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FIELD OPERATION
MINERALS MANAGEMENT SERVICE

KUVLUM PREDECISION STUDIES

FINAL REPORT
June 1994

KUVLUM PREDECISION STUDIES

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I. EXECUTIVE SUMMARY

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I.1 Objective

The Kuvlum Predecision Studies were commissioned to evaluate the technical feasibility and conceptual cost of a Kuvlum development. The studies were primarily based on existing information in the form of joint industry studies, individual partner's work, and contractors' work. Two new studies were commissioned to focus current understanding of structures and tunnels on specific requirements of a Kuvlum development (Sandwell's Structure Study - Appendix 3 and Woodward-Clyde's Tunnel Study - Appendix 7).

The two areas considered frontier areas are the Arctic structure and the offshore crude transport mechanism (buried offshore pipeline or pipeline within a tunnel). The majority of the technical feasibility work focused on these two areas. The other areas, topsides, drilling, etc., were considered to be technically understood and the focus for these areas was cost.

Upon completion of the technical feasibility work, four discrete reserve cases were evaluated.

Case 1: 625MM BO developable from a single structure.

Case 2: 1600MM BO developable from a single structure.

Case 3: Determination of minimum reserve size for a single platform development.

Case 4: 1600MM BO developable from two structures.

Rate profiles, cost estimates, State of Alaska oil price forecasts, etc., were used as input in the two economic models to generate a discounted present worth (10%). The first model, OGRE (Oil and Gas Reserve and Economics Petroleum Software), is a discrete estimate model. Most likely cost estimates were used as input to this model. The second model was an Excel-based economic spreadsheet used with Crystal Ball risk analysis software. This model generated expected escalated capital costs and expected economics.

I.2 Technical Feasibility Results

Following is the results of the frontier area technical feasibility work. This work includes structures, pipelines, and tunnels.

Structure

Sandwell, Inc. performed a study of structures for use at the Kuvlum site. Results of the following two former Joint Industry projects were the basis for the study:

- *Joint Industry Study, Barrow Arch and Chukchi Sea Exploration and Production Structures.* Swan Wooster Engineering Co. Ltd., 1984, AOGA # 242.

- *Joint Industry Study Project, Beaufort and Chukchi Sea Arctic Production Platforms - Update.* Sandwell Inc., 1991, AOGA # 382.

The design ice loads is a dominant factor affecting the size and cost of permanent structures for Kuvlum. Independent work by two ice loading consultants arrived at a similar design ice load of 170-190K tons. Based on Sandwell and ARCO's recommendations, the study focused on gravity based, vertically sided structures. Two structure sizes were evaluated, a 230 ft. by 230 ft. topside deck area and a 350 ft. by 350 ft. topside deck area. These deck area requirements were determined during the topsides work.

The expected costs for the structures are given below:

230' x 230' ≈ $388MM
350' x 350' ≈ $575MM

The large structure was used in the economic analysis for all single structure production and processing cases. The smaller structure was used as a production only satellite structure in the economic analysis of the multiple structure case.

Pipelines

ARCO Exploration and Production Technology (AEPT) performed a study on the feasibility and cost of a 30" subsea pipeline to the Kuvlum site and infield pipelines from the main structure to the satellite structure. The study involved a literature review of various joint industry projects as well as contact with pipeline construction contractors.

Ice scour is a dominant design factor in the design and construction of a subsea pipeline. Ice scour determines the burial depth requirements of a pipeline, which is a major controller of cost and schedule. Vaudrey and Associates performed a probabilistic determination of the required burial depths. Reducing the risk of ice scour to 1 in 1000 involves burial of the pipeline to a depth of 25 feet. Existing equipment is not well suited for this burial depth in 100' of water but can be adapted. Several previous joint industry projects address Arctic pipeline construction and operation. An extensive review of this data and consultation with existing contractors enabled the generation of a conceptual plan and cost estimate.

The expected cost of a buried 30" oil line from the main structure to shore was $170MM and required six years to design, permit, and build. The expected cost of buried infield pipelines between the main structure and the satellite structure was $85MM.

Tunnels

Woodward-Clyde performed a study on the merits of providing a tunnel to the Kuvlum site. The tunnel option deemed most attractive was a 19 mile, single heading tunnel from Pt. Thomson to the Kuvlum site. The expected cost for this option was estimated at $575MM. The project has a duration of 7-8 years. These costs do not include the installation of the pipeline in the tunnel. The tunnel option for the Kuvlum development was not used in the economic evaluation.

I.3 Economic Analysis Results

Economic analysis were run on the four cases using the two economic models. The OGRE base discrete model was used to verify the Excel-based model. The results of the four cases are presented in detail in Section III.

The most compelling result of the economic analysis was the generation of the minimum economic reserve size for a single structure development. Expected present worth economics were run on reserve sizes ranging from 200MM BO to 800MM BO. Capital costs were interpolated from estimates made for other development scenarios. Cost of production and process facilities and O&M were interpolated based on reserve size. Cost of structure, pipeline, wells, and permitting were the same for all reserve sizes. Results of this economic analysis indicate 500MM-550MM BO are required for break-even discounted present worth (10%). These results are also presented in detail in Section III.

I.4 Conclusion

The Kuvlum Predecision Studies have compiled vast amounts of information regarding Arctic development and its related issues. Previous work, consultants, and new studies were instrumental in the generation of reasonable development scenarios and associated economics. Development of Kuvlum was judged to be technically feasible, but must overcome a significant reserve size hurdle to be economically viable. A Kuvlum development would be frontier relative to structures and pipelines and to a lesser extent to logistic and supply.

II. INTRODUCTION

II. INTRODUCTION

In late 1992, an oil discovery was announced at the Kuvlum exploratory well site in Camden Bay, located in the Eastern Beaufort Sea off the coast of Alaska. The discovery prompted this study on the feasibility and conceptual cost estimate of an offshore Arctic development.

The primary objectives of the study were:

1. Assessment of the technical feasibility of permanent structures, continuous drilling and production operations, and marine pipelines at Kuvlum.

2. Development of capital cost and operational cost sufficient to decision Kuvlum after the 1993 delineation wells.

3. Determine economic hurdles for several production rates and reserve sizes.

4. Establish groundwork for a smooth transition to detailed conceptual/preliminary engineering (pending delineation results).

The studies were separated into three phases based on objectives 1, 2, and 3. The fourth objective was a continuous process throughout the studies.

The initial phase of the studies involved a review of offshore Arctic technology developed in the 1970's and 1980's. The review included:

- Ice movements, characteristics, forces, and gouging.

- Arctic pipeline design, construction and operation.

- Experience with high production rates from modular facilities in the Arctic onshore, as well as offshore platforms in more temperate climates.

This review involved both extensive literature review and conversations with selected Arctic scientists and engineers inside and outside of ARCO. The conclusion of this review was that a Kuvlum development is technically feasible.

The second phase of the review focused on estimating conceptual costs for an Arctic development. The development was broken into basic cost components that included:

- Pipelines (main sales line, onshore and offshore, and infield lines)

- Structures (main and smaller satellites)

- Topside Facilities (drilling, production, and processing)

- Permitting Cost
- Well Cost
- Operation (O&M) Cost

Salvage and abandonment costs were not included. Technical information and cost estimates for each of these components are documented in this report.

The final phase of the studies was to perform economic analysis for several production rates and reserves sizes, using the component cost estimates previously generated. ARCO Alaska provided the State of Alaska oil price forecast, royalty, and taxation costs. In addition, to specific case analysis, an analysis was performed to determine the minimum reserve size for a single platform development. The results of these analysis are documented in this report.

III. ECONOMIC ANALYSIS

III. ECONOMIC ANALYSIS

Results are presented and discussed in this section. The various revenue and expenditure streams are developed throughout the various appendices.

Section IV describes the economic analytical models. Example input and output from selected runs are in Appendix A10.13.

III.1 Description of Development Cases Studied

This section describes the results of the economic analysis of the potential Kuvlum Development. See Section IV for description of the economic analysis models. Four alternative development cases are evaluated. These cases are summarized as follows:

Case 1: 120 MBOPD (40 wells) single platform (625 MM bbls reserves)
Case 2: 300 MBOPD (100 wells) single platform (1600 MM bbls reserves)
Case 3: Estimated minimum economic reserve size, single platform
Case 4: 300/MBOPD (100 wells) 1 vs. 2 platforms (1600 MM bbls reserves)

Cases 1, 2, and 3 assume a development scenario consisting of two delineation wells, a single offshore drilling and production/process platform (a steel gravity base structure, 350 ft. square), producing wells, associated process facilities on the structure, a trenched sales pipeline from the platform to shore and an onshore sales pipeline to the TAPS Pump Station 1.

Case 4 is similar to Case 2 except two platforms are considered to be required to develop Kuvlum.

Case 1: This case consists of 40 producing wells with a peak production rate of 120 MBOPD. The well count and daily annual production rates are shown in Figure III-5 as a function of years from the date of the delineation wells.

Case 2: This is the same as Case 1 except the number of development wells is increased from 40 to 100 and the peak production rate is increased to 300 MBOPD. The well count, daily and annual production rates are shown in Figure III-5.

Case 3: Consists of a series of sub-cases chosen to determine the minimum recoverable reserves required for an economic development (defined as $PW_{10}=0$). Case 3 assumes a constant number of development wells (100). Production/processing facilities and associated O&M costs are varied with reserve size. The sub-cases have total recoverable reserves of 200, 400, 600 and 800 MMBO. The well count, percent of total reserves produced each year, and field life are the same for all subcases. Daily and annual production rates for each subcase are shown on Figure III-6 as a function of years from the date of the delineation wells.

Case 4: This case is the same as Case 2 except two platforms are used. Each platform supports the drilling and production of 50 wells. However, the main platform performs all processing. The smaller (drill site) platform supports only drilling and production. A six mile subsea pipeline system (30", 20", 12" pipelines) connects the two platforms.

III.2 Capital Cost

Shown in Figures III-7, 8, 9 and 10 are the distributions of capital cost components for each case. Except for the main structure and the delineation wells, all of the component cost distributions are triangular, defined by minimum, most likely and maximum costs (MIN, ML and MAX). The distribution for the cost of the main structure is normal. As explained in Appendix 3 this resulted from the fact that the cost of the structure is made up of eleven triangularly distributed components. When these components are combined, the resulting distribution is close to a normal distribution. The delineation wells are input as a fixed cost since cost estimates for delineation wells are outside of the scope of this study.

Cummulative expenditure of these capital cost components vs. time is presented in Figures III-11 and III-12, graphically and numerically, respectively.

Figure III-13 shows total escalated capital cost vs. recoverable reserves for Cases 1 and 2. Figure III-14 is a similar plot for Case 3.

Timing of the expenditures and an annual inflation rate of 3% per year are used in computing total escalated capital costs.

In addition to the expected (mean) costs, 10% and 90% confidence limits are plotted. These limits, which range from 25% to 30% of the expected cost, provide a feel for the quality of the estimates. Total escalated capital costs are computed assuming the distribution of each cost component is independent of the other cost components (costs are not correlated with each other).

Figure III-15 provides a comparison between the total escalated capital cost for 1 and 2 platforms for Kuvlum development scenarios, Case 4.

Overall, the plots indicate that the capital cost is not strongly dependent on production rate (or reserve size). For example considering Cases 1 and 2, increasing production rate from 120 MBOPD to 300 MBOPD (an 150% increase) increases the capital costs from $1,750 MM to $2,290 MM (a 31% increase).

Capital cost is even less sensitive for Case 3 which assumes a constant number of wells (100). For this case, doubling reserves from 400 MMBO to 800 MMBO (or doubling the production rate) results in only a 13% increase in expected escalated capital cost.

Examination of the component costs indicates that the relationship between capital cost and production rate is weak because approximately half the cost ($900 MM) is for the offshore structure and pipelines which are constant for all production rates and the minimum facilities cost is approximately $300 MM to process 40 MBOPD.

The objective of Case 4 is to determine the impact of expanding the aerial extent of the reservoir (i.e., a thinner reservoir). The results shown in Figure III-15 indicate the escalated capital cost for a Kuvlum development will be increased by around 30% if two platforms are required instead of a single platform.

III.3 Present Worth

Shown on Figure III-16 is the plot of After Federal Income Tax Total Present Worth (PW10%) vs. Recoverable Reserves for Case 1 and Case 2. Figure III-17 is a similar plot for Case 3.

Figure III-18 provides a comparison of the PW between a single platform development (Case 2) and a two platform development (Case 4).

These plots result from performing a discounted cash flow analysis over the 6 years from the delineation wells to production startup and 25 years of production. Key factors/assumptions of this analysis are as follows:

- Discount rate for PW calculations = 10%
- Revenue based on production curves (Figure III-5 for Cases 1, 2, and 4, and Figure III-6 for Case 3)
- Oil prices (Appendix 9)
- Operating costs developed using the Beaufort Sea Offshore O&M Cost Calculator (Appendix 8)
- Capital costs as discussed above and developed in the appendix
- Tax rate (state and federal) = 39%
- Federal royalty = 12.5%
- Depreciation using the IRS Accelerated Cost Recovery System (ACRS) guidelines

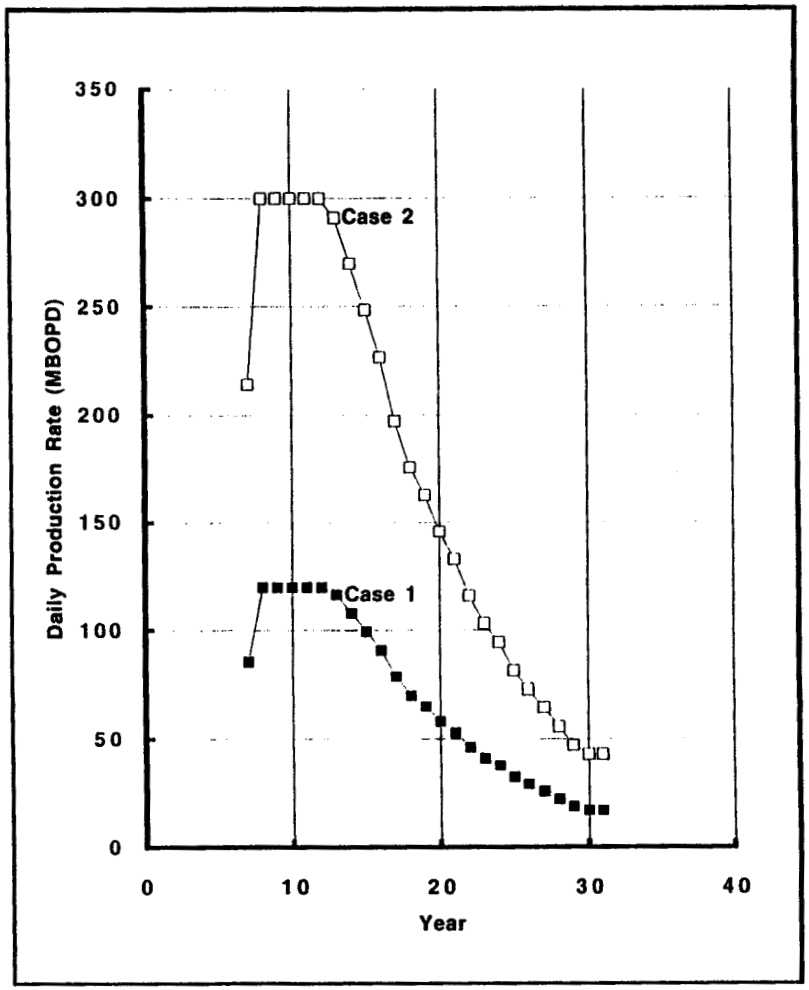
As with the capital costs, the expected (mean) present worth values and 10% and 90% confidence limits are shown. These limits were generated using the cost distributions for each of the cost components assuming the costs for each component are independent of the others.

The risk analysis did not consider uncertainty in oil price, production rate or operating cost.

For the conditions considered, the most interesting result for this analysis was the minimum economic reserve size of slightly less than 500 MMBO, Figure III-17. For a Kuvlum reservoir of 500 MMBO, reachable from a single platform, the total capital investment would be approximately $1.7 billion (Figure III-14) and the probability of the project being economic would be approximately 50%. Assuming no uncertainty in reserve estimates nor resulting production rates, reserves would have to be greater than 550 MMBO to ensure economic success at 90% confidence (assuming a 10% discount rate).

		Case 1 - 40 Wells, 2 Drill Rigs, 120 MBOPD Production Rate 625MM BBL Reserves			Case 2, 4 - 100 Wells, 2 Drill Rigs, 300 MBOPD Production Rate 1565 MM BBL Reserves		
*Nth Year	% of Reserves Produced in Nth Yr.	Well Count	Daily Production Rate MBOPD	Annual Production Rate MM BBL	Well Count	Daily Production Rate MBOPD	Annual Production Rate MM BBL
6	0.00%	0	0	0		0	0
7	5.00%	24	86	31.25	24	214	78.25
8	7.00%	40	120	43.75	48	300	109.55
9	7.00%	40	120	43.75	72	300	109.55
10	7.00%	40	120	43.75	96	300	109.55
11	7.00%	40	120	43.75	100	300	109.55
12	7.00%	40	120	43.75	100	300	109.55
13	6.80%	40	116	42.5	100	292	106.42
14	6.30%	40	108	39.375	100	270	98.595
15	5.80%	40	99	36.25	100	249	90.77
16	5.30%	40	91	33.125	100	227	82.945
17	4.60%	40	79	28.75	100	197	71.99
18	4.10%	40	70	25.625	100	176	64.165
19	3.80%	40	65	23.75	100	163	59.47
20	3.40%	40	58	21.25	100	146	53.21
21	3.10%	40	53	19.375	100	133	48.515
22	2.70%	40	46	16.875	100	116	42.255
23	2.40%	40	41	15	100	103	37.56
24	2.20%	40	38	13.75	100	94	34.43
25	1.90%	40	33	11.875	100	81	29.735
26	1.70%	40	29	10.625	100	73	26.605
27	1.50%	40	26	9.375	100	64	23.475
28	1.30%	40	22	8.125	100	56	20.345
29	1.10%	40	19	6.875	100	47	17.215
30	1.00%	40	17	6.25	100	43	15.65
31	1.00%	40	17	6.25	100	43	15.65
	100.00%		*625*	*625*		*1565*	*1565*

*=Total Reserves (MM BBL) = Sum(Daily Production Rates*365) = Sum(Annual Production)*



*Year 1 is 1994.
Drill Rate for each Case is 24 wells/year.

FIGURE III-5
Production Rate and Well Count for Case 1 and Case 2 (Case 4 Identical to Case 2)

Case 3

Basic Assumptions:

100 Wells
One Structure Two Drill Rigs
Drill Rate 24 wells/year

			Reserves and Design Production Rate			
			200MM BBL 40 MBOPD	400MM BBL 75 MBOPD	600MM BBL 115 MBOPD	800MM BBL 155 MBOPD
*Nth Year	Well Count	%Reserves Produced In Nth Year	Average Daily Rate in Nth Year			
			MBOPD	MBOPD	MBOPD	MBOPD
6	24	0.0%	0	0	0	0
7	48	5.0%	27	55	82	110
8	72	7.0%	38	77	115	153
9	**100	7.0%	38	77	115	153
10	100	7.0%	38	77	115	153
11	100	7.0%	38	77	115	153
12	100	7.0%	38	77	115	153
13	100	6.8%	37	75	112	149
14	100	6.3%	35	69	104	138
15	100	5.8%	32	64	95	127
16	100	5.3%	29	58	87	116
17	100	4.6%	25	50	76	101
18	100	4.1%	22	45	67	90
19	100	3.8%	21	42	62	83
20	100	3.4%	19	37	56	75
21	100	3.1%	17	34	51	68
22	100	2.7%	15	30	44	59
23	100	2.4%	13	26	39	53
24	100	2.2%	12	24	36	48
25	100	1.9%	10	21	31	42
26	100	1.7%	9	19	28	37
27	100	1.5%	8	16	25	33
28	100	1.3%	7	14	21	28
29	100	1.1%	6	12	18	24
30	100	1.0%	5	11	16	22
31	100	1.0%	5	11	16	22
			200	*400*	*600*	*800*

*Year 1 is 1994
**28 wells drilled in 9th year.

*=Total Reserves (MM BBL)= Sum(Daily Rate*365day/year)*

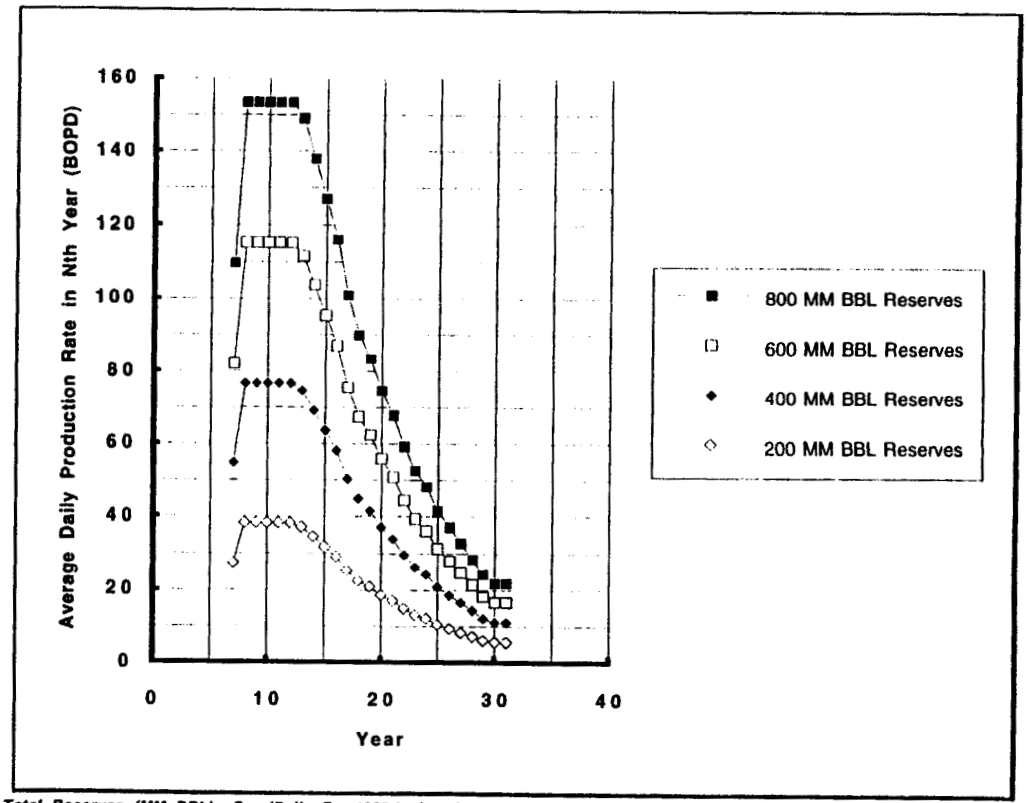


FIGURE III-6
Production Rate and Well Count for Case 3

Case 1 40 Wells, 2 Drill Rigs, 600 MM BBL Reserves, 120 MBOD Maximum Production and Processing Rate.

COMPONENT COST DISTRIBUTIONS (MM$)

Component			MIN	ML	MAX
Sales Pipeline - Kuvlum to Pt. Thompson			86.61	148.00	273.69
Main Structure (1) See Note			460.95	575.02	723.34
Production/Processing Facilities			154.11	401.00	803.16
Sales Pipeline - Pt. Thompson to TAPS			73.71	130.00	236.70
Permitting			7.58	20.00	51.89
Two Delin Wells				70.20	
Wells 24 wells/yr 3MM$/well 85% Intang	Number of Wells	40	68.04	120.00	218.05
Operating Cost		MM$/yr		104.64	

(1) Normal distribution for Main Structure. All other Distributions are Triangular.

Figure III-7
Case 1: Distributions of Cost Components

Case 2 100 Wells, 2 Drill Rigs, 1600 MM BBL Reserves,
300 MM BOPD Maximum Production and Processing Rate.

COMPONENT COST DISTRIBUTIONS (MM$)

Component			MIN	ML	MAX
Sales Pipeline - Kuvlum to Pt. Thompson			86.60	148.00	273.69
Main Structure (1) See Note.			460.95	575.02	723.34
Production/Processing Facilities			235.59	613.00	1227.78
Sales Pipeline - Pt. Thompson to TAPS			73.71	130.00	236.70
Permitting			7.58	20.00	51.89
Two Delin Wells				70.20	
Wells 24 wells/yr 3MM$/well 85% Intang	Number of Wells	100	170.10	300.00	546.24
Operating Cost			MM$/yr	174.96	

(1)Normal Distribution for Main Structure. All other Distributions are Triangular.

Figure III-8
Case 2: Distributions of Cost Components

Case 3 Determination of Minimum Economic Reserves for a PW10 = 0.0
200 MM BBL Reserves, 40 MBOPD Maximum Production/Processing Rate.

COMPONENT COST DISTRIBUTIONS (MM$)

Component		MIN	ML	MAX
Sales Pipeline - Kuvlum to Pt. Thompson		86.61	148.00	273.69
Main Structure (1) See Note.		460.95	575.02	723.34
Production/Processing Facilities		114.14	297.00	594.86
Sales Pipeline - Pt. Thompson to TAPS		73.71	130.00	236.70
Permitting		7.58	20.00	51.89
Two Delineation Wells			70.20	
Wells 24 wells/yr 3MM$/well 85% Intangibles	Number of Wells			
	100	170.10	300.00	546.24
Operating Cost	MM$/yr		75.26	

(1)Normal Distribution for Main Structure. All other Distributions are Triangular.

Figure III-9
Page 1 of 4
Case 3: Distributions of Cost Components
(Four different reserve sizes and production rates)

Case 3 Determination of Minimum Economic Reserves for a PW10 = 0.0
400 MM BBL Reserves, 75 MBOPD Maximum Production/Processing Rate.

COMPONENT COST DISTRIBUTIONS

Component			MIN	ML	MAX
Sales Pipeline - Kuvlum to Pt. Thompson			86.61	148.00	273.69
Main Structure (1) See Note.			460.95	575.02	723.34
Production/Processing Facilities			138.36	360.00	721.04
Sales Pipeline - Pt. Thompson to TAPS			73.71	130.00	236.70
Permitting			7.58	20.00	51.89
Two Delineation Wells				70.20	
Wells 24 wells/yr 3MM$/well 85% Intangibles	Number of Wells	100	170.10	300.00	546.27
Operating Cost		MM$/yr		89.80	

(1)Normal Distribution for Main Structure. All other Distributions are Triangular.

Figure III-9
Page 2 of 4
Case 3: Distributions of Cost Components
(Four different reserve sizes and production rates)

Case 3 Determination of Minimum Economic Reserves for a PW10 = 0.0
600 MM BBL Reserves, 115 MBOPD Maximum Production/Processing Rate.

COMPONENT COST DISTRIBUTIONS (MM$)

Component			MIN	ML	MAX
Sales Pipeline - Kuvlum to Pt. Thompson			86.61	148.00	273.69
Main Structure (1) See Note.			460.95	575.02	723.34
Production/Processing Facilities			161.42	420.00	841.22
Sales Pipeline - Pt. Thompson to TAPS			73.71	130.00	236.70
Permitting			7.58	20.00	51.89
Two Delineation Wells				70.20	
Wells 24 wells/yr 3MM$/well 85% Intangibles	Number of Wells	100	170.10	300.00 1663	546.27
Operating Cost		MM$/yr		104.64	

(1)Normal Distribution for Main Structure. All other Distributions are Triangular.

Figure III-9
Page 3 of 4
Case 3: Distributions of Cost Components
(Four different reserve sizes and production rates)

Case 3 Determination of Minimum Economic Reserves for a PW10 = 0.0
800 MM BBL Reserves, 155 MBOPD Maximum Production/Processing Rate.

COMPONENT COST DISTRIBUTIONS (MM$)

Component			MIN	ML	MAX
Sales Pipeline - Kuvlum to Pt. Thompson			86.61	148.00	273.69
Main Structure (1) See Note.			460.95	575.02	723.34
Production/Processing Facilities			176.71	460.00	921.33
Sales Pipeline - Pt. Thompson to TAPS			73.71	130.00	236.70
Permitting			7.58	20.00	51.89
Two Delineation Wells				70.20	
Wells **24 wells/yr** **3MM$/well** **85% Intangibles**	Number of Wells	100	170.10	300.00	546.24
Operating Cost			MM$/yr	119.76	

(1)Normal Distribution for Main Structure. All other Distributions are Triangular.

Figure III-9
Page 4 of 4
Case 3: Distributions of Cost Components
(Four different reserve sizes and production rates)

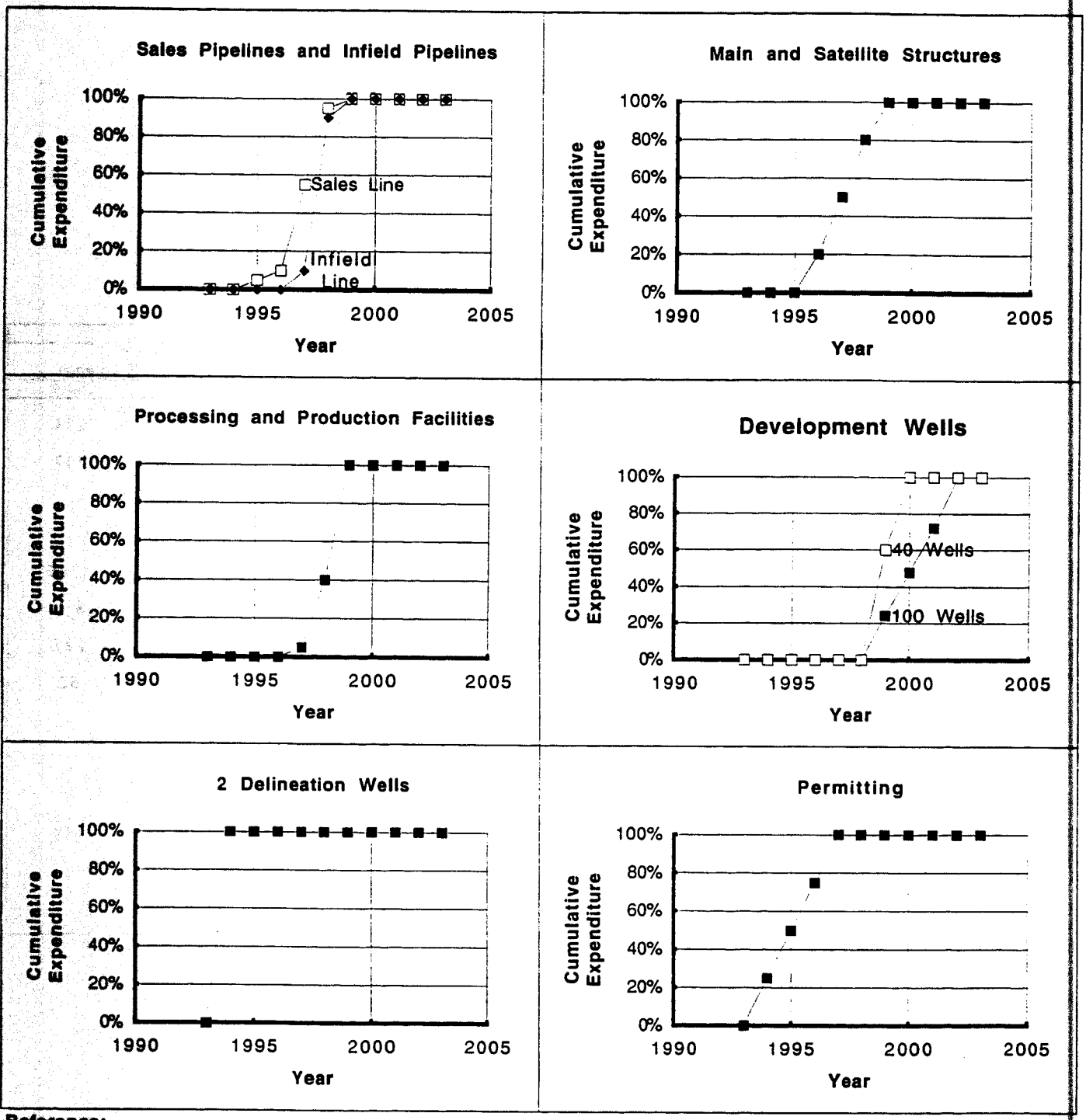
Case 4 100 Wells, 1600 MM BBL Reserves, 300 MMBOPD Maximum Production/Processing Rate.

COMPONENT COST DISTRIBUTIONS (IN MM$)

Component	Case 2 (repeated) 1 Drilling/Processing Platform and 2 Drilling Rigs.			Case 4 1 Drilling/Processing Platform and 1 Drilling Platform with 1 Drill Rig on each.		
	MIN	ML	MAX	MIN	ML	MAX
Sales Pipeline	87	148	274	87	148	274
Infield Pipeline	0	0	0	36	63	117
Main Structure (1)See Note		575			575	
Drilling Structure (1)		0			388	
Processing Facilities (2)	236	613	1228	228	592	1185
Production Facilities	0	0	0	60	155	310
Coastal Pipeline	74	130	237	74	130	237
Permitting	8	20	52	8	20	52
Two Delineation Wells		70			70	
Wells 24 wells/yr 3MM$/well 85% Intangibles 100 Wells	170	300 1856	546	170	300	546
Operating Cost, MM$/yr		175			201	

(1) Normal Distribution for Main Structure and Drilling Structure. All other Distributions are Triangular.
(2) For Case 2, both production and processing facilities are included on this line.

Figure III-10
Comparison of Cost Distributions of Case 2 to Case 4



Reference:

Figure III-12: Capital Expenditure Pattern for Kuvlum Development for each Component

FIGURE III-11
Cumulative Capital Expenditures for Kuvlum Development

ANNUAL EXPENDITURE IN PERCENT OF TOTAL COST OF EACH COMPONENT

Nth Year	Year	Main Sales Pipeline Kuvlum - Pt. Thomson	Infield Pipeline Main to Satellite	Main Kuvlum Structure	Drilling Structure (Satellite)	Processing Facilities	Production Facilities	Coastal Pipeline Pt. Thomson to TAPS	Permitting	Delineation Wells (2)	Development Wells (100) Cases 2,3 & 4	Development Wells (40) Case 1
	1993											
1	1994								25%	100%		
2	1995	5%						5%	25%	0%		
3	1996	5%		20%	20%			5%	25%	0%		
4	1997	45%	10%	30%	30%	5%	5%	45%	25%	0%		
5	1998	40%	80%	30%	30%	35%	35%	40%		0%		
6	1999	5%	10%	20%	20%	60%	60%	5%		0%	24%	60%
7	2000	0%									24%	40%
8	2001										24%	
9	2002										28%	
10	2003											

CUMULATIVE EXPENDITURE IN PERCENT OF TOTAL COST OF EACH COMPONENT

Nth Year	Year	Main Sales Pipeline	Infield Pipeline	Main Kuvlum Structure	Drilling Structure	Processing Facilities	Production Facilities	Coastal Pipeline Pt.	Permitting	Delineation Wells (2)	Development Wells (100)	Development Wells (40)
	1993	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
1	1994	0%	0%	0%	0%	0%	0%	0%	25%	100%	0%	0%
2	1995	5%	0%	0%	0%	0%	0%	5%	50%	100%	0%	0%
3	1996	10%	0%	20%	20%	0%	0%	10%	75%	100%	0%	0%
4	1997	55%	10%	50%	50%	5%	5%	55%	100%	100%	0%	0%
5	1998	95%	90%	80%	80%	40%	40%	95%	100%	100%	0%	0%
6	1999	100%	100%	100%	100%	100%	100%	100%	100%	100%	24%	60%
7	2000	100%	100%	100%	100%	100%	100%	100%	100%	100%	48%	100%
8	2001	100%	100%	100%	100%	100%	100%	100%	100%	100%	72%	100%
9	2002	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
10	2003	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

FIGURE III-12
Capital Expenditure Pattern for Kuvlum Development for Each Component

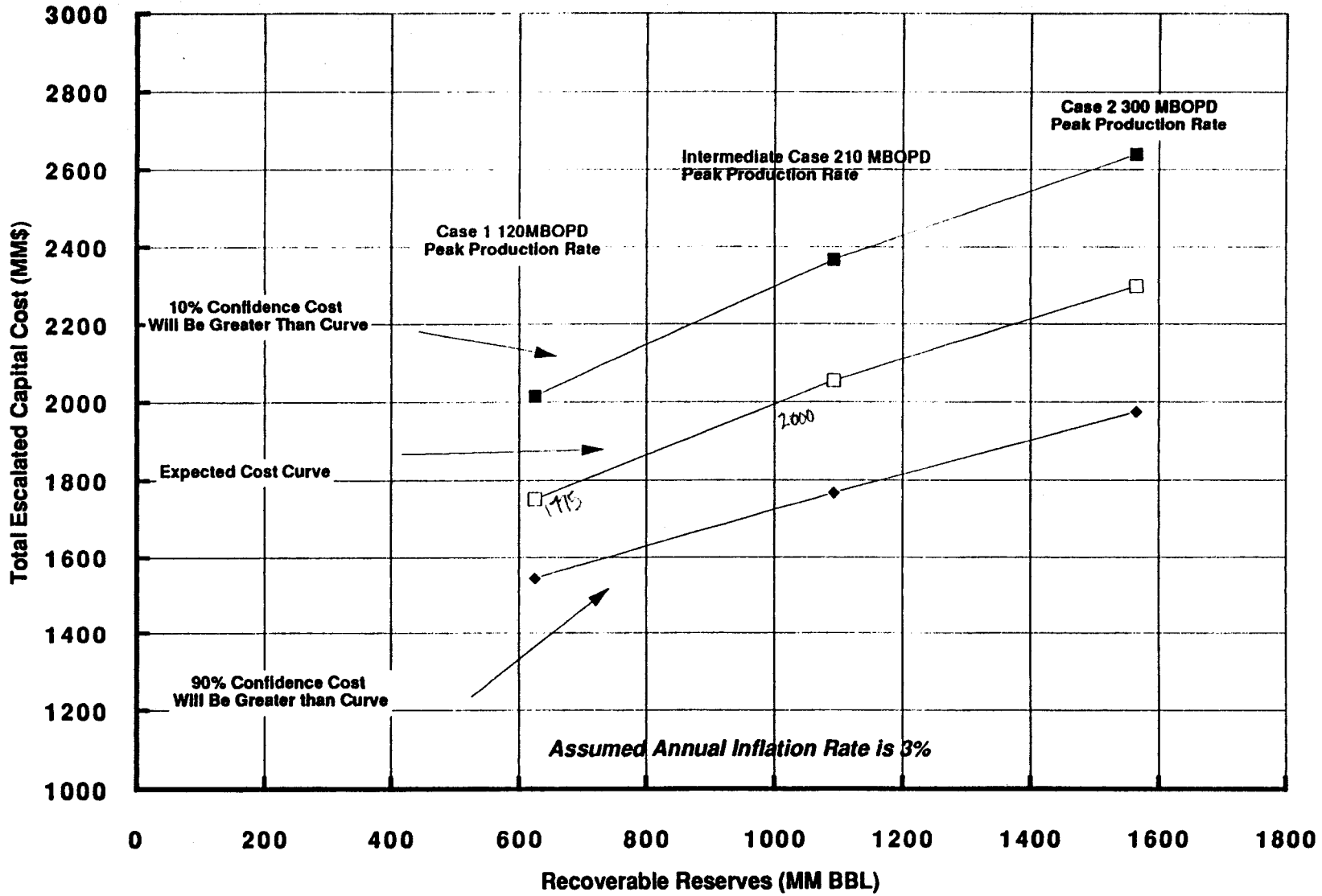


Figure III-13
Total Escalated Capital Cost versus Recoverable Reserves
(Case 1 and Case 2)

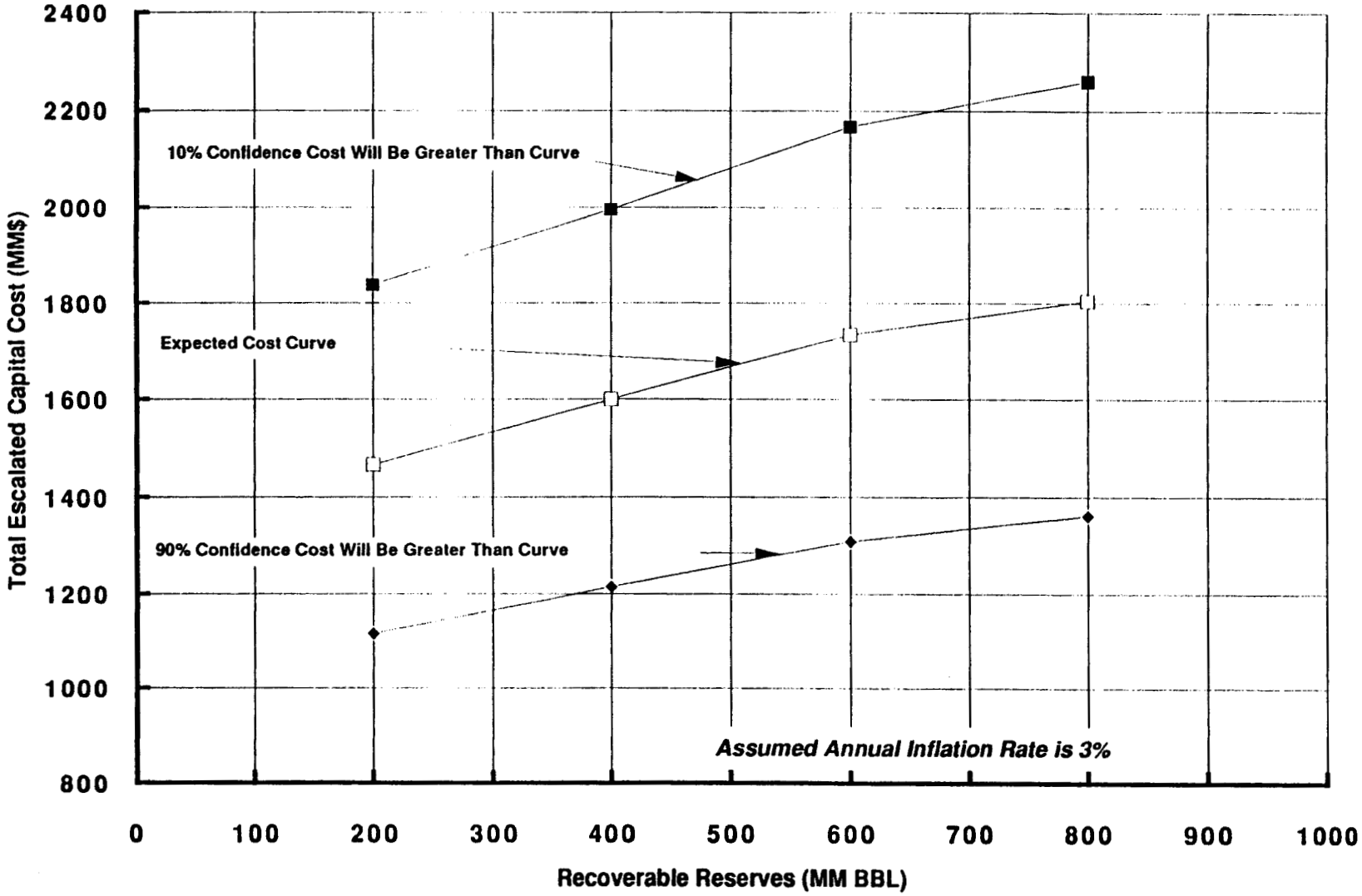
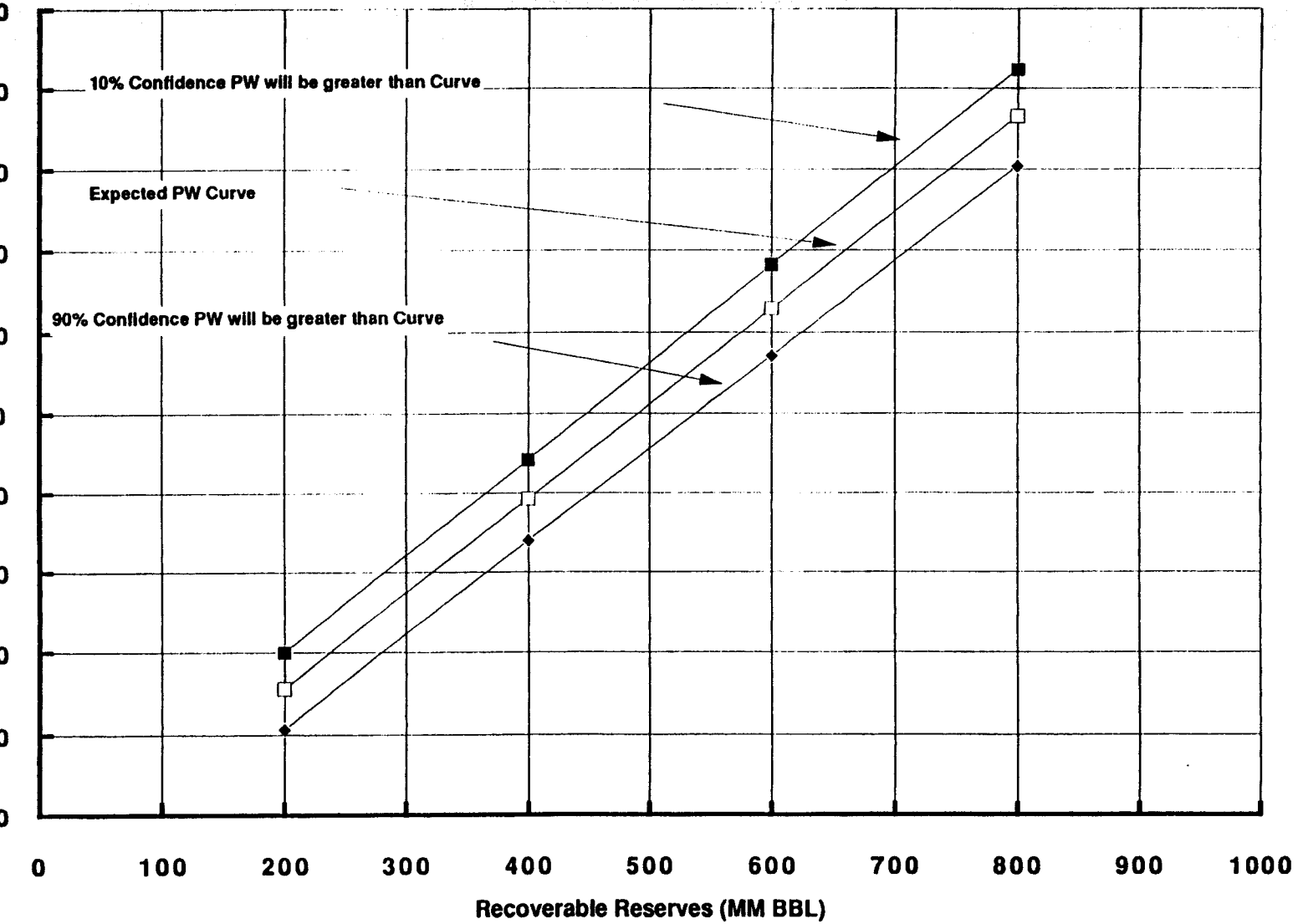


Figure III-14
Total Escalated Capital Cost versus Recoverable Reserves
(Case 3)



K72.xlc

1.00

K64.xlc

Figure III-17 Distribution of Present Worth of a Single Platform Development (Case 3).

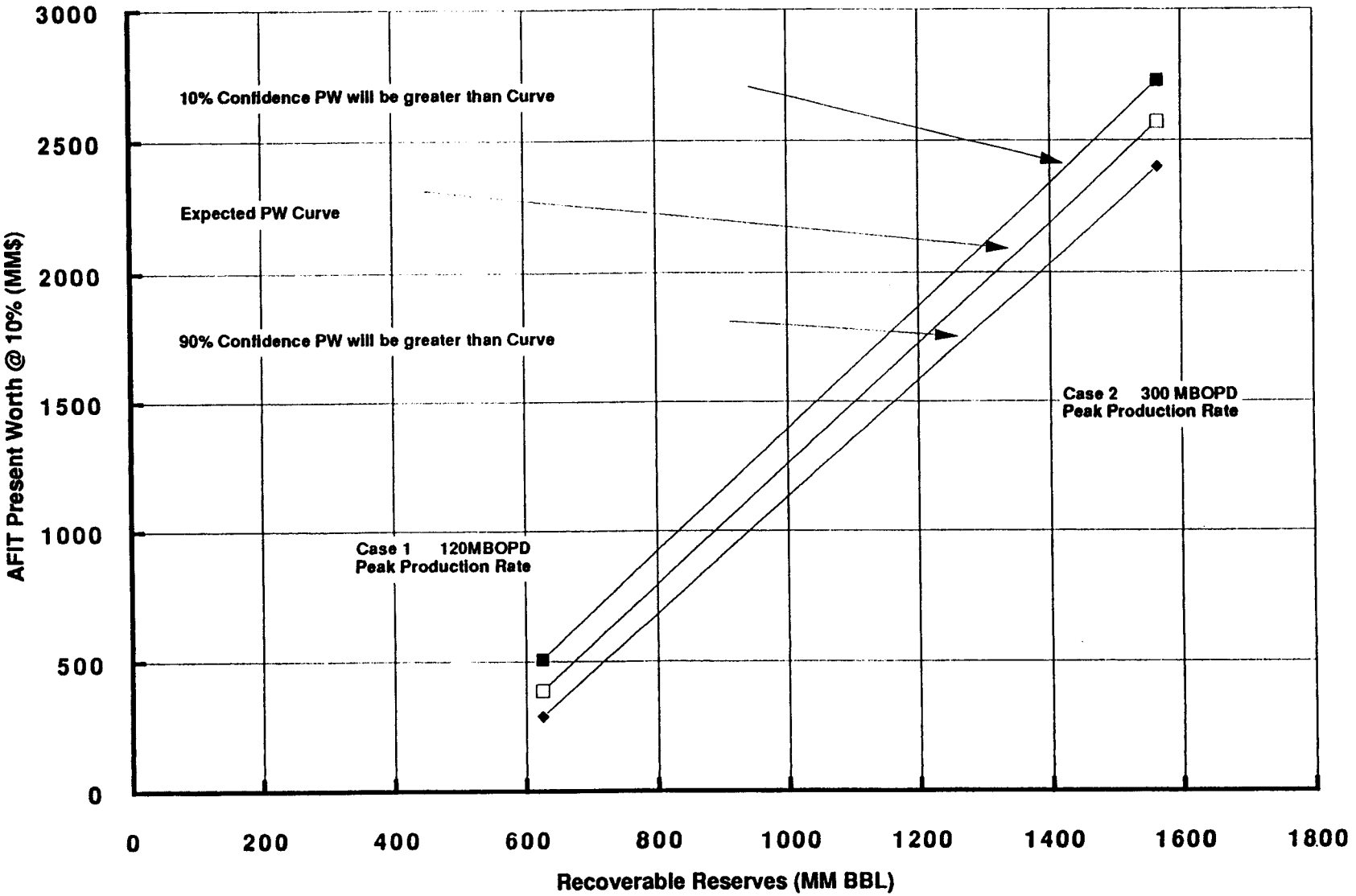


Figure III-16 Distribution of Present Worth for a Single Platform Development (Case 1 and Case 2).

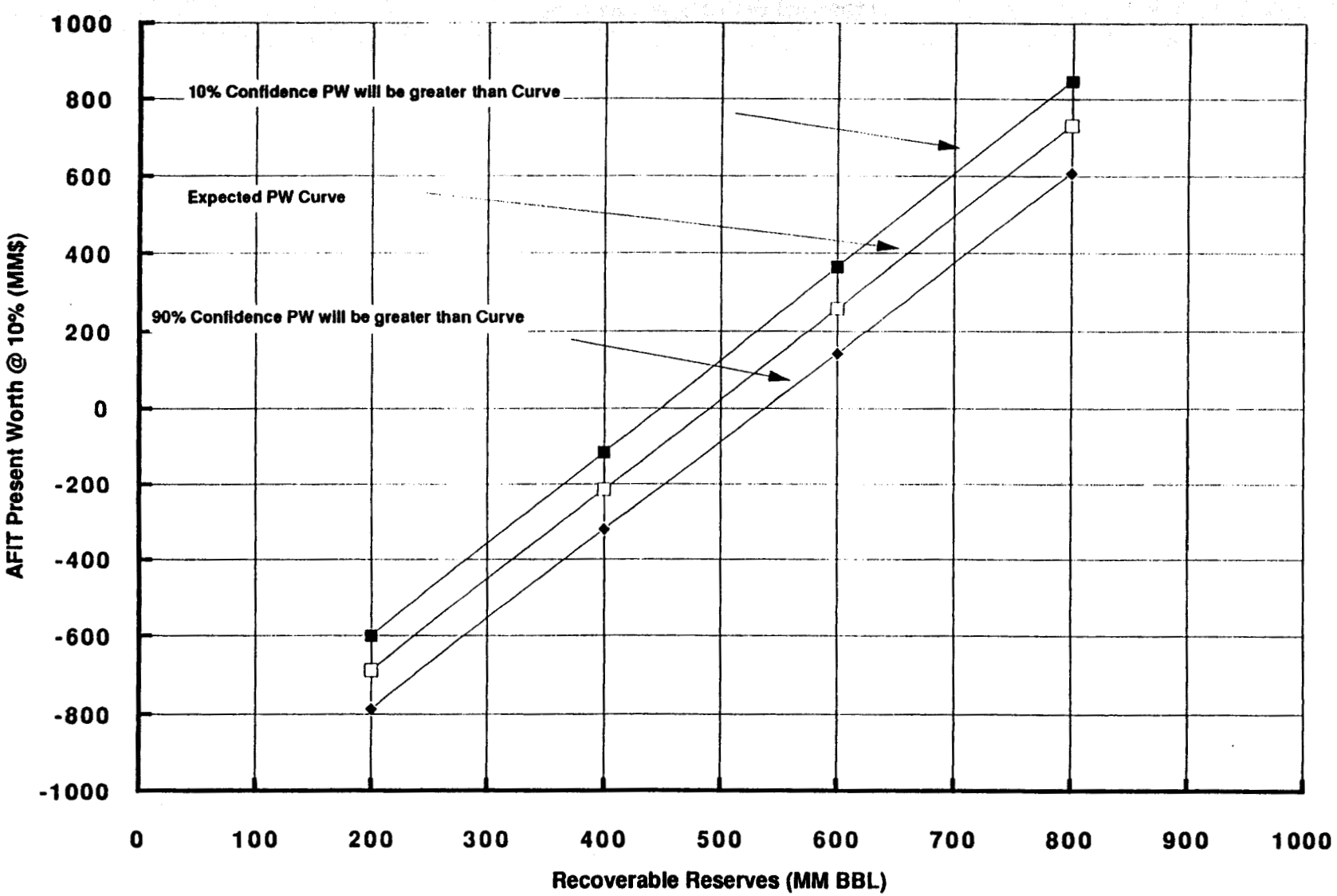


Figure III-17 Distribution of Present Worth of a Single Platform Development (Case 3).

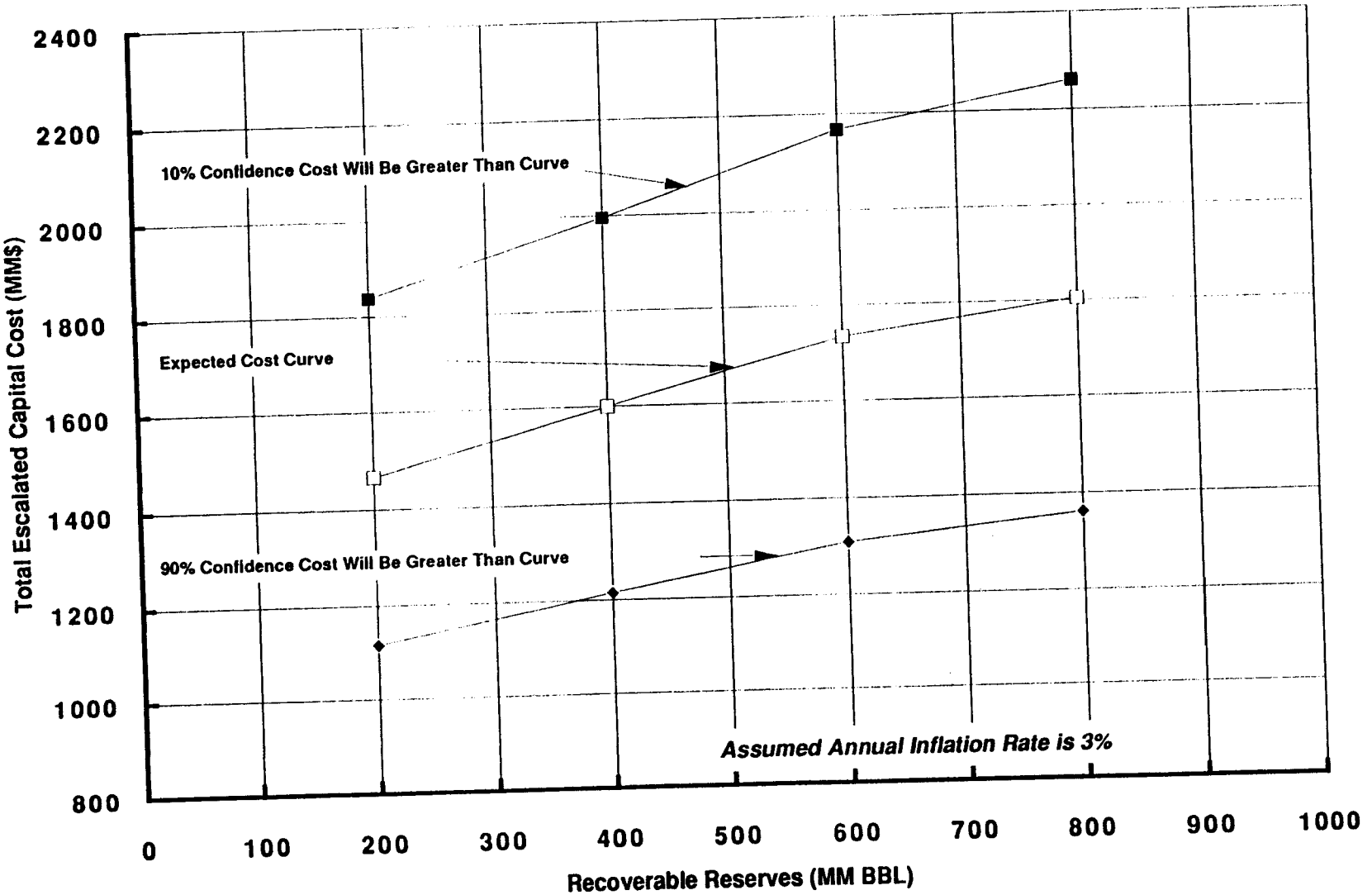


Figure III-14
Total Escalated Capital Cost versus Recoverable Reserves
(Case 3)

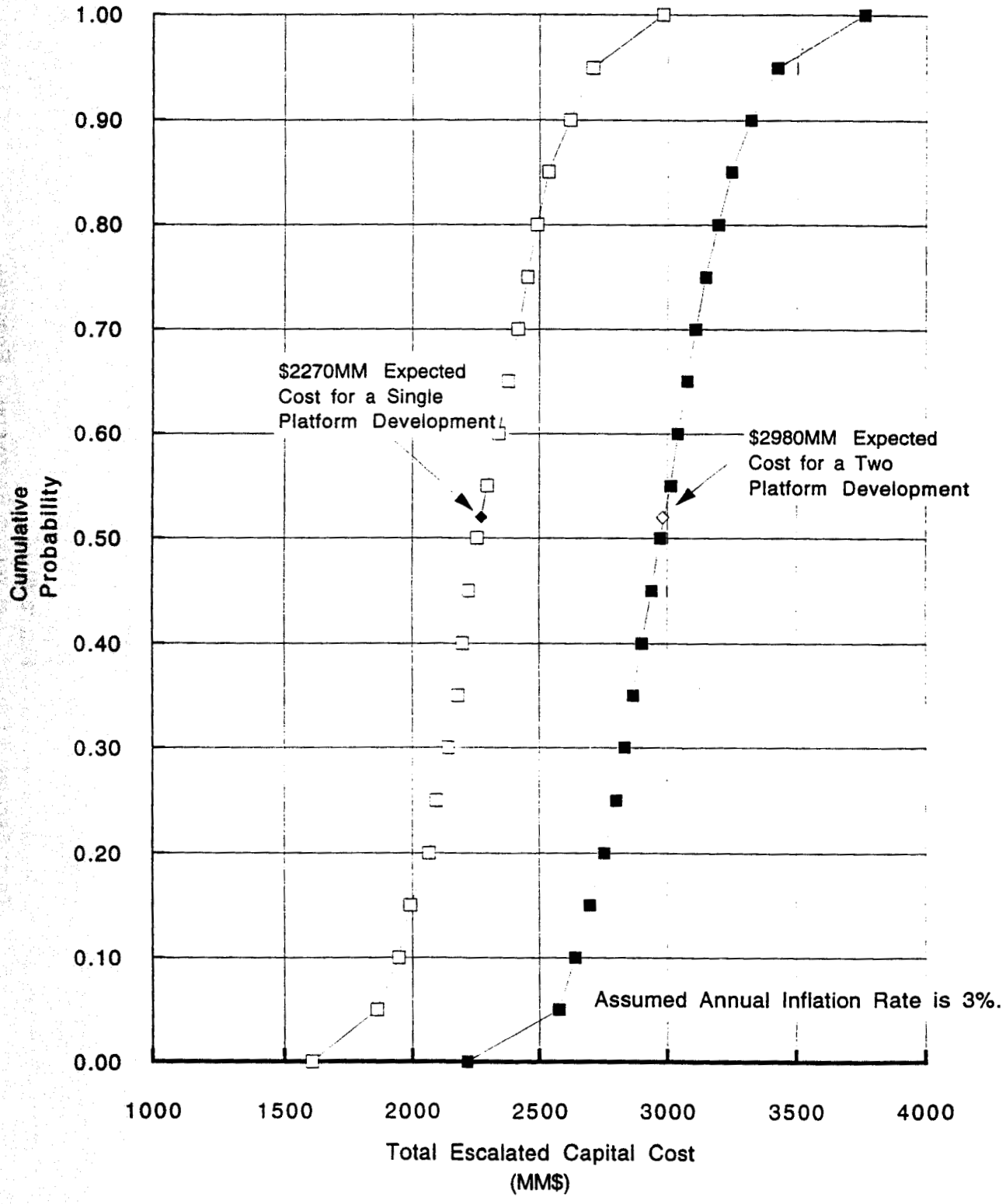


FIGURE III-15
Case 4 Comparison of Escalated Capital Costs for One and Two Platforms Approach (300MM BOPD Production/Processing)

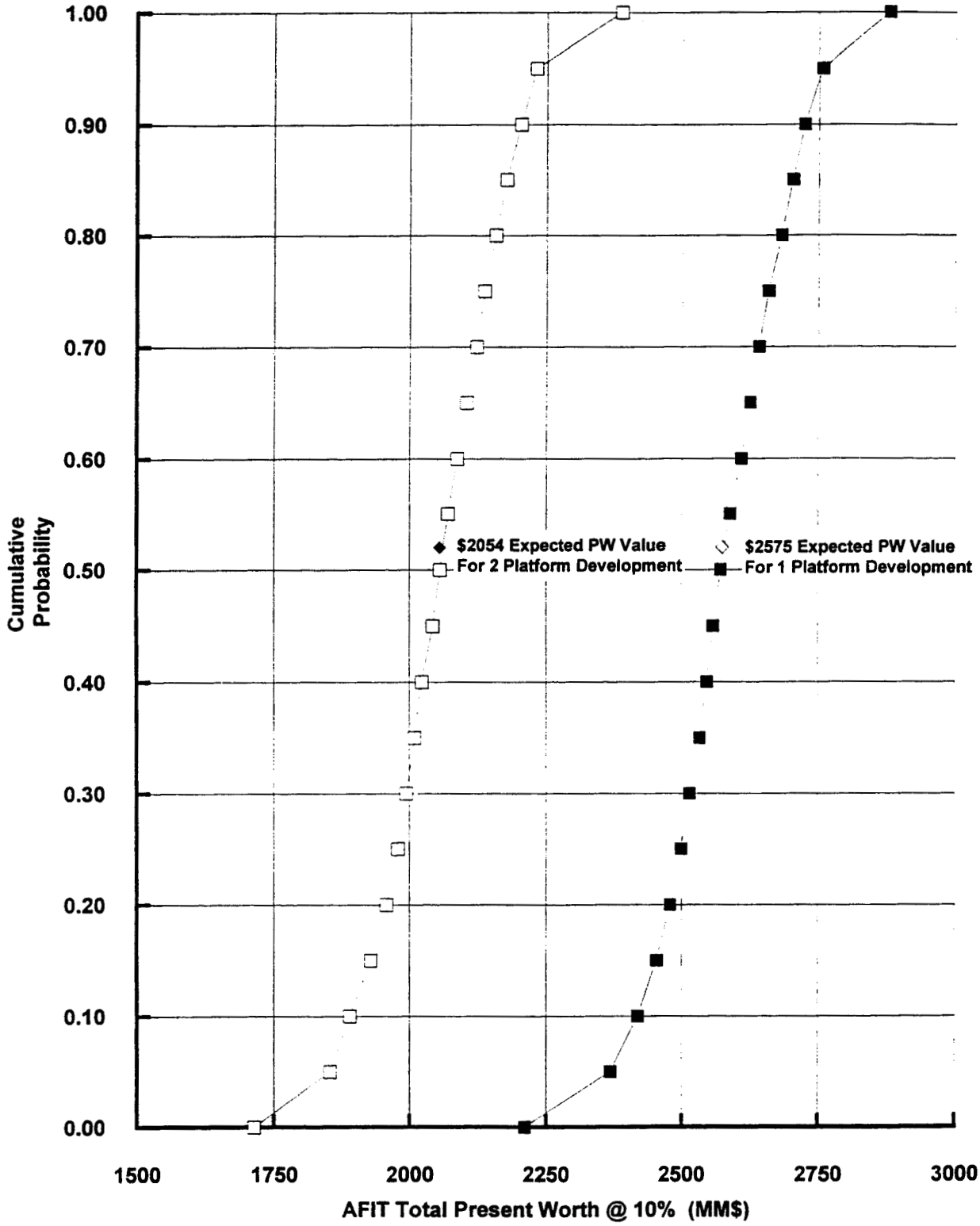


Figure III-18
Present Worth for One and Two Platforms Developments for 300 MBOPD Production (Case 4)

IV. DESCRIPTION OF ECONOMIC ANALYSIS MODELS

IV. DESCRIPTION OF ECONOMIC ANALYSIS MODELS

Two economic models are used in this economic analysis of a potential Kuvlum development. The first model is a discrete estimate model and the second a risk model.

IV.1 Discrete Estimate Model

The Oil and Gas Reserve and Economics (OGRE) Petroleum Software Library is used to construct the economic model of a Kuvlum development. Input to this model are the most likely cost estimates, the production curves, oil price projections and inflation assumptions presented in Section III Economic Analysis.

The results from this model are point estimates and do not include consideration of the uncertainties in capital costs.

This model serves two purposes. First, it provides a quick, easy-to-use tool to evaluate a wide range of alternatives. Second, it provides a basis to verify the risk analysis model.

OGRE input and results for Cases 1, 2, and 3 are contained in Appendix 10.

IV.2 Risk Analysis Model

The purpose of this model is to estimate the present worth of each case considering the uncertainties in each of the cost estimates. To accomplish this, the model calculates the expected (mean value) total escalated capital costs and the Present Worth (PW) and confidence bands about the expected PW.

Figures III-13 through III-17 present these confidence bands. One band or curve shows values for which there is a 90% chance the actual cost or PW will be greater. The other curve shows values for which there is a 10% chance of the actual cost or PW be greater.

The risk analysis model uses a Monte Carlo simulation to assess the impact of the uncertainty in each cost component. This model consists of a spreadsheet and the Crystal Ball risk analysis software. The spreadsheet performs all the cash flow calculations including:

- Distributing the costs according to expected construction spending patterns
- Depreciation and expense accounts as a function of time
- Federal royalty
- Taxes
- Revenue stream (production minus expenses)

As presented in Section III.2 Capital Cost, each of the cost components was described by a statistical distribution (either triangular or normal). For all components except the Main and Satellite Drilling Structures, a triangular distribution was used. The installed cost for each of the two structures was made up of eleven cost components which were judged to be largely independent (that is, the cost of one of the components is not indicative of the cost of any of the other components). Thus, costs for these two structures were developed using a Monte Carlo Simulation which assumed the components to be completely independent. This simulation resulted in a normal distribution.

The approach used to develop the cost distributions for these structures could have been used for all of the basic cost components, but was not due to the question of the level of independence between the cost of the sub-components. For example, how dependent is the total cost of structural steel on the cost of the separators? Defining the relationship in detail was beyond the scope of this study. The decision was made to use a simple additive approach for which the composite distribution for a component (e.g., pipelines) was defined by the sum of the minimums, most likelies, and maximums. This approach assumes all of the cost components are dependent. In other words, the costs are highly correlated. In the simulation, if the cost of one component falls at a given percentile of its range, the cost for all of the other components will be at the same respective percentile. The impact of this assumption is illustrated in Figure A1-3 Cost of Main Sales pipeline (30", buried) from Kuvlum Platform to Flaxman Island to Point Thomson.

In short, the additive approach will result in more widely distributed cost than an independent Monte Carlo simulation. The Expected Cost will be the same, but the tails will be significantly different as seen in Figure A1-3. The "real distribution" is somewhere between these extremes. Overall, this means that the results of this analysis produce somewhat wider distributions than would actually be expected. If further Kuvlum studies are undertaken, the level of dependence between cost components should be studied.

The Crystal Ball risk analysis software conducts the Monte Carlo simulation. For each trial these activities include:

- Drawing random samples from each distribution.
- Passing these results to the spreadsheet.
- Storing the results (AFIT total PW and Total Escalated Capital Costs vs. Cumulative Probability) from the spreadsheet.

At the completion of each run, which consists of 800 to 1000 trials, Crystal Ball performs a statistical analysis of the results that includes a calculated mean (expected value), and a cumulative probability distribution curve (probability that the actual amount shown on the curve will not be exceeded).

Inputs to this model are the same as for the OGRE model except costs, which in this case, are distributions, not discrete values. These inputs are summarized as follows:

- Production rate scenarios (production curves, Figures III-5 and III-6).
- Cost distributions for each of the components (Figures III-7 to III-10).
- Expenditure pattern for each component (Appendices 1-7 and Figures III-11 and III-12).
- Operating & Maintenance costs (Appendix 8).
- Oil price forecast (Appendix 9).

IV.3 Validation

For each case, the risk analysis model was compared with the results from the OGRE model. This was accomplished by input of the most likely cost estimates for each component into both the OGRE model (discrete estimate model) and risk analysis model. For this comparison, the Monte Carlo simulation was disabled so the risk analysis model operated as a discrete model. The difference in results between the models was less than 0.5% - considered well within the accuracy necessary for this study.

V. METHOD OF STUDY

V. METHOD OF STUDY

This section describes the methods used to assess the technical feasibility of installing production and transportation system and to estimate cost and revenue for a Kuvlum development. A range of reserve size and production rates are considered.

V.1 Technology Assessment

At the outset of this study existing technology for the offshore Arctic was evaluated. This evaluation involved reading the technical literature, interviews with selected Arctic scientists and engineers, and reviewing development plans of others for sites offshore Canada which were similar to Kuvlum conditions.

The decision was made early on to apply "existing" technology in this study of potential Kuvlum development. Existing in the sense that conceptual designs of structures and ice criteria developed during the 1970's and 1980's for offshore Canada and Alaska would be used as is or perhaps, if time permitted and if judged appropriate, updated to fit more closely the anticipated site and production requirements of Kuvlum. Similarly, the design and installation offshore and onshore pipelines would be based on existing technology and anticipated conditions from Kuvlum to TAPS Pump Station #1.

The decision to use existing technology and criteria was made primarily because time (less than one year) and budget (no major expenditures on technology or data collection would be made before completion of 1993 delineation wells) clearly did not allow any significant development of new technology or ice criteria. Several Arctic consultants were retained to summarize existing technology, environmental data and ice criteria applicable to Kuvlum. These consultants were asked to address future data programs and design studies if the decision was made to develop Kuvlum.

Upon completion of the review of existing technology, environmental data and ice criteria, the decision to use existing technology and data was judged to be technically sound as well as practical.

Development of Kuvlum is judged to be technically feasible within the range of cost estimated in this study. Site specific data (mainly geotechnical and ice) and better definition of production and transportation requirements obviously will narrow the range of costs estimates.

There was agreement between retained consultants and in-house engineering that permanent Kuvlum structures would be bottom founded and large because of the ice and bottom conditions, stability requirements during tow and installation, and production/drilling requirements. Restricting consideration to only vertically sided structures was discussed with retained consultants and decision was made to restrict the Kuvlum structures to this configuration. See Appendix 3 for additional discussion.

Adaptations of traditional offshore pipeline design and construction techniques were chosen for Kuvlum offshore sales and infield pipelines. Adaptations of traditional techniques were required due mainly to the burial depth required for protection against ice gouging and the brief window during summer for towing and installation. The connection of pipeline to structure is basically the only aspect where proven practice does not exist.

Tunnels were evaluated as a means of constructing offshore pipelines and protecting them from ice gouging and permafrost settlement. Tunnels as a means of access and as storage of large oil spills or blowouts were also evaluated. There is little published literature on offshore tunnels used for these purposes. Some private studies exist, but decision was made to not purchase or trade for these studies. Instead the decision was made to commission a tunnel study explicitly for Kuvlum requirements and route conditions. Existing tunnel technology was the primary basis for this study. Results of this study of tunnels are shown in Appendix 7.

Design, fabrication and installation of topside facilities for drilling, production and processing were based on existing technology.

V.2 Cost and Revenue Estimates

Ranges of reserve size, production/processing rate, produced stream characteristic, development well count and characteristic, and transportation needs were established in the second quarter of 1993 based on limited knowledge of Kuvlum. These ranges were selected to cover a reasonable spread of Kuvlum requirements. Production facilities, structures and pipelines were then sized to meet these requirements. Estimates of cost to design, fabricate, permit and install these facilities were made using latest cost data from onshore Alaska production facilities and past cost studies of offshore Arctic platforms and pipelines. Far East steel fabricators updated unit costs to build the large Kuvlum structures. Specific cost estimates are described in various sections in the Appendix.

Where appropriate, the general knowledge of the Kuvlum site was incorporated in the design and sizing of facilities. For example, the general knowledge of the Kuvlum soil conditions were used in sizing size and weight of Kuvlum structures and burial cost of the pipelines.

Costs for operation and maintenance, onshore pipelines and permitting were based on past experience with onshore North Slope fields. See Appendix 8, Appendix 2, and Appendix 5, respectively.

Development well costs were based on the 1992 discovery well and the first 1993 delineation well.

Royalty and tax rates are listed in Section III.3.

Revenue streams were based on State of Alaska Price Forecast shown in Appendix 9.

To convey the accuracy of these cost estimates, ranges of total installed costs were estimated for structures, production and processing facilities and pipelines.

Economic analysis were made based on these cost ranges. The analysis was made for several reservoir sizes and production rates. These cases as well as analysis performed and results obtained are described in Sections III and IV, and Appendix A10.13.

KUVLUM PREDECISION STUDIES

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APPENDIX 1

OFFSHORE SALES PIPELINE AND INFIELD PIPELINES

APPENDIX 1: OFFSHORE SALES PIPELINE AND INFIELD PIPELINES

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APPENDIX 1: OFFSHORE SALES PIPELINE AND INFIELD PIPELINES

Summary

The scope of work included investigating methods and costs for installing three sections of pipelines. Two of these sections would be part of any Kuvlum development, 1) the sales pipeline from the main production platform to Point Thomson (or Flaxman Island) and, 2) the sales pipeline from Point Thomson to Pump Station 1 of the Trans-Alaska Pipeline (TAPS). A third section may or may not be part of a Kuvlum development, the infield pipelines from a satellite platform to the main production platform.

The biggest part of the report deals with costs and methods of construction for the 30" sales pipeline from the main production platform to Flaxman Island. Methods of "conventional" construction for this section can be divided into protection and installation.

The main threat to this pipeline is ice gouging. Protection of the pipeline is provided by placing it in a trench which varies in depth from approximately 9 feet near the beach to over 22 feet at the main platform. Trenches of moderate dimensions may be dug by dredging, plowing, or jetting, but dredging is the only method currently available which can reliably achieve the depth needed along this route. The cutter suction dredge would be the primary trenching vessel.

Installation of the pipeline is technically feasible today by towing or pulling it into place or by using a lay barge; but making up the pipe on land and pulling it into place with an anchored pull barge is expected to provide the lowest cost and shortest time of exposure to possible ice interference. The time required for installation is an important determinant of the method because the open water season for construction with floating vessels averages only about two months per year. The weight of the pipe would be selected to have a slightly negative buoyancy when air-filled to keep the pulling force to a minimum. Design and construction of the sales pipeline would take about five years from the decision to go ahead to hydrostatic testing of the line. The expected cost of the section from the main platform to Point Thomson would be about $170 MM.

In addition to considering conventional construction for the sales pipeline from the main platform to Flaxman, the cost of placing the pipeline in a tunnel was estimated. Cost of the tunnel was estimated by Woodward-Clyde Consultants and is presented in Appendix 7. The cost of the tunnel and a pipeline in it so far exceeded the cost of conventional pipeline construction that it is not a competitive option.

Several methods of trenching and installation which have the potential to save significant costs by reducing dredge quantities but which would require research and development to make them feasible were briefly mentioned but were not used in cost estimates.

The pipeline can be connected to the production structure with a junction box and riser which allow either the pipeline or the structure to be placed first. The expected cost of this is included in the total above for the sales platform from the main platform to Point Thomson.

A route considered for the sales pipeline from Flaxman to TAPS Pump 1 was offshore in shallow water. The installation spread would work from thickened ice, slotting the ice and trenching through it, making up the pipe on the ice, and then lowering it into place. This offshore route provided no clear cost advantage compared to the route going across land from Point Thomson to TAPS Pump Station 1 and, therefore, the cost of the overland route was used in cost estimates for the overall development. The most likely cost estimated for the offshore route was $148MM. An expected cost was not calculated. The methods used for the offshore shallow water route are applicable to the short section of pipe connecting Flaxman Island to Point Thomson.

The infield pipelines would be laid in two bundles. One bundle would be only a 30" three-phase line carrying production from satellite to main. The other bundle would be a 20" gas injection line and a 12" gas lift or water injection line flowing back to the satellite. A separate power and instrument cable bundle would be laid in the same trench. The best methods of construction for the sales pipeline from the main production platform to Flaxman were also applicable to the infield pipelines. Typical trench depth for the infield pipelines would be 25 feet. The infield pipelines would be installed in the sixth year after the decision to go ahead. The expected cost of the infield pipelines would be $85 MM.

Assumptions

- Line length from main platform to Flaxman Island = 16 miles
- Line length from Flaxman Island to Pt. Thomson = 2.4 miles
- Line length from main platform to satellite platform = 6 miles
- 30" sales line coated for corrosion prevention, no weight coating
- All pipelines uninsulated thermally
- Trenches offshore from Flaxman Island will not be backfilled for the most likely case
- Trench profile from Figure A1-11
- Soil conditions described in Appendix A10.12.
- Onshore pipe make-up yard at Flaxman Island

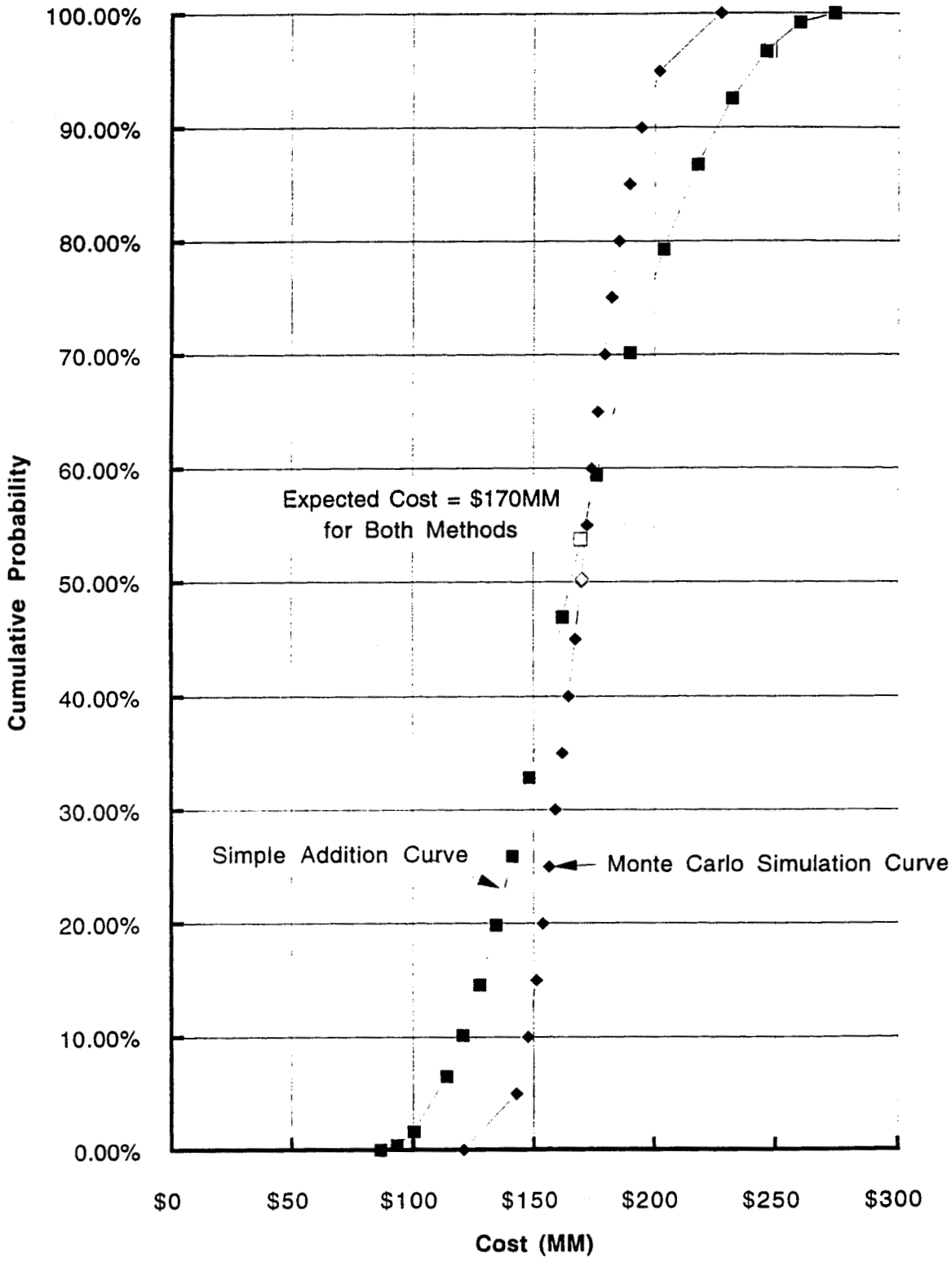


Figure A1-3
Main Sales Pipeline (30" Buried) from Kuvlum Platform to Flaxman Island to Pt. Thompson

This Spread Sheet will compute the unique Triangular Probability Density Distribution and the unique Cumulative Probability Curve determined by the k'%, Most Likely and k"% Cost Estimates

INPUT:		*Costs in $1,000,000*	
	k' & k'Cost Estimate	0.1	$120.50
	Most Likely Cost Estimate	b=	$148.00
	k''' & k'''Cost Estimate	0.9	$225.20

Sales Pipeline (30") from Kuvlum Platform to Flaxman Island to Pt. Thomson.

0% cost = $86.61 **100% Cost= $273.69**

See Table for Probability Density vs. Cost, Mean & Median Costs

To Calculate the Absolute Minimum Cost (0% Cost Estimate) which will be called "a" and the Absolute Maximum Cost (100% Cost Estimate) which will be called "c". Note the Most Likely Cost is called "b".

The k', Most Likely, and k"'Cost Estimates completely define the Triangular Probability Density Distribution and Cumulative Probability Curves. An interative procedure has to be used to calculate "a" and "c"; that is, the 0% Cost Estimate and the 100% Cost Estimate, respectively.

First step is to determine which set of equations are applicable to find "a"'and "c". This will depend on where the Most Likely Cost Estimate "b" lies relative to k' and k"'Cost Estimates.

Please note that k'Cost Estimate is always less than k"'Cost Estimate.

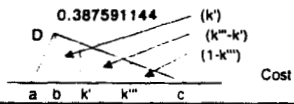
FOR THE ABOVE K'COST, MOST LIKELY COST AND K"'COST ESTIMATES USE XXXXXXX **MIDDLE CASE** XXXXXXX

CASE LEFT

If Most Likely Cost Estimate < k'Cost Estimate

c=	277.55000
D=	0.00945440
a=	66.00831725

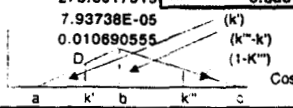
Therefore k2 for Most Likely Cost Estimate is equal to 0.387591144



CASE MIDDLE

If (k'CostEstimate<Most Likely Cost Estimate<k'''Cost Estimate), iterate to Find Absolute Minimum 'a' and Maximum 'c' Cost Estimates. Try values of 'a' until c'=c''. Trial 'a'= 86.61085

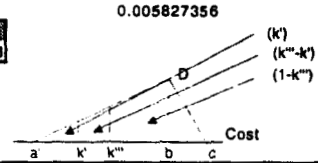
c'=	273.6918713	0.00001
c''=	273.6917919	0.0001
Delta=(c'-c'')=	7.93738E-05	86.61086
D=	0.010690555	



CASE RIGHT

If (k'Cost Esti.<k'''Cost Esti.>Most Likely Cost Esti.),

a=	68.15
c=	411.3588291
D=	0.005827356



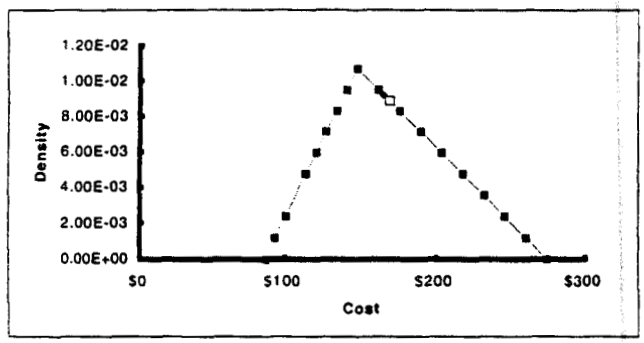
Is a <k'Cost Estimate? Yes, Valid
Is K'<K'''? Yes,Valid

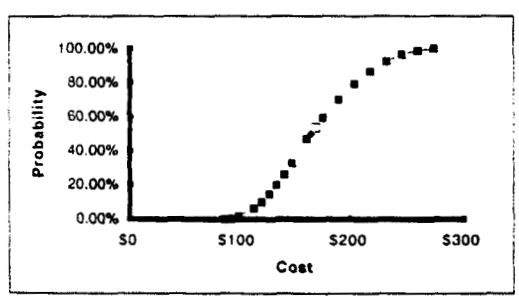
Please Note that you must enter the values calculated above into these slots before computing distributions.

Enter the Values of "a", "c", and D computed above		
	a=	$86.6109
	c=	$273.6919
	D=	0.01069056

Calculating Probability Density Distribution and Cumulative Probability Curves

	Cost in $1,000,000 $	Probability Density (1/$)	Cumulative Probability %
	$87	0.00E+00	0.00%
	$93	1.19E-03	0.41%
	$100	2.38E-03	1.62%
	$114	4.75E-03	6.48%
	$114	4.75E-03	6.48%
	$121	5.94E-03	10.13%
	$128	7.13E-03	14.58%
	$134	8.31E-03	19.85%
	$141	9.50E-03	25.93%
Most Likely	$148	1.07E-02	32.81%
	$162	9.50E-03	46.91%
	$176	8.31E-03	59.36%
	$190	7.13E-03	70.14%
	$204	5.94E-03	79.26%
	$218	4.75E-03	86.73%
	$232	3.56E-03	92.53%
	$246	2.38E-03	96.68%
	$260	1.19E-03	99.17%
Absolute Maximum	$274	0.00E+00	100.00%
MEAN COST	$169.43	8.87E-03	53.77%
MEDIAN COST	$165.26	0.009222455	50.00%





RSKWC12.xls Robert E. 12/14/93

FIGURE A1-4
Sales Pipeline (30") from Kuvlum Platform to Flaxman Island to Point Thomson

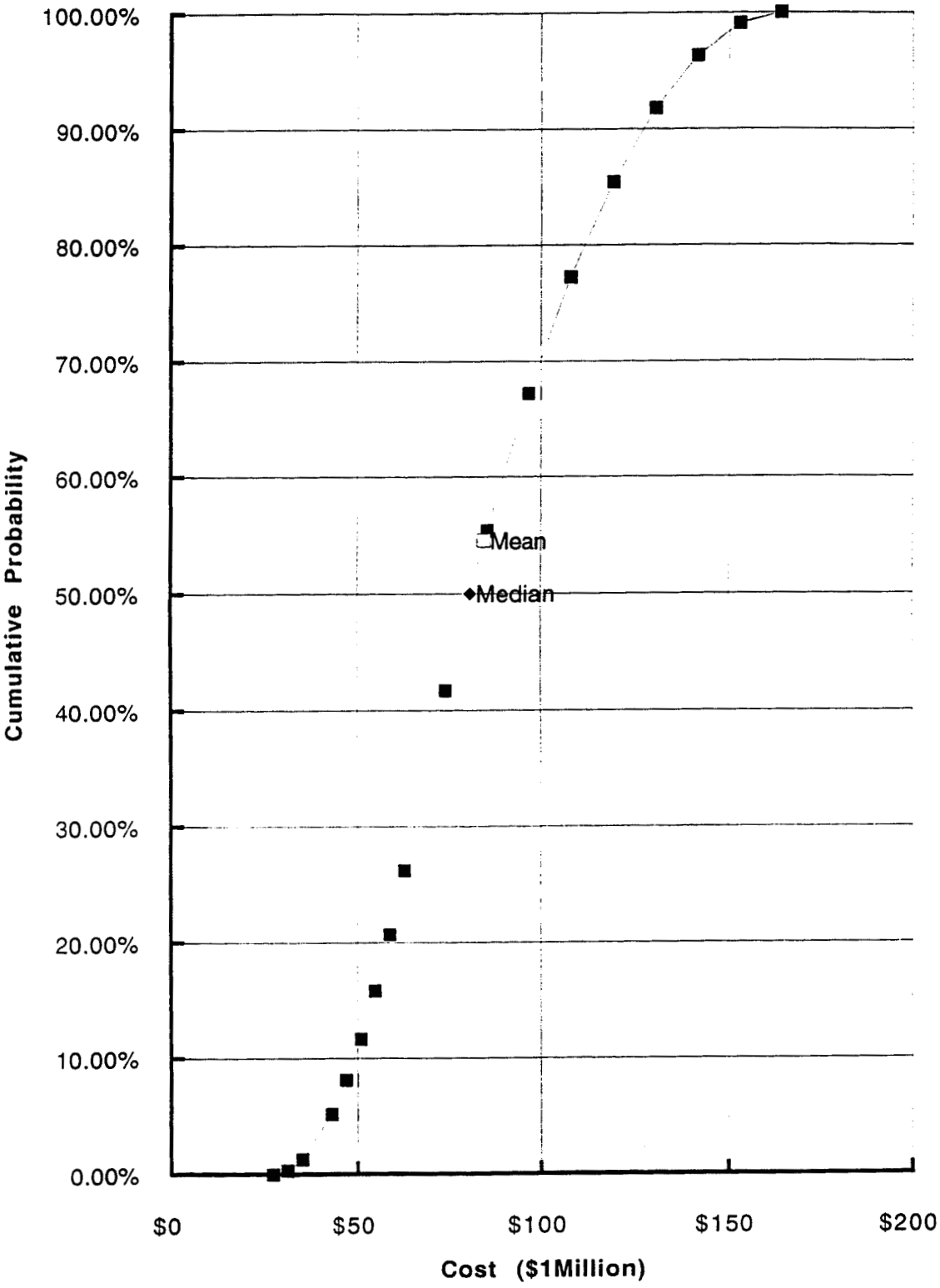


Figure A1-5
Cost of Infield Pipelines (30" , 20", 12") Buried

This Spread Sheet will compute the unique Triangular Probability Density Distribution and the unique Cumulative Probability Curve determined by the k'%, Most Likely and k"% Cost Estimates

INPUT:		Costs in $1,000,000	
	k' & k'Cost Estimate	0.1	$49.09
	Most Likely Cost Estimate	b=	$62.89
	k''' & k'''Cost Estimate	0.9	$126.98

Infield Pipelines (30, 20, 12 inch) between Main Platform and Drilling Platform, 6 Miles Length, Buried

0% cost = $26.82 **100%Cost= $164.32**

See Table for Probability Density vs Cost, Mean & Median Costs

To Calculate the Absolute Minimum Cost (0%Cost Estimate) which will be called "a" and the Absolute Maximum Cost (100% Cost Estimate) which will be called "c". Note the Most Likely Cost is called "b".

The k', Most Likely, and k"'Cost Estimates completely define the Triangular Probability Density Distribution and Cumulative Probability Curves. An interative procedure has to be used to calculate "a" and "c"; that is, the 0%Cost Estimate and the 100% Cost Estimate, respectively.

First step is to determine which set of equations are applicable to find "a"and "c". This will depend on where the Most Likely Cost Estimate "b" lies relative to k' and k"'Cost Estimates.

Please note that k'Cost Estimate is always less than k"'Cost Estimate.

FOR THE ABOVE K'COST, MOST LIKELY COST AND K"'COST ESTIMATES USE **XXXXXXX MIDDLE CASE XXXXXXX**

CASE LEFT

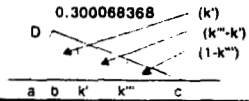
If Most Likely Cost Estimate < k'Cost Estimate

c= 165.91678

D= 0.01358767

a= 18.72453464

Therefore k2 for Most Likely Cost Estimate is equal to 0.300068368



CASE MIDDLE

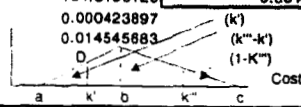
If (k'CostEstimate<Most Likely Cost Estimate<k'''Cost Estimate), iterate to Find Absolute Minimum 'a' and Maximum 'c' Cost Estimates. Try values of 'a' until c'=c''. Trial 'a'= 26.8222

c'= 164.3200362

c''= 164.3196123

Delta=(c'-c'')= 0.000423897

D= 0.014545683



CASE RIGHT

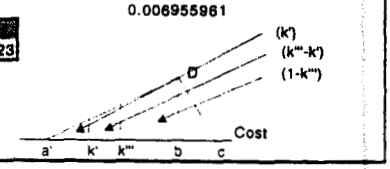
If (k'Cost Esti.<k'''Cost Esti.>Most Likely Cost Esti.),

a= 10.1507569

c= 297.8739469

D= 0.006955961

0.0001 0.001 26.8223



Is a <k'Cost Estimate? Yes, Valid

Is K'<K'''? Yes,Valid

Please Note that you must enter the values calculated above into these slots before computing distributions.

Enter the Values of "a", "c", and D computed above

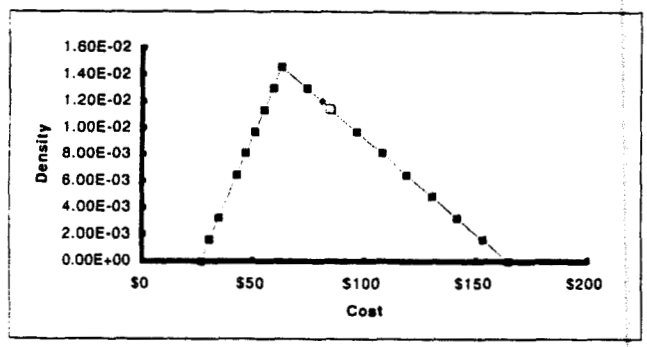
a= $26.8222

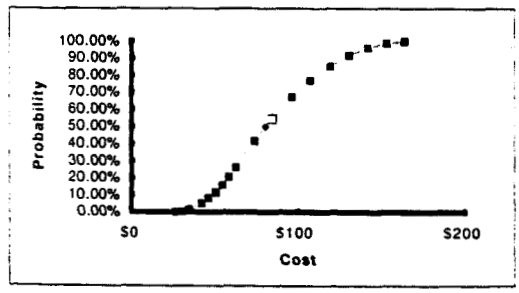
c= $164.3200

D= 0.01454568

Calculating Probability Density Distribution and Cumulative Probability Curves

	Cost in $1,000,000 $	Probability Density (1/$)	Cumulative Probability %
	$27	0.00E+00	0.00%
	$31	1.62E-03	0.32%
	$35	3.23E-03	1.30%
	$43	6.46E-03	5.18%
	$43	6.46E-03	5.18%
	$47	8.08E-03	8.10%
	$51	9.70E-03	11.66%
	$55	1.13E-02	15.87%
	$59	1.29E-02	20.73%
Most Likely	$63	1.45E-02	26.23%
	$74	1.29E-02	41.72%
	$85	1.13E-02	55.38%
	$97	9.70E-03	67.21%
	$108	8.08E-03	77.23%
	$119	6.46E-03	85.43%
	$131	4.85E-03	91.80%
	$142	3.23E-03	96.36%
	$153	1.62E-03	99.09%
Absolute Maximum	$164	0.00E+00	100.00%
MEAN COST	$84.68	1.14E-02	54.52%
MEDIAN COST	$80.82	0.011975362	50.00%





RSKWC12.xls Robert E. 12/14/93

FIGURE A1-6
Costs of Infield Pipelines (30", 20", 12") Buried

A1. OFFSHORE PIPELINE CONSTRUCTION FOR THE KUVLUM DEVELOPMENT

A1.1 Objectives

The purpose of this report is to provide cost estimates for offshore pipelines for the Kuvlum development. The estimates in this report can be grouped into three categories.

1. The first estimate is for "conventional" pipelines connecting the main production platform to the satellite platform and Flaxman Island, and connecting Flaxman Island to the beach near Pt. Thomson. Conventional means that a trench is dredged for the pipeline and the pipeline is placed in it by floating vessels.

2. The second estimate is for pipelines placed in tunnels connecting the same sites as above. Estimates provided by Woodward-Clyde must be combined with these to get the total cost of pipeline installation.

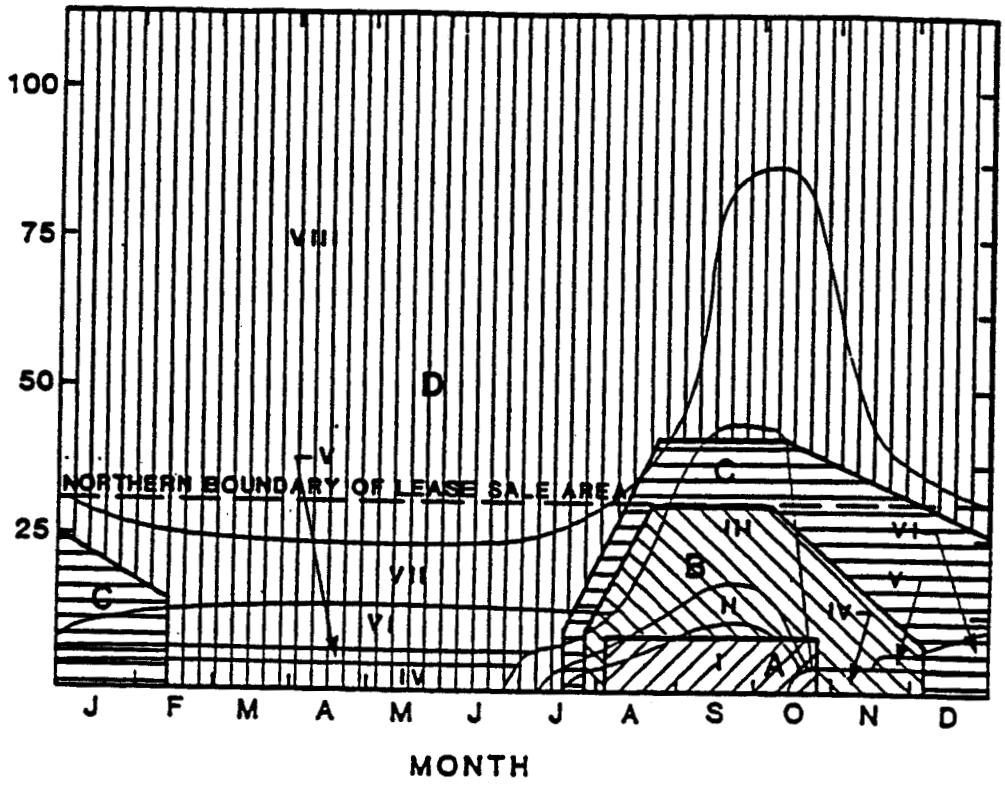
3. The third estimate is for an offshore pipeline in shallow water connecting Flaxman Island to Prudhoe Bay.

A1.2 Environmental Conditions

Ice Coverage

The ice conditions used for determining lengths of the summer and winter construction seasons were taken from the reference Offshore Pipeline Transportation Feasibility and Costs, Diapir Area, Alaska by R. J. Brown and Associates and from statistics supplied by Vaudrey and Associates, Inc. The RJBA report provides descriptions of median conditions at four different locations in the Beaufort and Chukchi Seas. The location of the one which was closest to the Kuvlum prospect is the area north from Barter Island and the descriptions of ice conditions there are included in this study for illustration. Because Barter Island juts out from the coastline more than Flaxman Island, which is the probable landfall of a Kuvlum sales pipeline, ice coverage actually diminishes to a distance farther out along a Kuvlum pipeline route than it does due north of Barter Island after breakup is well underway. Therefore, the physical ice zone plot for Barter Island, Figure A1-8, should be modified by assuming that the boundary for Construction Season A should be some distance, perhaps ten miles, farther offshore than shown in the drawing.

Brief descriptions of four different operating ice conditions are given in Figure A1-8 and the duration of those seasons in probabilities are given in Figure A1-9. Ice Condition A, which is defined as either less than eight inches of new ice or less than two oktas, is the only condition which is considered as being even partly suitable for open-water construction. Consistent with the needed modification mentioned above, it is reasonable to assume along a Kuvlum pipeline route that the offshore boundary for Season A is at twenty miles offshore rather than eight miles offshore.



PHYSICAL ICE ZONES

I	<1 OKTA
II	1–4 OKTA
III	5–7 OKTA
IV	SMOOTH FAST ICE
V	ROUGH FAST ICE
VI	VERY ROUGH MOBILE ICE
VII	UNCONSOLIDATED MOBILE ICE (7–8 OKTAS)
VIII	DRIFTING ICE PACK

OPERATING ICE CONDITIONS FOR FLOATING EQUIPMENT

A: <8" NEW ICE OR <2 OKTA

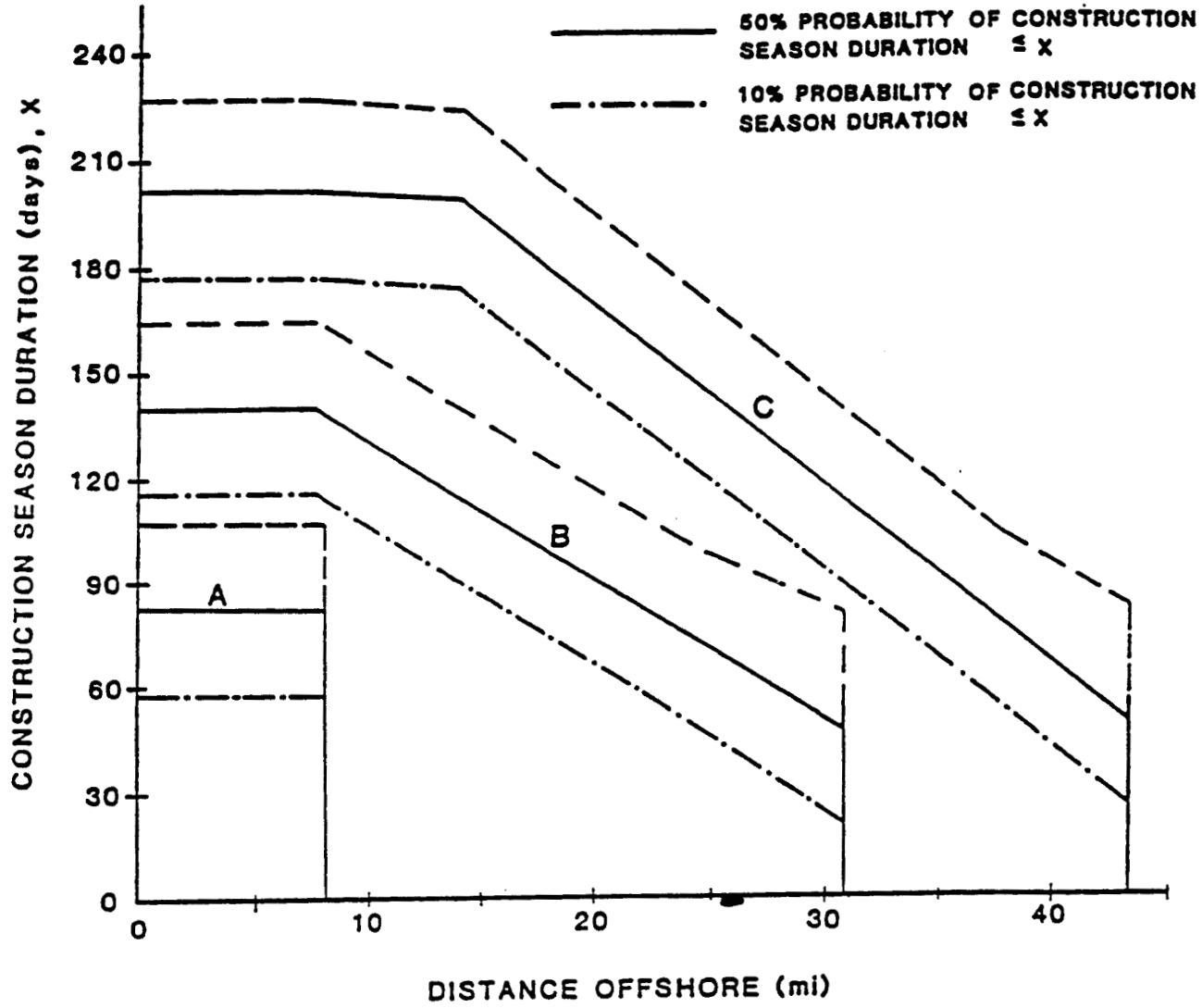
B: <2' NEW ICE OR <6 OKTA

C: <5' ICE WITH RIDGES OR >6 OKTA

D: >6' ICE WITH LARGE RIDGES INCLUDING PACK ICE

JOINT INDUSTRY STUDY	PHYSICAL ICE ZONES AND OPERATING ICE CONDITIONS BARTER ISLAND (NORTH)						
RJBA R. J. BROWN AND ASSOCIATES	SCALE	DRAWN	CHECKED	DATE	JOB NO	DRAWING NO.	REV.
	NONE	mes		1.3.84	2269.01	3-100	0

FIGURE A1-8



JOINT INDUSTRY STUDY	CONSTRUCTION SEASON DURATION BARTER ISLAND NORTH						
RJBA R. J. BROWN AND ASSOCIATES	SCALE	DRAWN	CHECKED	D.M.Y.	JOB NO.	DRAWING NO.	REV.
	AS NOTED	mes	GAL	9.2.84	2269.01	3-105	0

FIGURE A1-9

Vaudrey's statistics (Appendix A10.2) are given in terms of open water which is defined as less than one-tenth of ice coverage. Vaudrey's report gives the average open water season as 58 days for a point 10 to 12 miles northeast of Flaxman Island. Vaudrey defined open water as less than one-tenth ice coverage and, therefore, the average length of the season he defined was less than that defined for Ice Condition A in Figure A.1.1 and A.1.2 from RJBA's report. For scheduling purposes, it has been assumed that the average open water season for dredging and pipe laying will be two months. The report by Vaudrey is attached as an appendix.

The *Alaska Marine Ice Atlas* was also used to establish constraints on the schedule. Based on the retreat and advance of the ice edge as shown in the *Atlas*, it is assumed that the trench digging spread would be able to work only half a season during the first season it arrives in the Beaufort Sea because of the transit time along the coast of Alaska.

Ice Gouging/Preliminary Burial Depth

Figure A1-11 entitled 'Preliminary Burial Depth Profiles Along a Kuvlum Pipeline Route' was used to select burial depths for the pipeline. The assumption was made for the purposes of cost estimating that getting the top of the pipe below the predicted scour depth would be sufficient to protect the pipe from damage. It is clear from research done by the Center for Cold Oceans Resource Engineering and by others that soil deformation actually takes place below the scour under some circumstances and the assumption above is therefore not correct for all water depths. However, the required depth for burial to protect from unacceptable deformation cannot be determined at this time. The phenomena of ice gouging and sub-scour deformation are discussed further in the following paragraphs.

At least two different types of ice gouging can occur. An ice keel of large horizontal dimensions can cause a bearing capacity failure as its weight rests on the soil and it travels horizontally. This type of failure would obviously cause soil deformation beneath the soil surface and a pipe in this deformed soil could be significantly damaged. It is intuitive that the weight of an ice sheet and its ability to withstand an upward force without breaking or bending the sheet are the determinants of the vertical force. It is also intuitive that as the contact area between ice keel and soil increases, the pressure on the soil decreases. The depth of soil being deformed beneath the scour should be related to the plan dimensions of the loaded area if a bearing capacity failure is occurring. Therefore, the narrower an ice keel, the deeper it can force itself into the soil for a given ice sheet, but perhaps the lesser is its influence on soil deformation beneath the scour.

Another type of ice gouging could merely be plowing of the soil somewhat like the action of a farm plow. It seems reasonable that the plowing action would cause little deformation beneath the gouge. A pipe whose top is just below this type of gouge could probably survive the event without any significant consequences. A combination of gouging actions, both plowing and bearing capacity failure, is also obviously possible.

FIGURE 11
BURIAL DEPTH PROFILE
RP = 1000 Years (Lambda - 1)

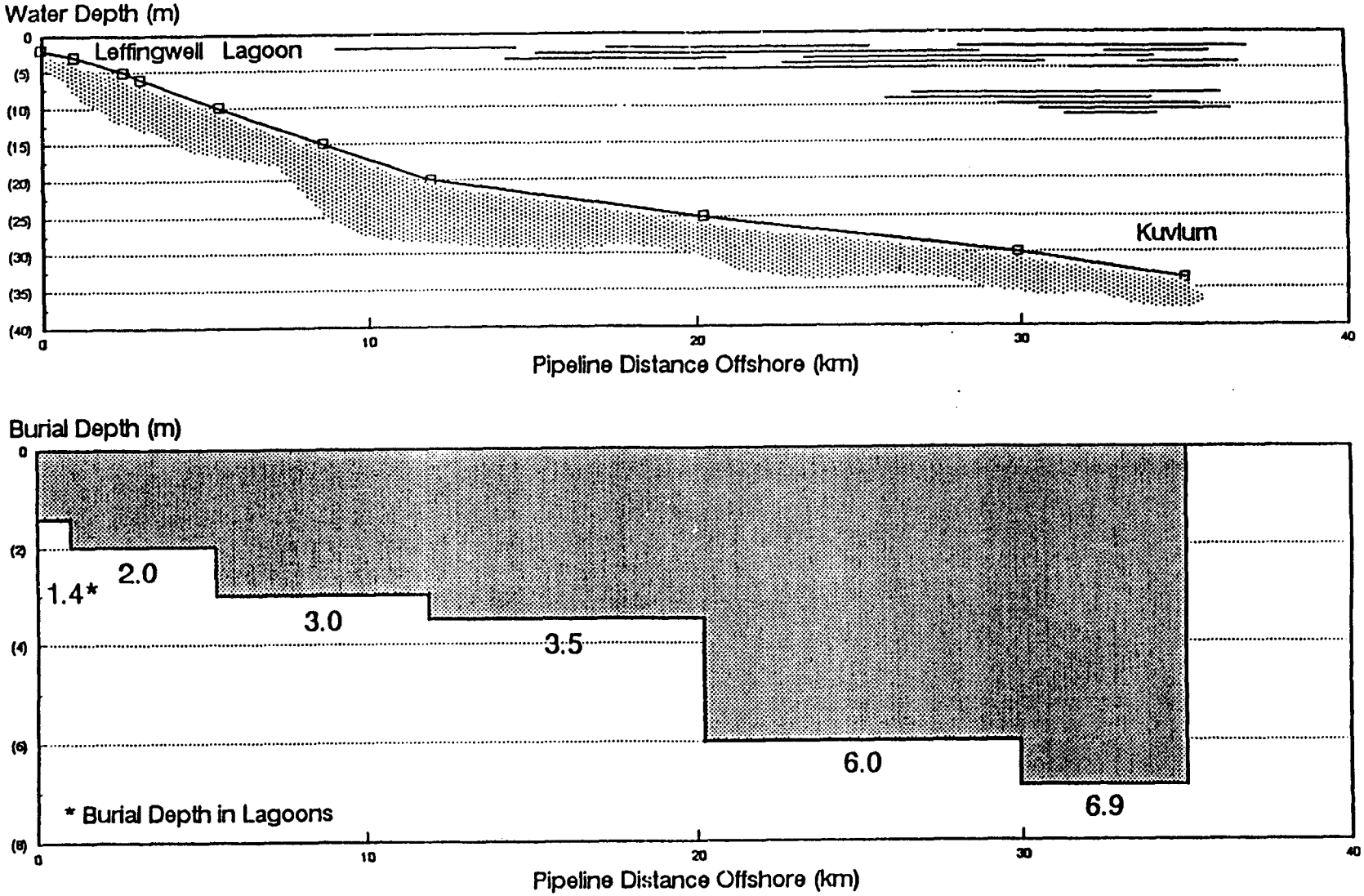


FIGURE A1-11

It is not known at this time what conditions determine the type of gouge that occurs and how the type of gouging varies with water depth, but it is not apparent at all that the ice keel which causes the maximum depth of scour would also cause soil deformation to the maximum depth below the scour. for this reason, it has been assumed that putting the top of the pipe just below the maximum predicted depth of scour would protect it from being significantly damaged. This assumption can be improved as knowledge increases.

Wind, Wave, and Current

Figure A1-13, Significant Wave Height Data, reproduced from the 1984 RJBA report defines oceanographic conditions for this study.

TABLE 3-2 SIGNIFICANT WAVE HEIGHT DATA
FROM R. J. BROWN 1984 REPORT

BEAUFORT SEA

MONTH	% LESS THAN	
	WAVE HEIGHT 3.3 ft	WAVE HEIGHT 6.7 ft
JULY	90	100
AUGUST	85	98
SEPTEMBER	76	92
OCTOBER	80	90

CHUKCHI SEA

MONTH		% LESS THAN	
	WAVE HEIGHT 3.3 ft	WAVE HEIGHT 6.7 ft	WAVE HEIGHT 9.8 ft
JULY	92	99	100
AUGUST	89	98	99
SEPTEMBER	85	97	99
OCTOBER	79	98	100

FIGURE A1-13
Significant Wave Height Data for Beaufort Sea and Chukchi Sea

A1.3 Soil Conditions

For purposes of calculating productivity of trenching in the Beaufort Sea soils, the soils must be classified as granular or cohesive. Cross Section A-A' of Figure 25 of the report found in Appendix 10.6 by Arctic GeoScience entitled *Eastern Beaufort Sea Synthesis* will be taken as representative and the percentage split between granular and cohesive of the soils in the top twenty feet of these borings will be assumed to be representative of the soil along the pipeline route. The soils in the top twenty feet of the borings of cross section A-A' are about 22% granular and 78% cohesive.

The following soil profiles are recommended for use of conceptual design of pipelines and tunnels for the Kuvlum prospect. These profiles are taken from the *Eastern Beaufort Sea Synthesis* compiled by Arctic GeoScience. The profiles are listed below in the order they would be encountered by a pipeline route from onshore to the Kuvlum platform site. Two routes are given below. Figure numbers in the route descriptions below refer to original figures in the Arctic GeoScience report.

Route 1: Crossing Flaxman Island

Soil Unit QHl/1c. The area of this unit is south of Flaxman Island and is shown crosshatched in green on Figure 16. The profile is shown in the lower half of Figure 20. Though the surficial part of the profile is labeled QHm, this profile is still applicable to the unit. Tunneling would possibly go to a depth deeper than the bottom of the profile. Therefore, the profile can be assumed to be dense to very dense sands and gravels below the maximum depth shown.

Soil Unit Qf/QPu/2A. This unit is north of Flaxman Island and is a relatively thin strip shown in white on Figure 16. The profile is shown in the upper half of Figure 21. Again, tunneling would possibly go to a depth deeper than the bottom of the profile. Therefore, assume dense to very dense sands and gravels exist below the maximum depth shown.

Soil Unit QPm/2B. This unit is shown with blue lines on Figure 16. The profile is shown in the lower half of Figure 21. Again, assume dense to very dense sands and gravels exist below the maximum depth shown.

Soil Unit QHm/2c. This unit is shown with green lines on Figure 17. The profile is shown in Figure 22. Assume that the soil below the profile can be diverse ranging from stiff marine clay and silt to very dense sands and gravels.

Route 2: East of Flaxman Island

QHd/1A or Qf/1B. The listing of two units, which are very similar, stems from having two different interpretations of data in the area. The QHd/1A unit is shown with green triangles in Figure 16 and the profile is shown in the upper half of Figure 19. The Qf/1B unit is shown as a purple crosshatched area on Figure 17 and the profile

would consist of the upper half of Figure 20 with a thin lag deposit of gravel, cobbles, and boulders imposed at the top. Assume that the subprofile labeled Sag Delta characterizes the strip rather than the subprofile labeled Colville Delta.

Qf/QPu 2A or QPm/2B. See descriptions above.

QHm/2C. See description above.

Assume that rock, by the civil engineer's definitions, would not be encountered until a depth of well below 1000 feet. Rock would not be encountered in some areas until below 2000 feet.

A1.4 Trenching

Trenching Methods - Feasibility and Costs

Cutter suction dredging is feasible, as stated by every reference, for dredging in the deeper waters. Minimization of over dredging can increase production rates. Control of trench depth and lateral position control are both important. Past heavy usage of cutter suction dredges was where large volumes of material had to be removed and excavation accuracy was not of primary importance. The 1984 RJBA Diapir Area report estimated peak production rates for trenching of 25,000 to 65,000 cubic yards per day depending on soil type (Figure A1-16). The cutter suction dredge is much better than a trailing suction dredge in cohesive soils. RJBA estimated typical excavation side slopes for long-term stability as 1:1 in stiff clay and 1:10 in loose sand. Slopes could be increased if only short-term stability is required. Ladder extensions can increase water depth applicability to 110 feet. Ice tolerance is poor. Weather sensitivity is poor; large dredges are limited to maximum swells of four to five feet. Power requirements for large dredges are 10,000 hp for main pumps and 3000 hp for the cutterhead. Enhancements considered by RJBA for existing equipment are to ice-strengthened hulls to Canadian Arctic Shipping Pollution Prevention Regulation (ASPPR) Level 2, install provision for sidecasting of spoil, and extend the ladder to enable dredging in deeper water depth; peak production rate would still be 65,000 cubic yards per day.

The Trailing Suction hopper dredging was claimed by RJBA in the Diapir Area report to be the most cost effective in water depths of 30 ft.-plus if enhanced. It is typically used for sand reclamation or maintenance dredging. The hopper is used to transport spoil. Peak production rate for existing equipment was estimated at 50,000 cubic yards per day using one draghead. Total dredging accuracy on existing equipment is ±15-17 feet perpendicular to the pipeline route. Shaping of a trench is more difficult than with a cutter suction dredge because it would be done with repeated passes. Typical depth of material removed in each pass is eight inches. Existing capability (1983) was 130 feet water depth with past extensions to 180 feet. Tolerance to ice is slightly better than the cutter suction dredge because the trailing arm includes gimbals. Production rate in clay is typically 50% to 75% of that loose sand. Enhancements to existing equipment recommended by RJBA are ice-

PEAK PRODUCTION RATES FOR LARGE
(10,000 PUMP HORSEPOWER)
SUCTION CUTTER DREDGE
from
R. J. Brown Report 1984

Material	Maximum Spoil Discharge Distance Miles	Peak Production Rate Cubic Yards/Days
Sand	2 to 4	50,000
Soft Clay	4	65,000
Stiff Clay	2	25,000

FIGURE A1-16
Peak Production Rates for Suction Cutter Dredge

strengthen the hull to ASPPR 2, install provisions for linking drag arms so that both can be used simultaneously, install provisions for side casting of spoil, extend drag arms if necessary. The Trailing Suction Hopper Dredge is not well suited for dredging in stiff clay.

Trailing suction dredging is favored by Ham/Volker Stevin for the Beaufort Sea but Great Lakes Dredge and Dock favors cutter suction dredging.

A single-pass plow was considered cost effective by RJBA in the Diapir Area report for trenches less than eight feet deep; development of a multi-pass plow was recommended for trench depths less than eleven feet. The plow is mechanically simple and is cheaper and faster than other trenching methods for limited trench depths. Plowing can be done before or after a pipeline is laid. Accuracy is generally good in the post-trench mode but can be non-uniform in areas of irregular bottom topography. Depth is limited by geometry of the plow beam and shares, structural strength of the plow frame and shares, stability of the trench after the plow frame has passed, bending stress in the pipe, and strength of the cradle which supports the pipeline at the rear end of the plow. Multi-pass plows have been studied but no records in literature report use on a production basis. Post-trenching is preferred, but pre-trenching is possible. Plowing has good tolerance to ice, wind, wave, and current. A multi-pass plow would require five-plus passes in stiff clay. RJBA predicts a pull rate of 3.2 miles/day. This corresponds to about 60,000 cubic yards per day of soil removal for a trench depth of eight feet having slopes of 1:1.5.

Low pressure (60-500 psi) jetting has peak production rates of 20,000 cubic yards per day in permeable medium-dense sand. Peak production rates for high pressure jetting in sand and soft silt are about 130,000 cubic yards per day. Jetting has good accuracy because it can follow a pipeline. Side slopes for low pressure jetting will approach the soil's angle of internal friction. Side slopes for high pressure jetting are often much less, being in the range of 1:3 to 1:5. North Sea high pressure jetting sleds have a maximum trench depth of approximately 13 feet. Air eduction systems become less effective at water depths below 150 feet, but jetting operations are easily conducted in water depths to 300 feet. Tolerance to ice, wind, wave, and current is relatively good. RJBA claims jetting is not well suited for use with bottom tow or pull installations because pipes of low submerged weight (unflooded) may float in slurried soils and trenching over tie-in assemblies would result in extra handling and risk to the pipeline.

Enhanced Trenching Methods Requiring Additional Development

The volume of material which has to be removed is a major part of the cost of installing a pipeline in the Arctic. A Pipe Burial Train was proposed by RJBA in the Diapir Area report as a means of reducing this volume. The concept consists of a long box, open at top and bottom, with jets mounted at the front to dig the trench through which the box is moving. The sides of the box are vertical and act as shoring to keep the trench walls from collapsing. as the train moves along, the previously laid pipeline passes through the box. The box is long enough that a pipe section contacts trench bottom before the rear of box passes that section of pipe.

Engineers at Shell conceived the Simultaneous Trench and Lay (STL) method for narrow trenches to fifteen feet depth. This method also minimizes the volume of material removed for the trench. It is similar to RJBA's Pipe Burial Train but the pipe is first laid out on fast ice rather than on the bottom. A slot is cut in the ice and the pipe passes into the slot and down into the box. The box contains guide rollers which control the pipe sagbend to a maximum allowable strain level so that the pipeline reaches trench bottom in the shortest possible horizontal distance. Some preliminary engineering of the STL method was done but no prototype was ever built for either the STL or the pipe burial train.

Another idea to minimize the volume of material removed for a trench was proposed by Bob Smith of ARCO Exploration and Production Technology. This is to use a slurry trench technique to support the trench walls and thereby achieve vertical walls without the need for shoring. Slurry trench construction is now a common technique for constructing cutoff walls under dams, for containing pollutants in permeable soil strata, and for constructing deep concrete basement walls and could be adapted for offshore use. Deep pipeline trenches would be a new use of the technique and some research and development would be required, but the method seems attractive because it would minimize soil removal and eliminate the need for shoring. Once a slurry trench is formed, a pipeline would be jetted to the bottom of it or a weighted pipe could be placed on the bottom of the trench.

Conclusions on Trenching

Dredging is the only currently feasible way to achieve the needed trench depths greater than about eight feet or so along the offshore part of the Kuvlum pipeline route. The weaknesses are that the cutter suction dredge is sensitive to weather and the trailing hopper dredge is inaccurate, gives very flat side slopes, and is slow in stiff clay. For scheduling and cost estimating purposes, it has been assumed that one cutter suction dredge will be used and it will work as long as four seasons just to dig trenches. Total reliance on the trailing suction hopper dredge is not reasonable because its best reported performance with respect to trenching accuracy was to achieve 1v:5h side slopes, a wasteful profile for stiff clay. One option that should be considered in conceptual engineering is to use both cutter suction and trailing hopper dredges in combination in order to make use of the strengths of both. The hopper dredge would make the first few passes and would always be working. The cutter suction dredge would work somewhat less but would make the final passes. Another option to consider in conceptual engineering is to use a plow to make the final six feet in order to lessen the volume required in dredging.

The assumed cross sections for volume calculations for the most likely case are 1v:1.5h in clay and 1v:3h in sand with a twenty foot trench width at bottom and 10% cleanup of the original dredge volume required. Calculated volumes for this and the other cases listed below are given in Figures A1-19 and A1-20.

Soil is Clay

Depth of Ice Gouging	Length of Route With this Scour Depth	Length of Clay-Covered Route With this Scour Depth	Depth to Bottom of Trench	Dredged Depth	Volume of Soil Dredged per Foot of Pipeline	Volume of Soil Dredged in This Segment
meters	miles	miles	feet	feet	cubic yards	cubic yards
6.9	0	0.00	25.1	25.1	53.71	0
6	3.6	2.81	22.2	22.2	43.76	648,801
3.5	5.9	4.60	14.0	14.0	21.21	515,454
3	4.5	3.51	12.3	12.3	17.60	326,186
2	1.5	1.17	9.1	9.1	11.27	69,630

Total Volume in Clay cubic yards = 1,560,071

Soil is Sand

Depth of Ice Gouging	Length of Route With this Scour Depth	Length of Sand-Covered Route With this Scour Depth	Depth to Bottom of Trench	Dredged Depth	Volume of Soil Dredged per Foot of Pipeline	Volume of Soil Dredged in This Segment
meters	miles	miles	feet	feet	cubic yards	cubic yards
6.9	0	0.00	25.1	25.1	88.80	0
6	3.6	0.79	22.2	22.2	71.09	297,286
3.5	5.9	1.30	14.0	14.0	32.07	219,798
3	4.5	0.99	12.3	12.3	26.06	136,222
2	1.5	0.33	9.1	9.1	15.83	27,585

Total Volume in Sand cubic yards = 680,891

Total Volume along Route cubic yards = 2,240,962

Total Volume along Route + 10% cubic yards = 2,465,058

FIGURE A1-19
Volume Calculations for the Sales Pipeline from Main Platform to Flaxman Island
(Most Likely Cross Section)

Soil is Clay

Depth of Ice Gouging, meters	Length of Route With this Scour Depth miles	Length of Clay-Covered Route With this Scour Depth miles	Depth to Bottom of Trench feet	Dredged Depth feet	Volume of Soil Dredged per Foot of Pipeline cubic yards	Volume of Soil Dredged in This Segment cubic yards
6.9	3.3	2.57	25.1	25.1	53.71	729,905
6	2.7	2.11	22.2	22.2	43.76	486,601

Total Volume in Clay cubic yards = 1,216,506

Soil is Sand

Depth of Ice Gouging meters	Length of Route With this Scour Depth miles	Length of Sand-Covered Route With this Scour Depth miles	Depth to Bottom of Trench feet	Dredged Depth feet	Volume of Soil Dredged per Foot of Pipeline cubic yards	Volume of Soil Dredged in This Segment cubic yards
6.9	3.3	0.73	25.1	25.1	88.80	340,380
6	2.7	0.59	22.2	22.2	71.09	222,964

Total Volume in Sand cubic yards = 563,344

Total Volume along Route cubic yards = 1,779,850

Total Volume along Route + 10% cubic yards = 1,957,835

FIGURE A1-20
Volume Calculations for Infield Pipeline (Most Likely Cross Section)

For the case with 90% confidence of non-exceedance (pessimistic case) it has been assumed that the slopes in sand will go to 1v:5h, clay will go to 1v:2h, the trench bottom width will be twenty feet and 10% of the total original dredge volume will be cleaned out a second time. It has also been assumed that the trench will have to be backfilled after the pipe is placed and, therefore, substantial additional time has been added to this case for backfilling (Figures A1-22 and A1-23).

For the case with 10% confidence of non-exceedance (optimistic case) it has been assumed that the slopes will be 1:1 in clay and 1v:3h in sand with a ten foot bottom width and 10% cleanout required. No back filling is required (Figures A1-24 and A1-25).

As mentioned above, an important assumption which has been attached to the case with 90% confidence of non-exceedance is that backfilling over the pipe will be required. Since an ice sheet will be pushed up while gouging, it will drop if there is a sudden decrease in bottom elevation, such as a wide trench with very flat slopes. It is not known whether the dimensions of ice keels and pipeline trenches match up in such a way that an ice keel would drop into a trench and damage the pipe, but it has been assumed for the pessimistic case that backfilling is needed to prevent this problem.

The deep-water dredging spread will take the trench from water depths of about twenty feet to the platform sites. Then winter excavation will take the trench from the twenty foot water depth back to shore, i.e., trenching machines working from fast ice sheets. Conventional backhoes can reach down from an ice sheet to thirty feet below the working surface without modification and would have no trouble doing the work from ten foot water depth into shore.

Available borings show almost no ice-bonded soil in the depth range in which trenching would take place, i.e., the top twenty feet or so, from the barrier islands out to deeper depths. Ice-bonding of soil is unlikely to interfere with trenching offshore from the barrier islands.

Soil is Clay

Depth of Ice Scour, meters	Length of Route With this Scour Depth, miles	Length of Clay-Covered Route With this Scour Depth, miles	Depth to Bottom of Trench, feet	Dredged Depth, feet	Volume of Soil Dredged per Foot of Pipeline cubic yards	Volume of Soil Dredged in This Segment, cubic yards
6.9	0	0.00	25.1	25.1	65.40	0
6	3.6	2.81	22.2	22.2	52.87	783,871
3.5	5.9	4.60	14.0	14.0	24.83	603,397
3	4.5	3.51	12.3	12.3	20.42	378,447
2	1.5	1.17	9.1	9.1	12.79	79,020

Total Volume in Clay cubic yards = 1,844,736

Soil is Sand

Depth of Ice Scour, meters	Length of Route With this Scour Depth, mies	Length of Sand-Covered Route With this Scour Depth, miles	Depth to Bottom of Trench, feet	Dredged Depth, feet	Volume of Soil Dredged per Foot of Pipeline cubic yards	Volume of Soil Dredged in This Segment, cubic yards
6.9	0	0.00	25.1	25.1	135.58	0
6	3.6	0.79	22.2	22.2	107.53	449,673
3.5	5.9	1.30	14.0	14.0	46.55	319,015
3	4.5	0.99	12.3	12.3	37.34	195,183
2	1.5	0.33	9.1	9.1	21.91	38,179

Total Volume in Sand cubic yards = 1,002,050

Total Volume along Route cubic yards = 2,846,786

Total Volume along Route + 10% cubic yards = 3,131,465

FIGURE A1-22
Volume Calculations for the Sales Pipeline from Main Platform to Flaxman Island
(Pessimistic Cross Section 90% Confidence of Non-Exceedance)

Soil is Clay

Depth of Ice Gouging, meters	Length of Route With this Scour Depth miles	Length of Clay-Covered Route With this Scour Depth miles	Depth to Bottom of Trench feet	Dredged Depth feet	Volume of Soil Dredged per Foot of Pipeline cubic yards	Volume of Soil Dredged in This Segment cubic yards
6.9	3.3	2.57	25.1	25.1	65.40	888,871
6	2.7	2.11	22.2	22.2	52.87	587,904
					Total Volume in Clay cubic yards =	**1,476,775**

Soil is Sand

Depth of Ice Gouging meters	Length of Route With this Scour Depth miles	Length of Sand-Covered Route With this Scour Depth miles	Depth to Bottom of Trench feet	Dredged Depth feet	Volume of Soil Dredged per Foot of Pipeline cubic yards	Volume of Soil Dredged in This Segment cubic yards
6.9	3.3	0.73	25.1	25.1	135.58	519,726
6	2.7	0.59	22.2	22.2	107.53	337,255
					Total Volume in Sand cubic yards =	**856,981**

Total Volume along Route cubic yards = 2,333,756

Total Volume along Route + 10% cubic yards = 2,567,132

FIGURE A1-23
Volume Calculations for Infield Pipeline
(Pessimistic Cross Section 90% Confidence of Non-Exceedance)

Soil is Clay

Depth of Ice Gouging	Length of Route With this Scour Depth	Length of Clay-Covered Route With this Scour Depth	Depth to Bottom of Trench	Dredged Depth	Volume of Soil Dredged per Foot of Pipeline	Volume of Soil Dredged in This Segment
meters	miles	miles	feet	feet	cubic yards	cubic yards
6.9	0	0.00	25.1	25.1	32.70	0
6	3.6	2.81	22.2	22.2	26.44	391,936
3.5	5.9	4.60	14.0	14.0	12.42	301,698
3	4.5	3.51	12.3	12.3	10.21	189,224
2	1.5	1.17	9.1	9.1	6.40	39,510

Total Volume in Clay cubic yards = 922,368

Soil is Sand

Depth of Ice Gouging	Length of Route With this Scour Depth	Length of Sand-Covered Route With this Scour Depth	Depth to Bottom of Trench	Dredged Depth	Volume of Soil Dredged per Foot of Pipeline	Volume of Soil Dredged in This Segment
meters	miles	miles	feet	feet	cubic yards	cubic yards
6.9	0	0.00	25.1	25.1	79.49	0
6	3.6	0.79	22.2	22.2	62.88	262,933
3.5	5.9	1.30	14.0	14.0	26.89	184,312
3	4.5	0.99	12.3	12.3	21.49	112,332
2	1.5	0.33	9.1	9.1	12.48	21,738

Total Volume in Sand cubic yards = 581,315

Total Volume along Route cubic yards = 1,503,683

Total Volume along Route + 10% cubic yards = 1,654,052

FIGURE A1-24
Volume Calculations for the Sales Pipeline from Main Platform to Flaxman Island
(Optimistic Cross Section 10% Confidence of Non-Exceedance)

Soil is Clay

Depth of Ice Scour, meters	Length of Route With this Scour Depth, miles	Length of Clay-Covered Route With this Scour Depth, miles	Depth to Bottom of Trench, feet	Dredged Depth, feet	Volume of Soil Dredged per Foot of Pipeline cubic yards.	Volume of Soil Dredged in This Segment, cubic yards
6.9	3.3	2.57	25.1	25.1	32.70	444,435
6	2.7	2.11	22.2	22.2	26.44	293,952
					Total Volume=	**738,387**

Soil is Sand

Depth of Ice Scour, meters	Length of Route With this Scour Depth, miles	Length of Clay-Covered Route With this Scour Depth, miles	Depth to Bottom of Trench, feet	Dredged Depth, feet	Volume of Soil Dredged per Foot of Pipeline cubic yards.	Volume of Soil Dredged in This Segment, cubic yards
6.9	3.3	0.73	25.1	25.1	79.49	304,699
6	2.7	0.59	22.2	22.2	62.88	197,200
					Total Volume =	**501,899**

Total Volume along Route cubic yards = 1,240,286

Total Volume along Route + 10% cubic yards = 1,364,315

FIGURE A1-25
Volume Calculations for Infield Pipeline
(Optimistic Cross Section 10% Confidence on Non-Exceedance)

A1.5 Offshore Pipe Laying

Pipe Laying - Feasibility and Costs - Conclusions

Methods considered as possible candidates for laying the sales pipeline were:

- A towed installation from a shore-based or island-based make-up site.
- A towed installation from a barge-based make-up site.
- An ice-based pipe-laying spread.
- A conventional lay barge.
- Third generation lay barge.

Criteria which weighed most heavily in the selection were cost, lay rate, and ability of the method to cope with ice conditions. Reel barges to install 30 inch diameter pipes do not exist and thus were not considered for the sales pipeline. A towed installation from a land-based make-up site is the most attractive method based on the criteria above. The R. J. Brown study for the Diapir lease sale showed the tow method to generally be the cheapest method of laying pipelines in the Arctic when it is applicable.

Figure A1-27 shows installation rates which can be expected with a towed installation from land. In contrast, typical installation rates predicted in the 1984 RJBA report were 0.75 miles per day for a conventional lay barge and 1.5 miles per day for a third generation lay barge in open water. Obviously, faster lay rates can be achieved on a given day when conditions are favorable and are comparable to temperate climates. For example, in 1994 the SEMAC I, claimed to be the world's fastest lay barge, achieved average lay rates of around three miles per day in the South China Sea and a peak rate of about four miles per day. Ice sheet-based methods would not be applicable to the whole length of sales pipeline because the ice is mobile over part of the route. The relatively high rate of installation of the tow method allows maximum productivity during periods of no ice or mild ice. Ideally the sales pipeline would be towed on bottom in the trench for the whole length. Maintaining the pipe in the trench during the whole tow would minimize instability during a storm and would allow minimum on-bottom weight, maximize the length of segments and minimize the size of tug (or pulling barge) required to pull a segment. If necessary, the tug would deal with ice incursion by dropping the towed end of the pipe and moving off collision course. The tug would have to come back later and reconnect to continue the tow. A lay barge could do the same thing but has to maintain tension on the pipe while the pipe is on the stinger and has then lower maneuverability. The entire placement of the sales pipeline would likely be completed during Ice Condition A.

The trench would have to be checked just before installation to insure that it was clean of soil filled in by storms or ice gouging. If plowing was to be used to achieve the final depth, it could be done just ahead of the pipe laying operation or it might be a separate operation.

The sales pipeline would most likely be placed in one segment. Infield pipelines would probably be placed in two parts because a bundle containing all the lines would be difficult to handle.

Ice Condition	Installation Rates			
	Max Effective (Miles/Day)		Average Effective (Miles/Day)	
	36-inch	16-inch	36-inch	16-inch
A	3.6	4.0	2.2	3.2
B	2.7	3.0	1.6	2.4
C	2.2	2.4	1.3	1.9
D	1.5	1.7	0.9	1.3

FIGURE A1-27
Tow Pipeline Installation Rates From Land

A1.6 Pipeline Design

Assumptions for the pipelines are as follows:

1. The sales pipeline is a 30 inch or 24 inch diameter crude oil line.

2. The following lines will connect the main processing platform with the satellite production platform:

    - 30" diameter three-phase line
    - 20" gas injection/water injection line
    - 12" gas lift line
    - Power cable
    - Fiber optic cable or other communication cable.

3. The satellite production platform is 6 miles away from the main processing platform.

4. None of the offshore pipelines will be insulated.

A1.7 Riser Design and Connection

Several methods were proposed by R. J. Brown in the Diapir area report to connect the pipeline to the platforms and these are briefly discussed below.

Directional drilling through the platform and further through the soil to connect with the pipe end could work but RJBA thought it might require a device on the sea floor to prevent loss of drilling mud at the exit point of the bit in the trench. Lowe of A&L Underground through this was no problem and that the mud loss was tolerable. Another alternative is to keep the top of the mud column below the water level in order to create balanced head; then the mud would at least drain out slowly as the water channels back up into the mud. Also, if the pipeline is in place before the structure is placed, the connection would probably require two connections because the pipe going through the drilled hole would be a spool requiring connection at both ends.

Use of a J-tube or horizontal pull tube either puts the pipe exit point at or near mudline or it requires the pull tube to go well below mudline which would make it extend well below the structure. Putting the pipe exit point near mudline would expose it to possible ice gouging. Putting a pull tube below the structure creates construction and structure placement problems. Use of a J-tube is not recommended.

The most straightforward option seems to be using a junction box for connection of the pipelines and risers. Pre-placement of a junction box as described by RJBA includes mining down through a berm after the structure is placed. This idea can be adapted as proposed below to avoid this mining.

The trench for the pipeline would be carried straight through the platform site. The pipe would terminate lying flat in the trench. A slotted cylinder would be placed over the end of the pipe so that the slot fits over the pipe. The slotted cylinder would be tall enough so that its top protrudes above mudline. The trench would be filled in with gravel and the gravel would be vibrated to densify it. The structure would have an open column in it which would fit over the top of the cylinder as the structure is placed. The dense gravel would provide a firm foundation for the structure. The connection would be made with the pipe end in the junction box by divers. This plan would eliminate the mining and could be designed for whatever tolerance on structure placement is desired. Grouting could be used if desired to plug around the connection between structure and cylinder to minimize or eliminate seepage. By making the pipe section underneath the structure a spool piece, the placement of this piece and the cylinder are not dependent on completion of the placement of the main pipeline. The disadvantage of this method is that it would possibly require more underwater activities in preparation for placement of the structure, but these activities have all been done in oil field work and they use known technology. This plan is proposed as the probable cheapest, but further investigation may show that the plan using directional drilling is cheaper.

The idea of a junction box would be adapted for the infield pipeline connections, possibly as follows. A junction box for the infield pipeline would also be placed in the trench before backfilling and structure placement. It would contain pipe segments for the steel pipelines and conduits for the power cable and fiber optic cable. Messenger lines would be placed in the conduits. The pipe segments would protrude beyond the bottom edge of the structure so that an underwater connection could be made with the pipes coming from the satellite platform. After backfilling is complete, the connection points would still be exposed for later use. The infield pipelines would be towed into position and the ends deflected or otherwise connected to the main platform first. The process of using a riser cylinder would be repeated at the satellite platform.

A1.8 Plans for Conventional Pipeline Segments of the Kuvlum Development

Pipelines for the Kuvlum Development have been divided into segments for description and cost estimating.

Sales Pipeline from Flaxman Island to Main Satellite Platform

The trench for this segment of pipeline would be primarily dredged with a cutter suction dredge. If risk analysis shows that the trench might not be completed on schedule with one dredge, then more than one dredge would be mobilized and possibly a combination of cutter suction and trailing suction hopper dredges would be used. The segment in water too shallow for the large dredges would probably be done by a mechanical excavation spread working from fast ice. An alternative for excavation of the trench in shallow water is a small dredge. The trench would be completed before the pipeline is placed in it. If enough sand and gravel spoil could be obtained by dredging the trench, it would be used for fill at the pipe make-up yard on Flaxman Island.

For the most likely case of pipeline installation, it was assumed that the pipe would be installed by towing. Costs supplied by Rockwater were used for the estimate. The pulling barge would arrive at the site during the summer before the summer planned for installation. Equipment required for onshore fabrication would be brought with the barge. The pipe would be initially welded into segments each approximately one-half mile long on Flaxman Island in preparation for towing out to sea. The 16 mile long pipe would be towed out in one segment. Expected rates of progress are shown in a previous table. Pulling forces required for different lengths of the offshore segment of the pipe are shown in Figure A1-31. The part of the pipe which is sliding onshore would add to these. Rockwater assumed that the pull barge would have a capacity of 800 tons. The winches for pulling would be trucked to the site, probably just before breakup, during the spring before the summer they were to be used. The leading end of the pipeline would be towed as far as the main platform site. A pulling barge working off anchors rather than a tug would probably be used for the pull because of its higher pulling capacity and better ability to control its position.

Costs were supplied by Great Lakes Dredge and Dock for a pipeline installed by a lay barge. These were greater than those used for the towed option and were used only for a check on the towed installation numbers.

Pipe Diameter, inches	Wall Thickness, inches	Insulation & Coating Thickness, inches	Average Density of Coatings lbs/cu. ft.	Weight of Empty Pipe in Air lbs/ft	Buoyant Force on Submerged Pipe, lbs/ft	Net Weight of Empty Pipe in Water, lbs/ft	Apparent Specific Gravity of Submerged Pipe	Assumed Coefficient of Friction of Pipe on Bottom	Pulling Force per Foot of Pipe, lbs.	Segment Length miles	Total Pulling Force Required, tons
30	0.875	1	150	373.88	357.44	16.4	1.046	0.70	11.50	3.0	91
30	0.875	1	150	373.88	357.44	16.4	1.046	0.70	11.50	4.0	121
30	0.875	1	150	373.88	357.44	16.4	1.046	0.70	11.50	5.0	152
30	0.875	1	150	373.88	357.44	16.4	1.046	0.70	11.50	6.0	182
30	0.875	1	150	373.88	357.44	16.4	1.046	0.70	11.50	7.0	213
30	0.875	1	150	373.88	357.44	16.4	1.046	0.70	11.50	8.0	243
30	0.875	1	150	373.88	357.44	16.4	1.046	0.70	11.50	9.0	273
30	0.875	1	150	373.88	357.44	16.4	1.046	0.70	11.50	10.0	304
30	0.875	1	150	373.88	357.44	16.4	1.046	0.70	11.50	11.0	334
30	0.875	1	150	373.88	357.44	16.4	1.046	0.70	11.50	12.0	364
30	0.875	1	150	373.88	357.44	16.4	1.046	0.70	11.50	13.0	395
30	0.875	1	150	373.88	357.44	16.4	1.046	0.70	11.50	14.0	425

FIGURE A1-31
Forces Required for Pulling Bottom-Towed Pipe

Make-Up Facility on Flaxman Island

The pipe make-up site on Flaxman Island would be about 300 ft. x 3000 ft. if it was to be used for making up the segments to be towed for the main offshore leg of the pipeline, i.e., Flaxman to the main production platform, and for making up the segments of the infield pipeline. 100,000 to 300,000 cubic yards of spoil from the dredging operation would be used for fill on this part of the site. The site would be oriented so that the pipe would be pulled directly from the made-up positions into the trench. Coated pipe would be delivered to the make-up facility for the sales pipeline and would be welded into segments approximately one-half mile long. A sketch of a possible facility for the towed option is shown in Figure A1-33 from the 1984 R. J. Brown report.

If pipe were to be placed in tunnels, then a much smaller make-up area would be required because smaller segments would be carried on a train into the tunnel. The pipe make-up area would need a relatively small part of the area constructed for tunnel liner storage.

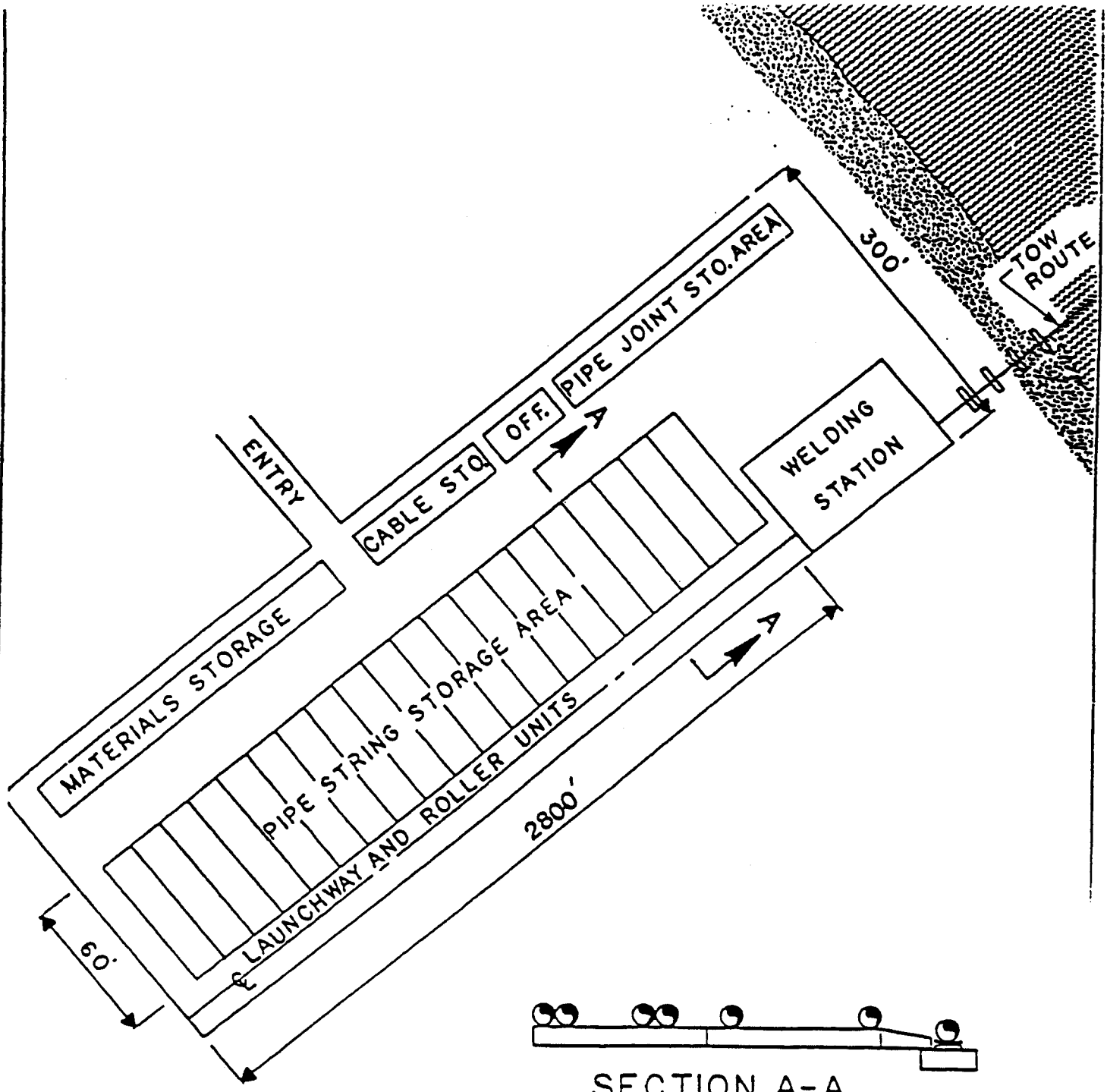
If the offshore pipeline in shallow water were built to carry oil from Flaxman back to Prudhoe Bay, then a storage yard for half the pipe might be used on Flaxman Island.

In order to use dredge spoil for the make-up site, the dredging operation would pump sand or gravel spoil into a dump scow. After its hold is filled, the dump scow would sail into shallow waters near Flaxman Island and dump the spoil into the water. It would continue this cycle until an adequate underwater stockpile is built. The last action of the dredge for that open water season would be to come to the underwater stockpile and dredge it up and pump it to the beach of Flaxman Island. The distance from the stockpile to the beach would be about a mile. The stockpile could be placed so that the dredge would work at maximum efficiency in pumping it to the beach. A spread of several scrapers, dozers, and compactors would be used to place and compact this fill.

Gravel pits exist in the Point Thomson area which were opened by Exxon for previous exploratory programs and use of gravel from these pits should be compared to the reclamation of spoil from dredging in the detailed planning stages of the project. This alternative may be more attractive since it would maximize the time the dredges can spend opening up a trench during the limited open water season. Also, use of the spoil is dependent on how much coarse-grained material actually exists along the trench route.

Sales Pipeline from Flaxman Island to the Mainland Beach

One option is to run the pipeline from Flaxman Island to the nearest mainland beach and run it as an onshore line from there to Pump Station 1. A second option, an offshore sales pipeline from Flaxman to Prudhoe Bay, is discussed below. The trench for this 2.2 mile long island-to-beach section of the sales pipeline would only have to be seven to eight feet deep to protect the 30" line from ice gouging. Plowing is the quickest and cheapest way of digging a trench when it is feasible but because of the difficulty of controlling the depth of plowing, this trench would probably be



SECTION A-A

NOTES:

- pipe unloaded and racked in single joints
- make-up ½ mile sections and shorter lengths as required
- the field joints are made up at welding station
- test pipe sections on storage rack and dewater
- roll lines onto launching units
- weld strings together at welding station while pipe is being pulled

JOINT INDUSTRY STUDY	SHORE BASED MAKE-UP FACILITY						
RJBA R. J. BROWN AND ASSOCIATES	SCALE	DRAWN	CHECKED	DATE	JOB NO	DRAWING NO	REV
	NONE	mes	RP	2.2.84	2269.01	6-110	0

FIGURE A1-33

made with backhoes working from grounded ice. All but two or three of the nearshore borings to which ARCO has access show unbonded soils in this lagoonal environment. Consequently, it is anticipated that excavation could make reasonable progress without difficulty. This would have to be confirmed with borings. A winter-time installation for this segment is envisioned with the equipment spread working from grounded ice. No river dumps into the sea near the landfall and protection from strudel scour would not be required.

Infield Pipeline from Main Platform to Satellite Platform

These pipelines would probably be made up in two bundles. One would be just the 30" pipeline. The other would be the 20" and the 12" together. Fiber optic and communication cables would be laid separately. The pipes would connect to junction boxes at both platforms if a towed installation was used. Conduits with messenger lines in them would exist for the fiber optic and communication cables. Cables can generally not be spliced under water. This must be done in the dry. Tows for the 30" and the 20" and 12" bundle would be off-bottom tows with lengths of chain and buoyancy capsules added to the pipelines as necessary to maintain the proper elevations of the pipes.

Along Shore Pipeline

The sales pipeline from Flaxman Island to Prudhoe Bay could be placed in shallow water, typically less than six feet, by working from the landfast ice during the winter. This option might be easier to permit than the cross-country option. Estimated costs are similar to the cross-country option and more detailed estimates would be required to show if there is any significant difference between the cross-country and the along shore option. Figure A1-35 gives the lengths of this route in segments and required depths of excavation and excavation volume for each segment.

Coated pipe would be staged on Flaxman Island and at Prudhoe Bay. One intermediate material staging area could be Tigvariak Island if needed.

One major step in getting construction underway would be to build ice roads along the route by selectively accelerating ice thickening in order to make the ice landfast or at least to make it thick enough to safely carry the equipment.

Access to the sea bottom is obtained by sawing out segments of ice to provide access for excavating a trench. Two ditch witches would saw slots in the ice about five feet apart and parallel with the direction of the pipeline route. Rates of advance for this activity were reported by Shell as four to five feet per minute. A third ditch witch would saw transverse cuts to make ice blocks. A CAT 235 backhoe fitted with a gripping device could pick out blocks and hand them to one of two front end loaders. The front end loaders would move the blocs out of the way.

A series of three CAT 235 backhoes would excavate a trench in the soil through the slot. It is assumed that the backhoes could straddle the five foot slot to optimize the position of the machine for digging the trench. Dozers would move the soil farther to the side if necessary. Excavation is probably the slowest activity and this use of

K22.xls

Pipe Segment, miles	Water Depth, feet	Depth of Trench, feet	Volume of Excavation Per Foot of Length, cu. yds.	Voume of Excavation Per Mile, cu. yds.	Volume of Excavation for Segment, cu. yds.	Excavation Rate, cu. yds/day	Days Required for Excavation of Segment
4.5	0-7	7	3.8	19849	89320	10000	8.9
5.2	6	7	3.8	19849	103214	10000	10.3
3.2	6	7	3.8	19849	63516	10000	6.4
2.6	6	7	3.8	19849	51607	10000	5.2
1	9	7	3.8	19849	19849	10000	2.0
2.5	6	7	3.8	19849	49622	10000	5.0
3.3	6	7	3.8	19849	65501	10000	6.6
4.6	1 to 6	15	14.7	77733	357573	10000	35.8
4.1	2 to 3	15	14.7	77733	318707	10000	31.9
4	4 to 6	7	3.8	19849	79396	10000	7.9
1.5	6	7	3.8	19849	29773	10000	3.0
2.1	6	15	14.7	77733	163240	10000	16.3
17	6	15	14.7	77733	1321467	10000	132.1
						Total =	**271**

FIGURE A1-35
Excavation Volumes for a Pipeline in Shallow Water from Flaxman Island to Prudhoe Bay

CAT's in series is needed to speed up the operation. The trench would be seven feet deep in areas not subject to strudel scour and fifteen feet deep in areas which are subject to strudel scour. The basic assumptions for estimation of volume were that the solid is 50% sand and 50% clay, the sand would assume a 3h:1v slope, and the clay would stand vertically. For simplicity it was assumed that all slopers were 1.5h:1v since the calculated volumes are the same. Three CAT's working about 80% of the time could achieve an excavation rate of 10,000 cubic yards per day which gives an advance rate of about one-half mile per day with a seven foot trench or 1/8 mile per day with a fifteen foot trench. Adding CAT's to the excavation series could speed up the latter rate.

Pipe placement on the ice adjacent to the slot would follow or proceed with the excavation. Welding up the pipe, placement of anodes, and field coating would proceed as in an onshore spread. Six sidebooms would lower the pipe through the slot to the sea bottom. The excavated soil would be dozed back into the slot.

Ice slot maintenance may be necessary depending on how fast the pipe is placed in it.

The speed of excavation could control the progress of the operation if one spread was defined as having three of the CAT 235's working together. The table shows a time of about 270 days to excavate for the approximately 55 miles of pipeline. The route is longer than the overland route because it follows the curves in the beach to some extent and goes north to get around the Sagavanirktok Delta. Therefore, at least two spreads would be required to complete the pipeline in one season.

This along-shore pipeline is somewhat similar to parts of the ACETS line from Prudhoe Bay to the McKenzie River Delta. Information from the ACETS estimate made by R. J. Brown in 1986 was used along with information obtained from ARCO Kuparuk Facility Engineering to build up a detailed estimate of a cost of $148 million for this line. The detailed hand calculations have not been included in this report but are available on request.

For comparison purposes, a length of 48.7 miles of the ACETS line out of a total of 108 miles was shore crossings and winter pipeline construction. The winter pipeline construction was to be in 25 to 35 feet of water, however, and most of the trench excavation was done by dredge during the summer. The average cost of this 48.7 miles of the ACETS line was estimated to be $3.2 million per mile and the expectation is that this cost is somewhere between most likely and pessimistic of the along-shore pipeline conceived as part of this study. This rate would result in a cost of about $176 million for the along-shore line.

A1.9 Plans for Pipeline Segments in Tunnels

Sales Pipeline from Landfall to the Main Platform

Most of the welding to make up the sales pipeline would be done on the beach at the point of the tunnel's landfall, either on Flaxman Island or at Pt. Thomson.

Two alternatives for installing the sales pipeline in the main tunnel are envisioned. One way would be to make up segments on the beach which are as long as the rail train. The train would take the first segment to the end of the line, i.e., adjacent to the main platform, unload it by hoisting it or lifting it up into its place next to the tunnel ceiling, and then go back to the beach for the next segment. The shoreward end of the first segment would have to be left hanging down from the ceiling in a long overbend so that there would be access all around the pipe for making the weld between first and second segments.

After being brought into the tunnel, the seaward end of the second segment would be hoisted to create a long sagbend and mated with the shoreward end of the first segment. After the weld is complete, partial hoisting of the second segment would be completed and its shoreward end would be left in an overbend. This process is then repeated. Optimum use of this method would probably require some kind of hoisting system which is built into the rail cars.

Another method for installing the pipeline would be to entirely make up the pipeline on the beach and roll it directly into place on rollers. This would require rollers the full length of the tunnel and would require a pulling system which can advance through the tunnel and get its reaction from locking into the tunnel sides. The thrust required when the pipe reaches 16 miles in length could exceed 1000 kips if the rolling resistance is about 5% of pipe weight.

The first method described above probably requires more labor in the tunnel but would require considerably less hardware and simpler hardware. Details of the two methods have not been planned in enough detail to say which would be cheapest, but intuitively the first method seems cheaper because it requires much less hardware and because labor in the tunnel would probably not be significantly more expensive than labor at the make-up site.

Infield Pipelines

For installing the pipes in the infield tunnel, the first method would likely be cheaper because the pipe would be taken through the sales tunnel on the existing rails. The train would be as long as reasonably possible because each trip would be an average of 19 miles long. Probably section of 20" and 12" pipelines would be carried on a single trip.

A1.10 Schedules for the Kuvlum Development

It is assumed that a decision is made to pursue the project on January 1 of a given year. The schedule below fits with the most likely case for installation of the 30 inch line from Flaxman Island to the Main Platform site and from Flaxman back to Point Thomson (Figure A1-4).

Summer 3 - Mobilize dredging spread and begin dredging of trench for sales pipeline. Pump granular spoil to Flaxman Island. Spread and compact the spoil during fall.

Summer 4 - Complete compaction of make-up site on Flaxman Island. Continue dredging of trench for sales pipeline. Dredge trench wider near the structure at the point of planned connection. Begin dredging trench for infield pipeline if time allows. Deliver pipe to make-up site on Flaxman Island. Mobilize the barge which will be used for the towed installation of the pipeline.

Fall, Winter 4 - Mobilize on-shore pipe make-up spread and begin making up pipe on Flaxman Island. Complete making up 2500' long segments of pipe by breakup. Mobilize winter trenching spread for landfall. Complete trenching of the first mile or so of trench offshore between Flaxman and the main platform by time of break-up. Mobilize winches for the tow.

Summer 5 - Clean out trench where necessary. Assemble the pulling spread. Tow out the sales pipeline on bottom in the trench. While pipeline placement is going on, place the spool pieces in the trench at the structure site. Place the riser cylinder on top of the seaward end of the pipeline. Place riser cylinder and spool pieces for the infield pipelines. Fill in the trench around the riser cylinders. Place the structure on bottom. Make the final connection between pipeline end and spool piece. Use the dredging spread to continue dredging of the trench for the infield pipeline bundle.

Fall, Winter 5 - Complete installation of the 2.4 mile Flaxman Island to Point Thomson segment. Make up the infield pipeline bundle onshore. Complete the placement of the close-to-shore pipeline from Flaxman Island to Prudhoe Bay if this option is used.

Summer 6 - Complete dredging and clean-out of the trench for the infield pipelines. Tow out the first infield pipeline and place it in the trench. Connect the end to the spool piece at structure 1. Tow out the second bundle and place it in the trench. Repeat the process of using a riser cylinder at the satellite platform. Place the satellite structure on top of the riser cylinder.

Activity		Year	1												2												3												4											
		Season	Winter						Summer						Winter						Summer						Winter						Summer						Winter						Summer					
		Month	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
Overall Field Development	Feasibility Assessment & Engineering																																															
	Structure Construction																																																
	Offshore Pipeline Construction																																																
	Onshore Pipeline Construction																																																
	Development Wells & Production																																																
Pipeline Preliminary Engineering	Environmental Data Gathering		X	X	X	X	X	X	X	X																																							
	Preliminary Pipeline Design					X	X	X	X	X	X	X	X																																					
	Equipment Evaluation & Selection												X	X	X	X	X																																	
	Pipeline Route Survey									X	X	X																																					
	Pipeline Permits		X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X																		
Detail Engineering Procurement & Construction Management	Project Services Contractor on board									X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
	Design,Construct & Test																	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
	Specialized Equipment																										X	X	X	X	X	X	X																
	Detailed Pipeline Design														X	X	X	X	X	X	X	X	X	X	X	X																								
	Pipeline Installation Bid Prep & Award																								X	X	X	X																						
	Dredging Bid Prep & Award																	X	X	X																														
	Order Pipe & Materials																	X	X	X	X	X	X	X	X	X	X	X																						
	Manufacture Pipe																										X	X	X	X	X	X	X	X	X	X	X	X												
	Coat Pipe																																						X	X	X	X	X								
	Transport Pipe & Materials																																										X	X	X	X	X				
Pipeline Pre-Construction Activities	Place Dredge Spoil on Flaxman																																																
	Set Up Pipe Make-Up Base - Flaxman																																																
Pipeline Trenching	Dredge Modification & Mobilization																																																
	Pipeline Trench Dredging																																																
	Mobilization of Winter Excav. Spread																																																
	Shallow Water Excavation																																																
Offshore Pipeline Installation	Mobilize Tow Vessels & Spread																																																
	Make-Up Pipe on Flaxman Island																																																
	Pipeline Installation Flaxman to Main																																																
	Structure Approach																																																
	Pipeline Installation inshore of Flaxman																																																
	Pipeline Installation Main to Satellite																																																
Pipeline Tie-In to Facilities and Start-Up	Tie-In of Sales Pipeline at Main																																																
	Hydrostatic Testing of Sales Pipeline																																																
	Tie-In of Infield Pipeline																																																
	Hydrostatic Testing of Infield Pipelines																																																
	Start-Up of Main Platform																																																
	Clean Up and Demobilize																																																
	As-Built Surveys																																																

FIGURE A1-39, Page 1 of 2 (Note 8 years)
Most Likely Installation Schedule for 30 Inch Sales Pipeline from Main Platform to Point Thomson and Infield Pipeline between Main Platform and Satellite

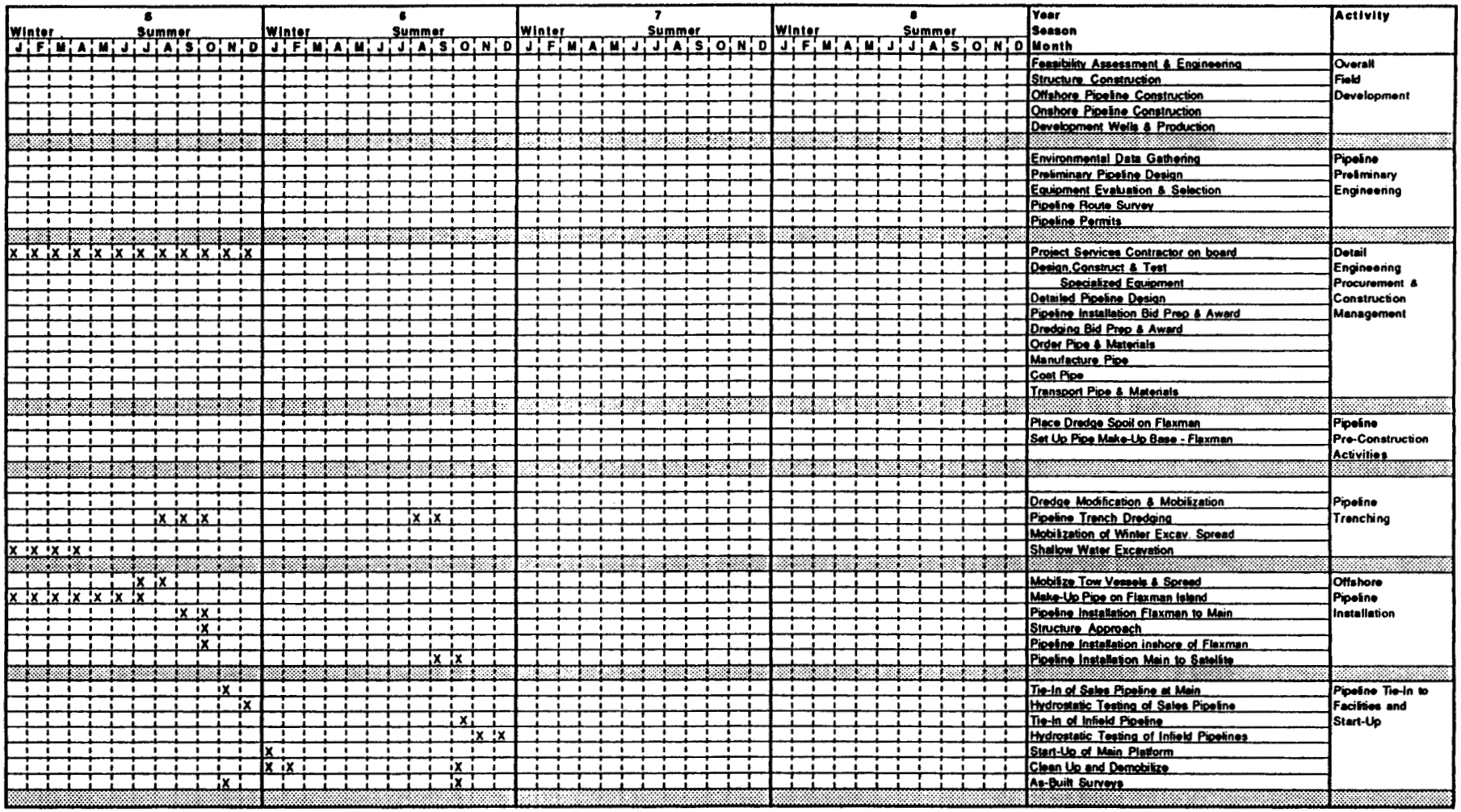


Figure A1-39, Page 2 of 2, (Note 8 Years)

Most Likely Installation Schedule for 30 Inch Sales Pipeline from Main Platform to Point Thompson and Infield Pipeline between Main Platform and Satellite. Note 2 Sheets 8 Years.

A1.11 Recommended Further Studies

Probably the most important studies which could reduce the cost of the pipelines are to precisely define the depth of trench required for prevention of damage to pipeline by ice-scouring and to improve the methods of dredging. Return intervals and analyses of sub-scour deformation should be somehow incorporated into determining the required depth of trenching.

A1.12 Estimate of Pipeline Costs

Figures A1-41 through A1-58 present the estimates of cost for the various pipelines. These estimates are based on the assumptions given throughout this writing. Figures A1-4 and A1-6 compute the cumulative probabilities vs. cost for the sales line. Plots of this data are shown in Figures A1-3 and A1-5.

MOST LIKELY COSTS OF 30 Inch PIPELINE AND INFIELD PIPELINES

Sales Pipeline (30 Inch) from Kuvlum Platform to Flaxman Island Includes dredged trench, towed pipe, material, protection, installation, & 20% for engineering.	**$136,641,914**
Sales Pipeline (30 Inch) from Flaxman Island to Point Thompson Includes burial, material, protection, installation, tie-ins & 20% for engineering Winter Construction.	**$11,364,503**
Infield Pipelines (30, 20, 12 Inch) from Kuvlum Platform to Satellite Platform Includes dredged trench, towed pipes, material, protection, installation, tie-ins and 20% for engingeering.	**$62,892,271**
Sales Pipeline (30 Inch) Placed in Tunnel from Kuvlum Platform to Flaxman Island Includes material, protection, installation, tie-ins and 20% for engineering. Does not include Cost of Tunnel.	**$32,544,554**
Sales Pipeline (30 Inch) Placed in Tunnel from Flaxman Island to Point Thompson Based on 5 mile length. Ratio used on Kuvlum to Flaxman segment. Does not include Cost of Tunnel.	**$9,915,923**
Infield Pipelines Placed in Tunnel from Kuvlum Platform to Satellite Platform. Includes material, protection, installation, tie-ins and 20% for engineering. Does not include Cost of Tunnel.	**$25,126,618**
Offshore Pipeline in Shallow Water from Flaxman Island to Prudhoe Bay Includes excavation, material, protection, installation, tie-ins and 20% for engineering.	**$147,564,086**

Reference: Figures A1-42, 43, 44, 45

Figure A1-41
Summary of Most Likely Costs of 30 Inch Pipelines and Infield Pipelines

KUVLUM PLATFORM TO FLAXMAN ISLAND

MATERIAL COSTS

Item	Quantity		Unit Cost	Reference for Unit Cost	Cost of Item
	Number	Units			
Line Pipe, 30" x .75" w.t., 235 lbs (16 miles)	86,064	ft	$118	GLD&D - 1994	$10,168,462
Miscell. Valves, Bends, Flanges	1	Lot	$200,000	Karlik - 1994	$200,000
Anodes, 3.5 tons/mile	112,000	lbs.	$2.90	RJBA-1984	$324,800
Corrosion/Abrasion Coating Fusion Bonded Epoxy, 7.85 sq.ft./ft., .2cu.ft/ft.	75000	sq. yds.	$4.72	ACETS -1986	$354,000
Concrete Weight Coating					
Consumables	20000	lbs.	$1	RJBA-1984	$20,000
Material Transport	3.1	35k sq. ft.	$1,000,000	WWC - McKay	$3,100,000
				Material Cost =	**$14,167,262**

PROTECTION COSTS

Item	Quantity		Unit Cost	Reference	Cost of Item
Mob & Demob: Sum of Dredge 1 and Related Support Vessels	1	ea.	$16,000,000	GLD & D	$16,000,000
Work Preparation	3	ea	$500,000	GLD & D	$1,500,000
Dredging Spread: Dredge 1	2	seasons		GLD & D	$0
6000 HP Icebreaking Tug	2	seasons		GLD & D	$0
Two launches	2	seasons		GLD & D	$0
Survey Vessel	2	seasons		GLD & D	$0
Sum	2	seasons	8160000	GLD & D	$16,320,000
Season Shutdown	3	seasons	500,000	GLD & D	$1,500,000
Wintering Over	2	ea	6,800,000	GLD & D	$13,600,000
				Protection Costs =	**$48,920,000**

INSTALLATION COST

Item	Quantity		Unit Cost	Reference	Cost of Item
Contractor's Project Management & Engineering	1	LS.	2,560,000	Rockwater 1994	$2,560,000
Mob and Demob: Towing Spread, Pulling Spread, Misc. Vessels, Sum of Installation Spread				Rockwater 1994	$10,704,000
Set-Up Shore Based Make-Up Site	1	each	5,600,000	WWC - McKay	$5,600,000
Fabrication	1	LS.	17,543,000	Rockwater 1994	$17,543,000
Installation	1	LS.	5,774,000	Rockwater 1994	$5,774,000
Pipeline Tie-In				RJBA-1984	$8,600,000
				Pipeline Installation Cost =	**$50,781,000**

Total Cost "Most Likely" of Sales Pipeline (Towed & Buried) Kuvlum Platform to Flaxman Island (Including 20% for Engineering) = $136,641,914

FLAXMAN ISLAND TO POINT THOMSON

MATERIAL COSTS

Item	Quantity		Unit Cost	Reference for Unit Cost	Cost of Item
	Number	Units			
Line Pipe, 30" x .75" w.t., 235 lbs/ft. (2.4 miles)	12,672	feet	$118	GLD&D - 1994	$1,497,197
Anodes, 3.5 tons/mile	16,800	lbs.	$2.90	RJBA-1984	$48,720
Corrosion/Abrasion Coating Fusion Bonded Epoxy, 7.85 sq.ft./ft.	11053	sq. yds.	$4.72	ACETS - 1986	$52,170
Concrete Weight Coating					
Consumables	3000	lbs.	$1	RJBA-1984	$3,000
Material Transport	0.453	35k sq. ft.	1000000.00	WCC- McKay	$453,000
				Material Cost =	**$2,054,087**

PROTECTION AND INSTALLATION COSTS (includes trenching the first mile or so from Flaxman to Platform)

Item	Quantity		Unit Cost	Reference	Cost of Item
Mob & Demob: Excavating and Earthmoving Equipment included in Sales Pipeline from Point Thomson to TAPS Pump Station #1					
Trenching 1 Mile Offshore from Flaxman	1	mi.	87532	ACETS /Kuparuk	$87,532
Incremental Mileage Pipeline Rate	2.4	mi	2637000	ACETS/Kuparuk	$6,328,800
Pipeline Tie-Ins				Guess	$1,000,000
				Installation and Protection Cost =	**$7,416,332**

Total Cost "Most Likely" of Sales Pipeline (Buried) Flaxman Island to Point Thomson Winter Installation (Including 20 % for Engineering) = $11,364,503

FIGURE A1-42
Most Likely Cost for Sales Pipeline (30 Inch, Buried) from Kuvlum Platform to Point Thomson

MATERIAL COSTS

Item	Quantity		Unit Cost	Reference for Unit Cost	Cost of Item
	Number	Units			
Line Pipe, 30" x .75" w.t., 235 lbs/ft. (6.12 miles)	32,414	feet	$118.15	GLD&D - 1994	$3,829,714
Line Pipe, 20" x .593"w.t., 123 lbs/ft.	32414	feet	$69.25	GLD&D - 1994	$2,244,670
Line Pipe 12" x .406"w.t., 53.7 lbs/ft.	32414	feet	$24.60	GLD&D - 1994	$797,384
Anodes on 30", 3.5 tons/mile	42,000	lbs.	$2.90	RJBA-1984	$121,800
Anodes on 20", 2.1 tons/mile	25,200	lbs.	$2.90	Interpolated	$73,080
Anodes on 12", 1.53 tons/mile	18,360	lbs.	$2.90	RJBA-1984	$53,244
Corrosion/Abrasion Coating on 30" Fusion Bonded Epoxy, 7.85 sq.ft./ft., .2cu.ft/ft.	28185	sq. yds.	$4.72	ACETS -1986	$133,033
Corrosion/Abrasion Coating on 20"	18799	sq. yds.	$4.72	ACETS -1986	$88,731
Corrosion/Abrasion Coating on 12"	11985	sq. yds.	$4.72	ACETS -1986	$56,569
Concrete Weight Coating					
Consumables	12000	lbs.	$1	RJBA-1984	$12,000
Material Transport	1.85	35k sq. ft.	1000000.00	WWC - McKay	$1,850,000
				Material Cost =	**$9,260,226**

PROTECTION COSTS

Item	Quantity		Unit Cost	Reference	Cost of Item
Mob & Demob: Sum of Dredge 1 and Related Support Vessels	0	ea.	$16,000,000	GLD & D	$0
Work Preparation	1	ea	$500,000	GLD & D	$500,000
Dredging Spread: Dredge 1	1.5	seasons		GLD & D	$0
6000 HP Icebreaking Tug	1.5	seasons		GLD & D	$0
Two launches	1.5	seasons		GLD & D	$0
Survey Vessel	1.5	seasons		GLD & D	$0
Sum	1.5	seasons	8160000	GLD & D	$12,240,000
Season Shutdown	1	seasons	500,000	GLD & D	$500,000
Wintering Over	1	ea	6,800,000	GLD & D	$6,800,000
				Protection Costs =	**$20,040,000**

INSTALLATION COST

Item	Quantity		Unit Cost	Reference	Cost of Item
Contractor's Project Management & Engineering	1	LS.	940,000	Rockwater 1994	$940,000
Winter Layover and Remob of Equipment	1	LS.	$4,000,000	Rockwater 1994	$4,000,000
Winter Camp Maintenance	1	LS.	1,000,000	Guessed	$1,000,000
Remob of Personnel	1	LS.	10,000	Guessed	$10,000
Set-Up Shore Based Make-Up Site	Included in Sales Pipeline				
Fabrication	1	LS.	6,440,000	Rockwater 1994	$6,440,000
Installation	1	LS.	2,120,000	Rockwater 1994	$2,120,000
Pipeline Tie-In				RJBA-1984	$8,600,000
				Installation Cost =	**$23,110,000**

Total Cost "Most Likely" of Infield Pipelines (Towed & Buried) Kuvium Platform to Satellite Platform (Including 20% Engineering) = $62,892,271

FIGURE A1-43
Most Likely Costs for Infield Pipelines (30", 20", 12", Buried) From Kuvium Main Platform to Satellite Platform

Kuvlum Platform to Flaxman Island

MATERIAL COSTS

Item	Quantity		Unit Cost	Reference for Unit Cost	Cost of Item
	Number	Units			
Total from Conventionally Installed Option					$14,167,262
Credit for Anodes, 3.5 tons/mile	-112,000	lbs.	$2.90	RJBA-1984	($324,800)
				Material Cost =	**$13,842,462**

INSTALLATION COSTS

Item	Quantity		Unit Cost	Reference	Cost of Item
Set-up of Pipe Yard on Flaxman Island	Included in next item.				
Welding of Multiple Joints, Train Operation,				ACETS II - 1986	$11,600,000
Placement in Tunnel					
Hydro-Testing and Pigging	1	each	$1,000,000	Guessed	$1,000,000
Riser from Tunnel to Platform	6	days	$113,000	ACETS II Spread	$678,000
				Installation Cost =	**$13,278,000**

Total Cost Sales Pipeline (30 Inch) placed in Tunnel from Kuvlum Platform to Flaxman Island (Includes material, protection, installation, tie-ins & 20% for Engineering)= $32,544,554

Flaxman Island to Point Thomson

Total Cost Sales Pipeline (30") placed in Tunnel from Flaxman Island to Point Thomson
Bases on 5 miles length and ratio from Kuvlum to Flaxman Cost not including riser cost.
(Includes material, protection, installation, tie-ins & 20% for Engineering)= $9,915,923

Kuvlum Platform to Satellite Platform

MATERIAL COSTS

Item	Quantity		Unit Cost	Reference for Unit Cost	Cost of Item
	Number	Units			
Total Cost for Conventionally Installed Case (See Figure A1-44)					$9,260,226
Credit for Anodes on three Pipelines	-85,560	lbs.	$2.90	RJBA-1984	($248,124)
Total =				**Material Cost =**	**$9,012,102**

INSTALLATION COSTS

Item	Quantity		Unit Cost	Reference	Cost of Item
Set-up of Pipe Yard on Flaxman Island	Included in Sales Pipeline				
Welding of Multiple Joints, Train Operation, Placement in Tunnel, Install of Power & Commissioning				ACETS - 1986	$9,335,746
Hydro-Testing and Pigging	3	each	$600,000	Guessed	$1,800,000
Riser Installations	7	days	$113,000	ACETS Spread	$791,000
				Installation Cost =	**$11,926,746**

Total Cost "Most Likely" Infield Pipelines (30", 20",12") placed in a Tunnel from Kuvlum Platform to Satellite Platform (Including 20% Engineering) = $25,126,618

FIGURE A1-44
Most Likely Costs of Sales Pipeline (30") Infield Pipelines (30", 20" 12") Placed Inside Tunnel (Cost of Tunnel Not Included)

Item	Quantity		Unit Cost	Reference for Unit Cost	Cost of Item
	Number	Units			
Ice Road Construction	56	miles	$35,000	McKay of WCC	$1,960,000
Gravel (Bedding Trench & Shore Crossing)	7,300	c.y.	$18	and *	$131,400
Construction Camp Maintenance & Support For slotting, trenching, lowering 108 men for 160 days=17,280 mandays	17280	manday	$125	* *	$2,160,000
Ice Slotting	160	days	$17,626	* *	$2,820,160
Mob & Demob for Ice Slotting	10	days	$17,626	* *	$176,260
Trenching	160	days	$26,056	* *	$4,168,960
Mob & Demob for trenching	10	days	$26,056	* *	$260,560
Pipe hauling, handling, welding, x-ray	56	miles	$1,202,864	Chaobal's AAI	$67,360,384
Pipe Lowering	160	days	$21,073	* *	$3,371,680
Mob & Demob for Pipe Lowering	10	days	$21,073	* *	$210,730
Surveying (Construction control and As Built)	160	days	$2,600	Allen-AEPT	$416,000
Small Tools & Supplies 20% of wages for slotting, trenching & lowering crews.	160	days	$10,368	* *	$1,658,880
Builder's Risk Insurance 1.5% of all Costs except Chaibal's AAI numbers & Small Tools.				* *	$228,896
Pipe 30 inch O.D. x0.562 inch wall, 177 lb/ft.	56	miles	$475,200	Chaobal's AAI	$26,611,200
Pipe Freight (467.28 tons/mile)*$350/ton=$163548/mile	56	miles	$163,548	Chaobal's AAI	$9,158,688
Anodes (weight = 0.2% of pipe wgt.), wgt=0.002*177lb/ft*5280ft/mile*56 miles= 104,671 lb.	104,671	lbs.	$3.25	ACETS II	$340,181
Crew Changes (250 changes/month)*6months=1500 changes.	1500	changes	$1,000	Allen-AEPT	$1,500,000
Contractor Engineering = 2.5% of everything except Ice roads, Pipe hauling, handling,welding,x-ray, and Pipe and Freight.				ACETS II	$436,093
PMT, Design & Data Gathering = 20% of total.				Karlik- AlOGC	$24,594,014
			Total Cost of Sales Pipeline (30 Inch) along Shallow Water Route from Flaxman Island to Prudhoe Bay =		**$147,564,086**

* Crew sizes from Alaska-Canada Energy Transportation System (ACETS) Phase II Report.

** ACETS Phase II, Allen-AEPT, and Nelson-Farrar. AEPT is ARCO Exploration and Production Technology.

FIGURE A1-45
Most Likely Costs of Sales Pipeline (30", Buried)
Along Shallow Water Route from Flaxman Island to Prudhoe Bay

PESSIMISTIC COSTS OF 30 Inch PIPELINE & INFIELD PIPELINES

Sales Pipeline (30 Inch) from Kuvlum Platform to Flaxman Island Includes dredged trench, towed pipe, material, protection, installation, & 20% for engineering.	**$208,707,187**
Sales Pipeline (30 Inch) from Flaxman Island to Point Thompson Includes burial, material, protection, installation, tie-ins & 20% for engineering Winter Construction.	**$16,475,906**
Infield Pipelines (30, 20, 12 Inch) from Kuvlum Platform to Satellite Platform Includes dredged trencn, towed pipes, material, protection, installation, tie-ins and 20% for engingeering.	**$126,975,273**

Reference: Figures A1-47, 48

Figure A1-46
Summary of Pessimistic Costs of 30 Inch Pipelines and Infield Pipelines

KUVLUM PLATFORM TO FLAXMAN ISLAND

MATERIAL COSTS

Item	Quantity		Unit Cost	Reference for Unit Cost	Cost of Item
	Number	Units			
Line Pipe, 30" x .75" w.t., 235 lbs/ft.	86,064	feet	$154.00	1.3 * GLD&D	$13,253,856
Miscellaneous Valves, Bends, Flanges	1	lot	$200,000	Karlik - 1994	$200,000
Anodes, 3.5 tons/mile	112,000	lbs.	$2.90	RJBA-1984	$324,800
Corrosion/Abrasion Coating Fusion Bonded Epoxy, 7.85 sq.ft./ft., .2cu.ft/ft.	75000	sq. yds.	$13.50	RJBA-1984	$1,012,500
Concrete Weight Coating					
Consumables	20000	lbs.	$1	RJBA-1984	$20,000
Material Transport	3.1	35k sq. ft.	$1,000,000	WWC - McKay	$3,100,000
				Material Cost =	**$17,911,156**

PROTECTION COSTS

Item	Quantity		Unit Cost	Reference	Cost of Item
Mob & Demob: Sum of Dredge 1 and Related Support Vessels	1	ea.	$16,000,000	GLD & D	$16,000,000
Work Preparation	4	ea	$500,000	GLD & D	$2,000,000
Dredging Spread: Dredge 1	4	seasons		GLD & D	$0
6000 HP Icebreaking Tug	4	seasons		GLD & D	$0
Two launches	4	seasons		GLD & D	$0
Survey Vessel	4	seasons		GLD & D	$0
Sum	4	seasons	$8,160,000	GLD & D	$32,640,000
Season Shutdown	4	seasons	$500,000	GLD & D	$2,000,000
Wintering Over	4	ea	$6,800,000	GLD & D	$27,200,000
				Protection Costs =	**$79,840,000**

INSTALLATION COST

Item	Quantity		Unit Cost	Reference	Cost of Item
For Pessimistic Case use 1.5 X Pipeline Installation Cost for Most Likely Case. See Spreadsheet A.1.13.	1.5		$50,781,000	Figure A1-44	$76,171,500
				Pipeline Installation Costs =	**$76,171,500**

Total Cost "Pessimistic" of Sales Pipeline (Towed & Buried) Kuvlum Platform to Flaxman Island (Including 20% for Engineering) = $208,707,187

FLAXMAN ISLAND TO POINT THOMSON

MATERIAL COSTS

Item	Quantity		Unit Cost	Reference for Unit Cost	Cost of Item
	Number	Units			
Line Pipe, 30" x .75" w.t., 235 lbs/ft.	12,672	feet	$154.00	1.3*GLD&D	$1,951,488
Anodes, 3.5 tons/mile	16,800	lbs.	$2.90	RJBA-1984	$48,720
Corrosion/Abrasion Coating Fusion Bonded Epoxy, 7.85 sq.ft./ft.	11053	sq. yds.	$13.50	RJBA-1984	$149,216
Concrete Weight Coating					
Consumables	3000	lbs.	$1	RJBA-1984	$3,000
Material Transport	0.453	35k sq. ft.	1000000.00	WCC- McKay	$453,000
				Material Cost =	**$2,605,424**

PROTECTION AND INSTALLATION COSTS (includes trenching the first mile or so from Flaxman to Platform)

Item	Quantity		Unit Cost	Reference	Cost of Item
For Pessimistic case use 1.5 X Installation & Protection Cost for Sales Pipeline from Flaxman Island to Point Thomson. See Figure A1-44.	1.5		$7,416,332	Figure A1-44	$11,124,498
				Installation and Protection Cost =	**$11,124,498**

Total Cost "Pessimistic" of Sales Pipeline (Buried) Flaxman Island to Point Thomson Winter Installation (Including 20 % for Engineering) = $16,475,906

FIGURE A1-47
Pessimistic Cost for Sales Pipeline (30", Buried) from Kuvlum Platform to Point Thomson

MATERIAL COSTS

Item	Quantity		Unit Cost	Reference for Unit Cost	Cost of Item
	Number	Units			
Line Pipe, 30" x .75" w.t., 235 lbs/ft. 6.12 miles	32,414	feet	$154.00	1.3 X GLD & D	$4,991,756
Line Pipe, 20" x .593"w.t., 123 lbs/ft.	32414	feet	$90	1.3 X GLD & D	$2,917,260
Line Pipe 12" x .406"w.t., 53.7 lbs/ft.	32414	feet	$32	1.3 X GLD & D	$1,037,248
Anodes on 30", 3.5 tons/mile	42.000	lbs.	$2.90	RJBA-1984	$121,800
Anodes on 20", 2.1 tons/mile	25,200	lbs.	$2.90	Interpolated	$73,080
Anodes on 12", 1.53 tons/mile	18,360	lbs.	$2.90	RJBA-1984	$53,244
Corrosion/Abrasion Coating on 30" Fusion Bonded Epoxy, 7.85 sq.ft./ft., .2cu.ft/ft.	28185	sq. yds.	$13.25	RJBA-1984	$373,451
Corrosion/Abrasion Coating on 20"	18799	sq. yds.	$13.25	RJBA-1984	$249,087
Corrosion/Abrasion Coating on 12"	11985	sq. yds.	$13.25	RJBA-1984	$158,801
Concrete Weight Coating					
Consumables	12000	lbs.	$1	RJBA-1984	$12,000
Material Transport	1.4	35k sq. ft.	1000000.00	WWC - McKay	$1,400,000
				Material Cost =	**$11,387,727**

PROTECTION COSTS

Item	Quantity		Unit Cost	Reference	Cost of Item
Mob & Demob: Sum of Dredge 1 and Related Support Vessels	0	ea.	$16,000,000	GLD & D	$0
Work Preparation	4	ea	$500,000	GLD & D	$2,000,000
Dredging Spread: Dredge 1	3.5	seasons		GLD & D	$0
6000 HP Icebreaking Tug	3.5	seasons		GLD & D	$0
Two launches	3.5	seasons		GLD & D	$0
Survey Vessel	3.5	seasons		GLD & D	$0
Sum	3.5	seasons	8160000	GLD & D	$28,560,000
Season Shutdown	4	seasons	500,000	GLD & D	$2,000,000
Wintering Over	4	ea	6,800,000	GLD & D	$27,200,000
				Protection Cost =	**$59,760,000**

INSTALLATION COST

Item	Quantity		Unit Cost	Reference	Cost of Item
For Pessimistic Cost use 1.5 X Pipeline Installation Cost for Most Likely Case. See Spreadsheet A.1.14.	1.5		$23,110,000	Figure A1-45	$34,665,000
				Installation Cost =	**$34,665,000**

Total Cost "Pessimistic Cost" of Infield Pipelines (Towed & Buried) Kuvlum Platform to Satellite Platform (Including 20% Engineering) = **$126,975,273**

FIGURE A1-48
Pessimistic Cost for Infield Pipelines (30", 20", 12", Buried)
From Kuvlum Main Platform to Satellite Platform

OPTIMISTIC COSTS OF 30 Inch PIPELINES and INFIELD PIPELINES

Sales Pipeline (30 Inch) from Kuvium Platform to Flaxman Island Includes dredged trench, towed pipe, material, protection, installation, & 20% for engineering.	**$111,263,232**
Sales Pipeline (30 Inch) from Flaxman Island to Point Thomson Includes burial, material, protection, installation, tie-ins & 20% for engineering Winter Construction.	**$9,156,523**
Infield Pipelines (30, 20, 12 Inch) from Kuvium Platform to Satellite Platform Includes dredged trench, towed pipes, material, protection, installation, tie-ins and 20% for engingeering.	**$49,092,262**

Reference: Figures A-50,51.

Figure A1-49
Summary of Optimistic Costs of 30 Inch Pipelines and Infield Pipelines

KUVLUM PLATFORM TO FLAXMAN ISLAND

MATERIAL COSTS

Item	Quantity		Unit Cost	Reference for Unit Cost	Cost of Item
	Number	Units			
Line Pipe, 30" x .875" w.t., 235 lbs/ft. 16.3 miles	86,064	ft.	$90	ARCO Kuparuk	$7,745,760
Misc. Valves, Bends, Flanges	1	Lot	$200,000	Karlik - 1994	$200,000
Anodes, 3.5 tons/mile	112,000	lbs.	$2.90	RJBA-1984	$324,800
Corrosion/Abrasion Coating Fusion Bonded Epoxy, 7.85 sq.ft./ft., .2cu.ft/ft.	75000	sq. yds.	$4.72	ACETS 1986	$354,000
Concrete Weight Coating					
Consumables	20000	lbs.	$1	RJBA-1984	$20,000
Material Transport	3.1	35k sq. ft.	$1,000,000	WWC - McKay	$3,100,000
				Material Cost =	**$11,744,560**

PROTECTION COSTS

Item	Quantity		Unit Cost	Reference	Cost of Item
Mob & Demob: Sum of Dredge 1 and Related Support Vessels	1	ea.	$16,000,000	GLD & D	$16,000,000
Work Preparation	2	ea	$500,000	GLD & D	$1,000,000
Dredging Spread: Dredge 1	1.25	seasons		GLD & D	
6000 HP Icebreaking Tug	1.25	seasons		GLD & D	
Two launches	1.25	seasons		GLD & D	
Survey Vessel	1.25	seasons		GLD & D	
Sum	1.25	seasons	7000000	GLD & D	$8,750,000
Season Shutdown	2	seasons	500,000	GLD & D	$1,000,000
Wintering Over	2	ea	6,800,000	GLD & D	$13,600,000
				Protection Costs =	**$40,350,000**

INSTALLATION COST

Item	Quantity		Unit Cost	Reference	Cost of Item
For Optismistic Case use 0.80 X Pipeline Installation Cost for Most Likely Case. See Figure A1-44.	0.8		$50,781,000	Figure A1-44	$40,624,800
				Pipeline Installation Costs =	**$40,624,800**

Total Cost "Optimistic" of Sales Pipeline (Towed & Buried) Kuvlum Platform to Flaxman Island (Including 20% for Engineering) = **$111,263,232**

FLAXMAN ISLAND TO POINT THOMSON

MATERIAL COSTS

Item	Quantity		Unit Cost	Reference for Unit Cost	Cost of Item
	Number	Units			
Line Pipe, 30" x .875" w.t., 272 lbs/ft. 2.4 miles	12,672	feet	$90	ARCO Kuparuk	$1,140,480
Anodes, 3.5 tons/mile	16,800	lbs.	$2.90	RJBA-1984	$48,720
Corrosion/Abrasion Coating	11053	sq. yds.	$4.72	RJBA-1984	$52,170
Fusion Bonded Epoxy, 7.85 sq.ft./ft.					
Concrete Weight Coating					
Consumables	3000	lbs.	$1	RJBA-1984	$3,000
Material Transport	0.453	35k sq. ft.	1000000.00	WCC- McKay	$453,000
				Material Cost =	**$1,697,370**

PROTECTION AND INSTALLATION COSTS (includes trenching the first mile or so from Flaxman to Platform)

Item	Quantity		Unit Cost	Reference	Cost of Item
For Optimistic case use 0.80 X Installation & Protection Cost for Sales Pipeline from Flaxman Island to Point Thomson. See Figure A1-44.	0.8		$7,416,332	Figure A1-44	$5,933,066
				Installation and Protection Cost =	**$5,933,066**

Total Cost "Optimistic" of Sales Pipeline (Buried) Flaxman Island to Point Thomson Winter Installation (Including 20 % for Engineering) = **$9,156,523**

FIGURE A1-50
Optimistic Cost for Sales Pipeline (30", Buried)
from Kuvlum Platform to Point Thomson

MATERIAL COSTS

Item	Quantity		Unit Cost	Reference for Unit Cost	Cost of Item
	Number	Units			
Line Pipe, 30" x .875" w.t., 272 lbs/ft. 6.12 miles	32,414	feet	$90	ARCO Kuparuk	$2,917,260
Line Pipe, 20" x .593"w.t., 123 lbs/ft.	32414	feet	$53	ARCO Kuparuk	$1,717,942
Line Pipe 12" x .406"w.t., 53.7 lbs/ft.	32,414	feet	$19	ARCO Kuparuk	$615,866
Anodes on 30", 3.5 tons/mile	42,000	lbs.	$2.90	RJBA-1984	$121,800
Anodes on 20", 2.1 tons/mile	25,200	lbs.	$2.90	Interpolated	$73,080
Anodes on 12", 1.53 tons/mile	18,360	lbs.	$2.90	RJBA-1984	$53,244
Corrosion/Abrasion Coating on 30" Fusion Bonded Epoxy, 7.85 sq.ft./ft., .2cu.ft/ft.	28185	sq. yds.	$4.63	RJBA-1984	$130,497
Corrosion/Abrasion Coating on 30"	18799	sq. yds.	$4.63	RJBA-1984	$87,039
Corrosion/Abrasion Coating on 30"	11985	sq. yds.	$4.63	RJBA-1984	$55,491
Consumables	12000	lbs.	$1	RJBA-1984	$12,000
Material Transport	1.85	35k sq. ft.	1000000.00	WWC - McKay	$1,850,000
				Material Cost =	**$7,622,218**

PROTECTION COSTS

Item	Quantity		Unit Cost	Reference	Cost of Item
Mob & Demob: Sum of Dredge 1 and Related Support Vessels	0	ea.	$16,000,000	GLD & D	$0
Work Preparation	1	ea	$500,000	GLD & D	$500,000
Dredging Spread: Dredge 1	1	seasons		GLD & D	$0
6000 HP Icebreaking Tug	1	seasons		GLD & D	$0
Two launches	1	seasons		GLD & D	$0
Survey Vessel	1	seasons		GLD & D	$0
Sum	1	seasons	7000000	GLD & D	$7,000,000
Season Shutdown	1	seasons	500,000	GLD & D	$500,000
Wintering Over	1	ea	6,800,000	GLD & D	$6,800,000
				Protection Cost =	**$14,800,000**

INSTALLATION COST

Item	Quantity		Unit Cost	Reference	Cost of Item
For Optimistic Cost use 0.80 X Pipeline Installation Cost for Most Likely Case. See Figure A1-45	0.8		$23,110,000	Figure A1-45	$18,488,000
				Installation Cost =	**$18,488,000**

Total Cost "Optimistic Cost" of Infield Pipelines (Towed & Buried) Kuvlum Platform to Satellite Platform (Including 20% Engineering) = **$49,092,262**

FIGURE A1-51
Optimistic Cost for Infield Pipelines (30", 20", 12", Buried)
From Kuvlum Main Platform to Satellite Platform

MOST LIKELY COSTS of 24 Inch PIPELINES

Sales Pipeline (24 inch) from Kuvlum Platform to Flaxman Island Includes dredged trench, towed pipe, material, protection, installation, & 20% for engineering.	**$129,974,563**
Sales Pipeline (24 inch) from Flaxman Island to Point Thompson Includes burial, material, protection, installation, tie-ins & 20% for engineering Winter Construction.	**$10,875,562**
Sales Pipeline (24 inch) Placed in Tunnel from Kuvlum Platform to Flaxman Island Includes material, protection, installation, tie-ins and 20% for engineering. Does not include Cost of Tunnel.	**$29,245,459**
Sales Pipeline (24 inch) Placed in Tunnel from Flaxman Island to Point Thom Based on 5 mile length. Ratio used on Kuvlum to Flaxman segment. Does not include Cost of Tunnel.	**$8,884,956**

Reference: Figures A1-53,54.

Figure A1-52
Summary of Most Likely Costs of 24 Inch Pipelines

KUVLUM PLATFORM TO FLAXMAN ISLAND

MATERIAL COSTS

Item	Quantity		Unit Cost	Reference for Unit Cost	Cost of Item
	Number	Units			
Line Pipe, 24" x .75" w.t., 186 lbs/ft. 16.3 miles	86,064	ft.	$94	GLD&D - 1994	$8,090,016
Miscell. Valves, Bends, Flanges	1	Lot	$200,000	Karlik - 1994	$200,000
Anodes, 3.5 tons/mile	112,000	lbs.	$2.90	RJBA-1984	$324,800
Corrosion/Abrasion Coating Fusion Bonded Epoxy, 6.28 sq.ft./ft.,	60,000	sq. yds.	$4.72	ACETS -1986	$283,200
Concrete Weight Coating					
Consumables	20000	lbs.	$1	RJBA-1984	$20,000
Material Transport	2.5	35k sq. ft.	$1,000,000	WWC - McKay	$2,500,000
				Material Cost =	**$11,418,016**

PROTECTION COSTS

Item	Quantity		Unit Cost	Reference	Cost of Item
Mob & Demob: Sum of Dredge 1 and Related Support Vessels	1	ea.	$16,000,000	GLD & D	$16,000,000
Work Preparation	3	ea	$500,000	GLD & D	$1,500,000
Dredging Spread: Dredge 1	2	seasons		GLD & D	$0
6000 HP Icebreaking Tug	2	seasons		GLD & D	$0
Two launches	2	seasons		GLD & D	$0
Survey Vessel	2	seasons		GLD & D	$0
Sum	2	seasons	8160000	GLD & D	$16,320,000
Season Shutdown	3	seasons	500,000	GLD & D	$1,500,000
Wintering Over	2	ea	6,800,000	GLD & D	$13,600,000
				Protection Cost =	**$48,920,000**

INSTALLATION COST

Item	Quantity		Unit Cost	Reference	Cost of Item
Contractor's Project Management & Engineering	1	LS.	2,560,000	Rockwater 1994	$2,560,000
Mob and Demob: Towing Spread, Pulling Spread, Misc. Vessels, Sum of Installation Spread				Rockwater 1994	$10,704,000
Set-Up Shore Based Make-Up Site	1	each	5,600,000	WWC - McKay	$5,600,000
Fabrication	1	LS.	14,736,120	Rockwater 1994	$14,736,120
Installation	1	LS.	5,774,000	Rockwater 1994	$5,774,000
Pipeline Tie-In				RJBA-1984	$8,600,000
				Pipeline Installation Cost =	**$47,974,120**

Total Cost "Most Likely" of Sales Pipeline (Towed & Buried) Kuvlum Platform to Flaxman Island (Including 20% for Engineering) = **$129,974,563**

FLAXMAN ISLAND TO POINT THOMSON

MATERIAL COSTS

Item	Quantity		Unit Cost	Reference for Unit Cost	Cost of Item
	Number	Units			
Line Pipe, 24" x .75" w.t., 186 lbs/ft. 2.4 miles	12,672	feet	$94	GLD&D - 1994	$1,191,168
Anodes, 3.5 tons/mile	16,800	lbs.	$2.90	RJBA-1984	$48,720
Corrosion/Abrasion Coating Fusion Bonded Epoxy, 6.28 sq.ft./ft.	8845	sq. yds.	$4.72	ACETS - 1986	$41,748
Concrete Weight Coating					
Consumables	3000	lbs.	$1	RJBA-1984	$3,000
Material Transport	0.362	35k sq. ft.	1000000.00	WCC- McKay	$362,000
				Material Cost =	**$1,646,636**

PROTECTION AND INSTALLATION COST (Includes trenching the first mile or so from Flaxman Island to Platform)

Item	Quantity		Unit Cost	Reference	Cost of Item
Mob & Demob: Excavating and Earthmoving Equipment included in Sales Pipeline from Point Thomson to TAPS Pump Station #1.					
Trenching 1 Mile Offshore from Flaxman	1	mi.	87532	ACETS /Kuparuk	$87,532
Incremental Mileage Pipeline Rate	2.4	mi	2637000	ACETS/Kuparuk	$6,328,800
Pipeline Tie-Ins				Guess	$1,000,000
				Installation and Protection Cost =	**$7,416,332**

Total Cost "Most Likely" of Sales Pipeline (Buried) Flaxman Island to Point Thomson Winter Installation (Including 20 % for Engineering) = **$10,875,562**

FIGURE A1-53
Most Likely Cost for Sales Pipeline (24", Buried)
From Kuvlum Platform to Point Thomson

Kuvlum Platform to Flaxman Island

MATERIAL COSTS

Item	Quantity		Unit Cost	Reference for Unit Cost	Cost of Item
	Number	Units			
Total from Conventionally Installed Option					$11,418,016
Credit for Anodes, 3.5 tons/mile	-112,000	lbs.	$2.90	RJBA-1984	($324,800)
				Material Cost =	**$11,093,216**

INSTALLATION COSTS

Item	Quantity		Unit Cost	Reference	Cost of Item
Set-up of Pipe Yard on Flaxman Island	Included in next item.				
Welding of Multiple Joints, Train Operation,				ACETS II - 1986	$11,600,000
Placement in Tunnel					
Hydro-Testing and Pigging	1	each	$1,000,000	Guessed	$1,000,000
Riser from Tunnel to Platform	6	days	$113,000	ACETS II Spread	$678,000
				Installation Cost =	**$13,278,000**

Total Cost Sales Pipeline (24 Inch) placed in Tunnel from Kuvlum Platform to Flaxman Island (Includes material, protection, installation, tie-ins & 20% for Engineering)= $29,245,459

Flaxman Island to Point Thomson

Total Cost Sales Pipeline (24 Inch) placed in Tunnel from Flaxman Island to Point Thomson
Bases on 5 miles length and ratio from Kuvlum Platform to Flaxman Island Cost not including riser cost.
(Includes material, protection, installation, tie-ins & 20% for Engineering)= $8,884,956

FIGURE A1-54
Most Likely Costs of Sales Pipeline (24") Placed Inside Tunnel
(Cost of Tunnel Not Included)

PESSIMISTIC COSTS of 24 Inch PIPELINES

Sales Pipeline (24 Inch) from Kuvlum Platform to Flaxman Island Includes dredged trench, towed pipe, material, protection, installation, & 20% for engineering.	**$199,510,878**
Sales Pipeline (24 Inch) from Flaxman Island to Point Thomson Includes burial, material, protection, installation, tie-ins & 20% for engineering Winter Construction.	**$15,862,579**

Reference: Figure A1-56

Figure A1-55
Summary of Pessimistic Costs of 24 Inch Pipelines

KUVLUM PLATFORM TO FLAXMAN ISLAND

MATERIAL COSTS

Item	Quantity		Unit Cost	Reference for Unit Cost	Cost of Item
	Number	Units			
Line Pipe, 24" x .75" w.t., 186 lbs/ft. 16.3 miles	86,064	feet	$123.20	1.3 * GLD&D	$10,603,085
Miscellaneous Valves, Bends, Flanges	1	lot	$200,000	Karlik - 1994	$200,000
Anodes, 3.5 tons/mile	112,000	lbs.	$2.90	RJBA-1984	$324,800
Corrosion/Abrasion Coating Fusion Bonded Epoxy, 6.28 sq.ft./ft., .2cu.ft/ft.	60,000	sq. yds.	$13.50	RJBA-1984	$810,000
Concrete Weight Coating					
Consumables	20000	lbs.	$1	RJBA-1984	$20,000
Material Transport	2.5	35k sq. ft.	$1,000,000	WWC - McKay	$2,500,000
				Material Cost =	**$14,457,885**

PROTECTION COSTS

Item	Quantity		Unit Cost	Reference	Cost of Item
Mob & Demob: Sum of Dredge 1 and Related Support Vessels	1	ea.	$16,000,000	GLD & D	$16,000,000
Work Preparation	4	ea	$500,000	GLD & D	$2,000,000
Dredging Spread: Dredge 1	4	seasons		GLD & D	$0
6000 HP Icebreaking Tug	4	seasons		GLD & D	$0
Two launches	4	seasons		GLD & D	$0
Survey Vessel	4	seasons		GLD & D	$0
Sum	4	seasons	$8,160,000	GLD & D	$32,640,000
Season Shutdown	4	seasons	$500,000	GLD & D	$2,000,000
Wintering Over	4	ea	$6,800,000	GLD & D	$27,200,000
				Protection Costs =	**$79,840,000**

INSTALLATION COST

Item	Quantity		Unit Cost	Reference	Cost of Item
For Pessimistic Case use 1.5 X Pipeline Installation Cost for Most Likely Case. See Figure A1-55.	1.5		$47,974,120	Figure A1-44	$71,961,180
				Pipeline Installation Costs =	**$71,961,180**

Total Cost "Pessimistic" of Sales Pipeline (Towed & Buried) Kuvlum Platform to Flaxman Island (Including 20% for Engineering) = **$199,510,878**

FLAXMAN ISLAND TO POINT THOMSON

MATERIAL COSTS

Item	Quantity		Unit Cost	Reference for Unit Cost	Cost of Item
	Number	Units			
Line Pipe, 24" x .75" w.t., 186 lbs/ft. 2.4 miles	12,672	feet	$123.20	1.3*GLD&D	$1,561,190
Anodes, 3.5 tons/mile	16,800	lbs.	$2.90	RJBA-1984	$48,720
Corrosion/Abrasion Coating Fusion Bonded Epoxy, 6.28 sq.ft./ft.	8845	sq. yds.	$13.50	RJBA-1984	$119,408
Concrete Weight Coating					
Consumables	3000	lbs.	$1	RJBA-1984	$3,000
Material Transport	0.362	35k sq. ft.	1000000.00	WCC- McKay	$362,000
				Material Cost =	**$2,094,318**

PROTECTION AND INSTALLATION COSTS (includes trenching the first mile or so from Flaxman to Platform)

Item	Quantity		Unit Cost	Reference	Cost of Item
For Pessimistic case use 1.5 X Installation & Protection Cost for Sales Pipeline from Flaxman Island to Point Thomson. See Figure A1-55.	1.5		$7,416,332		$11,124,498
				Installation and Protection Cost =	**$11,124,498**

Total Cost "Pessimistic" of Sales Pipeline (Buried) Flaxman Island to Point Thomson Winter Installation (Including 20 % for Engineering) = **$15,862,579**

FIGURE A1-56
Pessimistic Cost for Sales Pipeline (24", Buried)
From Kuvlum Platform to Point Thomson

OPTIMISTIC COSTS OF 24" PIPELINE

Sales Pipeline (24 Inch) from Kuvlum Platform to Flaxman Island Includes dredged trench, towed pipe, material, protection, installation, & 20% for engineering.	**$105,904,685**
Sales Pipeline (24 Inch) from Flaxman Island to Point Thomson Includes burial, material, protection, installation, tie-ins & 20% for engineering Winter Construction.	**$8,761,102**

Reference: Figure A1-58.

FIGURE A1-57
Summary of Optimistic Costs of 24" Pipelines

KUVLUM PLATFORM TO FLAXMAN ISLAND

MATERIAL COSTS

Item	Quantity		Unit Cost	Reference for Unit Cost	Cost of Item
	Number	Units			
Line Pipe, 24" x .75" w.t., 186 lbs/ft. 16.3 miles	86,064	ft.	$72	ARCO Kuparuk	$6,196,608
Misc. Valves, Bends, Flanges	1	Lot	$200,000	Karlik - 1994	$200,000
Anodes, 3.5 tons/mile	112,000	lbs.	$2.90	RJBA-1984	$324,800
Corrosion/Abrasion Coating Fusion Bonded Epoxy, 6.28 sq.ft./ft.	60000	sq. yds.	$4.72	ACETS 1986	$283,200
Concrete Weight Coating					
Consumables	20000	lbs.	$1	RJBA-1984	$20,000
Material Transport	2.5	35k sq. ft.	$1,000,000	WWC - McKay	$2,500,000
				Material Cost =	**$9,524,608**

PROTECTION COSTS

Item	Quantity		Unit Cost	Reference	Cost of Item
Mob & Demob: Sum of Dredge 1 and Related Support Vessels	1	ea.	$16,000,000	GLD & D	$16,000,000
Work Preparation	2	ea	$500,000	GLD & D	$1,000,000
Dredging Spread: Dredge 1	1.25	seasons		GLD & D	
6000 HP Icebreaking Tug	1.25	seasons		GLD & D	
Two launches	1.25	seasons		GLD & D	
Survey Vessel	1.25	seasons		GLD & D	
Sum	1.25	seasons	7000000	GLD & D	$8,750,000
Season Shutdown	2	seasons	500,000	GLD & D	$1,000,000
Wintering Over	2	ea	6,800,000	GLD & D	$13,600,000
				Protection Costs =	**$40,350,000**

INSTALLATION COST

Item	Quantity		Unit Cost	Reference	Cost of Item
For Optismistic Case use 0.80 X Pipeline Installation Cost for Most Likely Case. See Figure A1-53.	0.8		$47,974,120	Figure A1-53	$38,379,296
				Pipeline Installation Costs =	**$38,379,296**

Total Cost "Optimistic" of Sales Pipeline (Towed & Buried) Kuvlum Platform to Flaxman Island (Including 20% for Engineering) = **$105,904,685**

FLAXMAN ISLAND TO POINT THOMSON

MATERIAL COSTS

Item	Quantity		Unit Cost	Reference for Unit Cost	Cost of Item
	Number	Units			
Line Pipe, 24" x . 75" w.t., 186 lbs/ft.	12,672	feet	$72	ARCO Kuparuk	$912,384
Anodes, 3.5 tons/mile	16,800	lbs.	$2.90	RJBA-1984	$48,720
Corrosion/Abrasion Coating Fusion Bonded Epoxy,6.28 sq.ft./ft.	8845	sq. yds.	$4.72	RJBA-1984	$41,748
Concrete Weight Coating					
Consumables	3000	lbs.	$1	RJBA-1984	$3,000
Material Transport	0.362	35k sq. ft.	1000000.00	WCC- McKay	$362,000
				Material Cost =	**$1,367,852**

PROTECTION AND INSTALLATION COSTS (Includes trenching the first mile or so from Flaxman to Platform)

Item	Quantity		Unit Cost	Reference	Cost of Item
For Optimistic case use 0.80 X Installation & Protection Cost for Sales Pipeline from Flaxman Island to Point Thomson. See Figure A1-44.	0.8		$7,416,332	Figure A1-55	$5,933,066
				Installation and Protection Cost =	**$5,933,066**

Total Cost "Optimistic" of Sales Pipeline (Buried) Flaxman Island to Point Thomson Winter Installation (Including 20 % for Engineering) = **$8,761,102**

FIGURE A1-58
Optimistic Cost for Sales Pipeline (24", Buried)
From Kuvlum Platform to Point Thomson

A1.13 Annotated Bibliography

Bryce, P.W., and J. M. Key. *Modified Reel Method for Subsea Arctic Pipelines*, Proceedings of the Second ASCE Conference on Pipelines in Adverse Environments, ASCE, San Diego, 1983, pp. 486-499. Discusses the Modified Reel Methods of laying pipelines. First method is to mount several prespooled reels of pipe on a supply barge. After the pipe laying reel ship depletes one spool, it gets another reel from the supply barge. The second method would not use the pipe laying reel ship but would just use a pipe laying barge which could take pipe directly from the supply barge, straighten it, and feed it off a stinger. After one spool is depleted, the relative position of the supply barge and lay barge would be changed so that the next reel could be used. All reels would stay on the supply barge. References made to 14" diameter pipe, none larger. Example is given of laying two 50" pipelines with a total on-site time of 55 days. Lay rate of 1200' per hour less 10% weather downtime is assumed. This results in a lay rate of about 5 miles per day not including diving, inspecting, equipment maintenance, etc. They suggest a reel vessel could lay up to 25 miles of small diameter pipe per day. Draft limitations constrain the existing pipe laying reel ships.

Carstens, D. K., and E. J. Thompson. *Self Propelled Pipeline Trencher for Offshore Arctic Applications*, Proceedings of the Arctic Offshore Technology Conference, Calgary, Alberta, October 1986. Paper describes the Sea Squirt Trencher, a self-propelled trencher designed to operate from the power supplied by a low pressure water hose from the support vessel. Water supply would be from support vessel's fire pumps or from skid-mounted pumps. Trench is cut by using jets arranged along the front and bottom of the machine. Machine digs its own hole. Spoil is removed from the trench using water eductors. Spoil is discharged near the seabed at velocities of 25 ft./sec. Propulsion is produced by the forward reaction force on the machine caused by the rearward direction of the spoil eductors. Authors claim that the use of eductor thrust for the propulsion of the trencher removes any need for the machine to ride on the seabed for traction, having to grab the pipeline for traction, or having to be pulled by a support vessel. Trencher rides the pipeline on a set of freewheeling rollers, horizontal and vertical, which provide a guidance system, support the trencher, and set the depth of trench. Trencher remains vertical because center of buoyancy is above center of gravity. Front jets are aimed upward which holds trencher down. One prototype weighs less than two tons and trenches 36" pipe to a depth of several meters. Field test trenched four meters deep in firm sand. Can make multiple passes. Trencher would be built for specific line or range of line sizes. Further test and optimization is required.

Corona, Emilio. ARCO Exploration and Production Technology, Personal Communication, Nov. 4, 1993. Three icebreakers being used with the Kulluk are described below. The icebreaker Kalvik has approximately 350 tons of bollard pull, has 20,000 to 24,000 horsepower, costs about $40,000 per day. Icebreaker Miscaroo has about 18,000 horsepower, somewhat less bollard pull. Icebreaker Ikaluk is similar to Miscaroo. The Miscaroo and Ikaluk are $20,000 to $30,000 per day each. Another boat of lesser horsepower is also used with the spread. Eight to

ten thousand hp, typical of some tugboats for Gulf of Mexico, generally gives 100 tons of bollard pull. Emilio believes the Kalvik is or is close to the most powerful commercial icebreaker in North America.

Dickson, L.J. *Apache - The World's First Pipelaying Reel Ship*, Proceedings of the Deep Offshore Technology Conference, Palma De Mallorca, Spain, 1981, Vol. 3, pp. 74-82. Capabilities of the Apache are to spool 16 inch O.D. pipe and to lay 12.75 inch O.D. pipe in 3000 ft. water depths. Maximum pipe lay rate of 2 knots. Capacity of the 82 foot diameter reel is 5.7 miles of 16" pipe of 50.5 miles of 4" pipe depending on wall thickness. On the Chevron Ninian project, the Apache laid 10.75" pipe at speeds of 0.4 miles per hour in the latter stages of the work. The 17.2 km line was laid in less than three weeks from loading out of the first pipe to pressure testing of the line in place. On the Texaco Tartan project, the Apache laid two 6" lines simultaneously from the same reel. Considerable care was required during reeling to insure that both lines were always on the same layer on the reel to avoid a difference in the lengths of the lines.

van Ginkel, Nick, Ham/Volker Stevin. Personal Communication, Nov. 2, 1993. Nick believes suction hopper dredges are better than the cutter suction dredges in the deeper water along the route because they can accommodate 6-8 ft. waves while a cutter suction dredge is restricted to operations in 3 ft. waves or less. He reported typical production rates of 20,000 cubic meters per day (26,000 cubic yards per day) for some non-U.S. flag vessels that they have. U.S. vessels which are Jones act-legal have typical production rates of 10,000 cubic meters per day. ARCO would not want to use these smaller vessels for trenching in the Beaufort. Nick suggested that plowing after trenching should be used for the final 5-6 feet of depth of trench in deep water. THe use of plowing would significantly reduce the amount of spoil that had to be removed from the trench. In using a hopper dredge in the past for trenching, the side slopes achieved were typically 1v:5h in both sand and clay. Some approximate dredging costs are: 1) Mob/demob for a hopper dredge = $8MM, 2) two seasons of operations for a hopper dredge = $8MM, 3) mob/demob and two(?) season of operations for a trencher = $10MM, 4) mob/demob and two(?) season of operations for a cutter suction dredge = $10MM.

Hood, G.L., D. M. Masterson, and J. W. Watts. *Installation of a Subsea Completion in the Canadian Arctic Islands*, Journal of Canadian Petroleum Technology, Oct.-Dec. 1981, Vol. 20, No. 4, pp. 41-52. Well location was Drake F-76, east side of Sabine Peninsula in the Drake Point gas field. Was 1200 meters offshore in 55 meters of waters. Was a project of Panarctic Oils, Ltd. Well drilling and setting of tree was done from a fast ice platform. Eighteen inch carrier pipe contained two 6" flow lines, five other smaller lines, heat tracing lines. Soil shear strength was about 60 psf at sea floor and 125 psf at about 16 feet below sea floor. Trench depth of 1.5 meters was selected. Four meter deep trench was desired but it was feared the walls would collapse because of the soils weak strength. Trench was plowed. Grounded ice berm was constructed out to 5 meters water depth to protect the pipe bundle from ice scour. Pipe bundle was made up onshore in a heated tent. ONe foot wide slot was cut in ice from shore to the ice platform. A 2" pull cable was laid

from an ice-based winch to the shore. Winch was first used to pull the plow from a near-shore launch hole to the end of the plowed trench. Plow was recovered and cable was then utilized to pull the flowline bundle into place on the sea bed. Shoreward of the plow launch hole, the trench had been extended by drilling and blasting in permafrost and by clamshelling in unfrozen soil. Subsea completion manifold at bundle's end was pulled laterally 55 meters to get in place for the connection. First 100 meters of bundle was supported by buoys and weighted by chains to float 3 meters off bottom. Rig was released in April 1978 after successful well test.

Lowe, Alex, President of A & L Underground, Olathe, Kansas. Personal Communication, Nov. 5, 1993. Alex believes it is technically feasible to make a directionally drilled connection to a pipe from the structure. He said that the maximum radius of a drilled hole was 1200 times the pipe diameter. This may be a conservative limit. This is slightly less than 2 degrees per 100 feet of 30" pipe. Because of this limit on radius, he would prefer to see the drilling rig sitting in a chamber of the structure whose floor is at the same elevation as the sea bottom, or even better, at a distance below the sea floor so that the hole is a horizontally drilled hole. He sees the loss of drilling mud at break-through as no big issue. Depending on geology, the hole could possibly be drilled with straight water. The problem of water running back into the drilling chamber through the drilled hole can be handled with a seal or, if necessary, the chamber can be pressurized. He sees this application of directional drilling as using existing technology.

Masterson, D. M., and P. St. J. Price. *Arctic Pipeline Installation Method Uses Ice Sheet for Support*, Offshore, March 1989, Vol. 49, No. 3, pp. 29-31. Comprehensive pipeline safety monitoring and surveillance can be classified into (1) corrosion and material quality monitoring, 2) structural deformation monitoring and reliability analysis, and 3) encroachment and surveillance monitoring. This paper is a shorter version of the conference paper below.

Masterson, D. M., and P. St. J. Price. *Arctic Offshore Pipeline Installation and Operation*, Proceedings of the Eighth International Conference on Offshore Mechanics and Arctic Engineering, The Hague, The Netherlands, March 19-23, 1989, Vol. V, pp. 405-413. Floating ice platforms can be thickened at a relatively high rate by using sprayed ice. Thickening rates can be 0.3 to 0.5 meters per day. Pumps with a capacity of 12 to 20 cubic meters/minute at a nozzle pressure of 1.4 MPa are typically used to deliver the water. The material is granular, permeable, and porous. It is readily moved by earth-moving equipment. Spray ice behaves as a soft ice or a stiff soil. Can be regarded as having both cohesion and a friction angle. One kilometer of a floating right of way 1.5 meters thick and 40 meters wide could be built in about seven days using five 12 m3/min. capacity pumps. Authors suggest that a grounded berm could be built to either side of a floating right of way to extend the range of floating fast ice. They have not analyzed the actual capacity of such berms.

Mueser, Bill and Stan Ekren, Great Lakes Dredge and Dock. Personal Communications, December 17, 20, 1993. Their cutter suction dredges typically use spuds to turn and advance in water depths up to about 100 feet. Then anchors are

used. Swing anchors are used to turn the stern of the cutter dredge from side to side. The cutter head of the dredge is 6-8 feet wide and Bill's guess is that the minimum width of trench they could dig is 10 feet wide at the bottom. A trench would be cut by making successive swaths, each of which is more or less vertical sided and which decrease in width as they go deeper. Because of the narrow width of the trench, their production rate is dependent on rate of travel, not on pump or cutting capacity. In order to collect and use some of the dredge spoil for a working area on Flaxman Island, they would employ a dump scow. The dredge would discharge spoil into the dump scow instead of wasting it to the side. The dump scow takes the material as near to the beach as possible and dumps it into an underwater stockpile. The dredge comes later and dredges the material up and pumps it through a pipeline to the island. An onshore equipment spread is required to move the material around and dewater it on the island. Day rate on a dump scow would be $2400 per day. Also, a dump scow could be used as a material transport barge in getting pipe or other materials up to the site.

Proper, Leon, McDermott, Inc. Personal Communication, Nov. 2, 1993. Discussed required ditch width for laying from a lay barge. McDermott's usual experience with laying a pipeline in a plowed ditch has been in a situation where the plow is making the ditch just ahead of touchdown of the pipe. In this situation, the large diameter pipelines (maybe 16" and larger) go into the ditch automatically. Smaller diameter pipelines may want to get out of the ditch but the contractor can go back with a cable working from a boat and pull the pipe into the ditch. Leon knew of no case where they had laid a pipe into a previously dredged ditch with no plow in the spread. Having an as-built survey of a ditch would not be sufficient information to get the pipeline into the ditch. An ROV might or might not supply enough information to get the pipe into a narrow ditch. New method, such as using transponders, may require development to accommodate a narrow ditch. Leon said McDermott had plowed a ditch as deep as 8' and jetted in a pipe to get over 16' of cover in an anchorage area.

Brown and Associates. *Marine Pipeline Engineering: State of the Art*, Evolution of Pipeline Plowing. Plowing generally digs deeper and moves faster than jetting. *New Techniques for Marine Pipeline Burial*. Old-style jetting makes much flatter side slopes on a trench than plowing.

Rochelle, W.R., and D. M. Simpson. *Methods for Protecting Subsea Pipelines and Installations*, Production and Transportation Systems for the Hibernia Discovery Symposium, St. John's, Newfoundland, 1981, pp. 253-269. General discussion of hazards and trenching.

> Jetting: In-air weight of jet sled is typically 55 tons to 100 tons. Typical jetting barge may be 100 ft. x 400 ft. Jetting pumps could have total capacity of 20,000 gpm at pressure of 2500 psi. Jetting spread typically achieves depth of 1 meter plus pipe diameter. More passes are needed for deeper depths. Shear strength of 100 psi is claimed to be approximate upper limit for jetting. Advance rate varies with soil strength, but maximum is around 500 meters/hour due to time required to move barge anchors.

Mechanical Trenching: Reports that as of the date of writing 46 devices for mechanical trenching for pipelines have been through various stages of development. Another 36 have been developed for cable burial. Brown & Root's Mechanical Underwater Trencher (MUT) will supposedly work in soils of 0.5 to 700 psi shear strength, dig trenches 12' deep, and bury coated pipes 6" to 42" in diameter. Cuts bi-directionally with four rotating cutters. Has in-air weight of 135 tons. Maximum forward speed of 600 meters/hour. Depth of trench per pass will depend on type of material and forward speed.

Plowing: Trench depth is controlled by size of plow, prime mover and soil strength. Example is 36" line between Statfjord and Condeep. Trench was 1.1 meters deep. Plow was 40 ft. long and weighed 55 tons.

Backfilling or Filling on Top of Line: Used where specific risks to pipeline have been identified, where remedial action is required.

Weak Link Philosophy

Repair: Mechanical connectors, hyperbaric welding.

Subsea Production Protection: Protective shelters, berms, glory holes.

Serpas, Ray, Hudson Engineering. Personal Communication, Oct. 28, 1993. McDermott has three or four plows in Morgan City. Plows are relatively small and are for relatively small lines. The plows are not considered uniquely designed for only one job. They cut square trenches rather than a V-trench. More information is available from Leon Proper or Dan Sullivan, Manager of Offshore Operations.

Sitjhoff, Roy, Rockwater, Inc. Personal Communication, Dec. 10, 1993. Roy recommends using mechanical excavation for the 2.4 mile segment from Flaxman to the beach rather than trying to use a plow. The difficulty in getting a plow to cut a trench of constant depth influences his opinion. He believes it would be cheaper to tow a 16-mile pipeline rather than to tow out two 8-mile segments and make a subsea connection between them. He estimates eleven days to tow out the 16-mile section and envisions it would be done with an anchored barge rather than with a tug or towboat. For the satellite line, the two would probably be off-bottom. The chain which controls position of floatation would provide a way of getting something into the trench which can then guide the pipeline into the trench. The tow sled would be off-bottom so it will not hang up on anything. The satellite lines would probably be two tows. One would be the 30" alone. The other would be a bundled 20" and 12". The cables would also be placed into the trench separately.

Wainwright, J.G., and J. G. Bomba. *The Installation of Arctic Offshore Pipelines*, Proceedings of the 11th International Conference on Offshore Mechanics and Arctic Engineering, Safety and Reliability, Calgary, Alberta, June 7-12,. Vol. II, pp. 115-122. Directional drilling for the shore approach offers advantages of achieving adequate depth for protection from scour, minimizing environmental effects to the

shore line, and providing ability to work at any time of the year. Entry angle ranges from a few degrees above horizontal to 20 degrees above horizontal, typically 8-15 degrees. Authors believe state of the art will allow a 2000 meter long drilled hole. A 48" pipeline has been installed in about a 1000 meter long run. Pilot hole should be expected to exit within a few meters of target point. Bottom tow method can be used for launching offshore pipelines from shore. Can be used with direct launch or side launch. Factors existing in the Arctic which make bottom tow attractive are availability of make-up sites onshore, limited obstructions on the sea floor, smooth sea floor contours, availability of tow vessels, if icebreakers are mobilized.

APPENDIX 2

ONSHORE SALES PIPELINE

APPENDIX 2: ONSHORE SALES PIPELINE

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APPENDIX 2: ONSHORE SALES PIPELINES

Summary

The onshore portion of the 30" sales line was assumed to be 45 miles of VSM (vertical support member) supported pipeline. The "Most Likely" cost for this pipeline was estimated to be $130MM. An optimistic cost was estimated to be 80% of this Most Likely cost and a pessimistic cost was estimated to be 150% of this Most Likely cost. Design and construction methods were modelled after existing Prudhoe Bay and Kuparuk pipelines.

Assumptions

The onshore portion of the 30" sales line was assumed to run cross-country from Pt. Thomson to TAP's Pump Station #1, a distance of 40 miles. Ten percent was added to the distance to account for expansion loops and diversions around wetlands, animal habitat, etc. The line will be supported on VSM's spaced at 55 feet. A gravel road will accompany the pipeline.

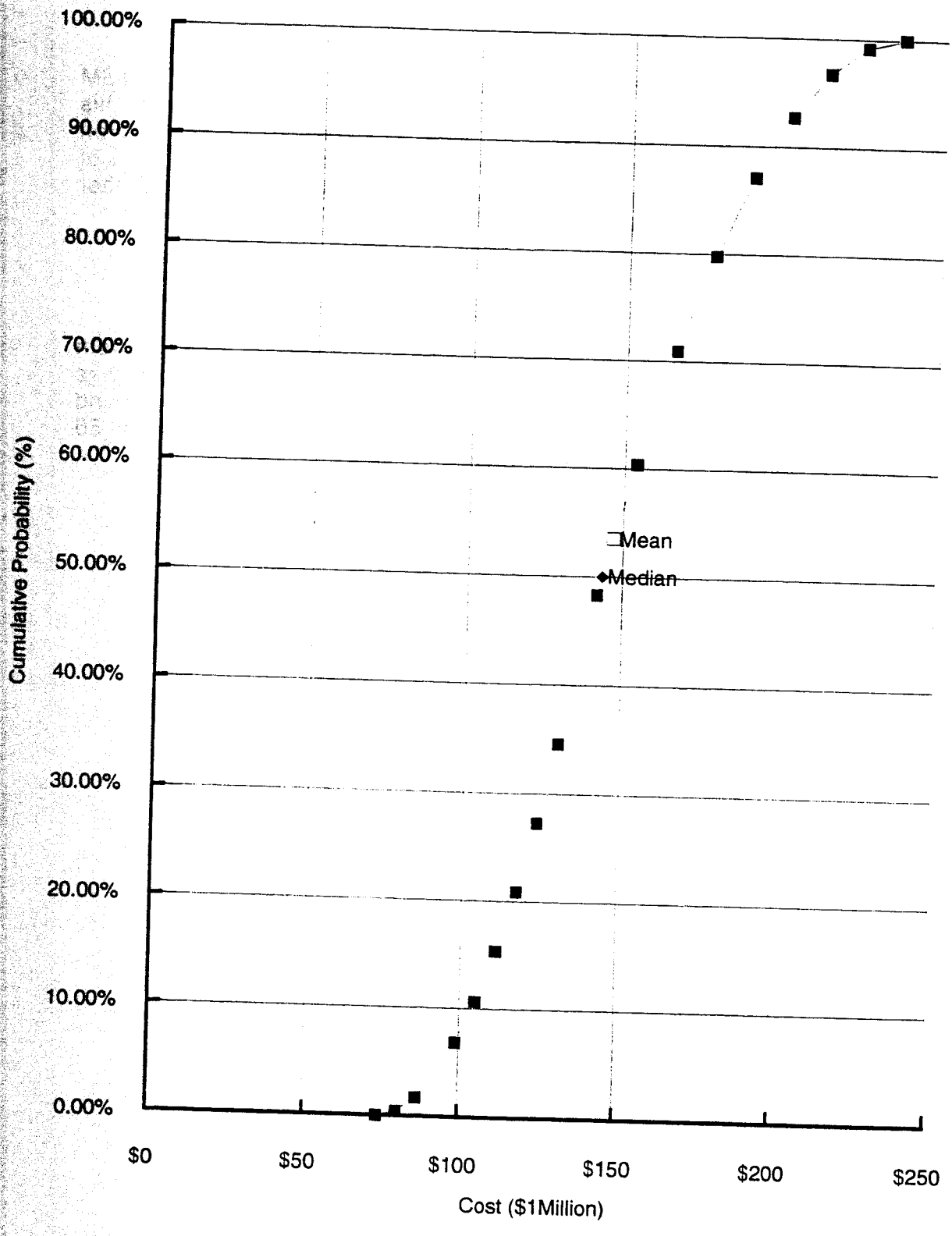


FIGURE A2-2
Sales Pipeline (30") From Point Thomson to TAPS Pump Station #1 (Onshore Route)

This Spread Sheet will compute the unique Triangular Probability Density Distribution and the unique Cumulative Probability Curve determined by the k'%, Most Likely and k"% Cost Estimates

INPUT:

	Costs in $1,000,000	
k' & k'Cost Estimate	0.1	$104.00
Most Likely Cost Estimate	b=	$130.00
k''' & k'''Cost Estimate	0.9	$195.00

Sales Pipeline (30 Inch) from Point Thomson to TAPS Pump Station #1. Onshore Route

0% cost = $73.71 **100%Cost= $236.70**

See Table for Probability Density vs Cost, Mean & Median Costs

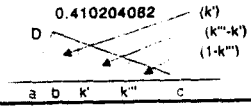
To Calculate the Absolute Minimum Cost (0%Cost Estimate) which will be called "a" and the Absolute Maximum Cost (100% Cost Estimate) which will be called "c". Note the Most Likely Cost is called "b".

The k', Most Likely, and k"'Cost Estimates completely define the Triangular Probability Density Distribution and Cumulative Probability Curves. An interative procedure has to be used to calculate "a" and "c"; that is, the 0%Cost Estimate and the 100% Cost Estimate, respectively.

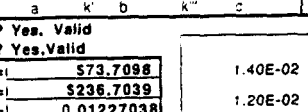
First step is to determine which set of equations are applicable to find "a"and "c". This will depend on where the Most Likely Cost Estimate "b" lies relative to k' and k"'Cost Estimates.
Please note that k'Cost Estimate is always less than k"'Cost Estimate.

FOR THE ABOVE K'COST, MOST LIKELY COST AND K"'COST ESTIMATES USE **XXXXXXX MIDDLE CASE XXXXXXX**

CASE LEFT
If Most Likely Cost Estimate < k'Cost Estimate
c= 240.50000
D= 0.01067504
a= 53.14705882
Therefore k2 *for Most* Likely Cost Estimate is equal to 0.410204082

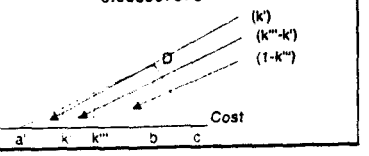


CASE MIDDLE
If (k'CostEstimate<Most Likely Cost Estimate<k"'Cost Estimate), iterate to Find Absolute Minimum 'a' and Maximum 'c' Cost Estimates. Try values of 'a' until
c'=c". Trial 'a'= 73.70978
c'= 236.7038894
c"= 236.7038212
Delta=(c'-c")= 6.81902E-05
D= 0.012270382



	0.00001	
	0.0001	73.70979

CASE RIGHT
If (k'Cost Esti.<k"'Cost Esti.>Most Likely Cost Esti.),
a= 58.5
c= 348.0454545
D= 0.006907378



Is a <k'Cost Estimate? Yes. Valid
Is K'<K"'? Yes.Valid

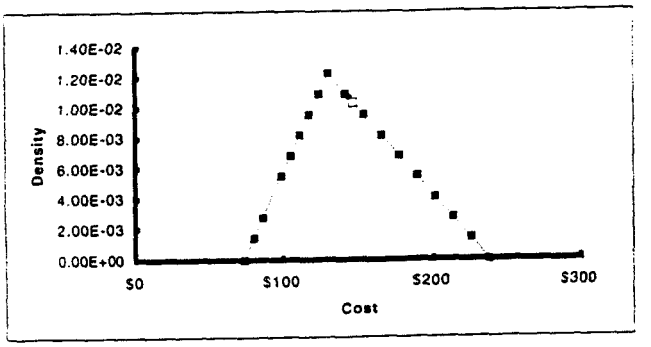
Please Note that you must enter the values calculated above into these slots before computing distributions.

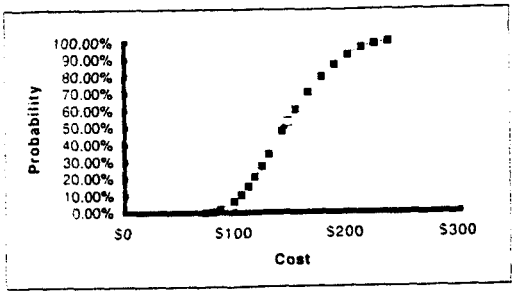
Enter the Values of "a", "c", and D computed above →

a=	$73.7098
c=	$236.7039
D=	0.01227038

Calculating Probability Density Distribution and Cumulative Probability Curves

	Cost in $1,000,000 $	Probability Density (1/$)	Cumulative Probability %
	$74	0.00E+00	0.00%
	$80	1.36E-03	0.43%
	$86	2.73E-03	1.71%
	$99	5.45E-03	6.82%
	$99	5.45E-03	6.82%
	$105	6.82E-03	10.66%
	$111	8.18E-03	15.35%
	$117	9.54E-03	20.89%
	$124	1.09E-02	27.29%
Most Likely	$130	1.23E-02	34.54%
	$142	1.09E-02	48.27%
	$154	9.54E-03	60.40%
	$166	8.18E-03	70.90%
	$177	6.82E-03	79.79%
	$189	5.45E-03	87.07%
	$201	4.09E-03	92.73%
	$213	2.73E-03	96.77%
	$225	1.36E-03	99.19%
Absolute Maximum	$237	0.00E+00	100.00%
MEAN COST	$146.80	1.03E-02	53.53%
MEDIAN COST	$143.45	0.010723558	50.00%





RSKWC12.xls Robert E. 12/14/93

FIGURE A2-3
Sales Pipeline (30") from Point Thomson to TAPS Pump Station #1 (Onshore Route)

Onshore Sales Pipeline
Cost Estimation Sheet

45 miles of 30" at $1.88MM/mile (see cost breakdown sheet)	$85MM
45 miles of VSM's at $0.470MM/mile	$21MM
45 miles of gravel road at $0.530MM/mile ($100/lf)	$24MM
MOST LIKELY COST	**$130MM**

(Note bridge costs are not included in this estimate.)

ARCO ALASKA INC.
30" ~~Subsea~~ pipeline (Flaxman Is. to Prudhoe bay)
Project Leader: Junius Allen
Prepared by : Shekhar Chaobal
Jan. 16, 1994

	For 5280 ft long pipe 30" pipe wt 0.562" X65, 80' joints pipe from Panama city Florida	For 1 mile 5280' Material cost	Labor cost	Unit rate
1	30" pipe 0.562 wt x65 external coated (epoxy)	$476,200		External coating $15/F
2	Freight (Panama city Fl. to Jobsite)	$163,548		$350/Ton
3	Pipe Handling at Flaxman staging yard 0.85 manhour/ft		$137,280	Labor rate $40/Hr
4	Pipe hauling/placing along ice road 0.88 manhour/ft		$185,856	Labor rate $40/Hr
5	Field welds (5280/80=66 welds/mile)		$84,480	32 hrs/weld
6	Radioghraphy		$15,840	6 mh/weld
7	Indirect cost Includes heat & light	~~mob, demob~~	$275,248	65% Of direct cost
8	Equipment rental ~~mob, demob~~		$202,112	38% of above
9	Allocations		$200,000	$20/(dir/indir) manhrs.
10	Ice road 30' wide 6" high		$32,000	
11	Ice road maintenance		$6,400.00	20% of road cost
12	Coating of welds	$4,290	$13,200	
13	Shrink sleeves on welded joints	$2,640	$7,920	
14	Misc. cost & labor (Snow fences,weld shelters,ice pads cribbing)	$50,000	$24,000	Labor rate $40/Hr
	For 5280' pipeline >>>>>>	$695,678	$1,184,334	
	TOTAL COST >>>>>>>>	$1,880,012		

This Estimate Does not Include following cost.

1) CONTINGENCY
2) UOC ~~Unit Operators Cost~~
3) Engineering ~~Design~~
4) Gravel roads and pads
5) Airfare
6) Survey
7) Trenching and ditching
8) stringing operation
9) Gravel work if any
10) Bending
11) Concrete coating
12) Lower-in pipe in to trench
13) Tie-ins
14) Backfill etc.
15) As build survey
16) wt. collars
17) Cathodic protection
18) Main line Valves
19) Stream or river flow crossing
20) Erosion control
21) Any kind of pipe support if needed.

Note: This is a conceptual estimate with the upper and lower ranges are +50% to-30%

~~22,000 man-hours/mile~~

FIGURE A2-5

APPENDIX 3

STRUCTURES

APPENDIX 3: STRUCTURES

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APPENDIX 3: STRUCTURES

Scope

Sandwell, Inc., Calgary and Vancouver, Canada, was retained to estimate costs and schedules of Kuvlum structures. Their report, *Conceptual Engineering and Analysis of Structures for the Kuvlum Field*, March 1994, is a part of this section.

Initially Sandwell tasking was to estimate the costs and schedules of up to six structures which would support the six drilling and production cases shown in Appendix 4: Topsides Facilities, Production and Processing. These six cases were chosen to cover the anticipated range of a Kuvlum development. Plans were to use these six estimates to interpret costs and schedules for specific cases defined using 1993 delineation drilling results. Sandwell determined that only two structures needed to be studied to cover the anticipated Kuvlum cases and recommended that only these two structures be estimated. This recommendation was accepted.

These two structures were: 1) a drilling structure which would support a single drilling rig, approximately 50 wells, and only primary production (separation of produced fluids), and 2) a drilling/processing structure which would support two drilling rigs, 100 wells, and both primary production and processing.

Sandwell was also charged with the responsibility of developing appropriate ice load criteria. These criteria are described in their report.

All other environmental and loading criteria are described in Sandwell's report.

Summary

Design, fabrication (Far East), towing and installing the smaller structure (drilling) at Kuvlum requires 4-1/2 years. The larger structure (drilling/processing) requires 5 to 6 years.

Table 6.5 of Sandwell's report presents the total installed costs of these two structures, excluding topside facilities costs. Ranges of cost for each of the eleven components are shown. Sandwell simply sums these component costs to arrive at a total cost. After several discussions with Sandwell, decisions were made by ARCO to consider these eleven cost components as being triangularily distributed and independent of each other. Monte Carlo simulation was used to compute a distribution of total cost for each structure. Please see Section 6.3.4 in Sandwell's report for additional discussion.

The resulting distributions of total cost are shown in Figure A3-3 Cost Distribution for Sandwell's 350' x 350' structure, and Figure A3-4 Cost Distribution for Sandwell's 230' x 230' structure.

As expected the range of total cost computed by Monte Carlo simulation are less than that obtained by simply adding pessimistic, best and optimistic estimates of the eleven cost components. The Monte Carlo simulation was made using Crystal Ball software. Crystal Ball fits a normal distribution to the distribution curve computed by simulation. This normal distribution is also shown in these two figures. These normal distributions of total cost are used in the economic analysis of this report, Section III.

Crystal Ball software requires triangular distributions be defined by three points, the absolute minimum, most likely, and absolute maximum. These points were calculated from Sandwell's cost ranges. Figures A3-5, A3-6, and A3-7 present results of these calculations.

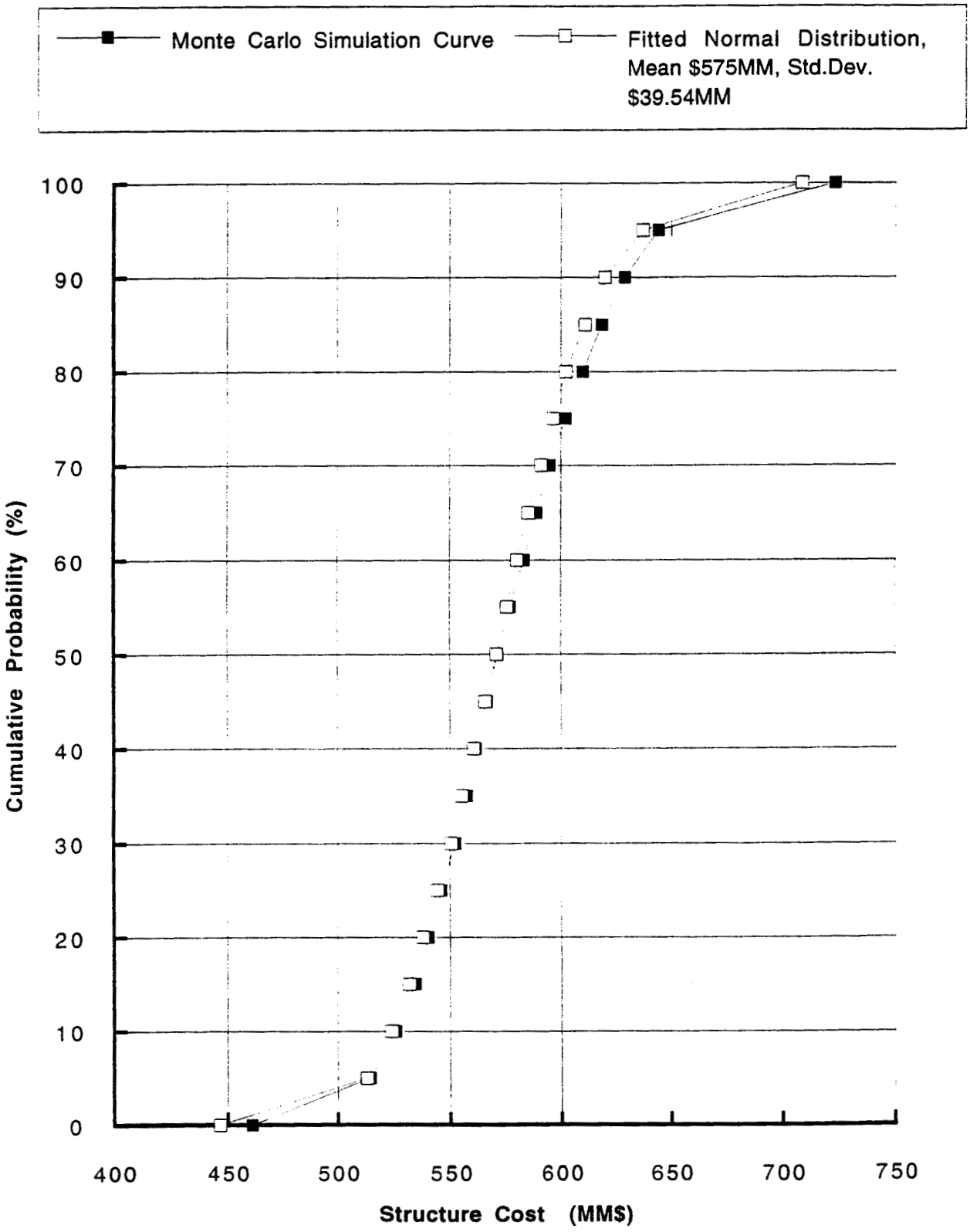


FIGURE A3-3
Cost Distribution for Sandwell's 350' x 350' Structure

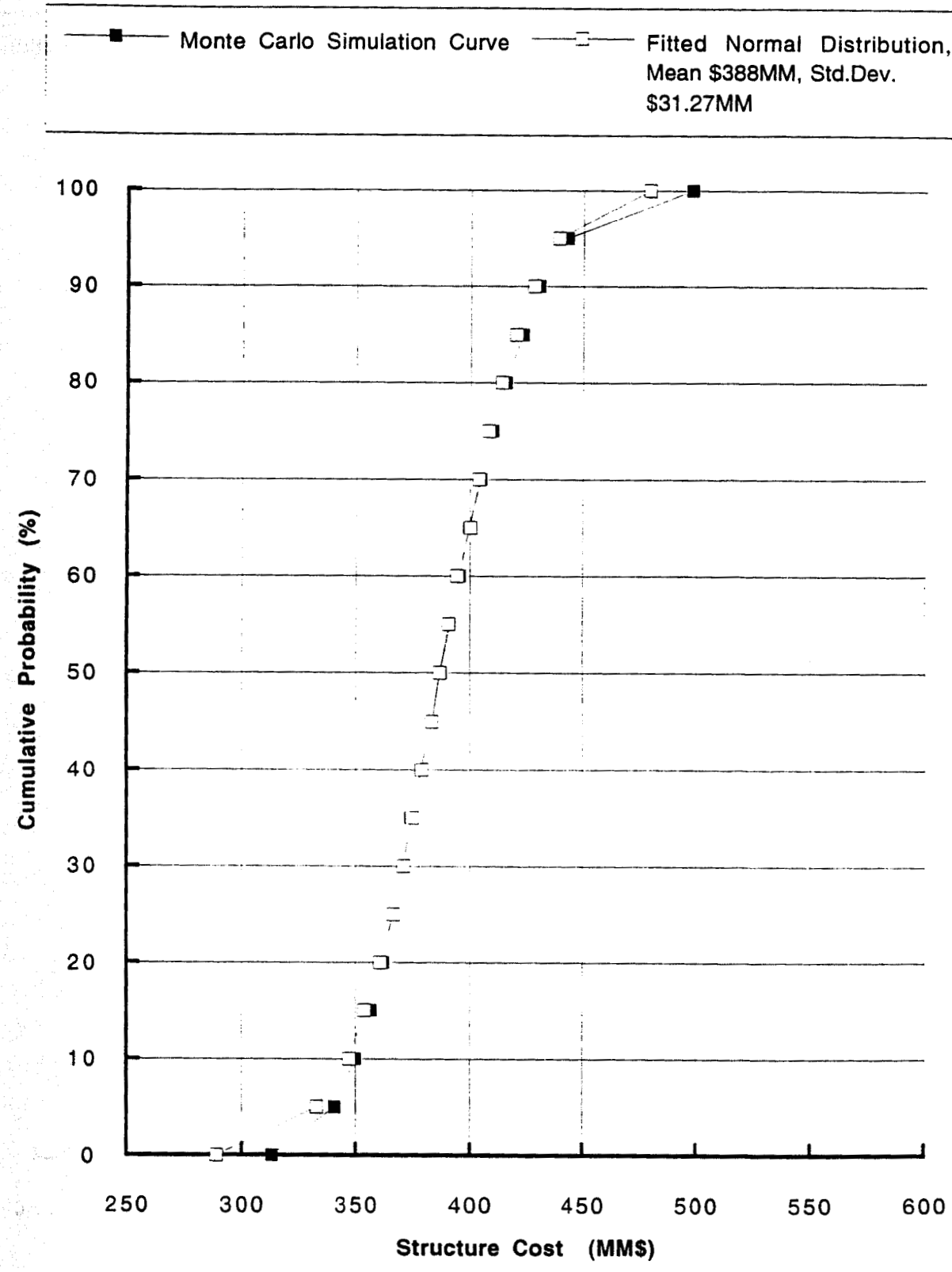


FIGURE A3-4
Cost Distribution for Sandwell's 230' x 230' Structure

Listing of the Minimum and Maximum Cost Estimates Components from the two Kuvlum Structures in Kuvlum Sandwell Report referenced below.

Reference: 1.Sandwell Report "Conceptual Engineering and Analysis of Structures for Kuvlum Field" Report #113147. Table 6.5 in this report has cost estimates of the various component of the structure.
2. Spreadsheets KS3501 thru KS35011.xls and KS2301 thru KS23011.xls.

Procedure: The Sandwell report presents cost estimates of various components of these two structures in terms of the 10%, Most Likely, 90% cost estimates, that is, "optimistic, a most likely and pessimistic estimates."
A triangular distribution of cost estimates is completed defined by these three values.

ARCO Economic Evaluation Models needs the Minimum (0%) Cost Estimate, Most Likely Cost Estimate, Maximum (100%) as input. The above spreadsheets computes these values from the Sandwell values.

The results of these 22 Spreadsheets are compiled here: Curves for each triangular distributions are on the spreadsheets

For the 350ft X 350 ft Structure Costs are in $MM

Component	Sandwell Table 6.5			From Spreadsheets		
	Optimistic 10% Estimate	Most Likely Estimate	Pessimistic 90% Estimate	Minimum 0% Estimate	Maximum 100% Estimate	Probability Density of Most Likely
1. Hull Fabrication	$305.9874	$322.0920	$370.4058	$28.4714	$400.4100	0.017409
2. Structure Outfitting	$16.5300	$17.4000	$52.2000	$9.7311	$70.0072	0.033181
3. Move to Completion Site	$5.8900	$6.2000	$9.3200	$5.0749	$10.9801	0.338684
4. Towing & Installation	$10.5165	$11.6850	$29.2125	$6.3973	$38.4862	0.062327
5. On Stie Support	$24.3000	$27.0000	$81.0000	$12.4215	$109.2073	0.020664
6. Cathodic Protection	$9.0000	$10.0000	$15.0000	$7.3152	$17.8878	0.189168
7. Hematite Ballas	$2.3750	$2.5000	$3.1250	$2.1644	$3.4860	1.513345
8. Foundation Preparation	$0.9500	$1.0000	$3.0000	$0.5593	$4.0234	0.577343
9. Undergrouting	$3.6224	$3.8130	$7.6260	$2.7836	$9.6177	0.292648
10.Toe Protection	$5.7000	$6.0000	$18.0000	$3.3555	$24.1404	0.096224
11.Miscellaneous	$76.7768	$80.8842	$119.4965	$66.4277	$140.5154	0.026995

For the 230ft X 230 ft Structure Costs are in $MM

Component	Sandwell Table 6.5			From Spreadsheets		
	Optimistic 10% Estimate	Most Likely Estimate	Pessimistic 90% Estimate	Minimum 0% Estimate	Maximum 100% Estimate	Probability Density of Most Likely
1. Hull Fabrication	$182.3383	$191.9350	$220.7253	$170.1128	$238.6037	0.029290
2. Structure Outfitting	$10.7350	$11.3000	$33.9000	$6.3196	$45.4644	0.051092
3. Move to Completion Site	$5.5100	$5.8000	$8.7000	$4.7475	$10.2717	0.362041
4. Towing & Installation	$8.0865	$8.9850	$22.4625	$4.9191	$29.2934	0.018056
5. On Stie Support	$24.3000	$27.0000	$81.0000	$12.4215	$109.2073	0.020664
6. Cathodic Protection	$5.8500	$6.5000	$9.7500	$4.7549	$11.6271	0.291029
7. Hematite Ballas	$6.6500	$7.0000	$8.7500	$6.0603	$9.7607	0.540480
8. Foundation Preparation	$0.9500	$1.0000	$3.0000	$0.5593	$4.0234	0.577343
9. Undergrouting	$3.0020	$3.1600	$6.3200	$2.3069	$7.9706	0.353122
10.Toe Protection	$3.8000	$4.0000	$12.0000	$2.2370	$16.0936	0.144336
11.Miscellaneous	$52.2199	$55.0024	$86.1894	$44.2933	$102.9643	0.034088

FIGURE A3-5
Listing of the Minimum and Maximum Cost Estimates Components for the Two Sandwell Structures

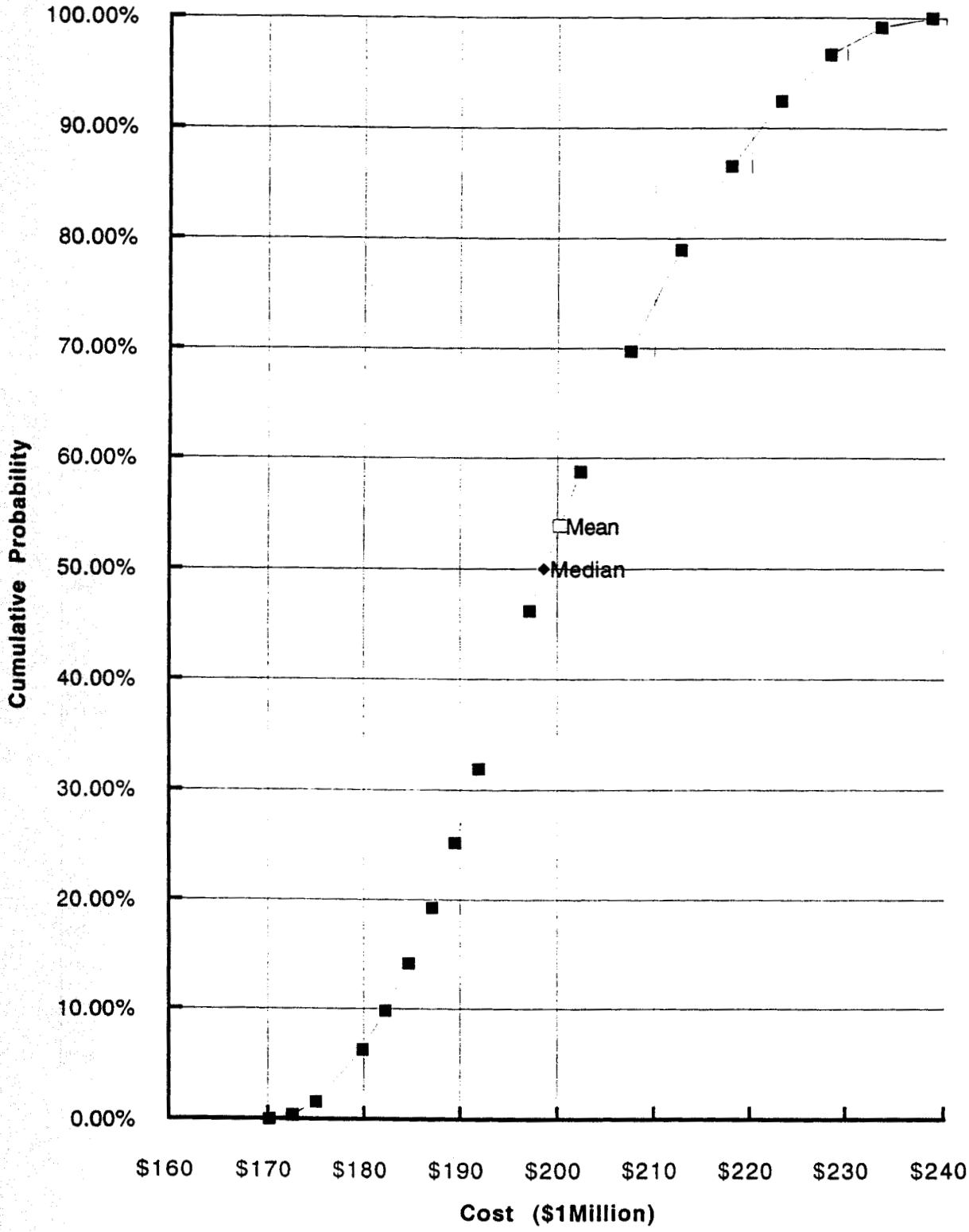


FIGURE A3-6
Example Calculation of Maximum and MInimum Costs of a Component (Hull Fabrication) Given in Sandwell's Structure Report (230' x 230' Structure - Table 6.5)

This Spread Sheet will compute the unique Triangular Probability Density Distribution and the Unique Cumulative Probability Curve determined by the k'%, Most Likely and k"% Cost Estimates

INPUT:	Costs in $1,000,000		
k' & k'Cost Estimate	0.1	$182.34
Most Likely Cost Estimate	b=	$191.94
k''' & k'''Cost Estimate	0.9	$220.73

To compute Maximum and Minimum Costs for Component 1 "Hull Fabrication" of Sandwell 230x230ft Structure Table 6.5. Example Calculation.
0% cost = $170.11 **100%Cost= $238.61**
See Table for Probability Density vs Cost, Mean & Median Costs

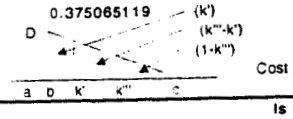
To Calculate the Absolute Minimum Cost (0%Cost Estimate) which will be called "a" and the Absolute Maximum Cost (100% Cost Estimate) which will be called "c". Note the Most Likely Cost is called "b".

The k', Most Likely, and k"'Cost Estimates completely define the Triangular Probability Density Distribution and Cumulative Probability Curves. An interative procedure has to be used to calculate "a" and "c"; that is, the 0%Cost Estimate and the 100% Cost Estimate, respectively.

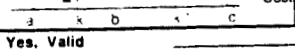
First step is to determine which set of equations are applicable to find "a"and "c". This will depend on where the Most Likely Cost Estimate "b" lies relative to k' and k"'Cost Estimates.
Please note that k'Cost Estimate is always less than k"'Cost Estimate.

FOR THE ABOVE K'COST, MOST LIKELY COST AND K"'COST ESTIMATES USE **XXXXXXX MIDDLE CASE XXXXXXX**

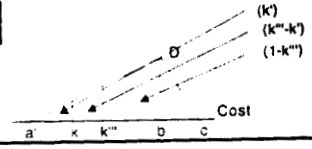
CASE LEFT
If Most Likely Cost Estimate < k'Cost Estimate
c= 239.92500
D= 0.02604709
a= 163.1409998
Therefore k2 for Most Likely Cost Estimate is equal to 0.375065119



CASE MIDDLE
If (k'CostEstimate<Most Likely Cost Estimate<k"'Cost Estimate), iterate to Find Absolute Minimum 'a' and Maximum 'c' Cost Estimates. Try values of 'a' until c'=c". Trial 'a'= 170.1124 Incr. a
c'= 238.6101743 0.0001
c"= 238.6093358 0.001 170.1125
Delta=(c'-c")= 0.000838419
D= 0.029198029



CASE RIGHT
If (k'Cost Esti.<k"'Cost Esti.>Most Likely Cost Esti.),
a= 163.145
c= 291.1005565
D= 0.015630427



Is a <k'Cost Estimate? Yes, Valid
Is K'<K"'? Yes,Valid

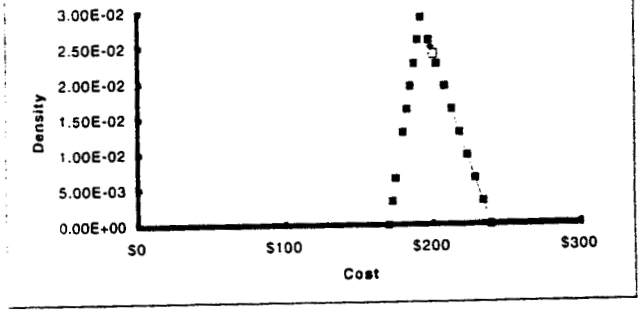
Please Note that you must enter the values calculated above into these slots before computing distributions.

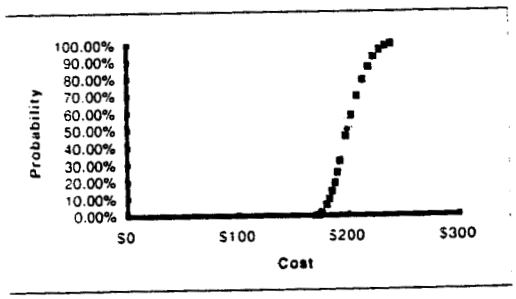
Enter the Values of "a", "c", and D computed above ▶

a=	$170.1124
c=	$238.6102
D=	0.02919803

Calculating Probability Density Distribution and Cumulative Probability Curves

	Cost in $1,000,000 $	Probability Density (1/$)	Cumulative Probability %
	$170	0.00E+00	0.00%
	$173	3.24E-03	0.39%
	$175	6.49E-03	1.57%
	$180	1.30E-02	6.29%
	$180	1.30E-02	6.29%
	$182	1.62E-02	9.84%
	$185	1.95E-02	14.16%
	$187	2.27E-02	19.28%
	$190	2.60E-02	25.18%
Most Likely	$192	2.92E-02	31.87%
	$197	2.60E-02	46.17%
	$202	2.27E-02	53.78%
	$207	1.95E-02	59.72%
	$213	1.62E-02	73.97%
	$218	1.30E-02	86.54%
	$223	9.73E-03	92.43%
	$228	6.49E-03	96.64%
	$233	3.24E-03	99.16%
Absolute Maximum	$239	0.00E+00	100.00%
MEAN COST	$200.22	2.40E-02	53.90%
MEDIAN COST	$198.63	0.025012497	50.00%





RSKWC12.xls Robert E. 12/14/93

FIGURE A3-7
Example Calculation for Maximum and Minimum Costs of a Component (Hull Fabrication) Given in Sandwell's Structure Report (230' x 230' Structure - Table 6.5)

Sandwell

CONCEPTUAL ENGINEERING AND ANALYSIS OF STRUCTURES FOR THE KUVLUM FIELD

113147

FINAL REPORT

FOR

ARCO ALASKA, INC.

BY

SANDWELL INC.
CALGARY, ALBERTA

In association with

B. WRIGHT & ASSOCIATES
CALGARY, ALBERTA

IYER & ASSOCIATES
CALGARY, ALBERTA

March, 1994

Sandwell

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March 22, 1994

113147

Mr. R.E. Smith
Senior Engineering Consultant
ARCO Exploration and Production Technology
2300 West Plano Parkway
Plano, Texas
75075-8499

Dear Bob:

Re: Conceptual Engineering and Analysis of Structures for the Kuvlum Field

Sandwell is pleased to present the final technical and cost report related to the above engineering feasibility analysis. The work has been conducted under contract to ARCO to perform conceptual design and costing of structures to support drilling, production and processing for its Kuvlum prospect in the Beaufort Sea. According to the terms of reference provided by ARCO, only vertical sided, steel structures were considered.

In the report, a comprehensive overview of the ice environment of the Beaufort Sea in the Kuvlum region is provided. The site is located in 110 ft. of water in an ice environment which can be harsh. In addition to level first year ice and the associated first-year ridges, more extreme features such as large ridge and rubble fields and multi-year ice floes are present. On rare occasions extreme features such as multi-year hummock fields and ice island fragments occur. These extreme ice features govern the design loads, determining the dimensions and weight of the gravity base structures required for global stability.

The global design ice loads have been determined probabilistically using the computer model developed by Gulf Canada, a model which contains both ice load and failure algorithms as well as a Monte Carlo simulator. The statistical distributions of ice feature occurrence and of their physical parameters, such as thickness and diameter, are based on an extensive data base compiled for the Beaufort Sea by operating oil companies such as Gulf over a 20 year period and have been adapted to the Kuvlum site. The ice crushing loads have been determined using a global pressure vs. ice thickness curve compiled using data from full scale structures for the 1991 Joint Industry Project conducted by Sandwell. The Gulf model produced as an end product curves of ice load vs. probability of occurrence. The scenarios of ice interaction causing loads with a low probability of excedence were checked individually to ensure that they were physically realistic. 10,000 simulations were run to produce loads with a probability of occurrence of 10^{-3} or greater.

Two sizes of structures were considered for the Kuvlum site, the larger having a main hull 350 ft. by 350 ft. and the smaller having a main hull 230 ft. by 230 ft. The 350 ft. square structure is capable of supporting the wet weight of drilling, production and processing facilities during tow (Cases 1 & 2) while the 230 ft. square structure is capable of supporting drilling and production facilities only (Cases 3 & 4). For the Case 3 loading, only the dry weight can be on deck while the structure is towed to site. The bases of the structures are larger than the mail hull to maintain the shear stress applied to the soil within the

allowable limit of 1.33 ksf.

During tow to the site, the Metacentric Height (GM) of the 350 ft. square structure is greater than 400 ft. and that of the 230 ft. square structure is greater than 300 ft. The GM during setdown is considerably less and governs the deck load which can be placed in the construction yard for the 230 ft. square structure in one case (Case 3). The requirements for towing the structures to site are outlined in the report.

The total hull steel weight for the 350 ft. square structure is 95,730 tons and for the 230 ft. square structure is 57,062 tons.

The costs of the hull fabrication plus the costs of placing the structures has been estimated using a format similar to the 1991 JIP. A best estimate cost (statistically the "mode") has been obtained using in-house information and estimates provided by two Asian fabricators. Hull steel fabricated costs of $3,500 to $3,700/tonne were used. The total, best estimate, in-place cost for the 350 ft. square structure is $488,574,000 and for the 230 ft. square structure is $321,682,000. Along with the best estimates of cost, the most reasonable pessimistic and optimistic costs were estimated, thus permitting cost confidence limits to be obtained using standard statistical techniques. It has been assumed that the cost distributions are "positively skewed", resulting in a higher probability of cost overrun than of underrun.

Yours truly,

SANDWELL INC.

D.M. Masterson, Ph.D., P.Eng.
Manager Engineering

DMM/rk

cc: J. Eldred

Sandwell

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1.0 INTRODUCTION AND SCOPE

ARCO Alaska Inc. contracted Sandwell to perform a feasibility engineering analysis of structures for their Kuvlum prospect in the Beaufort Sea, Alaska. In accordance with the terms of reference for the scope of work, Sandwell provided conceptual overview and analysis of different vertical sided structures. Over the past decade, there has been considerable controversy on whether sloping or vertical sided structures are best able to mitigate ice related concerns, particularly rubble generation and clearing. While only vertical sided structures are considered in this study, an optimum shape would be determined at a more detailed stage of design. Sandwell's overview is based on the company's experience with Arctic offshore structures going back to the 1970's. This experience includes the design and on-site engineering for the Molikpaq, the design of the Tarsiut Caissons and of the Esso CRI, and the design review of the SSDC and its Mat. In addition, over 300 projects have been carried out to conceptually design and evaluate structures for the Arctic offshore. This direct experience allows Sandwell to evaluate structures very rapidly and to quickly arrive at reliable steel weights.

Once the structural concepts had been determined, Gulf's ice load model was used to analyze their behavior in the ice environment. A comprehensive analysis was conducted using appropriate ice scenarios based on local data. Impacts by thick ice features were modelled and the effects of "floe berg" impacts were considered. Global loads and their probability of occurrence were calculated and plotted as distributions. The effects of local ice pressures have been considered in the conceptual design of the structures.

In this work, use has been made of the results of two former Joint Industry projects, these being:

"Joint Industry Study, Barrow Arch and Chukchi Sea Exploration and Production Structures" by Swan Wooster Engineering Co. Ltd. (a predecessor company of Sandwell Inc.), 1984

"Joint Industry Project, Beaufort and Chukchi Sea Arctic Production Platforms - Update" by Sandwell Inc., 1991

ARCO was a participant in the first project and has purchased a copy of the second, and is thus fully entitled to the use of the information contained in these reports. Structural detail and cost information from these reports has been used where applicable and modifications have been made where required. The development of the information drawn from the joint industry reports has not been repeated in the present report and the reader is referred back to the original documents. As requested by ARCO, three levels of costs have been provided, these being the most likely, the pessimistic and the optimistic cost estimates. These estimates have then been used to derive confidence limits for the costs.

2.0 ENVIRONMENTAL OVERVIEW

2.1 General

The Beaufort Sea environment is one of the most severe in the world and will significantly influence the design and operation of development systems being considered for the offshore. Sea ice is well known as the primary environmental constraint in the area, since it is usually ice covered for at least nine months of the year. Clearly, structures that are designed for Arco's Kuvlum development project will have to withstand this sea ice environment, together with more conventional offshore influences such as summer storm waves.

Kuvlum is located in the intermediate water depths of the Beaufort Sea, in roughly 110 ft of water. Here, the winter ice cover is normally comprised of moving first year ice with frequent ridging. More extreme ice features are also relatively common in the vicinity of Kuvlum and include large ridge and rubble fields, multi-year floes, and on very rare occasions, multi-year hummock fields and ice island fragments. From the perspective of bottom founded production structures, these extreme ice features are of greatest importance, since they will govern the environmental design loads.

During the summer period, the Beaufort's ice cover gives way to a brief open water season, although late ice clearance, early freeze-up and ice intrusions from the polar pack can significantly affect the number of open water days experienced in any given year. This summer open water season is very important in terms of providing a "window" for various marine operations, including the tow and installation of fixed structures.

In general terms, open water conditions at Kuvlum are comparatively easy, since the wave climate is quite mild and is not a significant design concern. However, the occurrence of ice intrusions can quickly change the complexion of the Beaufort's summer environment and impact marine operations, including the tow and installation of structures. In addition, some of the ice features that can be encountered during summer ice intrusions (eg: multi-year floes and floebergs) have the potential to exert large loads on fixed structures, and must be considered from this perspective.

Low temperatures, occasional strong winds, fog, and poor visibility are also important environmental factors but more in terms of constraining operations than influencing design. In the following sections, a brief overview of ice conditions in the general Kuvlum area is given as background to the design ice loads discussed later in the report.

2.2 Winter Ice Coverage

In October, the Beaufort Sea normally begins to freeze-up, with new ice forming in the shallow nearshore waters and progressively growing seaward, where this seasonal ice cover eventually merges with the southern boundary of the permanent polar pack. Over the winter period, the ice cover in the general vicinity of Kuvlum is comprised of three basic ice zones (Figure 2.1), including:

- The relatively stable ***landfast ice***, which extends from the shoreline to water depths between 50 and 70 feet.
- The sporadically moving ***shear or seasonal pack ice zone***, which lies between the outer edge of the landfast ice and the more northerly polar pack.
- The northerly ***polar pack ice,*** which is primarily comprised of multi-year ice and is present year round.

During the winter months, Kuvlum lies in the mobile shear or seasonal pack ice zone, beyond the landfast ice and well to the south of the polar pack. Depending upon the particular year, this seasonal pack ice zone can be anywhere from a few tens of miles to a hundred or more miles in width. In its southern reaches, where Kuvlum is located, the seasonal pack is sometimes subjected to large scale shearing action, caused by relative motions between the offshore ice cover and the stable landfast ice. At other times, the pack ice around Kuvlum behaves like a "quasi-stationary" floating extension to the landfast ice. Immediately to the south of Kuvlum, the landfast ice is generally very narrow because of the steep nearshore bathymetric gradients in Camden Bay. Here, the landfast ice is normally only several miles in width, with its northern edge typically located ten or more miles from the Kuvlum site.

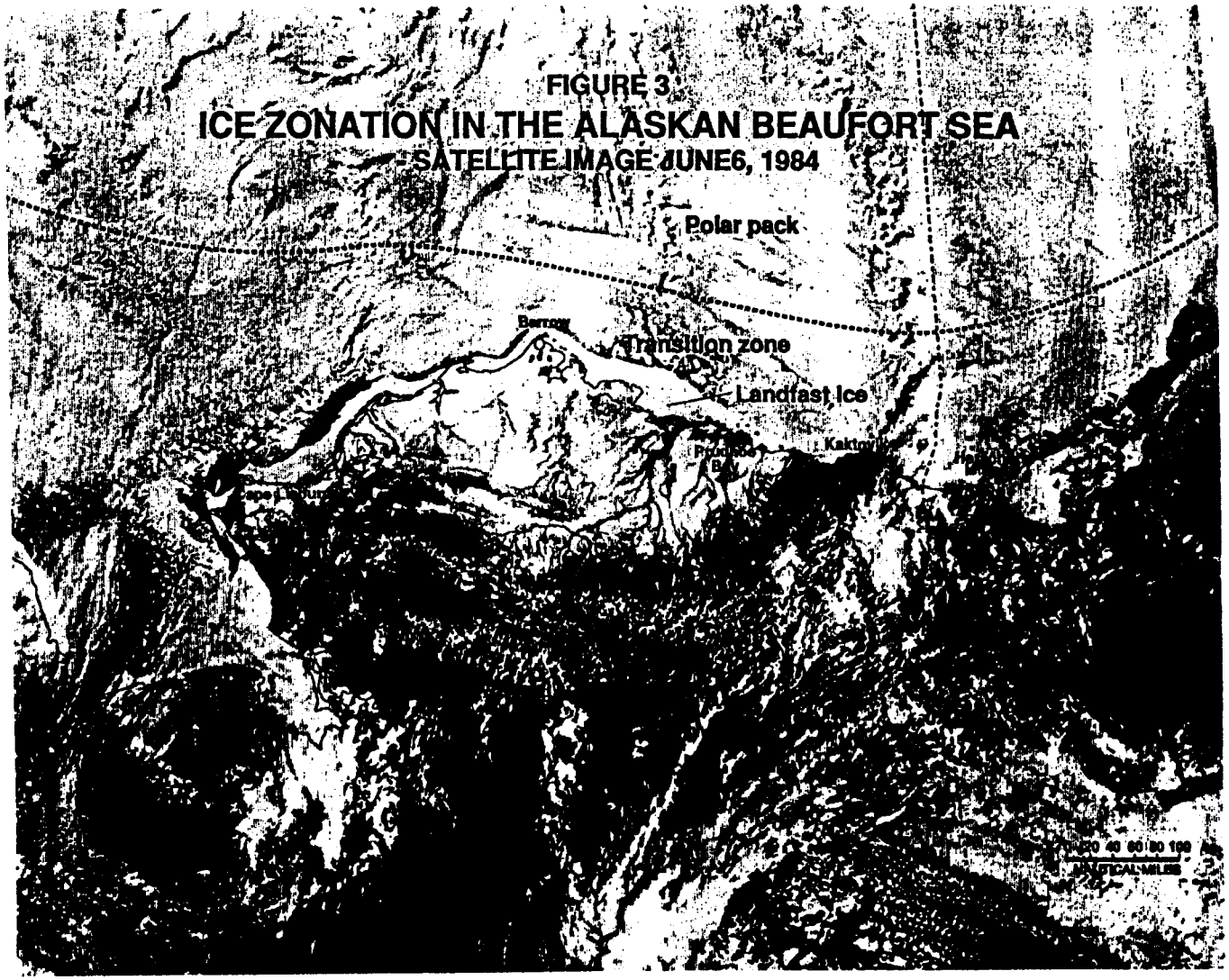


Figure 2.1 - Schematic of Ice Zonation

A representative example of winter ice conditions around Kuvlum is given in Figure 2.2, which shows a high resolution satellite radar image (ERS-1 SAR) of the general area taken on April 13, 1993. Here, the Kuvlum location is about 10 miles beyond the fast ice edge with trace concentrations of small multi-year ice floes in its immediate vicinity. Higher concentrations of old ice are also visible between 40 and 50 miles to the north, towards the polar pack ice edge. Clearly, first year ice is the predominant ice type in the general Kuvlum area, with substantial areas of ridging and rubble being evident.

Although this SAR image is representative of typical winter ice conditions around Kuvlum, the specific ice conditions experienced at the location are highly variable from year to year and within any given year. The question of variability in ice conditions, particularly in relation to the risk of extreme ice feature interactions, is a very important design consideration for Beaufort Sea development structures.

2.3 Variability

Obviously, development structures deployed at Kuvlum will be exposed to various ice conditions and the potential for significant ice forces throughout the year and, given their long deployment time frames, the cumulative likelihood for high ice forces over a number of years. Significant ice loads can be generated by a wide variety of ice features since there are many "ice parameter combinations" that result in similar load levels, for different ice/structure interaction scenarios in different seasons. Recognizing the complexities of the ice environment around Kuvlum, a probabilistic approach has been used to define design ice load distributions and associated risk levels in this study. This probabilistic approach involves repeated simulations of the interaction between fixed offshore structures and a variety of extreme ice features, across a range of winter and summer interaction scenarios. Through a prior arrangement between Sandwell and Gulf Canada Resources, Gulf's probabilistic ice loading model has been used as a basis for this work.

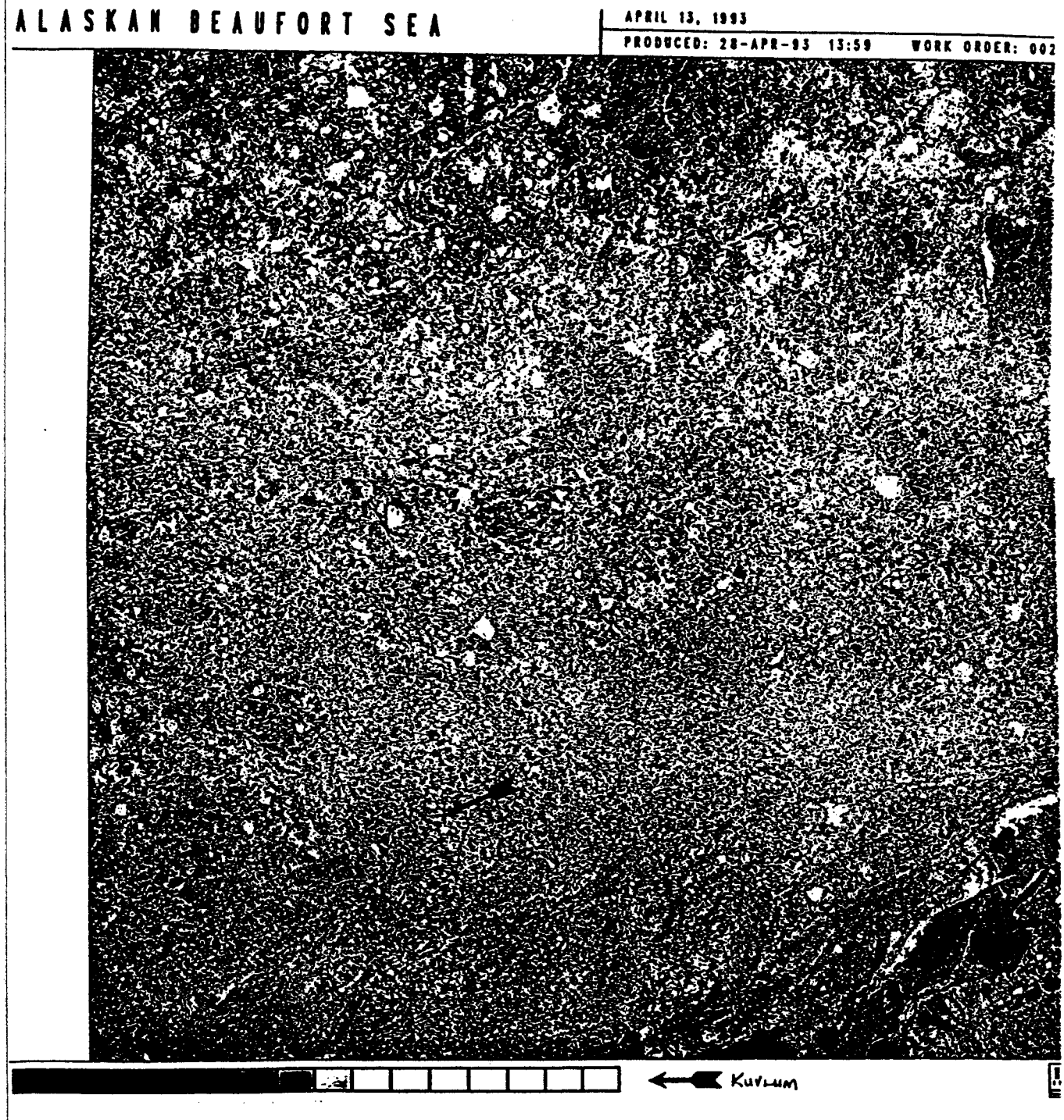


Figure 2.2 - ERS - 1 SAR Image Showing Representative Winter Ice Conditions Around the Kuvlum Location

To apply this model, the design loading consideration is subdivided into winter and summer ice/structure interaction scenarios and reviewed in terms of normal and extreme events. Statistical descriptions of the ice parameters that are relevant to important ice loading scenarios are then used to reflect the effects of the variability in ice conditions. This is accomplished by coupling known ice parameter distribtions with the extreme ice interaction scenarios through a Monte Carlo process to synthesize a large number of expected extreme interactions. Global load distributions for the structures under consideration are then determined for repeated simulations with a sophisticated ice loading model.

As background, a brief description of winter and summer ice conditions at Kuvlum is given in the following sections, together with expected ice/structure interaction scenarios and specific information on some of the key ice parameter distributions used in the loading analysis. A discussion of the probabilistic ice load model and its results in the context of this study is given in Section 3, together with the other relevant design criteria.

2.4 Winter Ice Conditions

Freeze-up at Kuvlum normally begins in the early to mid October period. At this time, open water is sometimes found around Kuvlum but more often, low concentrations of remnant first year ice and some multi-year floes are also present, as a result of summer ice dynamics. After "poorer" summer seasons, moderate to high concentrations of thick first year ice and multi-year floes are more typical during freeze-up, representing a more extreme situation.

As freeze-up continues, the offshore waters around Kuvlum become covered by high concentrations of thin, newly formed ice with variable concentrations of thicker remnant first year ice (formally termed second year ice) and multi-year floes interspersed within it. Since this fall pack ice is highly mobile, extensive leads and open water areas are quite common during early freeze-up. However, by mid November, a continuous first year ice cover one to two feet thick normally develops, with areas of thick, older ice often trapped within it. From an ice force perspective, the growing first-year pack ice cannot exert

significant loads on fixed structures, but is important inasmuch as it provides an additional driving force on thick ice features frozen into it, over and above the wind and water stresses.

The offshore pack ice continues to grow in thickness as freeze-up progresses into winter, with differential movements giving rise to frequent pressure ridging, occasional leads and small transient open water areas. Although the ice cover is continuous, it is comprised of a variety of ice types. In the vicinity of Kuvlum, first year ice predominates, growing to a thickness of three to four feet by late January, and reaching a maximum thickness of about 6 feet in the late April to early May time frame (Figure 2.3). Because this is a moving pack ice area, variable quantities of new, grey and grey white ice (less than 1 foot thick) are also present throughout the winter and spring periods, in regions where leads have opened and refrozen. As noted earlier, a range of multi-year ice concentrations can also be found within the winter ice cover at Kuvlum (see Figure 2.2), depending upon the particular year. Since multi-year floes can be miles in extent and have mean thicknesses that normally vary between 10 and 20 feet, they are extreme ice features of high importance from a design loading perspective (Figure 2.4).

Once the seasonal ice cover is established, it is difficult for multi-year ice to move into the Kuvlum area from the north, although old ice floes can be advected towards the location from the east or west, depending upon the regional distribution of multi-year ice and the winter movement patterns. Over the freeze-up and winter periods, the presence of substantial concentrations of multi-year ice in the Kuvlum area represents a high risk to structures in terms of extreme ice loads, and is the distinction between normal and extreme situations that is used here.

The winter ice cover in the Kuvlum area is usually very rough since it contains substantial numbers of first year pressure ridges (Figure 2.5). These ridges are comprised of a sail and keel portion and can be anywhere from 15 feet to 130 feet in total thickness. Most of the first year ridges found around Kuvlum form during the late freeze-up and early winter period. Their sails and keels are a porous accumulation of broken ice blocks, with void volumes typically ranging between 20 and 30%. A consolidated layer (caused by refreezing) is present at the waterline of these ridges, and usually attains a thickness of

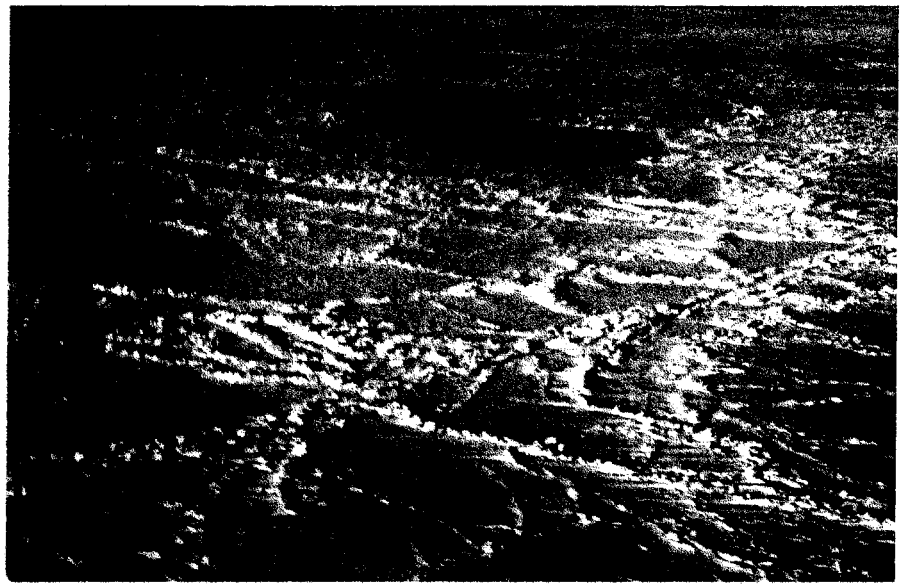


Figure 2.3a - Winter Pack Ice Conditions
(Level Ice Areas and Ridges are Common in the Pack Ice)

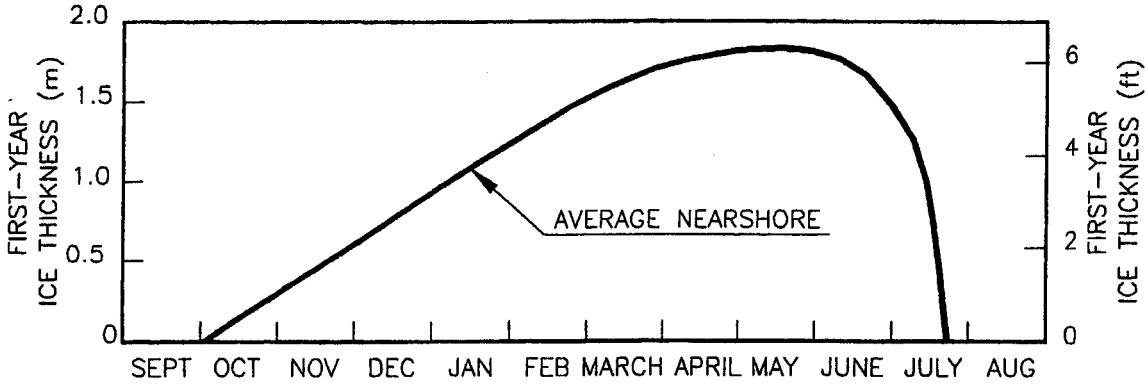


Figure 2.3b - Ice Thickness Growth Curve



Figure 2.4a - Aerial View of Multiyear Ice Floe



Figure 2.4b - Multiyear Ice Floe

(Multiyear ice floes can be miles in extent and have mean thicknesses that vary between 10 and 20 feet).

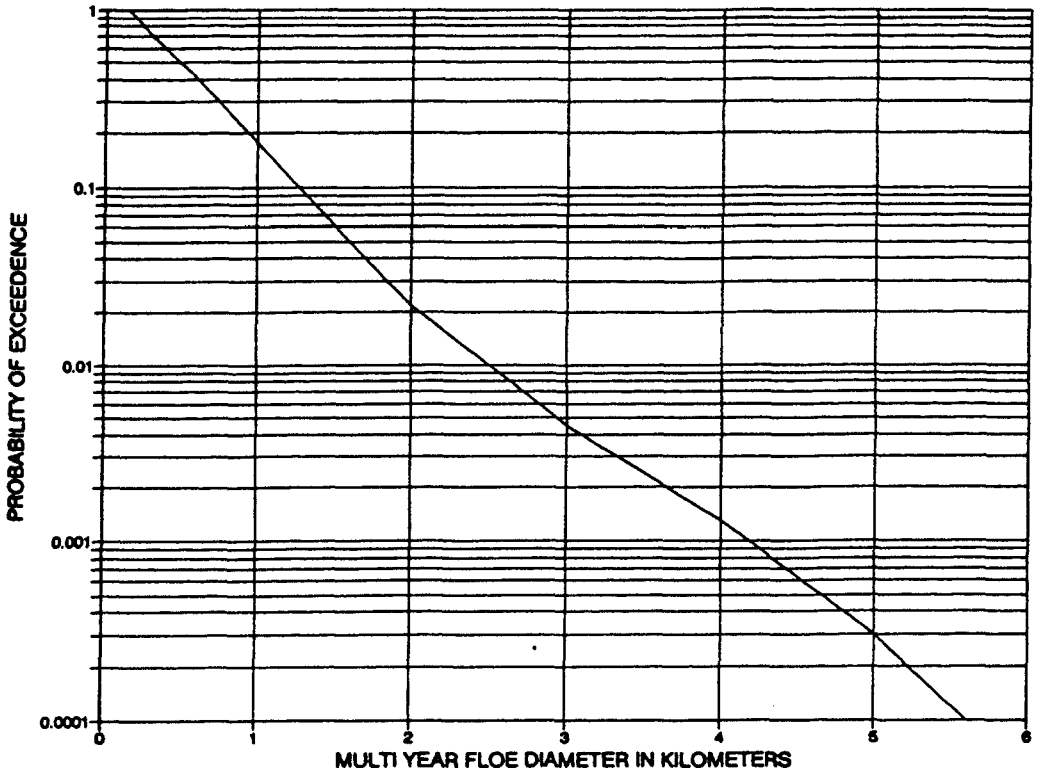


Figure 2.4c - Multiyear Floe Size Distribution

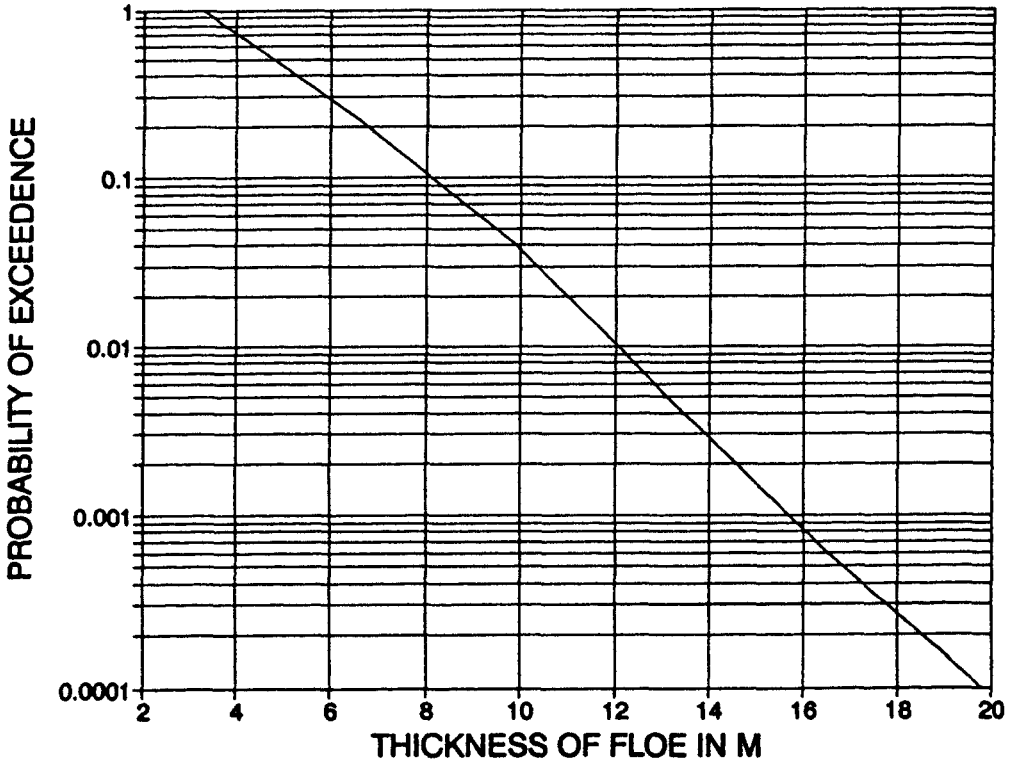


Figure 2.4d - Multiyear Ice Thickness Distribution



Figure 2.5a - Rough Ridged Landscape

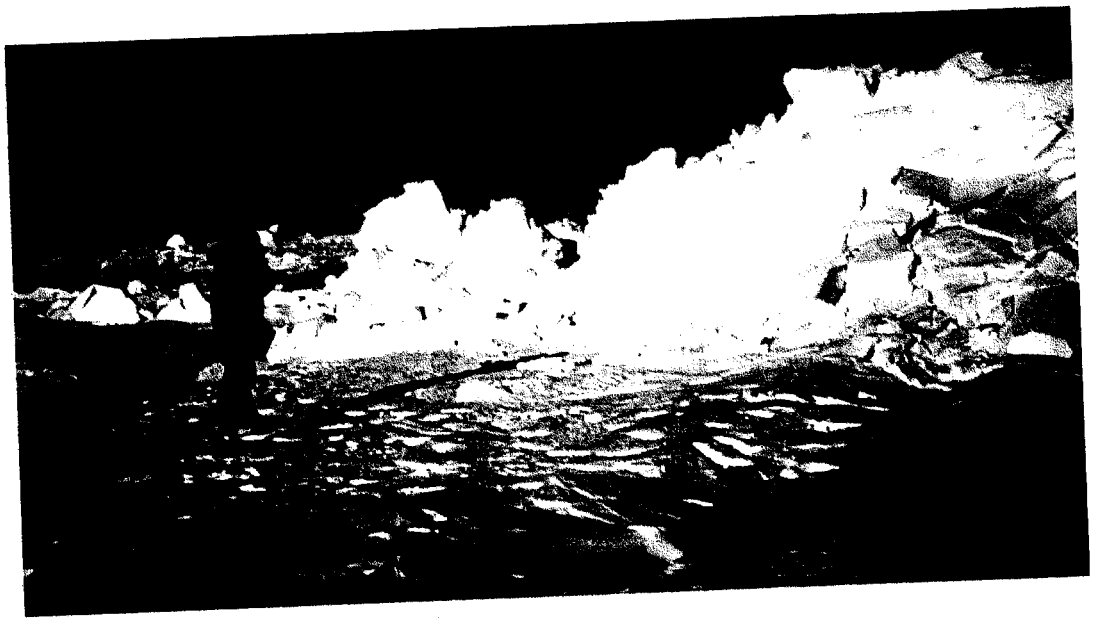


Figure 2.5b - First Year Pressure Ridge

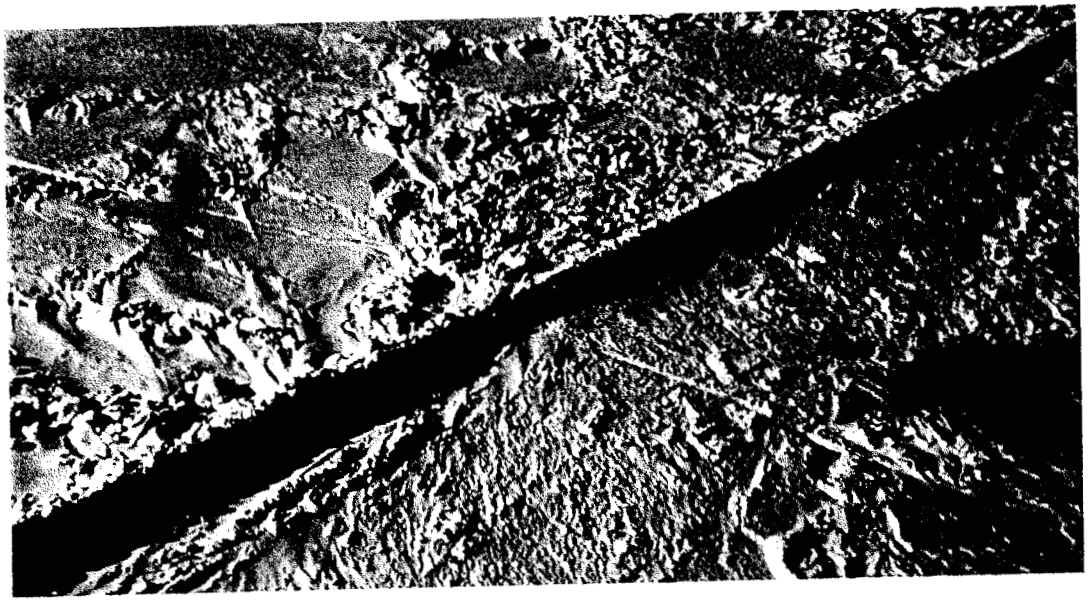


Figure 2.5c - First Year Shear Ridge

about twice the surrounding level ice thickness. Shear ridges that are formed through shear action rather than compression are also found in the general Kuvlum area, but are much less frequent than pressure ridges. Normally, these shear ridges are not as porous as pressure ridges and have a larger keel to sail ratio (8:1 versus 4.5:1). Although not as rough as the outer edge of the landfast ice, the ice cover around Kuvlum has typical ridge frequencies of 5 to 20 per mile.

First year ridges represent one of the more extreme thickness elements within the general ice cover at Kuvlum and are an issue from the perspective of vessel navigation and seafloor scour. However, because of their limited areal extent and partial consolidation, first year ridges are not a significant concern in terms of design loads on fixed structures. Accordingly, ridge interactions are viewed as normal ice/structure interaction events, and not treated as a design loading consideration. Drifting first year ridge and rubble fields that form in the pack and at the fast ice edge are also found within the winter ice cover around Kuvlum and are much more formidable than singular ridge features (Figure 2.6). Although these first year ridge formations can be quite extensive and very thick in comparison to the level ice cover, they are not solid and strong throughout their total thickness. As a result, these first year features are not a major concern in terms of design loads on production structures, when compared with multi-year ice.

Multi-year floes, which contain multi-year ridges, represent the most severe type of ice feature commonly found within the moving pack ice around Kuvlum and are a key consideration in terms of design loads on production structures. As noted earlier, the mean thickness of multi-year floes can be several times the maximum first year ice thickness while multi-year ridges contained within these floes can be anywhere from 30 to 140 feet in peak total thickness (Figure 2.7). Unlike first year ridges, multi-year ridges are solid, since their voids spaces have become refrozen over time. In terms of multi-year ice interaction scenarios and probabilistic loads, the frequency, geometry and orientation of ridges within multi-year floes is a very important consideration.

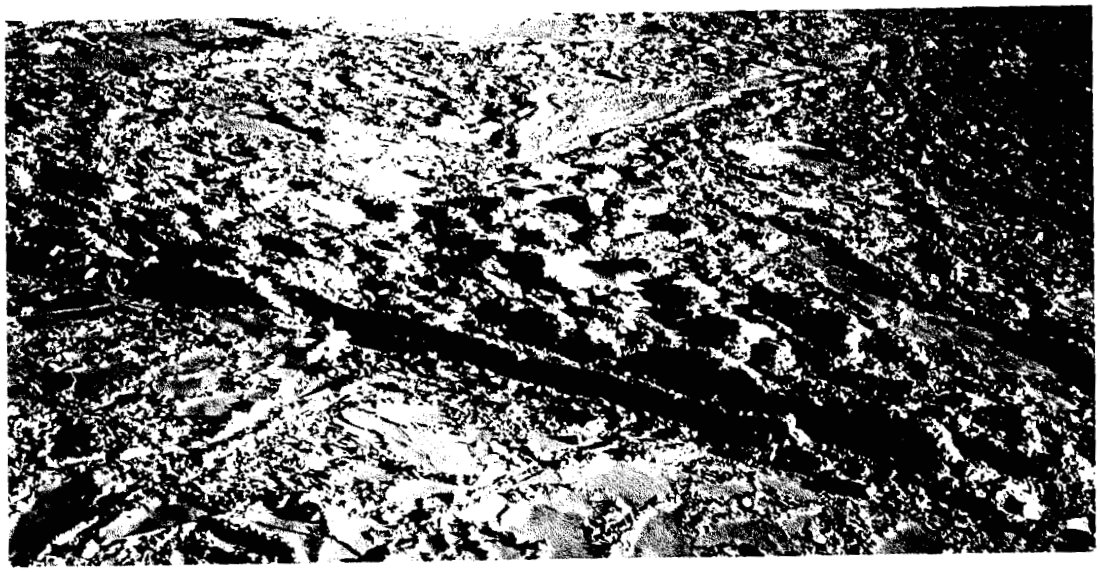


Figure 2.6 - First Year Ice Cover With First Year Ridge and Rubble Fields



FIGURE 2.7a – MULTIYEAR RIDGE IN MULTIYEAR ICE FLOE

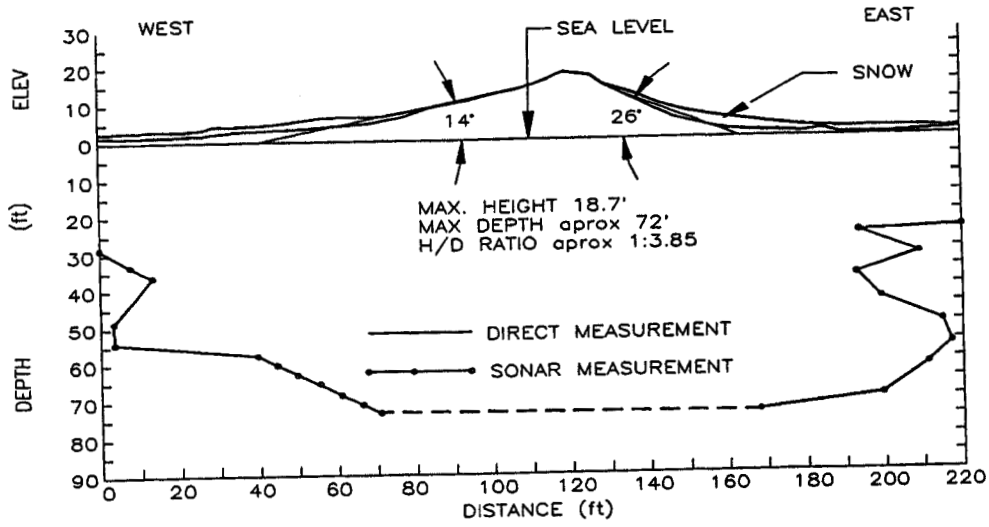


FIGURE 2.7b – MULTIYEAR RIDGE CROSS SECTION

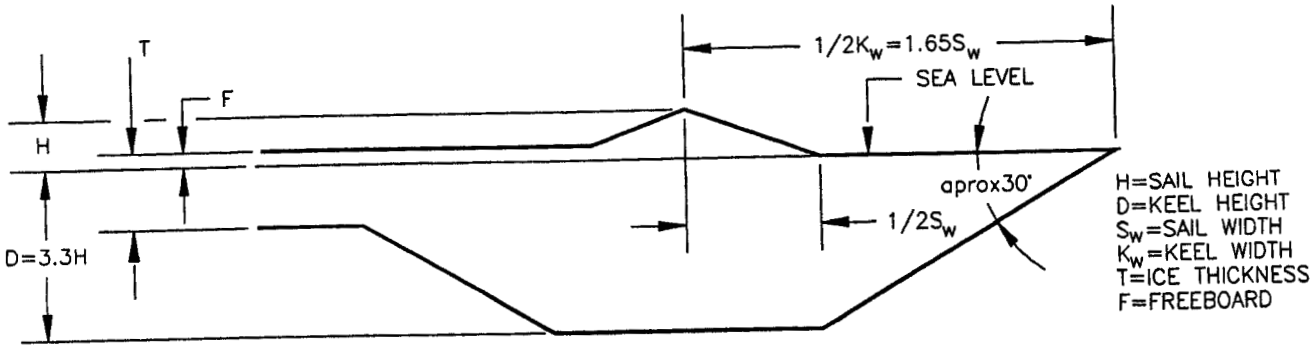


FIGURE 2.7c – MULTIYEAR RIDGE MODEL (AFTER KOVACS)

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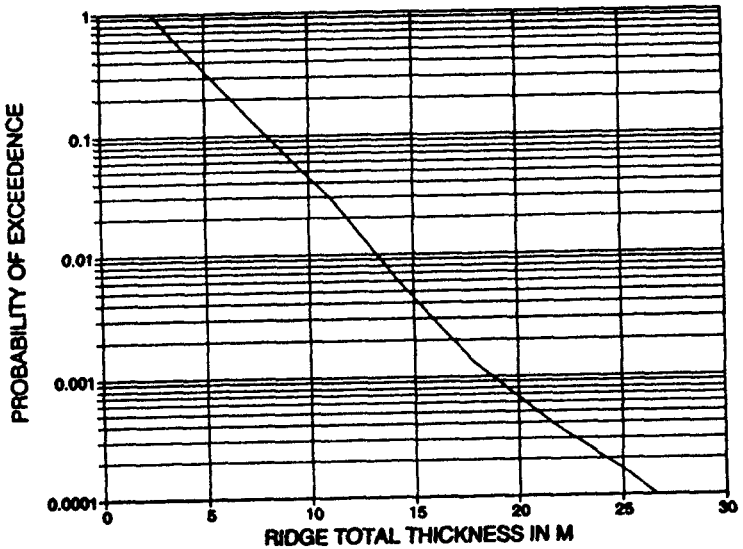


Figure 2.7d - Multiyear Ridge Thickness Distribution

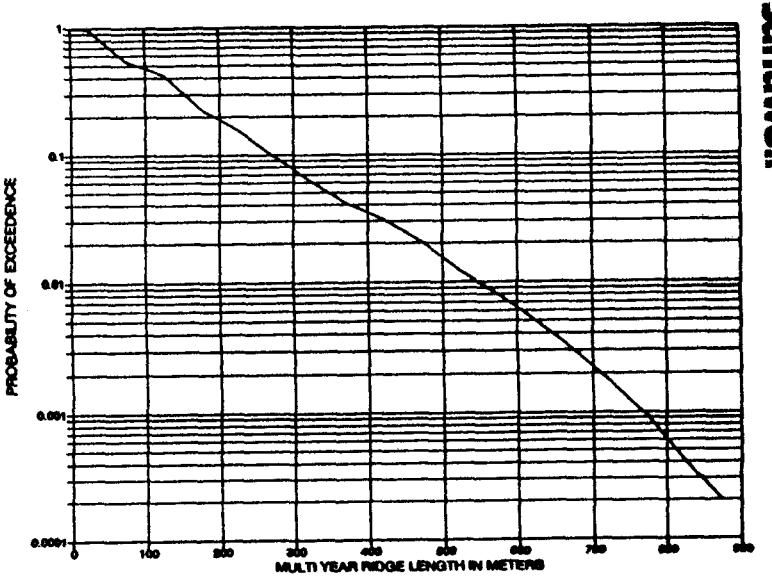


Figure 2.7e - Multiyear Ridge Length Distribution

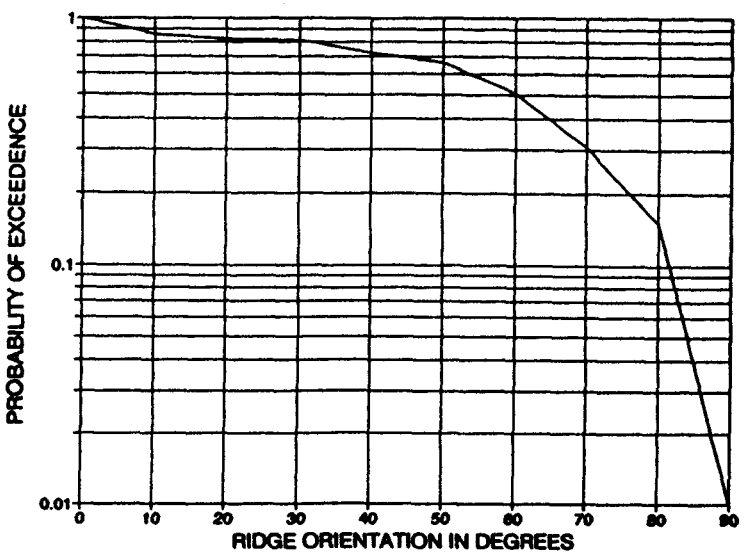


Figure 2.7f - Multiyear Ridge Orientation Distribution

Very rough multi-year floes, termed multi-year hummock fields (equivalent to large old floebergs) and small ice island fragments are sometimes found within the drifting Beaufort Sea pack ice cover, but are very infrequent (Figure 2.8). Although relatively little information is available about their occurrence frequencies and geometries, these extreme ice features should also be recognized from a design loading perspective.

Table 2.1 provides a summary of the winter (and summer) ice/structure interaction scenarios that are considered important for the design of Kuvlum production structures. The extreme ice/structure interaction scenarios identified here have been probabilistically modelled using specific ice parameter distributions to repeatedly synthesize extreme ice interaction conditions. Obviously, the frequency of occurrence of extreme ice feature interactions is of high importance in establishing design load recurrence periods, with impact rates normally determined from their concentrations, sizes and movements.

In terms of winter ice movements, long term motions of the pack ice cover around Kuvlum are from east to west, following the clockwise circulation of the Beaufort Gyre. However, on shorter time scales, the ice can move in any direction and is quite variable in terms of drift speeds. For example, slow longshore ice movements with an onshore drift component are quite frequent along the Alaskan coast in winter and are associated with shear ridging in the vicinity of the landfast ice edge. Significant onshore pack ice movements are also common, particularly during the fall and early winter, and lead to the formation of pressure ridges in both the landfast and pack ice zones. Typical pack ice movement rates are in the order of several miles per day, although the ice may remain stationary for time periods of a week or more, or experience extreme motions of 10 to 20 miles per day (Figure 2.9). Around Kuvlum, slip-stick motions of the ice cover are quite common and are the result of the pack ice shearing along the landfast ice edge.

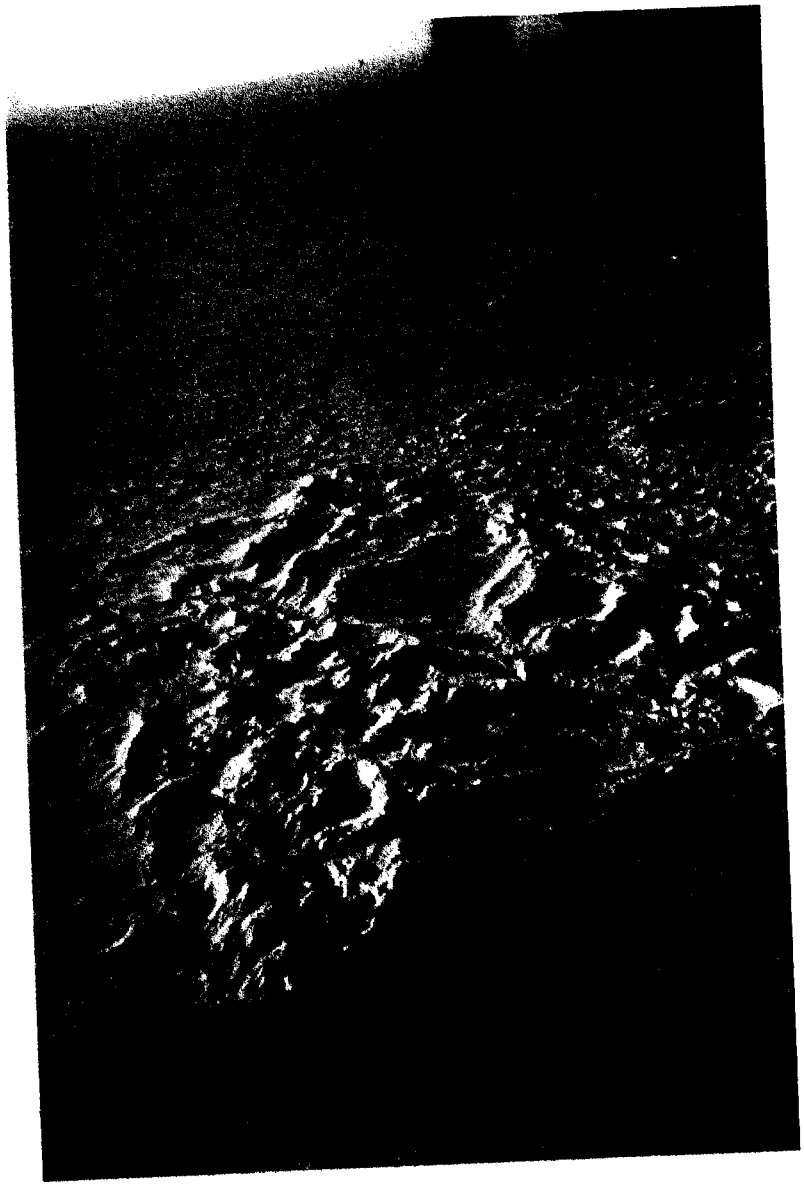


Figure 2.8 - Multi Year Hummock Field

TABLE 2.1 ICE STRUCTURE INTERACTION SCENARIOS

WINTER NORMAL		WINTER EXTREME	
First Year Ice	Low loads, do not govern design	Multi-Year Floes	Probabilistic, loads governed by various forces limiting failure mechanisms, including pack ice driving forces
First Year Ridges	Low loads, do not govern design	Multi-Year Hummock	Deterministic calculation as data base is very limited
First Year Rubble	Low loads, do not govern design	Floebergs	Probabilistic, as for Multi-year floes
		* Ice Islands	
SUMMER NORMAL		**SUMMER EXTREME**	
As above, excluding large floebergs		Multi-Year Floes	Probabilistic, loads governed by limiting mechanisms of failure and kinetic energy dissipation, no pack ice driving force
		Multi-Year Hummock	Deterministic Calculation
		Floebergs	Probabilistic

NOTE: Ice islands have been discussed with Arco and a decision made not to consider them. They are extremely rare with the liklihood of a significant interaction being remote. If one should occur around Kuvlum, it could be identified and tracked well before (weeks to months) arriving near the structure and appropriate shut down and evacuation measures could be taken.

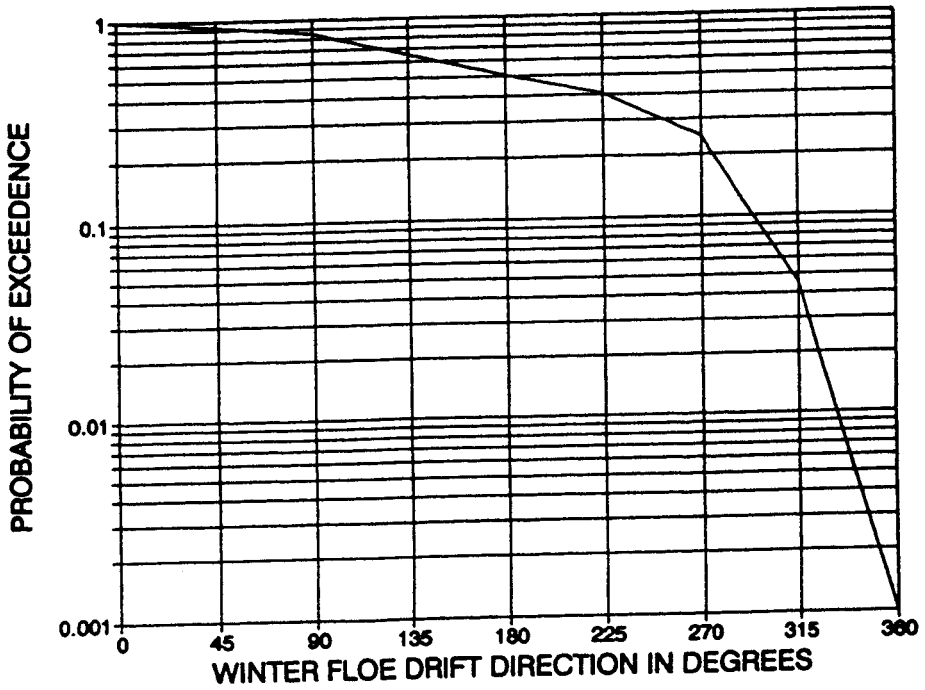


Figure 2.9a - Winter Ice Movement Direction Distribution

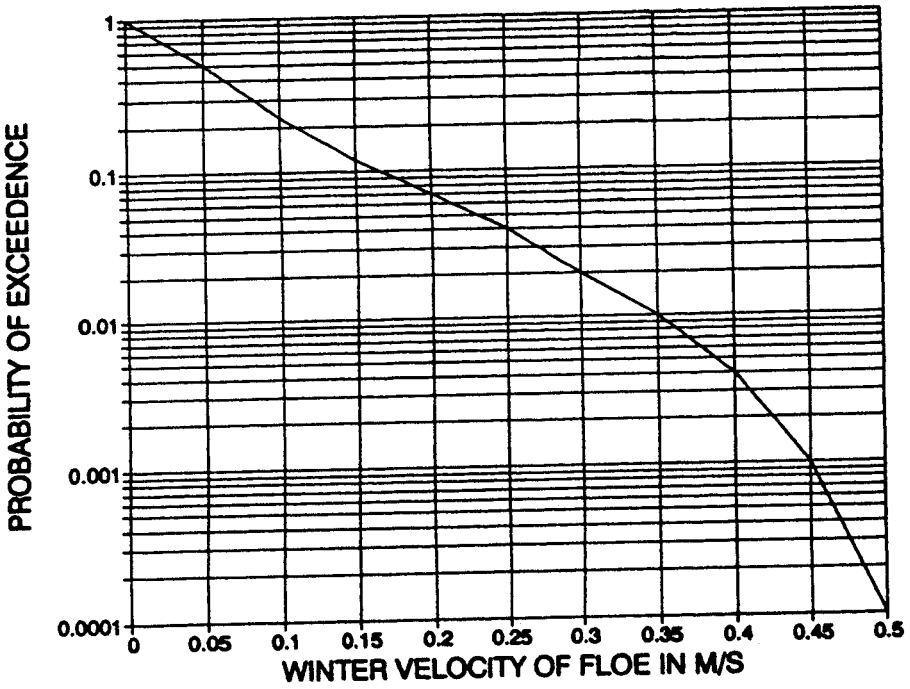


Figure 2.9b - Winter Velocity Distribution

2.5 Summer Ice Conditions

Break-up of the landfast and seasonal pack ice zones around Kuvlum normally commences in the mid to late July period, with significant open water leads usually occurring earlier at Kuvlum and to its east, than in the western Beaufort. Decreasing concentrations of drifting ice are experienced across the region throughout late July and the first part of August, as the ice moves off to the northwest under the influence of winds and currents (Figure 2.10). By mid to late August, the open water season generally commences, and the Beaufort Shelf becomes typical of a marginal ice zone. During this period, a low ice concentrations/open water band between 50 and 100 miles in width normally stretches from the coastline to the edge of the polar pack, persisting until early October when freeze-up begins again.

This open water season can be quite variable, with significant differences occurring from year to year and from location to location. If, for example, northerly winds persist for most of the summer, a poor ice year will result with high ice concentrations, including multi-year ice floes, moving into the coastal areas from the more northerly polar pack. Alternatively, if offshore winds predominate, an extensive open water season will be experienced in the Alaskan Beaufort Sea.

During the summer and early freeze-up periods, wind driven ice intrusions from the north are relatively frequent at Kuvlum, with variable concentrations of first and multi-year ice often moving into the area from further offshore. Movement rates are also quite variable in terms of both speed and direction during the summer and early freeze-up months, but average about 0.3 kt with short term extremes in excess of 1 kt (see Figure 2.11). During these summer ice intrusions, a range of ice features can be expected at Kuvlum, including some that are capable of generating large ice loads on fixed production structures. Shortly after break-up, first year ice thicknesses of 4 to 6 feet are common, decreasing to 2 to 3 feet in thickness as the summer progresses. Since these first year ice floes are normally in a warm, weak deteriorated state, they are not a significant design concern.



Figure 2.10a - Break-up Conditions

(Regional Ice Cover in July in Kuvlum, ice cover starting to retreat)

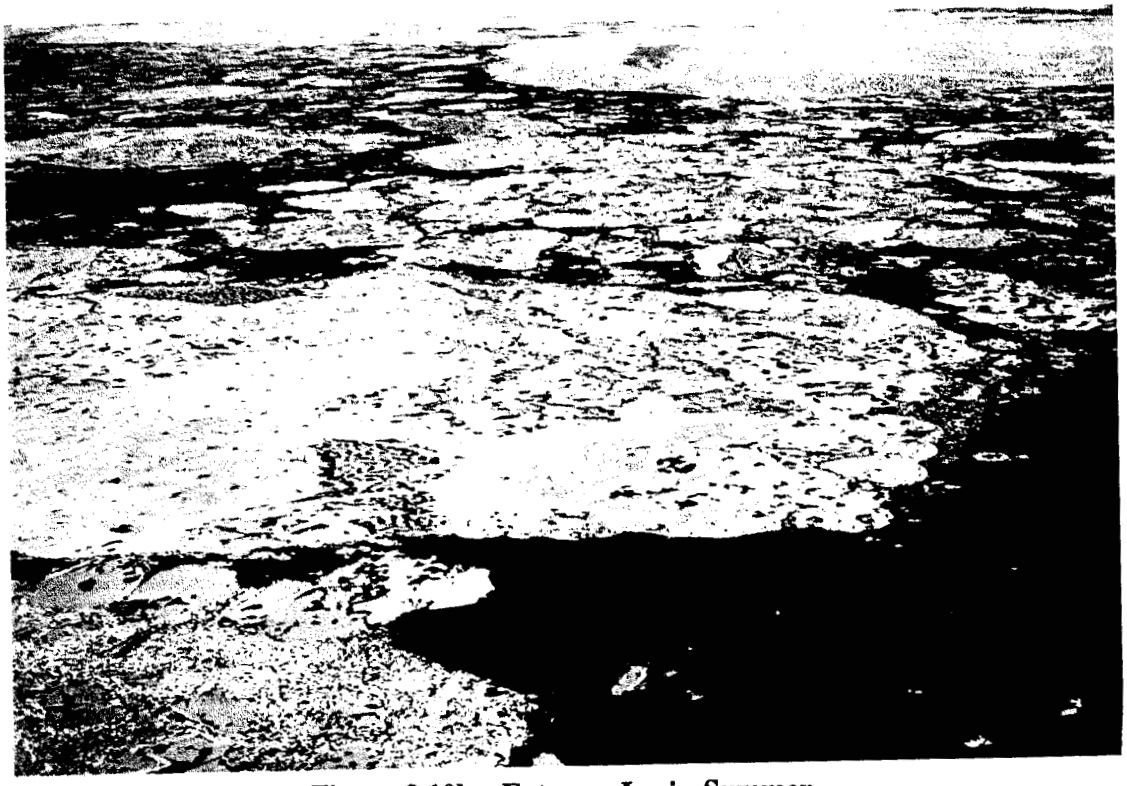


Figure 2.10b - Extreme Ice in Summer

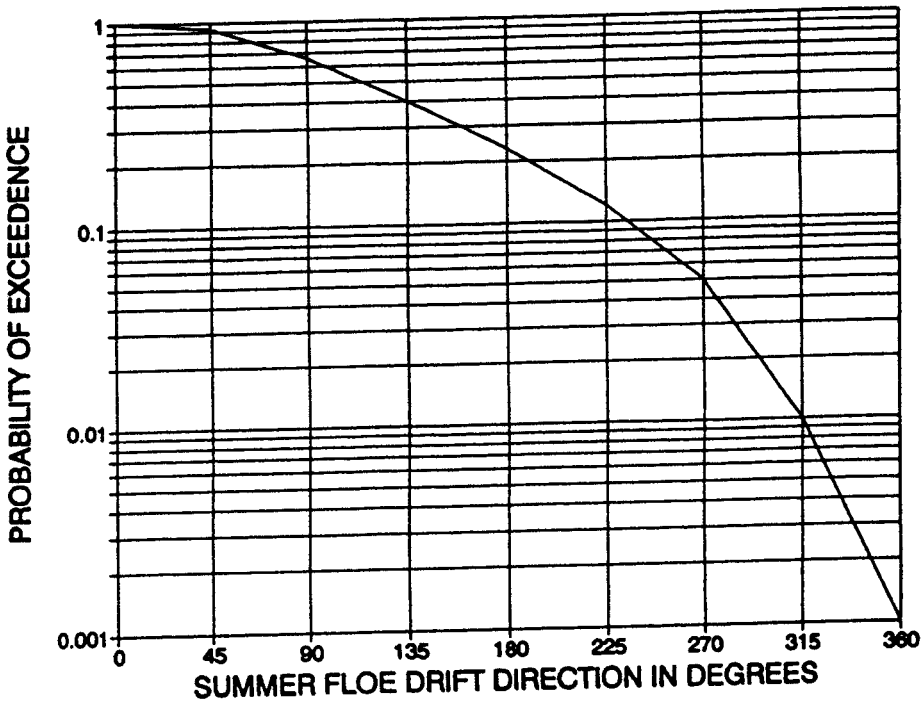


Figure 2.11a - Summer Ice Movement Direction Distribution

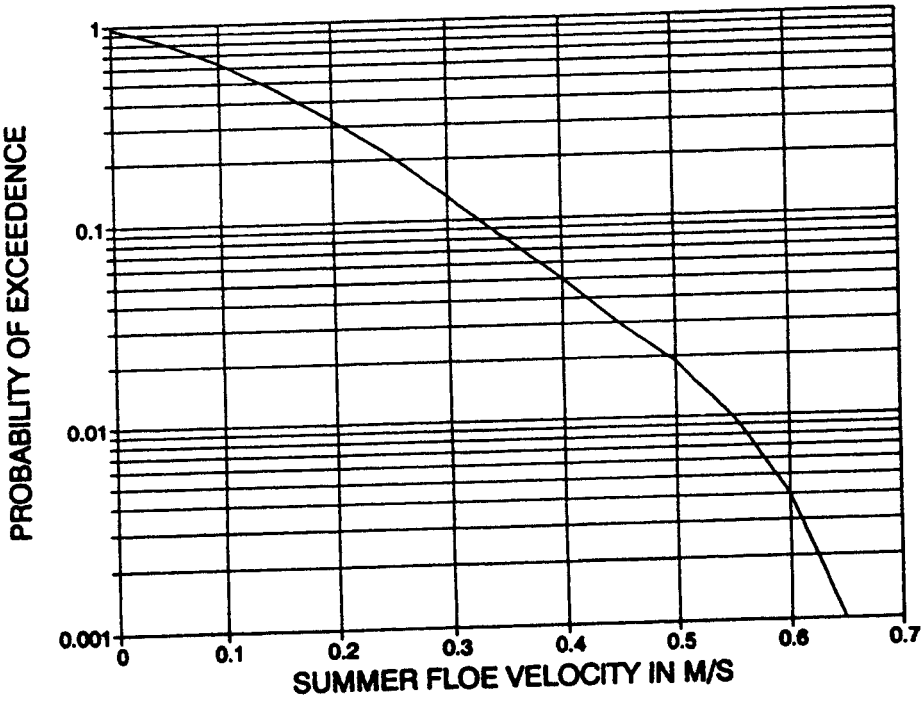


Figure 2.11b - Summer Velocity Distribution

However, multi-year floes and ridges can also be present within the summer ice cover and are of more consequence because of their greater thickness and structural integrity (Figure 2.12). Summer multi-year ice interactions are an extreme scenario that must also be considered from a design loading perspective. It is important to note that these summer floes are driven by winds and currents but unlike the winter situation, are not frozen into a surrounding first year ice cover. Because of this, the environmental driving forces available to sustain these extreme feature interactions is somewhat limited, with the resultant loads largely controlled by the kinetic energy of the floes.

Floebergs, which originate from the grounded and heavily ridged ice areas that form along the Alaskan Coast each winter, are also relatively common in the Kuvlum area during summer. These ice features are drifting fragments of massive ridge and rubble fields and can be several miles in extent, quite consolidated and anywhere from 50 to 90 feet in mean thickness (Figure 2.13). Since many of these floebergs are thicker and often considerably larger than many of the multi-year floes found in the summer pack around Kuvlum, they represent another extreme ice feature that must be considered in design. Table 2.1 summarizes the key summer ice/structure interaction scenarios that should be considered, while relevant ice parameter distributions are provided in the Figures.



Figure 2.12 - Summer Multi Year Ice Conditions

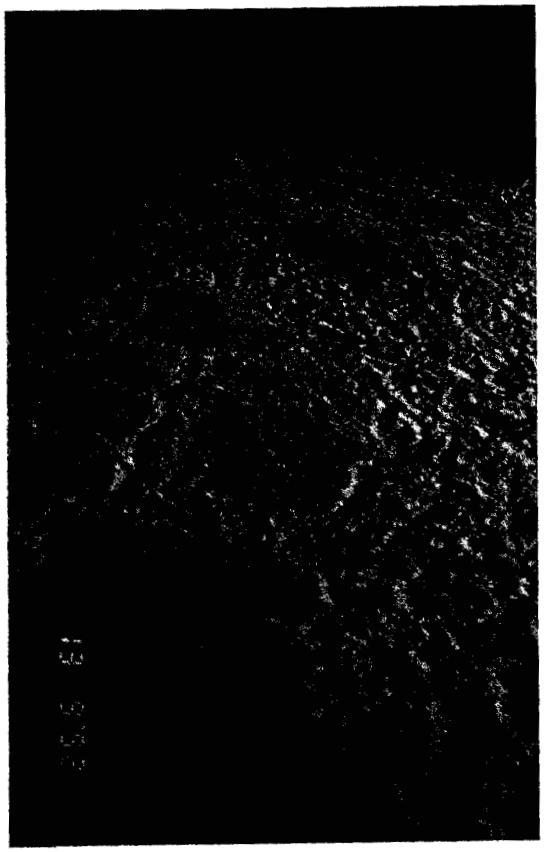


Figure 2.13a - Summer Floe Berg



Figure 2.13b - Summer Floe Berg

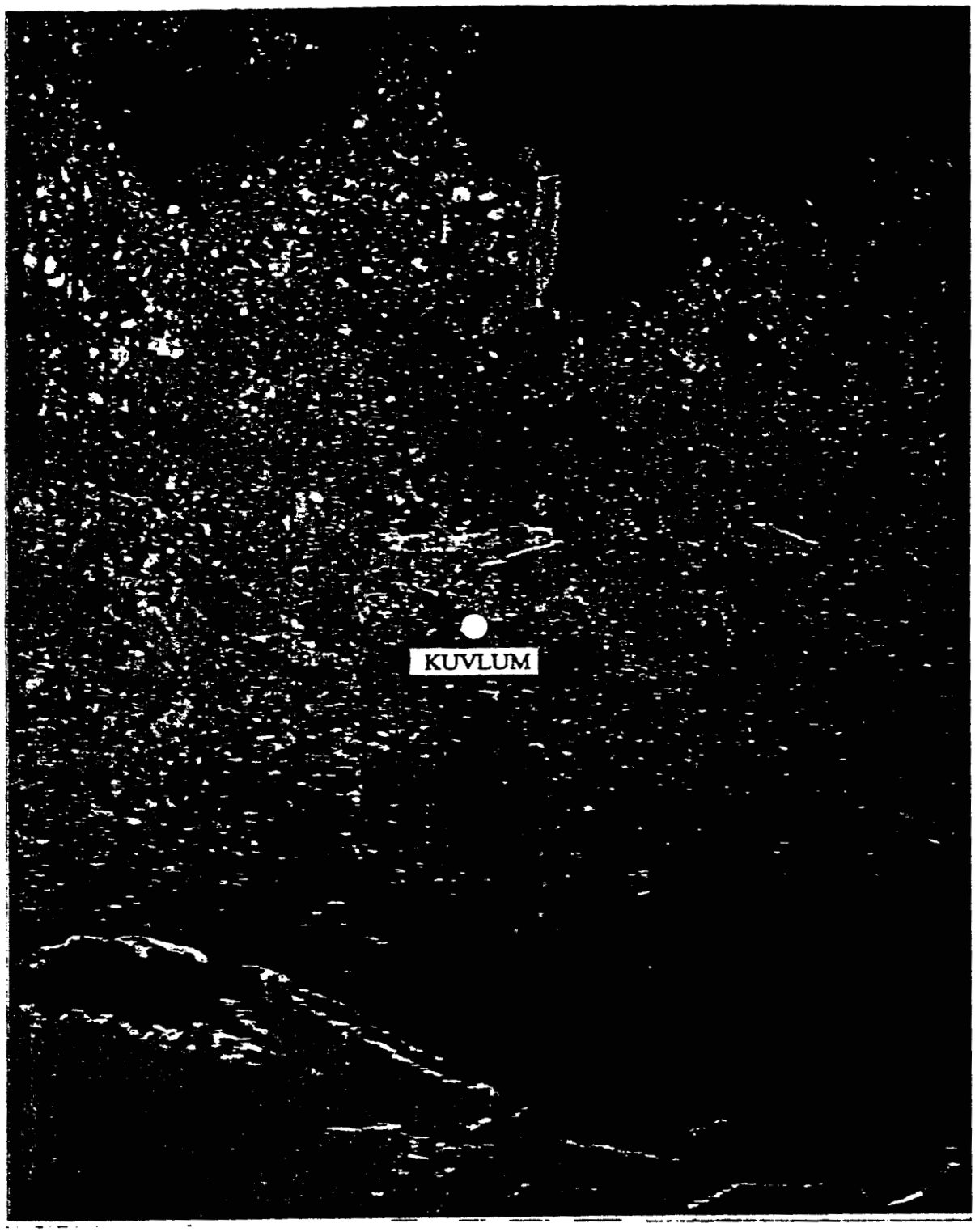


Figure 2.13c - SAR Imagery

Blow up of the Ice off Browlow Point, September 4, 1992

(Note the numerous floebergs)

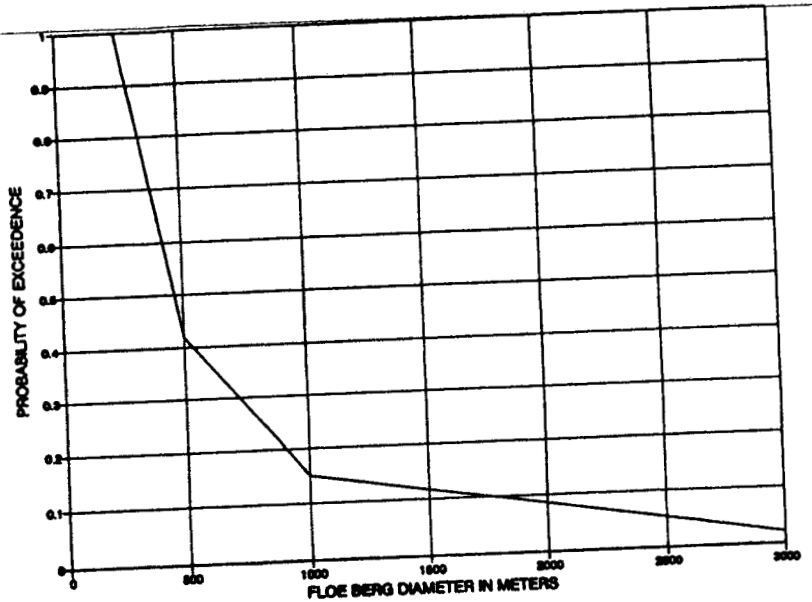


Figure 2.13d - Floe Berg Diameter Distribution

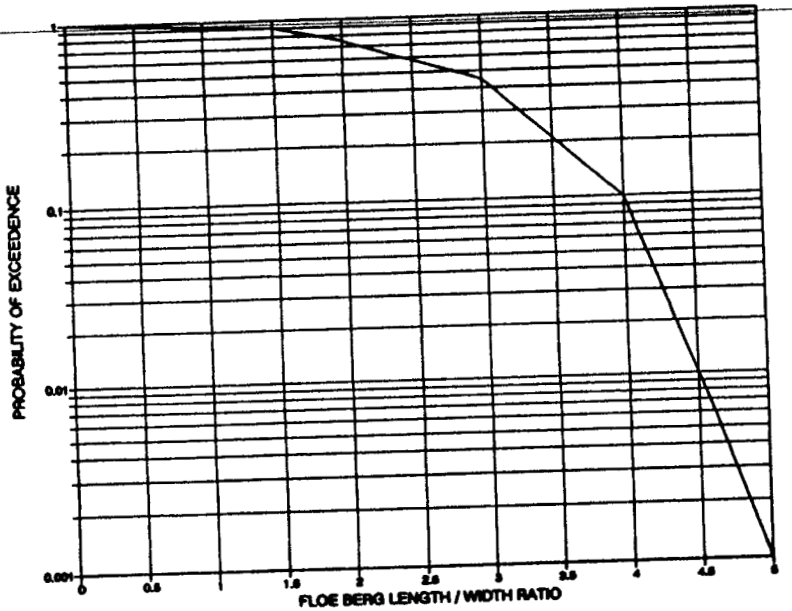


Figure 2.13e - Floe Berg Length/Width Ratio Distribution

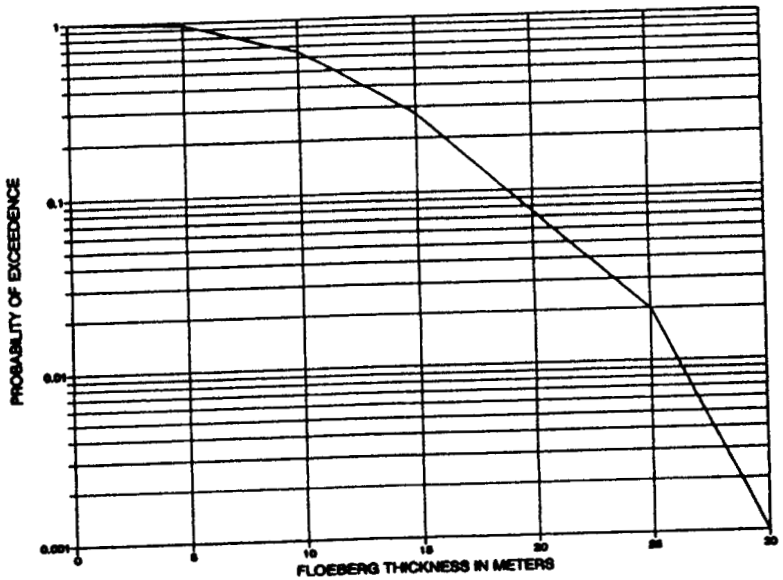


Figure 2.13f - Floe Berg Thickness Distribution

3.2 Probabilistic Ice Load Model

3.2.1 Methodology

In order to determine global ice loads as a function of return period, and select an appropriate design load level, a global ice load distribution in representative ice conditions is required. As noted earlier, there are many combinations of ice parameters which, for different ice/structure interaction scenarios experienced in different seasons, can generate similar load values. Because of this, a probabilistic approach involving repeated simulations of extreme ice feature interactions has been used to define ice load distributions for the structure concepts under consideration here. This methodology is shown schematically in Figure 3.1 and is analogous to the approach recommended in the recent CSA Code for the Design of Fixed Offshore Structures.

The ice/structure interaction scenarios that are important in terms of global design loads on Kuvlum structures have been highlighted in Section 2 (Table 2.1), along with the specific ice parameter distributions that are relevant to these scenarios. Most of these ice parameter distributions are those contained in Gulf Canada's probabilistic load model, and reflect Gulf's detailed data base on the nature of the Beaufort Sea ice cover. The distributions have been established from a synthesis of various types of Beaufort sea ice information, including systematic ice cover observations collected by government agencies, satellite and airborne remote sensing data, information obtained from icebreakers, submarines, drilling platforms and drifting buoys, as well as a variety of ice based investigations. Where warranted, these distributions have been adjusted (on the basis of actual data) to be more site specific for Kuvlum. A wide range of ice parameters are included in the model, since they can all have an effect on the ice/structure interaction process and resultant design load distibutions (see following figure).

Table 3.1 provides a summary of the ice information that is used in conjunction with the probabilistic ice load model, subdivided by interaction sceanario. As noted earlier, the basic approach is to synthesize a large number of extreme ice features and the associated interaction conditions using a Monte Carlo process, and in turn, calculate global ice loads for each synthesized interaction with a deterministic load model.

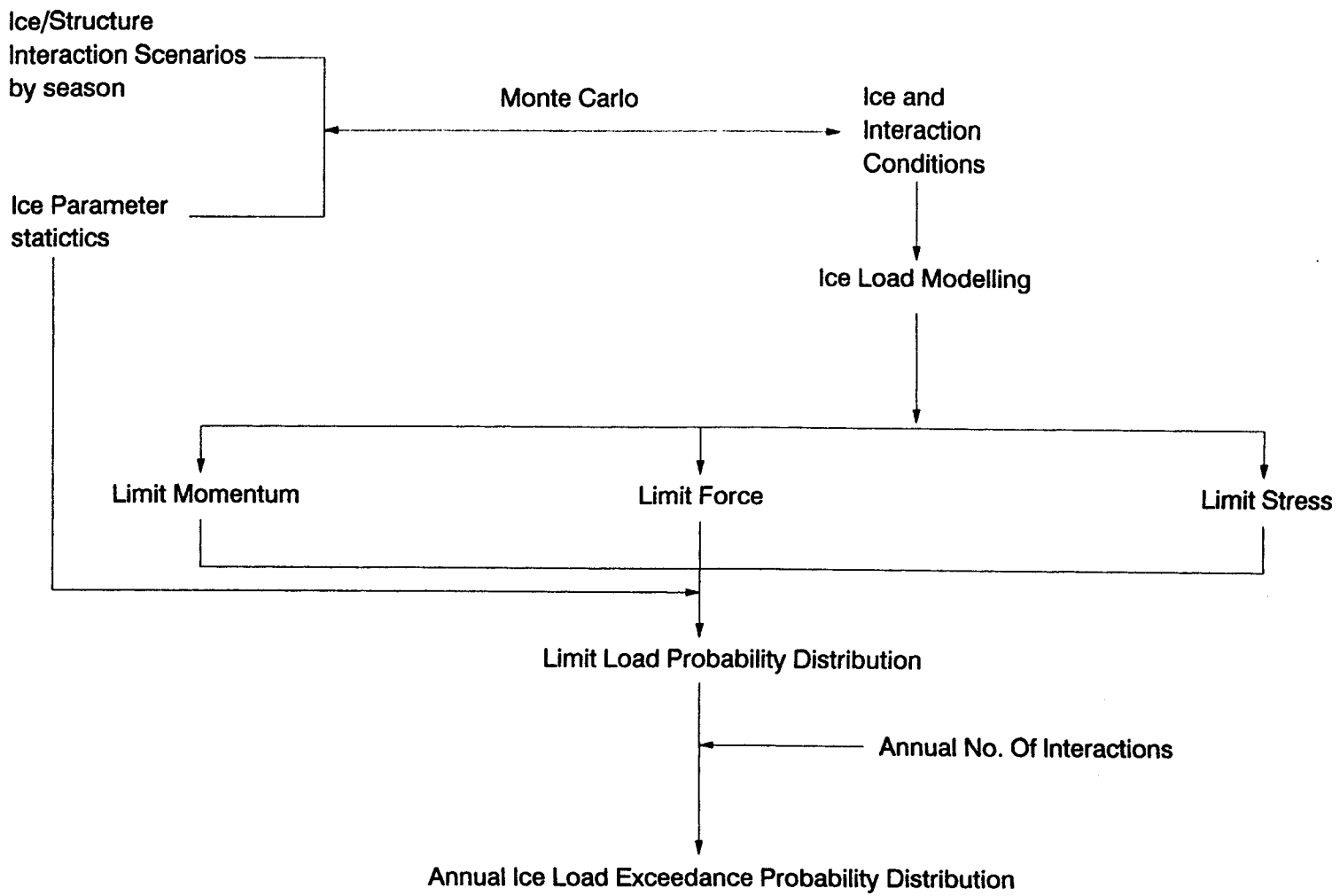


Figure 3.1 PROBABILISTIC ICE LOAD COMPUTATIONAL METHODOLOGY

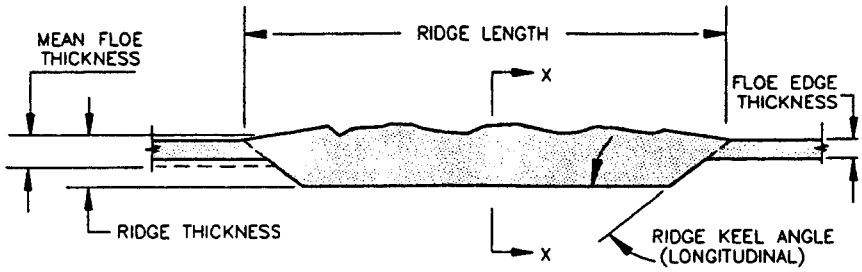
TABLE 3.1 SUMMARY OF ICE INFORMATION FOR LOAD CALCULATIONS

MULTI-YEAR FLOE PARAMETERS WINTER AND SUMMER	COMMENTS	FLOEBERG PARAMETERS WINTER AND SUMMER	COMMENTS
Velocity	Prob. distribution, B. Sea	Velocity	Prob. distribution, B. Sea
Diameter	Prob. distribution, Site Specific	Floeberg Diameter	Prob. distribution, Arco report *
Average Thickness	Prob. distribution, B. Sea	Consolidated Thickness	Prob. distn, based on qualitative observation
Ridge Spacing	Prob. dist, (exponential), B. Sea	-	-
Ridge Thickness	Prob. distribution, B. Sea	Floeberg Thickness	Prob. distribution, judgemental
Ridge Length	Prob. distribution, B. Sea	Floeberg Length/Width Ratio	Prob. distribution, judgemental
Ridge Width	Prob. distribution, uniform, judgemental	-	-
Ridge Side Slopes	Prob. distribution, B. Sea	Floeberg Side Slopes	Prob. distribution, judgemental
Ridge Orientation	Probable distribution, B. Sea	Floeberg Orientation	Prob. distribution, as for ridges in multi year ice (winter)
Ridge Occurence at the Floe Edge	Deterministic, B. Sea	-	-
Floe Edge Thickness	Prob. distribution, judgemental	Floeberg Edge Thickness	Prob. distribution, judgemental
Floe Approach Angle	Prob. distribution, B. Sea	Floeberg Approach Angle	Prob. distribution, as for multi year floe
Pack Ice Thickness (only for winter)	Ice growth curve, site specific	Pack Ice Thickness (only for winter)	Ice growth curve, site specific

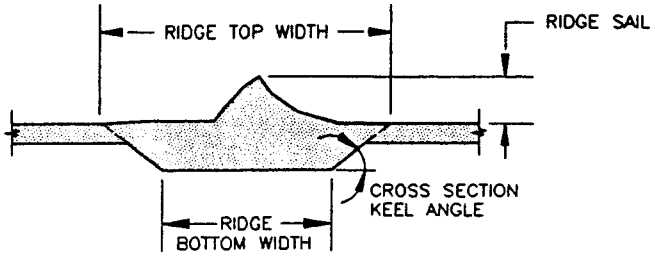
NOTE: 1) Arco Report on Floe Berg: Submitted by Brian Wright, Canatec et al.

2) All distribution are numerical unless otherwise specified

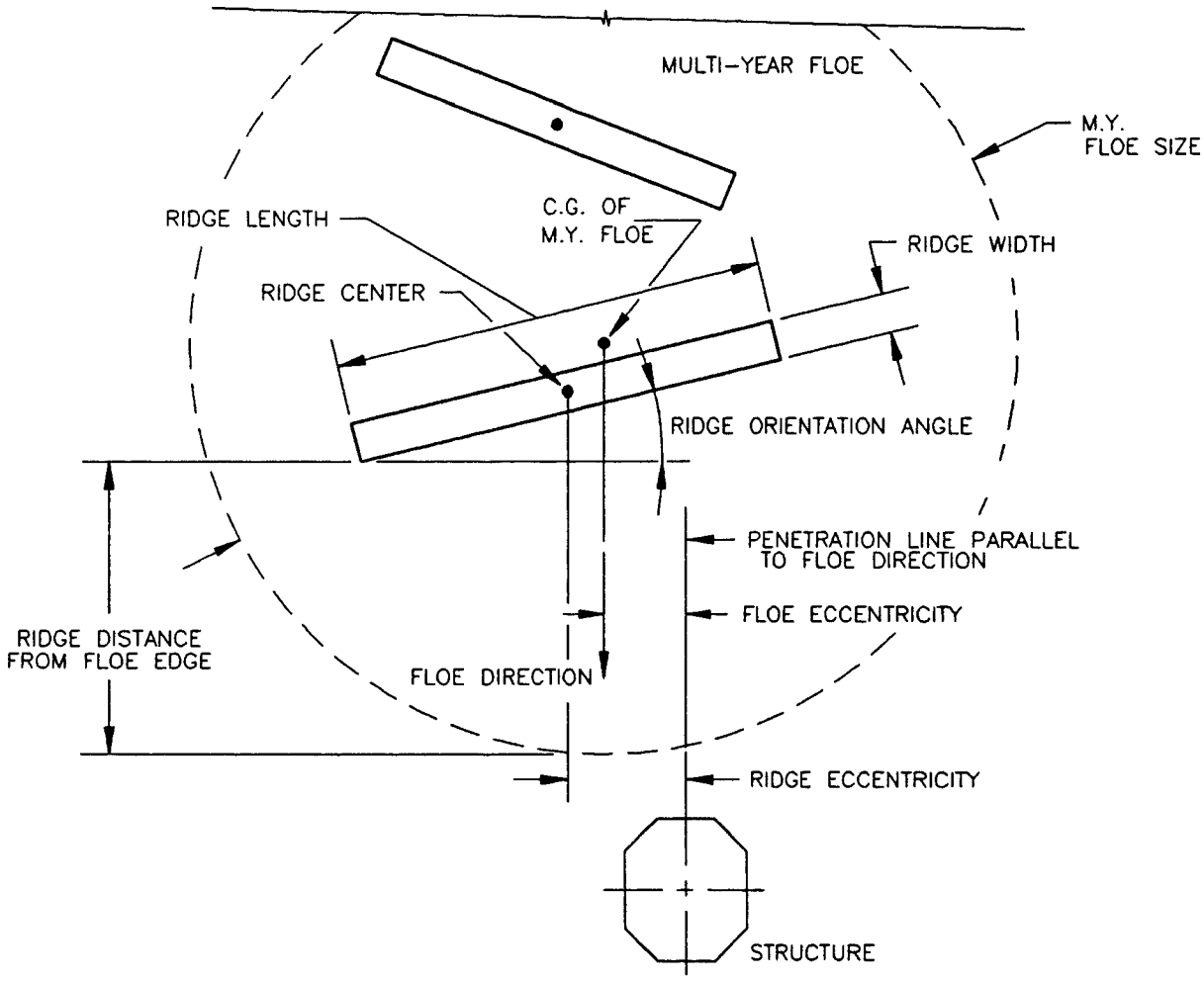
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RIDGE LONGITUDINAL SECTION



RIDGE SECTION X–X



MULTIPLE RIDGES WITHIN FLOE

PARAMETERS OF THE SYTHESIZED MULTI YEAR FLOE

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3.2.2 Interaction Conditions

The next step in the probabilistic ice load calculation methodology is to determine the global ice load on the structure, for each synthetic ice feature interaction with it. The loads that are determined from repeated simulations are used to form a load exceedence probability distribution for one interaction, and then combined with the expected number of extreme ice feature impacts to give global design loads as a function of return period.

In modelling each interaction, the effects of eccentric (off center) ice feature impacts are modelled by randomly selecting an eccentricity coefficient from a uniform distribution. For the winter scenarios, the ice feature is assumed to be frozen into the surrounding first year ice cover, and the pack ice thickness randomly selected from the ice growth curve (Figure 2.3). Once the ice feature is defined and the ice/structure interaction conditions are set, a deterministic ice loading model is used to compute the time dependent global loads during the interaction. This ice loading model is quite complex, since it considers various force limiting mechanisms for level ice and ridges, tracks the displacements of failed ice fragments, and computes peak global loads on the structure (it also has the facility to handle loads on submerged berms of various geometries, compute moments and horizontal load distribtions, and so forth).

3.2.3 Ice Failure Mechanisms

In terms of force limiting mechanisms, the upper limit to the global ice load is the force required to fail the ice directly against the structure in its easiest mode of failure, referred to as the limit stress force. Since only vertically sided structures are considered in this concept development work, the ice load model assumes that level ice will crush directly against the platform.

When thick ice features load wide structures, their kinetic energy may be dissipated by the work done (during ice failure) before they completely envelope the structure. This reduces the ice load in proportion to the contact width and if the floe stops, reduces the potential exposure of the structure to higher loads from other thick ice features that may

be present (eg: ridges) within the it. This force limiting mechanism is referred to as limit momentum and is also included in the ice loading model. "Limit momentum" forces do occur in certain simulations, particularly those associated with the summer multi-year floe interaction scenarios, where the pack ice does not provide high driving forces. An example of this is schematically shown in the following figure (top figure).

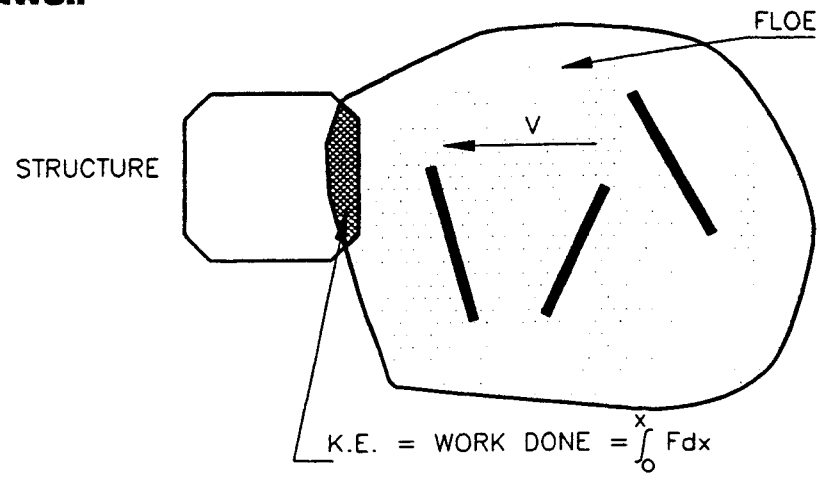
Even though the load in this limit momentum case is largely governed by the initial floe energy, the magnitude of the load is a function of the deformation characteristics of the ice and the structure at the contact interface. For example, if a structure is stiff and is directly impacted by a multi-year floe, the energy will be dissipated by ice failure over a fairly short distance and time span, resulting in relatively high loads during the interaction. Alternatively, if a ridge keel interacts with and scours a berm (not an option considered in this conceptual design work), energy will be dissipated over a longer distance, and the maximum value of the load during the interaction will be reduced.

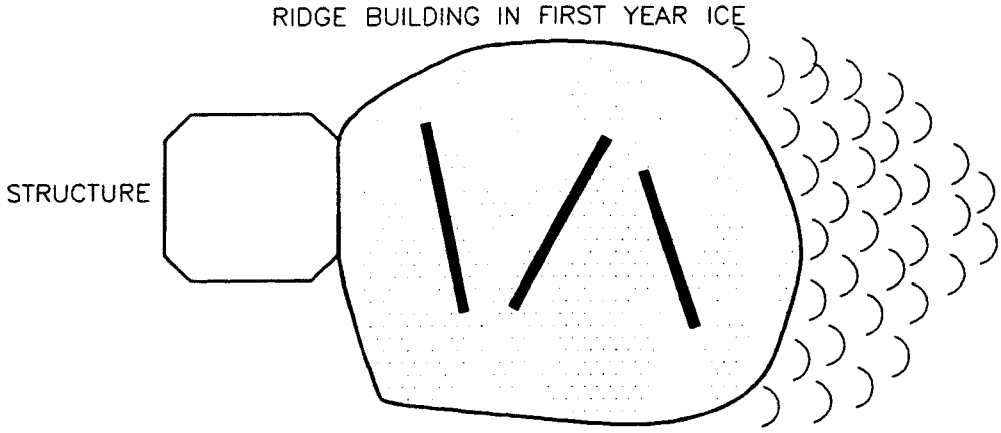
In the summer period, after a floe's momentum has been expended, there is usually insufficient driving force from the winds and currents for continued ice failure against the structure, and it will come to rest (wind and current driving forces are limited by the fetch or size of the floe). However in winter, the surrounding pack ice will continue to exert forces on the floe which in turn, can be transmitted to the structure. If there is enough driving force from the pack ice, the potential for continued floe penetration and interaction with thick ice features (eg: ridges) within the floe is increased (before and if the floe comes to rest). However, the ability of the pack ice to transmit high forces may be limited by ridge building at the floe edges. This load limiting mechanism, which involves pack ice failure and ridge building behind an extreme ice feature, is shown schematically in the previous figure (middle figure).

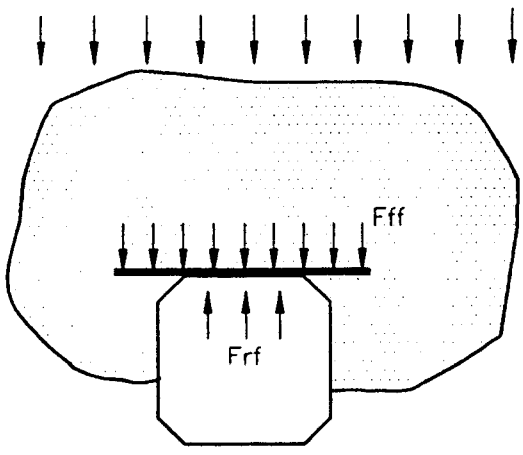
This failure mechanism is referred to as "limit drive force" and is also included in the ice loading model. Because the pack ice driving forces can be relatively high, particularly for a frozen in situation, there are many winter interaction simulations where extreme ice features do not stop.

The "limit stress" forces for thick ice features failing directly against a structure can be

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Frf = RIDGE FAILURE LOAD
Fff = FAILURE OF ICE BEHIND RIDGE IN MULTI-YEAR FLOE.
Frb = FORCE REQUIRED TO FAIL FIRST YEAR ICE DRIVING THE FLOE AND INITIATE RIDGE BUILDING.

ICE FAILURE MECHANISMS

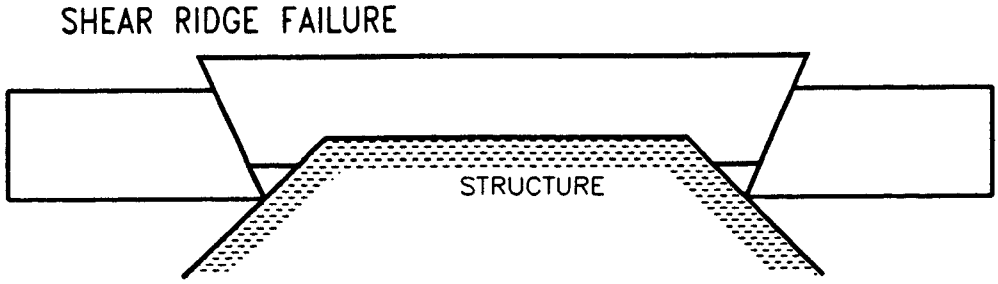
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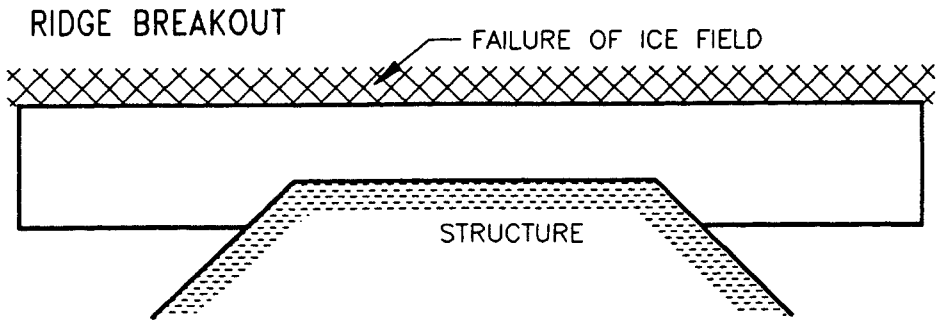
very large. If there are "weak links" within the ice feature (eg: level ice behind a thick ridge), the ice may fail at one of these weak links at lower levels, rather than directly on the structure. This possibility is also recognized in the deterministic ice loading model by calculating and comparing the relative force levels at weak links during the simulated interactions, as shown in the previous figure (bottom figure).

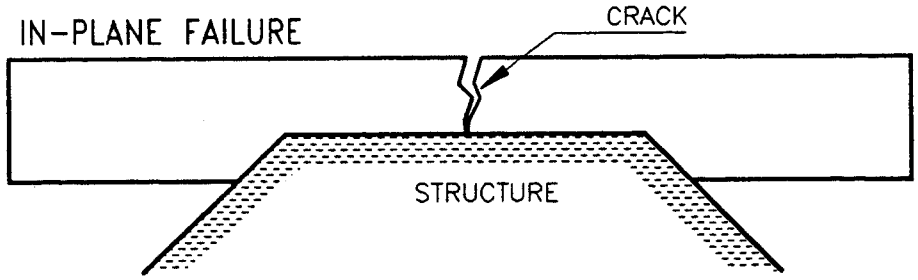
Here, the lowest of the Frf, Fff and Frb force values determines the relevant global ice load.

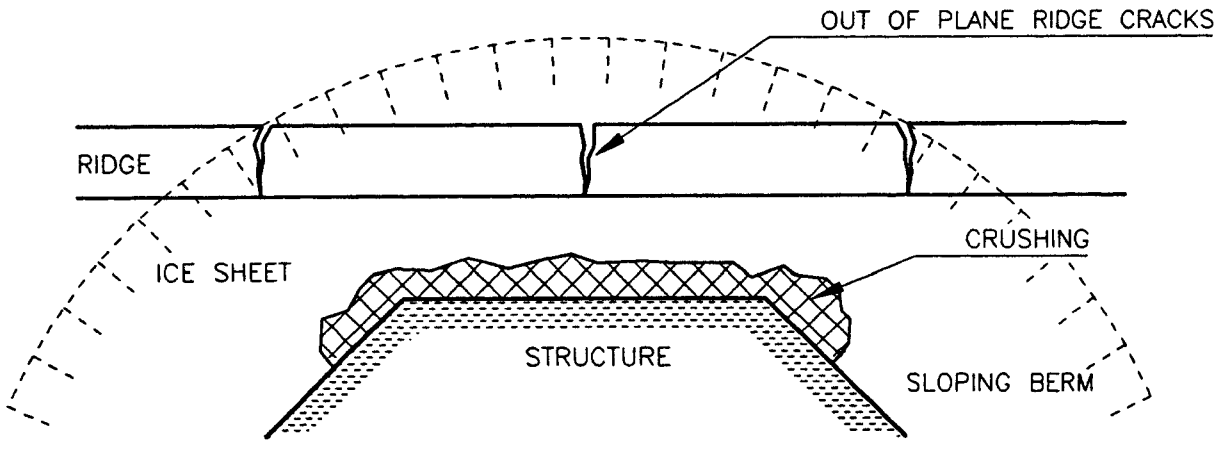
In all of the interaction scenarios, simulations which involve thick ridges embedded in large thick ice features tend to generate the highest load values. Ridge failure loads that are associated with in plane shear, bending and break-out failure mechanisms are also computed in the model for the embedded ridge cases (the model also has the capacity to treat out of plane ridge failure forces for interactions with uplift on sloped or bermed structures). These ridge loads are then compared with the limit stress ridge crushing loads within the model, to determine the correct failure mode and thus the governing global interaction force. These ridge failure mechanisms are shown schematically in the following figure.

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RIDGE FAILURE MECHANISMS

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The ice load model uses a type of discrete element technique, combined with a time stepping algorithm. Floes and ridges are fictitiously divided into beams of equal width, running along the floe movement direction. The interaction forces on the structure (and berm, if applicable) are determined for each beam at each time step during incremental penetration, and then summed algebraically to give the resultant global force on the structure. Compatibility along the fictitious joints is maintained. Failure pressures are assigned on the basis of the ice thickness and its variation across the width of contact, and generally involves a large number of beams.

3.2.4 Ice Pressures and Strength Values

The key ice failure pressure and strength parameters that are input into the deterministic ice loading model are summarized as follows.

Crushing pressure:

Large scale ice crushing pressures can be expressed as a function of aspect ratio, contact area or the ice thickness only. The ice pressure curve that has been used in this work is the one developed for the Joint Industry Project and is shown in Figure 3.2a. The curve's upper bound has been used for the winter season. However, for the summer season, the effective ice failure pressures are expected to be less, because of temperature effects. In view of this, the Joint Industry winter pressure curve has been reduced by a factor of 0.75 to reflect lower summer ice pressures.

For ice failing within a multi-year floe behind a ridge, a factor of 1.5 is applied to the crushing pressure curve values, since the ridge will be frozen into the floe. This factor reflects the requirement for higher pressure to break a ridge out from a frozen in condition.

Pack Ice Pressure

The pack ice pressures at which the first year ice frozen to a multi-year floe is assumed to fail (ridge building) are shown as a function of scale in Figure 3.2b. Here, frozen in pack ice pressures are assumed for the winter interaction cases and are higher than those commonly cited (3 times that for an unfrozen or free boundary condition) .

Shear and Flexural Strengths:

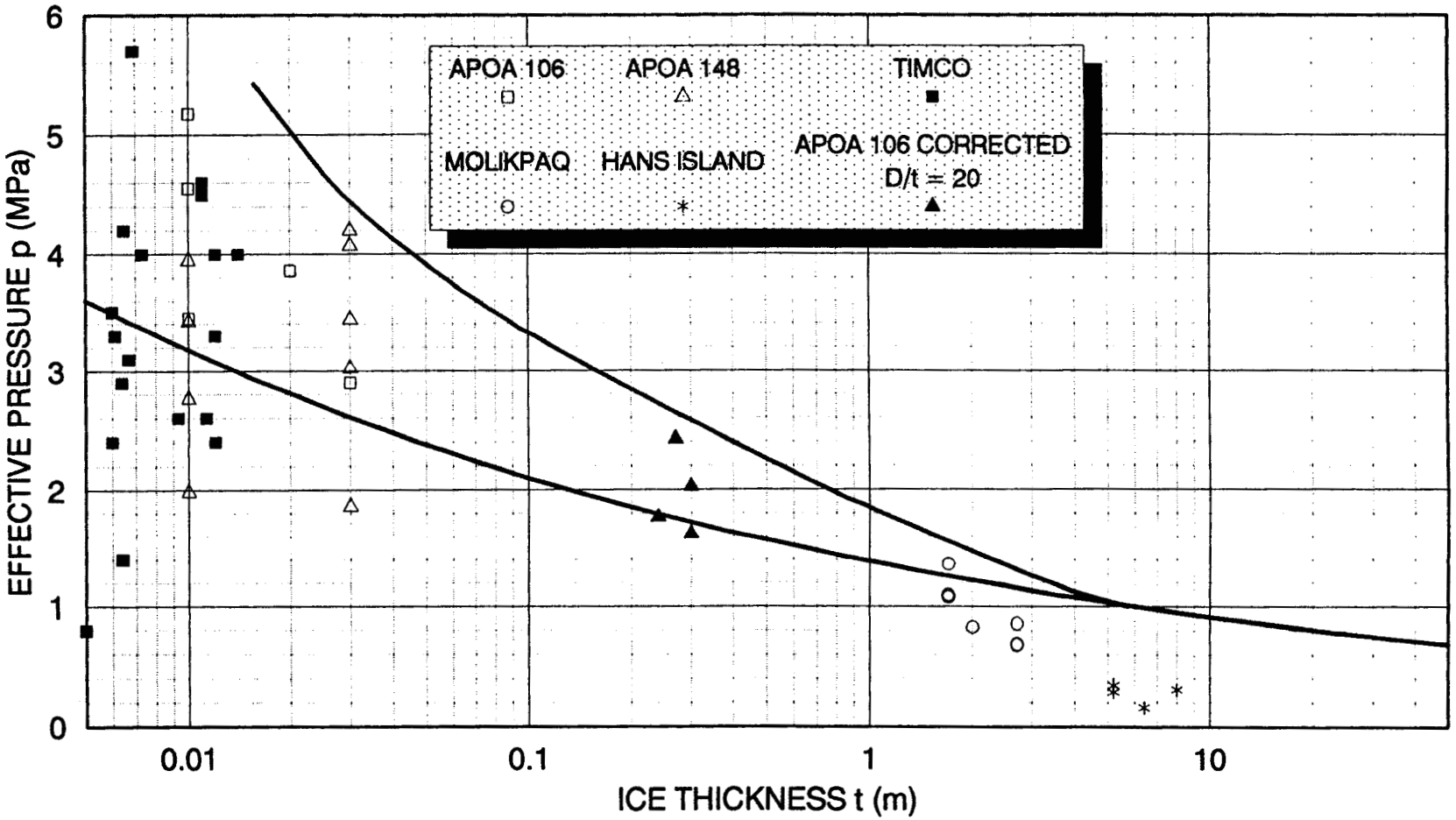
The bulk shear strength assumed for multi-year ridges is 0.25 MPa and the flexural strength is taken as 0.50 MPa.

By way of summary, this deterministic ice loading model is used within the probabilistic framework for each simulated multi-year ice interaction, many of which involve several ridge encounters. To compute the appropriate global ice load, each interaction is checked within the model to determine whether a limit stress, limit momentum, limit force or ridge failure condition governs. Weak links and in plane ridge failure modes are also checked in terms of failure forces to determine the correct ice failure mode and the appropriate global ice load for the governing condition. For floeberg interactions, the same model, with some modifications, has been applied.

3.3 Probabilistic Global Design Load Criteria

3.3.1 General

This probabilistic ice loading model has been used to develop global load design criteria for the development structure concepts considered in this work. The most important interaction scenarios for these Kuvlum structures have been identified as multiyear ice floes with ridges, floebergs and multiyear hummock fields.

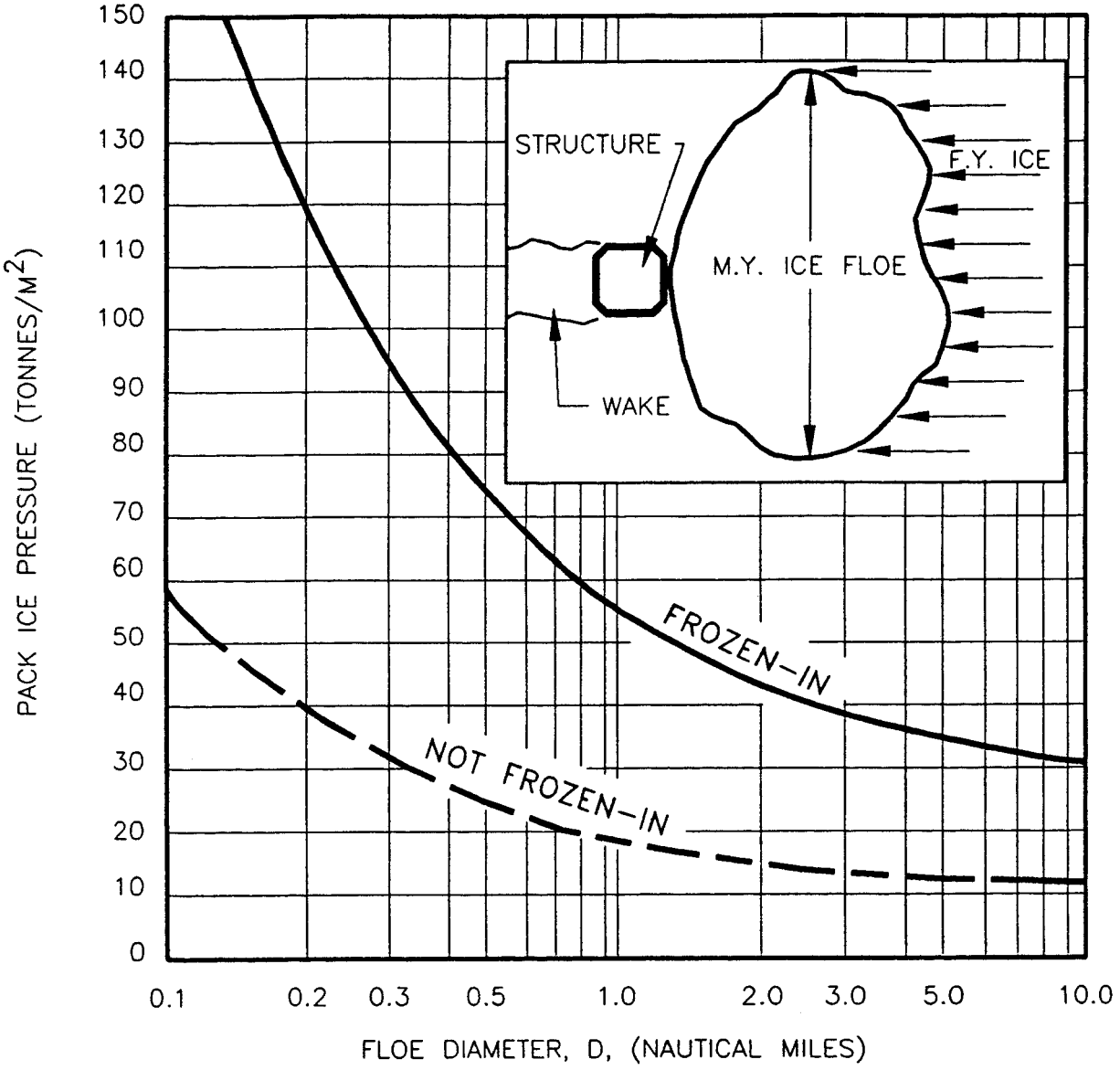


$p = 1.38t^{-0.181}$, $r = 0.602$

Hans Island, APOA 122, corrected APOA 106 data not part of regression

FIGURE 3.2a ICE PRESSURE VS. THICKNESS FOR LARGE ASPECT RATIO - 1991 JIP

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PACK ICE PRESSURE CURVES

FIGURE 3.2b

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Details of the probabilistic model, primarily related to multi-year ice interactions, have been discussed in the preceeding Sections and relevant ice parameter distributions have been highlighted in Section 2. This model, with some modifications, has also been used to compute the probabilistic ice loads due to floebergs. Multi-year hummock field interactions have also been identified as an extreme scenario but are considered as an extremely rare event. Since there is insufficient information on the characteristics of these ice features and their occurrence frequencies at Kuvlum, multi-year hummock field loads have been estimated deterministically, to establish where the potential hummock load level fits into the multi-year ice load distribution curve.

Here, the results of the probabilistic load assessment are summarized for the two basic structure concepts addressed in the subsequent sections of this report. Both concepts are vertically sided with slightly rounded corners, as shown in Figure 3.3. At the waterline, their side wall dimensions 110 and 70 m respectively. For the purpose of global load calculations carried out here, the rounded shape of their corners has been approximated by an octagon.

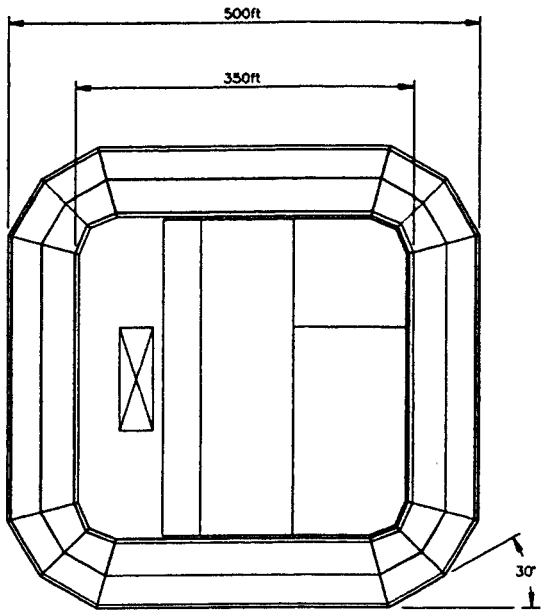
3.3.2 Multiyear Ice Floe Interactions

3.3.2.1 110 m Structure

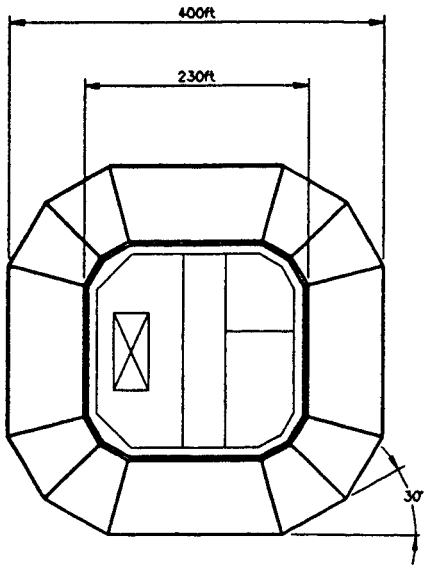
Winter

Figure 3.4 shows the multi-year ice load exceedence distribution, based upon 1000 simulated floe interactions. This is the basic load distribution curve that gives the probability of exceedence versus load for one floe impact. If one floe impact per year is assumed, then the probability of exceedence becomes the annual probability of exceedence.

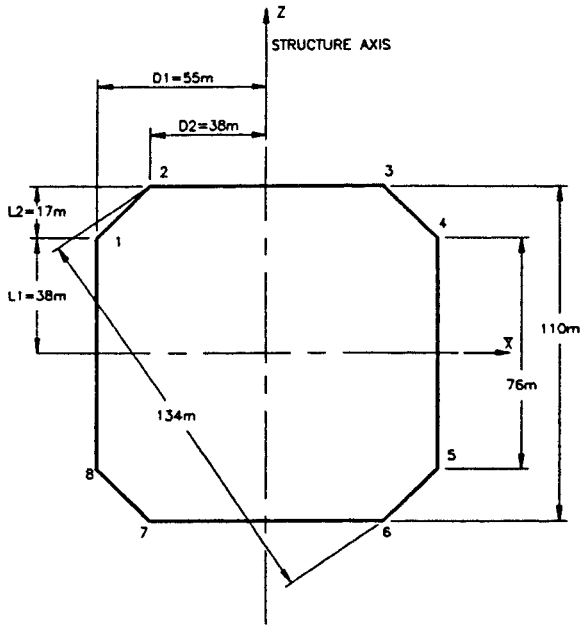
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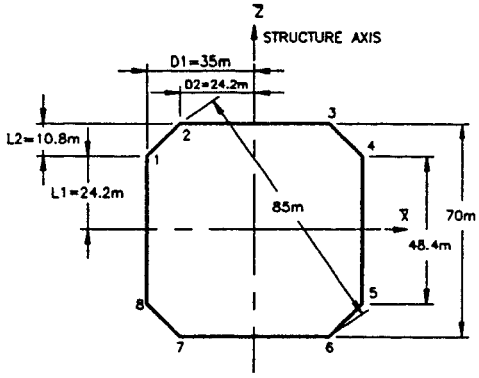


PLAN



PLAN





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PLAN OF 110m & 70m STRUCTURE
WITH ASSUMED OCTAGONAL SHAPES

FIGURE 3.3

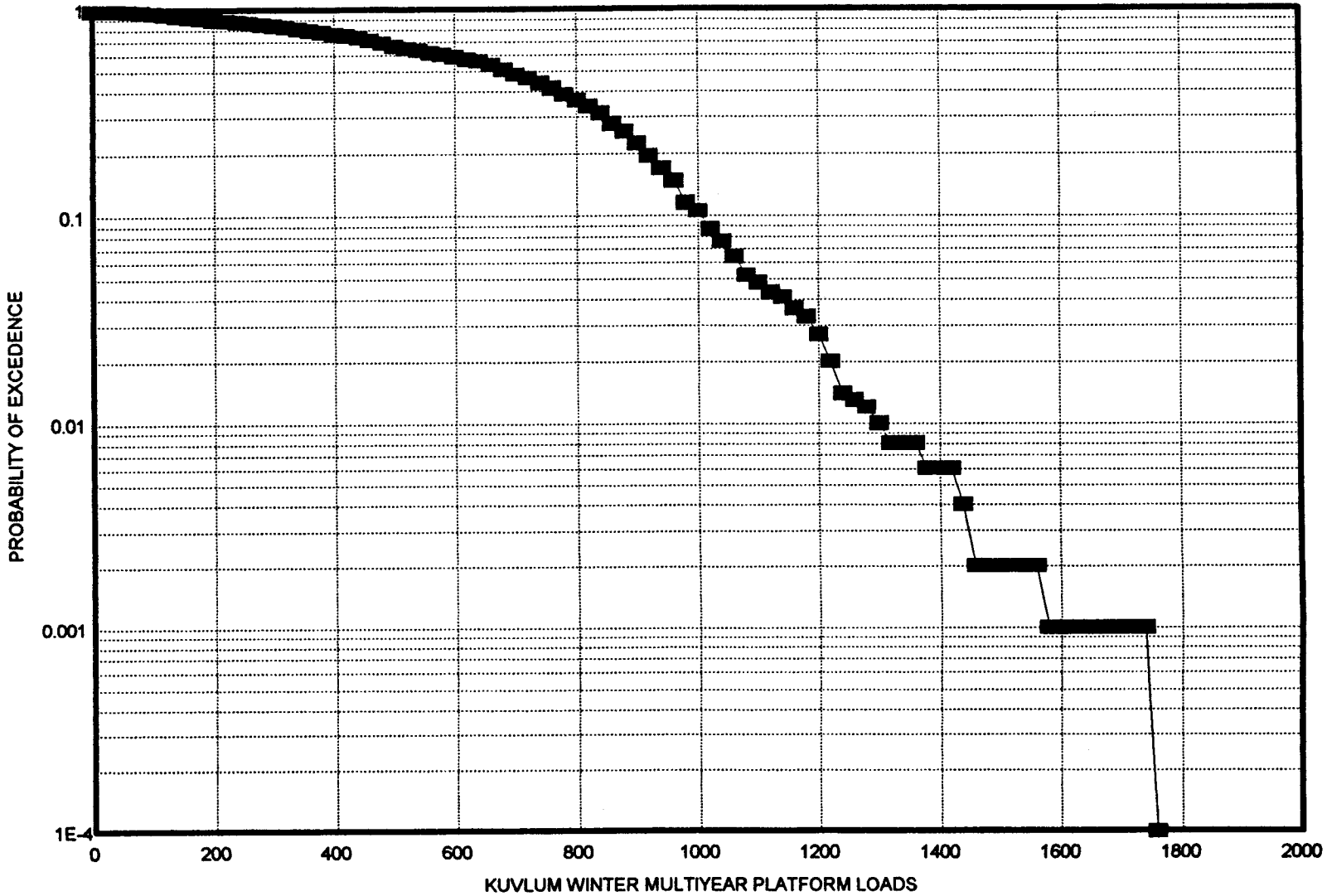


Figure 3.4 Probabilistic Loads For 110 m Structure
Winter - 1000 Simulations

Given the number of simulations, the tail portion of the curve is not properly defined beyond the 10^{-3} probability level and also shows some scatter at probabilty levels < 10^{-2}. Although Arco's specified interest involves global design loads at 10^{-2} and 10^{-3} risk levels, another model run was made with 10,000 simulations, with the objective of better assessing the tail of the load distribution.

Figure 3.5 shows the probability exceedence curve for one floe interaction, based upon 10,000 floe impact simulations. The distribution is quite smooth up to the 10^{-3} exceedance probability level and fairly well behaved at lower risk levels. Clearly, more than 10,000 simulations would lead to a more accurate definition of the load exceedence probability curve in the 10^{-3} to 10^{-4} range. However, budget, computing time and scope of work constraints simply did not allow this more rigorous approach. Instead, trends were established for the behaviour of the tail portion of the load exceendence curve (from the 1000 and 10,000 floe simulation results) and applied with reasonable judgement, as discussed later.

As outlined earlier, fairly high multi-year ice concentrations can, at times, be expected in the Kuvlum area, suggesting a mean winter impact rate that may be greater than one floe per winter. Since the load exceedence curves that have been shown reflect load probabilities for one winter floe interaction, they will change as the annual number of impacts increases (or decreases). However, it is very difficult to realistically establish the expected number of winter multi-year floe interactions with any degree of accuracy, due to data limitations. For example, ice charts from the freeze-up and break-up periods indicate a mean multi-year ice concentration around Kuvlum of about 0.8/10ths (ie: 8%). Given ice movements and floe sizes, this suggests an extremely high number of annnual winter impacts and is inconsistent with conditions shown on periodic winter SAR imagery and experience in the area. As a result, the approach taken here was to assess the sensitivity of the load distribution curve to variations in the annual number of winter impacts, over a reasonable range of values.

Figure 3.6 shows the load probability distribution curves for annual winter impact values of 5, 10, 25 and 50. The effect of scatter at low risk levels for a singular floe interaction are felt at somewhat higher probability of exceedence levels, as the annual number of

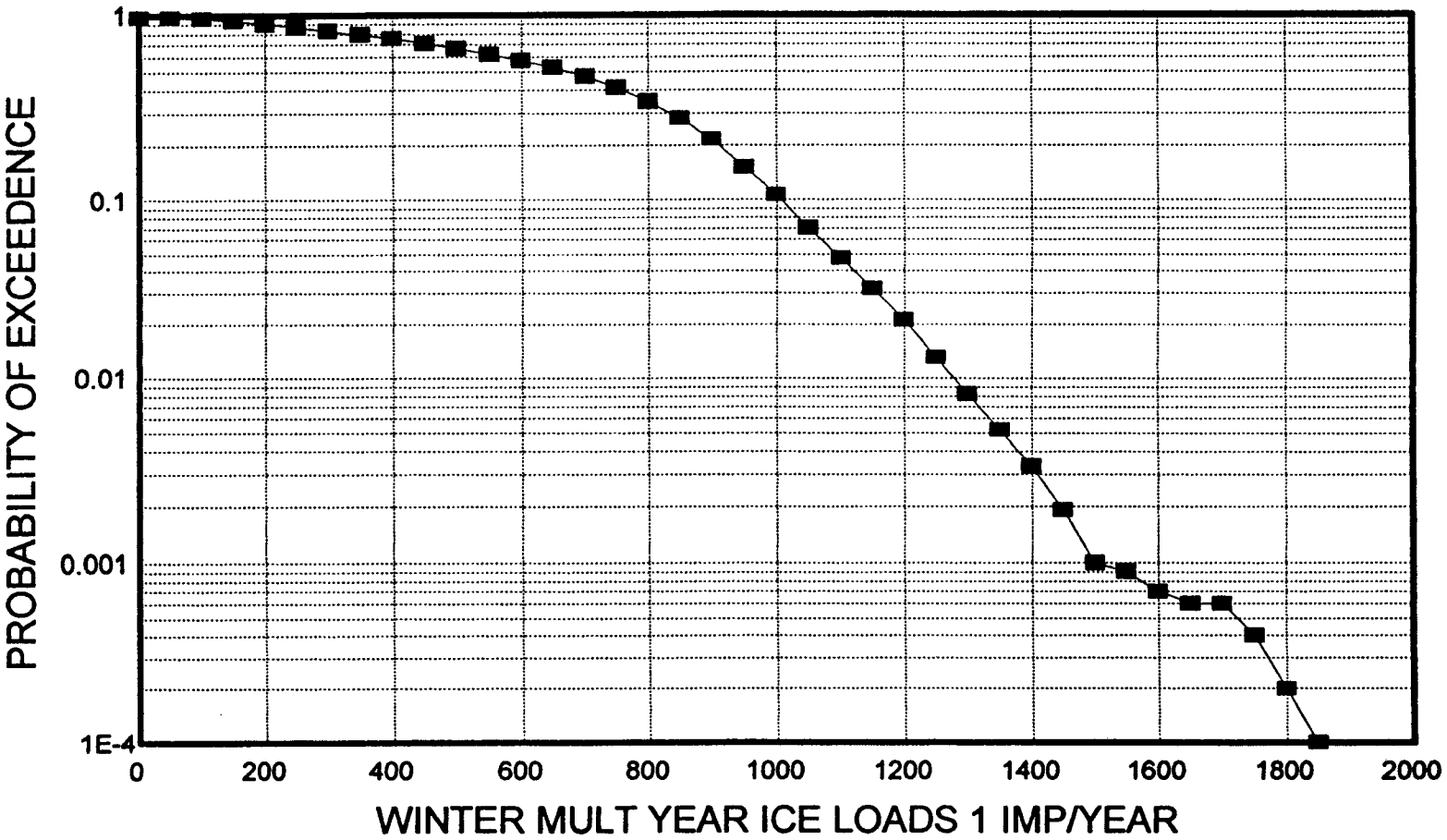


Figure 3.5 Probabilistic Multi Year Loads for 110 m Structure
Winter 10000 - Simulations

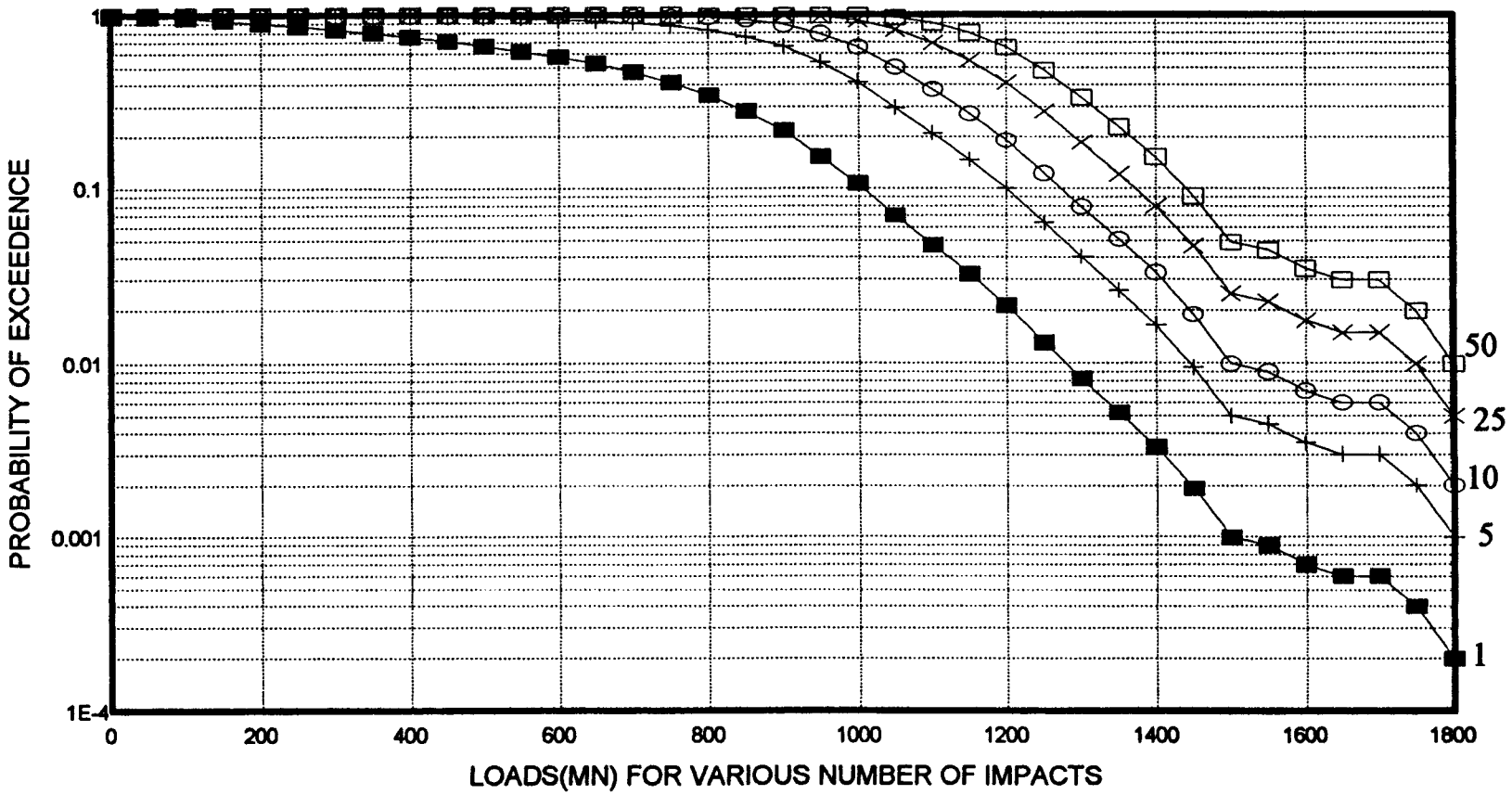


Figure 3.6 Multi Year Load Sensitivity for Various Number of Annual Impacts
Winter 10000 Simulations - 110 m Structure

impacts increases. An increased number of simulations (ie: > 10,000) would reduce the degree of uncertainty in the tail portion of these curves. However, the results that are shown in Figure 3.6 are considered reasonable, and the scope of increased simulation efforts not warranted at this conceptual design stage.

Table 3.1 provides a comparison of global loads on the 110 m structure at the 0.01 probability level (100 year return period) as a function of the annual number of winter multi-year floe impacts. These global load values converge to a maximum of 1600 MN and the difference in 100 year load levels for 10 impacts per year and 50 impacts per year is very small.

Although an increase in the number of simulations would be required to confirm it, it is likely that at lower probability of exceedence levels of 10^{-3} and 10^{-4} ,the tail portions for the load exceedence distribution curves would also converge. Based upon the available information, 0.001 probability loads (1000 year return period) would be between 1600 and 1700 MN and the their variation with annual winter collision floe impact frequencies of more than 10 per winter would be practically insignificant.

Summer

Global ice loads caused by summer multi-year floe interactions with the 110m structure have been computed in a similar manner.Load exceedence probability results, based upon 10,000 floe interaction simulations are given Figure 3.7, assuming 1 and 10 impacts per summer season. The maximum global load is 550 MN (at probability levels less than 0.001) and is considerably less than the winter multi-year ice loads. This results from the following:

- A lower ice failure pressure is used in the summer load computaiions than in winter

- There is no pack ice driving force

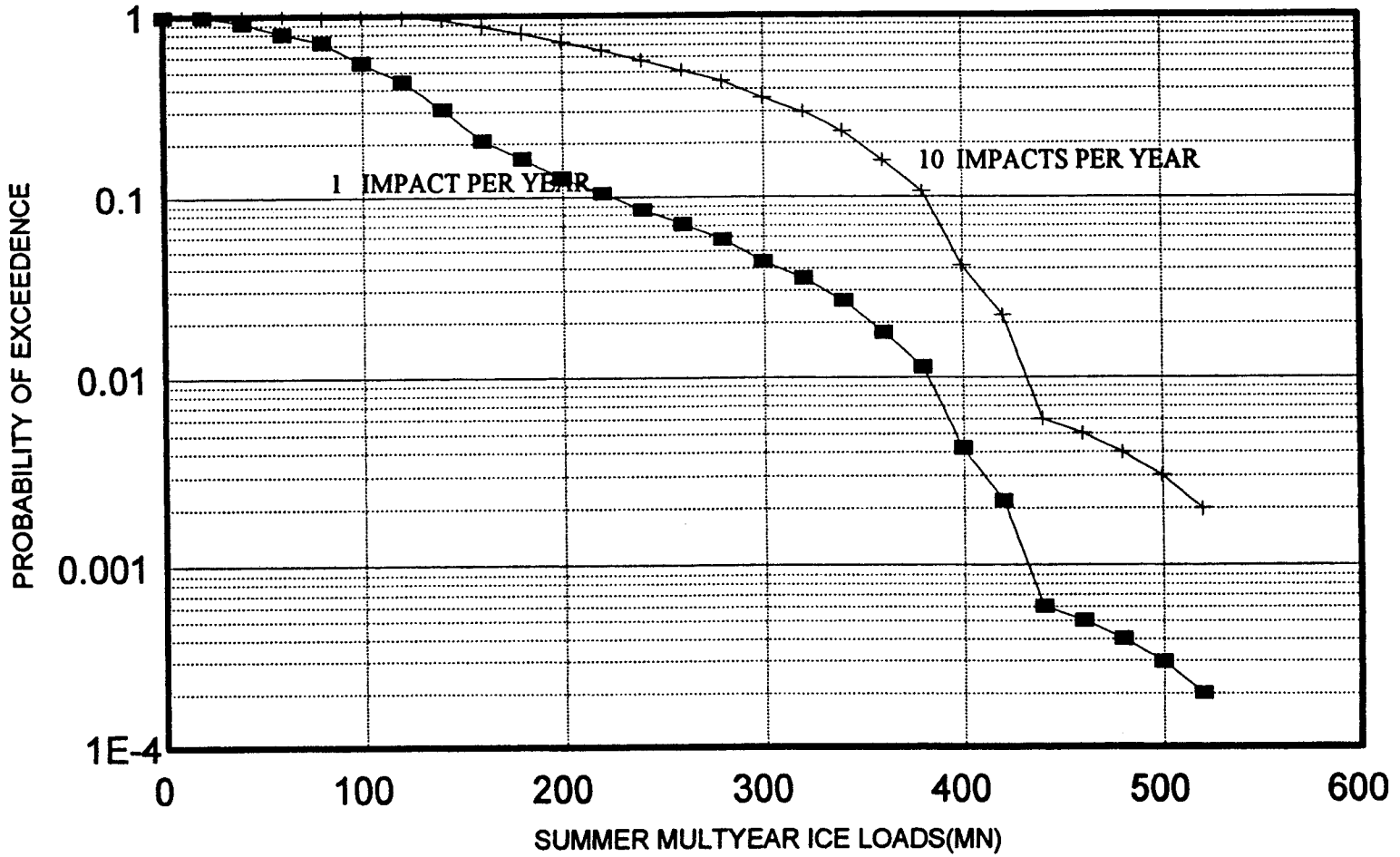


Figure 3.7 Probabilistic Multi Year Floe Loads for 110 m Structure
Summer - 10000 Simulations

- The loads are limited by the dissipation of the kinetic energy.
- Due to this kinetic energy dissipation limitation, most of the interactions are limited to a maximum of one ridge encounter in the floe.

Clearly, the summer multi-year ice loads are small in comparison to the winter loads and do not govern the design.

3.3.2.2 70 m Structure

Probabilistic ice loads have been developed for the 70 m structure in exactly the same manner as for the 110 m platform. However, only winter multi-year floe interactions were simulated for the 70 m structure because of the significantly lower load levels that are associated with summer floe interactions. Figure 3.8 shows the probability distributions for winter floe interaction loads on this smaller structure, for one and ten impacts per winter, based upon 10,000 simulations. Resultant global design loads are summarized in Table 3.2. For this 70 m structure, the global design loads at the 0.01 and 0.001 probability levels (100 and 1000 year return periods) are 1200 and 1300 MN respectively, assuming ten multi-year interactions per winter. Based upon the more thorough ice load assessment for the 110 m structure, the design loads for the smaller structure are expected to be quite insensitive to an increase in the number of winter interactions.

It is interesting to note that the ratio of the cross dimension of the smaller and larger structure is 0.63, while the ratios of the load values cited varies from 0.72 to 0.76. Although one might expect the two ratios to be identical, the differences reflect the fact that the ice load model includes a variety of ice failure mechanisms and not just the limit stress.

3.3.3 Floeberg Interactions

In addition to its application in determining multi-year ice forces, the probabilistic load model has, with some modifications, been used to assess floeberg interaction load levels.

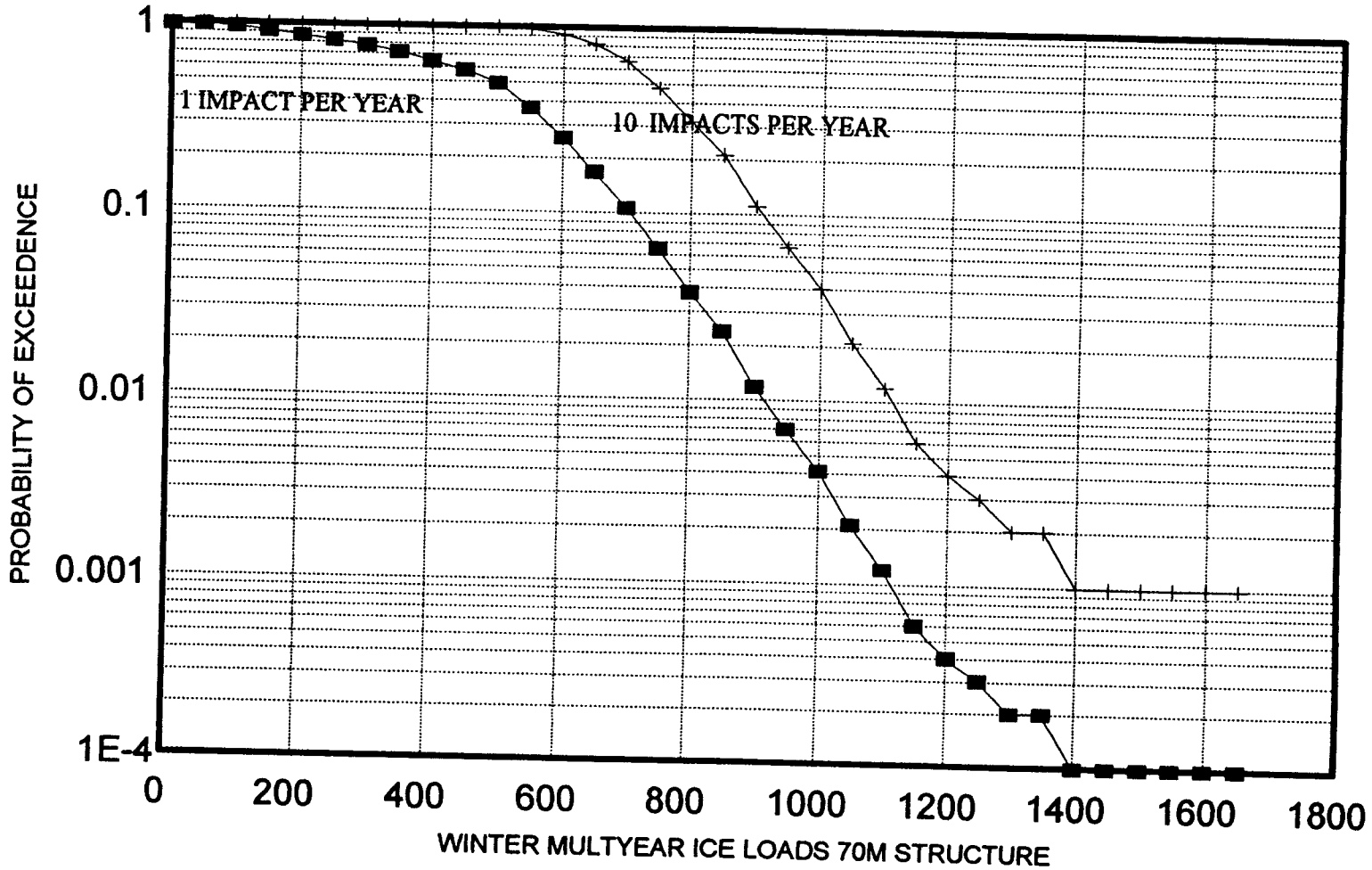


Figure 3.8 Probabilistic Multi Year Floe Loads for 70 m Structure
Winter - 10000 Simulations

Obviously, the geometry and properties of floebergs are different from those of the muliyear ice floes. As shown in Figure 2.11, floebergs are typically rectangular in plan, are heavily ridged and partialy consolidated. The probability distributions for their length, length to width ratio, consolidated layer and total thickness (including the keel portion) that are shown in this figure have been incorporated into the probabilistic model and used to synthesize floebergs.

Within the model, the total floeberg thickness is converted into an equivalent solid ice thickness, based upon the ratio of the rigidities of the unconsolidated and consolidated portions. Past studies on ridges and rubble fields indicate a value of 0.1 for this ratio. For modelling compatability, the floeberg is treated as long, wide single ridge embedded in a embedded in a wide expanse of first year ice. Using this approach, the first year ice and floeberg becomes the equivalent system for a multi-year floe with ridges (handled explicitly by the model). In the winter situation, the first year pack ice provides infinite kinetic energy to the floeberg, and as a result, the force limiting failure mechanisms are limit stress crushing of the floeberg at the structure and limit force break out and ridge building behind it.

A probabilistic analysis involving 1000 simulations was carried out for winter floeberg impacts on the 110m structure. Figure 3.9 shows the global load probability distributions for 1 and 4 floeberg impacts per winter. Four winter impacts (annually) is considered as a slightly conservative expectation. The resultant global design loads associated with winter floeberg interactions are summarized in Table 3.4 at the 0.01 and 0.001 risk levels. A design load of about 1200 MN is indicated as appropriate value, suggesting that multi-year ice loads will govern the structure design. Because of this and the relative magnitude of the winter floeberg forces, summer floeberg load estimates were not carried out and are considered unnecessary. Similarly, floeberg interactions with the 70 m structure were considered unnecessary since the winter mult-year ice loads will also govern their design.

3.3.4 Multi-Year Hummock Field Interactions

Although multi-year hummock fields have been observed in the Beaufort Sea, information

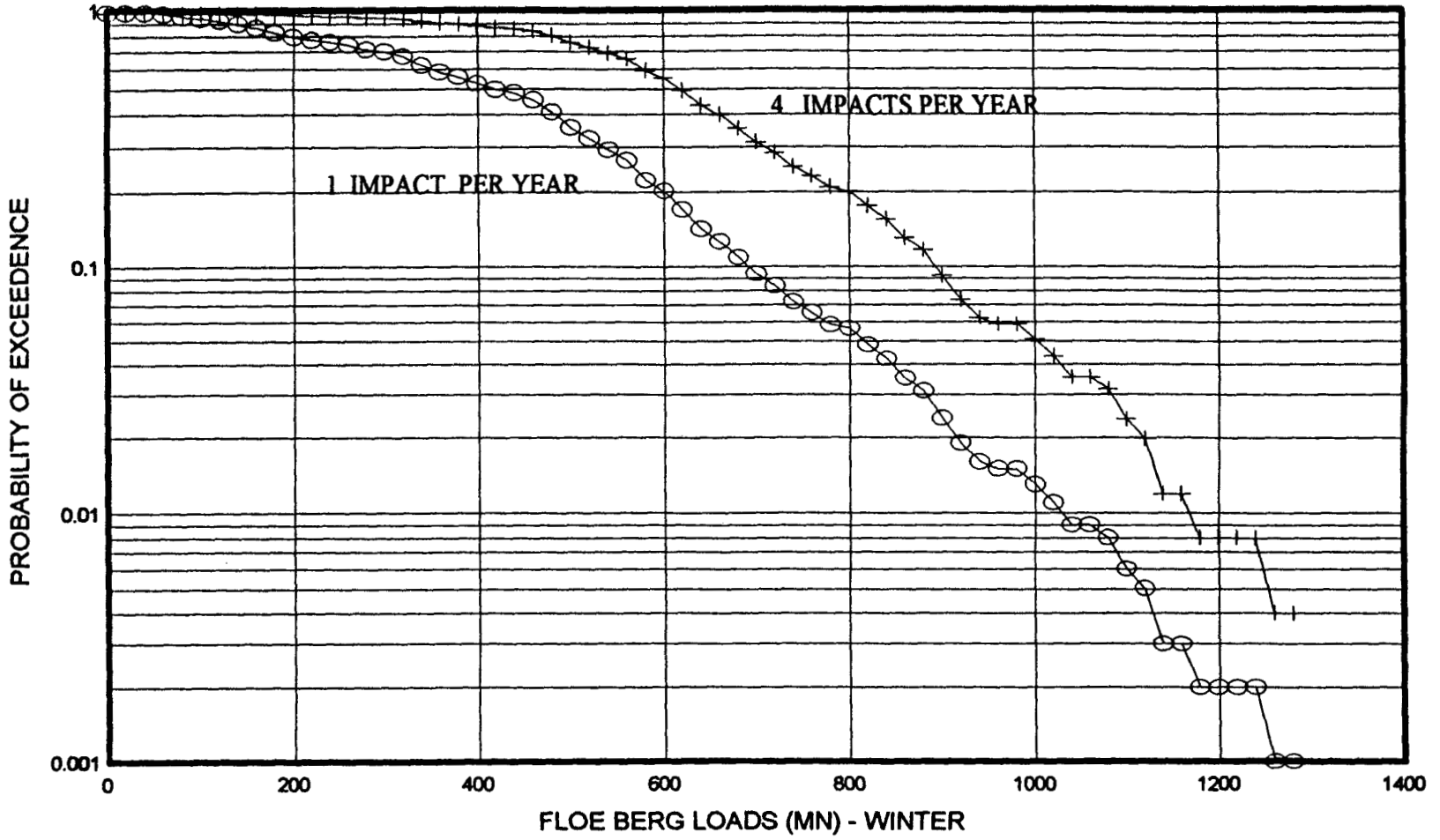


Figure 3.9 Probabilistic Floe Berg Loads for 110 m Structure
Winter 1000 Simulations

regarding their occurrence frequencies and geometrical characteristics is scarce. Because of this, a simple deterministic analysis has been carried out based upon reasonable assumptions, to estimate potential iteraction load levels. The intent of this calculation is to recognize multi-year hummock fields as extreme features and to compare deterministic global load estimates for this type of interaction scenario with the load probability exceedence curve for multi year ice floes interactions.

Here, a hummock field 2 km x 2 km x 20m thick and frozen into first year winter pack ice is assumed. With the ice pressure curve from the probabilistic model (see Figure 3.3), the ice failure pressure for global crushing of the 20m hummock field is 0.7 MPa. For 2m of pack ice, limit stress forces will govern the interaction and are shown as follows.

110 m Strucure

Load = 110m x 20m x 0.7 MPa = 1540 MN

70 m Structure

Load = 70m x 20m x 0.7 MPa = 980 MN

These loads assume full broadside envelopment of the structure are slightly less than the extreme winter loads for multi-year ice floes. The corresponding multi-year hummock field loads for summer will be much less than the winter loads, due to the absence of pack ice driving forces and lower ice failure pressures.

TABLE 3.1 **COMPARISON OF LOADS (MN) FOR A PROBABILITY OF EXCEEDENCE LEVEL OF 0.01 - STRUCTURE 110 m. NUMBER OF SIMULATIONS 10000**

	ANNUAL NUMBER OF IMPACTS				
Probability of Exceedence	1	5	10	25	50
0.01	1300	1450	1550	1575	1600
0.001	1550	-	1700 (Estimate)		

TABLE 3.2 **PROBABILISTIC MULTI YEAR ICE LOADS (MN) STRUCTURE SIZE 70 m NUMBER OF SIMULATIONS 10,000**

	NUMBER OF IMPACTS PER YEAR	
Probability of Exceedence	1	10
0.01	900	1100
0.001	1100	1300 (estimate)

TABLE 3.3 **PROBABILISTIC FLOEBERGE LOADS (MN) STRUCTURE SIZE 110m NUMBER OF SIMULATIONS 1000**

	NUMBER OF IMPACTS PER YEAR	
Probability of Exceedence	1	4
0.01	1050	1150
0.001	1250	1300 (est)

4.0 STRUCTURES

As specified in our original proposal and in the contract, only vertical walled structures were investigated. Over the past decade, both vertical sided and sloped sided structures have been proposed for Beaufort Sea operations. While there has been some controversy on which is more appropriate, it has been observed that both shapes have worked satisfactorily. In terms of ice clearing, vertical structures, especially if flat sided, tend to accumulate ice rubble whereas cone shaped structures tend to permit an easier clearance of the broken ice. Design ice forces on vertical sided structures resulting from the crushing of multi-year ice features are high and it may be argued that sloped sided structures, by encouraging ice failure in bending rather than crushing, are able to reduce design ice loads. However, this difference tends to diminish with the deep keeled design ice features. From the perspectives of construction and vessel manoeuvering in close proximity of the structure, vertical sided structures are preferred. It is apparent that there are a number of tradeoffs to be made and it is recognized that the selection of the most appropriate structure shape will need to be made at a later phase of more detailed design in order to arrive at a rationalized geometry.

Only steel structures have been considered although there are potential advantages in concrete or in steel structures with composite walls. Considering that the maximum towing draft around Point Barrow to be 60 ft., and ideally would be limited to about 35 ft. to minimize the probability of being blocked by ice each summer, steel structures present an advantage because of their lower draft requirements compared to concrete. It is difficult to design a concrete structure which would be limited to such a shallow towing draft. Concrete, on the other hand, has distinct advantages for large structures subjected to heavy loads, especially for the base of the structure or for walls which are required to withstand high differential heads. Concrete also provides good ballast for towing and for on bottom stability, whereas steel structures for the arctic usually require the addition of solid ballast.

In the initial work scope provided by ARCO, three drilling/production platforms and three drilling platforms were to be investigated. Because of the size of structure required to resist the large ice forces at the Kuvlum site, it was only necessary to design two

structures, one with a 350 ft. square hull and one with a 230 ft. square hull. The 350 ft. dimension was selected on the basis of the JIP work and the 230 ft. dimension was investigated to examine the feasibility of a smaller structure that could be fabricated in existing world yards. The ramifications of these choices will be made clear in the following sections.

4.1 Soils

Two soil profiles were provided by ARCO for the Kuvlum conceptual design, and a profile called Middle and Outer Shelf Stratigraphy was suggested as the most appropriate (letter from Junius Allen, July 23, 1993). A strictly cohesive soil with a shear strength of 2 ksf over a controlling depth was used but the structure was also made stable against sliding assuming a granular soil with a ϕ angle of 30°. As stipulated by ARCO, the factor of safety in bearing was 2.0 and for sliding was 1.5 for the 1 in 100 year ice load.

Should the 2 ksf material be overlain by 15 ft. of 0.5 ksf soil as suggested as a possibility in the July 23, 1993 letter of Junius Allen, then skirts would be required to penetrate this material and to transmit the stresses to the more competent material below. Otherwise, the softer surficial material would have to be removed from the structure location by dredging.

Discussions with ARCO indicated that shear strength of the foundation soil would be a lower bound. As will be seen later in this section, this soil parameter governs the selection of the structure base area and better soil on site would lead to structures with smaller bases.

4.2 Deck Loads

ARCO provided Sandwell with several alternative well and production equipment configurations for consideration in the design of the Kuvlum structures. Out of these, four different configurations were chosen for the conceptual designs. A reasonably detailed

set of calculations were performed to size the required members and to obtain the weights which have an important effect on the floating stability of the structure during tow out and set down. Deck steel weights can vary considerably depending on the spans involved. For instance, the long spans typical in Gulf of Mexico structures result in steel weights of approximately 100 psf whereas gravity base Arctic structures with internal bulkheads have deck weights of about 50 psf. The Molikpaq, with its large, hollow core, had a long span, box girder deck with a weight of about 200 psf.

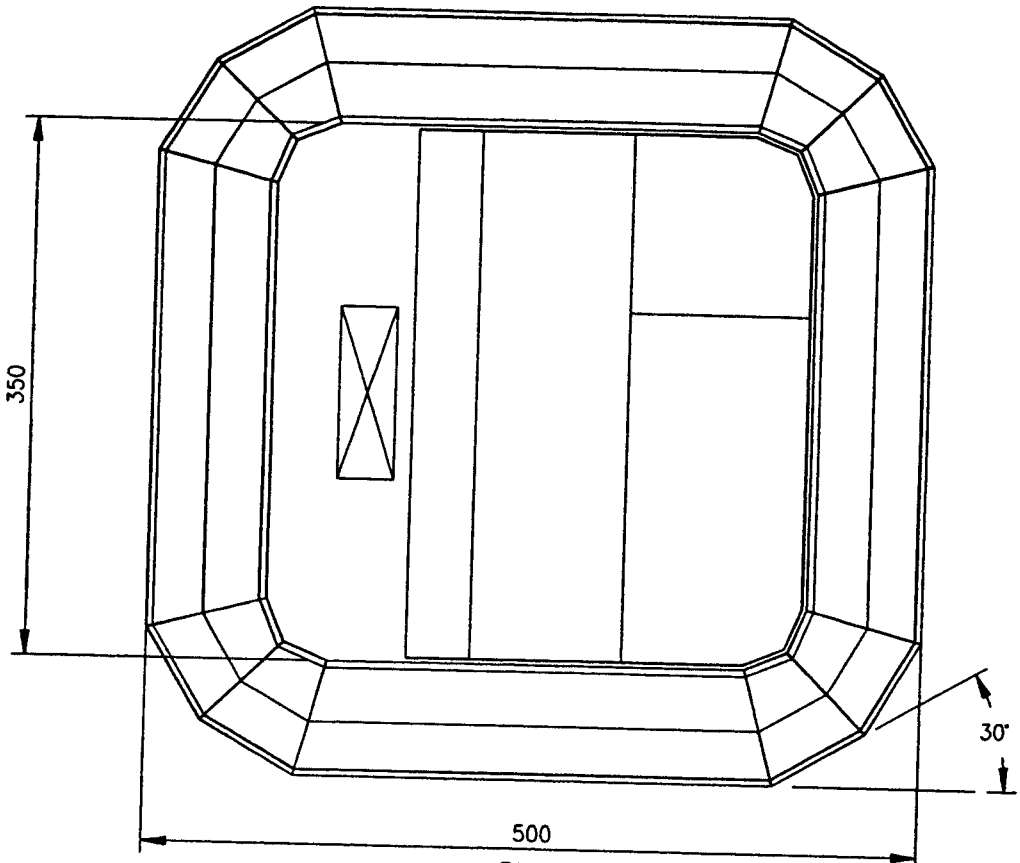
Both structures have two level decks, fabricated from stiffened plate with a hierarchy of three sizes of supporting deck beams and girders. For the calculation of representative beam dimensions for the deck, four uniform loads were considered; 200, 500, 1000, 1500 psf. No concentrated loads were included, although they would be for the final deck design. The beams are summarized in Table 4.1.

Analysis of the floating stability during tow and installation indicated that the larger hull (350 ft by 350 ft) would be required for Cases 1 and 2. The smaller hull (230 ft by 230 ft) would suffice for Case 3 only if significant reductions of deck loads were made for tow and installation, as shown in Table 4.2. The 230 ft by 230 ft hull is sufficient for Case 4 with the full operating deck load during tow and installation.

4.3 350 Ft. by 350 Ft. Square Hull Structure

4.3.1 Description

The general arrangement of the 350 ft. square hull steel structure is depicted in Figure 4.1. The main hull tapers outward in the lower 40 ft. to intersect the base which, because of bottom stability considerations, has been sized at 500 ft. by 500 ft. This taper reduces the bending stresses in the cantilevered portion of the base induced by bottom pressure and uplift moment from the ice forces. The detailing of the structure is similar to that described in the 1991 JIP report by Sandwell.

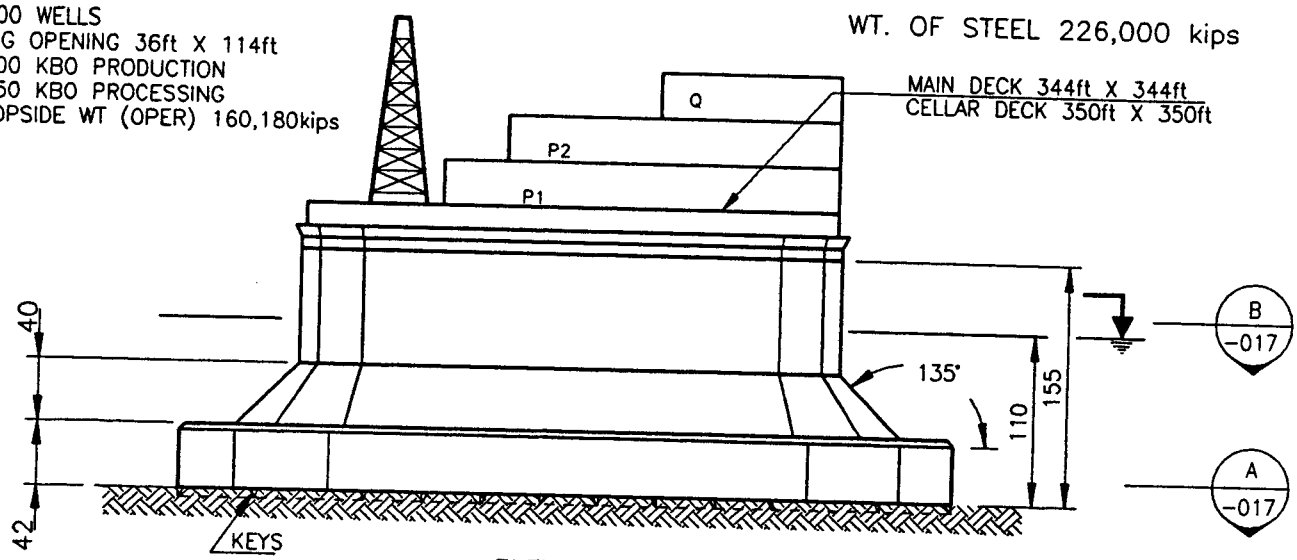


PLAN

RIG, PRODUCTION & PROCESSING

2 RIGS
100 WELLS
RIG OPENING 36ft X 114ft
300 KBO PRODUCTION
450 KBO PROCESSING
TOPSIDE WT (OPER) 160,180kips

WT. OF STEEL 226,000 kips



ELEVATION

FIGURE 4.1

DWG No.	REFERENCE	REF. No.

REV.	BY	DATE	REVISION	APP'D

APPROVED

DATE

A. 113147 C 014

		YR.	MO.	DAY
SCALE	1in = 125ft			
DRAWN	BG	93	12	06
CHECK				
DESIGN		93	10	22
DES. CHK.				

KUVLUM – 70 WELLS – 2 RIGS
500 ft. X 500 ft. BASE
350 ft. STRUCTURE

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SANDWELL CAD FILE NO. 3147C014

TABLE 4.1 DECK BEAM DIMENSIONS FOR TWO STRUCTURES

SPAN (ft)	NUMBER OF BEAMS		LOAD (psf)	DEPTH (ft)
	350 ft x 350 ft	230 ft x 230 ft		
40	18	12	200	2
			500	3
			1,000	3.5
			1,500	4
20	35	23	200	0.75
			500	1.0
			1,000	1.1
			1,500	2
10	100	66	200	3 in.
			500	4 in.
			1,000	4 in.
			1,500	6 in.

This analysis indicated that a deck framing steel weight of 50 psf would be representative for the structures.

TABLE 4.2 DECK LOADINGS

Case No.	No. Wells/ Rigs	Production Rate (KBOD)	Processing (KBOD)	Operating Deck Load (kips)	Float Out Deck Load (kips)	Deck Steel Wt. (kips)
1	60/2	150	150	112,277	112,277	18,380
2	100/2	300	450	160,180	160,180	18,380
3	70/2	210	0	80,654	61,654	5,290
4	40/1	120	0	46,780	46,780	5,290

The ice wall consists of a skinplate stiffened by an arrangement of longitudinal stiffeners and transverse frames, supported by deep horizontal girders and bulkheads. An annular space of 35 ft. width behind the entire ice face is provided to give a "double hulled" configuration. This space would normally be flooded, but access for inspection and repair

of the ice face could readily gained by dewatering these compartments.

The design of the ice wall requires reliable information on local ice pressures and their variation with contact area. Good information has been collated on this from a variety of sources including large scale indentor tests, tests at Hans Island and from instrumentation on the Molikpaq and on icebreakers. The large scale indentor tests, which are a source of much of the data, were conducted by Sandwell personnel in the Arctic in trenches or tunnels excavated in the ice (Masterson et al, 1992, Masterson et al, 1993). This information has been combined with local pressure information from ship/ice impact trials and is described in "Local pressures in ship/ice and structure/ice interactions", by D.M. Masterson and R.M.W. Frederking, Cold Regions Science and Technology, 21(1993). A copy of this paper is included in Appendix C. This work has formed the basis of the local ice pressure design criteria for the recently revised API RP2N standard.

The skinplate of the ice wall is designed recognizing that it has significant post yield strength resulting from the establishment of a membrane or catenary mechanism. A description of the design procedure is given in the 1991 JIP and will not be repeated here. The recognition of this membrane behavior in design results in a significant reduction in the required skinplate thickness. Membrane action has been used for many years in the design of steel bridges and other structures. It has also been used successfully in the design of icebreakers and was used by Sandwell in the design of the Molikpaq, the only structure to have resisted impacts by thick multi-year ice in the Arctic. Considerable information on the behaviour of the structure was obtained during these impacts, and inspection of the Molikpaq indicated that the plates were not damaged in any way.

The structure is compartmentalized internally by watertight and non watertight bulkheads on 38 ft. spacings as shown on Dwg 113147-C-017 in Appendix B, thus determining the main span of the deck framing girders. The outer skin of the hull has 1.25 in. plate and the inner skin has 3/4 in. plate. The internal bulkheads are 1 in. plate stiffened. The design of the watertight bulkheads conforms to that outlined in the 1991 JIP. To establish the maximum hydrostatic level for the bulkhead design, the following conditions have been considered:

- one compartment damaged while floating
- refloating the platform at the end of its service life, with one compartment damaged, which requires the bulkheads to withstand a differential level, the value of which would be established during detailed design, during the deballasting process
- differential loading due to variations in level of internal solid ballast

The bulkheads are used to distribute the loads into the structure, and the resulting in-plane loads govern the thickness of the bulkheads near the ice face. The stresses from ice loads are dissipated rapidly and thus further inside the structure, differential pressure due to ballasting and/or drawdown in cells used for storage becomes the dominating load for the watertight bulkheads. A factored differential pressure of 29 psi, which is equivalent to 66 ft. of seawater, was used for the general design of watertight bulkheads. If sand ballast were used, this would correspond to 33 ft. of fill. Although non watertight bulkheads will usually experience insignificant hydrostatic pressure, the possibility of pressure differentials from ballasting with solids must be carefully considered in a detailed design, unless the bulkhead is extremely "transparent".

The principal support for the base plate of the structure is main the bulkheads but, to resist the base pressures, it is further supported by an orthogonal grid of stiffeners, frames and beams. Sizing conforms to the procedures outlined in the 1991 JIP. Skirts are provided on the base of the structure to provide penetration to reach undisturbed soil and also to allow undergrouting. The skirts are designed to resist the temporary loads which may be experienced prior to full undergrouting of the base and also to transfer the loads to the competent material in the permanent condition. With the skirts penetrating to the competent material, the full base area can be used for stability against the design ice loads.

A moonpool or opening of 26 ft. by 114 ft. for up to 100 wells has been provided in the structure as shown in Figure 4.1. The opening is off centre to accommodate the topsides and rig layout specified by ARCO. Further details of the structure are provided in Appendix B.

4.3.2 Floating Stability

An important aspect of the design of large offshore structures is the floating stability during tow out and set down. While code requirements vary, a positive metacentric height or GM of about 3 ft. must be maintained. Heavy topside loads often make it difficult to maintain a positive GM for certain shapes of steel structures, although the vertical walled structures considered in this work exhibit more desirable floating characteristics than do conical structures.

The program Mathcad was used to calculate the GM for the 350 ft. by 350 ft. square hulled structure. For topside loading Case 1 in Table 4.1, the tow out draft is 41 ft. with the full operating load on the deck. Included in the structure weight is 240,000 kips of hematite ballast in the base which may be required for on-bottom stability. The associated GM is 492 ft., a very acceptable value. The GM reduces during setdown but the structure is still hydrostatically very stable.

For Case 2 of Table 4.1, the tow out draft is 41 ft. and the associated GM is 479 ft. Stable and very accurate set-down can be achieved for this case.

Table 4.3 summarizes the towing characteristics of the 350 ft by 350 ft structure.

TABLE 4.3 TOWING CHARACTERISTICS OF 350 FT SQUARE STRUCTURE

Case	Solid Ballast During Tow (kips)	Deck Steel Weight (kips)	Deck Load (kips)	Towing Draft (ft)	Metacentric Height (ft)
1	240,000	18,380	112,277 (Full Oper.)	41	492
2	190,000	18,380	160,180 (Full Oper.)	41	479

Notes: 1. 2,000 kips was added to equipment weight for Case 1 because of deck overhang of 23 ft.
2. 5,000 kips was added to equipment weight for Case 2 because of deck overhang of 22.5 ft. on 3 layers.

4.3.3 Design Ice Forces

A detailed description of the Gulf ice load model and the procedure for determining the ice loads for different probabilities of occurrence is given is Section 3. Based on the results of that analysis, the following ice loads were used to design this structure. These loads are similar to the lower bound loads used in the 1991 JIP.

TABLE 4.4 DESIGN ICE FORCES FOR 350 FT. SQUARE STRUCTURE

Return Period (years)	Ice Force (kips)
100	348,000
1,000	382,000

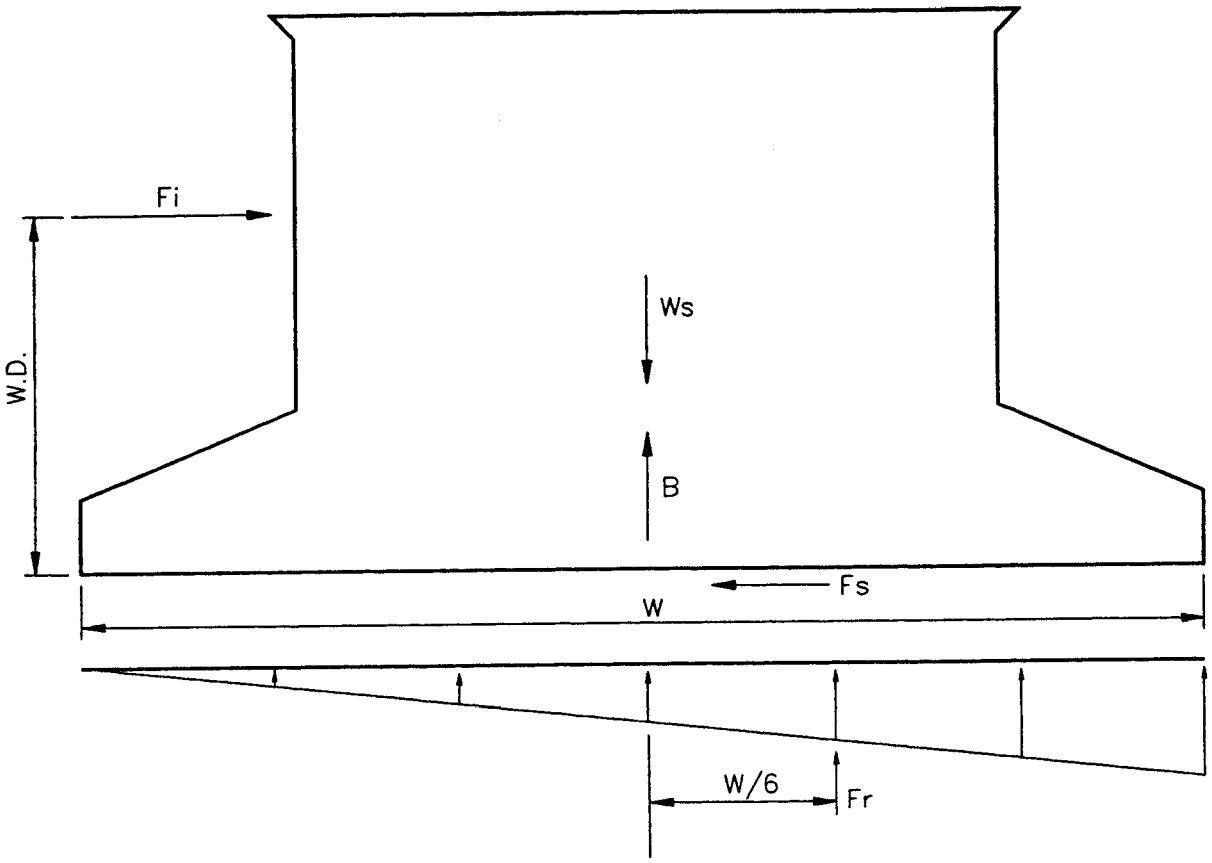
The 100 year return period ice load has been used in this study as a base design case for the determination of allowable soil stresses and ballast requirements. The sensitivity of these parameters to the 1000 year return period ice force has also been demonstrated.

4.3.4 Structure On-Bottom Stability

Using the above ice forces, the on-bottom stability of the structure against sliding and uplift was determined. For uplift, a simple approach using an assumed triangular pressure distribution allowing no base tension is adequate for this stage of the design. This is conservative since the soil pressure is unlikely to be linearly distributed as assumed. An alternate method is to assume a rectangular block of constant pressure which, in the direction of loading, is less than the entire structure width. This will lead to somewhat less conservative answers. Furthermore, the negative skin friction from the skirts must be considered in a final analysis. In view of the relatively small amount of information available on the soils at Kuvlum, it was considered unwarranted to introduce such refinements for this study.

The results of the on-bottom stability analysis are shown in Table 4.5. Figure 4.2 shows

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Fi = ICE FORCE
Ws = WEIGHT OF STRUCTURE AND ITS CONTENTS
B = BUOYANCY
Fr = FOUNDATION REACTION
Fs = FOUNDATION SHEAR
W.D. = WATER DEPTH
W = WIDTH OF STRUCTURE BASE

FIGURE 4.2 – FORCES ON STRUCTURE

3147\3147SK01.DWG

TABLE 4.5 ON BOTTOM STABILITY - 350 FT. SQUARE HULL STRUCTURE

(1) Water Depth (ft)	(2) Ice Force Return Period (years)	(3) Ice Force (kips)	(4) Ratio Soil Shear Stress/ Allow.	(5) Requ'd Bottom Wt. to prevent uplift (kips)	(6) Requ'd Bottom Wt. for Sliding (granular material) (kips)	(7) Ratio of Righting to Lifting Moment	(8) Wt. of Hematite Ballast (kips)	(9) Wt. on Bottom With Ballast (kips)	(10) Max. Bearing Pressure (ksf)	(11) Ratio of Bearing Strength to Pressure
110	100	348,000	1.04	459,306	602,683	1.32	240,000	605,459	4.3	2.6
110	1,000	382,000	1.14	503,754	661,006	1.32	300,000	665,459	4.7	2.6

Notes:

1. Soil bearing strength 12 ksf
2. Weight on bottom required to prevent sliding in column 6 assumes friction only soil with ϕ angle of 30°. If this were true on site, then more solid ballast would be needed.

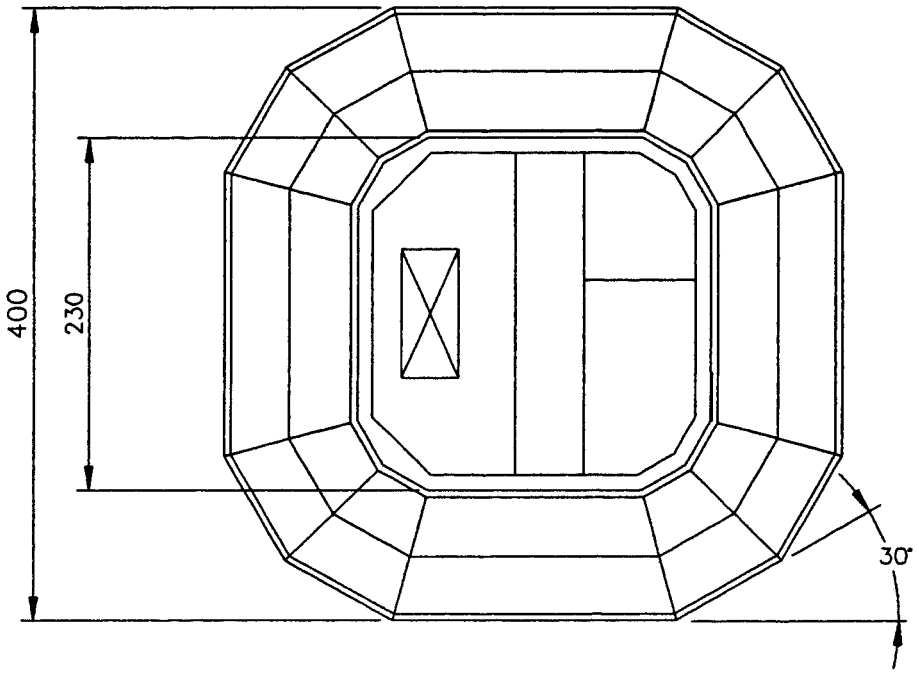
The base width of the structure has been chosen such that, for the 1 in 100 year force, the shear stress in the soil (column 4) is close to the allowable stress of 1.33 ksf (2 ksf/1.5). At the 1 in 1,000 year force level, the shear stress in the soil is 1.14 times allowable, or 1.52 ksf, which is still below the ultimate strength specified. For both loads, the ratio of righting to uplift moment is 1.32. The maximum bearing pressure in the soil (columns 10 and 11) is only approximately 1/3 of the allowable bearing capacity of 12 ksf. Thus this structure is able to withstand the anticipated forces, including those associated with a large return period.

Even though the bottom material has been assumed to be cohesive, at this initial stage of the design it is good practice to consider sliding stability on granular soil. In this case, the stability is a function of structural weight, and this has been calculated considering that the soil at the Kuvlum site might be a friction-only material with a ϕ angle of 30°. It can be seen from column 6 of Table 4.5 that a considerable increase in weight is required than for a cohesive material. Consequently, if a sandy soil was found at the site, about 240,000 kips additional solid ballast would be required to realize the required strength and sliding resistance. This represents several shiploads of hematite and it could brought to the structure after set down. The additional ballast also could be added at the construction yard, with some resulting compromise in towing draft.

4.4 230 Ft. by 230 Ft. Square Hull Structure

4.4.1 Description

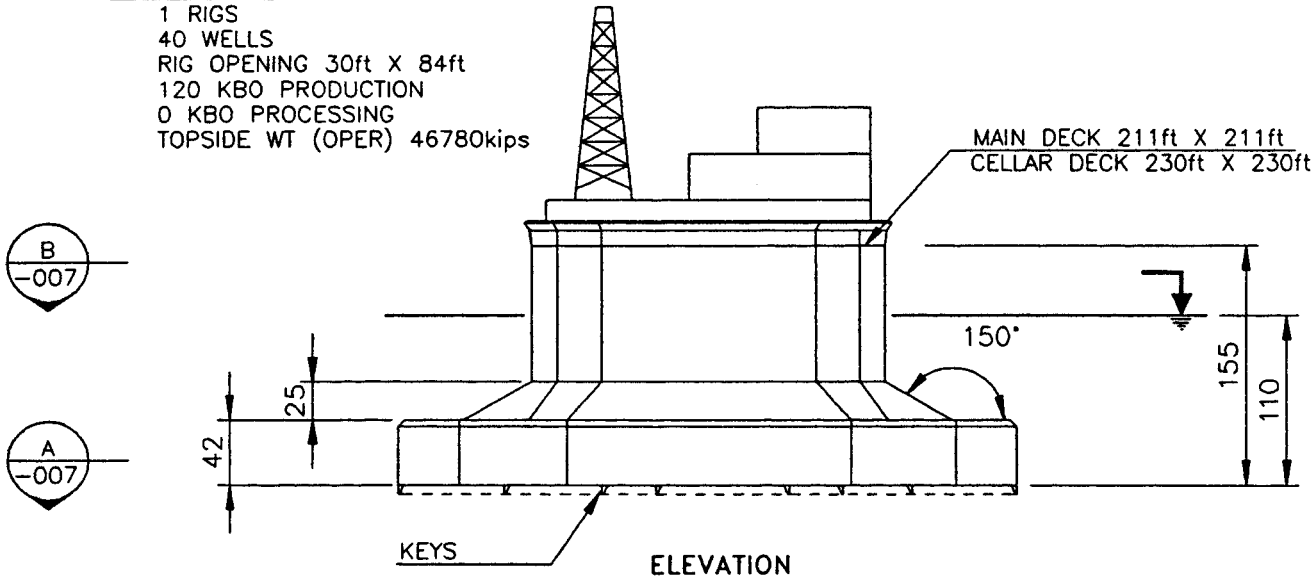
A smaller structure than the previous one was investigated to examine the feasibility of using a lower cost facility and a structure which could possibly more readily be built in existing world yards. Cases 3 and 4 from Table 4.2, both of them involving production only and no processing, were considered. The resulting structure is shown in Figure 4.3. Its hull is 230 ft. by 230 ft. and is vertical to the base where there is a sharp taper to the width of the base. The required base is 400 ft. by 400 ft. because of on-bottom stability



PLAN

WT. OF STEEL 114,000 kips

RIG AND PRODUCTION
1 RIGS
40 WELLS
RIG OPENING 30ft X 84ft
120 KBO PRODUCTION
0 KBO PROCESSING
TOPSIDE WT (OPER) 46780kips



ELEVATION

FIGURE 4.3

DWG No.	REFERENCE	REF. No.	REV.	BY / DATE	REVISION	APP'D

APPROVED	SCALE	1in = 125ft	YR.	MO.	DAY
DATE	DRAWN	BG	93	12	06
	CHECK				
A. 113147 C 006	DESIGN	SR	93	08	06
	DES. CHK.				

KUVLUM – 40 WELLS – 1 RIGS
400 ft. X 400 ft. BASE
230 ft. X 230 ft. STRUCTURE

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DWG. 113147 C 006 REV

SANDWELL CAD FILE NO. 3147C006

considerations. This base is larger relative to the hull dimension and results from the fact that the ice forces do not scale linearly since large ice features, driven by the pack, govern the ice forces. The ice wall internal framing and bulkheads and base plate of this structure are basically the same as the 350 ft. by 350 ft. structure and reference should be made to Section 4.3.1. The base cantilever is greater in this case and thus the bending stress will be higher, requiring a thickening of the baseplate and more stiffening at critical locations. Keys again are provided on the base to penetrate weaker surficial bottom soils and to facilitate undergrouting at set down. As for the larger structure, the local ice pressures specified in the 1991 JIP and in Masterson and Frederking (1993) were used to design the ice wall. Plate thicknesses are the same and typical dimensions and spacing are given in Figure 4.2.

The moonpool is offset from the centre, as it is for the larger structure, to accommodate ARCO's specified topside layout. The opening is 30 ft. by 84 ft. and will accommodate up to 70 wells. Further details of the structure are provided in the figures in Appendix B.

4.4.2 Floating Stability

Case 3 has a capacity for 70 wells, production and no processing. As tabulated in Table 4.2, the total operating deck load, including deck steel, for this Case is 80,654 kips. The total solid ballast required for on-bottom stability is 155,000 kips. With full operating load and full solid ballast in place, the GM becomes negative during setdown. If the deck load is reduced by 20,000 kips, a stable setdown would be achieved and the tow-out draft would be 39.5 ft at a GM of +331 ft. It can be seen that for the structure to be hydrostatically stable while maintaining a draft of under 40 ft, there can be a tradeoff between deck dry weight and solid ballast. The deck load can be increased, as long as this increase is offset by a reduction in the solid ballast. The optimum weight balance would be a matter for the detailed design stage and will require examination of relative cost implications of towing, shipment of consumables to site and placement of solid ballast at site. For the purposes of conceptual design, it is sufficient to recognize that making these decisions is required.

Similarly, for Case 4 (40 wells, production and no processing), the structure, with full hematite ballast in place and a full operation deck load of 46,780 kips, would have a draft of 39.5 ft and a GM of 344 ft.

Table 4.6 summarizes the towing characteristics of the 230 ft by 230 ft structures.

TABLE 4.6 TOWING CHARACTERISTICS OF 350 FT SQUARE STRUCTURE

Case	Solid Ballast During Tow (kips)	Deck Steel Weight (kips)	Deck Load (kips)	Towing Draft (ft)	Metacentric Height (ft)
3	155,000	5,290	61,654 (20,000 kips removes)	39.5	331
4	185,000	5,290	46,780 (Dry Wt.)	39.5	344

Note: 1. 1,000 kips was added to equipment weight for both cases because of deck overhang of 18 ft.

2. 20,000 kips was removed from Case 3 since the GM becomes negative during setdown with full operating load.

4.4.3 Design Ice Forces

A detailed description of the Gulf ice load model and the procedure for determining the ice loads for different probabilities of occurrence is given is Section 3. Based on the results of that analysis, the following ice loads were used to design this structure.

TABLE 4.7 DESIGN ICE FORCES FOR 230 FT. SQUARE STRUCTURE

Return Period (years)	Ice Force (kips)
100	202,000
1,000	270,000

As for the 350 ft by 350 ft structure, the 100 year return period ice load has been used in this study as a base design case for the satisfaction of allowable soil stresses and the determination of the required weight of ballast. The sensitivity of these parameters to the 1000 year return period ice force has also been demonstrated.

4.4.4 Structure On-Bottom Stability

Using the above ice forces, the on-bottom stability of the structure against sliding and uplift was determined. For uplift, the same design assumptions were made as in the larger structure and the procedure is as described in Section 4.3.4.

The results of the on-bottom stability analysis are shown in Table 4.8.

The base width of the structure has been chosen such that, for the 1 in 100 year force, the shear stress in the soil (column 4) is equal to the allowable stress of 1.33 ksf (2 ksf/1.5). At the 1 in 1,000 year force level, the shear stress in the soil is 1.29 times allowable or 1.72 ksf, which is still below the ultimate strength specified. For the 1 in 100 year force, the ratio of righting to uplift moment is 1.29 and, for the 1 in 1,000 year force, it is unity. The maximum bearing pressure in the soil (columns 10 and 11) is less than 1/2 the ultimate bearing capacity of 12 ksf and is thus within the stated limits of ARCO. Thus this structure is able to withstand the anticipated forces, including those associated with a low return period.

Because of the large amount (270,000 to 300,000 kips) of solid ballast required for stability against uplift, column 6 indicates that the effective weight on bottom is sufficient to ensure stability against sliding should the bottom soil be a friction only material with a ϕ angle of 30°. Thus the 230 ft. by 230 ft. square hull structure, while being at a disadvantage over the large 350 ft. by 350 ft. square hull structure during tow out because of draft and stability limitations, achieves a good balance between the various design components while on location.

TABLE 4.8 ON BOTTOM STABILITY - 230 FT. SQUARE HULL STRUCTURE

(1) Water Depth (ft)	(2) Ice Force Return Period (years)	(3) Ice Force (kips)	(4) Ratio Soil Shear Stress/ Allow.	(5) Requ'd Bottom Wt. to Resist Uplift (kips)	(6) Requ'd Bottom Wt. for Sliding (Gran. Material (kips)	(7) Ratio of Righting to Lifting Moment	(8) Wt. of Hematite Ballast (kips)	(9) Wt. on Bottom With Ballast (kips)	(10) Max. Bearing Pressure (ksf)	(11) Ratio of Bearing Strength to Pressure
110	100	202,000	1.00	342,522	349,847	1.29	280,000	440,876	5.17	2.3
110	1,000	270,000	1.27	445,500	467,654	1.00	280,000	443,851	5.56	2.2

Notes:

1. Soil bearing strength 12 ksf

4.5 Steel Quantities

To accurately obtain steel quantities by take off, a detailed design of the structures would be required, something not feasible within the cost and time constraints of a feasibility study. A convenient way of determining the weight of a structure in a study such as this is through the use of known ratios of steel weight to total enclosed volume. Sandwell keeps an extensive data base on steel weights and enclosed hull volumes for arctic and non arctic structures and ships. Surveys by naval architects have found that barges on the west coast have a steel density of 5 to 9 lb. per ft^3 of enclosed volume with a most typical value of 5.8 lb/ft^3. The same survey found that ships plying southern waters have a typical steel density of 5 lb/ft^3 of enclosed volume. Both the Molikpaq and the Esso CRI used catenary design taking advantage of the current thinking at the period. However, it was always anticipated in the designs that there was an inherent reserve in capacity due to the highly redundant nature of the structures. Recent research, the results of which The Molikpaq caisson, discounting the volume of the hollow core, has a steel density of 13 lb per ft^3 of enclosed volume. Esso's CRI caisson, also designed by Sandwell, had a steel density of 10 lb/ft^3. Recent research, the results of which are largely confidential, appears to confirm the increase in the inherent capacity of such highly redundant plated structures is greater than previously thought and this has a significant implication on the steel/volume ratio. Specifically, research is confirming that membrane action will develop for larger span to depth ratios than considered feasible before. This allows an increased spacing of stiffeners, somewhat increased sizes of support members, a reduction in welding and an overall reduction in cost. On this basis, it is considered appropriate for the Kuvlum structures to have a steel hull density of 8 to 10 lb per ft^3 of enclosed volume.

Surveys of vessels afloat have also shown that the steel density is not a constant but is a function of the enclosed volume, with the density decreasing as the volume increases. Thus 10 lb/ft^3 has been used for the 230 ft. square structure and 8 lb/ft^3 has been used for the 350 ft. square structure. The hull steel tonnages for the two structures are listed below.

350 ft. by 350 ft. structure	95,730 tons

230 ft. by 230 ft. structure	57,062 tons.

4.6 Construction Schedule

Based on experience with the Molikpaq and the CRI, it is estimated that three (3) years would be required for conceptual and detailed design through to construction for the smaller structure. An additional 1 to 1 1/2 years would be required for the larger hull. This assumes that construction occurs in an established yard with a good track record of bringing in projects on time and on budget. It also assumes that a consensus on the concept(s) is reached in a reasonable length of time and that a designer is chosen who has considerable experience with Arctic offshore structures, both from a design and construction perspective.

5.0 TOWING AND INSTALLATION

5.1 General Towing Requirements

A comprehensive package of general information on towing and installation was provided in the 1984 JIS. Much of this information was provided by Wijsmuller Engineering B.V. The basic information was repeated in the 1991 JIP for the sake of completeness.

5.1.1 Tow Routes and Environmental Conditions

The assumption is that the tow routes will be from Asia and the route length is about 3,600 miles to Kuvlum. The route leads over deep water from the point of departure to the Aleutians. Afterwards, both tows have to traverse water depths of approximately 20 fathoms or less.

From the cumulative probability of wave heights for the North Pacific Ocean, it has been previously concluded that the average wave resistance expected during the towing operation falls within the margin of accuracy of the drag calculations. This conclusion does not hold true for higher incidental seastates.

A seastate with a significant wave height of 12 feet has a probability of exceedance of approximately 5%. It is recommended that a requirement for not less than zero headway, with a head-on wind of 40 knots and 1 knot current, be implemented. This sets a lower limit for the bollard pull under tow. Such a requirement is meaningful from a safety point of view and also prevents the demoralizing effect of little or no headway for substantial periods of time.

ARCO's requirement for a maximum draft of 35 ft. is difficult to achieve with full internal ballast in the structure. However, it is possible to reduce the solid ballast during tow to achieve the desired draft while maintaining stability. For example, in Case 4, reducing the solid ballast to 150,000 kips for tow from the 185,000 kips required for on-bottom stability will yield a towing draft of 35 ft., as opposed to the 51 ft. draft for the

full ballast condition. The remaining 35,000 kips of solid ballast would then need to be placed into the structure on site. In Cases 1 to 3, the towing drafts with full internal ballast are shallower, ranging from 36 ft to 39 ft, and by reducing appropriate amounts of solid ballast, the towing drafts for these Cases can be reduced to 35 ft. With a 35 ft draft and allowing for 20 % under keel clearance, one can navigate at about the 7 fathom contour. A requirement to navigate along, or outside of, the 10 fathom curve to the Beaufort Sea will significantly increase the likelihood of encountering pack ice of higher concentrations and containing a greater percentage of large and very large (greater than 1500 ft) floes which must be considered when evaluating risk.

5.1.2 Bollard Pull

A simple way to judge the capability of a tug is by its certified bollard pull. In practically all cases, the certified bollard pull is established at the maximum continuous rating, M.C.R., of the main engines. In practice, however, tug owners tend to operate the main engines at approximately 80% of M.C.R., which means that the bollard pull will also be reduced to approximately 80% of certified bollard pull. This means that, in cases of emergency, there is a latent reserve of approximately 20%.

5.1.3 Tug Spread

Once the resistance of the tow at different speeds is known, a total bollard pull must be chosen in order to establish an average towing speed. At this stage it is only possible to make estimates as one can only speculate as to what tugs will be available when it comes to execution of the operation.

At present, it appears appropriate to assume that the tugs which carry out the tow will also carry out the positioning of the platform. Consequently, it may be more advantageous to use a greater number of smaller tugs rather than a few large ones. By using a spread of smaller tugs, the breakdown of one tug would also have less of an impact on the tow. With the same tugs towing and assisting during platform setdown, mobilization and

demobilization costs will be reduced.

To prevent trouble in case of a total breakdown of one of the vessels, a reasonable number of tugs must be used. On the other hand, the total number of vessels must not be too great to avoid difficulty with communications and command. In 1984, Wijsmuller considered that a minimum of 6 tugs and a maximum of 8 are reasonable figures for these type of structures, but this does not mean that 5 or 9 tugs are totally impractical. The towing configuration for 6 tugs could be as sketched in Figure 5.1. The boat in the rear, not connected to the tow, is a rescue/stand-by vessel which should be a tug of approximately 40 t bollard pull.

The somewhat unorthodox towing arrangement is chosen in consideration of coping with a total breakdown of one tug, and in an attempt to avoid disconnection at the end of the tow and reconnection before positioning of the platform.

One tug of 100 t bollard pull will consume approximately 40 t of fuel a day, which means that the bunkers of most tugs will not be sufficient to complete the round trip and refuelling will be required en route.

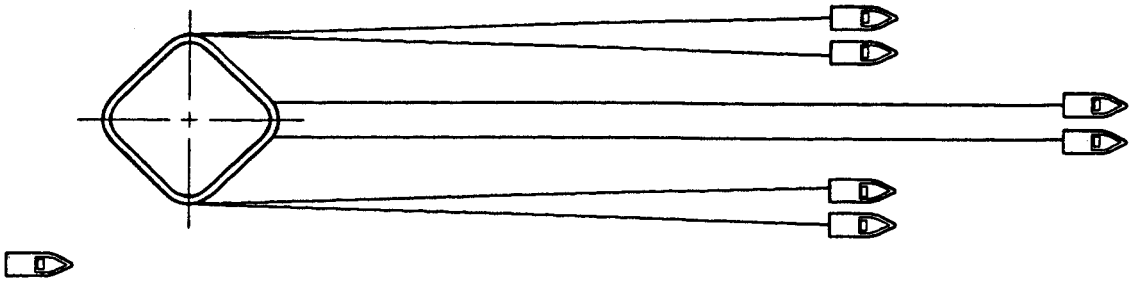
5.1.4 Refuelling

The location for refuelling depends upon many factors, but it is expected to be completed in the vicinity of the Aleutians or before. Some of the possibilities are:

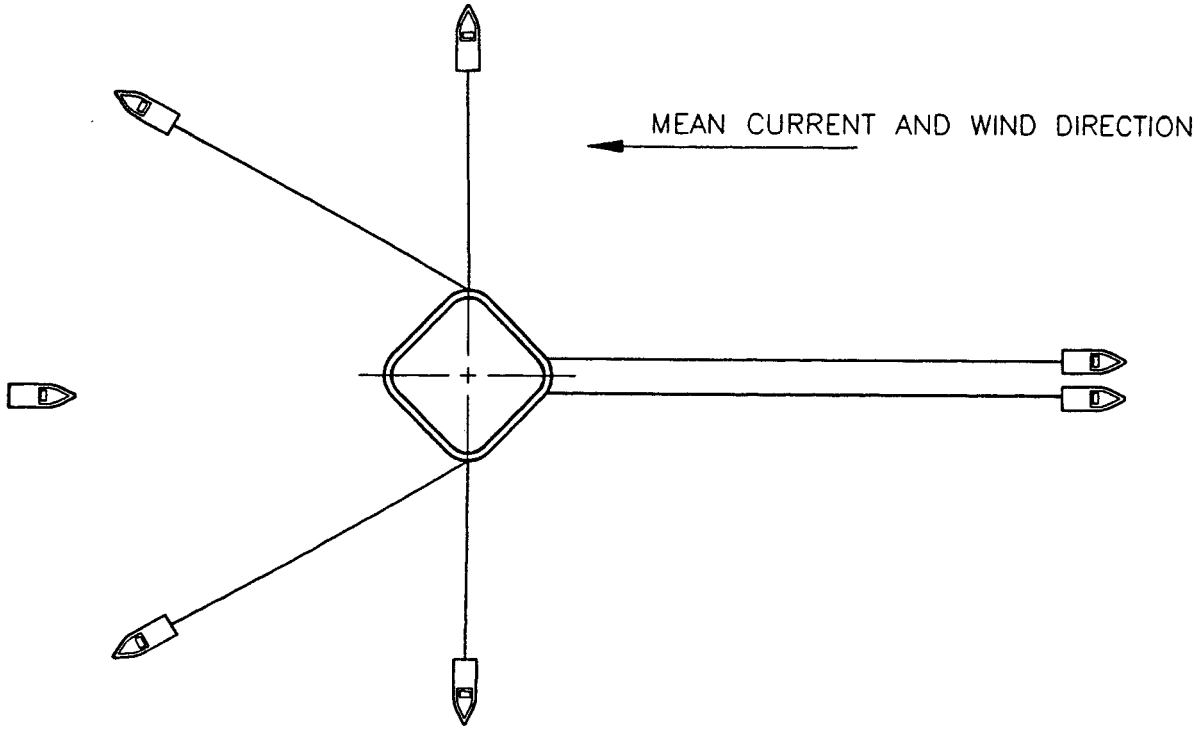
- To arrange for a fuel barge in the vicinity of the Aleutians
- To provide a fuel barge along with the tow
- To provide fuel onboard the platform
- To refuel at Dutch Harbour.

Reference may be made to the 1984 JIS study for a detailed discussion on these alternatives.

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CONFIGURATION DURING TOWING



CONFIGURATION DURING POSITIONING

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FIGURE 5.1 TOWING AND POSITIONING CONFIGURATIONS

5.2 Resistance Under Tow

5.2.1 General

In order to be able to predict the towing speed, it is necessary to estimate the towing resistance which in turn depends, amongst other things, upon the configuration of the tow.

Several of the variables which may influence the resistance are:

- Displacement and draft
- Heading
- Trim
- Form and appendages
- Waves.

Wave resistance is highly dependent on the regularity of the seastate and, for this study, an irregular seaway is assumed. In calculating the total resistance, unfavorable secondary conditions are considered, which are introduced into the resistance calculations as "calm water max".

Without tank tests, accurate resistance curves cannot be plotted. However, much can be inferred from previous work. For the shallow steel structures, experience from the Molikpaq, SSDC and other Beaufort Sea designs are relevant. The Molikpaq had a displacement of 44,000 tonnes during its trans-Pacific tow and a total of 48,000 BHP in connected tug capacity. During the design phase, tank tests were conducted in order to estimate the towing resistance curves. Checks with one or two day's results for bollard pull measurements during the tow indicated that these measurements correlated within approximately 15% of the Molikpaq tank tests.

A considerable volume of data has been published on the towing conditions for the concrete North Sea structures. These structures have towing displacements in the range of 200,000 - 800,000 tonnes, and drafts in the range of 25 - 125 m.

Resistance calculations were performed in detail in the 1984 JIS and repeated in the 1991 JIP. Table 7.2 of the 1991 JIP has been referred to for determining the required tow time for the tug configuration assumed in this study.

5.3 Installation Procedure

5.3.1 Positioning

There is now a wealth of experience worldwide in accurately setting down large structures. Steel jacket type structures and steel gravity structures such as the Maureen Platform have been accurately set over pre-drilled templates. The accuracy now being achieved in setting large concrete platforms is such that installation over pre-set templates is also being considered. This experience, together with the experience gained in the Beaufort Sea on the Molikpaq, SSDC and CIDS, gives confidence that the structures can be placed with the accuracy required. It is also believed that, if required, they could be set with great accuracy over a junction box already on the seabed for a pipeline connection or a line to an export terminal.

It is desirable to use the same number of tugs for towing and for positioning on location. A possible configuration for 6 tugs which can be achieved without disconnection is shown in Figure 5.1. It will be necessary to establish a weather window (2 to 4 days) for set down.

Also, for the positioning of the platform, a minimum requirement for bollard-pull must be set. Wijsmuller recommended that the lower limit for the bollard pull should be based on zero headway in 20 knots of wind and a 2 knot current. The number of tugs required is approximately half that required for the ocean tow, with a minimum of 4.

5.3.2 Set-down

The ballasting operations must be carefully controlled to prevent erosion of any soft

surficial material under the skirts which could occur with a rapid descent, to keep an even keel as the skirts penetrate the surface, and to control the contact between the surface and skirts or setdown pads. To take account of these issues, certain features may be incorporated in the design:

- Valve systems capable of controlling the rate of descent, so as to allow water underneath the caissons to escape without eroding the seabed material (the last metre of descent being completed in approximately one hour)
- A piping system to allow for the controlled differential ballasting between compartments and trimming as necessary to achieve a level set-down
- Set-down pads (thickened and strengthened areas in the base, 3 in total) in the base of the structure to provide a level support prior to base undergrouting
- Skirts to cater for unevenness in the seabed (regardless of whether required for reasons of stability).

The base undergrouting must be completed prior to the structure being fully ballasted. This is a potentially vulnerable time for the structure, as it cannot sustain large ice impacts or severe sea states during the grouting operation. Therefore, grouting and final ballasting must be achieved in the minimum possible time.

Based on previous experience, and discussions with offshore contractors on other work, the following procedure may be used to meet the above requirements.

- Install positioning tripod off seabed
- Tow platform over location
- Deploy restraining tugs
- In sea conditions no greater than H_s = 4 ft, accurately locate platform over final location (and junction box if any)
- Add ballast water slowly either by gravity feed or pumping
- Trim as necessary by differential ballasting between compartments
- Terminate ballasting and skirt penetration to achieve sufficient contact pressure for stability after touch-down

- Check perimeter of skirts, by divers, and secure any zones where piping might occur during grouting
- Place toe protection around periphery of structure
- Grout underbase
- Allow grout to cure (approximately 3 days
- Complete water ballasting of structure
- Sandfill designated compartments within the structures
- Complete erosion protection.

The equipment required for undergrouting will be in-built and similar to systems in North Sea gravity based structures.

6.0 STRUCTURE COSTING

6.1 Source of Costing

As for the 1991 JIP, the costs have been built up in such a manner that ARCO may include its own unit prices either to undertake cost sensitivity or to revise the figures at a later date. Recent steel fabrication costs have been obtained from IHI of Japan and from Hyundai of Korea, both of these fabricators having readily supplied costs per tonne of fabricated steel. Also, both fabricators have indicated that the total tonnage of steel is not a problem for their yards, and in fact Hyundai has quoted a slightly lower price per tonne for the larger structure. The fabricators have indicated, though, that the size of the bases of both structures exceeds the width of their yards. Hyundai has a capability at present to accept structures and vessels up to 90 m (295 ft.) wide. Hyundai are planning to build a larger dock in the future and this would be available for the construction of a Kuvlum structure.

It is interesting to note that IHI quoted a fabricated cost per tonne of ¥ 500,000. At current exchange rates, this represents a cost of U.S. $4,600 per tonne. However, the Yen has been appreciating in value against the dollar and it has become difficult to evaluate Japanese ship construction in any currency except Yen. Sandwell has determined that VLCC oil carriers with about 43,000 t of hull steel have been built in Japan for about $2,000/t. Hyundai quoted a price of U.S. $3,550 per tonne for the 350 ft. by 350 ft. structure and U.S. $3,700 per tonne for the 230 ft. by 230 ft. structure. Thus there is a 4 % discount for the structure with the larger amount of steel.

As a point of reference, the Molikpaq was constructed in the early 1980's and the hull cost was $2,800/t and the deck cost was $3,400/t. IHI thought that, after having accumulated the experience of constructing the Molikpaq, that subsequent structures would be less expensive. Making the assumption that the potential cost reduction for the Molikpaq would be offset by inflation, it appears that the costs per tonne which have been quoted are likely conservative. This is also the indication from prices received over the years for other structures.

Towing and placing costs have been taken from the 1991 JIP with adjustments made based on recent work on other offshore projects.

6.2 Cost Estimate

The cost estimates for the 350 ft. by 350 ft. and the 230 ft. by 230 ft. structures are given in Table 6.1 below. If the construction cost items 1,2 and 3 for the 230 ft. by 230 ft. structure are totalled, the sum is $214,000,000 for a structure containing 57,000 t of steel. The cost of the Molikpaq was $96,000,000 for the same items and it contained 24,500 t of steel. If one multiplies the cost of the Molikpaq by the ratio of steel tonnages (57/24.5 x $96,000,000), then the cost of the 230 by 230 ft. structure is $223,000,000, a calculation lending some comfort to the figures listed in Table 6.1

TABLE 6.1 SUMMARY OF STRUCTURE COSTS

	ITEM		COST (U.S. $ x 1000)	
			350 FT. SQ. STRUCTURE	230 FT. SQ. STRUCTURE
1.	Hull Fabrication	*	$322,092	$191,935
2.	Structure Outfitting			
	Ballast System		$6,000	$4,000
	H & V		$2,500	$1,500
	Installation		$2,000	$1,000
	Service Water		$1,000	$1,000
	Fuel System		$1,000	$ 800
	Drainage		$1,000	$ 800
	Grouting System		$3,900	$2,200
	Total	*	$17,400	$11,300
3.	Move to Completion Site			
	Tow Cranes		$2,000	$2,000
	Testing & Commissioning		$2,200	$2,000
	Tow Preparation		$2,000	$1,800
	Total	*	$6,200	$5,800
4.	Towing & Installation			
	Tugs - 100 ton bollard pull		$11,145	$8,580
	Tugs - 40 ton bollard pull		$540	$405
	Total	*	$11,685	$8,985
5.	On Site Support			
	Tugs		$2,500	$2,500
	Support Vessels		$7,200	$7,200
	Icebreaker		$4,800	$4,800
	Diving		$2,500	$2,500
	Air Transport		$10,000	$10,000
	Total	*	$27,000	$27,000
6.	Cathodic Protection	*	$10,000	$6,500
7.	Hematite Ballast	*	$2,500	$7,000
8.	Foundation Preparation	*	$1,000	$1,000
9.	Undergrouting	*	$3,813	$3,160
10.	Toe Protection	*	$6,000	$4,000
11.	Miscellaneous			
	Site Investigation		$2,000	$2,000
	Engineering		$20,385	$13,334
	Project Management		$52,999	$34,668
	Verification		$3,000	$3,000
	Insurance		$2,500	$2,000
	Total	*	$80,884	$55,002
Grand Total			$488,574	$321,682

Details of some of the costs are given below.

1) TUG COSTS

Rates 100 t bollard pull tug	$ 28,000/day - in use (incl fuel)	
	$ 17,000/day - standby	
	$780,000 - mob/demob	
40 t bollard pull tug	$ 9,000/day - in use (incl. fuel)	

350 Ft. Square Structure

60 days tow time (Table 7.2 of 1991 JIP)

100 t Tugs			
Towing	6 x $28,500 x 60	=	$10,260,000
Positioning	6 x $28,500 x 1	=	$ 171,000
Standby	6 x $17,000 x 7	=	$ 714,000
Total			**$11,145,000**
40 t Tugs	1 x $9,000 x 60	=	$ 540,000
Grand Total Tugs			**$11,685,000**

230 ft. Square Structure

45 days tow time (Table 7.2 of 1991 JIP)

100 t Tugs			
Towing	6 x $28,500 x 45	=	$ 7,695,000
Positioning	6 x $28,500 x 1	=	$ 171,000
Standby	6 x $17,000 x 7	=	$ 714,000
Total			**$ 8,580,000**
40 t Tugs	1 x $9,000 x 60	=	$ 405,000
Grand Total Tugs			**$ 8,985,000**

2) UNDERGROUTING

$2,000,000 + base area x 2.5 ft. x $2.90/ft^3

3) HEMATITE BALLAST

Unit cost = $50/ton

6.3 Cost Confidence Limits

6.3.1 Introduction

As part of the conceptual design of structures for ARCO at their Kuvlum site, Sandwell was requested to cost the structures and to provide upper and lower confidence limits for these costs. Specifically, costs at the 10 percent and 90 percent level of confidence were to be provided, along with the most likely cost which would be the estimated cost. In order to perform this task, two tools were required. One was a data base of costs derived from past experience with structures and the other was a probabilistic analytical method. Sandwell has derived the necessary cost information from its own experience with offshore Arctic structures, from contact with suppliers and fabricators and from the literature. The statistical analytical tool and its use are described below.

6.3.2 Distribution Function

Choosing a proper distribution function is important if realistic and reliable estimates of the confidence limits are to be obtained. Initially it was thought that a normal (symmetrical), Gaussian distribution would be sufficient. However, Gaussian distribution assumes that the probability density function is symmetrical and that the cost differential at any corresponding level of confidence below or above the mean cost is the same. Thus the mean cost minus the 10% confidence level cost would have the same absolute value as the mean minus the 90% confidence level cost. The 10% confidence level is that cost above which the cost falls 90 times out of 100 and the 90 % confidence level is that cost below which the cost falls 90 times out of 100. In a normal distribution, the mean cost is the most frequent cost and is the cost which is exceeded 50 times out of a hundred and, conversely, is not reached 50 times out of a hundred.

Experience with projects has shown that the costs, especially those estimated at preconceptual and conceptual engineering stages, are more likely to overrun than they are to underrun during the subsequent project execution. Statistically this means that the distribution is "skewed" and the mean, or average value, and the mode, the most frequent

value, are not the same. The probability density function for a skew distribution is shown in Figure 6.1. This density function is for a log normal distribution, a distribution commonly used to statistically model data which are not uniform by distribution. The equation for log normal distribution is as follows.

$$P(\ln(x)) = \frac{1}{\sqrt{2\pi \ln\left(1 + \frac{s^2}{m^2}\right)}} \exp - \frac{\left(\ln(x) - \ln\left(\frac{m}{\sqrt{1 + \frac{s^2}{m^2}}}\right)\right)}{2\ln\left(1 + \frac{s^2}{m^2}\right)}$$

where:

s = standard deviation of the variable x

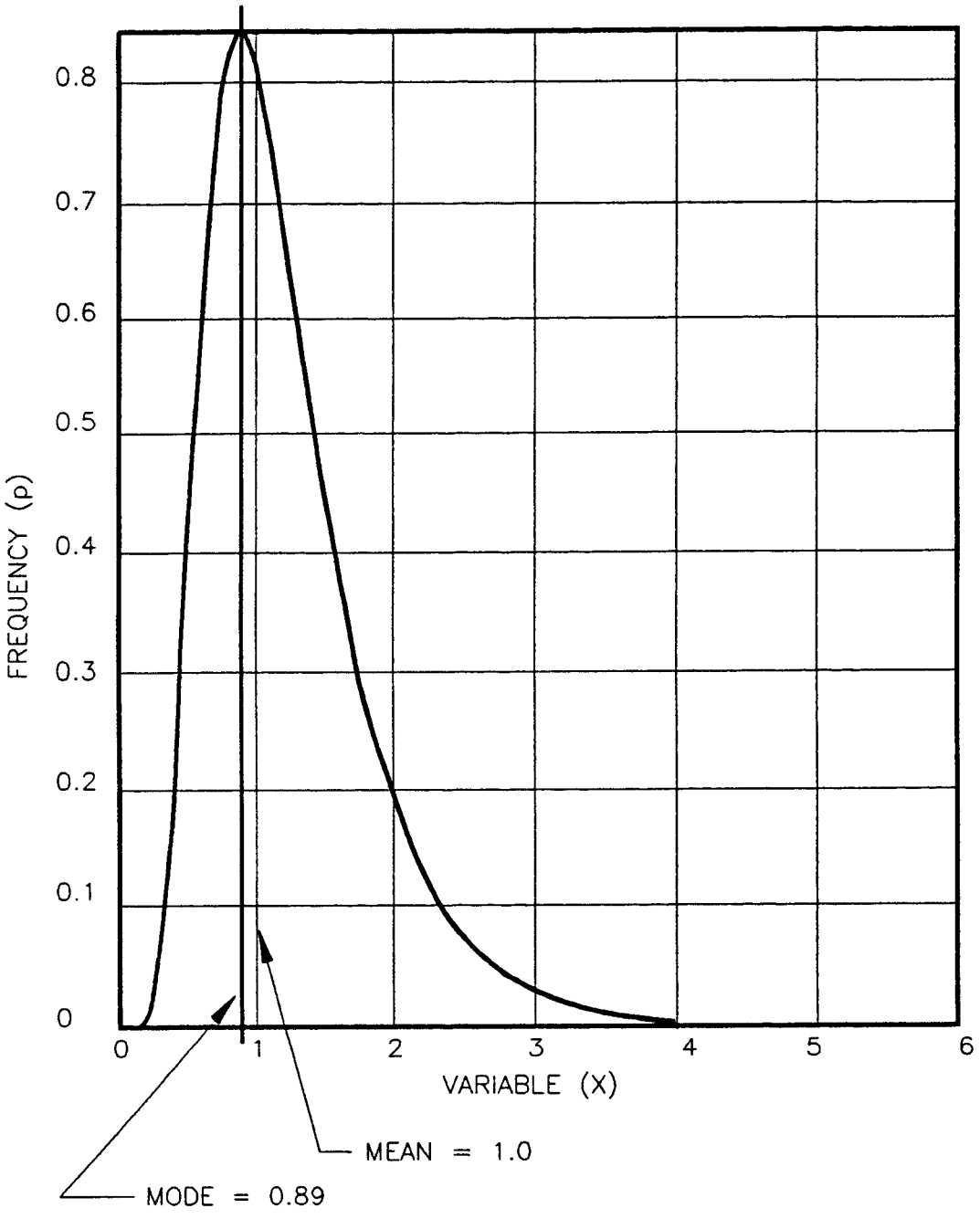
m = mean of the variable x

The mode, or most frequent value, is given by:

$$mode = \frac{m}{\sqrt{1 + \frac{s^2}{m^2}}}$$

Figure 6.1 has been plotted for illustrative purposes. The arithmetic mean was taken as x = 1 and the standard deviation was taken as 0.5. Using the above formula the mode was calculated to be 0.894. As the standard deviation becomes larger, then the difference between the mode and the mean becomes larger. For a standard deviation which is a small percentage of the mean, the mode and mean become very close and the distribution tends to normal or symmetrical.

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FIGURE 6.1 EXAMPLE SKEW (LOG NORMAL) PROBABILITY DISTRIBUTION

6.3.3 The Beta Distribution

An approach more readily applied to cost analysis is given in standard texts such as "Advanced Engineering Economics" by Chan S. Park and Gunter P. Sharp-Bette, John Wiley, 1990. The text outlines a method suggested by Hillier and which is commonly used in risk analysis, the suggested method being to take an "optimistic", a "pessimistic" and a "most likely" estimate. These three estimates determine an upper bound, a lower bound and the mode. From these, a mean and a standard deviation are estimated from approximate expressions and a Beta function is then used to describe the distribution. The method is particularly applicable to selecting a distribution in the absence of data. Thus, if:

H	=	pessimistic estimate
L	=	optimistic estimate
M	=	most likely estimate (mode)
m	=	mean = (H + 4M + L)/6
s	=	standard deviation = (H - L)/6

Then:

$$p(x) = \frac{\Gamma(a + b + 2)}{\Gamma(a + 1)\Gamma(b + 1)} x^a (1 - x)^b, \quad 0 \le x \le 1$$

or

$$p(x) = cx^a (1 - x)^b$$

Γ is Euler's gamma function. In addition:

$$a = \frac{(m - L)^2 \left(\frac{H - m}{H - L}\right)}{s^2} - \frac{m - L}{H - L} - 1$$

$$b = \frac{\frac{m - L}{H - L}(H - m)^2}{s^2} + \frac{m - L}{H - L} - 2$$

a and b are shape parameters. The distribution has the advantage of being closed or bounded, unlike the log normal distribution but can be similarly skewed and can be "shaped", unlike the simple triangular distribution. These equations were used in Mathcad, along with estimates of the optimistic, pessimistic, most likely and mean costs of a structure to obtain the 10 and 90 percent confidence limits.

The parameters chosen, along with the results of the calculations are shown in Table 6.2 below.

TABLE 6.2 COST CONFIDENCE LEVELS USING BETA DISTRIBUTION

ITEM	LOWEST	HIGHEST	MOST LIKELY EST.	m = Mean	10 % CONFID. LEVEL COST	90 % CONFID. LEVEL COST	10 % - EST.	90 % - EST.
Structure	$270 MM	$600 MM	$300 MM	$345 MM	$283 MM	$423 MM	$17 MM	$123 MM

An upper bound of two (2) times the estimated cost has been used, resulting in an assumption in the worst reasonable case, the cost can never more than double. A parametric analysis has shown that the 90 % confidence level cost is not highly sensitive to the upper bound cost assumed. The principal conclusion is that a broad range of factors could cause a 42% cost overrun at the 10% confidence level.

6.3.4 Application To Kuvlum Structures

The detailed costs presented in Table 6.1 were analyzed using the Beta distribution method to determine the 10 percent and 90 percent confidence limits. ARCO has used the costs of Table 6.1 to determine the confidence limits by applying their usual procedures. These confidence limits are presented to illustrate a method of applying the technique.

Table 6.3 contains the cost breakouts from Table 6.1 which are considered to be the best

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TABLE 6.3 COST VARIANCES - 350 FT. BY 350 FT. STRUCTURE

ITEM	PESSIMISTIC COST	OPTIMISTIC COST	BEST ESTIMATE (MODE)
1. Hull Fabrication	$370,405,800	$305,987,400	$322,092,000
2. Structure Outfitting	$52,200,000	$16,530,000	$17,400,000
3. Move to Completion Site	$9,300,000	$5,890,000	$6,200,000
4. Towing & Installation	$29,212,500	$10,516,500	$11,685,000
5. On Site Support	$81,000,000	$24,300,000	$27,000,000
6. Cathodic Protection	$15,000,000	$9,000,000	$10,000,000
7. Hematite Ballast	$3,125,000	$2,375,000	$2,500,000
8. Foundation Preparation	$3,000,000	$950,000	$1,000,000
9. Undergrouting	$7,626,000	$3,622,350	$3,813,000
10. Toe Protection	$18,000,000	$5,700,000	$6,000,000
11. Miscellaneous	$119,496,474	$76,776,825	$80,884,200
TOTALS	$708,365,774	$461,648,075	$488,574,200

COST VARIANCES - 230 FT. BY 230 FT. STRUCTURE

ITEM	PESSIMISTIC COST	OPTIMISTIC COST	BEST ESTIMATE (MODE)
1. Hull Fabrication	$220,725,250	$182,338,250	$191,935,000
2. Structure Outfitting	$33,900,000	$10,735,000	$11,300,000
3. Move to Completion Site	$8,700,000	$5,510,000	$5,800,000
4. Towing & Installation	$22,462,500	$8,086,500	$8,985,000
5. On Site Support	$81,000,000	$24,300,000	$27,000,000
6. Cathodic Protection	$9,750,000	$5,850,000	$6,500,000
7. Hematite Ballast	$8,750,000	$6,650,000	$7,000,000
8. Foundation Preparation	$3,000,000	$950,000	$1,000,000
9. Undergrouting	$6,320,000	$3,002,000	$3,160,000
10. Toe Protection	$12,000,000	$3,800,000	$4,000,000
11. Miscellaneous	$86,189,395	$52,219,915	$55,002,400
TOTALS	$492,797,145	$303,441,665	$321,682,400

estimates or, statistically, the mode. The most reasonable pessimistic and optimistic costs have also been listed. The distributions have been assumed to be positively skewed, reflecting the higher probability of cost overrun than underrun.

Obviously, the hull is the most significant cost, being about 60 percent of the total of the mode or best estimate. It is also recognized from experience that, especially in established yards with a good track record of bringing in projects on time and on budget, this is one of the more controllable costs. Thus, as a percentage, lower variances between the upper and lower bounds and the best estimate have been used than for some of the other costs. Experience indicates that structure outfitting costs are much more likely to overrun. If ice or weather conditions are unfavorable, towing and on-site work could easily double. Unexpected bottom conditions could increase the cost of set down and of undergrouting. Thus much higher upside variances have been applied to these costs.

To obtain the upper and lower bounds for the Beta analysis, the sum of all the pessimistic and optimistic costs has been taken. It is recognized that this it is not likely that either of these would occur on one project, as some items may come in on budget while others overrun. The probability of all of the items reaching the most pessimistic cost on one project is 1 in 2^{11} or in 2,048, if the costs were independent and random. However, several of the weather and ice affected activities would all be affected and thus, for establishing the upper and lower bounds, the sums of these costs is not an unreasonable number. ARCO has used a Monte Carlo method to obtain the total pessimistic and optimistic costs which is a more rigorous and correct approach.

With the summary modes pessimistic and optimistic costs from Table 6.3, it is possible to determine the confidence limits. This was done using Mathcad and the results are listed below in Table 6.4 for the two structures.

TABLE 6.4 COST CONFIDENCE LIMITS FOR KUVLUM STRUCTURES

STRUCTURE - INSTALLED	BEST ESTIMATE COST (MM $)	10 % CONFIDENCE LIMIT (MM $)	90 % CONFIDENCE LIMIT (MM $)
350 ft by 350 ft	489	474	580
230 ft by 230 ft	322	311	393

For the 350 ft. by 350 ft. structure, the 90 percent confidence limit cost is 18.6 percent higher than the best estimate and the 10 percent confidence limit cost is 3.1 percent lower than the best estimate. For the 230 ft. by 230 ft. structure, the 90 percent confidence limit cost is 22.0 percent higher than the best estimate and the 10 percent confidence limit cost is 3.4 percent lower than the best estimate. Thus, for both structures, the costs are much more likely to increase than to underrun. As pointed out previously, these figures are likely conservative but they do look reasonable.

7.0 REFERENCES

REFERENCES

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8.0 APPENDICES

APPENDIX A

Floating Stability Calculations Mathcad Printout

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CALCULATE THE FLOATING STABILITY OF SQUARE STRUCTURES
file FLTCASE1.MCD 350ft structure - 500ft base - 2 rigs - 60 wells
150 KBO production

Define the parameters 150 KBO processing

Width and height of the base - base is square

$H_b := 42 \cdot ft$

$kips \equiv 1000 \cdot lb$

$W_b := 500 \cdot ft$

Height of the structure from bottom of base to bottom of deck and height to C.G. of deck

$H_s := 155 \cdot ft$ $H_s = 155 \cdot ft$

Height of hull from top of base to bottom of deck

$H_h := H_s - H_b$

$H_d := H_s + 30 \cdot ft$

$i := 0..3$ $H_d = 185 \cdot ft$

Width and Length of the structure - structure above base is square

$W_s := 350 \cdot ft$ $W_s = 350 \cdot ft$

$r_b := 120 \cdot ft$ $r_s := 40 \cdot ft$

$corn_b := r_b^2 \cdot (4 - \pi)$ $corn_s := r_s^2 \cdot (4 - \pi)$

$A_b := W_b^2 - corn_b$ $A_s := W_s^2 - corn_s$

Calculate the deck loads
I ADDED 2000 KIPPS TO WEIGHT OF EQUIP AS DECK OVERHANGS 23ft

$W_{steel} := 0.05 \cdot \frac{kips}{ft^2} \cdot W_s^2 \cdot 3$

$W_{steel} = 1.838 \cdot 10^4 \cdot kips$

$W_{equip} := \begin{bmatrix} 2000 \\ 50967 \\ 112277 \\ 112277 \end{bmatrix} \cdot kips$

no modules
dry wt.
including deck steel
= 50000kips
20000kips not
installed

$W_{d_i} := W_{steel} + W_{equip_i}$

$W_d = \begin{bmatrix} 2.038 \cdot 10^4 \\ 6.934 \cdot 10^4 \\ 1.307 \cdot 10^5 \\ 1.307 \cdot 10^5 \end{bmatrix} \cdot kips$

Draft of the structure

$j := 0..2$

$$Draft := \begin{pmatrix} 25 \\ 30 \\ 41 \end{pmatrix} \cdot ft \qquad Draft = \begin{pmatrix} 25 \\ 30 \\ 41 \end{pmatrix} \cdot ft$$

DIAMETER OF HOLE

$d := 74 \cdot ft$ (equivalent dia)

Define unit weights for water and steel

$$\gamma_w := .064 \cdot \frac{kips}{ft^3} \qquad \gamma_s := 10 \cdot \frac{lb}{ft^3}$$

Weight of hematite ballast in base

$W_{bal} := 240000 \cdot kips$

Calculate the water ballast height

$$c1_{i,j} := \left[\left(Draft_j \right) \cdot A_b - \frac{\pi}{4} \cdot d^2 \cdot Draft_j \right] \cdot \gamma_w \ldots + -\gamma_s \cdot H_b \cdot \left(A_b - \frac{\pi}{4} \cdot d^2 \right) - \gamma_s \cdot H_h \cdot \left(A_s - \frac{\pi}{4} \cdot d^2 \right) - W_{d_i} \ldots + -W_{bal}$$

$$c2_{i,j} := \gamma_w \cdot \left(A_b - \frac{\pi}{4} \cdot d^2 \right)$$

$$c1 = \begin{bmatrix} -1.17 \cdot 10^8 & -4.238 \cdot 10^7 & 1.219 \cdot 10^8 \\ -1.66 \cdot 10^8 & -9.135 \cdot 10^7 & 7.292 \cdot 10^7 \\ -2.273 \cdot 10^8 & -1.527 \cdot 10^8 & 1.161 \cdot 10^7 \\ -2.273 \cdot 10^8 & -1.527 \cdot 10^8 & 1.161 \cdot 10^7 \end{bmatrix} \cdot lb$$

$$H_{wb_{i,j}} := \frac{c1_{i,j}}{c2_{i,j}}$$

$Draft^T = (25 \quad 30 \quad 41) \cdot ft$

$$H_{wb} = \begin{bmatrix} -7.838 & -2.838 & 8.162 \\ -11.117 & -6.117 & 4.883 \\ -15.222 & -10.222 & 0.778 \\ -15.222 & -10.222 & 0.778 \end{bmatrix} \cdot ft$$

Calculate the ht. of centre of buoyancy KB

$$KB_{i,j} := \frac{Draft_j}{2} \qquad KB = \begin{bmatrix} 12.5 & 15 & 20.5 \\ 12.5 & 15 & 20.5 \\ 12.5 & 15 & 20.5 \\ 12.5 & 15 & 20.5 \end{bmatrix} \cdot ft$$

Calculate the ht. of the centre of gravity, K.G.

$$c5_{i,j} := H_b^2 \cdot A_b \cdot \frac{\gamma_s}{2} + A_s \cdot H_s \cdot \gamma_s \cdot \left(H_b + \frac{H_s}{2}\right) + W_{d_i} \cdot H_d \cdots$$
$$+ \left(H_{wb_{i,j}}\right)^2 \cdot A_b \cdot \frac{\gamma_w}{2} - \frac{\pi}{8} \cdot d^2 \cdot H_b^2 \cdot \gamma_s \cdots$$
$$+ \frac{-\pi}{4} \cdot d^2 \cdot \gamma_s \cdot H_s \cdot \left(H_b + \frac{H_s}{2}\right) - \frac{\pi}{8} \cdot d^2 \cdot \gamma_w \cdot \left(H_{wb_{i,j}}\right)^2$$

$$c6_{i,j} := H_b \cdot A_b \cdot \gamma_s + A_s \cdot \gamma_s \cdot H_s + W_{d_i} + W_{bal} \cdots$$
$$+ H_{wb_{i,j}} \cdot A_b \cdot \gamma_w - \frac{\pi}{4} \cdot d^2 \cdot \gamma_s \cdot \left(H_s + H_b\right) - \frac{\pi}{4} \cdot d^2 \cdot \gamma_w \cdot H_{wb_{i,j}}$$

$$KG_{i,j} := \frac{c5_{i,j}}{c6_{i,j}} \qquad KG = \begin{bmatrix} 66.11 & 55.377 & 42.283 \\ 88.654 & 74.042 & 55.498 \\ 117.417 & 97.868 & 72.386 \\ 117.417 & 97.868 & 72.386 \end{bmatrix} \cdot ft$$

Calculate the distance from the centre of buoyancy to the metacentre, BM

$$BM_{i,j} := \frac{\frac{1}{12} \cdot \left(W_b^4 - d^4\right)}{Draft_j \cdot A_b - \frac{\pi}{4} \cdot d^2 \cdot Draft_j}$$

$$BM = \begin{bmatrix} 892.411 & 743.675 & 544.153 \\ 892.411 & 743.675 & 544.153 \\ 892.411 & 743.675 & 544.153 \\ 892.411 & 743.675 & 544.153 \end{bmatrix} \cdot ft$$

Sandwell

Calculate the metacentric ht., GM, which must be positive for floating stability

$$GM_{i,j} := KB_{i,j} + BM_{i,j} - KG_{i,j}$$

$$Draft^{T} = (\,25 \quad 30 \quad 41\,)\cdot ft$$

$$GM = \begin{bmatrix} 838.801 & 703.298 & 522.369 \\ 816.257 & 684.633 & 509.155 \\ 787.493 & 660.807 & 492.267 \\ 787.493 & 660.807 & 492.267 \end{bmatrix} \cdot ft$$

Sandwell

CALCULATE THE FLOATING STABILITY OF SQUARE STRUCTURES

file FLTCASE2.MCD 350ft structure - 500ft base - 100 wells 2 rigs

300 KBO production

Define the parameters

450 KBO processing

Width and height of the base - base is square

$H_b := 42 \cdot ft$

$kips \equiv 1000 \cdot lb$

$W_b := 500 \cdot ft$

Height of the structure from bottom of base to bottom of deck and height to C.G. of deck

$H_s := 155 \cdot ft$ $H_s = 155 \cdot ft$

Height of hull from top of base to bottom of deck

$H_h := H_s - H_b$

$H_d := H_s + 30 \cdot ft$

$i := 0..3$ $H_d = 185 \cdot ft$

Width and Length of the structure - structure above base is square

$W_s := 350 \cdot ft$ $W_s = 350 \cdot ft$

$r_b := 120 \cdot ft$ $r_s := 40 \cdot ft$

$corn_b := r_b^2 \cdot (4 - \pi)$ $corn_s := r_s^2 \cdot (4 - \pi)$

$A_b := W_b^2 - corn_b$ $A_s := W_s^2 - corn_s$

Calculate the deck loads

I ADDED 5000 KIPPS TO WEIGHT OF EQUIP AS DECK OVERHANGS 22.5ft ON 3 LAYERS

$W_{steel} := 0.05 \cdot \frac{kips}{ft^2} \cdot W_s^2 \cdot 3$

$W_{steel} = 1.838 \cdot 10^4 \cdot kips$

$W_{equip} := \begin{bmatrix} 5000 \\ 95186 \\ 160180 \\ 160180 \end{bmatrix} \cdot kips$

no modules

dry wt.

total wt of production equip and drilling equip

$W_{d_i} := W_{steel} + W_{equip_i}$

Draft of the structure

$j := 0..2$

$$Draft := \begin{pmatrix} 25 \\ 35 \\ 41 \end{pmatrix} \cdot ft \qquad Draft = \begin{pmatrix} 25 \\ 35 \\ 41 \end{pmatrix} \cdot ft$$

$$W_d = \begin{bmatrix} 2.338 \cdot 10^4 \\ 1.136 \cdot 10^5 \\ 1.786 \cdot 10^5 \\ 1.786 \cdot 10^5 \end{bmatrix} \cdot kips$$

Diameter of hole

$d := 74 \cdot ft$ (equivalent hole dia)

Define unit weights for water and steel

$$\gamma_w := .064 \cdot \frac{kips}{ft^3} \qquad \gamma_s := 10 \cdot \frac{lb}{ft^3}$$

Weight of hematite ballast in base

$W_{bal} := 190000 \cdot kips$

Calculate the water ballast height

$$c1_{i,j} := \left[\left(Draft_j \right) \cdot A_b - \frac{\pi}{4} \cdot d^2 \cdot Draft_j \right] \cdot \gamma_w \ldots + -\gamma_s \cdot H_b \cdot \left(A_b - \frac{\pi}{4} \cdot d^2 \right) - \gamma_s \cdot H_h \cdot \left(A_s - \frac{\pi}{4} \cdot d^2 \right) - W_{d_i} \ldots + -W_{bal}$$

$$c2_{i,j} := \gamma_w \cdot \left(A_b - \frac{\pi}{4} \cdot d^2 \right)$$

$$c1 = \begin{bmatrix} -7.005 \cdot 10^4 & 7.929 \cdot 10^4 & 1.689 \cdot 10^5 \\ -1.602 \cdot 10^5 & -1.09 \cdot 10^4 & 7.87 \cdot 10^4 \\ -2.252 \cdot 10^5 & -7.589 \cdot 10^4 & 1.371 \cdot 10^4 \\ -2.252 \cdot 10^5 & -7.589 \cdot 10^4 & 1.371 \cdot 10^4 \end{bmatrix} \cdot kips$$

$$H_{wb_{i,j}} := \frac{c1_{i,j}}{c2_{i,j}}$$

$Draft^T = (25 \quad 35 \quad 41) \cdot ft$

$$H_{wb} = \begin{bmatrix} -4.691 & 5.309 & 11.309 \\ -10.73 & -0.73 & 5.27 \\ -15.082 & -5.082 & 0.918 \\ -15.082 & -5.082 & 0.918 \end{bmatrix} \cdot ft$$

Calculate the ht. of centre of buoyancy KB

$$KB_{i,j} := \frac{Draft_j}{2}$$

$$KB = \begin{bmatrix} 12.5 & 17.5 & 20.5 \\ 12.5 & 17.5 & 20.5 \\ 12.5 & 17.5 & 20.5 \\ 12.5 & 17.5 & 20.5 \end{bmatrix} \cdot ft$$

Calculate the ht. of the centre of gravity, K.G.

$$c5_{i,j} := H_b^2 \cdot A_b \cdot \frac{\gamma_s}{2} + A_s \cdot H_s \cdot \gamma_s \cdot \left(H_b + \frac{H_s}{2}\right) + W_{d_i} \cdot H_d \cdots$$
$$+ \left(H_{wb_{i,j}}\right)^2 \cdot A_b \cdot \frac{\gamma_w}{2} - \frac{\pi}{8} \cdot d^2 \cdot H_b^2 \cdot \gamma_s \cdots$$
$$+ \frac{-\pi}{4} \cdot d^2 \cdot \gamma_s \cdot H_s \cdot \left(H_b + \frac{H_s}{2}\right) - \frac{\pi}{8} \cdot d^2 \cdot \gamma_w \cdot \left(H_{wb_{i,j}}\right)^2$$

$$c6_{i,j} := H_b \cdot A_b \cdot \gamma_s + A_s \cdot \gamma_s \cdot H_s + W_{d_i} + W_{bal} \cdots$$
$$+ H_{wb_{i,j}} \cdot A_b \cdot \gamma_w - \frac{\pi}{4} \cdot d^2 \cdot \gamma_s \cdot \left(H_s + H_b\right) - \frac{\pi}{4} \cdot d^2 \cdot \gamma_w \cdot H_{wb_{i,j}}$$

$$KG_{i,j} := \frac{c5_{i,j}}{c6_{i,j}} \qquad KG = \begin{bmatrix} 66.726 & 49.379 & 43.814 \\ 107.871 & 78.199 & 67.912 \\ 138.322 & 99.56 & 85.789 \\ 138.322 & 99.56 & 85.789 \end{bmatrix} \cdot ft$$

Calculate the distance from the centre of buoyancy to the metacentre, BM

$$BM_{i,j} := \frac{\frac{1}{12} \cdot \left(W_b^4 - d^4\right)}{Draft_j \cdot A_b - \frac{\pi}{4} \cdot d^2 \cdot Draft_j}$$

$$BM = \begin{bmatrix} 892.411 & 637.436 & 544.153 \\ 892.411 & 637.436 & 544.153 \\ 892.411 & 637.436 & 544.153 \\ 892.411 & 637.436 & 544.153 \end{bmatrix} \cdot ft$$

Calculate the metacentric ht., GM, which must be positive for floating stability

$$GM_{i,j} := KB_{i,j} + BM_{i,j} - KG_{i,j}$$

$$Draft^{T} = (\,25 \quad 35 \quad 41\,)\cdot ft$$

$$GM = \begin{bmatrix} 838.184 & 605.557 & 520.838 \\ 797.04 & 576.737 & 496.741 \\ 766.589 & 555.377 & 478.864 \\ 766.589 & 555.377 & 478.864 \end{bmatrix} \cdot ft$$

Sandwell

CALCULATE THE FLOATING STABILITY OF SQUARE STRUCTURES

file FLTCASE3.MCD 230ft structure - 400ft base - 2 rigs - 70 WELLS

210 KBO production
0 KBO processing

Define the parameters

Width and height of the base - base is square

$H_b := 42 \cdot ft$

$kips \equiv 1000 \cdot lb$

$W_b := 400 \cdot ft$

Height of the structure from bottom of base to bottom of deck and height to C.G. of deck

$H_s := 155 \cdot ft$ $H_s = 155 \cdot ft$

Height of hull from top of base to bottom of deck

$H_h := H_s - H_b$

$H_d := H_s + 30 \cdot ft$

$i := 0..3$ $H_d = 185 \cdot ft$

Width and Length of the structure - structure above base is square

$W_s := 230 \cdot ft$ $W_s = 230 \cdot ft$

$r_b := 135 \cdot ft$ $r_s := 45 \cdot ft$

$corn_b := r_b^2 \cdot (4 - \pi)$ $corn_s := r_s^2 \cdot (4 - \pi)$

$A_b := W_b^2 - corn_b$ $A_s := W_s^2 - corn_s$

Calculate the deck loads

I ADDED 1000 KIPPS TO WEIGHT OF EQUIP AS DECK OVERHANGS 22.5ft ON 3 LAYERS

$W_{steel} := 0.05 \cdot \frac{kips}{ft^2} \cdot W_s^2 \cdot 2$

$W_{steel} = 5.29 \cdot 10^3 \cdot kips$

$W_{equip} := \begin{bmatrix} 1000 \\ 27484 \\ 61654 \\ 81654 \end{bmatrix} \cdot kips$

no modules
dry wt.
including deck steel
= 50,000 kips

$W_{d_i} := W_{steel} + W_{equip_i}$

$W_d = \begin{bmatrix} 6.29 \cdot 10^3 \\ 3.277 \cdot 10^4 \\ 6.694 \cdot 10^4 \\ 8.694 \cdot 10^4 \end{bmatrix} \cdot kips$

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Draft of the structure

$j := 0..2$

$$Draft := \begin{pmatrix} 25 \\ 30 \\ 39.5 \end{pmatrix} \cdot ft \qquad Draft = \begin{pmatrix} 25 \\ 30 \\ 39.5 \end{pmatrix} \cdot ft$$

Diameter of hole

$d := 57 \cdot ft$ (equivalent hole dia)

Define unit weights for water and steel

$$\gamma_w := .064 \cdot \frac{kips}{ft^3} \qquad \gamma_s := 10 \cdot \frac{lb}{ft^3}$$

Weight of hematite ballast in base

$W_{bal} := 155000 \cdot kips$

Calculate the water ballast height

$$c1_{i,j} := \left[\left(Draft_j \right) \cdot A_b - \frac{\pi}{4} \cdot d^2 \cdot Draft_j \right] \cdot \gamma_w \ldots + -\gamma_s \cdot H_b \cdot \left(A_b - \frac{\pi}{4} \cdot d^2 \right) - \gamma_s \cdot H_h \cdot \left(A_s - \frac{\pi}{4} \cdot d^2 \right) - W_{d_i} \ldots + -W_{bal}$$

$$c2_{i,j} := \gamma_w \cdot \left(A_b - \frac{\pi}{4} \cdot d^2 \right) \qquad c1 = \begin{bmatrix} -4.889 \cdot 10^4 & -3.514 \cdot 10^3 & 8.27 \cdot 10^4 \\ -7.537 \cdot 10^4 & -3 \cdot 10^4 & 5.622 \cdot 10^4 \\ -1.095 \cdot 10^5 & -6.417 \cdot 10^4 & 2.205 \cdot 10^4 \\ -1.295 \cdot 10^5 & -8.417 \cdot 10^4 & 2.049 \cdot 10^3 \end{bmatrix} \cdot kips$$

$$H_{wb_{i,j}} := \frac{c1_{i,j}}{c2_{i,j}}$$

$Draft^T = (25 \quad 30 \quad 39.5) \cdot ft$

$$H_{wb} = \begin{bmatrix} -5.387 & -0.387 & 9.113 \\ -8.305 & -3.305 & 6.195 \\ -12.07 & -7.07 & 2.43 \\ -14.274 & -9.274 & 0.226 \end{bmatrix} \cdot ft \qquad W_d = \begin{bmatrix} 6.29 \cdot 10^3 \\ 3.277 \cdot 10^4 \\ 6.694 \cdot 10^4 \\ 8.694 \cdot 10^4 \end{bmatrix} \cdot kips$$

Calculate the ht. of centre of buoyancy KB

$$KB_{i,j} := \frac{Draft_j}{2}$$

$$KB = \begin{bmatrix} 12.5 & 15 & 19.75 \\ 12.5 & 15 & 19.75 \\ 12.5 & 15 & 19.75 \\ 12.5 & 15 & 19.75 \end{bmatrix} \cdot ft$$

Calculate the ht. of the centre of gravity, K.G.

$$c5_{i,j} := H_b^2 \cdot A_b \cdot \frac{\gamma_s}{2} + A_s \cdot H_s \cdot \gamma_s \cdot \left(H_b + \frac{H_s}{2}\right) + W_{d_i} \cdot H_d \cdots$$
$$+ \left(H_{wb_{i,j}}\right)^2 \cdot A_b \cdot \frac{\gamma_w}{2} - \frac{\pi}{8} \cdot d^2 \cdot H_b^2 \cdot \gamma_s \cdots$$
$$+ \frac{-\pi}{4} \cdot d^2 \cdot \gamma_s \cdot H_s \cdot \left(H_b + \frac{H_s}{2}\right) - \frac{\pi}{8} \cdot d^2 \cdot \gamma_w \cdot \left(H_{wb_{i,j}}\right)^2$$

$$c6_{i,j} := H_b \cdot A_b \cdot \gamma_s + A_s \cdot \gamma_s \cdot H_s + W_{d_i} + W_{bal} \cdots$$
$$+ H_{wb_{i,j}} \cdot A_b \cdot \gamma_w - \frac{\pi}{4} \cdot d^2 \cdot \gamma_s \cdot \left(H_s + H_b\right) - \frac{\pi}{4} \cdot d^2 \cdot \gamma_w \cdot H_{wb_{i,j}}$$

$$KG_{i,j} := \frac{c5_{i,j}}{c6_{i,j}} \qquad KG = \begin{bmatrix} 46.703 & 39.015 & 31.13 \\ 67.248 & 55.922 & 43.526 \\ 94.218 & 78.126 & 59.821 \\ 110.244 & 91.327 & 69.516 \end{bmatrix} \cdot ft$$

Calculate the distance from the centre of buoyancy to the metacentre, BM

$$BM_{i,j} := \frac{\frac{1}{12} \cdot \left(W_b^4 - d^4\right)}{Draft_j \cdot A_b - \frac{\pi}{4} \cdot d^2 \cdot Draft_j}$$

$$BM = \begin{bmatrix} 601.522 & 501.269 & 380.71 \\ 601.522 & 501.269 & 380.71 \\ 601.522 & 501.269 & 380.71 \\ 601.522 & 501.269 & 380.71 \end{bmatrix} \cdot ft$$

Calculate the metacentric ht., GM, which must be positive for floating stability

$$GM_{i,j} := KB_{i,j} + BM_{i,j} - KG_{i,j}$$

$$Draft^T = (\,25 \quad 30 \quad 39.5\,)\cdot ft$$

$$GM = \begin{bmatrix} 567.319 & 477.254 & 369.331 \\ 546.774 & 460.347 & 356.934 \\ 519.805 & 438.142 & 340.639 \\ 503.778 & 424.942 & 330.944 \end{bmatrix} \cdot ft$$

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CALCULATE THE FLOATING STABILITY OF SQUARE STRUCTURES

file FLTCASE4.MCD 230ft structure - 400ft base - 1 rig - 40 WELLS

120 KBO production
0 KBO processing

Define the parameters

Width and height of the base - base is square

$H_b := 42 \cdot ft$

kips ≡ 1000·lb

$W_b := 400 \cdot ft$

Height of the structure from bottom of base to bottom of deck and height to C.G. of deck

$H_s := 155 \cdot ft$ $H_s = 155 \cdot ft$

Height of hull from top of base to bottom of deck

$H_h := H_s - H_b$

$H_d := H_s + 30 \cdot ft$

$i := 0..3$ $H_d = 185 \cdot ft$

Width and Length of the structure - structure above base is square

$W_s := 230 \cdot ft$ $W_s = 230 \cdot ft$

$r_b := 135 \cdot ft$ $r_s := 45 \cdot ft$

$corn_b := r_b^2 \cdot (4 - \pi)$ $corn_s := r_s^2 \cdot (4 - \pi)$

$A_b := W_b^2 - corn_b$ $A_s := W_s^2 - corn_s$

Calculate the deck loads

I ADDED 1000 KIPPS TO WEIGHT OF EQUIP AS DECK OVERHANGS 22.5ft ON 3 LAYERS

$W_{steel} := 0.05 \cdot \frac{kips}{ft^2} \cdot W_s^2 \cdot 2$

$W_{steel} = 5.29 \cdot 10^3 \cdot kips$

$W_{equip} := \begin{bmatrix} 1000 \\ 18733 \\ 46780 \\ 46780 \end{bmatrix} \cdot kips$

no modules
dry wt.

including deck steel
= 50,000 kips

$W_{d_i} := W_{steel} + W_{equip_i}$

$W_d = \begin{bmatrix} 6.29 \cdot 10^3 \\ 2.402 \cdot 10^4 \\ 5.207 \cdot 10^4 \\ 5.207 \cdot 10^4 \end{bmatrix} \cdot kips$

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Draft of the structure

$j := 0..2$

$$Draft := \begin{pmatrix} 25 \\ 30 \\ 40 \end{pmatrix} \cdot ft \qquad Draft = \begin{pmatrix} 25 \\ 30 \\ 40 \end{pmatrix} \cdot ft$$

Diameter of hole

$d := 57 \cdot ft$ (equivalent hole dia)

Define unit weights for water and steel

$$\gamma_w := .064 \cdot \frac{kips}{ft^3} \qquad \gamma_s := 10 \cdot \frac{lb}{ft^3}$$

Weight of hematite ballast in base

$W_{bal} := 150000 \cdot kips$

Calculate the water ballast height

$$c1_{i,j} := \left[\left(Draft_j\right) \cdot A_b - \frac{\pi}{4} \cdot d^2 \cdot Draft_j \right] \cdot \gamma_w \ldots + -\gamma_s \cdot H_b \cdot \left(A_b - \frac{\pi}{4} \cdot d^2\right) - \gamma_s \cdot H_h \cdot \left(A_s - \frac{\pi}{4} \cdot d^2\right) - W_{d_i} \ldots + -W_{bal}$$

$$c2_{i,j} := \gamma_w \cdot \left(A_b - \frac{\pi}{4} \cdot d^2\right)$$

$$c1 = \begin{bmatrix} -4.389 \cdot 10^4 & 1.486 \cdot 10^3 & 9.224 \cdot 10^4 \\ -6.162 \cdot 10^4 & -1.625 \cdot 10^4 & 7.451 \cdot 10^4 \\ -8.967 \cdot 10^4 & -4.429 \cdot 10^4 & 4.646 \cdot 10^4 \\ -8.967 \cdot 10^4 & -4.429 \cdot 10^4 & 4.646 \cdot 10^4 \end{bmatrix} \cdot kips$$

$$H_{wb_{i,j}} := \frac{c1_{i,j}}{c2_{i,j}}$$

$Draft^T = (\ 25 \quad 30 \quad 40\ ) \cdot ft$

$$H_{wb} = \begin{bmatrix} -4.836 & 0.164 & 10.164 \\ -6.79 & -1.79 & 8.21 \\ -9.881 & -4.881 & 5.119 \\ -9.881 & -4.881 & 5.119 \end{bmatrix} \cdot ft \qquad W_d = \begin{bmatrix} 6.29 \cdot 10^3 \\ 2.402 \cdot 10^4 \\ 5.207 \cdot 10^4 \\ 5.207 \cdot 10^4 \end{bmatrix} \cdot kips$$

Calculate the ht. of centre of buoyancy KB

$$KB_{i,j} := \frac{Draft_j}{2}$$

$$KB = \begin{bmatrix} 12.5 & 15 & 20 \\ 12.5 & 15 & 20 \\ 12.5 & 15 & 20 \\ 12.5 & 15 & 20 \end{bmatrix} \cdot ft$$

Calculate the ht. of the centre of gravity, K.G.

$$c5_{i,j} := H_b^2 \cdot A_b \cdot \frac{\gamma_s}{2} + A_s \cdot H_s \cdot \gamma_s \cdot \left(H_b + \frac{H_s}{2}\right) + W_{d_i} \cdot H_d \ldots$$
$$+ \left(H_{wb_{i,j}}\right)^2 \cdot A_b \cdot \frac{\gamma_w}{2} - \frac{\pi}{8} \cdot d^2 \cdot H_b^2 \cdot \gamma_s \ldots$$
$$+ \frac{-\pi}{4} \cdot d^2 \cdot \gamma_s \cdot H_s \cdot \left(H_b + \frac{H_s}{2}\right) - \frac{\pi}{8} \cdot d^2 \cdot \gamma_w \cdot \left(H_{wb_{i,j}}\right)^2$$

$$c6_{i,j} := H_b \cdot A_b \cdot \gamma_s + A_s \cdot \gamma_s \cdot H_s + W_{d_i} + W_{bal} \ldots$$
$$+ H_{wb_{i,j}} \cdot A_b \cdot \gamma_w - \frac{\pi}{4} \cdot d^2 \cdot \gamma_s \cdot \left(H_s + H_b\right) - \frac{\pi}{4} \cdot d^2 \cdot \gamma_w \cdot H_{wb_{i,j}}$$

$$KG_{i,j} := \frac{c5_{i,j}}{c6_{i,j}} \qquad KG = \begin{bmatrix} 46.6 & 39.013 & 31.001 \\ 60.282 & 50.271 & 39.132 \\ 82.209 & 68.319 & 52.177 \\ 82.209 & 68.319 & 52.177 \end{bmatrix} \cdot ft$$

Calculate the distance from the centre of buoyancy to the metacentre, BM

$$BM_{i,j} := \frac{\frac{1}{12} \cdot \left(W_b^4 - d^4\right)}{Draft_j \cdot A_b - \frac{\pi}{4} \cdot d^2 \cdot Draft_j}$$

$$BM = \begin{bmatrix} 601.522 & 501.269 & 375.952 \\ 601.522 & 501.269 & 375.952 \\ 601.522 & 501.269 & 375.952 \\ 601.522 & 501.269 & 375.952 \end{bmatrix} \cdot ft$$

Sandwell

Calculate the metacentric ht., GM, which must be positive for floating stability

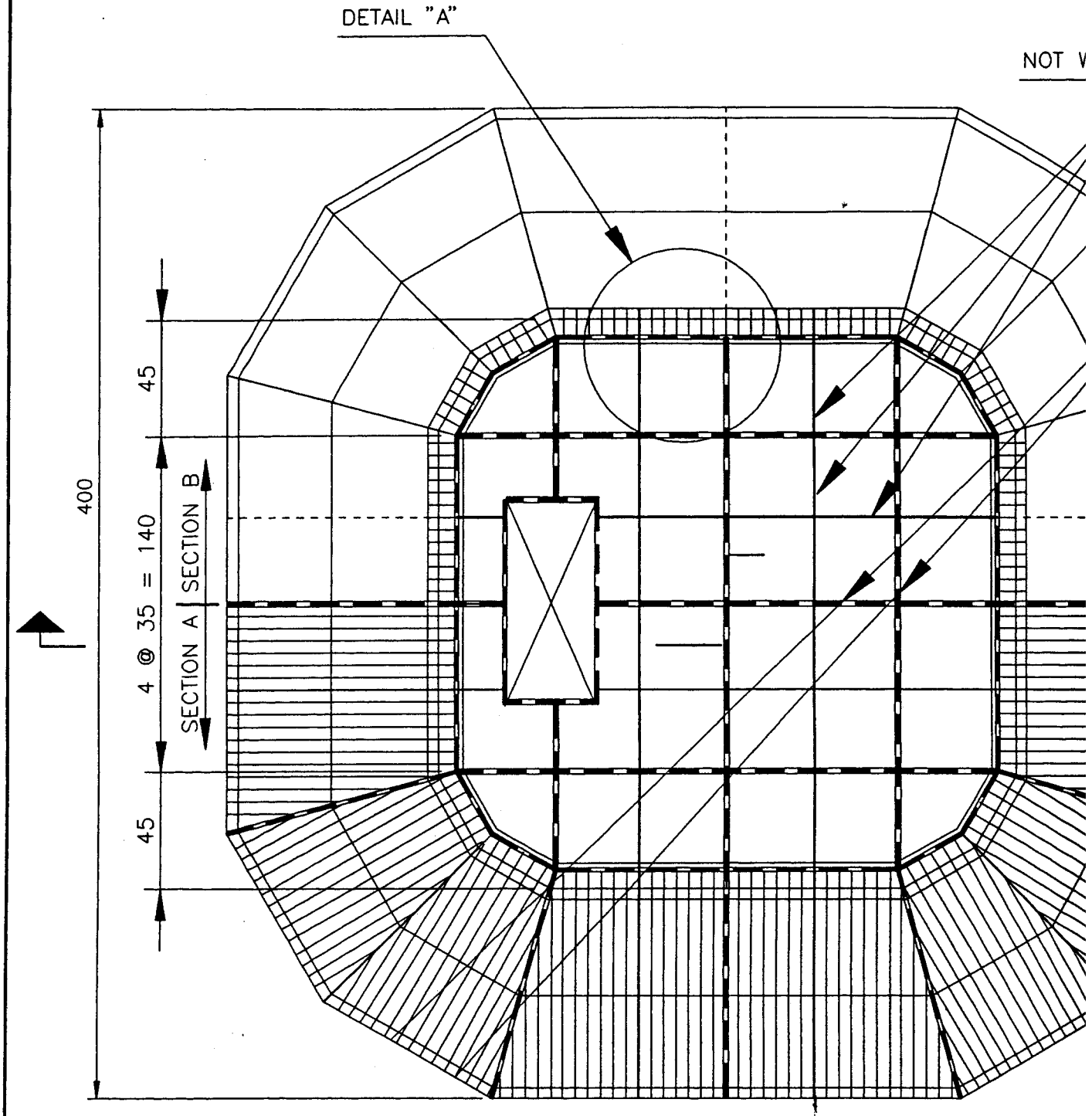
$$GM_{i,j} := KB_{i,j} + BM_{i,j} - KG_{i,j}$$

$$Draft^{T} = (\,25 \quad 30 \quad 40\,)\cdot ft$$

$$GM = \begin{bmatrix} 567.422 & 477.256 & 364.95 \\ 553.74 & 465.998 & 356.819 \\ 531.814 & 447.95 & 343.775 \\ 531.814 & 447.95 & 343.775 \end{bmatrix} \cdot ft$$

APPENDIX B

Structural Drawings



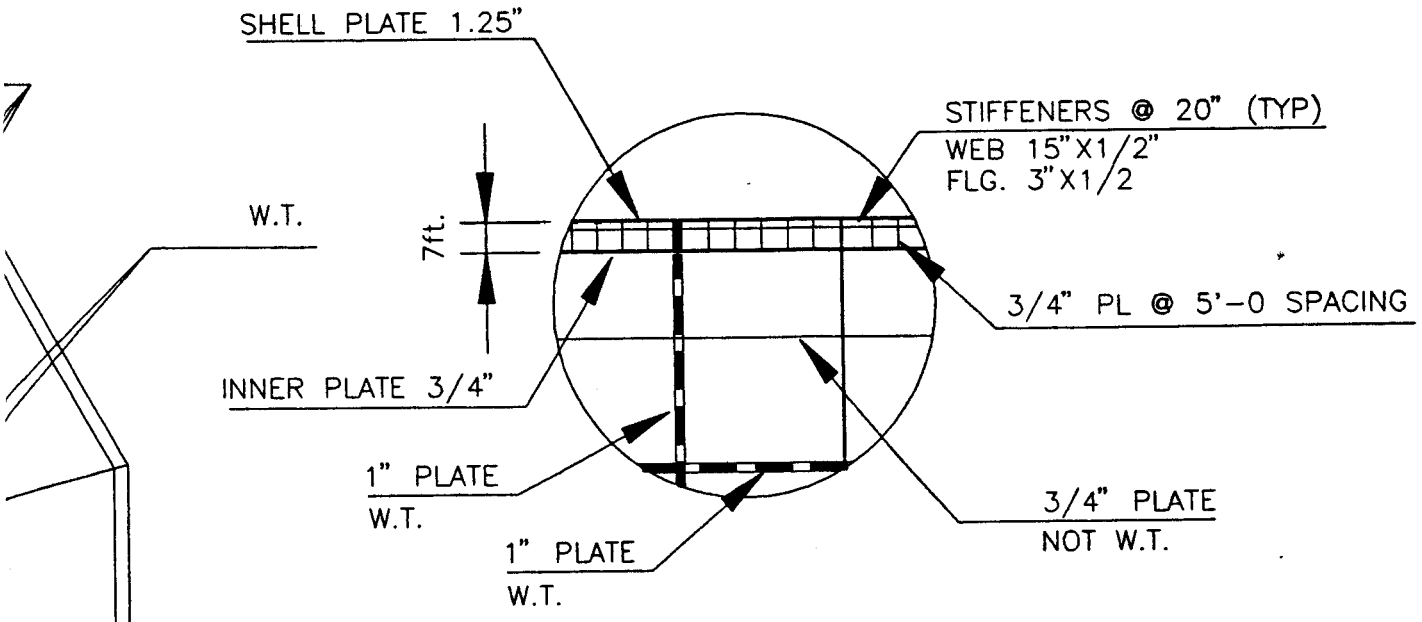
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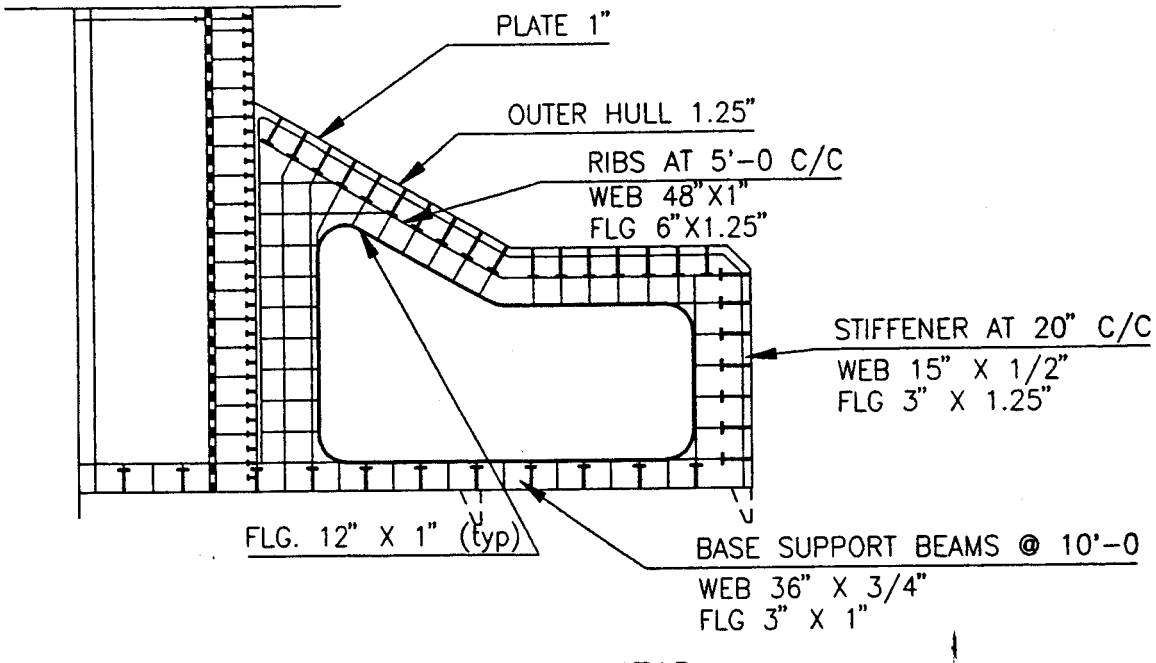
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DETAIL A

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INTERMEDIATE BULKHEAD

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KUVLUM
400ft BASE – 230ft DECK
BULKHEAD LAYOUT

Sandwell

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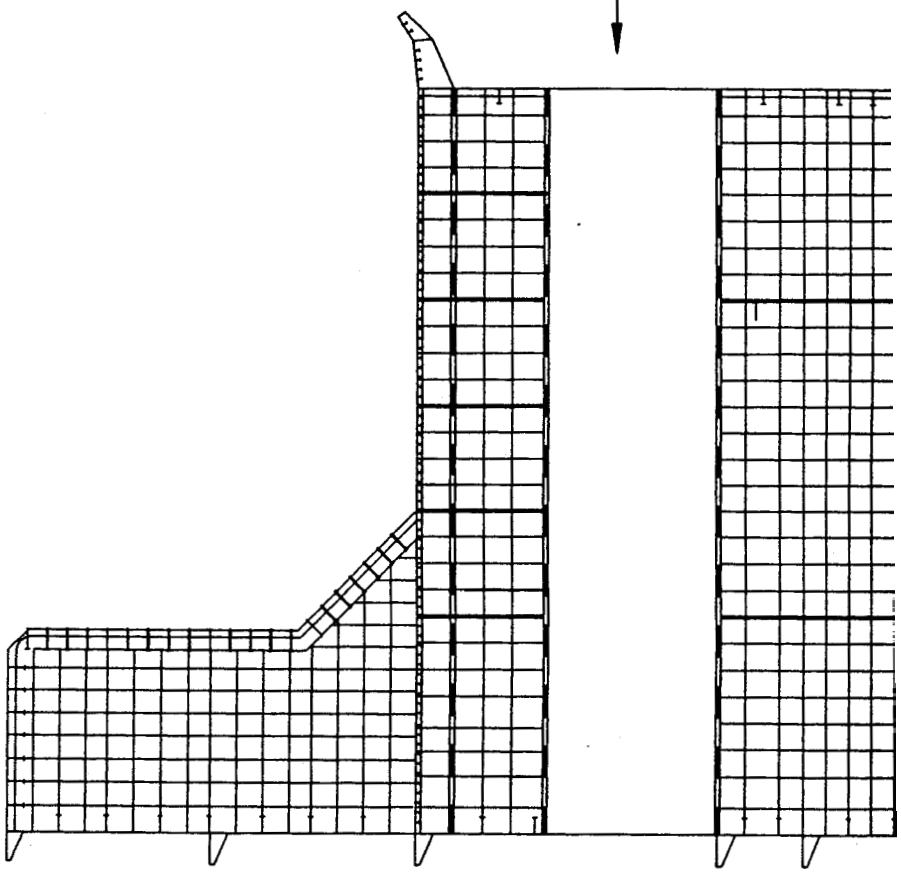
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WATER TIGHT BULKHEAD

MOON POOL



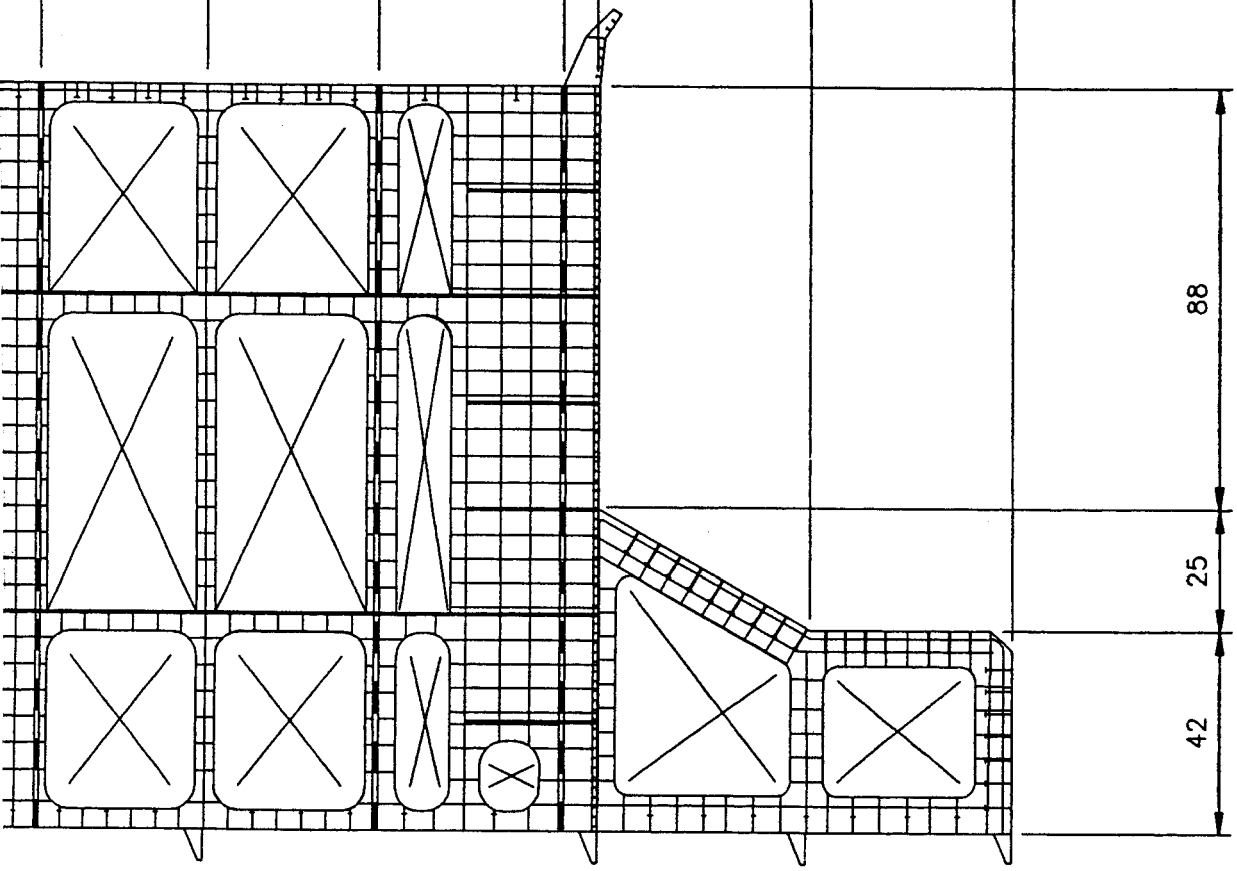
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MAIN BULKHEAD



A
—007

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KUVLUM
400ft BASE – 230ft DECK
BULKHEAD SECTIONS

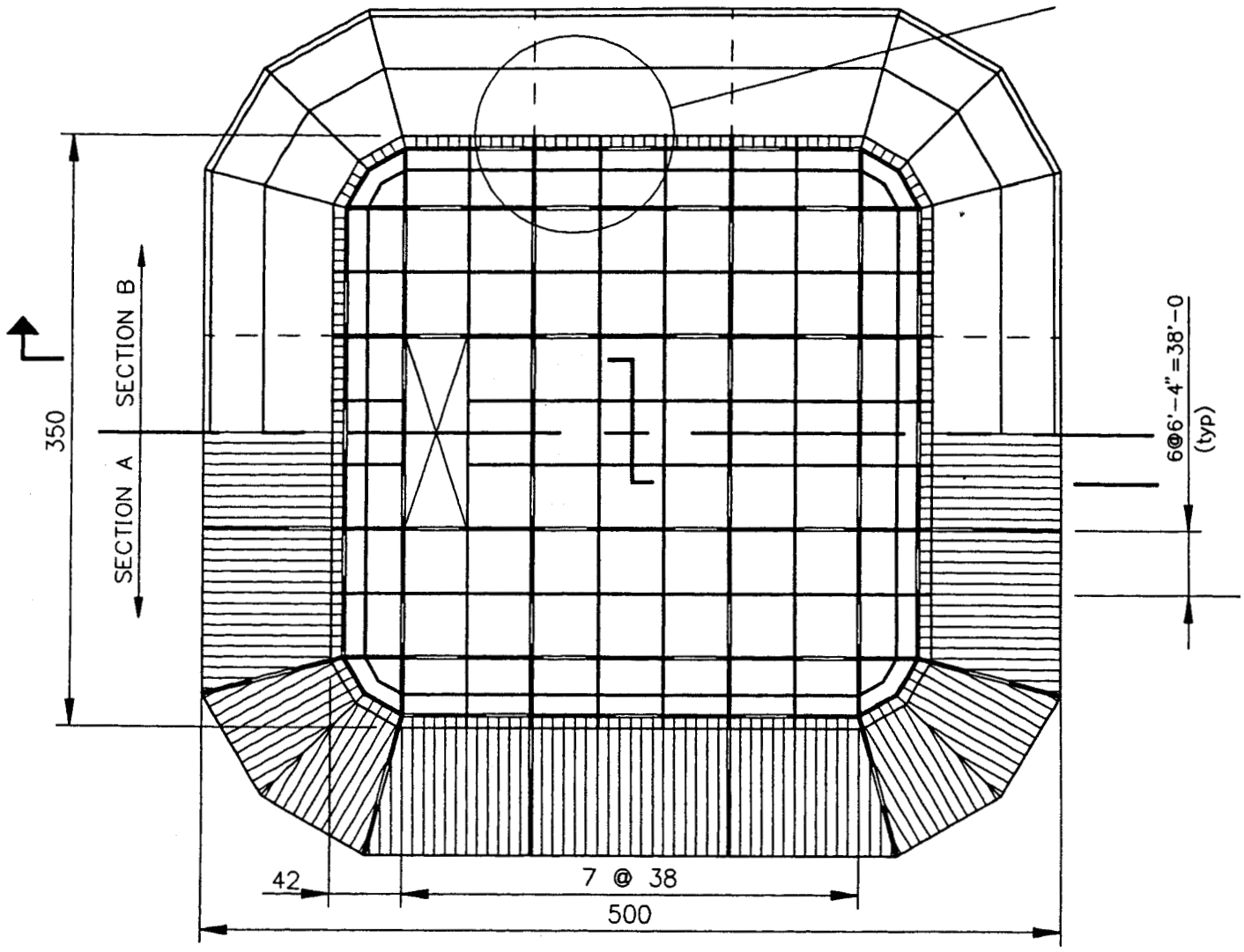
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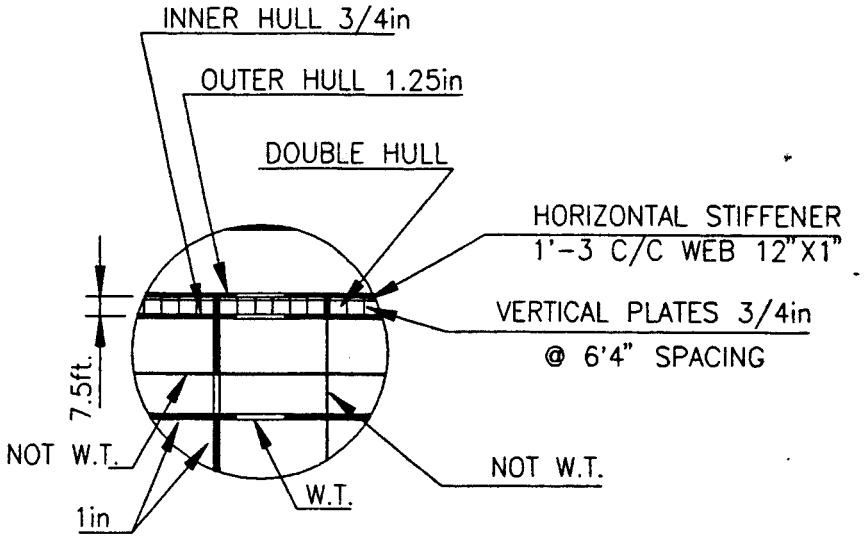
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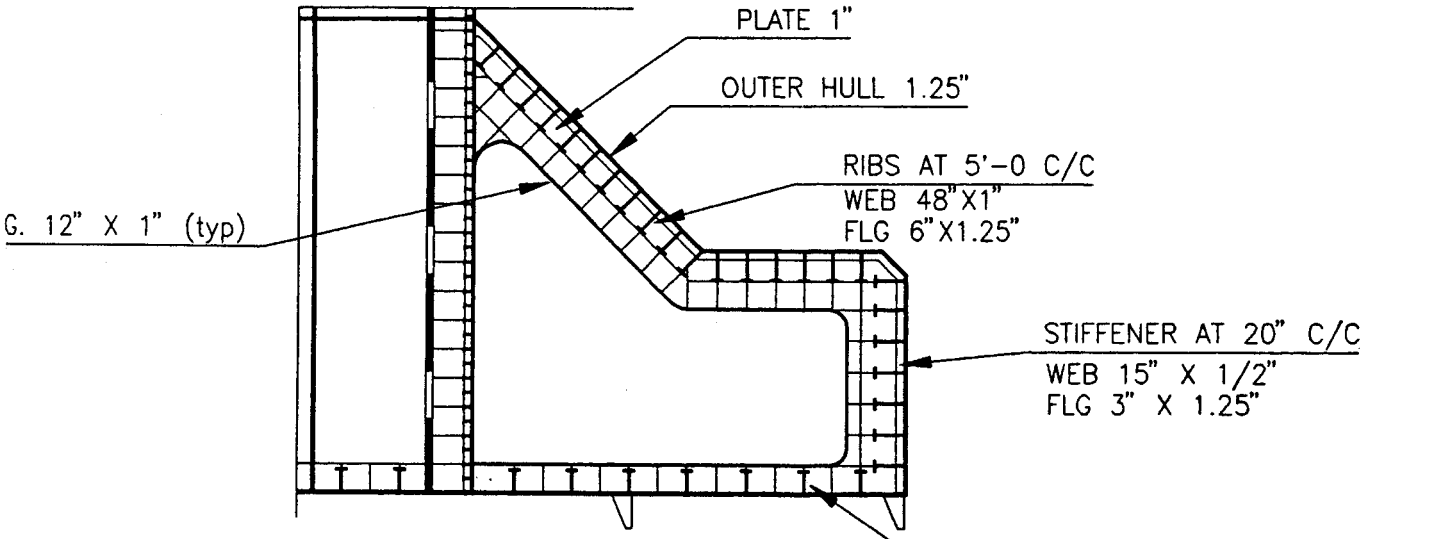
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WITH MAIN BULKHEADS

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DETAIL A



INTERMEDIATE BULKHEAD

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KUVLUM
500FT BASE - 350FT DECK
BULKHEAD LAYOUT

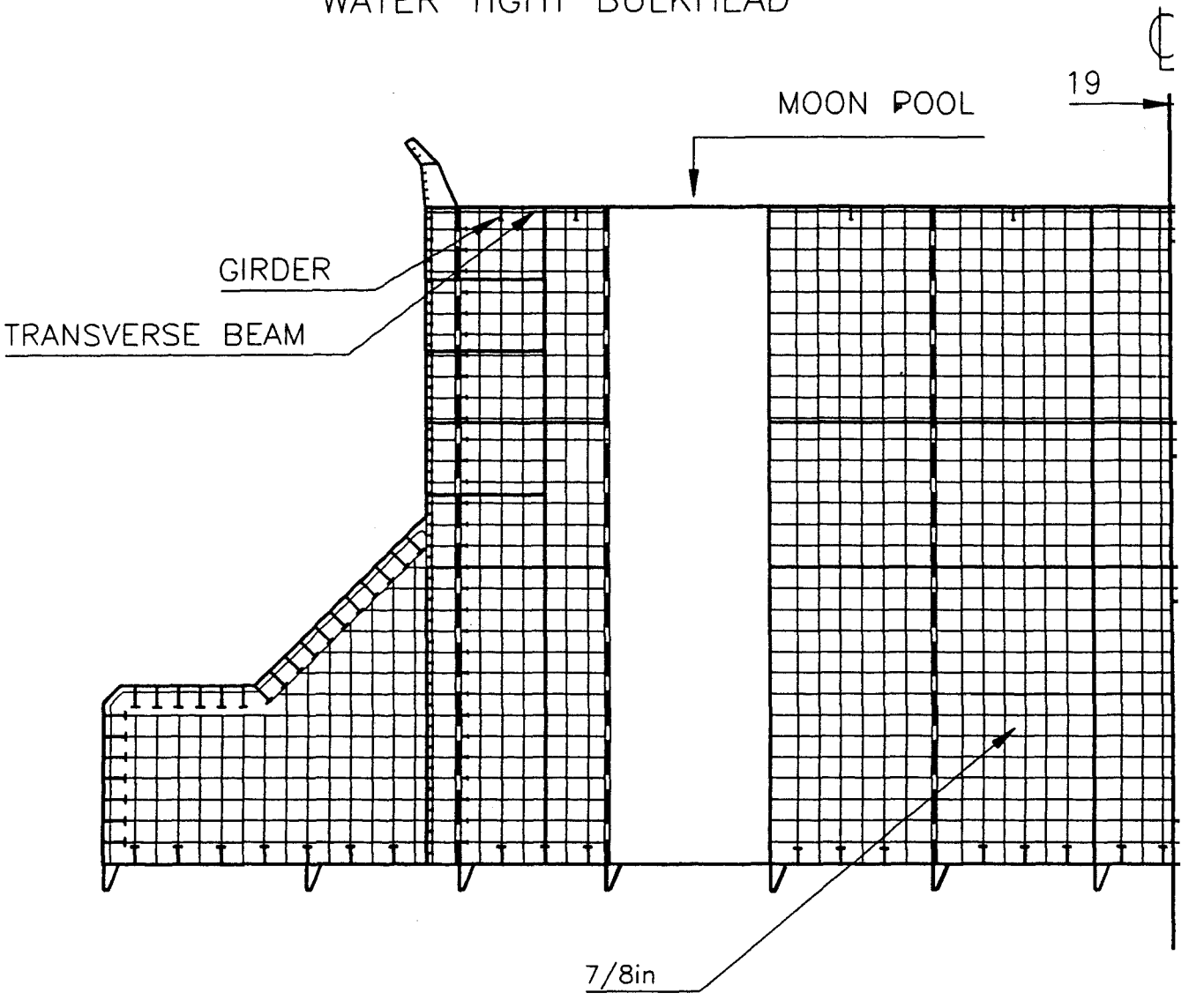
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WATER TIGHT BULKHEAD

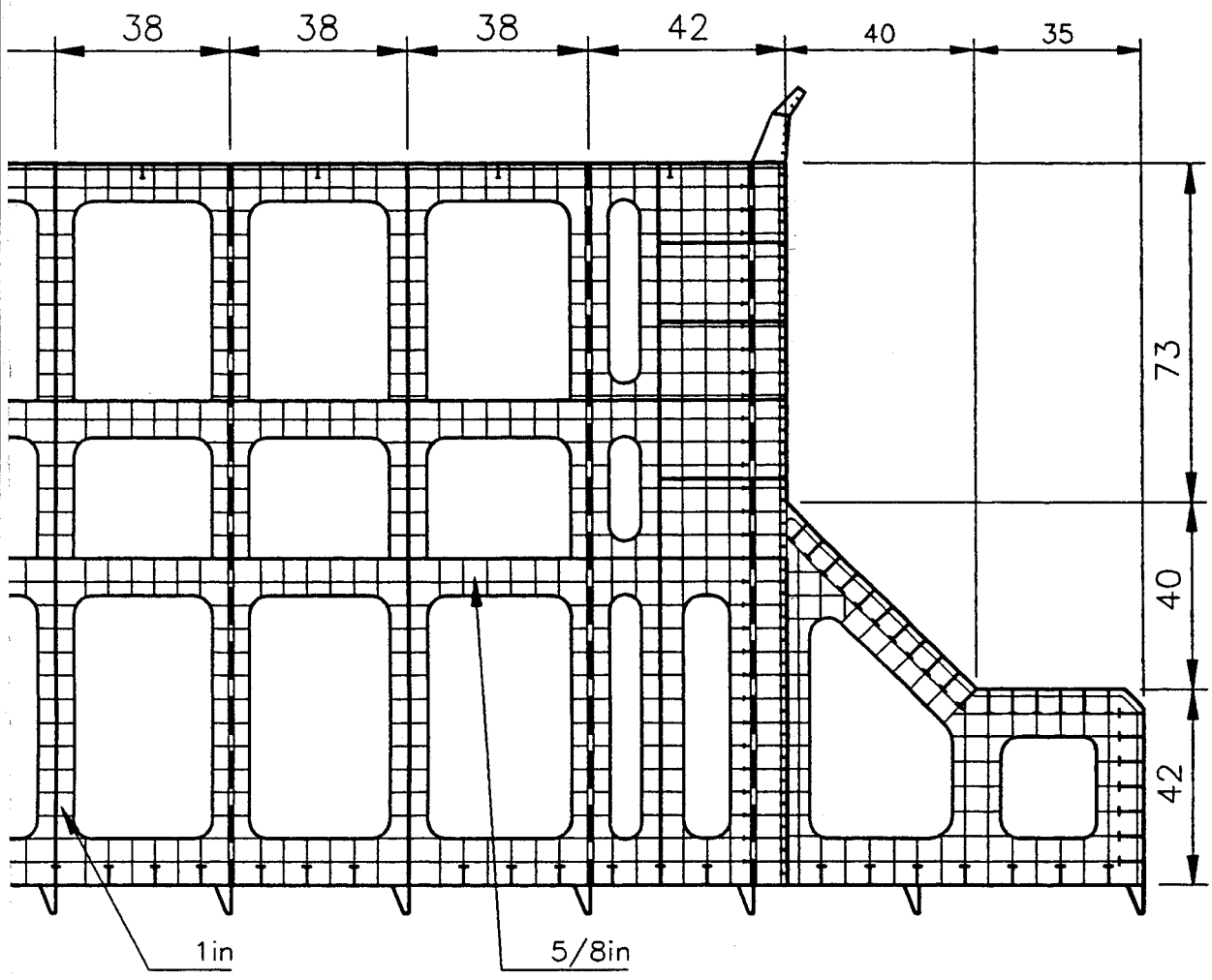


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TRANSVERSE BEAM AND MAIN BULKHEAD



A
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KUVLUM
500FT BASE – 350FT DECK
BULKHEADS

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APPENDIX C

Paper by Masterson and Frederking on Local Ice Pressures

Cold Regions Science and Technology, 21 (1993) 169–185
Elsevier Science Publishers B.V., Amsterdam

Local contact pressures in ship/ice and structure/ice interactions

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(Received 6 November 1991; accepted after revision 13 January 1992)

ABSTRACT

Masterson, D.M. and Frederking, R.M.W., 1993. Local contact pressures in ship/ice and structure/ice interactions. *Cold Reg. Sci. Technol.*, 21: 169–185.

Data on local ice pressures and forces were compiled. The two primary sources were controlled indenter experiments in the field and ship trials. Loads and average local pressures on areas up to 7 m^2 were examined. All the data were plotted on a basis of average pressure versus contact area. Similar trends of decreasing pressure with increasing contact area were observed for all data sets. In order to extrapolate these data to larger contact areas, measurements on structures with contact areas greater then 100 m^2 were reviewed. The larger contact area data indicate that the trend of decreasing local ice pressures levels off at larger areas. Based on all the data examined, design curves for local ice pressures on structures were suggested.

Introduction

Both the design of ship hulls and fixed structures for use in ice covered waters requires a knowledge of the "local" pressures which the ice is capable of exerting on the structures. This type of loading is in contrast to "global" loading which affects the overall stability of structures in particular and is associated with the total force causing the bow print during a ship ram. The problem of determining these "local pressures" is a long standing one which has faced the designers of ships and offshore structures throughout the history of operations in ice covered waters. Local loads affect areas from 1 m^2 up to as much as 100 m^2 and determine the design of steel plate thicknesses plus spacing and size of bracing or concrete wall thicknesses and the amount of reinforcing. The loads are applied over a roughly circular or square area which is generally far from a free edge of the ice sheet, as shown in Fig. 1. Local loads on ships are often applied over an area which is rectangular. The new Arctic Shipping Pollution Prevention Regulations (ASPPR) proposes an aspect ratio (width of the loaded area/height of loaded area) of 8:1 for this situation. When contact is over the full thickness of the ice, then the loading becomes identical to a global loading on a structure (Fig. 2). Failure to design properly for these large local pressures has resulted in the local failure of the structure, sometimes with catastrophic results (Canadian Coast Guard, 1989). As the loaded area approaches 100 m^2, it becomes difficult in most cases to distinguish between local and global ice behaviour and loads and often the two become confused (Sanderson, 1988).

Over the last twenty years much has been learned about the problem of local ice pressures on ships and

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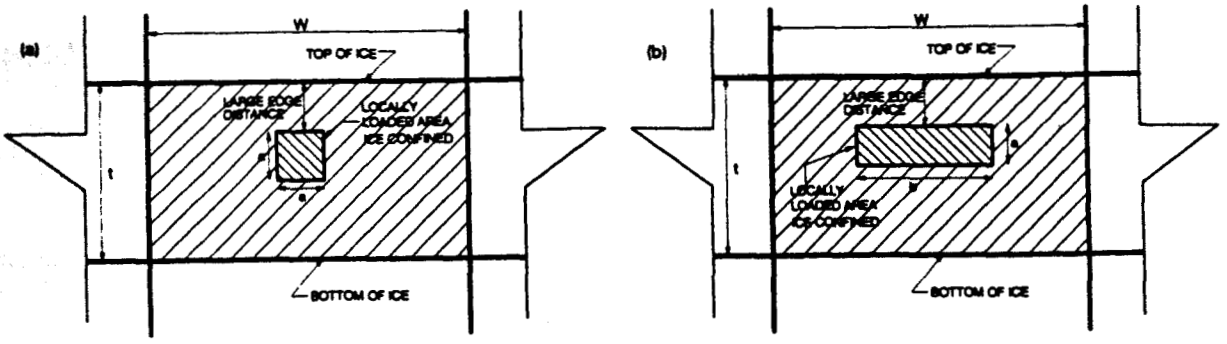


Fig. 1. Local ice loading. Aspect ratio of local ice contact = (a) $a/a = 1$; (b) $= b/a > 1$.

offshore structures. Ships such as icebreakers and Arctic class cargo carriers have had their hulls instrumented to facilitate the direct measurement of local ice pressures (CANMAR, 1982, 1985; German & Milne/VTT, 1985; Kivisild et al., 1989). Likewise, offshore structures such as lighthouses and oil drilling and production platforms have been instrumented to gain similar knowledge. The interpretation of the information gained and the derivation of local pressure vs. contact area relationships is often difficult because of the lack of control during the impact events. In many cases the ice thickness is not known with any accuracy or the translation of sensor readings into pressures is rendered difficult by the inability to perform meaningful calibrations.

In conjunction with the instrumentation of structures, large scale field impact tests have been conducted under controlled circumstances (Johnson and Benoit, 1987; Frederking et al., 1990; Masterson et al., 1992). These tests took place in large tunnels or trenches excavated into the ice and hydraulic rams were used to impact steel or aluminum indentors up to 2 m in diameter against a wall of ice. Sensors measured pressure, load and displacement accurately. The pressure vs. area information thus gained has been of considerable help in interpreting the measurements made on structures. Thin walled, fluid filled flat jacks have also been used to obtain ice pressure information with good success and control.

It has been found that the effective local ice pressure decreases as the size of the loaded area increases, a phenomenon called size or scale effect (Iyer, 1983). This observation has important implications for the design of hull structures, since only smaller, local areas have to withstand the higher pressures and the larger areas, encompassing expensive structural work, can be designed for significantly lower pressures.

This paper examines the major sources of ice/hull and ice/structure pressure information and presents it in a summarized and succinct form. Information from different sources, admittedly involving different aspect ratios (generally defined as the ration of the width of loaded area to the height of the loaded area or thickness of the ice cover) is combined into one master plot which contains ice pressures for contact areas ranging from less than 1 m^2 to about 100 m^2. By using information from ship impacts, field tests and large scale offshore platforms it is possible to develop a design criteria covering this large range of contact areas and to thus point the way for the design of ship hulls for ships of much larger displacement than has previously been possible and for structures subjected to impacts by large ice masses.

It should be noted that since this work was commissioned by the Canadian Coast Guard with the view of extrapolating local pressure vs. area relationships from ships in the 5,000/40,000 tonne displacement range to 200,000 tonne displacement ships, the primary emphasis is on ship hull pressures during ramming of thick ice. However, much of the larger scale data has been obtained from measurements during ice interaction with larger, fixed structures and the pressure vs. area information applies equally to the design of fixed structures. The data contained herein has been used in redrafts of

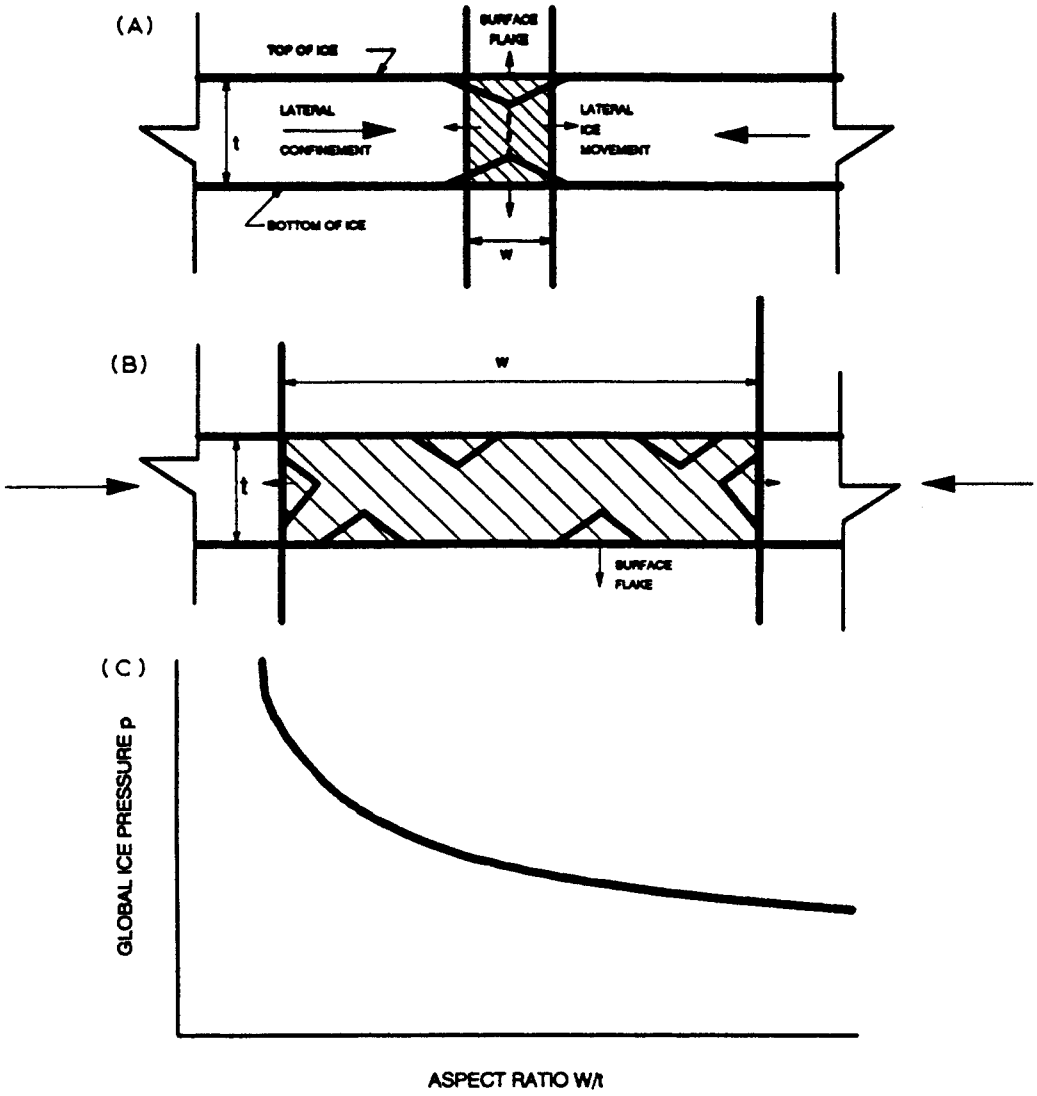


Fig. 2. Global loading and aspect ratio effects. (A) Ice impact with narrow structure. (B) Idem with wide structure. (C) Aspect ratio effect on ice structure.

the CSA S471 code on loadings on offshore structures and in the API RP2N offshore structure code.

Data sources and comparisons of data

The sources of pressure vs. area information used to derive the recommendations for this project are listed below and described briefly. They have been taken from indentor and flat jack field tests, ship ramming trials and from ice interactions with a full scale structure and with an island. Only data from sources which were well documented and verifiable were used. With the exception of one case, the measurement of contact area and load were precise or reasonably so. Note that the pressures presented are averages over the contact area to which they relate.

Indentor tests

(1) Pond Inlet

Field tests have been conducted in tunnels or trenches excavated in iceberg and multi-year ice to obtain pressure vs. area information at medium to large scale. The first set of such tests was conducted using steel indentors up to 2 m in diameter at a grounded iceberg near Pond Inlet, N.W.T. for Mobil Canada and the Hibernia Group of companies (GEOTECH, 1985; Johnson and Benoit, 1987; Masterson et al., 1992). Tunnels 3 m square by 15 m deep were excavated into the side of the iceberg at water line and the test apparatus was place crosswise in the tunnels. Four hydraulic rams of 4 MN capacity, powered by an accumulator bank, forced the spherical indentors against one wall of the tunnel while reaction pads pushed against the other wall. The impact velocity of the spherical indentors was in all cases 0.1 m/sec. The tests were servo-controlled with the controlling function being a displacement vs. time function in the form of a quarter sine wave. Displacement of the indentor and load on each of the rams was measured continuously during the tests and displacement information was fed back to the servo-controller. Thus the degree of control during the tests was high.

Because of the spherical shape of the indentors, the area of indentor in contact with the ice varied with its penetration into the ice. The large 2 m diameter indentor had an area in contact with the ice at full penetration of 3 m^2 and thus one test yielded a pressure vs. area curve increasing from 0 contact area to the full 3 m^2. The summarized results of the Pond Inlet tests are presented in Fig. 3, a pressure vs. area curve for the 0.02, 0.1, 0.5, 1.0 and 3.0 m^2 diameter tests. The peak pressures derived from the force vs. time trace are plotted since the force, and thus pressure, cycled at about 15 Hz during the tests (Fig. 4). It is seen that there is a definite decrease in pressure with increasing area. The aspect ratio for these tests was 1:1.

(2) Arctic Petroleum Operators Association (APOA) "nutcracker" tests

In 1969–70 and 1970–71, Imperial Oil Limited conducted indentor tests on fresh water ice at Tuktoyaktuk in the N.W.T. of Canada and at Eagle Lake east of Calgary (Croasdale, 1970 and 1971). These landmark tests had as their ultimate goal the determination of global loads on offshore structures but the smaller aspect ratios achievable at the time render the results relevant to the present topic. The small aspect ratio led to considerable lateral confinement of the ice, as indicated schematically in Fig. 2a. The pressures obtained are plotted in Fig. 3 with the Pond Inlet data. It is seen that the agreement between the two data sets is quite good for all ranges of loaded area covered.

It is highly recommended by the authors that the readers of this paper examine the two APOA re-

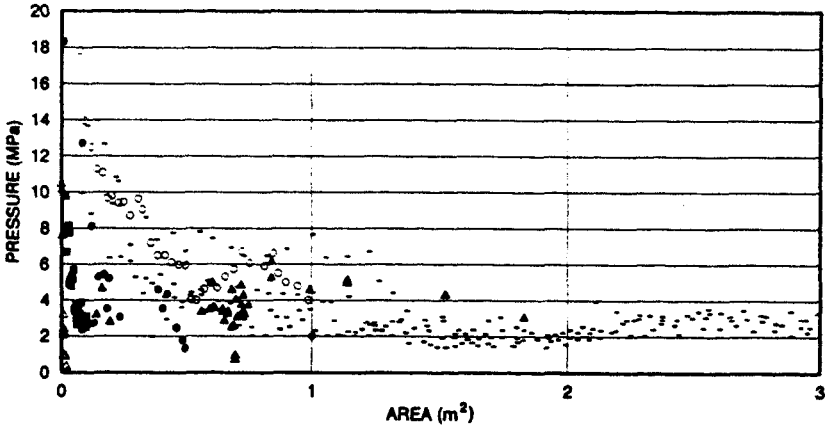


Fig. 3. Pond inlet and APOA 1 and 9 data. (O) 1.0 m^2 indentor pond inlet; (&cirf;) 0.5 m^2 indentor pond inlet; (■) 0.1 m^2 indentor pond inlet; (▲) 0.02 m^2 indentor pond inlet; (–) 3.0 m^2 indentor pond inlet; (▲) APOA 1 and 9.

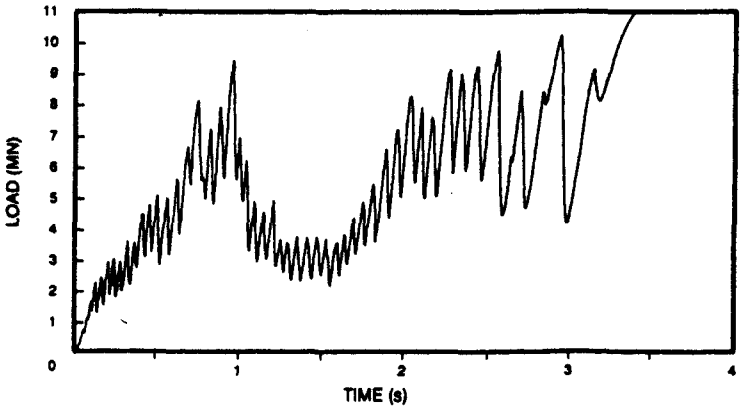


Fig. 4. Typical load vs. time trace for pond inlet tests.

ports referred to. They contain many useful insights which would greatly benefit present-day engineers and researchers.

(3) Hobson's Choice Ice Island

The Canadian Coast Guard showed considerable interest in the Pond Inlet indentor tests because of their applicability to ship design and in 1989, they and Transportation Development Centre funded a field new test program (Frederking et al., 1990). The location was Canada's Research Ice Island, called Hobson's Choice by many, situated 20 km north-west of Ellef Ringnes Island in the Canadian Arctic Islands. The results from the 1989 tests are plotted in the summary graph of Fig. 11 below. The results showed that ice pressures over the contact area were not uniform; i.e. the ice pressures in the centre of the contact area were 2 or 3 times the average pressure (National Research Council, 1989; Frederking et al., 1990). This was also found to be the case for the Pond Inlet tests (Masterson et al., 1992).

In April and May 1990, a second test program was carried out at Hobson's Choice (Sandwell Inc., 1990). The motivation for this field program was to measure ice contact pressures for various interaction geometries and indentor (structural) stiffness. Ice contact pressures on areas up to 1.5 square meters and at speeds of 0.1 m/s to 0.4 m/s were obtained. The ice tested was in a multi-year floe approximately 10 m in thickness, the same floe which had been tested in the previous program. The final aspect ratios were about 1:1.

(4) Flat jack tests

A means of obtaining ice pressures on areas up to 2 m^2 using thin walled, fluid filled flat jacks was devised and used for Gulf Canada in the 1980's (Iyer and Masterson, 1987, 1991; GEOTECH, 1983. 1984). These flat jacks consisted of two sheets of 24 gauge (0.61 mm) thick stainless steel welded at the edges to form an envelope into which a fluid could be pumped through included fill tubes. The flat jacks were inserted into a chain saw cut in the ice and frozen into the cut with water. Various shapes of flat jacks were tested, including triangular, square and rectangular. The loaded areas varied from 0.162 m^2 to 1.96 m^2 and the displacement rates varied from 2.9×10^{-6} m/s to 0.06 m/s (equivalent strain rates of 2.14×10^{-6} to 3.44×10^{-2} s^{-1}). At the lower rates, the ice was being loaded in the creep range. The displacement rate depended on the size of the flat jack being filled and on the type of pumping equipment being used, the higher rates having been obtained using an accumulator as in the indentor tests.

The inclusion factor, an indication of edge effects of a loading device, is very low for the flat jacks and thus the internal pressure of the fluid in the flat jack is within 5 percent of the pressure being applied to the ice. Also, the uniform contact with the ice from the beginning of the test means that a very reliable value for elastic modulus of the ice can be obtained

at large scale. These elastic modulus values have been subsequently used in the interpretation and evaluation of the dynamic characteristics of the indentor test apparatus. Because the flat jacks' walls were composed of thin metal, they were flat and pliant and conformed to the ice surface. Thus, in contrast to the rigid, spherical indentors of Pond Inlet, they did not cause the extrusion following crushing of the ice. They did cause a bulb of crushed ice to form in front of the flat jack face (Masterson, 1992) and a maximum or ultimate pressure was attained (Iyer and Masterson, 1987, 1991). Thus while the processes were different for the spherical indentor and the flexible flat jacks, in both types of tests a maximum pressure was reached and these pressures, at any given area, are comparable. The aspect ratio for these tests was 1:1.

The ultimate pressures of the flat jack tests (Iyer and Masterson, 1987, 1991) have been extracted and plotted, along with the results of the indentor tests and ship pressure measurements, in the summary graph of Fig. 11. Since there was a high degree of control during these tests, and since they cover a large range of strain rates, they are very useful in this examination of the problem of local pressures on ships' hulls and structures, especially since the highest pressures have been found to occur at the lower strain rates in other indentor tests.

Ship trials

(1) M.V. Arctic dedicated trials — June 1984

In June of 1984 a field trial program was carried out with the M.V. Arctic which had been previously instrumented with strain gauges and accelerometers (German & Milne/VTT, 1985; VTT, 1981). The principal objective of the tests was to obtain the total bow ice loading on the M.V. Arctic as a function of her indentation into a large multi-year ice feature. The test instrument used to measure these loads was the M.V. Arctic herself, through her response to load inputs. Nine multi-year ice floes were impacted in the area of 76°N and 78°W in north western Baffin Bay near Coburg Island.

To determine pressure/area information from the tests the size and shape of the bow print or indentation had to be determined. The bow form of the M.V. Arctic in simplest terms is an inclined wedge. Therefore the shape of the contact between the bow and the ice could be described by two symmetric flat triangular surfaces having a common side along the stem. Even though the area increases, the shape remains constant during indentation. Assuming the ice floe edge to be a right angle and all impacts to be normal to the ice edge, and knowing the geometry of the bow, the area of the two contact faces is a function of the depth of the indentation into the ice. The indentation depth was determined from integrations of vertical and horizontal bow accelerations. When the bow began rising during a ram this signified that it was sliding rather than crushing the ice and the contact area had reached a maximum. Indentation into the ice was defined as the difference between total surge motion and sliding motion. Calculated indentations were checked by direct measurements in some cases and found to be in reasonable agreement.

Strain gauges measured the dynamic hull girder response and a finite element program was in turn used to deduce the vertical and horizontal loads at the bow. Because neither lateral loads or frictional loads were measured, considerable care had to be taken to obtain the best estimate of the force component normal to the hull. Assuming all interactions measured were the result of rams with the ship's axis oriented perpendicular to the floe edge and neglecting friction, the force component normal to the triangular contact face could be determined. This normal force, together with the contract area calculated from the indentation was used to determine peak values of pressure vs. area for each ram.

During the dedicated trials a total of 142 rams were accomplished into 9 ice floes. In 30 of these rams, covering an impact speed range of 0.26 to 2.1 m/s, the ice failed only by crushing and the initial contact areas were small. The ice force vs. indentation or penetration relationship derived from the trial results was found to be almost linear. This information was used to derive a pressure vs. area relationship in which no speed dependency was observed over the trials speed range. The results were consistent as well between ice floes.

Peak values of the pressure vs. area data from the M.V. Arctic dedicated trials are plotted in Fig. 5, showing a dependence of ice pressure on the loaded

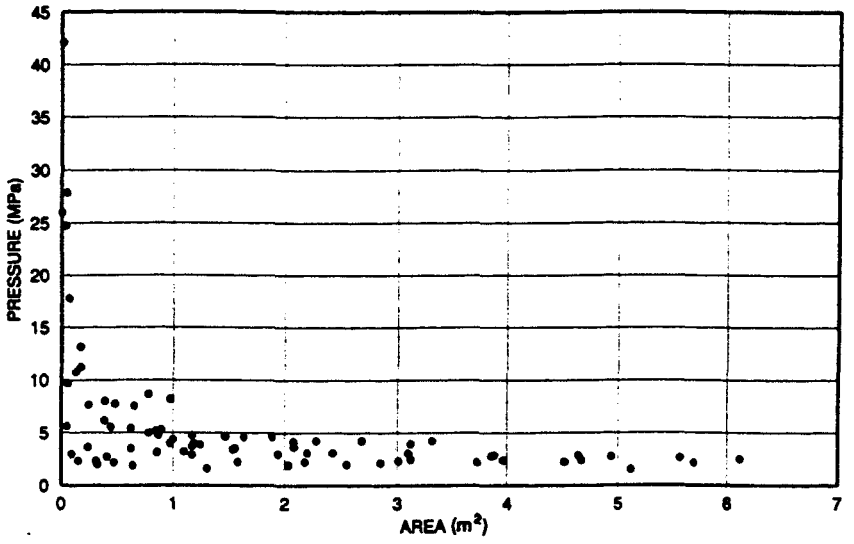


Fig. 5. Pressure vs. area: M.V. Arctic data.

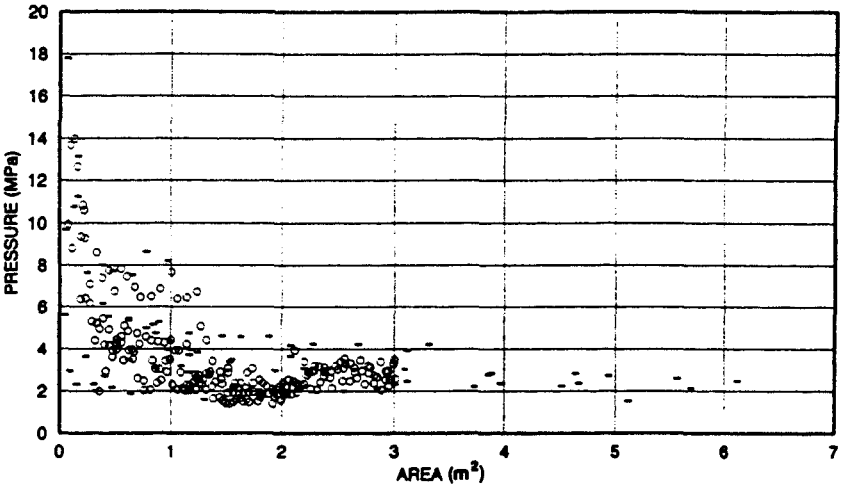


Fig. 6. Pressure vs. area: (O) 3 m² inlet; (–) M.V. Arctic data.

area. In Fig. 6 the majority of the M.V. Arctic data is plotted with the 3 m² Pond Inlet indentor data. Note that in both cases contact area is calculated from simple geometric considerations. The agreement between the two data sets is remarkably good, especially when it is remembered that the Pond Inlet tests were conducted on iceberg ice with spherical indentors and the M.V. Arctic tests were conducted on multi-year sea ice with a ship. It strongly supports the conclusion that ice pressure vs. area relationships are relatively independent of ice type and of the loading device. Considerable care was taken in both sets of tests in the choice of test location (only results from impacting competent ice were included in the calculations of pressure vs. area) and in the measurement of force and penetration (area). The aspect ratio of the loaded areas is not discussed in the German & Milne/VTT report. It is stated in German & Milne/VTT, 1985 that no speed dependency was observed in the pressure vs. area relationship over the speed range of the M.V. Arctic trials. Figure 7 indicates that the effect of speed on

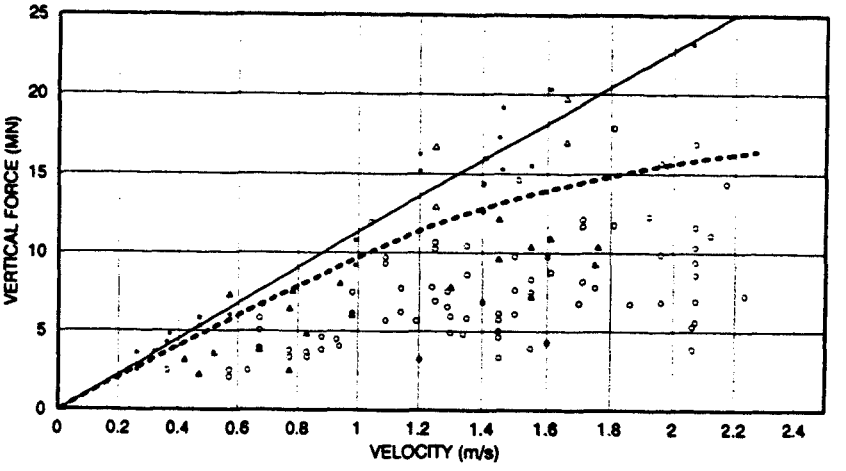


Fig. 7. Maximum total vertical bow forces of all rams vs. ramming speed for the M.V. Arctic (German and Milne/VTT, 1985). (•) Good rams; (○) major break; (▲) old notch; (▲)unsymmetric.

the vertical bow force may diminish with increasing speed as shown by the dashed line which is an attempt to provide a curve of best fit to the scatter of data.

A comment on the statistical treatment of the Pond Inlet and M.V. Arctic data is warranted at this point. The Pond Inlet set is represented as a series of maxima during individual tests. Each test thus provides a pressure vs. area curve comprised of the order of 50 data points. Four 3 m^2 tests were performed, thus providing about 200 data points for the set used in the present analysis. This compares reasonably well with the amount of data obtained from the M.V. Arctic trials. Although 142 rams were executed, only 30 involved crushing over small areas. For each ram, 5 to 10 data points of peak pressure vs. area were obtained. Thus the "size" of the two data sets is similar. The excellent agreement between the data sets attests to the statistical significance associated with their comparison.

More data (i.e. more rams or more indentor tests) would not likely change the distributions significantly, especially at two standard deviations. There are enough data available to conclude that the sample is representative of the population.

(2) Kigoriak trials — August and October 1981

Canmar measured local ice loads and the global movement of the Kigoriak in ramming in two test periods (CANMAR, 1982, 1985). The first, in August 1981, took place in relatively weak but thick first and second year ice (A rams). The second, in October 1981, occurred in generally strong multi-year ice (B rams). The average impact velocities for the August tests ranged between 2.36 and 6.31 m/s and for the October tests ranged between 1.54 and 2.1 m/s. The port side of the bow was extensively instrumented and only local pressures were measured on the starboard side. Areas covered by each of four pressure gauges were 0.025 m^2. Ice load measurements on the port side on two areas named A1 (1.25 m^2) and A2 (6.0 m^2), were carried out by measuring and summing shear differences in the intermediate frames and the web frames (CANMAR, 1985). Loaded areas other than 1.25 m^2 and 6.0 m^2 were determined in the following manner. Area A1 was comprised of six panels, each of area 0.208 m^2, for a total loaded area of 1.25 m^2. Area A2 was comprised of three panels each of area 0.667 m^2 and 12 panels each of area 0.333 m^2 for a total area of 6.0 m^2. Thus the approximate area of contact could be measured from these shear differences on panels within the instrumented area. The ram was assumed to be symmetric if the pressure gauges on the starboard side responded at the same time as the shear gauges on the port side. It should be noted that while the contact areas discussed previously in this paper were based on simple geometric relations, an alternate means of describing contact area was used in analyzing the Kigoriak data. In this case the con-

tact area was defined by the area which registered a load above some minimal threshold, an area which was found to be substantially smaller than the bow print area. The total bow print areas were measured from a camera looking over the bow. CANMAR, in developing their ship–ice interaction model then calculated a contact factor which was the ratio of the contact area to the bow print area. This ratio was typically one third.

Measurements of rigid body movement were done by means of two 16 mm movie cameras located on the ice. Estimates of penetration and impact velocity were done by projecting the film onto a graphical screen using single frame editing techniques. The measurement program resulted in pressure vs. area information which was of particular use in this study.

The pressure vs. area information from these field trials was redigitized and the August and October 1981 results are plotted in Figs. 8 and 9 respectively. The Pond Inlet 3 m^2 indentor data are plotted along with it in the figures. There is again a definite trend of decreasing pressure with contact area, as was noted with the M.V. Arctic and other test results. The agreement between the Pond Inlet and the Kigoriak data is not as good as it was between the Pond Inlet and the M.V. Arctic data. There is more scatter in the Kigoriak data than in that of the M.V. Arctic and the pressures from the Kigoriak trials are somewhat lower. Since the instrumentation packages on both ships were of similar quality, the difference is mainly ascribed to a wider variation in the properties and integrity of the ice floes impacted by the Kigoriak.

It is stated in CANMAR (1985) that upon "reanalysing the 1981 local pressure data by accounting for portions of the total contact area, the envelope curve for smaller areas rises considerably. This is an obvious consequence of the good confinement offered to small panels within the contact area". This has an important effect on areas of the order of 0.2 m^2 and would raise the values of pressure to the left end of the plots of Figs. 8 and 9. However, at the larger areas edge effects begin to influence the pressures and the effect would diminish and disappear. CANMAR (1985) indicates that for area a of 1 m^2 and larger this effect no longer is significant. Cognisance of the variation of pressure across the contact area was taken in the indentor tests since it was noted from measurements that the pressure decreased from a high value near the centre of the indentor to a low, unconfined value at the perimeter where large flaking of ice was observed (see triangular pressure distribution postulated in Canadian Coast Guard, 1989). Thus all tests results have this common denominator and differences appear to lie in the quality and type of ice impacted and in the assurance that crushing dominated the ice failure.

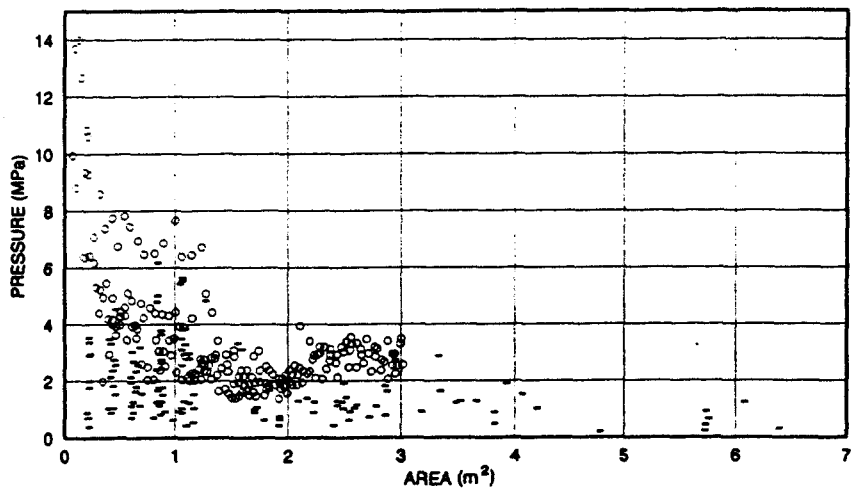


Fig. 8. Pond inlet 3 m^2 tests (O) and Kigoriak August 1981 data (–).

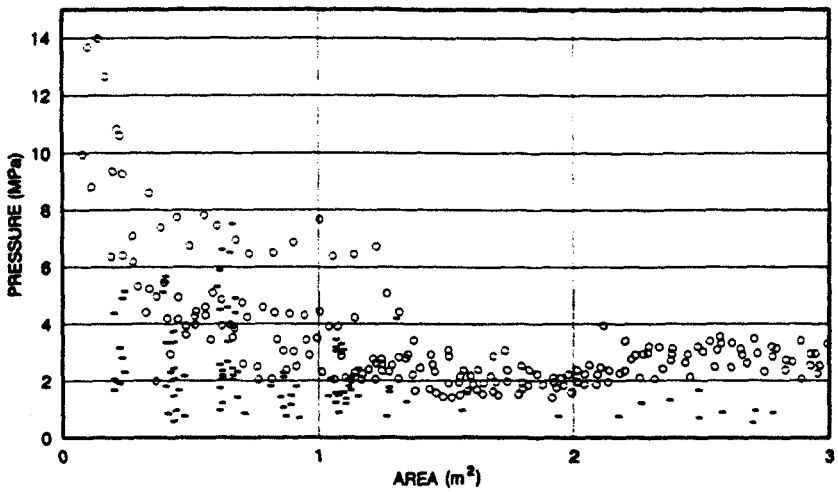


Fig. 9. Pond inlet 3 m² tests (O) and Kigoriak October 1981 data (–).

(3) USCGC Polar Sea ice impact pressure measurements (ARCTEC, 1986)

In 1982 the USCGC POLAR SEA was instrumented with an array of strain gauges on the port bow for the purpose of measuring ice impact pressures. The local ice impact loads data collection program was done during four deployments of the Polar Sea between the fall of 1982 and the fall of 1984 to acquire data in different geographical areas. 2039 individual impacts are identified in ARCTEC, 1986. Sixty-seven known multi-year ice events were identified in the North Chukchi Winter 83 data which included dedicated rams of multi-year ridges. Contact areas were determined from the response of the array of strain gauges on the port side of the ship and, consequently, these contact areas are not as accurately defined as for the M.V. Arctic and Kigoriak trials. Also, in some instances, there was not the opportunity to investigate the nature of ice failure in the contact area to determine whether crushing was the dominant mode.

The results of the pressure vs. total contact area determinations are plotted in Fig. 10 along with the 3 m² indentor data from Pond Inlet. There is a noted

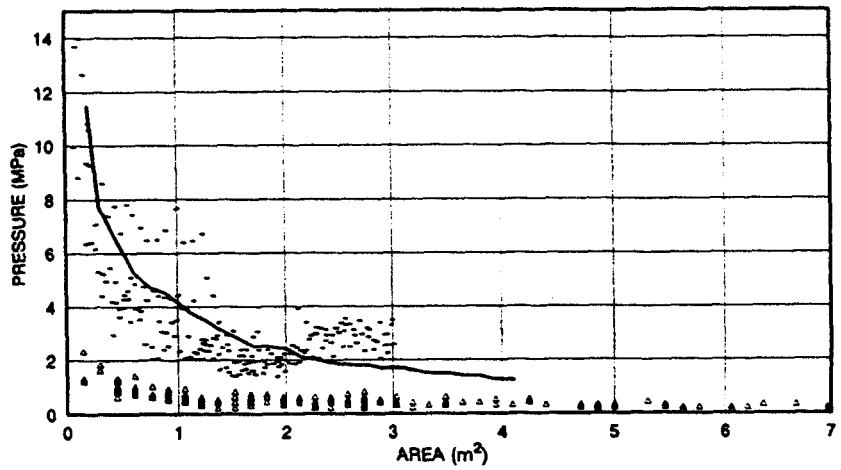


Fig. 10. Pressure vs. area: Polar Sea — N. Chukchi, 1983 (▲); (–) Pond Inlet 3 m²; (——) Polar Sea &mdash max. values.

trend of decreasing pressure with area in the POLAR SEA data but it is seen that the pressures fall well below the Pond Inlet values and thus below those of the M.V. Arctic. The values correspond to the lower end of the envelope of the Kigoriak values. The data plotted are for the North Chukchi Winter 1983, considered to have the heavier ice conditions and showing the highest ice pressures of any of the regions.

The pressures plotted for the Polar Sea in Fig. 10 represent the highest pressure recorded on a particular area when only that area of the hull was loaded. Since each strain gauge on the hull was largely independent, it was possible to estimate the area of the hull loaded by the ice by the gauge response. When larger areas of the hull were loaded, the same gauges covering the area in question would most likely register much higher pressures. Thus, to obtain thr true upper envelope pressure vs. area curve for the Polar Sea data, it was necessary to examine each particular area of the instrumental portion of the panel under all load scenarios and to pick the highest value recorded. The results of this rather massive excercise, considering the amount of data collected, are shown by the solid curve in Fig. 10. It is seen that the Polar Sea data then agree quite well with the Pond Inlet data.

Molikpaq measurements

During the winter drilling season of 1985–86 at the Amauligak site, Gulf's Molikpaq MODU caisson structure experienced several impacts by first-year and multi-year ice which caused forces well beyond the threshold level and which also caused dynamic response of the structure (Jefferies and Wright, 1988). Some of the first-year ice interactions involved ice thicknesses of about 2 m over as much as a 90 m width of structure, resulting in large aspect ratios compared to normal ship bow/ice interactions which have been reported to be a maximum of about 8 (CANMAR, 1985, Canadian Coast Guard, 1989). However, as ships become larger the aspect ratios of the interactions will also grow as there is a limit to the thickness of the ice features which are contacted. Because of its large scale, this information is considered to be most relevant to the

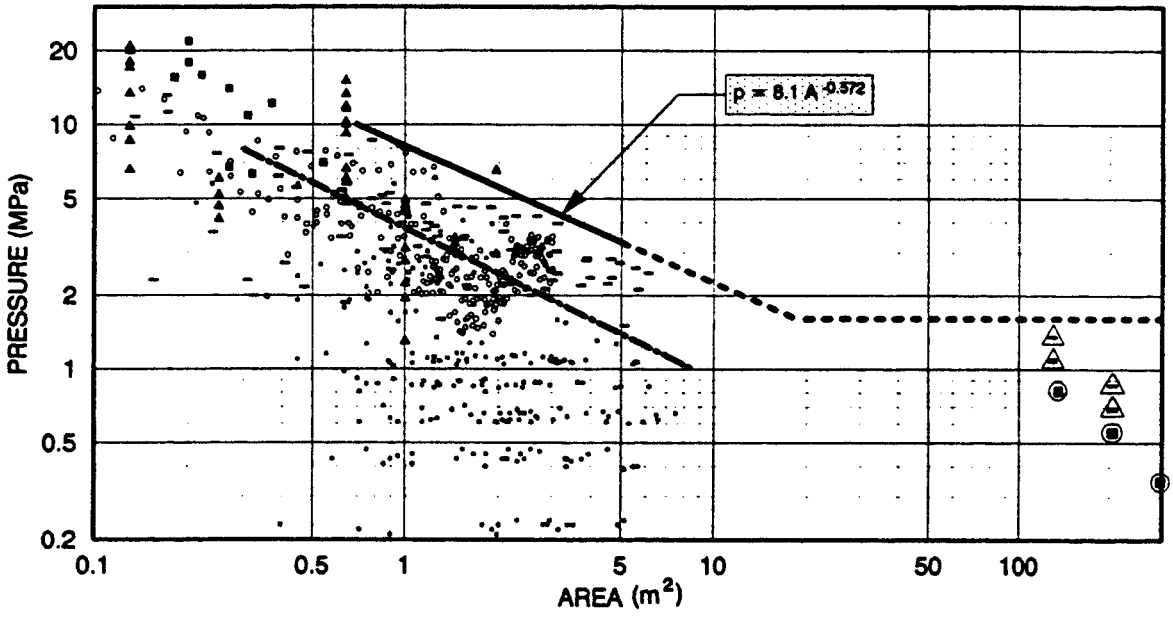


Fig. 11. Pressure vs. area (local pressure: combined data. (○) 3 m² inlet; (–) M.V. Arctic; (•) Kigoriak; (▲) Flat Jack data; (■) 1989 Hobson's Choice; filled square in circle: Hans Isl., 1983; dash in triangle: Molikpaq, May 1986. (——) 2STD; (– · – · –) mean all data.

task of projecting pressure vs. area relationships to larger ship and structure impacts.

The forces were measured by means of strain gauges placed on the bulkheads of the Molikpaq (Jefferies and Wright, 1988) and were checked by Sandwell with loads calculated from global deformations of the caisson measured by means of extensometers located on all sides of the deck. The considerable checking and verification of the loads by various parties lends confidence to the values reported here. The summary graph of Fig. 11 contains the region of values for the Molikpaq impacts with first-year ice in May, 1986.

Hans Island data

Three projects were conducted in 1980, 1981 and 1983 at an island between Greenland and Ellesmere Island called Hans Island to measure the total impact force of a major ice feature on an island (APOA 1980, 1982, 1985; Danielewicz and Blanchet, 1983). These experiments made possible the prediction of loads during the collision of a large, fast moving multi-year ice floe with a structure in open water.

The ice floes encountered at Hans Island consisted of warm multi-year ice similar to that which periodically invades the Beaufort Sea in the summer. This is in contrast to the cold ice encountered during the indentor and ship ram programs and the Molikpaq events.

Local ice pressures were derived from measurements made during these tests and are plotted in Fig. 11. They are the same scale as the Molikpaq results but the pressures are lower, most likely a reflection of the warm decaying ice and its consequent lower strength. Because of the difficulty of determining accurate local pressures from the Hans Island data, it is presented here only for information and comparison and does not play a key role in determining the pressure envelope of Fig. 11.

Discussion

The task of arriving at a pressure vs. area relationship for the design of larger ships and of structures has been tackled by combining the data previously presented and discussed into one graph in order to provide direction for the future in determining local pressures on ships' hulls and structures. The magnitude of the required extension of present design practice can be appreciated when it is realized that the ship with the largest displacement to date on which measurements have been made is the M.V. Arctic with a displacement of 40,000 tonnes and that ships with displacements up to 200,000 tonnes are contemplated for ice covered water navigation. Production structures placed in the Western Beaufort or North Chukchi Seas will, over their lifetime, experience impacts by ice masses of the order of 20 m in thickness resulting in "local" pressures under relatively confined conditions over large areas.

Present and future ships

Table 1 lists pertinent facts regarding present and future ice going ships. Displacement and power are self explanatory. The maximum ice force possible for the ship was determined from a relationship given in Canadian Coast Guard, 1989. It is:

$$F_{max} = 2.6D^{0.9}\{1 + (P/D^{2/3})^{1/3}\} \quad (1)$$

where P=ship's power (in MW), D=ship's displacement (in kt) and F_{max}=ice force (in MN). The contact area as a result of the force is calculated using a pressure vs. area relationship which will be described later. The dimensions of the contact area are listed assuming, for now, an aspect ratio of 8:1. Table 1 has a column F_{max}/D which is the maximum impact force divided by the ship mass, giving an acceleration value. In ship impacts it is apparent that the maximum deceleration lies between 0.36 g and 0.64 g. This is contrasted with maximum accelerations of about 0.08 g measured during the Molikpaq events of 1986. The ice impact velocities at the Molikpaq vary from the creep range to a maximum of 0.6 m/s with the average during the measurements of interest being in the range of 0.1 to 0.2 m/s (Jefferies and Wright, 1988) and thus the impacts were at a lower speed than for the ships. Because of its mass and stiffness (approximately 200,000 tonnes), it is likely that the global accelerations of the Molikpaq were less than those measured by the accelerometers which would have sensed the local accelerations of the steel. Thus the

TABLE 1

Calculation of ice contact areas for ships

Ship	Displacement D (ktonnes)	Power (MW)	F_{max} (MN)	Contact area (m^2)	F_{max}/D (g)	Dimensions of contact area for aspect ratio 8:1	
						Depth (m)	Width (m)
1. Kigoriak	7	13	37.8	25.2	0.55	1.8	14.2
2. John A. Macdonald	9.16	11	45.0	30.0	0.50	1.9	15.5
3. Polar Sea	11.656	14	56.8	37.9	0.50	2.2	17.4
	11.656	45	72.6	48.4	0.64	2.5	19.7
4. Louis St. Laurent	14.28	20	71.2	47.5	0.51	2.4	19.5
5. M.V. Arctic	40	11	142.4	94.9	0.36	3.4	27.6
6. Future 1	80	36	301.5	201.0	0.38	5.0	40.1
7. Future 2	200	48	648.9	432.6	0.33	7.4	58.8

accelerometer readings probably represent an upper bound to the Molikpaq accelerations. Thus it is clear that in ship/ice interactions the ship's momentum and kinetic energy provide the energy for the impact force while for fixed structures, it is the ice motion which provides the energy for the resulting impact force. It is interesting to note that the mass of the Molikpaq is of the same order as the displacement of the larger ships contemplated for future ice covered water transit.

Combined data

A pressure vs. area graph for the combined data is presented in Fig. 11. Individual points are plotted for the 3 m^2 Pond Inlet, M.V. Arctic, Kigoriak and the Flat Jack data. The dashed line is the mean of this data and the 2STD solid line is a line two standard deviations from the mean. Tables 2, 3 and 4 show the effects of including or not including some of the data in these calculations. As can be seen from the tables, the mean and standard deviations are calculated by dividing the areas into ranges and then computing the statistical values for the pressures within those ranges.

Tables 2 and 3 contain the Kigoriak data while Table 4 does not. It is evident from the standard deviations listed that including the Kigoriak data increases the scatter of the combined data. However, the 2STD line is not significantly changed by its inclusion since the resulting lower mean offsets the higher standard deviation.

TABLE 2

Pressure vs. area data — Pond Inlet, M.V. Arctic and Kigoriak 1981; Gulf flat jack data

Area range (m^2)	Mean pressure (MPa)	Std. dev. (MPa)	No. points
0–0.5	8.68	7.01	73
0.5–1	3.87	2.81	117
1–2	2.20	1.35	185
2–3	1.98	1.13	116
>3	1.27	0.98	69
		Total	560

TABLE 3

Pressure vs. area data — Pond Inlet, M.V. Arctic and Kigoriak 1981

Area range (m^2)	Mean pressure (MPa)	Std. dev. (MPa)	No. points
0–0.5	8.09	7.17	59
0.5–1	3.21	2.01	95
1–2	2.16	1.32	180
2–3	1.98	1.13	116
>3	1.27	0.98	69
		Total	560

The 2STD line for the combined data of Fig. 11 forms an envelope to the data. Its equation is:

$$p = 8.1A^{-0.572} \quad \text{for } A \leqslant 19\ \text{m}^2 \qquad (2)$$

TABLE 4

Pressure vs. area data — Pond Inlet and M.V. Arctic

Area range (m^2)	Mean pressure (MPa)	Std. dev. (MPa)	No. points
0–0.5	8.8	7.1	51
0.5–1	4.5	1.6	50
1–2	2.7	1.2	95
2–3	2.8	0.6	68
>3	2.7	0.6	19
		Total	283

Also, for areas greater than 19 m^2, the upper envelope (not a 2STD line) is:

$$p = 1.5 \text{ MPa for } A > 19 \text{ m}^2 \quad (3)$$

where p = pressure (in MPa) and A = area (in m^2).

Since F_{max} of Table 1 is:

$$F_{max} = p \cdot A \quad (4)$$

then:

$$F_{max} = 8.1A^{0.428} \quad \text{for } A \leq 19 \text{ m}^2$$

$$F_{max} = 1.5A \quad \text{for } A > 19 \text{ m}^2$$

This relationship was used to calculate the areas of Table 1.

The indentor data does constitute a standard since crushing was the mode of failure for the ice and the contact area is known with considerable precision. The M.V. Arctic data agrees well with it and the Kigoriak data is in reasonable agreement.

The Molikpaq data is shown in Fig. 11. Since this pressure information was collected at high aspect ratio, it might be expected to form a somewhat lower bound to the pressure vs. area curve. To complete the envelope of pressures, the 2STD line for the combined data was extended downward and to the right to intersect a horizontal line bounding the Molikpaq data.

Whether the larger areas of crushing shown in Fig. 11 develop on ship's hulls will depend on how the ships are operated and on their respective hull strengths. From observing the test results, the M.V. Arctic has not developed the contact area in crushing the formula indicates it is capable of while the Kigoriak has. However, the maximum impact velocity for the M.V. Arctic rams was 2.1 m/s while for the Kigoriak average impact velocities reached 6.31 m/s. The measurements of penetration from both programs show that this value, and thus total contact area, do depend on impact velocity. The envelope of Figure 11 does provide pressure values over a very wide range of areas for use in design and likely encompasses values of interest for any practical ship.

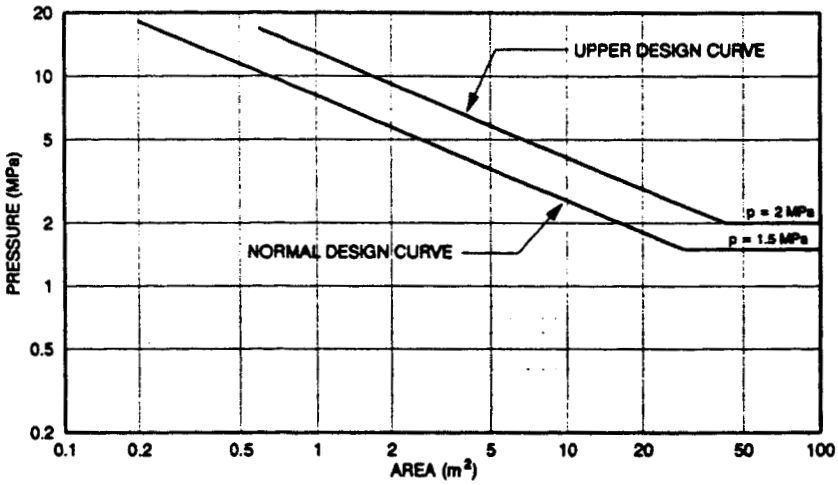


Fig. 12. Pressure vs. area. Recommended design curve. Normal: $0.1 < A < 29$ m^2, $p = 8.1A^{-0.5}$; upper: $0.1 < A < 42$ m^2, $p = 13A^{-0.5}$.

Suggested design curves

Figure 12 contains suggested design curves for local ice pressures on structures. The curves are based on the information presented previously and summarized in Fig. 11. The "normal" or lower bound design curve closely follows the 2STD curve of Fig. 11, except the exponent (slope in a log plot) has been changed to −0.5. This is conservative, leading to higher pressures at larger areas. The "upper" design curve is essentially a 3STD curve to the data of Figure 11 and thus results in a lower probability that pressures will exceed its bounds. The associated probabilities of 2 and 3 standard deviations are, approximately, 0.05 and 0.001 respectively. The 1.5 and 2 MPa values at the larger areas do not represent standard deviation multiples as there is insufficient data at this scale to perform such a calculation.

Structures such as the Molikpaq (Bruce and Harrington, 1982) have been designed using pressures conforming to the normal design curve of Figure 12 and have performed well under heavy ice loading with no visible local damage to the structure. Thus future design practice conforming to the guidelines given in Figure 12 should result in safe structures which do not experience significant ice damage.

Summary and conclusions

Ice pressure vs. area information from different sources has been assembled with the view of providing information relevant to the design of structures for local loads. The pressures are relevant to the determination of steel plate thicknesses and the spacing and size of bracing or concrete wall thicknesses and the amount of reinforcing.

The bulk of data available covers loaded areas of 0.1 to about 8 m^2. Much of this information has been obtained from tests with high confinement, i.e. where the loaded area is relatively far from any free surface and thus confinement of the ice results. The other body of data covers areas larger than 100 m^2. It was principally obtained from Gulf's Molikpaq and in this case the aspect ratio was large and the loaded area is close to a free surface.

A detailed examination of 83,000 multi-year ice thickness borings taken in the Arctic Islands during over-the-ice seismic operations (Masterson et al., 1991) revealed that the majority of multi-year is 12 m thick or less. Less than a handful of the holes drilled were 20 m and the lateral extent of ice of this thickness was small (50 m or less). Thus as loaded areas become large, even for "local" pressures, free surfaces will likely be in close proximity and affect the failure mode and thus pressures. The load areas of the Molikpaq are of the same order as they would be for a large tanker ship of 80,000 to 200,000 tonnes displacement and therefore the pressures should be similar.

Admittedly, such large loaded areas with relatively large aspect ratios and free surfaces bounding them are little different than global loading scenarios. However, side shell and bow pressures on a ship still present a challenge to one designing frames, plates and bracings. The problem is similar for fixed structures. Pressures on smaller loaded areas within the large area are covered by portions of the pressure–area curve to the left.

In the case of impacts by lumped masses such as icebergs, the boundary conditions may be different and a free surface may not be in close proximity at large loaded areas. In this case the pressures could be higher. At present there is no large scale data available to the authors to quantify this situation. However, even icebergs have ledges, shelves and uneven surfaces plus flaws and it is difficult to imagine a loaded area of hundreds of m^2 with no free surface nearby.

Specific conclusions summarizing the work are listed below:

(1) Ice pressure vs. contact area information from indentation and flat jack tests, large scale indentor tests, instrumented ship rams and from fixed structure measurements has been combined to produce a local pressure vs. area curve covering a large range of contact areas (0.1 m^2 to 100 m^2).

(2) Indentor and flat jack tests are conducted with a high degree of control and thus are useful as a base for comparing data from various sources.

(3) The ice used to gather the pressure vs. area information was carefully chosen and was solid, cold (at least −10°C) and without major flaws. The pressure vs. area information was obtained from ice of the following different sources:

- multi-year ice for the flat jack tests and for the Kigoriak and M.V. Arctic rams and for the Hans Island tests
- fresh-water lake ice for the APOA "Nutcracker" tests
- iceberg ice for the Pond Inlet indentor tests
- first year ice for the Molikpaq.

(4) In spite of the different ice types, the combined data present a coherent overall picture with effective ice pressure decreasing as the contact area increases. If there is a bias in the information presented, it may be towards higher pressures since for the indentor and flat jack tests and for the ship rams solid floes were deliberately chosen. The Kigoriak events represent impacts by thicker, stronger ice than had been observed during any of the other years of its operation.

(5) Over the range of velocities at which tests were conducted there was no significant effect of impact velocity on the ice pressure experienced. Thus the combination of Kigoriak data (impact velocities up to 6.31 m/s) with M.V. Arctic data (impact velocities up to 2.1 m/s) with indentor data (impact velocities of 0.1 m/s) and Molikpaq data (impact velocities of a maximum of 0.6 m/s) is reasonable. The Hans Island data, where impact velocities were higher than for the Molikpaq and of similar scale, does not show higher pressures, although the ice at Hans Island was warm, summer ice and that impacting the Molikpaq in 1986 was cold, winter ice. The accurate determination of local ice pressures from the Hans Island data is difficult. Thus it is presented more for comparison and is not used to determine the pressure envelope.

(6) The previous conclusion is not meant to imply that impact velocity does not have important consequences for structure or ship response. Jefferies and Wright (1988) show that certain ice velocities can alter the dynamic response of fixed structures significantly, often with undesirable consequences. However, this is more often a global rather than a local effect. Structures such as lighthouses have failed under dynamic loading (Maattanen, 1980). Two jack-up structures in the Bohai Gulf also failed as a result of dynamic loading (Jizu et al., 1983).

(7) Proposed local ice pressures design curves are presented and are based on the ice impact information assembled during this project. The curves represent reasonable upper bounds of the data and have been verified by field experience.

Acknowledgement

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APPENDIX 4

TOPSIDE FACILITIES AREA, WEIGHT, AND COST

APPENDIX 4: TOPSIDE FACILITIES AREA, WEIGHT, AND COST

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APPENDIX 4: TOPSIDE FACILITIES AREA, WEIGHT, AND COST

Summary

A wide range of drilling, production and processing requirements was selected to cover possible economic developments of Kuvlum. Basic description of this range is:

Basic requirements:

- 2 drill rigs/platform
- 40 to 100 wells/platform
- 10 month supply of drilling consumables on board

Complete listing of requirements and their ranges are given in this section.

GOSP (General Offshore Simulation Program) was used to estimate area, weight and cost for production, processing, utilities and quarters. Nelson-Farrar Cost Indices were used to update GOSP internal cost data sets. GOSP user input cost values were updated using ARCO Alaska's North Slope onshore experience and recent costs for large, North Slope production modules fabricated on the coast of the Gulf of Mexico.

ARCO Alaska furnished area, weight and cost for drilling facilities.

Modular construction on the coast of the Gulf of Mexico Coast was assumed. These modules were then assumed to be towed by barge to the Far East, installed and certified on a gravity Kuvlum structure fabricated in the Far East. The structure with installed modules and consumables was then towed to Kuvlum.

Area and weight estimates are shown in Figures A4-20 through A4-25 for six cases, three drilling/primary production cases and three drilling/production/ processing cases. Scaled sketches of these six topside facilities are shown in Figure A4-26. Deck dimensions varied from 240' square on two levels, to 350' square on three levels. Bulk storage of consumables were placed in the large gravity structure above and below water line.

Most likely costs of topsides facilities were estimated for these six cases. Optimistic (10%) and pessimistic (90%) costs were estimated to be 0.70 and 1.70 of the most likely costs. Triangular distribution of costs was assumed which yields expected costs equaling 1.13 times the most likely costs.

Based on the results of these six cases, most likely costs of drilling/production/ processing facilities, fabricated on the Gulf Coast, towed and installed on a Kuvlum structure at a protected water site in the Far East, can be approximated in terms of oil rate by the following expression:

- Most Likely Cost = 250$MM + (1.6$M/MBOPD)*Oil Rate in MBOPD

This cost expression includes a 0.30$MM/MBOPD cost for towing to the Far East site and installation. This equation fits the plotted values titled "Cost of Facility on Drill and Process Platforms for Cases Selected by AAI" in Figure A4-33 and "Cost of Facility on a Drill and Process Platform for Case 3" in Figure A4-34.

For only drilling and primary separation facilities, most likely cost expression is:

- Most Likely Cost = 70$MM + (0.70$MM/MBOPD)*Oil Rate in MBOPD.

This equation fits the plotted values titled "Cost of Facility on Drill Platforms at 120, 210, and 300 MBOPD" in Figure A4-33 and "Interpolated Cost of Drilling Facility at 40, 75, 115, 150, and 155 MBOPD" in Figure A4-34.

Distribution of topsides facilities cost for Section III - Economic Analysis Cases 1, 2, and 3 are shown graphically and numerically in Figures A4-3 through A4-16. These cost distributions are developed here in Appendix 4.

Assumptions

Major assumptions not mentioned above were:

- Drilling mud and cuttings are processed and injected subsurface from the platforms.
- Produced water is reinjected.
- Excess gas is reinjected.
- Sales quality oil is sent to sales pipeline.
- All processing is offshore, no onshore facilities.
- All power is generated on the processing platform.
- Access by large helicopter from Prudhoe during winter and spring.
- Resupply by barge each summer around Point Barrow, or for extreme summer ice years from Prudhoe Bay.

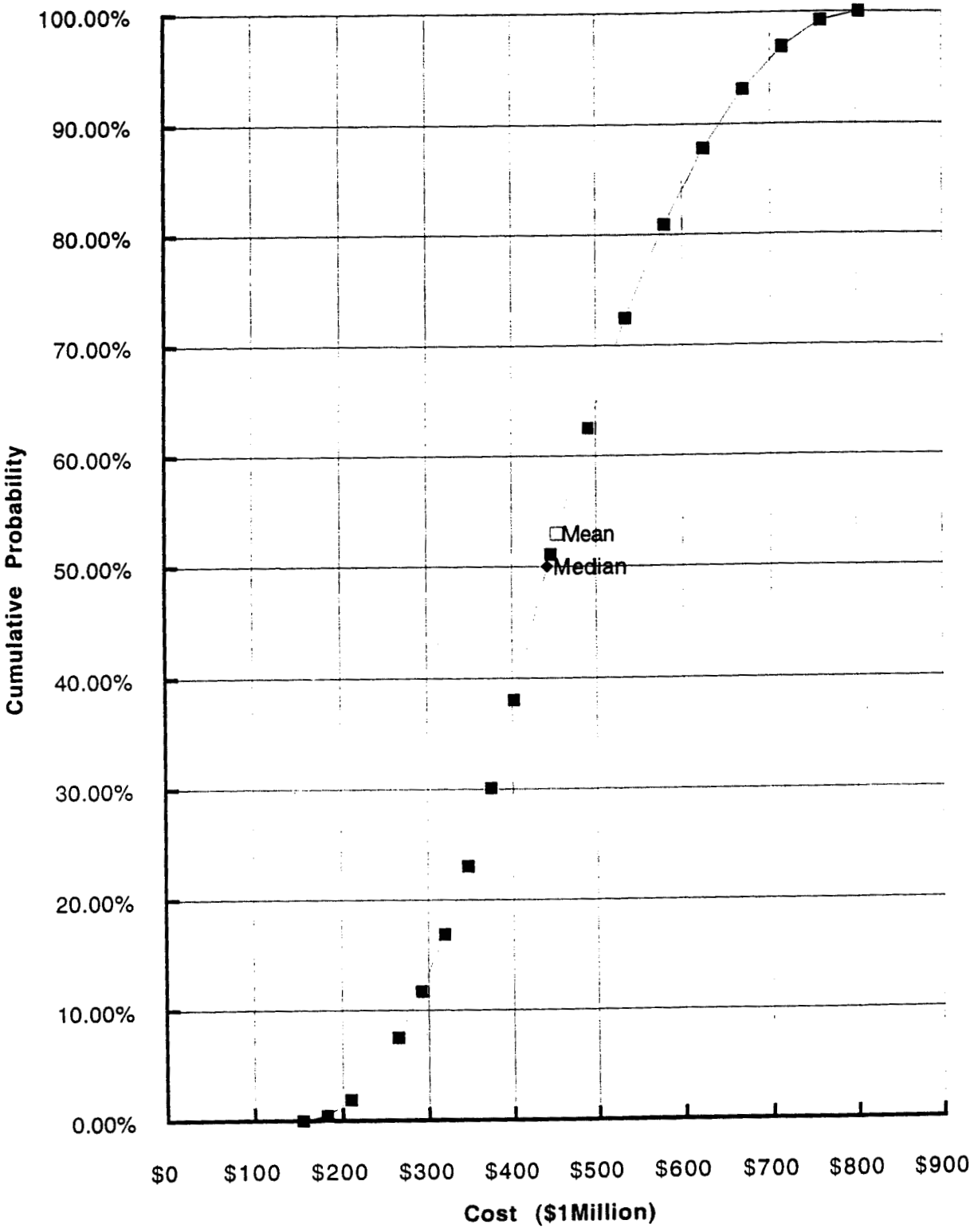


FIGURE A4-3
Topsides Facilities Cost for Case 1 (40 Wells, 2 Drill Rigs, 120 MBOPD) Production and Processing

This Spread Sheet will compute the unique Triangular Probability Density Distribution and the unique Cumulative Probability Curve determined by the k'%, Most Likely and k"% Cost Estimates

INPUT:

	Costs in $1,000,000	
k' & k'Cost Estimate	0.1	$280.70
Most Likely Cost Estimate	b=	$401.00
k"' & k"'Cost Estimate	0.9	$641.60

Topsides Facilities Cost for Case 1, 40 Wells, 1 Drill Rig, 120 MBOPD Production and Processing.

0% cost = $154.11 100%Cost= $803.16

See Table for Probability Density vs Cost, Mean & Median Costs

To Calculate the Absolute Minimum Cost (0%Cost Estimate) which will be called "a" and the Absolute Maximum Cost (100% Cost Estimate) which will be called "c". Note the Most Likely Cost is called "b".

The k', Most Likely, and k"'Cost Estimates completely define the Triangular Probability Density Distribution and Cumulative Probability Curves. An interative procedure has to be used to calculate "a" and "c"; that is, the 0%Cost Estimate and the 100% Cost Estimate, respectively.

First step is to determine which set of equations are applicable to find "a"and "c". This will depend on where the Most Likely Cost Estimate "b" lies relative to k' and k"'Cost Estimates.

Please note that k'Cost Estimate is always less than k"'Cost Estimate.

FOR THE ABOVE K'COST, MOST LIKELY COST AND K"'COST ESTIMATES USE XXXXXXX MIDDLE CASE XXXXXXX

CASE LEFT

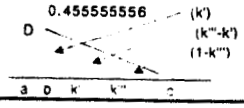
If Most Likely Cost Estimate < k'Cost Estimate

c= 822.05000

D= 0.00258613

a= 48.69285714

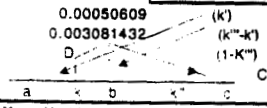
Therefore k2 for Most Likely Cost Estimate is equal to 0.455555556



CASE MIDDLE

If (k'CostEstimate<Most Likely Cost Estimate<k"'Cost Estimate), iterate to Find Absolute Minimum 'a' and Maximum 'c' Cost Estimates. Try values of 'a' until c'=c". Trial 'a'= 154.1135

c'=	803.1624347	0.0001
c"=	803.1619286	0.001
Delta=(c'-c")=	0.00050609	
D=	0.003081432	



CASE RIGHT

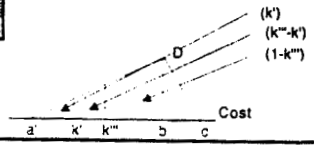
If (k'Cost Esti.<k"'Cost Esti.>Most Likely Cost Esti.),

a= 100.25

c= 1182.95

D= 0.001847234

154.1136



Is a <k'Cost Estimate? Yes. Valid

Is K'<K"'? Yes,Valid

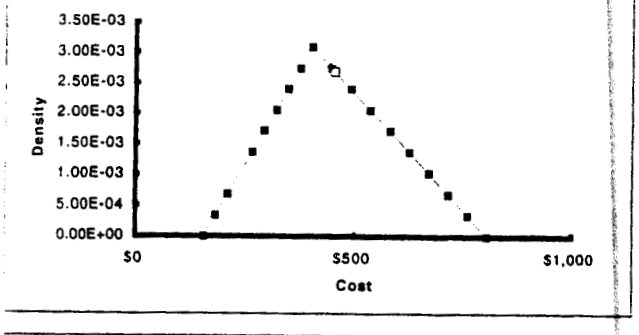
Please Note that you must enter the values calculated above into these slots before computing distributions.

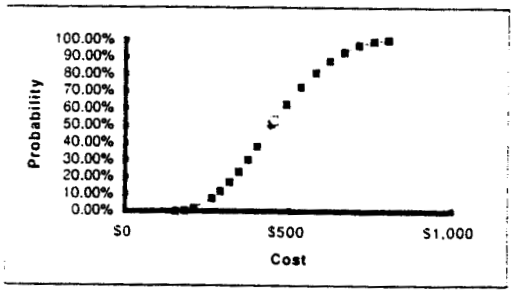
Enter the Values of "a", "c", and D computed above

a=	$154.1135
c=	$803.1624
D=	0.00308143

Calculating Probability Density Distribution and Cumulative Probability Curves

	Cost in $1,000,000 $	Probability Density (1/$)	Cumulative Probability %
	$154	0.00E+00	0.00%
	$182	3.42E-04	0.47%
	$209	6.85E-04	1.88%
	$264	1.37E-03	7.51%
	$264	1.37E-03	7.51%
	$291	1.71E-03	11.74%
	$319	2.05E-03	16.91%
	$346	2.40E-03	23.01%
	$374	2.74E-03	30.05%
Most Likely	$401	3.08E-03	38.04%
	$446	2.74E-03	51.04%
	$490	2.40E-03	62.52%
	$535	2.05E-03	72.46%
	$580	1.71E-03	80.88%
	$624	1.37E-03	87.76%
	$669	1.03E-03	93.12%
	$714	6.85E-04	96.94%
	$758	3.42E-04	99.24%
Absolute Maximum	$803	0.00E+00	100.00%
MEAN COST	$452.76	2.68E-03	52.96%
MEDIAN COST	$441.90	0.00276806	50.00%





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FIGURE A4-4
Topside Facilities Cost for Case 1 (40 Wells, 2 Drill Rigs, 120 MBOPD) Production and Processing

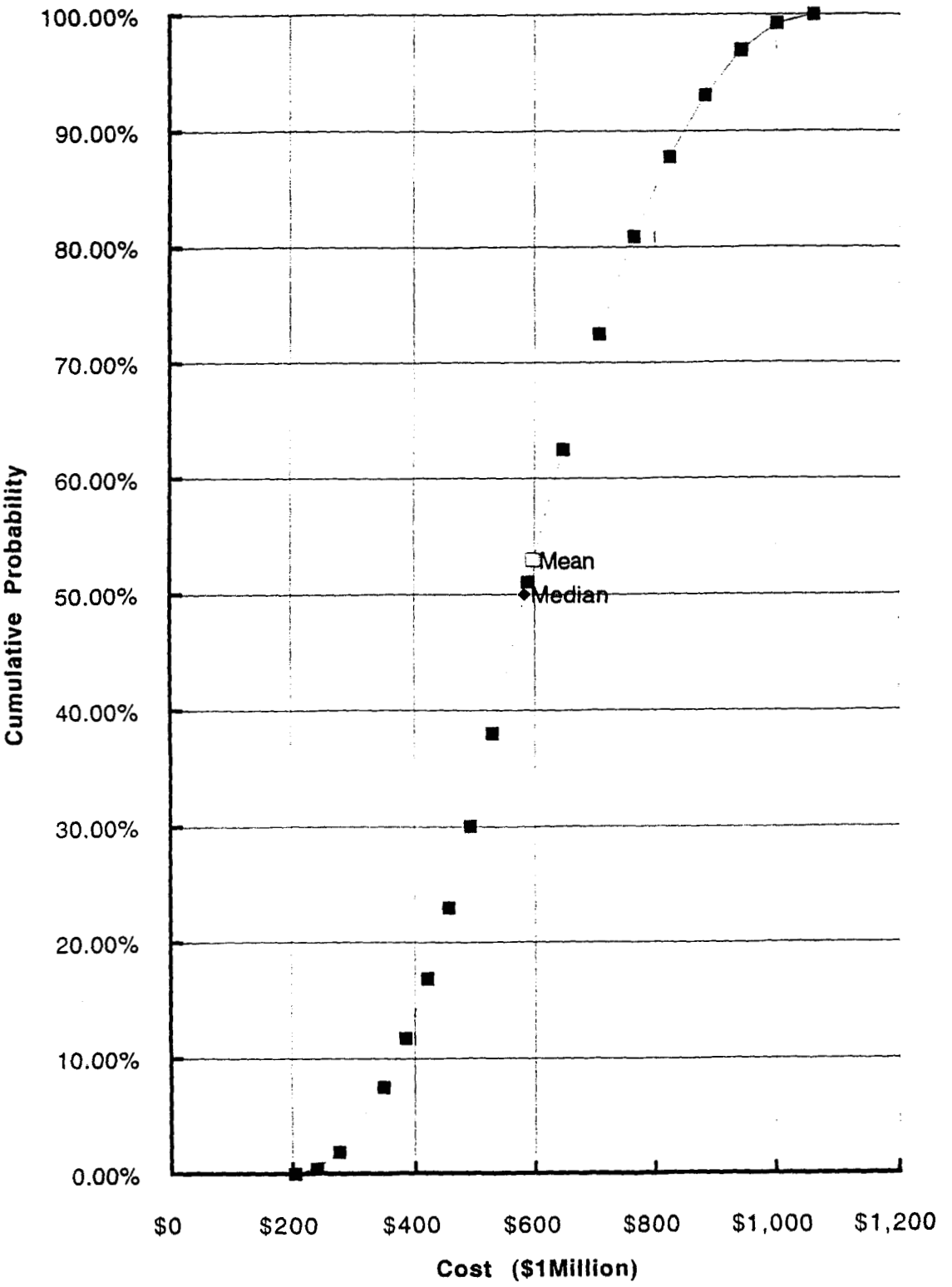


Figure A4-5
Topsides Facilities Cost for Intermediate Case between Case 1 and Case 2 (70 Wells, 2 Drill Rigs, 210 MBOPD)
Production and Processing

This Spread Sheet will compute the unique Triangular Probability Density Distribution and the unique Cumulative Probability Curve determined by the k'%, Most Likely and k'"% Cost Estimates

INPUT:	Costs in $1,000,000		
k' & k'Cost Estimate	0.1	$370.30
Most Likely Cost Estimate	b=	$529.00
k''' & k'''Cost Estimate	0.9	$846.40

Topsides Facilities Cost for Intermediate Case between Case 1 and Case 2, 70 Wells, 2 Drill Rigs, 210 MBOPD Production and Processing.
0% cost = $203.31 **100%Cost= $1,059.53**
See Table for Probability Density vs Cost, Mean & Median Costs

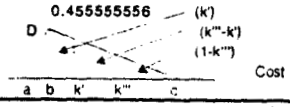
To Calculate the Absolute Minimum Cost (0%Cost Estimate) which will be called "a" and the Absolute Maximum Cost (100% Cost Estimate) which will be called "c". Note the Most Likely Cost is called "b".

The k', Most Likely, and k'"Cost Estimates completely define the Triangular Probability Density Distribution and Cumulative Probability Curves. An interative procedure has to be used to calculate "a" and "c"; that is, the 0%Cost Estimate and the 100% Cost Estimate, respectively.

First step is to determine which set of equations are applicable to find "a"and "c". This will depend on where the Most Likely Cost Estimate "b" lies relative to k' and k'"Cost Estimates.
Please note that k'Cost Estimate is always less than k'"Cost Estimate.

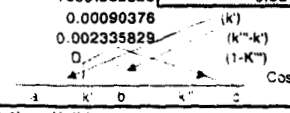
FOR THE ABOVE K'COST, MOST LIKELY COST AND K'"COST ESTIMATES USE **XXXXXXX MIDDLE CASE XXXXXXX**

CASE LEFT
If Most Likely Cost Estimate < k'Cost Estimate
c= 1084.45000
D= 0.00196037
a= 64.23571429
Therefore k2 for Most Likely Cost Estimate is equal to 0.455555556

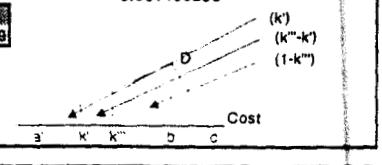


CASE MIDDLE
If (k'CostEstimate<Most Likely Cost Estimate<k'"Cost Estimate), iterate to Find Absolute Minimum 'a' and Maximum 'c' Cost Estimates. Try values of 'a' until c'=c". Trial 'a'= 203.3068

		Incr. 'a'	Delta
c'=	1059.533729	0.0001	STEP
c"=	1059.532825	0.001	203.3068
Delta=(c'-c")=	0.00090376		
D=	0.002335829		



CASE RIGHT
If (k'Cost Esti.<k'"Cost Esti.>Most Likely Cost Esti.),
a= 132.25
c= 1560.55
D= 0.001400266



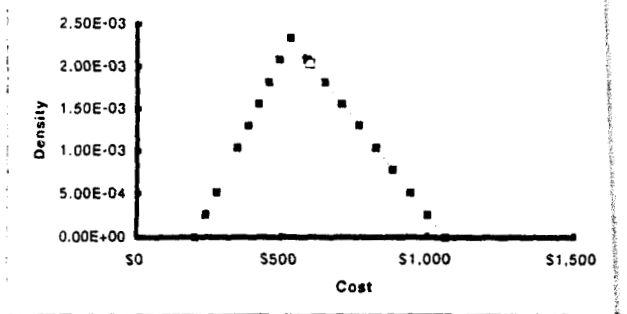
Is a <k'Cost Estimate? Yes. Valid
Is K'<K'"? Yes,Valid

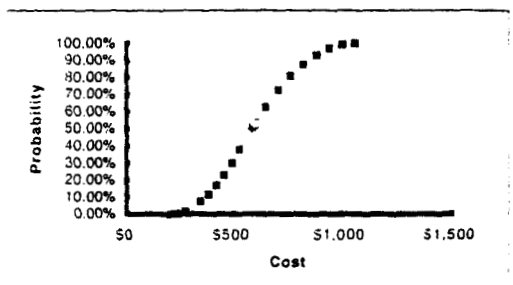
Please Note that you must enter the values calculated above into these slots before computing distributions.

Enter the Values of "a", "c", and D computed above		
	a=	$203.3068
	c=	$1,059.5337
	D=	0.00233583

Calculating Probability Density Distribution and Cumulative Probability Curves

	Cost in $1,000,000 $	Probability Density (1/$)	Cumulative Probability %
	$203	0.00E+00	0.00%
	$239	2.60E-04	0.47%
	$276	5.19E-04	1.88%
	$348	1.04E-03	7.51%
	$348	1.04E-03	7.51%
	$384	1.30E-03	11.74%
	$420	1.56E-03	16.91%
	$457	1.82E-03	23.01%
	$493	2.08E-03	30.05%
Most Likely	$529	2.34E-03	38.04%
	$588	2.08E-03	51.04%
	$647	1.82E-03	62.52%
	$706	1.56E-03	72.46%
	$765	1.30E-03	80.88%
	$824	1.04E-03	87.76%
	$883	7.79E-04	93.12%
	$942	5.19E-04	96.94%
	$1,001	2.60E-04	99.24%
Absolute Maximum	$1,060	0.00E+00	100.00%
MEAN COST	$597.28	2.04E-03	52.96%
MEDIAN COST	$582.95	0.002098283	50.00%





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FIGURE A4-6
Topsides Facilities Cost for Intermediate Case between Case 1 and Case 2 (70 Wells, 2 Drill Rigs, 210 MBOPD) Production and Processing

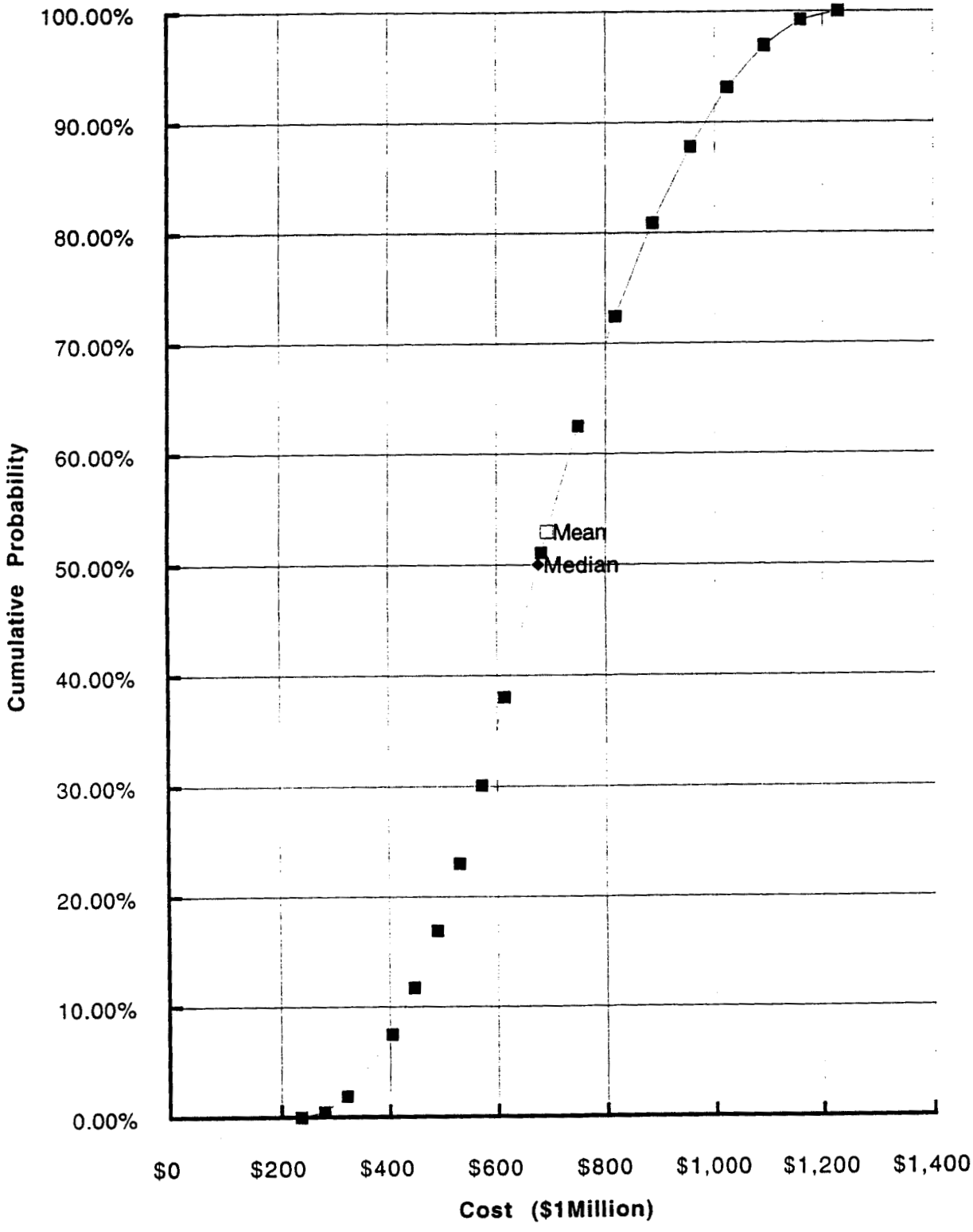


FIGURE A4-7
Topsides Facilities Cost for Case 2
(100 Wells, 2 Drill Rigs, 300 MBOPD) Production and Processing

This Spread Sheet will compute the unique Triangular Probability Density Distribution and the unique Cumulative Probability Curve determined by the k'%, Most Likely and k"% Cost Estimates

INPUT:

	Costs in $1,000,000	
k' & k'Cost Estimate	0.1	$429.10
Most Likely Cost Estimate	b=	$613.00
k"' & k"'Cost Estimate	0.9	$980.80

Topsides Facilities Cost for Case 2, 100 Wells, 2 Drill Rigs, 300 MBOPD Production and Processing.

0% cost = $235.59 100%Cost= $1,227.78

See Table for Probability Density vs Cost, Mean & Median Costs

To Calculate the Absolute Minimum Cost (0%Cost Estimate) which will be called "a" and the Absolute Maximum Cost (100% Cost Estimate) which will be called "c". Note the Most Likely Cost is called "b".

The k', Most Likely, and k"'Cost Estimates completely define the Triangular Probability Density Distribution and Cumulative Probability Curves. An interative procedure has to be used to calculate "a" and "c": that is, the 0%Cost Estimate and the 100% Cost Estimate, respectively.

First step is to determine which set of equations are applicable to find "a"and "c". This will depend on where the Most Likely Cost Estimate "b" lies relative to k' and k"'Cost Estimates.

Please note that k'Cost Estimate is always less than k"'Cost Estimate.

FOR THE ABOVE K'COST, MOST LIKELY COST AND K"'COST ESTIMATES USE

XXXXXXX MIDDLE CASE XXXXXXX

CASE LEFT

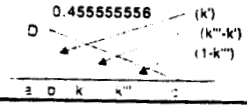
If Most Likely Cost Estimate < k'Cost Estimate

c= 1256.65000

D= 0.00169174

a= 74.43571429

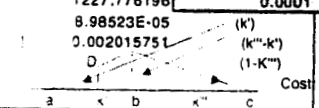
Therefore k2 for Most Likely Cost Estimate is equal to 0.455555556



CASE MIDDLE

If (k'CostEstimate<Most Likely Cost Estimate<k"'Cost Estimate), iterate to Find Absolute Minimum 'a' and Maximum 'c' Cost Estimates. Try values of 'a' until c'=c". Trial 'a'= 235.59007 Incr= 0.00001

c'=	1227.776285	0.00001
c"=	1227.776196	0.0001 235.59008
Delta=(c'-c")=	8.98523E-05	
D=	0.00201575	



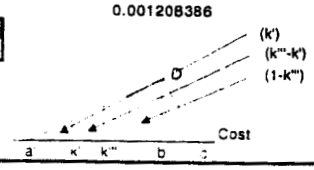
CASE RIGHT

If (k'Cost Esti.<k"'Cost Esti.>Most Likely Cost Esti.),

a= 153.25

c= 1808.35

D= 0.001208386



Is a <k'Cost Estimate? Yes, Valid

Is K'<K"'? Yes,Valid

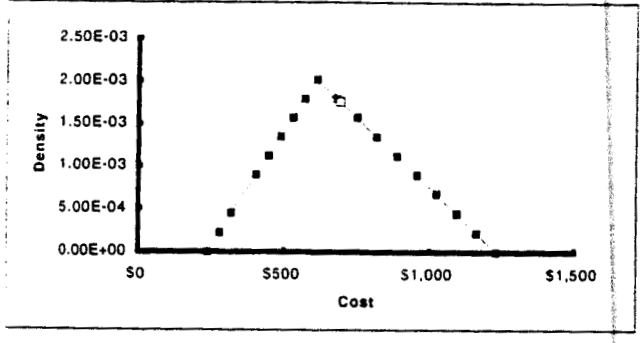
Please Note that you must enter the values calculated above into these slots before computing distributions.

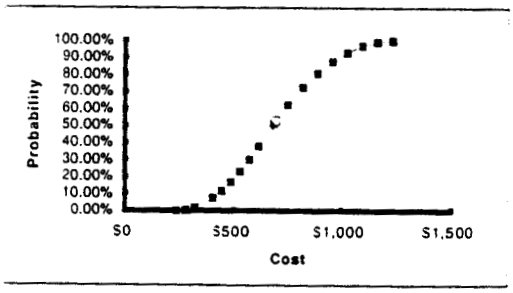
Enter the Values of "a", "c", and D computed above

a=	$235.5901
c=	$1,227.7763
D=	0.00201575

Calculating Probability Density Distribution and Cumulative Probability Curves

	Cost in $1,000,000 $	Probability Density (1/$)	Cumulative Probability %
	$236	0.00E+00	0.00%
	$278	2.24E-04	0.47%
	$319	4.48E-04	1.88%
	$403	8.96E-04	7.51%
	$403	8.96E-04	7.51%
	$445	1.12E-03	11.74%
	$487	1.34E-03	16.91%
	$529	1.57E-03	23.01%
	$571	1.79E-03	30.05%
Most Likely	$613	2.02E-03	38.04%
	$681	1.79E-03	51.04%
	$750	1.57E-03	62.52%
	$818	1.34E-03	72.46%
	$886	1.12E-03	80.88%
	$955	8.96E-04	87.76%
	$1,023	6.72E-04	93.12%
	$1,091	4.48E-04	96.94%
	$1,159	2.24E-04	99.24%
Absolute Maximum	$1,228	0.00E+00	100.00%
MEAN COST	$692.12	1.76E-03	52.96%
MEDIAN COST	$675.52	0.001810756	50.00%





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FIGURE A4-8
Topsides Facilities Cost for Case 2
(100 Wells, 2 Drill Rigs, 300 MBOPD) Production and Processing

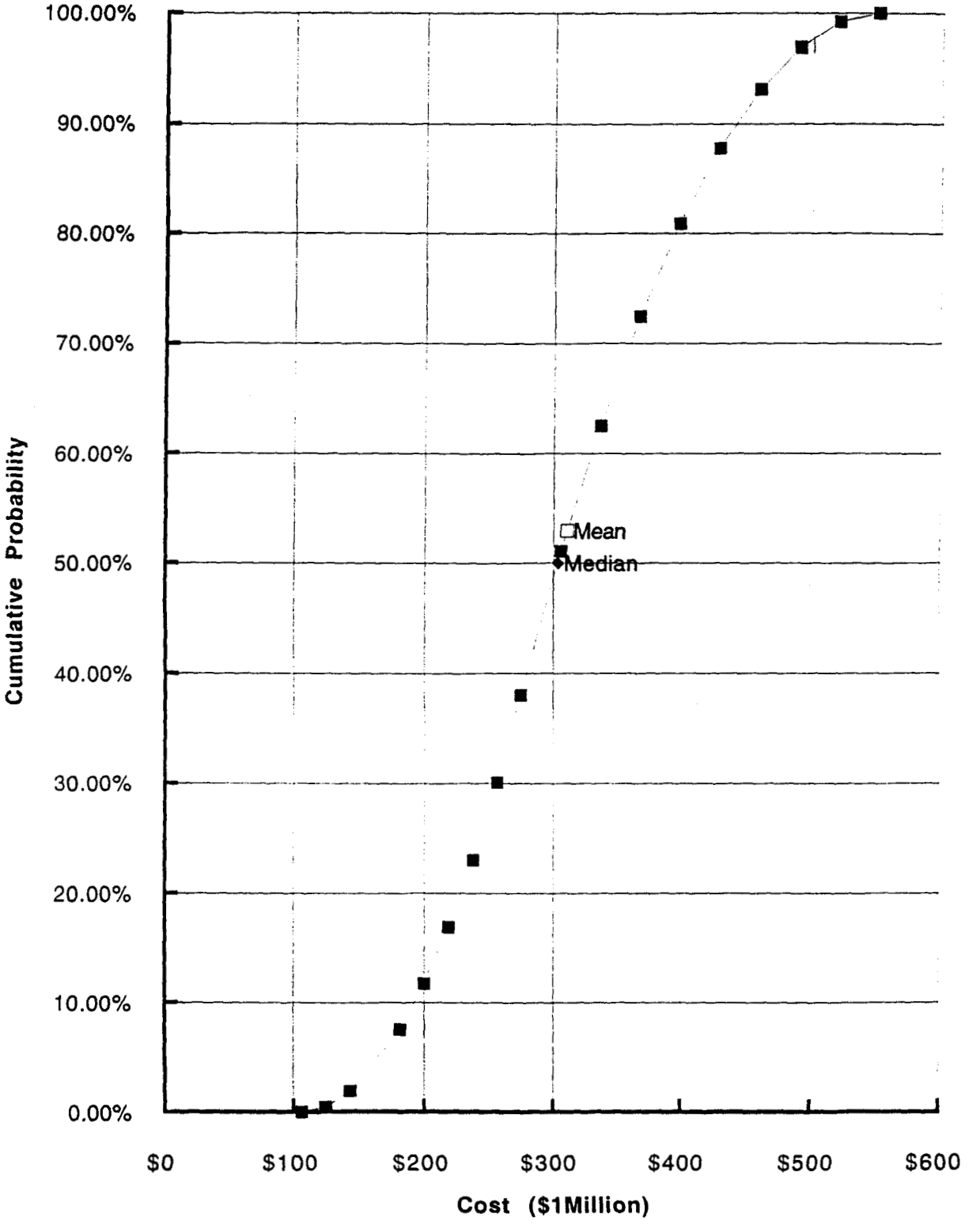


FIGURE A4-9
Topsides Facilities for Case 3. To find Minimum Reserves needed for a PW10 = 0.00 (100 Wells, 2 Drill Rigs, 40 MBOPD) Production and Processing (Reserves 200 Million BBL)

This Spread Sheet will compute the unique Triangular Probability Density Distribution and the unique Cumulative Probability Curve determined by the k'%, Most Likely and k"% Cost Estimates

INPUT:

	Costs in $1,000,000	
k' & k'Cost Estimate	0.1	$192.50
Most Likely Cost Estimate	b=	$275.00
k"' & k"'Cost Estimate	0.9	$440.00

Topsides Facilities Cost for Case 3. To find Minimum Reserves needed for a PW10 = 0.00. 100 Wells, 2 Drill Rigs, 40 MBOPD Production and Processing. Reserves 200 Million BBL.
0% cost = $105.69 **100%Cost= $550.80**
See Table for Probability Density vs Cost, Mean & Median Costs

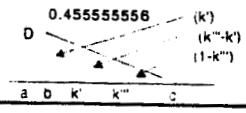
To Calculate the Absolute Minimum Cost (0%Cost Estimate) which will be called "a" and the Absolute Maximum Cost (100% Cost Estimate) which will be called "c". Note the Most Likely Cost is called "b".

The k', Most Likely, and k"'Cost Estimates completely define the Triangular Probability Density Distribution and Cumulative Probability Curves. An interative procedure has to be used to calculate "a" and "c"; that is, the 0%Cost Estimate and the 100% Cost Estimate, respectively.

First step is to determine which set of equations are applicable to find "a"and "c". This will depend on where the Most Likely Cost Estimate "b" lies relative to k' and k"'Cost Estimates.
Please note that k'Cost Estimate is always less than k"'Cost Estimate.

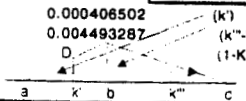
FOR THE ABOVE K'COST, MOST LIKELY COST AND K"'COST ESTIMATES USE XXXXXXX **MIDDLE CASE** XXXXXXX

CASE LEFT
If Most Likely Cost Estimate < k'Cost Estimate
c= 563.75000
D= 0.00377104
a= 33.39285714
Therefore k2 for Most Likely Cost Estimate is equal to 0.455555556

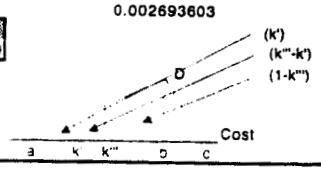


CASE MIDDLE
If (k'CostEstimate<Most Likely Cost Estimate<k"'Cost Estimate), iterate to Find Absolute Minimum 'a' and Maximum 'c' Cost Estimates. Try values of 'a' until c'=c". Trial 'a'= 105.6888

c'=	550.7972421	0.0001	STEP
c"=	550.7968356	0.001	105.6889
Delta=(c'-c")=	0.000406502		
D=	0.004493287		



CASE RIGHT
If (k'Cost Esti.<k"'Cost Esti.>Most Likely Cost Esti.),
a= 68.75
c= 811.25
D= 0.002693603



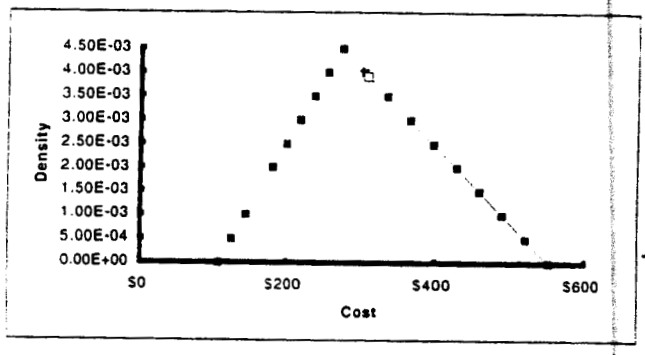
Is a <k'Cost Estimate? Yes, Valid
Is K'<K"'? Yes,Valid

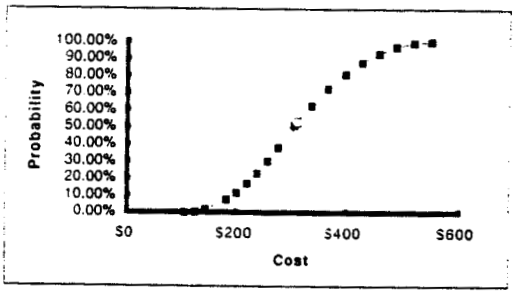
Please Note that you must enter the values calculated above into these slots before computing distributions.

Enter the Values of "a", "c", and D computed above		
	a=	$105.6888
	c=	$550.7972
	D=	0.00449329

Calculating Probability Density Distribution and Cumulative Probability Curves

	Cost in $1,000,000 $	Probability Density (1/$)	Cumulative Probability %
	$106	0.00E+00	0.00%
	$125	4.99E-04	0.47%
	$143	9.99E-04	1.88%
	$181	2.00E-03	7.51%
	$181	2.00E-03	7.51%
	$200	2.50E-03	11.74%
	$219	3.00E-03	16.91%
	$237	3.49E-03	23.01%
	$256	3.99E-03	30.05%
Most Likely	$275	4.49E-03	38.04%
	$306	3.99E-03	51.04%
	$336	3.49E-03	62.52%
	$367	3.00E-03	72.46%
	$398	2.50E-03	80.88%
	$428	2.00E-03	87.76%
	$459	1.50E-03	93.12%
	$490	9.99E-04	96.94%
	$520	4.99E-04	99.24%
Absolute Maximum	$551	0.00E+00	100.00%
MEAN COST	$310.50	3.91E-03	52.96%
MEDIAN COST	$303.05	0.004036334	50.00%





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FIGURE A4-10
Topsides Facilities Cost for Case 3. To find Minimum Reserves needed for a PW10 = 0.00 (100 Wells, 2 Drill Rigs, 40 MBOPD) Production and Processing (Reserves 200 Million BBL)

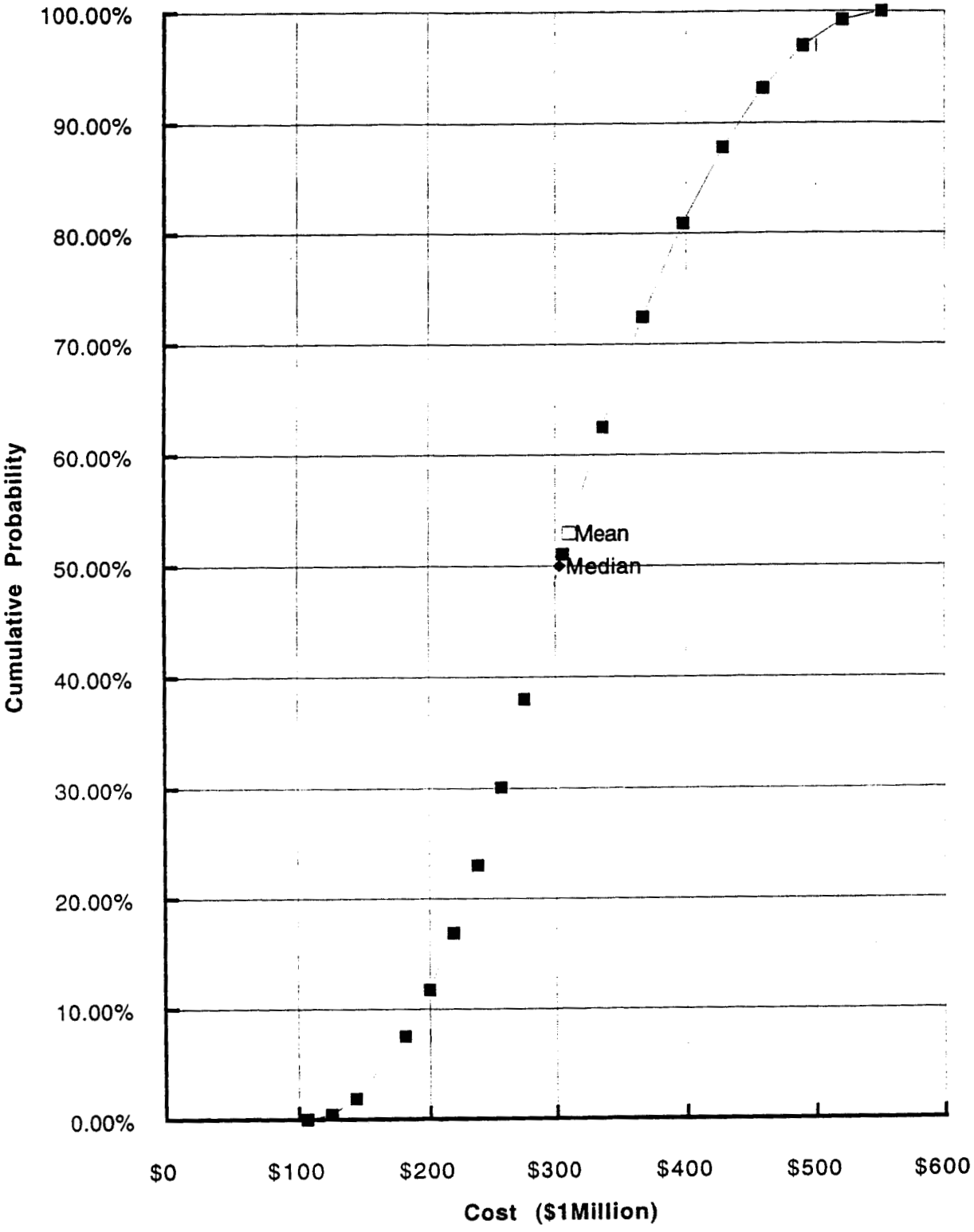


FIGURE A4-11
Topsides Facilities for Case 3. To find Minimum Reserves needed for a PW10 = 0.00 (100 Wells, 2 Drill Rigs, 75 MBOPD) Production and Processing (Reserves 400 Million BBL)

This Spread Sheet will computs the unique Triangular Probability Density Distribution and the unique Cumulative Probability Curve determined by the k'%, Most Likely and k"% Cost Estimates

INPUT:	*Costs in $1,000,000*		
k' & k'Cost Estimate	0.1		$231.00
Most Likely Cost Estimate	b=		$330.00
k''' & k'''Cost Estimate	0.9		$561.00

Topsides Facilities Cost for Case 3. To find Minimum Reserves needed for a PW10 = 0.00. 100 Wells, 2 Drill Rigs, 75 MBOPD Production and Processing. Reserves 400 Million BBL.
0% cost = $119.34 **100%Cost= $711.21**
See Table for Probability Density vs Cost, Mean & Median Costs

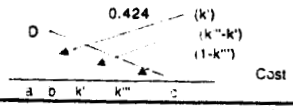
To Calculate the Absolute Minimum Cost (0%Cost Estimate) which will be called "a" and the Absolute Maximum Cost (100% Cost Estimate) which will be called "c". Note the Most Likely Cost is called "b".

The k', Most Likely, and k"'Cost Estimates completely define the Triangular Probability Density Distribution and Cumulative Probability Curves. An interative procedure has to be used to calculate "a" and "c"; that is, the 0%Cost Estimate and the 100% Cost Estimate, respectively.

First step is to determine which set of equations are applicable to find "a"and "c". This will depend on where the Most Likely Cost Estimate "b" lies relative to k' and k'''Cost Estimates.
Please note that k'Cost Estimate is always less then k'''Cost Estimate.

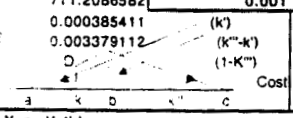
FOR THE ABOVE K'COST, MOST LIKELY COST AND K"COST ESTIMATES USE XXXXXXX **MIDDLE CASE** XXXXXXX

CASE LEFT
If Most Likely Cost Estimate < k'Cost Estimate
c= 726.00000
D= 0.00290909
a= 38.5
Therefore k2 for Most Likely Cost Estimate is equal to 0.424

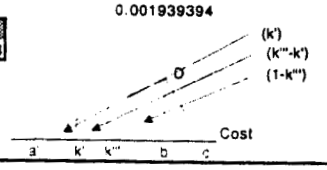


CASE MIDDLE
If (k'CostEstimate<Most Likely Cost Estimate<k'''Cost Estimate), iterate to Find Absolute Minimum 'a' and Maximum 'c' Cost Estimates. Try values of 'a' until c'=c". Trial 'a'= 119.3375 **Incr'al 'a' Delta=** 0.0001 **STEP=** 0.001

c'=	711.2090436	
c"=	711.2086582	119.3376
Delta=(c'-c")=	0.000385411	
D=	0.00337911	



CASE RIGHT
If (k'Cost Esti.<k'''Cost Esti.>Most Likely Cost Esti.),
a= 66
c= 1097.25
D= 0.001939394



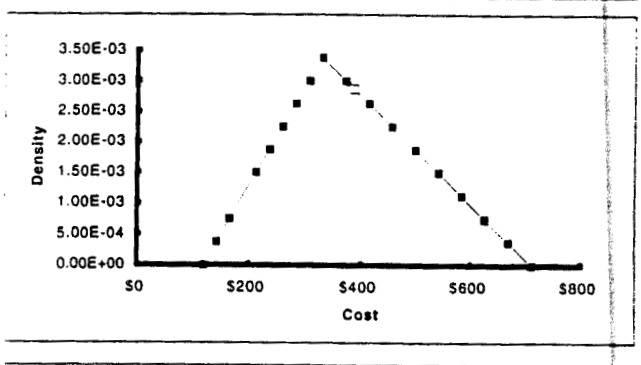
Is a <k'Cost Estimate? Yes, Valid
Is K'<K"'? Yes,Valid

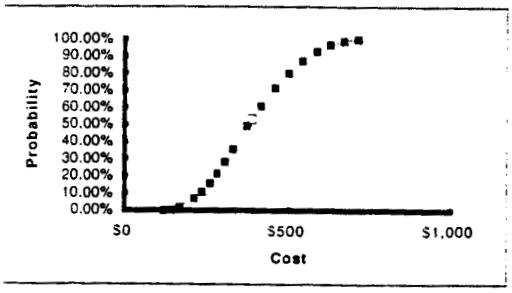
Please Note that you must enter the values calculated above into these slots before computing distributions.

Enter the Values of "a", "c", and D computed above		
	a=	$119.3375
→	c=	$711.2090
	D=	0.00337911

Calculating Probability Density Distribution and Cumulative Probability Curves

	Cost in $1,000,000 $	Probability Density (1/$)	Cumulative Probability %
	$119	0.00E+00	0.00%
	$143	3.75E-04	0.44%
	$166	7.51E-04	1.76%
	$213	1.50E-03	7.03%
	$213	1.50E-03	7.03%
	$236	1.88E-03	10.99%
	$260	2.25E-03	15.82%
	$283	2.63E-03	21.53%
	$307	3.00E-03	28.12%
Most Likely	$330	3.38E-03	35.59%
	$372	3.00E-03	49.11%
	$415	2.63E-03	61.04%
	$457	2.25E-03	71.37%
	$499	1.88E-03	80.12%
	$542	1.50E-03	87.28%
	$584	1.13E-03	92.84%
	$626	7.51E-04	96.82%
	$669	3.75E-04	99.20%
Absolute Maximum	$711	4.34E-19	100.00%
MEAN COST	$386.85	2.88E-03	53.37%
MEDIAN COST	$375.33	0.00297728	50.00%





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FIGURE A4-12
Topsides Facilities Cost for Case 3. To find Minimum Reserves needed for a PW10 = 0.00 (100 Wells, 2 Drill Rigs, 75 MBOPD) Production and Processing (Reserves 400 Million BBL)

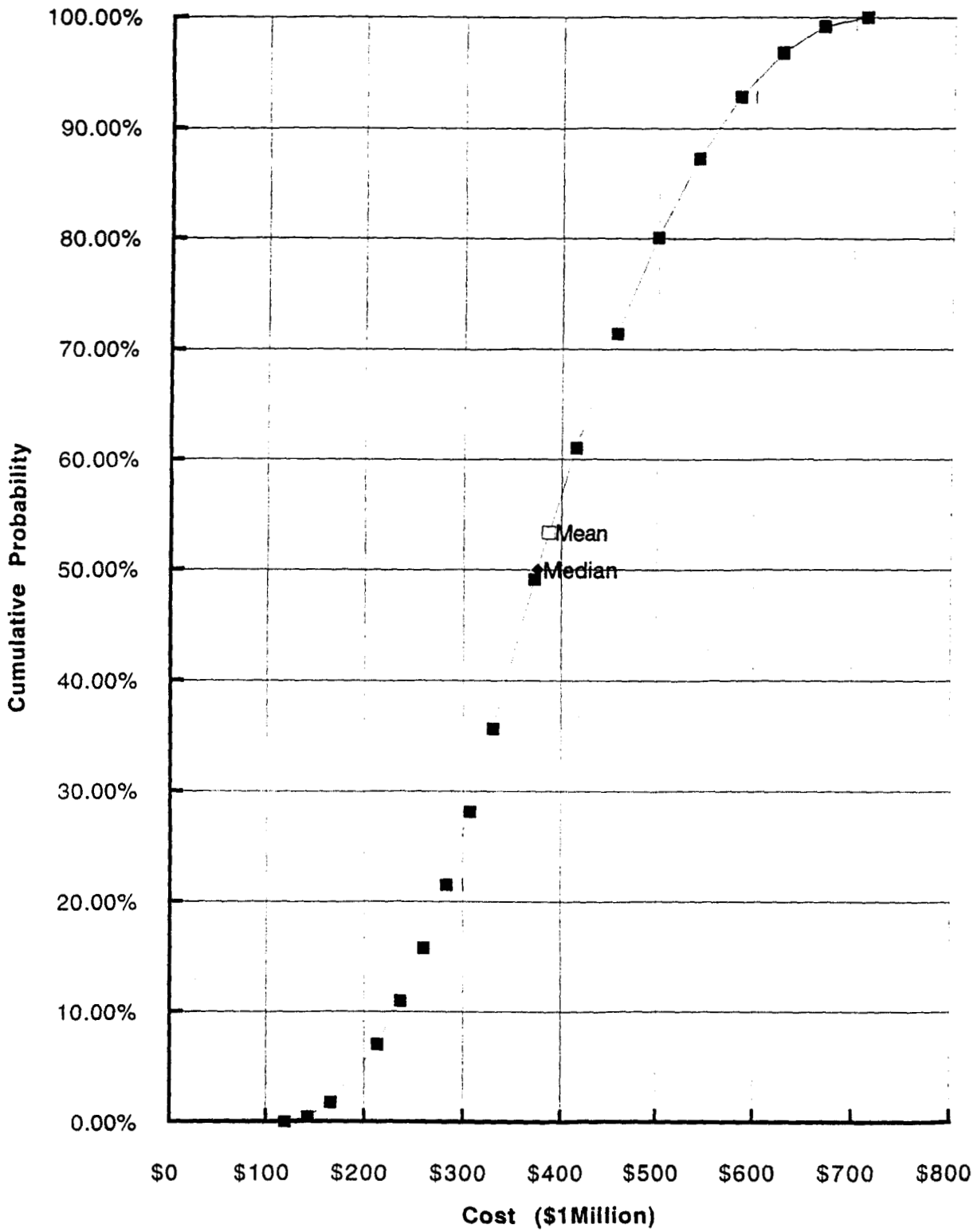


FIGURE A4-13
Topsides Facilities for Case 3. To find Minimum Reserves needed for a PW10 = 0.00 (100 Wells, 2 Drill Rigs, 115 MBOPD) Production and Processing (Reserves 600 Million BBL)

This Spread Sheet will compute the unique Triangular Probability Density Distribution and the unique Cumulative Probability Curve determined by the k'%, Most Likely and k"% Cost Estimates

INPUT:

	Costs in $1,000,000	
k' & k'Cost Estimate	0.1	$275.80
Most Likely Cost Estimate	b=	$394.00
k''' & k'''Cost Estimate	0.9	$630.40

Topsides Facilities Cost for Case 3, To find Minimum Reserves needed for a PW10 = 0.00. 100 Wells, 2 Drill Rigs, 115 MBOPD Production and Processing. Reserves 600 Million BBL.
0% cost = $151.42 100%Cost= $789.14
See Table for Probability Density vs Cost, Mean & Median Costs

To Calculate the Absolute Minimum Cost (0%Cost Estimate) which will be called "a" and the Absolute Maximum Cost (100% Cost Estimate) which will be called "c". Note the Most Likely Cost is called "b".

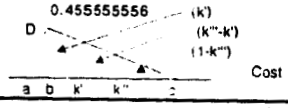
The k', Most Likely, and k'"Cost Estimates completely define the Triangular Probability Density Distribution and Cumulative Probability Curves. An interative procedure has to be used to calculate "a" and "c"; that is, the 0%Cost Estimate and the 100% Cost Estimate, respectively.

First step is to determine which set of equations are applicable to find "a"'and "c". This will depend on where the Most Likely Cost Estimate "b" lies relative to k' and k'"Cost Estimates.

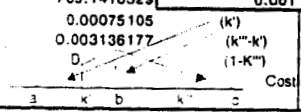
Please note that k'Cost Estimate is always less than k'"Cost Estimate.

FOR THE ABOVE K'COST. MOST LIKELY COST AND K"COST ESTIMATES USE XXXXXXX MIDDLE CASE XXXXXXX

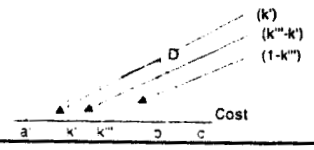
CASE LEFT
If Most Likely Cost Estimate < k'Cost Estimate
c= 807.70000
D= 0.00263207
a= 47.84285714
Therefore k2 for Most Likely Cost Estimate is equal to 0.455555556



CASE MIDDLE
If (k'CostEstimate<Most Likely Cost Estimate<k'"Cost Estimate), iterate to Find Absolute Minimum 'a' and Maximum 'c' Cost Estimates. Try values of 'a' until c'=c''. Trial 'a'= 151.4232 Increment 0.0001 STEP 151.4233
c'= 789.1424039
c''= 789.1416529
Delta=(c'-c'')= 0.00075105
D= 0.003136177



CASE RIGHT
If (k'Cost Esti.<k'"Cost Esti.>Most Likely Cost Esti.),
a= 98.5
c= 1162.3
D= 0.001880053



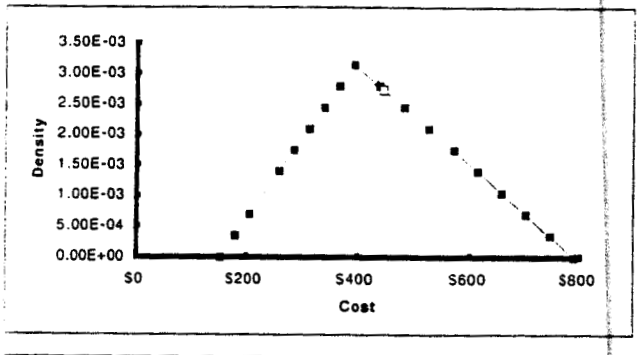
Is a <k'Cost Estimate? Yes. Valid
Is K'<K'"? Yes.Valid

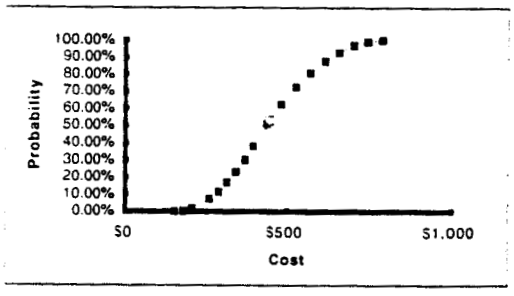
Please Note that you must enter the values calculated above into these slots before computing distributions.

Enter the Values of "a", "c", and D computed above → a= $151.4232, c= $789.1424, D= 0.00313618

Calculating Probability Density Distribution and Cumulative Probability Curves

	Cost in $1,000,000 $	Probability Density (1/$)	Cumulative Probability %
	$151	0.00E+00	0.00%
	$178	3.48E-04	0.47%
	$205	6.97E-04	1.88%
	$259	1.39E-03	7.51%
	$259	1.39E-03	7.51%
	$286	1.74E-03	11.74%
	$313	2.09E-03	16.91%
	$340	2.44E-03	23.01%
	$367	2.79E-03	30.05%
Most Likely	$394	3.14E-03	38.04%
	$438	2.79E-03	51.04%
	$482	2.44E-03	62.52%
	$526	2.09E-03	72.46%
	$570	1.74E-03	80.88%
	$614	1.39E-03	87.76%
	$657	1.05E-03	93.12%
	$701	6.97E-04	96.94%
	$745	3.48E-04	99.24%
Absolute Maximum	$789	0.00E+00	100.00%
MEAN COST	$444.86	2.73E-03	52.96%
MEDIAN COST	$434.18	0.002817237	50.00%





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FIGURE A4-14
Topsides Facilities Cost for Case 3. To find Minimum Reserves needed for a PW10 = 0.00 (100 Wells, 2 Drill Rigs, 115 MBOPD) Production and Processing (Reserves 600 Million BBL)

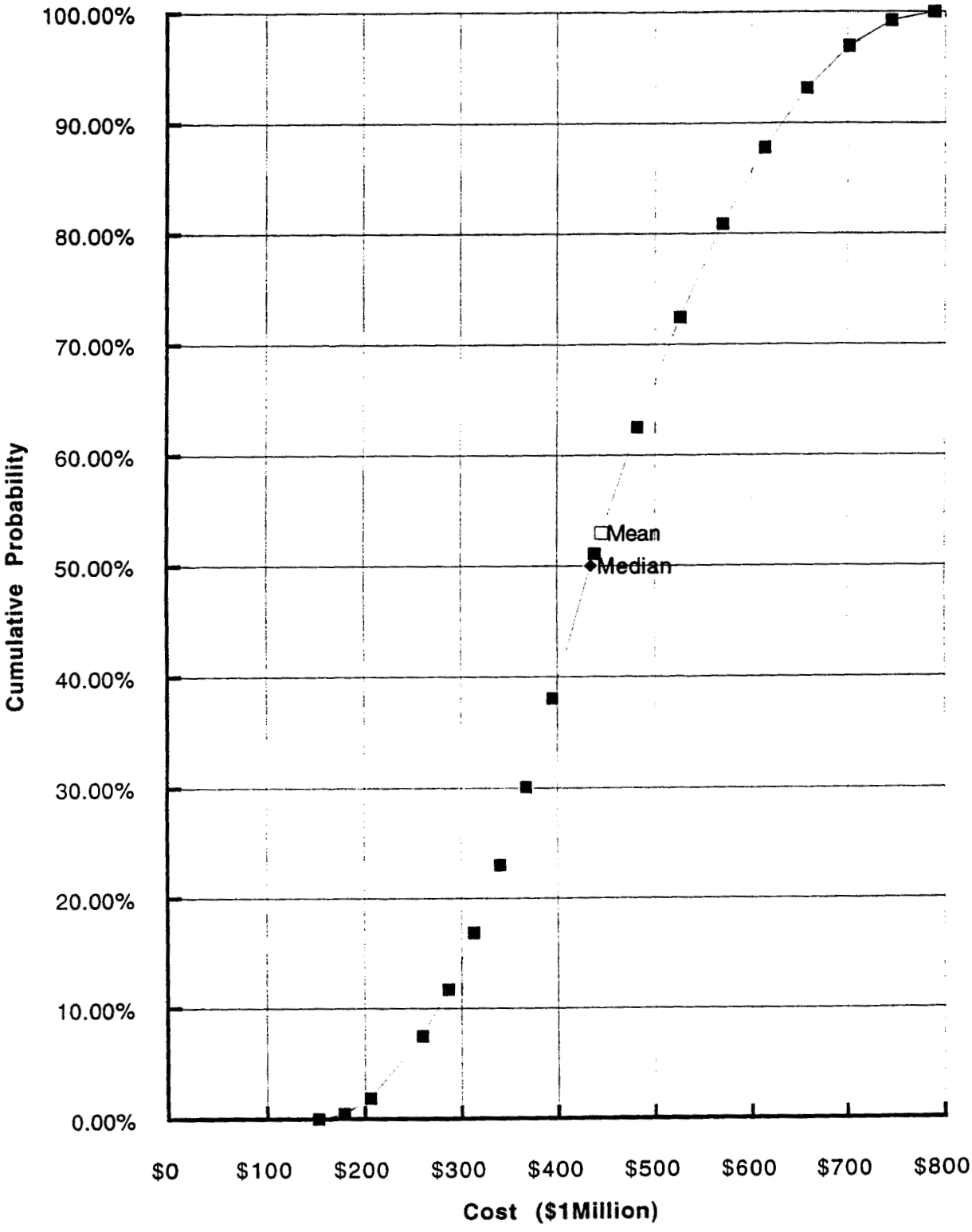


FIGURE A4-15
Topsides Facilities for Case 3. To find Minimum Reserves needed for a PW10 = 0.00 (100 Wells, 2 Drill Rigs, 155 MBOPD) Production and Processing (Reserves 800 Million BBL)

This Spread Sheet will compute the unique Triangular Probability Density Distribution and the unique Cumulative Probability Curve determined by the k'%, Most Likely and k"% Cost Estimates

INPUT:	Costs in $1,000,000		
k' & k'Cost Estimate	0.1		$319.90
Most Likely Cost Estimate	b=		$457.00
k"' & k"'Cost Estimate	0.9		$731.20

Topsides Facilities Cost for Case 3, To find Minimum Reserves needed for a PW10 = 0.00, 100 Wells, 2 Drill Rigs, 155 MBOPD Production and Processing. Reserves 800 Million BBL.
0% cost = $175.64 100%Cost= $915.32
See Table for Probability Density vs Cost, Mean & Median Costs

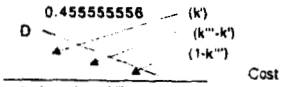
To Calculate the Absolute Minimum Cost (0%Cost Estimate) which will be called "a" and the Absolute Maximum Cost (100% Cost Estimate) which will be called "c". Note the Most Likely Cost is called "b".

The k', Most Likely, and k"'Cost Estimates completely define the Triangular Probability Density Distribution and Cumulative Probability Curves. An interative procedure has to be used to calculate "a" and "c"; that is, the 0%Cost Estimate and the 100% Cost Estimate, respectively.

First step is to determine which set of equations are applicable to find "a"and "c". This will depend on where the Most Likely Cost Estimate "b" lies relative to k' and k"'Cost Estimates.
Please note that k'Cost Estimate is always less than k"'Cost Estimate.

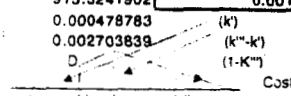
FOR THE ABOVE K'COST, MOST LIKELY COST AND K"'COST ESTIMATES USE XXXXXXX MIDDLE CASE XXXXXXX

CASE LEFT
If Most Likely Cost Estimate < k'Cost Estimate
c= 936.85000
D= 0.00226923
a= 55.49285714
Therefore k2 for Most Likely Cost Estimate is equal to 0.455555556

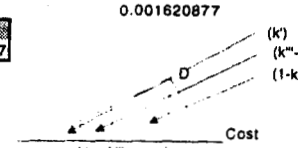


CASE MIDDLE
If (k'CostEstimate<Most Likely Cost Estimate<k"'Cost Estimate), iterate to Find Absolute Minimum 'a' and Maximum 'c' Cost Estimates. Try values of 'a' until c'=c". Trial 'a'= 175.6356

c'=	915.324669	Increment	Stop
c"=	915.3241902	0.0001	
Delta=(c'-c")=	0.000478783	0.001	175.6357
D=	0.002703839		



CASE RIGHT
If (k'Cost Esti.<k"'Cost Esti.>Most Likely Cost Esti.),
a= 114.25
c= 1348.15
D= 0.001620877



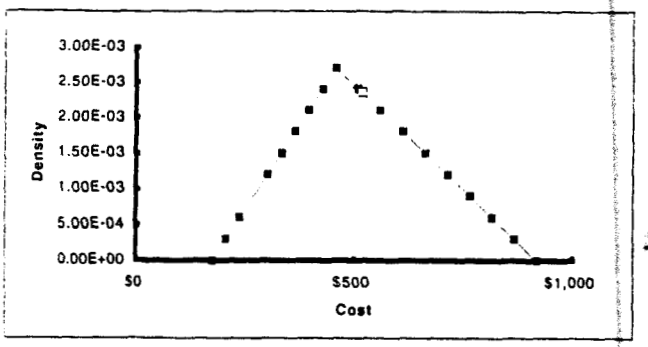
Is a <k'Cost Estimate? Yes, Valid
Is K'<K"'? Yes,Valid

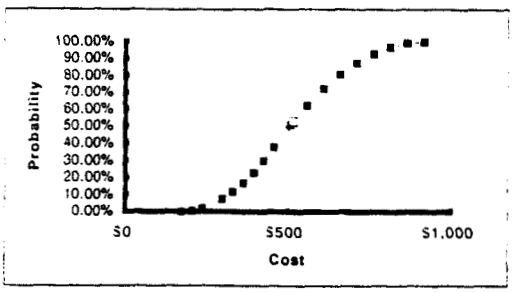
Please Note that you must enter the values calculated above into these slots before computing distributions.

Enter the Values of "a", "c", and D computed above		
	a=	$175.6356
	c=	$915.3247
	D=	0.00270384

Calculating Probability Density Distribution and Cumulative Probability Curves

	Cost in $1,000,000 $	Probability Density (1/$)	Cumulative Probability %
	$176	0.00E+00	0.00%
	$207	3.00E-04	0.47%
	$238	6.01E-04	1.88%
	$301	1.20E-03	7.51%
	$301	1.20E-03	7.51%
	$332	1.50E-03	11.74%
	$363	1.80E-03	16.91%
	$394	2.10E-03	23.01%
	$426	2.40E-03	30.05%
Most Likely	$457	2.70E-03	38.04%
	$508	2.40E-03	51.04%
	$559	2.10E-03	62.52%
	$610	1.80E-03	72.46%
	$661	1.50E-03	80.88%
	$712	1.20E-03	87.76%
	$763	9.01E-04	93.12%
	$813	6.01E-04	96.94%
	$864	3.00E-04	99.24%
Absolute Maximum	$915	8.67E-19	100.00%
MEAN COST	$515.99	2.36E-03	52.96%
MEDIAN COST	$503.61	0.002428867	50.00%





RSKWC12.xls Robert E. 12/14/93

FIGURE A4-16
Topsides Facilities Cost for Case 3. To find Minimum Reserves needed for a PW10 = 0.00 (100 Wells, 2 Drill Rigs, 155 MBOPD) Production and Processing (Reserves 800 Million BBL)

A.4 TOPSIDE FACILITIES AREA, WEIGHT, AND COST

A4.1 Scope

To enable rapid economic evaluation of Kuvlum after the 1993 definition drilling program, six cases were estimated. Three cases were for drilling platforms with only primary separation, not processing of the produced hydrocarbon. Three cases were for drilling and processing platforms. A wide range of drilling and processing requirements for these six cases were selected hopefully to cover requirements of a Kuvlum development. Plans were to estimate cost and size of a Kuvlum platform by interpolating between these six cases using drilling and processing requirements defined by the 1993 drilling.

The six cases were:

Case/Platform	Wells	Rigs	Production KBOPD	Processing KBOPD
1. Drilling	40	2	120	0
2. Drilling	70	2	210	0
3. Drilling	100	2	300	0
4. Drilling & Processing	60	2	150	150
5. Drilling & Processing	70	2	210	300
6. Drilling & Processing	100	2	300	45

Estimates of topsides area, weight and cost were done primarily by utilizing the GOSP (General Offshore Simulation Program) developed as a joint industry project administrated by Gulf Oil Co. and then Chevron during the period from 1979 through 1986.

The input for GOSP runs was developed from the "Design Basis for Prospect Evaluation" completed by AAI.

GOSP was not used to estimate the drilling consumables storage requirements and drilling rig sizes. These drilling estimates were provided by AAI.

A4.2 Area and Weight Estimates for Drilling Rigs, Equipment, and Consumables Storage

Estimate of area and weight for the drilling rig, drilling utilities and drilling/completion consumables were developed on the basis for information provided by AAI, which is shown in Section A4.6.

The rig size and weight is based on Pool Arctic Alaska Drilling Rig #428. In addition to the area required by the rig, an area allowance was used to provide additional deck area for skidding the rig around to access all wells.

Consumables storage space was provided for ten months of operations without resupply. The consumables storage included drill pipe, drilling tools, casing, bentonite, barite, cement, miscellaneous sack storage, tubing, well heads and trees. In addition, liquid storage for diesel fuel, drilling water, potable water, oil base and completion fluid is provided in the base of the platform substructure for ten months of operation based on quantities estimated by Eldorado Engineering for their proposed bottom founded Arctic drilling structure.

For platforms with one drill rig and two drill rigs, consumables for 17 and 34 wells were provided, respectively.

The drilling area and space requirements for the drilling rig and well consumables were placed on Figure A4-41, which is shown in Section A4-6. This drilling spreadsheet was linked to spreadsheets for processing, utilities and quarters, Figures A4-20 through A4-25, so that changes in the drilling requirements assumption would be reflected in the topsides areas and weights estimates. The skidding area allowance was input directly into these topsides spreadsheets.

A4.3 Area and Weight Estimates for Processing, Utilities and Quarters

The basic processing design basis provided at the Kuvlum Partner's Meeting on July 21, 1993 was used as input to GOSP as well as other process decisions that are consistent with AAI's onshore operations experience.

The GOSP program can not directly model the desired configuration so generally two runs were made and additional hand correction added in order to estimate the desired configuration. Sample outputs of the input decisions analysis for the largest drilling only platform and the largest drilling and processing platform are shown in Section A4.6 All of the output would be too voluminous to include in this report but is available for review if requested.

Estimates of area and weight for the above six cases are shown in the Figures A4-20 through A4-22 for drilling-only cases, and Figures A4-23 through A4-25 for drilling and processing cases. Please note that each spreadsheet requires two pages.

Equipment is located in the cellar deck, which is part of the substructure deck framing system, or in one or two levels of process/utility modules stacked above the cellar deck. The drilling rig and equipment modules are also set above the cellar deck.

An allowance of 30% of the cellar deck area is made for the steel framing of the deck.

Generally speaking, equipment located in the cellar deck consists of storage, pumps, water treating and utility systems. The main deck/first module level contains the drilling rig, separators, quarters and compression equipment. If a

second level is required, rotating equipment including generation and compression are moved to this level. Several iterations were required to achieve balance between deck levels.

Area requirements shown on the topside Figures A4-20 through A4-25 were used to develop scaled sketches of these six decks. These sketches are shown in the Figure A4-26 "Scaled Sketches of the Six GOSP Runs to Size Decks." Calculations of areal dimensions are shown in Figure A4-27.

KUVLUM STRUCTURES - TOPSIDE SIZE & WEIGHT				Sheet 1 of 2.
	Equipment Location			
Structure Size:	Drilling		Drilling	
Approx. 233 X 233 feet	Platform		40 Wells	
			1 Drill Rig	
			17 Wells Storage	
			120 MBOPD Production	
			0 MBOPD Processing	
		DRY WT.	OPER WT	AREA
		(kips)	(kips)	(sq. ft.)
Main Deck Modules				
Drilling Substructure	X	1500	3200	1386
Drilling Derrick	X	incl.	incl.	incl.
Mud Processing	X	1300	2700	4482
Ready Drill Pipe and Tubular Rack	X	incl.	incl.	incl.
Rig Skidding Area	X	0	0	9280
Cementing Unit	X	40	40	200
Logging Unit	X	20	20	200
Cuttings & Drilling Waste Processing/Injection	X	incl.	incl.	incl.
Cuttings and Drilling Waste Storage	X	13	378	480
Material Handling Cranes	X	1208	3162	632
Area subtotal =				16660
Production Separators	(primary)	169	245	1760
Test Separators	X	incl.	incl.	incl.
Gas Compression				
Gas Dehydration				
Relief System/Flare Boom	X	262	262	317
Power Generation	X	448	466	3715
Emergency Generators	X	25	25	399
Power Distribution	X	625	625	2793
Fuel Gas Compression System	X	42	45	962
Fuel Gas System	X	18	18	45
Control Center	X	19	19 incl.	
Labs & Work Shops	X	420	420	6000
Heating Ventilating & Air Conditioning	X	82	82	0
Fire Protection	X	1231	1263	555
Module Steel	X	5345	5444	6451
Area subtotal =				22997
Quarters	X	2142	2292	7650
Helideck & Helihanger	X	728	759	0
Communications & Navaids	X	24	24	58
Escape Systems	X	148	148	496
Area subtotal =				8204
Number of Module Levels =				1
Total =		**15661**	**21489**	**47861**

FIGURE A4-20, Page 1 of 2
Topside Size and Weight for Drilling Platform with 40 Wells, 1 Drill Rig, 120 MBOPD Production and No Processing

		Sheet 2 of 2.		
	Equipment Location	DRY WT. (kips)	OPER WT (kips)	AREA (sq. ft.)
Cellar Deck				
Cement Storage (P-Tanks)	X	174	3064	5684
Mud Storage (P-Tanks & Sacks)	X	275	5375	9561
Tubular Storage w/ Overhead Cranes	X	200	12355	10779
Misc Drilling Equipment Stores	X	0	813	958
Wellhead Bay	X	0	0	4278
Trees	X	0	0	0
Manifolds	X	715	933	3456
Crude Metering				
Crude Export Pumps	X	13	16	33
Pipeline Pigging	X	99	159	223
Produced Water Treating				
Water Injection Pumps				
Seawater Lift Pumps	X	25	33	22
Seawater Distribution Pumps	X	17	22	40
Cooling Medium System				
Heating Medium System				
Fresh Water Maker/Transfer Pumps	X	25	50	352
Water Chlorination System	X	5	6	34
Drain Separator System	X	134	234	671
Instrument Air System	X	59	62	1022
Utility Air System	X	11	11	0
Diesel Fuel System	X	18	33	234
Inert Gas System				
Chemical Injection System	X	39	390	407
Fire Pumps	X	53	63	1009
Fire Protection	X	64	96	555
Heating Ventilating & Air Conditioning	X	104	104	0
Spare Parts Storage	X	0	344	1546
Quarters Stores	X	0	0	0
Sewage System	X	42	128	747
Total =		**2072**	**24291**	**41611**
X 1.3 = Total Cellar Deck				**54094**
Lower Hull				Bbls
Diesel Storage	X			136000
Helicopter Fuel Storage	X			8000
Drilling Water Storage	X			35000
Fresh Water Storage	X			20000
Oil Base Storage	X			8500
Completion Fluid Storage	X			8500
Drainage Sump Tanks	X			500
Corrosion Inhibitor	X			10000

FIGURE A4-20, Page 2 of 2
Topside Size and Weight for Drilling Platform with 40 Wells, 1 Drill Rig, 120 MBOPD Production and No Processing

KUVLUM STRUCTURES - TOPSIDE SIZE & WEIGHT		Sheet 1 of 2.		
	Equipment Location			
Structure Size:	Drilling	Drilling		
Approx. 313 X 313 feet	Platform	70 Wells		
		2 Drill Rig		
		34 Wells Storage		
		210 MBOPD Production		
		0 MBOPD Processing		
		DRY WT. (kips)	OPER WT (kips)	AREA (sq. ft.)
Main Deck Modules				
Drilling Substructure	X	3000	6400	2772
Drilling Derrick	X	incl.	incl.	incl.
Mud Processing	X	2600	5400	8964
Ready Drill Pipe and Tubular Rack	X	incl.	incl.	incl.
Rig Skidding Area	X	0	0	16410
Cementing Unit	X	80	80	400
Logging Unit	X	40	40	400
Cuttings & Drilling Waste Processing/Injection	X	incl.	incl.	incl.
Cuttings and Drilling Waste Storage	X	13	378	480
Material Handling Cranes	X	1210	4084	632
Area subtotal =				30058
Production Separators	(primary)	278	403	3076
Test Separators	X	incl.	incl.	incl.
Gas Compression				
Gas Dehydration				
Relief System/Flare Boom	X	400	400	544
Power Generation	X	780	810	7105
Emergency Generators	X	25	25	397
Power Distribution	X	882	882	3842
Fuel Gas Compression System	X	30	32	621
Fuel Gas System	X	19	19	46
Control Center	X	28	28	incl.
Labs & Work Shops	X	420	420	6000
Heating Ventilating & Air Conditioning	X	91	91	0
Fire Protection	X	1446	1484	648
Module Steel	X	6406	6513	6987
Area subtotal =				29266
Quarters	X	4417	4677	10517
Helideck & Helihanger	X	728	759	0
Communications & Navaids	X	16	24	58
Escape Systems	X	296	296	992
Area subtotal =				11567
Number of Module Levels =				1
Total =		**22909**	**32949**	**70891**

FIGURE A4-21, Page 1 of 2
Topside Size and Weight for Drilling Platform with 70 Wells, 2 Drill Rigs, 210 MBOPD Production and No Processing

			Sheet 2 of 2.	
	Equipment Location	DRY WT.	OPER WT	AREA
Cellar Deck				
Cement Storage (P-Tanks)	X	348	6128	11368
Mud Storage (P-Tanks & Sacks)	X	544	10744	18927
Tubular Storage w/ Overhead Cranes	X	400	24710	21558
Misc Drilling Equipment Stores	X	0	1626	1916
Wellhead Bay	X	0	0	5175
Trees	X	0	0	0
Manifolds	X	1407	1830	6804
Crude Metering		0	0	0
Crude Export Pumps	X	27	34	73
Pipeline Pigging	X	154	250	339
Produced Water Treating				
Water Injection Pumps				
Seawater Lift Pumps	X	26	35	22
Seawater Distribution Pumps	X	18	24	40
Cooling Medium System				
Heating Medium System				
Fresh Water Maker/Transfer Pumps	X	33	76	593
Water Chlorination System	X	5	7	34
Drain Separator System	X	155	269	671
Instrument Air System	X	60	63	1022
Utility Air System	X	11	11	0
Diesel Fuel System	X	19	34	234
Inert Gas System				
Chemical Injection System	X	55	749	636
Fire Pumps	X	53	63	1009
Fire Protection	X	68	106	648
Heating Ventilating & Air Conditioning	X	121	121	0
Spare Parts Storage	X	0	620	2958
Quarters Stores	X	0	0	0
Sewage System	X	71	205	1116
Total =		**3575**	**47705**	**75143**
X 1.3 = Total Cellar Deck				**97686**
Lower Hull				**Bbls**
Diesel Storage	X			210000
Helicopter Fuel Storage	X			8000
Drilling Water Storage	X			70000
Fresh Water Storage	X			30000
Oil Base Storage	X			17000
Completion Fluid Storage	X			17000
Drainage Sump Tanks	X			500
Corrosion Inhibitor	X			17500

FIGURE A4-21, Page 2 of 2
Topside Size and Weight for Drilling Platform with 70 Wells, 2 Drill Rigs, 210 MBOPD Production and No Processing

KUVLUM STRUCTURES - TOPSIDE SIZE & WEIGHT		Sheet 1 of 2.		
	Equipment Location			
Structure Size:	Drilling	Drilling		
Approx. 326 X 326 feet	Platform	100 Wells		
		2 Drill Rig		
		34 Wells Storage		
		300 MBOPD Production		
		0 MBOPD Processing		
		DRY WT. (kips)	OPER WT (kips)	AREA (sq. ft.)
Main Deck Modules				
Drilling Substructure	X	3000	6400	2772
Drilling Derrick	X	incl.	incl.	incl.
Mud Processing	X	2600	5400	8964
Ready Drill Pipe and Tubular Rack	X	incl.	incl.	incl.
Rig Skidding Area	X	0	0	22860
Cementing Unit	X	80	80	400
Logging Unit	X	40	40	400
Cuttings & Drilling Waste Processing/Injection	X	incl.	incl.	incl.
Cuttings and Drilling Waste Storage	X	13	378	480
Material Handling Cranes	X	1214	4088	632
Area subtotal =				36508
Production Separators	(primary)	453	658	4301
Test Separators	X	incl.	incl.	incl.
Gas Compression				
Gas Dehydration				
Relief System/Flare Boom	X	542	543	731
Power Generation	X	780	810	7105
Emergency Generators	X	25	25	397
Power Distribution	X	892	892	3864
Fuel Gas Compression System	X	30	32	621
Fuel Gas System	X	20	20	46
Control Center	X	28	28 incl.	
Labs & Work Shops	X	420	420	6000
Heating Ventilating & Air Conditioning	X	99	99	0
Fire Protection	X	1668	1711	747
Module Steel	X	7482	7597	7491
Area subtotal =				31303
Quarters	X	4417	4677	12620
Helideck & Helihanger	X	728	759	0
Communications & Navaids	X	16	24	58
Escape Systems	X	296	296	992
Area subtotal =				13670
Number of Module Levels =				1
Total =		**24547**	**34681**	**81481**

FIGURE A4-22, Page 1 of 2
Topside Size and Weight for Drilling Platform with 100 Wells, 2 Drill Rigs, 300 MBOPD Production and No Processing

		Sheet 2 of 2.		
	Equipment Location	DRY WT.	OPER WT	AREA
Cellar Deck				
Cement Storage (P-Tanks)	X	348	6128	11368
Mud Storage (P-Tanks & Sacks)	X	544	10744	18927
Tubular Storage w/ Overhead Cranes	X	400	24710	21558
Misc Drilling Equipment Stores	X	0	1626	1916
Wellhead Bay	X	0	0	8555
Trees	X	0	0	0
Manifolds	X	2221	2902	9648
Crude Metering				
Crude Export Pumps	X	41	51	100
Pipeline Pigging	X	188	306	405
Produced Water Treating				
Water Injection Pumps				
Seawater Lift Pumps	X	28	37	22
Seawater Distribution Pumps	X	19	25	40
Cooling Medium System				
Heating Medium System				
Fresh Water Maker/Transfer Pumps	X	33	77	593
Water Chlorination System	X	5	7	34
Drain Separator System	X	176	303	671
Instrument Air System	X	62	64	1022
Utility Air System	X	12	12	0
Diesel Fuel System	X	20	36	234
Inert Gas System				
Chemical Injection System	X	56	750	636
Fire Pumps	X	53	63	1009
Fire Protection	X	84	127	747
Heating Ventilating & Air Conditioning	X	138	138	0
Spare Parts Storage	X	0	620	2958
Quarters Stores	X	0	0	0
Sewage System	X	71	204	1116
Total =		**4499**	**48930**	**81559**
X 1.3 = Total Cellar Deck				**106027**
Lower Hull				Bbls
Diesel Storage	X			210000
Helicopter Fuel Storage	X			8000
Drilling Water Storage	X			70000
Fresh Water Storage	X			30000
Oil Base Storage	X			17000
Completion Fluid Storage	X			17000
Drainage Sump Tanks	X			500
Corrosion Inhibitor	X			25000

FIGURE A4-22, Page 2 of 2
Topside Size and Weight for Drilling Platform with 100 Wells, 2 Drill Rigs, 100 MBOPD Production and No Processing

KUVLUM STRUCTURES - TOPSIDE SIZE & WEIGHT		Sheet 1 of 2.		
	Equipment Location			
Structure Size:	Drill/Prod	Drilling/Processing		
Approx. 357 X 357 feet	Platform	60 Wells		
		2 Drill Rigs		
		34 Wells Storage		
		150 MBOPD Production		
		150 MBOPD Processing		
		DRY WT. (kips)	OPER WT (kips)	AREA (sq. ft.)
Main Deck Modules				
Drilling Substructure	X	3000	6400	2772
Drilling Derrick	X	incl.	incl.	incl.
Mud Processing	X	2600	5400	8964
Ready Drill Pipe and Tubular Rack	X	incl.	incl.	incl.
Rig Skidding Area	X	0	0	14260
Cementing Unit	X	80	80	400
Logging Unit	X	40	40	400
Cuttings & Drilling Waste Processing/Injection	X	incl.	incl.	incl.
Cuttings and Drilling Waste Storage	X	13	378	480
Material Handling Cranes	X	1231	6494	632
Area subtotal =				27908
Gas Compression	X	3090	3401	33818
Gas Dehydration	X	358	442	3806
Relief System/Flare Boom	X	669	670	1124
Power Generation	X	1396	1573	7350
Power Distribution	X	2088	2088	9057
Emergency Generators	X	25	25	397
Fuel Gas Compression System	X	incl.	incl.	incl.
Fuel Gas System	X	27	27	62
Control Center	X	43	43	incl.
Labs & Work Shops	X	630	630	9000
Heating Ventilating & Air Conditioning	X	207	207	0
Fire Protection	X	3033	3152	1338
Module Steel	X	19062	19232	13552
Area subtotal =				79504
Quarters	X	2142	2306	10200
Helideck & Helihanger	X	728	759	0
Communications & Navaids	X	16	24	58
Escape Systems	X	148	148	496
Area subtotal =				10754
Number of Module Levels =				1
Total Main Deck =		**40626**	**53519**	**118166**

FIGURE A4-23, Page 1 of 2
Topside Size and Weight for Drilling/Processing Platform with 60 Wells, 2 Drill Rigs,150 MBOPD Production and 150 MBOPD Processing

		Sheet 2 of 2.		
	Equipment Location	DRY WT.	OPER WT	AREA
Cellar Deck				
Cement Storage (P-Tanks)	X	348	6128	11368
Mud Storage (P-Tanks & Sacks)	X	544	10744	18927
Tubular Storage w/ Overhead Cranes	X	400	24710	21558
Misc Drilling Equipment Stores	X	0	1626	1916
Production Separators	X	1034	1872	12959
Test Separators	X	incl.	incl.	incl.
Trees	X	0	0	0
Manifolds	X	2713	3560	5814
Crude Metering	X	incl.	incl.	incl.
Crude Export Pumps	X	184	239	2344
Pipeline Pigging	X	258	411	558
Produced Water Treating	X	411	754	5215
Water Injection Pumps	X	817	1019	6131
Seawater Lift Pumps	X	245	470	96
Seawater Distribution Pumps	X	24	32	40
Cooling Medium System	X	113	174	322
Heating Medium System	X	186	441	1351
Fresh Water Maker/Transfer Pumps	X	32	61	592
Water Chlorination System	X	7	10	235
Drain Separator System	X	303	510	671
Instrument Air System	X	82	86	1223
Utility Air System	X	16	16	0
Diesel Fuel System	X	24	43	234
Inert Gas System				
Chemical Injection System	X	64	441	504
Fire Pumps	X	53	63	1009
Fire Protection	X	203	322	1338
Heating Ventilating & Air Conditioning	X	238	238	0
Spare Parts Storage	X	0	660	3060
Quarters Stores	X	0	0	0
Sewage System	X	42	128	746
Subtotal Cellar Deck =		**8341**	**54758**	98211
X 1.3 = Total Cellar Deck				**127674**
Lower Hull				Bbls
Diesel Storage	X			210000
Helicopter Fuel Storage	X			8000
Drilling Water Storage	X			70000
Fresh Water Storage	X			30000
Oil Base Storage	X			17000
Completion Fluid Storage	X			17000
Drainage Sump Tanks	X			500
Corrosion Inhibitor	X			12500

FIGURE A4-23, Page 2 of 2
Topside Size and Weight for Drilling/Processing Platform with 60 Wells, 2 Drill Rigs, 150 MBOPD Production and 150 MBOPD Processing

KUVLUM STRUCTURES - TOPSIDE SIZE & WEIGHT			Sheet 1 of 2.		
	Equipment Location				
Structure Size:	Drill/Prod		Drilling/Processing		
Approx. 360 X 360 feet	Platform		70 Wells		
			2 Drill Rigs		
			34 Wells Storage		
			210 MBOPD Production		
			300 MBOPD Processing		
			DRY WT.	OPER WT	AREA
			(kips)	(kips)	(sq. ft.)
Main Deck Modules Level 1					
Drilling Substructure	X		3000	6400	2772
Drilling Derrick	X		incl.	incl.	incl.
Mud Processing	X		2600	5400	8964
Ready Drill Pipe and Tubular Rack	X		incl.	incl.	incl.
Rig Skidding Area	X		0	0	16410
Cementing Unit	X		80	80	400
Logging Unit	X		40	40	400
Cuttings & Drilling Waste Processing/Injection	X		incl.	incl.	incl.
Cuttings and Drilling Waste Storage	X		13	378	480
Material Handling Cranes	X		1222	5423	632
Area subtotal =					30058
Quarters	X		4438	4706	12680
Helideck & Helihanger	X		728	759	0
Communications & Navaids	X		16	24	58
Escape Systems	X		296	296	992
Area subtotal =					13730
Production Separators	X		1900	3516	19740
Test Separators	X		incl.	incl.	incl.
Power Distribution	X		2980	2980	12714
Gas Dehydration	X		749	916	7053
Relief System/Flare Boom	X		727	730	2189
Fuel Gas Compression System	X		incl.	incl.	incl.
Fuel Gas System	X		25	26	74
Control Center	X		43	43	incl.
Labs & Work Shops	X		630	630	9000
Heating Ventilating & Air Conditioning	X		286	286	0
Heating Medium System	X		266	771	2161
Fire Protection	X		2430	2595	1022
Module Steel	X		29869	30168	20651
Area subtotal =					74604
Total Level 1			**52338**	**66167**	**118392**
Level 2 (UP)					
Gas Compression	X		4325	4755	51458
Power Generation	X		1716	1948	8702
Emergency Generators	X		25	25	399
Total Level 2			6066	6728	**60559**

FIGURE A4-24, Page 1 of 2
Topside Size and Weight for Drilling/Processing Platform with 70 Wells, 210 MBOPD Production and 300 MBOPD Processing

		Sheet 2 of 2.		
	Equipment Location	DRY WT.	OPER WT	AREA
Cellar Deck				
Cement Storage (P-Tanks)	X	348	6128	11368
Mud Storage (P-Tanks & Sacks)	X	544	10744	18927
Tubular Storage w/ Overhead Cranes	X	400	24710	21558
Misc Drilling Equipment Stores	X	0	1626	1916
Wellhead Bay	X	0	0	5175
Trees	X	0	0	0
Manifolds	X	3817	5117	6804
Crude Metering	X	incl.	incl.	incl.
Crude Export Pumps	X	293	375	3538
Pipeline Pigging	X	593	955	1196
Produced Water Treating	X	733	1396	9873
Water Injection Pumps	X	1492	1874	9600
Seawater Lift Pumps	X	363	804	170
Seawater Distribution Pumps	X	22	29	40
Cooling Medium System	X	144	251	720
Fresh Water Maker/Transfer Pumps	X	41	86	601
Water Chlorination System	X	8	12	259
Drain Separator System	X	236	401	671
Instrument Air System	X	79	82	1223
Utility Air System	X	14	14	0
Diesel Fuel System	X	22	39	234
Inert Gas System				
Chemical Injection System	X	75	798	747
Fire Pumps	X	53	63	1009
Fire Protection	X	256	421	1022
Heating Ventilating & Air Conditioning	X	185	185	0
Spare Parts Storage	X	0	502	2415
Quarters Stores	X	0	0	0
Sewage System	X	71	204	1116
Subtotal Cellar Deck =		**9789**	**56816**	100182
X 1.3 Total Cellar Deck				**130237**
Lower Hull				Bbls
Diesel Storage	X			210000
Helicopter Fuel Storage	X			8000
Drilling Water Storage	X			70000
Fresh Water Storage	X			30000
Oil Base Storage	X			17000
Completion Fluid Storage	X			17000
Drainage Sump Tanks	X			750
Corrosion Inhibitor	X			25000
Drainage Sump Tanks	X			500
Corrosion Inhibitor	X			10000

FIGURE A4-24, Page 2 of 2
Topside Size and Weight for Drilling/Processing Platform with 70 Wells, 210 MBOPD Production and 300 MBOPD Processing

KUVLUM STRUCTURES - TOPSIDE SIZE & WEIGHT		Sheet 1 of 2.		
	Equipment Location			
Structure Size:	Drill/Prod	Drilling/Processing		
Approx. 395 X 395 feet	Platform	100 Wells		
		2 Drill Rigs		
		34 Wells Storage		
		300 MBOPD Production		
		450 MBOPD Processing		
		DRY WT. (kips)	OPER WT (kips)	AREA (sq. ft.)
Main Deck Modules Level 1				
Drilling Substructure	X	3000	6400	2772
Drilling Derrick	X	incl.	incl.	incl.
Mud Processing	X	2600	5400	8964
Ready Drill Pipe and Tubular Rack	X	incl.	incl.	incl.
Rig Skidding Area	X	0	0	22860
Cementing Unit	X	80	80	400
Logging Unit	X	40	40	400
Cuttings & Drilling Waste Processing/Injection	X	incl.	incl.	incl.
Cuttings and Drilling Waste Storage	X	13	378	480
Material Handling Cranes	X	1233	4903	632
Area subtotal =				36508
Quarters	X	4438	4716	12680
Helideck & Helihanger	X	728	759	0
Communications & Navaids	X	16	24	58
Escape Systems	X	296	296	992
Area subtotal =				13730
Production Separators	X	2867	5278	29799
Test Separators	X	incl.	incl.	incl.
Gas Dehydration	X	1128	1376	10640
Relief System/Flare Boom	X	908	913	3395
Power Distribution	X	2065	2065	15605
Fuel Gas System	X	29	29	79
Control Center	X	60	60 incl.	
Labs & Work Shops	X	630	630	9000
Heating Ventilating & Air Conditioning	X	398	398	0
Heating Medium System	X	325	992	2790
Fire Protection	X	3298	3530	1390
Module Steel	X	42939	43297	27585
Area subtotal =				100283
Total Level 1 =		**67091**	**81564**	**150521**
Level 2				
Gas Compression	X	5350	5865	71529
Power Generation	X	3186	3512	20085
Emergency Generators	X	25	25	397
Total Level 2=		**8561**	**9402**	**92011**

FIGURE A4-25, Page 1 of 2
Topside Size and Weight for Drilling/Processing Platform with 100 Wells, 300 MBOPD Production and 450 MBOPD Processing

	Sheet 2 of 2.			
	Equipment Location	DRY WT.	OPER WT	AREA
Cellar Deck				
Cement Storage (P-Tanks)	X	348	6128	11368
Mud Storage (P-Tanks & Sacks)	X	544	10744	18927
Tubular Storage w/ Overhead Cranes	X	400	24710	21558
Misc Drilling Equipment Stores	X	0	1626	1916
Wellhead Bay	X	0	0	8555
Trees	X	0	0	0
Manifolds	X	6430	8615	10368
Crude Metering	X	incl.	incl.	incl.
Crude Export Pumps	X	432	549	5283
Pipeline Pigging	X	984	1590	1831
Produced Water Treating	X	1062	2047	14581
Water Injection Pumps	X	2326	2919	12784
Seawater Lift Pumps	X	477	1213	245
Seawater Distribution Pumps	X	25	33	40
Cooling Medium System	X	190	350	915
Fresh Water Maker/Transfer Pumps	X	42	88	601
Water Chlorination System	X	11	17	327
Drain Separator System	X	315	528	671
Instrument Air System	X	100	104	1439
Utility Air System	X	17	17	0
Diesel Fuel System	X	25	44	234
Inert Gas System				
Chemical Injection System	X	80	811	755
Fire Pumps	X	53	63	1009
Fire Protection	X	355	587	1390
Heating Ventilating & Air Conditioning	X	247	247	0
Spare Parts Storage	X	0	980	4182
Quarters Stores	X	0	0	0
Sewage System	X	71	204	1116
Subtotal Cellar Deck =		**14534**	**64214**	120095
X 1.3 = Total Cellar Deck				**156124**
Lower Hull				Bbls
Diesel Storage	X			210000
Helicopter Fuel Storage	X			8000
Drilling Water Storage	X			70000
Fresh Water Storage	X			30000
Oil Base Storage	X			17000
Completion Fluid Storage	X			17000
Drainage Sump Tanks	X			750
Corrosion Inhibitor	X			37500
Drainage Sump Tanks	X			500
Corrosion Inhibitor	X			10000

FIGURE A4-25, Page 2 of 2
Topside Size and Weight for Drilling/Processing Platform with 100 Wells, 300 MBOPD Production and 450 MBOPD Processing

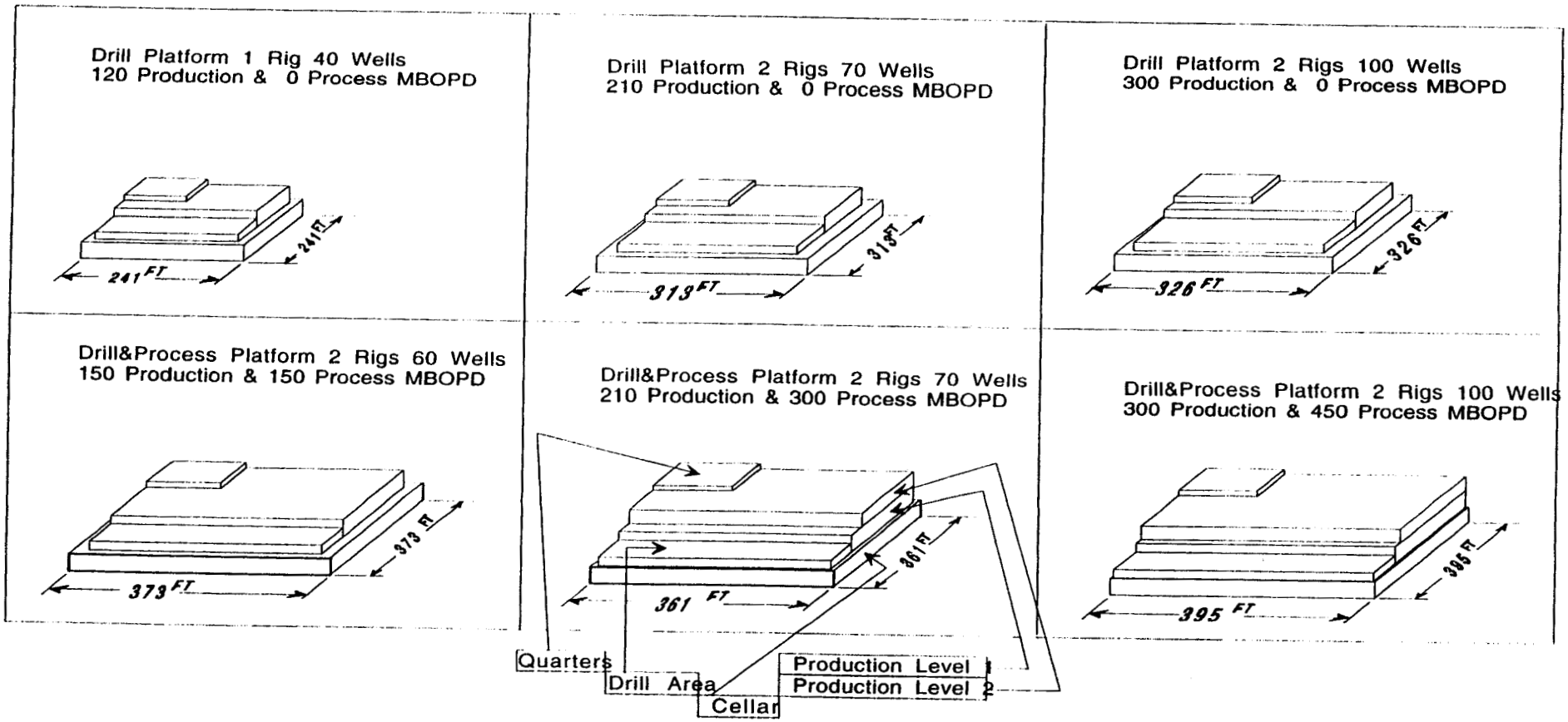
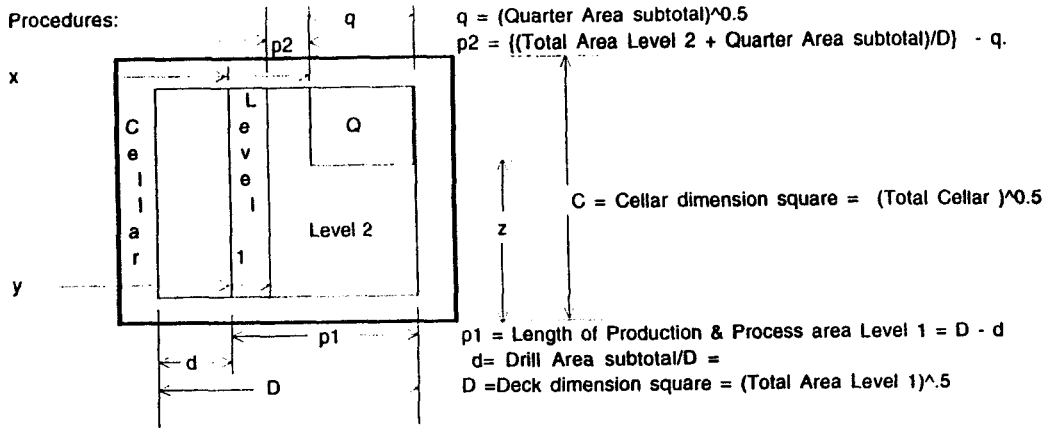


FIGURE A4-26
Scaled Sketches of the Six GOSP Runs to Size Decks
Drill Rigs Not Shown

To Compute Deck Layouts based on Area Requirements shown in "KUVLUM STRUCTURES - TOPSIDE SIZE & WEIGHT"



Case Prod. Rate MBOPD	Spread-sheets	Area Requirements from Spreadsheets: Area Cellar Deck sq ft	Drill Area Subtotal sq ft	Level 1 TotalArea sq ft	Level 2 TotalArea sq ft	Quarter Area sq ft	Computed dimensions from the Area Requirments: C Cellar ft	D Level 1 ft	d Drilling ft	q Quarter ft	p2 Level 2 ft	p1 see sketch ft	x see sketch ft	y see sketch ft	z see sketch ft
Drill 120	A.3.1.	54094	16660	47861	0	8204	233	219	76	91	N/A	143	52	N/A	128
Drill 210	A.3.2	97686	30058	70891	0	11567	313	266	113	108	N/A	153	46	N/A	159
Drill 300	A.3.3.	106027	36508	81481	0	13670	326	285	128	117	N/A	158	41	N/A	169
D&P 150	A.3.4.	139448	27908	118166	0	10754	373	344	81	104	N/A	263	159	N/A	240
D&P 210	A.3.5.	130237	30058	118392	60559	13730	361	344	87	117	99	257	140	41	227
D&P 350	A.3.6.	156124	36508	150521	92011	13730	395	388	94	117	155	294	177	21	271

FIGURE A4-27
Calculation for Deck Layouts Based on Area Requirements on Figures A4-20 through A4-25

A4.4 Cost of Topside Facilities

GOSP internal cost data sets were updated to third quarter 1993 using the Oil and Gas Journal Nelson-Farrar Cost Indices. Various past updates of GOSP internal cost data sets were catalogued on a spreadsheet and compared with the variation of Nelson-Farrar Indices for the same time frame. A sort was done on the combined spreadsheet and a best fit between GOSP internal cost indices and the Nelson-Farrar Indices was determined. This bet fit was used to update GOSP Indices to the present Figure A4-45 Nelson-Farrar Cost Indices (9 pages), lists the indices used (Section A4.8). The GOSP user input cost values were based on a study report of AAI Alaska module construction costs and past experience.

A rigorous study of topsides cost was made in 1983 by Brown & Root in the HiDeck Study to compare conventional modular construction and derrick barge lifts versus integrated installation of the entire deck offshore. Their cost results were updated to 1993 using the Nelson-Farrar Refinery Construction Index. A GOSP run was made to duplicate the facility used in the Brown & Root study. The costs were compared and found to agree within reasonable estimating limits. Please see A4.8.

With updated cost data sets, GOSP runs were made to estimate cost of topsides modules and equipment loaded on barges on the Gulf of Mexico Coast. These costs are shown in the following table for the six cases previously described. Drilling Rig costs are not included in these costs.

Most Likely Cost of Topsides Facilities ($MM)

Case	Cost Gulf of Mexico	Tow & Installed on Substructure Far East Site	Cost ready for tow to Kuvlum Site
Drilling (40 Wells)	$110	$26	$136
Drilling (70 Wells)	$160	$34	$194
Drilling (100 Wells)	$180	$35	$215
Drilling & Processing (60 Wells)	$400	$49	$449
Drilling & Processing (70 Wells)	$530	$62	$592
Drilling & Processing (100 Wells)	$710	$81	$791

Estimates of cost to tow these deck modules and equipment for the Gulf of Mexico to a protected water site in the Far East and to install them on an anchored Kuvlum structure are shown in the second column of the above table. Figures A4-30 and A4-31 present these cost estimates.

Please note that the above costs are most likely estimates. An optimistic cost level (10% confidence that the cost would be lower) is judged to be 0.70 times the most likely cost. A pessimistic cost level (90% confidence that the cost would be lower) is judged to be 1.7 times the most likely cost.

These topside costs for the six cases were intended to bracket the anticipated production and process requirements including quarters and utilities for a Kuvlum development. Results of the 1993 definition drilling indicated that reserves are less than anticipated when these six cases were selected. Therefore, a procedure was developed to extrapolate these costs to lower drilling, production and processing requirements. This procedure is shown on Figure A4-33 for Cases 1 and 2. Figure A4-34 is for Case 3 which is used to determine the minimum reserves required for a PW12=0.0.

Please note that Cases 1, 2 and 3 were defined based on the 1993 drilling program and are the cases used in the Economic Analysis, Section 3. These cases are described in Figures A4-33 and A4-34 in the lower left hand corner.

For triangular cost distribution and considering that the 10% confidence level is 0.70 of the most likely and the 90% confidence level is 1.6 of the most likely, the cumulative probability cost curves for Cases 1, 2 and 3 are computed and shown in the Figures A4-3 through A4-15.

TO ESTIMATE THE COST OF TOWING, INSTALLING AND CERTIFYING FACILITIES ON KUVLUM STRUCTURES

Basic Assumptions:

Facilities are loaded on barges in the Gulf of Mexico and towed to a protected site in the Far East. At this protected site the facilites are lifted and installed on the anchored Kuvlum structure by marine derrick barge. The facilities are hooked -up and certified before the plaform is towed to Kuvlum.

Preparation of the protected site, anchor spreads, small nearby shore base and tow of structure to site are included in this cost estimate.

To Estimate Size and Number of Barges and Tugs:

From "Kuvlum Topsides Estimates Report"							Estimate of Number of Barges			{5}Cargo per Barge kips	{6}Average Draft of Barge ft.
Platform Type	Number of Wells	Number of Drill Rigs	Prod. Rate MBOPD	Process Rate MBOPD	{1} Dry Wgt. kips	{2} Deck Area sq. ft.	{3}Estimate by Area	{4}Estimate by Wgt.	Use		
Drill	40	1	150	0	17733	101955	1.4	1.4	2	8867	6.5
Drill	70	2	210	0	26484	168577	2.3	2.1	3	8828	6.5
Drill	100	2	300	0	29046	187508	2.6	2.3	3	9682	6.8
Drill&Process	60	2	150	150	48967	245840	3.4	3.9	4	12242	7.8
Drill&Process	70	2	210	300	68193	309188	4.3	5.4	5	13639	8.4
Drill&Process	100	2	300	450	90186	398656	5.5	7.1	7	12884	8.1

{1} Dry Wgt. = Sum of all Facility and Modular Steel dry weight.
{2} Deck Area = Sum of all deck floor areas="Deck Area of Facilities"
{3} Required Deck Area of Barges= Deck Area of Facilities/(2*Efficiency of Stacking Two High).
Efficiency of stacking two high = 0.9
Deck Area of a Barge = Width* Length of the Barge Width= 100 ft. Length= 400 ft.
Number of Barges required = Required Deck Area of Barges/Deck Area of a Barge
{4} Required Number of Barges by Wgt. = Dry Wgt./Barge Displacement available for Cargo
Draft of Unloaded Barge = 1.50 ft
Draft of Trimming Ballast = 1.50 ft
Desired Approximate Draft under Tow = 8.00 ft
Draft remaining for Cargo = 5.00 ft
Barge Displacement available of Cargo = Draft remaining for Cargo*0.0635*Barge Width*Barge Length
= 12700 kips
{5} Cargo per Barge = Dry Wgt/Number of Barge
{6} Average Draft of Barge = Unloaded and Trim Drafts + (Cargo per Barge)/(0.0635*Width*Length of Barge)

FIGURE A4-30, Page 1 of 3
Estimate of Cost of Towing, Installing and Certifying Topside Facilities on Kuvlum Structures

TO ESTIMATE THE COST OF TOWING, INSTALLING AND CERTIFYING FACILITIES ON KUVLUM STRUCTURES

To Estimate Towing Speed

From "Kuvlum Topsides Estimates Report"					Average	Displace-	"A"	{7}Tow Force on Barge at Various Speed in Calm Water				
Platform Type	Number of Wells	Number of Drill Rigs	Prod. Rate MBOPD	Process Rate MBOPD	Draft of Barge ft.	ment "D" Average kips	Projected Frontal Area sq. ft.	8 mile/hour kips	7 mile/hour kips	6 mile/hour kips	4 mile/hour kips	2 mile/hour kips
Drill	40	1	150	0	6.5	16487	649.07	280	214	157	70	17
Drill	70	2	210	0	6.5	16448	647.56	279	214	157	70	17
Drill	100	2	300	0	6.8	17302	681.18	294	225	165	73	18
Drill&Process	60	2	150	150	7.8	19862	781.96	337	258	190	84	21
Drill&Process	70	2	210	300	8.4	21259	836.95	361	276	203	90	23
Drill&Process	100	2	300	450	8.1	20504	807.23	348	267	196	87	22

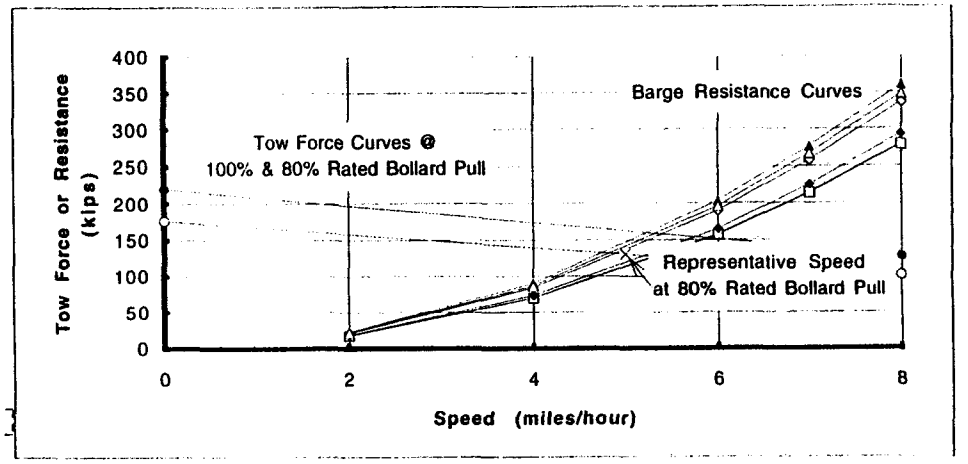
{7} Tow Force on Barge in kips = 0.001337*(V^2)*(A*D)^0.5 Please note that this expression is a crude estimate of the Tow Force vs. Speed. It is modification of the Tow Force equation in Sandwell's AOGA Report "*Beaufort and Chukchi Sea, Arctic Production* Platforms-Update" Section 7. Modifications were: 1. Change units from tonnes, meters, knots to kips, feet, miles per hour. 2. Reduce the force coefficient by 0.70. Also please note that the correct coefficient in AOGA report is 0.0056 not 0.086.

Where: V is in miles per hour
A is Projected Frontal Area of Barge in sq. ft. = Draft*Width of Barge
D is Displacement of Barge in kips

To Estimate Cost of Tug and Barge from Gulf of Mexico to Far East Protected Water Site

Day Rates of 220 kips (100 tonnes) Bollard Pull Tug		
In service including fuel =	$28,500	/day
Stand by =	$17,000	/day
Day Rate of 100x400 ft. Barge =	$5,000	/day
Representative Speed @ 80% BP=	5.00	miles/hour
Distance from GOM to Far East Site =	12,000	miles
TowTime GOM-Far East = Distance/Speed =	100	days
Mob and Demob time = 1/2 Tow Time =	50	days
Day Rates for a 100 ft X 400 ft Barge		
In Service =	$3,000	/day
Stand by =	$3,000	/day
Total Standby Time for Tug =	10	day
Total Standby Time for Barge =	20	day
{8}Total Cost of Tug & Barge = Sum of (Rates*Times) =	*$4,955,000*	per Unit

{8}Does not include Barge Time at Site.



TO ESTIMATE THE COST OF TOWING, INSTALLING AND CERTIFYING FACILITIES ON KUVLUM STRUCTURES

To Estimate Cost of Lifting, Installing and Certifying Facilities at Protective Site in Far East

Marine Spread During Major Lifts
2,000 Ton Derrick Barge with Full Support $180,000 /day

FIGURE A4-30, Page 2 of 3
Estimate of Cost of Towing, Installing and Certifying Topside Facilities on Kuvlum Structures

Average Lift	2,000	kips
Duration of a Major Lift	2	day
Mob&Demob =	$4,000,000	

Marine Spread after Majors Lifts, during Hookup and Certification

Quarter&Staging Barge with Full Support	$50,000	/day
Cranes on Structure are used.		
Mob&Demob =	$2,000,000	

Labor Crew after Major Lifts	$50,000	/day
Days for Hookup and Certification per Major Lifts =	5	days/major lift
Preparation of Protected Water Site and Shore Base Mob&Demob	$4,000,000	

From "Kuvlum Topsides Estimates Report"						Number of Major Lifts	Days of Majors Lifts Days	Days of Hookup & Certification Days	Major Lifts + Mob& Demob	Hookup & Certification + Mob & Demob	Number Tug& Barge Units	Tug & Barges
Platform Type	Number of Wells	Number of Drill Rigs	Prod. Rate MBOPD	Process Rate MBOPD	(1) Dry Wgt. kips							
Drill	40	1	150	0	17733	8.87	17.7	44.3	$7,191,940	$8,433,250	2	$9,910,000
Drill	70	2	210	0	26484	13.24	26.5	66.2	$8,767,120	$10,621,000	3	$14,865,000
Drill	100	2	300	0	29046	14.52	29.0	72.6	$9,228,280	$11,261,500	3	$14,865,000
Drill&Process	60	2	150	150	48967	24.48	49.0	122.4	$12,814,060	$16,241,750	4	$19,820,000
Drill&Process	70	2	210	300	68193	34.10	68.2	170.5	$16,274,740	$21,048,250	5	$24,775,000
Drill&Process	100	2	300	450	90186	45.09	90.2	225.5	$20,233,480	$26,546,500	7	$34,685,000
											From Sheet 1	See Sheet 2 for Unit Cost

From "Kuvlum Topsides Estimates Report"						Total Cost for Tow, Installation & Certification of Facility
Platform Type	Number of Wells	Number of Drill Rigs	Prod. Rate MBOPD	Process Rate MBOPD	(1) Dry Wgt. kips	
Drill	40	1	150	0	17733	$25,535,190
Drill	70	2	210	0	26484	$34,253,120
Drill	100	2	300	0	29046	$35,354,780
Drill&Process	60	2	150	150	48967	$48,875,810
Drill&Process	70	2	210	300	68193	$62,097,990
Drill&Process	100	2	300	450	90186	$81,464,980

FIGURE A4-30, Page 3 of 3
Estimate of Cost of Towing, Installing and Certifying Topside Facilities on Kuvlum Structures

To Duplicate Figure 7.3 Tow Resistance Curves of Sandwell 1991 Structure Study.

Tow Bollard Pull Curves Scaled from Figure 7.3		
BP tonnes	Speed knots	Tow Force tonnes
1200		
	0	1200
	5	833
1000		
	0	1000
	5	694
800		
	0	800
	5	553
600		
	0	600
	5	413
400		
	0	400
	5	274
200		
	0	200
	5	127

Tow Resistance Scaled from Figure 7.3 P2L-60 Steel Conical	
Speed knots	Tow Force Tonnes
1	67
1.5	153
2	274
2.5	421
3	611
3.5	837

Tow Resistance Equation page 7-4

R=0.0056*(V^2)*(A*D)^.5 Note that the coefficient k=0.086 in Sandwell Report is changed to 0.0056.

V is Speed in Knots (1.1515 miles per hour)

A is Submerged Frontal Projected Area in square meters (10.764 square feet)

D is displacement in tonnes (2,200 lb)

For P2L-60 Steel Conical

Submerged width= 110 m

Draught = 13.1 m

A=110*13.1 1441 m^2

D= 107600 tonnes

Speed Knots	R Tonnes
0	0
0.1	1
0.2	3
0.3	6
0.4	11
0.5	17
0.6	25
0.7	34
0.8	45
0.9	56
1	70
1.1	84
1.2	100
1.3	118
1.4	137
1.5	157
1.6	179
1.7	202
1.8	226
1.9	252
2	279
2.1	308
2.2	337
2.3	369
2.4	402
2.5	436
2.6	471
2.7	508
2.8	547
2.9	586
3	628
3.1	670
3.2	714
3.3	759
3.4	806
3.5	854
3.6	904
3.7	955
3.8	1007
3.9	1061
4	1116
4.1	1172

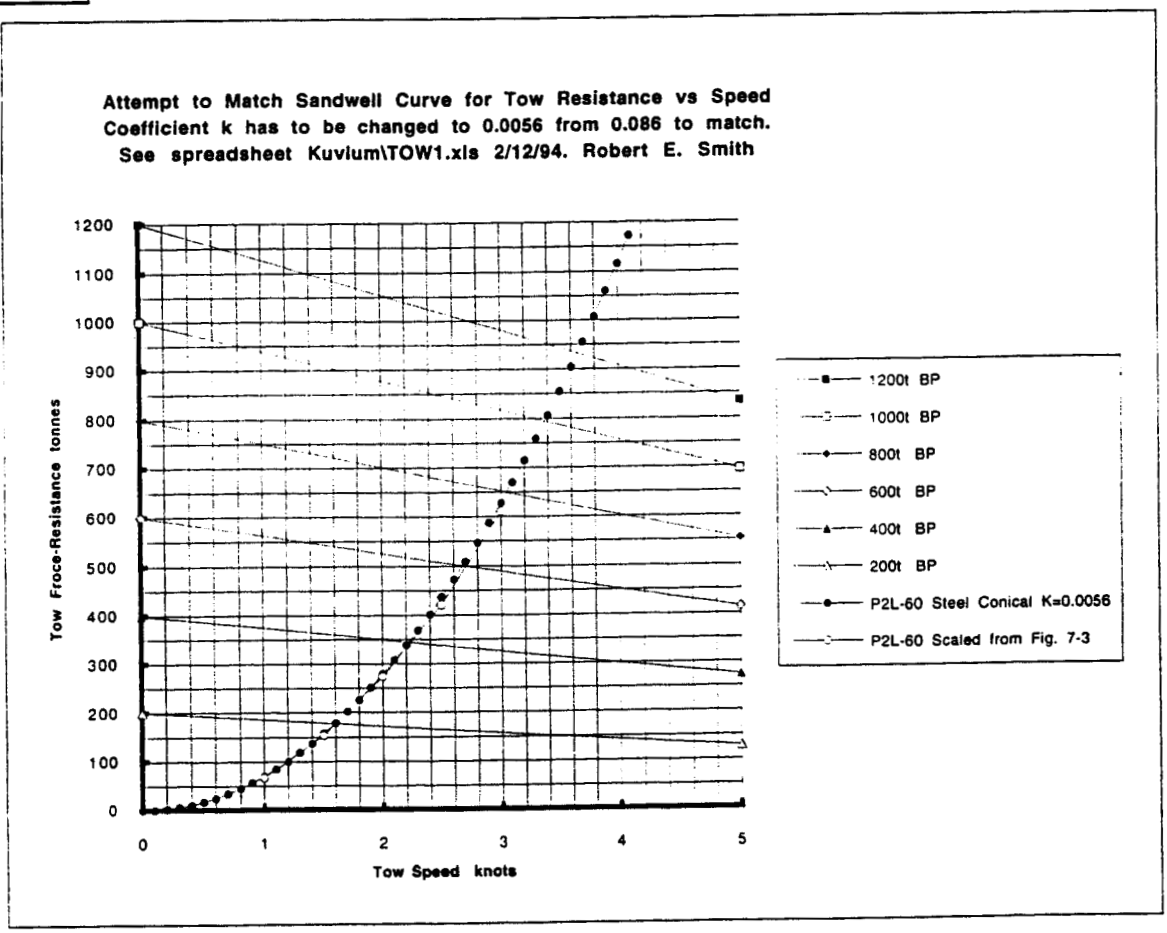


FIGURE A4-31
Duplication of Tow Resistance Curve from Sandwell 1991 Structure Report

A4.5 Schedule for Engineer, Procurement and Construct Topside Facilities

Design of topsides facilities will take 1.5 years, procurement 2.5 years, and fabrication/installation on a Kuvlum structure 2 years for the smallest deck and 3 years for the largest. Considering overlap between these efforts, the overall time to EPC topside facilities will take 3.5 years for the smallest deck and 4.5 years for the largest deck.

To Develop Most Likely Cost Estimates of Topsides Facilities for Case 1 and Case 2, which are not one of the six cases estimated above.

Spreadsheet KPFEST.XLS

Summary of Cost Estimates of Topside Facilities for the Six Cases

Type of Platform	Number of Wells	Production Rate MBOPD	Process Rate MBOPD	Most Likely Costs *Facility Cost on a Kuvlum Structure at a Far East Site $MM
Drilling	40	120	0	136
Drilling	70	210	0	194
Drilling	100	300	0	215
Drill&Process	60	150	150	449
Drill&Process	70	210	300	592
Drill&Process	100	300	450	791

Cases for Economic Analysis defined by AAI. Estimated from above above 6 cases, 3 Drill and 3 Drill&Process Platforms.

Type of Platform & CaseNumber	Number of Wells	Production Rate MBOPD	Process Rate MBOPD	*Facility Cost on a Kuvlum Structure at a Far East Site $MM
Drill&Process Case 1	40	120	120	$401
Drill&Process **	70	210	210	$529
Drill&Process Case 2	100	300	300	$613

**This case not defined by AAI, but analyzed anyway to observe trend.

Interpolated Cost of Facility on a Drilling Platform for 150 MBOPD (See Graph)= $155 MM

Determination of Cost of Process Facilities excluding the Cost of Facilities which would be on a Drilling Platform.
Cost of Process Facilities = Facility Cost - Cost of Facility of a Drilling Platform

Production Rate MBOPD	Cost of Facility on Drill Platf. $MM	Process Rate MBOPD	Facility Cost $MM	Cost of Process Facility at Process Rate $MM
150	$155	150	$449	$294
210	$194	300	$592	$398
300	$215	450	$791	$576

See Graph Below
Interpolated Cost of Process Facility @ 120MBOPD = $265 MM
Interpolated Cost of Process Facility @ 210 MBOPD = $335 MM

* Facility Cost (includes procurement and fabrication onshore Gulf of Mexico; tow to protected water site in the Far East where facilities are installed and certified on a Kuvlum structure and made ready for tow to a Kuvlum site) = (Cost of Facility on a Drilling Platform + Cost of Process Facility) at the same MBOPD. rate.

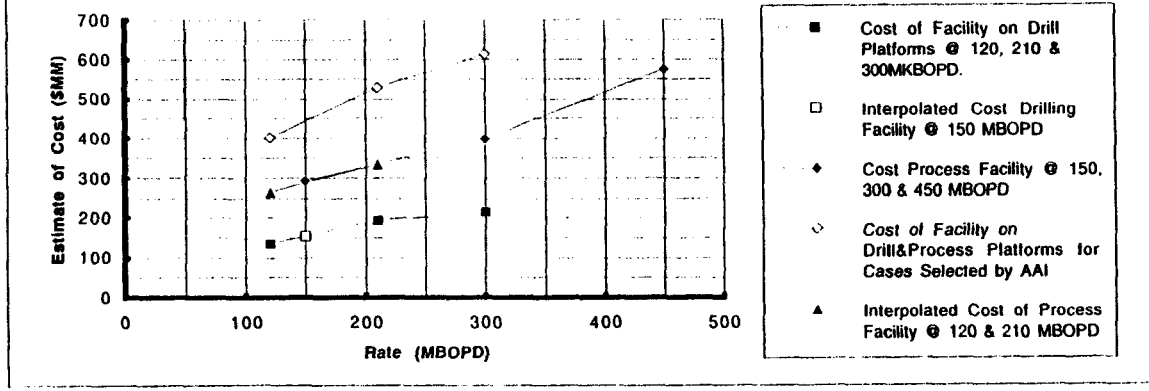


FIGURE A4-33
Case 1 and Case 2 Most Likely Installed Costs of Topsides Facilities on a Kuvlum Structure

To Develop Cost Estimates of Facilities for Kuvlum Case 3 which is not a specific case estimated by "Kuvlum Topsides Estimates Report". Case 3 analysis is to determine Minimum Reserves needed for a PW10=0.0

Summary of Cost Estimates from "Kuvlum Topsides Estimates Report"

Type of Platform	Number of Wells	Production Rate MBOPD	Process Rate MBOPD	"Facility Cost on a Kuvlum Structure at a Far East Site $MM
Drilling	40	120	0	136
Drilling	70	210	0	194
Drilling	100	300	0	215
Drill&Process	60	150	150	449
Drill&Process	70	210	300	592
Drill&Process	100	300	450	791

Case 3 Facility Cost. Estimated from above 6 cases, 3 Drill and 3 Drill&Process Platforms.

Type of Platform	Number of Wells	Production Rate MBOPD	Process Rate MBOPD	"Facility Cost on a Kuvlum Structure at a Far East Site $MM	Reserves MMBBL
Drill&Process	100	40	40	$297	200
"	"	75	75	$356	400
"	"	115	115	$416	600
"	"	155	155	$457	800

Interpolated Cost of Facility on a Drilling Platform for 40MBOPD (See Graph)=	$84 MM
Interpolated Cost of Facility on a Drilling Platform for 75 MBOPD (See Graph)=	$107 MM
Interpolated Cost of Facility on a Drilling Platform for 115MBOPD (See Graph)=	$133 MM
Interpolated Cost of Facility on a Drilling Platform for 150MBOPD (See Graph)=	$155 MM
Interpolated Cost of Facility on a Drilling Platform for 155 MBOPD (See Graph)=	$159 MM

Determination of Cost of Process Facilities excluding the Cost of Facilities which would be on a Drilling Platform.

Cost of Process Facilities = Facility Cost - Cost of Facility of a Drilling Platform

Production Rate MBOPD	Cost of Facility on Drill Platf. $MM	Process Rate MBOPD	Facility Cost $MM	Cost of Process Facility at Process Rate $MM
150	$155	150	$449	$294
210	$194	300	$592	$398
300	$215	450	$791	$576

See Graph Below

Interpolated Cost of Process Facility @ 40 MBOPD =	$190 MM
Interpolated Cost of Process Facility @ 75MBOPD =	$223 MM
Interpolated Cost of Process Facility @ 115MBOPD =	$261 MM
Interpolated Cost of Process Facility @ 155 MBOPD =	$298 MM

" Facility Cost (includes procurement and fabrication onshore Gulf of Mexico; tow to protected water site in the Far East where facilities are installed and certified on a Kuvlum structure and made ready for tow to a Kuvlum site) = (Cost of Facility on a Drilling Platform + Cost of Process Facility) at the same MBOPD. rate.

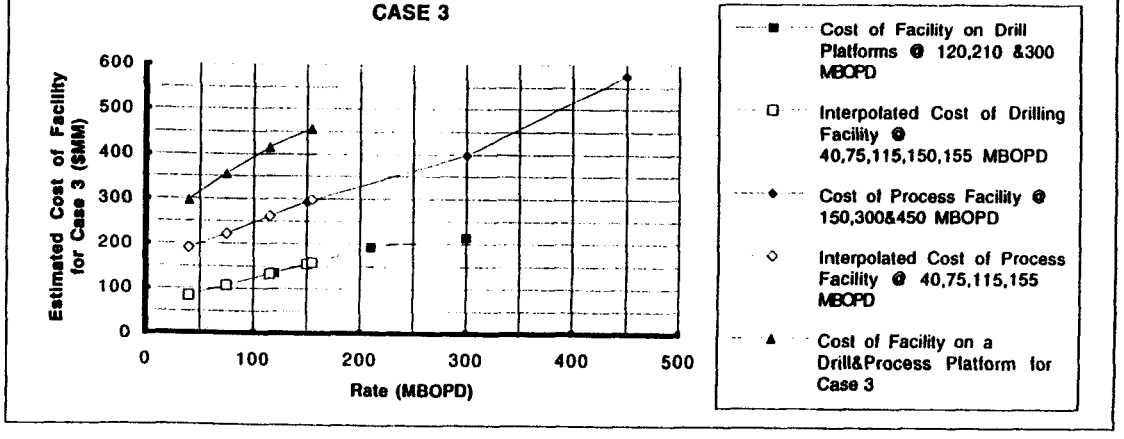


FIGURE A4-34
Case 3 Most Likely Installed Costs of Topsides Facilities on a Kuvlum Structure

A4.6 Estimates of Area and Weight for Drilling Rig, Drilling Utilities and Consumables. Input from ARCO Alaska, Inc.

ARCO Alaska, Inc.

DATE: 6/23

TO: Tom Proehl, Bill Kazokas

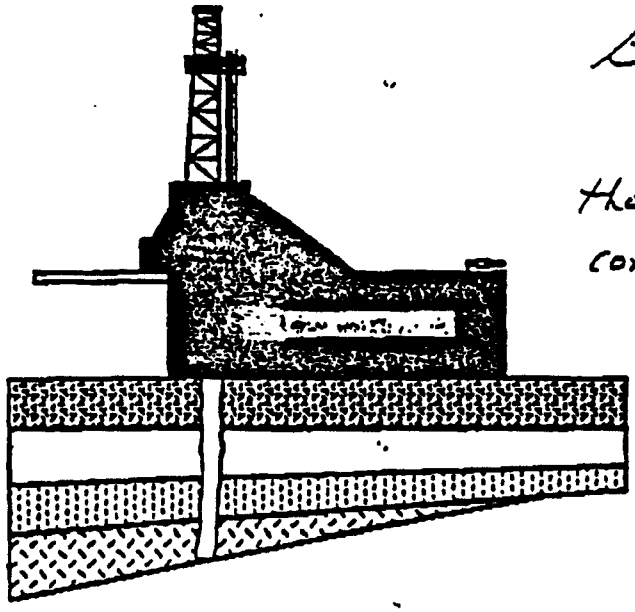
FAX NO:

ATTN:

FROM: Tim Billingsley 265-6575
Fax 265-6224

WE ARE TRANSMITTING 2 PAGES (EXCLUDING THIS COVER LETTER).

IF YOU DO NOT RECEIVE ALL THE PAGES, PLEASE CALL BACK AS SOON AS POSSIBLE TO TELEPHONE (907)263-4556.



Bill/Tom,
Here's some
thoughts on
consummables.
Tim B.

FIGURE A4-36, Page 1 of 3

KUVLUM PROJECT
Drilling Consummables

Per Well

1. Casing

20"		94#/,	4 JTS
13-3/8"	1000' TVD	1000' MD	72K # 25 jts
9-5/8"	4000' TVD	5000' MD	235K 125 jts
7"	7000' TVD	10000' MD	290K 250 jts
			600K 400Jts

(# of joints would be a big problem to store on the platform for 1 year's worth of drilling)

2. Cement

13-3/8"	600 sx
9-5/8"	300 sx
7"	250 sx

1150 sx X 1.5 excess = 1700 sx or 170K lbs

PTANK

3. Mud

PTANKS
JACK STOCKLEY

Bentonite	500 sx or 50 K
Barite	2000 sx or 200 K
Misc	50 k

P-TANK
JACK STOCKLEY

total = 300 K/well

DRILL PIPE 5 STRINGS 19.5#/,
300 JTS + 2 @ 30'

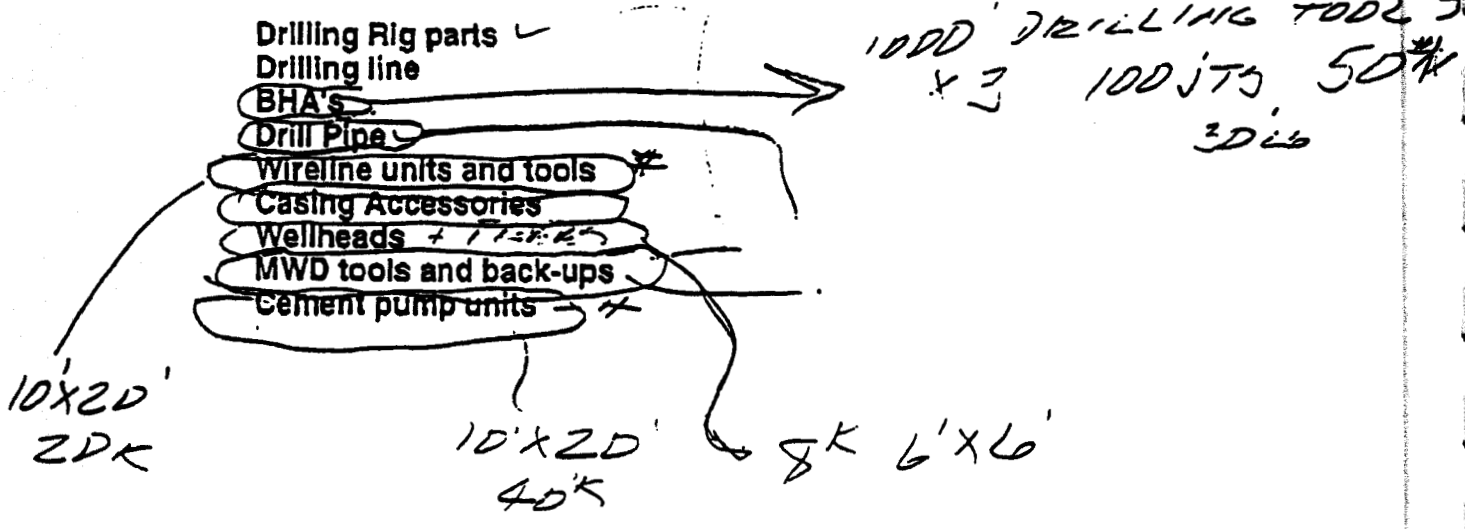
# of wells per year = 20 for 1 rig and 40 for 2 rigs

TUBING 250 JTS 3½" 12.5#/, 125K

250 JTS 4½" 9.5#/,

Drilling Tools

1 year's worth of drilling tools would be substantial.



Tim Billingsley 265-6575 6/23/93

ARCO Alaska, Inc.

DATE: 6/29/93 6:30 T-

TO: Tom Proehl, Bill Kazokas

FAX NO: 754-3920

ATTN:

FROM: Tim Billingsley 265-6575
Fax 265-6224

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Tom/Bill,
Here's a rig spec for you. Any comments?

Tim B

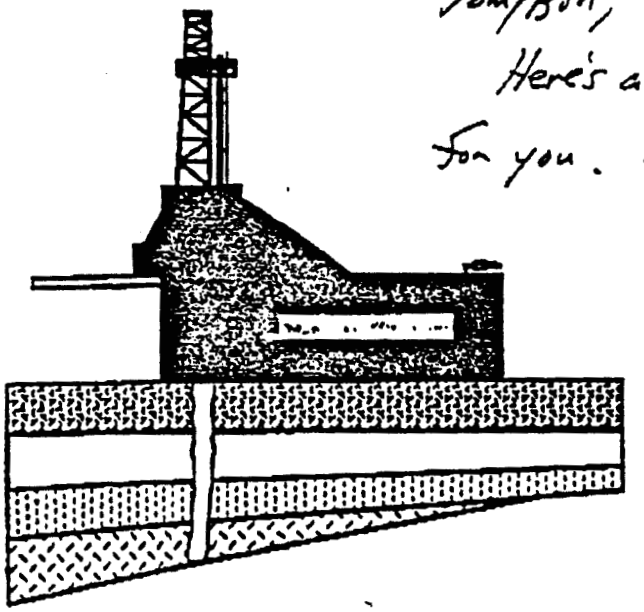


FIGURE A4-37, Page 1 of 2

Conceptual Rig Specifications
Kuvlum Platform Project

1. Drilling Rig requirements

Depth- 7000' TVD, 11,000' TVD max
Max casing weight- 500K

Drawworks- 2000 HP
Top Drive- 1000 HP

Mud Pumps- 2 @ 1600 HP each
Mud Pits- 1200 bbl total
(1200 @ 12 ppg = 600 K)
Drill Water and rig water- Desalinization plant?

Drill Cuttings- Disposal permit or processing (Ball Mill) required?

Overall Dimensions (from Cook Inlet platform rigs)

Substructure- 33' x 42' (rig floor is 40' above platform deck)
Dead Weight = 1500K — + DERRICK
Variable weight = 1000K
Total Weight = 2500K

Utility Module- 50' x 52' (top is 40' above platform deck)
Dead Weight =1500K

Pipe Rack - 45' x 50'
COVERED

Tim Billingsley 265-6575 6/29/93

FIGURE A4-37, Page 2 of 2

ARCO Alaska, Inc.

DATE: 8/2/93

TO: Bill Kazokas

FAX NO: 754-3920

ATTN:

FROM: Jim Billingsley 265-6525

WE ARE TRANSMITTING 5 **PAGES (EXCLUDING THIS COVER LETTER).**

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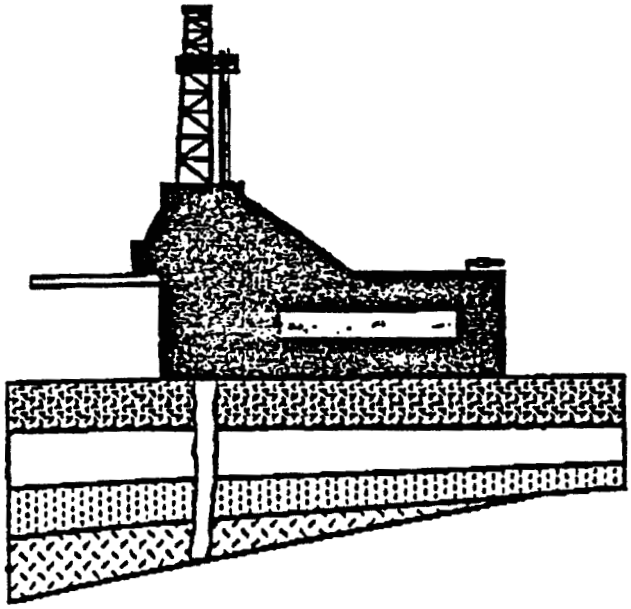


FIGURE A4-38, Page 1 of 5

PAA Rig 428
General Specifications

- *1000 Kip Boot Strap Mast--165 Ft. X 25 Ft.*
- *Varco Top Drive Drilling System*
- *Ideco E-2100 Drawworks*
- *Oilwell 37 1/2" Independent Rotary Drive*
- *500 Ton Traveling Block*
- *650 Ton Swivel*
- *Solar Centaur Turbine & Generator (Prime Power)*
- *Two Caterpillar D-399 Generator Sets (Stand-by Power)*
- *General Electric Generation III SCR System*
- *Peak Load: 2500 KW @13,800 VAC, 200 Amp, 3 Phase*
- *Two 100 HP Steam Generators*
- *Turbine Waste Heat Recovery System*
- *Two Oilwell A-1700 PT Mud Pumps*
- *430 BBL Active Mud Tank*
- *Triple Derrick Mod. 58 Flo-Line Cleaner*
- *Degasser*
- *Desander*
- *Mud Cleaner*
- *Provisions for High Volume Centrifuge*
- *500 BBL Drill Water Storage*
- *Structures Designed Per API RP 2A Seismic Criteria (Zone 4)*

ITEMS TO CONSIDER

DERRICK TYPE & RATING

NATIONAL TOP DRIVE

LARGER DRAWWORKS TO DRIVE ROTARY TABLE RATHER THAN INDEPENDENT DRIVE

LARGER MUD PIT SYSTEM

LARGER CAPACITY FOR DRILL WATER STORAGE – GIRDER BEAM TANKS

INSTALL HIGH VOLUME CENTRIFUGE

PAA Rig 428
Weights and Dimensions

Rig Module

Overall Length: 42 Ft.
Overall Width: 33 Ft.
Rig Floor Height: 40 Ft.
Dead Weight: 1345 Kips
Variable Load: 1663 Kips
Total Operating Load (Max): 3008 Kips

Utility Module

Overall Length: 50 Ft.
Overall Width: 52 Ft. 3 In.
Pipe Rack Height: 38 Ft. 6 In.
Pipe Rack Dimensions: 45 Ft. x 50 Ft. (1000 Kips Capacity)
Dead Weight: 1310 Kips
Variable Load: 1410 Kips
Total Operating Load (Max): 2720 Kips

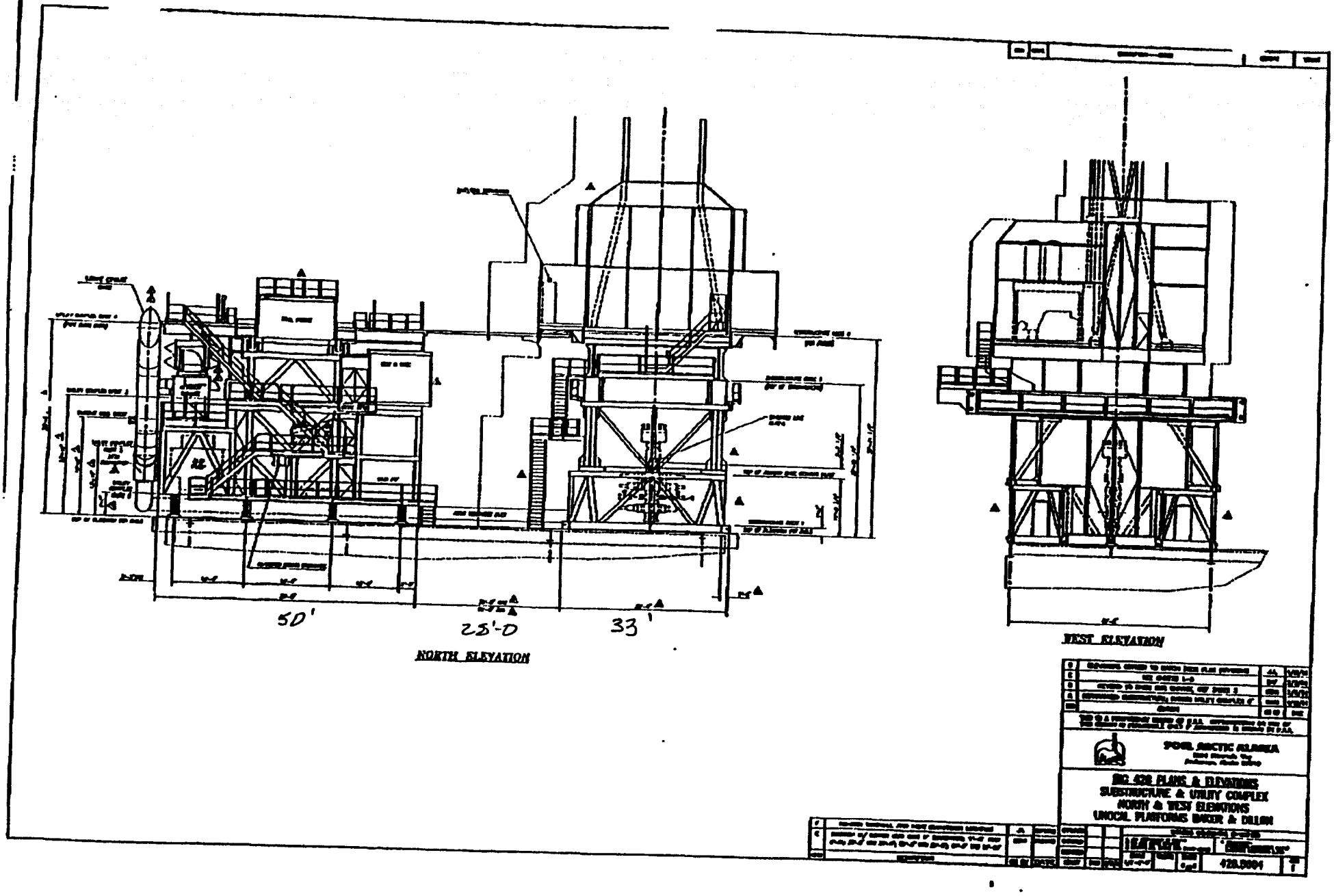


FIGURE A4-38, Page 4 of 5

FIGURE A4-38, Page 5 of 5

Kazokas, Bill (PC)

From: JELDRED
Subject: Drilling/spare parts
Date: Mon, Aug 9, 1993 1:28PM
Priority: High

FROM: ARCO(JELDRED)

TO: MSPRCMS1(WKAZOKA) DATE: 1993-08-09
TIME: 13:28

CC:

SUBJECT: Drilling/spare parts
PRIORITY: R
ATTACHMENTS:

Bill,
Spoke with Tim Billingsley about dry waste and cuttings storage. He said to assume one 500 Bbl tank to store the cuttings prior to having an annulus for injection. From there the cuttings will be ground and slurried for injection. The injection facility would be part of the rig and require no more area than currently used for a rig.

For qtrs storage, I would assume that the rig is being constantly resupplied via helicopter with all consumables that are transportable by that method. Therefore I would treat this item as insignificant at this point.

For spare parts storage, I would assume we have a module area approximately equal to the size of one of the turbine modules for storage of a spare rotor, critical motors, pumps, etc. I think we would maintain a minimum spare parts inventory on board, realizing that all but the largest pieces of equipment can be transported via helecopter sling in a true emergency. This area could be part of a "shop" area.

Call me if you need more information than this.
John

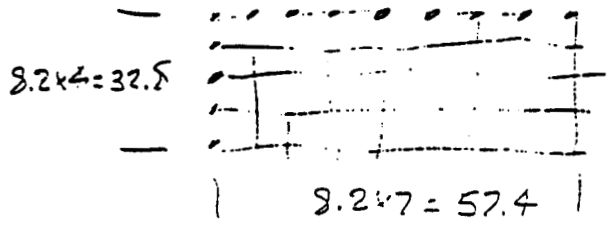
FIGURE A4-39

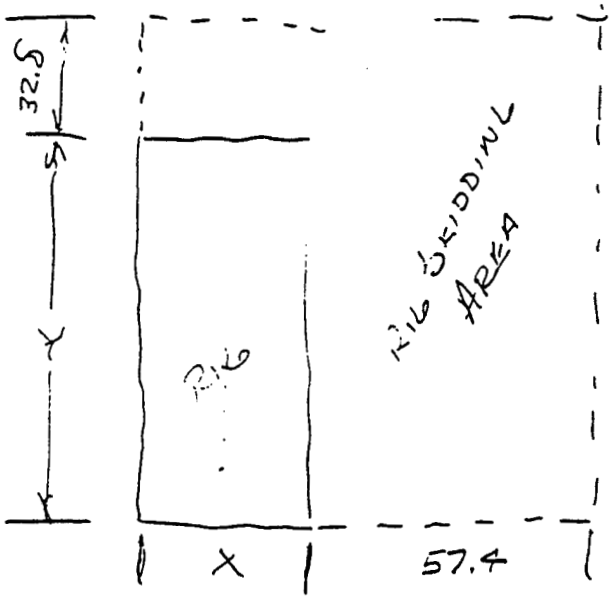
General Purpose Worksheet

Subject	Page No.	Of
File	By	Date

RIG SKIDDING AREA

40 WELLS = 8 x 5 PATTERN





AREA = 57.4(Y+32.8) + X(32.8)

SAY X = 53.5

Y = 98.3

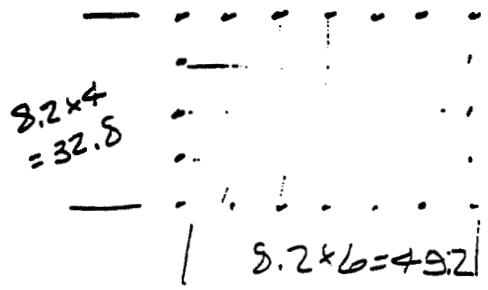
∴ AREA = 9280

General Purpose Worksheet

Subject	Page No.	Of
File	By	Date

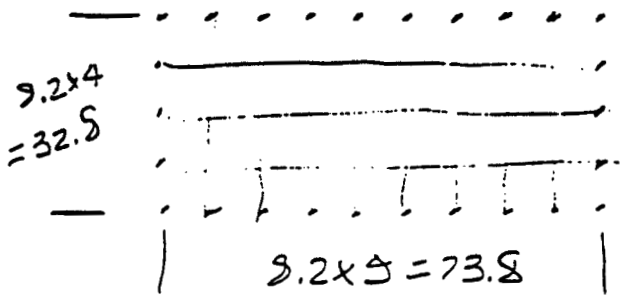
RIG SKIDDING AREA

35 WELLS = 7 x 5



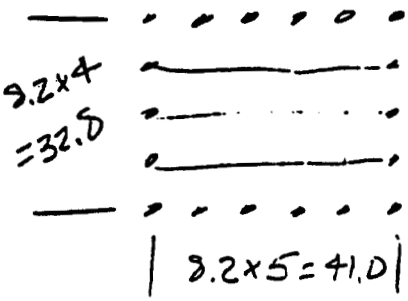
AREA = 49.2[58.3 + 32.8]
+ 53.5(32.8)
= 8205

50 WELLS = 10 x 5



AREA = 73.8[58.3+32.8]
+ 53.5(32.8)
= 11430

30 WELLS = 6 x 5



AREA = 41.0[58.3+32.8)
+ 53.5(32.8)
= 7130

DRILLING.XLS

Drilling Rig Size Assumptions

For purposes of analysing the weight, space and arrangement of the drilling rig and consumables. assume that the structural deck will provide for two deck levels. The rig substructure and modules will set above the top deck roof level
The well consumables can be on main and cellar decks
Liquid storage of fuel and water can be in the hull below decks

	Amount	Weight	Space	Deck Area
Drill Rig Substructure & Derrick	1 ls		1386 sq ft	1386 sq ft
Dead Load		1500 kips		
Variable Load		700 kips		
Hook load		1000 kips		
(Plan Dimensions = 33' x 42')				
(Rig Floor Height = 40')				
Total =		3200 kips		1386 sq ft
Utility Module (+bridging struct)	1 ls		4482 sq ft	4482 sq ft
Dead Load		1300 kips		
Variable Load		1400 kips		
(Plan Dimensions = 50' x 52')				
(Pipe Rack Height = 38' 6")				
Total =		2700 kips		4482 sq ft
Wireline Unit & Tools	1 ls	20 kips	200 sq ft	200 sq ft
(Plan Dimensions = 10' x 20')				
Cement Unit				
(Plan Dimensions = 10' x 20')	1 ls	40 kips	200 sq ft	200 sq ft
Drilling Pipe (1 Rig, 10 months)	900 jts	527 kips	2940 cu ft	196 sq ft
(3 strings of 300 jts)				
Drilling Tools (1 Rig, 10 months)	100 jts	150 kips	750 cu ft	150 sq ft
Liquid Consumables,10 months	1 Rig	2 Rigs		
Drill Water Storage	35000 bbls	70000 bbls		
Oil Base Storage	8500 bbls	17000 bbls		
Completion Fluid Storage	8500 bbls	17000 bbls		
Potable Water Storage	20000 bbls	30000 bbls		
Fuel Storage	136000 bbls	210000 bbls		

Well Consumables - One Well

Mud	Amount	Weight	Space	Deck Area
Bentonite (P-tanks)	500 sx	50 kips	500 cu ft	196 sq ft
Barite (P-tanks)	2000 sx	200 kips	2000 cu ft	392 sq ft
Misc (Sack Storage)	500 sx	50 kips	500 cu ft	67 sq ft
Cement (P-tanks)	1700 sx	170 kips	1700 cu ft	392 sq ft
Conductor				
20"	6 jts	23 kips	807 cu ft	40 sq ft
Casing				
13-3/8"	25 jts	72 kips	1440 cu ft	72 sq ft
9-5/8"	125 jts	235 kips	3445 cu ft	172 sq ft
7"	250 jts	290 kips	4489 cu ft	224 sq ft
Tu 4-1/2"	250 jts	95 kips	2500 cu ft	125 sq ft
Wellheads & Trees	1 ls	8 kips	540 cu ft	36 sq ft

P-tanks have capacity of 1000 sacks each, weigh 6 kips empty and take a deck space of 14 ft dia. and 20 ft high.
Sack storage is assumed to be stored on pallets (50 sx/pallet) stored 3 high in racks that add 2% to the weight. Assume each pallet bank uses 4 ft by 5 ft of floor space.
Drill Pipe is assummed to be 30 ft lengths stored in pipe racks 15 ft high
Drilling Toos are assumed to be in 30 ft lengths stored in racks 5 ft high
Well tubulars are assumed to be 40 ft long and stored in racks 20 ft high
Wellheads and trees are assumed to require a space 6 ft in dia. and 15 ft high
Storage Racks and overhead travelling hoists are assumed to weigh 200 and 400 kips respectively for 1 and two drill rigs

A4.7 GOSP Management Decisions Examples

OUTPUT SUPPRESSION LEVELS (OSUP) MANAGEMENT DECISIONS

COMPLETE OUTPUT SPECIFIED FOR CENTRAL COMPLEX
PROCESS AND UTILITY BALANCES (NO SUPPRESSION)

COMPLETE OUTPUT SPECIFIED FOR PLATFORM OR COMPLEX SYSTEM
WEIGHT AND AREA ESTIMATES (NO SUPPRESSION)

COMPLETE OUTPUT SPECIFIED FOR SUBSTRUCTURE AND
BRIDGE ESTIMATES (NO SUPPRESSION)

COMPLETE SYSTEM COST ESTIMATE OUTPUT SPECIFIED
FOLLOWING EACH SYSTEM OUTPUT

PROGRAM WILL NOT CEASE EXECUTION AFTER MANAGEMENT DECISIONS MESSAGES

FIGURE A4-43, Page 1 of 12

ENVIRONMENTAL (FACT) MULTIPLOT PARAMETERS

DESIGN WATER DEPTH SPECIFIED AS 110.0 FT

DESIGN STORM WAVE HEIGHT SPECIFIED AS 40.0 FT

MEDIUM SOIL CONDITIONS SPECIFIED

DESIGN MAXIMUM SEA WATER TEMPERATURE SPECIFIED AS 45.0 DEG F

DESIGN MAXIMUM AMBIENT AIR TEMPERATURE SPECIFIED AS 60.0 DEG F

DESIGN MINIMUM AIR TEMPERATURE SPECIFIED AS -20.0 DEG F

PLATFORM FUNCTION ASSIGNMENT (PFAC) ASSIGNMENTS

PLATFORM CONFIGURATION SPECIFIED AS
SINGLE INTEGRATED PLATFORM, EXCLUDING WELL PLATFORMS

ALL FUNCTIONS WILL BE ASSIGNED TO PLATFORM J

OUTPUT SUPPRESSION LEVELS (SUPP) MANAGEMENT DECISIONS

COMPLETE OUTPUT SPECIFIED FOR CENTRAL COMPLEX
PROCESS AND UTILITY BALANCES (NO SUPPRESSION)

COMPLETE OUTPUT SPECIFIED FOR PLATFORM OR COMPLEX SYSTEM
WEIGHT AND AREA ESTIMATES (NO SUPPRESSION)

COMPLETE OUTPUT SPECIFIED FOR SUBSTRUCTURE AND
BRIDGE ESTIMATES (NO SUPPRESSION)

NO COST OUTPUT SPECIFIED

PROGRAM WILL NOT CEASE EXECUTION AFTER MANAGEMENT DECISIONS MESSAGES

ENVIRONMENTAL (ENVI) PARAMETER DECISIONS

DESIGN WATER DEPTH SPECIFIED AS 110.0 FT

DESIGN STORM WAVE HEIGHT SPECIFIED AS 40.0 FT

MEDIUM SOIL CONDITIONS SPECIFIED

DESIGN MAXIMUM SEA WATER TEMPERATURE SPECIFIED AS 45.0 DEG F

DESIGN MAXIMUM AMBIENT AIR TEMPERATURE SPECIFIED AS 60.0 DEG F

DESIGN MINIMUM AIR TEMPERATURE SPECIFIED AS -20.0 DEG F

PLATFORM [illegible] ASSIGNMENT (AREA) IN ACTIVE DECISIONS

PLATFORM CONFIGURATION SPECIFIED AS
SINGLE INTEGRATED PLATFORM, EXCLUDING WELL PLATFORMS

ALL FUNCTIONS WILL BE ASSIGNED TO PLATFORM J

LIVING QUARTERS & PERSONNEL SUPPORT UTILITIES (LIVU)

MANAGEMENT DECISIONS

A LIVING QUARTERS IS SPECIFIED

NUMBER OF MEN FOR LIVING QUARTERS IS SPECIFIED AS 250

STEEL LIVING QUARTERS SPECIFIED

NUMBER OF LEVELS FOR LIVING QUARTERS NOT SPECIFIED
****** WILL BE INTERNALLY CALCULATED

LIVING QUARTERS SPACE SPECIFIED AS 250.0 SQ FT/MAN

LIVING QUARTERS LENGTH NOT SPECIFIED
****** WILL BE CALCULATED INTERNALLY

LIVING QUARTERS WIDTH NOT SPECIFIED
****** WILL BE CALCULATED INTERNALLY

NO LIVING QUARTERS CANTILEVER SPECIFIED

FIRST HELIDECK SPECIFIED AS STEEL, FOR 40-PERSON (CHINOOK) HELICOPTER

NO SECOND HELIDECK SPECIFIED

REFUELING RIG SPECIFIED FOR FIRST HELIDECK

HELIHANGAR SPECIFIED FOR FIRST HELIDECK

CONVENTIONAL AFFF FIRE SPRAY PLANT SPECIFIED

NO DEDICATED EMERGENCY GENERATOR SPECIFIED FOR LIVING QUARTERS

ONE DISH ANTENNAS SPECIFIED

MATERIAL HANDLING (MTLH) MANAGEMENT DECISIONS

PLATFORM J :

NUMBER OF CRANE(S) SPECIFIED AS 3

TYPE 3 CRANE SPECIFIED AS COUNTERWEIGHTED PEDESTAL

CRANE MAXIMUM LIFTING CAPACITY SPECIFIED AS 75.0 S. TONS

ELECTRIC HOISTS SPECIFIED

EQUIPMENT SPECIFICATIONS (TASB) MANAGEMENT DECISIONS

VESSEL CODE FOR PRODUCTION SYSTEMS SPECIFIED AS ASME, DIV 2 (LESS CONSERV

CORROSION ALLOWANCE FOR PRODUCTION VESSELS SPECIFIED AS 1/8 INCH

CONVENTIONAL SHELL AND TUBE HEAT EXCHANGERS SPECIFIED FOR MAIN PROCESS DUTIES REQUIRING SHELL AND TUBE EXCHANGERS

TURBINE DRIVER TYPE SPECIFIED AS AIRCRAFT-DERIVATIVE TURBINES ONLY

SYSTEMS BULK ADJUSTMENT FACTOR (SBAF) MANAGEMENT DECISIONS

***** ONLY THE SYSTEMS LISTED BELOW WERE SPECIFIED TO BE ADJUSTED
***** ALL OTHER SYSTEM ADJUSTMENT FACTORS WILL DEFAULT TO 1.0

ADJUSTMENT FACTORS (JADJ) MANAGEMENT DECISIONS

***** ONLY THE CATEGORIES LISTED BELOW WERE SPECIFIED TO BE ADJUSTED
***** ALL OTHER ADJUSTMENT FACTORS WILL DEFAULT TO 1.0

EMERGENCY ELECTRICAL POWER ADJUSTMENT FACTOR SPECIFIED AS 2.0

PLATFORM J :

OTLIER RATE ADJUSTMENT FACTOR SPECIFIED AS 1.2

PLATFORM FUNCTIONAL LOCATION (PFAS) MANAGEMENT DECISIONS

FUNCTION LOCATION SUMMARY

PLATFORM J:
- LIVING QUARTERS
- PRODUCTION
- PRODUCTION MANIFOLD
- WELLHEAD/DRILLING
- POWER GENERATION AND MAIN POWER DISTRIBUTION
- UTILITIES
- GAS TREATMENT
- GAS COMPRESSION
- WATER INJECTION
- FIRST HELIDECK
- FLARE
- OIL EXPORT RISER
- GAS EXPORT RISER

FIGURE A4-43, Page 12 of 12

A4.8 Cost Indices Used to Update GOSP Cost Data Sets.

General Purpose Worksheet

Subject	Page No.	Of
	By	Date

SEPT 1983 HIDECK

100 KBOD

	HIDECK	CONVENTIONAL	
MAJOR EQUIP & BULKS	77,275	77.939	100227.2
ONSHORE HOOKUP	10.657	11.589	17905.5
DECK STRUCTURE & MODULE	25.293	26.654	52709.2
ENGINEERING	15.307	16.585	26565.3
PJT MGMT	10.306	12.513	17843.6
	138868	145 280	

ASSUME 1991

LOAD SEPT 93 ⟶ 232113

ESCALLATION
DOJ INDEX
REFINERY CONST

SEPT 83 = 1044.4
MAR 93 1606.1
SEP 93 = 1606.1 x 1.0175 = 1634.2

$$\frac{1634.2}{1044.4} = 1.565$$

145 280 (1.565) = 227.324

OK

2%

FIGURE A4-45

A4.9 Cost Comparison Between HiDeck and GOSP Run Using Updated Indices.

COST (COST)
MANAGEMENT DECISIONS

ONSHORE AVERAGE DIRECT LABOR COST SPECIFIED AT $ 62.0/MANHOUR
****** VALUE APPEARS HIGH. PLEASE CHECK DESIGN BASIS

ONSHORE AVERAGE PERSONNEL PRODUCTIVITY SPECIFIED AT 100.0 %

PRELIMINARY AND DETAILED DESIGN COST SPECIFIED AS 15.0 %
OF DIRECT LABOR AND MATERIALS FOR COST FOR THE TOPSIDES

COST OF TRANSPORTATION OF MAJOR EQUIPMENT AND BULK
MATERIALS TO ONSHORE MARSHALLING YARD SPECIFIED AT 8.0 %
OF MAJOR EQUIPMENT & BULKS COST

PROCUREMENT COST IS SPECIFIED AT 0.0 %
OF DIRECT LABOR AND MATERIALS FOR COST FOR TOPSIDES
****** VALUE APPEARS LOW, PLEASE CHECK DESIGN BASIS

ENGINEERING PROJECT MANAGEMENT COST SPECIFIED AT 5.0 %
OF DIRECT LABOR AND MATERIALS FOR COST FOR TOPSIDES

CONSTRUCTION PROJECT MANAGEMENT COST SPECIFIED AT 5.0 %
OF DIRECT LABOR AND MATERIALS FOR COST FOR TOPSIDES
****** VALUE APPEARS HIGH, PLEASE CHECK DESIGN BASIS

CONTRACTORS MOBILIZATION/DEMOBILIZATION COST SPECIFIED AT 0.0 %
OF DIRECT LABOR AND MATERIALS FOR COST FOR TOPSIDES
****** VALUE APPEARS LOW, PLEASE CHECK DESIGN BASIS

CONTRACTORS EQUIPMENT COST SPECIFIED AT 7.0 %
OF MAJOR EQUIPMENT AND BULK MATERIALS FOR COSTS FOR TOPSIDES

CONTRACTORS WAREHOUSING & LAYDOWN COST SPECIFIED AT 0.0 %
OF DIRECT LABOR COST FOR TOPSIDES
****** VALUE APPEARS LOW, PLEASE CHECK DESIGN BASIS

CONTRACTORS CONTINGENCY & PROFIT SPECIFIED AT 10.0 %
OF DIRECT LABOR COST FOR TOPSIDES

MODULE STRUCTURAL STEEL DIRECT LABOR COST SPECIFIED AT $ 1250.0/KIP
****** VALUE APPEARS HIGH, PLEASE CHECK DESIGN BASIS

MODULE STRUCTURAL STEEL MATERIALS FOR COST SPECIFIED AT $ 400.0/KIP
****** VALUE APPEARS LOW, PLEASE CHECK DESIGN BASIS

FINISHING AND MISCELLANEOUS STEEL DIRECT LABOR COST SPECIFIED AT $ 1250.0/KIP

FINISHING AND MISCELLANEOUS STEEL MATERIAL FOR COST SPECIFIED AT $ 400.0/KIP
****** VALUE APPEARS LOW, PLEASE CHECK DESIGN BASIS

COST OF TRANSPORTATION OF TOPSIDES FRACTED STEEL IS SPECIFIED AT
0.0 % OF THE TOPSIDES STEEL MATERIALS FOR COST
****** VALUE APPEARS LOW, PLEASE CHECK DESIGN BASIS

COST OF OFFSHORE CONSTRUCTION EQUIPMENT IN PLATFORM J IS SPECIFIED AT $ 1.000 MM

COST OF PAINTING MATERIALS & DIRECT LABOR FOR THE TOPSIDES
IS SPECIFIED AT 0.0 % OF TOPSIDES DIRECT LABOR COST

TOPSIDES BARGE TRANSPORT COST IS SPECIFIED AT $ 0.0 M/DAY
***** VALUE APPEARS LOW. PLEASE CHECK DESIGN BASIS

TOPSIDES BARGE TRANSPORT TIME SPECIFIED AT 0. DAYS
***** VALUE APPEARS LOW. PLEASE CHECK DESIGN BASIS

TOPSIDES DERRICK BARGE COST IS SPECIFIED AT $ 0.0 M/DAY
***** VALUE APPEARS LOW. PLEASE CHECK DESIGN BASIS

TOPSIDES DERRICK BARGE TIME SPECIFIED AT 0. DAYS
***** VALUE APPEARS LOW. PLEASE CHECK DESIGN BASIS

TOPSIDES MOBILIZATION/DEMOBILIZATION SPECIFIED AT $ 0.000 MM
***** VALUE APPEARS LOW. PLEASE CHECK DESIGN BASIS

ENGINEERING COST OF HOOKUP AND COMMISSIONING IS SPECIFIED AT
0.0 % OF HOOKUP AND COMMISSIONING COST
***** VALUE APPEARS LOW. PLEASE CHECK DESIGN BASIS

HOOKUP AND COMMISSIONING FOR GRAVITY STRUCTURES:

ONSHORE LABOR IS SPECIFIED AT 0.0 MANHOURS/KIP
OF MAJOR EQUIPMENT AND BULK MATERIALS
***** VALUE APPEARS LOW. PLEASE CHECK DESIGN BASIS

INSHORE LABOR IS SPECIFIED AT 0.0 MANHOURS/KIP
OF MAJOR EQUIPMENT AND BULK MATERIALS
***** VALUE APPEARS LOW. PLEASE CHECK DESIGN BASIS

OFFSHORE LABOR IS SPECIFIED AT 0.0 MANHOURS/KIP
OF MAJOR EQUIPMENT AND BULK MATERIALS
***** VALUE APPEARS LOW. PLEASE CHECK DESIGN BASIS

ONSHORE LABOR COST IS SPECIFIED AT $ 0.0 M/MANHOUR
***** VALUE APPEARS LOW. PLEASE CHECK DESIGN BASIS

INSHORE LABOR COST IS SPECIFIED AT $ 0.0 M/MANHOUR
***** VALUE APPEARS LOW. PLEASE CHECK DESIGN BASIS

OFFSHORE LABOR COST IS SPECIFIED AT $ 0.0 M/MANHOUR
***** VALUE APPEARS LOW. PLEASE CHECK DESIGN BASIS

COST OF CONCRETE FOR GRAVITY SUBSTRUCTURE IS
SPECIFIED AT $ 0.00 /CUBIC METER
***** VALUE APPEARS LOW. PLEASE CHECK DESIGN BASIS

AMOUNT OF CONCRETE FOR GRAVITY SUBSTRUCTURE IS NOT SPECIFIED
WILL BE ESTIMATED INTERNALLY

THE COST OF MECHANICAL OUTFITTING OF GRAVITY SUBSTRUCTURE
IS SPECIFIED AT $ 0.0 MM
***** VALUE APPEARS LOW. PLEASE CHECK DESIGN BASIS

COST OF SCOUR PROTECTION FOR GRAVITY SUBSTRUCTURE
IS SPECIFIED AT $ 0.0 MM
***** VALUE APPEARS LOW. PLEASE CHECK DESIGN BASIS

COST OF [illegible] FOR GRAVITY SUBSTRUCTURE IS
SPECIFIED AT $ 0.00 MM
***** VALUE APPEARS LOW. PLEASE CHECK DESIGN BASIS

FLOTEL USAGE TIME SPECIFIED AT 0. DAYS
***** [illegible]

***** VALUE APPEARS LOW. PLEASE CHECK DESIGN BASIS

THE SUBMAT DECK DIRECT LABOR COST FOR THE SUBSTRUCTURE
IS SPECIFIED AT $ 0.0/KIP
***** VALUE APPEARS LOW. PLEASE CHECK DESIGN BASIS

THE SUPPORT DECK MATERIALS FOR COST FOR THE SUBSTRUCTURE
IS SPECIFIED AS $ 0.0/KIP
***** VALUE APPEARS LOW. PLEASE CHECK DESIGN BASIS

RISER MATERIAL COST SPECIFIED AT $ 0.0 /KIP
***** VALUE APPEARS LOW. PLEASE CHECK DESIGN BASIS

RISER DIRECT LABOR COST SPECIFIED AT $ 0.0 /KIP
***** VALUE APPEARS LOW. PLEASE CHECK DESIGN BASIS

RISER TIE-IN COSTS SPECIFIED AT $ 0.0 /INCH-DIAMETER-FT
***** VALUE APPEARS LOW. PLEASE CHECK DESIGN BASIS

THE OVERALL CONTINGENCY COST IS SPECIFIED AT
0.0 % OF THE TOTAL INSTALLED PLATFORM COST
***** VALUE APPEARS LOW. PLEASE CHECK DESIGN BASIS

THE COST OF INSURANCE IS SPECIFIED AT 0.0 %
OF THE TOTAL INSTALLED PLATFORM COST
***** VALUE APPEARS LOW. PLEASE CHECK DESIGN BASIS

THE COST OF CERTIFICATION IS SPECIFIED AS 0.0 %
OF THE TOTAL INSTALLED PLATFORM COST
***** VALUE APPEARS LOW. PLEASE CHECK DESIGN BASIS

ESCALATION IS SPECIFIED AT 0.0 %
OF THE TOTAL INSTALLED PLATFORM COST
***** VALUE APPEARS LOW. PLEASE CHECK DESIGN BASIS

THE COST OF ABANDONMENT IS SPECIFIED AT 0.0 %
OF THE TOTAL INSTALLED PLATFORM COST

MISCELLANEOUS COSTS FOR PLATFORM J ARE SPECIFIED AT $ 0.000 MM

PLATFORM J
SYSTEM COST SUMMARY

(THIRD QUARTER 1993 COST DATA BASE)

SYSTEM	MAJOR EQUIPMENT COST, FOB $(000)	MAJOR EQUIPMENT LABOR COST $(000)	BULK MATERIALS COST, FOB $(000)	BULK MATERIALS LABOR COST $(000)	ONSHORE MATL & LABOR CO $(000)
MANIFOLD	10291.5	84.4	23775.7	21533.3	55684.
SEPARATION	3497.7	172.9	4280.7	4316.9	12268.
CRUDE METERING	1462.9	60.0	715.9	724.3	2963.
LOW PRES. GAS COMPR.	1388.2	89.4	543.7	615.8	2637.
REINJ. GAS COMPR.	40217.7	544.5	7759.0	8528.7	57049.
REINJ. GAS DEHYD.	3771.5	114.3	1111.3	1058.5	6055.
SPHERE LAUNCHER	74.8	4.9	1245.7	904.3	2229.
PRODUCED WATER	4631.2	205.7	1343.8	1685.2	7865.
RELIEF	3803.1	60.6	641.7	881.6	5386.
WATER INJECTION	11992.0	207.1	9895.4	3508.4	25592.
POWER GENERATION	21888.7	184.3	1243.3	878.8	24195.
POWER DISTRIBUTION	15694.5	148.6	6622.3	15443.5	37908.
SEA WATER	1362.6	55.7	3858.3	1560.9	6837.
SERVICE WATER	17.9	1.2	74.1	102.0	195.
COOLING MEDIUM	303.5	17.4	545.5	686.3	1558.
HEATING MEDIUM	359.2	13.9	832.2	1091.5	2296.
FRESH WATER	271.2	13.1	36.2	48.9	369.
CHLORINATION	106.8	3.1	49.4	17.4	176.
SEWAGE	62.3	15.3	96.0	133.6	308.
EFFLUENT WATER	146.3	20.1	1098.6	1391.3	26
INSTRUMENT AIR	202.6	17.7	79.1	99.4	3
UTILITY AIR	0.0	0.0	64.3	81.0	145.
FUEL GAS	32.7	2.5	89.5	111.6	235.
DIESEL FUEL	43.0	2.9	67.2	84.5	197.
INERT GAS	39.0	2.8	44.5	55.9	142.
CHEMICAL INJECTION	114.7	19.0	151.5	176.4	461.
FIRE PROTECTION	2832.4	85.9	14442.9	3459.1	20800.
MATERIAL HANDLING	3999.2	68.6	76.3	93.8	4237.
SAFETY	1492.3	66.6	153.8	189.2	1891.
HEATING/VENTILATION	103742.4	54.2	0.0	0.0	103806.
CONTROL CENTER	1547.2	14.0	69.0	157.0	1737.
NAVAIDS/COMMUNICATION	1035.5	9.1	0.0	0.0	1045.
BUILDINGS	2940.4	113.9	0.0	0.0	3054.
SUBTOTAL	239351.8	2464.7	81006.3	69609.4	392431.
TOPSIDES ERECTED STEEL					
LIVING QUARTERS	14201.6	288.9			14490.
PRIMARY HELIDECK	1162.3	60.9			1223.
MODULE STEEL	16901.6	78170.2			95071.
FINISHING STEEL	301.4	1394.1			1695.
SUBTOTAL	32567.0	79914.1			112481.
PLATFORM TOTALS	271918.5	82378.8	81006.3	69609.4	5049.

***** WILL DEFAULT TO ADIABATIC FLASH TEMPERATURE

SECOND STAGE OPERATING PRESSURE SPECIFIED AS 50.0 PSIG

OPERATING TEMPERATURE OF SEPARATION STAGE 2 NOT SPECIFIED
***** WILL DEFAULT TO ADIABATIC FLASH TEMPERATURE

NUMBER OF TEST SEPARATORS SPECIFIED TO BE 2

TEST SEPARATOR DESIGN RATE SPECIFIED AS 5.0% OF TOTAL CRUDE THROUGHPUT

FIRST STAGE SEPARATOR PARAMETERS :

HORIZONTAL VESSEL SPECIFIED FOR MAIN PRODUCTION SEPARATOR

WATER SEPARATION SPECIFIED

SEPARATOR SIZING METHOD SPECIFIED AS LIQUID RESIDENCE TIME CONTROLLING

OIL-GAS SEPARATOR RESIDENCE TIME SPECIFIED AS 4.0 MINUTE(S)

PRODUCED WATER ENTRAINMENT IN OIL PHASE OF PRODUCTION SEPARATORS
SPECIFIED TO BE 20.0 PERCENT

SECOND STAGE SEPARATOR PARAMETERS :

HORIZONTAL VESSEL SPECIFIED FOR MAIN PRODUCTION SEPARATOR

WATER SEPARATION SPECIFIED

SEPARATOR SIZING METHOD SPECIFIED AS LIQUID RESIDENCE TIME CONTROLLING

OIL-GAS SEPARATOR RESIDENCE TIME SPECIFIED AS 4.0 MINUTE(S)

PRODUCED WATER ENTRAINMENT IN OIL PHASE OF PRODUCTION SEPARATORS
SPECIFIED TO BE 20.0 PERCENT

TEST SEPARATOR PARAMETERS :

HORIZONTAL VESSEL SPECIFIED FOR MAIN PRODUCTION SEPARATOR

SEPARATOR SIZING METHOD SPECIFIED AS LIQUID RESIDENCE TIME CONTROLLING

OIL-GAS SEPARATOR RESIDENCE TIME SPECIFIED AS 4.0 MINUTE(S)

TEST SEPARATOR PARAMETERS :

HORIZONTAL VESSEL SPECIFIED FOR MAIN PRODUCTION SEPARATOR

SEPARATOR SIZING METHOD SPECIFIED AS LIQUID RESIDENCE TIME CONTROLLING

OIL-GAS SEPARATOR RESIDENCE TIME SPECIFIED AS 4.0 MINUTE(S)

TEST SEPARATOR PARAMETERS :

HORIZONTAL VESSEL SPECIFIED FOR MAIN PRODUCTION SEPARATOR

SEPARATOR SIZING METHOD SPECIFIED AS LIQUID RESIDENCE TIME CONTROLLING

PRODUCTION SEPARATOR INTERNALS SPECIFIED AS DIXON PLATES
FOR ALL HORIZONTAL PRODUCTION SEPARATORS

CRUDE VISCOSITY SPECIFIED AS 3.0 CENTIPOISE

REID VAPOR PRESSURE OF EXPORT CRUDE NOT SPECIFIED

CRUDE EMULSION TREATMENT (EMUL) MANAGEMENT DECISIONS

EMULSION TREATMENT OPTION SPECIFIED AS HEATER TREATER WITH SOURCE WELL FOR DILUTION WATER

CRUDE EMULSION TREATER OR DESALTER RATE SPECIFIED AS 450. MBOPD

ALLOCATED DILUTION WATER RATE NOT SPECIFIED
***** NO DILUTION WATER WILL BE ALLOCATED
***** PLEASE CHECK DESIGN BASIS

RESIDENCE TIME FOR EMULSION TREATER SPECIFIED AS 10.0 MINUTES

MINIMUM EMULSION TREATMENT TEMPERATURE SPECIFIED AS 120.0 F

EMULSION TREATER HEATING OPTION SPECIFIED AS HEATING MEDIUM

CRUDE METERING AND EXPORT (EXPO) MANAGEMENT DECISIONS

CRUDE EXPORT PRESSURE SPECIFIED AS 500.0 PSIG

MAXIMUM CRUDE EXPORT TEMPERATURE SPECIFIED AS 150.0 F

CRUDE BOOSTER PUMPS SPECIFIED TO BE ALLOCATED IN THE SEPARATION SYSTEM

CRUDE METERING SPECIFIED

CRUDE METER PROVER SPECIFIED

CRUDE EXPORT RATE SPECIFIED AS 18.80 MBOPD

TYPE OF DRIVER FOR CRUDE EXPORT PUMPS SPECIFIED AS ELECTRIC MOTORS

CRUDE EXPORT PUMP CONFIGURATION SPECIFIED AS 3 X 50% PUMPS
***** PLEASE CHECK PRODUCTION TRAIN CONFIGURATION FOR CONSISTENCY

MAXIMUM HORSEPOWER FOR CRUDE EXPORT PUMP SPECIFIED AS 3500.0 HP

CRUDE STORAGE TIME NOT SPECIFIED
***** TOPSIDE CRUDE OIL SURGE TANKAGE WILL NOT BE ALLOCATED

CRUDE EXPORT PUMP LOCATION SPECIFIED AS PLATFORM TOPSIDES

PRODUCED WATER TREATMENT (PWT) MANAGEMENT DECISIONS

INITIAL PRODUCED WATER RATE SPECIFIED AS 100.0 MBWPD

DESIGN PRODUCED WATER RATE SPECIFIED AS 405.0 MBWPD
***** EXCEEDS 300 MBWPD. PLEASE CHECK DESIGN BASIS

PRODUCED FORMATION WATER SPECIFIED TO BE TREATED
FOR OIL REMOVAL AND REINJECTED INTO A SUBSTRATA HORIZON

PRODUCED FORMATION WATER INJECTION PRESSURE SPECIFIED AS 2000.0 PSIG

MINIMUM PRODUCED FORMATION WATER TREATMENT TEMPERATURE NOT SPECIFIED
***** PRODUCED WATER HEATER WILL NOT BE ALLOCATED
***** PLEASE CHECK DESIGN BASIS

3 X 50% PRODUCED WATER DISPOSAL PUMPS SPECIFIED

NO PRODUCED WATER FILTRATION SPECIFIED

AN API CLASSIFIER NOT SPECIFIED

CPI UNIT(S) NOT SPECIFIED
***** BUT DESIGN PRODUCED WATER RATE IS GREATER THAN ZERO
***** PLEASE CHECK DESIGN BASIS

A FLOTATION UNIT SPECIFIED

PRODUCED WATER FLASH TANK RESIDENCE TIME SPECIFIED AS 2.5 MINUTES

GAS DISPOSAL PARAMETERS (GDSP) MANAGEMENT DECISIONS

GAS DISPOSAL MODE SPECIFIED AS
ALL ASSOCIATED GAS REINJECTED, DEDUCTING FUEL GAS

REINJECTION GAS PRESSURE SPECIFIED AS 4000. PSIG

MAXIMUM OPERATING PRESSURE FOR ALL GAS TREATING
COLUMNS SPECIFIED AS 2000.0 PSIG

GAS COMPRESSION (GCOM) MANAGEMENT DECISIONS

CENTRIFUGAL COMPRESSORS SPECIFIED FOR LOW PRESSURE DUTIES
***** RECIPROCATING COMPRESSORS WILL BE ALLOCATED IF INLET
***** FLOWRATE TO LESS THAN USER SPECIFIED MINIMUM

MINIMUM INLET FLOWRATE FOR CENTRIFUGAL COMPRESSORS SPECIFIED AS 300.0 ICFM

TYPE OF DRIVER FOR REINJECTION GAS COMPRESSORS
SPECIFIED AS COMBUSTION GAS TURBINES

REINJECTION GAS COMPRESSION TRAIN CONFIGURATION SPECIFIED AS 3 X 50% TRAINS

GAS INTERCOOLER OUTLET TEMPERATURE SPECIFIED AS 80.0 F

MAXIMUM COMPRESSOR OUTLET TEMPERATURE SPECIFIED AS 400.0 F

MAXIMUM RATIO OF COMPRESSION FOR CENTRIFUGAL COMPRESSORS SPECIFIED AS 5.0

GAS LIFT COMPRESSION FACILITIES SPECIFIED

GAS LIFT INCREMENTAL GAS/OIL RATIO SPECIFIED AS 1200.0 SCF/BBL

INTEGRATED GAS LIFT AND REINJECTION GAS COMPRESSION
AND TREATMENT FACILITIES SPECIFIED

GAS LIFT PRESSURE SPECIFIED AS 2000. PSIG

TYPE OF DRIVER FOR GAS LIFT GAS COMPRESSORS
SPECIFIED AS COMBUSTION GAS TURBINES

GAS LIFT COMPRESSION TRAIN CONFIGURATION SPECIFIED AS 3 X 50% TRAINS

FUEL GAS COMPRESSION CONFIGURATION SPECIFIED AS 3 X 50% COMPRESSORS

HYDROCARBON DEW POINT CONTROL (GDEW) MANAGEMENT DECISIONS

NO HYDROCARBON DEW POINT CONTROL FACILITIES SPECIFIED FOR REINJECTION GAS

NO HYDROCARBON DEW POINT CONTROL FACILITIES SPECIFIED FOR GAS LIFT GAS

NO HYDROCARBON DEW POINT CONTROL FACILITIES SPECIFIED FOR FUEL GAS

GAS DEHYDRATION (GDRY) MANAGEMENT DECISIONS

REINJECTION GAS DEHYDRATION FACILITIES SPECIFIED

GAS LIFT GAS DEHYDRATION FACILITIES SPECIFIED

EXPORT/REINJECTION GAS DEHYDRATION TRAIN
CONFIGURATION SPECIFIED AS 2 X 75% TRAINS

GAS LIFT GAS DEHYDRATION TRAIN CONFIGURATION SPECIFIED AS 2 X 75% TRAINS

GLYCOL REGENERATION HEATING SOURCE SPECIFIED AS DIRECT FIRED HEATERS
****** MULTIPLE SKIDS WILL BE ALLOCATED IF HEATING LOAD EXCEEDS 5.0 MMBTU/HR

GLYCOL REGENERATOR DIRECT FIRED HEATER
CONFIGURATION SPECIFIED AS 2 X 75% UNITS

WATER DEW POINT TEMPERATURE OF GLYCOL CONTACTOR OVERHEAD NOT SPECIFIED
****** WILL DEFAULT TO 20 DEG F

CONDENSATE DISPOSAL (COND) MANAGEMENT DECISIONS

CONDENSATE SPECIFIED TO BE RECYCLED TO LAST STAGE GAS/OIL SEPARATOR

GAS SCRUBBING (GSWT) MANAGEMENT DECISIONS

SOUR GAS TREATMENT FACILITIES NOT SPECIFIED FOR GAS LIFT GAS

SOUR GAS TREATMENT FACILITIES NOT SPECIFIED FOR REINJECTION GAS

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WATER INJECTION (WINJ) MANAGEMENT DECISIONS

WATER INJECTION SPECIFIED

WATER INJECTION RATE SPECIFIED AT 450.00 MBWPD

NUMBER OF DEAERATORS SPECIFIED AS 2 X 50%

INLET OXYGEN CONCENTRATION SPECIFIED AT 10. PPM

OUTLET OXYGEN CONCENTRATION SPECIFIED AT 0.005 PPM

TYPE OF DEAERATOR SPECIFIED AS STRIPPING GAS

STRIPPING GAS RATE SPECIFIED AT 6.0 SCF/BBL

WATER INJECTION PRESSURE SPECIFIED AT 2000. PSIG

TYPE OF WATER INJECTION PUMP DRIVER SPECIFIED AS COMBUSTION GAS TURBINES

WATER INJECTION PUMP SPEED SPECIFIED AT 6000. RPM

NUMBER OF WATER INJECTION PUMPS NOT SPECIFIED
***** WILL BE INTERNALLY CALCULATED (3000 KW INCREMENTS)

TYPE OF WATER INJECTION FILTERS SPECIFIED AS DUAL MEDIUM DOWNFLOW FILTERS

OPTION FOR UV STERILIZATION OF INJECTION WATER NOT SPECIFIED
***** WILL DEFAULT TO NO UV STERILIZER ALLOCATED

POWER DISTRIBUTION, POWER GENERATION AND RELATED UTILITIES (POWR) MANAGEMENT DECISIONS

POWER GENERATION ON PLATFORM SPECIFIED

TYPE OF MAIN POWER GENERATION SPECIFIED AS TURBINE ALTERNATORS

POWER GENERATION CYCLES SPECIFIED AS 60 HZ

MAIN POWER GENERATION TRAIN CONFIGURATION SPECIFIED AS
100.0% OF TOTAL DESIGN LOAD PER POWER GENERATOR

NUMBER OF MAIN POWER GENERATORS SPECIFIED AS 2

NUMBER OF MAIN POWER GENERATORS OPERATING SPECIFIED AS 1

STARTING AIR SYSTEM NOT SPECIFIED

A FUEL GAS HEATER IS SPECIFIED

TWO EMERGENCY GENERATORS SPECIFIED

TREATED DIESEL STORAGE FOR ONE MAIN POWER GENERATOR
SPECIFIED AT 9.20 DAYS
***** EXCEEDS 7 DAYS, PLEASE CHECK DESIGN BASIS

UNTREATED DIESEL STORAGE FOR ONE MAIN POWER GENERATOR
SPECIFIED AT 99.20 DAYS
***** EXCEEDS 21 DAYS, PLEASE CHECK DESIGN BASIS

METHOD FOR POWER DISTRIBUTION EQUIPMENT ESTIMATION
SPECIFIED AS 'ELEMENT' METHOD

PLATFORM 1 :

BATTERY BANK WATTAGE NOT SPECIFIED
***** WILL BE INTERNALLY ESTIMATED

BATTERY BANK DISCHARGE PERIOD SPECIFIED AS 9.0 HOURS

BATTERY BANK RECHARGE PERIOD SPECIFIED AS 9.0 HOURS

GENERAL UTILITY (UTIL) MANAGEMENT DECISIONS

TYPE OF INSTRUMENT AIR COMPRESSOR SPECIFIED AS ROTARY SCREW

AIR COOLING SPECIFIED FOR ALL MAIN PROCESS DUTIES

HEATING MEDIUM HEAT SOURCE SPECIFIED AS
TURBINE ALTERNATOR EXHAUST WASTE HEAT RECOVERY
****** TURBINE ALTERNATORS WILL BE DERATED 2.5% FOR WHR UNITS

POTABLE WATER USAGE SPECIFIED AS100.0 USGPD PER MAN

TYPE OF WATERMAKER SPECIFIED AS REVERSE OSMOSIS UNIT

PLATFORM J :

FIRE PUMP CONFIGURATION SPECIFIED AS 3 X 50% DEDICATED DIESEL DRIVERS

FIRE PUMP RATE SPECIFIED AS 9000. USGPM

FIRE WATER FOAM SYSTEM NOT SPECIFIED

FIRE WATER DELUGE SYSTEM SPECIFIED FOR HAZARDOUS AREAS

STRUCTURAL FIREPROOFING SPECIFIED

PLATFORM AREA FOR WORKSHOPS AND STORAGE AREAS SPECIFIED TO BE 9000. SQ FT
****** EXCEEDS 1200 SQ FT. PLEASE CHECK DESIGN BASIS

CONTROL CENTER LOCATION SPECIFIED AS IN THE LIVING QUARTERS

CONTROL CENTER AREA IN LIVING QUARTERS SPECIFIED AS 900.0 SQ FT

AN INERT GAS GENERATOR IS NOT SPECIFIED

METHANOL STORAGE QUANTITY SPECIFIED AS 800. BBLS

CORROSION INHIBITOR STORAGE QUANTITY SPECIFIED AS 400. BBLS

GLYCOL STORAGE QUANTITY NOT SPECIFIED, BUT GAS DEHYDRATION SPECIFIED
****** WILL DEFAULT TO 75.0 BBLS

LUBE OIL STORAGE QUANTITY SPECIFIED AS 600. BBLS
****** EXCEEDS 500 BBLS. PLEASE CHECK DESIGN BASIS

SEAL OIL STORAGE QUANTITY SPECIFIED AS 400. BBLS
****** EXCEEDS 300 BBLS. PLEASE CHECK DESIGN BASIS

UNTREATED DIESEL STORAGE QUANTITY (IN ADDITION TO THAT SPECIFIED
FOR MAIN POWER GENERATION) SPECIFIED AS 800. BBLS
****** EXCEEDS 500 BBLS. PLEASE CHECK DESIGN BASIS

COMMODITY STORAGE LOCATIONS (STOR) MANAGEMENT DECISIONS

TREATED DIESEL STORAGE LOCATION
SPECIFIED AS CRANE PEDESTAL

UNTREATED DIESEL STORAGE LOCATION
SPECIFIED AS CONCRETE CELL

POTABLE WATER STORAGE LOCATION
SPECIFIED AS DEDICATED TANK BETWEEN SUPPORT BEAMS

DRILL WATER STORAGE LOCATION
***** NOT SPECIFIED. WILL DEFAULT TO CONCRETE CELL

CORROSION INHIBITOR STORAGE LOCATION
SPECIFIED AS DEDICATED TOPSIDES STORAGE TANK

LUBE OIL STORAGE LOCATION
SPECIFIED AS DEDICATED TOPSIDES STORAGE TANK

SEAL OIL STORAGE LOCATION
SPECIFIED AS DEDICATED TOPSIDES STORAGE TANK

GLYCOL STORAGE LOCATION
***** NOT SPECIFIED. WILL DEFAULT TO DEDICATED TOPSIDES STORAGE TANK

METHANOL STORAGE LOCATION
SPECIFIED AS DEDICATED TANK BETWEEN SUPPORT BEAMS

LIVING QUARTERS & PERSONNEL SUPPORT UTILITIES (LIVQ)

MANAGEMENT DECISIONS

A LIVING QUARTERS IS SPECIFIED

NUMBER OF MEN FOR LIVING QUARTERS IS SPECIFIED AS 250

STEEL LIVING QUARTERS SPECIFIED

NUMBER OF LEVELS FOR LIVING QUARTERS NOT SPECIFIED
****** WILL BE INTERNALLY CALCULATED

LIVING QUARTERS SPACE SPECIFIED AS 250.0 SQ FT/MAN

LIVING QUARTERS LENGTH NOT SPECIFIED
****** WILL BE CALCULATED INTERNALLY

LIVING QUARTERS WIDTH NOT SPECIFIED
****** WILL BE CALCULATED INTERNALLY

NO LIVING QUARTERS CANTILEVER SPECIFIED

FIRST HELIDECK SPECIFIED AS STEEL, FOR 40-PERSON (CHINOOK) HELICOPTER

NO SECOND HELIDECK SPECIFIED

REFUELING SKID SPECIFIED FOR FIRST HELIDECK

HELIHANGER SPECIFIED FOR FIRST HELIDECK

CONVENTIONAL AIRCRAFT SERVICE PLANT SPECIFIED

NO DEDICATED EMERGENCY GENERATOR SPECIFIED FOR LIVING QUARTERS

ONE DISH ANTENNAE SPECIFIED

MATERIAL HANDLING (MTLH) MANAGEMENT DECISIONS

PLATFORM J :

NUMBER OF CRANE(S) SPECIFIED AS 3

TYPE OF CRANE SPECIFIED AS COUNTERWEIGHTED PEDESTAL

CRANE MAXIMUM LIFTING CAPACITY SPECIFIED AS 75.0 S. TONS

ELECTRIC HOISTS SPECIFIED

EQUIPMENT SPECIFICATIONS (ESSP) MANAGEMENT DECISIONS

VESSEL CODE FOR PRODUCTION SYSTEMS SPECIFIED AS ASME, DIV 1 (MOST CONSERVATIV

CORROSION ALLOWANCE FOR PRODUCTION VESSELS SPECIFIED AS 1/8 INCH

CONVENTIONAL SHELL AND TUBE HEAT EXCHANGERS SPECIFIED FOR
MAIN PROCESS DUTIES REQUIRING SHELL AND TUBE EXCHANGERS

TURBINE DRIVER TYPE SPECIFIED AS AIRCRAFT-DERIVATIVE TURBINES ONLY

SYSTEMS BULK ADJUSTMENT FACTOR (SADJ) MANAGEMENT DECISIONS

***** ONLY THE SYSTEMS LISTED BELOW WERE SPECIFIED TO BE ADJUSTED
***** ALL OTHER SYSTEM ADJUSTMENT FACTORS WILL DEFAULT TO 1.0

[illegible] - [illegible] - [illegible] - [

COST OF PAINTING MATERIALS & DIRECT LABOR FOR THE TOPSIDES
IS SPECIFIED AT 0.0 % OF TOPSIDES DIRECT LABOR COST

THE LOADOUT/SEA FASTEN COST IS SPECIFIED AT 0.0 %
OF THE TOTAL TOPSIDE ONSHORE ERECTED COST
***** VALUE APPEARS LOW. PLEASE CHECK DESIGN BASIS

TOPSIDES BARGE TRANSPORT COST IS SPECIFIED AT $ 0.0 M/DAY
***** VALUE APPEARS LOW. PLEASE CHECK DESIGN BASIS

TOPSIDES BARGE TRANSPORT TIME SPECIFIED AT 0. DAYS
***** VALUE APPEARS LOW. PLEASE CHECK DESIGN BASIS

TOPSIDES DERRICK BARGE COST IS SPECIFIED AT $ 0.0 M/DAY
***** VALUE APPEARS LOW. PLEASE CHECK DESIGN BASIS

TOPSIDES DERRICK BARGE TIME SPECIFIED AT 0. DAYS
***** VALUE APPEARS LOW. PLEASE CHECK DESIGN BASIS

TOPSIDES MOBILIZATION/DEMOBILIZATION SPECIFIED AT $ 0.000 MM
***** VALUE APPEARS LOW. PLEASE CHECK DESIGN BASIS

ENGINEERING COST OF HOOKUP AND COMMISSIONING IS SPECIFIED AT
0.0 % OF HOOKUP AND COMMISSIONING COST
***** VALUE APPEARS LOW. PLEASE CHECK DESIGN BASIS

HOOKUP AND COMMISSIONING FOR GRAVITY STRUCTURES:

ONSHORE LABOR IS SPECIFIED AT 0.0 MANHOURS/KIP
OF MAJOR EQUIPMENT AND BULK MATERIALS
***** VALUE APPEARS LOW. PLEASE CHECK DESIGN BASIS

INSHORE LABOR IS SPECIFIED AT 0.0 MANHOURS/KIP
OF MAJOR EQUIPMENT AND BULK MATERIALS
***** VALUE APPEARS LOW. PLEASE CHECK DESIGN BASIS

OFFSHORE LABOR IS SPECIFIED AT 0.0 MANHOURS/KIP
OF MAJOR EQUIPMENT AND BULK MATERIALS
***** VALUE APPEARS LOW. PLEASE CHECK DESIGN BASIS

ONSHORE LABOR COST IS SPECIFIED AT $ 0.0 M/MANHOUR
***** VALUE APPEARS LOW. PLEASE CHECK DESIGN BASIS

INSHORE LABOR COST IS SPECIFIED AT $ 0.0 M/MANHOUR
***** VALUE APPEARS LOW. PLEASE CHECK DESIGN BASIS

OFFSHORE LABOR COST IS SPECIFIED AT $ 0.0 M/MANHOUR
***** VALUE APPEARS LOW. PLEASE CHECK DESIGN BASIS

COST OF CONCRETE FOR GRAVITY SUBSTRUCTURE IS
SPECIFIED AT $ 0.00 /CUBIC METER
***** VALUE APPEARS LOW. PLEASE CHECK DESIGN BASIS

AMOUNT OF CONCRETE FOR GRAVITY SUBSTRUCTURE IS NOT SPECIFIED
WILL BE ESTIMATED INTERNALLY

THE COST OF MECHANICAL OUTFITTING OF GRAVITY SUBSTRUCTURE
IS SPECIFIED AT $ 0.0 MM
***** VALUE APPEARS LOW. PLEASE CHECK DESIGN BASIS

COST OF SEAWATER PENETRATIONS FOR GRAVITY SUBSTRUCTURE
IS SPECIFIED AT 0.0 MM

[illegible] SPECIFIED AT 0.00 MM
****** VALUE APPEARS LOW. PLEASE CHECK DESIGN BASIS

FLOTEL USAGE TIME SPECIFIED AT 0. DAYS
****** VALUE APPEARS LOW. PLEASE CHECK DESIGN BASIS

FLOTEL COST SPECIFIED AT $ 0.0 M/DAY
****** VALUE APPEARS LOW. PLEASE CHECK DESIGN BASIS

THE SUPPORT DECK DIRECT LABOR COST FOR THE SUBSTRUCTURE
IS SPECIFIED AT $ 0.0/KIP
****** VALUE APPEARS LOW. PLEASE CHECK DESIGN BASIS

THE SUPPORT DECK MATERIALS FOR COST FOR THE SUBSTRUCTURE
IS SPECIFIED AS $ 0.0/KIP
****** VALUE APPEARS LOW. PLEASE CHECK DESIGN BASIS

RISER MATERIAL COST SPECIFIED AT $ 0.0 /KIP
****** VALUE APPEARS LOW. PLEASE CHECK DESIGN BASIS

RISER DIRECT LABOR COST SPECIFIED AT $ 0.0 /KIP
****** VALUE APPEARS LOW. PLEASE CHECK DESIGN BASIS

RISER TIE-IN COSTS SPECIFIED AT $ 0.0 /INCH-DIAMETER-FT
****** VALUE APPEARS LOW. PLEASE CHECK DESIGN BASIS

THE OVERALL CONTINGENCY COST IS SPECIFIED AT
0.0 % OF THE TOTAL INSTALLED PLATFORM COST
****** VALUE APPEARS LOW. PLEASE CHECK DESIGN BASIS

THE COST OF INSURANCE IS SPECIFIED AT 0.0 %
OF THE TOTAL INSTALLED PLATFORM COST
****** VALUE APPEARS LOW. PLEASE CHECK DESIGN BASIS

THE COST OF CERTIFICATION IS SPECIFIED AS 0.0 %
OF THE TOTAL INSTALLED PLATFORM COST
****** VALUE APPEARS LOW. PLEASE CHECK DESIGN BASIS

ESCALATION IS SPECIFIED AT 0.0 %
OF THE TOTAL INSTALLED PLATFORM COST
****** VALUE APPEARS LOW. PLEASE CHECK DESIGN BASIS

THE COST OF [illegible]MENT IS SPECIFIED AT 0.0 %
OF THE TOTAL INSTALLED PLATFORM COST

MISCELLANEOUS COSTS FOR PLATFORM J ARE SPECIFIED AT $ 0.000 MM

ADJUSTMENT FACTORS (UADJ) MANAGEMENT DECISIONS

***** ONLY THE CATEGORIES LISTED BELOW WERE SPECIFIED TO BE ADJUSTED
***** ALL OTHER ADJUSTMENT FACTORS WILL DEFAULT TO 1.0

EMERGENCY ELECTRICAL POWER ADJUSTMENT FACTOR SPECIFIED AS 2.0

PLATFORM J :

RELIEF RATE ADJUSTMENT FACTOR SPECIFIED AS 1.2

PLATFORM FUNCTION ASSIGNMENT (PFAS) MANAGEMENT DECISIONS

FUNCTION LOCATION SUMMARY

PLATFORM J:
- LIVING QUARTERS
- PRODUCTION
- PRODUCTION MANIFOLD
- WELLHEAD/DRILLING
- POWER GENERATION AND MAIN POWER DISTRIBUTION
- UTILITIES
- GAS COMPRESSION
- FIRST HELIDECK
- FLARE
- OIL EXPORT RISER

SUBSTRUCTURE (SUBS) MANAGEMENT DECISIONS

TYPE OF SUBSTRUCTURE SPECIFIED AS CONCRETE GRAVITY

PLATFORM J :

PLATFORM WIDTH NOT SPECIFIED
***** WILL BE DETERMINED INTERNALLY

TYPE OF CATHODIC PROTECTION NOT SPECIFIED
***** WILL DEFAULT TO PASSIVE CATHODIC PROTECTION

TOPSIDES STRUCTURAL MANAGEMENT DECISIONS

PLATFORM J :

TYPE OF SUPPORT DECK SPECIFIED AS PLATE GIRDER

UTILITY EQUIPMENT SPECIFIED TO BE PLACED IN MODULE SUPPORT FRAME OR SUPPORT DECK

PERCENT USABLE AREA OF THE SUPPORT DECK SPECIFIED AS 70.0%

TYPE OF TOPSIDE STRUCTURE SPECIFIED AS SKID TYPE MODULE

NUMBER OF DECK LEVELS SPECIFIED AS ONE

SUPPORT DECK PLAN AREA NOT SPECIFIED
***** WILL BE CALCULATED INTERNALLY

EQUIPMENT MAINTENANCE FACTOR SPECIFIED AS 3.6

MAXIMUM MODULE WIDTH SPECIFIED AS 60.0 FT

MODULE HEIGHT SPECIFIED AS 26.0 FT

MODULE LENGTH NOT SPECIFIED
***** WILL BE CALCULATED INTERNALLY

MODULE SPACING SPECIFIED AS 5.0 FT

LIVING QUARTERS SPECIFIED TO BE PLACED ON FIRST MODULE LEVEL (ON SUPPORT DECK

TYPE OF ENCLOSURE FOR PRODUCTION
SPECIFIED AS TOTALLY ENCLOSED

TYPE OF ENCLOSURE FOR WELLHEAD
SPECIFIED AS TOTALLY ENCLOSED

TYPE OF ENCLOSURE FOR MANIFOLD
SPECIFIED AS TOTALLY ENCLOSED

TYPE OF ENCLOSURE FOR GAS COMPRESSION
SPECIFIED AS TOTALLY ENCLOSED

TYPE OF ENCLOSURE FOR GAS TREATMENT
SPECIFIED AS TOTALLY ENCLOSED

TYPE OF ENCLOSURE FOR UTILITIES
SPECIFIED AS TOTALLY ENCLOSED

TYPE OF ENCLOSURE FOR POWER GENERATION
SPECIFIED AS TOTALLY ENCLOSED

TYPE OF ENCLOSURE FOR RELIEF
SPECIFIED AS TOTALLY ENCLOSED

DRILLING (DRIL) MANAGEMENT DECISIONS

DRILLING ESTIMATION LEVEL SPECIFIED AS 'SECOND LEVEL'
TOTAL DRILLING AREA AND BUILDING BLOCK WEIGHT CATEGORIES SHOULD BE SPECIFIE

DRILLING AREA ALLOCATION SPECIFIED AS 16000. SQ FT

MINIMUM LAYDOWN AREA FOR DRILLING NOT SPECIFIED
***** WILL DEFAULT TO 0.0 SQ FT

DRILLING POWER AND UTILITIES INTEGRATION OPTION SPECIFIED AS
DRILLING POWER SUPPLIED BY MAIN PRODUCTION POWER GENERATORS AND
DRILLING UTILITIES INTEGRATED WITH MAIN PRODUCTION UTILITES

TOTAL INSTALLED DRILLING POWER ALLOCATION SPECIFIED AS 6.0 MW

TWO INTEGRATED DRILLING RIGS SPECIFIED

DEDICATED DRILLING POWER GENERATION NOT NECESSARY FOR OPTIONS SELECTED

NO DIESEL-BASED OR MINERAL OIL-BASED MUD SPECIFIED

NO STEAM GENERATOR SPECIFIED

NO MUD BURNERS SPECIFIED

AMOUNT OF DRILLING WATER STORAGE SPECIFIED AS 10000. BBLS

AMOUNT OF POTABLE WATER STORAGE SPECIFIED AS 1000. BBLS

AMOUNT OF DRILLING BARITES STORAGE SPECIFIED AS 3400. KIPS

AMOUNT OF DRILLING CEMENT AND BENTONITE STORAGE SPECIFIED AS 3740. KIPS

DRILLING 'LIVE' MUD OPERATING LOAD SPECIFIED AS 600. KIPS

DRILLING 'RESERVE' MUD OPERATING LOAD SPECIFIED AS 600. KIPS
***** EXCEEDS 600 KIPS. PLEASE CHECK DESIGN BASIS

AMOUNT OF DRILLING SACK STORAGE SPECIFIED AS 850. KIPS
***** LESS THAN 1100 KIPS. PLEASE CHECK DESIGN BASIS

DRILLING MUD PUMP WEIGHT SPECIFIED AS 200. KIPS

DRILLING CASING WEIGHT SPECIFIED AS 10000. KIPS

DRILLING TUBING WEIGHT SPECIFIED AS 2125. KIPS

DRILLING SHALE SHAKER WEIGHT SPECIFIED AS 200. KIPS

DRILLING DERRICK WEIGHT NOT SPECIFIED
***** WILL DEFAULT TO 150 KIPS

DRILLING SUBSTRUCTURE WEIGHT SPECIFIED AS 500. KIPS

DRILLING DERRICK WEIGHT SPECIFIED AS 700. KIPS
***** EXCEEDS 600 KIPS. PLEASE CHECK DESIGN BASIS

DRILLING STRUCTURAL STEEL WEIGHT SPECIFIED AS 400. KIPS

DRILLING SETBACK SPECIFIED AS 800. KIPS

KILL PIPING SPECIFIED

ONE KILL PUMP SPECIFIED

KILL PUMP DISCHARGE PRESSURE SPECIFIED AS 4000. PSIG

DRILL BLOWOUT PREVENTER WEIGHT SPECIFIED AS 40. KIPS

DRILLING TOOLS AND MISCELLANEOUS WEIGHT SPECIFIED AS 50. KIPS

DRILLING ENVIRONMENTAL LOAD SPECIFIED AS 50. KIPS

WELLHEAD(S)/MANIFOLD(S) (WHMU) MANAGEMENT DECISIONS

NO BRIDGE-CONNECTED WELLHEAD PLATFORMS SPECIFIED

WELLHEAD IS ASSIGNED TO AN INTEGRATED PLATFORM

WELLHEAD SPACING SPECIFIED AS 8.2 FT

NUMBER OF PRODUCTION WELLS SPECIFIED AS 50

NUMBER OF WATER INJECTION WELLS NOT SPECIFIED
***** NO WATER INJECTION WELLS WILL BE ALLOCATED

NUMBER OF GAS REINJECTION WELLS NOT SPECIFIED
***** NO GAS REINJECTION WELLS WILL BE ALLOCATED

NUMBER OF SPARE CONDUCTORS SPECIFIED AS 50
***** EXCEEDS 10. PLEASE CHECK DESIGN BASIS

DIAMETER OF CONDUCTORS SPECIFIED AS 20.0 IN

SHUT-IN WELLHEAD PRESSURE SPECIFIED AS 1500.0 PSIG

WELLHEAD MANIFOLD DESIGN PRESSURE SPECIFIED AS 1500.0 PSIG

NUMBER OF SUBMERSIBLE PUMPS NOT SPECIFIED
***** NO SUBMERSIBLE PUMPS WILL BE ALLOCATED

THROUGH-FLOW-LINE (TFL) TOOL ACCESS NOT SPECIFIED

WELL START-UP HEATER NOT SPECIFIED

TEST SEPARATOR DESIGN RATE SPECIFIED AS 5.0% OF TOTAL CRUDE THROUGHPUT

FIRST STAGE SEPARATOR PARAMETERS :

HORIZONTAL VESSEL SPECIFIED FOR MAIN PRODUCTION SEPARATOR

NO WATER SEPARATION SPECIFIED

SEPARATOR SIZING METHOD SPECIFIED AS LIQUID RESIDENCE TIME CONTROLLING

OIL-GAS SEPARATOR RESIDENCE TIME SPECIFIED AS 2.0 MINUTE(S)

TEST SEPARATOR PARAMETERS :

HORIZONTAL VESSEL SPECIFIED FOR MAIN PRODUCTION SEPARATOR

SEPARATOR SIZING METHOD SPECIFIED AS LIQUID RESIDENCE TIME CONTROLLING

OIL-GAS SEPARATOR RESIDENCE TIME SPECIFIED AS 4.0 MINUTE(S)

TEST SEPARATOR PARAMETERS :

HORIZONTAL VESSEL SPECIFIED FOR MAIN PRODUCTION SEPARATOR

SEPARATOR SIZING METHOD SPECIFIED AS LIQUID RESIDENCE TIME CONTROLLING

OIL-GAS SEPARATOR RESIDENCE TIME SPECIFIED AS 4.0 MINUTE(S)

TEST SEPARATOR PARAMETERS :

HORIZONTAL VESSEL SPECIFIED FOR MAIN PRODUCTION SEPARATOR

SEPARATOR SIZING METHOD SPECIFIED AS LIQUID RESIDENCE TIME CONTROLLING

OIL-GAS SEPARATOR RESIDENCE TIME SPECIFIED AS 4.0 MINUTE(S)

TEST SEPARATOR PARAMETERS :

HORIZONTAL VESSEL SPECIFIED FOR MAIN PRODUCTION SEPARATOR

SEPARATOR SIZING METHOD SPECIFIED AS LIQUID RESIDENCE TIME CONTROLLING

OIL-GAS SEPARATOR RESIDENCE TIME SPECIFIED AS 4.0 MINUTE(S)

PRODUCTION SEPARATOR INTERNALS SPECIFIED AS DIXON PLATES
FOR ALL HORIZONTAL PRODUCTION SEPARATORS

CRUDE VISCOSITY SPECIFIED AS 3.0 CENTIPOISE

REID VAPOR PRESSURE OF EXPORT CRUDE NOT SPECIFIED

GAS/OIL PRODUCTION (PROD) MANAGEMENT DECISIONS

SPECIFIED RESERVOIR FLUID COMPOSITION

COMPONENT	MOLE %
CH4	45.490
C2H6	3.590
C3H8	3.750
IC4H10	1.210
NC4H10	2.010
IC5H12	0.930
NC5H12	1.050
NC6H14	2.020
N2	0.070
CO2	0.270
H2S	0.000
C7+ NO.1	39.610
C7+ NO.2	0.000
TOTAL	100.000

***** WATER WILL BE ADDED TO SATURATE THE RESERVOIR FLUID

CONVENTIONAL CRUDE PRODUCTION FACILITIES SPECIFIED

DAILY CRUDE PRODUCTION RATE SPECIFIED AS 300.0 MBOPD

C7+ COMPONENT NO. 1 API GRAVITY SPECIFIED AS 33.0 DEGREES API

C7+ COMPONENT NO. 1 MOLECULAR WEIGHT SPECIFIED AS 233.0

C7+ COMPONENT NO. 1 NORMAL BOILING POINT NOT SPECIFIED
***** WILL BE INTERNALLY ESTIMATED

C7+ COMPONENT NO. 1 CRITICAL TEMPERATURE NOT SPECIFIED
***** WILL BE INTERNALLY ESTIMATED

C7+ COMPONENT NO. 1 CRITICAL PRESSURE NOT SPECIFIED
***** WILL BE INTERNALLY ESTIMATED

NUMBER OF PRODUCTION TRAINS SPECIFIED AS 2

PRODUCTION TRAIN PRODUCTIVITY FACTOR SPECIFIED AS 90.0 PERCENT

NUMBER OF SEPARATION STAGES PER TRAIN SPECIFIED AS 1

DESIGN PRESSURE FOR PRODUCTION EQUIPMENT PRIOR TO COMPRESSION
SPECIFIED AS 300. PSIG

FLOWING WELLHEAD PRESSURE SPECIFIED AS 200. PSIG

FLOWING WELLHEAD TEMPERATURE SPECIFIED AS 80.0 DEG F

FIRST STAGE OPERATING PRESSURE SPECIFIED AS 150.0 PSI;

FIRST STAGE OPERATING TEMPERATURE NOT SPECIFIED
***** WILL DEFAULT TO ADIABATIC FLASH TEMPERATURE

CRUDE EMULSION TREATMENT (EMUL) MANAGEMENT DECISIONS

NO CRUDE EMULSION TREATER OR DESALTER SPECIFIED

CRUDE METERING AND EXPORT (EXPO) MANAGEMENT DECISIONS

CRUDE EXPORT PRESSURE SPECIFIED AS 200.0 PSIG

MAXIMUM CRUDE EXPORT TEMPERATURE SPECIFIED AS 150.0 F

CRUDE BOOSTER PUMPS SPECIFIED NOT TO BE ALLOCATED IN THE SEPARATION SYSTEM UNLESS EMULSION TREATMENT IS SPECIFIED OR THE SUCTION PRESSURE OF THE CRUDE EXPORT PUMP IS LESS THAN 25 PSIG

CRUDE METERING NOT SPECIFIED

CRUDE EXPORT RATE SPECIFIED AS 12.50 MBOPH

TYPE OF DRIVER FOR CRUDE EXPORT PUMPS SPECIFIED AS ELECTRIC MOTORS

CRUDE EXPORT PUMP CONFIGURATION SPECIFIED AS 2 X 50% PUMPS
***** PLEASE CHECK PRODUCTION TRAIN CONFIGURATION FOR CONSISTENCY

MAXIMUM HORSEPOWER FOR CRUDE EXPORT PUMP SPECIFIED AS 3500.0 HP

CRUDE STORAGE TIME NOT SPECIFIED
***** TOPSIDE CRUDE OIL SURGE TANKAGE WILL NOT BE ALLOCATED

CRUDE EXPORT PUMP LOCATION SPECIFIED AS PLATFORM TOPSIDES

PRODUCED WATER TREATMENT (PWT) MANAGEMENT DECISIONS

INITIAL PRODUCED WATER RATE NOT SPECIFIED
***** WILL SATURATE RESERVOIR FLUID AT FLOWING WELLHEAD CONDITIONS

DESIGN PRODUCED WATER RATE NOT SPECIFIED
***** WILL SATURATE RESERVOIR FLUID AT FLOWING WELLHEAD CONDITIONS

PRODUCED WATER SEPARATION IS NOT SPECIFIED FOR THE GAS/OIL SEPARATION TRAIN
AND NO EMULSION TREATMENT OR DESALTING FACILITIES ARE SPECIFIED
***** WILL SHIP PRODUCED WATER TO SHORE WITH CRUDE
***** EFFLUENT WATER FROM OTHER SOURCES WILL BE TREATED AND DUMPED OVERBOARD

MINIMUM PRODUCED FORMATION WATER TREATMENT TEMPERATURE NOT SPECIFIED
***** PRODUCED WATER HEATER WILL NOT BE ALLOCATED
***** PLEASE CHECK DESIGN BASIS

NO PRODUCED WATER FILTRATION SPECIFIED

AN API CLASSIFIER NOT SPECIFIED

CPI UNIT(S) NOT SPECIFIED

A FLOTATION UNIT NOT SPECIFIED

NO PRODUCED WATER TREATMENT OPTIONS ARE SPECIFIED
PRODUCED WATER DISPOSAL CAISSON WILL BE SIZED AS A SKIMMER PILE

PRODUCED WATER FLASH TANK RESIDENCE TIME SPECIFIED AS 0.1 MINUTES
***** LESS THAN 2 MINUTES, PLEASE CHECK DESIGN BASIS

GAS DISPOSAL PARAMETERS (GDSP) MANAGEMENT DECISIONS

GAS DISPOSAL MODE SPECIFIED AS
ALL ASSOCIATED GAS FLARED, DEDUCTING FUEL GAS

MAXIMUM OPERATING PRESSURE FOR ALL GAS TREATING
COLUMNS SPECIFIED AS 2000.0 PSIG

GAS COMPRESSION (GCOM) MANAGEMENT DECISIONS

MINIMUM INLET FLOWRATE FOR CENTRIFUGAL COMPRESSORS SPECIFIED AS 300.0 ICFM

GAS INTERCOOLER OUTLET TEMPERATURE SPECIFIED AS 80.0 F

MAXIMUM COMPRESSOR OUTLET TEMPERATURE SPECIFIED AS 400.0 F

MAXIMUM RATIO OF COMPRESSION FOR CENTRIFUGAL COMPRESSORS SPECIFIED AS 5.0

GAS LIFT COMPRESSION FACILITIES NOT SPECIFIED

FUEL GAS COMPRESSION CONFIGURATION SPECIFIED AS 1 X 100% COMPRESSOR

HYDROCARBON DEW POINT CONTROL (GDFV) MANAGEMENT DECISIONS

NO HYDROCARBON DEW POINT CONTROL FACILITIES SPECIFIED FOR FUEL GAS

GAS DEHYDRATION (GDHY) MANAGEMENT DECISIONS

DEDICATED FUEL GAS DEHYDRATION FACILITIES NOT SPECIFIED

CONDENSATE DISPOSAL (COND) MANAGEMENT DECISIONS

CONDENSATE SPECIFIED TO BE RECYCLED TO LAST STAGE GAS/OIL SEPARATOR

WELLHEAD(S)/MANIFOLD(S) (WHMN) MANAGEMENT DECISIONS

NO BRIDGE-CONNECTED WELLHEAD PLATFORMS SPECIFIED

WELLHEAD IS ASSIGNED TO AN INTEGRATED PLATFORM

WELLHEAD SPACING SPECIFIED AS 8.2 FT

NUMBER OF PRODUCTION WELLS SPECIFIED AS 50

NUMBER OF WATER INJECTION WELLS SPECIFIED AS 40
***** EXCEEDS 30. PLEASE CHECK DESIGN BASIS

NUMBER OF GAS REINJECTION WELLS SPECIFIED AS 10

NUMBER OF SPARE CONDUCTORS NOT SPECIFIED
***** NO SPARE CONDUCTORS WILL BE ALLOCATED

DIAMETER OF CONDUCTORS SPECIFIED AS 20.0 IN

SHUT-IN WELLHEAD PRESSURE SPECIFIED AS 4000.0 PSIG

WELLHEAD MANIFOLD DESIGN PRESSURE SPECIFIED AS 4000.0 PSIG

NUMBER OF SUBMERSIBLE PUMPS NOT SPECIFIED
***** NO SUBMERSIBLE PUMPS WILL BE ALLOCATED

THROUGH-FLOW-LINE (TFL) TOOL ACCESS NOT SPECIFIED

WELL START-UP HEATER NOT SPECIFIED

GAS/OIL PRODUCTION (PROD) MANAGEMENT DECISIONS

SPECIFIED RESERVOIR FLUID COMPOSITION

COMPONENT	MOLE %
CH4	45.490
C2H6	3.590
C3H8	3.750
IC4H10	1.210
NC4H10	2.010
IC5H12	0.830
NC5H12	1.050
NC6H14	2.020
N2	0.070
CO2	0.270
H2S	0.000
C7+ NO.1	38.810
C7+ NO.2	0.000
TOTAL	100.000

****** WATER WILL BE ADDED TO SATURATE THE RESERVOIR FLUID

CARBON DIOXIDE CONTENT OF THE GAS IS GREATER THAN 10 PSI PARTIAL PRESSURE
****** PLEASE CHECK CORROSION ALLOWANCES

CONVENTIONAL CRUDE PRODUCTION FACILITIES SPECIFIED

DAILY CRUDE PRODUCTION RATE SPECIFIED AS 450.0 MBPD

C7+ COMPONENT NO. 1 API GRAVITY SPECIFIED AS 33.0 DEGREES API

C7+ COMPONENT NO. 1 MOLECULAR WEIGHT SPECIFIED AS 233.0

C7+ COMPONENT NO. 1 NORMAL BOILING POINT NOT SPECIFIED
****** WILL BE INTERNALLY ESTIMATED

C7+ COMPONENT NO. 1 CRITICAL TEMPERATURE NOT SPECIFIED
****** WILL BE INTERNALLY ESTIMATED

C7+ COMPONENT NO. 1 CRITICAL PRESSURE NOT SPECIFIED
****** WILL BE INTERNALLY ESTIMATED

NUMBER OF PRODUCTION TRAINS SPECIFIED AS 3

PRODUCTION TRAIN PRODUCTIVITY FACTOR SPECIFIED AS 40.0 PERCENT

NUMBER OF SEPARATION STAGES PER TRAIN SPECIFIED AS 2

DESIGN PRESSURE FOR PRODUCTION EQUIPMENT PRIOR TO COMPRESSION NOT SPECIFIED
****** WILL DEFAULT TO OPERATING PRESSURE PLUS 50 PSI OR
****** 1.10 X OPERATING PRESSURE, WHICHEVER IS GREATER

FLOWING WELLHEAD PRESSURE SPECIFIED AS 200. PSIG

FLOWING WELLHEAD TEMPERATURE SPECIFIED AS 90.0 DEG F

DRILLING (DRTL) MANAGEMENT DECISIONS

DRILLING ESTIMATION LEVEL SPECIFIED AS 'SECOND LEVEL'
TOTAL DRILLING AREA AND BUILDING BLOCK WEIGHT CATEGORIES SHOULD BE SPECIFIED

DRILLING AREA ALLOCATION SPECIFIED AS 16000. SQ FT

MINIMUM LAYDOWN AREA FOR DRILLING NOT SPECIFIED
***** WILL DEFAULT TO 0.0 SQ FT

DRILLING POWER AND UTILITIES INTEGRATION OPTION SPECIFIED AS
DRILLING POWER SUPPLIED BY MAIN PRODUCTION POWER GENERATORS AND
DRILLING UTILITIES INTEGRATED WITH MAIN PRODUCTION UTILITES

TOTAL INSTALLED DRILLING POWER ALLOCATION SPECIFIED AS 6.0 MW

TWO INTEGRATED DRILLING RIGS SPECIFIED

DEDICATED DRILLING POWER GENERATION NOT NECESSARY FOR OPTIONS SELECTED

NO DIESEL-BASED OR MINERAL OIL-BASED MUD SPECIFIED

NO STEAM GENERATOR SPECIFIED

NO MUD BURNERS SPECIFIED

AMOUNT OF DRILLING WATER STORAGE SPECIFIED AS 10000. BBLS

AMOUNT OF POTABLE WATER STORAGE SPECIFIED AS 1000. BBLS

AMOUNT OF DRILLING BARITES STORAGE SPECIFIED AS 3400. KIPS

AMOUNT OF DRILLING CEMENT AND BENTONITE STORAGE SPECIFIED AS 3740. KIPS

DRILLING 'LIVE' MUD OPERATING LOAD SPECIFIED AS 600. KIPS

DRILLING 'RESERVE' MUD OPERATING LOAD SPECIFIED AS 400. KIPS
***** EXCEEDS 300 KIPS. PLEASE CHECK DESIGN BASIS

AMOUNT OF DRILLING SACK STORAGE SPECIFIED AS 850. KIPS
***** LESS THAN 1100 KIPS. PLEASE CHECK DESIGN BASIS

DRILLING MUD PUMP WEIGHT SPECIFIED AS 200. KIPS

DRILLING CASING WEIGHT SPECIFIED AS 10000. KIPS

DRILLING TUBING WEIGHT SPECIFIED AS 2125. KIPS

DRILLING SHALE SHAKER WEIGHT SPECIFIED AS 200. KIPS

DRILLING SUBBASE WEIGHT NOT SPECIFIED
***** WILL DEFAULT TO 150 KIPS

DRILLING SUBSTRUCTURE WEIGHT SPECIFIED AS 400. KIPS

DRILLING DERRICK WEIGHT SPECIFIED AS 800. KIPS
***** EXCEEDS 300 KIPS. PLEASE CHECK DESIGN BASIS

DRILLING STRUCTURAL STEEL WEIGHT SPECIFIED AS 4200. KIPS

DRILLING RISER SPECIFIED AS 500. KIPS

KILL PIPING SPECIFIED

ONE KILL PUMP SPECIFIED

KILL PUMP DISCHARGE PRESSURE SPECIFIED AS 4000. PSIG

DRILL BLOWOUT PREVENTER WEIGHT SPECIFIED AS 40. KIPS

DRILLING TOOLS AND MISCELLANEOUS WEIGHT SPECIFIED AS 50. KIPS

DRILLING ENVIRONMENTAL LOAD SPECIFIED AS 50. KIPS

SUBSTRUCTURE (SUBS) MANAGEMENT DECISIONS

TYPE OF SUBSTRUCTURE SPECIFIED AS CONCRETE GRAVITY

PLATFORM J :

PLATFORM WIDTH NOT SPECIFIED
****** WILL BE DETERMINED INTERNALLY

TYPE OF CATHODIC PROTECTION NOT SPECIFIED
****** WILL DEFAULT TO PASSIVE CATHODIC PROTECTION

TOPSIDES STRUCTURAL MANAGEMENT DECISIONS

PLATFORM J :

TYPE OF SUPPORT DECK SPECIFIED AS PLATE GIRDER

UTILITY EQUIPMENT SPECIFIED TO BE PLACED IN MODULE SUPPORT FRAME OR SUPPORT DECK

PERCENT USABLE AREA OF THE SUPPORT DECK SPECIFIED AS 70.0%

TYPE OF TOPSIDE STRUCTURE SPECIFIED AS SKID TYPE MODULE

NUMBER OF DECK LEVELS SPECIFIED AS TWO

TOP DECK LEVEL EQUIPMENT AND STRUCTURAL STEEL ALLOCATION SPECIFIED TO BE SAME AS LOWER LEVELS

SUPPORT DECK PLAN AREA NOT SPECIFIED
***** WILL BE CALCULATED INTERNALLY

EQUIPMENT MAINTENANCE FACTOR SPECIFIED AS 3.6

MAXIMUM MODULE WIDTH SPECIFIED AS 60.0 FT

MODULE HEIGHT SPECIFIED AS 26.0 FT

MODULE LENGTH NOT SPECIFIED
***** WILL BE CALCULATED INTERNALLY

MODULE SPACING SPECIFIED AS 5.0 FT

LIVING QUARTERS SPECIFIED TO BE PLACED IN FIRST MODULE LEVEL (ON SUPPORT DECK

TYPE OF ENCLOSURE FOR PRODUCTION
SPECIFIED AS TOTALLY ENCLOSED

TYPE OF ENCLOSURE FOR WELLHEAD
SPECIFIED AS TOTALLY ENCLOSED

TYPE OF ENCLOSURE FOR MANIFOLD
SPECIFIED AS TOTALLY ENCLOSED

TYPE OF ENCLOSURE FOR GAS COMPRESSION
SPECIFIED AS TOTALLY ENCLOSED

TYPE OF ENCLOSURE FOR GAS TREATMENT
SPECIFIED AS TOTALLY ENCLOSED

TYPE OF ENCLOSURE FOR UTILITIES
SPECIFIED AS TOTALLY ENCLOSED

TYPE OF ENCLOSURE FOR WATER INJECTION
SPECIFIED AS TOTALLY ENCLOSED

TYPE OF ENCLOSURE FOR POWER GENERATION
SPECIFIED AS TOTALLY ENCLOSED

TYPE OF ENCLOSURE FOR [illegible]

PLATFORM J

TOPSIDES OFFSHORE INSTALLATION COSTS

	COST $(000)
LOADOUT/SEA FASTEN	13897.9
BARGE TRANSPORT	0.0
DERRICK BARGE	0.0
MOBILIZATION/DEMOBILIZATION	0.0
PUSHOVE HOOKUP & COMMISSIONING	0.0
INSHORE HOOKUP & COMMISSIONING	0.0
OFFSHORE HOOKUP & COMMISSIONING	0.0
ENGR COST FOR HOOKUP & COMMISSIONING	0.0
SUBTOTAL TOPSIDES INSTALLATION COST	13897.9
TOTAL TOPSIDES INSTALLED COST	709280.8

PLATFORM J

TOPSIDES ONSHORE ERECTED COSTS

	COST $(000)
DIRECTS:	
MAJOR EQUIPMENT FOB COST	239351.8
BULK MATERIALS FOB COST	81006.3
MAJOR EQUIPMENT DIRECT LABOR COST	2464.7
BULK MATERIALS DIRECT LABOR COST	69609.4
TOPSIDES ERECTED STEEL:	
FINISHING & MEZZANINE STEEL FOB COST	301.4
MODULE STEEL MATERIALS FOB COST	15901.6
HELIDECK MATERIALS FOB COST	1162.3
LIVING QUARTERS MATERIALS FOB COST	14201.6
FINISHING & MEZZANINE STEEL DIRECT LABOR	1394.1
MODULE STEEL DIRECT LABOR	78170.2
HELIDECK DIRECT LABOR COST	60.9
LIVING QUARTERS DIRECT LABOR	288.9
SUBTOTAL TOPSIDES ERECTED STEEL	112481.1
TOTAL TOPSIDES DIRECTS	504912.6
INDIRECTS:	
DESIGN	75736.9
PROCUREMENT	0.0
ENGR PROJECT MANAGEMENT SERVICES	25245.6
CONSTR PROJECT MANAGEMENT SERVICES	25245.6
CONTRACTORS MOBILIZATION & DEMOBILIZATION	0.0
CONTRACTORS EQUIPMENT	22435.0
CONTRACTORS WAREHOUSING & LAYDOWN	0.0
CONTRACTORS CONTINGENCY & PROFIT	15198.8
EQUIP. & BULKS TRANSPORT TO MARSHALLING YARD	25623.6
SUBTOTAL INDIRECTS	189480.6
TOTAL TOPSIDES ONSHORE ERECTED COST	694393.1

GENERAL UTILITY (UTIL) MANAGEMENT DECISIONS

TYPE OF INSTRUMENT AIR COMPRESSOR SPECIFIED AS ROTARY SCREW

AIR COOLING SPECIFIED FOR ALL MAIN PROCESS DUTIES

HEATING MEDIUM HEAT SOURCE SPECIFIED AS
TURBINE ALTERNATOR EXHAUST WASTE HEAT RECOVERY
****** TURBINE ALTERNATORS WILL BE DERATED 2.5% FOR WHR UNITS

POTABLE WATER USAGE SPECIFIED AS 50.0 USGPD PER MAN

TYPE OF WATERMAKER SPECIFIED AS REVERSE OSMOSIS UNIT

PLATFORM J :

FIRE PUMP CONFIGURATION SPECIFIED AS 3 X 50% DEDICATED DIESEL DRIVERS

FIRE PUMP RATE SPECIFIED AS 8000. USGPM

FIRE WATER FOAM SYSTEM NOT SPECIFIED

FIRE WATER DELUGE SYSTEM SPECIFIED FOR HAZARDOUS AREAS

STRUCTURAL FIREPROOFING SPECIFIED

PLATFORM AREA FOR WORKSHOPS AND STORAGE AREAS SPECIFIED TO BE 6000. SQ FT
****** EXCEEDS 1000 SQ FT. PLEASE CHECK DESIGN BASIS

CONTROL CENTER LOCATION SPECIFIED AS IN THE LIVING QUARTERS

CONTROL CENTER AREA IN LIVING QUARTERS SPECIFIED AS 600.0 SQ FT

AN INERT GAS GENERATOR IS NOT SPECIFIED

METHANOL STORAGE QUANTITY SPECIFIED AS 400. BBLS

CORROSION INHIBITOR STORAGE QUANTITY SPECIFIED AS 400. BBLS

GLYCOL STORAGE QUANTITY NOT SPECIFIED
****** WILL DEFAULT TO NONE ALLOCATED

LUBE OIL STORAGE QUANTITY SPECIFIED AS 600. BBLS
****** EXCEEDS 500 BBLS. PLEASE CHECK DESIGN BASIS

SEAL OIL STORAGE QUANTITY SPECIFIED AS 600. BBLS
****** EXCEEDS 500 BBLS. PLEASE CHECK DESIGN BASIS

UNTREATED DIESEL STORAGE QUANTITY (IN ADDITION TO THAT SPECIFIED
FOR MAIN POWER GENERATION) SPECIFIED AS 999. BBLS
****** EXCEEDS 500 BBLS. PLEASE CHECK DESIGN BASIS

COMMODITY STORAGE LOCATIONS (STOR) MANAGEMENT DECISIONS

TREATED DIESEL STORAGE LOCATION
SPECIFIED AS CRANE PEDESTAL

UNTREATED DIESEL STORAGE LOCATION
SPECIFIED AS CONCRETE CELL

POTABLE WATER STORAGE LOCATION
SPECIFIED AS DEDICATED TANK BETWEEN SUPPORT BEAMS

DRILL WATER STORAGE LOCATION
***** NOT SPECIFIED. WILL DEFAULT TO CONCRETE CELL

CORROSION INHIBITOR STORAGE LOCATION
SPECIFIED AS DEDICATED TOPSIDES STORAGE TANK

LUBE OIL STORAGE LOCATION
SPECIFIED AS DEDICATED TOPSIDES STORAGE TANK

SEAL OIL STORAGE LOCATION
SPECIFIED AS DEDICATED TOPSIDES STORAGE TANK

METHANOL STORAGE LOCATION
SPECIFIED AS DEDICATED TANK BETWEEN SUPPORT BEAMS

WATER INJECTION (WINJ) MANAGEMENT DECISIONS

WATER INJECTION SYSTEM NOT SPECIFIED

POWER DISTRIBUTION, POWER GENERATION AND RELATED UTILITIES (POWR) MANAGEMENT DECISIONS

POWER GENERATION ON PLATFORM SPECIFIED

TYPE OF MAIN POWER GENERATION SPECIFIED AS TURBINE ALTERNATORS

POWER GENERATION CYCLES SPECIFIED AS 60 HZ

MAIN POWER GENERATION TRAIN CONFIGURATION SPECIFIED AS
100.0% OF TOTAL DESIGN LOAD PER POWER GENERATOR

NUMBER OF MAIN POWER GENERATORS SPECIFIED AS 2

NUMBER OF MAIN POWER GENERATORS OPERATING SPECIFIED AS 1

STARTING AIR SYSTEM NOT SPECIFIED

A FUEL GAS HEATER IS SPECIFIED

TWO EMERGENCY GENERATORS SPECIFIED

TREATED DIESEL STORAGE FOR ONE MAIN POWER GENERATOR
SPECIFIED AT 9.90 DAYS
***** EXCEEDS 7 DAYS. PLEASE CHECK DESIGN BASIS

UNTREATED DIESEL STORAGE FOR ONE MAIN POWER GENERATOR
SPECIFIED AT 99.00 DAYS
***** EXCEEDS 21 DAYS. PLEASE CHECK DESIGN BASIS

METHOD FOR POWER DISTRIBUTION EQUIPMENT ESTIMATION
SPECIFIED AS 'ELEMENT' METHOD

PLATFORM J :

BATTERY BANK VOLTAGE NOT SPECIFIED
***** WILL BE INTERNALLY ESTIMATED

BATTERY BANK DISCHARGE PERIOD SPECIFIED AS 8.0 HOURS

BATTERY BANK RECHARGE PERIOD SPECIFIED AS 8.0 HOURS

GAS SWEETENING (GSWT) MANAGEMENT DECISIONS

NO EXPORT, REINJECTION, OR LIFT GAS SPECIFIED

RELIEF AND FLARE (RELF) MANAGEMENT DECISIONS

PLATFORM J :

RELIEF SYSTEM CONFIGURATION SPECIFIED AS
HORIZONTAL VESSELS WITH H.P. AND L.P. SYSTEM

FLARE CONFIGURATION SPECIFIED AS INCLINED (15 DEGREES) FLARE BOOM

MAXIMUM TOLERABLE CONTINUOUS FLARE RADIATION INTENSITY
SPECIFIED AS 300. BTU/HR-SQ FT

"MAXIMUM" TOLERABLE EMERGENCY FLARE RADIATION INTENSITY
SPECIFIED AS 2000. BTU/HR-SQ FT

CONTINUOUS RELIEF MACH NUMBER SPECIFIED AS 0.25 TIMES SONIC VELOCITY

EMERGENCY RELIEF MACH NUMBER SPECIFIED AS 0.40 TIMES SONIC VELOCITY

TYPE OF FLARE TIP SPECIFIED AS SMOKELESS

FLARE SHIELD WATER NOT SPECIFIED

NO LIQUID WASTE BURNERS SPECIFIED

APPENDIX 5

PERMITTING COSTS

APPENDIX 5: PERMITTING

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Summary	A5-1

APPENDIX 5: PERMITTING

Summary

Permitting costs were estimated to have a "most likely" cost of $20MM. The estimated uncertainty of the permitting cost is shown in Figures A5-2 and A5-3. An optimistic cost is estimated to be 75% of the Most Likely cost. A pessimistic cost is estimated to be 200% of the Most Likely cost. As shown in Figure A5-3, a triangular distribution is assumed. These costs included field and office work for an Environmental Impact Statement as well as data collection and processing involved in all necessary permits.

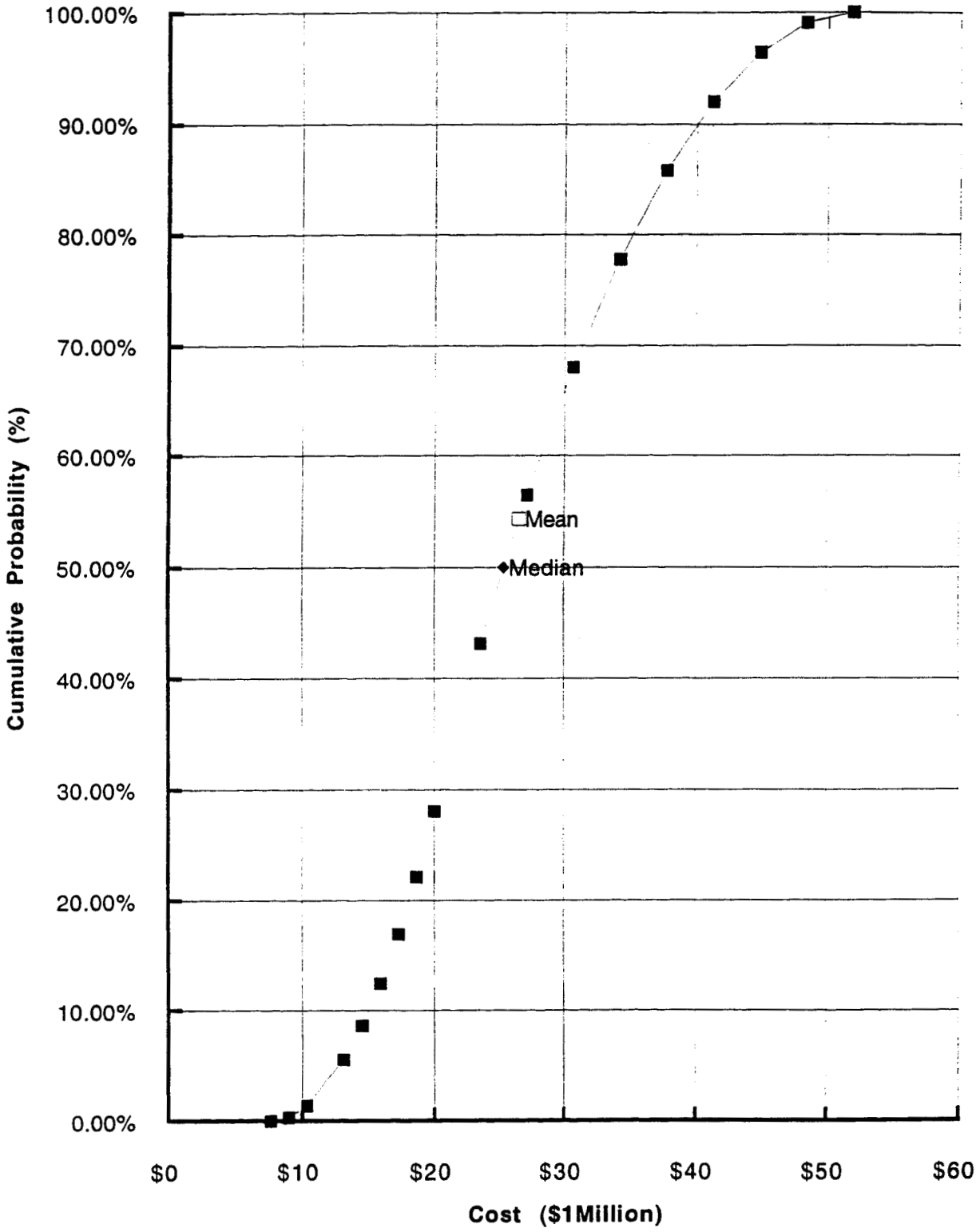


FIGURE A5-2
Permitting Costs

This Spread Sheet will compute the unique Triangular Probability Density Distribution and the nique Cumulative Probability Curve determined by the k'%, Most Likely and k"% Cost Estimates

INPUT:

	Costs in $1,000,000	
k' & k'Cost Estimate	0.1	$15.00
Most Likely Cost Estimate	b=	$20.00
k''' & k'''Cost Estimate	0.9	$40.00

Permitting Costs

0% cost = $7.58 100%Cost= $51.89

See Table for Probability Density vs Cost, Mean & Median Costs

To Calculate the Absolute Minimum Cost (0%Cost Estimate) which will be called "a" and the Absolute Maximum Cost (100% Cost Estimate) which will be called "c". Note the Most Likely Cost is called "b".

The k', Most Likely, and k'"Cost Estimates completely define the Triangular Probability Density Distribution and Cumulative Probability Curves. An interative procedure has to be used to calculate "a" and "c"; that is, the 0%Cost Estimate and the 100% Cost Estimate, respectively.

First step is to determine which set of equations are applicable to find "a"and "c". This will depend on where the Most Likely Cost Estimate "b" lies relative to k' and k'"Cost Estimates.

Please note that k'Cost Estimate is always less than k'"Cost Estimate.

FOR THE ABOVE K'COST, MOST LIKELY COST AND K"COST ESTIMATES USE

XXXXXXX MIDDLE CASE XXXXXXX

CASE LEFT

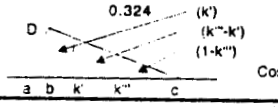
If Most Likely Cost Estimate < k'Cost Estimate

c= 52.50000

D= 0.04160000

a= 4.423076923

Therefore k2 for Most Likely Cost Estimate is equal to 0.324



CASE MIDDLE

If (k'CostEstimate<Most Likely Cost Estimate<k'''Cost Estimate), iterate to Find Absolute Minimum 'a' and Maximum 'c' Cost Estimates. Try values of 'a' until c'=c". Trial 'a'= 7.58319

c'= 51.88528577

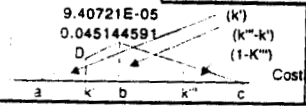
c"= 51.8851917

Delta=(c'-c")= 9.40721E-05

D= 0.045144591

0.00001

0.0001 7.5832



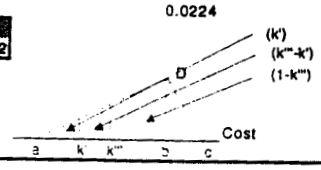
CASE RIGHT

If (k'Cost Esti.<k'''Cost Esti.>Most Likely Cost Esti.),

a= 2.5

c= 91.78571429

D= 0.0224



Is a <k'Cost Estimate? Yes, Valid

Is K'<K'"? Yes,Valid

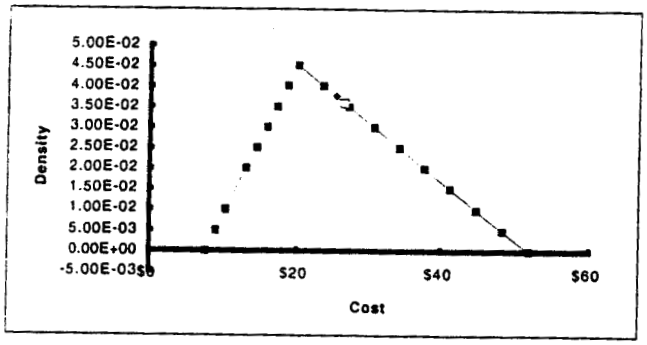
Please Note that you must enter the values calculated above into these slots before computing distributions.

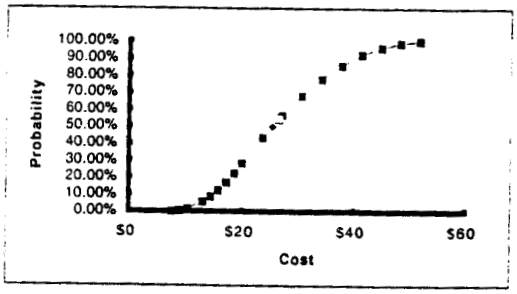
Enter the Values of "a", "c", and D computed above

a=	$7.5832
c=	$51.8853
D=	0.04514459

Calculating Probability Density Distribution and Cumulative Probability Curves

	Cost in $1,000,000 $	Probability Density (1/$)	Cumulative Probability %
	$8	0.00E+00	0.00%
	$9	5.02E-03	0.35%
	$10	1.00E-02	1.38%
	$13	2.01E-02	5.54%
	$13	2.01E-02	5.54%
	$14	2.51E-02	8.65%
	$16	3.01E-02	12.46%
	$17	3.51E-02	16.95%
	$19	4.01E-02	22.15%
Most Likely	$20	4.51E-02	28.03%
	$24	4.01E-02	43.13%
	$27	3.51E-02	56.46%
	$31	3.01E-02	68.01%
	$34	2.51E-02	77.79%
	$38	2.01E-02	85.78%
	$41	1.50E-02	92.00%
	$45	1.00E-02	96.45%
	$48	5.02E-03	99.11%
Absolute Maximum	$52	-6.94E-18	100.00%
MEAN COST	$26.49	3.60E-02	54.34%
MEDIAN COST	$25.31	0.037627703	50.00%





RSKWC12.xls Robert E. 12/14/93

FIGURE A5-3
Permitting Costs