LIBERTY DEVELOPMENT PROJECT

EVALUATION OF PIPELINE SYSTEM ALTERNATIVES: EXECUTIVE SUMMARY

BP Exploration (Alaska), Inc. (BPXA) submitted a Development and Production Plan (DPP) for its proposed Liberty Development in February 1998. As discussed in the DPP, BPXA plans to produce sales-quality crude oil at Liberty Island, located in Foggy Island Bay approximately 6 miles offshore of Alaska's North Slope in the Beaufort Sea. Liberty will be a self-contained drilling and production facility built on a manmade 5-acre gravel island in about 22 feet of water (Figure 1). According to the DPP, the oil will be delivered from Liberty to the trans-Alaska pipeline by means of a 12-inch-diameter pipeline approximately 7.6 miles from Liberty Island to a tie-in with the existing Badami oil pipeline, which connects with the Endicott oil pipeline.

The 6.1-mile offshore segment of the Liberty oil pipeline is the most challenging aspect of the project, since the pipeline must be built in the nearshore landfast ice zone of the Beaufort Sea. BPXA retained INTEC Engineering, Inc. of Houston, Texas, to prepare a conceptual engineering report to evaluate and present the design alternatives for the pipeline. The report provides permitting and resource agencies information for evaluating alternatives in the Liberty Environmental Impact Statement. A peer review of these conceptual designs will be conducted by an independent engineering contractor selected by the agencies.

The INTEC report reviews four design alternatives, which are shown in Figure 2:

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

In order to fully evaluate these alternatives, the report covers:

- Project design criteria applicable to all alternatives
- Installation methods available for all alternatives
- Construction costs
- Operations and maintenance issues
- System reliability
- Leak detection systems

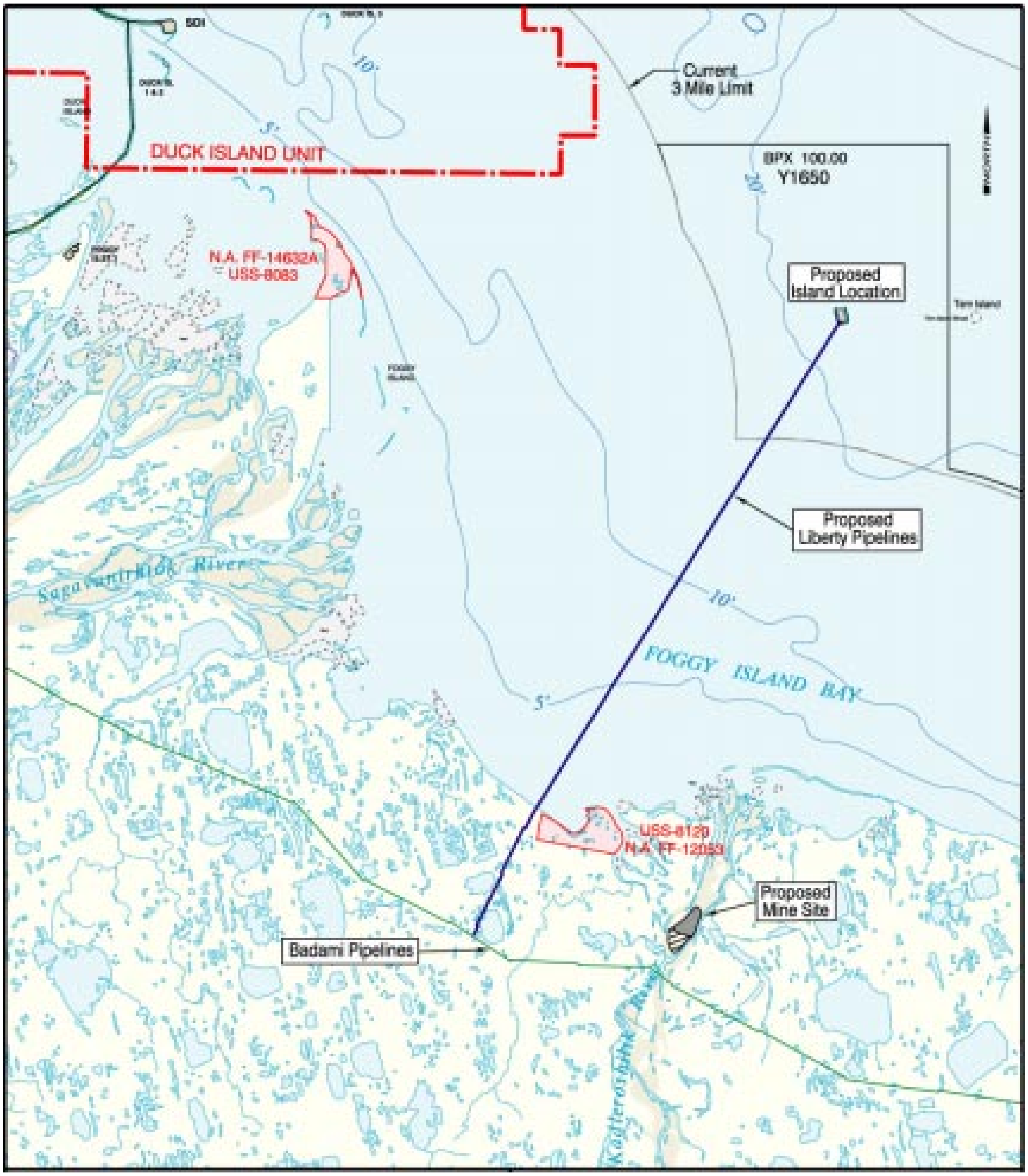


FIGURE 1
LIBERTY PROJECT LOCATION MAP

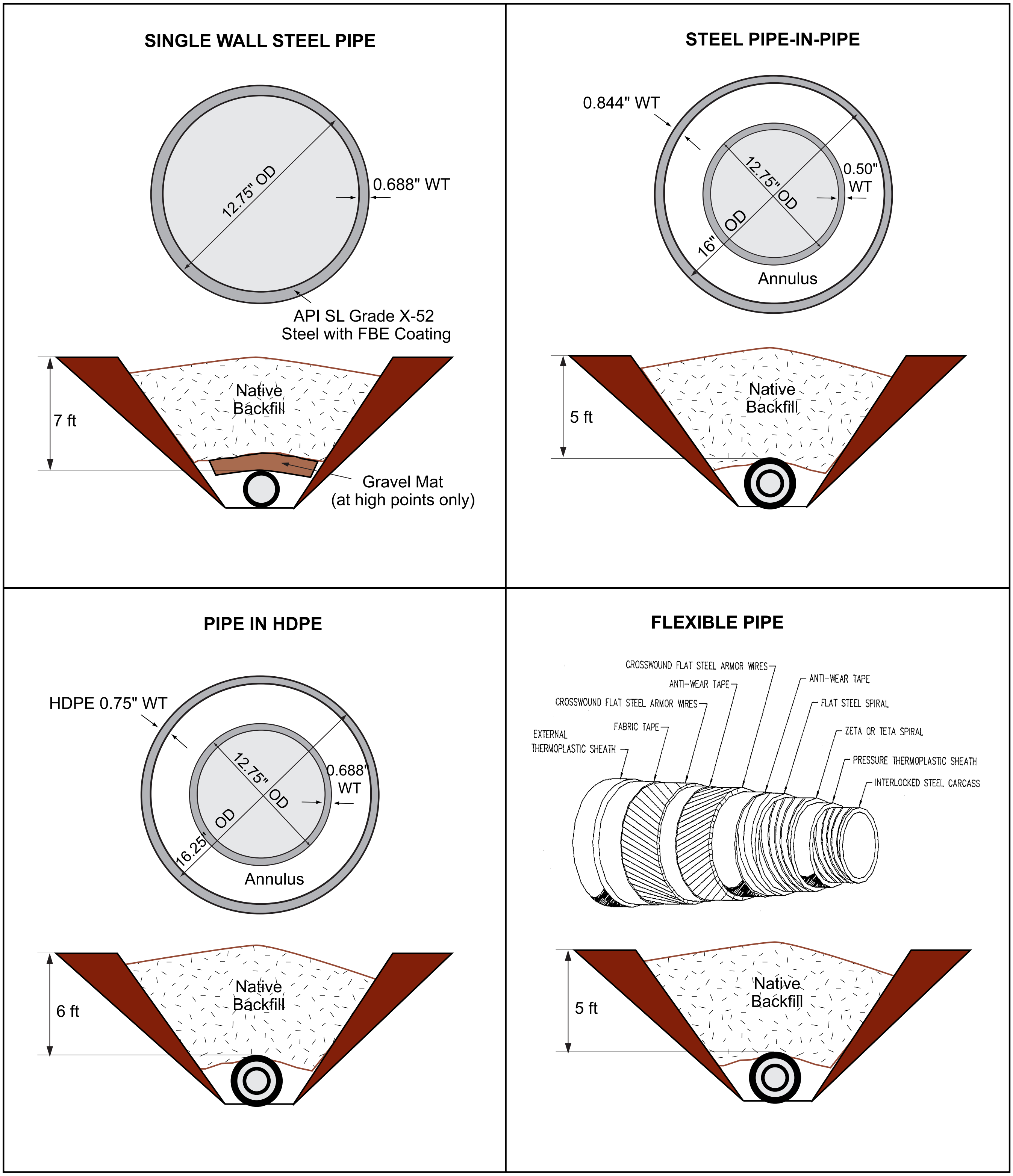


FIGURE 2
LIBERTY PIPELINE ALTERNATIVES

1. SUBSEA PIPELINE DESIGN BASIS

1.1 Safety Requirements

Any pipeline alternative must be designed for safe installation and operation. Safety requirements for a subsea arctic crude oil pipeline are based on a combination of government regulations, industry design codes, and project-specific engineering evaluations:

- U.S. Department of Transportation (DOT) Pipeline Safety Regulations, 49 CFR Part 195, Transportation of Hazardous Liquid by Pipeline.
- ASME B31.4 Code for Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids.
- API RP 2N, Recommended Practice for Planning, Designing, and Constructing Structures and Pipelines for Arctic Conditions.
- Pipeline Design Technical Review – Liberty system alternatives are reviewed through the ongoing U.S. Minerals Management Service (30 CFR 250 Subpart J) and Alaska right-of-way lease procedures (A.S. 38.35), and industry peer reviews.
- State of Alaska Regulations – 18 AAC 75 includes specific design requirements for leak detection and also requires a best available technology review of certain pipeline system components (e.g., leak detection, cathodic protection, and communications systems).

1.2 Additional BP Design Objectives

In addition to regulatory and project-specific design requirements, the subsea pipeline system alternative should satisfy the following design objectives:

- Exceeding minimum Alaska State regulatory requirements for crude oil pipeline leak detection (18 AAC 75). The two state-of-the-art leak detection systems presently in use on existing North Slope pipelines and proposed for all Liberty pipeline system alternatives exceed these requirements.
- A supplemental leak detection system is desirable to detect smaller leaks before they can accumulate large volumes of spilled oil during the ice-covered season.
- Pipeline inspection pigging should monitor pipe conditions which could lead to a potential leak formation if uncorrected. This includes periodic wall thickness measurement, pipe body ovalization, and pipe geometry (bending) monitoring inspections with tools run through the pipeline.
- Pipeline construction during the winter ice-covered season is desirable for minimizing environmental impacts.
- Reasonable pipeline capital costs are required to support development economics.

1.3 Pipeline Design Criteria

A buried subsea pipeline must be designed to withstand the forces applied to it by the oil in the pipe and by any environmental events that have the potential to act on the pipeline. Table 1 summarizes these forces.

TABLE 1
DESIGN BASIS FOR LIBERTY PIPELINE ALTERNATIVES

CRITERIA	SPECIFICATION
Crude Oil API Gravity	25.4°
Crude Oil Specific Gravity	0.9 (@60°F)
Design Oil Flowrate	65,000 bbl per day
Pipeline Length (subsea section)	6.1 miles
Maximum Pressure at Badami Tie-in	1,050 psig
Maximum Allowable Operating Pressure	1,415 psig
Maximum Operating Temperature (at inlet)	150°F
Minimum Flowing Temperature: (at inlet)	120°F
Lowest Ambient Air Temperature:	-50°F
Design Ice Gouge Depth in Seafloor	3 feet
Design Strudel Scour Span	≈1 foot
Design Thaw Settlement (single wall steel)	1 foot
Design Prop Height for Upheaval Buckling	1.5 feet

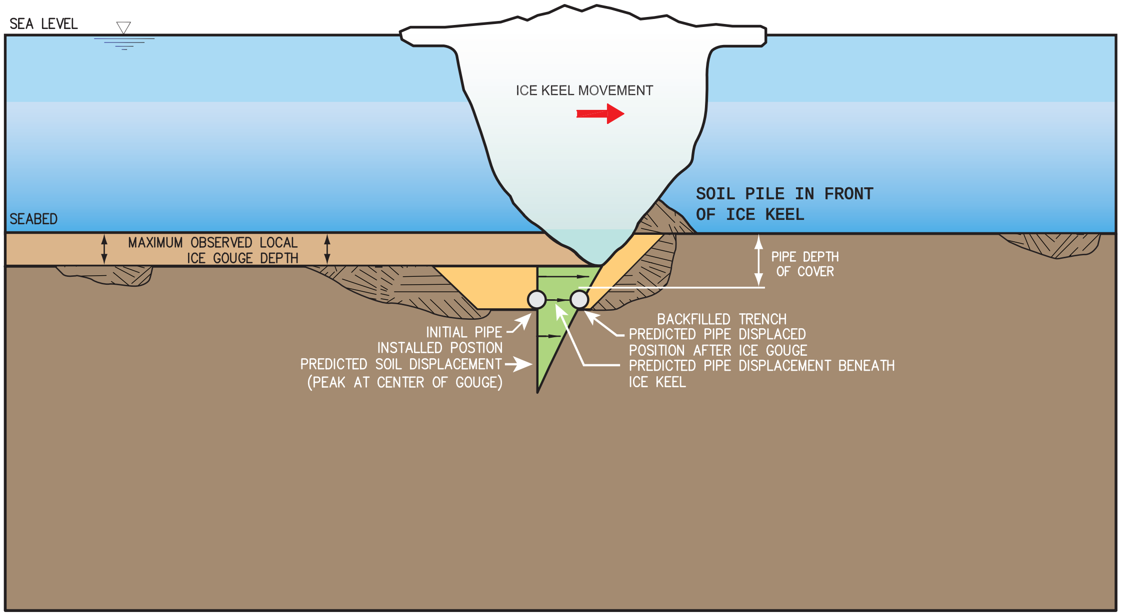
The design oil flowrate is 65,000 barrels per day based on reservoir and field production considerations. This, in turn, establishes the minimum temperature and inlet pressure at the tie-in of the Liberty pipeline with the Badami pipeline. The pipeline internal diameter is established based on **pipeline length**, **flowrate**, and **pressure**.

The **pipe submerged weight** is a key design parameter since the pipeline must be heavy enough to sink and stay in the trench during installation. When the trench is excavated and then backfilled after the pipeline is installed, a slurry of soil and sea water may form in the trench bottom. The required pipeline submerged weight to counteract the buoyancy imparted by the slurry affects the pipeline configuration and installation procedure.

Two key factors determine how deep the pipeline would be buried in the seabed. The first is the **depth of cover**, which is defined as the distance from the top of pipe to the original undisturbed seafloor. Adequate depth of cover is important for protecting the buried pipe from loads induced by "ice keel gouging" and "strudel scour."

- **Ice Keel Gouging:** During fall freeze-up and spring breakup, sea ice in the Beaufort Sea tends to pile up at some locations creating pressure ridges, some of which have keels that periodically form gouges into the seabed. Therefore, proper design requires establishing the extreme-event ice gouge depth along the pipeline route. However, in addition to being buried below the design expected ice gouge depth, the pipeline must resist strains caused by potential seabed soil movements from the gouge (Figure 3). The pipeline depth of cover (measured from the original seabed to top of pipe) performs this task. Based on an analysis of extensive data on the pipeline route, a design gouge depth of 3 feet will be used which is more than two times deeper than observed values.

ICE KEEL LOADING



STRUDEL SCOUR

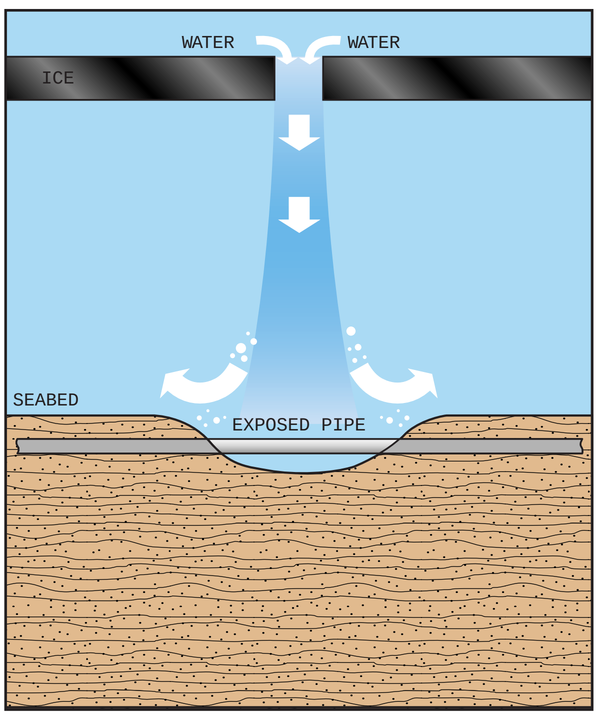


FIGURE 3
ICE KEEL LOADING AND STRUDEL SCOUR

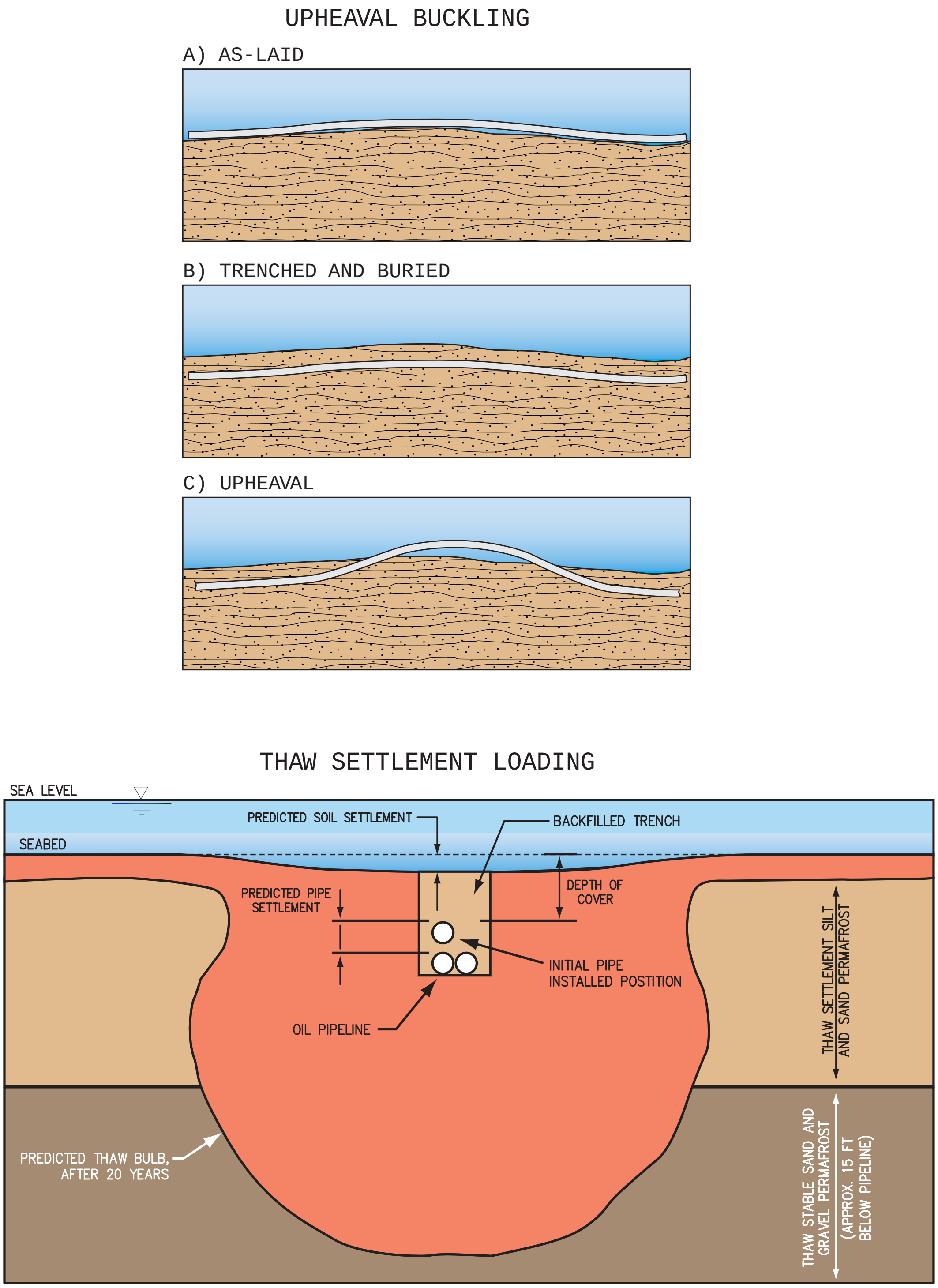


FIGURE 4
UPHEAVAL BUCKLING AND THAW SETTLEMENT

- **Strudel Sour:** Scouring of the seafloor by water draining through "strudel" holes in the ice. This occurs in spring when rivers thaw before the nearshore ice sheet, and river water flows out over the ice. Strudel scour can expose the pipeline and erode material under the pipe, causing strain on the pipeline (Figure 3).

Another design consideration is the **backfill thickness**. This is important where the difference between the ambient temperature and pressure during the installation and pipeline operation is great. This pipe expansion due to temperature differences — in combination with the pipe wall thickness, backfill soil properties, and the levelness of the trench — affects the pipe vertical stability due to **upheaval buckling** (Figure 3). When a buried steel pipeline operates at a temperature and pressure higher than at installation, it will try to expand lengthwise, and at individual high points along the pipe, the pipe exerts an upward force into the soil cover. If the upward force exceeds the resistance of the soil cover, the pipeline stiffness, and the pipeline weight, the pipeline will move up and may be become exposed on the seafloor. This phenomenon is known as upheaval buckling.

Another external pipe load directly caused by backfill thickness is the result of **thaw settlement** (Figure 4). In nearshore shallow waters of Foggy Island Bay, the soil under the pipeline could contain permafrost. Because the pipeline will be warm, a "thaw bulb" will develop around the pipe. If the frozen soil has a high ice content, this thawing can cause the soil to settle, and the soil cover on the pipeline loads it, placing strain on the pipeline. Deeper pipeline trenching can increase the backfill thickness and thus leads to an increased overburden load during thaw settlement, but it also can reduce the amount of settlement. However, deeper pipeline trenching protects the pipeline from strudel scour and ice gouging.

Finally, the pipeline must avoid excessive internal and external corrosion over the project life, and external corrosion control is required for each pipeline alternatives.

2. INSTALLATION METHODS

Possible methods for excavating the trench and installing the pipeline were reviewed. Trenching methods include conventional excavation with dredging, plowing, jetting, and mechanical trenching. Installation methods include use of lay vessels, reel vessels, tow or pull methods, and installation in winter through an ice slot. The possibility of using directional drilling from shore was also examined, but too many technical difficulties were identified. Completing one hole and installing a pipeline by directional drilling is a relatively complex undertaking, but is nevertheless technically feasible. However, a series of directional drilling operations would magnify the complexity of the installation, would likely require two construction seasons, and would also require the design of protection of the seabed connections between drilled sections.

Only one hydrocarbon pipeline has been built in an arctic offshore environment, and it was installed using a bottom-pull method for the bundle installation and a plow for trenching. The project was installed off Melville Island in the Canadian High Arctic between 1976 and 1979. The Drake Field experience shows that a high level of quality assurance was needed during construction. However, it is important that the pipeline was only 4,000 feet long (12% of the proposed pipeline length), but the make-up of the pipe bundle lasted 4.5 months, not including pipeline installation. Thus, considerably more time was needed than for a more conventional pipeline configuration.

The different configurations of the alternatives have different implications on the construction and installation program. For example, the single wall pipeline would be buried in a deeper trench, whereas the pipe-in-pipe alternative requires extensive make-up assembly and more equipment. On balance, the pipe-in-pipe and pipe-in-HDPE alternatives are much more difficult to construct than the single wall or flexible pipe alternatives. Therefore, the risk will be much higher that the construction work will not be completed in a single season.

The preferred construction method is from an ice platform in winter using conventional excavation equipment and off-ice installation techniques. Reasons include the following:

- This method uses conventional, proven equipment available locally.
- Ice-strengthening and ice-cutting techniques are well understood.
- A through-ice test trenching program has been carried out on the North Slope to prove the feasibility.
- Other construction methods would require that significant equipment be mobilized to the North Slope, which may require the equipment to over-winter (i.e., barges).
- Open-water construction equipment is not designed for these shallow water depths.
- A skilled labor force is available.
- Alaskan content in the project is maximized.

3. COST AND SCHEDULE

Cost estimates range from $31 million for the single-wall steel pipe to $61 million for the steel pipe-in-pipe, including the base case cost plus a contingency value. The contingency value is estimated based on the confidence associated with meeting the proposed schedule. For the pipe-in-pipe and the pipe-in-HDPE alternatives, there is a high likelihood that an additional construction season will be required to complete these more complex construction programs. Therefore, the contingency includes a portion of the additional season construction costs.

4. OPERATIONS AND MAINTENANCE CONCERNS

The main difference in maintenance of the pipeline systems is that monitoring cannot be accomplished in all structural components of some alternatives. It is not presently feasible to monitor the integrity of the outer jacket pipe of the pipe-in-pipe, pipe-in-HDPE, and flexible pipe alternatives. Post-failure monitoring could be achieved for these two 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.

TABLE 2
SUMMARY COMPARISON OF ALTERNATIVES

Description	Pipeline Alternative			
	Single Wall	**Pipe-in-Pipe**	**Pipe-in-HDPE**	**Flexible Pipe**
Configuration				
Depth of Cover (feet)	7	5	6	5
Duration of Trenching (days)	33	26	30	24
Gravel Backfill (yds^3) [Does not include 50% contingency]	9,000 (in gravel mats)	0	10,000 (30 yds^3 every 100 feet)	10,000 (30 yds^3 every 100 feet)
Pipe Specific Gravity	1.6	2.2	1.2	1.1
Number of Welds/ Connections	808 welds; 11 are tie-ins	1616 welds; 66 are tie-ins	808 welds, 808 fusions; 66 connections are tie-ins	13 connections; 11 tie-ins
Cost				
Budgetary Cost ($ millions)	31	61	44	37
Relative Cost (%)	100	195	140	120
Schedule				
Estimated Schedule Basis	Single winter season	Single winter season	Single winter season	Single winter season
Likelihood of Additional Season for Construction (%)	10	80	60	10
Installation				
Ice Thickness (feet)	8.5	10.5	8.5	8.5
Relative Quantity of Construction Equipment per Season (%)	100	120	115	90
Considerations	Identification of vertical pipeline profiles that do not meet the design criteria	• Pipe-in-pipe assembly logistics • Assurance of dryness of 12-in. pipe prior to pipe-in-pipe assembly • Achieving pull-in of 12-in. to outer jacket • Handling pipe-in-pipe system (210 lb/ft) and large stiffness • Thicker ice platform needed	• Assurance of dryness of 12-in. pipe prior to pipe-in-HDPE assembly • Executing pipe-in-HDPE assembly • Maintaining pipeline stability in trench • First application of the HDPE of this type	• Logistics for transporting and handling heavy reels • Maintaining pipeline stability in trench
Operation & Maintenance Concerns	Conventional operations	Monitoring of outer pipe integrity	Monitoring of outer pipe integrity	Monitoring of flexible cross-section
Leak Detection				
Standard Mass Balance and Pressure Point Analysis	Yes	Yes	Yes	Yes
Supplemental System	LEOS	Annulus monitoring	Annulus monitoring	Annulus monitoring

Cleanup strategies for a potential spill would be similar for any of the pipeline alternatives. The manpower and capabilities would be in place to successfully monitor, control, and clean up any spill at any time of the year, however remote the possibility. There is a risk of a secondary spill volume during repair of alternatives with an annulus; this risk must be considered during the development of detailed repair procedures.

- For all pipeline alternatives, there are periods (breakup and freeze-up) when a repair could not be carried out.
- For alternatives with an annulus, all moisture and oil would need to be removed from the annulus during repair. Any moisture that remains in the annulus could potentially cause corrosion of the inner or outer pipe. Any oil that remained in the annulus could potentially leak out at a later time if the integrity of outer pipe, jacket, or sheath was compromised.
- Not all repairs are able to return some pipeline systems to the same integrity level as originally constructed.

For all alternatives except the single wall pipe, repair is difficult, if not prohibitive. The issues include pipe retrieval, repair splicing and annulus purging (for pipe-in-pipe and pipe-in-HDPE), and long-term pipe integrity.

5. LEAK DETECTION SYSTEMS

Conventional state-of-the-art leak detection for any of the pipeline alternatives can be achieved using two independent systems. Mass balance line pack compensation (MBLPC) and pressure point analysis (PPA) can be applied to any of the alternatives and combined have an expected threshold of 0.15% of the volumetric flow. Leaks beneath this threshold would be detected using a supplemental system such as LEOS, which is a commercially available system installed alongside the pipe in the trench. LEOS is able to detect leaks smaller than the 0.15% threshold and is currently considered the best available technology. Annulus monitoring has been recommended as a supplemental leak detection system for those configurations with an annulus and would be expected to provide a threshold of detection as good as LEOS. However, if desired, LEOS could be applied to any of the pipeline alternative systems.

The offshore oil pipeline would be continuously monitored, and all system parameters would be relayed back as electronic signals to a standalone computer. The system parameters would be compared to predetermined alarm set-points and calculated values.

6. RISK ASSESSMENT

In order to determine the probability of the pipeline being damaged from external forces, a risk assessment was performed which evaluated the likelihood of four categories of damage to each alternative:

1. Displaced pipeline with no leak
2. Cross-section buckle in the pipe with no leak

3. Small or medium leak (125 bbl to environment)
4. Large leak or rupture (1,567 bbl to environment)

Figure 5 identifies the initiating events and causes of a failure.

The main conclusion of the risk analysis is that the risk, expressed in barrels of oil spilled into the environment, is negligible for all alternatives. The safeguards in the single wall 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. The single wall pipeline system is also relatively easier to repair.

The double wall systems are the second best. Their risk of oil spills is more than an order of magnitude greater than the single wall pipe, but the risk is still very small and acceptable and can be further reduced with the increased cost of greater depth of cover. Given the higher risk, cost, and the difficulty of repair, these systems are less suitable than the single wall system. The flexible pipe system has a risk of oil spill nearly 100 times greater than the single wall pipeline. This risk is still relatively low and can be decreased by increasing its burial depth. However, even if the depth of cover is increased, this alternative is unattractive because of the extra difficulties for installation with heavy reels and the possible repair of 2,800-foot segments. This system is not recommended for this application.

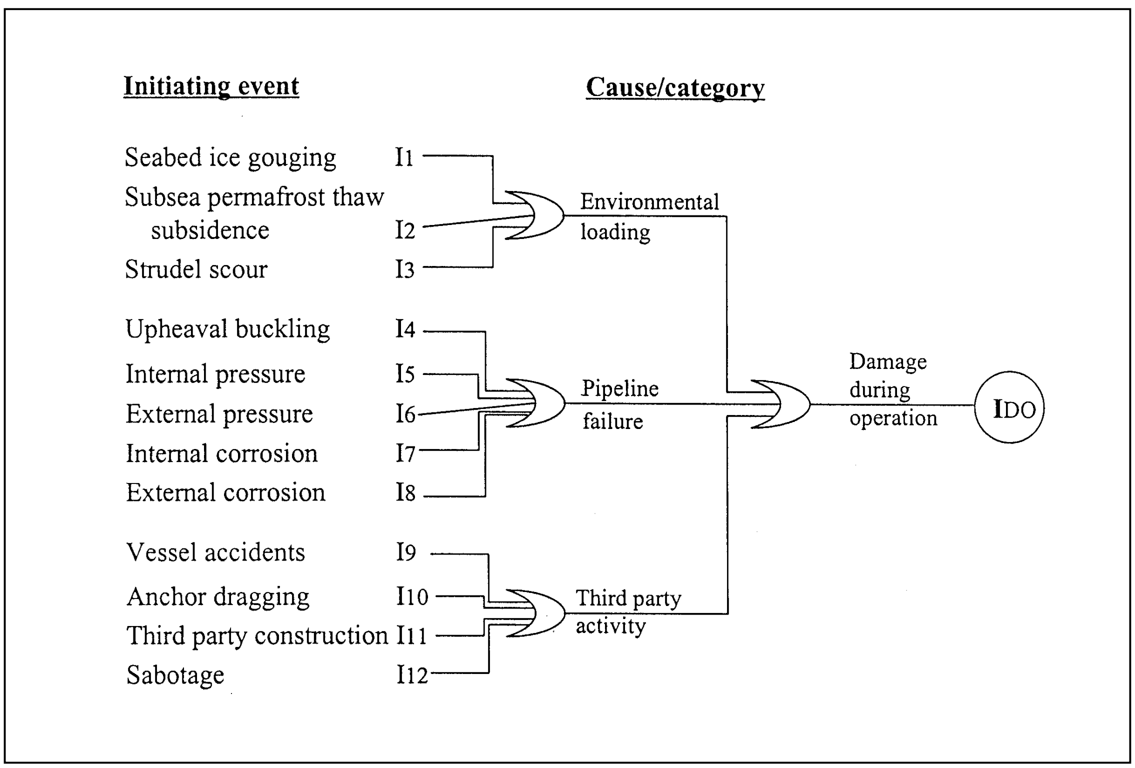


FIGURE 5
POTENTIAL DAMAGE-CAUSING EVENTS EVALUATED IN RISK ASSESSMENT

The shallower depth of cover for the pipe-in-pipe system is the main factor increasing the risk of oil spilled into the environment. To make this risk similar to that of the single wall pipe, the depth of cover needs to be increased to 7 feet — at an increased cost of about $10 million.

TABLE 3
RISK OF OIL SPILLED INTO ENVIRONMENT FOR DIFFERENT ALTERNATIVES

Alternative	Single Wall	Pipe-In-Pipe	Pipe-In-HDPE	Flexible Pipe
Risk (bbls)	0.0016	0.028	0.014	0.14
Relative risk	1	18	9	88

"Risk" = frequency x consequences, in units of the consequence
Example: Single wall risk = $(1 \times 10^{-5}) \times 125$ bbls + $(2 \times 10^{-7}) \times 1{,}567 = 1.6 \times 10^{-3}$ bbls
"Relative risk" = system risk divide single wall pipe system risk

7. CONCLUSIONS AND OBSERVATIONS

The evaluation of pipeline alternatives for BP Exploration's Liberty Development concluded that any of the alternatives can be designed structurally to meet the functional requirement of transporting oil and resisting forces imposed by environmental factors. However, the single wall steel pipeline offers the most advantages over the other alternatives by providing the lowest risk of a spill to the environment.

The primary aim of pipeline design is to engineer a pipe or conduit that will transport a product from one location to another without failing from internal or external forces. A significant part of the design effort is to economically optimize the pipe diameter, wall thickness, and material strength, while still safely achieving the design throughput. In the case of steel pipe materials, close attention is paid to protecting the pipe from corrosion. Internal corrosion may be due to the product transported in the line or the unintentional introduction of a corrosive substance at some point during pipeline operation. External corrosion may be due to the surrounding soil or water if the line is buried or installed under water. Generally, steps are always taken to limit corrosion by application of an external corrosion coating, installation of cathodic protection, and if required, the injection of corrosion inhibitors into the product stream during pumping or compression.

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. Specific conditions such as the corrosiveness of the transported product are always considered in the design. 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.

The pipe-in-pipe and pipe-in-HDPE alternatives are more expensive and would most likely require an additional construction season compared to the single wall and flexible alternatives. Monitoring of the pipeline's integrity during operation is required to allow for preventive maintenance. The single wall 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.