V. REVIEW OF EXISTING PIPELINE REGULATIONS

A. SCOPE OF REVIEW

The present US federal safety standards for hydrocarbon pipelines contained in Title 49, Parts 191, 192 and 195 do not, in general, address problems and requirements of the offshore Arctic environment. The applicability of these standards to pipelines in temperate offshore areas is discussed in the report "Offshore Pipeline Facility Safety Practices," by Dravo Van Houten, Inc., prepared for the Office of Pipeline Safety in December 1977. The Arctic environment, however, presents special hazards to offshore construction or activity because of low temperatures, thick ice formations, and inaccessibility to industrial centers for equipment, materials and personnel. These hazards are discussed in detail in Section II of this report.

Regulations for these oil and gas pipelines should ensure system safety and provide protection for the fragile biota. To evaluate present standards, it is necessary to define the specific problems of the Arctic conditions. Then, existing regulations should be examined to determine whether or not these problems are addressed.

This review will not be confined to US federal safety standards alone. In addition, two American industry codes, and government regulations for Canada, Norway and Great Britain, will be included. In some cases, industry or foreign documents may suggest desirable additions to our own government specifications. A brief review of the six regulatory bodies is provided in Part B of this section.

Table 5-1 lists those items of concern peculiar to the Arctic offshore which are considered sufficiently important to require federal regulations.

Table 5-1.

1.	Low Temperature Material Properties	7.	Pressure Testing
2.	Ice Scour	8.	Inspection and Monitoring Procedures
3.	Permafrost	9.	Environmental Impact
4.	Pipeline Stabilization	10.	Leak-handling Procedures
5.	Corrosion Protection	11.	Safety Device'
6.	Welding Inspection	12.	Thermal Expansion] Contraction

In Part C of this section these 12 items are considered individually and the way they are addressed in the six sets of regulations under review. In each case, an analysis has been conducted to determine the degree to which each item is addressed in the regulation. Section VI of this report recommends appropriate changes to the US Code of Federal Regulations, and provides justification for each instance.

B. REGULATIONS REVIEWED IN THIS SECTION

Six groups of regulations are reviewed and analyzed with respect to their applicability to offshore gas and oil pipelines in the Beaufort and Chukchi Seas off northern Alaska.

1. United States Title 49 Code of Federal Regulations (CFR)
   Parts 191, 192 and 195 (US)
   Revised October 1, 1979
   Published by the Office of the Federal Register
   National Archives and Records Service
   General Services Administration

Part 191 - Transportation of Natural and Other Gas by Pipeline; Reports of Leaks; Part 192 - Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards; Part 195 - Transportation of Liquids by Pipeline, govern United States gas and oil pipelines in interstate and foreign commerce. The three parts cover onshore and offshore lines from the outlet flange of specified OCS facilities to the customer. Parts 192 and 195 include materials, design, operation and maintenance requirement, among others.

Reports of gas line leaks are regulated by Part 191 while reports of liquid leaks are included in Part 195. Parts 191, 192 and 195 are under the jurisdiction of the US Department of Transportation, Materials Transportation Bureau. Citations of Title 49 CFR Parts 191, 192 and 195 in this report will appear, for example, as "US 191.1" for clarity in distinguishing between US standards and standards from other nations and organizations.

2. <u>Recommended Practice for Design, Construction, Operation and Maintenance of Offshore Hydrocarbon Pipelines</u>
   RP 1111
   First Edition March, 1976
   Published by the Transportation Department
   American Petroleum Institute (API)

As the title shows, the practices prepared by API, an oil industry trade association, cover only offshore hydrocarbon pipelines. Requirements for both gas and oil lines are combined except where differences are specified due to the nature of the product carried. Leak-reporting activities are not covered although a section on emergency plans is included. The API practices are intended for all climatic regions, however, "nothing in the recommended practice should be considered as a fixed rule without regard to sound engineering judgment." (API RP 1111 - Para 100).

3. American National Standard Code for Pressure Piping
   B31.4 - <u>Liquid Petroleum Transportation Piping System</u> - 1974
   B31.8 - <u>Gas Transmission and Distribution Piping Systems</u> - 1975
   American National Standards Institute (ANSI)
   Published by the American Society of Mechanical Engineers

ANSI codes B31.4 and B31.8 provide national standards for onshore and offshore pressure piping involving liquid petroleum and gas, respectively. US Part 195 and the British Institute of Petroleum (IOP) incorporate B31.4 by reference. IOP also incorporated B31.8 by reference.

The codes prescribe minimum requirements for the design, materials, construction, assembly, inspection and testing of pipelines. Users of the codes are cautioned that government agencies may have issued regulations that differ. When there is a conflict, the ANSI codes do not apply. System leak reporting and emergency measures are not covered.

4. Canadian Standards Association
   2183 - Oil Pipeline Transportation Systems - September, 1977
   2184 - Gas Pipeline Systems - October, 1975
   Published by the Canadian Standards Association (CSA)
   Rexdale, Ontario, Canada

Canadian standards 2183 and 2184 establish essential requirements for the design, installation and operation of oil and gas pipelines, respectively. The standards refer to prohibitions of unsafe practices and warn where caution must be exercised.

The gas pipeline standard has a supplementary section titled "Additional Requirements for Pipelines in Northern Regions." The supplement provides for special conditions not covered in the main text.

Both 2183 and 2184 state that they should not prevent the development of new equipment or practices, nor prescribe specifically how such new innovations should be handled (CSA 2183.1.1.4, 2184.1.1.4). The Canadian National Energy Board has jurisdiction over most Canadian hydrocarbon pipelines and enforces the CSA standards.

5. <u>Rules for the Design, Construction and Inspection of Submarine Pipelines' and Pipeline Risers</u>
Det norske Veritas (DnV), Norway
1976

As the title states, the Norwegian rules govern the design, construction and inspection of submarine pipelines. The rules apply to both gas and oil lines with specific rules concerning one or the other noted when necessary. The rules are based on the assumption that the pipeline is designed and constructed according to sound engineering practice (DnV 1.2.4.1).

Det norske Veritas is a supervisory and inspection body. Where recognized, DnV rules serve as a supplement to national regulations - if there is any discrepancy, the national regulations apply. Leak reporting and emergency measures are not covered.

6. <u>Petroleum Pipelines Safety Code</u>
Applied Science Publishes LTD on behalf of the Institute of Petroleum (IOP), Great Britain
1967

The British code sets forth general requirements for the safe design, construction and operation of carbon steel pipelines for gas and oil. The code is not a handbook and does not replace the need for appropriate experience and competent engineering judgment (IOP 1.1).

Supplements covering emergency procedures (incorporating leak reporting) and submarine pipelines are included. Appendices covering emergency action,, removal of oil from a watercourse, and approvals required for submarine pipelines also are presented. A statement in the maintenance section says, "Pipelines designed and constructed in accordance with this code are expected to have an indefinite life" (IOP 9.1).

C. REVIEW OF APPLICABILITY OF EXISTING REGULATIONS

1. Low Temperature Materials Properties

a. Regulations. US gas and oil safety standards each contain a general statement requiring pipe and components to maintain their structural integrity under temperature conditions to be encountered (US* 192.53(a), 195.102). No other mention of low-temperature considerations is made.

API recommended practices cautions designers to consider low-temperature properties of materials where applicable (API 1111.200.3).

ANSI codes for gas and oil pipelines state that they do not apply to lines with internal pressures above 15 psig if the design temperature is below minus 29°C (minus 20°F) (ANSI B31.400.1.2(c), B31.802.13(b)). Pipeline engineers are cautioned that some of the materials meeting the code may not be suitable in the lower temperatures (ANSI B31.401.3.1, B31.814).

Each of the CSA standards for gas and oil lines includes a general statement cautioning designers to consider low-temperature properties of materials where applicable (CSA Z183.3.1.1.2, 2184.3.1.2.1). The CSA gas standards require that attention be given to tensile strength and notch toughness at designated temperatures when specified operating conditions are encountered (CSA 184.3.1.2.2 and 3). The CSA gas standards also require that all materials and components for pipelines in northern regions must have adequate properties for the operating conditions and temperatures there (CSA 2184.11.2.1.1). Other clauses in the supplement consider such temperature related topics as cooling due to gas expansion

* Note: US in this report refers to Title 49 of the Code of Federal Regulations normally abbreviated as - 49 CFR.

(Joule-Thompson effect); evidence of certification, testing methods and testing temperature, and soil characteristics (CSA 2184.11.2.1.2, 2184.11.2.2.1 and 2, 2184.11.3.1, respectively).

DnV provides rules for environmental temperature data and defines design temperatures (DnV 2.3.7, 2.5, respectively). Pipelines are to be designed against brittle fracture (DnV 4.1.2). Material selection is to be based on, among other criteria, the temperatures to which the pipeline may be subjected during installation and operation (DnV 5.1.1.2). Pipes are to be impact tested at a temperature related to the minimum design temperature (DnV 5.2.3.7).

IOP code specifies that pipeline design stress need not be varied for metal temperatures between 118°C (244°F) and minus 25°C (minus 13°F). For gas pipelines, transition temperature to brittle fracture should be below the minimum expected temperature (IOP 2.1.4). Fatigue life is to be considered when a large number of temperature and/or pressure cycles are likely (IOP 2.6.4(b)). The materials section has a general statement requiring that pipes and components have properties suitable for the lowest temperature (IOP 3.1.1).

b. Analysis. The effects of low temperature upon pipes and components are covered by each of the standards reviewed. The US and API codes have only general statements. Additional information, such as definitions of minimum, maximum and differential design temperatures between pipe sections (similar to DnV 2.5) might be added to the US standards. A statement directing attention to tensile strength and notch-toughness at the lowest temperature to be encountered might be appropriate in view of the brittle fracture hazard. Two other topics for consideration are the possibilities of metal fatigue, caused by cycling loads due to internal pressure and/or external load variation, and changes in gas temperature from gas expansion in pipelines.

2. Ice Scour

a. Regulations. US Title 49 safety standards do not address ice scouring except by general statements requiring that pipelines be adequately protected against anticipated external loads (US 192.103, 195.110(a)). The gas line standards require protection from hazards (US 192.317(a)) although there is not a corresponding hazard protection requirement in the oil line standards.

API and ANSI require protection from hazards (API 200.5, ANSI B31.401.51 and 402.1, B31.841.13) but neither mentions ice scouring. Although the word scour is used in API 200.5, its context clearly shows that it refers to abrasives suspended in solution and not bottom-scouring from drifting ice keels. According to Canada's standards for northern regions (CSA Z184.11.3.1(a)), investigation of ice scour depths, among other factors, should be consistent with good engineering practice. Protection from conditions including ice effects is required in the main text of the oil standards (CSA 2183.3.1.2.1). A general statement about protection from abnormal loads appears in the gas standards (2184.6.4.2).

Det norske Veritas requires consideration of ice conditions and their effect on the pipeline. Ice scour is mentioned, as are ice forces and ice problems during installation (DnV 2.3.6.1). Environmental loads assumed for normal operation are not to be less than the most probable severest load within 100 years (DnV 3.3.1.3). Ice loads such as scour are to be considered (DnV 3.3.6).

Ice or ice scouring does not appear in the IOP codes. The only reference covering such situations is the requirement that unusual loadings be allowed for in accordance with accepted engineering practice (IOP 2.1.8).

b. Analysis. Except for CSA and DnV rules, ice scouring and its effects on subsea pipelines are not covered directly by the regulations, although it would be governed indirectly by other regulations in reference to external hazards. The Canadian and Det norske Veritas rules merely mention the problem; they do not define requirements.

Ice scour presents an engineering problem.. Additional research needs to be done for better determination of the locations, depths, frequency and forces involved. For the US standards, a requirement might be added that ice scouring possibilities be investigated and measures taken to prevent damage to both gas and oil pipelines.

3. Permafrost

a. Regulations. Permafrost and/or the effects of frozen soil (i.e., frost heave or thaw subsidence) on pipelines is not covered directly in the US standards. Apart from a requirement that gas pipelines shall be protected from unstable soil (US 192.317(a)), there is no mention of the problem. API's recommended practices does not cover frozen soil nor does it include any statements regarding pipelines in unstable soil. The ANSI liquid petroleum standard states that consideration in the design be given to systems where subsidence is known to occur (ANSI B31.401.5.5). The ANSI gas line code does not contain a similar statement; however, it does say that unequal settlements may produce added bending stresses in buried pipe and that uniform support of trenched pipe is essential (ANSI B31.835.5).

Permafrost and frozen soil are cited as items to be considered in the Northern Regions supplement to the Canadian standards. Preliminary investigations of surface and subsurface conditions shall be undertaken. These shall include forecasting the seasonal behavior of the soil and soil characteristics, such as temperature, susceptibility to frost heaving, heaving capacity, potential instability, and the capacity to support plant life following disturbance (CSA Z184.11.3.1(a)). Stress calculations shall be made in areas where degradation or growth of permafrost is possible, to determine whether the piping system should be restrained (CSA 2184.11.3.2). For below-grade installations, when the ground or backfill (i.e., ice-rich permafrost) prevents adequate support, or subsidence will occur consequently, measures shall be employed to achieve adequate support. Such measures may include, but are not limited to, use of a more stable backfill, modification of the thermal regime, or pilings (CSA Z184.11.4.1.1). Likewise, when the ground or fill material surrounding the pipeline is known to be susceptible to frost heaving, measures shall be employed to protect the pipeline from such damage (CSA 11.4.1.2). Measures also shall be taken to reduce disturbance of deleterious permafrost (CSA 11.4.4.2.2).

Det norske Veritas does not refer to permafrost per se. The rules require a detailed route survey that, among other factors, must include seabed geotechnical properties including possible unstable deposits (DnV 2.2.1, 2.2.5). Pipelines are to be designed against loss of inplace stability (DnV 4.1.2.1) and design analyses are to be based on soil mechanics, among other criteria (DnV 4.1.1.1).

Permafrost or other ice-related soil problems are not considered in the IOP code. The only reference to unstable soil is related to a soil/water slurry during subsea trenching which may affect the negative buoyancy of a pipeline (IOP 11.4.5(b)).

b. Analysis. With the exception of the Canadian standards, the regulations reviewed here essentially do not address the problems of pipelines in frozen soils. Hot oil pipelines are particularly sensitive because of the possibility of melting and subsequent subsidence of frozen areas. Conversely, refrigerated gas lines may induce additional freezing of the soil which can allow an ice bulb to form around the pipe, causing frost heave problems.

Inclusion of a general requirement that surface and subsurface soil conditions be investigated would be' an appropriate addition to US Parts 192 and 195. Without specifying details, it also may be required that measures be used to achieve adequate support for the pipe in unstable or frozen areas. The term "adequate" would be defined in terms of pipe stress already in the standards. A statement also could be included cautioning designers about degradation or growth of frozen soils that could affect a pipeline adversely.

4. Pipeline Stabilization

a. Regulations. US gas and oil standards require that all offshore pipes at depths between 3.6m (12 ft) and 60m (200 ft) must be installed so that the top of the pipe is below the natural bottom unless supported by stanchions, held in place by anchors, heavy concrete coating, or protected by an equivalent means (US 192.319(c), 195.246(b)). Exposed gas lines must have enough anchors and supports to prevent undue strain, resist longitudinal forces, and prevent or damp out excessive vibrations (US 192.161(a)). A similar requirement for oil lines does not appear 'in Part 195.

API recommends that exposed pipelines be stabilized by suitable means and entrenched lines should have sufficient weight to prevent flotation (API 500.8.1).

Weight coating is not covered directly in ANSI standards. For oil lines, coating is defined as a dead load (ANSI B31.401.6.2). Expansion of above-ground oil lines may be prevented by anchoring them so expansion or contraction is absorbed in the same way as for buried piping (ANSI B31.419.1(d)). For gas lines, ANSI requires that bends or offsets in buried pipes be resisted by anchorage, restraint due to soil friction, or by longitudinal stresses in the pipe (ANSI B31.835.1).

CSA oil line standards state that there are fundamental differences in loading conditions for buried, or otherwise restrained, piping and pipe not subject to substantial axial restraint. The effect of restraints shall be considered in the stress calculations (CSA 2183.3.5.1.3.5). Weight coatings, river weights, anchors or other means shall be used to maintain position of subsea pipe under anticipated conditions of buoyancy and water motions (CSA 2183.8.5.1.1). Buried gas pipelines shall have bends or offsets resisted by anchorage, soil friction or longitudinal stresses in the pipe. Care should be taken to distribute anchorage loads so that the bearing pressure is within safe limits (CSA 2184.5.6.1-2).

Det norske Veritas defines weight coating as a material providing negative buoyancy to a pipeline (DnV 6.7.2.1). Documentation of performance and specifications of weight coatings are required (DnV 6.7.3-4). Detailed application criteria are provided. Other pipeline anchoring systems are subject to special consideration (DnV 6.7.5-6). Pipelines are to be designed to prevent excessive damage to, or loss of, weight coating (DnV 4.1.2.1). The weight coating must be designed to remain in place for the life of the line and shall resist minor impacts. A weight coating not continuous over the joints should add negligible stiffness to the pipe to avoid overstressing girth welds (DnV 4.2.5). Pipelines shall not move, apart from permissible deformation from thermal expansion, and a limited amount of settlement after installa-' tion (DnV 4.2.6.1).

IOP codes allow weight coating, or weights fitted at intervals, to achieve negative buoyancy. Negative buoyancy normally should be calculated for empty pipelines regardless of the contents' weight (IOP 11.4.5). Weight coating is covered in detail including specific coatings and methods of application. Coated pipes shall be stored during curing so coating is not damaged and, if necessary, shall be protected from frost. Dangers may arise if coating is too strong causing excessive bending stress at field joints during laying (IOP 11.5.1.4).

b. Analysis. The US safety standards mention only weight coatings. Since weight coatings probably will be the preferred method of obtaining a negative buoyancy for Arctic offshore pipelines, it would be desirable to provide guide-lines for weight coatings similar to those for protective coatings (US 192.461 and 195.238). Other regulations such as DnV discussed above have detailed requirements of weight coatings.

5. Corrosion Protection

a. Gas Pipeline Regulations. Each buried or submerged US gas pipeline installed after July 31, 1971 must be pro-tected against external corrosion and must have an external protective coating and a cathodic protective system (US 192.455). Cathodic protection must meet specific test criteria and be controlled so as not to damage the protective coating or pipe (US 192.463). Cathodic protection systems must be tested once each calendar year; the power source and various other equip-ment must be tested at intervals not exceeding two months (US 192.465). Standards for electrical isolation, test stations, test leads and interference currents are provided (US 192.467, 192.469, 192.471, 192.473, respectively). Corrosive contents may not be transported unless the corrosive effect has been investigated and steps taken to minimize internal corrosion (US 192.475(a)). Standards for inspection of pipe, and replacement if corroded, as specified (US 192.475(b)).

API recommended practices state that submerged steel pipelines should be protected by an external coating effective in the environment to which it is exposed (API 801.1). Design, installation and maintenance of cathodic protection systems should be in accordance with National Association of Corrosion Engineers (NACE) Recommended Practice 06-75. Stipulations should be made that:

- Galvanic anode systems use only alloys which have been successfully tested.
- Galvanic anode systems be designed for periodic replacement or for the life of the pipeline.
- Components be located and installed to minimize being damaged.
- Electrical interference currents from neighboring pipelines or structures minimized.
- Allowance for water depth and provision made for the effect of electrical current variation with time,
- Insulated joints for electrical isolation of portions of the system, if practical, be above water (API 802).

The effectiveness of the system should be evaluated at least annually. Impressed voltage and current output must be verified and recorded at two-month intervals (API 804). For internal corrosion control, API recommends NACE RP 01-75 be used to determine the need for a mitigation program. The variables of each case will determine the methods that should be used. A monitoring program should be established to evaluate the results (API 803).

ANSI gas standards state that applications of some corrosion control practices requires a significant amount of competent judgment. Deviation from the provisions is permissible, provided the operating company can demonstrate that the objectives have been achieved (ANSI B31.861.1). All new lines shall be protected externally with a coating material (ANSI B31.862.111). Unless the company can prove it is unnecessary, all facilities with insulated-type coatings shall be cathodically protected in accordance with NACE RP 01-72 (ANSI B31.862.113). Requirements for coating inspection, installation of electrical connections and electrical interference are provided (ANSI B31.862.112, 862.114, 862.116, respectively). Electrical measurements and inspections must be made of cathodic protection systems. The type, number and location of the tests shall establish the degree of protection provided. However, each operating company shall inspect its impressed current cathodic protection facilities at least annually (ANSI B31.864.1-2). Internal corrosion has to be prevented. Definitions of non-corrosive and corrosive gases are provided as well as general standards for inhibitors and internal coatings (ANSI B31.863.1-3).

CSA standards require coating and cathodic protection on new systems (CSA Z184.8.2). Electrical requirements are specified (CSA 2184.8.2.5-10, 2184.8.2.9 and 2184.10.4.2). The operating company shall establish surveys that verify the operation of the various devices. The frequency of these surveys is to be detailed in the company's operating and maintenance plan (CSA 2184.8.3.2). When active corrosive agents are known to be in the gas being conveyed, or if evidence of internal corrosion is discovered, the gas shall be analyzed periodically and precautions taken to prevent a hazardous condition (CSA 2184.9.1.1.3).

According to DnV rules, external coating and cathodic protection by sacrificial anodes or impressed current is normally required for all submerged pipelines. Wall thickness allowance is considered necessary where internal or external erosion may be expected. Electrical insulating devices are to be installed when needed (DnV 6.1.3). A detailed coating specification is provided which includes characteristics and properties to be submitted to DnV for approval. Also to be submitted for approval are procedure specifications for pipe coating and field joint coating application (DnV 6.2.2-5). Corrosion protection by sacrificial anodes is covered by sections on design, materials and installation. A design and material specification is to be submitted for approval (DnV 6.4). Corrosion protection by impressed current has a virtually identical section on design and also requires a design specification to be submitted for approval (DnV 6.5).

Internal protection must be considered for pipelines which, during installation or operation, may be subjected to corrosion. Treatment of the product may be utilized as a means of controlling corrosion, as may pigging at regular intervals, and corrosion monitoring (DnV 6.6.1.1). If internal corrosion protection is necessary, specifications of the systems to be used are to be submitted for approval. Application of inhibitors or internal coating may be relevant means of corrosion protection.

IOP codes state that submarine pipelines should be coated externally to protect against corrosion (IOP 11.5.1.3)'. Basic requirements for the design of cathodic protection for coated pipelines include insulation of the pipeline from the soil. Measuring points should be provided along the pipeline to determine potential, especially in highly corrosive soils and vulnerable water areas (IOP 7.3.6). General guidelines for sacrificial anode and impressed current systems is provided (IOP 7.4). Pipe-to-soil potential measurements should be taken at least annually or whenever an abnormal condition is indicated (IOP 7.5). No increase in thickness need be made unless internal corrosion, external corrosion or erosion is expected. Neither is allowance required when corrosive fluid is to be transported, provided that long-term measures are taken to prevent such corrosion. Criteria for determining whether a gas is non-corrosive and non-erosive are provided (IOP 2.2.3(b)).

b. Oil Pipeline Regulations. US oil line standards, like the gas line standards, require protective coating and cathodic protection (US 195.238, 195.242) on lines installed since April 1970. Characteristics of the coating are provided (US 195.238), as are cathodic protection test lead requirements (US 195.244). Cathodic protection systems shall be tested at intervals not exceeding 12 months while each rectifier must be inspected at intervals not exceeding two months (US 195.416). No commodity that would corrode the pipe or components may be transported unless the corrosion effect is mitigated (US 195.418(a)). Standards for inspection of pipe, and replacement if corroded, are specified (US 195.418).

API recommended practices for liquid oil line corrosion control are the same as those for gas lines.

ANSI standards require control of external corrosion of new buried or submerged oil lines but do not dictate how it is to be achieved. However, within 12 months after installation, the operating company must inspect the buried or submerged system. If a corrosive condition exists, the piping system shall be protected cathodically (ANSI B31.461.1.1(a)). Protective coatings, if used, shall have characteristics listed in the standards (ANSI 461.1.2).

Electrical isolation, test lead and electrical interference standards are provided (ANSI B31.461.1.4-6). Cathodic protection systems for oil lines shall be tested at intervals not exceeding 15 months, while impressed current power sources and various other devices shall be inspected at intervals not exceeding two months (ANSI 231.461.3). Mitigation of internal corrosion through the use of frequent scraping, pigging, or sphering, dehydration, inhibition, or internal coating is suggested and non-specific standards are given for dehydration, inhibitors and internal coatings (ANSI B31.462.1).

CSA standards require coating and cathodic protection on new oil pipeline systems (CSA Z183.10.2.1); electrical requirements are specified (CSA Z183.10.2.5, 2183.10.2.6-7, Z183.10.2.7.2, respectively); corrosion control test stations are to be provided at intervals; test lead connections must be secure, conductive and, with the test leads, insulated from the environment (CSA 2183.10.2.9); pipelines shall be surveyed at intervals not exceeding 15 months to establish that the cathodic protection meets accepted criteria; impressed current systems operation shall be verified at intervals of not more than six weeks; operation of other devices shall be verified at intervals not exceeding 10 weeks or a year, depending on the device (CSA Z183.10.2.9). The operating company shall determine the internal corrosive effects of the commodity being transported in oil lines. Appropriate action shall be taken to minimize the effects of internal corrosion. Actions to be considered include, but are not limited to, dehydration, inhibitors, pigging and internal coating. Adequate techniques shall be utilized to determine the effectiveness of the internal corrosion mitigation (CSA 2183.11).

DnV and IOP rules for liquid oil pipeline corrosion protection are the same as for gas lines previously described.

c. Analvsis. External corrosion effects are the same for both gas and oil pipelines, yet the US Part 192 goes into greater detail than Part 195. Briefer Part 195 standards do not conflict with those in Part 192 and the possibility of making the external corrosion sections of both parts identical should be considered. US gas line regulations, while not as detailed as the Canadian and Det norske Veritas rules, appear to need no additions to make them suitable for Arctic subsea conditions. Likewise, internal corrosion protection standards in Parts 192 and 195 appear to be satisfactory.

6. Welding Inspection

a. Regulations. Visual inspection of welding must be conducted, according to the US standards for gas and oil pipelines, to insure that welding is performed in accordance with approved procedures and the weld's acceptability is determined according to API standard 1104-1973, Section 6 (US 192.241, 195.228). One hundred percent of offshore gas and oil pipeline field butt welds, with insignificant exceptions, must be nondestructively tested. If testing all welds is not practicable, not less than 90 percent shall be done. Nondestructive testing must be performed by any process that will indicate clearly imperfections that may affect the integrity of the weld (US 192.243, 195.234).

API practices state that all girth welds should be inspected visually. If practical, 100 percent of the girth welds in the pipeline should be inspected by radiographic or other nondestructive methods before coating the weld area. In no case should fewer than 90 percent of such welds be so inspected (API 600.3.2).

Standards of acceptability for various welding characteristics according to ANSI gas and oil pipeline codes, are set forth under API standard 1104 and are applicable to the determination of defects located by visual inspection, radiography or other nondestructive methods (ANSI B31.434.8.5(b), B31.826.2(c)). One hundred percent of the girth welds on offshore oil pipelines shall be inspected by radiographic or other accepted nondestructive methods (visual inspection excepted) (ANSI B31.434.8.5). The ANSI gas line standard (B31.826.2) specifically does not mention offshore applications regarding girth weld inspection. However, at major or navigable river crossings, with insignificant exceptions, 100 percent nondestructive testing (excepting visual and trepanning) shall be performed if practical, but otherwise not less than 90 percent.

The Canadian Standards Association does not specify visual inspection of girth welds; however, standards of acceptability apply to the determination of defects by visual, radiographic or other nondestructive test methods of gas and oil lines (CSA 2183.5.10.1, 2184.4.11.1). One hundred percent of offshore gas and oil pipeline girth welds shall be radiographically inspected (CSA 2183.5.9.1.2.1, 2184.4.10.2.1.2). Detailed descriptions and specifications of welding defects that are and are not allowed appear in the gas and oil standards (CSA 2183.4.11.3-10, 2184.5.10.3-10). Standards for the production of radiographs also are given (CSA 2183.5.12, Z184.4.13.1).

Det norske Veritas rules for offshore gas and oil pipelihes require visual examination of field welds before, during and after welding (DnV 8.6.2). All field welds are to be examined 100 percent by either radiography, or ultrasonic plus magnetic particle testing. If radiographic examination is applied, the society may specify additional spot examinations by ultrasonics, or other relevant methods, dependent on the applied welding method (DnV 8.6.3.1). External appearance characteristics of field welds are specified (DnV 7.2.6.11). Detailed standards of acceptability for welding are supplied which include both the weld itself and results of the various means of nondestructive testing (DnV 10.5). Procedure specifications and related requirements for nondestructive testing are given (DnV 1.2-4).

Institute of Petroleum rules state that all field welding of individual pipes should be examined by radiographic methods (IOP 11.5.1.2). The topic is repeated in a later section which states that a complete radiographic examination of all but welds on submarine pipes should be made, usually by means of a suitable x-ray machine (IOP 11.5.3.3). The radiographic procedure should conform to the requirements of API standard 1104 or British standard 2910 (IOP 5.3.13).

b. Analysis. Visual inspection of pipeline welds is required by all of the regulations reviewed. Detailed standards of acceptability are listed, either directly or by reference. All of the regulations reviewed concur that 100 percent of the girth welds be tested nondestructively. Some, including the US, permit only 90 percent if testing 100 percent of the welds is not practical.

The US standards are as applicable as any of those reviewed in terms of suitability for the Arctic with the exception of clauses permitting nondestructive testing of 90 percent of welds if 100 percent testing is not practical. The possibility of requiring testing of all welds without exception may be preferred.

7. Pressure Testing

a. Regulations. US standards require pipelines to be pressure-tested before being placed in service and before being returned to service after a segment has been relocated or replaced (US 192.503(a), 195.302(a)). Gas pipelines must use liquid, air, natural gas or inert gas that is compatible with the pipeline material, relatively free of sediment and, except for natural gas, nonflammable (US 192.503(b)).

If air, natural gas or inert gas is used as the test medium, the maximum hoop stress is limited to 90 percent of SYMS for Class 1 location gas lines (US 192.503(c)). Gas pipelines to be operated at a hoop stress of 30 percent or more of SMYS and all offshore pipelines installed after July 31, 1977, when hydrostatically pressure-tested, must be tested to 125 percent of maximum operating pressure. The strength test must be conducted by maintaining the pressure at or above the test pressure for at least eight hours (US 192.505).

Each liquid oil pipeline must be tested hydrostatically without leakage. The test pressure which is 125 percent of the maximum operating pressure must be maintained for at least 24 hours (US 195.302). Offshore liquid oil pipelines must use water as the test medium (US 195.306(a)).

API specifies that all new pipeline systems be pressure tested after construction (API 601.3.1). Every point in an offshore hydrocarbon pipeline system should be subjected to a test pressure not less than 125 percent of the internal design pressure, plus the external pressure at that point. The duration of the post-installation pressure tests should not be less than eight hours. Pressure tests should be conducted using water as the test medium, except that air or gas may be used, provided a failure or rupture of the pipeline would not endanger personnel. Effects of temperature change should be taken into account when interpretations are made of recorded test pressures (API 601.4.1).

ANSI codes require all liquid petroleum and gas pipelines to be tested after construction (ANSI B31.437.1, B31.841.31). Liquid petroleum piping systems to be operated at a hoop stress of more than 20 percent of the SMYS shall be subjected to a hydrostatic test equivalent to not more than 1.25 times the internal design pressure at that point. The test duration shall not be less than eight hours. It shall be conducted with water, except under certain specified conditions when the use of liquid petroleum, that does not vaporize rapidly, is permitted. Effects of temperature changes shall be taken into account when interpretations are made of recorded test pressures (ANSI B31.437.4.1). All gas pipelines to be operated at a hoop stress of 30 percent or more of the SMYS shall be tested with air or gas or hydrostatically to 1.1 times the maximum operating pressure (ANSI B31.841.3).

CSA requires that oil and gas pipelines be pressure-tested (CSA 2183.7.11, 2184.6.4.7). Oil pipelines shall undergo successfully a test pressure of 125 percent of the intended maximum operating pressure for 24 hours, or a strength test of not less than four hours duration and a proof test (CSA 2183.7.1.2). Buried gas pipelines to be operated at 30 percent or more of SMYS shall be tested to at least 1.25 times the maximum operating pressure for a minimum of 24 hours.

The testing medium for oil pipelines, with a maximum operating pressure greater than 100 psig, shall be water wherever practicable. Oil may be used for special situations (CSA 2183.7.4.1.1). Air or other gases may be used as the testing medium for oil pipelines with a pressure of 100 psig or less (CSA 2183.7.4.2). Gas pipelines shall be tested with air, gas or an approved liquid. Wherever practicable, a liquid instead of a gaseous medium shall be used (CSA Z184.6.4.8.1.2).

In Northern regions, the stresses and reactions of gas lines in unstable soil shall be investigated when the weight of the test medium contributes additional stresses. The temperature of the test medium shall be such as to prevent detrimental melting of permafrost (CSA Z184.11.5.2).

DnV requires pipelines to be tested hydrostatically after installation to 1.25 times the design pressure for 24 hours. Design pressure is defined as the maximum steady state operating pressure for which the pipeline system is built. Hoop stress shall not exceed 90 percent of SMYS (DnV 8.8.4). Test mediums are not specified.

IOP codes require a hydrostatic pressure test on the completed pipeline, or on each completed section, as convenient. Water is the only test medium specified for hydrostatic testing (IOP 6.4). The pressure shall be raised to 1.5 times the maximum working pressure or to that which will result in a hoop stress equal to 90 percent of the SMYS for 24 hours, (which corresponds to the 49 CFR 192.111 Class 1 location 0.72 design factor multiplied by 1.25). If the ground temperature at pipe depth is 0°C (32°F) or less, or may fall to that before the test is completed, or if water of satisfactory quantity is not available in sufficient quality, an air test to 1.1 times the maximum operating pressure should be made (IOP 6.3).

b. Analysis. Pipeline pressure test requirements are generally consistent among the rules reviewed. For US offshore pipelines, the test pressure factor is 1.25 times maximum operating pressure, increasing to 1.5 for inhabited onshore areas. This is considered satisfactory for Arctic offshore applications.

One difference among the standards that bears further scrutiny is the duration of testing. API and ANSI require eight hours while CSA, DnV and IOP require 24 hours. The US standards list eight hours for gas lines and 24 hours for oil.. It appears that eight hours duration would be too short a period for adequate testing of a subsea Arctic line. Equalization of temperature throughout the test medium may not occur within eight hours, and the logistics involved in physically inspecting for leaks might not be completed satisfactorily within that period.

8. Inspection and Monitoring Procedures

a. Material and Construction Inspection

(1) Gas Pipeline Regulations. Every US pipeline must be inspected to ensure that it is built in accordance with the standards (US 192.305). Each length of pipe and all components must be inspected visually at the site to ensure that they have not sustained any visually determinable damage (US 192.307). Each external coating must be inspected just before lowering the pipe into the ditch and backfilling (US 192.461(c)).

API recommended practices state that the operating company should make provisions for suitable inspection of pipelines and related facilities by qualified inspectors to assure compliance with the construction specifications (API 500.2). During construction, pipelines and related facilities should be inspected for compliance with the material, construction, welding, fabrication and testing provisions of the recommended practice and the written specifications (API 600.1). API inspection requirements cover materials and installation. Inspection of materials concentrates on pipe condition and coating (API 600.3.1). Installation inspection includes joint surfaces and alignment, field coatings, welds, fit of pipe on the bottom and cover, if any (API 600.3.2).

ANSI standards state that the operating company shall make provisions for suitable inspection of pipelines and related facilities by qualified inspectors (ANSI B31.841.221). For gas lines to operate at 20 percent or more of SMYS, certain installation inspections shall be at sufficiently frequent intervals to assure good quality. The inspections include the pipe surface before coating and before lowering into the ditch, joint conditions before and after welding, ditch bottom condition, pipe fit in ditch, and repairs and special tests, if any (ANSI B31.841.222).

CSA requires pipelines to be inspected to ensure they are built in accordance with the standard and construction specifications (CSA 6.4.6.1-2).

DnV rules state that the owner is to provide adequate inspection during fabrication. Before installation, an inspection may be required to assure that no damages have occurred during transportation (DnV 1.6.2-3). The owner is to provide adequate inspection during installation which takes place under the surveillance of DnV. The surveyor (DnV inspector) is to inspect all phases of the installation process that may affect structural integrity and is to assure that the installation proceeds according to approved procedures (DnV 1.6.4).

IOP states that the company and the contractor each should employ a competent supervisor with an adequate staff to ensure that the code recommendations are met (IOP 5.4). Installation inspections for submarine pipelines includes pipe-end conditions, alignment before welding, welding and undersea inspections (IOP 11.5.3.1-3, 8).

(2) Oil Pipeline Regulations. US inspection standards for liquid oil lines are essentially identical to the gas line standards already mentioned. US liquid oil line citations are: inspection of construction in accordance to

standards (US 195.204), visual inspection of materials (US 195.206) and inspection of pipe coating (US 195.238(b)).

API practices for gas lines (API 500.2, 600.1) previously described, also apply to liquid oil lines.

ANSI standards state that the operating company shall make provisions for suitable inspection of pipelines and related facilities by qualified inspectors (ANSI B31.434.2). Fabricated items and pipe (before coating) shall be inspected before assembly into the mainline or manifolding (ANSI B31.434.5). All piping components must be inspected visually to insure that no mechanical damage has occurred before connection. During construction, the following shall be inspected: pipe surface before and after coating, joint fit-up, welds, repairs, ditch condition, pipe fit into ditch, installation of components, backfill, and crossings, if any (ANSI B31.436.5.1).

CSA requires installation inspection provisions that shall be adequate to ensure quality and safety. Inspection requirements shall begin at the field installation location (CSA 2183.6.1). Pipe shall be inspected visually for defects (CSA 2183.6.2.1.1). Installation inspections include pipe condition before any coating and before lowering and backfilling, welds, repairs, ditch condition and backfilling (CSA 2183.6.2.1.2).

DnV rules (DnV 1.6.2-4) and IOP codes (IOP 5.4) for gas lines also apply to liquid oil lines.

(3) Analysis. Of the standards reviewed, only the US codes do'not provide specific requirements for inspection during and after pipe installation. The US has a general statement to the effect that the line must be inspected to ensure it is built to standards and that the pipe coating shall be inspected before lowering into a ditch but does not

provide specific information like the others, i.e., ANSI B31.436.5.1 (oil) and B31.841.222 (gas).

Otherwise, the various codes are reasonably consistent although the ANSI and CSA gas line standards lack provisions for visual inspection of materials before construction. DnV was the only one to include inspection during component fabrication in their pipeline rules. Presumably, such inspections are covered elsewhere by the other standards-makers.

b. Monitoring During Operation

(1) Gas Pipeline Regulations. According to US standards, each operator shall have a procedure for continuing surveillance of its facilities to determine changes in class location, failures, leakage history, corrosion, substantial changes in cathodic protection requirements, and other unusual conditions, and to take appropriate action (US 192.613(a)). Each operator shall have a patrol program to observe surface conditions, on and near the right-of-way, for factors affecting safety and operation. The frequency of patrols for offshore lines is a minimum of one per year (US 192.705). Each pressure-limiting station, relief device (except rupture discs), and pressure-regulating station with its equipment, must be subjected to inspections and tests at intervals not exceeding one year (US 192.739). Each transmission line valve, that might be required during any emergency, must be inspected and partially operated at intervals not exceeding one year (US 192.745). Cathodic protection systems must be tested once each calendar year (US 192.463).

API practices state that each operating company should develop working, inspection and maintenance procedures based both on recommended practice and on the company's experience, knowledge of its facilities, and operational conditions (API 700.1). Each operator should maintain a periodic pipeline patrol program to observe conditions along the route which could affect safe operation (API 701.5). Pressure-limiting devices and other safety equipment on non-production platforms should be subjected to periodic inspections at a maximum interval of six months (API 701.6). Above-water valves should be inspected annually (API 701.9). The effectiveness of the cathodic protection system shall be evaluated at least annually (API 804).

ANSI requires each company to have an operating and maintenance plan in accordance with the code (ANSI B31.850.2). Each operating company shall establish and implement procedures for continuing surveillance of its facilities. A periodic patrol program shall be maintained to observe surface conditions affecting the safety and operation of the pipeline (ANSI B31.851.1-2). All pressure-limiting and regulating stations shall be subject to systematic, periodic inspections and suitable tests (ANSI B31.853.31). Valves that might be required during an emergency shall be inspected periodically and partially operated at least once a year (ANSI B31.853.4). Each operating company shall inspect its impressed current cathodic protection facilities at least annually (ANSI B31.864.2).

Each company, according to CSA standards, shall have a written plan covering operating and maintenance procedures in accordance with the standard (CSA Z184.9.1.1.1(a)).

It must maintain a periodic transmission line patrol program to observe surface conditions affecting safety and operation (CSA 2184.9.2.1). All relief devices and equipment in pressure-limiting and pressure-regulating stations shall be subjected, at least annually, to inspections and tests (CSA 2184.9.6.1.1). Transmission line valves that might be required during an emergency shall be inspected and partially operated at least once a year (CSA 2184.9.7.1). The operating company shall establish surveys that its cathodically-protected pipeline systems meet accepted criteria for cathodic protection (CSA Z184.8.3.2.1).

DnV rules state that the owner should provide running inspection sufficient to initiate maintenance work to retain built-in safety (DnV 9.2.3.1). The frequency and extent of periodic surveys will depend on various factors, one of which is the degree of exposure to potential damage. Normally, a periodical survey is to be carried out annually unless otherwise agreed upon with DnV (DnV 9.3.1.1-2). DnV requires an annual survey to verify that no unacceptable damages have occurred to the pipe, corrosion protection system or weight coating. Other parts of the annual survey include test of the cathodic protection system, inspection by gauging-pig and when the nature of the pipeline prohibits direct inspection, measurement by internal pig-type instruments. Pipe wall thickness measurements may be required when there is reason to believe corrosion or erosion is occurring. Pressure-limiting and other safety devices should be tested and inspected annually (DnV 9.3.2).

According to the IOP code, the operation of pipelines depends to a large extent on the pipe contents, and each operator should formulate a procedure for safe pipeline operation. Particular emphasis should be upon protection from overpressure, instruments to give warning and to shut down pumps in case of damage to the pipeline, regular inspection of the route, and regular checking of the cathodic protection system (IOP 8.1). IOP recommends that long submarine pipeline routes be inspected regularly by aerial patrol (IOP 11.9). Regular underwater inspection should be carried out where there is risk of damage to the pipeline (IOP 11.10). If the pipeline crosses areas where there is particular danger of water pollution being caused by any leakage, a 24-hour static pressure test (1.5 times maximum working pressure or to that which will result in a hoop stress equal to 90 percent of the SMYS) should be conducted once per year (IOP 9.2).

(2) Oil Pipeline Regulations. US standards require that each carrier shall prepare and follow written procedures for conducting normal operations, and for maintenance and handling of abnormal operations and emergencies (US 195.402(a)). Each carrier shall, at intervals not exceeding two weeks, inspect the surface conditions on or near to each pipeline right-of-way (US 195.412(a)). At intervals not exceeding 12 months, each carrier shall conduct tests to determine whether the cathodic protection is adequate (US 195.416). Each mainline valve shall be inspected at intervals not exceeding six months (US 195.420(b)).

As previously mentioned, DnV and API recommended practices for monitoring oil lines are the same as those for gas lines.

ANSI requires each operating company to have an operating and maintenance plan based on the provisions of the code (ANSI B31.450.1). Each company shall maintain a periodic pipeline patrol program, including underwater crossings, to observe surface conditions and other factors affecting the safety and operation of the line (ANSI B31.451.5). Pipeline valves shall be inspected when necessary and partially-operated at least once a year (ANSI B31.451.7). Controls, pressure limiting devices and other safety equipment shall be subjected to inspections and tests at least annually (ANSI B31.452.2). Cathodic protection facilities shall be inspected at least each calendar year, but with intervals not exceeding 15 months (ANSI B31.461.3(a)).

With the exception of corrosion control monitoring, CSA standards for liquid oil lines are the same as for gas lines, although the wording is different. Citations for liquid oil standards are: operating and maintenance plan (CSA Z183.9.2.1), right-of-way patrolling (CSA Z183.9.13.4), and control and safety devices (CSA 2183.9.5). Cathodic protection systems shall meet accepted criteria by a survey each calendar year, but at intervals not exceeding 15 months (CSA 2183.10.3.2.1). This is in contrast to the gas line standards which state survey intervals as "periodic."

IOP codes for liquid oil inspection during operation are the same as those for gas lines with the following exception. Para. 9.2 states that a static pressure test (1.5 times maximum working pressure or to that which will result'in a hoop stress equal to 90 percent of the SMYS) of 24 hours duration should be performed once a year if the pipeline crosses areas where there are particular dangers of water pollution being caused by any leakage. Para. 9.2 goes on to state that such tests are impracticable on continuously operated hot oil pipelines.

(3) Analysis. All of the standards require a procedure for operation and maintenance of pipelines. All require periodic patrolling of the right-of-way and inspection of various pipeline features.

One difference between the standards reviewed is the maximum time interval permitted between patrols or inspections. With one exception, the US standards are equal or more stringent than the others (API recommends a six-month maximum interval between pressure-limiting and safety device inspections while the US specifies a one-year maximum). Many of the codes require "periodic" patrolling and inspection without mentioning time limits. DnV defines periodic as a maximum of one year unless otherwise agreed upon. Because of the hazardous environment of the subsea Arctic, consideration might be given to reducing the US 12-month maximum between gas line patrols. Adverse weather conditions may make the US two-week oil line patrol interval (US 195.412(a)) unrealistically frequent.

Valve inspection standards provided the greatest disparity in requirements. The US codes require gas line valves that might be used in an emergency to be inspected and partially operated ever 12 months while each oil line main valve shall be inspected every six months. CSA oil line valves, DnV gas and oil valves, and IOP gas and oil valves are not mentioned in their respective codes concerning inspections. However, the valve inspections could be covered indirectly by other regulations.

None of the standards addressed subsea valve inspection; the closest was API's mention of above-water valve inspection, but no matching standard for underwater valves was provided. Only IOP specified subsea inspections under certain conditions (IOP 11.10).

9. Environmental Impact

a. Regulations. US gas line standards require operators to establish written procedures for shutting down and reducing pressure in any section necessary for minimizing hazards to life or property (US 192.615(a,(6)). The liquid pipeline standard also specifies that if a condition presents an immediate hazard to persons or property, the carrier may not operate the affected part of the system until corrective measures have been taken (US 195.401(b)) and in case of pipeline abandonment safety and environmental hazards were to be minimized (US 195.401 (C.10); 1979).

API Recommended Practices 1111 makes no reference to environmental effects of pipeline operations.

ANSI liquid oil line standards state that the primary purpose of their code is to establish requirements for safe design, construction, inspection, testing, operation and maintenance of liquid petroleum transportation piping systems for, among other goals, reasonable protection of the environment (ANSI 400(c)). A written emergency plan, discussed in Topic 10 of this section, shall be established by the operator and include procedures for remedial action to protect the environment and limit accidental discharges (ANSI B31.454(a)). ANSI gas line standards (B31.8) do not mention environmental effects.

CSA gas and oil line standards each contain requirements for environmental protection. For oil lines, each company shall establish effective pollution prevention and control measures to minimize the effect of the operation upon the environment. Aspects to be considered include sensitivity of route and terrain traversed, vegetation, noise pollution, thermal pollution, and aesthetics (CSA 2183.9.6). Similarly, for gas lines, all facilities shall be designed, installed and operated to prevent or control pollution. Various aspects to be considered are listed (CSA 2184.11.3.3.1-2).

DnV rules include no provision for pipeline system effects on the environment.

IOP codes include environmental effects to be considered. Although they are intended for onshore applications, the following three also might apply to shoreline and subsea Arctic situations: before work starts, a record should be made of any existing special features so they may be adequately reinstated if disturbed; it is essential that contractor's workmen avoid trespassing outside the working limits of the pipeline route (IOP 5.1.1); due consideration should be given at all times to the protection of established fishing rights and to the preservation of fish (IOP 5.1.8).

b. Analysis. The effect of pipelines upon the environment, with the exception of CSA and IOP standards, and brief statements in US 195, generally is not addressed by the codes reviewed. However, in the case of the US standards, such effects are under the jurisdication of governmental bodies other than the Department of Transportation. Nonetheless, minimizing the effects of a pipeline involves engineering and inspection (i.e., patrolling) functions which do appear in the standards. It is beyond the scope of this analysis to determine the kind or amount of overlap between governing agencies.

10. Leak Handling Procedures

a. Gas Pipeline Regulations. US Part 191 prescribes requirements for reporting gas leaks and test failures. It does not apply to those occurring in the gathering of gas outside the limits of any city, town or village or any designated residential or commercial area (US 191.1).

US Part 192.615 contains emergency plan requirements. Each operator shall establish written procedures to minimize the hazard resulting from a gas pipeline emergency. Subjects the procedures must provide for include: events requiring immediate response; communication with appropriate fire; police and other officials; prompt and effective response to a notice of emergency; and the availability of personnel, equipment, tools and materials, as needed at the scene of an emergency. Other subjects include emergency shutdown, making safe any hazards, and beginning an investigation of the failure (US 192.615). Each operator shall establish procedures for analyzing accidents and failures to determine the cause and minimize a recurrence (US 192.617).

API recommended practices require a written emergency plan which includes procedures for expedient remedial action. This plan should provide for personnel training, liaison with officials, and measures to control pollution (API 702). Accidents and significant material failures must be investigated to determine their cause, and steps taken to prevent their recurrence (API 701.10).

ANSI requires each operating company to set up an emergency plan and acquaint appropriate employees and public officials with the plan (ANSI B31.850.4). Procedures shall be established to analyze all failures and accidents, and to minimize the possibility of a recurrence (ANSI B31.850.5).

CSA standards require each operator to have a written plan which shall include procedures for safe shutdown of the pipeline, or part thereof, in the event of a failure or other emergency (CSA Z184.9.1.3.3).

DnV rules for gas lines contain no material relating to this topic.

IOP requires pipeline leaks in the United Kingdom to be reported to the Ministry of Power (IOP 10.3.12). A model leakage report form is provided (IOP Appendix C). The purpose of drawing up emergency procedures for a pipeline is to ensure that the operating staff and others to be involved are informed regarding action to be taken in the event of an emergency (IOP 10.1). Factors to be considered, among others, are liaison with public authorities, scope of emergency procedures, emergency equipment availability, remedial action, and emergency exercises (IOP 10.2-5). Each of the above subjects, and others, has detailed guidelines to aid in the preparation of emergency procedures for individual pipelines. IOP Appendix A contains laws regarding government notification of accidents, and Appendix B provides instructions for removal of oil from a watercourse.

b. Oil Pipeline Regulations. US standards require the reporting of certain pipeline accidents to the Department of Transportation via DOT Form 7000-1 (US 195.54). Some incidents requiring a report include: an explosion or fire not set intentionally by the carrier; loss of 50 or more barrels of liquid; and death or bodily harm to any person (US 195.50). Telephonic notice of certain serious accidents also is required (US 195.52). Each carrier shall prepare and follow a manual of written procedures for normal operations and emergencies. If the Secretary finds that a carrier's procedures are inadequate, he may require them to be amended. Specific requirements for procedures are provided (US 195.402). Each carrier shall establish and conduct a continuing training program to instruct personnel in the various normal and emergency procedures that relate to their assignments (US 195.403). Each company must have a communication system to provide for the transmission of information needed for the safe operation of its pipeline system (US 195.408). A continuing public education program shall be established to enable the public to recognize and report liquid pipeline emergencies (US 195.440).

API recommended practices for liquid oil lines are identical to those already mentioned for gas lines.

ANSI requires each operating company to have a written emergency plan which shall include procedures for prompt remedial action. The plan shall provide for training personnel, liaison with civil agencies and cooperative leak notification with other pipeline operators, among other subjects (ANSI B31.454). Each company must report changes in conditions affecting the system, establish procedures to analyze all failures and accidents, attempt to minimize a recurrence, and modify plans and procedures as conditions require (ANSI B31.450.2).

CSA standards state that records shall be maintained to assist in the development of procedures for use during emergency conditions. Among others, the records shall include a list of agencies to contact in case of emergency, containing names and phone numbers of key personnel, and location and description of major repair equipment (CSA 2183.9.9.4).

DnV rules for liquid oil lines contain no material relating to this topic.

IOP codes for liquid oil lines are the same as those previously described concerning gas lines.

c. Analysis. There is a wide disparity among the regulations reviewed. The IOP codes devote an entire chapter to emergency procedures and include various appendices on the subject while DnV rules do not mention emergencies at all. CSA standards, usually highly-detailed, provide little guidance.

The US standards contain detailed material on gas and oil leak reporting requirements which appear to be adequate. The combination of telephonic and written reports of certain incidents also would be applicable to Arctic conditions, although delays in making telephone contact (probably via radio from the field) with the DOT could be expected.

Emergency plan requirements are essentially the same between the organizations that require them with the exception of the minimal CSA provisions. The only differences are in the amount of detail explaining the various procedures that are required. Provision for personnel emergency training and review might be added to US gas line standards in a manner similar to the new oil line standards (US 195.403; 1979). Failure investigation requirements between those who addressed it were nearly identical. Remedial action, mentioned only by API, ANSI and IOP provided no additional information on the subject. Inclusion of a requirement in the US standards for a complete remedial action plan, updated regularly, for Arctic pipelines should be considered.

11. Safety Devices

a. Regulations. US gas pipeline standards contain criteria for emergency shutdown systems, pressure-limiting devices and additional safety equipment for compressor stations. Each compressor station (except for unattended field stations, 1,000 horsepower or less) must have an emergency shutdown system (US 192.167), pressure relief or other devices to prevent operating pressures exceeding the maximum by more than 10 percent (US 192.169), adequate fire protection facilities, a device to prevent excessive speed of specified prime movers, and other safety devices (US 192.171).

Each US liquid oil line pump station must be provided with safety devices that prevent over-pressuring, a device for emergency shutdown and, if power is necessary to actuate the safety equipment, an auxiliary power supply (US 195.262). No carrier may permit the pressure in a pipeline during surges or other variations to exceed 110 percent of the operating pressure limit. Each carrier must provide adequate controls and protective equipment to control the pressure within this limit (US 195.406(b)).

API gas and oil practices state that a safety system should be provided that will prevent or minimize the consequences of over-pressure or leaks (API 400). Gas compressor stations and other gas pipeline facilities on non-production platforms should be provided with a safety system in accordance with ANSI B31.8 and be protected by valves or other components to shut off flow of gas to the platform in an emergency (API 402.4).

Liquid hydrocarbon pipeline facilities on non-production platforms in which pressure generating equipment is installed should be provided with a safety system appropriate to the pipeline and with an effectiveness equal to that of API 14C,

Appendix A, Section A9. The design of the safety system also should consider the need for limitation of surge pressure and other variations (API 402.1).

ANSI gas line standards for protection against accidental over-pressuring require suitable pressure-relieving or pressure-limiting devices (ANSI B31.845.1). Specific types of these devices and requirements for their design and capacity are mentioned (ANSI B31.845.2-4).

ANSI oil line standards specify requirements for installation of pressure controls and protective equipment, including pressure-limiting devices, regulators, controllers, relief valves, and other safety devices (ANSI B31.434.20.6).

CSA requires each gas line compressor station to have an emergency shutdown system and CSA provides requirements for such a system (CSA 2184.6.6.5.1.1). Pressure-relief or other suitable protective devices shall be installed and maintained to assure that the maximum allowable operating pressure of the station piping and equipment is not exceeded by more than 10 percent (CSA 2184.6.6.6.1). Various other compressor-station safety devices also are required (CSA 2184.6.6.6-7, 9). Every pipeline system shall be equipped with suitable pressure-relieving or pressure-limiting devices (CSA 2184.6.8.1). Requirements for the design and capacity of these installations are provided (CSA 2184.6.8.6-7).

CSA liquid oil line standards require installation of pressure-limiting devices to ensure that maximum pressure, including all transient pressures, shall not exceed either 88 percent of the proof-test pressure or that pressure corresponding to 93 percent of the SMYS (CSA 2183.7.5.1.2).

DnV rules for gas and oil lines assume that the pipeline is operated and controlled by a system designed according to generally recognized codes or standards, including requirements for adequate automatic- emergency shutdown systems (DnV 1.2.4.2).

The IOP section on operation, covering gas and oil lines, states that particular emphasis should be placed on safety devices for protecting the pipeline from pressures in excess of those for which it was designed. Also important are warning instruments and shutdown pumps, in case of damage caused to the pipeline by Act-of-God or third-party activities (IOP 8.1).

b. Analysis. Of the standards reviewed, the US requirements for both gas and oil lines are the most complete. The US Parts 192 and 195 seem adequate for Arctic subsea pipeline systems.

In contrast, DnV rules provide essentially no material on the subject. API and IOP codes cover safety devices in general terms, although the API gas line practices incorporate ANSI B31.8 by reference. ANSI gas line standards include requirements for the design and capacity of protective devices, a subject also covered in the CSA gas line standards, but not in any of the others. However, the ANSI and CSA gas line standards apply only to above ground systems. ANSI oil line standards specify installation requirements for safety equipment but do not discuss the devices themselves. The CSA standards provide detailed requirements for gas lines but include minimal material for oil lines.

12. Thermal Expansion/Contraction

a. Regulations. US gas line standards state that each pipeline must be designed with enough flexibility to prevent thermal expansion or contraction from causing: excessive stresses in the pipe or components; excessive bending or unusual loads at joints; undesirable forces or moments at points of connection to equipment, or at anchorage, or guide points (US 192.159). Section 419 of ANSI B31.4 must be followed for US oil line expansion and flexibility requirements (US 195.110).

API recommended practices for expansion and flexibility incorporate ANSI B31.832-3 (gas lines) and ANSI B31.419 (oil lines) by reference (API 203).

ANSI gas line standards for expansion and flexibility apply to above-ground piping only (ANSI B31.832.1). Since these are not applicable to the Arctic subsea environment, they will not be covered here. ANSI oil line standards on expansion and flexibility are applicable to both above-ground and buried piping. Piping shall be designed to have sufficient flexibility to prevent expansion or contraction from causing excessive stresses in the piping material, unacceptable bending moments at joints, or too large forces or moments at connections to equipment, or at anchorage or guide points. Expansion calculations are necessary for buried lines if significant temperature changes are expected, such as when the line is to carry heated oil. Unless movements are restrained, the necessary flexibility shall be provided (ANSI B31.419.1). Means of achieving flexibility and information for making calculations are given (ANSI B31.419.5-6, Figure B31.419.6.4(c)).

CSA gas line expansion and flexibility standards apply to above-ground piping only (CSA Z184.5.3) and will not be covered here. CSA oil line standards apply to both above-ground and buried systems and are virtually identical to ANSI B31.419 described above.

DnV rules for gas and oil lines define thermal expansion and contraction as functional loads. These loads primarily include the effect of product temperature on material temperature. Possible other causes of changes in material temperature will be considered (DnV 3.2.2).

IOP codes state that when variations in pipeline temperature occur, allowance should be made for the effects of thermal expansion and contraction (IOP 2.1.5). IOP codes concerning expansion and flexibility and information to make such calculations are essentially identical to ANSI B31.419.

b. Analysis. Thermal expansion and contraction, and thus flexibility, may be expected to be a greater problem for an Arctic subsea pipeline than one in a more temperate location because of low temperatures. The standards reviewed require sufficient flexibility to prevent excessive stresses. The US standards appear suitable for Arctic subsea applications, but interaction between the pipe and soil (case of constrained pipe) should be addressed and the constrained versus non-constrained pipe cases distinguished.

ANSI standards, or nearly identical copies of ANSI standards, form the basis of all but the DnV rules. API, ANSI and CSA gas line expansion/contraction standards apply only to above-ground situations, but guidance is provided in other paragraphs on restraints and anchoring of buried lines. DnV rules barely address thermal expansion and contraction.

VI. RECOMMENDATIONS FOR ARCTIC PIPELINE SAFETY STANDARDS

This section addresses recommended changes or additions to the safety standards in the applicable portions of CFR 49, Part 192 (gas pipelines) and Part 195 (liquid pipelines) revised October 1, 1979. The recommendations are limited to those aspects which affect offshore Arctic pipelines carrying gaseous or liquid hydrocarbons. Furthermore, according to a Memorandum of Understanding (MOU) between DOT and DOI (dated May 6, 1976) the standards cited above apply only to pipelines originating at the outlet flange of an offshore production facility and extending to an onshore facility.

Dravo Van Houten, Inc. conducted a review of offshore pipeline safety practices for the Office of Pipeline Safety in December 1977. Many recommendations were made in that review for amendments to Parts 192 and 195, some of which apply to offshore Arctic Pipelines. The applicable recommendations are not repeated here but reference will be made to the Dravo Van Houten report as required.

Although MOU's exist between DOT and DOI on pipelines, there appears to still be dual responsibility as indicated in the USGS Gulf of Mexico OCS Order #9, effective October 30, 1970. It remains apparently unchanged in later OCS Orders for the Gulf of Alaska (March 1976) and for Arctic Alaska (still in the draft form). According to Order #9 "Oil and Gas Pipelines," the USGS area supervisor "is authorized to approve the design, other features, and plan of installation of all pipelines for which a right of use or easement has been granted....including those portions of such lines which extend onto or transverse areas other than the outer continental shelf."

It is assumed in these recommendations that hydrocarbons transported through a pipeline in the Arctic Sea would be in the form of natural gas, crude oil, or oil/gas (two phase) mixture. Cryogenic fluids are not considered since, if any gas liquefaction plants are to be built in the future, they would most likely be a part of an onshore installation.

In the discussion of the federal safety standards Parts 192 and 195, other pipeline regulations listed in Chapter V were analyzed there to obtain a better understanding of the approaches used by other agencies. In addition, the following two documents were reviewed,

- Environmental Protection Agency "Oil Pollution Prevention," Federal Register, Vol. 38, No. 237, December 11, 1973.
- Germanischer Lloyd (W. Germany) "Allgemeine Grundsatze fur Verlegung, Prufung und Uberwachung von Rohrleitunger unter Wasser," March 1973.

The recommended changes or additions to the Federal Safety Standards for hydrocarbon pipelines in the Arctic Sea were derived from the discussions in previous sections of Arctic pipeline state of the art, problems and hazards peculiar to the area, and environmental concerns. A brief justification is presented in this chapter after each recommendation.

A. RECOMMENDATIONS FOR PART 192 (GAS PIPELINES)

1. Para. 192.17 Filing of Inspection and Maintenance Plans

a. Suggested Change. At present Part 192 does not consider contingencies connected with an offshore Arctic gas leak, Emergency plans are identified in Para. 192.615 but these apply primarily to populated onshore areas. A special and more detailed plan is required due to the severe environment, availability and response time of men and equipment, and difficult logistics in the Arctic when an emergency occurs.

Two options are available: one is to modify Para. 192.615 to address the Arctic offshore situation; the second is to require in Para. 192.17 an additional Gas Leak Control Plan to be submitted by the pipeline operator.

b. Justification. The access to a submarine pipeline in the Beaufort or Chukchi Seas is difficult. The detection and repair of gas leaks is hampered by the ice that covers the surface for approximately nine months of the year, and by low temperatures that make outdoor activities difficult and hazardous (see Section 11). The difficulties are further amplified by problems of equipment transportation during the break-up or freeze-up periods, and the long distances to industrial centers for manpower and equipment (see Section IV.E, F). Gas escaping from a defective pipeline can accumulate and migrate under the ice in an unpredictable manner posing environmental and fire hazards. The need to stop such a leak as soon as possible is mandatory.

All this creates a scenario quite different from the lower 48 States where the main concern is about the safety of the surrounding population and not about a procedure for pipeline repair. On the Arctic offshore there is a need for a prepared-in-advance contingency plan which would: take into account seasonal differences; define repair techniques; identify the availability of equipment and personnel; identify transportation means; and define a management set-up to deal with the problem.

It was noted that the standards for liquid pipelines Para. 195.401 (1979 amendment) amplified the requirements for a manual on operations, maintenance and emergencies. A similar manual is needed for gas pipelines to make the procedures for gas and liquid pipelines as similar as possible, While it is recognized that a gas leak is less damaging to the environment than an oil leak, repairs required for each impose similar problems in the Arctic offshore.

The 1979 liquid pipeline amendments added Para. 195.403 on the training of personnel for maintenance and emergencies. For gas pipelines the training requirement is mentioned in one subparagraph 192.615 (b) (2). Expanding this requirement for gas pipelines appears desirable.

API-RP 1111 contains in Para. 702 a requirement for an emergency plan which includes "protection of the environment, limitation of discharge from the pipeline system and for failure investigations."

2. Para. 192.51 - 192.55 Materials (Also 192.65)

a. Suggested Changes. Pipeline materials and components for Arctic offshore application should be limited to steel only. Cast iron, copper or plastic listed in the present safety standards should be excluded from Arctic offshore use. The Appendix B of the safety standards lists a number of material specifications. ANSI B31.8 should be added to the appendix. It contains codes for transmission and distribution lines and ASTM A671, A672 addressing electric fusion steel pipe at low and moderate temperatures. The need for good mechanical properties at low temperatures and good fracture toughness should be emphasized in the safety standards. Maximum allowable stress should be specified during transportation and installation of the pipe.

b. Justification. Materials that may be marginal under rigorous Arctic conditions should be excluded because of the potentially significant environmental impact and the high repair cost associated with pipeline failures. Det norske Veritas (DnV) (Section 5), Institute of Petroleum (IOP)

(Section 3), and American Petroleum Institute (API) (RP-1111, Section 3) rules all specify steel exclusively for pipe in cold environments.

Although submarine pipelines once installed in the Arctic Sea will be subjected to a relatively constant and moderate external temperature of about minus 1.8°C (29°F), in most cases the transportation, storage, installation and pressure-testing may expose the pipe materials to ambient temperatures as low as minus 50°C (minus 60°F). Consequently, low transition temperatures and high fracture toughness should be a primary characteristic of Arctic pipeline material. Pipe stress during transportation and installation should be limited to a level that prevents pipe damage under the lowest temperatures encountered (See Section IV.A).

The Canadian Standards Association (CSA) specifies fracture toughness properties at design temperatures (2184, Para. 3.1.2.2) and so does DnV (Para. 5.2.3).

Because of the importance of high fracture toughness in preventing crack propagation, a criteria for it should be stipulated in the safety standards (such as Charpy V-Notch, NDT or others).

3. Para. 192.103 Pipe Design - General

a. Suggested Change. The list of external loads should be expanded to include forces from wind, waves, currents, subsea or shoreline permafrost induced forces (thaw subsidence or frost heave if gas temperature is below freezing), ice movement, erosion and soil movement, thermal loads, and seismic activity.

b. Justification. This item was brought out in the Dravo Van Houten report (p. 4-33 through 4-44). It is covered in the API - RP-1111 (Para. 200.5) and in DnV (Section 2.3).

Some of these forces such as wind, wave, currents and ice movement will be important during the installation phase, others such as ice scouring, geotechnic forces and seismicity will be of significance in the operational phase. It is considered necessary to have various external forces listed to bring to the designer's attention the unique hazards associated with Arctic offshore pipelines (see Section IV.D).

4. Para. 192.159 Flexibility

a. Suggested Change. A brief statement is made in this paragraph concerning the effect of thermal expansion or contraction of the pipeline. This paragraph should be clarified by a requirement that stresses resulting from expansion or contraction should be combined with other internal or external loads for either constrained or unconstrained pipelines. Reference to ANSI B31.8-1975 would be appropriate.

b. Justification. Recent cracks found in the Trans Alaska pipeline, which were mainly caused by pipe sagging, illustrated the need for an accurate prediction of all loads when designing for standard minimum yield strength. The API practices regarding thermal expansion or contraction refer to ANSI B31.8 (Para. 210.7). The DnV rules require that loads due to thermal expansion be included in an internal pressure stress calculation (Para. 3.2.2.4). Similarly, CSA Standard Z-184 specifies calculations of combined stresses considering thermal expansion or contraction (Para. 5.4).

Discussion on thermal and other external loads is contained in Section IV.D of this report as well as in item 3 above.

5. Para. 192.163 Compressor Stations: Design and Construction

a. Suggested Change. An anti-icing system for compressor units should be required in view of potential icing hazards.

b. Justification. The icing of compressor inlets is a problem experienced in Prudhoe Bay installations and discussed' in Section IV.J.2 of this report, It is a unique problem of this environment and should be addressed in safety standards for Arctic offshore pipelines (see Section IV.J.l).

6, Para. 192.179 Transmission Line Valves

a. Suggested Change. CFR 49 allows the use of ductile iron in addition to steel for valves (Para. 192.145). Valve material for the Arctic offshore pipelines should be limited to steel only, with mechanical properties matching those of the pipe material.

CFR 49 should request the placement of block and check valves at the offshore platform outlet and at the onshore inlet of a pipeline. Presently, Para. 192.179(d) specifies that "offshore segments of transmission lines must be equipped with valves or other components to shut off the flow of gas to an offshore platform in an emergency."

b. Justification. The two issues discussed above also were brought forth in the Dravo Van Houten Report (p. 4-107 to 4-111). The requirement for steel as a valve material has the same justification as that given for pipes in item 2 of this section. In the other regulations reviewed, such as API (by reference to ANSI B31.8), Institute of Petroleum (Para. 2.4.8), DnV (Para. 5.3.1) specify steels as valve material.

The block and check valves located at both ends of the offshore pipeline would shut off the flow in the event of a pipe failure and the resulting pressure drop. It would prevent a backflow from onshore pipelines, thus limiting the amount of gas lost to the environment.

7. Para. 192.223 Qualification of Welding Procedures

a. Suggested. It is recommended that underwater welding technology be recognized in the safety standards. It is not mentioned in CFR 49. Recognition of this technology through the definition of criteria for underwater welding could assure the use of the best available techniques, Although, to our knowledge, there are no existing standards for wet welding at this time, practices and procedures do exist that are referenced by the ship classification societies.

b. Justification. In view of the short season for pipe-laying barges in the Arctic Sea, the possibility of underwater welding rather than barge welding of pipe sections cannot be disregarded. The technology of underwater welding either in dry habitat (hyperbaric or atmospheric environment) or to a lesser degree wet welding is progressing, and a number of successful underwater welding operations were conducted in the last few years (see Section I.D). An alternative to a welded joint, a mechanical joint, has not proven always reliable in the past. (Example: There are several leaking joints in recently-completed gas pipelines from Ekofisk field to Emdden.) However problems with mechanical joints largely have been resolved (R.J. Brown and Associates, private communication) and if so, they offer means for fast connection operation and relative ease of repairs.

DnV rules provide requirements and criteria for underwater welding of pipe tie-ins (Para. 8.7.4).

8. Para. 192.317 Protection from Hazards

a. Suggested Change. Ice scouring and ice riding onshore should be added to the hazards mentioned for offshore pipelines and pipe risers.

b. Justification. Self-explanatory for Arctic offshore pipelines (see Section II.B).

9. Para. 192.319 Installation of Pipe in a Ditch

a. Suggested Change, Three changes in the text of this paragraph are recommended for Arctic offshore pipelines:

(1) Warning of the existence of offshore and/or shoreline permafrost which, depending on the gas temperature, can lead to thaw subsidence (warm gas), or frost heave (cold gas). This may cause either sagging or uplifting of the pipe introducing additional stresses which should be taken into account in the pipe design. Furthermore, the safety standard should indicate a need for reduction of heat transfer between the pipe and the surrounding medium (by pipe insulation or other means) if it appears that during the operational life of a pipeline excessive movement of the pipe may occur. Trenching operations should consider the existence of discontinuous subsea permafrost, and a detailed geotechnic survey of pipeline route should be required to establish permafrost location and boundary.

(2) Flagging the need for negative buoyancy of a pipe to maintain pipe stability in a trench under all conditions, including saturated soils prone to instability or liquefaction.

(3) Sub-paragraph 192.319.c either should be modified or replaced by another applicable to Arctic offshore. Presently, this sub-paragraph reads: "All offshore pipe in water at least 12 feet deep but not more than 200 feet deep, as measured from the mean low tide, must be installed so that the top of the pipe is below the natural bottom unless the pipe is supported by stanchions, held in place by anchors or heavy concrete coating, or protected by an equivalent means."

The recommended text should state a requirement that at water depths up to 200 ft the pipe be installed so that the top of the pipe is below the maximum amount of ice scour depth expected in 100 years at a given location. If burial to such a depth is not feasible, then the pipe must be protected by other means to withstand anticipated external loads. Pipe emerging onshore should be installed in a manner as to safeguarding it against erosion, soil movement, soil liquefaction, ice override, and shoreline permafrost degradation.

b. Justification. The rationale for changing these three items is:

(1) Subsea permafrost was found in the Beaufort Sea at various water depths *(see* Section II.C). Some of this permafrost is of relic type, but near-shore or barrier islands permafrost is a continuation of onshore formation. The subsea permafrost is mostly "soft" with the temperature close to its melting point since the surrounding sea water temperature of minus 1.8°C (29°F) is only slightly below the fresh water freezing point. Consequently, the thermal equilibrium is finely balanced, and a small amount of heat extraction or addition will upset this and create a new set of conditions which must be examined and compensated for in the pipeline design. In general, the subsea permafrost is discontinuous and is very much a function of location. Consequently, a detailed geotechnic survey of a pipeline route before design and construction are started is important for pipeline safety and should be addressed in the safety standards.

Locally encountered permafrost also will have an effect on the type of equipment which could be used for trenching, on the rate of trenching, and on pipeline-installation time. Of the specifications reviewed only the Canadian Standards Institute (CSA 2184, Para. 11.3.1 and 11.4.4.2.2) discusses problems related to permafrost degradation.

The DnV rules specify the need for geotechnical surveys using various investigating methods (Para. 2.25).

(2) The need for negative buoyancy to ensure pipe-in-ditch stability is evident. It becomes particularly important in areas subject to slope instability, soil-mass movements, or soil liquefaction. The Dravo Van Houten Report (p. 4-84) emphasizes the soil movement in the surf zone and the need to address this problem in the safety standards.

The DnV rules address in detail the problem of on-bottom stability and negative buoyancy under various forces acting on the pipe (Para. 4.2.6).

(3) Ice is a major hazard to an offshore system in the Arctic Sea as discussed in Section II.B of this report. If the pipe is installed from the ice surface, ice movement is critical. For pipe-laying in a trench, scouring of the sea bottom by floating massive ice blocks is a hazard to approximately 60m (200 ft) water depth. Some data on the depth of scour and scour frequency were given in Section II.B. Ice also may be driven onshore overriding any near-shore installations as the result of a storm. Consequently, the design of a pipeline crossing a shoreline must receive proper attention. This should be mentioned in the safety standards.

10. Para, 192.327 Cover

a. Suggested Change. The pipe should be covered (after installation in a trench) in all areas where the surcharge weight stabilizes the pipe where wave and current action is intensive such as in the surf zone, and/or where damage by the invading ice is very likely, such as on the beach area.

In other locations the need for pipe cover would depend on the evaluation of wave and current forces, and the possibility of pipe damage by barges and fishing boat anchors. The depth of the cover would be variable, and should be sufficient to avoid the hazard of ice scour already discussed under item 9.

b. Justification. The purpose of the cover is to protect the pipe from external forces and, in some instances, to control pipe overbend caused by thermal expansion. There may be locations in the Arctic Ocean where the external forces acting on a pipe placed in a trench are negligible and where danger of pipe overbend is small. Consequently, in such locations pipe cover might not be required. On the other hand, there are areas such as surf zone, river deltas, and beach approaches where the pipe should be covered with a suitable soil to prevent its movement and exposure to external forces. There is also the consideration of seabed soil type. In the Beaufort Sea, for example, soil consists mainly of fine silt or silty sands in the top 5 to 10m (16 to 33 ft) which could offer inadequate protection as a cover (see Section II.C.1). Finally, a natural backfill process due to waves, storm tides, and currents should be considered as a long-term method of pipe cover. Thus, safety standards should require covering in critical areas, but allow the pipe owner to perform an analysis to show whether the pipe should or should not be covered in other locations.

The API practice (Para. 500.8.3) and IOP (Para. 11.5.7.2) are a similar approach to the cover problem.

The thickness of the cover (between the top of the pipe and the sea bottom) must ensure that the pipe is not damaged by long-term ice scour, by ice overriding a beach area crossed by a pipe, from exposure by thermal expansion or by soil movement in the surf zone. The problem of ice scour also was mentioned in the Dravo Van Houten Report (p. 4-49). Since any one of these hazards is a strong function of location, it is considered preferable not to specify fixed values in the standards. Rather, the pipeline designer should be requested to supply data proving that the selected depth of trench and cover thickness is adequate and safe.

11. Para, 192.455 External Corrosion Control

a. Suggested Change. External protective coatings and cathodic protection should be provided for all offshore pipes in the Arctic Sea. Exceptions to that requirement listed in items (b), (c), and (f) of this paragraph should not apply to Arctic offshore pipelines.

b. Justification. The environment of Arctic offshore pipelines (i.e., corrosion and the difficulty of inspection of buried pipes) dictates the application of the best anti-corrosion technology available. The pipeline failure analysis performed in Section III of this report identifies corrosion as the most frequent cause of failure.

The Dravo Van Houten report stresses the importance of external coatings for submerged pipes (p. 4-141 to 4-143), and quotes appropriate paragraphs of API, DnV and IOP regulations all of which specify external anti-corrosion coatings for submerged pipes.

12. Para. 192.503 General Requirements (Pressure Test)

a. Suggested Change. The present safety standards do not specify that the pressure test be done after installation of a pipe. Such a requirement is necessary and should be included in the standards. Furthermore, if a pipeline is to be covered, a pressure test with unburied pipe in a trench could be followed by a similar test after the trench is filled, if there is a possibility of pressure-caused leakage or pipe damage during the covering process.

The safety standards allow the test medium to be liquid, air, natural gas or inert gas (Para. 192.503b). It is recommended that only water, with a freezing point depressant, be used in the pressure testing of Arctic offshore pipelines. A liquid is prepared, instead of air or natural gas, because it is not compressible and would tend to more fully stress the pipeline to prove its integrity. Due to the Arctic sea conditions it may not be possible to gain access to the pipeline for long time periods if repairs are needed. Therefore, proof tests of the initial integrity should be emphasized.

The present safety standards specify maintenance of the test pressure for at least eight hours. It is recommended that this time be increased to 24 hours for installed pipelines unless the operator can show that pressure stabilization, considering temperature effects and a complete inspection, can be done in shorter time. However, the test period should not be less than eight hours. At least 24 hours are needed to stabilize the temperature stresses and to detect shifting.

b. Justification. Considering the difficulty connected with repairs of submarine pipelines in the Arctic Sea, every reasonable effort should be made to assure pipe integrity before the pipeline becomes operational. Pressure testing after placement of a pipeline in a trench would provide assurance that no damage occurred during the pipe-laying operation. Pressure testing after the trench is filled would provide assurance that no damage resulted from the covering process (see Section IV.B).

The API practices specify pressure testing after installation (Para. 601.3.1.b) with the duration to be not less than eight hours (Para. 601.4.1.c).

IOP Code specifies pressure testing of completed pipeline in each completed section with a duration of 24 hours (Para. 6.4).

DnV rules specify hydrotesting after installation (Para. 8.8.4) with pressurized time of 24 hours after pressure stabilization (Para. 8.8.4.3).

CSA Standards require pressure testing after construction and before being placed in operation and, for all buried pipelines, the pressurized time is specified a minimum of 24 hours after stabilization (Para. 6.4.8.1.1).

The requirement for 24 hours pressurized time appears necessary to allow for compensation of any temperature effect and to provide sufficient time for underwater pipe inspection.

The requirement for liquid rather than gas as a test medium is dictated by potentially large temperature differences between air and sea water in the Arctic which, with a compressible medium, would result in large pressure variations and would require a long time for pressure stabilization.

13. Para. 192.705 Transmission Lines: Patrolling

a. Suggested Changes. This paragraph was written in the existing standards for onshore pipelines. For Arctic offshore pipelines patrolling would consist of aerial inspections during the winter period (October - June), at least one underwater inspection between ice break-up and freeze-up, and special inspections following unusual operational or environmental events.

b. Justification. During winter months, when the water surface is covered by ice, little can be seen on the ice surface unless a major gas eruption breaks up the ice. Occasional aerial overfly offers the only means of patrolling a pipeline during that period.

In the summer months, after the water surface is ice free, underwater inspections by manned or unmanned submersibles should provide good information on the pipeline health.

14. Items Not Addressed in Detail in Chapter 192 Safety Standards

a. Weight Coating

(1) Suggested Change. Weight coating, which will have to be produced in the offshore Arctic, is mentioned only briefly in 192.319(c). It is recommended that a paragraph be added in the subpart C (Pipe Design) setting criteria for weight coating design similar to those for protective coatings in 192.461.

(2) Justification. This item was brought up in the Dravo Van Houten Report (p. 4-74). It is to be noted that DnV rules discuss strength of weight coating (Para. 4.2.5) and weight coating design criteria (Para. 6.7).

The use of weight coatings for Arctic offshore pipelines to maintain negative buoyancy probably would be preferred over any other devices because of high expected reliability, Consequently, guidelines for such coatings in safety standards would be desirable (see Section V.C.4).

b. Insulation Coating:

(1) Suggested Change. Insulation coating may be required on certain sections of the Arctic offshore pipeline. Criteria for such coating should be provided in the safety standards similar to those given for anti-corrosion coating in Para. 192.461.

(2) Justification. The permafrost problem was discussed already under item 9 of this section. Permafrost may be discontinuous in deeper waters and continuous near surface close to the shoreline. To prevent degradation of the permafrost in cases where it would affect pipeline integrity, control of heat transfer between the pipe and its surroundings would be required. Pipe insulation is one such means.

c. Communications

(1) Suggested Change. This very important aspect of Arctic offshore pipeline operation should be discussed in the safety standards, and a communication system with redundancy should be considered.

(2) Justification. Reliable communication systems between offshore and onshore and control signal transmissions to remotely operated valves and compressor stations are critical features of Arctic offshore pipeline operation. This was brought up in the Dravo Van Houten Report (p. 4-249) and it is even more important in remote Arctic locations.

The safety standards for liquid pipelines addressed the need for communications and the requirements were amplified in the 1979 amendment of Para. 195.408.

IOP code stressed a need for an adequate communication system (Para. 9.1). The need for communication systems also was discussed in Section IV.G of this report.

B. RECOMMENDATIONS FOR PART 195 (LIQUID PIPELINES)

1. Subpart B - Accident Reporting - Para. 195.50

a. Suggested Change. Present text of this paragraph is focused on harm to personnel and on property damage of at least $1,000. For the Arctic offshore, in addition to personnel hazards, an assessment should be made of the estimated impact of the accident on Arctic marine/terrestrial life. Requirements for such assessment shall be part of accident reporting. As an alternative, 195.50(b) should be changed to require reports of loss of 6.3 barrels (1 cubic meter) or more of liquid for Arctic waters.

b. Justification. The impact of oil spills on the Arctic environment was discussed in Section IV.J.1. Fragility of

Arctic biota, a long recuperative period, and possible difficulties associated with an oil spill, make an early assessment of environmental impact particularly important. The revision in 1979 to Para. 195.402 covers adequately the requirements levied on an operator in case of an emergency. However, it does not refer to any environmental impact assessment except for Para. 195.52.a.4 which requires accident reporting that resulted in water pollution, violating applicable water quality standards.

In the Arctic waters, and particularly in the nearshore areas where future oil/gas exploration can take place, any marginal oil spill will have some impact which requires assessment. Thus, a requirement for an oil spill control and contingency plan in the safety standards may be desirable.

2. Para. 195.102 - Design Temperatures

a. Suggested Change. The effect of low temperatures on the pipeline and its components should be stressed in the safety standards. A requirement should be added in the standards for material fracture toughness at the lowest temperature to which the pipe and components will be exposed.

Since the oil is usually warm or heated, maximum, minimum and differential pipe temperatures (that is, differences in temperatures of various pipe sections) should be considered in the pipeline design. This should be mentioned in this paragraph (see Section VI.A.4).

b. Justification. The need for low-temperature properties of Arctic offshore pipeline materials already was discussed for gas pipelines under Para. B.2. The arguments presented there apply also to oil pipelines.

For materials exposed to low temperatures, the Charpy V notch test could be used to indicate loss of ductility; but other data such as Drop Weight Temperature Test (DWTT), Nil Ductility Transition (NDT), critical stress intensity (K_{Ic}), critical crack opening displacement (COD) (used by Alyeska) should be considered in selection of suitable materials for Arctic offshore pipelines. Pipe stress during transportation and installation should be limited to a level safe enough to prevent pipe damage under the lowest temperatures encountered (see Section IV.A). Approaches of this type are under study as reported in 1976 ASM International Conference proceedings (edited by M.B. Ives), and at the 1979 Sixth Symposium on Line Pipe Research (AGA) listed in the references.

API in the RP-1111 in Para. 200.3 of practices cautions designers about the need to consider low temperature properties of materials, and *so* does ANSI B31-4 in Para. 401.3.

DnV specified Charpy V notch toughness test (Para. 5.2.3.6) for pipeline materials and defines values of energy absorption as a function of specified minimum yield strength (SMYS) at temperatures related to the minimum design temperature.

3. Para. 195.110 - External Loads

a. Suggested Change. This paragraph in its present form deals with two subjects: external loads, and the need for flexibility in pipeline systems by reference to ANSI B31.4.

It is recommended that the external loads paragraph be amplified (as discussed for gas pipelines under item A.3) to include a warning of potential permafrost hazards, to consider ice scouring problems, and to include effects of soil movement and beach erosion. As in the case of the gas pipeline safety standard (Para. 192.159), it also is recommended that pipeline flexibility be discussed in a separate subparagraph.

Since the external loads and flexibility requirements are similar for the two types of pipelines, gas and oil, it would be desirable that safety standards for the two systems be consistent and similar.

b. Justification. Justification for the recommended changes is similar to that presented under items A.3 and A.4 in Section VI for gas pipelines.

The oil pipeline differs from the gas transporting line in that the oil will be either warm or heated to keep its lowest temperature above the pour point. Consequently, an expansion of the pipe after its installation is inevitable, and should be compensated. This is particularly important for buried pipes constrained in a trench by the stiffness of the soil. Calculation of thermal stresses additive to hoop stresses (caused by internal pressure) may dictate an increase in the pipe wall design thickness.

The approach taken in other regulations already has been discussed for the gas pipelines system under items A.3 and A.4 in Section VI and in more detail in Section V.

In addition to those, the CSA standard 2183 specifies methods of thermal stress calculations for restrained and non-restrained pipes (Para. 3.5.1.3.4) in a manner similar to that shown in ANSI B31.4.

4. Para. 195.214 Welding General

a. Suggested. It is recommended that underwater welding be allowed in the safety standards and that requirements be set for approval of such welds for tie-ins and for pipe repairs (see Section VI.A.7).

b. Justification. Similar to that presented for gas pipelines in Section VI.A.7.

5. Para. 195.242 Cathodic Protection System

a. Suggested Change. Presently, the safety standards (Para. 195.242.b) allow for installation of a cathodic protection system within one year after completion of construction. It is recommended that this be amended so that application of cathodic protection commences immediately following construction of each part of a pipeline system and the pipeline protected in its entirety within one year after construction.

b. Justification. Construction of a pipeline in the Arctic offshore may take more than one season because of the short period of time available with summer construction. That would mean that a part of the pipe could be submerged for up to three years before cathodic protection is installed. Even if a pipeline is built during one season (winter construction) the safety standards now allow one year before a submerged pipe is cathodically protected.

Considering the difficulty of corrosion-monitoring in the Arctic Seas and of inspecting the protective coating for flaws it would be prudent to require installation of cathodic protection during or immediately following the pipeline construction.

The Dravo Van Houten report addressed the subject of cathodic protection (p. 4-145 to 4-147) and quotes API, IOP and DnV regulations which specify the requirement without any defined time delay. The Title 49, Part 192, Gas Pipeline Safety Standards (Para. 192.463) do not specify any delay time in cathodic protection installation.

On the other hand the CSA Z-183-1977 (Para. 10.2.4.2) stated that "the application of cathodic protection shall commence as soon as practicable after installation of the new pipeline and shall be completed within two (2) years."

6. Para. 195.246 Installation of Pipe in a Ditch

a. Suggested Change. The wording of this paragraph is similar to that of the gas pipeline (Para. 192.319.b.c), and recommendations made for the gas pipeline standard (see Section VI.A.9) apply.

Thus, safety standards should require consideration of subsea and shoreline permafrost degradation caused by a warm oil pipeline, or pipe structural integrity. The operational life of the pipeline should be considered in the thermal analysis. If necessary, means (such as pipe insulation, low-conductivity bedding materials, or other provisions) should be provided to reduce the heat transfer between the pipe and permafrost to an acceptable level.

A detailed geotechnical survey of the pipeline route should be required in the standards before pipeline design is completed, not only for the purpose of identifying sea bottom soil properties but also to facilitate planning for suitable trenching equipment.

The standards should call for the depth of trenching to be determined by the expected worst case of ice scouring depths. On the beach, and on beach approaches, the trench depth should depend upon the magnitude of projected shore erosion and ice override (see Section VI.A.9).

The need for negative buoyancy of the pipe under adverse conditions should be stressed in the standards to assure pipe-in-trench stability.

b. Justification. The justification presented for gas pipelines under Item A.9 in Section VI also applies to oil pipelines. However, in the case of warm oil flowing in the pipe, thawing of permafrost and thaw consolidation would occur. Depending on the extent of the thawed area, sagging of the pipe could take place under the weight (in water) of the pipe and the weight of the surcharge.

In the DnV rules the problem of pipe sagging in low shear strength soil (which is similar to ice rich thawed permafrost) is addressed in Para. 4.2.6.

7. Para. 195.248 Cover Over Buried Pipeline

a. Suggested Change. The depth of cover for Arctic offshore pipelines should not be defined at fixed values as it is in the current safety standards. It should be related to environmental hazards so that the safety of the pipeline is assured under the worst predicable environmental and man-made conditions, Thus, the long-term hazards of ice scour, shore erosion, ice override on beaches, current and wave actions, as well as boat anchors, must be considered in the selection of trench depth and cover thickness. It is recommended, therefore, that the standards be amended reflecting this approach.

The requirement for pipe cover should be specified as mandatory in surf zone and beach crossing areas. Here, thermal expansion combined with soil mass movement could cause pipe overbend and subsequent pipe exposure (see gas pipeline Item A.10 Section VI). In other areas, the option of not providing a cover over a pipe should be justified by the pipeline designer.

b, Justification. Justification is similar to that presented for gas pipelines under Item A.10 in Section VI,

At shore-approach and beach-crossing areas, ice-rich permafrost could be present close to the surface. There, warm oil pipelines must be covered properly to prevent melting of the permafrost or exposure due to distortions caused by thermal expansion.

8. <u>Para. 195.252 Backfilling</u>

a. <u>Suggested Change</u>. Present requirements specify that backfill shall protect pipe coating and provide firm support to the pipe. In the standards backfill appears to be distinguished from pipe cover, i.e., from the materials deposited over the top of the pipe, and is considered to be the bedding material deposited below and around the pipe.

For Arctic offshore pipelines, the backfill material may perform the additional function of insulating the warm-oil pipe from underlying permafrost. This may introduce further requirements of the backfill which should be mentioned in the standards (long-term thermal durability, and limited sea water absorption).

b. <u>Justification</u>. Backfilling for offshore pipelines was discussed in the Dravo Van Houten Report (p. 4-201) but it appears that backfill and pipe cover were considered synonymous. Similar lack of distinction between backfill and cover can be found in the API practices (Para. 500.8.3) and in the IOP Safety Code (Para. 11.5.7.2). It would be desirable, therefore, in the 195 (and 192) safety standards to make a clear distinction between the two if such a difference is intended. Otherwise, cover and backfilling should be combined in one section.

The presence of subsea, near-shore, or onshore permafrost may require backfill to have certain insulating characteristics.

9. <u>Para. 195.262 Pumping Equipment</u>

a. <u>Suggested Change</u>. The safety standards should include a requirement for anti-icing systems on pumping equipment.

b. <u>Justification</u>. Clogging of compressor inlets by ice or snow has been a problem on pumping equipment in the Arctic (discussed under Section VI.A.5).

10. <u>Para. 195.302 General Requirements (Hydrostatic Testing)</u>

a. <u>Suggested Change</u>. The safety standards should specify hydrostatic testing of an offshore pipeline after it is laid in a trench. A second pressure test may be required after the pipe is covered. Similar recommendations were made for gas pipelines under Item A.12 of Section VI.

With respect to the test medium specified in Para. 195.306 as water, mention should be made in the standards of the use of additives to depress the freezing point below that of the lowest temperature expected during hydrotesting.

b. <u>Justification</u>. Reasons given under Item A.12 of Section VI for pressure testing also apply to oil pipelines, except for arguments in favor of 24-hour test duration and the exclusive use of liquids. Both already are specified for oil pipelines in the existing safety standards.

If hydrotest is carried out after the pipe is installed in a trench, and temperature equilibrium with sea water is established the temperature will be approximately minus 1.8°C (29°F) and only a small amount of antifreeze would be necessary. However, the temperatures could be lower during transportation, storage, and onshore testing of pipeline components, and under such conditions a higher proportion of antifreeze additive will be required.

11. <u>Items Not Addressed in Detail in Chapter 195 Safety Standards</u>

a. <u>Transmission Line Patrolling</u>

(1) <u>Suggested Change</u>. This requirement should be included as part of Subpart F - Operation and Maintenance; see discussion for gas pipelines in Item A.13 of Section VI. At present there is a statement regarding biweekly right-of-way inspection in 195.412. This may not be possible for Arctic

offshore pipelines because of climatic limitations.

(2) Justification. Arguments given for gas pipeline patrolling, discussed under Item A.13 of Section VI, apply to oil pipelines. Pipeline inspection becomes more important in this case because of the greater impact of oil spill on the Arctic environment. Fortunately, oil leaks are much easier to detect than gas leaks (see Section IV.J). It is logical to increase the frequency of aerial inspection for oil pipelines as compared to gas pipelines, particularly in the first year of operation, to provide for early detection of any oil leaks. However, the two-week requirement in 195.412 may not be realistic for Arctic offshore. It is a question of whether any meaningful right-of-way inspection can be done from the air, which might be the only available inspection means in winter. Furthermore, aerial inspection may be limited because of periods of poor visibility. Monthly aerial inspection in winter and underwater inspection during summer should be considered.

Special inspections are required after events which could affect pipeline integrity (such as exceptionally heavy ice intrusion, seismic activity, man-made damage).

b. Weight Coating. Comments made for gas pipeline under Item A.14 of Section VI apply.

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