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# CHUKCHI SEA TRANSPORTATION

# FEASIBILITY AND COST COMPARISON

# JOINT INDUSTRY STUDY

## PHASE 2

## APPENDIX F - RISK ASSESSMENT

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## APPENDIX F - RISK ASSESSMENT

NOVEMBER 1986

JOB NO. H-046.3

INTEC ENGINEERING, INC.

APPENDIX F - RISK ASSESSMENT

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## CHAPTER 1

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## CHAPTER 1
## INTRODUCTION, SUMMARY, CONCLUSIONS AND RECOMMENDATIONS

### 1.1 INTRODUCTION

INTEC Engineering Report "Chukchi Sea Transportation Feasibility and Cost Comparison Joint Industry Study" (No. H-046.2) addressed crude oil pipeline and tanker transportation systems between the Lease Sale 109 area and tanker loading terminals in southern Alaska. Preliminary designs and cost estimates were developed for offshore pipelines, icebreaking tankers and tanker loading terminals. Recommended transportation systems were then defined for different field locations and throughput rates.

Cost estimates used for the economic comparison between different transportation systems included contingency factors to account for possible variations in the facility costs. The objective of this study extension is to develop statistical distributions for these possible cost variations which will more accurately define the economic risks associated with the different transportation scenarios.

### 1.2 SUMMARY

This appendix is a supplement to the Joint Industry Study final report and is organized into four chapters. Chapter 1 contains the introduction, summary, conclusions and recommendations.

Chapter 2 describes the procedures used to analyze the transportation system cost risks. In Chapter 3, uncertainties leading to offshore pipeline, tanker and terminal construction cost variations are identified and quantified. The duration of the summer ice free construction season is one of the important variables in quantifying construction risk and is addressed in Section 3.2.2.

Chapter 4 presents the probability distributions for pipeline, tanker and terminal installed costs. The resulting effects on crude oil transportation costs for three representative transportation scenarios are presented.

## 1.3 CONCLUSIONS

Risk analysis results indicate 50 to 70 percent probabilities that the actual tanker, terminal and offshore pipeline costs will be less than the values utilized in the Chukchi Sea transportation system evaluations. These non-exceedance probabilities can be increased by increasing the contingency factors applied to the estimated facility costs. However, cost contingency factors of over 200 percent (over 3 times the estimated cost) may be required to reduce the probability of cost overruns to essentially zero. Selection of cost contingency factors must be based on a company's field development risk philosophy.

The relationships between Chukchi Sea transportation facility cost contingency factors and the probabilities of cost overruns are defined in Chapter 4 and are summarized in the following paragraphs.

Much of the facility cost overrun risk is a result of uncertainties in design criteria and other cost estimating uncertainties. As an alternative to applying high cost contingency factors, further engineering studies will improve cost estimating accuracy, thus reducing the contingency factors required to obtain a specified probability of cost non-exceedance. For example, application of site specific soils data will significantly reduce the uncertainties in offshore terminal and pipeline costs and may result in lower risk adjusted cost estimates.

Offshore Pipelines

Risk analysis of offshore pipeline cost uncertainties indicates a 30 percent probability that offshore pipelines will actually cost more than the values utilized in the transportation system evaluation. Primary factors contributing to this risk of cost overruns include:

- trenching equipment productivity and unit cost variations from estimated values;
- installation equipment productivity and unit cost variations from estimated values; and
- possible pipeline design changes.

Two additional factors are identified which can have major impacts on the offshore pipeline costs: possible requirement for insulation over their full length, and possible requirement for significantly deeper trenching. Because of their importance, these two factors are addressed separately as major design requirements.

Offshore pipeline costs developed for the transportation system evaluation included a 25 percent contingency factor. This contingency factor would have to be increased to approximately 55 percent to reduce the probability of a cost overrun to 10 percent. The total offshore pipeline cost probability distribution, without considering trench depth or insulation requirements, is shown on Drawing No. F-101.

Estimated offshore pipeline capital costs will increase by 30 percent if the crude oil properties or overland pipeline design requirements dictate that the pipeline must be insulated over its full length. If route specific soils data and/or ice gouge protection requirements dictate significantly deeper pipeline trenches than predicted based on the present study, estimated offshore pipeline capital costs could increase by approximately 100 percent. In either case, a contingency factor of 55 percent must once again be applied to the increased estimated capital cost to reduce the probability of a cost overrun to 10 percent.

If these two major design requirements are included in the offshore pipeline cost probability distribution, they will significantly increase the required contingency factors. For example: assuming a 20 percent probability for insulating the pipe and a 20 percent probability for significantly deeper trenching would require approximately a 135 percent contingency factor to obtain a 10 percent probability of cost overrun.

Icebreaking Tanker Fleet

Risk analysis results indicate a 50 percent chance of the actual icebreaking tanker fleet capital costs exceeding values utilized in the transportation system evaluation. Major factors contributing to the risk of cost overruns include:

- sea ice condition variations;
- transit speed variations resulting from following flaw leads and/or navigating around severe ice features; and

- shipyard construction cost variations.

A cost contingency factor of approximately 50 percent is required to account for these uncertainties, and to reduce the probability of a cost overrun to 10 percent (Drawing No. F-101).

Tanker Loading Terminals

The risk of actual tanker loading terminal costs exceeding the costs utilized in the transportation system evaluation is 40 percent for both the offshore and nearshore terminal locations. Major factors contributing to the risk of cost overruns include:

- possible poor structure foundation conditions;
- possible structure design variations;
- offshore structure fabrication cost variations;
- terminal interconnecting pipeline cost variations; and
- onshore facility construction cost uncertainties.

A cost contingency factor of approximately 80 percent for the offshore terminal or 70 percent for the nearshore terminal is required to account for these uncertainties and reduce the probability of cost overruns to 10 percent. The transportation system evaluations were based on costs which included a 15 percent contingency factor.

Effects on Transportation Costs

The effects of applying increased contingency factors to the estimated offshore pipeline, tanker and loading terminal construction costs are limited by the percentage of the total transportation cost they represent. For the three scenarios evaluated, the maximum transportation cost increase due to any one system component is 12 percent (increasing the tanker fleet capital cost in Scenario 2A).

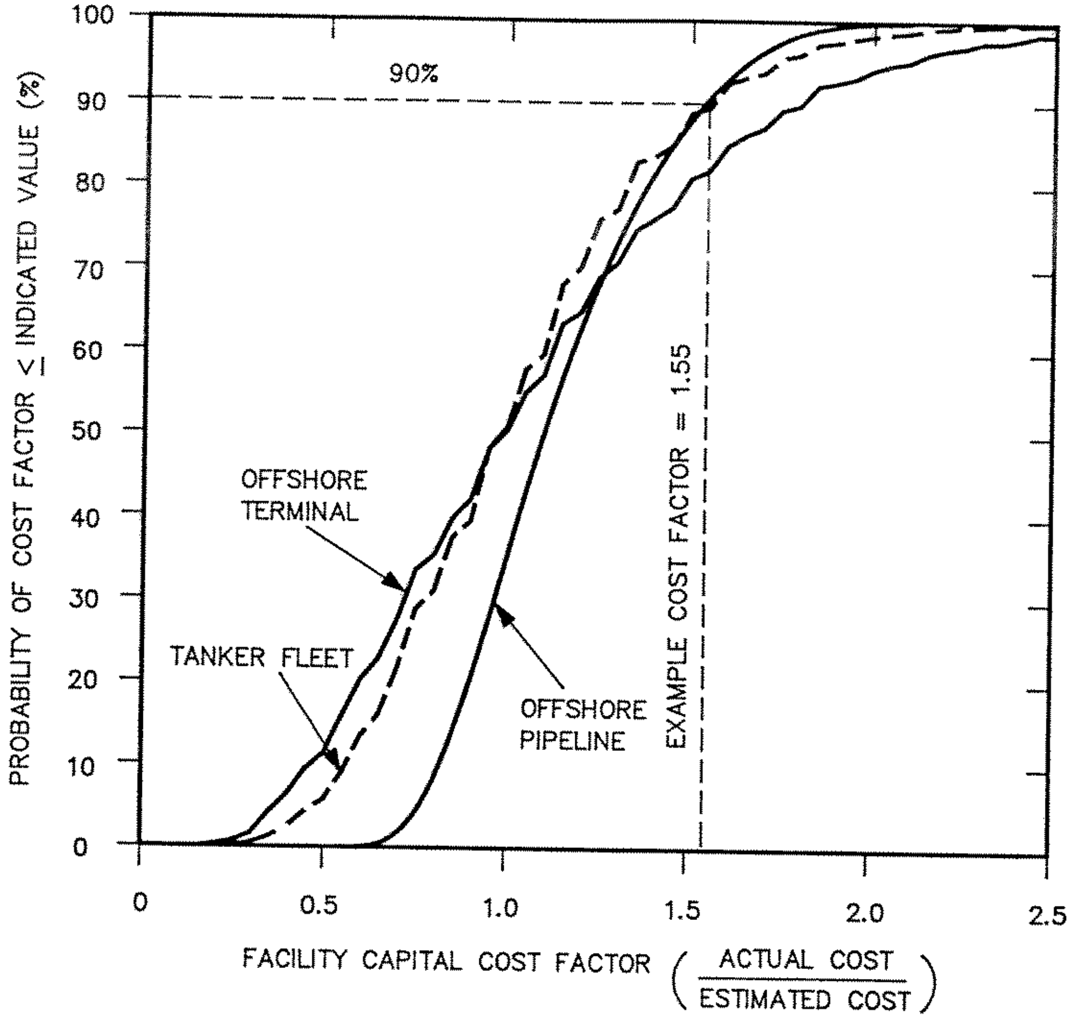
High contingency factors (yielding low probabilities of cost overruns) should not be applied to each of the transportation system component costs when calculating the total crude oil transportation cost. This is because there is a low probability of the pipeline, tanker and terminal costs all increasing significantly at the same time except as a result of causes such as inflation or environmental permitting delays. The present risk analysis does not address either of these overall project uncertainties.

## 1.4 RECOMMENDATIONS

Three recommendations are derived from the Chukchi Sea crude oil transportation system risk assessment. First, it is recommended that study Participants apply tanker, terminal and offshore pipeline cost contingency factors corresponding to the probability of cost overruns which they consider acceptable. Recommended transportation facility cost contingency factors are presented as a function of the non-exceedance probability.

The second recommendation is to identify the optimal crude oil transportation system on a risk adjusted basis by applying the selected cost contingency factors. Because the crude oil transportation system is an integral part of any Chukchi Sea field development, however, risk assessment should be done on an overall project basis. Such an assessment would include considering the effects of transportation system construction delays and system operation interruptions on crude oil production and overall field development economics.

Finally, the risk assessment has highlighted key areas of uncertainty and risk associated with the offshore pipelines, tankers and terminals. Future design and cost estimating efforts should be focused on those areas which have the largest impacts on system cost or performance.




NOTES:

1) EXAMPLE APPLICATION: TO OBTAIN A 90% PROBABILITY OF THE ACTUAL OFFSHORE PIPELINE CAPITAL COST NOT OVER-RUNNING THE BUDGET, 1.55 TIMES THE ESTIMATED COST MUST BE BUDGETED ( A 55% CONTINGENCY FACTOR MUST BE APPLIED).

2) THE FOLLOWING CONTINGENCY FACTORS WERE ASSUMED FOR THE PREVIOUS TRANSPORTATION SYSTEM EVALUATION REPORT: OFFSHORE PIPELINES – 25%, TANKER FLEET – 0%, TERMINALS – 15%.

| JOINT INDUSTRY STUDY CHUKCHI SEA TRANSPORTATION | COST PROBABILITY DISTRIBUTIONS | | |
|---|---|---|---|
| INTEC ENGINEERING, INC. | SCALE NONE | DRAWN BY R. GROBE | DRAWING No. F-101 |
| | DATE 10-23-86 | JOB No. H-046.3 | |

# APPENDIX F - RISK ASSESSMENT

## CHAPTER 2

## RISK ANALYSIS PROCEDURES

# CHAPTER 2
# RISK ANALYSIS PROCEDURES

## 2.1 GENERAL

Proposed Chukchi Sea crude oil transportation systems contain several aspects which significantly increase the risk of cost variations compared to non-arctic transportation systems. These factors include:

- severe environmental conditions;
- remote location; and
- limited experience to date constructing and operating arctic transportation facilities.

Incorporating these uncertainty elements into arctic transportation system planning requires a more rigorous risk analysis procedure than is typically employed for other transportation systems. Procedures used to analyze the risk of cost variations for three representative transportation scenarios considered are described in this chapter.

## 2.2 TRANSPORTATION SYSTEM RISK MODEL

The objective of the present risk assessment is to quantify risks of Chukchi Sea transportation facility construction cost variations and their effects on the overall crude oil transportation cost. Transportation system costs will also vary as a function of the crude oil production and economic evaluation criteria considered, for example:

- crude oil properties;
- field life;
- production profile;
- interest rate;
- inflation rate;
- tax conditions; and
- assigned costs due to crude oil production interruptions.

While variations of this type have a significant impact in defining the preferred transportation system and calculating the transportation cost, they are not part of the present analysis. Study participants may wish to apply their own criteria or range of criteria to assess the impact of these uncertainties.

The Chukchi Sea crude oil transportation system evaluation is based on the cost of all necessary transportation facilities from the offshore production structure to a tanker loading terminal in southern Alaska. Transportation facilities considered include the following:

- icebreaking tankers;
- offshore tanker loading terminals;
- nearshore tanker loading terminals;
- transshipment terminals;
- offshore pipeline systems;
- overland pipeline systems; and
- the existing Trans Alaska Pipeline System.

The Chukchi Sea Transportation Study concentrated on the icebreaking tankers, tanker loading terminals and offshore pipelines as the transportation system components which have the greatest degree of cost uncertainty. The present risk assessment will therefore concentrate on identifying and quantifying uncertainties for these three system components. Construction and operating experience from existing Alaskan overland pipelines and the Valdez terminal help to improve the reliability of cost estimates for the other transportation system components.

Risks associated with the following three representative Chukchi Sea transportation scenarios are evaluated:

- offshore pipeline from Central site to Wainwright and overland pipeline to TAPS (Scenario 1B);
- offshore terminal at Central site and icebreaking tanker transport to Unimak Pass (Scenario 2A); and
- offshore/overland pipeline to nearshore terminal at Kivalina and then tankers to Unimak Pass (Scenario 3B).

All three scenarios are based on the Central Chukchi Sea site as defined in Chapter 7 of the Transportation Study report. A crude oil throughput rate of 400 MBPD is considered for the risk assessment.

Crude oil transportation costs are computed based on required facility capital costs plus the present worth of the annual operating and maintenance costs over the field life. Percentage breakdowns of the costs for each component of the three transportation systems considered are presented below. The cost data are based on the scenario evaluation results presented in Chapter 7 of the Transportation Study report.

Scenario 1B - Offshore Pipeline to Wainwright - Transportation Cost Breakdown

| System Component | Capital Cost (Percent) | O&M Cost (Percent) | Total Cost (Percent) |
|---|---|---|---|
| Offshore Pipeline | 10.2 | 1.9 | 12.0 |
| Production Structure | 6.3 | --- | 6.3 |
| Overland Pipeline | 21.3 | 6.8 | 28.1 |
| TAPS Tariff | --- | 53.5 | 53.5 |
| TOTAL | 37.8 | 62.2 | 100.0 |

Scenario 2A - Tankers to Unimak Pass - Transportation Cost Breakdown

| System Component | Capital Cost (Percent) | O&M Cost (Percent) | Total Cost (Percent) |
|---|---|---|---|
| Offshore Loading Terminal | 29.1 | 4.1 | 33.2 |
| Unimak Pass Terminal | 15.1 | 4.1 | 19.2 |
| Tanker Fleet | 23.4 | 24.2 | 47.6 |
| TOTAL | 67.6 | 32.4 | 100.0 |

Scenario 3B - Pipeline to Kivalina and Tankers to Unimak Pass - Transportation Cost Breakdown

| System Component | Capital Cost (Percent) | O&M Cost (Percent) | Total Cost (Percent) |
|---|---|---|---|
| Offshore Pipeline | 11.7 | 2.2 | 13.9 |
| Production Structure | 4.1 | --- | 4.1 |
| Overland Pipeline | 6.4 | 1.3 | 7.7 |
| Nearshore Loading Terminal | 11.2 | 3.6 | 14.8 |
| Unimak Pass Terminal | 12.1 | 3.6 | 15.7 |
| Tanker Fleet | 22.1 | 21.7 | 43.8 |
| TOTAL | 67.6 | 32.4 | 100.0 |

The impact of capital cost variations on the total transportation cost is computed based on the percentage contribution to the total cost.

## 2.3 RISK COMBINATION PROCEDURE

Individual factors affecting transportation system costs are identified and then quantified using the cost estimating computer programs developed as part of the Chukchi Sea Transportation Study: CHUKCHI1 and CHUKCHI2. Program input data are adjusted to model the cost variation factors considered.

Tanker, terminal and offshore pipeline cost uncertainties are grouped into major categories in Chapter 3 and cost probability distributions are estimated for each category. These distributions are later combined in Chapter 4. The cost uncertainty groupings and probability distribution estimating procedures are based partially on calculations and partially on engineering judgement.

Construction cost estimates prepared for the offshore pipelines include a 25 percent cost contingency factor. A 15 percent contingency factor was included for the offshore and nearshore terminal costs and no contingency factor was included for the tanker fleet.

These contingency factors were intended to cover additional costs associated with uncertainties in the facility construction cost estimates. Many of these uncertainties are presently being addressed individually in the risk assessment. Contingency factors are therefore left out of the facility cost estimates in the risk analysis to avoid accounting for uncertainties twice.

Transportation system cost probability distributions resulting from individual factors in the risk assessment are combined for a total component cost probability distribution using a numerical procedure. The procedure involves preparing a two-level probability tree and then tabulating the cumulative joint probability distribution.

For some of the factors considered in the risk assessment, cost increases due to one factor may be partially offset by changing another variable. For example, if an increased pipeline trench depth is required, a higher capacity trenching method may be preferred. This type of interdependency between factors is noted where applicable. All resulting transportation cost probability distributions are assumed to be statistically independent.

All cost variations are expressed in terms of relative cost factors (actual facility cost divided by the estimated facility cost). Presentation in this form allows the risk analysis results to be readily applied to the costs developed for the other transportation scenarios.

APPENDIX F - RISK ASSESSMENT

## CHAPTER 3

## TRANSPORTATION COST RISK SOURCES

# CHAPTER 3
# TRANSPORTATION COST RISK SOURCES

## 3.1 GENERAL

Transportation cost risk sources are identified in this chapter. These risks are then quantified and the effects on the transportation facility capital cost are presented. Offshore pipeline, tanker and terminal risk sources are addressed separately.

Transportation system cost risk sources include both design and construction uncertainties. Offshore pipeline, tanker and terminal designs used in the transportation system evaluations are based on the best data available within the scope of the Chukchi Sea Joint Industry Study. It is recognized that facility design uncertainties remain which may significantly impact the facility costs. Factors included in this category are facility design changes possible during the preliminary and detail facility design stages. Design changes resulting from changes in the system performance requirements and environmental impact concerns are not addressed.

During the transportation facility construction phase, the actual facility costs may vary from the estimated costs due to estimating inaccuracies and other risks. The estimating inaccuracies may include variations in construction spread day rates and productivities or materials cost variations. Construction risks include mechanical and weather downtimes and adverse sea ice conditions.

## 3.2 OFFSHORE PIPELINES

Uncertainties in the design and construction of offshore pipelines in the Chukchi Sea may result in variations of the actual costs as compared to the estimated costs presented in the Transportation Study report.

The estimated offshore pipeline capital costs for Scenarios 1B and 3B are $785 million and $886 million, respectively. The percentage cost breakdown between the different cost items is shown below:

Offshore Pipeline Capital Cost Breakdown (Percent)

| Cost Item | Scenario 1B (Pipeline to Wainwright) | Scenario 3B (Pipeline to Kivalina) |
|---|---|---|
| Materials | 11.4 | 14.7 |
| Materials Logistics | 5.8 | 7.5 |
| Trenching | 30.3 | 26.3 |
| Installation, Tie-ins/ Shore Crossings | 19.7 | 19.0 |
| Pump Station | 2.4 | 2.1 |
| Project Services (15%) | 10.4 | 10.4 |
| Contingency (25%) | 20.0 | 20.0 |
| TOTAL | 100.0 | 100.0 |

Offshore pipeline cost risks are analyzed for Scenario 1B. The impact of the risk factors on Scenario 3B total offshore pipeline costs is approximately the same as for Scenario 1B because of the similar cost breakdown.

Offshore pipeline uncertainties associated with each major cost item are addressed in the following sections. The possible use of thermal insulation over the full length of the offshore pipelines or the possible requirement for deeper trenching are addressed separately in Section 3.2.6.

### 3.2.1 Pipeline Materials Cost

Factors which can impact the pipeline materials cost include:

- detail design of pipeline outside diameter, wall thickness, steel grade, corrosion coating and weight coating requirements; and
- cost estimating accuracy per unit of pipeline materials.

The overall uncertainty in the pipeline materials cost is judged to be as follows:

| Probability of Cost Factor $\leq$ Indicated Value (Percent) | Pipeline Materials Cost Factor $\left(\frac{\text{Actual Cost}}{\text{Estimated Cost}}\right)$ |
|---|---|
| 10 | 0.70 |
| 50 | 1.00 |
| 90 | 1.40 |

The cost factor probability density function is specified above in terms of three points on the cumulative probability density function curve.

Materials logistics costs are assumed to vary by the same amount as the materials costs and to be dependent on the materials costs.

### 3.2.2 Pipeline Trenching Cost

Important variables affecting the offshore pipeline trenching cost include trenching equipment productivity, summer construction season durations and equipment cost estimate uncertainties. These risk factors are discussed in the following paragraphs and then combined to define an overall trenching cost variability. The effects of trench depth requirements and soil type are addressed in Section 3.2.6.

Trenching Equipment Productivity

The estimated pipeline trenching equipment productivity is based on an effective production rate and production rate factors to account for weather and mechanical downtime. There is extensive worldwide experience with most of the trenching methods considered and several of the methods have been used under arctic conditions.

The actual trenching equipment production rates obtained while constructing a Chukchi Sea pipeline may vary from the estimated rates for reasons which include the following:

- actual weather conditions experienced during trenching operations;
- actual mechanical breakdowns experienced; and
- production rate estimation inaccuracies, especially where associated with new types of trenching equipment or new applications for existing equipment.

The estimated range of trenching equipment production rates and the resulting effect on the trenching cost based on the program CHUKCHI2 are shown below.

| Risk Factor | Probability of Cost Factor ≤ Indicated Value (Percent) | Pipeline Trenching Production Rate Cost Factor $\left(\frac{\text{Actual Cost}}{\text{Estimated Cost}}\right)$ |
|---|---|---|
| Trenching Production Rate = 150% of Estimated Rate | 10 | 0.78 |
| Trenching Production Rate = Estimated Rate | 50 | 1.00 |
| Trenching Production Rate = 50% of Estimated Rate | 90 | 1.65 |

<u>Trenching Season Durations</u>

The number of weeks each summer when the sea ice conditions will allow trenching equipment to operate varies from year to year. The base case trenching cost estimates assume median year ice conditions, i.e.: there is a 50 percent probability of the actual summer construction season being either longer or shorter than the specified duration.

Information on season duration variability is presented in Study Appendix B for the 6/10 ice concentration criterion. Comparing the season durations at different points in the Chukchi Sea for the median ice year, and the 20 and 80 percent probability ice years allows Drawing No. F-301 and Table 3.1 to be prepared. As indicated, there is a large amount of season duration variability for the areas with relatively short seasons (less than 10 weeks) and much less variability in areas with longer summer seasons (more than 15 weeks). Table 3.1 is assumed to also characterize the season duration variability for other Chukchi Sea ice conditions (Ice Conditions A, B and C).

Plotting the median year, 20 and 80 percent probability season durations on normal (Gaussian) probability paper and fitting with straight line segments can be used to approximate the cumulative probability distribution. As an example, Drawing No. 302 shows this distribution for a single year based on a 10 week median season duration.

Offshore pipeline trenching operations for transportation Scenarios 1B and 3B are scheduled over multiple summer seasons. This will reduce the impact of construction season duration variability because of the relatively low probability of having two or more successive years with bad summer construction seasons. Drawing No. F-302 also shows the cumulative probability distributions for two and three years based on the same 10 week median season duration.

If longer than normal summer seasons are experienced during pipeline construction, the trenching could be completed ahead of schedule with some associated cost savings possible. If unusually severe ice conditions are encountered, trenching costs may increase significantly. The amount of this increase is in part dependent on the amount of increased resources applied to keep the project on schedule. Some pipeline construction schedule delays may be acceptable if the severe ice conditions also delay the production structure installation.

Response options in the event of shorter than normal summer seasons include: adding additional ice management vessels to extend the working season, using the existing trenching equipment for additional years, and/or mobilizing additional trenching spreads. The cost impact will depend on the trenching method employed and equipment availability.

The construction season duration risk effects for pipeline trenching cost are estimated by adjusting the season durations in the CHUKCHI2 computer program. The estimated range of trenching cost for Scenario 1B and Ice Condition A is shown below based on a 3 summer season trenching program:

| Risk Factor | Probability of Cost Factor ≤ Indicated Value (Percent) | Pipeline Trenching Season Cost Factor $\left(\frac{\text{Actual Cost}}{\text{Estimated Cost}}\right)$ |
|---|---|---|
| Longer Than Normal Construction Seasons (12 weeks) | 20 | 0.91 |
| Median Year Construction Seasons (10 weeks) | 50 | 1.00 |
| Shorter Than Normal Construction Seasons (7 weeks) | 80 | 1.19 |

<u>Other Trenching Cost Factors</u>

Uncertainty also exists in the estimated trenching equipment costs for construction/modification, operation and for support spread operation. Trenching equipment and support spread day rates used in the pipeline cost estimates are based on sufficient worldwide fleet utilization to justify new vessel construction. The rates are therefore higher than day rates prevailing under the currently depressed offshore construction market conditions.

The overall offshore pipeline trenching cost variability due to the combined effects of the risk factors described in this section is estimated to be as follows:

| Probability of Cost Factor < Indicated Value (Percent) | Pipeline Trenching Cost Factor $\left(\frac{\text{Actual Cost}}{\text{Estimated Cost}}\right)$ |
|---|---|
| 10 | 0.50 |
| 50 | 1.00 |
| 90 | 2.00 |

### 3.2.3 Pipeline Installation Cost

Important risk factors in defining the offshore pipeline installation cost include installation equipment productivity, construction season durations during pipeline installation and other estimating uncertainties. Factors are discussed separately in the following paragraphs and then combined for an overall pipeline installation cost probability distribution. The effect of fully insulating the pipelines is addressed in Section 3.2.6.

#### Pipeline Installation Productivity

Pipeline installation rates for the different methods considered are estimated based on the pipe diameter and approximate mechanical and weather downtime factors. There is extensive worldwide experience in the use of conventional and third generation laybarges and bottom pull methods but their arctic application experience is limited. There are also significant uncertainties in the actual production rates obtainable with newer methods such as the arctic laybarge concept and through-ice laying. The effects of sea ice on laybarge operations could cause significant variations in the installation rates. Rapid ice movements are expected to reduce laybarge productivities.

The estimated variability of pipeline installation productivity is shown below along with the effects on installation cost computed using CHUKCHI2 for Scenario 1B.

| Risk Factor | Probability of Cost Factor ≤ Indicated Value (Percent) | Pipeline Installation Production Rate Cost Factor $\left(\frac{\text{Actual Cost}}{\text{Estimated Cost}}\right)$ |
|---|---|---|
| Installation Production Rate = 125% of Estimated Rate | 10 | 0.95 |
| Installation Production Rate = Estimated Rate | 50 | 1.00 |
| Installation Production Rate = 60% of Estimated Rate | 90 | 1.62 |

Installation Season Durations

The effects of variations in the summer construction season duration during the years when the pipeline is to be installed will be similar to those described for trenching. The estimated probability distribution for installation cost variations is shown in the following table for Scenario 1B.

| Risk Factor | Probability of Cost Factor ≤ Indicated Value (Percent) | Pipeline Installation Season Cost Factor $\left(\frac{\text{Actual Cost}}{\text{Estimated Cost}}\right)$ |
|---|---|---|
| Longer Than Normal Construction Seasons (12 weeks) | 20 | 1.00 |
| Median Year Construction Seasons (10 weeks) | 50 | 1.00 |
| Shorter Than Normal Construction Seasons (7 weeks) | 80 | 1.44 |

Other Installation Cost Factors

Offshore pipeline installation costs can also vary to a lesser extent due to the uncertainties listed below:

- Structure tie-in and shore crossing. These costs may vary significantly, but their effect is limited because they represent only a small portion of the total installation cost.

- Estimating inaccuracies for the installation equipment operating costs and support spread costs will contribute to uncertainty in the pipeline installation costs. (Vessel day rates used in the cost estimates are generally based on a high utilization of the worldwide fleet and not the presently depressed market conditions.)

- Variability in pipeline survey, testing and start-up costs is assumed to contribute to pipeline installation cost variability.

The overall offshore pipeline installation cost variability resulting from pipeline design uncertainties, equipment productivity, season duration variations and other risk sources described in this section is estimated to be as follows:

| Probability of Cost Factor ≤ Indicated Value (Percent) | Pipeline Installation Cost Factor $\left(\frac{\text{Actual Cost}}{\text{Estimated Cost}}\right)$ |
|---|---|
| 10 | 0.75 |
| 50 | 1.00 |
| 90 | 1.75 |

### 3.2.4 Pump Station Cost

Offshore pipeline pump stations for transportation Scenarios 1B and 3B will be located on the offshore production structure. Cost estimates were computed on a dollar per pump horsepower basis and the variability of these costs is judged to be as follows:

| Probability of Cost Factor ≤ Indicated Value (Percent) | Pipeline Pump Station Cost Factor $\left(\frac{\text{Actual Cost}}{\text{Estimated Cost}}\right)$ |
|---|---|
| 10 | 0.50 |
| 50 | 1.00 |
| 90 | 2.00 |

### 3.2.5 Pipeline Project Services Cost

Costs for offshore pipeline project services are estimated to be 15 percent of the subtotal of all other offshore pipeline costs. Project services costs are assumed to vary as a direct function of other project costs.

### 3.2.6 Pipeline Trench Depths and Thermal Insulation

If the offshore pipeline requires deeper trenching or requires insulation over its full length, the construction cost will increase significantly. Because of the importance of these two factors and the difficulty in estimating a probability for either requirement, they are addressed separately in this section as major design requirements. If either is found necessary during further design work, offshore pipeline construction costs will increase by the amounts presented in this section.

#### Thermal Insulation

Without thermal insulation, oil flowing in the offshore pipeline will cool to a temperature slightly warmer than the surrounding seawater.

While this is adequate for the assumed base case offshore pipeline design conditions, it may be desirable to insulate the offshore pipeline so that the oil reaches the shoreline at a higher temperature (as may be required for subsequent overland pipeline transportation or due to a high crude oil wax content). The offshore pipelines are assumed to be insulated in water depths less than 20 feet but this requirement may also be increased if the route survey shows that additional thaw-sensitive subsea permafrost exists.

The effects of fully insulating the Scenario 1B offshore pipeline are computed using the program CHUKCHI2 as shown below (Study Report Table 6.13):

- Non-insulated capital cost = $\$785 \times 10^6$
- Fully insulated capital cost = $\$1,009 \times 10^6$

If the offshore pipeline is actually installed fully insulated, the capital cost would be increased from the estimated cost (non-insulated) by the following cost factor:

$$\text{Pipeline insulation cost factor} = 1.29 \quad \left(\frac{\text{actual cost}}{\text{estimated cost}}\right)$$

Trench Depth and Soil Type

Pipeline trench depth required to limit the risk of ice keel damage is one of the most important factors in the pipeline design process. Three different trench depth calculation methods which predict widely varying trench depths are described in Chapter 6 of the study report. The recommended calculation procedure is incorporated into the CHUKCHI2 cost estimating program. Required input for the calculation procedure includes the desired risk of ice keel-pipeline contact and the seabed soil conditions.

The available soil data for the Chukchi Sea indicate that 0 to 10 feet of loose soil typically overlay a hard soil layer. The base case assumption of a 6 foot loose soil layer is considered conservative and adequate to account for local variations in the thickness of this layer. There is, however, a possibility that the loose soil layer is thicker or that the hard soil will not provide the expected ice gouge protection, thus requiring deeper trenching.

If the hard soil layer is not present, then the recommended pipeline depth of cover will be increased, varying along the pipeline route from 8 to 13 feet for Scenario 1B. Variations in the required depth of cover, which will be calculated after site-specific ice gouge data are gathered and analyzed, can be modelled by adjusting the risk of ice keel contact input into the computer program. Increasing or decreasing by a factor of ten the risk of contact in 10 years from the 1 percent base case value results in maximum pipeline depths of cover ranging from 10 to 16 feet.

The effects of different trenching requirements on the total offshore pipeline construction cost are computed for Scenario 1B using CHUKCHI2 as shown below.

The trenching equipment considered in each case is selected as optimal for the specific trenching requirements.

| Trenching Requirements | Pipeline Capital Cost |
|---|---|
| Soft soil layer over hard soil, depth of cover = 2 feet below top of hard soil (cost estimate basis) | = $ 785 x $10^6$ |
| Hard soil not present, maximum depth of cover = 10 feet | = $1,340 x $10^6$ |
| Hard soil not present, maximum depth of cover = 13 feet | = $1,530 x $10^6$ |
| Hard soil not present, maximum depth of cover = 16 feet | = $1,660 x $10^6$ |

In summary, the total offshore pipeline capital cost could more than double if both the soil conditions and trenching requirements are found to be more severe than estimated. This can be expressed in terms of a cost factor as follows:

$$\text{pipeline trenching requirement cost factor} \cong 2.0 \left(\frac{\text{actual cost}}{\text{estimated cost}}\right)$$

## 3.3 ICEBREAKING TANKERS

Transportation Scenarios 2A and 3B employ icebreaking tanker fleets operated in conjunction with the crude oil storage facilities at the loading and trans-shipment terminals. The computer program CHUKCHI1 is used to evaluate specific tanker and terminal storage requirements and to estimate facility costs.

Icebreaking tanker cost risk sources are presented in this section independent of the trade-offs which exist between tanker and terminal costs. If future design work reveals major cost differences for either the tankers or terminals, then the optimal tanker/terminal facilities combination might also change. For example, if estimated tanker costs were to greatly increase during the detail design stage, additional crude oil storage could be justified and fewer tankers would be needed. This type of mitigating response to tanker and terminal cost risks is judged to be of secondary importance and is not reflected in the tanker/terminal cost variabilities.

Tanker fleet capital cost risk sources are grouped and described in the following three categories:

- Number and size of tankers;
- Tanker design details; and
- Construction cost variations.

A cost factor probability distribution is estimated for each of these categories.

### 3.3.1 Number and Size of Tankers

The required number and deadweight tonnage of the icebreaking tanker fleet will be determined based on the performance of individual vessels. If they perform better than expected, then fewer or smaller tankers are required, and the capital costs will be reduced (provided the tankers have not already been built). If performance is below expectations, additional tankers may have to be constructed.

Major areas of uncertainty which can influence vessel performance and the required number of tankers are:

- sea ice conditions;
- vessel transit speed; and
- delays in transit.

Tanker performance is also influenced by vessel design details and the fleet support systems employed. These uncertainties and their influences on tanker fleet costs are considered separately in Section 3.3.2.

Sea Ice Conditions

The sea ice conditions which icebreaking tankers encounter during actual operations may be different than those simulated in the transit analysis. The Chukchi Sea ice report prepared by DF Dickens as part of the Joint Industry Study is a comprehensive summary of publicly available ice data. There are, however, limitations on both the amount of data available and the manner in which it is reported by the government agencies. Ground truthing is needed to reduce some of the uncertainty for critical data such as multi-year ice concentrations.

Icebreaking tanker performance is influenced by the sea ice concentrations and the availability of open water. The sensitivity to varying ice concentrations is indicated by the decreasing tanker transit speeds in the more northerly ice zones and during winter months (Table 4.6 in the Transportation Study report).

Available data on pressure ridge height, frequency, spacing and keel depth to sail height ratio are limited. Actual ridge statistics experienced by the tankers may vary from those applied in the transmit simulation. Reported ice data are also suspected of over-estimating the amount of multi-year ice present by including weaker, second-year ice features in the estimates.

Uncertainty also exists in how sea ice conditions vary from year to year. Ice data used as input for the tanker transit simulation conservatively assumed worst year (approximately 10-year average return period) ice conditions in all ice zones and all months of a single year. Assumptions are made in the transmit simulation on the relative proportion of thin and thick first year ice, pressure ridge distributions, and the ability to avoid essentially all multi-year ice features. As a result, the estimated worst year transit speeds remained within 10 percent of the mean year transit speeds for two-thirds of the ice zones and months analyzed (see Table 4.6 of study report). This simulation result may not be as conservative as assumed.

Tanker Transit Speed

Actual tanker transit speeds may vary from the calculated values due to uncertainties in the transit simulation procedures. These variations are independent of the accuracy in specifying the sea ice conditions and relate to transit simulation uncertainties.

The transit speed calculations presented in the study report are based on worldwide arctic shipping experience. Because of the large percentage of the time icebreaking tankers will spend in transit, variations in the transit speed will have a major impact on the required number and size of tankers. Areas in which there is uncertainty in the calculated transit speeds are described in the following paragraphs.

Data analysis indicates that open water or thin ice flaw leads are present year-round throughout the Chukchi Sea. Calculated transit speeds are based on not following these leads except along the coast in Ice Zone 5. The tanker's ability to exploit these leads will depend on its ability to identify them using its ice surveillance systems and then negotiate through the leads given the vessel's size, speed and minimum turning radius. If the vessel speed increase in the leads is adequate to offset the increased distance travelled to follow the leads, the overall transit speed may be increased.

Calculated tanker transit speeds are based on avoiding all multi-year ice features and avoiding all sea ice if the total ice concentration is less than 6/10. If this is found to be impractical during actual operation or if the tanker must deviate significantly from a straight line route to avoid ice features, then the overall transit speed will be reduced.

More detailed transit speed analysis, model studies and prototype icebreaking tanker testing may also reveal variations from the calculated vessel transit speeds.

Tanker Transit Delays

There are risks of tanker transit delays due to severe storms, ice pressure and unscheduled repairs. These risks are partially accounted for in the tanker evaluation by establishing a minimum of two tankers for any transportation scenario. Delays due to pressured ice are addressed in the study report and are considered in establishing the terminal crude oil storage requirements. Year-round surface vessel rescue capability is provided by the icebreaker assigned to the tanker loading terminal if tanker assistance is required.

Tanker Number and Tonnage Variability

The tanker fleet for transportation Scenario 2A (400 MBPD between central Chukchi Sea and Unimak Pass) consists of five 150,000 dwt tankers. Alternatively, eight 100,000 dwt or four 200,000 dwt icebreaking tankers could be used with an estimated tanker fleet capital cost differential of plus 34 percent or minus 10 percent, respectively.

The transportation scenario evaluation requirement to round the number of tankers upward to the nearest integer number can, in this case, cause rounding off errors of up to approximately 25 percent. This can be overcome in the field development preliminary design stage by adjusting the tanker size or by making compensating adjustments in the terminal crude oil storage volume.

Tanker average transit speed variations of plus or minus 25 percent will result in 150,000 dwt tanker fleet requirements of 4 or 7 tankers (minus 20 percent or plus 40 percent from the base case value of 5 tankers).

The overall variability of the icebreaking tanker fleet capital costs associated with all tanker number and size uncertainties described in this section is estimated to be as follows:

| Probability of Cost Factor ≤ Indicated Value (Percent) | Tanker Number and Size Cost Factor $\left(\frac{\text{Actual Cost}}{\text{Estimated Cost}}\right)$ |
|---|---|
| 10 | 0.70 |
| 50 | 1.00 |
| 90 | 1.30 |

### 3.3.2 Tanker Design Details

In addition to tanker fleet cost variations resulting from uncertainty in their general performance, the tanker and support system design can also influence the costs. The icebreaking tanker designs presented in the study report are based on existing technology and proven design features. The designs are, however, not necessarily state-of-the-art and have not been optimized.

Tanker design features which may either increase or decrease the actual vessel capital costs include the following:

- propulsion system design;
- hull shape;
- tanker draft;
- structural design;
- possible use of nonsegregated ballast tanks;
- special requirements for safety, pollution prevention and control systems; and
- ice surveillance system costs.

The overall icebreaking tanker fleet design details are estimated to contribute to the capital cost uncertainty as follows:

| Probability of Cost Factor $\leq$ Indicated Value (Percent) | Tanker Fleet Design Details Cost Factor $\left(\frac{\text{Actual Cost}}{\text{Estimated Cost}}\right)$ |
|---|---|
| 10 | 0.75 |
| 50 | 1.00 |
| 90 | 1.25 |

### 3.3.3 Construction Cost Variations

With a given number of tankers and a well defined vessel design, actual icebreaking tanker construction costs can further vary from the estimated costs due to estimating inaccuracies. This type of variation is indicated by the varied cost estimates prepared by the U.S. shipyards based on specified vessel steel weights, engine horsepower and principal dimensions. Of the three U.S. shipyards providing cost information, the standard deviation of their estimates is approximately 15 percent of the mean value used in the scenario evaluations. This corresponds to the following probability distribution for costs:

| Probability of Cost Factor ≤ Indicated Value (Percent) | Tanker Shipyard Construction Cost Factor $\left(\frac{\text{Actual Cost}}{\text{Estimated Cost}}\right)$ |
|---|---|
| 16 | 0.85 |
| 50 | 1.00 |
| 84 | 1.15 |

## Foreign Tanker Construction

If present regulations prohibiting the use of foreign-built tankers to transport crude oil out of the Lease Sale 109 area are changed, significant tanker construction cost savings may be realized. Foreign tanker construction costs are approximately 40 to 45 percent less than U.S. construction costs.

Efforts to repeal the "Jones Act" or to allow export of Chukchi Sea crude oil in foreign flag tankers are expected to encounter considerable political opposition. Therefore, the probability of using foreign constructed tankers is considered to be low.

## Other Construction Cost Variations

Additional factors contributing to uncertainty in the tanker construction costs include:

- shipbuilding market conditions;
- number of tankers constructed and the ability to spread out the development costs;
- tanker construction schedule;
- extent to which foreign materials and machinery are permitted to be used; and
- inclusion of a cost contingency factor for changes during and after construction.

The overall variability of icebreaking tanker construction costs due to shipyard location, market conditions and other estimating inaccuracies is estimated to be as follows:

| Probability of Cost Factor ≤ Indicated Value (Percent) | Tanker Construction Cost Factor $\left(\frac{\text{Actual Cost}}{\text{Estimated Cost}}\right)$ |
|---|---|
| 10 | 0.70 |
| 50 | 1.00 |
| 90 | 1.30 |

## 3.4 TANKER TERMINALS

Transportation Scenario 2A considers loading icebreaking tankers at an offshore terminal located at the central Chukchi Sea site. In Scenario 3B, tankers are loaded at a nearshore terminal located near Kivalina. Uncertainties in terminal design and construction create risks of the actual installed terminal costs being different from the estimated costs.

Tanker terminal capital cost risks are addressed separately for the offshore and nearshore locations. Risk sources are grouped into the following two categories:

- terminal concept and design; and
- terminal construction.

The required terminal crude oil storage volume is calculated based on maintaining the desired throughput efficiency for the overall tanker/terminal transportation system. Providing additional storage will reduce production shut-ins due to tanker arrival delays or loading interruptions. There is uncertainty in the optimal terminal storage volume and this causes uncertainty in the terminal cost. This source of uncertainty must be quantified in an overall field development risk analysis. The terminal storage volumes and production shut-in estimates calculated using CHUKCHI1 are assumed for the present risk analysis.

Terminal capital costs used in the transportation system evaluation (program CHUKCHI1) are based on even increments of 2 million barrels of crude oil storage. Round-off errors in determining the cost for terminals with intermediate storage volumes are not included in the present risk analysis.

### 3.4.1 Offshore Terminal

#### Offshore Terminal Concept and Design

Major areas of uncertainty in the offshore terminal concept and design which are described in the following paragraphs include:

- terminal concept selection;
- terminal design details;

- structure foundation conditions; and
- terminal support vessel requirements.

Offshore tanker loading terminal design concepts and structure types are selected in the Chukchi Sea study using a decision analysis procedure. This procedure is used because the individual concepts are presently not developed in sufficient detail to allow a definitive selection to be made on the basis of cost or other criteria. As a result, there is uncertainty in which terminal design and structure types will actually be selected for detailed design and construction.

The maximum differential in assigned numerical ratings between the first and second choices in the concept evaluation summary (Table 5.5 in the Transportation Study report) is 16 percent. At many of the decision analysis nodes, some of the terminal concepts are indicated to be clearly undesirable for reasons stated in the Chapter 5 text. In other cases the decision analysis results are more subjective. An example of this is the decision to install a separate loading structure versus a combined production/storage/loading structure.

Loading the tankers from a production/storage/loading structure would eliminate the separate loading structure and interconnecting pipeline costs for the offshore terminal. The overall cost reduction is estimated to be approximately $220 million or 17 percent of the direct terminal construction cost.

The selected structure concept for the production/

storage structure is a bottom-founded monolithic gravity structure. This structure type is well suited to the large crude oil storage volumes and the high ice loads anticipated.

Uncertainty in the preferred concept for the separate tanker loading structure relates to its ability to efficiently moor and load tankers. Further design work and operating experience may dictate changes due to ice rubble field formation, ice loads on moored tankers or other factors.

Once the structure concept is established, further design changes may result from uncertainties in design criteria, foundation conditions, support system requirements and other structural design details. Ice loads are the most important environmental design criterion. Variations from the values assumed for preliminary design purposes are expected to affect the offshore terminal structure capital cost by approximately 10 percent.

Offshore terminal costs could increase significantly if poor structure foundation conditions are encountered. If a weak surficial soil layer is encountered, a subcut and backfill may be required to support the gravity structures. Considering that only 0.6 percent of the base case offshore terminal cost is for foundation preparation, foundation costs could increase to 5 to 10 percent of the total structure cost if significant amounts of dredging are required.

Approximately 80 percent of the estimated offshore terminal direct construction cost is for the fabricated steel and concrete materials (Transportation Study report Table 5.14). Structural material quantities and properties are estimated based on a preliminary structure design and may vary during the detail design. The estimated variability, independent of the structure concept selection process, follows:

| Probability of Cost Factor $\leq$ Indicated Value (Percent) | Offshore Terminal Structure Materials Quantities Cost Factor $\left(\frac{\text{Actual Cost}}{\text{Estimated Cost}}\right)$ |
|---|---|
| 10 | 0.70 |
| 50 | 1.00 |
| 90 | 1.30 |

Terminal facilities and equipment costs are estimated to be 2.3 percent of the terminal construction cost. Included are the tanker mooring system, crude oil loading system, structure ballast water system, accommodations and all safety and control systems. Detail evaluation of these types of system requirements will frequently identify features overlooked in a preliminary cost estimate. Therefore, these costs are more likely to increase from the estimated values than decrease.

One icebreaking terminal support vessel is estimated to be required per tanker loading berth. There is a risk that the actual number of icebreakers required to assist in tanker mooring or to otherwise support terminal operations will be different. This risk is estimated to be as follows:

| Risk Factor | Probability of Cost Factor = Indicated Value (Percent) | Offshore Terminal Icebreaker Cost Factor $\left(\frac{\text{Actual Cost}}{\text{Estimated Cost}}\right)$ |
|---|---|---|
| Zero Icebreakers Required | 20 | 0.88 |
| 1 Icebreaker Required | 40 | 1.00 |
| 2 Icebreakers Required | 40 | 1.12 |

The overall offshore terminal capital cost variability due to uncertainties in the terminal concept and design is estimated to be as follows:

| Probability of Cost Factor ≤ Indicated Value (Percent) | Offshore Terminal Concept and Design Cost Factor $\left(\frac{\text{Actual Cost}}{\text{Estimated Cost}}\right)$ |
|---|---|
| 10 | 0.60 |
| 50 | 1.00 |
| 90 | 1.50 |

<u>Offshore Terminal Construction</u>

Variations in the actual offshore terminal capital cost can also result from uncertainties and risks during its fabrication, towing to site and installation. These uncertainties are addressed in the following paragraphs independently from the uncertainties leading to the terminal detail design.

Unit costs for fabricated steel and concrete were obtained from eight U.S. and foreign contractors (Transportation Study report Table 5.13). An indication of the uncertainty in the actual fabrication yard costs will be is given by variations in the quoted costs. Of the five Far East contractors providing cost information, the standard deviation of quoted reinforced concrete cost is 46 percent of the mean unit cost. The standard deviation for the fabricated steel cost is 18 percent of the mean.

The concrete and steel costs make up approximately 80 percent and 20 percent, respectively, of the total structure cost. This suggests an overall structure materials cost variability as follows:

| Probability of Cost Factor $\leq$ Indicated Value (Percent) | Offshore Terminal Structure Materials Cost Factor $\left(\frac{\text{Actual Cost}}{\text{Estimated Cost}}\right)$ |
|---|---|
| 16 | 0.60 |
| 50 | 1.00 |
| 84 | 1.40 |

Variations between high and low bids would normally be expected and the contract would generally be given to the lowest bidder. Additional uncertainties, however, will also result from variations in the prevailing market conditions and the terminal construction schedule.

The offshore terminal construction cost used in the scenario evaluations is based on U.S. fabrication. Far East fabrication costs are about 40 percent lower. Because of their experience in building similar structures, Far East contractors are also expected to have lower risk levels for fabrication site permitting problems, construction schedule delays and cost over-runs than U.S. contractors. The probability of using a Far East contractor is judged to be about 50 percent.

The cost for field construction activities to install the offshore terminal structures is 13 percent of the total direct construction cost. These costs are highly variable due to estimating uncertainties and variations in the construction season duration. Sand fill for the structures and foundation berm is assumed to be available at the terminal site. If it must be brought to the site, the costs would be significantly higher.

The mean summer season duration for less than 3/10 ice concentration is 7.5 weeks at the central Chukchi Sea site. One year out of five, however, this construction season is one week long or less. If this occurs during one of the two summers when structures are to be installed, additional construction equipment and icebreaker support would be required to install the structure without a schedule delay of one year. The cost for this additional equipment or for using it an additional year could more than double the estimated installation cost.

The estimated cost for the pipeline connecting the offshore terminal production/storage structure and tanker loading structures is 6 percent of the terminal construction cost. The variability of this cost component is estimated based on Section 3.2 to be as follows:

| Probability of Cost Factor ≤ Indicated Value (Percent) | Offshore Terminal Pipeline Construction Cost Factor $\left(\frac{\text{Actual Cost}}{\text{Estimated Cost}}\right)$ |
|---|---|
| 10 | 0.80 |
| 50 | 1.00 |
| 90 | 1.55 |

The overall offshore terminal capital cost variability due to uncertainties in the terminal construction cost is estimated to be as follows:

| Probability of Cost Factor ≤ Indicated Value (Percent) | Offshore Terminal Construction Cost Factor $\left(\frac{\text{Actual Cost}}{\text{Estimated Cost}}\right)$ |
|---|---|
| 10 | 0.50 |
| 50 | 1.00 |
| 90 | 1.50 |

### 3.4.2 Nearshore Terminal

Nearshore Terminal Concept and Design

There are fewer uncertainties in the terminal concept selection and design for the nearshore terminal at Kivalina. The site is further away from the polar pack ice and not subject to high concentrations of multi-year ice. Crude oil storage facilities and terminal support systems can be built onshore using conventional arctic design technology.

There are generally fewer terminal concept options available for the nearshore terminal than for the offshore terminal and therefore the terminal concept uncertainty is considered to be less. Remaining terminal concept options include selecting the location of the crude oil storage facilities and the tanker loading structure. The selected nearshore terminal concept uses an onshore tank farm.

The nearshore tanker loading structure concept of a bottom-founded monolithic SPM is considered to be well suited for the less severe winter ice conditions at Kivalina. If poor foundation conditions are found for the structure, foundation preparation costs will increase. The nearshore terminal location could alternatively be moved to a more favorable site along the coast.

The nearshore terminal loading structure fabrication cost makes up 50 percent of the total direct construction cost (Transportation Study report Table 5.17). The variability in the structure materials quantities due to design uncertainties is assumed to be the same as for the structures at the central site.

The onshore crude oil storage facility is designed as a conventional tank farm. Major design uncertainties for the storage tanks relate to their operation in the arctic environment. If crude oil must be stored for extended periods during tanker loading interruptions, the tanks may require thermal insulation and/or heating systems. Insulation would increase the tank construction cost by 10 percent. If thaw sensitive permafrost is present at the tank farm site, the tank foundation costs may be significantly increased.

One class 6 icebreaking terminal support vessel is assumed to be used at the nearshore terminal. It costs less than the class 8 icebreaker for the offshore terminal, but still represents 26 percent of the total terminal capital cost. If the number of icebreakers changes as discussed for the offshore terminal, the terminal cost would change accordingly.

The overall nearshore terminal capital cost variability due to uncertainties in the terminal concept and design is estimated as follows:

| Probability of Cost Factor ≤ Indicated Value (Percent) | Nearshore Terminal Concept and Design Cost Factor $\left(\frac{\text{Actual Cost}}{\text{Estimated Cost}}\right)$ |
|---|---|
| 10 | 0.70 |
| 50 | 1.00 |
| 90 | 1.40 |

<u>Nearshore Terminal Construction</u>

The nearshore terminal capital cost can also vary due to cost estimating uncertainties and risks during construction. These uncertainties are assumed to be independent of the design uncertainties addressed in the preceding paragraphs.

The variability of fabricated steel and concrete costs for the tanker loading structure is assumed to be the same as described for the offshore terminal.

The mean summer open water construction season duration at Kivalina is 20 weeks, based on the 3/10 ice concentration criterion. Year to year variability in season duration is small, as indicated by the data presented in Section 3.2.2. The worst year out of 5 years will have a summer season duration of 18 weeks and this is not expected to significantly affect estimated offshore construction costs.

Onshore facilities and construction make up approximately 30 percent of the nearshore terminal direct construction cost. Cost estimating uncertainties for these facilities are relatively high, especially for the civil works such as site preparation, containment berm, foundations, roads and utilities. These costs are dependent on site specific conditions and their variability is estimated to be as follows:

| Probability of Cost Factor $\leq$ Indicated Value (Percent) | Nearshore Terminal Onshore Facility Cost Factor $\left(\frac{\text{Actual Cost}}{\text{Estimated Cost}}\right)$ |
|---|---|
| 10 | 0.70 |
| 50 | 1.00 |
| 90 | 1.50 |

The cost estimating uncertainty for the pipeline between the tank farm and tanker loading structure is assumed to be the same as stated for the offshore terminal.

The costs of land acquisition, permitting and environmental protection measures for the onshore facilities are uncertain. These costs are not separately addressed for the nearshore terminals in the base case cost estimates and are not included in the present risk analysis.

The overall nearshore terminal capital cost variability due to uncertainties in the terminal construction cost is estimated to be as follows:

| Probability of Cost Factor $\leq$ Indicated Value (Percent) | Nearshore Terminal Construction Cost Factor $\left(\frac{\text{Actual Cost}}{\text{Estimated Cost}}\right)$ |
|---|---|
| 10 | 0.70 |
| 50 | 1.00 |
| 90 | 1.50 |

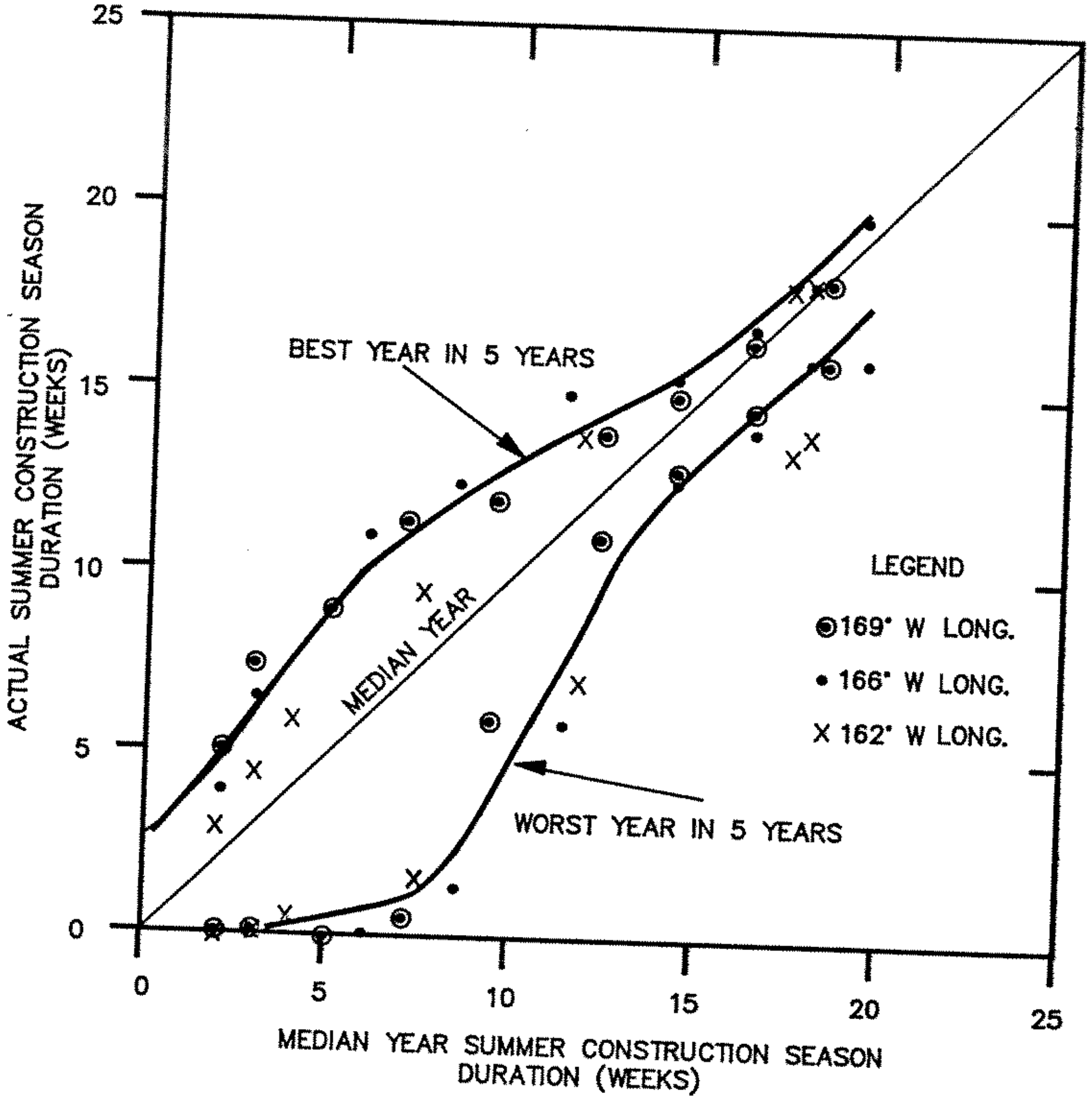
## TABLE 3.1
## SINGLE YEAR SUMMER CONSTRUCTION SEASON DURATIONS

| MEDIAN YEAR DURATION (Weeks) | WORST YEAR IN 5 YEARS (20% PROBABILITY SEASON DURATION ≤) (Weeks) | BEST YEAR IN 5 YEARS (80% PROBABILITY SEASON DURATION ≤) (Weeks) |
|---|---|---|
| 5 | 0 | 9 |
| 10 | 5 | 13 |
| 15 | 13 | 16 |
| 20 | 18 | 21 |

NOTES:

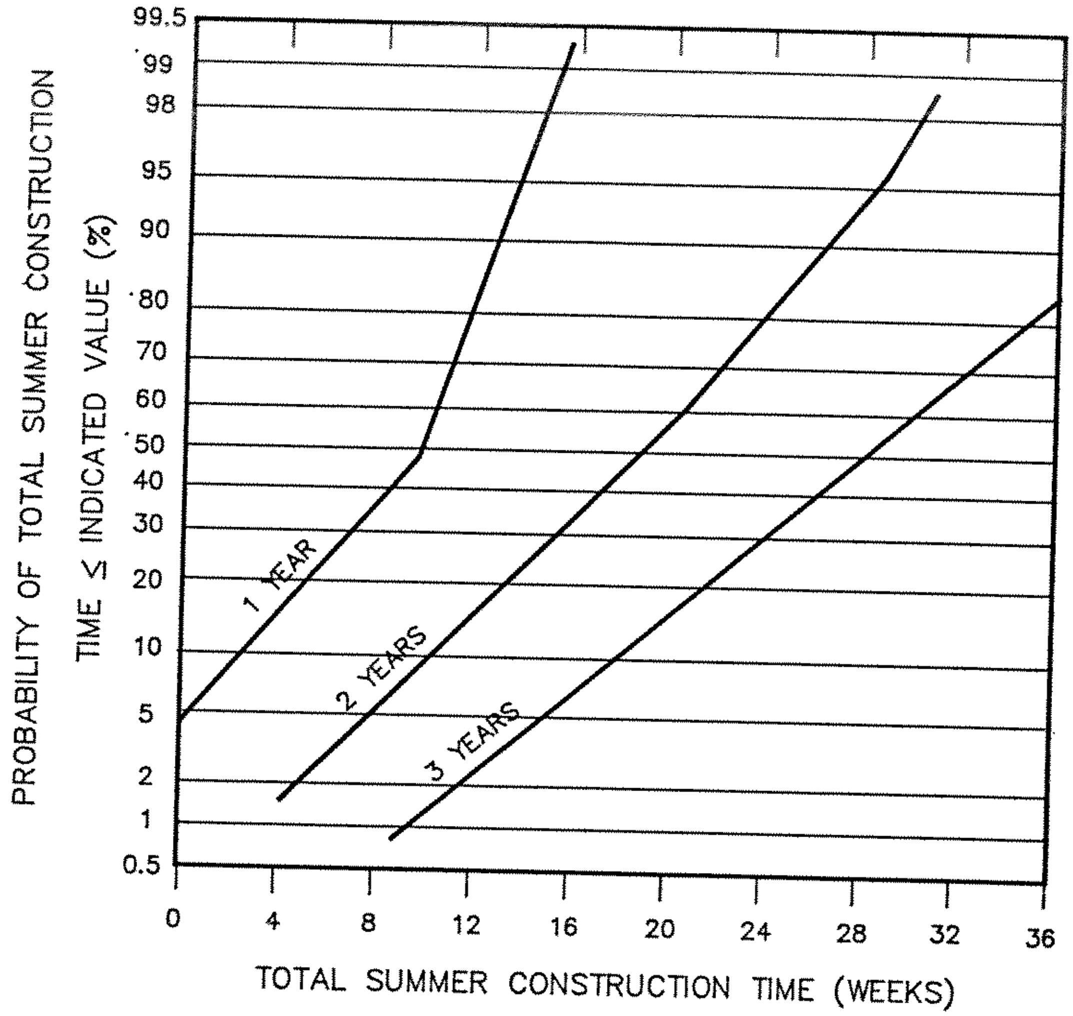
(1) Worst and best year season durations are based on data reduction from DF Dickens' Figures 12, 14 and 15, and are approximate.

(2) Example application: If the duration of a single summer construction season during a median ice year is 10 weeks, one year out of 5 years the summer season will be less than or equal to 5 weeks long.




NOTE: BASED ON D.F. DICKENS FIGURES 12,14,&15 FOR 6/10 ICE CONCENTRATION IN LEASE SALE 109 AREA.

| | | | |
|---|---|---|---|
| JOINT INDUSTRY STUDY<br>CHUKCHI SEA TRANSPORTATION | SUMMER CONSTRUCTION SEASON<br>VARIABILITY | | |
| INTEC ENGINEERING, INC. | SCALE NONE | DRAWN BY R. GROBE | DRAWING No. F-301 |
| | DATE 10-24-86 | JOB No. H-046.3 | |




NOTE: BASED ON A MEDIAN YEAR SUMMER CONSTRUCTION SEASON DURATION OF 10 WEEKS.

| | | | |
|---|---|---|---|
| JOINT INDUSTRY STUDY<br>CHUKCHI SEA TRANSPORTATION | MULTIPLE YEAR SUMMER CONSTRUCTION SEASON DURATIONS | | |
| INTEC ENGINEERING, INC. | SCALE NONE<br>DATE 10-23-86 | DRAWN BY R. GROBE<br>JOB No. H-046.3 | DRAWING No. F-302 |

# APPENDIX F - RISK ASSESSMENT

## CHAPTER 4

## CRUDE OIL TRANSPORTATION COST VARIABILITY

# CHAPTER 4
# CRUDE OIL TRANSPORTATION COST VARIABILITY

## 4.1 OFFSHORE PIPELINE RISK

Offshore pipeline capital cost risks are described and quantified in Section 3.2. Results are expressed in terms of cost factor probability distributions for the major cost components. Their relative contributions to the total offshore pipeline capital cost are summarized below based on Scenario 1B (pipeline to Wainwright).

| Cost Item | Percentage of Offshore Pipeline Capital Cost |
|---|---|
| Materials and Materials Logistics | 21.5 |
| Trenching | 37.9 |
| Installation | 24.6 |
| Pump Stations | 3.0 |
| Subtotal | 87.0 |
| Project Services (15%) | 13.0 |
| Total | 100.0 |

Project services costs are assumed to be variable but remain 15 percent of the subtotal for other costs. The separate cost item for contingencies is omitted because the effects of uncertainties are now being calculated in the risk analysis.

Adding the probability distributions for the individual cost items yields the total offshore pipeline capital cost probability distribution shown on Drawing No. F-401. The results are plotted in the form of the cumulative probability density function of the cost factor (actual pipeline cost/estimated pipeline cost). These results exclude possible cost increases due to fully insulating the pipelines or increased trenching requirements.

Review of Drawing No. F-401 indicates a 35 percent probability of the actual offshore pipeline installed cost being less than or equal to the estimated cost (cost factor = 1.0; contingency factor = 0 percent). With the 25 percent contingency factor applied in the transportation system evaluations (cost factor = 1.25), there is a 70 percent chance that the actual costs will not exceed the values used. In order to be 90 percent certain that the pipeline capital cost is not exceeded, a contingency factor of 55 percent should be applied. The expected cost, defined as the first moment of the cost probability distribution, is 13 percent greater than the estimated cost.

Offshore pipeline capital costs made up 10.2 percent of the total crude oil transportation cost for Scenario 1B (pipeline to Wainwright). Increasing the offshore pipeline capital cost contingency factor from 25 percent to 55 percent would raise the total transportation cost by 2 percent.

For Scenario 3B (pipeline to Kivalina and tankers to Unimak Pass), offshore pipeline capital costs made up 11.7 percent of the total transportation cost. Increasing the contingency factor from 25 percent to 55 percent would raise the total transportation cost by 3 percent.

## 4.2 ICEBREAKING TANKER RISK

Icebreaking tanker fleet cost probability distributions are developed in Section 3.3 for:

- number and size of tankers;
- tanker design details; and
- construction cost variations.

The total tanker fleet capital cost probability distribution is determined by multiplying the individual cost factor distributions. The resulting tanker fleet cost factor distribution is shown on Drawing No. F-402. The irregularities in the curve result from the numerical risk combination procedure.

Review of Drawing No. F-402 indicates a 50 percent probability of the actual tanker fleet cost being less than or equal to the estimated cost. Because no tanker cost contingency factor was applied in the transportation system evaluations, there is also a 50 percent chance that the actual costs will not exceed the values used. To obtain a 90 percent chance of the actual tanker fleet cost being less than the cost used in the scenario evaluations, a contingency factor of 50 percent must be applied. The expected tanker fleet cost equals the estimated cost.

The tanker fleet capital cost made up 23.4 percent of the crude oil transportation cost for Scenario 2A (tankers to Unimak Pass). Adding a 50 percent contingency factor on the tanker fleet capital cost to account for risks would increase the total transportation cost by 12 percent.

For Scenario 3B, 22.1 percent of the total transportation cost was for the tanker fleet construction. A 50 percent increase in this cost would raise the total transportation cost by 11 percent.

## 4.3 TANKER LOADING TERMINAL RISK

### 4.3.1 Offshore Loading Terminal

Offshore tanker loading terminal capital cost probability distributions are developed in Section 3.4.1 for terminal concept and design variations and for construction cost variations. The total cost factor probability distribution is determined by multiplying the two cost distributions together as shown on Drawing No. F-403.

There is approximately a 50 percent probability of the actual offshore terminal capital cost being less than or equal to the estimated cost. With the 15 percent contingency factor which was applied in the transportation system evaluation, this probability increases to 60 percent. To obtain a 90 percent chance that the offshore terminal capital cost is not exceeded, a contingency factor of 80 percent should be applied. The expected cost of the offshore terminal is 4 percent greater than the estimated cost.

The offshore tanker loading terminal capital cost at the central Chukchi Sea site made up 29.1 percent of the total crude oil transportation cost for Scenario 2A. Increasing the terminal capital cost contingency factor from 15 percent to 80 percent would increase the total transportation cost by 16 percent.

### 4.3.2 Nearshore Loading Terminal

Nearshore tanker loading terminal capital cost probability distributions are developed in Section 3.4.2 for a loading terminal at Kivalina (Scenario 3B). The total calculated cost factor probability distribution is presented on Drawing No. F-404.

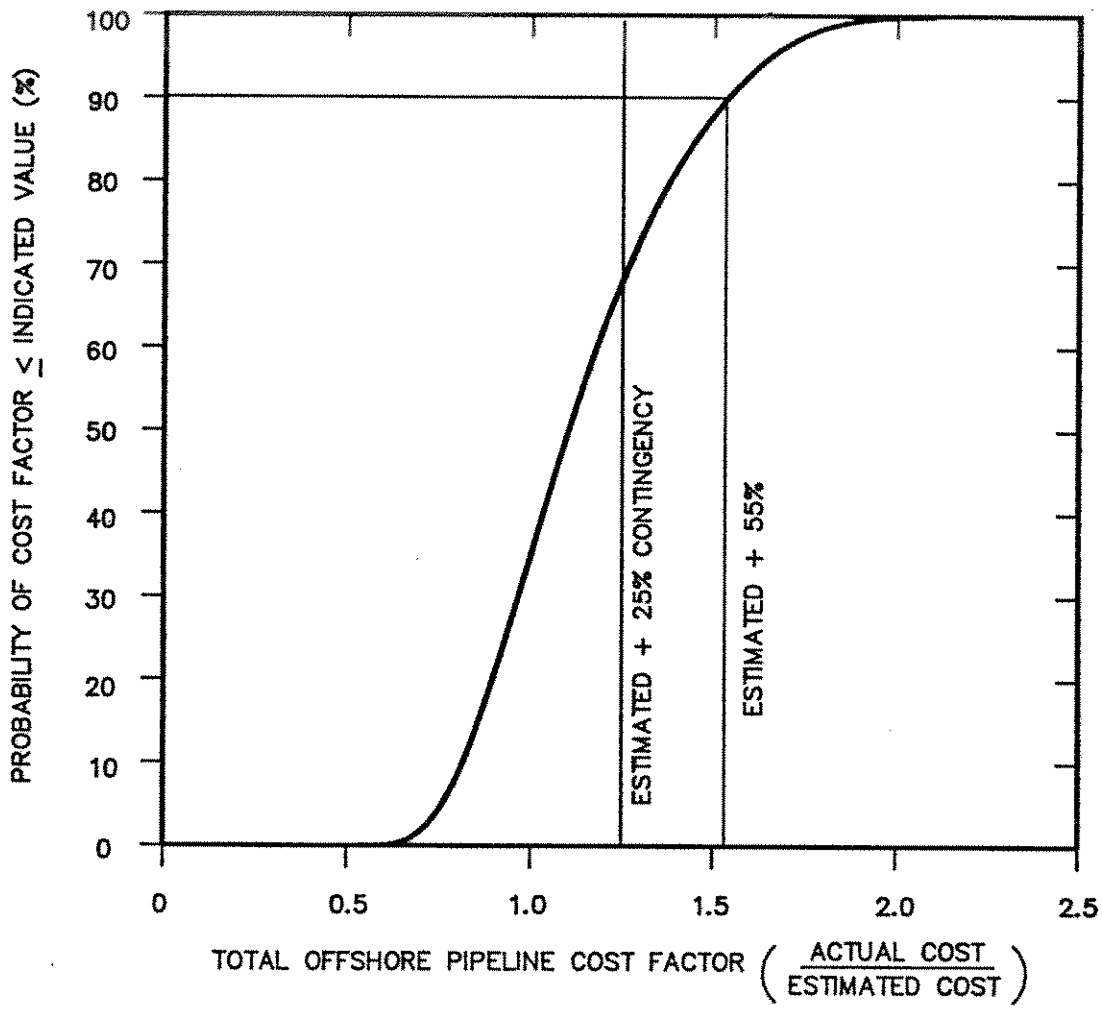
There is a 45 percent probability of the actual nearshore terminal capital cost being less than or equal to the estimated cost. With the 15 percent contingency factor which was applied in the transportation system evaluations, there is a 60 percent non-exceedance chance. To obtain a 90 percent chance that the nearshore terminal capital cost is not exceeded, a 70 percent contingency factor should be applied. The expected cost for the nearshore terminal is 10 percent greater than the estimated cost.

The nearshore tanker loading terminal capital cost of Kivalina makes up 11.2 percent of the total crude oil transportation cost for Scenario 3B. Allowing a 70 percent contingency factor to the terminal capital cost to account for risks will increase the total transportation cost by 5 percent.

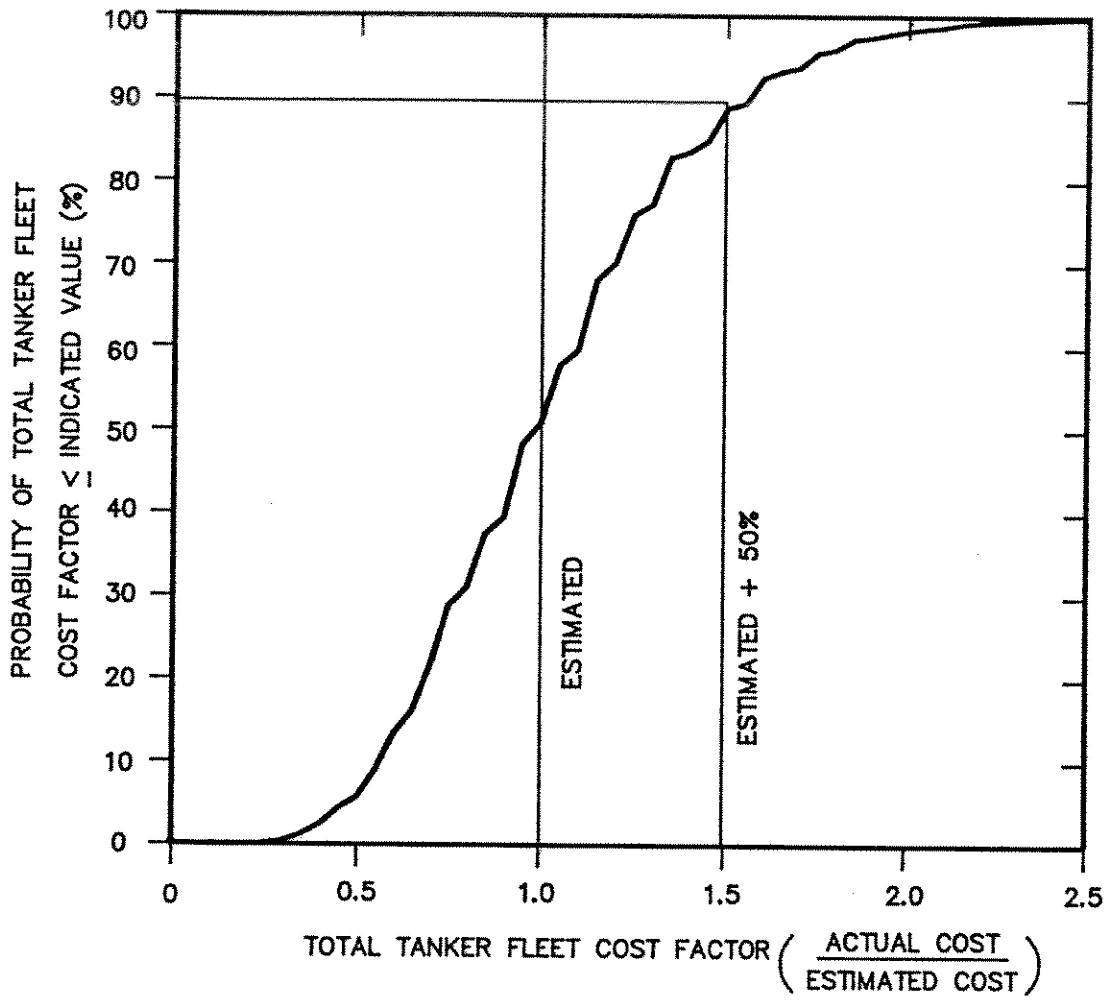
## 4.4 ALTERNATE TRANSPORTATION FACILITY DESIGNS

Review of Drawings No. 401 through 404 indicates that there is a finite chance of the transportation facility costs being up to 2.5 times the estimated cost. This would be a result of multiple factors being worse than expected when preparing the cost estimate. While this is possible, the risk analysis results indicate that the probability of this is less than 5 percent.

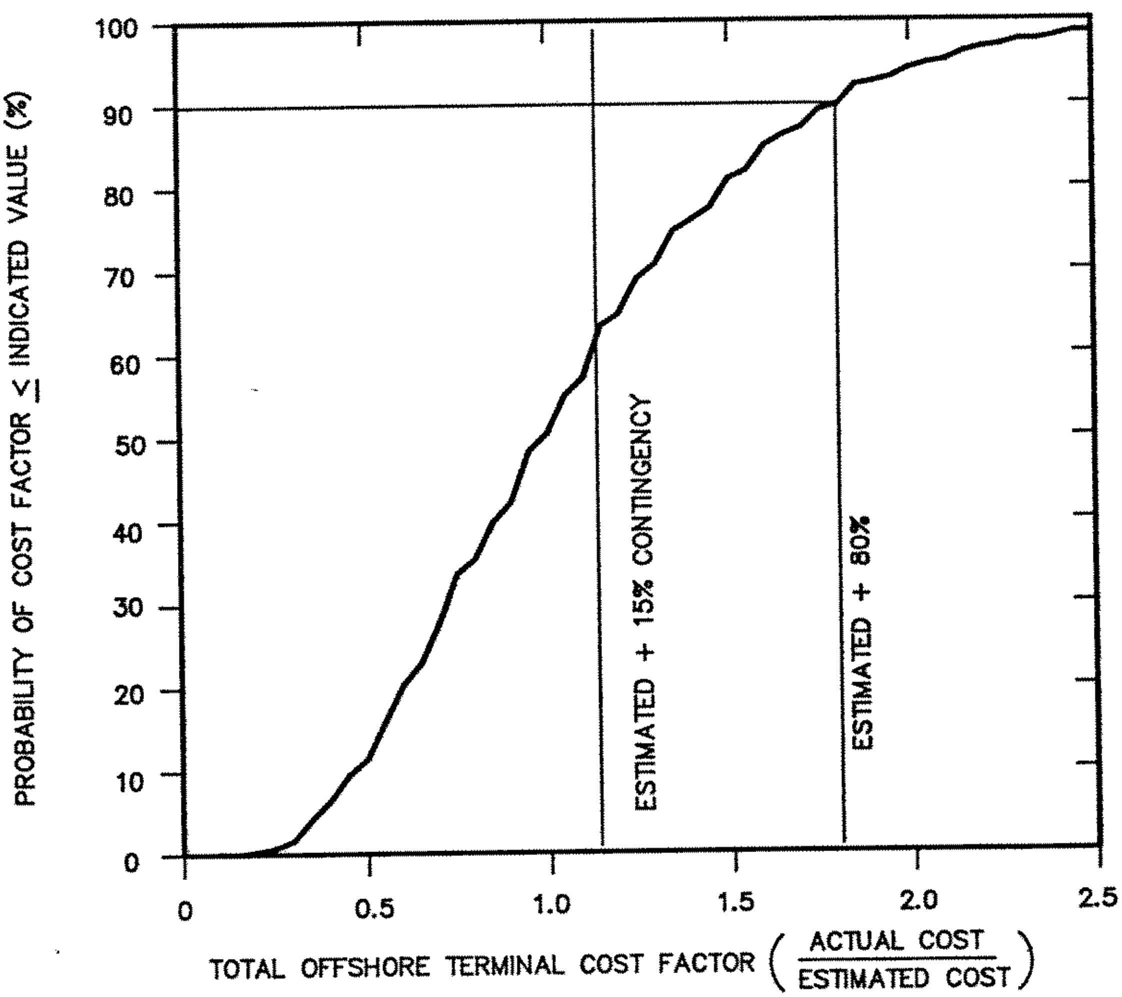
Transportation facility cost estimates are also based on the use of existing technology. If further investigation indicates that the actual cost for one or more of the transportation system components is much greater than the estimated cost, alternate designs or construction techniques may be devised which limit the impact on the overall crude oil transportation cost.




| JOINT INDUSTRY STUDY<br>CHUKCHI SEA TRANSPORTATION | TOTAL OFFSHORE PIPELINE COST FACTOR<br>PROBABILITY DISTRIBUTION | | |
|---|---|---|---|
| INTEC ENGINEERING, INC. | SCALE NONE | DRAWN BY R. GROBE | DRAWING No. F-401 |
| | DATE 10-23-86 | JOB No. H-046.3 | |




| | | | |
|---|---|---|---|
| JOINT INDUSTRY STUDY<br>CHUKCHI SEA TRANSPORTATION | TOTAL TANKER FLEET COST FACTOR<br>PROBABILITY DISTRIBUTION | | |
| INTEC ENGINEERING, INC. | SCALE NONE<br>DATE 10-23-86 | DRAWN BY R. GROBE<br>JOB No. H-046.3 | DRAWING No. F-402 |

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| JOINT INDUSTRY STUDY<br>CHUKCHI SEA TRANSPORTATION | TOTAL OFFSHORE TERMINAL COST<br>FACTOR PROBABILITY DISTRIBUTION |

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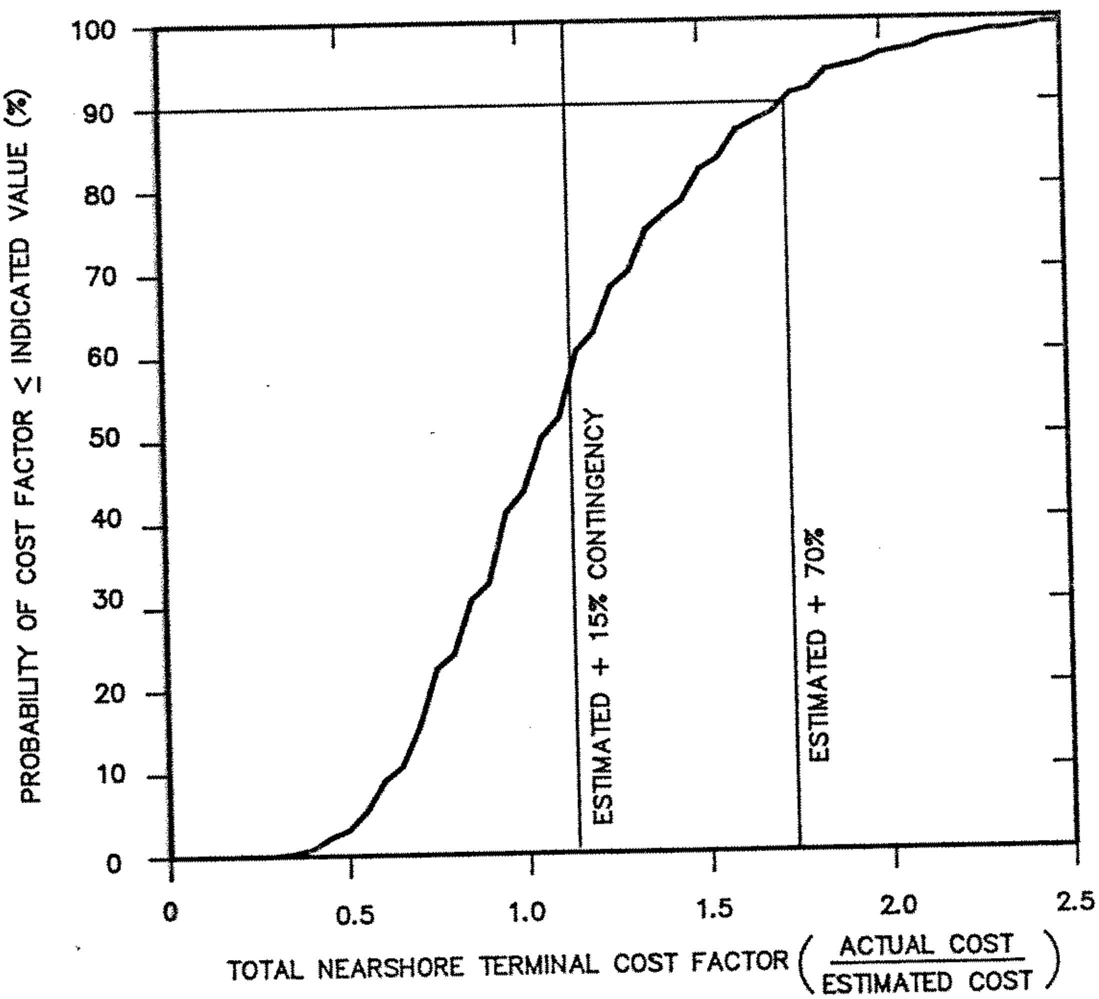
| INTEC ENGINEERING, INC. | SCALE NONE<br>DATE 10-23-86 | DRAWN BY R. GROBE<br>JOB No. H-046.3 | DRAWING No. F-403 |

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| JOINT INDUSTRY STUDY<br>CHUKCHI SEA TRANSPORTATION | TOTAL NEARSHORE TERMINAL COST FACTOR PROBABILITY DISTRIBUTION | | |
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