Final Report:

Independent Evaluation of Liberty Pipeline System Design Alternatives

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Prepared for

Minerals Management Service

April 2000

STRESS ENGINEERING SERVICES, INC.

Houston, Texas

FINAL REPORT
INDEPENDENT EVALUATION OF LIBERTY PIPELINE SYSTEM DESIGN ALTERNATIVES

PN1996535

Prepared for

Minerals Management Service

Prepared by: ______________________

George R. Ross, Ph.D.

Reviewed by: ______________________

Joe R. Fowler, Ph.D., P.E.

Contributing Team Members

Jack E. Miller, P.E. **Paul J. Kovach, P.E.**

Claudio Allevato, ASNT III **Carl G. Langner, Ph.D., P.E.**

Stress Engineering Services, Inc.

13800 Westfair East Drive

Houston, Texas 77041

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SUMMARY

This report describes the work performed by Stress Engineering Services, Inc. (SES) in reviewing four candidate pipeline design concepts for the Liberty Development Project.

The proposed Liberty pipeline consists of a 12 inch nominal diameter pipeline approximately 7.6 miles in length. The pipeline will connect Liberty Island, a manmade island in Foggy Island Bay, to the existing Badami oil pipeline onshore. The 7.6 mile route includes approximately 6.12 miles which are offshore. The maximum water depth along the route is 22 ft at Liberty Island. Since the region is environmentally sensitive, it is of utmost importance that all reasonable measures be taken to protect the environment during the construction and operation of the pipeline.

The material provided for review consists of the November 1, 1999 report “Pipeline System Alternatives” prepared by INTEC Engineering, Inc. for BP Exploration. This report is referred to as the *INTEC report* throughout this document. We were also supplied with the July 1999 report “Northstar Development Project Prototype Leak Detection System Design Interim Report” and the August 1999 report “Northstar Development Project Buried Leak Detection System Preliminary Design and System Description" which were also prepared by INTEC Engineering, Inc. for BP Exploration. In this document, these reports are referred to as the *LEOS reports*. On February 29, 2000, we received a package of information from INTEC on the ice keel gouge finite element analysis. The package consisted of calculation numbers CN 0851.02.T19.301 and CN 0851.02.T19.302, both of which were issued July 20, 1999.

The INTEC report presents four primary candidate concepts, a single wall steel pipe, a steel pipe-in-pipe, a steel pipe-in-HDPE (high density polyethylene), and a flexible pipe system. Subalternatives are presented for three of the four candidates (there is not a subalternative presented for the flexible pipe system). The LEOS reports present information on the LEOS leak detection system which is part of the proposed Liberty pipeline monitoring system.

The primary goal of the review was to ensure that all of the candidate designs were considered equally and that the conceptual designs, construction methods, inspection techniques, repair methods, loads, cost estimates, and operations/maintenance practices were reasonable.

As part of the review we have come across a large number of items about which we have questions and/or comments/observations. Most of these comments are on minor issues which we are sure can be addressed easily or which the designers may intend to address during the preliminary or detailed design phases. We are confident that any of the four candidate concepts could be designed to fulfill the intended function of the pipeline. However, the concepts do have different levels of risk and different anticipated costs, both during installation and during the twenty year design life. Our comments/observations and questions are presented in the following subsections.

Design Issues

1. The INTEC report states that pipe-in-pipe designs are used for insulation or installation reasons. While this is true, this past practice should not exclude the potential for using a pipe-in-pipe system for leak containment or other legitimate reasons. It seems that the main advantage of the pipe-in-pipe and pipe-in-HDPE systems, the ability to contain small leaks, has been discounted.
2. It is our opinion that the HDPE sleeve used in the pipe-in-HDPE concept could contain small leaks, but could not contain the operating pressure of the pipeline. However, it should be noted that a small leak in the inner pipe would not result in the HDPE sleeve being immediately subjected to the operating pressure of the pipeline. Therefore, we expect that there would be time to detect the presence of oil in the annulus with either the LEOS system or by pressure fluctuations in the annulus before the burst pressure of the HDPE sleeve was reached. Furthermore, the bulkheads at each end of the pipeline could be fitted with a pressure relief system that keeps the pressure in the annulus from exceeding the burst pressure of the HDPE sleeve. This

pressure relief system could be connected to a reservoir which would prevent any oil leaked into the annulus from entering the environment.

3. The outer pipe of the steel pipe-in-pipe could not only contain small leaks, but could also contain the operating pressure of the pipeline. This design, like the pipe-in-HDPE design, could also be fitted with sensors to monitor the pressure of the annulus and a reservoir which would prevent any oil leaked into the annulus from entering the environment. Since the outer steel pipe can withstand the operating pressure of the pipeline, it is feasible that the pipeline could remain in operation even if there was a leak in the inner pipe. At a minimum this would mean that if the inner pipe develops a leak, the oil could be pumped from the pipeline before repairs are made. Unless both the inner and outer pipes were leaking simultaneously, this would prevent oil from entering the environment. This contrasts with the single wall pipe concept in which any leak would cause both an oil spill and an automatic shut-in of production from the facility until the pipeline is repaired.
4. We are concerned that the INTEC report has chosen to minimize the burial depth of each concept. This choice prejudices the equal comparison of the different concepts. Another issue which makes the comparison of the designs unequal is that the inner pipe (flowline) of the steel pipe-in-pipe concept is thinner than the single wall pipe. We would have preferred that the burial depths and the flowline wall thicknesses of all the alternatives be identical to that used in the single wall pipe concept. However, the effect of the change in pipe wall thickness on the equal weighing of the alternatives is minor in comparison to the effect of the burial depth. By assigning different burial depths to the different concepts, the benefit of using an alternative design (as opposed to a single wall pipe) can be lost. The single wall pipe is picked as the best pipeline system candidate. However, the risk of an oil leak is primarily a function of the burial depth and the single wall pipe is buried the deepest. While the chosen depths appear appropriate for each design concept, we would adopt a different approach. The depth of cover for the single wall pipe is 7 feet. We would prefer to keep this depth constant for all of the concepts. If this were done, questions would be answered as to how much benefit do you get when an outer pipe is added to a single wall pipe (i.e., If the only change is adding the outer pipe, what is the benefit?).

5. The driving forces behind considering the alternative concepts are not stated. The purpose of considering such alternatives would be some perceived improvement over a traditional single wall design. We feel that there should be a clear statement of the perceived benefits of the pipe-in-pipe, pipe-in-HDPE, and flexible pipe concepts.

Technical Merits

1. As mentioned in our intermediate report, we have concerns about the finite element modeling of the ice keel soil/pipe interaction using ANSYS. The cause of concern here is that the geometric nonlinearity was not included in the analysis. We have spoken with the INTEC representatives, Michael Paulin and Andre Nogueira, about the exclusion of the nonlinear geometric effects from the finite element analysis. Their reasoning behind neglecting the nonlinear geometric effects appears to be due to the increased run time which would have resulted. There were some checks made of the pipe-in-pipe and single wall steel pipe which included the nonlinear geometric effects. However, these check runs have not been through INTEC's quality assurance checks. From our conversation with INTEC, the check runs showed that the trends in the strains remained the same when the nonlinear geometric effects were included as when the nonlinear geometric effects were neglected. Therefore, they used the runs that neglect the nonlinear geometric effects for the conceptual design. We think that this topic is in a gray area between conceptual and preliminary design. In our opinion, if the finite element analysis was felt to be needed at this level, then both the geometric and material nonlinearity should have been included. It may be prudent to use the conceptual design phase to narrow the candidates from four to two and perform the finite element analysis on the two final candidates including the nonlinear geometry effects before selecting the final candidate.
2. We understand that there is another contract for the review of the spillage probability and damage calculations. We consider this an important activity since, the INTEC report definition of a small chronic leak (Category 3 damage, see p 5-38) appears unrealistically low at only 1 barrel a day. Even a 1 inch long crack 0.001 inches wide

could discharge approximately 29 bbls/day from an 1100 psi line. A 1 barrel/day leak from an 1100 psi line corresponds to a 0.007 inch diameter hole.

Inspection Issues

1. The main method for inspection of the pipeline, with regards to internal and external corrosion will rely on the use of smart pigs to be run inside the pipe. In the event the pipe curvature is changed by loads such as ice keel gouging or upheaval buckling, there is a possibility the instrumented pig may not be able to go through the pipe. We recommend that INTEC review this possibility, and investigate methods for solving this problem, in case it arises. The point is that the ability of the pig to pass through the line may be more limiting than the allowable strain in the pipe.
2. As we understand the current LEOS system, the system uses a small tube which is permeable to hydrocarbons and the contents of this tube would be checked once every 24 hours to determine if a small leak is present. The time required to check the contents of the tube would be approximately six hours. Therefore, there is an eighteen hour hold time during which the hydrocarbons have time to permeate the LEOS tube. As the system exists, Siemens estimates that a leak as small as 0.3 bbls/day could be detected. However, we understand that for the steel pipe-in-pipe and pipe-in-HDPE alternatives that the air in the annulus might be sampled instead of installing a sampling hose. Our concern with this method has to do with the ability to detect the location of a leak. The leak locating abilities of the LEOS system depend on determining where in the flow stream the hydrocarbons are located. The proposed pipe-in-pipe and pipe-in-HDPE designs have centralizers in the annulus. This makes the flow characteristics in the annulus more complex than in a tube and mixing of the air in the flow stream would be expected. We expect that the more complex flow characteristics will make it more difficult to locate a leak. However, there may be an advantage in that the hydrocarbons do not need to permeate a LEOS tube before being detected if the entire annulus is sampled. Whichever method is chosen, we would recommend that a third party demonstration test be conducted on the

supplemental leak detection system in the same configuration as would be implemented in the Liberty project.

3. In terms of the mass balance and pressure point systems, our primary concern is with false alarms. The concern here is that if the system does not contain self diagnostics that minimize false alarms, the operators will summarily dismiss an actual leak as a false alarm. In order to prevent this, a system should be adopted that has capabilities that allow the operator to accurately determine the difference between an actual leak and a false alarm and self diagnostics to minimize false alarms.
4. For the flexible pipe system, a disadvantage that is not mentioned in the INTEC report is that the flow balance calculations become more complex. The flexible line can be expected to expand under pressure more than a steel pipe would. This would mean that the variation in the internal volume of the line due to internal pressure will be greater than for a steel pipe and may affect the flow balance calculations.
5. The leak detection threshold of 0.3 BOPD by Siemens is stated, in the LEOS reports, to have been based on experience. The accuracy of this estimate is difficult to assess because it depends on a variety of factors such as the permeability of the soil if the tube is buried beside a pipeline, the size of the annulus if the tube is in the annulus, the permeability of the sensor tube, the location of the tube in relation to the leak, and the hold time between sampling runs. The ability to detect a leak using the LEOS system is dependent on the concentration of oil around the sampling tube. Therefore, the question one should ask in regards to the leak detection threshold is what concentration of oil around the sampling tube is required before a leak can be detected. Once this is known, one would assume that the tube is located at the furthest possible position from the leak and determine either experimentally or numerically the time necessary for the oil concentration around the tube to reach a detectable level for a given leak rate. Such analysis/experimentation is beyond the scope of this review. We would recommend that a third party demonstration test be conducted using the configuration proposed for the Liberty project supplementary leak detection system.
6. For the flexible pipe system, there is not a true annulus. The INTEC report states that the sampling for leak detection would occur in the annulus, but this annulus is filled

with steel strips. One would be counting on being able to pump clean air through an annulus that contains steel wraps. This seems unlikely to work. It also seems unlikely that oil could be extracted from this annulus. The ability of the system to sample from this annulus, with internal pressure applied to the pipe, needs to be confirmed. Does BP have any data to confirm that this sampling is possible?

7. For the flexible pipe system, jumpers across the connections are to be used to provide a continuous pathway for the leak detection system to sample the air in the annulus. It is not clear how this would be accomplished. Have any conceptual designs of these jumpers been proposed?

Operations Issues

1. The INTEC report states that the pipeline will be shut down if pressure or temperature limits are exceeded. Our concern about this is that flow assurance problems may be encountered if the pipeline cools with oil in the line. If the oil properties at ground temperature are such that the oil can still flow, this may not be a problem. However, for some oil compositions at low temperatures, blockages could form when the line is shut down and make it difficult to restart the line. We would be interested in seeing a restarting procedure in case such a shutdown takes place.
2. We would suggest that the annulus pressure be monitored for the pipe-in-pipe and pipe-in-HDPE concepts. A pressure buildup in the annulus could be indicative of a leak in the inner pipe. This would provide another avenue for leak detection in addition to the mass balance and pressure point systems which operate continuously and monitoring either the annulus contents or the contents of a LEOS tube which would be done once a day.

Repair Issues

1. It is stated that repair could not occur at some times during the year, specifically during break-up and freeze-up of the ice sheet (pages 1-6 and 3-33 of the INTEC report). This amounts to approximately 5-6 months out of the year. It would seem

that this would have an effect on the amount of oil lost. The pipeline would be shutdown, and clean-up would proceed, but there would still be oil in some parts of the line. Is it possible for oil that remains in the pipeline to continue to leak before repairs could be made? Has this been taken into account in the oil spillage calculations?

2. For cases where there is an annulus, in order to prevent corrosion, all moisture would need to be removed from the annulus after a repair. The drying operations following a repair would be more difficult than the drying operations after initial construction because of debris drawn into the annulus during the damage period and the subsequent repair activities. Such debris would include soil, sand, and gravel, in addition to seawater and hydrocarbons. Not all of these materials and objects would be removed by the drying process and may increase the time necessary to dry the annulus. As a result, a significant amount of moisture could be present for a long period of time (i.e., the 2.5-3 month period when repairs could not be made during a freeze-up or break-up plus the drying time). We would expect that drying the annulus could take a month or more. This means that moisture would be present on the order of 4 months. This would be more than enough time for corrosion to begin in the annulus. Therefore, installing a cathodic protection system on the inner pipe should be considered. Such a system could consist of a sprayed aluminum or other cathodic coating applied to the inner pipe to provide in-situ cathodic protection. Another method would be to attach anodes to the inner pipe. Either of these methods should supply adequate cathodic protection for the inner pipe. The drawback to this is that the cathodic protection of the inner pipe could not be monitored.
3. Mechanical repair devices are used as permanent repairs around the world. These devices include external leak repair clamps as well as in-line pipe coupling devices. However, the INTEC report states that mechanical repairs are not considered appropriate for permanent arctic offshore repairs. Is there engineering evidence that supports this or is this based on a perceived risk?
4. We are aware that both bolted and welded split sleeves are commonly used for the repair of small leaks. However, it is not clear which kind of sleeve is being

referenced in the INTEC report. It would be helpful if drawings of the candidate repair equipment and installation method were included in the report.

5. We agree that the repair of the pipe-in-pipe design would be much more involved and that the restoration of the outer pipe to original integrity is doubtful given the types of repairs described. From the INTEC report, we envision the proposed repair of the outer pipe to consist of a clamshell that has a larger diameter than the outer pipe. Using such a repair would result in having to use fillet welds on the ends of the repair section and would include longitudinal welds to join the clamshell sections. This type of repair is illustrated in Figure 3 and would not restore the outer pipe to its original integrity. However, if the repair pipe has the same diameter, wall thickness, and material properties as the original pipe and is installed using butt welds that are inspected by UT examination, it should be possible to restore the pipe to near its original integrity. This type of repair is included in Figure 4. The repair includes longitudinal welds, but the fillet welds are replaced by butt welds. In order to implement this type of repair, the ends of the pipe would have to be prepared and the repair section cut to length in the field. When designing the pipeline, the designers should consider the capacity of a repaired pipe when establishing the design allowables. If the repaired pipeline would not be as sound as the new line, the design allowables should be based on the repaired pipe strength.
6. We have a few questions concerning the repair of the flexible pipe alternative. Why is a flanged connection considered temporary? Is there standard repair equipment for flexible pipe? What do the repair connections look like? How could/would end fittings be installed in the field? It appears that any permanent repair to the flexible pipe system would consist of replacing an entire 2800 ft section. This significant effort may increase the repair costs of the line enough to offset any initial savings of using the flexible pipe system. Replacement sections would have to be kept on site, or production could be halted for months waiting for a replacement section.
7. The INTEC report discusses both repair time frames and methods of repair. Our experience has been that the delivery of mechanical connectors or bolted split sleeves can be on the order of two months. We would also expect that connectors constructed

of materials appropriate for the arctic environment could take even longer to obtain. Is there a plan for stocking the discussed products locally?

Construction Issues

1. There is no mention of the procedures which would be required to abandon an uncompleted line and then successfully resume construction. Has this been considered?
2. For the concepts involving inserting the inner pipe into an outer pipe or sleeve, there is a possibility of damage to the corrosion protection coating during this operation. Emphasis is placed on keeping the annulus dry to prevent corrosion and that the inner pipe would not be cathodically protected. It would seem prudent to include some cathodic protection of the inner pipe. This cathodic protection could consist of a sprayed aluminum or other cathodic coating or anodes attached to the inner pipe. The drawback here is that the cathodic protection in the annulus could not be monitored. However, the system would be in place and could provide some benefit.
3. In the pipe-in-pipe construction sequence, it is stated that the “inner pipe extends beyond the outer pipe”. The inner and outer pipes must be the same lengths eventually so this statement is not clear. It would seem that the first section should be made with a short outer pipe. The rest of the inner and outer pipes should be made the same length but the inner pipe sticks out at the first field weld so that this weld can be made and inspected. The outer pipe would then be slid over this weld and the outer field weld made and inspected. Is this the intended method?
4. Induction heating is mentioned as a method of joining the HDPE pipe and later a fusion joining machine is mentioned. Which is the intended method and what are the implications of the joining method to the construction process?
5. For the flexible pipe alternative an area of concern is the welding of the connectors and their subsequent coating. The integrity of this system depends on these joints so the fabrication and long term performance needs careful attention.
6. For the pipe-in-HDPE concept, it is stated that only visual inspection of the fusion welds is possible. We agree with this and that the best avenue for assuring the quality

of the fusion welds is to qualify the procedure using test samples fusion welded by the same machine and operators as would be used during installation.

7. We agree that both the steel pipe-in-pipe and pipe-in-HDPE alternatives would be more difficult to construct than either the single wall steel pipe or the flexible pipe. However, there are some refinements to the construction process that could reduce the time required to install the steel pipe-in-pipe and pipe-in-HDPE alternatives. First, the single wall steel pipe strings that are to be towed to the trench are 3000 ft long. However, the pipe-in-pipe and pipe-in-HDPE strings are only 1000 ft long. This increases the number of tie-in locations by a factor of three. In addition, the time to make each connection is longer for the pipe-in-pipe and pipe-in-HDPE alternatives because of the additional connection of the outer pipes or sleeves. It would seem that the main factor affecting the length of the string that can be towed is the weight of the string. For the steel pipe-in-pipe, a 1300 ft string is approximately the same weight as the 3000 ft single wall steel pipe string. If 1300 ft strings were used, the number of tie-in locations would be reduced from 33 to 25 and the connections could be made in approximately 8 fewer days. For the pipe-in-HDPE alternative, 2600 ft strings weigh approximately the same as the single wall steel pipe 3000 ft string. Using 2600 ft long pipe-in-HDPE strings would reduce the time for the field joints from 22 days to 9 days. In both cases, preparing longer strings would increase the pipe string make-up time. However, this could be offset by increasing the size of the crew. Another way to speed up the construction would be to use two pipelaying spreads either starting in the middle of the route and working toward opposite shores or starting onshore and working toward a central tie-in. In the INTEC report, the construction timelines for the single wall, steel pipe-in-pipe, and pipe-in-HDPE, start in mid December and end in mid April. The timeline for the flexible pipeline is shorter running from mid December to mid March. However, the INTEC report states that the ice is stable in Zone 1 by December and break-up occurs at the end of May. Therefore, it would seem that equipment mobilization, road construction, and make-up site preparation could begin December 1st and construction could continue through May. This amounts to eight weeks that are currently not included in the construction timeline. If half of this time is discounted for weather variations, there are four weeks

that could be included in the construction timeline or 28 days more time available for construction than included in the current timeline. The longest timeline is currently 107 days for the pipe-in-HDPE alternative. An increase in the timeline of 28 days constitutes a 25 % increase. Therefore, we feel that with proper scheduling and the mobilization of adequate numbers of trained personnel it should be possible to complete the construction of any of the four designs in one season. The keys to completing the work in one season are to make sure that the preparation of the pipe strings proceeds at a rate that keeps up with or exceeds the trenching activities and minimizing the number of field joints. In other words, the trenching activities should be the limiting factor in the construction timeline. The main advantage to the construction method presented in the report is that the strings can be fabricated before trenching is started. If the pipe strings could be completed in the fall, before the winter freeze-up or enough manpower is allocated to ensure that the pipe string preparation exceeds the trenching rate, it should be possible to complete the pipeline in one season. With any of the alternatives, the possibility of construction requiring a second season is present and should be considered when the construction is planned. However, we feel that if a single wall pipe can be constructed in one season, then the other alternatives could also be completed in one season. It would be the factors that are unpredictable, such as an unusually short winter, which one would expect to result in a second construction season and these unpredictable factors would affect any of the designs.

8. We would suggest, if scheduling permits, that the hydrotest of the pipeline be conducted before backfilling. The main factor affecting the ability to hydrotest before backfilling is scheduling. The INTEC report estimates that backfilling activities will take between 30 and 44 days, a significant percentage of the construction season. If waiting to backfill until after hydrotesting would result in a second construction season, then backfilling should proceed as the pipe is installed. However, if the hydrotest could be conducted before backfilling, this would facilitate any repairs that need to be made. In addition, maintaining some pressure in the line during the backfilling operation should be considered. This would lock in some

tensile stresses in the pipeline, which would help reduce the effects of the thermal expansion that will occur as the pipeline heats up to its operating temperature.

9. As an alternative to a hydrotest of the annulus of the pipe-in-pipe and pipe-in-HDPE alternatives, the annulus could be tested using pressurized dry air or dry nitrogen. During this test, a diver or ROV could "walk" the pipeline route and look for bubbles. Any leaks in the outer pipe or sleeve would be indicated by bubbles.
10. The INTEC report mentions that localized jetting may be necessary to fluidize the trench bottom in order to lower a pipe that has become "high grounded" during installation. This means that jetting equipment will need to be on site throughout the pipelaying process. Otherwise, if jetting is required, delays in getting the equipment could prevent the completion of the pipeline in one season. In addition, suction equipment may be needed to remove material from localized high spots.

Costs

1. The 5 million dollar contingency for a second construction season of the pipe-in-HDPE candidate appears low. We understand that INTEC based this on the perceived likelihood of a second season being required to complete construction. However, the costs for mobilization, ice thickening/road construction, and demobilization for the pipe-in-HDPE concept total 9.7 million dollars. There are also no costs included for the abandonment of the line at the end of the first construction season and the retrieval of the partially completed pipeline so that construction can be resumed. Therefore, the 5 million dollar contingency for the second season work seems low. For the steel pipe-in-pipe, the contingency cost allocated for a second season of 15 million dollars is more reasonable.
2. We feel that it should be possible to complete construction of any of the alternatives in one season. This would have the most effect, in terms of cost, on the steel pipe-in-pipe alternative. Completing the construction of the steel pipe-in-pipe in one season would reduce the cost by 15 million dollars and bring the pipe-in-pipe costs closer to the single wall steel pipe cost.

Alternative Design Concepts

1. We would be interested in knowing if concepts such as putting a flexible, composite, or polymer pipe inside a steel pipe have been considered. If so, what factors eliminated this option from consideration? It would be more difficult to install than a single wall pipe, but we would think that it would be easier to construct than the steel pipe-in-pipe. If the inner pipe was nonmetallic, the concern about cathodic protection of the inner pipe would be eliminated. One issue that would need to be addressed is how to prevent damaging the inner nonmetallic pipe when the outer steel pipe is welded.
2. There is a modification to the steel pipe-in-HDPE concept that we would suggest investigating. The HDPE sleeve could be prefabricated as a unit with an inner thin wall HDPE pipe and an outer HDPE pipe with the foam in-between. In order to use this HDPE sleeve with the foam in place, an adequate installation clearance between the thin wall HDPE pipe and the inner pipe would be required. A further variation would be to perforate the thin wall HDPE pipe and replace the polyurethane foam with an oil absorbent material. In this scenario, the HDPE sleeve assembly becomes an oil containment barrier and a leak detection system could monitor the annulus between the steel pipe and the perforated thin wall HDPE pipe. A sketch of this alternative is included as Figure 1 in this report.
3. Another variation to the steel pipe-in-HDPE concept would be to use a thick wall (16 inch O.D. x 1.25 inch wall) HDPE sleeve without centralizers. The closer fit between the HDPE sleeve and the inner pipe and elimination of the centralizers would provide better distribution of the inner pipe weight to the HDPE sleeve. This may lower the risk of damaging the HDPE sleeve when handling the assembled pipe strings. The thicker wall HDPE sleeve would also have a higher allowable pressure and the elimination of the centralizers would simplify construction.

Items to be Considered in Preliminary Design

1. For the pipe-in-pipe concept, it is stated that there will be a locked in compressive load in the inner pipe. There will be centralizers/spacers in the design to keep the curvature of the two pipes approximately equal. The inner pipe should be checked for buckling between the centralizers due to the thermal expansion if this design concept is carried forward. Buckling could lead to a fatigue failure or to fretting at points of contact between the two pipes if the temperature fluctuations are sufficient.
2. A possible hydrostatic test of the outer pipe is mentioned on page 5-17 of the INTEC report. This would require drying of the annulus after the hydrotest. In addition, if such a test is done the inner pipe must be pressurized or otherwise assured of being collapse resistant. Collapse should not be a problem with the currently proposed inner pipes, but should be included in the preliminary design checks.
3. For the pipe-in-HDPE concept, the pipe transport method mentioned is the same as for the pipe-in-pipe technique. The spacers between the inner pipe and the HDPE outer sleeve are not described in any detail. However, the spacers must be designed so that the weight of the inner pipe is distributed along the length of the HDPE sleeve. The inner pipe is so heavy that the ability of the HDPE sleeve to carry this load, unless it is well distributed, is doubtful. An alternative would be to use a thicker walled HDPE sleeve and a smaller annulus size and omit the centralizers. This would distribute the weight of the inner pipe over a larger area than if centralizers were present. This would also aid in construction since the centralizers would not be installed. Buckling of the inner pipe would have to be considered in detail in the preliminary design phase if such a concept were adopted. The possible impact loads during construction/transport should also be considered since the impact strength of HDPE at -50^{o}F can be expected to be approximately ½ that of HDPE at 73^{o}F.

DISCLAIMER

Stress Engineering Services has performed a review of the documentation provided by the Minerals Management Service and INTEC. This documentation consisted of the November 1, 1999 report “Pipeline System Alternatives”, the July 1999 report “Northstar Development Project Prototype Leak Detection System Design Interim Report”, the August 1999 report “Northstar Development Project Buried Leak Detection System Preliminary Design and System Description" prepared by INTEC Engineering, Inc. for BP Exploration, conversations with David Roby of MMS, a conversation with Michael Paulin and Andre Nogueira of INTEC, and a package of information from INTEC on the ice keel gouge finite element analysis consisting of calculation numbers CN 0851.02.T19.301 and CN 0851.02.T19.302. This review is at the level of conceptual design only. Stress Engineering Services has not performed any detailed design or stress analysis work that would be required to ensure that any of the pipeline design concepts discussed in this document are safe to install and operate.

1.0 INTRODUCTION

The proposed Liberty pipeline consists of a 12 inch nominal diameter pipeline approximately 7.6 miles in length. The pipeline will connect Liberty Island, a manmade island in Foggy Island Bay, to the existing Badami oil pipeline onshore. The 7.6 mile route includes approximately 6.12 miles which are offshore. The maximum water depth along the route is 22 ft at Liberty Island. Since the region is environmentally sensitive, it is of utmost importance that all reasonable measures be taken to protect the environment during the construction and operation of the pipeline.

Stress Engineering Services (SES) was contracted to provide an independent review of four design concepts for the Liberty Pipeline. The design concepts were presented in the November 1, 1999 report “Pipeline System Alternatives” prepared by INTEC Engineering, Inc. for BP Exploration. This report is referred to as the *INTEC report* throughout this document. We were also supplied with the July 1999 report “Northstar Development Project Prototype Leak Detection System Design Interim Report” and the August 1999 report “Northstar Development Project Buried Leak Detection System Preliminary Design and System Description" which were also prepared by INTEC Engineering, Inc. for BP Exploration. In this document, these reports are referred to as the *LEOS reports*. The LEOS reports were provided to answer questions we had about the proposed LEOS leak detection system. On February 29, 2000, SES received a package of information from INTEC containing information on the ice keel gouge finite element analysis. The package contained calculation numbers CN 0851.02.T19.301 and CN 0851.02.T19.302.

The INTEC report presents four primary candidate concepts, a single wall steel pipe, a steel pipe-in-pipe, a steel pipe-in-HDPE (high density polyethylene), and a flexible pipe system. Subalternatives are presented for three of the four candidates (there is not a subalternative presented for the flexible pipe system). The four concepts and the subalternatives are presented in the following outline;

I. Single Wall Steel Pipe (X-52 steel pipe, 12.75 inch O.D., and 0.688 inch wall thickness)

- A) Straight pipe
- B) Zigzag pattern

II. Steel Pipe-in-Pipe

- A) Inner pipe: X-52 steel pipe, 12.75 inch O.D., and 0.688 inch wall thickness
  Outer pipe: X-52 steel pipe, 16 inch O.D., and 0.5 inch wall thickness
  - i) Structural bulkheads at Liberty Island and at shore crossing only
  - ii) Structural bulkheads at ½ mile intervals, at Liberty Island, and the shore crossing
- B) Inner pipe: X-52 steel pipe, 12.75 inch O.D., and 0.5 inch wall thickness
  Outer pipe: X-52 steel pipe, 16 inch O.D., and 0.844 inch wall thickness
  - i) Structural bulkheads at Liberty Island and at shore crossing only
  - ii) Structural bulkheads at ½ mile intervals, at Liberty Island, and the shore crossing

III. Steel Pipe-in-HDPE

- A) Inner pipe: X-52 steel pipe, 12.75 inch O.D., and 0.688 inch wall thickness
  Outer Sleeve: HDPE sleeve, 15.25 inch O.D., and 0.25 inch wall thickness
  Annulus filled with PU (polyurethane foam)
- B) Inner pipe: X-52 steel pipe, 12.75 inch O.D., and 0.688 inch wall thickness

Outer Sleeve: HDPE sleeve, 16.25 inch O.D., and 0.75 inch wall thickness
Air in Annulus

IV. Flexible Pipe System (12 inch I.D. and 1.47 inch wall)

The INTEC report discusses each alternative and selects the following four as primary concepts;

I. Single Wall Steel Pipe (X-52 steel pipe, 12.75 inch O.D., and 0.688 inch wall thickness)

A) Straight pipe

II. Steel Pipe-in-Pipe

B) Inner pipe: X-52 steel pipe, 12.75 inch O.D., and 0.5 inch wall thickness
Outer pipe: X-52 steel pipe, 16 inch O.D., and 0.844 inch wall thickness

i) Structural Bulkheads at Liberty Island and at shore crossing only

III. Steel Pipe-in-HDPE

B) Inner pipe: X-52 steel pipe, 12.75 inch O.D., and 0.688 inch wall thickness
Outer Sleeve: HDPE sleeve, 16.25 inch O.D., and 0.75 inch wall thickness
Air in Annulus

IV. Flexible Pipe System (12 inch I.D. and 1.47 inch wall)

Of these four concepts, *the INTEC report selects the Single Wall Straight Pipe* as the best candidate. In addition to these conceptual designs, a section is also included in the INTEC report which discusses containment concepts, comments on these concepts are also included in the review.

This review was conducted with the primary goal of minimizing the possibility of a pipeline failure. In order to accomplish this goal, the review must determine if all of the candidate designs were considered equally and if the conceptual designs, construction methods, inspection techniques, repair methods, loads, cost estimates, and operations and maintenance practices were reasonable.

In addition, in recognition that the possibility of failure exists in any design, the minimization of the amount of oil introduced into the environment and as a result the impact on the environment is also of prime importance. This minimization of environmental impact requires the consideration of techniques to detect leaks, contain leaks, and recover material leaked into the environment.

The possibility of leakage and the environmental loading factors are considered in the review. However, since other contracts will or have been awarded to study these factors in detail, the review focuses on the completeness of these factors rather than the actual values assigned to these parameters. The primary goal in reviewing the leakage and environmental loading factors is to determine if all the factors are being considered rather than to perform a detailed analysis of the factors.

This report is divided into seven main sections. The first section consists of this introduction. Section 2 contains the comments we received from MMS on our intermediate and draft final reports and our responses to the comments. Section 3 provides a brief description of the design concepts. Section 4 contains a discussion of the design issues. Section 5 contains a discussion of the life cycle costs. Section 6 discusses the containment concepts. Recommendations are presented in Section 7. Each topic is discussed in Sections 4 and 5 as it pertains to all four design concepts. As a result, the treatments of each design concept are easily compared.

2.0 RESPONSE TO REPORT COMMENTS

As part of this project, SES provided the MMS an intermediate report and a draft final report. The MMS provided SES with comments on both of these reports. This section contains responses to the comments. The comments received are included in italics. Responses are included immediately following the comments.

The following comments were on the intermediate report.

1. *The discussion on second season construction costs focused on the pipe-in-HDPE. The costs associated with a second construction season for the steel pipe-in-pipe should be discussed in more detail. Also Stress should more fully review the proposed construction methodologies presented in the BP/Intec Report to determine if the estimates of the probability of requiring a second construction season are reasonable.*

    The comments on the second season construction costs used the pipe-in-HDPE as an example, because the 5 million dollar contingency cost is unreasonably low. The costs for mobilization, ice thickening/road construction, and demobilization alone total 9.7 million dollars.

    For the steel pipe-in-pipe, the contingency cost allocated for a second season of 15 million dollars is more reasonable. This is enough to cover the mobilization, ice thickening/road construction, and demobilization costs which total 3.72 + 4.70 + 1.84 = 10.26 million dollars. If you then assume that one third of the trench will have to be retrenched, there is another 5.46/3 = 1.82 million dollars required. In addition, the make-up site would have to be prepared which adds 2.59 million dollars. Therefore, the contingency for a second season would be around 10.26 + 1.82 + 2.59 = 14.67 million dollars. The costs for abandonment of the line at the end of the first season and retrieval of the line so that construction can resume have not been included. This could be a complex procedure since the annulus would need to be kept dry and some of the backfill removed to allow the uncompleted end of the pipeline to be lifted to the surface. However, a second season cost on the order of 15-16 million dollars seems reasonable for the steel pipe-in-pipe alternative.

The above discussion about contingency costs has the underlying assumption that it is likely that the construction would not be completed in one season. We agree that both the steel pipe-in-pipe and pipe-in-HDPE alternatives would be more difficult to construct than either the single wall steel pipe or the flexible pipe. However, there are some refinements to the construction process that could reduce the time required to install the steel pipe-in-pipe and pipe-in-HDPE alternatives. First, the single wall steel pipe strings that are to be towed to the trench are 3000 ft long. However, the pipe-in-pipe and pipe-in-HDPE strings are only 1000 ft long. This increases the number of tie-in locations by a factor of three. In addition, the time to make each connection is longer for the pipe-in-pipe and pipe-in-HDPE alternatives because of the additional connection of the outer pipes or sleeves. It would seem that the main factor affecting the length of the string that can be towed is the weight of the string. For the steel pipe-in-pipe, a 1300 ft string is approximately the same weight as the 3000 ft single wall steel pipe string. If 1300 ft strings were used, the number of tie in locations would be reduced from 33 to 25 and the connections could be made in approximately 8 fewer days. For the pipe-in-HDPE alternative, 2600 ft strings weigh approximately the same as the single wall steel pipe 3000 ft string. Using 2600 ft long pipe-in-HDPE strings would reduce the time for the field joints from 22 days to 9 days. In both cases, preparing longer strings would increase the pipe string make-up time. However, this could be offset by increasing the size of the crew. Another way to speed up the construction would be to use two pipelaying spreads either starting in the middle of the route and working toward opposite shores or starting onshore and working toward a central tie-in. In the INTEC report, the construction timelines for the single wall, steel pipe-in-pipe, and pipe-in-HDPE, start in mid December and end in mid April. The timeline for the flexible pipeline is shorter, running from mid December to mid March. However, the INTEC report states that the ice is stable in Zone 1 by December and break-up occurs at the end of May. Therefore, it would seem that equipment mobilization, road construction, and make-up site preparation could begin December 1st and construction could continue through May. This amounts to eight weeks that are currently not included in the construction timeline. If half of this time is discounted for weather variations, there are four weeks that could be included in the construction timeline or 28 days more time available for construction than included in the current timeline. The longest timeline is currently 107 days for the pipe-in-HDPE alternative. An increase in the timeline of 28 days constitutes a 25 % increase. Therefore, we feel that with proper scheduling and the mobilization of adequate numbers of trained personnel it should be possible to complete the construction of any of the four designs in one season.

The construction method as described in the INTEC report consists of fabricating long pipe strings. These pipe strings are dragged to the field and welded onto the previous strings to form the pipeline. Heavy machinery would be required to align the pipe ends at the tie-in welds and the crews must be careful to keep moisture out of the annulus. Meanwhile, the trenching work and the lowering of the pipeline into the ditch would proceed as possible. The keys to completing the work in one season are to make sure that the preparation of the pipe strings proceeds at a rate that keeps up with or exceeds the trenching activities and minimizing the number of field joints. In other words, the trenching activities should be the limiting factor in the construction timeline. The main advantage to this construction method is that the strings can be fabricated before trenching is started. If the pipe strings could be completed in the fall, before the winter freeze-up or enough manpower is allocated to ensure that the pipe string preparation exceeds the trenching rate, it should be possible to complete the pipeline in one season. This would also reduce the cost of the steel pipe-in-pipe by the 15 million dollar contingency and bring the pipe-in-pipe costs closer to the single wall steel pipe cost.

With any of the alternatives, the possibility of construction requiring a second season is present and should be considered when the construction is planned. However, we feel that if a single wall pipe can be constructed in one season, then the other alternatives could also be completed in one season. It would be the factors that are unpredictable, such as an unusually short winter, which one would expect to result in a second construction season and these unpredictable factors would affect any of the designs.

2. *On page 17 of the Intermediate Report the question "Can the HDPE contain a leak?" was asked. Stress should give their opinion, with appropriate supporting information, on this matter.*

It is our opinion that the HDPE sleeve used in the pipe-in-HDPE concept could contain small leaks. However, if the inner pipe were to rupture so that the HDPE sleeve were subjected to the operating pressure of the pipeline, the sleeve would fail due to the load from the internal pressure.

The tensile strength of high density polyethylene is in the range of 20-37 MPa (2.9-5.4 ksi), Ref. Ashby, M.F., and Jones, D. R. H., "Engineering Materials 2: An Introduction to Microstructures , Processing and Design, Pergamon Press, 1988, (28 MPa per McCrum, N. G., Buckley, C. P., and Bucknall, C., B., "Principles of Polymer Engineering", Oxford Science Publications, 1992).

The proposed HDPE sleeve has an outside diameter of 16.25 inches and a wall thickness of 0.75 inches. This makes the mean radius of the sleeve 7.75 inches. For the maximum allowable operating pressure of the line of 1415 psi (INTEC report page 3-25) the hoop stress is 1415*7.75/0.75 = 14622 psi = 14.6 ksi. Since 14.6 ksi is much greater than 5.4 ksi, the HDPE sleeve would be expected to burst if it were subjected to the maximum operating pressure of the pipeline. The 0.75 inch wall thickness could only hold an internal pressure on the order of 523 psi (i.e., 5.4*1000=Pressure*7.75/0.75 gives Pressure = 523 psi).

However, it should be noted that a small leak in the inner pipe would not result in the HDPE sleeve being immediately subjected to the operating pressure of the pipeline. The volume of the annulus between the inner pipe and the HDPE sleeve is approximately 3.1416*[(14.75/2)^2-(12.75/2)^2]*6.12*5280*12 = 16750207 cubic inches = 72512 gallons = 1727 barrels. Using the production rate of 65000 bbl/day and assuming all of the oil were flowing into the annulus, it would take approximately 38 minutes to fill the annulus with oil. It should be noted that this is the lower bound on the time required to fill the annulus and would be an extreme condition that is very unlikely. Therefore, we expect that there would be time to detect the presence of oil in the annulus with either the LEOS system or by pressure fluctuations in the annulus before the burst pressure of the HDPE sleeve is reached. Furthermore, the bulkheads at each end of the pipeline could be fitted with a pressure relief system that keeps the pressure in the annulus from exceeding the burst pressure of the HDPE sleeve. This pressure relief system could be connected to a reservoir which would prevent any oil leaked into the annulus from entering the environment.

3. *On page 16 of the Intermediate Report Stress states that it is their opinion that the nonlinear geometry effects related to ice keel soil/pipe interactions should be included in the finite element modeling. This topic needs to be expanded upon. Stress should explain what geometric nonlinearity is and why excluding these effects from the finite element modeling is a cause for concern. Stress should discuss what affect the inclusion or exclusion of these effects could have on the calculated maximum strain in the various pipelines. Stress should address whether or not this type of analysis is typically done at the conceptual stage and if not at what stage in a pipeline design would this work be performed. Also, Stress should talk with Intec about this subject to try to determine their reason for leaving these effects out of their modeling.*

There are two primary sources of nonlinearity to be considered in stress analysis. The first type is material nonlinearity. A material is said to be nonlinear if the relationship between the stress and strain is nonlinear. If the strain in a material is proportional to the applied stress then a plot of stress versus strain will be a straight line (i.e., a line with a constant slope) and the material is said to behave in a linear fashion. For a nonlinear material, the slope of the stress versus strain curve is not constant. Nonlinear geometric effects have to do with the extent of deformation of the body being analyzed. If the deformations in the body are small, the effect of the deformation on the results is small, the nonlinear geometric effects can be neglected, and the equilibrium equations can be written with respect to the undeformed body. However, when deformations are large the deformation of the body can affect the loading on the body. Large deformations are defined as large rotations or displacements in the body that can alter the location or distribution of loads. When this occurs, the equilibrium equations must be written with respect to the deformed geometry. A simple example of a problem with geometric nonlinearities is illustrated in Figure 2. In Figure 2, a cantilever beam is subjected to a load P which is initially perpendicular to the beam. For a small deflection, the moment arm, A, is approximately equal to the length of the beam, L. This is illustrated in Figure 2(a). However, for larger deflections, the moment arm A is less than the beam length, L, and A is dependent on the load P. This is illustrated in Figure 2(b).

After the Intermediate report for this project was issued, the question was raised as to whether the geometric nonlinearity would typically be included at the conceptual stage and if not at what stage in the pipeline design should the geometric nonlinearity be incorporated in the analysis. In our opinion, the geometric nonlinearity should be included at this conceptual level. The INTEC report includes results from finite element analysis which incorporates the material nonlinearity, but neglects the geometric nonlinearity. This is an unusual assumption. In most cases, if not all, when material nonlinearity is incorporated, the geometric nonlinearity is also included. One would expect to see analyses where both the material and geometric response is linear, the material response is linear and the geometric response nonlinear, or where both the material and geometric response is nonlinear. By including the material nonlinearity in the analysis, one is assuming that the deformations are large enough so that yielding of the material could occur.

It is difficult to predict what the effect of the geometric nonlinearity would be on the analysis results. At a minimum, we would suggest taking the finite element run which resulted in the largest displacements and strains and rerunning the problem with the nonlinear geometry effects included. By comparing the results, one would get a feel for the effect of the geometric nonlinearity on the resulting stresses and strains.

We have spoken with the INTEC representatives, Michael Paulin and Andre Nogueira, about the exclusion of the nonlinear geometric effects from the finite element analysis. Their reasoning behind neglecting the nonlinear geometric effects appears to be due to the increased run time which would have resulted. There were some checks made of the pipe-in-pipe and single wall steel pipe which included the nonlinear geometric effects. However, these runs have not been through INTEC's quality assurance checks yet and therefore the results are preliminary. The runs showed that there was an increase in the strains (15-20%), but the trends remained the same and the strains were still well below the allowable strains.

At this level of design, our main concern is that any analysis done on the four design concepts results in the proper ranking of the designs. From our conversation with INTEC, INTEC's checks showed that the trends in the strains remained the same when the nonlinear geometric effects were included as when the nonlinear geometric effects were neglected. Therefore, they used the runs that neglect the nonlinear geometric effects for the conceptual design. We think that this topic is in a gray area between conceptual and preliminary design. In our opinion, if the finite element analysis was felt to be needed at this level, then both the geometric and material nonlinearity should have been included. It may be prudent to use the conceptual design phase to narrow the candidates from four to two and perform the finite element analysis on the two final candidates including the nonlinear geometry effects before selecting the final candidate.

4. *The analysis of supplemental leak detection beginning on page 32 should be expanded. Stress should indicate whether they believe that Siemens' estimate of a leak detection threshold of 0.3 BOPD is reasonable. Also, Stress makes the statement that using the annulus as opposed to the LEOS sampling tube would likely affect sampling rate and sensitivity. This should be expanded upon to indicate how Stress believes these factors will be affected.*

As we understand the current LEOS system uses a small tube which is permeable to hydrocarbons and the contents of this tube would be checked once every 24 hours to determine if a small leak is present. The time required to check the contents of the tube would be approximately six hours. Therefore, there is an eighteen hour hold time during which the hydrocarbons have time to permeate the LEOS tube. By knowing the sampling rate, the time the sampling was started, and when a leak was detected, the location of the leak can be estimated. As the system exists, Siemens estimates that a leak as small as 0.3 bbls/day could be detected.

The leak detection threshold of 0.3 BOPD by Siemens is stated to have been based on experience in the LEOS reports. The accuracy of this estimate is difficult to assess because it depends on a variety of factors including:

1. The permeability of the soil if the tube is buried beside a pipeline.
2. The size of the annulus if the tube is in the annulus.
3. The permeability of the sensor tube.
4. The hold time between sampling runs.
5. The location of the tube in relation to the leak.

The ability to detect a leak using the LEOS system is dependent on the concentration of oil around the sampling tube. Therefore, the question one should ask in regards to the leak detection threshold is what concentration of oil around the sampling tube is required before a leak can be detected. Once this is known, one would assume that the tube is located at the furthest possible position from the leak and determine either experimentally or numerically the time necessary for the oil concentration around the tube to reach a detectable level for a given leak rate. Such analysis/experimentation is beyond the scope of this review.

Although we can not comment on the reasonableness of the 0.3 BOPD threshold as it relates to the Liberty pipeline, it should be noted that such a low threshold indicates a high degree of confidence on the part of Siemens. In addition, a 0.3 BOPD leak rate is well below a reasonable leak rate. We would expect that any leak in the pipeline would be at a minimum on the order of a 29 BOPD leak. We estimate that a 1 inch long crack 0.001 inches wide would leak approximately 29 bbls/day at 1100 psi. This is equivalent to a 0.036 inch (0.9 mm) diameter hole (which is about the size of a pencil lead). It is difficult to imagine a case for this pipeline where a leak would be smaller than this 29 BOPD figure. This is almost 100 times the threshold cited by Siemens.

One would think that if the tube were in an annulus that a smaller leak could be detected since the oil would be confined to the annulus rather than being able to soak into the soil. In the event of a small leak in the inner pipe, the oil would spray from the hole and impinge of the inner wall of the outer pipe. This would create a mist of oil that should surround the inner pipe in a short time. Therefore, we would expect that leaks on the side of the pipe opposite the LEOS tube would be detected sooner if confined in an annulus than if the tube were buried in soil. By confining the oil in the annulus, the concentration of oil around the sampling tube would be higher and as a result more hydrocarbons would permeate the tube wall and the probability of detecting a leak would be increased.

Our concern about sampling the entire annulus rather than using a sampling tube has to do with the ability to detect the location of a leak. The leak locating abilities of the LEOS system depend on determining where in the flow stream the hydrocarbons are located. The proposed pipe-in-pipe and pipe-in-HDPE designs have centralizers in the annulus. This makes the flow characteristics in the annulus more complex than in a tube and mixing of the air in the flow stream would be expected. We expect that the more complex flow characteristics will make it more difficult to locate a leak.

The LEOS reports which were provided present information on finite element analysis of oil plumes around a buried pipe and other supporting information on the LEOS system. However, due to the critical environmental issues for this pipeline, we would recommend that a third party demonstration test be conducted on the configuration of the supplemental leak detection system selected for the Liberty Project.

5. *Stress should analyze the designs to ensure that they have all been "equally designed", that one system has not been over or under designed to make it appear to be a superior or inferior design to the other alternatives. The issue of the variable burial depth will make this analysis difficult, but it should be possible to review the other components of the designs to ensure that they are comparable.*

In terms of being equally designed, the single wall steel pipe, the steel pipe-in-pipe, and the pipe-in-HDPE are most easily compared. For these three alternatives, two of the alternatives have a 0.688 inch wall thickness for the pipe which is intended to carry the product. The third alternative, the steel pipe-in-pipe has a 0.5 inch wall thickness product line. This means that for a given bending moment, applied to the product line alone, the stresses in the pipe-in-pipe product line would be 31.6% higher. We would have preferred to see the same wall thickness for all three of the product lines (i.e., kept the D/t ratio constant). However, the design is strain based and given the loading conditions we would expect that the pipe-in-pipe would have approximately the same curvature even if the wall thickness were changed from 0.5 inches to 0.688 inches. Since the outside diameter is kept constant at 12.75 inches, the strain in the outer fiber of the pipe for a given curvature is the same regardless of wall thickness. In addition, increasing the wall thickness of the inner pipe to 0.688 inches would only increase the overall bending stiffness of the pipe-in-pipe system by 7% if the 0.844 inch wall thickness outer pipe were retained. Therefore, this change in wall thickness should not have a significant effect on the results at this conceptual design level. The use of a thinner wall pipe does mean that there is a smaller corrosion allowance, but may also result in a lower cost for the pipe. The difference in the material cost would be minor and should not affect the conclusions. From the INTEC report, the effect of the smaller corrosion allowance can not be determined.

A comparison of the flexible pipe system to the other designs is difficult, since the concept of a flexible pipe system is significantly different from a "rigid" pipe concept. However, the same loading conditions were examined for the flexible pipe system as were for the other three alternatives.

Our major concern at this point remains that the burial depths were varied from alternative to alternative. For a truly equal consideration of all of the designs, the burial depth should have been kept constant. There would be some effect due to the smaller corrosion allowance of the inner pipe in the pipe-in-pipe candidate, but the magnitude of this effect can not be determined from the INTEC report. We expect the effect would be insignificant in comparison to the effect of the burial depth. However, the burial depth issue is a major concern since changing the burial depth can make the alternative with the deepest burial depth appear superior to the other alternatives.

6. *The discussions on leak detection leads one to believe that there is actually a leak detection system that is accurate. In my experience such is not the case.*

Leak detection issues in regards to the LEOS system are discussed in item 4 above. In terms of the mass balance and pressure point systems, our primary concern is with false alarms. The concern here is that if the system does not contain self diagnostics that minimize false alarms, the operators will summarily dismiss an actual leak as a false alarm. In order to prevent this, a system should be adopted that has capabilities that allow the operator to accurately determine the difference between an actual leak and a false alarm and contains self diagnostics that reduce the number of false alarms.

7. *There is little to no discussion of corrosion protection in this report.*

Corrosion protection is going to be the most difficult aspect of installing a 6 mile long casing. If HDPE is to be used, shielding of CP protective current will occur unless an anode is provide inside of the casing. Assuming that the casing will remain without an electrolyte is not an acceptable assumption. OPS experience with PVC and HDPE casings is that eventually an electrolyte migrates into the casing and subsequently corrosion of the carrier pipe occurs because protective current cannot reach the metallic surface of the carrier pipe because of the shielding effect of the HDPE.

Filling the annulus with some sort of "inert" material has not been effective either. This material acts much the same as the HDPE in that it shields the carrier pipe from protective current of a CP system.

If a metal casing is to be used I would suggest that the carrier pipe be built to the same strength standard as if there were no casing. The reason for this is that it is very probable that the casing will eventually corrode enough such that it will not be able to provide resistance to external forces. OPS experience with casings has shown that corrosion of the interior of the casing, not the carrier, occurs when an electrolytic path is provided between the carrier and the casing.

CFR 49 195.242 requires that a CP system be installed that will protect the carrier pipe, along with a test procedure that will be used to evaluate adequacy of the CP system. The CP system must be installed and operational no more than 1 year after completing construction. This code requirement will not be waived and therefore it makes the design and review of the CP system the critical issue.

The INTEC report states that cathodic protection will be provided for the single wall pipe alternative.

For the pipe-in-pipe and pipe-in-HDPE concepts, we agree that assuming that the annulus remains free of an electrolyte may be overly optimistic and that providing the inner pipe with some form of cathodic protection should be considered. There are several sources for the introduction of moisture in the annulus which would have to be prevented over the lifetime of the pipeline. First during construction, snow and water must be prevented from entering the annulus. Any snow or water that enters the annulus would form puddles in the low spots in the line. There is also the risk of introducing moisture into the annulus when the supplemental leak detection system is sampling the annulus. If the annulus is sampled once a day for 20 years, there will be 7300 samples taken during the life of the pipeline. For the pipe-in-HDPE concept, there is also the possibility that moisture may be absorbed by the HDPE and migrate into the annulus. Finally, moisture is likely to be introduced into the annulus during any repairs. Given these risks, we feel that it is likely that at some time in the 20 year operating life of the pipeline that moisture will be introduced in the annulus. This along with the potential damage of the pipe coating is the driving force behind our suggestion of a sprayed aluminum or other cathodic coating being applied to provide in-situ cathodic protection. Another method would be to attach anodes to the inner pipe. Either of these methods should supply adequate cathodic protection for the inner pipe. The drawback to this is that the cathodic protection of the inner pipe could not be monitored.

It should be noted that for the Colville River crossing, there was no corrosion control for the carrier pipes other than an external coating. This was done because the designers felt that the annulus could be kept dry, the condition monitored, and actions taken if moisture was detected in the annulus (Ref. Material Performance, February 2000, NACE, page 18). This is the method proposed in the INTEC report. In addition, the INTEC report states that the outer pipe for the steel pipe-in-pipe will be fitted with a cathodic protection system. If a cathodic protection system were installed on the inner pipe, the annulus could still be monitored and with the goal of keeping the annulus dry. The cathodic protection of the inner pipe would be a method of providing additional protection.

We agree that, for a pipe-in-pipe design, the inner pipe should be designed so that the pipeline could operate without the outer pipe. The point is to get improvement over the single wall pipe design by adding an outer pipe. It would be possible to greatly reduce the benefit of adding the outer pipe if the wall thickness of the inner pipe were significantly reduced.

The following comments were made concerning the draft final report. The comments received are included in italics. Responses are included immediately following the comments.

The report has done a good job of meeting the objectives of the study and answering the questions that were raised on the Intermediate Report. Some new questions have been raised that need to be addressed in the final report.

1. *In several locations the report states that "inert" material or liquid would prohibit the use of supplemental leak detection. Please explain why the use of supplemental leak detection would be prohibited if an inert material were added to the annulus.*

In our draft final report, the filling of the annulus with an inert material is mentioned on pages 19, 42, and 59. As presented in the INTEC report, the use of an inert material is in relation to the pipe-in-pipe and pipe-in-HDPE alternatives. The idea is to fill the annulus of the pipe-in-pipe or pipe-in-HDPE with an inert material to prevent corrosion of the inner pipe.

We would envision that this would amount to filling the annulus with the material and sealing the annulus to prevent the escape of the inert material or the introduction of moisture into the annulus. If this is the case then sampling the entire annulus would not be possible. If the inert material were a solid or a liquid, the ability of the LEOS system would be impaired since the inert material would increase the time necessary for the hydrocarbons to come in contact with the LEOS tube (this is a result of the inert material being less permeable than air). In addition, it would seem likely that if a solid or liquid was used, that air pockets would still be present in the annulus.

It may be possible that a LEOS tube could be used when an inert gas, such as dry nitrogen gas, is contained in the annulus under a small amount of pressure, but the possible collapse of the LEOS tube due to the pressure of the inert gas would need to be considered. Therefore, filling the annulus with an inert material may not prohibit the use of a supplemental leak detection system, but would complicate the implementation of a supplemental leak detection system.

Our main concern here is that the addition of an inert material in the annulus of a pipe-in-pipe system would be an obstacle to sampling the annulus. Therefore, a better statement would be that filling the annulus with an inert material would complicate the implementation of a supplemental leak detection system rather than prohibit the use of a supplemental leak detection system. We feel that fewer obstructions in the annulus would increase the likelihood of detecting a leak.

2. *How will the type of inert material (i.e. solid, liquid, or gas) affect the ability to use supplemental leak detection in the annulus?*

If a solid or liquid is contained in the annulus, the time required for the concentration of hydrocarbons around a LEOS tube to reach a detectable level would increase because solids and liquids are less permeable than a gas. In addition, there are further complications with filling the annulus with a solid or liquid. We would expect that there would still be air pockets in the annulus if it were filled with a solid or liquid. Furthermore, two benefits of the annulus are that the pressure in the annulus could be monitored and that the annulus can act as a reservoir to contain oil. An increase in the pressure of the annulus could indicate a leak in the inner pipe. If the annulus were filled with a liquid, the pressure build up which would accompany a leak in the inner pipe would be much more rapid and there would be no reservoir to contain leaked oil. If a solid were used, it may not be possible to monitor the pressure in the annulus and the possibility of detecting a leak as a pressure change in the annulus would be lost. Therefore, it would be preferable if a gas was contained in the annulus so that the pressure could be monitored and in the case of a leak the pressure build-up would be slow enough so that there would be time to shut-in the pipeline.

An alternative to maintaining a fixed amount of nitrogen gas in the annulus, would be to continuously flow dry nitrogen gas through the annulus and to periodically monitor the exhaust gas for water and hydrocarbons. This system would operate on a similar principle to the LEOS system. The problem with this is that since the flow is continuous, it may be more difficult to determine the location of a leak than if the gas had a residence time and sampling occurred once a day as is the case with the currently proposed LEOS system.

3. *Its apparent that filling the annulus with an inert material would affect the ability to draw samples from the annulus to test for the presence of hydrocarbons. Is it possible that LEOS, or some other form of supplemental leak detection, that does not rely on sampling the entire annular space could work if the inert material is gas, liquid, or a porous and permeable solid?*

It may be possible to use a LEOS tube if an inert gas, under a small amount of pressure, is in the annulus. However, the possible collapse of the tube due to the pressure of the gas in the annulus must be considered.

Other than sampling the annulus contents and testing the contents for the presence of hydrocarbons, we know of only two other techniques which could be used to monitor the annulus. First, the pressure in the annulus could be monitored. In this case, pressure variations would indicate a leak. Second, the annulus could be monitored using acoustic emissions (AE). In order for this to work, sensors would have to be placed in the annulus at intervals along the pipeline length. A leak could then be detected by the sound the leaking fluid makes. While this may be possible, the implementation of such a system would be complex. If sensors were placed every 50 ft, there would need to be approximately 646 sensors along the 6.12 mile offshore route. These sensors would need to be connected to a monitoring station for collecting and interpreting the data. Finally the sensors would need to be designed to survive the 20 year operating life of the pipeline.

Leaving the annulus empty or filled with gas at low pressure, provides the benefit that a significant quantity of leaked-in hydrocarbon can be stored in the annulus before the pressure builds up. This buys time before the well must be shut in and before the annulus must be opened to tank storage at one or both ends. Note that both the outer pipe and the inner pipe are designed to contain the well shut-in pressure. Filling the annulus with a solid or liquid is not recommended, because in addition to the solids and liquids being less permeable to hydrocarbons, the benefits of this storage feature would be reduced.

4. *In several locations the report states that assuming the annulus remains free of an electrolyte may be overly optimistic. Please explain why this is overly optimistic.*

In our draft final report, it is mentioned on pages 18 and 42 that assuming that the annulus remains free of an electrolyte may be overly optimistic. There are several sources for the introduction of moisture in the annulus which would have to be prevented over the lifetime of the pipeline. First during construction, snow and water must be prevented from entering the annulus. Any snow or water that enters the annulus would form puddles in the low spots in the line. There is also the risk of introducing moisture into the annulus when the supplemental leak detection system is sampling the annulus. If the annulus is sampled once a day for 20 years, there will be 7300 samples taken during the life of the pipeline. For the pipe-in-HDPE concept, there is also the possibility that moisture may be absorbed by the HDPE and migrate into the annulus. Finally, moisture is likely to be introduced into the annulus during any repairs. Given these risks, we feel that it is likely that at some time in the 20 year operating life of the pipeline that moisture will be introduced in the annulus.

We agree that efforts should be made to keep the annulus dry and this is a good defense against corrosion of the pipeline inside the annulus. However, providing some form of cathodic protection in the annulus of the pipe would provide additional protection and should be considered carefully.

5. *In several locations the report indicates that drying the annulus would be a difficult operation. Please explain why this would be a difficult operation.*

We envision the drying process to consist of flowing warm dry air through the annulus of the pipe, using a vacuum drying process, or some combination of the two. A pig cannot be used to push water out of the annulus. Therefore, the drying process will depend solely on evaporating the water.

Given the length of the line, our preference would be to flow heated dry air through the annulus. If a vacuum drying process is used, it is possible that problems with freezing the water may be encountered. Over 500 calories are used in evaporating 1 gram of water. This will quickly cool any remaining water to below 32^{o} F and produce ice. Ice has a very low vapor pressure and will evaporate more slowly than liquid water. Because of the low ambient temperature, this type of freezing during vacuum drying is probable. To prevent this, it may be necessary to supply additional heat to the system. One way to supply additional heat would be to flow heated water through the inner pipe. However, the water flowed through the pipe would likely be contaminated and the subsequent treatment and disposal of the water must be considered.

The possibility of drying the annulus being difficult is mentioned in the draft final report on pages x, 58, and 73 and is referring to drying the annulus after a repair. The drying operations following a repair would be more difficult because of debris drawn into the annulus during the damage period and the subsequent repair activities. Such debris would include soil, sand, and gravel, in addition to seawater and hydrocarbons. Not all of these materials and objects would be removed by the drying process and may increase the time necessary to dry the annulus.

Another consideration is the traces of hydrocarbons left in the annulus after a repair. Since hydrocarbons would be left in the annulus, the leak detection system would have to be recalibrated to allow for the concentration of hydrocarbons that are present in the annulus.

6. *The report indicates that drying the annulus, presumably after a repair, would take a month or more. Please explain the basis for this estimate.*

Our draft final report states that drying the annulus could take a month or more on pages x, 59, and 73 and is referring to drying the annulus after a repair. This estimate is based on experience of one of our team members and includes some time for setting up a drying system and drying the annulus.

While the pipe-in-pipe system is being repaired, the equipment required for drying the annulus would be assembled. This equipment would include a large air compressor, air drying equipment, vacuum pump, vacuum gauge, leak-proof valves, and the associated piping and hoses. If a large enough compressor is not on site, a rental air compressor of sufficient size may need to come from the “lower 48”, requiring two to three weeks lead time. We would allow one or two days time to hookup the compressor. After the compressor is hooked up, it would be operated one to two days to pump dry air into the annulus. Then several days would be required to hook up the vacuum pump and to test for leaks. Finally, we assume a period of one to two weeks of operating the vacuum system before the P-I-P annulus would be sufficiently dry. Please note, that these are only estimates and we have not performed any modeling to estimate drying times.

Our concern here is that if the outer pipe leaks, moisture could be present for a long enough time for corrosion to begin. Therefore, providing cathodic protection for the inner pipe should be considered.

7. *What methods are available for drying the annulus of a double wall pipeline system?*

We are familiar with two methods of drying a P-I-P annulus, either applying a vacuum or flowing warm dry air or nitrogen through the annulus. If only a small amount of water is present, the annulus may be dried by applying a hard vacuum sufficient to evaporate water at the near-freezing seawater temperature. This technique takes time, up to two weeks, because of weld outgassing and because the individual water molecules must travel by Brownian motion through the long narrow annular passage to the large-capacity vacuum pump at one end.

If the annulus contains a significant quantity of water, which would be likely after repairing a leak in the outer pipe, then most of the water can be removed by blowing a strong flow of dry air or dry nitrogen through the annulus. A large air compressor may be used to pump warm dry air into the annulus at one end and the moist air would exit at the other end. Any water remaining in the annulus after this operation could be removed by vacuum as described above. The common pipeline drying method, involving a pigging train interspersed with large quantities of methanol, obviously cannot be applied to an annulus configuration.

8. *Is vacuum drying an option; essentially lowering, temporarily, the annulus pressure below the boiling point of water and evacuating? Could this be accomplished while hydrotesting the carrier pipeline with warm water, therefore elevating the operating temperature of the annulus and melting any snow or ice remaining from installation?*

It is possible that vacuum drying could be used. If this is done, efforts should be made to elevate the temperature of the annulus during the operation and filling the inner pipe with warm water may be a good approach. A problem with vacuum drying is that the evaporation process depends on some heat being present. While applying a vacuum will lower the boiling point, it is also possible that some of the water will freeze before the evaporation process is complete. To prevent this, some heat may need to be added to the system. Flowing warm water through the inner pipe would be one way to supply heat to the annulus. However, the water flowed through the pipe would likely be contaminated and the subsequent treatment and disposal of the water must be considered.

9. *In a number of locations in the report, beginning with page xvi, Stress expresses an interest in the concept of putting a flexible, composite, or polymer pipe inside a thick walled steel pipe. The report states that if the inner pipe was nonmetallic that the concerns over corrosion of the inner pipe would be eliminated. Please indicate if Stress believes there would be any other advantages or disadvantages related to this concept.*

The primary advantages of using a flexible, composite, or polymer pipe inside a thick walled steel pipe are:

a. The flexible, composite, or polymer pipe would not corrode.
b. The flexible, composite, or polymer pipe would be lighter. Therefore, longer pipe strings could be towed to the trench and the number of field joints reduced.
c. There would be fewer joints in the flexible, composite, or polymer pipe than in a steel inner pipe
d. The outer steel pipe strings (1000 to 3000 ft) could be made and then the inner pipe pulled through the outer pipe.

The primary disadvantages of using a flexible, composite, or polymer pipe are:

a. The flexible, composite, or polymer pipe would be more difficult to repair than a steel pipe.
b. There is a possibility of damaging the inner pipe when welding the outer pipe field joints. Therefore, a procedure for preventing this damage would need to be developed.

3.0 DESCRIPTION OF DESIGN CONCEPTS

This section provides brief descriptions of the design concepts as presented in the INTEC report. This is intended to provide the reader with an overall view of the candidates. For a detailed review of the concepts, the reader is referred to the INTEC report.

3.1 Single Wall Steel Pipe

The first candidate design consists of a single wall steel pipe. The pipe is an API 5L Grade X-52 material with a 12.75 inch outside diameter and a 0.688 inch wall thickness. The pipe is coated with a (fusion-bonded epoxy) FBE coating and cathodic protection is provided to inhibit corrosion. Two subalternatives of the single wall steel pipe are presented. The first is a straight pipeline that is to be buried to a depth that allows for 7 feet of native backfill on top of the pipeline. Gravel mats are to be placed at high points in the line to reduce the possibility of upheaval buckling of the pipeline. The second is a zigzag pipeline with an 8^{o} bend and would require less backfill. The INTEC report presents the straight pipeline as the primary candidate for a single wall steel pipeline.

3.2 Steel Pipe-in-Pipe

The second candidate design presented in the INTEC report consists of a steel pipe-in-pipe design. There are two subalternatives presented. The first subalternative has an X-52 steel inner pipe with a 12.75 inch O.D. and a 0.688 inch wall thickness. The outer pipe is X-52 steel pipe with a 16 inch O.D. and a 0.5 inch wall thickness. The second subalternative has an X-52 steel inner pipe with a 12.75 inch O.D. and a 0.5 inch wall thickness. The outer pipe for the second subalternative is X-52 steel pipe with a 16 inch O.D. and a 0.844 inch wall thickness.

Two variations on these subalternatives are also presented in the INTEC report. These variations have to do with the placement of structural bulkheads in the pipeline. In the first variation, there are only two locations for bulkheads, i.e., at Liberty Island and at the shore crossing. In the second variation, structural bulkheads would be located at Liberty Island, at the shore crossing, and at ½ mile intervals along the length of the pipeline.

The INTEC report presents the subalternative consisting of an X-52 steel inner pipe with a 12.75 inch O.D. and a 0.5 inch wall thickness, an X-52 steel outer pipe with a 16 inch O.D. and a 0.844 inch wall thickness, and bulkheads only at Liberty Island and the shore crossing as the primary candidate for a steel pipe-in-pipe pipeline. For this candidate, the amount of native backfill required is 5 feet.

3.3 Steel Pipe-in-HDPE

Another candidate for the Liberty Pipeline is a steel pipe in a high density polyethylene (HDPE) sleeve. This candidate consists of an X-52 steel inner pipe with 12.75 inch O.D. and a 0.688 inch wall thickness. Two subalternatives are presented for the pipe-in-HDPE. The first subalternative has an outer HDPE sleeve with a 15.25 inch O.D. and a 0.25 inch wall thickness. In this alternative, the annulus is filled with PU (polyurethane) foam. The second subalternative has an outer HDPE sleeve with a 16.25 inch O.D. and a 0.75 inch wall thickness. Air is in the annulus of the second subalternative. The second subalternative is presented as the primary pipe-in-HDPE candidate. The native backfill for this candidate is 6 feet.

3.4 Flexible Pipe

The final pipeline candidate consists of a flexible pipe. The flexible pipe is constructed of layers of thermoplastic and steel strips. The layers are not bonded together. This lack of bonding increases the flexibility of the pipe (i.e., the pipe bends easier). In this type of pipe, the thermoplastic layers serve as a fluid barrier and the steel layers provide the reinforcement necessary to carry the load. There is no subalternative presented for this candidate. The proposed burial of this candidate consists of 5 feet of native backfill.

4.0 DISCUSSION OF DESIGN ISSUES

This section of the report presents a discussion of items that fall under the category of design issues as defined by the MMS request. The following sections discuss each of the items listed as related to each of the design concepts.

4.1 Design Objectives and Basis

The design objectives and basis are relatively straightforward and as presented in the INTEC report appear reasonable as would be applied to designing a pipeline. However, there is a concern about the intended purpose for investigating the pipeline alternatives. We agree that any pipeline should be designed to safely fulfill the required operating parameters and meet the required standards. Our concern is that the primary purpose for investigating the pipeline alternatives, as we understand the situation, is to ensure that the environment is protected in the best possible manner.

In this light, we would view the single wall steel pipe as a baseline design and the driving force behind investigating other alternatives would be to determine if additional protection from leaks and/or better leak detection abilities could be obtained with the alternate concepts. The standard in the industry is to use a single wall pipe. We believe that the main question to be answered here is; Is there a better alternative? Therefore, before an alternative concept can be considered, a clear statement outlining the possible/perceived benefits is needed.

The INTEC report states, on page 5-1, that there is no known case where pipe-in-pipe has been used for secondary containment and that it is usually for installation or thermal insulation reasons. While this is true, this past practice should not exclude the potential for using a pipe-in-pipe system for leak containment or other legitimate reasons. In addition, the INTEC report does not state the reason for considering pipe-in-pipe for this project. It seems that the methodology has discounted the principal advantage of the pipe-in-pipe and pipe-in-HDPE systems, i.e., the ability to contain and provide an annulus to facilitate the detection of small leaks. Another advantage to the pipe-in-pipe concept is that it is feasible that the pipeline could remain in operation even if the inner pipe contains a small leak. At a minimum, this would mean that if a leak is detected in the inner pipe, the oil could be pumped from the line before repairs are made. This would prevent the oil from being introduced into the environment. This contrasts with the single wall pipe concept in which any leak would result in an oil spill and an automatic shut-in of production until the pipeline is repaired.

The pipe-in-HDPE concept is said to provide additional mechanical protection to the pipeline, but not add to the structural integrity of the pipeline. It would seem that the primary purpose would be to provide an annulus which could be used for leak detection and aid in the containment of small leaks. However, the driving force behind considering this concept is not stated.

Similarly, the reason behind considering the flexible pipe system is not stated. We would expect there to be some perceived benefit for using this system in order for it to be one of the four primary candidates.

4.2 Loading Conditions

The loading conditions on the pipeline are discussed in this section. Since the pipeline is to be constructed in an arctic environment, the environmental loading conditions deserve special treatment and are presented in a separate subsection.

4.2.1 Environmental

Environmental loading conditions which are considered in the INTEC report include ice keel gouging, strudel scour, thaw settlement, and upheaval buckling. We agree that these are the environmental loads that should be considered. It is stated in the INTEC report that the likelihood of combined events leading to failure is not included in the study. However, we believe that at the conceptual level the primary concern is that all of the conditions have at least been considered separately. The likelihood of combined events leading to a failure would be better suited to the preliminary design phase.

4.2.2 Other

Causes of failure, other than environmental loading conditions, which are presented in the INTEC report include internal pressure, internal corrosion, external corrosion, vessel accidents, and sabotage. Erosion of the pipe wall is not mentioned, but should not be a problem if the product is adequately filtered before it enters the pipeline.

4.3 Elimination of Candidate Designs/Consistent Design Criteria

This section discusses how the candidate designs were eliminated from consideration and if consistent design criteria were used in assessing each concept. To provide a thorough discussion, the elimination of the subalternatives for each primary concept is considered first in sections 4.3.1 through 4.3.4. Section 4.3.5 discusses the selection of the best alternative.

4.3.1 Single Wall Steel Pipe

Two subalternatives were presented for the single wall steel pipe concept; a straight pipe and a zigzag pattern. Of these two concepts, the straight pipe version is selected as the primary candidate. If a single wall pipeline alternative is taken to the preliminary design phase, we would suggest further consideration of the zigzag alternative due to its resistance to upheaval buckling. It is stated in the INTEC report on page 4-10 that the straight pipe version was picked since the fabrication and installation of the straight pipe version are more like a conventional on-land installation. However, both versions would require alignment clamps for welding. Therefore, there would be little difference in the installation of the straight pipe and zigzag alternatives.

4.3.2 Steel Pipe-in-Pipe

The steel pipe-in-pipe concept is presented as four subalternatives. Two of the alternatives have structural bulkheads at only Liberty Island and the shore crossing. The other alternatives have structural bulkheads at Liberty Island, the shore crossing, and at ½ mile intervals along the pipeline. Table 5-6 on page 5-12 of the INTEC report lists the advantages and disadvantages of the alternative structural bulkhead locations.

Advantages listed for having bulkheads only at Liberty Island and at the shore crossing are simpler offshore construction, unobstructed annulus to facilitate a supplemental leak detection system, and that if an inner pipe leak occurs oil can be flushed out of the annulus. The one disadvantage listed is that if the inner pipe leaks, the oil in the annulus is free to spread longitudinally. It should also be noted that there is no obstruction to the spread of moisture in the annulus either.

Advantages, which are listed in Table 5-6 of the INTEC report, to having the additional structural bulkheads at ½ mile intervals along the pipeline include that oil from a leak in the inner pipe would be contained within the ½ mile interval. It should also be noted that moisture introduced into the annulus would also be restricted to the ½ mile interval. The disadvantages listed in the INTEC report are the more complicated offshore construction, the obstruction of the annulus which would make it more difficult to implement supplemental leak detection systems, and that the bulkheads are potentially exposed to high pipe bending strains. This last disadvantage, the high pipe bending strains, is a result of the structural bulkheads having a higher bending stiffness than the rest of the pipeline. Because of this, when the pipeline bends in a region containing a bulkhead, there would be a tendency for the line pipe to deform to a greater extent than the bulkheads and kink at the line pipe to bulkhead transition. This should be accounted for in the final design. However, we feel that an adequate transition could be designed to prevent kinking at the transition.

Of the advantages and disadvantages listed, we feel that the critical consideration is the ability to implement the supplemental leak detection system in the annulus of the pipeline. Therefore, we feel that the choice of having structural bulkheads only at Liberty Island and the shore crossing is correct.

Once the decision has been made to have structural bulkheads only at Liberty Island and the shore crossing, the remaining subalternatives consist of:

A. Inner pipe: X-52 steel pipe, 12.75 inch O.D., and 0.688 inch wall thickness
   Outer pipe: X-52 steel pipe, 16 inch O.D., and 0.5 inch wall thickness
B. Inner pipe: X-52 steel pipe, 12.75 inch O.D., and 0.5 inch wall thickness
   Outer pipe: X-52 steel pipe, 16 inch O.D., and 0.844 inch wall thickness

Subalternative (A) uses an inner pipe of the same dimensions as those proposed for the single wall steel pipeline and an outer pipe with a 16 inch O.D. and a 0.5 inch wall thickness. Subalternative (B) uses an inner pipe with a thinner wall than the single wall alternative (i.e., 0.5*100/0.688 = 72.67% of the single wall pipe thickness).

In the INTEC report, subalternative (B) is chosen as the primary configuration. The reason for this selection is cited as a slightly better structural response and installation. The decision seems to primarily be a result of subalternative (B) requiring less backfill to resist upheaval buckling and the predictions of lower ice keel strains, since subalternative (A) was ranked higher in Section 5.3.2 Fabrication and Installation considerations of the INTEC report.

The choice of subalternative (B) over subalternative (A) is not entirely clear due to the ranking of (A) being higher in Table 5-5 on page 5-11 of the INTEC report and the estimated weight in air of alternative (B) being 33 lbs/ft greater than alternative (A). In addition, we would have preferred that the inner pipe of the pipe-in-pipe alternatives have the same dimensions as the single wall pipe alternative. However, the design is primarily strain based and given the loading conditions we would expect that the pipe-in-pipe would have approximately the same curvature even if the wall thickness were changed from 0.5 inches to 0.688 inches. Since the outside diameter of the inner pipe is kept constant at 12.75 inches, the strain in the outer fiber of the pipe for a given curvature is the same regardless of wall thickness. In addition, increasing the wall thickness of the inner pipe to 0.688 inches would only increase the overall bending stiffness of the pipe-in-pipe system by 7% if the 0.844 inch wall thickness outer pipe were retained. Therefore, this change in wall thickness should not have a significant effect on the results at this conceptual design level. The use of a thinner wall pipe does mean that there is a smaller corrosion allowance, but may also result in a lower cost for the pipe. The difference in the material cost would be minor and should not affect the conclusions. From the INTEC report, the effect of the smaller corrosion allowance can not be determined.

Nonetheless, at this level of design, subalternative (A) and (B) are essentially the same design since we would expect the pipe wall thicknesses to change when more detailed analysis is carried out. It is common practice to choose a preliminary pipe size and make modifications to the dimensions as more analysis is done. Therefore, we have no major problems with the choice to concentrate on subalternative (B).

A concern we do have is that it seems that there is an emphasis in the design selection to minimize the burial depth of the pipeline. By doing this, the benefit of using an alternative design (as opposed to a single wall pipe) can be lost.

4.3.3 Steel Pipe-in-HDPE

There are two alternatives to the steel pipe-in-HDPE. The inner pipe is the same in both subalternatives. The differences in the alternatives are in the dimensions of the HDPE sleeves that enclose the inner pipe and that the annulus of subalternative (A) is filled with a polyurethane foam. The annulus in subalternative (B) is not filled.

The differences in the subalternatives which are presented include:

1. Subalternative (A) would have locked in compressive stresses in the inner pipe due to the differences in the thermal expansions of the foam, HDPE, and steel which are bonded together.
2. Subalternative (B) is perceived to be easier to install and have a slightly better structural response.

It should be noted that the bond between the foam and the steel pipe could be weakened/eliminated by applying a release agent to the steel pipe prior to injecting the foam. If such a configuration is used, provisions for a leak detection system in the annulus would need to be made.

There is a slight modification to this alternative that we would suggest investigating. The HDPE sleeve could be prefabricated as a unit with an inner thin wall HDPE pipe and an outer HDPE pipe with the foam in-between. In order to use this HDPE sleeve with the foam in place, an adequate installation clearance between the thin wall HDPE pipe and the steel inner pipe would be required. A further variation would be to perforate the thin wall HDPE pipe and replace the polyurethane foam with an oil absorbent material. In this scenario, the HDPE sleeve assembly becomes an oil containment barrier and a leak detection system could monitor the annulus between the steel pipe and the perforated thin wall HDPE pipe. A sketch of this alternative is included as Figure 1 in this report.

We agree that as proposed, that subalternative (B) should be easier to install. It should also be easier to fit with a supplemental leak detection system than subalternative (A) which has the entire annulus filled with foam. Therefore, we can see the logic in choosing subalternative (B) over subalternative (A) as the primary pipe-in-HDPE candidate. Our concern is that with some slight modifications to this concept we feel that it may be possible to greatly increase the ability of this concept to limit the spread of leaked oil.

A further concern has to do with the material properties of HDPE. On page 6-24 of the INTEC report it states that " The failure strain for HDPE is approximately 50 times that of steel." Since HDPE is a viscoelastic material, its properties are a function of temperature and strain rate. The failure strains, impact resistance, and modulus of HDPE should be checked in the installation and operating temperature range.

4.3.4 Flexible Pipe

The flexible pipe system proposed consists of a 12 inch I.D. by 1.47 inch wall thickness flexible pipe system. The individual pipe segments would be approximately ¾ of a mile long and would be joined by welding the metal end fittings of the segments together.

Advantages of the flexible pipe option are the fast construction speed and the relatively low cost. The principal disadvantage is the complex construction of the flexible pipe. It is likely that 6 miles of flexible pipe would contain at least one defect that could lead to a leak. This makes quality control during the manufacture of the pipe critical.

There is no subalternative presented for this design concept.

4.3.5 Comparison of the Four Concepts

The INTEC report selects the single wall pipe as the best candidate concept for the pipeline. There are certain advantages to this configuration which should be noted. These include:

1. Most existing pipelines are single wall pipelines. As a result of this, pipeline designers, contractors, and operators are comfortable with this type of pipeline (i.e., it is a known technology).

2. There is existing technology that allows for the inspection of the entire pipeline.

Our concern with this selection is that all the designs do not seem to have been weighed equally. We feel that in order to equally compare the concepts, all of the concepts should be buried at the same depth. Since each concept is buried at a different depth, the soil pressures resulting from environmental loads, such as Ice Keel Gouging, on all of the designs are different. As a result, the study does not present a good comparison of designs.

Another issue which makes the comparison of the designs unequal is that the inner pipe (flowline) of the steel pipe-in-pipe concept is thinner than the single wall pipe. We would have preferred that the burial depths and the flowline wall thicknesses of all the alternatives be identical to that used in the single wall pipe concept. However, the effect of the change in pipe wall thickness on the equal weighing of the alternatives is minor in comparison to the effect of the burial depth. By assigning different burial depths to the different concepts, the benefit of using an alternative design (as opposed to a single wall pipe) can be lost. The single wall pipe is picked as the best pipeline system candidate. However, the risk of an oil leak is primarily a function of the burial depth and the single wall pipe is buried the deepest. While the chosen depths appear appropriate for each design concept, we would adopt a different approach. We would fix the burial depth for all of the concepts at that of the single wall pipe. Since the primary effect of the burial depth on the cost of the pipeline is the trenching cost, the increased cost for using the same burial depth for all of the lines is a small percentage of the total cost. The increased trenching cost for burial of the pipe-in-pipe, pipe-in-HDPE, and flexible pipe at the same depth as the single wall concept would be approximately \$1.6 million, \$0.6 million, and \$2.2 million dollars respectively (based on the trenching cost estimates in the INTEC report).

The INTEC report does make statements which illustrate that the risk analysis results summarized in Table 9-3 of the INTEC report would be different if the concepts were all buried at the same depth. On page 13 of the INTEC report, the following statement is made:

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

However, on page 9-9 of the INTEC report, it is reported that if the pipe-in-pipe system had a depth of cover of 7 feet, it would have a risk of oil spillage about <u>*6 times less*</u> than the single wall pipe system. In addition, the 10 million dollar cost increase does not seem reasonable based on the cost figures presented in the report.

4.4 Technical Merits

In terms of the technical merits of the INTEC report, there are some questions concerning some items and some comments we have on others. The first question has to do with the finite element modeling of the ice keel soil/pipe interaction using ANSYS. The cause of concern here is that the geometric nonlinearity was not included in the analysis. From page 3-5 of the INTEC report, "Non-linear geometry effects were <u>not</u> included in the conceptual design analysis". This statement means that the effects of large deflections were not included in the analysis. In our opinion, these effects should be included.

There are two primary sources of nonlinearity to be considered in stress analysis. The first type is material nonlinearity. A material is said to be nonlinear if the relationship between the stress and strain is nonlinear. If the strain in a material is proportional to the applied stress then a plot of stress versus strain will be a straight line (i.e., a line with a constant slope) and the material is said to behave in a linear fashion. For a nonlinear material, the slope of the stress versus strain curve is not constant. Nonlinear geometric effects have to do with the extent of deformation of the body being analyzed. If the deformations in the body are small, the effect of the deformation on the results is small, the nonlinear geometric effects can be neglected, and the equilibrium equations can be written with respect to the undeformed body. However, when deformations are large the deformation of the body can affect the loading on the body. Large deformations are defined as large rotations or displacements in the body that can alter the location or distribution of loads. When this occurs, the equilibrium equations must be written with respect to the deformed geometry. A simple example of a problem with geometric nonlinearities is illustrated in Figure 2. In Figure 2, a cantilever beam is subjected to a load P which is initially perpendicular to the beam. For a small deflection, the moment arm, A, is approximately equal to the length of the beam, L. This is illustrated in Figure 2(a). However, for larger deflections, the moment arm A is less than the beam length, L, and A is dependent on the load P. This is illustrated in Figure 2(b).

After the Intermediate report for this project was issued, the question was raised as to whether the geometric nonlinearity would typically be included at the conceptual stage and if not at what stage in the pipeline design should the geometric nonlinearity be incorporated in the analysis. In our opinion, the geometric nonlinearity should be included at this conceptual level. The INTEC report includes results from finite element analysis which incorporates the material nonlinearity, but neglects the geometric nonlinearity. This is an unusual assumption. In most cases, if not all, when material nonlinearity is incorporated, the geometric nonlinearity is also included. One would expect to see analyses where both the material and geometric response is linear, the material response is linear and the geometric response nonlinear, or where both the material and geometric response is nonlinear. By including the material nonlinearity in the analysis, one is assuming that the deformations are large enough so that yielding of the material could occur. It is difficult to predict what the effect of the geometric nonlinearity would be on the analysis results. At a minimum, we would suggest taking the finite element run which resulted in the largest displacements and strains and rerunning the problem with the nonlinear geometry effects included. By comparing the results, one would get a feel for the effect of the geometric nonlinearity on the resulting stresses and strains.

We have spoken with the INTEC representatives, Michael Paulin and Andre Nogueira, about the exclusion of the nonlinear geometric effects from the finite element analysis. Their reasoning behind neglecting the nonlinear geometric effects appears to be due to the increased run time which would have resulted. There were some checks made of the pipe-in-pipe and single wall steel pipe which included the nonlinear geometric effects. However, these runs have not been through INTEC's quality assurance checks yet and as a result are preliminary. The runs showed that there was an increase in the strains (15-20%), but the trends remained the same and the strains were still well below the allowable strains.

At this level of design, our main concern is that any analysis done on the four design concepts results in the proper ranking of the designs. From our conversation with INTEC, INTEC's checks showed that the trends in the strains remained the same when the nonlinear geometric effects were included as when the nonlinear geometric effects were neglected. Therefore, they used the runs that neglect the nonlinear geometric effects for the conceptual design. We think that this topic is in a gray area between conceptual and preliminary design. In our opinion, if the finite element analysis was felt to be needed at this level, then both the geometric and material nonlinearity should have been included. It may be prudent to use the conceptual design phase to narrow the candidates from four to two and perform the finite element analysis on the two final candidates including the nonlinear geometry effects before selecting the final candidate.

During our initial review of the INTEC report, the trends for ice keel max strains for the pipe-in-pipe and pipe alone seemed odd. The ice keel max strains for the single pipe, presented in tables 4-2 and 4-3, are higher than the ice keel max strains for the pipe-in-pipe, presented in tables 5-2 and 5-3. Since the single pipe is buried deeper than the pipe-in-pipe, we expected that the strains in the pipe-in-pipe would be higher. After examining the information SES received from INTEC on February 29, 2000, we have noted that the values in the tables are all for a 7 ft depth of cover. Since this is the case, the trends seem reasonable.

We understand that there is a separate contract to review the spillage probability and damage calculations. We feel that this is an important activity since, the INTEC report definition of a small chronic leak (Category 3 damage, see p 5-38) appears unrealistically low at only 1 barrel a day. Even a 1 inch long crack 0.001 inches wide could discharge approximately 29 bbls/day from an 1100 psi line. A 1 barrel/day leak from an 1100 psi line corresponds to a 0.007 inch diameter hole.

For the pipe-in-pipe concept, it is stated that there will be a locked in compressive load in the inner pipe. There will be centralizers in the design to keep the curvature of the two pipes approximately equal. The inner pipe should be checked for buckling between the centralizers due to the thermal expansion if this design concept is carried forward.

On page 6-1 of the INTEC report, it is stated that the HDPE will not add to structural integrity only give mechanical protection. This leaves the following questions unanswered;

- Can the HDPE contain a leak?
- If not, then what is the purpose of the HDPE pipe in the design?

It is our opinion that the HDPE sleeve used in the pipe-in-HDPE concept could contain small leaks. However, if the inner pipe were to rupture so that the HDPE sleeve were subjected to the operating pressure of the pipeline, the sleeve would fail due to the load from the internal pressure. The tensile strength of high density polyethylene is in the range of 20-37 MPa (2.9-5.4 ksi), Ref. Ashby, M.F., and Jones, D. R. H., "Engineering Materials 2: An Introduction to Microstructures, Processing and Design, Pergamon Press, 1988, (28 MPa per McCrum, N. G., Buckley, C. P., and Bucknall, C., B., "Principles of Polymer Engineering", Oxford Science Publications, 1992). The proposed HDPE sleeve has an outside diameter of 16.25 inches and a wall thickness of 0.75 inches. This makes the mean radius of the sleeve 7.75 inches. For the maximum allowable operating pressure of the line of 1415 psi (INTEC report page 3-25) the hoop stress is 1415*7.75/0.75 = 14622 psi = 14.6 ksi. Since 14.6 ksi is much greater than 5.4 ksi, the HDPE sleeve would be expected to burst if it were subjected to the maximum operating pressure of the pipeline. The 0.75 inch wall thickness could only hold an internal pressure on the order of 523 psi (i.e., 5.4*1000=Pressure*7.75/0.75 gives P = 523 psi).

However, it should be noted that a small leak in the inner pipe would not result in the HDPE sleeve being immediately subjected to the operating pressure of the pipeline. The volume of the annulus between the inner pipe and the HDPE sleeve is approximately 3.1416*[(14.75/2)^2-(12.75/2)^2]*6.12*5280*12 = 16750207 cubic inches = 72512 gallons = 1727 barrels. Using the production rate of 65000 bbl/day and assuming all of the oil were flowing into the annulus, it would take approximately 38 minutes to fill the annulus with oil. It should be noted that this is the lower bound on the time required to fill the annulus and would be an extreme condition that is very unlikely. Therefore, we expect that there would be time to detect the presence of oil in the annulus with either the LEOS system or by pressure fluctuations in the annulus before the burst pressure of the HDPE sleeve is reached. Furthermore, the bulkheads at each end of the pipeline could be fitted with a pressure relief system that keeps the pressure in the annulus from exceeding the burst pressure of the HDPE sleeve. This pressure relief system could be connected to a reservoir which would prevent any oil leaked into the annulus from entering the environment.

The outer pipe of the steel pipe-in-pipe could not only contain small leaks, but could also contain the operating pressure of the pipeline. This design, like the pipe-in-HDPE design, could also be fitted with sensors to monitor the pressure of the annulus and a reservoir which would prevent any oil leaked into the annulus from entering the environment. Since the outer steel pipe can withstand the operating pressure of the pipeline, the pipeline could still operate if there was a leak in the inner pipe. At a minimum this would mean that if the inner pipe develops a leak, the oil could be pumped from the pipeline before repairs are made. This would prevent oil from entering the environment. In contrast, a leak in a single wall pipe would result in an oil spill and an automatic shut-in of production until the pipeline was repaired.

We would be interested in knowing if concepts such as putting a corrosion resistant pipe (i.e., either HDPE, flexible, or composite) as a flowline inside a steel pipe have been considered. The outer steel pipe would be cathodically protected and could contain the full pipeline pressure and the use of a nonmetallic inner pipe would eliminate the concern about the cathodic protection of the inner pipe. If such a concept has been considered, what factors eliminated this option from consideration? It would be more difficult to install than a single wall pipe, but we would think that it would be easier to construct than the steel pipe-in-pipe.

The primary advantages of using a flexible, composite, or polymer pipe inside a steel pipe are:

a. The flexible, composite, or polymer pipe would not corrode.
b. The flexible, composite, or polymer pipe would be lighter. Therefore, longer pipe strings could be towed to the trench and the number of field joints reduced.
c. There would be fewer joints in the flexible, composite, or polymer pipe than in a steel inner pipe
d. The outer steel pipe strings (1000 to 3000 ft) could be made and then the inner pipe pulled through the outer pipe.

The primary disadvantages of using a flexible, composite, or polymer pipe as a flowline inside a steel pipe are:

a. The flexible, composite, or polymer pipe would be more difficult to repair than a steel pipe.
b. There is a possibility of damaging the inner pipe when welding the outer pipe field joints. Therefore, a procedure for preventing this damage would need to be developed.

In the proposed pipe-in-pipe and pipe-in-HDPE designs, centralizers/spacers will be installed in the annular space between the inner and outer pipe or HDPE sleeve. When designing these centralizers, care should be taken to ensure that the centralizers are sized so that the outer pipe is not damaged from the shear loads imparted by the centralizers.

5.0 DISCUSSION OF LIFE CYCLE COSTS

This section of the report discusses the issues that affect the life cycle costs of the pipeline. Among these are the construction methodology, the cost estimates, operations, maintenance, repair, and inspection/leak detection.

5.1 Construction Methodologies

This section discusses issues concerning the initial construction of the pipeline. A separate section is included for each of the design concepts. This introductory section includes some comments applicable to more than one of the design concepts.

For all of the concepts, the basic method of construction is to use heavy equipment to cut through the ice, remove ice from the slot, and dig the trench to the necessary depth with backhoes. The approach is reasonable, and has been demonstrated as being feasible in connection with the Northstar project. Therefore, we feel that this method of installation is a good choice. Specific comments are included below.

For both the steel pipe-in-pipe and steel pipe-in-HDPE, the INTEC report states that there is a significant chance that construction could not be completed in a single season. However, there is no mention of the procedures which would be required to abandon an uncompleted line and then successfully resume construction.

We agree that both the steel pipe-in-pipe and pipe-in-HDPE alternatives would be more difficult to construct than either the single wall steel pipe or the flexible pipe. However, there are some refinements to the construction process that could reduce the time required to install the steel pipe-in-pipe and pipe-in-HDPE alternatives. First, the single wall steel pipe strings that are to be towed to the trench are 3000 ft long. However, the pipe-in-pipe and pipe-in-HDPE strings are only 1000 ft long. This increases the number of tie-in locations by a factor of three. In addition, the time to make each connection is longer for the pipe-in-pipe and pipe-in-HDPE alternatives because of the additional connection of the outer pipes or sleeves. It would seem that the main factor affecting the length of the string that can be towed is the weight of the string. For the steel pipe-in-pipe, a 1300 ft string is approximately the same weight as the 3000 ft single wall steel pipe string. If 1300 ft strings were used, the number of tie in locations would be reduced from 33 to 25 and the connections could be made in approximately 8 fewer days. For the pipe-in-HDPE alternative, 2600 ft strings weigh approximately the same as the single wall steel pipe 3000 ft string. Using 2600 ft long pipe-in-HDPE strings would reduce the time for the field joints from 22 days to 9 days. In both cases, preparing longer strings would increase the pipe string make-up time. However, this could be offset by increasing the size of the crew. Another way to speed up the construction would be to use two pipelaying spreads either starting in the middle of the route and working toward opposite shores or starting onshore and working toward a central tie-in.

In the INTEC report, the construction timelines for the single wall, steel pipe-in-pipe, and pipe-in-HDPE, start in mid December and end in mid April. The timeline for the flexible pipeline is shorter, running from mid December to mid March. However, the INTEC report states that the ice is stable in Zone 1 by December and break-up occurs at the end of May. Therefore, it would seem that equipment mobilization, road construction, and make-up site preparation could begin December 1st and construction could continue through May. This amounts to eight weeks that are currently not included in the construction timeline. If half of this time is discounted for weather variations, there are four weeks that could be included in the construction timeline or 28 days more time available for construction than included in the current timeline. The longest timeline is currently 107 days for the pipe-in-HDPE alternative. An increase in the timeline of 28 days constitutes a 25 % increase. Therefore, we feel that with proper scheduling and the mobilization of adequate numbers of trained personnel it should be possible to complete the construction of any of the four designs in one season.

The construction method as described in the INTEC report consists of fabricating long pipe strings. These pipe strings are dragged to the field and welded onto the previous strings to form the pipeline. Heavy machinery would be required to align the pipe ends at the tie-in welds and the crews must be careful to keep moisture out of the annulus. Meanwhile, the trenching work and the lowering of the pipeline into the ditch would proceed as possible. The keys to completing the work in one season are to make sure that the preparation of the pipe strings proceeds at a rate that keeps up with or exceeds the trenching activities and minimizing the number of field joints. In other words, the trenching activities should be the limiting factor in the construction timeline. The main advantage to this construction method is that the strings can be fabricated before trenching is started. If the pipe strings could be completed in the fall, before the winter freeze-up or enough manpower is allocated to ensure that the pipe string preparation exceeds the trenching rate, it should be possible to complete the pipeline in one season. This would also reduce the cost of the steel pipe-in-pipe by the 15 million dollar contingency and bring the pipe-in-pipe costs closer to the single wall steel pipe cost.

With any of the alternatives the possibility of construction requiring a second season is present and this possibility should be considered when the construction is planned. However, we feel that if a single wall pipe can be constructed in one season, then the other alternatives could also be completed in one season. It would be the factors that are unpredictable, such as an unusually short winter, which one would expect to result in a second construction season and these unpredictable factors would affect any of the designs.

Both the pipe-in-pipe and pipe-in-HDPE concepts involve inserting the inner pipe into an outer pipe or sleeve. A concern we have is the possible damage to the corrosion protection coating during this operation. We understand that a test pipe was transported across the ice to check for damage due to transport, but damage during installation is still a concern. If the coating is damaged, then the only protection against external corrosion of the inner pipe is keeping the annulus dry. This is acknowledged on page 5-27 of the INTEC report.

Assuming that the annulus remains free of an electrolyte may be overly optimistic and providing the inner pipe of any pipe-in-pipe system containing a steel inner pipe with some cathodic protection should be considered. There are several sources for the introduction of moisture in the annulus which would have to be prevented over the lifetime of the pipeline. First during construction, snow and water must be prevented from entering the annulus. Any snow or water that enters the annulus would form puddles in the low spots in the line. There is also the risk of introducing moisture into the annulus when the supplemental leak detection system is sampling the annulus. If the annulus is sampled once a day for 20 years, there will be 7300 samples taken during the life of the pipeline. For the pipe-in-HDPE concept, there is also the possibility that moisture may be absorbed by the HDPE and migrate into the annulus. Finally, moisture is likely to be introduced into the annulus during any repairs. Given these risks, we feel that it is likely that at some time in the 20 year operating life of the pipeline that moisture will be introduced in the annulus. This along with the potential damage of the pipe coating is the driving force behind our suggestion of a sprayed aluminum or other cathodic coating being applied to provide in-situ cathodic protection. It should be noted that sprayed aluminum coatings are not yet readily available for large quantities of line pipe. However, sprayed aluminum coatings have been used widely for many other offshore applications. The point is that the use of a sprayed aluminum coating is feasible, but there remains some development work before it can be used routinely. Using the current technology, the use of a sprayed aluminum coating may be cost prohibitive. Another method would be to attach anodes to the inner pipe. Either of these methods should supply adequate cathodic protection for the inner pipe. The drawback to this is that the cathodic protection of the inner pipe could not be monitored.

The INTEC report mentions the possibility of filling the annulus of the pipe-in-pipe or pipe-in-HDPE with an inert material to prevent corrosion of the inner pipe. We would envision that this would amount to filling the annulus with the material and sealing the annulus to prevent the escape of the inert material or the introduction of moisture into the annulus. If this is the case then sampling the entire annulus would not be possible. If the inert material were a solid or a liquid, the ability of the LEOS system would be impaired since the inert material would increase the time necessary for the hydrocarbons to come in contact with the LEOS tube (this is a result of the inert material being less permeable than air). In addition, it would seem likely that if a solid or liquid was used, that air pockets would still be present in the annulus.

Our main concern here is that the addition of an inert material in the annulus of a pipe-in-pipe system would be an obstacle to sampling the annulus which would complicate the implementation of a supplemental leak detection system. We feel that fewer obstructions in the annulus would increase the likelihood of detecting a leak. It may be possible that a LEOS tube could be used when an inert gas, such as dry nitrogen gas, is contained in the annulus under a small amount of pressure, but the possible collapse of the LEOS tube due to the pressure of the inert gas would need to be considered.

It should be noted that for the Colville River crossing, there was no corrosion control for the carrier pipes other than an external coating. This was done because the designers felt that the annulus could be kept dry, the condition monitored, and actions taken if moisture was detected in the annulus (Ref. Material Performance, February 2000, NACE, page 18). The approach presented in the INTEC report is similar. The annulus is to be kept dry and monitored and the outer pipe for the steel pipe-in-pipe will be fitted with a cathodic protection system. If a cathodic protection system were installed on the inner pipe, the annulus could still be monitored and with the goal of keeping the annulus dry. The cathodic protection of the inner pipe would be a method of providing additional protection.

Throughout the INTEC report hydrostatic testing follows backfilling in the construction sequences. We would suggest, if scheduling permits, that the hydrotest of the pipeline be conducted before backfilling. The main factor affecting the ability to hydrotest before backfilling is scheduling. The INTEC report estimates that backfilling activities will take between 30 and 44 days. This is a significant percentage of the construction season. Therefore, it may not be possible to wait to backfill until after hydrotesting. If waiting to backfill until after hydrotesting would result in a second construction season, then backfilling should proceed as the pipe is installed. However, if hydrotesting before backfilling could occur then any necessary repairs could be performed without having to immediately begin excavation. In addition, maintaining some pressure in the line during the backfilling operation should be considered. This would lock in some tensile stresses in the pipeline, which would help reduce the effects of the thermal expansion that will occur as the pipeline heats up to its operating temperature. Another drawback to this would be that the trench would have to be kept ice free until after hydrotesting. However, the main factor affecting the ability to hydrotest before backfilling is scheduling. An alternative may be to delay backfilling over the field joints (for example the joints between the 3000 ft sections in the single wall pipe alternative or over the connections every ¾ mile in the flexible pipe case) until after hydrotesting.

As an alternative to a hydrotest of the annulus of the pipe-in-pipe and pipe-in-HDPE alternatives, the annulus could be tested using pressurized dry air or dry nitrogen. During this test, a diver or ROV could “walk” the pipeline route and look for bubbles. Any leaks in the outer pipe or sleeve would be indicated by bubbles. This alternative would only be feasible if the construction schedule could permit backfilling to wait until after the testing is complete. If delaying the backfilling operations would result in a second construction season, then backfilling should proceed with the installation of the pipe.

The INTEC report mentions that localized jetting may be necessary to fluidize the trench bottom in order to lower a pipe that has become “high grounded” during installation. This means that jetting equipment will need to be on site throughout the pipelaying process. Otherwise, if jetting is required, delays in getting the equipment could prevent the completion of the pipeline in one season. In addition, suction equipment may be needed to remove material from localized high spots.

5.1.1 Single Wall Steel Pipe

The single wall steel pipeline is the base case and is also the best understood. As a result, there is more experience with this alternative as far as construction is concerned. The methodology described is similar to that used on pipelines all over the world with specific modifications for the arctic conditions.

Most pipelines are fabricated beside the trench but in this case 11 strings each about 3000 feet long will be fabricated and transported to the trench over an ice road. The primary concern with this transportation method would be the abrasion of the protective FBE coating on the pipe during transport. However, we understand that a test pipe was transported across the ice as part of the Northstar project and that the FBE coating was able to withstand the abrasion.

5.1.2 Steel Pipe-in-Pipe

The pipe-in-pipe alternative assumes an FBE external coating for corrosion protection of the inner pipe. This coating could be a sprayed aluminum or other cathodic coating and provide in-situ cathodic protection rather than using a FBE coating that is only a protective barrier that will allow corrosion to occur at any holidays, defects, or damaged areas. This is particularly important since damage to the coating during installation seems likely.

The inner pipe must be supported so it does not lie on the bottom of the outer pipe. Spacers are mentioned but in 5.2.3 (page 5-8) the spacers are located at 40-foot intervals and in 5.4.3.1 (page 5-15) at 10-foot intervals. The use of 40-foot intervals may not be adequate and 10-foot intervals seem more appropriate. Also the method of installation of the spacers is not mentioned.

An annulus leak detection system is mentioned elsewhere but not included in the construction sequence in 5.4.3.1 (page 5-16). If the sampling is to occur through a LEOS tube, the system must be incorporated at this stage and cannot be inserted later. Such installation will also complicate the construction operations for this alternative. If it can be demonstrated that sampling the entire pipe annulus provides good leak detection capabilities, the elimination of the LEOS tube would simplify construction.

A possible hydrostatic test of the outer pipe is mentioned on page 5-17. If such a test is done the inner pipe must be pressurized or otherwise assured of being collapse resistant. This should not be a problem for the proposed inner pipe. However, this check should be included in the preliminary design. As previously mentioned, an alternative to hydrotesting the annulus would be to test the annulus with pressurized dry air or dry nitrogen and look for bubbles. If a hydrotest is conducted, the annulus would need to be dried after the test.

This same section also says, “ inner pipe extends beyond the outer pipe”. The inner and outer pipes must be the same lengths eventually so this statement is not clear. It would seem that the first 1000-foot length should be made with a short outer pipe. The rest of the inner and outer pipes should be made the same length but the inner pipe sticks out at the first field weld so that this weld can be made and inspected. The outer pipe would then be slid over this weld and the outer field weld made and inspected. It should be noted that the spacers/centralizers between the inner and outer pipe will complicate the installation process and could possibly make it more difficult to slide the outer pipe over the inner pipe.

5.1.3 Steel Pipe-in-HDPE

Induction heating is described as the method for bonding the HDPE pipe (6.4.3.1 page 6-14). The HDPE itself is not conductive so special methods are required to use this technique. The large diameter and heavy wall HDPE used in either alternative will be a challenge for induction bonding of the outer pipe. There is also some mention of a fusion joining machine in section 6.4.4.2 on page 6-16 of the INTEC report. This section states that some redesign of current machinery would be required to build a fusion joining machine for this job. Which is the intended method and what are the implications of the joining method to the construction process?

The spacers between the inner pipe and the HDPE outer sleeve are not described in any detail. However, the pipe transport method mentioned on page 6-14 of the INTEC report is the same as for the pipe-in-pipe technique. This makes the appropriate design of the spacers critical. The spacers must be designed so that the weight of the inner pipe is distributed along the length of the HDPE sleeve. The inner pipe is so heavy that the ability of the HDPE sleeve to carry this load, unless it is well distributed, is doubtful. If the thickness of the HDPE were greater (i.e., in the 1.25-1.5 inch range), the annulus gap small, and the centralizers eliminated, then the handling problems with this alternative may be lessened. In this configuration, the weight of the inner pipe would be better distributed along the HDPE sleeve and as a result, the likelihood of the inner pipe punching a hole in the sleeve would be reduced. The possible impact loads during construction/transport should also be considered since the impact strength of HDPE at –50°F can be expected to be approximately ½ that of HDPE at 73°F.

The lowering of the pipe-in-HDPE pipeline into the trench also will require additional special equipment because of the weight of the inner pipe and this is not addressed in 6.4.4.6 (page 6-17). The number of side booms proposed for lowering the pipe-in-HDPE alternative is the same as for the single wall steel pipe (i.e., 4 side booms). It would seem that either more side booms or special spreader beams would be required to ensure that the load is supported more uniformly during installation.

Finally, it is stated on page 6-15 of the INTEC report that an external leak detection system could be bundled to the pipeline. We would think that this would not be needed. Why would the leak detection system in the annulus acting in conjunction with the mass balance and pressure point analysis systems not be adequate?

5.1.4 Flexible Pipe

The flexible pipe alternative seems to be reasonably well addressed from a construction viewpoint. If larger reels could be handled; this could be the preferred alternative from a construction viewpoint. The only area of concern, in terms of construction, is the welding of the connectors and their subsequent coating. The integrity of this system depends on these joints so the fabrication and long term performance needs careful attention. The INTEC report states that the steel connectors will be field coated for corrosion protection and "may have a sacrificial-anode cathodic protection system" (page 7-20 of the INTEC report). We believe that the cathodic protection system would be needed for this type of installation.

5.2 Cost Estimates

The INTEC report includes cost estimates for each of the four design concepts. The estimates are presented as order of magnitude estimates. Therefore, the main objective in reviewing the cost estimates is to make sure that the relative costs of each of the design concepts are reasonable. Since the baseline design is a traditional single wall pipeline design, we feel that the costs of the alternative designs should be compared to this baseline. Table 5.2.1 was created using the information from the INTEC report. The table presents a summary of the cost figures for each of the design concepts. There are three (3) numbers in the table that are underlined. The underlined numbers are entries that do not agree with the numbers in the INTEC report. We believe that these were either typographical or computational errors and have replaced the values with what we believe are the intended values. The changes are minor and the effects on the estimated costs are negligible.

The overall trends in the cost numbers appear reasonable. Comments on individual line items are included in the following paragraphs.

The first activity listed in the cost table is mobilization. The variation in these costs from one concept to the other would depend on the differences in the amount of equipment and manpower required for each concept. From comparing the entries for the four design concepts, it is apparent that these differences are reflected in the cost per day to mobilize. The general trends in the mobilization costs are as one would expect given the equipment required as presented in the INTEC report. The mobilization costs from the lowest to the highest are for the flexible pipe system, single wall pipe, pipe-in-HDPE, and pipe-in-pipe.

The costs for ice road construction are the same for the single wall pipe, the pipe-in-HDPE, and flexible pipe. The cost is greater for the steel pipe-in-pipe as a consequence of the greater weight of the pipeline and the amount of equipment required for the installation. This greater weight manifests itself in the need for thicker ice roads. The weight in air for the single wall pipe is 90.18 lbs/ft. For the pipe-in-pipe, the weight in air is 211 lbs/ft. The weights in air for the pipe-in-HDPE and flexible pipe are 103.93 lbs/ft and 84.4 lbs/ft respectively. Since the weight of the pipe-in-pipe concept is over twice that of all the other alternatives, the higher ice thickening/ice road construction costs for this concept seem reasonable.

The ice cutting and slotting costs are the same for the single wall steel pipe, the steel pipe-in-HDPE, and the flexible pipe. The ice cutting and slotting costs are the greatest for the steel pipe-in-pipe. This is as one would expect due to the thicker ice road requirements for the steel pipe-in-pipe alternative.

The trenching costs are a function of the amount of material removed and water depth. Since the route for the pipeline is the same for all four concepts, the difference in trenching costs must be attributed solely to the amount of material removed. We have checked the cost for trenching per cubic yard of material removed using the costs presented in the INTEC report and have found that the cost is consistent for all of the designs.

The make-up site preparation costs are also consistent with what one would expect. The single wall pipe and flexible pipe alternatives would require a smaller make-up site and consequently have a lower make-up site preparation cost than the steel pipe-in-pipe or pipe-in-HDPE alternatives.

The trends associated with the pipe string make-up are also reasonable. The flexible pipe does not have a make-up cost since the pipe is supplied in prefabricated spooled sections. Of the remaining three designs the lowest cost is for the single wall pipe, the next highest cost is for the pipe-in-HDPE, and the highest cost is for the pipe-in-pipe.

The pipe string transportation costs are a function of the weight of the pipe string and the ease of handling. The flexible pipe weighs less than the single wall pipe, but the additional costs of unspooling the pipe are likely to offset the savings in transportation costs. The pipe-in-pipe and pipe-in-HDPE alternatives are more bulky than the other alternatives. The pipe-in-pipe weighs the most, but the handling of the HDPE will likely complicate the transport of the string. Therefore, it is reasonable to assume that the transportation cost for these two alternatives are similar. The relative costs for pipe string transportation appear reasonable.

The costs associated with the field joints in the pipeline are a function of the number of joints (or welds), and the difficulty in making the connection. The INTEC report assigns the lowest cost figures with the flexible pipe alternative. This is reasonable since this alternative contains the fewest number of joints. The other alternatives in terms of increasing field joint costs are the single wall pipe, the steel pipe-in-HDPE, and the steel pipe-in-pipe. Although this trend seems reasonable, we would think that the cost of the pipe-in-HDPE would be closer to the steel pipe-in-pipe cost. However, this is difficult to quantify since the construction method for the pipe-in-HDPE is not well defined at this level of conceptual design.

Pipe installation costs should be largely a function of the weight of the pipeline. This is reflected in the installation costs presented in the INTEC report. The costs presented for the flexible pipe, single wall steel pipe, and steel pipe-in-HDPE are all comparable. The cost for the pipe-in-pipe installation is much greater than the other three. The one comment we have on this aspect is that handling considerations should also affect the installation costs. It would seem that it would be much easier to damage the pipe-in-HDPE alternative than the others since the HDPE sleeve must support the heavy steel inner pipe. We feel that this would make the cost for the installation of the pipe-in-HDPE alternative closer to that of the pipe-in-pipe.

The costs for backfilling the pipe-in-HDPE and flexible pipe alternatives are higher than for the other alternatives. This appears to be a function of having to place the backfill more carefully for the first few feet of backfill. This is to prevent creating a slurry in the trench that is dense enough to float the pipe. The pipe-in-HDPE cost is highest since the depth of cover for this alternative is greater than that of the flexible pipe. Since the single wall steel pipe and steel pipe-in-pipe would both be stable in the ditch, the difference in backfilling cost is attributed to the difference in burial depths.

The hydrostatic testing costs are the same for all the concepts. This is as one would expect.

The demobilization for each alternative is predicted to take 2 days. This is slightly less than the mobilization time. One question about this cost is the day rate for the demobilization for the steel pipe-in-pipe alternative. For the other three concepts, the day rate for mobilization and demobilization is the same. For the steel pipe-in-pipe, the demobilization rate is $320,000 a day less than the mobilization rate.

The material and transportation costs for the four concepts are also presented.

We do have a question about the contingency costs for construction that extends to a second season. It seems that these costs are low for the steel pipe-in-HDPE. At a minimum, we would think that the contingency would include the costs for mobilization, ice thickening/road construction, and demobilization. For the pipe-in-HDPE concept, the sum of these costs is 9.7 million dollars. There are also no costs included for the abandonment of the line at the end of the first construction season and the retrieval of the partially completed pipeline so that construction can be resumed. Therefore, the five million dollar contingency for the second season work seems low.

For the steel pipe-in-pipe, the contingency cost allocated for a second season of 15 million dollars is more reasonable. This is enough to cover the mobilization, ice thickening/road construction, and demobilization costs which total 3.72 + 4.70 + 1.84 = 10.26 million dollars. If you then assume that one third of the trench will have to be retrenched, there is another 5.46/3 = 1.82 million dollars required. In addition, the make-up site would have to be prepared which adds 2.59 million dollars. Therefore, the contingency for a second season would be around 10.26 + 1.82 + 2.59 = 14.67 million dollars. The costs for abandonment of the line at the end of the first season and retrieval of the line so that construction can resume have not been included. This could be a complex procedure since the annulus would need to be kept dry and some of the backfill removed to allow the uncompleted end of the pipeline to be lifted to the surface. However, a second season cost on the order of 15-16 million dollars seems reasonable for the steel pipe-in-pipe alternative.

Table 5.2.1 Cost Comparison Table

Activity	Single Wall Steel Pipe				Steel Pipe-in-Pipe				Steel Pipe-in-HDPE				Flexible Pipe			
	Number of Spreads	Duration (days)	Spread Cost ($1000/day)	Cost (million $)	Number of Spreads	Duration (days)	Spread Cost (thousand$/day)	Cost (million $)	Number of Spreads	Duration (days)	Spread Cost ($/day)	Cost (million $)	Number of Spreads	Duration (days)	Spread Cost ($/day)	Cost (million $)
Mobilization	1	3	1020	3.06	1	3	1240	3.72	1	3	1144	3.43	1	3	910	2.73
Ice Thickening/Road Construction	1	47	84	3.95	1	56	84	4.70	1	47	84	3.95	1	47	84	3.95
Ice Cutting and Slotting	3	11	29	0.96	3	14	29	1.22	3	11	29	0.96	3	11	29	0.96
Trenching	2	10	60	7.08	2	8	60	5.46	2	9	60	6.48	2	7	60	4.92
	2	19			2	15			2	18			2	13		
	3	20			3	15			3	18			3	14		
Make-up Site Preparation	1	37	41	1.52	1	47	55	2.59	1	47	55	2.59	1	37	41	1.52
Pie String Make-up (Welding)	1	17	140	2.38	1	48	240	11.52	1	34	220	7.48				0.00
Pipe String Transportation/unspool	1	8	78	0.62	1	10	78	0.78	1	10	78	0.78	1	8	78	0.62
Pipe String Field Joints	1	10	31	0.31	1	33	***31***	1.02	1	22	31	0.68	1	9	31	0.28
Pipeline Installation	1	35	43	1.51	1	29	88	2.55	1	37	43	1.59	1	30	43	***1.29***
Backfilling	1	36	42	1.51	1	30	42	1.26	1	44	42	1.85	1	38	42	***1.60***
Hydrostatic Testing	1	5	84	0.42	1	5	84	0.42	1	5	84	0.42	1	5	84	0.42
Demobilization	1	2	1020	2.04	1	2	920	1.84	1	2	1144	2.29	1	2	910	1.82
Material Cost and Transportation				3.10				4.5				3.33				13.7
Contingency	10%			2.85	10%			4.16	10%			3.58	10%			3.38
	A portion of costs for second season			0.00	A portion of costs for second season			15.00	A portion of costs for second season			5.00	A portion of costs for second season			0
Material Cost and Transportation				31.3				60.7				44.4				37.2

Comments		31 given as 60 in table, but total cost given as 1.02 mill		1.29 figure given as 1.12 1.6 figure given as 1.43

5.3 Operations and Maintenance

The operations and maintenance issues are covered well for the conceptual design phase. There are some good points made in the INTEC report which should be noted. The operations activities discussed in the INTEC report include monitoring the pipeline, metering the flow, and pumping. The maintenance procedures are primarily inspection activities intended to ensure that the pipeline and pipeline protection systems are working properly.

5.3.1 Monitoring, Pumping, and Metering

The monitoring, pumping, and metering activities are interrelated. The oil will be pumped through the pipeline and meters used to provide a measurement of the flow through the line. This metering of the flow will serve two purposes. First, the oil producer and purchaser both want an accurate measurement of the amount of oil flowing from the Liberty pipeline into the Badami pipeline. Secondly, this accurate measurement of flow into and out of the pipeline will provide a leak detection capability. The INTEC report states that there will be three flow meters, one upstream from the Liberty Island pumps, one downstream from the Liberty Island pumps, and one just before the pipeline flows into the Badami pipeline.

Pressure and temperature measurements will also be obtained at Liberty Island, the shore crossing and the Badami tie-in. These measurements will be compared to the operating temperature and pressure limits and the pipeline will be shutdown if the limits are exceeded. The concern we have about this centers around the potential flow problems that may be encountered if the pipeline cools with oil in the line. If the oil properties at ground temperature are such that the oil can still flow, this may not be a problem. However, for some oil compositions at low temperatures, blockages could form when the line is shut down and make it difficult to restart the line. We would be interested in seeing a restarting procedure in case such a shutdown takes place.

For some of the designs, not all of the components can be monitored. The main components which could not be monitored are the outer pipe of the steel pipe-in-pipe alternative, the outer HDPE sleeve for the pipe-in-HDPE alternative, and the outer jacket of the flexible pipe. While this is true, the supplementary leak detection system could be used to monitor the pipeline for the presence of water in the annulus. Therefore, damage severe enough to cause a leak in the outer pipe, sleeve, or jacket would be detected by the supplemental leak detection system.

The flexible pipe system presents some unique challenges in terms of monitoring. The flexible pipe construction is very complex. This will make the readings from instrumented pigs more difficult to interpret than readings from a steel pipe. In addition, the expansion of the flexible pipe due to internal pressure can be expected to be greater than that of a steel pipe. This would mean that the variation in the internal volume of the line due to internal pressure will be greater than for a steel pipe and may affect the flow balance calculations.

We would suggest that, for the designs with an annulus, the pressure in the annulus be monitored. An increase in the annulus pressure could be indicative of a leak in the inner pipe. This would provide another avenue for leak detection in addition to the mass balance and pressure point systems which operate continuously and monitoring either the annulus contents or the contents of a LEOS tube which would be done once a day.

5.3.2 Clean-up

The clean-up strategies for a potential oil spill presented in the INTEC report are similar for all of the pipeline alternatives. Plans are to have the manpower and capabilities to monitor, control, and clean-up any spill at anytime of year.

There is a risk of a secondary spill during repair of alternatives with an annulus. However, this is a known risk and by having a clean-up crew at the site during the repair the impact could be minimized. In addition, if the leak is in the inner pipe only and the outer pipe can withstand the pressure, the oil could be pumped out of the pipeline before repairs are begun. This would prevent oil from being introduced into the environment.

5.3.3 Inspection Plan

The INTEC report states that a recommended inspection plan and schedule would be developed during detailed engineering. We agree that this is when a detailed plan should be developed. Since these designs are at the conceptual level, we would expect that the line items for inspection be identified. The INTEC report has included a thorough list of inspection activities including:

1. An external offshore route survey will be conducted every 5 years to determine backfill integrity. (bathymetry or swath surveys in > 6ft water, single-beam fathometer in < 6ft of water)
2. Shoreline erosion will be assessed in an annual survey.
3. The valve pad will be placed far enough from shore so it will not be affected by erosion.
4. Cathodic protection would be checked by measuring the electrical potential of the pipeline annually (not valid for flexible pipe or pipe-in-HDPE).

5. The pipeline wall thickness will be monitored by pigging (either ultrasonic or magnetic flux leakage).
6. Deformations/dents will be monitored using mechanical caliper pigs or equivalent.
7. The pipeline configuration will be monitored by pigging.
8. The external corrosion of the pipeline will be assessed as part of the wall thickness pigging operation (This is only valid for the single wall pipe because an outer pipe can not be monitored with a pig.).
9. The expansion of the pipeline will be noted during routine checks at the surfacing point on the island and in the riser casing at the shore.
10. The moisture content in the annulus will be monitored for concepts with an annulus. This serves a twofold purpose. The moisture in the annulus must be kept low to prevent corrosion of the inner pipe and excessive moisture in the annulus could indicate a leak in the outer pipe.
11. The flexible pipe inspection will include pigging (RT, eddy current, video).
12. The INTEC report acknowledges that the cathodically protected end fitting on flexible pipe can not be monitored.

5.4 Repair Issues

The repair of the pipeline is covered fairly well in the INTEC report. However, there are a few items which we have questions/comments about.

It is stated on page 1-6 of the INTEC report that not all of the repairs can return the pipeline to the same integrity as the original construction. This statement is then specifically tied to the pipe-in-pipe design on pages 5-4 and 5-30 of the INTEC report. It is stated that the outer pipe can not be repaired to the same integrity as the original construction. The reasoning behind this seems to be that a clamshell or patch repair would have to be used. From the INTEC report, we envision the proposed repair of the outer pipe to consist of a clamshell that has a larger diameter than the outer pipe. Using such a repair would result in having to use fillet welds on the ends of the repair section and would include longitudinal welds to join the clamshell sections. This type of repair is illustrated in Figure 3 and would not restore the outer pipe to its original integrity. However, if the repair pipe has the same diameter, wall thickness, and material properties as the original pipe and is installed using butt welds that are inspected by UT examination, it should be possible to restore the pipe to near its original integrity. This type of repair is included in Figure 4. The repair includes longitudinal welds, but the fillet welds are replaced by butt welds. In order to implement this type of repair, the ends of the pipe would have to be prepared and the repair section cut to length in the field.

When designing the pipeline, the designers should consider the capacity of a repaired pipe when establishing the design allowables. If the repaired pipeline would not be as sound as the new line, the design allowables should be based on the repaired pipe strength rather than the strength of the new pipe.

It is stated that repair could not occur at some times during the year, specifically during break-up and freeze-up of the ice sheet (pages 1-6 and 3-33 of the INTEC report). This amounts to approximately 5-6 months out of the year. It would seem that this would have an effect on the amount of oil lost. The pipeline would be shutdown, and clean-up would proceed, but there would still be oil in some parts of the line. This contingency should be included in the oil spill probability calculations.

It is stated on page 1-6 of the INTEC report that for cases where there is an annulus, all moisture would need to be removed from the annulus after the repair. The drying operations following a repair would be more difficult than drying the annulus after initial construction , because of debris drawn into the annulus during the damage period and the subsequent repair activities. Such debris would include soil, sand, and gravel, in addition to seawater and hydrocarbons. Not all of these materials and objects would be removed by the drying process and may increase the time necessary to dry the annulus.

We would be interested in time estimates for drying the annulus since a significant amount of moisture could be present for a long period of time (i.e., the 2.5-3 month period when repairs could not be made plus the drying time). We would expect that drying the annulus could take a month or more. This estimate is based on the experience of one of our team members and includes some time for setting up a drying system and drying the annulus. While the pipe-in-pipe system is being repaired, the equipment required for drying the annulus would be assembled. This equipment would include a large air compressor, air drying equipment, vacuum pump, vacuum gauge, leak-proof valves, and the associated piping and hoses. If a large enough compressor is not on site, a rental air compressor of sufficient size may need to come from the "lower 48", requiring two to three weeks lead time. We would allow one or two days time to hookup the compressor. After the compressor is hooked up, it would be operated one to two days to pump dry air into the annulus. Then several days would be required to hook up the vacuum pump and to test for leaks. Finally, we assume a period of one to two weeks of operating the vacuum system before the P-I-P annulus would be sufficiently dry. Please note, that these are only estimates and we have not performed any modeling to estimate drying times.

This means that moisture could be present for approximately 4 months. This would be more than enough time for corrosion to begin in the annulus. It may be that a sprayed aluminum or other cathodic coating to provide in-situ cathodic protection (as described in the construction section of this report) should be used. Another method would be to attach anodes to the inner pipe. Either of these methods should supply adequate cathodic protection for the inner pipe. The drawback to this is that the cathodic protection of the inner pipe could not be monitored. However, the cathodic protection would be present and is certainly a better alternative than depending on keeping the annulus dry as the sole source of corrosion prevention.

Section 5.5.5.3 suggests the pipe-in-pipe annulus could be pumped full of an inert fluid after construction. The idea is to fill the annulus of the pipe-in-pipe or pipe-in-HDPE with an inert material to prevent corrosion of the inner pipe. We would envision that this would amount to filling the annulus with the material and sealing the annulus to prevent the escape of the inert material or the introduction of moisture into the annulus. If this is the case then sampling the entire annulus would not be possible. If the inert material were a solid or a liquid, the ability of the LEOS system would be impaired since the inert material would increase the time necessary for the hydrocarbons to come in contact with the LEOS tube (this is a result of the inert material being less permeable than air). In addition, it would seem likely that if a solid or liquid was used, that air pockets would still be present in the annulus.

Furthermore, two benefits of the annulus are that the pressure in the annulus could be monitored and that the annulus can act as a reservoir to contain oil. An increase in the pressure of the annulus could indicate a leak in the inner pipe. If the annulus were filled with a liquid, the pressure build up which would accompany a leak in the inner pipe would be much more rapid and there would be no reservoir to contain leaked oil. If a solid were used, it may not be possible to monitor the pressure in the annulus and the possibility of detecting a leak as a pressure change in the annulus would be lost. Therefore, it would be preferable if a gas was contained in the annulus so that the pressure could be monitored and in the case of a leak the pressure build-up would be slow enough so that there would be time to shut-in the pipeline.

Our main concern here is that the addition of an inert material in the annulus of a pipe-in-pipe system would be an obstacle to sampling the annulus. We feel that fewer obstructions in the annulus would increase the likelihood of detecting a leak.

Another consideration is the traces of hydrocarbons left in the annulus after a repair. Since hydrocarbons would be left in the annulus, the leak detection system would have to be recalibrated to allow for the concentration of hydrocarbons that are present in the annulus.

The INTEC report also states that mechanical repairs are not considered appropriate for permanent repairs. However, we are aware that mechanical repair devices, including external leak repair clamps as well as in-line pipe coupling devices, are used as permanent repairs around the world. Is there engineering evidence that supports the elimination of mechanical repairs or is this based on a perceived risk?

We have a few questions concerning the repair of the flexible pipe alternative. Why is a flanged connection considered temporary? Is there standard repair equipment for flexible pipe? What do the repair connections look like? How could/would end fittings be installed in the field? It appears that any permanent repair to the flexible pipe system would consist of replacing an entire 2800 ft section. This significant effort may increase the repair costs of the line enough to offset any initial savings of using the flexible pipe system. Replacement sections would have to be kept on site, or production could be halted for months waiting for a replacement section.

The INTEC report states that misalignment/displacement of the pipeline will be monitored. However, there is no proposed repair procedure for a displaced pipeline in the report in case the displacements exceed the design allowables.

5.5 Inspection/Leak Detection Issues

The information relayed by the INTEC report shows that there has been significant thought given to the issue of inspection and leak detection. During construction, welds are to be subjected to radiographic (RT) and ultrasonic (UT) inspections and a hydrotest will be conducted. The pipe will be monitored using smart pigs throughout the life of the pipeline. Leak detection will be accomplished using monitoring techniques such as MBLPC (mass balance line peak compensation), PPA (pressure point analysis), and LEOS.

Although we would like to see more detailed descriptions of the RT and UT methods, these are well accepted methods for which standards exist and we feel comfortable with the application of these methods. In fact, we would point out that although the INTEC report states that only UT will be conducted on the outer pipe tie-in welds for the pipe-in-pipe alternative (page 5-18 of the INTEC report) this is not a reason for concern. A well designed UT procedure executed by a qualified technician should be able to detect any linear or cracklike defects in the welds as well or better than a RT inspection. This is especially true if an automated UT method, such as time of flight diffraction (TOFD), is used.

For the pipe-in-HDPE concept, it is stated that the fusion welding of the HDPE could only be visually inspected after the weld was completed. We agree that there is not a practical inspection method for these welds. The inner pipe would obstruct attempts to use radiography and the attenuation of the HDPE makes ultrasonic examination impractical. The best avenue for assuring the quality of these fusion welds is to qualify the procedure using test samples fusion welded by the same machine and operators as would be used during installation. The possible pre-qualification of the weld technique is mentioned on page 6-16 of the INTEC report.

The main method for inspection of the pipeline, with regards to internal and external corrosion will rely on the use of smart pigs to be run inside the pipe. This method will also be used to monitor the flexible pipe system. These readings will be compared to initial “baseline” readings and any significant deviation from the original readings could indicate that corrosion, deformation, out-of-roundness, or other forms of damage might be happening in the system. Most instrumented pigs have a minimum radius of curvature, as a function of diameter, through which they can pass. In the event the pipe curvature is changed by loads such as ice keel gouging or upheaval buckling, there is a possibility the instrumented pig may not be able to go through the buckled portion due to its small radius of curvature. We recommend that INTEC review this possibility, and investigate methods for solving this problem, in case it arises. The point is that the ability of the pig to pass through the line may be more limiting than the allowable strain in the pipe. It should also be noted that even with 7 feet of cover, a visual examination can locate a significant upheaval buckle.

For leak detection, all of the concepts rely on MBLPC, PPA, and some form of the LEOS system. In terms of the mass balance and pressure point systems, our primary concern is with false alarms. The concern here is that if the system does not contain self diagnostics that minimize false alarms, the operators will summarily dismiss an actual leak as a false alarm. In order to prevent this, a system should be adopted that has capabilities that allow the operator to accurately determine the difference between an actual leak and a false alarm and contains self diagnostics which will minimize the false alarms.

The INTEC report states that the LEOS system has been in service for 21 years. The LEOS reports present a history of the system and some analysis that has been done on the system. The system appears to be a good choice for a supplemental leak detection system.

As we understand the current LEOS system uses a small tube which is permeable to hydrocarbons and the contents of this tube would be checked once every 24 hours to determine if a small leak is present. The time required to check the contents of the tube would be approximately six hours. Therefore, there is an eighteen hour hold time during which the hydrocarbons have time to permeate the LEOS tube. By knowing the sampling rate, the time the sampling was started, and when a leak was detected, the location of the leak can be estimated. As the system exists, Siemens estimates that a leak as small as 0.3 bbls/day could be detected.

The leak detection threshold of 0.3 BOPD by Siemens is stated to have been based on experience in the LEOS reports. The accuracy of this estimate is difficult to assess because it depends on a variety of factors including:

1. The permeability of the soil if the tube is buried beside a pipeline.
2. The size of the annulus if the tube is in the annulus.
3. The permeability of the sensor tube.
4. The hold time between sampling runs.
5. The location of the tube in relation to the leak.

The ability to detect a leak using the LEOS system is dependent on the concentration of oil around the sampling tube. Therefore, the question one should ask in regards to the leak detection threshold is what concentration of oil around the sampling tube is required before a leak can be detected. Once this is known, one would assume that the tube is located at the furthest possible position from the leak and determine either experimentally or numerically the time necessary for the oil concentration around the tube to reach a detectable level for a given leak rate. This type of experimentation/analysis is beyond the scope of this review. Therefore, we can not comment on the reasonableness to the 0.3 BOPD threshold as it pertains to the Liberty pipeline. We would recommend that a third party demonstration test be conducted on the supplemental leak detection system in the same configuration as would be implemented in the Liberty project.

Although we can not comment on the reasonableness of the 0.3 BOPD threshold as it relates to the Liberty pipeline, it should be noted that such a low threshold indicates a high degree of confidence on the part of Siemens. In addition, a 0.3 BOPD leak rate is well below a reasonable leak rate. We would expect that any leak in the pipeline would be at a minimum on the order of a 29 BOPD leak. We estimate that a 1 inch long crack 0.001 inches wide would leak approximately 29 bbls/day at 1100 psi. This is equivalent to a 0.036 inch (0.9 mm) diameter hole (which is about the size of a pencil lead). It is difficult to imagine a case for this pipeline where a leak would be smaller than this 29 BOPD figure. This is almost 100 times the threshold cited by Siemens.

One would think that if the tube were in an annulus that a smaller leak could be detected since the oil would be confined to the annulus rather than being able to soak into the soil. In the event of a small leak in the inner pipe, the oil would spray from the hole and impinge of the inner wall of the outer pipe. This would create a mist of oil that should surround the inner pipe in a short time. Therefore, we would expect that leaks on the side of the pipe opposite the LEOS tube would be detected sooner if confined in an annulus than if the tube were buried in soil. By confining the oil in the annulus, the concentration of oil around the sampling tube would be higher and as a result more hydrocarbons would permeate the tube wall and the probability of detecting a leak would be increased.

We understand that for the steel pipe-in-pipe and pipe-in-HDPE alternatives that the air in the annulus might be sampled instead of installing a sampling hose. Our concern about sampling the entire annulus rather than using a sampling tube has to do with the ability to detect the location of a leak. The leak locating abilities of the LEOS system depend on determining where in the flow stream the hydrocarbons are located. The proposed pipe-in-pipe and pipe-in-HDPE designs have centralizers in the annulus. This makes the flow characteristics in the annulus more complex than in a tube and mixing of the air in the flow stream would be expected. We expect that the more complex flow characteristics will make it more difficult to locate a leak.

For the flexible pipe system, there is not what we would consider a true annulus. The INTEC report states that the sampling would occur in the annulus, but this annulus is filled with steel strips. One would be counting on being able to pump clean air through an annulus that contains steel wraps. This seems unlikely to work. It also seems unlikely that oil could be extracted from this annulus. The ability of the system to sample from this annulus, with internal pressure applied to the pipe, needs to be confirmed. In addition, jumpers would be needed to provide a continuous sampling path around the connectors. It seems that jumpers which would bridge the connector to provide a continuous path through the annulus and prevent moisture from entering the annulus would be difficult to install.

It is particularly important that the leak detection abilities of the supplemental leak detection system be confirmed, since the small leak (Category 3 damage, see p 5-38) is unrealistically low at only 1 barrel a day. An equivalent diameter for a hole with a 1bbl/day discharge rate is only 0.007 inches. Even a 1 inch long crack 0.001 inches wide could discharge 29 bbls/day from an 1100 psi line. This could be well below the 0.15% threshold accuracy of the other leak detection systems (0.15% of 65,000 bbl/day is 97.5 bbl/day). This 0.15% figure is also a lower bound for the mass balance and pressure point systems. The upper bound for the systems is not given.

6.0 CONTAINMENT CONCEPTS

There is a brief section in the INTEC report that discusses containment concepts. Among the alternatives discussed are external coatings, an outer pipe shrink wrap, and materials designed to absorb oil. As presented, these containment concepts would be applied outside of the pipe or pipe-in-pipe concepts. This would amount to placing a geomembrane in the trench prior to burial of the line and wrapping the pipeline or using oil absorbent materials as a part of the backfill. We agree that for this application these alternatives would be not be practical to install and maintain. Certainly, we would not expect an oil absorbent material exposed to water for a 20 year period to retain its oil absorbent properties. If such materials are incorporated in the design, the logical approach would seem to be incorporating oil absorbent materials in an annulus of a pipeline system. This would limit the longitudinal spreading of the oil and reduce the chance of a secondary spill during repair. Such a concept is presented in Section 7.8 of this report.

7.0 RECOMMENDATIONS

Our review of the Liberty pipeline design alternatives has resulted in a large number of questions and comment/observations. Most of these comments are on minor issues which we are sure can be addressed easily or which the designers may intend to address during the preliminary or detailed design phases. We are confident that any of the four candidate concepts could be designed to fulfill the intended function of the pipeline. However, we do feel that these questions and comments/observations should be addressed.

Our primary observation that leads us to the conclusion that all of the designs were not assessed equally is the varying burial depths presented in the INTEC report. Overall, we are concerned that there is not a clear statement of the perceived benefits of the alternative designs and that the main advantage of the pipe-in-pipe and pipe-in-HDPE systems, the ability to contain small leaks, has been discounted.

Another important area of concern is about the assumptions used in the finite element analysis. The INTEC report states that the nonlinear geometry effects were not included in the analysis. We feel that the effects of the geometric nonlinearity should be included. We have consulted INTEC about the analysis and their reasoning behind neglecting the nonlinear geometric effects appears to be due to the increased run time which would have resulted. It may be prudent to use the conceptual design phase to narrow the candidates from four to two and perform the finite element analysis on the two final candidates including the nonlinear geometry effects before selecting the final candidate.

Among our comments/observations, we have included some suggestions for some additional design alternatives. These observations, along with others, are listed in the following subsections.

7.1 Design Issues

1. The INTEC report states that pipe-in-pipe designs are used for insulation or installation reasons. While this is true, this past practice should not exclude the potential for using a pipe-in-pipe system for leak containment or other legitimate reasons. It seems that the main advantage of the pipe-in-pipe and pipe-in-HDPE systems, the ability to contain small leaks, has been discounted.
2. It is our opinion that the HDPE sleeve used in the pipe-in-HDPE concept could contain small leaks, but could not contain the operating pressure of the pipeline. However, it should be noted that a small leak in the inner pipe would not result in the HDPE sleeve being immediately subjected to the operating pressure of the pipeline. Therefore, we expect that there would be time to detect the presence of oil in the annulus with either the LEOS system or by pressure fluctuations in the annulus before the burst pressure of the HDPE sleeve was reached. Furthermore, the bulkheads at each end of the pipeline could be fitted with a pressure relief system that keeps the pressure in the annulus from exceeding the burst pressure of the HDPE sleeve. This pressure relief system could be connected to a reservoir which would prevent any oil leaked into the annulus from entering the environment.
3. The outer pipe of the steel pipe-in-pipe could not only contain small leaks, but could also contain the operating pressure of the pipeline. This design, like the pipe-in-HDPE design, could also be fitted with sensors to monitor the pressure of the annulus and a reservoir which would prevent any oil leaked into the annulus from entering the environment. Since the outer steel pipe can withstand the operating pressure of the pipeline, it is feasible that the pipeline could remain in operation even if there was a leak in the inner pipe. At a minimum this would mean that if the inner pipe develops a leak, the oil could be pumped from the pipeline before repairs are made. Unless both the inner and outer pipes were leaking simultaneously, this would prevent oil from entering the environment. This contrasts with the single wall pipe concept in

which any leak would cause both an oil spill and an automatic shut-in of production from the facility until the pipeline is repaired.

4. We are concerned that the INTEC report has chosen to minimize the burial depth of each concept. This choice prejudices the equal comparison of the different concepts. Another issue which makes the comparison of the designs unequal is that the inner pipe (flowline) of the steel pipe-in-pipe concept is thinner than the single wall pipe. We would have preferred that the burial depths and the flowline wall thicknesses of all the alternatives be identical to that used in the single wall pipe concept. However, the effect of the change in pipe wall thickness on the equal weighing of the alternatives is minor in comparison to the effect of the burial depth. By assigning different burial depths to the different concepts, the benefit of using an alternative design (as opposed to a single wall pipe) can be lost. The single wall pipe is picked as the best pipeline system candidate. However, the risk of an oil leak is primarily a function of the burial depth and the single wall pipe is buried the deepest. While the chosen depths appear appropriate for each design concept, we would adopt a different approach. The depth of cover for the single wall pipe is 7 feet. We would prefer to keep this depth constant for all of the concepts. If this were done, questions would be answered as to how much benefit do you get when an outer pipe is added to a single wall pipe (i.e., If the only change is adding the outer pipe, what is the benefit?).
5. The driving forces behind considering the alternative concepts are not stated. The purpose of considering such alternatives would be some perceived improvement over a traditional single wall design. We feel that there should be a clear statement of the perceived benefits of the pipe-in-pipe, pipe-in-HDPE, and flexible pipe concepts.

7.2 Technical Merits

1. As mentioned in our intermediate report, we have concerns about the finite element modeling of the ice keel soil/pipe interaction using ANSYS. The cause of concern here is that the geometric nonlinearity was not included in the analysis. We have

spoken with the INTEC representatives, Michael Paulin and Andre Nogueira, about the exclusion of the nonlinear geometric effects from the finite element analysis. Their reasoning behind neglecting the nonlinear geometric effects appears to be due to the increased run time which would have resulted. There were some checks made of the pipe-in-pipe and single wall steel pipe which included the nonlinear geometric effects. However, these check runs have not been through INTEC's quality assurance checks. From our conversation with INTEC, the check runs showed that the trends in the strains remained the same when the nonlinear geometric effects were included as when the nonlinear geometric effects were neglected. Therefore, they used the runs that neglect the nonlinear geometric effects for the conceptual design. We think that this topic is in a gray area between conceptual and preliminary design. In our opinion, if the finite element analysis was felt to be needed at this level, then both the geometric and material nonlinearity should have been included. It may be prudent to use the conceptual design phase to narrow the candidates from four to two and perform the finite element analysis on the two final candidates including the nonlinear geometry effects before selecting the final candidate.

2. We understand that there is another contract for the review of the spillage probability and damage calculations. We consider this an important activity since, the INTEC report definition of a small chronic leak (Category 3 damage, see p 5-38) appears unrealistically low at only 1 barrel a day. Even a 1 inch long crack 0.001 inches wide could discharge approximately 29 bbls/day from an 1100 psi line. A 1 barrel/day leak from an 1100 psi line corresponds to a 0.007 inch diameter hole.

7.3 Inspection Issues

1. The main method for inspection of the pipeline, with regards to internal and external corrosion will rely on the use of smart pigs to be run inside the pipe. In the event the pipe curvature is changed by loads such as ice keel gouging or upheaval buckling, there is a possibility the instrumented pig may not be able to go through the pipe. We

recommend that INTEC review this possibility, and investigate methods for solving this problem, in case it arises. The point is that the ability of the pig to pass through the line may be more limiting than the allowable strain in the pipe.

2. As we understand the current LEOS system, the system uses a small tube which is permeable to hydrocarbons and the contents of this tube would be checked once every 24 hours to determine if a small leak is present. The time required to check the contents of the tube would be approximately six hours. Therefore, there is an eighteen hour hold time during which the hydrocarbons have time to permeate the LEOS tube. As the system exists, Siemens estimates that a leak as small as 0.3 bbls/day could be detected. However, we understand that for the steel pipe-in-pipe and pipe-in-HDPE alternatives that the air in the annulus might be sampled instead of installing a sampling hose. Our concern with this method has to do with the ability to detect the location of a leak. The leak locating abilities of the LEOS system depend on determining where in the flow stream the hydrocarbons are located. The proposed pipe-in-pipe and pipe-in-HDPE designs have centralizers in the annulus. This makes the flow characteristics in the annulus more complex than in a tube and mixing of the air in the flow stream would be expected. We expect that the more complex flow characteristics will make it more difficult to locate a leak. However, there may be an advantage in that the hydrocarbons do not need to permeate a LEOS tube before being detected if the entire annulus is sampled. Whichever method is chosen, we would recommend that a third party demonstration test be conducted on the supplemental leak detection system in the same configuration as would be implemented in the Liberty project.
3. In terms of the mass balance and pressure point systems, our primary concern is with false alarms. The concern here is that if the system does not contain self diagnostics that minimize false alarms, the operators will summarily dismiss an actual leak as a false alarm. In order to prevent this, a system should be adopted that has capabilities that allow the operator to accurately determine the difference between an actual leak and a false alarm and self diagnostics to minimize false alarms.

4. For the flexible pipe system, a disadvantage that is not mentioned in the INTEC report is that the flow balance calculations become more complex. The flexible line can be expected to expand under pressure more than a steel pipe would. This would mean that the variation in the internal volume of the line due to internal pressure will be greater than for a steel pipe and may affect the flow balance calculations.
5. The leak detection threshold of 0.3 BOPD by Siemens is stated, in the LEOS reports, to have been based on experience. The accuracy of this estimate is difficult to assess because it depends on a variety of factors such as the permeability of the soil if the tube is buried beside a pipeline, the size of the annulus if the tube is in the annulus, the permeability of the sensor tube, the location of the tube in relation to the leak, and the hold time between sampling runs. The ability to detect a leak using the LEOS system is dependent on the concentration of oil around the sampling tube. Therefore, the question one should ask in regards to the leak detection threshold is what concentration of oil around the sampling tube is required before a leak can be detected. Once this is known, one would assume that the tube is located at the furthest possible position from the leak and determine either experimentally or numerically the time necessary for the oil concentration around the tube to reach a detectable level for a given leak rate. Such analysis/experimentation is beyond the scope of this review. We would recommend that a third party demonstration test be conducted using the configuration proposed for the Liberty project supplementary leak detection system.
6. For the flexible pipe system, there is not a true annulus. The INTEC report states that the sampling for leak detection would occur in the annulus, but this annulus is filled with steel strips. One would be counting on being able to pump clean air through an annulus that contains steel wraps. This seems unlikely to work. It also seems unlikely that oil could be extracted from this annulus. The ability of the system to sample from this annulus, with internal pressure applied to the pipe, needs to be confirmed. Does BP have any data to confirm that this sampling is possible?

7. For the flexible pipe system, jumpers across the connections are to be used to provide a continuous pathway for the leak detection system to sample the air in the annulus. It is not clear how this would be accomplished. Have any conceptual designs of these jumpers been proposed?

7.4 Operations Issues

1. The INTEC report states that the pipeline will be shut down if pressure or temperature limits are exceeded. Our concern about this is that flow assurance problems may be encountered if the pipeline cools with oil in the line. If the oil properties at ground temperature are such that the oil can still flow, this may not be a problem. However, for some oil compositions at low temperatures, blockages could form when the line is shut down and make it difficult to restart the line. We would be interested in seeing a restarting procedure in case such a shutdown takes place.
2. We would suggest that the annulus pressure be monitored for the pipe-in-pipe and pipe-in-HDPE concepts. A pressure buildup in the annulus could be indicative of a leak in the inner pipe. This would provide another avenue for leak detection in addition to the mass balance and pressure point systems which operate continuously and monitoring either the annulus contents or the contents of a LEOS tube which would be done once a day.

7.5 Repair Issues

1. It is stated that repair could not occur at some times during the year, specifically during break-up and freeze-up of the ice sheet (pages 1-6 and 3-33 of the INTEC report). This amounts to approximately 5-6 months out of the year. It would seem that this would have an effect on the amount of oil lost. The pipeline would be shutdown, and clean-up would proceed, but there would still be oil in some parts of the line. Is it possible for oil that remains in the pipeline to continue to leak before

repairs could be made? Has this been taken into account in the oil spillage calculations?

2. For cases where there is an annulus, in order to prevent corrosion, all moisture would need to be removed from the annulus after a repair. The drying operations following a repair would be more difficult than the drying operations after initial construction because of debris drawn into the annulus during the damage period and the subsequent repair activities. Such debris would include soil, sand, and gravel, in addition to seawater and hydrocarbons. Not all of these materials and objects would be removed by the drying process and may increase the time necessary to dry the annulus. As a result, a significant amount of moisture could be present for a long period of time (i.e., the 2.5-3 month period when repairs could not be made during a freeze-up or break-up plus the drying time). We would expect that drying the annulus could take a month or more. This means that moisture would be present on the order of 4 months. This would be more than enough time for corrosion to begin in the annulus. Therefore, installing a cathodic protection system on the inner pipe should be considered. Such a system could consist of a sprayed aluminum or other cathodic coating applied to the inner pipe to provide in-situ cathodic protection. Another method would be to attach anodes to the inner pipe. Either of these methods should supply adequate cathodic protection for the inner pipe. The drawback to this is that the cathodic protection of the inner pipe could not be monitored.
3. Mechanical repair devices are used as permanent repairs around the world. These devices include external leak repair clamps as well as in-line pipe coupling devices. However, the INTEC report states that mechanical repairs are not considered appropriate for permanent arctic offshore repairs. Is there engineering evidence that supports this or is this based on a perceived risk?
4. We are aware that both bolted and welded split sleeves are commonly used for the repair of small leaks. However, it is not clear which kind of sleeve is being referenced in the INTEC report. It would be helpful if drawings of the candidate repair equipment and installation method were included in the report.

5. We agree that the repair of the pipe-in-pipe design would be much more involved and that the restoration of the outer pipe to original integrity is doubtful given the types of repairs described. From the INTEC report, we envision the proposed repair of the outer pipe to consist of a clamshell that has a larger diameter than the outer pipe. Using such a repair would result in having to use fillet welds on the ends of the repair section and would include longitudinal welds to join the clamshell sections. This type of repair is illustrated in Figure 3 and would not restore the outer pipe to its original integrity. However, if the repair pipe has the same diameter, wall thickness, and material properties as the original pipe and is installed using butt welds that are inspected by UT examination, it should be possible to restore the pipe to near its original integrity. This type of repair is included in Figure 4. The repair includes longitudinal welds, but the fillet welds are replaced by butt welds. In order to implement this type of repair, the ends of the pipe would have to be prepared and the repair section cut to length in the field. When designing the pipeline, the designers should consider the capacity of a repaired pipe when establishing the design allowables. If the repaired pipeline would not be as sound as the new line, the design allowables should be based on the repaired pipe strength.
6. We have a few questions concerning the repair of the flexible pipe alternative. Why is a flanged connection considered temporary? Is there standard repair equipment for flexible pipe? What do the repair connections look like? How could/would end fittings be installed in the field? It appears that any permanent repair to the flexible pipe system would consist of replacing an entire 2800 ft section. This significant effort may increase the repair costs of the line enough to offset any initial savings of using the flexible pipe system. Replacement sections would have to be kept on site, or production could be halted for months waiting for a replacement section.
7. The INTEC report discusses both repair time frames and methods of repair. Our experience has been that the delivery of mechanical connectors or bolted split sleeves can be on the order of two months. We would also expect that connectors constructed

of materials appropriate for the arctic environment could take even longer to obtain. Is there a plan for stocking the discussed products locally?

7.6 Construction Issues

1. There is no mention of the procedures which would be required to abandon an uncompleted line and then successfully resume construction. Has this been considered?
2. For the concepts involving inserting the inner pipe into an outer pipe or sleeve, there is a possibility of damage to the corrosion protection coating during this operation. Emphasis is placed on keeping the annulus dry to prevent corrosion and that the inner pipe would not be cathodically protected. It would seem prudent to include some cathodic protection of the inner pipe. This cathodic protection could consist of a sprayed aluminum or other cathodic coating or anodes attached to the inner pipe. The drawback here is that the cathodic protection in the annulus could not be monitored. However, the system would be in place and could provide some benefit.
3. In the pipe-in-pipe construction sequence, it is stated that the "inner pipe extends beyond the outer pipe". The inner and outer pipes must be the same lengths eventually so this statement is not clear. It would seem that the first section should be made with a short outer pipe. The rest of the inner and outer pipes should be made the same length but the inner pipe sticks out at the first field weld so that this weld can be made and inspected. The outer pipe would then be slid over this weld and the outer field weld made and inspected. Is this the intended method?
4. Induction heating is mentioned as a method of joining the HDPE pipe and later a fusion joining machine is mentioned. Which is the intended method and what are the implications of the joining method to the construction process?
5. For the flexible pipe alternative an area of concern is the welding of the connectors and their subsequent coating. The integrity of this system depends on these joints so the fabrication and long term performance needs careful attention.

6. For the pipe-in-HDPE concept, it is stated that only visual inspection of the fusion welds is possible. We agree with this and that the best avenue for assuring the quality of the fusion welds is to qualify the procedure using test samples fusion welded by the same machine and operators as would be used during installation.
7. We agree that both the steel pipe-in-pipe and pipe-in-HDPE alternatives would be more difficult to construct than either the single wall steel pipe or the flexible pipe. However, there are some refinements to the construction process that could reduce the time required to install the steel pipe-in-pipe and pipe-in-HDPE alternatives. First, the single wall steel pipe strings that are to be towed to the trench are 3000 ft long. However, the pipe-in-pipe and pipe-in-HDPE strings are only 1000 ft long. This increases the number of tie-in locations by a factor of three. In addition, the time to make each connection is longer for the pipe-in-pipe and pipe-in-HDPE alternatives because of the additional connection of the outer pipes or sleeves. It would seem that the main factor affecting the length of the string that can be towed is the weight of the string. For the steel pipe-in-pipe, a 1300 ft string is approximately the same weight as the 3000 ft single wall steel pipe string. If 1300 ft strings were used, the number of tie-in locations would be reduced from 33 to 25 and the connections could be made in approximately 8 fewer days. For the pipe-in-HDPE alternative, 2600 ft strings weigh approximately the same as the single wall steel pipe 3000 ft string. Using 2600 ft long pipe-in-HDPE strings would reduce the time for the field joints from 22 days to 9 days. In both cases, preparing longer strings would increase the pipe string make-up time. However, this could be offset by increasing the size of the crew. Another way to speed up the construction would be to use two pipelaying spreads either starting in the middle of the route and working toward opposite shores or starting onshore and working toward a central tie-in. In the INTEC report, the construction timelines for the single wall, steel pipe-in-pipe, and pipe-in-HDPE, start in mid December and end in mid April. The timeline for the flexible pipeline is shorter running from mid December to mid March. However, the INTEC report states that the ice is stable in Zone 1 by December and break-up occurs at the end of May.

Therefore, it would seem that equipment mobilization, road construction, and make-up site preparation could begin December 1st and construction could continue through May. This amounts to eight weeks that are currently not included in the construction timeline. If half of this time is discounted for weather variations, there are four weeks that could be included in the construction timeline or 28 days more time available for construction than included in the current timeline. The longest timeline is currently 107 days for the pipe-in-HDPE alternative. An increase in the timeline of 28 days constitutes a 25 % increase. Therefore, we feel that with proper scheduling and the mobilization of adequate numbers of trained personnel it should be possible to complete the construction of any of the four designs in one season. The keys to completing the work in one season are to make sure that the preparation of the pipe strings proceeds at a rate that keeps up with or exceeds the trenching activities and minimizing the number of field joints. In other words, the trenching activities should be the limiting factor in the construction timeline. The main advantage to the construction method presented in the report is that the strings can be fabricated before trenching is started. If the pipe strings could be completed in the fall, before the winter freeze-up or enough manpower is allocated to ensure that the pipe string preparation exceeds the trenching rate, it should be possible to complete the pipeline in one season. With any of the alternatives, the possibility of construction requiring a second season is present and should be considered when the construction is planned. However, we feel that if a single wall pipe can be constructed in one season, then the other alternatives could also be completed in one season. It would be the factors that are unpredictable, such as an unusually short winter, which one would expect to result in a second construction season and these unpredictable factors would affect any of the designs.

8. We would suggest, if scheduling permits, that the hydrotest of the pipeline be conducted before backfilling. The main factor affecting the ability to hydrotest before backfilling is scheduling. The INTEC report estimates that backfilling activities will take between 30 and 44 days, a significant percentage of the

construction season. If waiting to backfill until after hydrotesting would result in a second construction season, then backfilling should proceed as the pipe is installed. However, if the hydrotest could be conducted before backfilling, this would facilitate any repairs that need to be made. In addition, maintaining some pressure in the line during the backfilling operation should be considered. This would lock in some tensile stresses in the pipeline, which would help reduce the effects of the thermal expansion that will occur as the pipeline heats up to its operating temperature.

9. As an alternative to a hydrotest of the annulus of the pipe-in-pipe and pipe-in-HDPE alternatives, the annulus could be tested using pressurized dry air or dry nitrogen. During this test, a diver or ROV could "walk" the pipeline route and look for bubbles. Any leaks in the outer pipe or sleeve would be indicated by bubbles.
10. The INTEC report mentions that localized jetting may be necessary to fluidize the trench bottom in order to lower a pipe that has become "high grounded" during installation. This means that jetting equipment will need to be on site throughout the pipelaying process. Otherwise, if jetting is required, delays in getting the equipment could prevent the completion of the pipeline in one season. In addition, suction equipment may be needed to remove material from localized high spots.

7.7 Costs

1. The 5 million dollar contingency for a second construction season of the pipe-in-HDPE candidate appears low. We understand that INTEC based this on the perceived likelihood of a second season being required to complete construction. However, the costs for mobilization, ice thickening/road construction, and demobilization for the pipe-in-HDPE concept total 9.7 million dollars. There are also no costs included for the abandonment of the line at the end of the first construction season and the retrieval of the partially completed pipeline so that construction can be resumed. Therefore, the 5 million dollar contingency for the second season work

seems low. For the steel pipe-in-pipe, the contingency cost allocated for a second season of 15 million dollars is more reasonable.

2. We feel that it should be possible to complete construction of any of the alternatives in one season. This would have the most effect, in terms of cost, on the steel pipe-in-pipe alternative. Completing the construction of the steel pipe-in-pipe in one season would reduce the cost by 15 million dollars and bring the pipe-in-pipe costs closer to the single wall steel pipe cost.

7.8 Alternative Design Concepts

1. We would be interested in knowing if concepts such as putting a flexible, composite, or polymer pipe inside a steel pipe have been considered. If so, what factors eliminated this option from consideration? It would be more difficult to install than a single wall pipe, but we would think that it would be easier to construct than the steel pipe-in-pipe. If the inner pipe was nonmetallic, the concern about cathodic protection of the inner pipe would be eliminated. One issue that would need to be addressed is how to prevent damaging the inner nonmetallic pipe when the outer steel pipe is welded.
2. There is a modification to the steel pipe-in-HDPE concept that we would suggest investigating. The HDPE sleeve could be prefabricated as a unit with an inner thin wall HDPE pipe and an outer HDPE pipe with the foam in-between. In order to use this HDPE sleeve with the foam in place, an adequate installation clearance between the thin wall HDPE pipe and the inner pipe would be required. A further variation would be to perforate the thin wall HDPE pipe and replace the polyurethane foam with an oil absorbent material. In this scenario, the HDPE sleeve assembly becomes an oil containment barrier and a leak detection system could monitor the annulus between the steel pipe and the perforated thin wall HDPE pipe. A sketch of this alternative is included as Figure 1 in this report.

3. Another variation to the steel pipe-in-HDPE concept would be to use a thick wall (16 inch O.D. x 1.25 inch wall) HDPE sleeve without centralizers. The closer fit between the HDPE sleeve and the inner pipe and elimination of the centralizers would provide better distribution of the inner pipe weight to the HDPE sleeve. This may lower the risk of damaging the HDPE sleeve when handling the assembled pipe strings. The thicker wall HDPE sleeve would also have a higher allowable pressure and the elimination of the centralizers would simplify construction.

7.9 Items to be Considered in Preliminary Design

1. For the pipe-in-pipe concept, it is stated that there will be a locked in compressive load in the inner pipe. There will be centralizers/spacers in the design to keep the curvature of the two pipes approximately equal. The inner pipe should be checked for buckling between the centralizers due to the thermal expansion if this design concept is carried forward. Buckling could lead to a fatigue failure or to fretting at points of contact between the two pipes if the temperature fluctuations are sufficient.
2. A possible hydrostatic test of the outer pipe is mentioned on page 5-17 of the INTEC report. This would require drying of the annulus after the hydrotest. In addition, if such a test is done the inner pipe must be pressurized or otherwise assured of being collapse resistant. Collapse should not be a problem with the currently proposed inner pipes, but should be included in the preliminary design checks.
3. For the pipe-in-HDPE concept, the pipe transport method mentioned is the same as for the pipe-in-pipe technique. The spacers between the inner pipe and the HDPE outer sleeve are not described in any detail. However, the spacers must be designed so that the weight of the inner pipe is distributed along the length of the HDPE sleeve. The inner pipe is so heavy that the ability of the HDPE sleeve to carry this load, unless it is well distributed, is doubtful. An alternative would be to use a thicker walled HDPE sleeve and a smaller annulus size and omit the centralizers. This would distribute the weight of the inner pipe over a larger area than if centralizers were

present. This would also aid in construction since the centralizers would not be installed. Buckling of the inner pipe would have to be considered in detail in the preliminary design phase if such a concept were adopted. The possible impact loads during construction/transport should also be considered since the impact strength of HDPE at -50^{o}F can be expected to be approximately ½ that of HDPE at 73^{o}F.

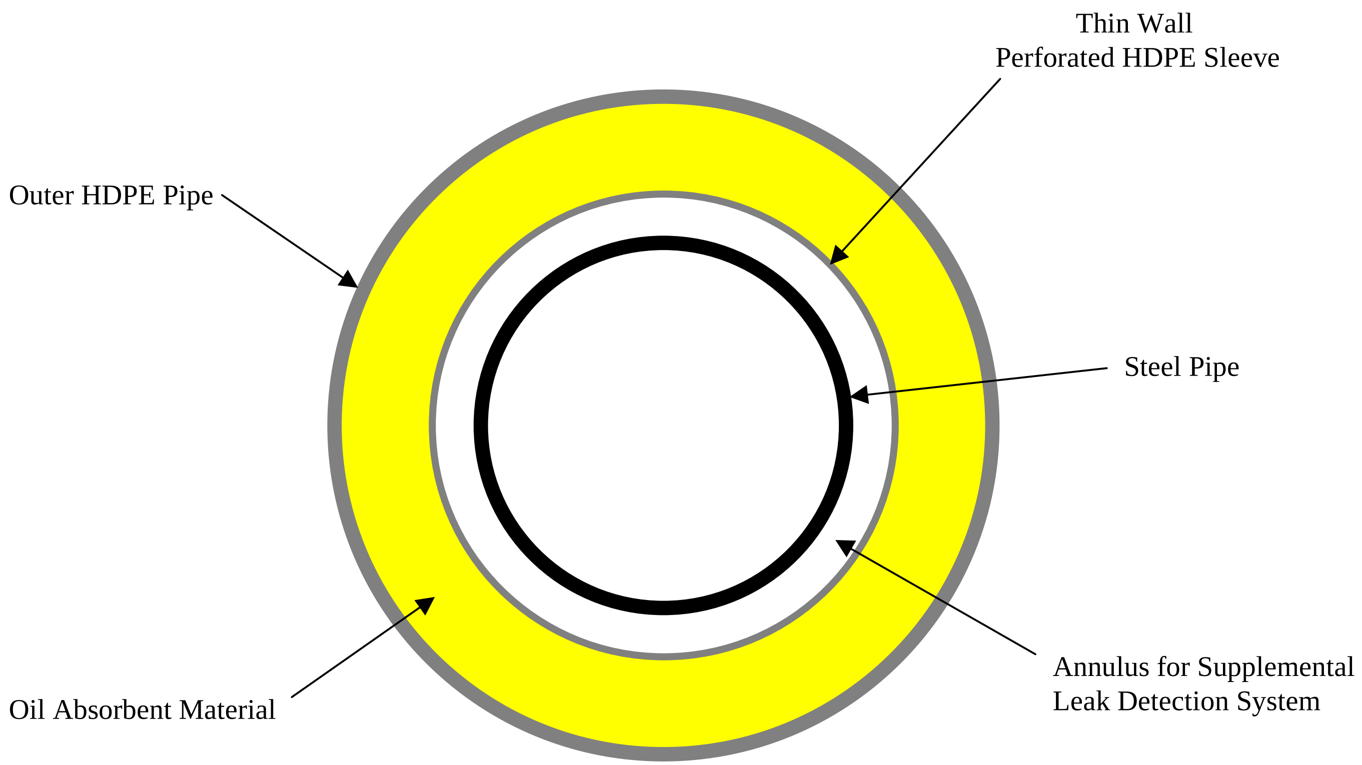
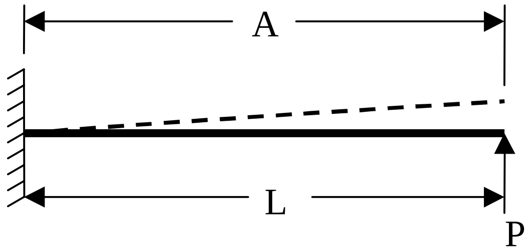
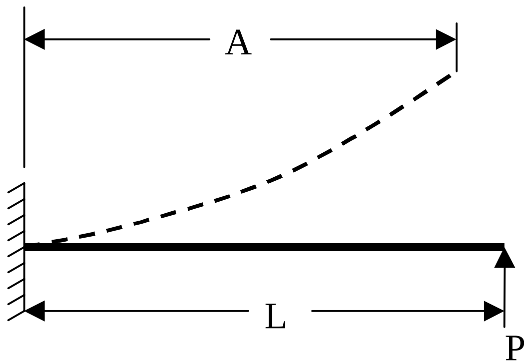


Figure 1. Alternative Suggestion: Steel Pipe-in-HDPE with Oil Absorbent Material in the Annulus



a) Small Deflections



b) Large Deflections

Figure 2. An Example of Geometric Nonlinearity

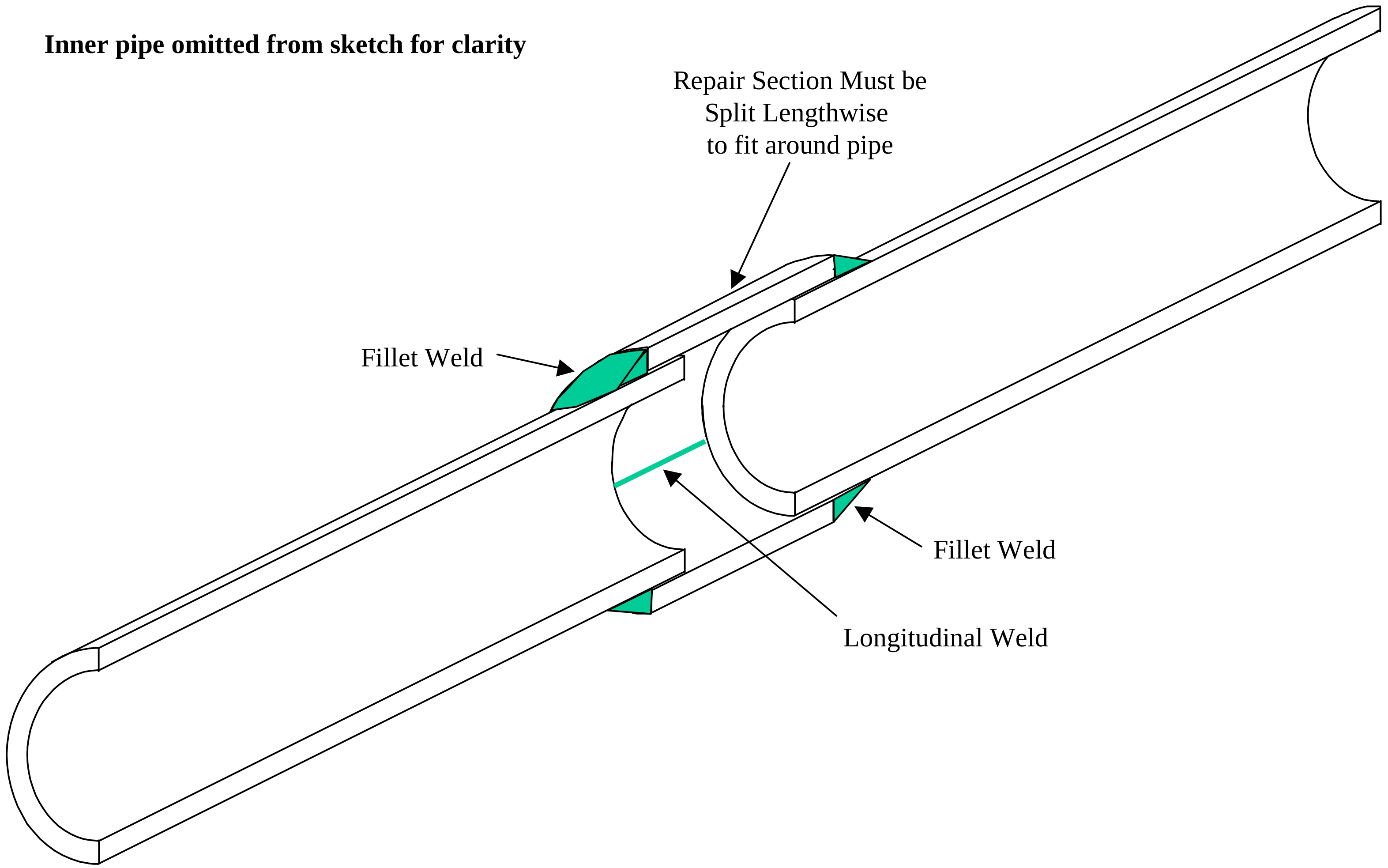


Figure 3. Fillet Weld Repair of Outer Pipe: Pipe-in-Pipe Alternative

Inner pipe omitted from sketch for clarity

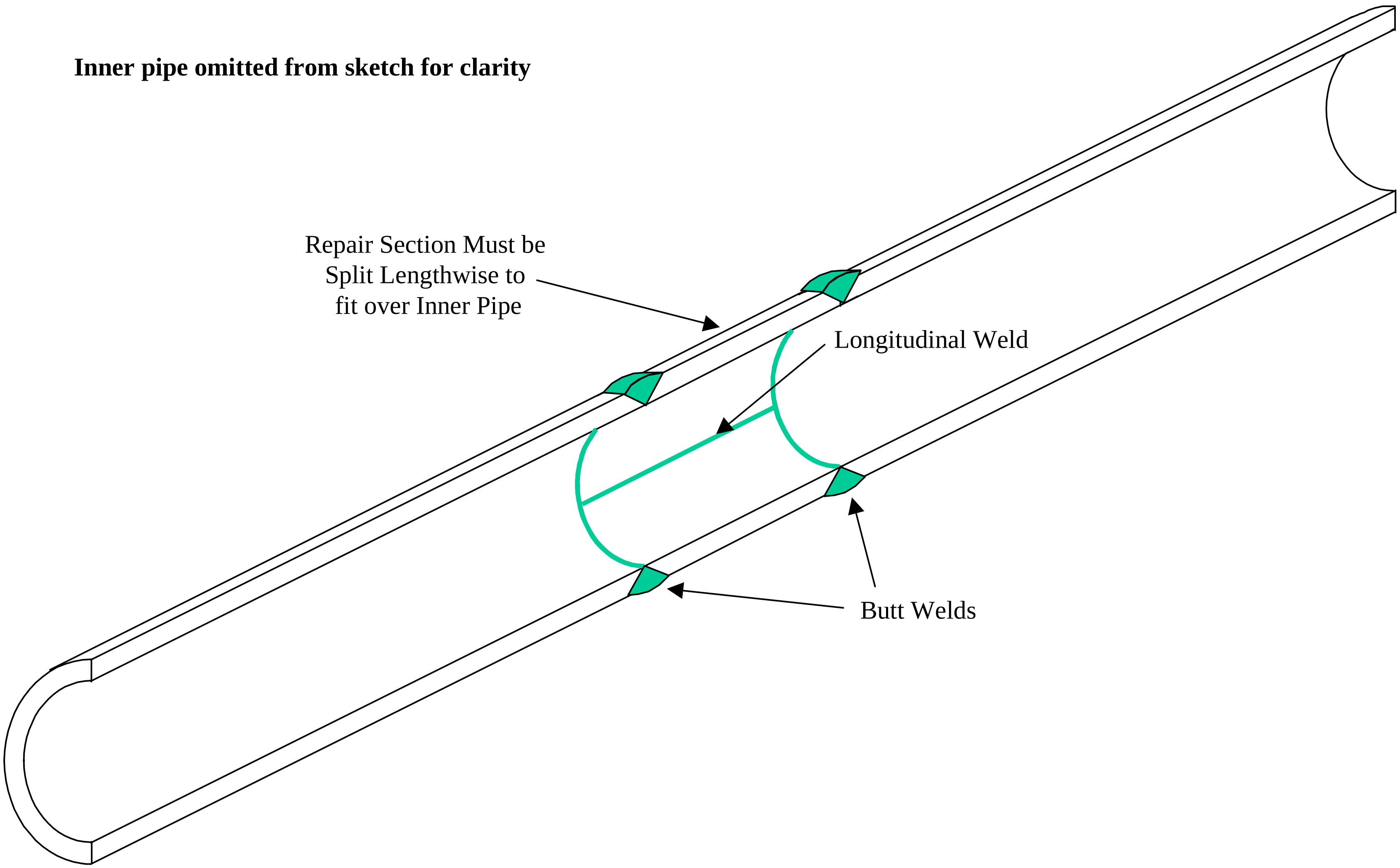


Figure 4. Butt Weld Repair of Outer Pipe: Pipe-in-Pipe Alternative