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FINAL REPORT

Updates to Fault Tree Methodology and Technology for Risk Analysis
Liberty Project

BOEM Contract Number M11PC00013

May, 2016

By

Bercha International Inc.
Calgary, Alberta, Canada

U.S. Department of the Interior
Alaska Outer Continental Shelf Region
Environmental Sciences Management

OCS Study BOEM 2016-052

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May 2016

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ABSTRACT

The present document deals with the evaluation of oil spill potential associated with a proposed development at the Liberty prospect (the Project), generally located in the South Beaufort Sea in the landfast ice zone, inside the barrier islands, approximately 9 km (5 miles) offshore as. The Project is proposed to be a self-contained offshore drilling and production facility located on an artificial gravel island with a pipeline to shore. Detailed information on the Project used in this work, is based primarily on the Liberty Development Plan by Hilcorp Alaska, Inc.

Oil spill occurrence estimates were generated for the Project. Because sufficient historical data on offshore oil spills for this region do not exist, an oil spill occurrence model based on fault tree methodology was developed and applied. Using the fault trees, base data from the Gulf of Mexico and Pacific OCS as well as North Sea data on well control incidents including the variability of the data, were modified and augmented to represent expected Arctic offshore oil spillage frequencies. Because the proposed pipeline to shore is a pipe in pipe conduit and historical loss of containment data is very sparse, additional reliability analysis was conducted to generate loss of containment probabilities.

Three principal spill occurrence indicators, as follows, were quantified for each year of each scenario, as well as scenario life of field averages:

- Spill frequency per 1,000 years
- Spill frequency per 10^9 barrels produced
- Spill index, the product of spill size and spill frequency

These indicators were quantified for the following spill sizes:

- Small (S): 50 - 99 bbl
- Medium (M): 100 - 999 bbl
- Large (L): 1,000 - 9,999 bbl
- Huge (H): >= 10,000 bbl

Quantification was carried out for each future year for the Project scenario, with a range of development parameters, in duration up to 25 years. In addition, a comparative scenario for non-Arctic locations was formulated and analyzed for oil spill occurrence. Generally, it was found that the non-Arctic spill indicators were likely to be higher than those for similar scenarios in the Arctic. The computations were carried out using a Monte Carlo process to permit the inclusion of uncertainties in the base and scenario data and Arctic effects and resultants. A wide range of details for each scenario was generated, including the following:

- Expected time history of spill occurrences over the scenario life.
- Spill occurrence variations by spill volumes in the above spill size ranges.
- Spill occurrence variation by spill cause such as work boat anchoring or ice gouging.
- Spill occurrence contribution from each main facility type, including pipelines, the island, and wells.
- Comparison of spill occurrence predictions between Arctic and non-Arctic scenarios.

- Life of field averages of spill occurrence estimators.
- The variability in the results due to uncertainties in the inputs was expressed as cumulative distribution functions and statistical measures.

In this final report, a detailed description of the methodology, results, and conclusions and recommendations is given, as well as a section on constraints of the study.

ACKNOWLEDGEMENTS

Grateful acknowledgement for funding and direction is made to BOEM, Alaska OCS Region. In particular, the following BOEM personnel are acknowledged together with their roles:

- Heather Crowley, Contracting Officer's Representative Advisor
- Rebecca Kruse, Contracting Officer

This work was carried out by Bercha International Inc (Bercha). Key Bercha personnel on the project team were as follows:

- Dr. Frank G. Bercha, Project Manager and Principal Engineer
- Milan Cerovšek, Reliability Engineering Specialist
- Wesley Abel, Offshore Engineering Specialist
- Susan Bercha, Editorial and Word Processing Manager

EXECUTIVE SUMMARY

A. Introduction

The United States Department of the Interior, Bureau of Ocean Energy Management (BOEM) Alaska Outer Continental Shelf (OCS) Region uses oil spill occurrence estimates for National Environmental Policy Act assessments for all parts of their area of assessment, ranging from near shore through shallow water, to deeper water. Although land to 3 nautical miles is not within BOEM jurisdiction, it is included in the BOEM environmental impact analysis; hence it is also included in the study area here.

B. Summary of Work Done

Oil spill occurrence estimates were generated for the proposed offshore drilling and production facility located on an artificial gravel island with a pipeline to shore at the Liberty prospect (the Project), located in the South Beaufort Sea in the landfast ice zone, inside the barrier islands, approximately 9 km (5 miles) offshore. Because sufficient historical data on offshore oil spills for this region do not exist, an oil spill occurrence model based on fault tree methodology was developed and applied. Using the fault trees, base data from the Gulf of Mexico and Pacific OCS and, for losses of well control also from the North Sea, including the variability of the data, were modified and augmented to represent expected Arctic offshore oil spillage frequencies. Because the proposed subsea pipeline is a pipe-in-pipe, for which historical data are not available, a reliability analysis was carried out to develop loss of containment frequencies applicable to pipeline.

Three principal spill occurrence indicators, as follows, were quantified for each year of each scenario, as well as scenario life of field averages:

- Spill frequency per 1,000 years
- Spill frequency per 10^9 barrels produced
- Spill index, the product of spill size and spill frequency

These indicators were quantified for the following spill sizes:

- Small (S): 50 - 99 bbl
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Quantification was carried out for each future year for the Project scenario, with a range of development parameters, in duration up to 25 years. In addition, a comparative scenario for non-Arctic locations was formulated and analyzed for oil spill occurrence. Generally, it was found that the non-Arctic spill indicators were likely to be higher than those for similar scenarios in the Arctic. The computations were carried out using a Monte Carlo process to permit the inclusion of uncertainties in the base and scenario data and Arctic effects. A wide range of details for each scenario was generated, including the following:

- Expected time history of spill occurrences over the scenario life.
- Spill occurrence variations by spill volumes in the above spill size ranges.
- Spill occurrence variation by spill cause such as work boat anchoring or ice gouging.
- Spill occurrence contribution from each main facility type, including pipelines, the island, and wells.
- Comparison of spill occurrence predictions between Arctic and non-Arctic scenarios.
- Life of field averages of spill occurrence estimators.
- The variability in the results due to uncertainties in the inputs was expressed as cumulative distribution functions and statistical measures.

In this final report, a detailed description of the Project, the methodology, results, and conclusions and recommendations is given, as well as a section on constraints of the study.

C. Conclusions

C.1 General Conclusions

Oil spill occurrence indicators were quantified for the proposed Liberty Development Project (the Project) in the south Beaufort Sea. The quantification included the consideration of the variability of historical and future scenario data, as well as that of Arctic effects in predicting oil spill occurrence indicators. Consideration of the variability of all input data yields both higher variability and a higher expected value of the spill occurrence indicators. The three types of spill occurrence indicators were: annual oil spill frequency, annual oil spill frequency per billion barrels produced, and annual spill index – additionally, the Project year 15 and life of field (LOF) averages for each of these three oil spill indicators were assessed.

C.2 Oil Spill Occurrence Indicators by Spill Size and Source

How do spill indicators for the Project scenario and for its non-Arctic counterpart vary by spill size and source? Table C.1 summarizes the Life of Field average spill indicator values by spill size and source. The following can be observed:

- Spill frequency per 10^3 years and per 10^9 barrels produced decreases with increasing spill size for all Arctic and non-Arctic scenarios.
- The spill index increases with spill size for all Arctic and non-Arctic scenarios.
- All non-Arctic scenario spill indicators are greater than their Arctic counterparts.
- The island contributes the most (82%) to the two spill frequency indicators.
- Pipelines are second in relative contribution to spill frequencies (15%).
- Wells are the lowest contributors to frequency indicators (4%) but highest contributors to spill index (83%)
- It can be concluded that the island is likely to have the most, but smaller spills, while wells will have the least number but larger spills. Pipelines will be in between, with more spills than wells.

Table C.2 gives the contributions to spill indicators for substantial (>=1,000 bbl) spills only; although trends are similar, the contribution percentages are different.

Table C.1
Summary of Life of Project Field Average Spill Indicators by Spill Source and Size

Spill Indicators LOF Average	Liberty			Liberty Non Arctic		
	Spill Frequency per 10^3 years	Spill Frequency per 10^9 bbl produced	Spill Index (bbl)	Spill Frequency per 10^3 years	Spill Frequency per 10^9 bbl produced	Spill Index (bbl)
Small and Medium Spills 50-999 bbl	1.947	0.397	0.867	3.397	0.692	1.512
	87%	87%	6%	89%	89%	8%
Large Spills 1,000-9,999 bbl	0.160	0.033	0.859	0.253	0.052	1.353
	7%	7%	6%	7%	7%	7%
Huge Spills =>10,000 bbl	0.123	0.025	12.133	0.178	0.036	15.447
	6%	6%	88%	5%	5%	84%
Substantial Spills =>1,000 bbl	0.283	0.058	12.992	0.431	0.088	16.799
	13%	13%	94%	11%	11%	92%
All Spills	2.230	0.454	13.859	3.827	0.780	18.311
	100%	100%	100%	100%	100%	100%
Pipeline Spills	0.331	0.067	0.830	0.640	0.130	1.537
	15%	15%	6%	17%	17%	8%
Island Spills	1.818	0.370	1.457	3.087	0.629	2.297
	82%	82%	11%	81%	81%	13%
Well Spills	0.080	0.016	11.572	0.100	0.020	14.476
	4%	4%	83%	3%	3%	79%
Island and Well Spills	1.898	0.387	13.029	3.187	0.649	16.773
	85%	85%	94%	83%	83%	92%
All Spills	2.230	0.454	13.859	3.827	0.780	18.311
	100%	100%	100%	100%	100%	100%

Table C.2
Summary of Life of Project Spill Indicators for Substantial Spills by Facility and Well Type

Spill Source LOF Average Substantial Spills => 1,000 bbl	Liberty		
	Spill Frequency per 10^3 years	Spill Frequency per 10^9 bbl produced	Spill Index (bbl)
Pipeline	0.100	0.020	0.740
	35%	35%	6%
Island	0.123	0.025	0.691
	43%	43%	5%
Wells	0.060	0.012	11.562
	21%	21%	89%
Island and Wells	0.183	0.037	12.252
	65%	65%	94%
All	0.283	0.058	12.992
	100%	100%	100%
Production Wells	0.027	0.005	5.092
	44%	44%	44%
Development Wells Drilling	0.034	0.007	6.469
	56%	56%	56%
All Wells	0.060	0.012	11.562
	100%	100%	100%

C.3 The Variance of Oil Spill Occurrence Indicators

A Monte Carlo analysis of the Project annual and Life of Field average spill indicators was conducted to evaluate the effects of input uncertainties on these indicators**.** The Cumulative Distribution Functions (CDF) presented in the report contain extensive information on the statistical properties of the spill indicators. Generally, the following can be observed from the analysis:

- The variance of the frequency spill indicators (frequency and frequency per barrel produced) generally decreases as spill size increases for pipelines and the island. For example, pipeline huge spills are less variable than small, medium, or large spills. For the island, small and medium spills are more variable than large and huge spills.
- For wells, huge spills show greater variance than smaller ones.
- For all facilities, the frequency spill indicators for small and medium spills show significantly more variability than those for large and huge spills.
- The variability of the spill index for the pipeline, unlike the frequency spill indicators, shows a greater variance for large and huge spills than for small and medium spills. The opposite occurs for the island (ie, small and medium spills are the most variable).
- For wells, the variance in huge spills spill index dominates. There is very little variance in large, medium, and small spills.
- For all facilities, the spill index for huge spills is more variable than for smaller spills.

D. The Methodology and its Applicability

An analytical tool for the prediction of oil spill occurrence indicators for systems without history, such as future offshore oil production developments in the Beaufort Sea, has been developed based on the utilization of fault tree methodology. Although the results generated are voluminous, they are essentially transparent, simple, and easy to understand. The analytical tool developed is also quite transparent, very efficient in terms of computer time and input-output capability. In addition, the predictive model is setup so that input variables can be entered as distributions to yield result distributions.

A wealth of information that can be utilized for the optimal planning and regulation of future developments is generated by the analytical tool. Key aspects of the analytical tool capability may be summarized as follows:

- Ability to generate expected and mean values as well as their variability in rigorous numerical statistical format.
- Use of verifiable input data based on BSEE and BOEM or other historical spill data and statistics.
- Ability to independently vary the impacts of different causes on the spill occurrences as well as add new causes such as some of those that may be expected for the Arctic or other new environments.

- Ability to generate spill occurrence indicator characteristics such as annual variations, facility contributions, spill size distributions, and life of field (LOF) averages.
- Ability to generate comparative spill occurrence indicators such as those of comparable scenarios in more temperate regions. The model developed provides a basis for estimating each Arctic effect's importance through sensitivity analysis as well as propagation of uncertainties.
- Capability to quantify uncertainties rigorously, together with their measures of variability.

E. Suggested Improvement to the Methodology and Results

During the work, a number of areas were identified where future improvements could be made, including: the input data, the scenarios, the application of the fault tree methodology, and finally the oil spill occurrence indicators themselves have been identified. These suggestions are summarized in the following paragraphs.

Two categories of input data were used; namely the historical spill data and the Arctic effect data. Although a verifiable and optimal historical spill data set has been used, the following shortcomings may be noted:

- Gulf of Mexico and Pacific (OCS) historical databases were compiled by BSEE and BOEM for pipelines and facilities, and were used as a starting point for the fault tree analysis. Although these data are adequate, a broader population base would be expected to give more robust statistics. For well loss of well control (LOWC) data, both the BSEE and BOEM and the proprietary SINTEF data were used, providing a wider data sample.
- The Arctic effects include modifications in causes associated with the historical data set as well as additions of spill causes unique to the Arctic environment. Quantification of existing causes for Arctic effects on historical statistics was done in a relative cursory way restricted to engineering judgment. However, the additive or Arctic unique effects, were evaluated more rigorously.
- Upheaval buckling effect assessments were included on the basis of professional judgment used in previous studies; no engineering analysis was carried out for the assessment of frequencies for Beaufort Sea locations to be expected for these effects.

The following comments can be made on constraints associated with the indicators that have been generated:

- The model generating the indicators is fundamentally a linear model which ignores the effects of scale, of time variations such as the learning and wear-out curves (Bathtub curve), climate change, and production volume non-linear effects.
- With current methodology, the likelihood of different spill size distributions is assumed constant throughout all production years even though the production decreases from approximately 60,000 barrels per day (BPD) to 2,000 BPD over the project life cycle. One can speculate that the potential for Large and Huge spills varies together with the production rate. Although this was not investigated in this study, it is recommended that it be addressed in future studies due to the large variation in production volumes from start to end of production. However, as done here, the results are conservative.

F. Recommendations

The following recommendations based on the work may be made:

- Continue to utilize the Monte Carlo spill occurrence indicator model for new Arctic OCS scenarios to support BOEM needs, as it is currently the best predictive spill occurrence model available.
- Utilize the oil spill occurrence indicator model to generate additional model validation information, including direct application to existing non-Arctic scenarios, such as GOM and PAC projects, which have an offshore oil spill statistical history.
- Utilize the oil spill occurrence indicator model in a sensitivity mode to identify the importance of different Arctic effect variables introduced to provide a prioritized list of those items having the highest potential impact on Arctic oil spills.
- Generalize the model so that it can be run both in an adjusted expected value and a distributed value (Monte Carlo) form with the intent that expected value form can be utilized without the Monte Carlo add-in for preliminary estimates and sensitivity analyses, while for more comprehensive rigorous studies, the Monte Carlo version can be used
- Conduct calculations of the spill indicators as a function of the variable annual oil production rates as spill size and frequency distributions are likely to be a function of these variable production rates.

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GLOSSARY OF TERMS AND ACRONYMS

Bbbl	Billion Barrels
BOEM	**B**ureau of **O**cean **E**nergy **M**anagement, Department of the Interior
BOP	**B**low**o**ut **P**reventer
BPD	**B**arrels **P**er **D**ay
BSEE	**B**ureau of **S**afety and **E**nvironmental **E**nforcement, Department of the Interior
CDF	**C**umulative **D**istribution **F**unction
Consequence	The direct effect of an accidental event.
DPP	**D**evelopment and **p**roduction **p**lan
GOM	**G**ulf **o**f **M**exico OCS
Hazard	A condition with a potential to create risks such as accidental leakage of natural gas from a pressurized vessel
MMbbl	Million Barrels
LDPI	**L**iberty **d**rilling and **p**roduction **i**sland
LOC	**L**oss **o**f **C**ontainment
LOF	**L**ife **o**f **F**ield
LOFn	**L**oss **o**f **F**unctio**n**
LOWC	**L**oss **o**f **W**ell **C**ontrol
MMS	**M**inerals **M**anagement **S**ervice. On October 1, 2011, the Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE), formerly the Minerals Management Service (MMS), was replaced by the Bureau of Ocean Energy Management (BOEM) and the Bureau of Safety and Environmental Enforcement (BSEE) as part of a major reorganization
Monte Carlo	A numerical method for evaluating algebraic combinations of statistical distributions.
OCS	**O**uter **C**ontinental **S**helf
PAC	Pacific OCS
PIP	**P**ipe **i**n **p**ipe
QRA	**Q**uantitative **R**isk **A**ssessment

Risk	A compound measure of the probability and magnitude of adverse effect.
RLS	Release
SINTEF	The Foundation for Scientific and Industrial Research at the Norwegian Institute of Technology
Spill Frequency	The number of spills of a given spill size range per year. Usually expressed as spills per 1,000 years (and so indicated).
Spill Frequency per Barrel Produced	The number of spills of a given spill size range per barrel produced. Usually expressed as spills per billion barrels produced (and so indicated).
Spill Index	The product of spill frequency for a given spill size range and the mean spill size for that spill size range.
Spill Occurrence	Characterization of an oil spill as an annual frequency and associated spill size or spill size range.
Spill Occurrence Indicator	Any of the oil spill occurrence characteristics; namely, spill frequency, spill frequency per barrel produced, or spill index (defined above).
Spill Sizes	Small (S): 50 - 99 bbl Medium (M): 100 - 999 bbl Large (L): 1,000 - 9,999 bbl Huge (H): >=10,000 bbl Substantial >=1,000 bbl

CHAPTER 1

INTRODUCTION

1.1 General Introduction

The United States Department of the Interior, Bureau of Ocean Energy Management (BOEM) Alaska Outer Continental Shelf (OCS) Region uses oil spill occurrence estimates for National Environmental Policy Act assessments for all parts of their area of assessment, ranging from nearshore through shallow water, to deeper water. Although land to 3 nautical miles is not within BOEM jurisdiction, it is included in the BOEM environmental impact analysis; hence it is also included in the study area here. In 2002, 2006, 2008, and 2014 studies were carried out by Bercha International Inc. [13, 16, 17, 18, 19] * to assess and quantify oil spill occurrence indicators for the Chukchi and Beaufort seas. In the present study, the latest methodologies based on fault tree analysis developed for the assessment of oil spill rates associated with exploration and production facilities and operations in OCS Arctic waters [13] are applied to a specific Scenario; namely, the Liberty Development Project, hereinafter called the Project.

The prediction of the reliability (or failure) of systems without history can be approached through a variety of mathematical techniques, with one of the most preferable and accepted being fault trees [1, 6, 10, 23, 32, 61], and their combination with numerical distribution methods such as Monte Carlo simulation [6, 16]. In the previous studies [13, 16, 17], fault tree methodology was applied to the prediction of oil spill rates for oil and gas developments in the Beaufort and Chukchi Sea.

As there are limited offshore Arctic oil spill occurrences, associated data worldwide and from the Gulf of Mexico (GOM) and Pacific (PAC) OCS data [15] were used as a starting point to develop a simulation model of oil spill occurrence probabilities. The model for non-Arctic occurrence probabilities was then modified to include Arctic effects and their variabilities. In the early studies [19], variability in the non-Arctic input data was considered; but variability of the future development scenario physical facility parameters, such as miles of subsea pipeline, was not considered. In the present study, as well as in the preceding fault tree studies [13, 16] both the historical data variability and that of the future development scenario characteristics is included in calculation of oil spill occurrence probabilities.

The present document deals with the evaluation of oil spill potential associated with a possible development at the Liberty prospect (the Project), generally located in the South Beaufort Sea in the landfast ice zone, inside the barrier islands, approximately 9 km (5 miles) offshore as shown in Figure 1.1. Information on the Project used in this work, including Figure 1.1, is based primarily on the Liberty Development Plan by Hilcorp Alaska, Inc. [28].

* Numbers in square brackets refer to citations listed in the "References" section of this report.

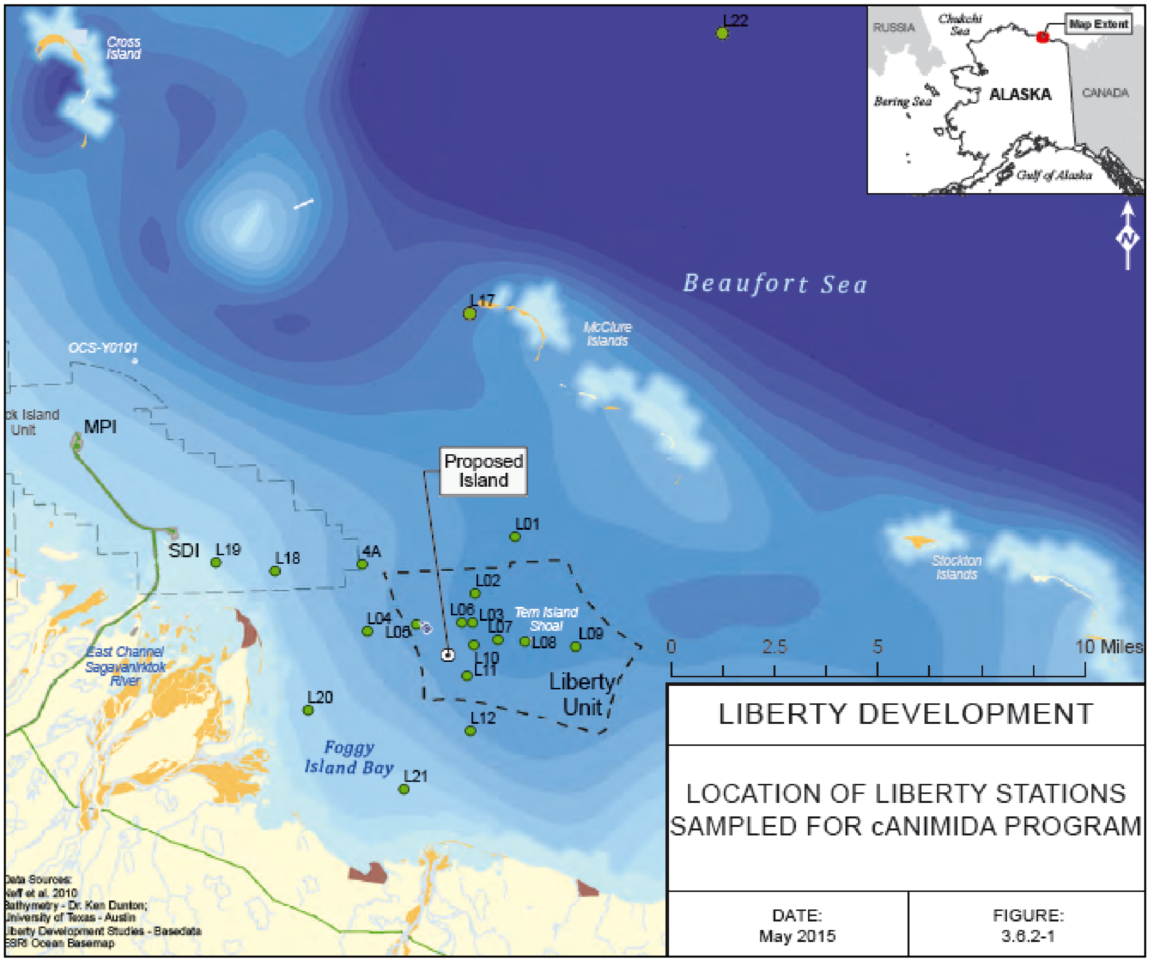


Figure 1.1: Project Location Map [28]

1.2 Study Objectives

The Contractor for this work, Bercha International Inc. (Bercha), has the principal objective to conduct a fault tree analysis and associated outputs as generally described below, using the Liberty Development and production plan (DPP) information [28]. Improvements to fault tree methodology, any revisions in Arctic and GOM spill occurrence factors developed and provided by Contractor are to be included. The work is to include the quantification of robustness of the statistics and predictions, (Confidence Limits on spill occurrence estimates), and precision or variance of estimates. Spill occurrence rates (occurrence rates) for multiple size ranges of crude and diesel spills should be projected. The primary focus should be in terms of the number of spills of at least 1,000 bbl that is projected to occur. Generation of life-of-field spill occurrence estimators and spill occurrence estimators converted to number of spills per billion barrels produced over the life of the development and production scenario shall be included.

The specific objectives of this study are as follows:

- Assimilate North Sea and U.S. OCS oil spill statistics [14, 15], and evaluate their applicability to the Project.
- Develop the fault trees for estimating oil spill occurrences from the proposed Project associated with spills of different size categories.
- Using the fault tree approach in a Monte Carlo simulation, develop alternative oil spill indicators and assess their variability, including effect of variability of both the historical data and the future development scenario parameters.
- Evaluate the variability of alternative oil spill indicators for a similar development scenario in a non-Arctic location.

1.3 Project Overview

The Project location is the Beaufort Sea Outer Continental Shelf (OCS) as generally illustrated in Figure 1.1. Of interest is the offshore area from landfall to approximately the 6 m (19 feet) isobaths

The Project will be a self-contained offshore drilling and production facility located on an artificial gravel island with a buried pipeline to shore. As shown in Figure 1.1, the island will be located approximately 9 km (5.5 miles) offshore in Foggy Island Bay of the Beaufort Sea OCS in approximately 6 meters (19 feet) of water, roughly 3.2 km (2 miles) west of the Tern Island shoal. A subsea pipeline from the island to shore, and then onshore to the Badami pipeline will deliver the produced crude oil. Figure 1.2 shows the pipeline route from the island to shore and to the Badami pipeline.

The Project and its principal functional Project components described and analyzed in the present study are:

- The Liberty drilling and production island (LDPI)
- Oil and gas wells
- The subsea pipeline
- The Project as integrated

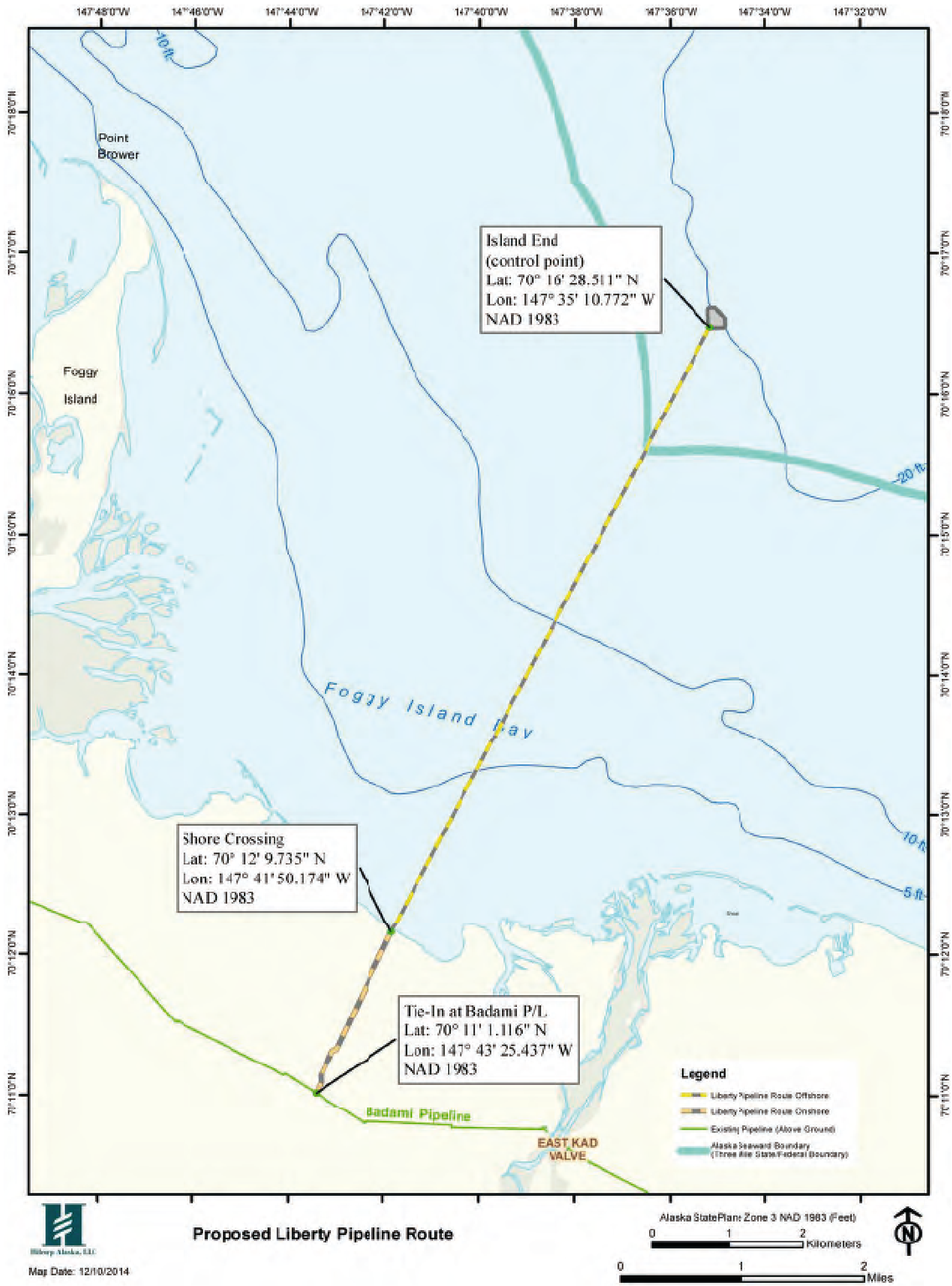


Figure 1.2: Project Detailed Location Map [28]

Following the review phase, the Project execution schedule [28 (Executive Summary, Section 3)] includes the following principal milestones:

- Year 1: Start 2017 estimated
- Year 2-5: Island, facilities, and pipeline construction.
- Year 3-5: Drilling operations
- Year 4-5: Production operations startup
- Year 4-25: Oil production
- Year 25: End of oil production

1.4 Analysis Background

The final reports [13, 16, 17, 18, 19] described the methodology and results of the Bercha fault tree method for the evaluation of oil spill occurrence estimators for the Beaufort and Chukchi seas. The focus of the first report [19] was on the initial development of a fault tree method to model both non-Arctic GOM spill causes as well as Arctic causes and effects that would be encountered in the Beaufort and Chukchi Seas OCS Regions. The variability of the parameters associated with Arctic effects was developed in order to provide an estimate of the variance in the spill occurrence predictions resulting directly from variances in the Arctic effects. In addition, in 2006 [17, 18] and 2008 [16], and 2014 [13], variance in the Gulf of Mexico (GOM) and other historical data was incorporated. In the most recent reports [13, 16], the variability of the future development scenario parameters is also considered. In the present study, all variances are considered in a manner analogous to that of the October 2014 [13] study. These variances were numerically incorporated through the use of Monte Carlo simulation for the fault tree model numerical predictions.

1.5 Technical Approaches

Uncertainties in the results of oil spill occurrence predictions generated in this study can be attributed to uncertainties in input data, scenario characterization, and the occurrence model. In the original 2002 study [19], uncertainties in input data were quantified for the Arctic effects only. Uncertainties in the scenario were included through the choice of scenarios representing the expected and maximum development levels. In the 2014 Chukchi Sea Lease Sale 193 study [13], uncertainties in the non-Arctic input data were also included. Thus the principal sources of uncertainty in the occurrence results were those caused by uncertainties in both the Arctic and non-Arctic input parameters.

The non-Arctic input parameters fall under two principal categories as follows:

- Spill frequencies
- Spill volumes

These spill frequencies and volumes as used in the study were derived from the following principal sources:

- Pipeline spills – GOM and PAC OCS data and PIP reliability analysis
- Platform spills – GOM and PAC OCS data
- Well (drilling and production) Loss of Well Control (LOWC) spills – GOM and North Sea data

Because the subsea pipeline proposed [28] is a pipe in pipe (PIP) or double walled pipeline, and no applicable historical date for such pipelines are available, it was necessary to also conduct a reliability analysis for subsea PIP containment failure rates and release size distributions for input into the fault tree analysis.

The specific sources of all data and the PIP reliability analysis are described in detail in Chapter 2 of this report. The inclusion of variability of the input data, including Arctic effects, is intended to provide a realistic estimate of the spill occurrence indicators and their resultant variability.

The following main facility parameters were used as expected values:

- Number of wells drilled
- Number of production wells
- Subsea pipeline length

1.6 Scope of Work

Task 1: ***Data Assimilation and PIP Reliability analysis***

a) Update of GOM and PAC pipeline and platform spill statistics [4, 15].

b) Reliability analysis of PIP in GOM environment similar to that of pipeline historical data

c) Loss of Well Control (LOWC) statistics [4, 14].

d) Assimilation and update of Project information [28].

Task 2: ***Development of Arctic Spill Frequency Causal Event and Total Probability Distributions***

a) Development of Arctic spill frequency causal event probability distributions associated with pipeline spills.

b) Development of Arctic spill frequency causal event probability distributions associated with platform spills.

c) Development of Arctic spill frequency causal event probability distributions associated with well drilling and production well LOWCs.

Task 3: ***Development of Non-Arctic Total Annual Spill Frequency and Volume Probability Distributions***

a) Development of non-Arctic total annual spill frequency and volume distribution for pipeline.

b) Development of non-Arctic total annual spill frequency and volume distribution for island.

c) Development of non-Arctic total annual spill frequency and volume distribution for well drilling and production wells.

Task 4: ***Generation of Oil Spill Occurrence Estimator Probability Distributions***

a) Variability in future development scenario parameters.

b) Monte Carlo model runs for Arctic Project scenarios.

c) Monte Carlo model runs for comparative non-Arctic scenario.

Task 5: ***Reporting***

a) Preliminary results following completion of Tasks 1, 2, 3, and 4 in Technical Reports #1, 2, and 3.

b) Draft Final Report and Final Report.

1.7 Work Organization

The present study consists of statistical and reliability investigations, followed by numerical simulation. Although the assimilation of historical and future scenario data is of key importance to the work, the salient contribution consisted primarily of the analytical work involving fault trees and oil spill occurrence indicator generation. Although the individual calculations are relatively simple, the subdivision of the calculations into realistic representative categories of facilities, spill sizes, and water depth for different variables in the scenario resulted in a relatively complex mix of computations, and they are generally illustrated in the flow chart in Figure 1.3.

The flow chart in Figure 1.3, of course, does not show all the different combinations and permutations; rather, it indicates the typical calculations for one case, and suggests the balance by dotted lines. Moving from left to right; initially historical data were obtained for each of three principal facility categories, pipeline, platform (island in the figure), and wells. Wells were categorized in two ways: according to producing wells and the drilling of exploration and development wells. For each of the above facility subcategories, spill causes were analyzed for small, medium, large, huge, and substantial spills, defined as follows:

- Small (S): 50 to 99 bbl
- Medium (M): 100 to 999 bbl
- Large (L): 1,000 to 9,999 bbl
- Huge (H): >= 10,000 bbl
- Substantial (SB): >= 1,000 bbl

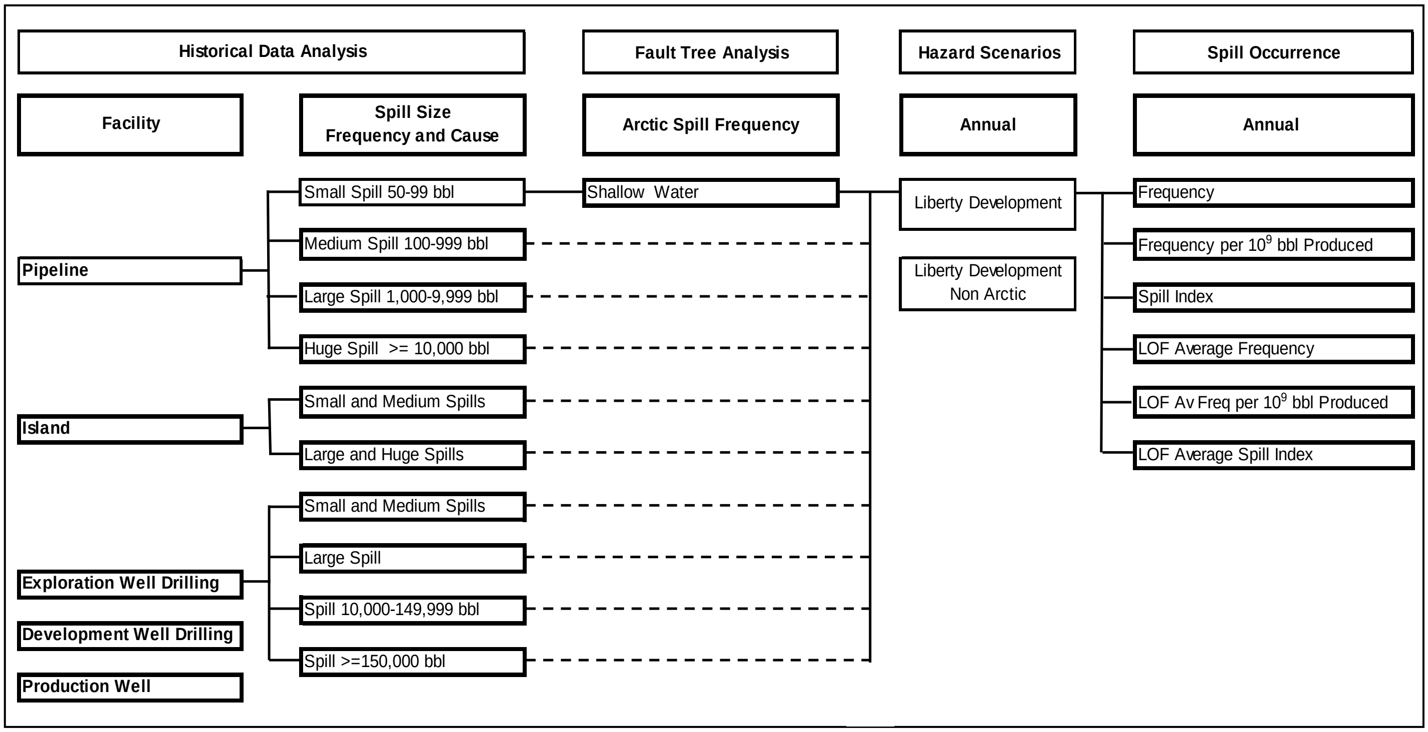


Figure 1.3: Calculation Flow Chart

Substantial spills, which are spills of 1,000 bbl or more (Large and Huge), are also identified. Fractional spill sizes were rounded up or down to the nearest whole number, with rounding up for any decimal ending in 5. For example, a spill of 99.5 bbl is taken as 100 bbl; 99.42 is taken as 99 bbl.

For well Loss of Well Control (LOWC) releases, one additional category of spill volumes is added: spills >= 150,000 bbl [4, 14].

In the interests of conciseness and clarity, the above main categories of spill sizes will generally be designated by either their name (small, medium, large, huge, substantial) or, when space is limited, by their acronym (S, M, L, H, and SB) in the balance of this report.

The proposed Liberty future development scenario as defined in the DPP [28], as well as a comparable non-Arctic (hypothetical) scenario were analyzed. The hypothetical non-Arctic scenario was developed for comparative purposes on the assumption that it was located with the same facility and water depth distribution as the Project in a non-Arctic area such as the GOM OCS. This permitted the comparison of the spill indicator results with and without the application of the fault tree analysis to account for Arctic effects.

Finally, for each of the scenarios considered, four principal oil spill occurrence indicators were generated, as follows:

- Oil spill frequency
- Oil spill frequency per billion barrels produced
- Spill index, which is the product of the oil spill frequency and the mean spill size (for the particular category under consideration)
- Life of Field Average Indicators for each of the 3 indicator types above.

1.8 Outline of Report

Following this brief introductory chapter, Chapter 2 summarizes the historical data assimilation and analysis detailed in [14, 15] and the PIP reliability analysis, Chapter 3 defines the Project development scenario used. Chapter 4 details the fault tree analysis to obtain Arctic oil spill frequencies. Chapter 5 summarizes the results of the oil spill occurrence indicator computations and their statistical distributions. Chapter 6 summarizes conclusions and recommendations including a section on the benefits of, and future recommendations derived from the present study. Extensive references and bibliography are given in the References.

CHAPTER 2

HISTORICAL DATA AND STATISTICS

2.1 Approaches to Historical Data

Historical data on offshore oil spills from pipelines, platforms, and Loss of Well Control (LOWC) were utilized as a numerical starting point for predicting Arctic offshore oil spill characteristics. Because statistics on Arctic offshore oil spills do not exist, oil spill statistics for temperate offshore locations were utilized, and subsequently analytically adjusted to represent the Project Arctic conditions. Although Arctic offshore exploration and production was started in the early 1970s, operations have been sporadic, with very few spills, so that a statistical history cannot be generated [12, 27].

The following data sets or databases were utilized:

(a) GOM and PAC OCS Pipeline Spills (1972-2010)
(b) GOM and PAC OCS Platform Spills (1972-2010)
(c) LOWC, GOM and North Sea Data (1980-2011)

The GOM and PAC pipeline and platform statistics categories of data are discussed in detail in the GOM and PAC update report [15], while the LOWC data are based on the results of an ongoing BOEM analysis [14], summarized in the recently published paper [4]. The contents of the balance of this chapter are restricted to the presentation of only those data sets utilized in the present study.

2.2 Pipeline Spills

The pipeline spill statistics generated in this update are basic spill statistics. First, the number of spills by size occurring for each causal category is given. Next, spill causes by two principal spill size categories are given, and transformed to spill frequencies per kilometer-year by dividing the number of kilometer-years exposure. And finally, the spill frequency distribution for spills of different size categories, by pipe diameter is determined. Table 2.1 summarizes the spill occurrences by size for each of the principal causes reported in the Bureau of Safety and Environmental Enforcement (BSEE) database. Both the exact spill size in barrels and the spill size distribution by each of the spill size categories are given in Table 2.1.

Table 2.2 gives the pipeline hydrocarbon spill statistics by cause. These statistics are given as the probability of occurrence per kilometer-year of operating pipeline. Thus, for example, approximately 13.44 spills per 100,000 km-yrs in the small and medium size category are projected. Of these, it is expected that approximately 6.7% or 0.90 per 100,000 km-yrs can be attributed to pipe corrosion.

Finally, Table 2.3 summarizes the pipeline spill statistics by spill size and pipe diameter.

Table 2.1
Analysis of GOM and PAC OCS Pipeline Spill Data for Causal Distribution and Spill Size (1972-2010)

Cause Classification	Number of Spills 1972-2010	Spill Size (bbl)													Number of Spills					
		1	2	3	4	5	6	7	8	9	10	11	12	13	S	M	L	H	SM	LH
CORROSION	4														1	2	1		3	1
External	1	80													1				1	
Internal	3	100	5000	414												2	1		2	1
THIRD PARTY IMPACT	20														2	7	8	3	9	11
Anchor Impact	13	19833	65	50	300	900	323	15576	2000	800	1211	2240	870	1500	2	5	4	2	7	6
Jackup Rig or Spud Barge	2	200	3200													1	1		1	1
Trawl/Fishing Net	5	4000	100	14423	4569	4533										1	3	1	1	4
OPERATION IMPACT	4														3		1		3	1
Rig Anchoring	1	50													1				1	
Work Boat Anchoring	3	50	5100	50											2		1		2	1
MECHANICAL	3															3			3	
Connection Failure	2	135	150													2			2	
Material Failure	1	210														1			1	
NATURAL HAZARD	28														9	15	4		24	4
Mud Slide	3	250	80	8212											1	1	1		2	1
Storm/ Hurricane	25	3500	1720	671	126	200	250	260	95	123	960	50	55	132	8	14	3		22	3
		50	75	100	862	67	108	69	108	56	1316	209	268							
UNKNOWN	3	119	190	188												3			3	
TOTALS	62														15	30	14	3	45	17

Table 2.2
Distribution and Frequency of Historical Pipeline Spills (1972-2010)

Cause Classification 1972-2010	Small and Medium Spills 50-999 bbl				Large and Huge Spills >=1,000 bbl			
	Historical Distribution (%)	Number of Spills	Exposure (km-years)	Frequency (spill per 10^5 km-year)	Historical Distribution (%)	Number of Spills	Exposure (km-years)	Frequency (spill per 10^5 km-year)
CORROSION	6.67	3		0.896	5.88	1		0.299
External	2.22	1		0.299	0	0		0
Internal	4.44	2		0.597	5.88	1		0.299
THIRD PARTY IMPACT	20.00	9		2.688	64.71	11		3.286
Anchor Impact	15.56	7		2.091	35.29	6		1.792
Jackup Rig or Spud Barge	2.22	1		0.299	5.88	1		0.299
Trawl/Fishing Net	2.22	1		0.030	23.53	4		1.195
OPERATION IMPACT	6.67	3		0.896	5.88	1		0.299
Rig Anchoring	2.22	1	334,764	0.299			334,764	
Work Boat Anchoring	4.44	2		0.597	5.88	1		0.299
MECHANICAL	6.67	3		0.896				
Connection Failure	4.44	2		0.597				
Material Failure	2.22	1		0.299				
NATURAL HAZARD	53.33	24		7.169	23.53	4		1.195
Mud Slide	4.44	2		0.597	5.88	1		0.299
Storm/ Hurricane	48.89	22		6.572	17.65	3		0.896
UNKNOWN	6.67	3		0.896				
TOTALS	100.00	45		13.442	100.00	17		5.078

Table 2.3
GOM and PAC OCS Pipeline Spills Statistics Summary (1972-2010)

GOM and PAC OCS Pipeline Spills, Categorized 1972-2010			Spill Statistics (Number of Spills)	Exposure (km-years)	Frequency (spills per 10^5 km-years)
By Pipe Diameter		< = 10"	38	222,716	17.062
		> 10"	24	112,047	21.420
By Spill Size		Small <100 bbl	15	334,764	4.481
		Medium 100 - 999 bbl	30	334,764	8.962
		Large 1000 - 9999 bbl	14	334,764	4.182
		Huge >=10000 bbl	3	334,764	0.896
By Diameter, By Spill Size	<=10"	Small <100 bbl	11	222,716	4.939
		Medium 100 - 999 bbl	19	222,716	8.531
		Large 1000 - 9999 bbl	7	222,716	3.143
		Huge >=10000 bbl	1	222,716	0.449
	> 10"	Small <100 bbl	4	112,047	3.570
		Medium 100 - 999 bbl	11	112,047	9.817
		Large 1000 - 9999 bbl	7	112,047	6.247
		Huge >=10000 bbl	2	112,047	1.785

2.3 Pipe in Pipe (PIP) Spills

Tables 2.4 and 2.5 give the derivation of PIP loss of containment frequencies for the GOM and PAC OCS conditions (same as historical conditions). The frequencies given are per 10^5 km-yr. Table 2.4, for Small and Medium spills, gives a PIP loss of containment (LOC) frequency of 4.449 from a historical single pipe frequency of 13.442. Table 2.5, for Large and Huge spills, gives a PIP LOC frequency of 1.105 from a historical single pipe frequency of 5.078.

Tables 2.4 and 2.5 give both the LOC and LOFn frequencies. LOC occurs when both pipes fail so that oil spills into the ocean environment. Loss of Function (LOFn) occurs when either pipe fails as it initiates a shutdown of the pipeline, so that it does not function.

Table 2.6 gives the derived values for the present study. For example, if there were 30 data points [15], the upper 90% (or high value) was the third highest, while the lower 90% (or low value) was selected as the third lowest, which was invariably zero, as numerous years had no spills. Next, the third highest value was divided by the historical value to get the high factor. Finally, the high factor was used to obtain the high value by multiplying the applicable historical frequency by this high factor. The mode is calculated from the triangular distribution relationship [31], as follows:

Mode = 3 x Historical - High - Low **(2.1)**

Table 2.4
PIP Small and Medium Spill Frequency Derivation

Cause Classification 1972-2010	Small and Medium Spills 50-999 bbl							
	Historical Distribution (%)	Historical Frequency (spill per 10^5km-year)	NPS 12 Frequency (spill per 10^5km-year)	NPS 16 Frequency (spill per 10^5km-year)	Loss of Containment (LOC) Frequency (spill per 10^5km-year) PIP Pipeline	Loss of Containment (LOC) Frequency Distribution (%) PIP Pipeline	Loss of Function (LOFn) Frequency (spill per 10^5km-year) PIP Pipeline	PIP Pipeline Frequency Change Explanation
CORROSION	6.67	0.896	0.627	0.358	< 0.001	0.00	0.985	LOC due to internal NPS12 and external NPS16 per km-yr
External	2.22	0.299	0.030	0.299	< 0.001	0.00	0.329	90% reduced external corrosion on NPS12 due to inert annulus
Internal	4.44	0.597	0.597	0.060	< 0.001	0.00	0.657	90% reduced internal corrosion of NPS16 due to inert annulus
THIRD PARTY IMPACT	20.00	2.688	0.717	2.688	0.597	13.43	3.405	
Anchor Impact	15.56	2.091	0.418	2.091	< 0.001	0.00	2.509	80% reduction in NPS12 failure if external NPS16 occurs
Jackup Rig or Spud Barge	2.22	0.299	0.299	0.299	0.597	13.43	0.597	Both pipes fail sequentially if impacted P(LOC)=P(NPS16)+P(NPS12), conservatively evaluated with an "OR" gate.
Trawl/Fishing Net	2.22	0.299	0.000	0.299	0.000	0.00	0.299	Trawl/Fishing Net will only fail external NPS16 pipe
OPERATION IMPACT	6.67	0.896	0.209	0.896	0.209	4.70	1.105	
Rig Anchoring	2.22	0.299	0.149	0.299	0.149	3.36	0.448	LOC occurs 50% of NPS16 failure. P(LOC) = 0.5P(NPS16)
Work Boat Anchoring	4.44	0.597	0.060	0.597	0.060	1.34	0.657	LOC is 10% of NPS 16. P(LOC) = 0.1P(NPS16)
MECHANICAL	6.67	0.896	0.896	0.896	0.000	0.00	1.792	
Connection Failure	4.44	0.597	0.597	0.597	< 0.001	0.00	1.195	LOC only if both occur so P(LOC) is product of the independent pipe LOCs.
Material Failure	2.22	0.299	0.299	0.299	< 0.001	0.00	0.597	LOC only if both occur so P(LOC) is product of the independent pipe LOCs
NATURAL HAZARD	53.33	7.169	7.169	7.169	3.346	75.20	14.338	
Mud Slide	4.44	0.597	0.597	0.597	0.060	1.34	1.195	LOC is 10% of NPS 16. P(LOC) = 0.1P(NPS16)
Storm/ Hurricane	48.89	6.572	6.572	6.572	3.286	73.86	13.144	LOC is 50% of NPS 16. P(LOC) = 0.5P(NPS16)
UNKNOWN	6.67	0.896	0.896	0.896	0.297	6.67	0.896	Adjusted to be the same as Historical %
TOTALS	100.00	13.442	10.514	12.905	4.449	100.00	22.523	

Table 2.5
PIP Large and Huge Spill Frequency Derivation

Cause Classification 1972-2010	Large and Huge Spills >=1,000 bbl							
	Historical Distribution (%)	Historical Frequency (spill per 10^5km-year)	NPS 12 Frequency (spill per 10^5km-year)	NPS 16 Frequency (spill per 10^5km-year)	Loss of Containment (LOC) Frequency (spill per 10^5km-year) PIP Pipeline	Loss of Containment (LOC) Frequency Distribution (%) PIP Pipeline	Loss of Function (LOFn) Frequency (spill per 10^5km-year) PIP Pipeline	PIP Pipeline Frequency Change Explanation
CORROSION	5.88	0.299	0.597	0.030	< 0.001	0.00	0.896	LOC due to internal NPS12 and external NPS16 per km-yr
External	0.00	0.000	0.000	0.000	0.000	0.00	0.000	
Internal	5.88	0.299	0.299	0.030	< 0.001	0.00	0.329	90% reduced internal corrosion of NPS16 due to inert annulus
THIRD PARTY IMPACT	64.71	3.286	0.657	3.286	0.597	54.05	3.943	
Anchor Impact	35.29	1.792	0.358	1.792	< 0.001	0.00	2.151	80% reduction in NPS12 failure if external NPS16 occurs
Jackup Rig or Spud Barge	5.88	0.299	0.299	0.299	0.597	54.05	0.597	Both pipes fail sequentially if impacted so P(LOC)=P(NPS16)+P(NPS12), conservatively evaluated with an "OR" gate.
Trawl/Fishing Net	23.53	1.195	0.000	1.195	0.000	0.00	1.195	Trawl/Fishing Net will only fail external NPS16 pipe
OPERATION IMPACT	5.88	0.299	0.030	0.299	0.030	2.70	0.329	
Rig Anchoring	0.00	0.000	0.000	0.000	0.000	0.00	0.000	
Work Boat Anchoring	5.88	0.299	0.030	0.299	0.030	2.70	0.329	LOC is 10% of NPS 16. P(LOC) = 0.1P(NPS16)
MECHANICAL	0.00	0.000	0.000	0.000	0.000	0.00	0.000	
Connection Failure	0.00	0.000	0.000	0.000	0.000	0.00	0.000	
Material Failure	0.00	0.000	0.000	0.000	0.000	0.00	0.000	
NATURAL HAZARD	23.53	1.195	1.195	1.195	0.478	43.24	2.390	
Mud Slide	5.88	0.299	0.299	0.299	0.030	2.70	0.597	LOC is 10% of NPS 16. P(LOC) = 0.1P(NPS16)
Storm/ Hurricane	17.65	0.896	0.896	0.896	0.448	40.54	1.792	LOC is 50% of NPS 16. P(LOC) = 0.5P(NPS16)
UNKNOWN	0.00	0.000	0.000	0.000	0.000	0.00	0.000	
TOTALS	100.00	5.078	2.479	4.809	1.105	100.000	7.557	

Table 2.6
PIP Pipeline Spill Frequency Distribution Properties

GOM and PAC OCS Pipeline Spills, Categorized 1972-2010 NPS > 10"	Frequency Unit	Low Factor	High Factor	Historical	Low	Mode	High
Small (50-99 bbl)	Spill per 10^5 km-years	0	2.81	1.182	0	0.224	3.320
Medium (100-999 bbl)	Spill per 10^5 km-years	0	2.81	3.249	0	0.617	9.130
Large(1,000-9,999 bbl)	Spill per 10^5 km-years	0	2.81	1.360	0	0.258	3.821
Huge (=>10,000 bbl)	Spill per 10^5 km-years	0	2.81	0.388	0	0.074	1.092

2.4 Platform Spills

The primary island or platform spill statistical information required is the spill frequency distribution by different causes and spill sizes, and the spill rate per well year. The historical data used here is that given for platforms, but modified later specifically for Arctic effects on the Liberty island. Table 2.7 summarizes the spill size distribution among the principal reported causes. As can be seen, the major cause attributable to over 50% of the spills is that of Hurricanes. Also, hurricanes caused many of the larger spill volumes, giving the largest spill volume total. The largest single spill, however, is the tank failure which caused a spill of nearly 10,000 barrels [15]. From a review of the platform spill data [15], it can be seen that platform spills as defined here, are limited to those caused from process, storage, or transfer equipment losses of containment, so that they do not include LOWCs, which are dealt with subsequently here in Section 2.5.

Table 2.7
Analysis of GOM and PAC OCS Platform Spill Data by Causal Distribution and Spill Size (1972-2010)

Cause Classification	Number of Spills 1972-2010	Spill Size (bbl)															Number of Spills					
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	S	M	L	H	SM	LH
Equipment Failure	36	9,935	130	50	300	77	104	321	60	95	83	118	210	50	228	600	19	16	1		35	1
		77	320	200	77	107	50	643	50	58	52	50	55	400	55	280						
		50	75	435	62	127	50															
Human Error	13	95	120	286	58	400	100	60	64	100	600	170	60	264			5	8			13	
Collision	1	119																1			1	
Weather	7	7,000	239	100	1,500	80	214	100									1	4	2		5	2
Hurricane	67	1,456	66	497	741	52	55	264	106	66	510	141	242	204	195	325	27	36	4		63	4
		380	130	110	195	307	71	159	94	51	101	51	50	51	97	614						
		1,572	77	2,000	181	188	101	1,494	67	659	166	53	51	63	528	59						
		133	51	54	685	103	62	205	52	513	200	550	140	50	127	70						
		194	170	196	72	58	54	62														
TOTALS	124																52	65	7		117	7

The spill rate data, given here using an exposure variable of production well-years [15], is shown in Table 2.8, again, by causal distribution as well as for two broad spill size categories of small and medium spills and large and huge spills. Here, it becomes immediately evident that the largest spill potential in terms of volume is attributable to hurricanes, which are responsible for roughly 57% of the large and huge spills. Finally, Table 2.9 gives the fault tree analysis statistical input data derived from Table 2.8. It should be noted that for platforms, only the two spill size categories given in Table 2.9 have been assessed [15].

Table 2.8
Causal and Spill Size Distribution of GOM and PAC OCS Platform Spills (1972-2010)

Cause Classification 1972 – 2010 (no LOWC)	Small and Medium Spills 50-999 bbl				Large and Huge Spills >=1,000 bbl			
	Historical Distribution (%)	Number of Spills	Exposure (well-years)	Frequency (spill per 10^4well-year)	Historical Distribution (%)	Number of Spills	Exposure (well-years)	Frequency (spill per 10^4well-year)
Equipment Failure	29.91	35	245,486	1.426	14.29	1	245,486	0.041
Human Error	11.11	13		0.530				
Collision	0.85	1		0.041				
Weather	4.27	5		0.204	28.57	2		0.081
Hurricane	53.85	63		2.566	57.14	4		0.163
TOTALS	100.00	117		4.766	100.00	7		0.285

Table 2.9
Platform Historical Spill Frequency Variability (1972-2010)

Spill Size	Frequency Unit	Low Factor	High Factor	Historical	Low	Mode	High
Small and Medium Spills (50-999 bbl)	Spill per 10^4 well-year	0	3	4.766	0.000	0.000	14.298
Large and Huge Spills (>= 1,000 bbl)	Spill per 10^4 well-year	0	3	0.285	0.000	0.000	0.855

2.5 Loss of Well Control (LOWC) Data

The development scenarios considered under this study include both the drilling of exploratory and development wells, and the production wells producing oil. In earlier studies [18, 10], to identify a basis for the non-Arctic historical oil well blowout statistics, a number of sources were reviewed including the Northstar and Liberty oil development project reports [51], a study by Scandpower giving the cumulative distribution function for oil blowout releases [54, 55], as well as the book by Per Holand entitled “Offshore Blowouts” [31], which gives risk analysis data from the SINTEF worldwide offshore blowout database [30].

However, the recent work for BOEM on LOWC statistics [4, 14] was used as the principal data source for the present work. Table 2.10 gives a summary of the historical data analysis for production wells and the drilling of exploratory and development wells based on GOM data. The combination of these statistics together with the cumulative distribution function for LOWC release volumes given in [4, 20], results in the LOWC spill volume frequency distribution as summarized in Table 2.11.

Table 2.10
Well LOWC Historical Spill Size Distribution (1980 - 2011)

Event	Frequency Unit	Small and Medium Spills 50-999 bbl	Large Spills 1,000-9,999 bbl	Small, Medium, and Large Spills 50-9,999 bbl	Spills 10,000-149,999 bbl	Spills >=150,000 bbl	All Spills
		Historical Frequency 1980-2011 BSEE Data					
Production Well	spills per 10^4 well-year	0.028	0.011	0.039	0.007	0.005	0.051
Exploration Well Drilling	spills per 10^4 wells	1.330	0.539	1.869	0.350	0.217	2.436
Development Well Drilling	spills per 10^4 wells	0.283	0.115	0.398	0.075	0.046	0.519

Table 2.11
Well LOWC Historical Spill Probability and Size Variability (1980 - 2011)

Spill Size	Event	Frequency Unit	Low Factor	High Factor	Frequencies			
					Historical	Low	Mode	High
Small and Medium Spills 50-999 bbl	Production Well	spill per 10^4 well-year	0.448	1.545	0.028	0.012	0.028	0.043
	Exploration Well Drilling	spill per 10^4 wells	0.439	2.036	1.330	0.584	0.698	2.708
	Development Well Drilling	spill per 10^4 wells	0.437	1.760	0.283	0.124	0.227	0.498
Large Spills 1000-9,999 bbl	Production Well	spill per 10^4 well-year	0.448	1.545	0.011	0.005	0.011	0.017
	Exploration Well Drilling	spill per 10^4 wells	0.439	2.036	0.539	0.237	0.283	1.097
	Development Well Drilling	spill per 10^4 wells	0.437	1.760	0.115	0.050	0.092	0.202
Small, Medium and Large Spills 50-9,999 bbl	Production Well	spill per 10^4 well-year	0.448	1.545	0.039	0.017	0.039	0.060
	Exploration Well Drilling	spill per 10^4 wells	0.439	2.036	1.869	0.821	0.981	3.805
	Development Well Drilling	spill per 10^4 wells	0.437	1.760	0.398	0.174	0.320	0.700
Spill 10,000-149,999 bbl	Production Well	spill per 10^4 well-year	0.448	1.545	0.007	0.003	0.007	0.011
	Exploration Well Drilling	spill per 10^4 wells	0.439	2.036	0.350	0.154	0.184	0.713
	Development Well Drilling	spill per 10^4 wells	0.437	1.760	0.075	0.033	0.060	0.131
Spill >=150,000 bbl	Production Well	spill per 10^4 well-year	0.448	1.545	0.005	0.002	0.005	0.007
	Exploration Well Drilling	spill per 10^4 wells	0.439	2.036	0.217	0.095	0.114	0.442
	Development Well Drilling	spill per 10^4 wells	0.437	1.760	0.046	0.020	0.037	0.081

2.6 Arctic Effects Statistics

2.6.1 General Approaches to the Quantification of Arctic Effects

There are essentially two main categories of Arctic effects; namely, those that are unique to the Arctic, such as marine ice effects, and those that are the same types of effects as those in temperate areas, but occurring with a different frequency, such as fishing net impacts on subsea pipelines. The first will be termed “unique” effects; the second, “modified” effects. Modified Arctic effects are dealt with in conjunction with the fault tree analysis described in Chapter 4. Only those Arctic effects or hazards unique to the Arctic, and potentially having a historical occurrence database, such as ice gouging, are discussed in the balance of this section.

2.6.2 Ice Gouging

Ice gouging occurs when a moving ice feature contacts the sea bottom and penetrates into it, generally as it moves against a positive sea bottom slope. The ice feature can be a multiyear ridge, a hummock, or ice rafting formation. Various studies have been conducted on the frequency and depth distribution of ice gouges [2, 11, 25, 36, 42, 47, 62], and a number of assessments of the likelihood of resultant subsea pipeline failure [44, 62] have also been carried out. Pipeline failure frequencies at different water depth regimes as a result of ice gouging in this study have been estimated on the basis of the historical ice gouge characteristics [2, 29] together with an analytical assessment [2, 44, 62] of their likelihood to damage a pipeline.

According to Weeks [65, 66], a relationship between the expected probability of pipeline failure from ice gouging and ice gouging local characteristics may be expressed as follows:

$$N = e^{-kx} H_S \cdot F \cdot T \cdot L_P \cdot \sin\Phi \qquad \textbf{(2.2)}$$

Where:

N	=	Number of pipeline failures at burial depth of cover x (meters)
k	=	Inverse of mean scour depth (m^{-1})
x	=	Depth of cover (m)
H_S	=	Probability of pipeline failure given ice gouge impact or hit
F	=	Scour flux per km-yr
T	=	Exposure time (years)
L_P	=	Length of pipeline (km)
Φ	=	Gouge orientation (degrees) from pipeline centerline

The following basis was used for the gouging frequency calculations given in Table 2.12:

- Section 7.2.1 of the DPP [28] gives a minimum depth of 2.29 m, a maximum depth of 3.35m, and a mode of 3.05m.
- Vaudrey [63] formula used: $N = e^{-kx} H_S \cdot Hs \cdot F \cdot \sin\Phi$

- Liedersdorf [36] gives mean scour depth of 0.2m, flux of 2/km-yr, and conditional single pipeline failure probability of 0.83.
- Vaudrey [63] gives an average gouge depth of 0.43 ft or 0.13 m (Table 6.4, page 48 [63]). The greater gouge depth of 0.2 m is used here.
- PIP pipeline failures from gouging were estimated to be as 50% of single wall failures.

Table 2.12
Liberty Pipeline Ice Gouging Frequency Calculation

Value	Depth of cover (m)	Inverse of Gouge depth (per m)	Conditional Pipeline Failure Probability	Gouge flux (per km-year)	Gouge Orientation (degrees)	Value	Number of Single Wall Pipeline Failures	Number of PIP Pipeline Failures	PIP Small Spills	PIP Medium Spills	PIP Large Spills	PIP Huge Spills
							(per 10^5 km-year)					
	X	K (1/mean depth)	Hs	F	Φ		Ns	N	20%	20%	50%	10%
MAX	3.35	5	0.83	2	45	MIN	0.0062	0.0031	0.0006	0.0006	0.0016	0.0003
MODE	3.05	5	0.83	2	45	MODE	0.0280	0.0140	0.0028	0.0028	0.0070	0.0014
MIN	2.29	5	0.83	2	45	MAX	1.2500	0.6250	0.1250	0.1250	0.3125	0.0625

2.6.3 Strudel Scour

When water collects on top of the landfast ice, generally from rivers running into the Arctic seas, and drains through a hole in the ice, its hydrodynamic effect on the ocean floor below forms a depression which is called a strudel scour. Numerous studies have been conducted on strudel scour [25, 33, 35, 48], so that a prediction on the number of strudel scours per unit area can be made on the basis of historical data. Strudel scours are restricted to shallower water such as the Liberty location.

The following basis was used for the Liberty strudel scour frequency calculation given in Table 2.13:

- Upstream Technology Group [62], T5.9, page 120, gives a basis for the calculations used here. Inputs are given for 1.8 mile Base Case, and converted here to unit per km.
- In addition as for ice gouging, it is estimated PIP pipeline failures are 50% of single wall pipeline failures.
- Spill size distribution is weighted to large spills [62] and P2.12 of Bercha International Inc., OCS Study MMS 2008-035 [16].

Table 2.13
Liberty Pipeline Strudel Scour Frequency Calculation

Value	Number of Critical Scours	Number of Scours	Conditional Pipeline Failure Probability	Number of Single Wall Pipeline Failures	Number of PIP Pipeline Failures	PIP Small Spills	PIP Medium Spills	PIP Large Spills	PIP Huge Spills
	(per 10^5 km-year)			(per 10^5 km-year)					
				100%	100%	20%	20%	50%	10%
MIN	1.60	0.5523	0.02	0.0110	0.0055	0.0011	0.0011	0.0028	0.0006
MODE	3.40	1.1736	0.02	0.0235	0.0117	0.0023	0.0023	0.0059	0.0012
MAX	20.00	6.9037	0.02	0.1381	0.0690	0.0138	0.0138	0.0345	0.0069

2.6.4 Upheaval Buckling

Upheaval buckling occurs in a pipeline as a result of its thermal expansion which causes it to buckle upwards to accommodate the extra length generated from thermal effects. Unfortunately, there appears to be no defensible analytical method for calculating the probability of upheaval buckling of Arctic subsea pipelines in general. Accordingly, upheaval buckling has been taken simply as a percentage of the strudel scour effects quantified in previous work [16, 17]. Assuming that upheaval buckling occurs 20% as often as strudel scour, the distribution shown in Table 2.14 can be derived. Upheaval buckling is expected to be independent of water depth; accordingly, the same values have been used for each water depth range. Other Arctic effects have been incorporated on the basis of values used in preceding studies [16, 17].

Table 2.14
Summary of PIP Pipeline Arctic Unique Effect Inputs

ARCTIC	Spill Size	PIP LOC Frequency Increment per 10^5 km-year			REASON
		Min	Mode	Max	
Ice Gouging	S	0.0006	0.0028	0.1250	Ice Gouge Failure Rate calculated using exponential failure distribution for 3.05 m cover, 0.2 m average gouge depth, 2 gouges per km-yr flux.
	M	0.0006	0.0028	0.1250	
	L	0.0016	0.0070	0.3125	
	H	0.0003	0.0014	0.0625	
Strudel Scour	S	0.0011	0.0023	0.0138	Average Frequency of 3.4 critical scours/10^5 km-yr and 100 ft of bridge length with 2% conditional P/L failure probability. The same spill size distribution as above.
	M	0.0011	0.0023	0.0138	
	L	0.0028	0.0059	0.0345	
	H	0.0006	0.0012	0.0069	
Upheaval Buckling	S	0.0002	0.0005	0.0028	The Failure Frequency is 20% of that of Strudel Scour.
	M	0.0002	0.0005	0.0028	
	L	0.0006	0.0012	0.0069	
	H	0.0001	0.0002	0.0014	
Thaw Settlement	S	0.0001	0.0002	0.0014	The Failure Frequency is 10% of that of Strudel Scour.
	M	0.0001	0.0002	0.0014	
	L	0.0003	0.0006	0.0035	
	H	0.0001	0.0001	0.0007	
Other Arctic	S	0.0002	0.0006	0.0143	To be assessed as 10% of all arctic effects.
	M	0.0002	0.0006	0.0143	
	L	0.0005	0.0015	0.0357	
	H	0.0001	0.0003	0.0071	

2.6.5 Thaw Settlement

Thaw settlement occurs when a permafrost lens or formation over which the pipeline was installed melts as a result of the heat generated by the pipeline and ceases to support the pipeline so that the pipeline overburden loads the pipeline and causes it to deflect downwards [39]. Thaw settlement LOC for the PIP has been taken at 10% of the probability of strudel scours.

2.6.6 Summary of Pipeline Arctic Unique Effects

Table 2.14 summarizes Arctic unique effects for the Liberty PIP pipeline, in accordance with the discussion on the derivation of these effects given in the above subsections. In addition, distribution of the effects among four spill size categories is given.

2.6.7 Platform Arctic Unique Effects

This section covers potential causes of platform spills (other than LOWC'S, which are included under wells) that are uniquely associated with the Arctic, are ice forces and low temperature effects. Although the possibility that ice forces will cause spills varies greatly from facility to facility, some broad assumptions have been made in regard to the likelihood of spills being caused by ice force effects. Specifically, it was assumed that the platforms are designed for a 10,000 year return period with a reliability level of 99%, in accordance with the ISO 19906 Arctic Structures, Reliability, *Section 7.2.2.3* [34]. That is, 1% of the time, the 10,000 year return period ice force can cause a spill. Further, it was assumed that 85% of spills so caused are small and medium, with large and huge spills associated with 15%. In regards to facility low temperature, a percentage of historical facility releases was taken. Specifically, it was assumed that the facility low temperature effects will cause small and medium spills at a rate of 6% of that of total historical small and medium spills, and large and huge spills at a rate of 3% of that associated with large and huge historical spills. Finally, other Arctic unique causes were assumed to constitute another 10% of the sum of the above spill rates in each of the spill categories. Table 2.15 summarizes the resultant Arctic unique effect frequencies derived for platforms on a per well-year exposure basis.

Table 2.15
Summary of Platform Unique Arctic Effect Inputs

Arctic Unique Cause	Size	Min	Mode	Max	Reason
Ice Force	SM	0.001	0.009	0.085	Assumed 10,000 year return period ice force causes spill 1% of occurrences (99% reliability). 85% of the spills are SM as due to ride-up impact only.
	LH	0.000	0.002	0.015	
Facility Low Temperature	SM	0.043	0.086	0.128	Assumed fraction of Historical Equipment Failure release frequency with 6% for SM and 1% for LH spill sizes.
	LH	0.000	0.000	0.001	
Other Arctic	SM	0.004	0.009	0.021	10% of sum of above.
	LH	0.000	0.000	0.002	

2.7 Historical Spill Size Distribution

Tables 2.16, 2.17, and 2.18 give the historical spill volume distributions obtained from available historical data. In each case, the mode was taken as the historical average spill size in each spill size category, while the high and low values were taken to be the upper and lower bounds of each spill size category. The high values for Huge spills were chosen on the basis of the upper 90% confidence interval spill volumes in the databases.

Table 2.16
Historical Pipeline Spill Volume Distribution Parameters

Spill Size	Small Spills 50-99 bbl			Medium Spills 100-999 bbl			Large Spills 1,000-9,999 bbl			Huge Spills =>10,000 bbl		
Spill Expectation	Low	Mode	High	Low	Mode	High	Low	Mode	High	Low	Mode	High
Pipeline Diameter <= 10" Spill	50	58	99	100	226	999	1,000	4,436	9,999	10,000	14,423	20,000
Pipeline Diameter > 10" Spill	50	58	99	100	387	999	1,000	3,932	9,999	10,000	17,705	20,000

Table 2.17
Historical Platform Spill Volume Distribution Parameters

Spill Size	Small and Medium Spills 50-999 bbl			Large and Huge Spills =>1,000 bbl		
Spill Expectation	Low	Mode	High	Low	Mode	High
Platform Spill	50	158	999	1,000	6,130	10,000

Table 2.18
Historical LOWC Spill Volume Distribution Parameters

Spill Size	Small and Medium Spills 50-999 bbl			Large Spills 1,000-9,999 bbl			Spills 10,000-149,999 bbl			Spills =>150,000 bbl		
Spill Expectation	Low	Mode	High	Low	Mode	High	Low	Mode	High	Low	Mode	High
Well Spill	50	500	999	1,000	4,500	9,999	10,000	20,000	150,000	150,000	200,000	1,000,000

CHAPTER 3

LIBERTY DEVELOPMENT PROJECT INFORMATION

3.1 Liberty Project Summary

Information on the Liberty Development Project (the Project) is largely based on the Liberty Development Plan by Hilcorp Alaska, Inc. [28].

The geographical study area is the Beaufort Sea Outer Continental Shelf (OCS) as generally illustrated in Figure 3.1. Of interest is the offshore area from landfall to approximately the 6 m (20 ft) isobath. This area is selected due to the proposed future oil and gas development within it [28].

The Liberty Development will be a self-contained offshore drilling and production facility located on an artificial gravel island with a pipeline to shore. The island will be built about 9 km (5.6 mi) offshore in Foggy Island Bay of the Beaufort Sea OCS in approximately 6 m of water, about 3 km (2 mi) west of the Tern Island shoal.

Infrastructure and facilities necessary to drill wells and process and export approximately 60,000 to 70,000 BPD to shore will be installed on the island. There will be slots for 16 wells, which include accommodations for 5-8 producing wells, 4-6 water and/or gas injection wells, and up to two disposal wells at surface wellhead spacing of 15 feet between wellheads. Produced gas will be used for fuel gas, artificial lift, and re-injection into the reservoir. Seawater will be treated and used to waterflood the Liberty reservoir. Following waterflood breakthrough, produced water will be commingled with seawater and re-injected for reservoir support. A nominal 12 inch sales oil pipeline inside 16 inch outer pipe will transport crude oil to the Badami Sales Oil Pipeline. The offshore portion of the pipeline will be approximately 9 km (5.6 mi) long, and the overland portion will be approximately 2.4 km (1.5 mi) long to the Badami pipeline tie-in point as shown in Figure 3.2.

Associated onshore facilities to support the project will include use of permitted water sources, construction of gravel pads to support the pipeline tie-in location and Badami ice road crossing, ice roads and ice pad construction, hovercraft shelter, small boat dock, and development of a gravel mine site west of the Kadleroshilik River. In addition, existing North Slope infrastructure will be used to support this project.

The Liberty Drilling and Production Island (LDPI) will be constructed to recover reserves from two federal leases (OCS-71585) in Foggy Island Bay in the Beaufort Sea, northeast of the Prudhoe Bay Unit, and east of the Duck Island Unit. The LDPI will be located approximately 8 km (5 mi) north of the Kadleroshilik River and 7.3 miles southeast of the SDI. The LDPI will be built in approximately 6 m (19 ft) of water, elevation of the top of the LDPI will be +4.6 m (15 ft) Mean Low Water (MLLW). The LDPI location is shown in Figure 3.2.

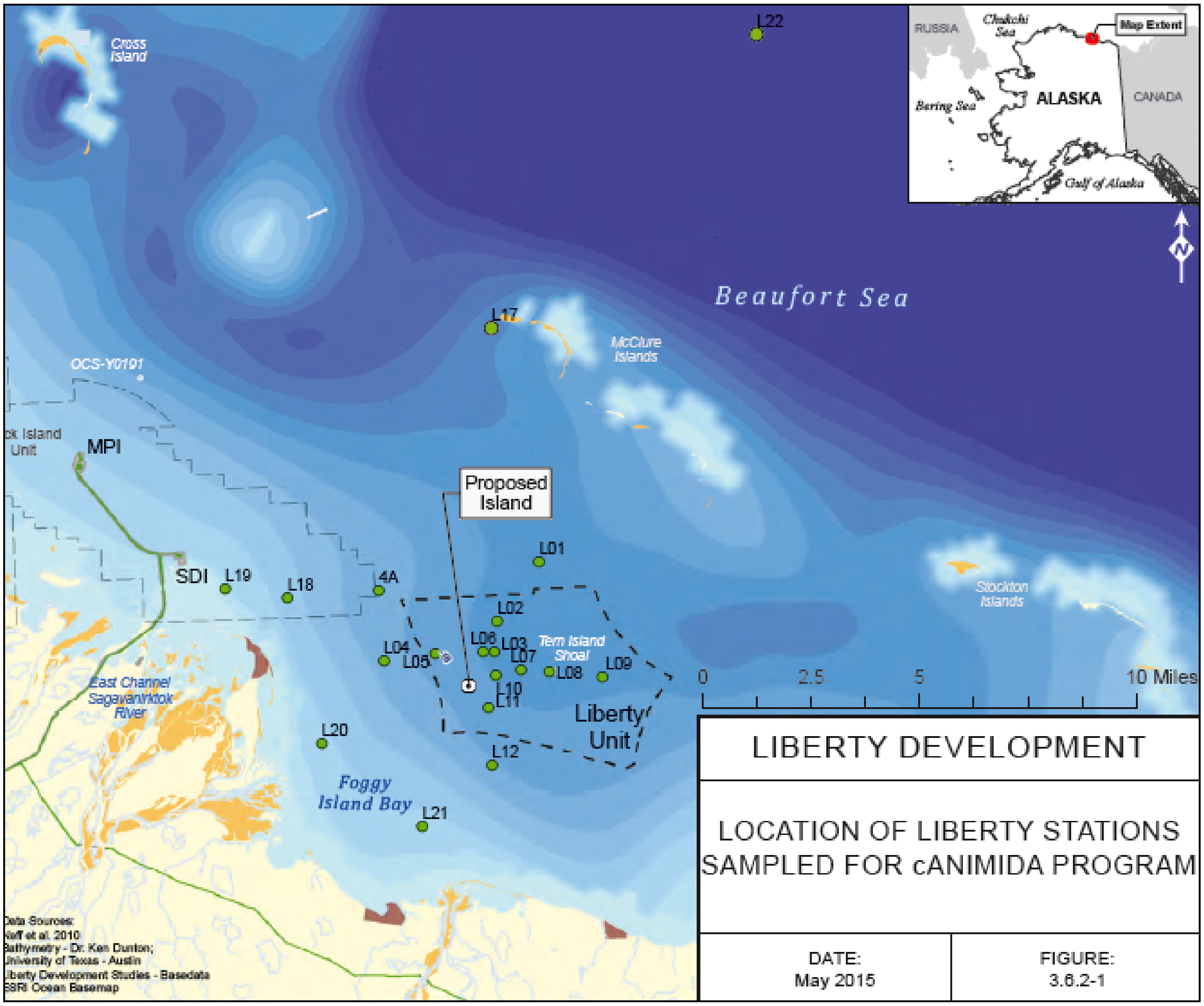


Figure 3.1: Project Location Map [28]

The Project and its principal functional Project components described herein and analyzed in the present study are:

- The Liberty drilling and production island (LDPI)
- Oil and gas wells
- The subsea pipeline
- The Project as integrated

The project life cycle, following hearings and approvals, spans approximately 25 years, as described in Section 3.3.6.

Salient details on the Project and its components follow.

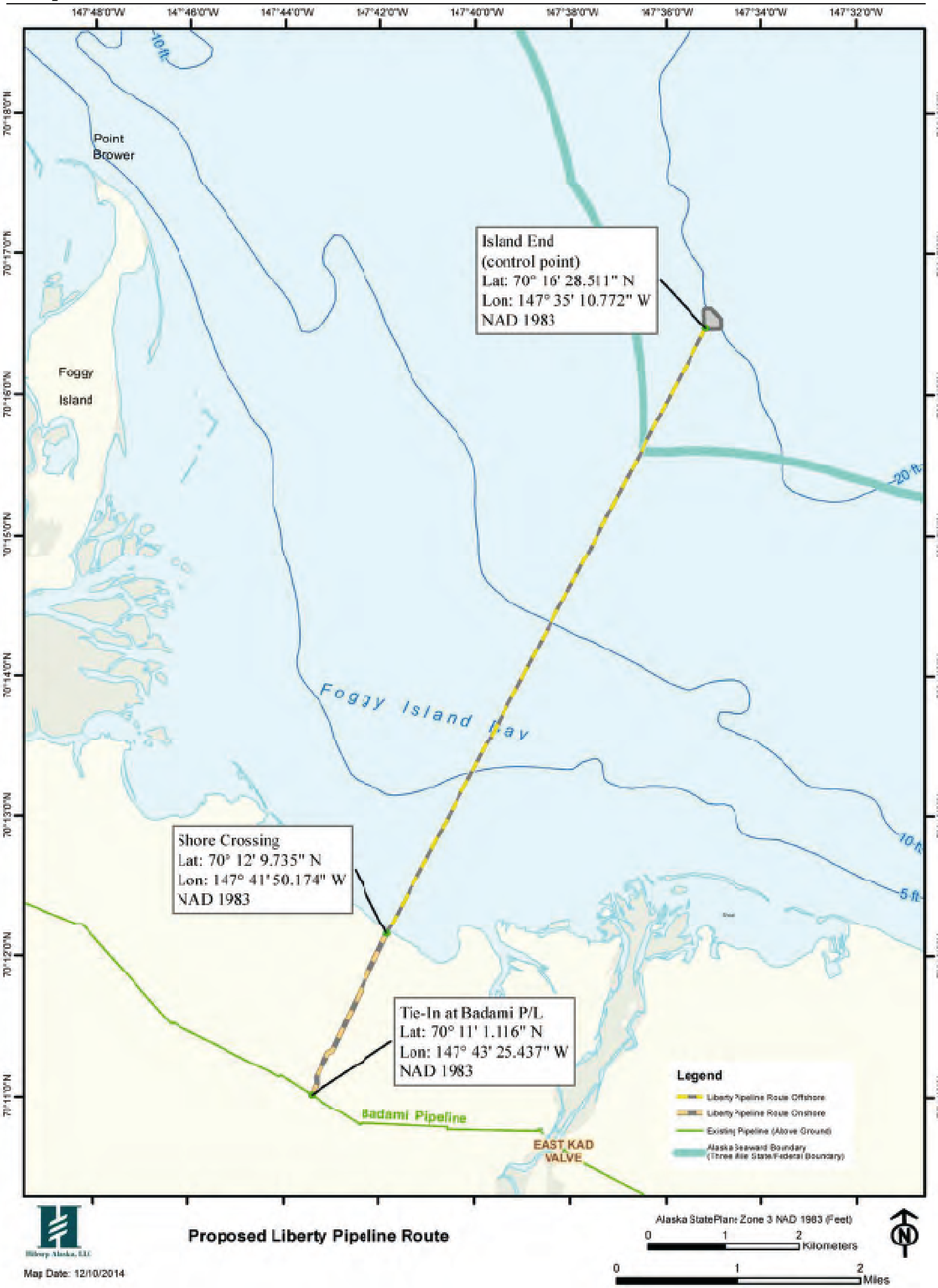


Figure 3.2: Project Detailed Location Map [28]

3.2 Liberty Drilling and Production Island (LDPI)

This section gives a brief description of the LDPI and its facilities to facilitate a general understanding of the report; details are given in Sections 6 and 9 in [28]. As was shown n Figure 3.2, the Liberty Drilling and Production Island (LDPI) will be will be an artificial gravel island located approximately 8 km (5 mi) north of the Kadleroshilik River and 7.3 miles southeast of the SDI as was shown in Figure 3.2. The LDPI will be built in approximately 6 m (19 ft) of water, elevation of the top of the LDPI will be +4.6 m (15 ft) Mean Low Water (MLLW).

A conceptual rendering of the LDPI is shown in Figure 3.3. As can be seen, it is semi-rectangular in shape, with sloped sides armored to protect it from ice scour and impact. Figure 3.4 shows a plan view of the island giving principal dimensions and locations of the main facilities.

Figure 3.3: Rendering of LDPI [28]

As can be seen in Figures 3.3 and 3.4, oil storage (Area 19) and oil production (Area 12) are located in the southern and central parts of the island, where there is less potential for ice or storm effect incursions. The relief well (Area 2) is located away from the production area as it needs to remain intact in case of a well control incident. Oil spills from the island facilities are limited by containment berms surrounding tankage and process facilities, location of containment well within island protective perimeter, and island stability including protection against ice incursions and loading. Table 3.1 lists more detailed information on each area shown in Figure 3.4.

Figure 3.5 gives a simplified block diagram of the production process. Basically, oil produced from the wells is metered, the water and gas are separated, and the sales oil is again metered and sent to the pumps to flow into the pipeline to shore.

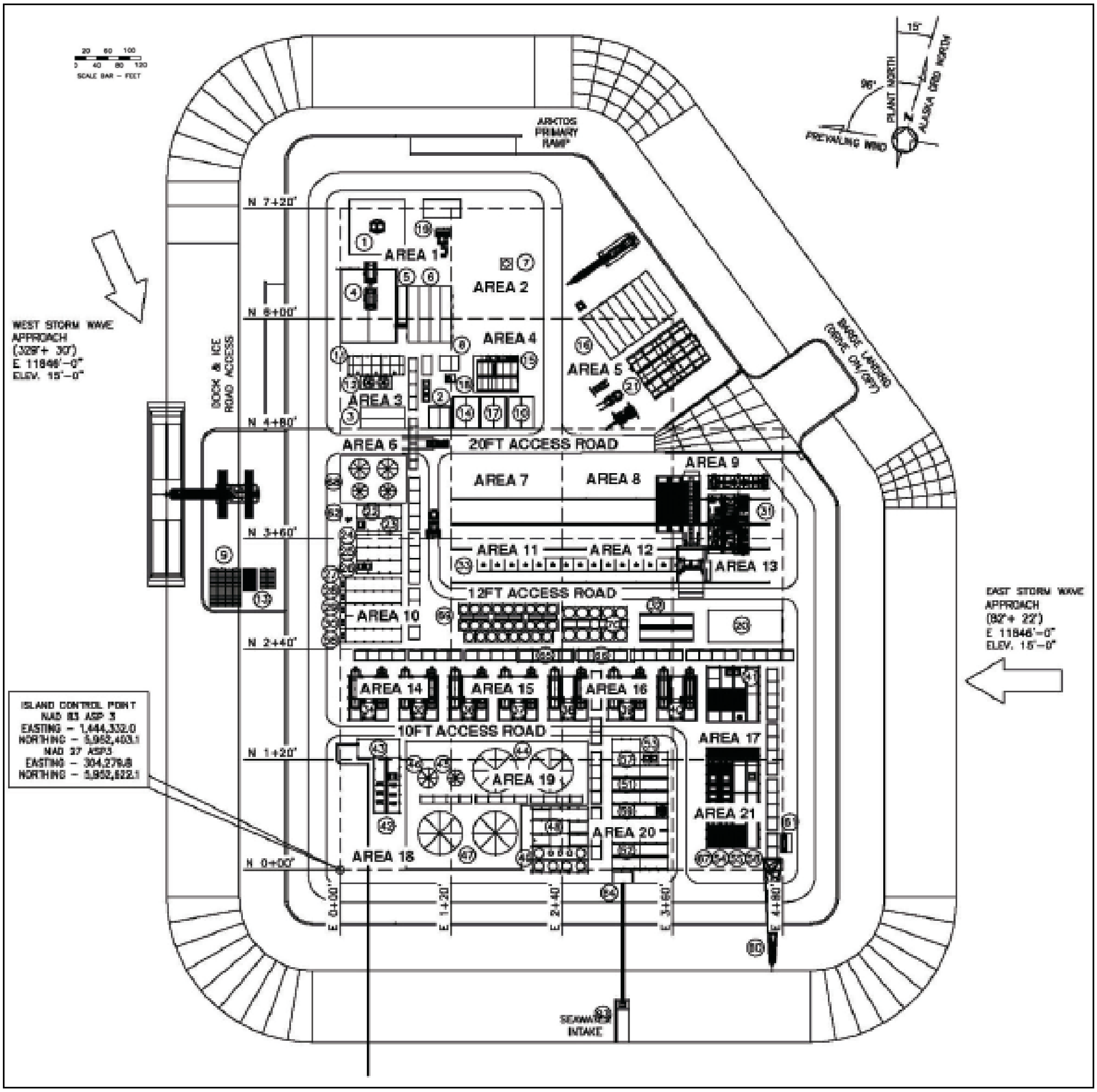


Figure 3.4: Plan of LDPI and Facilities [28, page 154]

Table 3.1: LDPI Plan (Figure 3.4) Facility Description [28]

AREA 1	1	HELI-PAD	AREA 14	34	TRAIN #7 PRODUCTION MODULE
	4	HANGER/ARKTOS STORAGE		35	TRAIN #6 PRODUCTION MODULE
	5	FREEZER/DRY STORAGE MODULE	AREA 15	36	TRAIN #5 PRODUCTION MODULE
	6	MAIN CAMP		37	TRAIN #4 PRODUCTION MODULE
	19	GRAVEL STORAGE		55	PRODUCTION MANIFOLD MODULE
AREA 2	7	RELIEF WELL LOCATION	AREA 16	38	TRAIN #3 PRODUCTION MODULE
AREA 3	2	FIRE & RESCUE		39	TRAIN #2 PRODUCTION MODULE
	3	POTABLE WATER STORAGE MODULES		56	GAS LIFT/INJECTION MANIFOLD MODULE
	8	SEWAGE PLANT	AREA 17	40	TRAIN #1 PRODUCTION MODULE
	11	STANDBY GENERATOR MODULE		41	FG & INJECTION COMPRESSION MODULES
	12	DIESEL STORAGE	AREA 18	42	SALES OIL PUMP & LACT MODULES
	18	INCINERATOR		43	PIPELINE/PIGGING MODULE
AREA 4	10	WELDING SHOP		46	FIRE WATER TANK-5000BBL
	14	GENERAL SHOP		47	SALES OIL TANKS-15000BBL
	15	WAREHOUSE STORAGE	AREA 19	44	PRODUCED WATER & SEA WATER
	17	ELECTRICAL SHOP			TANKS-15000BBL
	-	RELIEF RIG RESERVED SPACE		45	SLOP TANK
AREA 5	16	DRILLERS' CAMP		48	UTILITY MODULE
	21	VEHICLE SHELTER & STORAGE		49	CHEMICAL TANK FARM
AREA 6	22	CONTROL ROOM MODULE #1	AREA 20	51	P.W. TREATMENT MODULES #1 - #3
	23	CONTROL ROOM MODULE #2		52	P.W. TREATMENT MODULES #4 - #7
	62	MICROWAVE COMMUNICATION TOWER		53	VRW
	66	DIESEL TANK FARM		57	WATER INJECTION/OFFSPEC PUMP MODULE
AREA 7	-	RIG SKID BEAMS		59	S.W. TREATMENT MODULES
AREA 8	-	RIG SKID BEAMS			(SW ACCELERATES)
AREA 9	31	DRILLING RIG/UTILITY MODULE	AREA 21	54	COMPRESSION TRAIN #1 MODULE
AREA 10	24	SWITCHGEAR		55	COMPRESSION TRAIN #2 MODULE
	25	MCC #1		56	COMPRESSION TRAIN #3 MODULE
	26	MCC #2		60	FLARE BOOM
	27	POWER GENERATOR #1		61	FLARE KNOCK-OUT DRUM
	28	POWER GENERATOR #2		57	COMPRESSION TRAIN #4 MODULE
	29	POWER GENERATOR #3		9	C-CAN-LAYDOWN AREA
	30	POWER GENERATOR #4		13	C-CAN LAYDOWN AREA
	58	POWER GENERATOR #5		83	SEA WTER INTAKE CAISSON
AREA 11	33	PRODUCTION & INJECTION WELL AREA		54	SEA WATER INJECTION PUMP MODULE
	59	DRILLING CEMENT SILOS			
AREA 12	32	DRILLING SUPPORT BUILDING			
	33	PRODUCTION & INJECTION WELL AREA			
	70	DRILLING MUD SILOS			
AREA 13	20	GRIND INJECTION FACILITY			

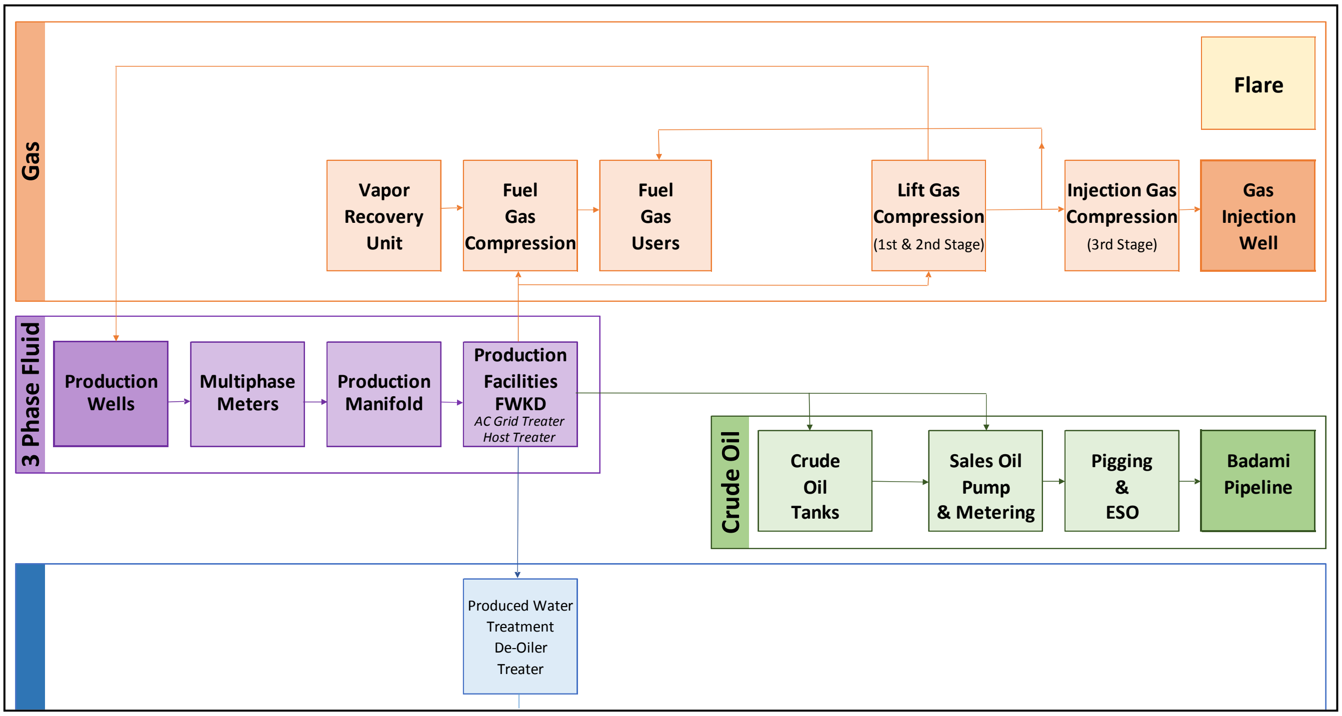


Figure 3.5: Block Diagram of Oil Production System [28]

3.3 Oil and Gas Wells

As described in Section 3.1, infrastructure and facilities necessary to drill wells and process and export approximately 60,000 to 70,000 BPD to shore will be installed on the island. There will be slots for 16 wells, which include accommodations for 5-8 producing wells, 4-6 water and/or gas injection wells, and up to two disposal wells at surface wellhead spacing of 15 feet between wellheads. Produced gas will be used for fuel gas, artificial lift, and re-injection into the reservoir. Seawater will be treated and used to waterflood the Liberty reservoir. Following waterflood breakthrough, produced water will be commingled with seawater and re-injected for reservoir support.

The drilling schedule, shown in Figure 3.6, is integrated into the project schedule as described subsequently in Section 3.5.

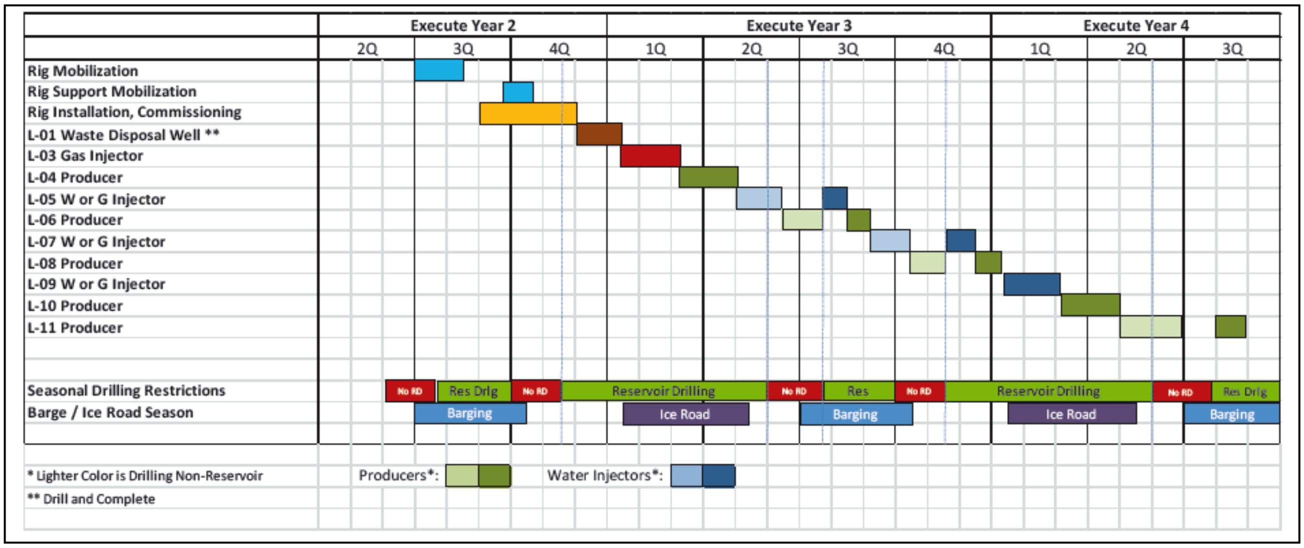


Figure 3.6: Project Drilling Schedule [28]

The LDPI drilling unit will be designed with the following safety equipment [28]:

- Well control equipment, including surface hole diverter system, main BOP stack, choke manifold, accumulator closing system, and control panels. The BOP stack will include shear rams. All blowout preventer equipment (BOPE) will meet regulatory standards.
- Flow monitoring system to detect downhole flow.
- Pit volume totalizer system to monitor drilling mud volumes in the drilling unit pits to allow detection of possible influx volume from downhole formations.
- Trip tank to monitor for proper hole fill when running drill pipe into and out of the well. Trip tank can help detect potential influxes from swab pressures and potential mud losses form surge pressures.
- Mud gas separator and vacuum degasser.
- Drill string and tubular BOP devices including inside blowout preventer (IBOP), full opening safety valve, upper and lower Kelley valves.
- Hydrogen sulfide (H_2S) and combustible gas detector and alarm systems.
- Fire detection and suppression system
- Crown savers, mud pump pressure relief valves, and torque limiters.
- First aid equipment and supplies.

The primary well control mechanism for the Liberty Development drilling program will be the hydrostatic pressure exerted by the drilling fluid. The optimal mud weight used will be based on information gathered on offset wells including Liberty No. 1, the Tern Island wells, and wells drilled at the Endicott field. Other engineering decisions that factor into the primary well control plan include casing setting depths, casing burst ratings, fracture gradient of the exposed shoe, and pressure losses while circulating. All data of a geologic and engineering essence have been included in the drilling design basis, which defines the proposed mud weights, casing design, and proposed circulating system practices. Note: the drilling fluid program will be designed and implemented in accordance with 30 CFR 250.455-459.

The secondary well control mechanism for the Liberty Development drilling program equipment is a BOP system, which includes the equipment, personnel, and procedures used to detect a kick and control a well that has been exposed to an underbalance condition.

3.4 Subsea Oil Pipeline

As summarized in Section 3.1, a nominal 12 inch sales oil pipeline inside 16 inch outer pipe or pipe in pipe (PIP) will transport crude oil to the Badami Sales Oil Pipeline. The offshore portion of the pipeline will be approximately 9 km (5.6 mi) long, and the overland portion (not analyzed herein) will be approximately 2.4 km (1.5 mi) long to the Badami pipeline tie-in point as shown in Figure 3.2, in Section 3.1.

Based upon the soil characteristics and the predicted environmental loading conditions along the pipeline route, such as permafrost thaw settlement, seabed ice gouging, strudel scour, and upheaval buckling, the mechanical design of the pipelines will be based on a limit-state design approach. The primary design considerations for the limit-state design include critical strains in bending and the burst pressure for individual lines. For example, the compressive and tensile strain limits -- engineering critical analysis (ECA) weld flaw sizes -- for the pipelines will be evaluated in detail.

Historical local and regional data are being used for the purpose of ice gouge and strudel scour design for 100-year exceedance probability events. The preliminary target trench depth range is 11 feet to 13 feet with a minimum 7.5 feet of depth of cover to the top of the pipe. Analyses will be performed for ice gouge, strudel scour, and permafrost to evaluate the maximum strain in the pipelines over this trench depth range. Approximately 7 feet is the estimated maximum trench bottom width. The physical parameters of pipeline design are further described below in Table 3.2 and Figure 3.7.

Table 3.2: Subsea Pipeline Properties [28]

Design Property	Specification
Design flowrate	65,000 BPD
Maximum operating pressure	1415 psig
OD of inner export pipe	12.78” (12” nominal)
Nominal wall thickness, inner PIP	0.500”
Grade of inner PIP	API-5L X52
OD of outer PIP	16.00”
Nominal wall thickness, outer PIP	0.625”
Grade of outer PIP	API-5L X52
Nominal diameter of coiled tubing spare	4.0”
Nominal wall thickness	0.300”
Grade of coiled tubing	API-5LCP X65

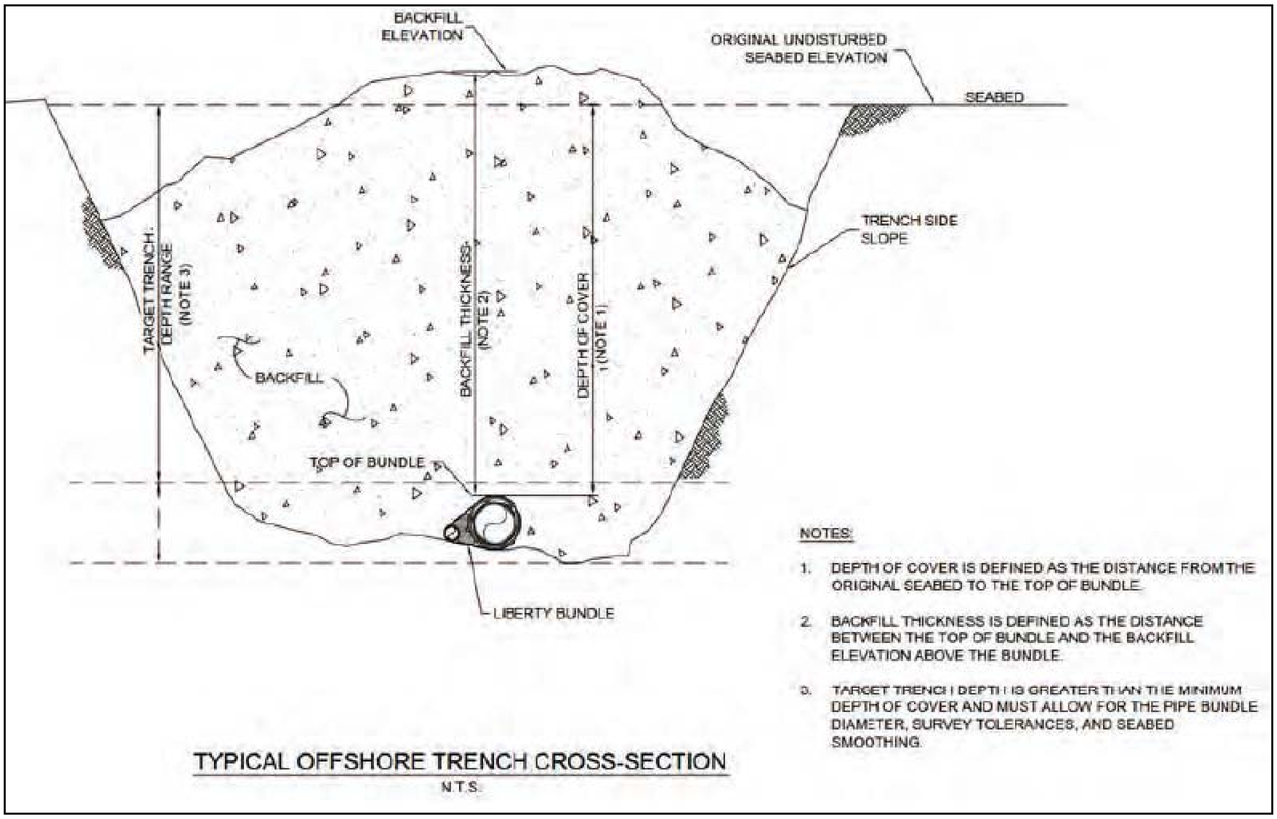


Figure 3.7: Subsea Pipeline Cross Section [28]

A number of issues are addressed in routing, design, and monitoring to mitigate potential risk to pipeline integrity, such as thaw settlement. Key design advantages include:

- Limit-state design, including finite element analysis of the pipeline bundle, to determine the maximum longitudinal strains (axial and bending) in the pipelines, based on predicted permafrost thaw settlement and the expected environmental and operational loadings.
- The use of a vacuum insulated PIP configuration for the single-phase production pipeline to reduce heat transfer into the surrounding soils and to provide a secondary leak detection system by annulus pressure monitoring.
- Fiber optic cable distributed temperature sensing system.
- Straight line route to minimize route length.
- The use of thaw stable gravel bedding beneath the pipeline at the shore and LDPI approach transitions.

Mass balance and pressure monitoring leak detection systems will be incorporated into the export pipeline design. These systems work in parallel and provide redundant measurements to ensure accuracy. It is expected that under optimal conditions, these systems would be capable of detecting a leak 1 percent of the volumetric flow in the pipeline over a 24-hour period. Custody transfer metering will be located on the LDPI and a flow meter will be located at the tie-in with the Badami Pipeline to enhance the performance of the leak detection system. Communication links to interface with Badami and Endicott pipeline leak detection systems and controls will also be provided.

Specific provisions for ice effects, including scour, gouging, thaw settlement, and upheaval buckling as quantified for the risk assessment were included in the subsea pipeline design.

3.5 The Project

The Project life cycle, following hearings and approvals, spans approximately 25 years. Thus, following the review phase, the Project execution schedule [28, Executive Summary, Section 3] includes the following principal milestones:

- Year 1: Start 2017 estimated
- Year 2-5: Island, facilities, and pipeline construction.
- Year 3-5: Drilling operations
- Year 4-5: Production operations startup
- Year 4-25: Oil production
- Year 25: End of oil production

The principal project input for the analysis is the drilling and production schedule. This was established with BOEM and Hilcorp, and is given in Table 3.3.

Table 3.3
Drilling and Production Schedule

Year	Development Wells Drilling				Producing Wells	In-use Pipeline Length (km)	Annual Production (bbl)
	Waste Disposal	W or G Injector	Producer	Total			
2	1			1			
3		3	3	6			
4		1	2	3	5	9.01	23,038,204
5					5	9.01	19,956,844
6					5	9.01	12,427,316
7					5	9.01	8,362,712
8					5	9.01	7,443,660
9					5	9.01	6,427,520
10					5	9.01	4,995,928
11					5	9.01	4,585,928
12					5	9.01	4,081,184
13					5	9.01	3,585,232
14					5	9.01	3,206,432
15					5	9.01	2,990,872
16					5	9.01	2,805,536
17					5	9.01	2,581,504
18					5	9.01	2,288,624
19					5	9.01	2,059,248
20					5	9.01	1,797,176
21					5	9.01	1,364,208
22					5	9.01	1,156,176
23					5	9.01	1,005,080
24					5	9.01	854,328
25					5	9.01	784,792
Total	**1**	**4**	**5**	10			**117,798,504**

CHAPTER 4

FAULT TREE ANALYSIS FOR ARCTIC OIL SPILL FREQUENCIES

4.1 General Description of Fault Tree Analysis

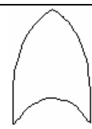
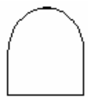
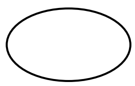
Fault trees are a method for modeling the probabilities of the occurrence of failures. They are used when an adequate history is not available to provide failure statistics. Developed initially by Rasmussen for the U.S. Nuclear Regulatory Commission in the early 1970s [61], fault trees have become a popular risk analytic tool for predicting risks, assessing relative risks, and quantifying comparative risks [6, 10, 12]. In 1976, Bercha first used fault trees to quantify oil spill probabilities in the Canadian Beaufort Sea for the Canadian Department of the Environment [12]. In the present study they are used for the transformation of historical oil spill statistics for non-Arctic regions to predictive oil spill statistics for Arctic regions for the Liberty Project.

4.2 Fault Tree Methodology

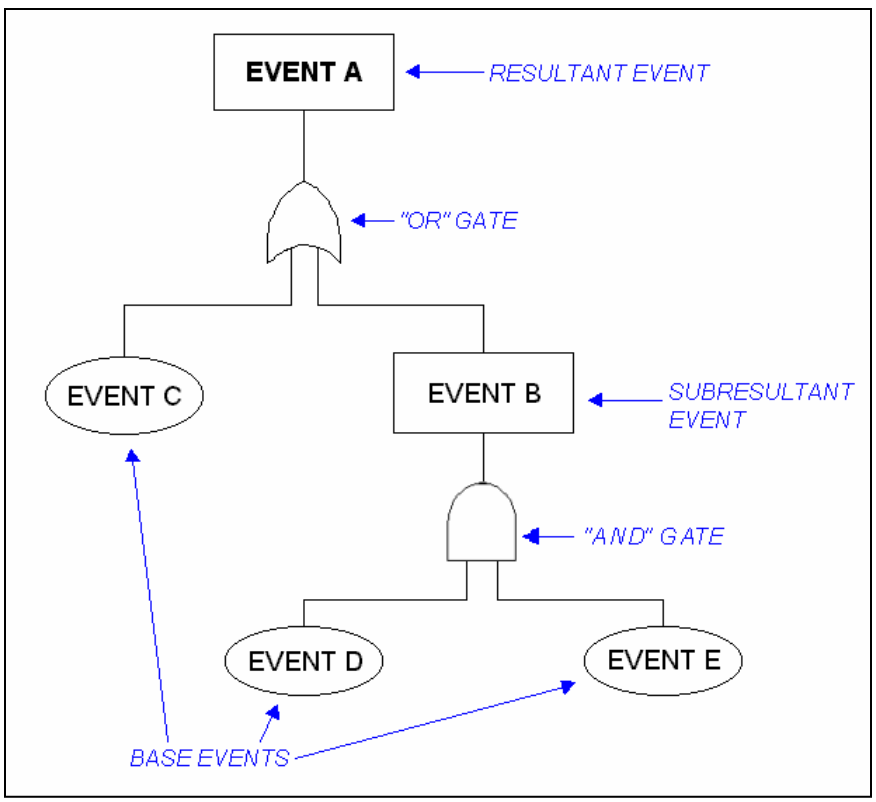
4.2.1 Fault Tree Analysis Basics

The basic symbols used in the graphic depiction of simple (as used here) fault tree networks are illustrated in Figure 4.1(a). As may be seen, the two types of symbols designate logic gates and event types. The basic fault tree building blocks are the events and associated sub-events, which form a causal network. The elements linking events are the AND and OR gates, which define the logical relationship among events in the network. The output event from an OR gate occurs if any one or more of the input events to the gate occurs. The output event from an AND gate occurs only if all the input events occur simultaneously.

The basic structure of a fault tree is illustrated in Figure 4.1(b). Because of their connection through an AND gate, Event D and Event E must both occur for the resultant Event B to occur. An OR gate connects Events B and C; therefore, the occurrence of either one or both of Events B and C results in the occurrence of the resultant Event A. As may be seen, the principal fault tree structures are easy to apply; however, the representation of complex problems often requires very large fault trees, which become more difficult to analyze and require more advanced techniques such as minimal cut-set analysis [1, 6, 10]. For the present application, a simple system connected through OR gates only will be used.

SYMBOL	DESCRIPTION
A. LOGIC	
	EITHER / OR GATE
	AND GATE
B. EVENT	
	RESULTANT EVENT
	BASIC EVENT

(a) Basic Fault Tree Symbols



(b) Basic Fault Tree Structure

Figure 4.1: Fault Tree Basics

Computationally, the probability of input events joined through an AND gate are multiplied to calculate the probabilities of the output event. The probabilities of input events joined through an OR gate are added to calculate the probability of the output event. The relevant equations and associated assumptions may be summarized as follows:

For AND Gate:

$$P = \prod_{n}^{i=1} P_i \tag{4.1a}$$

Example: Output Event Probability = P_x
Input Events failure probabilities, P_1, P_2, ….

$$P_x = P_1(P_2)(P_3) \tag{4.1b}$$

For OR Gate:

$$P = 1 - \prod_{n}^{i=1}(1 - P_i) \tag{4.2a}$$

Example: Output Event Probability = P_y
Input Event failure probabilities, P_1, P_2, …

$$P_y = 1 - \prod_{n}(1 - P_1)(1 - P_2)(1 - P_3)$$

$$P_y = P_1 + P_2 + P_3;\ for\ P_i \leq 0.1 \tag{4.2b}$$

In more complex fault trees, it is necessary to assure that base events which affect more than one fault tree branch are not numerically duplicated. This is done through the use of minimal cut-set theory [1, 6]. However, as indicated earlier, the fault trees used in this study are sufficiently simple in structure and level of detail to exclude the requirement of using minimal cut-set theory in their computation algorithms.

4.2.2 Current Application of Fault Trees

Figure 4.2 illustrates a two-tier fault tree that can be used to develop pipeline large spill frequencies for the Arctic study area from the historical frequencies. Note that this example is illustrative of the process only, and does not correspond to the same numerical values used in computations later. The type of fault tree shown, to be used extensively later, is a relatively simple fault tree showing the resultant event, the spill, generated from a series of subresultant events corresponding to the pipeline spill causal classification, such as that shown in Table 2.3. The upper tier of numbers (marked “H”) below each of the events in the fault tree represents the historical frequency (per 100,000 km-yr) while the lower one (marked “A”) represents the modified frequency for Arctic operations. As these fault trees are composed entirely of OR gates, the computation of resultant events is quite simple – consisting of the addition of the probabilities of events at each level of the fault tree to obtain the resultant probability at the next higher value.

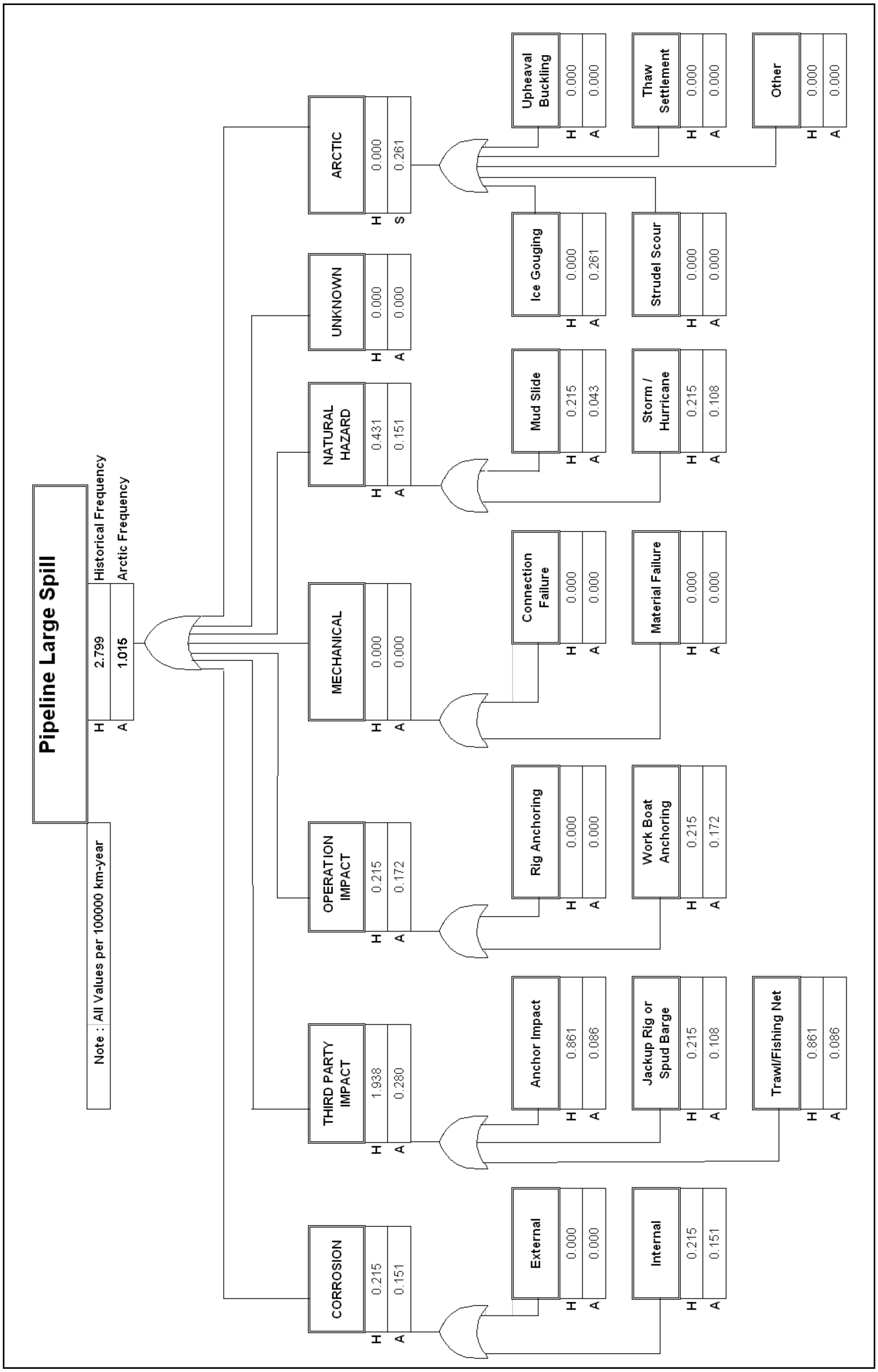


Figure 4.2
Example of Fault Tree to Transform Historical (GOM and PAC) to Arctic Spill Frequencies[1]

[1] The input data used here are only illustrative and do not represent the inputs used later in this study.

For example, to obtain the "Natural Hazard" Arctic ("A") probability of 0.151, add 0.043 and 0.108. Essentially, the fault tree resultant (top event) shows that the Arctic frequency of spills (for the example pipeline category, location, and spill size) is approximately 1 in 100,000 km-yr or 1.015 x 10^{-5}/km-yr. The non-Arctic historical frequency for this spill size, by comparison, is 2.799 x 10^{-5}/km-yr, or approximately 2.8 times higher. Both frequencies are for illustrative purposes only.

4.2.3 Monte Carlo Simulation

A type of numerical simulation, called Monte Carlo simulation [9] can be used to obtain the outcome of a set of interactions for equations in which the independent variables are described by distributions of any arbitrary form. The Monte Carlo simulation is a systematic method for selecting values from each of the independent variable distributions and computing all valid combinations of these values to obtain the distribution of the dependent variable. Naturally, this is done utilizing a computer, so that thousands of combinations can be rapidly computed and assembled to give the output distribution.

Consider the example of the following equation:

$$\boldsymbol{X = X_1 + X_2} \quad \textbf{(4.3)}$$

Where X is the dependent variable (such as the resultant spill frequency) and X_1 and X_2 are base event probabilities joined through an OR gate. Suppose now that X_1 and X_2 are some arbitrary distributions that can be described by a collection of values x_1 and x_2. What we do in the Monte Carlo process, figuratively, is to put the collection of the X_1 values into one hat, the X_1 hat, and the same for the X_2 values – into an X_2 hat. We then randomly draw one value from each of the hats and compute the resultant value of the dependent variable, X, using Equation 4.3. This is done several thousand times. Thus, a resultant or dependent variable distribution, X, is estimated from the computations of all valid combinations of the independent variables (X_1 and X_2).

Generally, the resultant can be viewed as a cumulative distribution function as illustrated in Figure 4.3. Such a cumulative distribution function (CDF) is also a measure of the accuracy or, conversely, the variance of the distribution. As can be seen from this figure, if the distribution is a vertical line, no matter where one draws on the vertical axis, the same value of the variable will result – that is, the variable is a constant. At the other extreme, if the variable is completely random then the distribution will be represented as a diagonal straight line between the minimum and maximum value. Intermediate qualitative descriptions of the randomness of the variable follow from inspection of the CDF in Figure 4.3.

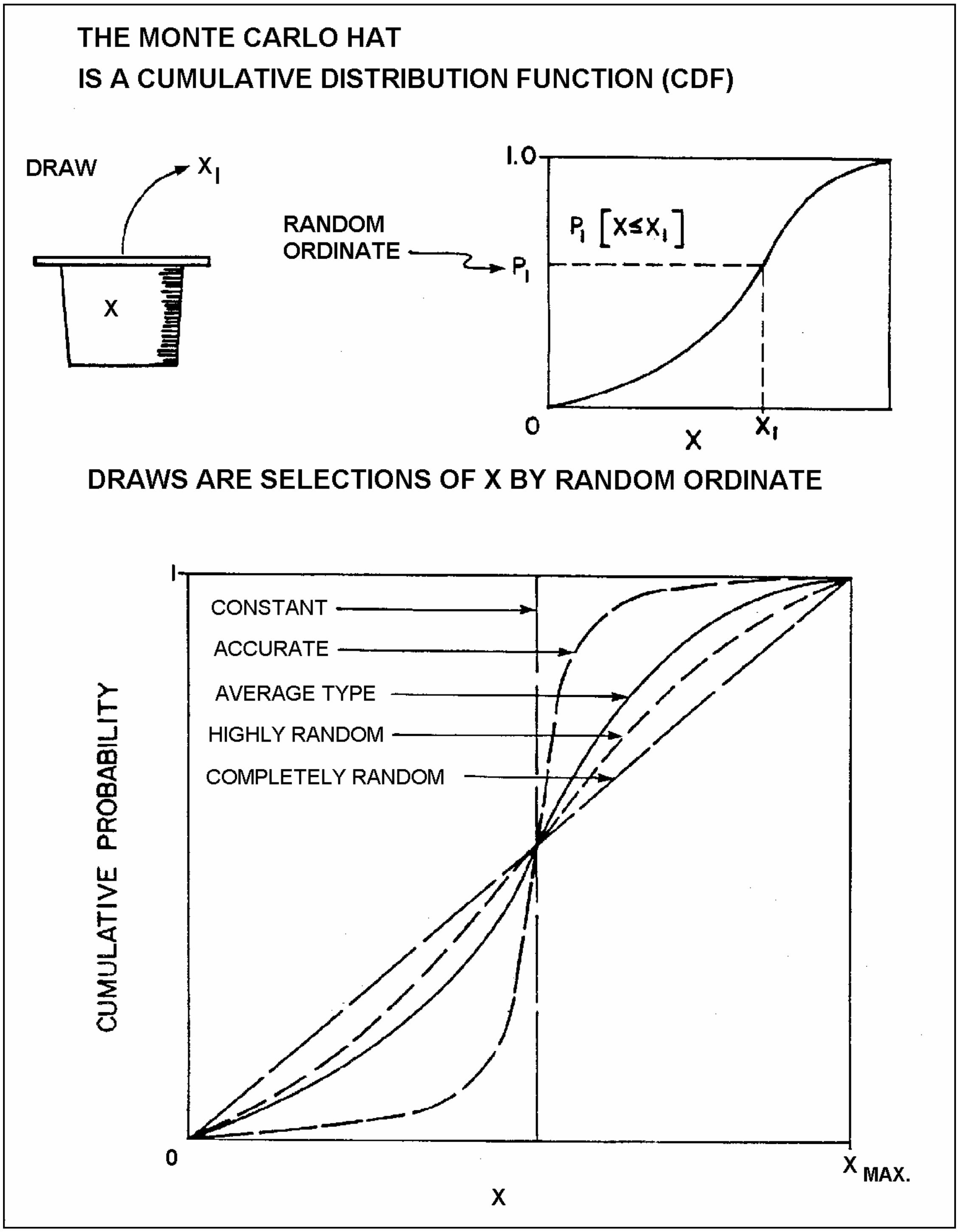


Figure 4.3: Monte Carlo Technique Schematic

There are two other important concepts related to the CDF that enter into Monte Carlo modeling: namely, auto-correlation and cross-correlation. Suppose the variables X_1 can vary only within a specified interval over the simulation time increment. Then, after the first random draw, the next draw would be restricted within certain limits of the initial draw simply as a result of the physical restrictions of the problem. Such a restriction is represented as an auto-correlation coefficient. Now, suppose that not only are the X_1 restricted, but also the X_2. Suppose further, however, that given a certain X_1, a restriction were placed on the range of X_2 associated with that X_1. Say, only small X_1 could associate with the full range of X_2, while large X_1 could only be associated with certain lower X_2. Then, such a relationship would be expressed as a cross-correlation factor and certain limits would be imposed for the drawing on both X_1 and associated X_2. In the present analysis, all distributed variables are considered to be independent – so that auto and cross-correlations need not be invoked.

4.2.4 Distribution Derived from Historical Data for Monte Carlo Analysis

In order to model the variability of the base data and its distribution through the Arctic effects, using the Monte Carlo approach, an appropriate distribution needs to be derived. As in the previous study [16, 17], a Triangular Distribution was selected.

According to [31, 43], the Triangular Distribution is typically used as a descriptor of a population for which there is only limited sample data, as is the current case. The distribution is based on a knowledge of a minimum and maximum, which was derived from the historical data here, and an educated guess as to what the modal value might be. Here, the modal value was chosen to be a function of the average historical value, as given in Equation 2.1. Despite being a simplistic description of a population, the Triangular Distribution is a very useful one for modeling processes where the relationship between variables is understood, but data are scarce.

Also, when combining several variables in a functional relationship utilizing numerical methods, as is done in Monte Carlo Simulation, the Triangular Distribution is a preferred one due to its simplicity and relatively accurate probabilistic resultant when evaluated by a large number of random draws, as occurs in the Monte Carlo process. The data used here typifies sparse data with a preferred or modal value and an easily identifiable maximum and minimum. Then, for the case of the simple upper and lower 100% confidence interval (called High and Low), the expected value ***E*** (or mean value) of the Triangular Distribution can be expressed as:

$$E = (High + Mode + Low) / 3 \qquad \textbf{(4.4)}$$

For maximum and minimum which are not at the 100% confidence interval level – such as those at 90% confidence levels – a Monte Carlo computation is used to evaluate the expected value of each distribution. Based on the historical data presented earlier in Chapter 2 the Triangular Distribution expected values computed from the low, mode, and high values at 90% confidence intervals are given in Tables 4.1, 4.2, and 4.3, for pipelines, the island, and wells, respectively. The modes from high and low values were calculated as described in Section 2.2.

Table 4.1
PIP Pipeline Spill Frequency Distribution Properties

GOM and PAC OCS Pipeline Spills, Categorized 1972-2010 NPS > 10"	Frequency Unit	Low Factor	High Factor	Historical	Low	Mode	High	Expected
Small (50-99 bbl)	Spill per 10^5 km-years	0	2.81	1.182	0	0.224	3.320	1.482
Medium (100-999 bbl)	Spill per 10^5 km-years	0	2.81	3.249	0	0.617	9.130	4.076
Large(1,000-9,999 bbl)	Spill per 10^5 km-years	0	2.81	1.360	0	0.258	3.821	1.706
Huge (=>10,000 bbl)	Spill per 10^5 km-years	0	2.81	0.388	0	0.074	1.092	0.487

Table 4.2
Island Spill Frequency Distribution Properties

Spill Size	Frequency Unit	Low Factor	High Factor	Historical	Low	Mode	High	Expected
Small and Medium Spills (50-999 bbl)	Spill per 10^4 well-year	0	3	4.766	0.0000	0.0000	14.298	6.355
Large and Huge Spills (>= 1000 bbl)	Spill per 10^4 well-year	0	3	0.285	0.0000	0.0000	0.855	0.380

Table 4.3
LOWC Frequency Distribution Properties

Spill Size	Event	Frequency Unit	Low Factor	High Factor	Frequencies				
					Historical	Low	Mode	High	Expected
Small and Medium Spills (50-999 bbl)	Production Well	spill per 10^4 well-year	0.448	1.545	0.028	0.012	0.028	0.043	0.028
	Exploration Well Drilling	spill per 10^4 wells	0.439	2.036	1.330	0.584	0.698	2.708	1.530
	Development Well Drilling	spill per 10^4 wells	0.437	1.760	0.283	0.124	0.227	0.498	0.299
Large Spills (1,000-9,999 bbl)	Production Well	spill per 10^4 well-year	0.448	1.545	0.011	0.005	0.011	0.017	0.011
	Exploration Well Drilling	spill per 10^4 wells	0.439	2.036	0.539	0.237	0.283	1.097	0.620
	Development Well Drilling	spill per 10^4 wells	0.437	1.760	0.115	0.050	0.092	0.202	0.122
Small, Medium and Large Spills (50-9,999 bbl)	Production Well	spill per 10^4 well-year	0.448	1.545	0.039	0.017	0.039	0.060	0.039
	Exploration Well Drilling	spill per 10^4 wells	0.439	2.036	1.869	0.821	0.981	3.805	2.150
	Development Well Drilling	spill per 10^4 wells	0.437	1.760	0.398	0.174	0.320	0.700	0.421
Spill (10,000-149,999 bbl)	Production Well	spill per 10^4 well-year	0.448	1.545	0.007	0.003	0.007	0.011	0.007
	Exploration Well Drilling	spill per 10^4 wells	0.439	2.036	0.350	0.154	0.184	0.713	0.403
	Development Well Drilling	spill per 10^4 wells	0.437	1.760	0.075	0.033	0.060	0.131	0.079
Spill (=>150,000 bbl)	Production Well	spill per 10^4 well-year	0.448	1.545	0.005	0.002	0.005	0.007	0.004
	Exploration Well Drilling	spill per 10^4 wells	0.439	2.036	0.217	0.095	0.114	0.442	0.250
	Development Well Drilling	spill per 10^4 wells	0.437	1.760	0.046	0.020	0.037	0.081	0.049

4.2.5 Approaches to Assessment of Arctic Spill Frequency Variability

The method for assessment of Arctic spill frequency variability consists of systematically perturbing the variability of all the causal events, plus that of the Arctic unique effects. In this approach, the non-Arctic variable distribution is multiplied by an adjustment or correction distribution to obtain the Arctic variable distribution.

4.3 Pipeline Fault Tree Analysis

4.3.1 Arctic Pipeline Spill Causal Frequency Distributions

The effects of the Arctic environment and operations are reflected in the effect on facility failure rates in two ways; namely, through "Modified Effects", those changing the frequency component of certain fault contributions such as anchor impacts which are common to both Arctic and temperate zones, and through "Unique Effects" or additive elements such as ice gouging which are unique to the Arctic offshore environment. Table 4.4 shows the frequency modifications (in %) and frequency increment additions (per 10^5 km-yr) developed for Arctic pipelines for different spill sizes throughout the three relevant water depth ranges. The right hand column of the table gives a summary of the reasoning behind the effects. For the Arctic unique effects, both the mode value (from Table 2.14) and the expected value, determined through the Monte Carlo analysis, are given. The mode values differ from the expected values due to skewness of the distributions introduced through the assigned values of the upper and lower bounds (Table 2.14). The following comments can be made for each of the causes described:

- *External corrosion* – Due to the low temperature, limited biological and lowered chemical effects are expected. Coatings will be state of art and high level of quality control will be used during pipeline installation resulting in high integrity levels of coating to prevent external corrosion.
- *Internal corrosion* – Additional (above historical levels) inspection or smart pigging is anticipated.
- *Anchor impact* – The very low traffic densities of third party shipping in the area justify a 50% reduction in anchor impact expectations on the pipeline.
- *Jack-up rig or spud barges* – Associated or other operations are going to be substantially more limited than they are in the historical data population in the GOM and PAC OCS.
- *Trawl/Fishing net* – Less fishing is expected in the Beaufort Sea.
- *Rig anchoring* – Although it is anticipated that no marine traffic except possibly icebreakers will occur during the ice season, an increased traffic density during the four month open water season to resupply the platforms is expected, justifying only a 20% decrease in this failure cause.
- *Work boat anchoring* – The same applies to work boat anchoring as to rig anchoring.
- *Mechanical connection failure or material failure* – No change was made to account for Arctic effects.

Table 4.4
PIP Pipeline Arctic Effect Derivation Summary

CAUSE CLASSIFICATION 1972-2010	Spill Size	PIP Pipeline Arctic LOC Frequency Change %				REASON
		Min	Mode	Max	Expected	Note: Reduction in Frequency in either NPS 12 or 16 will reduce PIP LOC Frequency
CORROSION						
External	All	(90)	(30)	(10)	(45.91)	Low temperature NPS16, state of art coating.
Internal	All	(90)	(40)	(10)	(47.93)	Dehydrated oil, regular pigging internal pipe.
THIRD PARTY IMPACT						
Anchor Impact	All	(90)	(50)	(10)	(50.00)	Low traffic, patrols and warnings.
Jackup Rig or Spud Barge	All	(90)	(60)	(10)	(52.07)	Low facility density, unlikely presence of jackup or barge as drilling is from island.
Trawl/Fishing Net	All	(90)	(40)	(10)	(47.93)	Low fishing activity, warning signs.
OPERATION IMPACT						
Rig Anchoring	All	(90)	(70)	(10)	(54.09)	No rig anchoring as island used as drill platform. No rigs planned near pipeline.
Work Boat Anchoring	All	(70)	(40)	(10)	(40.00)	Low work boat traffic especially during ice season (8 months).
MECHANICAL						
Connection Failure	All					No change
Material Failure	All					No change
NATURAL HAZARD						
Mud Slide	All	(90)	(80)	(10)	(55.97)	Sea bottom gradient low.
Storm/ Hurricane	All	(90)	(85)	(10)	(56.76)	Fewer severe storm effects inside barrier islands.
ARCTIC	Spill Size	PIP LOC Frequency Increment per 10^5 km-year				REASON
		Min	Mode	Max	Expected	
Ice Gouging	S	0.0006	0.0028	0.1250	0.0517	Ice Gouge Failure Rate calculated using exponential failure distribution for 3.05 m cover, 0.2 m average gouge depth, 2 gouges per km-yr flux.
	M	0.0006	0.0028	0.1250	0.0517	
	L	0.0016	0.0070	0.3125	0.1292	
	H	0.0003	0.0014	0.0625	0.0258	
Strudel Scour	S	0.0011	0.0023	0.0138	0.0065	Average Frequency of 3.4 critical scours/10^5 km-yr and 100 ft of bridge length with 2% conditional pipeline failure probability. The same spill size distribution as above.
	M	0.0011	0.0023	0.0138	0.0065	
	L	0.0028	0.0059	0.0345	0.0161	
	H	0.0006	0.0012	0.0069	0.0032	
Upheaval Buckling	S	0.0002	0.0005	0.0028	0.0013	The Failure Frequency is 20% of that of Strudel Scour.
	M	0.0002	0.0005	0.0028	0.0013	
	L	0.0006	0.0012	0.0069	0.0032	
	H	0.0001	0.0002	0.0014	0.0006	
Thaw Settlement	S	0.0001	0.0002	0.0014	0.0006	The Failure Frequency is 10% of that of Strudel Scour.
	M	0.0001	0.0002	0.0014	0.0006	
	L	0.0003	0.0006	0.0035	0.0016	
	H	0.0001	0.0001	0.0007	0.0003	
Other Arctic	S	0.0002	0.0006	0.0143	0.0060	To be assessed as 10% of all Arctic effects.
	M	0.0002	0.0006	0.0143	0.0060	
	L	0.0005	0.0015	0.0357	0.0150	
	H	0.0001	0.0003	0.0071	0.0030	

- *Mudslide* – Low gradient resulting in limited mudslide potential.
- *Storms* – Considerably fewer severe storms are anticipated on an annual basis in the Arctic particularly shoreward of the barrier islands than in GOM or PAC, due to damping of the ocean surface by ice cover and reduction of fetch by barrier islands in open water season.
- *Arctic unique effects* – Arctic effects are effects which are unique to the Arctic and are not reflected in the historical fault tree itself. Arctic effects were discussed in detail in Chapter 2, Section 2.6. The discussion in that section is summarized in the right hand column of Table 4.4. The frequency increments in this table are again given as both the “mode” values and the “expected” values. The mode values are the mode values given in Table 2.14. The expected values, however, are those calculated using the Monte Carlo method with the low, mode, and high values from Table 2.14, as inputs to the Monte Carlo. The expected values are clearly considerably higher than the mode or most likely values. This lack of coincidence between expected and mode values is due to the skewness of the distribution.

Derivation of the Arctic effect distributions is accomplished through the construction of a secondary triangular distribution by which the historical causal frequency distributions are multiplied to provide the resultant Arctic effect distribution. This secondary distribution utilizes the value of mode adjustments from Table 4.4, with appropriate second order perturbations for the upper and lower 90% confidence interval bounds. Table 4.5 summarizes these Arctic effect distributions. For the Arctic modified effects, given in the top of the table, the secondary distribution is simply the frequency change used as the mode of the distribution, and 90% upper and lower confidence interval changes given under the Min and Max columns. For the Arctic unique effects, total frequency increments are given, with the upper confidence interval value at approximately 45 times the mode, and the lower bound value at approximately $^1/_5$ of the modal value in the case of S (small) spill Ice Gouging.

4.3.2 Arctic Pipeline Fault Tree Frequency Calculations

Incorporation of the frequency effects as variations in and additions to the historical frequencies can be represented in a fault tree, as shown for the large spill size for Arctic pipelines in Figure 4.4. In this figure, the historical frequency as well as those associated with S, M, L, and H spill sizes are shown under each of the event boxes.

The PIP frequency calculation fault tree shown is in Figure 4.4. Consider the bottom line for Huge Spills. This tells us that the Huge spill frequency for PIP pipelines was 0.487 (per 10^5 km-yr) as derived by a reliability analysis based on historical data. With the first and second order frequency changes attributable to Arctic effects, this frequency is reduced to 0.258 for Huge spills for the Liberty PIP pipeline.

Table 4.5 gives the detailed fault tree inputs. Table 4.6 summarizes the fault tree output expected values of the pipeline spill frequencies for each spill size for the historical \pip and the Liberty PIP, and Figure 4.5 graphically depicts these results. Clearly the Liberty PIP LOC frequency is lower than historical frequencies.

Table 4.5
PIP Pipeline Arctic Effect Causal Distribution Derivation Summary

CAUSE CLASSIFICATION 1972-2010	Historical PIP Pipeline %	SMALL SPILLS 50-99 bbl				MEDIUM SPILLS 100-999 bbl				Historical PIP Pipeline %	LARGE SPILLS 1,000-9,999 bbl				HUGE SPILLS >= 10,000 bbl			
		Frequency spills per 10^5km-year	Frequency Change	New Frequency	New Distribution %	Frequency spills per 10^5km-year	Frequency Change	New Frequency	New Distribution %		Frequency spills per 10^5km-year	Frequency Change	New Frequency	New Distribution %	Frequency spills per 10^5km-year	Frequency Change	New Frequency	New Distribution %
CORROSION	0.00	0.000	(0.000)	0.000	0.00	0.000	(0.000)	0.000	0.00	0.00	0.000	(0.000)	0.000	0.00	0.000	(0.000)	0.000	0.00
External	0.00	0.000	(0.000)	0.000	0.00	0.000	(0.000)	0.000	0.00									
Internal	0.00	0.000	(0.000)	0.000	0.00	0.000	(0.000)	0.000	0.00	0.00	0.000	(0.000)	0.000	0.00	0.000	(0.000)	0.000	0.00
THIRD PARTY IMPACT	13.43	0.199	(0.104)	0.095	12.27	0.547	(0.285)	0.262	12.98	54.05	0.922	(0.480)	0.442	46.32	0.263	(0.137)	0.126	48.86
Anchor Impact	0.00	0.000	(0.000)	0.000	0.00	0.000	(0.000)	0.000	0.00	0.00	0.000	(0.000)	0.000	0.00	0.000	(0.000)	0.000	0.00
Jackup Rig or Spud Barge	13.43	0.199	(0.104)	0.095	12.27	0.547	(0.285)	0.262	12.98	54.05	0.922	(0.480)	0.442	46.32	0.263	(0.137)	0.126	48.86
Trawl/Fishing Net																		
OPERATION IMPACT	4.70	0.070	(0.035)	0.035	4.48	0.192	(0.096)	0.096	4.73	2.70	0.046	(0.018)	0.028	2.90	0.013	(0.005)	0.008	3.06
Rig Anchoring	3.36	0.050	(0.027)	0.023	2.94	0.137	(0.074)	0.063	3.11									
Work Boat Anchoring	1.34	0.020	(0.008)	0.012	1.54	0.055	(0.022)	0.033	1.62	2.70	0.046	(0.018)	0.028	2.90	0.013	(0.005)	0.008	3.06
MECHANICAL	0.00	0.000		0.000	0.00	0.000		0.000	0.00									
Connection Failure	0.00	0.000		0.000	0.00	0.000		0.000	0.00									
Material Failure	0.00	0.000		0.000	0.00	0.000		0.000	0.00									
NATURAL HAZARD	75.20	1.115	(0.632)	0.482	62.03	3.065	(1.739)	1.326	65.58	43.24	0.738	(0.418)	0.319	33.47	0.211	(0.120)	0.091	35.30
Mud Slide	1.34	0.020	(0.011)	0.009	1.13	0.055	(0.031)	0.024	1.19	2.70	0.046	(0.026)	0.020	2.13	0.013	(0.007)	0.006	2.24
Storm/ Hurricane	73.86	1.095	(0.621)	0.473	60.91	3.010	(1.709)	1.302	64.39	40.54	0.691	(0.392)	0.299	31.34	0.198	(0.112)	0.085	33.06
ARCTIC			0.066	0.066	8.50		0.066	0.066	3.27			0.165	0.165	17.31		0.033	0.033	12.78
Ice Gouging			0.052	0.052	6.65		0.052	0.052	2.56			0.129	0.129	13.54		0.026	0.026	10.00
Strudel Scour			0.006	0.006	0.83		0.006	0.006	0.32			0.016	0.016	1.69		0.003	0.003	1.25
Upheaval Buckling			0.001	0.001	0.17		0.001	0.001	0.06			0.003	0.003	0.34		0.001	0.001	0.25
Thaw Settlement			0.001	0.001	0.08		0.001	0.001	0.03			0.002	0.002	0.17		0.000	0.000	0.12
Other Arctic			0.006	0.006	0.77		0.006	0.006	0.30			0.015	0.015	1.57		0.003	0.003	1.16
UNKNOWN	6.67	0.099		0.099	12.71	0.272		0.272	13.44									
TOTALS	100.00	1.482	(0.705)	0.777	100.00	4.076	(2.054)	2.021	100.00	100.00	1.706	(0.752)	0.954	100.00	0.487	(0.229)	0.258	100.00

Expected Values per 10^5 km-year

PIP Pipeline Spill

	Historical	Arctic	
S	1.482	0.777	Small Spill (50-99 bbl)
M	4.076	2.021	Medium Spill (100-999 bbl)
L	1.706	0.954	Large Spill (1,000-9,999 bbl)
H	0.487	0.258	Huge Spill (=> 10,000 bbl)

CORROSION

	Historical	Arctic
S	0.000	0.000
M	0.000	0.000
L	0.000	0.000
H	0.000	0.000

External

	Historical	Arctic
S	0.000	0.000
M	0.000	0.000
L	0.000	0.000
H	0.000	0.000

Internal

	Historical	Arctic
S	0.000	0.000
M	0.000	0.000
L	0.000	0.000
H	0.000	0.000

THIRD PARTY IMPACT

	Historical	Arctic
S	0.199	0.095
M	0.547	0.282
L	0.922	0.442
H	0.263	0.126

Anchor Impact

	Historical	Arctic
S	0.000	0.000
M	0.000	0.000
L	0.000	0.000
H	0.000	0.000

Jackup Rig or Spud Barge

	Historical	Arctic
S	0.199	0.095
M	0.547	0.282
L	0.922	0.442
H	0.263	0.126

Trawl/Fishing Net

	Historical	Arctic
S	0.000	0.000
M	0.000	0.000
L	0.000	0.000
H	0.000	0.000

OPERATION IMPACT

	Historical	Arctic
S	0.070	0.036
M	0.192	0.096
L	0.046	0.028
H	0.013	0.008

Rig Anchoring

	Historical	Arctic
S	0.050	0.023
M	0.137	0.063
L	0.000	0.000
H	0.000	0.000

Work Boat Anchoring

	Historical	Arctic
S	0.020	0.012
M	0.055	0.033
L	0.046	0.028
H	0.013	0.008

MECHANICAL

	Historical	Arctic
S	0.000	0.000
M	0.000	0.000
L	0.000	0.000
H	0.000	0.000

Connection Failure

	Historical	Arctic
S	0.000	0.000
M	0.000	0.000
L	0.000	0.000
H	0.000	0.000

Material Failure

	Historical	Arctic
S	0.000	0.000
M	0.000	0.000
L	0.000	0.000
H	0.000	0.000

NATURAL HAZARD

	Historical	Arctic
S	1.115	0.482
M	3.065	1.326
L	0.738	0.319
H	0.211	0.091

Mud Slide

	Historical	Arctic
S	0.020	0.009
M	0.055	0.024
L	0.046	0.020
H	0.013	0.006

Storm/ Hurricane

	Historical	Arctic
S	1.095	0.473
M	3.010	1.302
L	0.531	0.299
H	0.196	0.085

UNKNOWN

	Historical	Arctic
S	0.099	0.099
M	0.272	0.272
L	0.000	0.000
H	0.000	0.000

ARCTIC

	Historical	Arctic
S	0.000	0.066
M	0.000	0.066
L	0.000	0.165
H	0.000	0.033

Ice Gouging

	Historical	Arctic
S	0.000	0.052
M	0.000	0.052
L	0.000	0.129
H	0.000	0.026

Strudel Scour

	Historical	Arctic
S	0.000	0.006
M	0.000	0.006
L	0.000	0.016
H	0.000	0.003

Upheaval Buckling

	Historical	Arctic
S	0.000	0.001
M	0.000	0.001
L	0.000	0.003
H	0.000	0.001

Thaw Settlement

	Historical	Arctic
S	0.000	0.001
M	0.000	0.001
L	0.000	0.002
H	0.000	0.000

Other Arctic

	Historical	Arctic
S	0.000	0.006
M	0.000	0.006
L	0.000	0.015
H	0.000	0.003

Figure 4.4
Spill Frequencies for Arctic PIP Pipeline

Table 4.6
Expected Value Summary of Arctic PIP Pipeline Spill Frequencies

Pipeline Spill Size	Spill Frequency per 10^5 km-year		Expected Spill Frequency per 10^5 km-year	
	Historical Pipeline	Historical PIP Pipeline	Historical PIP Pipeline	Arctic PIP Pipeline
Small Spills 50-99 bbl	3.570	1.182	1.482	0.777
Medium Spills 100-999 bbl	9.817	3.249	4.076	2.021
Large Spills 1,000-9,999 bbl	6.247	1.360	1.706	0.954
Huge Spills =>10,000 bbl	1.785	0.388	0.487	0.258

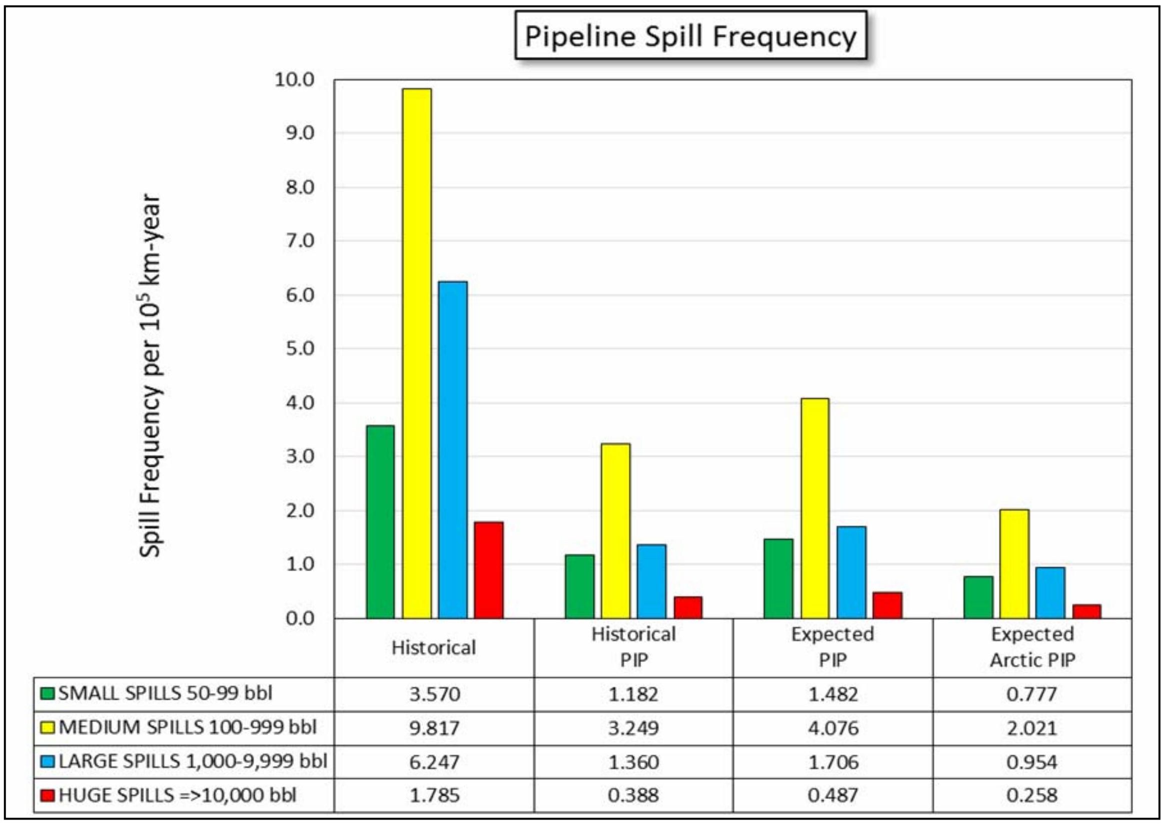


Figure 4.5: **Expected Value Summary of Arctic PIP Pipeline Spill Frequencies**

4.4 Island Fault Tree Analysis

4.4.1 Arctic Island Spill Causal Frequency Distributions

Table 4.7 summarizes the variations in the modified and unique Arctic effect inputs for the island. As for pipeline unique effects, both the Triangular Distribution expected and modal values are given.

The first two modified cause classifications, equipment failure and human error modes were reduced by 30 and 20%, respectively, primarily as a result of the state-of-the-art engineering, construction, and operational standards and practices expected. Collisions were reduced by 80% based on low vessel traffic expectations. As before, storms tend to be less severe in the Arctic, and certainly during the ice season would have limited impact on the facility, resulting in an 85% reduction in hurricane causes. However, weather in general, including very low temperatures, have been increased by 20%.

Unique effects are also included. Increments in facility spills were attributed to ice force, low temperature effects, and unknown effects which were taken as a percentage of the other unique Arctic effects. Ice force effect calculations were based on the 1/10,000 year ice force causing spills, predominantly small and medium. Increase of low temperature effects was estimated as 6% for S and M spills, and 1% for L and H spills (as large spills are highly unlikely from the island process facilities) of historical process facility spill rates.

Changes in frequency distribution attributable to Arctic effects were calculated using the secondary effect probability distribution, as was done for pipelines. Table 4.8 summarizes the principal distribution parameters for both the Arctic modified and Arctic unique effect distributions.

4.4.2 Arctic Island Fault Tree Spill Frequency Calculations

Figure 4.6 shows the fault tree developed for the island Arctic spills for small and medium (SM), and large and huge spill (LH) sizes in accordance with [15]. Again, the fault tree gives the historical value, together with the calculated values for these spill sizes. Table 4.9 summarizes the historical and derived Arctic expected values of island spill frequencies, and Figure 4.7 gives a bar chart with these values.

Table 4.7
Island Arctic Effect Derivation Summary

CAUSE CLASSIFICATION 1972 – 2010 (no LOWC)		Island Arctic Spill Frequency Change %				REASON
		Min	Mode	Max	Expected	
EQUIPMENT FAILURE	All	(60)	(30)	(10)	(33.96)	State of the art, High QC, High Inspection and Maintenance Requirements
HUMAN ERROR	All	(60)	(20)	(10)	(31.96)	More qualified personnel
COLLISION	All	(90)	(80)	(10)	(55.97)	Low traffic density, island resistant to ship impacts
WEATHER	All	10	20	30	20.00	Cold Temperatures, rapid changes or cycling
HURRICANE	All	(90)	(85)	(10)	(56.76)	Fewer severe storm effects inside barrier islands.
ARCTIC UNIQUE	Spill Size	Spill Frequency Increment per 10^4 well-year				REASON
		Min	Mode	Max	Expected	
Ice Force	SM	0.001	0.009	0.085	0.0362	Assumed 10,000 year return period ice force causes spill 1% of occurrences (99% reliability). 85% of the spills are SM as due to ride-up impact only.
	LH	0.000	0.002	0.015	0.0064	
Facility Low Temperature	SM	0.043	0.086	0.128	0.0855	Assumed fraction of Historical Equipment Failure release frequency with 6% for SM and 1% for LH spill sizes.
	LH	0.000	0.000	0.001	0.0004	
Other Arctic	SM	0.004	0.009	0.021	0.0121	10% of sum of above.
	LH	0.000	0.000	0.002	0.0007	

Table 4.8
Arctic Island Spill Size Frequency Distribution

CAUSE CLASSIFICATION 1972 - 2010 (no LOWC)	Historical Distribution %	SMALL AND MEDIUM SPILLS 50-999 bbl				Historical Distribution %	LARGE AND HUGE SPILLS =>1,000 bbl			
		FREQUENCY spills per 10^4well-year	Frequency Change	New Frequency	New Distribution %		FREQUENCY spills per 10^4well-year	Frequency Change	New Frequency	New Distribution %
EQUIPMENT FAILURE	29.91	1.901	(0.646)	1.255	33.94	14.29	0.054	(0.018)	0.036	13.40
HUMAN ERROR	11.11	0.706	(0.226)	0.480	12.99					
COLLISION	0.85	0.054	(0.030)	0.024	0.65					
WEATHER	4.27	0.272	0.054	0.326	8.81	28.57	0.109	0.022	0.130	48.71
HURRICANE	53.85	3.422	(1.942)	1.480	40.00	57.14	0.217	(0.123)	0.094	35.10
ARCTIC			0.134	0.134	3.619			0.007	0.007	2.791
Ice Force			0.036	0.036	0.98			0.006	0.006	2.39
Facility Low Temperature			0.086	0.086	2.31			0.000	0.000	0.15
Other Arctic			0.012	0.012	0.33			0.001	0.001	0.25
TOTALS	100.00	6.355	(2.656)	3.699	100.00	100.00	0.380	(0.113)	0.268	100.00

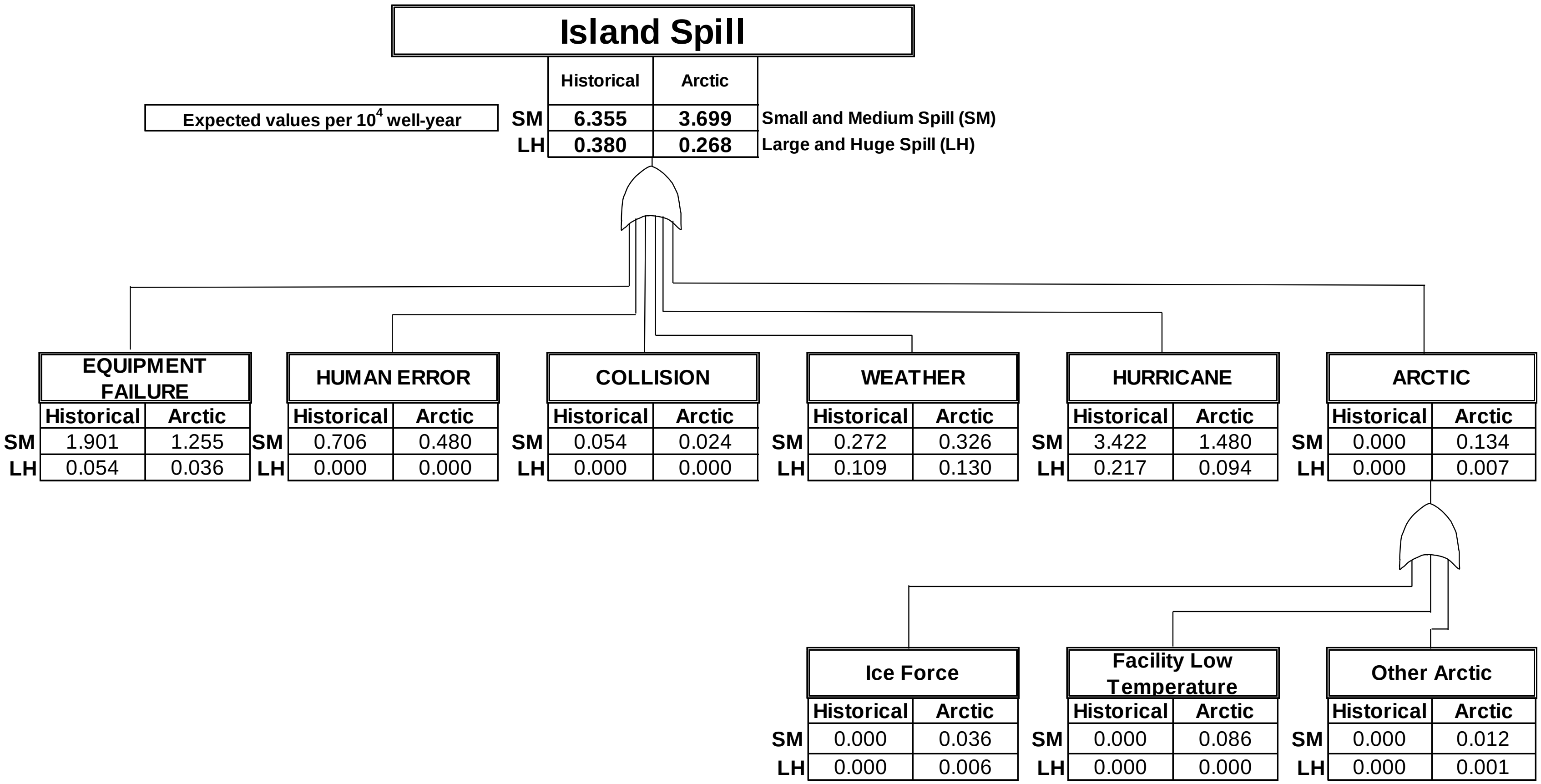


Figure 4.6
Spill Frequencies Liberty Island Fault Tree

Table 4.9
Arctic Island Spill Frequency Expected Value Summary

Island Spill Size	Spill Frequency per 10^4 well-year	Expected Spill Frequency per 10^4 well-year	
	Historical	Historical	Arctic
SMALL AND MEDIUM SPILLS 50-999 bbl	4.766	6.355	3.699
LARGE AND HUGE SPILLS =>1,000 bbl	0.285	0.380	0.268

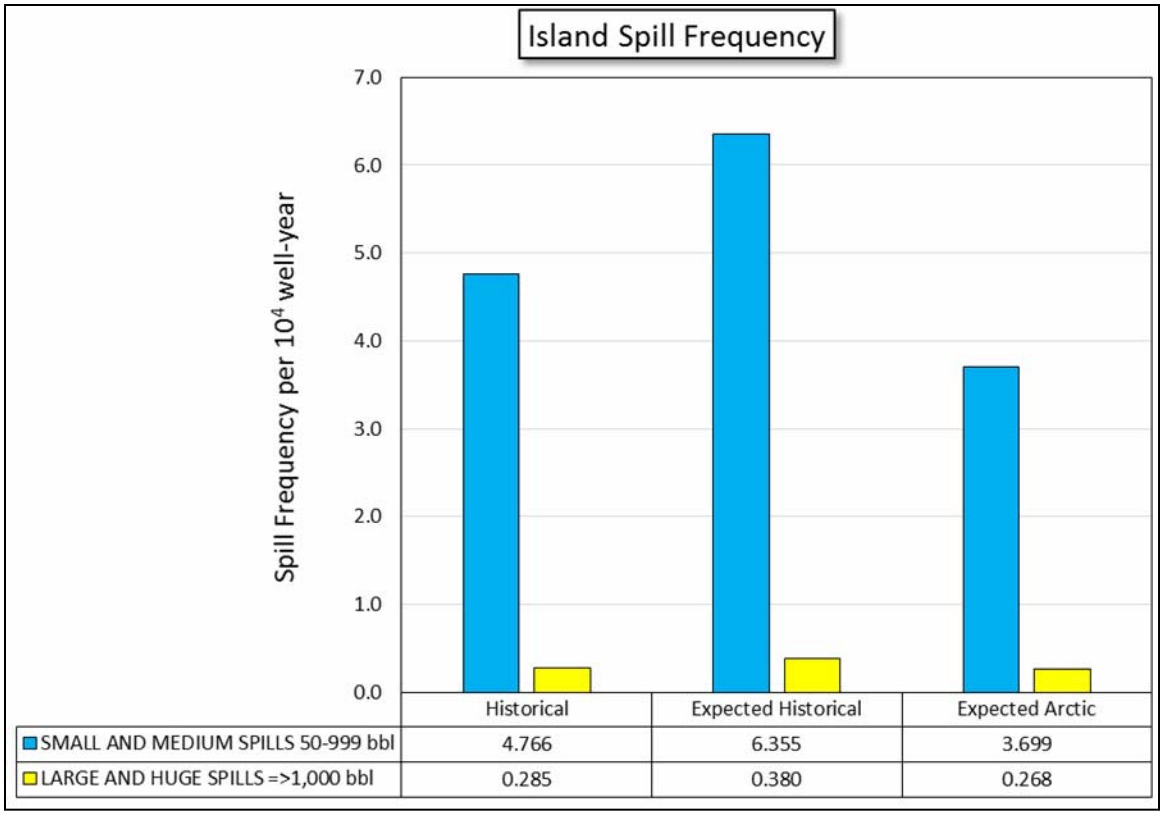


Figure 4.7: Arctic Island Spill Frequency Expected Value Bar Chart

4.5 Loss of Well Control (LOWC) Arctic Frequency Analysis

4.5.1 LOWC Arctic Effects

The historical data, as described in Chapter 2, were modified for each well type, spill size, and water depth range for Arctic effects (on historical values), as described in Table 4.10. No Arctic unique effects were introduced for LOWC.

Table 4.10
LOWC Fault Tree Analysis Arctic Effect Summary

Spill Size	Event	Frequency Unit	Historical Frequency Change %	Reason
Small and Medium Spills 50-999 bbl	Production Well	spill per 10^4 well-year	(30)	State of the art, High QC, High Inspection and Maintenance standard
	Exploration Well Drilling	spill per 10^4 wells	(10)	Highly qualified drilling contractor. Better logistics support
	Development Well Drilling	spill per 10^4 wells	(10)	Highly qualified drilling contractor. Better logistics support
Large Spills 1,000-9,999 bbl	Production Well	spill per 10^4 well-year	(30)	State of the art, High QC, High Inspection and Maintenance standard
	Exploration Well Drilling	spill per 10^4 wells	(10)	Highly qualified drilling contractor. Better logistics support
	Development Well Drilling	spill per 10^4 wells	(10)	Highly qualified drilling contractor. Better logistics support
Spill 10,000-149,999 bbl	Production Well	spill per 10^4 well-year	(30)	State of the art, High QC, High Inspection and Maintenance standard
	Exploration Well Drilling	spill per 10^4 wells	(10)	Highly qualified drilling contractor. Better logistics support
	Development Well Drilling	spill per 10^4 wells	(10)	Highly qualified drilling contractor. Better logistics support
Spill >=150,000 bbl	Production Well	spill per 10^4 well-year	(30)	State of the art, High QC, High Inspection and Maintenance standard Safety culture dedicated to avoid large spills in Arctic
	Exploration Well Drilling	spill per 10^4 wells	(10)	Highly qualified drilling contractor. Better logistics support
	Development Well Drilling	spill per 10^4 wells	(10)	Highly qualified drilling contractor. Better logistics support

4.5.2 Arctic LOWC Spill Frequency Calculation

Table 4.11 gives the details of the frequency calculation for LOWC. No fault tree was required here, as only base events with no causal distributions were modeled for each case. The modifications given in Table 4.10 were applied to historical values to yield the values summarized in Table 4.11.

Figures 4.8 and 4.9 give, respectively, the well drilling and production well historical and Project LOWC frequency bar charts.

4.6 Spill Volume Distributions

Tables 4.12, 4.13, and 4.15 summarize the spill volume distribution parameters for each project component, including the expected value that was calculated utilizing a Monte Carlo calculation. The spill volume parameters were derived from the historical data described in Section 2.7. No Arctic effects are factored into the spill volume values.

Table 4.11
Arctic LOWC Frequencies

Spill Size	Event	Frequency Unit	Historical Frequency	Frequency Change *Middle Shelf*	New Frequency *Middle Shelf*
Small and Medium Spills 50-999 bbl	Production Well	spill per 10^4 well-year	0.028	(0.008)	0.019
	Exploration Well Drilling	spill per 10^4 wells	1.530	(0.153)	1.377
	Development Well Drilling	spill per 10^4 wells	0.299	(0.030)	0.269
Large Spills 1,000-9,999 bbl	Production Well	spill per 10^4 well-year	0.011	(0.003)	0.008
	Exploration Well Drilling	spill per 10^4 wells	0.620	(0.062)	0.558
	Development Well Drilling	spill per 10^4 wells	0.122	(0.012)	0.109
Spill 10,000-149,999 bbl	Production Well	spill per 10^4 well-year	0.007	(0.002)	0.005
	Exploration Well Drilling	spill per 10^4 wells	0.403	(0.040)	0.362
	Development Well Drilling	spill per 10^4 wells	0.079	(0.008)	0.071
Spill >=150,000 bbl	Production Well	spill per 10^4 well-year	0.004	(0.001)	0.003
	Exploration Well Drilling	spill per 10^4 wells	0.250	(0.025)	0.225
	Development Well Drilling	spill per 10^4 wells	0.049	(0.005)	0.044

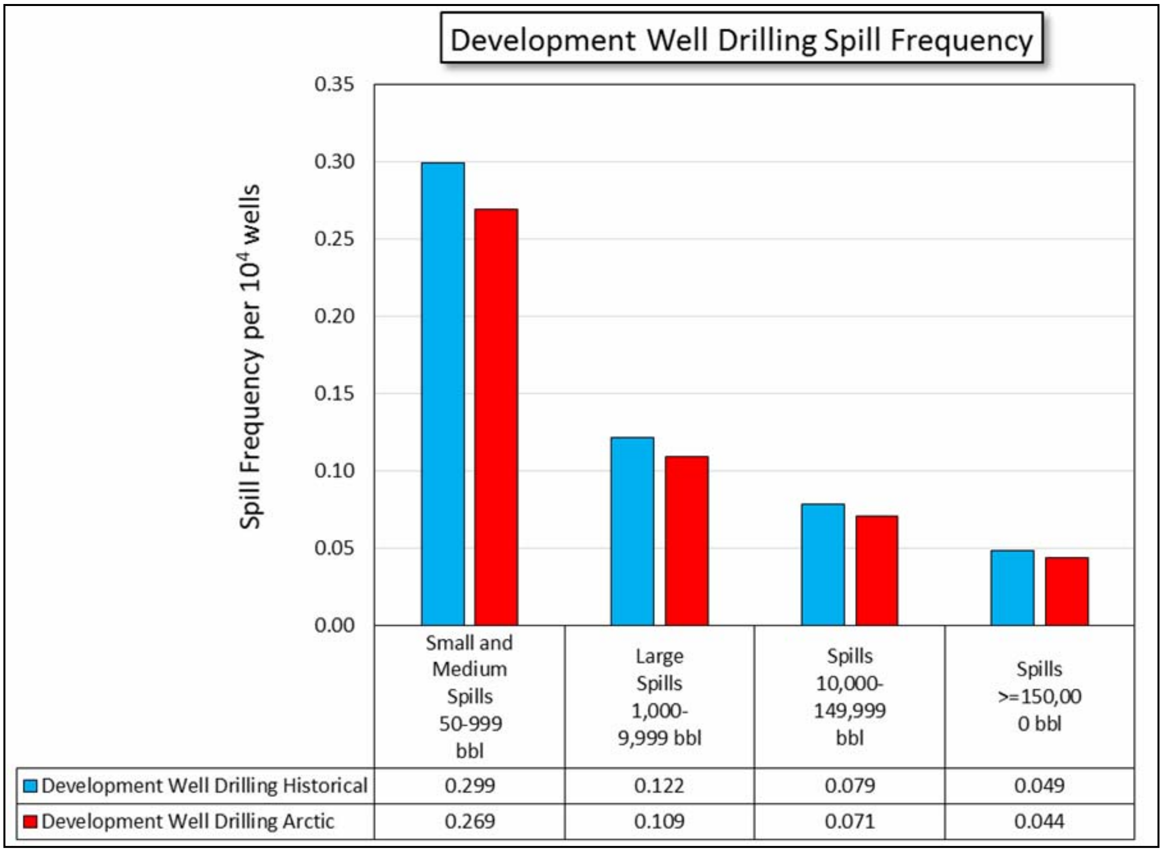


Figure 4.8: Drilling LOWC Frequencies

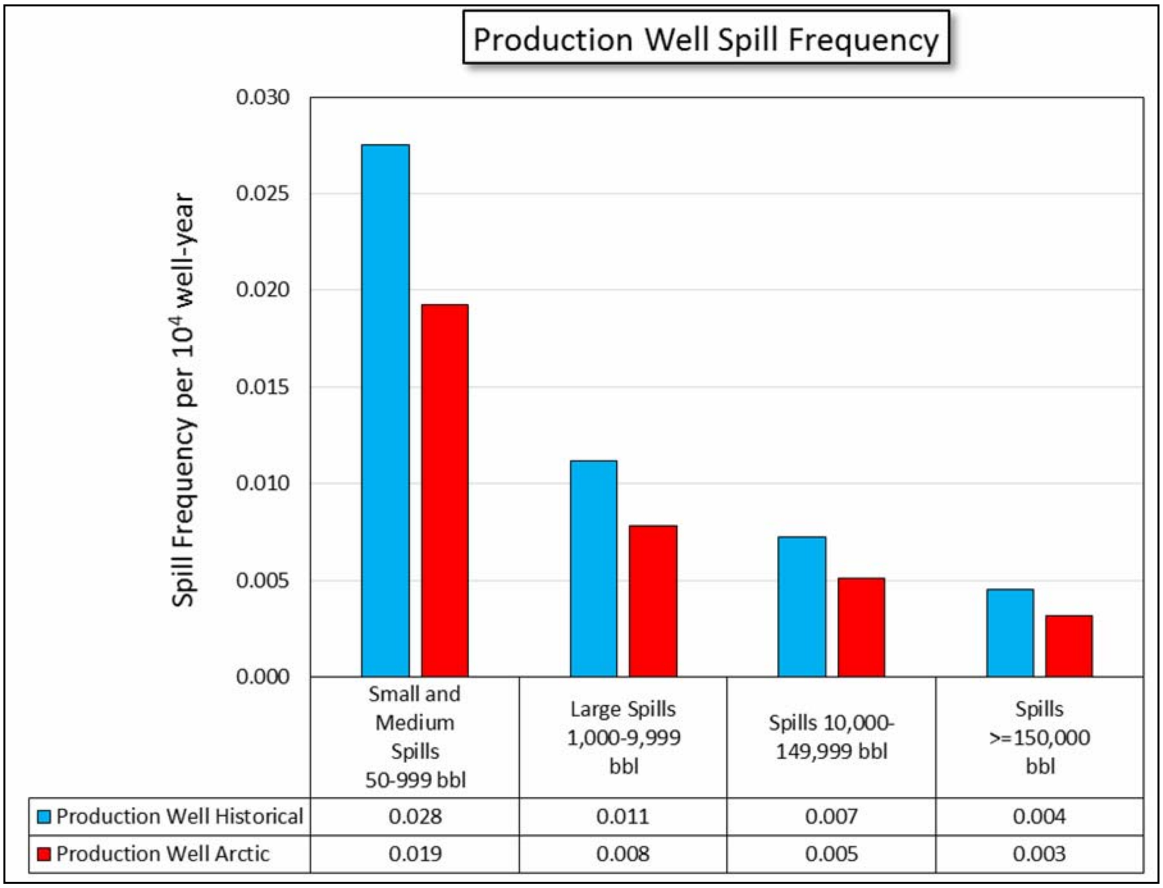


Figure 4.9: Production Well LOWC Frequencies

Table 4.12
Pipeline Spill Volume Parameters

Spill Size	Small Spills 50-99 bbl				Medium Spills 100-999 bbl				Large Spills 1,000-9,999 bbl				Huge Spills =>10,000 bbl			
Spill Expectation	Low	Mode	High	Expected	Low	Mode	High	Expected	Low	Mode	High	Expected	Low	Mode	High	Expected
Pipeline Diameter > 10" Spill	50	58	99	71	100	387	999	516	1,000	3,932	9,999	5,176	10,000	17,705	20,000	15,552

Table 4.13
Island Spill Volume Parameters

Spill Size	Small and Medium Spills 50-999 bbl				Large and Huge Spills =>1,000 bbl			
Spill Expectation	Low	Mode	High	Expected	Low	Mode	High	Expected
Island Spill	50	158	999	452	1,000	6,130	10,000	5,631

Table 4.14
LOWC Spill Volume Parameters

Spill Size	Small and Medium Spills 50-999 bbl				Large Spills 1,000-9,999 bbl				Spills 10,000-149,999 bbl				Spills =>150,000 bbl			
Spill Expectation	Low	Mode	High	Expected	Low	Mode	High	Expected	Low	Mode	High	Expected	Low	Mode	High	Expected
Well Spill	50	500	999	519	1,000	4,500	9,999	5,292	10,000	20,000	150,000	68,349	150,000	200,000	1,000,000	502,734

CHAPTER 5

OIL SPILL OCCURRENCE INDICATOR QUANTIFICATION

5.1 Definition of Oil Spill Occurrence Indicators

Four primary oil spill occurrence indicators (generally referred to as "spill indicators" after this) were quantified in this study. These are as follows:

- Frequency in spills per 1,000 years.
- Frequency in spills per 10^9 barrels produced in each year.
- Spill index, the product of spill frequency and associated average spill size.
- Life of field indicators.

The spill indicators defined above are subdivided for the Project as follows:

- By facility type (3 types).
- By spill size (4 sizes).
- By year (2 to 25, which is 24 years inclusive).

The above combinations translate into 12 sets of spill indicators per year. Given that these are calculated for each year, with the scenario lasting for 24 years, gives 288 sets of indicators. In this chapter, we will present and describe the salient results of the indicator evaluation.

5.2 Oil Spill Occurrence Indicator Calculation Process

The oil spill occurrence indicator calculation process is shown in the flow chart presented as Figure 5.1. This chapter discusses the spill occurrence indicator calculations as shown in the right hand column ("Spill Occurrence") in Figure 5.1. Previous chapters covered the balance of the items in that figure.

Essentially, this chapter addresses the combining of the development scenario described in Chapter 3 with the unit-spill frequency distributions presented in Chapter 4 to provide measures of oil spill occurrence, the oil spill indicators for the Project. Although the calculation is complex because of the many combinations considered, it is a simple process of accounting. Essentially, the quantities of potential oil spill sources are multiplied by their appropriate unit oil spill frequency to give the total expected spill distributions. To develop the probability distributions by the Monte Carlo process, each of the combinations needs to be sampled, in this case a sampling of 3,000 iterations was carried out for each combination studied. This translates into roughly 12 million arithmetic operations to generate the Monte Carlo results.

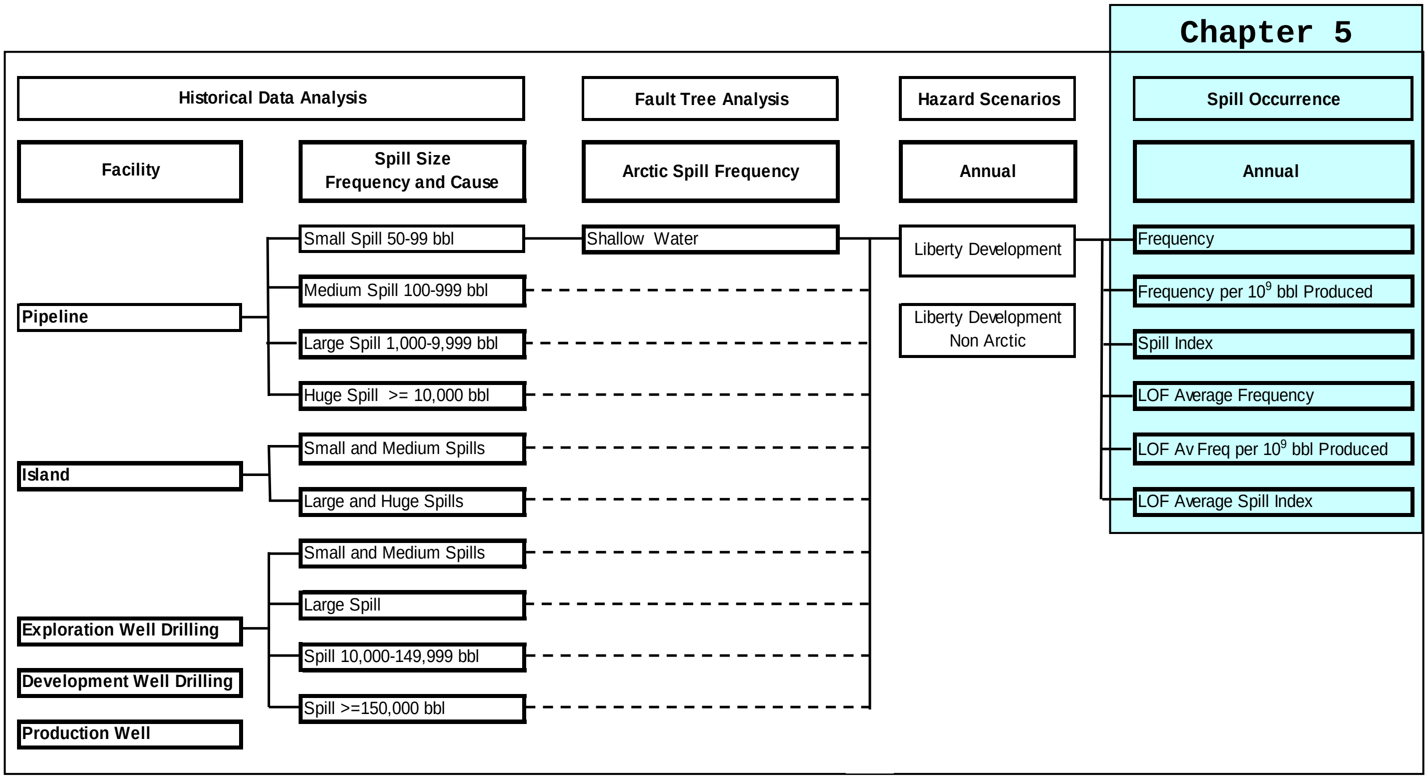


Figure 5.1: Calculation Flow Chart

5.3 Summary of Project Oil Spill Occurrence Indicators

5.3.1 Project Oil Spill Occurrence Indicators

Each of the principal annual total Project oil spill occurrence indicators including those for the pipeline, island, and wells by spill size for each year is given in Figures 5.2, 5.3, and 5.4. As can be seen, each of these figures spans the development scenario from year 2 to 25, as described earlier in Table 3.3. Next, Figures 5.5, 5.6, and 5.7 give spill indicators by spill size for the pipeline, island, and wells, respectively.

Each of the indicators has been subdivided into three segments for each year, those corresponding to spills 50-999 bbl (small and medium), spills 1,000-9,999 bbl (large), and spills >=10,000 bbl (huge). It should be noted that the spill frequency associated with each spill size is only the shaded increment shown in each of the bars. The horizontal axis gives Project years starting in Year 2 the first year with spill potential. Thus, for example, in Figure 5.2 for the year 10, small and medium spills are approximately 2.1 per thousand years. Next, in that year, large spills are approximately 0.16 per thousand years, as shown in the second bar increment. Finally, the top increment corresponds to huge spills, and is approximately 0.11 per thousand years. The same form of presentation applies for the spills per 10^9 barrels produced and for the spill index shown in Figures 5.3 and 5.4. For years in which no production exists (2 and 3), the spills per 10^9 barrels produced (Figure 5.3) are not applicable. The spills per 10^9 barrels produced continue to rise exponentially to the final production year (25), because the facility quantities (and hence spill rate) remain relatively high, while production volumes decrease considerably for each of the last few years. Clearly, the spill index (Figure 5.4) is dominated by the huge spills. The reader should note that following this detailed presentation of the total Project spill indicators in separate figures, each facility three spill indicators will be given in one figure in order to conserve space and make the report a little more concise.

Spill indicators by facility type were also quantified. All three spill indicators for pipelines are shown in Figure 5.5. Figure 5.6 shows the spill indicators for the island (only for the two spill size categories available from the base data [15]), and Figure 5.7 shows the spill indicators for drilling of wells and producing wells. Numerous conclusions can be drawn from the comparison of these spill indicators. For example, it can be seen that the major contributors to spill frequency is from the island (Figure 5.6), as for platforms in earlier studies [13, 16]. However, the largest of the facility spill expectations, as represented by spill index, is from the wells (Figure 5.7).

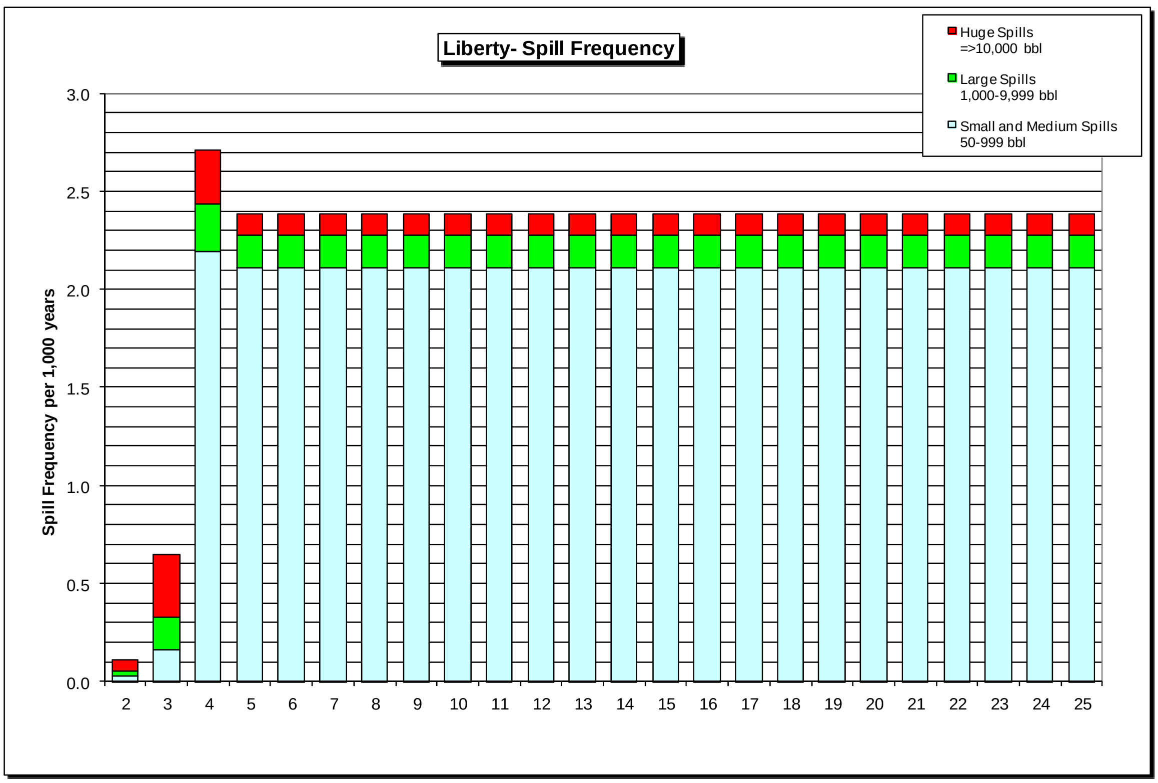


Figure 5.2: Project Spill Frequency per 1,000 Years

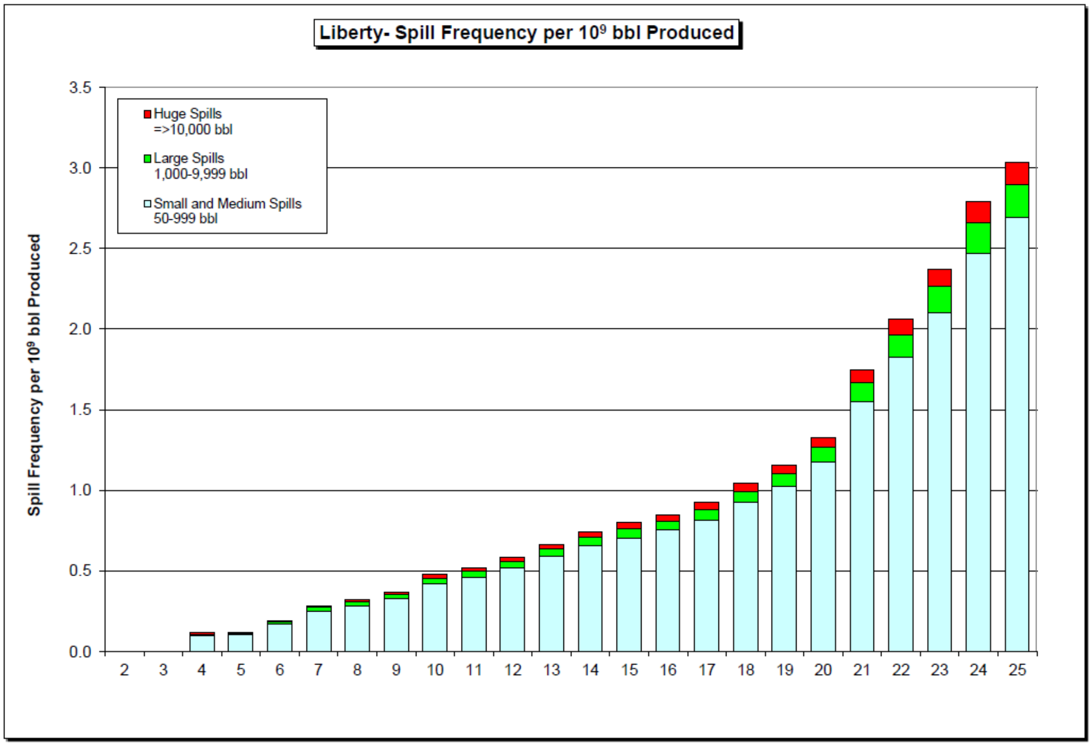


Figure 5.3: Project Spill Frequency per 10^9 Barrels Produced

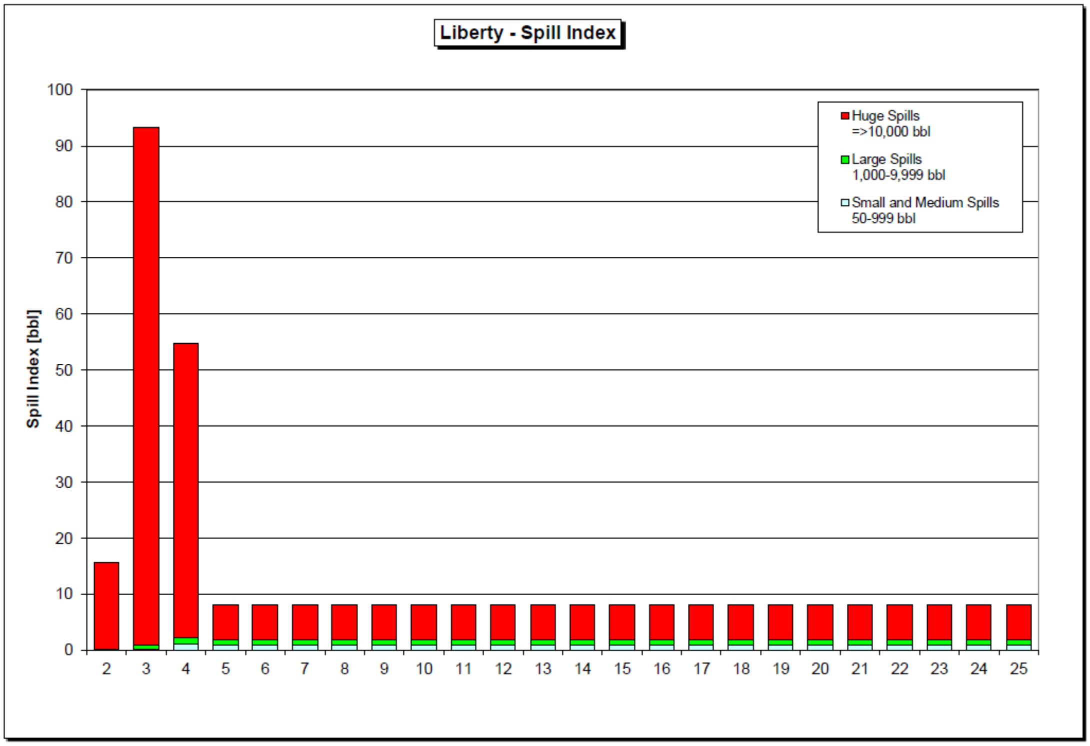


Figure 5.4: Project Spill Index

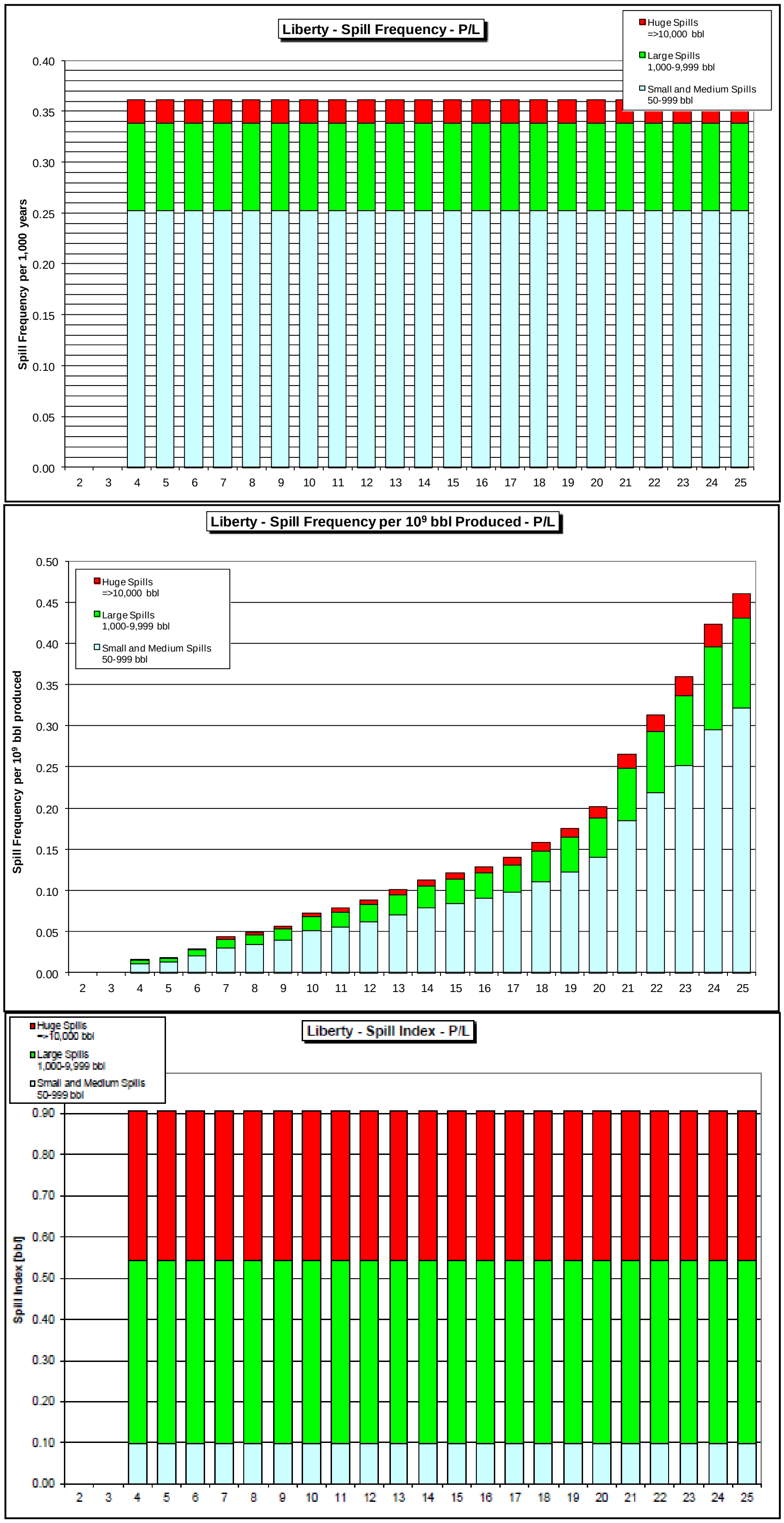


Figure 5.5: Project Spill Indicators – Pipeline

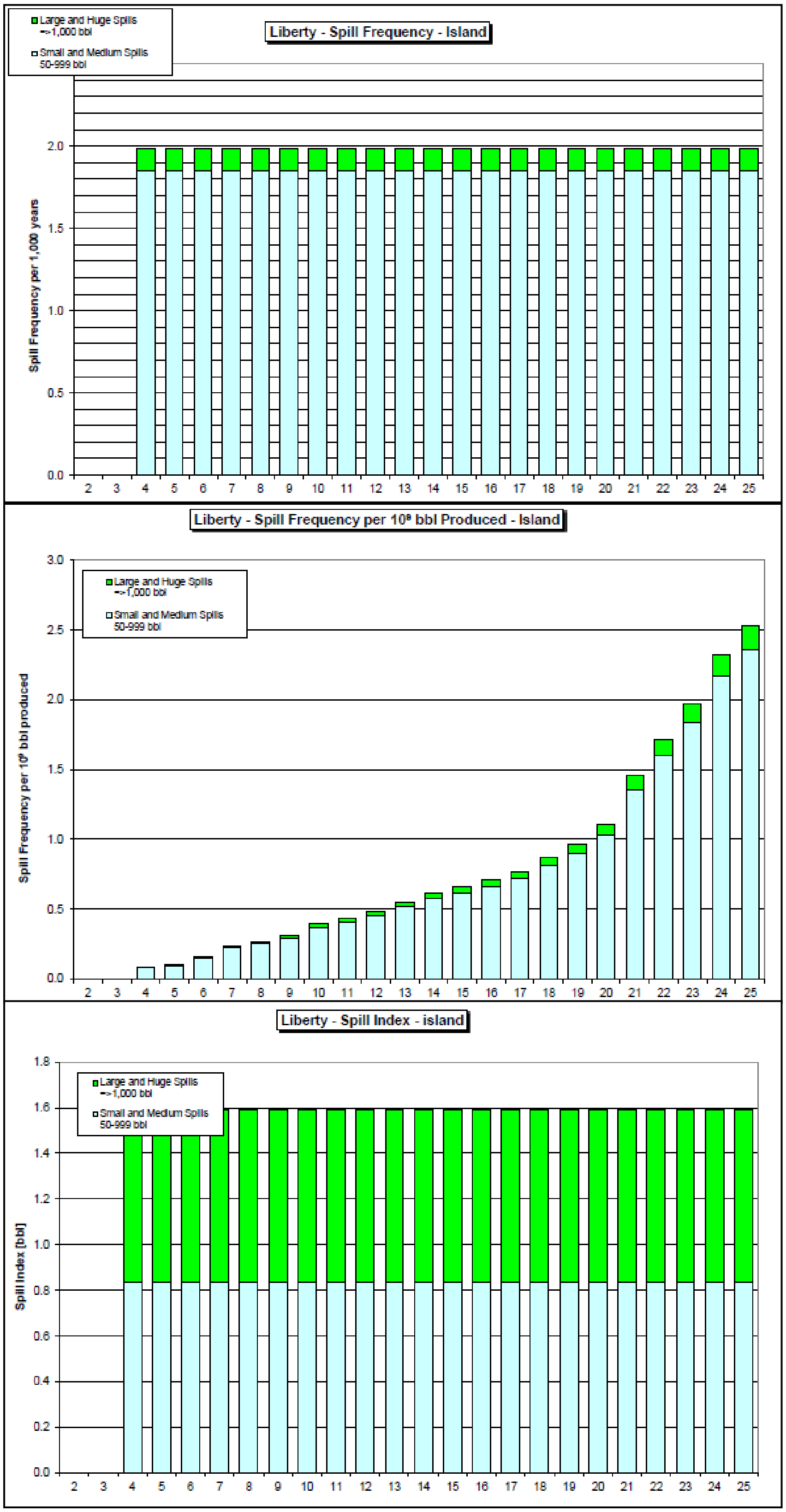


Figure 5.6: Project Spill Indicators – Island

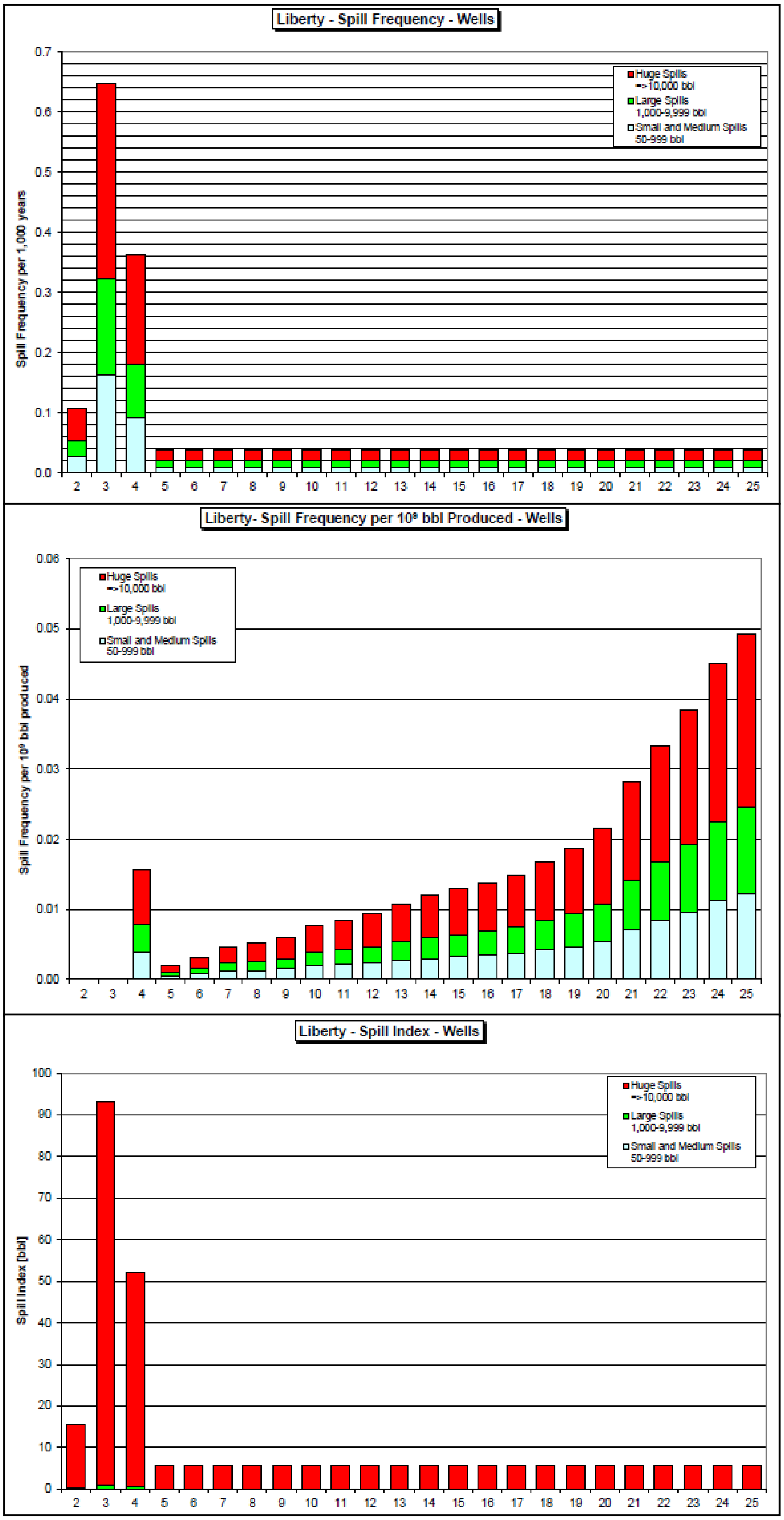


Figure 5.7: Project Spill Indicators – Wells

Finally, as part of the assessment of the Project scenario, a Monte Carlo analysis was carried out for each year, with the distributed inputs described earlier. The tabular results of the Monte Carlo simulation are summarized in Table 5.1 for the Project year 15. This table gives the statistical characteristics of the calculated indicators for each of three spill size ranges, as well as a tabular summary of their cumulative distribution curves. Figure 5.8 shows graphs of the calculated cumulative distribution functions. Basically, the vertical axis gives the probability in percent that the corresponding value on the horizontal axis will not be exceeded. Thus, for example, referring to the right-hand central graph, for substantial spills >= 1,000 bbl (large and huge), there is a 50% probability that a spill frequency will be no more than 0.085 per billion barrels produced in year 15. In other words, there is a 50% chance that large and huge spills will occur at a rate of 0.085 per billion bbl or less.

The frequency spill indicator variability can be estimated from the upper (95%) and lower (5%) bound values. For example, for large spill frequency (from Table 5.1), the lower bound (0.038) is 23% of the mean (0.163); the upper bound (0.332), 203% of the mean. The flattening or decrease in slope of the CDFs above 90% and below 10% can be attributed to the use of the triangular distribution with designated limits at corresponding (± 10%) levels.

In addition, the Life of Field (LOF) averages were calculated. Table 5.2 shows the composition of the spill indicators for the Project Life of Field average, and includes all principal sources combined. The variability of the spill indicators for the Life of Field averages is shown in the following figures for all principal sources individually and combined. Figure 5.9 illustrates the variability of the spill frequency. Figure 5.10 shows variability of frequency per billion barrels produced. Figure 5.11 shows the variability of the Spill Index.

Figures 5.12 and 5.13 give the bar graphs of the Project LOF spill indicators by spill size and source, respectively, for both the project and its non-Arctic counterpart.

Table 5.3 gives the summary of spill indicators by spill size and source facility for both the project and its non-Arctic counterpart, to be discussed further in Section 5.3.2.

Table 5.1
Project Year 15 – Monte Carlo Results

Liberty Year 15	Small and Medium Spills (50-999 bbl)	Large Spills (1,000-9,999 bbl)	Huge Spills (=>10,000 bbl)	Substantial Spills (=>1,000 bbl)	All Spills	Small and Medium Spills (50-999 bbl)	Large Spills (1,000-9,999 bbl)	Huge Spills (=>10,000 bbl)	Substantial Spills (=>1,000 bbl)	All Spills	Small and Medium Spills (50-999 bbl)	Large Spills (1,000-9,999 bbl)	Huge Spills (=>10000 bbl)	Substantial Spills (=>1000 bbl)	All Spills
	Frequency Spills per 10^3 years					Frequency Spills per 10^9 bbl Produced					Spill Index (bbl)				
Mean =	2.115	0.163	0.109	0.272	2.387	0.707	0.054	0.037	0.091	0.798	0.940	0.874	6.245	7.119	8.058
Std Deviation =	1.635	0.090	0.062	0.138	1.651	0.547	0.030	0.021	0.046	0.552	1.036	0.619	3.618	3.729	3.876
Variance =	2.672	0.008	0.004	0.019	2.726	0.299	0.001	0.000	0.002	0.305	1.074	0.383	13.091	13.902	15.021
Skewness =	0.913	0.759	0.743	0.711	0.917	0.913	0.759	0.743	0.711	0.917	2.078	1.291	1.067	1.005	0.924
Kurtosis =	3.511	3.576	3.325	3.372	3.539	3.511	3.576	3.325	3.372	3.539	8.890	5.334	4.141	4.044	3.855
Mode =	0.644	0.128	0.080	0.186	1.175	0.215	0.043	0.027	0.062	0.393	0.155	0.515	4.390	5.990	4.980
Minimum =	-0.754	-0.036	-0.011	-0.040	-0.528	-0.252	-0.012	-0.004	-0.013	-0.176	-0.532	-0.356	0.003	0.379	0.353
5% Perc =	0.106	0.038	0.027	0.082	0.361	0.036	0.013	0.009	0.028	0.121	0.015	0.142	1.792	2.387	2.998
10% Perc =	0.311	0.057	0.038	0.110	0.559	0.104	0.019	0.013	0.037	0.187	0.074	0.218	2.347	3.001	3.711
15% Perc =	0.490	0.072	0.047	0.131	0.753	0.164	0.024	0.016	0.044	0.252	0.128	0.289	2.765	3.502	4.275
20% Perc =	0.658	0.084	0.055	0.149	0.922	0.220	0.028	0.018	0.050	0.308	0.182	0.354	3.174	3.947	4.768
25% Perc =	0.825	0.095	0.062	0.167	1.092	0.276	0.032	0.021	0.056	0.365	0.242	0.418	3.558	4.356	5.195
30% Perc =	0.999	0.107	0.069	0.185	1.258	0.334	0.036	0.023	0.062	0.421	0.296	0.483	3.915	4.746	5.618
35% Perc =	1.180	0.117	0.076	0.202	1.440	0.395	0.039	0.025	0.068	0.482	0.358	0.545	4.277	5.148	6.044
40% Perc =	1.380	0.127	0.083	0.218	1.650	0.461	0.043	0.028	0.073	0.552	0.427	0.607	4.638	5.557	6.485
45% Perc =	1.565	0.138	0.091	0.235	1.841	0.523	0.046	0.030	0.079	0.616	0.505	0.671	5.046	5.954	6.902
50% Perc =	1.782	0.149	0.099	0.253	2.059	0.596	0.050	0.033	0.085	0.689	0.591	0.739	5.439	6.384	7.357
55% Perc =	2.003	0.161	0.109	0.271	2.268	0.670	0.054	0.036	0.091	0.758	0.692	0.813	5.910	6.838	7.849
60% Perc =	2.233	0.173	0.117	0.290	2.503	0.747	0.058	0.039	0.097	0.837	0.809	0.894	6.404	7.348	8.347
65% Perc =	2.462	0.187	0.127	0.310	2.750	0.823	0.062	0.042	0.104	0.919	0.932	0.977	6.931	7.864	8.890
70% Perc =	2.765	0.201	0.137	0.333	3.032	0.924	0.067	0.046	0.111	1.014	1.101	1.077	7.508	8.482	9.482
75% Perc =	3.104	0.216	0.148	0.356	3.354	1.038	0.072	0.050	0.119	1.121	1.299	1.184	8.220	9.144	10.205
80% Perc =	3.474	0.235	0.161	0.384	3.762	1.162	0.079	0.054	0.128	1.258	1.539	1.316	9.015	9.919	11.045
85% Perc =	3.910	0.257	0.175	0.420	4.198	1.307	0.086	0.059	0.141	1.404	1.855	1.482	9.989	10.948	12.062
90% Perc =	4.425	0.286	0.194	0.464	4.729	1.479	0.096	0.065	0.155	1.581	2.286	1.706	11.298	12.361	13.488
95% Perc =	5.262	0.332	0.224	0.529	5.589	1.759	0.111	0.075	0.177	1.869	3.083	2.072	13.381	14.412	15.454
Maximum =	9.078	0.651	0.373	0.995	9.464	3.035	0.218	0.125	0.333	3.164	9.725	5.076	25.254	27.212	28.260

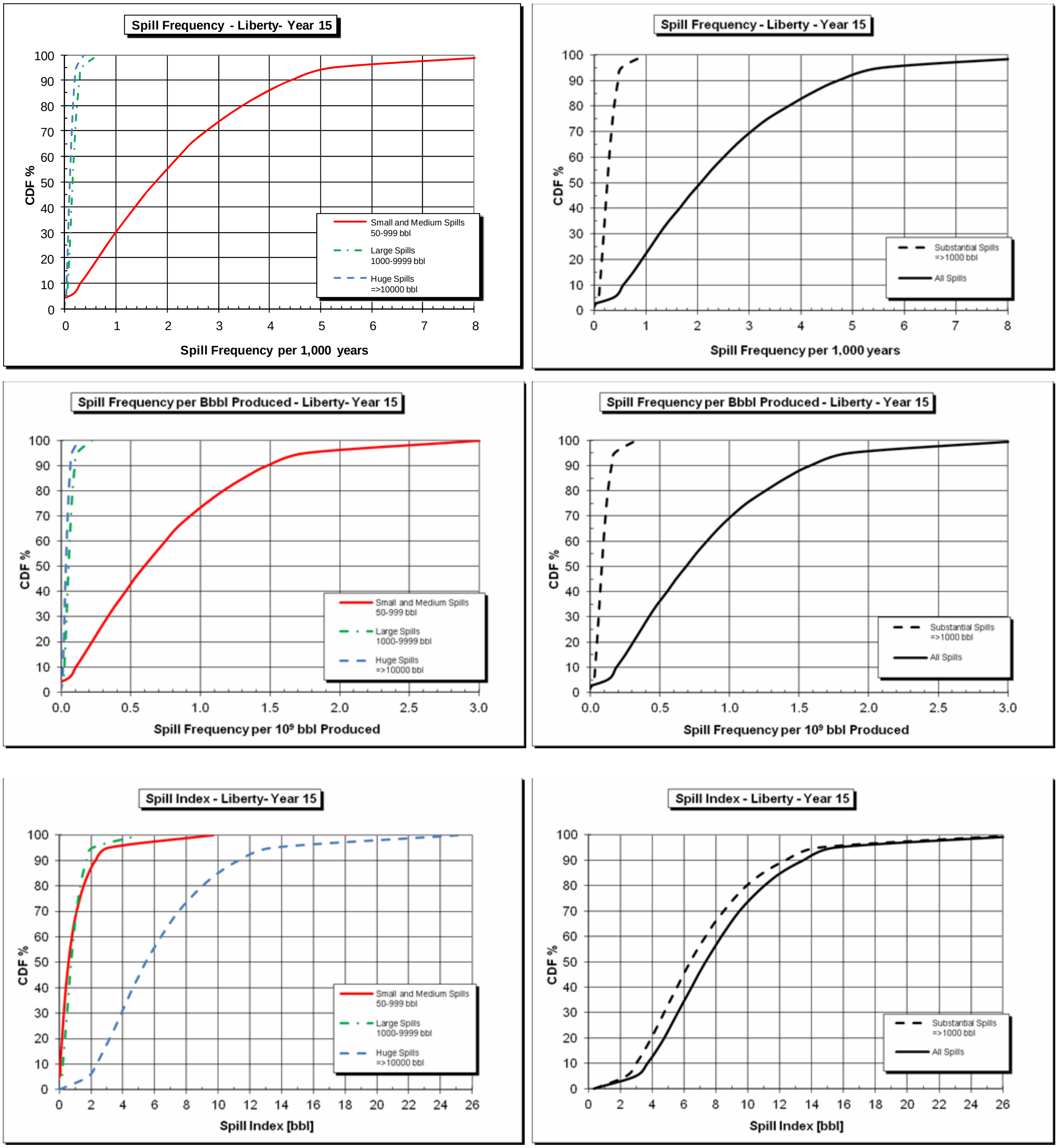


Figure 5.8: Project Spill Indicator Distributions – Year 15

Table 5.2
Composition of Project Spill Indicators –Life of Field Average

Liberty	Small and Medium Spills (50-999 bbl)	Large Spills (1,000-9,999 bbl)	Huge Spills (=>10,000 bbl)	Substantial Spills (=>1,000 bbl)	All Spills	Small and Medium Spills (50-999 bbl)	Large Spills (1,000-9,999 bbl)	Huge Spills (=>10,000 bbl)	Substantial Spills (=>1,000 bbl)	All Spills	Small and Medium Spills (50-999 bbl)	Large Spills (1,000-9,999 bbl)	Huge Spills (=>10000 bbl)	Substantial Spills (=>1000 bbl)	All Spills
All years Average LOF	Frequency Spills per 10^3 years					Frequency Spills per 10^9 bbl Produced					Spill Index (bbl)				
Mean =	1.946	0.160	0.123	0.283	2.229	0.397	0.033	0.025	0.058	0.454	0.866	0.860	12.148	13.008	13.874
Std Deviation =	1.493	0.082	0.058	0.127	1.507	0.304	0.017	0.012	0.026	0.307	0.943	0.568	6.774	6.834	6.906
Variance =	2.230	0.007	0.003	0.016	2.271	0.093	0.000	0.000	0.001	0.094	0.889	0.323	45.885	46.700	47.697
Skewness =	0.910	0.696	0.688	0.634	0.915	0.910	0.696	0.688	0.634	0.915	2.075	1.259	1.044	1.022	1.002
Kurtosis =	3.572	3.421	3.201	3.200	3.605	3.572	3.421	3.201	3.200	3.605	8.982	5.307	4.028	3.986	3.964
Mode =	0.716	0.120	0.087	0.185	0.836	0.146	0.024	0.018	0.038	0.170	0.136	0.449	5.964	9.165	10.188
Minimum =	-0.704	-0.026	-0.005	-0.007	-0.549	-0.144	-0.005	-0.001	-0.001	-0.112	-0.743	-0.199	0.522	0.568	1.019
5% Perc =	0.097	0.045	0.044	0.105	0.354	0.020	0.009	0.009	0.021	0.072	0.017	0.177	3.877	4.580	5.252
10% Perc =	0.292	0.063	0.056	0.132	0.557	0.059	0.013	0.011	0.027	0.114	0.073	0.259	4.830	5.571	6.332
15% Perc =	0.453	0.076	0.064	0.153	0.727	0.092	0.016	0.013	0.031	0.148	0.122	0.323	5.601	6.387	7.158
20% Perc =	0.606	0.088	0.072	0.171	0.882	0.123	0.018	0.015	0.035	0.180	0.171	0.383	6.312	7.127	7.920
25% Perc =	0.765	0.099	0.079	0.187	1.047	0.156	0.020	0.016	0.038	0.213	0.222	0.443	6.990	7.836	8.670
30% Perc =	0.927	0.109	0.086	0.203	1.207	0.189	0.022	0.018	0.041	0.246	0.279	0.499	7.684	8.529	9.388
35% Perc =	1.091	0.119	0.093	0.219	1.373	0.222	0.024	0.019	0.045	0.280	0.337	0.556	8.385	9.231	10.120
40% Perc =	1.272	0.129	0.100	0.235	1.550	0.259	0.026	0.020	0.048	0.316	0.403	0.613	9.091	9.979	10.860
45% Perc =	1.455	0.139	0.107	0.251	1.738	0.297	0.028	0.022	0.051	0.354	0.475	0.675	9.858	10.743	11.633
50% Perc =	1.651	0.150	0.114	0.267	1.930	0.336	0.031	0.023	0.054	0.393	0.555	0.740	10.628	11.541	12.447
55% Perc =	1.854	0.160	0.122	0.284	2.138	0.378	0.033	0.025	0.058	0.436	0.644	0.806	11.517	12.422	13.331
60% Perc =	2.071	0.171	0.130	0.301	2.350	0.422	0.035	0.026	0.061	0.479	0.747	0.880	12.496	13.370	14.290
65% Perc =	2.301	0.184	0.139	0.321	2.587	0.469	0.037	0.028	0.065	0.527	0.872	0.959	13.514	14.414	15.301
70% Perc =	2.557	0.197	0.148	0.341	2.838	0.521	0.040	0.030	0.069	0.578	1.021	1.051	14.622	15.497	16.433
75% Perc =	2.842	0.211	0.159	0.363	3.126	0.579	0.043	0.032	0.074	0.637	1.194	1.155	15.871	16.792	17.722
80% Perc =	3.167	0.227	0.171	0.388	3.452	0.645	0.046	0.035	0.079	0.703	1.411	1.274	17.403	18.296	19.215
85% Perc =	3.550	0.247	0.185	0.417	3.847	0.723	0.050	0.038	0.085	0.784	1.691	1.422	19.275	20.163	21.109
90% Perc =	4.050	0.272	0.204	0.457	4.342	0.825	0.056	0.041	0.093	0.885	2.096	1.628	21.742	22.658	23.560
95% Perc =	4.821	0.311	0.230	0.516	5.125	0.982	0.063	0.047	0.105	1.044	2.776	1.954	25.454	26.405	27.315
Maximum =	9.264	0.612	0.401	0.977	9.570	1.887	0.125	0.082	0.199	1.950	10.390	5.571	47.745	48.317	49.605

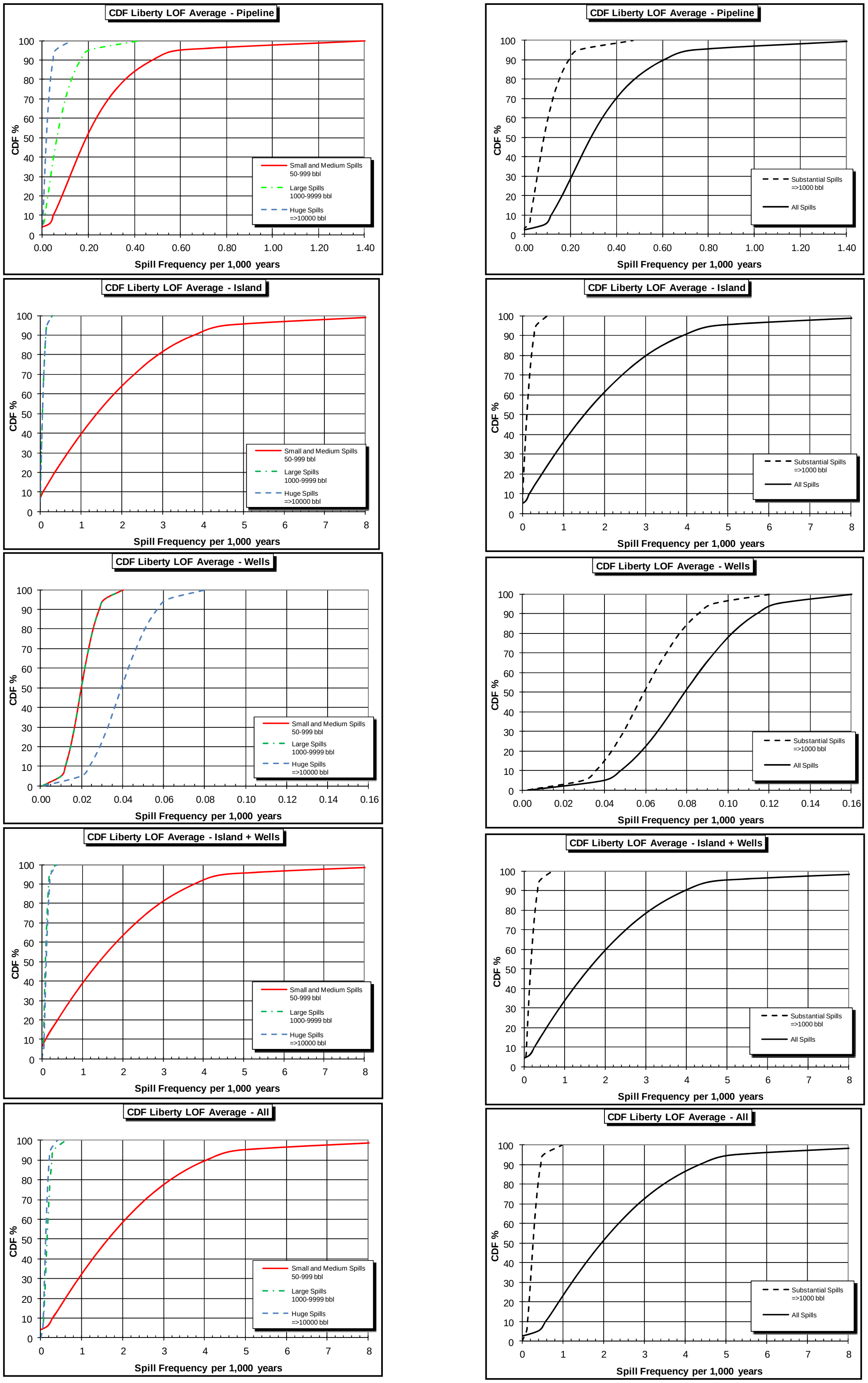


Figure 5.9: Project Life of Field Average Spill Frequency Variability

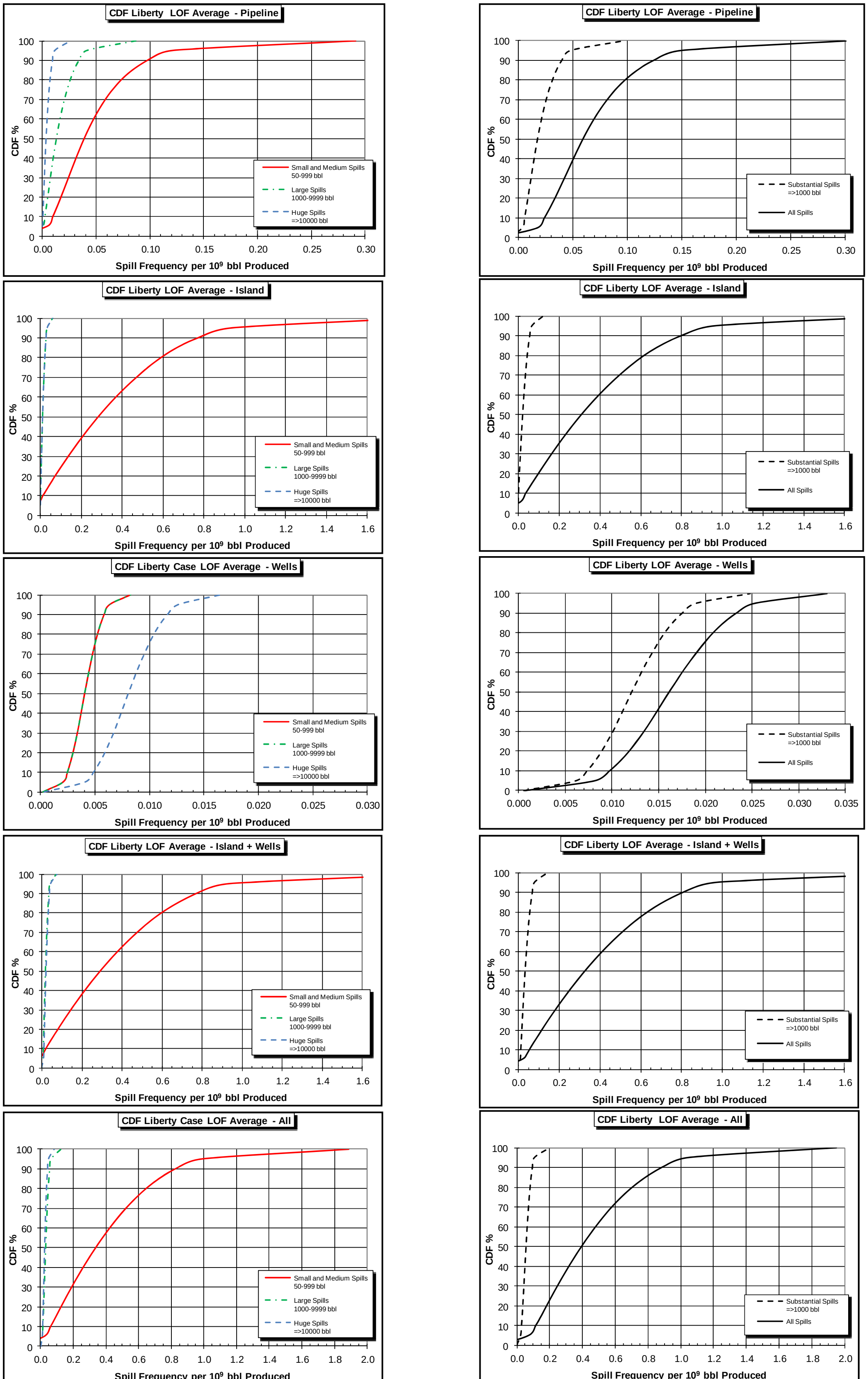


Figure 5.10: Project Life of Field Average Spills per 10^9 Barrels Produced

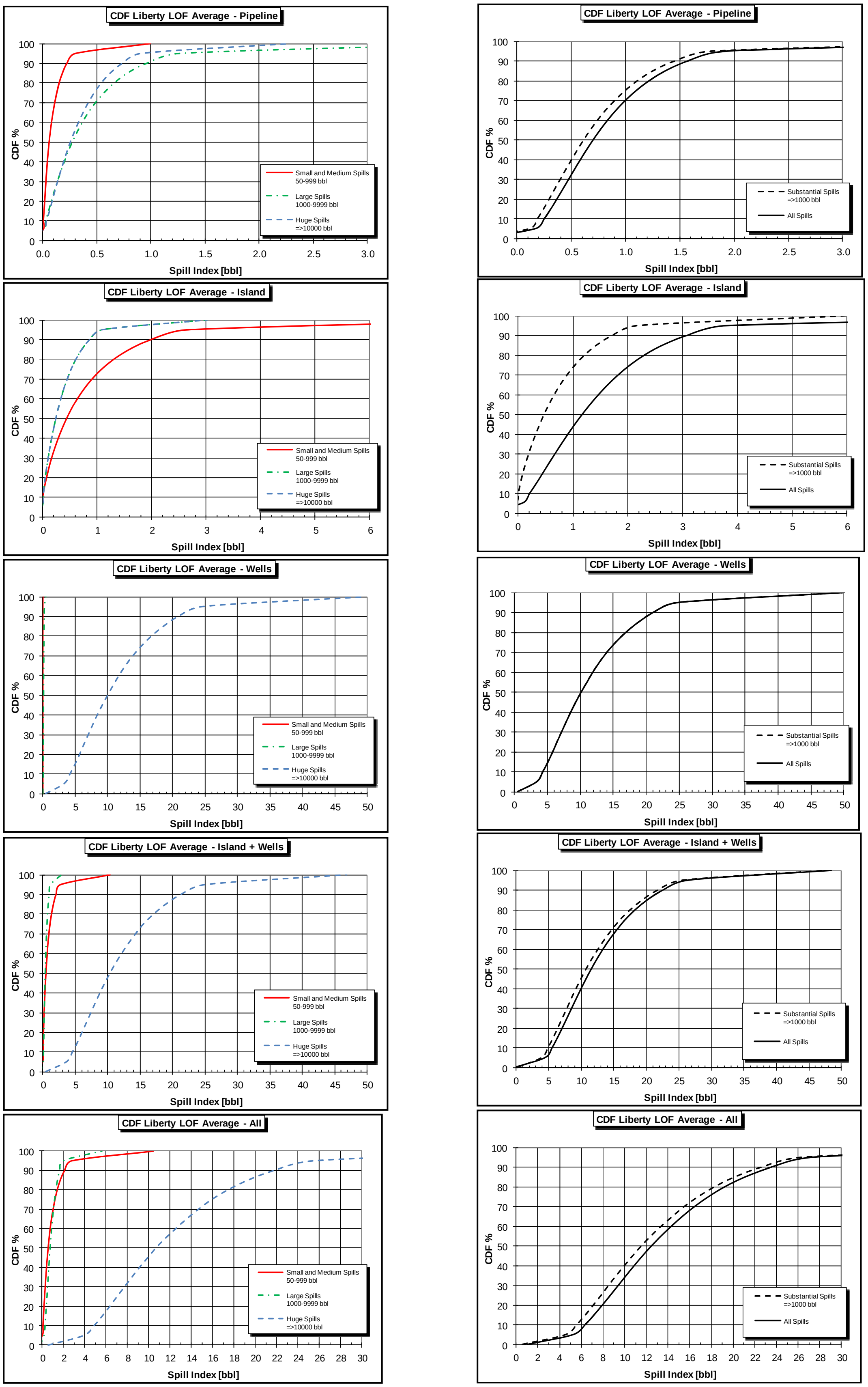


Figure 5.11: Project Life of Field Average Spill Index Variability

Table 5.3
Summary of Spill Indicators for All Scenarios

Spill Indicators LOF Average	Liberty			Liberty Non Arctic		
	Spill Frequency per 10^3 years	Spill Frequency per 10^9 bbl produced	Spill Index (bbl)	Spill Frequency per 10^3 years	Spill Frequency per 10^9 bbl produced	Spill Index (bbl)
Small and Medium Spills 50-999 bbl	1.947	0.397	0.867	3.397	0.692	1.512
	87%	87%	6%	89%	89%	8%
Large Spills 1,000-9,999 bbl	0.160	0.033	0.859	0.253	0.052	1.353
	7%	7%	6%	7%	7%	7%
Huge Spills =>10,000 bbl	0.123	0.025	12.133	0.178	0.036	15.447
	6%	6%	88%	5%	5%	84%
Substantial Spills =>1,000 bbl	0.283	0.058	12.992	0.431	0.088	16.799
	13%	13%	94%	11%	11%	92%
All Spills	2.230	0.454	13.859	3.827	0.780	18.311
	100%	100%	100%	100%	100%	100%
Pipeline Spills	0.331	0.067	0.830	0.640	0.130	1.537
	15%	15%	6%	17%	17%	8%
Island Spills	1.818	0.370	1.457	3.087	0.629	2.297
	82%	82%	11%	81%	81%	13%
Well Spills	0.080	0.016	11.572	0.100	0.020	14.476
	4%	4%	83%	3%	3%	79%
Island and Well Spills	1.898	0.387	13.029	3.187	0.649	16.773
	85%	85%	94%	83%	83%	92%
All Spills	2.230	0.454	13.859	3.827	0.780	18.311
	100%	100%	100%	100%	100%	100%

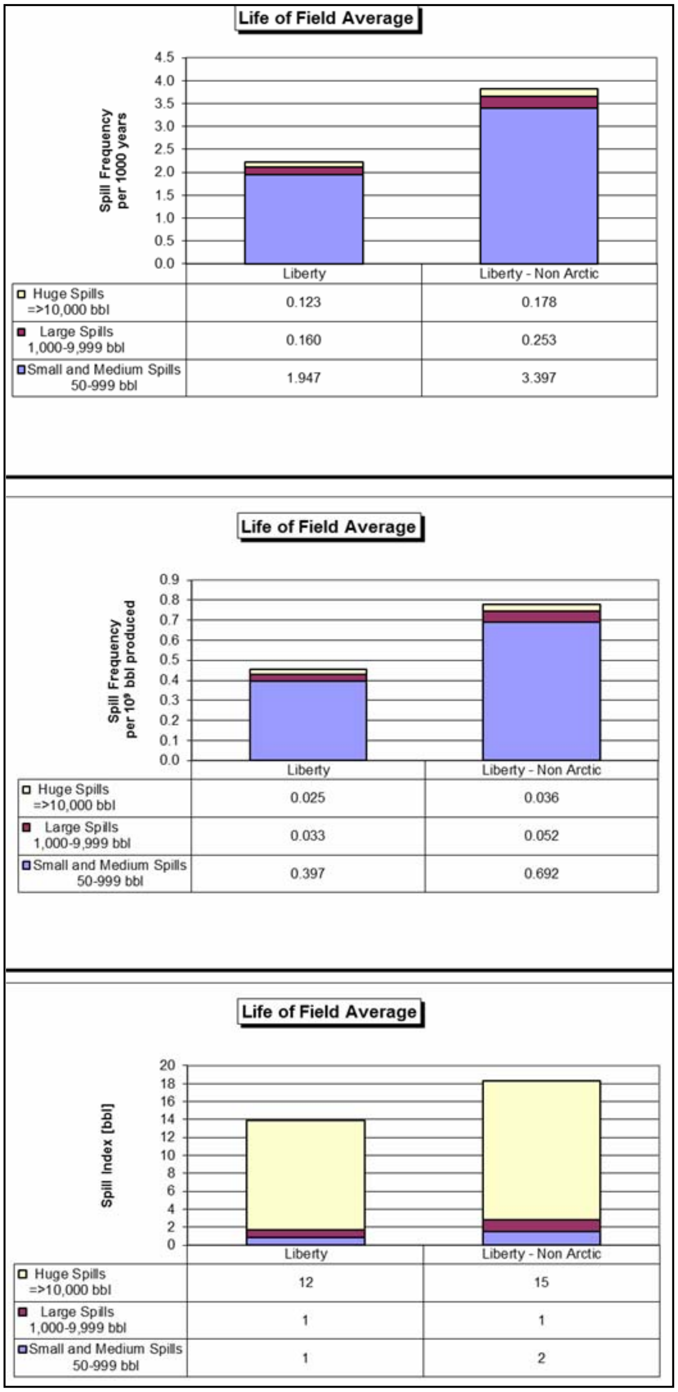


Figure 5.12: Project Life of Field Spill Indicators – By Spill Size

Figure 5.13: Project Life of Field Spill Indicators – By Source Composition

5.3.2 Comparative Non-Arctic Indicator Assessment

To give an idea of the effect of the frequency variations introduced in Chapter 4, the Project scenario was also modeled utilizing unaltered historical frequencies. That is, no changes to incorporate the Arctic effects were introduced in the spill indicator calculations. Put yet another way, it was assumed that the facilities of the scenario would behave as if they were designed for and located in the Gulf of Mexico environment rather than in the Arctic environment, with the same facility quantities and production rates as their Arctic counterparts. Figures 5.14, 5.15, and 5.16 show the total values calculated for each of the three spill indicators. The dark histogram bar on the right side corresponds to the Arctic spill indicator, while, that on the left, corresponds to the computation based on non-Arctic frequencies only. Spill frequency in an absolute sense is considerably higher for the non-Arctic situation, roughly by 40%. Thus, spills per 10^9 barrels produced for the Arctic development scenarios can also be expected to have a 40% lower oil spill occurrence rate than similar development scenarios would have in the GOM.

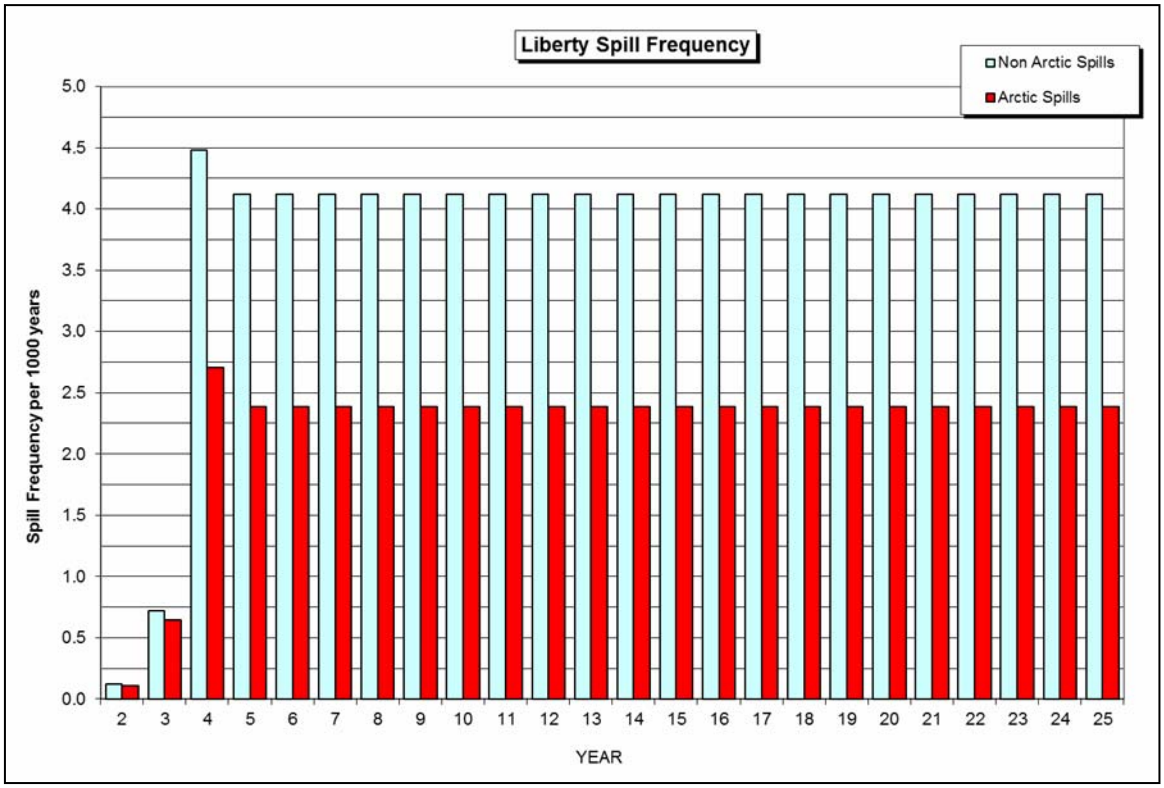


Figure 5.14: Arctic and Non-Arctic Project Spill Frequency

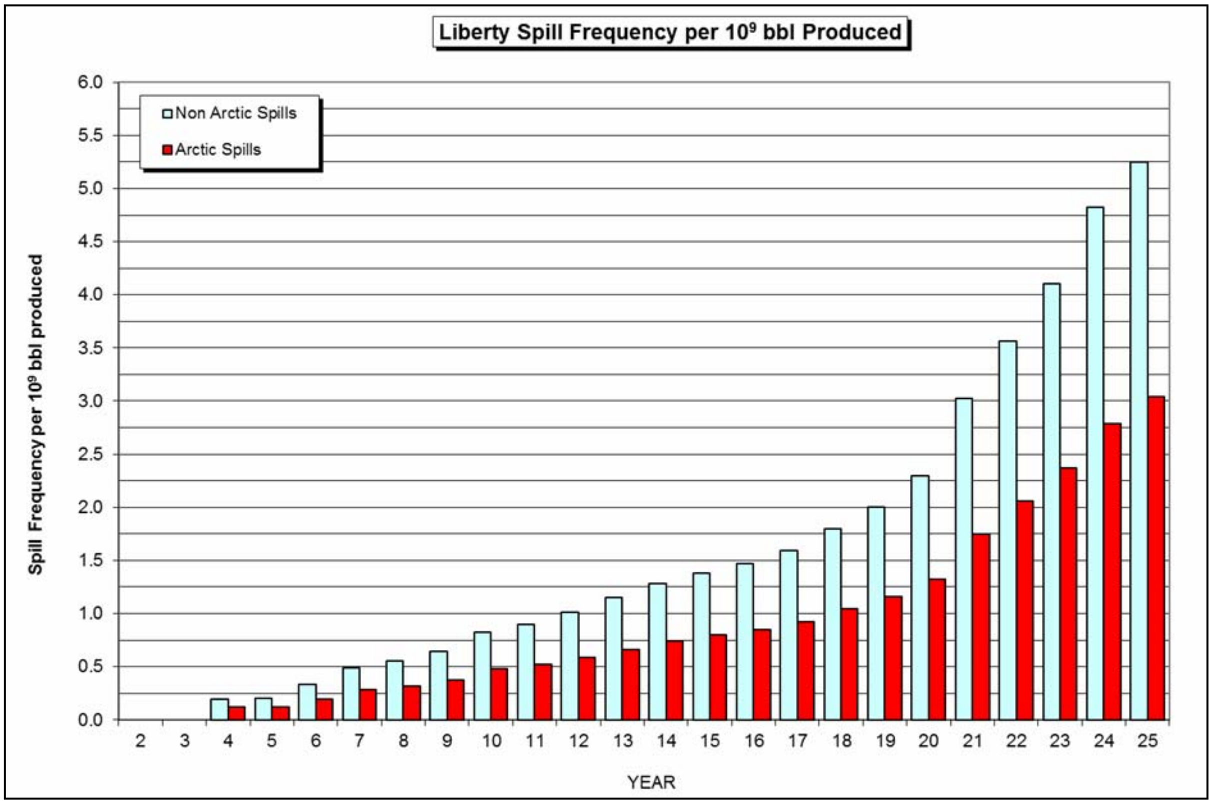


Figure 5.15: Arctic and Non-Arctic Project Spill Frequency per 10^9 Barrels Produced

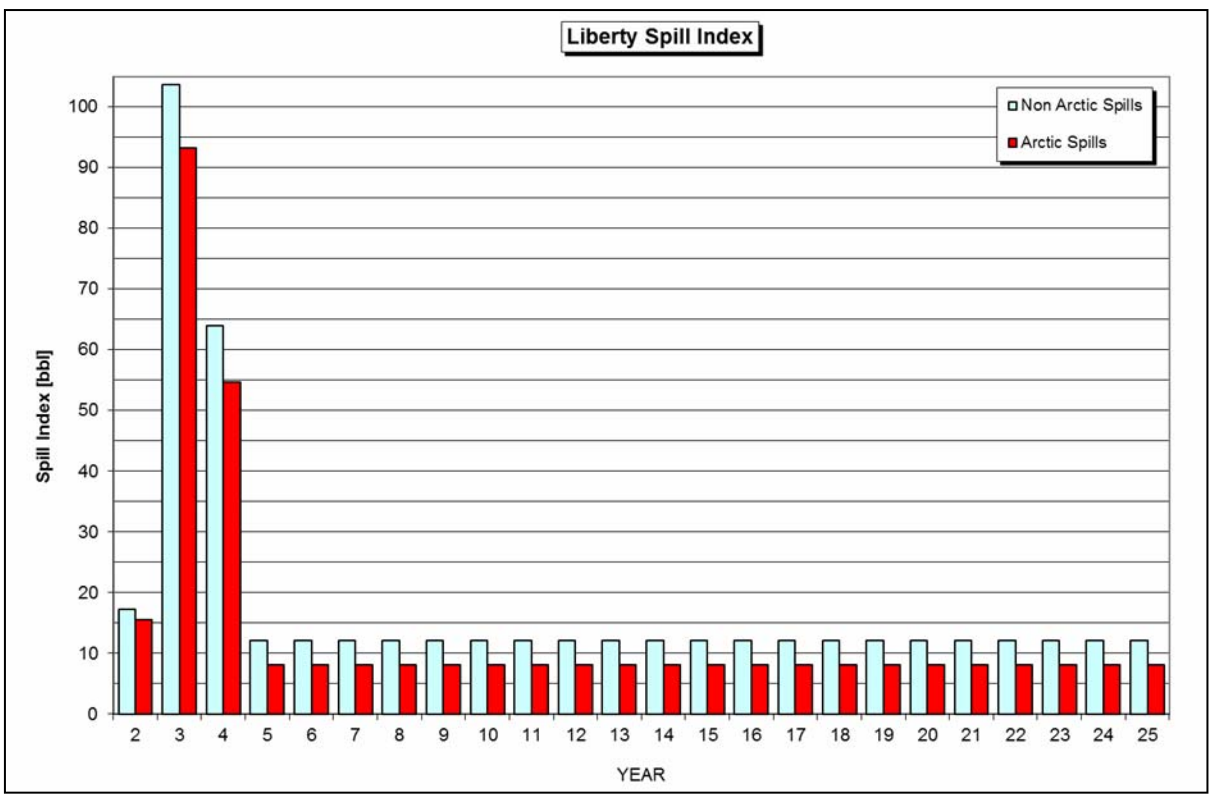


Figure 5.16: Arctic and Non-Arctic Project Spill Index

5.4 Summary of Representative Oil Spill Occurrence Indicator Results

How do spill indicators for the Project and for its non-Arctic counterpart vary by spill size and source? Table 5.3 summarized the Life of Field average spill indicator values by spill size and source. The following can be observed:

- Spill frequency per 10^3 years and per 10^9 barrels produced decrease with increasing spill size for both regions.
- The spill index increases with spill size for both regions.
- All non-Arctic region spill indicators are greater than their Arctic counterparts.
- The island contributes the most (82%) to the two spill frequency indicators.
- Pipelines are second in relative contribution to spill frequencies (15%).
- Wells are the lowest contributors to both frequency spill indicators (4%) and the most to spill index (83%).
- It can be concluded that the island is likely to have the most, but smaller spills, while wells will have the least number but larger spills. Pipelines will be in between, with more spills than wells.

Figures 5.14 to 5.16 compare spill indicators for Arctic and Non-Arctic spills

Figures 5.17 and 5.18 show relative contributions by source and spill size for year 15 and Life of Field average spill indicators, respectively. Although Life of Field average absolute values are smaller than the year 15 values, the proportional contributions by spill facility source and spill size are similar. “TOTAL” in the figures designates the sum of the spill indicators for all spill sizes and sources.

Figures 5.9, 5.10, and 5.11, earlier, showed the Cumulative Distribution Functions (CDF) the Project Life of Field average spill indicators. Generally, the following can be observed from the figures:

- The variance of the frequency spill indicators (Figures 5.9 and 5.10) generally decreases as spill size increases for pipelines and the island. For example, in the top left-hand graph of Figure 5.9, the pipeline huge spills plot has a much steeper (less variable) slope than that of small and medium spills, and is steeper than that of large spills. For the island, small and medium spills are more variable than large and huge spills.
- For wells, huge spills show much greater variance than smaller ones.
- For all facilities, as seen in Figure 5.9 (left side bottom graph), the frequency spill indicators for small and medium spills show significantly more variability than those for large and huge spills.
- The variability of the spill index (Figure 5.11) for the pipeline, unlike the frequency spill indicators, shows a greater variance for large and huge spills than for small and medium spills. The opposite occurs for the island (ie, small and medium spills are the most variable).

- For wells, the variance in huge spills spill index dominates, with very little variance in the large, medium, and small spills, which are plotted nearly vertically in Figure 5.11 (third graph from top on left side).
- For all facilities, the spill index for huge spills is more variable than for smaller spills (Figure 5.11 left side bottom graph).

The Cumulative Distribution Functions contain extensive information on the statistical properties of the spill indicators. For example, from Figure 5.9 and more exactly from Table 5.2, for substantial spills, the Life of Field average 50% value is 0.267 (spills per 1,000 years), and the range is between 0.105 at the lower 5% confidence level and 0.516 at the upper 95% confidence level. A similar percentage variation is shown for the Life of Field average spill frequency per 10^9 barrels produced. The spill index variability shown in Figure 5.11 is proportionally higher. For example, in Figure 5.11 (bottom right graph) the substantial spill Life of Field average 50% value is 11.541 (bbl), and the range is between 4.580 at the lower 5% confidence level and 26.405 at the upper 95% confidence level.

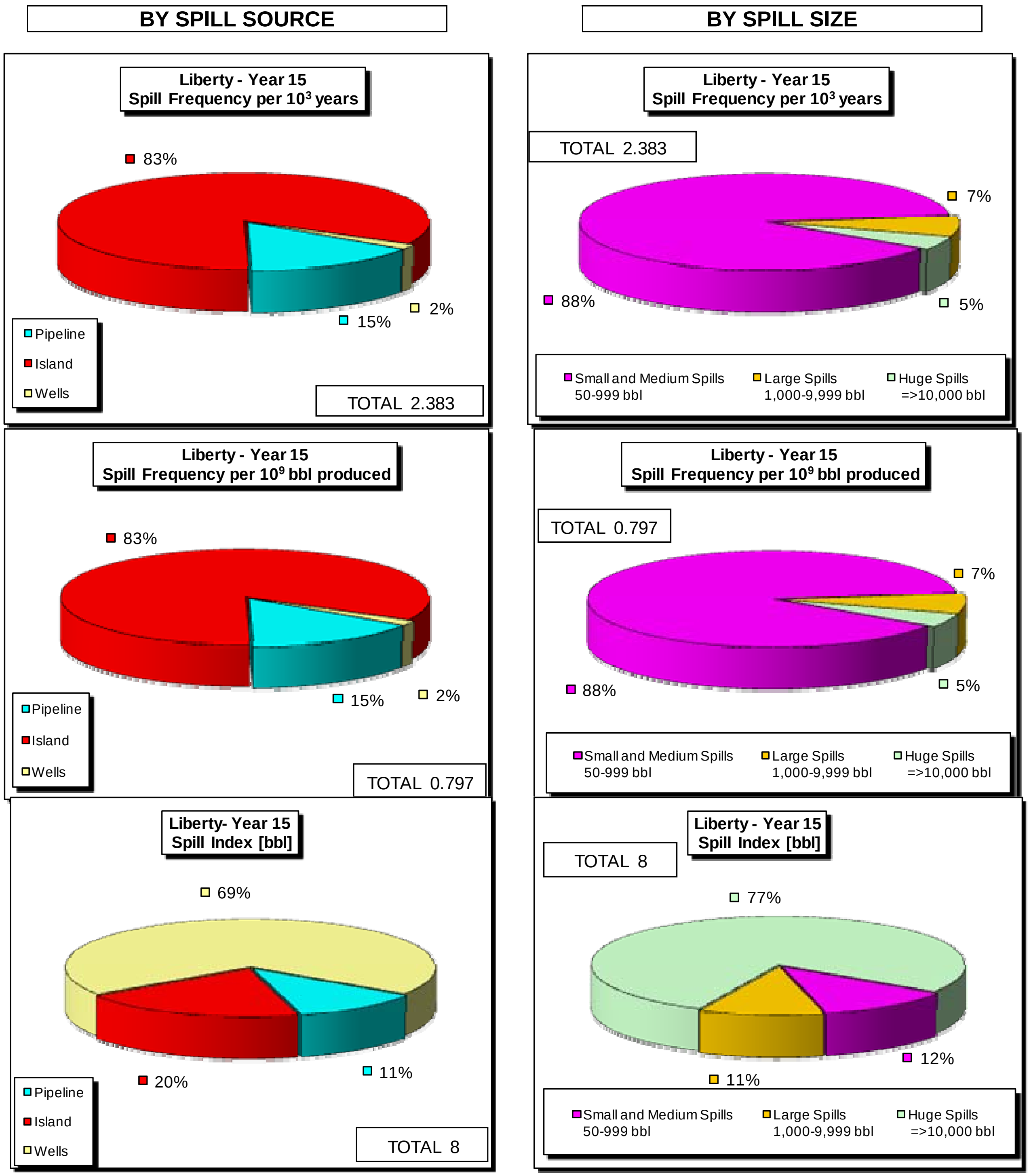


Figure 5.17: Project – Year 15 – Spill Indicator Composition by Source and Spill Size

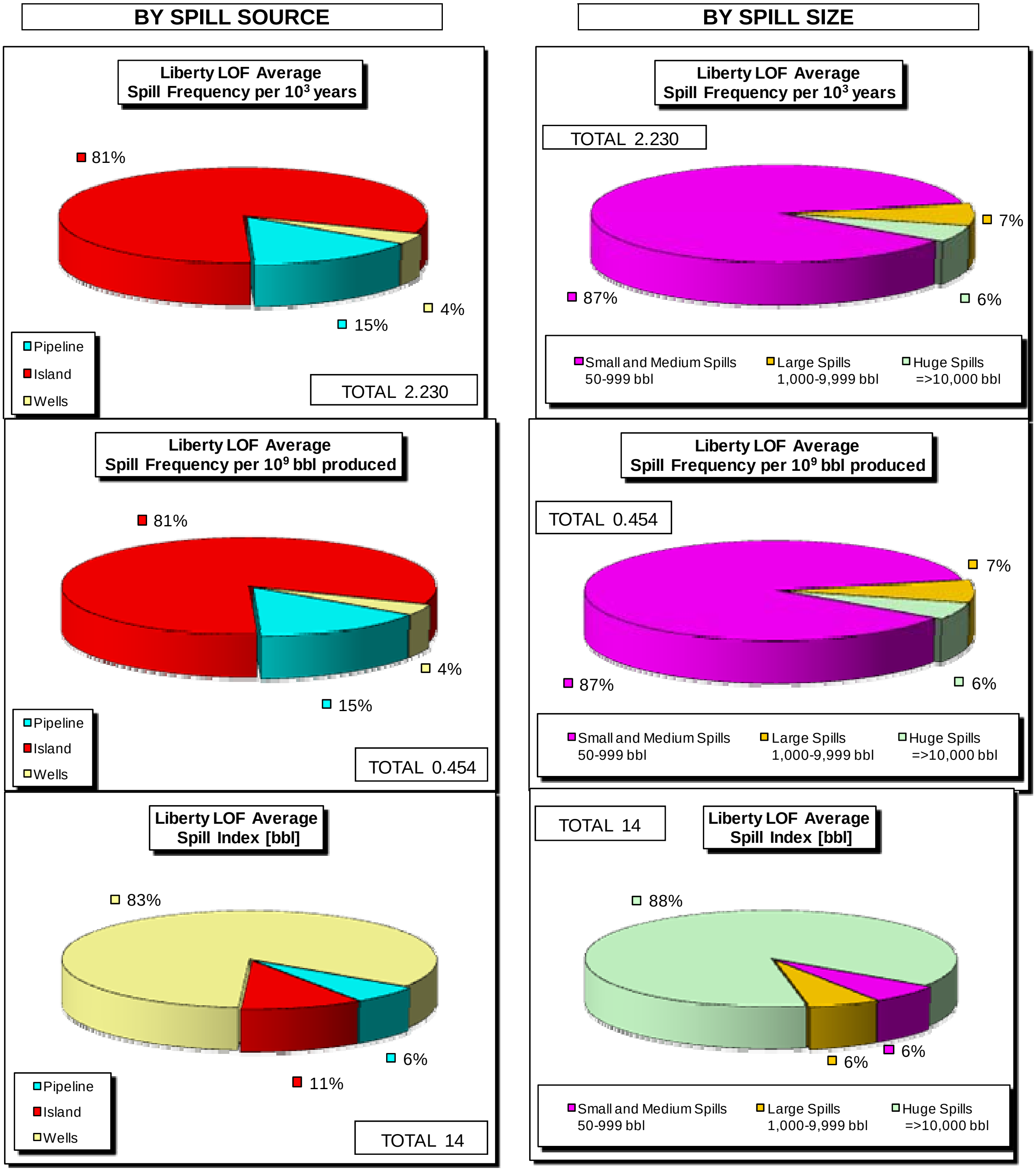


Figure 5.18: Project – Life of Field Average Spill Indicator Composition by Source and Spill Size

CHAPTER 6

CONCLUSIONS AND RECOMMENDATIONS

6.1 Conclusions

6.1.1 General Conclusions

Oil spill occurrence indicators were quantified for the proposed Liberty Development Project (the Project) in the south Beaufort Sea. The quantification included the consideration of the variability of historical and future scenario data, as well as that of Arctic effects in predicting oil spill occurrence indicators. Consideration of the variability of all input data yields both higher variability and a higher expected value of the spill occurrence indicators. The three types of spill occurrence indicators were: annual oil spill frequency, annual oil spill frequency per billion barrels produced, and annual spill index – additionally, the Project year 15 and life of field (LOF) averages for each of these three oil spill indicators were assessed.

6.1.2 Oil Spill Occurrence Indicators by Spill Size and Source

How do spill indicators for the Project scenario and for its non-Arctic counterpart vary by spill size and source? Table 6.1 and Figures 6.1 and 6.2 summarize the Life of Field average spill indicator values by spill size and source. The following can be observed:

- Spill frequency per 10^3 years and per 10^9 barrels produced decreases with increasing spill size for all Arctic and non-Arctic scenarios.
- The spill index increases with spill size for all Arctic and non-Arctic scenarios.
- All non-Arctic scenario spill indicators are greater than their Arctic counterparts.
- The island contributes the most (82%) to the two spill frequency indicators.
- Pipelines are second in relative contribution to spill frequencies (15%).
- Wells are the lowest contributors to frequency indicators (4%) but highest contributors to spill index (83%)
- It can be concluded that the island is likely to have the most, but smaller spills, while wells will have the least number but larger spills. Pipelines will be in between, with more spills than wells.

Table 6.2 gives the contributions to spill indicators for substantial (>=1,000 bbl) spills only; although trends are similar, the contribution percentages are different.

Figures 6.3 and 6.4 show relative contributions by source and spill size for year 15 and Life of Field average spill indicators, respectively. Although Life of Field average absolute values are smaller than the year 15 values, the proportional contributions by spill facility source and spill size are similar. “TOTAL” in the figures designates the sum of the spill indicators for all spill sizes and sources.

Table 6.1
Summary of Life of Project Field Average Spill Indicators by Spill Source and Size

Spill Indicators LOF Average	Liberty			Liberty Non Arctic		
	Spill Frequency per 10^3 years	Spill Frequency per 10^9 bbl produced	Spill Index (bbl)	Spill Frequency per 10^3 years	Spill Frequency per 10^9 bbl produced	Spill Index (bbl)
Small and Medium Spills 50-999 bbl	1.947	0.397	0.867	3.397	0.692	1.512
	87%	87%	6%	89%	89%	8%
Large Spills 1,000-9,999 bbl	0.160	0.033	0.859	0.253	0.052	1.353
	7%	7%	6%	7%	7%	7%
Huge Spills =>10,000 bbl	0.123	0.025	12.133	0.178	0.036	15.447
	6%	6%	88%	5%	5%	84%
Substantial Spills =>1,000 bbl	0.283	0.058	12.992	0.431	0.088	16.799
	13%	13%	94%	11%	11%	92%
All Spills	2.230	0.454	13.859	3.827	0.780	18.311
	100%	100%	100%	100%	100%	100%
Pipeline Spills	0.331	0.067	0.830	0.640	0.130	1.537
	15%	15%	6%	17%	17%	8%
Island Spills	1.818	0.370	1.457	3.087	0.629	2.297
	82%	82%	11%	81%	81%	13%
Well Spills	0.080	0.016	11.572	0.100	0.020	14.476
	4%	4%	83%	3%	3%	79%
Island and Well Spills	1.898	0.387	13.029	3.187	0.649	16.773
	85%	85%	94%	83%	83%	92%
All Spills	2.230	0.454	13.859	3.827	0.780	18.311
	100%	100%	100%	100%	100%	100%

Table 6.2
Summary of Life of Project Spill Indicators for Substantial Spills by Facility and Well Type

Spill Source LOF Average Substantial Spills => 1,000 bbl	Liberty		
	Spill Frequency per 10^3 years	Spill Frequency per 10^9 bbl produced	Spill Index (bbl)
Pipeline	0.100	0.020	0.740
	35%	35%	6%
Island	0.123	0.025	0.691
	43%	43%	5%
Wells	0.060	0.012	11.562
	21%	21%	89%
Island and Wells	0.183	0.037	12.252
	65%	65%	94%
All	0.283	0.058	12.992
	100%	100%	100%
Production Wells	0.027	0.005	5.092
	44%	44%	44%
Development Wells Drilling	0.034	0.007	6.469
	56%	56%	56%
All Wells	0.060	0.012	11.562
	100%	100%	100%

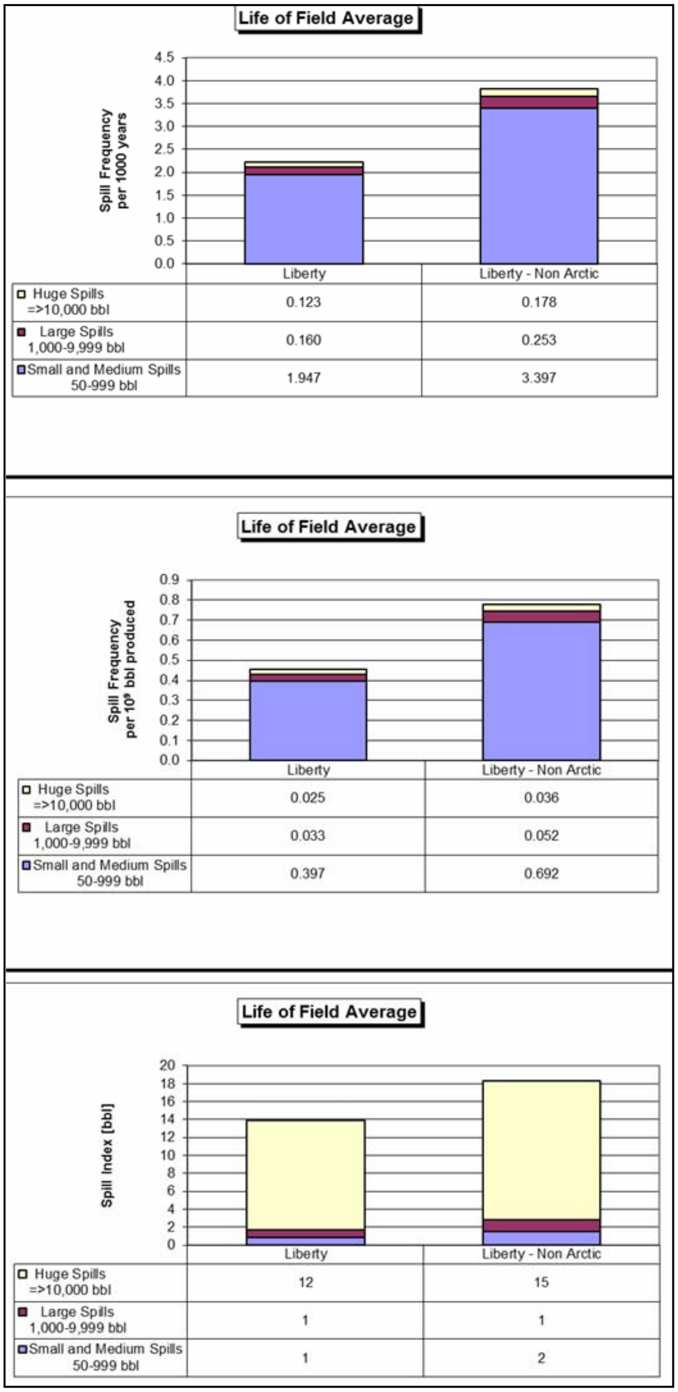


Figure 6.1: Project Life of Field Spill Indicators – By Spill Size

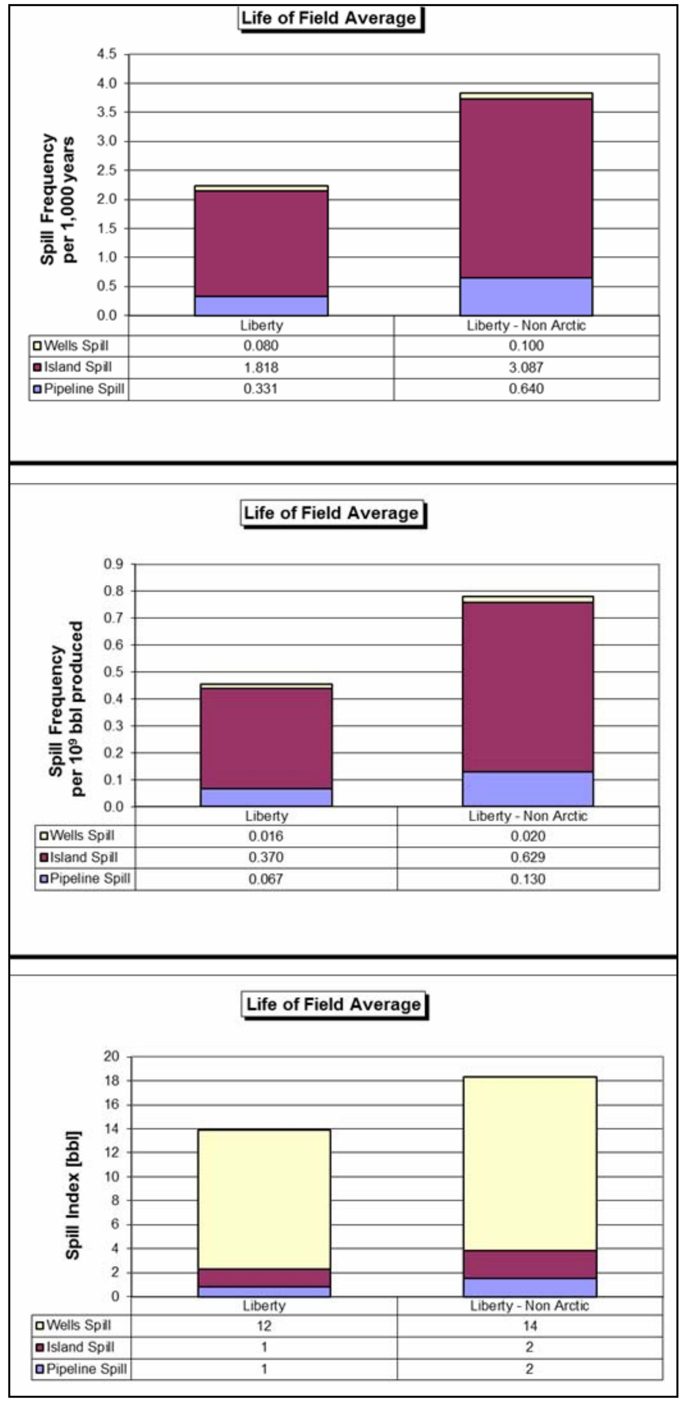


Figure 6.2: Project Life of Field Spill Indicators – By Source Composition

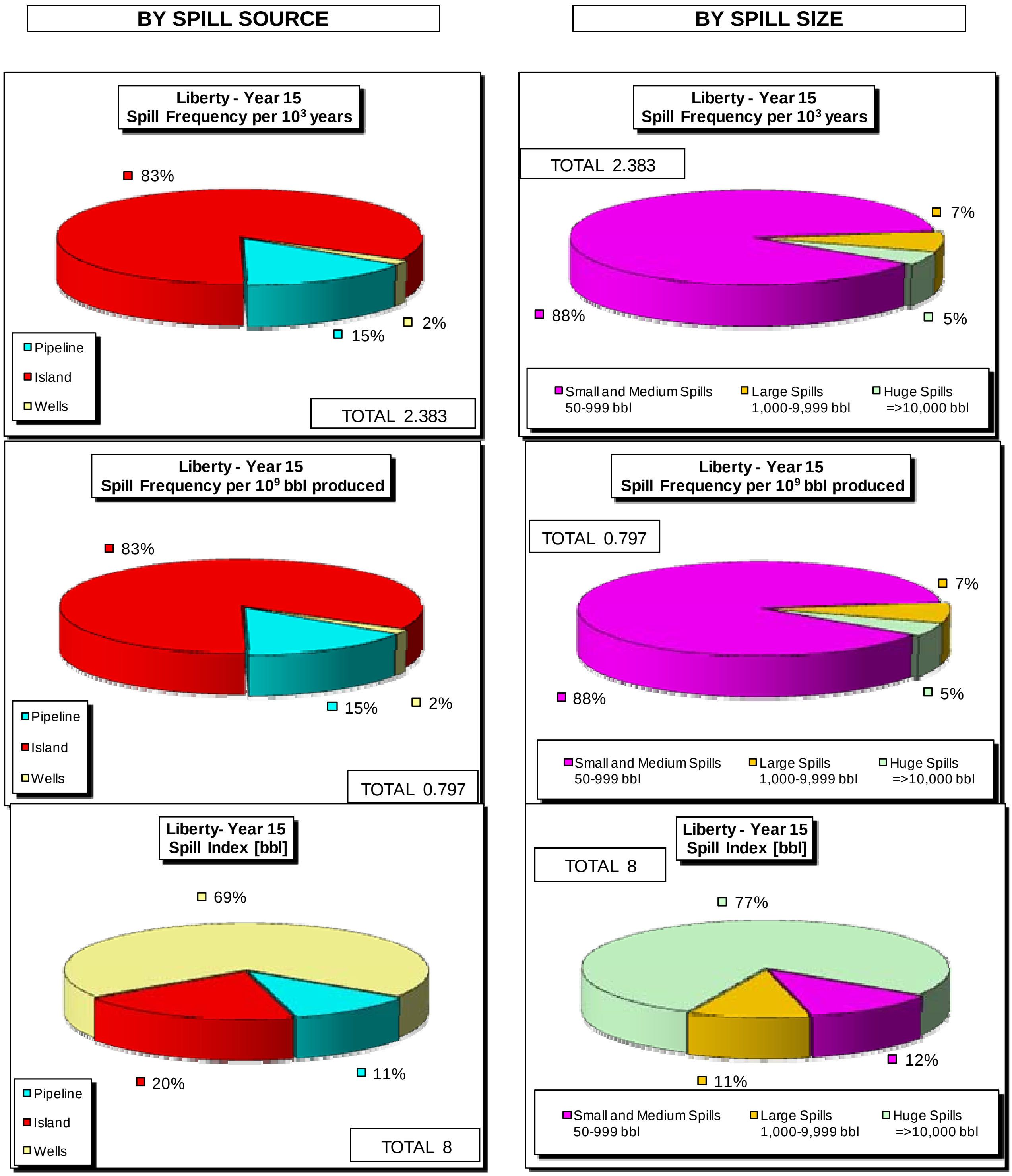


Figure 6.3: Project – Year 15 – Spill Indicator Composition by Source and Spill Size

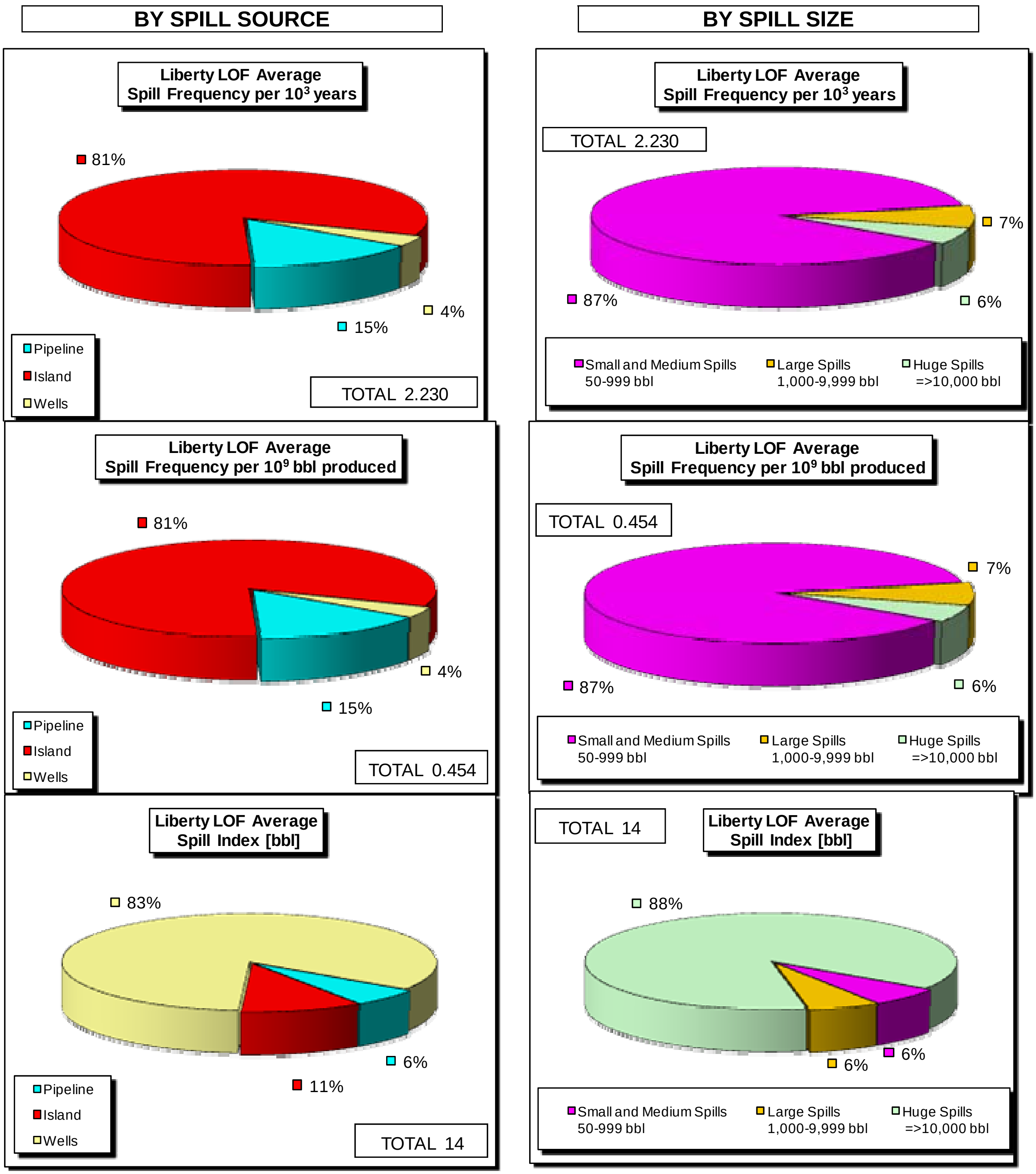


Figure 6.4: Project – Life of Field Average Spill Indicator Composition by Source and Spill Size

6.1.3 The Variance of Oil Spill Occurrence Indicators

Figures 6.5, 6.6, and 6.7 show the Cumulative Distribution Functions (CDF) for the Project Life of Field average spill indicators. Generally, the following can be observed from the figures:

- The variance of the frequency spill indicators (Figures 6.5 and 6.6) generally decreases as spill size increases for pipelines and the island. For example, in the top left-hand graph of Figure 6.5, the pipeline huge spills plot has a much steeper (less variable) slope than that of small, medium, and large spills. For the island, small and medium spills are more variable than large and huge spills.
- For wells, huge spills show greater variance than smaller ones.
- For all facilities, as seen in Figure 6.5 (left side bottom graph), the frequency spill indicator for small and medium spills show significantly more variability than those for large and huge spills.
- The variability of the spill index (Figure 6.7) for the pipeline, unlike the frequency spill indicators, shows a greater variance for large and huge spills than for small and medium spills. The opposite occurs for the island (ie, small and medium spills are the most variable).
- For wells, the variance in huge spills spill index dominates, with very little variance in the large spills and small spills and medium spills which are plotted nearly vertically in Figure 6.7 (third graph from top on left side).
- For all facilities, the spill index for huge spills is more variable than for smaller spills (Figure 6.7 left side bottom graph).

The Cumulative Distribution Functions contain extensive information on the statistical properties of the spill indicators. For example, from Figure 6.5 for all substantial spills (bottom right graph), the Life of Field average 50% value is 0.3 (spills per 1,000 years), and the range is between 0.1 at the lower 5% confidence level and 0.5 at the upper 95% confidence level. A similar percentage variation is shown for the Life of Field average spill frequency per 10^9 barrels produced in Figure 6.6. The spill index variability shown in Figure 6.7 is proportionally higher. For example, in Figure 6.7 (bottom right graph) the Life of Field average 50% value is 11.5 (bbl), and the range is between 4.6 at the lower 5% confidence level and 26.4 at the upper 95% confidence level.

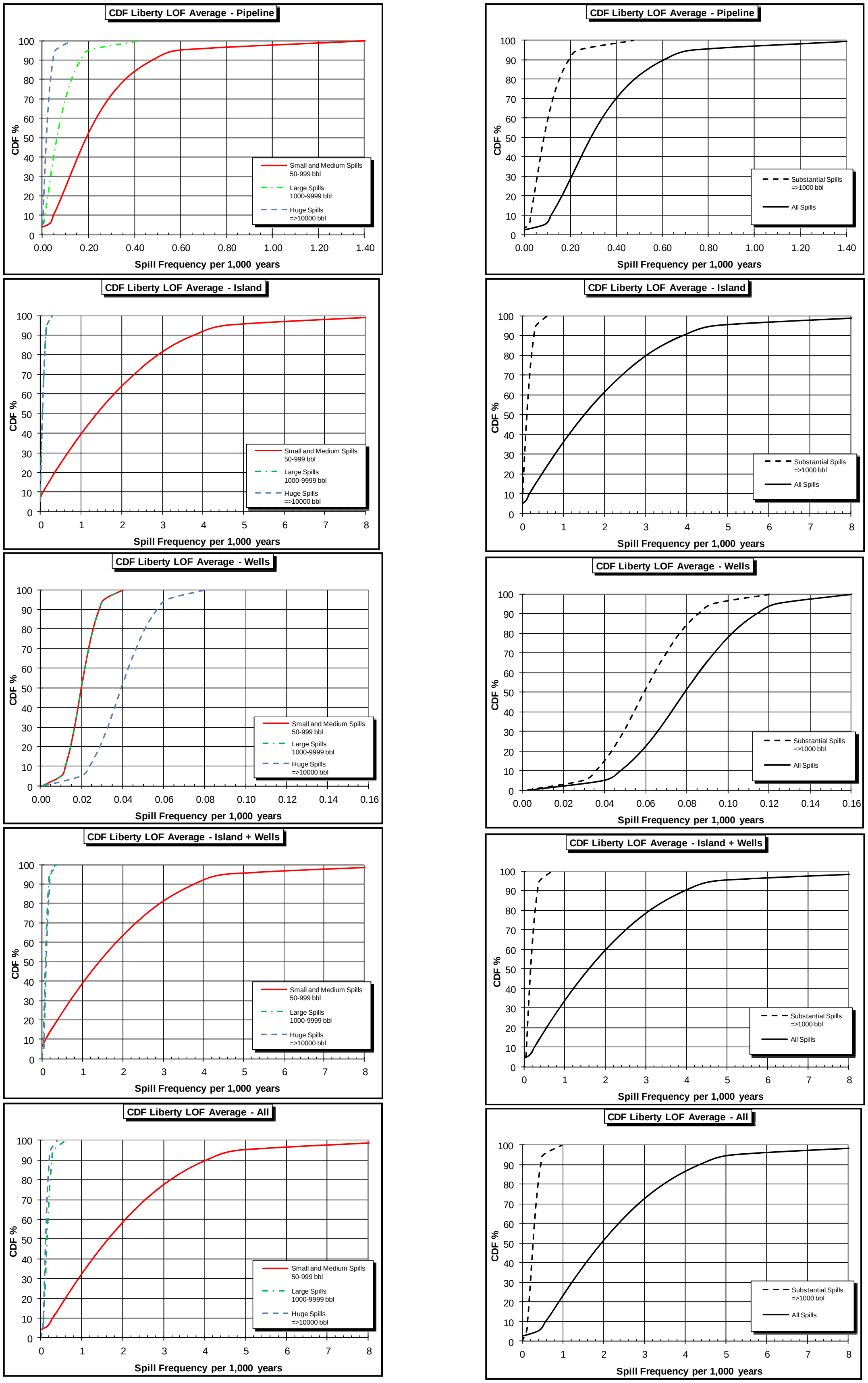


Figure 6.5: Project Life of Field Average Spill Frequency Variability

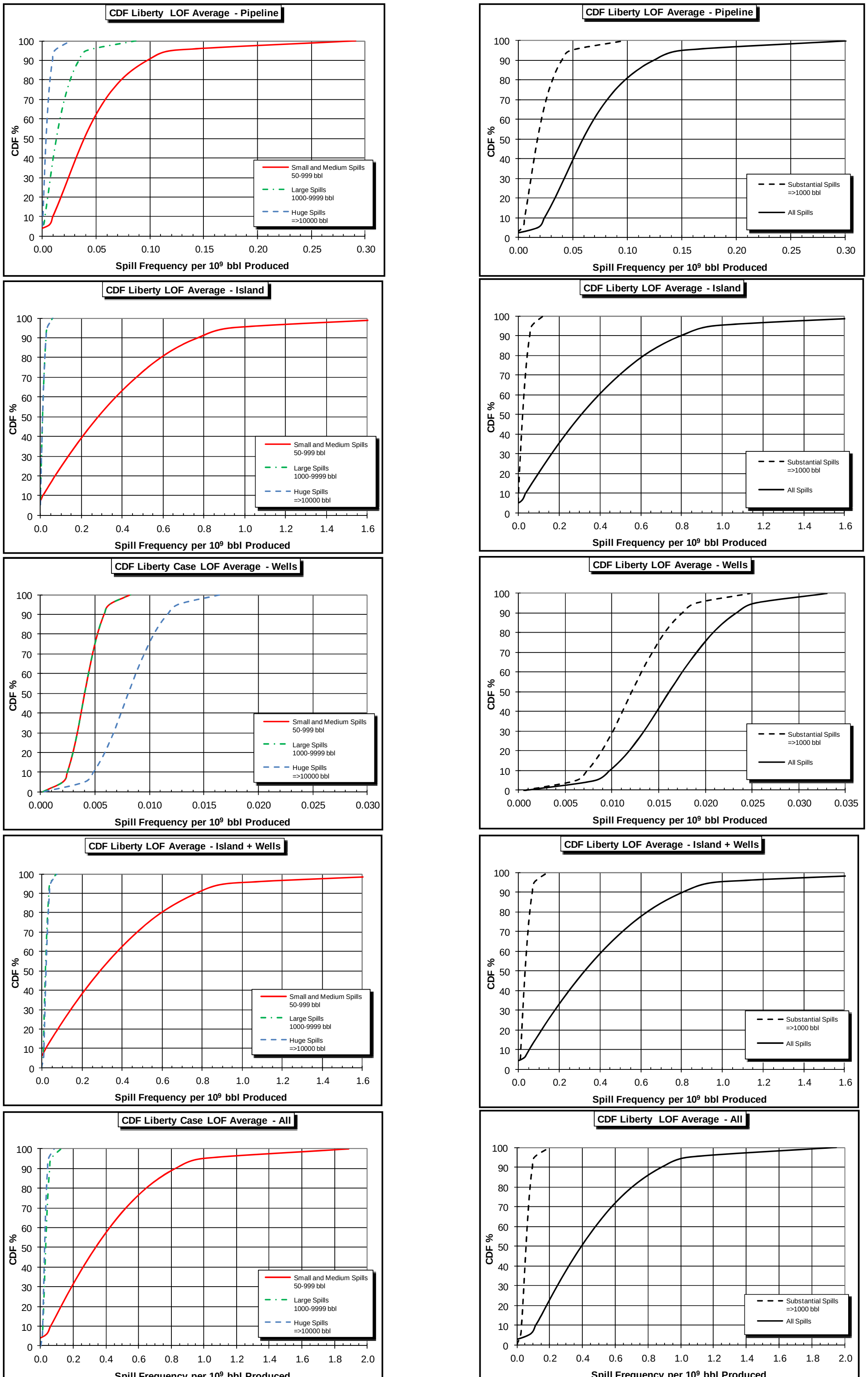


Figure 6.6: Project Life of Field Average Spills per 10^9 Barrels Produced

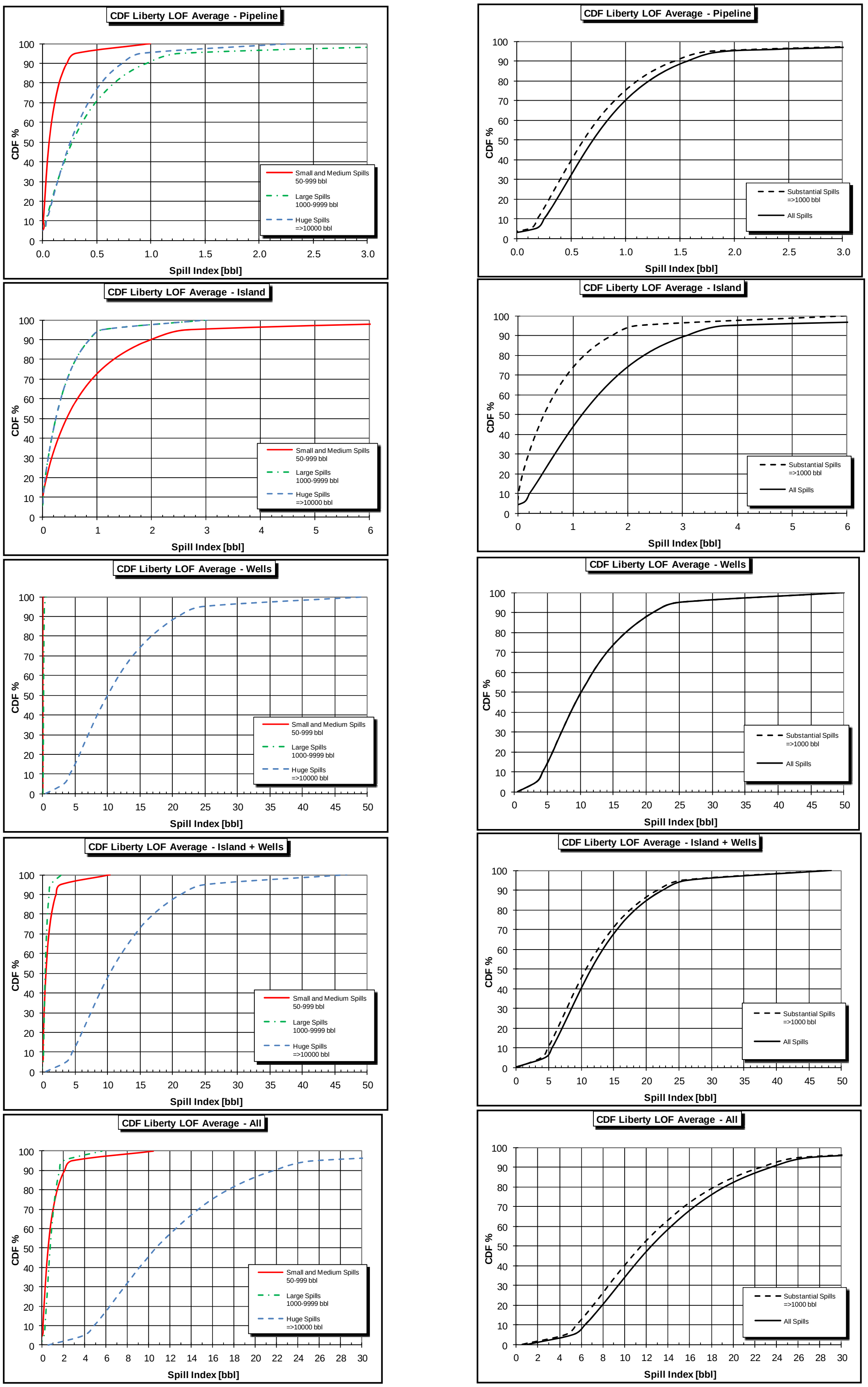


Figure 6.7: Project Life of Field Average Spill Index Variability

6.2 Conclusions on the Methodology and its Applicability

An analytical tool for the prediction of oil spill occurrence indicators for systems without history, such as future offshore oil production developments in the Beaufort Sea, has been developed based on the utilization of fault tree methodology. Although the results generated are voluminous, they are essentially transparent, simple, and easy to understand. The analytical tool developed is also quite transparent, very efficient in terms of computer time and input-output capability. In addition, the predictive model is setup so that input variables can be entered as distributions to yield result distributions.

A wealth of information that can be utilized for the optimal planning and regulation of future developments is generated by the analytical tool. Key aspects of the analytical tool capability may be summarized as follows:

- Ability to generate expected and mean values as well as their variability in rigorous numerical statistical format.
- Use of verifiable input data based on BSEE and BOEM or other historical spill data and statistics.
- Ability to independently vary the impacts of different causes on the spill occurrences as well as add new causes such as some of those that may be expected for the Arctic or other new environments.
- Ability to generate spill occurrence indicator characteristics such as annual variations, facility contributions, spill size distributions, and life of field (LOF) averages.
- Ability to generate comparative spill occurrence indicators such as those of comparable scenarios in more temperate regions. The model developed provides a basis for estimating each Arctic effect’s importance through sensitivity analysis as well as propagation of uncertainties.
- Capability to quantify uncertainties rigorously, together with their measures of variability.

6.3 Suggested Improvement to the Methodology and Results

During the work, a number of areas were identified where future improvements could be made, including: the input data, the scenarios, the application of the fault tree methodology, and finally the oil spill occurrence indicators themselves have been identified. These suggestions are summarized in the following paragraphs.

Two categories of input data were used; namely the historical spill data and the Arctic effect data. Although a verifiable and optimal historical spill data set has been used, the following shortcomings may be noted:

- Gulf of Mexico and Pacific (OCS) historical databases were compiled by BSEE and BOEM for pipelines and facilities, and were used as a starting point for the fault tree analysis. Although these data are adequate, a broader population base would be expected to give more robust statistics. For well LOWC data, both the BSEE and the proprietary SINTEF data were used, providing a wider data sample.
- The Arctic effects include modifications in causes associated with the historical data set as well as additions of spill causes unique to the Arctic environment. Quantification of existing causes for Arctic effects on historical statistics was done in a relative cursory way restricted to engineering judgment. However, the additive or Arctic unique effects were evaluated more rigorously.
- Upheaval buckling effect assessments were included on the basis of professional judgment used in previous studies; no engineering analysis was carried out for the assessment of frequencies for Beaufort Sea locations to be expected for these effects.

The following comments can be made on constraints associated with the indicators that have been generated:

- The model generating the indicators is fundamentally a linear model which ignores the effects of scale, of time variations such as the learning and wear-out curves (Bathtub curve), climate change, and production volume non-linear effects.
- With current methodology, the likelihood of different spill size distributions is assumed constant throughout all production years even though the production decreases from approximately 60,000 barrels per day (BPD) to 2,000 BPD over the project life cycle. One can speculate that the potential for Large and Huge spills varies together with the production rate. Although this was not investigated in this study, it is recommended that it be addressed in future studies due to the large variation in production volumes from start to end of production. However, as done here, the results are conservative.

6.4 Recommendations

The following recommendations based on the work may be made:

- Continue to utilize the Monte Carlo spill occurrence indicator model for new Arctic OCS scenarios to support BOEM needs, as it is currently the best predictive spill occurrence model available.
- Utilize the oil spill occurrence indicator model to generate additional model validation information, including direct application to existing non-Arctic scenarios, such as GOM and PAC projects, which have an offshore oil spill statistical history.
- Utilize the oil spill occurrence indicator model in a sensitivity mode to identify the importance of different Arctic effect variables introduced to provide a prioritized list of those items having the highest potential impact on Arctic oil spills.
- Generalize the model so that it can be run both in an adjusted expected value and a distributed value (Monte Carlo) form with the intent that expected value form can be utilized without the Monte Carlo add-in for preliminary estimates and sensitivity analyses, while for more comprehensive rigorous studies, the Monte Carlo version can be used
- Conduct calculations of the spill indicators as a function of the variable annual oil production rates as spill size and frequency distributions are likely to be a function of these variable production rates.

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