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NORTHSTAR DEVELOPMENT PROJECT PIPELINES DESCRIPTION AND ENVIRONMENTAL LOADINGS

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ABSTRACT

BP Exploration (Alaska) Inc. is presently developing the Northstar oilfield, 9.7 km offshore the Alaskan Beaufort Sea coast. Northstar drilling and production facilities will be located at Seal Island and the project includes constructing the first subsea oil production pipeline in the Arctic. The twin 273.1 mm (10-inch) offshore and overland oil and gas pipeline systems are described along with major aspects of the design. A limit state design procedure for pipe bending is employed to safely and efficiently address the principal marine environmental loadings caused by seabed ice gouging and permafrost thaw settlement.

INTRODUCTION

The Northstar oilfield was discovered by Shell in 1983 with exploration wells drilled from Seal Island (US ACE 1999). This man-made gravel island was built in 1982 and later abandoned by Amerada Hess in 1994. BP Exploration (Alaska) Inc., (BPXA, BP Amoco Group) acquired the majority of the Northstar Unit leases in 1995 and is proceeding with development plans for the field. The island was rebuilt and enlarged during January through May 2000 and connected by pipelines to existing Alaska North Slope facilities during this same winter construction season. Trenching of the offshore pipeline section took 5 weeks and installation took 3 weeks, finishing on April 15, 2000.

The field has approximately 25 million cubic meters recoverable reserves of light sweet crude oil but has been considered to have marginal economics, largely due to its offshore Arctic location. Northstar is the first offshore oil field in the Arctic to be developed using a subsea pipeline. As such, it must address technical and permitting challenges (Palmer 2000, Braden et al 1998) in addition to its historical economic challenges. The Northstar offshore pipeline preliminary and detailed design has been ongoing since 1996. The Northstar Project Final Environmental Impact Statement (US ACE 1999) and the State Right-of-Way lease were issued in 1999.

Seal Island is located 9.7 km offshore the Alaskan Beaufort Sea coast in approximately 11.3 m water depth and 18 km northwest of Prudhoe Bay (Fig. 1). Crude oil will be processed on Seal Island and shipped via a 273.1 mm (10-inch) pipeline to the shore crossing at Point Storkersen and then an additional 18 km overland to the Trans-Alaska Pipeline System (TAPS) Pump Station 1. Natural gas will be transported out to Seal Island via a second 273.1-mm pipeline for fuel and reservoir management purposes. Seal Island production facility modules are being fabricated in Anchorage and transported by barge to the North Slope.

OVERLAND PIPELINE DESIGN

Overland sections of the two pipelines are supported a minimum of 1.5 m above ground on conventional Vertical Support Members (VSM's) to protect the tundra from melting and to allow for caribou passage. The 273.1 mm OD, 7.1 mm WT, API 5L X-65 (448 MPa) overland pipe has 51 mm thick polyurethane foam to minimize heat loss. Winter ambient air temperatures reach -46°C and the oil is cooled on Seal Island to an average annual temperature of +10°C prior to introduction into the uninsulated subsea pipeline. The Northstar crude oil has a nominal API gravity of 42 degrees (0.82 SG) and is compatible with this relatively low arctic pipeline operating temperature, but it will be necessary to reheat the oil prior to delivery to TAPS. Additional overland design features include pipeline thermal expansion loops ("Z" and "U" shapes), low temperature pipe steel specifications, a gas compressor station, and a pile-supported crossing of the Putuligayuk River.

OFFSHORE PIPELINE BASIC DESIGN

The Northstar oil and gas pipeline systems satisfy typical offshore pipeline design requirements such as throughput capacity, internal pressure, stability and cathodic protection as noted in Table 1. The 15.1-mm offshore pipe wall thickness was selected largely on the basis of providing a high pipe specific gravity (1.60 with respect to seawater) for stability during subsea trench backfilling operations. A secondary effect of the resulting low pipe diameter to wall thickness ratio (D/t = 18.1) is that the wall thickness is a conservative factor of 2.8 times the design code requirement for internal pressure containment.

The pipelines were bundled together over most of their length to facilitate installation procedures. The cathodic protection system includes a dual layer fusion bonded epoxy coating and low temperature aluminum anodes. There are no flanges, valves, or pipe fittings on the subsea portion of the line. This helps simplify the pipeline installation and minimizes the potential for small leaks which may be difficult to detect by conventional means during the winter ice-covered season.

LIMIT STATE DESIGN FOR BENDING

Steel pipelines are commonly bent beyond their yield strain limits during construction. Examples include 2.8% maximum strain for 273.1-mm pipe (ASME B31.8-1995) in overland pipe bending machines used to form the line to match the trench geometry. Offshore pipeline installation by the reel method bends pipe through at least two cycles of approximately 2% maximum strains during the reeling and unreeling process. These construction applications of limit state design subsequently confirm that an ultimate limit state condition was not exceeded through as-built pipe inspection and a hydrostatic pressure test prior to start of pipeline operations. Operational pipelines commonly rely on limit state bending strain criteria during fitness-for-purpose evaluations after an unplanned loading event. However, incorporation of limit state bending criteria into the original pipeline design philosophy is less common.

The limit state design procedure can be described as avoiding all limit state conditions which would interfere with the functional aspects of the pipeline system. The Northstar pipeline limit state design for bending used a combination of existing US and international design codes and standards to perform a project-specific Engineering Critical Assessment (ECA) for bending limit state conditions. Pipelines exposed to bending in excess of conventional stress-based design limits must safely resist the following potential failure mechanisms:

- Localized buckling or excessive ovalization. This compressive strain failure mechanism may prevent inspection pig passage or ultimately lead to a leak in the deformed pipe body section.
- Unstable weld flaw propagation. This tensile strain failure mechanism may result in a weld fracture or crack which creates a pipeline leak.

Limit state pipeline bending design can be utilized for non-cyclic, displacement-controlled loads, such as those applied to pipes in free spans or due to soil movements. One advantage of a limit state design approach is that a low D/t pipe's ability to safely withstand bending strains on the order of 10 times the yield strain limits may be utilized to optimize design parameters such as trenching requirements. The disadvantage of limit state design is that the designer must more thoroughly assess the factors influencing the pipe's limit state performance. The Northstar pipeline limit state design and experimental validation of these limit strain criteria are addressed in Nogueira et al. (2000 and 1999) and Lanan et al. (1999).

Loading conditions for which limit state pipe bending criteria were applied to the Northstar pipelines included seabed ice gouging and permafrost thaw subsidence. Strudel scour and upheaval buckling loading conditions described below were not assessed using limit state bending strain criteria but may be considered for future offshore arctic pipelines.

SEABED ICE GOUGING

Irregular keels beneath the floating sea ice periodically contact the seabed in the Northstar Project area and form gouges. The preferred method of protecting a subsea pipeline from excessive ice keel loadings is to trench the pipe to some depth beneath the maximum predicted gouge depth (Lanan et al. 1986). The minimum pipeline depth of cover (original undisturbed seabed to top of pipe) for most of the Northstar pipe route was determined to be 2.1 m, based on ice gouging and other environmental loading conditions.

The Northstar pipeline route benefits from its relatively sheltered Beaufort Sea location within the seasonal landfast ice zone. Due to the project's long development history, seabed ice gouges in the pipeline vicinity have been measured during 10 separate years of summer open water season surveys. The deepest gouge observed to date has been 0.6 m beneath the surrounding seabed and the average gouge recurrence rate is 4.7 new gouges/km/year. Based on this extensive site-specific data set, the maximum gouge depth along the pipeline route during a 100-year return period event has been estimated to be 1.0 m. This prediction is based on an exponential gouge depth distribution function but alternative distributions were also considered such as a log-normal distribution, which predicted a 0.7 m deep gouge for a 100-year return period. A conservatively high value of 1.1 m was utilized in the pipeline design calculations.

The Northstar pipelines seaward of the nearshore barrier islands will be trenched to a depth at least 3.5 times the deepest ice gouge observed in the pipeline route vicinity. When an ice keel gouges the seabed, stresses are applied to the soil. These stresses induce vertical and lateral soil displacements beneath the ice keel (See Figure 2) which vary as a function of the depth below the seabed, soil type, and the gouge depth, width and orientation (Nixon et al. 1996 and Woodworth-Lynas et al. 1996). The effect of this soil displacement and resulting loading on the pipeline is typically modeled through non-linear finite element analysis with plastic steel behavior and large displacement capabilities. The soil-pipe interaction is simulated by non-linear spring elements. The bending is applied in a displacement-controlled manner by imposing the soil displacement field at the pipeline depth to spring nodes. In turn the springs pull (or push) the pipeline elements and the resulting pipeline strains are calculated. Analyses indicate the Northstar pipeline may develop maximum bending strains of approximately 1.4% due to ice keel loadings. This equates to a 273.1-mm pipe centerline bending radius of approximately 9.8 m but this maximum bending strain is only imposed on less than one meter of the 9.7-km subsea pipeline length.

PERMAFROST THAW SUBSIDENCE

The transition from a buried offshore arctic pipeline to an overland pipeline will typically encounter subsea permafrost. The classical definition of permafrost is soil which is below 0 °C for two or more years but because of the freezing point depression for seawater, subsea permafrost must typically be below -2 °C in order to be frozen. Ice-bonded permafrost is found along the Northstar pipeline route in water depths less than about 1.5 m, which corresponds to the maximum thickness of the natural sea ice at the end of the winter season. The oil and gas pipelines operate at temperatures above this soil pore water freezing point and a thaw bulb will gradually form around the pipe (Figure 3). The overburden load initially shared by the soil particles and the frozen pore water is transferred to the soil skeleton alone and, depending on the initial moisture content and soil properties, thaw settlement can result (Nixon et al. 1991). The maximum total settlement during the Northstar pipeline lifetime is predicted to be approximately 0.6 m and is partially limited by the presence of an underlying thaw-stable gravel layer.

A buried pipeline transitioning through thaw-sensitive permafrost will lose support and attempt to settle with the soil. Uniform settlement will not induce bending strains in the pipe but a worst case scenario is assumed for design purposes in which a critical width span of soil settles beneath the pipe. This differential settlement is assumed to have the same magnitude as the maximum total settlement and the pipe would be loaded as it attempts to support the soil above it. The Northstar pipeline analysis was conducted in a similar manner to that described above for ice keel gouging and yields maximum bending strains of approximately 1.1%. Conservatisms in the thaw settlement analysis included assuming the worst case (critical) span length for soil settlement forms, and the span location coincides with the maximum residual installation strain and with a girth weld which has the lowest resistance to bending strain. The probability of these circumstances combining is very low, as may be assessed in a reliability based analysis.

In the case of permafrost thaw settlement, maximum bending strains generally increase with increased pipeline depth of cover. The approximately 3.2 km long offshore route section within the 0 to 1.5 m deep Gwydyr Bay is not subject to significant ice gouging and therefore has a 1.8 m depth of cover. Increased trench depths were provided near the shoreline and barrier islands for protection from potential seabed erosion.

STRUDEL SCOUR

Strudel scour craters are formed in the seabed during spring river breakup when the river overfloods the bottomfast sea ice in the nearshore coastal zone. The overflood water drains through holes in the ice sheet and can erode the seabed sediments (Leidersdorf et al. 1996). If the scour occurs above the pipeline route and is deep enough, it can form an unsupported pipe span which is subjected to hydrodynamic and gravitational loads. While this is an interesting natural phenomenon, survey data shows large/deep strudel scours in the Northstar project vicinity are relatively rare. Pipe span displacements in a strudel scour are limited by the span geometry and restraint from adjacent buried pipe sections, thus a limit state design philosophy may be used if necessary. The Northstar pipeline strudel scour design is based on the more conservative elastic bending and vortex induced vibration criteria.

UPHEAVAL BUCKLING

When a buried steel pipeline is operated at a temperature higher than its temperature during installation (-2 °C winter seawater temperature), it will try to expand longitudinally. A long buried pipeline is prevented from freely expanding by the restraint provided by the surrounding soil, and thus it will develop an axial compressive force. If the buried pipeline has some residual vertical curvature, typically due to trench bottom irregularities during installation, the effect of the axial force near the high points of the pipeline will attempt to move the pipe upward through the trench backfill material (Palmer et al. 1990). An upheaval buckle formed by this mechanism may experience significant vertical displacement and plastic deformation but is not expected to exceed a failure limit state because of the high resistance to pipe cross-section buckling or unstable fracture of a girth weld. The Northstar pipelines are designed to avoid this serviceability limit state condition, however, primarily because this could leave the pipe exposed above the seabed to more severe loading from ice keels. The as-layed Northstar pipeline overbends were surveyed and found to be within acceptable limits established based on the trench backfilling conditions.

PIPELINE TRENCHING REQUIREMENTS

The pipelines were trenched into the seabed for ice keel protection and to accommodate potential seabed erosion, strudel scour and upheaval buckling forces. Trenching requirements were primarily specified in terms of the minimum depth of cover (distance from the original undisturbed seabed to top of pipe.) Following pipeline installation, the trench was fully backfilled with native soil. The minimum backfill thicknesses (distance from the backfill surface to top of pipe, including backfill placement tolerances) are shown on the offshore pipeline profile (Figure 4).

ISLAND AND SHORE APPROACHES

Seal Island eroded and submerged approximately 3 years after the gravel bag slope protection was removed. During January through May 2000, the island was rebuilt with additional gravel and stabilized using steel sheet pile. Concrete block slope protection mattresses will be installed during summer 2000. The pipelines approach the south side of Seal Island through a sheet pile slot and gravel bedding contoured to a 107-m radius. The island surface piping extending to the crude oil processing module and pigging facilities is low temperature steel and thermally insulated. The gas pipeline will be temporarily connected to the utility module for fuel supply following the summer 2000 sealift. The oil and gas pipelines will both be connected to the process module following the planned 2001 sealift.

The shore approach at Point Storkersen extends approximately 37 m onshore of the receding coastal bluff line. The pipes then transition onto a gravel valve pad through a 2.4-m diameter casing. The shore approach trench was over-excavated and the native soil beneath the pipelines was replaced with thaw-stable gravel to help limit potential permafrost thaw settlement and pipeline loadings.

OFFSHORE PIPELINE MATERIALS

The Northstar offshore pipe was manufactured by Sumitomo Corp. to a project specific specification based on the limit state design requirements. A 358 MPa (52 ksi) Specified Minimum Yield Strength was selected based on conventional industry experience with reeled pipeline installations. The maximum yield to ultimate tensile strength ratio was 0.85. The steel chemistry was designed to produce high Crack Tip Opening Displacement (CTOD) values and to minimize loss of yield strength within the weld heat affected zone (HAZ).

The pipeline girth weld internal high-low remaining after weld fit-up using an internal line-up clamp was found to be a significant factor in determining the allowable pipeline bending strain. For this reason, the pipe specifications included internal diameter tolerances which are more restrictive than standard seamless pipe specifications based on the OD and wall thickness tolerances. Conventional API 5L weld bevels were specified and no internal end taper was applied at the pipe mill.

PIPELINE CONSTRUCTION

The Northstar pipelines were constructed in 2000 using winter construction methods which minimize the environmental impacts. The overland pipelines were constructed from an ice road built on the tundra surface and the offshore sections were constructed from the sea ice surface. The offshore construction included flooding the natural ice surface with seawater to reach a thickness of 2.6 m, slotting the ice and then excavating a trench in the seabed using a backhoe. The pipelines were bundled and lowered into the seabed trench using sidebooms supported on the floating ice work surface. Trench spoils were then returned to the trench as backfill over the pipes.

Pipeline welding used manual Shielded Metal Arc Welding (SMAW) similar to conventional overland pipelines on the North Slope. Extensive welding procedure tests demonstrated that conventional workmanship standards for Northstar weld flaw acceptance satisfy the weld fracture limit strain criteria (Nogueira et al. 2000.) Girth weld Non-Destructive Examination (NDE) utilized both X-ray radiographs and automatic ultrasonic inspection. This double inspection procedure ensured that the maximum weld flaw size potentially remaining in the welds is smaller than the predicted critical size for fracture initiation.

The offshore pipeline construction civil work (ice road construction, trenching and backfilling) was performed by AIC. The overland pipeline construction and offshore pipeline fabrication and lowering in were done by HCC. Trench excavation utilized backhoes mounted on wide track undercarriages (Figure 5) and took 5 weeks to complete. The pipe lowering in procedure utilized conventional sidebooms (Figure 6), started 2 weeks after the start of pretrenching, and reached Seal Island on April 15, 2000. Hydrostatic pressure testing and trench backfilling from the stockpiled spoils materials were completed before the spring break-up.

PIPELINE OPERATIONS PLANS

There has been considerable focus during the Northstar permitting process on the sensitivity of the Alaskan Beaufort Sea environment and the potential hazard posed by pipeline leaks. Small leaks below the pipeline leak detection system's detection threshold could theoretically accumulate under the winter ice sheet for a significant time period and are the most difficult to address with conventional pipeline technology. The Northstar pipeline's thick wall design and lack of subsea pipe fittings are intended to minimize the potential for small leaks. Additionally, the pipeline operating plans include an aggressive combination of pipeline route surveillance, inspection pigging and leak detection systems.

Routine pipeline inspection pigging will include a combination of pipe wall thickness measurement and geometry pig runs to look for conditions which, if left unabated, could lead to pipe failure. These inspections are scheduled to identify potentially excessive pipe corrosion or permafrost thaw settlement induced bending strains.

Northstar's conventional pipeline leak detection systems will include pipe monitoring with both Pressure Point Analysis and Mass Balance Line Pack Compensation leak detection systems (EFA Technologies). These systems will be supported by a prototype leak detection system designed to sense the presence of oil outside the pipes. The LEOS system (Siemens AG) which was selected for this first offshore application is based on hydrocarbon diffusion into a buried sensor tube. Air in the tube is periodically displaced and passed through a sensitive gas detector to identify the presence of a potential hydrocarbon leak. The LEOS tube was installed as part of the pipeline bundle.

CONCLUSIONS

Primary loading conditions for a subsea arctic pipeline include seabed ice gouging and permafrost thaw subsidence. Strudel scour and upheaval buckling were not found to be controlling load cases for the Northstar oil and gas pipelines but may be for other projects. Limit state design for pipe bending allows more accurate prediction of potential pipe failure mechanisms such as buckling and unstable weld flaw propagation. In the case of Northstar, this allowed a safe design without excessive trenching requirements and helped facilitate the winter ice-based construction procedures. Planned pipeline operating procedures will also significantly reduce the potential of developing leaks or allowing them to go undetected for a significant time period.

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Table 1. Northstar Offshore Pipeline Data

Pipe outside diameter	273.1 mm (10.75 in.)
Pipe wall thickness	7.1 mm (0.594 in.)
Steel grade	API 5L Grade X52 (358 MPa)
Pipe manufacture	Seamless, 12 m (40 ft) joint lengths
Coating	1.0 mm (40 mils) dual layer FBE
Cathodic protection	Aluminum sacrificial anodes
Pipe SG	1.60 with respect to seawater
Length	2 pipe bundle 9.7 km (6.0 miles) long
Water depth	0 – 11.3 m (0 – 37 feet)
Maximum Allowable Operating Pressure	10.2 MPa (1480 psig)
Oil max. throughput	7,750 m^3/day (65,000 bbl/day)
Gas max. throughput	2,830,000 m^3/day (100 mmscfd)

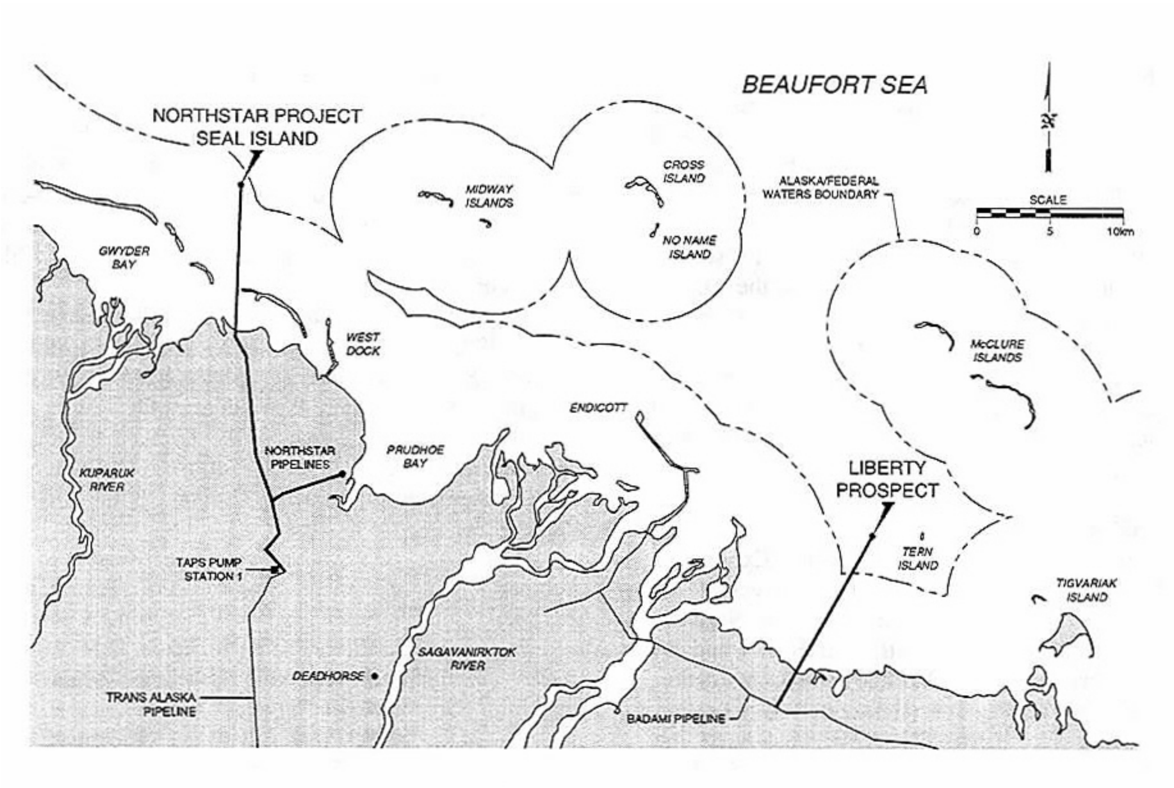

Figure 1: Northstar Project Location Map

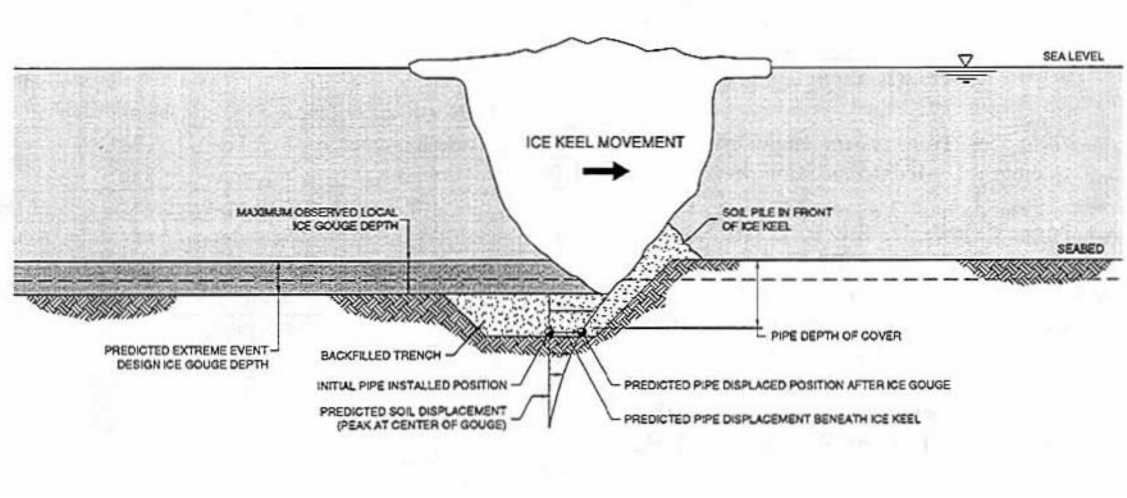

Figure 2: Pipeline Ice Keel Loading

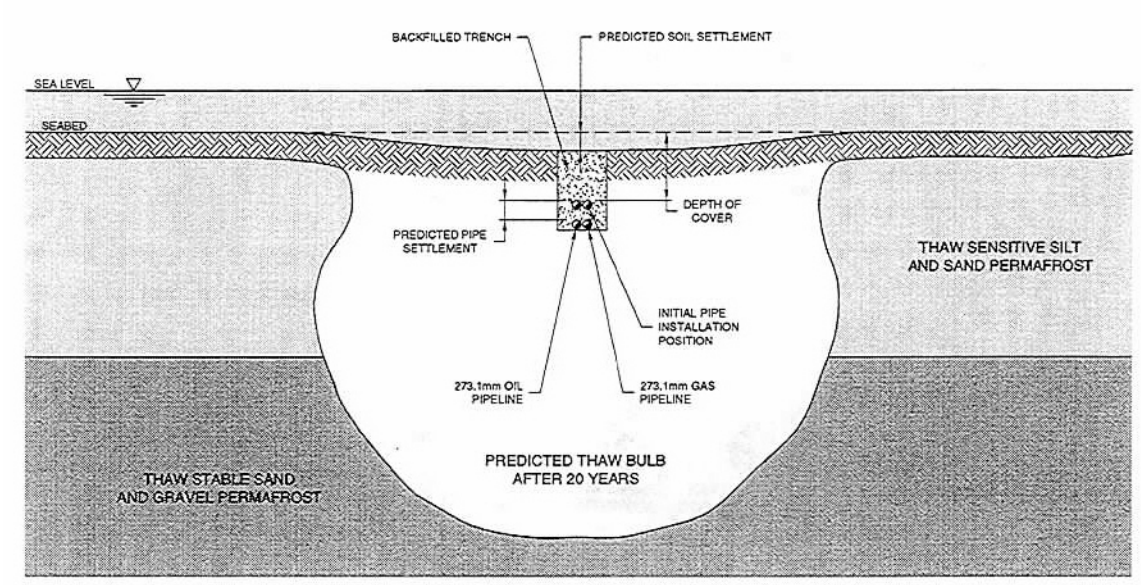

Figure 3: Pipeline Subsea Permafrost Thaw Subsidence Loading

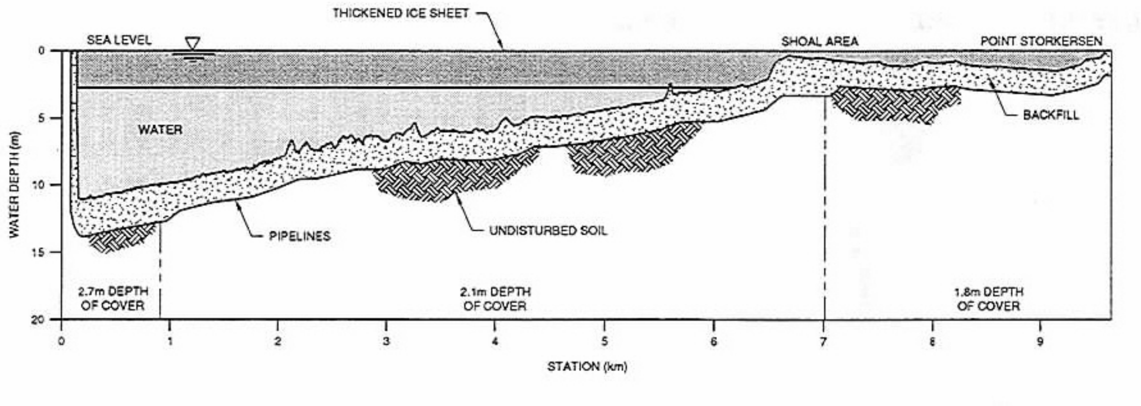

Figure 4: Northstar Offshore Pipeline Profile

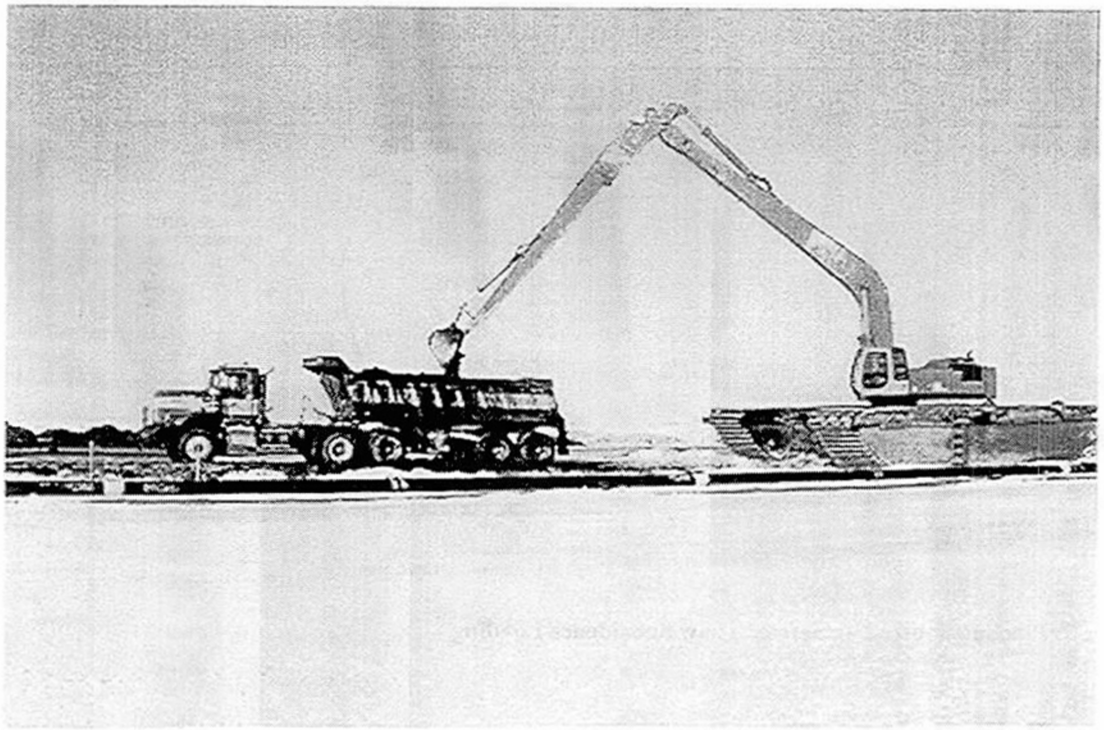

Figure 5: Offshore Pipeline Pre-Trenching Operations

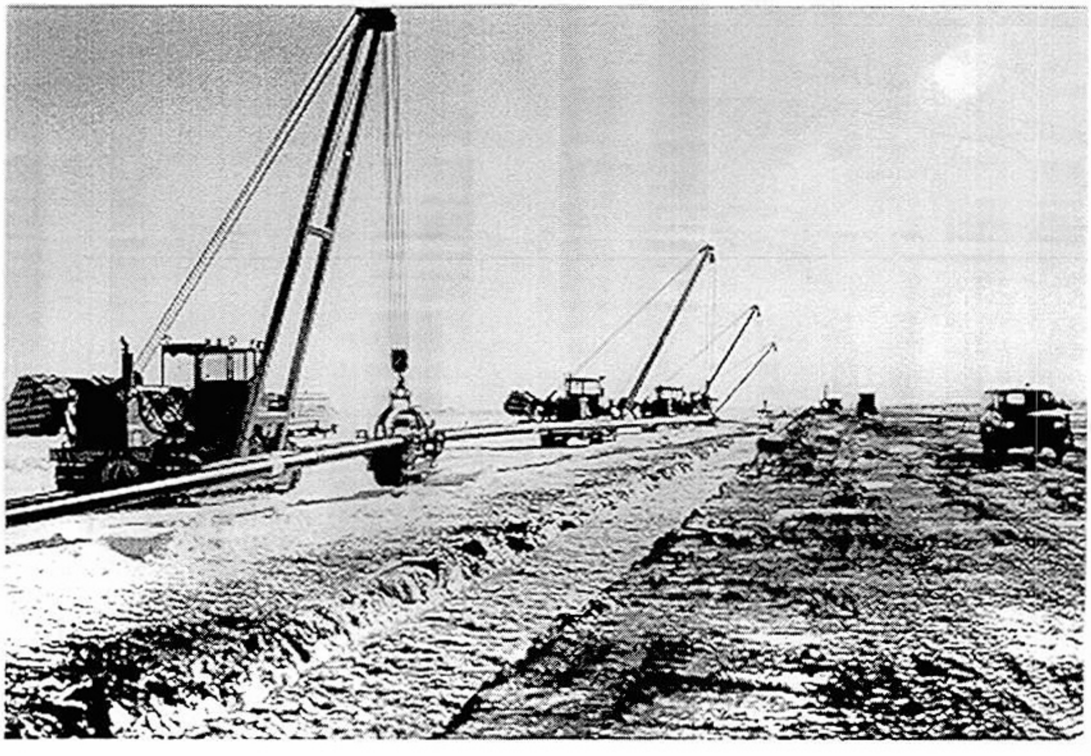

Figure 6: Offshore Pipeline Installation Operations