Report No. DOT/RSPA/MTB-80/1

ASSESSMENT OF

ARCTIC OFFSHORE PIPELINES

Energy Interface Associates, Inc.
PO Box 1173, Palos Verdes Estates, CA 90274

April 1980

FINAL REPORT

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State-of-the-art Arctic pipeline technology is discussed with emphasis on offshore applications in the Beaufort Sea. Environmental conditions, physical hazards (excluding military and sabotage damage), unique requirements, modes of failure and countermeasures are described. Existing US pipeline regulations are reviewed to identify pstential gaps in regulations for Arctic offshore applications. Regulations of Canada, Great Britain and Norway are also reviewed. Changes to US Title 49 Parts 192 and 195 are recommended and include addition of contingency plan requirements, low-temperature material characteristic requirements, and revised procedures for installation, testing and monitoring.

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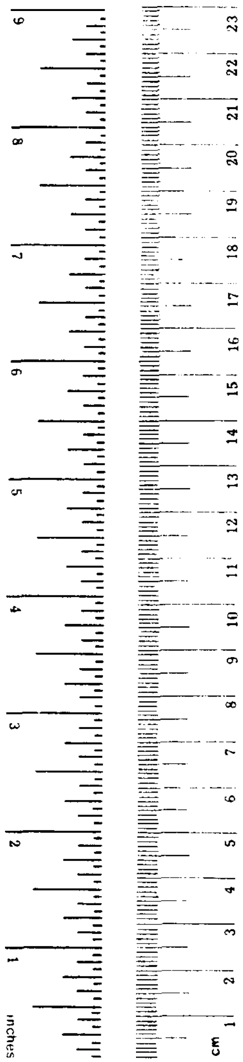
METRIC CONVERSION FACTORS

Approximate Conversions to Metric Measures

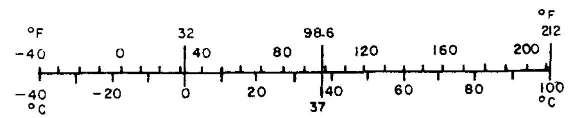
Symbol	When You Know	Multiply by	To Find	Symbol
		LENGTH		
in	inches	*2.5	centimeters	cm
ft	feet	30	centimeters	cm
yd	yards	0.9	meters	m
mi	miles	1.6	kilometers	km
		AREA		
in^2	square inches	6.5	square centimeters	cm^2
ft^2	square feet	0.09	square meters	m^2
yd^2	square yards	0.8	square meters	m^2
mi^2	square miles	2.6	square kilometers	km^2
	acres	0.4	hectares	ha
		MASS (weight)		
oz	ounces	28	grams	g
lb	pounds	0.45	kilograms	kg
	short tons (2000 lb)	0.9	tonnes	t
		VOLUME		
tsp	teaspoons	5	milliliters	ml
Tbsp	tablespoons	15	milliliters	ml
fl oz	fluid ounces	30	milliliters	ml
c	cups	0.24	liters	l
pt	pints	0.47	liters	l
qt	quarts	0.95	liters	l
gal	gallons	3.8	liters	l
ft^3	cubic feet	0.03	cubic meters	m^3
yd^3	cubic yards	0.76	cubic meters	m^3
		TEMPERATURE (exact)		
°F	Fahrenheit temperature	5/9 (after subtracting 32)	Celsius temperature	°C

*1 in = 2.54 (exactly). For other exact conversions and more detailed tables, see NBS Misc. Publ. 286, Units of Weights and Measures, Price $2.25, SD Catalog No. C13.10:286.



Approximate Conversions from Metric Measures

Symbol	When You Know	Multiply by	To Find	Symbol
		LENGTH		
mm	millimeters	0.04	inches	in
cm	centimeters	0.4	inches	in
m	meters	3.3	feet	ft
m	meters	1.1	yards	yd
km	kilometers	0.6	miles	mi
		AREA		
cm^2	square centimeters	0.16	square inches	in^2
m^2	square meters	1.2	square yards	yd^2
km^2	square kilometers	0.4	square miles	mi^2
ha	hectares (10,000 m^2)	2.5	acres	
		MASS (weight)		
g	grams	0.035	ounces	oz
kg	kilograms	2.2	pounds	lb
t	tonnes (1000 kg)	1.1	short tons	
		VOLUME		
ml	milliliters	0.03	fluid ounces	fl oz
l	liters	2.1	pints	pt
l	liters	1.06	quarts	qt
l	liters	0.26	gallons	gal
m^3	cubic meters	35	cubic feet	ft^3
m^3	cubic meters	1.3	cubic yards	yd^3
		TEMPERATURE (exact)		
°C	Celsius temperature	9/5 (then add 32)	Fahrenheit temperature	°F



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LIST OF ABBREVIATIONS

ACV	air cushion vehicle
AGA	American Gas Association
ANSI	American National Standards Institute
API	American Petroleum Institute
ASCE	American Society of Civil Engineers
ASTM	American Society of Testing and Materials
BLM	US Bureau of Land Management
CFR	Code of Federal Regulations
COD	critical crack opening displacement
CRREL	Cold Regions Research and Engineering Laboratory (US Army Corps of Engineers)
CSA	Canadian Standards Association
DnV	Det norske Veritas
DOE	US Dept. of Energy
DOI	US Dept. of the Interior
DOT	US Dept. of Transportation
DWTT	drop weight tear test
EIA	Energy Interface Associates, Inc.
EIS	environmental impact statement
g	acceleration of gravity
GMAW	gas metal arc welding
GTAW	gas tungsten arc welding
IOP	(British) Institute of Petroleum
J	joule(s)
K_{Ic}	critical stress intensity
kPa	kilo Pascal
kt	knot(s)
LAST	lowest anticipated service temperature
MOU	memorandum of understanding
NACE	National Association of Corrosion Engineers
NARL	Naval Arctic Research Laboratory
NDT	nil-ductility temperature
NRCC	National Research Council of Canada
NTIS	National Technical Information Service
OCS	outer continental shelf
OCSEAP	Outer Continental Shelf Environmental Assessment Program
OGJ	Oil and Gas Journal
OTC	Offshore Technology Conference
PB	probe boring
PH	probe hole
pc	preconsolidation pressure
po	overburden pressure
POAC	Port and Ocean engineering under Arctic Conditions
psi	pounds per square inch
SMAW	shielded metal arc welding
SMYS	specified minimum yield strength
TAPS	Trans Alaska Pipeline System
TIG	tungsten inert gas
USGS	US Geological Survey

FOREWORD

The Beaufort and Chukchi seas ajoining the northern and northwestern shores of Alaska (Figure F-1) will become, in the near future, focal areas of offshore drilling for gas and oil. The first lease sale in the Beaufort Sea took place in December 1979. Fundamental to the development and production of offshore hydrocarbon reservoirs are pipelines to transport gas/oil from offshore platforms to onshore facilities. These pipelines are of particular importance in the Arctic offshore since ice covers the seas approximately 80 percent of the year making marine transportation expensive and hazardous.

This document contains a review of the new technology applicable to Arctic offshore pipelines. The purpose of the review was to provide recommendations for updating the existing Code of Federal Regulations (CFR), Title 49 Parts 192 and 195, to reflect the current state-of-the-art technology. In the process of performing this task information/data on: (1) offshore hazards that affect pipeline design and operation was identified and analyzed, (2) new concepts for Arctic offshore pipeline construction and operation were reviewed, (3) the unique requirements of these pipelines were identified, (4) offshore failures were reviewed and summarized, (5) standards of domestic and foreign organizations were reviewed for their relevance to Arctic offshore pipelines, and (6) recommendations for research were defined. This information/data is presented in the text.

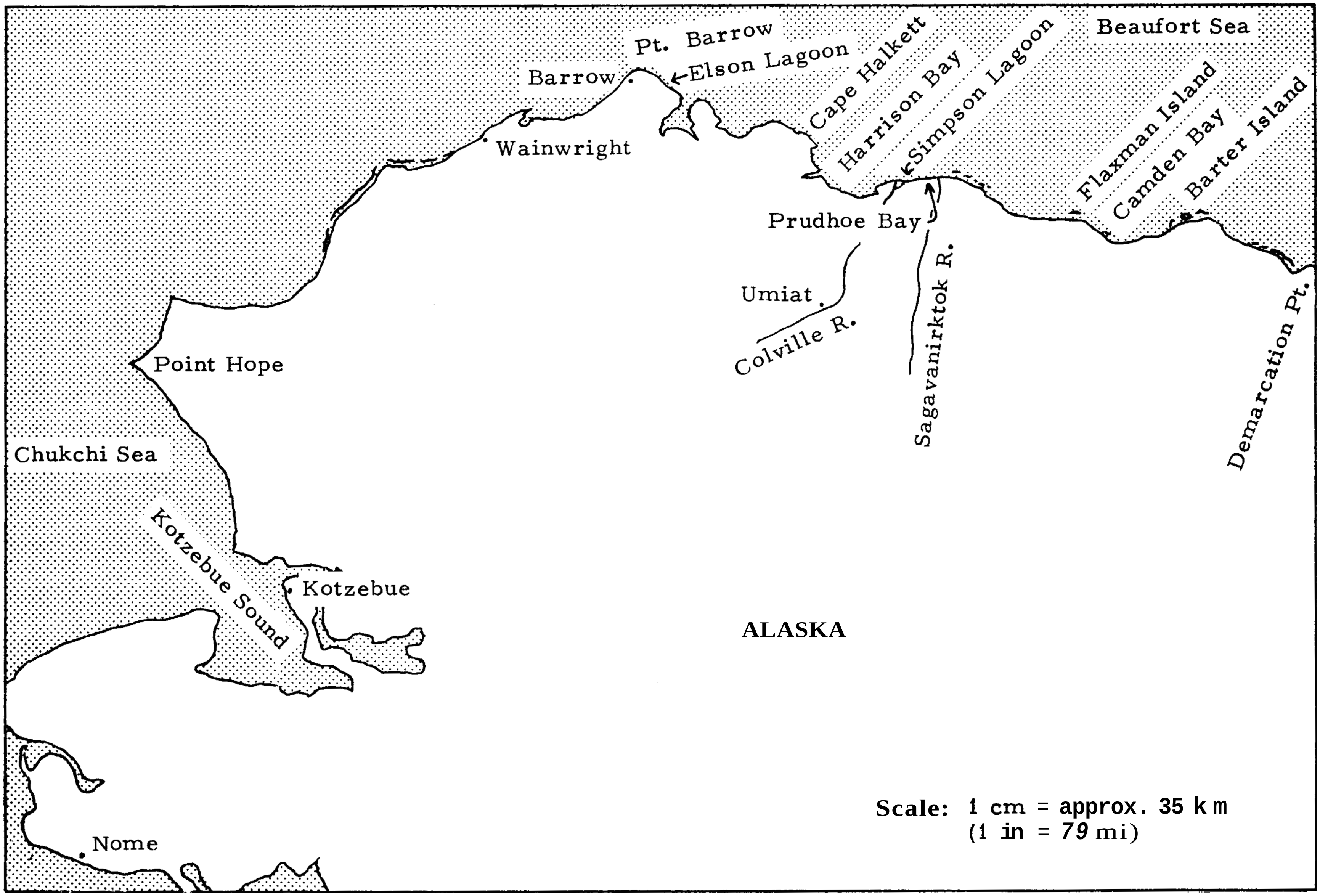


Figure F-1. Northern Alaska

I. STATE-OF-THE-ART OF ARCTIC PIPELINE SYSTEMS

The technology of gas/oil pipelines has undergone continuous development during the last 100 years. However, in recent years the state of technology has advanced significantly from the construction of the Trans Alaska Pipeline and a pilot project conducted by Panarctic Oil Company in Arctic waters.

The Trans Alaska Pipeline System (TAPS) was constructed from Prudhoe Bay to Port Valdez and completed in 1977. Many papers were written on the subject of design, construction and operation of the TAPS (Merrett, 1979; Williams, 1979; Hanamoto, 1978; Oil and Gas Journal, 1974; and Pietsch, 1973, for example). This pipeline, 1.22m (48 in) in diameter, is approximately 1300 km (800 mi) long, half of which is underground. It carries warm oil 60°C (140°F) pressurized to about 800 psi. The major problems were thermal isolation between the warm oil and the cold environment, construction on permafrost, frozen river crossings, transportation and logistics, low human efficiency, and the stringent Arctic environmental concerns.

The pilot project was of particular interest to this study because it is the first offshore gas pipeline in the Canadian Arctic Islands. This was designed for Panarctic Oil Company by R. J. Brown and Associates and completed in the winter of 1978. The pipeline is 1.2 km (0.75 mi) long and connects an offshore well with Melville Island. It consists of a bundle of pipes enclosed in a 0.46m (18 in) diameter carrier pipe. Various papers on the subject were published (Brown, 1977, 78, 79; Kaustinen, 1976; Palmer, 1979). A special method of trenching and pipe-laying was employed using ice surface as the work base. Unique designs and construction techniques were used in the subsea wellhead connection, in the splash zone and in beach area crossed by the pipe.

The experience of these two projects form a technology base for Arctic pipelines. The review of the state of technology will be confined to those areas affected by the Arctic offshore environment. They are:

A. Materials and Welding Processes
B. Pipe Laying
C. Trenching
D. Tie-Ins and Repairs
E. Sea-Bottom Protection
F. Monitoring and Surveillance
G. Environmental Impacts
H. Economics of Arctic Pipelines

Each of these areas are discussed in the following paragraphs.

A. MATERIALS AND WELDING PROCESSES

Low temperatures of the Arctic pose special requirements for pipeline materials to avoid the brittle fracture associated with high localized stresses. During transportation, storage and installation, pipe material will be subjected to temperatures as low as minus 50°C (minus 60°F). Suitable material should be selected to prevent brittle fracture at the anticipated stress levels. Low-temperature material properties and tests to demonstrate material fracture toughness are discussed on pages 4-1 through 4-5.

The low temperature fracture problem was recognized in both projected and installed Arctic pipelines. API X60, X65, and X70 steels were used in the Alyeska pipeline and were required to have a minimum Charpy V-Notch impact energy of 68J (50 ft-lb) average and 475 (35 ft-lb) minimum at minus 10°C (14°F). In addition, the Drop Weight Tear Test (DWTT), based on fracture appearance criteria on full thickness pipe specimens, was performed to insure against brittle fracture. API 5LX steel was used in the Panarctic gas pipeline and was required to have a minimum Charpy V-Notch impact energy of 345 (25 ft-lb) at minus 50°C (minus 60°F).

The proposed Alaskan Arctic Gas Pipeline (replaced by Alcan pipeline) intended to use API X70 steel for the 1.22m (48 in) diameter pipe with Charpy V-Notch impact energy and DWTT fracture requirements that ensure a minimum amount of ductile rupture based on percent of shear.

Field pipe welding and pipe bending are other processes affected by the low temperature of the Arctic. The control of thermal input during welding is important for high-grade welds. Excessive heat input may cause a substantial reduction of fracture toughness in the heat affected zone because of grain growth. Insufficient heat input could cause local hardening of the material, leading to brittle fracture susceptibility by the formation of untempered martensite (Chandler, 1976).

Above-ground welding of pipes in the Arctic is usually done in protected enclosures with pipe preheating, when necessary. In the construction of the TAPS, a special welding machine was developed for pipe alignment before automatic welding of pipe sections (Hanamoto, 1978). The Panarctic gas line was welded in a specially-constructed heated enclosure (Palmer, 1979). There is a trend in the pipeline industry for automation of pipe alignment combined with multi-pass welding controlled by a computer. Such equipment, employing hot-wire, gas tungsten arc welding (GTAW), has been described (Merrick, 1978).

The quality of the welds is critical to pipeline integrity and it is commonly accepted that 100 percent non-destructive testing (radiographic usually) of welds will be done for offshore pipelines. TAPS (although an onshore pipeline) and Panarctic pipelines followed that rule.

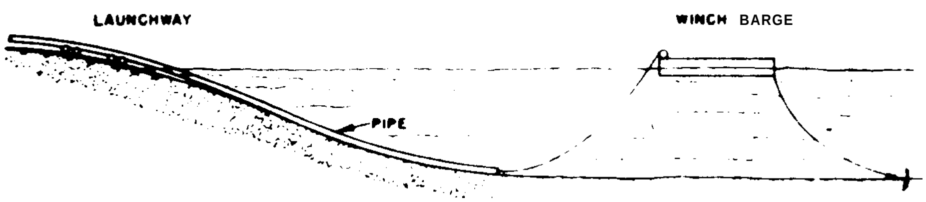
Similar caution was applied to field bending of Arctic pipelines. For example, Alyeska developed a special machine in which preheated pipes were bent to the required closely controlled curvature (Hanamoto, 1978).

B. PIPE LAYING

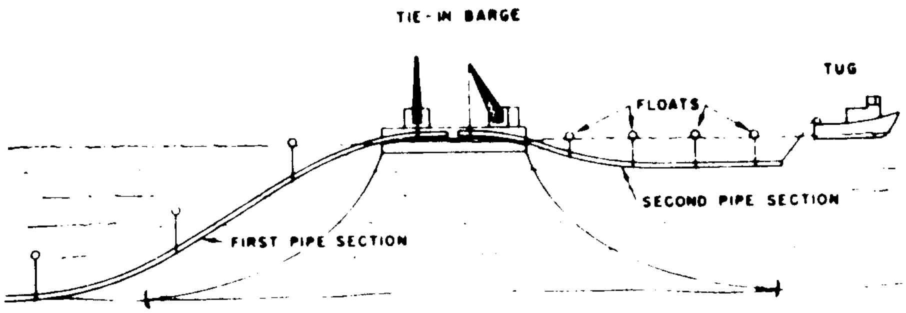
Development in the last decade of offshore oil and gas reservoirs resulted in a growing network of underwater pipelines and rapid development in pipe-laying technology. This progress was centered around laying pipes in greater water depths, improvements in the rate of laying, and increases in length and diameter. Not all of this progress is applicable to Arctic offshore. In the Arctic, it is anticipated that most of the hydrocarbon discoveries will be in water depths of less than 30m (100 ft) for the next one or two decades. The length and diameter of pipelines are not expected to break any records since the distances to offshore facilities are expected to be less than 80 km (50 mi) in the Alaskan Beaufort Sea and the pipe diameter anticipated to be less than 1.22m (48 in). However, a rapid rate of pipe-laying would be of interest in the Arctic due to the shortness of the working season. (See Section IV.B).

Figure 1-1 presents a brief review of four different methods of pipe-laying developed for non-Arctic operations.

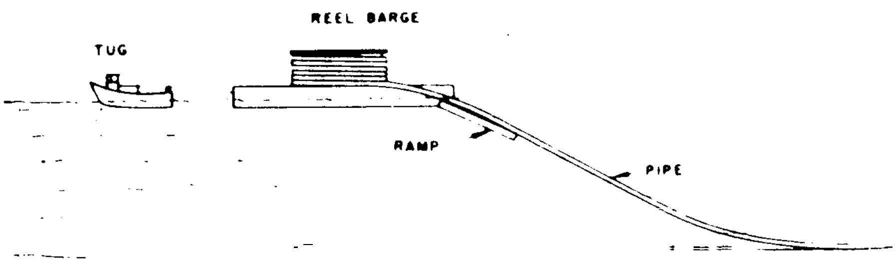
The Bottom Pull Method is shown in Figure 1-la. Lengths of pipe sections are welded onshore and then pulled along the sea bottom, from one terminus to the other. A winch firmly anchored on a barge is used as the pulling force. The length of the pipeline pulled is limited by the power of the winch and the allowable tension in the pipe. To reduce the winch



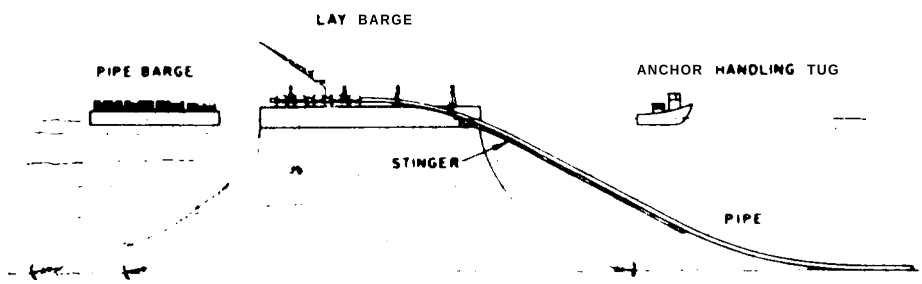
A. **Bottom** Pull Method



B. Flotation Method



C. Reeled Pipe Method



D. **Lay** Barge Method

Figure 1-1. Pipe Laying Methods (Lamb, reprinted from Offshore Drilling and Producing Technology, (c) 1976 Harcourt Brace Jovanovich, Inc, by permission loading and pipe tension, a part of the pipe can be made buoyant and lifted off the sea bottom by using floats connected to the pipe. Special precautions must be taken to prevent the damage to the pipe coating during the pull operation. This method, with advantages of simplicity and economy, is limited to relatively short offshore distances because of a rapid increase of pulling force with distance (Lamb, 1976; Brown, 1977).

In the Flotation Method (Figure 1-lb), pipe sections are welded into a number of long strings onshore. Floats are attached to provide buoyancy and the strings then are towed into position, A barge holds one end of a laid string until the next one arrives and is tied-in. Floats are released automatically to lower the pipe to the bottom (Lamb, 1976). An advantage of this method is that it does not limit pipeline length and permits a fast pipe-laying rate if the barge can be moved rapidly enough to its next position. A disadvantage is its sensitivity to sea state (Lockridge, 1977).

The Reeled Pipe Method is shown in Figure l-lc. In this case, the pipe is fabricated into a continuous length and spooled onto a large-diameter reel. The line is laid by unwinding the reel from a moving barge, in a manner similar to cable laying. Tension is applied by pipe tensioner(s) to limit the sag in the pipeline which is particularly critical in deep waters (Lamb, 1976). The process continues until the reel is empty, and repeated after the reel is refilled on the shore. Since only small amounts of plastic (1 to 2% strain) deformities of the pipe are allowed, the reel diameter must be large and the pipe size small. At present, pipes up to 0.3m (12 in) diameter have been installed by this method, although designs are available to install 0.6m (24 in) diameter pipe (Lockridge, 1977). Also, at present, equipment is available (Santa Fe Apache Strip) to reel-lay pipes up to 0.4m (16 in) diameter (Hale, 1977). The advantage of this method is a rapid rate of pipe-laying, its disadvantage is limited pipe diameter and inability to lay concrete coated pipes.

The Lay Barge Method (Figure 1-1d) is most commonly-used to lay larger-diameter pipes in the open sea. Pipe sections are joined on the barge in multiple welding stations so that the laying process is continuous with intermittent barge movement. Radiographic inspection of welds and coating of welded joints are a part of this process. The barge is advanced periodically by winching in the anchor lines and the pipe is lowered through a pontoon support (stinger) or by inclined ramps. Tension is applied to the pipe to control its sag curvature and bending stresses.

Pipe-laying in the Arctic offshore regions requires innovations and/or modifications of the existing methods. During open-water season, lay barges could he used with reinforced hulls to withstand the impact of small ice floes. Because of the short duration of that period it may be necessary to dig the trench for a buried pipe in the previous season. Another alternative of a bottom tow, is shown in Figure 1-2. It is assumed that a length of a pipe has to be installed joining a previously laid nearshore pipe with an offshore structure. Again, because of the short season, pipeline strings are stored in a trench from previous seasons, ready for immediate installation. An ice-strengthened vessel deploys a plow to cut a trench and pulls the strings into position as shown. Strings can be joined by welding or by mechanical connectors and this technique allows the application of bottom pull method to longer pipelines.

During the long Arctic winter season advantage could be taken of the ice, which covers the sea 80 percent of the year,

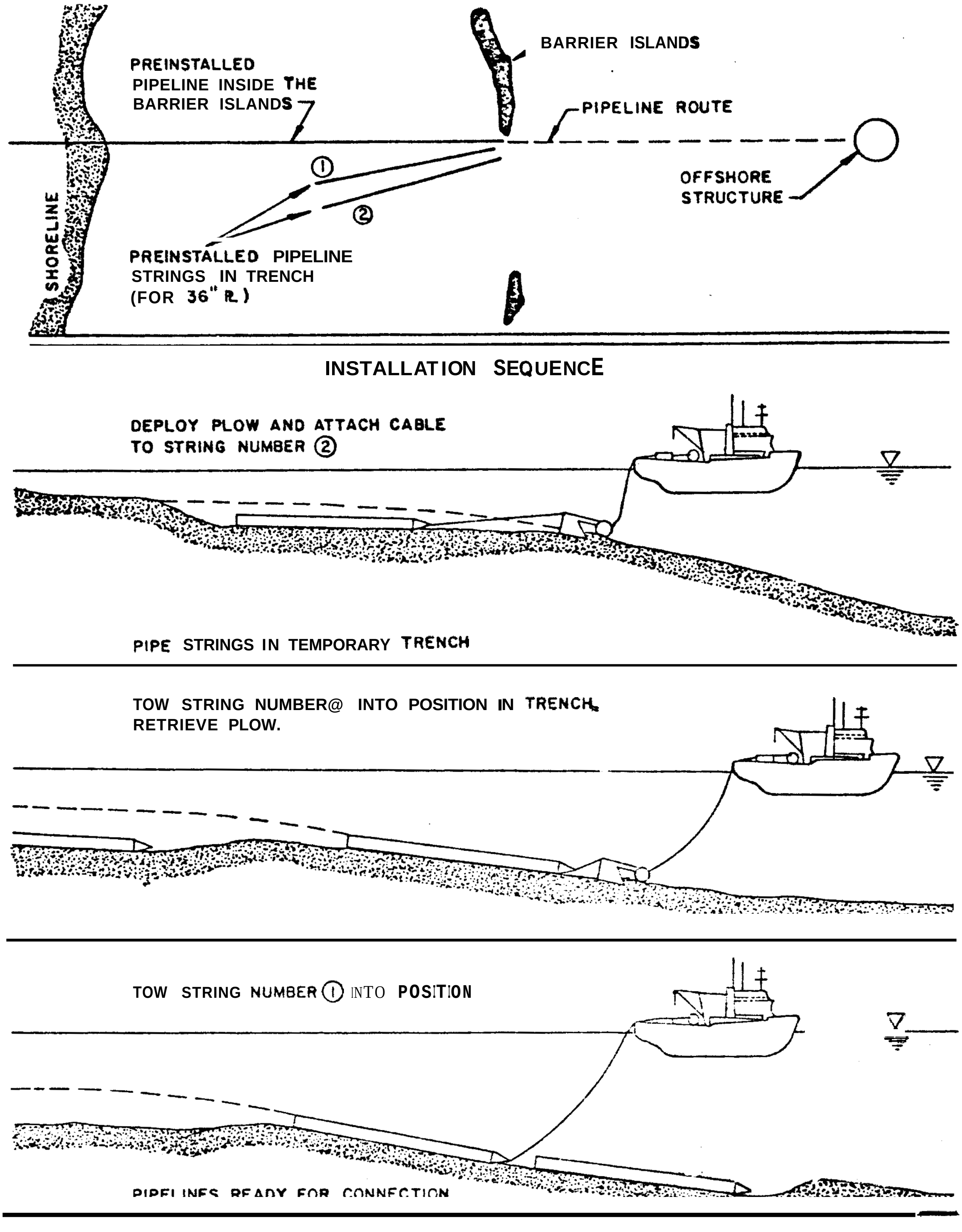


Figure 1-2. Towing Method During Open Water Season (R. J. Brown, 1979)

as a work platform. A pipe-laying technique based on this approach is shown in Figure 1-3. This involves a pipe pulling technique where the pipeline is assembled onshore and is pulled to an offshore location. Pipe strings of approximately one mile in length are welded on a shore ramp to form a continuous string of up to 10 miles long. Winches or gripper jacks are placed on thickened ice platforms, and a specially designed trencher is used to cut a slot in the ice for the pull cables. The cable is attached to the pipe string head and to a surface sled. The sled is pulled by a pair of winch-operated surface cables anchored to gripper jacks. This method is Arctic adaptation of bottom tow techniques and offers similar advantages and limitations.

Such a method was developed by R. J. Brown and Associates in the installation of the Panarctic gas line (Palmer, 1979). With the bottom tow, the connection of the pipe to the wellhead cannot easily be done by direct pull because the line would tend to stick and then to surge forward in an uncontrolled manner (Palmer, 1979). To avoid this, a lateral pull technique was employed by R. J. Brown and Associates for the Panarctic gas line. The pipeline first was pulled straight to a target displaced laterally 55m (180 ft) from the wellhead. By means of a separate ice-mounted winch, it then was pulled sideways forming an arc until the pipehead met the wellhead (Figure 1-4). A detailed description of the process is available (Brown, 1977).

For short lines, the pipe may be made up on the ice and lowered into position through a trenched slot in the ice. This method is most suitable in shallow protected waters having a smooth non-moving ice cover of near uniform thickness.

In contrast to the sheltered nearly-static ice in the Panarctic gas line area, the ice surface in the Beaufort Sea particularly outside the Barrier Islands is dynamic, and small

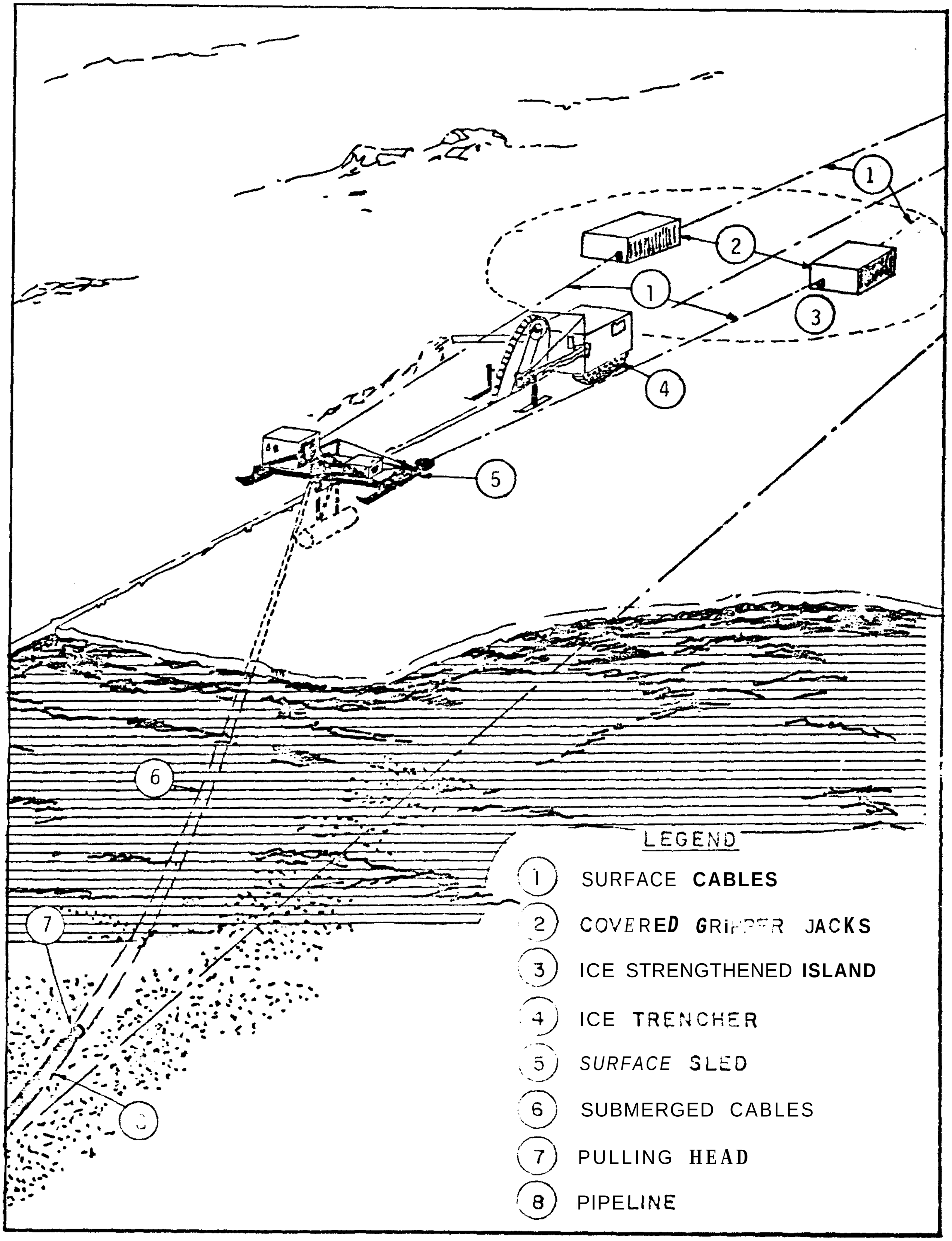


Figure 1-3. Pipe Laying From Ice During Winter Season (R. J. Brown, 1979)

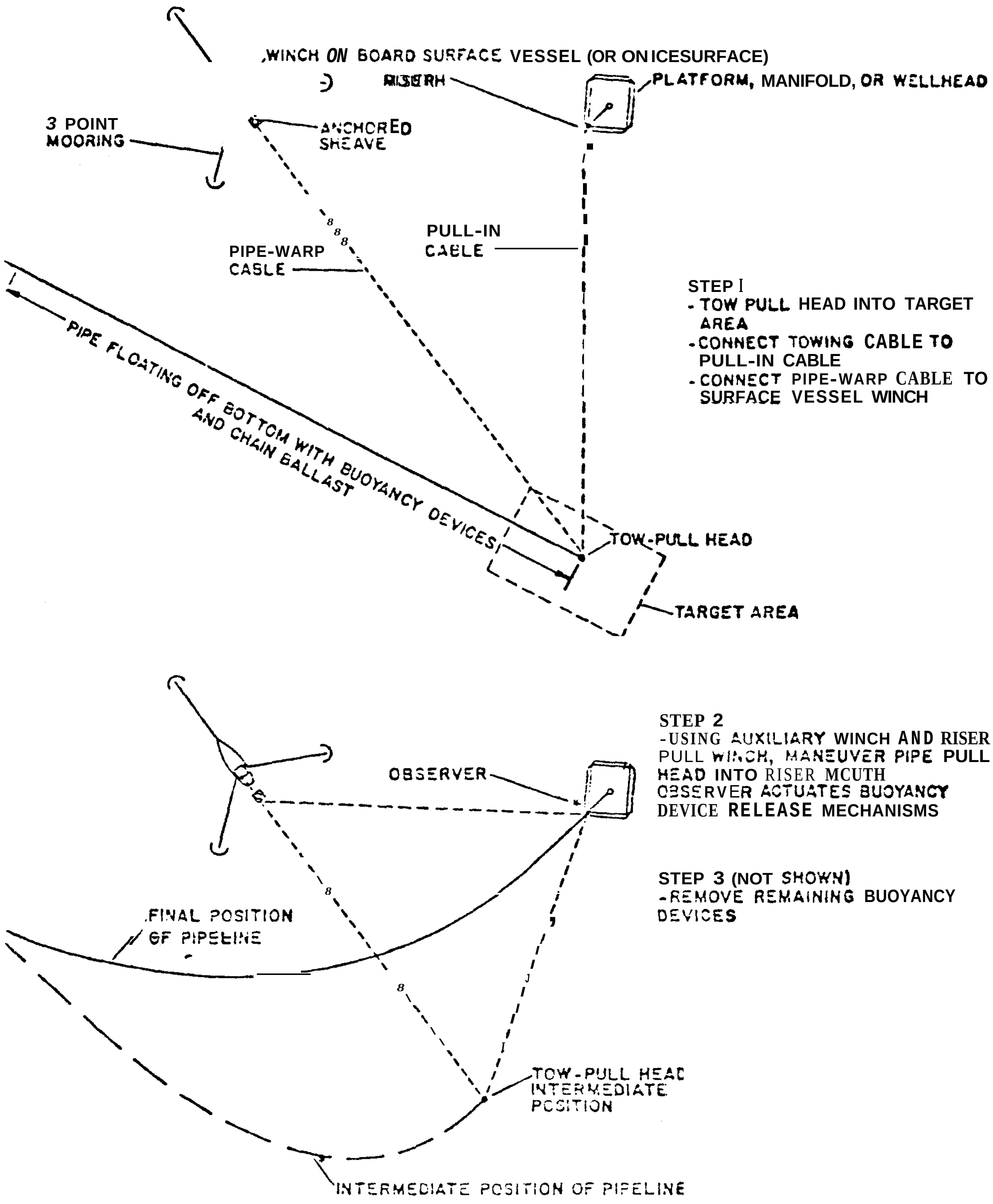


Figure 1-4. Diverless Pipe/Riser Connection (R. J. Brown, 1979)

to large movements occur frequently. This must be taken into account in any operation involving construction on ice, and suitable contingencies provided for.

In pipe-laying technology there are four areas requiring careful analyses and solution: (1) prediction of pipe stress during installation; (2) control and knowledge of exact pipe location throughout the operation (important when laying into pre-trenched ditch); (3) joining with an offshore riser; and, (4) protection of applied coatings. The technology for Arctic offshore pipe-laying is in its infancy, but the strong technical base acquired from offshore operations in other areas gives a reasonable assurance that pipe-laying in the Beaufort Sea can be accomplished successfully.

C. TRENCHING

Trenching in Arctic waters can be done with existing equipment although in some cases, it must be modified for ice operation and to withstand the severe Arctic environment. This subject is covered well in literature (Mellor, 1978; Brown, 1977; Lockridge, 1977; and Hironaka, 1974).

Pre-trenching (preparation of a trench before the pipe is laid) may be advantageous in the Arctic because it could be done in one season and the pipe laid in the next. The small amount of soil movement occurring on most of the Beaufort Sea bottom provides assurance that the trench will remain open, requiring only a cleanup before pipe-laying. However, with pre-trenching, the pipe-laying must be accurate, and the pipe must be guided to fit into the trench. The pre-trenching can be performed with suction cutter dredges, bucket dredges, clam shells, backhoes or plows. Most of these devices, especially the cutter dredges and backhoes, could trench in "soft" permafrost, but the use of plows may not be feasible in this type of soil unless preceded by a ripper plow. Where plowing is possible, the equipment employed will depend very much on the bearing strength of the seabed. For instance, Figure 1-5 shows a plow for stiff clay, and Figure 1-6 a plow with a large bearing surface for soft clays.

A few words should be said about trenching in "hard" permafrost or in rock. The main methods used here are drilling or blasting with shape charges (Mellor, 1978). A successful development of controlled shape charge blasting in frozen ground has been described (Oriard, 1979).

Post-trenching is done after a pipeline is laid on the bottom. Its chief advantage is the elimination of problems involved with accurate placement of a pipeline in a trench. Here, gravity causes a pipe to sink into a trench dug below it. Post-trenching can be performed by straddling the pipe with a plow, or with a sled carrying powerful water jets and a spoil removal system. The sled is pulled along the pipeline route by a surface barge containing high-pressure water pumps connected by hoses to the nozzles on a sled. The cuttings are removed by airlift, suction-dredge pump, or water education (Lockridge, 1977). Figure 1-7 shows a typical water jet-trenching arrangement. There is on-going development with jet-trenching for deep waters, and self-contained sleds with electrically driven water pumps are now being tested (Brown, 1977).

In view of the technology available, trenching in the Beaufort Sea for offshore oil/gas pipelines should not present any major problems. Trenching in onshore permafrost, in particular, was carried out successfully onshore over many miles of the TAPS.

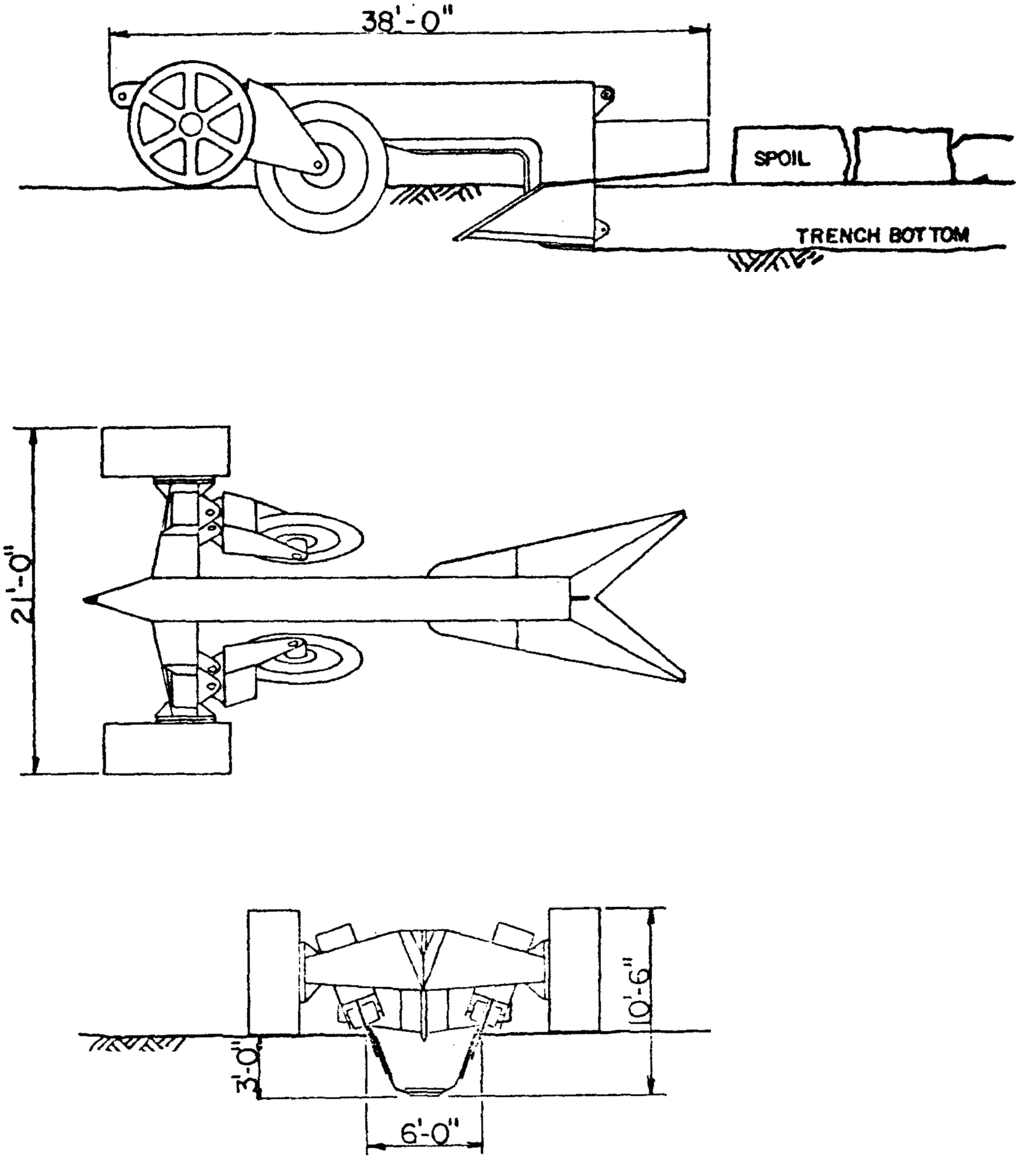
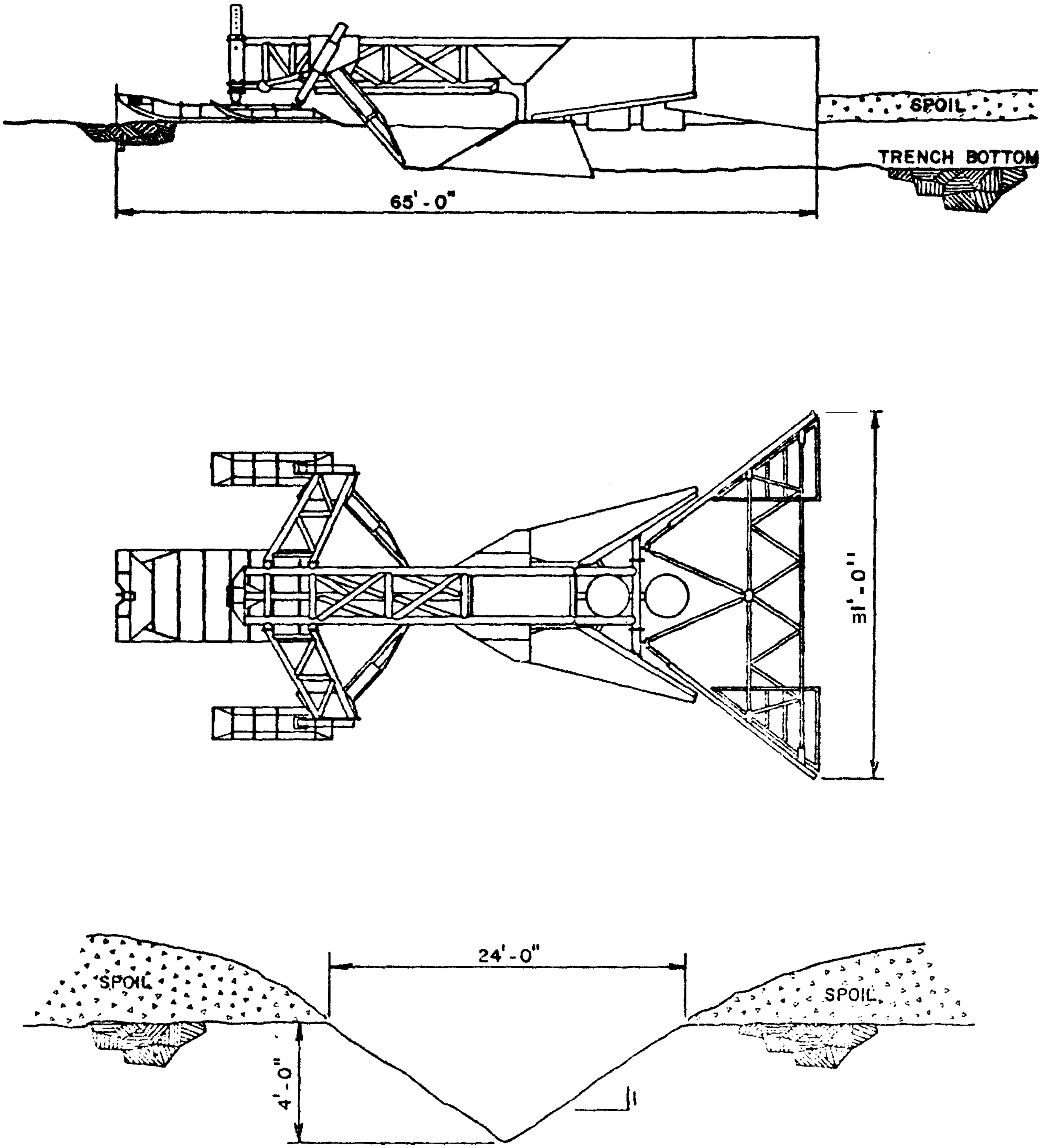


Figure 1-5. **Typical** Plow **for Stiff Clay** (R. J. Brown, 1979)



TYPICAL TRENCH **CROSS** SECTION

Figure 1-6. Plow **for** Soft **Clay or Granular Soils** with **Typical Trench (R.** J. **Brown, 1979)**

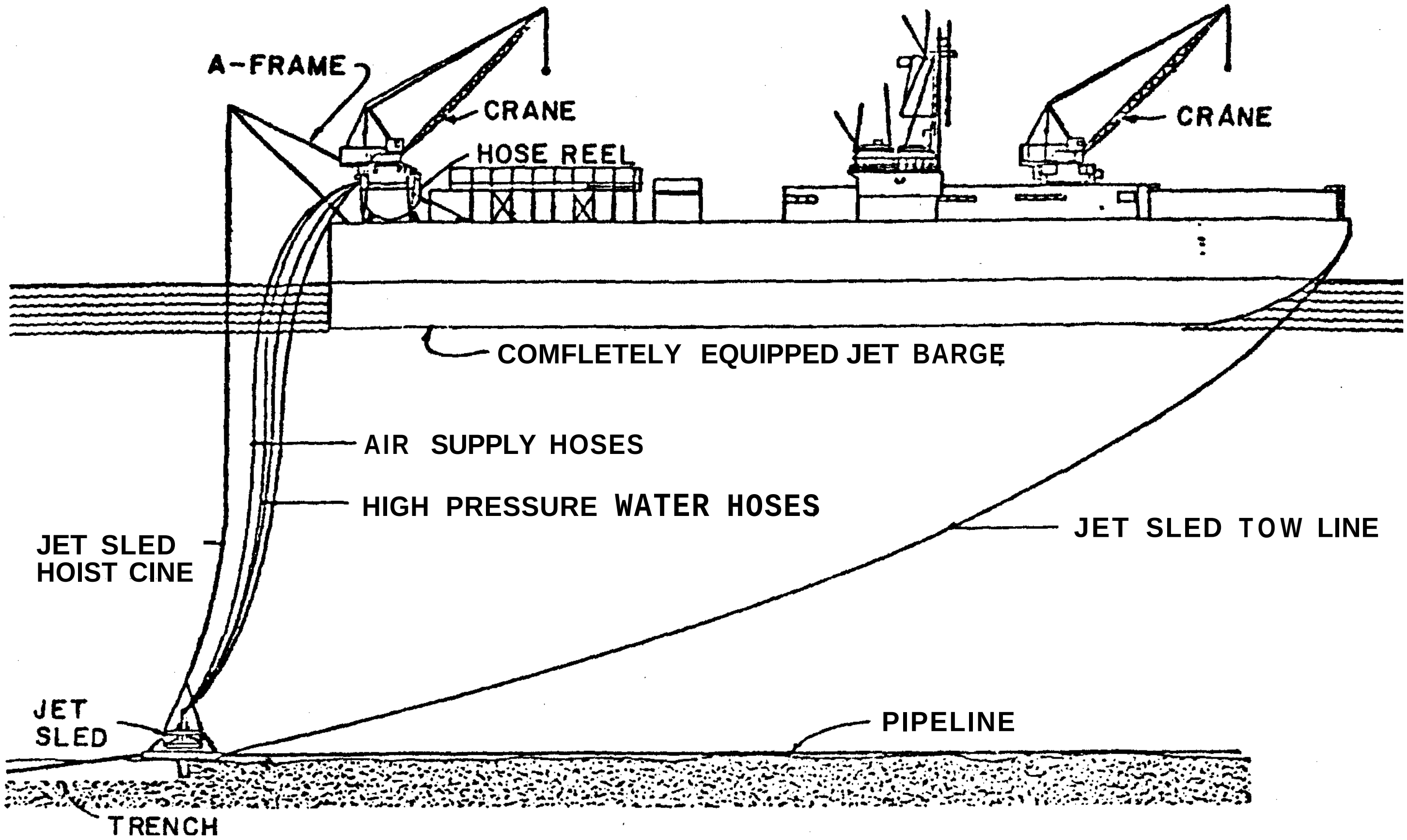


Figure 1-7. High Pressure Pipe Jetting (R. J. Brown, 1979)

D. TIE-INS AND PIPE REPAIRS

Joining sections of a pipe to form a string, then connecting strings to produce a pipeline and forming joints between the pipe and an offshore riser all have received a great deal of attention in offshore pipeline technology. The joints can be mechanical connectors, forged connections or weldments. Presently, with the development of underwater techniques, welding of pipe sections and pipe strings is the preferred method from a reliability standpoint.

Pipe tie-ins and repairs can be done either on the surface or on the sea bottom. The first method involves lifting the pipe ends or section of pipe needing repair onto a barge where the required welding is done. Figure 1-8 illustrates this procedure. A detailed description of deep-water pipeline tie-in in the North Sea, and the use of a curved tie-in spool piece, have been reported (Swank, 1979). Of course, mechanical joints, such as those described below, also could be used, but where technically feasible, surface weldments are considered more economical and reliable. In deep water, repairing or joining of pipes is performed on the sea bottom where the pipe essentially is left in situ, and a separate piece is either welded or mechanically joined to the pipe ends.

All mechanical connectors presently require some diver's assistance. Typical mechanical connectors which require the least surface support equipment are shown in Figures 1-9 and 1-10. Both rely on a ball and socket for angular alignment and include hydraulically assisted locking devices.

A variation of the ball and socket joint is the weldball in which a ball and socket are aligned and then the ball joint is welded in situ with diver assistance.

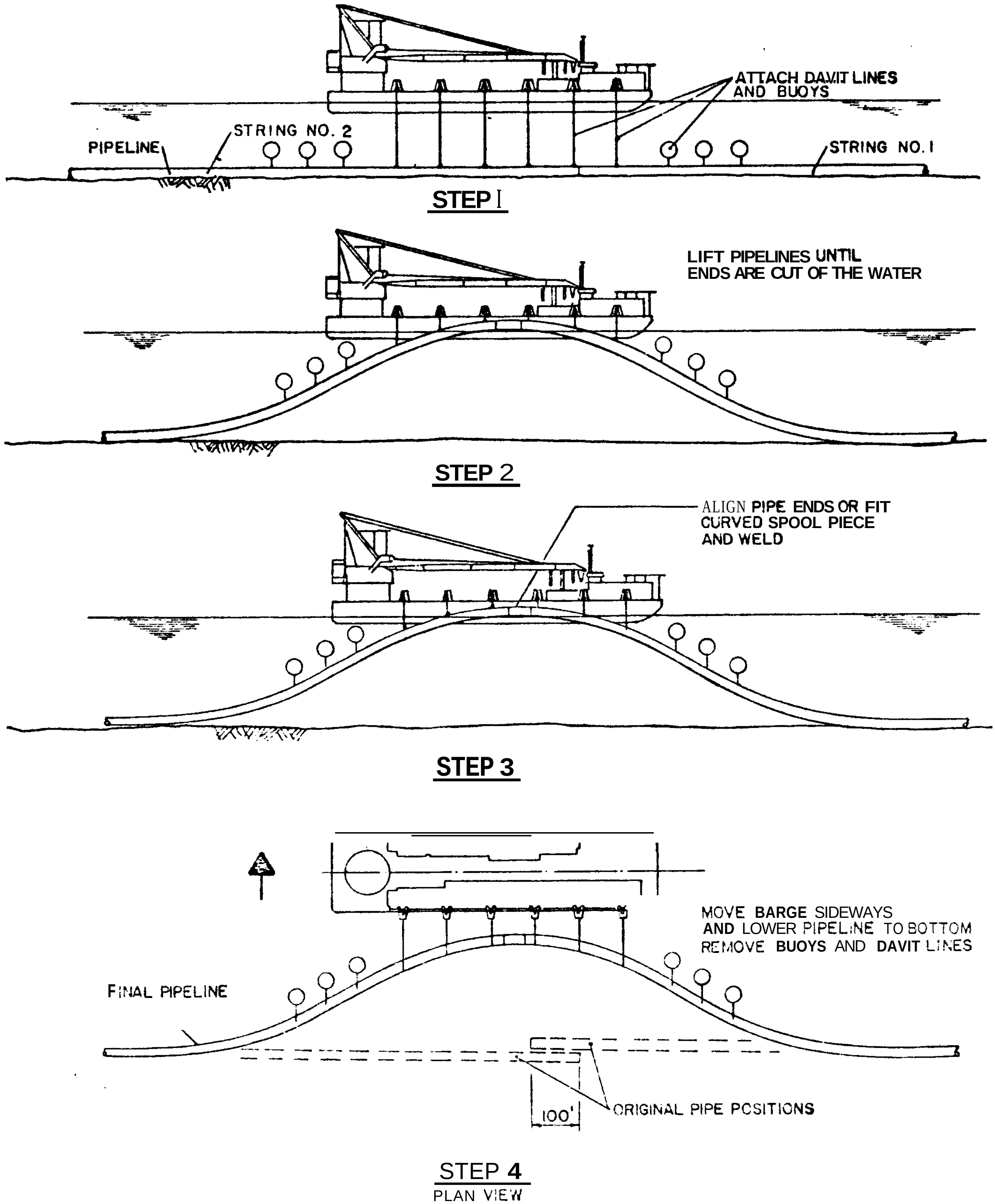


Figure 1-8. Surface Tie-In Procedure (R. J. Brown, 1979)

NOTES:

1 BOTTOM MANIPULATING FRAME (BMF) POSITIONED ONTO PIPELINE OR SPOOL PIECE.

2 HYDRO-BALL MALE AND FEMALE SECTIONS ARE CONNECTED BY USING HYDROCOUPLE HYDRAULIC RAMS CN THE SPOOL PIECE

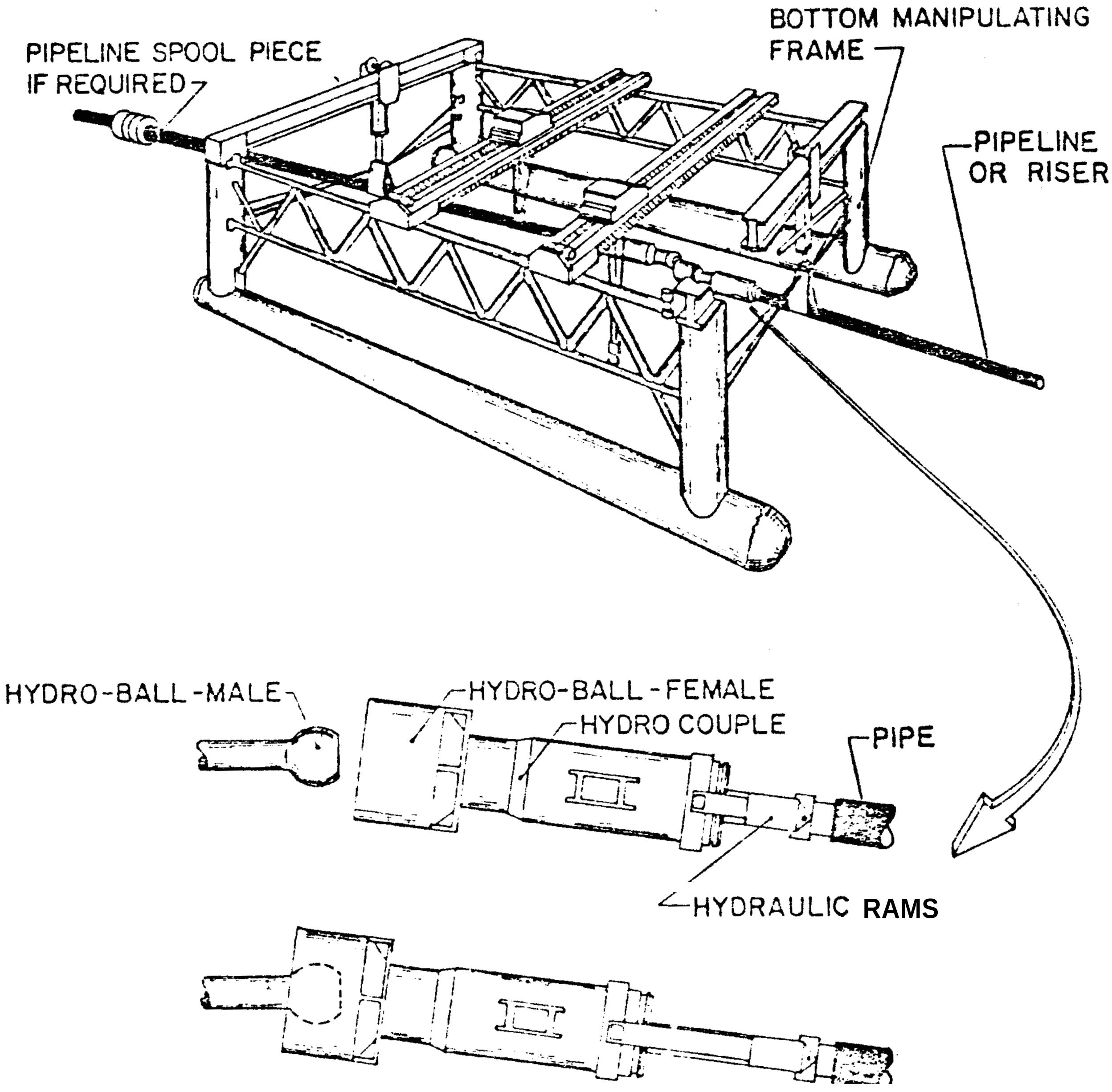


Figure 1-9. Mechanical Ball and Socket Connector (R. J. Brown, 1979)

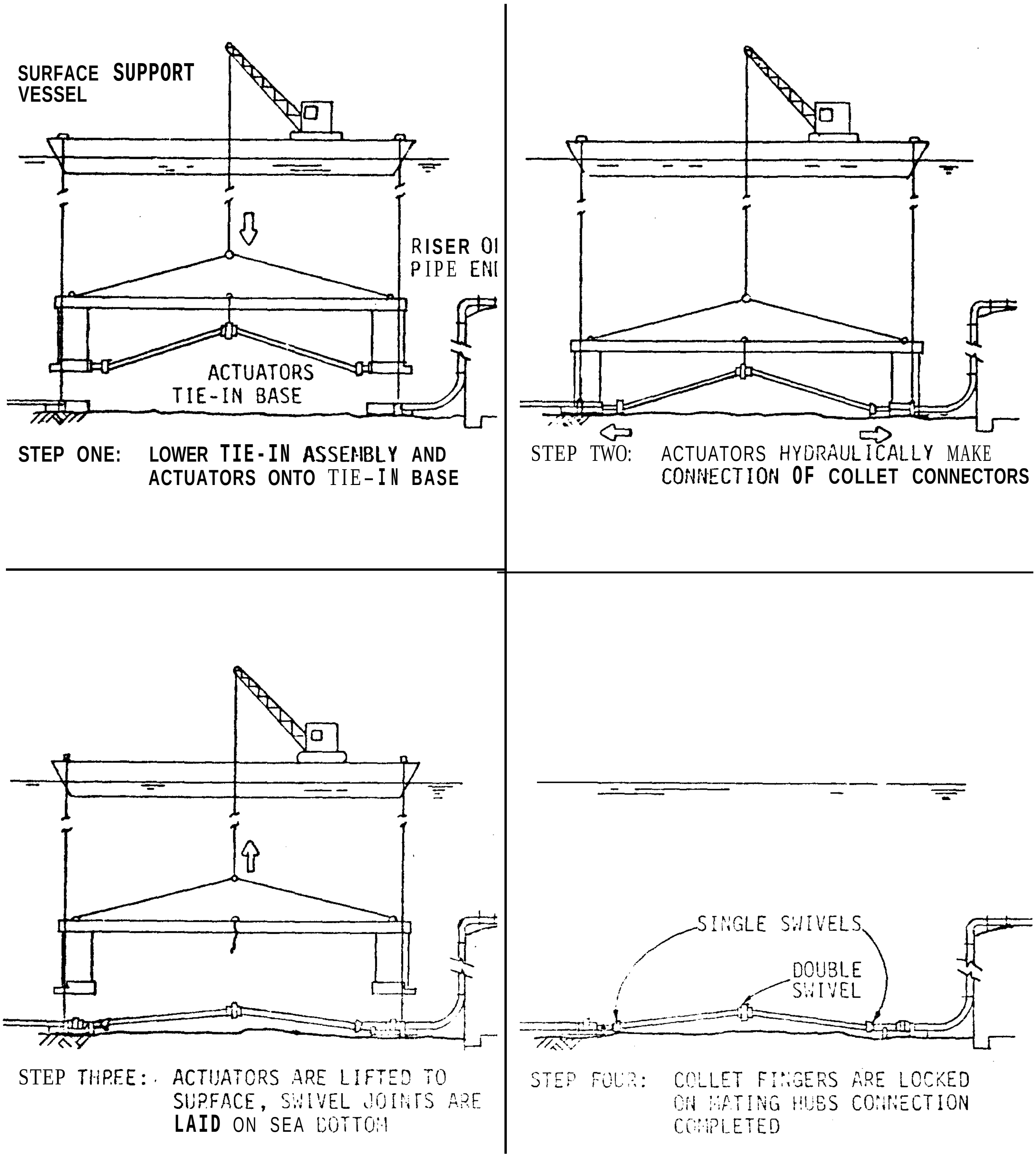


Figure 1-10. Diveriess Mechanical Connection (R. J. Brown, 1979)

Underwater welding, which has undergone substantial development recently, can be either "dry" or "wet." The dry welding is performed in a habitat which is either at hyperbaric pressure (i.e., pressure equal to the hydrostatic pressure at a given depth maintained with either breathable or inert gas with welders' own air supply) or is maintained at atmospheric pressure, The underwater equipment consists of a frame for aligning the pipe ends and the habitat where welding is performed. Figure 1-11 shows a hyperbaric habitat and Figure 1-12 an atmospheric one.

"Wet" pipe repairs can be made by underwater welding (Redshaw, 1978; Delaune, 1978; Corriatt and Bellamy, 1978; Merrick, 1978). The problems and solutions to a satisfactory wet welding technique have been discussed (Stepath, 1977). The main difficulty was rapid quenching resulting in hydrogen entrapment in the welded area. Surrounding the welding spot with a gas bubble and maintaining stability of this bubble was one of the approaches discussed. An overview of underwater welding techniques (Mohr, 1978) described the work of various companies using such methods as TIG (tungsten inert gas), SMAW (shielded metal arc welding), GTAW (gas tungsten arc welding), and GMAW (gas metal arc welding).

Another underwater method is explosive welding (Redshaw, 1978). The advantages claimed for this are both its simplicity, since no skilled welders are required, and the accurate control of the impact pressure between the flyer plate and the target by the gap between them.

Thus, for Arctic offshore pipelines, various options are available for tie-ins and repairs. Although the summer season is short, on-surface weldments could be considered, and the shallowness of the water should make such an operation fairly easy. In the winter season, when the surface is covered with thick and often moving ice, surface operation would be hazardous.

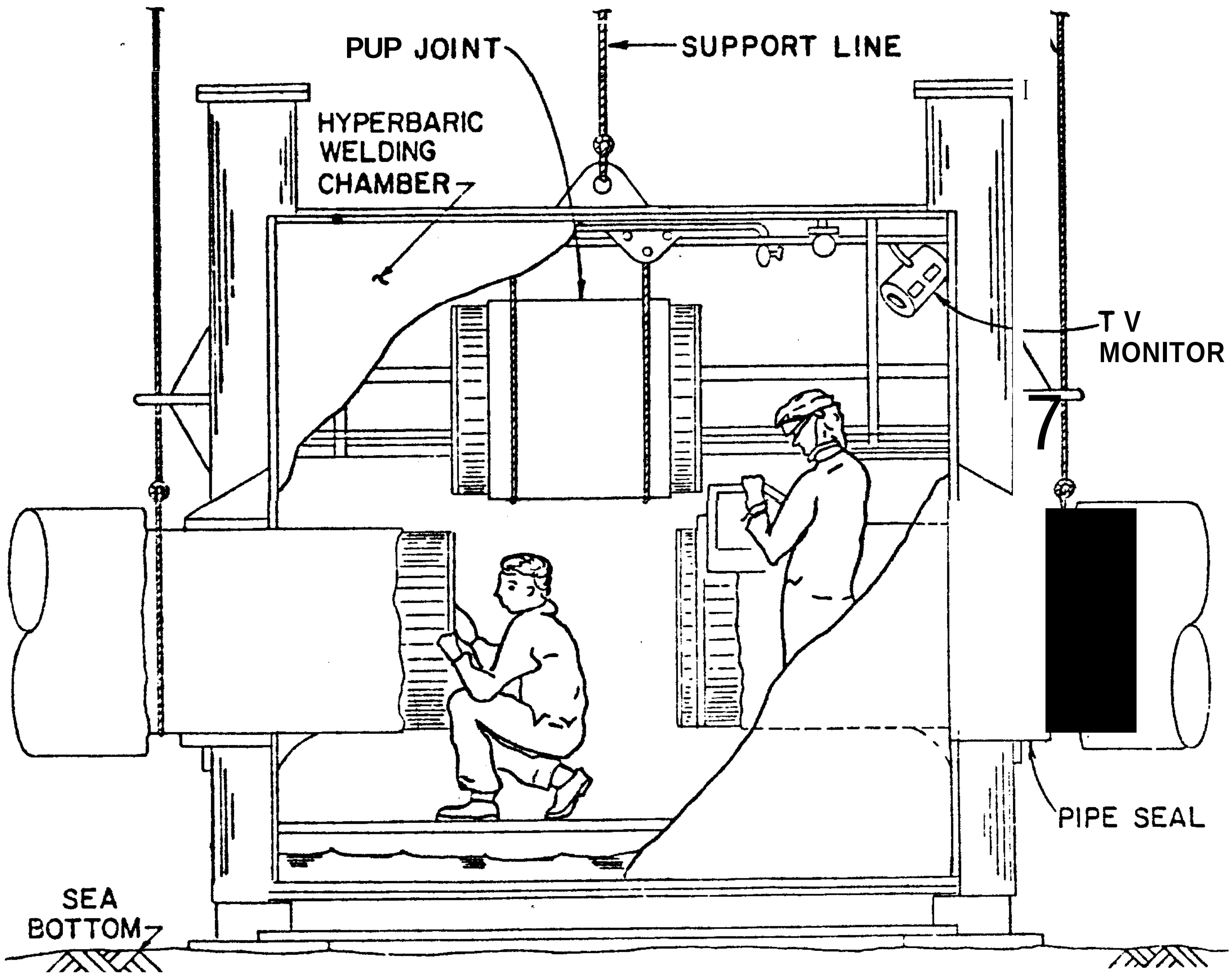


Figure 1-11. Hyperbaric Welding Chamber (R. J. Brown, 1979)

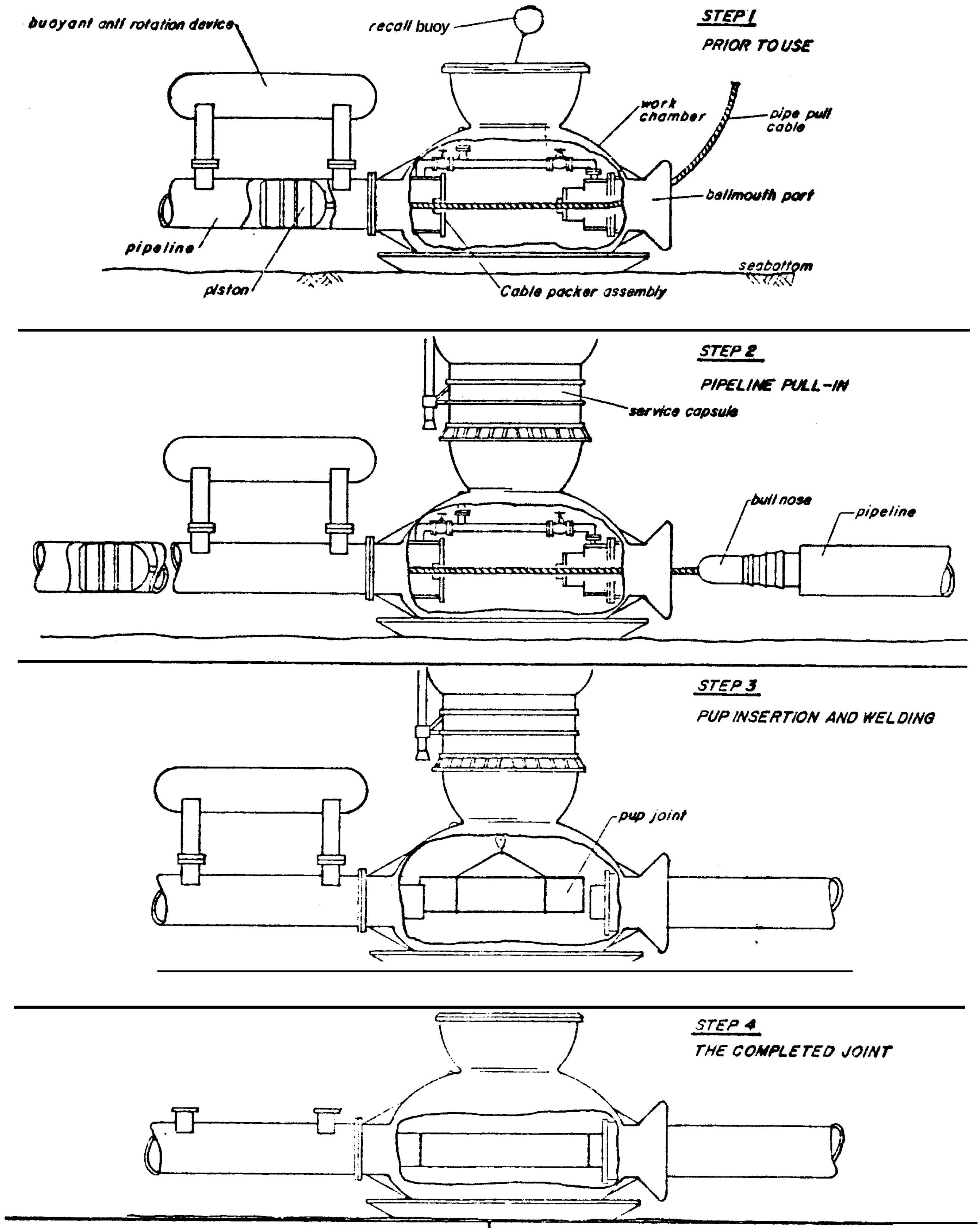


Figure 1-12. Subsurface Welded Connection at Atmospheric Pressure (R. J. Brown, 1979)

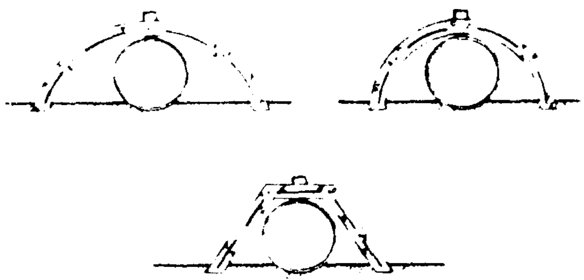
Underwater joint-completion with or without diver assistance probably would be the preferred method. Whether the joint is mechanical or welded depends on the location of the pipe, climate conditions, equipment availability, logistic support, and the economics of the operation, Whatever method is used, the operation should be planned well and completed in the shortest time possible to minimize the hazard of ice movement.

E. SEA BOTTOM PIPELINE PROTECTION

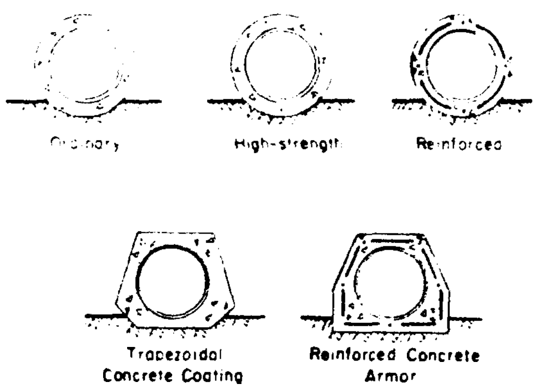
Protection of an Arctic offshore pipeline against damage from ice scouring the sea bottom is very important and is discussed in Section II.B.

Both buried and unburied pipes can be protected well. Various methods applicable to unburied pipes have been discussed (Mellor, 1978) and are shown in Figure 1-13. In one of these (Figure 1-13a) the pipe is ballasted with additional steel or iron, then covered with a reinforced concrete cover. Protection against waves and currents can be provided by either standard concrete weight coating or reinforced concrete coating. The weight coating can be shaped into trapezoidal form to minimize wave and current generated lift forces (Figure 1-13b). Finally, the pipe could be protected by a berm using granular fill and riprap (Figure 1-13c). The buried pipe is protected by being lowered into a trench of sufficient depth to safeguard against ice scour, anchor fouling or soil erosion in the surf zone. Covering the trench may be necessary in some areas, such as shipping lanes, beach approaches, or high-frequency ice scouring zones, to enhance the efficiency of the protection.

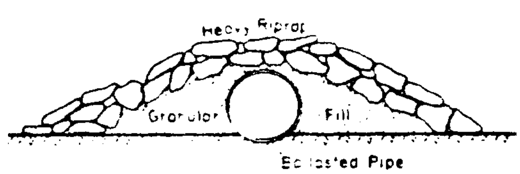
For Arctic offshore pipes the crossing of a beach is particularly hazardous because, in addition to the surface erosion, there is the possibility of ice invading the shore, scraping it and piling up at some distant island. As mentioned before, on page 1-1, R. J. Brown and Associates developed



A. Ballasted Pipe with Reinforced Concrete Covers



B. Ballasted Pipe with Different Concrete Coatings



C. Berm Protection

Figure 1-13. Protection Arrangements for Unburied Underwater Pipelines (Mellor, 1978) special precautions with the Panarctic gas line by covering the pipe with a massive, artificially formed block of ice and soil. Another solution is shown in Figure 1-14b where the pipe in its onshore approach is placed in a short tunnel excavated by directional drilling from onshore. If the pipeline is not very long, a tunnel to contain it may be considered (Figure 1-14e). Other methods of protection shown in this figure have already been discussed.

In summary, technology for protection of Arctic offshore pipelines is available, and the method adopted will depend on pipeline location and the economics of construction and maintenance,

F. MONITORING AND SURVEILLANCE

In monitoring a pipeline quantitative performance data are obtained from instruments located at appropriate points (Williams, 1979). Surveillance, on the other hand, consists of visual, acoustic or magnetic observations which provide qualitative information on pipeline location, structural integrity, and oil/gas leaks. For offshore pipelines, instrumentation usually is provided on both underwater and onshore locations to measure pressure, flow and temperature. Data are transmitted either continually or intermittently to a central control room.

Of special interest in the Arctic pipelines is the development of a "superpig" by the Alyeska Pipeline Service Company to detect any changes in the curvature of the pipe caused by pipe sagging (Anderson, 1979). The superpig operates on the differential arc method and consists of three sections; the battery, the transducer, and the instrumentation and data recorder portion. Tests with the superpig were, at present, not successful and future use of this device is uncertain.

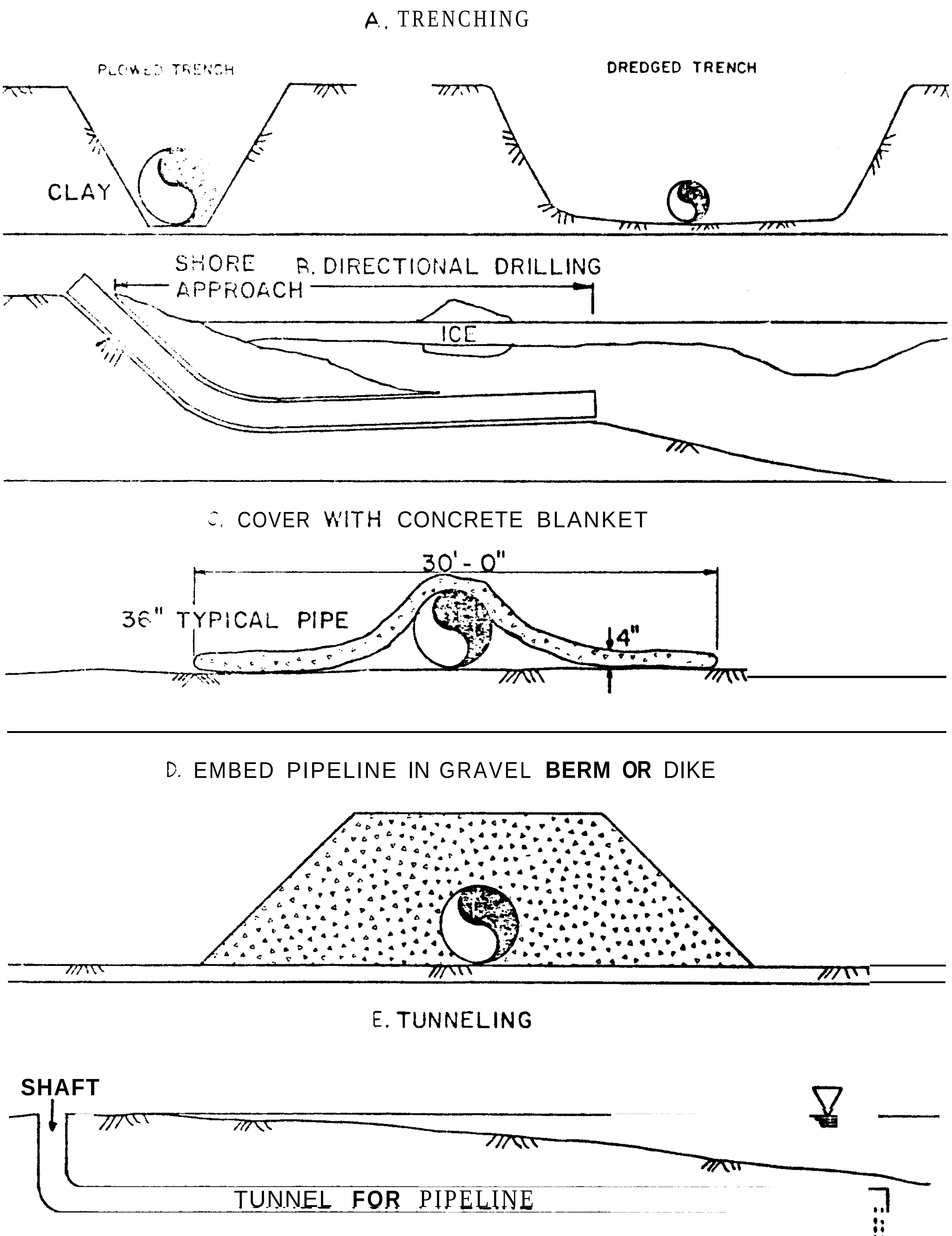


Figure 1-14. Pipeline Protection Methods (R. J. Brown, 1979)

Surveillance of underwater pipelines can be done either from the air, the sea surface, or underwater. Aerial surveillance would locate oil leaks and perhaps gas leaks if they were large. In the Arctic Ocean, where ice covers the water surface most of the year, the usefulness of aerial surveillance would be limited to those cases where the oil leak is large enough to penetrate through cracks in the ice. Although developmental work is being done through ice oil detectors (Spill Technology Newsletter, Vol. 4, March-April 1979) useable equipment is not yet available.

Surveillance from the sea surface may be carried out with side-scan sonar equipment with the support of a surface vessel. Figure 1-15 shows a schematic arrangement of such equipment. The electronic portion is installed on the survey vessel and the sonar transducer "fish" is towed behind it. An acoustic overview provides means for assessment of any exposure of the pipe, extent of burial scouring in the vicinity of the line, obstruction, and large-scale pipe movement (Brown, 1977).

Underwater inspection can be performed by divers, by manned submarines or by unmanned tethered or self-propelled underwater vehicles. Side-scan sonar and magnetometers are used and acoustic transponders may be mounted near or at the pipe to assist in its location (Brown, 1977; Durand and Stankoff, 1978). An underwater vehicle using side-scan sonar is shown in Figure 1-16. An echo sounder mechanically scans the pipe in a plane perpendicular to the axis of vehicle travel, at 40 times/sec, measuring the distance to the seabed while simultaneously recording the scanning angle. The sea bottom profile obtained is shown in the bottom part of Figure 1-16.

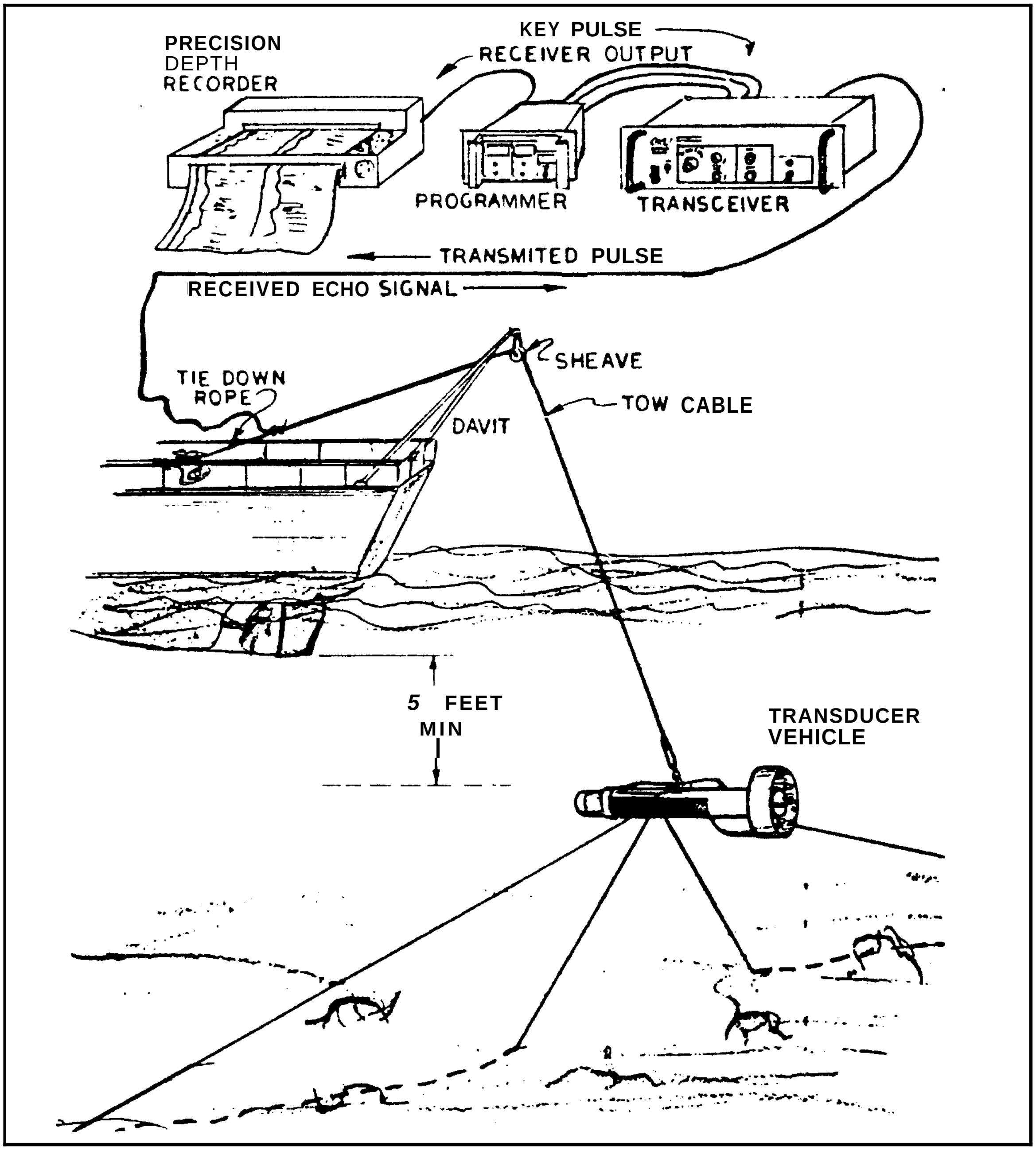
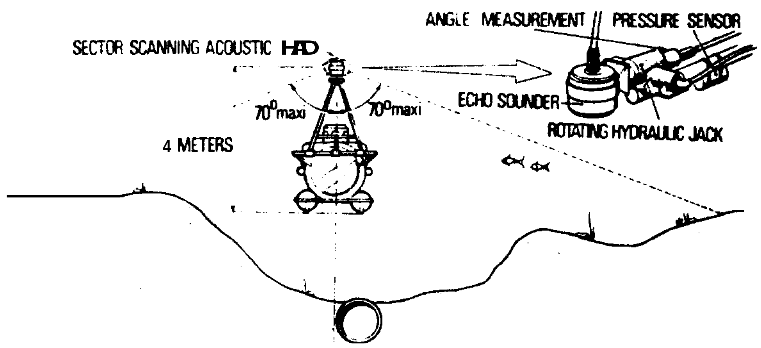
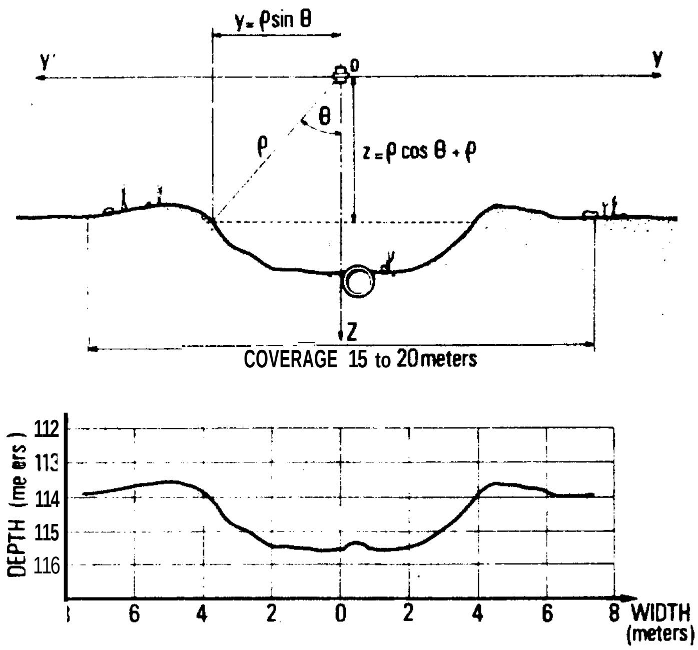


Figure 1-15. Schematic of Side-Scan SONAR Equipment (R. J. Brown, 1977)



A. **Sector Scanning Profiler Operating Principle**



B. **Construction of Sector Scanning Profile**

Figure 1-16. Underwater Surveying Technique (Durand & Stankoff, reprinted from Proceedings, (c) 1978 Offshore Technology Conference, by permission)

G. ENVIRONMENTAL IMPACTS

The fragility of Arctic terrestrial and marine biota requires careful planning of any industrial operations in order to minimize environmental impact. The Outer Continental Shelf Environmental Assessment Program (OCSEAP) addressed this problem in many individual and group studies during a number of years and recent results are summarized in the OCSEAP Synthesis Reports of 1977 and 1978. An environmental impact statement (EIS) is now a part of any major development and, in relation to the Arctic pipelines, such reports were prepared for the Trans Alaska Pipeline System, the Alaskan Arctic Gas Pipeline (not selected for construction) and the Alcan Gas Pipeline (to be built). During Arctic offshore pipeline construction there will be some environmental impact, mainly on benthic organisms. When the pipeline is operating, pumping stations are expected to have only a small effect on the environment.

The most significant environmental impact could occur during a major oil leak caused by pipe failure. An oil spill in the Beaufort Sea would pose special problems due to the presence of ice during most of the year, the remoteness from industrial and urban areas, and transportation difficulties. Problems connected with an oil spill in the Beaufort Sea were discussed in detail in EIA report, 1979 and it was concluded that the spring season (ice break-up) and the fall season (ice freeze-up) may pose difficulties in oil containment and disposal. During the winter period the oil would accumulate under the ice in a relatively small area. It then could be collected and disposed of by burning or other means. During the summer season, when the water is ice-free in the near-shore areas, techniques used in temperate zones for oil containment and disposal would apply. However, the technology of oil spill control in ice-covered and ice-infested waters is still in its infancy.

Fortunately, the problems that were encountered with the spill from the tanker Amoco-Cadiz, and from the Ixtoc well in the Gulf of Mexico, do not necessarily apply to a pipeline leak in the Beaufort Sea. There are two mitigating aspects of an oil spill from a pipeline: first, it can be controlled easily by closing some valves; second, the volume of oil spilled would be considerably less than that encountered in the two examples given. These facts, combined with pre-planned, comprehensive contingency procedures, could help substantially in alleviating the environmental hazards of an oil pipeline failure.

H. ECONOMICS OF ARCTIC PIPELINES

The economics of Arctic pipelines is not well understood and little data are available in the USA because of the pioneering character of onshore and offshore pipe-laying in that area. Vaulable experience onshore has been obtained with the TAPS which will be discussed later, and more data will become available when the construction of the Alcan gas pipeline is completed.

However, a substantial amount of cost information is available for onshore and offshore pipelines in the lower 48 states and analysis of such data was performed recently (Seaton, 1979). This analysis has shown that pipeline costs in the USA have climbed with time, particularly since 1973, as shown in Figure 1-17. This is caused by cost increases in both material and labor. Two major cost items, the line pipe and the pipeline construction, were debited with a cost index in 1978 of 505 and 416, respectively (Seaton). (Cost index taken as 100 in 1947).

On a dollar/mile basis offshore pipelines are more expensive than those onshore as shown in Figure 1-18 which employs 1978-1979 cost data. The offshore costs are averages

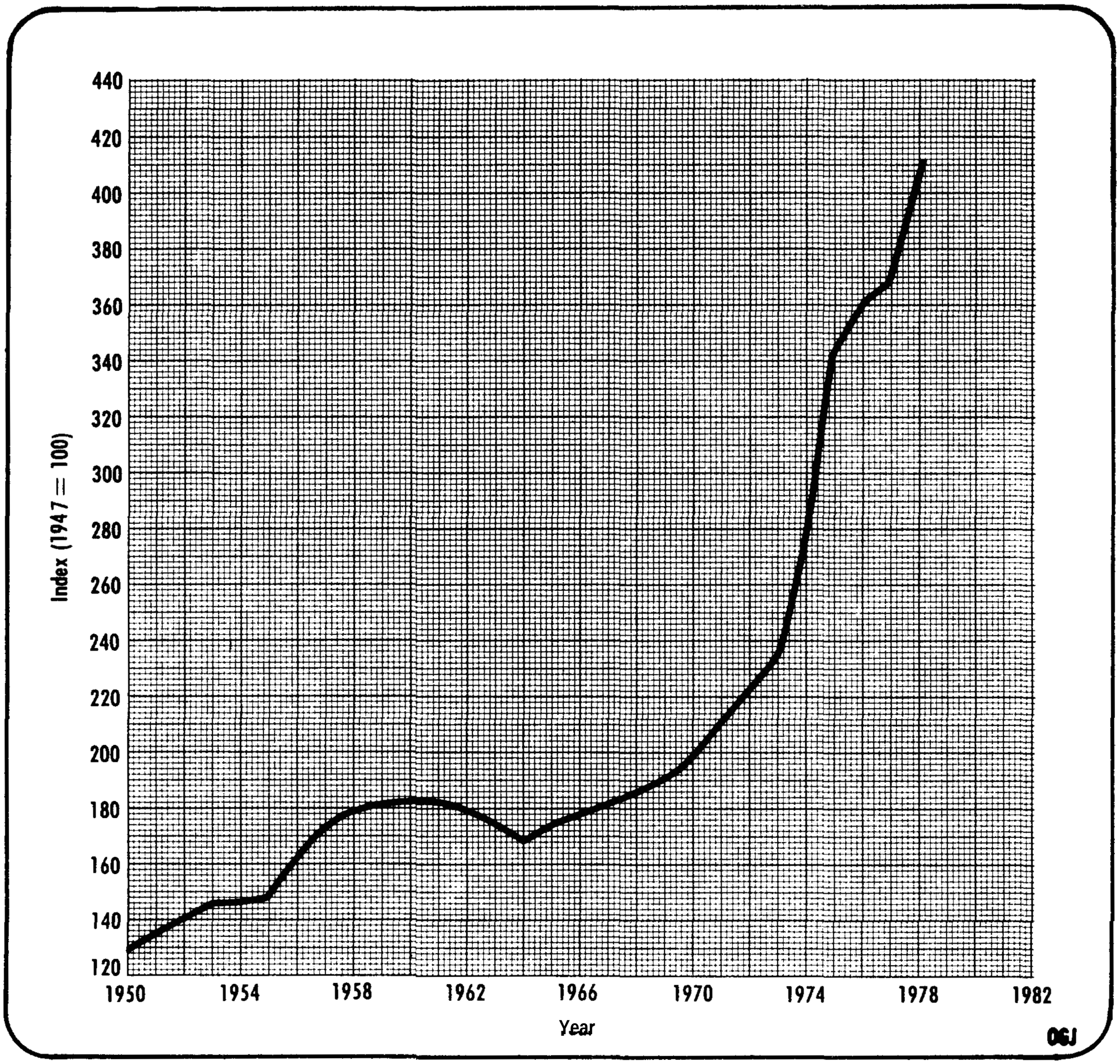


Figure 1-17. US Pipeline Construction Cost Index (Reprinted from Oil and Gas Journal, (c) 1979 *Petroleum* Publishing Company, by permission)

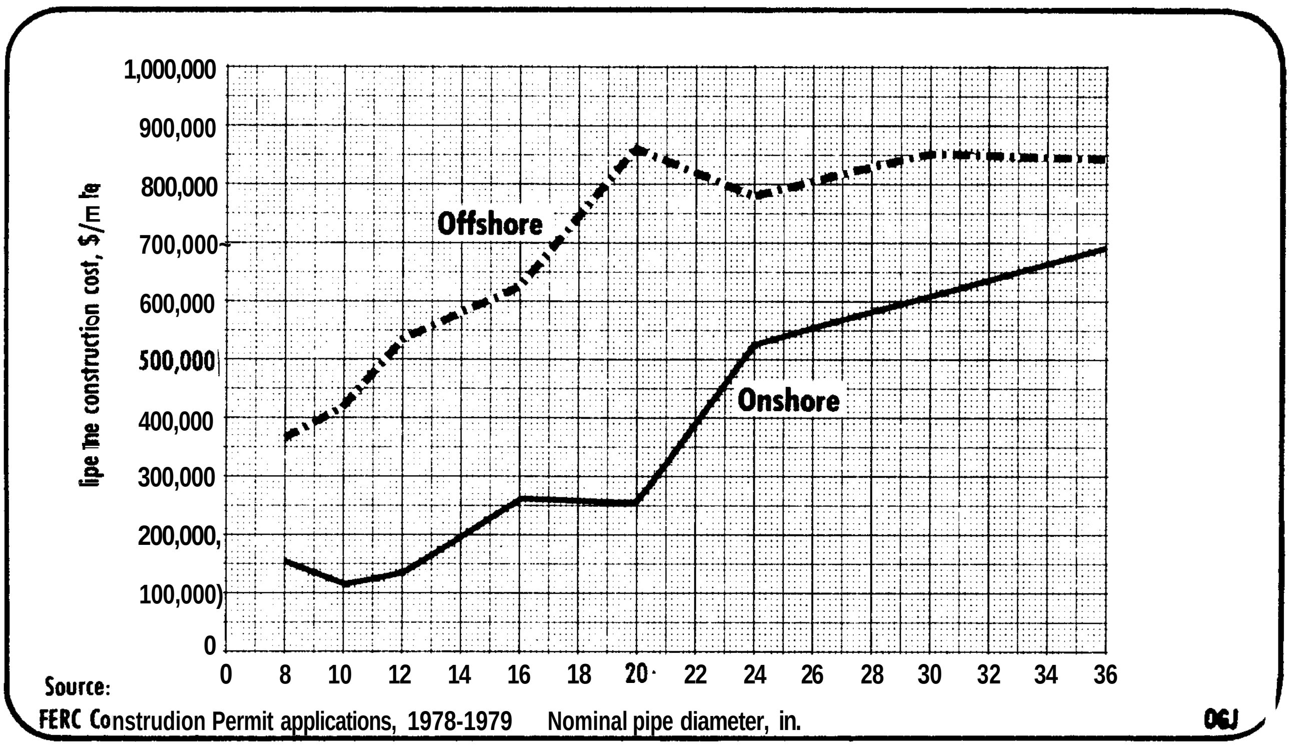


Figure 1-18. Average Pipeline Construction Costs -- FERC Construction Permit Applications, 1978-79 (Reprinted from Oil and Gas Journal, (c) 1979 Petroleum Publishing Company, by permission)

based mainly on pipelines in Louisiana where the cost/mile varied greatly even for the same pipe diameter. For instance, a 30 cm (12 in) diameter line cost/mile ranged from $453,000 to $1,433,000. Thus, the data in Figure 1-18 are indicative of the relative cost of onshore versus offshore pipelines, rather than the absolute cost which will be determined largely by pipeline route.

The 1.22m (48 in) diameter Trans Alaska Pipeline System carrying oil from Prudhoe Bay to Port Valdez (approximately 800 miles) presents a different case. It was the first major engineering undertaking in the USA Arctic and many problems connected with geotechnics of pipeline, route, materials, labor, and logistics had to be solved for the first time. The original cost estimate for the pipeline made in 1968 was for $1.046 billion. When the pipe was completed in 1977, the cost was $7.9 billion, or almost $10 million per mile (Comptroller's General Report, 1978). Evaluation of the cost escalation by the federal government indicated the importance of such items as detailed site-specific data, early resolution of technical and geological uncertainties, and detailed management planning and budgeting controls.

Another case of Arctic onshore pipeline has been described (Bock, 1979). This was a small-diameter 20 to 25 cm (8 to 10 in) gas pipeline of 235 km (146 mi) length supplying natural gas from the North Slope to pump stations 1, 2, 3 and 4 of the TAPS. To quote Bock:

> In the final analysis, in addition to ditching, the cost associated with the backfill operation, summer erosion control requirements, equipment repair and maintenance, welding, and hydrotest also showed variance levels which reflect the difficulty of estimating the cost of this project.

Thus, the cost of Arctic offshore pipelines is likely to be underestimated in the design stage. However, if advantage is taken of the TAPS, the Canadian experience, and the Comptroller General's recommendations, an estimate error probably could be reduced to a manageable level.