OFFSHORE PIPELINE REPAIR METHODS AND COSTS DIAPIR AREA, ALASKA

(OCS LEASE SALE NO. 87)

Addendum to:
OFFSHORE PIPELINE TRANSPORTATION
FEASIBILITY AND COSTS
JOINT INDUSTRY STUDY

RJBA

JOB NO. 2269.02
NOVEMBER 1984

R.J. BROWN AND ASSOCIATES
ZUG HOUSTON THE HAGUE SINGAPORE

OFFSHORE PIPELINE REPAIR METHODS AND COSTS DIAPIR AREA, ALASKA

(OCS LEASE SALE NO. 87)

Addendum to:
OFFSHORE PIPELINE TRANSPORTATION
FEASIBILITY AND COSTS
JOINT INDUSTRY STUDY

RJBA

JOB NO. 2269.02
NOVEMBER 1984

R. J. BROWN AND ASSOCIATES
ZUG HOUSTON THE HAGUE SINGAPORE

TABLE OF CONTENTS

CHAPTER 1
INTRODUCTION AND SUMMARY

1.1 INTRODUCTION

The subject covered in this report is offshore pipeline repair methods and costs in Diapir Area, Alaska (OCS Lease Sale 87). This report forms an addendum to the joint industry study report titled Offshore Pipeline Transportation Feasibility and Costs, Diapir Area, Alaska prepared by R. J. Brown and Associates (RJBA) in March 1984 under job no. 2269-01.

The objectives of this study were to determine equipment requirements and their costs to carry out offshore pipeline repair in Diapir Area, water depths 60 feet to 330 feet, on a year-round basis. It was assumed that pipeline repair work will be performed using conventional repair techniques and tools. These techniques include the repair of small dents and leaks by clamping a mechanical sleeve around the damaged area to the repair of a large damage, such as a line break, by replacing a section of pipeline with a spool piece about 500 feet in length. Pipeline repair work involving the replacement of a larger length of pipeline was considered new pipeline installation work. This will require the mobilization of an entire pipeline installation spread and was discussed in the main study report.

The subject of detecting a pipeline leak or a damage is not discussed in this report. It was assumed that a leak will be detected and confirmed by instrumentation in the pipeline system, and that its approximate location will be known. The repair operation begins with a survey and inspection task to determine the exact damage location and the extent of damage.

1.2 SUMMARY

The following paragraphs summarize the contents of each chapter contained in this report.

Conclusions and Recommendations

Chapter 2 summarizes the conclusions and recommendations from each subsequent chapter.

Repair Considerations

Repair considerations are discussed in chapter 3. These considerations include a discussion on hazards to pipelines in Diapir Area, repair techniques and problems associated with implementing the repair techniques in Diapir Area on a year-round basis. Trench fill-in due to natural sedimentation and ice keel activity influence the repair equipment requirements and costs. Estimates of trench fill-in due to sedimentation and ice keel activity in water depths of 65 feet and 100 feet are provided.

Pipeline Repair

Chapter 4 provides details of equipment requirements to carry out pipeline repair work in Diapir Area. Surface vessel and submarine vessel repair spreads are defined for Ice Condition A through D. Additional Ice Conditions E, consisting of a grounded massive ice feature and Ice Condition F, consisting of a stable ice sheet, are discussed. Equipment costs, day rates and spread productivities are given.

Repair Case Study

A case study of a repair scenario is provided in chapter 5. A repair schedule and a cost estimate are given for the repair of a 36 inch oil trunk line in 100 feet water depth. The repair cost includes the following cost elements:

- leak location
- survey and inspection
- repair material
- mobilization and demobilization costs of repair spread
- trench clearing and excavation costs
- pipeline repair costs
- logistic support costs and
- pipeline pressure testing costs.

CHAPTER 2
CONCLUSIONS AND RECOMMENDATIONS

2.1 GENERAL

This chapter contains the conclusions of the study summarized chapter by chapter. Where applicable, recommendations for additional studies or development effort are presented.

2.2 REPAIR CONSIDERATIONS

The major hazards Diapir Area pipelines will be exposed to are ice keels and permafrost degredation. Hazards of corrosion, instability and ship anchors are far less significant in this area compared to other major pipeline areas in the world.

Regular inspection of the pipelines for signs of internal and external deterioration can minimize unexpected pipeline shutdown caused by leaks. Such deterioration can be repaired during ice-free periods. The exception will be the case of a leak caused by a vessel anchor or an ice keel. Since pipelines in Diapir Area will be trenched to protect them from ice keels, the chance of such damage occurring is expected to be remote.

Conventional pipeline repair techniques can be used in Diapir Area. However, techniques that require bulky repair tools are more difficult to implement in more severe Ice Conditions. Thus, mechanical connector type repair is easier to implement when compared with repair methods using hyperbaric welding techniques.

The transport of a spool piece to work site can be achieved in a number of ways. Both bottom tow and off-bottom tow methods can be used without difficulty. The off-bottom tow method has the advantages of low tow vessel horsepower requirements and ease of manipulation at repair site. This technique is well suited for under ice repair work.

The soil fill-in to the pipeline trench has a significant impact on repair effort. This soil movement is caused by natural sedimentation and soil movement due to ice keel action on the sea floor. The proportion of the trench cross-section which must be excavated for damage inspection and repair will increase as years go by. In shallow water depth with high bed load transport rates and in areas with high rate of ice keel reworking of the sea bed, the trench may be fully filled-in and may require a major effort for pipeline repair access excavation.

2.3 PIPELINE REPAIR METHODS

Pipeline repair spreads will be exposed to the four operating Ice Conditions defined in the main study report. Two additional Ice Conditions are defined for pipeline repair purposes. They are: grounded massive ice features and stable ice platforms.

Trench clearing work for pipeline access must be carried out using remotely operated diver operated dredge pumps with hydraulic booms and cutterheads. Such dredging units are currently available. Power requirements for a dredge pump is estimated to be about 100 HP.

Floating and submarine vessel based pipeline repair spreads can be used in Diapir Area. The floating vessel repair spread will consist of a pipeline repair vessel, supply vessel and icebreaker vessels. Submarine vessel repair spread will consist of a submarine repair vessel and a submarine support vessel. Autonomous work submarines are currently under manufacture and a pipeline repair submarine can be developed from present day technology. A comparison of repair costs shows that the submarine vessel repair spread will cost less to operate in Ice Conditions C and D.

A submarine vessel operating base is needed for year-round pipeline repair work. The submarine vessel base can be located at a port designed for year-round operation or at an offshore platform. If the latter method is to be used the design of arctic offshore platforms must incorporate such facilities. A preliminary design of such a facility is recommended to determine its implications on platform design and construction. Furthermore, a preliminary design study of an arctic pipeline repair submarine is recommended to develop design and performance specifications for such a vessel.

Ice Condition E, a grounded massive ice feature, offers the most challenging repair situation. Pipeline repair in this situation will be slow and costly. Grounded ice features are commonly found in the transition zone, water depth 50 to 75 feet, during the winter months. However they can be present in shallower water as well as in deeper water. Bypass pipelines across the transition zone can reduce the risk of total pipeline shut down in case of a line damage in this area.

2.4 REPAIR CASE STUDY

The study case consists of pipeline repair work on the Scenario A, 36 inch Oliktok point trunkline in 100 foot water depth in Ice Condition C. The pipeline was repaired with a 300 foot long replacement spool piece using a submarine pipeline repair spread. The estimated repair duration and cost were 13 weeks and $ 13.7 million respectively.

CHAPTER 3
REPAIR CONSIDERATIONS

3.1 HAZARDS TO ARCTIC PIPELINES

Arctic pipelines, like their counterparts in other parts of the world, are subjected to a number of hazards. In addition to the hazards such as ship anchors, corrosion, hydrodynamic and soil instability, arctic pipelines will be exposed to the hazards of ice keel activity and permafrost degradation. A brief discussion of each of these hazards as applied to arctic offshore pipelines is given below.

Internal and External Corrosion

Arctic pipelines will be subjected to both internal and external corrosion. External corrosion of a pipeline is mitigated by corrosion coating and cathodic protection. Regular inspection of the pipeline can be made to ensure the integrity of the cathodic protection system over the operating life of the pipeline. Similarly, pipeline internal corrosion can be mitigated by use of proper operating procedures and corrosion inhibitors. Regular internal inspection with inspection pigs can detect internal corrosion problems and steps can be taken to remedy the situation. In arctic pipelines such inspection tasks can lead to preventative maintenance work where any defective parts of the pipeline system can be repaired during ice-free periods, whether such defects be found in the corrosion coating, the cathodic protection system, the pipe steel, or wherever.

Mechanical Damage

The risk of mechanical damage to pipelines caused by ship anchors will be relatively low in the arctic waters compared to other major pipeline areas of the world. This is because during most parts of the year there will be very little surface traffic and also because arctic pipelines will be trenched for protection from ice keels. However, this hazard cannot be totally eliminated due to the possible presence of construction vessels.

Hydrodynamic and Soil Instability

To properly designed and constructed pipelines these two hazards will not pose a threat because of the moderate hydrodynamic environment in the arctic and the relatively stable sea floor soils in Diapir Area.

Ice Keels

Ice keels constitute a major hazard to arctic pipelines. To reduce their exposure to this hazard, arctic pipelines are installed in deep trenches. This subject was discussed in detail in section 3.5 of the main study report.

Permafrost Degradation

Offshore arctic pipelines may encounter areas of permafrost. Hot pipelines can cause the permafrost to melt and, in thaw, unstable soils may lead to a loss of foundation support which in turn leads to progressive settlement and eventual pipeline failure in the form of a line buckle or rupture. Repair to pipeline damage caused by this type of failure is complex: not only must the pipe be repaired, it must also be provided with a firm foundation to prevent any further settlement. This type of pipeline situation may be rectified by providing piled supports to the repaired pipeline or by providing a thaw stable soil foundation under the pipe.

3.2 TYPES OF PIPELINE REPAIR

The emphasis of this study was to determine the equipment required to carry out year-round pipeline repair work in Diapir Area. It was considered that conventional repair techniques and tools will be used for the repair tasks. These techniques and tools consist of the following:

- Installation of a mechanical sleeve around the pipeline to repair small damages such as gouges, dents and small leaks.

- Replacing a pipe section with a spool piece to repair large dents, buckles or line rupture. The spool piece can be a few feet long to a few hundred feet long.

If a very long section of pipe must be replaced, that is, a section too long to transport by the methods discussed in section 3.3, then an entire pipe-lay spread will have to be mobilized to carry out the repair. This case is considered as new pipeline installation work and was covered in the main study report. This situation can arise when the length of the section of the pipeline to be replaced exceeds 1,000 feet.

3.3 REPAIR TECHNIQUES

To carry out each type of repair described in section 3.2 a number of operational problems must be overcome. These problems and the appropriate solutions are described below.

3.3.1 Mechanical Sleeve Repair

A typical split-sleeve clamp is shown on drawing No. A-300. To install the sleeve clamp the following tasks must be performed:

- Transport repair clamp, accessories and personnel to repair site.
- Access pipeline by clearing trench.
- Remove concrete coating, corrosion coating and clean pipe at repair location.
- Place clamp around repair pipe section and install bolts.
- Seal the annulus between pipe and clamp.

To carry out rapid repair work an inventory of repair clamps suitable for the pipelines in operation must be maintained. It was assumed in this study that such an inventory is maintained and that there is no lead time required to procure the repair clamps.

Methods and vessels required to transport the repair clamps and personnel to repair site are addressed in section 4.3.

Accessing the pipeline for repair will require dredging work to be performed. This work has to be performed with divers assistance as it is necessary to protect the existing pipe during this operation. Dredging methods and equipment are discussed in section 4.2.

Soil fill-in will be present in the trench due to natural sedimentation and soil movement due to ice keel activity on the sea floor. To plan the repair operation it is necessary to have an estimate of the soil to be removed from the trench. In a real repair operation this estimate will be prepared during the damage inspection survey. For the purpose of this report estimates of soil to be removed are provided in section 3.4, for both natural sedimentation and ice keel action.

Weight coating and corrosion coating removal, pipe cleaning and clamp installation work will be carried out by divers using conventional hand tools and power tools.

For the purpose of this report it was assumed that the time required to install the clamp after trench clearing is five days in calm open water conditions.

3.3.2 Spool Piece Repair

Spool piece repair of a pipeline can be carried out by a number of methods. They are:

- Surface tie-in repair
- Hyperbaric welded repair using:
  - . Alignment frame
  - . H-frames
  - . H-frames and weld ball
- Mechanical connector repair using:
  - . Swivels and non-misalignment connectors
  - . Length compensator and misalignment connectors

A brief discussion of these methods and their applicability to Diapir Area is given below. A summary is provided in Table 3.1.

Surface Tie-In Repair

A typical surface tie-in repair operation is depicted on drawing No. A-301. In this method the repair section is cut off and the pipe is lifted to the surface by the repair vessel. A spool piece section is welded to the pipe and then it is lowered to the sea floor. The maximum length of pipe that can be cut out and repaired with this method is limited to about 100 feet. In Diapir Area this method can be used only in Ice Condition A or open water conditions.

Even in Ice Condition A a disadvantage is the amount of dredging required to lower the welded section of the pipe to the required depth of soil cover.

Hyperbaric Welded Repair using Alignment Frame

A typical alignment frame is shown on drawing No. A-302. The alignment frame is used to align the ends of pipe for welding. This method will only be suitable for Ice Condition A mainly because of the difficulties in handling a large frame from the work vessel in the presence of sea ice.

Hyperbaric Welded Repair using H-Frames

H-Frames, smaller and lighter than an alignment frame, can be used to align the pipe ends. Here, the H-Frames are positioned such that sufficient length of pipe can be lifted off the sea floor to provide the flexibility required to align the pipe ends. This method can be used in Diapir Area in all ice conditions. However, the handling of the hyperbaric welding chamber with umbilical lines may pose ice related operational problems. A typical Hyperbaric welding chamber is depicted in drawing No. A-303.

Hyperbaric Welded Repair using H-Frames and Weld Ball

Drawing No. A-304 shows a typical weld ball. The introduction of the weld ball greatly reduces the accuracy of alignment required to make the weld. This method is also suitable for arctic pipeline repair work because of the reduced time required to complete the repair work. However, the comments made in the previous section regarding the hyperbaric welding chamber are valid for this method.

Mechanical Connector Repair using Swivels and Non-Misalignment Connectors

A typical spool piece installation is shown on drawing No. A-305. Use of swivels eliminates the need to achieve precision alignment of pipe ends.

Mechanical connectors must be secured to the ends of the pipeline after cutting out the repair section. The non-misalignment collet type connector such as those manufactured by Cameron Iron Works is not specifically built for pipeline repair work. Its use in this system requires that both ends of the pipe are lifted to the surface to weld on one connector half and attach the tie-in base. Thus, this system can only be used in Diapir Area under Ice Condition A.

Mechanical Connector Repair with Length Compensation and Misalignment Connectors

In this system the need for swivels is eliminated by using misalignment ball connectors. Length adjustment of the spool piece is accomplished via a length compensator. The connectors are mechanically attached to the pipe ends. This system is well suited for Diapir Area in all Ice Conditions.

Pipeline Repair Tools

Mechanical connection devices are widely used in offshore pipeline repair in place of hyperbaric welding. Two basic types of connection devices are available, namely, the sleeve type, which is used to attach pipe ends together, and interlocking types, which consist of male and female assemblies. For repair, both types are needed as the appropriate connection assembly must first be attached to the prepared pipe end.

Eight representative connectors are briefly reviewed in terms of advantages and disadvntages. It is noted that depending on market conditions and technological advancements, connectors available at the time of repair may be significantly different from those described. The following connector devices are presently available:

- Cameron Iron Works Collet Connector
- Comex Connector
- Big Inch Marine Flexiforge
- Daspit Brothers PermaLock and PermaKupl
- Hughes Hydrotech Hydrocouple
- Plidco Flange
- Star Subsea Maintenance Ltd. Starcouple
- Gripper Inc. Grip and Seal Couplings.

These devices are depicted on drawing A-306; their relative advantages and disadvantages are presented in Table 3.2. The connectors that accomodate axial misalignment (Hydrotech, Gripper, Comex), all utilize a ball type coupling as shown on drawing No. A-307.

A typical repair system utilizes a spool piece, two ball-type connectors and a gripping device at each end. The gripping sleeves, which allow for length adjustment, are first slid over the bare pipe ends. The spool piece is then lowered into position. Gripping devices and seals are set and tested, the connectors are set and tested and the repair is completed. Drawing No. A-308 through A-310 show pipeline repair operation with mechanical connectors based on a technique used by Hughes Hydrotech. Other manufacturers such as Gripper Inc. and Big Inch Marine Systems (BIMS) embody similar arrangements. Pipeline repair systems offered by these three manufacturers are summarized below; the costs are for ANSI Class 900 systems.

Make	Description	Cost $ 12.75" O.D.	24" O.D.	36" O.D.
Gripper	Utilizes 2 ball-type connectors and a grip and seal device at each end. Joint is made by tightening collet grips around pipe end.	140,000	360,000	860,000
Big Inch Marine	Joint is made by forging a connection hub on to each pipe end using a special mandrel. the system includes connectors to each end and two ball-type connectors. For pipe 16 inch and above, a length compensator is required.	50,000	220,000	570,000
Hughes Hydro MK IV	Two hydro couple connectors are used to make connections to the pipe ends. A spool piece with two ball-type connectors is used for the tie-in.	95,000	244,000	520,000

The costs given above for 24 inch and 36 inch systems include a length compensator.

In this study it was assumed that spool piece repair will be carried out using mechanical ball connectors with a length compensator. Specific problems encountered with this type of repair are discussed below together with their respective solutions.

To carry out a spool piece repair the following tasks must be performed.

- fabricate spool piece
- transport spool piece, handling equipment, tools and personnel to job-site
- excavate to expose damaged pipe section
- cut pipe section and remove
- install mechanical connectors to the pipe ends
- maneuver repair spool piece into location and align pipe ends with repair pipe
- activate mechanical connectors and complete connection.

An inventory of spare pipe, mechanical connectors, swivels and length compensators must be maintained to eliminate waiting time for the procurement of these articles.

The transportation of the spool piece to the repair site can create a special problem. Short lengths up to 100 feet or so can be fabricated on the work vessel if a surface vessel is used. Longer lengths of pipe can be towed to the repair site on bottom or off bottom. The off bottom tow method can be particularly attractive in the arctic during the ice covered months of November to June. A typical spool piece prepared for off bottom tow is shown on drawing No. A-311. In this method the pipeline spool piece is floated 6 to 10 feet off the sea floor with buoyancy tanks and drag chain assemblies. The drag chains are also used to maintain the hydrodynamic stability required during the tow operation. The low currents near the sea floor in Diapir Area during the ice covered months mean that the drag chain required to maintain tow spool piece stability is low. The required chain weight to ensure hydrodynamic stability of the towed spool piece and the estimated tow loads are given below for towing during ice covered months of November to June.

Pipe Nominal Diameter (Inch)	Chain Drag (a) Weight (lb/100 ft.)	Estimated (b) Tow Load (lb/100 ft.)
16	40	60
24	60	90
36	90	135

a Based on a winter design current velocity of 0.5 feet/sec.

b Based on a chain to sea floor resistance factor of 1.5.

Thus, the spool piece can be towed during the ice covered months with a lightly powered vessel such as a work submarine. Up to 1,000 feet long section can be towed with a thrust of 1,000 lbs. This method has another attraction namely, the relative ease of maneuvering the work piece into location. This can be accomplished with diver operated manual winches.

The bottom tow method can be used to transport the pipe spool piece to location in both summer and winter. High horsepower icebreakers can be used to perform this task. Table 6.13 in chapter 6 of the main study report presented length of pipe segments that can be bottom towed by tow vessels having pull capabilities of 150, 300 and 500 tons.

Pipe launching in winter months will also pose special problems. Pipe can be launched through a hole cut in the ice. It will be possible to drag the pipe on fast ice to a water depth the tow vessel can reach and lower it through a slot cut in the ice.

The effort of trench clearing work will be considerably greater for spool piece repair work. This work will have to be diver assisted. Estimates of dredging volumes are presented in section 3.4.

Cutting pipe sections, maneuvering the spool piece into location and making end connections will be carried out by conventional means with diver assistance.

In this study it was assumed that the time for replacing the spool piece once the trench has been cleared is 15 days in calm, ice-free water.

3.4 TRENCH FILL-IN

It is expected that deep trenches will be required for pipelines in the study area to afford protection from ice scours. These trenches will initially be open following installation of the pipeline, thus allowing easy access for inspecting, locating possible leaks and carrying out repair operations. As these trenches fill-in over the life of the pipeline, however, the volume of sediment which must be excavated to access the pipe can become quite large and this would therefore be a major consideration in any repair operation. Natural trench fill-in will result from marine sedimentation and ice keels gouging the seabed. During the brief arctic open water season, waves and steady currents can erode the trench sides and deposit sediment in its bottom.

Waves and currents in the lagoons behind the coastal barrier island are relatively small but the water depths are shallow. Therefore, small waves may be effective at filling in pipeline trenches. Areas seaward of the barrier islands are subject to more substantial wave action over a significant open water season duration. Further offshore, the open water seasons are progressively shorter and there are more numerous sea ice invasions. This, combined with the limitation in the fetch length due to the proximity of the permanent pack ice, acts with the greater water depths to reduce the rate of trench fill-in during the open water season.

During the ice covered season, and to a limited degree during open water conditions, ice keels can drag along the bottom causing ice scour marks. The plowing associated with this ice scouring can push seabed sediment into the pipeline trench. There is little movement of the winter fast-ice behind the barrier island or in shallow water and ice gouging is expected to push only limited amounts of soil into a trench in those areas. Further offshore, however, the depth and rate of occurence of ice gouges is greater and the rate of trench fill-in due to seabed reworking will be much more significant compared to the sedimentation rate.

The analysis methods utilized to evaluate trench fill-in due to sedimentation and ice gouging are rigorous but include several simplifying assumptions about the nature of marine processes. Additionally, because of the limited scope of work for the present study, data on waves, currents, sea bottom conditions and ice gouging have only been developed and synthesized at a reconnaissance level. These assumptions are deemed adequate for the purposes of this study. However, it must be kept in mind that fill-in rates herein determined are only first order estimates and are limited to the sediment types, seafloor conditions, and trench profiles assumed in the test case examples.

3.4.1 Summer Trench Fill-In

Marine sedimentation in seafloor trenches can develop from numerous natural processes. These processes are normally driven by ocean waves and currents and they are commonly influenced by the local input of sediment as well as the type of sediment on the sea floor. The geometry of the seafloor itself can also be important as depressions, especially sharper ones, tend to preferentially collect sediment.

In general, the marine sedimentation processes can be divided into two classes. One class results from a slow, uniform setting of fine suspended sediment onto the sea bottom. Although this process can be locally important, it is unlikely to be dominant in wide areas of the North Alaska continental shelf because the bottom sediments are primarily silts and fine sands. Such silts and fine sands tend to be transported and deposited by the second class of marine sedimentation processes, marine bedload processes.

The processes resulting in the transport of marine bedload sediment, along with the resulting deposition and erosion, have only recently been quantified. Even in the much simpler river environment, where bedload sediment is transported by a nearly steady and uniform current, the science of predicting erosion and deposition patterns is not well developed. In the marine environment, the processes are greatly complicated by the unsteadiness of near bottom fluid velocities resulting from the combined action of waves and currents. These processes are strongly nonlinear and no complete analytic solution has been found.

Modern methods for evaluating marine bedload transport often rely on various semi-empirical relationships between near bottom fluid stress and the instantaneous rate of sediment transport and commonly form the basis of numerical models. One such model was originally developed by Madsen and Grant (1976) for use in the engineering of a nuclear power plant which was to be located off of the New Jersey Coast (but which was never built). This model depended upon laboratory work done by numerous people at the sedimentation research laboratory of Berkley University as well as parallel work at the Danish Hydraulics Laboratory, most notably by Jonsson (1966). A similar model has been used by Niedoroda, et al, (1982) to compare computed fill-in rates against those measured in Southwest Ocean Outfall test pits located off the California Coast south of San Francisco. Results of this comparison were surprisingly good. A derivative of this model was selected for use in the present project to estimate the rate of pipeline trench fill-in during open water conditions.

Environmental Data for Sedimentation Analysis

The environmental parameters affecting the transport of sediment in the vicinity of the proposed pipeline trenches include:

- wave height, period and direction
- steady current velocity and direction
- duration and spatial extent of summer open water.

Each of these environmental conditions vary significantly throughout the Diapir Lease Sale Area and available non-propriety data are limited. A set of wave, current and open water season conditions which are representative for the study area were selected for use in this analysis. A site approximately 25 miles north of Oliktok Point with 65 to 100 ft. water depth was considered.

The summer wave and current conditions in the Alaskan Beaufort Sea result primarily from local wind conditions. Wind speed and direction data for September at Oliktok (Climatic Atlas) were utilized along with the open water fetch length rose to estimate the directional percent distribution of significant wave heights. The total percentage distribution for all directions corresponds to the significant wave height data presented in Table 3-2 of the main study report. Wave periods for each significant wave height were estimated from available data based on a constant wave slope.

The steady, wind induced bottom current speed was approximated as 2 percent of the wind speed. The direction of the bottom current was established based on the surface current heading in the same direction as the wind and the bottom current being reflected off the Alaskan shoreline. The set of wave and steady current conditions analyzed assume that the wave height and current speed are directly related via the wind speed. Similarly, the wave and current directions are directly related via the wind direction.

Computer Model

The computer model for marine bedload transport which was used in this project is of a finite difference type. The seafloor was represented by an array of depth points (24 points by 24 points) which are in vector form so that the seafloor was represented in three dimensions. The bedload transport and resulting patterns of erosion and deposition in the seafloor trench were computed for each combination of wave height, wave period, wave approach direction, bottom current speed, and bottom current direction established in the preceding paragraphs.

For each combination of the above parameters, the computation of bedload transport proceeded in a fixed manner. The wave period was divided into sixteen sub-intervals. A vector sum of the instantaneous near bottom wave orbital velocity and the mean bottom boundary layer velocity was made. This sum was used to evaluate a current friction factor from a Moody relationship, a wave friction factor from a Jonsson-type relationship and a combined wave current factor according to the algorithm first defined by Jonsson (1966). The evaluation of the latter parameter allows the determination of the instantaneous fluid stress acting on the bottom sediments. This fluid stress is compared to the critical fluid stress necessary to entrain (i.e., initiate movement of) bottom sediments using the well known Shields criteria.

If the computed Shields parameter exceeded the critical Shields parameter, then sediment transport during that one sixteenth of the wave cycle was computed using an Einstein-Brown relationship. The marine bedload transport which was computed during each or any of the sixteen sub-intervals of the wave period were summed and normalized to establish the time-average rate of bedload transport. This computation was made for each grid point of the depth grid. The time averaged bedload transport rates were multiplied by a time step interval which was selected to be proportional to the duration of the particular wave and current conditions in the overall wave climatology.

Patterns of erosion and deposition within the depth grid were computed using a sediment continuity equation. The sediment transport was parameterized as a volume flux. Hence, the porosity of the bottom sediment had to be estimated in order to determine the appropriate patterns of sedimentation and erosion.

It must be stressed that the Shields relationship and the Einstein-Brown equation are valid only where the force which stabilizes bedload sediment against transport is entirely gravitational. This limits the application of this computational routine to cohesionless sediments such as sands and silts. Strictly speaking, even these types of sediments may be stabilized to unknown degrees by the presence of organic material such as mucus from infauna in some continental shelf environments. This has been regarded as a detail which can be appropriately overlooked during this first order analysis.

Trench Fill-In Test Cases

Two test cases were selected to illustrate the approximate rate of pipeline trench fill-in on the relatively shallow and silty continental shelf of North Alaska. Case 1 was located at a water depth of 65 feet and Case 2 was located at a water depth of 100 feet. In both cases, the seafloor was assumed to be composed of a homogeneous layer of granular sediment with a grain size corresponding to the boundary between coarse silt and fine sand. The porosity was assumed to be forty percent. In both cases, the seafloor was taken to have a pipeline trench with sides slopes of 1 vertical to 2.5 horizontal. In the first case, where the water depth is 65 feet, the bottom of the trench is at a depth of 75.4 feet and has a 10 foot wide flat area. In the second case, where the general seafloor is taken to be at a depth of 100 feet, the trench is 23.4 feet, deep making the depth of its bottom at 123.4 feet. This trench is also assumed to have a narrow (10 foot) flat area at its bottom. The same wave and current climatology has been applied to both test cases but were adjusted for differences in water depths.

The average duration of open water conditions for Case 1 (65 foot water depth) has been taken as 30 days per year whereas the average open water duration at the 100 foot water depth site has been taken as 15 days. These average durations were computed based on the median duration and variability presented in the previous report. Both average durations are longer than the median durations.

The results of applying the above described computer model and oceanographic data to these test cases are shown in Drawing Nos. A-312 and A-313. Both cases are for a pipeline trench oriented north-south.

The estimated sedimentation in the pipeline trench for Case 1 is shown over a ten year period on Drawing No. A-312. The general pattern of erosion and deposition in the pipeline trench is similar during the first and second five year intervals. Erosion tends to dominate the eastern side of the trench and deposition dominates the western side. This appears to be caused by an asymmetry in the directional wave climatology. Larger waves from the northeast tend to dominate the annual climatology. These waves are associated with easterly winds which result in steady bottom currents with westerly components. The fill-in of the pipeline trench does not agree with the simplistic pattern of sediment collecting in the trench bottom. Instead, the form of the trench actually migrates to the east as it fills in.

The increasing depth of sediment over the pipeline does not follow a simple linear progression. According to the results obtained with the computer model, the pipe is covered with sediment on the order of 1 to 2½ feet in thickness over a period of five years, depending on the pipe diameter. During the second five year interval, the sediment cover increases to a thickness on the order of 8 feet above the pipe. If the same pattern continues to develop, the pipe will be buried to near the total pipeline depth of over 15 ft. within 15 years.

It is also important to note that the pipe cannot be found beneath the centerline of the trench as it undergoes the effects of marine bedload transport. The trench actually migrates while the location of the buried pipe is fixed. Similar results have been experienced in the North Sea and reported in non-proprietary studies.

The results of estimating the fill-in rate during the open water season for the second test case at a water depth of 100 ft. are shown on Drawing No. A-313. The effect of the greater water depth and short open water season are immediately apparent when this drawing is compared to the previous one. The bottom of the trench is covered by approximately 2 feet of sediment during the first 10 years. This increases to 3½ feet of sediment during the second 10 years and 4½ feet during the final 10 years. Thus, in a 30 year period, only approximately 4½ feet of bedload sediment collect on the bottom of the trench. The results of the change in shape and position of the pipeline trench are similar in pattern in 100 feet water depth as they were at 65 feet. The trench tends to migrate in an easterly direction as it fills in.

3.4.2 Winter Trench Fill-In

The Alaskan Beaufort Sea is typically covered by ice from October to June and there is very little wave and current activity which could cause fill-in of the pipeline trench. There is a potential, however, for ice keels to gouge the seabed in water depth less than 200 feet. If these gouges intersect the pipeline trench, they will push some sediment into the trench. This reworking of the seabed primarily occurs during the winter months but may also be associated with a summer ice intrusion.

Trench fill-in processes due to ice gouges which are necessary to define the pipeline repair site excavation requirements are shown on Drawing No. A-314. There will be a general fill-in of the trench by ice gouges which intersect the trench but do not contact the pipeline. This type of previous ice gouge is depicted by Gouge "A" on the drawing. The volume of soil pushed into the trench by each gouge is a function of factors including:

- ice gouge width, depth and profile
- trench depth, width and angle with respect to ice gouge and
- previous trench fill-in due to sediment transport and ice gouging.

Obviously, a shallow ice gouge will push only a small amount of soil into the trench. A deep gouge will largely fill a portion of the trench equal to the gouge width plus the gouge flank widths.

If it is assumed that the annual percent of the trench fill-in is equal to the percent of the seabed reworked each year, the trench fill-in can be characterized by the following equation:

$$G_T = 1 - (1 - K)^T$$

Where:

G_T = proportion of trench length filled in after T years
= proportion of seabed gouged after T years,

K = Fraction of seabed gouged each year

$= \frac{\text{Summation of gouge widths}}{\text{survey line length}}$

T = Time period in years

Measured valves for "K" range from approximately 0.01 to 0.02. The percentage of trench fill-in by ice gouging is shown on Drawing No. A-315 for "K" ranging from 0.01 to 0.05.

If the pipeline is damaged by an ice keel contact, the same ice keel will push soil into the surrounding trench. This type of local fill-in at the repair site is represented by Gouge "B" in Drawing No. A-314. Locating the damaged pipe section and making minor repairs will be simplified if the site is left exposed in the bottom of the ice gouge. If the pipe is displaced by the ice keel contact or sustains more than very local damage, the pipeline may require excavating over the full width of the impacting ice gouge. Required excavation volumes will vary as a function of the following variables:

- trench depth, width and side slope
- required excavation length
- extent of fill-in due to local ice gouge, general ice gouging and sedimentation
- required degree of overdredging.

3.4.3 Trench Fill-In Summary

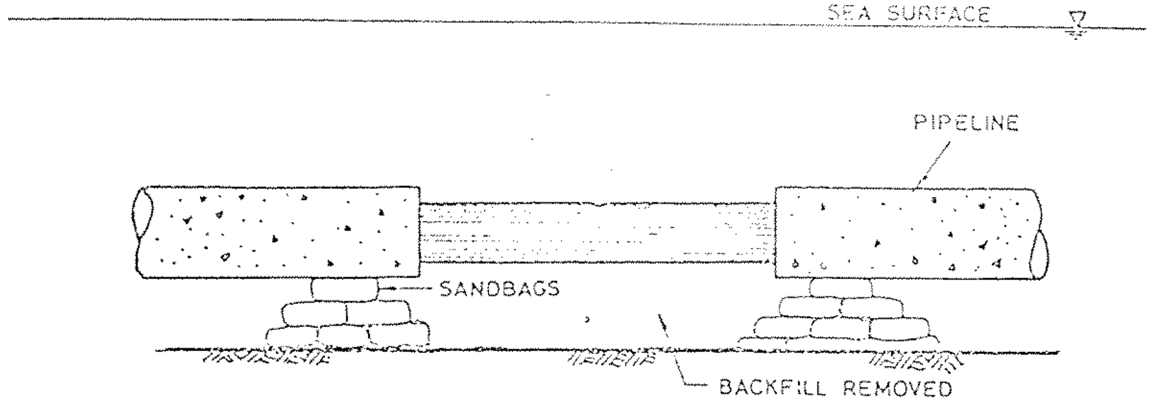
The proposed pipeline trenches in less than 200 feet water depth will experience significant fill-in due to both sedimentation and ice gouge reworking of the seabed. The proportion of the trench cross-section which must be excavated for damage inspection and repair will increase over the life of the pipeline. In shallow water depth with high bedload transport rates and in areas with high rate of ice keel reworking of the seabed, the trench may be fully filled in and require a major effort for pipeline repair access excavation.

TABLE 3.1
COMPARISON OF REPAIR METHODS

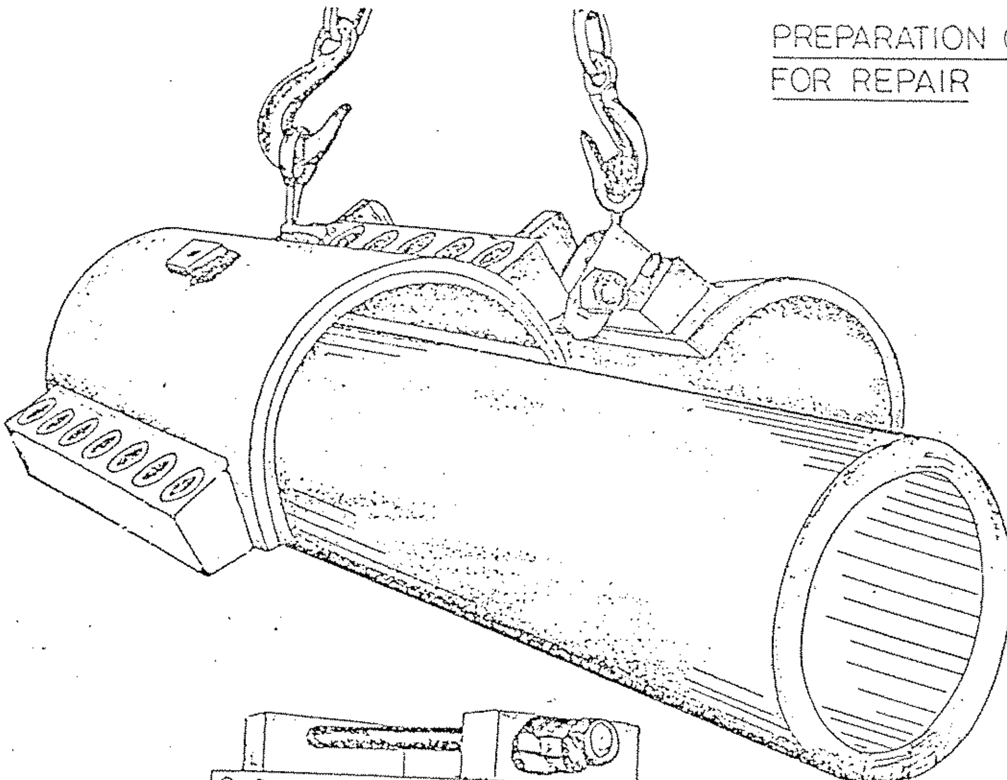
METHOD	APPLICABLE ICE CONDITION	REMARKS
Surface Tie-in Repair	A&F	Sensitive to the presence of sea ice.
Hyperbaric Weld using Alignment Frame	A	Bulky equipment. Best used in open water.
Hyperbaric Weld using H-Frames	B	Hyperbaric chamber may pose ice related operational problems. Otherwise suitable.
Hyperbaric Weld using H-Frames and Weld Ball	B	As above accurate alignment not required
Mechanical connectors with swivels and non misalignment connectors	A	Pipe ends must be lifted out of water to attach connectors.
Mechanical connectors with misalignment-ball connectors and length compensator.	D	Most expedient repair method for Diapir Area.

TABLE 3.2
SUMMARY OF MECHANICAL CONNECTORS

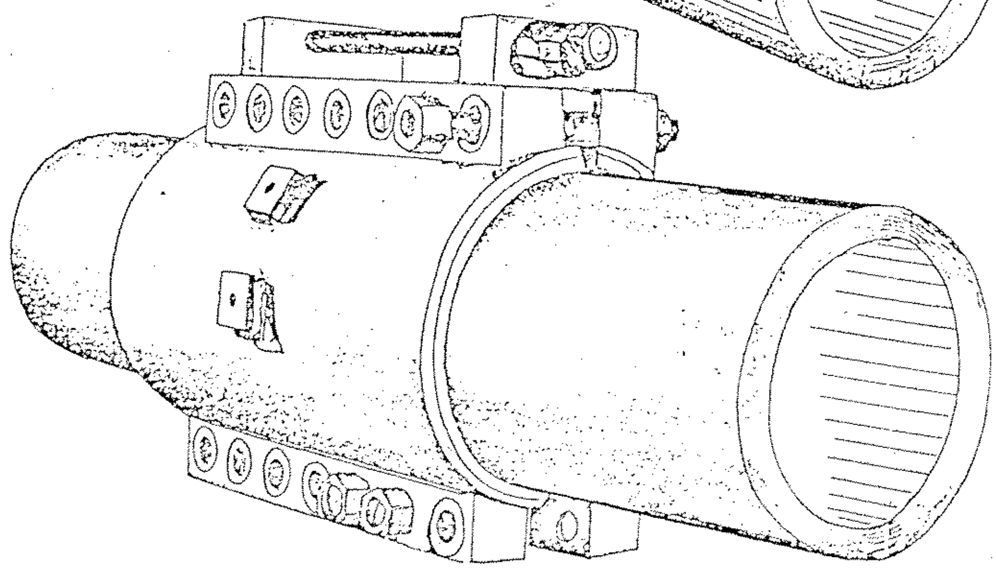
CONNECTOR	DESCRIPTION	LIMITATIONS	ADVANTAGES	DISADVANTAGES
Cameron Collet connector with sleeve	Hydraulically activated flange, explosively welded sleeve	None	Metallic gasket; widespread use with no known leaks	Explosive welding technique experimental; requires pre-installation of connector halves on pipe ends; no misalignment capability
Comex Connector	Worm screw activates slips and seals with misalignment connector	Diamters less than 16 inch	Misalignment tolerance ± 15°	No usage history
Big Inch Marine Flexiforge	Cold forging of pipe into collar. Used for flange attachment	None	Metal to metal seal; misalignment capability available	No major disadvantage
Daspit Brothers Permalok, Permakupl	Bolt Activated packing seals and slips	Small diamter pipe only	Low cost; widespread use	Reliability depends on installation; no misalignment capability
Hughes Hydrotech Hydro Couple	Hydraulically activated packing seals and slips	None	Allows ± 20° misalignment; widespread use; rapid installation	Elastomeric seals in sleeves. May require maintenance
Plidco Flange	Mechanical flange attachment with optional backwelding	Small diameter pipe	Cost	Temporary repair; reliability depends on installation
Starcouple	Cryogenic shrink sleeve of titanium nickel alloy	Diameters less than 2.625 inch	Metal to metal seal	No misalignment capability
Gripper	Bolt activated slips and seals with misalignment connector	None	Widespread use with no known leaks. Misalignment tolerance ± 15°.	No major disadvantage



PREPARATION OF THE PIPELINE FOR REPAIR

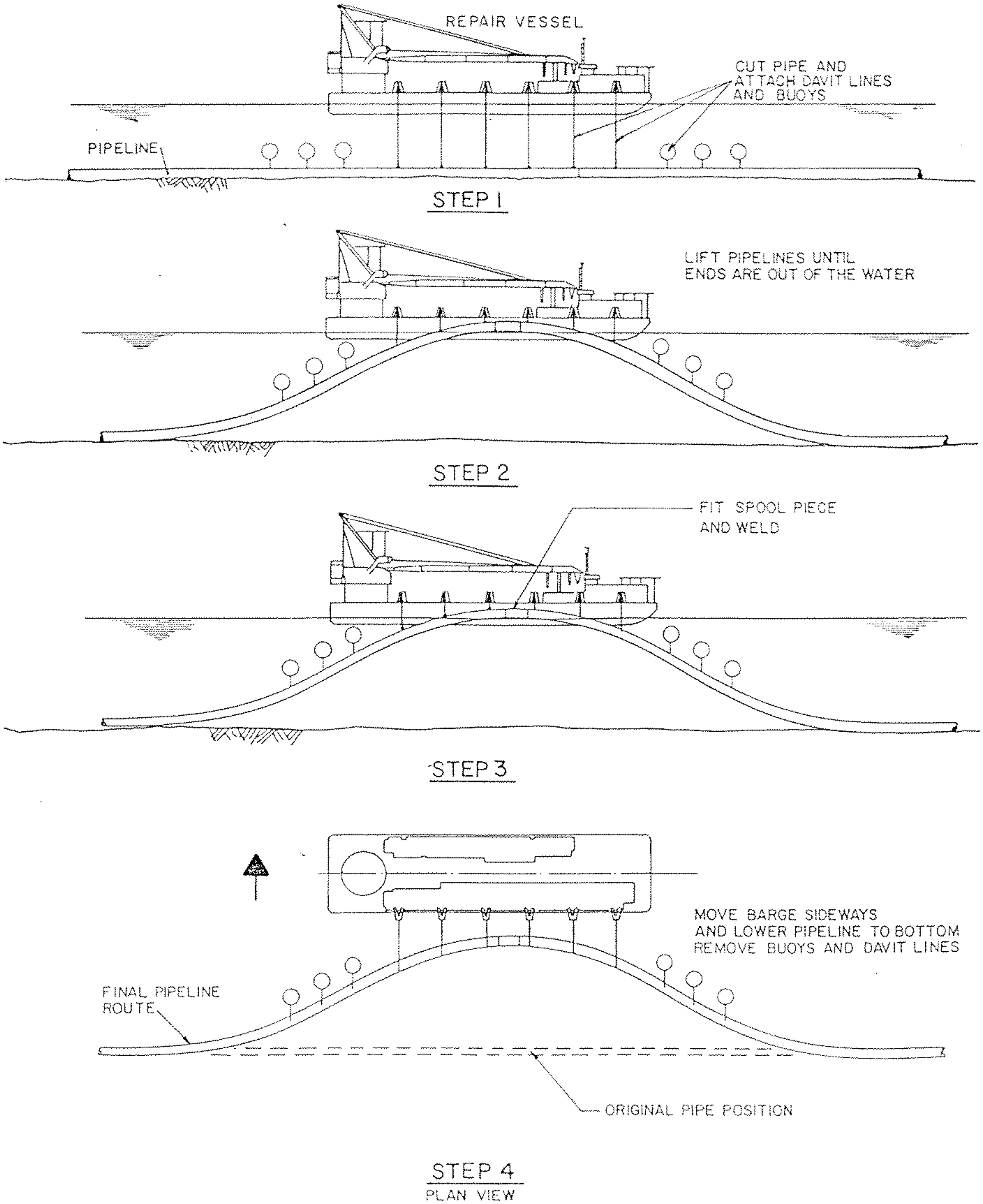


LOWERING THE HINGED SPLIT-SLEEVE OVER THE LEAK



BOLTING TO SECURE AND SEAL THE LEAK

JOINT INDUSTRY STUDY	INSTALLATION PROCEDURE FOR SPLIT-SLEEVE CLAMP					
RJBA R. J. BROWN AND ASSOCIATES	SCALE	DRAWN	CHECKED	D M Y	JOB NO	DRAWING NO.	REV
	NONE	JD		26.10.84	2269.02	A-300	0

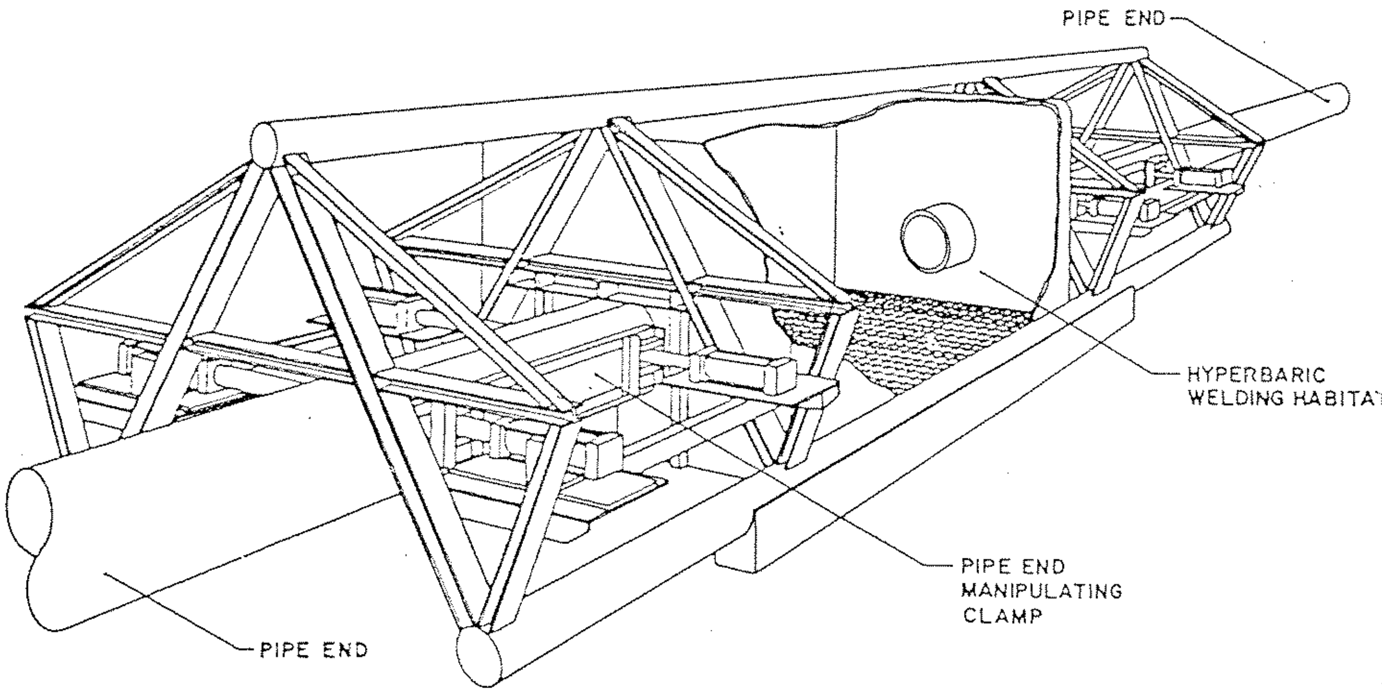


JOINT INDUSTRY STUDY

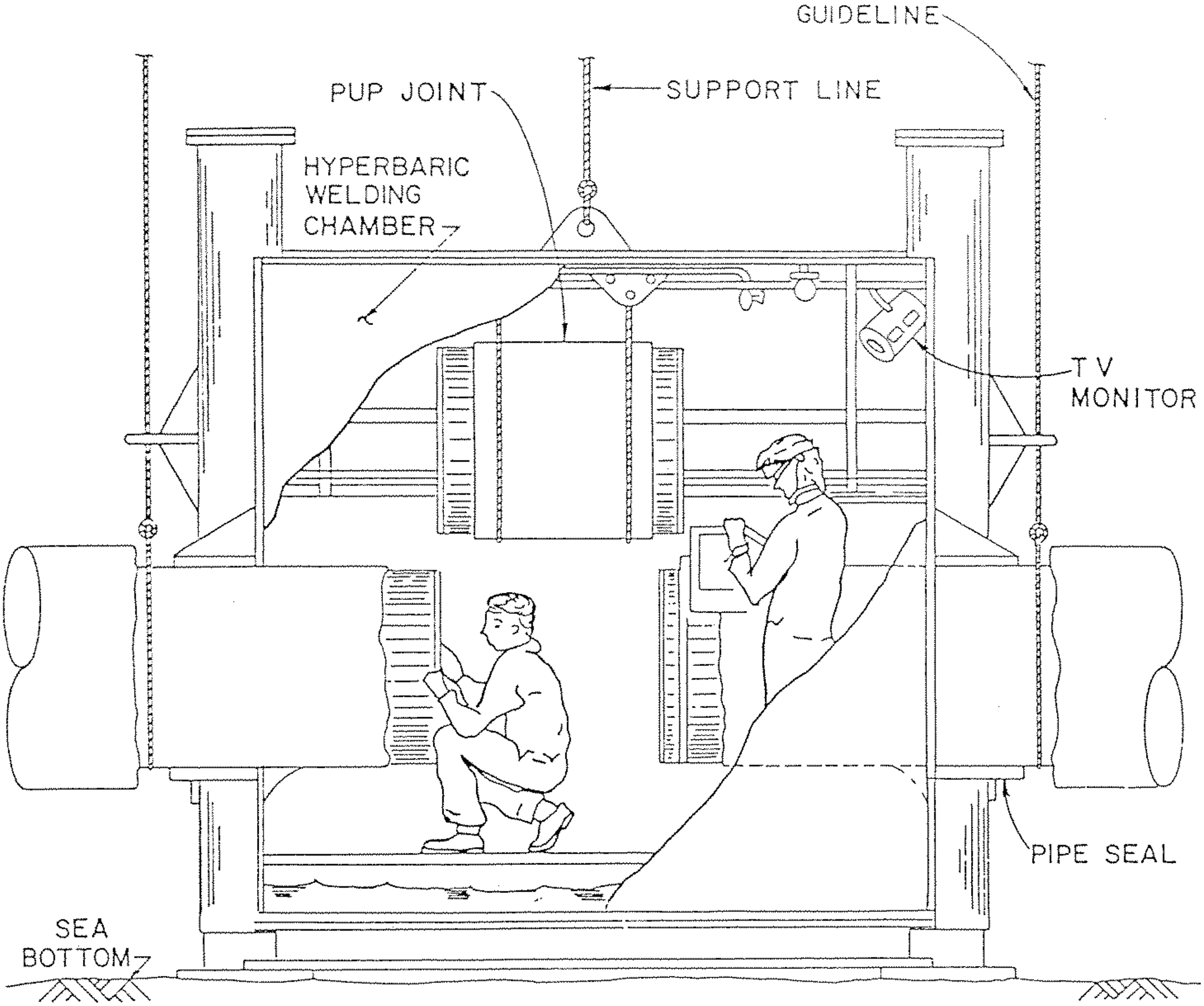
SURFACE TIE-IN REPAIR

RJBA
R. J. BROWN AND ASSOCIATES

SCALE	DRAWN	CHECKED	D.M.Y.	JOB NO	DRAWING NO.	REV
NONE	JD	RP	26.10.84	2269.02	A-301	0



JOINT INDUSTRY STUDY	WELDING HABITAT AND ALIGNMENT FRAME						
RJBA R. J. BROWN AND ASSOCIATES	SCALE	DRAWN	CHECKED	D.M.Y	JOB NO	DRAWING NO.	REV
	NONE	JD		26.10.84	2269.02	A-302	0

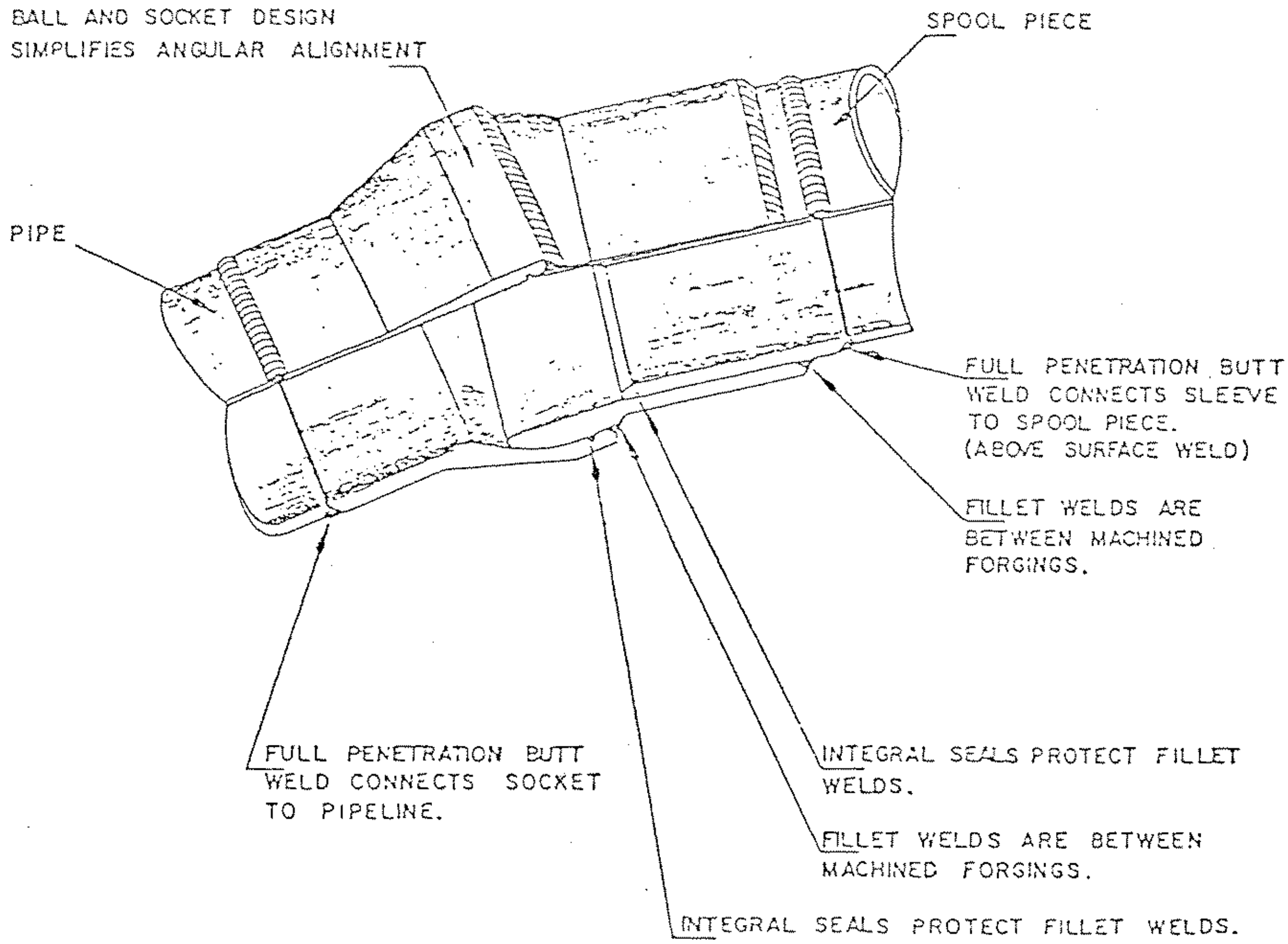


JOINT INDUSTRY STUDY

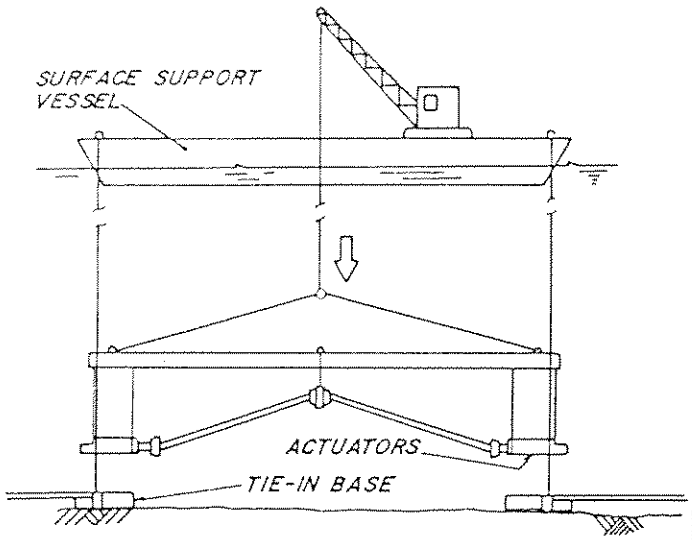
HYPERBARIC WELDING CHAMBER

RJBA
R. J. BROWN AND ASSOCIATES

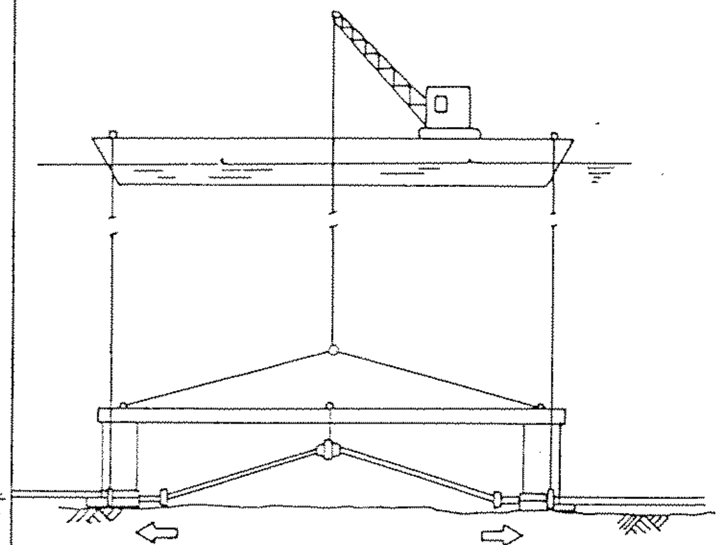
SCALE	DRAWN	CHECKED	D.M.Y	JOB NO	DRAWING NO.	REV
NONE	JD		26.10.84	2269.02	A-303	0



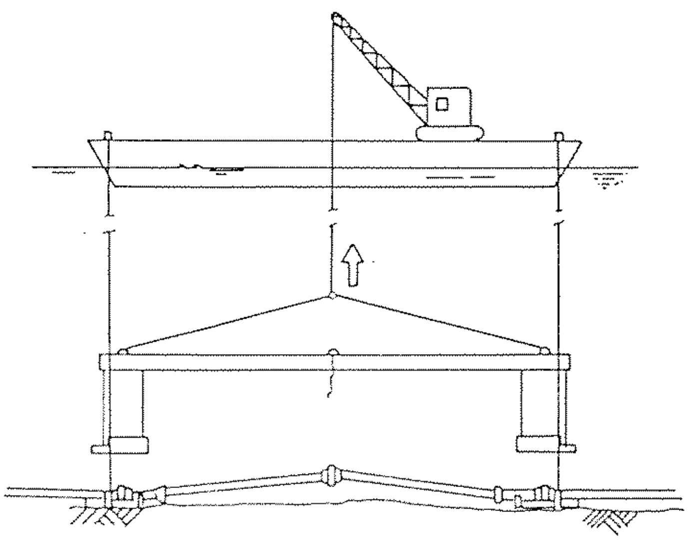
JOINT INDUSTRY STUDY	WELDBALL DESIGN						
RJBA R. J. BROWN AND ASSOCIATES	SCALE	DRAWN	CHECKED	D M Y	JOB NO	DRAWING NO.	REV.
	NONE	JD		26.10.84	2269.02	A-304	0



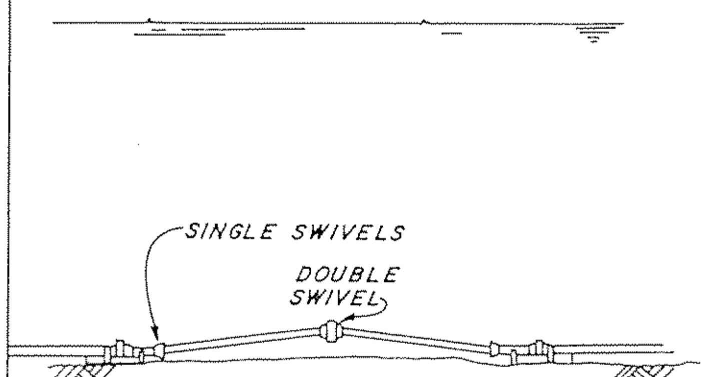
STEP ONE: LOWER TIE-IN ASSEMBLY AND ACTUATORS ONTO TIE-IN BASE



STEP TWO: ACTUATORS HYDRAULICALLY MAKE CONNECTION OF COLLET CONNECTORS

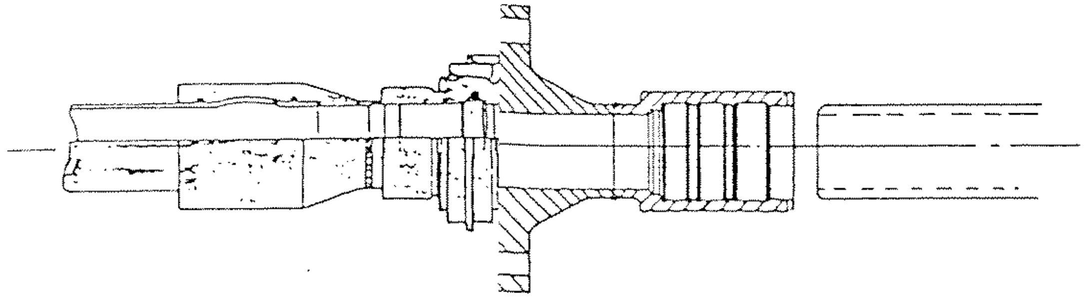


STEP THREE: ACTUATORS ARE LIFTED TO SURFACE, SWIVEL JOINTS ARE LAID ON SEA BOTTOM



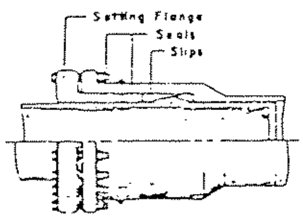
STEP FOUR: COLLET FINGERS ARE LOCKED ON MATING HUBS CONNECTION COMPLETED

JOINT INDUSTRY STUDY	SPOOLPIECE WITH SWIVELS AND NON-MISALIGNMENT CONNECTORS						
	SCALE	DRAWN	CHECKED	D.M.Y.	JOB NO.	DRAWING NO.	REV
RJBA R. J. BROWN AND ASSOCIATES	NONE	JD		26.10.84	2269.02	A-305	0

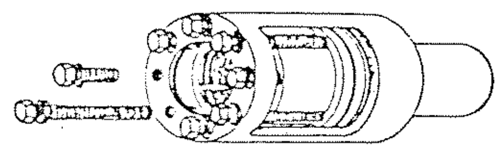


CAMERON — Collet Connector
VICKERS — Explosive Welding Sleev

IG INCH MARINE — Flexiforce

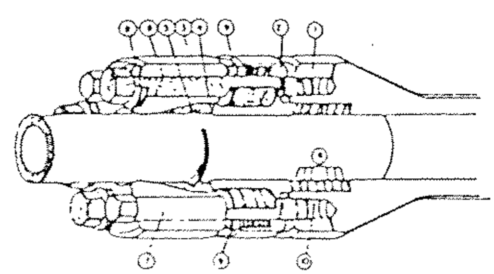


HUGHES — HYDROTECH — MARK V HydroCouple



DASPIT BROTHERS — Perma-Lok II

1 – PACKING FLANGE
2 – COMPRESSION GLAND
3 – SLIP FLANGE
4 – SLIPS
5 – SLIP SPRING
6 – PACKING RINGS
7 – PACKING SCREW
8 – SETTING SCREW
9 – BELLEVILLE SPRING
10 – LANTERN RING



COMEX COMECTOR II

	D.M.Y	REVISIONS	BY	CH'K	ENG'R	PROJ/ ENG'R	CLIENT

SCALE NONE | DRAWN JD | CHECKED

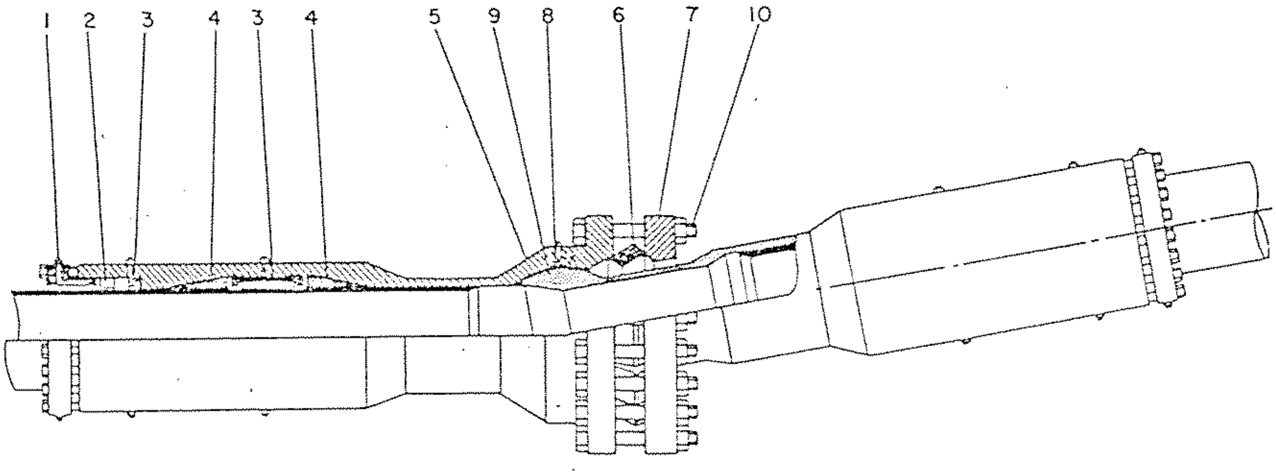
RJBA
R. J. BROWN AND ASSOCIATES

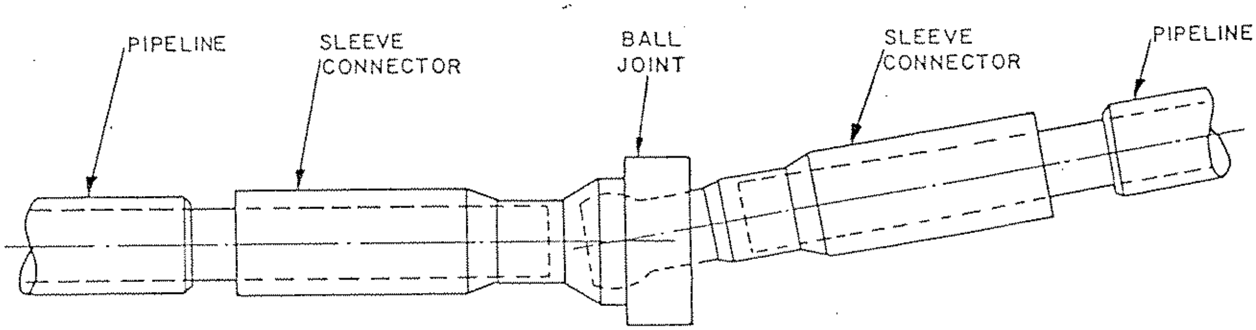
JOINT INDUSTRY STUDY

PIPELINE CONNECTORS

JOB NO	DRAWING NO	REV
2269.01	A-306	0

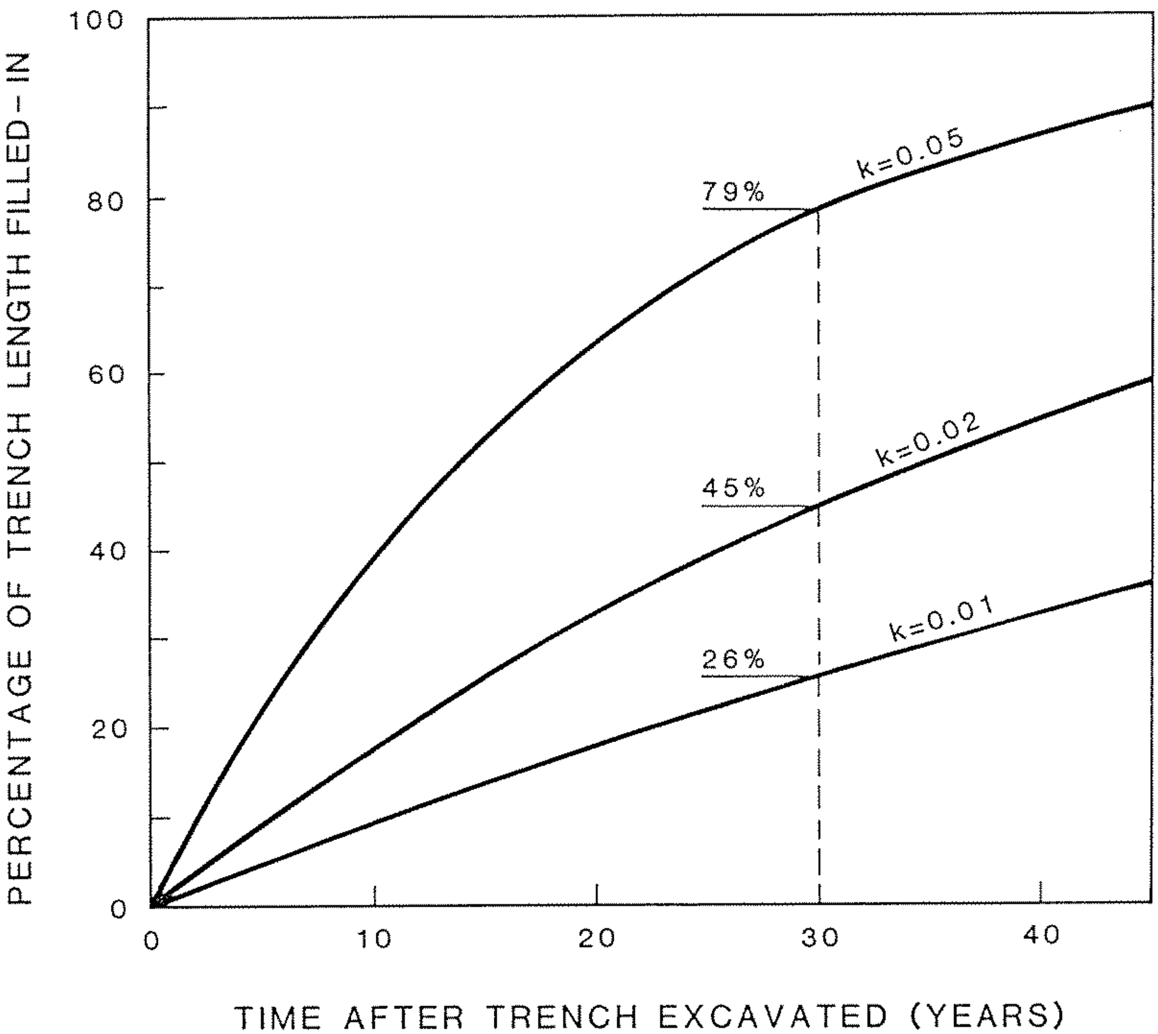
1, HYDRAULIC FLUID PORTS
2, PACKING
3, THRUST COLLAR
4, SLIP
5, SOCKET BODY
6, LOCKING FINGERS
7, ACTUATOR RING
8, SEAL
9, BALL
10, SETTING BOLTS





THE HYDROCOUPLE HALVES ARE DRAWN TOGETHER AND LOCKED AND SEALED IN PLACE

JOINT INDUSTRY STUDY	MECHANICAL REPAIR CONNECTORS					
RJBA R. J. BROWN AND ASSOCIATES	SCALE	DRAWN	CHECKED	D.M.Y.	JOB NO.	DRAWING NO.	REV
	NONE	JD		26.10.84	2269.02	A-307	0



k= PROPORTION OF SEABED REWORKED BY ICE GOUGES EACH YEAR

JOINT INDUSTRY STUDY	TRENCH FILL-IN BY ICE GOUGES						
RJBA R. J. BROWN AND ASSOCIATES	SCALE	DRAWN	CHECKED	D.M.Y.	JOB NO.	DRAWING NO.	REV.
	NONE	JD		2.11.84	2269.02	A-315	0

CHAPTER 4
PIPELINE REPAIR METHODS

4.1 REPAIR SITE ICE CONDITIONS

Four Ice Conditions that may be encountered by pipeline installation and trenching spreads in Diapir Area were defined in section 3.3 of the main study report; these were:

- Ice Condition A: less than 8 inches of first year ice or less than 2 okta of ice coverage
- Ice Condition B: less than 3 feet of first year ice or less than 7 okta of ice coverage
- Ice Condition C: 3 to 5 feet of ice with ridges and less than 7 okta of ice coverage and
- Ice Condition D: greater than 6 feet of ice with large ridges of 10 to 15 feet high including pack ice.

A pipeline repair spread, operating year round, may encounter all four Ice Conditions defined above. In addition two more Ice Conditions, Ice Condition E and F, may be encountered by this pipeline repair spread. Descriptions of these two Ice Conditions are given below.

- Ice Condition E: Grounded massive ice feature such as a ridge, an ice island, a rubble pile or a floeberg, with keel dug into the sea floor. Ice keel may or may not be directly on the pipeline route. However, movement of the ice feature may pose a threat to the pipeline or to the repair spread or to both.

- Ice Condition F: Fast ice, stationary and providing a stable work platform.

Pipeline repair work in Ice Condition E is considered as a special case. Pipeline repair methods and costs for working from a stationary, stable ice platform were discussed in a previous AOGA study. Therefore, operating in this Ice Condition is not addressed in this report. Drawing No. A-400 shows the major winter ice zones. Ice Condition F can exist around a grounded ice feature and around the grounded transition zone in winter months.

4.2 EXCAVATION AND TRENCH CLEARING

Soil back-fill in the trench must be removed to access the pipeline for repair. The estimated volumes of soil that must be removed for two types of pipeline repair operations were given in section 3.4 of this report. Removal of this soil must be carried out while the pipeline is still inside the trench. This requires that the operation be performed under careful control of the equipment operator to avoid any further accidental damage to the pipeline.

Both soft and hard soil material can be expected in the trench. Natural sedimentation will deposit soft material in the trench whereas ice keel plowing will tend to deposit hard soil materials. Therefore, the trench clearing equipment must be able to handle both types of soil. The trench clearing work is best carried out using a remotely operated or diver operated dredge pump.

Remotely operated and diver operated dredge pumps with hydraulic booms incorporating cutter heads are currently available in the market. These dredge pumps require a considerable amount of energy to operate. A typical dredge is shown on Drawing No. A-403. It is a remotely operated 6 inch dredge manufactured by Aluvial Mining and Shaft Sinking Company of U.K. This dredge has a hydraulic boom capable of reaching 30 feet.

This dredge absorbs 112 HP during operation and has a maximum solid handling capability of 200 cubic yards per hour. This solid handling capability reflects ideal operating conditions. In practice when handling soft sediments it may be possible to obtain a solid handling rate close to the ideal rates. However, when hard soils must be handled such as over-consolidated clays, which require solid cutting and chopping, the solid handling capacity will be greatly reduced. For the purpose of this study it was assumed that an average efficiency of 15% can be achieved by this pump during trench clearing work where a mixture of hard and soft soil sediments will be handled giving an average production rate 30 cubic yards per hour.

The hydraulic boom of this dredge pump can be fitted with a vibrating clay cutting head for handling clayey materials.

The dredge pump can be operated from a floating pipeline repair vessel remotely or with diver assistance. In the case of a submarine pipeline repair vessel the pump can be mounted inside the vessel with the hydraulic boom built as an integral part of the submarine. An arrangement of this nature would allow the trench clearing operation to be carried out under visual observations from the submarine.

The 100 HP energy requirement can be easily met when the pump is operated from a surface supported pipeline repair vessel. For an autonomous submarine vessel however, this energy requirement will dictate that the vessel power plant be increased to meet the energy demand of the dredge pump. This item is further discussed in section 4.3.

4.3 PIPELINE REPAIR

This section gives a description and costs of pipeline repair spreads suitable for each Ice Condition defined. Two types of repair spreads are considered. They are:

- floating vessel repair spreads
- submarine vessel repair spreads.

Table 4.1 gives a summary of minimum vessel requirements for Ice Condition A through D, for a pipeline repair spread consisting of floating vessels. Table 4.3 gives the same for pipeline repair spreads consisting of submarine vessels. Descriptions of the repair spreads are given below.

4.3.1 Pipeline Repair Spreads Consisting of Floating Vessels For Ice Conditions A Through D.

Each pipeline repair spread will contain:

- a pipeline repair vessel complete with survey and saturation diving equipment
- a supply vessel and
- icebreakers for anchor handling and ice management.

A description and cost of pipeline repair vessel are given below.

Pipeline Repair Vessel

The pipeline repair vessel is the central unit of the spread. The vessel could have a ship-shaped hull or a conical shaped hull. In this study it was assumed that the pipeline repair vessel will have a ice-strengthened, ship-shaped hull. This assumption was based on the following considerations:

- A ship-shaped vessel can be more easily maneuvered in different Ice Conditions with less icebreaker support compared to a conical vessel.
- Lower capital cost of a ship-shaped vessel.

A conical vessel may show superior capability in maintaining position in a given Ice Condition with less icebreaker support. However, for pipeline repair tasks, the ability to move the vessel in and out of the repair site under any Ice Condition is considered to be more important.

The floating ship-shaped pipeline repair vessel is similar to the pipeline connection vessel discussed under tow method in chapter 6 of the main study report.

The arctic multi-function support vessel described in section 5.5 of the main report can also be outfitted to perform pipeline repair work.

General specifications of a floating repair vessel suitable for operating in water depths of 60 to 330 feet in Diapir area are given below.

General Specifications for a Floating Pipeline Repair Vessel.

Vessel Characteristics

Overall length	approx. 400 feet
Waterline length	approx. 340 feet
Beam	approx. 70 feet
Depth to main deck	approx. 30 feet
Draft (maximum)	approx. 22 feet
Draft (normal operating)	approx. 17 feet
Deadweight on normal operating draft	approx. 2,000 ton

Deadweight on maximum draft approx. 5,200 ton

Deck Cranes and Winches

Two hydraulic service cranes having approximately 15 and 20 ton capacity at a reach of 50 feet.

Spool piece handling davits over central moon pool each approximately 120 ton capacity.

One hydraulic deck handling winch of approximately 30 ton capacity.

Machinery

Diesel electric power units.

Operating Ice Conditions, Ice Strengthening Class, Propulsion Power and Thruster Power (Bow and Stern Thrusters).

Operating Ice Condition	Ice Strengthening Class	Propulsion Power HP	Bow and Stern Thruster Power HP
A	Non Ice-Strengthened	10,000	3,000
B	4	20,000	6,000
C	8	35,000	12,000
D	8	35,000	12,000

Mooring System

Four point mooring system with underwater fairleads.

Dynamic positioning.

Ice Load Mitigating System

Heeling tanks.

De-icing System

Steam monitors.

Deck Work Area

Totally enclosed heated deck work area approximately 200 feet x 60 feet with a load rating of 1 ton/sq foot for fabrication work.

Fully equipped work-shop of approximately 1,000 sq feet area situated at main deck level for maintenance and repair work.

Diving System

Saturation diving complex rated to 500 foot depth with 12 divers.
Diving bell provided with motion compensating main cable and guide wires.

Heated moonpool approximately 15 feet x 15 feet for diving bell.

Heated moonpool approximately 150 feet x 10 feet for spool piece handling.

Survey and Inspection Equipment

ROV complete with video cameras and recorders.

Side scan sonar equipment

Precision echo sounder

The cost and lead time required to construct and equip this vessel are estimated to be $70 million and 3.5 years respectively. The operating cost for a class 4 vessel is estimated at $110,000 per day. The operating cost for a class 8 vessel is estimated at $140,000 per day. A summary of capital and operating costs are given in table 4.2.

4.3.2 Pipeline Repair Spreads Consisting of Submarine Vessels

Each repair spread will contain:

- an autonomous pipeline repair submarine and
- an autonomous supply submarine.

A description of each submarine vessel and general specifications are given below. A summary is provided in table 4.3.

Autonomous Pipeline Repair Submarine

Autonomous work submarines are currently being manufactured or under development for offshore operations such as subsea inspection, diverless intervention, diver lockout and rescue work. One autonomous submarine now available is the SEAHORSE II submarine manufactured by Bruker Meerestechnik of Germany. A general description of this vessel is given below.

SEAHORSE II Basic Unit

Principal Characteristics

Length overall	48 feet
Width	7.2 feet

Height over conning tower	14.1 feet
Height to deck level	9.2 feet
Hull diameter	7.2 feet
Weight in air	52.3 ton
Displacement submerged	1,835 cu ft
Operational depth	650 feet
Can be increased to	1,475 feet
Payload capacity (to 650 feet depth)	5.5 to 8.8 ton
Crew	4 to 6

Electric Propulsion System

Diesel engine output	154 HP
Electric Motor/Generator	108 HP
Main propeller (hydraulic) output	108 HP
Main Propeller speed	320 rpm
Control thrusters number	4
Control thruster output	13.4 HP
Control thruster speed	500 rpm
Cruising speed (approximately)	5 knots
Range surface	400 nm
Range subsea	100 nm
Battery capacity	400 V, 1000 Ah 24 V, 165 Ah

Life Support

Oxygen	3 x 1.8 cu ft at 200 bar
Life support endurance	1,600 man hours
Air	10 x 1.8 cu ft at 200 bar

Standard Equipment

Gyro compass	Pinger locator
Radar system	Pinger release
Sonar system	Television

Electronic log	Search light
Echograph	Flash light
Depth gauges	Anchoring system
Surface radio	Release buoy
Underwater communication	Navigation lights

The general arrangement of the SEAHORSE II submarine is shown on drawing No. A-401. It is claimed to be the first custom tailored commercial autonomous submarine for underwater inspection and research work. It can operate under water with total independence for a period of about one week. The vessel can be provided with diver lockout option with a diver lockout chamber accomodating up to six divers located between the engine compartment and the central section. It is separated from the rest of the submarine by means of two pressure-tight bulkheads. In each bulkhead there is a pressure-tight door to give a passageway from the forward section to the engine compartment. The lockout chamber is operated in the following manner: during travel the divers are under normal atmospheric conditions. Once the area and depth is reached where the divers are to be deployed, the doors in the chamber bulkheads are closed and the chamber is pressurized to ambient pressure. Thereafter the lockout hatches are opened and the divers can leave the submarine within a very short time while special ballast tanks are flooded adequately. The hatches are closed again by remote control from the pilot's compartment. By means of a compressor installed in the engine room, the lockout chamber is depressurized again until atmospheric pressure is reached.

The lockout chamber can be used for decompression of divers, at least for diving up to about 160 feet.

The cost of a SEAHORSE II submarine with diver lockout feature is estimated to be $ 3.0 million. An arctic version of this unit is estimated to cost $ 5.0 million.

The factor that limits the endurance of this submarine is the capacity of the lead acid batteries that store electric power. In order to overcome this limitation Bruker Meerestechnick is developing a self contained power source consisting of a closed cycle diesel engine which can operate under water using on board fuel and oxygen supply. It is estimated that the power plant will be available for operation in about 3 years from now.

The other systems that need development are the gas recovery system and diver heating system. Development work is under way currently on both these systems. The diver heating problem is expected to be solved when the underwater power plant is available, the heat rejected from the engine being used for this purpose.

Comex of Marseille, France and Cnexo, the French state agency responsible for deep ocean technology, are currently constructing the SAGA I autonomous work submarine. SAGA I overcomes the limited power capacity of electricity storage batteries by incorporating a solution developed for the Swedish Navy. SAGA I power plant consist of two 4 cylinder, United Stirlings 134 HP, 4-275 engines, a development of the smaller 40 HP 4-95 system designed for diver lockout submersibles. The engine is based on the closed-cycle Stirling principle and offers a compact total arrangement for air-independent power supply.

The unit is reported to have high efficiency, good power to weight ratio and low noise and vibration due to the fully controlled, pressurized fuel combustion arrangements. This arrangement is dubbed the "combustion gas recirculation system" and provides the combustion control of pure oxygen under pressure. Based on supplying oxygen to the externally-heated engine, by means of a set of ejector tubes with no moving parts, this approach creates a back flow of combustion gases inside the combustion chamber to reduce their temperature to the 3632°F design level of a standard engine heater.

An advanced liquid oxygen storage system with superior insulation is another important element of the package.

The 4-275 engine for SAGA I project generates about 108 HP in continuous operation and the integrated power module/LOX system provides more than 10,000 kWh from 11 short tons of oxygen.

Measuring 4 ft x 2.4 x 2.5 ft, each power unit weighs only 1,250 lb, develops 2,400 rpm and has a combustion chamber working pressure of 319 psi.

This working pressure allows exhaust gas to be evacuated directly at depths down to 656 ft, one of the advantages of the stirling concept compared to the diesel engine in subsea applications. Below this depth exhaust gas removal is handled by a booster pump which consumes very little power because of the high inlet pressure.

The main characteristics of the SAGA I submarine are given below.

SAGA I

Principal Characteristics

Length overall	92 feet
Width	24.3 feet
Main height over conning tower	27.9 feet
Surface displacement	319 ton

Main draft	12.0 feet
Submerged displacement	600 ton
Operational depth	1,968 feet
Diving operational depth	1,476 feet

Power Generation

Main engines	2 x 4-cyl United Stirling 134 HP 4-275 engines air independent fully controlled pure oxygen pressurized combustion arrangement complete with combustion gas recirculation
Main engine power capacity	10,000 kWh
Lead acid battery power capacity	820 kWh

Propulsion

Main propellers	Two hydrostatic transmissions each 75 HP. Hydrostatic transmissions can be directly powered by main engines or by back up electric motor.

Crew

Minimum crew	6
additional crew	1
Divers	6

Speed

Normal submerged	4 knots
Maximum submerged	6 knots
Surface	7 knots

Life Support

Atmospheric compartment	25 days

Tank Capacities

Buoyancy control tanks	440 cu ft
Payload adjustment tanks	107 cu ft
Water ballast	1,764 cu ft

The manufacturing cost of SAGA I submarine is estimated to be $17.0 million.

SAGA I extends the duration of submarine vessel supported underwater work activities to over one week. The self sufficiency of the submarine depends on its particular application, the distance between the base port and the work site and the energy required to perform the repair work. For example, when the round trip distance is 200 nautical miles and the operating depth is 450 feet, self sufficiency at the work site will be 7 days with energy consumption for work equipment being 240 kWh/day. For a round trip distance of 100 nautical miles and 7 days self sufficiency at work site, the energy consumption by work equipment can be raised to 470 kWh/day.

In each case the complete power of the lead acid batteries will be reserved as back-up or for emergency use.

SAGA I is scheduled for sea trials in mid 1986 and is expected to be operational in 1987.

Though SAGA I provides a giant step in autonomous work submarine technology it still does not satisfy entirely the requirements for an autonomous submarine pipeline repair vessel capable of operating year round in Diapir Area. The SAGA I with some modifications can be used in Diapir Area as an inspection and survey submarine with limited work capability. Incorporating a dredge pump with in the submarine would allow it to carry out trench clearing work and perform simple pipeline repair tasks such as the installation of a split sleeve clamp. However, depending on the extent of the trench clearing work required, more than one trip to the work site may be necessary .

Arctic Pipeline Repair Submarine

A work submarine that is capable of carrying out pipeline repair work throughout the ice covered periods in Diapir Area must have the following requirements:

Autonomous operating period	30 days
Life support (total crew)	60 days
Maximum height	15 feet
Cargo capacity for pipeline repair equipment	10 tons
Dredge pump for trench cleaning	100 HP
Saturation diving system	12 divers
Depth capability	500 feet

In addition to the arctic repair submarine, a supply submarine will be required to supply fuel and materials for the repair submarine and for other tasks such as inspection, survey and rescue work.

A low overall height will be desirable to reduce the risk of ice keel contact when operating in shallow water. The general specifications for an arctic pipeline repair submarine are given below.

<u>General Specifications for an Arctic Pipeline Repair Submarine</u>

<u>Main Characteristics</u>

Overall length	approx. 120 feet
Width	approx. 25 feet
Main height	approx. 15 feet
Submerged displacement	approx. 800 ton
Operational depth	approx. 600 feet
Diving operational depth	approx. 500 feet
Cargo capacity	approx. 15 ton

<u>Crew</u>

Submarine operation	6
Survey and navigation	1
Diving support	6
Divers	12

<u>Life Support</u>

Atmospheric compartment	36,000 man hrs.

Speed

Normal submerged	4 knots
Maximum submerged	6 knots
Surface	7 knots

Propulsion

Closed cycle stirling engine, closed cycle diesel engine or nuclear powered.

Thrust required for towing pipeline spool pieces	1,000 lb
Dredge pumps for trench clearing work	2 x 100 HP
Hydraulically controlled dredge head support arm	1 x 50 ft reach
H-Frames for handling pipelines and spool pieces	4 x 10 ton
Hydraulic power supply for ancillary equipment	80 HP

An arctic pipeline repair submarine having the above characteristics is estimated to cost $50.0 million. The development time required is estimated at 5 years. This submarine can be developed from extensions to existing technology and no new technology will be required.

Repair Submarine Spread Support Base

The submarine pipeline repair spread must be based at a location affording easy access to the pipelines. The spread can be located at an arctic port designed for year round operation; or at a port designed for operation during low ice conditions with the submarine launching and recovery in winter months being carried out over strengthened ice; or at an offshore fixed platform with suitable submarine support facility. In this study it is assumed that the pipeline repair submarine vessel spread will be based at a port designed for year round operation. This assumption is based on the fact that year round drilling and production activities will require logistic support and such support will be provided by both sea and air transportation methods. The icebreaker vessels and supply vessels required for these operations will require a port designed for year round operation.

The second choice for a submarine base is an offshore platform. The repair submarine base requires a space approximately 150 feet by and 60 feet by 25 feet high. This space must be located below sea level with a pressure-tight door and dewatering facilities built into the chamber.

Launching a repair submarine from strengthened ice is a practicable concept. However, when the weights of the lifting and transportation equipment required are considered, the cost of this operation may appear to be very high compared to the other two methods.

4.3.3 COMPARISON OF FLOATING VESSEL AND SUBMARINE VESSEL SPREAD COSTS

The cost of pipeline repair spread will depend on the service contract in existence between the operating company and the contracting company. In this study it is assumed that the spread is contracted to perform the repair task after the detection of the pipeline damage. The total cost of the pipeline repair spread is assumed to be made up of a fixed mobilization and demobilization cost and a variable time dependent cost. Drawing No. A-402 presents a cost comparison of floating and submarine repair spreads. To derive this cost comparison it was assumed that pipeline repair vessel, supply vessel, icebreaker vessels and submarine vessels will be available in Diapir Area. This assumption was made because these vessels will be required to support other Arctic offshore activities such as drilling, platform installation and logistic functions. The estimated mobilization and demobilization costs and day rates for the various spreads are as follows:

Spread Description	Ice Condition	Mob/Demob Cost $ million	Operating Day Rate $/day (x 1,000)
Surface Vessel	A	1.5	70
Surface Vessel	B	3.5	370
Surface Vessel	C	5.5	610
Surface Vessel	D	6.5	705
Submarine Vessel	ALL	4.0	130

To compare the repair costs it is necessary to incorporate a productivity derating factor to account for the loss of productivity due to sea ice. The following productivity derating factors were used in deriving the cost comparison curves shown on drawing No. A-402.

Spread Description	Ice Condition	Productivity Derating Factor
Surface Vessel	A	1.0
Surface Vessel	B	1.3
Surface Vessel	C	1.7
Surface Vessel	D	2.5
Submarine Vessel	C,D	1.3

It must be noted that the submarine vessel assisting repair will be subjected to the danger of encountering keels of large ice masses. It was assumed that ice movement monitoring operations will be carried out at regular intervals.

4.3.4 Pipeline Repair in Ice Condition E

Pipeline repair in Ice Condition E presents the most difficult task and the greatest threat to the pipeline repair spread. Two problems that must be overcome are: accessing the pipeline if the grounded ice feature is located directly above it and the danger to the pipeline repair spread should the ice feature move under ice pressure, wind shear or current loads.

Grounded ice features are found under a number of different circumstances. The most common of these is the grounding of pressure ridges along the transition zone, also known as the shear zone. Grounded ice conditions are present every year in the tranzition zone water depth ranges from 50 to 75 feet. The pressure ridges after grounding can be subjected to movements from the build up of ice pressure behind them. These pressure ridges will vary widely in length. Grounded ridges 25 miles and 10 miles long have been recorded, though these may be extreme sizes. More typical grounded ridges are less than a mile long to about 4 miles long.

Large ice features such as floebergs and ice islands can also get grounded during storms. The storm surges allow these features to float in to shallower waters where they are stranded when the storm surges subside.

In each case the pipeline repair situation under a grounded ice feature becomes a unique problem.

Accessing Pipeline Repair Area

The major problem in all these cases is accessing the pipeline. The shape of the ice keel, the location of the pipeline repair point with respect to ice keel, and the depth of ice keel embedment into the sea floor will determine the equipment and time requirements to access the pipeline.

Two methods can be used to achieve this objective. They are:

- tunnelling under ice features and
- refloating the ice feature.

Every year grounded ice features are present across the transition zone. Accessing a pipeline in this area in winter using present day technology may turn out to be an impossible task. One method of overcoming this problem is to install a bypass pipeline parallel to the main line during the time of pipeline construction to allow a secondary flow path.

A discussion of each of these methods follows.

Tunnelling

This method can be used in the case of large ice features which show no movement. The depth of embedment of the ice keel into the sea floor must be determined and the repaired pipeline must be lowered below this level to avoid further ice keel contact with pipeline. Tunnelling across the ice keel can be accomplished using a high pressure water lance operated by manned submarine or by ROV. Currently similar techniques are used in the Canadian east coast to secure tow lines to icebergs. Once the ice keel is tunnelled the soil must be excavated and removed to expose the pipeline and to lower it below the deepest ice keel penetration. This work can be carried out by a floating vessel moored to the ice feature, by a work submarine equipped with a dredge pump or by working off the ice feature and using it as a work platform. Naturally, these operations will be very slow and therefore costly.

Refloating The Ice Feature

This method can be applied to ice features with relatively small volume. The ice excavation work can be carried out with explosives and mechanical equipment. Stability of the ice feature may pose a danger to the crew and equipment.

Bypass Pipelines

A bypass pipeline can be installed during the construction of the pipeline to provide two flow paths across the transition zone. The minimum distance between these bypass lines must be greater than the largest grounded ice feature and the maximum length of ice scour. Valves must be installed to isolate each section of pipeline in case of damage. By this means the need to access the pipeline for immediate repair can be avoided. Repair work can be carried out when the grounded ice feature moves away from the pipeline damage site under natural forces.

CHAPTER 5
REPAIR CASE STUDY

5.1 STUDY CASE DESCRIPTION

The repair study case is the Scenario A, 36 inch Oliktok point oil trunkline given in the main study report. The location of the damage was assumed to be at mile post 68.3 in 100 feet water depth. Pipeline route and bathymetry are shown on drawing No. 4-100 of the main study report.

It was also assumed that the extent of damage requires a section of pipe 300 feet long to be replaced with a spool piece. The Ice Condition present at the time of damage and repair was assumed to be Ice Condition C.

The submarine vessel pipeline repair spread was chosen to illustrate the repair scenario. This choice was based on the consideration that this spread will be able to complete the repair at a lower cost, as was shown on drawing No. A-402.

5.2 PIPELINE REPAIR SCHEDULE

The pipeline repair schedule is given on drawing no A-500. The scenario repair case begins after the detection and confirmation of a line damage. The pipeline repair work is then made up of the following tasks:

- Inspect pipeline and locate damage.
- Survey damage location and estimate damage severity.
- Evaluate collected data and prepare detailed repair plan.
- Mobilize trench clearing spread, transport and

clear trench.

- Assemble repair pipe and material.
- Fabricate repair pipe spool piece.
- Launch and tow pipeline spool piece to repair site.
- Cut and remove damaged pipeline section.
- Replace damaged section with new spool piece.
- Test repaired pipeline.
- Demobilize equipment.

Leak location survey and inspection will be carried out using a manned autonomous submarine and is assumed to take 7 days. The data obtained from this survey is used to plan the repair operation. In order to expedite the repair work, the dredging and trench clearing work is started immediately after the survey operation.

The estimated volume of soil to be dredged from the trench is 10,000 cubic yards. The estimated time to dredge this material is 15 days at an average rate of 30 cubic yards per hour under ice free conditions. This time is increased by a factor of 1.3 to 20 days to allow for work interruptions due to ice keel movements. A total of 28 days is allowed to include travel time.

Meanwhile, pipeline repair materials are assembled and a spool piece is fabricated. The repair submarine completes the trench clearing operation and returns to base for refueling and crew change. The spool piece is next transported to the work site by the off bottom tow method and pipeline repair work is carried out. The estimated time for this work is 16 days in calm open water conditions. The weighted time allowing for work interruptions is 28 days. A total of 35 days are allowed to include the travel time to and from the work site.

On completion of the pipeline repair work the pipeline is pressure tested and put back into operation.

5.3 PIPELINE REPAIR COST

Pipeline repair cost is made up of the following components:

- damage location and survey cost
- material cost and spool piece fabrication cost
- excavation and trench clearing cost
- pipeline repair spread cost
- logistic support cost and
- pipeline testing cost.

A discussion of each cost component and the pipeline repair cost estimate are given below. A summary is presented in table 5.1.

Damage Location and Survey Cost

The task will be carried out by an automonous inspection submarine at a cost of $40,000/day. The estimated time period for this work is 7 days. The cost of this operation is estimated at $280,000. This vessel is also used to provide logistic support to the repair submarine. Mobilization and demobilization costs are given separately.

Material Cost and Spool Piece Fabrication Cost

Material requirements for the repair work are: corrosion and weight coated line pipe, mechanical connectors, buoyancy tank and chain assemblies and rigging for tow out. The material cost for 300 feet long spool piece is estimated at $750,000.

Repair Spread Mobilization and Demobilization Cost

A lump sum mobilization and demobilization cost is incurred to allow for preparing the vessels for the operation, the transport of personnel and the procurement of consumables. The mobilization and demobilization of the repair vessel spread consisting of the repair submarine and the support submarine are estimated at $ 4,000,000.

Excavation and Trenching Cost

The work will be carried out using a dredge pump (100 HP capacity) mounted in the work submarine. The day rate for the submarine vessel spread was estimated at $130,000 and the duration of this activity at 28 days. The cost of this operation is $3,640,000.

Pipeline Repair Spread Cost

The same spread used for excavation and trenching work will carry out this work. The estimated time to complete the work is 35 days at a cost of $4,550,000.

Logistic Support Cost

Cost of this item is included in the excavation and repair spread cost.

Pipeline Pressure Testing Cost

On completion of the repair work the repaired pipeline must be pressure tested. The cost of the pressure test including material and personnel is estimated to be $500,000.

TABLE 5.1

PIPELINE REPAIR COST ESTIMATE SUMMARY

Item	Cost $ x 1,000
Damage location and survey cost	280
Material and spool piece fabrication cost	750
Repair spread mobilization and demobilization cost	4000
Excavation and trenching day rate related cost	3640
Pipeline repair day rate related cost	4550
Logistic support cost (inc. above)	--
Pipeline pressure testing cost	500
Total Cost	13,720