Low Temperature Effects on Drilling Equipment (Seals, Lubricants, Embrittlement)

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Limitations of the Report

The scope of this report is limited to the matters explicitly covered and is prepared for the sole benefit of the Bureau of Safety and Environmental Enforcement (BSEE). In preparing the report, Wood Group Kenny (WGK) relied on information provided by BSEE and third parties. WGK made no independent investigation as to the accuracy or completeness of such information and assumed that such information was accurate and complete.

All recommendations, findings, and conclusions stated in this report are based on facts and circumstances as they existed at the time this report was prepared. A change in any fact or circumstance on which this report is based may adversely affect the recommendations, findings, and conclusions expressed in this report.

Executive Summary

Wood Group Kenny (WGK) is under contract with the Bureau of Safety and Environmental Enforcement (BSEE) to execute a technology and research project to assess Low Temperature Effects on Drilling Equipment and Materials. This study was performed in accordance with Section C (BSEE's Contract No. E14PC00012). A summary of the main findings follows.

The qualification of drilling structures and equipment for Arctic drilling and production of oil and gas involves different steps. The first step requires determining the Lowest Anticipated Service Temperature (LAST) of the materials that will be exposed to the Arctic environment. The second step requires an understanding of the effects of the Arctic environment in the degradation mechanism (or mechanisms) of the materials. In some cases, the qualification can follow existing regulations or international standards. In other cases (particularly at lower LAST), the existing regulation or standard is not applicable to the given environment.

Some of the challenges to drilling onshore and offshore wells in Arctic environments include the extremely cold temperature, frozen ground covered with ice, frozen seas during the long winter season, and a short drilling season. A rig that is capable of drilling in Arctic conditions can begin work earlier in the drilling season because the rig can move in when the sea ice starts to recede (thereby reducing total drilling costs). Well design should take into consideration materials selection for casing, cementing, drilling hydraulics, and drilling fluids and should account for potential thermal cycling of the formation. WGK has found that current industry initiatives have focused either on improving the safety and containment during drilling or on the selection of the appropriate vessels and offshore structures.

In the case of metallic materials, understanding the brittle fracture and fatigue life acceptance criteria of materials at the LAST in Arctic conditions is crucial. The current materials specifications are not specifically intended for Exploration and Production (E&P) in Arctic environments. The industry has been focusing on the improvement of a wide range of materials properties such as strength, fracture toughness, fatigue performance, weldability, and corrosion resistance. Additionally, the industry is now focusing on the improvement of fabrication, welding techniques, methods for analysis, and experimental measurements of fracture toughness. New guidelines for the selection and qualification of materials for Arctic applications and the standardization of techniques such as probabilistic fracture mechanics and reliability-based design for Arctic offshore applications are still under development. Therefore, additional guidance regarding codes and standards that are specifically targeted to increase safety during E&P in Arctic environments is needed.

Many non-metallic materials have been developed, tested and qualified for low temperature applications to their metallic counterparts. The mechanical properties of many non-metallic materials are very similar to their metallic counterparts. Some of them are lighter or 'immune' to corrosion, or both. Although some non-metallic materials may undergo other types of aging or degradation, their chemical interactions with the environment appear to be minimal.

Data regarding the performance of polymers and composites in Arctic conditions is limited. The industry is focusing on researching and developing new polymeric materials and composites (including fiber-reinforced polymers) as replacements for metallic components used in aggressive environments where the use of metallic components is prohibited. Constant improvement of the properties of polymers and composites and the development of new non-metallic materials to satisfy the need for longer life expectancy in harsh applications is underway; WGK has found that several companies at the forefront of this effort are not willing to share their findings.

WGK developed a survey questionnaire and sent it to material producers, equipment manufacturers, operators, testing laboratories, and consultants. The survey focused on the materials used in Arctic conditions and included some of the common practices for transportation, storage, drilling, and production. The survey identified gaps in the industry with respect to the storage, safe handling, and de-rating of the materials when they are used in Arctic environments. Currently, there are no guidelines that prescribe requirements for packing, shipping, safe handling, testing, qualification, and de-rating of materials that are conventionally used in the contiguous U.S. which may be applied to Arctic environments. Materials producers, equipment manufacturers, and operators need this information to de-rate and prescribe proper procedures for handling and deploying materials in Arctic conditions.

Recommendations

The use of drilling rigs that are capable of drilling in Arctic conditions could open up the drilling season beyond the conventional open water season, but it could increase the risk for failure of some materials due to their exposure to Arctic conditions for longer periods of time. To avoid premature failure of materials used in the manufacturing of such drilling rigs and the equipment used during oil and gas operations, WGK recommends that the industry:

1. Seek a better understanding of the properties of critical materials used in the Arctic.
2. Use high capacity mud cooling systems for Arctic drilling, as they prevent the thawing of permafrost and help to prevent materials failure.
3. During Arctic drilling, use a high viscosity fluid with minimal shear to reduce erosion and heat transfer effects.
4. Use Freeze Protected Slurries (FPS) (in conjunction with cement) to facilitate cement flow, prevent freezing, and help to develop good compressive strength, thereby enabling safer operations during Arctic drilling.
5. For well design, consider materials selection for casing, cements, drilling hydraulics,

and drilling fluids to account for thermal cycling, hydrate plugging, and other effects related to Arctic conditions.

6. Provide adequate mooring and emergency disconnect in order to be prepared for severe weather events in the Arctic.
7. Select the appropriate vessel and have a contingency plan in case of a spill caused by premature failure of the equipment.
8. Design metallic and non-metallic materials used in Arctic drilling and associated structures for the Lowest Anticipated Service Temperature (LAST), which could, in some cases, be as low as –76°F (–60°C).
9. Take into consideration the larger stress amplitudes resulting from wave loading, wind loads, thermal cycling, and impacts from floating ice when selecting materials and designing structures to be used in the Arctic.
10. Thoroughly review the degradation mechanisms of metallic materials, with specific emphasis on loss of fracture toughness at low temperatures.
11. Take into consideration the control of fracture properties of metallic materials (Charpy V Notch [CVN] and Crack Tip Opening Displacement [CTOD]) for robust structural design against brittle fracture.
12. Base materials selection and design guidelines of Arctic environments on strong engineering principles and adequately conservative statistical and design margins.
13. Qualify new materials and welding techniques after carefully considering existing standards that are suitable for cold climates but taking into account the extreme Arctic conditions and temperature cycles present in the Arctic.
14. Use reliability-based methods to incorporate statistically bounding low temperature fracture toughness into structural design and fatigue life assessment to enhance structural integrity for Arctic applications.
15. Develop relevant methods for analysis and experimental measurements of fracture toughness of metallic materials and welded metals.
16. Take into consideration the design loads and accumulation of ice in the structures exposed to Arctic environments.
17. Although several polymeric materials are qualified at lower temperatures, conduct a thorough review of the degradation mechanisms at low temperatures in the service environment before a polymeric material can be used in Arctic temperatures.
18. Develop guidelines that prescribe the requirements for packing, shipping, handling, testing, qualifying, and de-rating materials that will be used in Arctic environments.

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Signatory Legend		
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	Approved	Luis F. Garfias

Table of Contents

List of Figures

List of Tables

1.0 Introduction

1.1 General

Oil and gas exploration (and production) in the harsh environment of the Arctic requires requalification of the existing materials and equipment as well as development of new materials and technologies to resist the low Arctic temperatures. In general, most materials are qualified at the expected service temperature. However, in Arctic environments, the lowest expected ambient temperature can significantly affect the performance and operability of conventional materials (such as metals, gaskets, seals, lubricants, hydraulic fluids) that are exposed to those cold temperatures. In Arctic regions, the minimum expected ambient temperatures are well below –40°F (–40°C). Based on industry best practices, the minimum design temperatures and qualification of materials and equipment used in Arctic drilling should be around –76°F (–60°C)[1].

Despite all the available information on the different materials and their applications in extreme environments, very little is known about the performance and failure modes of these materials when they are subjected to storage, transportation, and deployment in an offshore environment in Arctic temperatures near –76°F (–60°C). The testing programs of the major companies in the oil and gas industry have not considered the unusual combination of conventional atmospheric degradation followed by exposure to very low temperatures in Arctic environments (while the equipment is being prepared to be installed) and then immersion in low temperature waters (near the freezing point, when the equipment is installed). This study focuses primarily on drilling materials and the associated structures in Arctic conditions.

1.2 Project Objectives

The primary objective of this study is to conduct a review and selection of existing and new materials, fluids, and drilling methodologies commonly used in the Gulf of Mexico (GOM) and North Sea and to re-evaluate them for the temperatures and extreme conditions in the Arctic.

This study also proposes a roadmap for effective qualification of new and existing materials (metallic materials, cladded materials, polymers, and reinforced composites), fluids, and drilling methodologies. Using current specifications that are applicable to the

[1] Qualification of materials and equipment used in cold environments is typically done 20°C below the minimum design temperature. In this case, 20°C below -40°F (-40°C) yields -76°F (-60°C). Additionally, it is well known that in the Arctic, the temperatures can frequently remain below -40°F (-40°C) for long periods of time and can sometimes be as low as -76°F (-60°C).

environments, this roadmap may include:

- Selecting the materials.
- Defining the testing protocols.
- Understanding the qualification basis.

The roadmap may be similar to the one for selecting materials in the GOM and the North Sea. However, it will need to be re-evaluated, taking into consideration the 'cycles' in the temperatures and the extreme conditions of the Arctic regions. The new technologies must be tested and qualified for the purpose of safe operations in Arctic environments.

1.3 Abbreviations

A list of abbreviations that are used throughout this report follows.

ABS	American Bureau of Shipping
API	American Petroleum Institute
ASTM	American Society of Testing and Measurement
AWS	American Welding Society
BCC	Body-Centered Cubic
BHA	Bottom Hole Assembly
BOP	Blowout Preventer
BS	British Standards
BSEE	Bureau of Safety and Environmental Enforcement
CD	Current Density
CE	Carbon Equivalent
CMC	Ceramic Matrix Composite
CMP	Critical Metal Parameter
CP	Cathodic Protection
CRA	Corrosion Resistant Alloy
CTOD	Crack Tip Opening Displacement
CVI	Closed Visual Inspection
CVN	Charpy V-Notch
DBTT	Ductile to Brittle Transition Temperature
DC	Design Class

DNV	Det Norske Veritas (DNV Global)
DO	Dissolved Oxygen
DP	Dynamic Positioning
DSS	Duplex Stainless Steel
E&P	Exploration and Production
ECA	Engineering Critical Assessment
EDC	Excavated Drill Center
EDPM	Ethylene Propylene Diene Monomer
EDS	Emergency Disconnect Sequence
EWI	Edison Welding Institute
EEMUA	Engineering Equipment and Materials Users Association
EPDM	Ethylene Propylene Diene Terpolymer
EPIC	Engineering Procurement Installation and Construction
FAD	Failure Assessment Diagram
FBE	Fusion Bonded Epoxy
FCAW	Flux-Cored Arc Welding
FCC	Face-Centered Cubic
FDBT	Fatigue Ductile to Brittle Transition
FE	Finite Element
FEA	Finite Element Analysis
FEM	Finite Element Model
FFKM	Perfluoroelastomer
FEPM	Tetrafluoroethylene
FKM	Fluoroelastomer
FPS	Freeze Protected Slurry
FRP	Fiber Reinforced Polymer
GMAW	Gas Metal Arc Welding
GOM	Gulf of Mexico
GVI	General Visual Inspection

HAZ	Heat Affected Zone
HDPE	High-density Polyethylene
HNBR	Hydrogenated Nitrile Butadiene Rubber
HPCC	High Performance Composite Coating
Hs	Wave heights
HSS	High Strength Steel
IM	Integrity Management
IMR	Inspection, Maintenance, and Repair
IRHD	International Rubber Hardness Degree
ISO	International Organization for Standardization
LAST	Lowest Anticipated Service Temperature
LAT	Lowest Astronomical Tide
LDPE	Low-density Polyethylene
LED	Light-Emitting Diode
LMRP	Lower Marine Riser Package
LNG	Liquefied Natural Gas
LRFD	Load and Resistance Factor Design
MA	Metallic Above Water
MAG	Metal Active Gas
MDPE	Medium-density Polyethylene
MC	Material Category
MI	Metallic Below Water
MIC	Microbial Induced Corrosion
MIG	Metal Inert Gas
MMC	Metallic Matrix Composite
Mn	Manganese
MOB	Man Over Board
MODU	Mobile Offshore Drilling Unit
Multi-SAW-NG	Multilayer-multipass-multiwire Narrow Gap Submerged Arc Welding

NA	Non-metallic Above Water
NACE	National Association of Corrosion Engineers (NACE International)
NBR	Nitrile Butadiene Rubber
NDE	Non-Destructive Examination
NG	Narrow Gap
NGW	Narrow Gap Welding
NI	Non-metallic Below Water
Ni	Nickel
NORSOK	Norsk Sokkels Konkuranseposisjon
NR	Natural Rubber
PE	Polyethylene
PEEK	Polyetheretherketone
POD	Point Of Disconnect
PSL	Product Specification Level
PP	Polypropylene
PPS	Polyphenylene sulfide
PTFE	Polytetrafluoroethylene
PVDF	Polyvinylidenefluoride
PWHT	Post Weld Heat Treatment
RAO	Response Amplitude Operator
RBD	Reliability-Based Design
RGD	Rapid Gas Decompression
ROV	Remotely Operated Vehicle
SAW	Submerged Arc Welding
SCE	Safety Critical Equipment
SCL	Shear Connection Link
SCR	Steel Catenary Riser
SENB	Single-Edge Notched Bend
SMYS	Specified Minimum Yield Strength

STC	Strategic Technology Committee
TM	Turret Moored (rig)
TOLC	Top of The Line Corrosion
Tp	Time period
TS	Technical Specification
TSA	Thermal Spray Aluminum
UFJ	Upper Flex Joint
UTS	Ultimate Tensile Strength
UV	Ultraviolet
VDL	Variable Deck Load
VIM	Vortex Induced Motion
VIV	Vortex-Induced Vibration
WBM	Water-based Mud
WGK	Wood Group Kenny
WSOG	Well-Specific Operating Guidelines
XLPE	Cross-linked Polyethylene
YS	Yield Strength

2.0 Drilling Technologies and Environmental Challenges

2.1 Introduction

Several critical parameters should be considered before selecting a drilling rig that can operate offshore in the Arctic environment, with the objective being to minimize (or avoid) failure of major equipment or components which can lead to oil spills polluting the environment. The critical environmental parameters to be considered during selection include:

- Water depth (shallow or deep water).
- Metocean conditions (wind, waves, current, and climate).
- Operating window (seasonal or year-round).
- Ice conditions with specific site ice data and ice features such as land fast ice, ridges, pack ice, icebergs, ice floes, and ice drift velocities.

In addition to the environmental parameters affecting the vessel selection, other important considerations include:

- Whether the vessel needs to have a double-ended hull.
- Ice management systems.
- Station keeping technologies.
- Marine riser systems.
- Subsea equipment.
- Materials that can perform in the Arctic conditions to maintain the structural integrity of the drilling vessel.

Many fluids have been tested and used as additives for lubricants, hydraulic fluids, inhibitors, scavengers, and combinations of these in traditional drilling projects. Innovative drilling techniques and operations in extreme environments (including offshore exploration and production in northern regions) have been implemented successfully and are currently in operation. Very few recommended practices, international standards, and regulations apply to drilling operations in Arctic conditions. Drilling contractors, operators, and service companies need to evaluate their existing methods and any newly adopted methods before they can be used successfully in Arctic environments.

2.2 Drilling Environment Limitations

Some of the challenges while drilling onshore and offshore in Arctic environments include the extreme cold temperature, the frozen sea during the long winter, and the inaccessibility of some of the areas. Some of the offshore areas in the Arctic Ocean can be covered in ice for up to 10 months each year. Under those conditions, many materials used during drilling operations can fail or degrade more quickly. In some cases, drilling through the ice-covered Arctic Ocean may not even be possible. Therefore, the drilling season in the Arctic is very short.

Temperatures can frequently remain below –40°F (–40°C) for long periods of time and can be as low as –76°F (–60°C) for months. At these temperatures, the viscosity of oil increases, resulting in its inability to flow through pipelines. Additionally, the low temperatures significantly reduce the period of time during which personnel can work on the rig (refer to Figure 2.1).

Figure 2.1: Ice Formation on a Vessel [133]

Shallow waters in the Arctic Ocean range from a couple of feet to approximately 650 ft. (198 m). The deepest water depths range from 5,000 ft. to 8,000 ft. (1,524 m to 2,438 m). Figure 2.2 shows the approximate locations where water depths are less than 820 ft. (250 m). Drilling in deeper waters in the Arctic adds increased challenges because the rig will need materials that can resist the Arctic conditions and sustain larger loads in the deeper waters (see also Figure 2.3).

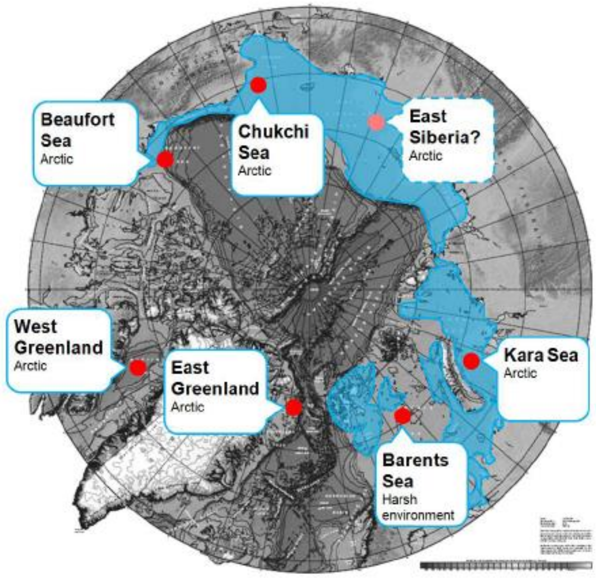

Figure 2.2: Areas of Water Depth Less than 820 ft. (250 m) [132]

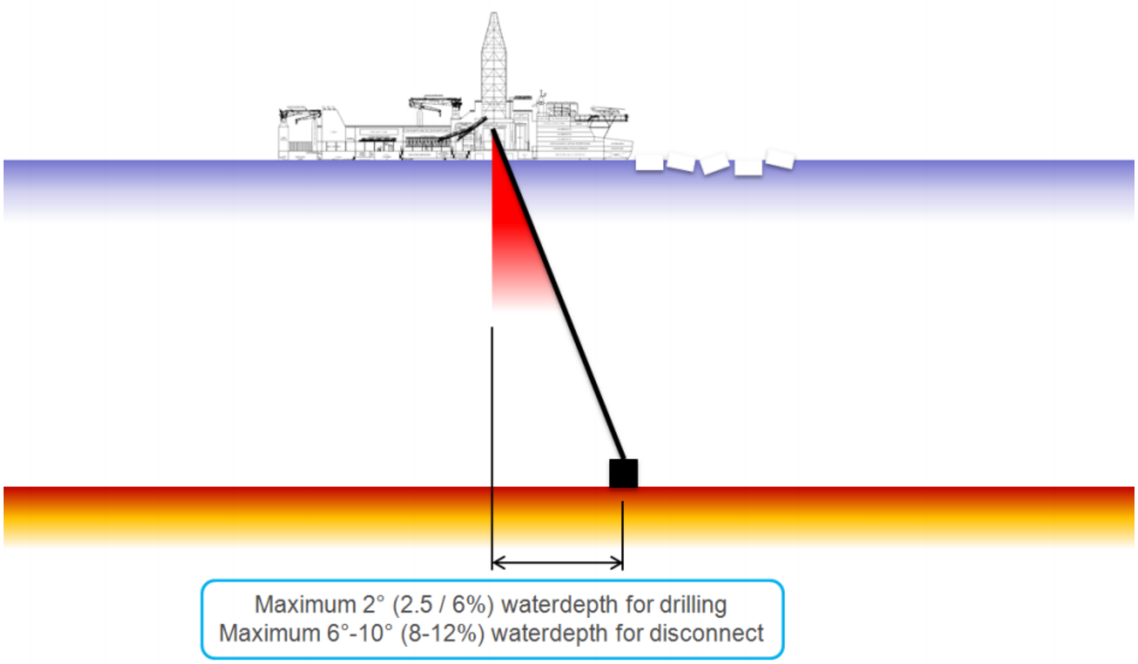

Figure 2.3: Operating Window for Floating Rigs Based on Water Depth [132]

2.3 Drilling Season

The environmental challenges in the Arctic make drilling and production more expensive because special equipment is required to extract the hydrocarbons from the wells. Additional challenges may include those related to the processing and transportation of the hydrocarbons from the remote locations. The cost to drill and complete the well is one of the most significant expenditures incurred in the Arctic conditions.

The length of the drilling season determines the total cost for drilling and limits the capacity to drill multiple wells in a season. The presence of seasonal ice (Figure 2.4) in the Arctic throughout the year also limits the ability to safely operate under those conditions. Typically, from October to May, the sea is covered with a thick layer of ice. In June, the ice layer begins to defrost and eventually breaks. Transportation, drilling, and offshore operations can be accomplished safely between July and September, when the sea is not covered with ice.

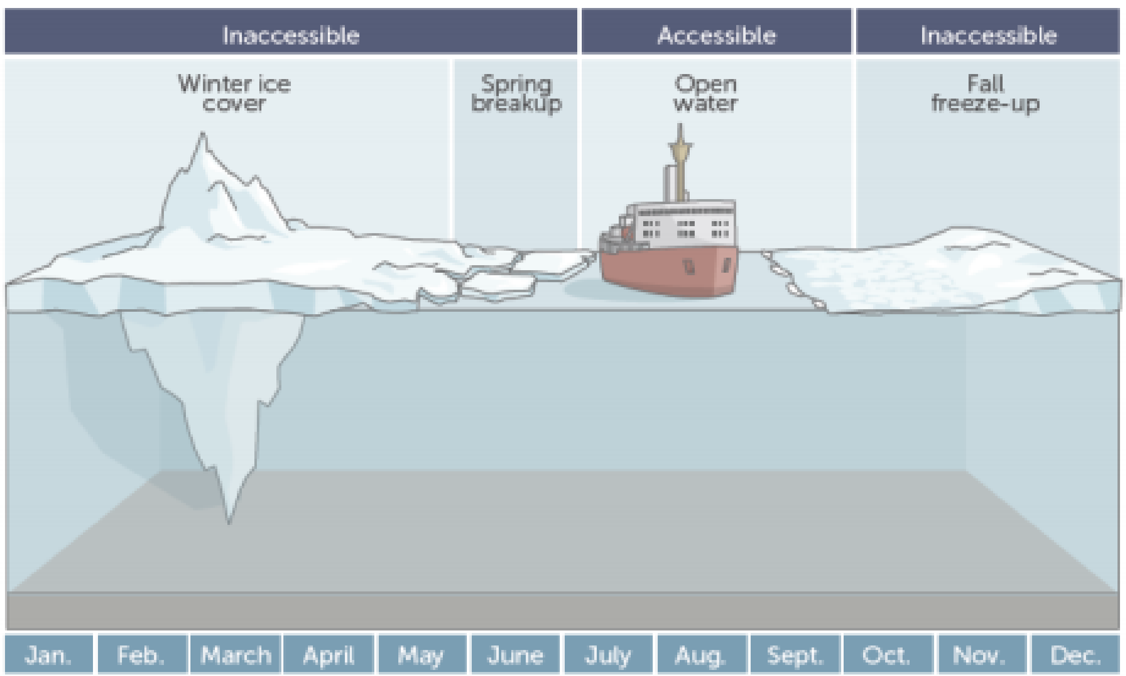

Figure 2.4: Seasonal Ice in the Arctic [106]

During the earlier years of Arctic drilling, exploration campaigns required multiple seasons to complete a drilling program because of the presence of sea ice. The costs of mobilization, demobilization, startup, and shut down increase the total project cost if the drilling campaign is prolonged for multiple years. The total project cost can be reduced substantially by extending the drilling season (thereby reducing the number of years) or by drilling continuously in one single year.

Figure 2.5 shows a schematic representation of the drilling season (shown in the inside belt). Drilling typically begins once the sea ice thins down or starts to break, which normally occurs around May. Operations are terminated when the sea ice starts to form during early autumn (around September thru October). The project must account for an allowance for contingency relief drilling, which should be finished before the sea ice starts appearing, thereby making drilling impossible. Taking into account the contingency days for relief drilling, the total drilling window is reduced to 90 days or less. In some areas such as Beaufort Sea and the Russian Arctic, the drilling window could be reduced further because of sea ice incursions in the normal open water season.

Figure 2.5 also shows the possibility of extending the window for safe drilling by using a rig that is capable of working in the presence of sea ice (refer to the outside belt). A rig that is capable of drilling in Arctic conditions can start the drilling season earlier, as the rig can begin operating when the sea ice starts to recede (around April). The drilling season can also be extended into October and November if the rig can drill while the sea ice is still forming. Extending the drilling season (such as from 4 to 7 months) using a rig that is capable of drilling in Arctic conditions has the potential to substantially increase the drilling season and reduce the total drilling costs because of fewer mobilization, startup, and shut down operations. Drilling during the extended season or the entire year requires a rig that can drill in Arctic conditions, and it may need automated controls with minimum (or remote) Operator intervention.

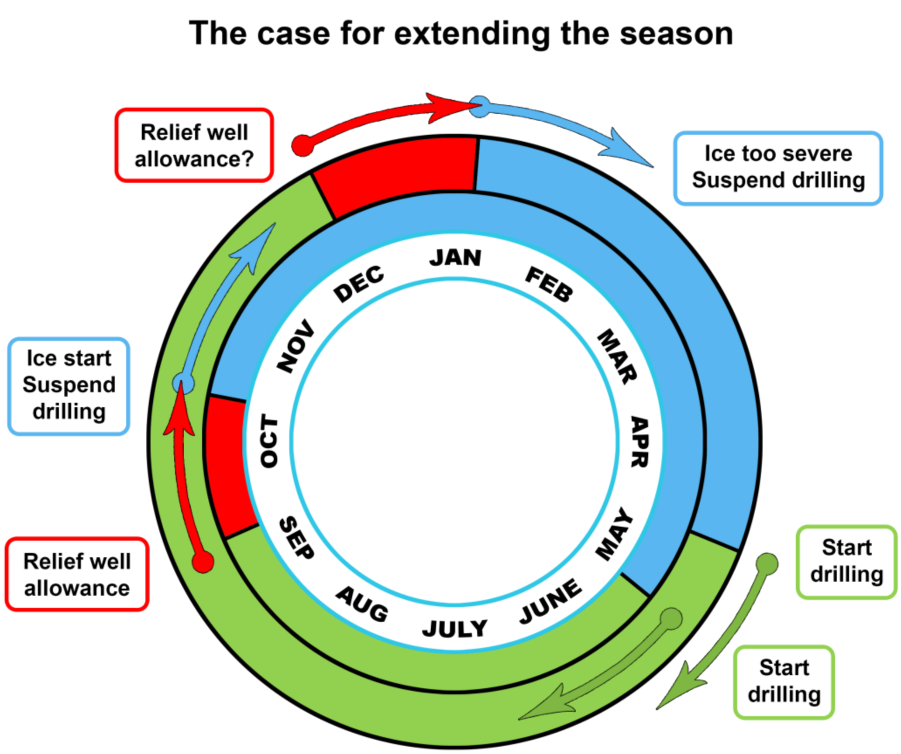

Figure 2.5: Extended Arctic Drilling Season [133]

2.4 Arctic Land Rigs

A rig that can drill in Arctic conditions must be customized for the low temperature environment of –40°F (–40°C). The rig should be capable of resisting the cold temperatures and the wind chill, which affect the physical properties of the materials of which the rig is constructed. Additionally, the ice and cold wind around the rig can increase the risk for materials degradation by external sources. For example, mechanical damage caused by contact with a large block of ice may affect the protective coating of the structure, which can lead to structure failure caused by corrosion and mechanical deformation.

Rig personnel must be provided protection so that they can work safely and comfortably in the Arctic environment. The entire rig may have to be isolated from the environment. The drill floor, the mast area, and the monkey board should be housed in an environment that is completely closed in (refer to Figure 2.6).

A conventional rig design for very cold temperatures separates each module into sections (such as the mud pump house, the air heater container, the variable frequency drive container, the generator room, and the diesel tanks room). Each module is separated into different rooms that are properly isolated from the outside environment. The rooms may be heated or may contain insulated walls (or both) to avoid the formation of ice inside the room, thereby providing safe operating conditions for personnel. There is potential for intelligent designs that could reuse or recycle the energy to keep the systems above freezing temperatures.

Figure 2.6: Onshore Arctic Rig [97]

2.5 Arctic Offshore Rigs

Specifications for some of the vessels that have recently been designed or redesigned for Arctic operations are shown in Table 2.1 and are explained in more detail in the following sub-sections.

Table 2.1: Drilling Vessels Designed for Arctic Operations

	Drilling Vessel	Vessel Type	Specification
1	Noble Kulluk	Drilling Barge	Circular platform; designed to mitigate ice damage[2]
2	Northern Lights	Semi-submersible	Totally enclosed derrick
3	Bully-1	Drillship	Self-propelled capability in thin ice zone; resistant to small-sized floe
4	DrillMAX ICE IV	Drillship	Two derricks and top drive; double hull
5	XDS 3600	Drillship	X-shaped prow; strong, self-propelled capability in floe zone

2.5.1 Drillships

Drillships (refer to Figure 2.7) that have been specially designed or modified for sea ice operations can also be suited for operations in the Arctic. There is ample experience in the maritime industry for operating ships in sea ice conditions. Drillships can be considered inherently safe in sea ice if they are sufficiently strengthened to resist impact with sea ice and can offer good protection to underwater equipment. Specifically, in relation to equipment passing through the splash zone, drillships are superior to other conventional vessels because of the moonpool, which offers protection to this equipment.

The moonpool, which is a hull opening in the ship, provides access to the sea and is used to lower and retrieve equipment such as the blowout preventer (BOP) and the riser into or from the sea. The completely enclosed moonpool provides sufficient protection to the riser and allows the vessel to operate, even during harsh environmental conditions such as high seas or in ice-infested areas.

Drillships offer a high Variable Deck Load (VDL), which enables high load carrying capacity for the rig to operate at draft. When drilling in deep water (which is typically farther from the land base), it is difficult to resupply consumables. A rig that can store sufficient consumables can operate without frequent replenishment from the shore base.

[2] Noble Kulluk, which was designed for Arctic operations, is no longer in operation. The rig was hauled to China, where it was dismantled in a shipyard south of Shanghai.

Drillships also have good transit speeds and propulsion systems that allow them to move away from the well during bad weather and emergency situations. Additionally, drillships can be used in exploratory drilling, where they must mobilize from one well to another. Despite these advantages, drillships are more susceptible to motion than semi-submersibles, and they do not perform as well in harsh environments [132].

Figure 2.7: Bully-1 Drill Ship from Noble [110]

The DrillMAX ICE (refer to Figure 2.8) is based in part on Stena's DrillMAX design, which was developed around the year 2000. The rig is equipped with a number of fully automated applications (including ballast discharge, mud systems, and dynamic positioning [DP3]) that help maximize the ease of operation. The rig has dual derricks and allows greater flexibility, allowing the ship to work on both the BOP and the top-hole drilling operation simultaneously.

Figure 2.8: Stena's DrillMAX ICE rig [121]

One of the critical modifications on the vessel (to suit the Arctic environment) is the hull reinforcement, which is a band of steel between 21 ft. (6.4 m) and 46 ft. (14 m) above the baseline to ensure that there is enough hull integrity for the Arctic's ice-laden seas. Other upgrades include the special power management, propulsion, and anti-icing systems.

The rig is driven by six ice-classed 5.5MW azimuth thrusters. The rig is also equipped with two moonpools at the port and starboard sides that allow allow the installation of two separate Remotely Operated Vehicle (ROV) systems.

The anti-icing system is designed to protect the helicopter deck, deck piping, lifeboat escape exits, ventilation intakes, and drainage system. The enhanced de-icing machines are designed to keep the decks, gangways, and handrails clear of ice throughout the entire time the drillship is in operation. The anti-icing system design has been tested in various low temperatures and wind conditions to verify that the anti-icing system is fit for purpose. This extensive testing has resulted in new types of handrails, heated walkways, and light fixtures (all of which contribute to safe operation in Arctic environments).

The electrical cables have been tested and approved to function at –40°F (–40°C) to comply with ice class +1A1 classification. Because traditional florescent lights do not work properly at temperatures below –22°F (–30°C), light-emitting diode (LED) lights have been developed for outside use. The knuckle boom cranes, which are used on the decks, are rated up to –22°F (–30°C). Some of the other specialized equipment that has been especially developed for the vessel provide bridge control, drill control, DP3 station-keeping systems, and related automation systems.

Another benefit of drillships is their larger capacity to store equipment and supplies (Figure 2.9), thus reducing the need for supply trips, which increases operational costs. The idea is to achieve four to six months of operation without the need to obtain additional supplies to operate. These vessels can carry large stocks of drill string, drilling mud, fuel, and other consumables [98].

Figure 2.9: XDS 360 [114]

2.5.2 Semi-submersibles

Semi-submersible vessels face significant challenges, such as the exposure of equipment in the splash zone and sea ice loading caused by the 'clogging' of sea ice in between the columns, which effectively renders them unsuitable for Arctic applications. In harsh environments, semi-submersibles ('semis') are considered to be superior because of their better motion characteristics. Semis have lower variable deck loads (compared to drillships), which reduces the amount of equipment and supplies they can carry. Additionally, their low transit speeds are less suitable for Arctic areas, which are usually located in remote areas and therefore require long periods of time enroute toward the area for drilling [132].

Figure 2.10 shows an image of the *Northern Lights*, which is a semi-submersible vessel [126].

Figure 2.10: Northern Lights (Semi-submersible Vessel)

2.5.3 Drilling Barge

Some drilling barges have been custom built to resist the issues associated with drilling in icy waters. The Kulluk [115], which is no longer in service, incorporated a 24-faceted conical hull, which was ice strengthened to meet the American Bureau of Shipping (ABS) Ice Class IAA requirements. It also met the Canadian Arctic Shipping Pollution Prevention Act (Arctic Class IV classification). The double-hull barge *Kulluk* (shown in Figure 2.11) had an inverted cone design, which caused the ice to break downward and away from the vessel, thereby protecting the drilling riser and the mooring system. The rig, which had to be towed onto the drilling location, was moored by 12 radially deployed anchor lines. The *Kulluk* could operate in shallow waters from 78 ft. (23.8 m) to 180 ft. (54.9 m) and was fitted to operate year-around in the Arctic environment. The *Kulluk* was designed to operate in ice up to 4.2 ft. (1.3 m) thick. Two Class 4 icebreakers and two ice-class supply ships provided ice management when the *Kulluk* drilled two discovery wells [20].

Figure 2.11: Kulluk Drilling Barge [115]

2.5.4 Jack-up Drilling Rigs

Jack-up drilling rigs (refer to Figure 2.12) face significant challenges in sea ice conditions, including equipment exposure in the splash zone and survival strategies. However, they offer a unique capability in shallow water. Provided that specific challenges are addressed, they are suitable for the full range of categories, although they are subject to operational limitations [132]. Jack-up drilling rigs are currently used in Arctic shallow waters with better ocean conditions and longer ice-free periods. The jack-up drilling rigs have adopted low temperature-resistant materials and equipment.

The Russian jack-up drilling platform *Prirazlomnoye* operates in the Pechora Sea; this rig can operate in thin ice waters with temperatures as low as –22°F (–30°C) [102].

Figure 2.12: Jack-up Drilling Rig

The *Endeavour*, which is a Marathon LeTourneau 116-C jack-up rig, was manufactured with steel certified to 14°F (–10°C) and can operate in the Chukchi Sea and in the Beaufort Sea. Its existing capabilities make it suitable for most water depths in the Cook Inlet and in the northern Alaskan waters. This jack-up, which is designed to operate in water depths up to 300 ft. (91.4 m), is constructed of 14°F (–10°C) rated steel, which allows it to perform safely in the Arctic [60].

2.5.5 Completely Enclosed Rigs

Several completely enclosed rigs have been developed specifically for offshore operations in extreme climate conditions. The main objective of these vessels is to ensure that the functions, systems, and equipment that are considered important to the safety of the vessel, personnel, and the environment will function properly throughout the year or while the rig is in operation. Some of the completely enclosed rigs are highlighted in the text that follows.

NanuQ

GustoMSC has developed the NanuQ series of drillships, which comprises three units [20](refer to Figure 2.13): the NanuQ 5,000 Turret Moored (TM) rig, the NanuQ 5,000 Dynamic Positioning (DP) drillship, and the NanuQ 3,500 DP drillship.

The NanuQ 5,000 TM rig (Figure 2.13) is designed to drill in Arctic seas from extended seasons to year-round operations in water depths up to 5,000 ft. (1,524 m). The vessel is capable of operating in multi-year ice thicknesses up to 13 ft. (3.9 m) and has direct positioning capability for station keeping during mooring system hook-up [132]. The selected turret position combines good weather and ice-vaning properties with good motion characteristics at the well center, allowing for both sea ice and open water operations. Suitable for exploration and developmental drilling, the NanuQ is self-propelled and offers ice class Polar Class 2 (year-round operation in moderate multi-year ice conditions, allowing year-round access to all Arctic areas).

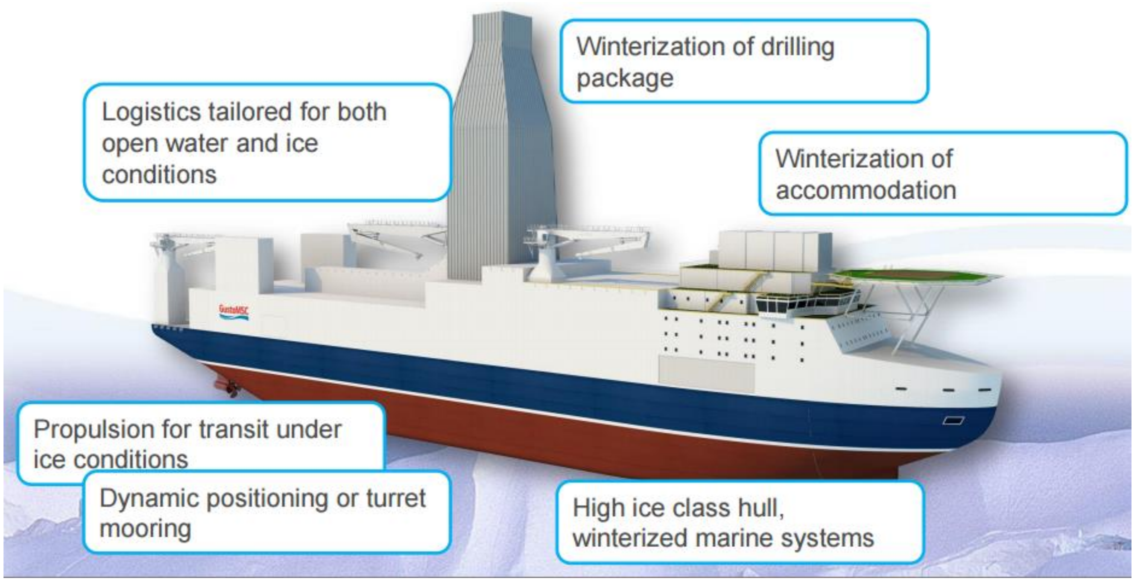

Figure 2.13: NanuQ Drillship

The NanuQ 5,000 DP drillship has a DP Class 3 redundant DP system and is designed for deeper Arctic waters and harsh environments; it has a mid-ship well center. This unit is capable of exploration and development drilling with the TM and is self-propelled with ice classes up to Polar Class 2.

The NanuQ 3,500 DP is dedicated to exploration drilling in extended seasonal mode. It is primarily based on dynamic positioning with a DP Class 3 redundant system complemented with a spread mooring system to allow operations in shallow water with some restrictions. This unit is self-propelled and offers ice class up to Polar Class 4 (year-round operation in thick first-year ice, which may include old ice inclusions), which is sufficient for extended seasonal operations in most Arctic areas.

Sevan Driller Arctic Version

A circular platform performs well for withstanding the impact of icebergs and floe (floating ice). The Sevan Marine semi-submersible platform [117] has a circular shape that can be used in both shallow and deep water (refer to Figure 2.14). It is designed to operate in water depths from 197 ft. (60 m) to 4,921.3 ft. (1.5 km), and it can withstand ice thicknesses up to 6.6 ft. (2 m). The topsides, piping, and electric cables on the platform are fully enclosed and isolated from the low temperature environment. This platform has a fully enclosed moonpool area, a simple structural layout (which allows for easy ice strengthening), a large load carrying capacity to store equipment, a permanent mooring system with protected mooring chains and wires, and a quick release mechanism for the system's mooring chains and wires. Because of the shape of the vessel, there is no need for 'ice vaning,' which results in an improved operability window.

Figure 2.14: Sevan Driller Arctic Version

JBF Arctic

The JBF Arctic (refer to Figure 2.15) is a round floater that is designed with eight columns and a round deck box [70]. It is designed to drill wells in the Arctic environment and can be moored in waters with ice thicknesses up to approximately 10 ft. (3 m). The design allows for operations at two operating drafts to adapt to water depths ranging from 200 ft. (61.0 m) to 5,000 ft. (1,524 m). The design can be customized to set the rig on the seabed in shallow water. When operating in ice, the rig will ballast to ice draft (partly submerged deck box) to protect the riser against level ice, rubble, and ice ridges. The round, cone-shaped deck box has a heavily strengthened structure at the waterline level to deflect and break the ice. The round floater is also strengthened to transit through broken ice with icebreaker assistance. In the absence of ice, the rig has the advantage of operating at semi-submersible draft and is designed for year-round operations in the Arctic. The unique design combines the advantages of a conventional semi-submersible (resulting in very low motions in waves) and a heavily strengthened ice-resistant unit when operating in ice at deep draft. Station keeping in waters covered with ice is achieved by a 20-point mooring system.

To increase drilling efficiency and minimize the time required for drilling as much as possible, the rig is outfitted with dual derrick systems. The two well centers have the same capacity, allowing various activities to be done at each well center. This allows for simultaneous operations and provides an extremely high level of redundancy. The complete drilling system is enclosed and provides a comfortable working environment for the crew. Because of the integrated design of the BOP handling system, the substructure is flush with the main deck of the vessel. Materials can therefore be handled safely. The design of the unit includes the following Arctic-ready features:

- Enclosed derrick and working areas
- Enclosed lifeboats, life rafts, and Man Over Board (MOB) boats
- Enclosed mooring windlasses[3] and loading hose stations
- Enclosed ROVs and protected launching
- Heat tracing of the heli-decks
- Enclosed riser storage and pipe rack area
- Heat tracing and snow covers on exposed escape ways
- Heat tracing of exposed pipes
- Sealing of exposed doors and hatches
- Heat tracing of all exposed stairs and walkways
- Insulation or heat tracing or both on all fluid piping that may freeze
- Heating coils for exposed tanks

[3] A windlass is a type of winch that is used especially on ships to hoist anchors and retrieve mooring lines. Windlasses were formerly used to lower buckets into and hoist them out of wells.

- Thermal insulation of the upper hull
- Design for zero spill and low air emissions to match the Arctic requirements

Figure 2.15: JBF Arctic Round Floater

JBF Winterized

The *JBF Winterized* (refer to Figure 2.16) is a dynamically positioned semi-submersible drilling unit suitable for up to 10,000 ft. (3,048 m) water depth in Arctic environments. It has dual derricks, and the drilling system is completely enclosed to allow for a comfortable working environment [70]. Apart from the traditional drilling operations, the *JBF Winterized* can be used to install christmas trees and perform well testing and well completions. In the absence of ice or very thin ice, this semi-submersible may be a good option for drilling in the Arctic.

Figure 2.16: JBF Winterized Semi-submersible Drilling Unit

IN-ICE

Inocean has developed an Arctic drillship concept based on the INO-80 concept called IN-ICE [71]. The ship is completely enclosed (refer to Figure 2.17) and winterized and has large storage facilities for drilling operations during extended periods of time in the Arctic. The ice class allows for a substantially extended drilling season in the Arctic with a Polar Class-4 ice class (year-round operation in thick, first-year ice, which may include old ice inclusions). The *IN-ICE* drillship has a conventional bow design for operations in rough open water wave conditions, as well as a moderate stern for aft-way operations in managed ice. The stern is optimized more for preventing ice from entering the moonpool than for ice breaking. The drillship positioning takes place through 'thruster-assisted turret mooring' in the shallow parts of the operational area and by dynamic positioning in the deeper water depth. The design is rated for 10,000 ft. (3,048 m) of water depth in temperatures down to –40°F (–40°C).

Figure 2.17: IN-ICE Ship

2.6 Ice Gouging

Wind and currents are key environmental variables that drive icebergs. Ice gouging initiates when the tip of the keel at the bottom of the iceberg interacts with the seabed. The pressure applied by the keel on the seabed results in a zone of overconsolidated soil. The soil resistance on the iceberg's keel may cause the iceberg to tilt upward, which decreases the interaction between the keel and the soil, thus facilitating the iceberg's movement forward. Fracture of the keel tip may occur, which results in a smaller iceberg that can travel farther toward shallower water depths [136]. Ice gouging can be classified into single and multiple keel events, as shown in Figure 2.18.

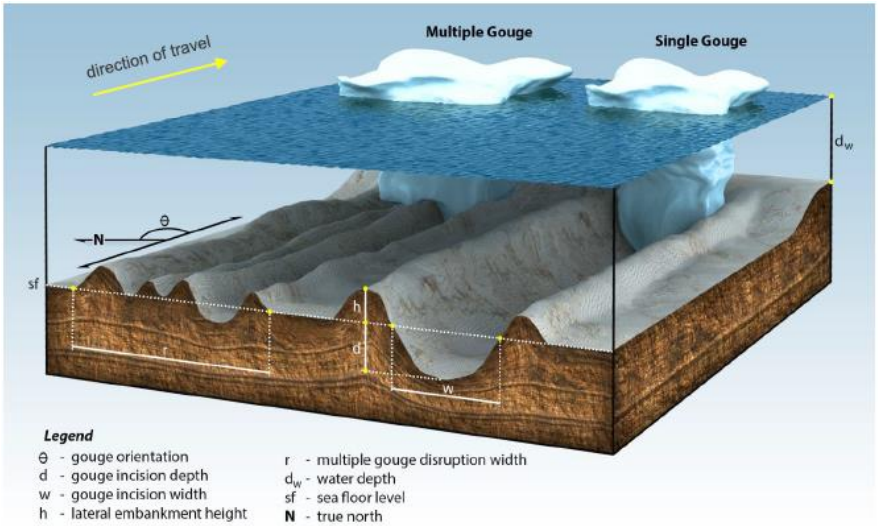

Figure 2.18 Single and Multiple Keel Icebergs [136]

2.7 Mud Cellars (Glory Holes)

Free floating and seabed gouging by icebergs pose a significant threat to equipment that protrudes above the seabed in Arctic offshore regions. To reduce this hazard, subsea equipment such as wellheads and BOPs can be placed below the mud line in excavations in which exposure to iceberg keels is significantly reduced [67]. The ice gouging depth varies by region, but the maximum water depth where ice gouging has been observed is at 656 ft. (200 m) [120]. If the depth where the subsea equipment is located is less than 656 ft. (200 m), excavations may be needed to protect the equipment from ice gouging [120]. The placement of the subsea equipment is below the lowest point that an iceberg, which is passing overhead, can touch. The risk of impact with an ice keel is the primary driver for the protection of subsea equipment, but secondary factors such as operational and maintenance issues or protection from fishing equipment (such as ship anchors) may also come into play.

Two projects currently use mud cellars (refer to Figure 2.19) to protect wellheads and associated subsea equipment from iceberg keel impact and subsequent damage. The Terra Nova [64] and the White Rose projects are located on the Grand Banks (in the Canadian east coast), where mud cellars are the preferred method for protecting subsea facilities.

Figure 2.19: Mud Cellars in the Terra Nova Field

The White Rose project uses three mud cellars in water depths ranging from 395 ft. (120.4 m) to 410 ft. (125.0 m). The Terra Nova project uses five mud cellars in water depths ranging from 310 ft. (94.5 m) to 330 ft. (100.5 m). Table 2.2 provides the available data for the Terra Nova and White Rose Glory Holes [20].

Table 2.2: Terra Nova and White Rose Glory Hole Locations and Dimensions [43]

Field	Mud Cellar Location	Dimensions (ft.)	Dimensions (m)	Depth (ft.)	Depth (m)
Terra Nova	Southeast	82 X 82	25 X 25	33	10.1
	Northwest	82 X 82	25 X 25		
	Northeast	148 X 82	45.11 X 25		
	Southwest	213 X 82	65 X 25		
	Far east	142 X 76	43.3 X 22.9	34	10.4
White Rose	Southern	190 X 146	57.9 X 44.5	30	9.1
	Central	191 X 163	58.2 X 49.7		
	Northern	125 X 56	38.1 X 17.1		

Other protection strategies have been considered for the Canadian east coast, including cased mud cellars, soil and rock berms, and concrete structures. The protection of subsea facilities by a cased mud cellar for the Canadian Beaufort Sea for water depths up to around 100 ft. (30.5 m) is shown in Figure 2.20 [20]. In this concept, a steel caisson is floated in and set down in a mud cellar, and then the mud cellar is backfilled. The upper caisson is sacrificial and will shear away during impact with a scouring ice feature.

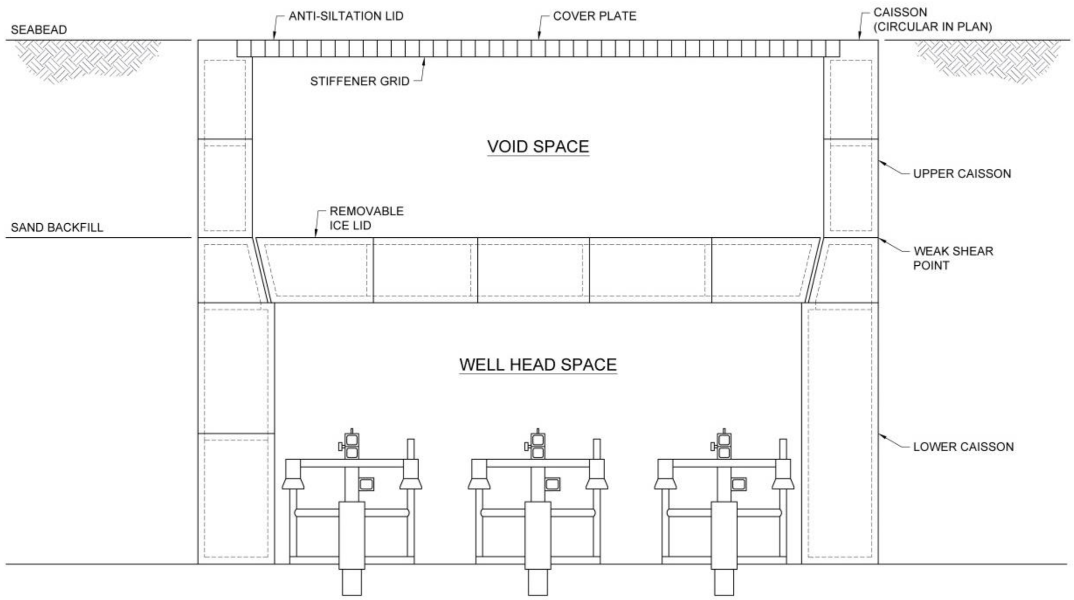

Figure 2.20: Subsea Facility Protection by a Steel Caisson

The robust ‘ice lid’ provides protection of the subsea facilities from the scouring ice. Excavation of a mud cellar is required to install this system. In water depths shallower than 100 ft. (30.5 m), the mud cellar may provide sufficient protection from ice keels. For small footprint subsea facilities smaller than 33 ft. (10.1 m) in diameter, a backfilled caisson may offer protection against fishing equipment or undue silting-in of the mud cellar. However, for larger footprints above 100 ft. (30.5 m), the mud cellar protection may be the preferred method, depending on the water depth [20].

2.8 Impact on Subsea Equipment

Subsea equipment such as wellheads and manifolds are vertical structures that extend several feet (meters) above the seabed, rendering them vulnerable to damage from gouging and floating icebergs. Techniques that are available for protecting such equipment from ice damage can be classified as preventive, protective, and sacrificial [136].

Preventive techniques are based on the assessment of the characteristics and frequency of a potential ice gouge event. Site selection is performed based on the review of risk assessments where the risk of contact is minimal.

Protective techniques are based on the use of fabricated structures to prevent direct contact with wellhead equipment.

The sacrificial technique is based on a probabilistic design approach where a design is considered acceptable if the estimated probability of exceedance meets an acceptable risk criterion. For equipment such as the wellhead, if the probability of occurrence exceeds the acceptability criteria limit, the wellhead design must incorporate a mechanical shear connection link (SCL). If an extreme loading event by an iceberg occurs, the SCL will isolate displacement of the wellhead system to a zone near the mud line while maintaining the integrity of the downhole safety barriers.

Successful implementation of the sacrificial technique requires information such as the iceberg's keel angles and near gouging keel distributions to determine the possibility of contact with floating and gouging icebergs. Survey data from seabed scanning is limited to induced gouges over a period of time. Crossing frequencies that are available in open literature do not include near-gouging events. This limits the amount of information required for successful implementation of a sacrificial design approach.

Design techniques that are commonly used for equipment such as wellheads installed above the mud line include:

- Excavated Drill Centers (EDCs) such as mud line cellars or glory holes: EDCs allow the installation of subsea equipment below the seafloor at greater depths than the anticipated gouge depth. This requires excavating the drill center and susceptible subsea equipment at the bottom of the excavation. The depth of the EDC takes into account the expected depth of the gouge from passing ice keels and the height of the subsea equipment. This technique has potential financial and environmental implications, as it requires the removal of a substantial portion of the seabed [136].
- Protective, truncated cone structures installed above the mud line: These structures sit at the mud line over the top of a single wellhead system and provide protection from direct interaction with an iceberg keel. The protective structure absorbs the energy by crushing the ice keel and diverting the iceberg over and around the structure. The size of the protective structure is determined by the size of the wellhead and tree system, requirements for ROV access, and the minimum slope required to achieve iceberg keel deflection [136].
- Sub-seafloor protective structures: This method is applicable to small well clusters and is similar in principle to the EDC approach, but it requires relatively smaller but more precise seabed excavations. The cost associated with this type of protective structure may be high for exploration wells and marginal field tie-ins [136].

2.9 Impact on Pipeline Design

Pipeline design traditionally uses stress-based methods governing materials selection and welding. Predominant loading, which is considered part of pipeline design, includes internal pressure from the contained fluid and external pressure from the water column. Designing pipelines for Arctic service increases their susceptibility to ice gouging. Ice gouging incidents could potentially result in significant design loads that render the stress-based approach impractical. Strain-based design is a viable option for Arctic service pipelines, as it allows for some permanent plastic strain.

Pipelines used in Arctic applications are protected from ice gouging and ice keel damage by means of trenching. Trenching requirements depend on design issues related to ice gouging, strudel scour, frost heave/thaw settlement, upheaval buckling, and sediment transport. Trenching must take into account the pipeline size and any over excavation. Other considerations to take into account as part of pipeline and trenching design include ice gouge depths, subgouge deformations, pipe response, and strain capacity. Continuum and finite element analysis (FEA) may be used to model ice keel-seabed-pipeline interactions [136]

2.10 Drilling Operations

2.10.1 Drilling Fluids

The frozen surface layer in the Arctic is called permafrost. Permafrost becomes solid at the freezing point of water. The thickness of the permafrost can vary up to 2,000 ft. (609 m) [7], depending on the location of the Arctic region. Permafrost can also occur in some offshore Arctic regions that are close to the seabed in the fast ice zones, which become deeper with increasing water depth. The permafrost depth varies from place to place, and its properties can change over time. In the presence of permafrost, heave pressures, thawing, frost penetration, creep drainage, thermal conditions, and settlements will affect the drilling operations and will have greater impact on the materials (both metallic and non-metallic) [7].

Some of the early drilling campaigns in the Arctic regions encountered significant problems related to drilling through shallow permafrost (in sections with holes). These difficulties were caused by thawing of the permafrost. The lessons learned from these earlier operations have resulted in the use of chilled drilling mud to reduce the thawing of the permafrost during the well construction phase. In the Arctic regions of Alaska and Canada, local regulations dictate that the permafrost layer must be protected during the entire well lifecycle. In addition, a low temperature-resistant drilling mud is necessary to prevent the drilling fluids from freezing.

During drilling operations in Arctic environments, protecting the permafrost using only cooled mud has been difficult. When drilling larger surface hole sections (16 inches [406.4 mm] or larger), higher pump rates are normally required to effectively drill and clean the wellbore. This results in high flow rates that produce high friction and heat loss because of flow through the small drill pipe and the bottomhole assembly (BHA). The drilling fluid gets hot because of friction, and it has to be cooled using heat exchangers. The industry has been using air/drilling fluid, sea water/drilling fluid, and cooled glycol/drilling fluid heat exchangers to resolve this problem.

The heat exchangers required to cool the mud have been designed to be both internal and external to the mud tank system. Some of the problems encountered when selecting the proper heat exchangers have included:

- Frequent clogging.
- Poor heat transfer performance (because of surface freezing).
- Internal freezing, which in turn has led to the suspension of the cooling process and resulted in wellbore degradation and thawing.

Experience has shown that drilling in Arctic environments results in more problems related to keeping the wellbore intact during drilling, running the drill string, and cementing than during the actual drilling of the well. Some of the causes could be any of the following [128]:

- Shale hydration with water-based mud in the wellbore under the permafrost section in certain fields (such as the Mackenzie Delta) where the formation is highly unconsolidated, as it once was within the permafrost section
- Thermal convection in the wellbore, which results in the melting of the permafrost, which is caused by the warm fluid below the permafrost
- Mud with higher chloride content that comes in contact with the permafrost (when the drill pipe is being pulled out of the hole or when the casing is run into the hole). Higher chloride content around metallic materials can increase their propensity for developing pitting corrosion and crevice corrosion.
- Drilling through the permafrost, which can be unstable because of the presence of large boulders, caving, loose gravels, annulus washouts, and mud losses

Some Operators have resolved some of these problems by using engineering solutions such as [128]:

- Casing while drilling with a non-retreivable drill bit system for the large diameter casing strings.
- Using a high capacity mud cooling system with an ammonia refrigeration unit that can cool glycol fluid.
- Using a heat exchanger with an unrestrictive spiral design to remove the heat from the drilling fluid.

- Using a high viscosity fluid that is specially designed to have minimal shear to reduce erosion and heat transfer effects (to reduce the risk for permafrost thawing).

Additionally, some of the best practices while drilling through the permafrost with water-based mud (WBM) include:

- Reducing the flow rate to 422 gal./min (1,600 liter/min) for a 16-inch (406.4-mm) hole size to minimize drill washout.
- Maintaining funnel viscocity greater than 66.2 sec/quart (70.0 sec/liter) to control caving and improper hole cleaning.
- Keeping the mud cool to prevent melting of the permafrost.
- Limiting the fluid loss to less than 0.3 ounces (8.9 mililiters).
- Limiting the rate of penetration to 32.8 feet/hour (10.0 meters/hour) while drilling highly unconsolidated zones (normally the first half section of the permafrost).
- Reducing the velocity from the drill bit jet; less than 196.8 feet/second (60 meters/second) if possible.
- Cleaning the hole effectively by pumping high visocity pills or sweeps.
- Preparing the rig to pump pills to resolve balling of drill bits/stabilizers.
- Using a detergent pill to break up any clay formation and coat the BHA.
- Cleaning the bit surface using an inhibitive pill.
- Dispersing clay by using a caustic soda pill that has high pH.
- Using Safety Critical Equipment (SCE) such as centrifuges.
- Maintaining reactive clay content to below 4.4 lb/ft^3 (70.5 kg/m^3)[35].

2.10.2 Cementing

The wellbore in a permafrost area is known to have a low fracture gradient that could lead to fluid losses during drilling operations. The cement hydration reaction is very slow in a permafrost zone and can allow portland cement to freeze before it develops compressive strength, which could lead to failure of the cement sheath. To solve this problem (known as cement slurry freezing), ‘freeze protected slurries’ (FPS) should be used. Examples of FPS are slurries containing high concentrations of gypsum cement, low heat hydration Arctic slurry, and high solids content slurry. An optimized-particle-size cement system can also be considered.

Using these engineering solutions allows the cement to flow and set as needed and develop a good compressive strength of the cement sheath (which can be effective at low temperatures). The hydration of cement is an exothermic reaction, and the heat that is generated could lead to thawing of the permafrost [47]. Therefore, some of the engineering solutions explained in Section 2.10.1 could be used.

2.10.3 Well Control in Subsea Environments

There are multiple well control challenges in the Arctic. Well control in Arctic regions includes all of the traditonal aspects of conventional well control. Different problems can be encountered onshore and offshore.

In the onshore wells, there is a concern for reduced geothermal gradients and low surface temperature while drilling, which could result in dangerous conditions. There is high probability of encountering in situ hydrates in the formation and inducing hydrate creation within the wellbore during wellbore operations. The upper section of the wellbore has cool temperatures, which could result in the formation of hydrates. The area below the permafrost, which can be 2,000 ft. (609.6 m) below the permafrost, could have in situ hydrate formation. The kick could result in significant gas volume and the presence of water because of hydrate formation.

In an offshore environment, hydrate control is still a major issue. Glycol is injected into the BOP stack and the riser equipment to prevent hydrates. The hydrates plug formation takes place in the cooler upper section of the wellbore during circulating operations. The hydrates plug can block the wellbore and result in failure to perform well control during an influx scenario. The well design should take into consideration the thermal cycling of the formation, and the equipment should be selected carefully, choosing the right materials for casing, cements, drilling hydraulics, and drilling fluids [104].

One of the requirements for floating rigs is the ability to drill a relief well in the same season using a separate drilling rig, which is available when an emergency arises. One strategy suggests the use of a second BOP on the rig, which can allow the rig to drill its own relief well. This option assumes that the rig will be able to quickly disconnect from the wellhead and move out of the station. If a fixed production platform can be used all year, drilling can be conducted without the previously mentioned issues.

In shallow locations, the subsea equipment can be exposed to ice scour. In this situation, the BOP is placed in a mud cellar (glory hole) below the seabed. This helps to disconnect the BOP from the drilling rig when an emergency arises and prevent mechanical damage to the BOP caused by ice.

2.11 Permafrost

Arctic wells must be designed to penetrate permafrost formations. Onshore, in the Alaskan North Slope, there are several wells located in permafrost regions that have been successfully producing hydrocarbons for decades. The Operators have designed, constructed, and maintained these wells and have maintained operational integrity.

Permafrost is located below the seabed on the Arctic shelf down where the water level was during the last ice age. In the Canadian Beaufort Sea, this is roughly at 426.5 ft. (130 m) of current water depth. Methane hydrate is located below the permafrost on the Arctic shelf and is similar to marine hydrate deposits found in the GOM. In the Arctic, marine hydrates are at shallower water depths because the water and sub-seabed temperatures are lower. A large number of offshore wells have been safely drilled through both the permafrost and the methane hydrate layer, mainly by ensuring control of the bottomhole pressure and the temperature during the drilling and completions process.

A casing string is normally run from the surface through the permafrost and into the rock below the permafrost. This casing string (usually the surface casing for surface wells and the conductor casing for subsea wells) is cemented from the shoe to the wellhead. Because permafrost thawing can create some subsidence in the permafrost zone, the selected casing material needs to have good ductility and strain capacity.

Some of the drilling and completion techniques applied on wells onshore (in the Arctic) can be used offshore while drilling Arctic wells. The lessons learned [111] onshore are:

- Install insulated conductors deep enough to resist subsidence.
- Use a mud cooler for drilling the permafrost hole and reduce washout caused by thawing.
- Use cement that has been formulated to work in the permafrost (with low heat of hydration); the conductor and surface casings can be fully cemented with permafrost cement.
- To reduce or eliminate permafrost melting during production operations, cover the conductor with thermo-siphons.
- Vacuum insulating the tubing can prevent heat from transferring from the reservoir to the permafrost zone.
- Using an insulating packer fluid (which is an oil-based system that has lower conductivity and less convection) reduces heat transfer from the reservoir.
- During cold start-up, inject methanol to prevent hydrate formation.

3.0 Drilling Vessel Selection and Planning

3.1 Drilling Vessel Selection

The selection of a drilling vessel is dependent upon a number of factors, the most significant of which is the type of vessel: semi-submersible or drillship.

The development of semi-submersibles (also called semi-subs) has come from the desire for a vessel configuration that will reduce the significant motions (heave, pitch, and yaw) under wave loading. The location of the hull structure of the semi-sub, which is at a deeper draft, provides stability to the rig. Typically, a semi-sub will be more suitable for mooring configurations than a drillship. The power requirements to maintain a station for a semi-sub will be less than those of a drillship, as the hull structure is not subjected to the same wind, wave, and current loading. The day rate for semi-subs is generally less costly than for a drillship; however, to determine the annual cost, this should only be considered in conjunction with a vessel uptime assessment.

In contrast, the primary advantages of the drillship are the higher transit speeds, large storage volumes, and the ability to store produced fluids.

3.2 Vessel Uptime Assessment

A vessel uptime assessment may be performed to identify the expected vessel uptime based on weather conditions at the proposed well location. The Contractor can conduct this assessment on behalf of the Operator during the rig selection phase.

The vessel uptime assessment is an optional work scope, as the economic advantages of available rigs may be well understood. This will primarily be used for new geographical locations or new vessel designs.

3.2.1 Method for Vessel Uptime Assessment

A vessel uptime assessment is a statistical analysis of theoretical vessel uptime for the weather conditions of the drilling campaign. Depending on the selected rig station keeping option, a number of wave headings will be considered. For DP rigs, the rig will typically be oriented into the oncoming wave (head sea); however, the probability of larger angles of wave incidence remains and should be considered.

Wave and wind data are taken from monthly scatter diagrams. For preliminary analysis, typical conditions for the region are sufficient. The statistical analysis should consider drilling connection and re-latching operations based on the most probable maximum response characteristics of the vessel and the wind speeds. The Drilling Contractor specifies the operating guidelines. Maximum vessel limitations are typically provided in terms of heave range, pitch amplitude, and roll amplitude. Wind-driven operating limits for drilling, re-latch, etc. should also be provided.

For each wave class in the scatter diagram, the most probable maximum heave range, roll amplitude, and pitch amplitude are calculated. Considering the number of occurrences of each wave, the cumulative occurrence of a sea state is defined; in turn, the percentage of uptime of the drilling rig considering the duration of the drilling campaign is determined.

3.2.2 Outputs of Vessel Uptime Assessment

The vessel uptime assessment provides the following outputs:

- Operability Statistics—The operating statistics for a specific rig at the proposed location are provided. Operability statistics for connected drilling operations are used to compare various rigs during the selection phase, which will allow the Operator to gain a complete understanding of the cost associated with drilling a well. A sample of the drilling operability statistics is shown in Figure 3.1 and Figure 3.2.
- Days in Operation—The total number of operating days and downtime days (hours) are provided for the proposed drilling campaign.
- Comparison of Rig Performance—The uptimes of contracting rigs are compared to identify the optimum rig for the proposed location. The vessel uptime should be considered in association with the day rate of the rig to make the final recommendations as to the selection of the rig that is most economically viable.

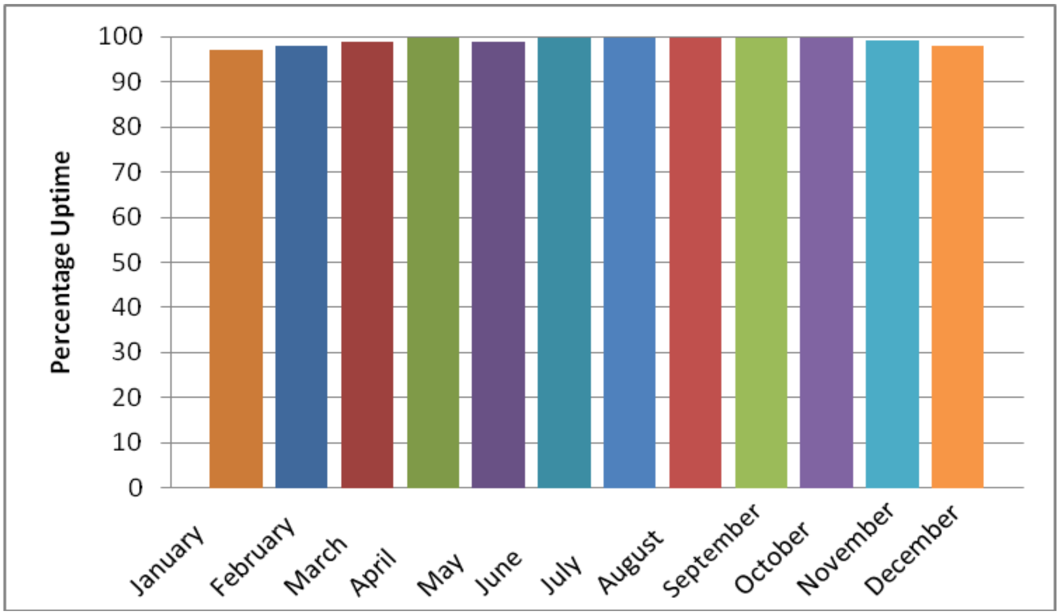

Figure 3.1: Sample Percentage Uptime Bow on Waves—Drilling Operations

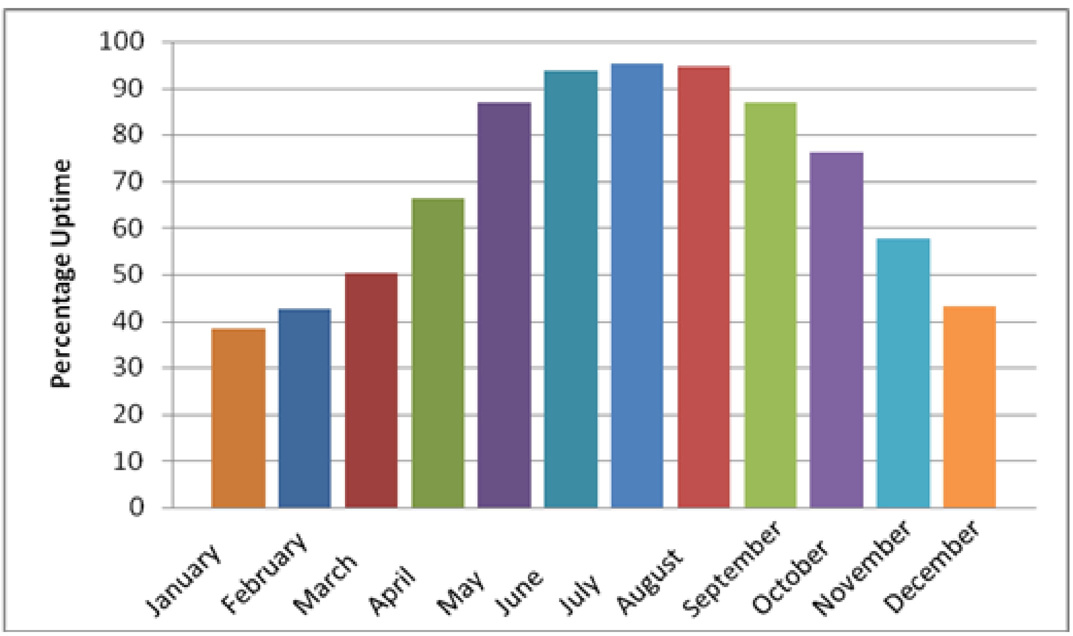

Figure 3.2: Sample Percentage Uptime Beam on Waves—Drilling Operations

3.3 Station Keeping Method

A major factor that dictates the selection of drilling vessels in the Arctic region is the threat of an iceberg at the site of operation. In general, when there is an annual probability of 10^{-2} ice or icebergs being present at the site of operation, iceberg management should be taken into consideration during the decision making process. If the water at the site is sufficiently deep, a DP drilling unit (drillship or DP semi-submersible) is preferred because of its ability to quickly move out of the iceberg's way. However, in relatively shallow water, the DP unit cannot provide sufficient response time for riser disconnection if a drift-off occurs, and a jack-up rig cannot be used because of the probable presence of an iceberg. A moored drilling unit with quick release system (typically a semi-submersible) and thrusters then becomes the most probable option.

Depending on the selected station keeping option, the Mobile Offshore Drilling Unit (MODU) uses mooring lines, thrusters, or a combination of both to maintain station above the wellhead. The mooring system consists of multiple anchors, and various spread mooring patterns are used to keep the rig on location. The mooring spread is generally chosen based on the shape of the vessel being moored and the expected environmental conditions on location. Alternatively, DP is employed using thrusters and generators on the rig. These propulsion units counteract the environmental forces to maintain station. The DP system is typically guided by signals from beacons located on the drill floor or by satellite data signals. Table 3.1 details the advantages and disadvantages associated with each station keeping option.

Table 3.1: Advantages and Disadvantages of Station Keeping Options

	Dynamically Positioned Rig	Moored Rig
Advantages	• Maneuverability, ability to change position • No anchor handling tugs are required • Independent of water depth[1] • Quick setup on location • No issues with obstructed seabed	• No complex thrusters, generators, controls • No risk of running off station due to blackout • No underwater hazard from thrusters
Disadvantages	• Complex system, thrusters, generators, etc. • High initial cost of installation • High fuel costs • Potential to lose position from blackout • Underwater diver/ROV hazard from thrusters • High maintenance • Limited watch circles • High bending loads in shallow water in loss of station keeping event	• Limited maneuverability when anchored • Anchor handling tugs are required • Not as suitable for deep water • Takes time to run anchors • Limited by obstructions on the seabed

[1] **Note**: Rigs will generally have a minimum and maximum operating water depth.

3.3.1 Mooring Design and Analysis

A mooring system that is used as the main station keeping method for a MODU is required to go through the process of layout and configuration design and static and dynamic analysis to ensure that the mooring system is suitable for the planned drilling operation at the site.

3.3.1.1 Mooring System Design

Mooring system design for a MODU includes primarily the following two tasks:

1. Layout design to determine the anchor location and mooring patterns
2. Configuration design to determine the mooring pay-out lengths or pre-tensions.

A MODU with mooring station keeping capability is typically equipped with on-board mooring equipment such as anchors, mooring chains, fairleads, and winches; and only the on-board mooring equipment is used for most operations. If it is determined that the on-board mooring equipment is not sufficient for the station keeping operation, additional mooring equipment can be included in the design, provided there are means to accommodate these additional mooring components.

If the MODU is equipped with thrusters, the available thrusters should be considered when designing the mooring system.

3.3.1.2 Mooring Static Analysis

After a preliminary mooring system has been designed, a static analysis should be performed to:

- Verify the mooring pay-out lengths and pre-tension.
- Balance the mooring system so that the nominal MODU position and headings are what they should be.

The system balance can be achieved quickly for a symmetry mooring system with a relatively flat seabed. When the mooring layout is not perfectly symmetric or the seabed bathymetry has large variations among the anchor locations, multiple iterations will be required before a mooring system design can be finalized.

3.3.1.3 Mooring Dynamic Analysis

Mooring dynamic analysis must be performed to predict extreme responses such as line tensions, anchor loads, and vessel offsets under the design environment and other external loads (for example, riser loads, tandem mooring loads). The responses are then checked against allowable values to ensure adequate strength of the system against overloading and sufficient clearance to avoid interference with other structures.

A mooring dynamic analysis typically includes:

- Creating a hydrodynamic model of the MODU and performing hydrodynamic analysis to generate hydrodynamic coefficients (that is, added mass, damping, and first and second order wave force transfer functions).
- Creating a mooring analysis model with designed mooring layout and configuration, and all the required properties of the MODU (including hydrodynamic data and wind and current force coefficients).
- Applying mean environmental (wind, wave and current) loads and performing static analysis to establish equilibrium of the mooring and hull systems.
- Applying dynamic environmental (wind, wave and current) loads and performing dynamic analysis for extreme mooring tensions, anchor loads, and vessel offsets.

If the mooring system is thruster assisted, the thrust force can be included as additional mean force, damping, and stiffness to the mooring system.

The mooring dynamic analysis can be conducted in both frequency domain and time domain. While the time domain mooring analysis is considered more accurate, it is very time consuming; therefore, the frequency domain method is often used for MODU mooring design.

3.3.1.4 Mooring Analysis Outputs

For MODU mooring system design, the two conditions that are typically considered are:

- Survival (riser disconnected)
- Operational (riser connected)

The most notable results from a survival mooring analysis are the extreme mooring tensions and anchor loads. For example, MODU mooring systems that are designed according to API-RP-2SK [10] should meet the safety requirement for tension factors in either 10-year or 5-year extreme environments, depending on the condition of the site.

The most important results from a mooring analysis for operational conditions are the vessel offsets and the associated environmental conditions. These results, combined with drilling riser analysis results, can be used to establish the operation limits for the drilling riser.

3.3.2 Dynamic Positioning Capability Assessment [10]

A holding capability analysis should be performed to determine whether a DP system can maintain the position of a floating vessel within an acceptable watch circle under the operating environment. This analysis should be performed for new designs as well as for individual operations.

Two methods can be used to analyze the holding capability of a DP system:

- A time domain system dynamic analysis is normally performed for new system designs and critical operations, especially those in shallow water.
- For routine operations in deep water, a simplified method addressing only the mean environmental forces can be used.

3.3.2.1 System Dynamic Anlysis

System dynamic analysis for a DP vessel is similar to that for a vessel with a thruster-assisted mooring. The major difference is that the mooring stiffness is not included in the system dynamic analysis.

3.3.2.2 Simplified Method

In the simplified method approach, the DP holding capability is assumed satisfactory if the DP capability is greater than the mean environmental load. The procedure basically involves calculating available DP thrust force in the design environmental condition for all headings and producing DP holding capability rosettes. The thrust reduction caused by thruster, current, and hull interactions should be considered for DP capability analysis. An example of the DP holding capability rosettes is shown in Figure 3.3.

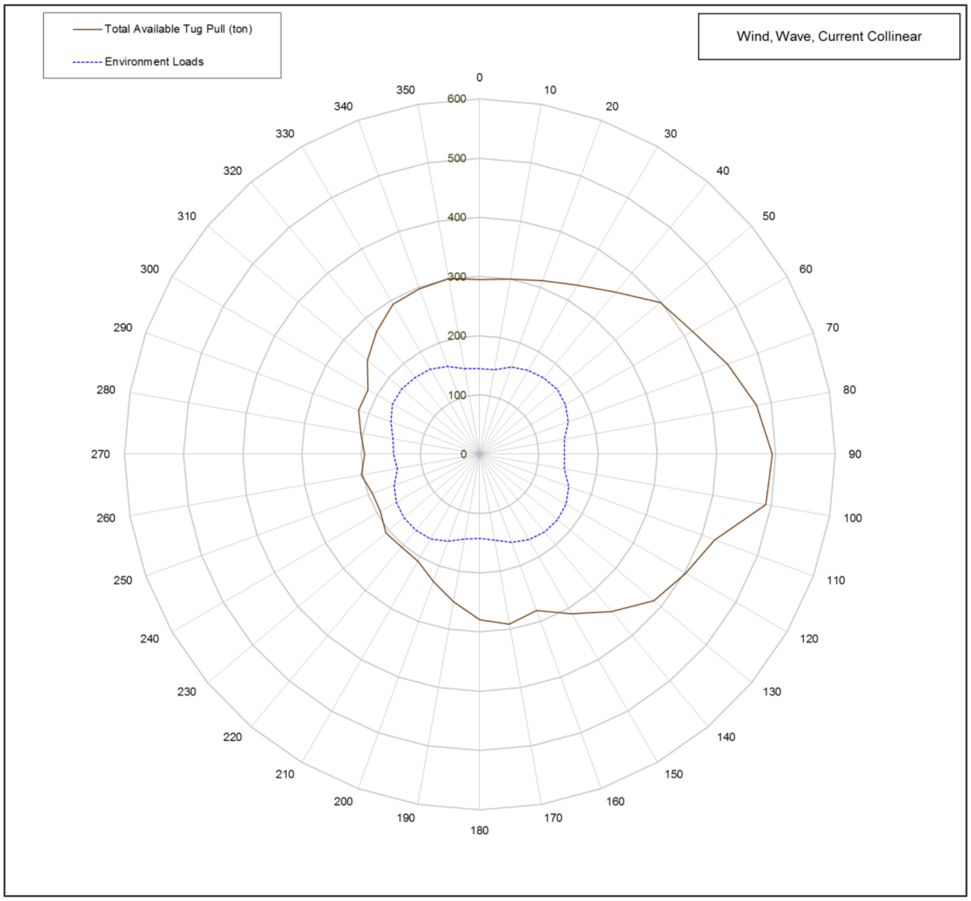

Figure 3.3: DP Holding Capability Rosettes

3.4 Operability Analysis

An operability analysis is performed to determine the maximum operating limits of the rig at the chosen wellsite. The optimum location of the vessel relative to the wellhead is determined for a variety of current and wave profiles.

3.4.1 Method for Operability Analysis

The purpose of the operability analysis is to determine the:

- Operating envelope for riser drilling operations.
- Operating envelope for riser standby (non-drilling) operations.
- Optimum space-out (stack-up) for the riser under consideration.
- Optimum applied top tension for the riser under consideration.
- Feasibility of the required maximum mud weight.

Before the operability analysis is conducted, the Drilling Contractor (or Analysis Contractor) should determine an applicable load case matrix. The Contractor must have knowledge of the operational philosophies of the rig, such as limiting parameters and safety envelopes. The output of the operability analysis should be a concise deliverable that can be used as input to the Well-Specific Operating Guidelines (WSOG).

Operability analyses are typically performed using a global drilling riser model that extends from the base of the conductor to the drill floor, as shown in Figure 3.4. The lateral stiffness of the soil is modeled against the conductor up to the mud line, and site-specific soil data should be provided. The influence of the surface casing on the stiffness of the riser system should also be considered. This will be affected by the cementing operation of the conductor and surface casing.

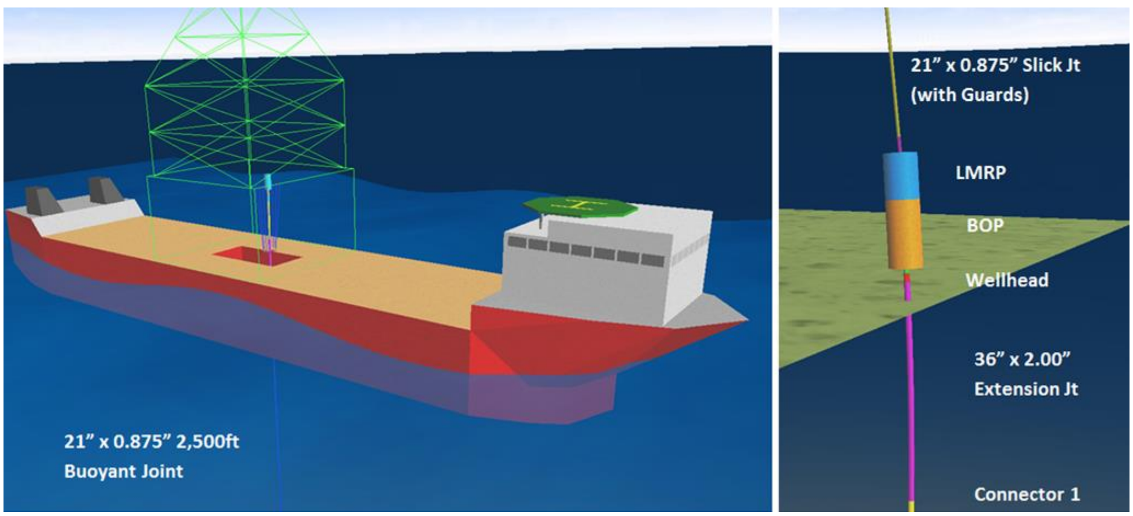

Figure 3.4: Typical Global Riser Model

Static analysis is performed for a range of current profiles at offsets ranging from 10% upstream to 10% downstream. The allowable vessel offsets are determined to be those in which no mechanical or operational limits in the system are exceeded. For the specified fluid densities, the applied tension may be optimized for operability performance. The selected applied tension must remain within the limits specified by minimum allowable tension [9] and the maximum allowable tension determined by the recoil analysis (see Section 3.8). The limiting criteria for the allowable drilling envelope under static current loading are typically the mean upper and lower flex joint angles.

Prior to dynamic analysis, a frequency screening may be conducted to determine the critical period of the vessel and riser system. Additionally, the vessel motion driver must be identified. The selected wave periods should consider these critical periods when running dynamic analysis. Dynamic analysis considers the same offset and current conditions as those that are specified for the static analysis with the addition of first order wave loading. Drilling operability will typically be limited by the mean lower flex joint angle in the downstream direction and the mean or maximum upper flex joint angle in the upstream direction.

A range of current and wave loading conditions should be considered when defining the operational and extreme operating envelopes for the rig for both drilling and standby operations.

3.4.2 Outputs of Operability Analysis

The typical output of an operability analysis is the operability envelope, which can be represented in different ways. The two most common ways are 'V'-shaped and 'N'-shaped charts.

The 'V'-shaped chart shows the utilization of the various components within the system against offset. In this context, utilization means the ratio of a calculated parameter to its allowable limit. Therefore, any component with utilization greater than 1.0 is unacceptable and therefore defines all or part of the envelope. (Figure 3.5 provides an example.) In this case, operability is limited to between –7% and –1.5% of water depth in the downstream direction (with the current). This envelope is defined by the two components that cross the utilization line of 1.0. The 'V'-shaped chart is useful for analytical purposes because the limiting component(s) are clearly defined. However, individual plots must be created for each analyzed environmental condition.

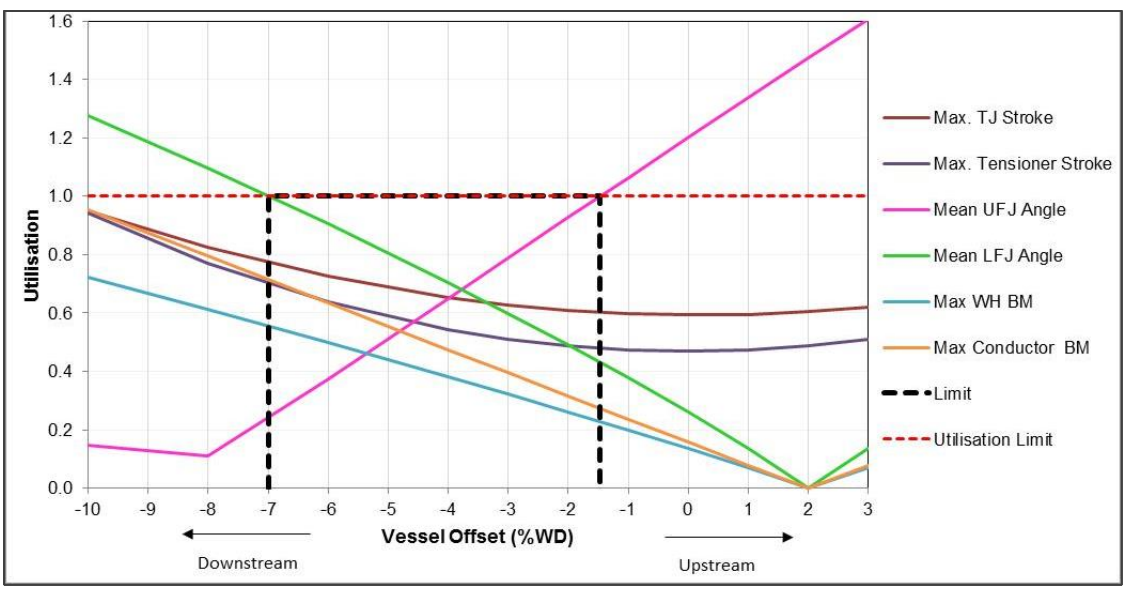

Figure 3.5: Typical 'V'-Shaped Operability Envelope

The 'N'-shaped operability chart also shows the envelope as a function of offset, but it considers different environmental conditions such as wave and current magnitudes. Generally, the operability envelope reduces in size with increasing environment, which is clearly shown by this type of chart. For example, Figure 3.6 shows an operability of –2.7% to +1.4% of water depth at the minimum current (2 ft./s) combined with a 10-year wave. As the current increases to the maximum expected velocity of 4.6 ft./s, this window reduces to –2.5% to –0.5% for the same wave.

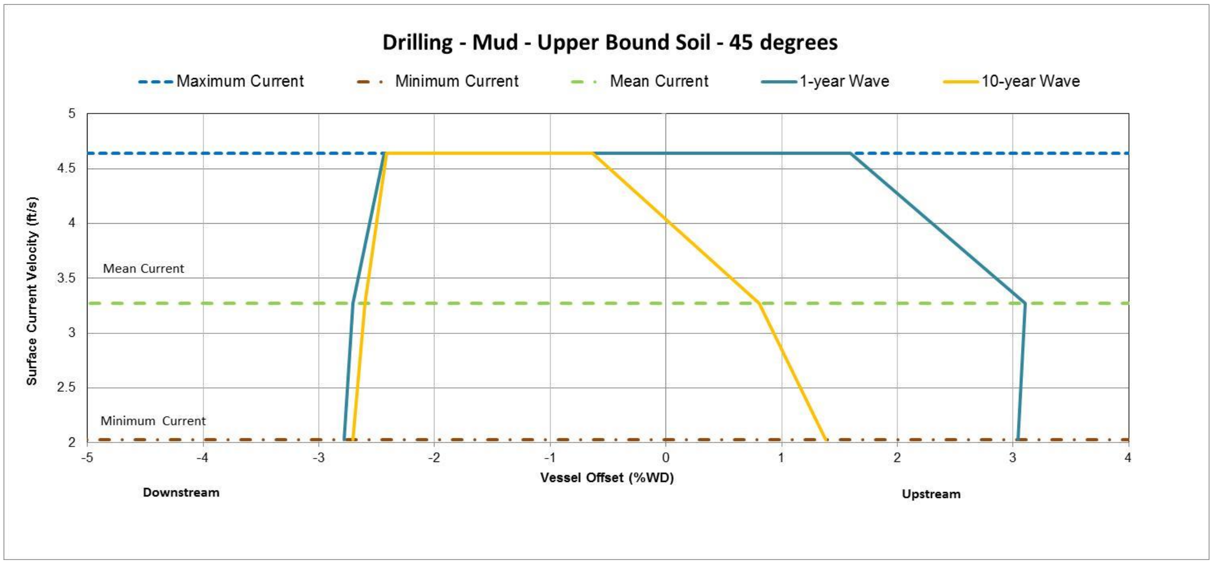

Figure 3.6: Typical 'N'-Shaped Operability Envelope

3.5 Drift-off Analysis

The drift-off and drive-off analyses are conducted for an accidental scenario in which the rig experiences an uncontrolled drift-off or dive-off event. The analysis is used to determine the point at which disconnect should occur. The Operator and the Analysis Contractor should have knowledge of the Drilling Contractor's operational practices in order to provide accurate guidance on drift-off limits.

3.5.1 Method for Drift-off Analysis

A drift-off analysis should be conducted for all dynamically positioned MODUs. The analysis will determine:

- The vessel offset and time when disconnect procedures must be initiated under extreme environmental conditions or drift-off/drive-off conditions.
- The limiting riser response criteria driving the riser disconnection.

The drift-off and drive-off scenarios are similar; however, thruster power is included in the drive-off event. This means that the vessel drift will happen much more quickly and thus reach the point of disconnect (POD) much sooner. It is likely that the power to the thrusters will be cut, changing the drive-off scenario to a drift-off scenario.

The analysis method is selected to closely represent the expected drift-off conditions. Critical combinations of environmental combinations (wind, wave, and current) and vessel drift conditions should be identified. Although many software products will calculate the time history of the vessel based on the applied environments and associated loads, the vessel drift conditions may be specified as a time history of vessel offset, which becomes a direct input into the analysis. In such cases, wind, current, and second-order wave force coefficients of the vessel along with thruster force description should be provided.

A standard drift-off analysis may look at the second order motions of the vessel and apply dynamic factors to account for the first order loading. Alternatively, a more detailed and intensive analysis may be conducted, whereby the drift-off is performed as follows:

1. Run the drift-off analysis without dynamic wave induced loads.
2. Identify critical offsets at which disconnect load criteria are exceeded.
3. Perform dynamic analyses with appropriate wave conditions at the offset position to estimate the dynamic load range.
4. Use the two sets of results to determine the disconnect point.

The Operator should agree with the design basis of the approach, which may vary, depending on the level of detail required.

Following the dynamic analyses of the drilling riser system, the disconnect point of the system can be identified. The specified environmental load conditions, which generate a stress or load equal to the disconnect criteria of the component, provide the allowable disconnect offset for that particular component when the following occurs:

- The allowable disconnect offset is determined for each of the key components along the drilling riser system.
- The overall disconnect point corresponds to the smallest allowable disconnect offset for all critical components along the drilling riser system.
- When the vessel offset at which the riser must be disconnected has been determined, the offset at which the disconnect procedure must be initiated can be determined. This allows for a time lag between initiating the disconnect and disconnecting the riser. This time lag may be dependent on drilling conditions and will be specific to each vessel. A duration in the order of 30-60 seconds is a typical estimate (provided by the Drilling Contractor).

- The disconnect initiation offset is determined from the excursion time history of the vessel.

The results from the drift-off analysis, particularly for normal environmental conditions, can then be used to identify alarm limits for the Drilling Contractor.

The two generally identified alarm conditions are defined as follows:

- Red Alarm—This alarm communicates that the Driller on the rig needs to hit the emergency disconnect button (to initiate disconnect).
- Yellow Alarm—This alarm is set to alert the Operator that drift-off is beginning to occur. This is generally based on Contractor standard philosophy.

A time lag between the yellow and red alarms is provided to give sufficient time for the Operator to attempt to rectify the drift-off or to perform any operations necessary before disconnect is initiated.

A range of extreme metocean conditions is typically used for a drift-off analysis. Because of the low probability of all events, including loss of station keeping and extreme weather conditions (wind, wave, and current). Care should be taken to avoid applying overly conservative operations. The applied direction of the environment will have a significant impact on the results, especially for a drillship. The vessel drift is driven by the exposed wind area; therefore, a beam on (90°) environment will cause much higher loading than a bow on (0°) environment.

3.5.2 Outputs of Drift-off Analysis

The output of the drift-off and drive-off analysis should provide the Operator with confirmation of the maximum time after power loss that the emergency disconnect sequence must be initiated.

Specific outputs from drift-off analysis include:

- <u>Red Alert Times</u>—The red alert time and distance will be determined. The red alert time is the latest time before POD when the Emergency Disconnect Sequence (EDS) can be safely completed. An example of the red alert is shown in Figure 3.7.
- <u>Limiting Component</u>—The critical component that requires initiation of the EDS should be determined. The time and distance after which this component reaches its limit is determined. Knowing which component is subject to reaching the maximum allowable operating criteria may allow the Drilling Contractor to improve monitoring or build a weak-link into the system.

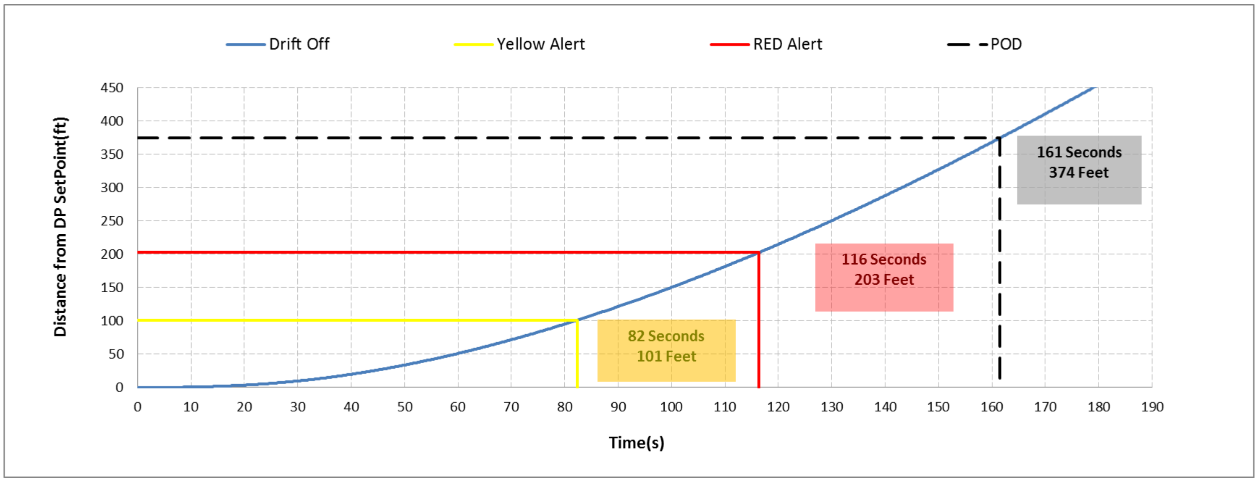

Figure 3.7: Sample Drift-off Results

3.6 Weak Point Analysis

The Operator should request weak point analysis at the preliminary analysis stage to confirm the suitability of the combined riser, wellhead, and casing system. The weak point is defined as the first component to fail should a drift-off scenario be allowed to continue without a disconnect occurring. Any failure of the wellhead or downhole components should be examined in detail. Failure below the BOP represents an unacceptable risk and may require that the Operator procure an improved wellhead or casing program.

3.6.1 Method for Weak Point Analysis

A riser weak point analysis should be conducted for both moored and DP rigs:

- For a moored drilling rig, the weak point of the system (risers, tensioners, wellhead, and casing) should be confirmed to be outside of the damaged mooring offsets of the rig.
- For a DP rig, the weak point should be identified when the rig cannot keep station, drifts off, and cannot initiate an emergency disconnect.

For a moored weak point analysis, the vessel is incrementally offset with vessel dynamics until one of the limits of the system components has been reached. When determining the weak point location, equipment capacities critical to well containment must be assessed on the basis of maintaining structural integrity and leak tightness. Components above the critical well containment component must be assumed to fail at a minimum structural capacity that includes no design factor and is based on reaching ultimate tensile strength (UTS) rather than yield (above the well barrier). Below the well barrier, the criteria must be based on Specified Minimum Yield Strength (SMYS).

The following component capacities are monitored for a moored weak point analysis:

- Tensioner axial capacity
- The riser's von Mises stress
- Wellhead bending moment
- Casing bending stress
- Conductor bending moment

For a DP rig, when the vessel loses the ability to maintain station, the vessel is subjected to a number of forces that determine the drift-off trajectory and velocity. The vessel is subjected to wave drift forces and wind and current loading. Wind loading, which is the primary driver, is magnified by increased exposed wind areas for topside structures. The vessel is allowed to drift until one of the components reaches its yield limit. The monitored components are the same as those identified for the moored weak point analysis.

3.6.2 Ouputs of Weak Point Analysis

Weak point analysis is performed to predict the most probable point of failure in the riser/wellhead/casing system. A recommendation can be made to the Operator as to the equipment required (for example, wellhead type, conductor wall thickness) to ensure that the system weak point is not in the pressure containment equipment.

Specifically, the outputs from the weak point analysis include:

- Weak Point—The most probable point of failure in the riser, wellhead, and casing system is predicted based on the analysis of the fully coupled system. If required, a weak point or weak link can be designed into the system to ensure failure at a particular component.
- Offset and Time of Failure—The weak point of the combined system is reached at a specific offset. For a DP rig, the loss of station may require an emergency disconnect to be performed before the weak point is reached. The EDS will take some time to complete; it is therefore necessary to know the latest time at which it can be initiated following a blackout (drift-off event). Knowledge of the time before the weak point is reached following loss of station is essential.
- Comparison of Soils—Weak point analysis is performed for both upper bound and lower bound soil strength profiles. The location of the weak point may vary, depending on the soil analyzed, with upper bound soil likely to induce bending in the wellhead and riser and lower bound soil inducing bending in the conductor pipe.

- Comparison of Wellhead Stickup—Higher wellhead stickup results in heavier loading on the conductor and casing system. The maximum stickup that can be achieved may be dependent on site-specific conditions and subsea architecture. Considering both high and low stickup will affect the results.
- Comparison of Cementing Conditions—Cementing conditions may significantly affect the system weak point. Cement shortfall may have the effect of transferring the point of fixity for the surface casing. In cases where a rigid lockdown of the wellhead is not achieved, the cementing conditions are an important consideration.
- Suitability of Casing Program and Wellhead—A recommendation as to the suitability of the casing program is made. It is desirable to have a system weak point in the riser to maintain the integrity of the pressure containment equipment.

Figure 3.8 provides a sample weak point analysis following a drift off event.

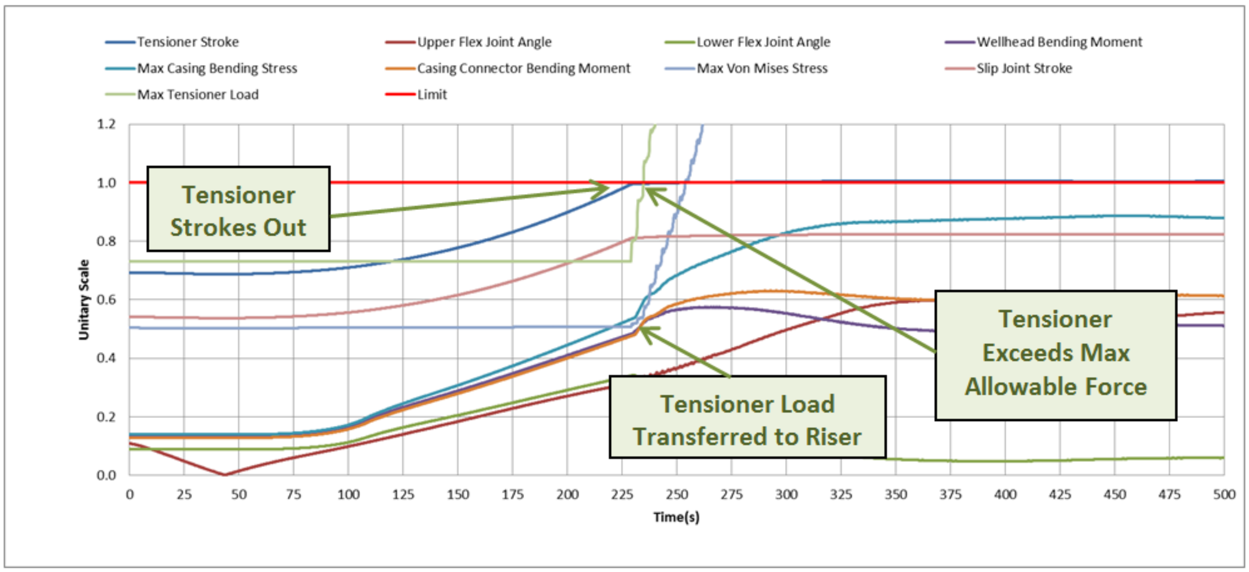

Figure 3.8: Sample Weak Point Analysis Following Drift Off Event

3.7 Hang-off Analysis

A hang-off analysis is performed (generally by the Analysis Contractor) to determine the maximum environmental conditions for which the riser can be supported by the vessel while it is disconnected from the wellhead. The Drilling Contractor (Rig Owner) conducts this analysis using the rig operating manual. The Operator should review the specific well conditions and global analysis of the operating manual to determine whether additional analysis is required.

3.7.1 Method for Hang-off Analysis

When adverse environmental conditions are encountered, it may be necessary to disconnect and suspend the drilling riser from the rig. This generally occurs in either of the following configurations:

1. Hard hang-off—The slip joint, diverter, and Upper Flex Joint (UFJ) are retrieved. The riser is disconnected and hung from either the gimbal spider or the hook by the uppermost riser joint or landing joint.
2. Soft hang-off—This is a term used to describe hang-off when the tensioners are still in place. In theory, a soft hang-off analysis will decouple the motions of the vessel from the riser response. In practice, the soft-hang off method used by different Drilling Contractors varies significantly.
    a. *Traditional soft hang-off*—The Lower Marine Riser Package (LMRP) is disconnected from the BOP and the tensioners are maintained close to mid-stroke. The tensioner anti-recoil valve is set to the fully open position. The tensioners are allowed to stroke, decoupling the vessel and riser motions.
    b. *Gimbal on the tensioners*—The tensioners are retracted to a minimal stroke between 2 and 5 feet (0.6 and 1.5 meters), and the anti-recoil valve is closed to a position of approximately 95%, reducing the flow across the valve. This dampens the response of the vessel and allows the riser to gimbal on the tensioners—similar to the hard hang-off approach.
    c. *Load share between the tensioners and hook*—The UFJ and diverter are retrieved. The riser is disconnected and hung from the hook on the landing joint. The tensioner pressure is adjusted to account for 50% of the wet weight of the riser. The remaining 50% load is taken by the hook.

Figure 3.9 shows examples of typical hang-off configurations.

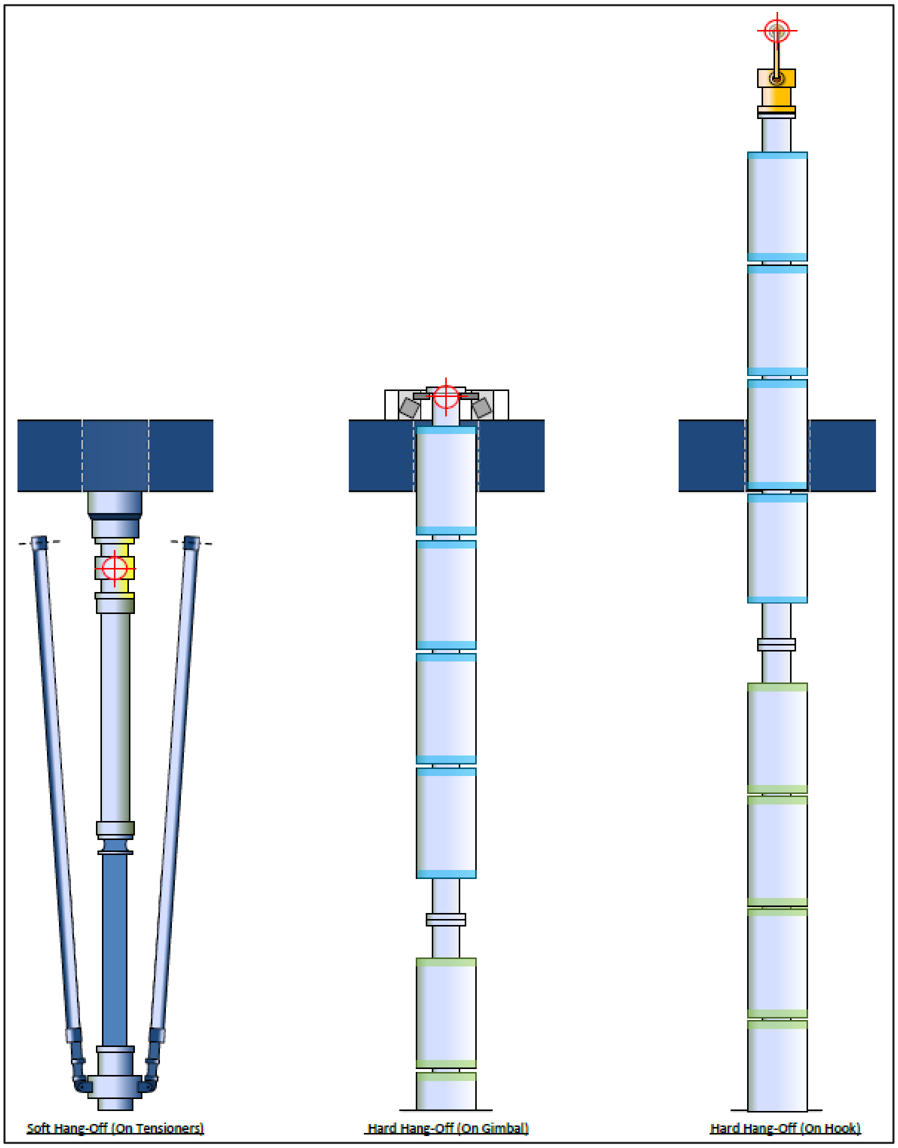

Figure 3.9: Typical Hang-off Configurations

Additional scenarios (such as inclusion of an intermediate flex joint beneath the landing joint) are also used to prevent clashing at the diverter housing during hang-off in high current regions.

3.7.2 Outputs for Hang-off Analysis

The output of the hang-off analysis should provide the Operator with confirmation of the maximum sea states for which a hard hang-off and soft hang-off may be performed.

Outputs from hang-off analysis include:

- Hang-off Envelopes—The allowable hang-off envelope is provided. This details the maximum allowable sea state for which the riser may be safely disconnected and suspended from the rig. An example of a hang-off envelope is provided in Figure 3.10.
- Riser Configuration—The feasibility of the riser configuration for hang-off is confirmed. A 'light' riser may tend towards compression, while a 'heavy' riser will impose larger stresses. Generally, the placement of a large number of buoyant joints will cause the riser to tend towards compression and will have an adverse effect on the recoil performance. This will be very difficult in heave-dominated regions or for vessels with a particularly high heave response.

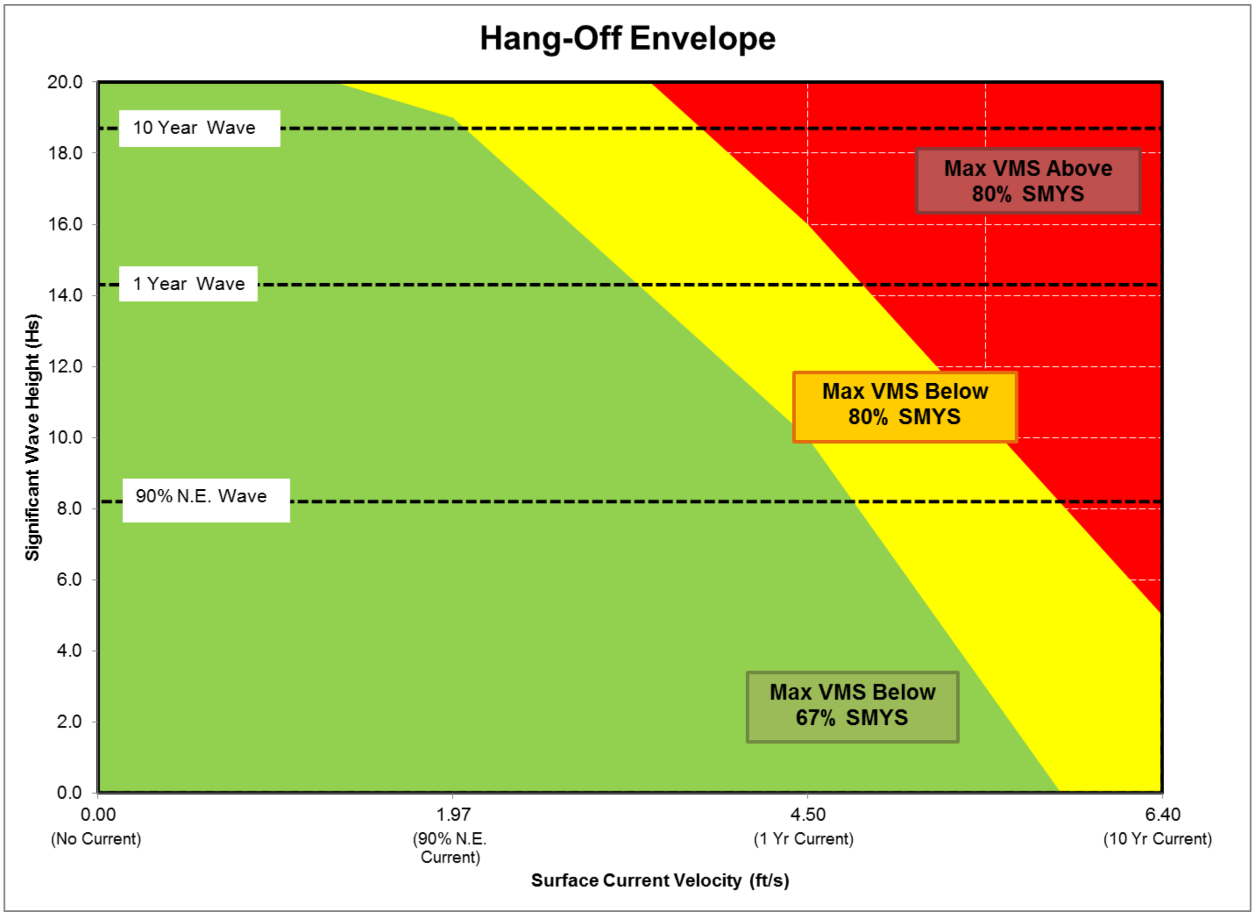

Figure 3.10: Sample Hang-off Envelopes

3.8 Recoil Analysis

A recoil analysis is performed (generally by the Analysis Contractor) to confirm the suitability for the selected riser configuration, mud weight, and associated top tension to safely disconnect in harsh environments. The Drilling Contractor (Rig Owner) conducts this analysis using the rig operating manual. The Operator should review the specific well conditions and global analysis (such as space-out, tensions, metocean) of the operating manual to determine whether additional analysis is required.

3.8.1 Method for Recoil Analysis

When drilling operations are being conducted from DP offshore drilling rigs, it may be necessary to perform an emergency disconnect of the riser system. This can occur because of the rapid onset of severe weather conditions or because of a failure of the DP system to keep the vessel on station, and it is necessary to avoid serious damage to the drilling riser or the well or both. Drilling risers are tensioned structures (most of the riser's ability to resist lateral loading is derived from the riser tension), and normally a certain amount of additional 'overpull' beyond that needed to keep the riser in tension is applied to ensure that the LMRP lifts clear of the BOP in an emergency disconnect scenario. Because of this, the riser tends to recoil with a sudden upward movement when disconnect occurs. Further, if the riser tensioning system continues to apply the same level of tension to the riser, it will continue to accelerate the riser's upward movement.

When it is disconnected, the LMRP should lift sufficiently clear of the BOP to avoid subsequent contact between the LMRP and the BOP. At the same time, the upward movement of the riser must be arrested in time to prevent collapse of the telescopic joint (which could cause impact loads on the drill floor) or compression in the tensioning lines. These conflicting requirements become more severe in deep water, where the ratio between the wet weight and inertia of the riser is reduced. To avoid these problems, it is necessary to implement an anti-recoil control system that controls the level of tension applied to the riser after an emergency disconnect. The anti-recoil control system must address the conflicting requirements of lifting the LMRP sufficiently clear of the BOP while not allowing slack to develop in the tensioning lines or compression to develop in the riser string. The riser stack-up, principally the ratio of the number of slick to buoyant joints, also critically affects the recoil response of the riser. This is often the governing factor in determining the number of slick joints that must be run in a particular stack-up.

Another influencing factor on the recoil reaction of the riser system after disconnect has been initiated is the position of the vessel in the heave cycle when the LMRP lifts off of the BOP. To capture the most difficult disconnect time, a total of eight disconnect points should be considered along the heave phase cycle as shown in Figure 3.11.

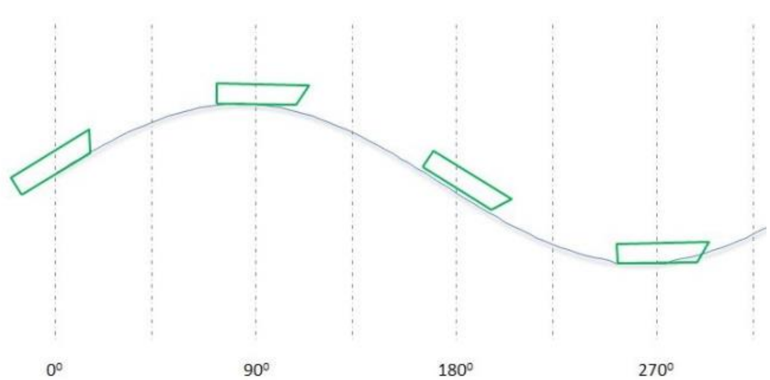

Figure 3.11: Schematic of Vessel Heave Cycle

3.8.2 Outputs of Recoil Analysis

The output of the recoil analysis should provide the Operator with confirmation that the selected stack-up is suitable for the proposed location and expected environments in the event of an emergency disconnect.

Outputs from recoil analysis include:

- Riser Configuration—The feasibility of the riser configuration for recoil is confirmed. A 'light' riser tends towards compression, while a 'heavy' riser imposes larger stresses. Generally, deep water and large mud weights require the placement of a number of slick joints at the base of the riser to mitigate compression. Refer to Figure 3.12.
- Applied Top Tension—The applied top tension should be confirmed by the recoil analysis. Depending on the riser tensions or lift after disconnect, the overpull may need to be increased or reduced. The tensions defined by the recoil analysis should be used in the operability analysis. Refer to Figure 3.13.
- Mud Weight—The maximum mud weight for a given riser configuration may be determined.

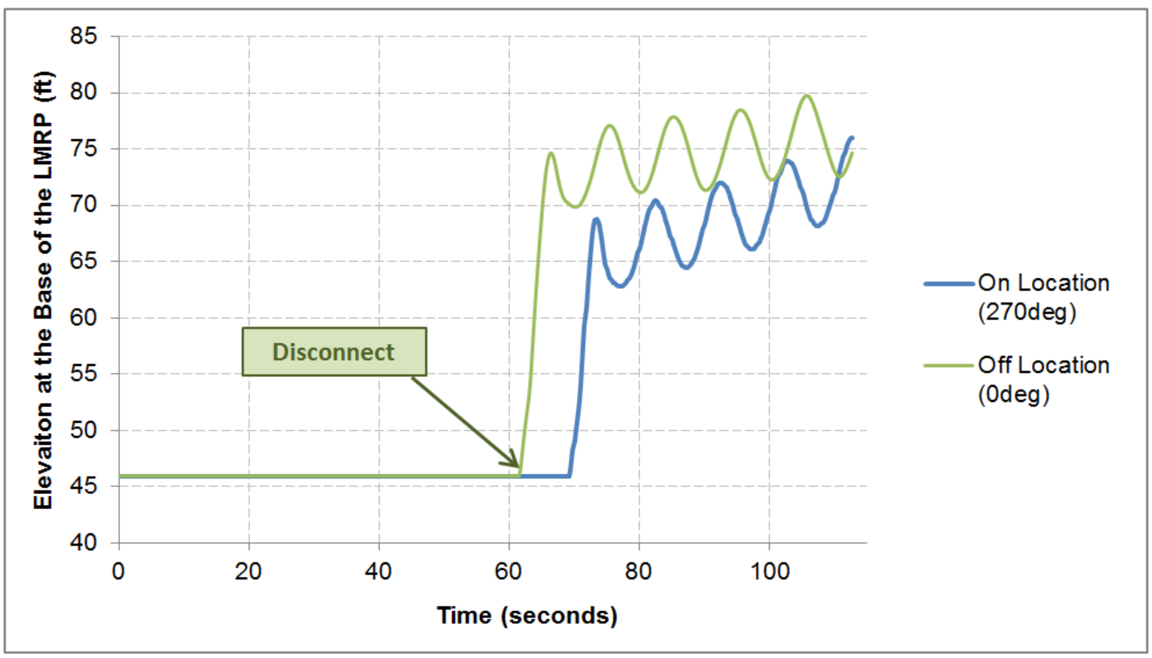

Figure 3.12: Sample Minimum LMRP Clearance

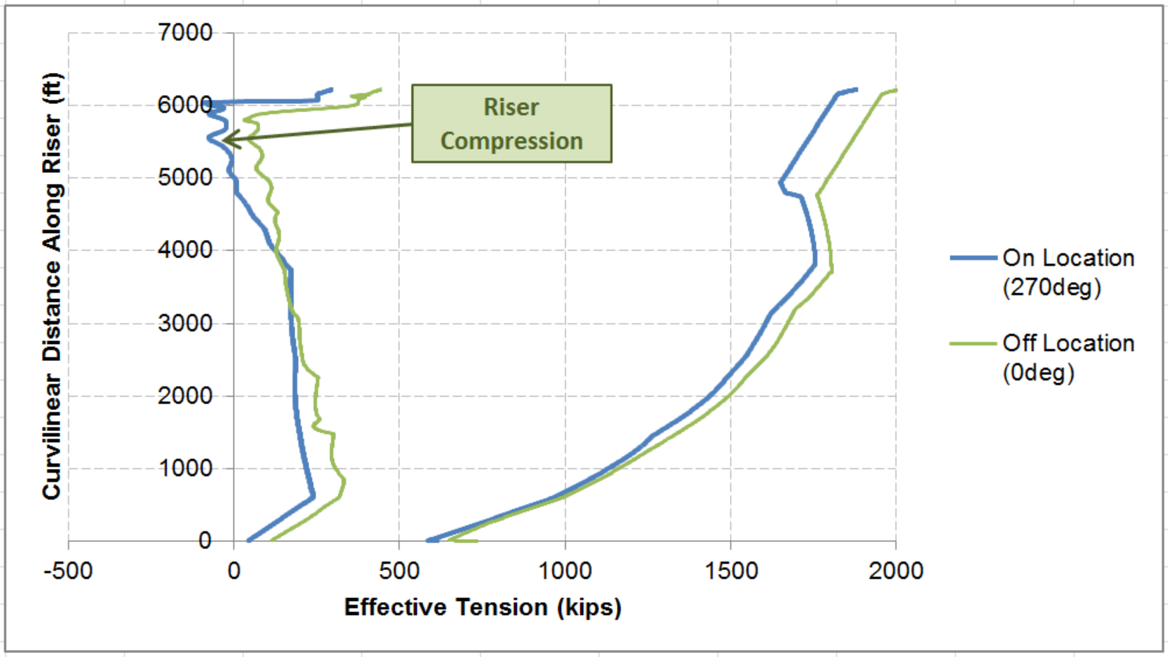

Figure 3.13: Sample Envelope of Riser Effective Tension

3.9 Fatigue Analysis

The Analysis Contractor conducts wave fatigue analysis to determine the predicted level of fatigue damage (damage rate) and fatigue life of a riser system that is located in a potentially harsh environment. The damage resulting from wave fatigue should be combined with other sources of fatigue to estimate the fatigue life of the riser. A wave fatigue analysis is always conducted by an Operator, while Contractors perform this analysis on an 'as needed' basis.

3.9.1 Method for Fatigue Analysis

Wave fatigue analysis should consider wave loading on the vessel/riser system and the loading transferred to the wellhead and conductor casing system caused by the wave action on the riser. The performance of wave fatigue analysis is based on the provided 1-year scatter diagram for the location.

Wave fatigue assessment is based on the conventional principle using S-N curves and the Palmgren-Miner Rule (Miner Rule) for fatigue damage accumulation. Damage is assessed by mapping the time series of the loads acting on the conductor/casing and riser with the load-to-stress curve to obtain time series of the hotspot stress.

If relevant, additional hotspot stress concentration factors may be applied before these stress-time series are subjected to rain-flow counting. Relevant S-N curves are then selected.

A wave scatter diagram is used for the wave fatigue analysis. This diagram details the wave loading to be applied to the Finite Element Model (FEM) during the fatigue analysis. The scatter diagram may be supplied as a 1-year scatter diagram; however, it is more beneficial to capture the specific duration in which the drilling campaign will be undertaken. The analysis is performed for all applicable individual waves with given wave heights (Hs) and associated peak time periods (Tp).

An FEM of the system should be developed using non-linear time domain Finite Element (FE) software to define the combined drilling riser, wellhead, and conductor system. The drilling riser, wellhead, conductor, and other equipment may be modeled as beam column elements, with appropriate properties to represent their mass, stiffness, and hydrodynamic drag. The soil support provided along the length conductor may be modeled using nonlinear springs to represent the lateral resistance provided by the soil, which acts as a restraint to deflections of the conductor. A series of time domain dynamic analyses are undertaken to simulate the effect of wave loading actions on both the vessel and the drilling riser. Vessel motions are simulated in the analysis through the use of Response Amplitude Operators (RAOs). Vessel motions, together with wave and current, act directly on the riser and combine to produce fatigue cycling of the wellhead and conductor system, which is simulated using FE software.

The time domain analyses consider irregular wave sea states, and from each simulation a series of response time traces for the deflections and loads in each element of the FEM are obtained. The stress cycle and intensity are obtained for all sea state conditions present in the wave scatter diagram, and the subsequent fatigue damage rate accrued from a number of sea states can be determined using rain-flow counting method and the Miner Rule.

The riser fatigue assessment should consider an irregular sea dynamic analysis in the time domain. The frequency domain is not recommended because of nonlinearities relating to the conductor and soil interaction, which reduce the accuracy of the analysis in the frequency domain.

It may not always be practical to include all wave realizations in the scatter diagram because the vessel will not always be in the connected mode or remain on location in extreme events. When selecting the cut-off sea states, it is recommended to consult the WSOG. The cut-off sea state is the sea state above which the riser is assumed to be disconnected from the well. The disconnected riser configuration should be analyzed for wave fatigue for sea states above this limit.

The limiting cut-off sea state is defined in the WSOG and will vary, depending on the vessel type and operational considerations. Additional factors that may have significant effects on the riser, wellhead, conductor, and casing fatigue and that should be considered on a case by case basis are:

- Wave spectrum
- Wave kinematics
- Current loading
- Method of station keeping
- Non-linear flex joints
- Riser hydrodynamics
- Soil data
- Wave spreading
- Moonpool hydrodynamics
- Wave directionality
- Structural damping
- Hydro-pneumatic tensioner model
- BOP hydrodynamics
- Mud weights

3.9.2 Outputs of Fatigue Analysis

The outputs of the wave fatigue analysis should provide the Operator with a detailed understanding of the suitability of the drilling riser and casing program to withstand damage resulting from wave loading.

Outputs from fatigue analysis include:

- Optimum Top Tension—The fatigue response of the system, specifically in the wellhead, can be mitigated by changing the stiffness and natural frequencies of the system. This can be achieved through changing the applied tension. Generally, the Drilling Contractor attempts to reduce fatigue by increasing the applied tension.
- Fatigue Damage—The fatigue damage at each hotspot (location of interest) is provided. This will allow the Operator to confirm the suitability of selected equipment and connectors. If a weld finish is not suitable, it may be improved, thus reducing the stress concentration factor.
- Requirements for Monitoring—If the wave fatigue damage is determined to be difficult, the Operator may decide to manage the risk though the use of a riser monitoring or management system. In addition to the riser, the displacements of the BOP can be captured to determine real time wellhead fatigue damage.

Figure 3.14 shows the results of typical wave fatigue analysis.

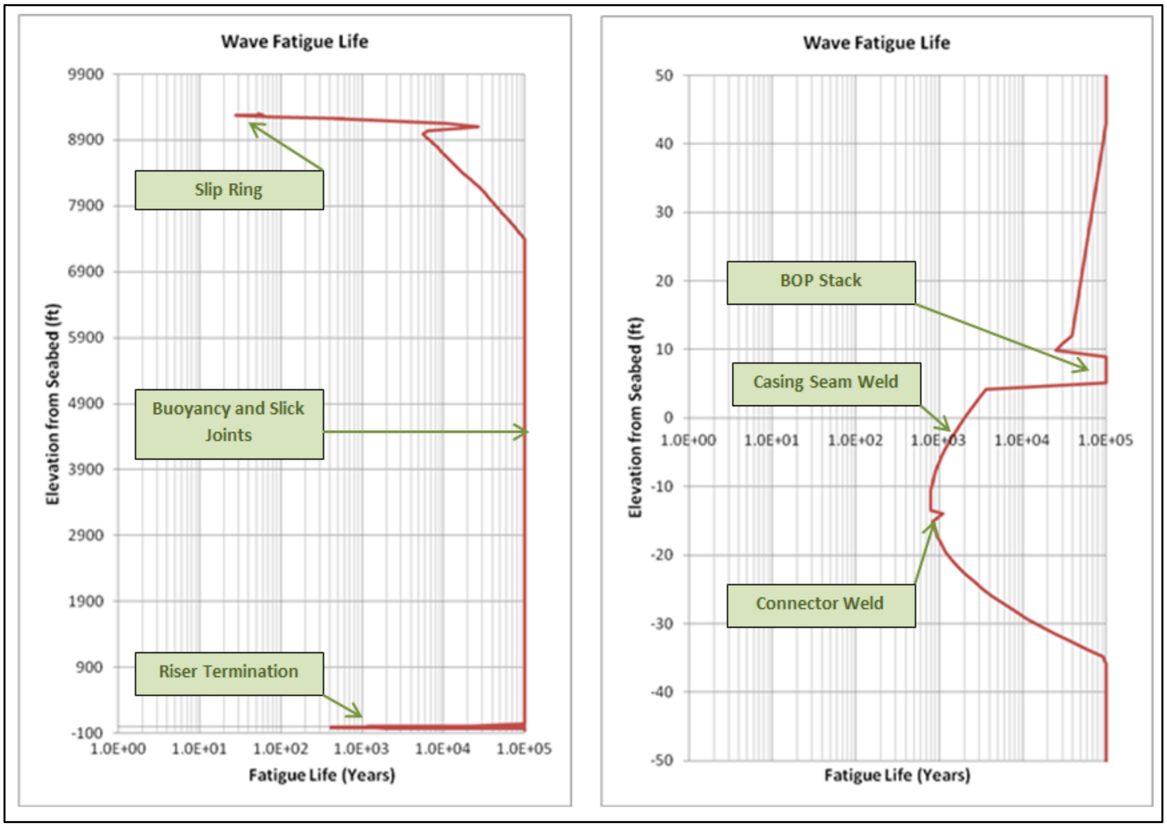

Figure 3.14: Typical Wave Fatigue Results

3.10 Vortex-Induced Vibration Fatigue Analysis

When a fluid flows around a cylinder, there will be flow separation because of the presence of the structure, resulting in shed vortices and periodic wakes. Because of the periodic shedding of the vortices, a force that is perpendicular to the flow direction is exerted on the cylinder, causing it to vibrate in the cross-flow direction. This is called Vortex-Induced Vibration (VIV). The Analysis Contractor conducts VIV fatigue calculations to determine the fatigue damage in the riser resulting from current loading. To estimate the fatigue life of the riser, the damage caused by VIV fatigue should be combined with other sources of fatigue.

3.10.1 Method for Vortex-Induced Vibration Fatigue Analysis

VIV analysis should be performed to determine fatigue damage in the riser, wellhead, and conductor. First, a modal analysis is performed in standard finite element software. The modal curvatures and displacements are then imported into VIV software such as Shear7. Both short- and long-term fatigue damage for extreme and background currents should be analyzed for each riser and casing component, including riser connectors, connector welds, and seam welds. For the conductor and casing system, the Vortex-Induced Motion (VIM) may be captured in finite element software. The VIM in the stack and casing is induced by the riser's VIV. The BOP stack displacements are extracted from the VIV software (Shear7) model and incorporated into the FEM. The fully coupled response of the system may be captured.

VIV of the drilling riser under current loading will induce lateral motion of the wellhead at the seabed and hence result in a contribution toward the damage accumulated in the wellhead whilst the drilling riser is in the connected state. The wellhead/conductor system damage contribution resulting from VIM is calculated for each top tension/mud weight combination, and associated durations.

The fatigue damage caused by VIV in the drilling riser may be analyzed using the VIV program (Shear7). The modal curvatures and frequencies for each top tension and mud weight combination are imported into the VIV program. The minimum and maximum excitation frequencies are determined as a function of the Strouhal number. VIV fatigue or 'lock-in' occurs when the vortex shedding frequency approaches the natural frequency of vibration of the riser.

When considering the VIM of the riser, the VIV program is limited, and an FEM should be considered. The lateral displacements and associated frequencies at the top of the wellhead are extracted from the VIV program for each of the applied currents. The displacements are then applied in a time domain-detailed, nonlinear FEM.

VIV response of a riser must determine:

- Fatigue damage caused by VIV and the critical locations.
- Drag amplification factors for the riser under VIV.
- Assessment of the requirement for optimization of riser tension to minimize VIV.
- The requirements for VIV suppression devices.

The VIV response of the riser is dependent on the applied current profile and the modal response of the riser system. VIV analysis should be conducted for all riser operations and scenarios that represent a significant variation in modal behavior. Typically, this occurs when connected riser operations have a large variation in mud weight over the life of the well or when tension and riser hang-off scenarios/deployment/retrieval may vary.

DNV RP F204, "Riser Fatigue" [56] states that all modes of operation, including connected, running, and hang-off, must be considered if they are relevant to fatigue damage. The relative importance of these contributions should be considered on a case by case basis. Obviously, the contributing damage from the hang-off operations concerns the riser only and has no impact on the damage to the wellhead, conductor, and casing system.

The load cases to consider for VIV analysis are the full current profiles for the expected duration of the drilling campaign. One-year data may be used; however, it may be more beneficial to use the current data for the expected drilling campaign only. Measured currents are preferred, but statistical non-exceedance currents may also be considered. Note that non-exceedance currents will have a built-in level of conservatism, which may lead to conservative VIV damage results.

3.10.2 Outputs of Vortex-Induced Vibration Fatigue Analysis

The output of the VIV fatigue analysis should provide the Operator with a detailed understanding of the suitability of the drilling riser and casing program to withstand damage caused by VIV. However, because of the significant conservatism of the analysis, the actual recorded VIV damage may be significantly less than the predicted analysis.

Outputs from VIV fatigue analysis include:

- Optimum Top Tension—The VIV response of the riser can be mitigated by changing the natural frequencies of the system. This can be achieved by changing the applied tension. Generally, Drilling Contractors will attempt to reduce VIV by increasing the applied tension.
- Fatigue Damage—The fatigue damage at each hotspot (location of interest) is provided, which allows the Operator to confirm the suitability of selected equipment and connectors. If a weld finish is not suitable, it may be improved, thereby reducing the stress concentration factor.
- Requirements for Monitoring—If the VIV damage is determined to be difficult, the Operator may decide to manage the risk though the use of a riser monitoring or management system. In addition to the riser, the displacements of the BOP can be captured to determine real time wellhead fatigue damage.

Figure 3.15 provides a sample of VIV fatigue results.

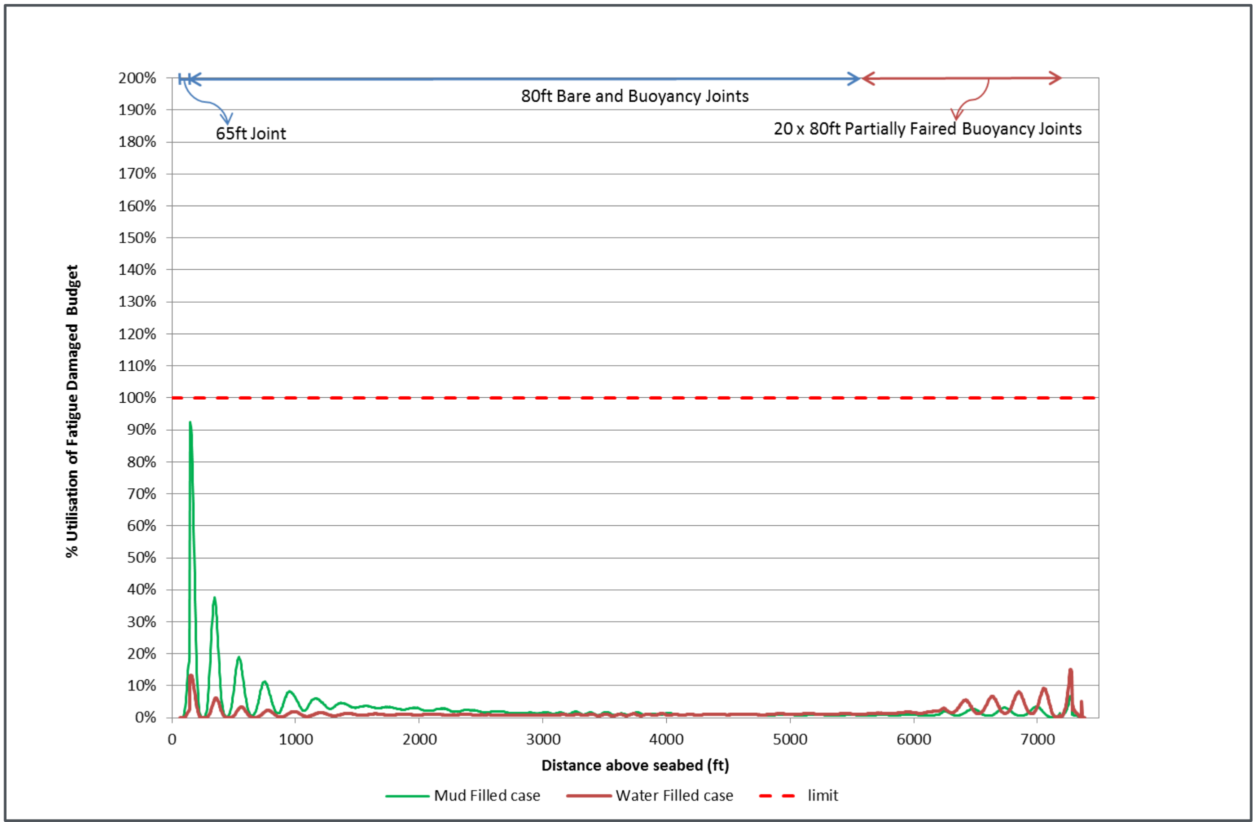

Figure 3.15: Sample VIV Fatigue Results

3.11 Transiting Analysis

Transiting operations occur when a vessel changes locations while the majority of the riser is deployed through the water column. This is done either when moving between wellsites in relatively close proximity or after a disconnect has occurred to avoid the onset of severe weather. The Contractor will provide for the general riser stack-up to remain deployed during the transit operation, and a range of vessel speeds will be examined. In particular cases where clashing between the riser and subsea infrastructure is a concern, the Contractor or Operator will supply the vessel excursion path to transit out of the field.

3.11.1 Method for Transiting Analysis

Transit analysis is conducted in two stages. A quasi-static (no wave loading) analysis is performed to determine the limiting currents based on evaluation criteria of component capacities and operational procedures. Secondly, a dynamic analysis is performed on the quasi-static models to quantify the wave effects on the riser. Irregular waves are subjected to the riser in the direction of the current during a three-hour storm simulation.

The limiting wave height is interpolated from the dynamic study results using the limiting criteria based on component capacities and operational procedures.

Frequency screening should be performed to determine the critical response period of the riser and vessel. Multiple current headings should be assessed with regard to vessel transit direction to examine the effects of varying magnitudes of superposition of vessel and current velocities. Wave screening in all of the five directions that the currents are applied is shown in Figure 3.16. This ensures that the maximum system response is captured, which results in the most conservative approach.

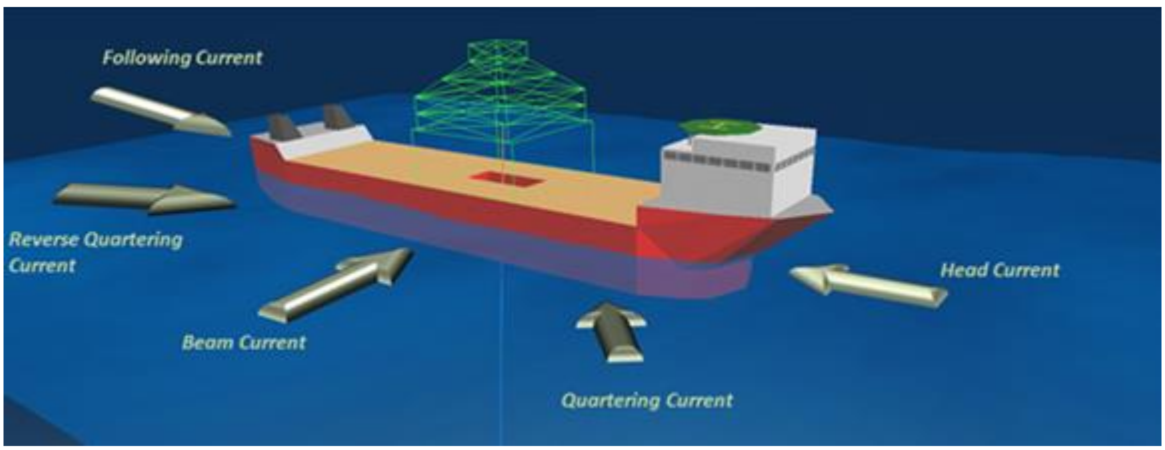

Figure 3.16: Current Headings for Transit Analysis

3.11.2 Outputs of Transiting Analysis

The results of a transit analysis should provide the Operator with a range of safe vessel speeds to transit so that the riser stays within the component and operational limits.

Outputs from the transiting analysis include:

- Utilization Tables—The riser utilization based on the von Mises stress for each vessel transit speed for varying currents and environmental directions is provided as a stop light table in Table 3.2.
- Riser Configuration—The feasibility of the riser configuration for transit is confirmed. Numerous buoyant joints with relatively larger diameters in the higher velocity areas of the current profiles can increase the stress in the riser and induce clashing at the diverter housing. Removing additional joints to move these larger diameter joints out of the swiftest areas of the profile can reduce component utilizations.

Table 3.2: Sample Results Table for Transit Analysis

Current	Dynamic Maximum Utilizations				
	Head	Quartering	Beam	Reverse Quartering	Following
Profile-1 (0.71 ft./s @ Surface)	0.8	0.95	0.89	0.89	0.78
Profile-2 (1.08 ft./s @ Surface)	0.97	**1.00**	0.85	0.88	0.82
Profile-3 (1.38 ft./s @ Surface)	**1.01**	**1.03**	0.85	0.89	0.83
Profile-4 (1.54 ft./s @ Surface)	**1.02**	**1.03**	0.85	0.89	0.83
Profile-5 (3.41 ft./s @ Surface)	**1.17**	**1.12**	0.94	0.93	0.90

3.12 Conductor Strength Analysis

Conductor strength assessments should be performed to identify the minimum required conductor wall thickness and connector capacities for a given well. Generally, the Operator provides a proposed well plan to the Analysis Contractor for assessment.

3.12.1 Method for Conductor Strength Analysis

The conductor strength assessment is performed to understand the extreme loads exerted on the conductor. The Operator generally provides the Analysis Contractor with a proposed well plan; however, the Analysis Contractor may analyze a range of conductor wall thickness and connector capacities.

Loading on the conductor is primarily induced from the drilling riser (due to vessel offset and first order motions) or due to current loading (which is magnified by the riser and BOP hydrodynamic behavior). The conductor sizing and strength analysis should be performed considering downstream offsets where the loading in the wellhead and conductor are at maximum. The vessel is offset in regular increments and at each offset, static and dynamic FE simulations are performed for appropriate environmental conditions. Von Mises stress, bending stress, and bending moments are extracted along the wellhead and conductor. Sensitivity analysis may also be performed to assess:

- Cemented and un-cemented conditions.
- Wellhead angle and wellhead stickup.
- Casing wall thickness, yield strength, and connector type.

3.12.2 Outputs of Conductor Strength Analysis

The output of the preliminary conductor sizing and strength analysis should provide the Operator with confirmation for the feasibility of the proposed drilling rig and casing program or an indication of the minimum requirements. The preliminary analysis will allow the Operator to procure the required components that tend to have a longer lead time in advance of the drilling campaign.

Specifically, outputs from the analysis include:

- Conductor Size and Steel Grade—The required wall thickness of the conductor and the associated steel grade (for example, 65ksi).
- Connector Capacity and Placement—The required connector capacities along the conductor are defined. The connector bending capacity should exceed the line pipe strength. Connector placement may have a significant influence on both strength and fatigue performance of the conductor. Typically, the highest bending zone is approximately 20–40 ft. below the mud line, depending on soil conditions. It may be necessary to locate the first conductor connector outside of this zone to improve strength and fatigue performance. An example of the conductor strength is shown in Figure 3.17.
- Soil Strength Effects—Comparisons of upper bound and lower bound soil should be studied to consider the conductor, connector, and wellhead capacities. Lower bound soil will generally be subjected to higher loads for increased depths below the mud line. Upper bound soil will generally induce larger loads to the wellhead and the upper portion of the conductor pipe.
- Preliminary Operating Envelope—The analysis will serve as an early indication regarding the downstream operating envelope of the drilling riser system.
- Effect of Conductor Stickup—The stickup of the conductor (the elevation above the mud line) will have a significant influence on the bending in the wellhead and conductor. Larger stickups will induce larger bending moment and stresses in the conductor.
- Drilling Versus Workover Condition—As the stack height increases, the bending in the conductor will also increase because of the lever arm effect. Additional weight on the stack will induce larger bending moments. This effect will be realized for workover conditions with subsea trees or additional components in the stack.

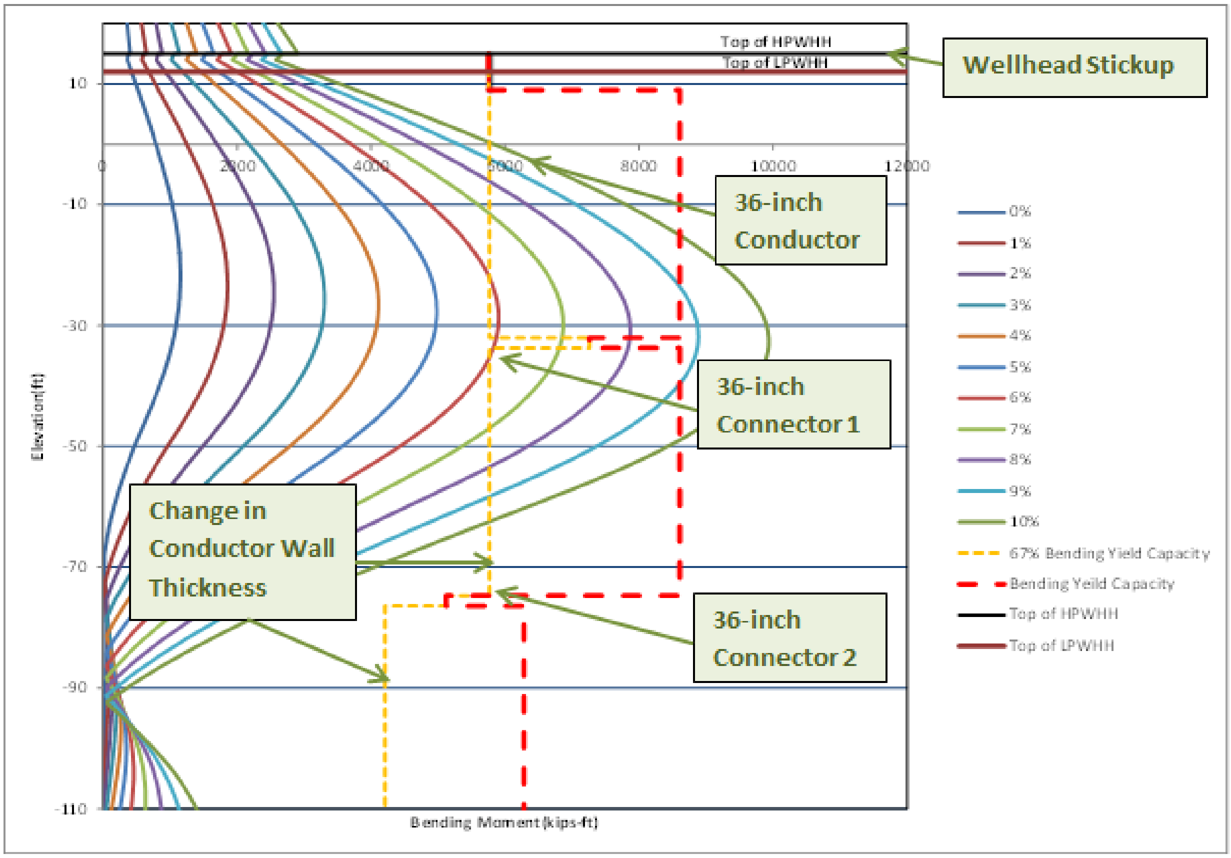

Figure 3.17: Sample Conductor Sizing and Strength Analysis

3.13 Axial Capacity Analysis

The axial capacity of the conductor and surface casing should be considered in the preliminary analysis phase. Generally, the Operator will provide a proposed well program for axial capacity assessment to the Analysis Contractor.

3.13.1 Method for Axial Capacity Analysis

The axial capacity of the conductor and surface casings are based primarily on the soil strength profiles, the cement or soil setup times, and the weight (length) of the casings. The maximum axial load on the conductor is equal to the weight of the conductor, the wellhead, the surface casing, and the cementing string. The axial capacity of the conductor will vary with time and will increase with cement setting times or reconsolidation of soil properties.

3.13.2 Outputs of Axial Capacity Analysis

The output of the axial capacity analysis is to provide a recommendation to the Operator as to the suitability of the proposed casing program at the specified location.

Specifically, the following outputs should be provided:

- Suitability of the Casing Program—The suitability for the casing lengths and setting depths should be confirmed. If the required axial capacity is not achieved, a recommendation to hold the casing and wait for cement to 'go off' (set) should be made.
- Potential for Slumping—If the axial capacity of the system is insufficient, a slumping assessment should be undertaken. Axial compression and bending stress are assessed to identify the potential for local buckling. Slumping of the conductor system may also occur in the event that there is a cement shortfall bending the conductor and casing.
- Effect of Upper and Lower Bound Soil—For a preliminary analysis where the site specific location is not defined, both upper and lower bound soil should be considered.

Figure 3.18 shows sample axial capacity after conductor jetting, and Figure 3.19 shows the same scenario during the first two days.

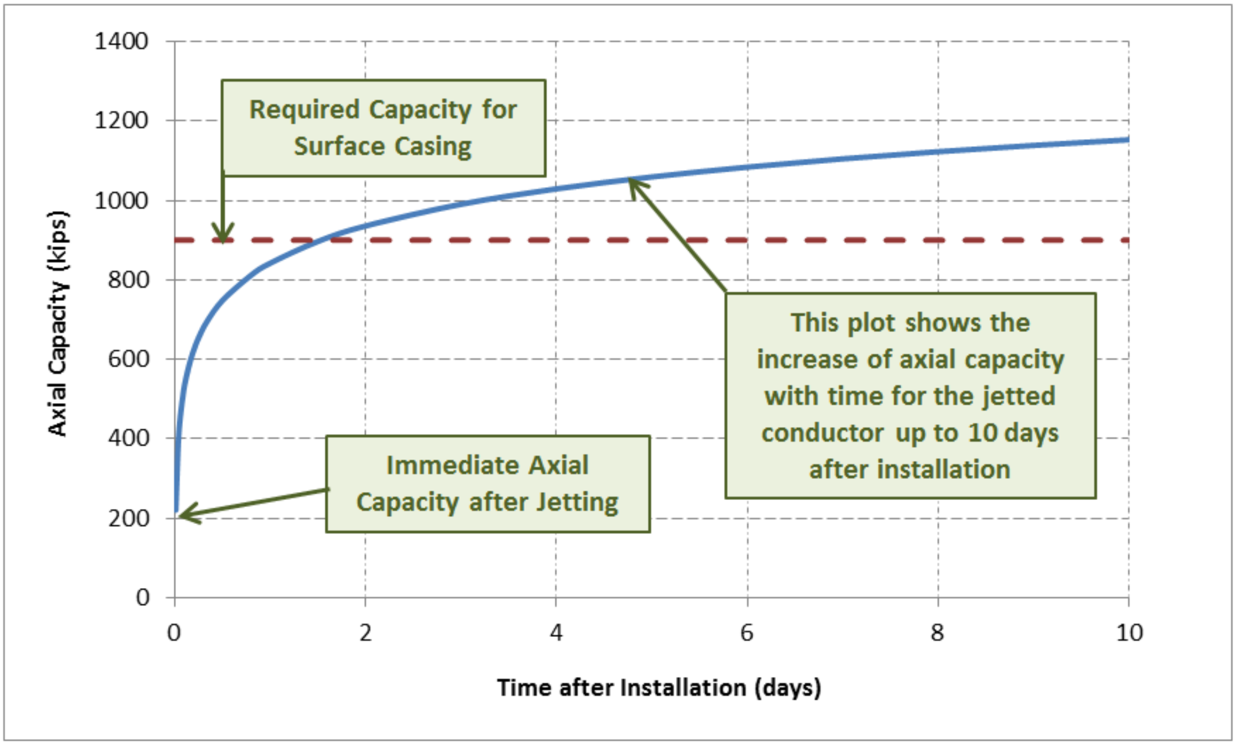

Figure 3.18: Sample Axial Capacity After Conductor Jetting

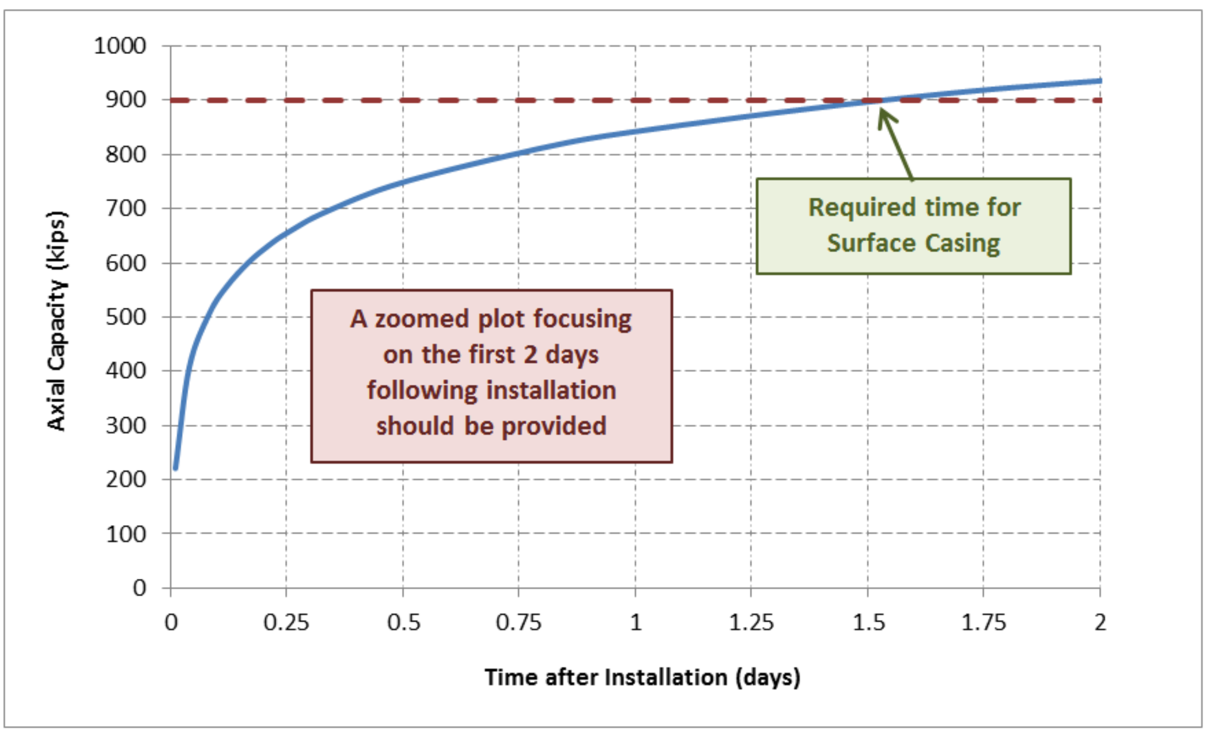

Figure 3.19: Sample Axial Capacity after Conductor Jetting—First 2 Days

3.14 Deployment and Retrieval Analysis

Deployment analysis should be performed to identify a feasible riser stack-up for installation for a given well. This analysis determines installation and retrieval envelopes. The Drilling Contractor (Rig Owner) conducts deployment and retrieval analysis using the rig operating manual. The Operator should review the specific well conditions and global analysis in the operating manual to determine whether additional analysis is required.

3.14.1 Method for Deployment and Retrieval Analysis

Deployment and retrieval analysis identifies the limiting metocean conditions for safe running and pulling of the riser. Typically, four stages of riser deployment/retrieval are considered. The deployment stages, which are shown in Figure 3.20, are:

- Stage 1: Splash zone/Wave zone deployment
- Stage 2: Intermediate 1 (50% deployed)
- Stage 3: Intermediate 2 (75% deployed)
- Stage 4: Landing (100% deployed)

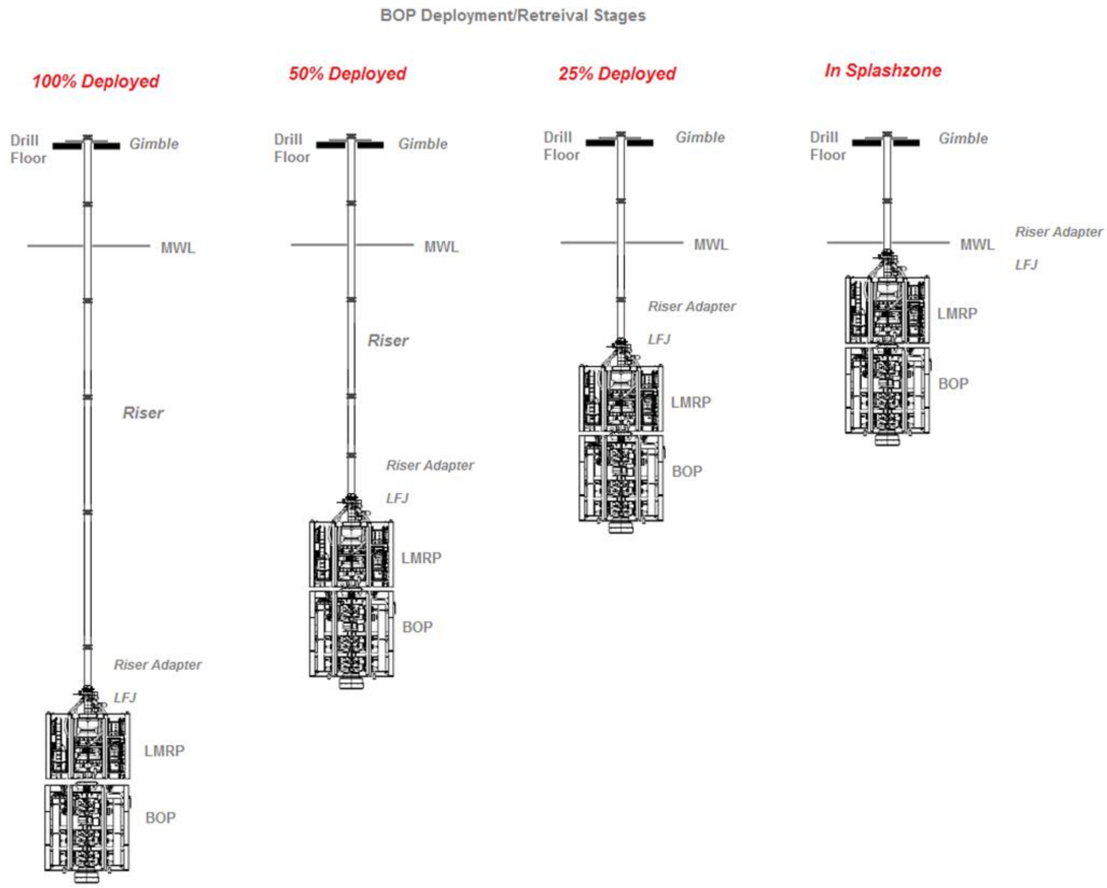

Figure 3.20: Riser Deployment/Retrieval

A frequency screening should be conducted for each stage of riser deployment to determine the critical response period of the riser and vessel. The selection of wave periods should consider these critical periods for dynamic load cases.

Excessive current and wave loading may induce large stresses when the riser is hanging in the slips or suspended from the gimbal. This is most problematic when the lower stack (BOP and LMRP) are in the high energy wave zone. If moonpool restraint or guidance systems are not used, double stands of risers should be created to reduce time in the high energy zone.

To identify the permissible maximum current and wave height combinations, a series of dynamic time domain FEMs are created at each stage. A combination of currents and waves should be run to determine an allowable envelope.

3.14.2 Outputs of Deployment and Retrieval Analysis

The outputs of the deployment analysis should provide the Operator with confirmation for the feasibility of the proposed configuration (to be deployed from the rig under consideration) and a deployment envelope of safe metocean limits.

Outputs from deployment and retrieval analysis include:

- Deployment Envelope—The analysis provides a deployment envelope detailing the allowable metocean conditions for deployment operations. This can be provided for each stage of deployment or as a single envelope representing all stages of deployment. An example of a deployment-operating window provided by the Analysis Contractor is presented in Figure 3.21.
- Landing of the BOP—The conditions under which BOP landing can take place are significantly less than those for standard deployment operations. As the BOP is landed in place, the heave of the rig and BOP is typically limited to approximately 6.6 ft. heave range (+/- 3.3 heave amplitude). The maximum allowable dynamic hook load must also remain within allowable limits. An example of allowable BOP landing sea states provided by the Analysis Contractor is presented in Figure 3.22.

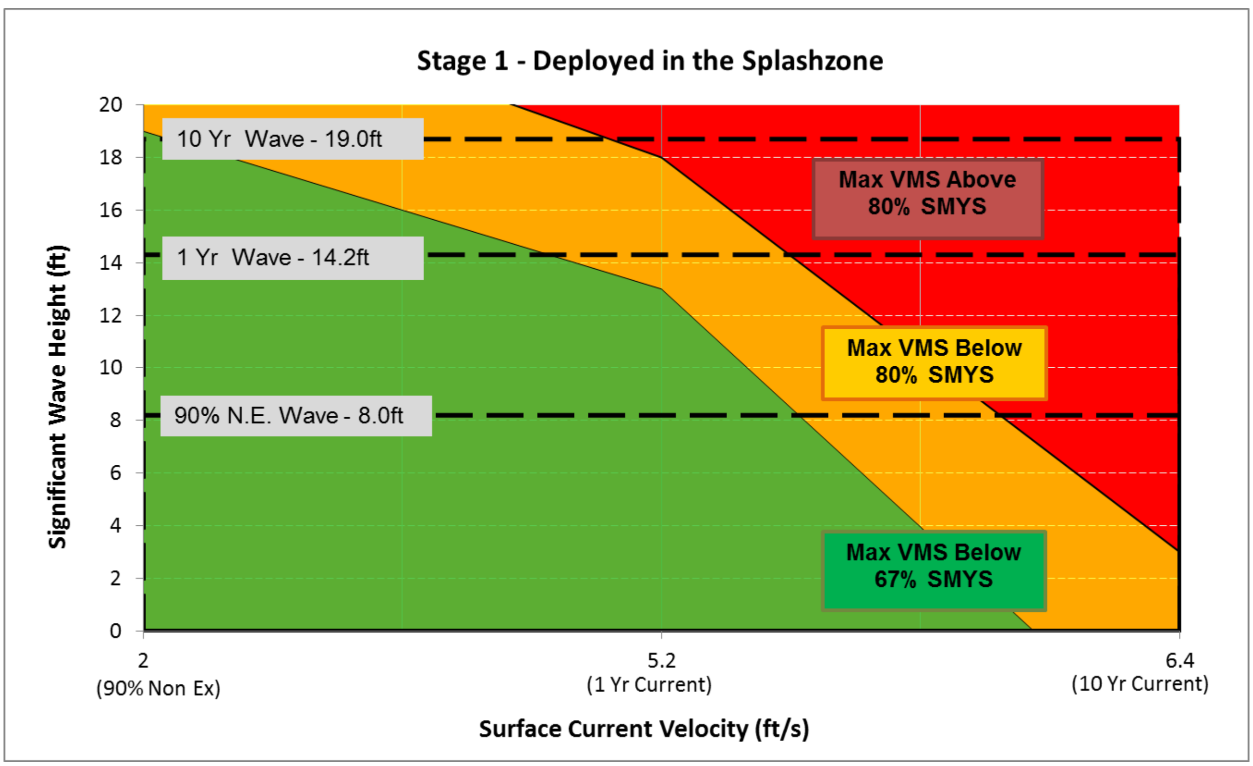

Figure 3.21: Sample Deployment Analysis Results

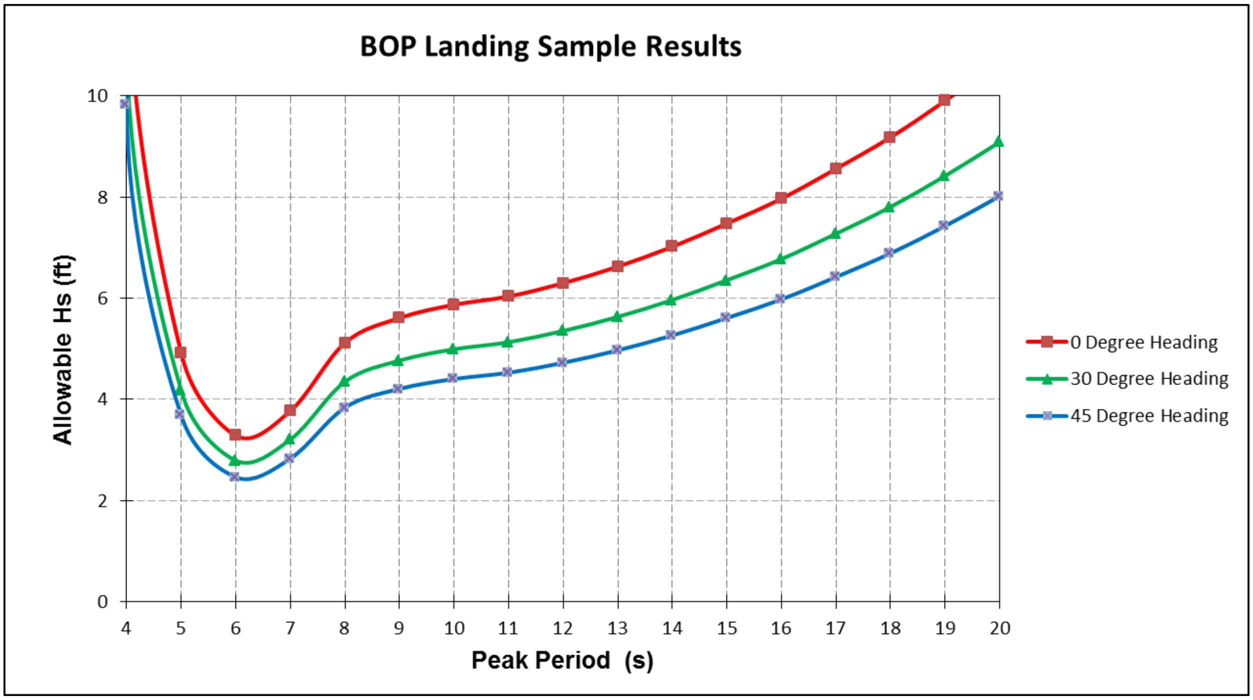

Figure 3.22: Sample BOP Landing Results

4.0 Literature Review of Materials for Arctic Conditions

4.1 Introduction

This section focuses on identifying the codes and standards that govern the selection and qualification of the materials used in Arctic environments. Existing codes and standards provide only general guidance on material property requirements for Arctic applications. The codes and standards recommend materials with adequate toughness to exhibit sufficient ductility at very low temperatures. Arctic drilling, exploration, and production are conducted below the design temperatures, which are near –76°F (–60°C). Most of the existing codes and standards do not specify the materials properties and design load demands that are typically found in Arctic conditions.

4.2 Existing Codes and Standards for Arctic Conditions

4.2.1 API Specification 16A [13] and ISO 13533:2010 [75]—Specification for Drill-through Equipment

This American Petroleum Institute (API) specification identifies the requirements for performance, design, materials, testing, inspection, welding, and shipping of drill-through equipment used for drilling (oil and gas). The specification defines a temperature rating for metallic materials based on the operating temperature range. A classification of T-75 has been assigned for an operating temperature range of –75°F to 250°F (–59.4°C to 121.1°C). For forgings and wrought products, the standard requires a minimum average Charpy toughness value of 20 J (15 ft-lb_f) for a T-75 temperature rating.

4.2.2 API 6A:2013—Specification for Wellhead and Christmas Tree Equipment [16]

API 6A:2013, Specification for Wellhead and Christmas Tree Equipment, is also a shared ISO standard (10423:2009 Petroleum and Natural Gas Industries—Drilling and Production Equipment—Wellhead and Christmas Tree Equipment [74]). This standard specifies requirements and gives recommendations for the design, materials, testing, inspection, welding, repair, and remanufacture of wellhead and christmas tree equipment for use in the petroleum and natural gas industries.

The standard establishes requirements for five Product Specification Levels (PSLs): PSL 1, 2, 3, 3G, and 4. The five PSL designations define different levels of technical quality requirements. The standard defines a temperature rating for metallic materials based on the operating temperature range. For the operating temperature range of –75°F to 180°F (–59.4°C to 82.2°C), a classification of 'K' has been created. For metallic materials used in drilling and production services, the standard requires a minimum average Charpy toughness value of 20 J (15 ft-lb_f) for all temperature ratings and PSLs.

4.2.3 API 16F:2004—Specification for Marine Drilling Riser Equipment [14]

This specification establishes standards of performance and quality for the design, manufacture, and fabrication of marine drilling riser equipment used in conjunction with a subsea BOP stack. The specification refers to API 16A [13] for low temperature applications.

4.2.4 API 5DP—Specification for Drill Pipe [15]

This standard provides material properties for the drill pipe body, including surface and weld zone hardness and Charpy V-notch absorbed energy requirements. Material property requirements provided in API 5DP are also applicable for drill pipe tool joints. Traditionally, drill pipe materials such as API and NS1 grades have ductile to brittle transition temperatures (DBTT) in the vicinity of –22°F to –40°F (–30°C to –40°C). For Arctic drill pipe applications, the materials should exhibit adequate fracture toughness at temperatures as low as –76°F (–60°C). The standard deals with some of the risks associated with drilling tubulars (such as drill pipe) that increase during transportation, storage, and surface handling in the permafrost region.

4.2.5 API Specification 7, 40th Edition—Specification for Rotary Drill Stem Elements [17]

This specification provides material property requirements for rotary drilling equipment, valve bodies, and associated components such as kellys, drill-stem stubs, and drill collars. This specification also includes material property requirements for Austenitic stainless steel drill collars.

4.2.6 NACE MR0175/ISO 15156 Part 1—General Principles for Selection of Cracking-Resistant Materials [107]

NACE MR0175/ISO 15156 provides general principles, requirements, and recommendations for the selection and qualification of metallic materials for service equipment used in oil and gas production and in natural gas sweetening plants in environments that contain hydrogen sulfide (H_2S). The standard addresses all the mechanisms of cracking that can be caused by H_2S, including sulfide stress cracking, stress corrosion cracking, hydrogen-induced cracking, stepwise cracking, stress-oriented hydrogen-induced cracking, soft zone cracking, and galvanically induced hydrogen stress cracking. Equipment covered under the scope of MR0175 include drilling; well construction; well-servicing equipment; wells (including subsurface equipment, gas lift equipment, wellheads, and christmas trees); flowlines; gathering lines; water-handling equipment; natural gas treatment plants; transportation pipelines for liquids, gases and multiphase fluids; field facilities; and field processing plants.

4.2.7 API Standard 53:2012—Blowout Prevention Equipment Systems for Drilling Wells [19]

This standard provides requirements on the installation and testing of blowout prevention equipment systems. No guidance is given for low temperature applications. The standard cites API 16A [13] as a reference.

4.2.8 ISO 19906:2010—Petroleum and Natural Gas Industries—Arctic Offshore Structures [88]

This international standard specifies the requirements and provides recommendations and guidance for design, construction, transportation, installation, and removal of offshore structures that are related to oil and gas exploration and production in the Arctic and cold regions [88]. While this standard does not specifically address MODUs, it refers to ISO 19905-1 for information on MODUs [87]. Offshore structures for use in Arctic and cold regions must be planned, designed, constructed, transported, installed, and decommissioned in accordance with ISO 19900:2013 [84] and supplemented by ISO 19906:2010 [88]. This standard requires that Arctic-grade steels have the ductility and toughness required for proper performance. Further, ISO 19906:2010 indicates that the appropriate toughness must be established in accordance with ISO 19902:2007 [86].

4.2.9 DNV-OS-B101:2009—Metallic Materials [51]

This offshore standard provides principles, technical requirements, and guidance for metallic materials to be used in the fabrication of offshore structures and equipment within main class. The standard requires a minimum average toughness (as listed in Table 4.1) of 27 J (20 ft-lb_f) for carbon and manganese steels.

Table 4.1: Toughness Requirements for Different Types of Steels per DNV OS B101

Steel Type	Minimum Design Temperature	Charpy V-notch	
		Test Temperature	Average Energy (J)
C and C-Mn	–67°F/–55°C	*	27
2 ¼ Ni	–85°F/–65°C	–94°F/–70°C	34
3 ½ Ni	–130°F/–90°C	–139°F/–95°C	34
9 Ni	–265°F/–165°C	–320.8°F/–196°C	41
* The test temperature must be 23°F/–5°C below the design temperature or –4°F/–20°C, whichever is lower.			

4.2.10 BS EN 10225:2009—Weldable Structural Steels for Fixed Offshore Structures—Technical Delivery Conditions [38]

BS EN 10225:2009 is frequently used for material property data for cold weather conditions. Material-specific codes such as EN10225, API 2W, and Norsok M101 provide requirements for minimum allowable Charpy values at –40°F (–40°C). Crack Tip Opening Displacement (CTOD) requirements in EN 10225:2009 are suggested only for steel plates of thicknesses greater than 3.9 inches (100 mm). More specifically, in the absence of relevant wide plate data, CTOD testing is required on sample plates of thicknesses up to 5.9 inches (150 mm), preferably using displacement control [38] in accordance with EN ISO 12737.

4.2.11 NORSOK M 101—Structural Steel Fabrication [109]

NORSOK M 101 contains CTOD requirements for butt welds (tubular and plates product types) and T-joints (plates) with specific dimensional requirements. The CTOD test temperatures are specified as 7°F (–13.8°C) in these standards. While Charpy V-Notch (CVN) values are important from a quality control standpoint, installation operations such as pipe lay in Arctic conditions would require more comprehensive test results based on fracture mechanics. While there are correlations between CVN and other linear-elastic and elastic-plastic fracture mechanics parameters, they do not yield precise toughness values.

4.2.12 ISO 19902:2007—Petroleum and Natural Gas Industries—Fixed Steel Offshore Structures [86]

Codes such as API RP 2N and ISO 19902 provide some guidance for the selection of steels for Arctic applications. Two methods are presented in ISO 19902 for the selection of steels that are expected to perform effectively over the design service life of a structure and allow for practical and economical fabrication and inspection, generally referred to as ISO 19902. These two methods are:

1. The Material Category (MC) approach
2. The Design Class (DC) approach

The MC method has evolved from practices adopted in the Gulf of Mexico (GOM) and other applications where American Society of Testing and Measurement (ASTM), API, and American Welding Society (AWS) standards are used, wherein each structure to be designed and built is assigned to a particular category.

The DC approach has evolved from the materials selection methods adopted in the North Sea region, which are consistent with the use of British Standards (BS), Engineering Equipment and Materials Users Association (EEMUA), NORSOK and European Standards (EN). The DC approach is used for large integrated engineering procurement installation and construction (EPIC) projects, where considerable resources are often devoted to materials selection [86]. This information is consistent with the guidance provided in API RP 2N (Planning, Designing, and Constructing Structures and Pipelines for Arctic Conditions) [8]. Section 11.9.1 of API RP 2N states that *"the design class approach described in ISO 19902 shall be used for material selection and particularly to determine toughness requirements." [7]*

Furthermore, API RP 2N specifies design class components to be monopoles, braced monopoles, and stiffened-plate structures to be developed in accordance with the principles defined in ISO 19902.

For structures in Arctic and cold regions, the LAST value that is used for material selection and testing should be defined in accordance with this standard if it is not specified explicitly in the regulatory requirements for the region.

The specific details of the design class approach are documented in Annex D of ISO 19902. The DC approach requires the selection of the steel toughness class to be based on a systematic classification of welded members and joints according to the structural significance and complexity of joints. The primary criteria for the determination of the appropriate design class of the component is to obtain alignment with the global integrity of the structure and the consequence of its failure. Other criteria that will influence the design class include the degree of redundancy, design uncertainties due to geometrical complexity, and the level of multiaxial stress of a joint [86]. Principles specified in Table 4.2 need to be applied to achieve compliance with component design class.

Table 4.2: Design Class—Typical Classification of Structural Components [86]

Design Class	Component Complexity[a]	Consequence of failure
DC 1	High	Applicable for joints and members where failure will have substantial consequences[b] and the structure possesses limited residual strength[c]
DC 2	Low	
DC 3	High	Applicable for joints and members where failure will be without substantial consequences[b] due to residual strength[c]
DC 4	Low	
DC 5	Any	Applicable for joints and members where failure will be without substantial consequences[b]

a. High joint complexity means joints where the geometry of the connected elements and weld type leads to high restraint and to a triaxial stress pattern. E.g. typically multi-planar plated connections with full penetration welds and also unstiffened leg nodes subject to high stress concentration.
b. "Substrantial Consequences" in this context meas that failure of the joint of member will entail either
- danger of loss of human life
- significant pollution, and/or
- major financial consequences

c. A structure may be assumed to have adequate residual strength if it meets the accidental limit states (ALS) requirements with the component under consideration damaged.

ISO 19902 also provides the relationship between the design class and toughness class, as shown in Table 4.3.

Table 4.3 Correlation between Design Class and Steel Toughness Class [86]

Design Class	Toughness Class [a]			
	CV2ZX/CV2Z [b]	CV2 [b]	CV1	NT
DC 1	X			
DC 2	X[c]	X		
DC 3	X[c]	X		
DC 4	X[c]		X	
DC 5				X

a. X with no superscript denotes default toughness choice.
b. For EN-steels CV2, CV2X and CV2ZX have identical requirements with respect to weldability.
c. Selection where joint design requires tensile strength through the thickness of the plate.

The strength groups and toughness classes in ISO 19902 are used to reference welding requirements (for example, preheat and electrode selection, where these tend to follow the steel). Plates, sections, and rolled tubular sections specified by the designer are required to conform to a recognized specification. Supplementary specifications can be required for the steel that is used to fabricate items intended for service in environments that are more demanding or where recognized steel grades are used in a thickness that is above the specified limits. Component level steel toughness class requirements are detailed in Annex D of ISO 19902 [86].

ISO 19906:2010 [88] refers to ISO 19902:2007 for the material properties of metallic materials such as fracture control and stress/strength values as a function of geometric variables (for example, tubular members and joints) [86]. Specific reference is also given to toughness class (presented in ISO 19902) for materials selection of structures used in Arctic and cold whether environments.

ISO 19902:2007 addresses degradation mechanisms that could potentially result in high corrosion rates, such as ice scouring in Arctic waters. (Although ice scouring may generate erosion alone, the corrosion on the structure after ice scouring will be high). The standard provides recommended LAST for various offshore operating regions worldwide.

The materials selection philosophy for low temperature applications is provided in Section 19.1 of ISO 19902:2007. It is presented in the form of a simplified flow chart in Figure 4.1.

The LAST is used to determine the toughness class for material selection, based on the material and design category approaches for low temperature applications. ISO 19902:2007 states that the LAST to be used in the selection of materials needs to be in accordance with applicable regulatory requirements (in the geographical region where the material will be deployed). Suggested LAST values are provided in Section A.19.2.2.4. The ISO 19902:2007 standard also categorizes steels into five strength groups (I through V). Each group has SMYS ranges and requires Charpy toughness values at specified temperatures below the LAST. Class CV2X and CV2ZX are required to be pre-qualified using Crack Tip Opening Displacement (CTOD) testing in addition to meeting the characteristics of CV2X and CV2ZX, respectively [86]. CTOD tests are considered to provide more representative measures of fracture toughness than the Charpy toughness tests.

It can be inferred from Table 4.4 that the NT (Not Tested using Charpy V Notch) category steel is not applicable for Arctic environments, based on the test temperature requirement. However, the CV1 category steels may be applicable, depending on the service temperature, thickness, cold work, restraint, stress concentration, impact loading, or lack of redundancy and whether improved notch toughness is required.

Class CV2 steels have a large margin between the Charpy V Notch (CVN) testing temperature and the service temperature. Steels in this class are potentially suitable for major primary structures or structural components and for critical and non-redundant components, particularly in situations of high stresses and stress concentrations, high residual stresses, severe cold work from fabrication, low temperatures, high calculated fatigue damage, or impact loading.

Table 4.4: Minimum Toughness Requirements [86]

Steel Group	SMYS Range Mpa (ksi)	Charpy Toughness J (ft-lbs)	Toughness Classes and Charpy Impact Test Temperature			
			NT (CVN testing not required)	CV1 Test at LAST	CV2 Test at 30°C (54°F) below LAST	CV2Z, CV2X & CV2ZX Test at 30°C (54°F) below LAST
I	220 - 375 (32 - 40)	20 (15)	No Test	X	X	Not Applicable
II	> 275 - 395 (> 40 - 57)	35 (25)	No Test	X	X	X
III	> 395 - 455 (> 57 - 66)	45 (35)	Combination Not Allowed	X	X	X
IV	> 455 - 495 (> 66 - 72)	60 (45)	Combination Not Allowed	X	X	X
V	> 495	60 (45)	Combination Not Allowed	Combination Not Allowed	X	X

Note: 'X' denotes tests required to achieve minimum Charpy values at the specified temperature.

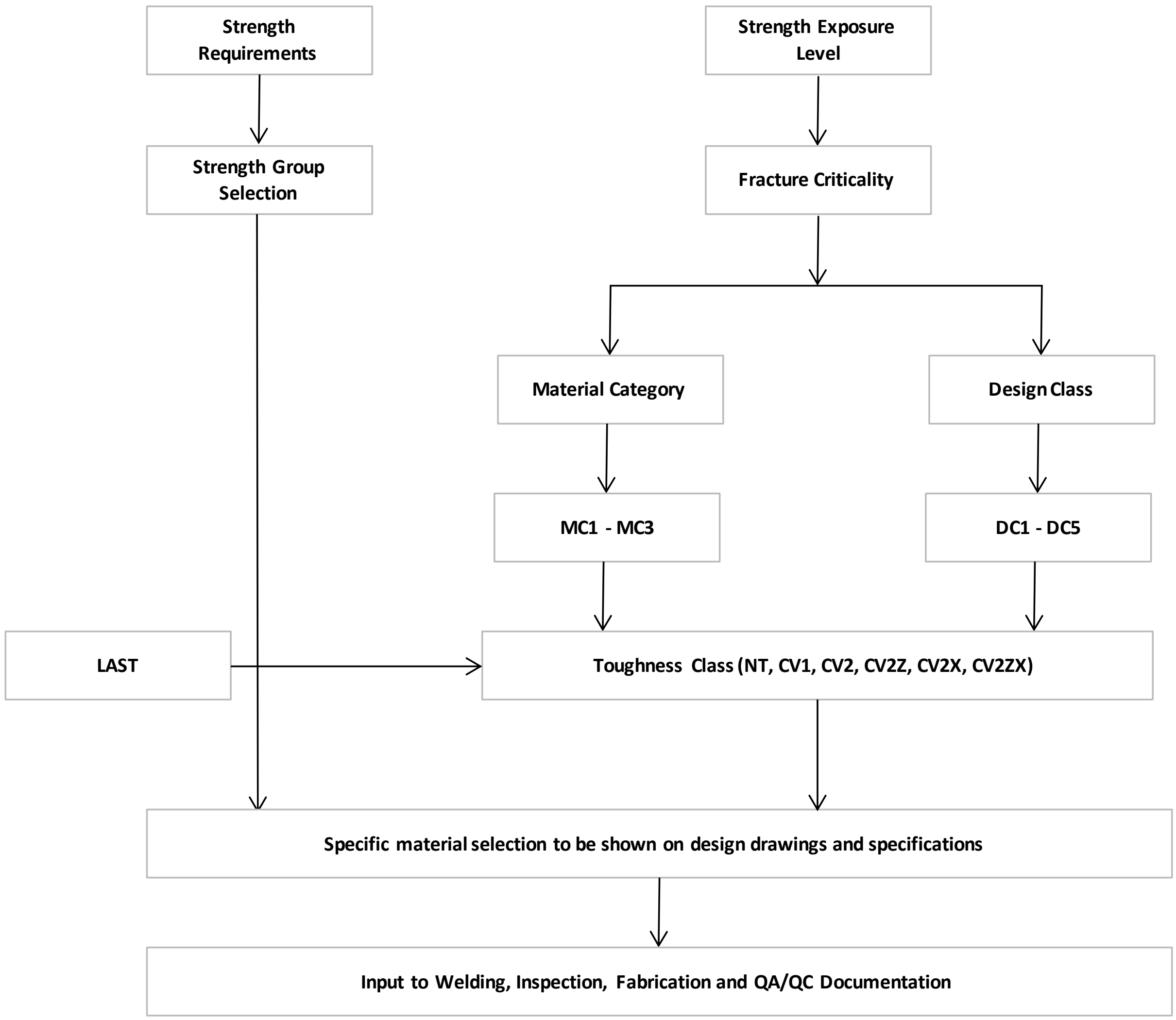

Figure 4.1: Materials Selection Flow Chart (Adapted from ISO 19902:2007) [86]

Class CV2Z steels are required to possess through-thickness (short transverse direction) ductility for resistance to lamellar tearing caused by tensile stress in the thickness direction. Through-thickness ductility must be demonstrated either by having a minimum reduction in the area of 30% in a tension test conducted on a specimen cut from the through-thickness direction, or by specifying sulfur content by a weight (P_S) of 0.006% or less.

It is important to note that the industry is currently evaluating materials for service at LAST of –76°F (–60°C). LAST values provided in ISO 19902 for various offshore operating areas (refer to Table 4.5) are limited to a minimum LAST of –20°F (–29°C).

Operators and regulators should keep in mind that information provided in ISO 19902 serves as general guidance with limitations on the LAST.

Table 4.5: Recommended Lowest Anticipated Service Temperatures in ISO 19902

Location	LAST in Air	LAST in Water
Gulf of Mexico	+14°F (–10°C)	+50°F (+10°C)
Southern California	+32°F (0°C)	+40°F (+4°C)
Cook Inlet, Alaska	–20°F (–29°C)	(–2°C) +28°F
North Sea, south of Latitude 62°	+14°F (–10°C)	+40°F (+4°C)
North Sea, north of Latitude 62°	Site-specific data should be used	
Mediterranean Sea, north of Latitude 38°	+23°F (–5°C)	+41°F (+5°C)
Mediterranean Sea, south of Latitude 38°	+32°F (0°C)	+50°F (+10°C)

4.2.13 Summary

A detailed review of codes and standards is documented in Section 4.2. This review provides a thorough review of existing industry practices, codes, and standards that provide guidance on material properties for low temperature service. It is evident from the review that ISO 19902 and API RP 2N are most applicable to low temperature service. It is important to note that there are technological gaps in ISO 19902 and API RP 2N that have required the industry to focus efforts on the development of new codes and standards to meet the LAST requirements of –76°F (–60°C).

In recent years, the ISO has taken significant steps in developing the technical basis for materials requirements for the demanding low temperature service that is expected in the Arctic. Detailed information on the codes and standards currently under development is presented in Section 4.3.

4.3 Codes and Standards Under Development

The industry is currently involved in developing the necessary codes and standards for Arctic conditions with LAST approximately –60°F (–51.1°C). This effort is being undertaken as part of the ISO/TC 67/SC 8 under the title “Petroleum and Natural Gas Industries, Arctic Operations: Material Requirements for Arctic Operations” [92].

Because of the limitations of the LAST specified in ISO 19902, it is important for the industry to track the ongoing efforts of the industry as part of the ISO Technical Committee to develop Material Requirements for Arctic Operations (ISO/TC67/SC8/WG5). The efforts are expected to address manufacturers’ requirements for bulk material supply and requirements for the fabrication of metallic materials. The specific purpose of this effort is to define the necessary modified or additional material requirements to ensure safe operations in Arctic areas with particular focus on the cold climate and interaction with seawater, ice, and snow. Requirements for polymers and composite materials are expected to be included in a separate document at a later stage.

Specific details of the properties considered as part of the efforts include:

- Fracture toughness, including test methods and acceptance criteria validation of the acceptance criteria based on fracture mechanics assessments. Importance is given specifically to welded structures and components with an emphasis on the toughness of the weld metal and the heat affected zone.
- Tensile properties, including the temperature sensitivity of the properties and the effect of tensile property sensitivity to fracture resistance.
- Fatigue resistance at low temperatures.
- Abrasion resistance, including the requirements to stainless steel cladding for ice protection and fabrication of clad plates.
- Corrosion resistance, including corrosion under ice and corrosion protection in the Arctic environment based on characteristic environmental parameters (such as sea water salinity and biological conditions).
- Sour service performance (hardness requirements) characteristic of Arctic operations.
- Maintenance and repair properties (such as in situ weldability and serviceability).

The ISO working group believes that the existing standards do not adequately cover some critical areas with respect to applications in Arctic environments. The intention of the working group is to defer as much as possible to existing standards and focus exclusively on the gaps identified in codes such as ISO 19902 and ISO 19906.

The technical specification (TS) document that ISO is developing is intended to handle potential degradation mechanisms as follows [68]:

<u>Fracture Toughness</u>:

Welded structures are required to operate above the DBTT. ISO 19902 requires that Charpy impact tests be performed at 32°F (0°C), 14°F (–10°C), or –22°F (–30°C) below the LAST. Additionally, CTOD testing is required at LAST with an acceptance criterion of 0.25 mm. However, in some regions of the Arctic where the LAST is much lower, test temperatures as low as –94°F (–70°C) can be difficult to meet. The TS expects to meet this challenge by adopting the following approach:

- Single-Edge Notched Bend (SENB) fracture mechanics tests, which are recommended to ensure sufficient constraint

- Constraint effect, which can be established by means of a simplified Weibull stress approach
- Statistical analyses of the test results to determine the characteristic fracture toughness to be compared with the toughness requirements
- Inclusion of both fracture mechanics testing and Charpy impact testing at the qualification stage, thereby allowing the use of Charpy impact testing at the production stage

It is important to note that the ISO working group reports that the codes and standards that use class approaches have relatively low requirements for Charpy impact energy and that such values do not necessarily prove that brittle fracture can be avoided. Based on this consideration, the new TS by ISO is expected to be designed with an acknowledgement of this fact and will implement more quantitative requirements to ensure the integrity of Arctic structures. The working group has also recognized that structural components with high utilization will be exposed to larger local plasticity, thereby necessitating higher toughness requirements. The TS is expected to provide different requirements for high utilization components (for example, ULS load above 80% of material yield strength). Furthermore, an engineering critical assessment in accordance with BS7910 or API 579 will be recommended in the TS with some guidance regarding applicable constraints and statistical treatment of test results [68].

Crack Arrest

In fracture mechanics, crack arrestability is a measure of whether the propagation of a crack will stop upon initiation. The conditions under which a crack could be arrested at room temperatures will not apply for Arctic temperatures. Structures designed in accordance with ISO 19902 requirements may incidentally assure that the structure is also safe from a crack arrestability standpoint for milder climates. It is important to note that this incidental crack arrestability may not be applicable in low temperature environments.

Welding and Fabrication Requirements

Based on the ongoing efforts in the ISO working group, qualification of steel and weldability is required to be based on fracture mechanics testing. The TS is expected to have requirements wherein fracture mechanics tests must be correlated with Charpy results in the pre-qualification phase to create steel- and weld-specific requirements. Charpy data will only serve as a quality control tool to assure that fracture tests performed in pre-qualification can be met. To assure the appropriate temperature-time sequence, welds that are created in low temperature environments will have additional requirements with respect to pre-heating and Post Weld Heat Treatment (PWHT). .

Fatigue Properties

For structures that are exposed to Arctic low-temperature environments, it is important to ensure that they are used at temperatures higher than the Fatigue Ductile to Brittle Transition (FDBT). Based on the preliminary work published by Hauge and coworkers [68] indicated that the Charpy DBTT is approximately 64.4°F (18°C) below the FDBT, the TS is expected to have the following recommendations:

- The Charpy value should be at least 27 J for LAST of –18°F (–28°C). If this is not achieved, then one of the two analyses should be performed.
- Fatigue tests should be performed at room temperature (RT) and LAST. If there is a significant acceleration of fatigue at LAST relative to RT, then the analyses should be performed to show that the structure maintains an acceptable fatigue life.
- Fatigue crack growth rate calculations should be conducted. Fatigue crack growth rates that are five times the RT must be used for all service conditions in which the temperature is below T_{27J}+18°C.

Protection Against Corrosion and Wear

Certain unique challenges related to corrosion and the designs of cathodic protection (CP) systems need to be addressed for the Arctic region. Some of the potential consequences from corrosion include:

1. Potential for increased oxygen in sea water, leading to increased current density requirements.
2. Higher level of electrical resistivity of cold water, leading to lower current output per anode.
3. Slower build-up of calcareous deposits at low temperatures, leading to high current density requirements.
4. Lower temperatures could lead to a higher rate of hydrogen build-up in the material.
5. Sub-zero temperatures in the splash zone could lead to the formation of ice and diminished coating performance.
6. Electrical resistivity of sea ice is orders of magnitude higher than that of sea water. Anodes fully encased in ice will be considerably less effective.
7. Mechanical wear caused by sea ice could lead to damage to calcareous deposits, anodes, and coating systems.
8. High salt concentration in these pockets may accelerate the corrosion.

5.0 Oil and Gas Survey Related to Arctic Materials

5.1 Introduction

Recently, WGK was invited to participate in the Edison Welding Institute (EWI) Strategic Technology Committee (STC) for oil and gas. The STC is a consortium of oil and gas Operators (including four major oil and gas Operators), suppliers, and manufacturers of equipment. The STC, which is member funded, shares internally the results of fundamental research and innovation on key topics for the oil and gas industry (including Arctic exploration and production).

After their September 14–15, 2015 meeting, WGK and EWI gathered additional information through an anonymous questionnaire ('the survey'), this was circulated to the members of the STC electronically. The summarized results of the key information from the Operators, materials suppliers, and equipment manufacturers are presented in the sub-sections that follow.

5.2 General Information About the Companies That Participated in the Survey

From the ten companies that participated in the survey, four companies are major oil and gas Operators, two companies are focused mainly on engineering and procurement, two companies are steel and pipe manufacturers, and two companies are engineering suppliers (one company is a welding engineering supplier). Nine of the companies are located in North America, and one is located in Asia.

5.3 General Information About the Engineers That Filled the Survey

Six of the ten engineers from the companies that participated in the survey are focused on materials engineering problems within their companies. The other four engineers consider themselves welding engineers.

5.4 Technical Questions Related to Materials and Specifications

Seven engineers answered the first question, which was related to the lowest anticipated design and operating temperatures for Arctic applications. Three engineers responded that the lowest temperature would be –50°F (–45.5°C), one engineer indicated –58°F (–50°C), and three engineers typed –60°F (–51.1°C).

Six engineers answered the question related to the targeted absorbed energy and CTOD values for Arctic environments. Some of the answers emphasized that this is a complex response that depends on the environment, while others responded with specific numbers. For example, one engineer wrote 40 Joules at –76°F (–60°C) with 0.15 mm CTOD, while another engineer wrote >50 Joules at –76°F (–60°C) with 0.25 mm CTOD.

With regard to the grades of steel that are currently being considered for Arctic environments, most of the engineers agreed on API 2W Grade 50 and 60 or API 5L X65. Other steel grades were also selected, as shown in Figure 5.1. The engineers were given the option of selecting several steels from the ones shown in Figure 5.1.

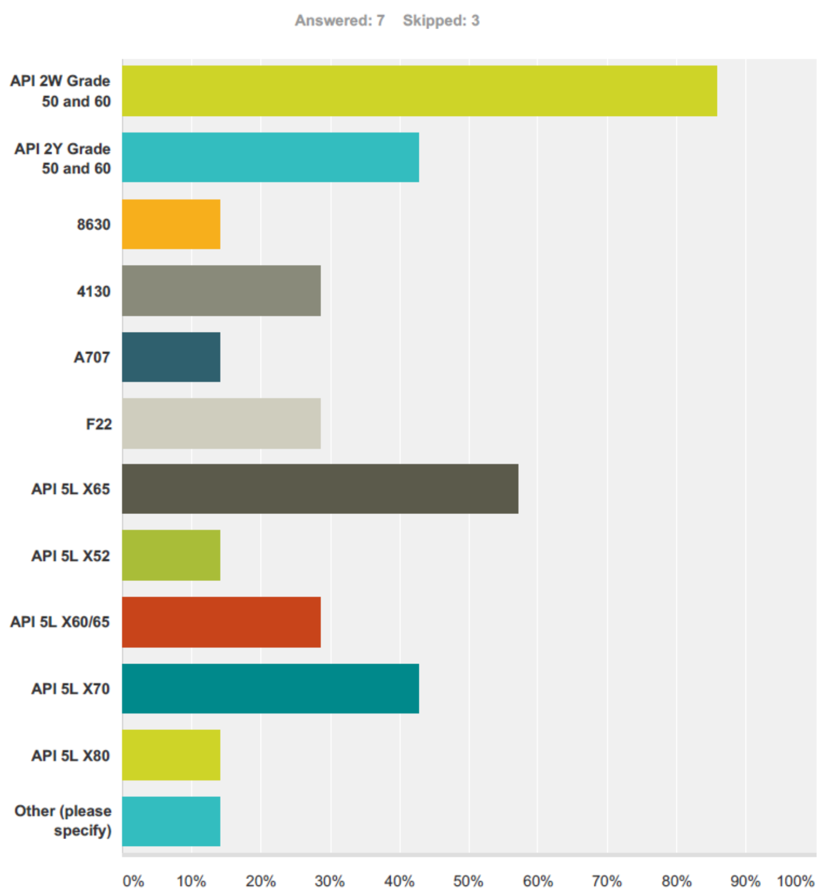

Figure 5.1: Grades of Steel That Are Currently Being Considered for the Arctic

Five engineers answered the question related to the upper limits on allowable strength for base metals and welds for Arctic environments. Their answers varied from a simple "*not defined*" to "*depends on the application,*" and one gave more specific answers with 50 ksi (344.7 MPa) and 60 ksi (413.6 MPa).

Six engineers gave specific values for the test temperature required for Charpy V-Notch (CVN) and CTOD tests. The results varied from –40°F (–40°C) to –76°F (–60°C).

Three engineers suggested that the use of AWS D1.1 [31] or API standards for materials selection aimed at building structures that will operate safely in Arctic environments. Furthermore, most of the engineers agreed that probabilistic fracture mechanics and reliability-based design methods for structures should be used to develop an exhaustive test matrix for Arctic design.

5.5 Technical Questions Related to Welding Engineering

Five engineers answered questions related to the minimum or maximum weld strength over-match requirements for Arctic environments. The answers varied, but they provided very little information, mainly because of the variables that needed to be considered. Additionally, five engineers selected most of the welding processes for structures used in Arctic environments. The engineers were given the option of selecting from several welding processes (refer to Figure 5.2).

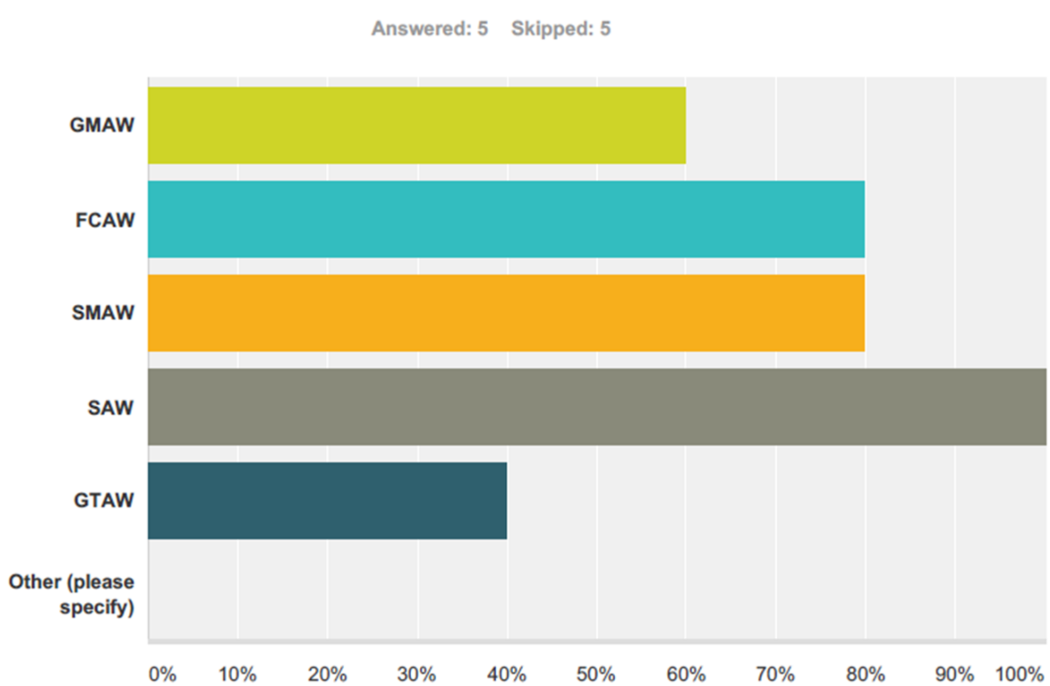

Figure 5.2: Welding Processes Being Considered for the Arctic

Similarly, five engineers agreed that specialized weld repair procedures should be developed and qualified for Arctic environments.

5.6 Survey Summary

In summary, the engineers (from oil and gas Operators, materials suppliers, and equipment manufacturers) agreed that fundamental work is required to ensure safe operations to design, build, and operate the equipment used to drill in Arctic environments. They identified several gaps in the industry, ranging from the requirements of the materials specifications to the need for more specific guidelines.

6.0 Metallic Materials Used in Arctic Environments

6.1 Introduction

The scope of this section is to provide a thorough overview of the low temperature effects on the metallic materials used for drilling equipment, including drilling rigs, drilling vessels, drilling risers, drill pipe, BOPs, and other offshore structures (such as cranes) associated with drilling and operations in the Arctic.

When drilling in Arctic regions under extremely harsh climatic conditions, it is important that the metallic materials used for drilling and producing oil and gas be evaluated. Some of the major challenges associated with Arctic drilling and operations include the following [4]:

- The Lowest Anticipated Service Temperature (LAST) that is being considered for the Arctic region, which is –76°F (–60°C)
- Significant variations in temperature
- The high loads that are applied to materials

While the focus of this section is on the metallic equipment associated with drilling equipment (such as drill pipes), the emphasis is on addressing the materials that are used to construct the drilling structures used for Arctic operations. The industry has been trying to develop codes and standards for qualifying the materials used in traditionally cold temperatures that can compensate for the harsh Arctic conditions. The aim is to ensure that after their qualification, the metallic materials will possess adequate mechanical properties that enable safe drilling in Arctic environments.

A summary of the typical loading and environmental conditions experienced by Arctic drilling and production equipment follows [100]:

<u>Above Water</u>

- Structures such as drilling rigs, platform structural elements, cranes, supporting blocks, and other related equipment are exposed to temperatures in the vicinity of -76°F (–60°C), which is the LAST in the Arctic region.
- Typical loads experienced by these structures include wind/wave loading (cyclic), seismic, and other static and dynamic loads.
- Depending on the location above water (for example, the splash zone), certain components could be exposed to corrosive environments.

Below Water

- Structures such as the base of the platform and other structural elements are expected to experience temperatures near 28°F (–2.2°C).
- Loads experienced by these structures include wave, seismic, and other static and dynamic loads.
- Structures below the waterline are exposed to corrosive environments and are potentially susceptible to biofouling.

Another important consideration that needs to be taken into account when selecting materials is the large variation in loads. A report published by the Pew Charitable Trusts titled "Arctic Standards – Recommendations on Oil Spill Prevention, Response, and Safety in the U.S. Arctic Ocean" states that the design loads in the Beaufort Sea and the Chukchi Sea are 10 to 20 times higher compared to the design loads of platforms in both the Gulf of Mexico (built for hurricanes and rough seas) and the Cook Inlet platforms (built for ice and storm events) [21]. Moreover, components such as pipelines are designed based on stress-based rules and strains only up to 0.5%. In Arctic environments, larger strains and deformations are expected because of thaw, settlement, frost heave, landslides, and iceberg scours, which can result in strains that far exceed the yield limit of the materials [124]. Significant efforts have been dedicated to the development of the strain-based design, particularly for materials that will be used in the Arctic region.

Considering the environmental and loading conditions, the materials used for drilling and oil and gas production in Arctic environments should take several material properties into consideration to maintain adequate structural integrity. Metallic materials operating at low ambient temperatures near –76°F (–60°C) are required to exhibit sufficient yield strength and adequate toughness properties. This directly translates into the resistance of the material to brittle fracture at low temperatures.

Materials used in the construction of drilling equipment and other associated structural elements are required to exhibit isotropic material properties (consistent through-wall properties). It is important to note that the materials selected should be capable of withstanding high magnitude loads and large variations in loading patterns (static and dynamic loads caused by wind and wave; fluctuating temperatures at the waterline), as well as other operational loads [101]. Structural elements used in drilling rigs and other above water structures are frequently exposed to impact from floating ice and therefore require high strength and toughness to achieve adequate protection from structural damage. Materials selection considerations are discussed in detail in Section 6.2.

6.2 Effects of Low Temperature on Metallic Materials

Environmental conditions in the Arctic are different from those experienced by metallic materials used for drilling and oil and gas operations in other parts of the globe. The most pressing challenge in terms of selection and long-term performance of metallic material is the presence of low ambient temperatures in the Arctic. For metallic materials, this directly translates into a transition from ductile to brittle behavior.

Structural steels and steel for piping and pressure vessels are required to show adequate integrity at service temperatures as low as –76°F (–60°C). Furthermore, during startup from a fully depressurized state, temperatures as low as –94°F (–70°C) are possible. The industry is faced with the challenge of qualifying materials that meet these stringent requirements while keeping the costs reasonably low [4]. The critical properties that most materials should have and their considerations are explained in the following sub-sections.

6.2.1 Material Toughness

Basic knowledge of the mechanical behavior of metals under extreme climate conditions is critical to avoiding failure modes that may affect the integrity of the components. The most obvious risk for metals operating at low temperatures is related to brittle fracture. This is particularly applicable at welded joints and the heat affected zone (HAZ) caused by the local variation in the microstructure of the welded materials. Brittle fracture is characterized by the development of rapid and unstable crack extension, which could lead to catastrophic failure of the material.

Ferritic steels are susceptible to reduced fracture toughness at low temperatures because of the ductile to brittle transition behavior that is characteristic for body-centered cubic (BCC) metals. Austenitic steels with face-centered cubic (FCC) structure do not show the ductile to brittle transition behavior. Addressing the risk of brittle fracture by shifting the ductile to brittle transition to lower temperatures rather than the LAST is essential for steels that will be used in Arctic environments. This can be achieved by using modern steel making and processing practices with better quality control, changing the steel chemical composition, improving the metallurgy (alloying with Nickel or Chromium or changing the grain size), and restricting deleterious elements such as sulfur and phosphorous.

For welds, it is important to have proper welding procedures and qualifications with a focus on, for example, surface preparation, preheating conditions, heat input, and deposition rate. Most of the current industry efforts are focused on improving the toughness of the weld metal and HAZ to achieve properties that are comparable to the base metal.

There is always a compromise between the strength of a material and its toughness, and trying to combine high strength with high toughness in a given material is a challenge. Additionally, toughness shows sensitivity to the section thickness of the component because of constraint effects. These considerations place significant demand on the toughness performance of the thick wall valve bodies and steel structures used in Arctic conditions.

The fracture toughness of the drill pipe used in the Arctic environment where the temperatures can go down to –76°F (–60°C) must be controlled. There is potential for damage during the transportation and handling of the metals in severe weather conditions. Under these conditions, the ductility of the steel may be reduced. This reduction, which is called the transition temperature, depends on the steel metallurgy and its grade. If the transition temperature of the steel grade is too high, the steel can become brittle at –4°F (–20°C).

Steels with low transition temperatures should be used in Arctic environments (or other considerations must be taken, such as de-rating for temperature). Although it is difficult to achieve low transition temperatures in high strength steel, the steel manufacturing process can be controlled to improve the steel transition temperature. Carbon steels with low phosphorous, low sulfur, and reduced content of inclusions and oxides (which will have few initiation sites for cracks and a low probability for fatigue) should be used. Some of the proprietary Arctic steel grades can operate at temperatures near –40°F (–40°C). Few high strength drilling materials can meet the Arctic drilling loads at temperatures as low as –76°F (–60°C).

To qualify a material to be used in conventional oil and gas production, the industry uses well-known, typical codes and standards that have been developed for room temperature applications. For extreme applications (not Arctic conditions), most codes require a minimum Charpy toughness value at or slightly below LAST to avoid the risk of brittle fracture. As it has been explained previously, codes and standards have not been established for the materials used in Arctic environments. The temperatures used for toughness testing in conventional oil and gas production vary significantly among the codes and standards.

The qualification of new materials for drilling and production of oil and gas in Arctic environments requires a complete understanding of the interaction between the materials and the environment (and the failure modes induced by operating at very low temperatures). Therefore, new codes and standards need to be developed for the correct qualification of materials for the drilling and production of oil and gas in Arctic environments [69].

6.2.2 Crack Arrestability

In addition to fracture toughness, an important aspect of thick structural steel related to its use for low temperatures is the crack arrest behavior. Crack arrest is defined as the ability of certain materials to arrest a crack once it has begun. A recent study [68] has shown that sub-zero temperatures can diminish the crack arrest behavior of some steels. The study also revealed that Charpy toughness values do not generally correlate well with crack arrest properties.

The ship industry is among the first to raise concerns regarding the potential safety of hull structures using thick steel, which may have insufficient crack arrest properties. Over the years, small-scale and full-scale tests have been used to characterize crack arrest behavior. The concept of the master curve using drop weight tests, which has been closely considered, provides a reasonable estimate of crack arrest behavior. This approach, which seems to be gaining attention, is in the process of being adopted by the International Organization for Standardization (ISO) TC67/SC8/WG5 as part of the new standard development for Arctic steel structures [93].

6.2.3 Fatigue Performance

Fatigue is an important consideration in the design of welded structures or components with geometrical stress concentrations when the structures or components are subjected to cyclic loading. The source of cyclic loading can be wind, waves, subsea currents, and thermal loading.

The fatigue life assessment of a material is based on either the classical stress-based approach or the more detailed fracture mechanics approach. In both approaches, fatigue curves (either in the form of stress versus number of cycles to failure [S-N] or fatigue crack growth rates [known as Paris curves]) need to be generated for the material under consideration, and the relevant service conditions must be taken into account.

Alvaro et al. conducted a recent review of the effect of low temperatures on the fatigue performance of steels in air [5] and concluded that as the temperature decreased, the S-N fatigue life generally improved (relative to the known life at room temperature). At lower temperatures (similar to those found in Arctic conditions), the improvement in fatigue life for steels was considered marginal. For fatigue crack growth curves, lower temperatures led to a slight reduction in the fatigue crack propagation as long as the temperature was above the ductile to brittle transition. These effects are favorable when conducting fatigue life assessments based on fatigue curves at room temperature, and they support the general assumption (included in some codes), that lower temperatures (relevant to Arctic conditions), will not significantly affect the fatigue behavior of the steel.

There have been few attempts to understand the effects of low temperatures on the fatigue behavior of welds. Additionally, there is lack of understanding of the effect of cold sea water or cold marine environments on the fatigue properties of most engineering materials.

For temperatures much lower than –76°F (–60°C), such as those encountered in cryogenic applications, the temperature effects on the fatigue of metals may differ significantly, depending on the metal microstructure and other variables [5].

6.2.4 Mechanical Properties

For most metals, as the temperature decreases to below room temperature, marginal increases in yield strength, tensile strength, hardness, and Young's modulus are expected. However, an increase in strength is usually coupled with a decrease in ductility. Industry codes dealing with design in Arctic environments have not addressed this slight increase in strength. BS EN ISO 15652:2010 [39] provides a relationship that can be used to estimate the yield strength of ferritic steels at lower temperatures based on the room temperature yield strength.

Another aspect of mechanical properties is the dependency of the mechanical behavior on strain rate as the temperature decreases. Past work has shown that increasing the strain rate generally decreases the yield strength, with a slight change in the ultimate tensile strength (for example, loss of work hardening) [125]. The effect of strain rate is an important consideration in the design of structures when dynamic loading is a major concern.

There is no data related to the combined effects of high strain effects and low temperature on steels and weldments that will be used in Arctic environments [125].

6.2.5 External Corrosion of Structures

Another important factor that should be considered for materials exposed to Arctic environments is their corrosion resistance (and corrosion control). Corrosion damage can affect structural integrity by decreasing the cross-section of the structure, which can potentially affect its ability to carry the load.

In addition, the presence of corrosion in fatigue-sensitive areas can increase the fatigue properties under cyclic loading. As more pits develop in the surface of the materials, these pits will act as the precursor sites for crack initiation.

General corrosion rates are relatively lower for cold environments, although considerable local differences can occur. For example, Arctic sea water is known to have different salinity from the tropics [105], which may change the corrosion rate for submerged structures. Typically, most of the carbon steel structures exposed to sea water are protected by using coatings or Cathodic Protection (CP) or both. Loss of adhesion of the coating as the temperature decreases and the possibility of the coating becoming brittle should be verified.

A number of studies have reviewed the CP requirements in Arctic environments (such as requirements for sea ice, frigid temperatures, and other extreme environmental conditions) [135, 94]. These studies highlighted several challenges that are not limited only to a reduced anode performance and changes in the current requirements (related to the nature of calcareous deposits formed on the steel under CP). The physical damage of the CP hardware resulting from ice impact, abrasion, and freezing conditions could affect the lifetime of the hardware. These studies revealed that the existing CP codes and recommended practices for CP design are only valid in temperatures that are greater than 41°F (5°C) [94].

To avoid overprotection issues, it is important to establish appropriate CP potential levels for structural steels in Arctic environments. Overprotection (excessively negative potentials) may lead to coating disbondment and increased risk of hydrogen generation (resulting in hydrogen embrittlement of the metal), particularly for high strength steels.

The cracking reported in the structures for some jack-up drilling rigs in the late 1980s highlighted the problems caused by overprotection of high strength steels [34]. Over the years, the industry has established several methods that can help address CP overprotection. These methods include the use of one or more of the following engineering strategies [34]:

- Dielectric shields
- Sacrificial coatings
- Voltage limiting diodes
- Voltage limiting resistors
- Low driving voltage anodes
- Finite element analyses to design the CP system

According to ISO 19902, steels with SMYS in excess of 720 MPa (104,427 psi) must not be used for critical cathodically protected components without special considerations.

Furthermore, welding (or other procedures affecting the ductility or tensile properties of the materials) must be conducted according to a qualified procedure that limits the hardness of the material to HV350. This restricts the use of welded structures to a maximum SMYS of approximately 550 MPa (79,770 psi) [86].

6.2.6 Internal Corrosion of Vessels and Pipelines

Top of the Line Corrosion (TOLC) may exist in Arctic conditions. This only occurs inside the pipelines that transport oil and gas, and it is typically caused by the cold external environment surrounding the pipelines. TOLC arises when hydrocarbons are transported with water (and gas), resulting in water condensation in the upper part of the pipeline where the corrosion inhibitors contained in the fluid cannot inhibit the corrosion in the gas phase.

In Arctic environments, the external low temperatures induce water condensation inside pipelines that are not well insulated externally. Corrosion modeling can be used to assess the areas that are most susceptible to TOLC along the pipeline and can assist in the selection of corrosion resistant alloys (CRAs) or other engineering strategies to mitigate TOLC.

Corrosion monitoring inside the pipelines typically involves corrosion coupons or online monitoring systems, although more innovative methods are currently being developed as alternative monitoring. The online monitoring systems help detect areas with high corrosion rates. Careful consideration should be given to the corrosion monitoring systems because they are prone to freezing in Arctic environments. Similarly, the installation and retrieval of corrosion coupons is challenging in Arctic environments.

6.3 Materials Consideration for Welding and Fabrication in Arctic Environments

Selecting the correct alloying element and the appropriate heat treatment is a key component of the qualification method for most structural materials that are used in the Arctic. The alloying elements and the heat treatment have a strong effect on the low temperature toughness; this was discussed in some detail as part of *Report 02: Evaluation of Emerging Drilling Techniques & Materials Proposed for Arctic Environments* of the *Low Temperature Effects on Drilling Equipment* report.

From the point of view of the design, the weld is typically considered the weakest area of the materials. It is therefore important to adequately understand the effect of metallurgical variables on the weld metal and weld consumables that will be used for low temperature applications. The intent of this sub-section is to provide an understanding of current industry efforts to achieve adequate weld metal properties during material fabrication.

The fabrication of offshore structures used in the Arctic climate poses significant challenges because of the synergistic effects of low temperatures (near –76°F [–60°C]), combined with high incident loads from wind, impacts from floating ice, freeze-thaw cycles, and corrosion. Reduction in the fracture toughness of the materials is of particular concern in Arctic environments. From a metallurgical standpoint, the addition of austenite stabilizers (such as nickel [Ni]) helps improve the mechanical properties of steel.

Recently, the Edison Welding Institute (EWI) performed a study to evaluate whether the currently available Flux Core Arc Welding (FCAW) wires are suitable for Arctic steel fabrication [51]. The study involved three Ni-containing steels (A203, A353, and A553) at various heat treated conditions (as-rolled, normalized, and quenched followed by tempered). The study evaluated the Ni-containing steels as functions of the relevant parameters. Although the base metals exhibited beneficial low temperature properties when the Ni content was increased to 9% [51, 5], the consumable wires used during FCAW typically did not yield the same weld properties as the base metal (even with the addition of Ni).

Differences in welding procedures and welding consumables may result in a drastic reduction in toughness values (in some cases 20% to 50% lower), based upon a type plate welding test from the AWS. Such drastic reductions in toughness, due to the welding consumables, may potentially render the Arctic grade steel (with Ni content greater than 3.5%) impractical for welding because of the structural design challenges [5].

A recent study that was performed on welded metals revealed that adding a combination of 1.0% to 3.7% Ni and 0.6% to 1.4% manganese (Mn) to steel will improve the toughness of the steel. Increasing these two alloying elements beyond these limits could promote the formation of martensite and other microstructural features that are potentially detrimental to the weld metal toughness [125].

More specifically, studies performed on weld metal and consumables used for Arctic applications have concluded that more thorough investigations are required to validate the standardization of Arctic steel welding by using FCAW wires [51]. A thorough review of the low temperature properties of nickel alloys and steels and the effect of heat treatment, section size, production practices, and fabricating procedures has been included in a publication provided by the International Nickel Company [5].

6.4 Advances in Fabrication and Welding of Materials Used in Arctic Environments

Addressing the challenges associated with the fabrication and welding of metals is vital to ensuring adequate structural integrity of Arctic structures. Because welding is a thermo-mechanical process, it has an effect on the mechanical and toughness properties of the base metal, particularly in the HAZ of the weld. The welding process variables need to be controlled to achieve the required metallurgical and mechanical properties. The use of induction coils is recommended when welding on structures in the Arctic (welding in cold conditions). Real time monitoring of the variables involved in the welding is also recommended. It is important to maintain a consistent temperature throughout the required area of the structure being welded [127]. It is also important to keep low limits on the Carbon Equivalent (CE) for structural steels and the Critical Metal Parameter (CMP) for weld cracking of steels with low carbon content and filler materials used in Arctic environments.

Welding consumables used for FCAW should have the toughness properties that are required for Arctic applications. It is also important to establish welding procedures and to validate the weld consumable toughness values using valid international specifications. Additionally, similar proposals have been made to evaluate new considerations for Charpy V-Notch (CVN) toughness determination methods for Arctic welding applications. Currently, toughness testing using CVN specimens is performed in accordance with ASTM A370 [24].

The specimens used for testing are typically machined from the metal plates and tubes; the tests are then conducted at –40°F (–40°C). For very thick steel plate, the toughness data is acquired from specimens obtained from various depths through the bulk and lateral positions of the weld cross-sections. The volume of the re-heated area on a CVN specimen will affect the resulting CVN toughness (which is expected to vary through the volume of the weld). This has a potential impact on the structural design considerations for Arctic structures because the toughness will vary through the bulk of the metal. Other considerations should be given to CVN specimen dimensions and test equipment that may be used for Arctic applications [131].

A constant demand for the use of longer and larger diameter pipes, steels, and plates with increased thickness and enhanced welding efficiency has resulted in the use of High Strength Steels (HSS) for the construction of Arctic offshore structures (ship hulls, jackets, drilling units, offshore platforms, ice breakers, and Liquefied Natural Gas [LNG] tanks). HSS are steels with yield strengths ranging from 36,259 to 101,526 psi (250 MPa to 700 MPa) with the specific benefit of having a very low weight-to-strength ratio [3].

While materials selection plays an important role, the welding of HSS requires the use of efficient technologies and precision welding process control to achieve good weldability and low temperature toughness in the HAZ and in the weld joints.

The primary challenges associated with welding for Arctic applications include [3]:

- Selecting welding techniques that produce welds with the required mechanical properties for welds and HAZ. Properties of interest include toughness, yield to tensile strength ratio, and cracking resistance.
- Welding parameter and process control to achieve weld bead microstructure and target grain sizes.
- Manufacturing high productivity welds at reduced costs.
- Control and minimization of weld residual stresses, corrosion, cold cracking, brittle failure, and/or fracture of materials.

From a materials selection and design standpoint, weldability is an important factor when considering the need for the material to retain adequate base metal fracture toughness in Arctic service. Because the welds are the most critical areas in most engineering materials, their lack of adequate toughness will result in fracture, regardless of the quality of the base metal. Therefore, it is highly recommended that the toughness for the weld metal and the HAZ be greater than that of the base metal. Additionally, if possible, this is best achieved without preheat or heat treatment after welding, which will result in a reduction of the cost of welding in the Arctic [116]. To address these issues, manufacturers, equipment suppliers, and engineering companies are trying to find the best alternatives to improve the toughness of welds and the HAZ at low temperatures.

The current trend focuses on the following aspects of welding:

- Formulating new weld consumables that are specifically designed for Arctic service
- Modifying a number of welding parameters for commercially available weld consumables that are known to have good toughness at low temperatures down to –4°F (–20°C) to assess their suitability and fracture toughness properties for use in Arctic environments
- Evaluating alternative welding techniques by changing the weld bead size, shape and placement, and joint geometry for a given set of welding parameters to achieve the optimum weld microstructure
- Identifying metallurgical controlling factors for toughness of multi-layered weld metal
- Developing guidance to the industry on consumable selection and the range of optimum welding parameters to ensure adequate weld toughness

Fabrication requirements (including welding) for such structures are demanding because of the low temperature environments associated with Arctic environments. Work is currently underway in Finland to build structures for Arctic applications in the Stockmann gas field project in the Barents Sea [63]. The steel used in the Stockmann gas field project is thermo-mechanically rolled F36 with a thickness of 0.78 to 2.36 inches

(20 to 60 mm). The Shipping Register's requirements for the F36 steel used in this project are [63]:

- Yield strength: 51.5 (ksi) 355 MPa
- Tensile strength: 71.1 to 89.9 ksi (490 to 620 MPa)
- Elongation: 21% minimum
- Charpy toughness (including welded joints):
  - Smaller than 2 inches (50 mm) need to be 24 J minimum (transverse) and 34 J minimum (longitudinal) at –76°F (–60°C)
  - Between 2 inches (50 mm) and 2.8 inches (70 mm) need to be 27 J minimum (transverse), 41 J minimum (longitudinal) at –76°F (–60°C)
- Fracture toughness requirements and Crack Tip Opening Displacement (CTOD):
  - CTOD of 1 mil or 0.001 inches (0.25 mm) minimum for structures exposed to wind and cyclic motion as well as seismic stresses
  - For Submerged Arc Welding (SAW), the filler metal can be CTOD tested at –50.8°F (–46°C) and –40°F (–40°C) for the two filler metals selected. However, CTOD testing is generally performed at 14°F (–10°C).

6.5 State-of-the-Art Welding Techniques

Several studies have been performed to identify efficient welding technologies for the construction of HSS in Arctic offshore structures. Some of the welding techniques that have been reviewed for Arctic applications include [3]:

- Multilayer-multipass-multiwire Narrow Gap (NG) Submerged Arc Welding (SAW) process (or Multi-SAW-NG).
- Dual-tandem NG pulsed-spray using the Metal Inert Gas (MIG) or Metal Active Gas (MAG) welding process.
- Laser-tandem using the MIG or MAG hybrid welding process.

Narrow Gap Welding (NGW) is covered in more detail in Section 6.5.1.

6.5.1 Narrow Gap Welding

NGW produces an arc weld in thick materials by means of a square-groove/I-groove or a v-groove (≤ 10°). The root pass in NGW is in the range of 19.7 to 393.7 mils (0.5 mm to 10 mm) between the different parts to be welded together. The effectiveness of NGW is ensured by employing a backing system or an U-groove design.

NGW offers the following advantages [61]:

- High productivity and reduction of cycle time
- Reduction in the consumption of welding consumables
- Reduced energy consumption
- Lower energy costs for preheating, resulting from shorter cycle times
- Reduced deformation/distortion resulting from lower heat input and reduced shrinkage

Some of the disadvantages of NGW that have been reported in the literature are [2]:

- Complex technology requiring enhanced Operator knowledge
- High cost and complexity associated with control equipment and welding heads
- More expensive filler metals
- Issues associated with magnetic arc blow when applied with Gas Metal Arc Welding (GMAW)
- Challenges associated with post-weld repair and inspection (including repairs using conventional welding techniques)
- High accuracy required with joint preparation to ensure consistent welds throughout the length of the joint
- Challenges associated with thick-walled components because of accessibility issues

It has also been reported that the mechanical properties of narrow gap joints are better than those achieved with conventional ‘V’ configurations. This could be a result of the progressive refinement of the weld bead by subsequent runs at the relatively low heat input. For thicker sections where post-weld inspection and repair may be required, there is a need for consistent weld performance and adequate in-process control and monitoring [109].

Additional considerations when employing NGW processes include [109]:

- Special joint configuration requirements
- Special welding heads and equipment
- Evaluation of modified consumables
- Arc length control and seam tracking requirements

Typical narrow gap joint configurations are illustrated in Figure 6.1.

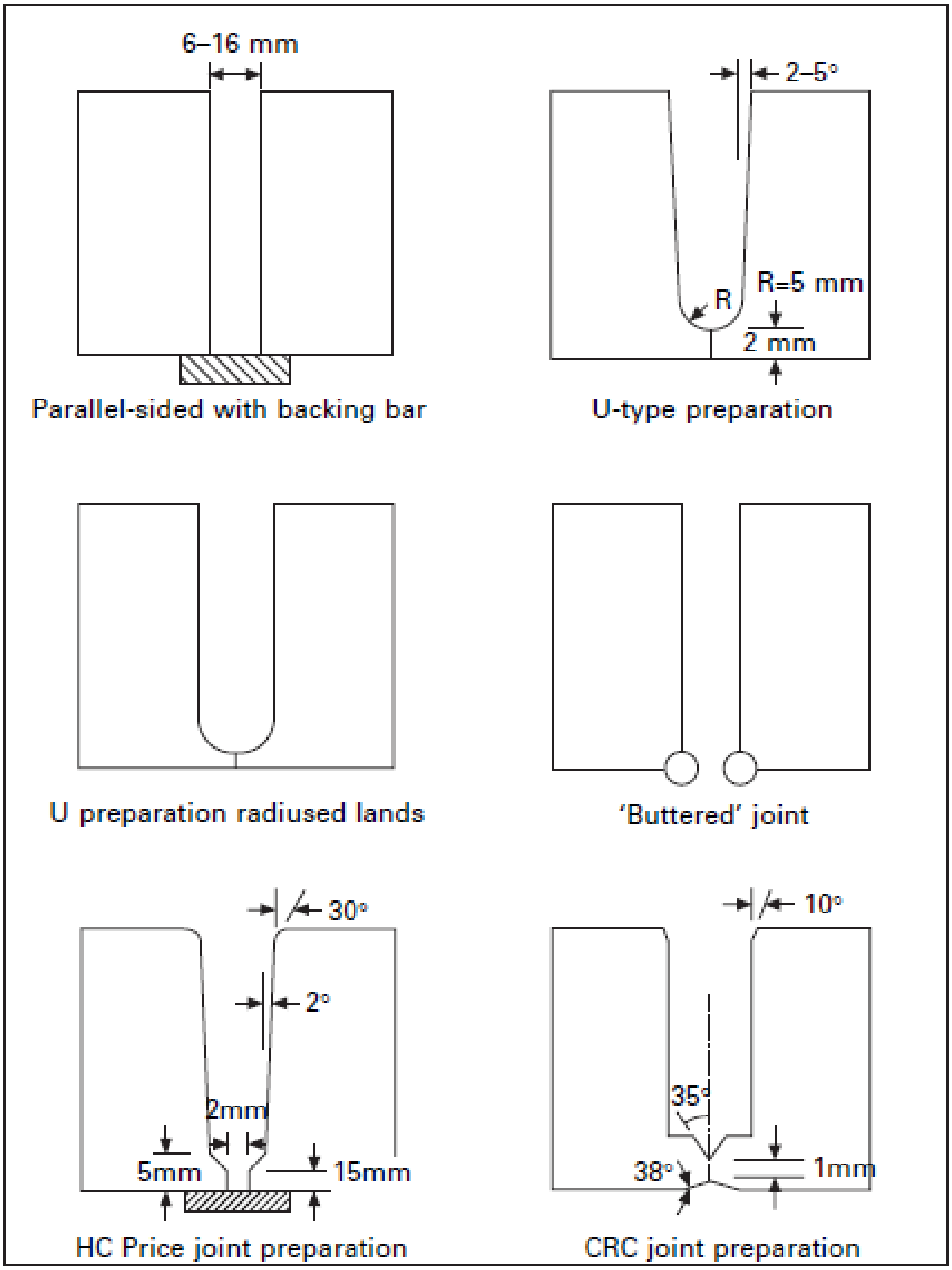

Figure 6.1: Typical Narrow Gap Joint Configurations [109]

Other common welding processes that are reported to be applicable for Arctic applications will be discussed briefly in the following sub-sections.

6.5.2 Narrow Gap Metal Submerged Arc Welding

Conventional SAW is a welding technique that involves the formation of an arc between a continuously fed bare wire electrode and the workpiece. The process uses a flux to generate protective gases and slag, and to add alloying elements to the weld pool. A shielding gas is not required for SAW. Multi-SAW-NG, which is a variation of the traditional SAW, makes use of multiple metal-cored filler wires (up to 6) in a single weld pool. More specifically, Multi-SAW-NG uses an NG welding technique and a deposition pattern resulting from multiple layers and multiple passes. This NG variation makes the SAW technique suitable for welding the high-strength steel offshore structures that are used in Arctic applications [3].

6.5.3 Narrow Gap Metal Inert Gas/Metal Active Gas Welding

Conventional MIG/MAG welding is a technique that is applicable for use for both thin and thick sections where an arc is struck between the end of a wire electrode and the workpiece. This results in melting both the wire and the workpiece to form a weld pool. The wire electrode serves as the heat source by means of the arc at the wire tip and as the filler metal at the joint. The weld pool is protected from the surrounding atmosphere by a shielding gas that is fed through a nozzle surrounding the wire electrode.

The dual-tandem NG pulsed-spray MIG/MAG welding technique, which is a variant of conventional MIG/MAG welding, uses four wire electrodes with a narrow gap groove design that works in a high-current pulsed-spray metal transfer mode. HSS used in Arctic welds require high quality weld joints with increased welding speed, which is achieved by using this technique. The presence of the dual-tandem torch helps increase the deposit rate and reduces metal weld volume [3].

Several studies have been performed to explore laser-tandem MIG/MAG hybrid welding for potential use with HSS in Arctic environments. The advantages of this technique include higher welding speeds, deeper penetration, better joint fit-up, enhanced tolerance, and better weld quality. However, the capital expenditure associated with this technique is high. Additionally, incorporating automation and precision alignment of the laser beam arc [3] is required.

6.5.4 Other Welding Considerations

A study supported by Total (a Global Energy Operator) to evaluate the challenges of welding in Arctic areas compared V-penetration welding to NG J-preparation mechanized welding.

The study revealed that the mechanized J-preparation welding had several advantages, including:

- Reduced volume of metal deposits.
- Increased welding speed.
- Reduced repair rates.
- Reduced welding lead time and costs.

Mechanized welding, which typically achieves very low repair rates, differs from conventional welding because of a decrease in the errors associated with human factors (such as welder performance) [127].

Mechanized welding requires [127]:

- Good dimensional tolerance and high quality base metal for the structural elements being welded.
- Welding procedure qualifications and control of essential welding variables.
- Control of key welding parameters such as heat inputs and thermal cycles in the base metal, weld metal, and HAZ.

Work published from the 2015 Arctic Technology Conference sheds some light on the construction of pipelines for cold conditions [44]. It has been reported that in anticipation of environmental loadings from permafrost thaw settlement, seabed ice gouging, strudel scour spanning, and upheaval buckling, pipeline design for Arctic environments would have to be strain-based for bending. With the use of strain-based designs, the allowable weld flaw size for bending strains could be smaller than those associated with a typical stress-based design. It is also expected that the Non-Destructive Examination (NDE) requirements may be equivalent to those considered for deep water steel catenary risers (SCRs) [44].

The development of detailed, component-specific procedures for on-ice construction activities is recommended. These detailed procedures should address potential differences in construction methods for differing ice conditions, welding requirements, trench depths, bundle sizes, as-built surveys, and other important variables. It is also important to allow sufficient time for the construction personnel to develop specific procedures (for example, for welding, NDE, qualification and testing, test trenches, bundle mock-ups, and pipeline heating) [44].

The qualification of welding equipment (such as welding consumables, hydraulic and pneumatic fluids, and batteries) in representative cold environments is vital to ensuring repeatable high quality welds for Arctic applications.

Preventive maintenance and integrity management (IM) are important aspects relating to drilling equipment and structures and are addressed in the following sub-sections.

6.6 Novel Design Methods for Arctic Applications

Reliability-based Design (RBD) has proved to be a suitable approach for designing structures for Arctic applications. In a traditional deterministic design, the design parameters include a safety factor, which is required to be greater than or equal to the minimum acceptable value. However, in an RBD, the approach is devised in such a way that the estimated reliability is greater than or equal to a target minimum reliability value.

A generalized method for RBD includes the following tasks:

1. Establish the optimum performance function for the structure and the equipment being designed.
2. Establish the required design variables and their associated target reliability levels.
3. Calculate the reliability for the structure and the equipment and compare it against the target reliability level.
4. Validate the design to determine the reliability of the final design using established probabilistic and statistical methods.

Based on refinement of the RBD models and lifecycle cost optimization, reliability targets could be potentially increased even further.

Taking into account all the uncertainties in the design process, parameters, and analysis models, RBD methods have been recommended for Arctic designs. In this approach, a characterization and probabilistic modeling is performed for all input parameters that are subject to significant uncertainty. The reliability analysis performed should be time dependent and should account for ground movement strains that vary with time. More specifically, in an RBD, the reliability and risk of the pipeline is evaluated, based on statistical simulation techniques (including statistical distributions for various design parameters). The overall reliability (the probability of reaching the design life) is estimated and is compared to the historical failure data (such as failure rates and acceptance criteria).

Reliability-based pipeline designs are not documented in the U.S. pipeline codes and standards [1]. However, this approach has already been used in the industry [48], and it has been reported that RBD is more accurate in predicting the structural behavior of the pipeline because it identifies true failure modes. This design approach also avoids unrealistic design criteria that leads to excessive conservatism. Because this method uses operational data, it is expected to integrate both design and operational considerations, which in turn simplifies in-service maintenance activities.

6.6.1 Reliability-based Fatigue Assessment

Fatigue loading is an important consideration when assessing the structural integrity of welded structures, platforms, and drilling equipment. Fatigue is governed by a number of parameters, including cyclic loading conditions, material properties, and local joint geometry. The two different approaches that can be used in fatigue life predictions are the S-N curve with the Miner's damage accumulation rule and the fracture mechanics approach (refer to Section 6.6.3).

6.6.2 Reliability-based S-N Fatigue Approach

Reliability-based methods for determining the fatigue life of ship structures have been performed based on the assumption that the Miner's rule was followed. The method is based on a structural reliability theory that can be applied to either RBD or in a Load and Resistance Factor Design (LRFD). In an RBD, selecting a target reliability level is important for setting the required guidelines for Arctic structures. This reliability level determines the probability of failure for the structure that is being designed.

There are several ways to establish the target reliability level. The most desired approach is based on values that have traditionally been accepted by the industry and can be found in industry codes and standards. Using the required data from a comprehensive reliability and failure database has also proven vital to achieving 'inherently reliable designs.'

In the case of structures that are being designed for Arctic oil and gas infrastructures, reliability-based S-N[4] fatigue is not a feasible approach because of the lack of:

- Sufficient reliability or failure data.
- Codes and standards applicable to this application.

Based on these challenges, it is important to develop a strong technical basis for the design parameters and the reliability limits selected for the novel structures being designed for Arctic environments [32]. During an RBD study, it is important to understand the uncertainties in the parameters that contribute to achieving adequate fatigue life of structures that are designed for Arctic environments. Some of the most common uncertainties are defined by the inherent scatter and the uncertainty in fatigue strength.

[4] S = Stress Amplitude; N = Cycles to Failure

Most uncertainties in fatigue strength are expected to arise from the following parameters [32]:

- Fabrication and assembly
- Metocean and sea conditions
- Wave loading
- Nominal loads from structural members
- Estimation of high stress concentration factor locations

In the case of designing structures for drilling and oil and gas operations in the Arctic region, temperature fluctuations should be considered an important factor in the RBD process. Ayyub et al. provide a sample of direct RBD and an LRFD approach [32].

At the March 2014 International Association of Oil and Gas Producers workshop (Reliability of Offshore Structures—Current Design and Potential Inconsistencies), one of the workshops, which focused on Arctic structures, addressed the following topics [73]:

- Safety and Ice Design Criteria in the ISO 19906: 2010 Standard for Arctic Offshore Structures [73]
- Barents 2020 Study—Floating Structures in Ice [73]

As part of this workshop, the presenter emphasized that site-specific data is needed to make informed decisions and reliability estimates in the Arctic. Additionally, the presenter noted that a long history of onshore and near-shore ice measurements for the Arctic region could be correlated to offshore ice and iceberg size measurements by observing associated glaciers. Arctic structures are far more sensitive to variations in ice size than they are to frequency of occurrence. One of the major impacts of ice is that it induces structural vibrations that could affect deck elevation with ice run-up. Flare profiles at the water line have been found to be effective in reducing ice-induced vibrations [73].

Based on a survey of literature for industry needs, the following areas have also been identified in terms of opportunities and challenges for technology [137]:

- Reliability-based prevention for mechanical damage
- RBD for mechanical damage
- Reliability-based planning of inspection and maintenance
- Development of RBD assessment guidelines

6.6.3 Reliability-based Fracture Mechanics Approach

The qualification of structural steel and welding procedures for low temperature applications requires fracture toughness testing in the form of CTOD, as opposed to CVN testing only. A lack of fracture mechanics design criteria that addresses toughness requirements for steel structures at low temperatures has been encountered in Arctic environments. Current design codes and standards do not generally give guidance for service temperatures below 6.8°F (–14°C), except for emphasizing the need for adequate toughness at the minimum service temperature [109]. One way to develop design toughness criteria is using the Engineering Critical Assessment (ECA) approach.

Fracture mechanics-based ECA is a procedure that is normally used to define the significance of imperfections and flaw sizes in welds at fatigue-sensitive locations based on toughness values and stress conditions. For example, ECA is widely used to determine flaw acceptance criteria for girth welds to be used during the fabrication of risers and flowlines. The approach can be used to determine characteristic toughness values for Arctic structure welds if stress and flaw acceptance criteria are known.

The reliability-based fracture mechanics approach, which assumes that weld imperfections behave like planar flaws, uses the concept of a Failure Assessment Diagram (FAD) that is outlined in British Standard (BS) 7910 [36]. The FAD assesses the tendency of growing fatigue cracks leading to component failure because of fracture and plastic collapse when the crack reaches a critical size. Fatigue crack growth is assessed based on the empirical Paris-Erdogan relationship between the crack growth rate and the elastic stress intensity range, which is the fatigue crack driving force. The stress intensity range is a linear elastic fracture mechanics parameter that is calculated based on cyclic stress, flaw size, and geometry.

It has been proposed that a reliability-based or a probabilistic fracture mechanics-based approach can be used to support the integrity management of drilling structures and platforms subject to uncertain variable amplitude loading in Arctic environments [50]. This numerical simulation method is used with the statistically defined defect size in the weld under consideration, and structural geometry and material property data in conjunction with load definitions that are also developed using statistical methods to allow estimating the probability of failure.

As part of such an assessment, it is important to understand the variations and sensitivities associated with the various parameters that are relevant to the design of drilling equipment and structures in the Arctic region, including:

- Low temperature material properties.
- Fracture toughness properties (such as CTOD) at the service temperature.

- Loading from marine environments representative of the Arctic region (probabilistic representation of wave, ice, and wind loadings) [50].
- Continuous updating of loading parameters because of the changes in drilling and operating parameters in extreme environments, which entails continuous updating of assumed loads based on condition assessments (environment and structural parameters) [50].

Statistical treatment of fracture toughness data is recommended for qualification and integrity assessments of welds. Acceptance criteria for fracture toughness data for Arctic conditions are not specified in design standards. To ensure robust designs, requirements to perform testing to obtain consistent and statistically significant results are necessary. A reliability-based calibration is recommended to ensure that adequate safety margins are incorporated into the ECA and design [68]. To obtain a reasonable confidence in the estimation, the statistical distribution used in the analysis should be selected, based on the size of the data set.

One of the main challenges to the reliability-based fracture mechanics approach is the uncertainty related to quantifying crack initiation in the initial stages of crack growth from the weld imperfection. Current industry efforts are focusing on the probabilistic fracture mechanical approach, which is based on the S-N curves [62]. These probabilistic methods are useful in cases where fracture mechanics-based concepts are used to customize the integrity management of structures and inspection planning. This method can be used in the Arctic region to achieve robust, long-term structural integrity.

6.7 Cathodic Protection in Arctic Conditions

Cathodic Protection (CP) of onshore pipelines and structures under Arctic conditions is achievable. The extremely cold temperatures typically freeze the soil in the cold months, which in turn increases soil resistivity. The cold temperatures also affect the resistivity of steel, reducing the voltage drop along the pipeline, and in turn allowing the CP current to distribute for longer distances along the pipeline. CP of subsea structures can be accomplished with the use of cold water alloy Aluminium-Zinc-Indium anodes, as these anodes are normally located below the ice.

6.7.1 Frozen Ground

In the case of onshore pipelines, the ground is expected to freeze and thaw resulting from normal weather and environmental conditions. The formation of a thaw bulb[5] could potentially occur as a result of heat transfer from the contents of the pipeline when the soil around the pipe freezes. The formation of the thaw bulb and the freeze and thaw cycles could potentially exert extreme soil stresses on the pipe coating.

The pipeline may also be subjected to extreme forces associated with frost heaves. If suitable areas of unfrozen ground are not accessible, a continuous sacrificial anode system may be required to supplement a conventional or deep well-type anode groundbed. The frozen ground may also act as an electrical shield if the pipeline is located in areas of frozen or wet soil. Ice formation may indicate reduced electro-chemical activity, while melting implies reactivation or an increase in the electro-chemical activity (increase in the corrosion around the defects on the pipeline). The design of the CP system for Arctic environments should take into account the different modes of degradation of the pipeline coating and the problems caused by freezing of the structures and equipment. It is important to note that the corrosion rate of steel decreases as the temperature decreases.

6.7.2 Soil Resistivity

Soil resistivity increases dramatically when temperatures drop to below freezing (refer to Figure 6.2). This is a concern for onshore structures where the soil can freeze down to the depth of the buried pipeline. This increase in soil resistivity may reduce or shield the amount of CP current that can reach the pipe. There is also evidence that in frozen soil, corrosion activity is dramatically reduced.

Field data from the Alaska North Slope indicates that typical frozen soil at –6°F (–21.1°C) has a resistivity in excess of 4,000 ohm-cm and a corrosion rate of 0.04 MPY to 0.44 MPY[6] (1.0 micrometres per year to 11.2 micrometres per year). The same soil at room temperature (about 70°F [21.1°C]) has a resistivity of 150 ohm-cm and a corrosion rate of 0.7 to 2.9 MPY (17.78 micrometres per year to 73.7 micrometres per year). The resistivity measurements may be lower than typical because of the soil's high chloride ion content resulting from its close proximity to the Arctic Ocean. Higher soil resistivity is also a factor in designing the anode groundbed for the CP system.

[5] In permafrost, an area of thawed ground below a building, pipeline, river, or other heat source.
[6] MPY = milli-inch per year (this is equal to 0.0254 mm per year or 25.4 micrometres per year).

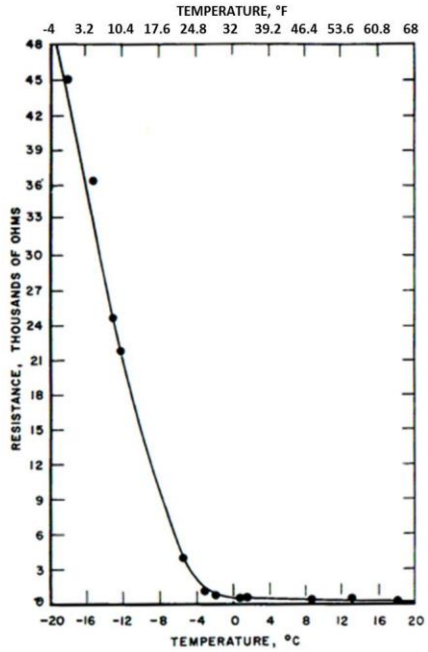

Figure 6.2: Typical Variation of Soil Resistivity with Temperature

6.7.3 Coatings

Higher integrity coatings should be considered for Arctic applications because of the possible soil stresses and environment temperatures. A three-layer FBE/PP[7] for the line pipe and a three-layer FBE/PP or FBP[8] with a PE[9] shrink sleeve for the field joints appear to be the industry-preferred coating systems.

The use of Thermal Spray Aluminium (TSA) coatings for offshore structures should be further evaluated for these environmental conditions. The use of High Performance Composite Coatings (HPCC) is showing excellent performance in Arctic conditions and permafrost terrain. These new technologies should be further evaluated.

6.7.4 Current Density

For the CP design of structures, the Current Density (CD) requirements are closely related to the hydrogen evolution and the oxygen content of the environment at the surface of the structure. At colder temperatures, the dissolved oxygen (DO) content in the water increases, but for frozen soil and ice, little data is available. There are

[7] Three-layer FBE/PP is a three-layer coating system that consists of a Fusion Bonded Epoxy (FBE), followed by a copolymer adhesive and an outer layer of Polypropylene (PP).
[8] FBP is a Fusion Bonded Polyester Coating.
[9] PE can be a Polyethylene coating or sleeve.

guidelines [55] that recommend suitable CDs for steel in sea water and sediments at low temperatures, but there are no guidelines for frozen soil.

6.7.5 Anodes

The two types of anodes that are typically used in oil and gas production are sacrificial anodes and impressed current.

Sacrificial Anodes

Aluminium anodes are used offshore and have been evaluated at low temperatures. They are not expected to be used in environments colder than 35.6°F (2°C). Current cold water anode chemistries should be sufficient.

Zinc and magnesium anodes may be used in below freezing temperatures. The electro-chemical properties and reliability of these anode materials should be evaluated at the target temperature or at –76°F (–60°C).

Impressed Current

Most conventional impressed current anodes should be suitable for use in Arctic conditions. These anodes are not dependent on the driving voltage between the anode and the cathode. The soil resistivity (as explained in Section 6.7.2) is the influencing variable. The properties and reliability of these systems should be evaluated at the target temperature or at –76°F (–60°C).

6.7.6 Microbial Induced Corrosion

Microbial Induced Corrosion (MIC) activity is temperature dependent. The common bacteria typically found in oil and gas infrastructures cannot live at temperatures below 50°F (10°C). Depending on the temperature and the environment, a thorough evaluation should be made to decide whether the structures will be at risk from MIC for short periods of time.

6.7.7 Telluric Earth Currents

Telluric earth current effects on pipelines are most prevalent in the higher latitudes, but significant telluric activity has been documented in pipelines at latitudes as low as 35°. Although the corrosion impact per year is small, over time, it could produce significant corrosion problems. Most telluric currents are produced by geomagnetic disturbances, although tidally-influenced effects have also been documented.

Telluric earth currents may not pose an immediate corrosion effect. They do, however, present a serious safety problem, as high voltage spikes on underground structures have been documented to cause personal injury and equipment damage. These effects can be minimized by using proper design. The effect on structures other than pipelines is normally negligible.

6.7.8 Integrity Management of Arctic Structures

The challenges associated with materials, design, and fabrication have been highlighted in the previous sections of this report. Materials selection, equipment design, and equipment fabrication need to follow a robust IM program to ensure long-term operation. A critical aspect of achieving a good IM program is establishing good monitoring and inspection programs and ensuring that sufficient mitigation systems are in place. When designing equipment and structures, accessibility for inspection should be a major consideration. Components must be designed in such a way that they can be readily inspected.

With regard to offshore drilling systems and structures in the Arctic for oil and gas exploration, the following monitoring systems have been proposed [134, 127]:

- Absolute and relative inelastic structural displacements
- Load variations within the structure (external and between components adjacent to each other)
- Variations in elastic and inelastic strains in the structure
- Measurement of dynamic responses in the structure
- Geotechnical systems, including piezometric, total pressure, and permafrost effects
- Aerial surveys
- Fiber optic temperature integrity and seabed erosion monitoring
- Internal corrosion coupon monitoring (for pipelines)
- Corrosion sensors, corrosion coupons, and monitoring devices
- Annual bathymetry, strudel scour, and ice gouge surveys

To ensure a good IM plan (while drilling in an Arctic environment) and to ensure good reliability of equipment and structures, include the following monitoring activities [134]:

- Monitoring the instantaneous response to dynamic loading of floating structures and vessels. Monitoring this parameter is important for drilling rigs, semi-submersibles, icebreakers, and other equipment.
- Monitoring instantaneous and long-term response of the structural components to static and dynamic loading caused by natural causes such as ice, wind, seismic, and wave loading. Monitoring this parameter is important for the design of gravity-based structures, tension leg platforms, moored structures, jack-ups, and other equipment.

The implementation of a robust IM and monitoring program results in the following benefits:

- Acquisition of reliable data regarding the behavior of the structure to help make safe operational decisions
- Historical and current reliability data on the structures, which helps engineers and Drilling Contractors evaluate existing design criteria and optimize them for future drilling and operations based on robust structural reliability data
- Periodic review of integrity monitoring data, which helps prioritize, decrease, or increase risks, as needed. This review helps with defining an inspection and monitoring program.
- The program helps the Bureau of Safety and Environmental Enforcement (BSEE) establish regulations and operational guidelines associated with drilling and exploration operations in the Arctic, which is the most important benefit.

It is important to note that equipment selected for monitoring and IM systems in the Arctic region would be required to meet performance specifications. The equipment deployed in Arctic environments would be required to fulfil the following requirements:

- Resist low temperature exposure of –76°F (–60°C).
- Resist marine environments (salt water) usually present in the summer.
- Require infrequent maintenance.
- Be exposed to high voltages, currents, and radio frequency/microwaves.
- Operate in mechanically hostile environments (ice/wave loading).
- Function in different operating environments between summer and winter.
- Be able to resist intermittent supply of electrical services and supply voltage.

While monitoring the previously listed requirements, it is important to manage the integrity of the equipment and structures used in the Arctic regions. Periodic inspections also need to be performed to ensure that there is no degradation of structures. The most essential inspections to be performed include:

- General and close visual inspections of structural elements and equipment that are exposed to extreme environments and loading conditions.
- General and close visual inspections of subsea structures using ROVs.
- CP surveys (depletion surveys and voltage measurements).

6.8 Lessons Learned in the Oil and Gas Industry Applicable to Specific Materials

While evaluating the materials property requirements for cold environments, the industry has applied the lessons learned from the codes and standards that are currently available. More work is needed to get better direction regarding the materials that could potentially exhibit the required fracture toughness and metallurgical properties that will allow them to operate safely in Arctic environments.

As discussed in Section 4.2, the industry is in the process of developing the required material standards (such as ISO standards) to be used while drilling in Arctic environments. A review of the requirements for most commonly used materials considered for use in Arctic environments (particularly a database of toughness properties and their respective test temperature requirements) is needed.

A recent evaluation of European and Russian materials that exhibit adequate toughness at low temperatures included carbon steels, stainless steels, and aluminium alloys [101].

The most commonly used metallic materials are carbon steels and other CRAs such as duplex stainless steels (DSS). Carbon steels have the advantage that they have a good strength to weight ratio. CRAs such as DSS possess good corrosion resistance and excellent strength, which makes them good candidate materials for offshore/subsea applications. Summaries of the properties of carbon steels, stainless steels, and duplex stainless steels are included in the following sub-sections.

6.8.1 Carbon Steels

High strength carbon steels possess several desirable properties for Arctic offshore structures, including weldability, low strength-to-weight ratio, and cost benefits. Carbon steels are available in various strength ranges. Steels with yield strengths (YS) < 450 MPa (65,266 psi) have good weldability, while some steels with YS > 600 MPa (87,022 psi) also have good weldability.

Literature reports have revealed that more research is required to evaluate the weldability of materials that will be used in Arctic offshore applications. Current standards do not include steels with YS > 500 MPa (72,518 psi) for offshore applications [101]. A study published in the open literature identifies the major European and Russian steels that are currently being used in Arctic environments with specific Charpy impact properties at different temperatures [101].

Det Norske Veritas (DNV) standards such as DNV-OS-C101 [52] and DNV-OS-B101 [51] also provide guidance on Charpy test temperatures. DNV-OS-C101 provides Charpy test requirements for general offshore steel structures. Structures that are above the lowest astronomical tide (LAT) are required to be designed with service temperatures that do not exceed the design temperatures. The Charpy test temperatures for various groups of carbon steels (Groups A, B, D, E and F) are provided in DNV-OS-B101 (refer to Table 6.1). Additionally, DNV OS-B101 provides mechanical property requirements for ferritic castings.

Table 6.1: Definition of Steel Grades According to DNV-OS-B101 [51]

Strength Group	Impact Testing				Symbol y	Min. Yield Stress (N/mm^2)
	Symbol x		Test Temperature (°C)	Test Temperature (°F)		
	Normal Weldability	Improved Weldability				
NS	A	-	_	-	Omitted	235
	B	BW	0	32		
	D	DW	-20	-4		
	E	EW	-40	-40		
HS	A	AW	0	32	27	265
	D	DW	-20	-4	32	315
	E	EW	-40	-40	36	355
	F	-	-60	-76	40	390
EHS	A	-	0	32	420	420
	D	DW	-20	-4	460	460
	E	EW	-40	-40	500	500
	F	-	-60	-76	550	550
					620	620
					690	690

x = designation of a steel according to the DNV offshore standards
W = letter included to designate a steel grade for improved weldability
y = a figure designating the strength group according to the specified YS (omitted for NS steels).

6.8.2 Stainless Steels

Stainless steels are well suited for low temperature operations in the Arctic environments. They have good corrosion resistance, even when they operate at lower temperatures. The mechanical properties and toughness of stainless steels vary significantly, depending on the type of steel. Because of the lack of standards in Europe to determine the use of stainless steels for offshore structural purposes, they are not commonly used in offshore construction. However, stainless steels are widely used for pipeline applications in the Arctic as well as other applications such as cargo tanks, storage tanks, shafts, and pressure vessels [101].

Based on the requirements in the standards for stainless steels, they only need to be tested if the service/operating temperature is below –157°F (–105°C), as specified by the following standards:

- Bureau Veritas, "Rules on Materials and Welding for the Classification of Marine Units" (pages 58–59 and 124–127) [42]

- Germanischer Lloyd Aktiengesellschaft, “Rules for Classification and Construction – Metallic Materials” (pages 1–10 and 102) [65]
- International Association of Classification Societies, “Requirements Concerning Materials and Welding” (pages 199–200) [72]
- Lloyd’s Register, “Rules and Regulations for the Classification of Floating Offshore Installation at a Fixed Location” (pages 119 and 187–188) [103]
- Polski Rejestr Statkow, “Rules for the Classification and Construction of Sea-going Ships—Part IX—Materials and Welding, 3rd Ed.” (Pages 95, 168–171) [112]
- Registro Italiano Navale, “Rules for the Classification of Ships, Part D—Materials and Welding” (Pages 60, 124–130) [113]

BS EN 10216-5:2013 [37] provides mechanical property requirements for stainless steel tubes for pressure purposes. The impact energy requirements are:

- Austenitic corrosion resistant steels in the solution annealed condition must exhibit 100J at room temperature in the longitudinal direction and 60J at both room temperature and –320.8°F (–196°C) in the transverse direction (refer to Table 6 of BS EN 10216-5:2013 [37]).
- Austenitic and ferritic steels in the solution annealed condition are required to exhibit a minimum of 40J at –40°F (–40°C) in the transverse direction (refer to Table 8 of BS EN 10216-5:2013).

6.8.3 Duplex Stainless Steels

Duplex stainless steels (DSS) have also been used in low temperature applications. Because of the presence of ferrite, DSS always have a transition temperature between room temperature and –58°F (–50°C). Some grades of DSS have been standardized for offshore structures use and are listed in Table 11 of BS EN 10088-4:2009. The DSS are required to maintain 40J at –40°F (–40°C).

7.0 Non-metallic Materials Used in Arctic Environment

7.1 Introduction

Innovative polymeric materials and composites (including fiber-reinforced polymers) have been introduced as replacements for the metallic components used in aggressive environments where the use of metallic components is prohibited. Many of these new reinforced polymers and composites have properties that are very similar to their metallic counterparts, with the additional benefit of being lighter than or 'immune' to metallic corrosion (although some may undergo other types of aging).

The oil and gas industry (including packers for sour services) has also subjected elastomers used as seals to some scrutiny. New materials are being developed to satisfy the need for longer life expectancy in harsh applications (normally at higher temperatures and in the presence of corrosive chemicals). These materials have been tested for use in very aggressive environments. However, there is a limited amount of data regarding the polymers and composites used in cold or Arctic environments, mainly because of the belief that polymers and composites will not undergo the mechanical failure that metallic materials undergo.

The purpose of this sub-section is to consider the commonly used elastomers, polymers (thermoplastics), and composites in oil and gas drilling operations, both for onshore and offshore applications, and to review their suitability at the low temperatures in Arctic environments.

7.2 Elastomers

7.2.1 Background

An elastomer is a polymer that is soft, elastic, and nearly incompressible; therefore, its volume changes very little when it is exposed to higher pressures. In the past, the term 'rubber' was used to describe materials that were extracted naturally from plants. On the other hand, the term 'elastomer' was used for materials that were produced synthetically. An elastomer is a polymer that shows elastic properties. Because the terms 'rubber-like' and 'elastomeric' mean almost the same thing, the terms 'rubber' and 'elastomer' are often used interchangeably to describe most elastomers.

The most characteristic property of elastomers is their high elasticity. Because of their unique structure, they can be deformed under relatively low stresses and recover quickly, without permanent damage, after the stress is removed. Elastomers consist of polymeric chains that are arranged in a cross-linked, amorphous network where interactions between the chains are weak.

The unique properties of elastomers are realized at near ambient temperature. When the temperature of an elastomer progressively decreases below ambient temperature, the stiffness increases and the elastomer gradually becomes brittle [89]. Because there are no chemical alterations, these transformations are totally reversible, and the elastomer recovers its original properties when the temperature is increased [82]. When an elastomer is cooled, it can crystallize (referred to as the first order transition) or go through a glass transition or Tg (referred to as the second order transition). Both processes lead to an increase of hardness and a decrease in elasticity [99].

Some rubber types (such as natural rubber [NR] and most siloxanes) are capable of crystallization, while other rubber types (such as Acrylonitrile-butadiene rubber [NBR] and Ethylene Propylene Diene Terpolymer [EPDM]) are not capable of crystallization.

The transition of a substance from the rubber-like state into the solid (but not crystalline) state is called glass transition, and it is characteristic of polymers and many low molecular mass substances. A glass transition can be observed in substances with low crystallization rates or in those that do not crystallize at all. Because many elastomers crystallize slowly or not at all, the glass transition is usually the major process that determines low temperature resistance. The change in mechanical properties as a function of temperature is shown in Figure 7.1 [49].

In the rubbery plateau region, the elastomer is elastic and flexible, as illustrated by a low elastic modulus. When the temperature is low enough, a sudden increase in elastic modulus occurs in the glass transition area, ultimately reaching the glassy state. Elastomers for engineering material purposes are generally required to be at an operating temperature where the elastomer is in the rubbery plateau region (above the Tg).

The Tg, which is not an absolute value, is dependent on the test conditions and test methods. It is a good indicator for the lowest service temperature of a given elastomer. If the Tg is lower than the lowest service temperature, the elastomer is likely to remain serviceable.

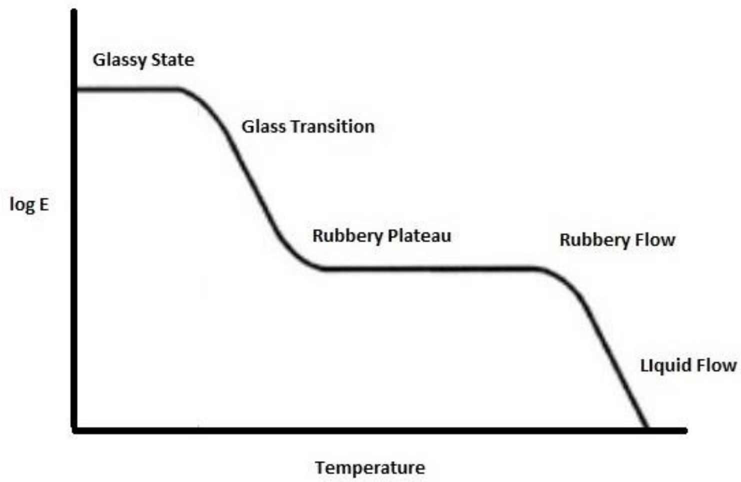

Figure 7.1: Relationship of Elastic Modulus (Log E) and Temperature [49]

The oil and gas industry will benefit from elastomers that can stand Arctic environmental conditions (for applications such as seals, packers, flexible joints, thermal insulation, and cable sheathings). The most desired property of the elastomer is its flexibility at very low temperatures, or below –40°F (–40°C).

In addition, some of these elastomers must have good resistance in the presence of the chemicals that are typically used in the oil and gas industry. In the case of thermal insulation, they must have some flame-retardant properties, even at low temperatures.

The elastomer properties can be selected, as required, for each application. They can be selected based on their mechanical properties, resistance to high or low temperatures, ability to remain intact under pressure, and compatibility with a large range of fluids such as oilfield chemicals, lubricants, oils, and acids.

7.2.2 Elastomers Commonly Used in the Oil and Gas Industry

A list of the most common elastomers that are currently in use in the oil and gas industry is presented in Table 7.1 [89] [82] [99].

Table 7.1: Most Common Elastomers Currently in Use in the Oil and Gas Industry

Abbreviation	Chemical Name	Common Name
ACM	Copolymer of ethylacrylate (or other acrylates) and a small amount of a monomer which facilitates vulcanization.	Acrylic
AU	Polyester urethane rubber	Polyurethane
BIIR	Bromo-isobutene-isoprene rubber	Bromobutyl
BR	Butadiene rubber	Polybutadiene
CIIR	Chloro-isobutene-isoprene rubber	Chlorobutyl
CM	Chloropolyethylene	Chlorinated polyethylene
CO, ECO	Polychloromethyloxiran and copolymer	Epichlorohydrin
CR	Chloroprene rubber	Neoprene
CSM	Chlorosulfonylpolyethylene	Chlorosulfonated polyethylene
EPDM	Ethylene Propylene Diene Terpolymer, propylene and a diene with the residual unsaturated portion of the diene in the	EPDM
EPM	Ethylene-propylene copolymer	EPM, EPR
EU	Polyether urethane rubber	Polyurethane
FEPM	Tetrafluoroethylene/propylene dipolymers	Tetrafluoroethylene
FFKM	Perfluoroelastomer	Perfluoroelastomer
FKM	Fluoroelastomer. Rubber having fluoro, perfluoroalkyl or perfluoroalkoxy substituent groups on the polymer chain	Fluorocarbon
FMQ	Silicone rubber having both methyl and fluorine substituent groups on the polymer chain.	N/A
HNBR	Hydrogenated Nitrile Butadiene Rubber (with some	Hydrogenated nitrile
IIR	Isobutene-isoprene rubber	Butyl
IR	Isoprene rubber, synthetic	Polyisoprene
MQ	Silicone rubber having only methyl substituent groups on the polymer chain, such as dimethyl polysiloxane	N/A
NBR	Acrylonitrile Butadiene Rubber	Nitrile
NBR/PVC	Blend of acrylonitrile-butadiene rubber and poly(vinyl chloride)	Nitrile/PVC
NR	Isoprene rubber, natural	Natural rubber
PMQ	Silicone rubber having both methyl and phenyl substituent groups on the polymer chain	N/A
PVMQ	Silicone rubber having methyl, phenyl and vinyl substituent groups on the polymer chain	N/A
Q	Silicone rubber	Silicone
SBR	Styrene-butadiene rubber	SBR
VMQ	Silicone rubber having both methyl and vinyl substituent groups on the polymer chain	N/A
XNBR	Carboxylic-acrylonitrile-butadiene rubber	Carboxylated rubber

The most commonly used elastomers for downhole applications are:

- Acrylonitrile (or Nitrile) Butadiene Rubber (NBR)
- Hydrogenated Nitrile Butadiene Rubber (HNBR)
- Fluoroelastomer (FKM)
- Tetrafluoroethylene (FEPM)
- Perfluoroelastomer (FFKM)

These elastomers and their current applications in drilling are discussed in the following sub-sections.

7.2.2.1 Acrylonitrile (or Nitrile) Butadiene Rubber

NBR is the most common elastomer used in drilling operations. Oilfield service companies have successfully used NBR for inflatable packer applications. NBR is also used as the elastomeric element in flexible joints. NBR is a synthetic rubber of copolymerized acrylonitrile and butadiene [33]. Increasing the acrylonitrile content increases the tensile strength and oil and heat resistance of an elastomer. On the other hand, low temperature flexibility, resilience, and H_2S resistance decrease with increased acrylonitrile content in these materials.

Nitriles may be used at low temperatures up to –20°F (–28.8°C), with some grades suitable for use as low as 58°F (–50°C), such as James Walker's NL56 [130]. Furthermore, nitriles are not generally suitable for service in solvents with high aromatic content, halogenated hydrocarbons, acetic acids, or organic and phosphate esters.

H_2S causes embrittlement in nitriles, primarily by attacking the acrylonitrile group.

7.2.2.2 Hydrogenated Nitrile Butadiene Rubber

HNBR materials may be used at temperatures typically as low as –20°F (–28.8°C), with some grades suitable at –67°F (–55°C), such as the James Walker Elast-O-Lion 900 series [130]. These materials are widely used downhole because they combine good mechanical properties with simple processing and have temperature capabilities that are higher than the conventional nitriles. HNBR has also been used successfully for inflatable packers.

HNBRs typically contain between 34% and 49% acrylonitrile, which strongly affects the physical and chemical properties. HNBR is known to have better H_2S resistance than conventional NBR [130].

7.2.2.3 Fluoroelastomers

FKM is a fluoroelastomer that was originally developed by DuPont (with the name of Viton). Daikin Chemical (Dai-El), 3M (Dyneon Fluoroelastomers), Solvay Specialty Polymers (Tecnoflon), and HaloPolymer (Elaftor) also produce FKMs. FKMs are more expensive than neoprene or nitrile rubber elastomers. They are often used where nitriles and ethylene propylene diene monomers (EDPMs) have failed to provide adequate sealing performance [58]. They provide higher heat and chemical resistance compared to NBR and HNBR.

The two basic types of FKM are copolymers and terpolymers. In addition to these two basic types, there are a number of specialized grades that are designed to improve properties such as chemical resistance and low temperature properties.

One of the available low temperature grades of FKM is FR25, which can operate at –42°F (–41.1°C) before the onset of stiffening. All FKMs are based on vinylidene fluoride monomer compounded with other monomers. Chemical resistance is generally improved by increasing the fluorine content, which also tends to affect their mechanical properties.

FKM fluoroelastomers tend to have excellent chemical resistance, but they have poor resistance to amine-based corrosion inhibitors.

7.2.2.4 Tetrafluoroethylene/Propylene Dipolymers

Tetrafluoroethylene/Propylene Dipolymer (FEPM) is usually recognized by the trade name of Aflas. FEPMs contain base polymers that differ in viscosity and molecular weight. FEPM seals are generally used with back-up seals because of their poor extrusion resistance. FEPM seals do not perform well in ambient temperatures, particularly when they are used as O-rings. The lowest operating temperature for Aflas used as seals is 89.6°F (32°C), as specified by the manufacturer [22].

FEPM is not as resistant to hydrocarbons as FKM. Testing of FEPM, following the ISO 1817:2007 standard [83] has resulted in a 10% to 20% swelling (compared to 1% to 5% swelling observed in FKMs and 10% to 35% swelling observed in nitriles). FEPM temperature and H_2S resistance is similar to that of FKM.

FEPM has good resistance to inorganic acids and poor resistance to organic acids.

7.2.2.5 Perfluoroelastomers

FFKM, which is a copolymer of tetrafluoroethylene and perfluoromethylvinyl ether, is also known as Kalrez & Chemraz. These elastomers have excellent chemical resistance and similar elastic properties to FKM materials. They are resistant to most oilfield chemicals and have excellent weathering resistance.

FFKM can withstand high levels of H_2S, but their low temperature sealing properties are very poor, making them unsuitable for use as seals in Arctic conditions.

7.2.3 Elastomers Used as Components in Drilling Applications

This sub-section presents options for elastomers used as components in drilling applications at low temperatures such as those found in the Arctic. Potential options and qualification/testing requirements for commonly used elastomers are discussed.

7.2.3.1 Topsides Seals

Historically, Nitrile Butadiene Rubber (NBR) and Hydrogenated Nitrile Rubber (HNBR) have been suitable for use only at temperatures as low as –4°F (–20°C) to –22°F (–30°C). New grades of NBR and HNBR rubbers are continuously in development and NBR and HNBR rubbers with operating temperatures as low as –58°F (–50°C) and –67°F (–55°C) are available. A number of silicone rubbers can be used at temperatures as low as –76°F (–60°C) with special grades as low as –112°F (–80°C).

Silicone rubbers are not resistant to hydrocarbons and therefore cannot be used in most drilling applications.

DNV OS E101 [54] states that elastomeric sealing materials used in critical components should be tested to ensure that they are compatible with all the fluids that they will be exposed to during service. It also states that the elastomers used must be suitable for the intended service and must be capable of sustaining the specified operating pressure and temperature of the particular unit or fluid.

Table 7.2 presents elastomers that are currently being used for drilling applications and may be suitable for use as seals in Arctic drilling applications.

Table 7.2: Elastomers Suitable for Use as Topsides Seals at Arctic and near Arctic Temperatures

Elastomer Type	Operating Temperature (°C)	Properties
Viton® GLT-200S (FKM), Dupont	–9°F (–22.8°C) [1, 2]	Compression set resistance. Fluid resistance similar to Viton® GLT-600S
Viton® GLT-600S (FKM), Dupont	–9°F (–22.8°C) [1, 2]	Compression set resistance. Water resistance and low volume swell in water.
Elast-O-Lion 101 (HNBR), James Walker	–20°F (–29°C) to 320°F (160°C)	Norsok M-710 qualified for RGD resistance and sour gas aging. Chemical and abrasion resistance.
Kalrez 0090 (perfluoroelastomer), Dupont	–40 °F (–40°C) to 482 °F (250 °C)	Good extrusion resistance. Excellent and wide ranging chemical resistance.
FR25/90 (FKM), James Walker	–42°F (–41°C) to 392°F (200°C)	Norsok M-710 qualified for RGD resistance and sour gas aging. ED resistance.
Kalrez 0040 (perfluoroelastomer), Dupont	–43.6°F (–42°C) to 428°F (220°C)	Hydrocarbon and chemical resistance.
NL56/70 (NBR), James Walker	–58°F (–50°C) to 230°F (110°C)	Resistance to mineral oils and water/glycol based hydraulic fluids.
Elast-O-Lion 985 (HNBR), James Walker	–67°F (–55°C) to 302°F (150°C)	Good RGD resistance at low temperatures. Excellent fuel/oil and chemical resistance for oilfield duties.

Notes

[1] This is 10°C above the glass transition temperature (Tg), which is a commonly used to determine the operating temperature of elastomers.

[2] Maximum operating temperature not made available

[3] The operating temperatures in Table 7.2 are for guidance; all materials should be qualified for use.

The requirements of DNV OS E101 for seals carrying hydrocarbon fluids can be met by BS 682 [39]. BS 682 gives property requirements for the tests in Table 7.3, which can be followed to qualify elastomer seals at low temperatures. These requirements are dependent on the hardness of the rubber being tested, from 46 to 95 IRHD.

There is a gap in the current industry testing conventions for use of seals in hydrocarbon service at Arctic temperatures. BS 682 [39] provides guidance for rubbers used at 5°F (–15°C) and above due to the compression set testing requirements. For temperature requirements below 5°F (–15°C), the Materials Supplier/Vendor should be consulted.

Table 7.3: Tests Recommended for Materials Used for Seals Carrying Gaseous Fuels, Gas Condensates, and Hydrocarbon Fluids

Property	Test Method
Permissible Tolerance on Nominal Hardness	ISO 48
Tensile Strength and Elongation at Break	ISO 37
Compression Set	
• 24 h at 158°F (70°C)	ISO 815
• 72 h at 73.4°F (23°C)	ISO 815
• 72 h at 23°F (–5°C)	ISO 815
Aging 7 Days at 158°F (70°C)	
• Hardness Change, Maximum	ISO 48
• Tensile Strength Change, Maximum	ISO 37
• Elongation at Break Change, Maximum	ISO 37
Stress Relaxation, Maximum	
• 7 Days at 73.4°F (23°C)	ISO 3384
• 90 Days at 73.4°F (23°C)	ISO 3384
Volume Change in Liquid B after 7 Days at 73.4°F (23°C), Maximum	ISO 1817
Volume Change in Liquid B and Subsequent 4 Days at 158°F (70°C) Air Drying, Maximum	ISO 1817
Volume Change in Standard Oil IRM 903 after 7 Days at 158°F (70°C)	ISO 1817
Ozone Resistance	ISO 1431-1

Compression Set Requirement

When rubber is held under compression, physical or chemical changes can occur that prevent the rubber from returning to its original dimensions after release of the deforming force. The result is a set, the magnitude of which depends on the time and temperature of compression, as well as on the time, temperature, and conditions of recovery. At low temperatures, changes resulting from the effects of glass hardening or crystallization become predominant.

Currently, industry standards specify a minimum compression set temperature only as low as 5°F (–15°C). BS 682 [39] recommends that compression set testing be performed in accordance with ISO 815-2 [91] at several temperatures, with a minimum temperature of 5°F (–15°C) for low aromatic hydrocarbons and 14°F (–10°C) for all others. The Supplier, Manufacturer, or Company compression should set requirements (expressed as a percentage of the initial compression) to be used if a seal service temperature lower than 5°F (–15°C) is required.

Note: ISO 815-2 [91] suggests preferred test times of 24 or 72 hours. ISO 815-2 [91] states that longer times may be used when studying crystallization, plasticizer migration, or long-term stability at specified temperatures. Because of the limited amount of testing data available at low temperatures and the possibility of long idling periods for seals under compression, the authors of this report recommend that longer test times for compression set testing be used when temperatures are below those specified in BS 682 [39].

7.2.3.2 Wellhead Seals

According to ISO 10423/API 6A [74], wellhead seals must be designed to operate in one or more of the specified temperature ratings with minimum and maximum temperatures as shown in Table 7.4, or to minimum and maximum operating temperatures as agreed between the purchaser and the manufacturer.

Minimum temperature is the lowest ambient temperature to which the equipment may be subjected. Maximum temperature is the highest temperature of the fluid that may directly contact the equipment. ISO 19906:2010 [88] also states that seals exposed to operation in low temperatures must be qualified for the specified service.

The design must consider the effects of differential thermal expansion from temperature changes and temperature gradients that the equipment can experience in service. Choosing the temperature rating is ultimately the responsibility of the user. The user should consider the temperature the equipment can withstand in drilling or production services or both when making these selections.

API 6A/ISO 10423 [16] requires that all non-metallic seals be qualified for service through hardness, tensile, elongation, compression set, modulus, and fluid immersion testing. Refer to Table 7.3 and API 6A/ISO 10423 [16] for test methods.

Table 7.4: API 6A/ISO10423 Operating Temperature Ratings for Wellhead Materials

Temperature Classification	Operating Range			
	Min (°C)	Max (°C)	Min (°F)	Max (°F)
K	–60	82	–76.0	179.6
L	–46	82	–50.8	179.6
N	–46	60	–50.8	140.0
P	–29	82	–20.2	179.6
S	–18	60	–0.4	140.0
T	–18	82	–0.4	179.6
U	–18	121	–0.4	249.8

Temperature Classification	Operating Range			
	Min (°C)	Max (°C)	Min (°F)	Max (°F)
V	2	121	35.6	249.8

Non-metallic pressure-containing or pressure-controlling seals must have written material specifications. The manufacturer's written specified requirements for non-metallic materials must define the:

- Generic base polymer(s)
- Physical property requirements.
- Material qualification, which must meet the equipment class requirement.
- Storage and age-control requirements.

For elastomeric seals that may come into contact with hydrocarbons, ISO 23936-2 [90] can also be used to provide guidance on qualification requirements and procedures.

Storage of non-metallic materials used as wellhead seals is discussed in ISO 10423/API 6A [74], which gives the following requirements:

- PSL 1 and PSL 2 (product specification level as defined in ISO 10423/API 6A)—Age-control procedures and the protection of non-metallic seals must be documented by the manufacturer.
- PSL 3 and PSL 4—The manufacturer's written specified requirements for non-metallic seals must include the following minimum provisions:
  - Indoor storage
  - Maximum temperature not to exceed 120°F (49°C)
  - Protection from direct natural light
  - Unstressed storage
  - Storage that prevents contact with liquids
  - Protection from ozone and radiographic damage

The manufacturer must define the provisions and requirements. A minimum temperature is not given in ISO 10423/API 6A [74]. However, it requires indoor storage, which suggests that arctic temperatures are not expected.

It is assumed that temperature classification K in Table 7.4 is suitable for the lowest Arctic temperatures expected; therefore, such guidance on qualifying wellhead seals to lower temperatures (–76°F or –60°C) is not given.

There are a number of common elastomers in Table 7.2 that are suitable for use as wellhead seals in Arctic conditions.

7.2.3.3 Packers and Drill Plugs

This sub-section refers to permanent and retrievable casing packers and bridge plugs, inflatable thru-tubing, casing and open hole packers, and open hole mechanical packers.

When selecting the appropriate seal (static, dynamic, nonactive, or active) the following factors should be considered [66]:

- Maximum pressure differential
- Maximum and minimum temperature
- Well fluids
- Seal application

Elastomers used in packers can be qualified as appropriate according to ISO 23936-2 [90] Clause 7, which requires a test of:

- Aging
- Rapid Gas Decompression (RGD)
- Hardness (ISO 48)
- Volume
- Tensile (modulus, tensile strength and elongation at break) (ISO 37)

Acceptable ranges for these properties are provided in ISO 23936-2 [90] Clause 7.

Note: ISO 23936-2 [90] has replaced NORSOK M-710, which has been withdrawn.

All new packers are typically designed to ISO 14310 [80]. Further to the requirements of ISO 23936-2 [90] for non-metals, ISO 14310 [80] requires that characteristics critical to the performance of the material be defined. These include:

- Compound type
- Mechanical properties; as a minimum:
  - Tensile strength at break
  - Elongation at break
  - Tensile modulus
- Compression set
- Durometer hardness

ISO 14310 also requires the use of design validation grades when designing new packers. Validation levels should be used to describe development test requirements for new packers. ISO 14310 and API 11D1 design validation grades are defined as:

- Grade V6 = Minimum grade (supplier specified)
- Grade V5 = Liquid test
- Grade V4 = Liquid test with axial loads
- Grade V3 = Liquid test with axial loads and temperature cycling
- Grade V2 = Gas test with axial loads
- Grade V1 = Gas test with axial loads and temperature cycling
- Grade V0 = V1 with special acceptance criteria (zero bubble)

Grades V0 to V3 are typically supplied by manufacturers. Contact the manufacturer/supplier for assistance when selecting a specific validation grade.

Table 7.5 presents elastomers that are currently used for drilling applications and may be suitable for use as packer and drill plug components in Arctic drilling applications.

Table 7.5: Elastomers Suitable for Use as Packer and Drill Plug Components at Arctic and Near Arctic Temperatures

Elastomer Type	Operating Temperature (°C)	Properties
Viton® GLT-200S (FKM), Dupont	–9°F (–23.8°C) [12]	Compression set resistance. Fluid resistance similar to Viton® GLT-600S
Viton® GLT-600S (FKM), Dupont	–9°F (–23.9°C) [12]	Compression set resistance. Water resistance and low volume swell in water
Elast-O-Lion 101 (HNBR), James Walker	–20°F (–29°C) to 320°F (160°C)	Norsok M-710 qualified for RGD resistance and sour gas aging. Chemical and abrasion resistance.
Kalrez 0090 (perfluoroelastomer), Dupont	–40 °F (–40°C) to 482 °F (250 °C)	Good extrusion resistance. Excellent and wide ranging chemical resistance
Kalrez 0040 (perfluoroelastomer), Dupont	–43.6°F (–42°C) to 428°F (220°C)	Hydrocarbon and chemical resistance
NL56/70 (NBR), James Walker	–58°F (–50°C) to 230°F (110°C)	Resistance to mineral oils and water/glycol based hydraulic fluids.
Elast-O-Lion 985 (HNBR), James Walker	–67°F (–55°C) to 302°F (150°C)	Good RGD resistance at low temperatures. Excellent fuel/oil and chemical resistance for oilfield duties

7.2.3.4 Blowout Preventer Components

ISO 13533 [75] requires that elastomeric materials used in ram-type or annular-type BOPs must be tested to verify their ability to maintain a seal at the extremes of their temperature classifications. Written specifications must be produced for all elastomers used. The specifications must include the following physical tests and limits for acceptance and control:

- Hardness in accordance with ASTM D 2240 [27] or ASTM D 1415 [26];

- Normal stress-strain properties in accordance with ASTM D 412 [29] or ASTM D 1414 [25];
- Compression set in accordance with ASTM D 395 [28] or ASTM D 1414 [25];
- Immersion testing in accordance with ASTM D 471 [30] or ASTM D 1414 [25].

Equipment must be designed for wellbore contacting elastomeric materials to operate within the temperature classifications of Table 7.6 [75]. All other elastomeric seals must be designed to operate within the temperatures of the manufacturers' written specifications.

Table 7.6: Temperature Ratings for Non-metallic Sealing Materials

Lower Limit			Upper Limit		
Code	Temperature		Code	Temperature	
	°F	°C		°F	°C
A	–15	–26	A	180	82
B	0	–18	B	200	93
C	10	–12	C	220	104
D	20	–7	D	250	121
E	30	–1	E	300	149
F	40	4	F	350	177
G	Other	Other	G	Other	Other
X	See note	See note	X	See note	See note
Note: These components may carry a temperature class of 40°F to 180°F (4°C to 82°C) without performing temperature verification testing provided they are marked as temperature class "XX" **Example:** Material "EB" has a temperature rating of 30°F to 200°F (–1°C to 93°C)					

Fluid contacting elastomeric seals employed in blowout preventers (BOPs) should be further qualified as appropriate in accordance with Clause 7 [90], which requires a test of:

- Aging
- Rapid Gas Decompression (RGD)
- Hardness (ISO 48)
- Volume
- Tensile (modulus, tensile strength and elongation at break) (ISO 37)

Acceptable ranges for these properties are given in ISO 23936-2 [90] Clause 7.

Table 7.7 presents elastomers that are currently used for drilling applications and which may be suitable for use as BOP components in Arctic drilling applications.

Table 7.7: Elastomers Suitable for Use as BOP Components at Arctic and Near Arctic Temperatures

Elastomer Type	Operating Temperature	Properties
Elast-O-Lion 101 (HNBR), James Walker	–20°F (–28.8°C) to 320°F (160°C)	Norsok M-710 qualified for RGD resistance and sour gas aging. Chemical and abrasion resistance.
NL56/70 (NBR), James Walker	–58°F (–50°C) to 230°F (110°C)	Resistance to mineral oils and water/glycol based hydraulic fluids.
Elast-O-Lion 985 (HNBR), James Walker	–67°F (–55°C) to 302°F (150°C)	Good RGD resistance at low temperatures. Excellent fuel/oil and chemical resistance for oilfield duties

Note: Minimum operating temperatures for HNBR rubbers vary greatly, and some grades may have minimum operating temperatures up to 13°F (25°C).

7.2.3.5 Flex/Ball Joints

Flex/ball joints used in drilling applications should be designed in accordance with an appropriate standard such as API STD 2RD [18]. Written specifications should be produced for all elastomers used in flex/ball joints. These component specifications should establish requirements for the method and process of manufacture, chemical composition, heat treatment, physical and mechanical properties, dimensions and tolerances, surface conditions, testing, examination and NDT, marking, temporary coating and protection, certification, and documentation.

API STD 2RD [18] states that non-metallic material selection must be based on an evaluation of the compatibility of the non-metallic material with the service environment, including temperature, cyclic loading, and composition of anticipated fluids and substances to which the material can be exposed.

Further to this, API STD 2RD states that the following should be considered as appropriate to non-metallic seal requirements and should be evaluated when selecting the material:

- Adequate physical and mechanical properties (such as hardness, strength, elongation, elasticity, flexibility, compression set, tear resistance) during all anticipated operations
- Resistance to high-pressure extrusion or creep
- Resistance to thermal cycling and dynamic loadings
- Resistance to issues associated with rapid gas decompression
- Degradation of properties during design life

ISO 23936-2 Clause 7 [90] can be followed to perform the evaluation.

ISO 1817 [83] is concerned with fluid compatibility with the cover and structural layers of the flex/ball joint and may be followed to ensure the further suitability of the elastomer. ISO 1817 addresses:

- Fluid permeation
- Aging
- Chemical compatibility
- RGD
- Fatigue analysis

Table 7.8 lists elastomers that are currently used for drilling applications and which may be suitable for use as flex/ball seal components in Arctic drilling applications.

Table 7.8: Elastomers Suitable for Use as Flex/Ball Seals at or Near Arctic Temperatures

Elastomer Type	Operating Temperature (°C)	Properties
Elast-O-Lion 101 (HNBR), James Walker	–20°F (–28.9°C) to 320°F (160°C)	Norsok M-710 qualified for RGD resistance and sour gas aging. Chemical and abrasion resistance.
NL56/70 (NBR), James Walker	–58°F (–50°C) to 230°F (110°C)	Resistance to mineral oils and water/glycol based hydraulic fluids.
Elast-O-Lion 985 (HNBR), James Walker	–67°F (–55°C) to 302°F (150°C)	Good RGD resistance at low temperatures. Excellent fuel/oil and chemical resistance for oilfield duties

7.2.4 Storage and Handling

Storage temperature is important because elastomers can be damaged and distorted if they are not handled properly. BS ISO 2230:2002 [41] recommends that the storage temperature should be below 77°F (25°C). If the storage temperature is below 59°F (15°C), care should be exercised during handling of the stored elastomers, as they may have stiffened and become susceptible to distortion if they are not handled carefully. Elastomers should be raised to approximately 86°F (30°C) throughout their mass before they are put in service.

BS ISO 2230:2002 contains detailed guidance on elastomer storage and handling. For very low storage temperatures, the manufacturer or supplier/vendor should be consulted.

7.2.5 Guidance Notes

The Tg of proposed elastomers to be used in the Arctic must be 18°F (10°C) below the minimum design temperature. As a rule of thumb, for every 50 bar increase in pressure, the Tg of elastomers will increase by 1.8 °F (or 1°C). As such, any elastomer seals used downhole must be able to remain flexible at temperatures below those shown in a TR-10 test, which is at a lower pressure than the seal will be during service.

A study by James Walker has shown that static O-rings can seal effectively at 59°F (15°C) below the TR-10 temperature [129].

If the elastomer is subjected to high temperatures, some of the plasticizers may be lost, depending on their volatility. Loss of plasticizers, particularly in NBR and HNBR, will degrade the properties of the rubber.

The Engineering Equipment and Materials Users Association (EEMUA) 194 [59] states that there are no useful elastomers which can operate with gaseous hydrocarbons below –49°F (–45°C). This is due in part to explosive decompression resistance.

7.2.6 Conclusions

A number of suitable elastomers are currently available for typical Arctic operating temperatures. Elastomer selection for the lowest Arctic temperatures of –72.4°F (–58°C) may not be required because sealing is not needed at these temperatures, due to their underground use where it is warmer and where warm fluids are passing close to the seals.

7.3 Polymers

7.3.1 Background

A polymer is a very high molecular-weight compound that is made up of a large number of simpler units, called monomers.

Polymers, which are typically lighter than metals, lack mechanical properties such as strength, toughness, and hardness. Polymers are typically used when corrosion resistance or chemical resistance is required rather than mechanical properties.

The most commonly used polymers in the oil and gas industry (and their operating temperatures) are shown in Table 7.9 [57] [123] [122].

Table 7.9: Most Common Used Polymers in Oil and Gas

Abbreviation	Chemical Name	Operating Temperature Range (°F)	Operating Temperature Range (°C)
HDPE	High Density Polyethylene	–58°F to 176°F	–50°C to 80°C
PA-11	Polyamide 11	–22°F to 167°F	–30°C to 75°C
PCTFE	Polychlorotrifluoroethylene	–400°F to 392°F	–240°C to 200°C
PE	Polyethylene	–148°F to 140°F	–100°C to 60°C
PEEK	Polyetheretherketone	–94°F to 500°F	–70°C to 260°C
PFA	Perfluoralkoxy	–328°F to 446°F	–200°C to 230°C

Abbreviation	Chemical Name	Operating Temperature Range	
		(°F)	(°C)
PP	Polypropylene	–4°F to 212°F	–20°C to 100°C
PPS	Polyphenylene sulphide	–94°F to 392°F	–70°C to 200°C
PTFE	Polytetrafluoroethylene	–400°F to 446°F	–240°C to 230°C
PVDF	Polyvinylidene fluoride	–22°F to 248°F	–30°C to 120°C

7.3.2 Existing Polymers Used for Drilling

A number of polymers are currently used in drilling operations. The most common application is as back-ups or secondary ring seals (to primary elastomer seals) where high pressures are found. Polymers are not incompressible and will ultimately deform plastically rather than elastically after a given stress is applied. This behavior makes them unsuitable as primary seals. Some polymers can be pre-stressed, which makes them suitable as back-up rings. The typical arrangement of back-up rings is shown in Figure 7.2.

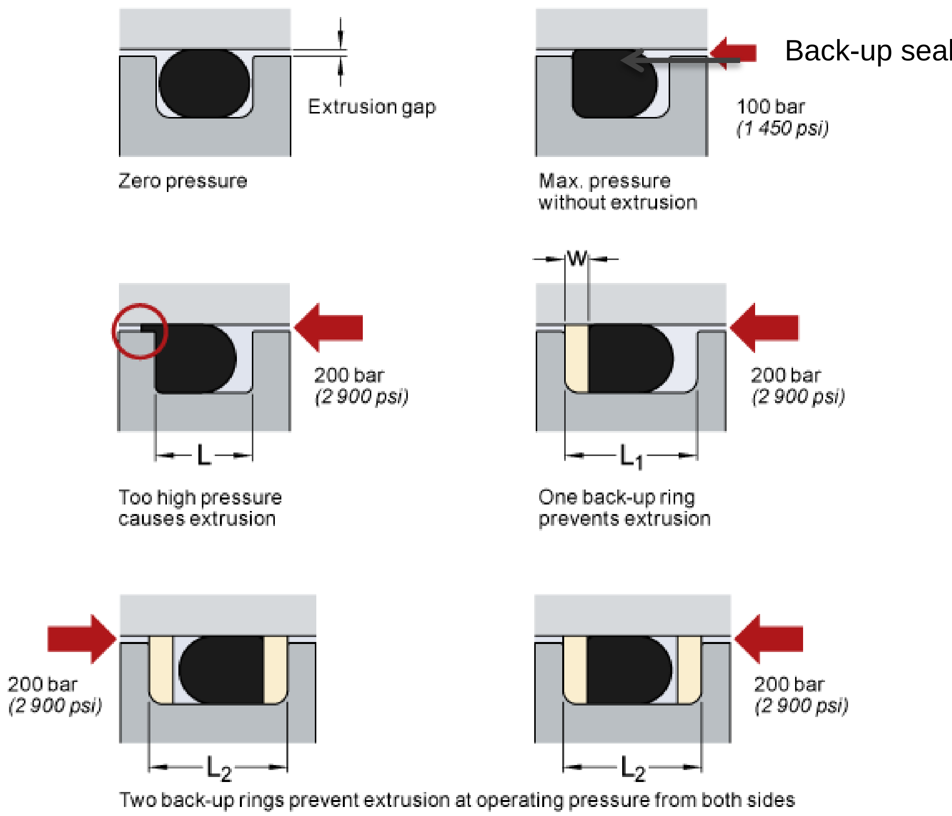

Figure 7.2: Illustration Showing the Difference Between No Back-up Seals and Two Back-up Seals [118]

Another application of polymers is for control line encapsulation. This application is discussed in Section 7.3.3.4.

7.3.3 Polymers Commonly Used in the Oil and Gas Industry

The most common polymers used in downhole applications are:

- Polyetheretherketone (PEEK)—Victrex, Arlon
- Polytetrafluoroethylene (PTFE)—Teflon
- Polyphenylene Sulfide (PPS)—Ryton
- Polyethylene (PE)

7.3.3.1 Polyetheretherketone

PEEK is a crystalline material with excellent mechanical properties at elevated temperatures. PEEK also has excellent chemical resistance.

The normal operating temperature range for PEEK is –94°F to 500°F (–70°C to 260°C) [46]. The main applications for PEEK are high temperature operations where chemical resistance is important. PEEK can be used at low temperatures as back-up seals for high pressures downhole. Other typical applications are valve seats and pump components.

PEEK is not resistant to a number of concentrated acids. Because of its resistance to low operating temperatures, PEEK is expected to be suitable for use in most Arctic environments.

7.3.3.2 Polytetrafluoroethylene

PTFE is extremely resistant to most oilfield chemicals and has an operating temperature range of –400°F to 446°F (–240°C to 230°C). PTFE is currently used downhole as a back-up seal. PTFE is also commonly used in the oil and gas industry and is suitable for extremely high pressure and high temperature applications. In addition, PTFE is used in the oil and gas industry as a seal in high temperatures or with aggressive chemicals.

PTFE seal properties include low friction and high wear resistance. PTFE can be used in the fabrication of seals, O-rings, and spring-energized PTFE seals [58]. Because of its resistance to low operating temperatures, PTFE is expected to be widely used in Arctic environments.

7.3.3.3 Polyphenylene Sulfide

PPS has good thermal stability; chemical resistance; inherent flame retardancy; and resistance to water, dry gas, and most hydrocarbons. PPS has limited resistance to high concentrations of aromatics. PPS also has good mechanical properties, high modulus, and high strength; but it has limited strain to failure.

The operating temperature range for PPS is –94°F to 392°F (–70°C to 200°C) [119], which makes it a good candidate for use in Arctic temperatures. PPS has recently found application as a downhole back-up seal. PPS is used less than PEEK and PTFE.

7.3.3.4 Polyethylene

There are several grades of Polyethylenes (PEs), including low-, medium-, and high-density grades. Polyethylene has generally good resistance to chemicals and solvents. The operating temperature limits are approximately –193°F to 149°F (–125°C to 65°C). The limits differ, depending on the grade and operating service. PE is commonly used for control line encapsulation. Because of its resistance to low operating temperatures, PE is expected to be suitable for use in most Arctic environments.

7.3.4 Polymers Used as Components in Drilling Applications

This section presents options for polymers used as components in drilling applications at low temperatures such as those found in the Arctic. Potential options and qualification/testing requirements for commonly used polymers are addressed.

Polymers are typically used as back-up seals, for control line encapsulation, and in flexibles in drilling applications, with other small uncommon applications such as valve components. Polymers that can operate well at Arctic temperatures are shown in Table 7.10.

Table 7.10: Recommended Temperature Limits for Thermoplastics Used As Linings [23]

Polymer	Minimum Operating temperature	
	°C	°F
PFA (Perfluoroalkoxy)	–198	–325
PTFE (Polytetrafluoroethylene), Teflon	–198	–325
PVDF (Polyvinylidenefluoride), Kynar	–18	0

7.3.4.1 Topsides – Piping and Liners

ASME B31.3 [23] requires that polymer pressure-containing pipework must conform to a listed specification. It states that the designer must verify that materials are suitable for service throughout the operating temperature range.

Table 7.10 shows recommended minimum operating temperatures from ASME B31.3 [23] for pipework constructed of the most commonly used polymer materials. These operating temperatures are conservative recommendations and do not reflect successful use in specific fluid services at these temperatures.

For non-metallics listed in ASME B31.3 [23], there are no added requirements (in addition to applicable material specification) for toughness tests at or above the listed minimum temperature. Below the listed minimum temperature, ASME B31.3 [23] requires that the designer must have test results at or below the lowest expected service temperature, which assure that the materials and bonds (flanges, threads, etc.) will have adequate toughness and are suitable at the design minimum temperature.

The material specification can be used to verify that the material is qualified for Arctic service. The appropriate specification should be checked to see whether it can be used at the operating temperature needed. For example, API 15LE [12] is the specification for polyethylene line pipe and is suitable for a minimum service temperature of –30°F (–34.4°C). This is unlikely to satisfy the operating temperature requirement for topsides pipework on a MODU or drilling platform in the Arctic all year, so further qualification would be needed to know whether it is suitable.

Polymer operating temperatures for topsides piping and liners based on manufacturer testing are presented in Table 7.11. Note that the operating temperature for PVDF is lower than that specified in ASME B31.3 [23], which is a general figure and does not consider other factors. Consult the manufacturer/vendor to verify that the polymer is suitable at the operating temperature desired, particularly when temperature limits stated in the material specifications are close.

Table 7.11: Properties of Polymers Suitable for Use in Drilling Applications at Arctic and Near Arctic Temperatures as Piping and Liners

Polymer Type	Brittleness Temperature/ Maximum Operating Temperature ASTM D746	Impact Strength at –22°F (–30°C) (Charpy) ISO 179-1	Comments
LDPE (Low-density Polyethylene)	–58°F (–50°C) to 104°F (40°C)	No break	N/A
MDPE (Medium-density Polyethylene)	–76°F (–60°C) to 122°F (50°C)	No break	N/A
HDPE (High-density Polyethylene)	–58[1]/–76°F (–50[1]/–60°C) to 140°F (60°C)	No break	High tensile and impact resistance at low temperature
XLPE (Cross-linked Polyethylene)	–76°F (–60°C) to 140°F (60°C) (note–generally higher than +60, depends on cross-linking technique	No break	N/A
PVDF (Polyvinylidenefluoride), Kynar	–76°F (–60°C) to 266°F (130°C)	No break	Typical alternative to PA-11 at high temperatures. Excellent chemical resistance and UV stability.
PA-11 (Polyamide)	–40°F (–40°C) to 158°F (70°C)	No break	Good flexibility. Good chemical and UV stability.
PA-12 (Polyamide)	–40°F (–40°C) to 158°F (70°C)	No break	Good flexibility. Good chemical and UV stability.

Note

[1] API 17B Recommended Practice for Flexible Pipe [6].

7.3.4.2 Wellhead Back-up Seals

The same guidelines for elastomer wellhead seals in Section 7.2.3.2 can be followed for polymeric back-up seals in wellheads. These guidelines are listed in Table 7.12.

API 6A/ISO 10423 [16] requires that all non-metallic seals should be qualified for service through hardness, tensile, elongation, compression set, modulus, and fluid immersion testing.

For polymeric seals that may come into contact with hydrocarbons, ISO 23936-2 [90] can provide guidance on qualification requirements and procedures.

Table 7.12: Properties of Polymers Suitable for Use in Drilling Applications at Arctic and Near Arctic Temperatures as Back-up Seals

Polymer Type	Brittleness Temperature /Maximum Operating Temperature ASTM D746	Impact Strength at –22°F (–30°C) (Charpy) ISO 179-1	Properties
PCTFE (Polychloro-trifluoroethylene)	–40°F (–40°C) to 266°F (130°C)	No break	High mechanical strength and low shrinkage rate at low temperatures providing excellent stability for valve seats
PEEK (Polyether-ether-ketone)	–85°F (–65°C) to 482°F (250°C)	No break	Excellent chemical resistance
PPS (Polyphenylene Sulfide), Ryton.	–58°F (–50°C) to 392°F (200°C)	No break	Excellent chemical resistance
PTFE (Polytetrafluoroethylene), Teflon	–328°F (–200°C) to 500°F (260°C)	No break	Good chemical resistance.

7.3.4.3 Flexible Pipe

The manufacturer must have records of tests on file which demonstrate that the materials selected for a specific application meet the functional requirements specified in ISO 13628-2/API 17J [78] for the service life and for both operation and installation conditions. The documented test records must conform to the ISO 13628/API 17J requirements or the manufacturer must conduct testing relevant to the application according to ISO 13628/API 17J.

The manufacturer must verify the physical, mechanical, chemical, and performance characteristics of all materials in the flexible pipe through a documented qualification program. The program must confirm the adequacy of each material based on test results and analysis that must demonstrate the documented fitness for purpose of the materials for the specified service life of the flexible pipe. As a minimum, the qualification program must include the tests specified in Table 7.13. The qualification of materials by testing should consider all processes (and their variation) adopted to produce the pipe that can impair the properties and characteristics required by the design.

Table 7.13: Test Procedures for Extruded Polymer Materials [78]

Characteristic	Tests	Test Procedure[a]		Comments[b]
		ISO or clause number[b]	ASTM[b]	
Mechanical/Physical Properties	Resistance to Creep	ISO 899-1	ASTM D2990	Due to temperature and pressure
	Yield strength/elongation	ISO 527-1 ISO 527-2	ASTM D638	–
	Ultimate strength/elongation	ISO 527-1 ISO 527-2	ASTM D638	–
	Stress relaxation properties	ISO 3384	ASTM E328	–
	Modulus of elasticity	ISO 527-1 ISO 527-2	ASTM D638	–
	Hardness	ISO 868	ASTM D2240 or ASTM D2583	–
	Compression strength	ISO 604	ASTM D695	–
	Hydrostatic pressure resistance	–	–	–
	Impact strength	ISO 179 (all parts) or ISO 180	ASTM D256	At design minimum temperature
	Abrasion resistance	ISO 9352	ASTM D4060	Or ASTM D1044
	Density	ISO 1183 (all parts)	ASTM D792	Or ASTM D1505
	Fatigue	–	ISO 178	c
	Notch sensitivity	ISO 179 (all parts)	ASTM D256	–
Thermal Properties	Coefficient of thermal conductivity	–	ASTM C177 ASTM C518	–
	Coefficient of thermal expansion	ISO 11359-2	ASTM E831	–
	Heat distortion temperatures	ISO 75-1 ISO 75-2	ASTM D648	–
	Softening point	ISO 306	ASTM D1525	–

Characteristic	Tests	Test Procedure[a]		Comments[b]
		ISO or clause number[b]	ASTM[b]	
	Heat capacity	ISO 11357-1 ISO 11357-4	ASTM E1269	–
	Brittleness (or glass transition) temperature	ISO 974	ASTM D746	Or glass transition temperature (ASTM E1356)
Permeation Characteristics	Fluid permeability	7.2.3.1	–	As a minimum to CH_4,CO_2, H_2S and methanol, where present, at design temperature and pressure
	Blistering resistance	7.2.3.2	–	At design conditions
Compatibility and Aging	Fluid compatibility	7.2.3.3	–	–
	Aging tests	7.2.3.4	–	–
	Environmental stress cracking	–	ASTM D1693-05	Method C. PE only
	Weathering resistance	–	–	Effectiveness of the UV stabilizer
	Water absorption	ISO 62	ASTM D570	Insulation material only

[a] The test procedures apply to polymer sheath materials and insulation layer materials, both polymer and non-polymer. The property requirements are specified in Table 9.

[b] For the purposes of the requirements for the listed test, the ASTM reference(s) listed is/are equivalent to the associated ISO International Standard, where one is given. Example: For the purpose of the procedure for the resistance-to-creep test, ASTM D2990 is the equivalent of ISO 899-1.

[c] The ISO 178 method for determination of flexural properties can be used as a basis for establishing a fatigue test method or can be modified in accordance with fatigue test methodologies established by manufacturers. The results of all tests made by the manufacturer or suppliers or both must be available for review by the purchaser.

API 17B [6] requires that for detailed engineering of flexible pipe, a validated aging model must be used to confirm the polymer service life requirements.

The criteria for the properties in Table 7.14 are specified in ISO 13628-2 [78] for materials currently used in flexible pipe applications. Additional criteria to design against failure are given in ISO 13628-11 [77]. Where new materials are proposed or used, the design criteria for the new materials should give at a minimum the safety level specified in ISO 13628-2 [78] and ISO 13628-11 [77].

Internal Pressure Sheath:

The manufacturer must document the mechanical, thermal, fluid compatibility and permeability properties of the material for the internal pressure sheath, as specified in ISO 13628-2/API 17J [78] for a range of temperatures and pressures that must include the design values. If the conveyed fluid contains gas, the polymer must be shown, by testing, not to blister or degrade during rapid depressurization from the maximum pressure and temperature conditions.

Intermediate Sheath:

The manufacturer must document the properties specified in ISO 13628-2/API 17J [78]. Refer to Table 7.14 for characteristics of the intermediate sheath material.

Outer Sheath:

The manufacturer must document the properties specified in Table 7.14 for the outer sheath material. A documented evaluation must be performed by the manufacturer to confirm compatibility of the outer sheath with all permeated fluids, ancillary components and all external environmental conditions specified in ISO 13628-2/API 17J [78] Section 5.5.

Table 7.14: Property Requirements of Extruded Polymer Materials [78]

Characteristic	Tests	Internal Pressure Sheath	Intermediate Sheath/ Anti-wear layer	Outer Sheath	Insulation Layer
Mechanical/Physical Properties	Resistance to Creep	X	X	X	X
	Yield strength/elongation	X	X	X	–
	Ultimate strength/elongation	X	X	X	X
	Stress relaxation properties	X	–	–	–
	Modulus of elasticity	X	X	X	–
	Hardness	–	–	X	–
	Compression strength	–	–	X	X
	Hydrostatic pressure resistance	–	–	–	X
	Impact strength	–	–	X	–
	Abrasion resistance	–	–	X	–
	Density	X	X	X	X
	Fatigue	X	X	X	–

Characteristic	Tests	Internal Pressure Sheath	Intermediate Sheath/ Anti-wear layer	Outer Sheath	Insulation Layer
	Notch sensitivity	X	–	–	–
Thermal Properties	Coefficient of thermal conductivity	X	X	X	X
	Coefficient of thermal expansion	X	X	X	X
	Softening point	X	X	X	X
	Heat capacity	X	X	X	X
	Brittleness (or glass transition) temperature	X	–	X	–
Permeation Characteristics	Fluid permeability	X	X	X	X
	Blistering resistance	X	–	–	–
Compatibility and Aging	Fluid compatibility	X	X	X	X
	Aging tests	X	X	X	–
	Environmental stress cracking	X	X	X	–
	Weathering resistance	–	–	X	–
	Water absorption	X	–	X	X
The property requirements specified for the insulation layer apply to the use of both polymers and non-polymers. Test procedures are specified in Table 11 (ISO 13628-2). There are no property requirements for manufacturing aid materials.					

Polymers that are suitable for use in drilling applications at Arctic and near Arctic temperatures as flexible pipe are presented in are presented in Table 7.15.

Table 7.15: Polymers Suitable for Use in Drilling Applications at Arctic and Near Arctic Temperatures as Flexible Pipe

Polymer Type	Brittleness Temperature/Maximum Operating Temperature ASTM D746	Impact Strength at –22°F (–30°C) (Charpy) ISO 179-1	Properties
HDPE (High Density Polyethylene)	–76°F (–60°C) to 140°F (60°C)	No break	High tensile and impact resistance at low temperature
XLPE	–76°F (–60°C) to 140°F (60°C) (note – generally higher than +60, depends on cross-linking technique	No break	N/A

Polymer Type	Brittleness Temperature/Maximum Operating Temperature ASTM D746	Impact Strength at –22°F (–30°C) (Charpy) ISO 179-1	Properties
PVDF (Polyvinylidenefluoride), Kynar	–76°F (–60°C) to 266°F (130°C)	No break	Typical alternative to PA-11 at high temperatures. Excellent chemical resistance and UV stability.
PA-11 (Polyamide)	–40°F (–40°C) to 158°F (70°C)	No break	Good flexibility. Good chemical and UV stability.
PA-12 (Polyamide)	–40°F (–40°C) to 158°F (70°C)	No break	Good flexibility. Good chemical and UV stability.

7.3.4.4 Encapsulations and Control Lines

Encapsulation and control lines are subsea equipment that can be designed in accordance with ISO 13628-1 [76]. This standard states that the selection of polymeric materials must be based on an evaluation of the functional requirements for the specific application. The materials must be qualified according to procedures described in applicable material/design codes. Depending on the application, properties for documentation and inclusion in the evaluation include:

- Thermal stability and aging resistance at specified service temperatures and environments.
- Physical and mechanical properties.
- Thermal expansion.
- Swelling and shrinking by gas and by liquid absorption.
- Gas and liquid diffusion.
- Decompression resistance in high pressure oil/gas systems.
- Chemical resistance.
- Control of manufacturing process.

Necessary documentation of all properties relevant to the design, type of application, and design life must be provided. The documentation must include results from relevant tests and confirmed successful experience in similar design, operational, and environmental situations. Compatibility tests, acceptance criteria, and methods for defining service life must be established for all fluids being handled. Permeation and absorption rates of service fluids, gases, and liquids present must be given for all polymeric materials. Encapsulation and control line materials must be qualified in accordance with ISO 23936-1 [90].

ISO 13628-5 [79] and EEMUA 194 [59] have further, more specific material requirements for encapsulations and control lines which may be followed. These requirements are extensive, and the user is directed to those documents if desired.

There are a number of polymers that are suitable for use as encapsulations and control lines in Arctic and low temperature conditions. These polymers are presented in Table 7.16.

Table 7.16: Properties of Polymers Suitable for Use in Drilling Applications at Arctic and Near Arctic Temperatures as Encapsulations and Injection Lines

Polymer Type	Brittleness Temperature/Maximum Operating Temperature ASTM D746	Impact Strength at –22°F (–30°C) (Charpy) ISO 179-1	Properties
ECTFE	–103°F (–75°C) to 320°F (160°C)	No break	N/A
ETFE	–112°F (–80°C) to 302°F (150°C)	No break	N/A
PTFE	–328°F (–200°C) to 500°F (260°C)	No break	N/A
PCTFE (Polychloro-trifluoroethylene)	–400°F (–240°C) to 392°F (200°C)	No break	High mechanical strength and low shrinkage rate at low temperatures providing excellent stability for valve seats.
PVDF (Polyvinylidenefluoride), Kynar	–60°F (–76°C) to 266°F (130°C)	No break	Typical alternative to PA-11 at high temperatures. Excellent chemical resistance and UV stability.
PA-11 (Polyamide)	40°F (–40°C) to 158°F (70°C)	No break	Good flexibility. Good chemical and UV stability.
PA-12 (Polyamide)	–40°F (–40°C) to 158°F (70°C)	No break	Good flexibility. Good chemical and UV stability.

Polymers should be tested in accordance with the methods in Table 7.17 to ensure that they are suitable for use at low temperatures.

Table 7.17: Tests Recommended for Polymers Used in Hydrocarbon Service

Test Method	Parameter Tested
ASTM D 1525	Test Method for Vicat Softening Point for Plastics
ASTM D 2240	Test Method for Rubber Property – Durometer Hardness (Shore A/D)
ASTM D 2990	Test Methods for Tensile, Compressive and Flexural Creep and Creep Rupture Test of Plastics
ASTM D 746	Test Method for Brittleness Temperature of Plastics and Elastomers by Impact

Test Method	Parameter Tested
ASTM D 790	Test Method for Flexural Properties of Un-reinforced and Reinforced Plastics and Electrical Insulating Materials
ASTM D 792	Test Methods for Specific Gravity and Density of Plastics by Displacement
ASTM D1654	Evaluation of Coatings in Corrosive Environments
ASTM D4541	Pull-Off Strength of Coatings
ASTM D638	Test Method for Tensile Properties of Plastics
ASTM D695	Test Method for Compressive Properties of Rigid Plastics
ASTM D714	Blistering on Coatings
DIN 53453	Testing of Plastics, Impact Flexural Test
ISO 868	Determination of Indentation Hardness by Means of a Durometer (Shore A/D hardness)

7.3.5 Storage and Handling

The storage temperature of polymers is not as critical as it is for elastomers. Most polymers that are used in the oil and gas industry can be used from cold temperatures below –40°F (–40°C) to warm temperatures above 140°F (60°C), so storing them in Arctic conditions may not cause any type of degradation. Some precautions must be taken at low temperatures, however, especially if the polymers become brittle and cannot absorb the impact from other harder materials.

7.3.6 Guidance Notes

Polymers are typically lighter than metals, and they lack mechanical properties such as high strength, toughness, and hardness. Therefore, polymers can be used where corrosion resistance or chemical resistance (rather than mechanical properties) is required.

7.3.7 Conclusions

A number of polymers are currently used for back-up seals, pipework, and flexible components and are borderline cases for use in Arctic temperatures. For topsides applications, a number of the currently used polymers in Table 7.11 and Table 7.12 may be suitable without additional qualification. A number of polymers may perform well in Arctic environments if they are qualified.

Polymers currently used for in-water subsea use are expected to be suitable at the sea temperature, especially if they have a long track record of good performance in the oil and gas industry in warm climates. The temperatures during storage and transport are likely to be the lowest temperatures experienced by the polymers, and there are a number of materials currently used which can operate at and below the lowest temperatures expected.

7.4 Composites

7.4.1 Background

Composites offer several advantages over conventional materials, including improved strength, stiffness, impact resistance, thermal conductivity, and corrosion resistance. A composite is a structural material that consists of a combination of two or more constituents. The constituents are combined at a macroscopic level and are mechanically and sometimes chemically bonded (through a polymer) [96].

Composites for oilfield use currently fall under one of the following categories:

- Fiber Reinforced Polymers (FRP)
- Metallic Matrix Composites (MMC)
- Ceramic Matrix Composites (CMC)

7.4.1.1 Fiber Reinforced Polymer (FRP)

The composites used in the oil and gas industry typically consist of small diameter, high strength fibers or particles that are mechanically bonded in a polymer matrix. The fibers may be arranged in various configurations and sizes, as shown in Figure 7.3.

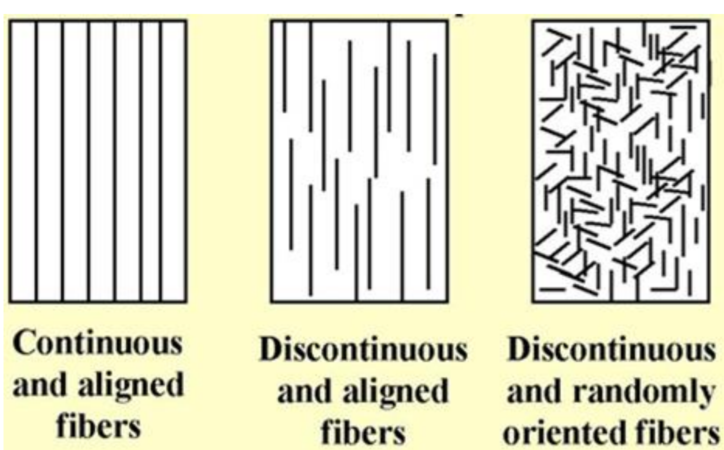

Figure 7.3: Typical Arrangements of Composites

The fibers are the main load carrying members while they are kept in the desired orientation through the matrix, which transfers the load to the fibers. Fiber materials for polymer matrix composites are typically glass, aramid, and carbon. Matrices can be formed from either a thermoplastic or a thermoset resin. Most commonly used thermoplastics are PE, Nylon, PPS, Polypropylene (PP) and Polyvinyl Chloride (PVC). Common thermosets are epoxy, polyester, and vinyl ester.

Changes in the temperature of the polymer in the polymeric matrix composite results in two very important effects [45]:

- A decrease in temperature, which will cause the matrix to shrink. In an FRP matrix composite, the coefficient of thermal expansion of the matrix is usually an order of magnitude greater than that of the fibers. A decrease in temperature caused by either cooling during the fabrication process or low temperature operating conditions will cause the matrix to shrink. Contraction of the matrix is resisted by the fiber/matrix interface bonding, which sets up residual stresses in the material. These residual stresses may be large enough to cause micro cracking in the composite.
- A lower temperature generally increases the strength and stiffness of the matrix.

7.4.1.2 Metallic Matrix Composites

MMCs use a metal such as aluminium as the matrix and reinforce it with fibers such as silicon carbide. MMCs can be classified in various ways. One classification is the consideration of type and contribution of reinforcing components. The reinforcing components can be further classified as continuous, short, and as particles [95]. This is illustrated in Figure 7.4.

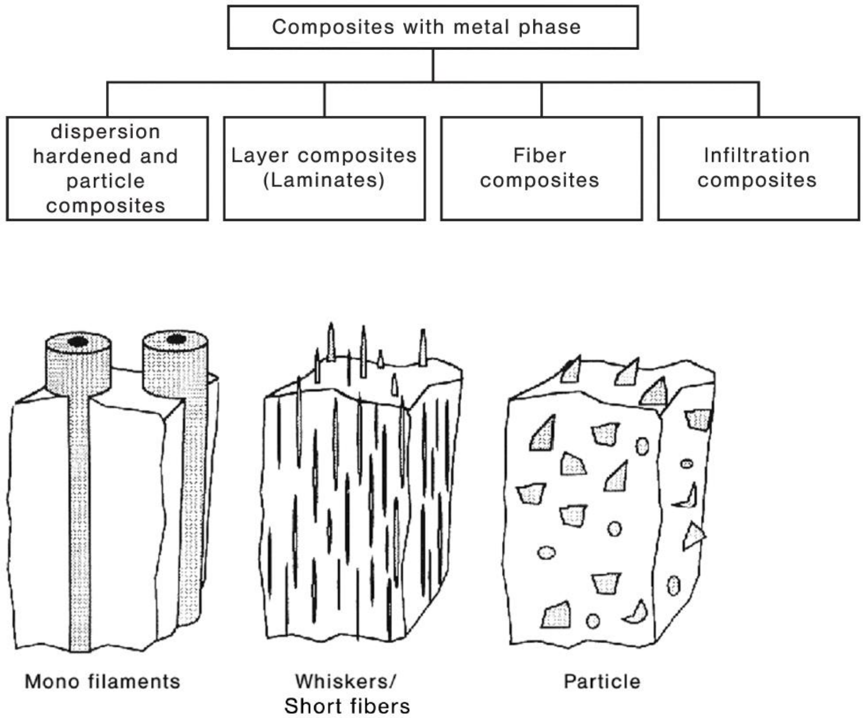

Figure 7.4: Arrangements of Composite Fillers

7.4.1.3 Ceramic Matrix Composites

CMCs use a ceramic as the matrix and reinforce it with short fibers or whiskers (such as those made from silicon carbide and boron nitride).

7.4.2 Composite Properties and Applicatons

Composites used in the oil and gas industry are lighter than metals and, in some cases, may have better mechanical properties. Composites may also have excellent corrosion resistance, which makes them suitable as direct replacements for some metallic components.

The most commonly used composites in the oil and gas industry and their applications are shown in Table 7.18.

Table 7.18: Common Composites in Oil and Gas Applications

Category	Sub-category	Operating Temperatures (°F)	Operating Temperatures (°C)	Common Applications
Glass fiber/epoxy	Aromatic-amine cured	-40°F to 212°F	-40°C to 100°C	Piping and components for water systems, chemicals and some hydrocarbons
	Cyclo-aliphatic cured	-40°F to 212°F	-40°C to 100°C	Piping and components for water systems, chemicals and some hydrocarbons
	Aliphatic-amine cured	-40°F to 185°F	-40°C to 85°C	Piping and components for water systems, chemicals and some hydrocarbons
	Anhydride cured	-40°F to 185°F	-40°C to 85°C	Piping and components for water systems, chemicals and some hydrocarbons
Glass-fiber/vinyl ester	Bisphenol A	-40°F to 185°F	-40°C to 90°C	As glass reinforced epoxy is not commonly used
	Novolac	-40°F to 194°F	-40°C to 100°C	As glass reinforced epoxy is not commonly used
Glass-fiber/polyester	Isophthalic	-58°F to 140°F	-50°C to 60°C	Chemical industry

7.4.3 Resins

The most commonly used fiber in FRP composites is glass, which is typically used with an epoxy, polyester, or vinyl ester resin. The resin used and its behavior in low temperatures is crucial to the mechanical properties. Resin types and applications are discussed in the following sub-sections.

7.4.3.1 Epoxy Resins

Epoxies are known for their excellent adhesion, chemical and heat resistance, mechanical properties, and outstanding electrical insulating properties. They also have excellent resistance to a range of hydrocarbons, acids, and alkalis. Epoxy resins have good adhesive properties to steel and therefore are also used as coatings both offshore and onshore. Glass fiber-reinforced epoxy composites are widely used for piping carrying water, acids, alkalis, and a number of hydrocarbons. They are generally suitable for use at temperatures between –40°F (–40°C) and 150°F (65.6°C). Some epoxy resins have been qualified to lower temperatures.

7.4.3.2 Vinyl Ester Resins

Vinyl ester resins have excellent corrosion resistance and are less brittle than polyester resins. They have good chemical resistance to a range of hydrocarbons, acids, and alkalis. Glass fiber-reinforced vinyl ester composites can be used for components that are in contact with water, acids, alkalis, and a number of hydrocarbons. The operating temperature for vinyl ester resin is somewhere between –58°F (–50°C) and 400°F (204.4°C).

7.4.3.3 Polyester Resins

Polyester resins are widely used in the chemical industry. The minimum operating temperature for polyester systems is –58°F (–50°C). Glass fiber-reinforced polyesters are not currently used in downhole applications.

7.4.4 Composites Used as Components in Drilling Applications

This sub-section presents options for composites used as components in drilling applications at low temperatures such as those found in the Arctic. Potential options and qualification/testing requirements for commonly used elastomers are addressed.

In drilling applications, composites are used mainly as packer components and occasionally as deck grating, hand railings, and ladders on topsides. Composites are not commonly used elsewhere in drilling at the present. DNV-OS-C501 [51] provides guidance on the effects of temperature on various mechanical properties of composites that may be used in low temperatures.

7.4.4.1 Topsides—Structural

ISO 19901-3 [129] recognizes the use of composites as a structural component on topsides, including as deck grating, hand railings, and ladders. It states that due to the large variation in composite material properties, their suitability is usually determined by type testing to meet performance criteria. ISO 19906 [88] discusses issues with ice accumulation on deck. When selecting a composite for use on topsides in Arctic conditions, the composite be verified to be suitable for use at the lowest temperature to which the component will be exposed.

DNV RP C501 [51] provides guidance and test methods for composites. To qualify any composites intended to be used for structural applications on topsides such as on a MODU or drilling platform, the testing requirements in DNV RP C501 [51] should be followed.

Table 7.19 shows the properties of the composite (Glass fiber/vinyl ester) that may be suitable for topsides structures in Arctic temperatures.

Table 7.19: Composites Suitable for Use as Topside Structural Components at Arctic and Near Arctic Temperatures

Composite Category	Sub-Category	Operating temperature	Common Applications	Properties
Glass fiber/vinyl ester	Bisphenol A	–40°F (–40°C) to 194°F (90°C)	MODU topsides deck gratings, handrails, and ladders.	Chemical resistance, impact/toughness/fatigue resistance

7.4.4.2 Topsides—Pipework

ASME B31.3 [23] requires that composite pressure containing pipework must conform to a listed specification. It states that the designer must verify that materials are suitable for service throughout the operating temperature range. Table 7.20 shows recommended minimum operating temperatures from ASME B31.3 [23] for pipework constructed of the most commonly used composite materials. These operating temperatures are conservative recommendations and do not reflect successful use in specific fluid services at these temperatures.

Table 7.20: Recommended Temperature Limits for Composite Pipework [23]

Composite Category	Minimum Operating Temperature	
	°C	°F
Glass fiber/epoxy	–29	–20
Glass fiber/vinyl ester	–29	–20
Glass fiber/polyester	–29	–20

For non-metallics listed in ASME B31.3 [23], there are no added requirements (in addition to applicable material specification) for toughness tests at or above the listed minimum temperature. Below the listed minimum temperature, ASME B31.3 [23] requires that the designer must have test results at or below the lowest expected service temperature, which assures that the materials and bonds (such as flanges and threads) will have adequate toughness and are suitable for the design minimum temperature.

Composite operating temperatures for topsides pipework based on manufacturer testing are presented in Table 7.21. Note that the operating temperatures are lower than those specified in ASME B31.3 [23] (which are general figures) and do not consider other factors. Contact the manufacturer to verify that the particular composite is suitable for the application.

Table 7.21: Composites Suitable for Use as Topsides Pipework in Arctic and Near Arctic Temperatures

Composite Category	Sub-Category	Operating Temperature (°F/°C)	Common Applications	Properties
Glass fiber/epoxy	Aromatic-amine cured	–40°F (–40°C) to 212°F (100°C)	Piping and components for water systems, chemicals, and some hydrocarbons	Chemical resistance, poor UV resistance
	Cyclo-aliphatic cured	–40°F (–40°C) to 212°F (100°C)	Piping and components for water systems, chemicals, and some hydrocarbons	Chemical resistance, poor UV resistance
	Aliphatic-amine cured	–40°F (–40°C) to 185°F (85°C)	Piping and components for water systems, chemicals, and some hydrocarbons	Chemical resistance, poor UV resistance
	Anhydride-cured	–40°F (–40°C) to 185°F (85°C)	Piping and components for water systems, chemicals, and some hydrocarbons	Chemical resistance, poor UV resistance
Glass fiber/polyester	Isophthalic	–58°F (–50°C) to 140°F (60°C)	Chemical containment and transport	Excellent chemical/corrosion resistance, good mechanical properties, good UV resistance

7.4.4.3 Packers and Drill/Bridge Plugs

All new packers are typically designed to ISO 14310 [80]. For composites, this requires that characteristics critical to the performance of the material are defined. These include:

- Compound type
- Mechanical properties; at a minimum:
  - Tensile strength at break
  - Elongation at break
  - Tensile modulus
- Compression set
- Durometer hardness

Table 7.22 presents testing methods suitable to measure these properties in composites. There are a number of other mechanical properties (which can be determined if required) that are not listed in the table.

Table 7.22: Tests Recommended for Composites Used as Packers for Composites in Arctic and Low Temperature Environments

Test Method	Parameters Tested
ISO 527 Plastics – Determination of tensile properties	Tensile Strength Elongation at break Tensile Modulus
ASTM D3039 Standard Test Method for Tensile Properties of Polymer Matrix Composite Materials	Tensile Strength Elongation at break Tensile Modulus
ASTM D638 Standard Test Method for Tensile Properties of Plastics	Tensile Strength Elongation at break Tensile Modulus
ASTM D695 Test Method for Compressive Properties of Rigid Plastics	Compressive properties
ASTM D395 Standard Test Methods for Rubber Property-Compression Set	Compression Set
ASTM D785 Standard Test Method for Rockwell Hardness of Plastics and Electrical Insulating Materials	Hardness

Validation test requirements that are not limited or restricted by the low temperature requirements of Arctic application are specified in ISO 14310 [80]. This means that composites used for packers in the Arctic can be qualified using ISO 14310 [80]. A number of composites are suitable for use at the temperatures that packers in the Arctic will be exposed. Currently used composite materials for packers, drill plugs, frac plugs, bridge plugs, etc. are not available in the public domain. Contact the manufacturer for specific information and recommendations.

7.4.5 Storage and Handling

Similar to most polymers, a composite packer component may experience temperatures below the operating temperature during storage and transportation. If correct handling and storage procedures are followed, temperatures that are below the operating temperature can be withstood without damage to the composite.

7.4.6 Guidance Notes

Because they may be immune to the attack by chemicals (corrosion resistance), composites offer several advantages over conventional polymers. Additionally, composites can be tailored to achieve high strength, stiffness, high impact resistance, and high thermal conductivity.

7.4.7 Conclusions

A number of composites are suitable for use at Arctic and low temperatures. If it is used as a packer component, a composite will not experience temperatures below the expected operating temperatures.

Composites currently used in topsides applications are not suitable for all conditions on Arctic topsides. The lowest expected temperatures, which may be as low as –72.4°F (–58°C), are on MODUs or drilling platform topsides. The composites most widely used at the moment are suitable for use at –72.4°F (–58°C).

8.0 Arctic Integrity Management

8.1 Introduction

The topics detailed in the earlier sections of this report focus on material property requirements, novel design methods, and fabrication techniques that can ensure reliable material integrity and sound structural designs for Arctic service. Subsequent to fabrication, installation, and project commissioning, it is important to have robust integrity management plans in place to ensure safe and reliable long-term operations.

Integrity management for Arctic service should be focused on managing the effects of degradation from material aging and other external forces. Developing integrity management programs that place emphasis on Inspection, Maintenance, and Repair (IMR) will provide the basis for safety and structural integrity for Arctic offshore structures. Several other aspects that need to be considered as part of the development of robust Integrity Management Plans are detailed in the following sub-sections.

8.2 Ice Management Plan

Ice management can be defined as the sum of all activities where the objective is to reduce or avoid interactions between structures and ice. A robust ice management plan will play a vital role in ensuring adequate protection to subsea equipment, topsides structures, and production equipment (including drilling vessels and associated infrastructures). Because drilling in the Arctic is a significant challenge, it is advisable that a separate ice management plan be developed to handle drilling activities. An additional long-term ice management plan is important to ensure that adequate steps are taken to address structural integrity during the operational phase.

A typical drilling ice management plan submitted by Shell Offshore Inc. is documented in the Bureau of Ocean Energy Management [138]. The Shell plan includes items such as:

- Roles and responsibilities associated with ice management procedures.
- Vessels/drilling units approved for use in accordance with the drilling ice management plan.
- Weather advisory procedures.
- Ice alerts and procedures.
- Established alert levels.
- Established responses to alert levels.
- Ice management philosophy.
- Well suspension contingencies.
- Mooring system recovery and release.

- Drill site access (onwards and return).
- Training.

Similar ice management plans are also required for long-term operations. All ice management plans are subject to BSEE approval.

8.3 Arctic Integrity Management—Offshore Structures and Subsea Equipment

Managing the integrity and reliability of Arctic offshore structures and subsea production equipment is an ongoing process throughout the project lifecycle. Key aspects of a robust Integrity Management Plan for Arctic structures and subsea equipment should address the following program elements [11]:

1. Safety and environmental information
2. Hazards analysis
3. Management of change
4. Operating procedures
5. Safe work practices
6. Assessment of risks to integrity based on available data:
   a. Detailed risk assessments (material aging and environmental effects on materials)
   b. Lessons learned from previous assessments
   c. Operating experience (if available)
   d. Design data
   e. Fabrication data books
   f. Installation and Commissioning reports
   g. Knowledge of loading, metocean data, and marine growth
7. Mitigations and Safeguards
   a. Engineering analyses for representative loads:
      - Static strength and overstress scenarios
      - Fatigue and fracture
      - Structural buckling
      - Foundation failure
      - Ice structure interactions
   b. Ice and severe weather management plan
   c. Monitoring systems in place [127]:
      - Monitoring absolute and relative inelastic structural displacement

- Load variations within the structure (external and between components adjacent to each other)
- Variations in elastic and inelastic strains in the structure
- Measurement of dynamic responses in the structure
- Geotechnical, including piezometric, total pressure and permafrost effects
- Ariel surveys
- Fiber optic temperature integrity and seabed erosion monitoring
- Annual bathymetry, strudel scour, and ice gouge surveys

The specific areas of interest when it comes to integrity management of structures include the following monitoring activities [134] [127]:

- Monitoring the instantaneous response to dynamic loading of floating structures and vessels, including drilling rigs, semi-submersibles, icebreakers, etc.
- Monitoring instantaneous and long-term response of the structural components to static and dynamic loading caused by natural causes such as ice, wind, seismic, and wave loading

Implementation of such a robust integrity management program results in the following benefits:

- Acquisition of reliable data regarding the behavior of the structure helps with making safe operational decisions.
- The existence of historical and current reliability data on the structures helps engineers and Drilling Contractors evaluate existing design criteria and optimize them for future drilling and operations based on robust structural reliability data.
- Periodic review of integrity monitoring data helps prioritize and decrease or increase risks as needed. It also helps with defining an inspection and monitoring program.

It is important to note that equipment selected for monitoring and integrity management systems in the Arctic region will be required to meet performance specifications in terms of the environment. Literature suggests that such equipment will be exposed to the following:

- Low temperatures –76°F (–60°C)
- Marine environments (salt water) that are usually present in the summer
- Infrequent maintenance requirements
- High voltages, currents, and radio frequency/microwaves
- Mechanically hostile environments (ice/wave loading)
- Significantly different operating environments between summer and winter
- Intermittent supply of electrical services and supply voltage

Periodic inspection of structures should be performed to ensure that degradation of structures has not occurred. The most essential inspections to be performed include:

- General Visual Inspection (GVI) and Closed Visual Inspection (CVI) of structural elements and equipment exposed to extreme environments and loading conditions.
- GVI and CVI using ROVs for subsea equipment.
- CP surveys (depletion surveys and voltage measurements).

9.0 Proposed Roadmap for Arctic Drilling and Materials

The objective of this section is to provide BSEE and Operators with a logically developed decision matrix that will allow for the selection of materials, design approaches, and drilling considerations in the low temperature environments (–76°F or –60°C) that are prevalent in the Arctic. This decision matrix is designed to assist BSEE, Operators, and steel fabricators with an appropriate strategy for Arctic drilling operations and to overcome challenges associated with material properties, design, and structural fabrication. As the central feature of this approach, a series of flow charts that provide detailed guidance are presented. These flowcharts provide guidance in the following areas:

- Drilling vessels and associated equipment
- Topsides process, production equipment, and structures
- In water structures, equipment, and pipelines (subsea)

Furthermore, the flow charts have been structured to separately handle materials selection and design for metallic and non-metallic materials. This approach has been selected based on the rationale that materials selection considerations and design methods adopted for load bearing members that are susceptible to the synergistic effects of cold temperatures and wind/wave loading are expected to be different from those for non-load bearing elements (typically non-metallic materials).

The flow charts have been developed to cover the entire lifecycle for Arctic operations. The aspects of the project lifecycle addressed as part of this roadmap include:

1. Drilling vessel selection (mobility, operability, and station keeping considerations).
2. Drilling operations (drilling fluid, cementing, and well control and containment).
3. Above water structures (materials selection, design, and fabrication).
4. Below water structures (designing protections for ice damage and the development of effective ice management plans).
5. Integrity management for long-term operations.

The Master Flow Chart in the decision matrix is divided into paths for the selection of metallic and non-metallic materials. The paths for the selection of both metallic and non-metallic materials are further divided into Above Water Structures and In-water Structures. The decision matrix uses the following acronyms that serve as pointers or links to more detailed flow charts:

- MA: Metallic Above Water
- MI: Metallic Below Water

- NA: Non-metallic Above Water
- NI: Non-metallic Below Water

The decision matrix for selecting and qualifying equipment and structures for drilling applications addresses the following environmental and operability considerations:

- Drilling rig, vessel selection, and drilling environments:
  - Operability and water depth considerations
  - Station keeping considerations
  - Mobility issues (ice breaker and drilling vessel hull design requirements)
- Drilling Operations:
  - Drilling fluids
  - Cementing
  - Well control and containment

Materials selection, design, and fabrication for topsides equipment (process and production) and structures above the water line are addressed in the decision matrix based on the following considerations:

- Weld and filler material:
  - Welding procedure selection for the Arctic
  - Weld toughness qualifications at –76°F (–60°C)
- Structural materials (except welds)—materials toughness qualification –76°F (–60°C)
- CTOD test requirements with stringent statistical bounds
- Structural and equipment design using novel design techniques
- Structural fabrication and qualification
- Regulatory approval

Materials selection is not considered to be a concern for subsea equipment and structures because the ambient temperatures are expected to be approximately 39°F (4°C). However, equipment design for the Arctic (especially in shallow waters) would need to take into account damage from ice gouging and ice scouring effects on pipelines and subsea equipment (such as wellheads and manifolds).

The decision matrix for in-water equipment and structures addresses the following concerns:

- Ice gouging and ice scouring threat to subsea pipelines and equipment
- Protection and mitigation methods for pipelines and subsea equipment
- Development of comprehensive ice management plans (drilling and operations) for regulatory approval

The proposed decision matrices for drilling vessel and equipment selection and guidance for selecting metallic and non-metallic materials are provided in Figure 9.1 through Figure 9.11.

Detailed descriptions of the proposed methodologies for drilling vessel and equipment selection, materials selection, and state-of-the-art design methodologies are provided in Section 3.0 of this report.

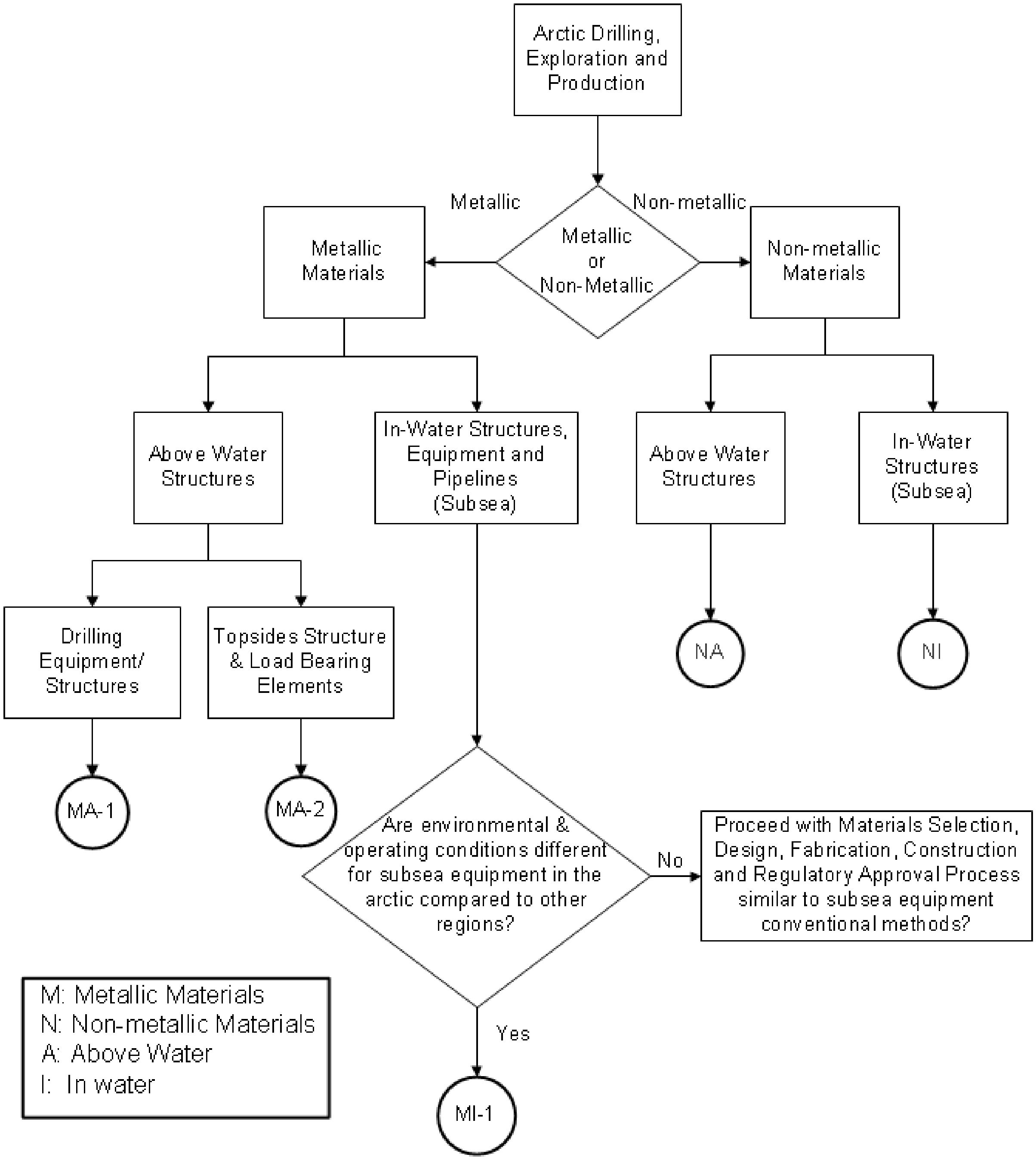

Figure 9.1: Master Decision Matrix

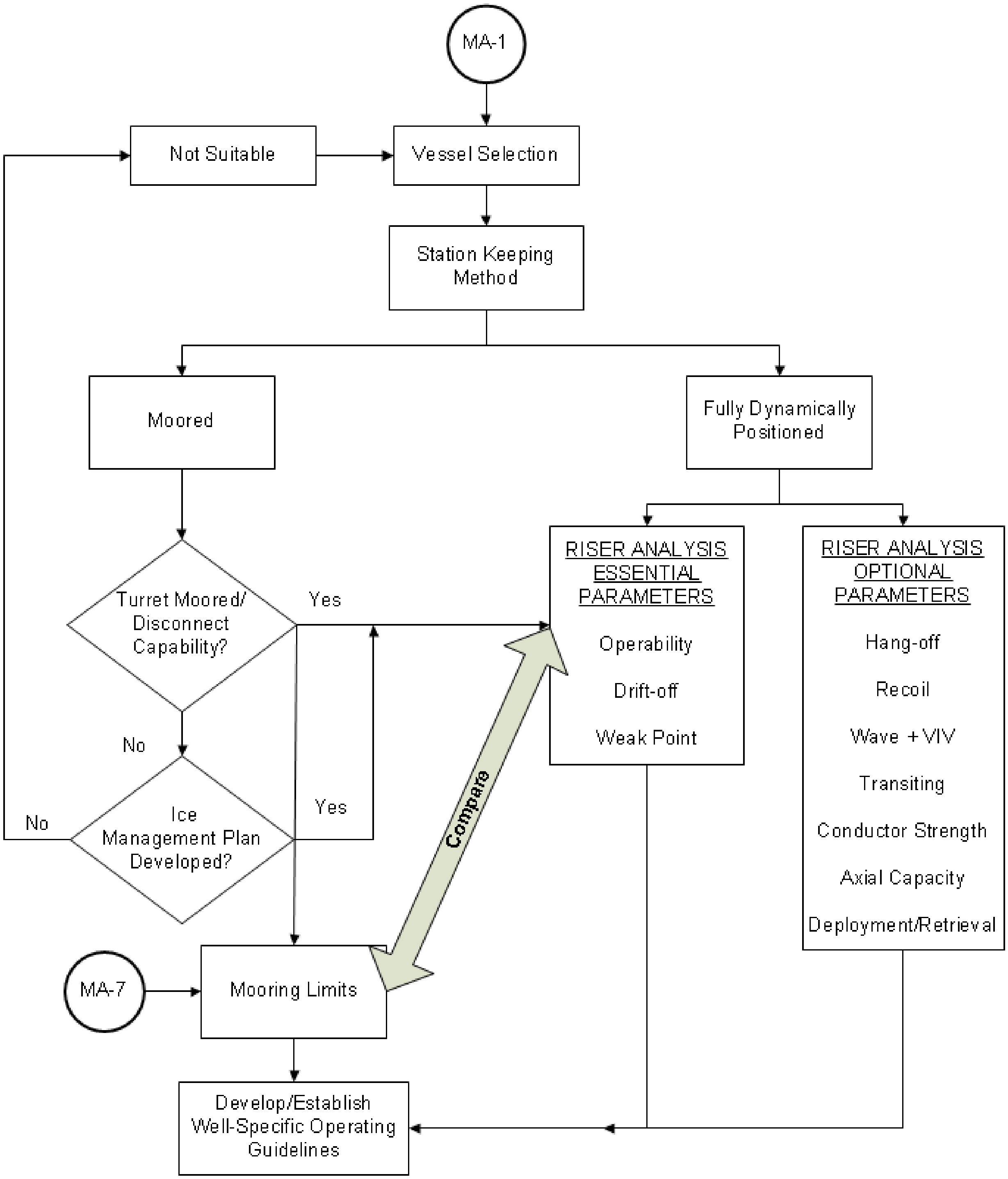

Figure 9.2: Drilling Vessel Consideration

Figure 9.3: Drilling Vessel—Mooring

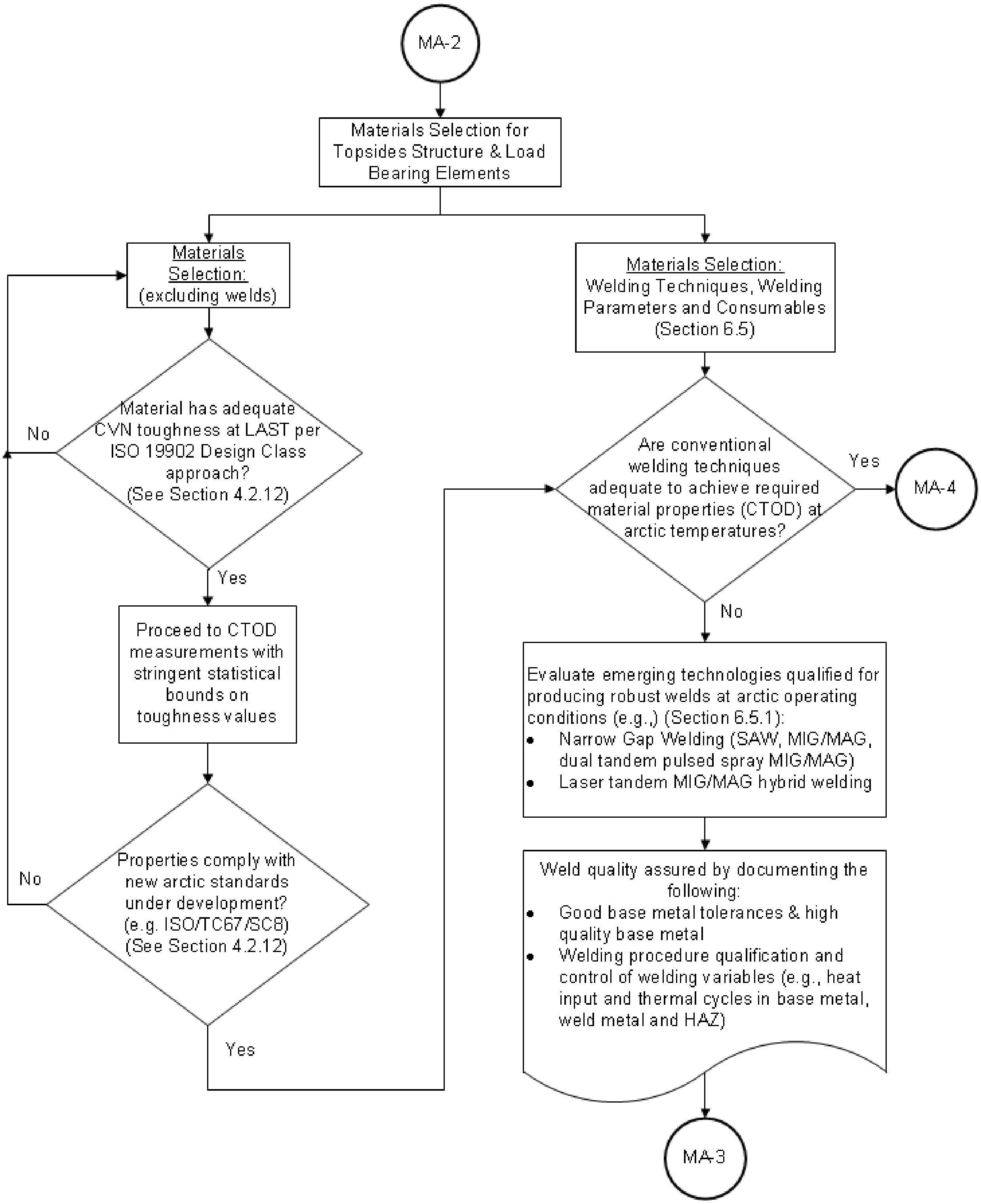

Figure 9.4: Metallic Materials (Structures) Above Water

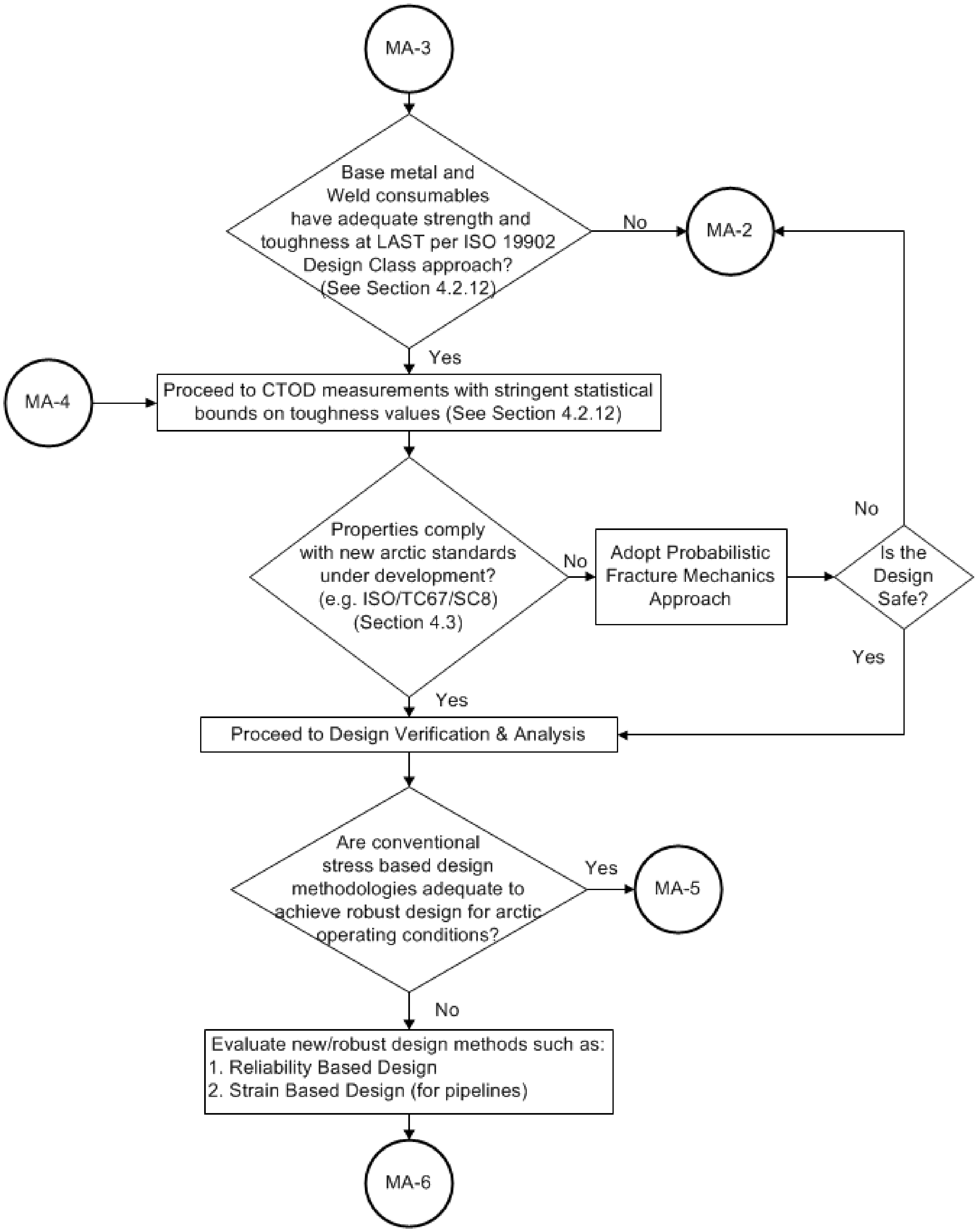

Figure 9.5: Metallic Materials (Structures) Above Water (*continued*)

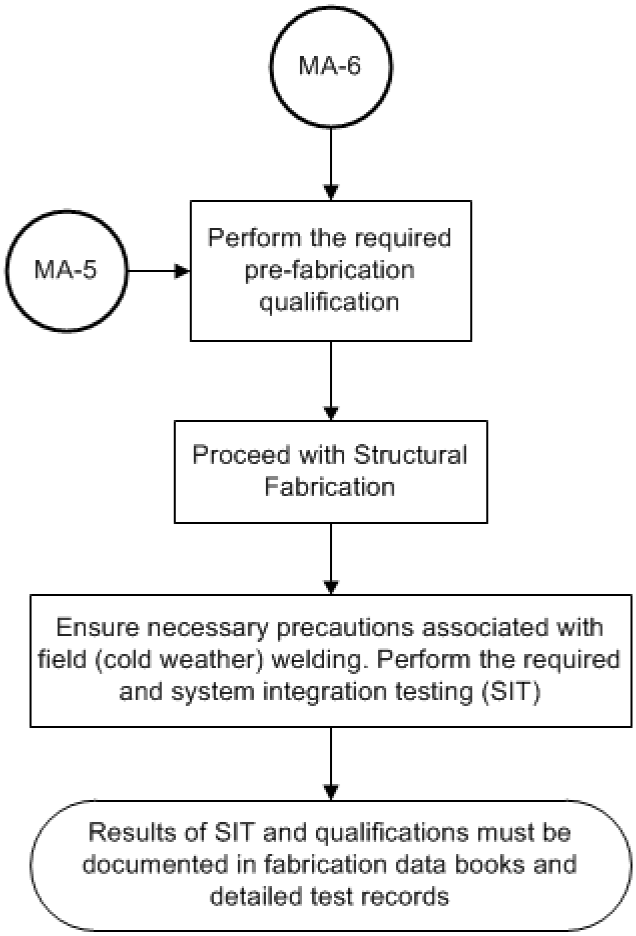

Figure 9.6: Metallic Materials (Structures) Above Water (*continued*)

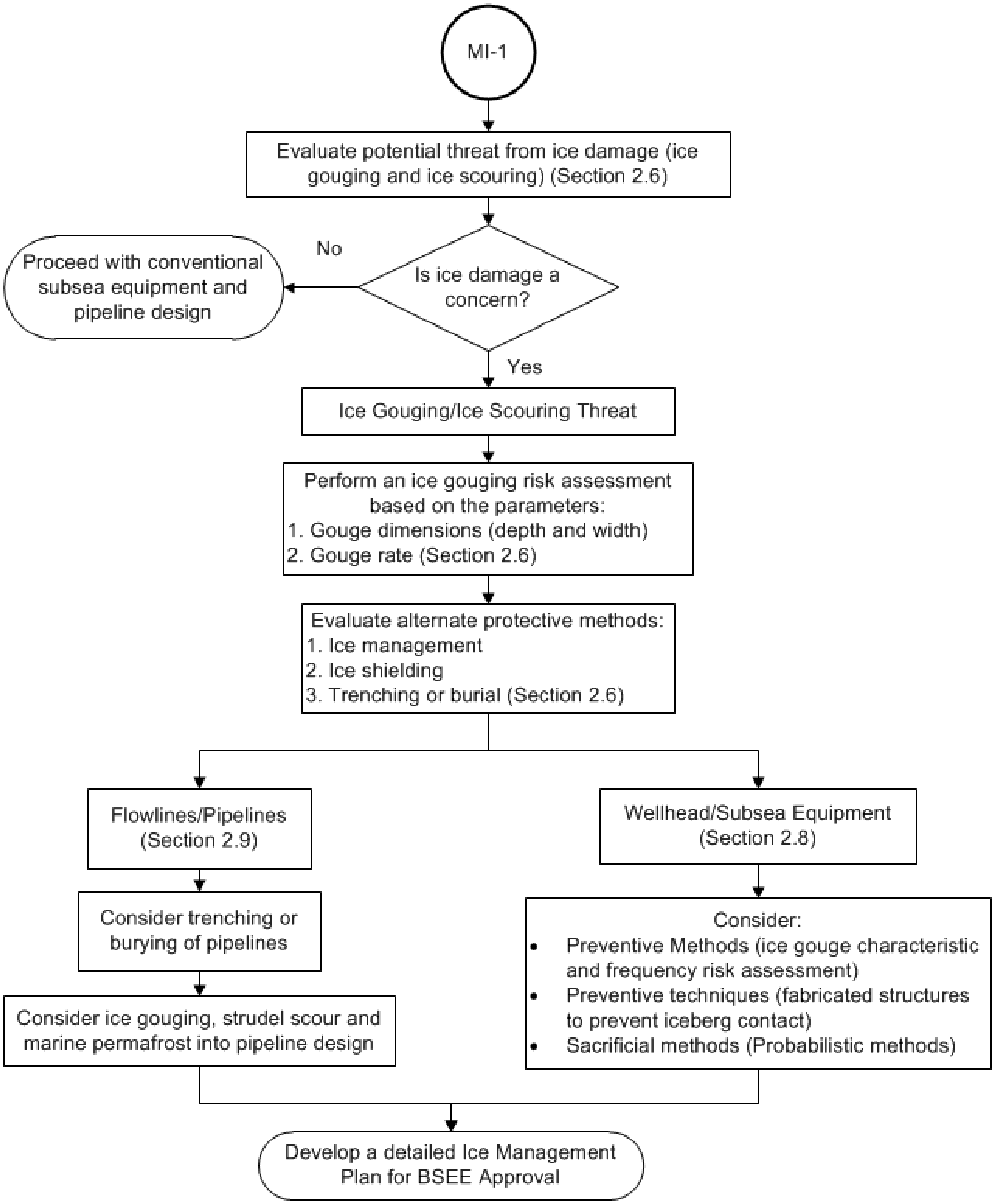

Figure 9.7: Metallic Materials (Structures) In-water Use

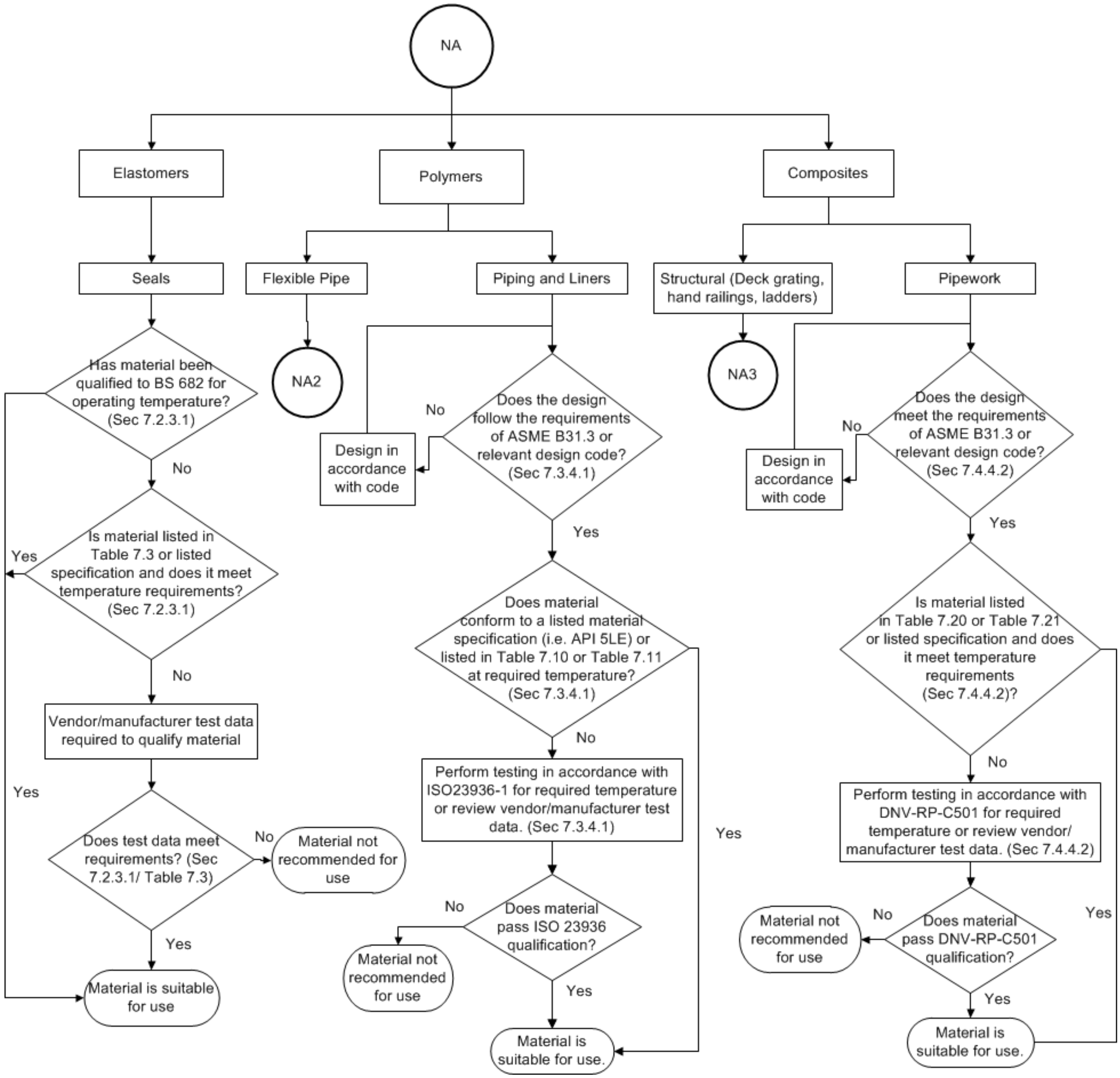

Figure 9.8: Non-metallic Materials Above Water

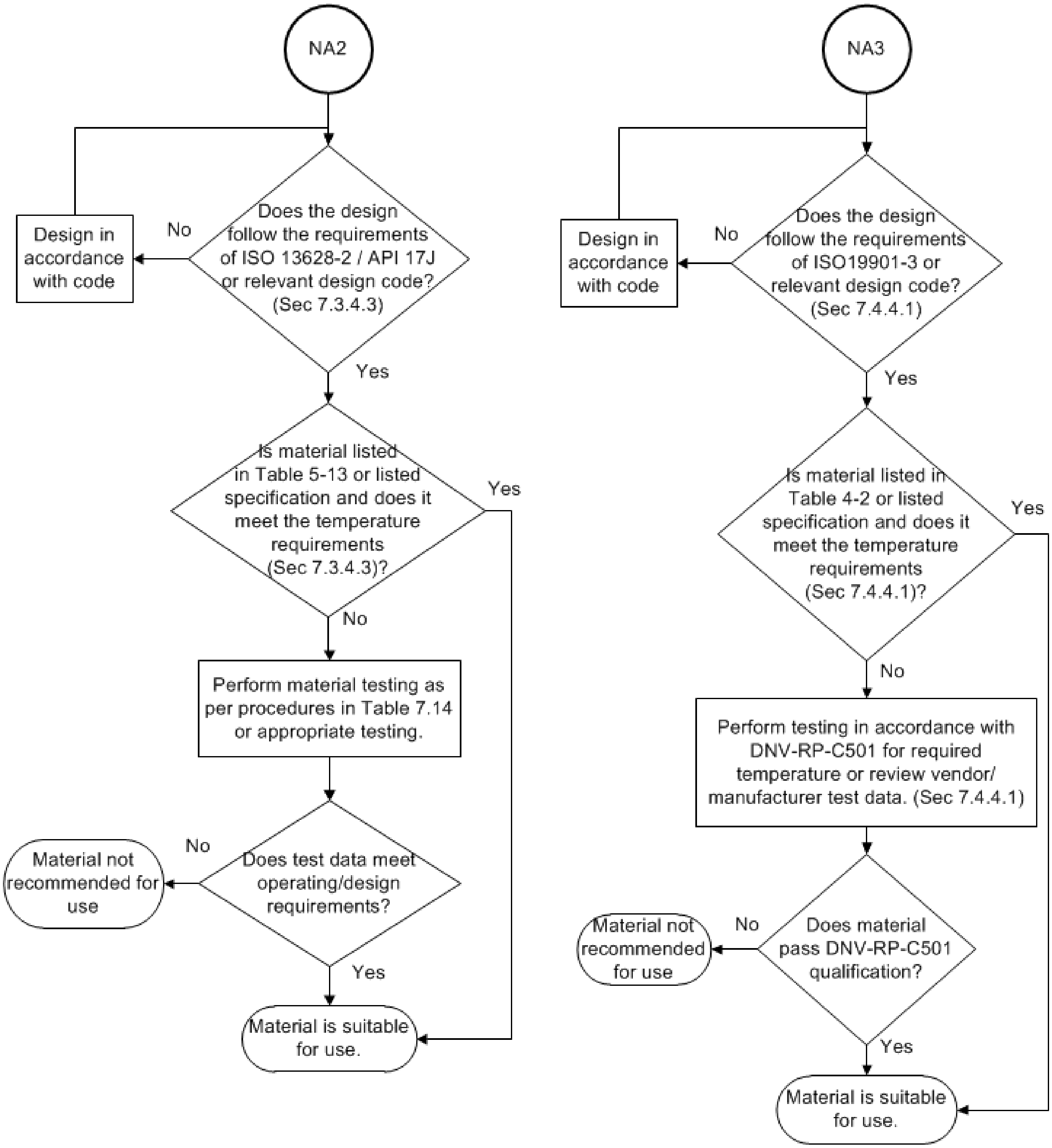

Figure 9.9: Non-metallic Materials Above Water

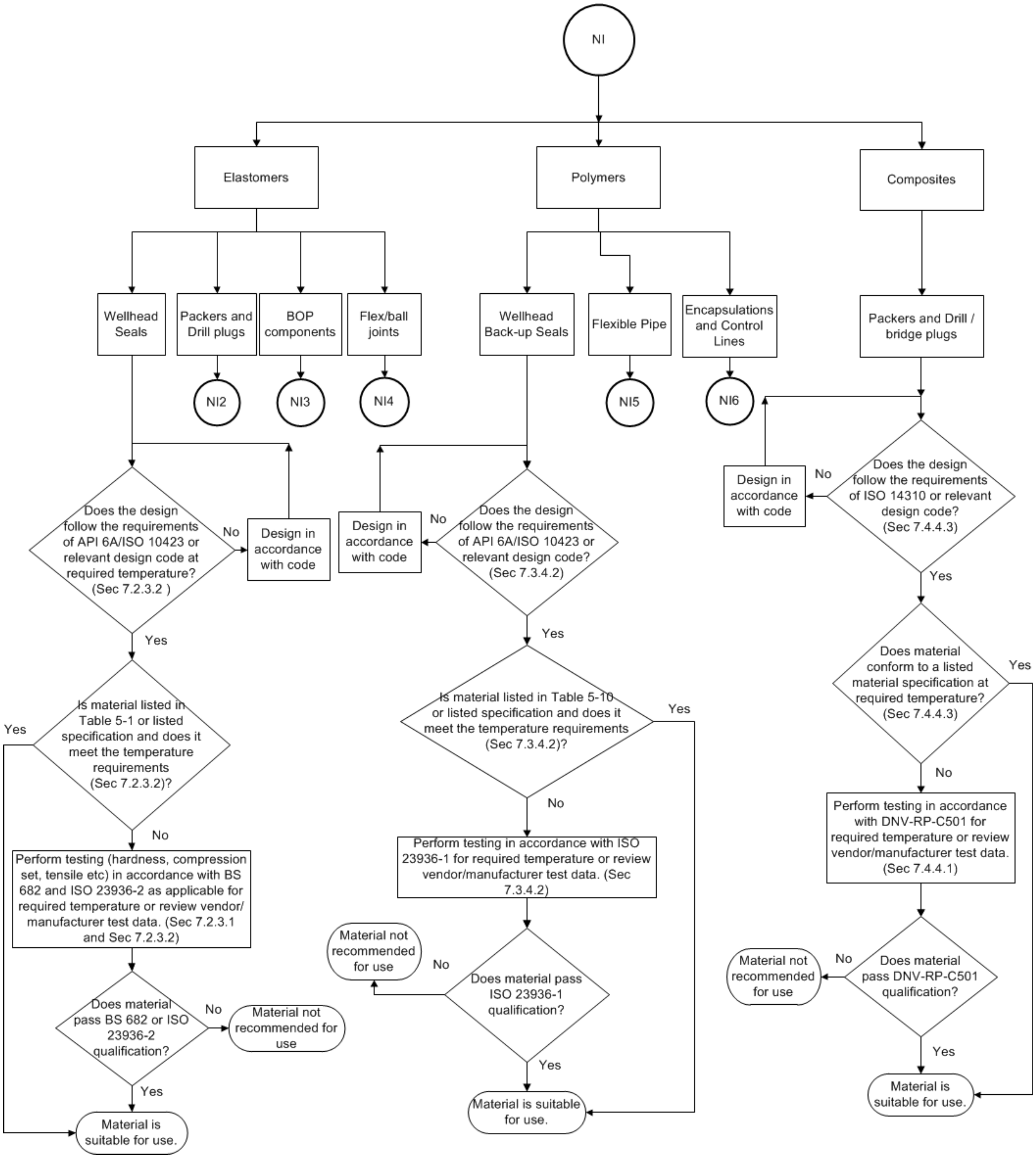

Figure 9.10: Non-metallic Materials In-water

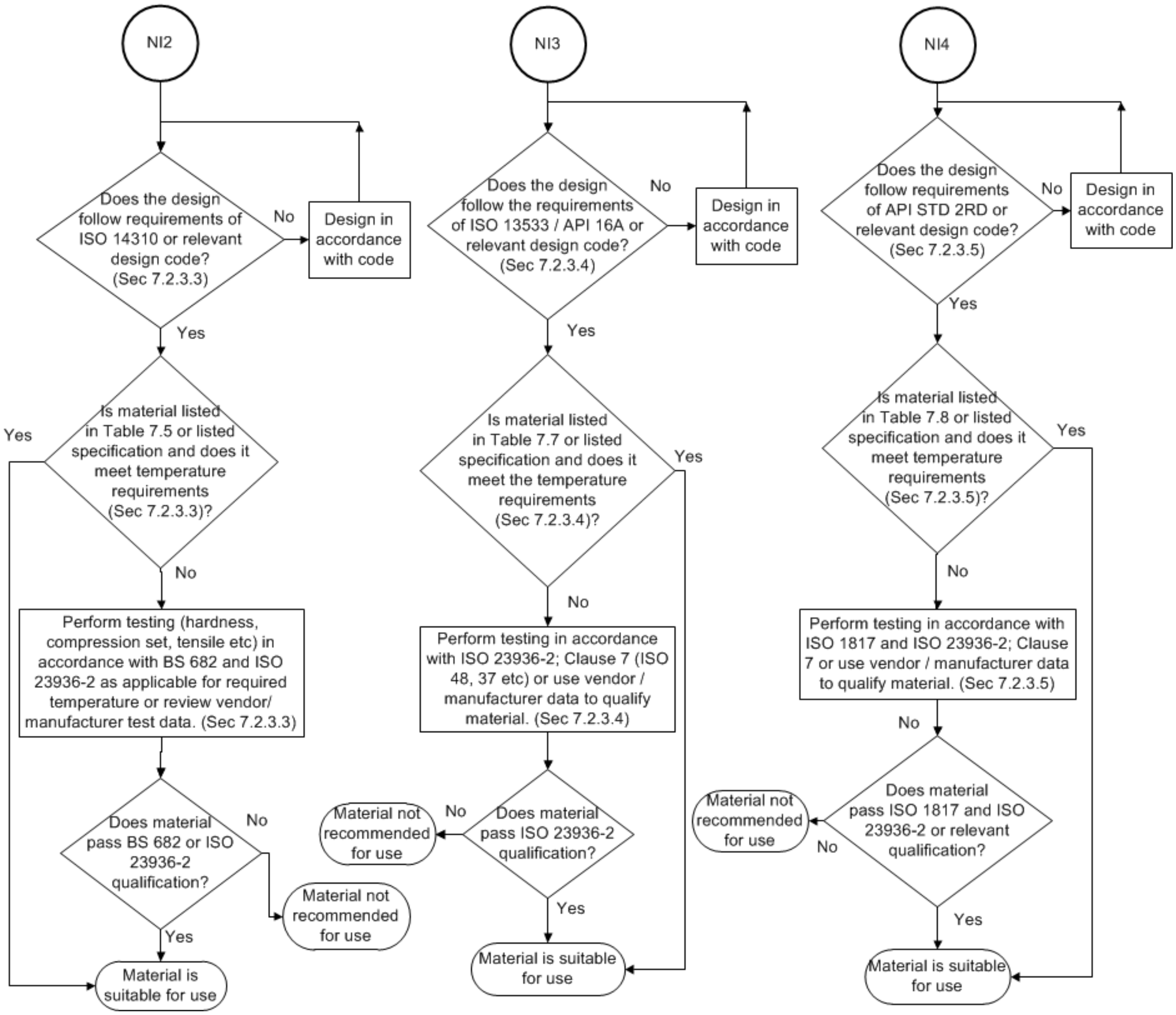

Figure 9.11: Non-metallic Materials In-water (*continued*)

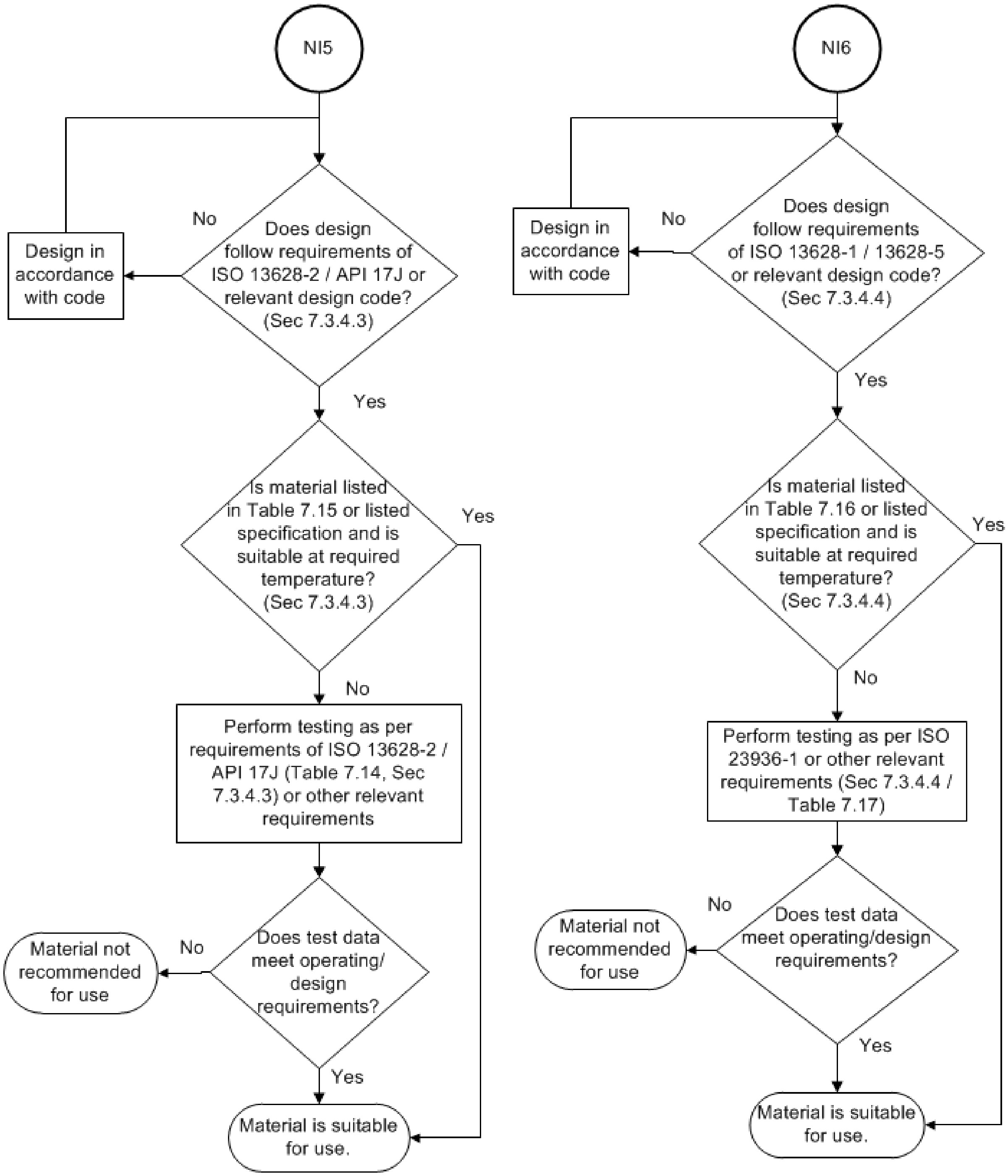

Figure 9.12: Non-metallic Materials In-water (*continued*)

10.0 Summary and Recommendations

10.1 Summary

Wood Group Kenny (WGK) is under contract with the Bureau of Safety and Environmental Enforcement (BSEE) to execute a technology and research project to assess Low Temperature Effects on Drilling Equipment and Materials. This study is performed in accordance with Section C (BSEE's Contract No. E14PC00012).

Qualification of drilling structures and equipment for Arctic drilling and production of oil and gas involves different steps. The first step requires determining the Lowest Anticipated Service Temperature (LAST) of the materials that are exposed to the Arctic environment. The second step requires an understanding of the effect of the Arctic environment in the degradation mechanism (or mechanisms) of the materials. In some cases, the qualification can follow existing regulations or international standards. In some other cases (particularly at lower LAST), the existing regulation or standard is not applicable to the given environment. A summary of the main findings for each of the sections of the report is provided in the following sub-sections.

10.1.1 Drilling Techniques and Drilling Fluids

Some of the challenges to drilling onshore and offshore wells in Arctic environments include the extremely cold temperature, frozen ground covered with ice, frozen seas during the long winter season, and a short drilling season. A rig that is capable of drilling in Arctic conditions can allow for an earlier start to the drilling season because the rig can move in when the sea ice starts to recede (thereby reducing total drilling costs). Well design should take into consideration materials selection for casing, cements, drilling hydraulics, and drilling fluids and should account for potential thermal cycling of the formation.

WGK has found that the current industry initiatives have focused either on improving the safety and containment during drilling or in the selection of the appropriate ships and offshore structures.

10.1.2 Metallic Materials

In the case of metallic materials, understanding the brittle fracture and fatigue life acceptance criteria of materials at the LAST in Arctic conditions is crucial. The current materials specifications are not specifically intended to be used for Exploration and Production (E&P) in Arctic Environments. The industry has been focusing on the improvement of a wide range of properties such as strength, fracture toughness, fatigue performance, weldability, and corrosion resistance. Additionally, the industry is now focused on the improvement of fabrication, welding techniques, and methods for analysis and experimental measurements of fracture toughness. Still under development are new guidelines for the selection and qualification of materials for Arctic applications and the standardization of techniques such as probabilistic fracture mechanics and reliability-based design for Arctic offshore applications. Therefore, additional work to guide the industry with codes and standards that are specifically targeted to increase safety during E&P in Arctic environments is needed.

10.1.3 Non-metallic Materials

The mechanical properties of many non-metallic materials are very similar to their metallic counterparts. Some of them are lighter and ‘immune’ to corrosion. Although some of these materials may undergo other types of aging or degradation, their chemical interactions with the environment appear to be minimal. Data regarding the performance of polymers and composites in Arctic conditions is limited. The industry is also focusing in the research and development of new polymeric materials and composites (including fiber-reinforced polymers) as a replacement for metallic components used in aggressive environments where the use of metallic components is prohibited. Constant improvement of the properties of commonly used polymers and composites and the development of new non-metallic materials to satisfy the need for longer life expectancy in harsh applications is underway; WGK has found that several companies at the forefront of this effort are not willing to share their findings.

10.1.4 Industrial Survey and Main Findings

WGK developed a survey questionnaire and sent it to material producers, equipment manufacturers, operators, testing laboratories, and consultants. The survey focused on the materials used in Arctic conditions and also included some of the common practices for transportation, storage, drilling, and production. The survey identified gaps in the industry with respect to the storage, safe handling, and de-rating of materials when they are used in Arctic environments.

Currently, there are no guidelines that prescribe requirements for packing, shipping, safe handling, testing, qualification, and de-rating of materials that are conventionally used in the contiguous U.S. that may be applied to Arctic environments. Materials producers, equipment manufacturers, and operators need this knowledge to de-rate and prescribe proper procedures for handling and deploying materials in Arctic conditions.

10.2 Recommendations

A summary of the main recommendations follows.

10.2.1 Drilling Techniques and Drilling Fluids

The use of drilling rigs that are capable of drilling in Arctic conditions could open up the drilling season beyond the conventional open water season, but it could increases the risk for failure of some materials due to their exposure to Arctic conditions for longer periods of time. To avoid premature failure of materials used in the manufacturing of such drilling rigs and the equipment used during oil and gas operations, WGK recommends that the industry:

1. Seek a better understanding of the properties of critical materials properties used in the Arctic.
2. Use high capacity mud cooling systems for Arctic drilling, as they prevent the thawing of permafrost and help to prevent materials failure.
3. During Arctic drilling, use a high viscosity fluid with minimal shear to reduce erosion and heat transfer effects.
4. Use Freeze Protected Slurries (FPS) (in conjunction with cement) to facilitate cement flow, prevent freezing, and help to develop good compressive strength, thereby enabling safer operations during drilling.
5. For well design, consider materials selection for casing, cements, drilling hydraulics, and drilling fluids to account for thermal cycling, hydrate plugging, and other effects related to Arctic conditions.
6. Provide adequate mooring and emergency disconnect in order to be prepared for severe weather effects in the Arctic.
7. Select the appropriate vessel and have a contingency plan in case of a spill caused by premature failure of the equipment.

10.2.2 Metallic Materials

In connection with metallic materials, WGK recommends that the industry:

1. Design metallic and non-metallic materials used in Arctic drilling and associated structures for the Lowest Anticipated Service Temperature (LAST), which could, in some cases, be as low as –76°F (–60°C).
2. Take into consideration the larger stress amplitudes resulting from wave loading, wind loads, thermal cycling, and impacts from floating ice when selecting materials and designing structures in the Arctic.

3. Thoroughly review the degradation mechanisms of metallic materials, with specific emphasis on loss of fracture toughness at low temperatures.
4. Take into consider the control of fracture properties of metallic materials (Charpy V Notch [CVN] and Crack Tip Opening Displacement [CTOD]) for robust structural design against brittle fracture.
5. Base materials selection and design guidelines for Arctic environments on strong engineering principles and adequately conservative statistical and design margins.
6. Qualify new materials and welding techniques after carefully considering existing standards that are suitable for cold climates but taking into account the extreme Arctic conditions and temperature cycles present in the Arctic.
7. Use reliability-based methods to incorporate statistically bounding low temperature fracture toughness into structural design and fatigue life assessment to enhance structural integrity for Arctic applications.
8. Develop relevant methods for analysis and experimental measurements of fracture toughness of metallic materials and welded metals.

10.2.3 Non-metallic Materials

In connection with non-metallic materials, WGK recommends that the industry:

1. Take into consideration the design loads and accumulation of ice in the structures exposed to Arctic environments.
2. Although there are several materials that can resist lower temperatures, conduct a thorough review of the degradation mechanisms at low temperatures in the service environment before a polymeric material can be used in Arctic environments.
3. Because of the lack of codes and standards, qualify polymeric materials that will be used in Arctic environments at the LAST.

10.2.4 Guidelines

Finally, while significant advances have been made towards safer drilling techniques, with more resistant materials, and better seals, the industry must develop guidelines that prescribe the requirements for packing, shipping, handling, testing, qualifying, and de-rating materials that will be used in Arctic environments.

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