Status of Arctic Pipeline Standards and Technology Final Report

9158-001-003

INTECSEA
WorleyParsons Group

PCCI
Marine and Environmental Engineering

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1 Executive Summary

In August 2017, BSEE awarded Contract E17PD00099 to PCCI, with INTECSEA as the lead subcontractor, for a project titled Status of Arctic Pipeline Standards and Technology. This Final Report summarizes the results of a comprehensive review and gap analysis of Arctic Pipeline standards, assessment of the suitability of a single-walled versus pipe-in-pipe system, and presents information on some of the advancements in pipeline design, installation, and operations, that may be applicable to an Arctic environment.

Offshore pipelines in an Arctic or ice covered environment face challenges different from traditional subsea pipeline design. This report provides an overview of what these challenges may entail, how they have been overcome in past projects, and technology advancements that may help with future developments. An assessment and gap analysis of the standards, codes and regulations is detailed and perceived gaps in regulations are presented. The comparison and suitability of single-walled pipe versus double-walled (pipe-in-pipe) systems was reviewed and details from current regulations provided.

Chapter Two introduces the objective and the scope of the project and the focus for this Final Report.

Chapter Three summarizes nine existing offshore Arctic pipelines in the U.S., Canada and Russia. Several of these pipelines are single-walled, and the others are a pipe-in-pipe system.

The Arctic-specific challenges described in Chapter Four include ice scouring (or gouging), strudel scours, permafrost thaw and frost heave. These four conditions cause increased strain in a pipeline, a need for monitoring and leak detection, and potentially innovative construction and repair solutions. These operating conditions may require unique designs but still must adhere to regulatory requirements and pipeline design codes, standards, and guidance. Given the differences from a typical offshore pipeline design, designers, operators and regulatory bodies need to be aware of the codes, standards and regulations applicable for proposed Arctic developments. Chapter Four also includes a discussion of design methods and principles that may be used in an Arctic environment and a summary of some of the key design challenges and solutions for the three previous Alaskan offshore Arctic pipelines.

Chapter Five gives a review of standards, codes, and regulations including three that are specific to Arctic operations and eight that are that are widely used for traditional subsea pipeline design. Also included were documents specific to leak detection. The review examined International and United States Federal Regulations, and those relating to offshore Alaska. These documents were qualitatively assessed using a traffic light approach. The most comprehensive offshore Arctic pipeline design standard included is ISO 19906 (Arctic Offshore Structures), with little other guidance found for offshore pipelines in Arctic regions beyond statements relating to the inclusion of environmental factors and considerations.

Chapter Five also summarizes five guidelines for monitoring and leak detection. The apparent industry best practice for Arctic offshore pipelines is to use a combination of a reliable internal/computational pipeline monitoring system with an external leak detection system. However, one particular system cannot be identified as best practice due to dependence on the pipeline design and application; a combination of monitoring strategies should be considered that are suitable for the application, and the best solution selected that satisfies project requirements and monitoring needs.

Chapter Six describes the Gap Analysis Matrix developed as part of this project. Using a traffic-light approach, it summarizes the existing guidelines and codes using three main categories; environmental loading, monitoring and leak detection, and installation and repair. The Gap Analysis Matrix summary is provided in Appendix A and additionally as Document Number 9158-001-002 as the native Microsoft Excel file.

Chapter Seven discusses Best Practices and Industry Development. This includes commentary on environmental data, monitoring and leak detection, trenching, installation, and repair. It provides details on what has previously been completed for existing projects and some of the limitations that may be experienced.

Chapter Eight summarizes the findings from previous Arctic design studies and analysis of alternatives. In assessing the suitability of single-walled versus pipe-in-pipe systems for Arctic offshore applications, it was found that both single-walled and pipe-in-pipe systems have been successfully designed, installed and operated on the Alaskan North Slope.

Chapter Nine further discusses the terms used in the comparison Matrix for single walled versus double-walled pipelines. It details discussion around the factors that were used for the comparison.

Chapter Ten discusses the identified gaps in Codes and Standards and their suitability to offshore Arctic pipeline design, construction, installation and monitoring. It also concludes there is no clear advantage or disadvantage for the single-walled pipeline or PIP system in terms of leak containment since the PIP system provides a means of secondary leak containment but also complicates monitoring of and repairs to the production flowline, compared to a single-walled design. The decision to adopt one design over the other should be made based on project-specific requirements and objectives.

Chapter Eleven highlights technology advancements that are occurring with pipeline design, installation and operations. While all advancements may not be specific to an Arctic environment, they are details that may influence and remove potential conservatism from future developments. Some of the topics presented include developments on the prediction of potential environmental loadings on the pipeline, materials that may be used, and leak detection and pipeline inspection methods to be used during operations.

2 Introduction

2.1 Objective

The objective of this Final Report is to provide the BSEE Alaska Region with a comprehensive offshore Arctic pipelines gap analysis to assess the comprehensiveness of current regulations, standards, and codes pertaining to design and development of offshore pipelines in the Arctic and to report on the state-of-the-art and emerging technologies for offshore pipelines in Arctic applications. When a development plan is submitted, a new pipeline is proposed, or modifications and/or repair to an existing pipeline is required, government officials will ensure that satisfactory technical and functional qualifications are being met by the proponents. The overall objective of the gap analysis matrix developed as part of this report is to provide a regulatory snapshot for understanding the maturity of formal Arctic offshore pipeline design guidance and how documents can be complementary for project development, based upon the regulatory framework at the time of this study.

The comparative discussion of single-walled versus pipe-in-pipe design summarizes previous reports and studies, as well as past projects and applicable codes and regulations in order to compare the suitability of single-walled and pipe-in-pipe designs, and ascertain the current state-of-practice. The basis for offshore Arctic pipeline design is to provide the safest and most economically prudent design for the environment. Understanding the benefits and functionality of different designs allows for evolution of this discussion and ensures that successful design practices and lessons learned where improvements can be made carry through to future designs.

A discussion on the key design principles used for current Alaskan North Slope offshore pipelines highlights the evolution of design methodology and the progression of design considerations. By highlighting and discussing some of the key challenges and solutions, advancements can be made for future projects. A review of some of the start-of-the-art and emerging technology for offshore pipelines that may be suitable for an Arctic environment provides insight on where further advancement may be needed.

2.2 Scope

This report includes the results of a literature review and gap analysis of regulations, standards, and codes, a review of single-walled versus double–walled pipeline suitability for Arctic offshore applications and a discussion on previous project challenges and solutions, and emerging offshore Arctic pipeline technology.

The regulatory assessment includes a comprehensive review of current United States, State of Alaska, and international regulations, standards and related specifications and technical reports for offshore hydrocarbon-carrying pipelines, with a focus on, but not limited to, pipelines in Arctic conditions. These documents are assessed based on the information they provide to aid the reader on considerations needed for offshore Arctic pipelines. This includes necessary information for the following categories:

- Design requirements for environmental loading conditions such as ice scouring, strudel scours, permafrost thaw settlement, and other factors.
- Incorporation of leak detection systems for Arctic environments.
- Installation, testing and repair requirements and challenges for Arctic environments.

The comprehensive review includes a comparison of the suitability of single vs. pipe-in-pipe (PIP) hydrocarbon-carrying pipelines in Arctic conditions. This comparison includes review of the Technology Assessment Program (TAP) study "An Engineering Assessment of Double Wall vs. Single Wall designs for Offshore Pipelines in an Arctic Environment." In addition to the information provided in the TAP report, other studies of design alternatives for the Liberty oil pipeline are included.

Single-walled vs. PIP pipeline technology are assessed against a number of criteria and then qualitatively ranked. The criteria to be considered include:

- Safety in design
- Leak containment
- Leak detection / operational monitoring
- Environmental footprint
- Materials requirements
- Installation (technology, lay-rates, impact on welding, etc.)
- Repair
- Cost
- Decommissioning

The review of the state-of-the-art and emerging Arctic pipeline technology has emphasis on United States, State of Alaska and international Arctic applications. In reviewing the status of technology, the following categories were considered:

- A review of design methods and principles that were used on current Alaskan North Slope offshore pipelines. Key challenges and solutions to these unique design issues are detailed.
- A review of emerging pipeline offshore technology that may be applicable for future offshore Arctic pipeline projects.

2.3 Abbreviations

Table 1 provides a list of abbreviations used throughout this report.

Table 1: Abbreviations

Abbreviation	Definition
ADEC	State of Alaska Department of Environmental Conservation
ALE	Arbitrary Lagrangian Eularian
API	American Petroleum Institute
ASME	American Society of Mechanical Engineers
AUT	Automated Ultrasonic Testing
AUV	Autonomous Underwater Vehicle
BAST	Best Available and Safest Technology
BAT	Best Available Technology
BOEM	Bureau of Ocean Energy Management
BPXA	British Petroleum Exploration Alaska
BSEE	Bureau of Safety and Environmental Enforcement
CEL	Coupled Eulerian Lagrangian
CFR	Code of Federal Regulations
CPM	Computational Pipeline Monitoring
CRES	Center for Reliable Energy Systems
CSA	Canadian Standards Association
CTOD	Crack-Tip Opening Displacement
DAS	Distributed Acoustic Sensing
DOI	Department of the Interior
DOT	Department of Transportation
DNVGL	Det Norske Veritas- Germanischer Lloyd

Abbreviation	Definition
DTS	Distributed Temperature Sensing
ECA	Engineering Critical Assessment
EU	European Union
FEA	Finite Element Analysis
ft	Feet
FOC	Fiber Optic Cable
GIS	Geographical Information System
HDPE	High-Density Polyethylene
ID	Inner Diameter
ISO	International Standards Organization
LDP	Leak Detection Program
LDS	Leak Detection System
LRFD	Load and Resistance Factor Design
m	Meter
MB	Mass Balance
MFL	Magnetic Flux Leakage
MMS	Minerals Management Service (currently BSEE, BOEM, and ONRR)
NPS	Nominal Pipe Size
OCS	Outer Continental Shelf
OTDR	Optical Time Domain Reflectometers
OD	Outer Diameter

Abbreviation	Definition
ONRR	Office of Natural Resources Revenue
PIP	Pipe-in-Pipe
PPA	Pressure Point Analysis
PSL	Pressure Switch Low
RMRS	Russian Maritime Registry of Shipping
ROV	Remotely Operated Vehicle
RTTM	Real Time Transient Monitoring
SBECA	Strain-Based Engineering Critical Assessment
SCADA	Supervisory Control and Data Acquisition
SES	Stress Engineering Services
SLS	Serviceability Limit States
SME	Subject Matter Expert
TAP	Technology Assessment Program
TRL	Technology Readiness Level
UK	United Kingdom
ULS	Ultimate Limit States
US	United States
UT	Ultrasonic Testing
VIV	Vortex Induced Vibration
VSM	Vertical Support Member
WT	Wall Thickness

3 Existing Offshore Arctic Pipelines

Nine offshore pipeline projects have been installed and operated in the Arctic and are summarized below. Additional pipelines installed north of the Arctic Circle but not exposed to seasonal sea ice conditions are not included in this review. The three US operational pipeline projects offshore Alaska, Northstar (BP, now operated by Hilcorp), Oooguruk (Pioneer, now operated by Caelus Energy) and Nikaitchuq (ENI), provide a significant experience base for designing, installing and operating future offshore Arctic pipelines. Figure 3-1 shows the location of these projects, including Endicott Island and the proposed location of Liberty. Figure 3-2 provides design details for the three operational Alaskan offshore pipelines / flowline bundles; these projects are discussed further in the subsections that follow.

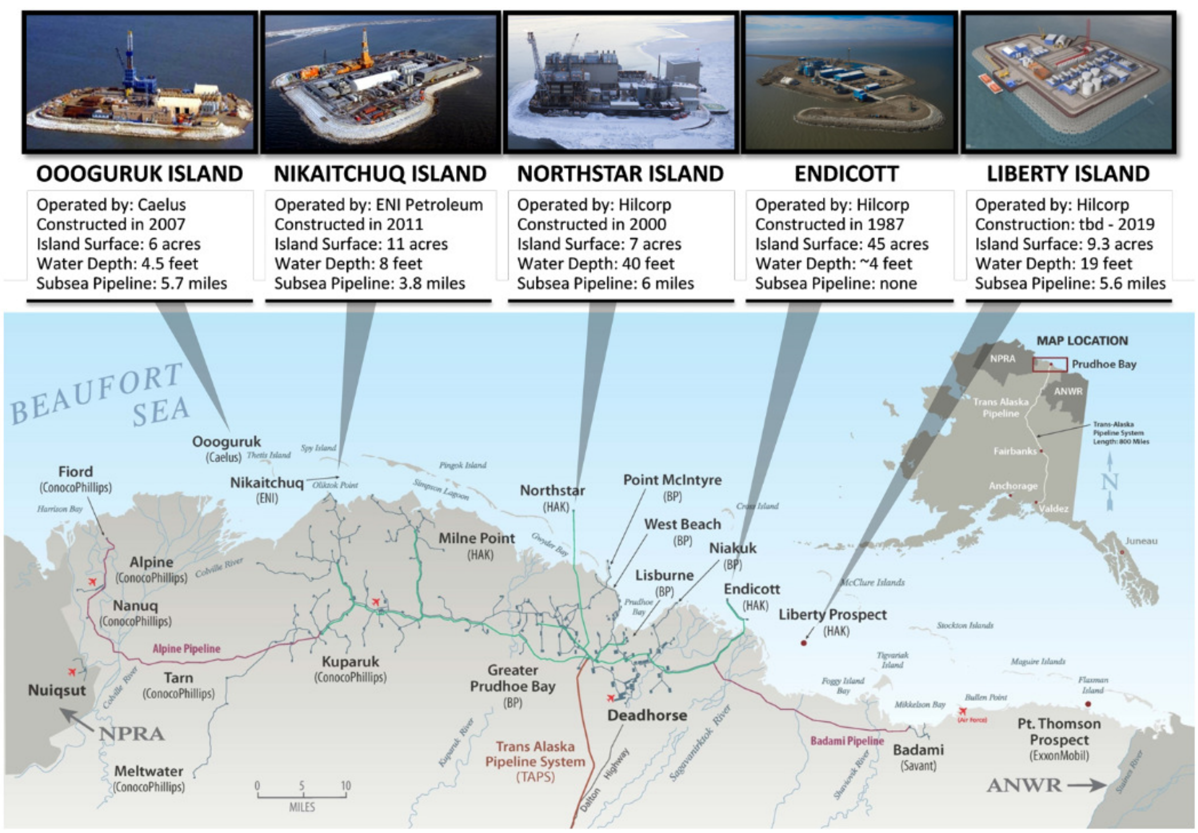

Figure 3-1: Alaskan Offshore Projects [Ref. 7]

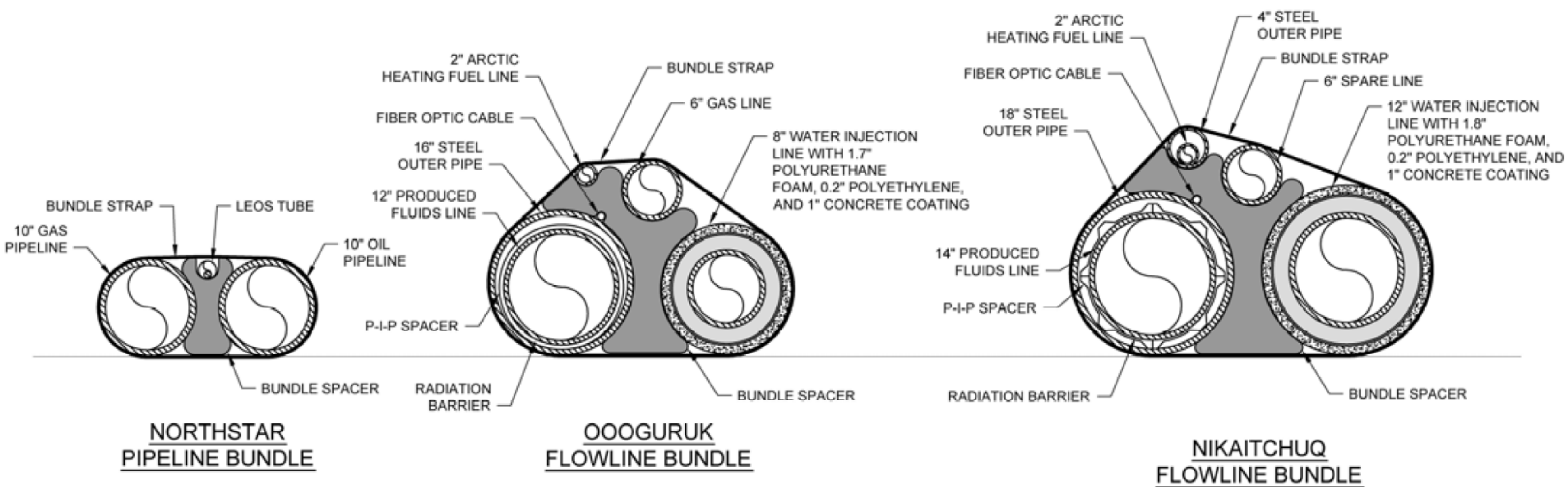

Figure 3-2: Northstar, Oooguruk, and Nikaitchuq Pipeline / Bundle Cross-Sectional Details [Ref. 17]

Figure 3-3 provides images that depict the definitions around trenching, backfill, and depth of cover. The consistent use of these terms can avoid confusion during design and installation.

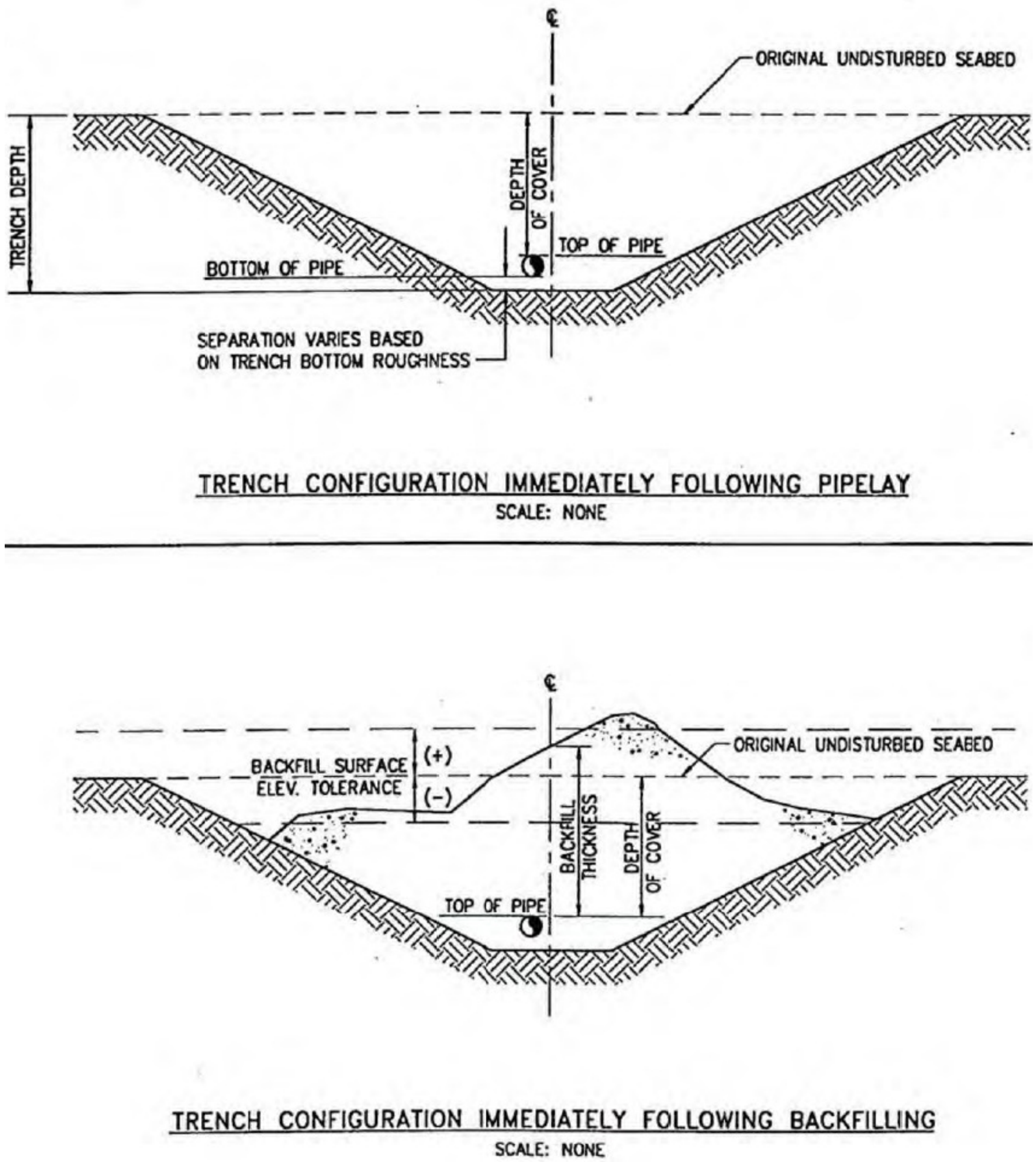

Figure 3-3: Pipeline Trenching Definitions

The Drake Project pipeline was a demonstration pipeline installed and operated in the Canadian Arctic Archipelago and the first major Arctic pipeline installed in North America. The Sakhalin pipelines also provide valuable information on designing and installing pipelines in an Arctic-like harsh environment offshore eastern Russia in the Sea of Okhotsk. Key design highlights of each of these projects are summarized in the following subsections, based upon the design approach of "single-walled" or "PIP".

3.1 Single-Walled

3.1.1 Northstar

The BP Exploration Alaska Northstar project pipelines were the first to be installed and operated offshore the Alaskan North Slope, 12 miles (19.3 km) northwest of Prudhoe Bay. The pipeline system was made up of a single-walled NPS 10 (273.05 mm), 0.594 inch (15.09 mm) wall thickness sales quality crude oil pipeline and a single-walled NPS 10 (273.05 mm), 0.594 inch (15.09 mm) wall thickness injection gas pipeline. The offshore pipelines are 6 miles (9.7 km) in length from Northstar Island (Figure 3-4) to the Alaskan coast. Production commenced in October 2001. The offshore pipelines were installed in a common trench between Seal Island (an artificial gravel island) and the shore crossing, with construction conducted from the ice in winter 2000-01 (Figure 3-5). The maximum design burial depths reach 7 feet (2.1 m) below seabed to top of pipe, except 9 ft (2.7 m) near the island [Ref. 11], and were excavated from the ice using backhoes. Side boom pipelayers were used to lower the pipelines in the trench.

Figure 3-4: Northstar Gravel Island [Ref. 11]

Figure 3-5: Northstar Pipeline Installation [Ref. 14]

Limit state strain criteria were developed for design of noncyclic pipeline displacements (permafrost thaw settlement, sub-ice keel soil deformation resulting from ice gouging, and Seal Island settlement), with allowable strain levels established based on the pipe dimensions and material grade.

The pipelines were designed for ice keel gouging using empirical methods. The ice gouging design utilized historical ice scour data collected in the general project area and employed empirical methods described in Ref. [1] and Ref. [2] to determine design ice scour depths and associated probability of exceedance to be used in pipeline trenching and burial depth selection. Ice scour surveys were collected along the pipeline route for design, and seabed surveys have continued to be performed each year since pipeline installation.

Strudel scours were another loading necessary for evaluation during the project design. Site-specific strudel scour dimensional and recurrence data was compiled and the allowable pipeline free span lengths evaluated for allowable strain and prevention of vortex induced vibrations following limit-state design philosophy. Pipeline upheaval buckling design was conducted to prevent the serviceability limit state condition of significant vertical displacement and plastic deformation of the pipelines. Conventional, internal computational methods of pressure point analysis and mass balance line pack compensation were used to detect leaks equal to or greater than 0.15% of flow. The pipeline leak detection system incorporated a state-of-the-art LEOS leak detection system, integrated with the Supervisory Control and Data Acquisition (SCADA) system. The external LEOS system supplied by Siemens AG was the first offshore application of this technology, based on hydrocarbon diffusion into a buried sensor tube. The minimum leak detection threshold is believed to be less than 0.15% of flow.

Although the Northstar pipeline was installed as a single pipeline, a PIP solution had also been considered during the early project stages. The Northstar Project Final Environmental Impact Statement reported that "Best available information is not sufficient to indicate that this (pipe-in-pipe) technology is as good or better than the proposed design for the Northstar carrier pipeline. However, the design appears to have merit in at least some specifications and warrants further consideration and analysis in future potential applications. In determining the appropriateness and practicability of a double-walled pipeline alternative there remain a degree of uncertainty surrounding the issues of reliability and structural integrity" [Ref. 3].

See References 14 and 17 for additional discussion of Northstar design and construction details.

3.1.2 Sakhalin

The Sakhalin 1 Project involved the construction and installation of multiple export pipelines up to 28 inch (711.2 mm) OD offshore Sakhalin Island, in the Sea of Okhotsk for a total offshore length of 6.8 miles (11 km). The pipelines were installed during summer open water seasons using traditional pipelay vessels. The pipelines were designed using a strain-based design methodology developed for the project due to a lack of existing international design standards suitable for pipeline design in Arctic environments [Ref. 4]. This Project Specific Design Code was developed in conjunction with Russian design institutes and relevant authorities. The pipelines were trenched and buried in water depths less than approximately 98 ft (30 m) for protection against ice gouging, with burial depths determined based on hindcast analysis of several years of ice scour survey data and considering potential seabed erosion [Ref. 4].

The Sakhalin 2 Phase 2 Project involved design and construction of approximately 168 miles (270 km) total length of pipeline. The pipelines include four separate 14 inch (355.6 mm) OD concrete weight coated crude oil and dry gas pipelines and two 30 inch (762.0 mm) multiphase pipelines, as well as a 4.5 inch (114.3 mm) OD monoethylene glycol pipeline. Much of the pipeline length was buried for protection against ice gouging, in water depths less than 105 ft (32 m). "The pipeline design took into account high strain capacity requirements and extremes of ambient temperatures to avoid the potential for brittle fracture. The installation method used was double joint S-lay combined with stringent AUT [Automated Ultrasonic Testing] inspection of the offshore welds" [Ref. 4]. These pipelines used an "Atmos leak detection system and an oil spill blockage system" [Ref. 4].

3.1.3 Kashagan

The Kashagan Project offshore flowlines, fuel lines and transfer pipelines are located in the North Caspian Sea in water depths reaching 23 ft (7 m). Pipeline diameters range from 8 to 28 inches (203.2 to 711.2 mm). Initial production began in September 2013 but was suspended on two occasions shortly after startup due to gas leaks caused by sulphide stress cracking corrosion [Ref. 5]. "A mix of conventional trenching in shallow flats, trenching from ice and offshore open water trenching using purpose-built excavating and backfilling equipment, have been used to achieve pipeline burial" [Ref. 4]. Design ice scour burial depths were determined based on probabilistic analysis of multiple years of ice scour survey data, and were generally less than 6.6 ft (2 m) [Ref. 4].

3.1.4 Varanday Oil Terminal

The Varanday Project includes twin 12.4 mile (20 km) long, 36 inch (914.4 mm) OD pipelines in water depths up to 69 ft (21 m) in the Russian Pechora Sea. The pipelines are buried 4.9 ft (1.5 m) below seabed for protection against ice gouging by first-year ice ridge keels and covered with imported sand backfill [Ref. 4].

3.1.5 Baydaratskaya Bay Pipeline Crossing

This project consisted of twin 48 inch (1219.2 mm) OD concrete weight coated gas pipelines crossing 42.3 miles (68 km) across Baydaratskaya Bay in the southern Kara Sea, Russia [Ref. 4]. A 24.9 mile (40 km) section was trenched and buried 4.9 ft (1.5 m) below seabed in water depths ranging from 29.5 to 75.5 ft (9 to 23 m) for protection against ice gouging, with surveyed scours being a maximum 3.3 ft (1 m) deep [Ref. 4].

3.2 Pipe-in-Pipe

3.2.1 Drake Project

The Panarctic Drake demonstration offshore pipeline was the first major subsea pipeline to be installed in the western Arctic, located in the Canadian Arctic Archipelago from the Drake F-76 well to Melville Island. The 0.68 mile (1.1km) pipeline was installed in 1978 to demonstrate gas transport via a PIP concept which used refrigerant in the annulus to avoid melting frozen soil around the pipe bundle [Ref. 4]. Reference 66 indicated that a coolant was circulated through the flowline bundle in order to freeze underlying seabed sediments and enhance seabed stability while the flowline trench was backfilled. The bundle consisted of two 6 inch (152.4 mm) OD flowlines with control and injection lines all contained in an 18 inch (457.2 mm) carrier pipe [Ref. 6].

3.2.2 Oooguruk

Pioneer Natural Resources Alaska developed the Oooguruk field on the Alaskan North Slope, near the mouth of the Colville River Delta, using a buried three-phase flowline following a pipe-in-pipe design approach from the gravel island to shore (Figure 3-6). The inner pipe is NPS 12 (323.85 mm) diameter with 0.5 inch (12.7 mm) wall thickness, while the outer carrier pipe is 16 inch (406.4 mm) OD with 0.625 inch (15.875 mm) wall thickness. Separate water injection (NPS 8 [219.08 mm], 0.562 inch [14.27 mm] WT with thermal insulation), gas injection (NPS 6 [168.28 mm], 0.5 inch [12.7 mm] WT), and Arctic heating fuel supply (NPS 2 [60.33 mm], 0.25 inch [6.35 mm] WT) pipelines are included in the flowline bundle. The pipe-in-pipe concept was chosen for the purpose of insulating the production flowline. An added benefit of the vacuum annulus was its availability as a leak detection system for the offshore production flowline.

Figure 3-6: Oooguruk Gravel Island [Ref. 11]

The offshore bundle (Figure 3-7) is 5.7 miles (9.2 km) in length in a maximum water depth of 7.4 ft (2.3 m). Grounded landfast ice was found to exist in the project area to water depths of 6 ft (1.8 m) during winter months. Since significant ice gouging generally occurs in water depths greater than 20 ft (6.1 m), the Oooguruk design determined that the project site was subject to minimal ice gouging and resulting subgouge deformations due to the ice becoming stable and landfast in early winter along the majority of the bundle route; Ref. [4] reported that ice gouging was not an issue for Oooguruk due to natural sheltering and shallow water location. A minimum 6 ft (1.8 m) depth of cover was selected to protect the flowlines against soil displacement caused by ice gouging and also provide mechanical protection against upheaval buckling [Ref. 11]. Optimized trench backfill material was also used for upheaval buckle mitigation (thawed natural soil backfill or gravel, depending on design requirements for local trench vertical imperfections / propagations and location along the pipeline route).

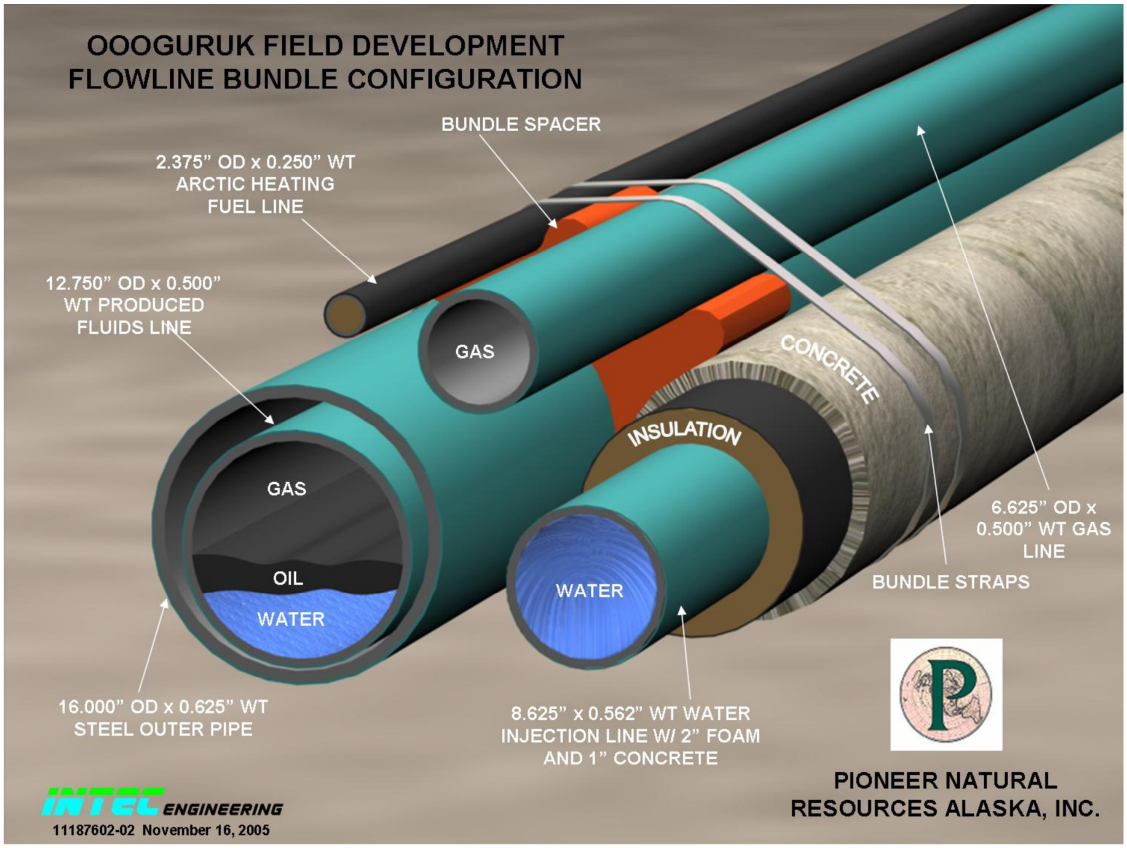

Figure 3-7: Oooguruk Bundle Details [Ref. 16]

Strudel scouring was assessed to be a major flowline design consideration due to the size of the Colville River. An Oooguruk flowline route survey was performed in summer 2005 to survey ice scours and/or strudel scours present on the seabed. The 100-year return period strudel scour dimension was found to exceed the allowable strudel scour dimensions for the flowlines to remain within their elastic stress range. However, the 100-year return design strudel scour dimension was believed to be too unpredictable to justify design of the flowlines for a strain-based, displacement limited criterion. Monitoring of the fiber optic temperature sensor (leak detection) system was recommended to detect indications of potential strudel scour and river channel migration erosional events along the flowline route.

As part of the limit state design approach, the maximum strain in the flowlines induced by differential thaw subsidence was considered. However, subsea permafrost offshore the Colville River Delta was found to be less prevalent than at similar water depths offshore Prudhoe Bay. At the shore crossing, thermal siphons and foam insulation boards were installed to reduce heat loss to the environment and limit the differential settlement between the below ground flowlines and the above ground, VSM supported flowlines.

Production flowline leak detection is provided via an annulus monitoring leak detection system as well as fiber optic temperature sensing. Pressure switch low monitoring is also utilized, along with open water offshore aerial surveys. The Arctic heating fuel line is also monitored using continuous volume balance monitoring during continuous flow periods, and shut-in pressure test monitoring during periods of low flow demand.

The flowline bundle construction and installation were conducted from the ice, in winter, by thickening the sea ice to make it bottomfast. The flowline bundle segments were made up on the ice work surface alongside the route, and then bundled using spacers and straps (Figure 3-8). Seabed trenching was performed through an ice slot and using backhoes to dig the required trench depth, with bundle installation completed by side boom pipelayers (Figure 3-9). Excavated soil (or engineered backfill, as required) was then placed back over the bundle through the ice slot.

See References 16 and 17 for additional discussion of Oooguruk design and construction details.

Figure 3-8: Oooguruk Flowline Bundle Fabrication [Ref. 16]

Figure 3-9: Oooguruk Flowline Bundle Being Lowered into the Trench [Ref. 16]

3.2.3 Nikaitchuq

Eni Petroleum Corporation developed the Nikaitchuq field located south of Spy Island in the Beaufort Sea, approximately 3.5 miles (5.6 km) north of Oliktok Point on the North Slope of Alaska. Produced fluids are transported to shore from the Spy Island Drillsite (a gravel island; see Figure 3-10) in approximately 6 ft (1.8 m) water depth via a buried three-phase flowline, and tie into a production facility located at Oliktok Point.

Figure 3-10: Spy Island Gravel Island [Ref. 11]

The Nikaitchuq flowline bundle is made up of a 14 inch (355.6 mm) by 18 inch (457.2 mm) PIP flowline carrying produced fluids, a NPS 12 (323.85 mm) water injection line, a NPS 6 (168.28 mm) spare flowline, and a 2 inch (50.8 mm) x 4 inch (101.6 mm) PIP Arctic heating fuel line. For the production flowline, the pipe-in-pipe concept was mainly chosen for the purpose of insulating the flowline, with the added benefit of allowing annular monitoring for leak detection.

The relatively shallow water and sheltered area of the flowline route prevent major ice features from gouging the seabed and limit the depth of ice keels and any resulting subgouge soil displacements affecting the flowlines. Based on summer 2007 survey data collected for pipeline design, the 100-year return ice scour depth was estimated to be 1.25 ft (0.4 m) and the project's design 100-year return period ice scour depth was assumed to be 2 ft (0.6 m). The design input values for ice scour depth and strudel scour dimensions were assumed, based on previous data analysis performed for Northstar and a single ice scour and strudel scour survey performed in 2007. Upheaval buckling design was completed using the closed-form analytical method provided by the industry-accepted (at that time) PC UPBUCK2 software program and required backfill thicknesses for a range of propagation heights were determined. PC UPBUCK has since been discontinued and no longer supported by the former vendor, Penspen.

A river overflood survey and associated strudel scour survey from summer 2007 indicated that no strudel scours developed over the project area (it was believed that the Nikaitchuq flowline route is located at the outer limits of the local river overflooding). The 100-year return period strudel scour was assumed to be

100 ft (30.5 m) in diameter at the flowline depth, which exceeded the allowable strudel scour dimension for the flowlines to remain within their elastic stress range; however, predicted flowline total strains are less than the flowline critical strains. However, it was still deemed important to monitor the fiber optic temperature sensor system for indications of potential strudel scour erosional events along the flowline route.

Permafrost thaw settlement potential was mitigated through a vacuum PIP design for the production flowline and insulating the 12 inch water injection line with 1.8 inches (46 mm) of polyurethane foam (PUF) insulation. Similar to the Oooguruk design, Nikaitchuq used thermal siphons and foam insulation boards in the trench, beneath the bundle, at the shore approach. A contingency cooling loop was also used to reduce heat loss to the environment and limit the differential foundation soil settlement.

The Nikaitchuq leak detection system was provided via the vacuum annulus of the production flowline and Arctic heating fuel PIP lines. The PIP concept was chosen for the Arctic heating fuel line to satisfy permit leak detection commitments. A mass balance leak detection system was not required for any of the bundle lines by Federal and State regulations or from a technical and Best Available Technology (BAT) basis at the time; the PIP vacuum annulus system for the production flowline was deemed to be better for leak detection. Although not intended specifically for leak detection, a fiber optic cable was installed with the flowline bundle for monitoring the temperature of the soil around the bundle. This soil temperature monitoring system is used to monitor both the performance of the insulation on the insulated flowlines and the potential exposure of the flowlines by strudel scour seabed erosion events or upheaval buckling. It is possible that if a leak were to occur, the fiber optic temperature monitor system could possibly detect the leak depending on which flowline leaks and the location of the leak in relation to the fiber optic cable.

The flowline bundle installation was performed in winter 2009 using the thickened sea ice as a construction platform; see Figure 3-11 and Figure 3-12. The flowlines were bundled using spacers and straps from the ice surface, and then lowered into a pre-excavated seabed trench through a slot cut in the ice using side boom pipelayers equipped with roller cradles. A custom beam supported by sidebooms on both sides of the trench slot was used to suspend the trailing roller cradle to ensure the sideboom reach capacity was not exceeded. Following pipelay, the trench was backfilled with the excavated soil and gravel (where necessary). An 8 ft (2.4 m) minimum cover depth was achieved to protect the flowline bundle against ice gouging and resulting subgouge soil deformation, and to prevent upheaval buckling.

See Reference 17 for additional discussion of Nikaitchuq design and construction details.

Figure 3-11: Nikaitchuq Flowline Bundle Installation [Ref. 11]

Figure 3-12: Nikaitchuq Flowline Bundle Installation [Ref. 17]

3.2.4 Liberty (Proposal)

The current version of the Liberty Project is a proposed gravel island and subsea pipeline located 15 miles east of Prudhoe Bay in Foggy Island Bay. Liberty is owned by Hilcorp Alaska, LLC (50%), BP Exploration (Alaska) Inc. (40%) and ASRC Exploration, LLC (10%). Hilcorp is currently planned to be the operator [Ref. 7]. The proposed detail of the subsea pipeline is described in Reference 7:

> *Oil would be transported to shore via a subsea, buried pipeline, then through a newly constructed 1.5-mile on-shore pipeline that would tie into the Badami pipeline – and eventually the trans-Alaska pipeline. The subsea pipeline would be a pipe-within-a-pipe, with a 12-inch-diameter inner pipe and a 16-inch-diameter outer pipeline similar to installations at Oooguruk and Nikaitchuq fields. The marine segment would be 5.6 miles in length, buried and installed during winter*.

The Bureau of Ocean Energy Management (BOEM) is currently (as of submission of this report) in a review period for Hilcorp's environmental impact statement draft seeking public comments.

4 Offshore Arctic Pipeline Design Challenges

4.1 Ice Scouring

Ice scouring, or gouging, is the most unpredictable event and can have the largest loading condition. Ice scouring occurs due to ice features reaching the seabed, be it ice ridges, stamukhi (grounded pressure ridge ice) or icebergs. The impact and grounding of an ice keel upon the seabed typically produces 'pock mark' indentations upon the seafloor. If the grounded ice possesses enough momentum or driving force to facilitate further movement, the ice keel may scrape along the seabed and create a furrow on the seafloor, which is known as an ice gouge or ice scour.

As an ice keel passes over any point in the seabed, vertical and lateral stresses are applied to the soil at the keel base, resulting in a distribution of vertical and lateral soil displacements with depth beneath the ice keel (subgouge plastic deformation of the soil). The movement of the soil can also load and move a trenched pipeline by imposing high shear and bending loads on the buried line, even if it is below the maximum ice keel scour depth. The configuration of the pipeline after gouging and the resulting strain in the pipeline depends on the pipeline properties, the soil characteristics, and the depth of the pipeline below the mudline. Design for ice scour protection typically involves burying the pipe sufficiently below the design ice scour depth, so that bending strains resulting from subgouge displacements are below acceptable limits.

Figure 4-1: Ice Keel Scouring over a Pipeline

4.2 Strudel Scouring

Strudel scouring can occur in early spring if an onshore river flow encounters an area with nearshore bottomfast ice during the spring breakup; the river water will overflow, spread offshore and drain through tidal and thermal cracks or seal breathing holes in the ice sheet. If the drainage rate is high, the high velocity current of the draining water at the seafloor can hydro-dynamically scour the seabed, which can potentially expose and impose high current loads on a pipeline. The exposed pipeline could then be at risk of Vortex Induced Vibration (VIV) as the strudel drain water or near bottom currents impact a free-spanning pipeline causing unacceptable vibrations. These strudel scours usually occur in 6.5 to 26 ft (2 to 8 m) water depth offshore from river deltas [Ref. 8]. The presence of a warm pipeline could also affect the possibility of strudel scouring. Hydrodynamic scour can reduce the cover initially placed over a pipeline and long-term sediment migration should be assessed and considered as part of burial depth requirements.

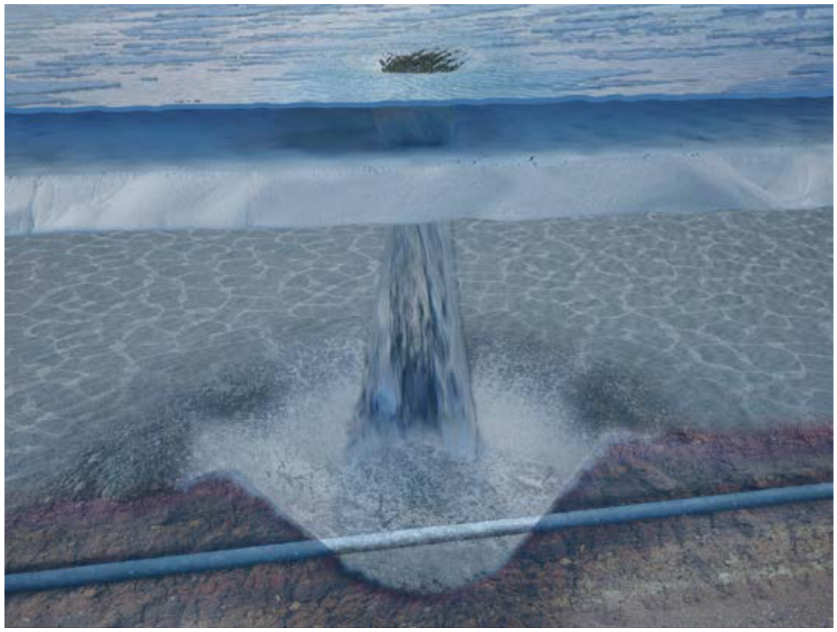

Figure 4-2: Strudel Scour over a Pipeline

4.3 Permafrost Thaw Settlement

Permafrost thaw settlement can occur when soil conditions below a pipeline trench contain ice-bonded permafrost. This typically occurs in shallow Arctic waters or near the shore crossing. When it occurs, the pipeline may lose its vertical support, and it may be supporting the soil overburden above (the trench backfill), causing additional loading on the pipeline. If an area of high thaw settlement is adjacent to an area of low or no thaw settlement (e.g., thaw stable soil), an unsupported pipeline span may develop. The differential settlement can induce strain in the pipe and should be accounted for in the design. Thaw settlement is an Arctic loading mechanism that can accumulate over a pipeline's operational life, and thus requires full life-cycle analysis.

Figure 4-3: Thaw Settlement and Frost Heave

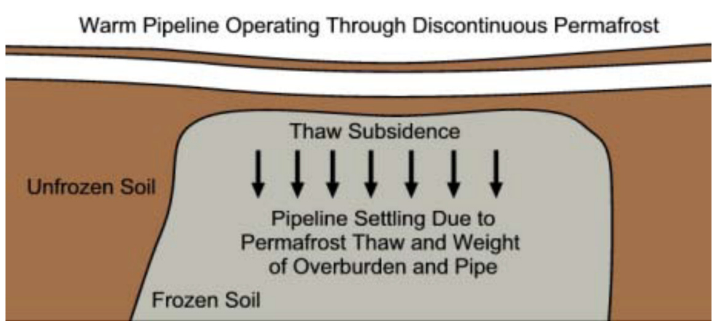

Figure 4-4: Mechanics of Discontinuous Permafrost Thaw Subsidence [Ref. 9]

4.4 Frost Heave

Frost heave can occur when an area of unfrozen soil experiences water migration / saturation and subsequent freezing. This produces formation of ice lenses and a frost bulb, which expands as it freezes and potentially displaces an overlaying pipeline upward in a localized area (see Figure 4-3).

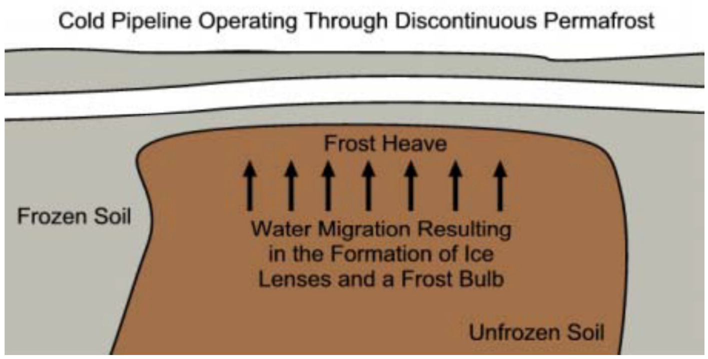

Figure 4-5: Mechanics of Frost Heave [Ref. 9]

4.5 Pipe Soil Interaction

Buried pipelines can be exposed to loads resulting from characteristic Arctic environmental phenomena, such as ice scouring, permafrost thaw settlement, or frost heave. Typically, when a buried pipeline is exposed to such loads implied via soil-pipe interaction, the strain in the pipe wall can be higher than that allowed by conventional design codes that are based on linear pipe material behaviour. In reality, pipe behavior is non-linear because of a potentially large deflection and plastic material properties. It is therefore necessary to complete a limit state, strain-based design by including the geometric and material non-linearity for Arctic loading events. The loading may change depending on if the interaction is due to ice scouring, thaw settlement or frost heave. Finite element analysis allows the modeling of non-linearities of the material, geometry and pipe-soil interaction.

4.6 Monitoring and Leak Detection in the Arctic

Sensitive Arctic environments and the presence of seasonal ice cover restricting offshore pipeline access heighten the importance of dependable and accurate leak detection technology. Leaks are always undesirable, but verification and correction is easier for non-Arctic subsea pipelines because they do not have ice cover and its associated logistical challenges.

4.7 Construction and Installation Techniques

The installation window for offshore Arctic pipelines will be determined based on the method used; open water (summer season) or on-ice (winter season). The current three Alaskan offshore pipelines have each used on-ice construction for assembly and installation. The use of bottom-fast ice for construction is also dictated by the ability/necessity for ice roads for trucks and equipment to access the construction and installation site. The short summer season for open water installation may lead to a multi-year operation depending on the length of the route. The Jones Act requirement also dictates that dredging vessels that may be needed to bury an offshore pipeline have to be constructed in the US and crewed with US personnel. To date, no project has completed dredging and the project would need to take on the responsibility and cost of the vessel.

4.8 Design Methods & Principles

Conventional offshore pipelines can often be designed using traditional design codes such as ASME B31.4 and B31.8. These codes are compatible with the design requirements of standard US DOT pipeline regulations such as CFR Parts 192 and 195. Additional, more advanced design procedures such as limit states design are then needed to address the more complex design requirements for offshore Arctic pipelines.

The Canadian Standards Association Oil and Gas Pipeline Systems Code CSA Z662 provide the main principles of limit states design as [Ref. 10]:

- Limit state identification
- Classification of limit states into Ultimate Limit States (ULS) and Serviceability Limit States (SLS), depending on consequences
- Developing limit state functions
- Establishing design criteria for safe and effective design

Limit states design methods can be classified as one of two approaches based on the method to establish and calibrate the design criteria [Ref. 10]; reliability based design (using probabilistic methods), or deterministic load and resistance factor design (LRFD). Reliability-based methods characterize load effects and structural resistance(s) probabilistically to predict that the probability of failure for a design criterion is less than an acceptable target level, as compared to LRFD methods which compare factored resistance (e.g., line pipe material yield strength, etc.) with the factored applied load condition for each applicable limit state [Ref. 10]. An example of the LRFD limit state design approach is provided by DNVGL-ST-F101 Submarine Pipeline Systems [Ref. 34] which "…is a risk-based limit state design code where the pipe integrity is ensured by design criteria for each relevant [failure] mode." See Reference 10 for more in-depth discussion of reliability-based and LRFD methods.

4.9 Key Design Challenges & Solutions

In Reference 11, Paulin et al. summarized that "There are many challenges associated with the design and installation of an Arctic subsea pipeline. These include the evaluation of environmental data, the collection and testing of geotechnical samples, design for these environmental and geotechnical conditions, and construction/installation planning for an environment characterized by a limited construction season and harsh environmental conditions." Many Arctic regions are environmentally sensitive and have limited ice-free construction time windows, which require significant effort in the planning, design, and execution phases for a successful offshore Arctic project [Ref. 48].

DeGeer and Nessim [Ref. 9] suggested that unique Arctic environmental load conditions using traditional stress-based limit state design methods would not be economic in many cases for Arctic pipeline development. Nogueira and Paulin [Ref. 12] report that applicable limit states for subsea Arctic pipelines can be expressed in relatively simple terms, including "…burst, ovalization (due to displacement controlled bending), and unstable weld flaw propagation due to tensile bending strains." "Strain-based or limit states design are normally considered for extreme loading conditions to optimize the design" of unique Arctic loading conditions [Ref. 48]. Hence, Arctic pipeline projects, such as Northstar, have employed strain-based design methodologies to facilitate project economics and to reduce the environmental impacts of field construction while maintaining a safe design.

The following four sub-sections illustrate key design challenges faced by each operational offshore Alaskan Arctic project and associated solutions to these challenges, as well as international experience from the Sakhalin-1 project.

4.9.1 Northstar

Seabed ice gouging was generally considered an obstacle to develop offshore the Alaskan North Slope and needed to be addressed as part of Northstar pipeline design. Ice scour and strudel scour evaluations require an adequate amount of historical data to support probabilistic analyses, and so several years of historical data is generally compiled and supplemented by project site-specific surveys to verify design events (as conducted for Northstar). For Northstar, "Thermal modeling and the results of geotechnical laboratory testing were used to assess the thaw settlement along the pipeline route. Finite element models were then used to assess pipeline strains as the result of the thaw settlement, ice keel gouging, and strudel scour" [Ref. 11].

Since the Northstar pipelines design was dependent on the ability to trench and backfill the lines to project specifications, a winter test trench program was performed on the North Slope in the spring of 1996 to estimate stable side slope configurations and confirm the ability to trench and backfill from the winter ice sheet [Ref. 11]. To ensure sufficient backfill weight was provided to resist upheaval buckling, a layer of recently excavated and thawed trench material was installed directly over the trenched pipelines. A layer of frozen soil could be placed overtop of the thawed material, as needed; if frozen material was placed directly over the pipeline, it was broken down to a maximum size of 2 inch (50 mm) [Ref. 11].

4.9.2 Oooguruk

The Oooguruk offshore Arctic flowline bundle system is located in a shallow water location on the Alaskan North Slope (maximum of 77 ft [2.1 m] water depth); however, "the location immediately offshore the Colville River Delta presented challenges with the flowline loading conditions, thermal interactions with the local environment and construction procedures" [Ref. 16].

"One key feature of the offshore route is its location in the shallow submerged pro-delta zone of the Colville River. Oooguruk is located approximately 3 miles (4.8 km) offshore of the eastern distributary channel of the largest river drainage on the Alaskan North Slope. The sea ice normally freezes during October and reaches a maximum thickness of up to 6 feet by April" [Ref. 16]. This location meant that seabed ice gouging was not a controlling trench design parameter, but strudel scouring was one of the major design loading conditions. Based on 3 years of strudel scour survey data collected along the bundle route, it was believed that an extreme strudel scour event could potentially expose the buried bundle and create an unsupported span. Design analysis found that the combined bundle performed better than the smallest individual flowline in terms of maximum allowable free-spans calculated based on conservative elastic stress-based design criteria.

In an effort to prevent permafrost thaw settlement or melting of winter sea ice due to the warm subsea flowlines, the production flowline was designed as an insulated PIP system to limit heat loss to the environment. Since the annular space (approximately 1 inch [25.4 mm] thick) was not compatible with a conventional foam insulation system, a vacuum, reflective foil wrap on the inner pipe, and a combination aluminium foil/woven polyolefin wrap were used to provide adequate thermal insulation and radiation barrier. The water injection line was insulated with conventional polyurethane foam and a watertight outer jacket, covered with concrete weight coating. Additionally, the subsea power cables were routed in a separate trench located approximately 50 ft (15.2 m) away from the flowline bundle in order to prevent power cable heat input from affecting bundle operating temperature and thermal expansion forces.

Similar to Northstar, the Oooguruk flowline used readily available Alaskan North Slope construction equipment and personnel for construction from the ice in winter. However, the Oooguruk flowline bundle was significantly heavier than the twin 10 inch (254 mm) Northstar pipeline bundle, necessitating that the sea ice be anchored to the seafloor (made bottomfast) along the full route length. "The primary advantages for working from bottomfast ice versus floating sea ice are the ability to store the trench spoils adjacent to the flowline trench and the significantly reduced requirements for ice sheet structural integrity to ensure the safety of the equipment and personnel" [Ref. 16]. Similar to Northstar, a test trench program was conducted in March/April 2006 to confirm feasibility of using conventional excavation equipment.

4.9.3 Nikaitchuq

Similar to Oooguruk, Nikaitchuq used a PIP system with a vacuum and radiation barrier in the annulus to limit heat loss to the environment and associated thaw settlement of discontinuous permafrost encountered along the route. The water injection flowline is insulated with polyurethane foam and an external high-density polyethylene (HDPE) jacket and concrete weight coating. The electrical power cables were installed in a separate trench from the flowline bundle system.

At the North Slope shore crossing, "a combination of summer reworking of frozen gravel fill, polystyrene board insulation laid above the waterline (beneath the pipes) and thermal siphon heat pipes were designed to limit thaw settlement beneath the pipes and foundations of adjacent structures" [Ref. 17].

In an effort to reduce the potential maximum differential temperature driving upheaval buckling, the flowlines were warmed with warm air as the flowline was lowered into the trench (to reduce the differential between the ambient air temperature on the ice surface and the seawater and later operational temperatures). This simplified field construction and reduced the need for engineered trench backfill at vertical prop locations (local high points along the trench bottom) [Ref. 17].

Installation was completed from a bottomfast ice sheet using sideboom pipelayers, and Nikaitchuq "was the heaviest flowline bundle installed to date in the offshore Arctic using this method" [Ref. 17]. Due to the high bundle weight, two sidebooms were required on each side of the trench with the bundle installed from a custom roller cradle on a beam assembly; see Figure 4-6.

Figure 4-6: Nikaitchuq Flowline Bundle Through-Ice Installation into Trench [Ref. 17]

4.9.4 Sakhalin

The Sakhalin pipeline design encountered a lack of existing international design standards suitable for Arctic pipeline design and encountered design challenges associated with earthquake loads. The project overcame these challenges by developing a Project Specific Design Code following strain-based design methodology [Ref. 4] and determining earthquake load criteria from a grass-roots probabilistic seismic hazard assessment which harnessed Russian and US seismic expert expertise [Ref. 64]. As part of this effort, "criteria for earthquake analyses of pipelines were developed in consultation with Russian and US experts" based on knowledge gained via "extensive analyses of Sakhalin Island seismicity and forensic analysis of the 1995 Neftegorsk earthquake" and extensive site investigation of the rupture zone [Ref. 64]. An ExxonMobil-sponsored workshop was held to define the project seismic design criteria.

5 Industry Regulations, Standards and Codes

A listing of regulations, standards, and codes relevant to offshore Arctic pipeline design, monitoring, and installation are presented in the following sections. A brief description is provided for each.

5.1 Arctic Specific Regulations

5.1.1 ISO 19906 (2010 Edition) - Petroleum and Natural Gas Industries – Arctic Offshore Structures

ISO 19906 was developed by a technical committee and put forward by vote to the member bodies for approval. The standard was developed in response "to the offshore industry's demand for a coherent and consistent definition of methodologies to design, analyze, and assess Arctic and cold region offshore structures. [Ref. 18]"

The scope of the standard focuses on recommendations and guidance for design, construction, installation, transportation and removal of structures and excludes that of operation, maintenance, service-life or repair of equipment. For the use of Arctic pipelines, Section 14 of the standard (in both the main body and appendix informative) applies only to that of flowlines and umbilicals, and not the transport of hydrocarbons via pipeline. These relevant definitions that provide the scope for the standards are provided below:

- Flowline (ISO 19906 Arctic Offshore Structures): piping on the sea floor linking one or more subsea wells to the production system.
- Flowline (ISO 13628 Subsea Production Systems): production/injection line, service line or pipeline through which fluid flows.
- Offshore Pipeline (ISO 13623 Pipeline Transportation): pipeline laid in maritime waters and estuaries seaward of the ordinary high water mark.
- Pipeline System (ISO 13623): pipelines, stations, supervisory control and data acquisition system (SCADA), safety systems, corrosion protection systems, and any other equipment, facility or building used in the transportation of fluids.

5.1.2 API RP 2N (2015 Edition) - Planning, Designing, and Constructing Structures and Pipelines for Arctic Conditions

The latest revision of API Recommended Practice 2N [Ref. 14] uses a modified version of ISO 19906 [Ref. 13]. The scope of the RP follows the same format as Reference 18 including the informative Annexes.

5.1.3 30 CFR Parts 250, 254, and 550 Federal Arctic Rule - Oil and Gas and Sulphur Operations on the Outer Continental Shelf — Requirements for Exploratory Drilling on the Arctic Outer Continental Shelf

The Department of the Interior (DOI), has added new requirements to regulations for exploratory drilling and related operations on the Outer Continental Shelf (OCS) seaward of the State of Alaska. The addition of the CFR parts 250 [Ref. 20], 254 [Ref. 21], and 550 [Ref. 22], focuses solely on the OCS within the Beaufort Sea and Chukchi Sea Planning Areas (Arctic OCS). It was designed to help ensure the safe, effective, and responsible exploration of Arctic OCS oil and gas resources. For pipeline design, reference is made to guidance provided in Recommended Practice API RP 2N.

Not all documents listed within this review are currently included in 30 CFR Part 250.198, Documents Incorporated by Reference [Ref. 20].

5.2 US Federal and State Regulations

5.2.1 49 CFR Part 192 (2011 Edition) – Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards

Part 192 of the Transportation Code of Federal Regulations prescribes the minimum safety requirements for pipeline facilities and the transportation of gas within the limits of the Outer Continental Shelf [Ref. 23]. Subparts of the code include, but are not limited to, details on materials, design, and operations. Exclusions for the regulation may occur if the pipeline is crossing from the OCS into state waters. Further details of exclusions to the code exist within 192.1.

5.2.2 49 CFR Part 195 (2017 Edition) - Transportation of Hazardous Liquids by Pipeline

Part 195 of the Transportation Code of Federal Regulations applies to pipeline facilities and the transportation of hazardous liquids including carbon dioxide on the Outer Continental Shelf [Ref. 29]. Subparts of the code include, but are not limited to, safety reporting, design, construction and operations and maintenance. Pipelines that are excluded from this code are listed within section 195.1.

5.3 General Pipeline Design

5.3.1 API RP 1111 (2015 Edition) – Design, Construction, Operation and Maintenance of Offshore Hydrocarbon Pipelines (Limit State Design)

This Recommended Practice sets out criteria for the design, construction, testing, operation, and maintenance of offshore steel pipelines utilized in the production, production support, or transportation of hydrocarbons, that is, the movement by pipeline of hydrocarbon liquids, gases, and mixtures of these hydrocarbons with water [Ref. 30].

5.3.2 CSA Z662-15 (2016 Edition) – Oil and Gas Pipeline Systems

This Canadian Standard covers the design, construction, operation, maintenance, deactivation, and abandonment of oil and gas industry pipeline systems that convey liquid hydrocarbons, natural gas, gas, and other liquids [Ref. 31].

5.3.3 ASME B31.4 (2016 Edition) - Pipeline Transportation Systems for Liquids and Slurries / ASME 31.8 (2016 Edition) - Gas Transmission and Distribution Piping Systems

These standards are part of the American Society of Mechanical Engineers (ASME) Code for Pressure Piping. ASME B31.4 addresses piping transporting hazardous products that are predominately liquid between facilities, production and storage fields, plants, and terminals, and within terminals and pumping, regulating, and metering stations associated with liquid pipeline systems. ASME B31.8 addresses piping transporting products that are predominately gas between sources and terminals, including compressor, regulating, and metering stations, and gas gathering pipelines.

5.3.4 DNVGL-ST-F101 (2017 Edition) – Submarine Pipeline Systems

This international Standard provides the user with criteria and recommendations on concept development, design, construction, operation and abandonment of Submarine Pipeline Systems [Ref. 34]. This standard is applicable for single rigid pipeline systems, pipeline bundles that are piggybacked or in an outer pipe, and pipe-in-pipe systems. Its sections include details on safety, design, construction and operations, with additional commentary sections and detailed appendices. This document supersedes the former DNV-OS-F101.

5.3.5 ISO 13623 (2017 Edition) – Petroleum and Natural Gas Industries – Pipeline Transportation

The international Standard in not intended to be a design manual, rather, it is to ensure its minimum requirements are met with sound engineering practice and judgement. It allows for the use of industry best practices and state-of-the-art techniques, such as reliability-based limit state design methods, providing the minimum requirements of this document are satisfied. In addition, this document allows individual countries to apply their national requirements for public safety and the protection of the environment [Ref. 35].

5.3.6 RMRS 2-020301-005 (2017 Edition) – Rules for the Classification and Construction of Subsea Pipelines

The Russian RMRS cover all technical aspects of design and construction of offshore subsea pipelines. The 2017 edition takes the experience of other classification societies into consideration [Ref. 36].

5.4 Monitoring & Leak Detection

5.4.1 API RP 1130 (2012 Edition) – Computational Pipeline Monitoring for Liquids

This Recommended Practice is to specifically cover computational pipeline monitoring (CPM) leak detection systems. These refer to software-based algorithmic monitoring tools that are used to enhance the abilities of a Pipeline Controller to recognize hydraulic anomalies on a pipeline [Ref. 23].

5.4.2 API TR 1149 (2015 Edition) – Pipeline Variable Uncertainties and Their Effects on Leak Detectability

This document describes procedures for predicting uncertainties in the detection of leaks in pipelines using computational methods based upon physical hydraulic state measurements. This class of pipeline leak detection methods is commonly called computational pipeline monitoring (CPM). A large number of factors are known to contribute to the effectiveness of CPM and it is essential to understand the uncertainty in the prediction made by the CPM algorithm in use regarding the existence, or absence of leaks [Ref. 24]. This document has been omitted from the monitoring and leak detection assessments in Section 6.2 and 6.4 as it does not address technology suitability or application, but is focused on CPM algorithm uncertainties and variables.

5.4.3 API RP 1175 (2017 Edition) – Pipeline Leak detection – Program Management

This pipeline Recommended Practice for leak detection program (LDP) management provides guidance to pipeline operators of hazardous liquid pipeline systems regarding a risk-based pipeline LDP management process [Ref. 25].

5.4.4 Alaska DEC 18 AAC 75 (Amended Oct. 1, 2017) – Department of Environmental Conservation: Oil and Other Hazardous Substances Pollution Control

This Alaskan State Department of Environmental Conservation regulation sets minimum requirements for leak detection systems and performance thresholds for single phase oil pipelines and technology selection and evaluation [Ref. 26].

5.4.5 DNVGL-RP-F302 (2016 Edition) - Offshore Leak Detection

This Recommended Practice is meant to define the process through the phases of a field development project for planning, design, integration and operation of an offshore leak detection system. Appendix A of DNVGL-RP-F302 provides country-specific regulations and requirements for offshore leak detection, including the EU, US, UK, and Norway. Appendix B.1 provides a high-level comparison between existing subsea leak detection techniques [Ref. 27].

6 Gap Analysis Matrix

Standards, regulations, and codes specific to offshore Arctic pipeline design have been reviewed and qualitatively compared to assess where gaps may exist. Documents specific to US federal rules, leak detection, and general pipeline design have also been included in the assessment as these will continue to be required for offshore design in Arctic waters.

The matrix has been divided into three main categories: environmental loading; monitoring and leak detection; and installation and repair. Within each of these categories, criteria relating to each have been identified to allow for the assessment of standards, regulations and codes. Each of the criteria is then categorized based on the information provided in the document that has been reviewed. The detail for each of the categories is provided in the following sections.

6.1 Environmental Loading

The environmental loading criteria highlighted within the matrix are those factors in addition to those considered for conventional offshore pipeline design. They include:

- Discussion of Limit States Design
- Physical and Mechanical Properties of Ice
- Iceberg and Ice Ridge Scour Design Requirements and Protection Methods
- Strudel Scour Design Requirements and Protection Methods
- Permafrost Thaw Settlement/Frost Heave Design Requirements and Protection Requirement
- General Design Properties
- Additional Requirements for General Pipeline Design Environmental Loadings (Water Currents, Geohazards, Seismicity, Subfreezing Temperatures, etc.)

The results for each document reviewed for these criteria are then assessed against the following parameters:

Red – No Arctic requirements discussed.

Yellow – The criteria have been mentioned as a "should be given consideration", however, no detail is provided to aid the designer.

Green – The criteria have been mentioned as a "should be given consideration" and guidance is provided for methods to incorporate the criteria into the design.

6.2 Monitoring and Leak Detection

Monitoring and leak detection are essential components for offshore pipelines and consideration needs to be given to incorporating the chosen technology and methods during design. The selection of a particular technology or method may affect constructability and/or operations. As such, leak detection specific regulations have been included as part of the review to determine if any special requirements have been made necessary for Arctic environments.

The criteria for monitoring and leak detection are listed as follows:

- General
- Internal System Requirements
- External System Requirements

- Computational Monitoring
- Survey Information

The results for each document reviewed for these criteria are then assessed against the following parameters:

Red – No Arctic requirements discussed.

Yellow – Arctic-specific monitoring and leak detection methods are addressed, but no guidance is provided.

Green – Specifically addresses Arctic offshore pipeline monitoring and leak detection methods and provides requirements and/or guidance.

6.3 Installation and Repair

Installation of offshore Arctic pipelines may use innovative techniques that are often based upon which season will provide the safest and most economical installation method. The same considerations are given for repair. Timing, accessibility and techniques may be driven by daylight, season, ice coverage, storms, sustenance fishing/hunting, migration, environmental impact, and working conditions for personnel, among others.

The criteria for installation and repair are listed as follows:

- Seasonal Construction Requirements
- Ice Road Details
- Trenching Requirements
- Inspection and Testing
- Repair
- Safety Equipment Requirement

The results for each document reviewed for these criteria are then assessed against the following parameters:

Red – No Arctic information has been provided.

Yellow – The criteria have been mentioned, however, no detail is provided for incorporation.

Green – The criteria have been mentioned and guidance is provided for best practice methods and considerations to be made during construction.

6.4 Gap Analysis Matrix Results

Completing a gap analysis of offshore Arctic pipeline regulations, codes and standards has provided insight on categories and criteria that are addressed by documents in both a qualitative and quantitative manner. It enables the user of the matrix to understand where gaps may exist in required regulations and understand when industry best practices are needed to complete design. A high-level review of the entire matrix shows that design documents for pipelines are brief in their acknowledgement of the Arctic environment, especially considering leak detection. An exception to this is ISO 19906 and the RMRS code. The ISO 19906 standard directs the reader to some of the best practices and allows for inclusion of current research. The RMRS code is strictly prescriptive for design loading conditions; not allowing the user to utilize best practices for an environment for which deign practices continue to evolve.

A more detailed review of the results of the matrix is provided for the following groupings of documents:

- Arctic Specific Regulations
- US Government Federal Regulations (specifically those corresponding to DOI and DOT regulations)
- General Pipeline Design
- Leak Detection Regulations
- Subsea Production Systems

6.4.1 Arctic Specific Regulations

Three codes were identified in Section 5.1 as being focused on Arctic design. The most comprehensive standard included in this review was ISO Arctic Offshore Structures (ISO 19906). It is important to note that Section 14 of this standard provides detail of scope for flowlines and umbilicals as per ISO 13628 and not pipeline transportation systems defined in ISO 13623. It is important for the designer to ensure the intended scope of the standard applies to the project development. Section 14 of the standard and then further in the informative Annex provides the user detailed guidance on using industry best practice principles for design considerations in an Arctic environment. The 2015 edition of API RP 2N adopted ISO 19906 with no apparent modifications.

In 2016, a new federal Arctic rule was incorporated into the US Code of Federal Regulations (30 Part 250, 254, and 550) relating to offshore exploration and drilling activities within the OCS. These parts have been included in this section of the assessment and a review indicates that there is no guidance for offshore pipelines in this region, only statements relating to the inclusion of environmental factors.

The color-coded summary of results is presented in Table 2, Table 3, and Table 4. The full results table, including informative text from the regulations are provided in Appendix A as a summary and Document Number 9158-001-002 as a Microsoft Excel file.

Table 2: Arctic Specific Regulations - Environmental Results

Criteria		ISO 19906	API RP 2N	30 CFR Part250, 254, 550
Limit States Design		G	G	R
Ice Properties		G	G	R
Iceberg and Ice Ridge Scour		G	G	Y
Strudel Scour		G	G	R
Permafrost Thaw Settlement/Frost Heave		G	G	R
General Design Properties		G	G	R
Additional Requirements for General Pipeline Design Environmental Loadings	General	-	-	Y
	Seismic Actions	G	G	-
	Geohazards	Y	Y	-

Table 3: Arctic Specific Regulations - Monitoring & Leak Detection

Criteria	ISO 19906	API RP 2N	30 CFR Part250, 254, 550
General	Y	Y	Y
Internal System Requirements	R	R	R
External System Requirements	R	R	R
Computational Monitoring	R	R	R
Survey Information	R	R	R

Table 4: Arctic Specific Regulations - Installation and Repair

Criteria	ISO 19906	API RP 2N	30 CFR Part250, 254, 550
Seasonal Construction Requirements	R	R	R
Ice Road Details	G	G	R
Trenching Requirements	G	G	R
Inspection and Testing	R	R	R
Repair	R	R	R
Safety Equipment Requirement	G	G	R

6.4.2 US Government Federal Regulations

For US regulations, specifically those related to the DOI and DOT have been included in this study. Two parts from Title 49 on Transportation were included as part of the review. In general, both parts of the regulation are very brief on the design of offshore pipelines and dictate minimum design requirements. Neither part makes mention of an ice or Arctic environment and special considerations in design that should be included. All red coding in the gap analysis matrix is a reflection of this. A takeaway from the regulation is to properly assess if it is applicable to the design based on the offshore location and whether the above mentioned Title 30, Part 250 would become applicable. Independent of this is that additional guidance should be applied when meeting the minimum requirements listed within Parts 192 and 195. There is discussion within the regulation regarding construction; however, again it is location independent and doesn't specifically provide information for Arctic locations.

The color-coded summary of the results is presented in Table 5, Table 6, and Table 7. The full results table, including informative text from the regulations is provided in Appendix A and within a Microsoft Excel file, Document Number 9158-001-002.

Table 5: US Government Federal Regulations (DOI and DOT specifically) - Environmental Results

Criteria		49 CFR Part 192	49 CFR Part 192
Limit States Design		**R**	**R**
Ice Properties		**R**	**R**
Iceberg and Ice Ridge Scour		**R**	**R**
Strudel Scour		**R**	**R**
Permafrost Thaw Settlement/Frost Heave		**R**	**R**
General Design Properties		**R**	**R**
Additional Requirements for General Pipeline Design Environmental Loadings	General	**R**	**R**
	Seismic Actions	**R**	**R**
	Geohazards	**R**	**R**

Table 6: US Government Federal Regulations (DOI and DOT specifically) - Monitoring & Leak Detection

Criteria	49 CFR Part 192	49 CFR Part 192
General	**R**	**R**
Internal System Requirements	**R**	**R**
External System Requirements	**R**	**R**
Computational Monitoring	**R**	**R**
Survey Information	**R**	**R**

Table 7: US Government Federal Regulations (DOI and DOT specifically) - Installation and Repair

Criteria	49 CFR Part 192	49 CFR Part 192
Seasonal Construction Requirements	**R**	**R**
Ice Road Details	**R**	**R**
Trenching Requirements	**R**	**R**
Inspection and Testing	**R**	**R**
Repair	**R**	**R**
Safety Equipment Requirement	**R**	**R**

6.4.3 General Pipeline Design

The documents listed in Section 5.3 are some of the world's most widely used design guidelines for offshore pipelines. Less familiar is the RMRS code; however, it has been included for review considering the currently operating Sakhalin pipelines. The main difference between the API, CSA, ASME, DNVGL and ISO standards and the RMRS code is the prescriptive nature of the Russian code. It is a document that provides users with academic calculations for design scenarios, but it fails to properly provide references, definitions of design properties, and inclusion of some of the most current design methodologies, an example being subgouge deformations.

As these documents can be used in conjunction with other design guidance for offshore pipelines in Arctic environments, positive review was carried out to see which documents provided users with details that should be included in design and further aided in establishing best practices to utilize. Design and protection for strudel scour continues to be an area that is poorly addressed within standards.

The color-coded summary of the results are presented in Table 8, Table 9, and Table 10. The full results table, including informative text from the regulations are provided in Appendix A and within a Microsoft Excel file, Document Number 9158-001-002.

Table 8: General Pipeline Design - Environmental Results

Criteria		API RP 1111	CSA Z662-15	ASME B31.4/31.8	DNVGL-ST-F101	ISO 13623	RMRS 2-020301-005
Limit States Design		R	Y	R	G	Y	R
Ice Properties		R	Y	R	R	R	R
Iceberg and Ice Ridge Scour		R	G	Y	Y	Y	G
Strudel Scour		R	R	R	R	Y	G
Permafrost Thaw Settlement/Frost Heave		R	Y	R	Y	Y	G
General Design Properties		R	Y	R	Y	G	G
Additional Requirements for General Pipeline Design Environmental Loadings	General	R	Y	R	Y	Y	G
	Seismic Actions	-	G	-	Y	-	-
	Geohazards	-	-	-	Y	-	-

Table 9: General Pipeline Design - Monitoring & Leak Detection

Criteria	API RP 1111	CSA Z662-15	ASME B31.4/31.8	DNVGL-ST-F101	ISO 13623	RMRS 2-020301-005
General	R	R	R	R	R	R
Internal System Requirements	R	R	R	R	R	R
External System Requirements	R	R	R	R	R	R
Computational Monitoring	R	R	R	R	R	R
Survey Information	R	R	R	R	R	R

Table 10: General Pipeline Design - Installation and Repair

Criteria	API RP 1111	CSA Z662-15	ASME B31.4/31.8	DNVGL-ST-F101	ISO 13623	RMRS 2-020301-005
Seasonal Construction Requirements	R	R	R	R	R	R
Ice Road Details	R	R	R	R	R	R
Trenching Requirements	Y	Y	Y	G	G	R
Inspection and Testing	Y	R	Y	Y	R	R
Repair	Y	R	R	Y	R	R
Safety Equipment Requirement	Y	R	R	Y	R	R

6.4.4 Leak Detection Regulations

Pipeline monitoring and leak detection codes and guidance listed in Section 5.4 are those perceived to be the most applicable to Alaskan Arctic offshore pipelines. The DNV Recommended Practice DNVGL-RP-F302 has been included as a comprehensive technology overview and recommended practice for planning, designing, integration and operation of systems for offshore leak detection. The recommended practice defines functional requirements and applicable regulations and standards for various types of leak detection systems, as well as establishing functional and design requirements, and presents best available technology selection techniques.

Table 11 provides a summary of the leak detection regulations assessment scheme, showing that only the Alaska DEC 18 AAC 75 regulation was found to specifically address some aspects of offshore Arctic pipeline leak detection system requirements. Overall, as shown in the table, there are very little formal design requirements or guidelines associated with offshore pipeline monitoring and leak detection which is a potential regulatory gap in addressing future Arctic offshore pipeline developments.

The full results table, including informative text from the regulations is provided in Appendix A and within a Microsoft Excel file, Document Number 9158-001-002.

Table 11: Leak Detection Regulations - Monitoring & Leak Detection

Criteria	API RP 1130	API RP 1175	Alaska DEC 18 AAC 75	DNVGL-RP-F302
General	R	R	G	R
Internal System Requirements	R	R	R	R
External System Requirements	R	R	R	R
Computational Monitoring	R	R	G	R
Survey Information	R	R	R	R

6.4.5 Identified Gaps

A primary gap identified in this review is that there is a lack of information provided for pipeline transportation systems. Information from ISO 19906 (and subsequently API RP 2N) only covers the scope of flowlines (as defined in ISO 13628). There is no guidance from this standard for further information of pipeline transportation systems in an Arctic environment. Another gap is in the installation and repair category with little emphasis on accounting for the harsh environment that crews will be operating in.

As indicated in Table 2 to Table 4 above, an identified gap in the new Federal Arctic Rule is that it doesn't address Arctic pipeline design requirements for unique environmental loading considerations. Reference is made to API RP 2N, but only in relation to Arctic drilling and exploration. That is, the Federal Arctic Rule excludes any requirement for compliance to or consideration of API RP 2N in relation to offshore pipeline design or Arctic structure design.

An area not included in this study, but equally important, is pipeline operations. The design and associated stipulations put forward for operation are important to be followed. Deviations from the operating philosophy that was considered in the design or from the pipeline operating recommendations may inadvertently introduce risks.

7 Best Practices and Challenges

The development of offshore Arctic pipelines has required the evolution from a traditional subsea pipeline stress based design approach to a strain based design. Strain based design accommodates for the displacement controlled loading conditions that may be experienced due to unique Arctic environmental design phenomena. The extreme environmental loadings that come with these locations can require a deeper burial depth, shorter construction and installation seasons, and potential pipeline bundling. This section will discuss some of the best practices and challenges associated with Arctic pipeline design, monitoring, and construction.

7.1 Environmental Data

Changing climate conditions in the Arctic can affect the design criteria used to build and operate offshore Arctic pipelines. Due consideration should be given to how the environmental conditions experienced during the pipeline's lifetime may vary from the design criteria derived from historical environmental records. Potentially varying environmental conditions may include:

- Increasing rates of coastal erosion
- Changing oceanographic conditions (e.g. waves, currents, storm surge) resulting from increased extent and duration of summer open water
- Warming or thawing of onshore and subsea permafrost
- Changing construction season durations (winter tundra travel, winter offshore ice roads, summer open water construction season)
- Changing seabed erosion or accretion patterns
- Seabed scouring due to ice wallowing. This phenomenon may be similar to seabed ice scouring but sea ice keels can have locally increased seabed penetration depths due to wave and current loadings on grounded sea ice features. Increased wave conditions may affect this potential pipeline loading condition.

In many cases, the environmental loadings experienced during the pipeline's lifetime will not be exactly the same as predicted during the pipeline design phase. Due consideration should be given to evaluating site-specific environmental conditions for offshore Arctic pipelines and for addressing potential future detrimental conditions through the pipeline monitoring, inspection and maintenance plans.

The most widely studied environmental loading on Arctic offshore pipelines has revolved around ice scouring and subsequently ice-pipe-soil interaction. A description of this loading event is discussed in section 4.1 and 4.5. As each environment is unique, it is typical to complete a seabed survey to gain an understanding as to if ice scouring is a necessary concern. A challenge with only completing one survey is that it is unknown when the scours may have occurred and if there has been infill to change the scour depth. A multi-year survey campaign would allow for a small historical sample and for a probabilistic evaluation of potential ice scour size, depth and frequency (reoccurrence).

This uncertainty in the data may lead to an overly conservative pipeline design and excessive burial depth. This can lead to increased costs and eliminating potential trenching and installation methods, depending on water depth and possibly also other design factors. Quantifying the level of conservatism for current ice scour design and analysis practices is difficult at present, as there have been no known significant ice scouring events affecting a large diameter offshore operational pipeline [Ref. 37].

7.2 Monitoring and Leak Detection

It is industry best practice for Arctic offshore pipeline leak detection to use a combination of a reliable internal/computational pipeline monitoring system with an external Leak Detection System (LDS); however, one particular system or technology (from those reviewed in Appendix B) cannot be recommended as best practice due to dependence on the pipeline design and application (e.g., the LEOS system has been successfully installed on the Northstar pipeline, and annular vacuum monitoring used on the Oooguruk and Nikaitchuq PIP systems). Periodic (passive) leak detection methods are also valuable in monitoring pipeline operational conditions and complimenting active internal and external LDS. A combination of monitoring strategies should be considered and evaluated for a particular application, and the best solution selected that meets the requirements of the project.

As exhibited in Table B.12 to B.16 of Appendix B, many existing leak detection systems are field proven with Technology Readiness Level (TRL) 7, but industry development is required to advance the TRL of Fiber Optic Cable (FOC) LDS (including Distributed Temperature Sensing [DTS] and Distributed Acoustic Sensing [DAS] systems) to mature these technologies for primary application as Arctic offshore pipeline leak detection methods.

Refer to Appendix B for further information.

7.3 Trenching

The definitions used for offshore Arctic pipeline trenching can be surprisingly complex and mean different things to different people/organizations. Best practices require clear definition of all pipeline trenching and trench backfilling parameters. These definitions can also be described in figures, such as Figure 3-3. Pipeline protection from seabed ice gouging and other mechanical loadings is generally provided by lowering the top of the pipe to a specified distance below the surrounding seabed elevation. The exact distance below the seabed is often referred to as the pipeline "depth of cover". This distance is then a function of 1) local variations of the seabed elevation (as influenced by any local seabed slope changes, sand waves, etc.); 2) the depth to which the trench was excavated below the seabed elevation; 3) the pipe outside diameter (OD); and 4) height imperfections in the trench bottom (Note that the as-laid pipeline will span between local high points on the trench floor and it will often not sit directly on the trench bottom).

Using the above definition for pipeline "depth of cover", the thickness of any potential natural or artificial trench backfill (or over-burden material) placed above the top of pipe is a separate and often equally important issue. Backfill material stacked on top of a pipeline is generally less stable than backfill contained within a pipeline trench and it does not provide the same level of mechanical protection from ice gouging and other loadings. One potential offshore Arctic pipeline loading condition which often does require a specified backfill thickness placed above the pipeline is upheaval buckling (potential global upward movement of the pipeline as it warms to an operating temperature above its installation temperature and the pipe tries to expand in the easiest direction available to it, sometimes in an upward direction). Clear definition is then required for the pipeline "backfill thickness" and for any backfill soil minimum physical properties necessary to provide upheaval buckling resistance or for other pipeline mechanical protection purposes.

Regulatory requirements for offshore pipeline trenching (e.g.: 49 CFR Parts 192 and 195) generally provide prescriptive minimum values for pipeline "depth of cover" as defined above. The pipeline design engineer should then factor in project-specific requirements for pipeline trenching and trench backfilling to meet project design needs. Clear definitions or trenching and backfill requirements should then continue into the offshore construction and operational monitoring phases of the pipeline project.

7.4 Installation

The three currently operating Alaskan offshore pipelines have each used on-ice construction for assembly and installation, as each is located in relatively shallow water that could be made bottom fast in winter. However, a best practice or industry standard cannot be readily identified for Arctic offshore pipeline installation as the method selection is dependent on various pipeline design factors, including water depth(s), pipeline mechanical design (e.g., single-walled vs. PIP, or bundle), and construction schedule / logistics. Arctic pipeline installation in water depths beyond the limits of bottom-fast ice could require use of more traditional pipeline installation methods / vessels during the summer open-water season; a task which hasn't been performed in the Alaskan offshore to date.

7.5 Repair

Pipeline integrity, safety, and reliability are the foremost goals of the pipeline design, installation, operation and maintenance procedures. Contingency repair plans are still necessary for emergency repair response. Repair plans should be coordinated with emergency response plans and field operations may be needed for an external discharge. These repairs will be specific to the project, operating conditions and limitations, and environment. Therefore, in order to prepare appropriate repair plans, understanding the challenges related to repair of pipelines in buried trenches will aid in planning. These challenges may include:

- Limitations based on the season in which the repair is needed. Ice coverage may limit vessels and seasonal access to Arctic pipelines.
- Limitations in pipeline flexibility for lifting the pipeline on to the ice for repair.
- The project may involve a bundle of pipelines that would be permanently bundled and would require unbundling for the repair.
- Limitations related to divers if required for the repair.
- Limitations of the ice strength due to discharge from the pipeline.
- Limitations on surface lifts and on-ice repair may lead to the ROV operated pipeline repair systems.

8 Design Considerations, Codes & Standards

8.1 TAPs Study 332

In November 1999, the Minerals Management Service (MMS) initiated and sponsored a workshop on Alaska Arctic Pipelines through the Technology Assessment and Research program. This workshop was held in Anchorage and led by C-CORE (St. John's, NL) along with AGRA Earth and Environmental, Colt

Engineering (now WorleyParsons Canada Services Ltd.) and Tri Ocean Engineering. The objective of this workshop was to examine the current state of practice for Alaskan offshore pipeline design, including the use of single-walled vs. PIP technology as documented in the TAR sponsored project "An Engineering Assessment of Double Wall Versus Single-walled Designs for Offshore Pipelines in An Arctic Environment" which was conducted by C-CORE [Ref. 3]. The principal objective of this study was to assess if a double walled pipeline design provides the same or greater engineering integrity and environmental robustness as compared to thick single-walled pipeline design for Arctic applications.

At the time of the TAPs Study 332, only the Drake Field Arctic offshore PIP (demonstration) system had been constructed. The study included a telephone survey of seven major pipeline operators at the time; none of which were aware of any operating or proposed PIP system designs for Arctic applications. The study work found that PIP systems have been used elsewhere (non-Arctic) for onshore and offshore applications for thermal insulation, leak containment, and production flowline protection. The study assessed design and construction of PIP systems, operations and maintenance, repairs, costs, and risks in assessing the comparative advantages and disadvantages.

The comparative cost assessment estimated material and construction costs for analogue systems developed as part of the study's project design basis. The considered (conceptual) single-walled pipeline was NPS 12 (323.85 mm) with 0.5 inch (12.7 mm) wall thickness of API Spec 5L grade X52 linepipe. The PIP system considered was an NPS 12 (323.85 mm) inner pipeline and NPS 14 (355.60 mm) outer pipeline with both lines having 0.375 inch (9.53 mm) wall thickness. Costs were considered to have a +/-25% accuracy and found that, considering design, materials, and construction, PIP systems (at the time) were approximately 1.27 times the cost of a single-walled design. The costs of trench excavation, backfill, and ice road construction were estimated to be the same for each system. Incremental costs associated with inspection and monitoring of the PIP outer pipe were excluded due to technology gaps at the time of the TAPs study; thus, actual cost differences could actually be higher for PIP vs. single-walled. Line pipe and coating costs used in TAPs Study 332 were factored from Northstar cost estimates.

PIP systems were found to have potentially lower lifecycle costs for fluid containment failure as a result of the secondary containment capability, but potentially higher lifecycle costs for functional failure as a result of the inability to "…readily inspect, evaluate, monitor and control outer pipe defects" [Ref. 3]. Containment failure costs included lost product and production interruption, and costs associated with repair, re-commissioning, and environmental remediation. Functional failure costs were identified as lost production and repair and recommissioning costs. In total, the PIP system lifecycle costs were estimated to be approximately 1.09 times those of a single-walled pipeline, although repair costs were not included due to the low probability of failure for either design.

Operating and maintenance costs were deemed to be similar for each system, including operational monitoring, leak detection, application of corrosion and chemical inhibition, and corrosion control, inspection, defect evaluation and defect control [Ref. 3]. Over a 20 year design life, operation and maintenance costs for a PIP system were estimated to be approximately 1.04 times that of a single-walled design.

The TAPs Study 332 comparative risk assessment found that a PIP system has greater associated operational risks, compared to a single-walled pipeline due to the increased amount of material, welds, and monitoring challenges. However, a PIP system has a lower risk of losing product to the environment in the event of a leak.

8.2 Liberty Pipeline Systems Alternatives

In February 1998, BP Exploration Alaska submitted a development and production plan for its proposed Liberty Development and subsequently commissioned INTEC Engineering (now INTECSEA) to prepare a conceptual engineering report to evaluate design alternatives for the proposed 6.1 mile offshore sales quality oil pipeline from Liberty Island in 22 ft (6.7 m) water depth to shore. The pipeline systems alternatives evaluation (including addendums and attachments) [Ref. 39] considered four design alternatives for a 20 year project design life:

- Single-walled steel pipeline, NPS 12 (323.85 mm) with 0.688 inch (17.48 mm) wall thickness
- Steel PIP system, NPS 12 (323.85 mm) inner pipe with 0.5 inch (12.7 mm) wall thickness and 16 inch (406.4 mm) carrier pipe with 0.844 inch (21.44 mm) wall thickness
- Single-walled steel pipe inside a high-density polyethylene sleeve, NPS 12 (323.85 mm) inner pipe with 0.688 inch (17.48 mm) wall thickness and 16.25 inch (412.75 mm) HDPE carrier pipe with 0.75 inch (19.05 mm) wall thickness
- Flexible pipe system

Each alternative was designed at the conceptual level and comparatively assessed considering installation methods, construction costs, operations and maintenance issues, system reliability, and suitable leak detection systems. Design work considered mechanical design, installation stability, ice keel gouging, upheaval buckling, thaw settlement, strudel scouring, and cathodic protection requirements. The Arctic specific design criteria for each considered pipeline alternative were as follows:

- 3 ft (0.9 m) design ice scour depth
- 1 ft (0.3 m) design strudel scour span
- 1 ft (0.3 m) design thaw settlement for the single-walled pipeline
- 1.5 ft (0.48 m) design propagation height for upheaval buckling

The study investigated possible methods for excavating the trench and installing the pipeline. Trenching methods included conventional excavation with dredging, plowing, jetting, and mechanical trenching. The considered installation methods included use of lay vessels, reel vessels, tow or pull methods, installation in winter through an ice slot (field proven), and directional drilling from shore which was discarded due to perceived technical difficulties.

The preferred construction method of constructing from the ice in winter using conventional trenching / excavation equipment and off-ice installation techniques was selected for various reasons, including use of conventional, field proven and locally available equipment, good understanding of ice strengthening and cutting techniques, summer open water construction equipment was not available for the shallow water depths, and other methods would require significant equipment mobilization to the North Slope.

The design burial depth for the single-walled pipeline was 7 ft (2.1 m) and 5 ft (1.5 m) for the PIP system. The total installed cost estimate for the single-walled pipeline option was $31 million vs. $61 million, nearly double, for the steel PIP system (due to differences in pipeline material and construction/fabrication costs).

The study found that the primary difference associated with operations and maintenance of the PIP system was that monitoring could not be performed for some structural components and "It is not presently feasible to monitor the integrity of the outer jacket pipe of the pipe-in-pipe. Post-failure monitoring could be achieved for [the PIP] systems using the annular leak detection system to detect the presence of water and oil. However, no preventive monitoring of the outer jacket pipe can be performed for these systems" [Ref. 39]. The ability to monitor was assessed in terms of the integrity of the outer pipe, including detecting dents, buckles, or the loss of wall thickness, for example due to corrosion.

Proposed leak detection systems were standard mass balance and pressure point analysis combined with a LEOS system for the single-walled pipeline and annulus monitoring for the PIP system.

A risk assessment was conducted for all alternatives, with the main conclusion that the overall risk of an oil spill to the environment was negligible for all alternatives. The single-walled pipeline was proposed to be the safest design alternative since "…safeguards in the single-walled pipeline alternative (i.e., depth of cover; trench backfill material and procedures; pipe wall thickness; cathodic protection system, anodes and coating; routine geometry pig inspections; and leak detection systems) provide a total system reliability that minimizes the risk of environmental oil spills" [Ref. 39]. The single-walled option was also identified as the easiest to repair. The PIP system was deemed to be the second best, of the four design options, in terms of safety and overall risk, with increased risk of spills (by an order of magnitude), higher cost, and increased difficulty to repair, compared to the single-walled design.

Thus, it was concluded that the single-walled steel pipeline offered the most advantages over the other alternatives by providing the lowest risk of a spill to the environment. The study concluded that "the single-walled pipe alternative is the only solution that allows all the design aspects to be monitored during operation — a very important consideration for a buried subsea pipeline" [Ref. 39].

The Liberty Pipeline Systems Alternatives study was subjected to independent review and commentary by Stress Engineering Services [Ref. 40], which addressed design, inspection, operations, repair, construction, and technical merits of considered alternatives as well as suggesting alternative design concepts. Attachment B of Reference [39], as well as the Pipeline Systems Alternatives Report Addendum addressed the comments. Most of the comments were minor in nature, however Stress Engineering Services did question whether all the design alternatives were assessed equally since varying burial depths were considered in the Liberty Pipeline Systems Alternatives study [Ref. 40] (7 ft [2.1 m] for single-walled design option and 5 ft [1.5 m] for the PIP system). This was addressed in Reference [39], where an evaluation was performed considering equal burial depth of 7 ft [2.1 m] for each option. At equal burial depths, the overall risk of the PIP system was estimated to be slightly lower than the single-walled pipeline, but the cost of the PIP was significantly higher ($66 million vs. $31 million) with a high likelihood of requiring more than one winter construction season. Therefore, the single-walled design was still carried forward as the preferred option; see Section 9.1 below for additional detail.

8.3 Design Codes, Standards & Recommended Practices

As reported by INTEC in the Liberty Pipeline Design Alternatives study [Ref. 39], "pipeline design codes and standards do not suggest a requirement to provide an outside pipe jacket whose sole purpose is to contain any loss of contents of the pipeline it surrounds. The conditions that might give rise to a loss of product from the inner pipe would also affect the outer pipe. Pipe-in-pipe systems are used in some cases, but the outer pipe does not serve as a back-up in the event that something has been omitted in the original design effort. Their prime function is to satisfy installation economics or another design condition, such as to thermally insulate or facilitate field installation."

Relevant US and international general pipeline design codes have been reviewed for commentary on PIP system design, with the findings detailed below. Note that API RP 2N, ISO 19906, ASME B31.8, 30 CFR Part 250, 254 and 550, and DNVGL-RP-F302 provided no commentary on PIP systems.

8.3.1 API RP 1111(2015 Edition) – Design, Construction, Operation and Maintenance of Offshore Hydrocarbon Pipelines (Limit State Design)

This API Recommended Practice 1111 [Ref. 30] Section 4.3.1.2 provides guidance on longitudinal and combined load design for PIP systems and determination of effective tension during pipelay. Section 4.3.1.4 provides recommended design practice for axial collapse/burst due to combined axial compressive load and internal pressure, which is a particular risk for deep water PIP construction laid via J-Lay or S-Lay methods. Arctic PIP applications are not addressed.

8.3.2 ASME B31.4 (2016 Edition) – Pipeline Transportation Systems for Liquids and Slurries

This design code provides minimal guidance on PIP system design, and is limited to commentary on external corrosion control for thermally insulated pipelines; see Chapter VIII, Clause 466.1.1 of Reference 32.

8.3.3 Code of Federal Regulations

TAPs Study 332 performed a literature review of the US Department of Transportation position on the use of PIP systems, including 49 CFR Parts 190-199, and found no guidance on whether or not PIP systems should be used [Ref. 3]. This was confirmed as part of the present study.

8.3.4 DNVGL-ST-F101 (2017 Edition) – Submarine Pipeline Systems

Standard DNVGL-ST-F101 [Ref. 34] provides guidance on design of offshore PIP systems and bundles. Section 5.5.11 addresses pipe-in-pipe and bundle design, with Section 13.6 providing informative commentary and guidance on PIP design and integrity management developed based on a Pipe-in-Pipe Workshop Series JIP (joint industry project).

Section 13.6 provides guidance on PIP and bundle design, including safety class, global system behaviour, design loads and limit states (for inner and outer pipes), buckling, collapse and on-bottom stability considerations, acceptable denting, anode design, bulkhead design and code breaks, reeling design, and construction (manufacturing and offshore), and operation.

Of note is Section 5.5.11.6 "Inspection possibilities are more limited for pipe-in-pipe and bundles, and hence detection of corrosion in annulus and external corrosion is challenging. Further, detection of leaks into annulus (from internal or external fluids) may not be easily identified and the associated environment in the annulus cannot be fully controlled or reversed. Documentation of the integrity in the operation phase may be limited for a pipe-in-pipe compared to a single pipe. This will again affect the life-time extension and re-assessment of the pipeline."

Reference 34 indicates that DNVGL-RP-F110 [Ref. 41] can be applied for global buckling design of a PIP system if the inner and outer pipes can be considered to be axially bonded (no axial sliding between inner and outer pipe). DNVGL-RP-F110 suggests that one method to prevent development of buckling is to introduce a PIP system to change the pipeline structure so that the inner line is supported by the outer and "the internal lines in the bundle might develop axial compressive forces in operation, but those forces can be balanced by tensile forces in the outer carrier, through end bulkheads and possibly intermediate bulkheads."

8.3.5 ISO 13628-1 (2005 Edition) – Petroleum and natural gas industries – Design and operation of subsea production systems – Part 1: General requirements and recommendations

International Standard ISO 13628-1 [Ref. 42] addresses PIP as a viable means to provide pipeline mechanical protection from boat traffic and bottom-fishing activities, and makes high-level qualitative statements on flowline design considerations and installation, but provides no direct guidance on PIP design.

8.4 Current State-of-Practice

In Arctic pipeline design, extreme environmental loadings tend to require deeper burials and short installation windows and high cost of installation on-ice may lead to the use of pipeline bundles to facilitate installation. Strain-based design is generally used for Arctic subsea pipelines due to the extreme displacement-controlled loading conditions, whereas traditional subsea pipeline design generally utilizes a stress-based approach. Arctic environmental load conditions could not use traditional stress-based limit state design methods as they would not be economic in many cases for Arctic pipeline development [Ref. 9].

The Northstar pipelines were the first offshore pipelines installed on the Alaskan North Slope. Limit State Strain Criteria was developed for the Northstar offshore pipeline segments' design (see Section 3.1.1). The design criteria were used in the design for noncyclic pipeline displacements (e.g. thaw settlement, sub-ice keel soil deformation, and island settlement). Allowable strain levels were established based on pipe dimensions and material grade and accounted for pipe out-of-roundness, maximum pipeline butt weld defect sizes, and residual pipe strains due to installation. Design data and criteria for each of the possible causes of pipeline deformation were established such that there was a minimal possibility of exceeding the criteria, and pipeline strains then calculated for each case and compared to allowable values. Applicable pipeline design codes and standards used for the offshore pipeline included API STD 1104, API RP 2N, ASME B31.4 and B31.8, DNV Rules for Submarine Pipelines (1981) and RP B401, and US DOT Code of Federal Regulations Title 49, Parts 192 and 195.

The Northstar offshore pipeline ice gouging design was the first application of the negative exponential function to define ice scour depth distribution as a function of water depth as described in Reference 1 and 2, using probabilistic analysis of repetitive seabed ice scour survey data. The negative exponential distribution had been used to describe the depth of ice scouring elsewhere in the Canadian Beaufort and Alaskan Chukchi Seas, but this was the first application to an operational pipeline on the North Slope.

The Pioneer Oooguruk flowline design was performed in accordance with ASME B31.4 and B31.8, as well as API RP 2N, where appropriate. Since all flowlines are located within Pioneer's and ConocoPhillips' unit boundaries of the State of Alaska and adjacent State waters, the lines are not "Right-of-Way" pipelines and are not under US DOT Regulatory Requirements. Where appropriate, requirements analogous to US DOI Regulations for offshore "Lease Term" flowlines were assumed.

Oooguruk adopted a limit state design approach for permafrost thaw settlement and strudel scouring evaluation. The limit state design approach considered the maximum strain induced in the flowlines by differential thaw subsidence, considering the elasto-plastic behavior of steel as well as that of the soil (including large displacements and rotations). The failure mechanisms for each of the offshore flowlines were grouped into two main categories: compressive limit states (local bending, ovalization) and tensile limit states (bursting, tensile fracture of base metal, girth weld fracture), and available references and design codes were used to determine the maximum allowable strain before these limit states were reached.

Similar to Northstar, the Eni Nikaitchuq flowlines were designed using limit state design practices, with the high strain capacity of the flowlines providing additional mechanical protection against loss of flowline containment and loss of serviceability during a strudel scour event, ice scour event or permafrost thaw settlement. The pipeline design codes ASME B31.4 and ASME B31.8 do not define a maximum allowable strain limit for a pipeline that is exposed to a noncyclic displacement. However, the codes do give guidance as to some of the effects that should be considered and the acceptance is defined as "so long as the consequences of yielding do not impair the serviceability of the installed pipeline." Design code API RP 2N was also used, where appropriate. All flowlines were located within Eni Petroleum's unit boundaries of the State of Alaska and adjacent State waters and were therefore not "Right-of-Way" flowlines and not subject to US DOT Regulatory Requirements.

The flowlines were designed to resist local buckling for critical longitudinal strains which were governed by flowline collapse due to bending, ovality and external pressure. The flowlines were also designed to resist weld flaw fracture for the maximum predicted flowline tensile strains for each pipe.

9 Assessment Criteria

Single-walled vs. double-wall (pipe-in-pipe) pipeline technology and design methodologies have been reviewed and comparatively assessed in terms of the following criteria:

- Safety in Design
- Leak Containment
- Leak Detection / Operational Monitoring
- Environmental Footprint
- Materials Requirements
- Installation (considering installation technology, lay / production rates, and impact on welding)
- Repair
- Cost
- Decommissioning

The assessment for each criterion is discussed in the following subsections, with the overall traffic-light assessment summarized in Section 9.10.

9.1 Safety in Design

As reported in TAPs Study 332, "There seems to be an underlying belief that pipe-in-pipe systems are safer than single pipe systems."

PIP systems provide increased resistance to bending due to the composite design, and can provide collapse resistance and protection for bundled internal pipes and cables. However, there are operating and monitoring complexities associated with the use of spacers and bulkheads or shear rings in PIP systems [Ref. 3].

In addition, a PIP system has two additional construction steps which could introduce additional construction risk to an offshore Arctic pipeline; drying of the annulus and leak testing and pressure testing of the outer pipe. However, these risks do not introduce application of unknown or unproven technology, and can be considered relatively minor challenges.

The TAPs Study 332 found that, based on non-Arctic pipeline failure rate data, "…the double wall alternative would reduce the system failure probability by a factor of approximately 0.5" with an annual failure probability of $0.6x10^{-3}$ for a PIP system and $1x10^{-3}$ for a single-walled pipeline. However, this assessment was subjectively reinterpreted and based on 'inferred (historical) statistics from the Gulf of Mexico' and the comparative results could be different if actual Arctic pipeline failure rate data were available.

Conversely, the Liberty Design Alternatives Study [Ref. 39], concluded that the single-walled steel pipeline provided the lowest risk of a spill to the environment compared to the PIP system (having spill risk an order of magnitude greater than single-walled design) since the single-walled option was the only that allowed all design aspects to be monitored during operations. The Liberty study was specifically performed for an Alaskan North Slope offshore pipeline and is felt to be a more reliable representation of comparative design safety of a single-walled pipeline vs. PIP system. Ref. [39] estimated damage frequencies for small/ medium and large/rupture leaks to be $1x10^{-5}$ and $2x10^{-7}$, respectively, for the single-walled pipeline and $3x10^{-4}$ and $1x10^{-5}$, respectively, for the steel PIP system. A contributing factor to these differences is the shallower burial depth for the PIP system, compared to the single-walled line, as a smaller cover depth is required for ice keel gouging protection (based on maximum strains imposed on the pipeline / inner and outer pipes).

When an equal burial depth was assessed in Ref. [39] for both the single-walled and PIP systems (based on comments from Ref. [40]), the overall risk of the PIP system was estimated to be slightly lower than the single-walled pipeline ($3.4x10^{-4}$ vs. $2.1x10^{-3}$, respectively), but the cost of the PIP was significantly higher ($66 million vs. $31 million) with a high likelihood of requiring an additional winter construction season (80% probability). An Independent Risk Evaluation for the Liberty Pipeline [Ref. 40] performed by Fleet Technology Limited also found that the total expected maximum risk for the PIP system was less than the single-walled design (24 barrels released vs. 45 barrels, over the project design life) for Arctic-specific hazards including ice gouging, strudel scour, thaw settlement, and upheaval buckling, as well as corrosion, operational failures and third party activities. The probability of a large leak over 1000 barrels was also deemed lower for the PIP system. However, this assessment only considered operational risks and did not consider limitations on operational monitoring and repair for a PIP system vs. single-walled design.

It is therefore proposed that the single-walled pipeline presents an advantage over the PIP system for this criterion.

9.2 Leak Containment

TAPs Study 332 found that "double wall pipeline configurations offer moderate-to-significant operating and maintenance advantages relative to single-walled pipelines because of the ability for secondary containment of oil in the event of an inner pipe failure" [Ref. 3]. However, PIP limits the ability to inspect the outer pipe for internal corrosion, so the PIP system potentially trades some level of corrosion protection for increased containment in the unlikely event of a leak. The limited capability to inspect and monitor the condition of the outer pipe and / or bulkheads and shear rings is perhaps the main disadvantage of a PIP relative to single-walled pipeline.

"The double wall alternative has a lower risk of containment failure (i.e. loss of product) compared with the single-walled pipeline. This is primarily due to the combined probabilities associated with simultaneous girth weld failure of both the inner and outer pipelines, as well as combined corrosion failure of the double wall system" [Ref. 3]. However, there is a risk of a secondary spill volume during repair of PIP systems that include an annulus and all moisture/fluids would need to be removed from the annulus to prevent corrosion of the inner or outer pipe [Ref. 39]. Clean up and removal or any fluid leaked into the annulus could be a complex and challenging endeavour.

TAPs Study 332 [Ref. 3] provided the annual failure probability of an offshore PIP system as $6x10^{-4}$ system failures/year, which is marginally lower than that of a conventional single-walled pipeline at $1x10^{-3}$

system failures/year. However, issues to be considered for the PIP system include the level of inspection possible, as well as leak detection, integrity monitoring, and maintenance of the outer pipe.

Flowline insulation and / or leak containment from the inner production flowline were the primary drivers to use a PIP system in the existing Arctic offshore applications (Oooguruk and Nikaitchuq; see Sections 3.2.2 and 3.2.3, respectively). As done for Oooguruk and Nikaitchuq, the PIP annulus can be vacuum monitored to detect hydrocarbons as part of the leak detection system.

However, secondary leak containment is the main aspect to be considered if a leak occurs from the inner production flowline. In Ref. [40], Stress Engineering Services was in favor of the leak containment potential provided by PIP systems and proposed that a PIP system could remain in operation if the inner line had leaked but if the outer carrier pipe could contain the operating pressure (at minimum, for a long enough period to clear the line of hydrocarbons prior to repair). However, once hydrocarbons have leaked into the PIP annulus, the monitoring and repair scenario becomes complicated, and if the leak was caused by mechanical damage due to ice gouging, for example, it is likely that both inner and outer pipes would be damaged. Depending on the leak rate from the inner pipeline, it is possible that the leak may not be detectable (e.g., due to technology limitations/minimum leak thresholds) which is undesirable (an undetected pipeline failure). The Liberty Pipeline System Alternatives study [Ref. 39] reported that "INTEC concurs with the suggestion by both the MMS and SES [Stress Engineering Services] in the SES Draft Final Report (p. 18 and p. 19) that the outer casing would probably fail and that the inner pipe should be designed as if there were no outer casing."

Also, a negative aspect of a PIP design is where there is a leak in the outer casing pipe which allowed water into the annulus which led to corrosion and loss of pipeline integrity.

It is proposed that there is no clear advantage or disadvantage for the single-walled pipeline or PIP system for this criterion since the PIP system provides a means of secondary leak containment but also complicates monitoring and repairs of the production flowline, compared to a single-walled design.

9.3 Leak Detection / Operational Monitoring

Leak detection and operational monitoring methods for PIP systems are limited, compared to single-walled designs, and there is a risk that any leak from the inner production line could go undetected in the annulus (depending on project specifics, including the type of leak detection system(s) being used).

Thus, a comparison of single-walled vs. PIP for advantages or disadvantages related to leak detection cannot be generalized due to the influence of project-specifics (installation conditions/burial, type of leak detection and monitoring systems being used, operator inspection programs and frequency, etc.). Similar to the Leak Containment findings in Section 9.2, it is proposed that there is no clear advantage or disadvantage for the single-walled pipeline or PIP system for this criterion since the PIP system provides a means of secondary leak containment but also complicates monitoring and repairs of the production flowline, compared to a single-walled design.

9.4 Environmental Footprint

Make up and construction of PIP system is more complex than construction of a single-walled pipeline, especially if being conducted from the ice in winter. Make up of a PIP system involves handling approximately double the amount of pipe joints and double the amount of tie-in girth welds (inner and outer pipes), as well as drying the PIP annulus post-construction. These activities can increase the construction spread footprint, compared to a single-walled pipeline.

TAPs Study 332 did not consider the environmental impact of construction, repairs, or leaks associated with single-walled or PIP systems. The Liberty Pipeline System Alternatives study provided a comparison of operational damages and failure consequences for single-walled and steel PIP systems, and found that the environmental impact of small/medium and large/rupture leaks is worse for a single-walled pipeline compared to the PIP option (transporting the same oil volume).

Over an analyzed 20 year project life and same burial depth, Reference [39] estimated the damage frequency for a single-walled pipe to be 1.3×10^{-5} for a small/medium leak releasing 125 barrels of oil and 3.0×10^{-7} for a large leak/rupture releasing 1567 barrels. For the PIP system, the damage frequency was estimated to be 2.8×10^{-7} for a small/medium leak releasing 25 barrels of oil and 2.1×10^{-7} for a large leak/rupture releasing 1567 barrels. See Table A2-23 of Reference [39] for further information. Thus, the PIP system was estimated to produce a comparatively smaller environmental impact than the single-walled design, in the event of a leak. However, as discussed in Section 9.1, the single-walled steel pipeline was found to have the lowest risk of a spill to the environment due mainly to better operational monitoring abilities compared to PIP.

It is proposed that there is no clear advantage or disadvantage for the single-walled pipeline or PIP system for this criterion since a PIP system can potentially reduce hydrocarbons released to the environment by a small/medium leak (large/ruptures are comparable), but the PIP also generates a larger environmental footprint during construction when compared to a similar single-walled design.

9.5 Materials Requirements

As reported in TAPs Study 332 [Ref. 3], "The comparison of design, material and fabrication costs indicates the double wall pipe to be 1.27 +/-25% times greater than a single-walled pipe. Other costs such as the civil works costs comprising excavation, backfill and ice road during construction and abandonment are estimated to be the same for both alternatives."

Intuitively, a PIP system could require approximately double the steel volume of a comparably sized single-walled pipeline, depending on key design parameters such as the pipeline wall thickness and diameter of inner and outer lines, and the design for pipe annulus guides or bulkheads/shear rings.

As each pipeline or PIP design is bespoke to the specific project needs and design requirements, a generalized or standard material requirements factor cannot be estimated for PIP vs. single-walled. However, it is proposed that the single-walled pipeline has an advantage over a comparably sized PIP system for this criterion due to decreased material and consumable requirements for the same production flowline diameter / volumetric flow rate.

9.6 Installation

As reported in TAPs Study 332 [Ref. 3], "The design and construction of a double wall pipe is more complex than a single-walled pipe because of the additional pipe, associated welds and tie in procedures. There are numerous design, operating and monitoring difficulties associated with spacers and bulkheads or shear rings. There is no compelling reason to use them when the primary function of the outer pipe is secondary containment."

In addition to PIP systems requiring approximately double the amount of girth welding compared to single-walled lines, PIP systems require the extra step of inserting one pipe inside the other as part of make-up.

Pipe make-up and installation related factors are simpler for single-walled designs, compared to PIP. The Drake Field experience exhibited that a high level of quality assurance was needed during construction of the PIP bundle on the ice; make-up of the test bundle length of ~ 4000 ft (1.2 km) took 4.5 months excluding installation, which is considerably longer than needed for a conventional single-walled pipe design [Ref. 39]. There is also a greater risk of minor weld flaws being undetected during make-up and installation of a PIP system due to the presence of the annulus, which can prevent detection of weld failures in the outer pipe.

As reported by TAPs Study 332, "Ice surface preparation and maintenance, cutting access to the sea bed through the ice surface, excavation of the trench, and final backfill operations are expected to be substantially the same for the single and double walled pipeline alternatives." However, as reported in the Liberty Pipeline System Alternatives study (addendum) [Ref. 39], it was found to be highly likely that a PIP system construction and installation duration would be longer than that of a comparable single-walled pipeline when installed in the same location and trenched and buried to the same depth (see table A2-22 of Ref. [39]). Stress Engineering Services [Ref. 40] agreed that construction of a steel PIP system would be more difficult than the single-walled option.

Since pipe make-up and installation related factors are simpler for single-walled designs, compared to PIP, it is proposed that single-walled designs have a clear advantage in this criterion.

9.7 Repair

As reported in TAPs Study 332 [Ref. 3], "A double wall pipe would be more complex to repair than a single-walled pipe but the greatest component of repair costs would be similar for both systems. A double wall section could be prepared during construction and stored for use in the unlikely event of a failure. The difference in repair costs in the case for a functional failure would be proportional to the difference in initial materials and fabrication costs. Similarly, repair costs of a double wall pipe for a total containment failure (failure of inner and outer pipes) would be greater than a single-walled pipe by about the same proportion…"

The Liberty Design System Alternatives study concluded similarly, that a single-walled pipeline design is the easiest to repair [Ref. 39] and that "A repair to the pipe-in-pipe system would return the pipe to near its original integrity but not necessarily all the way to its original integrity depending on the repair method used." See Section 8.2 for further discussion. Stress Engineering Services [Ref. 40] proposed that mechanical repair devices could be used for permanent repairs, but the Liberty Design System Alternatives study stated that these methods were not considered appropriate for Arctic applications. Stress Engineering Services [Ref. 40] agreed that repair of a PIP system would be more difficult than single-walled designs, and that "restoration of the outer pipe to original integrity is doubtful" for the repair methods considered by Ref. [39].

Therefore, it is proposed that single-walled designs have a clear advantage in this criterion.

9.8 Decommissioning

Typically, decommissioning of subsea pipelines consists of flushing/cleaning and abandonment in place; in this regard, single-walled and PIP systems have similar requirements and associated costs [see Ref. 3]. Thus there is no clear advantage or disadvantage of one design over the other.

It is possible that a governing body may impose abandonment costs scaled to the volume of steel / material to be abandoned on seabed; however, this would be project / location specific and is beyond the scope of this study.

It is proposed that single-walled and PIP systems have no apparent advantage or disadvantage over the other in this criterion.

9.9 Cost

As exhibited by cost estimates prepared as part of TAPs Study 332 [Ref. 3] and the Liberty Pipeline System Alternatives study [Ref. 39], it can be concluded that PIP systems are comparatively costlier than single-walled designs, and there is no reason to suspect that this has changed since the time either of these studies were performed.

Therefore, it is proposed that single-walled designs have a clear advantage in this criterion.

9.10 Traffic-Light Summary

The traffic light summary of the single-walled vs. PIP system comparison is provided below. However, it should be noted that a project-specific evaluation would be required on a case-by-case basis to determine the 'best' system for each project application.

The comparative assessment was based on the following qualitative scheme, using a traffic-light approach:

Red - Design option presents a clear disadvantage compared to the other.

Yellow - Design option presents no apparent advantage or disadvantage compared to the other.

Green- Design option presents a clear advantage over the other.

Table 12: Traffic Light Summary for Single-walled vs Pipe-in-pipe

Abbreviation	Single-Walled	Pipe-in-Pipe
Safety in Design	G	R
Leak Containment	Y	Y
Leak Detection / Operational Monitoring	Y	Y
Environmental Footprint	Y	Y
Materials Requirements / Quantity	Y	R
Installation / Schedule	G	R
Repair	G	R
Decommissioning	Y	Y
Cost	G	R

10 Suitability & Gap Analysis

10.1 Suitability for Arctic Applications

Both single-walled and PIP systems have been successfully designed and operated on the Alaskan North Slope, and there is no basis to conclude that one design is 'better' than the other. The PIP system allows for vacuum monitoring of the annulus for leak detection, and provides secondary containment in event of a leak in the inner production line, but this comes at the cost of increased construction costs and complexity, higher life cycle costs, and restrictions on monitoring and inspection of the outer pipe, and more complex repair. The decision to adopt one design over the other was made based on project-specific requirements and objectives.

10.2 Identified Gaps

The primary gap identified in this task is that there are very few published design codes, standards, or guidance related to general pipe-in-pipe design (see Section 8.3) and literature review performed as part of this task found no applicable design codes or guidance currently available that are Arctic-specific. Although an extensive literature review was performed, it should not be considered exhaustive.

As part of the comparative assessment of single-walled vs. PIP systems, the following technological gaps were identified for PIP systems (whether in Arctic or non-Arctic applications):

- Operational inspection and monitoring of the PIP outer pipe for corrosion in the annular space is currently a gap / limitation associated with PIP systems.
- Installation of single-walled and PIP systems from the ice surface in winter are similar operations; however, the pipeline weight is a factor to be considered in relation to the stability / thickness of the ice surface. It is possible that the in-air weight of a PIP system would be larger than that of a comparable single-walled design. If Arctic lines were to be installed in deeper water locations beyond the landfast ice extent limit for on-ice winter construction, and during the summer open water season, there would be limitations on available vessels capable of laying PIP in Arctic / harsh-environmental conditions and also limitations on possible PIP dimensions (since most PIP lines installed from a vessel are reel-laid). In the Alaskan Arctic offshore, the winter landfast ice extent generally reaches to approximately 65 ft (20m) water depth; however, there are practical limitations of approximately 50 ft (15m) combined trench depth and water depth for pipelines trenched and buried from the ice sheet. Operational draft limitations (vessel-specific) and vessel logistics would be a consideration for longer distance PIP lines, considering reel/carousel change outs and storage in Arctic waters.

11 Advancement of Arctic Pipeline Design Technologies

Arctic pipeline design tools have continued to evolve since the first offshore Arctic production pipeline (Northstar), and emergent technologies are necessary to balance between what is currently available and what is needed to effectively and economically design and install pipelines in Arctic regions. "Some of the earlier analyses used for assessing Arctic loading on pipelines was appropriate for those particular projects; but as industry moves into harsher Arctic conditions (for example, in areas with ice scours that are meters deep), advancements need to continue to ensure a proper balance between safety and economics. Expanding international knowledge about Arctic conditions, improvements in material behavior, advances in analytical techniques, wider acceptance of progressive design philosophies such as strain-based design, and implementation of reliable Arctic operational strategies are enabling additional offshore Arctic prospects to be considered and developed" [Ref. 38].

The pipelines currently operational in the Alaskan Arctic are in relatively shallow water depths and close to shore. "Pushing the limits to developments further offshore in deeper water will require that additional consideration be given to … burial for protection against ice gouging. Pipeline burial for protection in water depths from approximately 65 to 131 ft (20 to 40 m) will be a challenge given the more severe gouging in these water depths" [Ref. 48]. This is a result of water depth limitations on trenching and backfilling from the winter ice sheet and technology limitations for summer open water trenching and backfilling.

11.1 Probabilistic Design Approaches

Probabilistic assessment of ice scour or strudel scour depth statistics can be used to predict extreme ice scour or strudel scour depths at specified levels of acceptable risk, based on historical data from a given region and water depth. However, probabilistic analysis only considers numerical statistical modeling, and does not assess the methods used to obtain the data, ice scour or strudel scour depth resolution cut-offs, the effects of dynamic environmental activities (sedimentation, scour infilling, reworking), pipeline and scour orientations, scour or scour recurrence rates, and pipeline length, among other factors. Reference 9 suggested that "in many instances, gouging is considered the most important loading condition for offshore pipeline design, but it is also considered the most uncertain in terms of predictability."."

The Northstar pipelines were the first installed in the Alaskan offshore Arctic to use a probabilistic design approach for unique Arctic environmental phenomena (ice gouging). Historical ice scour data was compiled from the region (e.g., from the United States Geological Survey, and others) and data collected as part of project-specific seabed surveys for use in exceedance analysis to determine design return period ice scour depths (e.g., 1 in 100 year design event). This analysis was based on the exponential probability distribution function following methods described in Reference 2. Using this data, the "design for ice gouging for Northstar involved burying the pipeline sufficiently below the ice keel depth, so that bending strains resulting from subgouge displacements were below tolerable limits. Subgouge soil deformations were estimated from field measurements of ice scour depths and widths using empirical relationships developed through small scale geotechnical centrifuge models" [Ref. 38].

Seabed surveys have continued to be performed each year since pipeline installation, as part of Northstar operational monitoring, and have detected some ice scours exceeding the 100-year return period design depth. However, these deep ice scours were associated with ice wallowing (grounded ice being rocked/rotated due to waves and currents and further digging into the seabed) and were not located directly above the pipeline route. Therefore, the design ice scour depth was not technically exceeded.

Early investigators (e.g., Ref. 1, 2, 43, 44) had proposed the exponential distribution to be effective, but conservative in modeling ice scour depth statistics. However, subsequent study work (e.g., Ref. 45, 46, 47) has found that a mixed distribution using the Weibull distribution more accurately models ice scour depth data, and is suggested to provide particularly good fits to extreme scour depth data which must be considered in design (that is, the data distribution tails).

In addition to probabilistic analysis methods, deterministic ice scour models can be used to account for the interactions of environmental driving forces, soil reactive forces, ice keel strength, and/or hydrodynamic/hydrostatic ice feature energy during ice scour processes [Ref. 47]. However, deterministic approaches suffer from model uncertainty and are inherently limited by key assumptions and empirical relationships that facilitate application of these models to ice scour design and analysis procedures.

Emerging technology development related to probabilistic design approaches is focused on combined probabilistic analysis of ice scour depth statistics, subgouge pipe-soil interaction, and pipe failure mechanisms potentially leading to serviceability limitations of the pipeline. "Probabilistic methods can provide an objective, rational and quantitative framework to optimize design options with respect to technical, economic, and environmental criteria that meet specified target safety levels" [Ref. 48]. The interrelation of these design attributes in a probabilistic engineering model is shown schematically in Figure 11-1. This contrasts with previous analyses methods which included deterministic evaluations of multiple conditions which must be combined to exceed a pipeline's serviceability limitations.

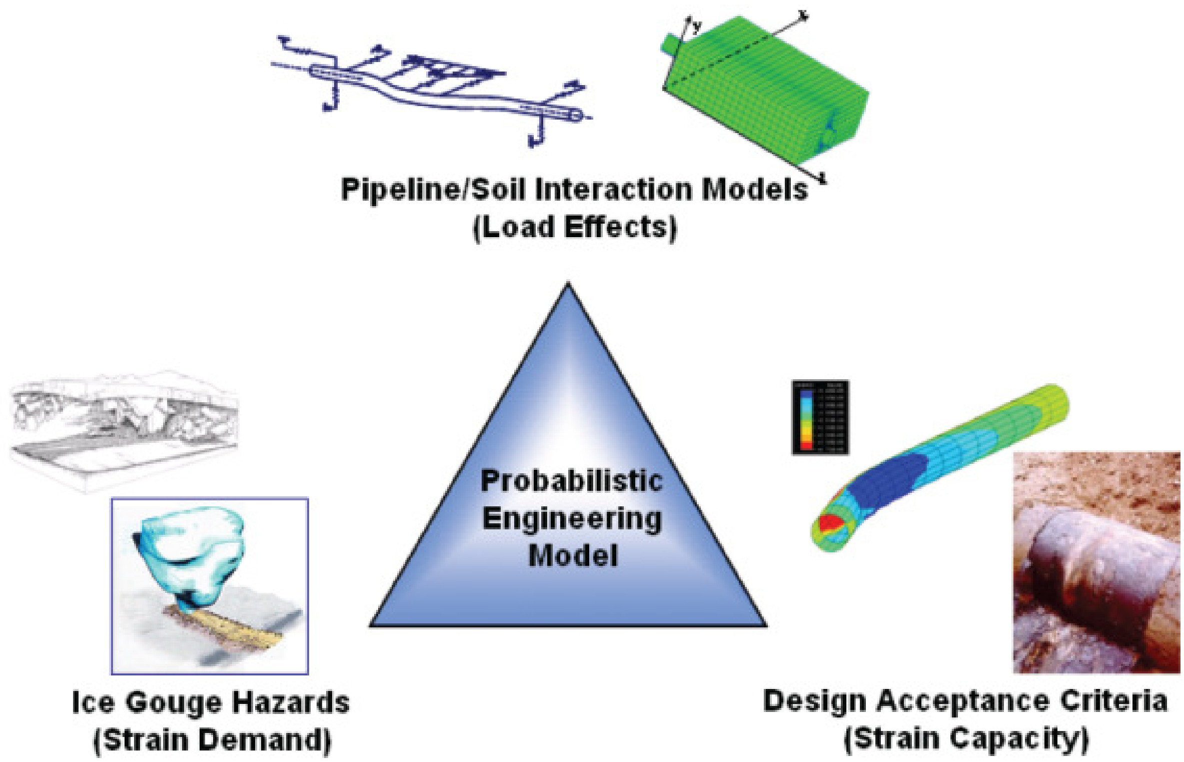

Figure 11-1: Schematic Illustration of the Integration of Strain Demand and Strain Capacity within a Probabilistic Design Framework [Ref. 48]

11.2 Finite Element Methods

When a buried pipeline is exposed to large deformation loads, the strain in the pipe wall can be higher than that allowed by conventional design codes that are based on the linear pipe behavior. In reality, pipe behavior is non-linear because of potentially large deflections and plastic material properties. It is therefore necessary to complete a limit state, strain-based design by including the geometric and material non-linearity. The finite element analysis allows the modeling of non-linearities of the material, geometry and pipe-soil interaction.

Finite Element Analyses (FEA) have been used to assess the integrity of the pipeline in the event of an environmental loading event, such as ice scouring, permafrost thaw settlement, frost heave, upheaval buckling and free spans occurring from strudel scours. Occasionally for Arctic projects, pipeline bundles have been used during installation. Recently, FEA has allowed for the assessment of these loading events on the entire bundle, versus analysis simplified as a single line. Further development of FEA techniques also allows for more confidence in understanding the pipeline response and its strain capacity. When designing to a strain-based limit, this value can help guide protection methods, remediation scheduling and burial depths. A schematic showing the subgouge deformation process from an iceberg is shown in Figure 11-2.

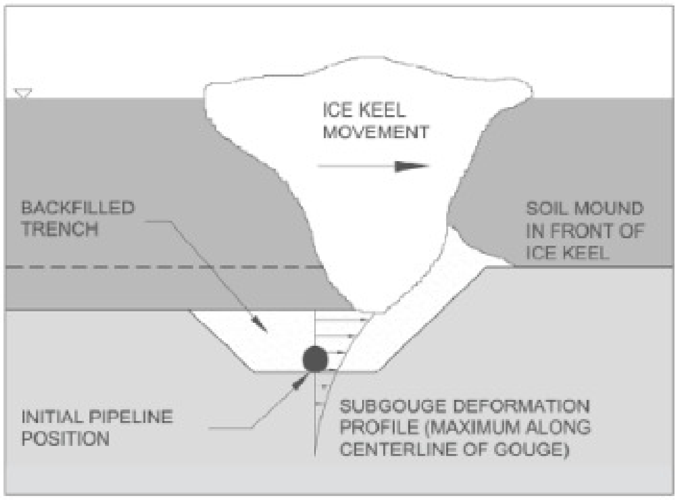

Figure 11-2: Subgouge deformation from iceberg scouring [Ref. 48]

Traditionally the Winkler (soil-spring) models have been applied to the soil-pipeline interaction processes. This de-coupling method, where the ice-soil interaction is treated separately and is an input to the model, can lead to an efficient computational timeline. A schematic showing how these springs are used in the analysis is shown in Figure 11-3. These models require experimental data to confirm the value of the non-linear spring coefficients and can vary based on soil type and cohesiveness.

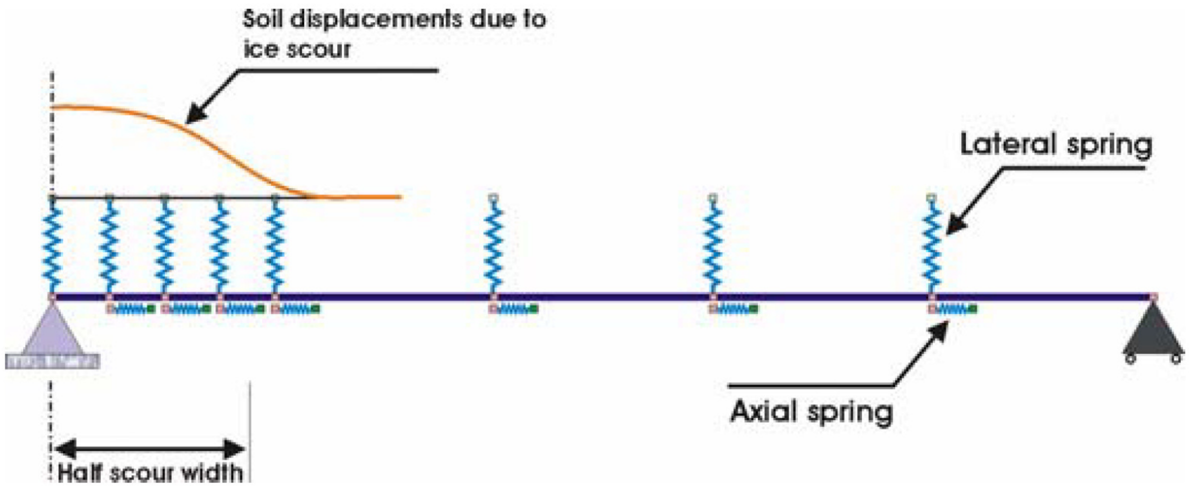

Figure 11-3: Example of Winkler spring method for ice scouring analysis [Ref. 67

An extension of these de-coupled models is now leading into three-dimensional coupled ice-soil-pipe interaction. This is achieved through the use of advanced modeling techniques, such as Coupled Eulerian Lagrangian (CEL) and Arbitrary Lagrangian Eularian (ALE) formulations. These are available in software packages such as ABAQUS and LS-DYNA, respectively, which can capture the soil behavior more accurately. INTECSEA, for example, has developed in-house subroutines for the CEL Advanced Constitutive soil models that more realistically simulate the soil behavior based on critical state soil mechanics theory. These models can address dilation issues and hardening/softening behavior of the soil which results in more accurate estimation of subgouge deformations under ice scour loads. An example of a resultant axial strain due to deformation is shown in Figure 11-4.

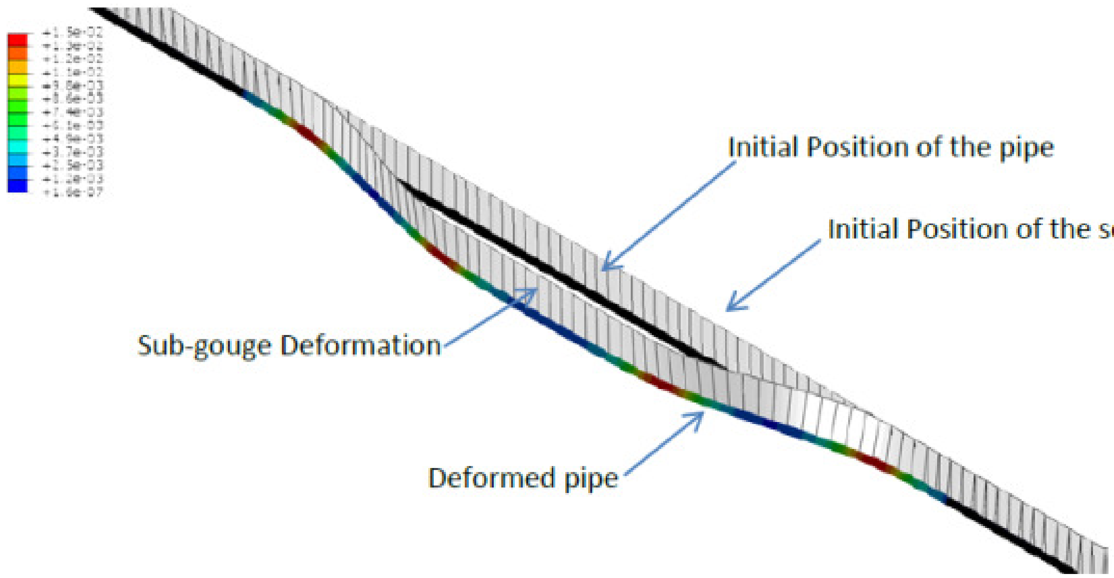

Figure 11-4: Axial Strains due to Subgouge Deformations [Ref. 38]

The CEL continuum FE models can address shortcomings in other simplified models such as directional decoupling of soil resistance, slice-to-slice decoupling of soil resistance and superposition of the ice load and pipe loads to soil which result in potentially conservative designs. In addition, these models can provide more understanding of ice gouging events such as soil failure mechanisms, non-uniform stress fields in the soils, pipeline cross-section ovalization, wrinkling and local buckling. The strength of the ice can also be used as input as well as the driving force behind the ice. This is in place of using a rigid indenter which is given a displacement regardless of the resistance it experiences. Use of these models can lead to more realistic and less conservative results which could result in reducing potentially excessive design conservatism and associated reductions in project capital costs.

11.3 Strain Based Design

Strain-based design is a LRFD design approach for a subset of limit states that are applicable to pipeline response from displacement controlled events, such as those experienced as a result of soil loads on a pipeline due to unique Arctic environmental loads or a seismic event. Unique Arctic environmental loads often impart strains in the pipe wall that are higher than that allowed by conventional design codes based on linear pipe behaviour; however, in reality, potentially large deflections and plastic material properties produce non-linear pipe behavior [Ref. 38]. "It is therefore imperative to complete a limit state, strain-based design by including the geometric and material non-linearities" [Ref. 38] when considering Arctic design events for both ultimate limit state and accidental limit state conditions.

The advancements in strain-based design have been progressing to capture the material properties and adequately trying to capture the tensile strain capacity. In recent years, strain-based design has been incorporated into the development of welded pipelines. Studies have investigated the following parameters on the strain capacity:

- Flaw depth
- Flaw length
- Yield-to-tensile (Y/T) ratio
- Weld overmatch
- Apparent crack-tip opening displacement (CTOD) toughness
- Weld cap height

ExxonMobil has completed full scale and numerical experiments to "...develop insights into characterization of the tensile strain capacity of welded pipelines," [Ref. 49]. Around the same time, models for strain-based design were being developed for PRCI, by the Center for Reliable Energy Systems (CRES), C-FER Technologies, and Microalloying International, through funding from DOT PHMSA. The aim of this research project was the tensile design procedures for pipelines when the applied longitudinal strain exceeds the yield strain. These would be complementary to the stress-based design procedures which focus on the control of hoop stress [Ref. 50]. The results of both of these studies are to be used with caution and to stay within the parameters set out during both the numerical and physical experimentation.

This tensile strain material understanding is also being used in engineering critical assessments (ECA). A Strain-Based ECA (SBECA) approach has been proposed and developed within the industry to compliment the standard use of BS 7910. Use of a standard for ECA eliminates the open interpretation by engineering consultants and installation contractors on public domain information and/or in-house project specific test data.

11.4 Materials

Traditionally, existing offshore Arctic pipeline developments have used relatively lower strength (yield and ultimate tensile), high ductility line pipe grades; for example:

- The Northstar project line pipe was API Spec 5L grade X52 seamless manufacture for the oil and gas lines, with field girth welding performed using manual Shielded Metal Arc Welding technique [Ref. 51].
- The Oooguruk production flowline PIP (inner and outer pipelines), water injection line, and gas line all used API Spec 5L grade X52 line pipe. The production flowline and PIP outer pipe were manufactured using HFI welding, with the water injection and gas lift/injection line being seamless manufacture [Ref. 16]. The Arctic heating fuel line was API 5LCP grade X65, coiled pipe [Ref. 17].
- Similar to Oooguruk, the Nikaitchuq production flowline PIP (inner and outer pipelines), water injection line, and spare line are API Spec 5L grade X52 line pipe. The Arctic heating fuel PIP system used API Spec 5LCP grade X52 for the inner and outer pipes [Ref. 17].
- The Sakhalin offshore pipelines used X60 line pipe for the offshore segments.

The Liberty Pipeline Systems Alternatives study [Ref. 39] considered non-traditional materials for two of the four design alternatives; these being a flexible pipe system (as commonly used in non-Arctic areas) and a single-walled steel pipeline inside a HDPE sleeve (outer carrier pipe). Newer 'plastic' pipes such as Smart Pipe Reinforced Thermoplastic Pipe [Ref. 55] have been developed as "…high strength, light weight, durable, self-monitoring, composite material that can be used as a stand-alone pipe for various offshore applications, or inserted as a tight fitting liner…" inside a traditional steel pipeline. Reference 55 indicates that Smart Pipe can detect pipeline movements in near real time, which would have advantages for monitoring seismic activity, frost heave or thaw settlement, impacts or disturbances due to ice gouging or strudel scouring, and potential leaks.

Corrosion resistant alloy materials are available for cladding or lining of traditional steel line pipe in corrosive or sour service applications, including low temperature environments. Reference 56 provides information related to high-strength, low alloy steels and corrosion resistant alloys suitable for demanding environments.

Mørk [Ref. 52] states that "Traditional stress-based design applications pose limited challenges in terms of pipe material property requirements and weld procedure qualification requirements. Offshore and onshore pipelines in Arctic areas are exposed to challenging loading conditions such as permafrost, fault crossings, and ice scouring, which can impose localized high strain demands upon pipelines. These loads, in combination with very low temperatures, need to be considered when material and weld procedures are selected and qualified for strain-based design purposes." "Permafrost thaw settlement and frost heave can impose long-term displacement-controlled bending on a subsea pipeline, and can contribute to a pipeline being strained outside the elastic limit into the plastic region of the material deformation; thus the need for strain-based design" [Ref. 53]. To accommodate large strain demands associated with Arctic environmental loads, pipe with low yield-to-tensile ratio and high uniform elongation properties is required [Ref. 52].

Work is underway to enhance the low temperature fracture resistance of steel for offshore oil and gas developments [Ref. 54], and testing technology to monitor for cracks using acoustic signals. The objective of this work is to shift the ductility curve towards lower temperature ranges, more suited to Arctic project developments. Materials for use in Arctic conditions require materials and welds that retain their toughness and fatigue performance at temperatures as low as -76°F (-60°C) [Ref. 56].

Onshore Arctic and cold climate pipelines (e.g., Northern Alberta) are adopting use of high strength steel line pipe grades such as X100 and X120; however, these have not yet been used subsea in the Arctic and present challenges in terms of low temperature embrittlement and materials welding.

11.5 Route Selection and Evaluation

Pipeline route selection is important during the early stages of project development to help guide subsequent data collection and assessments for detailed site analyses. The use of geo-survey Geographical Information System (GIS) databases that house project and publicly available data can be used to help evaluate potential pipeline routes. The information that may be contained within the database includes but is not limited to:

- Bathymetry
- Geology
- Iceberg Scouring and Wallowing
- River Discharge and Strudel Scour

- Infrastructure (safety zones, existing wells, existing pipelines and cables, etc.)
- Navigation areas
- Fishing Areas
- Animal Migration Paths
- Environmentally Sensitive Areas

Each of the above datasets can be used to create an individual map. The maps can then be layered to create a composition showing all datasets for the project location. With this information entered into the database, it is possible to classify and provide a weighting to the criteria on the basis of a risk to the pipeline. An example of what this may look like for a project region is shown in Figure 11-5. The overall composite can then be used to "…perform GIS-based, least-cost path pipeline routing techniques to produce optimal pipeline route options. Although the term 'cost' is associated with the routing technique, it does not refer to an actual financial value of the routing; instead, it reflects the input value of the composite map which, in this case, incorporates the relative hazard-weighting value" [Ref. 57].

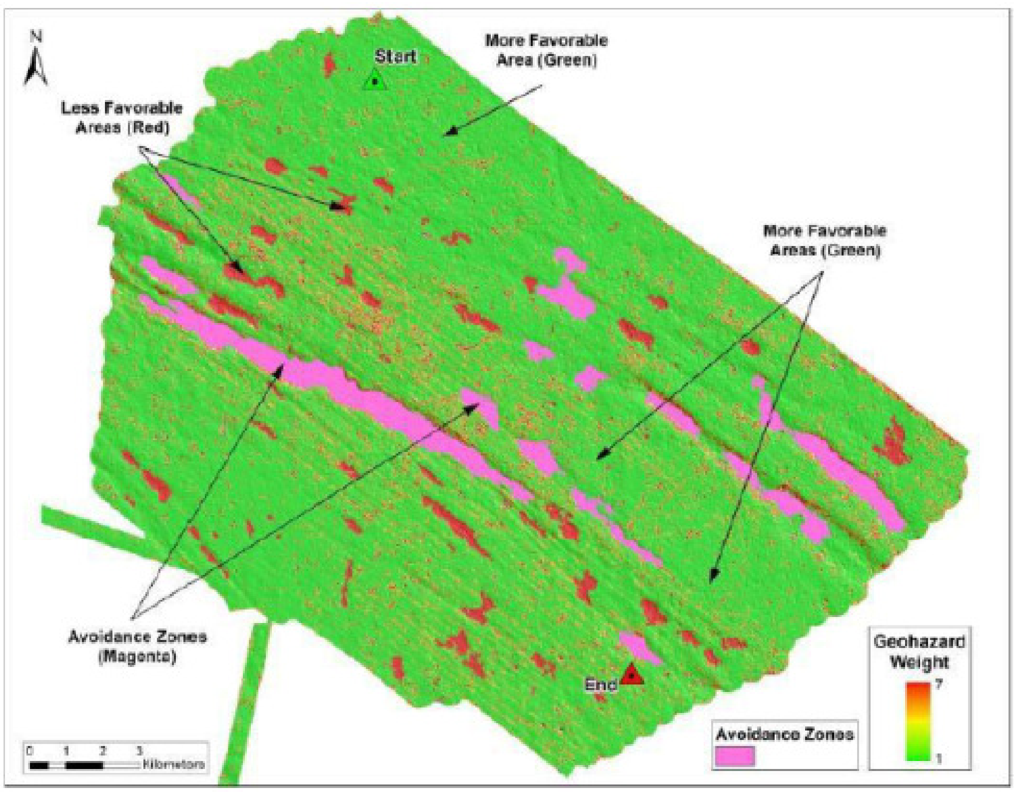

Figure 11-5: Weighted geohazard composite map draped over greyscale hillside image [Ref. 57]

The weighting of the criteria is subjective, but will be relative to the project. Certain bathymetry may not have the same risk factor as the potential for ice-pipeline interaction. A chosen route corridor from the least-cost options can be assessed as the project moves forward for subsequent surveys and project assessments.

11.6 Pipelay Vessels for Installation

As the trend of open-water season durations in the Arctic continues to grow, the potential for using a pipelay vessel for installation also increases. The three previous operational Alaskan offshore pipeline systems were all installed using the winter season on-ice method. Areas along the western coast, in the Chuckchi Sea, Bering Sea or in the Southern waters of Alaska may be able to employ a pipelay vessel. Pipelay vessels may be exempt from Jones Act compliance (discussed in Section 4.7) since the Jones Act applies to (harbour) dredging vessels operating in US waters and vessels transporting cargo between US ports, among other maritime issues (excluding pipelay) [Ref. 65]. No new pipelay vessels have been presently built in the US. Outside of the US, older pipelay vessels are starting to be replaced with new engineering designs to allow for a more economical pipelay solution.

An example of a new pipelay vessel is coming from Subsea 7 plans to replace the *Seven Navica* from Royal IHC. The new vessel will also be a reel lay system and will be capable of operating in shallow waters and up to depths of 9840 ft (3000 m). It will be able to install rigid flowlines, including PIP systems. Its expected arrival date is 2020 [Ref. 58]. The *Seven Navica* does not have ice classification (DNV 1A1) and details for the new IHC vessel are not published.

11.7 Trenching Methods for Arctic Applications

Offshore pipeline projects in the Arctic have required trenching and burial for protection. While advancements are being made for calculation methods of burial depth requirements, advancements are also needed in trenching methods. For inland areas, or locations where winter construction is the preferred method, it may be possible to complete trenching using conventional excavation methods conducted from the ice in winter, which have previously been used in offshore Alaska. For waters further offshore, more conventional methods of pipeline burial may be required. These include ploughs, mechanical trenchers and jetting rigs or sleds. The majority of these conventional methods have been designed to accomplish a maximum of 6.5 to 10 ft (2 to 3 m) of pipeline burial. Dredgers can be used but have water depth limitations and limited productivity. Land based equipment has been used for shore crossings, but is limited to shallow water depths where temporary construction berms can be used as a working platform. A summary of some of the limitations regarding conventional trenching equipment is presented in Table 13.

Table 13: Conventional Trenching Technology Limitations [Ref. 59]

Operating Season	Trenching Technology	Limitations
Summer	Conventional Excavation	Water and trench depth of 105 ft (32 m)
	Hydraulic Dredging – Cutter Suction	Water depths of 19- 115 ft (6 - 35 m)
	Hydraulic Dredging – trailing suction	Water depths of 19 – 508 ft (6 – 155

Operating Season	Trenching Technology	Limitations
	hopper	m)
	Jetting	Can achieve 10 ft (3 m) depth of cover, but requires multiple passes
Summer and Winter	Ploughing	Trench depths of 8 ft (2.5 m) depending on soil condition and multiple passes
Winter	On-Ice Excavation	Backhoe reach from landfast ice and water depth of 50 ft (15 m)

The presence of geotechnical features, such as permafrost, boulders, or large ice features, may be part of the need for extending the capabilities of the trenching equipment. Therefore, the trenching equipment and the associated project execution plan must be compatible with offshore Arctic conditions. The equipment must be able to create a suitable trench profile in the site-specific soil conditions. A viable option in deeper water may not be the best solution in nearshore areas (e.g., a plough may be effective in thawed soils in deeper water but it may not be effective through nearshore permafrost).

To operate in Arctic conditions, significant modifications to existing conventional equipment may be required. Vessels would require winterization to allow operation in below freezing conditions and their hulls may require strengthening to withstand ice loads. If construction cannot be completed in a single season, consideration must be given to mobilization and demobilization or overwintering of trenching equipment.

Several trenching techniques could be used for Arctic applications, and some are variations on conventional (summer) methods. Conventional backhoe excavation is a proven, but time-consuming method, and productivity would be similar for winter or summer construction. Ice-based excavation has been performed on several pipeline projects using hydraulic backhoes working from stable land-fast or bottom-fast sea ice. The sea ice is artificially thickened to support the trenching and pipelay activities. In this application, the reach of an extended or long-reach backhoe is limited (practically) to a combined water and trench depth of approximately 50 ft (15 m). An example of winter on ice excavation is shown in Figure 11-6. This construction method permits a continuous trenching, pipe-laying and backfilling program. Special consideration may need to be given to areas where ice-bonded permafrost may be encountered. Blasting has previously been used to assist in trenching pipelines through nearshore permafrost.

Deeper trenches can be dug using large vessel-mounted backhoe dredges, but the vessel would require ice-free access for trenching and subsequent backfilling. For example, the vessel-mounted backhoe dredge *Boskalis Magnor*, shown in Figure 11-7 has a maximum dredging depth of 105 ft (32 m) below the water surface [Ref. 60]. Thus, achieving depths greater than 15 meters implies that the pipelaying operation would occur from a vessel during summer rather than from the ice during winter.

Figure 11-6: Winter excavation using Conventional Backhoe

Figure 11-7: Conventional Excavation - Boskalis Magnor [Ref. 60]

Advancements in trenching technology to make equipment suitable for Arctic projects may include the following details [Ref. 59]:

- Burial depths greater than 10 ft (3 m), with potential trench depths as much as 23 ft (7 m)
- Trenching in soil conditions that are difficult and highly variable
- Trenching in water depths up to 985 ft (300 m)
- Deployment from vessels or use from vessels that are capable in operating in harsh marine conditions

11.8 Leak Detection

As previously reported in Section 7.2, it is industry best practice for Arctic offshore pipeline leak detection to use a combination of a reliable internal/computational pipeline monitoring system with an external leak detection system. Many existing leak detection systems are field proven with technology readiness level 7, with emerging technology for offshore Arctic application represented by leak detection using fiber optic cables, acoustic pigging, or real time transient modeling.

Leak detection using FOCs as a direct means of detecting leaks has yet to be proven in a subsea capacity, with distributed temperature sensing systems and distributed acoustic sensing systems requiring further development to advance the TRL. Related to use of FOC LDS in offshore applications, the use of subsea amplifiers to extend potential monitoring lengths is also an emerging technology that could boost the FOC signal locally to exceed current limitations of approximately 28 miles (45 km) length coverage. Options include optical amplifiers, electrical amplifiers, or removing fiber optic units that require multiple FOC loops extending from the remote unit. Since FOC are often installed for communications, the incremental costs of installing a FOC LDS are minimal with no subsea power requirements. FOC LDS exhibit good potential for monitoring of trenched and buried pipelines, but require qualification to advance their readiness level.

Since acoustic pigging is a periodic LDS that doesn't provide continuous monitoring, it is not recommended as a primary or secondary system and is suited as a tertiary system for periodic monitoring. The acoustic pig technology readiness level is 7, field proven, and acoustic pigging technology is currently used onshore with magnetic position markers along the pipeline external surface. However, development and qualification of an appropriate location tracking device is required for buried offshore pipeline application. Battery life technology could require advancement, depending on the pipeline length to be monitored.

RTTM leak detection technology is field proven in onshore oil (such as e.g., Trans Alaskan Pipeline System) and offshore gas pipelines, but not yet qualified for Arctic offshore applications. Qualification activities are required to confirm RTTM technology can meet relevant Alaskan and US Federal DOT regulatory requirements at acceptable leak detection rate thresholds. Some concerns currently identified with RTTM systems are their relatively high cost and instrumentation and calibration needs.

Additional details and discussion of current LDS technology readiness levels is contained in Appendix B.

Reference 61 details a new, proprietary, virbroacoustic wave technology for pipeline leak detection that has been tested and validated with experimental (non-Arctic) field application. It is reported that "vibroacoustic monitoring is an emerging technique for detection of leaks and third-party interference (TPI) on fluid transportation pipelines" [Ref. 61]. It uses a discrete network of monitoring stations spaced several kilometers apart along a pipeline to monitor fluid pressure transients and pipe wall vibrations. Thus, this system may not be appropriate for PIP system application or trenched and buried pipelines since "system performance depends on the capability of the pipeline to 'transmit' the vibroacoustic signals…" [Ref. 61] among other factors. The main benefit of this system is purported to be remote real-time monitoring of pipelines.

Reference 62 has developed a multi-mode leak detection system algorithm for offshore monitoring of single and dual-phase pipelines, based on the mass balance principal, hydraulic grade line method and sequential probability ratio testing to set alarm thresholds and define operational conditions by pattern recognition (and thereby reduce false alarms). The software system has been tested via simulation and with comparison against commercial LDS, as well as prototype testing on a single-phase gas pipeline. Additional qualification testing and field trials would be required to prove this technology for offshore Arctic application.

11.9 Operations

A method for monitoring the pipeline can be through geometry deformation monitoring. Smart pigging, or intelligent pigging (In-Line-Inspection), can be used to detect changes in the pipeline geometry, changes in pipe deformation, and estimate strain in the pipeline. The pigs (geopig, caliper pig, etc.) can be run to make an integrity assessment after an unexpected ice scour event. They can also help assess pipeline free spans that might exist after a strudel scour event, thaw settlement, or to identify any upheaval buckles. An advantage of utilizing pigs for yearly operational data collection is that assessments may be made of data trends. There may be an indication that span lengths are growing by a certain percentage or upheaval buckles are growing or stabilizing. In order to assess these measurements, a baseline survey (curvature, location, etc.) needs to be completed immediately after pipeline construction to ensure that strains resulting from installation are not treated as being the result of environmental loadings. Analysing the data that is provided by the pigs may allow for remediation planning and any qualification testing that may need to be performed the project location. A further description of caliper and geopigs pigs is provided below.

- Caliper pigs (Figure 11-8) sent after a gauging plate can accommodate a 30 to 50% change in inner diameter (ID). These pigs are required to prove that the selected metal loss tool (magnetic flux leakage [MFL] or ultrasonic testing [UT]) can fit through the pipeline system. Mechanical damage can also be identified, measured, and assessed using caliper pigs capable of measuring ID to identify denting, buckling, or other blockages. Typically, local deformations must exceed 2 to 3% of the pipeline ID to be recorded by a caliper pig. More accurate measurements can be made using more specialized pigs, like MFL or UT.
- Geometry measurement pigs (3-D inertial mapping of axial, vertical and lateral positions) are capable of measuring the physical positions of the pipeline for comparison to previous survey data and can be used to compute pipeline/flowline curvature and corresponding bending strains. To account for mapping drift, these surveys require a benchmarked elevation survey at, or near the exit flanges on both ends of the pipelines using conventional elevation survey equipment, and intermediate tie-in points from the as-laid survey. Geometry pigging is essential for monitoring the limit state bending strain conditions in offshore pipelines and flowlines.

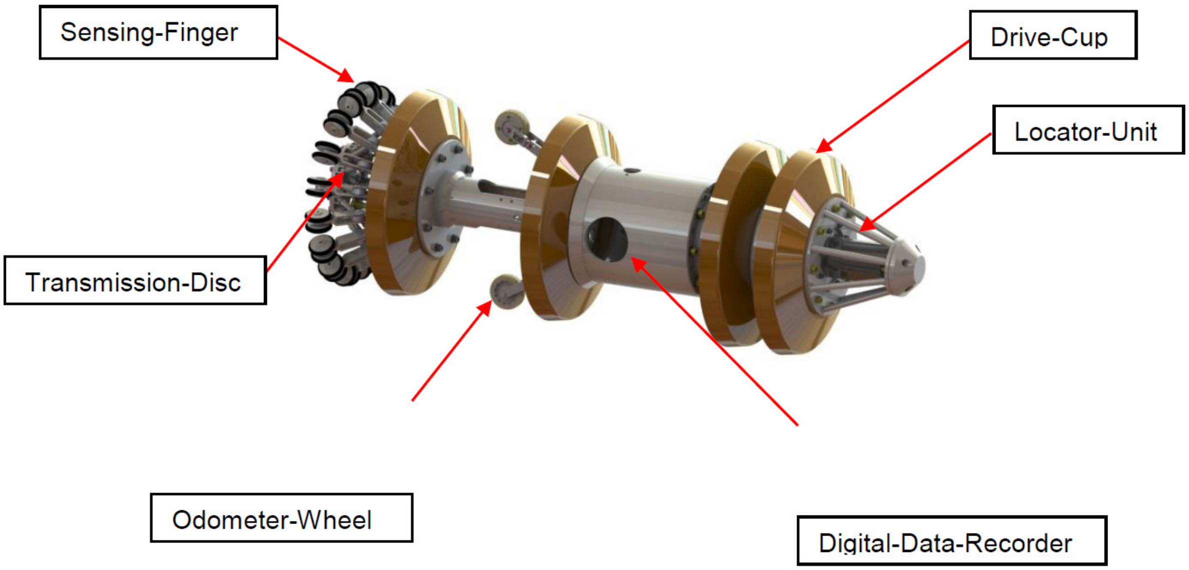

Figure 11-8: Example of a Caliper Pig [Ref. 63]

Considerations that need to be made to determine the appropriate pigging operations for the development include:

- Pipe diameter and flow conditions.
- Battery life of the pigs – this can be an issue for small diameters when stacking batteries.
- Low velocity pigs – this can lead to data storage limitations for long distance pipelines.
- Uses of valves – valves are the most common cause of pigs getting stuck.
- Bends – recommended sizing of bends to allow easy passing of pigs.
- Wax formation or other obstructions to the pipe cross section
- Pipe length– for long distance pipelines, the wear on the pig can become an issue.

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Appendix A Gap Analysis Matrix

Appendix B Monitoring and Leak Detection

Appendix B Monitoring and Leak Detection

Early detection of potential pipeline leakage is essential to minimize environmental damage, economic losses and negative perception. Offshore Arctic areas are environmentally sensitive and preventing leaks is considered a high priority for any proposed Alaskan offshore development. Existing, as well as emerging, leak detection system technologies are summarized in Figure B-1 and discussed further in the sub-sections that follow.

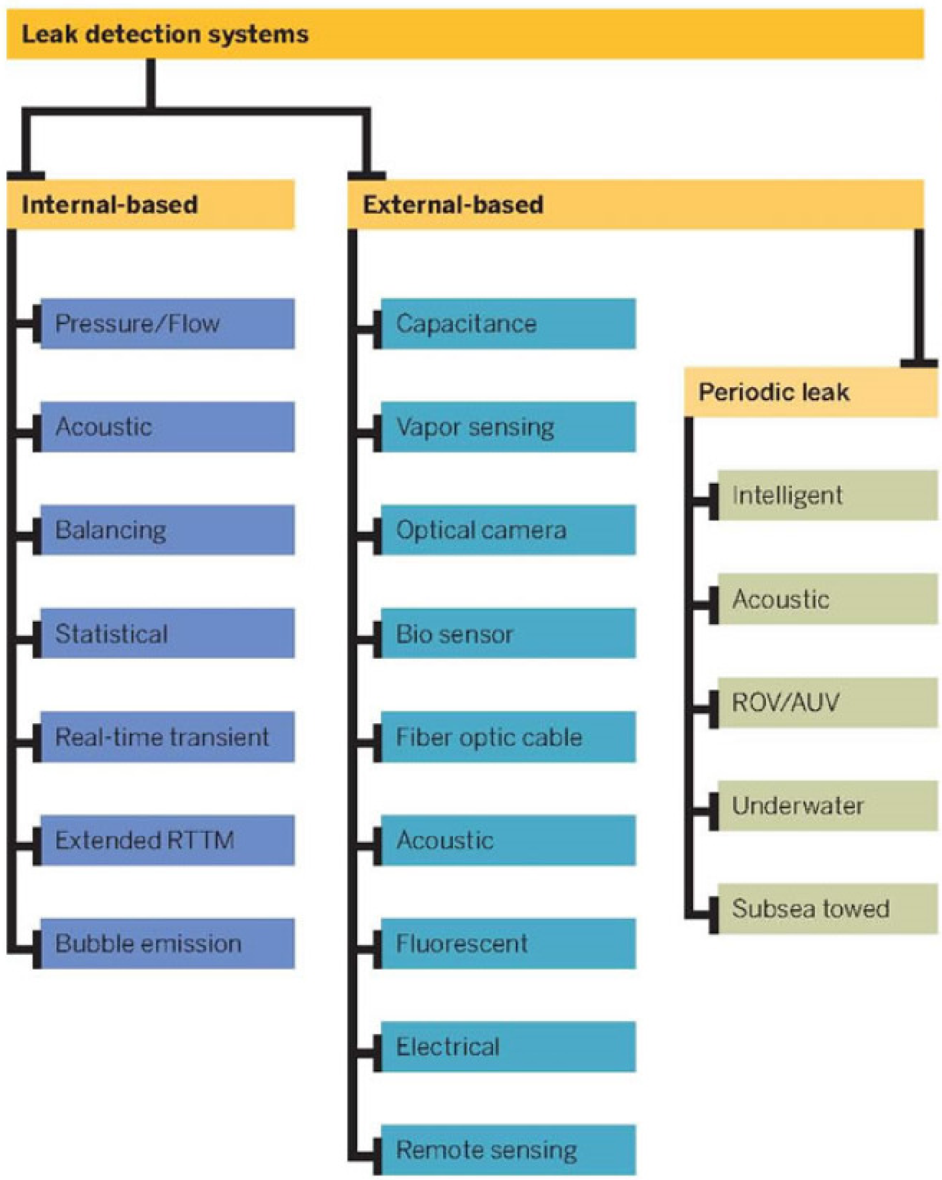

Figure B-1: Existing Leak Detection Systems [Ref. 1]

B.1 Current Leak Detection Technologies

Evaluation and assessment of leak detection technology suitability has been performed in a semi-quantitative manner, considering whether existing technologies have been applied in currently operating Arctic pipelines or field-proven via testing (e.g., TRL 4). This review should not be considered exhaustive since technology vendors have not been solicited as part of this exercise; rather, internal knowledge, past project information, and SME input has been used in this assessment. Available technologies have been organized considering their method of application; internal systems, external systems, and periodic methods. Existing LDS have been included in this evaluation, as well as emerging technologies.

B.1.1 Internal Leak Detection Systems

Internal-based systems utilize field sensor data that monitors internal pipeline parameters, such as pressure, temperature, viscosity, density, flow rate, contamination, product sonic velocity and product data at interface locations. These inputs are then used for inferring a commodity release by computation. Generally, these systems are installed along with the pipeline and other data acquisition systems, such as SCADA. The data acquired from these sensors is analyzed and used to determine the flow conditions inside the pipeline and potential loss of product. They have the ability to quickly detect large leaks, but have limited ability in detecting small, chronic leaks. The most common industry utilized internal LDS that are commercially available are discussed below.

B.1.1.1 Pressure Monitoring

Pressure monitoring systems use pressure measurements to monitor operating trends in the pipeline. If a set of parameters (e.g., pressure, flowrate) does not match historical trends or normal operating trends, an alarm is triggered indicating a potential leak.

Pressure Switch Low (PSL) monitoring involves continuously monitoring pressure at one end or two ends on a flowline. A predetermined threshold, below the range of normal operating pressure, is a preset for an alarm. If the pressure drops below this set point, an alarm will be triggered indicating a potential leak incident. This system is simple, inexpensive and efficient in detecting large leaks. However, it is not very efficient in detecting, as well as locating, small leaks or for monitoring transient operating conditions. It can be used for multiphase flowlines in onshore and offshore sections.

The flowlines will have pressure gauges, transmitters, and alarms at both ends of the pipeline/flowline. Approximate leak location can be determined by recording the time at which the pressure alarms were triggered at each end of the flowline and estimating the travel time and length from the time difference between the alarms. Sensitivity reduces with longer lengths, transient flow, etc. A summary of pressure monitoring systems is presented in Table B.1.

Table B.1: Summary of Pressure Monitoring / PSL Systems

Suitable for	Single phase oil/multiphase flow pipelines
Type of installation	Permanent
Type of monitoring	Continuous
Advantages	• Quick detection of large leaks

Suitable for	Single phase oil/multiphase flow pipelines
	• Well established and mature technology, PSL alarms are the most common type of pipeline leak detection systems • Simple, inexpensive and efficient • Has some leak location capability • Easily integrated into pipeline SCADA
Disadvantages	• Cannot detect small chronic leaks (sub 1% leaks) • Cannot locate small leaks accurately • Prone to false alarms • Potentially requires changes in design, introduces more sealing points (i.e. paths for leakage) • Not intended for low-flow or no-flow conditions • Challenges associated with multiphase leak detection

B.1.1.2 Mass Balance Method

Mass balancing is a software based accounting technique utilizing the principle of conservation of mass. The mass flow entering and exiting a pipeline is measured and calculated using various instruments and any resulting loss of mass infers a leak. The mass flow rates are adjusted for temperature and pressure measurements at the inlet and outlet flow meters, and any flow meters in between. Once the uncertainties are bounded, any greater discrepancy in the mass suggests that there is a leak present.

Multiphase flow is one of the most difficult situations for leak detection from internal measures of flowrate variables. There are several reasons for this. The flow consists of independent phases, variation of each phase volume along the flowline, different fluid velocities for each phase and sometimes a non-Newtonian behavior due to the formation of oil-water emulsion. For multiphase flowlines, the difficulty of accurately measuring flowrate precludes the use of mass balance techniques for small leaks. However, mass balance is much more accurate for single phase lines, generally detecting leaks of about 1% the daily throughput in ideal operating conditions. The performance characteristics of a mass balance system are described in Table B.2.

Table B.2: Summary of Mass Balance Systems

Suitable for	Single phase oil steady flow pipelines (not ideal for multiphase flow)
Type of installation	Permanent
Type of monitoring	Continuous
Advantages	• Can detect large pipeline leaks • Well established and matured technology • Suitable for single phase oil pipeline leak detection • Able to detect leaks in transient flow conditions less accurately
Disadvantages	• Cannot detect small chronic leaks (sub 1%

Suitable for	Single phase oil steady flow pipelines (not ideal for multiphase flow)
	leaks) • Cannot locate small leaks • Prone to false alarms and reported poor performance in transient flow conditions • Not intended for use under low-flow, no-flow or multiphase conditions

B.1.1.3 Real Time Transient Monitoring (RTTM) method

RTTM is the most sensitive but also the most complex and costly leak detection method in use. It is an enhancement of line balancing methods and involves the computer simulation of pipeline conditions using advanced fluid mechanics and hydraulic modeling. It uses laws such as, the law of conservation of momentum, conservation of energy, and numerous flow equations to model flow conditions (mass flow, pressure, density, temperature, etc.) within pipelines. Using various instruments required to measure the flow conditions, leaks can be detected during steady-state and transient conditions.

RTTM software can determine the pressure-flow profile at the outlet based on the data at the inlet. The computer can predict the size and location of leaks by comparing the measured data with the real time conditions. This analysis is done in a three step process:

1. The pressure-flow profile of the pipeline is calculated based on measurements at the pipeline or segment inlet.

2. The pressure-flow profile is calculated based on measurements at the outlet.

3. The two profiles are overlapped and the location of the leak is identified as the point where these two profiles intersect.

If the measured characteristics deviate from the computer prediction, the RTTM system sends an alarm to the pipeline controller. Note that models rely on properly operating and calibrated instruments for optimum performance. Any loss of data or calibration errors could result in false alarms or missed leaks, and the loss of a critical instrument could require system shutdown. Table B.3 summarizes the system characteristics.

This system's operating conditions are usually based on long lengths of pipeline systems. Therefore, this system is very sensitive to the quality of the input data.

Table B.3: Summary of Real Time Transient Monitoring Method

Suitable for	Single phase oil/multiphase flow pipelines
Type of installation	Permanent
Type of monitoring	Continuous
Advantages	• Very accurate for steady state conditions • Can detect small leaks • Good for long pipelines

Suitable for	Single phase oil/multiphase flow pipelines
Disadvantages	• Increased instrumentation is required • Unsteady flow creates errors (or, false alarms) • Calibration or loss of data could cause missed leaks or false alarms • Very expensive and complex system

B.1.1.4 Acoustic Monitoring System

When a leak occurs in a pressurized flowline, a low frequency acoustic pressure wave travels from the leak location to both ends of the flowline. Sensors placed along the flowline can detect these acoustic signals when the leak occurs. Initially, a base reading of the operating flowline is obtained at start-up. As the flowline continues to operate, the baseline is updated by filtering out the flowline's inherent pressure noise pattern that is measured by the acoustic sensors. Any deviation from the baseline's acoustic signal pattern would indicate a potential leak and trigger an alarm. Flowlines that use this to detect leaks require the following:

- A sensor that converts a pressure (acoustic) wave to an electric signal;
- A low noise amplifier that raises the signal to a usable level;
- Signal processing electronics for feature extraction and waveform capture;
- Microprocessor and DSP-based parallel distributing processing instrumentation;
- Knowledge-based software for easy analysis, defect correlation and development of expert systems that comply with demanding Arctic environment standards; and
- Decision and feedback electronics to utilize the information.

Acoustic LDS are influenced by background noise, which affects the leak detection sensitivity. Filtering out the background noise can filter out the low frequency noise for a small leak which may develop slowly. Leak location is determined whenever there is a detection of an event by local site station and the master station receives an indication from the second local site station flagging the same event. Once confirmed, the leak location is computed based on the time differential between the receipt of the indications from the two sites and the activation of an alarm. For single phase flowlines, leak location may be determined to within 100 ft (30 m) of the leak. For multiphase flowlines, leak location precision is reduced to within 330 to 665 ft (100 to 200 m) of the leak.

For multiphase flowlines, the sensitivity for detecting and locating a leak is described in terms of an equivalent leak dimension ranging from 0.2 to 0.5 inches (5 to 12.7 mm). This can equate to a fairly large liquid volume, and therefore would not offer the sensitivity that pressure switch low and mass balance combination can provide. Furthermore, acoustic monitoring relies on the passage of the noise signal that develops when a leak develops (or 'pops'). Once the noise signal from the leak initiation passes, there is no opportunity to detect or locate the leak.

Table B.4: Summary of Acoustic Monitoring System

Suitable for	Single phase oil / multiphase flowlines
Type of Installation	Permanent
Type of Monitoring	Continuous
Advantages	• Quick leak detection

Suitable for	Single phase oil / multiphase flowlines
	• Good for large leak detection • Can detect location of leak • Simplified sensor and software set-up with minimal calibration
Disadvantages	• Background noise severely affects leak detection capability for small leaks • Difficult for multiphase flow • Prone to false alarms • No leak detection capability once the leak-noise misses the sensor • Challenging for small leak detection on long pipelines

B.1.2 External Leak Detection Systems

External-based systems measure physical properties around the pipelines. Some of the external LDS sensors are used as point sensors and others are connected to the circumference of the pipeline for continuous leak monitoring. The most common industry utilized external LDS that are commercially available are described below.

B.1.2.1 Acoustic Leak Detection Systems

Underwater microphones, or hydrophones, are used to detect the acoustic signal generated by a rupture or leak flow. This technology is referred to as passive acoustic leak detection. Acoustic detection has been widely available commercially for traditional subsea leak detection for some time. This technology can be used to monitor critical areas (flanges, valves, etc.) in the form of a leak monitoring station sensor that can be installed nearby. Communications to surface can go through an existing subsea control module or by acoustic link.

Locating a leak on the pipeline is possible by using an array of sensors. Arrival time of an acoustic signal at each sensor can be used to locate the origin of the sound. Full pipeline monitoring may be achieved by installing a number of leak detection stations along the pipeline, making it not ideally suitable for long pipelines. However, it can be used to monitor subsea equipment leaks by communicating acoustically with each other in a distributed network with the last sensor linked to the surface. The acoustic signal increases with the leak size.

Minimum leak size detection and reliability for this technology is based on how strong the acoustic signals are (and how close the microphone is to the leak). The strength of the acoustic signal will be related to how much pressure drop occurs across the leak path. Background noise (e.g. natural seepage, transient flow, etc.) may affect the measurements. Passive acoustic sensors are not dependent on the chemical compound of the leaking medium or by seawater currents and turbidity. Summary capability of this LDS is presented in Table B.5.

Table B.5: Summary of Passive Acoustic LDS

Suitable for	**Subsea systems, connections, and short lengths of gas, oil, and multiphase flow pipelines**
Type of installation	Permanent or ROV operated
Type of monitoring	Continuous monitoring or intermittent ROV testing
Advantages	• Does not require shutdown for installation or calibration • Can work under low or non-flow conditions • Can detect small leaks • Can locate leaks accurately • Can use hydro-acoustic communications
Disadvantages	• Prone to false alarms • At high flow, background noise can mask the sound of a leak • Requires some differential pressure between inside and outside of pipeline • Multiple detector units required for continuous long pipeline monitoring • Increased installation and operational cost for sensor and communications system • Monitoring trenched and buried pipeline may be challenging

Another acoustic method exists that is referred to as active acoustics. In this approach, sound waves are emitted (sonar) and reflections are monitored from materials whose acoustic impedance is different to that of water (the impedance is a material characteristic and depends on sound velocity, density, salinity and temperature of the medium). This technology is most sensitive to gas or large leaks. However, this is not a continuous leak detection system.

B.1.2.2 Fiber Optic Cable Sensors

Fiber optic cable (FOC) sensors can be installed as point sensors or as a distributed network. Optical properties of point sensors change in the presence of hydrocarbons. More commonly, several different scattering effects of injected laser light are affected by changes in temperature, ambient conditions and strain, and vibration, some of which can be used to detect the leakage of hydrocarbons. With distributed fiber optic sensing, physical effects of standard telecommunication fibers are applied to infer the temperature and acoustic effects of leaks. By similar principles, fiber optics could also be able to detect geo-hazards and other third party interventions or activities on long pipelines that may lead to leaks.

FOC can accurately detect and locate leaks (and other events, such as ice gouging, earthquake, landslides, seabed erosion, etc.) along a continuous optical fiber. Multiple events may be detected at the same time and are accurately located. Increasing spatial resolution along the fiber decreases detection sensitivity for this technology. Fiber optic technology would have minimal external power or communication requirements and is immune to electrical interference. A distributed sensing FOC system for temperature and acoustic vibrations is a promising technology, which has had limited subsea applications for leak detection.

An oil leak produces local warming of the environment surrounding the pipeline while a gas leak produces local cooling caused by the Joules-Thompson effect during gas decompression. These thermal anomalies can be captured by distributed temperature sensing (DTS) systems with good spatial and temporal resolution. Similarly, the acoustic signature generated by leaking hydrocarbon can be detected using distributed acoustic sensing (DAS) systems.

FOC installed along the pipeline for DTS can measure the thermal and/or acoustic anomalies in real-time. This continuous placement of FOC replaces multiple sensor requirements along the pipeline and provides a backscattered signal at the source after sensing parameter anomalies. By analyzing the backscattered signature at the receptor, the presence and the location of leakage can be identified. This information can be passed immediately on to the pipeline control room through SCADA. In FOC distributed sensing systems, the Optical Time Domain Reflectometers (OTDR) principle is used for leak detection. An optical signal is emitted into the fiber and a sensor receives and measures the amount of light backscattered to the source. The time interval between the emission and backscattered detection can be easily converted to the distance to the backscattering anomaly (i.e., leak location). Typical spatial resolution is 3 feet (0.9 m) and temperature resolution is 0.5°F (0.3°C). The spatial and temperature resolution has been observed to reduce with length.

The DAS system operates by measuring the minute strain effects on the sensing cable. This strain is caused by vibrations generated in buried cable by acoustic waves arising from leakage. In a rupture and leaking environment, the backscattered signal is subjected to the incoming pressure waves which in turn modulate the backscattered signal.

For pipeline leak detection application, the DAS utilizes an interrogator unit at one or both ends of the pipeline and two or more fibers within a FOC bundle. The FOC acts as a distributed hydrophone system that picks up the acoustic waves produced by leakage. When a distinguishable acoustic signature associated with a pipeline leak is detected, a leak alarm is triggered along with information regarding the leak location.

Rayleigh-based DAS systems have monitoring capabilities up to 25 to 30 miles (40 to 48 km) with one instrument at one end of the pipeline. However, the system needs to be calibrated at the ambient conditions. The DAS system may have a limiting threshold because of background noise. However, the DAS does not require the cable to contact the leaking fluid, and thus it may be promising for buried pipeline applications. The sensitivity of the DAS to detect a small, chronic leak will be affected by spatial resolution, length of coverage, size/strength of leak, background noise, ability to discern acoustic signature of the leak, soil conditions, cable positions, distance from leak, and internal versus external pressures.

Table B.6 summarizes the leak detection capability of distributed sensing FOC systems.

FOC have been installed to monitor strain in flexible deep-water risers and as a leak detection system in brine and water/slurry onshore pipelines. A DTS system was also utilized in past Arctic subsea pipelines, however the primary objectives were not for leak detection. It was installed to monitor potential harmful conditions such as strudel scour or river channel migration erosional events. By monitoring the temperature along the flowline length and comparing it to various alarm settings, the operator may be notified early and able to react to unique Arctic events that may affect the integrity of the flowlines.

Table B.6: Summary of Fiber Optic Cable Sensors

Suitable for	**Single phase oil/multiphase flow pipelines, connections**
Type of installation	Permanent
Type of monitoring	Continuous monitoring
Advantages	• Does not require shutdown for calibration • Can work under low flow or transient conditions • Can detect very small leaks (sub 1% leaks) accurately • Can locate leaks accurately • Can be used on seabed as well as in buried conditions • Can use optical communications • Can also detect geohazards and third party interventions • No subsea power requirements • Not affected by any electrical or electromagnetic interferences • Can be used on long pipelines for continuous monitoring
Disadvantages	• Multiple detector units may be required for long (>45km) pipeline monitoring • Increased installation cost for sensor and communication system • Needs further evaluation and technical readiness level assessment

B.1.2.3 Vapor Sensing Tubes

This detection technology uses a sensor that absorbs fluid through a semi-permeable membrane and identifies the target contaminant on a molecular level. The detection principle is that dissolved hydrocarbon will change the resistance of an internal component in the sensor chamber which generates an electrical signal in the detector (e.g., LEOS hydrocarbon sensor).

The LEOS system (by Siemens Power Generation Group, Germany) comprises a perforated plastic tube with a thin water impermeable outer sheath that allows hydrocarbon molecules to diffuse into an air filled tube. The air inside the tube is replaced periodically and is passed through a hydrocarbon-sensing module. The module contains resistors sensitive to the presence of very small concentrations of hydrocarbon molecules. The presence and location of a leak is determined by measuring the time taken for the localized concentration of hydrocarbon molecules associated with a leak to reach the end of the tube.

The LEOS system may be considered for Arctic application based on its proven performance and industry experience, but it has length limitations (i.e. typically up to 9.3 miles [15 km]) as described in Table B.7.

Table B.7: Summary of Vapor Sensor Systems

Suitable for	Subsea pipeline and equipment monitoring
Type of installation	Permanent
Type of monitoring	Continuous monitoring system
Advantages	• **30 years of service history, river crossing and other onshore buried pipeline leak detection (e.g. Northstar pipeline)** • Capable of detecting small chronic leaks • Leak location accuracy is approx. 0.5% of total length • System is readily available • Discerning gas leak is rapid • Can work under low flow conditions • Established technology, less unknowns
Disadvantages	• Length limitation is 9.3 miles (15 kilometers) • Water depth limitation is 50 feet (15m) • Minimum bend radius: 2 feet (0.6 meters) • Slow detection. Detection time is determined by air circulation frequency, normally 12 or 24 hours • Additional protection required (e.g. perforated conduits) • Handling, installation and maintenance are difficult • Multiple sensors required along the pipeline • Only detects leaks that evolve into the sensing tube • Difficult to retrofit • May not be best suited for long buried pipelines (greater than 9.3 miles)

B.1.2.4 Annulus Monitoring in Pipe-in-Pipe (PIP) System

Vacuum annulus monitoring involves monitoring the vacuum pressure within the annulus between an inner and outer pipe for a PIP system. This system can be used to detect leaks in 2 ways; a leak in the outer pipe can be detected with an increased annulus pressure to e.g., hydrostatic pressure, whereas a leak in the inner pipe can be discovered with an increase in the annulus pressure to pipeline operating pressure.

In order to maintain the vacuum, permanently installed vacuum pumps with linked pressure gauges and logic controllers are required. The annulus volume can also provide a thermal insulation barrier and potentially improved flow performance. Applying the vacuum to the annulus after construction fulfils the role of a sensitive LDS; a logic control link to an alarm and to SCADA for operator access to the data would complete the LDS. Monitoring the annulus under vacuum conditions, as opposed to atmospheric conditions, provides the following distinct leak detection capabilities:

- Reduces pressure fluctuations due to temperature fluctuations within the annulus;
- Can determine if the casing pipe is compromised if the pressure in the annulus increases to approximately one atmosphere (absolute); and,
- Can determine if the inner production pipeline is compromised if the pressure in the annulus increases significantly above approximately one atmosphere (absolute).

A PIP system is typically used for pipeline insulation purposes and not specifically for LDS only. A summary of annulus monitoring leak detection capability is shown below in Table B.8.

Table B.8: Vacuum Annulus Monitoring System Summary

Suitable for	PIP lines
Type of installation	Permanent
Type of monitoring	Continuous
Advantages	• Sensitive to small leaks • Quick leak detection for small leaks to large leaks • Minimizes false alarms due to pressure increases caused by temperature fluctuations • System can be easily installed • Cost effective (if applied to a pre-determined PIP design, not a bespoke PIP design for LDS application) • Provides continuous monitoring during various flow conditions • Monitoring is not affected by flowline fluid type
Disadvantages	• Cannot detect the exact location of the leak • Vacuum pump/gauges require a heated environment • Slightly increased risk of annulus failure

B.1.3 Periodic Leak Monitoring Systems

These are not continuous leak monitoring systems, but can be used for periodic leak detection / monitoring, or when a leak is suspected. Established periodic leak testing systems are include Remotely Operated Vehicle (ROV)/overflight inspections, shut-in pressure leak tests, remote sensing, intelligent pigging and acoustic pigging, among others.

B.1.3.1 ROV Inspections / Overflights

Weekly aerial surveys of the route can be beneficial for leak monitoring overland pipeline route segments year-round and offshore pipelines during open water season. However, this method is ineffective for subsea Arctic pipelines during the months of ice cover. Therefore, other methods are required for monitoring the offshore section of the pipelines.

Visual inspections of the subsea pipeline using ROV/AUV survey are historically used for inspections, including pipeline leak detection. The water depth and burial condition influence the applicability of conventional ROV inspection or over flight surveying.

B.1.3.2 Remote Sensing Methods

Remote sensing satellites may be used to detect hydrocarbons under ice by providing radar remote sensing, image analysis, advanced signal processing applications, and synthetic aperture radar. Space borne or airborne radar application is affected by ice thickness and the available penetration through the ice would need to be evaluated. In the absence of ice or in broken ice, remote sensing can be used to detect hydrocarbon release. However, data must be collected, processed, and mapped to determine if oil and gas has been detected. During open water periods of the year, remote sensing methods could be used to provide supplemental monitoring of Arctic pipelines for leakage by capturing a few images per day (for review/comparison).

B.1.3.3 Intelligent / Smart Pigging

A pig is a medium propelled unit that travels through pipelines, normally without interrupting production, to carry out cleaning, inspection or other specialized activities. These pigs are routinely run more for corrosion and metal loss inspection, and maintenance. Specialized pigging systems provided by a number of companies are also capable of detecting leaks. Most of the specialized pig products can be added as needed after the design phase if the system is set up for regular pigging.

Intelligent pigging refers to the practice of using pigs to measure and record data of various types while traversing a pipeline. The pig is free floating, carries its own power supply and stores raw data for later analysis. In terms of leak detection, pigs can detect metal loss by measuring diameter, geometry, dents, scours and corrosion. When the information is analyzed after the pig is removed from the pipeline, localized metal loss can determine if there is a leak in the pipe.

The pipeline length, flow rate (travel speed), and pig battery life are factors which influence their application. For pipelines with a large diameter (such as 28 inch OD) battery life will not be a technology limitation. The added internal volume provides more space to stack batteries as necessary; battery concerns are more applicable for small diameter pipelines where the pig turns into a string of batteries.

One main concern for long pipelines is pig wear. This is particularly true for large diameter pipelines where heavier pigs tend to cause localized wear along the bottom of discs. To combat this effect, heavy pigs are often fitted with wheels to provide added support such that the discs do not have to support the entire weight of the pig. Additionally, the wheels are often cantered so that the pig rotates as it progresses through the pipeline to promote even wear of the discs.

A summary of its leak detection capability is provided in Table B.9.

Table B.9: Summary of Intelligent Pigging

Suitable for	**Single Phase Oil / Gas / Multiphase flow pipelines**
Type of Application	Intermittent Running
Type of Monitoring	Periodic
Advantages	• Accurately detects leaks • Sensitive to small leaks • Can simultaneously check for internal corrosion, scale/wax build up, cracking, etc. • Can be run during normal operations
Disadvantages	• Not a continuous (24x7) leak monitoring system • Requires a pig launcher and receiver for operation • Cannot instantaneously detect leaks, substantial volume of fluid may be release before detection • Ability to detect very small leak (sub 1% leak) is uncertain in transient conditions or multiphase flow conditions

B.1.3.4 Acoustic Pigging

Acoustic pigs can be used directly for leak detection. These pigs are similar to intelligent pigs in that they are periodically run through the pipeline and store data to be analyzed once the pigs are removed from the pipeline. However, they differ in that acoustic pigs emit an acoustic signal to propagate through the pipeline. If there is a leak, a specific noise will be received by the pig, the signal is stored and the leak is detected and located when the data is analyzed. The pig is a small ball that is much smaller than the pipeline's inner diameter (ID).

The positions of these pigs can be tracked with ultrasonic detection receivers positioned periodically along the pipeline. However, offshore applications are limited, especially for buried pipe. Position markers cannot easily be placed on the offshore buried pipeline which decreases the ability to locate the leak. Table B.10 summarizes the capabilities and limitations of acoustic pigging.

Table B.10: Summary of Acoustic Pigging

Suitable for	**Single Phase Oil/Gas/Multiphase flow pipelines**
Type of Application	Intermittent Running
Type of Monitoring	Periodic
Advantages	• Relatively high leak detection sensitivity • Ability to detect pin hole sized leaks of less than 0.04 gallon/min (0.15L/min) • Smaller than the pipe diameter so no concern in getting stuck • Acoustic receivers can transmit data in real-time.
Disadvantages	• No continuous monitoring, cannot instantaneously detect leaks

Suitable for	Single Phase Oil/Gas/Multiphase flow pipelines
	• Periodic testing – needs to be run during normal operation • Prone to false alarms • Currently unable to locate leaks in an offshore environment • Requires a pig launcher and receiver for operation • Cleaning pig noise may reduce leak detection sensitivity

B.2 Existing Offshore Alaskan Arctic Pipeline Leak Detection Systems

B.2.1 Northstar

BP Exploration Alaska developed the Northstar field on the North Slope of Alaska in the early 2000s. It was the first oil and gas production field in offshore Alaska and used dual NPS 10 pipelines – one for crude oil transport and one for gas export.

Along with aerial surveillance, the oil transmission lines used Mass Balance (MB) and the Pressure Point Analysis (PPA) (of EFA technologies) that was a combination of mass balance and pressure switch low monitoring. "Mass Balance Line Pack Compensation (MBLPC) was provided to cover small leaks with a minimum leak detection threshold of 0.15% of oil flow through the pipeline, and Pressure Point Analysis (PPA) was provided for rapid leak detection for larger leaks" [Ref. 4]. This provided the Northstar development with the required leak detection threshold limit of 1.0% daily throughput as specified in the Alaskan regulations. However, during permit application and approvals, BP was required to install a secondary leak detection system to detect smaller leaks (less than 1% of the daily throughput) and the location of the leakage. Northstar qualified and installed the LEOS system (i.e. vapor sensing tubes). It was developed by Siemens and although the detection time is slow, it can detect and locate leaks as little as < 0.15% of the daily throughput [Ref. 4].

The gas transmission lines are monitored using a mass balance system with a PSL alarm system installed in case the pressure drops below the threshold low pressure.

B.2.2 Oooguruk

The Oooguruk field has a gravel offshore drill site about five miles offshore Alaska in the Beaufort Sea that produces hydrocarbons and transports the multiphase flow to shore via flowline, installed in 2007. A water and gas flowline supplies the drill site with these fluids for injection. Aerial surveys are carried out periodically to visually inspect the pipeline and facilities.

The three phase PIP production flowline utilizes the PSL system to detect large leaks quickly. A vacuum annulus monitoring system inside the PIP is used as a supplementary system, to detect all (large and small) leak sizes; however it should be noted that the location of the leak is not easily identified. Due to the relatively lower environmental hazard/risk associated with a leak from either the water or gas flowlines when compared to the production flowline, only mass balance and pressure switch low monitoring was required.

A fiber optic cable DTS system was utilized in Oooguruk, however, the primary objective was not for leak detection. It was installed to monitor potential harmful conditions such as strudel scour or river channel migration erosional events [Ref. 4]. By monitoring the temperature along the flowline length and comparing it to various alarm settings, the operator may be notified early and able to react to unique Arctic events that may affect the integrity of the flowlines. Leak detection from the DTS system on Oooguruk is a secondary function [Ref. 4]. The leak detection technology based on distributed sensing FOC was recommended for use in the Oooguruk pipeline.

B.2.3 Nikaitchuq

The offshore flowline bundle for Eni's Nikaitchuq was installed in 2009. A buried pipe-in-pipe flowline transports the three phase production fluid from an offshore gravel drill site to an onshore processing facility. Similar to Oooguruk bundle, water and gas are supplied to the gravel drill site by a flowline each to inject into the reservoir.

The leak detection philosophy of Nikaitchuq mirrors the system installed in Oooguruk [Ref. 4]. A vacuum annulus monitoring system is installed in the production PIP flowline as a secondary LDS, along with a PSL (primary) system to identify the large leaks very quickly. The water injection and gas injection flowlines are monitored using a CPM mass balance system. Relatively less caution is taken with these lines because the environmental hazards are less. Aerial surveillance is recommended periodically to visually inspect all pipelines and facilities that are not buried or submerged in water.

As previously deployed in Oooguruk, a fiber optic DTS system is used on Nikaitchuq bundle to monitor seabed erosion and any events that may disrupt the integrity of the flowline. However, the FOC also provides an additional means of leak detection by identifying and locating an elevated temperature around the flowline [Ref. 4].

B.3 Review & Gap Analysis

Available public domain leak detection technology information compiled as part of past-project work and internal knowledge has been utilized to identify market-ready leak detection technologies marketed for Arctic pipeline application. This exercise was performed in the form of a Best Available and Safest Technology review, as discussed in Section B.4.1. Leak detection technologies were categorized for evaluation as:

- Primary / internal systems for single phase pipelines
- External systems for single phase pipelines
- Primary / internal systems for multiphase pipelines
- External systems for multiphase pipelines
- Periodic methods

B.3.1 Best Available and Safest Technology

As part of the Alaska Department of Environmental Conservation (ADEC) regulations, a Best Available and Safest Technology (BAST) review is required to compare performance of each LDS and evaluate their suitability for Arctic pipeline/flowline application. The following criteria are obtained from Section 18 AAC 75.425 (e) (4) for BAST review:

- Past project experience – whether each technology is the best in use in other similar situations and is available for use by the applicant;
- Suitability – whether each technology is transferrable / suitable to the applicant's operation;
- Decrease Spills – whether there is a reasonable expectation each technology will provide increased spill prevention or other environmental benefits;
- Cost (qualitative) – the cost to applicant of achieving best available technology;
- Technology readiness – the age and condition of the technology in use by the applicant;
- Compatibility with existing operations – whether each technology is compatible with existing operations and technologies in use by the applicant;
- Practicality / feasibility – the practical feasibility of each technology in terms of engineering and other operational aspects;
- Additional environmental impacts – whether other environmental impacts of each technology, such as air, land, water pollution, and energy requirements, offset any anticipated environmental benefits.

A technology review has been summarized based on in-house INTECSEA information for available technologies and then, a short-list was created as follows:

- Internal monitoring systems:
  - Mass Balance
  - Pressure Monitoring / Flow Trending
  - Software based Pressure Wave Monitoring
  - Real Time Transient Monitoring (RTTM)
- External monitoring systems were shortlisted to the following:
  - Vapor Sensing Tubes
  - Fiber Optic Cable (FOC) Distributed Sensing Systems (Temperature and Acoustic)
  - Pipe-in-Pipe Vacuum Annulus Monitoring (for PIP systems only)
- Periodic LDSs were also included:
  - Intelligent Pigging
  - Acoustic Pigging
  - ROV Inspections/Overflights, Optical Technologies / Visual Inspections
  - Remote Sensing Methods

Each leak detection system's method of operation, effectiveness, and performance has been reviewed in relation to Alaskan Arctic offshore pipeline application. A typical Best Available and Safest Technology (BAST) evaluation focuses on system(s) that are best suited for leak detection sensitivity and compatibility with Arctic offshore pipelines located in sensitive environmental areas, restricted winter access, and Arctic environmental phenomena.

An ideal leak detection system for offshore Arctic application would satisfy the following criteria [Ref. 3]:

- Sensitivity – detects hydrocarbon leaks (either multiphase or oil), both small and large
- Detection time – small leaks in days and large leaks in seconds or minutes (or hours)
- Sufficiently discerning to avoid false alarms
- Robust to survive installation and long-term operation from outages or reduced flows
- Minimum impact on production flowline operation from outages or reduced flows
- Can detect leaks under multiphase flow conditions, as applicable
- Accommodates the flowline fluid types and operating conditions
- Robust to survive installation and long-term operation in the Arctic environment
- Commercially available
- Technology Readiness Level (TRL) is adequate
- Additional environmental impacts are minimal

An ideal leak detection system would have the following additional characteristics from an operational repair and downtime reduction perspective. However, these characteristics are considered optional because they are not mandatory for the purpose of detecting a leak or minimizing release through a leak.

- Identifies leak location
- Identifies leak rate

Reviewed leak detection technologies are assessed under TRLs, a quantifiable maturity scale ranging from 0, a basic concept, to 7, production system field proven; see section B.10.4.2 of API RP 17N [Ref. 2]. Technologies that are deemed enabling or enhancing and rank lower than a TRL 6 require a qualification plan during project development to advance it to an appropriate TRL before project application.

The review results are detailed in Table B.11 through Table B.15, and provide a comparative evaluation of the available technologies and how they are applicable to Arctic offshore pipeline systems. Each system was qualitatively evaluated against the criteria described above.

Overall BAST recommendations are not provided in this report as final system selection is dependent on various factors such as pipeline design (single-walled vs. PIP), size and length, location, flow conditions, burial conditions, and operator/owner preferences. This technology review should not be considered a full BAST review as it was not performed for a specific project application and is based on previously compiled and generalized information.

Table B.11 Technology Review Primary / Internal Leak Detection Systems for Single Phase Pipelines

Primary CPM Systems: Single Phase Pipelines

BAST Criteria	**Mass balance**	**Pressure Monitoring**	**Acoustic Pressure Wave Monitoring**	**Real Time Transient Monitoring**
	Description	Description	Description	Description
Past Project Experience	Used on Northstar, Oooguruk WI/GI lines, and Nikaitchuq WI/GI lines Commonly used internationally onshore/offshore pipeline applications	Used in all past pipeline projects (Northstar, Oooguruk, Nikaitchuq) Common international onshore/offshore	No offshore Arctic experience, used for onshore pipeline leak detection	Trans Alaskan Pipeline System (and other major onshore systems)
Suitability to Alaskan Arctic Offshore	Highly Suitable	Highly Suitable	Somewhat suitable (flow rate variations may interfere with leak generated noise)	Not very suitable - normally used on longer, onshore pipelines
Decrease Spills	Reduce spill potential volume	Reduce spill potential volume	Reduces spill potential volume	Reduces spill potential volume
Cost (Qualitative)	Meters on ends of pipeline	Pressure monitoring system, meters, alarm/SCADA	Least expensive based on additional equipment required (acoustic sensors + comms cable)	Most Expensive - requires additional software and computer programs, inputs, training
TRL Level	7	7	6	6
Practicality/ Feasibility	Detection time is longer for large leaks than Pressure Monitoring but more accurate at detecting small leaks Cannot locate leaks	Can detect large pipeline leaks quickly Cannot accurately detect small leaks. There is some leak location capability	Can detect large pipeline leaks quickly Cannot detect small leaks. Able to locate leaks False alarms can be more common	More instrumentation and calibration is required More suitable to slowly varying flow conditions.
Additional Environmental Impacts	No	No	No	No
Compatibility with existing operations	Yes	Yes	Yes	Yes
Other Important Points	Need a communication cable / SCADA link to control room		May require intermediate acoustic sensors and communication cable	Unsteady flow may increase false alarms

Note: CPM = Computational Pipeline Monitoring

Table B.12 Technology Review External Leak Detection Systems for Single Phase Pipelines

External Systems: Single Phase Pipelines

BAST Criteria	Vapour Sensing Tubes / LEOS	Fiber Optic Cable Sensors	Point Acoustic Sensors
	Description	Description	Description
Past Project Experience	Used on Northstar and other under-river applications globally	Used in onshore water/slurry pipelines, onshore brine pipeline but not on offshore oil pipeline	Primarily a point sensor for subsea facilities, no true pipeline applications
Suitability to Alaskan Arctic Offshore	Slow Detection Rate (12 to 24 hours) Able to locate leaks Very small leak detection capability	No subsea power requirements, fast detection rate. Able to detect and locate leaks only if a significant temperature change at a cable location.	Point sensor technology. Not suitable to pipelines.
Decrease Spills	Reduces spill potential leaks	Reduces spill potential leaks	The technology is good for point sensing.
Cost (Qualitative)	Very expensive primarily due to installation (additional conduit is necessary for buried pipelines)	Increased installation costs for sensors and communication system, Unit costs aren't too expensive. Starting point is 1 armored cable in the bundle	Increased installation/operational costs
TRL Level	TRL: 7	TRL: 3	TRL: 7 for point sensing. Not tested for long pipeline lengths
Practicality/ Feasibility	Additional protection (conduits) required Installation is difficult Repair is difficult. Picks up all incidents along the pipeline (naturally occurring methane gas, hydrogen from anodes)	Needs qualification before installation Good for monitoring trenched/buried pipelines FOC needed for communications anyway, so incremental costs are small FOC is required to be close to the pipeline	Increased installation costs for sensors. Installation is already challenging Monitoring trenched/buried pipeline is a challenge
Additional Environmental Impacts	More equipment and labor is required for installation and repair	No	No
Compatibility with existing operations	Yes	Yes	Yes
Other Important Points		Developing technology but not field proven for subsea pipelines	

Note: CPM = Computational Pipeline Monitoring

Table B.13 Technology Review Primary / Internal Leak Detection Systems for Multiphase Pipelines

Primary CPM Systems: Multiphase Pipelines

BAST Criteria	Mass balance	Pressure Monitoring	Acoustic Pressure Wave Monitoring	Real Time Transient Monitoring
	Description	Description	Description	Description
Past Project Experience	Used on Northstar, Oooguruk WI/GI lines, and Nikaitchuq WI/GI lines Commonly used internationally onshore/offshore pipeline applications	Used in all past pipeline projects (Northstar, Oooguruk, Nikaitchuq) Common international onshore/offshore system	No offshore Arctic experience, used for onshore pipeline leak detection	Used on Ormen Lange subsea flowlines
Suitability to Alaskan Arctic Offshore	Suitable - multiphase flow decreases the accuracy	Highly Suitable	Somewhat suitable (any flowrate and slugging variations may interfere with leak generated noise)	Not very suitable - normally used on longer, onshore pipelines
Decrease Spills	Reduce spill potential volume	Reduce spill potential volume	Reduces spill potential volume	Reduces spill potential volume
Cost (Qualitative)	Multiphase meters on ends of pipeline	Pressure monitoring system, alarm/SCADA	Least expensive	Most Expensive - requires additional software and computer programs, inputs, training
TRL Level	7	7	6	6
Practicality/ Feasibility	Detection time is longer for large leaks than PSL but more accurate at detecting small leaks. Cannot locate leaks	Can detect large pipeline leaks quickly Cannot accurately detect small leaks. Some leak location capability	Can detect large pipeline leaks quickly Cannot detect small leaks. Able to locate leaks False alarms can be more common	More instrumentation and calibration is required More suitable to slowly varying flow conditions.
Additional Environmental Impacts	Yes	No	Yes	Yes
Compatibility with existing operations	No	Yes	No	No
Other Important Points	Need a communication cable / SCADA link to control room		May require intermediate acoustic sensors and communication cable	Unsteady flow may increase false alarms

Table B.14 Technology Review External Leak Detection Systems for Multiphase Pipelines

External Systems: Multiphase Pipelines

BAST Criteria	Vapour Sensing Tubes / LEOS	Fiber Optic Cable Sensors	Vacuum Annulus Monitoring (for PiP only)	Point Acoustic Sensors
	Description	Description	Description	Description
Past Project Experience	Used on Northstar, other under-river applications globally However, not used on multiphase PiP system	Used in onshore water/slurry pipelines, onshore brine pipeline but not on offshore oil pipeline	Used on Oooguruk and Nikaitchuq for multiphase PiP Flowlines	Primarily a point sensor for subsea facilities, no true pipeline applications
Suitability to Alaskan Arctic Offshore	Slow Detection Rate (12 to 24 hours) Able to locate leaks Very small leak detection capability	No subsea power requirements, fast detection rate Able to detect and locate leaks only if a significant temperature change at the cable location (More able to detect gas leaks due to JT cooling)	Unable to locate leaks Fast leak detection Requires pipeline is already PIP - not much extra to add monitoring on the ends	Point sensor technology. Can be eliminated More sound out of multi-phase, most effective in gas system
Decrease Spills	Reduces spill potential leaks	Reduces spill potential leaks	Reduces spill potential leaks	This technology is good for point sensing
Cost (Qualitative)	Very expensive primarily due to installation (additional conduit is necessary for buried pipelines)	Increased installation costs for sensors and communication system, Unit costs aren't too expensive. Starting point is 1 armored FOC	Cost effective, vacuum pump and additional instruments on either end.	Increased installation/operational costs
TRL Level	TRL: 7 for single phase pipeline. Not used for multiphase PiP system	TRL: 3	TRL: 7	TRL: 7 for point sensing. Not tested for long pipeline lengths
Practicality/ Feasibility	Additional protection (conduits) required Installation is difficult. Repair is difficult. Picks up all incidents (naturally occurring methane gas, hydrogen from anodes)	Needs qualification before installation Good for monitoring trenched/buried pipelines FOC needed for communications anyway, so incremental costs are small	Good for monitoring trenched/buried pipelines No intermediate bulkheads (technically one bulkhead in middle) Challenging to repair	Increased installation costs for sensors. Installation is already challenging Monitoring trenched/buried pipeline is a challenge
Additional Environmental Impacts	More equipment and labor is required for installation and repair	No	No	No
Compatibility with existing operations	Yes	Yes	Yes	Yes
Other Important Points		Developing technology but not field proven for subsea pipelines Able to monitor pipeline burial conditions (strudel scour, upheaval buckling, 3rd party intervention, iceberg interaction, etc.)		

Table B.15 Technology Review Periodic Leak Detection Systems / Methods

Periodic Leak Detection Systems

BAST Criteria	ROV Inspections / Overflights	Acoustic Pigging	Intelligent Pigging	Remote Surveillance Methods / Satellite
	Description	Description	Description	Description
Past Project Experience	Used on most Arctic projects in open water season and onshore sections	Used/tested on 870 km long, 12" OD Enbridge pipeline onshore. Used/tested on 20 km Petrobras onshore pipeline. Also, demonstrated on 69 km TransCanada pipeline system.	Experience with Onshore pipeline leak detection pigging.	System is ready for use. Seems like no expererience. We are collecting further information on this application.
Suitability to Alaskan Arctic Offshore	ROV Inspection: suitable for unburied pipelines, but not suitable for buried sections. Overflights: useful to observe water for oil sheen during open water season, however a length limitation for a single flight.	Suitable: Pigging will benefit a long pipeline. Not recommended as a primary or secondary LDS as it is not a continuous monitoring system but suggest running as a tertiary system for periodic leak testing. Long line may exceed current battery life technology. It can run 400 hrs without interruption.	Pigging will benefit a long pipeline. Not recommended as a primary or secondary LDS as not a continuous monitoring system but suggest running as a tertiary system. Long line may exceed current battery life technology (about 6 days to run a pig). It is good to use when a leak is suspected.	Somewhat suitable - Not a continuous monitoring system and it is not conventionally used due to disruptions with surface traffic (vessels). Only suitable during open water season. Long length may be a concern for monitoring.
Decrease Spills	Decrease spills but not deteactbale at the exact time of the leak.	Decrease potential spill volumes but not at the exact time of the leak.	Decrease spill volume but not at the exact time of the leak.	Decrease spills but not at the exact time of the leak.
Cost (Qualitative)	Least expensive	Inexpensive - pipeline doesn't require shutdown to run acoustic pigs	Inexpensive - pipeline doesn't require shutdown to run pigs down the line	Expensive - remote surveillance equipment, i.e. satellites, required
Technology Readiness Level	TRL: 7	TRL: 7	TRL: 7	TRL: 7
Practicality/ Feasibility	ROV Only useful during open water season (half of the year). Overflights may requires multiple helicopter/small plane flights to patrol long pipelines.	Useful for testing long lines. Pig is smaller than the ID so no risk in getting stuck in the pipeline. Background noise could cause false alarms. Battery life technology may require advancement before it is deployed through long pipelines without interruption.	Useful for testing long lines however may not be possible to push pig through the pipeline. Need further investigation.	Only useful during open water season. Then, it is possible to monitor the pipelines remotely, Data collection, processing and transmitting takes a long time.
Additional Environmental Impacts	Yes - multiple helicopter / plane flights.	No	There is some possibility of contamination.	No
Compatibility with existing operations	Yes	Yes - no shutdown required, just a slug and launcher to push the pig. Requires intermediate acoustic receivers connected to SCADA.	Yes - no shutdown required, just a slug and launcher to push the pig	Yes
Other Important Points	None	Can be used during normal operation. Can be used on pipelines with OD 12" or higher. Adequate power supply and storage capacity for entire pipeline traversing seems to be feasible. Need further investigation. (e.g. SmartBall).	Can be used during normal operation without shutdown for monitoring other properties, such as corrosion, metal loss, inner diameter, etc. and potential leaks. 6" to 34" line leak testing is feasible. Pigs can run 10 - 30 days continuously (e.g. EDAG LD pig, ARC Leak Detector pig, etc.).	Synthetic aperture radar housed inside satellite can be used to detect oil slicks, vessels and installation at sea. Oil slicks may be visible during open water season. Advanced sensors can detect oil slicks due to change in behaviour of sea surface. Image analysis are able to distinguish features (e.g., KSAT-Oil spill detection).

B.3.2 Technology Gaps

Based on the technology review presented in Section B.3.1, the following LDS technology gaps / limitations have been identified:

- Software-based pressure monitoring does not have any Arctic subsea experience.
- LEOS has a water depth limitation of around 50 ft (15 m) and length limitation of 9.3 miles (15 km).
- FOC also has a length restriction of approximately 28 miles (45 km) and is not currently proven for field installation. Longer lengths may be possible with amplifiers, but that would need to be assessed and qualified on a project-specific basis. Ref. [4] provides good information on the opportunities to extend FOC systems.
- Real-time identification of leak size is difficult, as well as issues with false alarms [Ref. 6].

B.3.3 Future Needs / Emerging Technology

Opportunities for technical advancement in LDS technology include:

- Leak detection using FOCs as a direct means of detecting leaks has yet to be proven in a subsea capacity. The technology readiness level (TRL) may be close to a standard of implementation (as evidenced by previous Arctic projects implementing FOC for other reasons), but additional steps towards qualification testing may be required to ensure the technology satisfactorily detects leaks. Both distributed temperature sensing and distributed acoustic sensing require further development in this area.
- Installing subsea amplifiers in FOC is an emerging technology to extend the length of potential monitoring distances. Potential options include: optical amplifiers using remotely pumped light from an above water source; electrical amplifiers to boost the signal locally to exceed 28 miles (45 km) coverage; or remote units to have several fiber loops extending from the remote units.
- Acoustic pigging is an emerging technology that may be useful to enhance LDS performance. Qualification of an acoustic pigging system will provide an accurate means of periodic leak detection. Currently, acoustic pigging has been used onshore with magnetic positioning markers set up along the pipeline to track the pig. Offshore buried pipelines will not allow for these markers to be installed and the pigs are unable to track their position as they move along the pipeline. A location tracking device must be developed in order for acoustic pigging to be useful for a long Arctic offshore pipeline.
- RTTM systems have been proven in onshore oil pipelines and offshore gas pipelines; however, the RTTM system must be taken a step further and be qualified for subsea Arctic use as a primary means of leak detection. Subsea application eliminates intermediate reading points along the pipeline which can create inaccurate results with just an inlet and outlet reading over a potentially long pipeline length. However, this system is very complex and a less than 1 per cent leak rate detection threshold can be achieved with frequent calibrations and precise modeling. Several vendors claim a minimum detectable leak rate of 0.5% of the daily throughput (in ideal operating conditions). More qualification steps should be carried out to confirm RTTM meets the stated claims and, in turn, Alaskan and US DOT regulations.

B.4 References

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