3.9 to 4.9 ft (120 to150 cm), respectively.

Multi-year ice thicknesses for both the Beaufort and Chukchi Seas range from 9.8 ft (3 m) upwards. Pressure ridge keels can be thick enough to gouge the seafloor and it is believed that modern gouging could occur out to approximately 165 ft (50 m) water depth in some areas.

4.3.2 Bering Sea and South

In general, the Bering Sea presents a much less severe ice environment compared to the Beaufort or Chukchi Seas. However, wave conditions and seismic effects are more of a concern. Norton Sound has an average winter temperature of between 10°F and 5°F (-12°C and -15°C). Winds prevail from the north during the winter and the 1/100 year speed can reach 110 knots (57 m/s). The 1/100 year significant wave height lies in the range of 29 to 37 ft (8.8 to 11.3 m), depending on water depth. Multi-year ice is essentially non-existent in the Bering Sea and is only present because of “break-out” of ice at the Bering Strait. First-year ice thicknesses can reach up to 4.9 ft (150 cm).

In the Southern Bering Sea lie the Navarin, St. George’s and the North Aleutian Basins. Temperatures for these areas are approximately the same; during February the mean temperature is approximately 35°F (2°C). Winds generally prevail from the north or northeast during the winter months. 1/100 year wind speeds for each area are as follows: 112 knots (Navarin); 112 knots (St. George’s); 106 knots (N. Aleutian). Of the 3 sub-regions contained within the South Bering Sea, St. George’s Basin is predicted to have the worst wave conditions, with a 1/100 year significant wave height of 45.6 ft (13.9 m) and a period of 15 seconds. From an ice perspective, the St. George and North Aleutian Basins do not experience ice each year, however, the Navarin Basin is encroached by ice annually. The mean maximum ice thickness for St. George’s and North Aleutian is approximately 2 ft (60 cm). Navarin Basin’s mean maximum ice thickness is approximately 4 ft (120 cm).

A summary of metocean and ice conditions for these areas is included in Appendix A.

4.4 Geotechnical Considerations

Areas of the Beaufort and Chukchi Seas are underlain by generally strong, competent soils. Soils are mostly “very stiff (2 to 4 ksf or 100 to 200 kPa) to hard (>4 ksf or >200 kPa) cohesive soils” or “dense to very dense granular soils”. Relatively weaker soils (firm (0.5 to 1 ksf or 25 to 50 kPa) to stiff (1 to 2 ksf or 50 to 100 kPa) silts and clays or loose to dense granular soils, ranging in thickness from 10 to 43 ft (3 to 13 m), are generally confined to a zone in shallower waters (less than 65 ft or 20 m) on the inner Beaufort Shelf. Seafloor soils are highly variable, partly as a result of ice gouging. Modern ice gouging may weaken seafloor soils to depths of typically 1.6 to 9.8 ft (0.5 to 3 m) in water depths up to 165 ft (50 m). Additional information is presented in Appendix B.

While these soils in a geotechnical sense may be considered to be strong and competent, from a structure foundation perspective, they may not provide ideal foundation conditions and some excavation may have to take place in cases (and perhaps the soils replaced). Where weaker soils overlay competent soils, excavation may have to take place depending on the weak layer thickness.

For the Bering Sea, silts, sands and gravels are present. Soil properties for St. George’s Basin, the North Aleutian Basin and the Navarin Basin have been adopted from PMB Systems Engineering et al. (1983) and are presented in Appendix B. It should be noted that given the limited information available to the study team, these are significant generalizations based on information from certain areas.

4.5 Bottom-Founded Structures

This Section of the report addresses the types of bottom-founded structures that would be suitable for exploration drilling and/or production development. Only the support platforms up to the top deck are addressed; topsides facilities are not included in estimates of costs and quantities. However, the effects of the topsides facilities (weight, carrying capacity, stability, etc.) have been considered and allowed for.

In terms of global size, structure cost and geometry, there is very little difference between dedicated exploration platforms and dedicated production platforms. In fact, an arctic mobile drilling structure is often more expensive than a production platform due to the fact that it must cater to a range of water depths, rather than a known set-down depth. Additionally, a mobile platform needs to be able to accommodate a range of foundation conditions including very weak clays. With production platforms, foundation characteristics are known and dredging of the top weak layers is an available option, but is often not practical in the case of short-term mobilization of an exploration structure.

4.5.1 Ice and Waves

In any location where substantial multi-year ice can impact a structure, the loads resulting from this interaction become the primary design condition and the structure shape and scantlings[1] are dictated by both local and global ice loading intensities. In such locations, wave loads are small by comparison and do not have any real effect on the design. Where there are deck cantilevers involved, wave slam dynamics must be designed for.

In the deepwater, more southerly basin areas where only first-year ice occurs, the platform design is primarily governed by wave loads. In these areas, it is still necessary to employ solid monolithic type structures as ice loads are still too locally intensive to permit jacket or “water transparent” type structures. However, the use of a monolithic type structure in order to eliminate local ice load effects, bridging and vibrations, results in relatively high global wave loads (an unfortunate “Catch 22” effect). In these areas, platforms similar to those proposed for the Sakhalin Island region would also be applicable.

[1] Scantlings are the interior framing members of the structure.

After ice loads, there are two other parameters that have a major effect on the global structure size optimization: water depth and foundation conditions. Generally, multi-year ice loads increase as the water depth increases, although not in direct proportion. Between 30 ft and 100 ft (10 m and 30 m) water depths, multi-year ice loads tend to increase linearly. Beyond 100 ft (30 m), multi-year ice loads continue to increase, but at a much lower rate. Thus, water depth has a twofold influence in that the deeper the water, the greater the horizontal design load, and also that the structure must increase in height and, hence, cost.

In multi-year ice areas, there are gravity base structure (GBS) solutions that would be considered safe and economical up to around 250 ft (75 m) water depths when foundation properties are good, and up to around 200 ft (60 m) water depths when foundation properties are relatively weak. <u>There are no known bottom-founded platform design solutions for the 330 ft (100 m) plus water depth range that could be deemed workable or proven for multi-year ice areas</u>. In the more southern areas, where multi-year ice is absent and only first-year consolidated ridge loadings are possible, bottom-founded solutions out to 425 ft to 500 ft (130 m to 150 m) water depths are potentially viable.

4.5.2 Foundation Conditions

The last of the three most important parameters is that of foundation strength and capacity. Foundation types range from “totally inadequate” (in which lateral relocation, excavation and/or replacement will be necessary) to “strong enough” to simply set-down directly on the seabed without any type of preparation. In the strong foundation category, there is often a thin weak layer of 3.3 to 9.8 ft (1 to 3 m) of soft, reworked cohesive material that needs to be removed. A structure can then be set-down directly onto the bottom of the shallow excavated pit. Where the soft material is only 3.3 ft (1 m) or so in thickness, it is possible to have a skirt system that will penetrate through to the stiffer material. Where the thickness of the weaker layer is 6.6 to 9.8 ft (2 to 3 m), excavation is the best solution as skirt systems that will transfer the shear from ice loads will be much more expensive than excavation.

Foundations differ widely. Even within relatively small areas it is not possible to loosely generalize with respect to foundation strength parameters. The following foundation types can be found throughout the areas of interest. The solutions suggested relate to permanent or production type structures where multi-year ice may impact the structure.

- Strong clay foundation to within 3.3 ft (1 m) of the sea bottom with an undrained shear strength of about 3 to 4 ksf (150 to 200 kPa) or greater.

Solution: Design structure with 6.6 ft (2 m) deep skirts and set directly on bottom or excavate weak layer and set-down in excavation hollow.

- Strong clay within 6.6 to 9.8 ft (2 to 3 m) of sea bottom. Solution: Excavate and set-down in bottom of excavation.
- Sandy frictional foundation or sandy frictional foundation on top of a strong clay foundation: Solution: Set-down directly on bottom, but be prepared to have an on-bottom contact force of approximately twice that required for a purely clay or cohesive foundation.
- Moderately stiff clay (with possible soft upper layer) with shear strengths in the range of 1.5 to 3.0 ksf (75 to 150 kPa. Solution: Consider the trade off between excavation and replacement and providing a very large base area to the structure.
- Weak clay foundation with shear strengths less than 1.5 ksf (75 kPa). Solution: Excavate to a specific depth and backfill with a granular material. The depth to which it is necessary to excavate could range between 16 and 82 ft (5 and 25 m), depending on the in-situ clay strength and the base area chosen for the structure. Other effects that influence the excavation depth are water depth and the magnitude of the design ice load.

With respect to foundation capacity for mobile drilling structures, the picture is somewhat different in that the structure will only be on location for a relatively short period of time. This allows for a basic design based on impact from first-year ridged ice, together with an alerts system that allows for securing the well in the event that a very large multi-year floe threatens to impact the structure. Historically, this means that temporary or exploration type structures can operate on either sandy cohesionless soils or cohesive soils that are stronger than about 600 psf (29 kPa) undrained shear strength. This 600 psf (29 kPa) minimum is not a given; the figure can be either higher or lower depending on the ratio of the water plane diameter to the base diameter of the structure. Generally, a value of 1 ksf (50 kPa) at the skirt tips will suffice for exploration drilling.

4.5.3 Location Scenarios for Proposed Structures

After a discussion on various factors that influence the choice of structures, ten (10) location scenarios are assessed with respect to the types of structures that may provide a possible solution; in addition, two (2) general structures (one with oil storage and one for mobile drilling) are assessed. Material quantities and approximate installed costs are tabled and discussed. Quantities and costs are also given for a platform in 100 ft (30 m) water depth with 331,000 tons (300,000 tonnes) of oil storage and for a typical mobile platform.

The location scenarios together with primary design assumptions are listed below in Table 4-1 and drawings for six possible solutions are included at the end of this Section.

Table 4-1: Location Scenarios – Bottom-Founded Structures

OCS Area	Option Number and (Drawing Number)	Water Depth, ft (m)	Approximate Distance Offshore, miles (km)	Governing Design Parameters
Beaufort Sea	1 (1)	33 (10)	6 (10)	Multi-year Ice, Weak Foundations
	2	100 (30)	25 (40)	Multi-year Ice, Weak Foundation[1]
	3	195 (60)	50 (80)	Multi-year Ice, Strong Foundation
	4 (2)	655 (200)[2]	55 (90)	First-year Ridges and Small Multi-year Floes
Chukchi Sea	5 (3)	100 (30)	45 (70)	Multi-year Ice, Strong Foundation
	6	195 (60)	235 (380)	Multi-year Ice, Weak Foundation
Bering Sea Norton Sound	7	33 (10)	20 (30)	First-year Ice, Sand Foundation
Norton Sound	8	65 (20)	25 (40)	First-year Ice / Waves, Weak Foundation[3]
Navarin Basin/St. Georges Basin	9 (4)	445 (135)	660/230 (1060/370)	Waves / Strong Foundation
N. Aleutian basin	10 (5)	330 (100)	30 (50)	Waves / Strong Foundation
2.2 million bbls (300,000 tonnes) Permanent Oil Storage Beaufort/Chukchi	11 (6)	100 (30)		Multi-year Ice Moderate Foundation
Mobile Drilling Platform all areas	12	33 to 115 (10 to 35)		First-year Ice on Weak Foundations to Some Multi-year When on Strong Foundations

[1] Since the ice loading conditions in the Chukchi Sea are similar to the Beaufort Sea, the foundation types chosen are reversed for the 100 ft (30 m) and 200 ft (60 m) scenarios in both areas to avoid duplication of work. In the event that material quantities are required for, say a 200 ft (60 m) weak foundation in the Beaufort, refer to the 200 ft (60 m) weak foundation in the Chukchi.

[2] At present, there is no known practical solution for a bottom-founded structure for the 655 ft (200 m) water depth in the Beaufort Sea. A semi-rigid triangular pre-stressed TLP (Semi-rigid Floater) is proposed as a solution which would permit year round exploration or early development drilling. However, it would not have the capacity to stay on location under the 100-year multi-year ice loading scenario and, hence, is not suitable for permanent production in multi-year ice areas.

[3] In Norton Sound in the 65 ft (20 m) water depth area, ice and wave loads are of the same order of magnitude. Wave loads will dominate the design from a point of view of required weight on bottom and ice loads will dominate from the aspect of local strength design.

4.5.4 Technical Feasibility of Structures

4.5.4.1 Ice Loads

In the Beaufort and Chukchi Sea areas, the 100-year design ice loading condition arises as a result of an interaction with thick multi-year ice. The load resulting from this interaction must be resisted with a factor of safety of about 1.5 with respect to the foundation (sliding and inclined bearing failure). Additionally, the structure should have a factor of safety of 1.0 against significant lateral movement or tilting under a 1000-year scenario. This load and resistance philosophy is not specified rigidly in offshore codes, but it is one that is generally accepted throughout ice-dominated areas. In the event that large quantities of oil are stored, then survivability or non-spillage may have to be demonstrated under a 10,000-year loading condition.

Since the outer shell of all structures must be designed to resist high local loads and since these local loads from first-year and multi-year ice are not terribly dissimilar (even though there could be a factor of four between the global load scenarios), the quantities of steel in a temporary drilling structure will not be much different than those in a permanent production structure. In fact, as mentioned earlier, temporary mobile structures may be more expensive due to having to cater to a set-down range rather than a specified depth.

In the case of exploration drilling, the historical approach is to establish foundation stability based on a deterministic first-year ice loading scenario and then to establish an ”alerts system” which would secure the well in the event that a large multi-year floe threatened the structure. This system works relatively well in shallower water depths where it can be almost guaranteed that large floes cannot impact the structure after freeze-up. In waters deeper than 65 to 100 ft (20 to 30 m), this approach becomes more problematic and site-specific. However, the probability of greater loads in deeper waters is often offset by a likely (but not guaranteed) increase in foundation strength that is typically observed as one goes farther offshore. Again, these arguments only apply to temporary “one well” drilling structures that have to sit on relatively weak clay foundations.

Prior to 1980, there was no real understanding of the global ice loads that could be imparted to a bottom-founded structure in the Beaufort Sea or the Chukchi Sea. The only methodology used was to establish the crushing strength (pressure) of small samples of pristine ice in the laboratory and then extrapolate directly to large contact areas. Most scientists recognized that, due to the brittleness of ice, linear extrapolation was conservative, but they had no way of knowing by how much. In 1980, in a water depth of around 100 to 130 ft (30 to 40 m), a 100-year ice load had an average consensus value of about 3,300,000 kips (1,500,000 metric tonnes or 15,000 MN).

Since that time, and particularly as a result of the Hans Island experiments in the mid 1980's, advances in the confidence of load estimation have been made. The evolution of ice load over time and with experience was presented in Figure 2-1. Today, ice scientists use probabilistic methods to determine 100-year (10^{-2}), 1000-year (10^{-3}) and 10,000-year (10^{-4}) loadings. In general, because of the slope of the ice load probability distribution curve, a factor of safety of 1.5 with respect to a 100-year load becomes the main criterion as it is more severe than survivability under the 1000-year load (and probably more severe than most 10,000-year scenarios). Such is not the case on the Canadian east coast, where icebergs are the dominant loading condition. In these areas, the 10^{-4} year loading can be up to 5 (five) times the 10^{-2} event.

When probabilistic loads are assessed, all the relevant factors (ice strength, floe size, etc.) with their individual probability distributions are fed into a Monte Carlo simulation. An important factor in this exercise is the waterline diameter of the structure being impacted. Another factor that is considered important by some is whether or not the structure has a sloping face. It is the authors' opinion and that of others (some, but not all) that the introduction of a slope will <u>not</u> reduce the loads from a large multi-year ice impact. This is because large amounts of ice can build up and crushing is then transferred to a pseudo vertical ice wall some distance back from the structure. For first-year and relatively thin multi-year ice, a slope should definitely reduce ice loads, but these scenarios do not govern the design. It is the authors' opinion that any proposal to significantly reduce the global load from a multi-year ice interaction as a result of interacting with sloping sides (as opposed to vertical sides) be viewed with skepticism.

The waterline diameters of bottom-founded structures suitable for exploration and development can be optimized to around 250 to 300 ft (75 to 90 m). Global ice loads are affected by the magnitude of the water line diameter, but not necessarily in a directly linear fashion. Also, water depth affects global multi-year loads. Between 30 and 100 ft (10 and 30 m) water depth, loads are approximately linearly affected (thickness effect) and after 100 ft (30 m) in a more modest manner (interaction frequency effect).

In the Beaufort and Chukchi Sea areas, where multi-year ice can impact structures, Table 4-2 gives approximate load ranges that modern probabilistic methods would predict. With respect to the Chukchi Sea, load ranges are given with respect to the northernmost areas.

In southern areas, close to the Bering Strait, loads can be expected to be approximately 30% less.

Table 4-2: Approximate Ice Load Ranges, Beaufort and Chukchi Seas

Water Depth, ft (m)	Approximate Value of 100-Year Design Ice Loading. Factor of Safety of 1.5 Required in Addition when Checking Foundation, kips (MN)
33 (10)	65,000 to 115,000 (300 to 500)
65 (20)	135,000 to 200,000 (600 to 900)
100 (30)	200,000 to 295,000 (900 to 1300)
130 (40)	225,000 to 315,000 (1000 to 1400)
165 (50)	245,000 to 335,000 (1100 to 1500)
195 (60)	270,000 to 360,000 (1200 to 1600)

In the event that a temporary deployment for an exploration structure is being considered, arguments as outlined above can be rationally developed such that the foundation only needs to resist first-year ice loading of the order of 45,000 to 90,000 kips (200 to 400 MN).

Local ice loading pressures are relatively independent of global design loads and they do not affect the overall external dimensions of the structure. Depending on the degree of conservatism chosen, these local ice-loading pressures can greatly affect the outer shell quantity requirements. Additionally, the outer shell design methodology is very important and whether or not it is a deformation-based design, as opposed to a stress-based design, can have an enormous effect. As an example, a typical local loading pressure could be about 435 psi (3 MPa) over approximately a 16 ft by 16 ft (5 m by 5 m) area (270 ft^2 or 25 m^2), with smaller areas having greater intensities.

4.5.4.2 Foundations

The effect of foundation strength has been discussed earlier and it must be restated that a strong foundation is a great asset to any bottom-founded development. How the structure is affected can be illustrated by the following brief example:

- Ice load: 225,000 kips (1000 MN);
- Water Depth: 155 ft (35 m) – a shallow example is presented such that inclined bearing failure will not be an issue;

- 13 ft (4 m) of cohesionless sandy material (φ=32 degrees) overlaying clay with an undrained shear strength of 3 ksf (150 kPa); and,
- Factor of safety against sliding: 1.5.

Because the top layer is frictional, resistance is a function of weight on bottom alone for this layer. The weight on bottom required is (Ice Load*FS)/(Tanφ), or about 275,000 tons (240,000 metric tonnes). This is a significant force and, depending on the structure design, it is difficult to achieve without solid ballast. Thus, even though cohesionless foundations are seen to be strong and desirable, they are not necessarily as good from an economic point of view as is a strong clay foundation. In this example, a less costly structure can be utilized if the 3 ksf (150 kPa) material came right to the surface, as approximately 165,000 tons (150,000 tonnes) only would be necessary as an on bottom weight.

In this example, as long as the on bottom weight exceeds 275,000 tons (240,000 tonnes), then the failure plane is lowered to the 3 ksf (150 kPa) interface. Now the criterion becomes one of base area contact and the base area required is given by (Ice Load*FS)/(Soil Shear Strength), or about 110,000 ft^2 (10,000 m^2). If the structure base is a square chamfered shape or octagonal, then this is equivalent to a base diameter of about 360 ft (110 m).

There are, of course, various additional checks that need to be verified (3D effects, inclined bearing, skirt effectiveness), but the basic requirements of 265,000 tons (240,000 tonnes) weight on bottom plus a base contact area of 110,000 ft^2 (10,000 m^2) need to be met for this example. A full 3D analysis could, however, lessen the base area requirement by a small amount. But there are other reasons why having a base width much less than 300 ft (90 m) can be disadvantageous (see Section below on vibrations).

There is not a lot of variation with respect to in-situ sandy granular foundation types and rudimentary checks need to be made with respect to possible liquefaction, but this has never proved to be a problem. However, with respect to the use of sand backfills, this is a different matter. Thus, stability can be achieved on all cohesionless foundations simply by means of weight alone.

However, in the event of a cohesive clay foundation, the structure base area requirement grows proportionally to the ice load and inversely as to the shear strength of the clay foundation.

There are many other reasons why a base diameter in the 330 to 400 ft (100 to 120 m) range is considered desirable and, thus, a clay shear strength of about 3 ksf (150 kPa) fits quite well and does not become an overriding design criterion. If, however, the in-situ shear strength is only about 1 ksf (50 kPa) and is relatively deep, then the only solution is to excavate and backfill with a sandy material or increase the base area size. In the above example, the base area would need to go to 323,000 ft^2 (30,000 m^2) and the base diameter to approximately 625 ft (190 m). This diameter would need to be achieved by an inverted cantilever design, but would nevertheless be extremely difficult and costly to build. The only real practical solution in this case is to excavate down to 50 ft (15 m) or so (to be determined) and then backfill with sand. Then a structure with a base of about 360 ft (110 m) could be safely deployed. *In the event that dredging and backfilling are seen to be undesirable from an environmental or political point of view, then a weak foundation may well become an economic showstopper for a gravity base structure*.

4.5.4.3 Steel vs. Concrete

Conventional wisdom in the 1980’s was that concrete arctic bottom-founded structures had the advantage over steel. At that time, local ice loads were thought to be phenomenally high, which favored thick-wall concrete as the construction material of choice. As well, steel plastic catenary mechanisms were not well understood, and this led to thicker steel “ice walls” with corresponding increases in steel weight and cost. Steel was also thought to have insufficient notch toughness for the arctic environment. Experience has proven, however, that steel is the preferred construction material of choice for high arctic and sub-arctic GBS concepts.

There are many additional implications with respect to the choice of steel versus concrete. For example, deepwater concrete concepts in the 330 to 460 ft (100 to 140 m) water depth range often attract greater wave loads due to their cylindrical shape and, thus, require greater weight on bottom (the wide cylindrical shape is required for draft and stability purposes). This greater bearing stress on the bottom will often be too severe for even moderately stiff foundations and, as a result, a greater base width is subsequently required than that of a “lighter” steel GBS. It is the authors’ experience that, in arctic or sub-arctic conditions, a concrete GBS can ultimately be made to satisfactorily perform from a technical point of view. However, experience has demonstrated (at least to the authors) that in virtually all cases where ice is involved, concrete solutions end up being close to two or more times the cost of steel solutions.

These cost factors of two or more are often not readily apparent and at first glance price differentials may not be obvious. For instance, a concrete structure can be designed relatively cheaply if it does not have to carry a full complement of topsides into the Arctic with load-out and hook-up being performed after set-down (this can also lead to decommissioning issues). Steel solutions can carry up to 33,070 tons (30,000 tonnes) or more topsides into the Arctic due to their inherent ability to be more stable and draft insensitive.

Therefore, in the shallower Beaufort and Chukchi Sea areas with water depths in the 65 to 130 ft (20 to 40 m) range, the compounded problems of draft and topsides floating stability requirements make concrete solutions very costly, as water line and flotation issues tend to govern the design.

There are additional subtleties with respect to the steel versus concrete issue. On the east coast of Canada, it is well recognized that the choice of concrete for Hibernia was essentially politically based. Again, this is perfectly in order as long as all parties recognize the cost implications. However, one of the more subtle aspects of the steel/concrete arctic suitability issue is that of the existence (or nonexistence) of proponents of either material. Essentially, the major offshore concrete contractors endeavor (as they should) to promote the good name of concrete (and, again, the only thing that the authors will cite against concrete is that the final cost to do a comparable job to steel in the Arctic will be significantly greater than that of steel). With respect to the existence of lobbyists for steel arctic construction, the shipyards of the world do not partake in promoting their capabilities. In short, if a company requires a cost for a steel platform they must take a specific design to a shipyard and seek answers. While they can construct the structure, shipyards do not have the ability to design them. Any type of design must be carried out by competent consultants. On the other hand, concrete contractors will often readily provide design, construction and cost estimating services.

4.5.4.4 Wave Loads

Wave loads in certain areas can become a primary design consideration, although for the Beaufort and Chukchi Sea areas it is generally ice loads that govern stability. There are three subsets, however, that need checking. The first is if a low cantilever overhang is included in the deck design, since wave slam can occur up to 50 ft (15 m) above the still water level. The second is the loss of on bottom contact force as the wave amplifies due to reflection at the front face of the structure. The third is shallow water.

As the water depth gets shallow, waves start to break when their height is about 80% of the water depth. Thus, in 33 ft (10 m) of water, the design wave becomes a 26 ft (8 m) breaking wave. Such a wave can exert considerably more force on a monolithic object than on its deep-water counterpart. Since ice loads are fairly low in 33 ft (10 m) water depths, it is possible that equivalence or "crisscrossing" of dominant load effects will occur around this water depth. Also, buoyancy effects can be relatively more severe.

Once moderately substantial ice is present, such as rafted ice of 1 to 2 ft (30 to 60 cm) nominal thickness, it is likely that for this and other reasons (vibrations, fatigue) the most economic structure is a solid monolithic GBS. These GBS structures have dimensions that are a substantial fraction of the impacting wavelength and, as a result, the dominant wave loads are inertial rather than drag based. Generally, inertial loads are proportional to the displacement or volume of the structure, a diameter squared function, while drag is proportional to diameter only. Furthermore, inertial loads are proportional to the maximum acceleration of the individual wave particle and maximum inertial loads tend to occur at still water, whereas maximum drag loads occur when the crest passes the structure. Since wave particle accelerations are greatest close to the water line and least at the seabed, it makes great sense to try and give a "pyramid" or conical shape to the structure in order to reduce inertial wave loads if the structure is to be deployed in deepwater, e.g., 200 to 445 ft (60 to 135 m), particularly if the accompanying ice loads are low. In shallower water where ice loads are high, there is no real benefit. However, in the US and Chukchi Sea areas, it makes sense (for other reasons) to start stepping the structure when the water depth reaches around the 165 ft (50 m) mark, if constructed of steel.

Accurate evaluation of wave loads involves the use of sophisticated computer programs that take into account wave diffraction effects on large structures of arbitrary shape. The final load is a function of wave height, water depth, wavelength, wave period and, most importantly, the specific shape of the structure. This is a time consuming and iterative effort. However, it has been carried out with respect to several structures and extrapolations have been estimated based on certain empirical rules. The loads shown in Table 4-3 below are approximate and are based on "pyramidal" or stepped structures being used in the deeper areas of interest.

Changing the shape from cylindrical to conical can have load reduction effects of 50% or more (this effect is graphically illustrated below in Figure 4-2). Such conical shapes are easy to achieve with steel but costly for concrete, and since the vertical centre of gravity (VCG) of the steel conical shape can be lowered by the use of solid ballast, very large amounts of topsides can be carried due to its relatively high hydrostatic stability. In the case of concrete, it is hard to lower the VCG without a very severe impact on the final draft and, hence, concrete solutions always tend to have issues relating to draft versus maximum topsides stability.

The following Table 4-3 illustrates approximate wave loading magnitudes in the location scenarios of interest. A very large variable is the shape or displacement of the structure itself. The maximum deep-water height input is assumed to be about 90 ft (28 m) in the southern basin areas and about 40 ft (12 m) in the Beaufort and Chukchi Sea areas. Structural shapes and displacements are based on the authors' experience of what is appropriate.

Table 4-3: Table of Wave and Ice Loads Used in Materials and Cost Estimation

OCS Area	Water Depth, ft (m)	Approximate Distance Offshore, miles (km)	Approximate Magnitude of 100-Year Wave Loading Base Shear on Typical Steel GBS Structure with Approximate Median 100-Year Ice Load in Brackets for Comparison, kips [MN]
Beaufort Sea	33 (10)	6 (10)	67,000 (90,000) [300 (400)[1]]
	100 (30)	25 (40)	90,000 (247,000) [400 (1100)]
	200 (60)	50 (80)	135,000 (315,000) [600 (1400)]
Chukchi Sea	100 (30)	45 (70)	90,000 (247,000) [400 (1100)]
	200 (60)	235 (380)	135,000 (315,000) [600 (1400)]
Bering Sea Norton Sound	33 (10)	20 (30)	67,000 (67,000) [300 (300)]
Norton Sound	65 (20)	25 (40)	90,000 (67,000) [400 (300)]
Navarin Basin/St George	445 (135)	660/230 (1060/370)	281,000 (45,000) [1250 (200)]
North Aleutian Basin	330 (100)	30 (50)	225,000 (45,000) [1000 (200)]

[1] While wave height is limited due to water depth the combination of storm surge and breaking waves can result in high loads

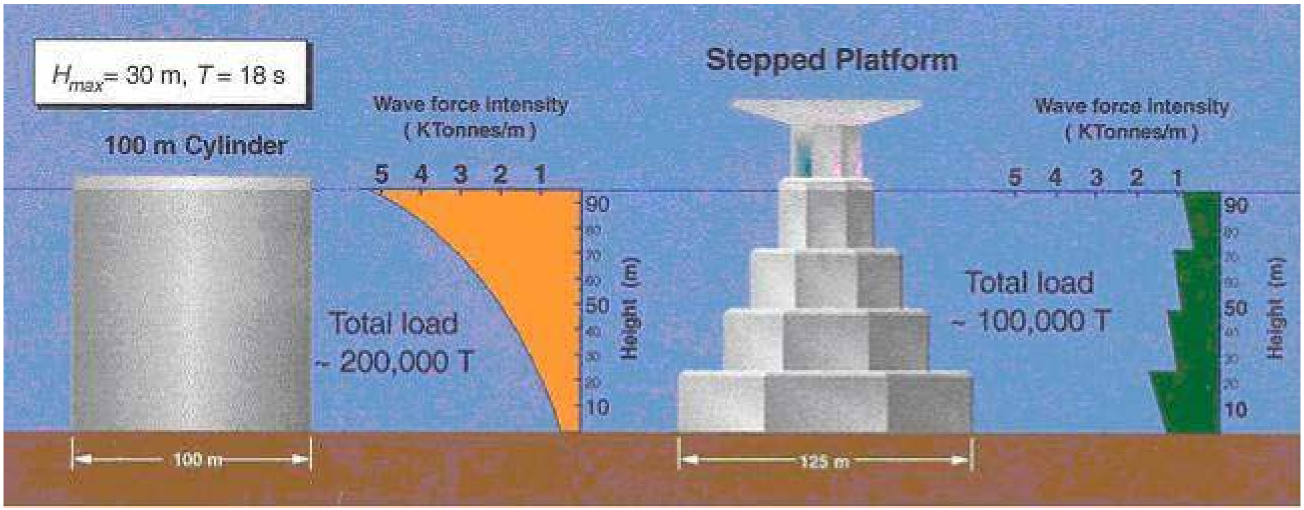


Figure 4-2: Wave Load Comparison of Hibernia-type GBS vs. Stepped-style GBS (Fitzpatrick and Kennedy, 1997)

4.5.4.5 Gravity & Foundation Reaction Loads

The foundation reacts to the structure and must have sufficient contact area to provide a factor of safety against sliding of 1.5 with respect to the 100-year (10^{-2}) design ice load and/or about 1.0 with respect to the 10^{-3} to 10^{-4} year load. Foundation reaction loads for a GBS are often overlooked, trivialized or their significance ignored. Reaction pressures possible on the bottom of a GBS are so varied in their intensity and location throughout the base area that it is useful to view the reaction pressures as “loads” rather than “supports”. As detailed in Fitzpatrick (1994), the recommended approach is to design the base from a pressure-area curve, similar to the ice load envelope curves that are traditionally used to establish the outer shell strength requirements.

Experience has shown that, even when soils are soft, very high local pressures can build up locally against the base of an offshore structure. These pressures are of the same order of magnitude as ice load pressures, which means that the structure base needs to be “as strong” as the vertical sides. This is an important consideration for GBS concepts in the areas of interest and makes such concepts sensitive to site-specific geotechnics. Once again, foundation conditions can be a significant factor in the technical and economic feasibility of GBS platforms.

For an exploration or mobile structure, skirt systems that cater to varying soil conditions are virtually mandatory. In some instances in mobile structures, where the skirts have been specifically designed for a range of soil conditions, complete penetration may not be achievable where soils are tough. Generally, skirts on mobile arctic structures need to be about 6.6 ft (2 m) high to cater to varying conditions. For permanent structures, the skirts can be designed to site-specific conditions. However, full penetration must be assured as differential settlements over the years could be a problem. Skirts are necessary in order to penetrate to undisturbed clay and, in the case of sandy foundations, to ensure sand particle to sand particle frictional resistance. Generally though, skirts for permanent structures will be thin to ensure complete penetration and will only need to be about 3.3 ft (1 m) or so in height.

4.5.4.6 Vibratory Loads

GBS structures are very large-based massive structures. The resulting presence of significant radiation damping available from the foundation – provided the base is greater than 330 ft (100 m) – plus the large mass, minimizes vibrational effects to a level of around 5 to 10% of gravity with a total system frequency on the order of 1 Hz. Potential vibratory effects from, for example, continuous first-year light ice are therefore of minor concern.

Radiation damping plays a significant role in eliminating the dynamic amplification of forced vibrational effects from ice. It is a complicated phenomenon, but its effects grow in accordance with a power law function of the base diameter of the structure. With a base diameter in the region of 165 to 200 ft (50 to 60 m), serious vibrations from even light first-year ice should be anticipated. With base diameters in the region of 330 ft (100 m), experience to date shows that sufficient damping is available such that dynamics will not be amplified to a level that would cause concern for stability or operations. While the platform is relatively unaffected, the topsides should be designed for seismic events or about 0.2 g due to vibration, unless it can be rigorously demonstrated that lesser levels are permissible.

4.5.4.7 Seismic Loads

The general Chukchi and Beaufort Sea regions may be categorized as those of relatively low seismicity. The Camden Bay area could be described as low to moderate. The base acceleration levels are so low so as not to be a design condition for the GBS structure itself. However, in most areas (and also because of low level ice vibrations) all topsides will require some lateral stiffening requirements.

However, towards the southern areas of interest close to the Aleutians, seismic activity will be a major design concern. Even though structures are to be designed for the very high seismic loads in these locations, these loads will not significantly affect the overall size or cost of the basic platform, but rather will require greater attention to foundation capacity. Additionally, some dynamic amplification will result in greater topsides stiffening or isolation requirements.

With a steel GBS, the VCG in deepwater seismic areas is very low (due to the enormous amount of concrete ballast required) and dynamic amplification of base shear through to the topsides is minimized. With a concrete GBS, the VCG is higher and greater vibratory effects (rocking) may well be sensed at the topsides location. There are cut-off points with respect to allowable vibrational levels and, in some instances, topsides isolation mechanisms may be deemed necessary. However, this last point is a relatively subtle technical difference between the two materials.

4.5.4.8 Fatigue Loading, Brittle Fracture, & Temperature Effects

The day-to-day loads from ice or waves induce only very low levels of stress in these types of GBS structures. When the level of load gets moderately high, there are only a very small number of cycles. Experience with arctic structures to date indicates that neither fatigue nor brittle fractures are governing design factors. Brittle fracture is, of course, a different phenomenon than fatigue, but because of the relative thinness of steel required and the great advances in cooling technology, the ductility of modern steels can be guaranteed at temperatures down to -58°F (-50°C) without any great premium in cost.

The effects of temperature are considered secondary and are not driving factors in determining the size and geometry of steel structures. Differential temperatures of 100°F to 125°F (40°C to 50°C) across a structure can be easily handled by steel. However, differential temperature stresses, in combination with ballasting and differential settlement effects, can be a more serious concern for the long-term serviceability of concrete, e.g., liquids tightness and crack control. For concrete, these effects can become a significant design condition and solutions may require very high levels of multi-axial pre-stressing steel. The effects are more pronounced in relatively shallow waters, 33 to 100 ft (10 to 30 m) where high shear stresses can build up in the concrete due to differential settlements.

4.5.4.9 Oil Storage Effects

Depending on the water depth and the foundation type, a certain amount of potential oil storage capacity can be provided relatively cheaply. All oil storage concepts to date in the Arctic are of the oil/water type. Oil/air concepts become enormously expensive, are viewed as more dangerous and, to date, a concept that no one has considered seriously. A certain amount of oil storage is generally considered to be reasonably “free” due to the other design and functional requirements of the structure.

In the event that the foundation is granular and great weight on bottom is required, then this initial amount of “free” storage can be higher than if the platform sits on a clay foundation, where much less weight is required on bottom.

This initial ”free” storage amount, therefore, depends on the water depth, the foundation type, the structure volume and whether or not solid ballast as opposed to water is used in the free space. This initial “free amount” is not entirely free, though, as double hulls must be provided. It would be reasonable to allow 5% of the basic structure cost as an addition to cater for the additional bulkheads. Again, this initial ”free” storage varies from concept to concept and can have values ranging from a few hundred thousand bbls up to 1.5 million bbls or more.

After this initial amount of relatively free storage, any additional barrels must be provided for by specifically increasing the volume of the platform. This increase in volume requires a certain amount of steel, about 55 to 66 lb/bbl (25 to 30 kg/bbl) and this approximately translates to $125-$150/bbl capital cost. Not a tremendous amount if the extra volume is only about 100,000 bbls ($12.5 MM to $15 MM), but a considerable figure if one requires extra storage of about 1,000,000 bbls which would cost around $125 MM to $150 MM extra.

Only one of the examples for which material quantities and costs are estimated in this report caters to oil storage; Option 11, Drawing No. 6 which contains storage for 331,000 tons (300,000 tonnes) or 2,200,000 million bbls of oil.

4.5.4.10 Platform Concepts

Platform concepts as the result of this study are reflected in Table 4-4, Table 4-5, and Table 4-6, and Drawings 1 to 6 provided in Figure 4-3 through Figure 4-8, respectively.

Table 4-4: Platform Particulars Options 1 to 4

Property/Site	Beaufort Sea Drawing No 1	Beaufort Sea	Beaufort Sea	Temporary Drilling Only, in Beaufort and Chukchi Seas Drawing No 2
Water depth, ft (m)	33 (10)	100 (30)	200 (60)	655 (200) plus
Median Ice Load, kips (MN)	90,000 (400)	250,000 (1100)	315,000 (1400)	150 to 200
Wave load, kips (MN)	65,000 (300)	90,000 (400)	135,000 (600)	Varies
Foundation Conditions	Weak	Weak	Strong	Varies
Base Diameter, ft (m) and [Base Area, ft^2 (m^2)]	360 (110) [130,000 (12,100)]	427 (130) [151,000 (14,000)]	377 (115) [118,000 (11,000)]	n/a
Overall Height from Tip of Skirts to Top of Main Deck, ft (m)	82 (25)	151 (46)	259 (79)	n/a
Quantity of Steel Required (EH36 OLAC), tons (tonnes)	25,000 (23,000)	55,000 (50,000)	77,000 (70,000)	83,000 (75,000)
Weight on Bottom. tons (tonnes)	121,000 (110,000)	303,000 (275,000)	165,000 (150,000)	n/a
Excavation and [Backfill Quantities], ft^3 (m^3)	7,000,000 (200,000) [7,000,000 (200,000)]	53,000,000 (1,500,000) [58,000,000 (1,650,000)]	1,400,000 (40,000) 2 m soft	n/a
Ballast Concrete Required SG 2.3, tons (tonnes)	41,000 (37,000)	66,000 (60,000)	165,000 (150,000)	132,000 (120,000) Steel Scrap
Displacement Including 30,000 tonnes Topsides, tons (tonnes)	99,000 (90,000)	154,000 (140,000)	275,000 (250,000)	n/a
Minimum Draft Including Topsides and Solid Ballast, ft (m)	30 (9)	65 (20)	100 (30)	n/a

Table 4-5: Platform Particulars Options 5 to 8

Property/Site	Chukchi Sea Drawing No 3	Chukchi Sea	Norton Sound	Norton Sound
Water Depth, ft (m)	100 (30)	200 (60)	33 (10)	65 (20)
Median Ice Load, kips (MN)	250,000 (1100)	315,000 (1400)	65,000 (300)	65,000 (300)
Wave Load, kips (MN)	65,000 (400)	135,000 (600)	65,000 (300)	90,000 (400)
Foundation Conditions	Strong	Weak	Strong Sand	Weak
Base Diameter, ft (m) and [Base Area, ft^2 (m^2)]	360 (110) [110,000 (10,000)]	375 (115) [120,000 (11,000)]	360 (100) [110,000 (10,000)] Square Base	395 (120) [150,000 (14,000)]
Overall Height from Tip of Skirts to Top of Main Deck, ft (m)	165 (50)	253 (77)	82 (25)	118 (36)
Quantity of Steel Required (EH36 OLAC), tons (tonnes)	44,000 (40,000)	77,000 (70,000)	22,000 (20,000)	44,000 (40,000)
Weight on Bottom, tons (tonnes)	110,000 (100,000)	330,000 (300,000)	110,000 (100,000)	165,000 (150,000)
Excavation and [Backfill Quantities], ft^3 (m^3)	1,800,00 (50,000)	61,800,000 (1,750,000) [65,300,000 (1,850,000)]	None	35,300,000 (1,000,000) [38,800,000 (1,100,000)]
Ballast Concrete Required SG 2.3. tons (tonnes)	50,000 (45,000)	165,000 (150,000)	38,500 (35,000)	44,000 (40,000)
Displacement Including 30,000 tonnes Topsides, tons (tonnes)	127,000 (115,000)	275,000 (250,000)	94,000 (85,000)	121,000 (110,000)
Minimum Draft Including Topsides and Solid Ballast, ft (m)	65 (20)	100 (30)	26 (8)	56 (17)

Table 4-6: Platform Particulars Options 9 to 12

Property/Site	Navarin Basin Drawing No 4	North Aleutian Basin Drawing No 5	Typical Platform with 300,000 tonnes of Storage Drawing No 6	Typical Mobile Drilling Platform
Water Depth, ft (m)	445 (135)	330 (100)	100 (30)	33 to 115 (10 to 35)
Median Ice Load, kips (MN)	45,000 (200)	45,000 (200)	295,000 (1300)	Varies
Wave Load, kips (MN)	280,000 (1250)	225,000 (1000)	100,000 (450)	Varies
Foundation Conditions	Strong Sand on Strong Clay	Strong Sand With/Without Strong Clay	Moderate	See Discussion, Weak to Very Strong
Base Diameter, ft (m) and [Base Area, ft^2 (m^2)]	475 (145) [185,000 (17,000)]	410 (125) [140,000 (13,000)]	330 (100) [110,000 (10,000)] Square Shape	425 (130) [150,000 (14,000)]
Overall Height from Tip of Skirts to Top of Main Deck, ft (m)	560 (170)	445 (135)	245 (75)	185 (56)
Quantity of Steel Required (EH36 OLAC), tons (tonnes)	176,000 (160,000)	88,000 (80,000)	94,000 (85,000)	61,000 (55,000)
Weight on Bottom, tons (tonnes)	496,000 (450,000)	386,000 (350,000)	303,000 (275,000)	Varies
Excavation and [Backfill Quantities], ft^3 (m^3)	None	None	18,000,000 (500,000) [18,000,000 (500,000)]	None
Ballast Concrete Required SG 2.3, tons (tonnes)	507,000 (460,000)	507,000 (460,000)	None	11,000 (10,000)
Displacement Including 30,000 tonnes Topsides, tons (tonnes)	717,000 (650,000)	628,000 (570,000)	127,000 (115,000)	83,000 (75,000 [Only 10,000t Topsides])
Minimum Draft Including Topsides and Solid Ballast, ft (m)	165 (50)	245 (75)	40 (12)	26 (8)

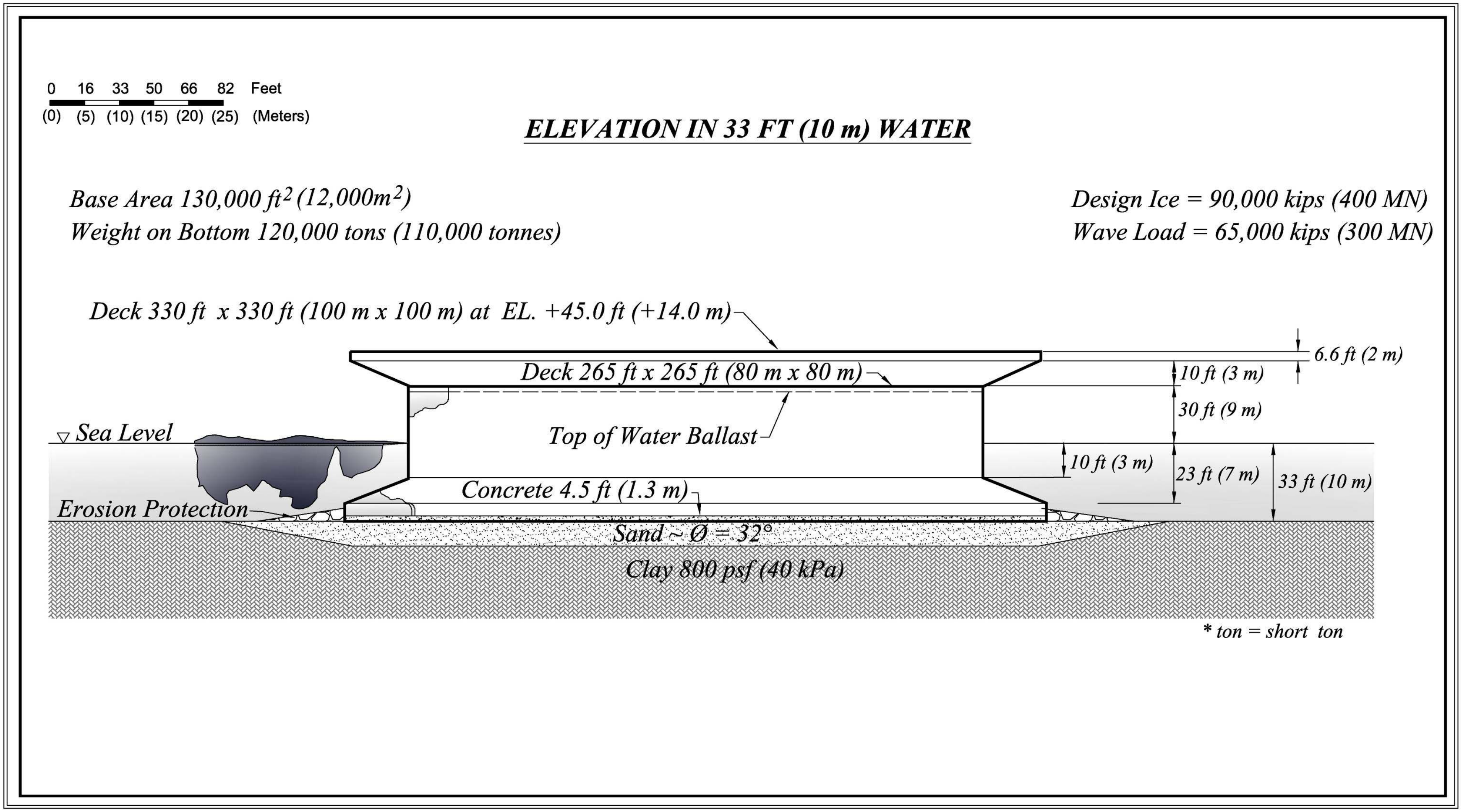


Figure 4-3: Drawing No.1, Option No.1 – Platform and Foundation for 33 ft (10 m) of Water

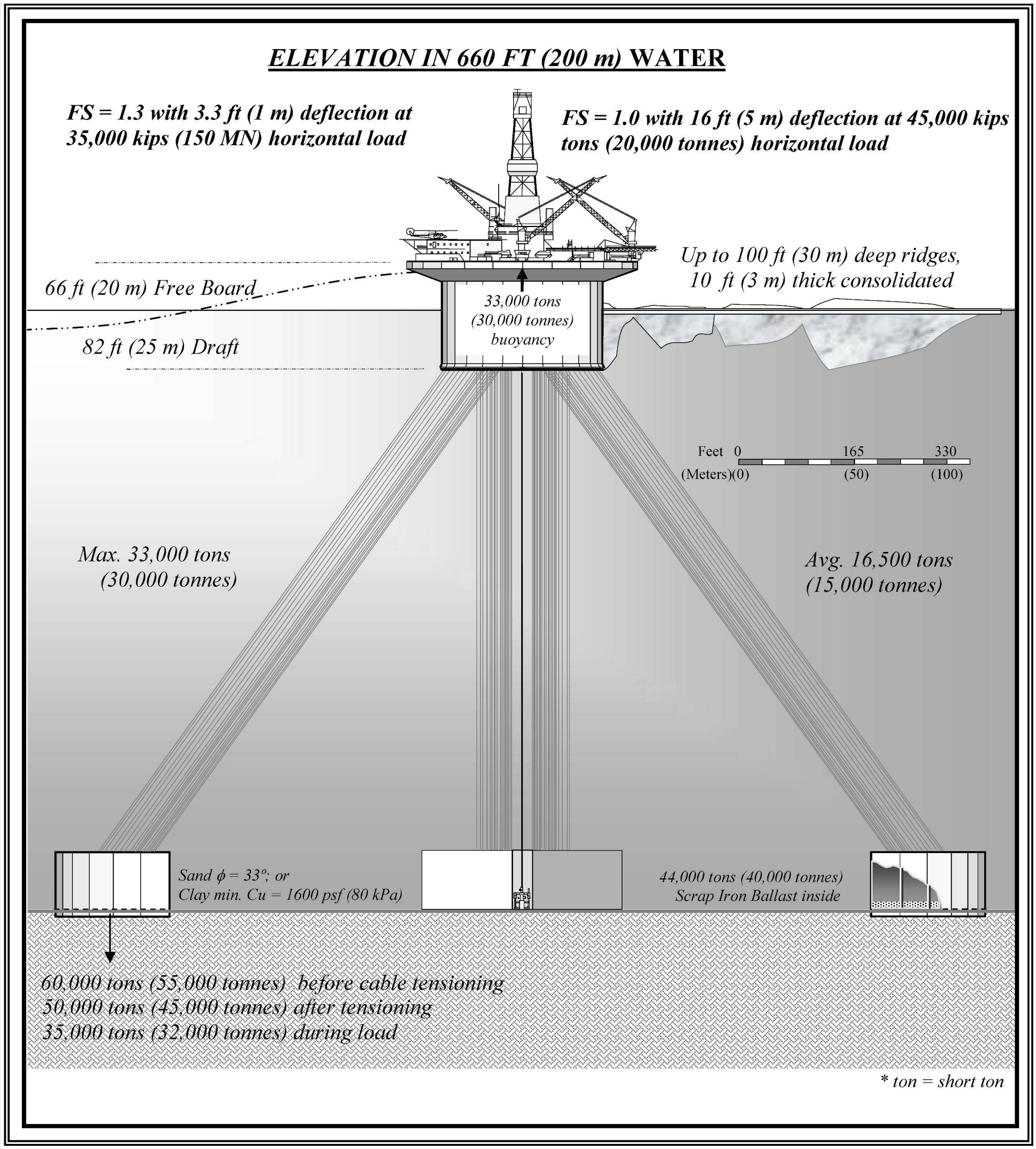


Figure 4-4: Drawing No.2, Option No.4 – 660 ft (200 m) Plus Mobile Exploration Concept

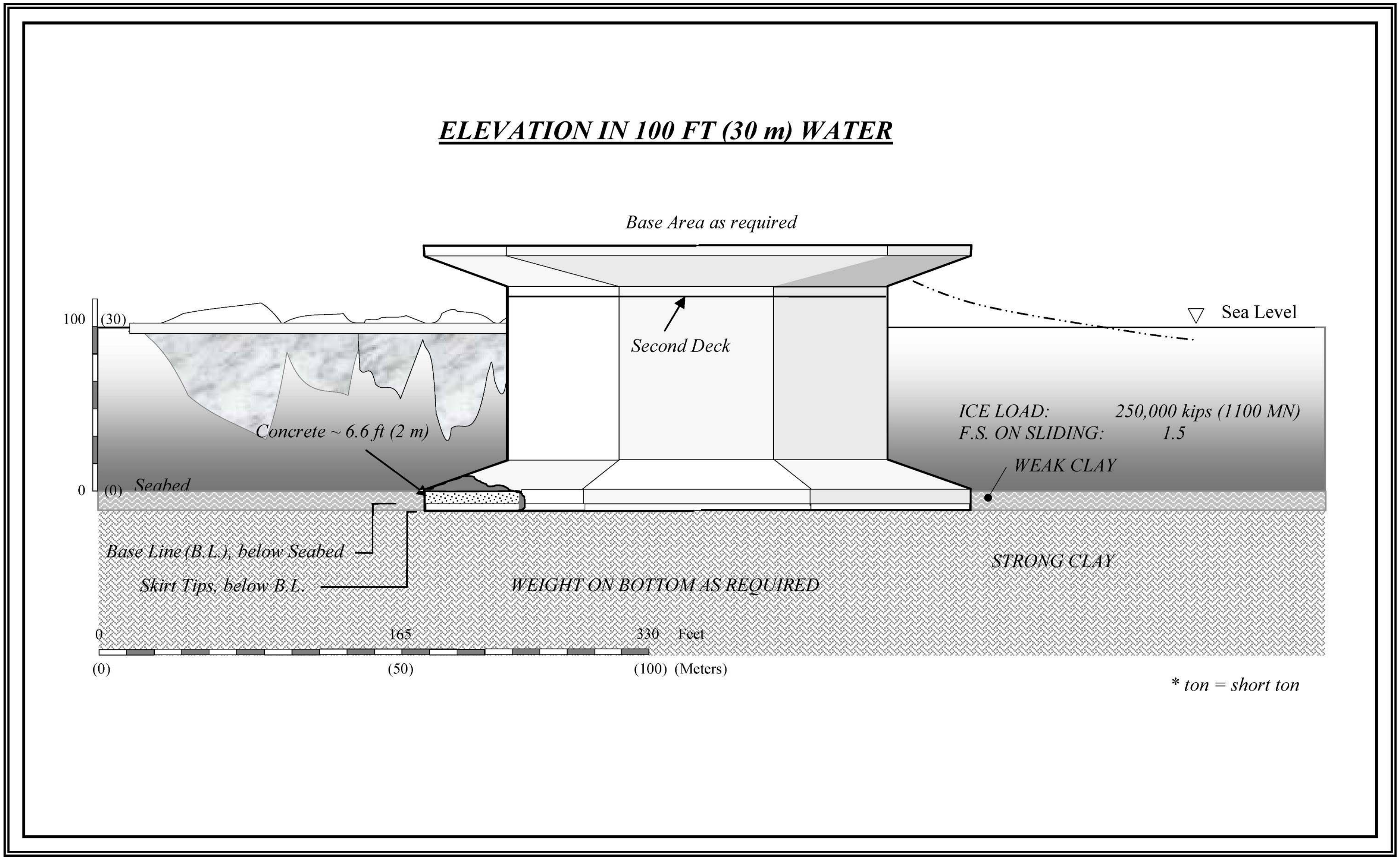


Figure 4-5: Drawing No.3, Option No.5 – Platform and Foundation for 100 ft (30 m) of Water

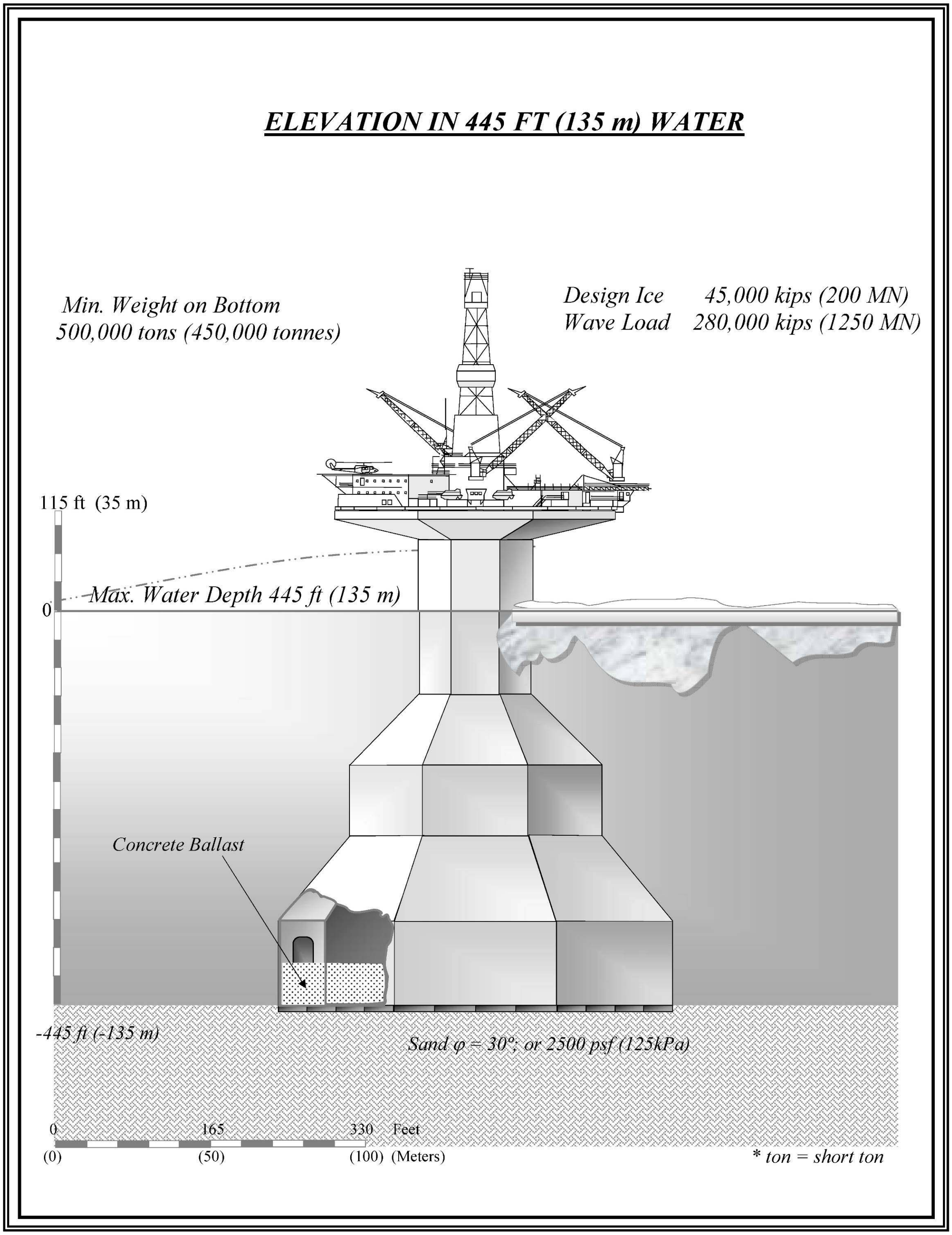


Figure 4-6: Drawing No.4, Option No.9 – 445 ft (135 m) Stepped Steel Structure

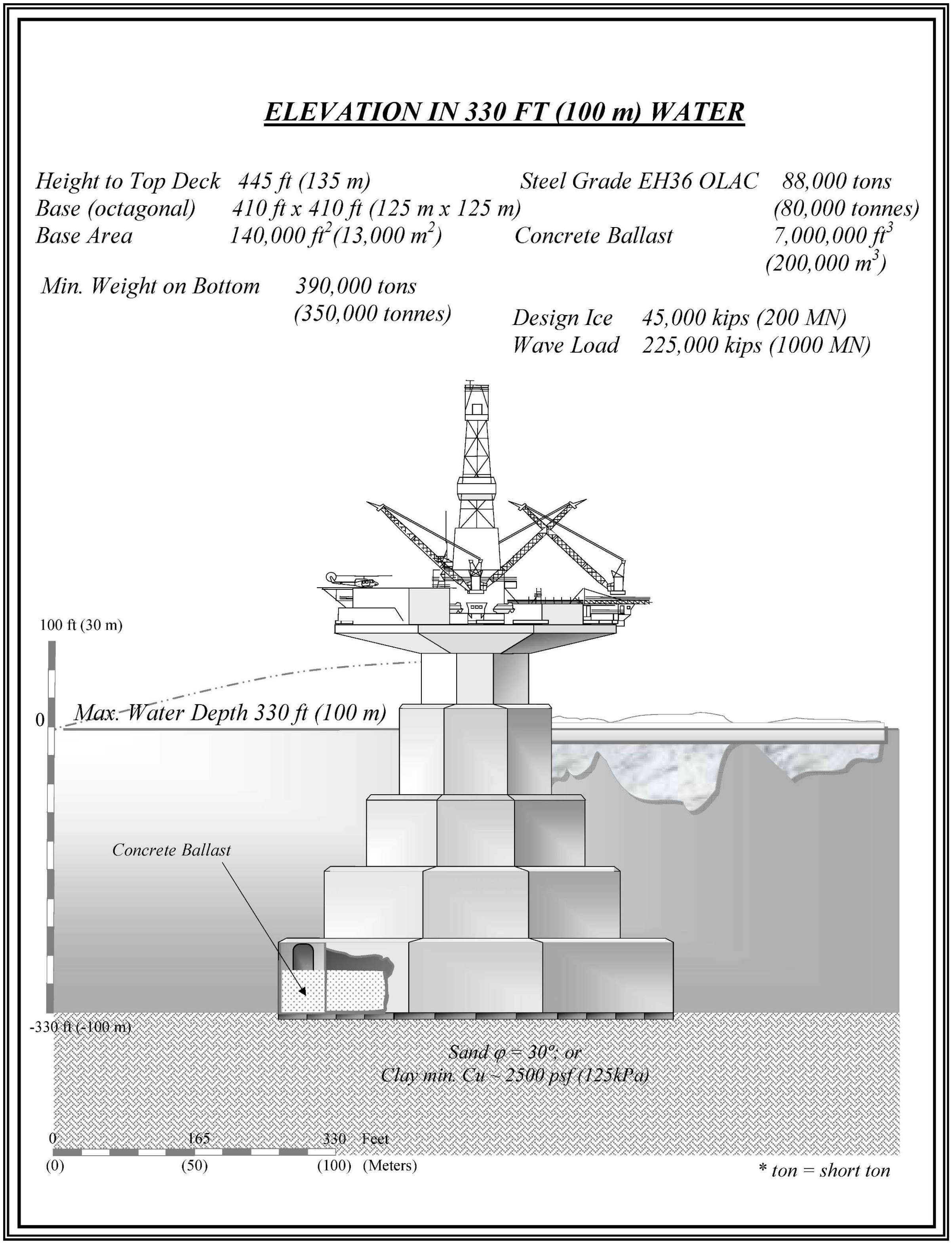


Figure 4-7: Drawing No.5, Option No.10 – 330 ft (100 m) Stepped Steel Structure

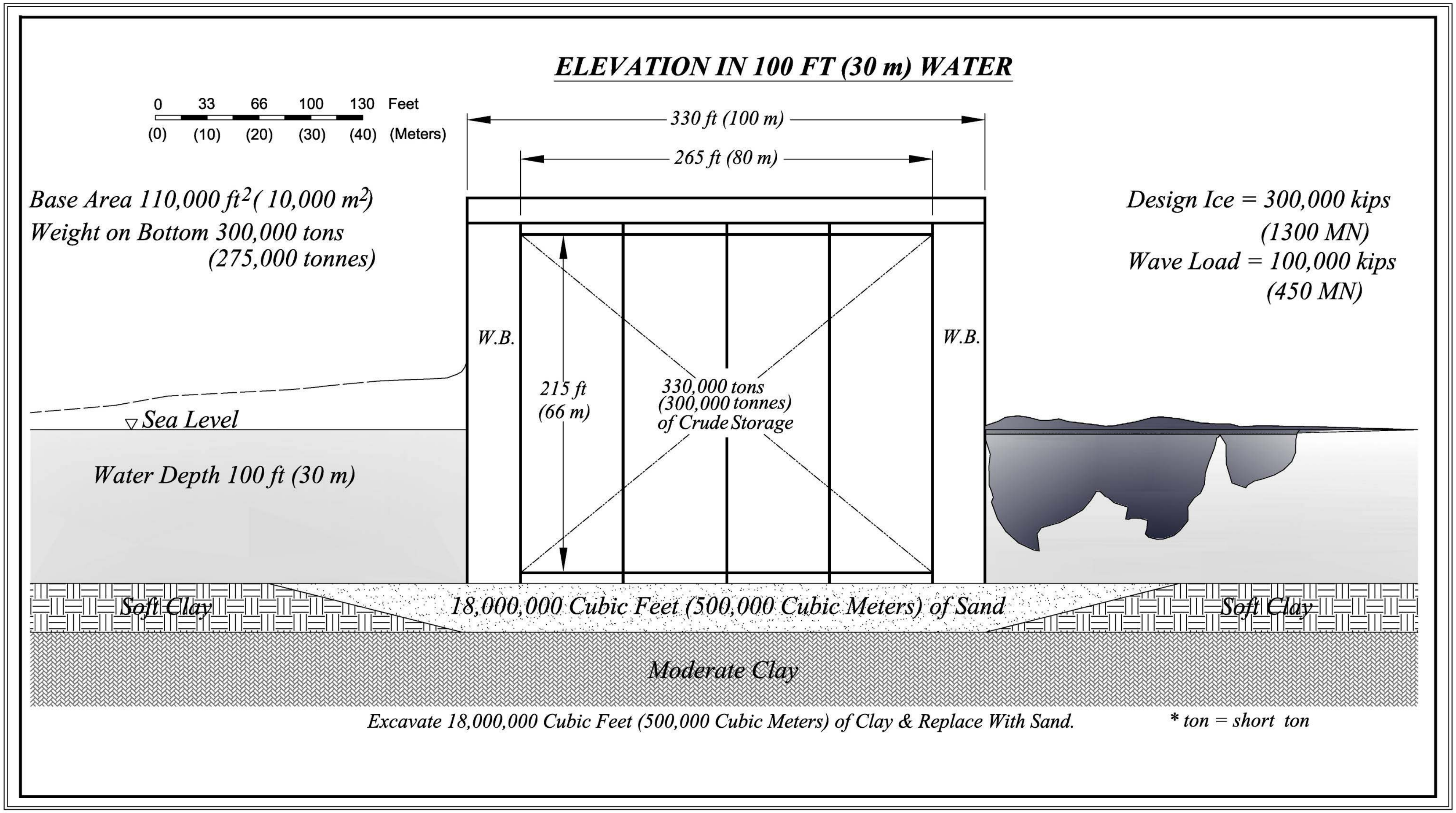


Figure 4-8: Drawing No.6, Option No.11 – 100 ft (30 m) Storage Hull Transverse Section and Design Particulars

4.5.5 Constructability

In the early-1990's, a Canadian firm (CANMAR) set the scope for, funded, and executed a major full-scale and partial-scale testing program for steel structures for use in ice-infested waters. The testing program was designed to quantify the degree of conservatism inherent in the state-of-the-art at that time and to demonstrate that significant savings in steel weight (and cost) were possible.

Four basic types of tests on low temperature ductile steel were conducted. The first two were plate and stiffener tests with hydrostatic pressure loading and the results were directly applicable to the outside wall and base of an arctic steel gravity structure. The last two tests were in-plane loading tests, and the results were used to improve the design performance of internal bulkheads (the members that transfer global loads through to the foundation). The testing program was carried out in Edmonton and demonstrated that steel weight savings of 25% to 30% were possible. When combined with increased ease of construction, total cost savings exceeded 30% compared to the best existing state-of-the-art at that time.

A technical paper, *State-of-the-art of Bottom-Founded Arctic Steel Structures* (Fitzpatrick, 1994), discusses the underlying engineering principles and the verification of these principles by the testing program. Additionally, CSA S473, the Canadian code for offshore steel structures in arctic regions, endorses the methodologies proven in that particular program.

The examples and steel quantities in this report incorporate the weight savings implied by the use of these latest design methodologies. The structures presented in this report could be constructed by a number of shipyards around the world.

Installation of a GBS structure in the Alaskan OCS will not be dissimilar to installations on Sakhalin, on the Grand Banks and in the North Sea. Weather and seasonal operational effects such as the presence of sea ice and freezing spray must naturally be taken into account, but structure draft, foundation preparation and decommissioning are considered to be more important issues.

Towing experience suggests that an average GBS platform can be towed at a speed of 3 to 4 knots. For a steel GBS, set-down at the site would be very rapid, taking only a few hours depending on the accuracy required. If the allowable location tolerance is around 16 to 33 ft (5 to 10 m), this could be achieved by floating vessels only. In the event that set-down accuracy of about 3.3 ft (1 m) is required, an anchored spread and a day or more of calm weather will be required. There should be no reason for extreme set-down accuracy unless the unit is required to sit precisely over pre-installed seabed systems, e.g., wellhead templates, pipeline connection, etc.

4.5.5.1 Foundation Issues

Relief in the seafloor topography resulting from ice gouging could affect the final placement location of a bottom-founded structure, although this should be evident from site surveys early in the project. Large gouges in the seafloor may require attention, as the bottom of the GBS structure needs to “bridge” these gaps. However, a small lateral transfer is all that is necessary.

As discussed in Section 4.5.4, of greater concern for bottom-founded structures is the soil strength profile at the installation site and the possible need for foundation improvement. Sites with soft/weaker upper layers may require excavation of these layers to expose the stronger soils below. This will either add to the overall height of the platform or require backfilling of the excavation with more competent material.

4.5.5.2 Weather Window

During installation, there will be some sea state limitations, but these are fairly well understood and are not considered showstoppers. Because the structures proposed have short skirt systems and are not reliant on foundation grouting, basically all that is required is to get the structure on location within +/-33 ft (+/-10 m) and then flood quickly. Normally, it takes up to 24 hours to get the structure located and flooding started.

With the structures proposed in this study, it is assumed that there will be a 33 ft (10 m) lateral tolerance on the set-down area. Then, with a reasonable spread of tugs and cables, set-down should be achievable in approximately a sea state of 10 to 13 ft (3 to 4 m) or more. Wind can be a potential issue; a 20 knot wind is not a problem but if winds are in the 40 knot range, installation becomes more difficult.

4.5.6 Capital Costs

In 1997, a very thorough cost investigation was carried out with respect to a stepped steel GBS for 310 ft (95 m) of water on Canada’s east coast. These 1997 costs are included in brackets alongside today’s estimated costs for the suggested North Aleutian Basin GBS solution, as it is similar in nature. It can be seen that the tabularized costs have been estimated as approximately **twice the 1997 costs**. There is no real justification for the large cost increases quoted other than that shipyards today are very busy with highly profitable facilities work and that they choose to ignore lower profitability work.

It is the author's opinion that a steel GBS could be built for much less than that indicated in the Table 4-7 through Table 4-9 and that shipyards would still make a significant profit.

An important way to significantly reduce the tabularized costs is to allow the shipyard to engineer and fabricate most of the facilities. As a result, one will get a much better price for the basic GBS. The costs shown assume that one has gone to bid with at least three far eastern yards (China excluded) on an open market and that nothing else other than the basic platform is being contracted. Chinese yards could be cheaper, but they are very unpredictable in their responses.

Table 4-7: Estimated 2007 Installed Platform Costs, in Millions of USD, Exclusive of Topsides Costs if Platform Only is Contracted to Shipyard, Options 1 to 4

Item	Beaufort Sea Drawing No 1	Beaufort Sea	Beaufort Sea	Temporary Drilling Only in Beaufort and Chukchi Seas Drawing No 2
Steel Fabrication ($MM)	140	300	420	450
Concrete Ballast ($MM)	5	7	17	30 (Steel Ballast)
Outfitting ($MM)	20	25	30	100
Foundation Excavation and Replacement if Necessary ($MM)	30	100	11	None
Towing to Site and Installation ($MM)	15	20	25	25
Engineering and Approvals (GBS Only) ($MM)	15	20	25	30
Contingency ($MM)	35	98	132	65
Totals ($MM)	**260**	**570**	**660**	**700**
Site Water Depth, ft (m)	33 (10)	100 (30)	200 (60)	655 (200) Plus
Cost in $Millions/meter of Water Depth, $MM/ft ($MM/m)	7.9 (26)	5.7 (19)	3.3 (11)	Less Than 1.1 (3.5)

Table 4-8: Estimated 2007 Installed Platform Costs, in Millions of USD, Exclusive of Topsides Costs if Platform Only is Contracted to Shipyard, Options 5 to 8

Item	Chukchi Sea Drawing No 3	Chukchi Sea	Norton Sound	Norton Sound
Steel Fabrication ($MM)	240	420	120	240
Concrete Ballast ($MM)	5	17	4	5
Outfitting ($MM)	25	30	20	20
Foundation Excavation and Replacement if Necessary ($MM)	11	110	0	75
Towing to Site and Installation ($MM)	15	30	10	15
Engineering and Approvals (GBS Only) ($MM)	20	25	15	20
Contingency ($MM)	64	153	26	55
Totals ($MM)	**380**	**785**	**195**	**430**
Site Water Depth, ft (m)	100 (30)	200 (60)	33 (10)	65 (20)
Cost in $Millions/meter of Water Depth, $MM/ft ($MM/m)	3.8 (12.7)	3.9 (13.1)	5.9 (19.5)	6.6 (21.5)

Table 4-9: Estimated 2007 Installed Platform Costs, in Millions of USD, Exclusive of Topsides Costs if Platform only is Contracted to Shipyard, Options 9 to 12

Item	Navarin Basin Drawing No 4	North Aleutian Basin Drawing No 5	Typical Platform with 300,000 tonnes of Storage Drawing No 6	Typical Mobile Drilling Platform
Steel Fabrication ($MM)	960	480 [280][1]	510	330
Concrete Ballast ($MM)	51	51 [25]	0	2
Outfitting ($MM)	50	50 [25]	75	20
Foundation Excavation and Replacement if Necessary ($MM)	0	0	45	0
Towing to Site and Installation ($MM)	70	60 [20]	15	10
Engineering and Approvals (GBS Only) ($MM)	35	30 [25]	25	10
Contingency ($MM)	334	129 [25]	130	78
Totals ($MM)	**1500**	**800 [400]**	**800**	**450**
Site Water Depth, ft (m)	445 (135)	330 [100]	100 (30)	33 to 115 (10 to 35)
Cost in $Millions/meter of Water Depth, $MM/ft ($MM/m)	3.4 (11.1)	2.4 [1.2] (8.0 [4.0])	8.0 (26.7)	3.9 (12.9) [Based on Max. Set-down Depth]

[1] Values and costs in brackets for North Aleutian Basin (Drawing No 5) are average values and costs obtained from 4 Shipyards in 1997 with respect to similar structure.

In Figure 4-9 below, 9 (nine) of the cost-estimated options are plotted. The estimated cost (Y-axis) is in millions of USD per foot (and per meter) water depth and the water depth (X-axis) is measured in feet (and meters). Options 1, 8, 2 and 6 represent structures on weak foundations. The remainder represent structures on strong foundations.

As an example of how the graph could be interpreted, consider a 165 ft (50 m) water depth. For a weak foundation, a cost of about $15 million/m can be read from the figure. Similarly, for a strong foundation the appropriate value is $11.5 million/m.

The relationship with the constructing shipyard and whether or not that shipyard is also involved with topsides construction must be considered. This constitutes an approximate 0.75 possible reduction factor for the platform.

Consider the following two permutations:

- 165 ft (50 m) water depth, good foundation and shipyard involved with topsides. The cost of a platform would then be $11.5 MM/m times 50 m times 0.75, which equals approximately $430 million.
- 165 ft (50 m) water depth, weak foundation and no shipyard relationship concerning topsides. The cost of platform would then be $15 MM/m times 50 m, which equals approximately $750 million.

Thus, even if the water depth and the ice loading conditions are perfectly defined, there is still the possibility of a wide variance in cost. In this simple example, depending on just the variance of two parameters (shipyard relationship and foundation conditions), the cost can vary between $430 million and $750 million.

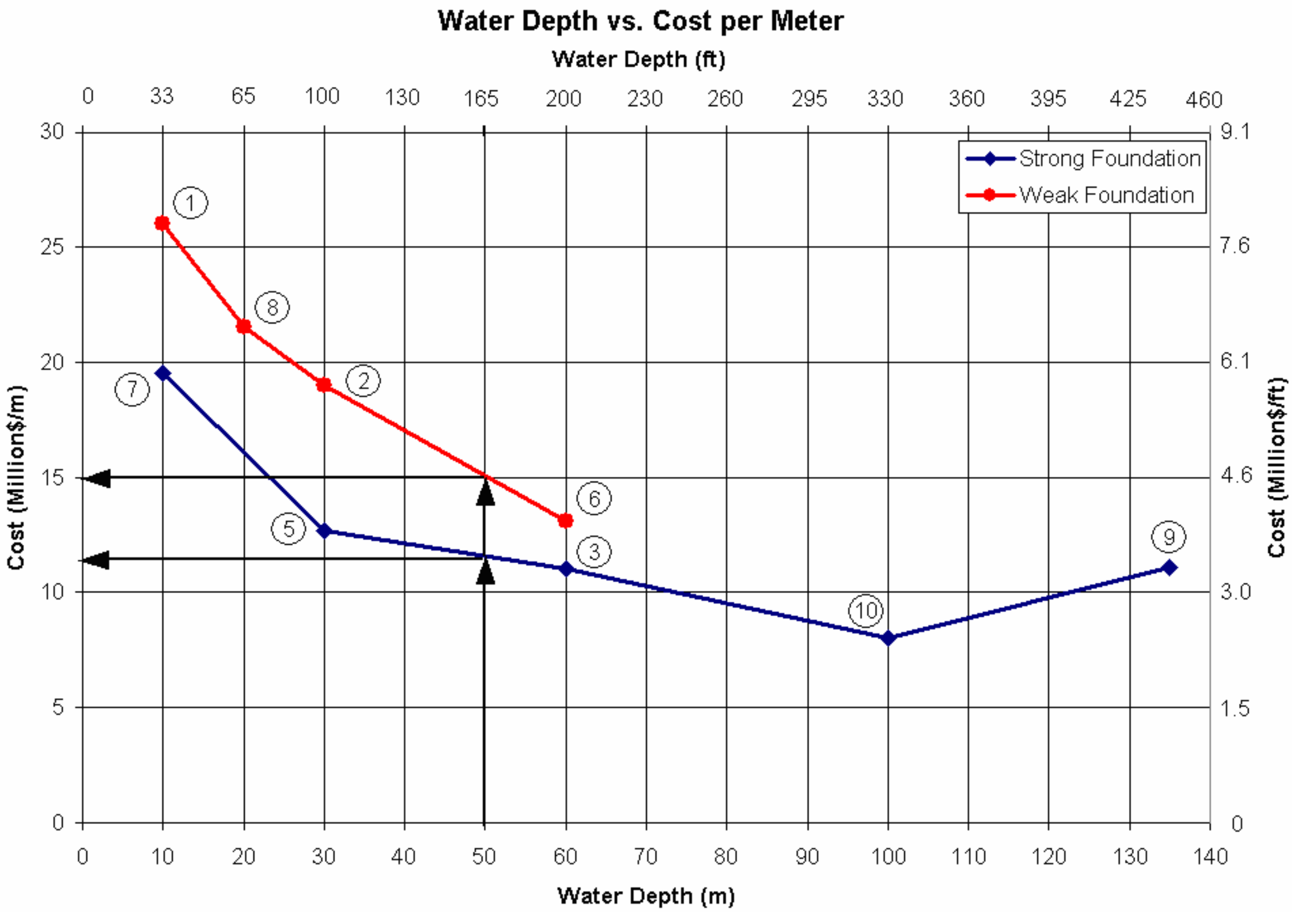


Figure 4-9: Estimated 2007 Installed Platform Costs (USD), Platform Only Contracted to Shipyard, Exclusive of Topsides

4.5.7 Environmental Considerations

There will potentially be some environmental considerations associated with the installation of a bottom-founded structure in the Alaskan OCS. A primary consideration will be whether or not dredging and/or backfilling will be required to prepare the foundation for a permanent bottom-founded structure.

The amount of material to be dredged/replaced will be a function of the soil conditions and loads on the structure. Areas may be required for spoil disposal and sources of more competent material may be required. Dredging (and backfilling, if required) will create some turbidity and some habitat alteration associated with construction/installation activities. It is anticipated that coarse sediment would settle to the seafloor very near the excavation, but that a plume of fine suspended sediment could drift several miles (MMS, 2003).

4.5.8 Operations, Maintenance, & Repair

A significant operational consideration is transport of production whether through a pipeline or by tanker. In the case of tanker transport, weather conditions are a key factor. Another key aspect of operations will be the safe evacuation of personnel in the event of an emergency.

Marine operations will require a number of vessels. Depending on regulatory requirements, one vessel may be required to be standby compliant at all times. Support vessels will be used for personnel transfer, ice management, bunkering, etc.

Maintenance and inspection shutdowns may be required for regulatory compliance. However, these shutdowns would likely be planned around favorable weather conditions. A maintenance and inspection philosophy would be developed for any offshore asset but given the harsh and remote location of the Alaskan OCS, site-specific consideration needs to be given to the environment.

While a planned inspection and maintenance program can be controlled to some degree, breakdowns occur. Consideration needs to be given to redundancy of critical equipment, spares philosophy and transport of personnel/equipment.

Supply and personnel logistics for operations will be an important consideration. A marine base will need to be established which is accessible year round, has warehouse storage, and has fluids and bulk storage. Supply vessels capable of year round work will be required that will be able to load and bunker production chemicals, diesel, fresh water, equipment/materials and drilling/completion bulk fluids.

Helicopters and a heliport will be required to transport personnel to and from a GBS and also provide emergency response support. Consideration needs to be given to environmental conditions such as freezing rain, snow and winter storms.

4.5.9 Abandonment & Decommissioning

In general, decommissioning of offshore platforms is perceived as technically difficult, costly and posing a number of environmental and safety risks. Decommissioning procedures for offshore installations that have reached the end of their useful life are usually included in governing legislation, e.g., C-NLOPB, Norwegian Petroleum Directorate, UK Oil and Gas Directorate. There are also international agreements relating to decommissioning that address removal and deep-sea disposal. For example, the

International Maritime Organization (IMO) has developed Guidelines and Standards for the removal of Offshore Installations and sets out conditions to protect navigation and maintain safety.

In general, the requirements of the regulatory body overseeing decommissioning might include, among others, the conditions that the bottom-founded structure be designed so that it can be removed if the authorities at that time so require and the requirement that the Certifying Authority reviews the suitability of the detailed design of the structure for eventual re-floating.

Based on these requirements, decommissioning will likely be an important consideration for any Alaskan OCS bottom-founded structure concept. The decommissioning experience of (and ongoing plans for) the North Sea has the most direct relevance to Alaskan OCS concepts.

As the fields in the North Sea have matured, the number of installations that require decommissioning in the near future has increased. The OSPAR Convention (1998), whose signatories include Norway and the UK, includes provisions relating to prevention and elimination of pollution from offshore installations. Recent amendments to this convention have essentially placed a ban on disposal at sea or abandonment in place for all installations. However, exceptions have been made for large concrete structures due to the "perceived complexity" of the operation. A recent example is the platforms in the North Sea's Frigg field, which ended production in 2004. Steel jacket platforms in the field will be completely removed, but the Norwegian and UK authorities have granted their consent to abandon a concrete GBS substructure on site. A recent industry study commissioned by the International Association of Oil and Gas Producers (OGP, 2003) has also identified numerous issues related to decommissioning of concrete GBS structures, including structural integrity when platforms are raised from the seabed, and weight and buoyancy issues during re-float (if re-float is shown to even be feasible).

4.6 Jacket & Jack-up Structures

Jacket platforms are used as permanent production structures. Jack-up platforms serve the offshore industry as an exploration structure. The jack-up combines the mobility of floating structure with the jacket platform's properties of wave transparency and fixity.

The jacket structure is the most common fixed offshore platform in the world. It was first used in the Gulf of Mexico and has since been adapted and modified for use all over the world. It comes in a variety of styles from the single-legged (monopod) to multi-legged structures.

The ice reinforced jacket platform was first successfully used in sea ice in the mid 1960's at the Cook Inlet developments (Figure 4-10). Three varieties of ice reinforced jacket structures have been used in the Inlet; the monopod, the tripod and the quadpod.

Figure 4-10: Unocal's Monopod Jacket Platform, Cook Inlet (Courtesy of CIRCAC, 2007)

Previous studies of the South Bering conducted by PMB Systems Engineering Inc. et al. (1983), the Norton Basin by Fluor Engineers Inc. (1982), and the North Aleutian Basin by Brian Watt Associates (1985) suggest that jacket structures may be suitable for use in the Bering Sea.

4.6.1 Technical Feasibility

4.6.1.1 Arctic Jacket Structure Design Considerations

The main consideration for the design of any jacket structure is the payload the structure has to carry, the capacity of the foundation and the environmental loads the structure must resist. The loads unique to offshore Arctic structures are temperature loading, sea ice static loads and the accompanying vibration loads. In many cases, the sea ice static and vibration loads are the controlling factor either globally or locally in the sizing of the structure members. Temperature is generally the controlling factor in material selection.

Sea ice in the Bering Sea has varying geometry, concentrations and mechanical properties. The structures in these areas have to be designed for the maximum ice load that results from three specific loading mechanisms.

- Momentum load is the load that results from the ice flow impacting the structure.
- Ridge building load is the pressure load the structure experiences as a ridge and rubble field builds.
- Pack-Ice loading is the tangential frictional loading that results from the ice flow passing by the ridge and rubble field that has formed in front of the structure (Cammaert and Muggeridge, 1988).

The load imparted to a structure by momentum, ridge building and pack ice loading relates to the width of the structure. In the case of a jacket structure, the load is a function of the jacket leg diameter (D) to distance between legs (W) ratio (D/W). If this D/W ratio is maintained above seven, then Sanderson (1988) suggests that the legs of a jacket structure will behave independently and ice bridging will not occur between the jackets legs. When the legs of the jacket act independently, smaller global loads are experienced by the structure. Sanderson (1988) does not indicate what the maximum sea ice thickness for which this D/W ratio value of seven is applicable. It is assumed that this D/W ratio is only applicable for non-rafted sea ice thickness of less than 3.3 ft (1 m). This conservative assumption is drawn from the study of data on Cook Inlet jacket structures. Beyond a sea ice thickness of 3.3 ft (1 m), additional testing is required to determine what D/W ratio will produce independent behavior of the jackets legs.

Figure 4-11: Sea Ice Loading a Jacket Leg, Cook Inlet (Courtesy of CIRCAC, 2007)

In addition to handling static sea ice loads, the jacket structure must handle the vibration loading resulting from the random ice edge hit, sudden ice load relaxation, unsystematic ice load level variations and continuous repeating ice load failures. Ice reinforced jacket structures are more susceptible to vibration than conventional jackets because they have less damping ability and tend to amplify vibrations similar to a portal frame.

The dynamic response of a jacket structure from sea ice is not fully understood. However, it is known that the vibration responses are proportional to the design static load and the thickness of the ice. There are a number of ways to reduce the vibration response. First, the foundation can be made as rigid as possible to minimize the displacement resulting from the dynamic loading. Second, the structural mass and stiffness of the jacket can be changed to reduce the structures resonance.

Another consideration is temperature loading across the arctic jacket structure. However, the temperature differential of 104°F to 122°F (40°C to 50°C) can be addressed by using low temperature steel that is readily available in today's market.

4.6.1.2 *Arctic Jacket Structure Enhancements*

Recent developments and lessons learned that should be used in the potential development of future jacket structures in the Arctic include:

- The use of lower temperature steels to avoid brittle failures;
- The use of double walled ice reinforced jackets to avoid local failures and protect interior members;
- The location of leg bracing well below the sea ice flow. This prevents the collection of rubble and ice bridging under and in front of the structure, hence eliminating the possibility of ice damage to the bracing system and reducing global and local loading; and,
- The use of X-bracing between jackets, rather then K-type bracing. The X-bracing jacket results in a safer design by increasing the redundancy of its members.

4.6.1.3 *Assessment of Jacket Platform*

The suitability of jacket structures has been assessed for the Bering, Beaufort and Chukchi Seas based on comparison of analogue areas such as Cook Inlet, review of current metocean data for the various regions and the review of prior studies.

Suitability of Jacket Platforms in the Bering Sea

A review of metocean data, prior studies of the South Bering, the Norton Basin, the North Aleutian Basin and George's Basin, along with an evaluation of the Cook Inlet jacket structures, indicates that jacket structures potentially can be used in some areas of the Bering Sea. However, if oil storage is required, jacket structures are limited by this requirement.

Previous studies of the 1980's (PMB Systems Engineering Inc. et al., 1983; Fluor Engineers Inc, 1982; Brian Watt Associates, 1985) indicate that jacket structures are suitable in George's Basin, Navarin Basin and the North Aleutian in water depths up to 600 ft (180 m). However, these studies do not consider the dynamic loading of the sea ice on jacket structures.

In light of a previous jacket failure in the Gulf of Bohai and the dysfunction of another as a result of ice induced vibrations (Cammaert and Muggeridge, 1988), there is a strong possibility that dynamic modeling, where ice is thicker than a few feet, may demonstrate that many low mass jacket platforms are unworkable and/or uninhabitable under modern vibration code limits.

Aside from the vibration problems, jackets used in sea ice have significant challenges with the protection of the conductor system. Options for protecting the conductors are to locate the system in the jacket legs or exterior to the legs in a separate ice reinforced enclosure. Both solutions have challenges and increase jacket platform costs. A combination of these solutions has been used in Cook Inlet.

If the conductor is located in the jacket legs and large production flows are required, the size of the legs will have to increase. A flow of 100,000 BOPD would require a leg diameter of 55 ft (17 m) (Brian Watt Associates, 1985). In turn, larger legs result in larger sea ice loads. The second problem with locating conductors in the jacket legs is that the piles that support the jacket legs are in close proximity to the conductor system and this reduces the effectiveness of the piles. This may result in the requirement of additional piles. Lastly, there are blowout concerns with regards to the well close to the jacket supporting piles and drilling incidents could damage the supporting piles.

If the conductor system is located outside of the legs, then it has to be reinforced to handle the local sea ice loading. This reinforcing, in turn, increases the global ice load and it also increases the possibility of ice bridging across the conductor and the legs, which again further increases the ice loading.

Jacket type structures could likely be made to work in light first-year ice and water depths less than 200 ft (60 m). The jacket structure's poor response to dynamic loading and the conductor system protection issues are a significant concern for application in the Navarin, St. George's, North Aleutian and Norton Basins.

<u>Suitability of Jacket Platforms in the Beaufort & Chukchi Seas</u>

Current design practices and understanding of jacket design make their application unsuitable for the Beaufort and Chukchi Seas. The primary load case in both areas is ice. The Beaufort Sea commonly experiences thick multi-year ice floes and the Chukchi has been observed with enormous multi-year ridges. The thickness of the ice not only significantly increases the load on the structure, but it also creates problems with the location of the jacket bracing. The bracing should be located below the underside of any ice features which could interact with the structure. Thick ice features means that the effective length to radius of gyration ratio (KL/R) of the jackets would significantly increase. The only way to deal with this increase in the KL/R ratio is to use larger jacket legs. If leg diameter is increased to compensate for the greater unsupported column length, it will result in increased wave loads and drag on the structure. This process becomes counter-intuitive, and one quickly arrives at the conclusion that alternative type structures would be more suitable to this loading scenario.

4.6.2 Constructability

Arctic jacket structure construction is very similar to typical jacket construction for the Gulf of Mexico, North Sea, etc. The only exception is that the procedures used to weld low temperature steels are slightly different than those for conventional steels.

Jacket fabrication would take place onshore using conventional shipbuilding techniques and equipment. Suitable facilities exist nearby in the Western USA, Russia and Japan.

The fabricated jacket would be loaded out on a barge and transported to site. Once onsite the jacket would be launched, upended and seated in place. Piles would then be driven through the jacket sleeves and installation would be completed with the loading and connecting of the deck and topsides at site. Jacket structures are hydrostatically unstable and, therefore, no topsides could be on board during installation.

4.6.3 Capital Costs

The capital costs associated with the platform design, fabrication, and installation would be directly related to the water depth, environmental loading and topsides requirements. As an indicator, the costs per tonne for conventional piles and jackets can be estimated as follows: piles – $2,500 per ton ($2,800 per tonne); jackets – $7,300 per ton ($8,000 per tonne). These costs are in USD and cover the material, fabrication labor, load-out and tie-down at the topsides fabricators quayside.

4.6.4 Environmental Considerations

Installation of a jacket structure would have minimal environmental issues associated with the activity. The major environmental considerations for offshore platforms inclusive of jacket types consist of the following:

- The presence of the platform: how will the presence affect the local ecosystem and industries such as commercial shipping and fish harvesting;
- The possibility of discharges from the platform;
- Platform noises, and the affect the noise will have on the marine environment;
- Platform emissions and flaring; and,
- The disposal of the drilling cuttings and other platform waste. This can be achieved safely by decontamination and reinsertion.

The jacket platform mitigates many of these concerns as a result of its small footprint and due to the fact that the topsides and jacket of the structure can be removed from the site at the end of its useful life.

4.6.5 Operations, Maintenance, & Repair

Many of the operations, maintenance and repair issues are similar to those presented in Section 4.5.8 for bottom-founded structures. An asset integrity program would be an important part of the operation of a jacket type structure in an ice environment. Inspection of a jacket structure would be different and depending on the severity of any particular season (in terms of waves or ice loads), additional inspections may be dictated. Physical inspections would be planned around open water as inspections in winter would be challenging.

4.6.6 Abandonment & Decommissioning

Considerations regarding abandonment and decommissioning have also been presented in Section 4.5.9 for bottom-founded structures and many of the points made there are relevant to jackets as well.

Jacket structures have been successfully removed from the Gulf of Mexico and the North Sea. Jacket structures can be removed with minimal difficulty with the exception of the piles. The removal process is essentially the reverse of the installation process.

The topsides and the deck are removed by a sea crane and placed on a barge. The barge is transported back to land where the top sides and deck can be recycled or alternatively retrofitted and installed at an alternative location.

The next step in the demolition process is the removal of the jacket. This is performed by cutting the jacket from the piles by the use of mechanical or thermal cutters. In some situations, the jacket can be separated from the piles using explosives. Once the jacket is separated from the piles, a sea crane is used to lift the jacket onto a barge where it is transported back to land. Back on land, the jacket is cut into small sections that can be handled by recycling and salvage yards.

Pile removal is possible. However, to date, a cost effective method has not been developed.

4.6.7 Commentary on Jack-ups

The jack-up rig was first introduced to the offshore industry in the mid 1950's. The jack-up rig was developed to provide a fixed base drill rig capable of operating in harsh environments (wave only) with the flexibility to relocate to alternate drilling locations.

Most of the world's jack-up fleet can operate in water depths of 30 to 300 ft (10 to 90 m) and drill to depths of 20,000 ft (6100 m). The recent state of the art jack-ups can operate in water depths of up to 500 ft (150 m) and drill to depths of 35,000 ft (10,500 m).

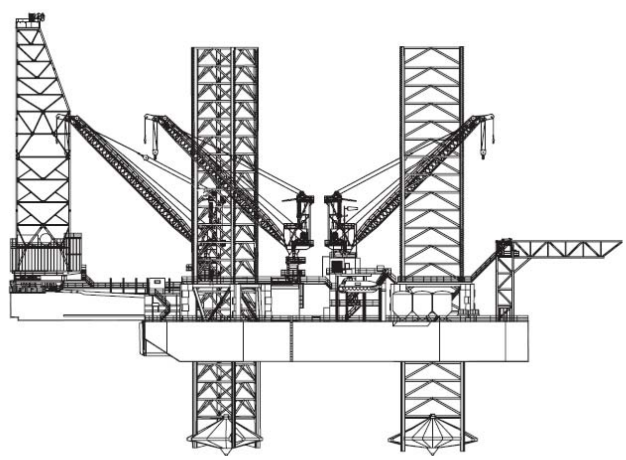


Figure 4-12: Gorilla Class Jack-up (LeTourneau Technologies, 2007)

Jack-up platforms have been constructed for numerous ocean environments. As of yet, none have been constructed to operate in sea ice environments. However, a study of jack-ups in ice for Sakhalin (CKJ Engineering, 1997), the development and implementation of a jack-up drilling program on the Grand Banks of Newfoundland and the anticipated construction of a new Russian ice-resistant jack-up rig are indicative that the operating range of jack-up drilling rigs can be marginally expanded to include areas of seasonal sea ice and of marginal sea ice concentration.

CKJ Engineering's study (CKJ Engineering, 1997) involved brief investigations into the structural feasibility of using jack-up Rig SX during freeze up in Sakhalin. Rig SX is a triangular shaped hull configured with three jack-up legs consisting of four chords complete with spud cans. The preliminary conclusion of this work was that, structurally, Rig SX can be safely operated, lowered and re-floated in up to 1 ft (30 cm) of first-year ice with improvement to the structure and reinforcing of the drilling riser. Improvements included positioning the rig such that the horizontals between the leg chords are situated to avoid any local ice loads and reinforcing the connections between the verticals and the leg chords.

Extrapolation of CKJ's study would suggest that a proportion of the world's jack-up fleet have the structural potential to operate in light early season first-year sea ice. A complete detailed structural and operational review of a particular rig would be required to determine the capabilities of each specific jack-up rig in sea ice.

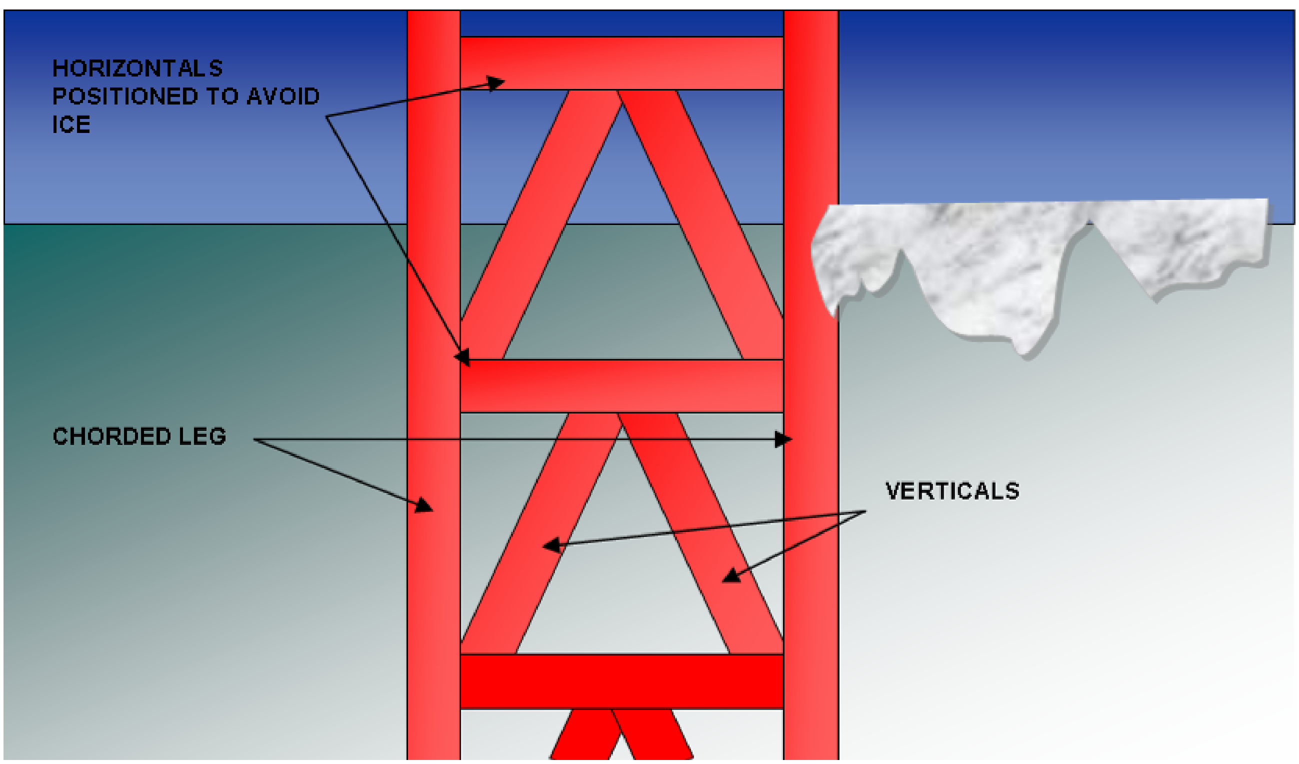


Figure 4-13: Positioning of Leg Horizontals to Avoid Sea Ice

The successful development and the implementation of a jack-up drilling program on the Grand Banks of Newfoundland, Canada was accomplished by the establishment of the understanding of the ice-free season and an ice management program (Bagnel, 2007). Prior to the summer of 2005 a jack-up had not been used off the coast of Newfoundland (Bagnel, 2007). The ice-free season was identified by a statistical analysis of the historic sea ice edge. The ice management program was inclusive of a sea ice and iceberg monitoring system, emergency rig relocation procedures and iceberg towing strategies. A Rowan Gorilla jack-up drill rig successfully drilled three wells on the Grand Banks during the summer of 2005 (Bagnel, 2007).

The Ice-resistant jack-up rig Arkticheskaya, the first of its kind, is under construction at the Severodvinsk Shipyard, Russia. It is being constructed to operate in Arctic water depths of up to 330 ft (100 m) and in ice floes of 1.6 ft (0.5 m) thick (MNP Global, 2007). The rig is owned by Gazprom and is expected to be commissioned in 2008 (Rigzone, 2007b).

Recent advancements in jack-up drilling depths, the results of CKJ Engineering's structural investigation, the successful development and implementation of a drilling program on the Grand Banks – coupled with the previous use of jack-ups in the Norton Basin (see Table 4-10) – indicate that the operating range of jack-up drilling rigs can be marginally expanded in the Bering Sea. The limit of this expansion is dependent on the development of an ice-free season, ice management programs and the study of individual rigs to determine sea ice loading capabilities.

Table 4-10: Historic Bering Sea Wells Drilled by Jack-up Platforms (MMS, 2007a)

HISTORIC BERING SEA WELLS DRILLED BY JACK-UP PLATFORMS			
Location	**Year Spudded**	**Water Depth, ft (m)**	**Drilling Unit**
Norton Basin	1985	55 (17)	Key Hawaii Jack-up
	1985	55 (17)	Key Hawaii Jack-up
	1984	54 (16.5)	Rowan Middletown Jack-up
	1985	40 (12)	Key Hawaii Jack-up
	1984	35 (10)	Rowan Middletown Jack-up
	1984	65 (20)	Key Hawaii Jack-up

Alternative drilling methods are recommended for exploration in the Beaufort and the Chukchi Seas due to the short ice-free season and the size and thickness of ice floes. These areas are better suited to alternative drilling methods such as ice class drillships or bottom-founded structures, e.g., SDC.

4.7 Ice Islands

Grounded ice islands have been used as exploration drilling structures in nearshore areas of the US and Canadian Beaufort Sea. Based on the current state-of-practice and technology, ice islands have been assessed with respect to other areas of the Alaska OCS.

Please note that the following Section draws significantly on the MMS Report No. 468 – *Ice Islands* (C-CORE, 2005). References are made to Report No. 468 for further information.

4.7.1 Technical Feasibility

From a general perspective, the technical feasibility of an ice island exploratory drilling platform is based on several fundamental regional and site specific considerations:

- Meteorological environment;
- Water depth;
- Landfast ice characteristics; and,
- Geotechnical (seabed) conditions.

With respect to meteorology, the winter temperature regime plays an important role. The temperature regime is important because of its influence on natural landfast ice thickness, spray ice construction process effectiveness and ice island/road integrity.

Natural landfast ice must be stable and sufficiently thick to permit mobilization of equipment and personnel for construction. Road construction and site preparation using light equipment may proceed when ice thickness reaches approximately 2.6 ft (80 cm) (C-CORE, 2005). In the Beaufort Sea, freeze-up typically begins in mid-October and as shown in Figure 4-14 below, ice thickens by an average rate of approximately 0.4 in/day (1 cm/day) (C-CORE, 2005). Based on Figure 4-14, during a “normal” winter temperature regime, road construction could start by about mid-December.

Spray ice production generally increases at lower temperatures (C-CORE, 2005). Observations indicate that efficiency in spray ice production can be achieved below -4°F (-20°C), but that the process becomes ineffective above 5°F (-15°C) (C-CORE, 2005). Wind speed also plays important role in spray ice production rates.

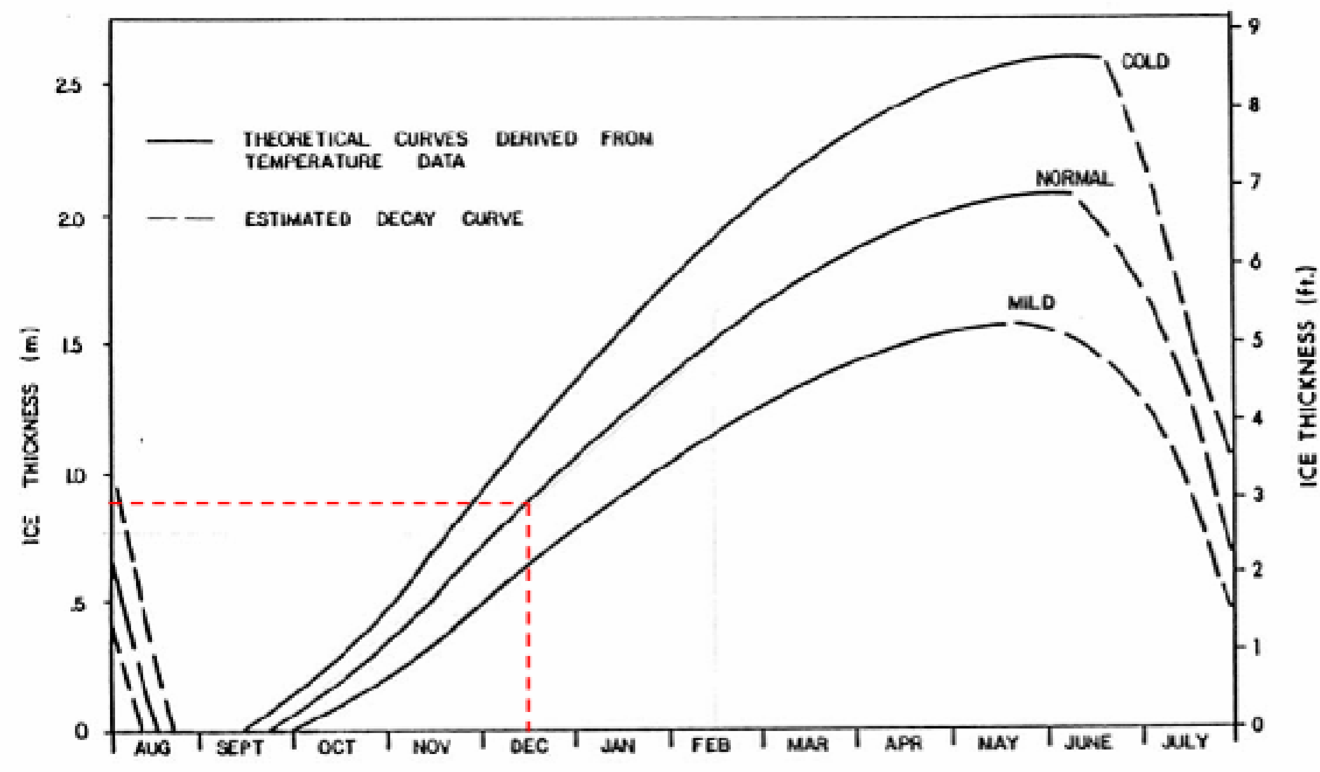


Figure 4-14: Typical Ice Thickness Growth for Canadian Beaufort Sea (Modified from C-CORE, 2005)

Ice strength is a function of temperature. Therefore, as the winter season draws to a close and temperatures begin rising above freezing, ice island/road integrity begins to deteriorate. Ice ablation also starts occurring when temperatures rise above freezing.

Ice roads must maintain adequate load capacity to permit safe demobilization upon completion of drilling activities and, therefore, this deterioration directly impacts the extent of time available for drilling operations. In the Beaufort Sea, ice road closures vary from year to year and with geographic location, but generally occur by late April to late June (C-CORE, 2005). Ice road closures, therefore, ultimately dictate the cessation of drilling activities and subsequent demobilization, to ensure equipment and personnel reach established land based infrastructure safely.

From this brief account, when evaluating the feasibility of an ice island, it is obvious that temperature regime is an important consideration and that lower temperatures and longer winter seasons are favorable. In the Beaufort Sea, temperatures below freezing are experienced more then 80% of the year and have been recorded in every calendar month (US Army Corps of Engineers, 1999).

Water depth is a fundamental factor that must also be considered when evaluating the feasibility of grounded ice island structures. Generally, as water depth increases, island freeboard requirements increase as well and, in turn, influence construction time/cost. Practical limits on freeboard are governed by spray ice equipment capacity and time, i.e., environment temperatures and durations. Review of previous ice island usage shows that, in practice, operational drilling islands have not been utilized in water depths greater than 25 ft (7.6 m).

Related to water depth, an ice island must be grounded soundly on the seabed to resist ice loads imposed by the surrounding ice sheet. This requirement is critical because any appreciable movement of the island during drilling operations can cause damage to the drill-string.

Ice loads within the nearshore landfast ice zone are typically caused by thermal expansion of surrounding ice and are typically restricted to seasonal (total) movements on the order of meters (C-CORE, 2005). Ice load magnitudes are influenced by a number of factors, including, location, ice thickness, ice velocity, total seasonal movement and air and ice temperature (C-CORE, 2005).

Ice loads imparted on an ice island will depend on the ice failure mode, rather than on the driving force of the ice sheet. Ice failure can be defined with respect to the landfast ice sheet or the island itself. Of the two modes which should be considered – crushing failure (of the surrounding ice sheet) and passive edge failure (of the ice island) – the crushing failure mode typically limits the upper bound of the force that can be imparted (C-CORE, 2005). The global resistance of the ice island must therefore be greater than this force by an appropriate factor of safety; previous operational ice islands used factors of 1.35 to 1.5. Figure 4-15 depicts the possible load limiting failure modes where the vertical scale is exaggerated by approximately five times.

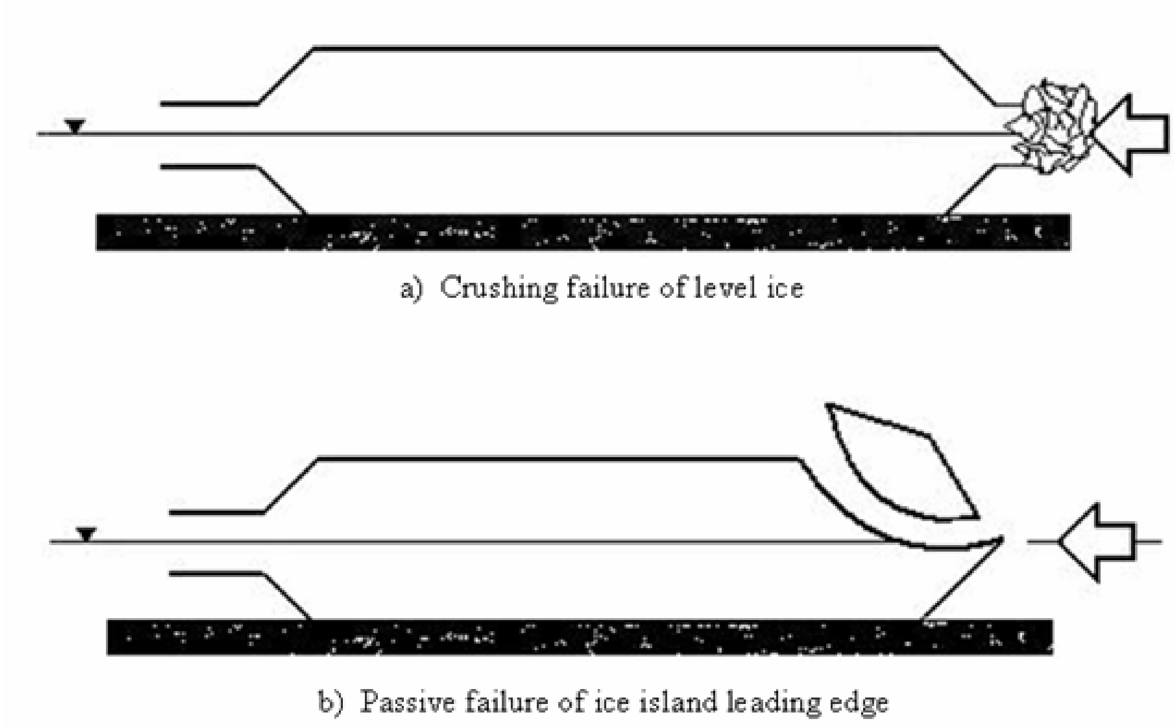


Figure 4-15: Spray Ice Island Potential Failure Modes (Modified from C-CORE, 2005)

Ice island global resistance is governed by one of two failure mechanisms; sliding (along sea floor) or shear failure (through the island core). Assuming that the shear capacity of soil beneath the island is less then than that of the ice island core, sliding resistance will be the governing failure mechanism. This is typical of the Canadian and Alaskan offshore Arctic where soils are of relatively low strength (C-CORE, 2005).

The sliding resistance of an ice island is a function of contact area and soil strength, and can be found from the following expression:

$$R_s = \frac{\pi D_c^{\,2}}{4}(c_u + (\rho_i g H + (\rho_{si} - \rho_w) g d) \tan\phi_s$$

Equation 4-1

Where,

R_s is the sliding resistance of the island;
D_c is the island core diameter;
ρ_i is above water spray ice density;
ρ_{si} is below water spray ice density;

ρ_w is sea water density;
c_u is the bottom material cohesion;
φ_s is bottom material friction angle;
H is island freeboard; and,
d is water depth.

A contact factor is sometimes incorporated into Equation 4-1 where soils are predominantly cohesive to account for potential voids between the ice and soil due to uneven grounding. Contact values of 0.85 or 0.9 have been used (C-CORE, 2005).

Seabed soil type can significantly affect ice island sliding resistance. Differences in soil type must be considered in the ice island design.

If the seabed soil type is clay, the contact area between the island and seabed will govern sliding resistance. This is attributed to the fact that the strength of a clay soil is defined by its undrained shear strength (cohesion) and is therefore independent of applied confining pressure when acting in an undrained manner. C-CORE (2005) indicates that “The main aim in determining allowable shear resistance is to ensure adequate contact pressure to develop shear failure at the ice/soil interface. A bearing pressure of about 520 psf (25 kPa) is considered acceptable”.

If the seabed soil is cohesionless, ice island sliding resistance is a function of the applied normal (vertical) stress and the soil internal angle of friction. Increasing bearing stress, by increasing freeboard, will therefore cause a rise in shear resistance at the soil/ice interface. This suggests that an optimized design can be obtained by reducing island diameter and increasing freeboard. However, as noted, there are practical limitations with respect to freeboard and adequate area must be maintained for drilling operations.

A more detailed discussion on design is beyond the scope of this document. The previous summarized paragraphs on design are intended to highlight design considerations and provide a fundamental level of understanding of ice island design, which will aid in assessing this technology for other Alaska OCS regions. It should also be noted that the preceding design concepts are based on a simplified model in which the ice island is effectively considered a rigid body. C-CORE (2005) states “This simplified model is convenient and has been shown to provide an acceptable level of confidence in design. However, it should be recognized that the island is not rigid, but acts as a continuum in which compression and distortion occurs”. Further information on ice island design, ice behavior, loading, failure modes, etc. can be found in the MMS Ice Islands report (C-CORE, 2005).

4.7.1.1 Feasibility of Selected Scenarios

From the review of ice islands, it is clear that they present a proven and economical option for exploration drilling structures in nearshore areas of the Beaufort Sea.

In practice, operational ice islands have been employed in water depths of up to 25 ft (7.6 m) in the Beaufort Sea. However, based on work reported in C-CORE (2005), the use of operational ice islands should be achievable in water depths of up to approximately 30 ft (9 m) (C-CORE, 2005). The MMS Ice Island study (C-CORE, 2005) suggests that “incremental improvements in equipment capacity with higher productivity would allow islands to be constructed into deeper water and it is considered that 40 ft (12 m) water depth should not present a problem”.

Ice island feasibility will depend on winter season duration and temperatures, water depth, landfast ice conditions and geotechnical considerations. Based on these fundamental considerations, Beaufort Sea experience and state-of-practice, ice island structures can be assessed for other Alaska OCS study areas.

If the location scenarios and water depths presented in Figure 4-1 are specifically considered with respect to operational ice islands used in practice, all OCS study areas would be precluded from further assessment.

OCS study area scenarios were created to help guide assessments, however, and were not intended as single examination points. Therefore, based on general water depths, Norton Sound might be considered for ice island use. To characterize the Norton Sound environment and aid in further assessment, Table 4-11 has been created to capture parameters indicative of ice island feasibility.

Table 4-11: Comparative Feasibility of Ice Island Construction in the Beaufort Sea and Norton Sound

Parameter	Beaufort Sea	Norton Sound
Mean Winter Temp., °F (°C)	-13 to -20 (-25 to -29)	+10 to +5 (-12 to -15)
Typical Freeze-up Date	Mid-Oct.[1]	Sept. – Nov.[2]
Typical Complete Ice Coverage	Nov. – May	~ (Nov. – May)
FDD[3]	5063	2875
Approximate Maximum Landfast Ice Thickness, ft (m)	6.6 (2.0)	4.9 (1.5)
Maximum Extent (month)	~Mar.	~Feb.
Typical Break-up Date	early to mid-Jun.	mid-may or later

Although Norton Sound does experience significant landfast ice during the winter, the use of ice islands for drilling may not be feasible as observed from Table 4-11. A primary reason for this assessment is that Norton Sound's average winter temperatures will prevent spray ice construction from being consistently effective.

Furthermore, the time frame between mobilization and demobilization will be shorter. From the table, break-up in Norton Sound can occur up to one month ahead of that in the Beaufort Sea, and based on differences in maximum ice thickness and freezing degree days, one can draw the conclusion that "sufficiently thick" ice needed to begin mobilizing will not exist until later into the winter season.

Also, since ice strength is a function of temperature, the thickness needed for mobilization in Norton Sound should be greater than that required in the Beaufort. Similarly, ice creep will become more of a concern with warmer temperatures and may result in unacceptable settlement of the drilling rig during operations.

Based on these considerations, it appears that ice islands will not be feasible for Norton Sound; at least for comparable water depth limits that are observed. However, without detailed analysis it is difficult to rule them out definitively. Consideration of ice loads and associated stability requirements, the possible use of innovative techniques such as chipped ice and reducing ice loads, and possible use of rubble piles to initiate island construction, may allow an ice island to work in very shallow nearshore water depths.

[1] Shore ice forms in September.
[2] "in shallow coastal bays and lagoons" (MMS, 1985)
[3] Freezing degree days based on ice thickness & empirical formula: $h = 0.01x\sqrt{[(8N_\theta-501)]}$ (Sanderson, 1988)

Nearshore areas of the Chukchi Sea (25 to 50 miles (40 to 80 km) from the coast) have been excluded from the upcoming lease sale 193. This obviously precludes the use of any shallow water structure such as ice islands in the short term. However, examination of the Chukchi Sea landfast, or perhaps more appropriately, contiguous ice zone, one can draw the conclusion that an ice island structure will likely not be feasible.

“The Chukchi Sea nearshore ice environment is much more dynamic and variable than that of the Beaufort Sea” (MMS, 1990a). In general, the term “contiguous ice” may be more appropriate then landfast because it is defined simply by ice continuous to shore and does not necessarily indicate that the ice has “stability inferred by the term fast ice” (MMS, 1990a). Contiguous ice is unreliable and “sudden break-aways” can occur (MMS, 1990a).

Beaufort Sea landfast ice is more stable than landfast ice that forms in the Chukchi Sea (MMS, 2007b). The mean occurrence date for the formation of stable landfast ice in the Chukchi Sea is around the 3rd week of February, while the Beaufort Sea can experience stable landfast ice conditions more than a month and a half earlier (MMS, 2007b). Also, as stated by MMS (2007b), “the growth of landfast ice is not continuous and can involve formation break-up and reformation”.

In the Chukchi Sea, landfast ice movements called “ice shoves” most commonly occur during freeze-up and break-up, however, they may occur at any time (MMS, 2007b). “Landfast-ice breakouts, where the landfast ice breaks off from the shore, occur along the northern Alaska coast. Breakouts can occur at any time of the year” (MMS, 2007b). More information regarding the Chukchi Sea ice environment can be found in MMS (2007b) and MMS (1990a).

In light of the above description of the contiguous/landfast ice present in the nearshore Chukchi Sea, it is difficult to conceive that an ice island may be suitable for the use as an exploration drilling structure. Additional analysis would be required to completely dismiss the concept.

If there were locations that would permit the use of an ice island drilling structure, very nearshore Ledyard Bay or just north of Icy Cape might be possibilities for consideration. These areas are at least partially protected and would possibly experience less dynamic conditions due to the bay environment.

4.7.2 Constructability

As discussed earlier in this report, the first ice structures constructed for exploratory drilling were floating ice pads used in the Canadian High Arctic during the 1970's and 1980's. The majority of these ice pads were constructed by employing flooding techniques. Average build-up rates achieved were slow, amounting to less than 3 in/day (only 70 mm/day). Also, using the flooding technique, Union Oil constructed the first grounded ice island during the winter of 1977-78 in Harrison Bay, Alaska. Similarly, slow build-up rates were experienced. Flooding is still used for ice road build-up and leveling.

Arctic winter drilling programs using land-based rigs are inherently time constrained and slow ice build-up rates were identified as a further limitation. The window of opportunity available to carry out such a drilling program is bound by the formation of stable landfast ice at the onset, and by the latest safe demobilization date, prior to break-up. Within this timeframe (in addition to equipment mobilization, ice road and island construction), the drilling of a relief well may be required. If same-season relief well capability is required, a relief pad will need to be constructed and the drilling schedule must contain adequate time to permit relief well completion, prior to the latest safe demobilization date. Needless to say, time is of the essence in such a drilling program. To maximize the potential operating window, the ice island must be constructed and ready to accept the rig as early as possible (C-CORE, 2005).

Alternative methods of ice island construction were investigated and through significant experimentation and study efforts spray ice technology was developed. All operational ice island drilling structures built in the US and Canadian Beaufort Sea (7 in total), employed this construction technique. Much higher build-up rates are achievable using spray ice.

In general terms, spray ice is produced by projecting a high pressure water jet into cold ambient air. The jet causes the airborne water to break into droplets thereby enhancing heat transfer, between the relatively warm seawater and the cold ambient air, as a result of increased surface area (C-CORE, 2005). This can result in water droplets forming ice crystals prior to reaching the ice island surface. The proportion of ice formed from the water jet depends on several parameters including water droplet size, air temperature, velocity and time that droplets are airborne (C-CORE, 2005). Table 4-10 below, taken during the Thetis Ice Island project in 2002-03, illustrates the production/application of spray ice.

Spray ice is typically applied in layers to the natural ice sheet. Over time, with continued application, the ice sheet will begin to sink as a result of the increased load and will eventually ground on the seabed (C-CORE, 2005). Spray ice production may continue until the design freeboard is reached. The rate at which the island can be built up is a function of the time required to freeze and cure the spray ice as it is applied (C-CORE, 2005).

Figure 4-16: Spray Ice Production - *Thetis Ice Island* Project (C-CORE, 2005)

Ice island construction time will vary depending on the volume of spray ice needed, meteorological conditions (primarily ambient temperature and wind conditions) and equipment and construction methods employed (C-CORE, 2005). In some cases, equipment may be used to spread and level fresh ice cover and, in some cases, even compact ice. For example, this occurred during the construction of Nipterk Ice Island where ice was compacted and leveled by bulldozers (C-CORE, 2005).

As shown in Table 4-12, construction time required for previous operational ice islands ranged from approximately 20 to 60 days (C-CORE, 2005). The *Thetis Ice Island* project carried out in 2002-03 employed several innovative measures to reduce ice island volume requirements and, hence, construction time:

- Reduction of design ice load (based on extrapolated maximum in-season ice thickness);

- Further reduction of design ice load by reducing the thickness of the surrounding landfast sheet; and,
- Use of chipped ice, which reduces the required freeboard because it has a higher density then spray ice.

Thetis ice islands were situated in Harrison Bay approximately 7 to 12 ft (2 to 3.5 m) of water. It should be noted that during construction periods of warmer than seasonal temperatures, spray ice production was negatively impacted. Additional information on these islands can be found in C-CORE (2005).

Table 4-12: Construction Times for Operational Islands (C-CORE, 2005)

Island Name	Start Date	End Date	Construction Time (days)
Mars	8-Jan-86	23-Feb-86	45
Angasak L-03	7-Dec-86	3-Feb-87	58
Nipterk P-32	28-Nov-88	20-Jan-89	53
Karluk	13-Dec-88	20-Jan-89	38
Ivik	24-Jan-03	17-Feb-03	24
Oooguruk	24-Jan-03	7-Mar-03	42
Natchiq	11-Feb-03	4-Mar-03	21

Ice island construction must be carried out in a timely fashion to allow maximum time for drilling. To that end, many different techniques and equipment are employed to maximize ice accretion rates. Some examples of techniques used are continuous spraying and cyclic spraying/curing (C-CORE, 2005). “Procedures have also been developed to account for changes in temperature and wind speed in order to maintain optimum ice production” (C-CORE, 2005).

Equipment-wise, there are two main pump types used: skid mounted pumps, which are supported by the landfast ice, and larger pumps mounted on floating or fixed structures (C-CORE, 2005). The MMS Ice Island report (C-CORE, 2005) provides a comprehensive overview of equipment and techniques employed.

Monitoring throughout the ice island construction phase is required in order to verify that design assumptions and specifications are complied with (C-CORE, 2005). Monitoring is also necessary to track schedule and identify any productivity issues (C-CORE, 2005). Upon construction completion, construction monitoring data is reviewed and as-built geometry checks and ice strength tests may be performed (C-CORE, 2005).

4.7.3 Capital Costs

Capital costs for an ice island structure will be directly proportional to the amount of ice needed, which generally depends on the ice loads expected, water depth and soil conditions. Cost optimization may be realized from considering several factors.

In general, the first and primary factor to be considered in cost optimization is simply minimization of the area required for drilling facilities. This is, of course, because reducing the diameter of the island will reduce the amount of ice needed by a squared factor.

The second factor is soil conditions and is also related to potential diameter reduction. As noted above, island sliding resistance for cohesionless soils is not dependent on contact area; therefore, for cohesionless soil conditions, island diameter should be minimized and freeboard increased to achieve required sliding resistance. C-CORE (2005) presents a good example, which demonstrates the sensitivity of island sliding resistance with respect to sand and clay soil conditions.

The use of chipped ice in combination with spray ice can reduce freeboard requirements and therefore reduce cost as well. The reason for this is that the density of chipped ice is greater than that of spray ice.

Another factor which can reduce capital cost is design ice load reduction. This can be achieved in two ways as noted above. The first involves monitoring ice conditions prior to and during construction and comparing them with historical norms. If ice thickness in comparison with the historical norm is low for a certain time of season, extrapolation based on the amount of winter season remaining may allow reduction of ice load. This premise was utilized during the construction of the Thetis ice islands (C-CORE, 2005). A second way that ice load reduction may be achieved is through physical reduction of the surrounding ice sheet thickness. This technique was also used during the Thetis ice island project (C-CORE, 2005).

Comparatively, as shown in Figure 4-17 below, ice islands are far more economical than gravel islands, although it should be kept in mind that the risks associated with the ice island drilling are higher, and gravel islands are more versatile with respect to water depths and ice loads.

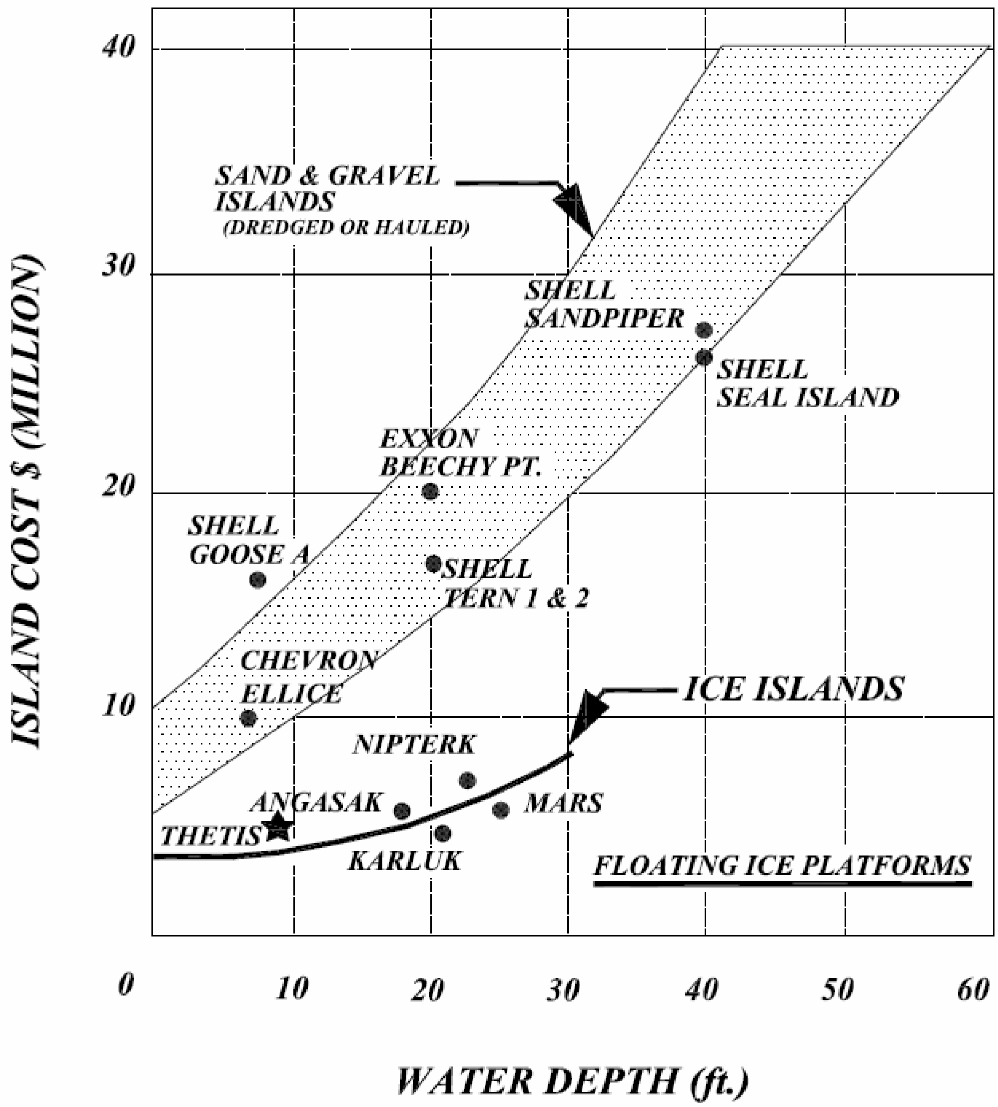


Figure 4-17: Cost of Ice Island vs. Gravel Islands (Reproduced from C-CORE, 2005)

4.7.4 Environmental Considerations

The continued use of ice islands in the Beaufort, or potentially elsewhere in the OCS, does not appear to cause an environmental concern.

The MMS Ice Islands report (C-CORE, 2005), however, does comment that crack formation within the island should be monitored to ensure that it does not create a potential leak path for contaminants. In addition, C-CORE (2005) states that “The risk of spillage of liquids such as drilling muds or fuel must also be mitigated with the use of strict handling procedures and containment devices such as drip trays.”

4.7.5 Operations, Maintenance, & Repair

As discussed throughout this assessment, time is a primary concern with respect to operations. However, drilling from ice islands has proven successful in the Beaufort Sea and, through continued optimization of design and construction and implementation of efficient drilling programs, risks associated with schedule will continue to be manageable and should be able to be reduced. Time available to carry out a drilling program from other areas in the Alaska OCS may be a limiting factor.

Movement, laterally and vertically (settlement), of ice islands must be prevented to avoid potential damage to the drill string. If island movement does occur, it may only do so within close tolerances. To monitor movement and gain insight into island integrity, “performance monitoring” is carried out. A monitoring program would include the following parameters (C-CORE, 2005):

- Natural ice thickness and movement;
- Island lateral movement and settlement;
- Ice temperature; and,
- Ice forces.

Ice islands may require maintenance to ensure that they perform as intended throughout their operational life. In addition to ensuring the structure’s performance, proper maintenance and monitoring can allow the structure life to be extended (C-CORE, 2005).

The main points of interest from a maintenance perspective are ice island temperature control, because the island’s structural integrity depends on it, and crack formation within the island (C-CORE, 2005). These are addressed further in C-CORE (2005).

4.7.6 Abandonment & Decommissioning

Requirements for abandonment and decommissioning are not seen as a concern with respect to the feasibility of this structure. It is assumed that upon demobilization of drilling facilities that the ice island would be left in an acceptable state. Requirements for such a state would be set forth in the Operator’s drilling lease agreement and is outside the scope of this document.

4.8 Gravel Islands

Although not a "high tech" technology, gravel islands have been successfully used in the Beaufort Sea for decades, and continue to be viewed as a candidate structure for exploration and/or production (for example, Northstar, Figure 4-18).

Figure 4-18: Northstar Island during Summer (Colaska, 2007)

In general, gravel islands remain attractive in that they are a proven technology, offer a short lead time, and are typically the most economical structure type for shallow water depths. For the Beaufort Sea in particular, the potential to re-use abandoned gravel islands, coupled with advancing extended-reach drilling (ERD) technology, may increase attractiveness considerably. As a result of recent increasing oil prices and increasing material and fabrication costs for other types of structures, it is not inconceivable that the current depths at which gravel islands are used will be surpassed.

For these reasons and the renewed interest in the Arctic, it was considered appropriate to assess gravel islands. The applicability of this structure type elsewhere in the Alaska OCS is also considered.

This Section discusses artificial gravel islands, referred to as "gravel islands". Caisson retained islands are not considered.

4.8.1 Technical Feasibility

The use of gravel islands for Arctic exploration and production has been proven. A total of 49 gravel islands have been constructed in the Beaufort Sea, 18 of which were located in US waters. The first gravel island, Immerk B-48, was constructed in 1972 in a water depth of approximately 43 ft (13 m). Since then, gravel islands have been constructed in a range of water depths, from on the order of several feet to over 60 ft. In theory, a gravel island has no depth limitation, but in practice it has been considered unfeasible beyond approximately 65 ft (20 m) because of economics and logistics (US Army Corps of Engineers, 1999).

The technical (and maybe economic) feasibility of using gravel islands is also dependant on whether the island extends above the waterline. The Tarsiut caisson was previously deployed in 65 ft (20 m) water depth but a gravel island was constructed to within 9.8 ft (3 m) of the water surface on which the caisson was founded. In deeper water, caissons might be considered to reduce the island footprint.

Based on the fact that gravel islands have been proven in the Arctic, the technical feasibility of gravel islands is not discussed in detail here. Instead, a summary and highlights of basic technical and design considerations is presented.

Landfast ice, typically ranging up to 6.6 ft (2 m) thick, covers the nearshore Beaufort Sea for about nine months of the year and has a considerable influence on island design and construction methods. In deeper water areas, multi-year ice incursions have to be considered and, in general, ice ride-up is more frequently encountered (Cammaert and Muggeridge, 1988).

As is generally the case with other arctic bottom-founded structures, the primary design requirement for a gravel island is that it must have adequate lateral stability to resist ice loads. A gravel island typically satisfies this requirement by virtue of its make up. A gravel island is comprised of massive amounts of gravel fill – typically on the order of hundreds-of-thousands to millions of cubic meters – and its base area is much larger than its surface. Gravel islands have greater resistance to sliding than other structures (US Army Corps of Engineers, 1999).

Gravel islands must also be capable of withstanding potential ice ride-up and wave conditions. Ice ride-up occurs when the surrounding ice sheet is forced up the sloped side of a gravel island. With respect to waves, both the resultant wave load, as well as the potential for over-topping, must be considered.

Although the return period and associated magnitudes will differ, both exploratory drilling (short-term use) and production (permanent) gravel islands must account for the above mentioned design considerations. For exploration gravel islands, design loads are generally based on 1/10 year events, while production island design loads are based on 1/100 year and, in some cases, 1/1000 year events.

In general terms, these environmental loads are managed through gravel island geometry. Ice ride-up is impeded by the sloped island sides due to friction and plowing forces and/or, in some cases, by discontinuity in slope (Cammaert and Muggeridge, 1988). Consideration also has to be given to ice fragments being driven into the island during storms. Figure 4-19 illustrates Northstar's ice protection design. Waves begin to break as they reach the sloped island sides, thereby dissipating energy before they reach the working surface. Wave overtopping is dealt with by placing the working surface above the design wave height and/or by placing a barrier around the working surface perimeter. The Northstar production island incorporated such a wall into its design.

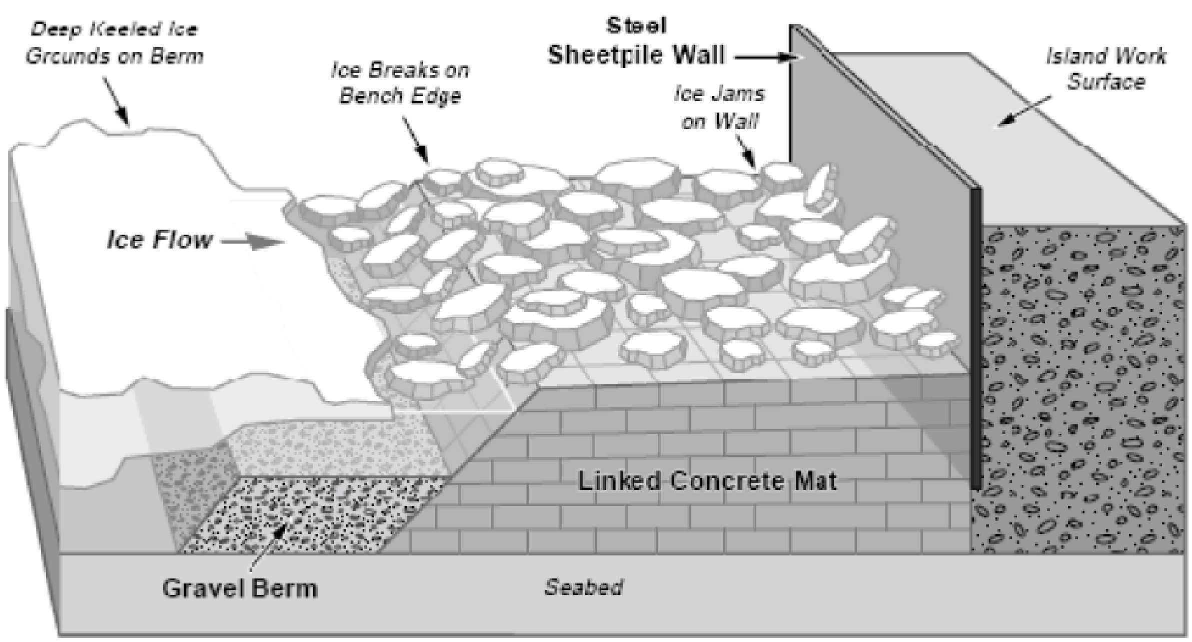


Figure 4-19: Northstar Production Island Ice Protection Design (BPXA, 2005)

In addition to design loads, the erosional effect of ice and waves (and potentially current) is another important consideration. A variety of methods/materials and combinations have been used to control gravel island erosion, including sandbags, various filter cloths and fabrics, sheet piles and concrete mats.

Figure 4-20: Ice Clearing on Northstar Island (Colaska, 2007)

Based on these considerations, the design of a production island will be more robust and typically more elaborate than that of an exploration island. Figure 4-21 and Figure 4-22 show some additional exploration and production gravel island designs.

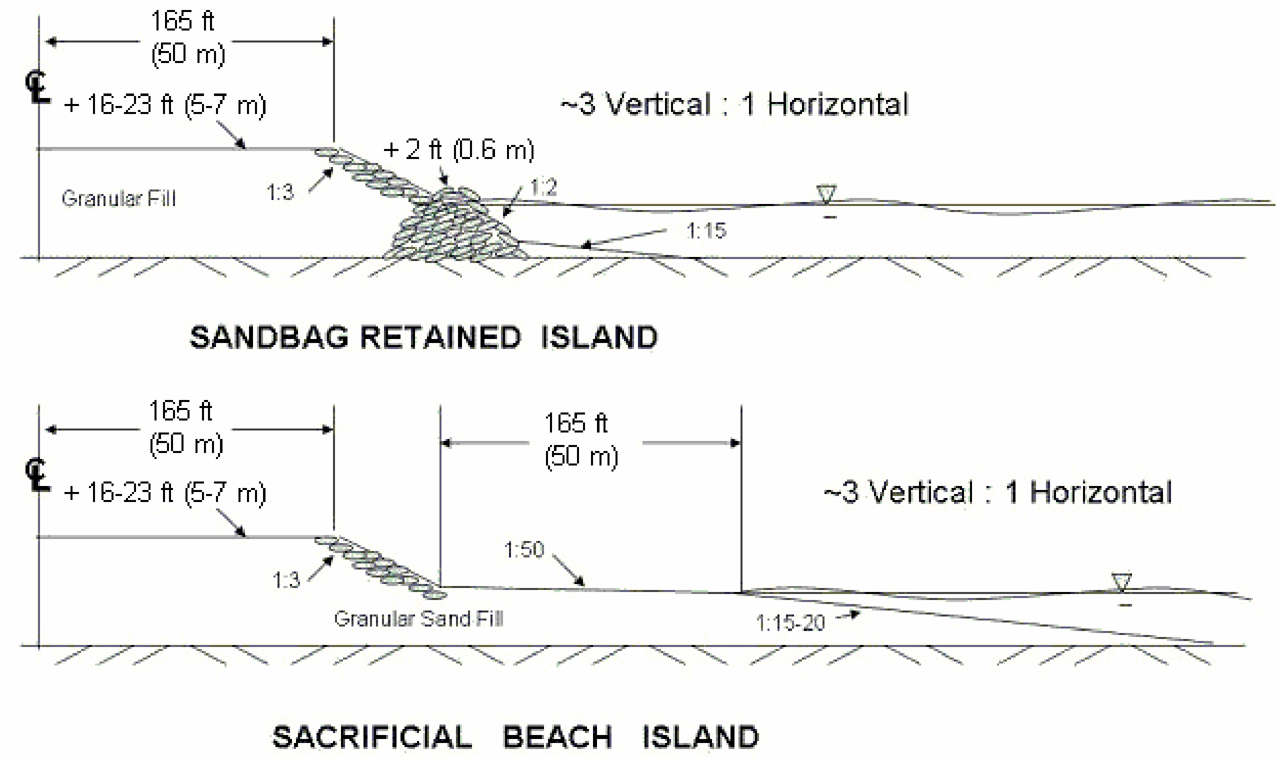


Figure 4-21: Basic Designs for Granular Fill Artificial Islands used in the Canadian Beaufort (drawn with an approximate vertical exaggeration of 3 times) (also presented in Section 3.4.3.2 as Figure 3-68)

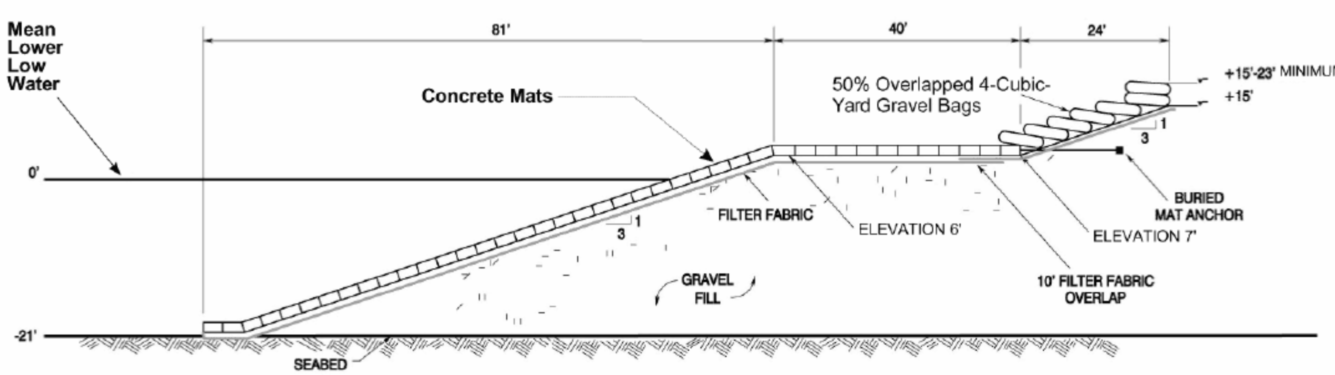


Figure 4-22: Proposed Liberty Production Island Slope Protection Design (dimensions are approximate) (MMS, 2002)

4.8.1.1 Feasibility of Selected Scenarios

Based on the OCS location scenarios identified in Section 4.2, and considering practical water depth limitations, nearshore areas of the Beaufort Sea, Chukchi Sea and Norton Sound can be considered for the use of a gravel island. Other Bering Sea location scenarios are excluded from assessment; however, this does not preclude the use of gravel islands in shallow coastal areas of the Bering Sea.

Although nearshore areas of the Chukchi Sea (25 to 50 miles (40 to 80 km) from the coast) have been excluded from the upcoming lease sale 193, future sales may open this area for leasing. Therefore, the nearshore Chukchi Sea will be assessed.

To carry out this assessment, a common water depth needed to be chosen and then a representative wave height selected. However, wave height data found during collection of metocean information (Appendix A) were not necessarily reported at consistent water depths. Therefore, in an attempt to be consistent, the water depth and associated wave height was selected based on the water depth for which the most wave data was available, about 33 ft (10 m) water depth. No nearshore wave data for the Chukchi was found, however, for perspective, Chukchi Sea offshore 1/100 year waves may reach upwards of 29 ft (8.8 m) based on maximum wind and fetch conditions.

Regarding multi year ice incursion; ridge keels would be depth limited in approximately 33 ft (10 m) of water for both the Beaufort and Chukchi Sea.

Table 4-13: OCS Gravel Island Assessment – Approximately 33 ft (10 m) Water Depth

Parameter	Beaufort	Chukchi	Norton Sound
Level first-year ice thickness, ft (cm)	6.6 (200)	4.9 (150)	4.9 (150)
Level Multi-year ice thickness, ft (cm)	9.8 – 16.4 (300-500)	9.8 – 16.4 (300-500)	-
Multi-year keel depth, ft (m)	Depth limited	Depth limited	-
Ice Movement/Velocity, ft/s (cm/s)	3.3 (100)	5.1 (154)	5.1 (154)
Wave Height (100-yr), ft (m)	*20 (6.1)*[1]	-[2]	*29 (8.8)*[3]

[1] Wave height value for water depth of ~ 36 ft (~11 m)
[2] No nearshore/shallow water wave height data available for comparison
[3] Wave height value for water depth of ~ 30 ft (~ 9 m) (w/ storm surge of 13 ft (4 m))

Based on the primary design condition for a gravel island (i.e. adequate lateral stability to resist ice loads), Norton Sound would be a feasible location for a gravel island. As noted below, increased wave conditions can be managed.

As described previously (Section 4.7.1.1), the nearshore Chukchi Sea ice environment is much more dynamic then the Beaufort Sea and, therefore, would require further consideration. Also, since no gravel island structure has been used in the Chukchi Sea, a more detailed assessment would be required to determine feasibility. From a qualitative stand-point, however, considering the primary design requirement is lateral stability, it would seem reasonable that a gravel island could be made to work in the nearshore Chukchi Sea. If a typical Beaufort Sea gravel island structure size would not afford the necessary weight and seabed contact area to achieve required lateral stability, then a larger gravel island could be built.

Similarly, as necessary to prevent ice ride-up, island freeboard could be increased and sloped sides could be lengthened; these changes would also be required to manage increased wave loads and prevent over-topping. With respect to erosion and local damage due to increase ice loads, slope protection design and materials might require further consideration.

The preceding assessment was based on a water depth of approximately 33 ft (10 m) and considered nearshore areas of Norton Sound and the Chukchi Sea. Considering the use of gravel islands for use in OCS up to current limits of practice (approximately 20 m or 65 ft), the assessment would be basically the same. Norton Sound would be feasible, but due to larger wave loads, island freeboard and potentially slope side lengths would need to be increased. Chukchi Sea considerations would also remain the same, but with increasing water depth larger ridges would be encountered, and therefore larger ice loads would be expected.

4.8.2 Constructability

There are basically two methods of constructing gravel islands: the onshore (hauled) method or the offshore (dredged) method.

The onshore method typically involves excavating material from onshore and transporting it to site via truck over ice roads. Material is dumped through a hole cut in the ice by conventional chain trenchers and backhoes. When using coarse materials, this method can “ensure very accurate placement and steep slopes of 1:3 (vertical-to-horizontal)”

(Cammaert and Muggeridge, 1988). The majority of gravel islands constructed in the US Beaufort have used this method. During the summer season, material can alternatively be transported to site via barge.

The offshore method involves dredging material and transporting it site via barge or pipeline. This method is typically used in deeper water where it is unfeasible to build ice roads or causeways. Islands constructed by dredging typically have side slopes “on the order of 1:15” (Cammaert and Muggeridge, 1988). Most gravel islands in the Canadian Beaufort were built using this method.

As discussed previously in the ice islands section (Section 4.7.1.1), the Chukchi Sea has a very dynamic ice environment and nearshore “landfast” or ”contiguous” ice is highly unreliable. Therefore, the truck hauling method will likely be infeasible. As indicated earlier (Section 4.7.1.1), Norton Sound ice roads will have limited use in comparison to the Beaufort Sea, which will therefore limit the use of truck hauling.

When constructing a gravel island, consideration must be given to the fact that a pipeline will need to be brought onto the island. The timing and method of pipeline installation should be such that interference with island construction and/or facilities installation is minimized.

4.8.3 Capital Costs

In comparison to other offshore structures, gravel islands are usually the most economical (US Army Corps of Engineers, 1999). As a function of water depth and size, gravel island construction costs have typically ranged between approximately \$10 million and \$40 million exclusive of topsides (US Army Corps of Engineers, 1999). Figure 4-17, included in the ice island section (Section 4.7.3), provides gravel island capital cost information based on water depth and illustrates the cost differences between ice and gravel islands.

The most recently proposed use of a gravel island was for the Liberty prospect located in the nearshore US Beaufort Sea. The proposed island was to be constructed in approximately 22 ft (6.7 m) of water and have a 345 ft x 680 ft (105 m x 207 m) working surface. Located 15 ft (4.6 m) above sea level, the island was estimated at \$50 million (MMS, 2002).

In general, the cost of a gravel island is directly proportional to the volume of fill required (i.e., water depth and island size) and the distance to transport it. In practice, gravel islands have been viewed as unfeasible because of economics and logistics at water depths of 65 ft (20 m) and greater (US Army Corps of Engineers, 1999). With the current price of oil today and the renewed interest in the Arctic, it is not inconceivable that gravel islands might be considered for greater water depths.

In the Beaufort Sea, cost savings may be realized through re-use of gravel from abandoned islands. This was put into practice several years back when gravel from NW Milne Island was reused “to enlarge F Pad (Milne Point unit) into marine waters” (US Army Corps of Engineers, 1999).

Further cost savings may be realized in the Beaufort Sea through the rehabilitation of abandoned gravel islands. This was also put into practice in 2001, when the abandoned Seal (exploration) Island was rehabilitated and turned into a production island for the Northstar project.

With regard to the Bering and Chukchi Seas, no cost savings based on the above are available. If a gravel island were eventually proposed for these areas, gravel sources would have to be found and transportation costs would have to be carefully considered. Based on the assessment above, one hypothesis can be made regarding cost: gravel islands for these areas will likely cost more than an island for the Beaufort Sea for a given depth (the $/m will be greater). This hypothesis stems from the constructability issues and environmental considerations (more severe ice and/or waves) discussed earlier.

4.8.4 Environmental Considerations

The main environmental considerations associated with the onshore construction method include the following:

- Gravel mine/pit development;
- Hauling of gravel;
- Gravel placement; and,
- Gravel mine/pit rehabilitation.

Some measures that that can help mitigate environmental considerations associated with construction are:

- Minimize facility/island size;

- Locate island as close to shore as possible;
- Use filter fabric to minimize leaching of silt and fine particulate;
- Construct island during winter using ice roads; and,
- Use ice roads for seasonal access.

A more comprehensive listing of potential mitigation measures can be found in MMS (2002).

The Chukchi Sea and Norton Sound do not experience the same quality of landfast ice as the Beaufort Sea, therefore the ability to mitigate environmental disturbances due to construction will be somewhat reduced.

During operations, "gravel islands are generally expected to dampen more noise than other types of structures" (US Army Corps of Engineers, 1999).

4.8.5 Operations, Maintenance, & Repair

With respect to operations, a gravel island does not differ significantly from other bottom-founded or fixed facilities. However, one notable operational consideration would be island access. During the winter season, access will be an issue if ice roads cannot be built or maintained. If ice roads cannot be built, consideration might need to be given to the construction of a causeway/gravel road for access.

The main concern for gravel islands with respect to maintenance and repair is, of course, erosion damage due to ice and wave action (and possibly due to current as well). However, "in contrast to other structures, gravel islands are relatively easy and inexpensive to repair" (US Army Corps of Engineers, 1999).

Annual inspections and maintenance/repair are typically carried out on the island working surface and slope protection system.

4.8.6 Abandonment & Decommissioning

Requirements for these activities will be set out in project-specific lease agreements. Following decommissioning of a facility, abandonment may fall within a range of activities from complete removal of facilities and structure, to basically a shutdown and preservation of the facilities for potential future use (US Army Corps of Engineers, 1999).

With respect to the structure, complete removal of a gravel island would pose much difficulty and many environmental considerations. Under a “complete removal” scenario, an alternative might be to remove all facilities, armor mats, barrier walls, etc. and allow the remaining gravel to deteriorate naturally. This method of abandonment has been historically acceptable in Alaskan Beaufort.

4.9 Floating Structures

There are only a limited number of floating exploration or production structures that have been used in ice environments. This Section of the report addresses the types of floating structures that might possibly be considered for exploration drilling and/or production development. Topsides are not included in this analysis, except in consideration of the requirement of the floating structure to support topsides weight, and provide a sufficiently stable platform for operations. For the purposes of discussion, the term “vessel” is used to describe any floating structure.

During exploration in the Canadian Arctic in the 1980’s, floating vessels (drillships) were used successfully with the support of icebreaking ships for ice management. In particular, the Kulluk, a round drilling barge purpose built by Gulf Oil to the Arctic Class IV specification, roughly equivalent to the modern IACS Polar Class PC4, operated in the Canadian Beaufort Sea. This vessel could operate through the open water season until early December (at the latest) with intensive ice management support. The Kulluk has recently been refurbished for exploration activities in the Alaskan OCS.

Historically, on the Grand Banks of Newfoundland, FPSOs (Floating Production, Storage and Offloading) have been the choice of floating production vessels under potential sea ice (first-year) and iceberg conditions. The hulls of both of the Grand Banks FPSOs (Terra Nova and White Rose) are designed to continue operations with light to moderate first-year pack ice (5 to 8 tenths) and can maintain their moorings in heavy first-year pack conditions (8 to 9 tenths). This ice cover would not have significant pressure ridges, nor would multi-year ice be present. Additionally, the hulls are designed to withstand the energy from a strike by a 110,000 ton (100,000 tonne) iceberg moving at 1 knot. This is an impact event and not a sustained load as might be found in the Beaufort or Chukchi Seas. In heavy pack conditions, or in the event of the approach of an unmanageable iceberg, the FPSOs are designed to disconnect from their moorings and an emergency disconnect can be effected in approximately 15 minutes. No continuous ice management support is required.

Modified spar, TLP (Tension Leg Platform) and semi-submersible designs have also been proposed for ice environments, although none have been built and there is much debate about the feasibility of these concepts in ice, particularly for Beaufort and Chukchi Sea applications. It is the authors' opinion that floating production systems for the Beaufort and Chukchi Seas are currently not technically feasible, even with continuous ice management. Floating systems may have some merit in southern Alaskan OCS areas, however.

Floating production platforms proposed for ice/iceberg areas are typically designed to be readily disconnected from their moorings and are operated in managed ice conditions. The ability of floating platforms to leave station allows the vessels to avoid extreme ice loads and also provides the capability for operations on a seasonal basis.

In ice-covered waters or regions prone to icebergs, the geometry and scantlings of the vessel must be chosen to handle ice loads. Any vessel will also need a mooring foundation design capable of handling environmental loads. Moored floating structures are typically used in water depths greater than 100 ft (30 m). However, yoke-moored FPSO's have been used in depths as shallow as 60 ft (18 m) in light first-year ice conditions (Bohai Bay).

4.9.1 Technical Feasibility

Seasonal exploration can be carried out using drillships and drilling barges and, in areas without multi-year ice, semi-submersibles or a TLP. However, for exploration, the only location that a floating structure might be capable of staying on station year-round might be the Bering Sea under light ice conditions. A Semi-rigid Floater structure like that presented in Section 3.3.2.6 (Figure 3-38) could work year-round under first-year ice conditions (loads ~ 22,000 tons (~ 20,000 tonnes)), but would need to have the ability to disconnect and leave station in the event of potentially higher loads.

No floating production structures could be economically designed to stay on station for the approximately 85,000 to 110,000 ton (75,000 to 100,000 tonne) multi-year ice loads found in the Beaufort and Chukchi Seas, and possibly northern Bering Sea depending on local ice conditions. In any design, an adequate factor of safety would need to be applied to the design load yielding an ultimate design load for the structure and moorings of something like 110,000 to 165,000 tons (100,000 to 150,000 tonnes).

In the southern Bering Sea, under light ice conditions, a floating structure might be feasible. However, additional information/data would be needed to fully assess the feasibility. Ice conditions in the Grand Banks are roughly analogous to operating conditions that predominate in the Bering Sea, particularly south of approximately 57° north latitude. North of 57°, pack concentrations tend to be greater than on the Grand Banks. In addition, the Bering Sea, due to the higher general concentration of ice, has pressure ridges which are not present on the Grand Banks which would need to be considered.

4.9.1.1 Ice Loads

In sub-arctic climates, with respect to managing ice loads, there are three approaches to the design and operation of a floating production structure in ice covered water: passive, semi-active and active (Makrygiannis et al., 2006).

The **passive** approach is to design the system to withstand interaction with all anticipated ice conditions (and other ice conditions). The **semi-active** approach is to design the system to withstand most environmental conditions, but also design the facility to leave station in anticipation of environmental events beyond the design capabilities of the system. An **active** approach would, as with the semi-active approach, utilize a floating structure that could move off station if environmental conditions dictated. However, to modify and control the operating environment, an active program of ice management is undertaken. Ice management involves the use of ice capable ships to break-up ambient ice conditions into small pans or rubble, or by means of towing, divert large ice features from the operating area.

In the Beaufort and Chukchi Seas, the design load event (~85,000 to 110,000 tons (~75,000 to 100,000 tonnes)) for a production structure would be the result of an interaction with a multi-year ice feature similar to one of the following scenarios:

- 6.2 mile (10 km diameter), 65 ft (20 m) thick floe traveling at 0.5 ft/s (0.15 m/s) over a contact width of 330 ft (100 m);
- 1.9 mile (3 km) diameter, 50 ft (15 m) thick floe traveling at 0.8 ft/s (0.25 m/s) over a contact width of 330 ft (100 m);
- Sustained load from a multi-year ice floe pushed against a structure by pack ice.

It is extremely unlikely that floes of this magnitude can be resisted by a floating production structure or ice management techniques used to bring the loads down to an acceptable level. With respect to the final point above, ice management techniques would not work for a year-round production scenario.

On the approach of unmanageable ice features, the production platform would need to disconnect from its moorings and leave station to avoid contact with these large features. If disconnection is required, the production platform will need to remain off station until ice conditions improve sufficiently for reconnection (this might possibly be until the spring season). As an example, this approach is used in Sakhalin for offloading, where the offloading buoy (SALM) remains in operation in the early winter with active ice management. When ice management is no longer possible, the buoy is laid into a trench on the sea-floor and operations are suspended until the spring.

In the southern part of the Alaskan OCS, where only first-year sea ice is present, the most important criteria for ice loading is the pack concentration (typically expressed as the ratio of ice to open water in tenths). At pack concentrations of less than 8 tenths, the ice loads are typically 50% or less of the loads at 10 tenths (note that 10 tenths ice denotes densely packed pans or blocks of ice, not an unbroken or refrozen sheet ice). However, this may not hold true if the ice pack concentrations less than 8 tenths contain large free-floating floes. Above concentrations of 8 tenths, loads increase with increased ice thickness (below 8 tenths ice loads are relatively insensitive to ice thickness but this will depend on whether or not free-floating floes are contained in the pack). In pack or managed ice, the loads are also largely independent of the drift speed of the ice (Comfort et al., 2001). These conclusions have been drawn from a wide range of model test data, with limited validation from operational experience. Figure 4-23 displays the effect of ice concentration on peak loads for various structure types in managed ice environments.

There is no known precedent for a moored structure operating in unmanaged continuous heavy ice conditions, but a wide range of model test experiments have been conducted to evaluate this scenario (Comfort et al., 2001). In general, ice loading will be greater in unmanaged ice than in managed ice. Ice thickness and drift speed become important factors in the ice loading in unmanaged ice, primarily due the need of the structure to break, as well as clear, the ice sheet. In particular, multi-legged semi-submersibles can experience loads disproportionate to the size of the individual column sizes if ice jams in between the legs of the structure.

Another significant potential issue with regards to the use of a floating structure in heavy (greater than 8 tenths) ice cover is the behavior of the ice as it interacts with the structure. If ice is forced under the structure, interaction with the mooring and riser systems might be problematic.

4.9.1.2 Wave Loads

The 100 year return wave conditions for the areas of study are shown below in Figure 4-24. It can be generalized that the intensity of the design wave condition decreases from south to north.

Wave loading on spar, semi-submersible or TLP designs tend to be lower than those acting on an FPSO design, due to reduced waterplane area (and therefore greater wave transparency) and by the nature that the natural response frequencies of these designs tend to be outside (faster or slower) the wave frequencies.

For illustrative purposes, Figure 4-25 illustrates approximate design wave loads for a 214,000 ton (194,000 tonne) (displacement) FPSO based on the environmental conditions given in Figure 4-24. An FPSO in the southern parts of the Bering would be subject to lower wave loads than those encountered on the Grand Banks of Newfoundland.

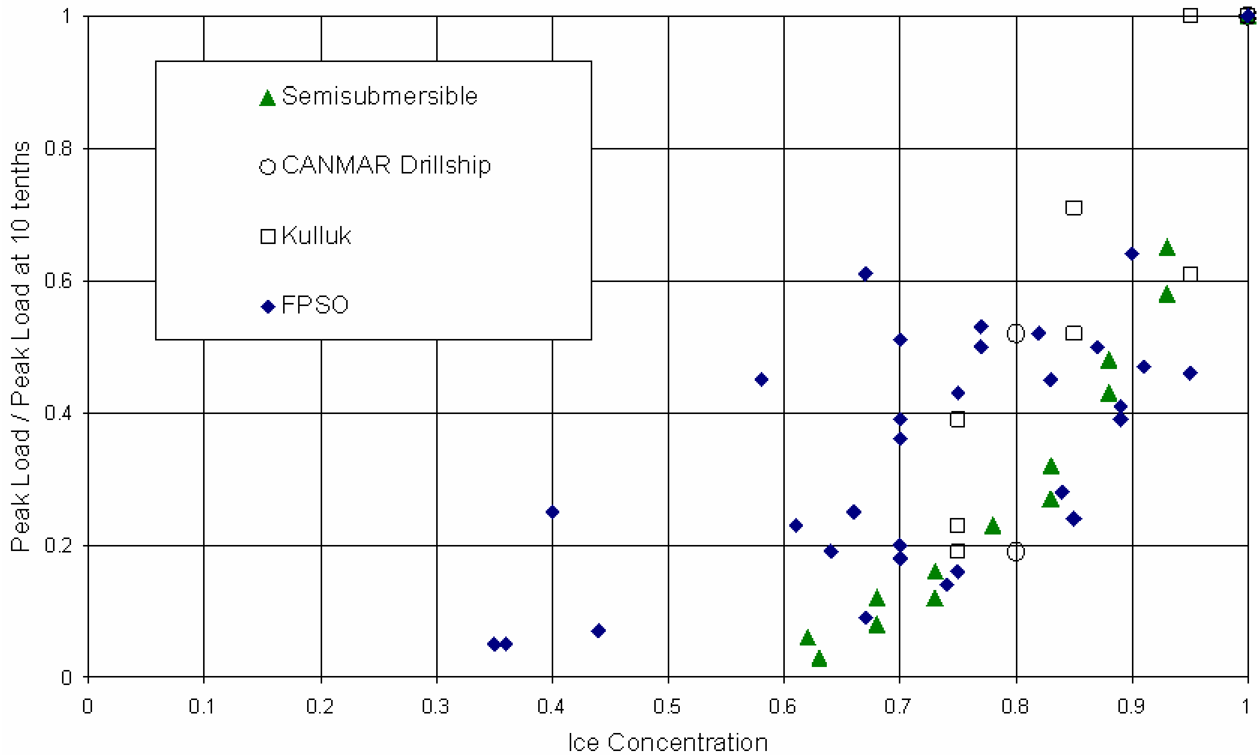


Figure 4-23: Peak Loads in Managed Ice - Effect of Ice Concentration on Various Structure Types (Reproduced from Comfort et al., 2001)

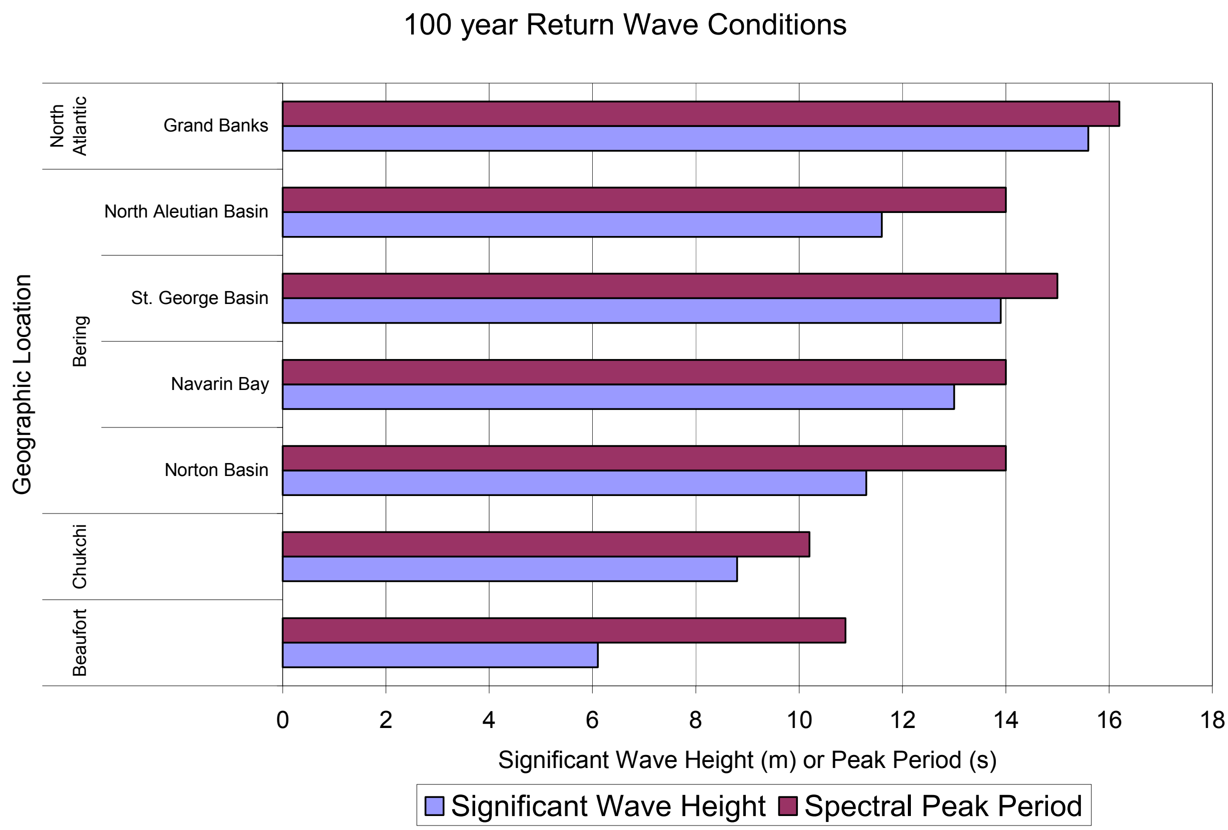


Figure 4-24: 100 year Return Wave Conditions in Area of Study; Grand Banks added for Comparison

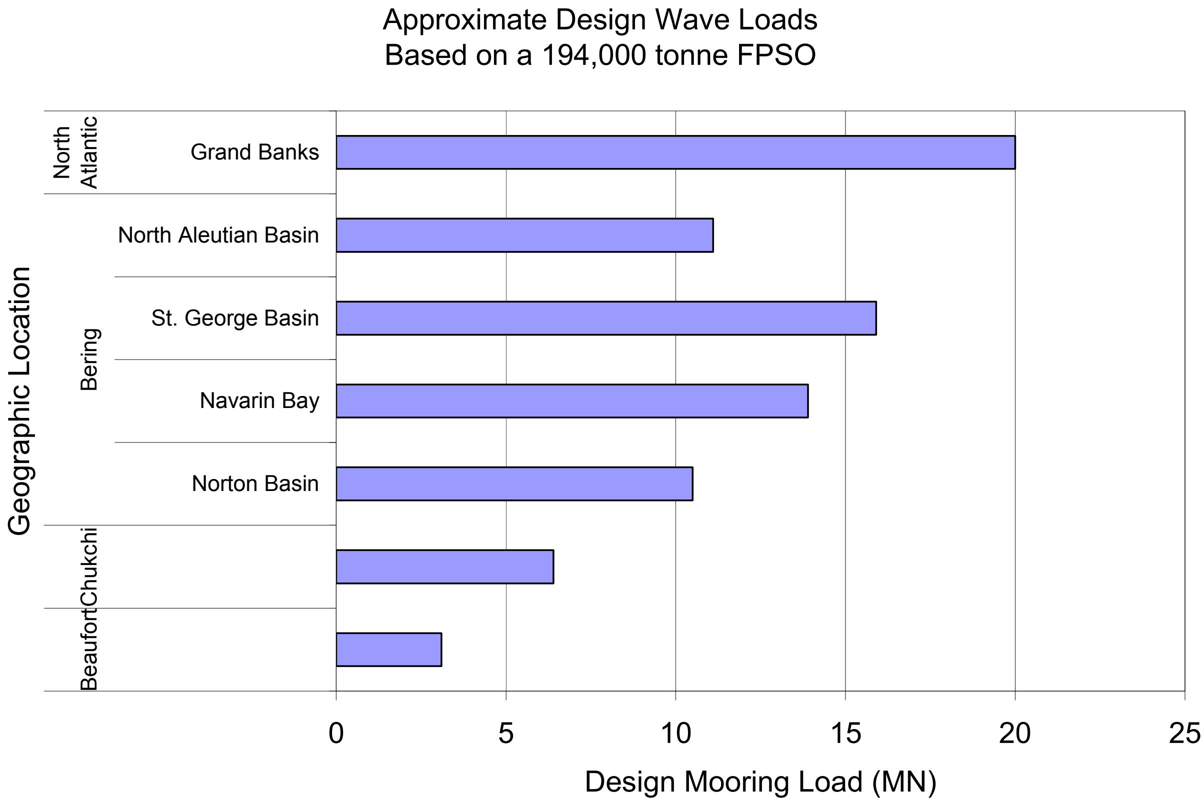


Figure 4-25: Approximate Design Wave Loads - FPSO Basis (Note: wave loads for the Beaufort and Chukchi are for summer conditions and are not meant to imply year round FPSO operations)

4.9.1.3 Dynamic Positioning

Dynamic positioning will typically be used by vessels acting in an exploration role, e.g. drillships and semi-submersibles, but dynamic positioning thrusters have also been used to supplement passive moorings on production platforms in marginal ice areas, e.g., Terra Nova on the Grand Banks.

The dynamic positioning systems installed in deepwater exploration vessels require significant thrust availability for sea-keeping in waves. These systems may also provide sufficient thrust for station keeping in broken first-year light ice conditions. There is the additional requirement that the vessel hulls be appropriately reinforced for operation in ice covered waters.

As a example of the technical (if not perhaps economic) feasibility of exploration at high latitudes, a drilling expedition was conducted in 2004 in the high-arctic where, with the ice-management support of two heavy icebreakers, the dynamically positioned drillship *Vidar Viking* successfully maintained station for up to 8 days while drilling at 88° latitude in ice up to 9 ft (2.7 m) thick (Keinonen et al., 2006).

4.9.1.4 Mooring

Modern mooring systems can provide extremely robust anchoring systems for floating structures. In most areas of application, mooring systems for floating structures are governed by wave loading.

In the Beaufort and Chukchi Seas, unfactored loads from first-year ice will be on the order of 45,000 kips (200 MN) (on a fixed structure) while unfactored loads from multi year ice can approach 225,000 kips (1000 MN) (on a fixed structure). Maximum ice loads in these areas are generally considered to range from 20 to 100 times the wave loads. It is possible in the southern Bering, in light first-year ice, that the dominant design criteria of the vessel mooring system could be wave loading, depending on the mooring stiffness. However, this would need to be confirmed in any detailed evaluation process

To provide a frame of reference for the amount of restoring force provided to a moored vessel, the approximate design mooring force for a selection of FPSOs and drillships is plotted[1] in Figure 4-26 with two icebreaking ships[2] to provide a comparison. The thrust or mooring system resistance available from such vessels is considerably less than forces from design ice conditions for both year-round exploration (22,000 ton (20,000 tonne)) and production (110,000 ton (100,000 tonne)) conditions.

[1] Adapted from Figure 4.1 of PERD (1998).
[2] Thrust is estimated from published information of ship break-power, with the assumption of approximately 0.026 tonnes of thrust per kW break-power.

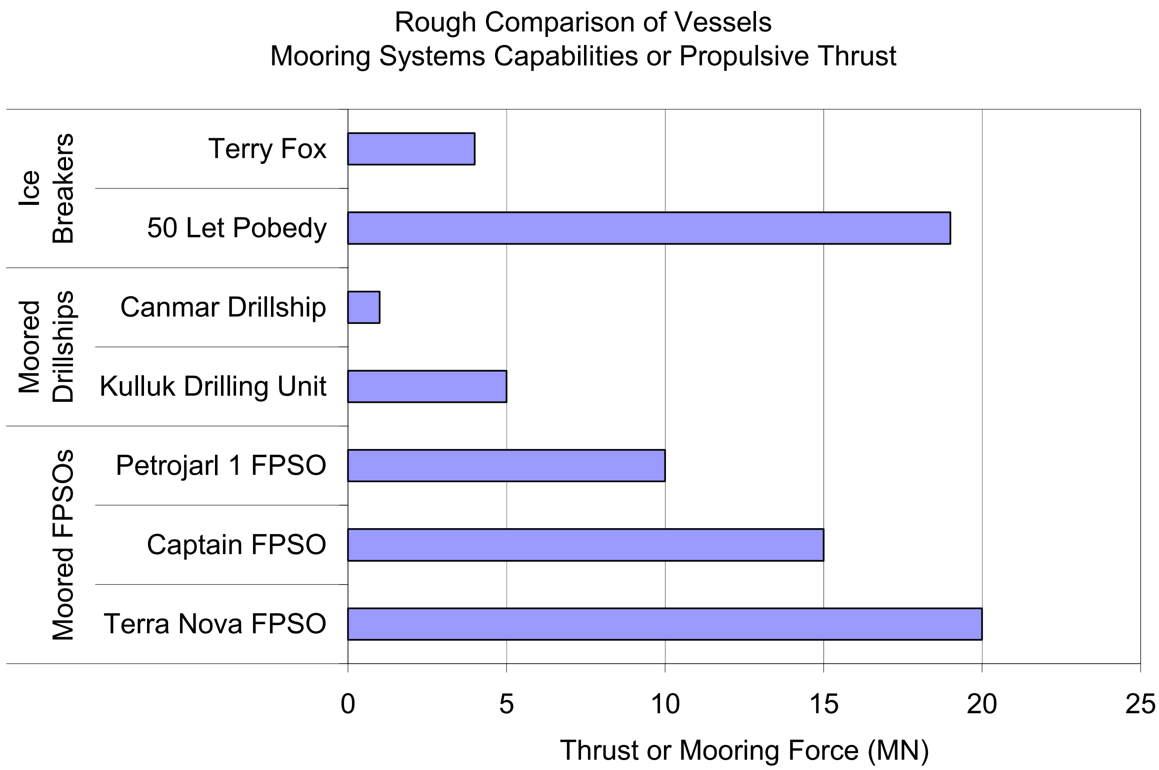


Figure 4-26: Rough Comparison of selected Vessel Mooring Systems; with selected Ice Breaker Bollard Thrust for comparison (Comfort et al., 2001)

4.9.1.5 Steel vs. Concrete

Steel has predominated as the construction material for floating structures (both for exploration and production) in ice covered waters. In general, this is due to the familiarity of ship builders and regulators with the material and its performance in ice from the experience with ice breaking ships.

Concrete has been proposed as a construction material for FPSO (Husky, 2001), Spar (Technip, 2004) and Semi-submersible designs of production structures. But, to date, no concrete floating structures have been installed in ice covered waters. These concepts have not been adopted due to the perceived novelty of the design and uncertainty of fabrication methods and costs (Husky, 2001); however, a concrete spar design is believed to be among design options considered for the development of the Shtokman Field in the Barents Sea.

4.9.1.6 Seismic

Moored floating structures are not generally critically affected by seismic activity. The vessels will respond to pressure waves from nearby seismic events, but the frequency of seismic-induced pressure waves are such that the ship will not respond with large motions, and so these pressure waves will not constitute a design condition. There may be some foundation considerations with respect to seismic events.

Seismic event induced waves (tsunami) offshore are of low amplitude and long wavelength, and again will not induce significant motions or loads of a moored structure in deep water. In the case of shoal water installations (or other bottom founded structures for that matter), the event of a tsunami may be a design consideration.

4.9.1.7 Oil Storage

FPSO and Spar designs have integral oil storage capability and could be used in conjunction with offloading shuttle tankers.

TLP and Semi-submersible based production facilities typically do not have integral storage and would require a pipeline connection for export. An FSO or direct loading of shuttle tanker can be used with a floating production platform without integral storage, but it is likely that a separate production platform and FSO would prove to be more expensive than a single FPSO of equivalent capacity (if a floating concept was feasible).

4.9.1.8 Floating Platform Concepts

Floating structure options include those presented in the following paragraphs. *Their applicability for use in the Alaskan OCS would depend on whether or not the structure was permanent or temporary, ice environment, water depth, etc. and would have to be evaluated during any detailed assessment. However, floating production systems for the Beaufort Sea, Chukchi Sea and possibly North Bering Sea are considered to be unfeasible. Floating production systems for the South Bering Sea may be found to be feasible.*

Drillships are either turret moored and/or utilize dynamic positioning (DP) to maintain station. The turret or DP system allows the vessel to weather-vane with the environmental loads. Moorings would tend to be used in shoal waters while DP would be used in deeper waters.

Drilling Barges can be designed to be insensitive to the direction of environmental loading and can therefore use a conventional mooring arrangement.

Semi-submersibles will, like drillships, use mooring and/or DP systems for station keeping. Semi-submersible designs can be used for exploration or production platforms, and have been used in the Bering Sea. Under anything but very light ice conditions, there is the possibility of ice jamming in between the structure's legs, thus creating the potential for very large global ice loads. Semi-submersibles do not have storage capacity and must have either a pipeline connection, a connection to an FSO, or direct offloading to tankers.

Tension Leg Platforms (**TLP's**) use taut moorings to maintain station and can be round or conical in shape as to be insensitive to the direction of environmental loading. As with semi-submersibles, TLP designs typically do not have storage capacity and will operate with a pipeline, FSO, or direct offloading to tankers.

Semi-rigid Floater which could work as an extended, possibly year-round, exploration platform in the Beaufort and Chukchi or south of the Bering as a year-round production and storage platform.

Floating Production Storage and Offloading (**FPSO**) platforms will typically be turret moored to allow the vessel to weather-vane with the environmental loads.

Yoke Moored FPSOs have been used in shoal waters (60 to 82 ft (18 to 25 m)). The yoke is itself a bottom-founded structure that allows the FPSO to weather-vane, and provides the connections from the production platform to the wells. This design requires that the yoke penetrate the water's surface, requiring that the yoke structure be capable of breaking ice. This system has been used in Bohai Bay where first-year ice thickness may reach 2.3 ft (0.7 m).

Spars are typically very deep draft vessels (~295 ft (~90 m)) which are suitable only for deep water installations. They have been proposed for developments in ice environments as the small water plane area and symmetrical shape will help to minimize ice loads. Spar designs also have integrated oil storage capacity.

4.9.1.9 Assessment by Alaskan OCS Area

Table 4-14 presents an overview of the possible use of floating structures for seasonal exploration, year round exploration and production in the Alaskan OCS areas of study.

Floating structures have been and will continue to be used for seasonal exploration. A floating structure will likely be only able to carry out year round exploration operations in the south Bering Sea under light ice conditions. However, a Semi-rigid Floater type structure that can handle a design ice load of 22,000 tons (20,000 tonnes) could be considered for year-round exploration. Based on current technology, no floating type structures could operate as a production structure in the most of the Alaskan OCS areas under investigation in this study. It is possible that a production structure might work in the southern Bering under light ice conditions.

Table 4-14: Feasibility of Applicable Floating Technologies in Study Areas

	Seasonal Exploration (July – November)	Year Round Exploration	Production
Beaufort Sea	Y	N[1]	N
Chukchi Sea	Y	N[1]	N
North Bering	Y	N[1]	N
South Bering	Y	P[1, 2]	P[2]

Notes: Y = can be carried out
N = not feasible
P = possible – further ice study and data collection needed

A significant consideration for any of the options would be the potential interaction of ice with the risers and mooring system as ice moves around and under the floating structure.

4.9.2 Exploration Operability in the Alaskan OCS

An assessment has been made of floating exploration operability in the areas of Alaskan OCS covered in this study.

4.9.2.1 Beaufort Sea Operability

Due to significant ice coverage in the Beaufort Sea, drilling operations in water depths of 200 to 655 ft (60 to 200 m) using conventional technology and mobile offshore drilling units (MODU's) available on today's market can expect to operate from July to mid October. Ice management resources such as adequately equipped and constructed vessels are required as well. Statistical wave data from the area suggests that there are no extreme wave induced motions to contend with, such as would be the case off Eastern Canada, for

[1] Semi-rigid Floater or FPSO could work in 330 ft+ (100 m+) water depth – such a structure could handle a design load of 22,000 tons (20,000 tonnes) but may have to leave station in the event of anticipation of higher loads.
[2] In light ice conditions.

example. An ice class drillship or specialty drilling units such as the Kulluk would likely be the most suitable rigs to utilize for drilling operations. Although a compromise in drilling efficiency is likely the case due to infrequent use or outdated drilling packages, these rig designs offer some protection from ice crush loads where others do not. Use of more modern drilling units without ice classification or design considerations would require detailed examination of risk and eventual agreement from the regulator.

4.9.2.2 Chukchi Sea Operability

Similar to the Beaufort, significant ice coverage in the Chukchi Sea means drilling operations in water depths up to 200 ft (60 m) using conventional technology and/or MODU's available on today's market can expect to operate from July to early October. Ice management resources such as adequately equipped and constructed vessels are required as well. It is apparent from statistical wind/wave data that the Chukchi Sea has more extreme wave conditions, potentially making a "Kulluk-like" drilling unit unsuitable for this area. Therefore, an ice class drillship would likely be the most suitable to utilize for drilling operations. A semi-submersible, due to its superior motion characteristics compared to a drillship, could also be a suitable option. The main drawback to a semi-submersible is the lack of ice classified rigs available on today's market. As pointed out earlier, use of more modern drilling units without ice classification or design considerations would require detailed examination of risk and eventual endorsement from the regulator.

4.9.2.3 Southern Bering Sea Operability

The Southern Bering Sea study area includes St. George Basin, Navarin Bay, North Aleutian Basin, and Norton Basin.

It is clear from the location, metocean, and ice data that the Navarin Bay, St. George Basin, and North Aleutian Basin areas are relatively ice-free for approximately 8 months of the year. This being the case, these areas are more favorable for conventional drilling units such as semi-submersibles and drill ships on a seasonal basis. These areas are also subject to the greatest wind/wave conditions of the study area. For example, wave data suggests 100-year significant wave height of almost 45 ft (14 m). This would place 100-year maximum wave height at approximately 60 ft (18 m), with potential for occasional occurrences higher than this. Historical data shows drilling activity in the Navarin Bay and St. George Basin with semi-submersibles with the earliest spud in August and latest end in March. The extreme winds in the area of approximately 110 knots maximum precludes use of drillships if an extended drilling program is envisioned in St. George Basin due to potential wind induced loads which could move the vessel off location past acceptable limits. In addition, there are areas in the world where year-round drilling activity has taken place in comparable conditions – the Grand Banks off Newfoundland.

The Norton Basin has had drilling activity in the past in shallower waters where jack-ups can be utilized. In deeper waters, it is anticipated conditions are very similar to the Navarin Bay, St. George Basin, and North Aleutian Basin areas.

4.9.3 Constructability

In all cases, the expected ice load will likely dominate the design of the floating structure's hull, in terms of its ability to withstand local ice loading and in providing minimum resistance to passing through the ice.

The new IACS Unified Requirements for Polar Class Ships will be implemented in March 2008. Most classification societies and regulators will likely require the hulls of floating structures to comply with these requirements in Arctic waters, although Polar Class designation my not be required in the areas south of 60° north latitude.

With regards to commissioning and tow out, FPSO, semi-submersible and TLP designs offer the option of dock side installation of the topsides units, and tow out of the assembled unit. Spar structures, due to their extreme draft, are normally towed out horizontally and upended on site, requiring the installation of topsides at the installation site.

4.9.4 Capital Costs

Capital costs for all types of construction have risen rapidly world wide in the last three years. To provide a reference for potential development costs, the preproduction development costs of the two FPSO developments on the Grand Banks are presented in Table 4-15. Also presented are costs for two other proposed development concepts; an FPSO development in the Arctic waters off of Greenland (EnCana, 2005) and a proposed mobile Semi-rigid Floater system (CKJ Engineering, 2005) intended for exploration in arctic waters (Section 3.2.2.6).

Table 4-15: Project Capital Costs for Selected Developments at Time of Completion or Proposal (USD)

Source	Project	Year	Total Preproduction ($ MM)	Structure Only ($ MM)
Completed Projects				
Husky	Terra Nova FPSO	2002	2,800	n/a
Husky	White Rose Sea Rose FPSO	2005	2,400	n/a
Proposed Projects				
EnCana	Greenland FPSO	2005	1,000	430
CKJ Engineering Ltd.	Semi-rigid Floater	2005	n/a	500

4.9.5 Environmental Considerations

Apart from the environmental considerations common to all offshore oil developments in arctic waters, the subsea environmental impact of a floating structure will be localized to the anchor and well sites (specific to the installation of a moored structure in the Alaskan OCS).

4.9.6 Operations, Maintenance, & Repair

Operations in ice covered waters impose additional requirements to normal offshore operating requirements. Ice forecasting, tracking and management is a vital component of operations in ice covered water.

In addition to ice management at the exploration/production site, ice management may be required for the shuttle tankers (if required), supply vessels, and for access to any onshore based facilities.

Evacuation of personnel from a floating platform (or in fact any platform beyond the landfast ice zone) in ice covered water remains a challenge for any development. Use of standard evacuation devices in ice, particularly in heavy concentrations of ice, is not possible. The primary challenge is to have an evacuation system that can function in such a wide range of environmental conditions, and while significant developments have been made recently in developing evacuation systems, much development is still required in this field.

4.9.7 Abandonment & Decommissioning

Decommissioning of production platforms in the North Sea has resulted in legislated requirements for the platforms to be decommissioned as opposed to abandoned. Although many of the North Sea platforms were intended to be disposed of at sea (or left in place in the case of fixed structures), regulators have virtually banned this practice and have required the removal of the floating structure for reuse or to be salvaged in other ways. For example, the Brent Spar in the North Sea was (with regulatory approval from UK authorities) to be sunk offshore, but public out-cry resulted in the platform being used as a ferry terminal.

Any development will most likely require the complete removal of the floating structure from the site to be re-commissioned at a different field, or salvaged or re-purposed if re-commissioning is not possible or economical.

4.10 Subsea Solutions

4.10.1 Technical Feasibility

In some cases, there may not be a requirement for an island/platform offshore. If the wellhead is located in water of sufficient depth, protection from ice would not be necessary. This was the case for the Drake PanArctic project in the 1970's, where the well location was chosen such that the top of the wellhead was deep enough to avoid contact by ice keels, predominantly less than 150 ft (45 m) deep in that area.

In areas with water depths less than the maximum ice keel depth, glory holes may need to be considered to protect the subsea facilities from ice ridge keels. This is considered to be approximately 200 ft (60 m) water depth in areas subjected to ice gouging.

There is a lower limit to where such protection structures would be effective as well. Glory holes would only offer protection from gouging keels. Where active ridge building is taking place (around 65 ft (20 m) water depth), there is the potential for a ridge to be pushed into an open glory hole. Further site-specific analysis would be required to determine the appropriate water depths between which this protection strategy could be used.

4.10.1.1 Subsea Tiebacks

Improvements in the area of subsea facilities and processing have been made in recent years in the pursuit of resources in harsh and remote environments. As a result of these improvements, fields requiring longer, deeper subsea tiebacks are now becoming much more technically and economically feasible. Gas tiebacks have reached 105 miles (170 km) (Statoil Snøhvit) and oil tiebacks have reached 40 miles (65 km) (Shell Expro “Penguin”).

Subsea processing could offer advantages to Arctic development due to potential distance between wellsites, the harsh environmental conditions and water depths further offshore. Subsea processing has primarily evolved around the development of: subsea booster pumps, subsea compressors, subsea separators and subsea gas dewpointing and dehydration.

For subsea tieback options on the Alaskan OCS, production would be through remotely-operated subsea facilities with pipelines running to offshore facilities and/or landfall. Offshore structures would not be required except during drilling of the wells and installation of the subsea equipment. Depending on the development, water depth, tieback distance and landfall location will vary. Technology has been developed (and continues to be progressed) which allows for separation and disposal of produced water subsea. This helps reduce flow assurance issues associated with pipelines and flowlines, as well as minimizing above water or onshore facilities. However, facilities still may be required to allow for the injection of hydrate inhibitors into the subsea facilities/pipelines/flowlines.

One of the most notable subsea projects is the Ormen Lange project. This project is comprised of subsea equipment located in 2800 to 3600 ft (850 to 1100 m) water depth and 75 miles (120 km) off Norway. The project will flow 2.5 Bcf/day (70 million m^3/day) of gas and 500,000 bbl/day of condensate to an onshore processing facility. Work is also planned to advance/qualify technology incorporate a subsea compression station into the project to boost production starting in 2015, as opposed to build an offshore platform to house compression facilities (Offshore Engineer, 2007)

4.10.1.2 Glory Holes & Protection

The risk of impact with an ice keel is the primary driver for protection of subsea facilities in the Alaskan OCS, although secondary factors may come into play such as operational/maintenance issues or protection from fishing equipment, ship anchors, etc. The type and degree of protection is usually determined through a site-specific risk assessment, which involves understanding the probability of ice incursion and the consequences should an impact occur.

Glory holes (Figure 4-27) are excavations in the seafloor into which subsea facilities can be installed for protection from scouring ice keels. This applies, of course, if the discoveries on the Alaskan OCS are located in an active ice gouge zone out to about 165 to 200 ft (50 to 60 m) water depth, depending on acceptable risk.

Two existing projects use open glory holes to protect wellheads and associated subsea equipment from iceberg keel impact. These are the Terra Nova and White Rose projects located on the Grand Banks (Canadian east coast) where, to date, glory hole excavation has been the preferred method of subsea facilities protection.

The White Rose project uses three glory holes in water depths ranging from 395 to 410 ft (120 to 125 m), whereas the Terra Nova project uses five glory holes in water depths ranging from 310 to 330 ft (95 to 100 m). Table 4-16 presents a summary of the glory hole dimensions from these projects.

Other protection strategies have been considered for the Canadian east coast including cased glory holes, soil/rock berms and concrete structures. However, open glory holes have been identified as the optimum solution for protecting subsea facilities from gouging iceberg keels in this region (Offshore Magazine, 2007). Again, depending on the water depth of development, this may not necessarily be the case in the Beaufort or Chukchi Seas.

A site-specific risk analysis of potential ice keel interaction with subsea facilities in the Alaskan OCS was beyond the scope of this study, but the following options would likely be considered:

- Do nothing, i.e., the risk analysis may suggest that discrete subsea facilities (not pipelines) placed directly on the seafloor, with no additional protection, will be acceptable (dependant on water depth);

- Reduce the probability of ice keel impact by placing subsea facilities in a glory hole, such as on the Grand Banks; and

- Reduce the probability (and/or consequences) of ice impact through some sort of additional mechanical protection of the subsea facilities.

The use of other methods, such as cased glory holes, may have some potential for smaller footprints like single wellheads.

Figure 4-28 is a sketch of a mechanical subsea facilities protection concept for the Canadian Beaufort Sea for water depths up to around 100 ft (30 m). In this concept, a steel caisson is floated in and set-down in a glory hole, and then the glory hole is backfilled. The upper caisson is sacrificial and will shear away during impact with a scouring ice feature.

The robust “ice lid” provides protection of the subsea facilities from the scouring ice above. This system has potential for the Canadian Beaufort because a more pressing need for mechanical protection is perceived by industry. For example, ridge-building activity in first-year ice conditions may form a grounded ridge inside the glory hole area. Pack ice movement could then cause this grounded ridge to move and threaten subsea facilities.

Excavation of a glory hole is required to install this system anyway and in deeper water (100 ft (30 m) plus maybe) the glory hole alone may provide sufficient protection from ice keels. Again, for small footprint subsea facilities (< 33 ft or 10 m diameter), a backfilled caisson may offer some protection against fishing equipment or undue silting-in of the glory hole, but for larger footprints (> 100 ft or 30 m), glory hole excavation alone may be the preferred method (depending on water depth).

4.10.1.3 Feasibility of Application of Subsea Technology at Location Scenarios

The use of subsea production facilities is another method of production for areas subject to ice gouging and can be envisioned as a viable alternative in certain cases on the Alaskan OCS. As presented previously, the technology has been used for long, deep tiebacks and in harsh environments subject to ice.

Subsea facilities can potentially be used at any of the location scenarios considered in this study. These facilities would need to be located in glory holes within the zone of gouging but could be placed directly on the seabed in areas of minimal risk.

Conceptually, where a subsea to beach option is not chosen, artificial gravel islands might be considered for water depths less than 50 ft (15 m), bottom-founded platforms from 50 ft (15 m) to some water depth where they are no longer technically or economically feasible, and, in deeper water, subsea solutions to shore or a platform in shallower water might be considered. When evaluating a subsea tiebacks solution, access to hydrocarbons might first be considered through extended-reach drilling followed by subsea wells tied back to the main production platform.

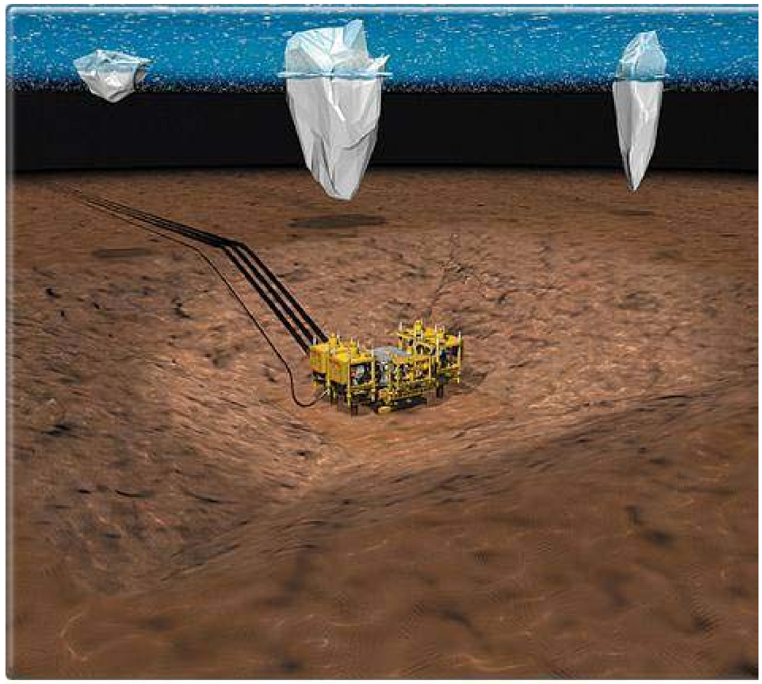


Figure 4-27: Glory Hole (From Coflexip Stena, 2000)

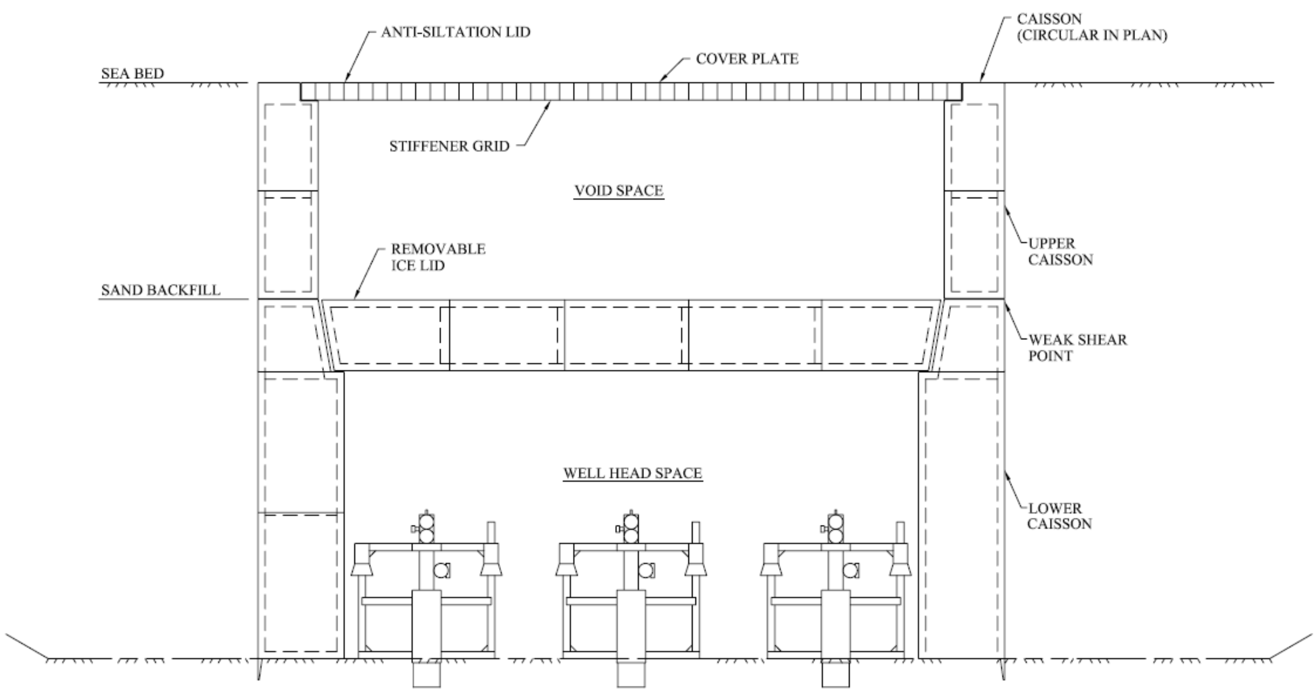


Figure 4-28: Mechanical Subsea Facilities Protection Concept for Water Depths to 30 m in the Canadian Beaufort Sea

Table 4-16: Overall Glory Hole Dimensions (Technip, 2001)

Field	Glory Hole	Base Dimensions, ft (m)	Depth, ft (m)	Side Slopes	Ramp Slope
Terra Nova	Southeast	82 x 82 (25 × 25)	33 (10)	1:3	
	Northwest	82 x 82 (25 × 25)			
	Northeast	148 x 82 (45 × 25)			
	Southwest	213 x 82 (65 × 25)			
	Far East	142 x 76 (43.2 × 23.2)	34 (10.3)		
White Rose	Southern	190 x 146 (58 × 44.4)	30 (9)	1:1.8	1:5
	Central	191 x 163 (58.3 × 49.7)			
	Northern	125 x 56 (38 × 17)			

For the location scenarios in water depths less than 65 ft (30 m), the use of subsea to beach or subsea tiebacks might be considered. However, this is in a region of grounded ice and ridge building. Therefore, a cover would likely be required to protect the facilities from ice keels entering the glory holes.

Open glory hole concepts may be sufficient in areas with greater than 100 ft (30 m) and less than 200 ft (60 m) water depth for subsea to beach or subsea tie back concepts. However, site-specific analyses would need to be carried out to assess the risk of an ice keel entering the glory hole and damaging facilities. At the 200 ft (60 m) water depth locations, depending on the ice gouging regime, it may be possible to put the subsea facilities directly on the seafloor.

Deeper water location scenarios will likely require some type of subsea facilities on the seabed, whether they are part of a subsea to beach option or tied into a central production facility.

The other aspect with regards to a subsea to beach option (or a tieback option, for that matter) is the distance to shore or to a platform. Recent records were approximately 30 miles (50 km) for oil and 100 miles (160 km) for gas. Therefore, some of the location scenarios will require additional technological development or facilities for distances greater than these.

In all cases, the overall depth of the glory hole (where used) and the requirement for tie back flowline burial would need to be determined through appropriate risk analyses.

4.10.2 Constructability

Installation of subsea equipment will require a number of dedicated vessels for the installation activities, as well as ice management capabilities. Installation may also require diving and ROV operations. Final seabed leveling using specialized equipment may be required to aid in positioning the seabed equipment. Other vessels would be required for ice management, survey, support, supply, etc. All would be required to be suitable for Arctic work.

Flowlines between subsea facilities, to a platform or to shore are given many of the same considerations as pipelines discussed in Section 4.11.

With regards to glory holes, there may be some uncertainty with regards to soil conditions in the Alaskan OCS. Geotechnical and geophysical information would need to be obtained to support an excavation. The mix and strength of soils can vary within a single excavation and the presence of boulders, cobbles, etc., will be difficult to identify before the start of excavation.

Equipment capable of digging glory holes will depend on water depth and could include cutter suction dredges, trailing suction hopper dredges, clamshell dredges, large drills, and other ROV based subsea excavators. Because of the uncertainty and variability about soil conditions, glory hole excavation methods that are less sensitive to soil conditions are preferable. There is considerable experience with the use of large “drill bits” to excavate well cellars (glory holes) in fairly challenging soil conditions.

4.10.3 Capital Costs

Subsea tieback costs are well established in the offshore oil and gas industry. Costs associated with long subsea to beach projects can be put in perspective by looking at some of the large subsea projects including Tordis, Snøhvit and Ormen Lange. Costs associated with wells, subsea booster pumps, subsea compression, subsea separation and subsea gas dewpointing and dehydration may need to be considered.

The selection of excavation equipment will depend on a number of variables including R&D/field trials of selected equipment, schedule, weather, presence of ice during construction, availability of equipment that is Jones Act compliant and required upgrades to equipment to work in an Arctic environment.

Excavation costs using a floating dredge can be estimated based on a current cost of $250,000 for a large dredger, plus mobilization/demobilization costs. Actual production rates would depend on the depth of glory holes required and site-specific soil conditions. Other vessels would be required for ice management, survey, support, supply, etc.

If a steel caisson was required in the glory hole, the additional cost to install and backfill a steel caisson is not prohibitive. A small caisson could be constructed for around $2 to $3 million USD and larger caissons for up to $30 million USD (excluding costs to backfill). At this cost, caissons could be attractive for operational/maintenance reasons or for additional “peace of mind” for facilities operated remotely from shore.

4.10.4 Environmental Considerations

As with dredging for pipeline trenches, glory holes will be required to be trenched to approximately 165 to 200 ft (50 to 60 m) water depth in areas subjected to ice gouging. The overall size and depth of the glory hole will be a function of the number of wells, height of the subsea equipment and required clearance between the bottom of the ice keel and the top of the equipment.

By the nature of excavating a glory hole, some seabed disturbance will take place. Areas will be required for spoil disposal. Trenching and disposal will create some turbidity and some habitat alteration. It is anticipated that coarse sediment would settle to the seafloor very near the trench, but that a plume of fine suspended sediment would drift several miles (MMS, 2003).

The placement of subsea facilities which do not require a glory hole will have minimal environmental considerations. Glory hole or not, a pipeline/flowline will be required to transport the produced hydrocarbons from the well site.

4.10.5 Operations, Maintenance, & Repair

A significant consideration for operation of subsea facilities will be flow assurance. Depending on the nature of the development, hydrate inhibition will need to be considered which may require an inhibitor injection and recovery system be installed on the platform/island or onshore.

Asset integrity management, scheduled maintenance and asset reviews will be an important aspect of the operation of subsea facilities. Subsea systems will require that periodic inspection, maintenance and repair activities be carried out which will require the deployment of working and support vessels. Ice management capabilities may be required to support these activities. An ROV or divers may also be deployed to accomplish these tasks. Having critical spares on hand will also need to be considered given the remoteness of the region.

An important aspect of the use of subsea facilities remote from shore or an island/structure is intervention. Unplanned interventions during open water may be handled with a construction vessel or support vessel. Any intervention work that needs to be done in winter would be very difficult and may require an ice class vessel with a moon pool and a work ROV. One of the big challenges will be equipment and personnel logistics.

4.10.6 Abandonment & Decommissioning

Decommissioning procedures for offshore installations that have reached the end of their useful life are usually included in governing legislation. There are also international agreements relating to decommissioning that address removal and deep-sea disposal. For example, the International Maritime Organization (IMO) has developed Guidelines and Standards for the removal of Offshore Installations and sets out conditions to protect navigation and maintain safety.

Some general requirements in other jurisdictions with regards to decommissioning include designing all subsea facilities such that, upon termination of production, they will be capable of being covered or removed so that the area is returned to a fishable condition. This may require that glory holes be filled in after the completion of a project. Based on these requirements, decommissioning will likely be an important consideration for any Alaskan OCS development project that uses subsea technology.

4.11 Pipelines & Flowlines

There are a number of issues to be considered with regards to the protection of pipeline and flowlines in arctic environments such as the Alaskan OCS, over and above what might normally be considered for pipeline design. These include issues surrounding design, construction, operations, maintenance and repair which are addressed in this Section. Pipelines have been designed, constructed and are operational, but these are in relatively shallow water depths and relatively close to shore. Pushing the limits to developments further offshore in deeper water will require additional consideration be given to some of these aspects.

4.11.1 Technical Feasibility

4.11.1.1 Design Issues

Surveys & Data Collection

It is accepted that a certain amount of data will need to be collected in support of arctic offshore pipeline design and construction planning; more than what would normally be collected for a pipeline in more temperate climates or above ground arctic pipelines. In general, it might be expected that the following be carried out:

- Detailed Bathymetric Survey;
- Ice Gouge Data Collection;
- Detailed Geotechnical Survey / Laboratory Testing (including permafrost testing);
- Sediment Transport Studies;
- Detailed Shore Crossing Survey and Evaluation of Shoreline Erosion;
- Ice Surveys.

Several years of data might be expected to support pipeline design and construction planning. It should be considered that data collection efforts may be hampered by ice or lack thereof in any particular year and that several seasons may be required to successfully gather all the data necessary for design and construction planning.

Geotechnical Conditions

Geotechnical information (field and laboratory) needs to be collected and analyzed to determine soil properties which will be used in design and the evaluation of potential thaw settlement. The results of the geotechnical testing/analysis, along with the pipeline design analyses, can also be used to determine or confirm trenching and backfilling requirements, thaw settlement or frost heave.

Pipeline Routing

Given the cost of arctic offshore pipelines, potential routing of offshore arctic pipelines is primarily evaluated based on minimizing length of pipeline and minimizing the potential loading from environmental conditions. Also of significant importance is minimizing the impact on the environment and maximizing use of existing infrastructure.

Metocean Conditions

The characteristics of the Arctic environment include ice-free summer ocean conditions during which waves and currents achieve their maximum values, partial ice cover conditions during spring break-up and fall ice freeze-up, which dampen wave generation and propagation, and extremely cold winter conditions when large expanses of open water generally do not exist, thereby precluding wave generation.

Meteorological factors important to the design and construction of the arctic facilities include wind, temperature, precipitation, barometric pressure and visibility. Ocean currents are normally of secondary importance, as other loadings will likely govern. However, currents can cause seabed erosion which could expose the pipeline or affect its stability. Water level fluctuations caused by tides, storm surge, winds, etc. must be considered in pipeline design. Waves must be considered in various aspects of the pipeline design, most notably sediment transport and pipeline stability.

All of these factors must be considered when evaluating constructability as they can create potential operational difficulties during periods of offshore summer construction, marine vessel transport, maneuvering and docking.

Ice can be characterized as landfast ice, the transition or shear zone, seasonal pack ice, first-year and multi-year pressure ridges, ice islands and icebergs. In the Arctic, heavy ice ridging typically happens at the edge of the landfast ice zone. In the Arctic, the average length of the ice coverage season could be approximately 300 days.

Ice Gouging

It is generally accepted that offshore arctic pipelines would need to be trenched to some depth below the seabed to protect the pipeline from the effects of pressure ridge ice or iceberg keels. Gouging of the seafloor is a nearshore feature for most northern continents where ice is present and where ice/iceberg keels travel into water with depths less than the keel draft, forming a gouge mark on the seafloor.

An offshore pipeline in such an environment may have a requirement that it not come in contact with ice and, therefore, it must be buried below the design ice keel gouge depth for protection. However, as the ice keel passes over any point in the seabed, vertical and lateral stresses are applied to the soil at the keel base, resulting in some distribution of vertical and lateral soil displacements with depth beneath the ice keel. This is typically termed "subgouge deformation" of the seabed beneath the gouging keel (Figure 4-29). This soil movement can impose forces on the buried pipeline and result in deformation. The configuration of the pipeline after gouging, and hence the strain in the pipeline, depends on the pipeline properties, the soil characteristics, the depth of the design ice gouge and the depth of the pipeline below the undisturbed seabed surface.

The pipe must be trenched sufficiently beneath the influence zone of soil displaced below the ice keel to limit pipeline strains to within acceptable limits. Analyses must be carried out to understand the soil displacements induced at the pipeline depth due to ice gouging and resulting strains in the pipeline evaluated, possibly through non-linear finite element analysis.

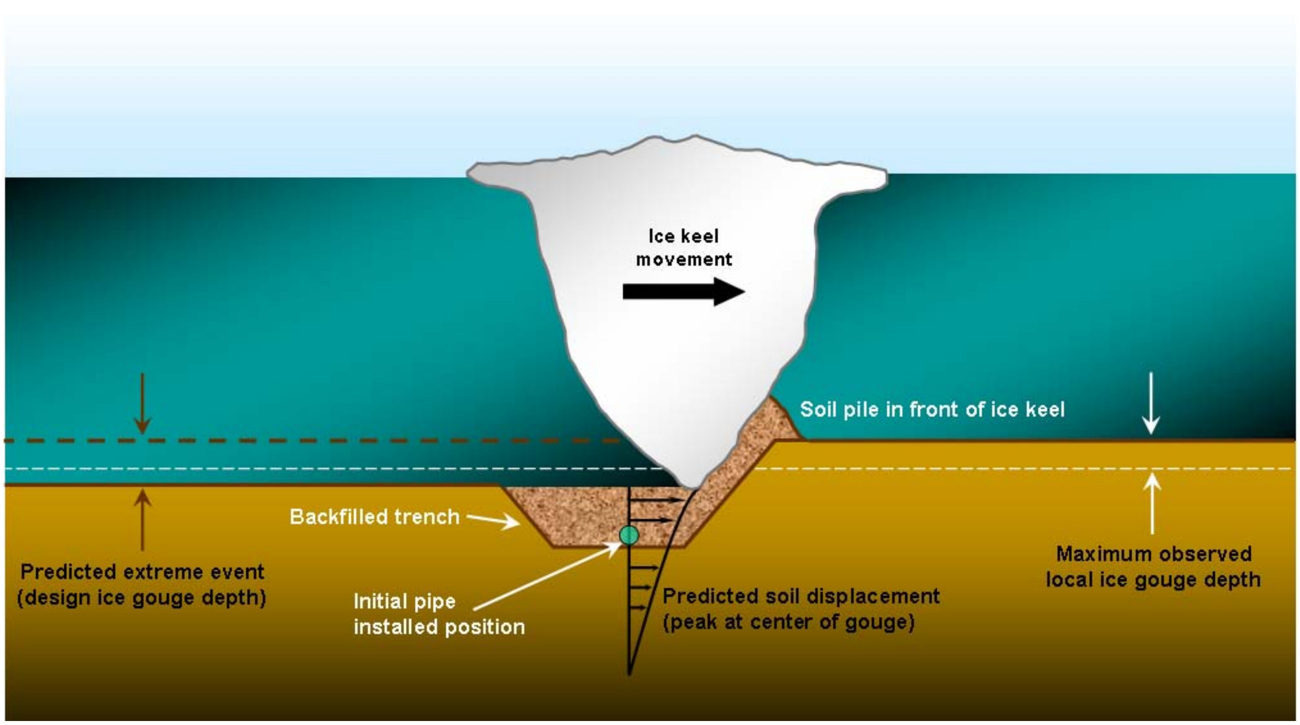


Figure 4-29: Ice Gouge and Subgouge Deformation

Geophysical surveys of the seabed are conducted and high-resolution bathymetry data taken to measure the depths and widths of individual ice gouges. Side-scan sonar records are also used to help identify the individual gouges and to measure the gouge orientation. Gouges on the seabed are altered by other gouge occurrences, sedimentation (infill) and sediment transport. Shallow areas exposed to waves and currents during the open water season could have all bathymetric traces of ice gouging destroyed by the end of each summer season. These issues, which could tend to mask the potential implications of ice gouging, would need to be appropriately accounted for in design.

Thaw Settlement & Frost Heave

In arctic areas, permafrost can be found through the pipeline shore crossing area and in shallow water. Thawing of ice-rich permafrost can result in loss of soil strength, excessive settlement, freestanding water and accelerated surface erosion onshore at shore crossings.

Differential settlement or frost heave is possible along a pipeline route due the fact that soil conditions or permafrost may not be continuous and uniform and the pipeline is not at a constant temperature along its length.

Analyses can be carried out to predict the thaw bulb extent, the thaw strain potential of the permafrost and the strains imposed on the pipeline. There are a number of ways to deal with the issue of thaw settlement, including incorporation of mitigative measures, avoiding excessive thawing by insulating the pipeline and designing the pipeline to take the strains.

If a pipeline is operated at a temperature lower than the freeze point of the surrounding soil's pore fluid, then the soil surrounding the pipeline could freeze, potentially subjecting the pipeline to frost heave. Alternatively, even if the pipeline were not operated below freezing, the active layer of the soil surrounding the pipeline could freeze, forming ice and pushing the soil surface upward. Analytical and numerical tools can be used to determine the behavior of pipelines undergoing frost heave in discontinuous environments.

Upheaval Buckling & Thermal Expansion

When a buried steel pipeline is operated at a temperature (and pressure) higher than that experienced during installation, it will try to expand longitudinally (thermal expansion). A long buried pipeline is not free to expand due to the restraint provided by the surrounding soil, and thus will develop a locked-in axial compressive force. If the buried pipeline has some residual vertical curvature, possibly due to trench bottom irregularities during installation, the effect of the axial force near the high points of these trench irregularities will attempt to buckle the pipeline upward at these locations. If the upward force exceeds the downward force, then the pipeline will move upward and may become exposed above the seabed. This phenomenon is known as “upheaval buckling” (Figure 4-30).

While this is a design issue not unique to the arctic, pipelines in such environments are normally installed at lower ambient temperatures and therefore will experience a larger temperature change when operating under steady state conditions.

The immediate effect of upheaval buckling for arctic offshore pipelines is that the pipeline could become exposed at the seabed, which increases the risk of impact by ice keels. Problems associated with upheaval buckling may include high bending stresses and loss of protective soil cover but may not directly cause a leak or exceed other limit states. However, upheaval buckling is a limit state that is an undesired condition and which must be designed against.

Minimum backfill thickness that must be placed over the pipeline for the selected design parameters and maximum allowable vertical variance (prop or imperfection) of the installed pipeline profile must be determined in design. The backfill on top of the pipeline is expected to provide the resistance needed to hold the pipeline in the installed position.

The larger temperature difference between the installation and operating temperatures experienced in arctic regions will also result in larger potential thermal expansions at the ends of unrestrained pipelines. This expansion must be accommodated through offshore or onshore expansion loops or by the risers at the shore crossings and the offshore island/platform.

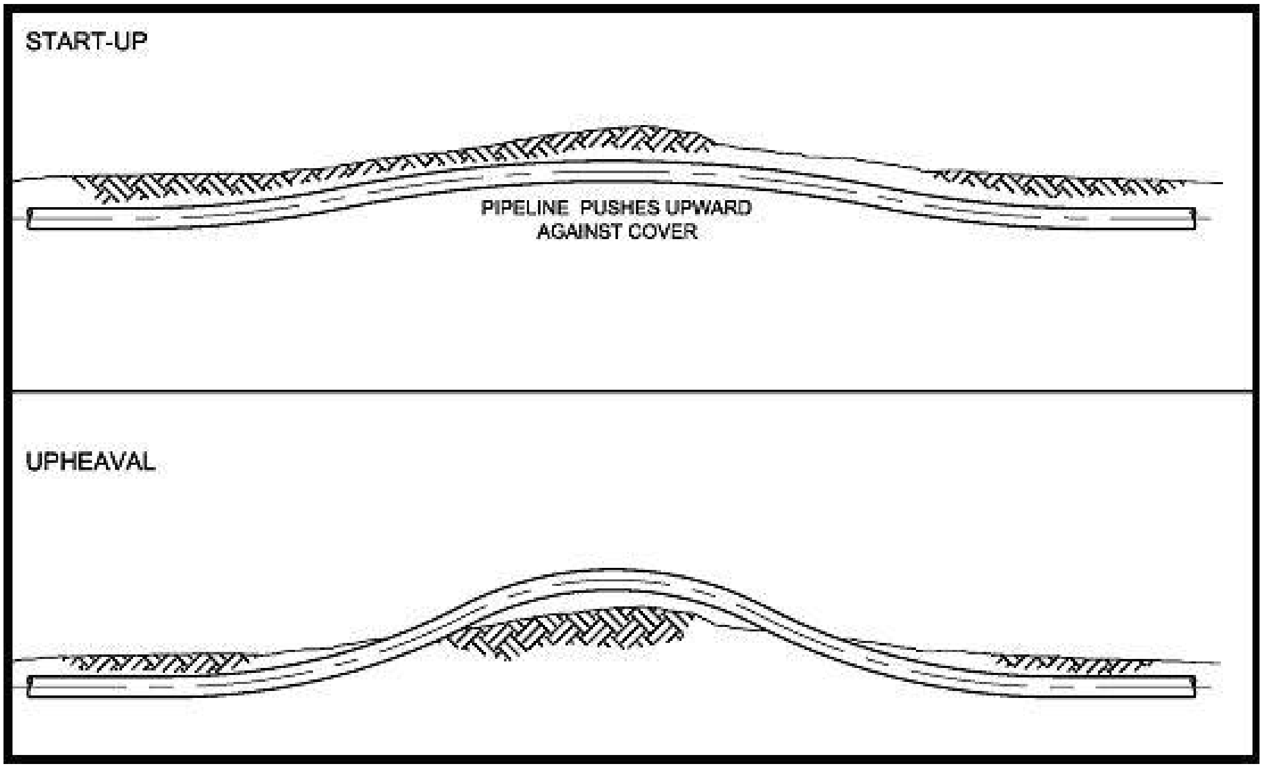


Figure 4-30: Subsea Pipeline Upheaval Buckling (After Palmer et al., 1990)

Strudel Scour

Nearshore arctic zones typically develop a bottomfast ice sheet during the winter season. If an onshore river flow encounters such an area during the spring breakup, the river water will overflow the bottom-fast ice sheet in the nearshore zone. This overflow water will spread offshore and drain through tidal and thermal cracks or seal breathing holes in the ice sheet. High velocity currents caused by the draining water at the seafloor can scour seabed sediment leaving a circular or linear scour in the seabed, which can potentially expose and impose high current loads on a pipeline (Figure 4-31). These phenomena are known as “strudel scours” and they usually occur in 6 to 30 ft (2 to 9 m) of water offshore from river deltas.

If a strudel scour happens on top of a pipeline alignment, there is the possibility that the scour could result in an unacceptable pipeline span. In extreme conditions, the pipeline span could possibly experience vortex-induced vibration (VIV) due to the water velocity of the strudel flow. An analysis to assess the pipeline span can be carried out using analytical or finite element methods.

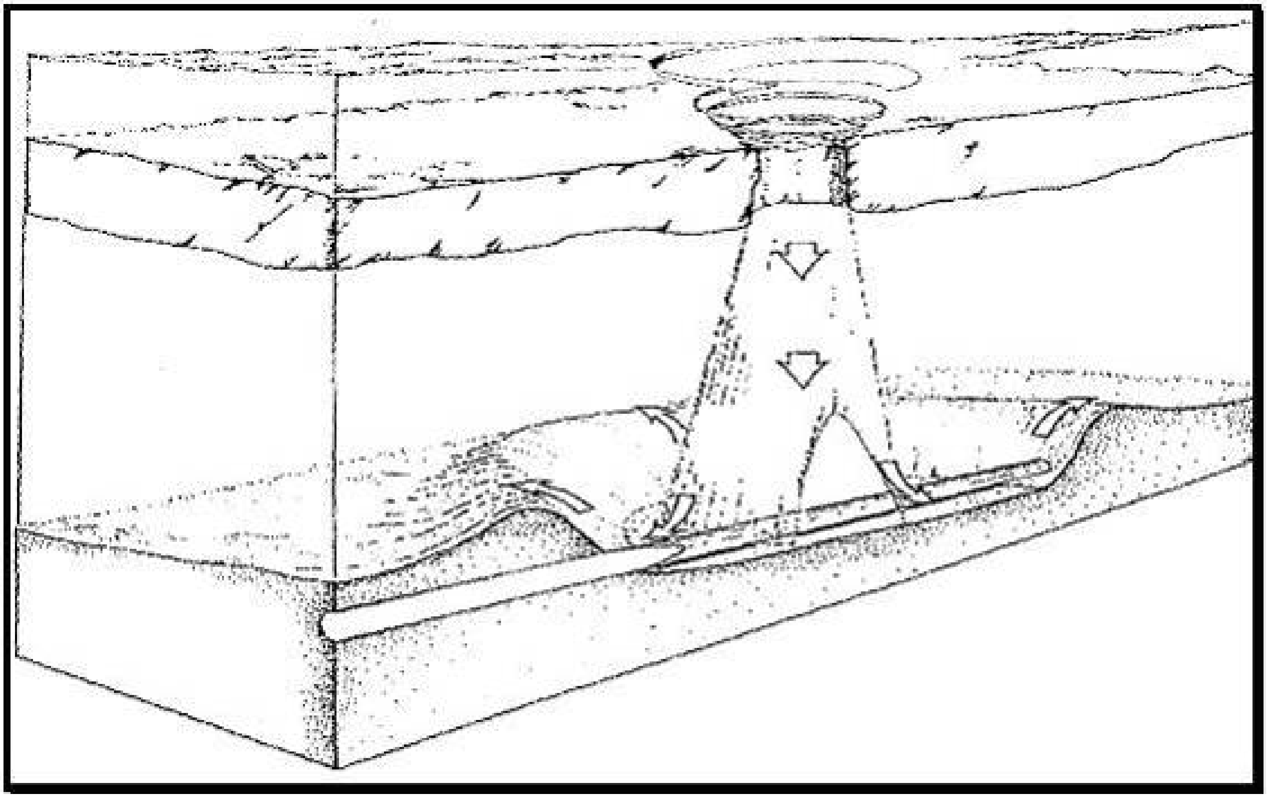


Figure 4-31: Strudel Scour (Courtesy of Minerals Management Service)

Ice Ride-Up, Grounding, Pounding & Wallowing

Sheet ice at the coastline can be driven ashore and ride up onto the beach. Shoreline pile-up can also occur, created by the rafting/stacking of the failed ice blocks onto each other. The design of a buried offshore pipeline which transitions to an aboveground pipeline should account for the setback distance as the result of ice encroachment.

Ice keels can be driven ashore and become grounded over a pipeline or rubble piles can form in place over a pipeline. “Ice pounding” refers to the occurrence of a small ice features bouncing up and down on the seabed in dynamic response to wave loadings. “Ice wallowing” is described as local seabed erosion around grounded ice features due to current flow disturbances and wave-induced motion of the ice feature displacing water and sediment. These potential loading scenarios should be considered during pipeline design.

Shoreline Erosion & Sediment Transport

Shoreline erosion must be considered in the determination of the setback distance of the point where a buried offshore pipeline transitions to an aboveground pipeline. Average long-term shoreline erosion rate, as well as the maximum short-term rates, should be considered. Gravel backfill, surcharge and re-vegetation may be required to prevent accelerated erosion at the shore crossing.

While sediment transport is not a design issue unique to arctic environments, it may result in an undesirable pipeline condition. The loss of backfill could result in larger ice keels intruding into an area where the water depth has been increased or it may become susceptible to upheaval buckling. In extreme cases, the pipeline could become exposed, either through upheaval buckling or loss of soil cover, which puts the pipeline at increased risk of damage from ice. The pipeline design should consider the long-term stability of the seabed/backfill.

Trenching & Backfill

Design issues related to ice gouging, strudel scour, frost heave / thaw settlement, upheaval buckling and sediment transport will determine pipeline trenching requirements in terms of depth of cover and backfill thickness. Pipeline protection is derived from both lowering the top of pipe below the surrounding seabed (depth of cover) and burial (backfill thickness).

Backfill materials, optimally, will consist of the soil (non-frozen) excavated from the trench. When native soil is used as backfill, it will be remolded and will be a composite blend of different materials excavated between the mudline and the base of the trench. This must be accounted for in the pipeline design, especially in the consideration of upheaval buckling and sediment transport potential. Select backfill, gravel, gravel filled bags or concrete mats may be considered in predetermined locations where native backfill is not adequate.

Limit State & Probabilistic Design

Offshore arctic pipelines, which rely on trenching and backfilling for protection, need to be deep enough to withstand environmental design conditions, e.g., ice gouging, but not so deep as to be impossible to construct or make the project uneconomical. A solution, therefore, is to design the pipeline based on strain rather then stress.

Limit state design is an approach whereby the various potential failure mechanisms are evaluated. The pipeline failure mechanism that has the lowest initiation strain is then selected as the governing condition and will dictate the design strain. Limit state strain criteria can be used in the design for non-cyclic pipeline displacements, e.g., thaw settlement, subgouge soil deformation and island settlement). It is apparent that if the pipeline strain can exceed that allowed by a stress-based design, the pipeline would not need to be buried as deep to meet design criteria during ice gouge events (for example), as it can be subjected to higher loads.

Probabilistic based design procedures can be used to optimize pipeline design. Elements of this type of design could include, for example, ice contact risk, ice gouge dimensions, soil properties, subgouge deformations, etc. to assess the pipeline loading. The pipeline resistance or strength could also be defined in terms of probability distribution functions associated with pipe dimensions and material properties.

<u>Leak Detection</u>

The use of thick walled pipe, omission of subsea valves and fittings and a well-planned inspection program minimize the potential for offshore pipeline leaks in the Arctic. Small leaks, however unlikely, which might normally be detectable on the open water surface during personnel/supply transport to and from the island/platform, could go undetected for several months under ice cover. Therefore, it might be expected that the pipeline system would be required to include a leak detection system to alert the operators of a possible pipeline leak. Such a leak detection system may be required to meet a minimum detection threshold over a set period of time to be in accordance with codes and standards and/or to meet federal or regional requirements.

<u>Pipeline / Flowline Architecture</u>

The pipeline/flowline configuration can significantly affect design, construction planning, operations, maintenance, and repair. Configurations can include a single wall steel pipeline, pipe-in-pipe system, a flowline bundle (open or closed bundle system), insulated pipelines and flexible pipelines.

4.11.1.2 Feasibility of Selected Scenarios

The main considerations with respect to a pipeline design in the Arctic are strudel scour, thaw settlement of permafrost, upheaval buckling and ice gouging.

The first two design issues happen over very limited distances of the nearshore portion of the pipeline and have been addressed in existing pipeline design, e.g. Northstar and Oooguruk. The third issue, upheaval buckling, can happen in any region of the pipeline if conditions are conducive to buckling. Installation procedures have been implemented on past projects (Northstar) to minimize the risk of upheaval buckling (considered limits on installed pipeline profile, use of select backfill or additional weight over imperfections). Therefore, it is generally felt that these three considerations can be designed for in future projects and for any of the selected location scenarios.

Strudel Scour

As indicated earlier in the report, a number of site-specific strudel scour surveys have been conducted for and in the vicinity of the Northstar Project (see, for example, Coastal Frontiers Corporation, 1999). Span analysis indicated that the pipeline remained elastic and within design code limits in the case of a strudel scour event that exposed the pipeline. The potential for vortex-induced vibrations of the Northstar bundle when exposed to a current jet resulting from the strudel was also evaluated and found to be nonexistent.

The change in strudel scour regime after startup of operations has been investigated by Leidersdorf et al. (2006). Annual monitoring of the strudel scours formed in the vicinity of the Northstar pipelines indicate that pipeline operations may locally increase the probability of scour formation. Circular scours up to 14 ft (4.3 m) deep and up to 105 ft (32 m) in diameter were recorded in the Northstar area. The maximum linear scour was 276 ft (84 m), but this scour only had a depth of 1.6 ft (0.5 m). Maximum scour depths were found in the 6.5 to 13 ft (2 to 4 m) water depth range. The potential cause of the increase in the frequency of scour formation over the pipelines may be the local thinning of the ice sheet above a buried warm pipeline in shallow water depths (Leidersdorf et al., 2006).

Pipelines from any of the Alaskan OCS location scenarios would need to pass through shallow water on a shore approach and could potentially be subject to strudel scour (depending on proximity to rivers and the overflood limits for a particular area). However, indicators are that this can be accommodated in design and operations as in the case of the Northstar pipelines.

Thaw Settlement

Thawing of ice bonded permafrost, if present along the pipeline route, can result in differential thaw settlement which could subject the pipeline to high strains. On the

Northstar project, the maximum thaw induced settlement potential in the ice-bonded permafrost region was found to be approximately 2 ft (0.6 m) close to the onshore transition within a few hundred feet from shore (Paulin et al., 2002). An operational limit state bending strain criterion was used to confirm the pipelines would be safe under the maximum predicted differential thaw settlement.

Pipelines from any of the Alaskan OCS location scenarios could potentially pass through zones of ice bonded permafrost. Using the Northstar pipeline as an example, differential settlement up to a certain magnitude can be accommodated in design and operations. If the differential settlement is beyond a certain value, other design solutions might be considered, such as overexcavation of ice rich soil under the pipeline, pipeline insulation, etc.

Ice Gouge

Ice gouge is an issue that has been studied or considered in conceptual pipeline design for decades. A number of buried offshore pipelines are being successfully operated in ice gouge environments, including projects in the Alaskan OCS (Northstar, Oooguruk).

Trench depths will increase in areas of more severe gouging. In nearshore zones (less than 30 ft (9 m) water depth), pipelines might be expected to be buried not as deep as in deeper water due to the less severe gouging. In the 65 to 130 ft (20 to 40 m) water depth range, ice gouging might be the most significant and result in the deepest burial. In deeper waters, the gouge depths begin to taper off, as do the burial depth requirements. Offshore pipelines will be required to be trenched to approximately 165 ft (50 m) water depth in areas subjected to ice gouging.

Ice gouging is only one factor in the overall determination of burial depth and must be examined in conjunction with other factors such as thaw settlement, upheaval buckling, strudel scour, pipeline stability and flow assurance. However, as mentioned above, these other aspects can likely be accommodated, given successful operation of projects in the shallow waters of the Beaufort. The ice gouging issue warrants further discussion (below).

Ice gouge depth distributions can be estimated using ice gouge data, e.g. depths and widths. Annual ice gouge recurrence rates can also be estimated where repetitive mapping surveys have been carried out. If repetitive mapping survey data is not available, the age of gouges cannot be determined and data may not accurately represent the current ice gouge regime. The same can be said for the location from which data is used. If site-specific data is not available, the use of ice gouge data from other regions may not accurately reflect the conditions at the area of interest.

However, in an initial screening study where there might not be adequate site-specific data, insight may be gained by looking at regional ice gouge datasets. Unfortunately, most of the published information from the Alaskan OCS is over 20 years old and there has been little attempt (except for specific projects) to collect data which might be used during screening studies.

A review of existing public domain ice gouge data available in public domain study/survey reports from the Beaufort, Chukchi and Bering Seas has been carried out. No statistical gouge data was found applicable to the Bering Sea. Information found included gouge data of known and unknown age and, where available, generalized discussions of ice gouge processes and observances. Ice gouge depths were generally observed to increase with increasing water depth, with the deeper ice gouges occurring beyond the 65 ft (20 m) isobar. Analysis of ice gouge width/depth relationships and distributions from the study areas has indicated a general trend of decreasing gouge width with increasing gouge depth.

Beaufort Sea

Summary plots of ice gouge depth vs. water depth for combined known and unknown age data and known age gouge data only are presented in Figure 4-32 and Figure 4-33 respectively, from ice gouge data reported from the Alaskan Beaufort Sea. References for the data used in these plots include Barnes et al. (1978), Rearic and McHendrie (1983) and Weber et al. (1989).

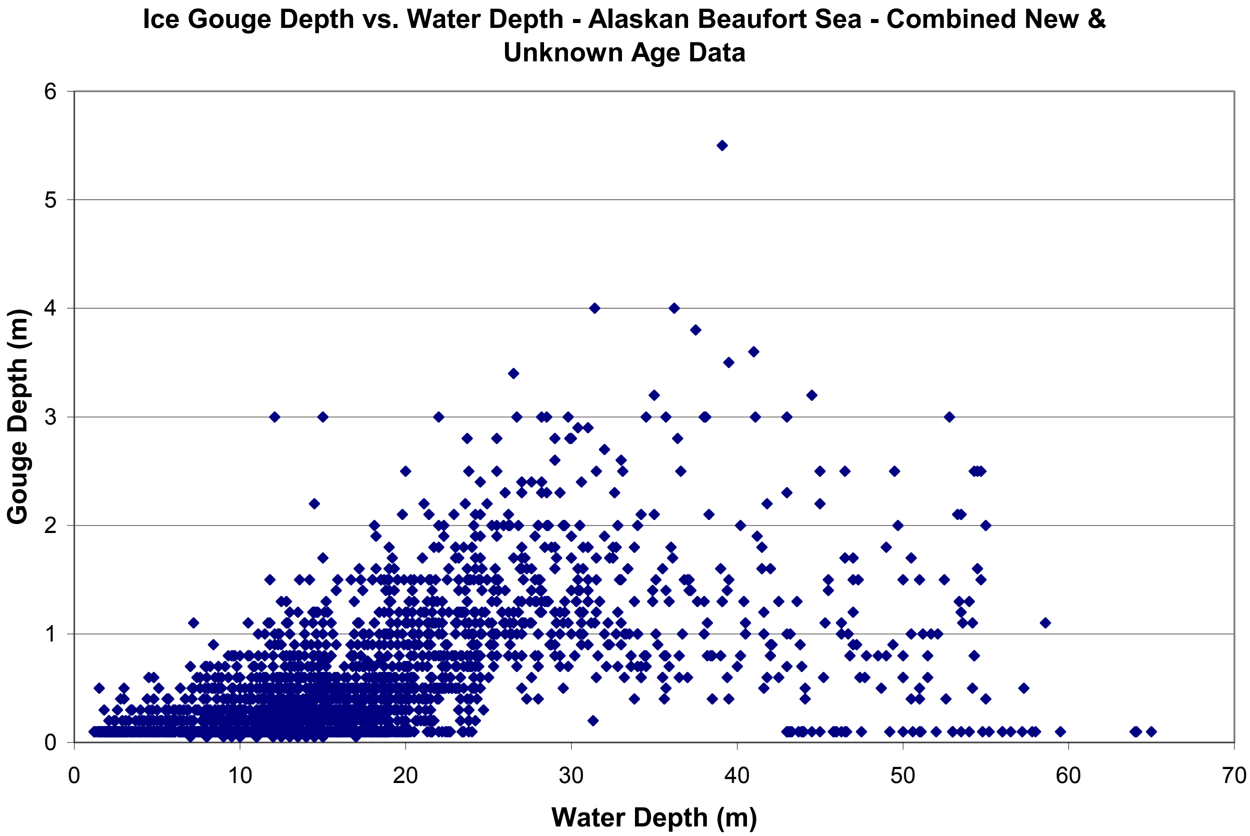


Figure 4-32: Ice Gouge Depth vs. Water Depth, Combined New & Unknown Age Gouge Data from the Alaskan Beaufort Sea

The data from Figure 4-32 are of unknown age and, therefore, it is not known if the ice/gouge regime at the time of creation is comparable to what it is today. Based on this information, gouges up to 18 ft (5.5 m) deep have been surveyed. Most gouges in water depth within 65 ft (20 m) are less than 6.6 ft (2 m). Beyond this water depth, as expected, gouge depths then increase significantly up to about 130 ft (40 m) water depth. After this point, ice gouge depth decreases with increasing water depth to near zero at 200 ft (60 m) water depth.

New gouge data available for the Beaufort is limited to less than approximately 80 ft (25 m) water depth. Of the data available, gouge depths are generally less than 5 ft (1.5 m).

Pipeline burial depth for this area (any of the location scenarios) would be a function of not only gouge statistics, but also design return period, pipeline geometry, line pipe characteristics, allowable strain limits, soil properties and assumed subgouge deformation field.

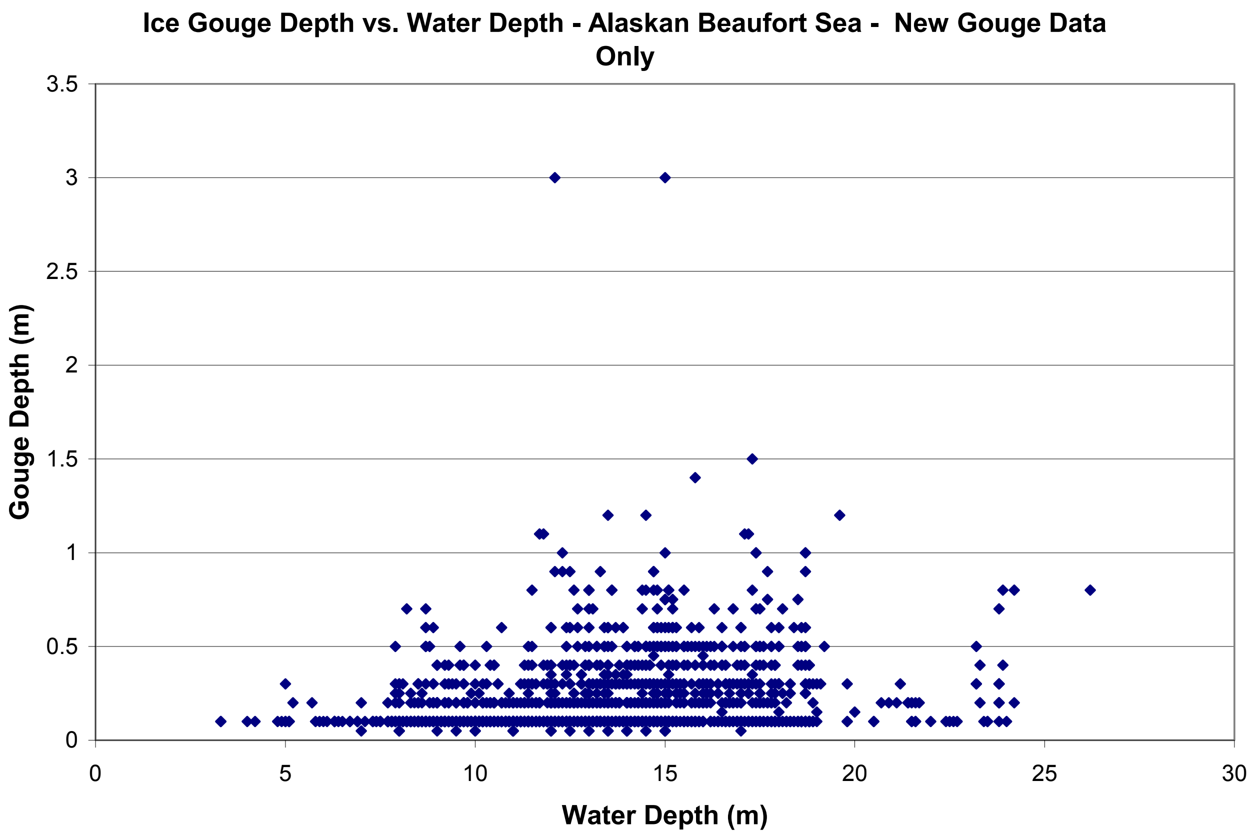


Figure 4-33: Ice Gouge Depth vs. Water Depth, Known Age Gouge Data from the Alaskan Beaufort Sea

Chukchi Sea

There are less data available in the public domain for the Chukchi Sea as compared to the Beaufort Sea, where inner shelf ice gouge data and reports have been reviewed as part of the current study. All of the data found was for gouges of unknown age. Figure 4-34 provides a summary plot of unknown age ice gouge depth vs. water depth data for gouge observances in the Chukchi Sea. References for the data presented in this plot include Toimil (1978) and Phillips et al. (1988)

The data from Figure 4-34 are of unknown age. Again, significant gouges (up to 15 ft or 4.5 m) have been identified. Gouges in water depth within 65 ft (20 m) are less than 8 ft (2.5 m) deep. Beyond this water depth, as expected, gouge depths increase up to about 130 ft (40

m) water depth. After this point, ice gouge depth decreases with increasing water depth to near zero at 200 ft (60 m) water depth. Pipeline burial would be a function of the same parameters as presented above in the Beaufort Sea Section.

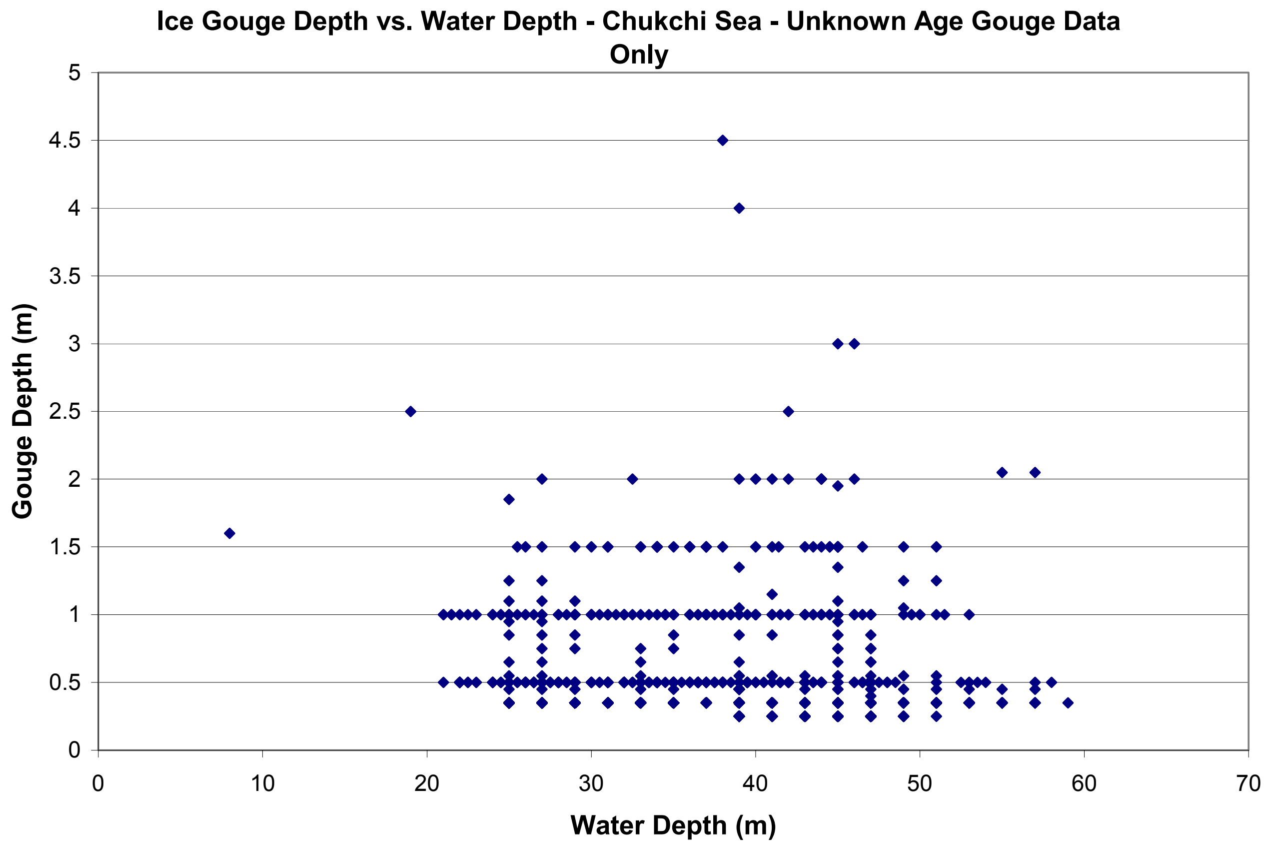


Figure 4-34: Ice Gouge Depth vs. Water Depth, Unknown Age Gouge Data from the Chukchi Sea

Bering Sea

Research of references in the public domain has limited ice gouge information relevant to the Bering Sea. No statistical/tabulated ice gouge data was found.

A review of geophysical records from a 1981 survey has indicated the presence of thousands of scours on the north Aleutian shelf of the Bering Sea (Molnia et al., 1983). Bering Sea gouge observations indicate depths up to 16 ft (5 m), widths which range from a few meters to greater than 820 ft (250 m) and lengths in excess of 985 ft (300 m) for gouges of unknown age (Molnia et al., 1983). Gouge orientations have been found to vary from shore-parallel to shore-perpendicular and vary in gouge trajectory. Ice gouges are observed in the northeastern Bering Sea in water depths ranging from 16 to 100 ft (5 to 30 m) (Thor and Nelson, n.d.).

Various ice gouge features have also been identified in Norton Sound of the eastern Bering Sea, including single, ice island and pressure ridge raking (multiplet) gouges. Single-keeled (solitary) ice gouges have been observed to ubiquitously dominate within Norton Sound, where gouge depths are reported to a maximum of 2.5 ft (0.75 m) deep (Thor et al., 1977). Single-keeled ice gouge widths have been observed to range from 16 to 200 ft (5 to 60 m), although the 49 to 82 ft (15 to 25 m) gouge width is most common (Thor et al., 1977). Ice island gouge widths of 250 to 330 ft (75 to 100 m) are reported, while pressure ridge raking formations were observed to range from 165 ft (50 m) to several kilometers wide (Thor et al., 1977). The maximum density of ice gouges occurs in central Norton Sound near the Yukon Delta in water depths ranging from 33 to 50 ft (10 to 15 m) (Thor et al., 1977; Thor and Nelson, n.d.). Ice gouge densities of up to 195 gouges/mile^2 (75 gouges/km^2) have been observed near the Yukon Delta. Little ice gouging is observed in water depths less than 33 ft (10 m) or greater than 65 ft (20 m) (Thor and Nelson, n.d.). Gouge orientation trends in Norton Sound occur in both the general north – south and east – west directions (Thor et al., 1977; Thor and Nelson, n.d.). The age of these observances is unknown.

Pipeline burial would be a function of the same parameters as presented above in the Beaufort Sea Section.

4.11.2 Constructability

4.11.2.1 Winter Construction vs. Open Water Construction

Offshore Arctic equipment and logistics requirements for summer and winter construction are quite different. Construction methods for summer (open water) and winter construction (from ice) need to be evaluated to identify the best potential method with respect to probability of success, logistics cost and schedule.

Winter construction is primarily affected by the ice environment. Construction cannot commence until the ice is of sufficient thickness and stability to support the weight of the equipment required to begin ice thickening. Ice ridges within the ice sheet could also affect construction. However, winter construction eliminates some of the environmental issues associated with summer construction. Given the requirement for a stable landfast ice surface from which to work, the distance offshore that winter construction might be applicable is restricted.

During an open-water construction scenario, activities and their timing may be primarily affected by considerations for environmental protection and the seasonal extent of ice-free water (which varies from year to year). To protect the tundra, onshore work is not typically planned for the summer which restricts access to shore-based staging areas from the sea or air. Offshore activities may be restricted due to environmental concerns. However, marine activities are permitted if care can be taken to avoid effects on wildlife (this often includes a conflict avoidance agreement with local sustenance activities). Any summer construction season will be short in duration and there could be ice incursions into the construction area during open water, which requires a management plan.

When considering open-water activities, consideration also needs to be given to the Jones Act or Coastwise Laws and potential requirements for US owned, operated and flagged vessels for the Alaskan offshore. This law could significantly influence decisions regarding the preferred construction scenario for projects off of Alaska.

4.11.2.2 Permafrost & Trenchability

The general assumption is that Arctic offshore pipelines will need to be trenched for protection and seabed trench excavation will be a critical activity for the pipeline installation schedule. Given the nature of the arctic environment, there is a possibility that permafrost could be encountered during trenching, regardless if a summer trenching or winter trenching program is planned. Either way, the trenching technique must be capable of trenching through permafrost.

Soil conditions must be considered when evaluating trenching options to come up with the most cost effective trenching spread configuration. The presence of high strength silts and clays or dense sands will affect trenching production rates. It is important that the trench remains open until the pipeline is placed in the trench, regardless of whether winter or summer construction is carried out.

4.11.2.3 Trenching Equipment

Trenching equipment must be compatible with arctic conditions. The equipment must be robust and able to operate in a summer or winter arctic environment, depending on the execution plan, and able to create a suitable trench profile in site-specific soil conditions.

Ice-based excavation could be carried out using hydraulic backhoes, clamshell buckets or similar methods. Conventional excavation is a proven but time-consuming method. The reach of an extended or long-reach backhoe is limited practically to a combined water and trench depth of approximately 50 ft (15 m). Special consideration may need to be given to areas where ice-rich or bonded permafrost may be encountered.

Most of the excavated trench soil would need to be temporarily stored on the ice before backfilling. The material excavated from floating ice would be trucked off and stored temporarily on bottomfast ice in a designated area. If stored on floating ice, consideration must be given to sinking or creep (deflection) of the ice. Once a section of the pipeline is installed in the trench, and its profile verified, backfilling using recently excavated trench spoils would commence.

Generally, floating trenching equipment has not been designed for arctic conditions. Floating vessels used in trenching or in support of trenching during open water may be subject to ice incursions. Equipment that is not designed for such an environment may be subject to damage under these conditions. Ice which does not come in direct contact with floating equipment could still affect construction if the ice were to come in contact with anchor lines. The need for ice management vessels in support of trenching operations will need to be considered during construction planning.

Several trenching techniques could be used during the summer. Some are applicable only to pre-trenching, i.e., before the pipeline is installed, whereas others are best suited to post-pipeline installation. These methods include, but are not limited to:

- Conventional excavation (hydraulic backhoes, clamshell buckets, etc);
- Hydraulic dredging (cutter suction dredges and trailing suction hopper dredges);
- Plowing;
- Jetting; and,
- Mechanical trenching.

Cutter suction dredges would have a water depth limitation of approximately 115 ft (35 m), while a large trailer suction hopper dredge could reach to approximately 460 ft (140 m). Protection of the installed pipeline could be provided by pre- or post-trenching techniques. However, pre-trenching or post-trenching immediately following installation would most likely be required for arctic conditions, since the pipeline would otherwise rest on the seabed and be potentially exposed to the action of ice moving into the area.

Historically, plows (Figure 4-35) have achieved a trench bottom depth on the order of 5 to 6 ft (1.5 to 1.8 m) with an average plowing speed on the order of 660 ft/hr (200 m/hr) (Brown and Palmer, 1985). Some multiple-pass plows have been fabricated that should have the capability of achieving a trench depth of 6.6 ft (2 m) if the soils are soft enough to allow plowing but strong enough to remain stable until the pipeline touches down in the bottom of the trench. Multiple-pass plows capable of excavating a trench 13 ft (4 m) deep have been investigated and tested on a small scale, but full-scale plows with this capability have not been fabricated. Brown and Palmer (1985) have indicated that multi-pass plows for arctic pipelines capable of trenching 13 to 20 ft (4 to 6 m) are feasible, depending on geotechnical conditions. Generally, plows tend to be quite large; approximately 110 to 330 tons (100 to 300 tonnes) dry weight and 30 to 90 ft (9 to 27 m) in length. Several plows have been fabricated for previous pipeline projects and these may be available for lease or purchase for arctic projects. The shore and island approaches would need to be excavated using other means and special consideration may need to be given to areas where ice-rich or bonded permafrost may be encountered.

Figure 4-35: Typical Subsea Plow (Courtesy of SMD Hydrovision, 2007)

Jetting (Figure 4-36) involves pulling a sled along the top of a pipeline after it has been installed. Water under high pressure is used to liquefy the soil, and air is used to lift it from under the pipeline. The pipeline lowers itself to the bottom of the trench as the jet sled advances.

To achieve a depth of cover of 9.8 ft (3 m) in most soil conditions, the jetting sled would have to be towed over the pipeline several times, thereby increasing the risk of damage to the pipeline. Due to the very large fluidized sediment load created, environmental concerns may be a significant issue. Another issue with jetting is the management of the excavated material. The spoils are in a fluidized form and if they must be returned to the trench to meet the design backfill requirements, soil may need to be barged in to backfill the pipeline.

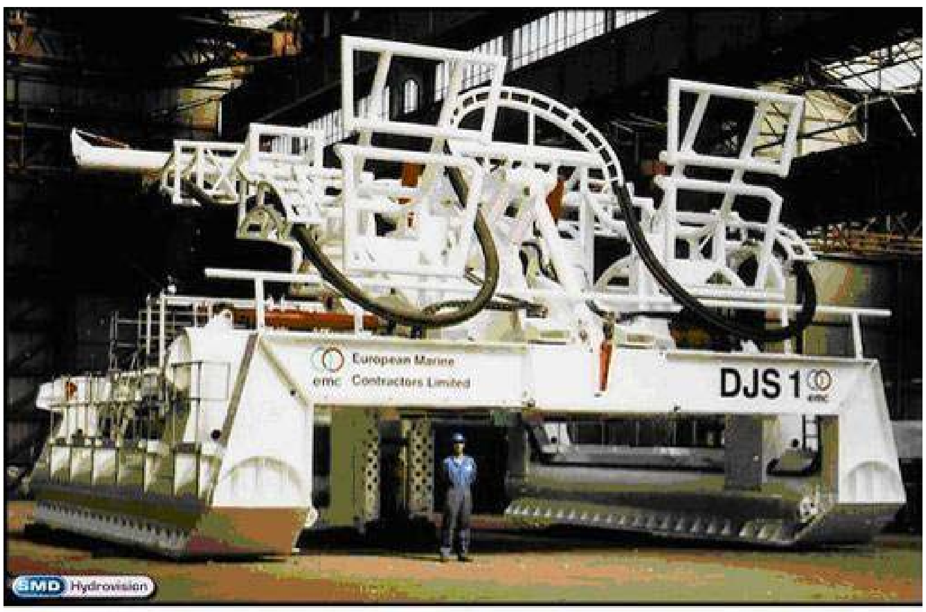


Figure 4-36: Typical Jet Sled (Courtesy SMD Hydrovision, 2007)

Mechanical trenching is commonly used for burying cables and umbilicals, and has been used on multiple pipeline trenching projects. Typically, this method is used in open water conditions and supported by a large marine vessel. The trenchers typically rely on hydraulic power to propel the caterpillar tracks (Figure 4-37) used for propulsion and to operate the cutting equipment. The hydraulic power requirements make these trenchers very large, often requiring large buoyancy tanks to keep the trencher from sinking into the soil and collapsing the trench, and to facilitate handling of the machine.

Mechanical trenching to achieve a depth of cover of 6.6 to 9.8 ft (2 to 3 m) is considered to be at the limit of what present installation equipment can achieve for soft soils. Another potential issue with mechanical trenching is the management of the excavated material. If it must be returned to the trench to meet the backfill requirements, soil may need to be barged in to backfill the pipeline.

Figure 4-37: Typical Subsea Mechanical Trencher (Courtesy of Rocksaw International, 2004)

4.11.2.4 Pipeline Installation

Installation equipment must be suitable for use under the appropriate environmental conditions regardless if summer construction or winter construction is planned. Similar general considerations apply as noted for trenching equipment operations.

Winter construction using a through-ice method relies on techniques and equipment that are proven. Ice-strengthening and ice-cutting techniques are well understood and have been applied on the Northstar and Oooguruk projects for pipeline installation. Backhoes are used universally for land and marine trenching within the limits of their capabilities. A potential disadvantage is that floating ice has a limit to its load bearing capacity and the combined weight of equipment and pipe must be considered before electing to use this method. This technique requires a relatively stable ice sheet and the combined water and trench depth is limited to approximately 50 ft (15 m).

During installation, the pipe is welded together into a continuous pipe string, either onshore or along the ice slot. If strings are made up onshore or in the nearshore, after they are welded they are towed over the ice and positioned alongside the ice slot. Tie-in welds would be made to join the pipeline strings together into a continuous length before it is lowered into the trench through the slot. Tie-in welds would be X-rayed or ultrasonically inspected before the field joint coating is applied.

Floating pipelay vessels have almost exclusively been designed for ice-free operation. Floating vessels used for installation or in support of installation in an arctic environment may be subject to ice incursions or damage. A pipeline off the end of a stinger or coming off a reel during laying may also be subject to potential damage from ice.

Ice conditions in the Beaufort Sea are highly variable. In some years, open water may exist for half the year, while in other years the ice does not recede at all. In addition, there are no safe havens in Alaskan waters into which a vessel can retreat from severe ice conditions. The decision may be taken that all vessels used on a particular project be of Ice Class, capable of navigating in ice under their own power and over-wintering in the Arctic.

4.11.2.5 Trenching & Backfill

After laying the pipeline in the trench, the placement of backfill material in the trench and over the pipe may be required. This is a normal activity associated with pipeline construction and typically returns the trench excavation spoils back into the pipeline trench.

In a winter construction scenario, where the trench is excavated through a slot in the ice, the trenching spoils will be brought to the ice surface. As the backhoe digs soil out of the trench, it will place these spoils to the side of the ice slot or directly into a dump truck for transport to an appropriate location.

Backfill should be placed over the pipelines as soon as practical after installation, which minimizes the amount of time the spoils are exposed to freezing temperatures. Frozen spoils create some challenges for construction as they may not spread easily over the pipeline trench cross-section or large pieces of frozen spoil may damage the pipeline.

In the simplest cases, the soil from the trench is left along both sides of the trench and is available for a backfill plow to pull the material back into the trench over top of the pipe. If the trench has been excavated using conventional excavation or a trailing-suction hopper dredge, the excavated material can be stored and reclaimed for backfill. However, the use of a cutter suction dredge for digging the trench may create a problem for the backfill operation, as these dredges normally either “rainbow” material from the trench or discharge it through a floating hose. However, it possibly could be stockpiled and retained for backfill.

If other mechanical trenching techniques are considered for trenching the pipeline, the excavated material may or may not be available for backfilling. If the pipeline has been jetted-in, the majority of the excavated material will be dispersed and may necessitate importing backfill.

If the trenching is conducted post-lay, after the pipeline installation backfilling can be accomplished by plowing, jetting or mechanical trenching. In the case of these methods, consideration needs to be given to the ability to move the backfill from the trenching machine back over top of the trenched pipeline.

The backfill on top of the pipeline is expected to provide the resistance needed to hold the pipeline in the installed position. The critical locations for the backfill thickness along the as-laid pipe profile are near the crests of local high points or overbends to resist upheaval buckling. If backfilling with native material will not meet requirements in terms of uplift resistance at a prop/overbend, the pipeline may need to be lowered or gravel/gravel bags/concrete mats used to provide additional uplift resistance.

4.11.3 Capital Costs

Capital costs of an offshore pipeline would effectively be made up of material costs and installation costs. Material costs would be based on the market price of line pipe, coatings and so on.

For relatively short pipelines located nearshore, installation from the ice would be based on costs of spreads to thicken ice, excavate a trench, weld up the pipeline, lay the pipeline and backfill the trench. Such activities have been carried out on previous projects (Northstar, Oooguruk). Costs could be obtained from contractors in Alaska experienced in such construction activities.

Open water installation costs are less definitive and will depend on the trenching/installation/backfill methods selected. There are other variables that will potentially affect capital cost, including R&D/field trials of selected equipment, schedule, weather, presence of ice during construction, availability of equipment that is Jones Act compliant, and required upgrades to equipment to work in an Arctic environment.

Installation costs can be estimated based on a best-case scenario, assuming that equipment can be found that is suitable for use in the Alaskan OCS. Again, it is stressed that is highly likely that that there would be additional costs associated with getting this equipment ready for an Arctic deployment. In the worst case, new equipment may have to be designed and built in order to execute projects in the Alaskan OCS.

Pipeline trenching costs using a floating dredge can be estimated based on a current cost of $250,000 per day for large dredger (plus mobilization/demobilization costs). Actual production rates would depend on the depth of trench required and site-specific soil conditions. Rates of 0.3 to 0.6 miles per day (500 m to 1 km per day) may be typical, extending to 1.2 miles (2 km) per day for shallow trenches in relatively soft soils. Rates of 165 ft/hr (50 m/hr) might be typical for a plough, jet sled or a mechanical cutter.

A trenching spread could vary from as simple as a tug to as complex as a lay barge. A typical spread day rate could approach $200,000 per day (plus mobilization/demobilization costs). Anchored lay barges could cost $250,000 per day, while a DP (dynamic positioning) vessel could approach $400,000 to $500,000 per day. Other vessels would be required for ice management, survey, support, supply, etc.

4.11.4 Environmental Considerations

Offshore pipelines will be required to be trenched to approximately 165 ft (50 m) water depth in areas subjected to ice gouging (see Ice Gouging of Section 4.11.1.1). The overall depth of the trench will be a function of the ice gouge protection and other design requirements, diameter of pipeline and any overdig to ensure pipeline position below mudline.

Pipeline construction could occur either during the summer open-water season or from ice during winter, when landfast ice has stabilized. The actual construction execution plan would depend on the length and location of the pipeline, project schedule, available equipment, etc. Due to the nature of burying a pipeline, some seabed disturbance will take place along the right of way. Depending on the methodology used, areas may be required for spoil storage or excess spoil disposal. Trenching and backfilling will create some turbidity and some habitat alteration associated with offshore pipeline construction and installation activities. It is anticipated that coarse sediment would settle to the seafloor very near the trench, but that a plume of fine suspended sediment would drift several miles (MMS, 2003).

4.11.5 Operations

Pipeline leak detection monitoring is an important aspect of pipeline operations that will need to meet regional requirements. The State of Alaska requires all transmission pipelines to subscribe to a “best available technology” (BAT) evaluation regarding leak detection. The criteria for a BAT evaluation are prescribed by the Alaska Department of Environmental Conservation and include availability (i.e., proven technology), compatibility with existing SCADA and hardware, transferability, effectiveness, etc.

There are a number of different approaches that could be used to monitor an oil or gas pipeline for leaks. Pipeline integrity checking and leak detection for arctic subsea pipelines can generally be categorized as follows (with no implied order of preference):

- Volumetric flow measurement;
- Pressure monitoring;
- Pressure measurement with computational analysis;
- External (adjacent to pipe) oil detection;
- Remote sensing (airborne or satellite);
- Geophysical sensing techniques;
- Pressure or proof testing;
- Pipe integrity checking (i.e., smart pigging);
- Visual inspection; and
- Through-ice borehole sampling.

Many of these are considered proven technology and others are under development. There are many variants of the above that are either experimental or are being developed. In addition to the principal leak detection methods cited above, there are other possible leak detection strategies that involve remote sensing techniques, fiber optic sensors, acoustics and electrical detection devices.

4.11.6 Maintenance & Repair

4.11.6.1 Monitoring & Maintenance

A pipeline monitoring/inspection philosophy is important to the successful operation of an arctic offshore pipeline. A good inspection plan optimizes the amount of useful information that can be gained from inspection surveys and pigging runs, and takes into account the criticality of the various systems. If inspection results are satisfactory, it can generally be inferred that the system is fit for service. When degradation is discovered, these areas may be designated for further evaluation or the situation may be severe enough to warrant immediate corrective repairs.

During detailed engineering, a recommended inspection plan and schedule should be developed. As the result of inspection, a pipeline's condition may be characterized as follows: conditions that require no action; conditions that require more rigorous monitoring schedules; or conditions that require immediate intervention. Such conditions are determined based on pigging test data and route survey data.

As suggested earlier in this report, annual monitoring of strudel holes formed in the ice sheet may be an important inspection activity. Annual monitoring of the strudel scours formed in the vicinity of the Northstar pipelines indicate that pipeline operations may locally increase the probability of scour formation. The potential cause may be the local thinning of the ice sheet above a buried, warm pipeline in shallow water depths.

4.11.6.2 Repair

The logistics for pipeline repairs largely depends on the season and sea ice conditions. Detailed repair procedures should be developed during detailed design and should consider scenarios that could occur at any time of the year. Envisioned repair techniques for offshore sections of arctic pipelines draw upon conventional offshore pipeline repair techniques and construction techniques used for conventional and arctic offshore pipelines.

Normally, it is assumed that welded permanent repairs would be the desired repair strategy, given the potential for high strain loading events. Mechanical pipeline repair systems may be used is if there is not enough time available during the remainder of the summer or winter season to make a permanent welded repair. In this case, a temporary repair might be carried out in order to avoid a long shutdown period.

In developing pipeline repair strategies, consideration also needs to be given to the potential location of the leak, and the extent (length) of damage. A repair to a leak under the bottomfast ice or damage which is localized will be easier to repair than damage in deeper water or which extends over one or more pipe joint. Depending on the extent of the damage, a temporary repair may be the first step with a permanent repair made when environmental conditions are more suitable.

Seasonal considerations must also be taken into account. Given the circumstances, temporary repairs may have to be made, followed by a permanent repair when ice and weather conditions have improved. In general, repairs could be conducted during open water using a repair barge or shallow-draft vessel, or during winter from the ice or using Ice Class vessels.

Most repair techniques can be used both from marine equipment and, with modifications, from a stable ice sheet of sufficient thickness. However, some repair techniques are compatible only with specific support equipment. Repair methods may generally be categorized as follows:

- Welded repair with cofferdam or berm;
- Hyperbaric weld repair;
- Surface repair;
- Tow-out of replacement string (welded in place or mechanical connectors);
- Spool piece with mechanical connectors; and,
- Split sleeve or other mechanical repair device.

Although mechanical repair devices have been used worldwide for permanent pipeline repairs, they have not been proven for a permanent arctic offshore repair where the pipeline may subsequently be subjected to significant strains. The short term and long-term acceptability of mechanical repair systems should be evaluated during detailed design. However, mechanical repair devices have the advantage that they are relatively easily deployed compared to a pipeline cut out and replacement.

4.11.7 Abandonment & Decommissioning

Decommissioning procedures for offshore installations that have reached the end of their useful life are usually included in governing legislation. There are also international agreements relating to decommissioning that address removal and deep-sea disposal. For example, the International Maritime Organization (IMO) has developed Guidelines and Standards for the removal of Offshore Installations and sets out conditions to protect navigation and maintain safety.

As per the Northstar development EIS (MMS, 1999), abandonment of development and production facilities could range from complete removal of all facilities to a requirement that most facilities be left in place for future use. Actual requirements would not be stipulated until near the end of the project, when potential future uses can be better identified. Buried offshore pipelines would be difficult to remove and activities associated with removal may have environmental considerations. Therefore, the decision might be made to pig the pipeline of any residual hydrocarbons and abandon the line in place.

4.12 Export Terminals

4.12.1 General Requirements

For the purposes of this report, a marine terminal is defined as a complex of structures and equipment for loading of hydrocarbon products, either pumped to a tanker from a storage facility located onshore or directly from a processing facility.

In most cases, marine transportation of hydrocarbon products starts with large storage facilities located onshore. The land-based components of these facilities (tank farms, loading pump stations, treatment plants, etc.) in the Arctic are basically the same as those in the moderate climate. The main difference is primarily in providing the conditions and the process equipment to allow continuous operation under low temperatures, icing and snowfall conditions. Flow assurance is a critical consideration for arctic and sub-arctic locations. Consequently, to ensure smooth operations, an important aspect of any terminal concept is the need for proper insulation and heat-tracing technology on piping and pipelines.

Hydrocarbons may be loaded on tankers at sea or in the vicinity of production platforms, either from the platform storage tanks or from a FSU (Floating Storage Unit). The FSU may also be used in the nearshore for temporary storage or trans-shipment loading. Several recent applications of these concepts in the Arctic were described in Section 3.2.1.2 (the production platform offloading at Prirazlomnoye field and the FSU in Kolsky Bay in the Barents Sea, Russia).

Particularly challenging in the Arctic is the offloading of products to tankers because this operation will need to be conducted in floating ice if year-round operations are going to be conducted.

4.12.2 Technical Feasibility

The technical feasibility of marine terminals in Arctic areas has been established through successful experience in a wide range of port facilities (Tsinker, 1995). These include the port structures and terminals in Nome, Cook Inlet, Anchorage and Valdez (Alaska), Godthab and De Long (Greenland), Nanisivik (North Baffin Island, Canada), St. David de Levis and Caps Noirs (Quebec, Canada), Norwegian and Russian ports in the Barents Sea (Murmansk, Arkhangelsk), and Magadan and Petropavlovsk (Okhotsk Sea, Russia). The most recent examples are the large Oil Terminal in DeKastri and the LNG Terminal in Prigorodnoye (Sea of Japan), Russia.

The common specific feature, as well as the main challenge in all of these ports and terminals projects, is that the marine structures are to be operated and maintained under adverse ice conditions:

- Very large lateral loading may be generated during floating ice/structure interaction both in the crushing and in the impact mode.
- Significant uplift and/or additional compression loads may be generated during tide variations due to ice adfreeze to the structure.
- The accelerated build-up of ice occurs on the structure due to tidal action, as well as due to wind- or wave-generated icing.
- The moving ice causes abrasion of structural members. In addition, concrete is subjected to cycles of freeze-and-thaw deterioration and steel to the potentially adverse effects of low temperatures.
- Floating ice not only directly affects the terminal structures, but also significantly complicates vessel operations:

- Ship traffic is to be restricted to certain lanes, offshore, in the approach channel and inside the port maneuvering areas. However, this protection measure may become insufficient during occasional winter and spring break-ups when large masses of floating ice enter the limits of ice-free shipping lanes.

- Berthing operations may become potentially hazardous because ice growth on the fenders eliminates their ability to deflect and absorb berthing energy.

- Large quantities of broken ice may create conditions where the vessel is unable to approach the dock unless floating ice is removed from the berthing area.

- The application of conventional (and affordable) floating navigation aids (buoys) becomes virtually impossible in heavy ice conditions. The problem is usually resolved by installation of more expensive onshore navigation systems.

The loads generated through ice/structure interaction, in most cases, govern the design of Arctic ports and terminal structures.

A general review of experience in operation of high-latitude oil and gas marine terminals indicates that existing technology of port structures design and construction is sufficient to support operations in the Alaskan OCS. New technology developments will be required in shipping operations, primarily by providing the highest level of safety of tanker operations in ice-infested waters and by maximizing the efficiency of ice management systems.

While technically feasible, no tanker traffic has been proposed in the EIS for upcoming Beaufort lease sales (MMS, 2003). Regulatory requirements would require pipelines, if economically feasible in comparison with barging or tankering production to shore. Because the EIS stipulates a preference to pipelines for transport, this suggests that MMS may consider tankering of hydrocarbons from the Chukchi OCS a less likely scenario (MMS, 2007b).

4.12.3 Constructability & Capital Costs

4.12.3.1 General Marine Terminal Concepts for Arctic & Sub-Arctic Conditions

At locations where the natural water depth is sufficient for berthing of large tankers and transport vessels, marine terminals can be built near shore. However, most of the coastal areas in the Arctic are shallow water, lagoon or beach formations, where the required 50 to 65 ft (15 to 20 m) water depth may be found only hundreds of meters offshore. Contemporary port engineering offers three solutions to this problem (as separate alternatives or combinations thereof):

- Approach trestle (access roadway);
- Approach (dredged) channel; and,
- Offshore TLU (Tanker Loading Unit) with underwater loading line.

Feasibility studies for marine hydrocarbon terminals designed for moderate climates often suggest that the approach trestle solution is the most expensive. This conclusion becomes more certain for the Arctic and sub-Arctic conditions because the relatively light structural supports for a trestle need to be increased significantly to resist ice loads.

The dredged channel option is also quite expensive and may have negative environmental impacts (disposal of dredge spoil). Two main cost-escalating factors in the Arctic are the short summer dredging season and the need for equipment mobilization to remote areas. Besides high costs, the dredged channel alternative is frequently rejected due to the long time required for its execution and, more frequently, because of the potential for environmental damage. In some Arctic coastal areas, storm wave action, prevailing current and long-shore sediment transport processes cause an accelerated siltation of the dredged channels.

The difficulties and high costs associated with access roadway and dredged channel alternatives apparently are the main reasons behind the decisions to construct offshore TLU's in several recent projects where operations need to be conducted in the floating ice, e.g. Sakhalin 1 DeKastri export terminal in the Sea of Japan and Varandey Terminal in the Barents Sea, Russia (see Section 3.2.7).

4.12.3.2 Offshore TLU Alternatives

The main advantage of offshore berthing is that the TLU may be sited at the required natural water depth without dredging or without construction of an expensive access roadway. One possible alternative is the sea island. This is essentially a traditional oil jetty arrangement (loading platform with breasting and mooring dolphins), except the whole loading structure is moved offshore and the oil is delivered through a subsea pipeline. For arctic conditions, the sea island is a reasonable solution because it may be constructed as a gravity-type structure (or group of gravity structures) which offer resistance to ice loads.

The other TLU alternative which has potential for arctic conditions is the bottom-founded SPM or Single Point Mooring. Other possible SPM arrangements, such as the Catenary Anchor Leg type (CALM buoy), Single Anchor Leg type (SALM buoy) and Multiple Buoy Mooring (MBM) cannot be used in the Arctic for year round operations. These solutions are vulnerable to damage from floating ice and hose handling is not conducive in sub-freezing temperatures. In addition, the CALM, SALM and MBM will not be able to sustain floating ice operational conditions. A SALM buoy has been used on the Sakhalin 2 project but tanker loading was halted in the winter (Figure 4-38). This type structure has suffered damage during severe weather and is scheduled to be replaced by a permanent pipeline to shore (Platts, 2007). For year-round operation in arctic and sub-arctic conditions, a bottom-founded SPM with a boom-supported hose string may be a viable option (Buslov et al., 2004).

There are two ways to ensure the lateral stability of a bottom-founded SPM in floating ice. It may de designed as a gravity structure (both of a caisson type or a tower type) or it may derive the necessary resistance to the ice loading from piles driven through sleeves attached to its base. For instance, according to available information, the Varandey oil terminal in the Barents Sea (Russia) is a wide turret tower with a caisson gravity base and a group of piles to supplement the lateral resistance (Section 3.2.7). The Sakhalin 1 SPM of the DeKastri terminal is a relatively slender tower with piles driven over the perimeter of a wide base. This structure also has a large ice-breaking cone at the water level intended to reduce the lateral ice load (Figure 4-39). The Sakhalin 1 SPM is the world's largest fixed tower structure of its kind. It weighs 3500 tons (3200 tonnes) and sits 200 ft (61 m) above sea level. It can handle tankers up to 110,000 DWT and is designed for year-round loading in the ice-infested Tatar Strait between Sakhalin Island and the Russian mainland (PennWell Publishing, 2007).

Figure 4-38: Ice Breaker “Smit Sibu” Providing Ice Management Operations for SALM Buoy Lay Down Operations on Sakhalin 2 (Courtesy of Don Connelly)

Figure 4-39: The Sakhalin 1 Fixed Tower SPM Sits 61 m above the Seabed (Courtesy of PennWell Publishing, 2007)

The application of ice-breaking cones is not without controversy. Some experts have warned that ice adfreeze resulting from tidal variations may create conditions under which the cone becomes totally inefficient. Moreover, the ice block frozen to the cone may generate higher loading in the ice crushing mode than the tower stem without a cone. This premise is similar to that presented in Section 4.5.4.1 with respect to the use of a sloped-sided structure for a GBS production structure.

Conceptual evaluations of structures for sub-arctic conditions, with level ice less than 3.3 ft (1 m), showed that the increase of the wall thickness of the steel pipe piles at the zones of maximum bending moment is a more cost efficient solution than the application of cones at the water level. In these cases, the cost for fabrication and installation of ice-breaking cones is higher than the cost of the extra steel required to provide the necessary strength of piles at the points of maximum stress.

Collapsible (articulated) and submerged SPM systems have also been proposed for application in the floating ice conditions (Tsinker, 1995).

4.12.4 Environmental Considerations

Hydrocarbon transport marine terminals are considered by countries having access to the Arctic seas as potentially having an impact on the environment. For instance, the maximum allowable level of hydrocarbon products in seawater in the Russian Federation is barely achievable by the best oil/water separators. Proposed solutions require the application of additional stormwater treatment technology. Other stringent requirements have resulted in the creation of Water Conservation Zones, where many industrial activities are disallowed.

Terminal concepts where tankers are loaded offshore require a subsea loading line as a key component of the overall facility design (for example, Sakhalin 1 DeKastri Export Terminal). The protection of this pipeline from ice gouging nearshore and at landfall is an important aspect of the overall terminal design.

One of the most challenging components of the operations of a marine terminal in arctic conditions is Oil Spill Response (OSR) in floating ice conditions. Solutions are developed through creation of detailed action scenarios and potential application of OSR personnel teams, vessels and available equipment.

To reduce the potential of oil spills from tankers, there has been a mandatory phase-in of double-hulled tankers, better navigational systems and tanker escorts (MMS, 2003).

Another consideration is that the use of tankers would result in air emissions from the tankers' engines during loading operations, transit and unloading.

4.12.5 Operations

Safe vessel operation in ice (Figure 4-40) is usually ensured by providing special ice control and ice management support/technology, such as ice breaking by terminal and escort icebreakers, ice suppression by thermal discharge, bubbler systems and ice dusting, and ice diversion by small islands, cells and dolphins. All of these inevitably increase the costs of terminal development in the Arctic and impose a range of requirements to the layout of the terminal facilities and their structural design.

The key component of vessel operations in ice in the vicinity of marine terminals is maintaining the operational areas (approach channels, maneuvering zones and turning circles, anchorages, etc.) free of ice as long as possible with minimal ice management. This particular requirement makes the design and the layout of arctic marine terminals more site-specific than any other initial investment cost consideration. For instance, it may be more cost efficient (in the long run) to extend the loading line further offshore beyond the required minimum water depth if it would allow placement of the TLU at the location where, based on the multi-year observations, the "polyniya" (area of sea free of ice) is most frequently observed.

The same considerations govern the location and the layout of the oil piers and TLU's with regard to the movement of ice under prevailing winds and tidal currents. The shoreline geometry, and particularly the natural rocks and islands, may be efficiently used to reduce the interaction of the structures with particularly large ice features. More than one approach channel may be maintained through the winter to make sure that at least one will remain free of ice if the wind changes. Lower cost breakwater and berthing front configurations may be sacrificed in favor of an alternative solution which provides better ice clearing conditions in the harbor.

Figure 4-40: Icebreaker and Tanker Trials at Sakhalin (Courtesy of PennWell Publishing, 2007)

4.12.6 Maintenance & Repair

A maintenance program for arctic terminals includes three types of inspections:

- Regular inspections performed at least once a year to identify the need for repairs;
- Detailed pre-construction inspections conducted if the decision to execute the repairs has been made. These inspections have a goal to identify the scope of the repair; and,
- Special inspections (investigations) may be required if the causes of existing damage are not immediately clear. Special inspections normally include some kind of in-situ testing (coring, sampling or NDT).

The specific features of all surveys to be performed on arctic structures are normally associated with damage caused by exposure to low temperatures, alternate freezing and thawing cycles and ice loading (pressure and impact). The most serious concern is normally associated with the potential damage from the ice loading: static and dynamic overstressing, bending, cracking and breakage of support components, etc.

Depending on the approach channel infill rates, dredging may need to be carried out periodically to ensure vessel access.

4.12.7 Abandonment & Decommissioning

Decommissioning procedures for offshore installations that have reached the end of their useful life are usually included in governing legislation. There are also international agreements relating to decommissioning that address removal and deep-sea disposal. For example, the International Maritime Organization (IMO) has developed Guidelines and Standards for the removal of Offshore Installations and sets out conditions to protect navigation and maintain safety.

Some general requirements in other jurisdictions with regards to decommissioning include designing facilities such that, upon termination of production, they can be removed or mothballed for future use.

4.13 Other Technologies

4.13.1 Extended Reach Drilling

4.13.1.1 Technical Feasibility

The Liberty FEIS (MMS, 2002) defines extended-reach wells as wells having departure ratios (or horizontal reach to vertical depth) of greater than 1.5. Such wells are increasingly being considered as a reservoir access option to reduce overall development footprint size and eliminate the need for offshore facilities.

As noted in Section 3.2.8, records continue to be set using extended reach drilling (ERD) technology. Application of the technology in Alaska also continues to grow (Figure 4-41) and has been used to increase access to the Alpine development reservoir (Alvord et al., 2007).

A long-reach US record for horizontal directional wells was set by BP in 1998 with a reach of 19,804 ft (6036 m) in the Niakuk Field (see Figure 4-41). While the well cost $6 million, the use of extended reach technology resulted in a cheaper solution over other drilling alternatives such as the construction of an artificial gravel island (Department of Natural Resources, 1999).

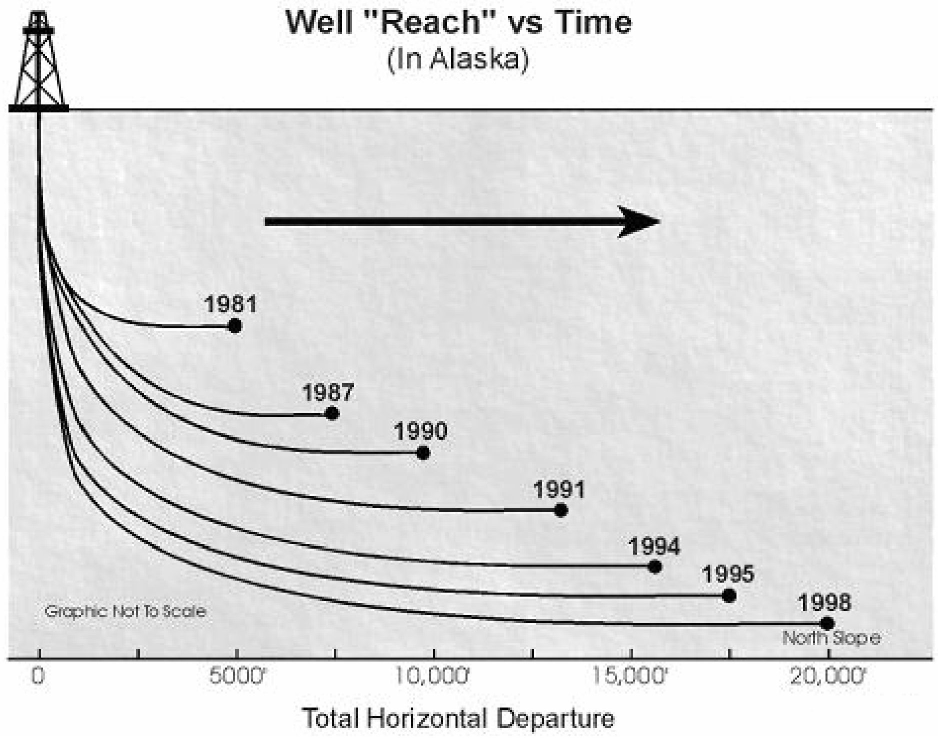


Figure 4-41: Well Reach vs. Time (Department of Natural Resources, 1999)

An evaluation of extended drilling technology was carried out by the MMS as part of the Liberty FEIS (MMS, 2002). That evaluation discusses extended-reach drilling in other settings, both on the North Slope of Alaska and elsewhere. The reader is referred to that document for additional details.

Only a few years ago, it was not considered feasible to develop the Liberty prospect using ERD (MMS, 2002). However, currently, the plan is to access the Liberty reservoir using this technology from Endicott Island where existing infrastructure exists. This will take the technology to distances of 40,000 to 45,000 ft (12,100 to 13,700 m) (Nelson, 2007b).

Current industry achievements have reached 37,000+ ft (11,300+ m) measured depth and reservoirs within this range should be reachable depending on site-specific conditions. Each development might be expected to contain a unique set of geologic conditions that affect drilling costs and long-term operations.

Therefore, ERD from shore is considered technically feasible for location scenario closest to shore presented in this study. While not specifically feasible for the other location scenarios, it is evident that the technology could be applied where the right conditions exist.

The use of ERD offshore could be considered for any of the other scenarios that would utilize a platform and on which the equipment could be mounted.

4.13.1.2 Constructability

Indications are that the technology exists to drill a 37,000+ ft (11,300+ m) well depending on site-specific conditions. In cases such as the Liberty prospect and the Sakhalin 1 fields, purpose built rigs may be required.

4.13.1.3 Capital Costs

Being able to drill from onshore or access additional reservoirs offshore from existing facilities should be less expensive than considering an offshore platform or gravel island.

The costs of drilling using extended reach technology, while not presented here, should be established within the industry. However, in cases new equipment may be needed. The Liberty prospect will require a new bigger drill rig as equipment on the North Slope does not have the capability to drill the wells. This rig would not be readily mobile and would be specifically designed for the Liberty project (Nelson, 2007b). An evaluation of extended drilling technology was carried out by the MMS as part of the Liberty FEIS (MMS, 2002). That evaluation discusses extended-reach drilling in other settings, both on the North Slope of Alaska and elsewhere and also presents some information on costs.

The Sakhalin 1 Project uses what is believed to be the world's largest land based drilling rig (Abraham, 2007). As an indication of drilling time, the 37,016 ft (11,282 m) Z-11 well drilled on Sakhalin Island was drilled in 61 days (Abraham, 2007), demonstrating that experience will cut drill times (and costs). The Sakhalin 1 project has increased drilling rates from 330 ft (100 m) per day in the first-year of operations to 660 ft (200 m) per day in recent wells, cutting the drilling time of ERD by 50% (PennWell Publishing, 2007).

It should be noted that each development project might be expected to contain a unique set of geologic conditions that affect drilling costs.

4.13.1.4 Environmental Considerations

Environmental considerations associated with drilling of wells are well understood and managed throughout the world including remote areas. The use of extended reach drilling, where feasible, should help minimize the overall footprint of facilities in Alaska, both onshore and in the OCS region.

4.13.1.5 Operations, Maintenance, & Repair

Operations associated with drilling extended reach wells is established within the industry. As these wells are likely to be drilled in remote locations, consideration needs to be given to supply and re-supply to areas with no permanent roads and delivery restricted to winter when ice roads can be built and maintained.

It should be noted that each development project might be expected to contain a unique set of geologic conditions that affect long-term operations.

Maintenance and repair issues associated with ERD should be established within the industry. As with operations, consideration needs to be given to access to areas with no permanent roads and delivery restricted to winter when ice roads can be built and maintained.

4.13.1.6 Abandonment & Decommissioning

Abandonment and decommissioning for an extended reach well should not be significantly different than a conventional well.

4.13.2 Well Intersection Method (WIM)

4.13.2.1 Technical Feasibility

Another method that may prove viable for installation of relatively short (approximately 3.5 miles or 6 km length or less) and small diameter (approximately 12-inch (305 mm) or less) pipelines or flowlines is the use of the Well Intersection Method (WIM). This method employs conventional oil and gas directional drilling technology to intersect two wells in a horizontal orientation. The WIM option entails drilling two wells with the largest possible diameters that intersect each other to provide a continuous flow path for hydrocarbon transportation. The wells would typically be cased and may employ solid expendable tubular (SET) technology to bridge the two ends of the casing in the well path at true vertical depth (TVD) and provide a continuous conduit for hydrocarbon transmission.

Two drilling rigs are employed simultaneously to perform the drilling (one at each end). The wells are “intersected” at approximately the mid-point. Since conventional drilling technology is used, traditional blowout preventers (BOPs) are employed to contain any potential shallow gas pockets that might be encountered. In addition, all drilling fluids are contained, helping eliminate the environmental issues associated with horizontal directional drilling (HDD). Also, since one drill pad at each end is all that is required to support the drill rigs, the environmental footprint associated with temporary construction work space is mitigated. Finally, since at least one and possibly both drill rigs may already be mobilized near the WIM drill sites, potentially very high construction spread mobilizations costs may be partially mitigated.

The use of the technology has been investigated by others in the industry (Lee et al., 2005) where the intersection of two wells (termed U-tube wells by the authors) was undertaken on land, not for development purposes, but to provide insight as to what could be undertaken using future implementation of the technology. The surface locations of the wells were approximately 1400 ft (430 m) from each other into an unconsolidated sandstone reservoir with a true vertical depth of 640 ft (195 m). The authors propose the technology can be used to tie-in step out wells and eliminate flowlines installed on the seafloor or to extend the length of already extended reach wells in harsh environments, such as those where ice gouge is an issue. The authors also suggest that, ultimately, spans of 6 to 12 miles (10 to 20 km) might be connected using the technology. By "daisy chaining" the spans together, longer length connections can be made.

Therefore, the use of WIM from an offshore facility might be feasible for the location scenario in the Beaufort closest to shore presented in this study. A single WIM connection would not be feasible for other location scenarios, but if daisy chaining spans together was feasible, the technology could be applied where the right conditions exist. The use of WIM offshore could then be considered for any of the other scenarios, as long as the daisy chain connections (where they are tied together) were adequately protected.

This technology may also have application in areas that will not permit pipelines across bays to be situated on the sea floor (Smith, 2004).

4.13.2.2 Constructability

While the WIM has been used, there are significant well planning and drilling technology issues that would have to be addressed before it could be used in the Arctic with confidence. Issues with regards to the distance between drill rigs, required pipeline (casing) size, pigging requirements and subsurface geology would have to be addressed. If individual intersections were to be daisy chained, some design/development effort would need to go into the connections near the surface and protection of same.

4.13.2.3 Capital Costs

The WIM is based on existing drilling technology and well costs can be used as a basis. Smith (2004) indicates that the Buckinghorse River crossing exceeded $12 million, but some of this was attributed to problems at the onset of drilling.

4.13.2.4 Environmental Considerations

Again, environmental considerations associated with the drilling of wells are well understood and managed. If technically and economically feasible, the use of such technology could reduce the amount of buried offshore pipeline on the Alaskan OCS.

4.13.2.5 Operations, Maintenance, & Repair

Based on information reviewed, it appears that the casing that is set using the Well Intersection Method would be operated similarly to a pipeline with some potential limitations, e.g., pigging.

In terms of existing operations, the Buckinghorse River crossing started transporting gas using WIM technology in December 2004, at a rate of 9 mmscf per day. Anadarko were also looking at potential conversion to a high-pressure system to increase throughput to approximately 30+ mmscf per day (Smith, 2004).

Given the technology used to implement a WIM transportation solution, maintenance and repair issues would be similar to those associated with drilling.

4.13.2.6 Abandonment & Decommissioning

Abandonment and decommissioning for a WIM technology solution should not be significantly different than a regular well.

4.13.3 Pilot Hole to Pilot Hole HDD

4.13.3.1 Technical Feasibility

A relatively new development in the horizontal directional drilling industry has been to drill two pilot holes, from entry points at either side of the crossing, and intersect them underneath the crossing, rather than to drill a single pilot hole from entry to exit. This possibly extends the reach over conventional HDD projects.

HDD is a proven technology with a strong track record in non-arctic applications. However, it has been used on the ARCO Alpine Development on the North Slope to cross the 4300 ft (1310 m) wide east channel of the Colville River with four individual pipelines.

Therefore, the use of pilot hole to pilot hole HDD technology would not be feasible to access any of the location scenarios presented in this study. However, if daisy chaining spans together was feasible, the technology could be applied where the right conditions exist. The use of this HDD technology could then be considered for any of the other scenarios as long as the daisy chain connections (where they are tied together) were adequately designed/protected.

4.13.3.2 Constructability

Where HDD is considered, the main technical constraint involves the influence of soil conditions. The effects of the presence of permafrost on the drilling operation must be considered. The presence of gravel or ice lenses would reduce the efficiency of the drilling operations and could result in collapse of the hole. In the case of a shore crossing, it can be performed after the shore crossing pad has been completed, thereby decoupling the construction schedules.

4.13.3.3 Capital Costs

HDD is a well-established technology and costs can be provided by HDD contractors.

4.13.3.4 Environmental Considerations

A major advantage of a HDD shore approach is that the shoreline is left undisturbed. Also, theoretically, HDD installations could be linked (daisy chain) if the connection can be engineered/constructed. The use of pilot hole to pilot hole HDD technology would increase the overall HDD reach and decrease the number of connections if a daisy chain approach was used.

4.13.3.5 Operations, Maintenance, & Repair

A pipeline HDD crossing would be operated in the same manner as a conventional pipeline crossing including periodic inspections of the shore approach.

A pipeline HDD crossing would be maintained in much the same manner as a conventional pipeline crossing. There should be less maintenance as the shoreline will have been undisturbed which would minimize any potential acceleration of shoreline erosion. If the pipeline is operated warmer than the surrounding permafrost, there is the potential for surface subsidence in areas where the pipeline is closer to the surface.

A potential issue with regards to HDD installations is the accessibility of the pipeline. By the nature of HDD installations, access to the pipeline could prove difficult. In a daisy chain scenario, burial/protection of the connections would have to be conducted periodically.

4.13.3.6 Abandonment & Decommissioning

A pipeline HDD crossing would be abandoned and decommissioned operated in the same manner as a conventional pipeline crossing.

5.0 SUMMARY, CONCLUSIONS AND RECOMMENDATIONS

5.1 Overview

Offshore hydrocarbon exploration and production requires a bottom-founded platform, an artificial island or a floating structure plus subsea equipment including pipeline/riser systems. Transportation of produced hydrocarbons to market is also an essential aspect of any development. An added complexity when hydrocarbon resources are located in cold regions is the presence of first-year and/or multi-year ice during a significant part of the year. Global climate changes may also result in longer open water seasons in the future, which may lead to more significant storm events that must be considered in the design of full-field offshore development concepts for cold regions.

The objective of this study is to deliver an assessment of oil and gas technology that may be applied to cold regions of the United States Outer Continental Shelf (OCS). Advances in harsh environment offshore exploration and production technology have made it economically and technically feasible for projects to proceed in ice-covered waters. This study assesses the current state of offshore technology in arctic and sub-arctic regions. The results of this assessment are then used to provide insight and guidance into existing/future exploration and development technologies that might be applied on the US OCS, in particular those areas in the Beaufort, Chukchi and Bering Seas. The work covers exploration structures, bottom founded and fixed production concepts, floating production concepts, terminals, pipelines and subsea facilities, and also touches on other technologies that might be relevant to Alaskan OCS exploration and development.

5.2 Assessment Methodology

In general, the study draws on a review of Alaskan OCS and analogue experience, current state-of-practice and state-of-the-art. Assessments of exploration and production options are primarily based on technical feasibility. As appropriate, other considerations have also been examined, as follows:

- Constructability;
- Capital costs;
- Environmental considerations;

- Operations;
- Maintenance and repair; and
- Abandonment and decommissioning.

Given the large geographic area encompassed by the Beaufort, Chukchi and Bering Seas, location scenarios were specified to help focus the assessments. These location scenarios were chosen based on current and historic activity/interest (including lease sales, drilling, studies, projects, etc.) and water depths (given the general differences in offshore facilities configuration in relation to water depth). Overall general applicability of the technology to the area of interest was also considered.

5.3 Summary & Conclusions

5.3.1 Bottom-Founded Structures

Exploration drilling for oil and gas in the Beaufort Sea began from gravel islands in shallow Alaskan State waters in the late 1960’s and similarly in the Canadian Beaufort Sea in the early 1970’s. With time, activities progressed into deeper waters. In 1976, ice reinforced drillships were first utilized in Canadian waters, followed in 1981 by the first use of a bottom-founded caisson system. Although touted as “mobile” structures, the caisson structures were not truly MODU’s (mobile offshore drilling units). The SSDC was the first MODU-type structure in the Beaufort Sea, coming into service in 1982 and, with the addition of the MAT in 1985, remains the only active bottom-founded exploration structure in the Arctic offshore.

In terms of global size, structure cost and geometry, there is very little difference between dedicated exploration platforms and dedicated production platforms. In fact, an arctic mobile drilling structure is often more expensive than a production platform due to the fact that it must cater to a range of water depths, rather than a known set-down depth. Additionally, a mobile platform needs to be able to accommodate a range of foundation conditions including very weak clays. With production platforms, foundation characteristics are known and dredging of the top weak layer(s) is an available option, but is often not practical in the case of short-term mobilization of an exploration structure.

5.3.1.1 Design Considerations

In any location where substantial multi-year ice can impact a structure, the loads resulting from this interaction become the primary design condition. In such locations, wave loads are small by comparison and do not have any real effect on the design. In the deepwater, more southerly basin areas (Bering Sea) where only first-year ice occurs, the platform design is primarily governed by wave loads. In these areas, it is still generally necessary to employ solid monolithic type structures as ice loads are still too locally intensive to permit jacket or “water transparent” type structures. However, the use of a monolithic type structure in order to eliminate local ice load effects, bridging and vibrations, results in relatively high global wave loads.

After ice loads, there are two other parameters that have a major effect on the global structure size optimization; water depth and foundation conditions. Generally, multi-year ice loads increase as the water depth increases, although not in direct proportion. Thus, water depth has a twofold influence in that the deeper the water, the greater the horizontal design load, and also that the structure must increase in height and, hence, cost. Foundation types can range from “totally inadequate” (in which lateral relocation, excavation and/or replacement will be necessary) to “strong enough” to simply set-down directly on the seabed without any type of preparation. Foundation requirements for an exploration structure will be considerably less than those for a permanent production structure given the differences in the design loads (first-year ice vs. multi-year ice loads).

5.3.1.2 Technical Feasibility of Structures

Ten (10) location scenarios are assessed with respect to the types of structures that may provide a possible solution; in addition, two (2) general structures (one with oil storage and one for mobile drilling) are assessed. The location scenarios, together with primary design assumptions are listed in Table 4-1.

In the Beaufort and Chukchi Sea areas, the 100-year design ice loading condition arises as a result of an interaction with thick multi-year ice. The outer shell of all structures must be designed to resist high local loads and since these local loads from first-year and multi-year ice are not terribly dissimilar (even though there could be a factor of four between the global load scenarios), the quantities of steel in a temporary drilling structure will not be much different than those in a permanent production structure. In fact, temporary mobile structures may be more expensive due to having to cater to a range of set-down conditions rather than a specified depth.

In the case of exploration drilling, the historical approach is to establish foundation stability based on a deterministic first-year ice loading scenario and then to establish an ”alerts system” which would secure the well in the event that a large multi-year floe threatened the structure. This system works relatively well in shallower water depths where it can be almost guaranteed that large floes cannot impact the structure after freeze-up. In waters deeper than 65 to 100 ft (20 to 30 m), this approach becomes more problematic and site-specific. However, the probability of greater loads in deeper waters is often offset by a likely (but not guaranteed) increase in foundation strength typically observed as one goes farther offshore. Again, these arguments only apply to temporary “one well” drilling structures that have to sit on relatively weak clay foundations.

In the Beaufort and Chukchi Sea areas, where multi-year ice can impact structures, Table 4-2 gives approximate load ranges that modern probabilistic methods would predict. With respect to the Chukchi Sea, load ranges are given with respect to the northernmost areas. In southern areas, close to the Bering Strait, loads can be expected to be approximately 30% less.

In the event that a temporary deployment for an exploration structure is being considered, arguments as outlined above can be rationally developed such that the foundation only needs to resist first-year ice loading of the order of 45,000 to 90,000 kips (200 to 400 MN).

Wave loads in certain areas can become a primary design consideration (Table 4-3), although for the Beaufort and Chukchi Sea areas it is generally ice loads that govern stability.

In multi-year ice areas, there are bottom-founded, e.g., gravity base structure (GBS), solutions that would be considered safe and economical up to around 250 ft (75 m) water depths when foundation properties are good, and up to around 200 ft (60 m) water depths when foundation properties are relatively weak. <u>There are no known bottom-founded platform design solutions for water depths greater than 330 ft (100 m) that could be deemed workable or proven for multi-year ice areas</u>. In the more southern areas, where multi-year ice is absent and only first-year consolidated ridge loadings are possible, bottom-founded solutions out to 425 to 500 ft (130 to 150 m) water depths are potentially viable.

5.3.1.3 Capital Costs

In Figure 4-9, 9 (nine) of the cost-estimated options were plotted. Costs range from approximately $3 million/ft ($10 million/m) for structures on strong foundations in deeper water to approximately $8 million/ft ($26 million/m) for structures on weak foundations in shallow water.

5.3.2 Jacket & Jack-up Structures

The jacket structure is the most commonly used fixed offshore platform. It was first used in the Gulf of Mexico and has since been adapted and modified for use all over the world. It comes in a variety of styles from the single-legged (monopod) to multi-legged structures.

The ice reinforced jacket platform was first successfully used in sea ice in the mid 1960's for Cook Inlet, Alaska developments. Conventional jacket designs have been modified to make them suitable for sea ice environments. Three varieties of ice reinforced jacket structures have been used there; the monopod, the tripod and the quadpod.

The main considerations for the design of any jacket structure are the payload the structure has to carry, the capacity of the foundation and the environmental loads the structure must resist. The loads unique to offshore Arctic structures are temperature loading, sea ice static loads and the accompanying vibration loads. In many cases, the sea ice static and vibration loads are the controlling factor (either globally or locally) in the sizing of the structure members. Temperature is generally the controlling factor in material selection.

The load imparted to a structure by momentum, ridge building and pack ice loading relates to the width of the structure. If the jacket legs are within a certain distance of each other, ice bridging can occur between the legs and higher loads will be experienced by the structure compared to the case where the legs are loaded independently.

In addition to static sea ice loads, the jacket structure must handle the vibration loading. Ice reinforced jacket structures are more susceptible to vibration than conventional jackets because they have less damping ability and tend to amplify vibrations. In light of jacket failure in the Gulf of Bohai and the dysfunction of another as a result of ice induced vibrations (Cammaert and Muggeridge, 1988), there is a strong possibility that jacket platforms are unworkable and/or uninhabitable under modern vibration code limits.

Previous studies have suggested that jacket structures are suitable for areas of the Bering Sea. These studies did not consider the vibration responses associated with the dynamic ice loading. Jacket type structures could likely be made to work in light first-year ice and water depths less than 200 ft (60 m). However, the jacket structure's potentially poor response to dynamic loading and the conductor system protection issue are a significant design issues for application in the Bering Sea. Current design practices and understanding of jacket design make their application unsuitable for the Beaufort and Chukchi Seas.

The protection and vibration issues associated with arctic jacket design and construction may be mitigated with further study and understanding of ice induced vibrations and the review and development of alternative damping techniques. Further study of jacket leg loading under thick ice conditions is required to determine if the jacket legs respond individually or as a group.

Developments in jack-up technology and the advancement of ice maintenance programs indicate that the operating range and season of jack-up exploration could be expanded in the Bering Sea.

5.3.3 Ice Islands

Grounded ice islands have been used successfully as exploration drilling structures in nearshore areas of the US and Canadian Beaufort Sea.

5.3.3.1 Technical Feasibility

In general, ice island technical feasibility is based on several fundamental regional and site specific considerations: meteorological environment, water depth, landfast ice characteristics and geotechnical (seabed) conditions.

Water depth is a fundamental factor that must be considered when evaluating the feasibility of grounded ice island structures. Generally, as water depth increases, island freeboard requirements also increase and, in turn, influence construction time/cost.

An ice island must be grounded soundly on the seabed to resist ice loads imposed by the surrounding ice sheet. This requirement is critical because any appreciable movement of the island during drilling operations can cause damage to the drill-string. Ice loads imparted on an ice island depend on the ice failure mode, rather than on the driving force of the ice sheet; crushing (failure) of the surrounding ice sheet typically limits the upper bound of these loads. Assuming that the shear capacity of soil beneath the island is less then than that of the ice island core, global ice island resistance will be governed by its sliding resistance (lateral stability).

In practice, operational ice islands have been employed in water depths of up to 25 ft (7.6 m) in the Beaufort Sea. However, based on work reported in C-CORE (2005), the use of operational ice islands might be achieved in water depths of up to approximately 30 ft (9 m). The MMS Ice Island Study (C-CORE, 2005) suggests that “incremental improvements in equipment capacity with higher productivity would allow islands to be constructed into deeper water and it is considered that 40 ft (12 m) water depth should not present a problem”.

Based on the location scenarios identified in this study, ice islands were assessed for both the nearshore Chukchi Sea and Norton Sound. Results of the assessment indicate that the use of ice islands in the nearshore Chukchi would likely be infeasible due to the unstable and unreliable landfast, or contiguous, ice zone. The assessment also indicates that ice islands would generally not be feasible for Norton Sound due to its warmer and shorter winter season. Efficient spray ice production would not be achievable, time available for construction and subsequent drilling operations would be reduced and creep/settlement would likely be more of an issue in comparison to ice islands used in the Beaufort Sea. Consideration of ice loads and associated stability requirements, the possible use of innovative techniques such as chipped ice and reducing ice loads, and possible use of rubble piles to initiate island construction, may allow an ice island to work in very shallow nearshore water depths. Further assessment would be required to ascertain ice island feasibility in these areas.

5.3.3.2 Construction

Initially ice islands were constructed using the flooding construction technique; however, build up rates were low. Alternative methods of ice island construction have been previously investigated and through significant experimentation and study efforts, spray ice technology was developed. All operational ice island drilling structures built in the US and Canadian Beaufort Sea (7 in total), employed this construction technique.

Construction time required for previous operational ice islands ranged from approximately 20 to 60 days (C-CORE, 2005). The *Thetis Ice Island* project carried out in 2002-03 employed several innovative measures to reduce ice island volume requirements and, hence, construction time:

- Reduction of design ice load (based on extrapolated maximum in-season ice thickness);

- Further reduction of design ice load by reducing the thickness of the surrounding landfast sheet; and,
- Use of chipped ice, which reduces the required freeboard because it has a higher density then spray ice.

5.3.3.3 Capital Cost

Capital costs for an ice island structure will be directly proportional to the amount of ice needed, which generally depends on the ice loads expected, water depth and soil conditions. Cost optimization may be realized in several ways, including reducing drilling facility footprint, reducing ice island diameter based on soil conditions, using chipped ice, and considering design ice load reduction techniques. Comparatively, ice islands are far more economical then gravel islands. However, gravel islands are more versatile with respect to water depths and ice loads. Figure 4-17 presented earlier illustrates the cost differences between ice and gravel island structures.

5.3.4 Gravel Islands

Although not a "high tech" technology, gravel islands have been successfully used in the Beaufort Sea for decades and continue to be viewed as candidate structures for exploration and/or production (for example, Northstar).

In general, gravel islands are attractive because they are a proven technology, offer a short construction lead time, and have historically been the most economical structure for shallow water depths. Given recent increasing oil prices and increasing material and fabrication costs for other types of structures, it is not inconceivable that the water depth for which gravel islands are considered might be increased.

5.3.4.1 Technical Feasibility

The use of gravel islands for arctic exploration and production has been proven. On the order of fifty (50) gravel islands have been constructed in the Beaufort Sea in water depths from several feet to over 60 ft (19 m). In theory, a gravel island has no depth limitation, but in practice water depth limitations have been considered to be approximately 65 ft (20 m) based on economics and logistics.

Landfast ice, typically ranging up to 6.6 ft (2 m) thick, covers the nearshore Beaufort Sea for about nine months of the year and has a considerable influence on island design and construction methods. In deeper water areas, multi-year ice incursions have to be considered and, in general, ice ride-up is more frequently encountered.

As is generally the case with other arctic bottom-founded structures, the primary design requirement for a gravel island is that it must have adequate lateral stability to resist ice loads. Gravel islands must also be capable of withstanding potential ice ride-up and wave conditions.

In general terms, these environmental loads are managed through gravel island geometry. Ice ride-up is impeded by the sloped island sides due to friction and plowing forces and/or, in some cases, by discontinuity in slope. Waves begin to break as they reach the sloped island sides, thereby dissipating energy before they reach the working surface. Wave overtopping is dealt with by placing the working surface above the design wave height and/or by placing a barrier around the working surface perimeter.

5.3.4.2 Feasibility of Selected Scenarios

Based on the OCS location scenarios investigated in this study, and considering practical water depth limitations, nearshore areas of the Beaufort Sea, Chukchi Sea and Bering Sea can be considered for the use of a gravel island.

Since no gravel island structure has been used in the Chukchi Sea, a more detailed assessment would be required to determine feasibility. From a qualitative stand-point, however, considering the primary design requirement is lateral stability, it would seem reasonable that a gravel island could be made to work in the Chukchi Sea. Due consideration would need to be given to the fact that the nearshore Chukchi Sea ice environment may be more dynamic then the Beaufort Sea.

In the nearshore Bering Sea, gravel islands may be subject to higher waves and larger wave loads. Any island design would need to take this into consideration.

5.3.4.3 Constructability

There are basically two methods of constructing gravel islands: the onshore (hauled) method or the offshore (dredged) method.

The onshore method typically involves excavating material from onshore and transporting it to site via truck over ice roads. Material is dumped through a hole cut in the ice by conventional chain trenchers and backhoes. The majority of gravel islands constructed in the US Beaufort have used this method. During the summer season, material can alternatively be transported to site via barge.

The offshore method involves dredging material and transporting it site via barge or pipeline. This method is typically used in deeper water where it is unfeasible to build ice roads or causeways. Most gravel islands in the Canadian Beaufort were built using this method.

The Chukchi Sea has a dynamic ice environment and nearshore “landfast” or “contiguous” ice is highly unreliable. Therefore, the truck hauling method will likely be infeasible. Norton Sound ice roads will have limited use in comparison to the Beaufort Sea, which will therefore limit the use of truck hauling.

When constructing a gravel island, consideration must be given to the fact that a pipeline will need to be brought onto the island. The timing and method of pipeline installation should be such that interference with island construction and/or facilities installation is minimized.

Typical costs associated with gravel islands were presented in Figure 4-17.

5.3.5 Floating Structures

There are only a limited number of floating exploration or production structures that have been used in ice environments.

5.3.5.1 Exploration

During exploration in the Canadian Arctic in the 1980’s, floating vessels (drillships) were used successfully with the support of icebreaking ships for ice management, e.g., CANMAR “Explorer III” drillship and CANMAR “Kigoriak” icebreaker. In particular, the Kulluk, a round drilling barge purpose built by Gulf Canada, operated in the Canadian Beaufort Sea. This vessel could operate through the open water season until early December (at the latest) with intensive ice management support.

5.3.5.2 Production

Historically, on the Grand Banks of Newfoundland, FPSOs (Floating Production, Storage and Offloading) have been the choice of floating production vessels under potential sea ice (first-year) and iceberg conditions. The hulls of both of the existing Grand Banks FPSOs are designed to operate in light to moderate first-year pack ice and can maintain their moorings in heavy first-year pack conditions. This ice cover would not have significant pressure ridges, nor would multi-year ice be present, as might be the case in the Alaskan OCS. Additionally, the hulls are designed to withstand the energy from a strike by a 110,000 ton (100,000 tonne) iceberg moving at 1 knot. This is an impact event and not a sustained load as might be found in the Beaufort or Chukchi Seas.

Modified spar, TLP (Tension Leg Platform) and semi-submersible designs have also been proposed for ice environments, although none have been built and there is much debate about the feasibility of these concepts in ice, particularly for Beaufort and Chukchi Sea applications.

Floating production platforms proposed for ice/iceberg areas are typically designed to be readily disconnected from their moorings and operated in managed ice conditions. The ability of these floating platforms to leave station would allow the vessel to avoid extreme ice loads and also provide the capability for operations on a seasonal basis. The amount of time that it might take any particular floating vessel to reconnect back on station will be a significant consideration in concept selection for any production site.

5.3.5.3 Alaskan OCS

Seasonal exploration can be carried out in the Alaskan OCS using drillships and drilling barges and, in areas without multi-year ice, semi-submersibles or a TLP. However, for exploration, the only location that a floating structure might be capable of staying on station year-round might be the Bering Sea under light ice conditions. A Semi-rigid Floater structure might work year-round under first- year ice conditions, but would need to have the ability to disconnect and leave station in the event of potentially higher loads. Fitzpatrick's Semi-rigid Floater is designed to stay in place year-round under 100-yr loading from a first-year ice, pack ice (NOIA, 2007).

The applicability of floating structures for use in the Alaskan OCS would depend on whether or not the structure was permanent or temporary, the ice environment, water depth, etc., and would have to be evaluated during any detailed assessment. However, floating production systems for the Beaufort Sea, Chukchi Sea and North Bering Sea are not considered to be technically feasible, even with continuous ice management. No floating production structures could be economically designed to stay on station with multi-year ice loads found in the Beaufort and Chukchi Seas, and possibly northern Bering Sea depending on local ice conditions. Floating systems may have some merit in southern Alaskan OCS areas, however.

Table 4-14 presents an overview of the possible use of floating structures for seasonal exploration, year round exploration and production in the Alaskan OCS areas of study.

Floating structures have been and will continue to be used for seasonal exploration. A floating structure will likely be only able to carry out year round exploration operations in the south Bering Sea under light ice conditions. However, a Semi-rigid Floater type structure could be considered for year-round exploration, if disconnects were permissible under extreme loading events. Based on current technology, no floating type structures could operate as a production structure in the most of the Alaskan OCS areas under investigation in this study. It is possible that a production structure might work in the southern Bering under light ice conditions.

5.3.6 Subsea Solutions

In some cases, there may not be a requirement for a production island or platform offshore. If the wellhead is located in water of sufficient depth, protection from ice would not be necessary. In areas with water depths less than the maximum ice keel depth, glory holes may need to be considered to protect the subsea facilities from ice ridge keels. This is considered to be approximately 165 to 200 ft (50 to 60 m) water depth in areas subjected to ice gouging.

5.3.6.1 Subsea Tiebacks

Improvements in the area of subsea facilities and processing have been made in recent years in the pursuit of resources in harsh and remote environments. As a result of these improvements, fields requiring longer, deeper subsea tiebacks are now becoming much more technically and economically feasible. Gas tiebacks have reached 105 miles (170 km) (Statoil Snøhvit) and oil tiebacks have reached 40 miles (65 km) (Shell Expro Penguin).

For subsea tieback options on the Alaskan OCS, production would be through remotely-operated subsea facilities with pipelines running to offshore facilities and/or landfall. Offshore structures would not be required in certain areas except during drilling of the wells and installation of the subsea equipment. Due consideration would need to be given to the design/protection of pipelines and flowlines tying in the subsea facilities.

Consideration would need to be given to the distances to shore or to a platform. Distances greater than those milestones stated above will require additional technological development or intermediate tie-in facilities for distances greater than these.

5.3.6.2 Subsea Facilities Protection

Glory holes (Figure 4-27) are excavations in the seafloor into which subsea facilities can be installed for protection from scouring ice keels. Although not in the Arctic, two existing projects use open glory holes to protect wellheads and associated subsea equipment from iceberg keel impact. These are the Terra Nova and White Rose projects located on the Grand Banks (Canadian east coast) where, to date, glory hole excavation has been the preferred method of subsea facilities protection.

Subsea facilities can potentially be used at any of the location scenarios considered in this study or, in general, for any development on the Alaskan OCS. However, there are limits on which technology should be considered.

There is a lower limit on when open glory holes would be effective. Glory holes only offer protection from gouging keels. Where active ridge building is taking place, at around perhaps 65 ft (20 m) water depth, or where grounded ridges are present, there is the potential for a ridge keel to be pushed into an open glory hole as the keel is being formed. Further site-specific analysis would be required to determine the range of water depths between which this protection strategy could be used. If glory holes were to be considered for protection in an active ridge building area, they may need to be cased and a cover incorporated into the design for protection.

Beyond the zone of active gouging, about 165 to 200 ft (50 to 60 m) water depth depending on the location, subsea facilities might be placed directly on the seabed (depending on the ice gouging regime). In any event, deeper water location scenarios (beyond which production platforms are not feasible) will likely require some type of subsea facilities on the seabed, whether they are part of a subsea to beach option or tied into a central production facility in shallower water.

5.3.7 Pipelines & Flowlines

There are a number of issues to be considered with regard to the protection of pipelines and flowlines in arctic environments such as the Alaskan OCS, over and above what might normally be considered for pipeline design in more temperate climates. These include issues surrounding design, construction, operations, maintenance and repair. Pipelines have been designed, constructed and are operational in the arctic, but these are in relatively shallow water depths and relatively close to shore. Pushing the limits to developments further offshore, in deeper water, will require that additional consideration be given to some of these aspects.

5.3.7.1 Design

Some of the main considerations with respect to pipeline design in the Arctic are strudel scour, thaw settlement of permafrost, upheaval buckling and ice gouging.

The first two design issues happen over very limited distances of the nearshore portion of the pipeline and have been addressed in existing pipeline designs. The third issue, upheaval buckling, can happen in any region of the pipeline if conditions are conducive to buckling. Installation procedures have been implemented on past projects to minimize the risk of upheaval buckling (considered limits on installed pipeline profile, use of select backfill or additional weight over imperfections). Therefore, it is generally felt that these three considerations can be designed for on future projects.

It is generally accepted that offshore arctic pipelines would need to be trenched to some depth below the seabed to protect the pipeline from the effects of pressure ridge ice or iceberg keels. This burial depth would be such that the ice would not contact the pipeline plus any required clearance between the bottom of the ice keel and the pipeline such that soil loadings on the pipeline are within acceptable limits (Figure 4-29). A number of buried offshore pipelines are being successfully operated in ice gouge environments, including projects in the Alaskan OCS (e.g., Northstar, Oooguruk).

Trench depths will increase in areas of more severe gouging. In nearshore zones (less than 33 ft (10 m) water depth), pipelines might be expected to be buried less deep than those in deeper water due to the less severe gouging. In the 65 to 130 ft (20 to 40 m) water depth range, ice gouging would be more extreme and result in the deepest burial. In waters deeper than this, gouge depths begin to taper off, as do the burial depth requirements. Offshore pipelines may be required to be trenched to approximately 165 to 200 ft (50 to 60 m) water depth in areas subjected to active ice gouging.

Ice gouging is only one factor in the overall determination of burial depth and must be examined in conjunction with other factors such as thaw settlement, upheaval buckling, strudel scour, pipeline stability and flow assurance. However, as mentioned above, these other aspects can likely be accommodated, given successful operation of projects in the shallow waters of the Beaufort.

5.3.7.2 Installation

Offshore arctic equipment and logistics requirements for summer and winter installation of pipelines are quite different. Construction methods for summer (open water) and winter construction (from ice) need to be evaluated to identify the best potential method with respect to probability of success, logistics cost and schedule.

While trenching from the ice to a certain water depth has been proven on projects in the nearshore Beaufort Sea, trenching and pipeline installation from floating vessels has not yet been attempted.

Floating vessels used in trenching or in support of trenching during open water may be subject to ice incursions. Equipment that is not designed for such an environment may be subject to damage under these conditions. Conventional trenching equipment may also have water depth or trench depth limitations which will need to be assessed.

Installation equipment must be suitable for use under the appropriate environmental conditions regardless if summer construction or winter construction is planned. Similar general considerations apply as noted for trenching equipment operations.

Given potential burial depth requirements for pipelines in deeper water (>50 ft or 15 m water depth), technology to economically trench and backfill these pipelines is considered one of the most significant issues with regards to successful project execution.

5.3.7.3 Operations

Consideration also needs be given to leak detection technology that might be used to detect leaks (in the unlikely event of a pipeline leak) in an environment where the sea is frozen over for most of the year.

An assessment on how pipeline repairs would be executed in the unlikely event of damage also needs to be carried out. The logistics for pipeline repairs will largely depend on the season, sea ice conditions and whether or not the repair is temporary or permanent. Further work is needed to determine if mechanical repair devices are appropriate for a permanent arctic offshore repair, where the pipeline may subsequently be subjected to significant strains.

5.3.8 Export Terminals

A marine export terminal is defined as a complex of structures and equipment for loading of hydrocarbon products, either pumped to a tanker from a storage facility located onshore or directly from a processing facility.

In most cases, marine transportation of hydrocarbon products starts with large storage facilities located onshore. The land-based components of these facilities (tank farms, loading pump stations, treatment plants, etc.) in the Arctic are basically the same as those in moderate climates. The main difference is primarily in providing the conditions and the process equipment to allow continuous operation under low temperatures, icing and snowfall conditions. Flow assurance is a critical consideration for arctic and sub-arctic locations. Consequently, to ensure smooth operations, an important aspect of any terminal concept is the need for proper insulation and heat-tracing technology on piping and pipelines.

Alternatively, hydrocarbons may be loaded on tankers at sea or in the vicinity of production platforms, either from the platform storage tanks or from a FSO (Floating Storage and Offloading) vessel. The FSO may also be used in the nearshore for temporary storage or trans-shipment loading.

Particularly challenging in the Arctic is the offloading of products to tankers. This operation would need to be conducted in floating ice if year-round operations are going to be carried out.

5.3.8.1 Technical Feasibility

The technical feasibility of marine terminals in arctic areas has been established through successful experience in a wide range of port facilities (Tsinker, 1995). These include the port structures and terminals in Nome, Cook Inlet, Anchorage and Valdez (Alaska), Godthab and De Long (Greenland), Nanisivik (North Baffin Island, Canada), St. David de Levis and Caps Noirs (Quebec, Canada), Norwegian and Russian ports in the Barents Sea (Murmansk, Arkhangelsk), and Magadan and Petropavlovsk (Okhotsk Sea, Russia). The most recent examples are the large Oil Terminal in DeKastri and the LNG Terminal in Prigorodnoye (Sea of Japan), Russia.

The common specific feature, as well as the main challenge in all of these ports and terminals projects, is that the marine structures are to be operated and maintained under adverse ice conditions. Very large lateral loads may be generated during floating ice/structure interaction, both in the crushing and in the impact mode. As well, significant uplift and/or additional compression loads may be generated during tide variations due to ice adfreeze to the structure. Floating ice not only directly affects the terminal structures, but also significantly complicates vessel operations:

The loads generated through ice/structure interaction, in most cases, govern the design of arctic ports and terminal structures.

A general review of experience in operation of high-latitude oil and gas marine terminals indicates that existing technology of port structures design and construction is sufficient to support operations in the Alaskan OCS. New technology developments will be required in shipping operations, primarily by providing the highest level of safety of tanker operations in ice-infested waters and by maximizing the efficiency of ice management systems.

While technically feasible, no tanker traffic has been proposed in the EIS for upcoming Beaufort or Chukchi lease sales. Regulatory requirements would require the use of pipelines (if economically feasible) rather than barging or tankering production to shore. An exception may be gas export by LNG or CNG.

5.3.9 Other Technologies

5.3.9.1 Extended Reach Drilling (ERD)

The use of extended reach drilling (ERD) has matured on some projects and upwards of 37,000 ft (11,200 m) wells are currently achievable. Therefore, ERD from shore is considered technically feasible for nearshore locations considered in this study. While not specifically feasible for location scenarios further offshore, it is obvious that the technology could be applied where the right conditions exist. The use of ERD offshore could be considered for any of the other scenarios that would utilize a platform and on which the equipment could be mounted.

5.3.9.2 Well Intersection Method (WIM)

The well intersection method (WIM) may offer an alternative means of transporting product from a producing well to shore in arctic environments. While the limit of this technology is currently estimated to be a maximum of approximately 6.2 miles (10 km), it has been suggested that spans may be daisy-chained together to make longer length connections (Lee et al., 2005). Further work is needed to verify this technique for arctic environments and to look at the economics compared to traditional trenched pipelines.

5.3.9.3 Pilot Hole to Pilot Hole HDD

A pilot hole to pilot hole HDD (horizontal directional drilling) installation can be considered as an option to conventional pipeline installation. However, there are length limitations to what can successfully be accomplished. If daisy-chaining spans together was feasible, the technology could be applied to access greater distance under the right conditions.

5.4 Recommendations

5.4.1 Ice and Metocean Information

As part of the scope of this study, the work was to include an evaluation of facilities not only in ice, but also in open water with large fetches and waves. If ice conditions in the Arctic deteriorate, it might be expected that fetch distances increase, resulting in higher waves.

There is general agreement that environmental conditions (especially waves and ice conditions) are changing in the Arctic. But no one definitively knows by how much, nor is there a compilation of current information (that the Study Team could find) that provides the information necessary for those interested in Alaska OCS projects to draw upon. The Study Team has tried to account for this in this study (somewhat) by reviewing a significant amount of literature, as well as holding discussions with selected stakeholders.

It has been suggested by stakeholders that the MMS might consider a future study to compile, collect, and/or generate (e.g., hindcast) ice, metocean, and meteorological information to be used by interested parties in screening studies.

5.4.2 Perceived Gaps

In carrying out this study, the Study Team identified additional information that would be "valuable to have" for future work. In addition, some technological areas were identified where advancements should be pursued.

These areas are included here as "perceived gaps" with respect to arctic development. This is not to imply that these are the responsibility of the MMS to advance (although they might be given consideration), but rather are included for completeness.

- Regional gouge database for the US Beaufort and Chukchi Seas. This would include a plan for repetitive mapping similar to the one established and maintained in the Canadian Beaufort by the Geological Survey of Canada (GSC);

- Ice gouge recurrence rates;
- Multi-year ice thickness distribution, ridge dimensions and frequency within a floe, floe size distribution, floe speed distribution;
- First-year ice thickness distribution, ridge dimensions;
- Regional geotechnical database for the US Beaufort, Chukchi and Bering Seas;
- Advancements in allowable/acceptable pipeline strain limits;
- Advancements in pipeline repair techniques for arctic pipelines;
- Advancements in pipeline leak detection systems for use in arctic environments;
- Advancements in subsea protection systems;
- Advancements in trenching technologies for use in an arctic environment including assessment, development and field trials;
- Clarity on emergency well control requirements;
- Advancements in determining maximum gouge depth based on ice strength and driving forces; and
- Evaluation of climate change and how it may affect exploration and development.

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