MIT
SEA
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PROGRAM

PRIMARY, PHYSICAL IMPACTS OF OFFSHORE PETROLEUM DEVELOPMENTS

REPORT TO COUNCIL ON ENVIRONMENTAL QUALITY

Massachusetts Institute of Technology

Cambridge, Massachusetts 02139

Report No. MITSG 74-20
April 1974

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MASSACHUSETTS INSTITUTE OF TECHNOLOGY
CAMBRIDGE, MASS. 02139

SEA GRANT PROGRAM

ADMINISTRATIVE STATEMENT

The Georges Bank Petroleum Study, research performed by M.I.T's Offshore Oil Task Force under the aegis of the National Sea Grant Program, was the forerunner of this report in four sections of a project undertaken for the Council on Environmental Quality by M.I.T's Department of Ocean Engineering. These studies on the initial physical effects of offshore oil development respond to the need for information on potential petroleum production from the Atlantic and Gulf of Alaskan continental shelves. In the first section of this report, written by H. S. Lahman, J. B. Lassiter III, and J. W. Devanney III, a range of hypothetical oil finds is analyzed for the number of platforms and the levels and types of petroleum transport that would be needed. Related to these production activities, the probability of oil spills and spill volume has been determined by J. W. Devanney III and R. J. Stewart. Following this, these researchers, assisted by William Briggs, have hypothesized the expected oil spill trajectories for the Atlantic coast and the Gulf of Alaska. The final section, written by J. B. Lassiter III, R. J. Powers, and J. W. Devanney III, explores the weathering of oil spills in examining the evaporation and diffusion of the lighter components from the slick. In presenting these four studies to the Council on Environmental Quality, the research team has provided important, significant analyses to aid in the assessment of the environmental impact of petroleum production on the continental shelves of the Atlantic coast and the Gulf of Alaska.

The M.I.T. Sea Grant Program has organized the printing and distribution of this report under the Sea Grant project established to disseminate important studies and research results developed at M.I.T. under other than Sea Grant support. Funds for this come in part from the Council on Environmental Quality, the National Sea Grant Program and in part from the Massachusetts Institute of Technology.

Ira Dyer
Director

April 1974

ROOM 3-282

(617) 253-7041

Forward

This volume comprises four studies undertaken by the M.I.T. Department of Ocean Engineering in support of the Council on Environmental Quality's presidentially mandated study of potential petroleum production on the Atlantic and Gulf of Alaskan continental shelves.

The four studies in order:

(1) An analysis of the number of platforms and amount and type of petroleum transport activity implied by a range of hypothetical finds.

(2) An analysis of the likelihood of oil spills and spill volume associated with these production activites.

(3) An analysis of the likely trajectories of such spills.

(4) An exploratory analysis of the evaporation and diffusion of the lighter components of an oil spill from the slick.

Each of the studies is an independent effort. No attempt has been made here to integrate their efforts into an overall assessment of the environmental impact of petroleum production in these areas. The reader is referred to CEQ's report to the President in this regard.

The study group is grateful to the Council of Environmental Quality for the opportunity to work on this important problem and is particularly grateful for the support and advice of Mr. Bruce Pasternack, Mr. Stephen Jellinek, and Dr. Stephen Gage. Computation was accomplished at the M.I.T. Information Processing Center.

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SIMULATION OF HYPOTHETICAL OFFSHORE PETROLEUM DEVELOPMENTS

by

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Report to

Council of Environmental Quality

April 1974

SIMULATION OF HYPOTHETICAL OFFSHORE PETROLEUM DEVELOPMENTS

TABLE OF CONTENTS

1. Introduction

The purpose of the research described in this report is to obtain estimates of the amount and type of development activity which would be engendered by a series of hypothetical finds on the outer continental shelf. As a function of the geological, locational, and financial/regulatory characteristics of a hypothetical find, we are interested in the investors' development strategy, the resulting oil and gas production through time, the number of platforms, amount of drilling activity, and mode (pipeline or tanker) and amount of transport activity. We are also interested in estimating the resulting landed cost of the oil and gas to the nation, the resulting investor profits and the resulting lease, royalty and tax payments. To this end, a computer program known as the Offshore Development Model has been constructed, tested, and exercised over a large number of possible finds. Section 2 describes this program. Section 3 describes the results of a number of runs exploring the sensitivity of the model's results to changes in the input variables. Section 4 summarizes these results and comments on the key findings.

The Offshore Development Model can be used at various levels of analysis with varying degrees of facility:

1. PRE-DECISION TO LEASE

   By government bodies to estimate in a preliminary, overall manner, economic and environmental impact of a wide range of hypothetical finds and to determine the effects of changes in lease bidding, royalty and regulatory policies. This is the use for which the program was designed and to which we gave first priority in making programming compromises.

2. POST-DECISION TO LEASE

By industry to estimate the profits it could make for a range of possible finds consistent with whatever geophysical data is available; this information in turn would be input to the determination of lease bids.

By government to estimate the profits industry could make for a range of possible finds consistent with whatever geophysical data is available, which information in turn would be used in determining which bids to reject and assessing the competitiveness of the bidding.

The program in its present form is reasonably well suited to this sort of analysis.

3. POST-EXPLORATORY DRILLING

By industry to determine the maximum profit development and transportation strategy for the given find.

By government to monitor the development to ensure that the find is produced in a real national income maximizing manner; for regulating oil and gas prices if price control is in effect and for determining allowables.

In its present form, the program is not really well suited to this task. More detailed, more specific costing routines would be indicated, but the basic logic and framework of the program is amenable to the changes required.

The program can also be used with minor modifications to simulate onshore developments which employ directional drilling from central pads, as is sometimes done in the Arctic.

2. Description of the model

2.1 General logic

The Offshore Development Model takes as input three sets of variables: geologic, locational, and financial/regulatory, as well as a number of program control variables and options. The geological variables include such descriptions of the hypothetical finds as oil in place, gas in place, number of fields, field separation, depth, permeability, porosity, formation thickness, initial reservoir pressure and temperature, gas and oil viscosity and density, etc. A complete list of these input variables is given in Table 2.1.1.

TABLE 2.1.1

RESERVOIR INPUT PARAMETERS

Oil in place	Gas specific gravity
Gas in place	Oil API number
Formation pressure	Gas viscosity
Formation temperature	Oil viscosity
Formation thickness	Water depth over field
Formation porosity	Depth to formation
Formation permeability	Kickout drilling depth
Pressure depletion increment	Drilling maximum slantangle
Number of fields containing reserves	Connate water
Field separation	

Locational parameters include water depth, relevant distances to shore, terminal draft limitations. A complete list of these input variables is given in Table 2.1.2.

Financial regulatory variables include landed price of oil and gas through time, cost of capital, the lease payment,

TABLE 2.1.2

TRANSPORTATION INPUT PARAMETERS

Tanker sea distance	Oil pipeline sea distance
Refinery port draft limit	Oil pipeline land distance
Refinery port "lost" time	Gas pipeline sea distance
Refinery port SBM distance to shore	Gas pipeline land distance
Refinery port SBM distance from refinery to shore	Refinery port terminal building option
	Pipe yield stress

royalties, oil and gas allowables if any. Table 2.1.3 lists these input variables.

TABLE 2.1.3

FINANCIAL INPUT PARAMETERS

Opportunity cost of capital	Yearly oil sale price
Borrowing interest rate	Yearly gas sale price
Debt/equity ratio	Initial production year (relative to 1972)
Lease fraction	Oil allowable
	Gas allowable

General program control variables are primarily concerned with computational options within the computer program. They include the minimum and maximum number of platforms per field which the program user wants the program to consider, the maximum number of platforms which can be installed in a single year, the maximum of pump/compressor platforms and an option which specifies whether oil and gas pipelines have the same destination.

The general logic of the program is indicated by Figure 2.1.1. Basically, the program examines a number of combinations of production schedule and transport systems and chooses that combination which maximizes the developer's present valued profits.

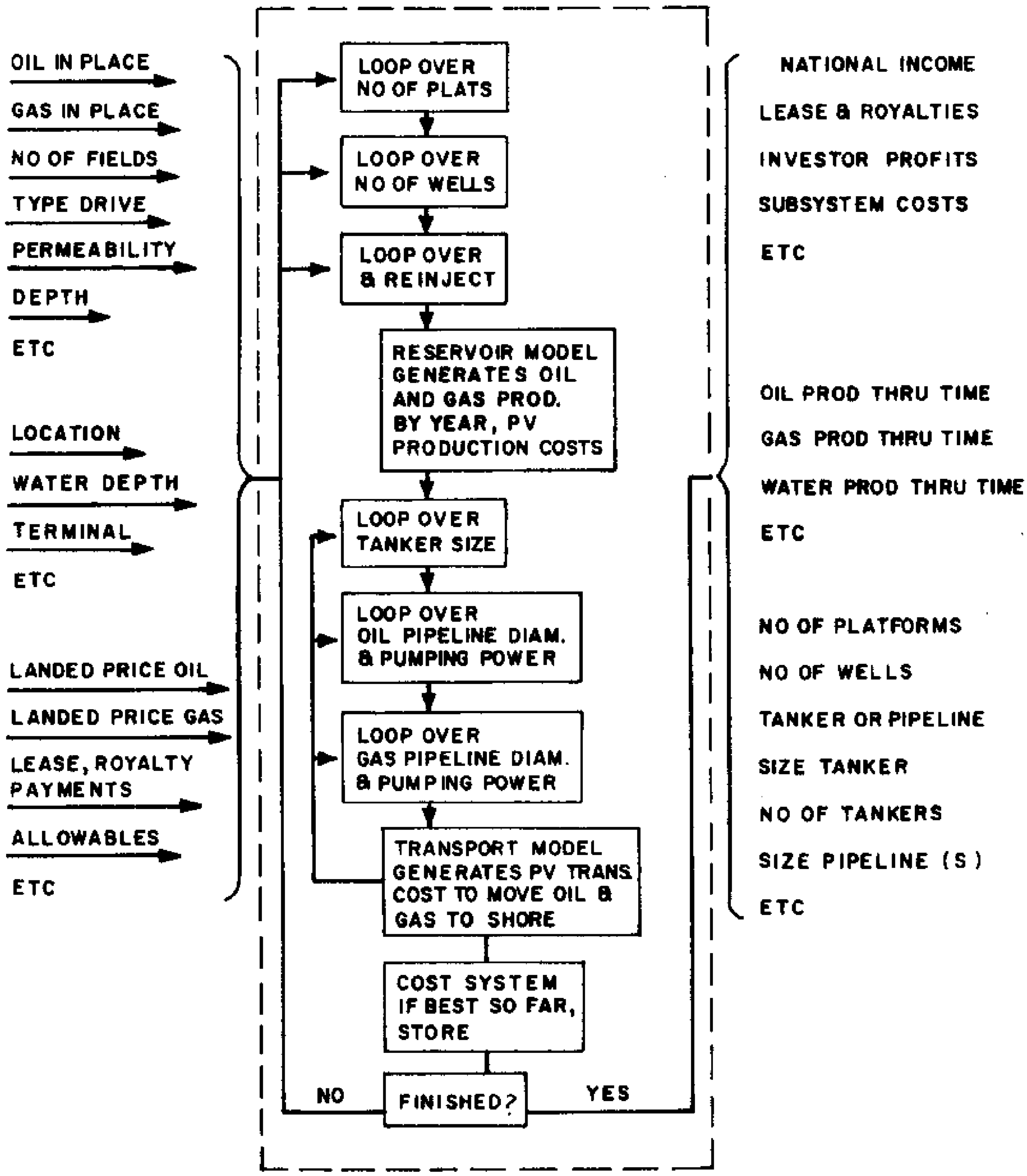

FIGURE 2.1.1 OFFSHORE DEVELOPMENT PROGRAM.

More precisely, the program takes as input two key developer decision variables: number of wells per platform, and amount of gas reinjection. The program then examines a range of number of platforms deployed. These three decision variables together with the reservoir's physical characteristics determine an oil and gas production schedule through time. This production by year is determined by a modified Muskat-Hoss gas drive reservoir model.

For each such production schedule, the program examines a range of both tanker and pipeline systems for transporting the oil and gas to shore.* Tankers of 20, 30, 40, 80, 150, and 250 thousand deadweight tons are considered, subject to terminal draft limitations. Pipelines ranging from 8 to 48 inches in diameter are examined in approximately 4 inch increments combined with 1 to 5 pump/compressor platforms and 1 to 4 parallel lines which may come on line at different times. That combination of tanker and gas pipeline, oil pipeline and gas pipeline, oil tanker only, or oil pipeline only which maximizes present valued gross revenue less transport costs is selected as the transport system for the particular production schedule under consideration.

This transport system and its cash flow are combined with the field capital and operating costs to generate all the cash flows associated with the combination of production schedule and transport system currently under analysis. The after-tax present valued profits associated with this combination are computed in a two-pass manner. Under the assumption

*The model operates under the assumption that gas can be transported to shore only by gas pipeline. Two-phase flow is not considered.

** SUMMARY OF CASE INPUTS **

FIELD INPUT CONSTRAINTS:

OIL IN PLACE........................	1,999 MMBBL	GAS IN PLACE.......................	1,999,998 MMCF
RESRVOIR TEMPERATURE...............	200 DEGF	RESERVOIR PRESSURE................	5,000 PSI
DEPTH TO FORMATION.................	10,000 FT	KICK-OUT DRILLING DEPTH...........	1,500 FT
OIL ALLOWABLE......................	9 MBPD	GAS ALLOWABLE.....................	99 MMCF/
0			
FORMATION THICKNESS................	40 FT	FORMATION POROSITY................	14.000 %
OIL API NUMBER.....................	30.000	OIL VISCOSITY.....................	2.000 CP
GAS SPECIFIC GRAVITY...............	0.600	DEPTH OF SEA OVER FIELD...........	78.000 FT
DRILLING MAXIMUM SLANTANGLE........	0.785 RAD	MAXIMUM REINJECTION...............	80.000 %
MAXIMUM WELLS PER PLATFORM.........	24	GAS SOL. MODEL PRESSURE INCREMENT..	50 PSI
NUMBER OF FIELDS HOLDING RESERVES..	2	RESERVOIR MODEL EMPLOYED...........GAS SOLUTION	
FORMATION PERMEABILITY.............	0.100 DAR		

DESTINATION CONSTRAINTS:

DISTANCE TO PORT VIA SEA LANES.............	36	OIL PIPELINE WATER DISTANCE................	36
OIL PIPELINE LAND DISTANCE.................	0	GAS PIPELINE WATER DISTANCE................	36
GAS PIPELINE LAND DISTANCE.................	0	SINGLE POINT MOORING DIST. TO SHORE........	0
SINGLE POINT MOORING DIST. ON SHORE........	0	TERMINAL CONSTRUCTION OPTION...............	0
REFINERY PORT DRAFT LIMIT..................	41		

FINANCIAL CONSTRAINTS:

DEBT/EQUITY RATIO: 0.000 LOAN INTEREST: 0.000 % LEASE FRACTION: 75.000 % OPPORTUNITY COST: 14.999 %

YEAR	GAS PRICE	CRUDE PRICE	YEAR	GAS PRICE	CRUDE PRICE	YEAR	GAS PRICE	CRUDE PRICE	YEAR	GAS PRICE	CRUDE PRICE	YEAR	GAS PRICE	CRUDE PRICE
1975	1.500	8.000	1976	1.500	8.000	1977	1.500	8.000	1978	1.500	8.000	1979	1.500	8.000
1980	1.500	8.000	1981	1.500	8.000	1982	1.500	8.000	1983	1.500	8.000	1984	1.500	8.000
1985	1.500	8.000	1986	1.500	8.000	1987	1.500	8.000	1988	1.500	8.000	1989	1.500	8.000
1990	1.500	8.000	1991	1.500	8.000	1992	1.500	8.000	1993	1.500	8.000	1994	1.500	8.000
1995	1.500	8.000	1996	1.500	8.000	1997	1.500	8.000	1998	1.500	8.000	1999	1.500	8.000
2000	1.500	8.000	2001	1.500	8.000	2002	1.500	8.000	2003	1.500	8.000	2004	1.500	8.000
2005	1.500	8.000	2006	1.500	8.000	2007	1.500	8.000	2008	1.500	8.000	2009	1.500	8.000
2010	1.500	8.000	2011	1.500	8.000	2012	1.500	8.000	2013	1.500	8.000	2014	1.500	8.000

******************************** SUMMARY OF CAPITAL + OPERATING COSTS ********************************
(DOLLARS)

YEAR	CAPITAL COSTS: FIELD PROD	TANKER TERMINAL	OIL PIPELINE	GAS PIPE W/O OIL	GAS PIPE W/ OIL	OPERATING COSTS: FIELD PROD	TANKER OPER	OIL PIPELINE	GAS PIPE W/O OIL	GAS PIPE W/ OIL
1976	5.70E+07	4.46E+07	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00F+00	0.00E+00	0.00E+00	0.00E+00
1977	6.72E+07	0.00E+00	1.56E+07	2.20E+07	2.20E+07	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
1978	5.56F+07	2.00E+06	1.55E+06	3.69E+03	3.63E+03	8.27E+06	2.22E+07	1.34F+06	1.79E+06	1.79E+06
1979	4.31E+06	0.00F+00	0.00E+00	1.85E+04	1.84E+04	8.29F+06	1.75E+07	1.45E+06	1.79E+06	1.79E+06
1980	0.00E+00	0.00E+00	0.00E+00	2.58E+05	2.58E+05	8.31E+06	1.31E+07	1.42E+06	1.80F+06	1.80E+06
1981	0.00E+00	0.00E+00	0.00E+00	6.78E+06	6.78E+06	8.31E+06	8.75E+06	1.40E+06	2.12E+06	2.12E+06
1982	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	8.31E+06	4.37E+06	1.40E+06	2.39E+06	2.39E+06

*********************** SUMMARY OF FIELD AND TRANSPORT PARAMETERS ***********************

YEAR	TOTAL WELLS	TOTAL PLATS	OIL PROD	GAS PROD	NUMBER TANKER	DWT TANKER	NUMBER TRIPS	OIL DIAM	OIL LINES	OIL PUMPS	GAS DIAM	GAS LINES	GAS PUMPS
1978	82	4	1.629E+08	3.356E+10	4	40000	183	24	1	1	30	1	1
1979	182	9	1.514E+08	8.238E+10	4	40000	183	24	1	1	30	1	1
1980	284	14	1.085E+08	2.156E+11	3	40000	183	24	1	1	30	1	1
1981	284	14	5.522E+07	7.263E+11	2	40000	183	24	1	1	30	1	1
1982	284	14	8.981E+06	3.380E+11	1	40000	183	24	1	1	30	1	1

************************************ SPILL DATA ************************************

YEAR	VOLUME (BBL) TANKER	PIPELINE	FIELD	TOTAL	NUMBER TANKER	PIPELINE	FIELD	TOTAL
1978	4,886	14,659	8,958	23,617	15	75	447	523
1979	4,541	13,625	8,326	21,952	14	70	416	486
1980	3,254	9,763	5,966	15,729	10	50	298	348
1981	1,656	4,969	3,036	8,006	5	25	151	177
1982	269	808	493	1,302	0	4	24	28

OIL IS SHIPPED BY PIPELINE

************************************ PRESENT VALUE TOTALS ************************************

FIELD PRODUCTION COST ($000).....	105,491	TANKER SYSTEM COST ($000)........	50,402
OIL PIPELINE COST ($000).........	10,754	GAS PIPE (W/ TANKERS) ($000).....	16,172
GAS PIPE (W/ PIPELINE) ($000)....	16,172	LEASE PAYMENTS ($000)............	779,280
GROSS REVENUES ($000)............	2,054,672	TOTAL NATIONAL COSTS ($000)......	132,418
TOTAL TRANSPORT COST ($000)......	26,927	INVESTOR PROFITS ($000)..........	539,217
TOTAL GAS PRODUCTION (MMCF)......	405,984	TOTAL OIL PRODUCTION (MBBL)......	180,712
GAS RECOVERY (%).................	69.915	OIL RECOVERY (%).................	24.347

************************************ EQUIVALENT REQUIRED FREIGHT RATE COMBINATIONS ************************************

GAS	0.300	0.400	0.500	0.600	0.700	0.800	0.900	1.000	1.100	1.200	1.300	1.400	1.500	1.600	1.700
OIL (NO LEASE)	0.059	-0.166	-0.391	-0.615	-0.840	-1.065	-1.289	-1.514	-1.738	-1.963	-2.188	-2.412	-2.637	-2.862	-3.086
OIL (W/ LEASE)	4.371	4.146	3.922	3.697	3.472	3.248	3.023	2.798	2.574	2.349	2.124	1.900	1.675	1.451	1.226

that a single corporation is developing the find and landing the petroleum, income tax and ad valorem taxes are determined according to U.S. corporate tax law. These tax payments are combined with the other cash flows to produce the present valued after-tax profits <u>before lease payment</u>.

The program then takes a user-specified proportion of these profits and assumes that this percentage of the economic rent associated with the project is turned over to the federal government in the form of a lease bid two years prior to initial production. The present valued profits after lease payment are then recomputed in their entirety, with the lease payment incorporated in the cash flows.

The user then may examine these results (the program is available on time sharing) and modify the wells per platform and amount of reinjection as he desires and repeat the entire process.*

2.2 The reservoir model

The core of the program is the reservoir model. The present reservoir model assumes gas drive, that is, the find is operating at production rates sufficiently great that the reservoir maintains constant volume throughout its producing life. Water influx is negligible. The driving mechanism for such reservoirs is gas expansion.

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*At the moment this is not completely true. The logic of the program will accept a range of wells per platform but our present platform cost expressions are based on 24-producing-well platforms. Thus, all the runs given in this report are based on 24-well platforms.

The basic logic of the reservoir model is indicated in Figure 2.2.1. The seven major steps in the model are: a pure gas reservoir routine, a non-retrograde oil/gas reservoir with an initial gas cap below bubble point, an algorithm for non-retrograde reservoirs above the bubble point, an algorithm for gas lift and sandface pressure adjustment, an algorithm for adjusting pressure depletion through gas reinjection, and a routine for converting from the pressure domain to the time domain.

All reservoir modelling is done in the pressure domain. That is, oil and gas production is computed as a function of pressure decrease in the reservoir. This computation is done only once for each set of reservoir parameters. It need not be repeated for each iteration on number of platforms since this variable affects only the time conversion of reservoir depletion. The results are stored and,after the first call to the reservoir model for a particular case, the model performs only the pressure-to-time conversion.

The model handles arbitrary initial pressures from 500 to 5,000 psi and uses a user-specified pressure decrement of 10 to 50 psi. The smaller the pressure decrement, the more accurate the computations at a cost in computer time.

For each pressure decrement, the difference in the volume of reservoir fluids between the higher and lower pressure is equated to the production of fluids over that pressure difference.

The form that this mass balance equation takes depends on the gas/oil ratio and whether the current pressure is such that

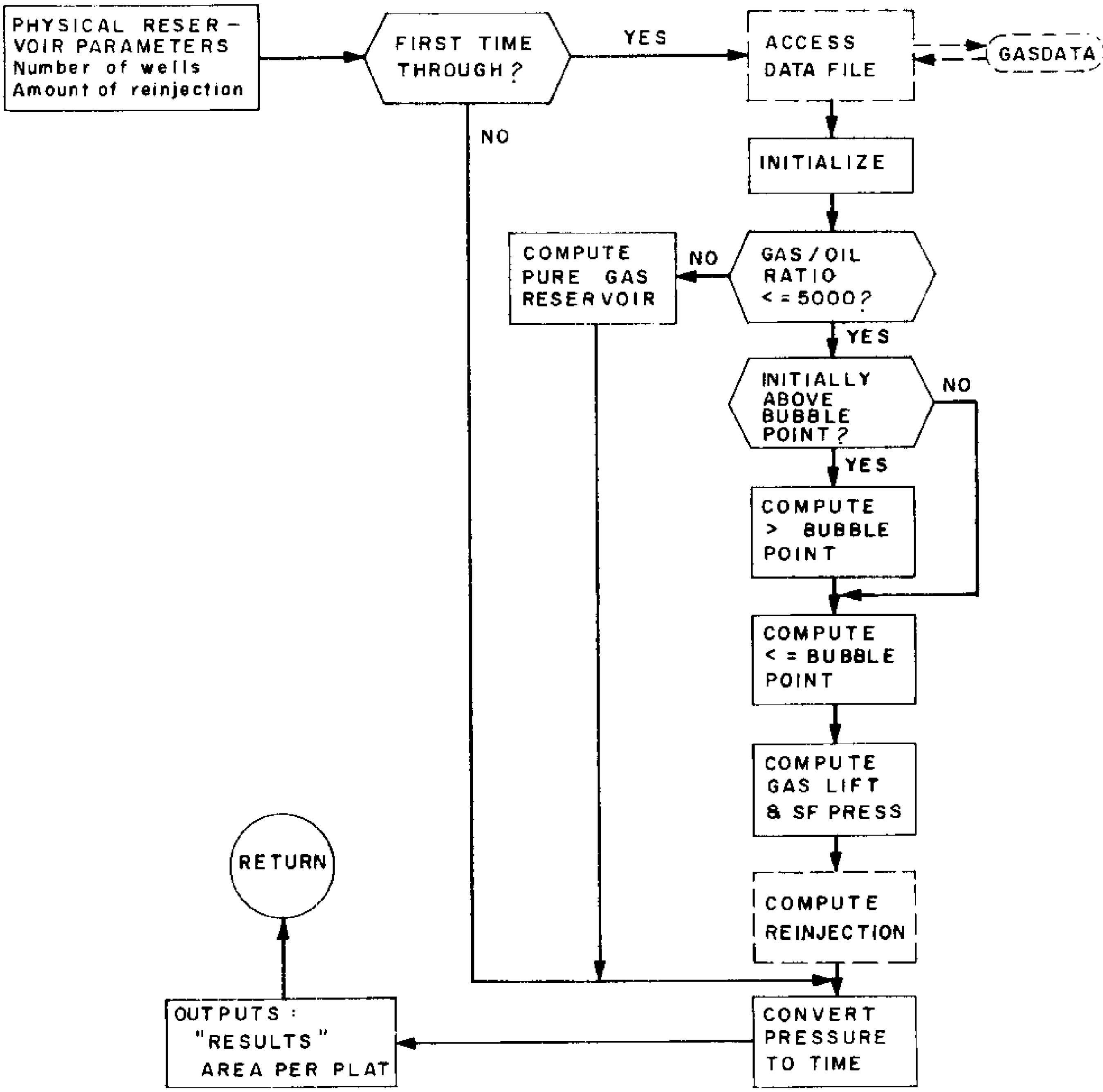

FIGURE 2.2.1 RESERVOIR MODEL LOGIC.

the reservoir is above the bubble point (all gas is dissolved in the oil) or below the bubble point (free gas has evolved).

If the input gas/oil ratio is above 5000:1, the model assumes that the reservoir is pure gas or gas/condensate. In general, this will only be true for gas/oil ratios much higher than 5000, 50,000:1 or higher. Thus, the present program leaves a gap between about 5000:1 and 50,000:1, the so-called retrograde reservoir, which it cannot handle.

For gas and gas condensate reservoir, the cumulative production at pressure p, G_p, is given by

$$G_p = G(1 - B_g/B_{gi})$$

where G is the initial volume of gas, B_{gi} is the initial gas volume factor, the ratio of the volume of the gas in the reservoir at initial reservoir pressure and temperature to the volume of this gas at the surface. B_g is the volume factor at pressure p.

Gas volume factors are computed by the real gas law using tables of the compressibility factor from Standing and Katz which are stored on disk [1]. These tables take as input the specific gravity of the gas as well as pressure and temperature. Throughout,the program assumes that reservoir temperature does not change during the field life.

For gas/oil ratios below 5000, and reservoir conditions above the bubble point, oil is produced solely by liquid and formation expansion with decrease in pressure. Above the bubble point, the model assumes oil, formation, and water compressibilities are constant and that the producing gas/oil ratio will remain at the initial solution gas/oil ratio. We assume formation porosity does not change with pressure.

The equations implementing this set of assumptions are:

$$N_p = \frac{N \cdot B_{oi}(C_o \cdot S_{oi} + C_f + S_w C_w) \cdot \Delta_p}{B_o \cdot S_{oi}}$$

$$B_o = B_{oi}(1 + C_o \Delta_p)$$

$$G_p = N_p \cdot R_{si}$$

where N_p is the cumulative oil production in standard barrels by the time the pressure has dropped to p; N is the original oil in place; B_{oi} is the initial oil volume factor (STB/bbl); C_o is the oil compressibility; S_{oi} is the initial oil saturation; C_f is the formation compressibility; S_w is the connate water saturation; C_w is the connate water compressibility; Δ_p is the difference between the initial pressure and p; B_o is the present oil volume factor; G_p is the cumulative gas production at p and R_{si} is the initial gas/oil ratio. For each run, the compressibilities are set at their input values, or lacking input, at the default values. The default values are

$$C_o = 2.0 \times 10^{-5}$$

$$C_f = 1.0 \times 10^{-6}$$

$$C_w = 3.2 \times 10^{-6}$$

All runs in this report used the default values.

The pressure at the bubble point is determined by the empirical relationship

$$p_b = \frac{18.0(R_{si}/\gamma_g)^{0.83}}{10^{(0.0125A - 0.00091T)}}$$

where γ_g is the gas specific gravity, A is the oil API number, and T is the reservoir temperature.

Below the bubble point pressures, things become a bit more complicated, since we are dealing with two phases and the percentage oil in the reservoir, S_o, is continually changing. The approach used is that of Múskat-Hoss [2], which involves the following assumptions:

1. Uniform pressure throughout the reservoir
2. The gas in solution is at equilibrium at all times
3. No gravity segregation during production
4. No water influx, no water production
5. If there is a gas cap, it does not expand
6. Injected gas is distributed uniformly throughout the producing horizon.

The latter three assumptions imply that we are dealing with a reservoir in which the sole producing mechanism is internal gas drive. The Muskat-Hoss approach involves solving for the change in oil saturation, ΔS_o, for each pressure decrement, Δp, via

$$\Delta S_o = \Delta p \cdot$$

$$\frac{\frac{S_o}{B_o B_g}\frac{dR_s}{dp} + \frac{S_o}{B_o}\left[\frac{k_g}{k_o} - \frac{R}{B_o B_g}\frac{\mu_g}{\mu_o}\right]\frac{\mu_o}{\mu_g}\frac{dB_p}{dp} + \left[m\left(1-S_w-\frac{S_{og}B_o}{B_{oi}}\right) + (1-S_w-S_o)\right]\frac{1}{B_g}\frac{dB_g}{dp} - m\frac{S_{og}}{B_{oi}}\frac{dB_o}{dp}}{1 + \frac{k_g \mu_o}{k_g \mu_g} - \frac{R}{B_o B_g}}$$

which, despite its forbidding form, is merely a restatement of the basic principle that what's in the reservoir has to fill the reservoir volume both before and after the pressure change. The number of terms is a reflection of the fact that several processes are happening simultaneously to change oil saturation with change in pressure. Some oil and gas is leaving the reservoir. The remaining oil and gas expand differentially and the oil and gas volume factors change. The solubility of the gas in oil changes and free gas is evolving which in this model is assumed to be distributed uniformely throughout the oil zone.

In this expression R is the producing gas/oil ratio, which from Darcy Law flow considerations is given by

$$R = B_o B_g \frac{k_g}{k_o} \frac{\mu_o}{\mu_g} + R_s$$

where k_g is the permeability of the formation to gas, k_o is the permeability to oil, μ_o and μ_g are the oil and gas viscosities (input) and R_s is the solution gas/oil ratio at the present pressure.

In this model, the gas and oil permeabilities are related to the absolute permeability of the formation, k, (input) and the present oil saturation and water saturation (input) by

$$k_g = k\ (1 - (S_o/(1 - S_w)))^2 (1 - (S_o/(1 - S_w))^2)$$

$$k_o = k(S_o/(1 - S_w))^4$$

These relations are from Wylie [3],

and hold for well compacted sandstone. For other formation materials, other expressions would have to be used.

B_o and B_g are the oil and gas volume factors, the ratio of the volumes at the surface to the volumes in the reservoir. B_g is obtained as before from the real gas law and tables of compressibility factor as a formation of gas specific gravity. B_o is estimated by the empirical relation [4]

$$B_o = 0.972 + 0.000147[R_s(\gamma_g/\gamma_o)^{0.5} + 1.25T]^{1.175}$$

where R_s is the equilibrium amount of gas in solution per barrel of oil at the present pressure; γ_g and γ_o are the gas and oil specific gravities, and T is the reservoir temperature.

m is the ratio of the initial gas cap volume to the oil zone volume. This is estimated from the original gas in place and oil in place by simply noting that the original gas, G, must either be in solution in the oil, N, or in a gas cap.

$$m = \frac{G - NR_{si}}{NB_{oi}B_{gi}}$$

The subscript i's in this expression refer to the initial situation. If the reservoir was originally above the bubble point, there was no gas cap, and under our assumption of negligible gravity separation, none will form during production.

At each pressure, the above set of equations is solved iteratively for the change in oil saturation, ΔS_o, and hence the oil saturation at the next lower pressure. Once the new oil saturation has been computed, the oil and gas production in the pressure interval can easily be obtained from mass/ balance considerations.

This entire process is repeated for each pressure decrement from the initial pressure down to 50 psi, and the gas and oil production as a function of pressure stored.

An optional feature of the model is to allow gas reinjection to enhance oil recovery. Assuming the reinjected gas is distributed uniformly through the producing zone, the effect of such reinjection is simply to alter the bubble point pressure and change the solution gas/oil ratio at p,

$$G_p = N_p R_s (1 - r)$$

$$R_s = \frac{G - G_p}{N - N_p}$$

where r is the reinjection ratio. p_b and B_{oi} are recalculated using the new R_s. Gas reinjection is performed only above the bubble point in this model.

After completion of all the pressure domain computations, the results must be converted into the time domain for the particular combination of number of wells per platform, n_w, and number of platforms per find, n_p, currently under analysis. The first step in this process is to compute the areal extent of an individual field, which, under our assumption of constant formation thickness, h, is simply

$$A_F = (N_p \cdot B_{oi} + N_G B_{gi})/(n_s \cdot \phi \cdot h \cdot (1 - S_w))$$

where n_s is the number of fields, ϕ is the porosity, and S_w is connate water saturation--all input.

The horizontal outreach, x_o, of a well drilled at max vertical deviation is computed using the given kickout depth and the vertical depth of formation, all three of which variables are input. The n_w wells are assumed to be equally spaced within an area $B_o 4x_o^2$ and the resulting distance between the wells, d_o, computed. If the area "covered" by the n_p platforms is larger than the field area, i.e. if

$$4n_p(x_o + d/2)^2 > A_F$$

then the max vertical deviation is adjusted downward so that the wells are arranged in an evenly spaced pattern over the structure, the distance between the wells, d_o, is recomputed, and the well drainage radius, r_e, is taken to be $d_o/2$. If the area covered by the platforms is less than the area of the structure, the wells are left in the original configuration and once again the well drainage radius is set at $d_o/2$ despite the fact that the exterior wells will be drawing from a larger portion of the reservoir than the interior. Under all the assumptions used already, principally internal gas drive and constant permeability, the errors induced will not be large for the well drainage radius enters into the equations logarithmically.

Having obtained the drainage radius, r_e, the actual oil and gas flow per well at any formation pressure, p_f, is computed by numerical integration of the radial Darcy Law flow equations:

$$q_o = \frac{7.08\ kh}{\ln(.608\ r_e/r_w)} \int_{p_w}^{p_f} \frac{k_{ro}(p)}{\mu_o B_o(p)}\, dp$$

$$q_g = \frac{7.08\ kh}{\ln(.608\ r_e/r_w)} \int_{p_w}^{p_f} \frac{k_{rg}(p)}{\mu_g B_o(p)}\, dp$$

where p_w is the well sandface pressure and r_w is the effective well bore radius currently set at .185 ft. The relative permeabilities, k_{ro} and k_{rg}, depend on the pressure through their dependence on oil saturation which in turn depends on pressure.

The sandface pressure is the variable which couples the flow in the formation to the flow in the well bore. The program begins by assuming a sandface pressure of 500 psi. It then generates oil and gas flows according to the above expressions. Using these flows, the program computes the pressure drop up the well bore in one hundred foot increments assuming isothermal flow. The pressure drop equation used is after Frick [5]

$$\Delta p = \frac{\Delta y \cdot M}{V_m} \left(1 + \frac{f q_o^2 V_m^2}{7.413 \times 10^{10} \cdot D^5} \right)$$

where Δp is the pressure drop in a hundred feet, and V_m equals cubic feet of mixed gas and oil at the pressure at height y in the well bore per standard barrel of oil, which in turn depends on the volume factors of the oil and gas and the gas/oil ratio in the wellbore. M is the mass of gas and oil associated with one standard barrel of oil, which depends on the specific gravities of the gas and oil and the producing gas/oil ratio; Δy is 100 ft; f is the friction factor, a function of the Raynolds Number [6], and D is the inside diameter of the tubing, currently set at .187 ft. If the resulting wellhead pressure is greater than 50 psi, then the resulting oil and gas flows are used. If the resulting wellhead pressure is less than 50 psi, gas lift is implemented. The program assumes that all gas-lift gas is introduced into the well bore at the bottom of the well. The program begins by employing enough gas to increase the gas/oil ratio in the well bore by 25%. It then recomputes the pressure drop for the new conditions. Due to the decreased density in the well bore and the release of compressional energy in the gas, a higher wellhead pressure will result. If the new wellhead pressure is greater than 50 psi, the resulting flows are used. If not, another 25% increment to the gas/oil ratio is tried. This process continues until either 50 psi is obtained at the wellhead or the well bore gas/oil ratio is four times the producing gas/oil ratio. In the latter event, the sandface pressure is increased by 50 psi, the flow from the formation recomputed and the well bore calculations repeated with the new sandface pressure.

Production continues until the necessary increase in sandface pressure to obtain 50 psi at the wellhead shuts off flow from the formation.

2.3 The field development routine

The model assumes that the aggregate oil and gas in place is distributed among a user-specified number of identical reservoirs whose distance to a central separation and processing point is also user-specified.

Exploration outlays are assumed to be $600,000 for seismic survey plus an outlay

$$9 \cdot \sqrt{\text{Number of Structures}} \times \$1.5 \times 10^6$$

for exploratory drilling. These outlays are assumed to take place three years prior to first production. None of the exploratory wells are used for subsequent production.

At present, the following expressions based on fits to reported cost figures in industry magazines and recent papers are used in costing the production facilities. These expressions are good only up to a water depth of approximately 250 ft. All figures are in 1972 dollars [7].

Drill platform (jacket and deck) = 9285*water depth + 3.8 x 10^6

Production platform = 8857*water depth + 4.2 x 10^6

+ 2*(platforms/field + 2)

*(214.30*water depth + 75000)

Transport platform, including separators =

14751.50*water depth + 10.8 x 10^6

Drilling cost = $18/ft where 20% of the wells drilled from each platform are assumed to be non-producers (dry holes)

Completion cost = .4 x drilling cost for each producing well

Annual per-field operating cost = $4.1 x 10^6

Water depth is in feet. All initial capital outlays are assumed to take place two years prior to installation.

2.4 Transport logic

The transportation package determines the transport system for oil and gas. The possible modes are oil tankers, oil pipelines, and gas pipelines. The model iteratively examines various tanker sizes (20, 30, 40, 90, 150, and 230 thousand DWT) and pipeline diameters (8 in through 48 in). For each mode the least present value cost system is selected.

Then a choice is made between oil tanker and oil pipeline systems (with and without concurrent gas pipelines) on the basis of the maximum difference between gross revenues and transport costs.

For the tanker system that tanker size which meets the draft limitations and which will most cheaply transport the oil is chosen. That is, tanker size is not allowed to vary through time with production rate. It is assumed that the tankers will be leased annually in any number necessary to the required capacity. The charter rate assumes a twenty-year recovery of initial costs at the investor's alternate opportunity cost. Storage cost at the field (5 days production at $20/bbl) are allocated to the tanker system. An option allows dredging or SBM construction at the refinery port if harbor facilities must be expanded. Cost data pertinent to the various tanker sizes is maintained in an external file. Table 2. 4.1 shows the principal figures used in determining charter rate. These data represent average figures for costs and performance for domestic tankers of the deadweight class, once again in 1972 dollars.

Pipeline costs are determined by iterating over diameter and number (1 to 4) of parallel lines. Table 2.4.2 shows the initial pipeline outlays assumed. For land lines, the capital outlay includes $10/ft right-of-way charges. When more than one line is used, the extra lines are added only as needed in the time stream. The number of pump stations required is determined exogenously to the transportation package (the main program iterates over transportation platforms) so that a tradeoff

TABLE 2.4.1

TANKER COSTS (U.S. FLAG)

Initial Cost (1972 dollars)	
20,000 DWT	$16,000,000
30,000	19,000,000
40,000	21,000,000
90,000	28,000,000
150,000	44,000,000
230,000	60,000,000
Annual Outlays	
Crew	$750,000
Insurance	2% initial cost
Maintenance	3% initial cost
Fuel	$20.00 per ton
Operating days/year	345
Port charges	$3,000/landfall, $\leq$ 40,000 tons $4,000/landfall, > 40,000 tons
Service speed	15 knots
Fuel rate	.35 lbs/ship-hour (slow speed diesal)

TABLE 2.4.2

PIPELINE CONSTRUCTION COSTS

Platform cost = \$(pump stations - 1) x (2,680,000 + 27,850 x water depth)

Line cost = \$1.11 x per-mile cost x distance

Pumping capital = \$185.2 x pump stations x horsepower/pump

Pumping operating \$9 x pump stations x horsepower/pump

General operating = \$lines x (165000 x pump stations + 750 x distance)

Diameter (in)	Land Cost/mi	Water Cost/mi
8	\$ 20,000	\$ 200,000
12	45,000	230,000
16	82,000	270,000
20	114,000	320,000
24	148,000	390,000
26	163,000	440,000
28	190,000	490,000
30	200,000	550,000
32	210,000	620,000
36	240,000	770,000
40	272,000	982,000
42	236,000	1,100,000
44	300,000	1,270,000
48	320,000	1,690,000

in time may be made between the building of field production platforms and transportation platforms according to construction constraints.

The initial outlay for a pump or compressor platform is assumed to be:

Pump platform cost = (Number of pump stations - 1)
*(2.68 x 10^6 + 2780*water depth)

That is, we assume that the first set of pumps at the field itself can be accommodated on the central processing platform. Like the production platform cost expression, this equation is good only for water depths less than 250 ft. In addition, an annual operating outlay of

Number of lines*(165*Number of pump stations + 750*Distance)

is charged the pipeline system.

The initial cost of pumps and compressors is assumed to be $175/hp. Annual operating costs are $4.00/hp. The program assumes produced gas is used for pump and compressor fuel at 116 cf/hp/day. This implies that the gas pipeline size will be dependent on whether or not there is an oil pipeline. Horsepower costs are added through the time stream as additional pumps or compressor power as required.

For oil lines, pressure drop and hence pump power is determined by Miller's Equation [8] and for gas lines, by iterative solution of the Modified Panhandle Equation [9]. Having obtained the pressure drop, the program computes the maximum pressure according to

DIAM > 20 in. Are Pressure <= 1080 psi

DIAM <= 20 in. Are Pressure < 1440*(DIAM - 8)psi

If this pressure is less than that generated by the program, then the corresponding combination of diameter and station spacing is considered infeasible.

2.5 The profits routine

This subroutine computes taxes, miscellaneous outlays, and produces present value investor profits. The package examines the capital and operating cost stream, introduces depletion, depreciation, "ad valorem taxes" (a catch-all overhead term for real estate taxes, process royalties, etc.), tax loss carryovers, borrowing, and debt financing. Depletion is figured at 22.5% of market value. Federal taxes are 48% less 7% investment credit. Local taxes are 8%.

The program assumes that the corporation developing and landing the find has no other operations. This limits the tax benefits of the early outlays to what can be obtained by carryforward. Otherwise it attempts to give the investor all the advantages available to him under present U.S. tax law. Double declining depreciation is used and full advantage of interest charges in the case of borrowed money is taken.

After computing the entire time stream of revenues and outlays before lease payments, and the resultant present value profit, the routine takes the user-specified fraction of these profits as a lease bid and enters this lease bid properly discounted into the time stream of outlays three years prior to first production. Investor profits and taxes are then recomputed.

2.6 Model limitations

The model suffers limitations in several areas: principally, lack of a retrograde gas depletion reservoir model, lack of water drive capability, inaccuracies in gathering and header net computations, limits on oil and gas pipeline capacities for high volume throughputs, improper pipeline system logic in certain cases, and the inability to handle platform schedules for extreme cases properly.

Lack of retrograde model; water drive model not operational.--At present the reservoir model is useful only for bubble-point or single-phase gas reservoirs under gas depletion drive. For retrograde reservoirs (i.e. those reservoirs whose gas/oil ratios are such that during pressure depletion the system shifts from single- to double- and back to single-phase systems), the model is inaccurate.

The seriousness of this limitation depends upon the necessity to model specific geological situations. Essentially, the present model leaves a gap between low and moderate (up to 5000) gas/oil ratios and very high (above 100,000) gas/oil ratios. Fortunately, many real pressure depletion reservoirs fall within the model's useful ranges and the model brackets those that don't.

A Buckley-Leverett water drive reservoir model (i.e. a model utilizing relatively slow pressure decline so that there is water influx into the original reservoir volume) is under development but is not incorporated in the present overall offshore development model. Development under water drive would reduce production rates but extend the life of the field for a given reservoir relative to the more rapid depletion which occurs with gas solution drive development.

Gathering and header net computations.--In actual offshore developments, the reservoir products are gathered at a central separator platform before separating oil and gas. The gathering and header nets leading to the central location are typically two-phase flow lines. Two-phase flow in pipelines is a difficult computational problem and such an analysis would be disproportionately expensive. For this reason the model assumes that oil and gas are separated at each platform and are transported through the gathering and header nets in separate parallel lines. This assumption allows costing these nets on the basis of single-phase flow. (Separator costs are allocated as in the real world; that is, separator costs are associated with a central single platform.)

For low to moderate peak volumes this simplification introduces only slight aberrations in gathering and header net costs. For very large, rapidly produced fields, or very small, slowly produced fields, however, this approach introduces significant diseconomies of scale, since overall size and pump power cost could be reduced by combining the two flows. For very large finds, the field cost generated by the model might be high by as much as 20% in extreme cases of rapid development of multifield finds. Generally speaking, the error introduced is unlikely to be large in the vast majority of cases. Thus, the added computational expense associated with modelling two-phase gathering and header nets did not appear to be justified.

Pipeline capacities.--Currently the model allows a maximum capacity of four 48-in parallel lines supported by five pump stations. In extreme cases of very large, rapidly produced finds with pipelines extending over 150 mi, this maximum capacity is insufficient to carry the peak load and, under present program logic, no pipelines are built. At present this model is incapable of piping only a portion of the peak capacity, thus none of the product will be offered for sale.

This is simply a computational problem which results from attempting to limit the number of central computational iterations in the pipeline package. Trivial changes in the program logic would implement larger pipeline system capacities, but computation would increase geometrically. Since the cases which will not be handled properly are quite extreme, the present computational bounds have been maintained.

Pipeline system logic defects.--There are several problems with the program's treatment of pipelines for transporting oil and gas from the offshore fields to the refinery. The worst difficulty lies in the handling of land pipelines (i.e, those extending from shore to refinery and not associated with SBM port facilities). At present only cases with one pump station (i.e. that at the transportation platform) may be handled accurately; the logic for placing multiple pump stations properly and distinguishing costs for land and sea pump stations is in error. For the purposes of this report all cases were run assuming the refinery was located at the point of pipeline landfall. Pipelines with one pump station and which extend over land will tend to overestimate the cost of the system for large or rapidly produced finds since systems employing smaller lines with more pump stations will be ignored. Correcting the error would require major alterations in the program and considerable increased computation.

The second serious logical defect in the model lies in the handling of oil and gas pipeline combinations when these lines have different destinations. The program only examines those cases where these separate lines have the same number of pump stations. Thus, it is impossible to compare such systems when the oil and gas pipelines have different numbers of pump stations. For the purposes of this report it has been assumed in all cases that oil and gas pipelines have the same landfall. Correcting this problem would require major alterations in the program and require considerable extra core requirements during execution, particularly for multi-case runs. It is noteworthy that for most bubble-point reservoirs this source of error is not significant so long as the oil and gas pipeline distances are approximately equal and the gas/oil ratio is not extremely low (i.e. less than 1,500).

A minor difficulty with the model is the treatment of parallel pipelines. When parallel lines are considered they are built as needed through the time stream. However, the model only considers parallel lines of the same diameter so that cases where the developer might initially build one or more large lines and supplement them later with a smaller line at peak production for multifield finds or where some of the peak gas production is flared are not considered. Thus in a few cases with exaggerated production peaks the model may return a system whose cost is higher than optimal by a few percent. Correcting this situation would increase computation time factorially.

Another minor problem lies in allocating oil transport by pure pipeline or pure tanker. Conceivably a developer might opt for a system based on pipelines with peak excess production carried by tankers. Such a system has merit, since one of the major costs of tanker systems is offshore storage which is a capital expense early in the time stream. Reduced pipeline capacity combined with reduced storage would make a combined system attractive for production schedules with sharp peaks. For such cases the model may overestimate the oil transport system cost by a few percent. Correcting this situation would also result in combinatorial increase in computation costs.

The model has been programmed with emphasis on computational efficiency rather than simulation sophistication in certain categories of transport and reservoir model. This policy has been followed with the intent that the program produce generally accurate results for a wide spectrum of potential offshore finds at reasonable cost. The current model is not designed to produce detailed analysis of particular finds. The programming structure of the model is such that such detailed analysis could be implemented without altering the basic fabric of the program.

Limitations on platform building schedule.--The program assumes that the production from all the fields in the find is brought to a central location from which it is then shipped to shore by pipeline or tanker.

Currently the model is limited to a maximum of nine separate fields containing the find and nine platforms per field for production. The first point is a very minor difficulty since larger numbers of fields would, in general, be landed from more than one central processing facility.

The number of platforms per field is limited by the fact that the program employs a convenient algorithm for determining gathering nets and drainage radii which is only accurate for up to nine platforms per field. Obviously other algorithms could be employed for greater platforms, but these have not been implemented. This presents difficulties in modelling "giant" single fields covering large areas at shallow or moderate depths which might be produced with more than nine platforms. For the purposes of a general economic impact model this is not a significant error since the approximation of such a field can be made by increasing the number of fields containing the reserves and using a small field separation. Such an approximation will introduce only minor inaccuracies.

A more subtle difficulty with the platform building schedule is the interaction between platforms per field and drainage radius of individual wells. As the number of platforms on a field increases, the effective drainage radius between wells decreases. While mutual "impedence" between wells is computed in the program via flow rate calculations, the effects of water or gas cut are not. Thus, for a reservoir of small areal extent and great formation thickness, production with large numbers of platforms, production may be overstated because in reality water and gas cut to the wells could be significant.

3. Results of simulations

3.1 The base-case oil finds

The Offshore Development Model has been exercised on a number of possible combinations of the input parameters to obtain insight on the type of development to be expected from a hypothetical find, the resulting financial flows, and to obtain a feeling for the relative importance of the various input parameters. Since the number of possible combinations of input parameters is astronomical, we have chosen to operate with ten base-case finds: five oil discoveries and five gas discoveries.

Let's take the base-case oil finds first. The five hypothetical oil finds studied have 100 million, 200 million, 500 million, 2 billion, and 10 billion barrels in place respectively. For these base-case runs all other reservoir parameters were set at the values listed in Table 3.1.1. Note that the gas/oil ratio for these five finds is 1000, which for the pressure and temperature assumed implies we are operating with bubble-point reservoirs.

In all our base-case runs, the landed price of oil was assumed to be $8.00 per barrel for oil and $1.50 per Mcf for gas. That is, oil price was set at $8.00 and gas at the energy equivalent price relative to oil. These prices were held constant in real terms throughout the analysis. In the base cases, the investor's real cost of capital was set at 15% per annum and no debt financing was employed. It was assumed

TABLE 3.1.1

BASE-CASE OIL FINDS: RESERVOIR PARAMETERS

Gas/oil ratio	1000:1
Reservoir pressure	5,000 psi
Reservoir temperature	200°F
Formation depth	10,000 ft
Formation thickness	40 ft
Formation porosity	14%
Formation permeability	0.1 darcy
Oil API	30
Oil viscosity	2 cp
Gas specific gravity	0.6
Gas well allowable	100 Mcf/day
Oil well allowable	10,000 bbl/day
Kickout drilling depth	1,500 ft
Drilling maximum slantangle	45°
Connate water	30%
Pressure depletion decrement	50 psi
Reservoir model employed	Gas solution drive
Fields holding reserves	1 for finds $\leq 500 \times 10^6$ bbls
	2 for finds $= 2 \times 10^9$ bbls
	5 for finds $= 10 \times 10^9$ bbls
Field separation	20 mi

that 75% of the investor's pre-lease-payments present value profits would be bid away in the form of a bonus payment.

Two site locations were chosen to represent contrasts in distance: a site on the outer Georges Bank, 146 mi from land in 252 ft of water, and a site 36 mi off of northern Florida in 78 ft of water.* In both cases the shoreside terminal draft limitation was set at 41 ft. Both tanker and pipeline transport systems were assumed to take the petroleum directly to shore.

The base-case oil development strategies are shown in Table 3.1.2. In general, this gas drive model tends to produce

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*In the nomenclature of reference 9 , the first site is USGS's potential development area EDS 1 and the second is USGS's potential development area EDS 12.

TABLE 3.1.2

BASE-CASE OIL FINDS DEVELOPMENT STRATEGIES

Oil In Place	36 Miles Offshore	146 Miles Offshore
100 MM bbls	80% reinjection 1 platform, 21 wells Life of field, 3 years 12" oil line, 8" gas line No intermediate stations Oil recoverable, 24% Gas recoverable, 70%	80% reinjection 1 platform, 21 wells Life of field, 3 years 20,000 DWT tanker, 12" gas line No intermediate stations Oil recoverable, 24% Gas recoverable, 70%
200 MM bbls	80% reinjection 2 platforms, 41 wells Life of field, 3 years 12" oil line, 12" gas line No intermediate stations Oil recoverable, 24% Gas recoverable, 70%	80% reinjection 2 platforms, 41 wells Life of field, 3 years 40,000 DWT tanker, 16" gas line No intermediate stations If oil line, 16" Oil recoverable, 24% Gas recoverable, 70%
500 MM bbls	80% reinjection 4 platforms, 81 wells Life of field, 4 years 20" oil line, 20" gas line No intermediate stations Oil recoverable, 24% Gas recoverable, 70%	80% reinjection 3 platforms, 61 wells Life of field, 5 years 40,000 DWT tanker, 20" gas line 1 intermediate station If oil line, 20" Oil recoverable, 24% Gas recoverable, 70%
2,000 MM bbls	80% reinjection 14 platforms, 284 wells Life of field, 5 years 24" oil line, 30" gas line No intermediate stations Oil recoverable, 24% Gas recoverable, 70%	80% reinjection 14 platforms, 284 wells Life of field, 5 years 40,000 DWT tanker, 24" gas line 2 intermediate stations If oil line, 24" Oil recoverable, 24% Gas recoverable, 70%
10,000 MM bbls	40% reinjection 35 platforms, 710 wells Life of field, 12 years 30" oil line, 30" gas line No intermediate stations Oil recoverable, 20% Gas recoverable, 73%	50% reinjection 35 platforms, 710 wells Life of field, 12 years 40,000 DWT tanker, 3 32" gas lines 1 intermediate station If oil line, 40" Oil recoverable, 21% Gas recoverable, 72%

fields quite rapidly, perhaps a factor of two as rapidly as the industry norm. We would expect water drive fields to be produced more slowly and we must remember that this program models neither gas cut nor water cut problems which can be exacerbated by rapid depletion. Nonetheless, it is possible that the industry's norm for gas drive fields is overly slow from the point of view of present value profits.

Despite the rapid production, the model uses relatively few platforms, reflecting the economies of directional drilling from multi-well platforms. Per-well rates for these geologies are quite substantial, running about 2,500 bpd at peak production.

In order to put the base-case finds in perspective, it is worthwhile to compare the sizes of these hypothetical finds with past offshore discoveries. The oil recoverability of these base-case finds is about 25%. Thus, the 100 million barrel in place find represents reserves of about 25 million barrels. As of January 1, 1969, 76% of the 131 oil discoveries offshore Louisiana had estimated reserves of less than 25 million barrels, 9% were put in the 25 to 50 million barrel range. Six of these finds had reserves of 50 to 100 million barrels, 7 had 100 to 200 million, and 6 were over 200 million barrels recoverable [10]. The largest purely offshore field in the Gulf is put at 650 million barrels recoverable, corresponding to about 2,600 million barrels on Figure 3.1.6.
In the Gulf, most of the production has been from finds in the 250 to 400 million barrel recoverable range, corresponding very roughly to 1,000 million barrels in Figure 3.1.6.

Some observers feel that the relatively small sizes of the offshore discoveries in the Gulf may be anomalous. They point out that the Gulf is characterized by an unusual amount of salt domes which tend to break up potentially larger accumulations as well as make these smaller structures more easily found. [11]. Indeed, both on the West Coast and in the North Sea, the finds have tended to be a good deal larger. The Ekofisk complex approaches 10 billion barrels in place in 7 structures, and the Brent field and the Forties field are of the same order of magnitude. The world's largest offshore discovery, Safaniya, in the Persian Gulf, is presently estimated at 27 billion barrels recoverable or something like 75 billion barrels in place.

At the base case oil and gas prices, the model favors considerable reinjection. That is, at energy equivalent prices, it pays the developer to delay his gas revenue for the base-case geology. However, investor profits are only a very weak function of amount of reinjection, as is indicated by Figures 3.1.1, 3.1.2, and 3.1.4. Changing percent reinjection from quite low (10%) to quite high (70%) typically changes investor profit by less than 10%.

The model claims that the investor will maximize his present valued profit by landing all the nearshore (36 mi) base-case finds by pipeline and all the well offshore (146 mi) base-case finds by tanker. A more detailed study of the effects of distance on choice of transport mode was undertaken for the three larger finds and the results are shown in Figures 3.1.4

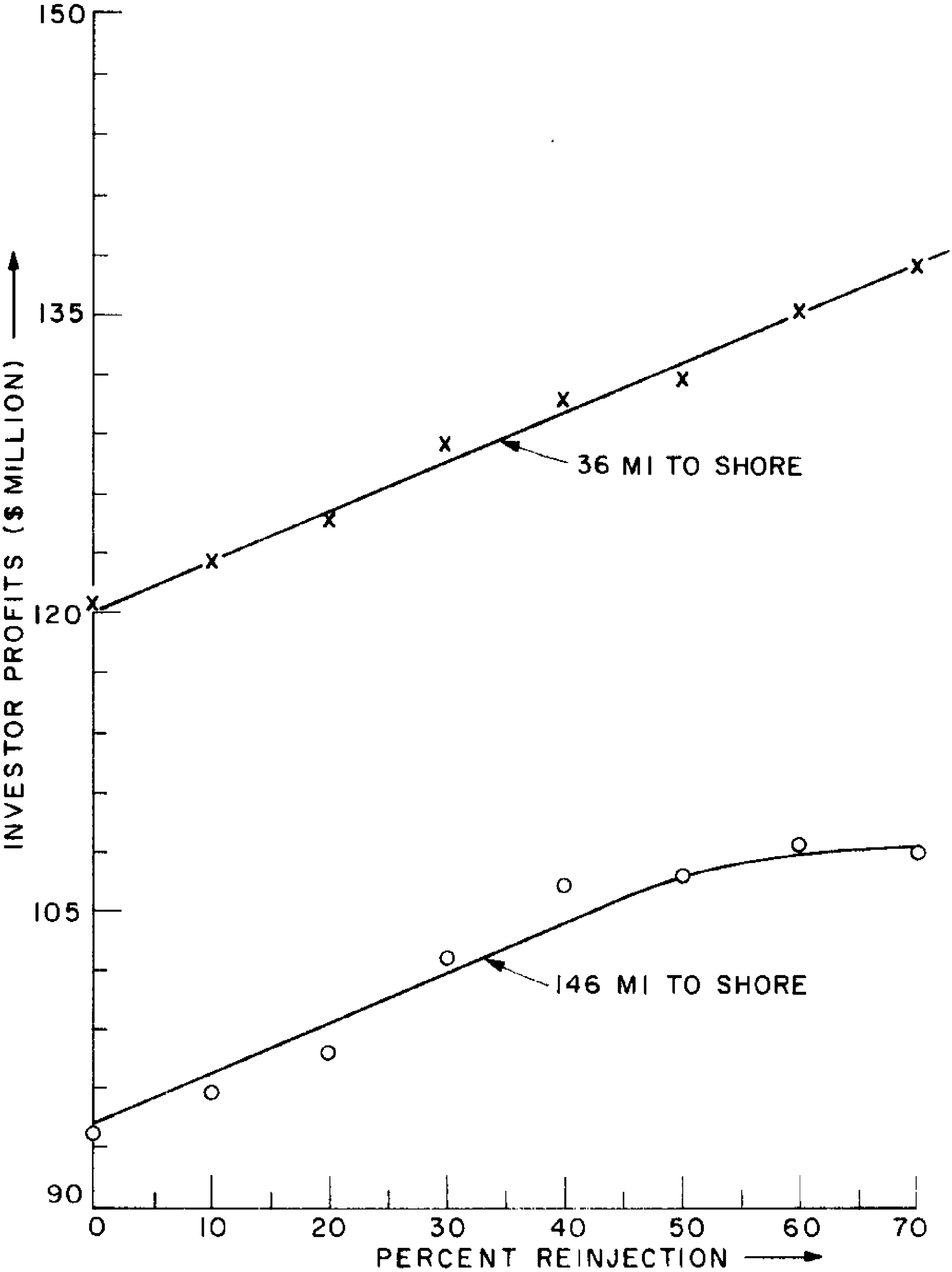

FIGURE 3.1.1 PROFITS VS. GAS REINJECTION FOR A 500 MILLION BARREL BASE-CASE FIND. OIL PRICE, $8.00/BBL; GAS PRICE, $1.50/MCF.

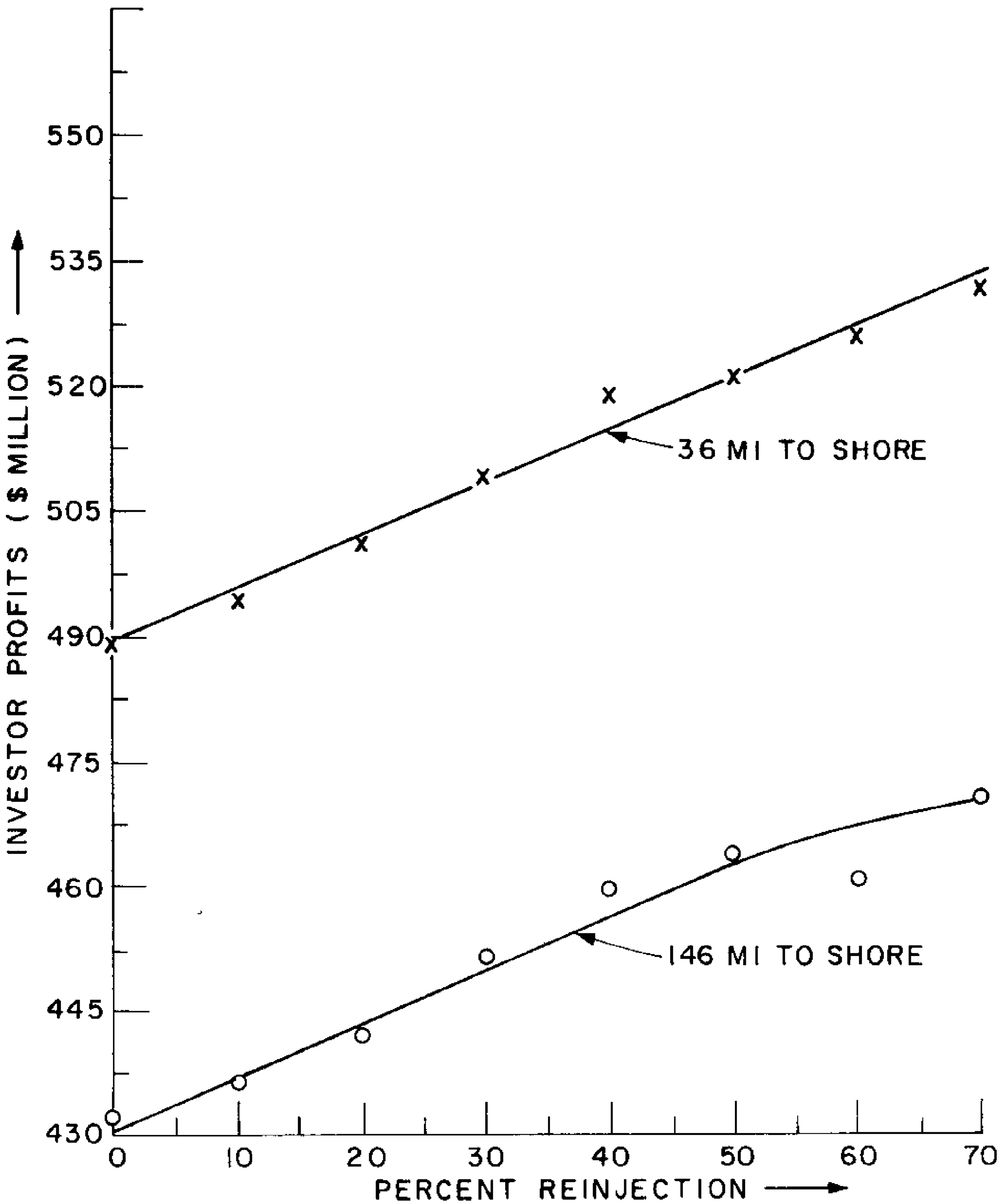

FIGURE 3.1.2 PROFITS VS. GAS REINJECTION FOR A 2,000 MILLION BARREL BASE-CASE FIND. OIL PRICE, $8.00/BBL; GAS PRICE, $1.50/MCF.

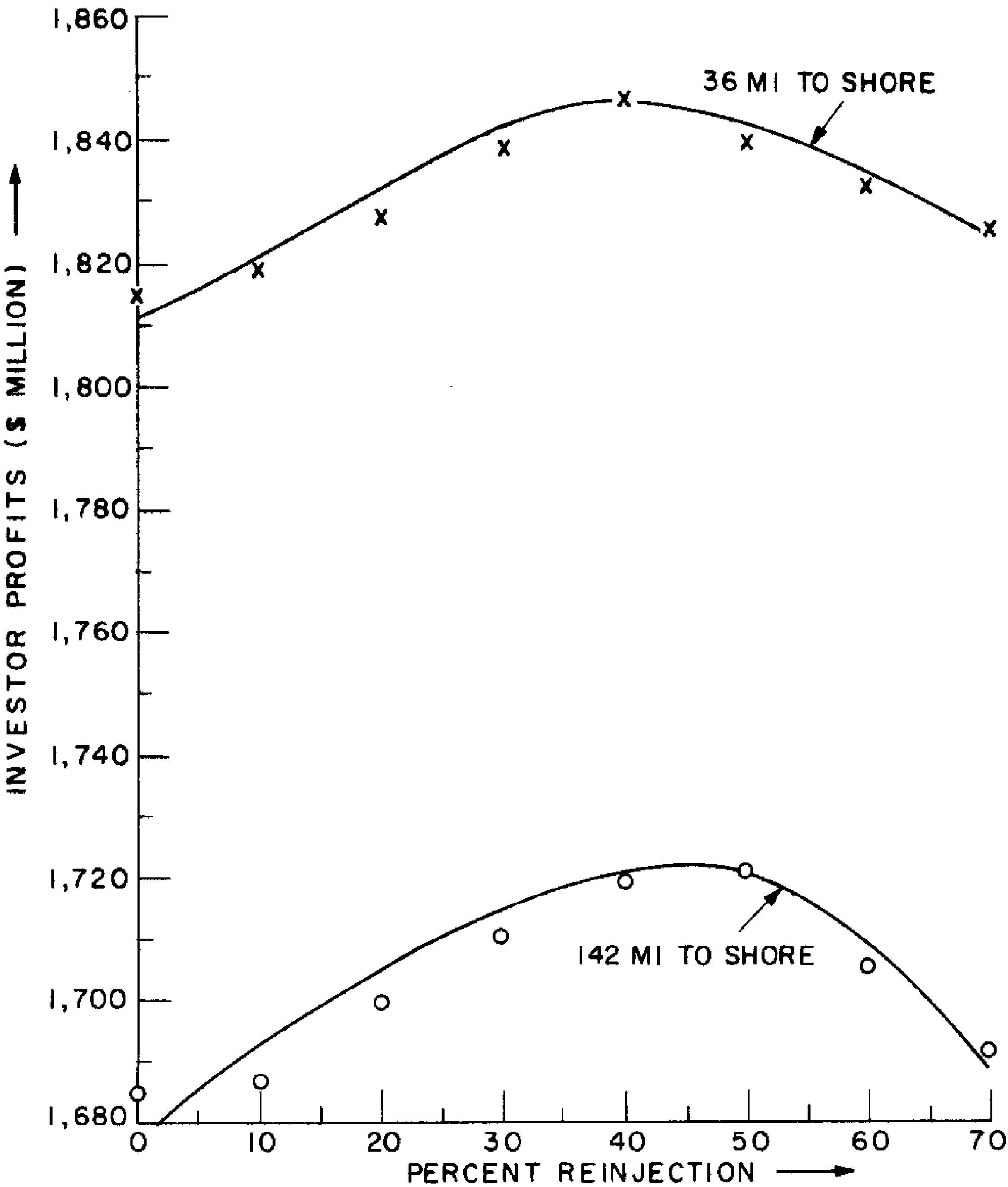

FIGURE 3.1.3 PROFITS VS. GAS REINJECTION FOR A 10,000 MILLION BARREL BASE-CASE FIND. OIL PRICE, $8.00/BBL; GAS PRICE, $1.50/MCF.

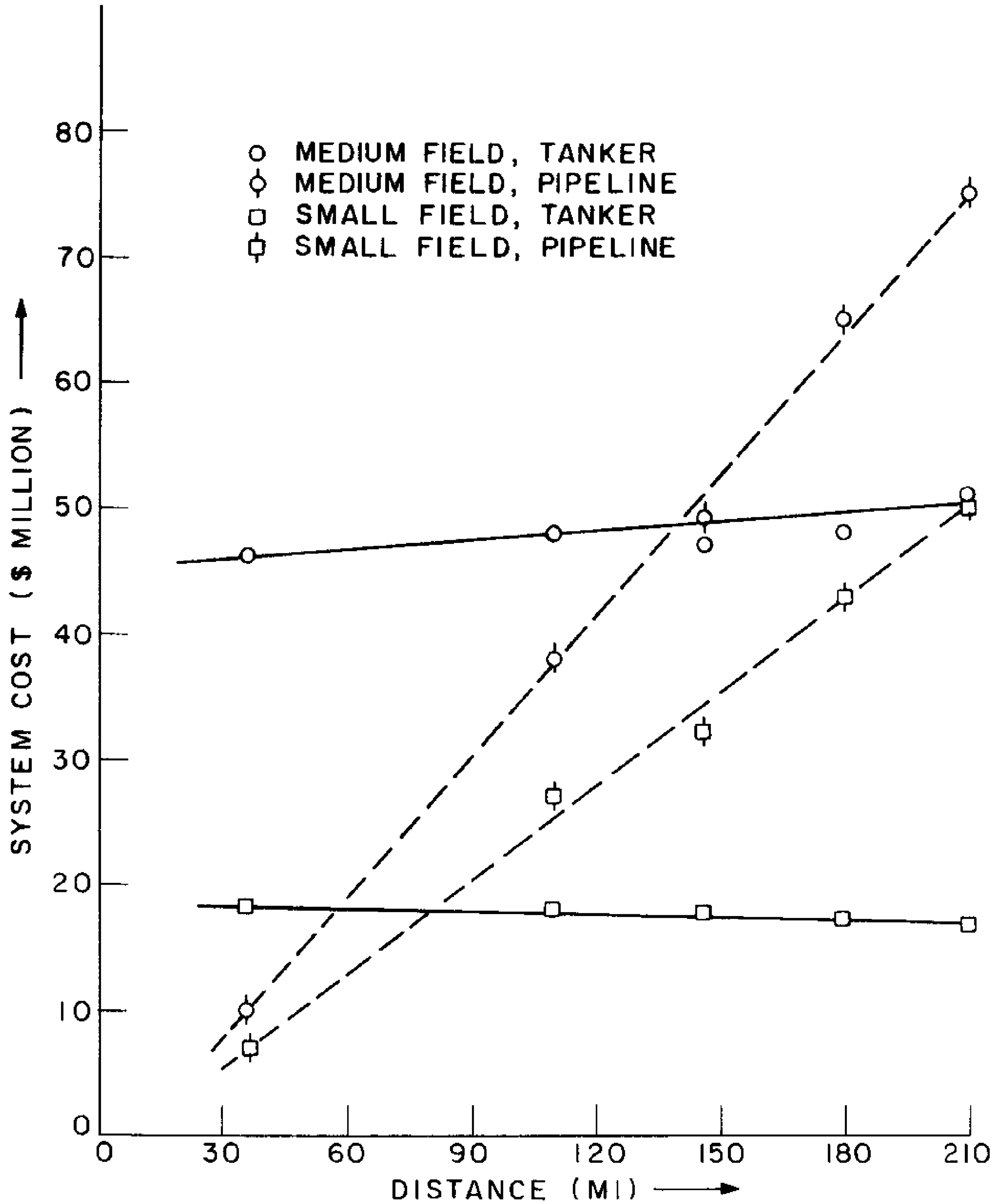

FIGURE 3.1.4 TRANSPORT COST VS. DISTANCE, 500 MILLION AND 2,000 MILLION BARREL BASE-CASE FINDS.

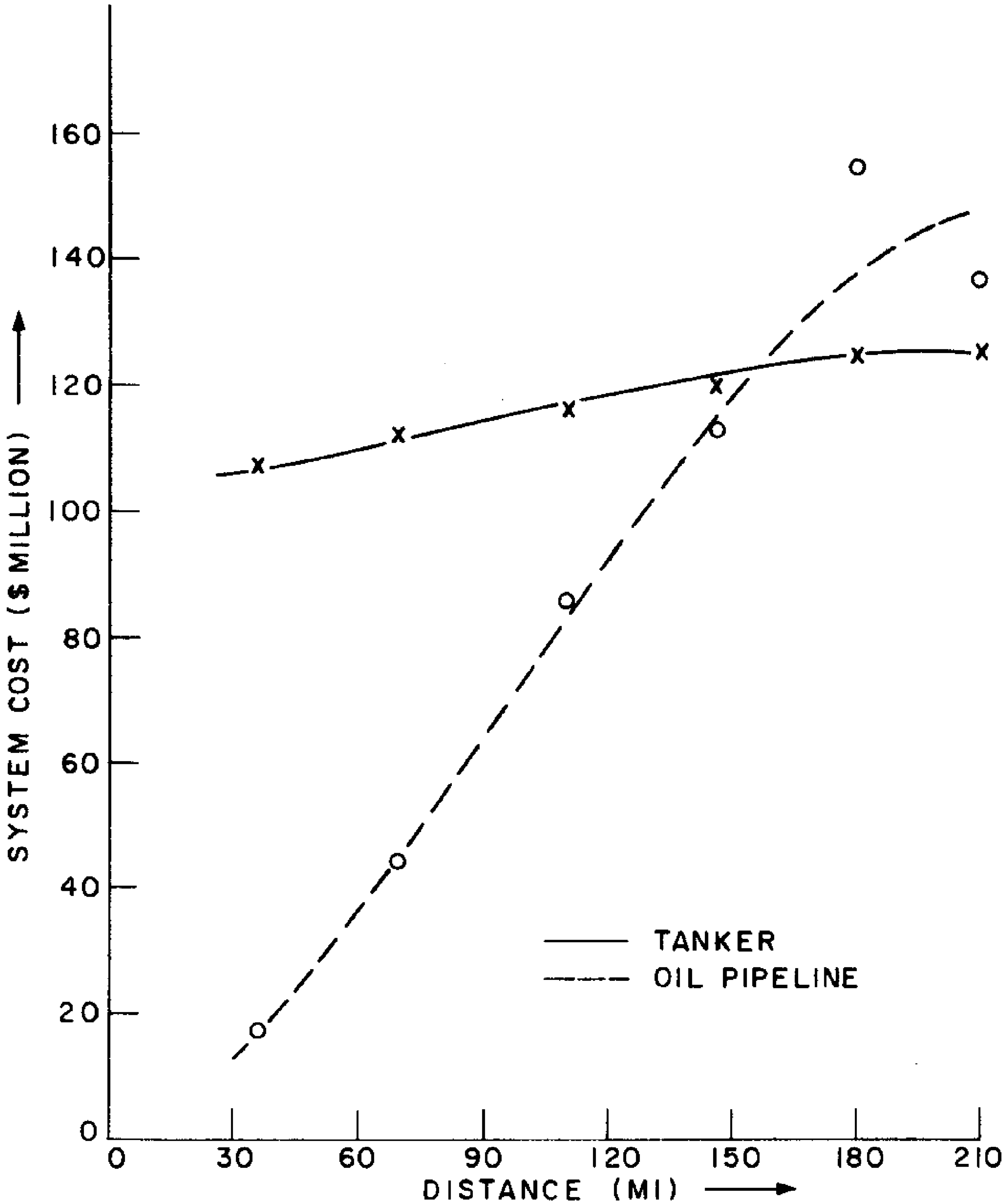

FIGURE 3.1.5 TRANSPORT COST VS. DISTANCE FOR 10,000 MILLION BBL BASE-CASE FIND.

and 3.1.5. In general, the larger the find and the shorter the distance to shore, the more the pipeline is favored over the tanker. For a 500 million barrel in place find, the breakeven distance is about 80 mi; for a 2,000 million barrel in place find, the breakeven distance is about 140 mi. For longer distances, the program favors tankers; for shorter distances, pipelines. The additional cost to the investor of using a pipeline for even a 500 million barrel find 146 mi offshore is about $20 million. This additional cost, if it were forced on the developer, would not prevent the development of this find. The same thing is true for the 200 million barrel find.

Certainly, the most striking result of the base-case oil runs is the relative cheapness of this petroleum for the larger finds from the point of view of the nation as a whole. The solid lines in Figure 3.1.6 show the unit resource cost of the landed crude as a function of field size. This is the price the investor would have to obtain in order to break even on all his cash flows at 15% cost of capital <u>before payments to public bodies</u>, assuming that no gas was landed.* This cost, then, does not contain lease payment, royalties or taxes. It is the cost to the nation in opportunities forgone associated with the resources employed in developing and landing this oil before non-market environmental effects, assuming the national marginal cost of capital is 15% real. This cost ranges as low as 45¢ per barrel (10 billion barrels, nearshore) and even for a 1 billion barrel find is only about a dollar. When one compares these figures

*"Break even" here implies a present value of 0 at 15% real.

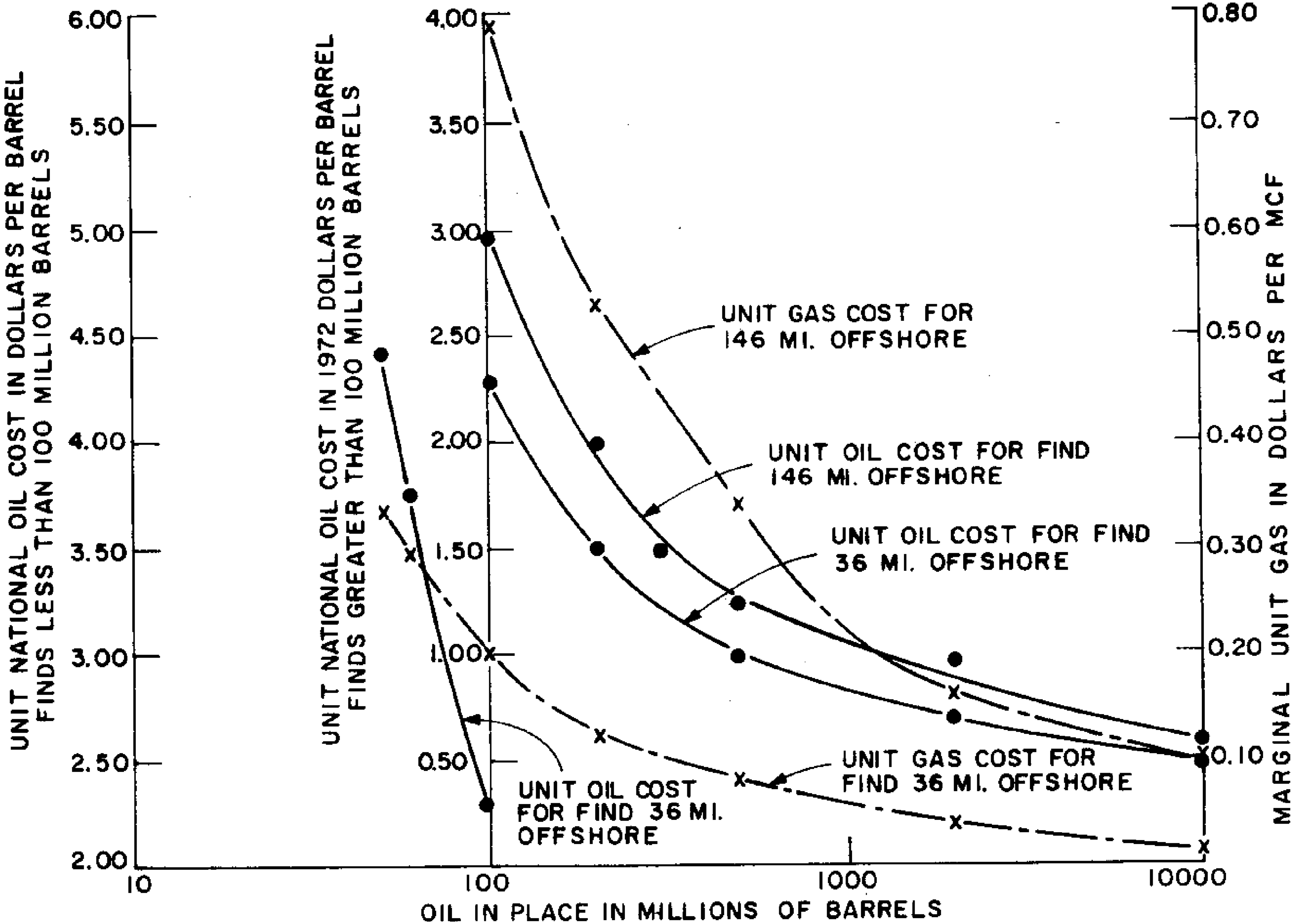

FIGURE 3.1.6 UNIT NATIONAL COST OF BASE DEVELOPMENTS.
Breakeven price before lease payment, royalties and taxes at 15%. Unit gas cost is based on the additional outlays required to land the gas given the oil is being landed. All figures in 1972 dollar.

with the likely cost to the nation of foreign crude ($6.00 to $10.00 landed), offshore oil can be cheap indeed. (Remember, all figures are in 1972 dollars.) However, the unit cost curves turn upwards very sharply in the neighborhood of 200 million barrels. The unit national cost of a 50 million barrel, nearshore find is close to $4.50 per barrel and the unit cost at this point is essentially inversely proportional to the size of the find. These runs are probably slightly biased against the very small fields, since we have not allowed the developer the option of using less than 24 well platforms.

The dotted lines in Figure 3.1.6 show the marginal unit national costs of landing the associated gas <u>given that the oil is already being landed</u>. These figures range from less than 3¢ per Mcf for the largest find close to shore to 90¢ per Mcf for the 100 million barrel find well offshore. At least for the larger finds, this is quite cheap compared to the cost of marginal gas, especially on the East Coast. Once again, the general pattern is one of sharp economies of scale up to about 500 million barrels in place, and rather gentle economies of scale thereafter.

One result of the disparity between the likely prices of petroleum and the unit national costs for the larger finds is that both the public revenue and the developer profit associated with the base-case oil finds can be quite large. The dotted lines in Figure 3.1.7 show the present valued investor profit associated with the base-case oil finds according to the model. Theyrange from a high of about $1.8 billion for the largest base-case oil find, dropping off to $17 million for the

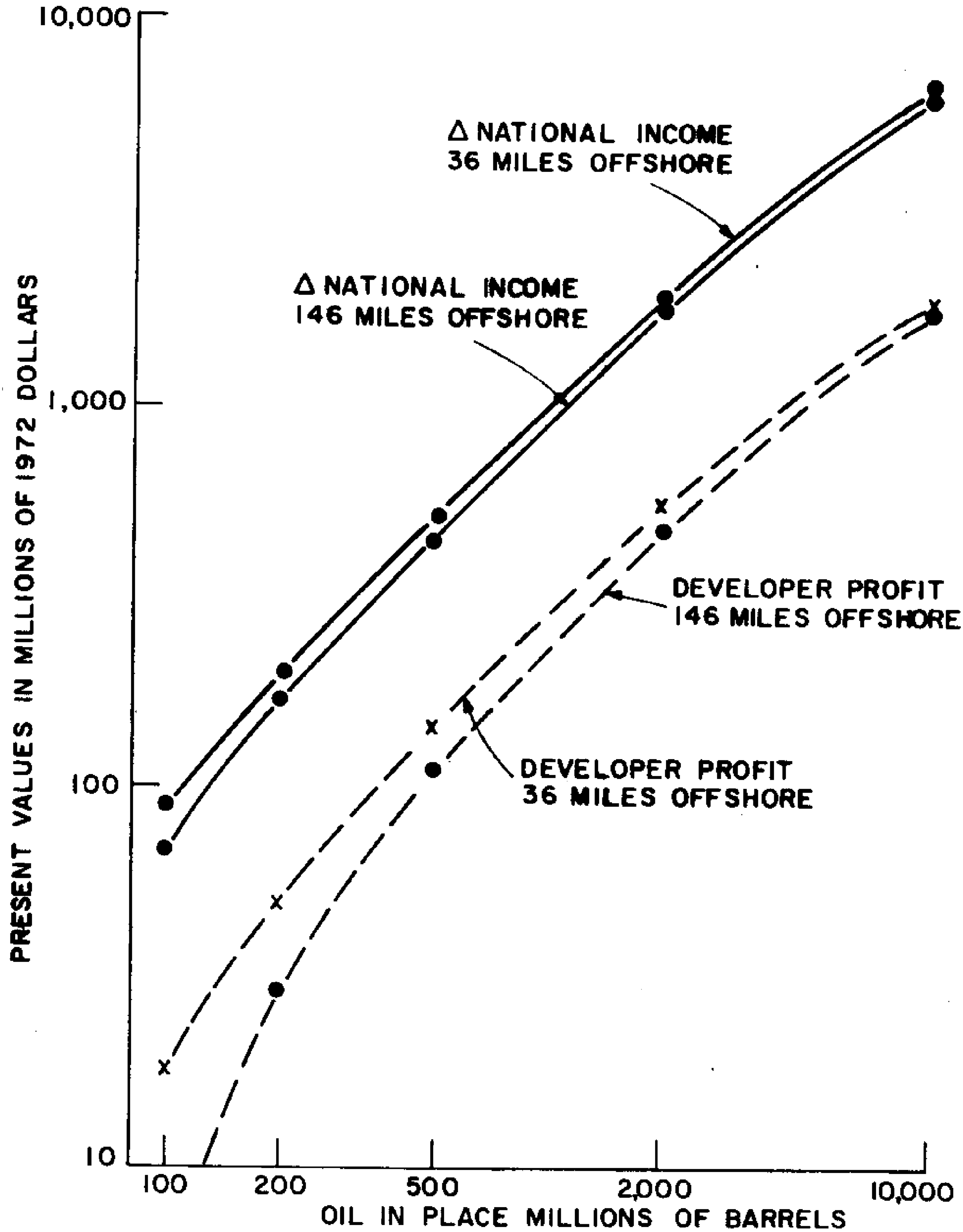

FIGURE 3.1.7 PRESENT VALUE OF Δ NATIONAL INCOME AND DEVELOPER PROFIT FOR BASE CASE DEVELOPMENTS
All figures in 1972 dollars present valued back to 1972
Change in national income based on assuming cost to nation of alternative oil and gas is $8.00 per barrel and $1.50 per Mcf. Developer and national cost of capital taken to be 15%. First year of production 1978.

100 million barrel find close to shore and $3.8 million for the 100 million barrel find 146 miles offshore.

Assuming that the landed cost to the nation of alternative oil and gas is $8.00 and $1.50 respectively, the base-case landed prices, the present valued increase in real national income associated with developing one of the base-case finds, is the difference between the development present valued resources and the present valued national costs.* This difference is shown in the solid lines in Figure 3.1.7. It ranges from a high of $6.5 billion to a low of $67 million. In deriving these curves we have assumed that the nation's opportunity cost of capital, like the developer's, is 15% real.

Assuming no price control and assuming the offshore development doesn't force all the $8.00 oil and $1.50 gas off the market, the offshore development will have no effect on market prices. In this case, all the increase in national income will take the form of public revenues (lease payments, royalties, and taxes) and developer's profits. Figure 3.1.7 indicates that under our assumption that the lease bid is 75% of the pre-lease-bid profits, the developer's share of the increase in national income ranges from a low of 20% of the total for the smallest base-case finds to a high of 28% for the largest. The change in this fraction is a result of the fact that for the smallest finds, our independent developer cannot take full advantage of his tax benefits, making the important, if unoriginal, point that in this capital-intensive

*This assumes environmental costs are zero. That is, this figure must be adjusted by the value of the net effect on the environment of the offshore development as opposed to that of the alternative source of the petroleum.

industry, U.S. tax laws are biased in favor of corporate bigness and against new entrants.*

The remaining 70% to 80%, the difference between the solid lines and the dotted lines in Figure 3.1.7, will go to the public under our assumptions in the form of lease bids, royalties and taxes. Due to the logarithmic nature of Figure 3.1.7, this difference cannot be estimated by eye.

In view of the disparity between our resource costs and likely prices, it is of interest to examine the sensitivity of our results to our cost figures. The model employs a wide variety of subsystem cost data for generating overall development outlays. Our cost estimates are admittedly second-hand. They are based on our best estimates of actual costs as gleaned from the industry literature. They are obviously subject to a number of possible errors. To test the sensitivity of the model to these costs, comparison cases were run for the two largest base-case finds by increasing production platform, drilling platform, and field operating costs by an arbitrary factor of two. The field transportation cost was increased by a factor of 1.5. The results of this comparison are given in Table 3.1.3. The only noticeable effect produced was the reduction of investor profits by a few percent; the investor's development strategy for construction and production was not affected. Since drilling costs, header net costs, gathering net costs,

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*To a certain extent this bias may be able to be overcome by such financial devices as leveraged leasing.

TABLE 3.1.3

COST COMPARISONS

	Standard Cost Case	Increased Cost Case
2,000 MM bbl find:		
Platforms per field	5	5
Investor profits	$ 508,711,000	$ 484,896,000
Field outlay costs	$ 87,216,000	$ 131,583,000
Life of field (yrs)	6	6
10,000 MM bbl find:		
Platforms per field	7	7
Investor profits	$1,846,205,000	$1,791,153,000
Field outlay costs	$ 247,650,000	$ 370,665,000
Life of field (yrs)	12	12

etc. were not altered for the comparison case, the effect of the changes altered total field outlay costs by considerably less than 50%.

To a first approximation, the only results of errors in cost data appears to be to change the minimum size field which is developable. For the larger base-case finds, the national income and investor profit results are quite insensitive to errors in the costing. Other geologies could be considerably more sensitive to costing inaccuracies. For example, if the reservoirs considered in the cost comparison were at very shallow depths and no header nets were required, platform cost increase would be a larger fraction of field costs and, consequently, might alter the discounted cost timestream sufficiently to cause the investor to choose a slightly different rate of production.

An obvious corollary is that, for all but marginal discoveries, development strategies and the pressure to develop will be quite insensitive to costs implied by environmental regulation. The cost of these regulations will be a measure of the loss in national income associated with them before the resulting environmental benefits. However, these costs will not affect development strategy or public or private profits greatly.

A perennial question is: how small can a find be and still be profitably developed? Figure 3.1.8 shows the results of a study of smaller field sizes maintaining all other reservoir parameters at their base-case values. For the base-case prices,

$8.00 and $1.50, it appears the cutoff point for a single independent find relatively close to shore is just under 50 million barrels in place and perhaps double that for a find at the outer limit of the continental shelf.

Interestingly enough, as indicated by the lower curves in Figure 3.1.8, even a rather sharp drop in prices has a more pronounced effect on investor profit than it has on minimal field size. These curves are based on a landed price of $3.00 per barrel for oil and 56¢ for gas, that is, we have maintained the gas price at its energy equivalent relevant to oil. This drop in prices increased the marginal field size to about 150 million barrels in place from the nearshore location and to about 225 million barrels in place for the site well offshore. Under this price assumption, investor profit and hence public revenue increases much less rapidly with field size than under the base case.* Inspection of the output of these runs indicated that the absolute level of the oil and gas price has very little effect on the developer's strategy provided the field can be profitably developed over the range of price variations. That is, as long as the ratio of the oil to gas price is maintained constant, the developer's strategy, if he develops, will be insensitive to the price level.

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*This does not imply that real national income would be decreased by a decrease in imported crude prices. Quite the opposite is true. Rather, this result indicates merely that domestic offshore oil is less valuable to the nation if lower world crude prices exist, because the offshore oil would be replacing a less costly alternative.

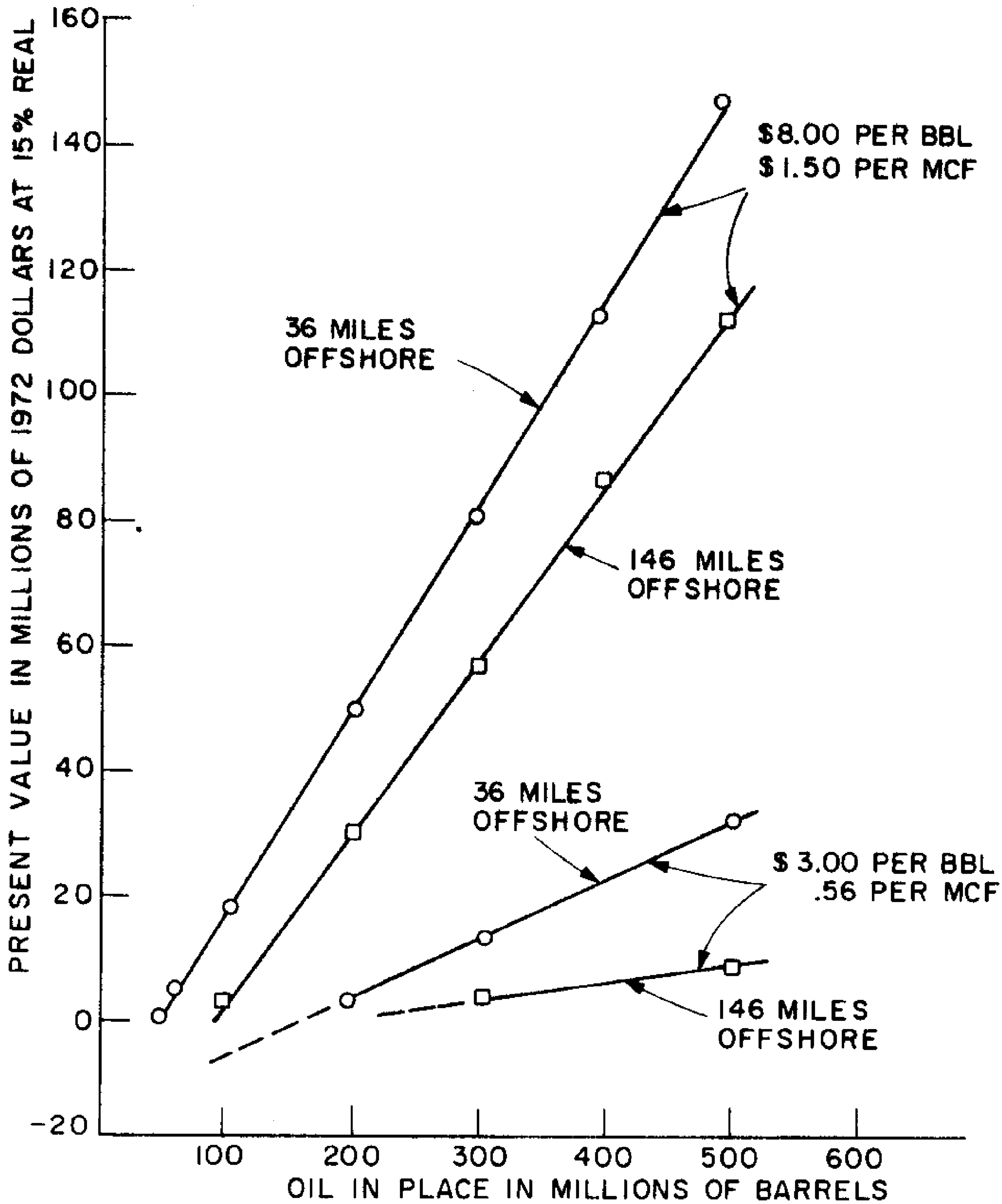

FIGURE 3.1.8 PRESENT VALUE OF INVESTOR PROFIT AS A FUNCTION OF FIND SIZE FOR SMALLER FINDS. All resevoir parameters except field size remaining at base case oil values.

3.2 The base-case gas finds

For our base-case gas finds, we have chosen to operate with discoveries of 200 billion, 500 billion, 1 trillion, 5 trillion, and 10 trillion standard cubic feet in place. We have used a gas/oil ratio of 100,000:1. Otherwise, all the oil base-case parameters have been left at their original values, including landed prices and location, with the exception that oil density has been set at API 45 and oil viscosity at cp. This combination of gas/oil ratio and initial pressure and temperature implies that we are dealing with single-phase, gas-condensate reservoirs. Table 3.2.1 summarizes the results of our base-case gas runs. For these reservoirs all the oil recovered will be in the form of condensate. Hence gas and oil recoveries are the same and, for all the runs,equal to 89%. No reinjection was employed.

Once again, the model produces the finds quite rapidly. The condensate is shipped to shore by tanker for the location well offshore; by pipeline for the nearer shore find. For the far offshore find, the program is somewhat erratic in its choice of more intermediate compressor platforms versus multiple gas lines, indicating that the tradeoff is a weak one. As higher-strength, thicker-wall pipe becomes available, we will see longer runs of larger diameter pipe. The base-case input parameters of 56,000 psi yield strength, .75" maximum wall diameter, and 1.75 safety factor are all rather conservative.

TABLE 3.2.1

BASE-CASE GAS FINDS DEVELOPMENT STRATEGIES

Gas In Place	36 Miles Offshore	146 Miles Offshore
200 MMM SCF	1 platform, 20 wells Field life, 1 year Gas line, 16" Condensate line, 8" No intermediate compressor stations	This find cannot be profitably developed at base-case prices. Nor can 300 MM SCF.
500 MMM SCF	1 platform, 20 wells Field life, 2 years Gas line, 26" Condensate line, 8" No intermediate compressor stations	1 platform, 20 wells Field life, 1 year Gas line, 26" Condensate landed by 20,000 DWT tanker 3 intermediate compressor stations
1,000 MMM SCF	3 platforms, 58 wells Field life, 6 years Gas line, 28" Condensate line, 8" No intermediate compressor platforms	2 platforms, 39 wells Field life, 6 years Gas line, 28" Cond. landed by tanker 2 intermediate compressor platforms
5,000 MMM SCF	12 platforms, 232 wells Field life, 8 years 2 30" gas lines Condensate line, 12" 1 intermediate compressor platform	12 platforms, 232 wells Field life, 9 years 42" gas line Cond. landed by tanker 4 intermediate compressor platforms
10,000 MMM SCF	20 platforms, 385 wells Field life, 12 years 3 32" gas lines Condensate line, 12" No intermediate compressor platforms	20 platforms, 385 wells Field life, 12 years 2 36" gas lines Cond. landed by tanker 3 intermediate compressor platforms

Notes:

All these finds have a gas recovery of 89% and an oil recovery of 89%. No reinjection was employed. 100 MMM SCF find, 36 miles offshore could not be profitably landed.

In order to put the sizes of the base-case gas finds in perspective, it is worth noting that 46% of the 222 gas finds offshore Louisiana as of 1969 have been put at under 25 billion cubic feet, 21% in the range of 25 to 100 billion cubic feet, and 23% in the range of 100 to 500 billion cubic feet. Fourteen fields were in the 500-1,000 billion cubic feet range and 8 were over 1 trillion cubic feet. Once again, due to the predominance of salt domes in the Gulf, this experience may be on the low side of future finds. There have been 5 gas finds in the North Sea, all over 4 trillion cubic feet; 2 were over 10 trillion cubic feet.

The Offshore Development Model claims that, at least for the larger finds, this gas can be quite cheap from a national income point of view. Figure 3.2.1 indicates that, even if we give the condensate no credit whatsoever, the breakeven price on the gas before lease bid, royalties and taxes--the landed unit cost to the nation--ranges from a low of 9¢ per Mcf for the 10 trillion cubic feet find 36 miles offshore to 37¢ per Mcf for the 500 billion cubic feet find 146 miles offshore. For any reasonable assumption about the future cost of gas to the nation, this is cheap gas, especially on the East Coast.

However, the unit cost curve turns upward extremely sharply in the neighborhood of 200 billion cubic feet for the site 36 miles offshore and at 400 billion cubic feet for the site 146 miles offshore.

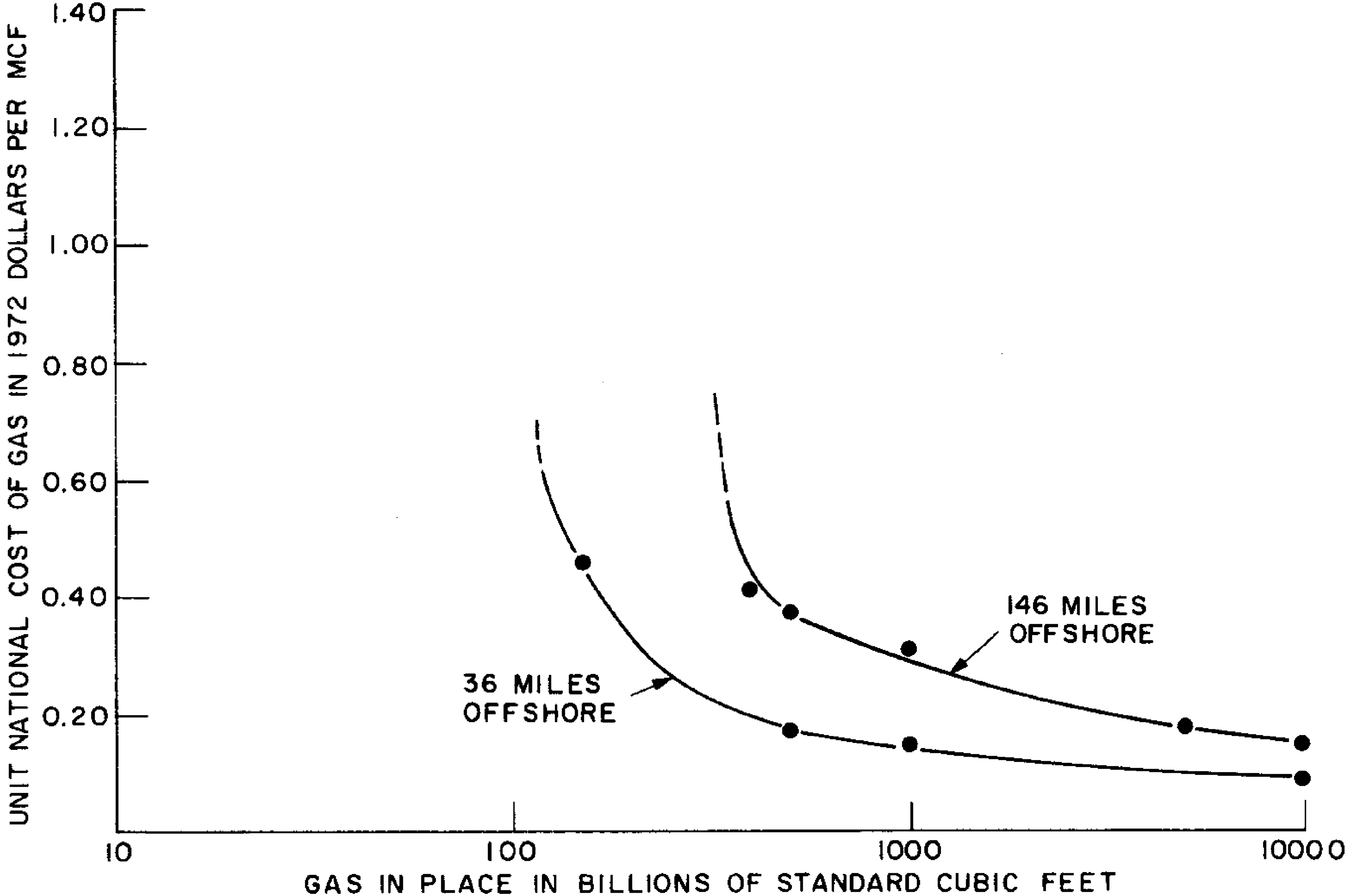

FIGURE 3.2.1 UNIT NATIONAL COST OF BASE CASE GAS FINDS.
All figures in 1972 dollars.

Given the base-case price assumption, $1.50 per Mcf for gas and $8.00 per barrel for condensate, public revenue and investor profit are quite large for the larger finds, as Figure 3.2.2 indicates. If these base-case prices are the cost to the nation of alternative sources of petroleum, then the sum of these two curves is the increase in national income associated with developing the find before environmental disbenefits.

3.3 Variations on a theme

We have made a rather large set of runs in which only one or two of the input parameters was varied from its base-case value. With respect to reservoir parameters, the results were quite insensitive to these variations, with three extremely important exceptions:

a. Formation permeability

b. Formation thickness

c. For the oil finds, oil viscosity.

These three variables control the flow rates through the formation to the well. For the three largest base-case oil finds, Figure 3.3.1 shows the effect of permeability on investor profits, and Figure 3.3.2 shows the effect of viscosity. In the latter figure, we have varied oil density at the same time as viscosity, for these variables are not independent, but it's the viscosity that's the key. The significance of these variables is demonstrated by the fact that certain finds combining low permeability and high oil fiscosity may be uneconomical for any reasonable prices, irrespective of

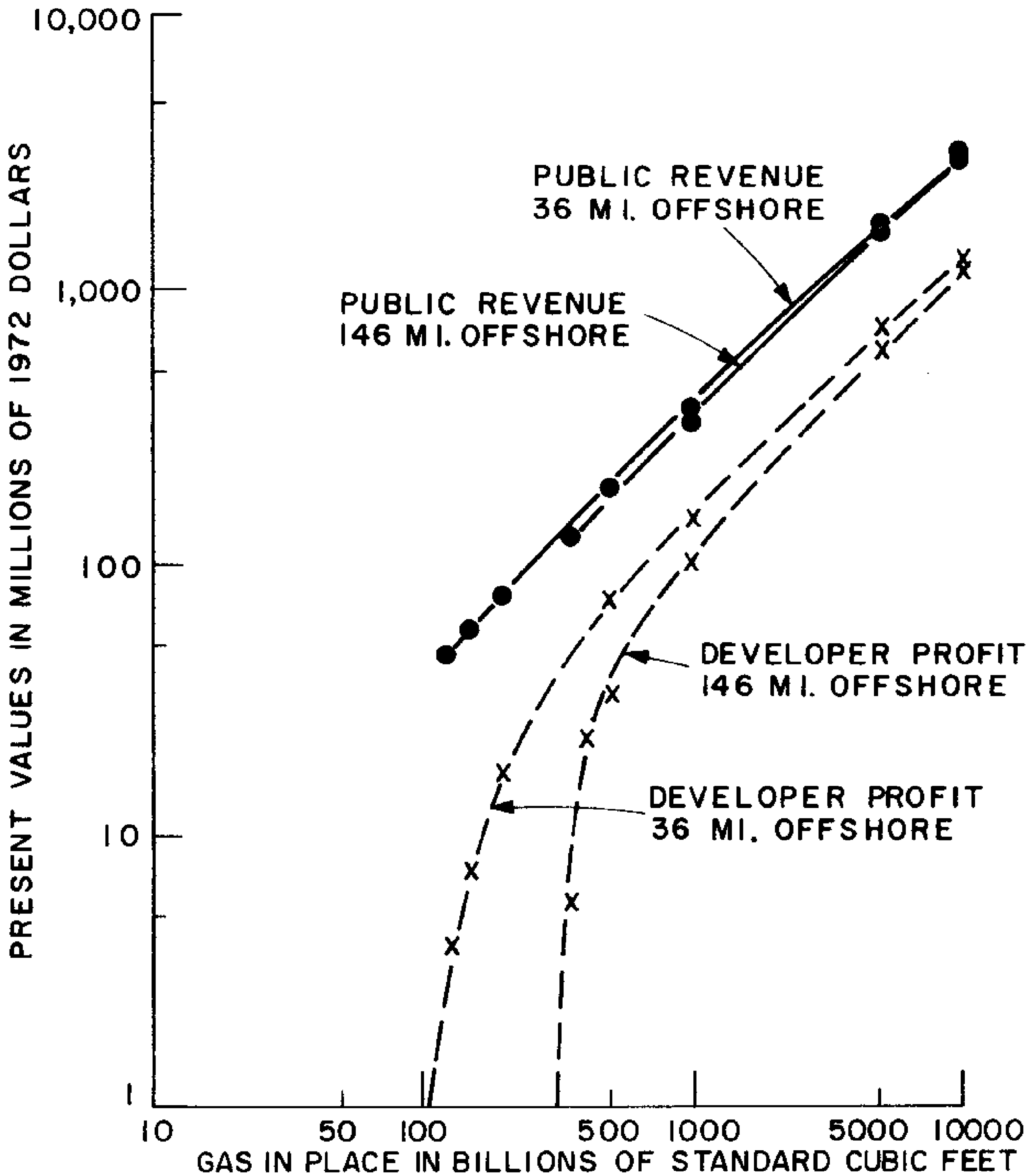

FIGURE 3.2.2 PRESENT VALUE OF INVESTOR PROFIT AND PUBLIC REVENUE FOR BASE CASE GAS FINDS.
All figures in 1972 dollars present valued back to 1972 at 15% real.
First year of production 1978.

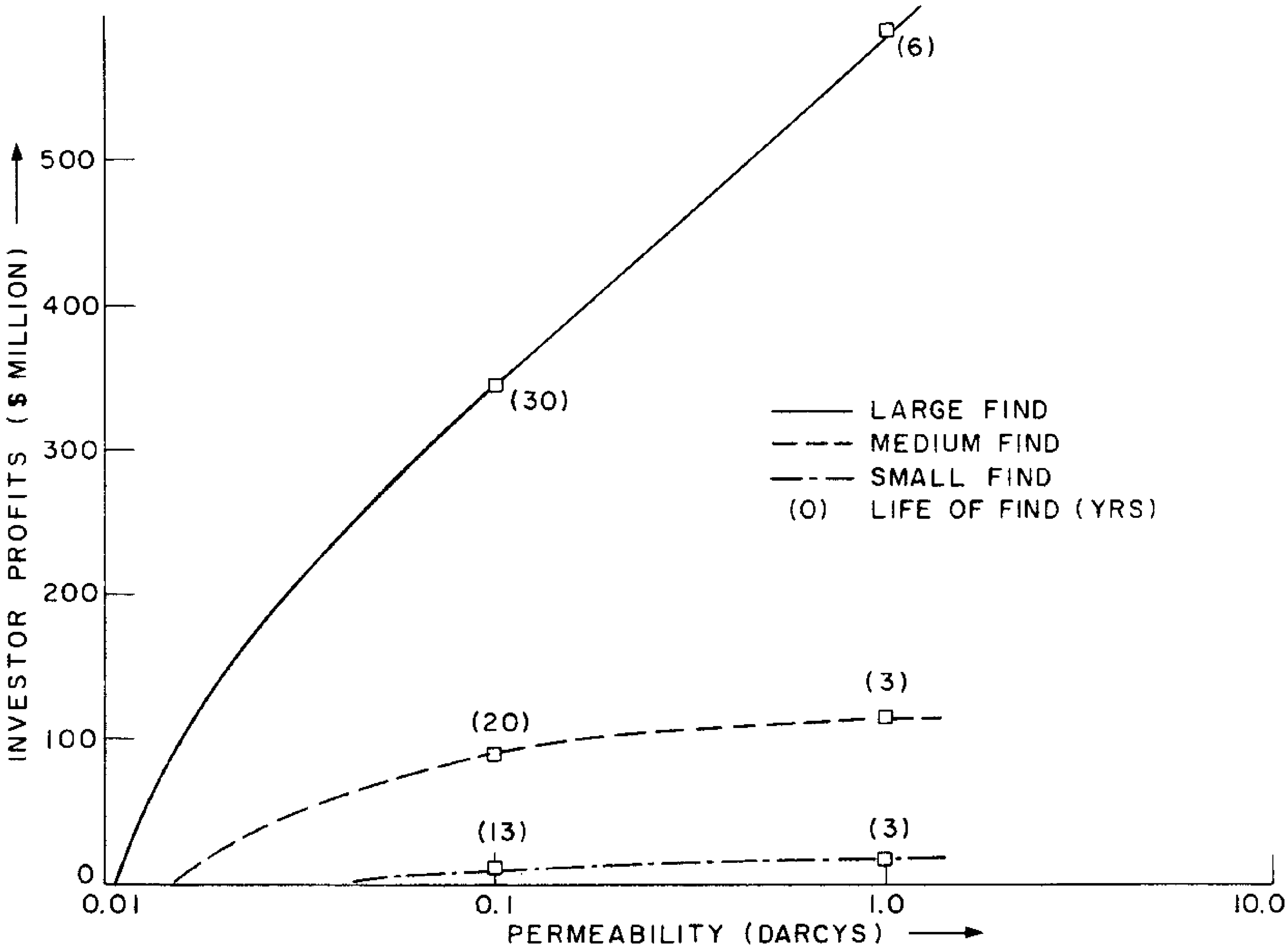

FIGURE 3.3.1 PROFITS VS. PERMEABILITY

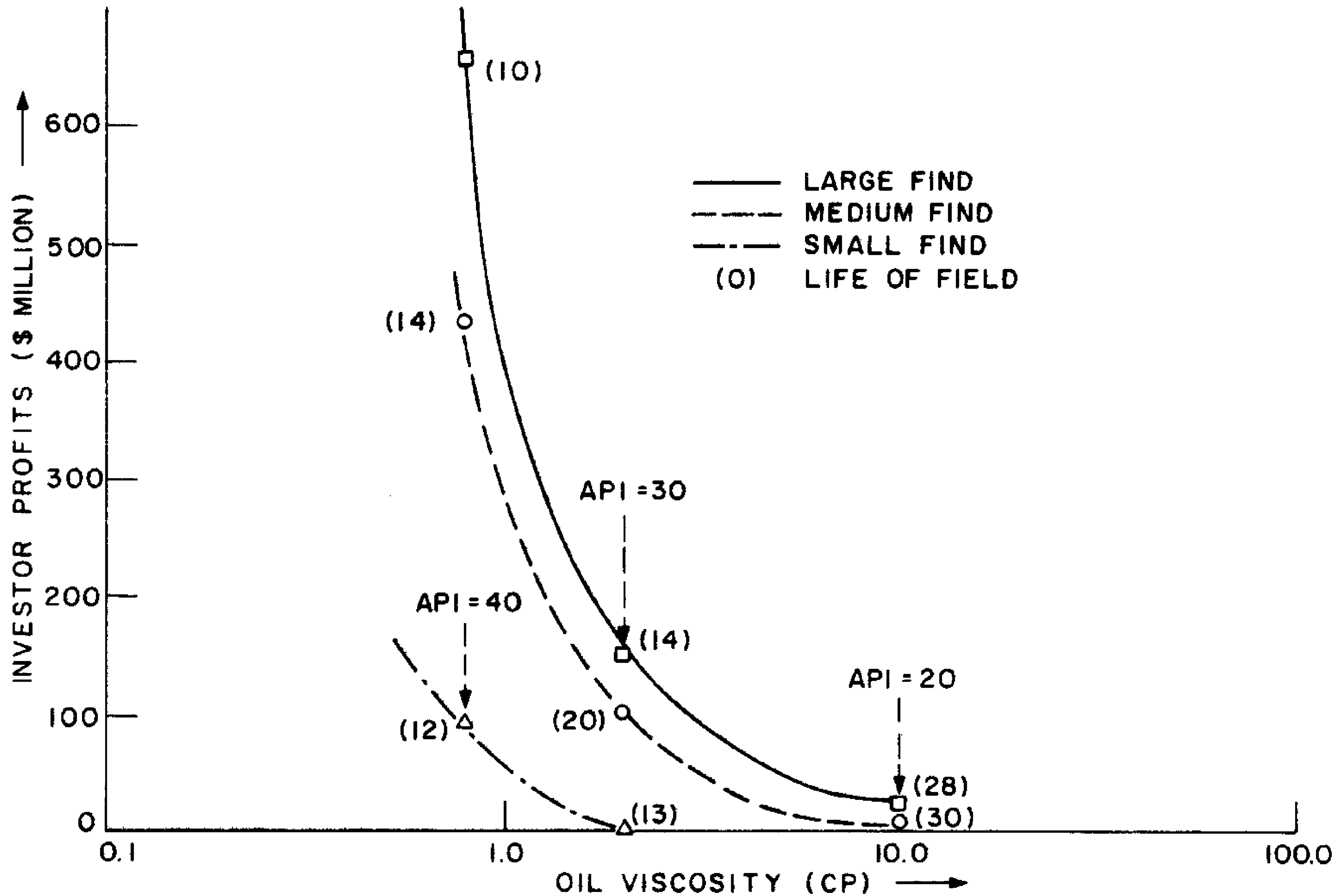

FIGURE 3.3.2 INVESTOR PROFITS VS. OIL VISCOSITY

the volume of petroleum in place. That is, if the well flow rates are sufficiently low, investment in the find cannot be justified no matter what the size of the find.

The effect of formation thickness on investor profits for the 2 billion barrel, base-case oil find is shown in Figure 3.3.3. Formation thickness serves as a partial surrogate for changes in permeability since it is the product of the permeability and the thickness which appears in the flow equations. In addition, large thickness implies smaller field areas, allowing the field to be covered by a smaller number of platforms. As in Figure 3.3.3, the effect of variations in formation thickness dies off as the formation thickness becomes large.

Other physical characteristics of the reservoir are generally minor in the extent to which they affect investor profits or production schedules. Typically, the maximum change in investor profits between extreme cases is on the order of less than 10%. Table 3.3.1 shows present value investor profits for various depths of formation.

TABLE 3.3.1

INVESTOR PROFITS AND FORMATION DEPTH

Depth	Profits
10,000 ft	$539,000,000
6,000	553,000,000
3,000	575,000,000

For a given oil and gas in place, the only influence porosity has in our model is to change the areal extent of the

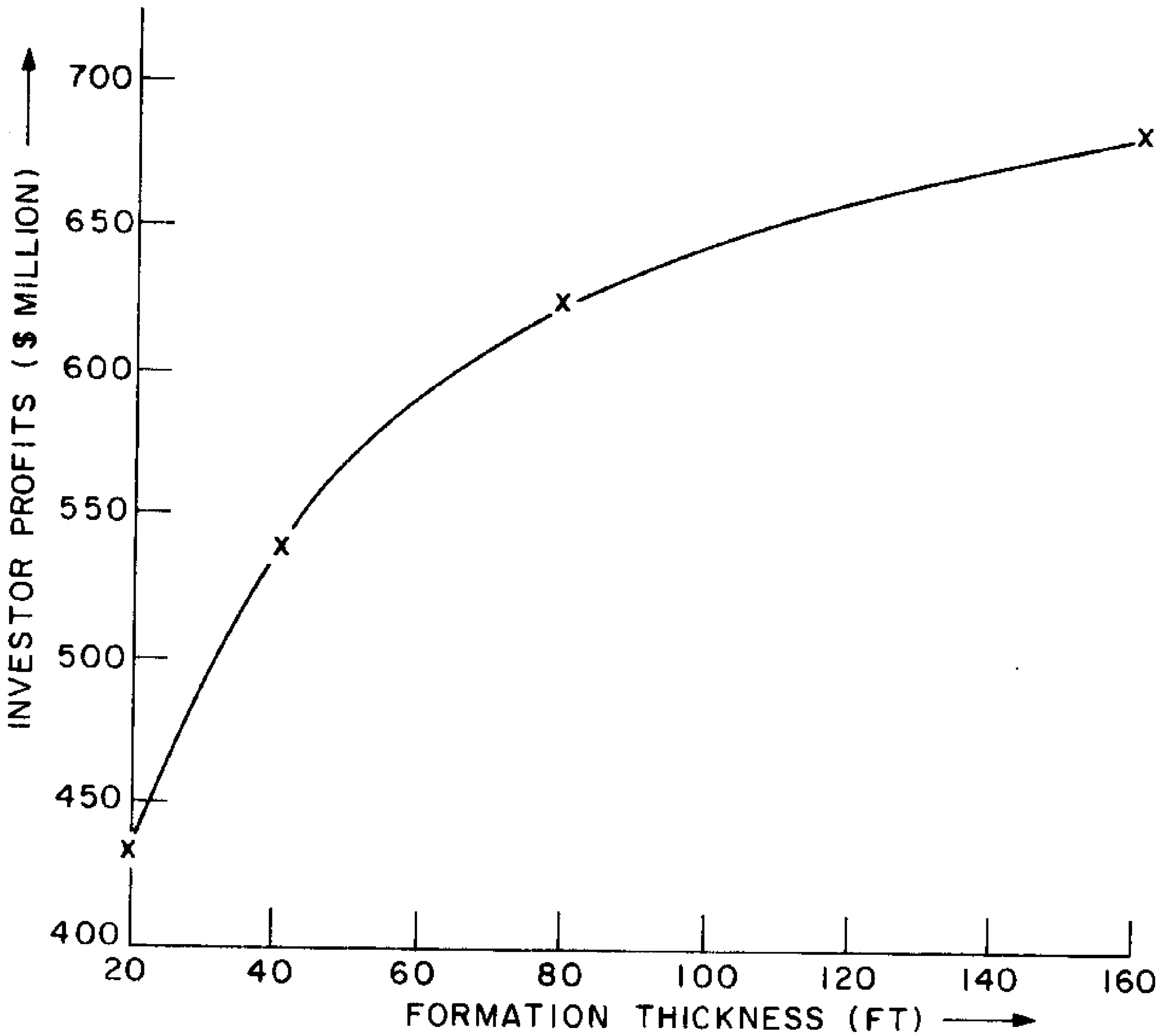

FIGURE 3.3.3 EFFECT OF FORMATION THICKNESS ON INVESTOR PROFIT OF 2 BILLION BARREL BASE-CASE OIL FINDS.

field in a manner which varies inversely with the porosity. This effect in turn will be extremely minor as long as the entire field can be covered by a given number of platforms. Doubling and halving porosity from the base-case value of 14% typically changes investor profits and Δ national income by at most a few percent in the base-case runs.

Most physical characteristics of the reservoir are dependent on one another. For example, at a depth of 10,000 ft, the reservoir will normally be at a different initial temperature and pressure than at, say, 3,000 ft, due to gradients within the lithosphere. Thus, one must be careful in varying such parameters one at a time when modelling "typical" fields except within narrow ranges.

With respect to financial/policy variables, we have already studied the effect of varying oil and gas price together and have seen that while this variation has little effect on the developer's strategy if the find remains profitable under the variation, it will affect the size of the smallest find that can be developed and for any find will have a sharp effect on public revenue and investor profit.

One can also vary the relative price of oil to that of gas. The principal effect of this variation is to change the investor's reinjection policy. As we have seen earlier at the base case prices, for all but the largest oil finds, gas is more valuably employed in reinjection than landed immediately. That is, at energy equivalent prices, gas production will be delayed in favor of oil for the base-case oil finds. For these gas depletion reservoirs, overall oil recovery may be increased by as much as 25% through use of reinjection while losing only 3%-5% in gas recovery. Upping the relative price of gas can change this. Figure 3.3.4 indicates that decreasing the ratio of oil price to gas price from 5 to 2 implies that the developer will use no reinjection. Under present U.S. policy it is quite likely that gas will be priced no higher than its energy equivalent relative to oil and we can expect to see a great deal of reinjection.

All of the cases examined so far have assumed that the real prices remain constant through time. If there are large variations in market price, the revenue streams will reflect these changes. If the investor expects, prior to his development, a large price increase during the life of the field, he would react to this by developing the field more slowly to take advantage of increased revenues later in the time stream (as long as the discounted increase in price is equal to or greater than his opportunity cost of capital net of transportation system savings for more uniform, lower volume throughput). Unfortunately, the model does not allow such strategies, since it assumes the investor will build the chosen number of platforms as fast as physically allowed. (To optimize platform building through time would be computationally prohibitive at this time.)

It is possible, however, to see such a philosphy reflected to a certain extent. If the price increase is extreme enough, the model will place fewer platforms (total) on the field overall since this will increase the life of the field well

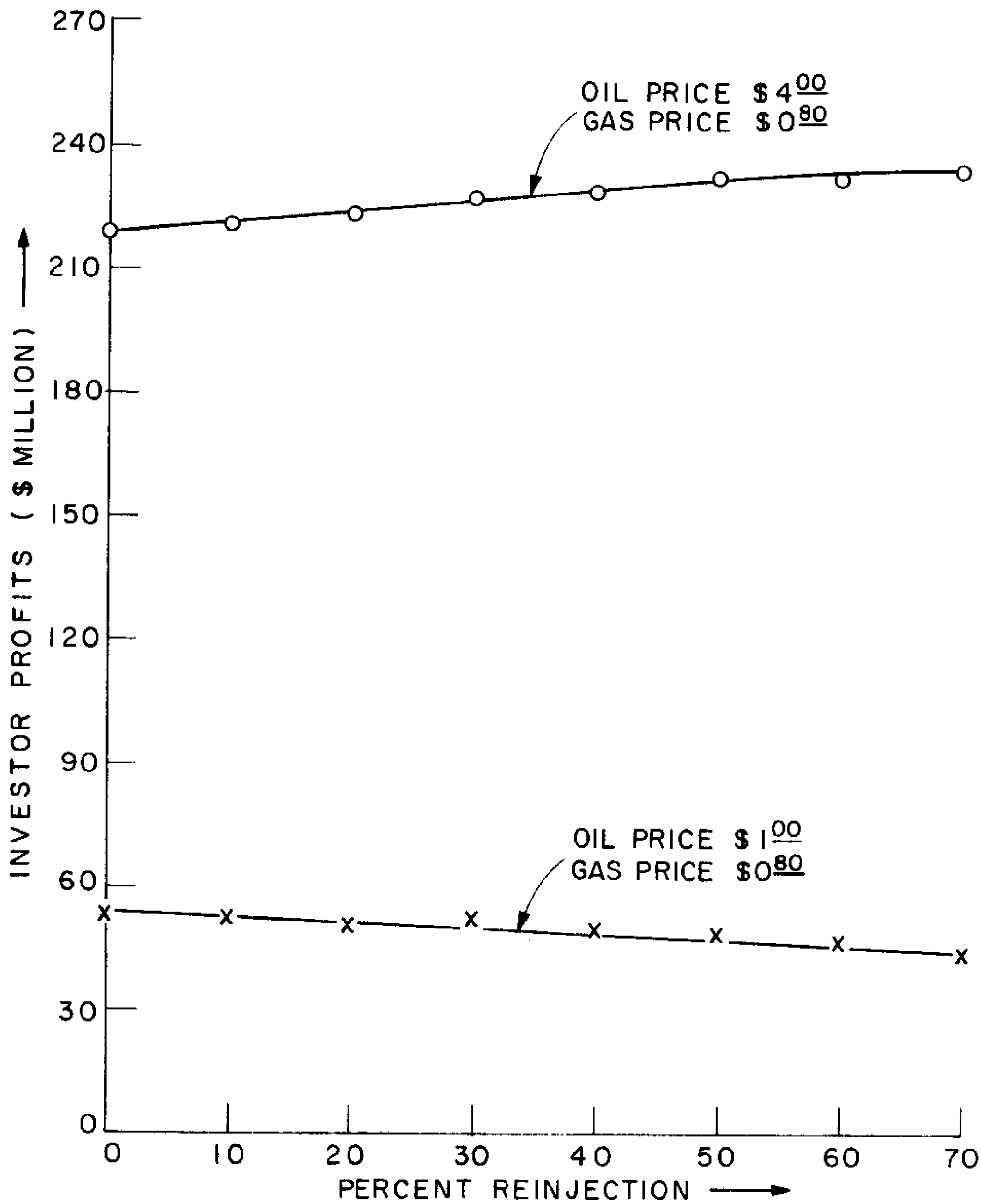

FIGURE 3.3.4 PROFITS VS REINJECTION FOR A 2,000 MM BBL BASE-CASE FIND, 30 MI OFFSHORE.

into the region of increased revenues. This approximation to the investor's behavior for a large find is illustrated in Table 3.3.2. The constant-price case held oil price at \$8.00 per barrel and gas price at \$1.50 per Mcf in all years. For the escalated case, oil price was held at \$6.00 per barrel and gas price at \$1.10 per Mcf through 1979 and escalated to \$8.00 per barrel and \$1.50 per Mcf thereafter. In 1979 the investor opted for more transportation platforms rather than field platforms and subsequently elected to use only five platforms per field (reserves held in five separate fields) rather than six for the escalated case.

While the example comparison of Table 3.3.2 does not show large changes in strategy, for a later price step, say 1982, the investor would probably initiate most of his platform building in 1980-1981, and this effect could be very significant. In the extreme, if the investor confidently expects a large price increase several years in the future he may well initially develop the field very slowly and then, immediately prior to the price increase, develop the field much faster.

The investor's alternate opportunity cost of capital is also a very significant variable. Since all revenue and cost timestreams must be discounted, the opportunity cost determines the profitability of the enterprise. Offshore development is a capital-intensive undertaking in the sense that enormous outlays are required prior to gaining any revenue whatsoever. Thus, at low opportunity cost, the investor

	Constant price			Escalated price		
Year	Platforms	Oil prod.	Gas prod.	Platforms	Oil prod.	Gas prod.
1978	4	2.5×10^{8}	2.1×10^{11}	4	2.3×10^{8}	1.2×10^{11}
1979	9	3.1×10^{8}	2.9×10^{11}	8	2.9×10^{8}	2.5×10^{11}
1980	14	3.2×10^{8}	4.4×10^{11}	13	3.1×10^{8}	4.0×10^{11}
1981	19	2.8×10^{8}	8.4×10^{11}	18	2.8×10^{8}	7.6×10^{11}
1982	24	2.2×10^{8}	1.4×10^{12}	23	2.2×10^{8}	1.2×10^{12}
1983	29	1.4×10^{8}	1.5×10^{12}	25	1.4×10^{8}	1.3×10^{12}
1984	30	8.3×10^{7}	1.2×10^{12}	25	8.8×10^{7}	1.2×10^{12}
1985	30	4.9×10^{7}	8.1×10^{11}	25	5.5×10^{7}	8.7×10^{11}
1986	30	3.1×10^{7}	5.3×10^{11}	25	3.6×10^{7}	6.1×10^{11}
1987	30	5.7×10^{6}	9.7×10^{10}	25	2.4×10^{7}	4.1×10^{11}
1988	-	-	-	25	6.7×10^{6}	1.4×10^{11}

TABLE 3.3.2

FIELD DEVELOPMENT AND PRICE CHANGES

will find smaller fields attractive and, to a certain extent, produce fields more slowly if total recovery will be increased in the future.

A surprisingly important input variable with respect to present valued public and private profits is the constraint on the number of platforms which can be installed in a given year. In all the runs described so far, it has been assumed that the maximum number of platforms which can be installed in a single year is five. For the base-case 10 billion barrel nearshore oil find, reducing this number to two cuts public and private profits by one-third, indicating in a situation where platform building capacity was in short supply, the investor would pay a very high premium to obtain his platforms earlier rather than later.

Table 3.3.3 shows the platform building and production schedule for the two different rate of installation constraints. Cutting the maximum number of platforms installed to two stretches the profit maximizing field life to 18 years, cutting present value revenue much more sharply than present value outlays.

TABLE 3.3.3

PLATFORM BUILDING AND PRODUCTION SCHEDULE FOR
BASE-CASE 10 BILLION BARREL OIL FIND

Year	Can Install 5 Platforms/Year			Can Install 2 Platforms/Year		
	Total Plats	Oil Prod MM bbl	Gas Prod MMM cu ft	Total Plats	Oil Prod MM bbl	Gas Prod MMM cu ft
1978	4	243	132	1	81	47
1979	9	309	161	3	142	75
1980	14	327	243	5	178	90
1981	19	314	449	7	193	109
1982	24	274	810	9	202	146
1983	29	216	1210	11	200	213
1984	34	147	1336	13	193	314
1985	35	92	1115	15	178	456
1986	35	58	817	17	156	622
1987	35	39	573	19	133	772
1988	35	25	375	21	108	867
1989	35	4	61	23	85	879
1990				25	66	807
1991				27	50	681
1992				29	37	544
1993				30	27	399
1994				30	14	204
1995				30	4	57

	5 Platforms/Year	2 Platforms/Year
	1 30" oil line 2 30" gas lines No intermediate pumping stations PV revenue = $6,890 MM PV national cost = $292 MM PV investor profit = $1,849 MM Δ national income = $6,589 MM	1 26" oil line 2 26" gas lines No intermediate pumping stations PV revenue = $4,737 MM PV national cost = $199 MM PV investor profit = $1,205 MM Δ national income = $4,538 MM

4. Summary

The results of the runs made to date may be summarized as follows:

1. For at least the internal gas drive fields studied, offshore oil production is characterized by very sharp economies of scale up to a break point field size and very gentle economies of scale thereafter.

2. For the base-case oil finds (1000:1 gas/oil ratio, permeability = .1 darcy, viscosity = 2 cp [API gravity 30]), this break point is in the neighborhood of 200 million barrels in place.

3. For the base-case gas finds (100,000:1 gas/oil ratio), this break point is in the neighborhood of 200 billion cubic feet in place for a find 36 miles offshore and 400 billion cubic feet for a find 146 miles offshore.

4. At base-case landed price assumptions, $8.00 per barrel and $1.50 per Mcf, the minimum-sized base-case oil find which can profitably be developed is between 50 and 100 million barrels in place. Halving the landed price approximately doubles the size of the marginal find. All dollar figures are in 1972 dollars.

5. Above the break points, the model claims that offshore petroleum can be very cheap compared with the likely landed cost of imported oil and gas. Unit landed costs before lease

bids, royalties and taxes of less than $1 for base-case oil finds of over 1 billion barrels in place and less than 30¢ per Mcf for base-case gas finds larger than 1 trillion cubic feet were obtained.

6. This implies that under the present rules of the game, both the public revenue and the investor profit associated with offshore finds over 1 billion barrels of oil in place or 1 trillion cubic feet will be quite large. Assuming the prices represent the cost to the nation of alternative sources of petroleum, the sum of the present value of these financial flows is the present value of the increase in real national income associated with developing such finds before environmental cost.

7. All of the above has a very important policy implication: domestic offshore development will be quite insensitive to changes in landed price of oil and gas over the likely range of these prices. For example, changing landed oil price from $8.00 to $3.00 implies that only a rather narrow range of field sizes which were profitable at $8.00 are no longer profitable. Price is very unlikely to be the operational limit on amount of domestic offshore activity.

8. The simulations imply that even a very large find will be developed by a relatively small number of platforms. The program uses 35 platforms and 710 flowing wells to develop a 10 billion barrel, 10 billion barrel in place find.

9. At 1000:1 oil/gas ratio and energy equivalent gas and oil prices, the investor will choose to use considerable

reinjection for the gas drive geologies assumed, delaying his gas revenues in favor of additional oil production.

10. For finds at the outer limits of the continental shelf (146 miles offshore), the program always favors tankers over pipelines for the delivery of oil to shore. For finds 36 miles offshore or less, the program always favors pipelines for delivering oil to shore. In general, the smaller the find and the further it is offshore, the more the program favors tankers. For a very small find (50 million barrels in place), the breakeven distance is about 40 miles, for a 500 million barrel in place find, the breakeven distance is about 140miles. However, in all the base-case oil finds over 200 million barrels, a requirement that the developer use pipeline rather than tanker would not prevent development of a find 146 miles offshore.

11. Variation in the absolute levels of oil and gas price has almost no effect on developer strategy as long as the field can be profitably developed over the range of the variation. Pricing gas at well above its energy equivalent relative to oil will reduce the amount of reinjection used.

12. The program results are quite insensitive to variations in reservoir parameter other than oil and gas in place, with three very important exceptions: permeability, formation thickness and oil viscosity. Investor profits and national cost can be quite sensitive to these variables. In fact, certain combinations of low permeability and high oil

viscosity preclude economical field development, no matter how large the field is.

13. The maximum rates at which platforms can be installed can be an extremely important variable in determining the profitability of very large finds. A developer, discovering such a find, would be willing to pay a very high premium to install his platforms quickly.

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ANALYSIS OF OIL SPILL STATISTICS

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ANALYSIS OF OIL SPILL STATISTICS

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1. Introduction

The purpose of the analysis described in this report is to utilize past spill experience to generate estimates of the likelihood of spillage by number and size of individual spill for a range of hypothetical offshore petroleum developments on the Atlantic and Gulf of Alaska continental shelf.

The data bases with which we have to work are:

a. The Coast Guard Pollution Incident Reporting Systems reports for the calendar years 1971 and 1972 [1] as amemded by the Coast Guard, October, 1973.* This data purports to cover all spills which reached United States navigable waters. It contains some 15,600 oil spills.

b. A record of 2,999 tanker casualties worldwide over the period 1969 to 1972 inclusive, containing reports on some 612 spills compiled by ECO Inc. [2]. We are reasonably confident that this data covers almost all the <u>large</u> tanker spills for this four-year period.

c. A data base generated for the Environmental Protection Agency by Computer Sciences Corporation and upgraded by ECO Inc. [3]. This tape combines records of the Office of Pipeline Safety and the Environmental Protection Agency, portions of U.S. Geological Survey records, and files of a number of state and

*This tape also contains the Coast Guard reports for 1970. However, the reporting system was not in full operation in that year.

Canadian provincial agencies, including the Texas Railroad Commission, the Louisiana Fish and Wild Life Commission and a number of California agencies. This data contains about 8,500 spills.

d. A data base compiled by MIT during the Georges Bank report based on a USGS survey of large spills and a survey of tanker casualties compiled by Westinform Ltd.[4].

e. A sample of some 300 spills at single buoy moorings worldwide gleaned from a number of sources, principally the Shell Oil submittal to the U.K. House of Lords during the hearings on the Anglesey Terminal made available to us through the Anglesey Defence Action Group.[5].

Obviously, in using this data to generate estimates of the probabilities of future spills we are implicitly assuming that future developments will employ present technology operated to recent-past standards. In this sense, these estimates will serve as a baseline from which any improvements will have to start.

1.1 Oil spill statistics in general

Anything more than a cursory glance at oil spill statistics reveals three striking features of this data which together pose an unusually difficult problem for statistical analysis:

a. The size range of an individual spill is extremely large. Magnitudes of spills range from a few gallons to tens of millions of gallons. The "Torrey Canyon" spill was approximately thirty million gallons and, with present tanker sizes, spills three and four times this size are conceivable. With respect to spill size, we are dealing with a variable which can range over eight orders of magnitude.

b. The great majority of all spills are at the lower end of this range. 96% of all the petroleum industry-related spills reported by the Coast Guard in 1972 were less than 1000 gallons and 85% of these spills were reported as less than 100 gallons. 85% of all the offshore platform spills reported by the Coast Guard in 1971 were less than 100 gallons and 98.6% of all these spills were less than 1000 gallons. Relatively speaking, most oil spills are small.

c. Most of the oil spilled is spilled in a few very large spills. The "Torrey Canyon" spilled twice as much oil as all the oil which was reported spilled in the United States in 1970,and two-thirds of the oil which was spilled in the United States in 1970 was spilled in three spills. 17 spills accounted for 70% of all the oil reported spilled in the United States in 1971, and 18 spills accounted for 85% of all the oil which was reported spilled in the U.S. in 1972.

These characteristics of oil spills imply that, with respect to prediction, a single-number estimate of the amount of oil which will be spilled in association with a particular development is almost meaningless. At very best, this estimate will be the <u>average</u> of the amount that will be spilled. However, in situations where the amount spilled can vary by a factor of a million, an average is of little use, for it is unlikely that the actual amount spilled will be anywhere near that average. For example, the average spill size of all offshore production spills in the United States in 1972 was reported by the Coast Guard to be 103 gallons. However, 55% of all these spills were at least ten times smaller than this average, while most of the oil was spilled in spills which ranged up to 1000 times this average, and we have observed offshore production spills which were over 10,000 times the size of this average. In short, even if we could estimate the average amount of oil which will be spilled in the future for some development, we would have learned very little, for few of the actual spills will be anywhere close to this average. Most will be much smaller. A few will be very much larger. It would be like characterizing a class made up entirely of Einsteins and idiots by their average I.Q. Further, the biological impact of any given amount of spillage will depend on the frequency and size of the spills making up that volume. Both the biological impact and the esthetic impact of ten average-sized spills will be quite different from the impact of a single spill which is ten times the average volume.

To make matters still worse, the fact that most of the oil spilled is spilled in the very large, very rare spills implies that even if we wanted to estimate the average of the amount which will be spilled from a particular development from the available spill data, our estimate of this average is unlikely to be very accurate. This problem can be demonstrated from the offshore production category. If in 1972 we had observed one Santa Barbara-sized spill, then the average of the amount spilled in that year from offshore production facilities would have been increased by more than a factor of ten. To put it another way, if we had used the data for offshore spills in 1970 rather than 1972 for our estimate of the average of offshore production facilities, our estimate would have been increased by more than a factor of ten. Obviously, an estimate which can be affected by a factor of ten by a single, not completely unlikely, occurrence cannot be regarded to be extremely accurate.

The usual approach to this problem is to use the average observed as an estimate of the average which will be spilled and then use classical statistical analysis which employs the sample size together with the variability observed in the sample to make such statements as "with 90% confidence the actual average is within y of the estimated average." Unfortunately, when one applies this reasoning to such spill categories as offshore pipelines where we have observed many small spills together with two extremely large spills, one finds that in order to be 90% confident, y is many times the estimated average. The statement that with 90% confidence the average of future large offshore pipeline spills is between -1,007,000 and 3,159,000 gallons, while perhaps true, affords us little insight into offshore pipeline spillage.* Therefore, it behooves us to find a better way.

In so doing, it is of interest to compare the Coast Guard spill reports for 1971 and 1972. Table 1.1 gives an overall summary of the results. The first category is for all oil spills, the second category involves only those coastal and offshore spills emanating from oil industry-related activities. Inland spills are not included in this category, nor are oil spills which occur after the oil is in the hands of the final users, e.g. spills from a utility's fuel tank. The final three categories break the non-inland, oil industry spills down by offshore tanker, terminal, offshore production facilities (platforms and pipelines), and onshore pipelines. The offshore tanker spills include only those tanker spills which did not occur in harbors or near terminals. Since the Coast Guard's reporting authority extends only out to the three-mile limit with respect to vessels, this category may not be indicative.

For now, the important thing to notice about this table is that while total oil production and consumption in the United States in 1972 was not that different from that in 1971, the volumes spilled, both total and in most of the categories, are quite different. This is because these totals

*Based on assuming that all known offshore pipeline spills over 1000 barrels are samples of a Normal process.

		1971	1972
All Spills	Number	7,461	8,287
	Volume (gal)	8,611,173	21,742,320
Non-inland, Petroleum Industry Spills	Number	4,023	4,078
	Volume	6,322,459	5,934,478
Terminal	Number	1,475	1,632
	Volume	5,283,915	2,296,828
Ships-offshore	Number	22	32
	Volume	16,315	2,168,811
Offshore production facilities	Number	2,452	2,252
	Volume	655,117	239,515
Onshore pipeline	Number	74	162
	Volume	367,112	1,229,324

Table 1.1

Comparison of 1971 and 1972 USCG Data

are completely dominated by a few very large spills. In 1971, there was only one spill over 1 million gallons (2,000,000 gal.) reported; in 1972, there were three such spills totaling 15,000,000 gallons. Given the dependence of the total amount spilled on a very few, very large spills, there is little reason to expect the volumes to agree. Our sample of very large spills is simply too small to expect any statistical regularity with respect to these particular spills.

On the other hand, the <u>number</u> of spills, both total and by major category, exhibits a definite pattern. With respect to incidence as opposed to amount, each individual spill counts equally and the sample of all spills is large enough so that if the processes generating spillage in 1971 and 1972 were similar, one would be quite surprised if the number of spills did not exhibit statistical regularity.

Table 1.2 breaks the 1971 and 1972 non-inland, oil industry-related spills down by region. Once again, there is much better agreement with respect to number of spills than there is to spill volume.

Table 1.3 shows a more detailed breakdown of the non-inland oil industry-related Coast Guard data by spill category. The terminal spills follow the same basic pattern - definite correspondence between number, little correspondence in total volumes. However, the offshore facilities spills when broken down into pipeline and production platform offer a glaring exception. This anomaly was presented to the relevent Coast Guard personnel, who commented that it was often a

	1971	1972
New England		
Number	311	365
Volume	852,763	397,731
Mid Atlantic		
Number	894	1034
Volume	465,087	9,431,839
Gulf		
Number	3927	3632
Volume	1,426,186	6,444,977
So. California		
Number	552	507
Volume	301,362	43,141

TABLE 1.2

COMPARISON OF REGIONAL STATISTICS

		1971	1972
BREAKDOWN OF TERMINAL SPILLS			
Tanker & barge	Number	917	912
	Volume (gal)	2,586,993	817,396
Refinery	Number	167	172
	Volume	2,197,417	34,624
Bulk storage & transfer	Number	391	548
	Volume	499,506	1,494,808
BREAKDOWN OF OFFSHORE PRODUCTION SPILLS			
Offshore tower	Number	1,087	2,211
	Volume	117,661	231,738
Offshore pipelines within 3 mi limit	Number	1,204	36
	Volume	515,913	7,326
Offshore pipelines outside 3 mi limit	Number	156	5
	Volume	14,540	451

Table 1.3

purely judgemental decision upon the part of the data coder whether to place a spill in the offshore production category or the offshore pipeline category and that due to personnel changes, it was quite possible that coding habits had changed. In view of the other data presented and in view of the agreement between the sum of the offshore pipeline and offshore production spills, we believe it is reasonable to assume that this was the case.

Table 1.4 compares the size distribution of non-inland, oil industry-related spill volumes for 1971 and 1972. Once again a definite pattern is demonstrated. It appears quite reasonable to assume that the same basic process is generating spill sizes in 1971 as in 1972. Note, however, that because there are so few spills in the very large categories, it is not particularly surprising that, for example, there were three spills over 1 million gallons in 1972 as opposed to one in 1971. Table 1.5 shows the volume distributions by category. Once again, with the aforementioned exception of offshore pipeline and towers, a definite pattern is observed.

In summary, the characteristics of oil spillage are such that dealing with total volume spilled directly leads to very little insight. Using classical techniques, confidence intervals are sometimes orders of magnitude larger than the estimator and only very weak statements can be made. However, both the number of spills and the spill size distributions exhibit definite regularity given the sample sizes available. These findings, together with the fact that, from the point

Gallons	1971	1972
0-1	2497	2387
1-10	1526	2020
10-100	2146	2509
100-1000	1000	1068
1K-10K	222	232
10K-100K	53	54
100K-1M	16	14
1M-10M	1	3
> 10 M	0	0
	7461	8287

TABLE 1.4

VOLUME DISTRIBUTION COMPARISON

ALL SPILLS

	0-1	1-10	10-100	100-1000	1K-10K	10K-100K	100K-1M	1M-10M
Terminal								
1971	384	247	458	282	77	19	7	1
1972	351	347	544	298	71	16	5	0
Ship-Offshore								
1971	4	6	8	0	4	0	0	0
1972	15	2	10	3	0	0	1	1
Pipeline								
1971	222	403	496	257	42	13	2	0
1972	15	24	61	61	32	7	3	0
Towers								
1971	230	305	395	146	13	2	0	0
1972	431	784	728	244	20	4	0	0

TABLE 1.5

VOLUME DISTRIBUTION BY CATEGORY

(Offshore and Coastal Petroleum Industry Data only) of view of environmental impact, estimates of the numbers and sizes of individual spills are at least as important as estimates of the total volume spilled, strongly suggest that the way to attack oil spill statistics is through a two-step process:

1. First, one should attempt to say what one can about how many spills will occur.
2. Secondly, one should attempt to say what one can about how much oil will be spilled in an individual spill.

Once one has completed these two sets of analyses, they can be combined, if desired, to yield statements about the total amount of oil which will be spilled.

This is the basic approach that will be undertaken. In so doing, we will divide spillage into five categories:

1. tankers and barges
2. onshore terminals
3. single buoy moorings (SBM's)
4. offshore production
5. offshore pipelines

This division by category, while somewhat arbitrary, will allow us to compare tanker versus pipeline transportation alternatives and is also suggested by the form of the available data.

In our analyses, we will make one further subdivision which is forced on us, in part, by the available data and, in part, by the fact that the processes generating large spills exhibit qualitative differences from the processes generating small spills.

All the available data bases we have on oil spillage falls into one of two categories:

A. Data which purports to be a complete record of all spills in a certain period emanating from a specific activity. These data bases typically contain a very large number of spills most of them quite small. They cover a relatively short period and a restricted geographic area (single county, single state) and contain none or very few large spills. The Coast Guard data is an example as is the Texas Railroad Commission report on the EPA tape.

B. Data which is a selective sample, either by design or by necessity, of only large spills. These data sets contain a relatively small number of spills, all or almost all by them quite large, but they usually cover longer periods of time than the (A) type data. The U.S. Ecological Survey of large offshore spills from 1964 on, is an example, as for all practical purposes is the ECO data on worldwide tanker spills.

In the face of this dichotomy, one is forced to analyze large spills separately from small spills lest one throw away the valuable information on the rare, very large spills contained in the selective compendia type B, but not in the type A. The dividing line between "large" and "small" spills is, of course, arbitrary but a convenient choice is 42,000 gallons (1000 barrels or 150 tons). Henceforth then, "large" is a shorthand way of saying "over 42,000 gallons" and "small" is a shorthand way of saying under 42,000 gallons. No value judgments about the biological implications are implied by these terms.

2. The probability densities on the number of spills and size of a spill

Following the above approach, within each category for a particular hypothetical offshore development we will be dealing with two variables:

1. The number of spills, n, of this category, which will occur in a given time period from this development.

2. The amount of oil which will be spilled, x, from an individual spill of this category emanating from this development.

One thing is immediately obvious. There is no way we can be sure of what values these two variables will take on. When one is faced with a variable which one cannot predict with certainty, such as n or x, one characterizes this variable by a probability density. A probability density is an assignment of likelihoods to each of the possible values of the variable. A sample assignment to the variable n is shown in Figure 2.1, which indicates that n can take on any of the values 0, 1, 2, 3 etc. with probability p(0), p(1), p(2), etc. The height of each arrow is proportional to the likelihood assigned to that value. When likelihoods are represented by probabilities, 0.00 represents the probability of an event which we are sure will not occur and 1.00 represents the probability of an event which is certain to occur. Since we are certain that n will take on at least one of its possible values, the probabilities p(0), p(1), p(2),... must sum to 1.00.

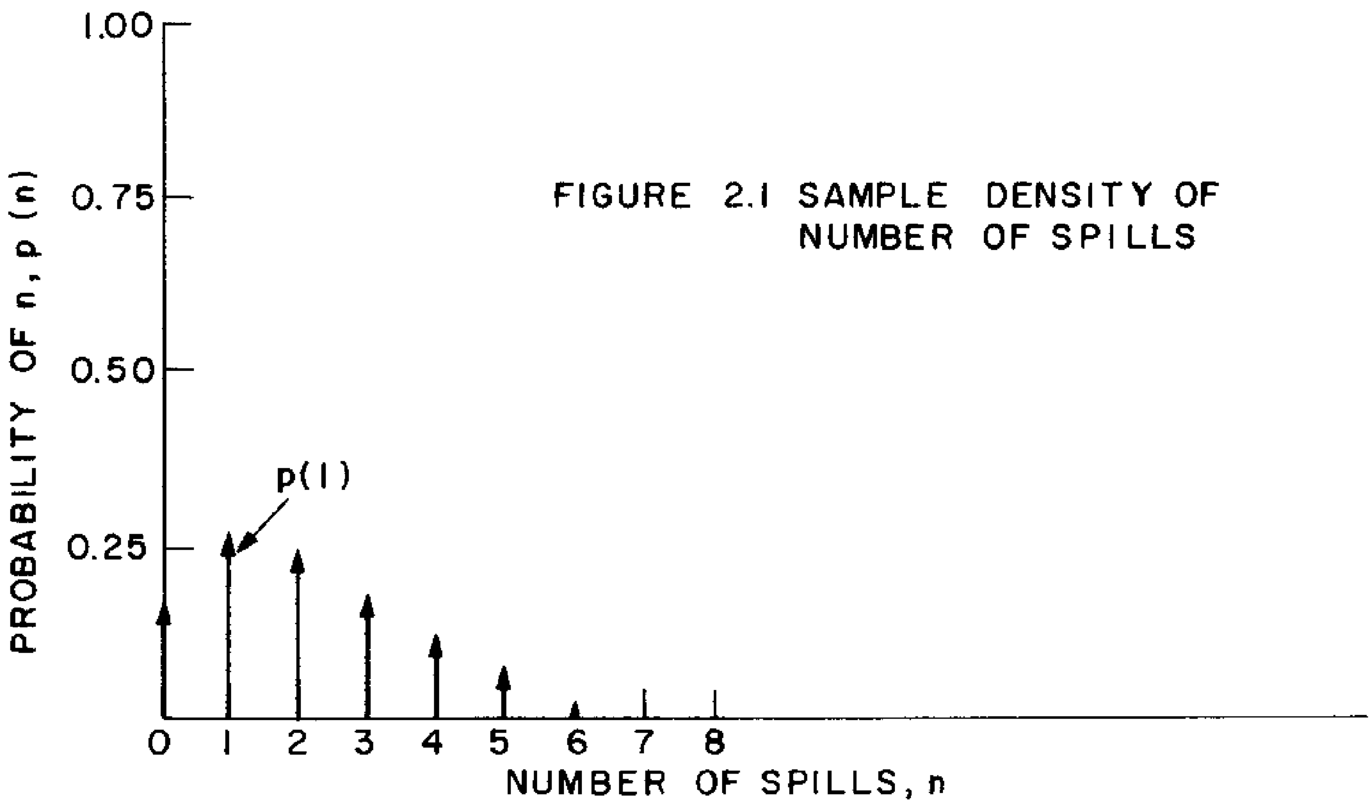

FIGURE 2.1 SAMPLE DENSITY OF NUMBER OF SPILLS

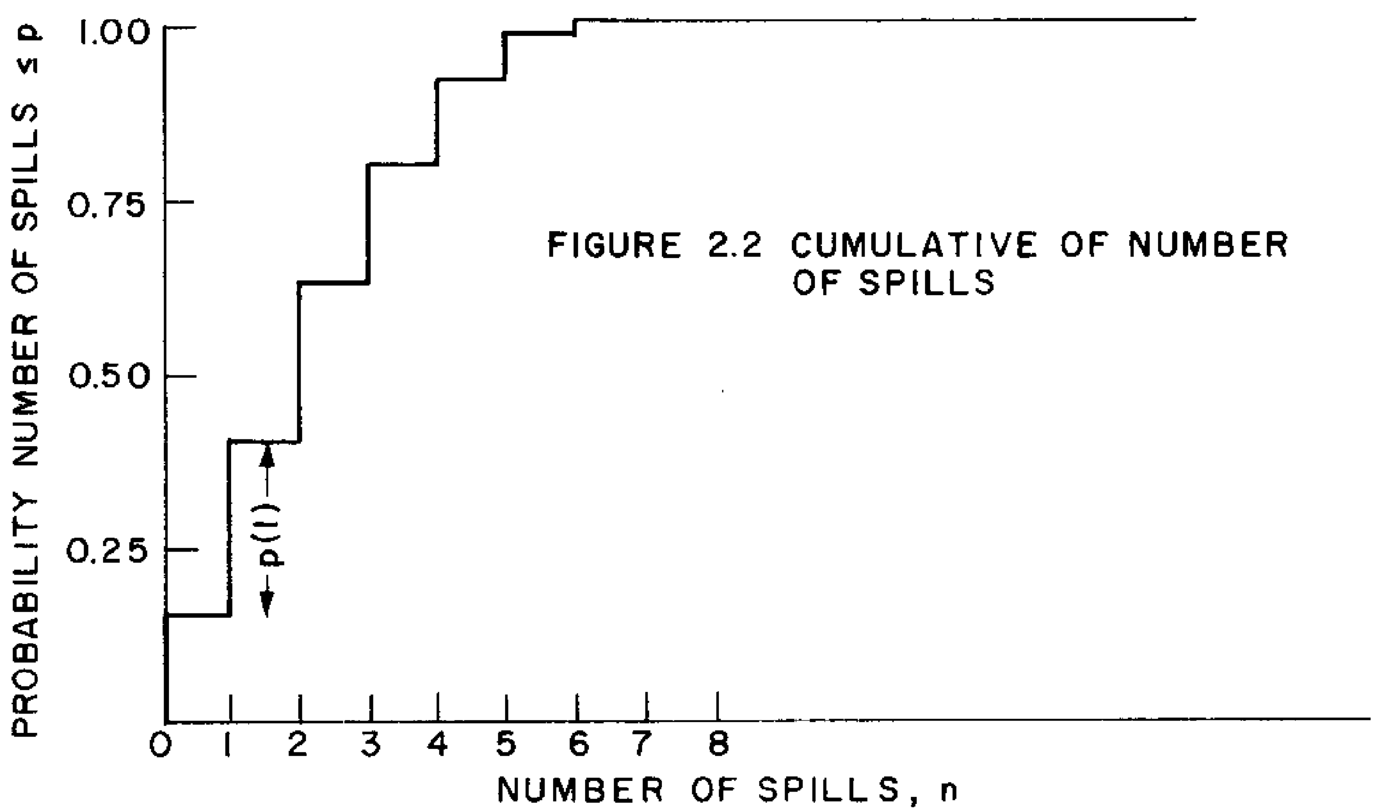

FIGURE 2.2 CUMULATIVE OF NUMBER OF SPILLS

If one multiplies each probability p(n) with the number of spills to which it has been assigned and sums these products, one obtains a measure of the central value of the density of the number of spills. This measure is called the mean of the density, MEAN(n). In symbols:

$$\text{MEAN}(n) = p(0)\cdot 0 + p(1)\cdot 1 + p(2)\cdot 2 + p(3)\cdot 3 + \ldots$$

The mean corresponds roughly to the average of all the possible values of n.

Another useful measure of a probability density is the variance. The variance is the sum of the squared difference between each possible number of spills and the mean where each difference is weighted by the probability of that value in the sum. In symbols:

$$\text{VAR}(n) = p(0)\cdot(0 - \text{MEAN}(n))^2 + p(1)\cdot(1 - \text{MEAN}(n))^2 + p(2)\cdot(2 - \text{MEAN}(n))^2 + \ldots$$

The variance is a measure of how spread out the density is. The larger the variance, the less likely the actual value of n will be close to the mean. A baseball team made up of 50% .200 hitters and 50% .400 hitters will have a much larger variance than a baseball team composed entirely of .300 hitters. Both teams would have the same mean.

Sometimes it is useful to represent the density of the number of spills in a slightly different form, the cumulative. The cumulative of the number of spills is simply a graph which indicates the likelihood that the number of spills will be less than n for all possible n. It is obtained by successively summing up the arrows as one moves to the right, increasing n as indicated by Figure 2.2, resulting in a staircase-like figure. The cumulative is convenient in that it is possible to read off the probability that the actual number of spills will be between any two specified values by simply subtracting the cumulative associated with the higher value from the cumulative associated with the lower. For example, in the cumulative indicated in Figure 2.2, the probability that n will be between 2 and 4 is .80 - .40 = .40. Often in drawing cumulatives we will simply fair a curve through the high points in the steps, a lazy practice which will cause no difficulty as long as we remember that the number of spills must be an integer.

Our other random variable, the amount of oil which will be spilled in an individual spill, x, like n is inherently uncertain. However, the description of our uncertainty about x is somewhat complicated by the fact that x can at least conceptually take on any value between 0 and some very large number. We are no longer limited to integers. In this case, it is meaningless to ask what the probability of a spill of exactly 42,032.39567... gallons is, for one can always make this probability zero by using enough decimal places in asking the question. However, it is not meaningless to ask what is the probability of a spill being larger than, say, 42,000.00... gallons and smaller than 42,100.00... gallons. Therefore, when we are dealing with <u>continuous</u> variables such as spill size, we assign a probability density such as the two shown in Figure 2.3. In these densities, the probability of a spill

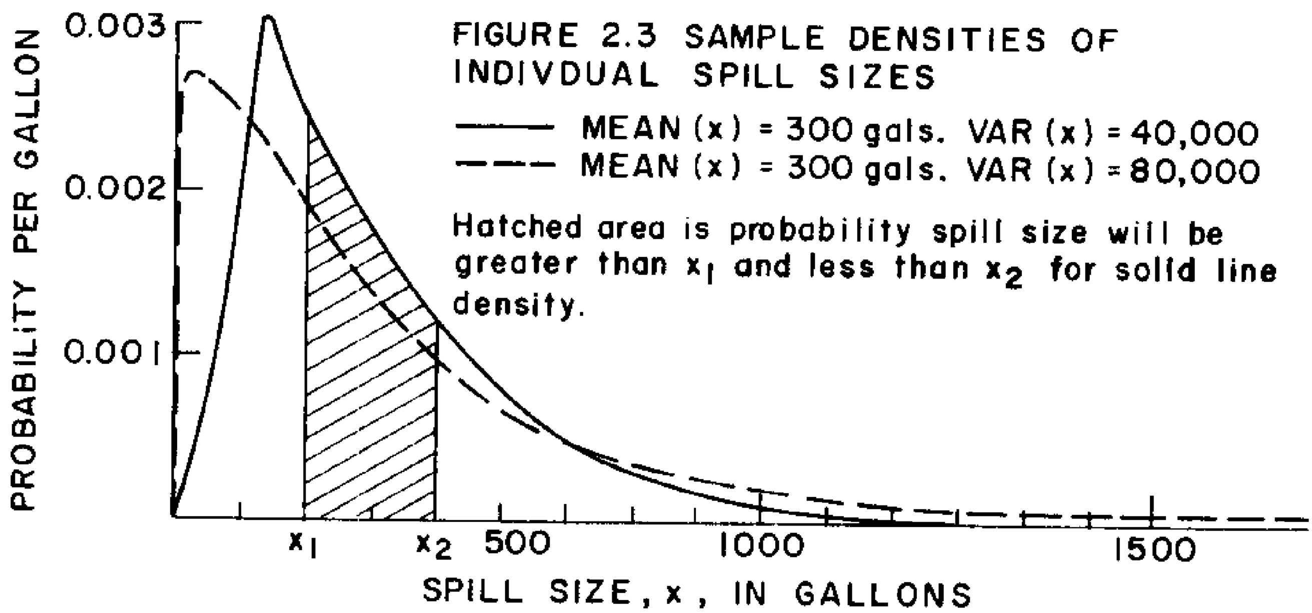

FIGURE 2.3 SAMPLE DENSITIES OF INDIVDUAL SPILL SIZES

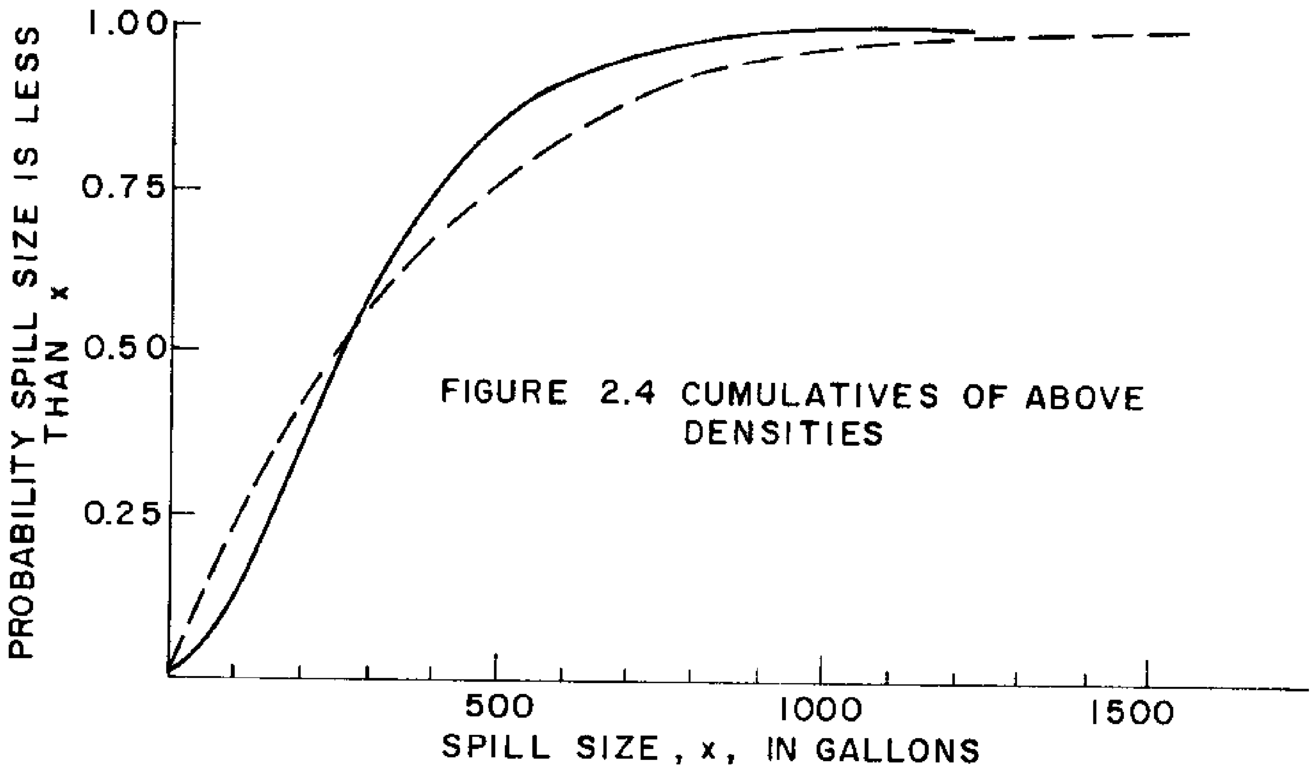

FIGURE 2.4 CUMULATIVES OF ABOVE DENSITIES

being larger than x_1 and smaller than x_2 is represented by the area under the density between x_1 and x_2. Thus, in intervals where the curve is high, there is more chance of the corresponding spill sizes than where it's low. If it is quite likely that the spill will be within a narrow range of sizes, then one obtains a sharply peaked, narrow density such as the solid density. If one is quite unsure of how large a spill will be, one will obtain a low, broad distribution, such as the dotted curve.

By summing the area above each small spill size interval multiplied by the corresponding spill size over all possible spill sizes, one obtains the mean of the spill size density, which once again is a measure of the average spill size. By summing the mean area about each interval multiplied by the square difference between the corresponding spill size and the mean, over all possible spill sizes, one obtains the variance of the density, which is a measure of the dispersion of the density. Both the densities shown in Figure 2.3 have the same mean, but the dotted density has a larger variance, implying that for this density the probability that a spill will be close to the mean in volume is much lower.

Our assignment of likelihoods to x can be represented by the cumulative of the density of x as well as by the density itself. Like the case of n, the cumulative is simply a graph indicating the probability that the actual spill size x will be less than x for all possible x. The cumulative of x is obtained by simply summing up the areas under the density as one moves to the right increasing x. Figure 2.4 shows the cumulatives for the densities shown in Figure 2.3. Notice how a tight density leads to a cumulative which rises sharply over a relatively narrow range while a widely dispersed density leads to a cumulative which rises more gradually over a much wider range. As in the case of n, one can obtain the probability that the spill size will be between any two given spill sizes by subtracting the value of the cumulative at the lower spill size from the value of the cumulative at the higher size.

Given that we are going to characterize inherently uncertain variables such as number of future spills of a particular category emanating from a particular hypothetic development and the amount spilled in such a future spill by probability densities, the key question becomes: how are we to assign these probabilities? At least conceptually, there are any number of ways one might go about assigning these likelihoods. We believe it is insightful to assign these probabilities in a manner which is consistent with the following ground rules:

1. <u>The assignment will depend only on the available statistics</u>. That is, we will not let our judgments about future improvements, changes in tanker size, and any non-quantitative experience we may have had relevant to spillage affect our assignment of likelihoods.

2. For each spill category, there is an underlying process generating spill occurrences and another generating spill size. <u>These underlying processes have been constant over the period over which we have spill data and the same processes will govern future spillage</u>.

3. <u>These processes generate spills independently</u>, that is, the fact that a spill occurs does not change the chances of the next spill occurring.

4. With respect to spill incidence, we will assume that <u>the probability of a spill's occurring in a particular short exposure interval is proportional to the amount of exposure in this interval</u>. Together with (3), this implies that spill occurrence is governed by a Poisson process.

5. With respect to spill size, we will assume that <u>this variable is governed by a Gamma process</u>. The Gamma process is a rather general set of processes which has some attractive analytical properties.

6. Consistent with (1), we will assume that before looking at the spill data, we have no idea which Poisson process is generating spill occurrence or which Gamma process is generating spill sizes. We are, in effect, tabulas rasas. <u>We therefore</u>

assign densities to the unknown parameters governing these processes, beginning with completely blank densities in which any of the possible values of these parameters is, for all practical purposes, equally likely.

7. As samples of spill occurrence and spill size become known, we change our feelings about these unknown parameters according to the laws of probability theory.

Now this is a rather long list of assumptions, and all of them, except, perhaps, the last, are open to question. For example, (3) can be challenged on the grounds that when a large spill occurs, there is generally an intensification of vigilance and care which will decrease the probability of a spill's occurring in the future from what it would have been. And it is certainly questionable whether the processes generating spills in the recent past are the same as those which will be generating spills in the future. It is even doubtful that the processes generating spills in the recent past were completely unchanged over the period during which the data was collected.

Nonetheless, let's accept these assumptions for the moment as working hypotheses and see where they lead us. We believe the results will be of great use even if they are regarded only as baselines from which modifications should begin. The list of assumptions underlying classical statistical analysis is at least as long and for at least certain of our spill categories involves such presumptions as: the next "large" spill has a significant probability of being negative in size. The above set of assumptions will at least avoid building on such imaginative foundations.*

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*Classical statistical analysis also involves making assumptions 1, 2, 3 and 7. Assumptions 4 and 5 are usually replaced by assuming that the random variables in question are governed by Normal processes. Most classical statisticians would be unwilling to assign probability densities to the parameters governing the unknown random processes, assumption 6, even densities which give no weight to whatever feelings we had about these processes before looking at the data. Strictly speaking, this unwillingness prohibits one from making probabilistic statements about the variables under analysis. In practice, such statements are often made anyway. When they are made anyway, from a logical point of view, the analyst is acting as if he accepts assumption 6.

3. Quantitative implementation of the assumptions

3.1 Spill incidence

As indicated in Section 2, our procedure is to assume that spill incidence for a particular category is governed by a Poisson process. Under this assumption, if we know the intensity of the Poisson process, λ, the density of the number of spills is given by

$$p(n|\lambda,t) = \frac{e^{-\lambda t}(\lambda t)^n}{n!}$$

where t is the amount of exposure contemplated in the hypothetical development currently under analysis and λ is the mean spill rate in spills per unit exposure.

This assumption leads to two problems: what should we use for t, the exposure variable, and what should we use for λ, the mean spill rate? With respect to t, <u>we will assume that the exposure variable in the Poisson process governing spill incidence is volume of oil handled</u>. Some empirical support for this presumption is offered in the next section for tanker spillage. Similar support in the other categories has not yet been developed - at present it is simply a working hypothesis, albeit an obvious and natural starting point for spill analysis. It is also a hypothesis which underlies, usually tacitly, almost all spillage analysis which has taken place to date. Nonetheless, other hypotheses, such as "the exposure variable is number of landings" or "number of platforms" or "number of wells" or "number of pipeline miles" certainly deserve attention and should be examined.

When we turn to the choice of λ, the mean spill rate, things become still more complicated. Under our basic ground rules, the only information we allow ourselves on λ is the spill data. This implies two things:

1. Even after observing, say, ν spills in τ volume handled, we cannot be certain about the value of λ. Such data does not necessarily imply that $\lambda = \nu/\tau$ for other λ could easily have resulted in the same experimental outcome. Of course, the more data we have, the larger ν and τ, the more likely it is that λ is "close" to ν/τ. In short, λ is an uncertain quantity and, therefore, we must describe our knowledge about this quantity by a probability density.

2. Before having observed any spill data under our ground rules we have essentially no feelings about λ other than that it's somewhere between 0 and ∞. This implies that however we describe our feelings about λ before observing any data, these prior feelings must be completely overwhelmed by whatever data we then observe.

We can meet requirements 1 and 2 and at the same time save ourselves some computational travail by assuming that our density on λ before observing any data is a Gamma in which the parameters are both zero.

Assumption 8 and some elementary probability analysis then reveals that, after having observed ν spills in τ volume handled, our density on λ is:

$$f(\lambda|\nu,\tau) = e^{-\lambda\tau}(\lambda\tau)^{\nu-1}\tau/(\nu - 1)!$$

The density on λ thus is the inlet through which our past spill experience enters the analysis.

Once one has the density on λ given the spillage we have observed, it is a simple matter to obtain the density on the number of future spills which will occur in a particular period given that we are going to handle t units of oil in that period. For each n, it is the probability that we will have n spills given each possible λ times that λ summed over all possible λ:

$$p(n|t,\nu,\tau) = \int_0^\infty p(n|\lambda,t)f(\lambda|\nu,\tau)d\lambda$$

After some algebra, the resulting density on n spills in a contemplated exposure of t units of oil handled given that we have already observed ν spills in our past exposure of τ units can be shown to be

$$p(n|t,\nu,\tau) = \frac{(n + \nu - 1)!t^n\tau^\nu}{n!(\nu - 1)!(t + \tau)^{n+\nu}}$$

which is known as the negative binomial density.

3.2 Spill size

We have adopted the same basic philosophy in obtaining densities of the size of an individual spill of given category. First we must hypothesize a random process which governs the size of a spill given that it occurs. A priori, we know only that a spill will not be negative in size. Thus, such commonly used processes as the Normal are out. We have chosen to assume that spill sizes are samples of a Gamma density.

$$f(x|\rho,\omega) = \frac{e^{-\omega x}(\omega x)^{\rho-1}\omega}{(\rho - 1)!}$$

The Gamma family of densities has two parameters, ρ and ω, and by varying these two parameters a complete range of means and variances can be obtained. In fact, for a given ρ and ω,

$$\text{MEAN}(x|\rho,\omega) = \rho/\omega$$

$$\text{VAR}(x|\rho,\omega) = \rho/\omega^2$$

Thus, by making ρ small, a high ratio of variance to square of the mean can be obtained - a widely spread out density. By making ρ large, a relatively small ratio of variance to mean squares--a tight density--can be obtained. All the Gamma densities have only one peak and apply only to $x \geq 0$. In fact, by varying ρ and ω it is possible to obtain a reasonable approximation of any single-peaked density over the interval 0 to ∞. Thus, if one believes that the density of spill sizes is single-peaked, one loses very little generality by assuming that this density is a Gamma.*

---

*There is no a priori reason for believing that the spill size density is single-peaked. Spills occasioned by different causes almost certainly have different most likely sizes. In

Having assumed that the density of spill size is a Gamma, the next question is what are the values of the parameters ρ and ω. The obvious answer is we don't know so we must specify a density over these two random variables. In so doing, we desire a density which

a. fits well with the Gamma in an analytical sense in order to keep our computational travail within reason;

b. depends only on the sample of spill sizes of the category in question.

Stewart [6] has shown that having observed on spills of volumes $(x_1, x_2, x_3, \ldots x_m)$ respectively a density which fits these requirements is the so-called Gamma-hyperpoisson:

$$f(\omega,\rho|m,s,p) = e^{-s\omega}\omega^{m\rho-1}/(\Gamma(\rho)^m S(m,s,p))$$

where $S(m,s,p)$ is a normalizing constant and

m = number of spills observed

$s = \Sigma x_i$ = total amount spilled

$p = \Pi x_i$ = product of all the individual spill sizes.

One can then obtain the density on x by multiplying the density on x given ω and ρ times the density on ω and ρ and then running over all possible values of ω and ρ. The result is

$$f(x|m,s,p) = \int_0^\infty \frac{(xp)^{\rho-1}\Gamma[(m+1)\cdot\rho]d\rho}{\Gamma(\rho)^{m+1}S(m,s,p)(x+s)^{(m+1)\cdot\rho}}$$

---

our actual analysis, we take a first step toward multiple peaks by dividing all spills into spills less than 42,000 gallons and spills greater than 42,000 gallons.

This is the density whose cumulative is shown in the spill size probability figures. Its mean is

$$\text{MEAN}(x) = \frac{s/m}{\bar{S}(m,s,p)} \int_0^\infty \frac{p^{\rho-1}\Gamma(m\rho)}{\Gamma(\rho)^m s^{m\rho}} \left\{\frac{\rho}{\rho - (1/m)}\right\} d\rho$$

which for large m tends quickly to the sample mean, s/m. For small m, the mean is higher than the sample mean.

4. Tanker spills over 42,000 gallons

Table 4.1 shows a listing of all non-inland tanker and barge spills over 1000 barrels (42,000 gallons) through 1972 of which we are aware. This list combines data from the ECO Inc. tape, the Georges Bank Petroleum Study (Westinform Ltd.), and the 1970, 1971, and 1972 Coast Guard Reports. In terms of volume, almost all the oil reported spilled by vessels is spilled in spills of this size. 98.4% of the volume reported in the ECO data occurred in 42,000 gallon spills or larger.

The great bulk of all these vessel spills are from the ECO Inc. data. This data was obtained by:

a. identifying some 3,000 tanker casualties that occured in the calendar years 1969 through 1972, principally through insurance company reports (Lloyd's Daily List);

b. internal data on oil company-owned and -chartered tankers involved in the incidents provided through the cooperation of the companies;

c. cross-check with other published data--newspapers and magazines--for details of particular incidents;

d. follow-up interviews with oil company personnel in the case of discrepancies.

The data covers 612 spills. We believe it to be a practically complete list of large tanker spills in the four-year period. In return for the company data, ECO agreed not to identify individual spills. Hence, we have deleted vessel name and exact date

TABLE 4.1

ESTIMATED SPILL IN GALLONS	LOCATION	SOURCE (ECO,CGD,GBS)	TANKER NAME	GROSS REGISTERED TONNAGE	DATE (DAY,MO,YR)
33,804,000	12	ECO		63,989	.12.72
29,000,000	2	GBS	Torrey Canyon		18. 3.67
13,828,000	12	ECO		29,189	. 7.70
13,500,000		GBS	World Glory		13. 6.68
11,240,000	6	ECO		28,339	. 2.71
9,554,000	23	ECO		21,999	. 6.72
8,912,000	1	ECO		16,231	. 1.72
8,800,000	1	GBS	Keo	15,797	5.11.69
8,772,000	1	ECO		19,183	. 2.70
8,434,000	17	ECO		17,328	. 1.69
8,432,000	1	ECO		15,797	. 1.69
8,304,000	1	ECO		20,084	. 3.71
6,250,000		GBS	R. C. Stoner		6. 9.67
5,808,000	2	ECO		17,519	. 3.72
5,732,000	2	ECO		12,607	. 1.70
5,620,000	15	ECO		11,765	. .71
5,300,000	2	GBS	A. M. Browig		20. 2.66
5,232,000	15	ECO		12,113	. 1.70
5,217,000	6	ECO		11,971	. 7.71
5,198,000	2	ECO		12,525	.10.70
5,142,000	11	ECO		11,563	. 4.70
5,000,000		GBS	Andron		5. 5.68
4,864,000	24	ECO		11,079	. 2.70
4,608,000	12	ECO		10,608	. .71
4,594,000	3	ECO		11,177	. 2.70
4,561,000	6	ECO		10,009	. 2.69
3,934,000	23	ECO		15,638	. 1.70
3,850,000	13	ECO		8,864	. 2.70
3,653,000	2	ECO		28,945	. 5.70
3,500,000	2	GBS	Poly Commander	28,945	5. 5.70
3,500,000	7	GBS	Ocean Eagle		3. 3.68
3,372,000	1	ECO		11,379	. 3.70
2,810,000	4	ECO		104,772	. 2.69
2,733,000	15	ECO		10,518	. 9.71
2,529,000	2	ECO		12,821	. 2.69
2,500,000	16	GBS	Tampico		. 3.57
2,457,000	15	ECO		12,200	.11.71
2,108,000	2	ECO		43,371	. 7.69
2,000,000	1	CGD			. 4.69
1,686,000	2	ECO		42,777	.10.70
1,686,000	20	ECO		30,714	. 3.70

SPILL IN GALLONS	LOCATION	SOURCE (ECO,CGD,GBS)	TANKER NAME	REGISTERED TONNAGE	DATE (DAY,MO,YR)
1,686,000	23	ECO		26,805	.12.72
1,651,000	1	ECO		11,208	. 4.72
1,630,000	13	ECO		52,629	.10.69
1,612,000	3	ECO		29,197	.11.71
1,500,000	1	GBS	Arrow	11,379	. 2.70
1,492,000	11	ECO		48,339	. 8.72
1,400,000	2	GBS	Pacific Glory	42,777	21.10.70
1,300,000	7	GBS	Gen. Colocotronis		7. 3.68
1,300,000		GBS	Esso Essen		29. 4.68
1,262,000	24	ECO		31,275	. 9.70
1,200,000	7	GBS	Argea Prima		17. 7.62
1,124,000	2	ECO		52,510	. 2.71
989,000	1	ECO		46,988	. 8.72
984,000	15	ECO		12,492	. 8.70
943,000	2	ECO		48,267	.11.71
940,000	16	ECO		10,448	. 1.71
939,000	16	ECO		10,533	. 1.71
900,000	20	GBS	Ocean Grandeur	30,714	3. 3.70
857,000	2	ECO		13,604	. 1.71
843,000	11	ECO		48,320	. 8.72
840,000	16	GBS	Oregon Standard	10,448	1.18.71
838,000	23	ECO		33,403	. 8.72
812,000	23	ECO		12,697	. 1.72
794,000	17	ECO		17,543	. 5.72
780,000	1	GBS	Esso Gettysburg		22. 1.71
730,000	2	GBS	Otto N. Miller		27. 3.65
702,000	2	ECO		12,223	. 9.69
674,000	1	ECO		31,289	. 3.69
630,000		GBS	Witwater		12.13.68
590,000	2	GBS	Benedicte	38,700	31. 5.69
562,000	2	ECO		38,700	. 5.69
562,000	12	ECO		97,450	. 9.70
560,000	2	GBS	Floreal		11. 9.65
534,000	13	ECO		17,420	. 2.69
525,000	5	ECO		12,595	. .72
506,000	1	ECO		23,420	. 2.70
501,000	13	ECO		11,237	.10.71
478,000	7	ECO		12,085	.10.69
478,000	1	ECO		30,770	. 7.69
450,000	2	ECO		15,983	. 2.70
436,000	1	ECO		24,008	. 8.70
420,000	7	ECO			. .72

ESTIMATED SPILL IN GALLONS	LOCATION	SOURCE (ECO,CGD,GBS)	TANKER NAME	GROSS REGISTERED TONNAGE	DATE (DAY,MO,YR)
420,000	16	GBS	Evje		2. 5.67
420,000	2	GBS	Gironde		19. 8.69
413,000	12	ECO		12,718	. 5.70
410,000	7	ECO		10,255	. 3.72
398,000	16	CGD	Barge		10.12.71
393,000	23	ECO		20,560	. 1.72
379,000	16	ECO		17,943	. 3.69
372,000	15	ECO		801	.10.70
351,000	23	ECO		13,235	. 4.69
351,000	1	ECO		23,665	. 1.71
351,000	23	ECO		12,029	.11.72
337,200	7	ECO		12,235	. 2.69
337,000	12	ECO		127,158	. 9.70
309,000	23	ECO		19,391	.12.72
306,000	1	CGD			23. 1.71
300,000	1	CGD	Barge		11. 5.71
290,000	1	GBS	Tim		18. 2.68
285,000	2	ECO		499	. 4.72
281,000	1	ECO		20,575	. 1.69
281,000	1	ECO		533	. 2.69
281,000	7	ECO		12,573	. 7.69
281,000	1	ECO		26,968	. 3.70
281,000	19	ECO		17,871	. 3.71
281,000	15	ECO		12,200	.12.71
281,000	13	ECO		105,397	. 6.72
281,000	23	ECO		12,648	. .72
281,000	11	ECO		12,174	. 4.72
264,000	2	ECO		12,377	.11.72
240,000	7	CGD			12. 6.71
239,000	2	ECO		11,842	. 1.70
233,000	1	ECO		16,417	. 2.70
225,000	13	ECO		296	. 8.69
220,000	2	GBS	Esso Wansworth		23. 9.65
220,000	16	CGD	Barge		26. 4.71
220,000	2	GBS	Efthycosta		8. 3.70
211,000	1	ECO		23,665	. 7.70
210,000	2	GBS	Hamilton Trader		30. 4.69
204,000	15	ECO		427	.12.71
200,000	1	GBS	R. L. Polling		10. 5.69
200,000	1	GBS	Barge		27.12.70
200,000	3	ECO		48,801	. 6.71
197,000	13	ECO		771	.11.71

ESTIMATED SPILL IN GALLONS	LOCATION	SOURCE (ECO,CGD,GBS)	TANKER NAME	GROSS REGISTERED TONNAGE	DATE (DAY,MO,YR)
197,000	23			13,393	. 2.70
180,000	16	GBS	Marita		20. 9.62
177,000	1	ECO		82,793	. 6.71
172,000	1	GBS	Florida		10. 9.69
169,000	2	ECO		12,575	. 4.69
169,000	15	ECO		382	. 8.70
169,000	5	ECO		1,944	. 3.72
168,000	7	CGD	Barge		1. 1.71
168,000	24	CGD	Barge		20. 7.72
168,000	1	GBS	Algol		9. 2.69
165,000	2	GBS	Hullgate		8. 4.71
160,000	4	ECO		13,580	. 7.69
147,000	7	CGD	Barge		15. 3.72
140,000	1	ECO		12,618	. 2.69
140,000	1	ECO		1,286	. 2.69
140,000	15	ECO		361	. 1.69
140,000	15	ECO		338	.10.70
140,000	16	ECO		14,671	. 1.71
140,000	2	ECO		1,594	. 4.71
140,000	23	ECO		1,594	. 6.72
140,000	17	ECO		14,456	. 3.72
140,000	2	GBS	Monti Ulia		27. 7.70
135,000	1	CGD			12. 6.72
135,000	15	ECO		282	. 2.71
134,000	5	ECO		3,738	. 6.70
131,000	1	GBS	Barge		22. 5.70
126,000	1	ECO		20,889	.12.72
126,000	2	ECO		12,146	.12.72
112,000	23	ECO		1,588	. 4.69
112,000	15	ECO		199	. 2.69
112,000	2	ECO		54,908	. 9.69
112,000	23	ECO		23,664	.10.72
112,000	13	ECO		854	. 2.72
110,000	23	ECO		3,553	. 8.71
100,000	1	CGD			22. 7.72
85,000	16	CGD			18. 1.71
84,000	1	ECO		382	. 3.69
84,000	2	ECO		12,493	. 4.69
84,000	2	ECO		12,423	. 4.70
84,000	1	GBS	Barge		26. 5.70
84,000	2	GBS	Texacao		11. 1.71
84,000	1	CGD	Barge		6. 9.72

ESTIMATED SPILL IN GALLONS	LOCATION	SOURCE (ECO,CGD,GBS)	TANKER NAME	GROSS REGISTERED TONNAGE	DATE (DAY,MO,YR)
82,000	13	ECO		395	. 2.72
76,000	7	GBS	Barge		23. 5.69
75,000	16	CGD	Barge		28. 2.71
72,000	2	ECO		13,718	. 5.71
72,000	2	GBS	Heruluv		15. 5.71
70,000	15	ECO		170	. 7.70
70,000	1	ECO		11,010	. 4.71
70,000	13	ECO			. .71
70,000	23	ECO		45,162	. 2.71
70,000	13	ECO		15,564	.11.72
70,000	17	ECO		16,563	.12.72
68,000	15	ECO		142	. 8.72
67,000	7	GBS	Barge		26. 5.70
67,000	1	GBS	Barge		12. 7.70
66,000	15	ECO		317	. 3.71
62,000	1	ECO		1,103	. 3.72
60,000	1	CGD	Barge		12. 5.71
56,000	2	ECO		15,880	. 8.69
56,000	24	ECO		11,136	. 5.69
56,000	2	ECO		107,426	.12.71
56,000	2	ECO		20,414	.12.71
56,000	15	ECO		357	. 9.72
47,000	13	ECO		899	. 2.72
46,000	20	ECO		254	.10.70
42,000	19	ECO		45,752	. 8.71
42,000	1	GBS	Kenai Peninsula		5.11.68
42,000	1	CGD			20. 1.72

from those spills for which our only source was the ECO tape. A cursory examination of the list will reveal that with respect to large spills, the non-ECO sources are woefully incomplete. For example, in 1969 ECO reports 40 large (over 42,000 gallons) spills. The other data sources combined report 8, 6 of which spills are in the ECO data. Since the data prior to 1969 is patently incomplete and since the Coast Guard data refers only to U.S. waters and contains only a small sample of non-harbor spills (see Table 1.1), we have decided to rely solely on the ECO Inc. data in deriving densities of tanker spills over 42,000 gallons.

With respect to the incidence of vessel spills, our earlier assumptions imply that the probability of n spills occurring given a specified amount of exposure, t, is given by

$$p(n|\lambda) = e^{-\lambda t} (\lambda t)^n/n!$$

where λ is a parameter which specifies the <u>intensity</u> of the Poisson process governing spill frequency. We will use the ECO spill data to make some judgments about λ. But first we have to ask ourselves what exposure variable, t, we should use. Several possibilities come immediately to mind - amount of oil being transported, number of landfalls, number of

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*Coast Guard personnel feel that their system is picking up 90% or more of the actual spills from fixed sources. However, the legal requirement for reporting extends only to the three-mile limit and these same personnel have some doubts that vessels operating near the three-mile limit are completely faithful reporters.

ton-miles, etc. In short, our task is to identify an explanatory variable, t, to which spillage appears related in the above manner. We also need an explanatory variable whose ability to explain we can test with the available data.

In attempting to find such a variable, we have made a number of false starts. Figure 4.1 shows one such failure. The ECO data breaks the world down into twenty regions and identifies in which of these regions each spill occurred. We hypothesized that spill frequency was proportional to the amount of oil flowing through each region. Department of Interior reports [7] on world oil flows were used to estimate the amount of oil flowing through each such region over the four-year period. We then plotted the number of spills which took place in each region against the amount of oil flowing through that region. Figure 4.1 shows the resulting scatter diagram. Obviously, there appears to be little or no dependence between spill incidence and regional throughputs. The total volume spilled in each region, Figure 4.2, also shows no relation to regional throughput but this was not unexpected because volume spilled can be drastically affected by a single spill. However, with a sample of 612 spills, if there were a relationship between incidence and regional throughput, with high probability Figure 4.1 would have revealed it.

The ECO Inc. data also breaks the spills down by locale:

1. pier (touching a dock)
2. harbor

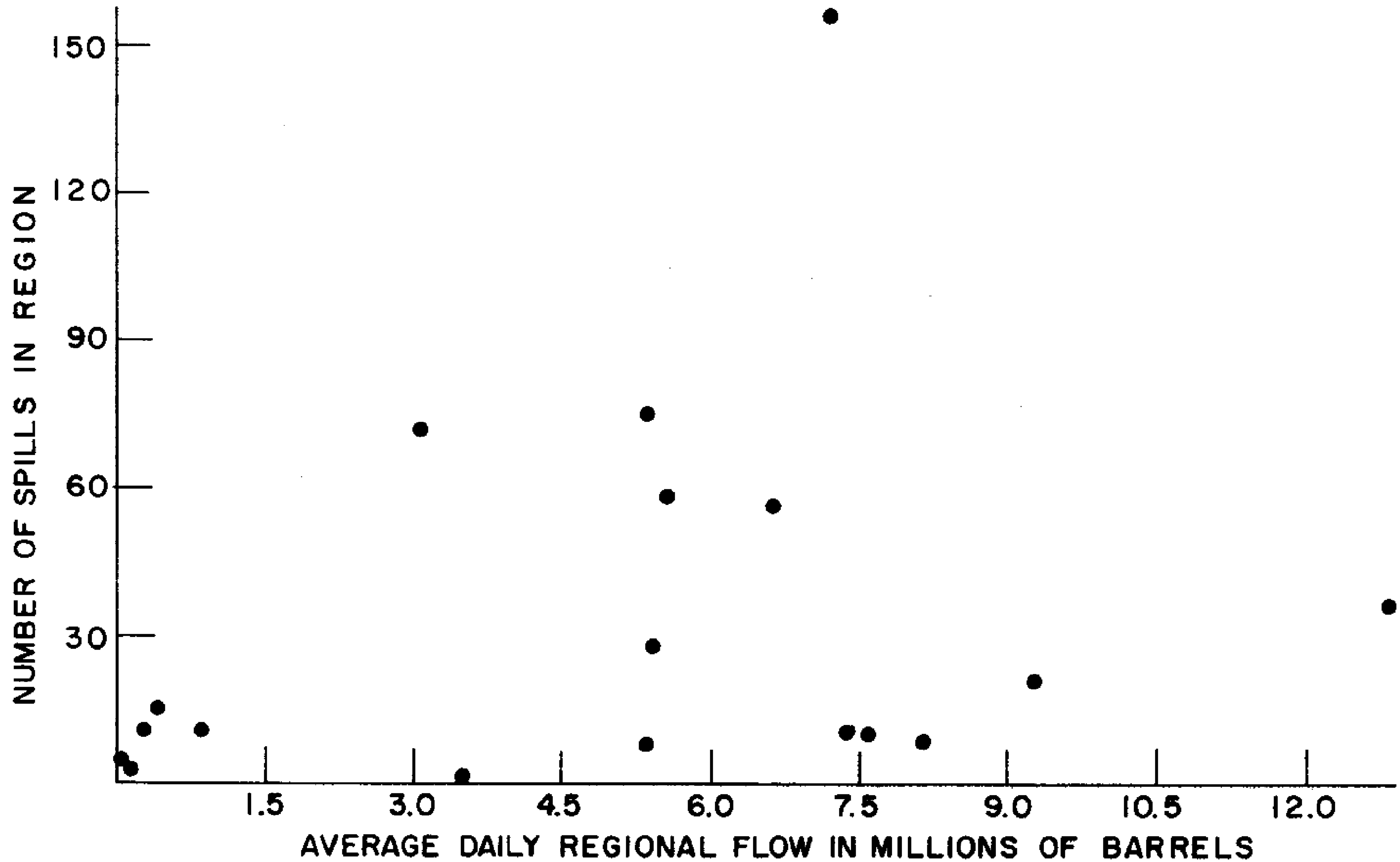


FIGURE 4.1 SCATTER DIAGRAM OF NUMBER OF SPILLS IN REGION VERSUS VOLUME OF CRUDE FLOWING THRU REGION. Based on all ECO spills (612).

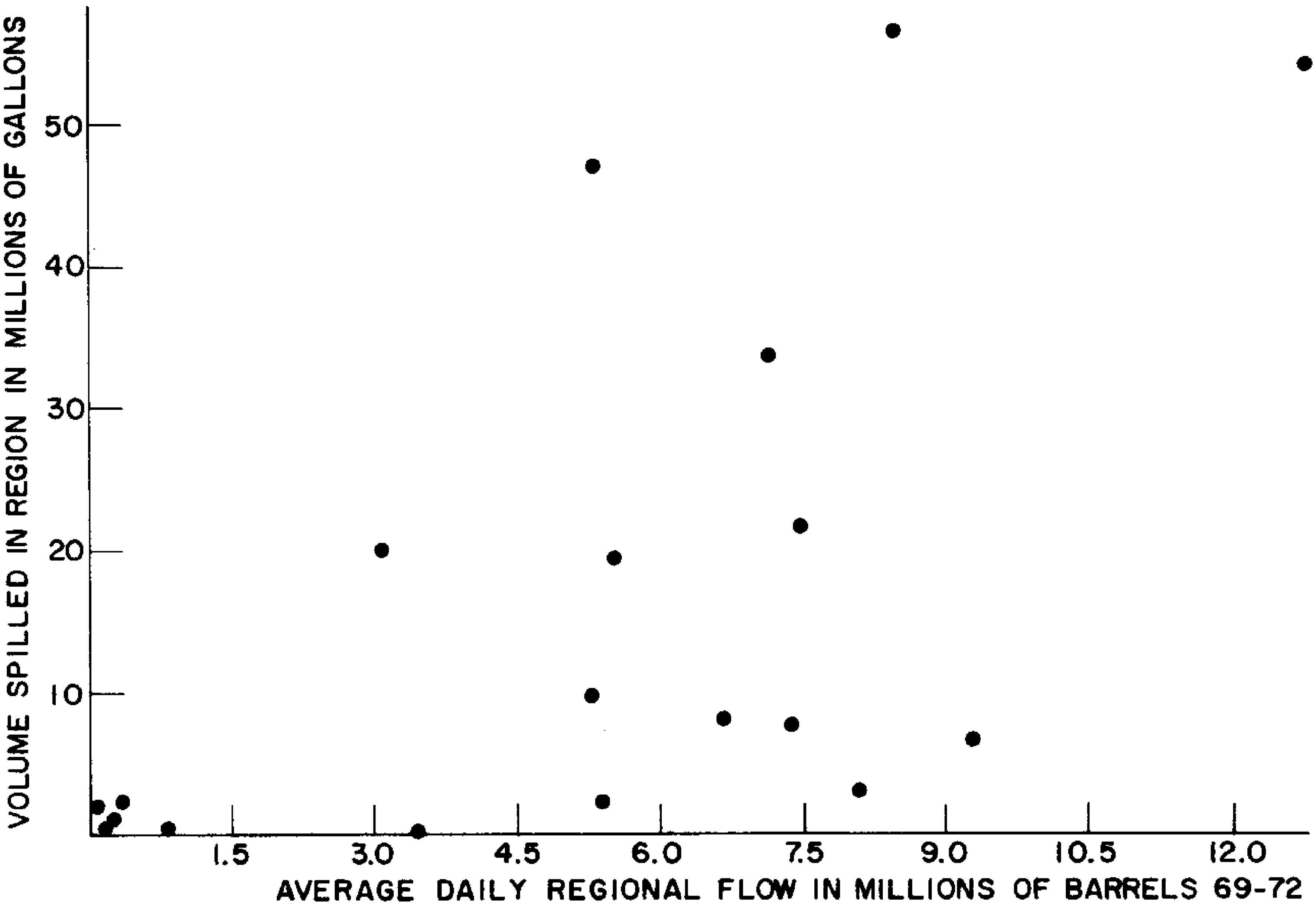


FIGURE 4.2 SCATTER DIAGRAM OF VOLUME SPILLED IN REGION VERSUS REGIONAL THROUGHPUT. Based on all 612 ECO spills.

3. bay

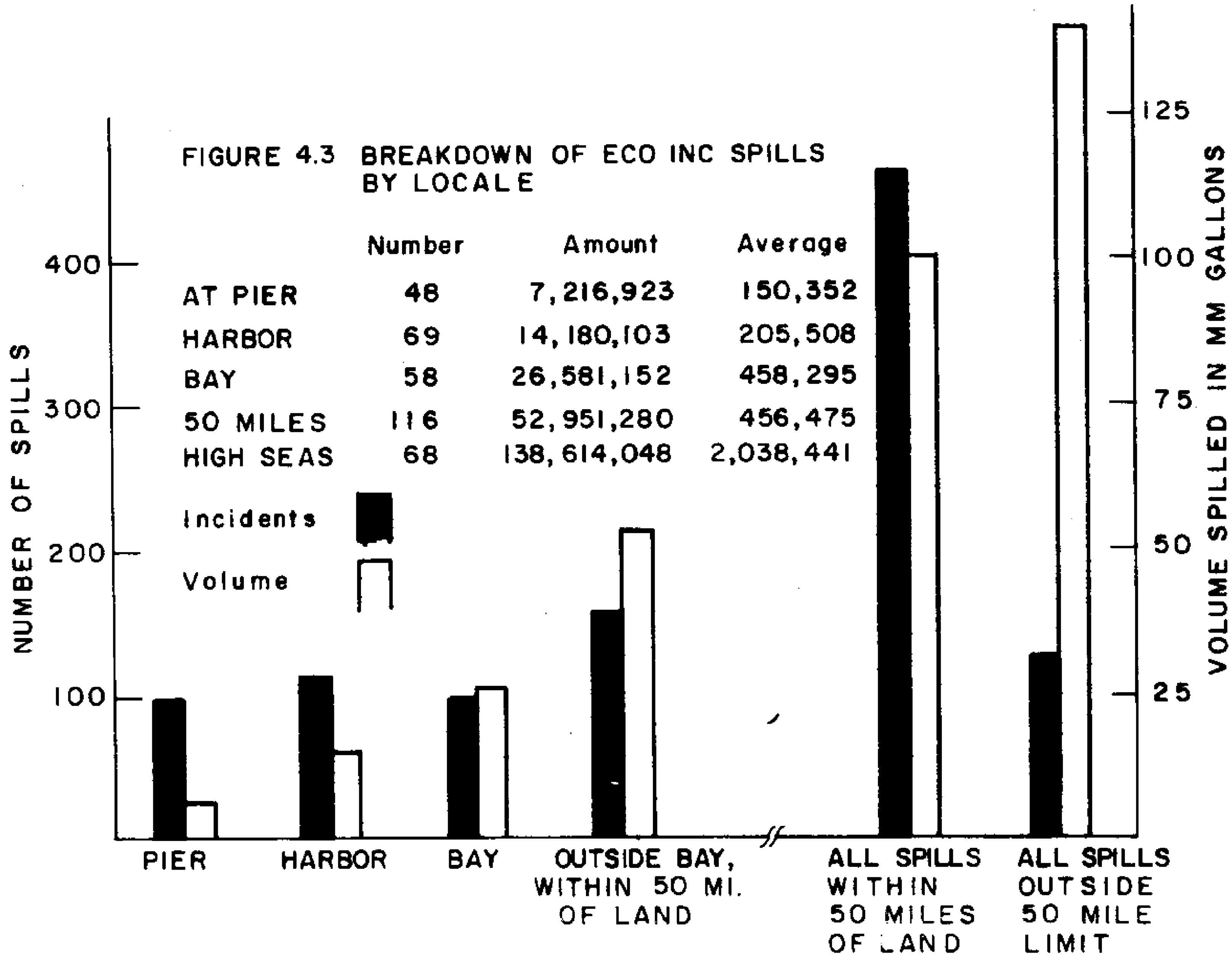
4. outside bay but within fifty miles of shore

5. outside fifty-mile limit.

Of the 359 spills for which locale is listed, 291 or 83% occurred within fifty miles of land. Figure 4.3 shows the breakdown. This figure, together with the earlier negative results, suggests that most spills occur at either end of the voyage. This suggestion is buttressed by Figure 4.4 which indicates that sizable portion of the spills are caused by grounding or ramming (vessel hits fixed structure) or collision. Groundings and rammings can only occur near shore, while collision frequency depends on traffic density, which is at a maximum near shore.

These results suggest that the amount of oil landed might be a better explanatory variable than regional throughput. Therefore, ECO Inc. personnel returned to Lloyd's Daily List and other records and identified on what major trade route each spill occurred. At the same time, trade route volumes for each of twelve major routes for the four years were compiled from Department of Interior sources. Figure 4.5 shows the resulting scatter diagram: number of spills on each route against volume handled on that route. This figure indicates a possible linear relationship. The least squares fit is $n = 3.9 + 10.1 \cdot v$ which has a correlation coefficient of .88 and a standard error of 8.3. Interestingly enough, the three points to the high side of this fit all involve routes which terminate in the U.S. This raises two possibilities:

FIGURE 4.3 BREAKDOWN OF ECO INC SPILLS BY LOCALE



	Number	Amount	Average
AT PIER	48	7,216,923	150,352
HARBOR	69	14,180,103	205,508
BAY	58	26,581,152	458,295
50 MILES	116	52,951,280	456,475
HIGH SEAS	68	138,614,048	2,038,441

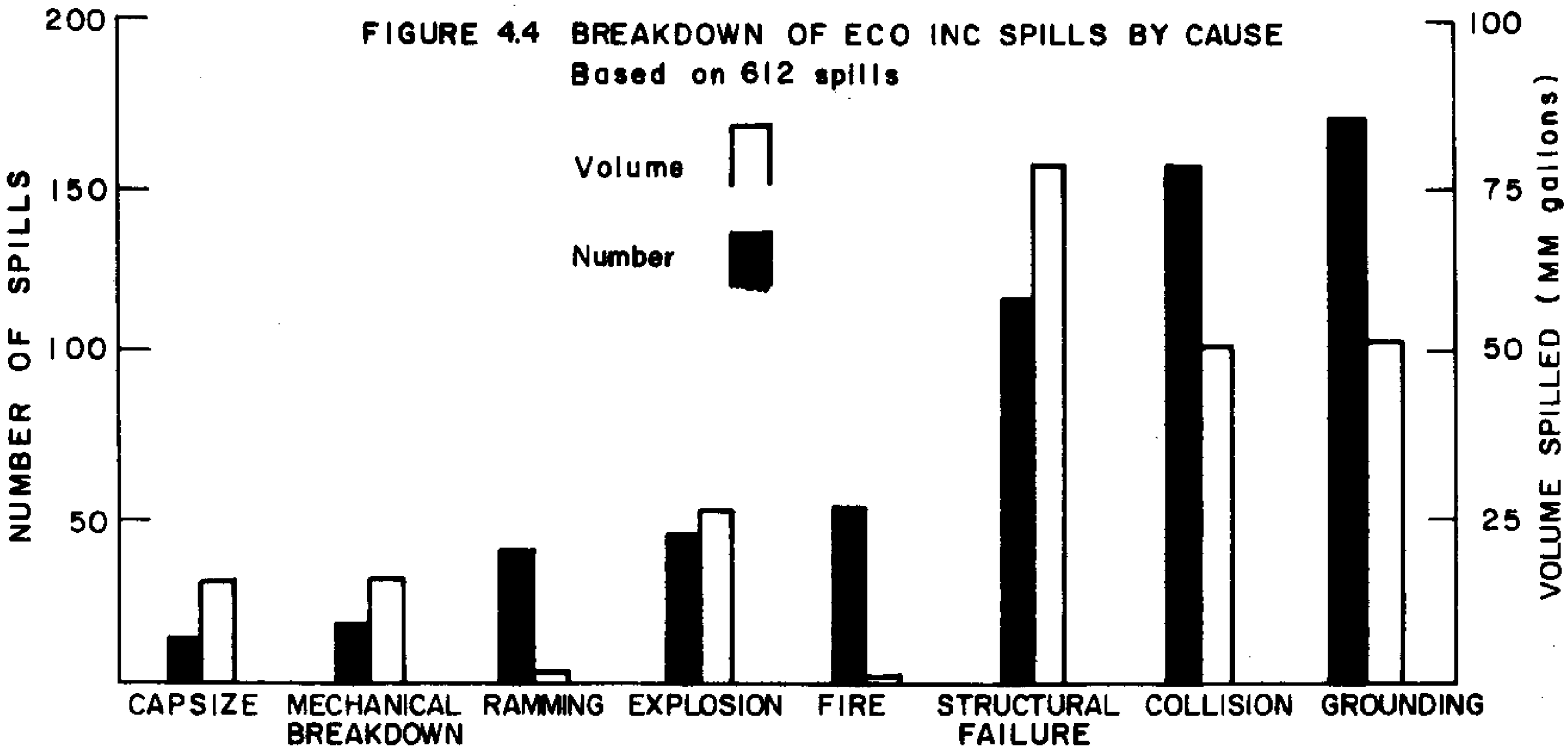


FIGURE 4.4 BREAKDOWN OF ECO INC SPILLS BY CAUSE
Based on 612 spills

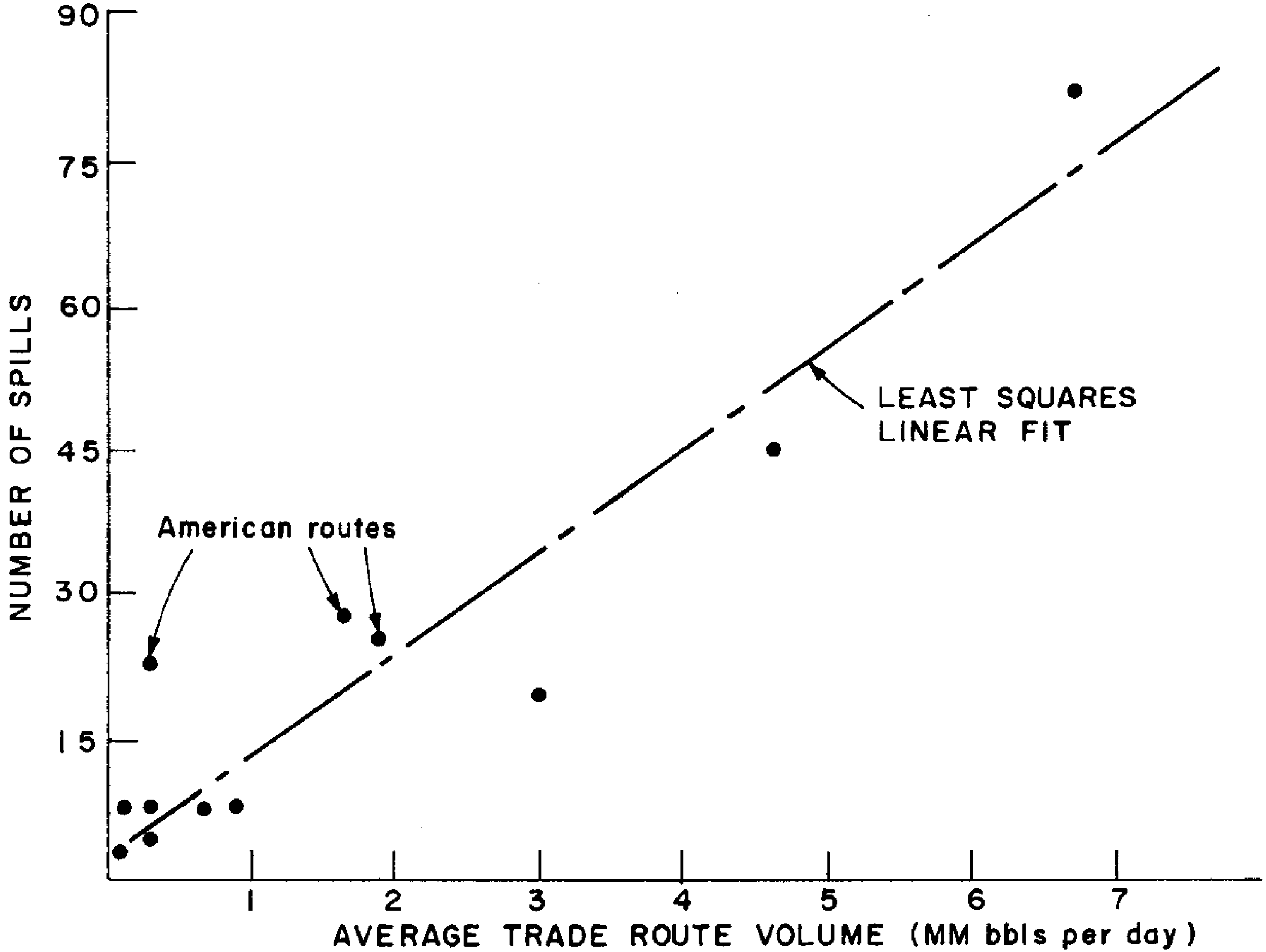


FIGURE 4.5 SCATTER DIAGRAM OF NUMBER OF SPILLS OBSERVED VERSUS AVERAGE TRADE ROUTE VOLUME, 69 THRU 72

1. Spills in U.S. waters are more carefully reported than elsewhere.

2. Since U.S. routes involve generally smaller ships than other major routes due to draft limitations at terminals, the same volume landed involves more landfalls. This suggests that the number of landfalls may be a still better explanatory variable than the volume landed. However, we did not check this possibility due to time comstraints, but, on the basis of Figure 4.5, chose to operate with volume landed as the exposure variable.

It is interesting to compare the correlation between number of spills and volume landed, Figure 4.5, with that between volume spilled and volume landed, Figure 4.6. As expected volume spilled shows a great deal less correlation, yet the assumption that volume spilled is proportional to volume landed is almost universally employed in oil-spill analysis.

As Section 3 argues, once one has decided to model spill frequency by a Poisson process, has chosen an exposure variable, and has assumed that the intensity of this process, λ, is an unknown variable whose density should depend solely on the available spill data,* then the probability of obtaining n spills in a given amount of exposure, t, having observed ν

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*To put this third assumption in precise but impenetrable jargon, we have assumed that the intensity λ is a random variable which is governed by the non-informative conjugate prior.

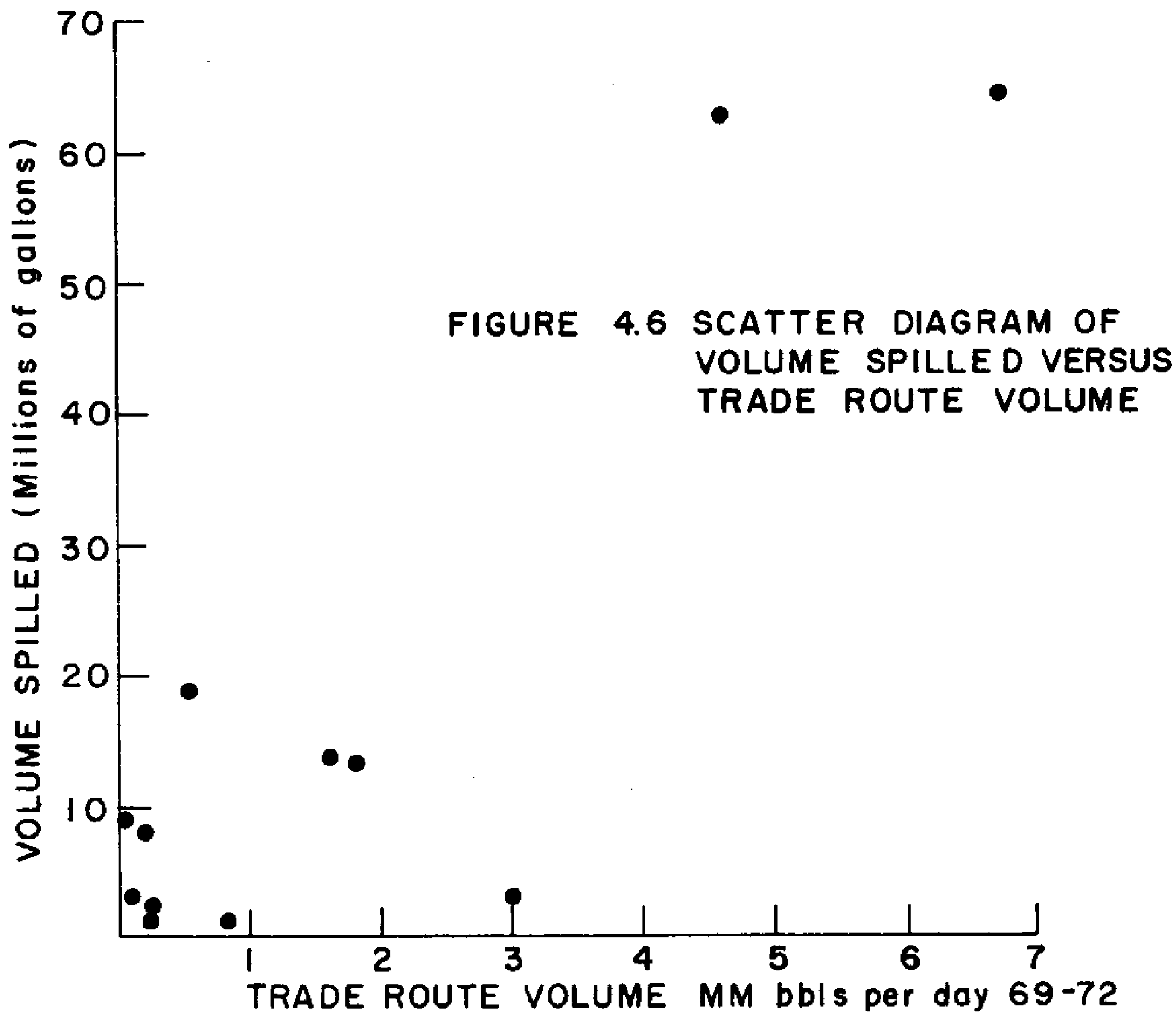

FIGURE 4.6 SCATTER DIAGRAM OF VOLUME SPILLED VERSUS TRADE ROUTE VOLUME

spills in an amount of exposure, τ, is given by

$$p(n) = \frac{(n + \nu - 1)!\,t^n \tau^\nu}{n!\,(\nu - 1)!\,(t + \tau)^{n+\nu}}$$

Figures 4.7, 4.8 and 4.9 show the resulting densities on the number of tanker spills over 42,000 gallons in the field life of a "small", "medium", and "large" find respectively if the finds are landed by vessel, where

1. A "small" find is defined to be 500 million barrels of oil in place, 500 billion cubic feet of gas, situated 146 miles offshore. The other reservoir parameters are those shown in Table 3.0.1 in the Offshore Development Model report. Under the assumption used therein, this field produces 122 million barrels of oil, has a field life of 5 years and a peak production rate of 73 million barrels per year. This find then corresponds in all respects to the small find studied in the Offshore Development Model [8].

2. A "medium" find is defined to be 2 billion barrels in place, 1000:1 gas/oil ratio, located in two structures 146 miles offshore. It too corresponds in all respects to the "medium" find studied in the Offshore Development Model report. Under the assumptions used therein, this find produces 567 million barrels in 5 years with a peak production year of 169 million barrels.

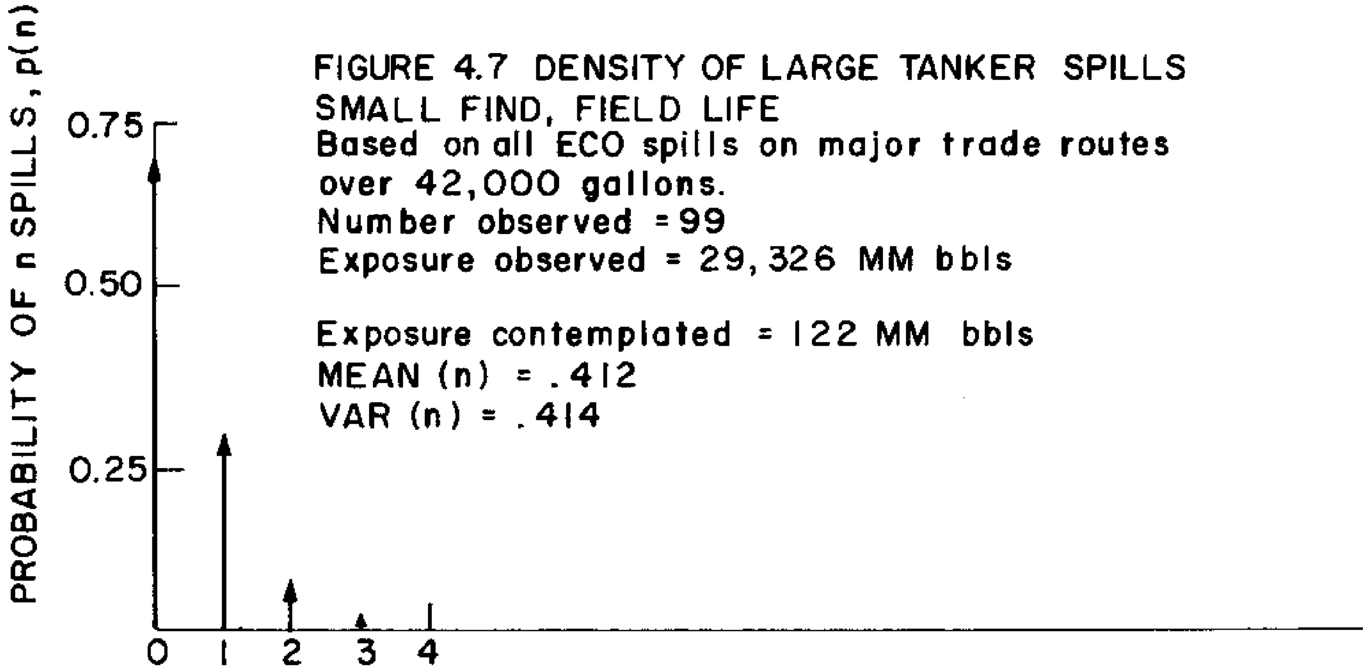

FIGURE 4.7 DENSITY OF LARGE TANKER SPILLS
SMALL FIND, FIELD LIFE
Based on all ECO spills on major trade routes over 42,000 gallons.
Number observed = 99
Exposure observed = 29,326 MM bbls

Exposure contemplated = 122 MM bbls
MEAN (n) = .412
VAR (n) = .414

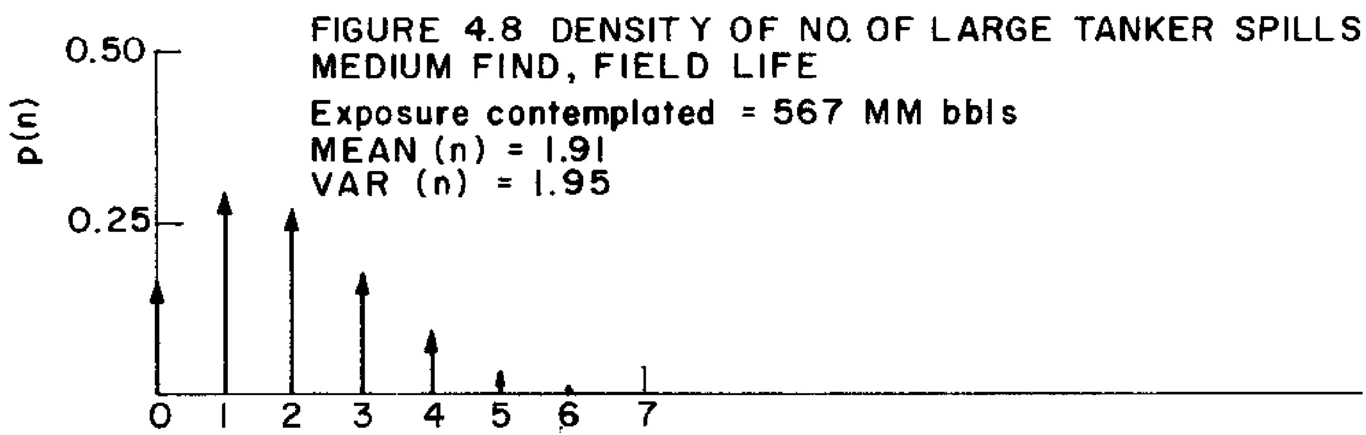

FIGURE 4.8 DENSITY OF NO. OF LARGE TANKER SPILLS
MEDIUM FIND, FIELD LIFE
Exposure contemplated = 567 MM bbls
MEAN (n) = 1.91
VAR (n) = 1.95

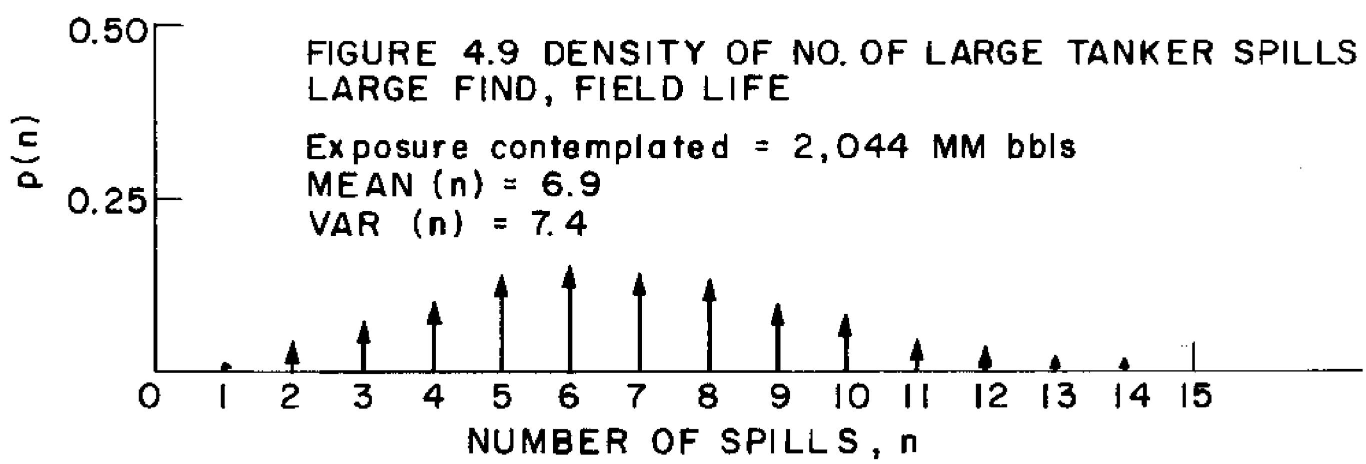

FIGURE 4.9 DENSITY OF NO. OF LARGE TANKER SPILLS
LARGE FIND, FIELD LIFE
Exposure contemplated = 2,044 MM bbls
MEAN (n) = 6.9
VAR (n) = 7.4

3. A "large" find is defined to be 10 billion barrels of oil in 5 structures and it corresponds to the "large" find studied in Section 3 of the Offshore Development Model report. Under the assumptions used therein, this find produces 2,044 million barrels of oil over 12 years with a peak production year of 327 million barrels.

These three figures are based on the fact that ECO has observed 99 spills over 42,000 gallons on our 12 major trade routes in the period 1968 through 1972. During that period, approximately 29 billion barrels of oil were landed on these trade routes, that is, we have observed an exposure of 29 billion barrels. The total exposure contemplated for the hypothesized small, medium, and large finds is 122, 567, and 2,044 million barrels respectively. Notice that, for the small find, while the mean, the central value, of the density is less than 1/2, there is a substantial probability, about .30, of 1 spill and a possibility, about 1 chance in 40, of as many as 2 tanker spills. For the larger fields, both the mean and variance increase as the densities shift to the right and spread out.

Figures 4.10 through 4.12 show the same densities for all spills over 100,000 gallons (approximately the size of the West Falmouth and "Tamano" spills), while Figures 4.13 through 4.15 show the densities for all spills over 1,000,000 gallons

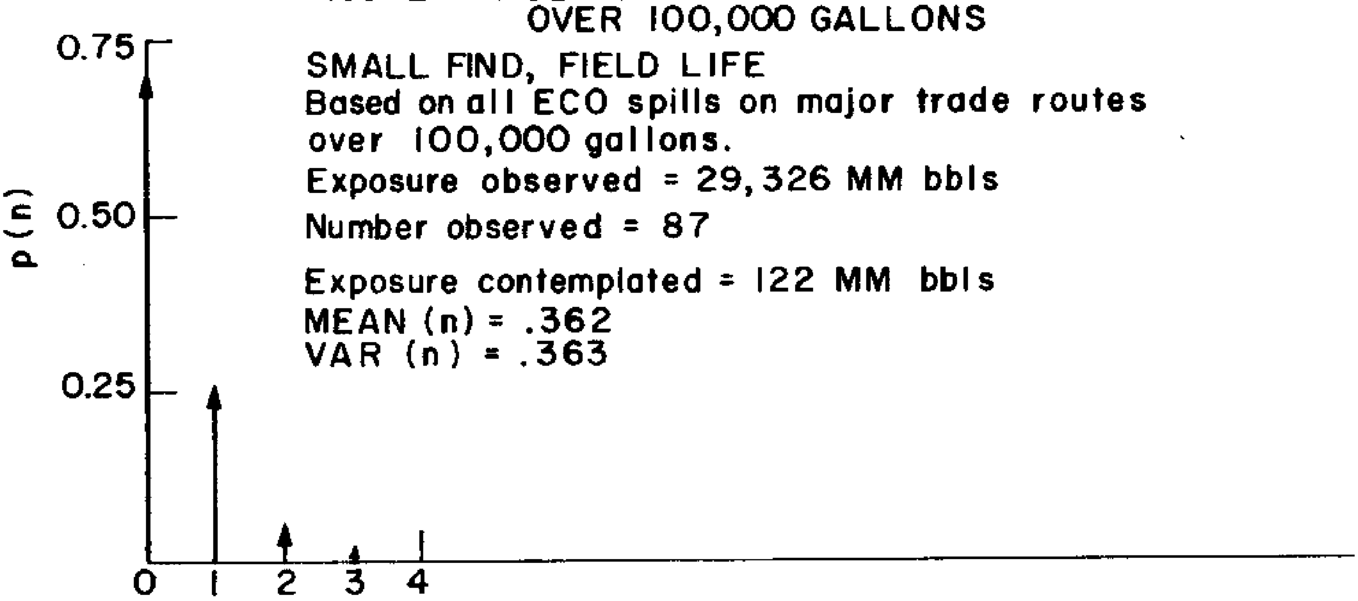

FIGURE 4.10 DENSITY OF NO. OF TANKER SPILLS OVER 100,000 GALLONS

SMALL FIND, FIELD LIFE
Based on all ECO spills on major trade routes over 100,000 gallons.
Exposure observed = 29,326 MM bbls
Number observed = 87
Exposure contemplated = 122 MM bbls
MEAN (n) = .362
VAR (n) = .363

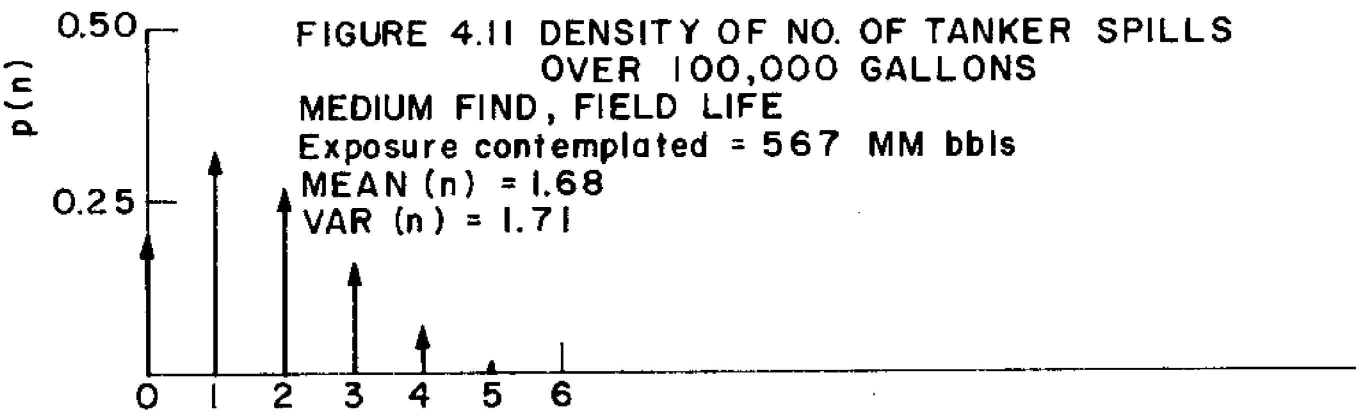

FIGURE 4.11 DENSITY OF NO. OF TANKER SPILLS OVER 100,000 GALLONS

MEDIUM FIND, FIELD LIFE
Exposure contemplated = 567 MM bbls
MEAN (n) = 1.68
VAR (n) = 1.71

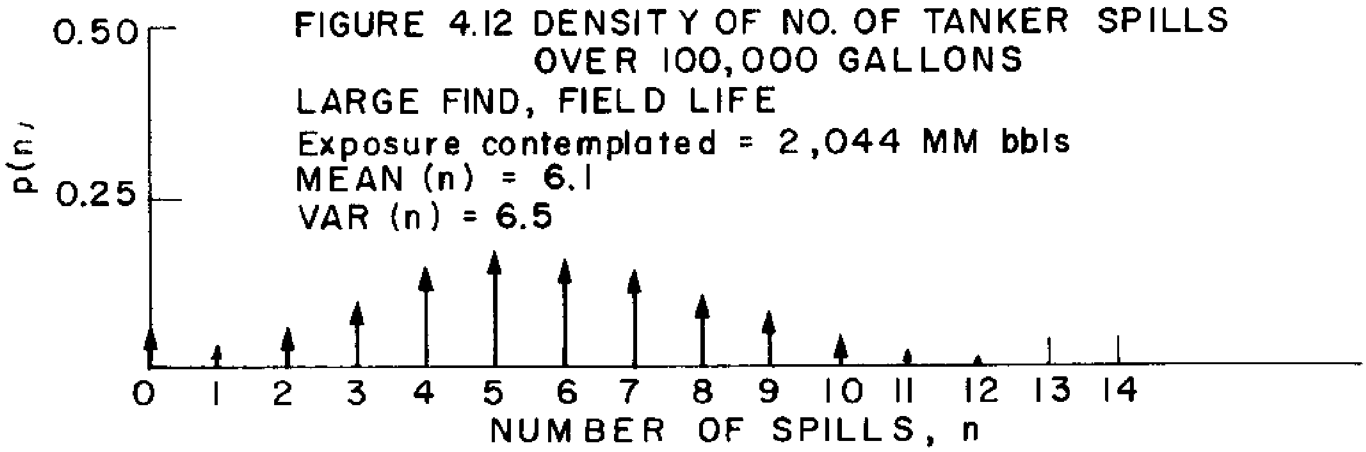

FIGURE 4.12 DENSITY OF NO. OF TANKER SPILLS OVER 100,000 GALLONS

LARGE FIND, FIELD LIFE
Exposure contemplated = 2,044 MM bbls
MEAN (n) = 6.1
VAR (n) = 6.5

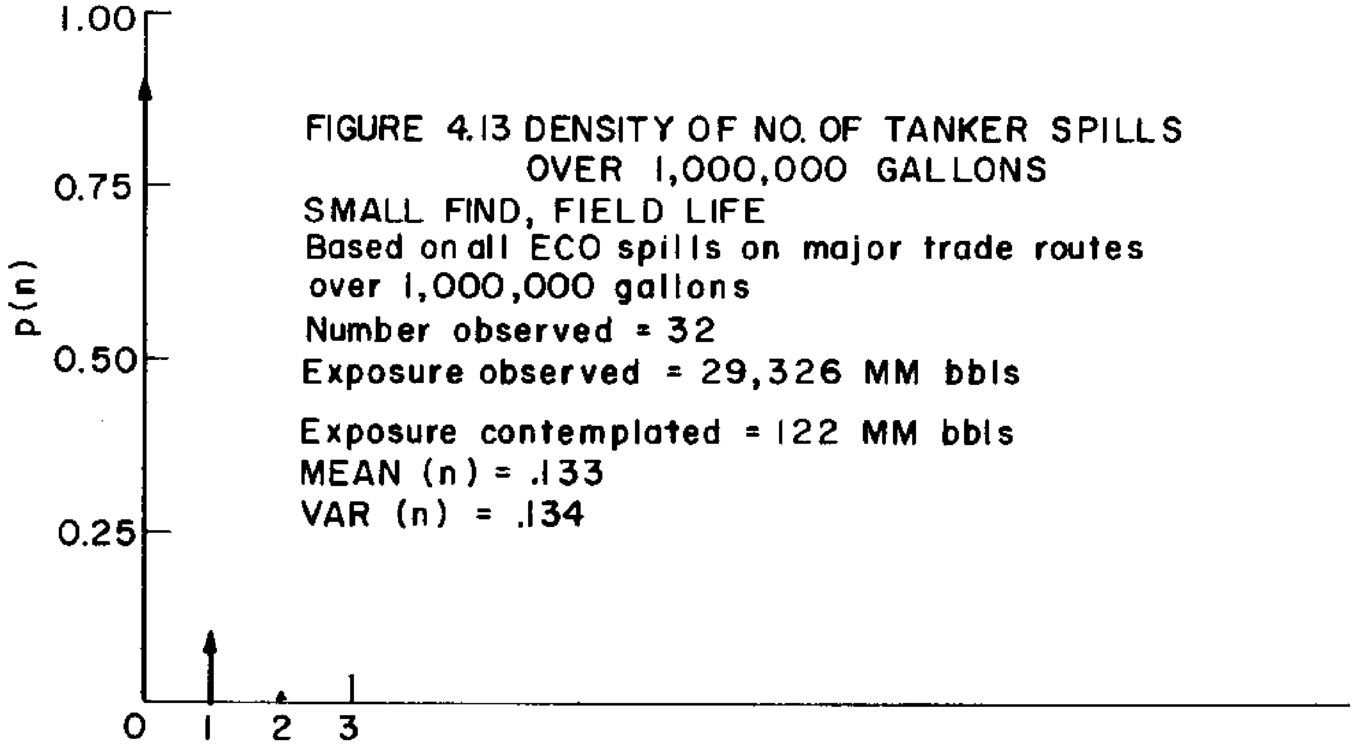

FIGURE 4.13 DENSITY OF NO. OF TANKER SPILLS OVER 1,000,000 GALLONS

SMALL FIND, FIELD LIFE

Based on all ECO spills on major trade routes over 1,000,000 gallons

Number observed = 32

Exposure observed = 29,326 MM bbls

Exposure contemplated = 122 MM bbls

MEAN (n) = .133

VAR (n) = .134

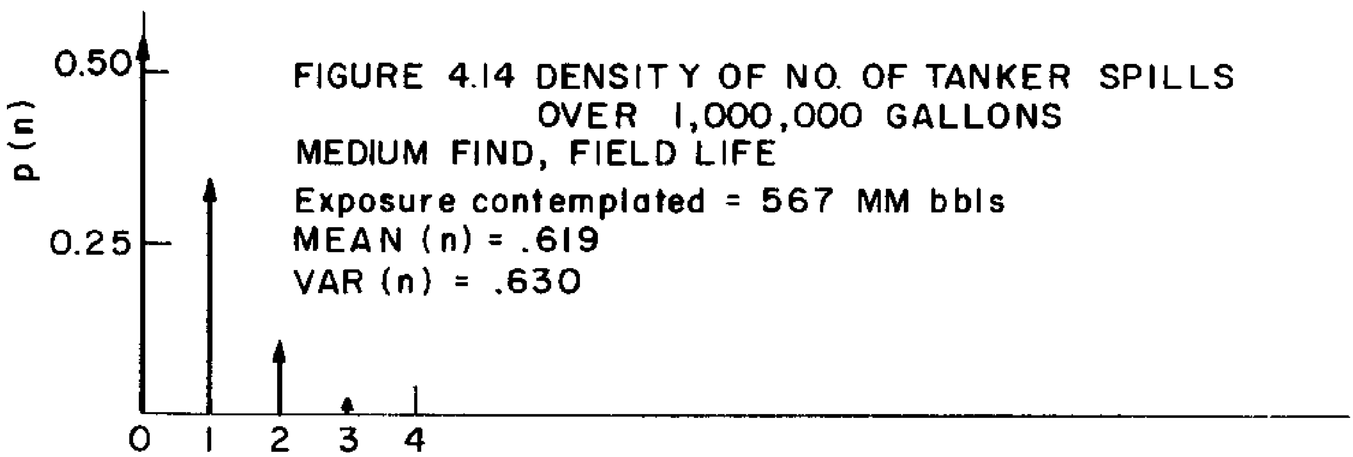

FIGURE 4.14 DENSITY OF NO. OF TANKER SPILLS OVER 1,000,000 GALLONS

MEDIUM FIND, FIELD LIFE

Exposure contemplated = 567 MM bbls

MEAN (n) = .619

VAR (n) = .630

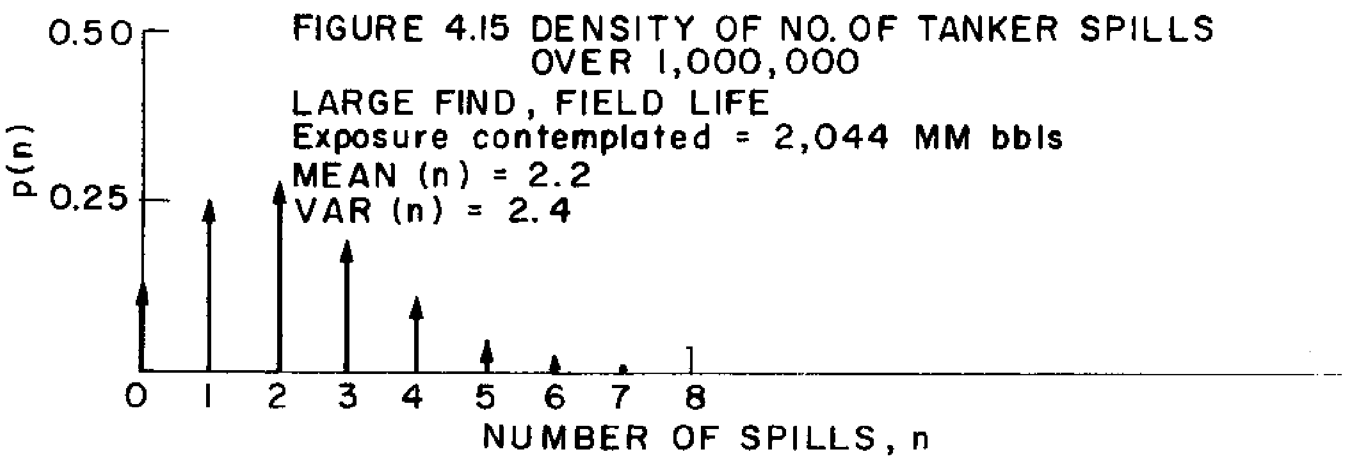

FIGURE 4.15 DENSITY OF NO. OF TANKER SPILLS OVER 1,000,000

LARGE FIND, FIELD LIFE

Exposure contemplated = 2,044 MM bbls

MEAN (n) = 2.2

VAR (n) = 2.4

(approximately one-third the size of the Santa Barbara spill) and Figures 4.16 through 4.18 show the three densities for all spills over 10,000,000 gallons (about one-third "Torrey Canyon"). Notice the increase in the ratio of the variance to the mean as the sample size becomes smaller, reflecting our greater uncertainty about the process generating very large spills.

The rather small change between the density of spills greater than 42,000 gallons and the density of spills greater than 100,000 gallons is perhaps suspicious. There are only 12 spills in the ECO data that are greater than 42,000 gallons but less than 100,000 gallons. Much of our other spill data--much of it admittedly non-tanker--indicates that smaller spills are much more frequent than larger spills. This may not be true for offshore tanker spills, as the ECO data indicates, or the ECO data may not be catching all the spills in this intermediate range. With respect to overall volume spilled, this is certainly not critical. However, the 42,000 gallon spill incidence density must be used with some caution.

The spill incidence analysis can be applied to any specific period during the hypothetical developments operation. For example, one might be interested in the density of the number of large tanker spills which will occur during the peak

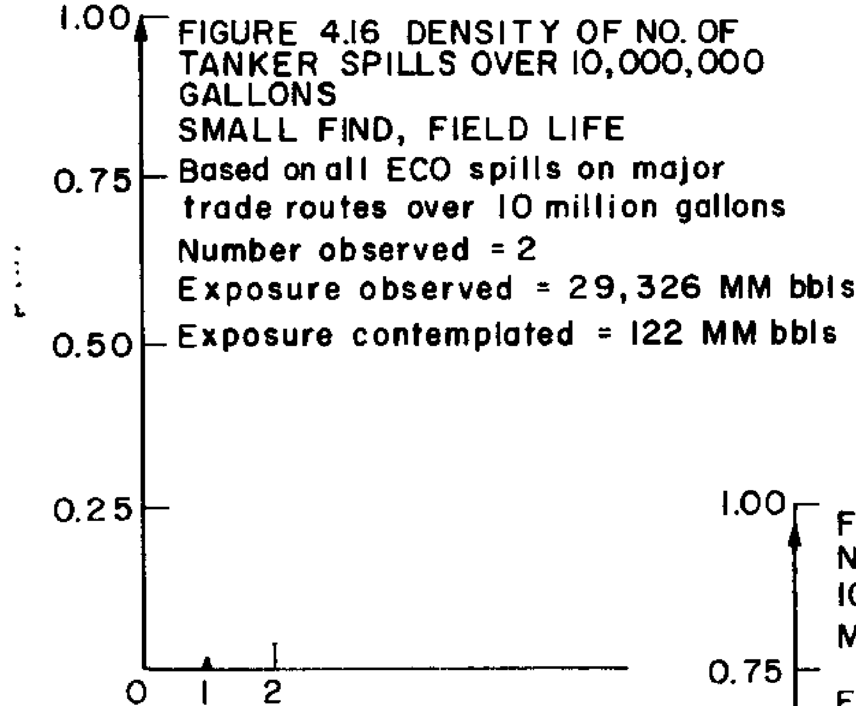

FIGURE 4.16 DENSITY OF NO. OF TANKER SPILLS OVER 10,000,000 GALLONS

SMALL FIND, FIELD LIFE

Based on all ECO spills on major trade routes over 10 million gallons

Number observed = 2

Exposure observed = 29,326 MM bbls

Exposure contemplated = 122 MM bbls

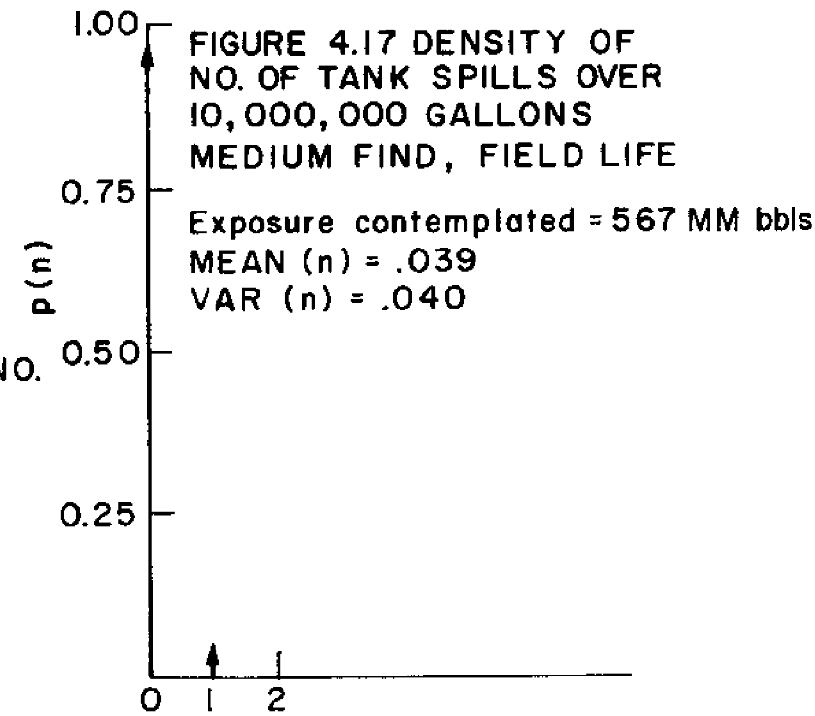

FIGURE 4.17 DENSITY OF NO. OF TANK SPILLS OVER 10,000,000 GALLONS

MEDIUM FIND, FIELD LIFE

Exposure contemplated = 567 MM bbls

MEAN (n) = .039

VAR (n) = .040

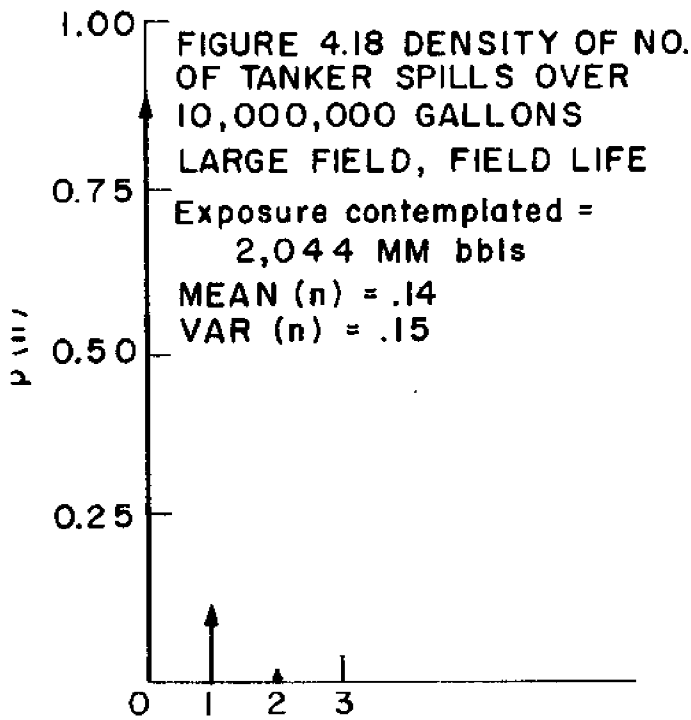

FIGURE 4.18 DENSITY OF NO. OF TANKER SPILLS OVER 10,000,000 GALLONS

LARGE FIELD, FIELD LIFE

Exposure contemplated = 2,044 MM bbls

MEAN (n) = .14

VAR (n) = .15

production year of a given find. This can be obtained by simply using the anticipated peak year production as the exposure contemplated value in the foregoing analysis.

Figures 4.19, 4.20, and 4.21 show the results for our small, medium, and large finds for the year of peak production.

From a biological point of view, the time between large spills may be at least as important as the number of such spills. Figure 4.22 shows the cumulative of the amount of oil handled between tanker spills, v. This density is a straightforward transformation of our earlier negative binomial.* This cumulative can in turn be put in terms of time for any period for which one knows the production rate. Figure 4.22 indicates the equivalent time between spills assuming the small find at peak production and the large find respectively. By reading up from the lower scales for any given time interval, one can find the probability that the time between successive spills will be less than the given interval. For example, assuming a small find at peak production, the probability that the time between successive tanker spills greater than 42,000 gallons will be less than 1 year is .15 while for a large field at peak production this probability

---

*The density of the "interarrival time" for a negative binomial process with parameters ν and τ is

$$f(v \mid \nu, \tau) = \nu\tau^{\nu}/(v + \tau)^{\nu+1}$$

The mean of this density is $\tau/(\nu - 1)$ and the variance is $\nu\tau^2/(\nu - 1)^2 \cdot (\nu - 2))$. This density quickly approaches the exponential for large ν.

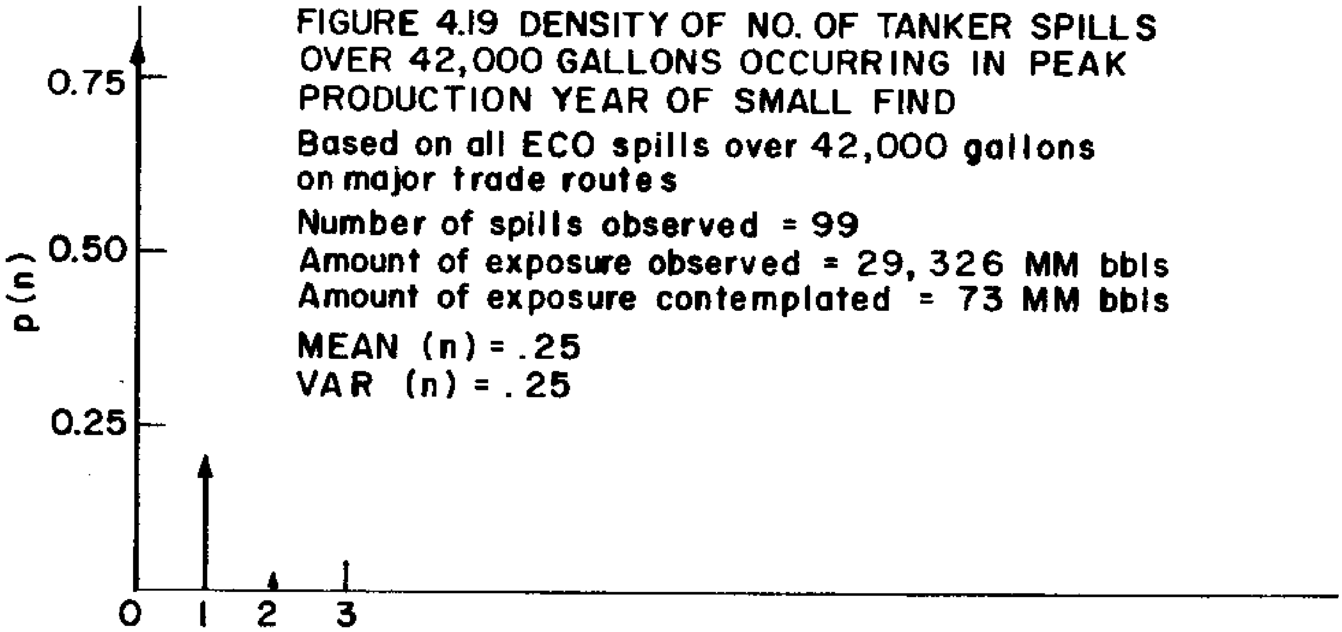

FIGURE 4.19 DENSITY OF NO. OF TANKER SPILLS OVER 42,000 GALLONS OCCURRING IN PEAK PRODUCTION YEAR OF SMALL FIND

Based on all ECO spills over 42,000 gallons on major trade routes

Number of spills observed = 99
Amount of exposure observed = 29,326 MM bbls
Amount of exposure contemplated = 73 MM bbls

MEAN (n) = .25
VAR (n) = .25

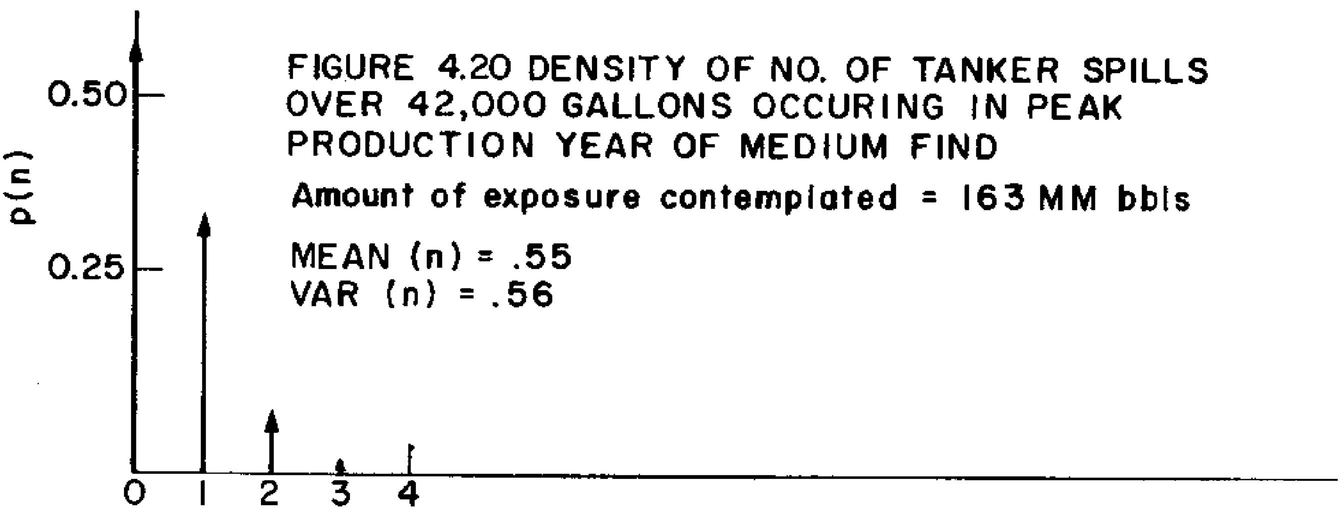

FIGURE 4.20 DENSITY OF NO. OF TANKER SPILLS OVER 42,000 GALLONS OCCURING IN PEAK PRODUCTION YEAR OF MEDIUM FIND

Amount of exposure contemplated = 163 MM bbls

MEAN (n) = .55
VAR (n) = .56

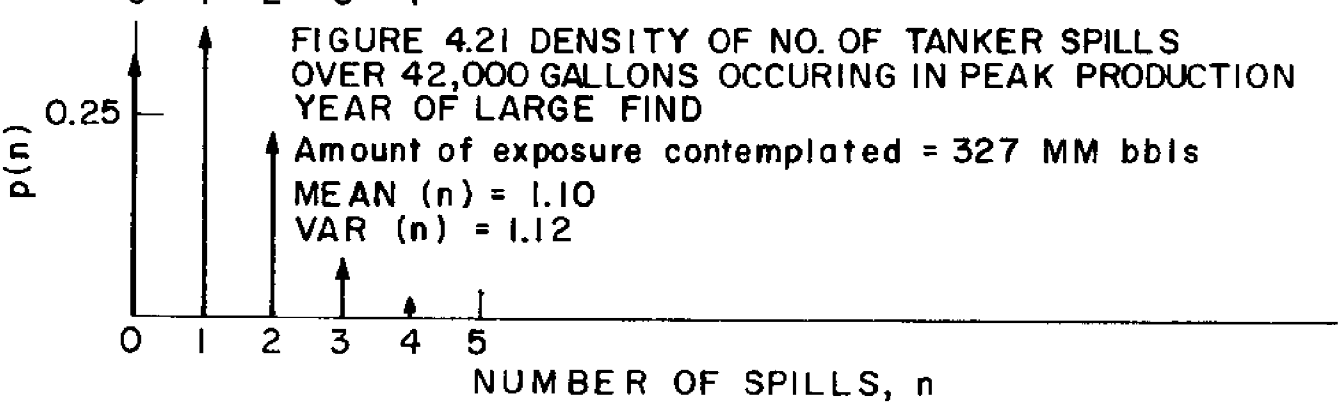

FIGURE 4.21 DENSITY OF NO. OF TANKER SPILLS OVER 42,000 GALLONS OCCURING IN PEAK PRODUCTION YEAR OF LARGE FIND

Amount of exposure contemplated = 327 MM bbls

MEAN (n) = 1.10
VAR (n) = 1.12

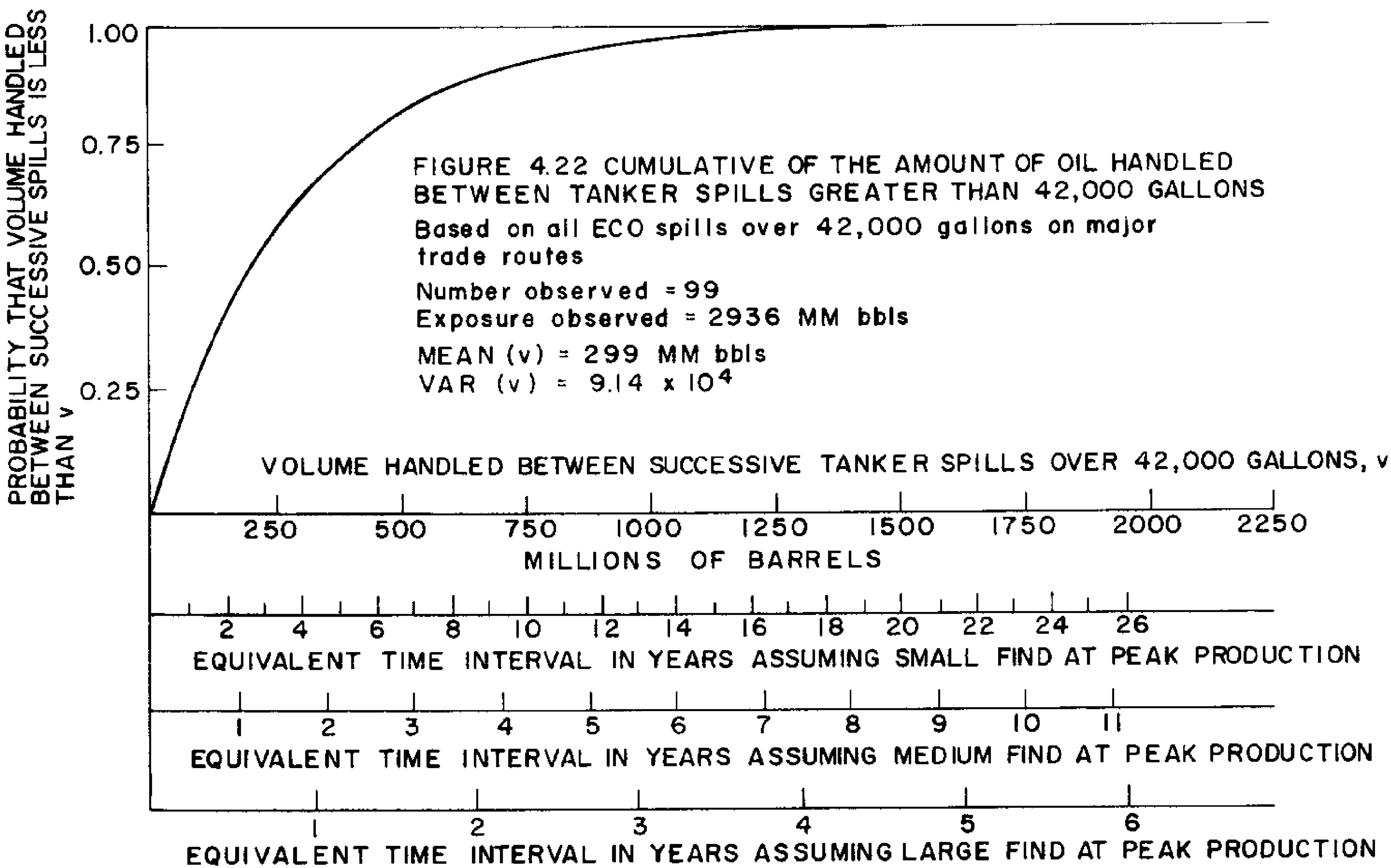

FIGURE 4.22 CUMULATIVE OF THE AMOUNT OF OIL HANDLED BETWEEN TANKER SPILLS GREATER THAN 42,000 GALLONS

Based on all ECO spills over 42,000 gallons on major trade routes

Number observed = 99

Exposure observed = 2936 MM bbls

MEAN (v) = 299 MM bbls

VAR (v) = 9.14×10^4

is .62. In using this graph, it is important to remember that in our hypothetical development, production remains near the peak for only a very few years.

Let us now turn to the problem of obtaining a density on the size of a large tanker spill given that a spill has occurred. As Section 3 argues, our assumptions imply that having observed m spills: $x_1, x_2, \ldots x_i, \ldots x_m$ where x_i is the quantity of the ith spill observed, then the density on size of the net spill, x, is given by

$$f(x) = \int_0^\infty \frac{p^{\rho-1} \, ((m+1)\rho)\, d\rho}{(\Gamma(\rho))^{m+1} s^{(m+1)\rho} S(s,p,m)}$$

where

m = number of spills observed

$s = \Sigma x_i$ = total amount of spillage observed

$p = \Pi x_i$ = product of all the spill quantities observed.

Figure 4.23 shows the cumulative of this density based on all ECO spills over 42,000 gallons. The mean is slightly over 2 million gallons, the mean squared is less than half the variance, indicating a widely dispersed distribution. And as the figure shows, the bulk of the probability is spread over three orders of magnitude ranging from 10,000 to 10 million gallons.

Before turning our attention to other spill categories, there are a few more qualitative insights we can glean from the ECO data.

1. There has been considerable discussion of the effect of vessel size on spillage - some holding that

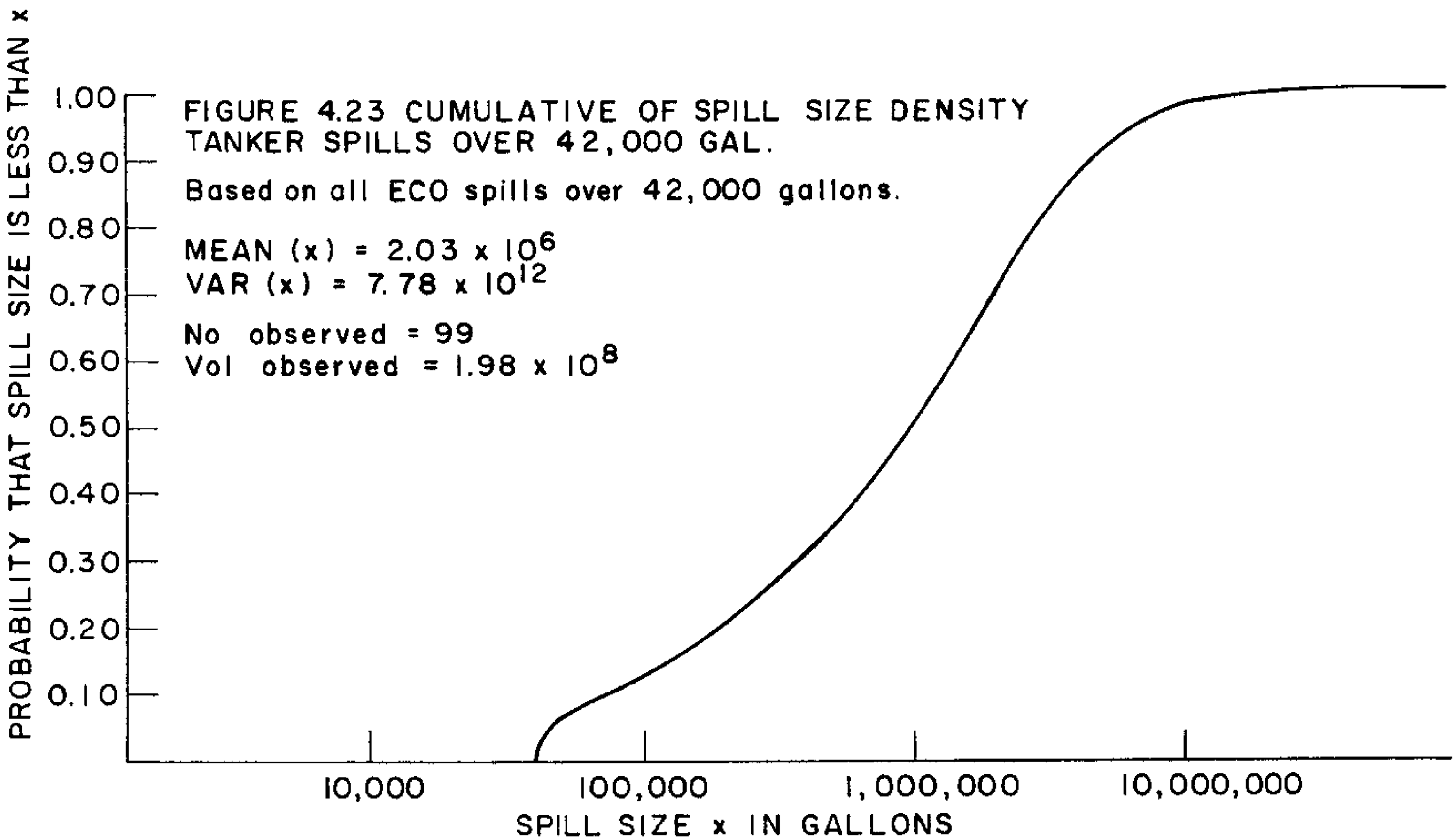

FIGURE 4.23 CUMULATIVE OF SPILL SIZE DENSITY TANKER SPILLS OVER 42,000 GAL.

increased vessel size will decrease spillage due to the smaller number of landfalls and economies of scale with respect to navigational equipment and crew training, others holding that larger vessels will exacerbate the problem due to poorer maneuverability and larger potential spill size. At least with respect to spill number, the ECO data comes down somewhat on the side of the large tankers, as indicated by Figure 4.24. Number of incidents per vessel-year appears to be only a weak function of size, and this figure is biased against the small ships in one sense, for small ships tend to trade on shorter route lengths and thus will make a good deal more landfalls in a year than a large ship. If number of landfalls is the best explanatory variable, then a comparison of spills per number of landfalls would be more meaningful, in which case the apparent superiority of the large ships in terms of incidents per vessel year in this diagram would undoubtedly disappear. On the other hand, a good portion of the incidents in the very large ship categories are explosion in the light conditions. If and when this problem is solved, the large ship's position would improve considerably. But the factor which tips the scales in favor of the large ships, as far as number of spills is concerned, is that even if the large ship

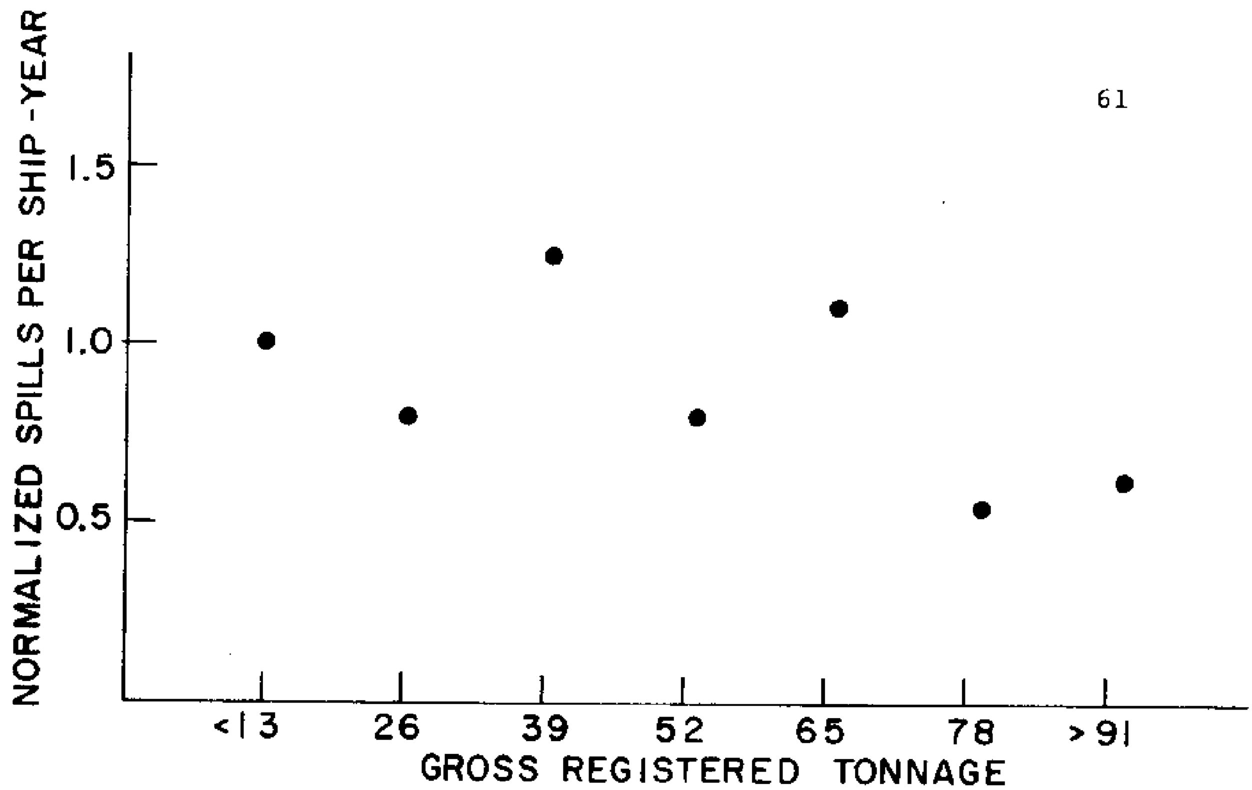

FIGURE 4.24 SPILL INCIDENCE AS A FUNCTION OF SHIP SIZE (NUMBER OF SPILLS PER SHIP-YEAR NORMALIZED RELATIVE TO SMALL TANKER EXPERIENCE)

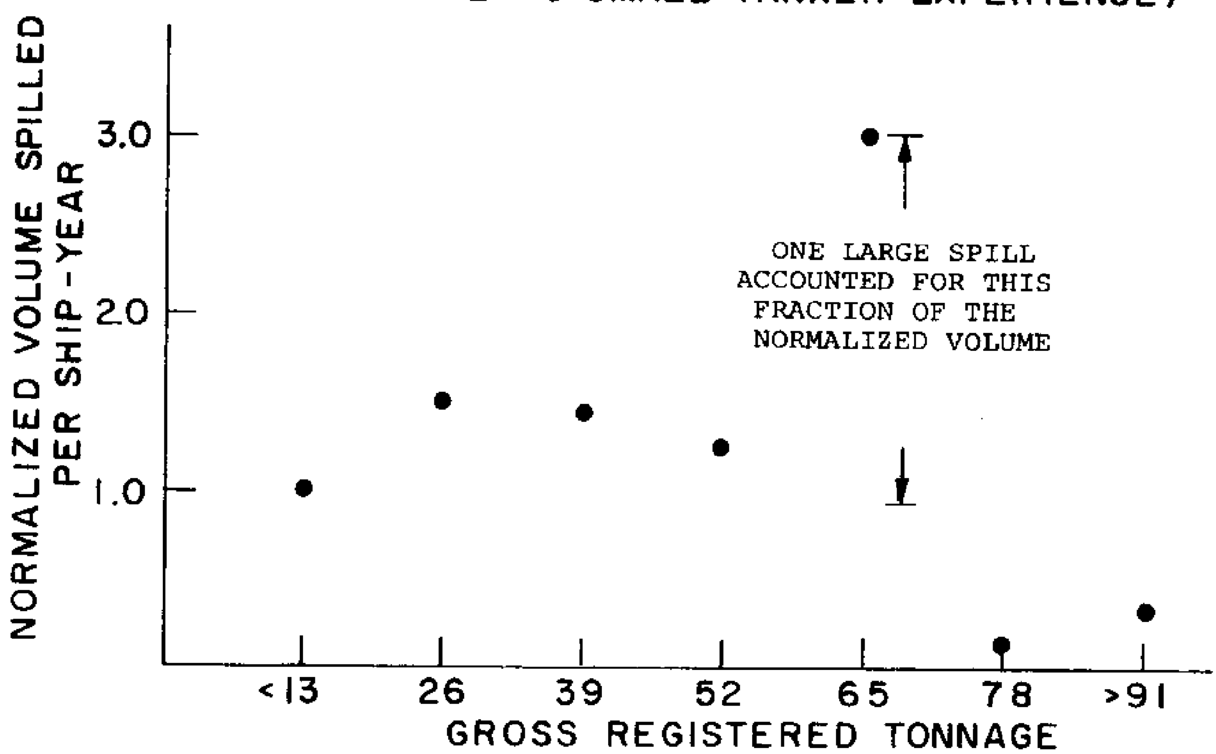

FIGURE 4.25 SPILL VOLUME AS A FUNCTION OF SHIP SIZE (TOTAL VOLUME SPILLED PER SHIP-YEAR BY SIZE CATEGORY NORMALIZED RELATIVE TO SMALL TANKER EXPERIENCE)

has about the same spill incidence in a year as the data indicates, in that year a large ship will be moving more oil than a small ship.

Grimes [13], in examining a sample of 13,379 tanker accidents (not spills) worldwide in the period 1959 through 1968, comes to somewhat similar conclusions. He finds that casualties per vessel remained almost constant over the period. He found that the stranding, collision, and fire rate for the tanker less than 20,000 tons was significantly higher than that of the rest of the population. The stranding rate for tankers over 50,000 tons showed no significant difference, the collision rate was somewhat lower (significant at 5%), and the fire rate was significantly high. The overall accident rate for tankers over 50,000 tons was very slightly lower than that of the rest of the population. Gaines's study did not discriminate between accidents causing spills and non-spill casualties.

2. Interestingly enough, Figure 4.25 together with Figure 4.24 indicate that the average size of the spills emanating from small ships is larger than the average size of spills resulting from big ships. However, factors other than size are probably determinant. As mentioned earlier, a significant portion of the large ship spills are tank explosions in the light condition involving a spill of only bunkers. On the other hand, many of the large small ship spills are structural failures which are almost certainly more a function of

ship age than size. Small ships tend to be considerably older than large ships. In short, we have not been able to identify any significant pattern which appears to be directly related to ship size and, therefore, have not derived densities by ship size.

This is perhaps unfortunate, for if there's one thing one can say with certainty about tanker spills, it is that the largest spill will be no greater than the vessel's displacement. Thus, changing vessel size will change the upper tail of the spill size density. But given the effect of tank explosions and, more importantly, vessel age, it would be misleading to attempt to analyse the change in the upper tail with the available data.*

3. It is of passing interest to examine the effect of time on large tanker spill incidence, Figure 4.26. As expected, there appears to be no strong relationship. This supports our working hypothesis that the process generating the occurrence of spills and spill size has been stable over the recent past. There may be a slight downtrend in

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*Also, slightly different analytical assumptions would be appropriate to analyzing this change. The Gamma process allows the possibility of a spill of infinite size, although it makes the probability of that spill astronomically small. For the purpose of representing the upper bound on spill size generated by vessel capacity, a different process, such as the Beta, where such a bound would appear explicitly, would be a better choice. Unfortunately, the conjugate prior for the Beta sampling process has not been derived as yet.

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incidence, especially as a proportion of total volume landed, but any such trend is overshadowed by the change in the dispersion between 1969-1970 and 1971-1972, for which we have no explanation.

A final comment on the ECO data. Two minor changes would improve the usefulness of this data base. One is that each spill be assigned to a trade route and two is a code which would indicate, for those spills occurring within the 50-mile limit, whether the spill occurred at the loading end of the voyage or the discharge end.

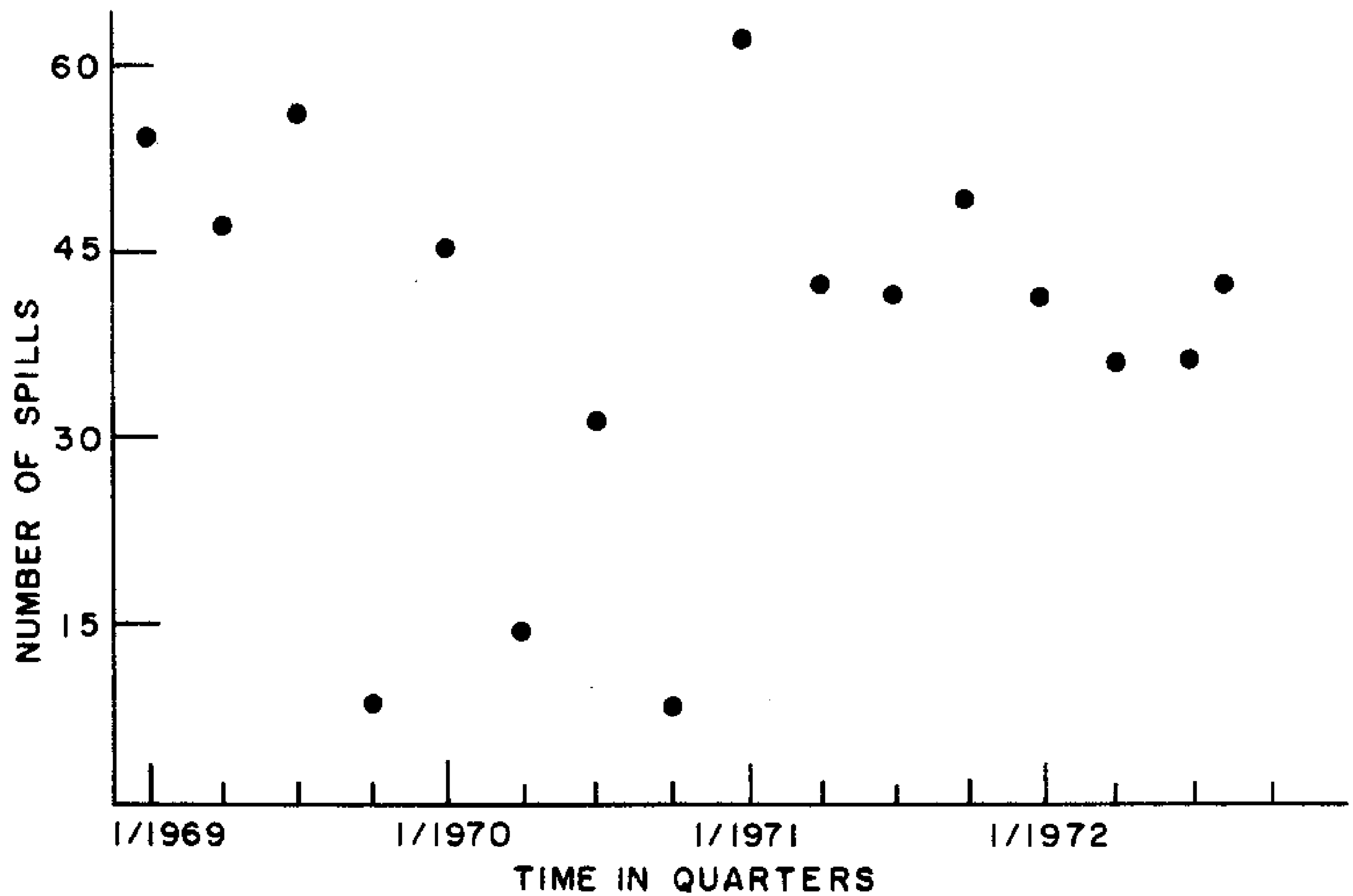

FIGURE 4.26 BREAKDOWN OF ECO SPILLS BY QUARTER OF OCCURRENCE

5. Vessel spills less than 42,000 gallons

As indicated earlier, the ECO data is not applicable to smaller operational spills, many of which occur during transfer operations in harbors. Therefore, in obtaining insight on these spills, we will use the Coast Guard 1971 and 1972 data. In 1971 and 1972 the Coast Guard reported 624 vessel-related, crude spills occurring within harbors. During that period, the U.S. imported 1.412 billion barrels of crude. Under the assumptions used earlier, that is, that we are dealing with a Poisson process in which the exposure variable is amount of oil landed whose intensity is a Gamma random variable about which we have no feelings prior to observing any data, likelihoods of the various possible numbers of spills are shown in Figures 5.1 , 5.2, and 5.3 for the small, medium, and large finds. In these figures, since we are dealing with much larger numbers of spills, instead of plotting the density itself, which would involve hundreds of arrows, we have shown the cumulatives of these densities. The cumulative is the probability for any given number of spills, n, that the actual number of spills will be less than or equal to n. It is merely the sum of all the arrows up to and including n. A glance at these three figures will indicate that with respect to near-terminal spills based on the Coast Guard data, we are dealing with much larger numbers than we obtained when we used the ECO data. However, most of these spills are relatively speaking much smaller than the spills in the ECO data. Figure 5.4 shows the cumulative of the spill size

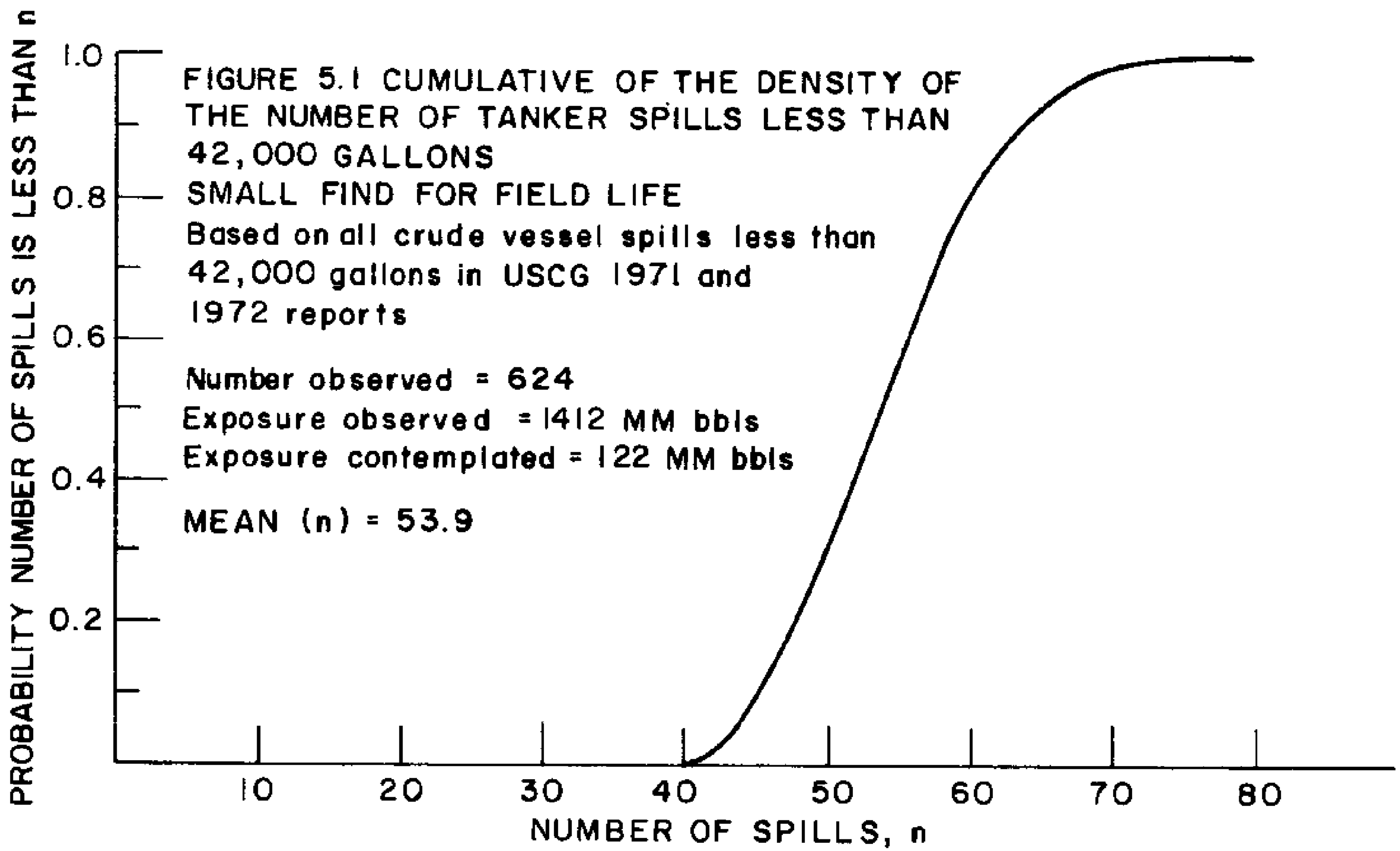

FIGURE 5.1 CUMULATIVE OF THE DENSITY OF THE NUMBER OF TANKER SPILLS LESS THAN 42,000 GALLONS
SMALL FIND FOR FIELD LIFE

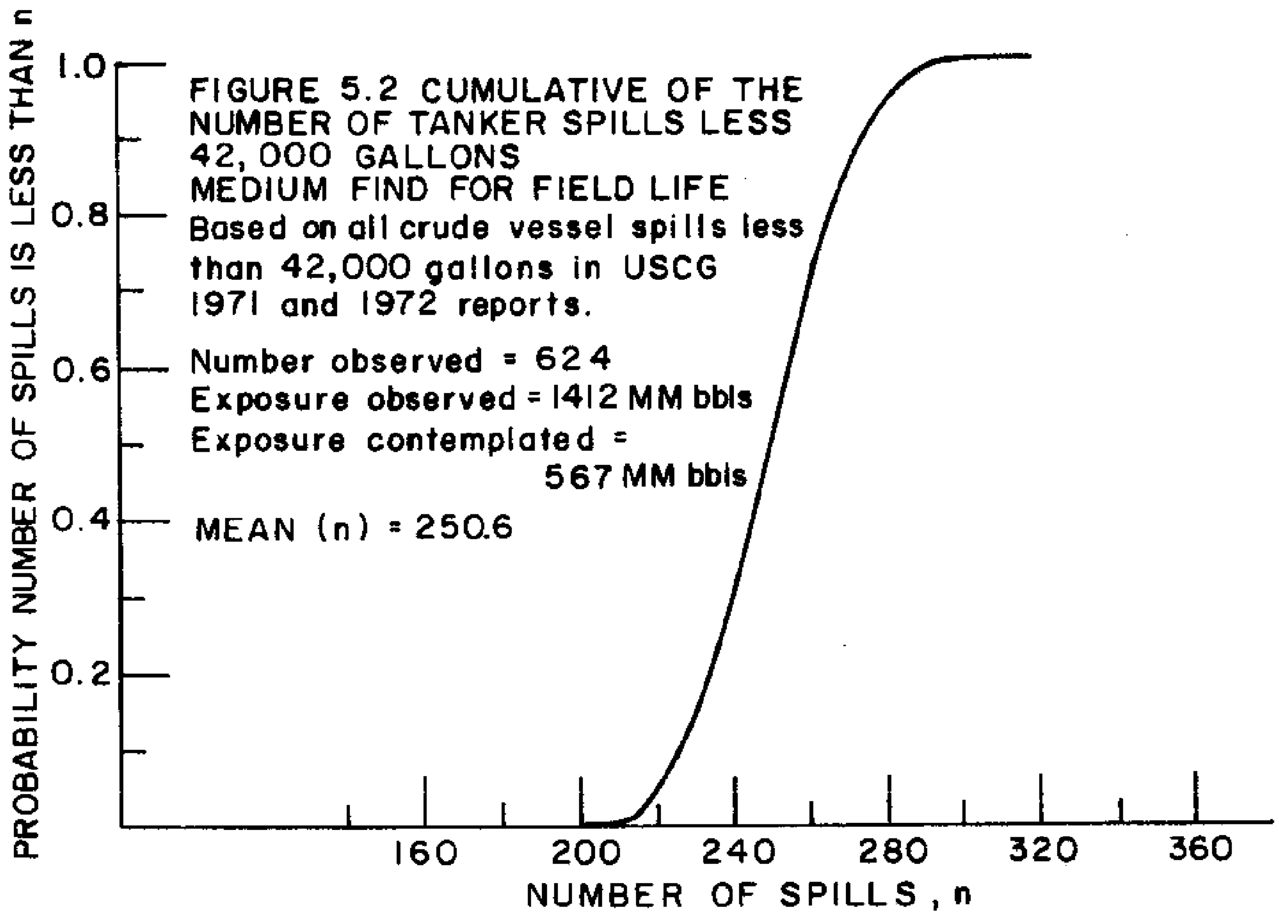

FIGURE 5.2 CUMULATIVE OF THE NUMBER OF TANKER SPILLS LESS 42,000 GALLONS MEDIUM FIND FOR FIELD LIFE

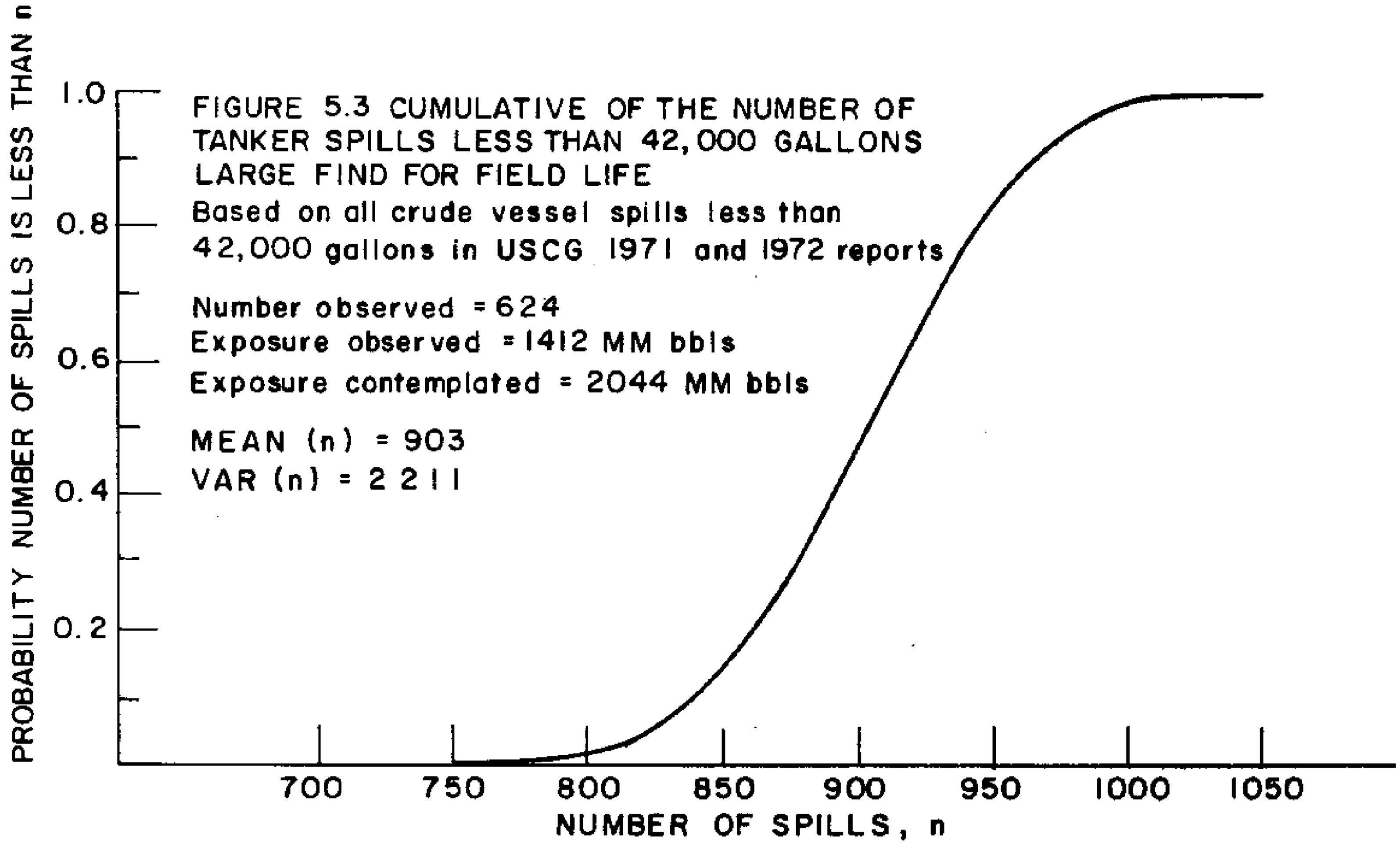

FIGURE 5.3 CUMULATIVE OF THE NUMBER OF TANKER SPILLS LESS THAN 42,000 GALLONS LARGE FIND FOR FIELD LIFE

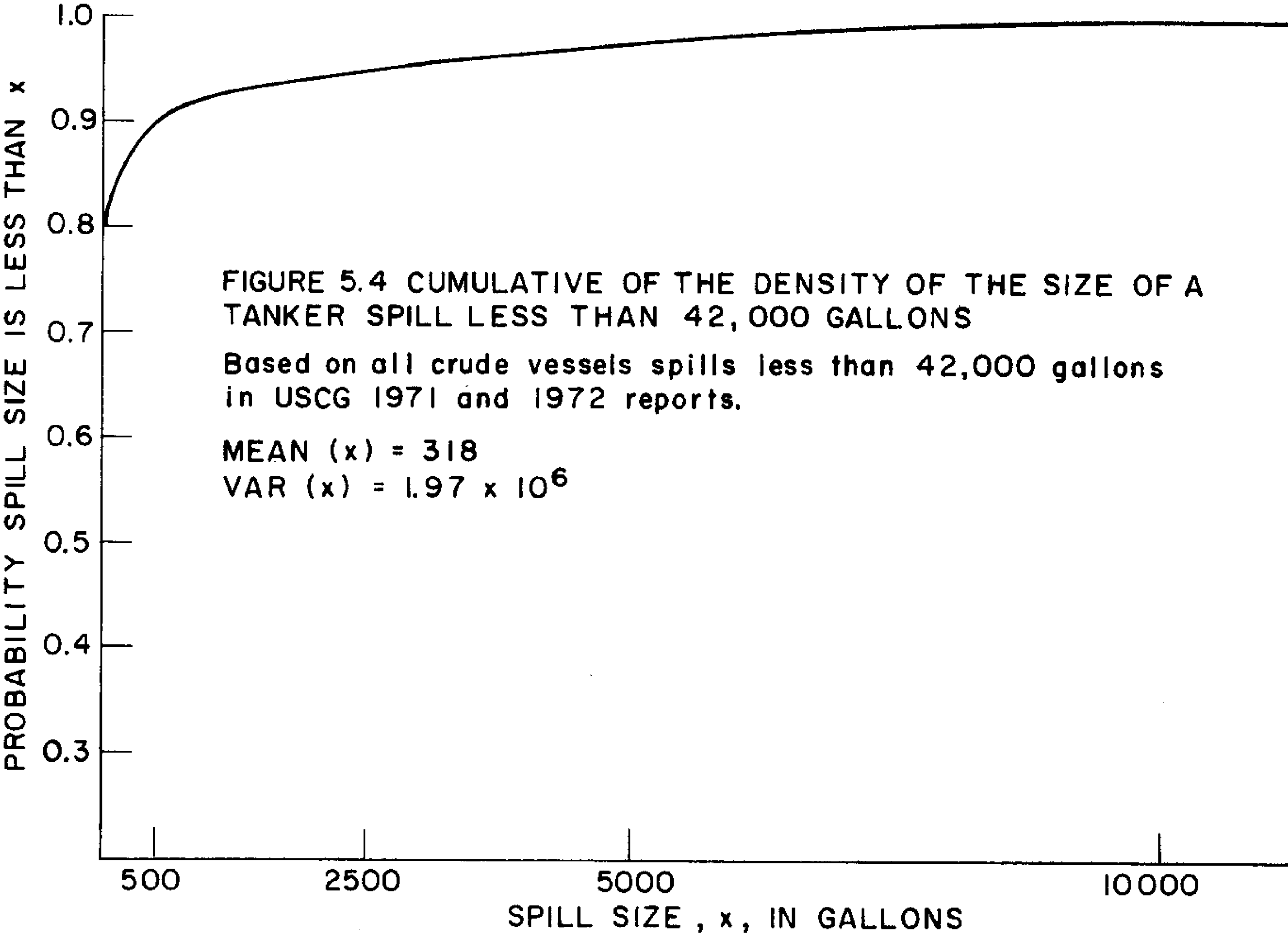

FIGURE 5.4 CUMULATIVE OF THE DENSITY OF THE SIZE OF A TANKER SPILL LESS THAN 42,000 GALLONS

Based on all crude vessels spills less than 42,000 gallons in USCG 1971 and 1972 reports.

MEAN (x) = 318
VAR (x) = 1.97×10^6

density. The mean of this density is 318 gallons while the variance is close to 2 million gallons squared. The ratio of the variance to the mean squared is close to 20, an extremely widely dispersed density. The only way the Gamma has of handling these extreme combinations of low mean and high variance is to place a great deal of the probability at the very low end, counterbalancing this by a very small amount of probability placed very far out in the rightward tail.* Hence the form of the cumulative shown in Figure 5.4, where the probability that the critical spill size will be less than the mean is about .87. This extreme skew may be trying to tell us that we should be modeling spill sizes by a multi-model density, for it does appear somewhat strange to place a significant amount of probability (about .05) in spills below 1 gallon, despite the fact that in the 624 tanker spills reported, no volumes less than 1 gallon were reported. This problem also shows up in numerical problems associated with the integration in the expression on the bottom of page 30. For this reason, in Figure 5.4 we have approximated the cumulative by a Gamma with the same mean and variance as the actual densities. The differences involved are not large.

The foregoing analysis was based on all tanker-barge spills of all types within harbors in the Coast Guard data. An issue of some importance in the context of Atlantic-Gulf of Alaska oil is the difference in spillage characteristics

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*The same thing is true of any other unimodal density over the interval $(0,\infty)$.

of single buoy moorings and fixed berths. To obtain some insight into this area, MIT and ECO Inc. undertook to obtain what data they could on SBM spillage. Unfortunately, data on past SBM spillage is hard to come by. There are no U.S. SBM installations. The excellent cooperation we have received from the industry in other areas simply has not been exhibited with respect to SBM spillage.

We have essentially three sets of data:

1. A sample of some 55 spills collected by ECO Inc. These spills are shown in Table 5.1.

2. A sample of some 200 spills made available to us by the Anglesey Defence Action Group. This is Shell Oil data which purports to cover all the spillage from Shell Oil SBM instllations through October 1971.* The data is summarized in Tables 5.2 and 5.3. The spillage reported in these tables is taken from submittals by Shell to the House of Lords during hearings concerning the large SBM installation which Shell is constructing off Anglesey [5]. During these hearings, Shell witnesses claimed these records are complete and that any spillage (defined to be oil reaching water) is fully recorded.

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*We asked for this data direct from Shell but received no response. We also made repeated requests to the SBM Forum, an industry organization to promote the transfer of information on single buoy mooring installations among users, to no avail.

TABLE 5.1

OFFSHORE TERMINAL SPILLS OBTAINED FROM SBM FORUM

Year Installed	Port	Type	Maximum Tanker Size	Spill Size, Gallons	Report Period	Cause
62	Brega	Fixed	100	33,600	62-72	Unloading arm
62	Brega	Fixed	100	21,000	62-72	Unloading arm
62	Brega	Fixed	100	8,400	62-72	Unloading arm
62	Brega	Fixed	100	16,800	62-72	Unloading arm
62	Brega	Fixed	100	4,200	62-72	
69	Brega	SALM	300	2,100	69-72	Hoses
70	Singapore	CALM	250		70-71	
71	Nakagusaku	SALM	250		71-72	
72	Botany Bay	SBM	80	1,260	72-72	Expansion piece
67	Huelva Bay	SBM	100	25,200	71-72	Mooring line and hose
67	Huelva Bay	SBM	100	420	71-72	Hoses
67	Huelva Bay	SBM	100	840	71-72	Hoses
67	Koshiba	SBM	100	21,000	67-72	Fishing vessel tore hoses
67	Koshiba	SBM	100	840	67-72	Hoses
67	Koshiba	SBM	100	420	67-72	Hoses
71	Tetney	SBM	210	25,200	71-72	Tanker hit buoy
71	Tetney	SBM	210	200	71-72	Hoses
71	Tetney	SBM	210	400	71-72	Hoses
70	Durban	SBM	220	8,400	71-72	Underbuoy hose
70	Durban	SBM	220	1,680	71-72	Hoses
70	Durban	SBM	220	420	71-72	Hoses
68	Wulsan	SBM	200	420	71-72	Hoses
68	Wulsan	SBM	200	630	71-72	Hoses
65	Gamba	SBM	90	420	67-72	Hoses
65	Gamba	SBM	90	6,300	67-72	Underbuoy hose
65	Gamba	SBM	90	200	67-72	Hoses
72	Porto Baleo	SBM	100		72-72	
72	Porto Baleo	SBM	250		72-72	
66	Wulsan	SBM	75	840	70-72	Hoses
66	Wulsan	SBM	75	600	70-72	Hoses

TABLE 5.1--Continued.

Year Installed	Port	Type	Maximum Tanker Size	Spill Size, Gallons	Report Period	Cause
65	Chiba	SBM	120	2,520	70-72	Buoy chain
65	Chiba	SBM	120	400	70-72	Hoses
65	Chiba	SBM	120	600	70-72	Hoses
68	Kawasaki	SBM	260	2,100	70-72	Buoy hit by vessel
68	Kawasaki	SBM	260	840	70-72	Hoses
68	Kawasaki	SBM	260	200	70-72	Hoses
71	Java	SBM	80	1,050	71-72	Swivel seals
71	Java	SBM	80	400	71-72	Swivel seals
72	Java	SBM	140		72-72	
63	Port Dickson	SBM	100	7,140	70-72	Hoses
63	Port Dickson	SBM	100	400	70-72	Hoses
63	Port Dickson	SBM	100	200	70-72	Hoses
63	Port Dickson	SBM	100	800	70-72	Hoses
64	Miri	SBM	65	400	70-72	SBM hose connection
64	Miri	SBM	65	600	70-72	Hoses
71	Seria	SBM	250		71-72	
67	Subic Bay	SBM	108	400	70-72	Valves
67	Subic Bay	SBM	108	1,000	70-72	Hoses
70	Saint John	SBM	350	200	70-72	Chafed underbuoy hose
70	Saint John	SBM	350	400	70-72	Chafed underbuoy hose
70	Saint John	SBM	350	200	70-72	Chafed underbuoy hose

TABLE 5.2

SHELL DATA: DISCHARGE SBM'S
1 OCTOBER 1971

Location	No of SBM's	Yrs	<150 Gal.	150-1500 Gal.	1500-9000 Gal.	>9000 Gal.	Reported Total Gallons	No of Ship Calls	Tons Handled x 10^{-6}
Yokkaichi	2	6	8	0	0	0	-	514	50.5
Niigata	1	5	15	0	0	0	210	104	6.6
Port Dickson	1	8	0	2	1	0	9,750	583	24.5
Kawasaki	1	3	24	0	0	0	-	194	21.9
Durban	1	1	13	5	5	0	-	91	7.4
Durban (thru 3/72)			16	5	5	0	17,100	111	9.3
Totals thru 10/71			60	12	11	0	27,060	1,486	111.1

TABLE 5.3

SHELL DATA: LOADING SBM'S
1 OCTOBER 1971

Location	No of SBM's	Yrs.	<150 Gal.	150-1500 Gal.	1500-9000 Gal.	>9000 Gal.	Reported Total Gallons	No of Ship Calls	Tons Handled $x\ 10^{-6}$
Gamba	1	4-7/12	0	12	3	8	1,856,000	303	11.4
Forcados	2	2	0	0	7	16	269,700	533	36.1
Mina-al-Fahal, Muscat	3	4	4	3	1	1	18,560	1,676	63.4
Halul Island, Qatar	1	9-7/12	7	0	2	0	11,600	816	43.7
Miri, Sarawak	3	10	15	11	8	10	335,530	2,250	36.1
Totals thru 10/71			26	26	21	35	2,491,000	5,578	196.7

3. A submittal from Exxon covering four of their installations. This data is summarized in Table 5.4.

The Exxon data suffers from the fact that spill incidence is not reported. The ECO data is incomplete, as can be seen by comparing the ECO Durban spills with the Shell data. Therefore, it appears that the best data we have is the Shell information received via Anglesey.

Shell witnesses at the House of Lords hearings maintained that the data for the loading ports is not relevant to unloading ports. Loading ports generally employ higher pressures (200-500 psi vs. 120-150 psi). Also, there's less valving in ship-to-shore operations due to the larger reception tank sizes. Valve operations onshore are usually more highly automated than those on board ships. Finally, tank overflows in ship-to-shore operations are much more easily contained than in operations where the vessel is the receptor. And the data indicates that loading installations do have rather different characteristics than unloading. From the point of view of volume, the record of the loading terminals is much worse than that of the discharge terminals. Gamba has the worst record. The largest spill was 3,400 tons which flowed for 4.5 hours.

At Forcados, the three largest spills were put at 350, 300, and 281 tons respectively. This terminal is 12 miles offshore and Shell blames communications problems from ship

TABLE 5.4

EXXON SUBMITTAL ON OFFSHORE TERMINAL SPILLS

Year Installed	Country	Type	Port	Maximum Vessel Size (DWT)	Total Tankers Handled	Total Throughput (Bbls)	Reported Spills (Gals)
1962	Libya	Fixed	Brega	100,000	2,300+	1,100,000,000	Approx. 84,000
1969	Libya	SALM	Brega	300,000			
1970	Singapore	CALM	Singapore	250,000	57	66,000,000	None reported*
1971	Okinawa	SALM	Nakagusuku Bay	250,000	19	23,000,000	None reported*
TOTALS					2,376+	1,189,000,000	Approx. 84,000

Data collected through 31 January 1973.

*Spills over 42 gallons would be reported.

to shore for these spills. At Mina-Al-Fahal in Muscat, the largest spill is placed at 36 tons. This was due to pumping to an unoccupied SBM and blowing out the hose. The next two spills are 20 tons (failure of an SBM bellowspiece), and 8 tons. At Halul Island off Qatar, the two largest spills are placed at 20 tons each. There is some conflict here within the testimony. One witness puts the total number of spills at Halul at 34, while the table says 9. At Miri, Sarawak, the largest spills were put at 375, 231, 183, 179, 75, 53, and 51 tons. They were all blamed on corrosion of pre-war-laid underwater pipeline.

The reported totals are 108 spills and 8,600 tons out of 5,578 calls and 196 million tons handled, or 1 spill for every 50 ships and an average reported spillage rate of 4.3×10^{-5}.

Interestingly enough, despite all the reasons why one would expect spillage to be more frequent in shore-to-ship operations than ship-to-shore, the discharge ports report a considerably higher frequency of spills than the loading ports. (Most loading ports are in countries where there is little or no non-company monitoring of spillage.) The totals for the discharge terminals are 89 tons and 99 spills out of 111 million tons landed and 1,486 calls, or about 1 spill every 15 ship calls and a reported average spillage rate of 8.9×10^{-7}. All the spill sizes in the discharge table were estimated from the slick size and thus are subject to a number of errors and biases.

The worst record is Durban, South Africa, which through 1971 reported about 1 spill every 5 ship calls and a reported average spillage rate of 5.9×10^{-6}. Shell claims Durban is a special case due to an unusually sharp vertical current gradient and generally rough water. Nonetheless, it is of interest to study the Durban spills in some detail (see Table 5.5). The largest spill, estimated at 4,400 gal, was caused by a deck line being blown out of an expansion point when a butterfly valve used to control hose drips during disconnect closed during pumping. The next largest, 3,000 gal, was caused by mooring lines parting during a squall, breaking the hoses. Another 3,000 gallon spill was caused by a collision with the buoy. A large number of the other spills are blamed on manufacturing defects in the hoses. It may be possible to eliminate some of these causes. Shell claims that redesign of the buoy makes penetration of the tanker hull in a collision much more unlikely. Several manufacturers now offer self-sealing disconnect devices. Nonetheless, it appears that an upper bound on discharge buoy operations is the Durban experience--1 spill every 5 ship calls with spill sizes ranging up to about 3,000 gal. A lower bound, using 1970-1971 technology, can be obtained by accepting the non-Durban data at face value, which would indicate a mean rate of 1 spill every 30 ship calls.

It is of some interest to compare this experience with shoreline fixed berth history. Our best data in this regard is the Milford Haven experience. Milford Haven is a modern, well-run, large-volume fixed berth complex in whose reporting

TABLE 5.5

LISTING OF FIRST 23 DURBAN SPILLS

	Date	Amount	Time to Discovery (minutes)	Cause
1	21.9.70	20	10	Bolts on 16" blind flange loosened
2	29.9.70	250	nil	Tanker hull leak, no. 5 port wing tank
3	30.9.70	85	5	Underwater hose leak, manufacturer's defect
4	4.10.70	6	nil	Spill from hose end during connect operation
5	10.10.70	1	nil	Underwater hose leak, manufacturer's defect
6	11.10.70	20	nil	Tanker ballast discharge valve leaking
7	18.11.70	1,470	nil	Floating hose rupture at buoy, manufacturer's defect
8	12.12.70	2,940	nil	Hull leak due to contact with SBM ballast box
9	22.12.70	42	nil	Underwater hose nipple, manufacturer's defect
10	3.1.71	24	5	Tanker "World Friendship" overboard discharge
11	31.1.71	85	5	Tanker "World Friendship" overboard discharge
12	6.2.71	4,410	nil	Butterfly valve shut against ship pumps blowing 24" deckline out of expansion joint
13	16.2.71	2,940	nil	Both end hoses parted when mooring lines broke in 40 knot squall, light condition
14	17.2.71	20	nil	During repair due to spill 13
15	18.2.71	20	nil	During repair due to spill 13
16	27.3.71	20	nil	Hose connection during heavy rain
17	31.3.71	880	nil	Floating hose nipple blew during discharge
18	6.5.71	1	5	Tanker hull leak, no. 2 port wing tank
19	15.5.71	20	5	Main sea valve leak, port pumproom
20	22.5.71	1,470	2	Main sea valve leak
21	14.6.71	620	nil	Tanker overflow from no. 3 starboard tank during discharge
22	11.7.71	72	nil	Tanker overflow from no. 1 port wing tank during discharge
23	24.10.71	600	nil	Floating hose rupture, ship end. Manufacturer's defect

we have some confidence. Milford Haven had been averaging one spill for about every 60 ship calls and an average spillage rate through 1972 of 1.8×10^{-6}.

In general, one would expect more small operational spills from an SBM operation than a shoreside fixed berth operation. The SBM has essentially all the operational causes that a fixed berth has plus ship motion, two sets of flexible hoses subject to wave action, and the possible loss of mooring. Therefore, as a beginning point, it might be reasonable to assume that you will have something better than twice the number of small operational spills from an SBM as from a fixed berth for the same number of ship calls.

From the data, theredoesn't appear to be much difference in the size of operational SBM spills and fixed berth spills. The average of the Milford Haven spills is in the neighborhood of 300 gallons, the average of the Shell discharge spills, about 300 gallons. We are more than a bit leery of comparing reported small spill volumes, and the same factors that tend to cause more small spills would seem to also tend to make these spills somewhat larger, but from the data it is impossible to distinguish any significant differences in small spill size.

In summary, with respect to operational unloading spills and based on data which on the SBM side is uncomfortably scarce and possibly lacking in quality, the number of small spills can be expected to be several times that of a well-run fixed berth, but we are unable from the data to say that the resulting spills will be significantly different in size from those occurring at a fixed berth.

Statements about loading operations are much more difficult to make. Accepting the Shell arguments, it appears that their loading data does not include a very large portion of smaller spills. It may well include most of the volume. However, most of the volume appears to have been caused by what could easily be termed gross negligence and we would expect better performance at an installation off the U.S. coast. A ballpark estimate of the spillage might be to use the Durban data. Under this assumption and once again reverting to the assumption that the relevant exposure variable is volume handled, the densities of the number of spills at SBM's for the small, medium, and large finds are shown in Figures 5.5, 5.6, and 5.7. They imply fairly large numbers of spills. However, these densities should not be given much weight. The simple truth is that we have no trustworthy data on SBM loading terminals operating under conditions comparable to the U.S. continental shelf.

With respect to large spills associated with ramming, grounding or collision, the SBM <u>may</u> have a distinct advantage over an equivalent shoreside facility. Ramming (hitting a berth) appears to be a very unlikely cause of large spills. No spills over 1000 barrels in the ECO data are attributed to ramming. Nonetheless, it is to the SBM's credit that it is possible to ram the berth with little or no spillage. At the Anglesey Hearings, a Shell witness stated that the Humber SBM had been rammed by a tanker on approach, with substantial damage to the buoy in mooring system, but no oil spillage, due in part to the hoses had been filled with sea water as far as the subsurface check valve.

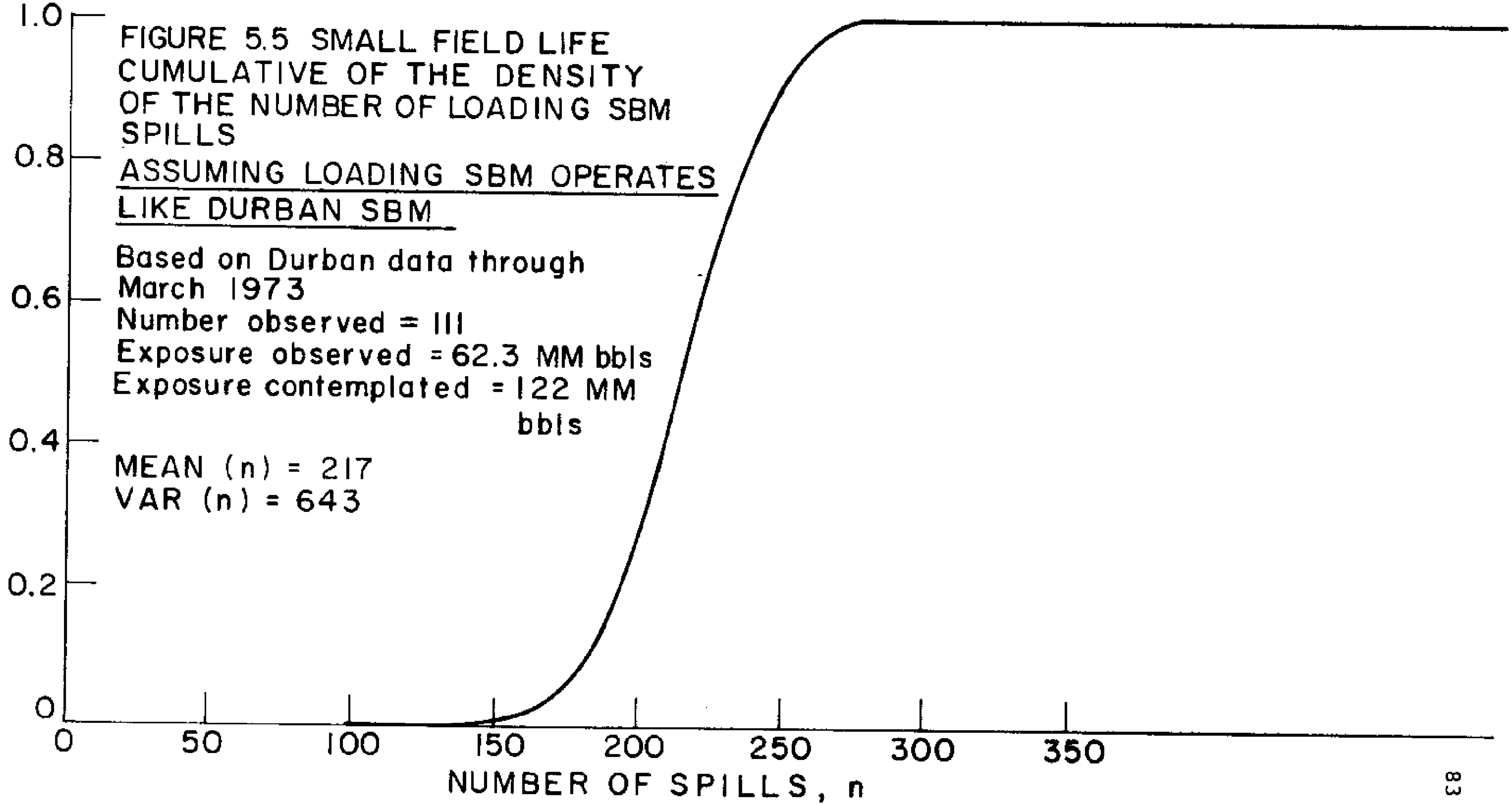

FIGURE 5.5 SMALL FIELD LIFE CUMULATIVE OF THE DENSITY OF THE NUMBER OF LOADING SBM SPILLS

<u>ASSUMING LOADING SBM OPERATES LIKE DURBAN SBM</u>

Based on Durban data through March 1973
Number observed = 111
Exposure observed = 62.3 MM bbls
Exposure contemplated = 122 MM bbls

MEAN (n) = 217
VAR (n) = 643

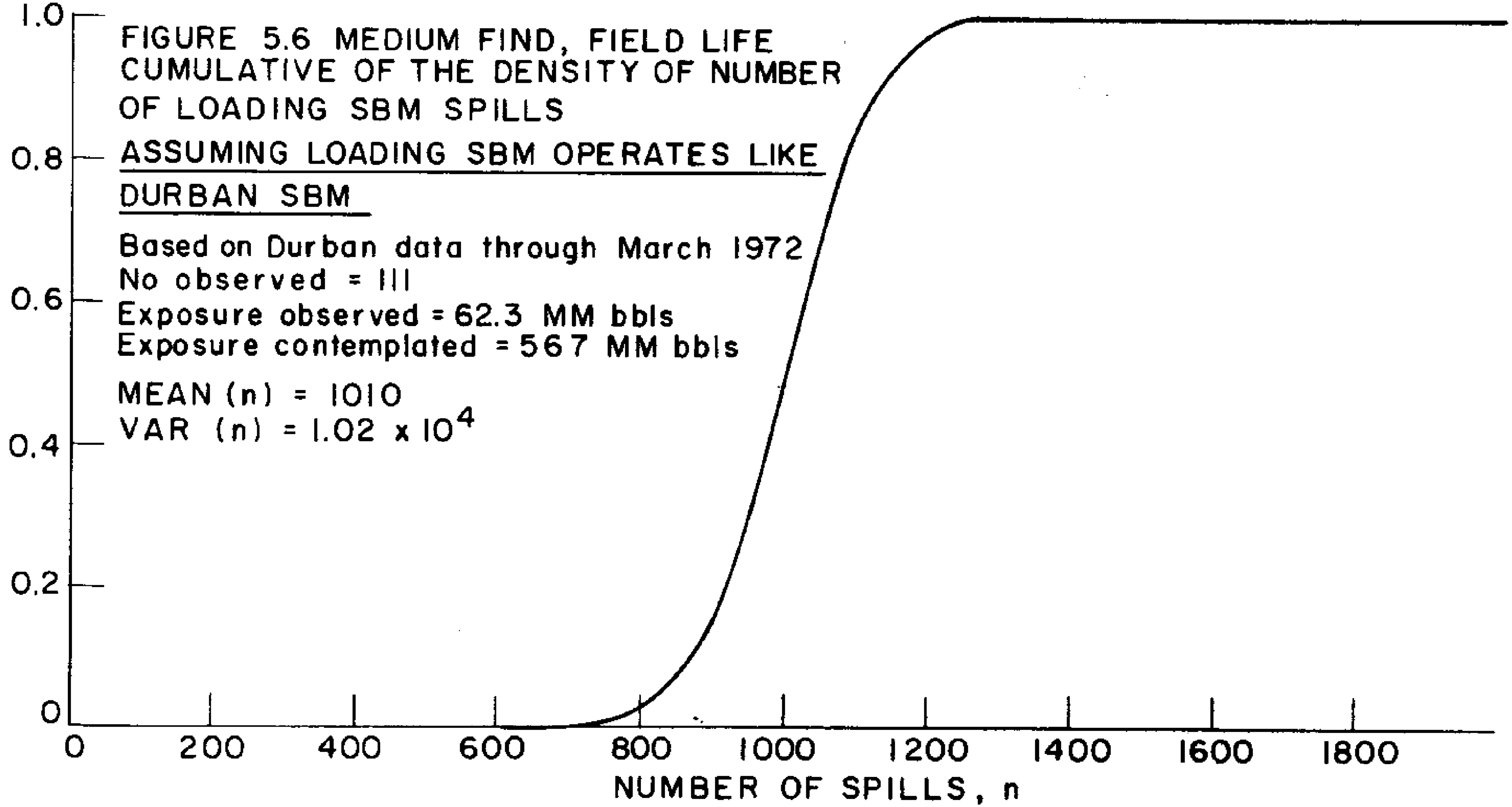

FIGURE 5.6 MEDIUM FIND, FIELD LIFE CUMULATIVE OF THE DENSITY OF NUMBER OF LOADING SBM SPILLS

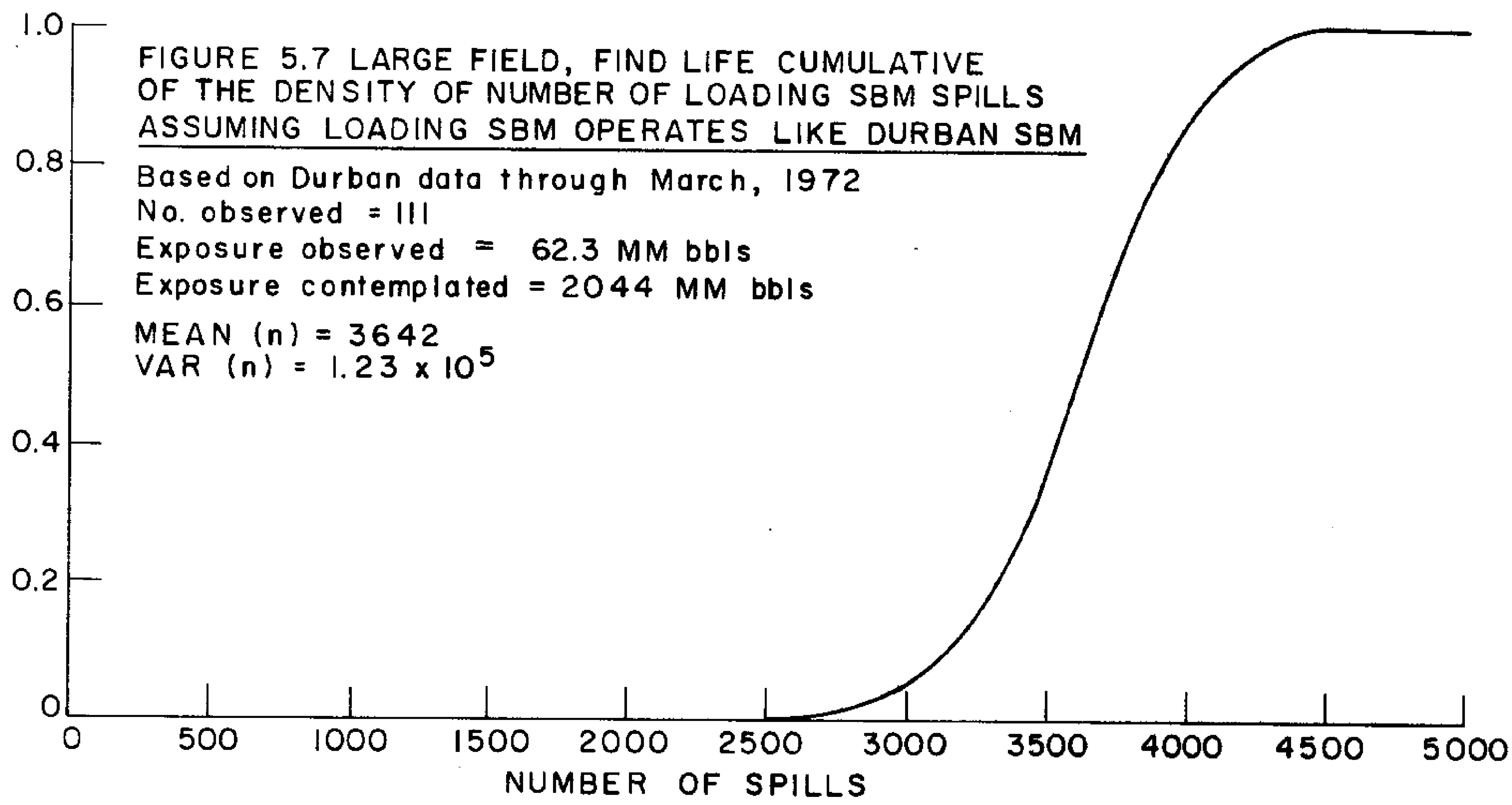

FIGURE 5.7 LARGE FIELD, FIND LIFE CUMULATIVE OF THE DENSITY OF NUMBER OF LOADING SBM SPILLS ASSUMING LOADING SBM OPERATES LIKE DURBAN SBM

Based on Durban data through March, 1972
No. observed = 111
Exposure observed = 62.3 MM bbls
Exposure contemplated = 2044 MM bbls

MEAN (n) = 3642
VAR (n) = 1.23×10^5

Of more importance to the SBM is the possible reduction of large tanker spills associated with grounding, and possibly very nearshore collisions. In the ECO data, groundings accounted for 28% of all the spills and about 25% of all the spillage. Almost all this grounding spillage was put in the harbor or entranceway category, that is, inside the sea buoy. Of this grounding spillage, 19%, or 5% overall, took place within the harbor, the remainder in the approaches. Depending on location, an SBM might be expected to reduce the probabilities of a portion of this spillage relative to those associated with an equivalent shoreside facility, either through reduction of the number of landfalls or through the fact that the tankers need not approach closer to land than the SBM's.

Obviously, any such reduction in spillage would be extremely site-dependent; witness the Conoco Brittania spill in which a tanker overshot the Humber SBM, dropped an anchor in an attempt to check its process, went aground, overriding the anchor which holed a tank, resulting in a large spill. But an offshore SBM might be expected to reduce the mean frequency of large spills by 5% to 25% over that of equivalent shoreside facilities, depending on location.

In summary, SBM's appear to have considerably higher incidence of small operational spills than well-run fixed berths in protected waters per ship call. However, it is quite possible the SBM may decrease the total volume spilled relative to fixed shoreside berths by decreasing the number of ship calls and increasing the minimum distance to shore.

Finally, our spill-tracking analysis [9] indicates that at least in certain locations, e.g. middle of Delaware Bay, SBM terminal spills would require a day or more to reach land, which has some advantages both biologically and with respect to the response time available to containment and cleanup systems.

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6. Offshore production spills greater than 42,000 gallons

Table 6.1 lists all spills larger than 42,000 gallons emanating from offshore platforms and pipelines in the period 1964 through 1972 of which we are aware.*

To obtain spill frequency and spill volume densities from this data, we will make the same assumptions used earlier in our analysis of tanker spills, including the assumption that the exposure variable in the Poisson process is volume of oil landed. We will do this despite the fact that we have been unable to make a quantitative check on this assumption as we did with tankers. The sample of large spills is simply too small for any test to have any discriminating power. For now, we will simply accept volume landed as the exposure variable as a working hypothesis. and although other variables such as number of flowing wells, number of platforms may be at least as good.

Under these assumptions, the densities of the number of platform spills greater than 42,000 gallons for the small, large, and medium find for field life are given in Figures 6.1, 6.2, and 6.3. For the large find, the mean number of such spills is about 4.7 and there is about a 90% chance we will have at least two spills and an 80% chance we will have less than six spills. Remember the amount of oil which the Offshore Development Model estimates will be landed from this find is a little over 2 billion barrels, which is about 50% of all the oil which was produced by U.S. offshore fields in the period 1964 through 1972. For the medium find hypothesis,

*There were several large platform spills prior to 1964 but no quantity data is available.

LOCATION	CAUSE	REPORTED AMOUNT	DATE
OFFSHORE PIPELINES			
LA, West Delta	Anchor dragging	6,600,000	15.10.67
Persian Gulf	Break	4,000,000	20.4.70
LA, coastal channel	Hit by tug prop	1,050,000	18.10.70
Chevron MP 299	Unknown	310,000	11.2.69
LA, Gulf ST 131	Anchor dragging	250,000	12.3.68
LA, coastal channel	Equipment failure	160,000	12.12.72
LA, coastal waters	Leak	155,000	17.3.71
TX, coastal channel	Leak	42,000	30.11.71
LA, coastal channel	Leak	42,000	28.9.71
OFFSHORE PLATFORMS			
Union "A", Santa Barbara	Blowout	3,250,000	28.1.69
LA, Shell ST 26 "B"	Fire	2,200,000	1.12.70
LA, Chevron MP 41 "C"	Fire	1,300,000	10.3.70
LA, MP Gathering net and storage	Storm	512,000	17.8.69
Signal SS 149 "B"	Hurricane	210,000	3.10.64
Platform, 15 mi offshore	-	168,000	20.7172
Continental EI 208 "A"	Collision	108,000	8.4.64
Mobil SS 72	Storm	105,000	16.3.69
Tennico SS 198 "A"	Hurricane	67,000	3.10.64

TABLE 6.1

KNOWN SPILLS OVER 42,000 GALLONS EMANATING FROM

OFFSHORE PRODUCTION FACILITIES THROUGH 1972

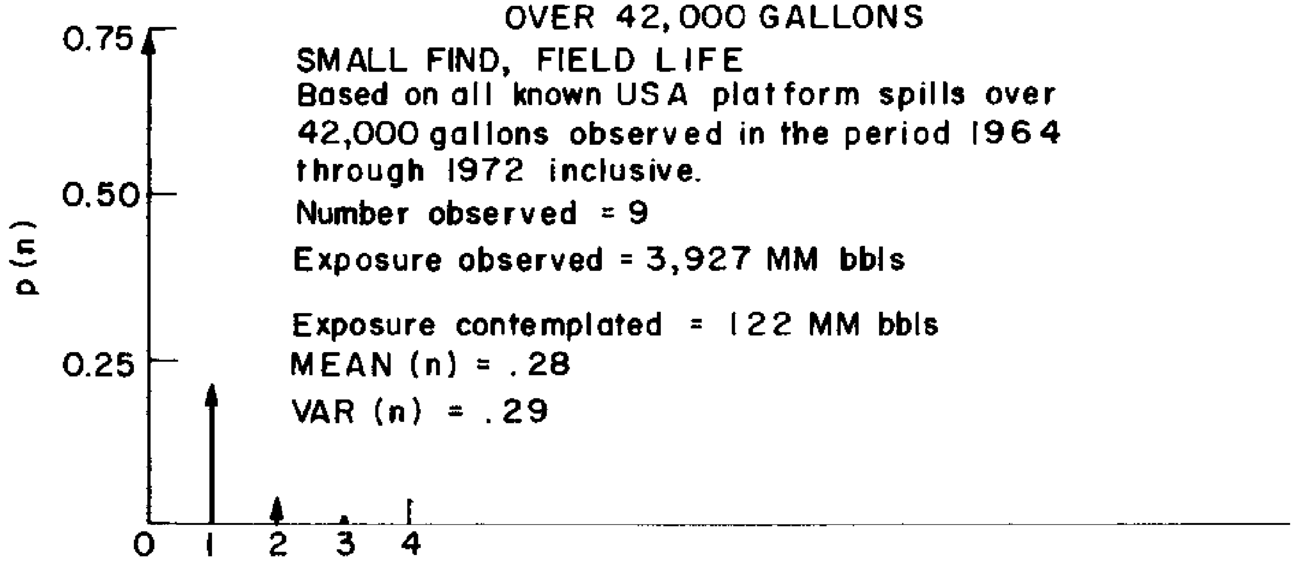


FIGURE 6.1 DENSITY OF NO. OF PLATFORM SPILLS OVER 42,000 GALLONS

SMALL FIND, FIELD LIFE

Based on all known USA platform spills over 42,000 gallons observed in the period 1964 through 1972 inclusive.

Number observed = 9

Exposure observed = 3,927 MM bbls

Exposure contemplated = 122 MM bbls

MEAN (n) = .28

VAR (n) = .29

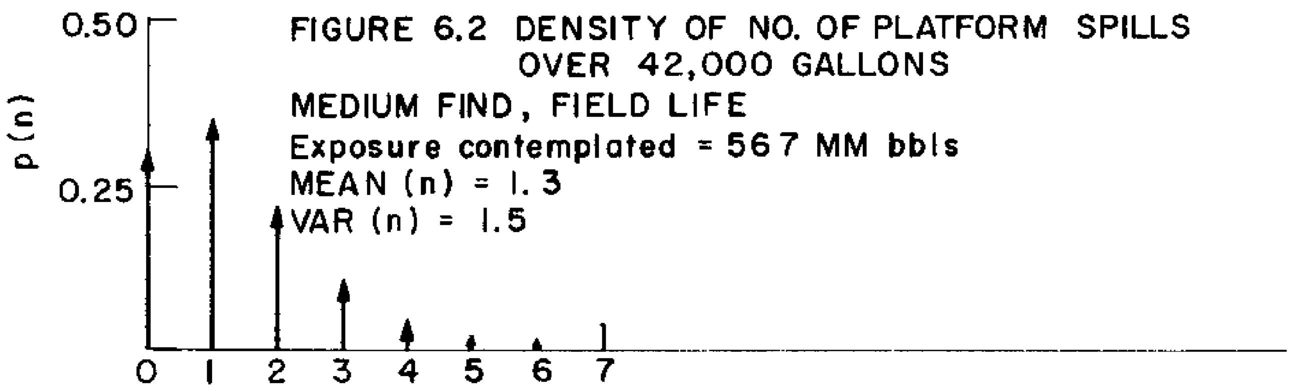


FIGURE 6.2 DENSITY OF NO. OF PLATFORM SPILLS OVER 42,000 GALLONS

MEDIUM FIND, FIELD LIFE

Exposure contemplated = 567 MM bbls

MEAN (n) = 1.3

VAR (n) = 1.5

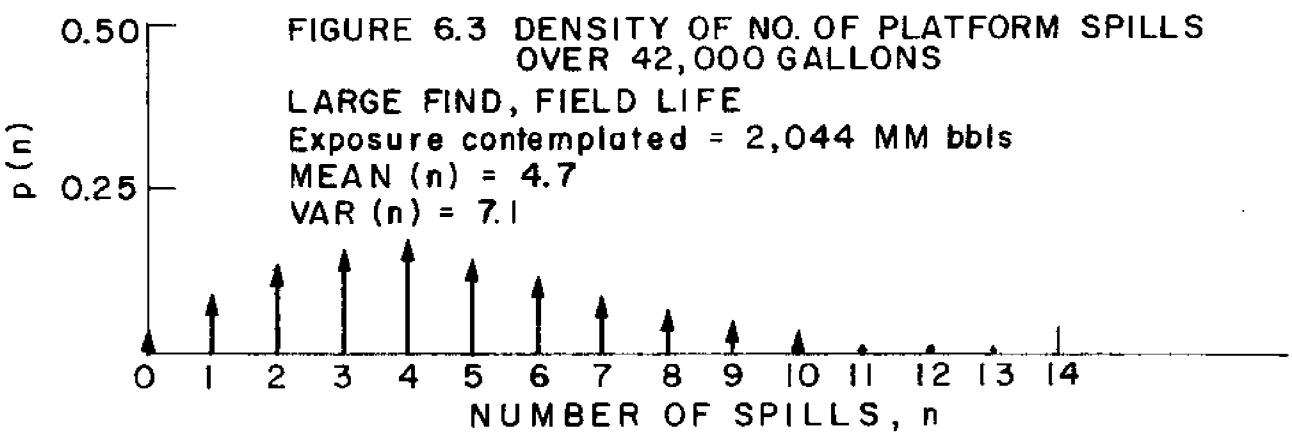


FIGURE 6.3 DENSITY OF NO. OF PLATFORM SPILLS OVER 42,000 GALLONS

LARGE FIND, FIELD LIFE

Exposure contemplated = 2,044 MM bbls

MEAN (n) = 4.7

VAR (n) = 7.1

which lands one-fourth as much oil, there is about a 30% chance we will have no platform spill over 42,000 gallons under our assumptions and about a 90% chance that the number of such spills will be 2 or less. For the small find hypothesis, there is about a .75 chance that we will have no large platform spill, a .2 chance we will have one such spill, and a .03 chance we will have two such spills. Figure 6.4 shows these three densities in terms of volume handled between spills and the equivalent time between spills at peak production.

Figure 6.5 shows the cumulative of the spill size density for these large platform spills. The mean is about one million gallons. There is a .80 chance such a spill if it occurs will be greater than 100,000 gallons, but it is quite unlikely that the spill will be greater than 10 million gallons. Clearly, in this category we are dealing with sizable spills.

When we turn to large spills from offshore pipelines, two important definitional problems arise. One, it is important to know whether a pipeline spill emanated from a transmission line (large diameter lines, often common carrier, which carry the production from a central processing facility in the field to shore) or from a gathering net line (generally smaller lines used to carry production from an individual platform to the central processing platform). This distinction is important to our comparison of tanker versus transmission lines for field-to-shore transport for the gathering net will be in place no matter which transport mode we use. Unfortunately, from the data there is no way of telling for

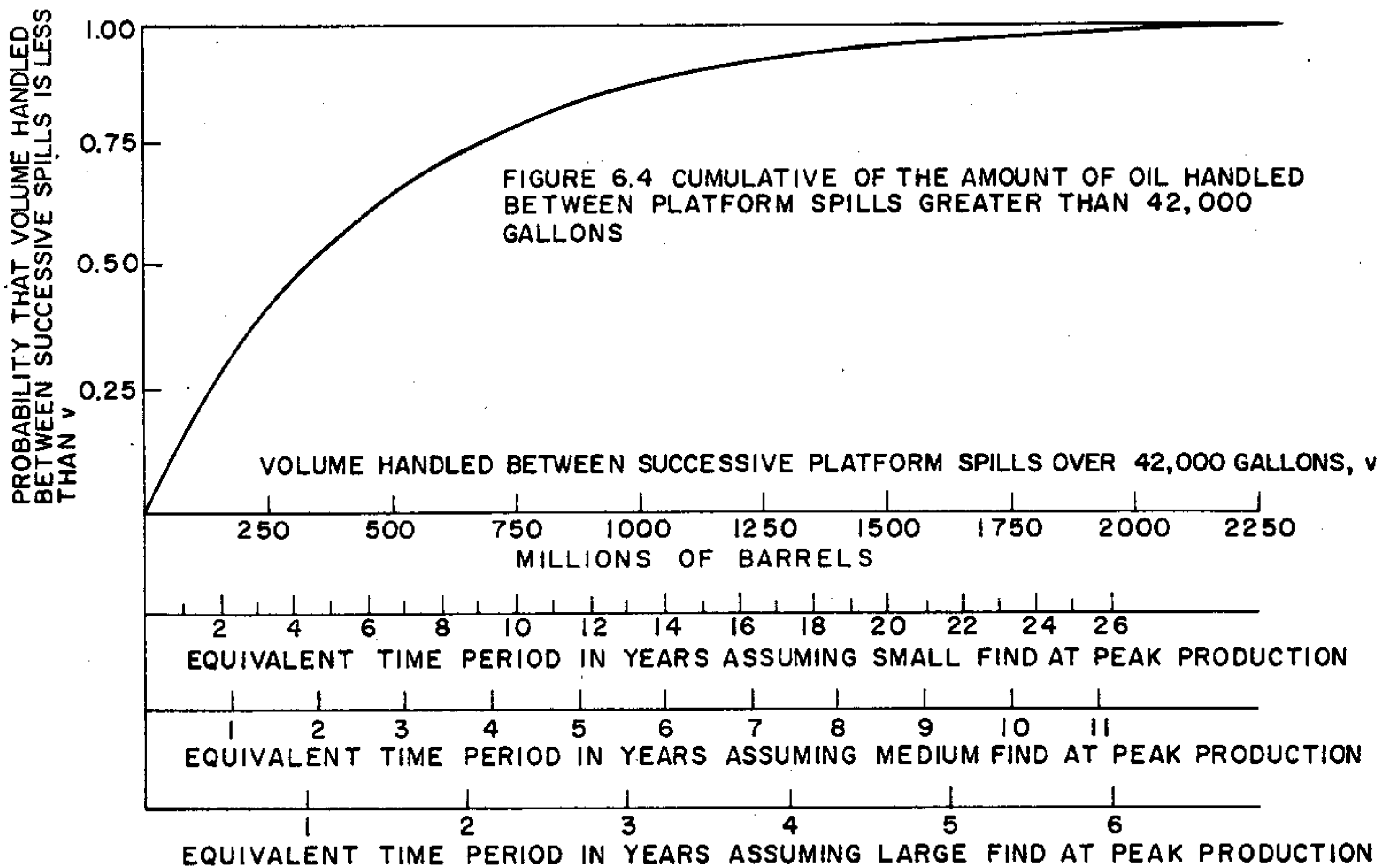


FIGURE 6.4 CUMULATIVE OF THE AMOUNT OF OIL HANDLED BETWEEN PLATFORM SPILLS GREATER THAN 42,000 GALLONS

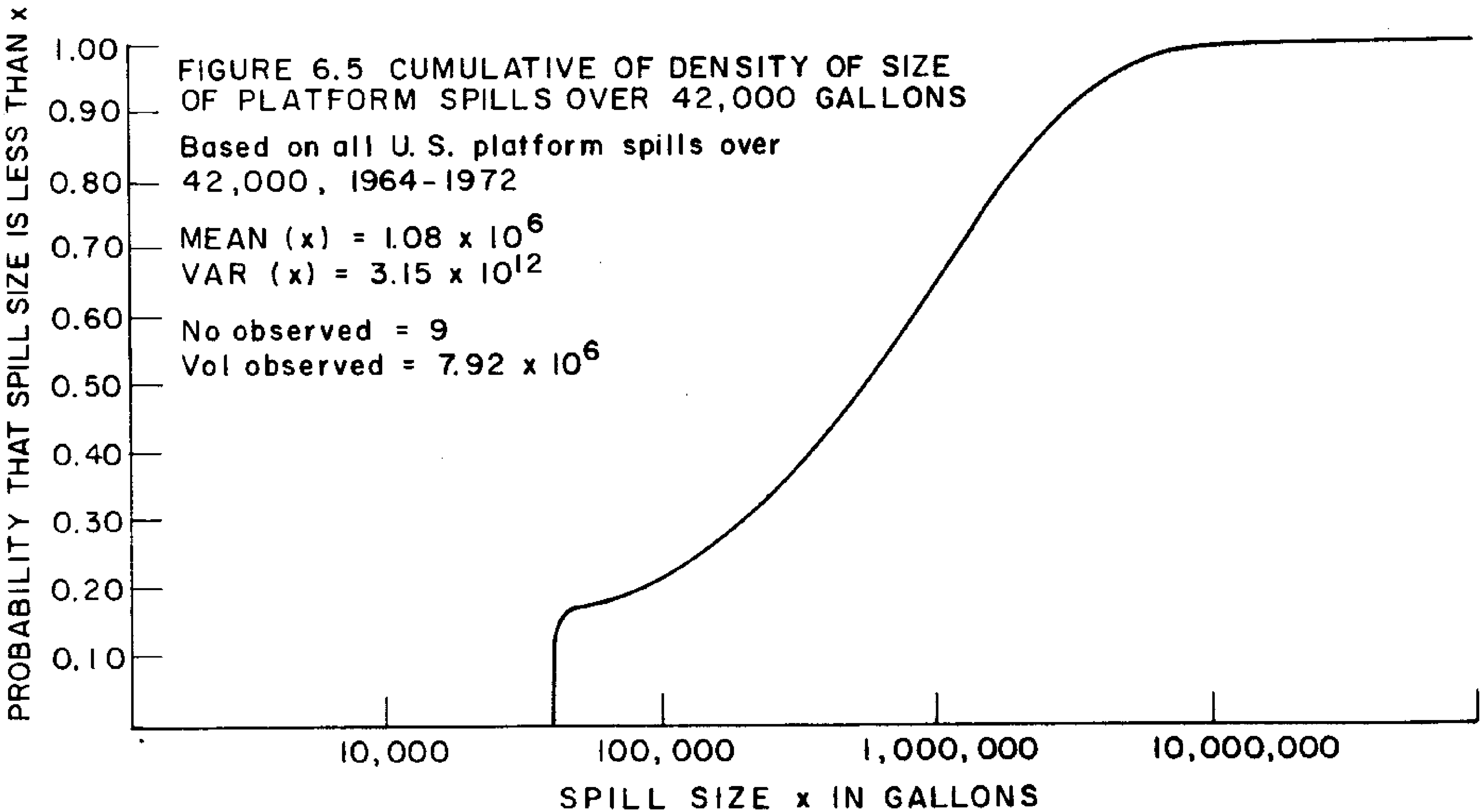


FIGURE 6.5 CUMULATIVE OF DENSITY OF SIZE OF PLATFORM SPILLS OVER 42,000 GALLONS

sure whether a spill involves a transmission line or a gathering net line.

The second definitional problem involves coastal pipeline spills. All but three of the large pipeline spills in Table 6.1 were in shallow coastal channels in which a large portion of the Gulf Coast pipeline network is laid. It is not at all obvious that spills generated by these lines would occur in a development in which all the production was well offshore. For example, the largest coastal pipeline spill was caused by a tug's propellor cutting a line in 10 ft of water. Assuming that the transmission lines were well buried when they came ashore, this type of accident would be hard to come by.

In the face of these uncertainties, we have chosen to display two sets of large pipeline incidence densities. Figures 6.6, 6.7, and 6.8 show the density of the number of pipeline spills over 42,000 gallons, using all known U.S. large offshore pipeline spills for the period 1967-1972 as a basis for our three hypotheses. Figure 6.9 puts these densities in terms of time between large pipeline spills at peak production. Figures 6.10, 6.11, and 6.12 show the similar densities based on all large, non-coastal U.S. pipeline spills in this period as the data base. For the non-coastal densities, the exposure used was all OCS production over the period 1967-1972, about 2 billion barrels, while for the all large offshore pipeline spills case, the exposure used was all U.S. offshore production 1967-1972, about 3.2 billion barrels. In general, both the mean and the variances under

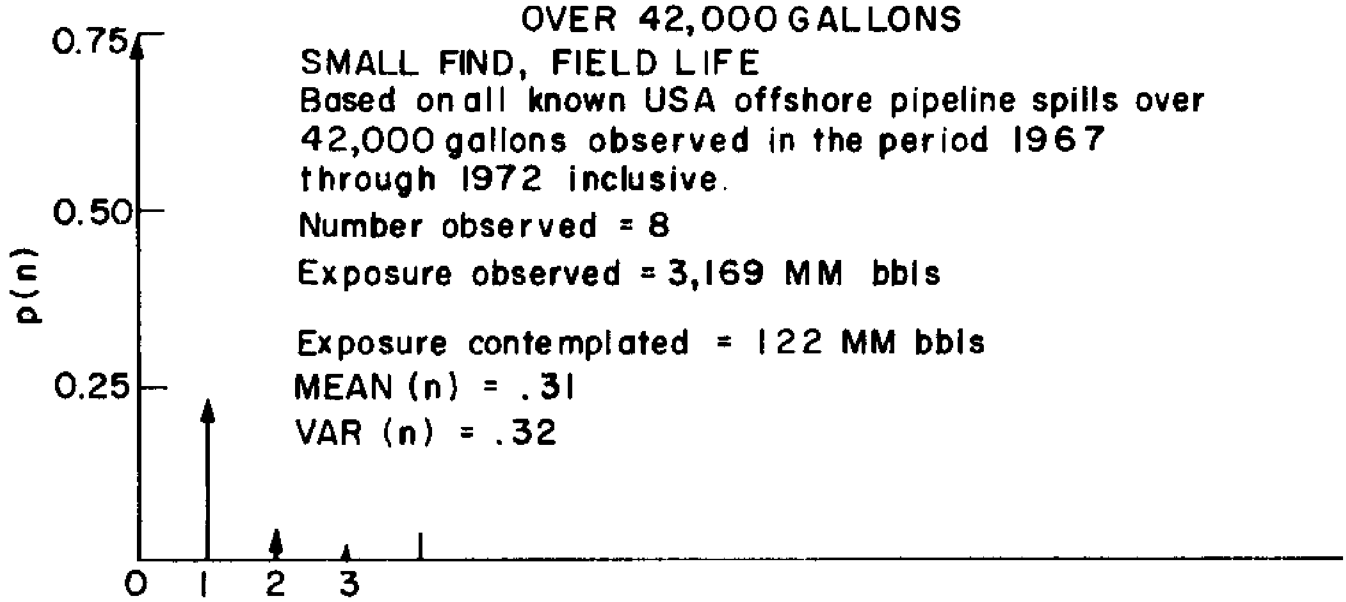


FIGURE 6.6 DENSITY OF NO. OF PIPELINE SPILLS OVER 42,000 GALLONS

SMALL FIND, FIELD LIFE

Based on all known USA offshore pipeline spills over 42,000 gallons observed in the period 1967 through 1972 inclusive.

Number observed = 8

Exposure observed = 3,169 MM bbls

Exposure contemplated = 122 MM bbls

MEAN (n) = .31

VAR (n) = .32

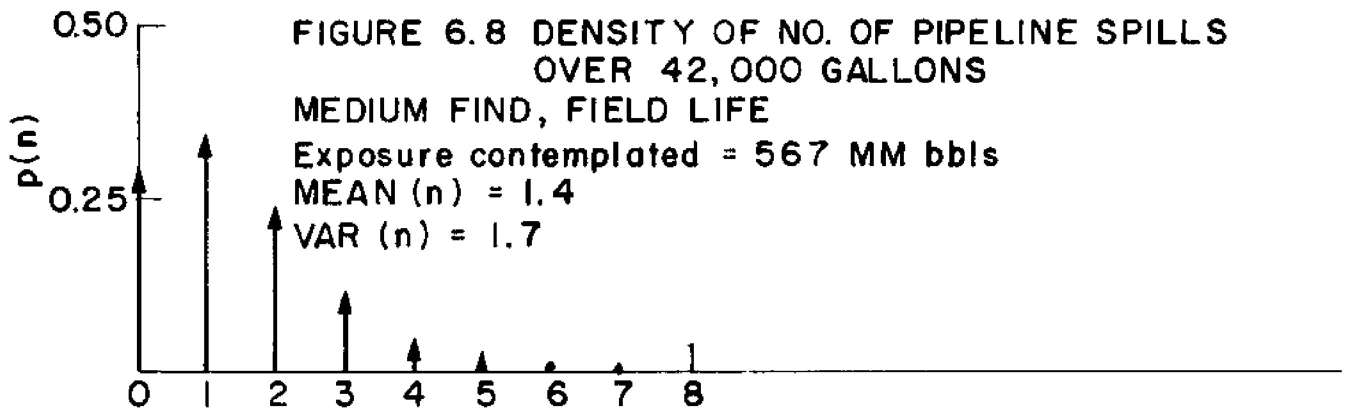


FIGURE 6.8 DENSITY OF NO. OF PIPELINE SPILLS OVER 42,000 GALLONS

MEDIUM FIND, FIELD LIFE

Exposure contemplated = 567 MM bbls

MEAN (n) = 1.4

VAR (n) = 1.7

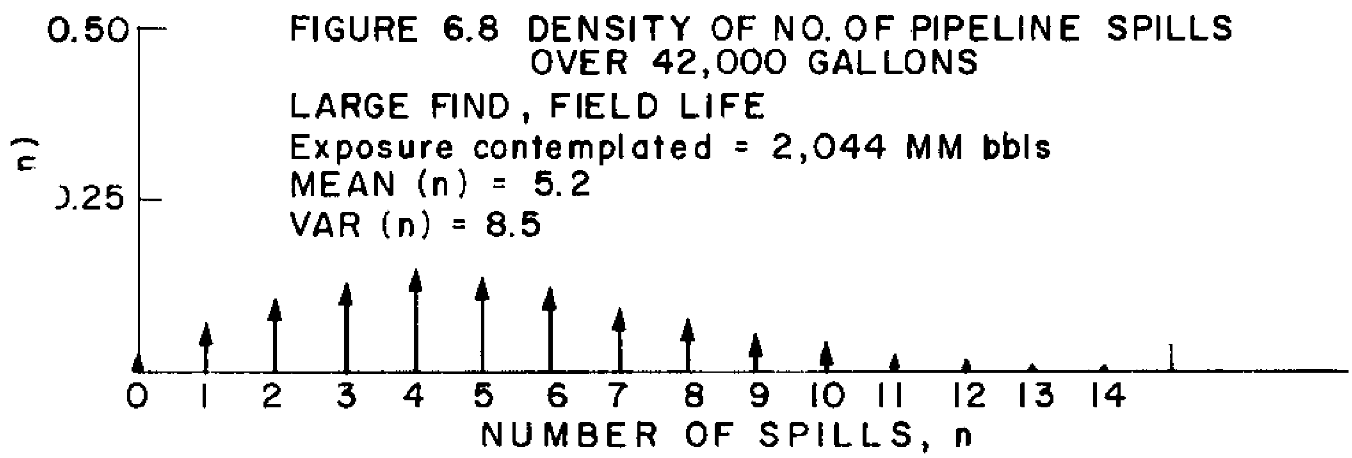


FIGURE 6.8 DENSITY OF NO. OF PIPELINE SPILLS OVER 42,000 GALLONS

LARGE FIND, FIELD LIFE

Exposure contemplated = 2,044 MM bbls

MEAN (n) = 5.2

VAR (n) = 8.5

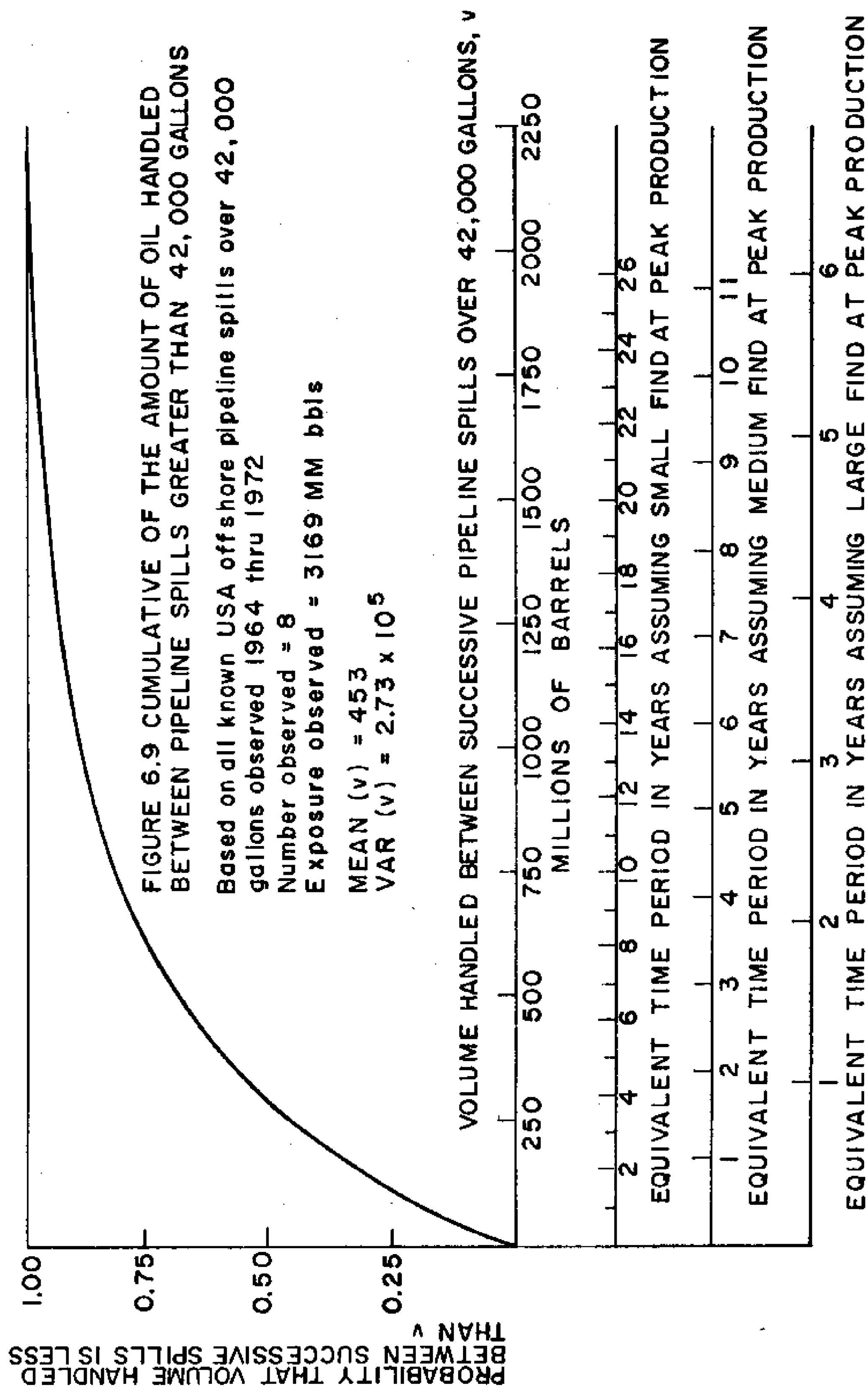


FIGURE 6.9 CUMULATIVE OF THE AMOUNT OF OIL HANDLED BETWEEN PIPELINE SPILLS GREATER THAN 42,000 GALLONS

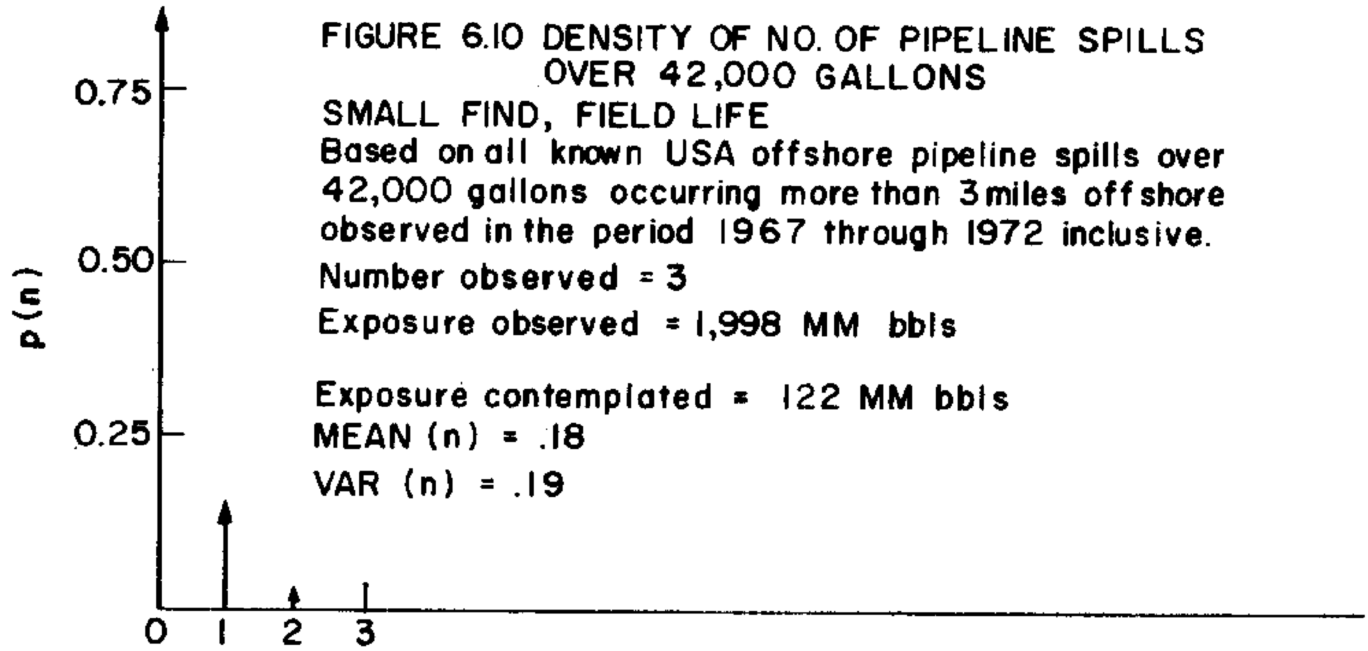


FIGURE 6.10 DENSITY OF NO. OF PIPELINE SPILLS OVER 42,000 GALLONS

SMALL FIND, FIELD LIFE

Based on all known USA offshore pipeline spills over 42,000 gallons occurring more than 3 miles offshore observed in the period 1967 through 1972 inclusive.

Number observed = 3

Exposure observed = 1,998 MM bbls

Exposure contemplated = 122 MM bbls

MEAN (n) = .18

VAR (n) = .19

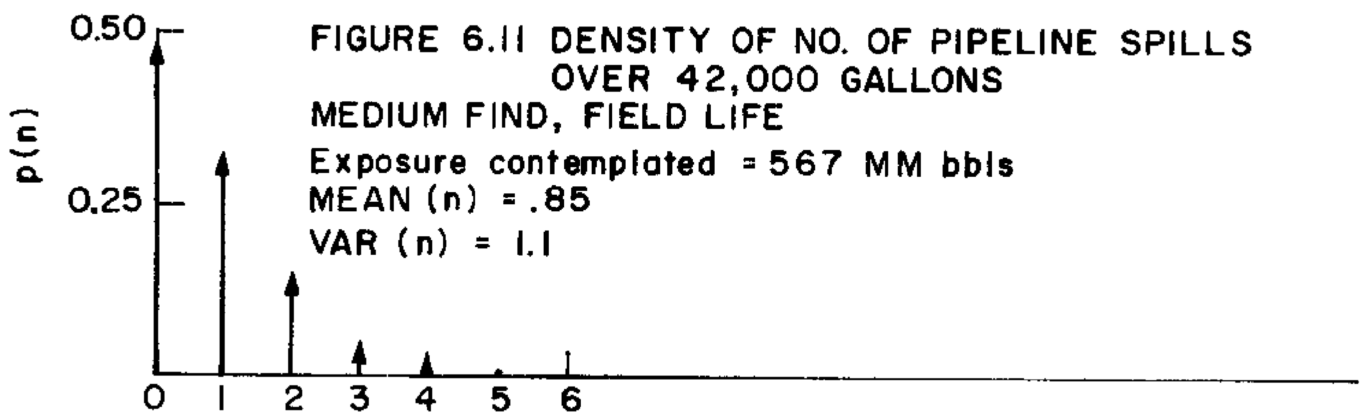


FIGURE 6.11 DENSITY OF NO. OF PIPELINE SPILLS OVER 42,000 GALLONS

MEDIUM FIND, FIELD LIFE

Exposure contemplated = 567 MM bbls

MEAN (n) = .85

VAR (n) = 1.1

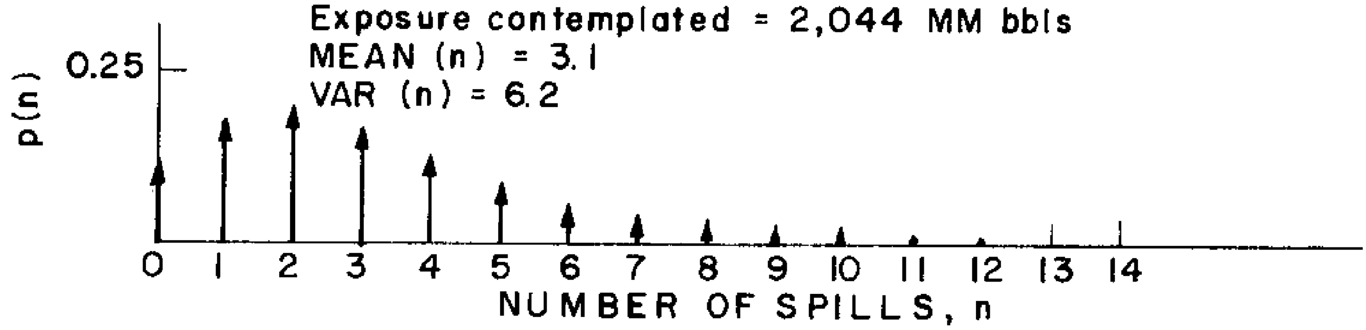
FIGURE 6.12 DENSITY OF NO. OF PIPELINE SPILLS OVER 42,000 GALLONS

LARGE FIND, FIELD LIFE

Exposure contemplated = 2,044 MM bbls

MEAN (n) = 3.1

VAR (n) = 6.2



the non-coastal hypothesis are about 30% less than the means and variances using all large offshore pipeline spills. Under the non-coastal assumption, we would expect to have somewhat smaller number of large spills from pipelines than from platforms; under the all offshore assumption, the number of large pipeline spills tends to be somewhat larger than large platform spills, but once again, it is in the same ballpark.

Figures 6.13 and 6.14 show the large pipeline spill size densities under the all-U.S. offshore and non-coastal hypotheses respectively. In both cases, the mean of the large pipeline spill density is considerably larger than the mean of the platform spills and in both cases, but especially under the non-coastal hypothesis, the density is very widely distributed. The variances are massive and there is a small, but not necessarily insignificant chance that such a spill would be greater than 10 million gallons. Notice that dropping the coastal spills is not all to the benefit of pipelines. For while it decreases the number of spills roughly speaking by 30%, it increases the mean of the size of a spill, if it occurs, by about 25%. Interestingly enough, despite the smaller sample, the variance of the non-coastal spills is lower than that of all large spills. The non-coastal spills exhibit slightly less variability. The smallest non-coastal spill is almost an order of magnitude larger than the smallest of all the large pipeline spills.

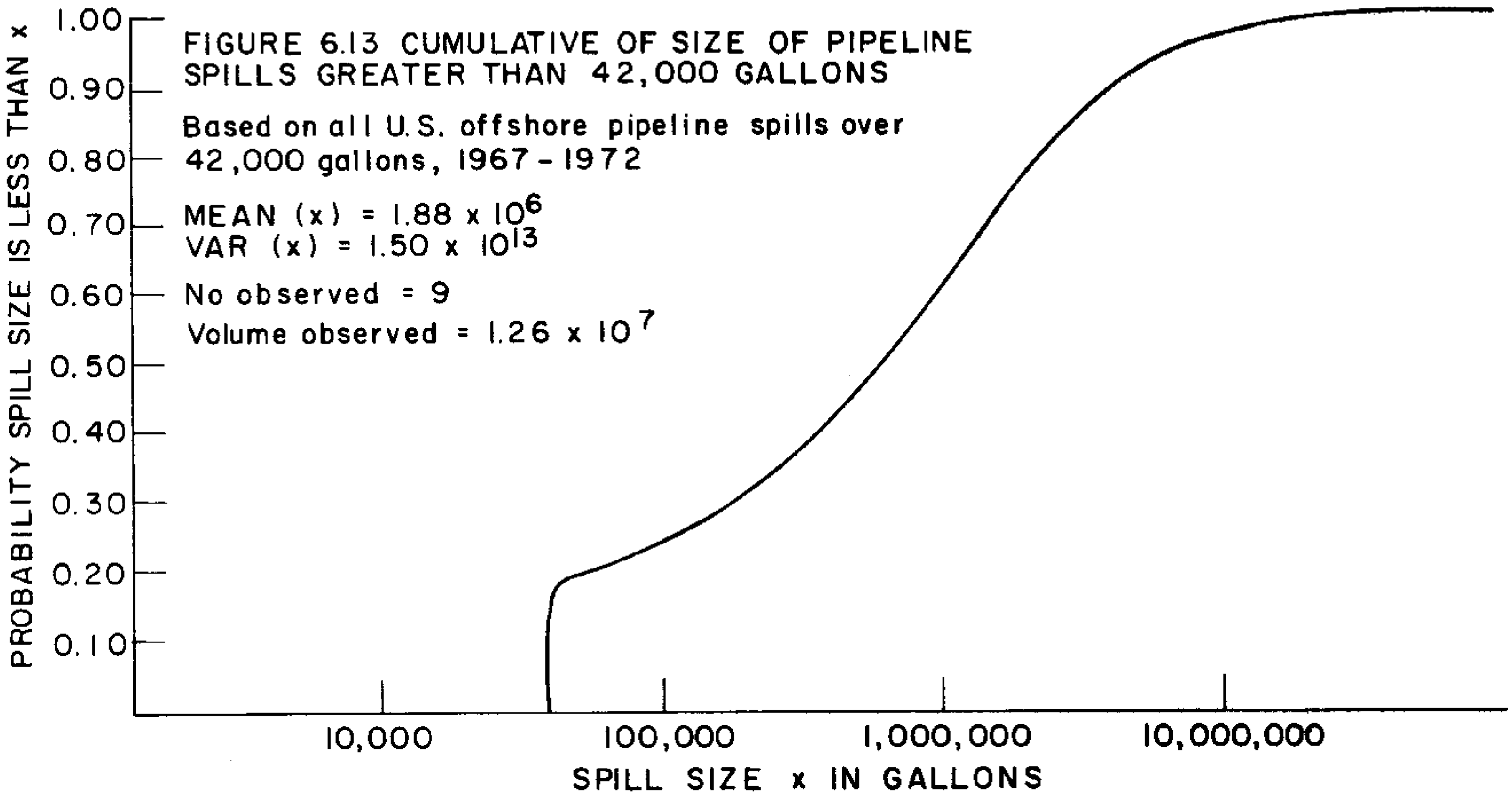


FIGURE 6.13 CUMULATIVE OF SIZE OF PIPELINE SPILLS GREATER THAN 42,000 GALLONS

Based on all U.S. offshore pipeline spills over 42,000 gallons, 1967 - 1972

MEAN (x) = 1.88×10^6
VAR (x) = 1.50×10^{13}

No observed = 9

Volume observed = 1.26×10^7

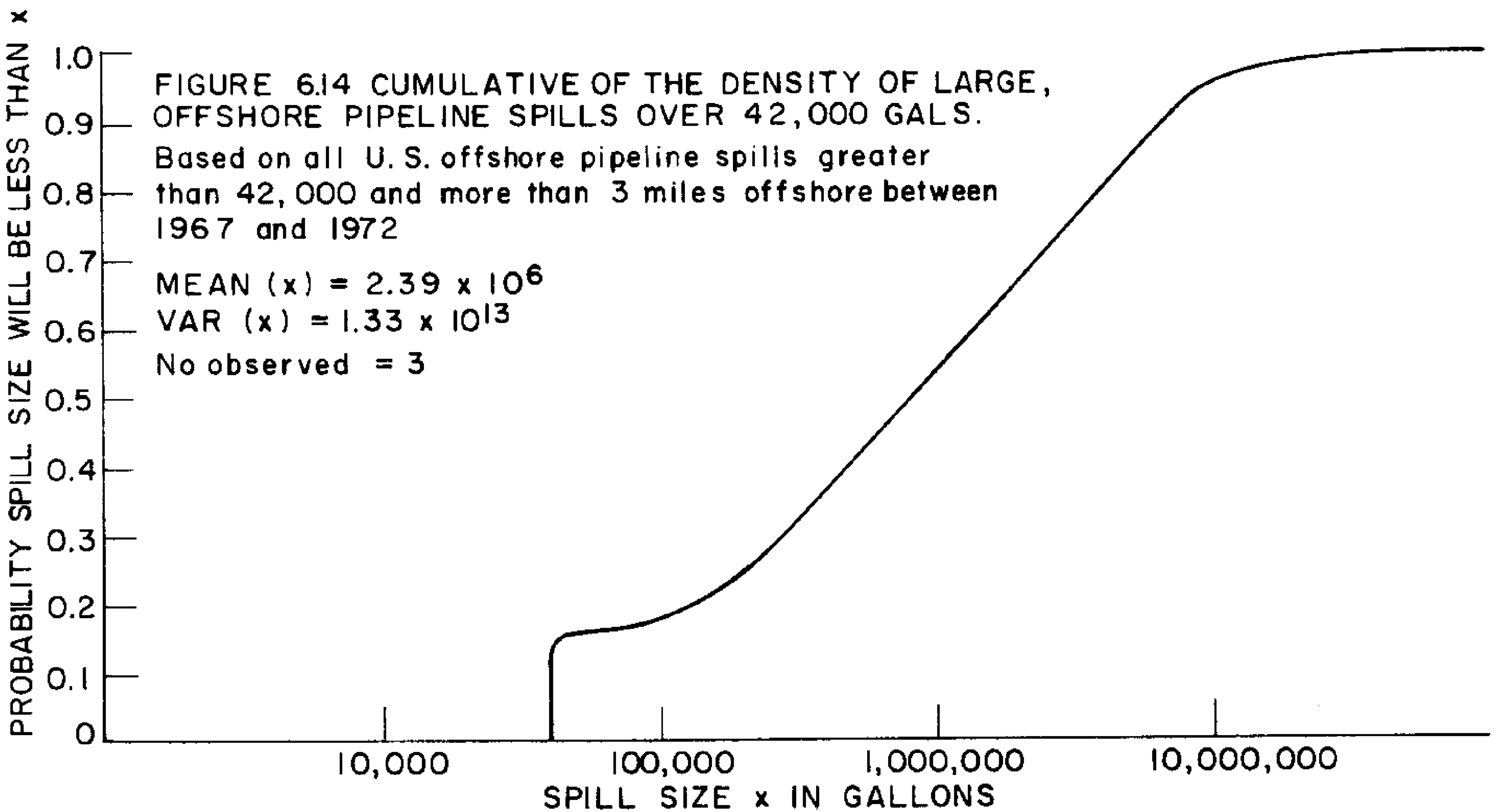


FIGURE 6.14 CUMULATIVE OF THE DENSITY OF LARGE, OFFSHORE PIPELINE SPILLS OVER 42,000 GALS.

Based on all U. S. offshore pipeline spills greater than 42,000 and more than 3 miles offshore between 1967 and 1972

MEAN (x) = 2.39×10^6

VAR (x) = 1.33×10^{13}

No observed = 3

7. <u>Small offshore production spills</u>

When we turn our attention to smaller offshore production spills, the 1971 and 1972 Coast Guard reports are undoubtedly the most complete source of data. In these two years, the Coast Guard reports some 5,700 offshore spills. The only other contender is the U.S. Geological Survey file on the EPA tape which contains only 800 offshore spills supposedly covering a wider period of time. Therefore, with respect to smaller offshore spills, we will confine our analysis to the Coast Guard data.

Unfortunately, the Coast Guard data suffers from the fact that the demarcation between transmission lines and platform and gathering net spills appears to be almost nonexistent as indicated by the shift from pipelines to offshore production facilities between 1971 and 1972 (see Table 1.3). This is most unfortunate, because it completely muddies our comparison of pipeline versus vessel for transport to shore as far as small spills are concerned.

There is very little one can do about this unless one is willing to assume that a find will not be landed by tanker and then one can lump together all of the offshore production spills in the Coast Guard data to make statements about all the small spills which will emanate from a development, irrespective of whether they are production facility spills or transmission line spills. This will be our approach. Needless to say, the ability to distinguish between gathering net spills and transmission line spills would be most welcome.

One may be able to do this from the raw Coast Guard reports. In any event, we strongly recommend that the Coast Guard system be modified so that these spills are distinguishable in the future.

With respect to these smaller offshore spills, we will make the same assumptions used earlier, including the assumption that the exposure variable in the Poisson process is volume of oil landed. At present, we have been unable to make a quantitative check on this assumption, as we did with tankers, since given the form the data is in, we have been unable to stratify the data in such a mahner as to generate a useful scatter diagram of spill against volume landed. To do so it would be necessary to, for example, discover in which lease block the spills occurred and compare those numbers with the production from that lease block.* Unfortunately, neither the spill location by lease nor the location by field is available from the Coast Guard file. This hypothesis and others (exposure parameter is number of wells, exposure parameter is number of platforms) certainly bear more investigation but for now, we will simply accept this as a working hypothesis and an obvious starting point for analysis.

The resulting densities on the number of spills for our sample for small, medium, and large fields, for field life, are shown in Figures 7.1, 7.2 and 7.3.

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*The total production in 1972 and 1971 are too close together to generate a useful scatter diagram. However, the fact that total offshore spill incidences in 1971 and 1972 are about the same (Table 1.1) is consistent with the hypothesis.

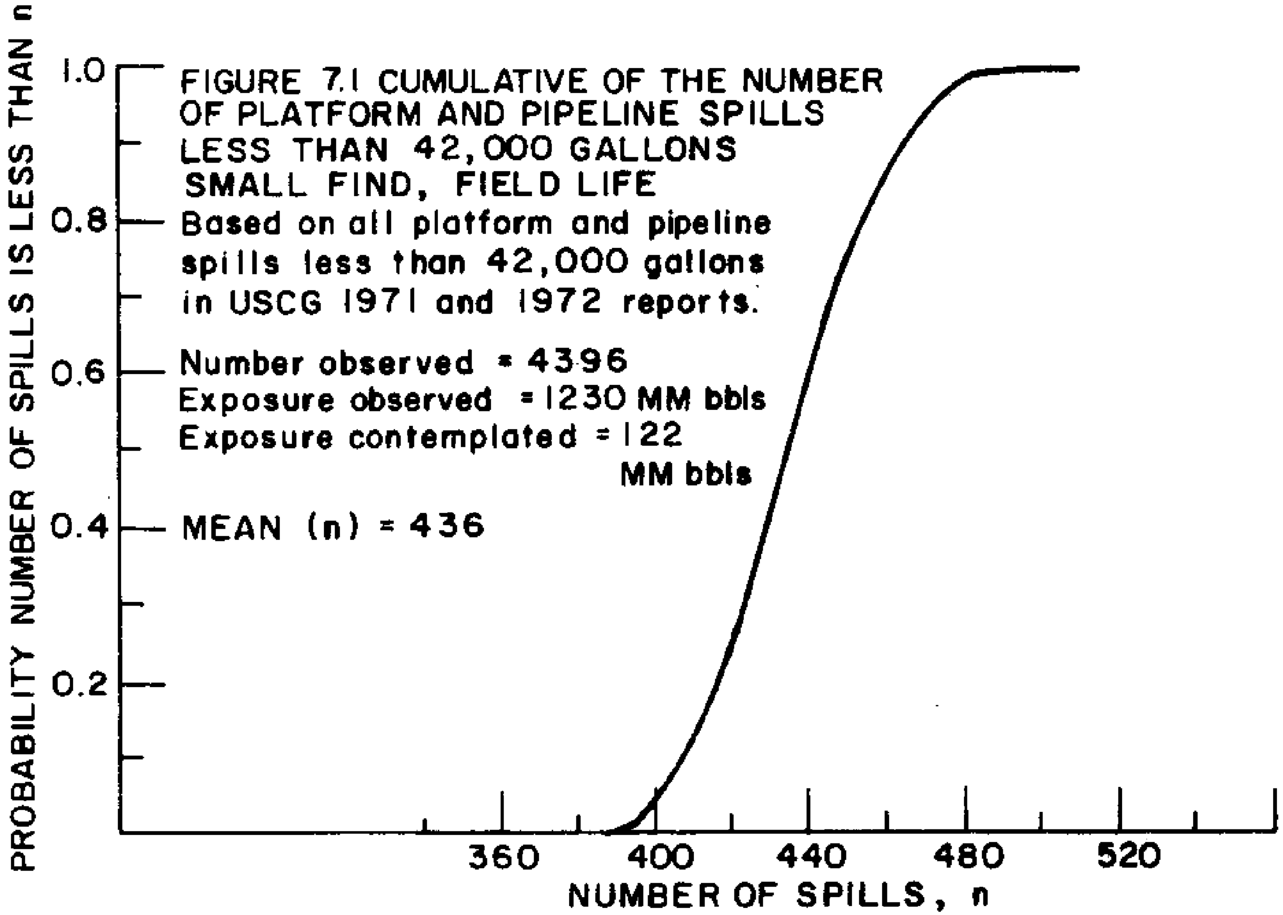

FIGURE 7.1 CUMULATIVE OF THE NUMBER OF PLATFORM AND PIPELINE SPILLS LESS THAN 42,000 GALLONS SMALL FIND, FIELD LIFE

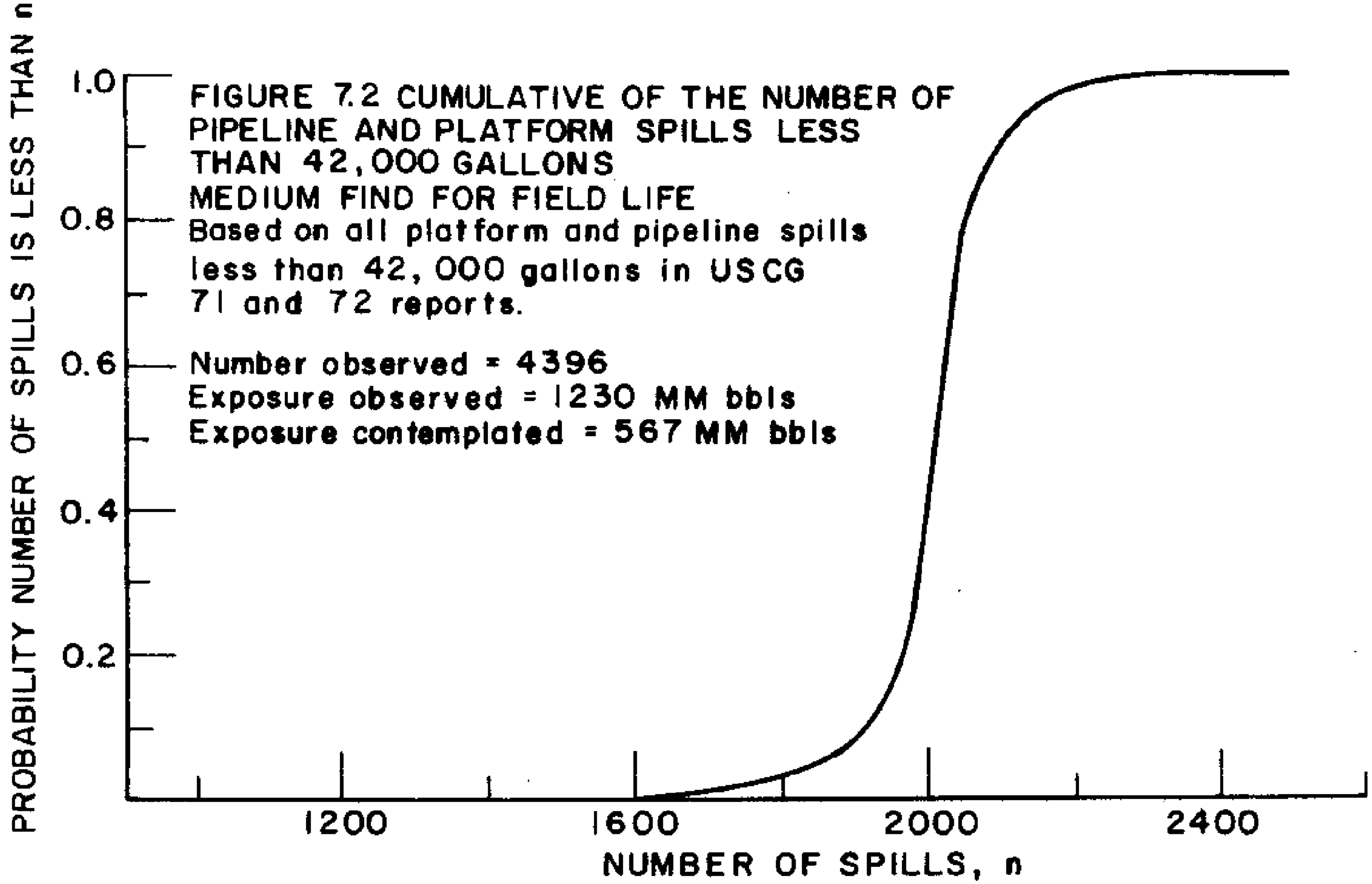

FIGURE 7.2 CUMULATIVE OF THE NUMBER OF PIPELINE AND PLATFORM SPILLS LESS THAN 42,000 GALLONS
MEDIUM FIND FOR FIELD LIFE
Based on all platform and pipeline spills less than 42,000 gallons in USCG 71 and 72 reports.

Number observed = 4396
Exposure observed = 1230 MM bbls
Exposure contemplated = 567 MM bbls

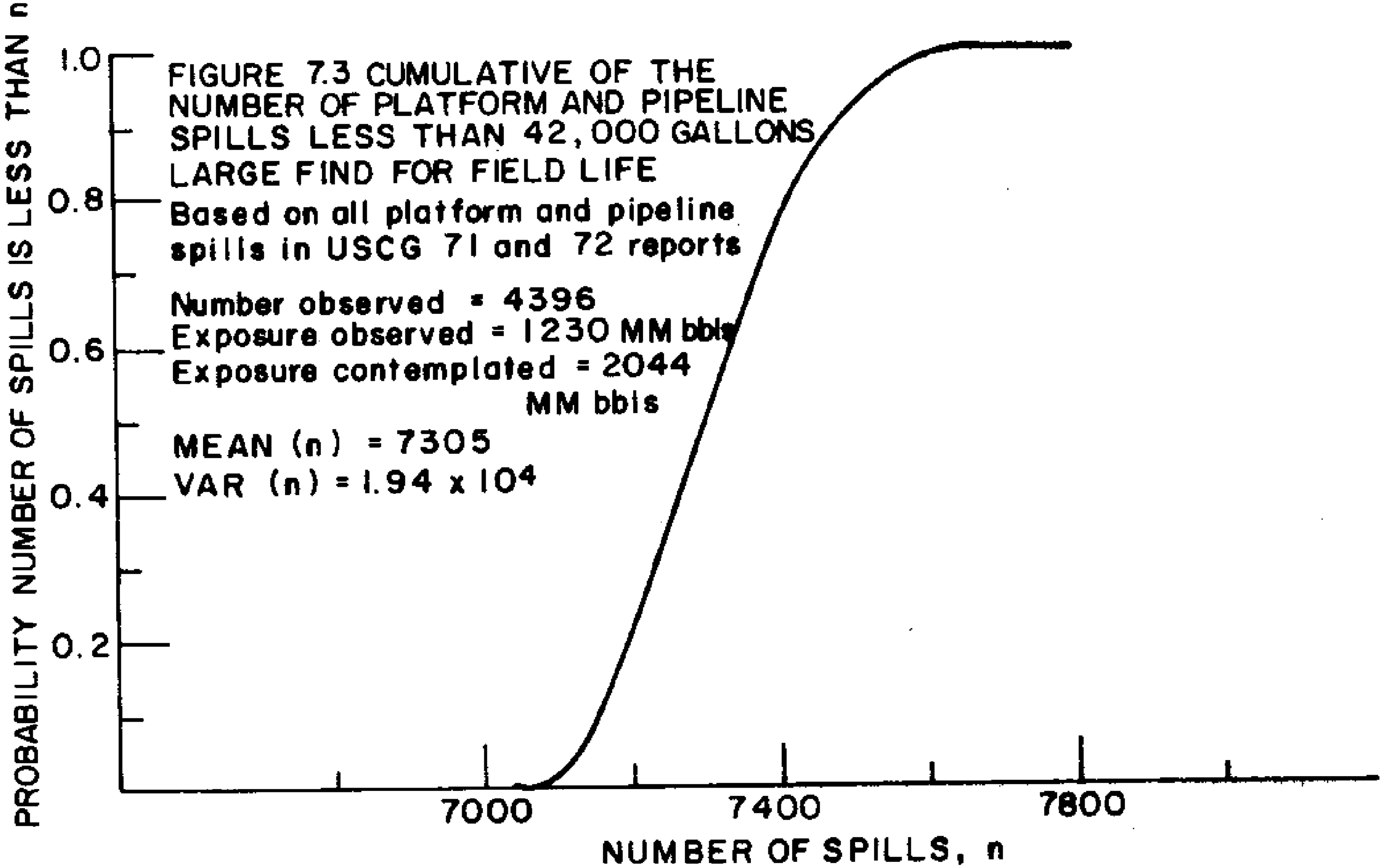

FIGURE 7.3 CUMULATIVE OF THE NUMBER OF PLATFORM AND PIPELINE SPILLS LESS THAN 42,000 GALLONS LARGE FIND FOR FIELD LIFE

Based on all platform and pipeline spills in USCG 71 and 72 reports

Number observed = 4396
Exposure observed = 1230 MM bbls
Exposure contemplated = 2044 MM bbls

MEAN (n) = 7305
VAR (n) = 1.94×10^4

These densities are reasonably tight. For example, according to the analysis, there is a very high probability that the number of small spills from our small find landed by pipeline will be between 1,900 and 2,300;and for our large find, we find that there is a high probability that the number of small spills will be between 7,100 and 7,600. Once again, these statements depend on our assumptions--principally that future developments will have the same spill incidence characteristics as past and that the proper exposure variable is volume handled and not, for example, number of platforms. Our Offshore Development Model indicates that future developments will be produced from a much smaller number of platforms per volume produced than has been past practice.

Most of these spills will be quite small, as is indicated by the cumulatives of the spill size densities for tower and pipeline spills less than 42,000 gallons based on the Coast Guard data (Figures 7.4 and 7.5). The means of the density of tower spills and pipeline spills greater than three miles offshore is about 100 gallons. In the Coast Guard data, the pipeline spills taking place less than three miles offshore are somewhat larger, perhaps reflecting the generally older facilities close to shore. Once again, these densities exhibit very high ratios of variances to means and thus are extremely skewed. The probability that an individual spill is less than the mean runs as high as .95. In other words, according to the analysis, over 90% of all these spills will be less than the mean in size.

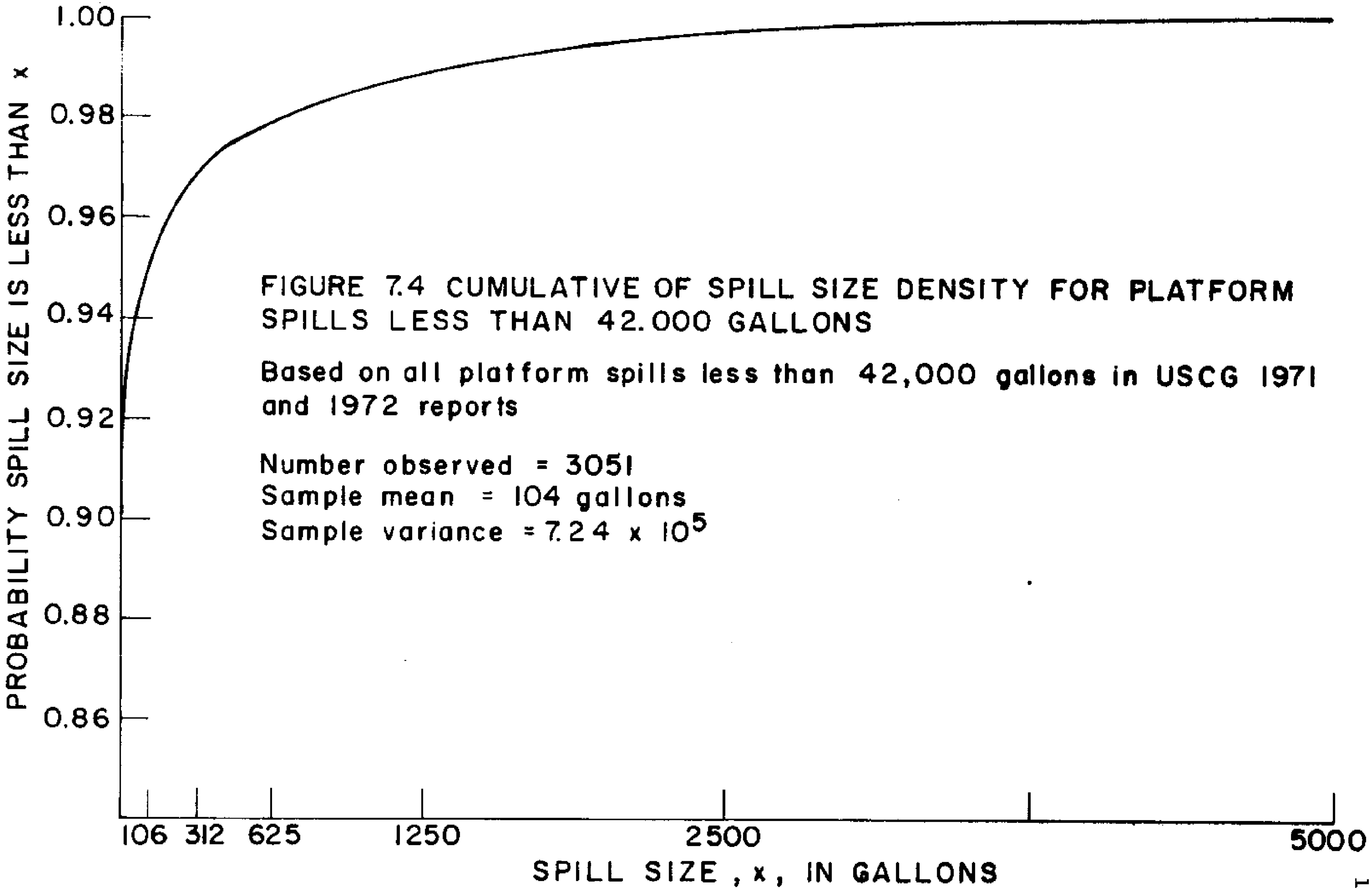

FIGURE 7.4 CUMULATIVE OF SPILL SIZE DENSITY FOR PLATFORM SPILLS LESS THAN 42.000 GALLONS

Based on all platform spills less than 42,000 gallons in USCG 1971 and 1972 reports

Number observed = 3051
Sample mean = 104 gallons
Sample variance = 7.24×10^5

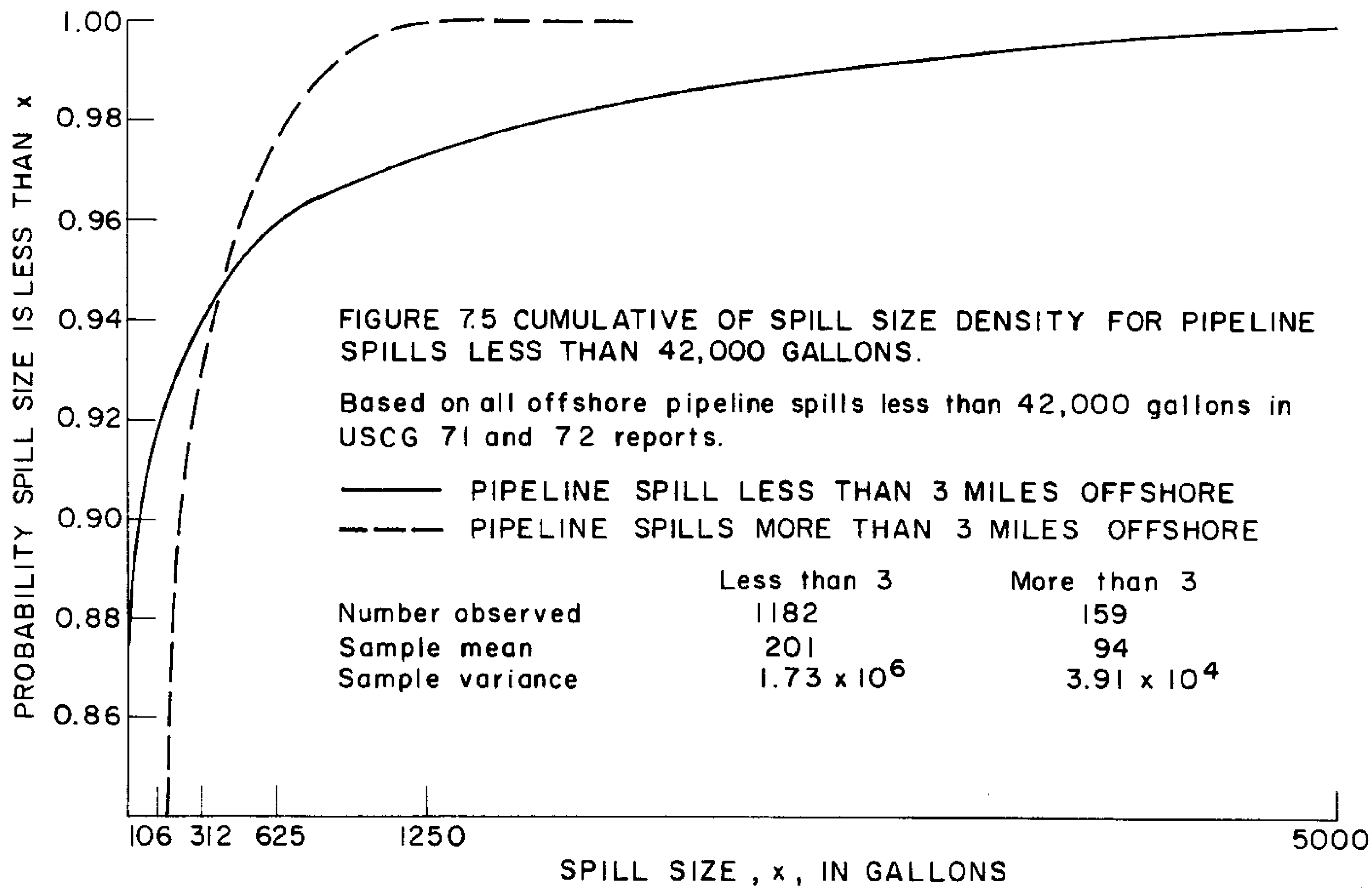

FIGURE 7.5 CUMULATIVE OF SPILL SIZE DENSITY FOR PIPELINE SPILLS LESS THAN 42,000 GALLONS.

Based on all offshore pipeline spills less than 42,000 gallons in USCG 71 and 72 reports.

——— PIPELINE SPILL LESS THAN 3 MILES OFFSHORE

– – – PIPELINE SPILLS MORE THAN 3 MILES OFFSHORE

	Less than 3	More than 3
Number observed	1182	159
Sample mean	201	94
Sample variance	1.73×10^6	3.91×10^4

7.1 Spill cause

Both the EPA and USCG tapes have been analyzed for the cause of spills from offshore production facilities. With respect to the EPA tape, the relevant data base was 1,019 spills, primarily from USGS files [1,3]. Only 9 of these spills were above 10,000 gallons. Therefore, this analysis speaks only to spills which are small by our definition. The sample of large spills is simply too small to do any meaningful statistical analysis of causes.

A cursory examination of large platform spills reveals that they have all been caused by some form of loss of well control. The earlier spills were associated with storm damage to platforms; the latter with drilling or workover operations. There is reason to believe that the surface-actuated down-hole valves presently being fitted will decrease the incidence or ameliorate the severity of at least some of these accidents. The surface-actuated, down-hole valve should have a considerably superior record to the storm choke due to the much larger pressure differential available for activation and the ease with which it can be tested. The marginal cost of these valves is about $5,000 per well, provided they are installed at the time the well is originally completed. However, the sample on large spills is too small and operational data on the down-hole valve not available to make any quantitative assessment of the improvement which would be obtained through use of these devices. They will not affect the incidence of spills occurring during drilling or workover or spills due to loss of formation integrity such as Santa Barbara. Nonetheless, the surface-activated, down-hole valve appears to be the single most important technological improvement available with respect to large spills, if only because it may prove capable of restricting spillage to a single well in the case of a major accident.

With respect to small platform spills, both the USCG and the EPA analyses point to various forms of vessel overflows as the common cause of spillage, primarily in the separation system. Frequently cited sources of trouble are dump valves, high-level sensors, pressure relief valves, and rupture disks.* Fully one-third of all the platform spills listed in the EPA data are associated with separation. Overflow of sumps was another common platform culprit. The Coast Guard lists pump failure as a relatively common cause, but the EPA data claims pumps are rare offenders offshore. But in general, there is no striking pattern to the cause data. The frequencies appear to be roughly proportional to the amount of equipment represented by the subsystems. There doesn't appear to be any glaringly apparent weak link. Perhaps the best chance for improvement with respect to small platform spills lies with more comprehensive and somewhat larger drain and sump systems.

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*It's a little difficult to separate cause from symptom in the data. A dump valve or rupture disk may be the source of a spill because it's doing its job of relieving abnormal pressure caused by a failure elsewhere in the system and still be listed as the cause of a spill.

With respect to pipelines, 92% of all the offshore spills in the EPA data occurred on the platform; only 6% in the gathering-distribution system. As noted earlier, it is impossible to separate gathering net spills from platform spills in the Coast Guard data. Thus, on the basis of the EPA data, most of the small offshore spills are emanating from the platforms. However, despite this, pipeline leaks and ruptures are by far the single most common source of spillage listed in both the Coast Guard and EPA data. Presumably many of these "pipeline" leaks are from pipes on the platforms. This may be only because crude is commonly found in pipes. Nonetheless, if we broaden our view to include the onshore pipeline spillage listed in the EPA tapes, we find that pipeline corrosion is the most common cause of spillage, especially of the larger spills, for these generally older lines. It appears that inspection and regulation of corrosion control measures should be given high priority in OCS monitoring, especially as the lines become older.

8. Total volume spilled

While it is certainly true, as we have pointed out, that as far as the environmental impact of marine petroleum activity is concerned the frequency and magnitude of individual spills is of considerably more importance than the total volume spilled, the total volume spilled, z, from an activity over its life is of more than passing interest. This section combines our earlier analyses in order to make statements about the total volume spilled.

Like spill incidence and individual spill size, total volume spilled cannot be predicted with certainty. It too is a random variable and as such we must necessarily be content with obtaining information about its density. It is probably obvious to the reader that for any given category and potential development the density of the total amount spilled, z, must depend in some manner on the density of the number of spills, n, and the density of the size of an individual spill, x. And in fact, it is a simple matter to write down the equation relating the density of the total amount spilled to the densities of the number of spills and the size of an individual spill. Since we already have the latter two animals, at least given the assumptions we have been willing to make, obtaining the density of the total volume spilled is merely a numerical computation problem. Unfortunately, for the case at hand, this numerical problem is anything but simple. Therefore, we will have to be satisfied with approximations to this density based on the following approach.

If one is willing to assume, as we have, that the size of an individual spill, x, is independent of the number of spills, n, then the mean and variance of the total amount spilled, z, is related to the means and variances of the number of spills and individual spill size in the following simple manner.

$$\text{MEAN}(z) = \text{MEAN}(n) \cdot \text{MEAN}(x)$$

$$\text{VAR}(z) = \text{MEAN}(n) \cdot \text{VAR}(x) + (\text{MEAN}(x))^2 \cdot \text{VAR}(n)$$

As indicated earlier, over 94% of all the volume spilled is spilled in spills of over 42,000 gallons. Therefore, we will be introducing very little error if in addressing the problem of the total amount of oil spilled, we restrict our attention to spills greater than 42,000 gallons. Under this restriction, Table 8.1 shows the means and variances of n and x, which we computed earlier for production platforms, offshore pipelines and tankers for spills over 42,000 gallons from our hypothetical small, medium and large finds. These particular numbers are based on:

1. All reported U.S. production platform spills from 1964 through 1972 over 42,000 gallons;
2. All reported U.S. offshore pipeline spills, including coastal spills, from 1967 through 1972;
3. All tanker spills on major trade routes over 42,000 gallons worldwide as reported by ECO Inc. for the period 1968 through 1972.

The last two columns show the mean and variances of the total amount spilled for each category and each find as computed

	MEAN(n)	VAR(n)	MEAN(x)	VAR(x)	MEAN(z)	VAR(z)
<u>Small Find</u>						
Platform	2.8×10^{-1}	2.9×10^{-1}	1.08×10^{6}	3.15×10^{12}	3.01×10^{5}	1.2×10^{12}
Pipeline	3.1×10^{-1}	3.2×10^{-1}	1.88×10^{6}	1.50×10^{13}	5.84×10^{5}	5.8×10^{12}
Tanker	4.1×10^{-1}	4.1×10^{-1}	2.03×10^{6}	7.79×10^{12}	8.36×10^{5}	4.9×10^{12}
<u>Medium Find</u>						
Platform	1.3×10^{0}	1.5×10^{0}	1.08×10^{6}	3.15×10^{12}	1.40×10^{6}	5.8×10^{12}
Pipeline	1.4×10^{0}	1.7×10^{0}	1.88×10^{6}	1.50×10^{13}	2.64×10^{6}	2.7×10^{13}
Tanker	1.9×10^{0}	2.0×10^{0}	2.03×10^{6}	7.79×10^{12}	3.88×10^{6}	2.3×10^{13}
<u>Large Find</u>						
Platform	4.7×10^{0}	7.1×10^{0}	1.08×10^{6}	3.15×10^{12}	5.06×10^{6}	2.3×10^{13}
Pipeline	5.2×10^{0}	8.5×10^{0}	1.88×10^{6}	1.50×10^{13}	9.80×10^{6}	10.8×10^{13}
Tanker	6.9×10^{0}	7.4×10^{0}	2.03×10^{6}	7.79×10^{12}	1.41×10^{7}	8.4×10^{13}

TABLE 8.1

MEAN AND VARIANCE OF TOTAL AMOUNT SPILLED BY CATEGORY from the above relationships. In general, the means and variances are of the same order of magnitude. There aren't any really striking differences. Platforms have the lowest means and variances. Tankers have the highest means but variances are lower than the pipeline variances. Once again we observe a situation in which the ratio of the variances to the mean are extremely large but less so for the large find than for the small find. With the large find, we have the law of large numbers beginning to work for us, but only very weakly.

In order to obtain some insight on the meaning of these means and variances, we have approximated the density of the total amount spilled by a Gamma with the same mean and variance. This is not completely consistent with our earlier assumptions but the errors introduced will be small. Figure 8.1 shows the results for the small find and Figure 8.2 the results for the large find. The striking feature about Figure 8.1 is the relatively high probability of having no spillage at all in spills over 42,000 gallons, that is, no spills over 42,000 gallons. This is reflected in the height of the vertical portion of the cumulatives to the left of the figure. If the find is landed by tanker the probability of having no spills over 42,000 gallons is .52. If the find is landed by pipeline the probability of no pipeline spills over 42,000 gallons is .75. The probability of no platform spills is .73. The most spread out of the densities is the pipeline. It crosses over both the platform cumulative at the low end and the tanker distribution at the high end. That is, despite

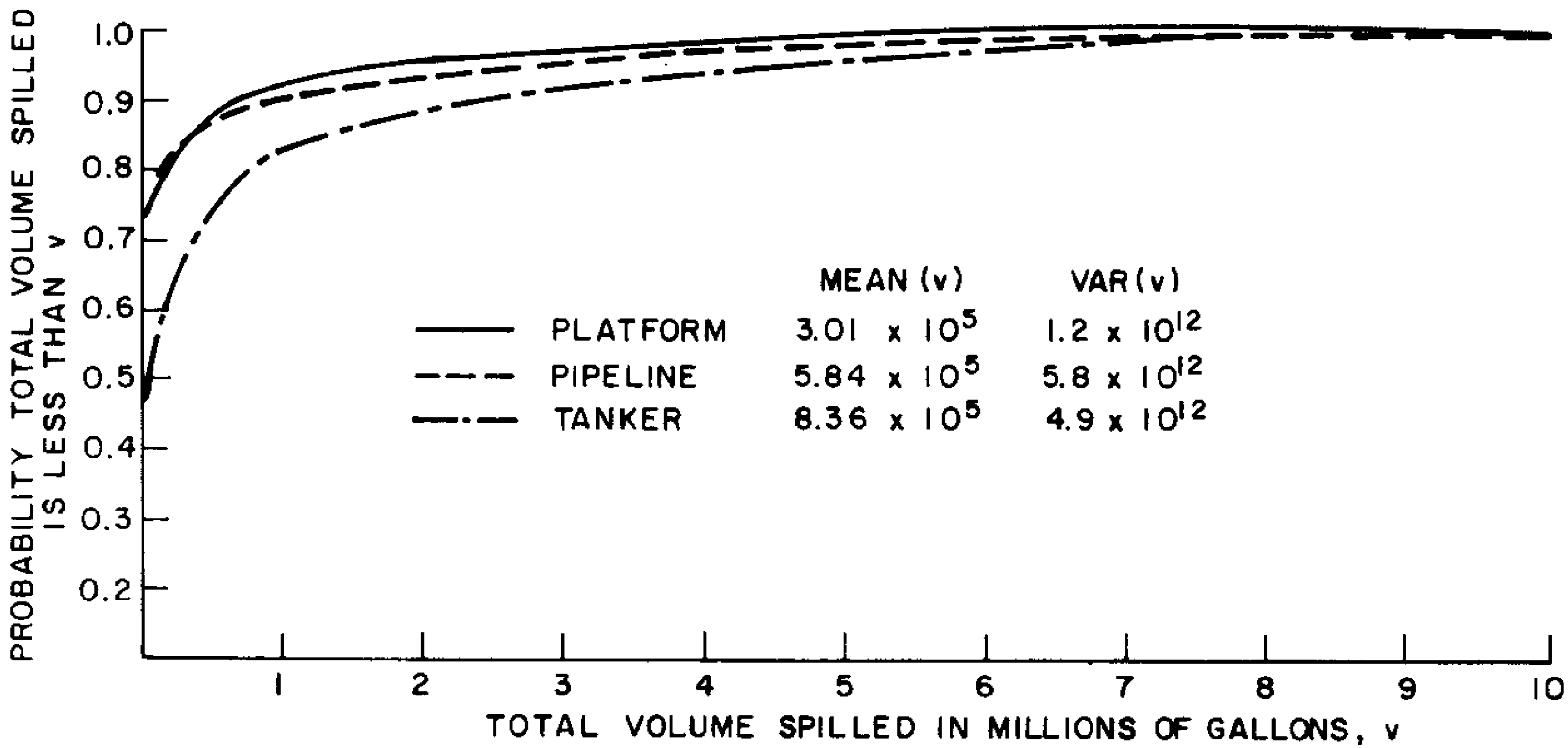

FIGURE 8.1 CUMULATIVE OF TOTAL VOLUME SPILLED FROM SMALL FIND OVER FIELD LIFE IN SPILLS LARGER THAN 42,000 GALLONS

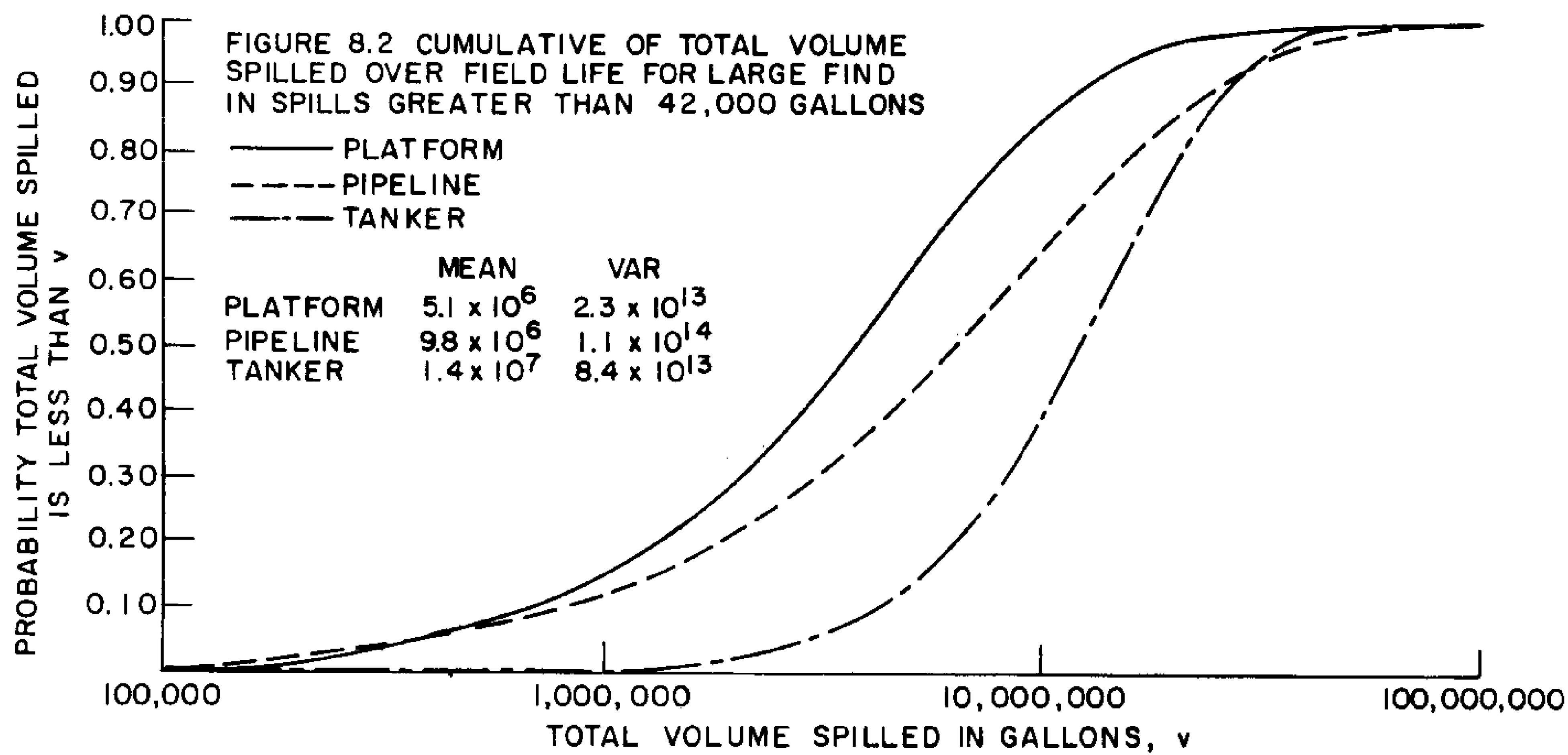
FIGURE 8.2 CUMULATIVE OF TOTAL VOLUME SPILLED OVER FIELD LIFE FOR LARGE FIND IN SPILLS GREATER THAN 42,000 GALLONS
PLATFORM
PIPELINE
TANKER
MEAN
VAR
PLATFORM 5.1 x 10^6 2.3 x 10^13
PIPELINE 9.8 x 10^6 1.1 x 10^14
TANKER 1.4 x 10^7 8.4 x 10^13
PROBABILITY TOTAL VOLUME SPILLED IS LESS THAN v
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
100,000
1,000,000
10,000,000
100,000,000
TOTAL VOLUME SPILLED IN GALLONS, v

the fact that the pipeline mean is higher than the platform mean there is a higher probability of having no large pipeline spills. Similarly, despite the fact that the pipeline mean is lower than the tanker mean, there is a higher probability of having an extremely large amount of spillage from large pipeline spills than there is from large tanker spills. However, the crossover point is quite high, about 9 million gallons, at which point there is in both cases a very high probability, above .99, that this total amount will not be exceeded. In short, it would take someone who is unusually worried about extremely high volumes of spillage relative to the more likely amounts to prefer the tanker on that account. On the other extreme, someone who is shooting for the highest probability of no spillage, regardless of what happens if there is spillage, would go for the pipeline over platforms if such a choice were possible. Despite these caveats, it is probably safe to say that most people would rank these densities in inverse order of their means. Nonetheless, anyone who expected the actual total spillage to by anywhere close to the mean is quite likely to be disappointed.

Figure 8.2's results are somewhat similar. Both crossovers still occur. However, because we are now dealing with a mean number of spills in each category in the neighborhood of 5 rather than .3 as in Figure 8.1, the law of large numbers implies the cumulatives are in a real sense tighter. The ratio of the variances to the square of the means has decreased by a factor of almost 10. The means have also increased by a factor of 10. This increase in the means is proportional to the volume produced under our assumptions.

8.1 Postscript

It is the almost universal practice in oil spill analysis, to generate "average spillage rates", usually obtained by simply dividing the total amount observed spilled in some activity over the volume handled. As we have indicated, this practice has very little to recommend itself and by themselves such average spillage rates are almost meaningless, particularly when they are offered as a prediction of the amount which will be spilled.

Nonetheless, it is of some interest to compare our mean spillage rates with the average spillage rates developed by others. The whole concept of a "mean spillage rate" only makes sense because we have assumed that the exposure variable in the Poisson process generating spills is volume handled - an assumption for which we were able to obtain some empirical evidence in the case of tankers (although number of tanker landings may well be better) but which was simply accepted in the case of pipelines and platforms. In any event, under this assumption, the mean spillage rates for our small, medium and large finds are all the same. By category the ratio of the mean of the total spillage to volume handled is:

Platforms	.00006
Offshore Pipelines	.00011
Tankers	.00016

Except for tankers, these rates are approximately the same as the "high" estimates developed in the Georges Bank report [10], that is, what used to be our high estimates of the mean spillage are now our average estimates. This is due primarily to the additional platform and pipeline spills in the present data base. The mean tanker spillage rate is about 5 times the high estimate developed in the Georges Bank study, reflecting the tremendous amount of spillage in the ECO data which we were not aware of when we wrote the Georges Bank study. The tanker spillage rate above is somewhat above that derived by SCEP and its follow-ons (.0001) [11]. The combined offshore platform and pipeline rate above is approximately the same as that obtained by the University of Oklahoma ($\sim$ .0002)[12]. In short, all analyses which make the assumption that spillage is in some sense proportional to the volume handled and use the same data are going to come up with about the same estimate of the average spillage rate.* However, even accepting the linearity hypothesis, by itself this estimate of the average spillage rate means very little. The variance of the spillage is at least as important and, from a biological point of view, the densities of the frequency and size of individual spills still more important.

*About the same, but not the same. The mean of our Gamma-based spill size density is higher than the classical estimator for small sample sizes.

9. Summary

1. The size range of an individual spill is extremely large--eight orders of magnitude. The great majority of all spills are at the lower end of this range. But most of the oil is spilled in a few very large spills.

2. For all the reasons given in 1, point estimates of spillage and spillage rates are practically meaningless. Further, from the biological point of view, the frequency and magnitude of individual spills is at least as important as total spillage. Therefore, we have attempted to estimate the probability densities of the number of spills of a given category which will occur from a given hypothetical development and the probability density of the size of these spills. In so doing, we have broken the analysis into six categories:

	> 42,000 gallons	< 42,000 gallons
Tanker/Barge		
Platform		
Offshore Pipeline		

3. In deriving these densities, we have taken a Bayesian approach and assumed spill incidence is generated by a Poisson process in which the exposure variable is volume handled and spill size by a Gamma process. We have used the available data to generate probability densities on the parameters of these processes starting with non-informative conjugate priors.

4. With respect to tanker spills above 42,000 gallons, the results indicate that for a small find (500 MM bbls in place) likelihood of no tanker spills is about .7, the likelihood of 1 such spill is about .25, and it is quite unlikely there would be more than 1 spill. However, for a large find (10,000 MM bbls in place), there will with high probability be somewhere between 4 and 10 spills, with the probability rather equally spread over these possibilities. The density of the size of these spills is spread over three orders of magnitude, with a mean of 2 million gallons and a standard deviation of 2.8 million gallons.

5. With respect to tanker spills below 42,000 gallons, the number of spills is much larger: in the hundreds for the small find and thousands for the large find. However, most of these spills are quite small. The mean size is 318 gallons and it's quite likely that an individual spill will be smaller than the mean. The available data on SBM spills is lacking in both quantity and quality. However, it appears that with respect to small operational spills, we can expect an SBM to have several times the incidence rate of a well-run shoreside fixed berth. However, the SBM may have a substantial effect on the density of large tanker spills by decreasing number of arrivals and decreasing the likelihood of groundings, which account for over 25% of all tanker spills over 42,000 gallons. If the SBM does have this effect, total volume spilled will almost certainly be lower for an SBM installation as opposed to an equivalent shoreside terminal.

6. With respect to platform spills over 42,000 gallons, the analysis indicates that for a small find, there is a .75 probability of no such spill, a .2 chance of 1 such spill, and it is quite unlikely that we will experience 2 or more such spills. For a large find, with high probability we will experience between 1 and 7 such spills with the probability rather equally spread over the possibilities. The density of the size of these spills is spread over two orders of magnitude, with a mean of about 1 million gallons and a standard deviation of 1.8 million gallons. The probability that such a spill will be less than 100,000 gallons is about .2. The probability that it will be greater than 5 million gallons is .05.

7. With respect to offshore pipeline spills over 42,000 gallons, a problem arises whether the coastal spills reported in the Gulf should be included in the data bases. The results aren't all that different, but assuming the coastal spills are included, the probability that we will have no large pipeline spills from a small find landed by pipeline is .75. The probability we will have 1 spill is about .2 and it is rather unlikely we will have more than 1 such spill. For a large find landed by pipeline, with high probability we will have somewhere between 1 and 9 large pipeline spills, with the probability rather equally spread over these possibilities. The density of the size of these spills is dispersed over an extremely large range. We are quite uncertain how large these spills will be. The mean is 1.9 million gallons; the standard deviation is 3.9 million gallons.

8. With respect to offshore production spills less than 42,000 gallons, it is impossible to separate the pipeline and platform spills in the Coast Guard data. The total number of both small platform and small pipeline spills will be in the hundreds for a small find and in the thousands for a large find. According to the EPA data, approximately 90% of these spills will emanate from the platforms. Almost all these spills will be quite small. The mean of these spills is about 100 gallons, and it is quite likely that an individual spill will be less than the mean.

9. With respect to total volume spilled over the field life, the mean for the small find is about 900,000 gallons for the small find landed by pipeline and 1,100,000 gallons for the small find landed by tanker. The variance is quite large and there is a substantial probability in both cases there will be no large spills at all. The standard deviation for the small find landed by pipeline is over 2.65 million gallons; if landed by tanker, 2.45 million gallons. Thus, there is a slightly higher chance of both small total spillage and very large total spillage with the pipeline rather than the tanker, reflecting our greater uncertainty about pipelines.

For a large find, the mean of the total spillage is 15 million gallons for pipeline transport and 19 million gallons for tanker. The ratio of the standard deviation to the mean is not quite so large for the large find as the small find, as the law of large numbers is beginning to work, although weakly. The standard deviation of the total spillage assuming tanker transport for the large find is 10.3 million gallons, and for the pipeline option is 11.5 million gallons.

10. All the above estimates of probabilities can reasonably be regarded as moderately pessimistic. They assume no improvement in technology or operations over the recent past. Also, other assumptions about the exposure variable in the Poisson process, such as platform spill incidence is proportional to number of platforms or tanker spill incidence is proportional to number of landfalls, would decrease the above estimates of spill incidence considerably, given the larger production per platform and vessel sizes are contemplated.

11. Finally, it is extremely important to realize that the above estimates of probabilities do not represent the net effect of OCS development. The net effect will depend on what one assumes about the oil which would be landed in the absence of the development. For example, if one assumes the same amount of crude will be landed on the East Coast with or without a development, then according to our analysis there is a substantial probability that there will be as many large spills without the find as with the find. Such assumptions are outside the scope of the primary effects analysis, and we have not undertaken to estimate these <u>net</u> effects.

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OIL SPILL TRAJECTORY STUDIES FOR ATLANTIC COAST AND GULF OF ALASKA

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Report to

Council on Environmental Quality

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OIL SPILL TRAJECTORY STUDIES FOR ATLANTIC COAST

AND GULF OF ALASKA

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CHAPTER I

DESCRIPTION OF APPROACH

Purpose

Oil spills can be transported many miles from the site of an accident by the action of wind, waves, and currents. The purpose of this study is to obtain insight into the likely behavior of oil spill trajectories emanating from each of the thirteen potential Atlantic outer continental shelf (OCS) production regions, Figure 1.1, and each of the nine potential production areas in the Gulf of Alaska, Figure 1.2, identified by the U.S. Geological Survey. In addition, we wish to examine in finer detail the likely behavior of oil spills emanating from three potential nearshore terminal areas, Buzzards Bay, Delaware Bay, and Charleston Harbor. Major emphasis in all these analyses will be placed on the probability of a spill's coming ashore, the time to shore, and, in the case of the terminal analyses, the wind conditions at the time the spill first reaches shore.

The state of knowledge with respect to oil spill transport

Despite the ten or fifteen papers available on the subject of oil spill transport on the ocean, it is fairly clear that we do not understand how the waves passing underneath an oil slick, the wind blowing over an oil slick, and the gross

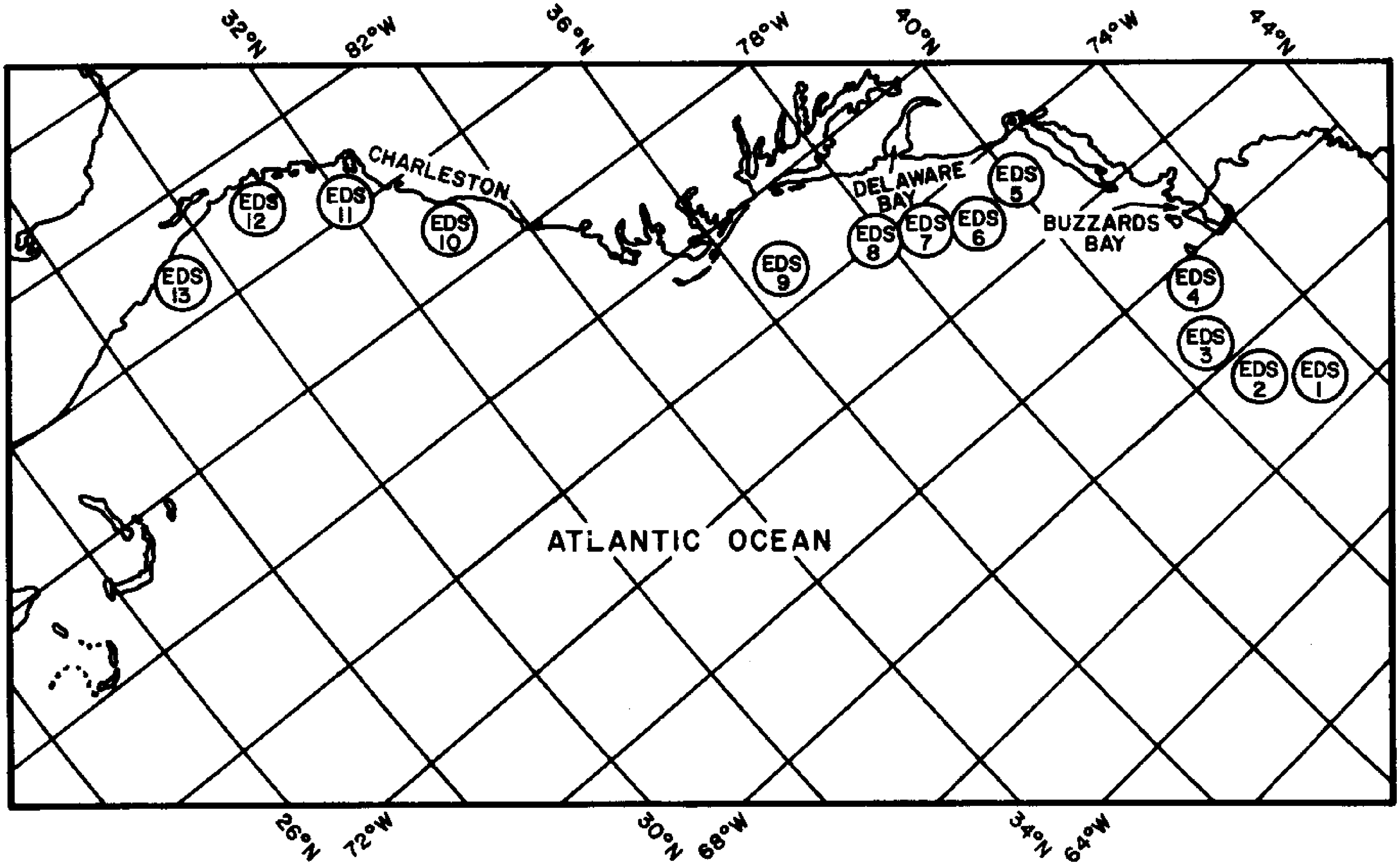

FIG. 1.1 LOCATION OF THE THIRTEEN HYPOTHESIZED EASTCOAST DRILLING SITES (EDS) AND THE THREE TERMINAL AREAS INVESTIGATED.

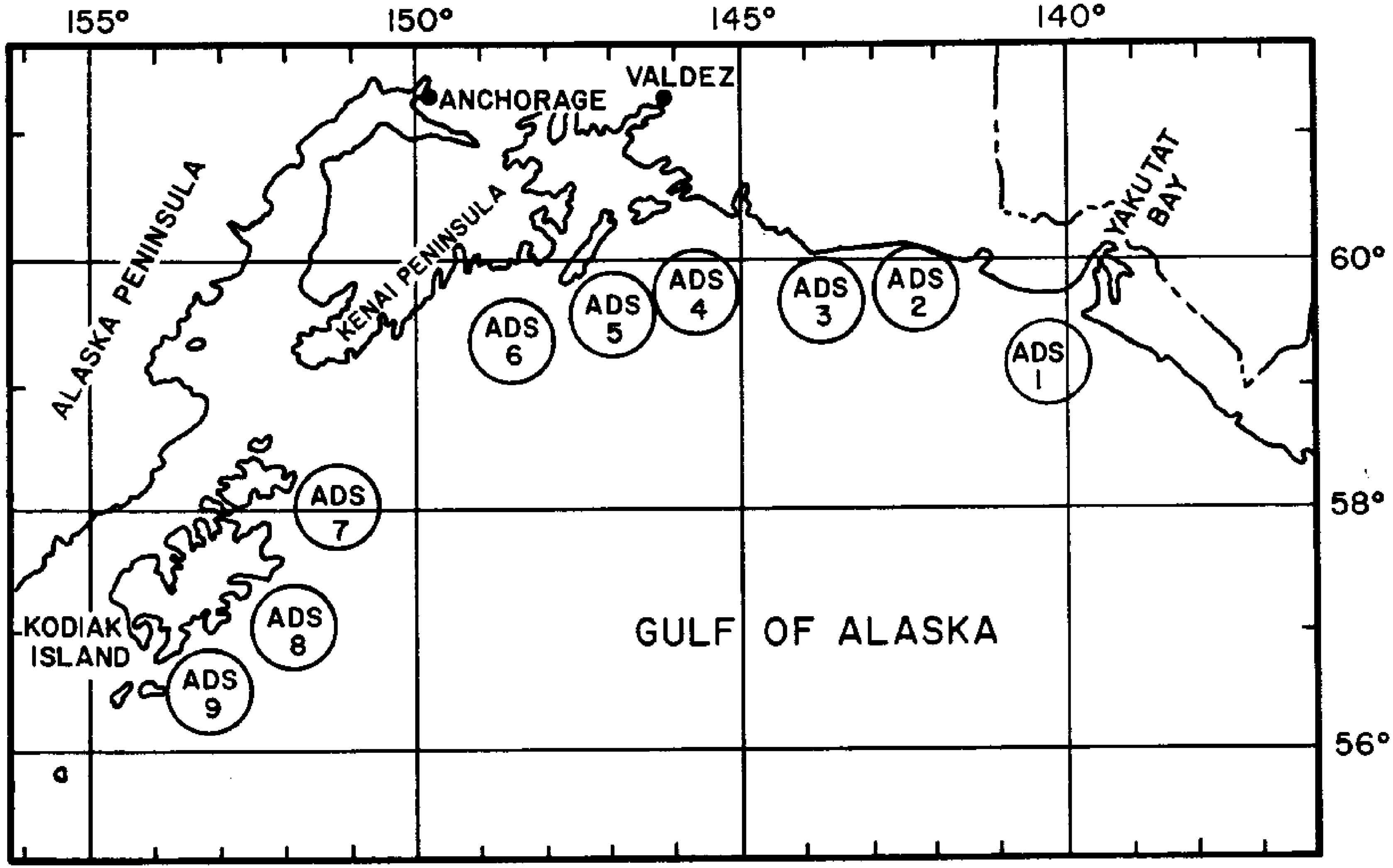

FIG. 1.2 LOCATION OF THE NINE HYPOTHESIZED GULF OF ALASKA DRILLING SITES (ADS).

motions of the underlying water combine to move the oil. In fact, we find that the motions of the water lying right at the air-sea interface in the absence of oil are still the subject of much current research (Lee, 1972, and Dorman, 1971).

Some of our ignorance with respect to oil spills is no doubt attributable to the novelty of our concern about oil spillage on the seas. It wasn't until the "Torrey Canyon" grounding and subsequent sinking (1967) that oil spills became important to the world at large. Since that time the number of tests involving the planned release of oil in the offshore region has been limited to no more than twenty, and these tests have usually had very specific goals associated with immediate operational problems, e.g., can we spot the oil on the surface using remote sensing devices (infrared, ultra-violet, and microwave scanners).

The available literature has tended to attribute the velocity imparted to the slick by the wind to the formation of a simple wind-induced surface boundary layer. A number of things seem to be responsible for this. First of all, an after-the-fact analysis of the trajectories of the major oil slicks of the "Torrey Canyon" disaster showed that the path of the oil at any instant could best be estimated by taking the vectorial sum of the underlying current velocity and 3.4% of the surface wind velocity (p. 150, Smith, 1969). Secondly, Wu's (1968) laboratory studies indicate that wind blowing over a clean water surface generated surface currents ranging from 3% to 5% of the wind speed, depending on the wind speed.

Moreover, Van Dorn's (1953) study of pond set-up included some data indicating that even if we suppress some of the wave motion with a surface film, we still get surface drift velocities similar to 3% of the wind speed. Finally, Hoult (1972) has presented a simple argument that if logarithmic, constant stress boundary layer profiles are formed in the air and in the water simultaneously, then the two profiles will differ only by a scaling factor equal to the square root of the ratio of the densities of air and water. This value is also approximately 3%. Unfortunately, this conjunction of similar values may amount to little more than happy coincidence.

There can be little doubt that Hoult's argument does indeed explain a major portion of Wu's observations. Furthermore, the existence of logarithmic profiles in surface wind boundary layers and in the underlying water have been verified in field observations reported by Dorman. This is about all that is required to validate the argument as it applies to water with a clean surface. However, these results do not apply to regions in which oil films cover the surface simply because it is known that the logarithmic behavior of the surface wind boundary layer collapses (see Ruggles, 1969, p. 40). Furthermore, Van Dorn's study also demonstrated that the shear force exerted on the surface of a pond having a thin surface film is only about half that observed on a pond having a clean surface. This indicates that Wu's results probably have only a qualitative bearing on our problem. Finally, Van Dorn's observation of the surface drift may be explained by invoking the arguments of Phillips (p. 38, 1969) regarding oil slick drift as induced by the action of suppressing waves.

This leaves us with only one really hard piece of information and that is the "Torrey Canyon" analysis. This, however, is a highly empirical observation. Judging by the comparison of observed and predicted trajectories in Figure 37 of Smith (1968), we can see that on some days a wind drift factor of 2.5% might have yielded a better fit, while on others, 4.5% might have been appropriate. Without a better understanding of the transport mechanism it is speculative to choose any particular value. In short, it is not at all clear that the present literature explains oil slick drift properly.

In addition to the uncertainties surrounding our understanding of oil spill transport, we also have the problem of specifying the motions of the waters in the offshore region. A brief listing of the type of motions we should like to consider would include tidal motions, geostrophic motions, and wavelike motions of either the inertial type or the Kelvin (or Shelfwave) type. Unfortunately, we are presently just at the point of being able to identify these motions. The creation of a model in which we coupled all of them together and attempted to relate them to atmospheric driving would be an almost hopelessly speculative task.

Our approach

In view of the abovementioned problems, it is clear that any sort of model we might conjure up for estimating spill trajectory probabilities must necessarily be a fairly humble and somewhat limited creature. Its results must be accepted with an amount of reservation commensurate with our uncertainty. Moreover, the model preferably should be fairly simple so that it is possible to understand the sensitivity of the output to variations in the parameters governing the model's behavior.

An obvious candidate for the job is the simple observation by Smith that the oil on the surface tends to move at a velocity approximately equal to the vectorial sum of 3% of the surface wind velocity and the current velocity, which we will divide into the tidal current and something we will call the residual current.

$$\vec{U}_{oil} = .03\vec{U}_{wind} + \vec{U}_{tidal} + \vec{U}_{residual} \qquad (1.1)$$

For the spills emanating from the potential offshore production sites, we will ignore the effect of tidal motions. This omission will generate minor errors as long as the spill trajectory covers a sizable number of tidal cycles, in which case the net transport due to tidal action will be quite small, or the tidal velocities are small or both. Over the Georges Bank the former consideration obtains; over the rest of the offshore area, the latter is true.

Our definition of residual current, as whatever's left over, is necessarily fuzzy. What we have in mind here is currents whose period of fluctuations is large with respect to the life of a spill, periods of the order of months. Included in this category would be river flows, the Gulf Stream, and large-scale geostrophic flows. Our basic assumption is that there is an underlying residual flow which is steady over the life of the spill. That is, our model explicitly omits medium-scale phenomena such as the eddies which are shed by the Gulf Stream, which have excursions of tens of miles and periods of several days. We are also ignoring shelf-wave phenomena.

Usually, the specification of this underlying residual current in an area of interest will be that set of input variables subject to the greatest uncertainty. Our procedure will be to use whatever current measurements are available, drift bottle data, the geostrophy of the region and considerable oceanographic intuition to develop hypotheses for these residual flows. We will then test the sensitivity of our results to changes in these hypotheses.

With respect to the wind, we require a model which exhibits both the variability and the persistance of the wind. In the past, in air quality studies involving the wind, the standard practice has been to consider only the steady-state properties of the wind. This has lead to much emphasis on the wind rose as the principle statistic. The wind rose gives us the probability that at any arbitrarily selected time the wind will be blowing from a particular direction at a mean speed (or perhaps in one of several speed ranges). If the phenomenon we are interested in is very short-lived, on the order of minutes or a very few hours. this may be acceptable.

However, if the phenomenon lasts for several hours or more, the length of time the wind blows in a particular direction and the direction to which it changes become important.

To simulate the random wind behavior through time, we have chosen to model the wind as a first-order Markov process which can make a jump from one direction to another every three hours. We assume that the probability that the wind will shift from one direction to another depends only upon the direction from which the wind is presently blowing. For our offshore spill tracking analyses, we assume there are nine such "directions" (CALM, N, NE, E, SE, etc.). The procedure then is to obtain tapes of the three-hourly records of a weather station as close as possible to the hypothetical spill area. Table 1.1 shows the wind data which was collected from the National Climatic Center for these analyses. A computer program was written which reads these tapes and for a given season outputs the percentages of time that, when the wind was in, say, the east, three hours later it was blowing from, say, the north. This ratio is used as an estimate of the probability of this shift. This was done for all eighty-one possible combinations of wind direction now and wind direction three hours from now for each weather station, in each of four seasons, generating 9 x 9 transition matrices such as that shown in Table 1.2 for the region lying off Yakutat in the Gulf of Alaska in winter. Presuming the wind is now from the north, then the values in the row of the matrix labeled N give us the estimates of the probabilities that the wind will be

TABLE 1.1

WIND DATA SELECTED FOR THE VARIOUS AREAS STUDIED

Region Modeled	Source of Wind Data	Type of Record
Georges Bank (offshore region)	Nantucket Island Airport	5 years, 3 hourly
Delaware Bay	Wilmington, Del. Airport	10 years, hourly and 3 hourly
Buzzards Bay	Otis AFB, Falmouth, Mass.	10 years, hourly and 3 hourly
Charleston Harbor	Charleston, S.C.	10 years, hourly and 3 hourly
Mid-Atlantic (offshore region)	Otis AFB, Falmouth, Mass.	10 years, hourly and 3 hourly
	Kennedy Airport, L.I., N.Y.	10 years, hourly and 3 hourly
	Atlantic City, N.J.	10 years, hourly and 3 hourly
	OSV "Hotel"	6 years, 3 hourly
South Atlantic (offshore region)	Charleston, S.C.	10 years, hourly and 3 hourly
	Savannah, Ga.	10 years, hourly and 3 hourly
	Jacksonville, Fla.	10 years, hourly and 3 hourly
	Daytona Beach, Fla.	10 years, hourly and 3 hourly
Gulf of Alaska	Yakutat, Alaska	5 years, hourly
	Middleton Is., Alaska	5 years, hourly
	Kodiak Naval Station, Kodiak, Alaska	3-1/2 years, 3 hourly

3 HOUR TRANSITION MATRIX: WINTER YAKUTAT, ALASKA

	CALM	N	NE	E	SE	S	SW	W	NW
CALM	0.691	0.03C	C.112	0.111	0.023	0.006	0.003	0.011	0.014
N	0.343	0.043	C.100	0.229	0.043	0.057	0.C14	0.057	0.114
NE	0.185	0.029	C.327	0.398	0.031	0.01C	0.003	0.009	0.007
E	0.073	0.0C7	C.154	0.659	0.077	C.011	0.C09	0.006	0.003
SE	0.057	0.007	C.084	0.324	0.395	0.C91	0.020	0.014	0.CC7
S	0.C41	0.017	C.C91	0.198	0.140	C.38C	0.091	0.025	0.017
SW	0.094	0.047	C.156	0.109	0.047	0.172	0.281	0.078	0.016
W	0.250	0.038	C.077	0.C58	0.077	0.038	0.192	0.212	0.058
NW	0.439	0.073	C.073	0.171	0.049	0.073	0.000	0.024	0.098

WIND STATISTICS FCR WINTER

DIRECTION	MEAN	STD DEV
CALM	C.CCC0E+00	C.00C0E+CC
N	4.C428E+00	1.5347E+C0
NE	6.3711E+00	3.6488E+00
E	8.6851E+CC	4.4299E+C0
SE	1.1811E+01	7.1261E+00
S	9.281CE+00	4.0782E+C0
SW	9.5938E+00	3.7405E+0C
W	6.9231E+00	4.5777E+00
NW	4.6829E+00	2.2679E+00

TABLE 1.2

in any of the nine states indicated by the column labels at a time three hours from now. For example, the probability is .343 that the wind will be calm three hours from now and .114 that it will be from the northwest. At the same time, the program computes the sample mean and standard deviation of the wind speed in each octant. Sample results of this computation are also shown in Figure 1.2.

For each launch point and season, this entire process is repeated 200 times, that is, 200 such samples are generated and tracked. The program keeps track of the percentage of these 200 spills which reach shore and where and the time they took to reach shore. This percentage is an estimate of the probability that a spill emanating from the specified launch point in the specified season will reach shore.

Wind model limitations

There are a number of possible pitfalls in the above model. We have already discussed an omission of large-scale eddies, our uncertainties about the residual current pattern. In addition, the wind statistics present some problems. First of all, there is the aliasing problem, the possibility that in selecting a three-hourly interval we are missing some important shorter-term fluctuations. Inspection of the auto-correlation function of the wind series for Nantucket Island indicated that, at least for this station, this was not the case. The average persistence of the wind was of the order of two to six hours, so we are catching most of the shifts.

Secondly, it is quite likely, given the cyclic nature of weather systems, that the probability of the wind direction three hours from now depends not only on the wind direction now, but also the wind direction three hours ago, and perhaps six hours ago. That is, in assuming a first order Markov process, we will be suppressing some of the systematic fluctuations in the wind. Furthermore, the future wind direction (and, more importantly, wind speed) is likely to be a function of the present wind speed as well as direction. Stewart, (73) in a detailed analysis of Nantucket data, concluded that the cumulative effect of the first order assumption and of suppressing the variability of the wind is the underestimation of net spill dispersion by about 10%. For the spills emanating from the potential offshore production sites, this error was accepted in the interests of computational efficiency.

These statistics are used in the following manner. A hypothetical spill is released from a specified point. A sample of the initial wind direction is obtained from steady-state statistics. The spill is then assumed to move under the influence of the residual current at the launch point and the mean wind from the selected direction according to equation (1.1) for three hours. Every simulated three hours the row of the transition matrix corresponding to the present wind direction is entered and sampled yielding a new wind direction and mean wind speed for the selected direction. The program also updates the residual current velocity and the season as the spill moves from one location to another. As the spill progresses on its trajectory, the computer keeps checking to see if it's reached shore or washed out of the region of interest. Assuming neither, the sample spill is allowed to go for 150 days. The result of this computation then is a wiggly line representing one possible spill trajectory which is consistent with the residual current hypothesis and the wind statistics.

For the more detailed analyses of the potential terminal areas, an expanded model was used to incorporate some of these phenomena. Here the state of the wind was described by one of 16 directions (N, NNW, NW, WNW, etc.) and one of three speeds (CALM, NOT CALM < 12 KNTS, > 12 KNTS). This implies a 33x33 transition matrix in which present wind speed can influence the likelihood of the wind speed and direction three hours from now. Also, once a state was obtained from the expanded transition matrix, the wind speed used was a sample from the wind speed density for that state as opposed to the mean of this density. If one attempts to go to a still more detailed description of the wind transitions, one finds that the number of occurrences of each transition is so low that the ratio of these occurrences to the total number for that row is an increasingly unreliable estimator of the probability of this transition.

Finally, and perhaps from a practical point of view, the most important problem with our wind model is that often the only available data in an area are from shoreside weather stations. The winds on shore may be materially different from those offshore due both to thermal effects and topography.*

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*We did ask for and receive the tapes for several lightships on the Atlantic Coast. Unfortunately, the wind reporting interval was irregular, apparently coupled to watch changes and mealtimes. Therefore, for our purpose, these data were essentially useless.

Throughout the analyses, we will try to keep this in mind and comment on the degree to which we can expect the available wind data to be representative.

CHAPTER II

ANALYSIS OF SPILLS EMANATING FROM POTENTIAL TERMINAL AREAS

Introduction

In this chapter our analysis of nearshore spills is presented for three potential terminal areas on the Atlantic Coast: Buzzards Bay, Delaware Bay and Charleston Harbor. The program used is the M.I.T. Nearshore Spill Tracking Model incorporating tidal currents and the 33x33 wind state transition matrix described earlier.

Current specification

The three areas used in the nearshore spill analyses were selected in part for the availability of published tidal current information. In all three regions, we were able to obtain hourly tidal current values from graphical displays of direction and numerical specifications of speed from U.S. Coast and Geodetic Survey publications (Tidal Current Charts, Delaware Bay, Buzzards Bay, and Charleston, S.C.). These hourly values were then entered into the gridwork we used to represent the transshipment area. The phase of the solar-lunar cycle was accounted for by applying the tabulated corrections for the spring and neap tides and by starting the process randomly during the lunar period. The publications containing this information had no statement of the accuracies we could expect from the charts, but it was our feeling, based on a survey of the data used to generate the Delaware Bay currents, that the charts were necessarily fairly empirical and approximate. However, we also felt that, compared with some of the other uncertainties we were forced to deal with, these charts were of a high quality.

One test we were able to perform to determine the quality of the current data was to estimate the average depth over each grid square (grid element) of Buzzards Bay and then to make a continuity calculation for a one-hour period of the tidal cycle. If the currents were accurately represented, if we could accurately specify the initial condition of the Bay, and if the currents were uniform with depth, then the tidal rise at the end of the hour should be on the order of 1/2 ft and it should be reasonably uniform over the Bay, or better yet, a wavelike profile should be evident.

The tidal rise observed for a grid element is controlled by the net flux of volume into (or out of) that element. The parameters determining the net flux into a grid element are the east-west velocity components of the grid elements lying on the east and west boundaries; the north-south velocity components of the grid elements to the north and south; the velocity components of the grid element itself; and the average depths in each grid element. The tidal rise in a grid element based on these parameters is as shown below.

Calculated Tidal Rise =

$$\frac{\text{Volume Flux into the Grid Element - Volume Flux Out}}{\text{Surface Area of the Grid Element}} \tag{2.1}$$

$$TR = TR_{true} + TR_{error} =$$

$$\frac{1}{\text{Area}} \sum_{i=1}^{2} \left(\frac{VX_i + VX_o}{2}\right) D_i - \sum_{j=3}^{4} \left(\frac{VY_j + VY_o}{2}\right) D_j \tag{2.2}$$

where the subscripts represent:

0 - the grid element being studied

1 - the grid element to the west

2 - the grid element to the east

3 - the grid element to the south

4 - the grid element to the north

and

D_i = minimum of [(depth in grid element + initial tidal height); and (depth in adjacent grid element + initial tidal height).]

We had little or no information about the initial tidal heights in the various grid elements so we were forced to do the calculations during an hour when there was little flow in the Bay. During this time we could assume small gradients in the tidal height and therefore approximate the initial heights as zero.

Selecting the period following maximum ebb and utilizing the equations above, we solved for the tidal rise. The results were not as discouraging as we might have expected: Typical tidal rises were on the order of one to five ft, and only a few places showed negative "rises." It was clear, however, that we were not in possession of a highly accurate model, as there was no pattern to the results. In order to estimate the magnitudes of the errors associated with such results, we performed the following analysis.

The calculated quantities in equation (2.2) were presumed to be composed of a true component and an error component that we presumed to be of zero mean, as shown below.

$$\begin{aligned} &(a) \quad VX_i = VX_{iT} + VX_{iE} \\ &(b) \quad VY_j = VY_{jT} + VY_{jE} \\ &(c) \quad D_i = D_{iT} + D_{iE} \end{aligned} \qquad (2.3)$$

These were substituted into equation (2.2) and the terms rearranged and the true tidal rise subtracted from both sides of the equation. The expected value of the squared tidal rise was then calculated. After the terms containing an error component with zero mean have been dropped, the equation reduces to equation (2.4).

$$\begin{aligned} E[TID_E{}^2] = {} & (0.456)^2 \; \bar{V}_E{}^2 \{8\bar{D}_E{}^2 + 2\sum_{i=1}^{4} \bar{D}_{iT} + 2\bar{D}_{1T}\bar{D}_{2T} - 2\bar{D}_{3T}\bar{D}_{4T}) \\ & + \bar{D}_E{}^2 \Big(\sum_{i=1}^{2} \overline{VX}_{iT} + \sum_{j=3}^{4} \overline{VY}_{jT}\Big) + 2\bar{D}_E{}^2 (\overline{VX}_{0T} = \overline{VY}_{0T}) + \\ & 2\bar{D}_E{}^2 \Big(\sum_{i=1}^{2} \overline{VX}_{0T}\bar{V}_{iT} + \sum_{j=3}^{4} \overline{VY}_{0T}\overline{VY}_{jT}\Big) \end{aligned} \tag{2.4}$$

Here the variance of the velocity errors and the variance of the depth errors have been presumed to be the equal for the grid element being considered and the four elements surrounding it. The mean velocity components, depths, tidal rises and squared tidal rises were calculated over the Buzzards Bay grid. The mean squared depth error was then estimated for the region by presuming that the true tidal rise was zero (a conservative estimate). Solving for the velocity component error, we obtained an RMS component velocity error of 0.22 knots, or a RMS total velocity error of 0.32 knots.

However, a closer investigation of the errors shows that many large errors occurred in the Vineyard Sound area. Here, high velocities, a complicated geography and rapidly varying depths combined to increase the error in the tidal rise model. An inspection of the spill model results for the two launch points in Buzzards Bay revealed that a relatively small percentage of the spills are influenced by the currents in Vineyard

Sound. Recalculating the errors for just the Buzzards Bay area yields an RMS component velocity error of 0.12 knots and an RMS total velocity error of 0.16 knots.

Clearly, the analysis leading to this result is relatively crude, and only good for orders of magnitude. Further, the continuity criterion is only peripherally related to the tidal current specification. However, it does tell us that our errors in the Buzzards Bay model are at least on the order of 0.1 to 0.2 knots. This in turn gives us some insight into the accuracies associated with our other two nearshore current models, for they were deduced by the same technique.

However, high as these errors might be, they are probably well within the other uncertainties associated with the analysis. Furthermore, there is, at present, no better simple technique for achieving this result. Certainly, on a qualitative level, we can expect these models to give illustrative results, and, within factors of two or three, the proper quantitative results. In summary, we should be dealing with a fairly representative model in the nearshore region.

<u>The spill model</u>

The spill was modeled for these nearshore studies as a nine-point array, as shown in Figure 2.1. The outer four points were chosen to be at a distance of 1/2 of a nautical mile from the center of the array. This is a length scale appropriate to the spread of a one-million-gallon oil spill after about 10 hours. The inner aray of four points is at a radial distance of about 0.25 nautical mile. This is appropriate to the spread of a one-million-gallon spill after one hour. The idea behind this

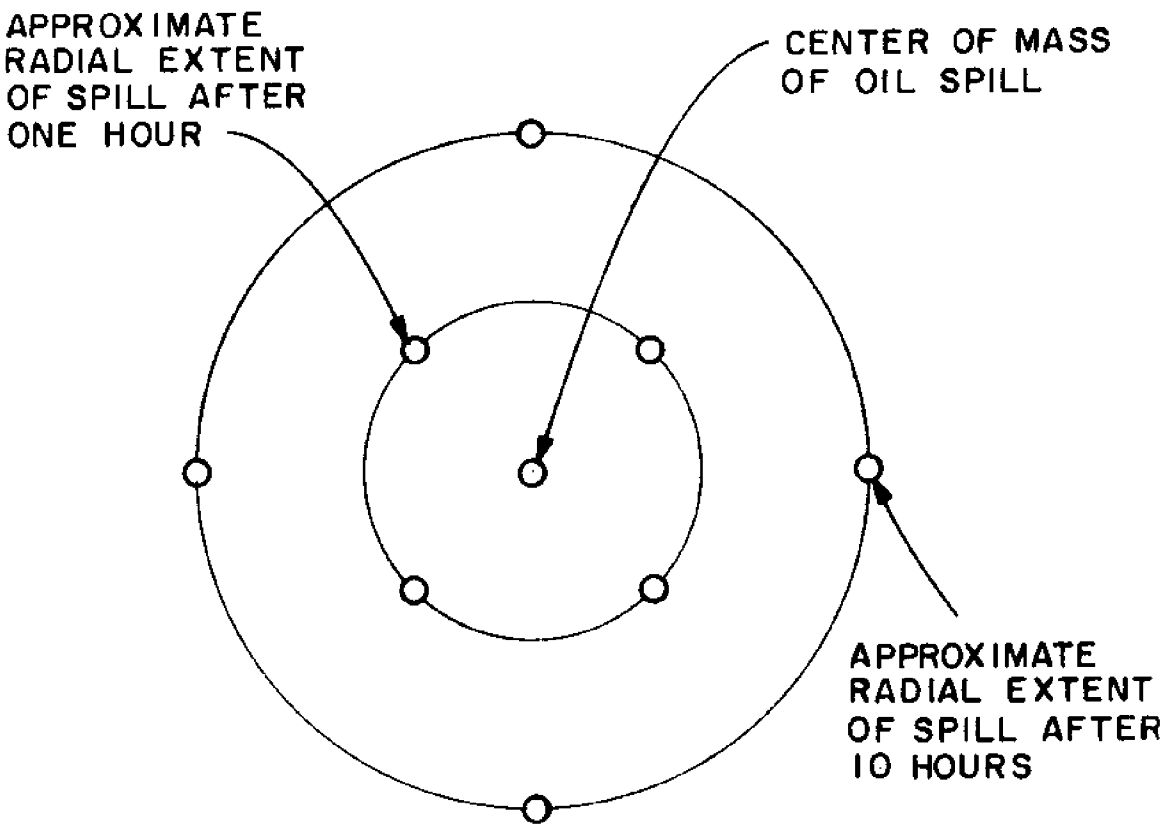


FIGURE 2-1 9 POINT ARRAY REPRESENTATION OF 1 MILLION GALLON OIL SPILL representation of an oil spill is that, while we are not able at present to determine the timewise variation of the shape and areal extent of an oil spill under realistic conditions, the effect of spreading may nevertheless be of great importance in the nearshore area. Consequently, it is desirable to see if the more removed points impact the same areas as the central point. Should different regions be impacted by outer and inner points, then we have a clear indication that the volume of the spill is important.

The parameters investigated in these studies are the percentage initial impact in a given shoreline grid area, the minimum and average times to shore for the initial impact, and the distribution of time and wind speed on impact.

Due to the rather rudimentary knowledge we now have with respect to the mechanisms responsible for the biological impact, the object in our analysis was merely to determine whether the grounding occurred in adverse circumstances, or in fairly benevolent ones. For this purpose, we have defined a "critical" impact area as one that during at least one season of the year gets hit by 5% or more of the spills released from the launch site, and, of the spills impacting this area, more than 20% beach themselves in winds over 12 knots and the majority of these do so within 30 hours. These are areas that have a high chance of being impacted by a spill under conditions that appear to be the most harmful.

The following sections summarize our results for each nearshore area. Each is arranged in the same fashion. First comes a figure of the area, indicating the gridwork we have used to represent the area. Next come four graphs indicating the seasonal probability of a shoreline grid area being hit by a spill released from the specified launch point. Then a graph indicating the average and minimum times to shore for all those areas having a greater than 5% chance of being struck during at least one season of the year. Next are four graphs depicting the behavior of the wind and the time to grounding for all the more likely (more than 5%) impact zones. These are the critical impact zones. The volume effects are then summarized by indicating which new areas become critical if we consider only the outer array, or which ones become critical with the middle array. The last graph depicts the growth in the probability of going ashore as a function of time. Finally, the results are briefly summarized for the launch point.

In reviewing these figures, remember that we are depicting probabilities and statistics relating to one trajectory. A 5% chance of being impacted means that in a large number of spills the area in question would be hit by about one-twentieth of the total number of spills. The rest of the time it would not be hit, unless it was hit with remnants of the spill after first going aground. These are only the initial impact points, and they serve only to locate the most exposed positions with respect to the indicated launch site.

Buzzards Bay

Figure 2.2 shows the map of Buzzards Bay employed by the nearshore spill model. The shoreline was broken down into 33 possible impact areas, as shown in Figure 2.2.

BUZZARD'S BAY

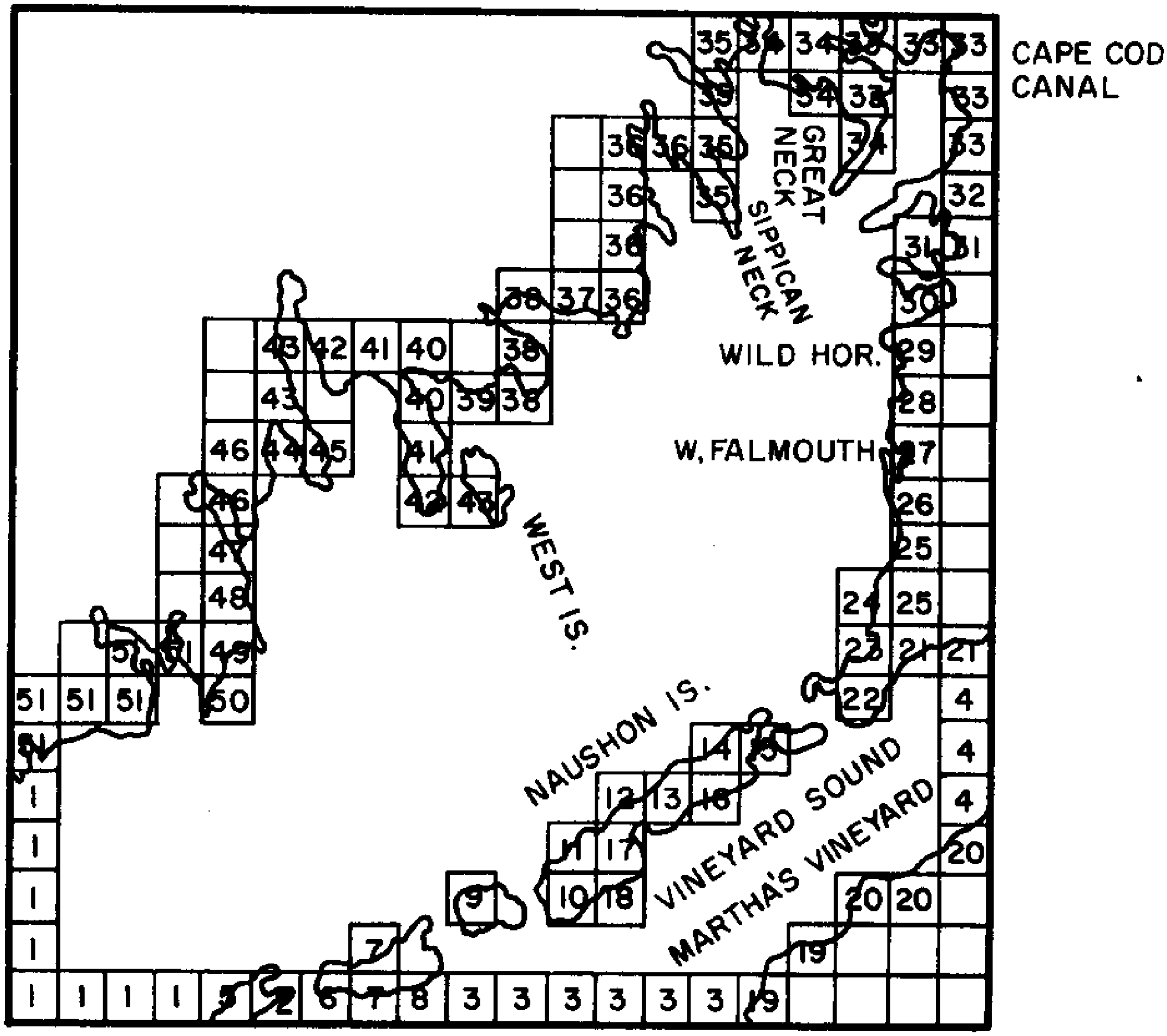


FIG. 2.2 MAP OF BUZZARD'S BAY

The wind data used for the Buzzards Bay studies were those for Otis Air Force Base, three miles inland from North Falmouth, for the years 1959 through 1968. Two spill launch points in Buzzards Bay were studied:

1) One mile off West Falmouth about one-half mile farther from shore than the place where the barge _Florida_ went aground and spilled about 100,000 gallons in December 1967.

2) Mouth of New Bedford Harbor.

Figures 2.3 through 2.6 show the model estimates of the likelihood of the first impact area for the primary (central point) of a spill emanating at the West Falmouth location. As the figures indicate, due to the strong westerly component in the wind, the Cape Cod shore is the high likelihood initial impact area. In spring and autumn, the impact areas are slightly more dispersed than in winter and summer. Figure 2.7 indicates the minimum and average times to initial grounding for several of the higher probability impact areas along the eastern shore of the Bay. The minimum times to shore range from one or two hours to 24 while the average times range from five hours to 40 hours. In general, the times to shore are somewhat smaller in summer and winter than they are in the spring and fall. West Falmouth and the immediately adjoining areas have the highest probabilities and the shortest landing times, as might be expected.

The wind conditions under which a spill comes ashore may be of some importance biologically. The higher the wind, the

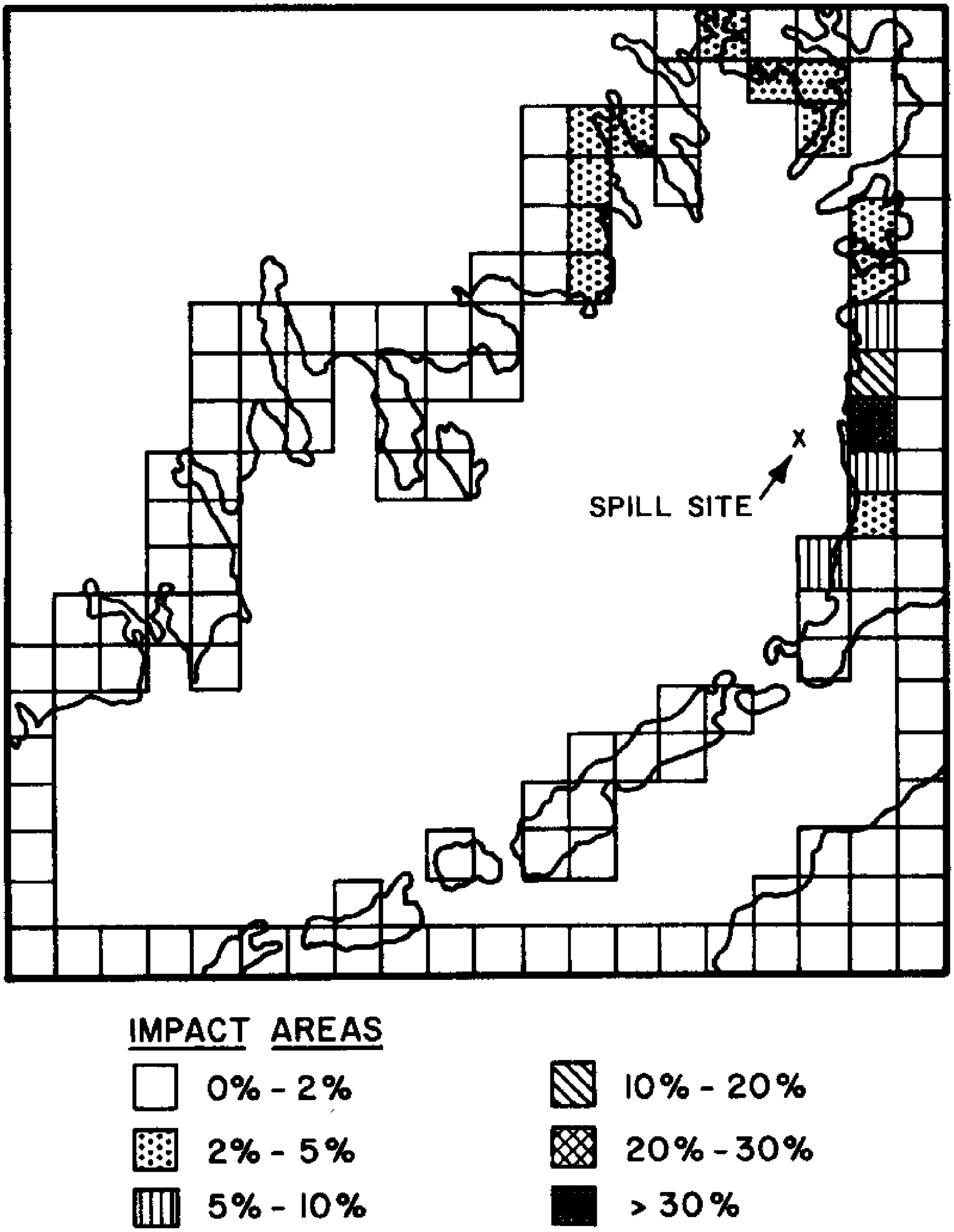
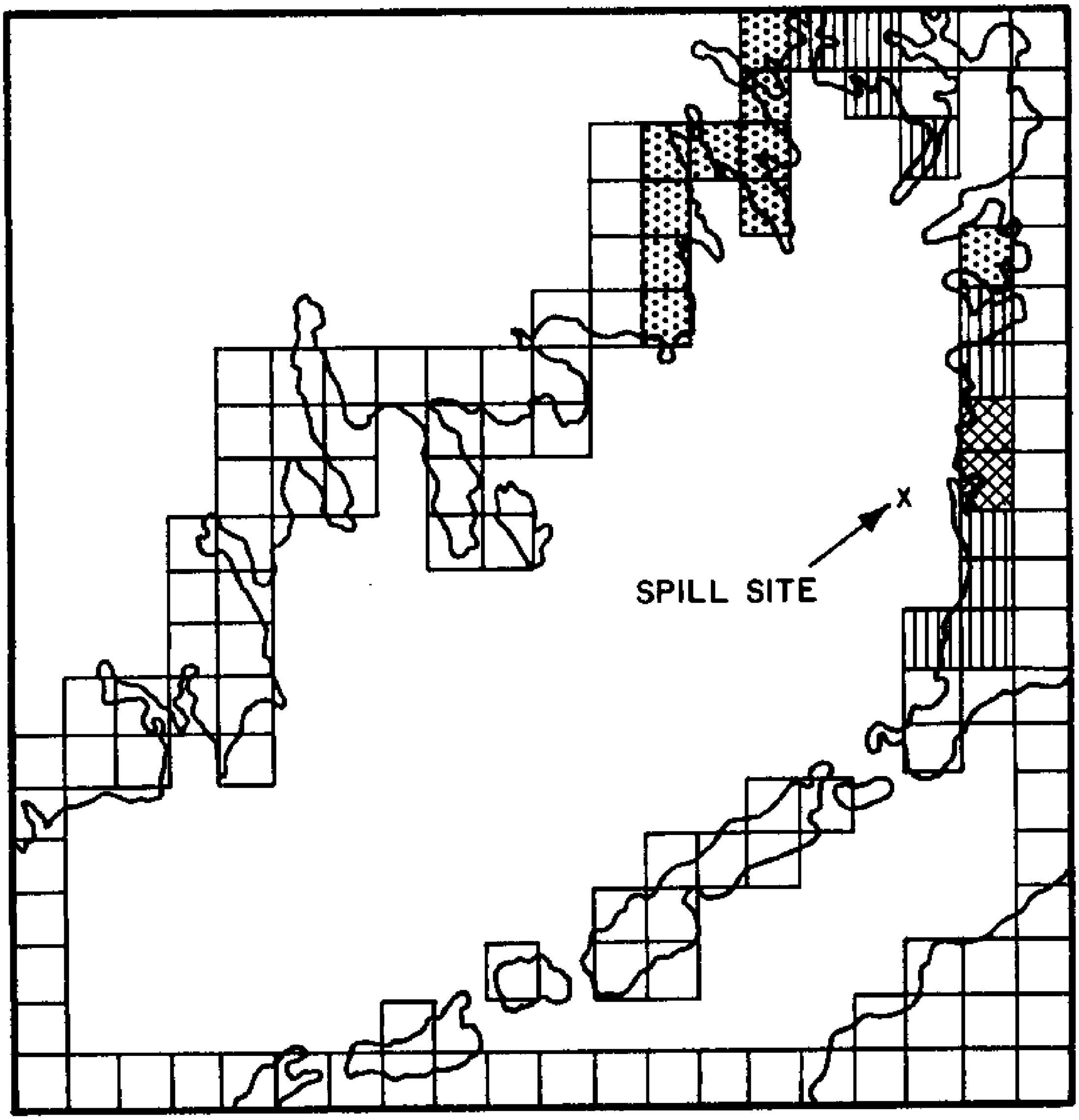


FIG. 2.3 BUZZARD'S BAY IMPACT AREAS FOR THE WEST FALMOUTH SPILL SITE. SEASON - WINTER



IMPACT AREAS

0% - 2%

2% - 5%

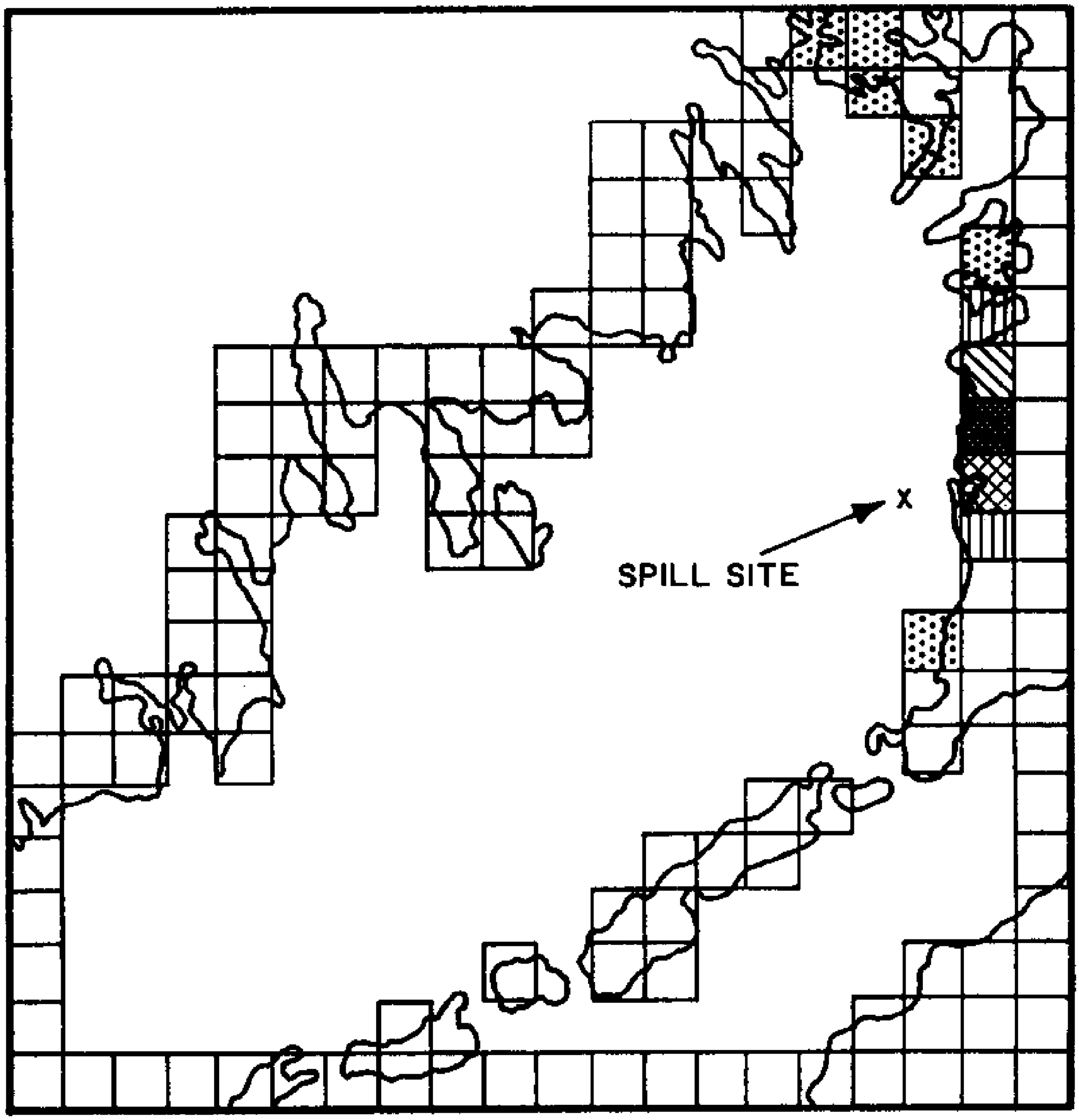
5% - 10%

10% - 20%

20% - 30%

> 30%

FIG. 2.4 BUZZARD'S BAY IMPACT AREAS FOR THE WEST FALMOUTH SPILL SITE. SEASON - SPRING



IMPACT AREAS

0% - 2%	10% - 20%
2% - 5%	20% - 30%
5% - 10%	> 30%

FIG. 2.5 BUZZARD'S BAY IMPACT AREAS FOR THE WEST FALMOUTH SPILL SITE. SEASON - SUMMER

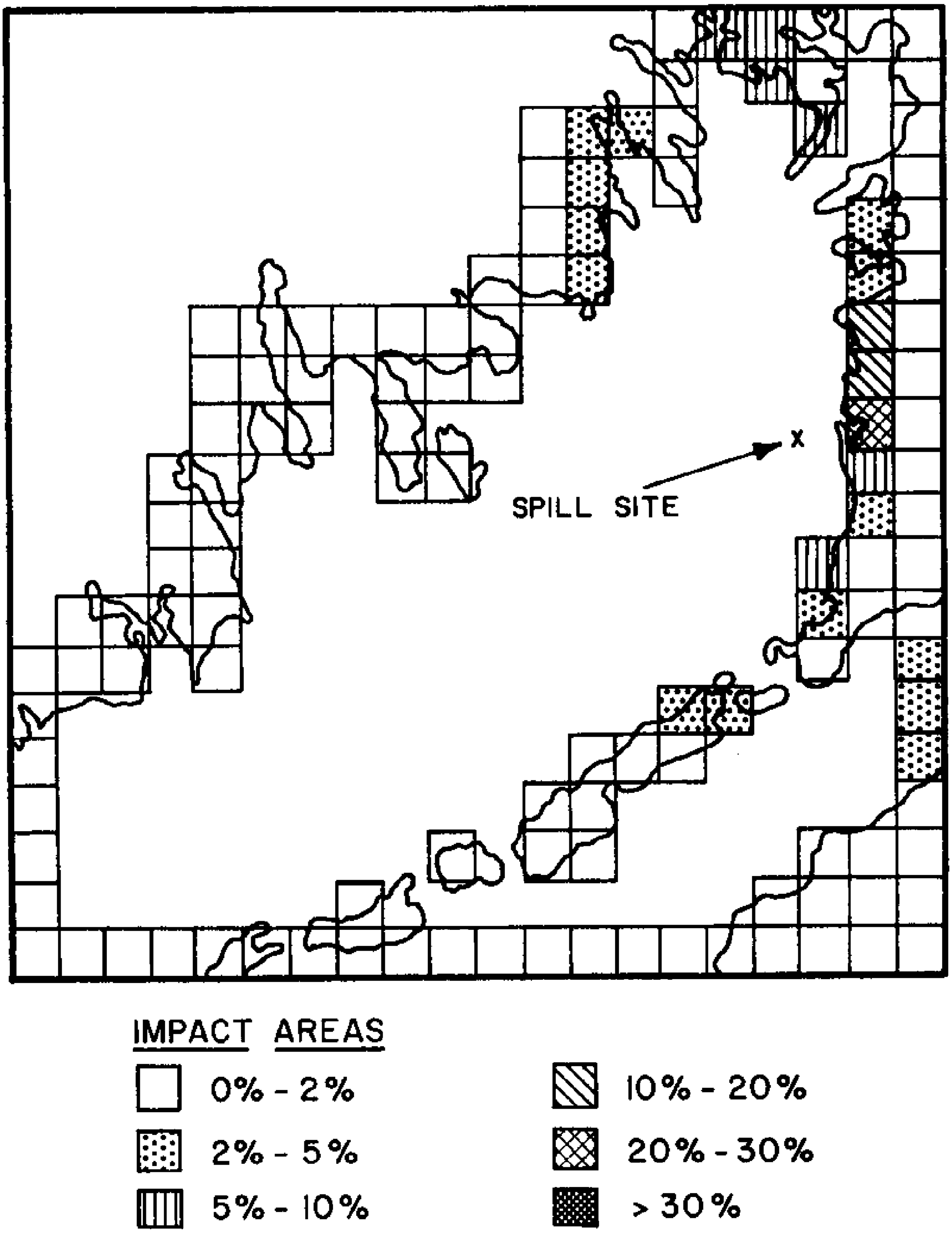


FIG. 2.6 BUZZARD'S BAY IMPACT AREAS FOR THE WEST FALMOUTH SPILL SITE. SEASON - AUTUMN

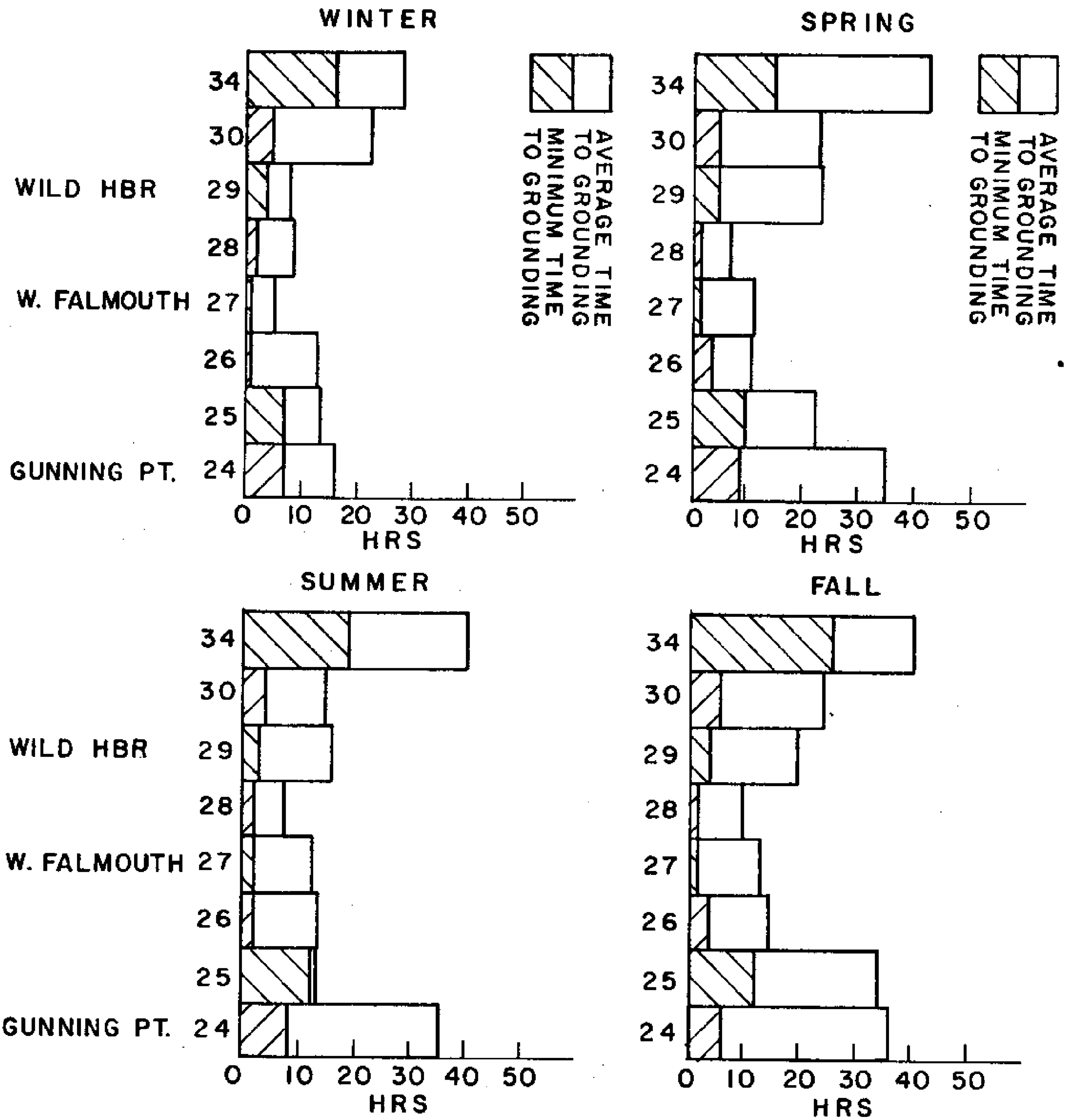


FIGURE 2-7 TIMES TO GROUNDING (WEST FALMOUTH SPILL SITE

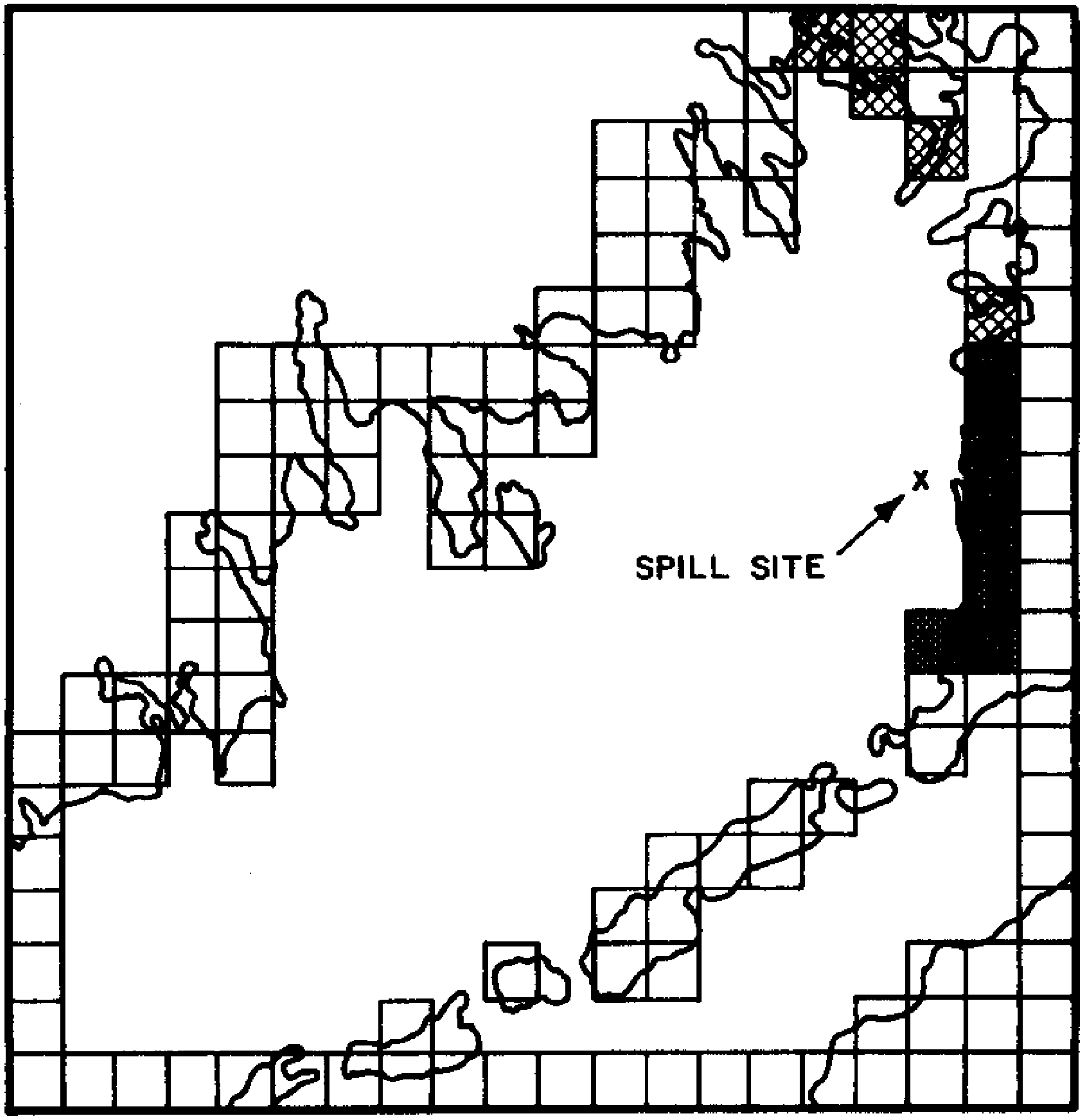
larger the waves, the more rapid and thorough the vertical mixing of oil components into the water column. Further, if the waves are breaking, then we can expect at least part of the slick will be folded physically into the water column. Lassiter et al. have analyzed some of these phenomena (same cover).

The wind conditions under which a spill occurs are also of considerable importance with respect to the dispatch with which a containment system can be deployed and its subsequent efficacy.

One of our purposes in going to the expanded transition matrix was to allow us to comment in at least a very preliminary manner on these phenomena. Waves begin breaking at about 12 knots and, with the expanded matrix, one can keep track of the number of spills which come ashore while the wind is blowing more than 12 knots.

In Figures 2.8 through 2.11, we have indicated the impact areas into regions in which less than 20% of the spills which come ashore in that region do so during wind speeds greater than 12 knots and areas in which more than 20% of the landings have this characteristic. Once again, a substantial portion of the eastern shore fits into the latter category.

Figure 2.12 together with the earlier figures indicates that for the West Falmouth launch site the size of the spill will have little effect on the amount of shore initially impacted. The oil from the secondary and tertiary points around the primary point behaves in essentially the same manner as the primary point, that is to say, with reasonably high probability the oil initially located at these points will move more or less directly to the eastern shore. This, of course, does not imply that the

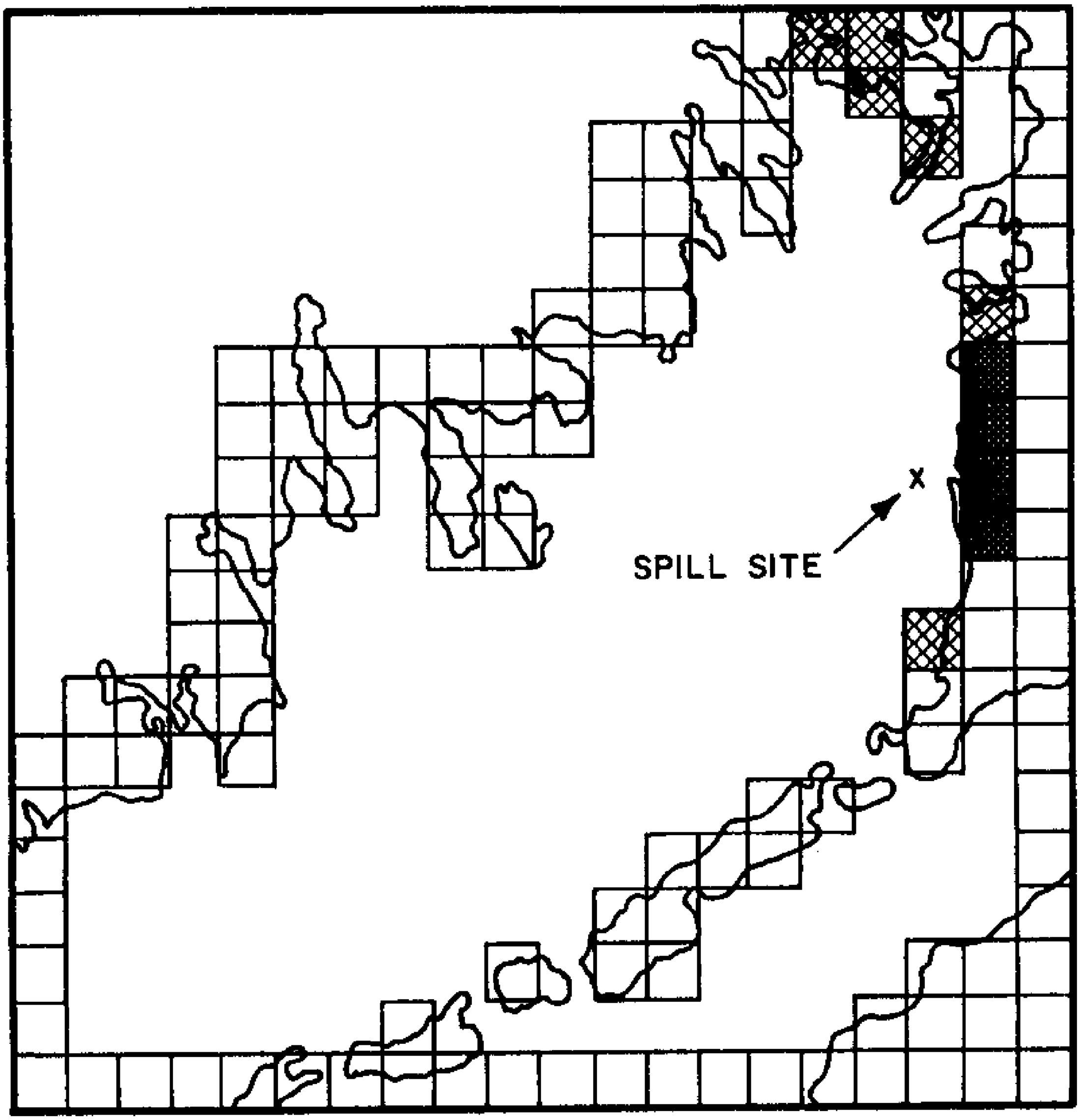


LIMITED TO AREAS WITH IMPACT >5% IN ANY SEASON

- <20% OF IMPACTS OCCUR WITH WIND >12 KNOTS
- MOST COME ASHORE WITH t>30 HRS
- MOST COME ASHORE WITH 10<t<30 HRS
- MOST COME ASHORE WITH t<10 HRS

(the last three: >20% OF IMPACTS OCCUR WITH WIND >12 KNOTS)

FIG. 2.8 BUZZARD'S BAY CRITICAL AREAS FOR SPILLS OCCURRING AT WEST FALMOUTH SITE. SEASON - WINTER

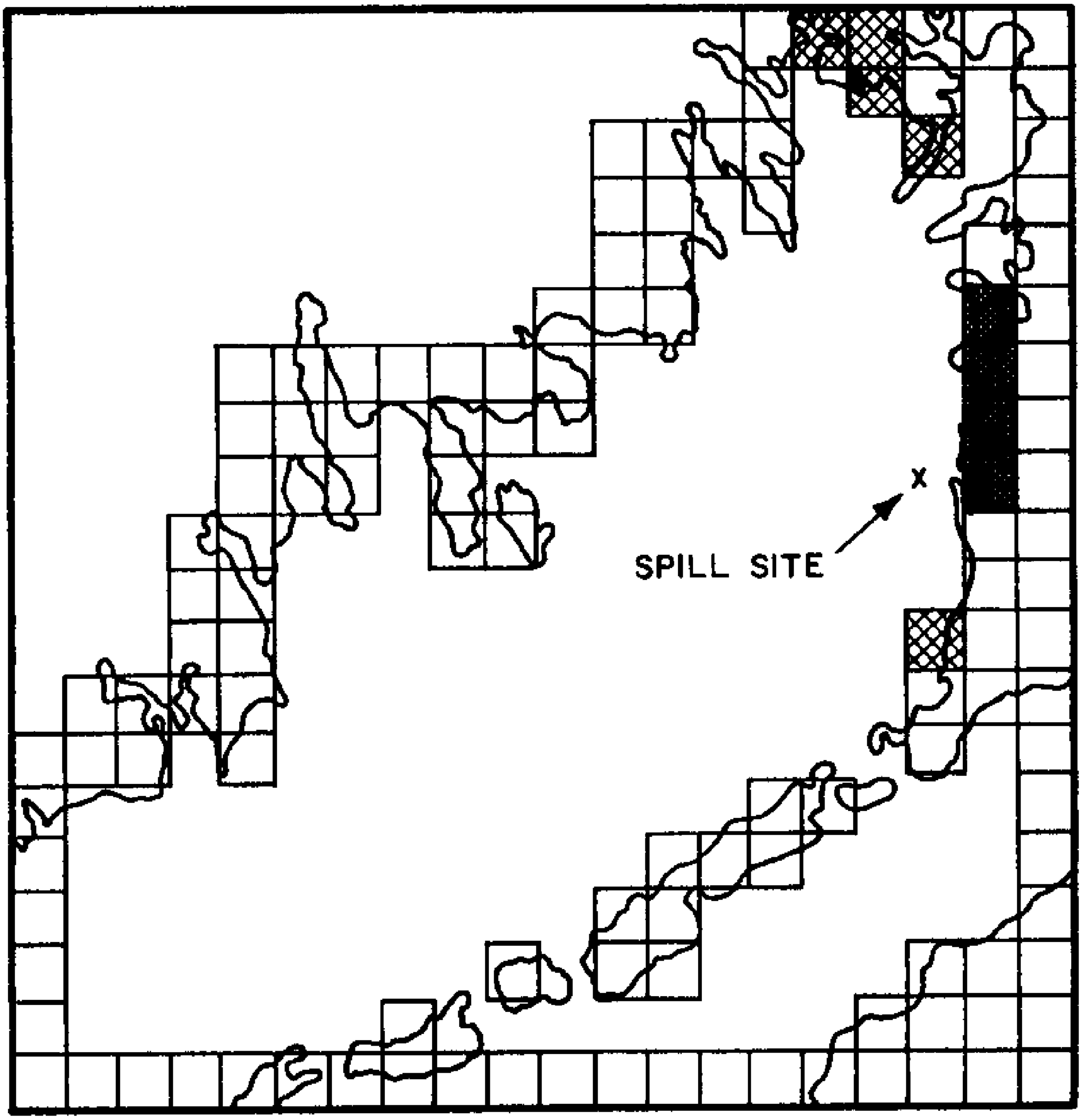


LIMITED TO AREAS WITH IMPACT >5% IN ANY SEASON

- <20% OF IMPACTS OCCUR WITH WIND >12 KNOTS
- MOST COME ASHORE WITH t > 30 HRS
- MOST COME ASHORE WITH 10 < t < 30 HRS
- MOST COME ASHORE WITH t < 10 HRS

(the last three: >20% OF IMPACTS OCCUR WITH WIND >12 KNOTS)

FIG.2.9 BUZZARD'S BAY CRITICAL AREAS FOR SPILLS OCCURRING AT WEST FALMOUTH SITE. SEASON - SPRING

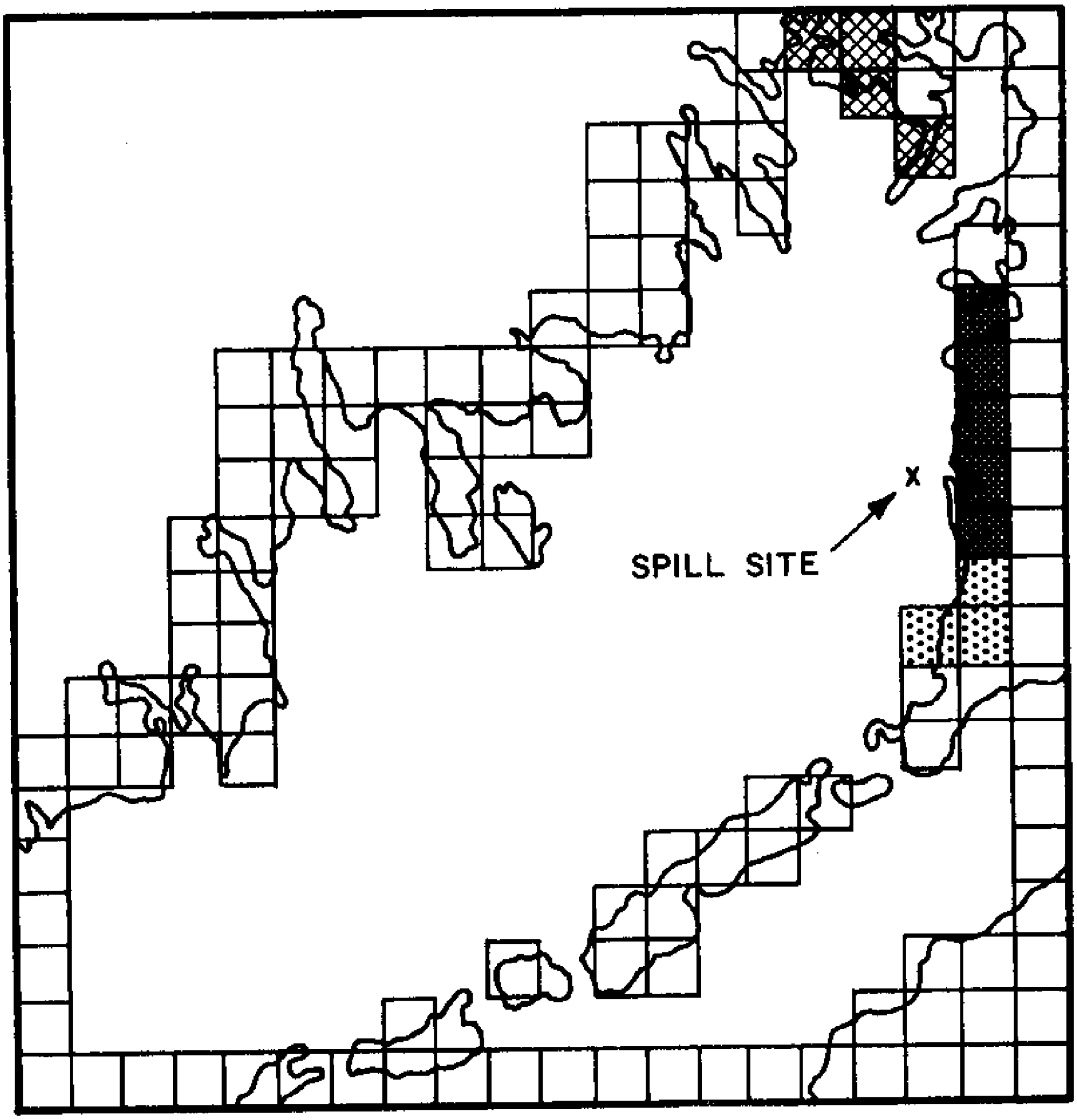


LIMITED TO AREAS WITH IMPACT >5% IN ANY SEASON

- <20% OF IMPACTS OCCUR WITH WIND >12 KNOTS
- MOST COME ASHORE WITH t>30 HRS
- MOST COME ASHORE WITH 10<t<30 HRS
- MOST COME ASHORE WITH t<10 HRS

(last three: >20% OF IMPACTS OCCUR WITH WIND >12 KNOTS)

FIG. 2.10 BUZZARD'S BAY CRITICAL AREAS FOR SPILLS OCCURRING AT WEST FALMOUTH SITE. SEASON - SUMMER

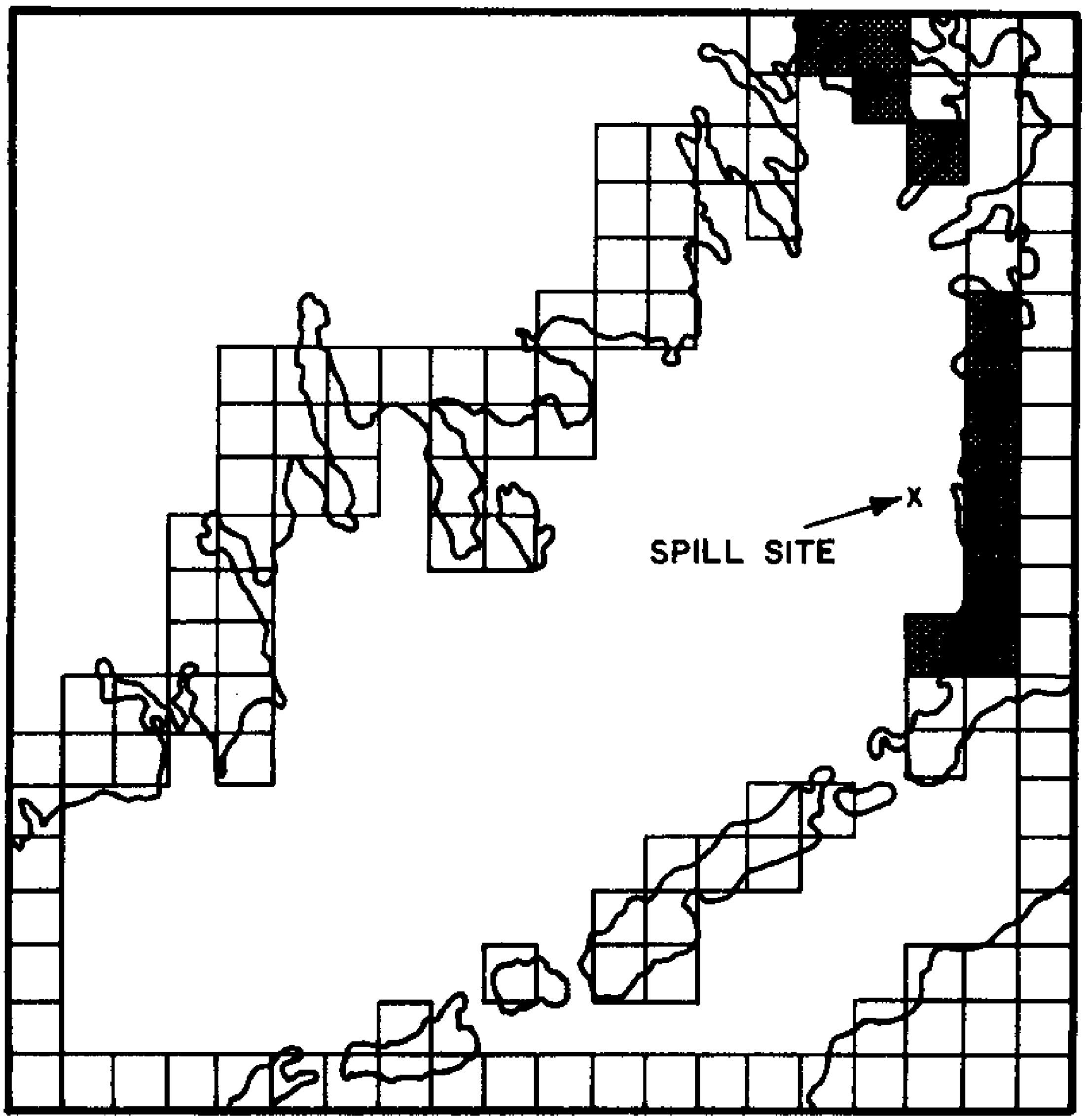


LIMITED TO AREAS WITH IMPACT >5% IN ANY SEASON

- <20% OF IMPACTS OCCUR WITH WIND >12 KNOTS
- MOST COME ASHORE WITH $t > 30$ HRS
- MOST COME ASHORE WITH $10 < t < 30$ HRS
- MOST COME ASHORE WITH $t < 10$ HRS

}> 20% OF IMPACTS OCCUR WITH WIND > 12 KNOTS

FIG. 2.11 BUZZARD'S BAY CRITICAL AREAS FOR SPILLS OCCURRING AT WEST FALMOUTH SITE. SEASON - AUTUMN



DEFINE CRITICAL AS IMPACT >5% IN ANY SEASON AND >20% COME ASHORE WITH WIND >12 KNOTS AND A MAJORITY OF THESE COME ASHORE WITHIN 30 HOURS.

- CRITICAL UNDER PRIMARY
- CRITICAL UNDER SECONDARY (BUT NOT PRIMARY)
- CRITICAL UNDER TERTIARY ONLY

* NOTE THAT SECONDARY AND TERTIARY POINTS CREATED NO NEW "CRITICAL AREAS".

FIG. 2.12 BUZZARDS BAY CRITICAL AREAS, POINT GROUP DEPENDENCE (FALMOUTH SPILL) amount of damage will be independent of the size of the spill.

Figure 2.13 indicates the percentage of spills aground as a function of time. Notice that in the summer and winter the times to shore are lower than for the other two seasons. This corresponds to the prevalence of the strong west and northwesterlies in the winter and the strong southwesterly breeze in the summer.

The main purpose of the West Falmouth analysis was testing the program in a relatively simple situation where we had, unfortunately, at least one piece of empirical data. A somewhat more interesting spill launch point is that indicated in Figure 2.14 located in the middle of the Bay south of New Bedford Harbor. As Figures 2.14 through 2.17 indicate, the initial impact areas for this launch point are considerably more widely dispersed than for the West Falmouth site. Once again, the eastern shore takes the brunt of the impact, but now there is a definite seasonal pattern. In winter and autumn the northerly component of the wind is so weak that most spills would with high probability initially impact the Elizabeth Islands, particularly Naushon Island. In summer, the prevailing southwesterly tends to move the impact area up to the Cape Cod shore. Spring exhibits the widest dispersion.

The times to shore are considerably higher than for the West Falmouth site with minima running from six hours to 60 hours and averages running from 20 to 100 depending on landing area. As Figure 2.19 shows, 50% of the spills are ashore in less than 40 hours, 75% are ashore in 60 hours, and 95% are ashore in 105 hours. The times to shore are much more sharply a function of

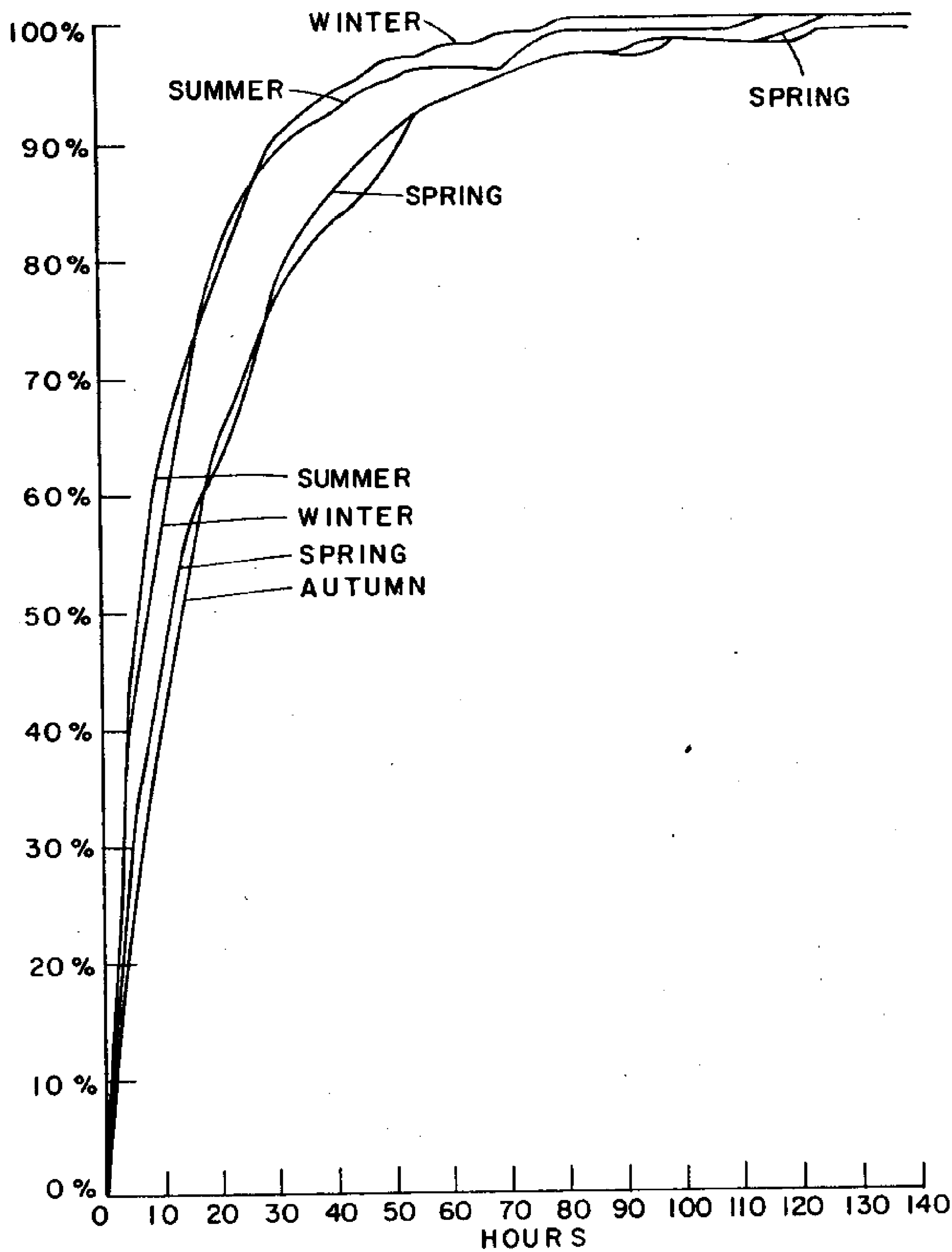
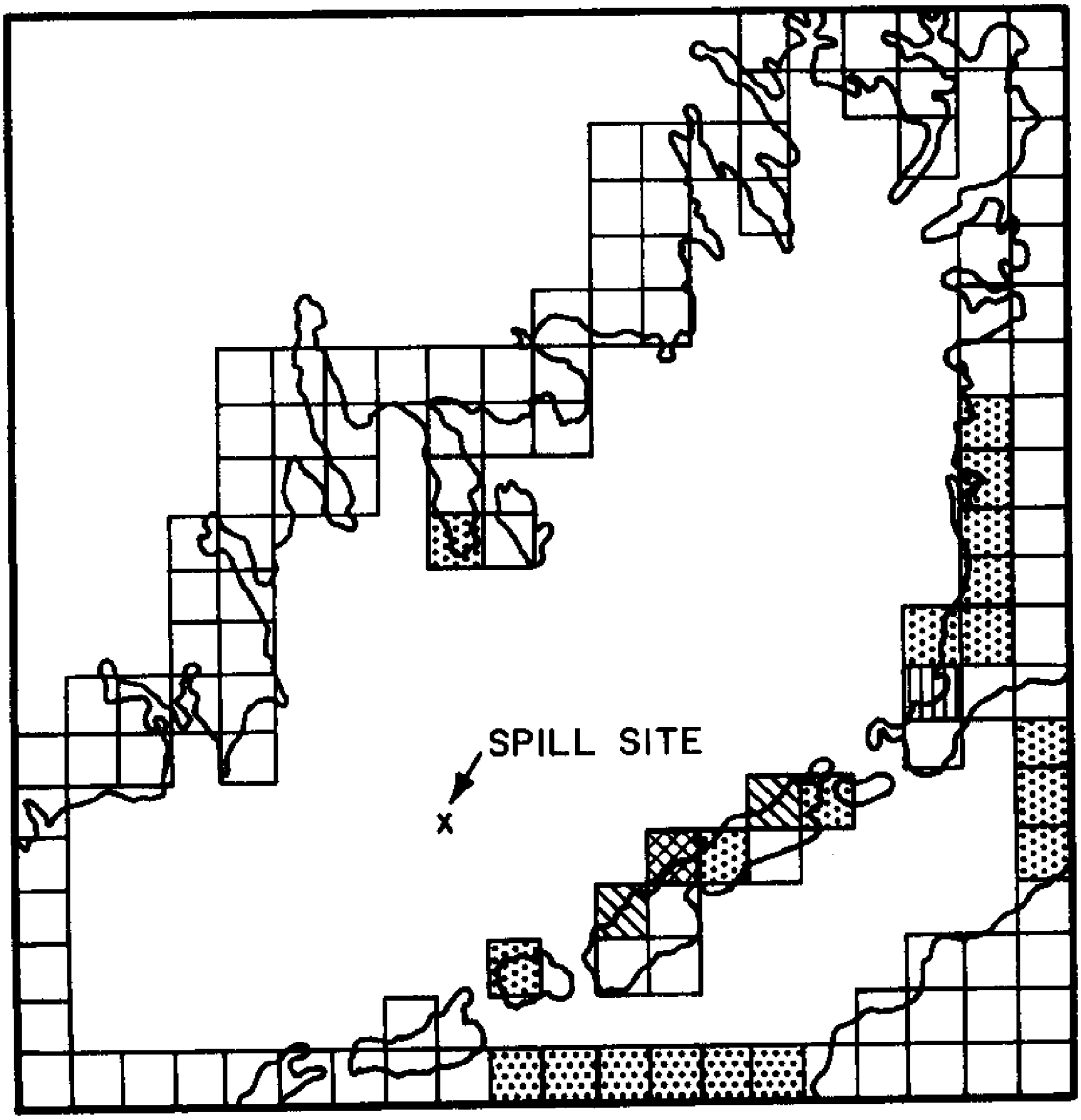


FIGURE 2-13 PERCENT ASHORE AS A FUNCTION OF TIME (WEST FALMOUTH SPILL SITE)



IMPACT AREAS

0% - 2%	10% - 20%
2% - 5%	20% - 30%
5% - 10%	>30%

FIG. 2.14 BUZZARD'S BAY IMPACT AREAS FOR THE NEW BEDFORD ENTRANCE SPILL SITE. SEASON - WINTER

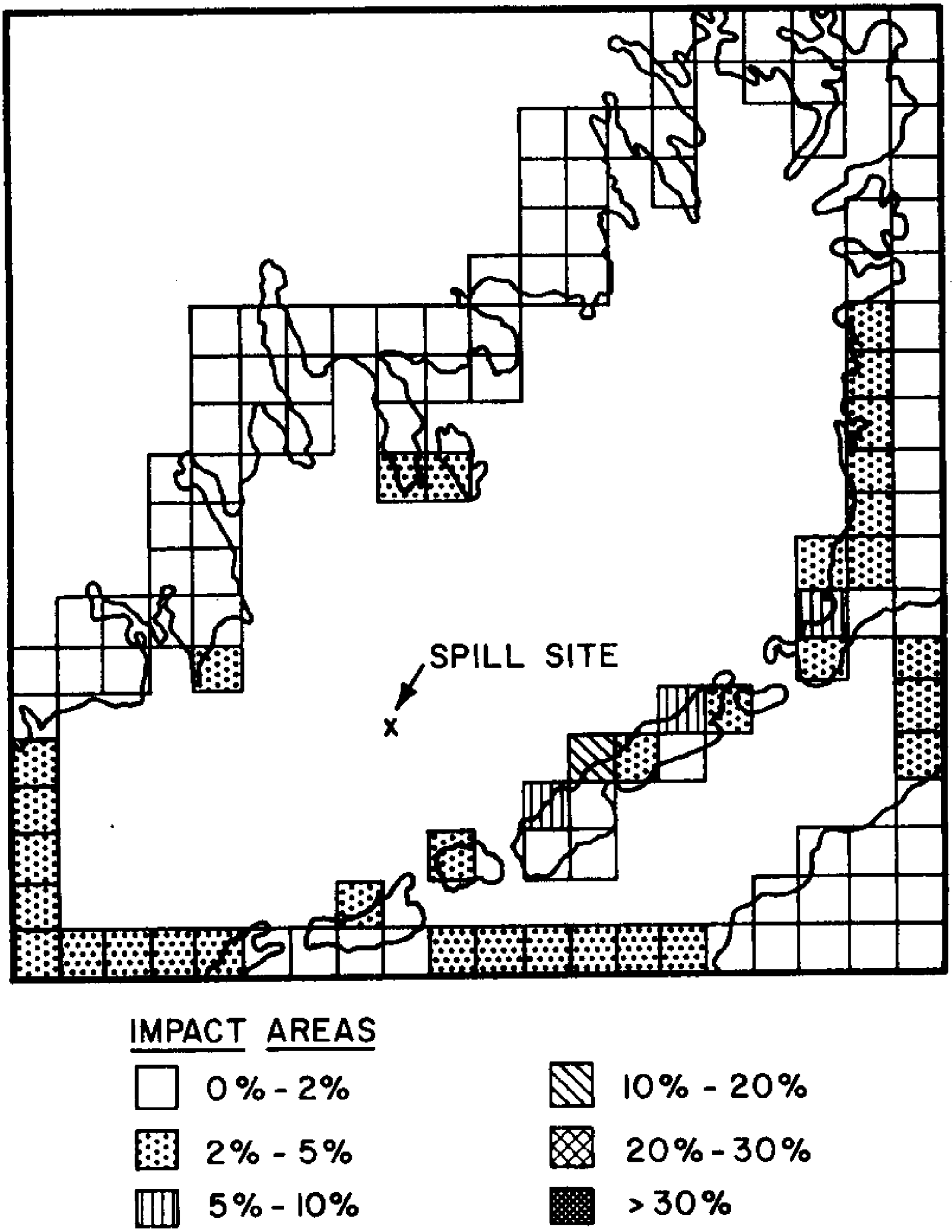


FIG.2.15 BUZZARD'S BAY IMPACT AREAS FOR THE NEW BEDFORD ENTRANCE SPILL SITE. SEASON - SPRING

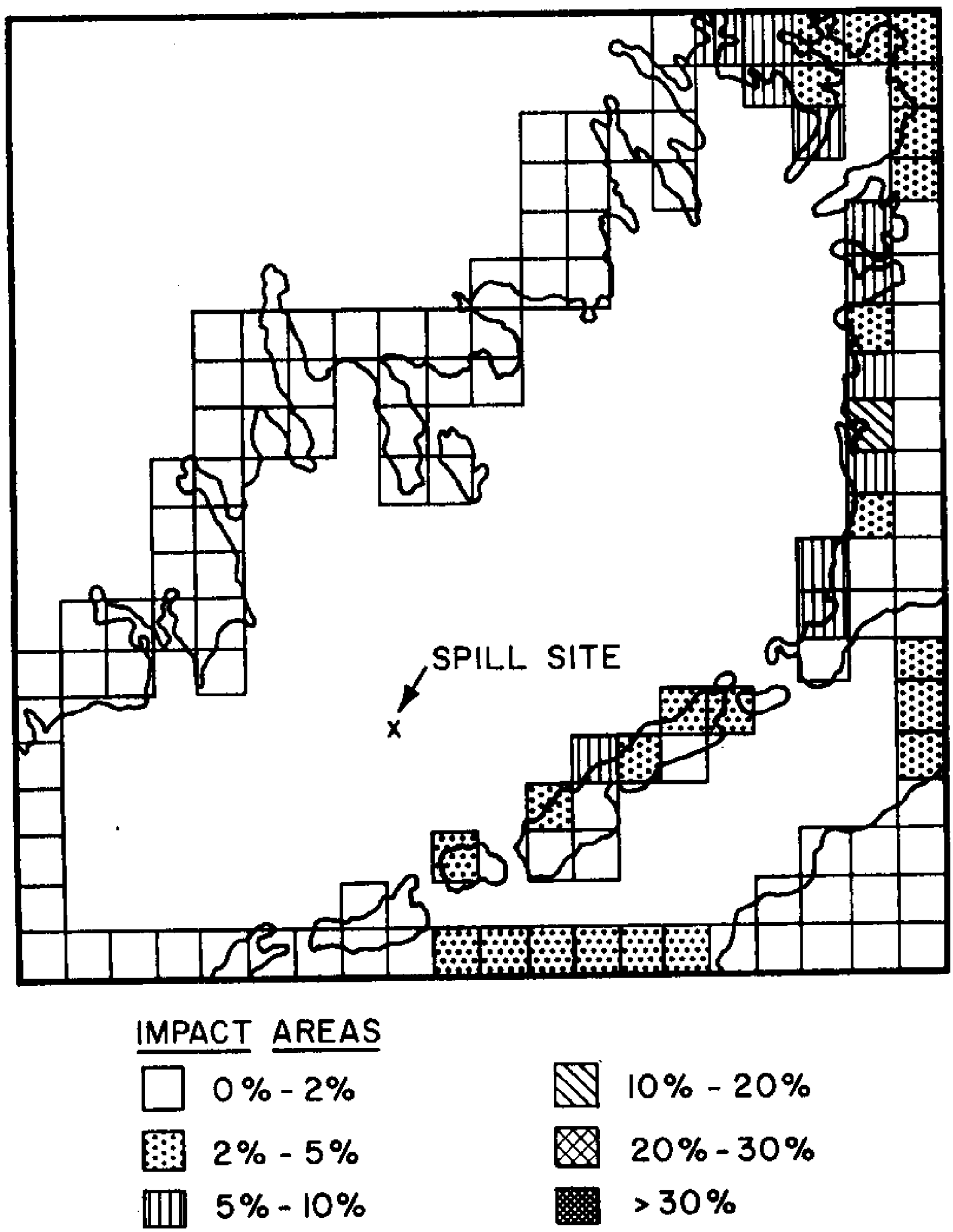


FIG.2.16 BUZZARD'S BAY IMPACT AREAS FOR THE NEW BEDFORD ENTRANCE SPILL SITE. SEASON - SUMMER

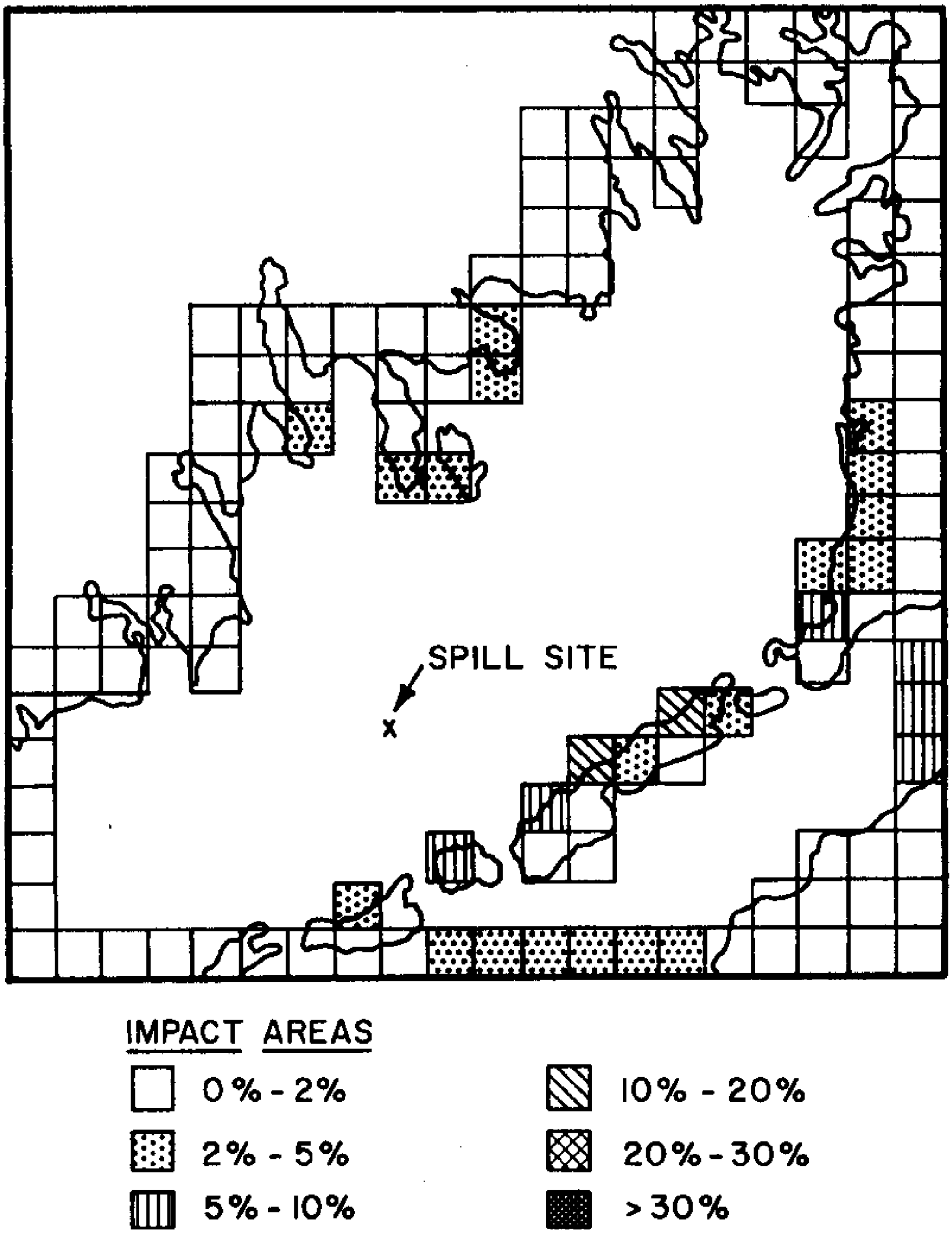


FIG. 2.17 BUZZARD'S BAY IMPACT AREAS FOR THE NEW BEDFORD ENTRANCE SPILL SITE. SEASON - AUTUMN

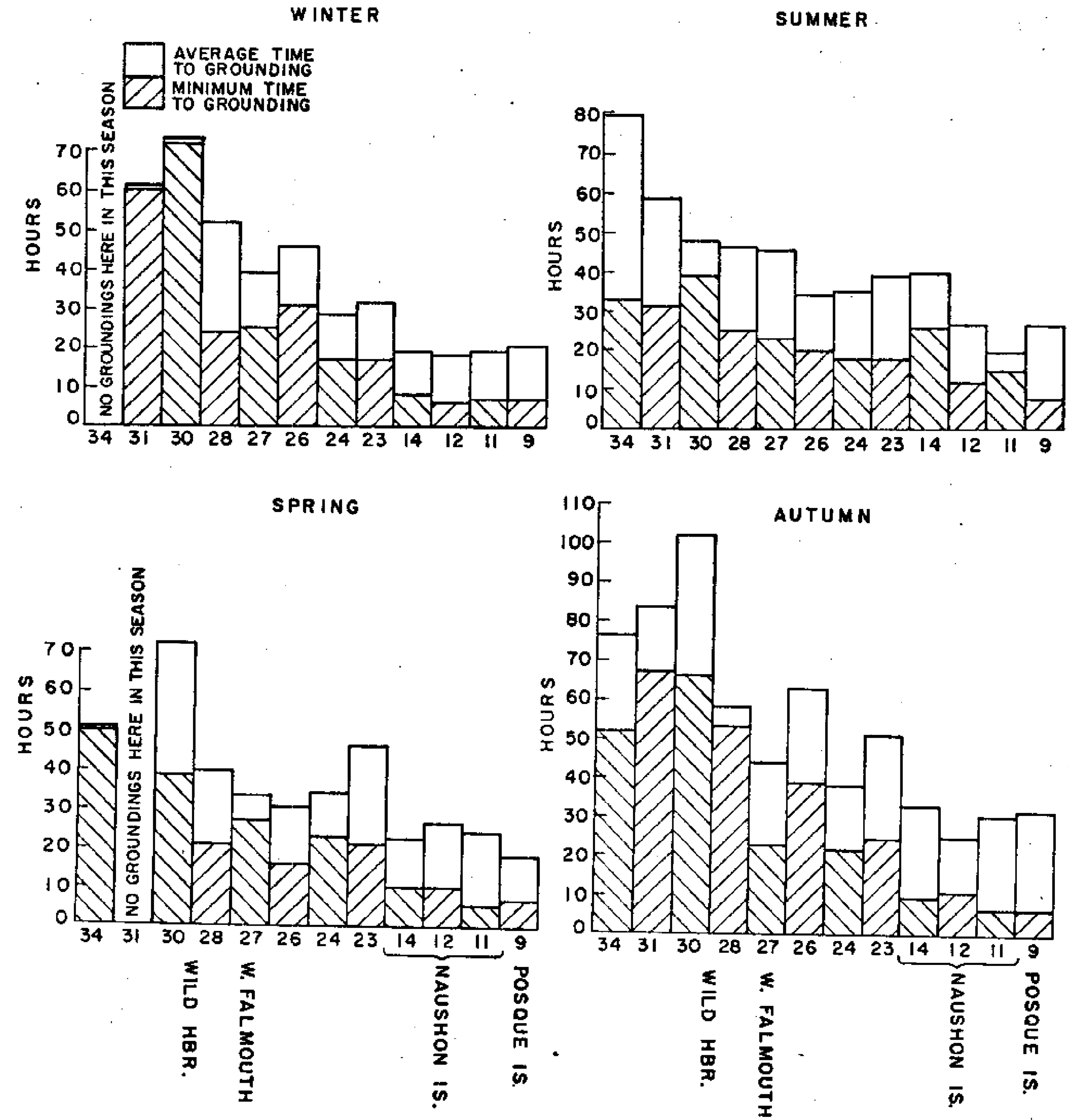


FIGURE 2-18 TIMES TO GROUNDING (ENTRANCE SPILL SITE)

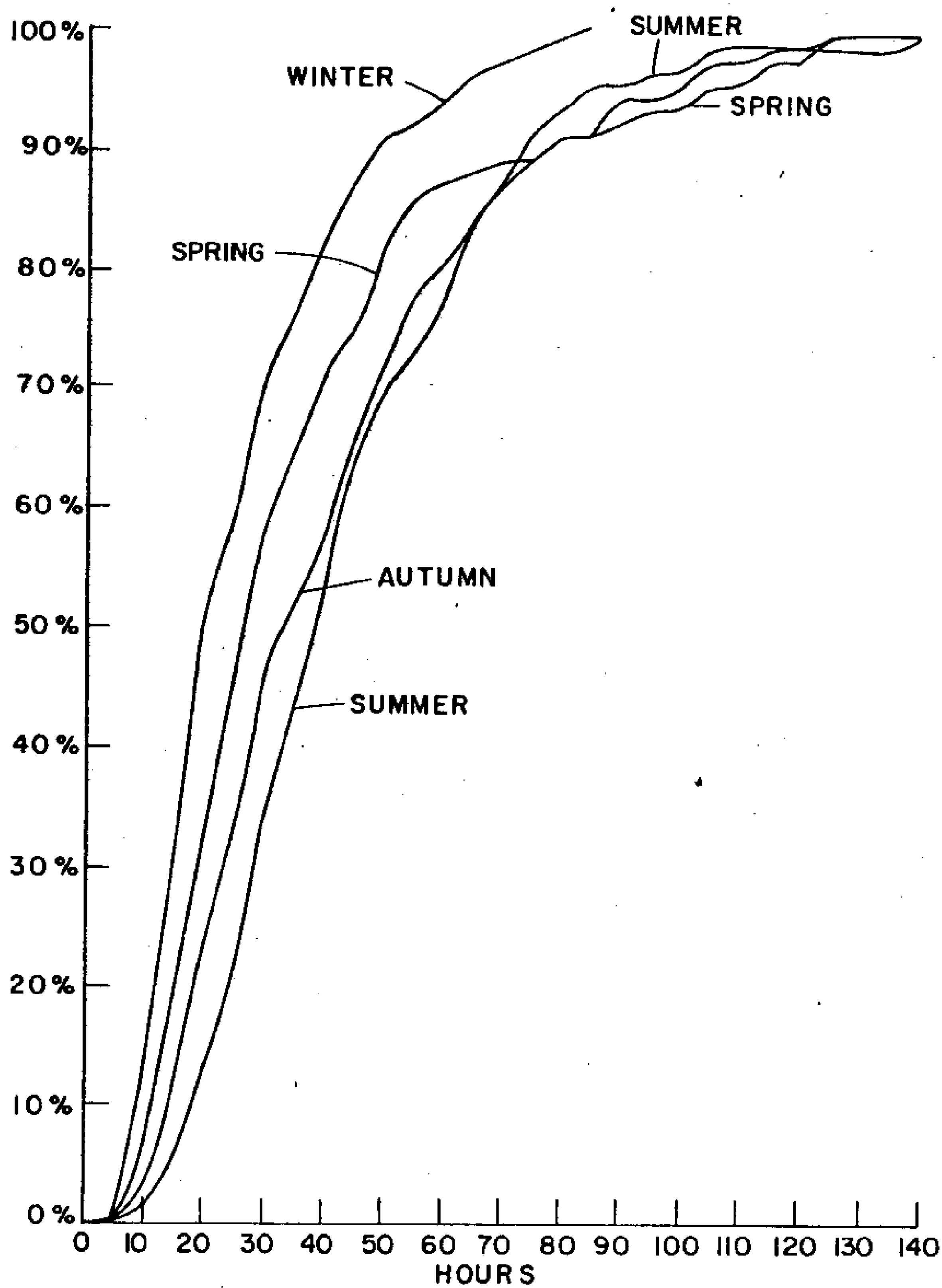
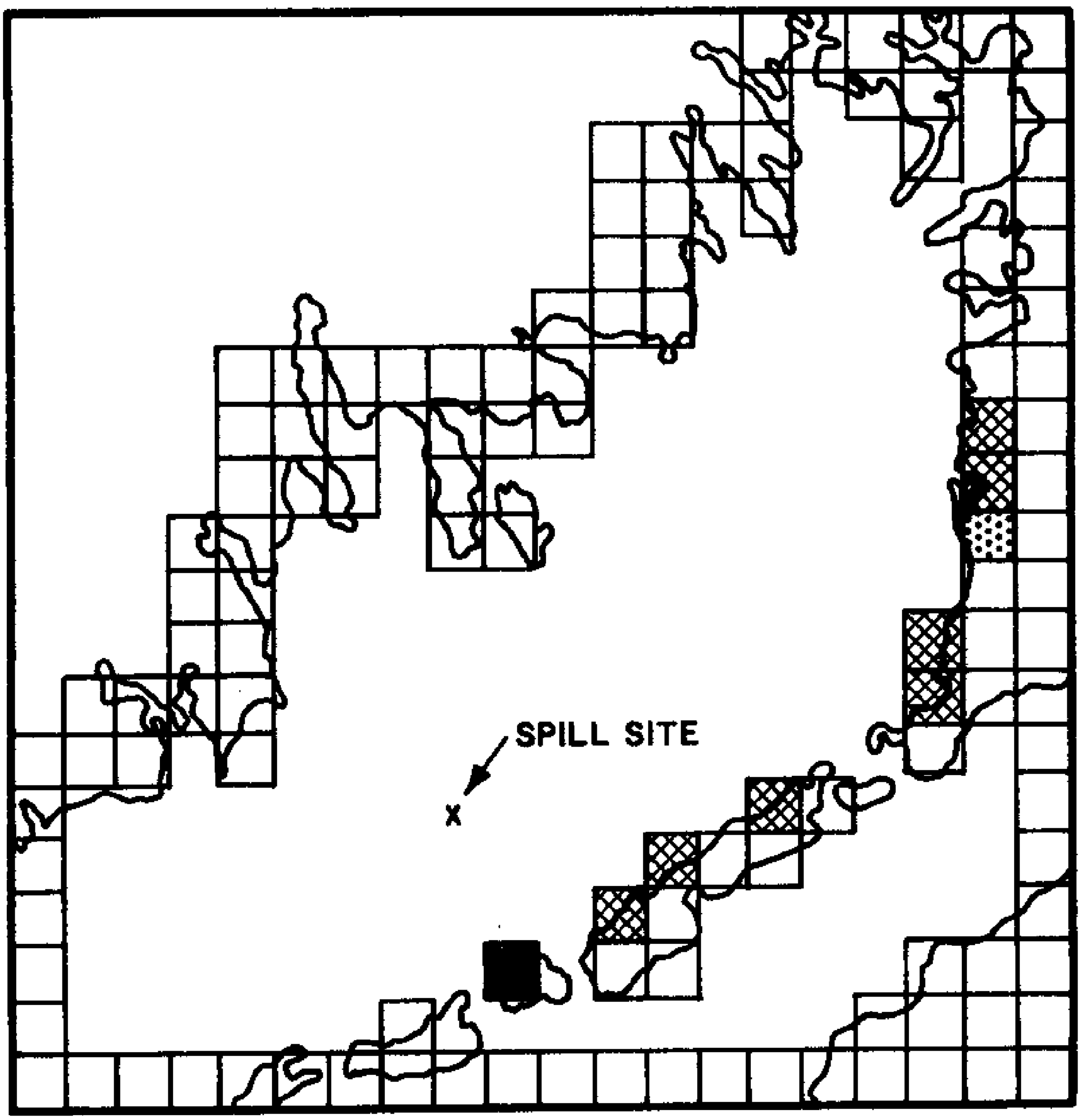


FIGURE 2-19 TOTAL PERCENT ASHORE AS A FUNCTION OF TIME
(LAUNCH PT: LOWER BUZZARDS BAY)

distance from launch point than they are of season.

Examining the wind conditions under which a spill comes ashore, we see from Figures 2.20 through 2.23 that areas ranging from Parque Isle to Wild Harbor have more than 20% of their spills coming ashore in winds over 12 knots. As we would expect, the areas in the most northerly part of Buzzards Bay are impacted in times over 30 hours, while the eastern and southeastern shores are typically impacted in under 30 hours.

Figure 2.24 indicates that the size of the spill does influence the area of impact of the spill. We can see that in the West Falmouth area the points in the secondary array come ashore under "critical" conditions as we have defined them, whereas the center of mass of the spill would not. Over the rest of the Bay the position of center of mass of the spill would provide an adequate description of the trajectory.

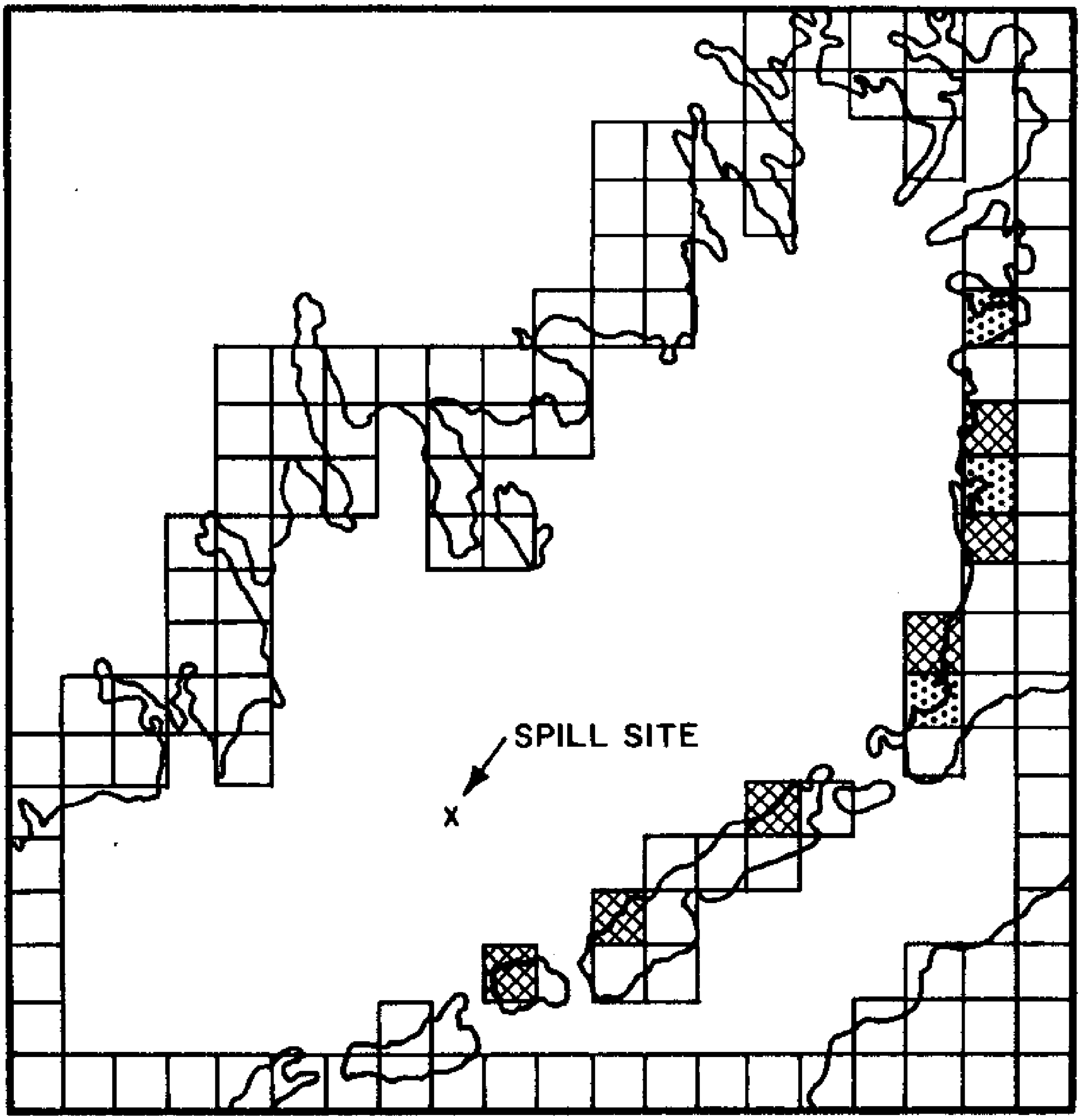


LIMITED TO AREAS WITH IMPACT > 5% IN ANY SEASON

- $< 20\%$ OF IMPACTS OCCUR WITH WIND > 12 KNOTS
- MOST COME ASHORE WITH $t > 30$ HRS
- MOST COME ASHORE WITH $10 < t < 30$ HRS
- MOST COME ASHORE WITH $t < 10$ HRS

$> 20\%$ OF IMPACTS OCCUR WITH WIND > 12 KNOTS

FIG. 2.20 BUZZARD'S BAY CRITICAL AREAS FOR SPILLS OCCURRING AT BAY ENTRANCE SITE. SEASON - WINTER



LIMITED TO AREAS WITH IMPACT > 5% IN ANY SEASON

- < 20% OF IMPACTS OCCUR WITH WIND > 12 KNOTS
- MOST COME ASHORE WITH t > 30 HRS
- MOST COME ASHORE WITH 10 < t < 30 HRS
- MOST COME ASHORE WITH t < 10 HRS

} > 20% OF IMPACTS OCCUR WITH WIND > 12 KNOTS

FIG.2.21 BUZZARD'S BAY CRITICAL AREAS FOR SPILLS OCCURRING AT BAY ENTRANCE SITE. SEASON - SPRING

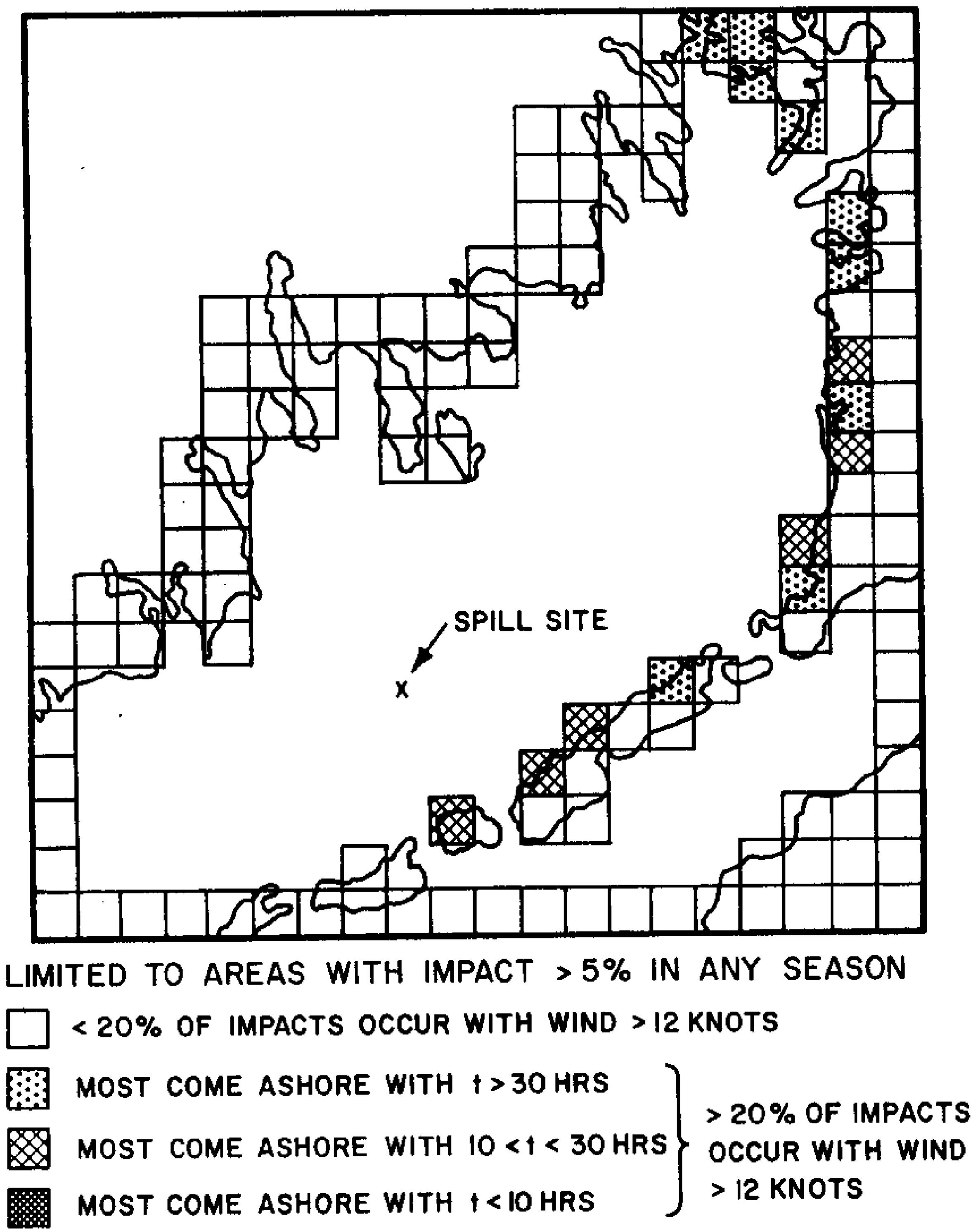
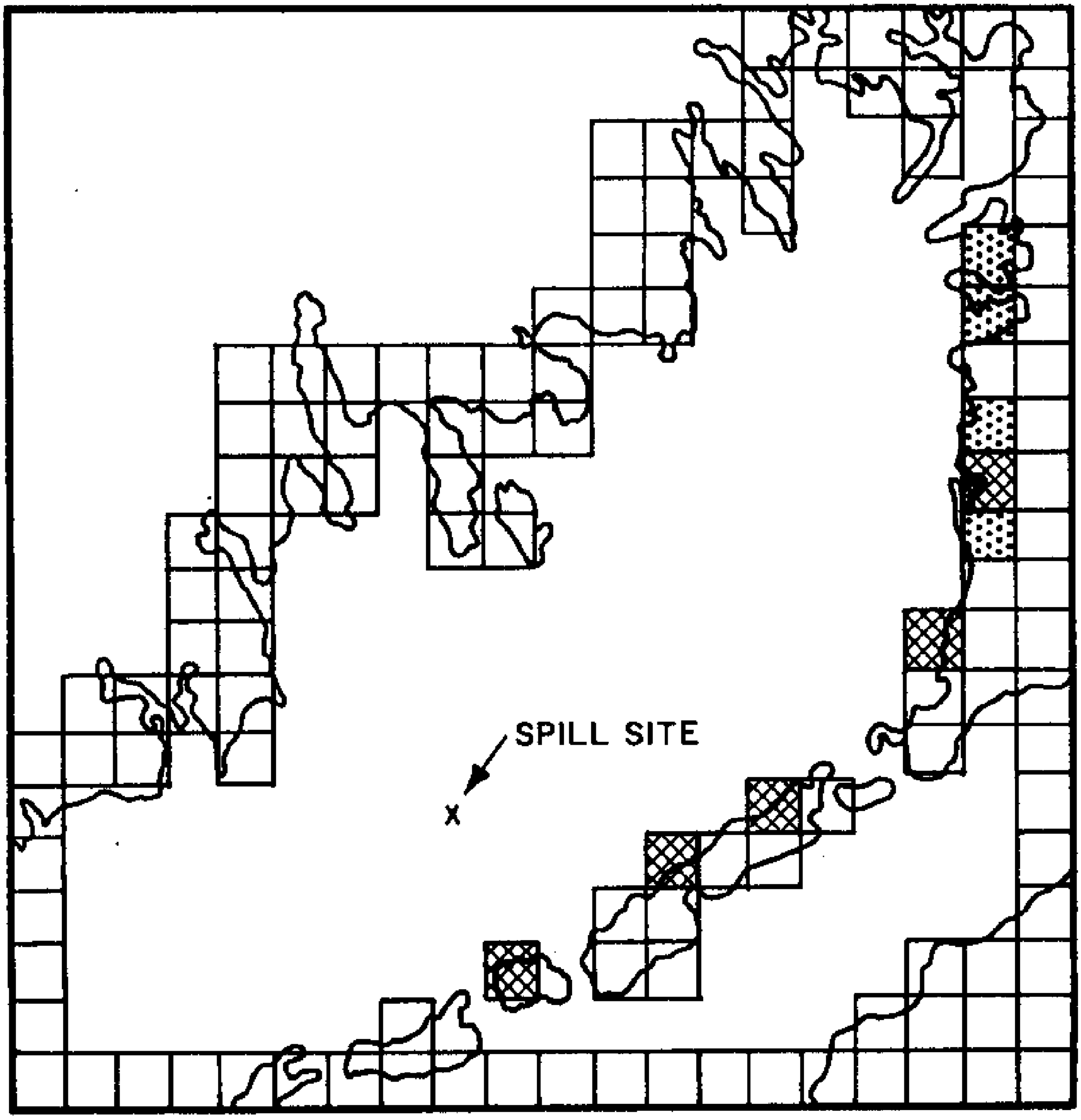


FIG.2.22 BUZZARD'S BAY CRITICAL AREAS FOR SPILLS OCCURRING AT BAY ENTRANCE SITE. SEASON - SUMMER

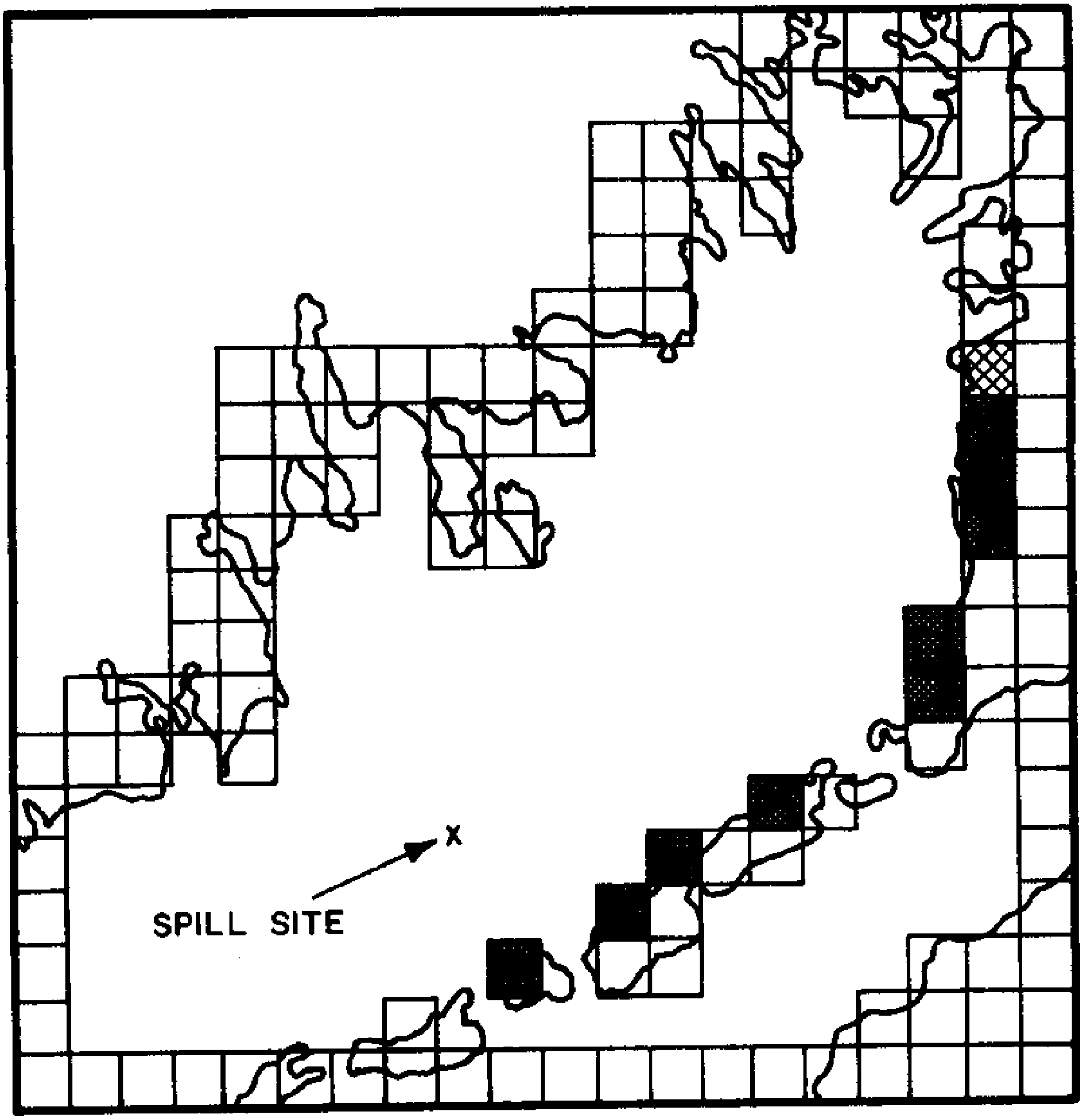


LIMITED TO AREAS WITH IMPACT > 5% IN ANY SEASON

- < 20% OF IMPACTS OCCUR WITH WIND > 12 KNOTS
- MOST COME ASHORE WITH t > 30 HRS
- MOST COME ASHORE WITH 10 < t < 30 HRS
- MOST COME ASHORE WITH t < 10 HRS

(the last three: > 20% OF IMPACTS OCCUR WITH WIND > 12 KNOTS)

FIG.2.23 BUZZARD'S BAY CRITICAL AREAS FOR SPILLS OCCURRING AT BAY ENTRANCE SITE. SEASON - AUTUMN



DEFINE CRITICAL AS IMPACT >5% IN ANY SEASON AND >20% COME ASHORE WITH WIND >12 KNOTS AND A MAJORITY OF THESE COME ASHORE WITHIN 30 HOURS.

CRITICAL UNDER PRIMARY

CRITICAL UNDER SECONDARY (BUT NOT PRIMARY)

CRITICAL UNDER TERTIARY ONLY

FIG. 2.24 BUZZARDS BAY CRITICAL AREAS, POINT GROUP DEPENDENCE (ENTRANCE SPILL)

<u>Delaware Bay</u>

Figure 2.25 shows the map of Delaware Bay used by the computer in the nearshore spill analyses. The shoreline was broken down into 51 subareas. Two spill sites were studied:

1) One in the upper central bay between Milford Neck and East Point;

2) And the other in the bay entrance midway between Cape Henlopen and Cape May.

The wind data used were those from Wilmington, Delaware, for the period 1963 through 1972.

Figures 2.26 through 2.29 for the upper central bay site exhibit some interesting characteristics. In winter, the most likely areas are to the east and southeast with very low probability attached to the north and most of the western shores. Spring exhibits a more diffusive pattern, but once again certain portions of the western shore are low-probability areas. In summer the lower bay is almost untouched, all the impact areas being confined to a band in the upper bay area. Autumn is rather similar to spring. In all seasons Egg Island Point is a very high-probability impact area with probability ranging from 29% in winter to 51% in summer.

It would seem that analyses such as these could be profitably used in the design and deployment of spill containment and collection systems.

With the exception of Egg Island Point, the times to first grounding for this site are considerably higher than they were for Buzzards Bay, as we can see in Figure 2.30. Delaware Bay

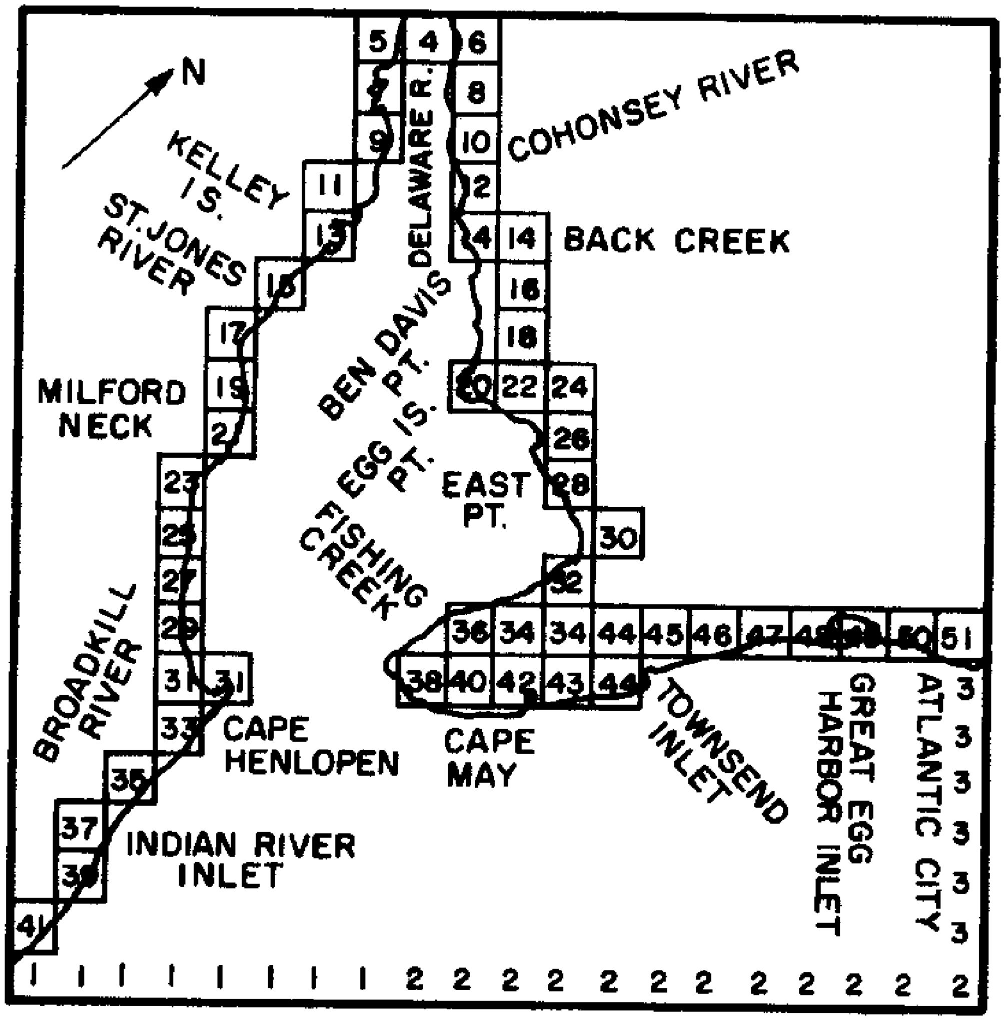


FIG. 2.25 MAP OF DELAWARE BAY AND ADJACENT COAST

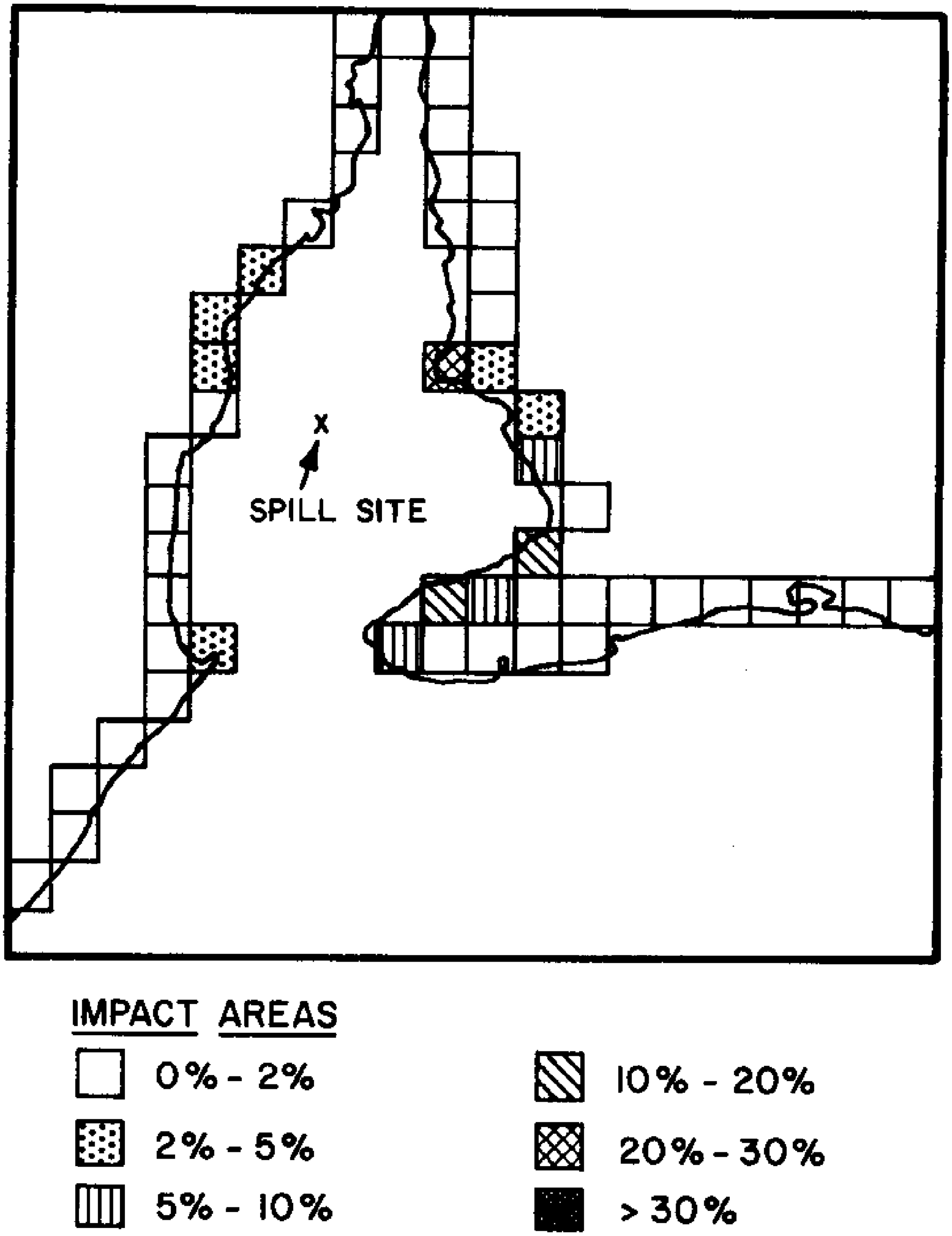


FIG. 2.26 DELAWARE BAY IMPACT AREAS FOR SPILLS OCCURRING AT THE UPPER BAY SITE. SEASON - WINTER

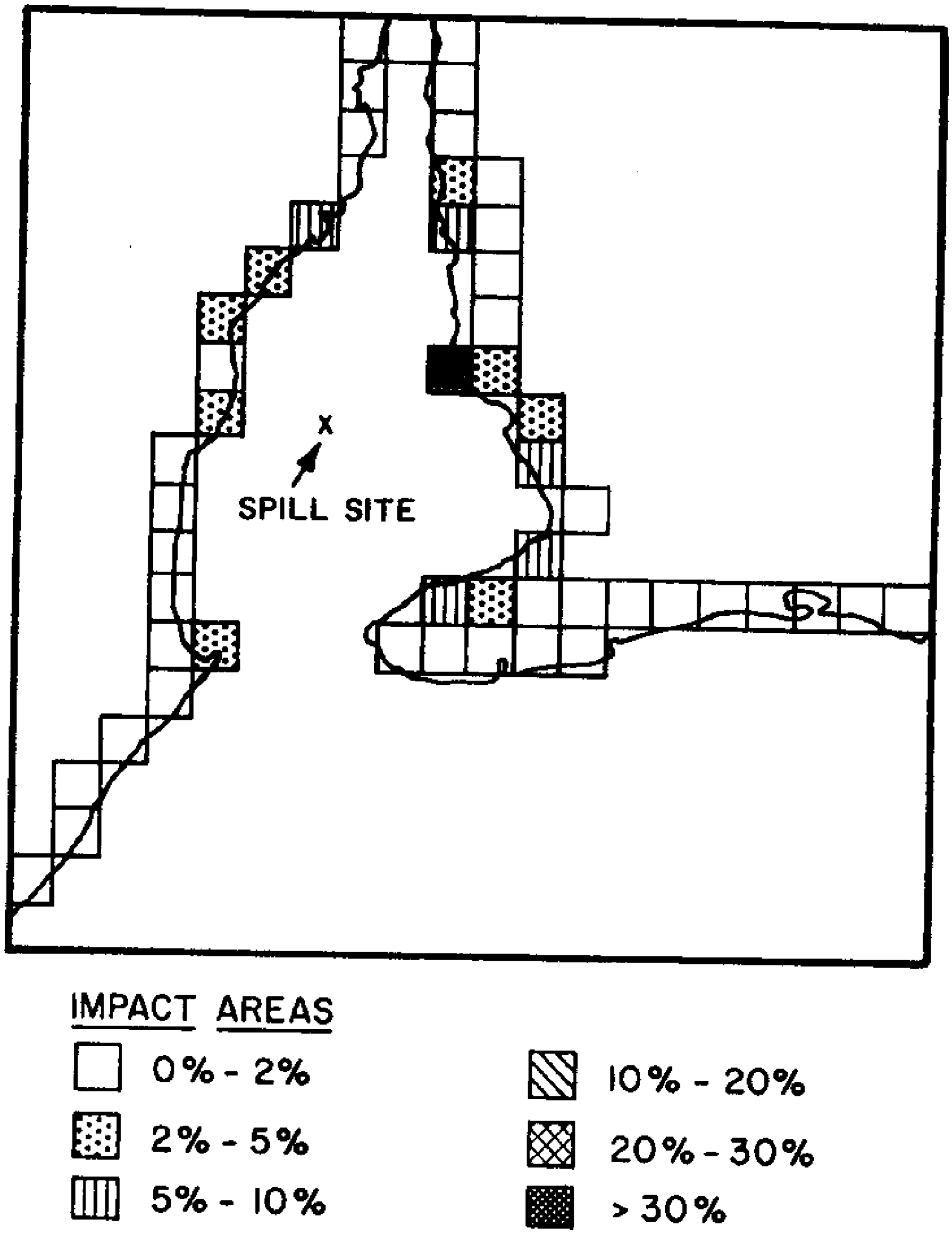


FIG. 2.27 DELAWARE BAY IMPACT AREAS FOR SPILLS OCCURRING AT THE UPPER BAY SITE. SEASON - SPRING

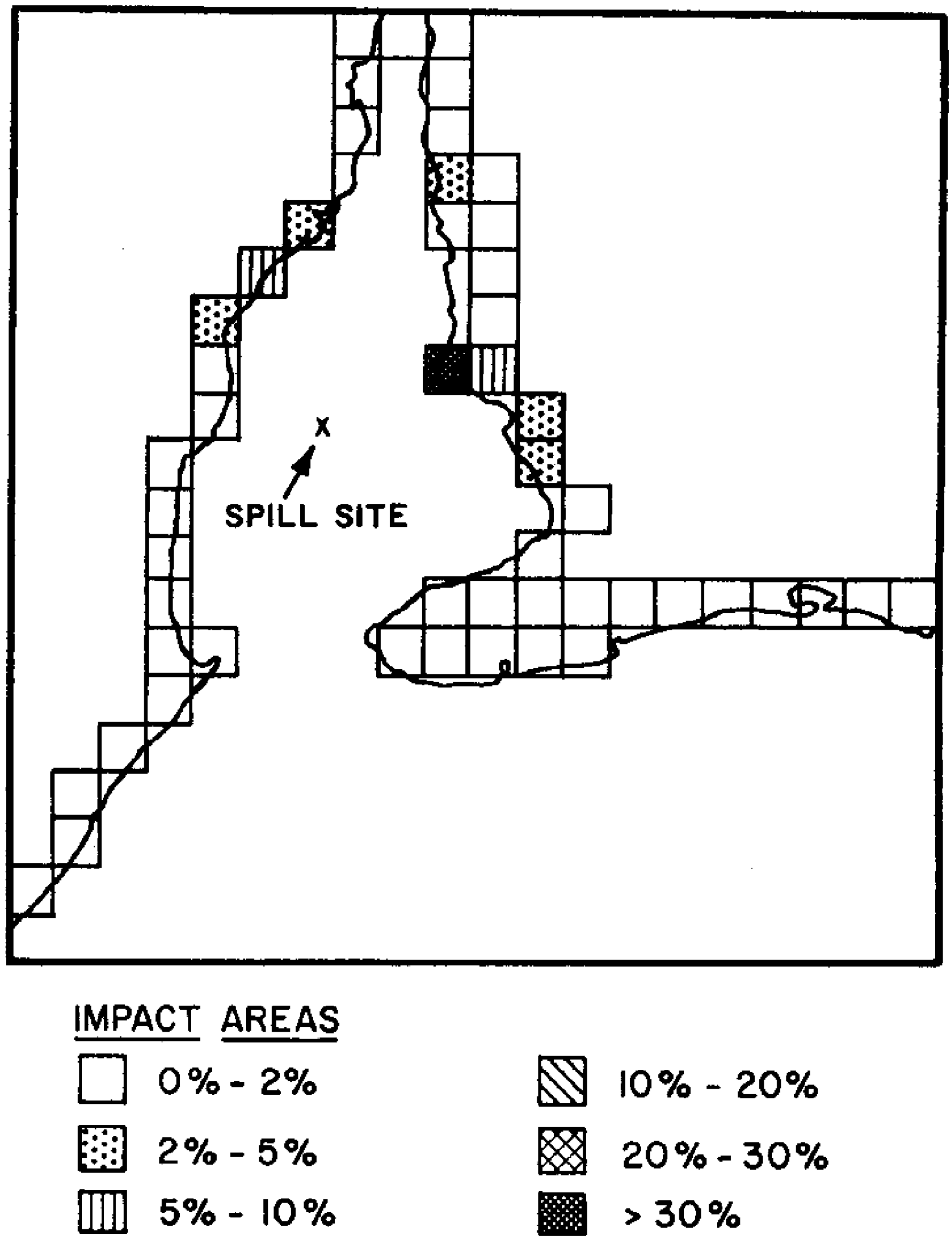
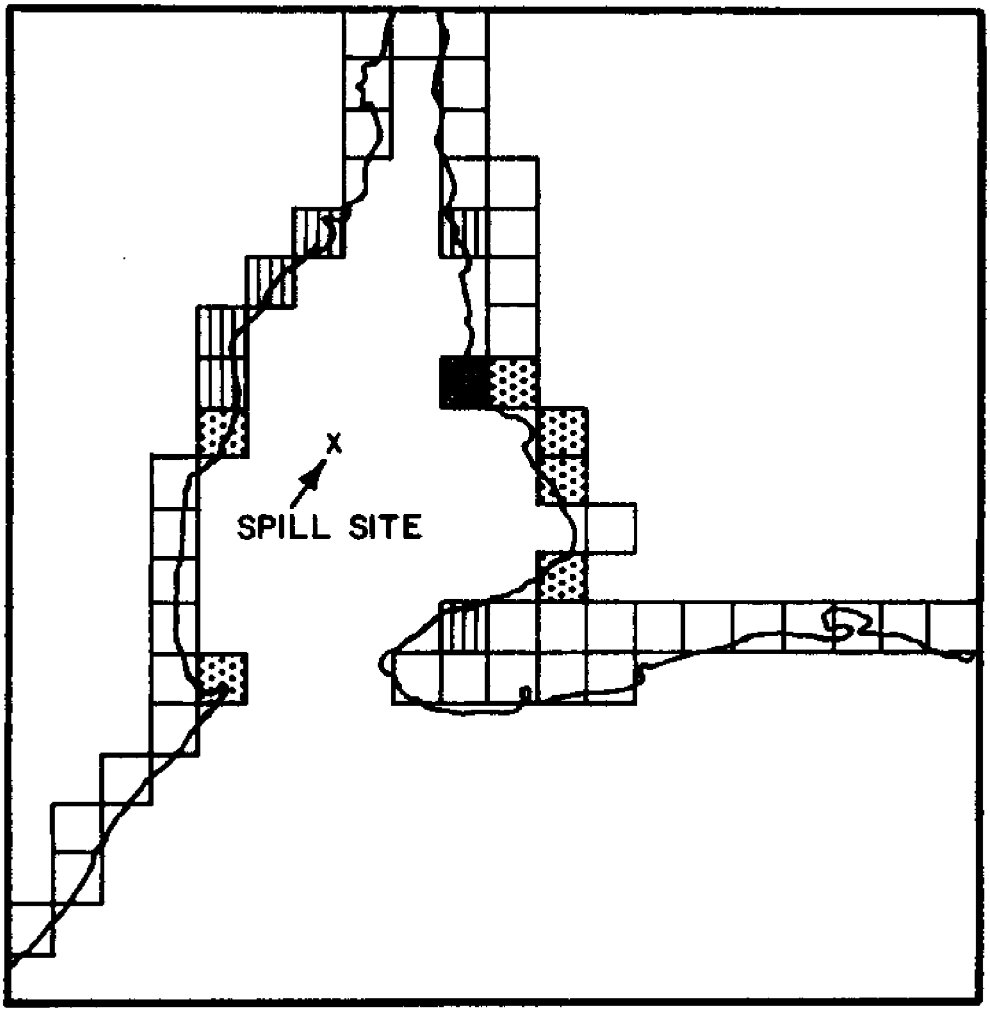


FIG. 2.28 DELAWARE BAY IMPACT AREAS FOR SPILLS OCCURRING AT THE UPPER BAY SITE. SEASON - SUMMER



IMPACT AREAS

0% - 2%

2% - 5%

5% - 10%

10% - 20%

20% - 30%

> 30%

FIG.2.29 DELAWARE BAY IMPACT AREAS FOR SPILLS OCCURRING AT THE UPPER BAY SITE. SEASON - AUTUMN

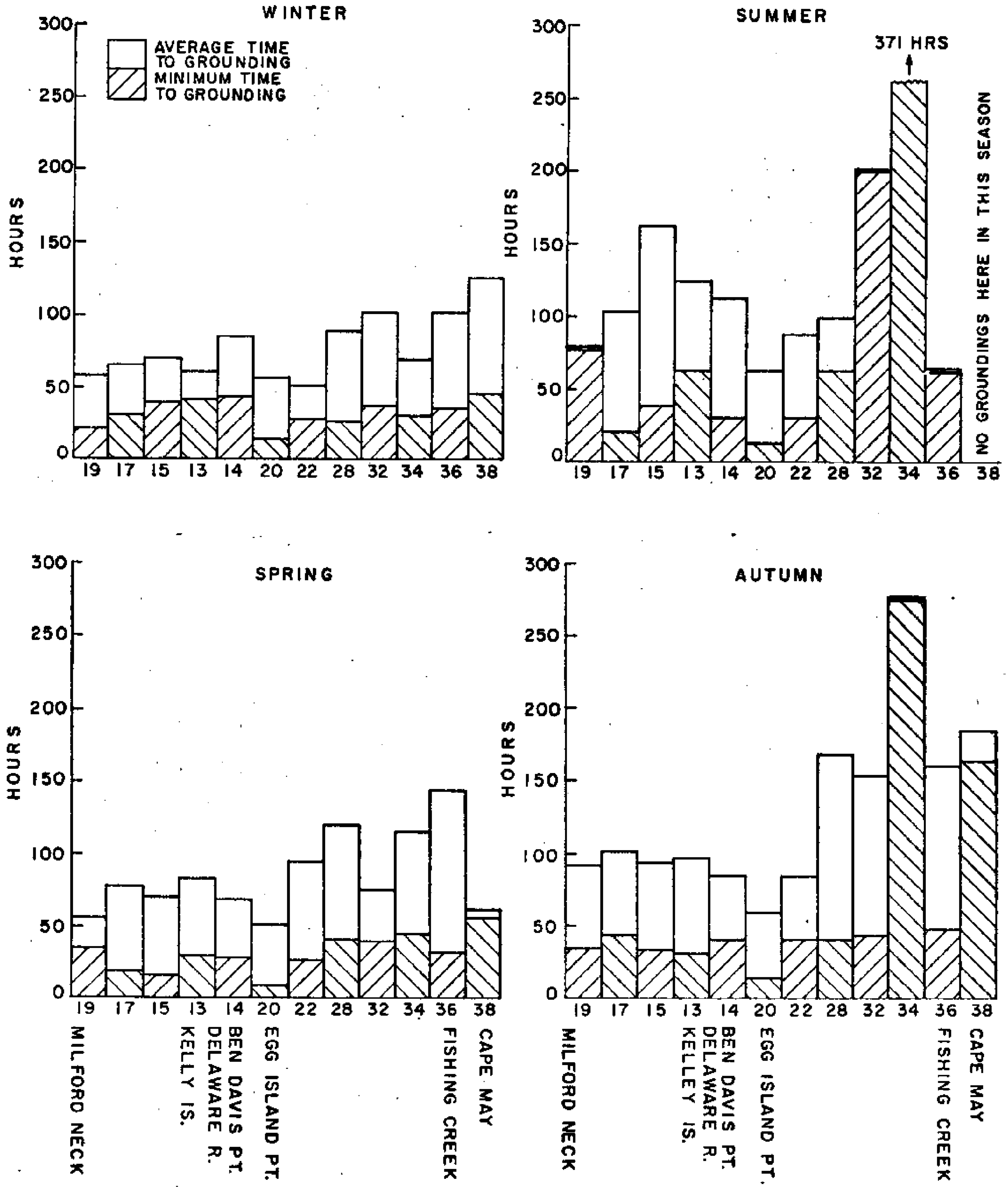


FIGURE 2-30 TIMES TO GROUNDING (UPPER SPILL)

is a rather sizable body of water and minimum times to shore range from 10 to 50 hours and average times to shore are always greater than 50 hours.

There is little seasonal variation in times to shore: For all seasons, 50% of the spills make initial impact within 75 hours, 60% of all spills make initial impact within 100 hours, and 80% of all spills make initial impact within 150 hours (Figure 2.31).

The winds in Delaware Bay tend to be somewhat lighter than those in Buzzards Bay and, in general, a smaller portion of the spills come ashore in winds over 12 knots. The areas in which more than 20% of the landings are in winds over 12 knots tend to be located in a band east and west of the launch site with the exception of the unfortunate Egg Island Point (Figures 2.32 through 2.35).

Figure 2.36 indicates that the volume effects are relatively inconsequential as no areas are "critical" impact areas except those that are also critical with respect to the center of mass of the spill. Part of this may be due to the larger scale of the grid representation we are using in Delaware (three-mile square elements) versus Buzzards Bay (one-mile square elements).

Figures 2.37 through 2.40 show the results for a spill launched at the bay entrance in the four seasons. In general, impacts are confined to the lower half of the bay, especially in the winter and fall. There is a 40% probability that a small spill will go out to sea without touching shore in the winter, but this probability drops to nil in the summer. The high-impact areas are the Capes and in summer Egg Island Point with the

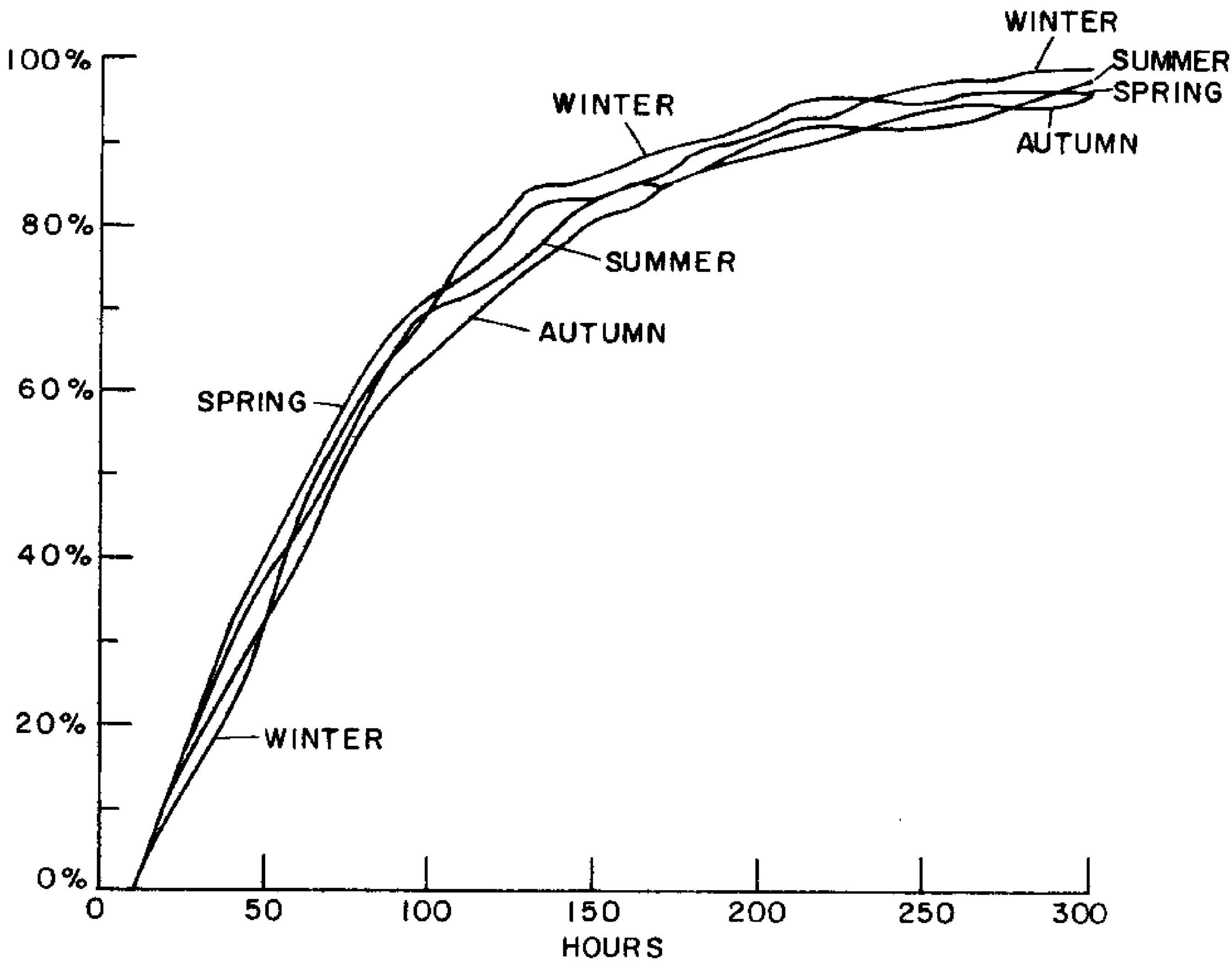


FIGURE 2-31 TOTAL PERCENT ASHORE AS A FUNCTION OF TIME (LAUNCH PT: CENTRAL BAY REGION)

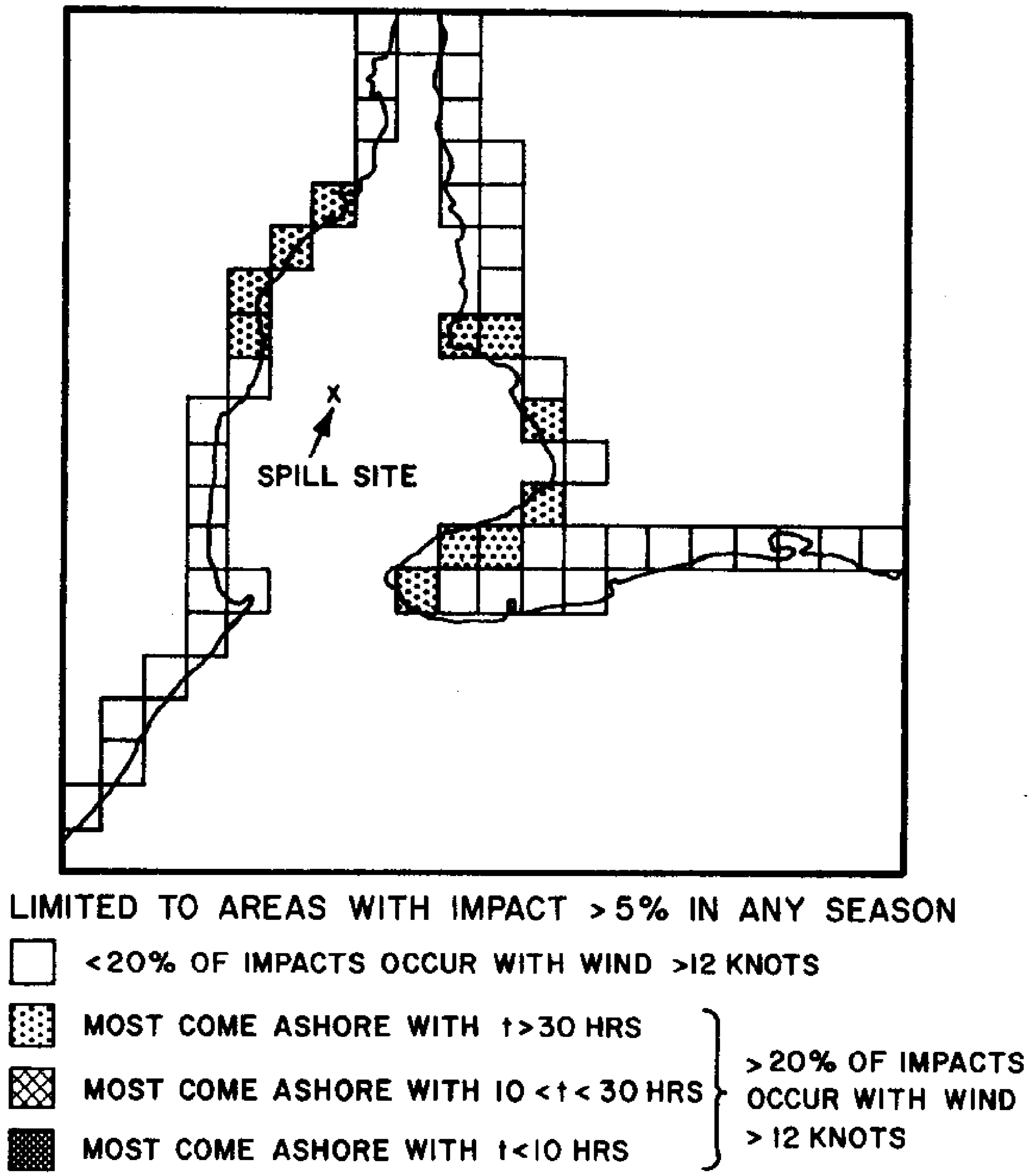
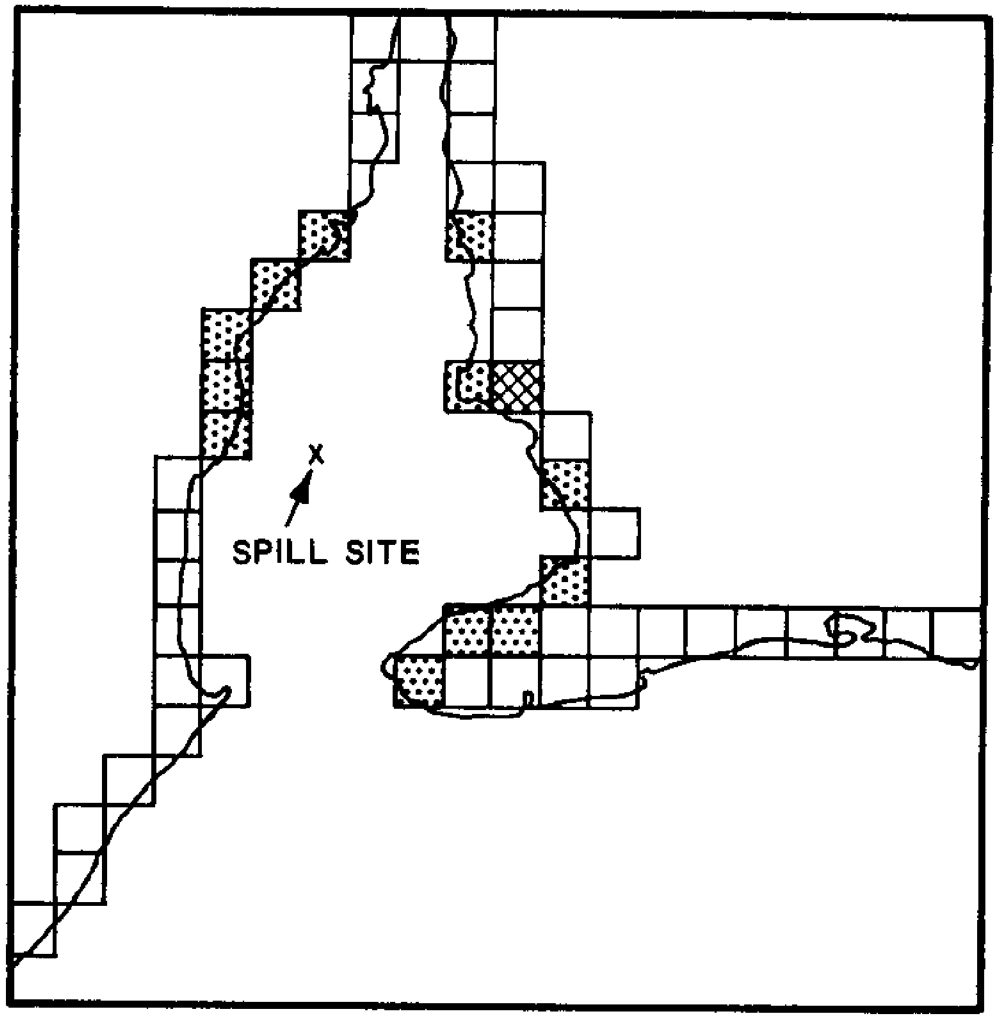


FIG. 2.32 DELAWARE BAY CRITICAL AREAS FOR SPILLS OCCURRING AT UPPER BAY SITE. SEASON - WINTER



LIMITED TO AREAS WITH IMPACT >5% IN ANY SEASON

<20% OF IMPACTS OCCUR WITH WIND >12 KNOTS

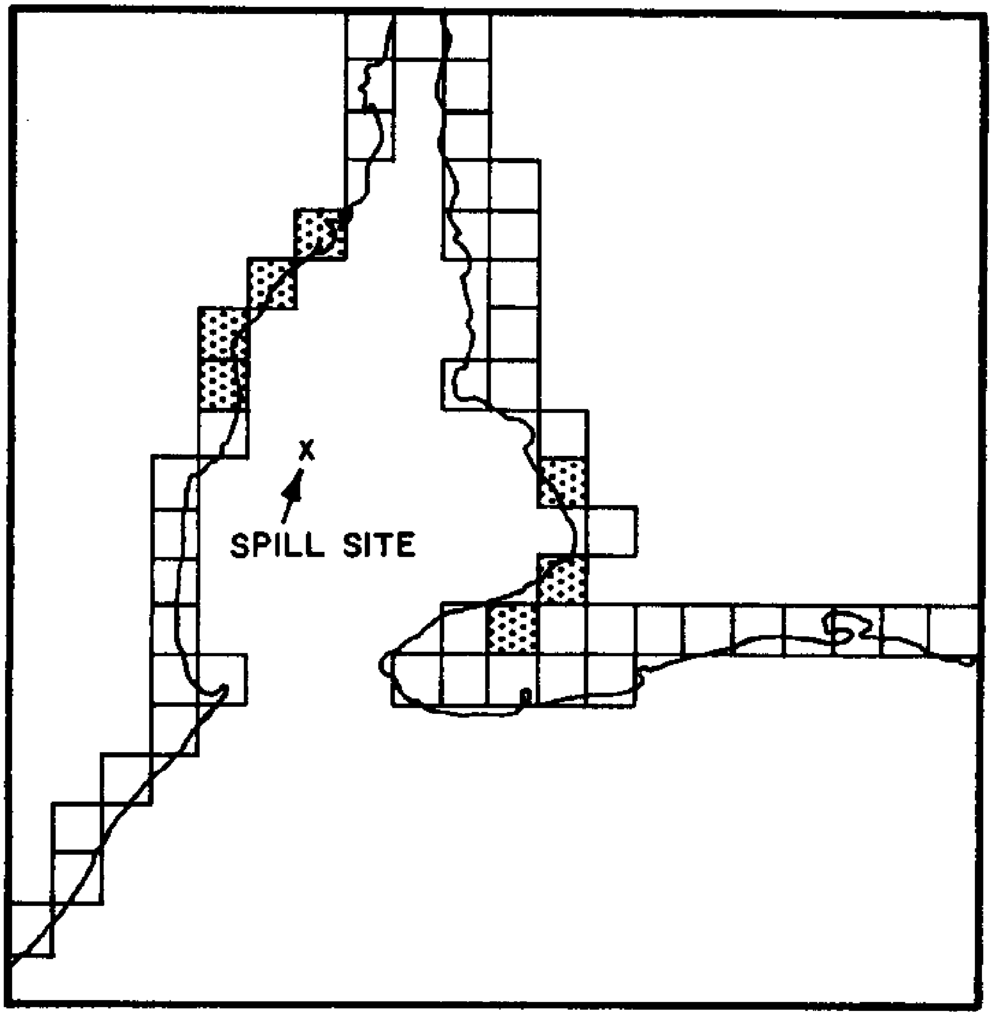
MOST COME ASHORE WITH t>30 HRS

MOST COME ASHORE WITH 10<t<30 HRS

MOST COME ASHORE WITH t<10 HRS

>20% OF IMPACTS OCCUR WITH WIND >12 KNOTS

FIG.2.33 DELAWARE BAY CRITICAL AREAS FOR SPILLS OCCURRING AT UPPER BAY SITE. SEASON - SPRING

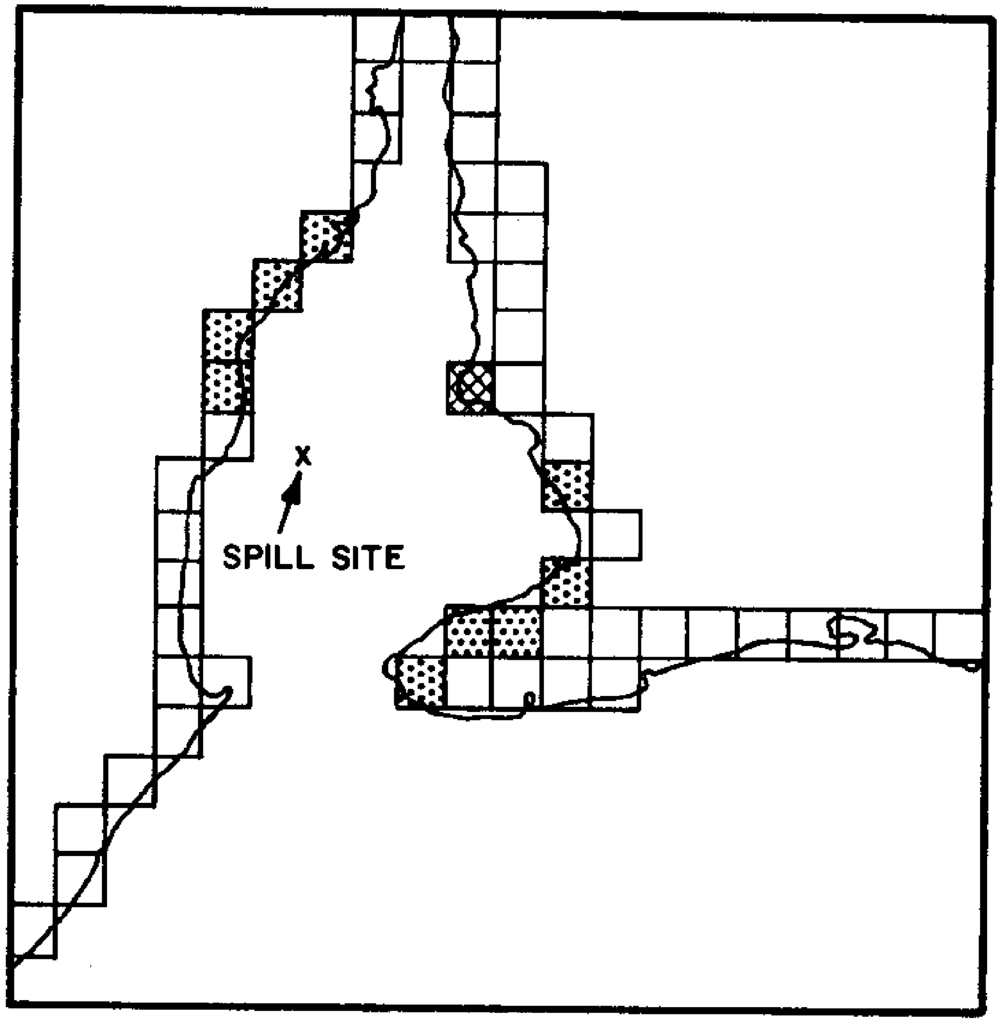


LIMITED TO AREAS WITH IMPACT > 5% IN ANY SEASON

- <20% OF IMPACTS OCCUR WITH WIND >12 KNOTS
- MOST COME ASHORE WITH $t>30$ HRS
- MOST COME ASHORE WITH $10<t<30$ HRS
- MOST COME ASHORE WITH $t<10$ HRS

(last three: >20% OF IMPACTS OCCUR WITH WIND > 12 KNOTS)

FIG. 2.34 DELAWARE BAY CRITICAL AREAS FOR SPILLS OCCURRING AT UPPER BAY SITE. SEASON - SUMMER

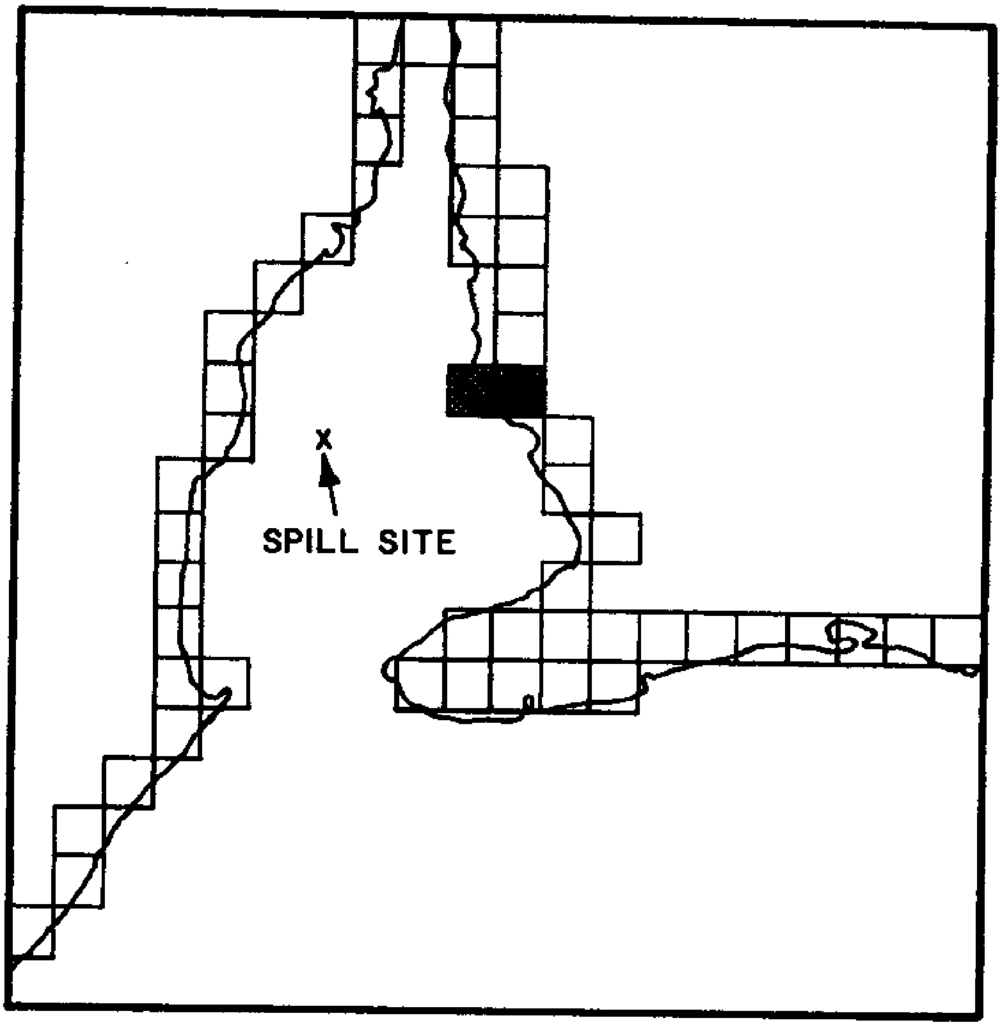


LIMITED TO AREAS WITH IMPACT > 5% IN ANY SEASON

- < 20% OF IMPACTS OCCUR WITH WIND > 12 KNOTS
- MOST COME ASHORE WITH $t > 30$ HRS
- MOST COME ASHORE WITH $10 < t < 30$ HRS
- MOST COME ASHORE WITH $t < 10$ HRS

} > 20% OF IMPACTS OCCUR WITH WIND > 12 KNOTS

FIG. 2.35 DELAWARE BAY CRITICAL AREAS FOR SPILLS OCCURRING AT UPPER BAY SITE. SEASON - AUTUMN



DEFINE CRITICAL AS IMPACT >5% IN ANY SEASON AND >20% COME ASHORE WITH WIND >12 KNOTS AND A MAJORITY OF THESE COME ASHORE WITHIN 30 HOURS.

- CRITICAL UNDER PRIMARY
- CRITICAL UNDER SECONDARY (BUT NOT PRIMARY)
- CRITICAL UNDER TERTIARY ONLY

FIG. 2.36 DELAWARE BAY CRITICAL AREAS, POINT GROUP DEPENDENCE (UPPER BAY SPILL)

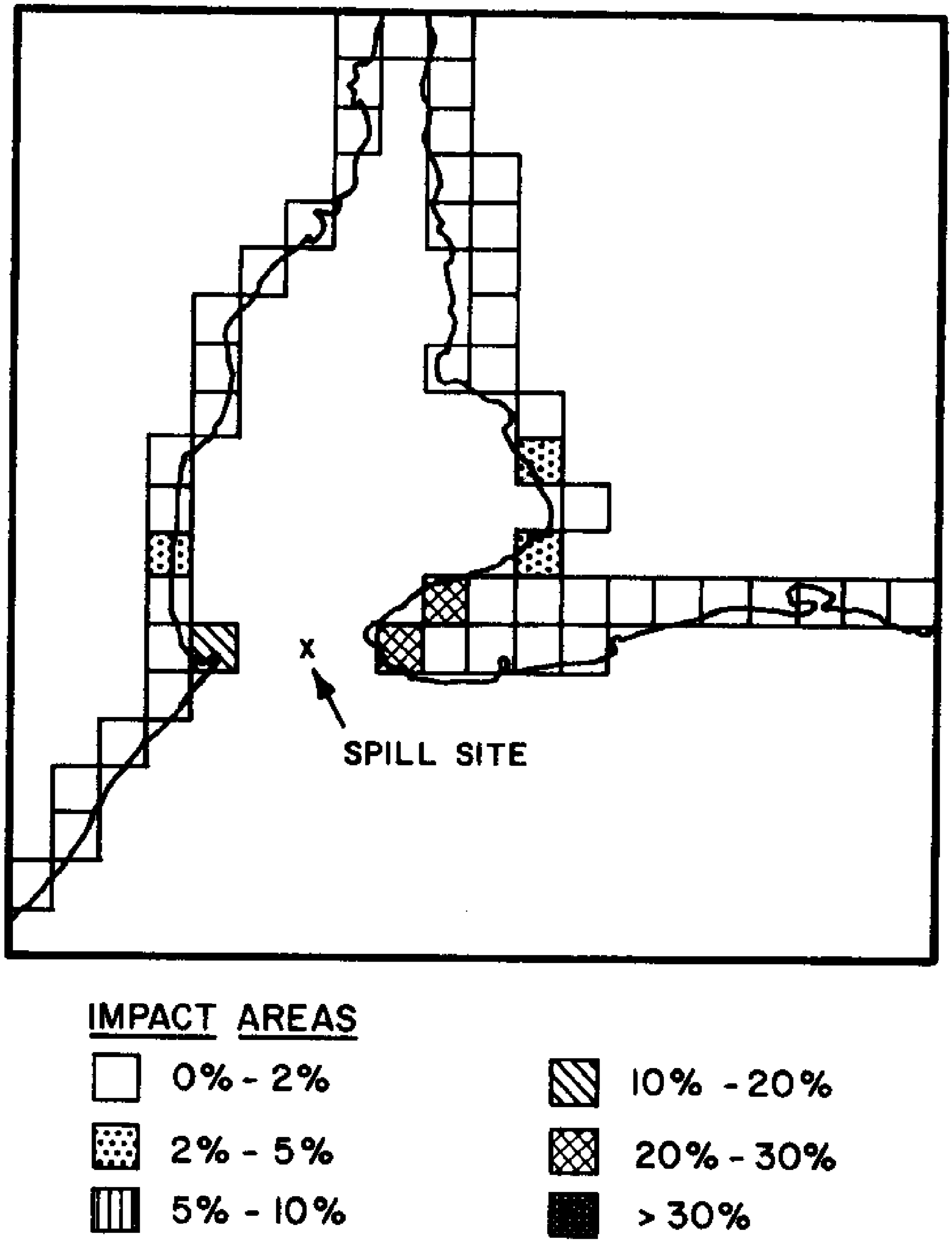
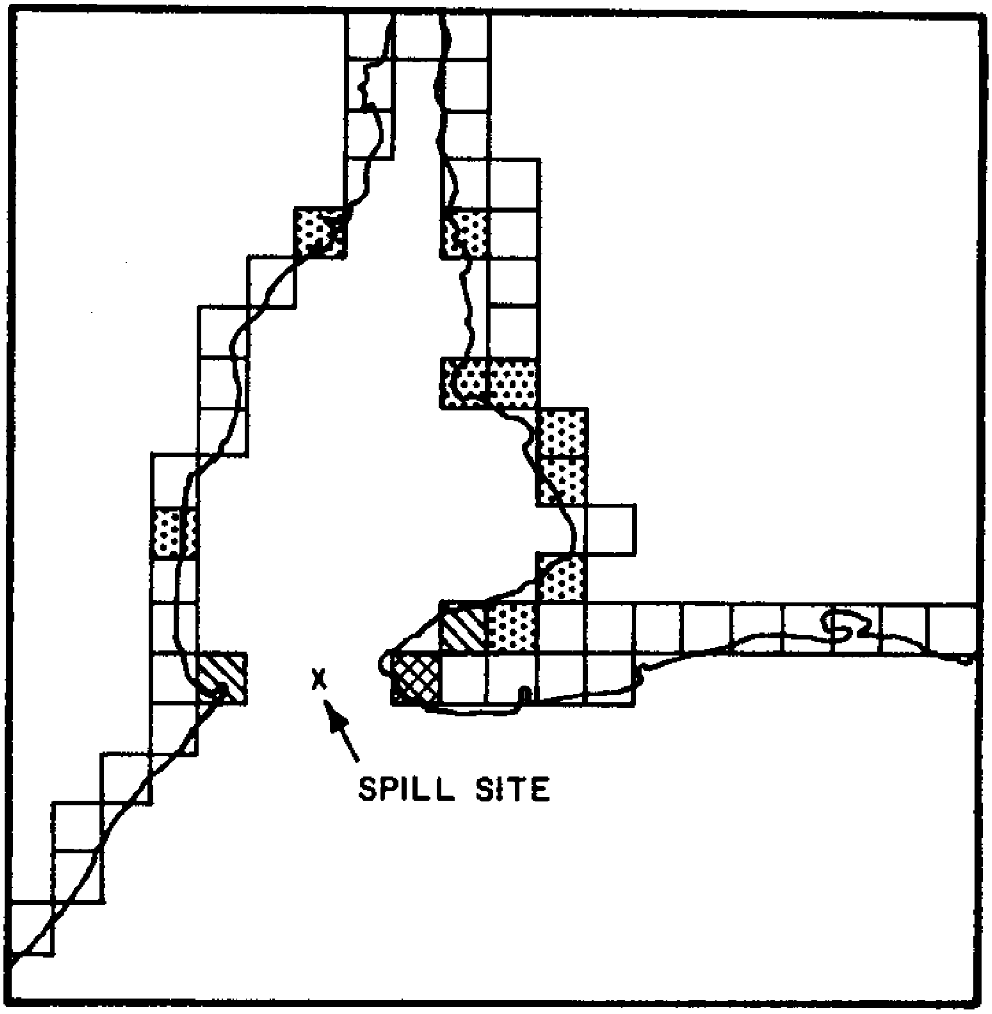


FIG. 2.37 DELAWARE BAY IMPACT AREAS FOR SPILLS OCCURRING AT THE DELAWARE BAY MOUTH SITE. SEASON - WINTER



IMPACT AREAS

0% - 2%

2% - 5%

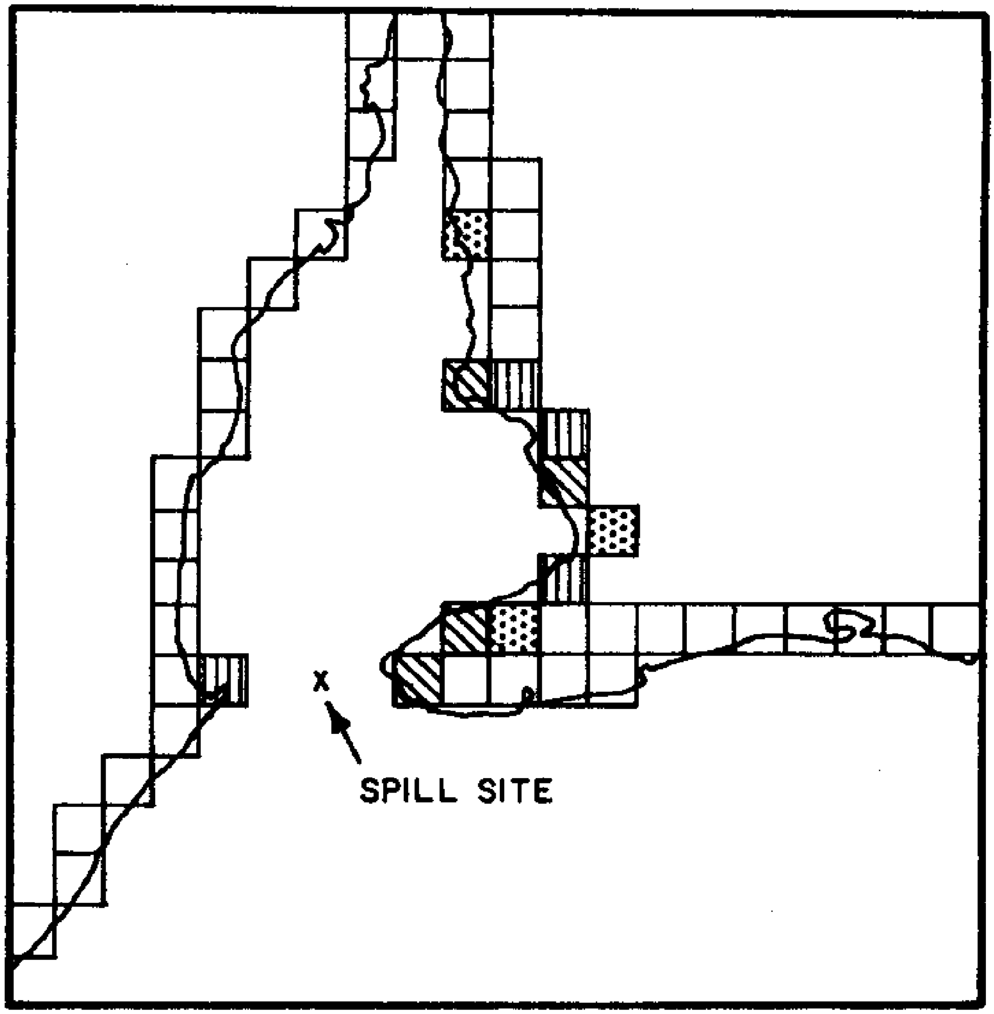
5% - 10%

10% - 20%

20% - 30%

> 30%

FIG. 2.38 DELAWARE BAY IMPACT AREAS FOR SPILLS OCCURRING AT THE DELAWARE BAY MOUTH SITE. SEASON - SPRING



IMPACT AREAS

0% - 2%	10% - 20%
2% - 5%	20% - 30%
5% - 10%	> 30%

FIG. 2.39 DELAWARE BAY IMPACT AREAS FOR SPILLS OCCURRING AT THE DELAWARE BAY MOUTH SITE. SEASON - SUMMER

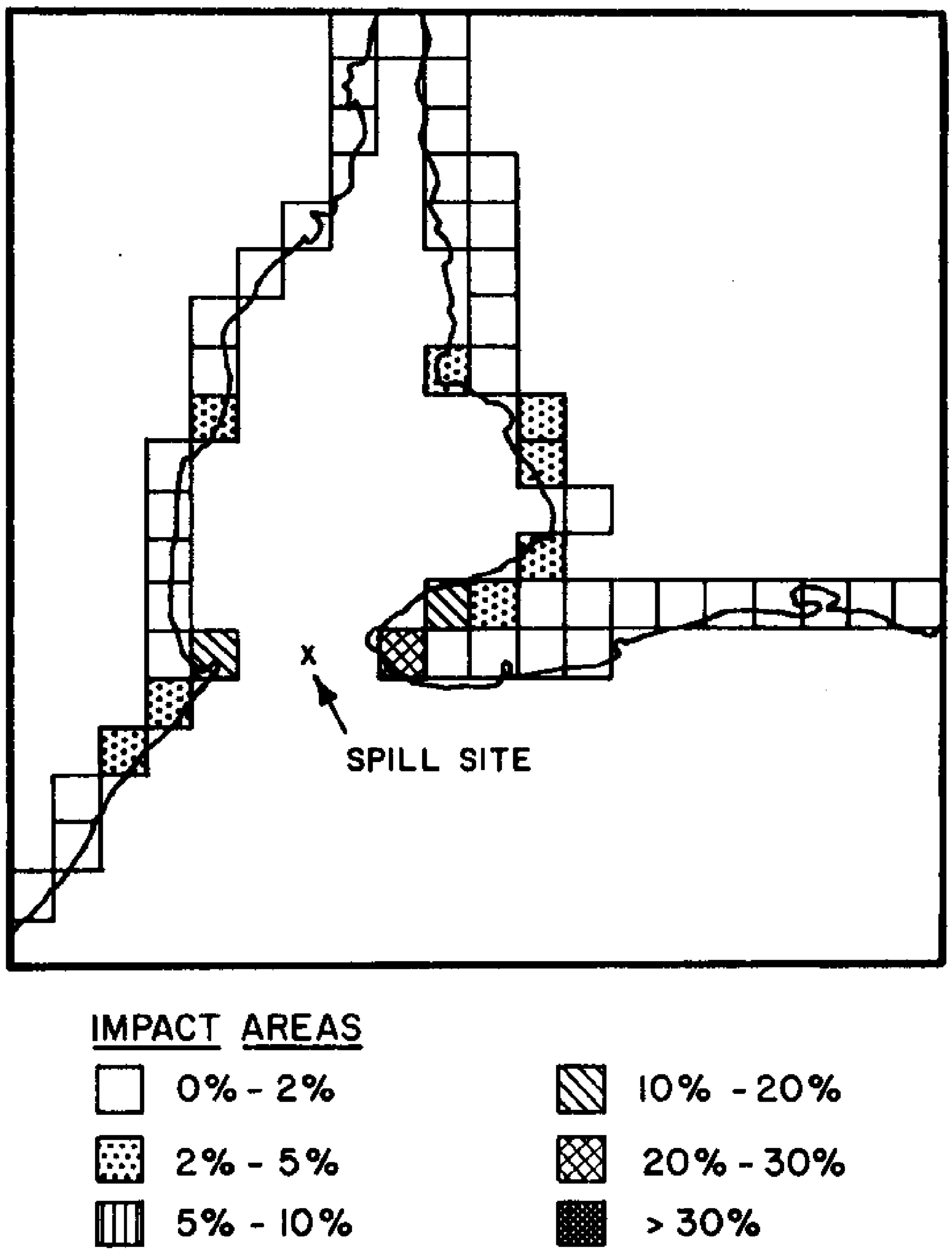


FIG.2.40 DELAWARE BAY IMPACT AREAS FOR SPILLS OCCURRING AT THE DELAWARE BAY MOUTH SITE. SEASON - AUTUMN

eastern shore getting a bit the worst of it. Interestingly enough, the recreational beaches to the north of Cape May on the ocean side are low-probability initial impact areas.

As shown in Figure 2.41, the times to shore are in the 10- to 50-hour range for the Capes, but considerably longer (50-100 hours) for the other areas. About 20% of the spills which come ashore or that exit the region through the ocean boundaries in seasons other than summer will do so in about 30 hours and 60% of the spills will be ashore or out to sea in from 75 hours (winter) to 125 hours (summer)(Figure 2.42). As this figure indicates, for this spill site this is considerable seasonal dependence in the time to shore.

With respect to wind speed upon landing, Figures 2.43 through 2.46 indicate that areas in which 20% of the spills that come ashore do so in winds over 12 knots are confined to the eastern shore with the exception of Cape Henlopen in the spring. In summer, the chances of this occurring are considerably lower than in the other seasons. Cape Henlopen is also the area most sensitive to spill size, as is indicated by Figure 2.47. Year-round Cape May is clearly the area most likely to be the hardest hit.

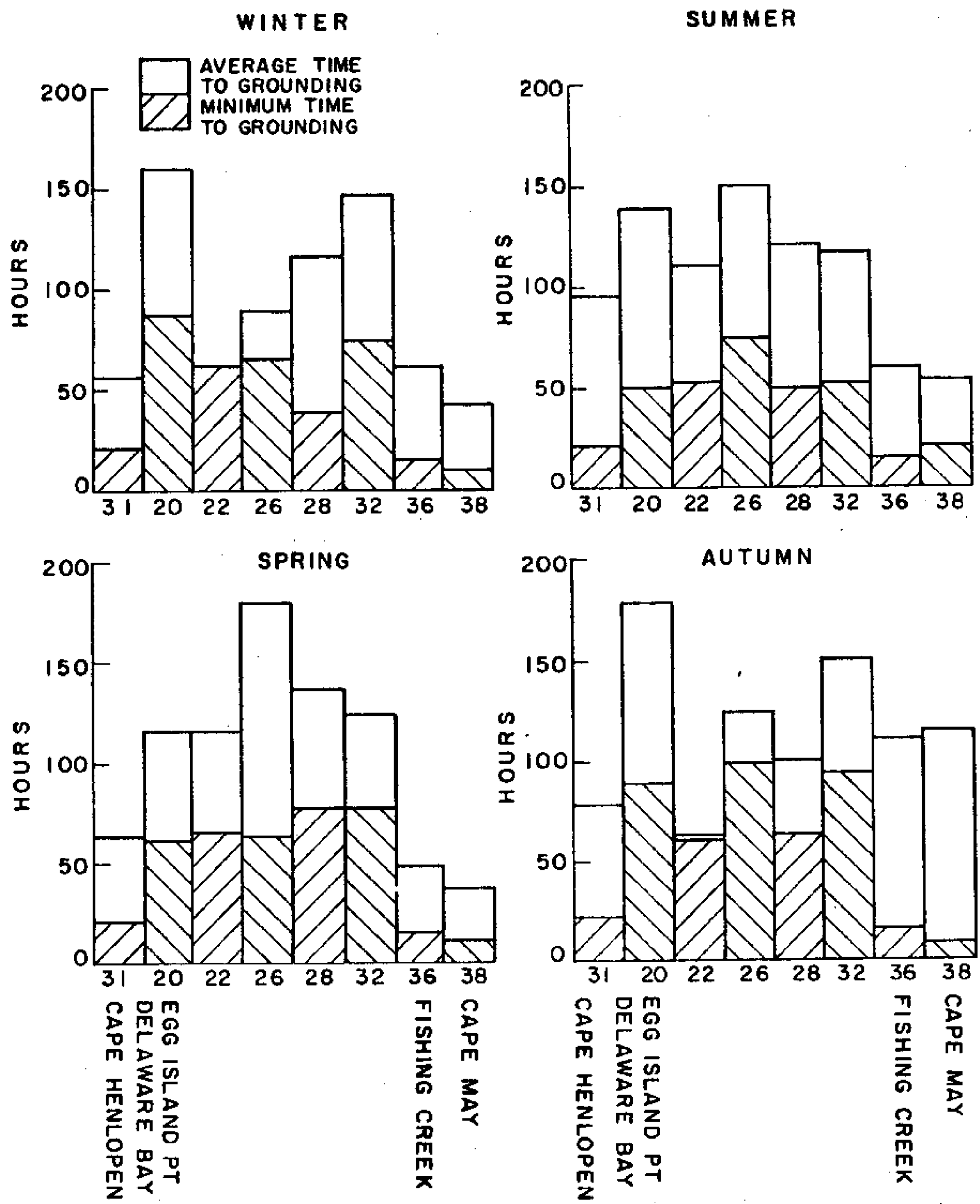


FIGURE 2-41 TIMES TO GROUNDING (DEL. BAY MOUTH SPILL)

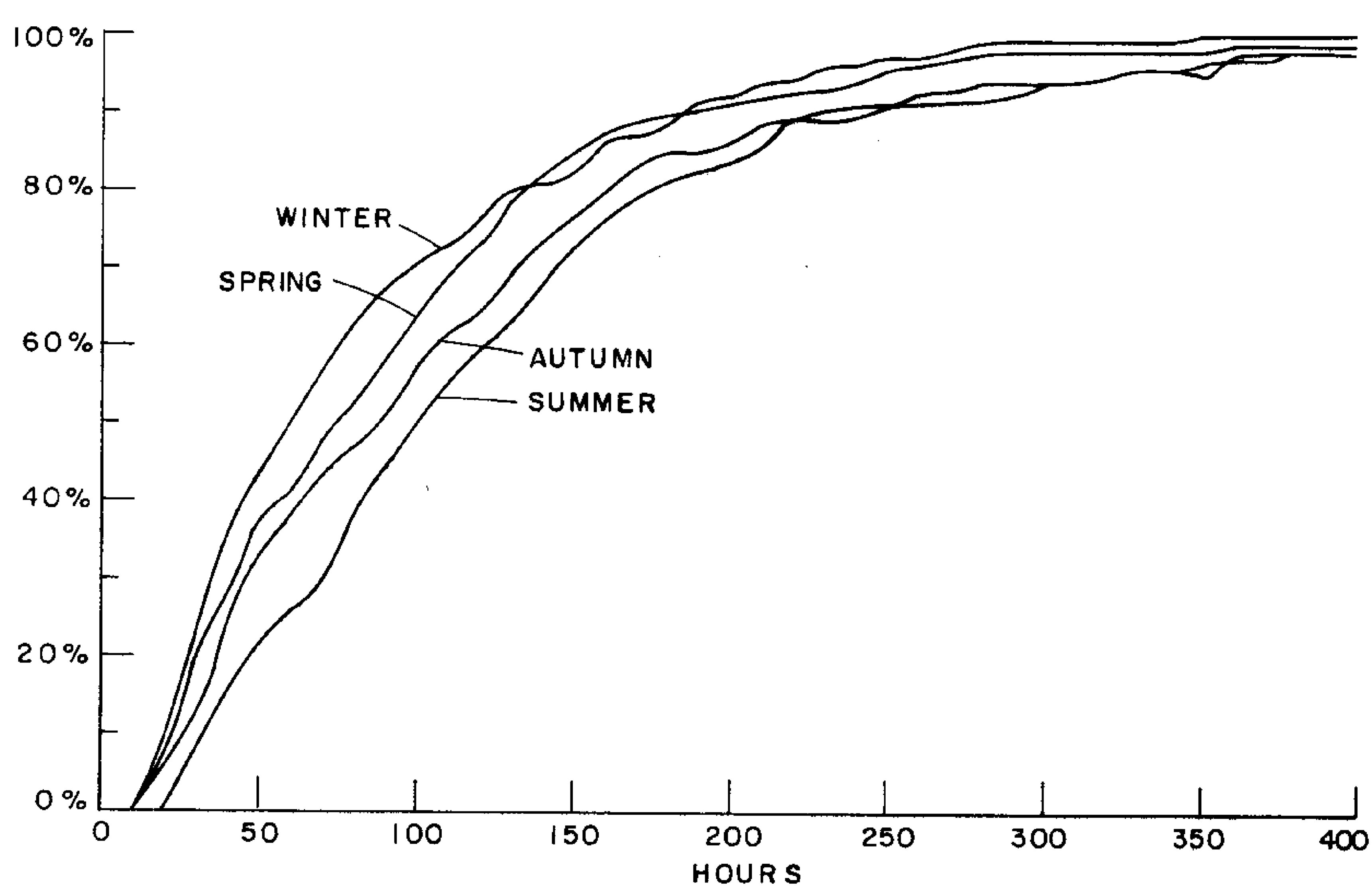
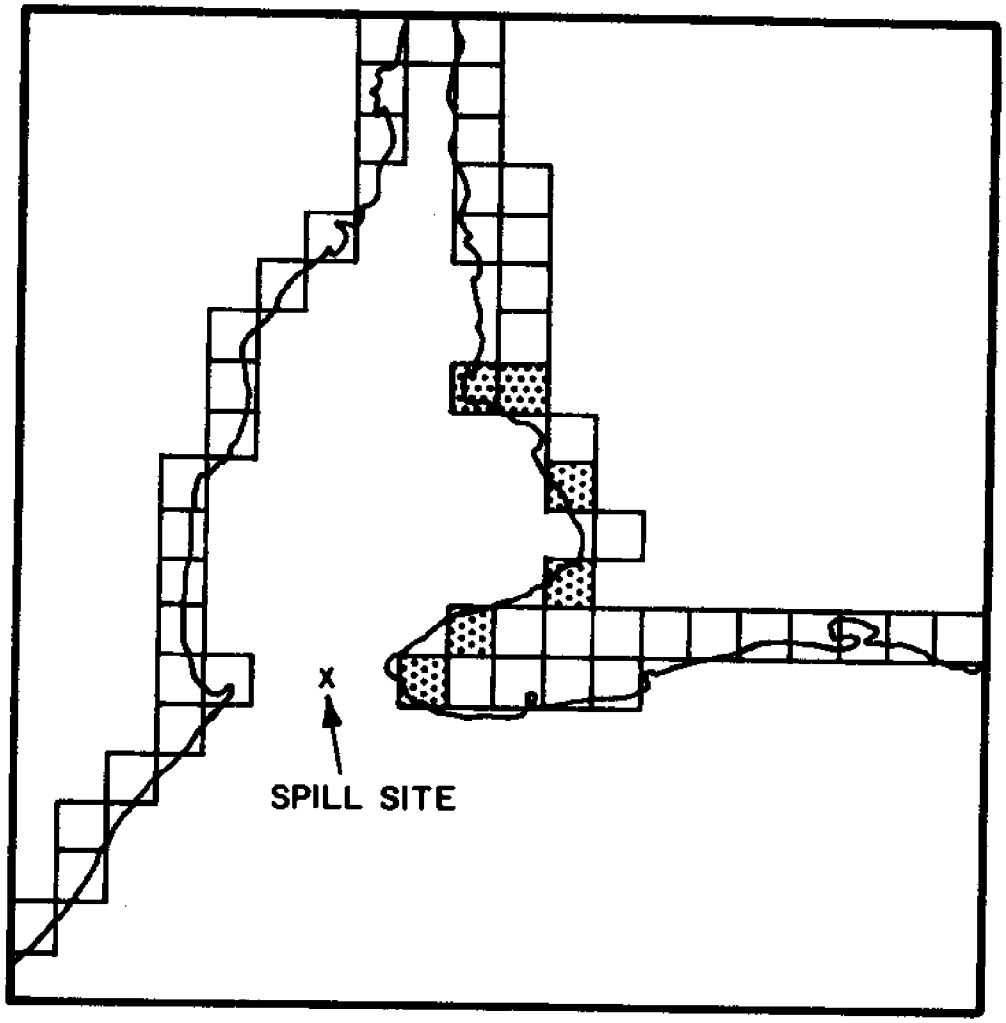


FIGURE 2-42 PERCENT ASHORE AS A FUNCTION OF TIME
(DELAWARE BAY MOUTH SPILL)



LIMITED TO AREAS WITH IMPACT >5% IN ANY SEASON

- <20% OF IMPACTS OCCUR WITH WIND >12 KNOTS
- MOST COME ASHORE WITH t>30 HRS
- MOST COME ASHORE WITH 10 < t < 30 HRS
- MOST COME ASHORE WITH t<10 HRS

>20% OF IMPACTS OCCUR WITH WIND > 12 KNOTS

FIG. 2.43 DELAWARE BAY CRITICAL AREAS FOR SPILLS OCCURRING AT BAY MOUTH SITE. SEASON - WINTER

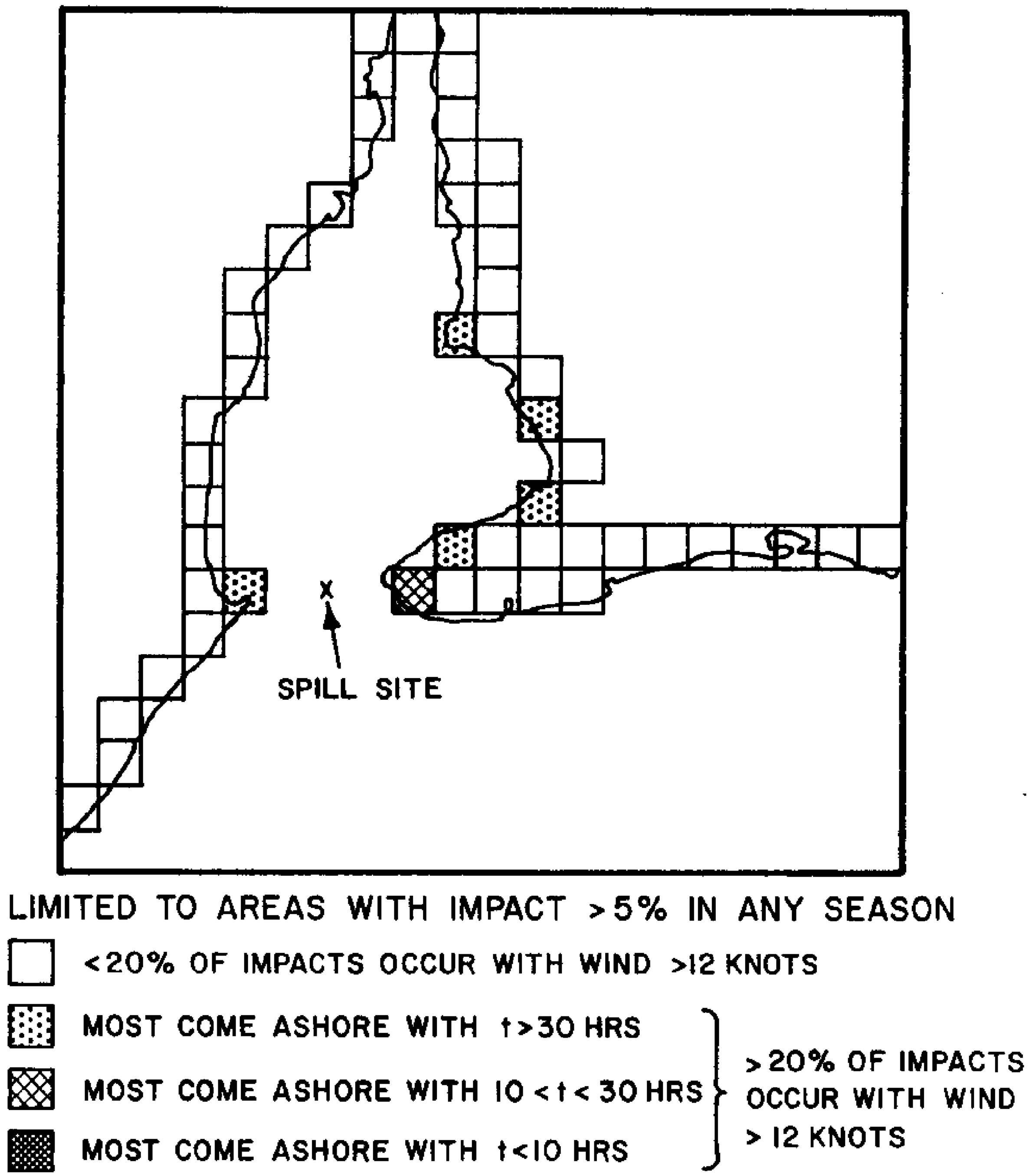
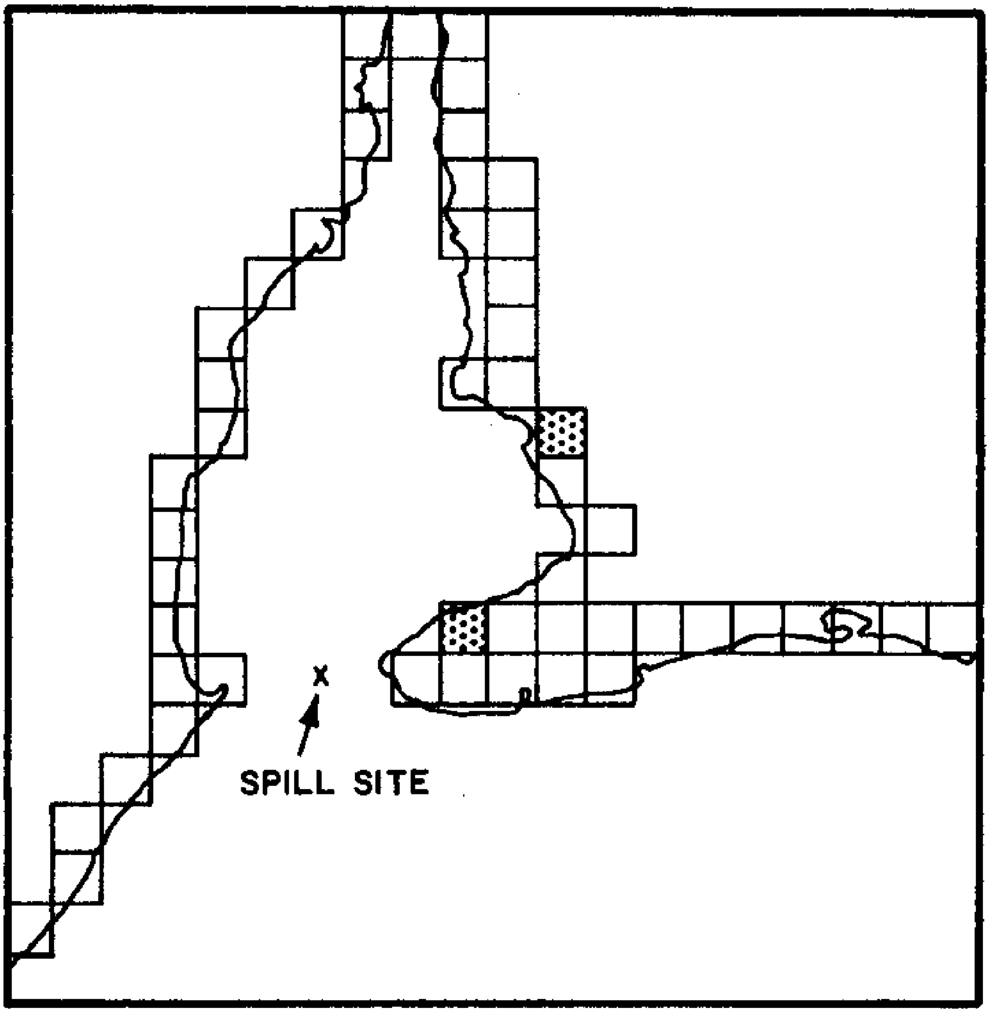


FIG. 2.44 DELAWARE BAY CRITICAL AREAS FOR SPILLS OCCURRING AT BAY MOUTH SITE. SEASON - SPRING

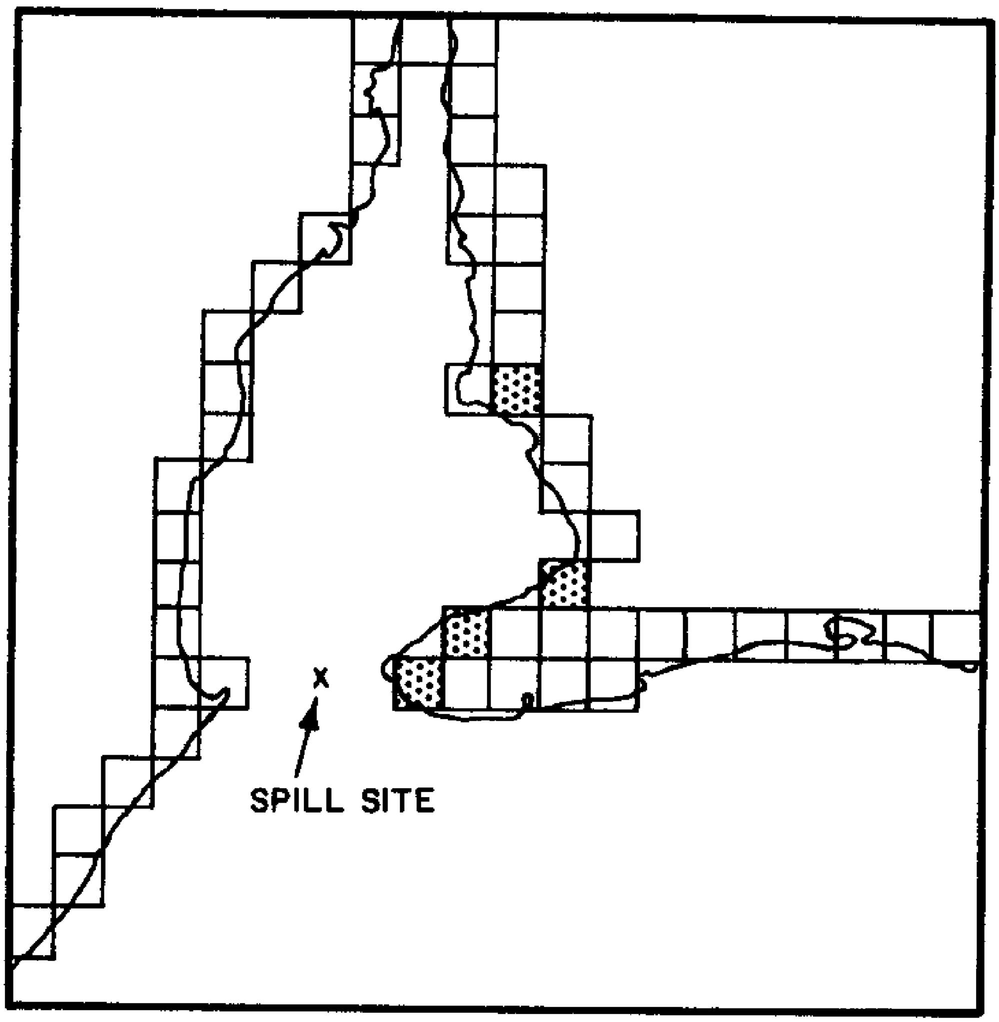


LIMITED TO AREAS WITH IMPACT >5% IN ANY SEASON

- <20% OF IMPACTS OCCUR WITH WIND >12 KNOTS
- MOST COME ASHORE WITH t>30 HRS
- MOST COME ASHORE WITH 10 < t < 30 HRS
- MOST COME ASHORE WITH t<10 HRS

(the last three: >20% OF IMPACTS OCCUR WITH WIND > 12 KNOTS)

FIG. 2.45 DELAWARE BAY CRITICAL AREAS FOR SPILLS OCCURRING AT BAY MOUTH SITE. SEASON - SUMMER

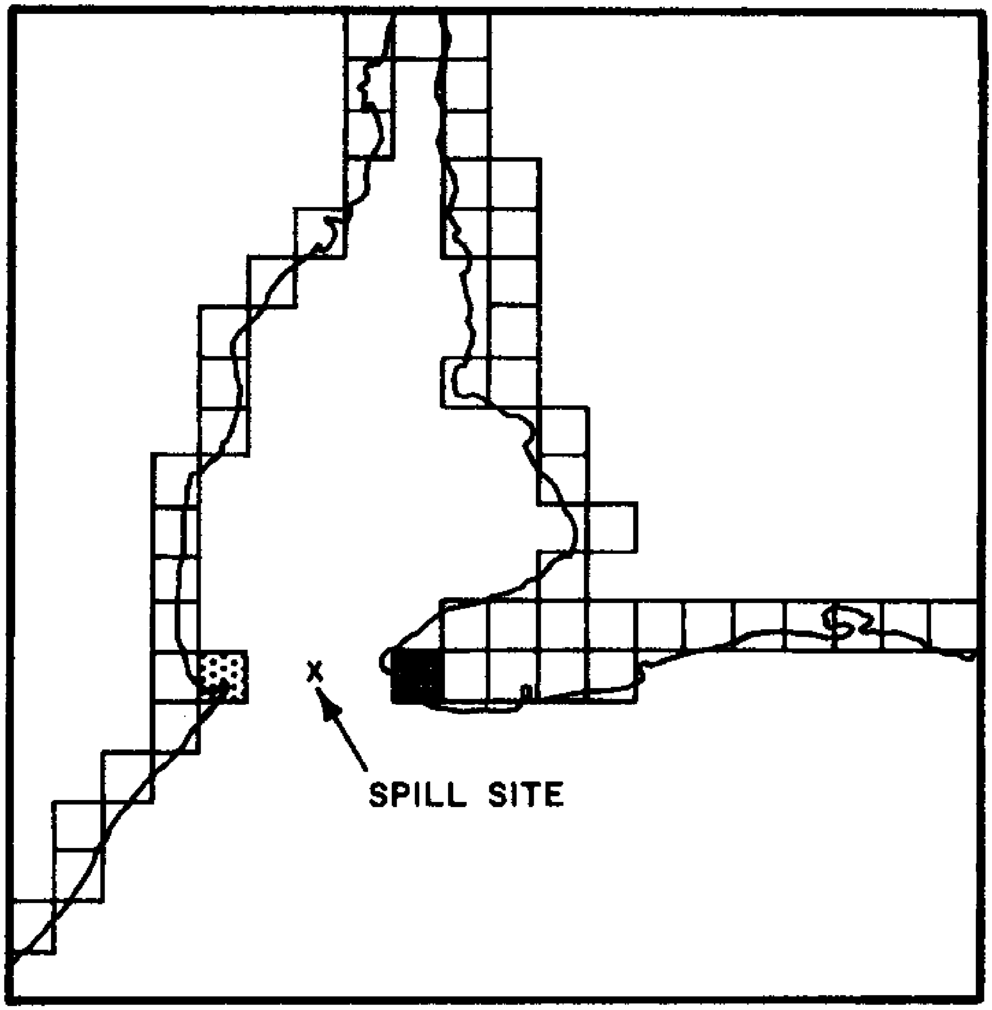


LIMITED TO AREAS WITH IMPACT >5% IN ANY SEASON

- <20% OF IMPACTS OCCUR WITH WIND >12 KNOTS
- MOST COME ASHORE WITH t>30 HRS
- MOST COME ASHORE WITH 10<t<30 HRS
- MOST COME ASHORE WITH t<10 HRS

(last three: >20% OF IMPACTS OCCUR WITH WIND >12 KNOTS)

FIG. 2.46 DELAWARE BAY CRITICAL AREAS FOR SPILLS OCCURRING AT BAY MOUTH SITE. SEASON - AUTUMN



DEFINE CRITICAL AS IMPACT >5% IN ANY SEASON AND >20% COME ASHORE WITH WIND >12 KNOTS AND A MAJORITY OF THESE COME ASHORE WITHIN 30 HOURS.

- ■ CRITICAL UNDER PRIMARY
- ▩ CRITICAL UNDER SECONDARY (BUT NOT PRIMARY)
- ⁙ CRITICAL UNDER TERTIARY ONLY

FIG. 2.47 DELAWARE BAY CRITICAL AREAS, POINT GROUP DEPENDENCE (BAY MOUTH SPILL)

Charleston Harbor

Figure 2.48 shows the map of Charleston Harbor used by the computer. Wind data were based on Charleston, S.C., weather records, 1963 to 1972. The shoreline was broken down into some 51 areas. A single spill site was studied, located in the center of the main harbor. Figures 2.49 through 2.52 indicate the results. With minor exceptions, there is very little seasonal dependence as far as the initial impact areas are concerned. They are spread rather evenly over the main part of the harbor.

Charleston Harbor is much smaller than the other two areas studied, and 60% of the spills are ashore within seven or eight hours (Figure 2.53). There is little seasonal dependence in the times to shore (Figure 2.54). Since the distances and times to shore are so small, the results are dominated by the tidal currents and seasonal wind rose properties.

Areas in which more than 20% of the spills come ashore in winds over 12 knots are localized in the Charleston-Hog Island areas (Figures 2.55 through 2.59) once again with little seasonal variation. However, as might be expected given the smaller distances, the initial impact areas are more sensitive to initial spill size. The smaller the area, the more important the spill spread is relative to spill transport (Figure 2.59).

General comments on nearshore spill problem

1. The foregoing analyses are quite frankly meant to be exemplary in nature. Our choice of sample harbors does not imply we are advocating any of these locations. Rather, the analyses undertaken are intended to be models of the sort of work which should be done in any terminal area under consideration. We be-

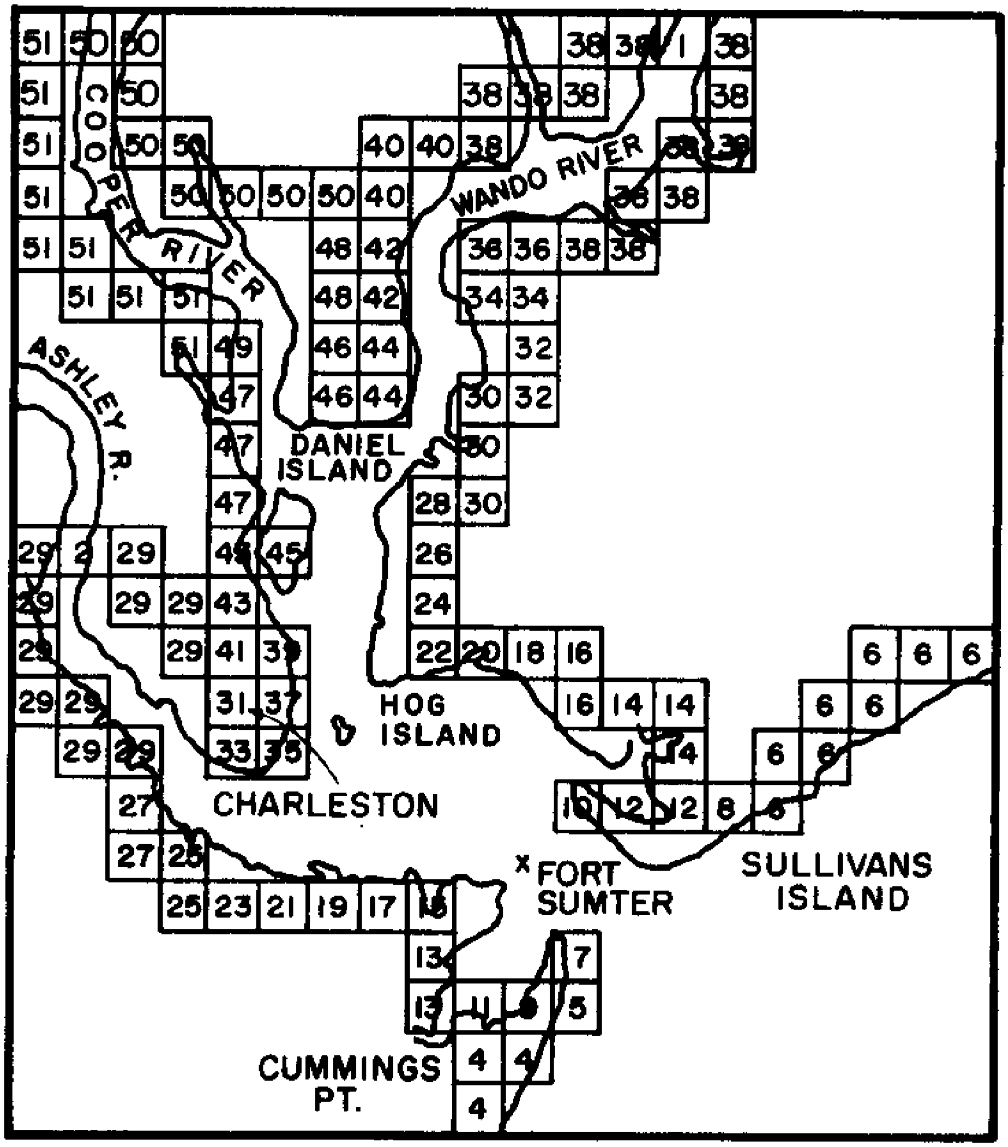


FIG. 2.48 MAP OF CHARLESTON HARBOR

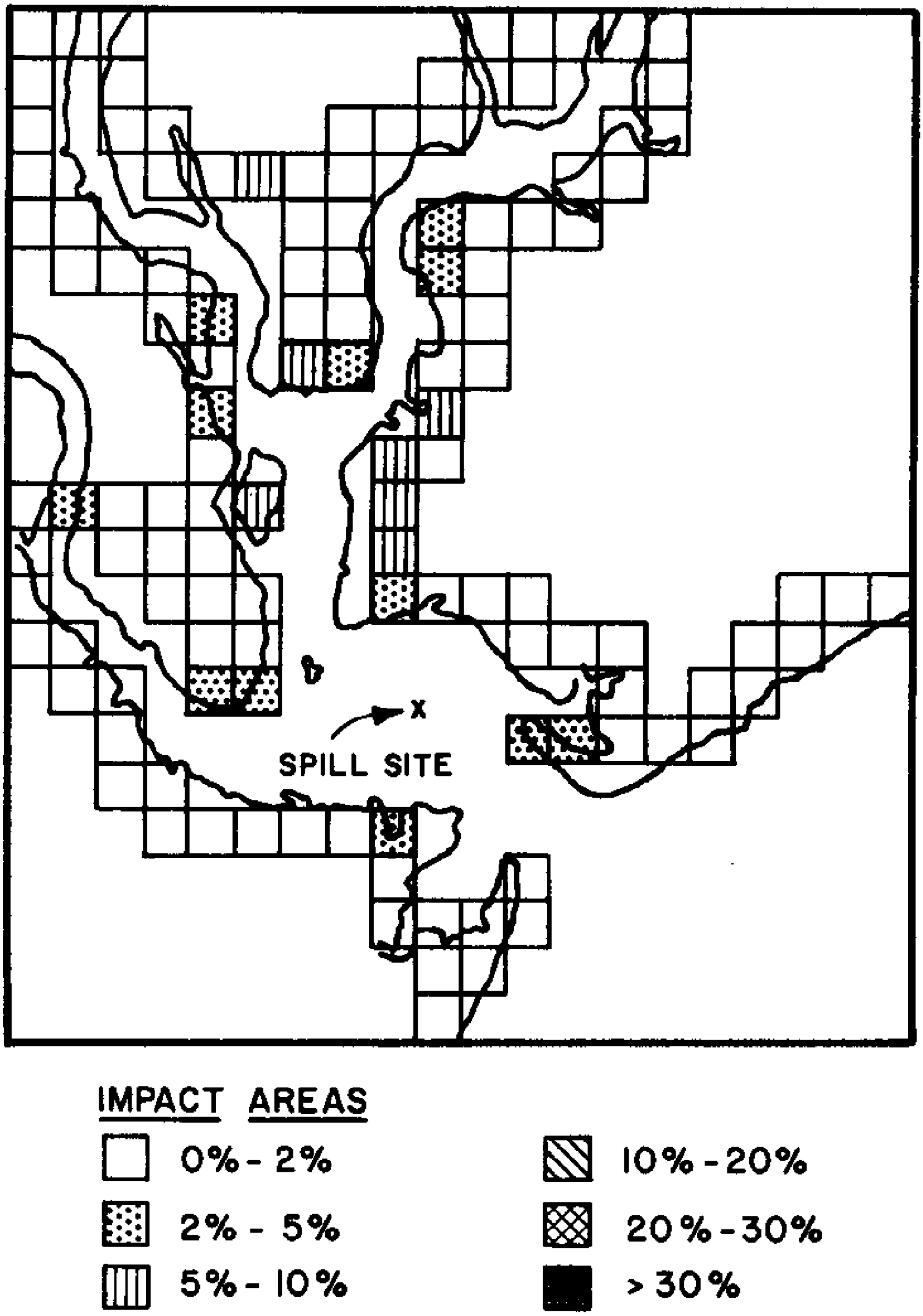
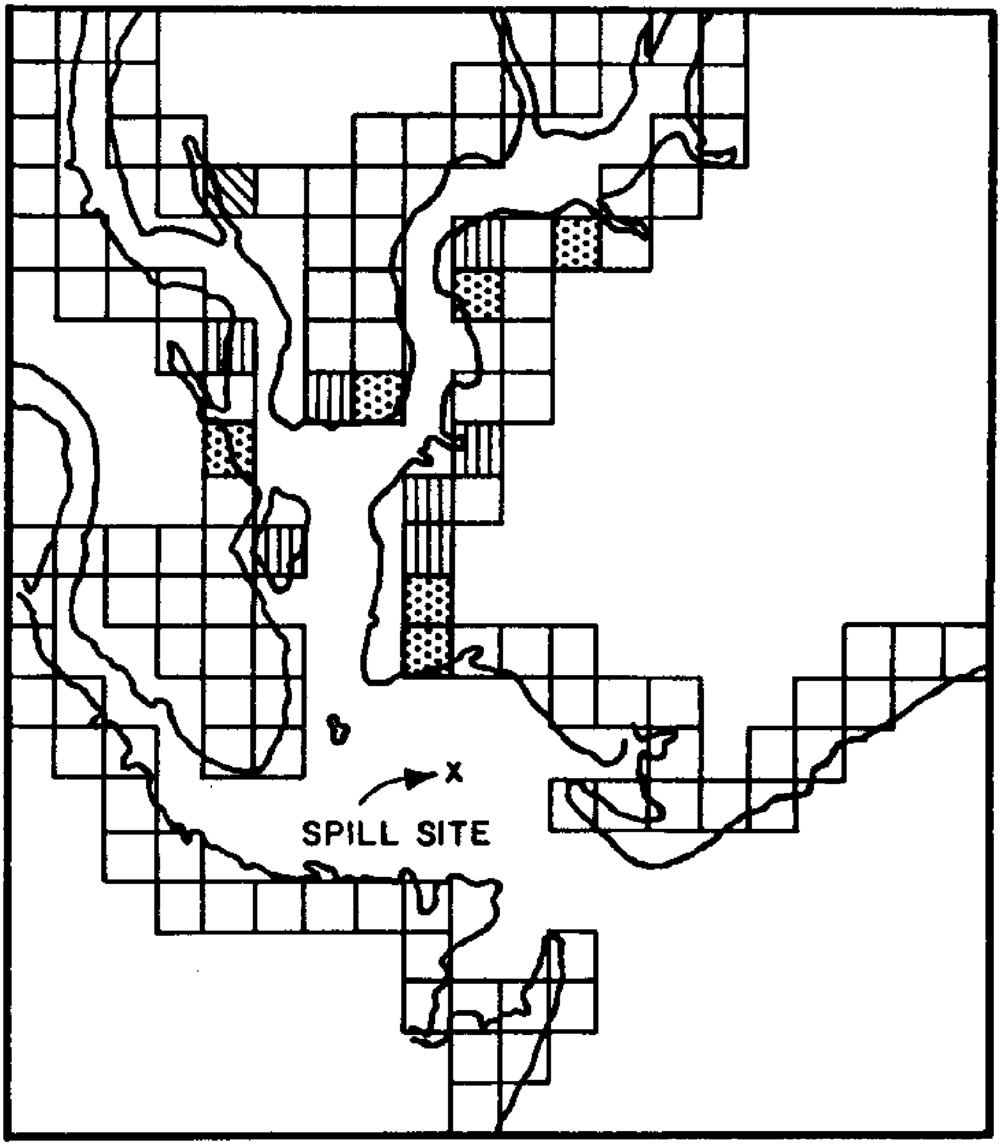


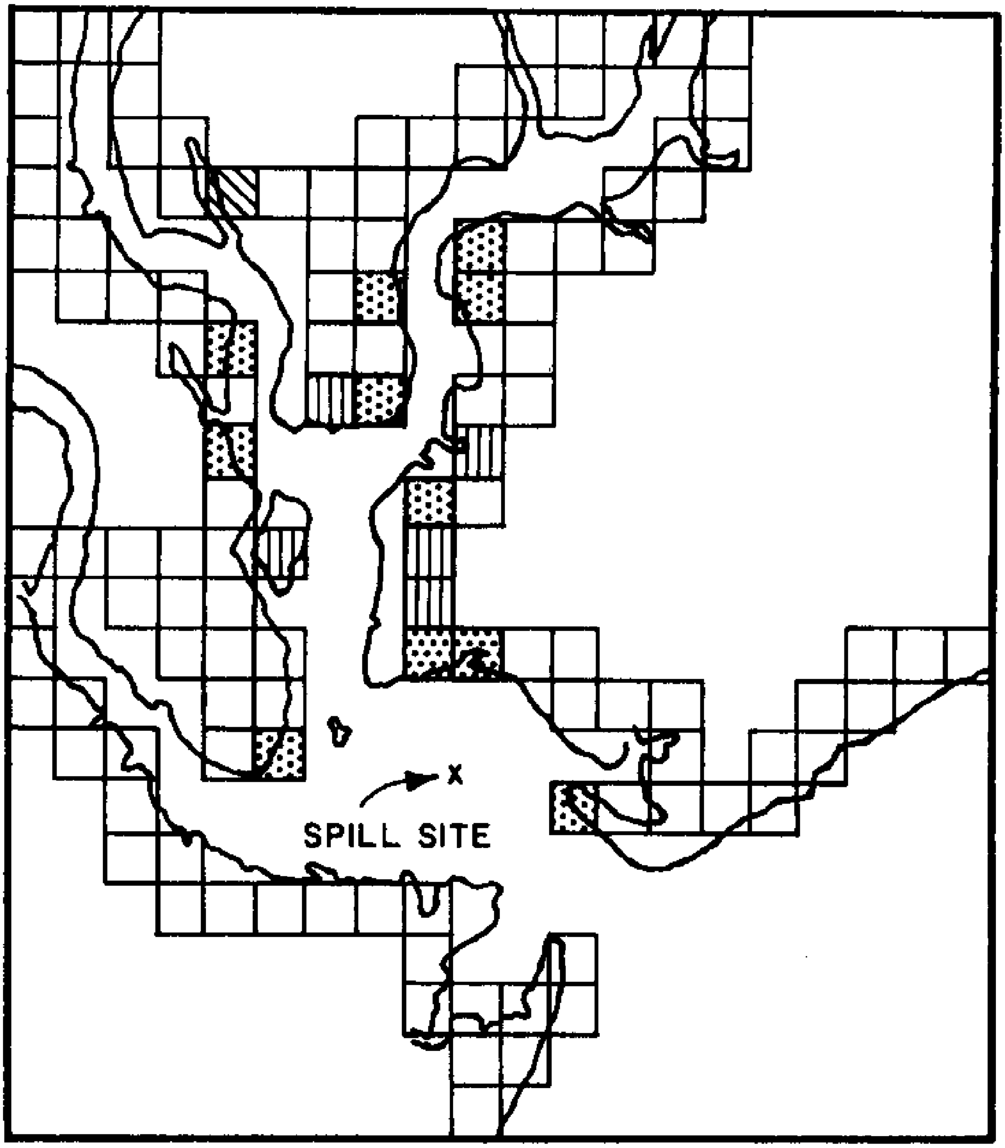
FIG. 2.49 CHARLESTON HARBOR IMPACT AREAS FOR SPILLS AT CENTRAL HARBOR SITE. SEASON - WINTER



IMPACT AREAS

- 0% - 2%
- 2% - 5%
- 5% - 10%
- 10% - 20%
- 20% - 30%
- > 30%

FIG. 2.50 CHARLESTON HARBOR IMPACT AREAS FOR SPILLS AT CENTRAL HARBOR SITE. SEASON - SPRING



IMPACT AREAS

0% - 2%

2% - 5%

5% - 10%

10% - 20%

20% - 30%

> 30%

FIG. 2.51 CHARLESTON HARBOR IMPACT AREAS FOR SPILLS AT CENTRAL HARBOR SITE. SEASON - SUMMER

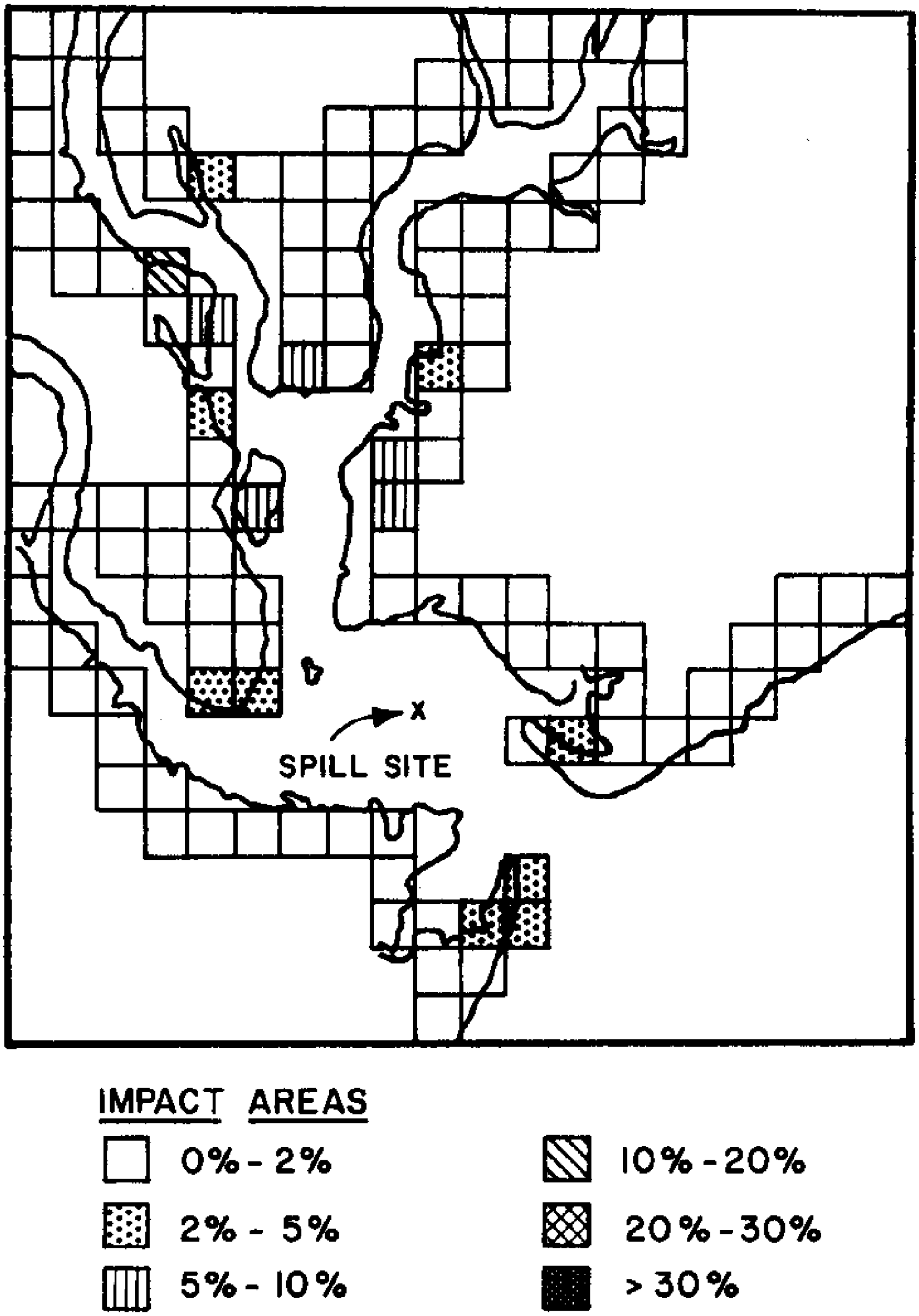


FIG. 2.52 CHARLESTON HARBOR IMPACT AREAS FOR SPILLS AT CENTRAL HARBOR SITE. SEASON - AUTUMN

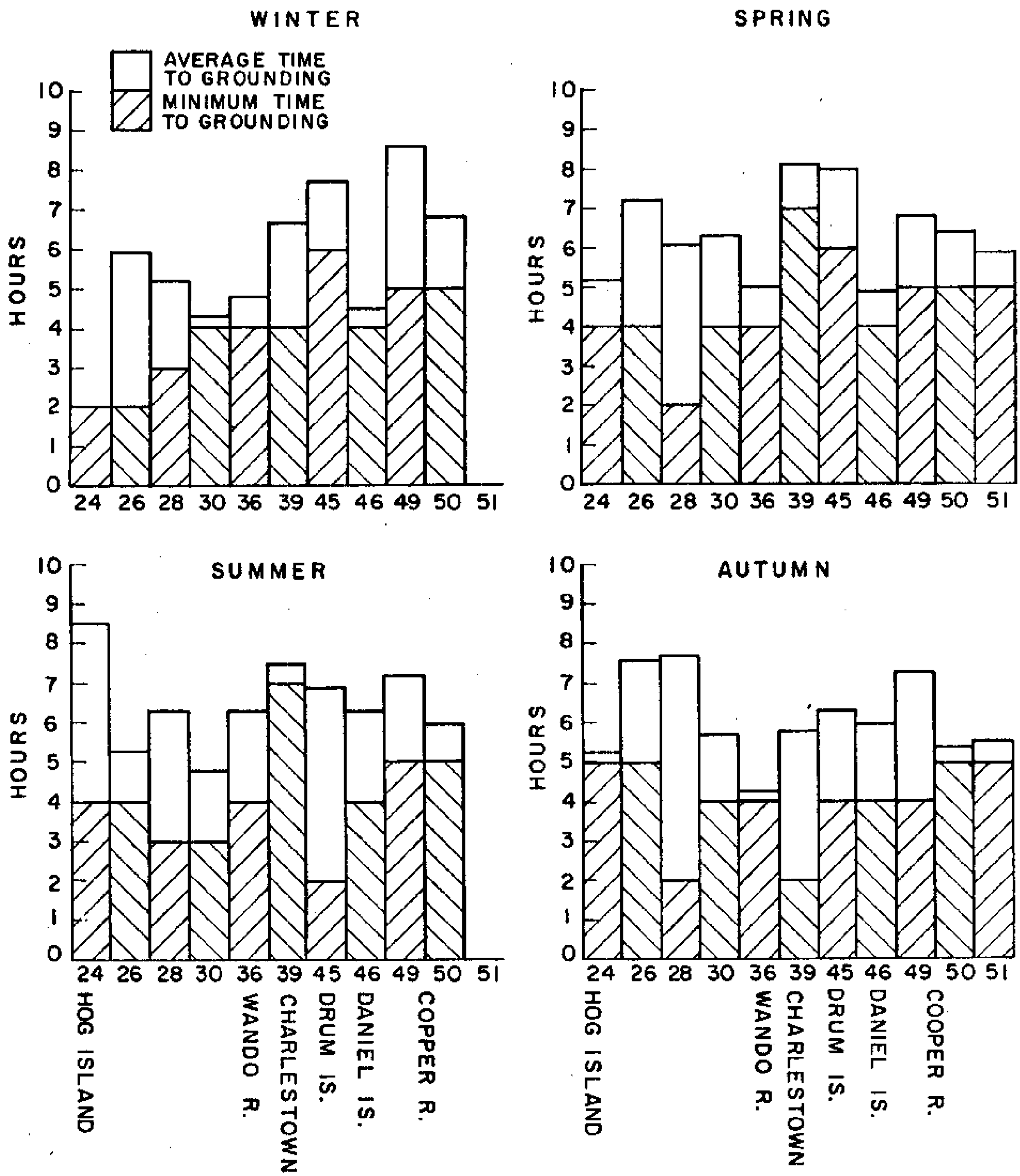


FIGURE 2-53 TIMES TO GROUNDING

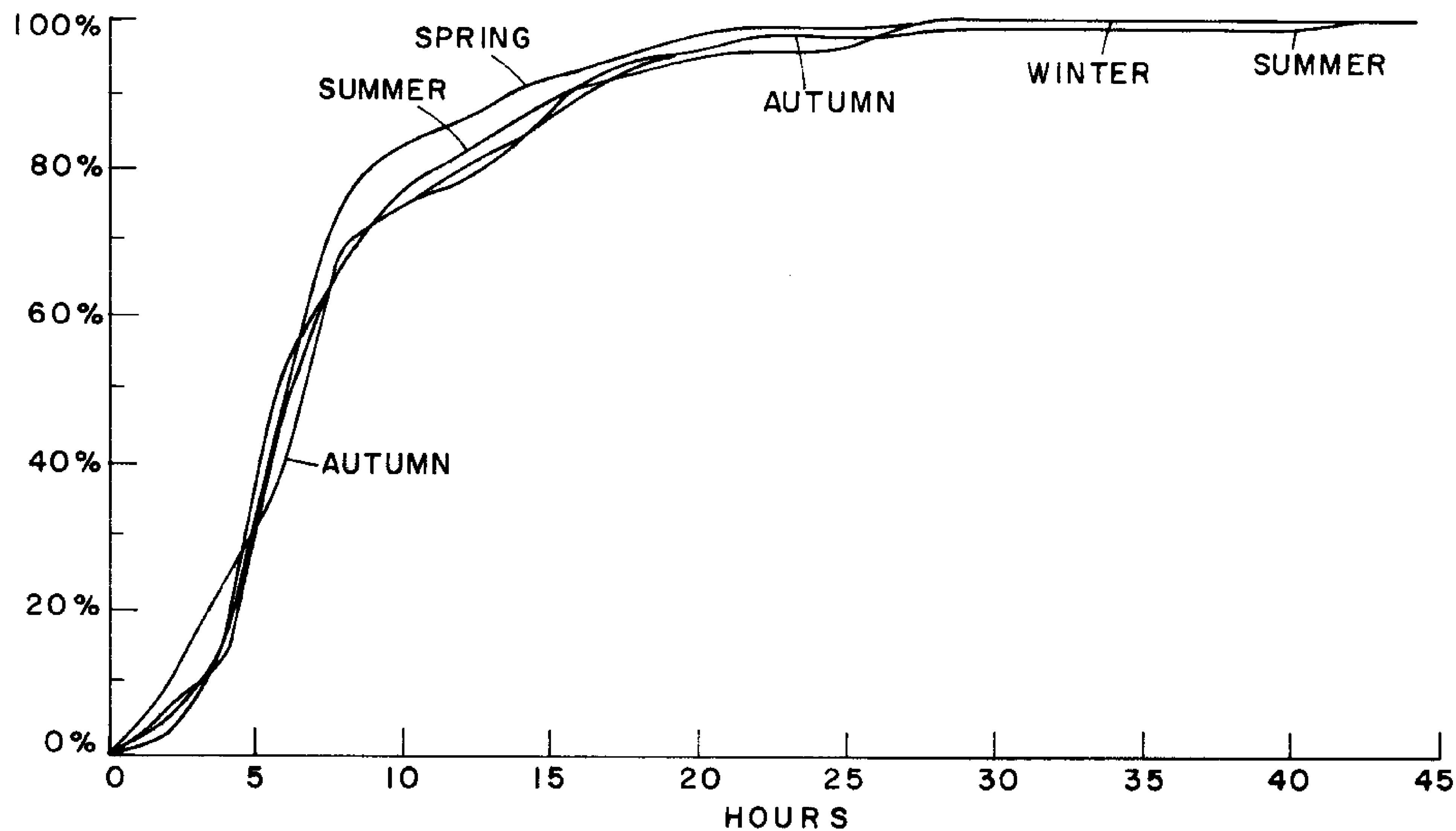
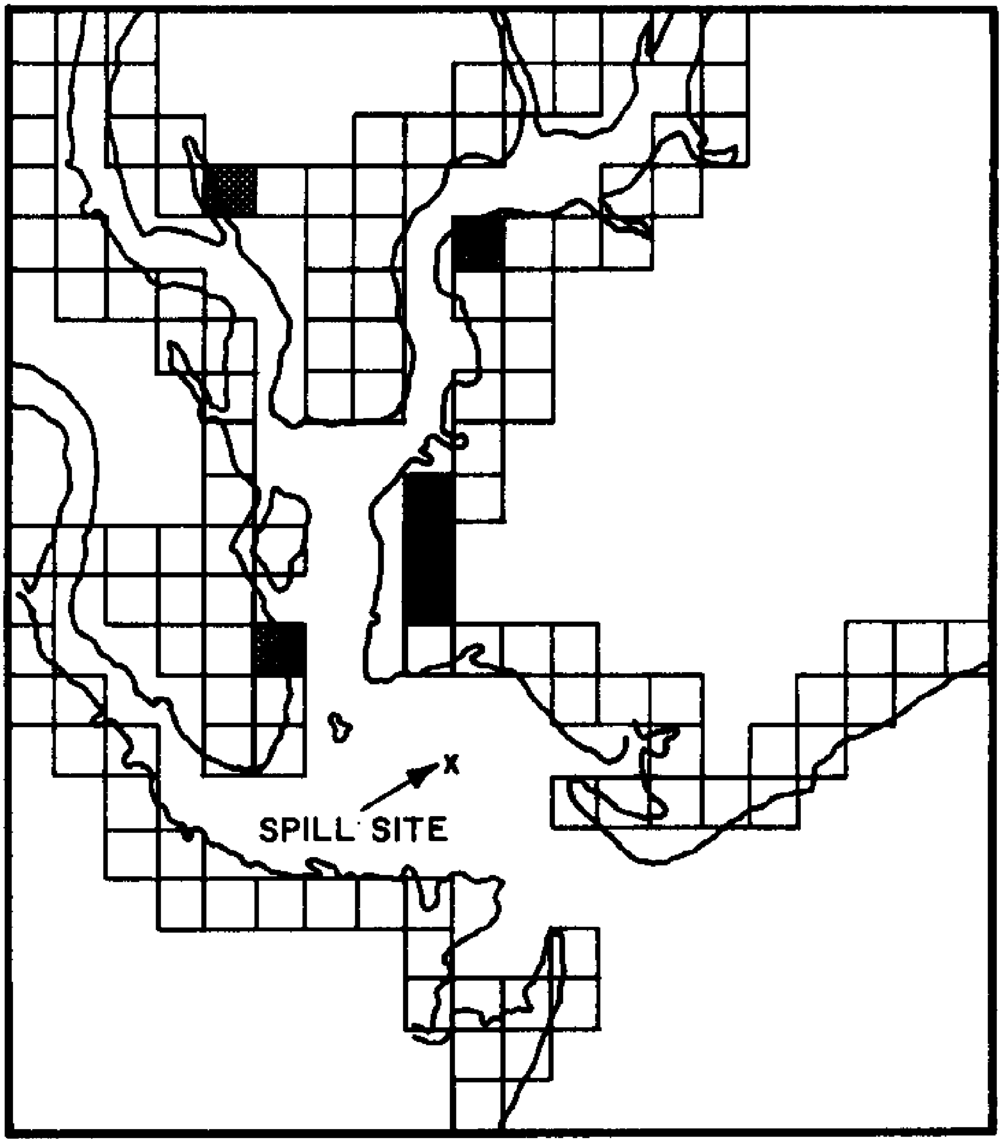


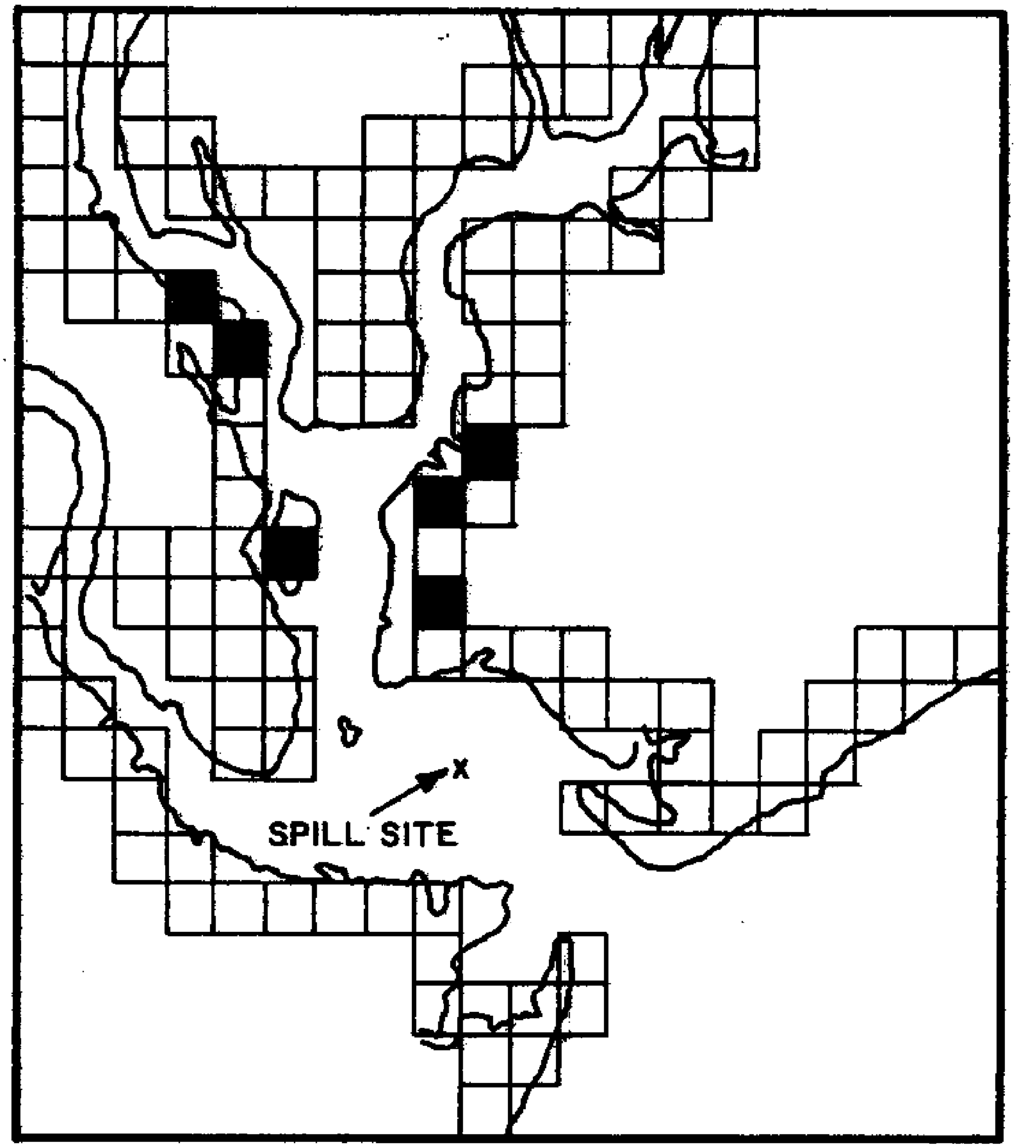
FIGURE 2-54 TOTAL PERCENT ASHORE AS A FUNCTION OF TIME (LAUNCH PT : CENTRAL HARBOR REGION)



LIMITED TO AREAS WITH IMPACT > 5% IN ANY SEASON

(open)	< 20% OF IMPACTS OCCUR WITH WIND > 12 KNOTS	
(dotted)	MOST COME ASHORE WITH t > 30 HRS	> 20% OF IMPACTS OCCUR WITH WIND > 12 KNOTS
(cross-hatched)	MOST COME ASHORE WITH 10 < t < 30 HRS	
(solid)	MOST COME ASHORE WITH t < 10 HRS	

FIG. 2.55 CHARLESTON HARBOR CRITICAL AREAS FOR SPILLS AT CENTRAL HARBOR SITE. SEASON - WINTER

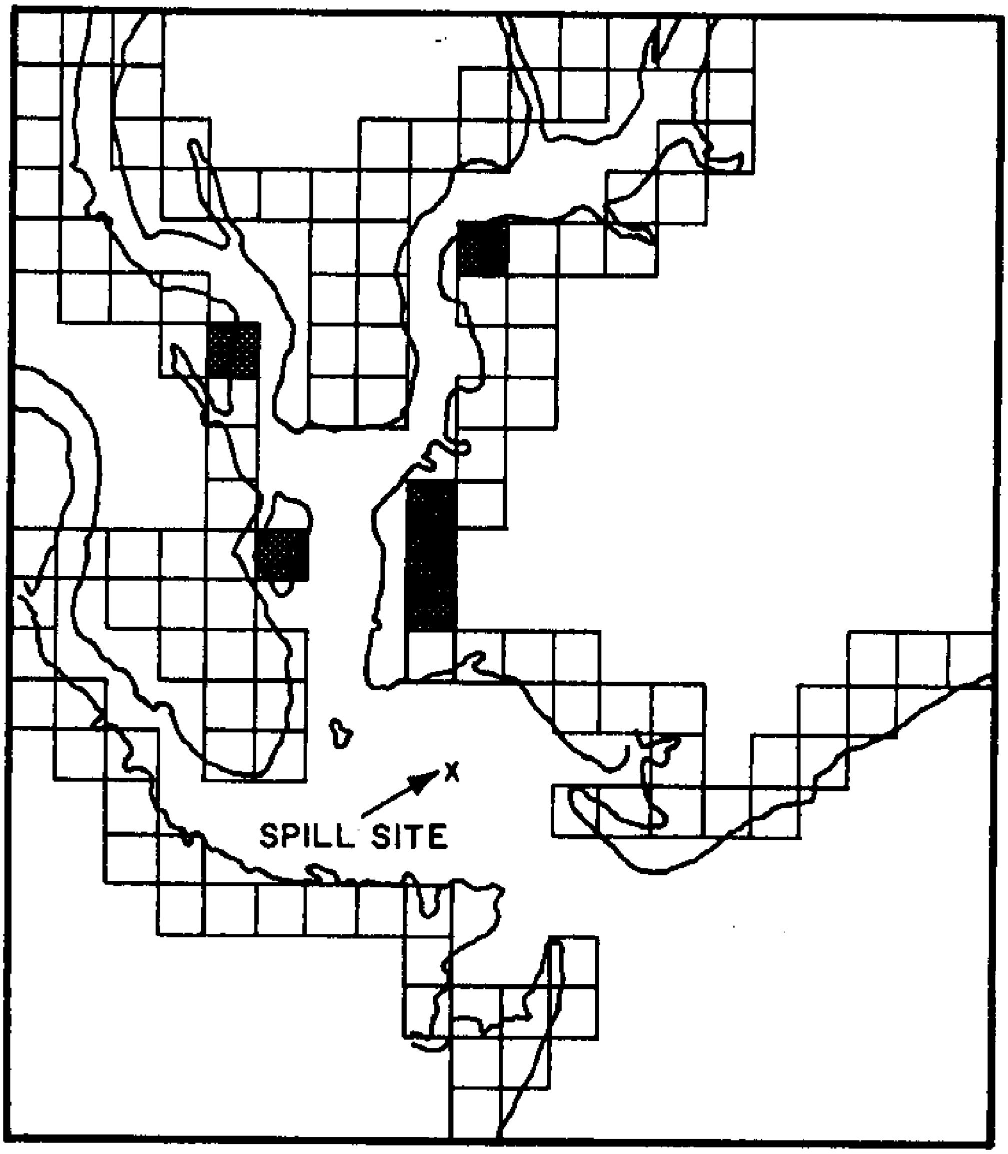


LIMITED TO AREAS WITH IMPACT > 5% IN ANY SEASON

- < 20% OF IMPACTS OCCUR WITH WIND > 12 KNOTS
- MOST COME ASHORE WITH $t > 30$ HRS
- MOST COME ASHORE WITH $10 < t < 30$ HRS
- MOST COME ASHORE WITH $t < 10$ HRS

} > 20% OF IMPACTS OCCUR WITH WIND > 12 KNOTS

FIG. 2.56 CHARLESTON HARBOR CRITICAL AREAS FOR SPILLS AT CENTRAL HARBOR SITE. SEASON - SPRING

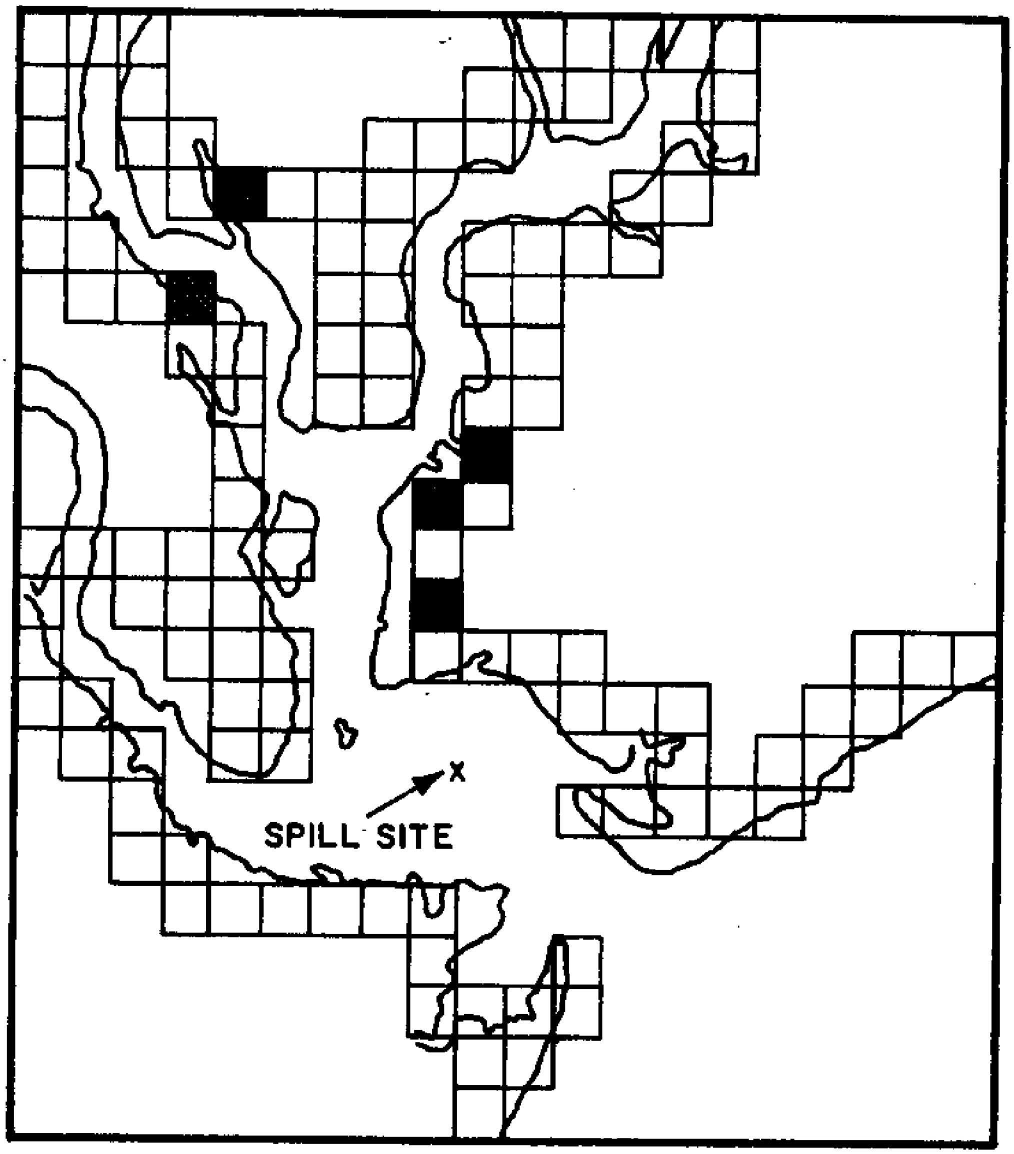


LIMITED TO AREAS WITH IMPACT > 5% IN ANY SEASON

- < 20% OF IMPACTS OCCUR WITH WIND > 12 KNOTS
- MOST COME ASHORE WITH $t > 30$ HRS
- MOST COME ASHORE WITH $10 < t < 30$ HRS
- MOST COME ASHORE WITH $t < 10$ HRS

(the last three: > 20% OF IMPACTS OCCUR WITH WIND > 12 KNOTS)

FIG. 2.57 CHARLESTON HARBOR CRITICAL AREAS FOR SPILLS AT CENTRAL HARBOR SITE. SEASON - SUMMER

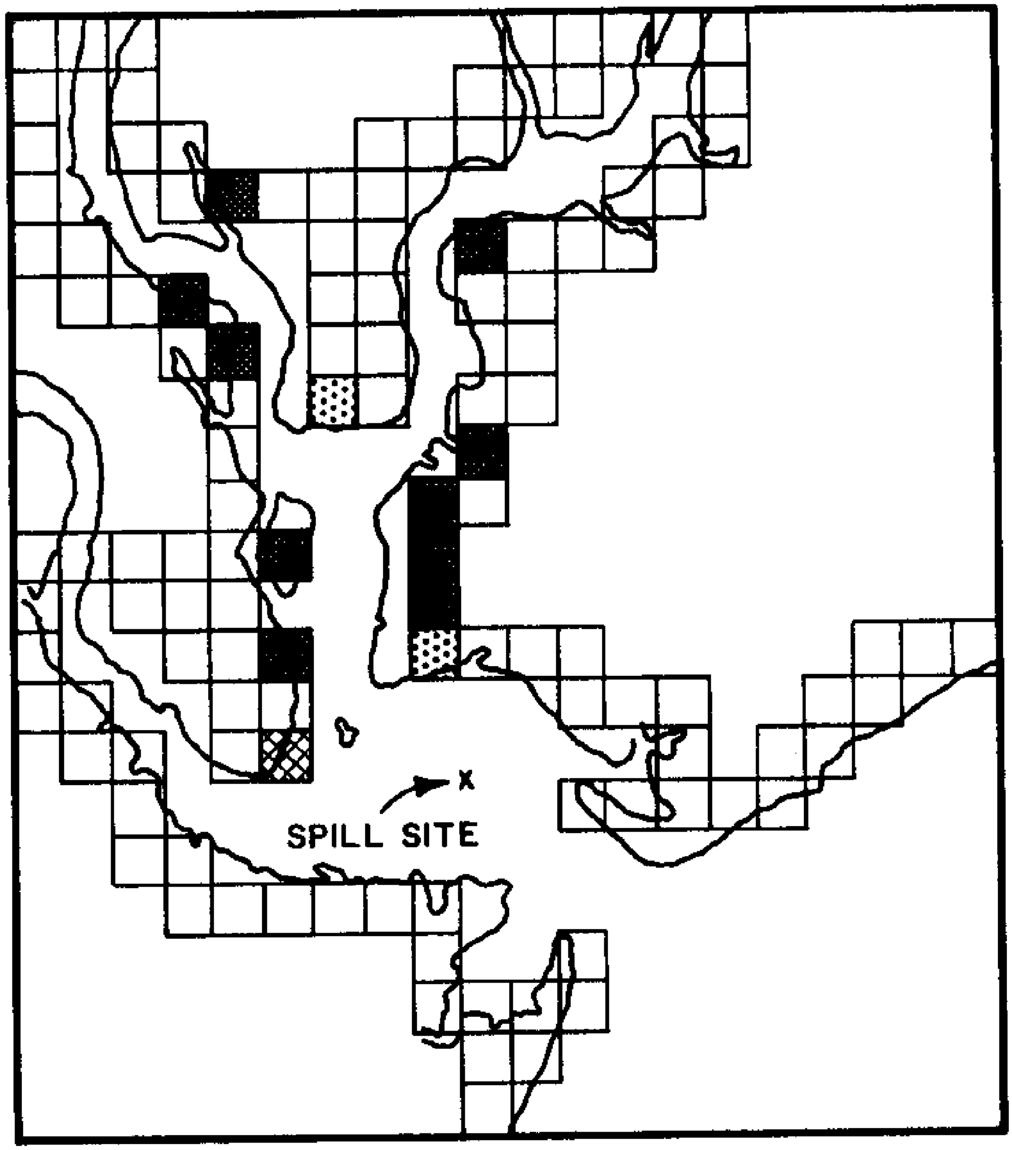


LIMITED TO AREAS WITH IMPACT > 5% IN ANY SEASON

- ☐ < 20% OF IMPACTS OCCUR WITH WIND > 12 KNOTS
- MOST COME ASHORE WITH t > 30 HRS
- MOST COME ASHORE WITH 10 < t < 30 HRS
- MOST COME ASHORE WITH t < 10 HRS

(last three: > 20% OF IMPACTS OCCUR WITH WIND > 12 KNOTS)

FIG. 2.58 CHARLESTON HARBOR CRITICAL AREAS FOR SPILLS AT CENTRAL HARBOR SITE. SEASON - AUTUMN



DEFINE CRITICAL AS IMPACT >5% IN ANY SEASON AND >20% COME ASHORE WITH WIND >12 KNOTS AND A MAJORITY OF THESE COME ASHORE WITHIN 30 HOURS.

- CRITICAL UNDER PRIMARY
- CRITICAL UNDER SECONDARY (BUT NOT PRIMARY)
- CRITICAL UNDER TERTIARY ONLY

FIG. 2.59 CHARLESTON HARBOR CRITICAL AREAS, POINT GROUP DEPENDENCE (CENTRAL HARBOR SPILL) lieve the sample results point to the value of such work for assessing certain aspects of the impacts of specified terminal locations, and provide insight on the design and deployment of containment and collection systems. Certainly, any such analysis should include a series of offshore locations of varying distances from the coast to help assess the tradeoffs associated with placing terminals further at sea.

2. Presuming that all spills will occur near the transshipment site, then it would appear to be possible to select these sites for the specific purposes of either making it highly unlikely a particular region is hit or, on the other hand, of making it highly probable that the spills will only hit in a relatively small region. It may be desirable to have different transshipment sites in different seasons.

3. No attempt has been made to assess any special biological problems associated with a particular set of critical impact areas, nor has an attempt been made to establish anything but the grossest sort of feel for the problem. The next step would appear to require some focusing of effort with respect to a particular nearshore region, and a more definite specification of the functions required of the transshipment site.

CHAPTER III

ANALYSIS OF SPILL TRAJECTORIES EMANATING FROM POTENTIAL OFFSHORE PRODUCTION SITES

Current specification

The spill trajectory predictions for the offshore region are of a fundamentally different nature than those for the three nearshore areas previously discussed. This distinction stems primarily from the uncertainty surrounding specification of the ambient current components contributing to the spill velocity. The non-wind-related currents in tidal areas will be composed of many different elements, but, on the whole, we know that predominant currents will be the tidal current and any net efflux from the rivers emptying into the nearshore region. Certainly we will introduce an error by ignoring the other motions, but this error will be small in comparison to the properly-defined tidal current.

In the offshore region, it is not possible to determine the predominant current components in this fashion. First of all, the total non-wind-related current may be composed of a relatively weak net motion and a relatively strong random motion of large wavelengths. In this circumstance, it is not physically correct to attempt to relate all randomness in the trajectory to the randomness in the surface wind. Unfortunately, there is no way of resolving this problem, within our present understanding of oceanic processes, because we do not have a statistical description of motions on this scale or frequency. Consequently, we shall be forced to hypothesize that these motions are weak, as compared to the wind-induced motions. As we shall see, some measures of drift bottle behavior tend to substantiate this hypothesis.

However, even with this simplification, we cannot fully specify the problem because the mean ambient motion is still indeterminant. We can make some educated guesses from the geostrophy of the region, mix this in with any other data available, and end up with an hypothesis, but there is no way of speaking of the resultant in any quantitative, error-oriented sense.

The problem with using drift bottle statistics to gain insight is that we don't know the appropriate drift formula to use. There is good reason, however, to speculate that it is similar to Smith's empirical formula for oil spills and that the drift coefficient is on the order of .03 or less. The reason is that measurements of the surface boundary layer motion have yielded surface drifts in the range .03 to .05 of wind speed (Wu, 1968, for example). The drift of a bottle may be less due to its tendency to average the boundary layer velocity over its depth. Csanady, 1963, for example, found that small jars drifted about 20% slower than foolscap-sized mimeo masters in two or three comparative measurements.

To determine the sensitivity of the drift bottle behavior to the value of this wind drift coefficient, we investigated hypothetical drift bottle behavior in the EDS 5 region for three values of the wind drift coefficient, .02, .03, and .04, using our best guess of the mean ambient current. (This mean ambient current hypothesis is discussed in a later section dealing with the mid-Atlantic region.) The results are depicted in the following two figures. Figure 3.1 shows the percentage impact in any given shoreline region for (.04) vs. (.03) and (.02) vs. (.03)

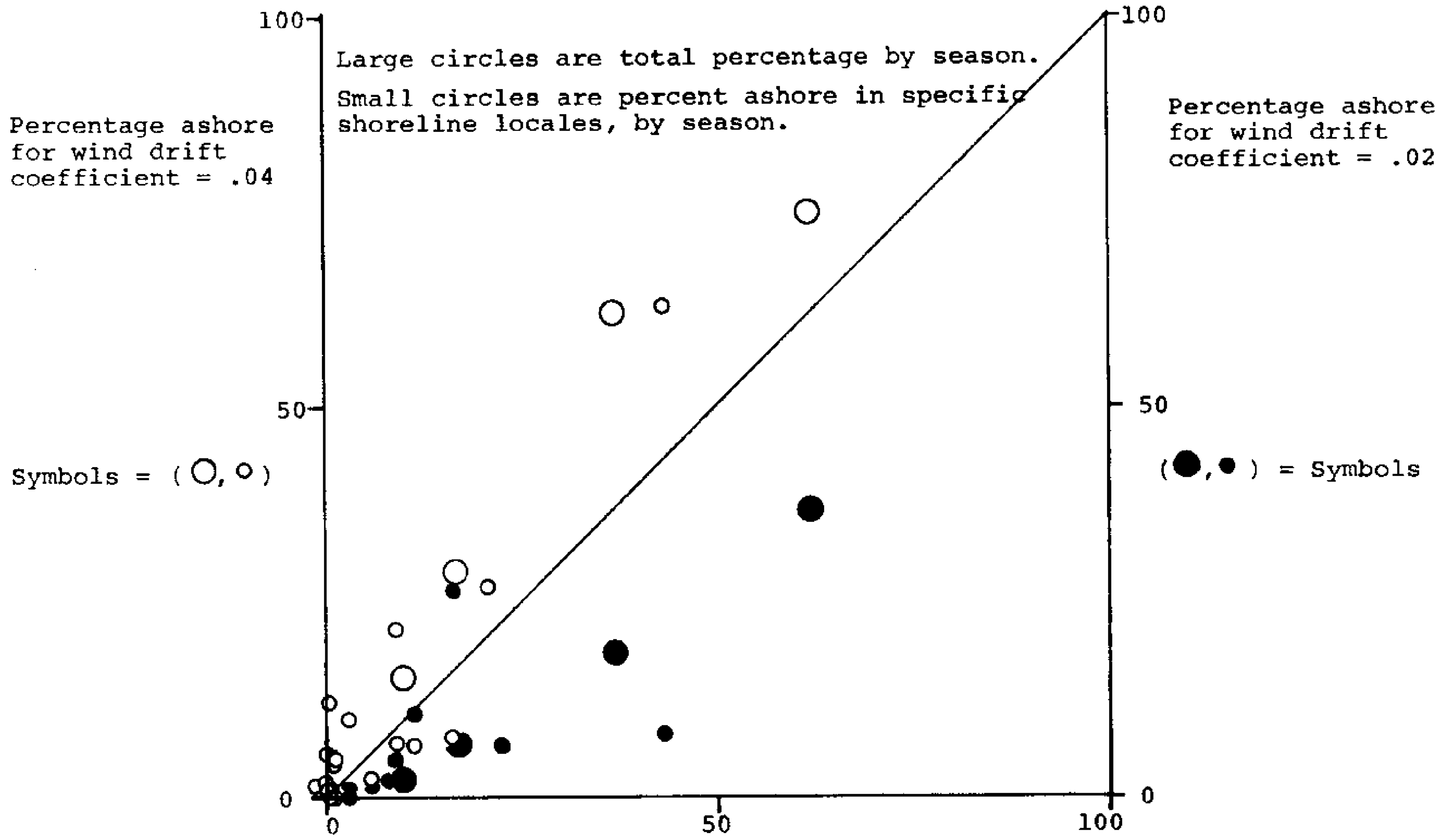


Figure 3.1--Sensitivity to wind drift coefficient. Launch point = 15 nautical miles north of EDS 5.

for all releases 15 nautical miles north of EDS 5. Figure 3.2 shows the same thing for launches from EDS 5. Note that in the first figure the circles all tend to group reasonably well about the diagonal line. This is an indication that, for this launch point, the results are fairly insensitive to the wind drift coefficient. The next figure isn't so reassuring, however, for we can see a marked difference between the .04 coefficient and the .03 coefficient. This result is a strong indication that we get markedly different behavior for these two hypotheses. The difference between the .03 and .02 values isn't as strong.

Thus, if we are to use the drift bottle data, we must make one more hypothesis regarding the bottle drift coefficient, namely, that it is closer to .03 than to .04 (or even .02). Having made this assumption, we can now verify portions of the predicted drift utilizing drift bottle data, provided we can derive the appropriate statistical measures from the available drift bottle data. This again is not an unambiguous problem, and the next section deals more fully with the drift bottle analysis. Subsequent sections then detail our studies of each of the four major offshore regions: the Georges Bank area, the mid-Atlantic area, the southern Atlantic coast area, and the Gulf of Alaska.

Drift bottle analysis

Drift bottle launch and recovery records were obtained for the Gulf of Alaska and the East Coast. In the Gulf of Alaska the drift bottle data consisted of the results of six separate cruises in which a number of bottles were released from about 60 stations. In the East Coast region, our data base consisted

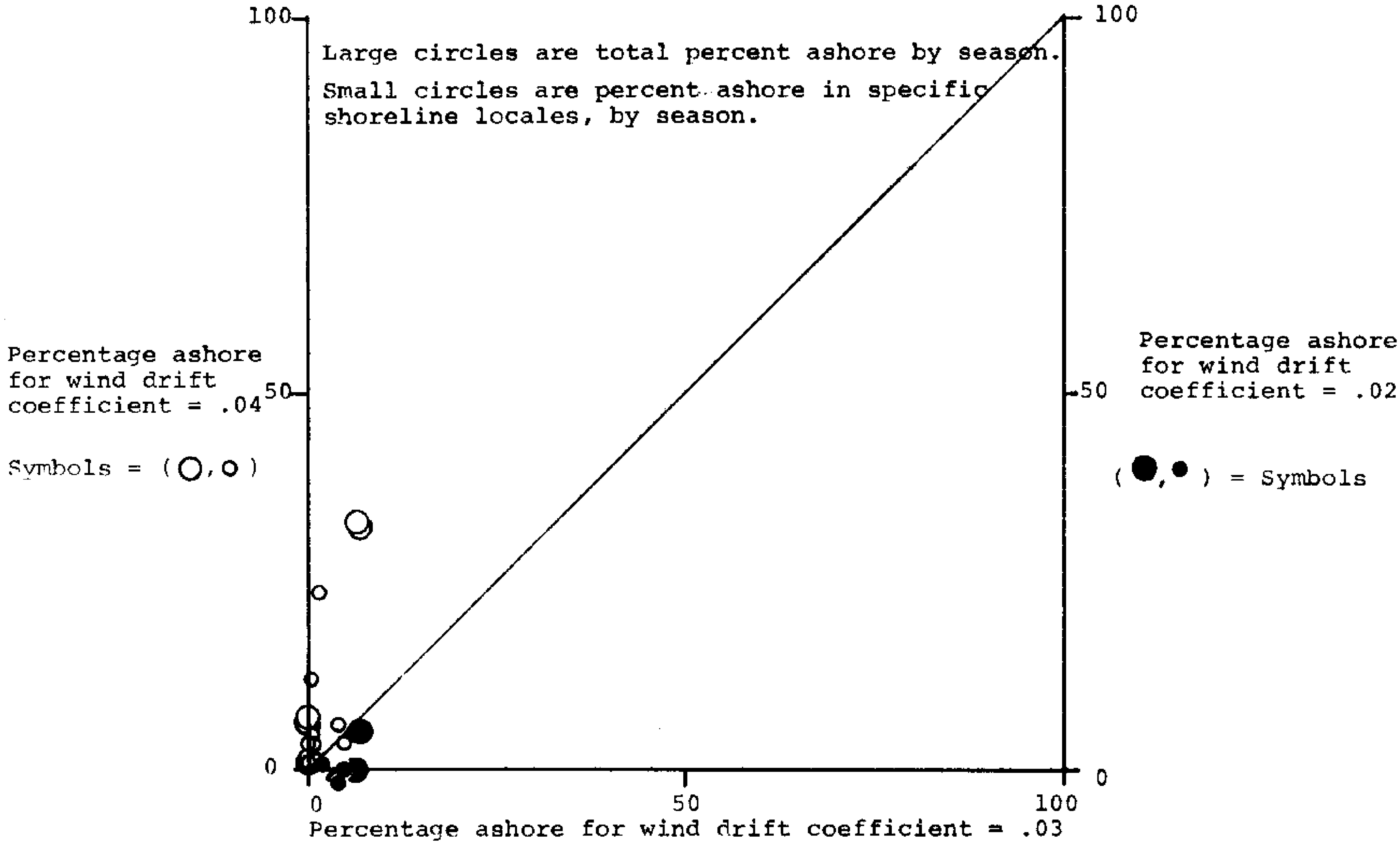


Figure 3.2--Sensitivity to wind drift coefficient. Launch point = EDS 5.

of about 35,000 release and recovery records obtained through NODC. These records documented the release of 189,542 separate bottles, released in 48,801 launch groups. Of this total, 16,964 bottles were recovered.

A drift bottle is essentially a soda pop bottle, well corked, containing a message offering the finder a modest reward for mailing an enclosed postcard to the investigator conducting the experiment. The bottles are launched in various configurations: unballasted; ballasted to near neutral buoyancy; fitted with wire and sheet metal drogues; and undrogued. In the last twenty years or so, the most common configuration has been the ballasted, undrogued bottle. Typically, the bottles are released in groups of five or six, although since 1960 East Coast lightships have been releasing bottles daily in groups of two. Prior to release, the serial numbers, date, and location are recorded. If the bottles are found and the finder returns the enclosed message as well as the date and place of recovery, the investigator can then come to some conclusions regarding the drift process. The parameters we selected to characterize the drift bottle launch and recovery process were: percentage recovered, region of recovery, and average and minimum time to recovery.

A key question to be answered with respect to the first parameter, the percentage recovered, is: Are bottles that are released together correlated in their recovery statistics? That is, do the bottles wash ashore in a group, or do they tend to behave independently?

In technical terms, the determining variable would be the relative strengths of the high and low wave number components of the power density spectrum of the bottle's velocity. If most of the motions were characterized by small length scale, random variations, then the bottles that initially were very close together would diverge rapidly from each other, while from an average point of view making only minor progress in leaving the initial launch site. On the other hand, if the bottle's motions were characterized by large-scale, random fluctuations, then the bottles would progress as a group away from the launch site, and within the group the average separation would increase only slowly with respect to the growth of the distance of the group from the mean path of all trajectories initiated at the launch site.

This consideration also has a strong bearing on the similarity of oil spill trajectories and drift bottle trajectories. It is fairly obvious that an oil spill will eventually cover a considerable area of the water's surface. In this condition, the motion of the center of mass of the oil will tend to represent an average of all the smaller wavelength components of the ambient turbulent motions. As a result, the motion of the center of mass of the oil should be affected primarily by the large-scale, lower-frequency phenomena acting on the spill. Thus, if we wish to verify that drift bottle motion is analogous to oil spill motion, we should like to know the scales of turbulent motion that are most responsible for the random trajectory behavior of drift bottles.

To gain some insight into this problem, we made a rough analysis of the drift bottle data for the entire East Coast, with the following results. First, we determined the distribution on launch and recovery group sizes. A launch group was defined as the collection of all bottles released from the same minute square of latitude and longitude on the same date (year, month, day). A recovery group was defined as all bottles recovered (anywhere) that were released from a common launch group. Table 3.1 shows the result of this analysis. Note that the average size of a launch group is in the range of four to five, and, if a recovery is made, the recovery group size is between one and two.

Next, we looked at the separation in time and distance between bottles washed ashore that were released in the same launch group. This is a somewhat biased measure of the correlation between bottles because the number of pairs contributing to the total goes as (n - 1)/2)n, where n is the number of recoveries. Thus, one release that resulted in 50 recoveries would contribute far more pairs than 25 recovery groups of size 2. This could substantially bias the findings. Nevertheless, this was one of the simpler things to do and, as Table 3.2 shows, the results are significant even if we presume that all the bottles recovered in the large (40 and above) recovery groups fell within the 10 miles and 10 days category and discard them for fear that they were released nearby, because this would contribute only 6,343 to the 9,744 pairs in this category. Therefore, the 10 miles and 10 days figure would still represent the major grouping of results.

Another way of getting at the same problem is to determine

Table 3.1

DISTRIBUTION ON RECOVERY AND LAUNCH GROUP SIZE

Number Recovered	Times Observed	(Normalized)	Number Launched	Times Observed	(Normalized)
1	6079	6.16281E-01	1	40	8.19655E-04
2	2401	2.43410E-01	2	25911	5.30952E-01
3	673	6.82279E-02	3	171	3.50403E-03
4	343	3.47729E-02	4	1416	2.90158E-02
5	238	2.41281E-02	5	9070	1.85857E-01
6	43	4.35929E-03	6	10280	2.10651E-01
7	22	2.23033E-03	7	5	1.02457E-04
8	16	1.62206E-03	8	10	2.04914E-04
9	9	9.12409E-04	9	12	2.45896E-04
10	3	3.04136E-04	10	517	1.05940E-02
11	2	2.02757E-04	11	11	2.25405E-04
12	4	4.05515E-04	12	1170	2.39749E-02
13	3	3.04136E-04	13	3	6.14741E-05
14	2	2.02757E-04	14	6	1.22948E-04
15	1	1.01379E-04	15	8	1.63931E-04
16	3	3.04136E-04	16	1	2.04914E-05
17	4	4.05515E-04	17	0	0.00000E+00
18	0	0.00000E+00	18	4	8.19655E-05
19	3	3.04136E-04	19	2	4.09828E-05
20	1	1.01379E-04	20	52	1.06555E-03
21	2	2.02757E-04	21	0	0.00000E+00
22	0	0.00000E+00	22	1	2.04914E-05
23	1	1.01379E-04	23	6	1.22948E-04
24	0	0.00000E+00	24	54	1.10653E-03
25	2	2.02757E-04	25	5	1.02457E-04
26	0	0.00000E+00	26	1	2.04914E-05
27	0	0.00000E+00	27	1	2.04914E-05
28	0	0.00000E+00	28	11	2.25405E-04
29	2	2.02757E-04	29	0	0.00000E+00
30	0	0.00000E+00	30	3	6.14741E-05
31	0	0.00000E+00	31	0	0.00000E+00
32	0	0.00000E+00	32	4	8.19655E-05
33	0	0.00000E+00	33	0	0.00000E+00
34	0	0.00000E+00	34	0	0.00000E+00
35	2	2.02757E-04	35	1	2.04914E-05
36	0	0.00000E+00	36	3	6.14741E-05
37	0	0.00000E+00	37	0	0.00000E+00
38	0	0.00000E+00	38	0	0.00000E+00
39	1	1.01379E-04	39	0	0.00000E+00
40	0	0.00000E+00	40	0	0.00000E+00
41	0	0.00000E+00	41	0	0.00000E+00
42	1	1.01379E-04	42	0	0.00000E+00
43	0	0.00000E+00	43	0	0.00000E+00
44	0	0.00000E+00	44	0	0.00000E+00
45	0	0.00000E+00	45	0	0.00000E+00
46	0	0.00000E+00	46	0	0.00000E+00
47	0	0.00000E+00	47	0	0.00000E+00
48	0	0.00000E+00	48	14	2.86879E-04
49	0	0.00000E+00	49	0	0.00000E+00
50	0	0.00000E+00	50	0	0.00000E+00
51	0	0.00000E+00	51	0	0.00000E+00
52	0	0.00000E+00	52	0	0.00000E+00
53	0	0.00000E+00	53	0	0.00000E+00
54	0	0.00000E+00	54	0	0.00000E+00
55	0	0.00000E+00	55	0	0.00000E+00
56	1	1.01379E-04	56	0	0.00000E+00
57	1	1.01379E-04	57	0	0.00000E+00
58	0	0.00000E+00	58	0	0.00000E+00
59	0	0.00000E+00	59	1	2.04914E-05
60	0	0.00000E+00	60	2	4.09828E-05
61	0	0.00000E+00	61	0	0.00000E+00
62	0	0.00000E+00	62	0	0.00000E+00
63	0	0.00000E+00	63	0	0.00000E+00
64	0	0.00000E+00	64	0	0.00000E+00
65	0	0.00000E+00	65	0	0.00000E+00
66	0	0.00000E+00	66	0	0.00000E+00
67	0	0.00000E+00	67	0	0.00000E+00
68	0	0.00000E+00	68	0	0.00000E+00
69	1	1.01379E-04	69	0	0.00000E+00
70	0	0.00000E+00	70	0	0.00000E+00
71	0	0.00000E+00	71	4	8.19655E-05
72	0	0.00000E+00	72	1	2.04914E-05

Table 3.2

SPATIAL AND TEMPORAL SEPARATIONS BETWEEN PAIRS OF BOTTLES RECOVERED FROM THE SAME LAUNCH GROUP

		Separation in Time (days)					
		<10	10 to 31.6	31.6 to 100	100 to 316	>316	Total
Separation	<10	9744	1997	1233	679	275	13928
in	10-31.6	3251	1267	954	274	83	5829
Distance	31.6-100	789	943	628	325	147	2832
(nautical miles)	100-316	101	185	436	184	43	949
	>316	7	15	52	62	61	197
	TOTAL	13892	4407	3303	1524	609	23735

if all bottles have the same likelihood of recovery irrespective of their launch group size. If this is the case, then the bottles act independently, and the correlations between recovery results should be negligible. Presuming that the bottles are independent, then the probability of recovering K_o bottles out of a release of size n is given by the binomial distribution:

$$p_k(k_0) = \binom{n}{k_0} p^{k_0} (1 - p)^{n-k_0}$$

where $0 \leq k_0 \leq n$, and p is the probability of finding one bottle.

To determine what the actual frequency was for the drift bottles, we generated the joint histogram of launch group size versus recovery group size shown in Table 3.3a. These results include only ballasted bottles, as we found that the other categories of bottles weren't consistently documented. Utilizing the binomial distribution, the equivalent predicted joint histogram shown in Table 3.3b was created. It can be seen that there are large differences between the two. In fact, looking at all launch groups up to size 30, we determined that, based on the chi-square test of goodness-of-fit criteria, the likelihood that the observed histogram came from a binomial process was less than one chance in 10 million. In short, it is extremely unlikely that the bottles do behave independently.

It is also possible to investigate the validity of the assumption that all bottle trajectories are perfectly correlated by the same technique. Presuming that all bottles that are launched survive their journey and that all bottles lying next to each other on the shore are found, we would immediately come to the conclusion that the predicted recovery matrix would consist of entries only in the 0 recovered column and in the main

Table 3.3

RECOVERY GROUP SIZE VERSUS LAUNCH GROUP SIZE

a. Observed
(All East Coast Ballasted Bottles)

Launch \ Recovery	0	1	2	3	4	5	6	Total # Launch Groups
1	41	14						55
2	22766	3183	0					25949
3	122	17	5	0				144
4	144	5	1178	40	0			1367
5	7290	926	425	255	171	0		9067
6	7722	1175	532	277	121	66	0	9893

b. Predicted by Binomial*
Distribution with P = .0807**

Launch \ Recovery	0	1	2	3	4	5	6
1	51	4					
2	21928	3852	169				
3	112	29	3	0			
4	976	343	45	3	0		
5	5952	2614	459	40	2	0	
6	5970	3146	691	81	5	0	0

*This distribution is the one appropriate for all bottles behaving independently.

**These tables are taken from a similar table, but of much larger dimensions. Including the larger-sized groups causes the value of P to be .0807. Looking just at the data in the table, P should be .084.

diagonal corresponding to n bottles launched, n bottles recovered. Clearly, this is a highly unlikely explanation also!

It is possible to carry this sort of analysis further. However, within the scope of this study, it was judged probable that it would not yield any new insights into the problem. In short, it seems highly unlikely that there is any simple way of treating large aggregates of drift bottle data such that the data support any simple hypothetical model.

Under these circumstances, we chose to take the conservative approach that all bottles launched do behave in a correlated fashion. This gives us higher probabilities of impact. Furthermore, the results of the analysis of the recovery group separations in time and distance tend to support such a conclusion. Therefore, all further calculations of percentage chance of impact will be based on the ratio of recovery groups to launch groups, and <u>not</u> on the more traditional number of bottles recovered versus the number of bottles released.

If we accept the hypothesis that drift bottles do drift according to the simple formula proposed, and if we accept the above technique for parameterizing the probability of recovery, then we can also gain some insight into the nature of the turbulence of the ambient currents by comparing our model's predictions to the drift bottle data. If we can match the percentage impacting shore using just the wind-related dispersion, then we may make the following statements:

1. If the predicted and observed probabilities were small, then the impacts are due to dispersion about the mean path. In this case, matching results would imply equivalent dispersive properties.

2. If the probabilities were large, then this implies that the impacts were due primarily to the mean motion, and we cannot gain much insight into the equivalence of the dispersive properties.

As we shall see in the comparisons for the Georges Bank region, we tend to get reasonable agreement between predicted and observed percent ashore. Further, with the exception of the results obtained for EDS 4, these values are typically small. This implies a reasonable match between the strength of the simulated dispersive properties and the properties indicated by the drift bottle results.

This is not the same as saying the dispersive behavior springs from the same source. It is plausible, however, to suspect that it is the wind that is responsible for the observed behavior, just as it is responsible for the simulated behavior.

Georges Bank area

The grid representation of the Georges Bank and adjacent shoreline is shown in Figure 3.3. Also shown on this figure are the specific spill launch sites investigated. As can be seen, all the drilling sites lie on Georges Bank or on Nantucket Shoals. Based on our experience from the Georges Bank study, we anticipated that most returns would be to the Cape Cod/ Nantucket Island/Buzzards Bay region with few returns elsewhere. Further, we anticipated strong seasonal variations in impact behavior and low percentages to shore from all but the drilling site closest to Nantucket Island.

The steady, ambient current field we hypothesized is shown in Figure 3.4. It is a descendant of the current pattern used in the Georges Bank study, with the principal changes being the westward flow south of the Bank versus the southerly and southwesterly flow used in the Georges Bank study.

The basis for the selection of this exact pattern is relatively sketchy, but we have considerable confidence in the broad outline of the pattern nevertheless. A few studies of the geostrophy of the Gulf of Maine have indicated a southwestwardly geostrophic component over the Gulf (see Bigelow, for example), and this is reflected in the pattern. Measurements of oil particle transport down the coast of Nova Scotia in the region of Chedabucto Bay have verified the southwestwardly flow hypothesized along the coast of Nova Scotia (Forrester). Long-term averages of deep current meter records in the region just south of Nantucket Shoals have indicated a net westward transport (Webster), and current meter measurements in the region lying

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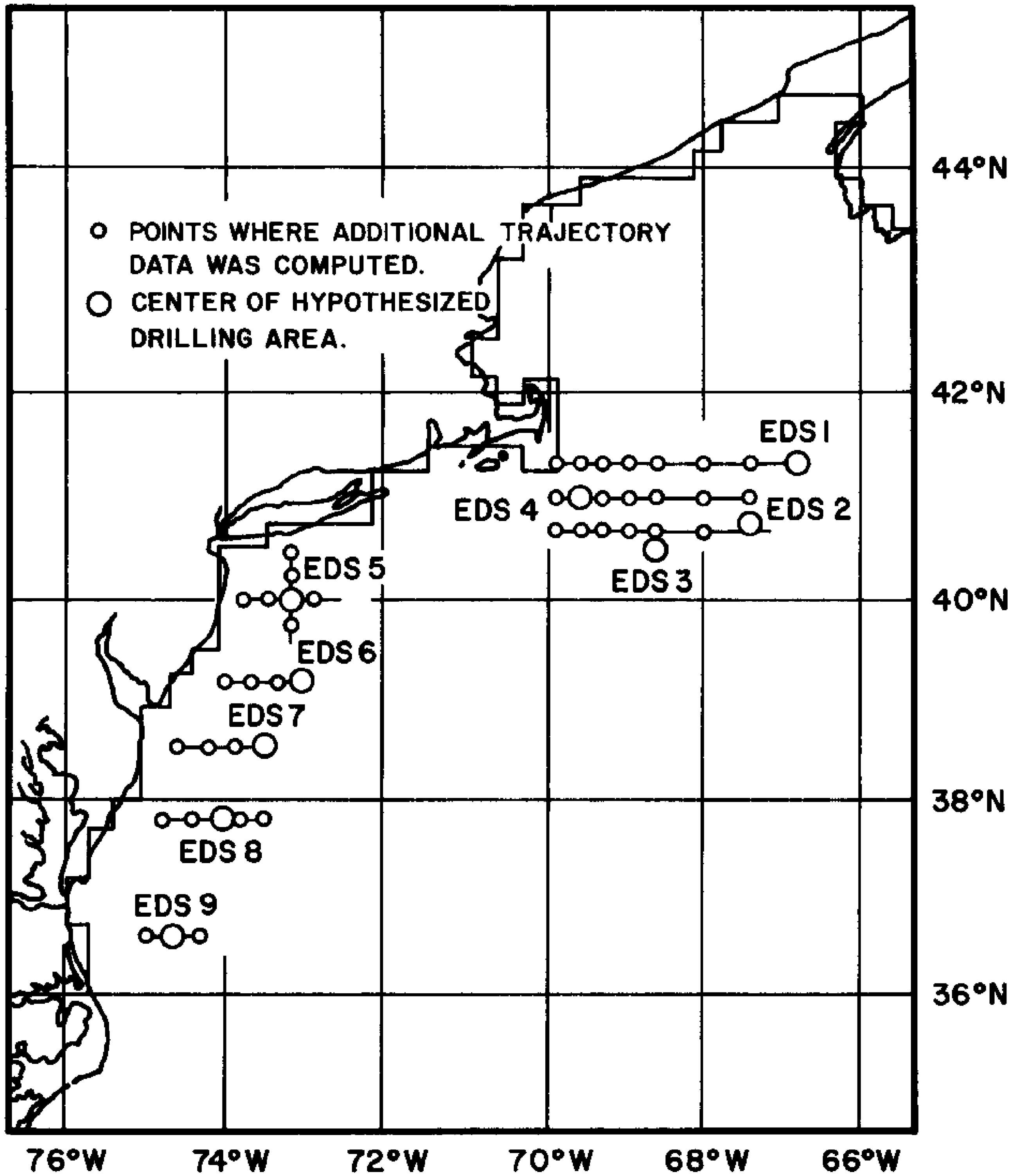


FIG.3.3 LOCATION OF POINTS IN THE MID-ATLANTIC BIGHT-GEORGES BANK REGION FOR WHICH DETAILED TRAJECTORY CALCULATIONS WERE MADE.

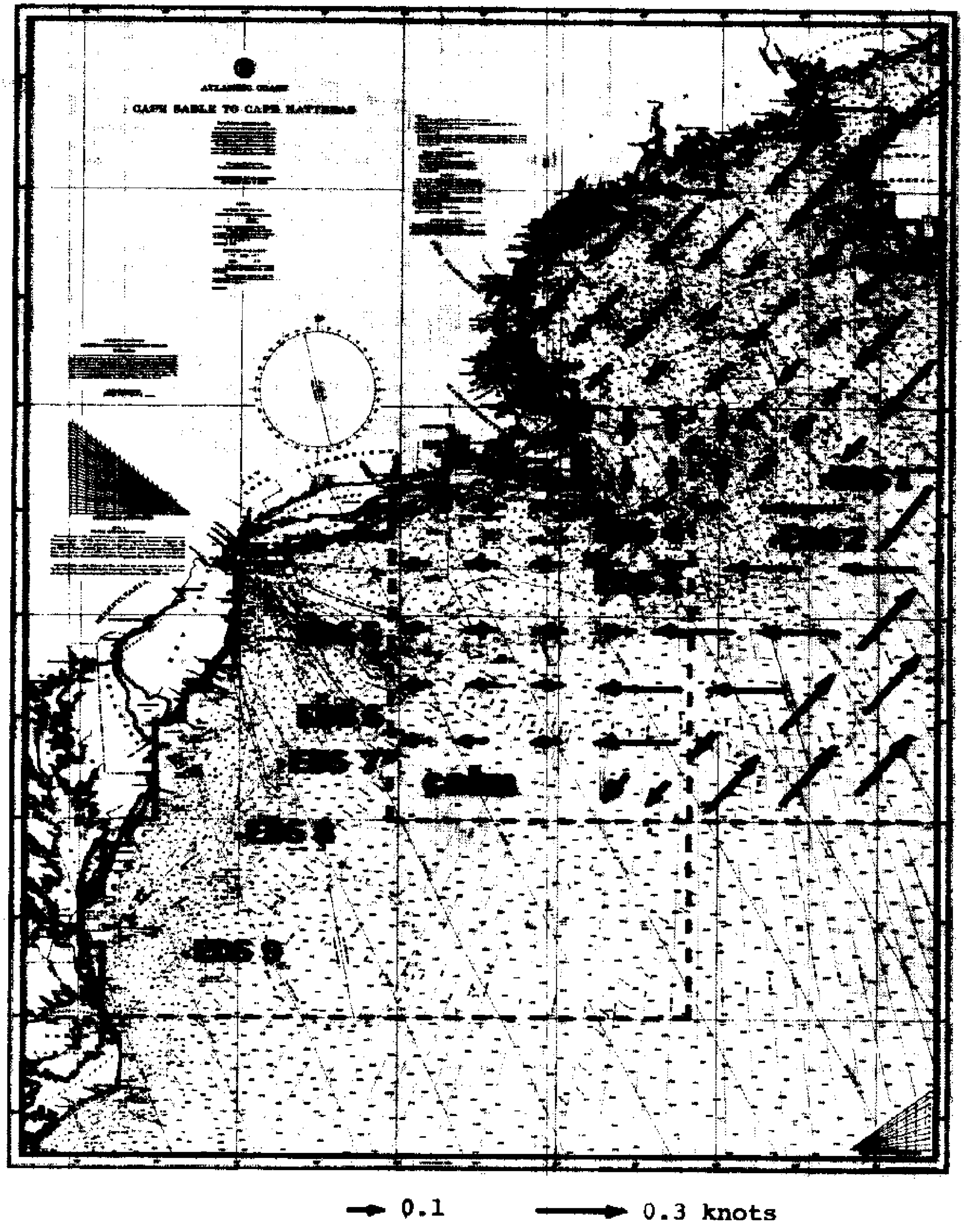


Figure 3.4--Hypothesized current pattern for the Gulf of Maine/Georges Bank area.

just south of Long Island have indicated a 0.2- to 0.3-knot westwardly transport (Taylor, personal communication). These features verify the broad outline. The reasons for selecting this specific pattern stem from the drift bottle analysis.

Figures 3.5, 3.6, 3.7, and 3.8 summarize the total drift bottle launch and recovery information for each of the four areas. Note that the preponderance of recoveries is made in the Cape Cod region. However, note also that a few at-sea recoveries were made north of EDS 1 and EDS 2. This behavior is compatible with our hypothesized current field for we have found that some of the simulated spills tend to go north in the spring and summer and it is only the steady 0.3- to 0.5-knot currents hypothesized in the northern and eastern Gulf that keep them from impacting Nova Scotia or the Maine coast.

The percentage bottle recoveries were calculated for each EDS region based on both the number of bottles recovered per the number launched and on the number of recovery groups per launch group. These data are presented in Table 3.4. Also shown are the minimum and average times to recovery. The percentage recovery statistics are based only on ballasted and unballasted bottle records. It was found that the drogued bottle records obtained from NODC were misleading since drogued bottle launch groups were reported only when recoveries had been made. The minimum and average times and the impact figures incorporated all bottles, however, as the absence of launch records would not be misleading. There were, however, some additional problems encountered, so these time figures should be viewed as tentative.

The comparison of the spill trajectory results using the

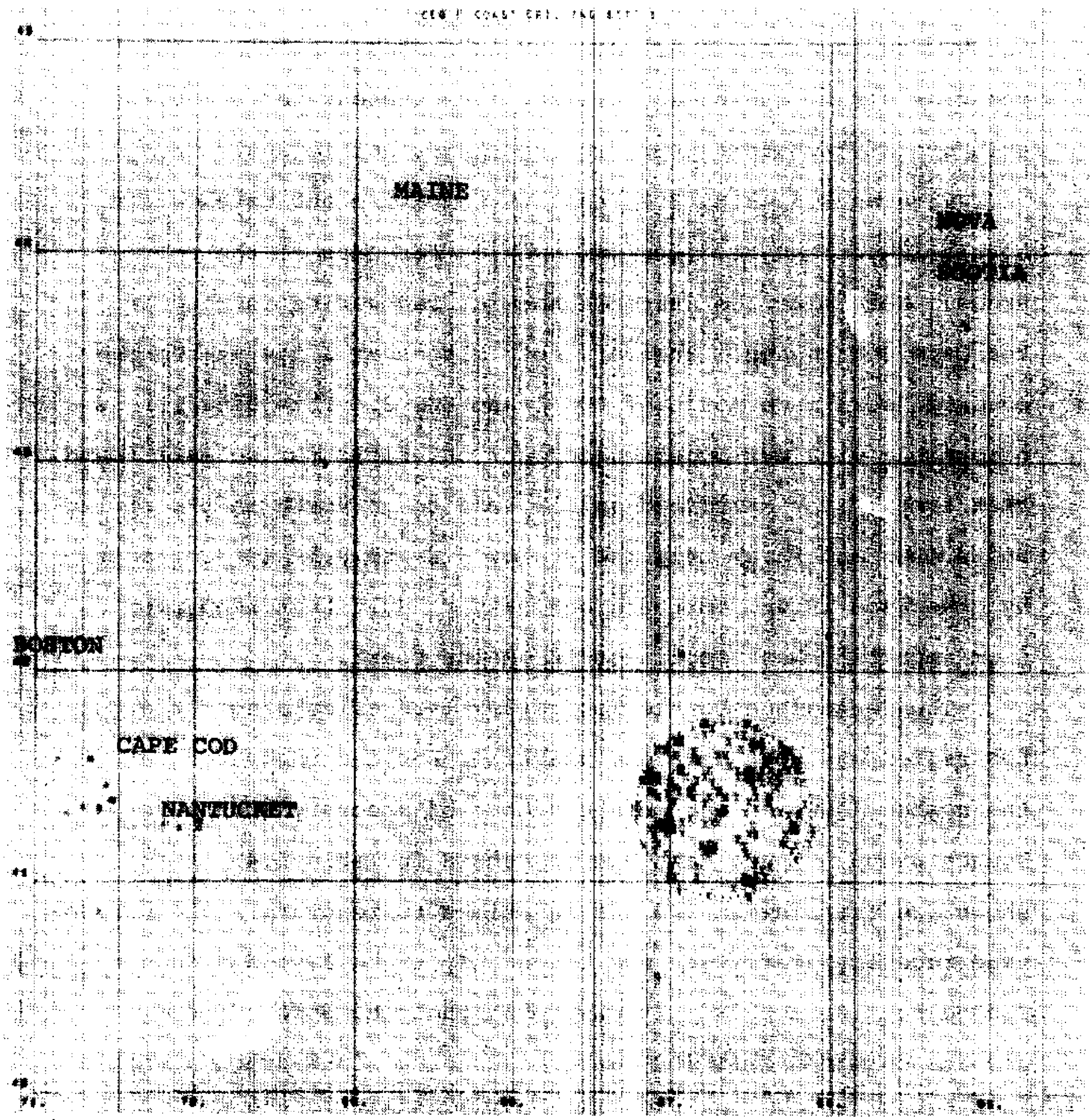


Fig. 3.5-- Summary of drift bottle release and recovery results for EDS 1.

x Indicates release location for a launch group

* Indicates reported recovery location

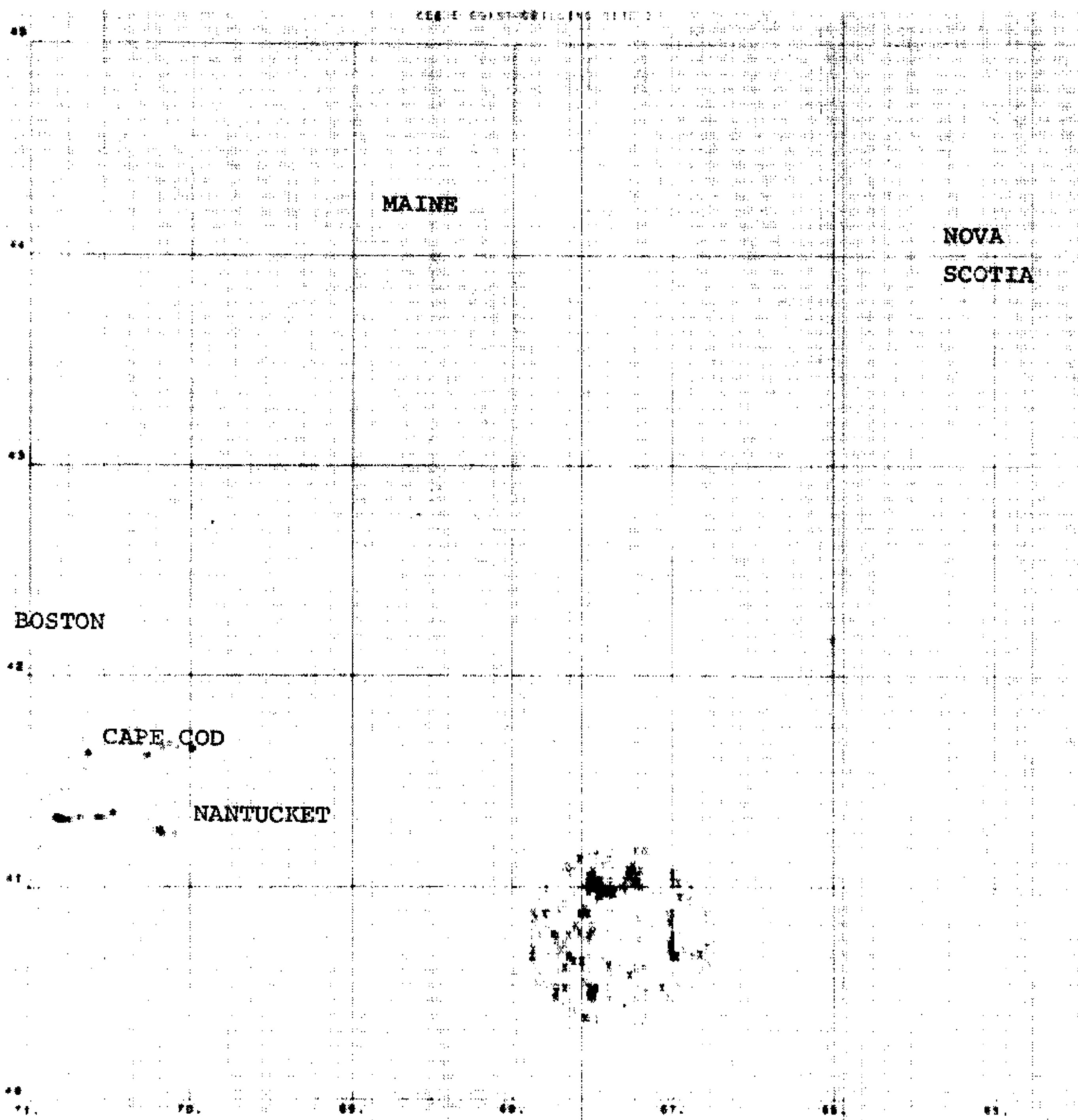


Fig. 3.6--Summary of drift bottle release and recovery results for EDS 2.

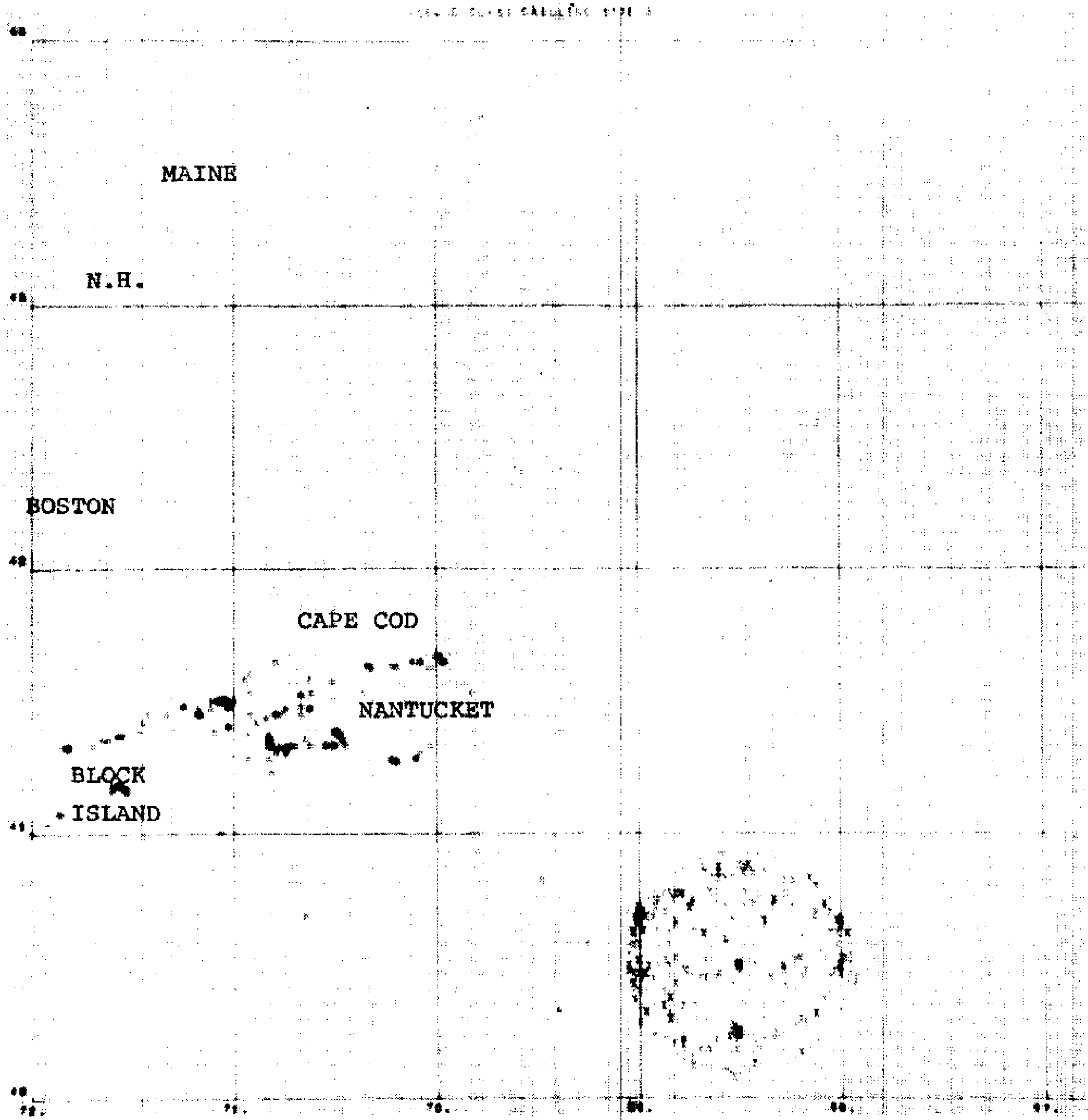


Fig. 3.7--Summary of drift bottle release and recovery results for EDS 3.

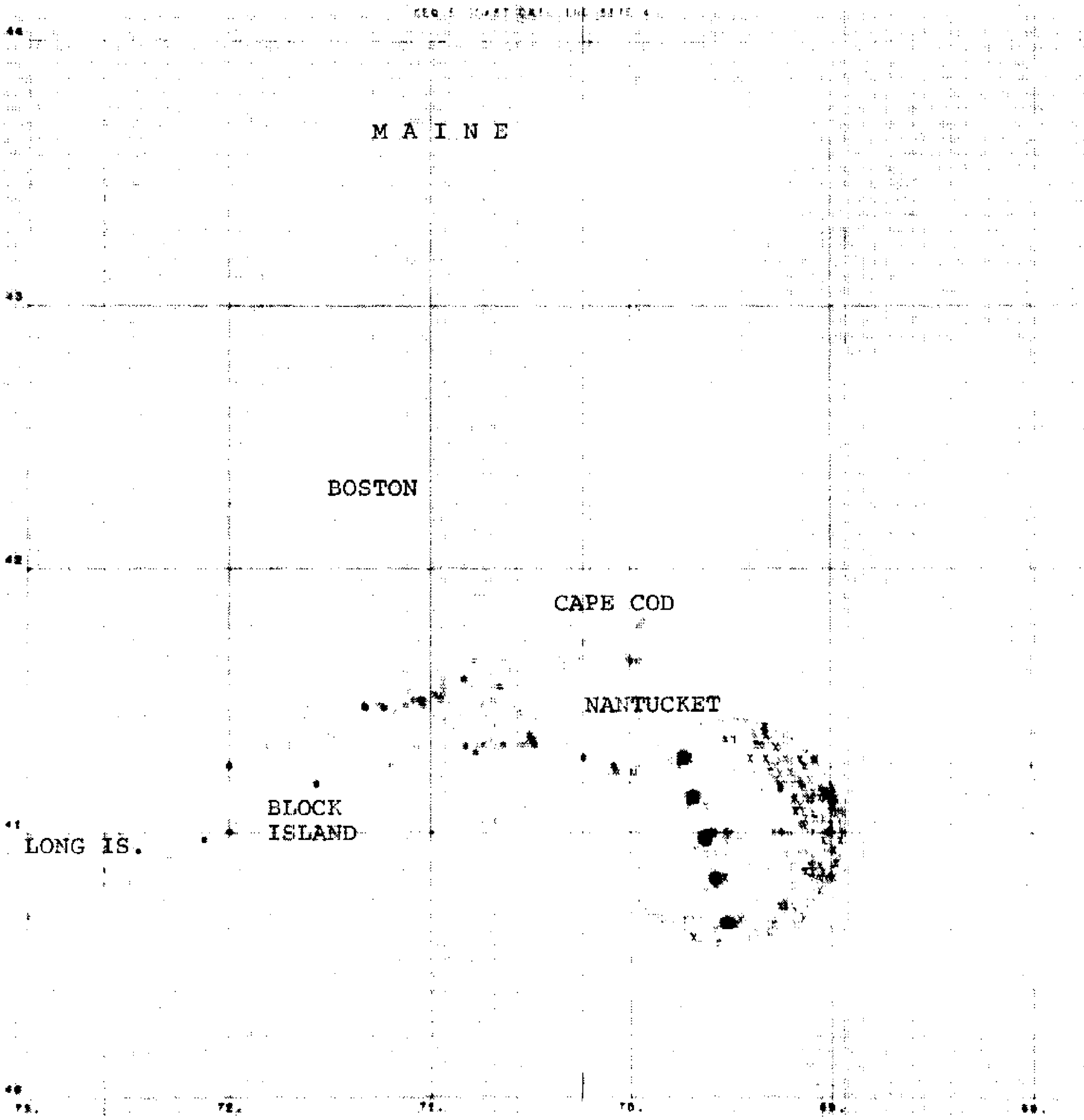


Fig. 3.8--Summary of drift bottle release and recovery results for EDS 4.

Table 3.4

DRIFT BOTTLE STATISTICS FOR
THE GEORGES BANK REGION

Summary of EDS 1 Recovery Statistics

	Winter	Spring	Summer	Autumn	Overall
Num. Rel. Grp:	35	83	27	51	196
Tot. Bot. Reld:	227	505	167	399	1298
Num. Rec. Grps:	0	4	0	0	4
Tot. Bot. Recd:	0	6	0	0	6
Percent Bot. Recd:	0.00	1.19	0.00	0.00	0.46
Percent Group Recd:	0.00	4.82	0.00	0.00	2.04
Minimum Time	N/A	44	47	N/A	44
Average Time	N/A	244	92.3	N/A	N/A

Summary of EDS 2 Recovery Statistics

	Winter	Spring	Summer	Autumn	Overall
Num. Rel. Grp:	16	71	40	45	172
Tot. Bot. Reld:	108	670	225	355	1358
Num. Rec. Grps:	0	15	1	2	18
Tot. Bot. Recd:	0	42	1	2	45
Percent Bot. Recd:	0.00	6.27	0.44	0.56	3.31
Percent Group Recd:	0.00	21.13	2.50	4.44	10.47
Minimum Time	N/A	44	35	60	35
Average Time	N/A	154	100	184	144

Summary of EDS 3 Recovery Statistics

	Winter	Spring	Summer	Autumn	Overall
Num. Rel. Grp:	19	81	36	84	180
Tot. Bot. Reld:	125	659	200	296	1280
Num. Rec. Grps:	0	21	3	1	25
Tot. Bot. Recd:	0	69	3	1	73
Percent Bot. Recd:	0.00	10.47	1.50	0.34	5.70
Percent Group Recd:	0.00	25.93	8.33	2.27	13.89
Minimum Time	N/A	33	N/A	N/A	N/A
Average Time	N/A	120	95	N/A	109

Summary of EDS 4 Recovery Statistics

	Winter	Spring	Summer	Autumn	Overall
Num. Rel. Grp:	53	101	49	93	296
Tot. Bot. Reld:	294	579	260	521	1654
Num. Rec. Grps:	0	28	14	3	45
Tot. Bot. Recd:	0	45	19	4	68
Percent Bot. Recd:	0.00	7.77	7.31	0.77	4.11
Percent Group Recd:	0.00	27.72	28.57	3.23	15.20
Minimum Time	N/A	32	3	22	3
Average Time	N/A	132	117	226	130

NOTE: Minimum and average times were calculated using all data including (by mistake) at-sea recoveries. Thus, the figures may be misleading. The more obvious inconsistencies have been thrown out and are marked N/A.

old Georges Bank current hypothesis and a null hypothesis is shown in Figure 3.9. Note that there is a very strong difference between the zero current hypothesis and otherwise. This is a clear indication of the sensitivity of our results to the proper current specification.

Figure 3.10 compares the total percentage recovery of drift bottles (based on the recovery group to launch group statistic) to the spill simulation results using our hypothesized current pattern. The sample sizes cause the values to be uncertain, hence the lines that have been drawn from the circles. These lines indicate the dimensions of the area in which we are 90% confident the true value lies. Note that all values lie close enough to the diagonal line to have their confidence zone overlap the diagonal line (that denotes agreement between the two data sets) with the exception of the EDS 4 point. This may be explained by the preponderance of drift bottle releases on the far side of EDS 4.

Figure 3.11 compares the average and minimum time figures obtained from the drift bottles with the equivalent figures for the spill simulation. This is, as we would expect, due to the uncertainties of recovery of a drift bottle.

Impact assessment

Figures 3.12 through 3.14 show the variation in the percentage ashore versus eastward distance of launch point from a north-south line running just east of Nantucket Island. As we have seen already, the percentage ashore is closely tied to the wind drift coefficient, so we must be careful to recognize that these are the proper figures only if the current pattern is as

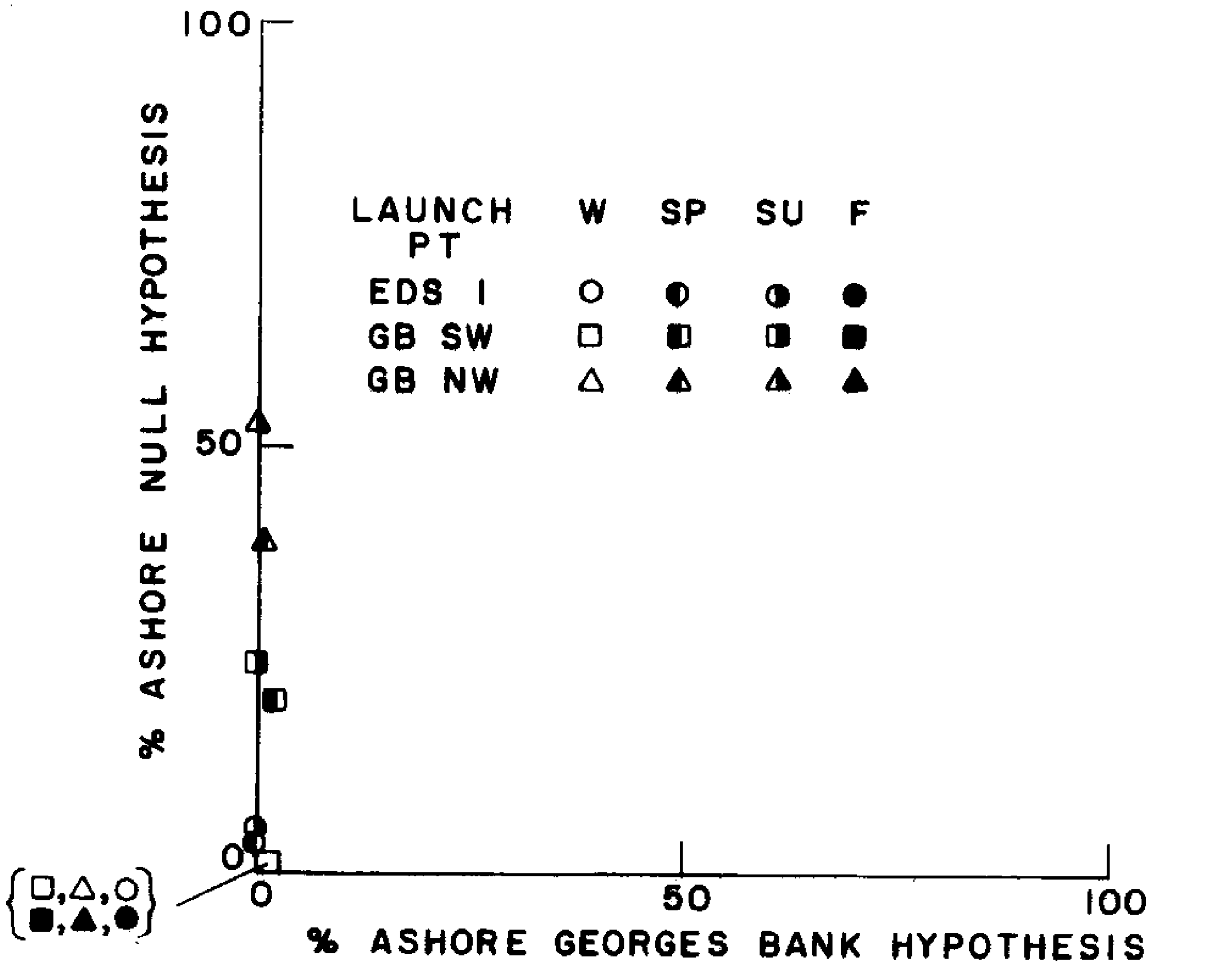


FIGURE 3-9 SENSITIVITY TO CURRENT SPECIFICATION GEORGES BANK REGION

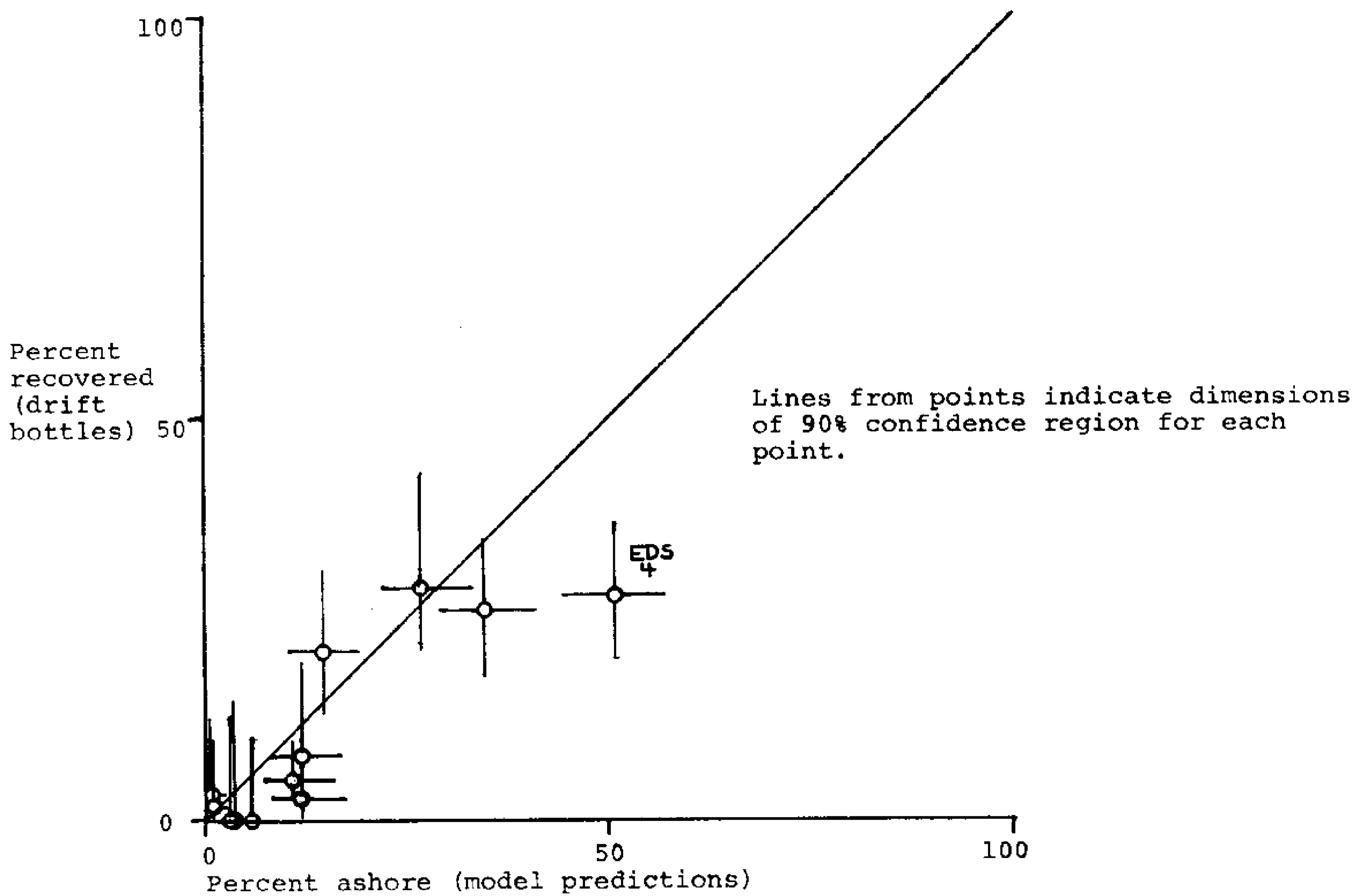


Figure 3.10--Georges Bank region--comparison of total percentage recovery of drift bottles vs. model predictions of percentage of spills ashore. (Note: Drift bottle percentage recovered is based on launch groups and recovery groups.)

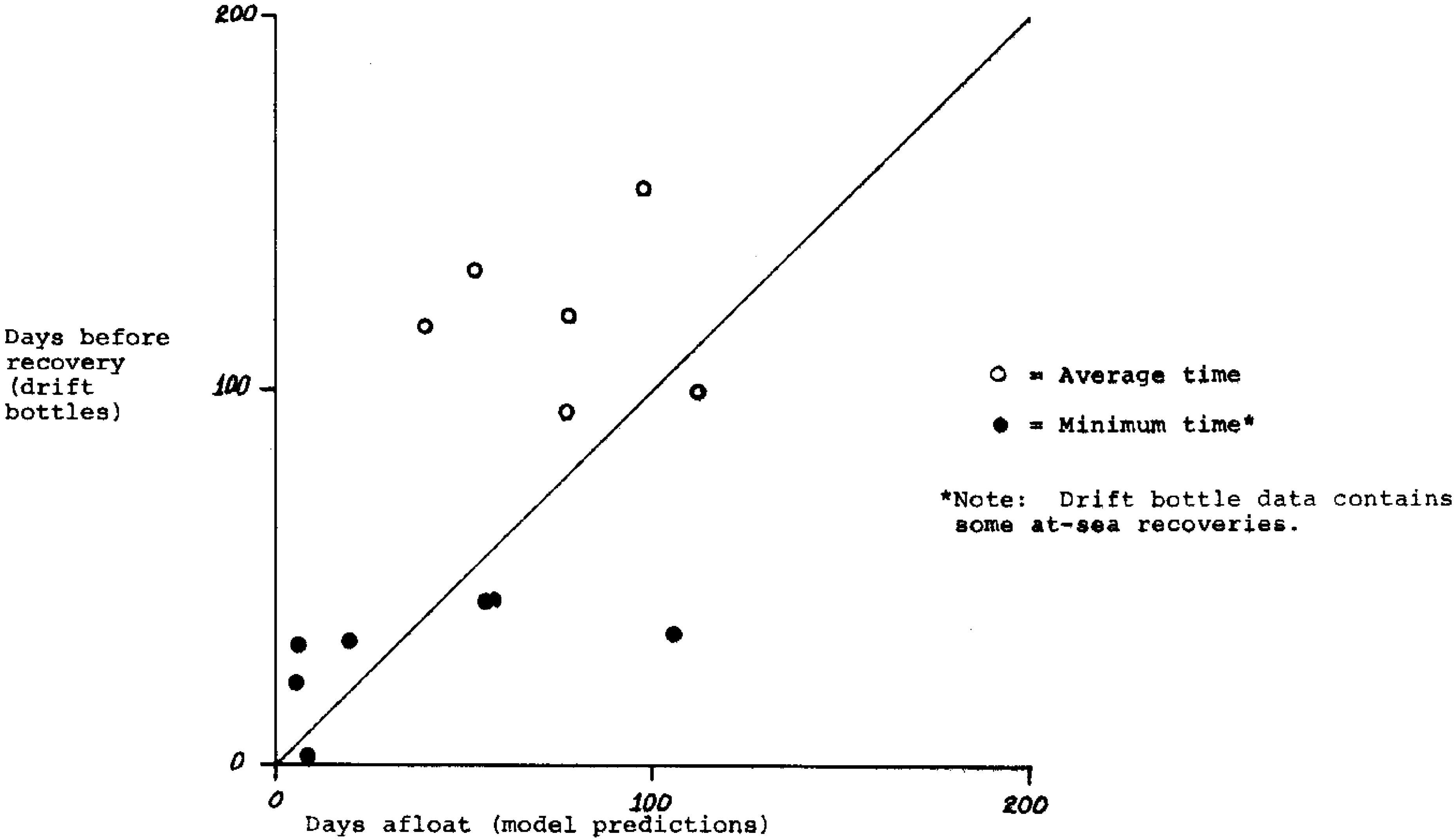


Figure 3.11--Georges Bank region--time afloat drift bottle data for EDS region and season vs. model predictions for EDS point and season.

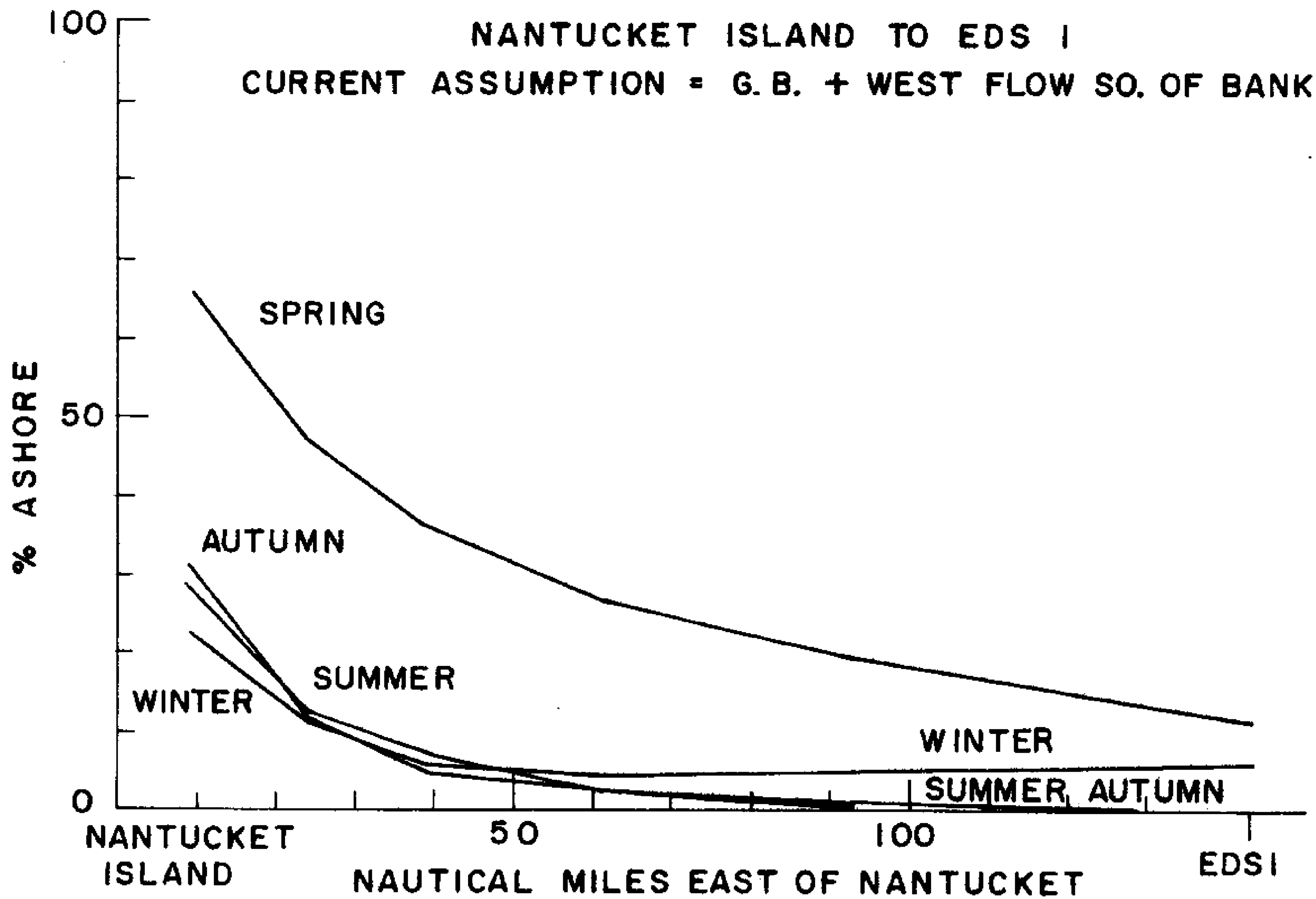


FIGURE 3-12 DEPENDENCE OF PROBABILITY OF A SPILL IMPACTING SHORE ON THE DISTANCE EAST OF NANTUCKET ISLAND OF THE SPILL LAUNCH SITE

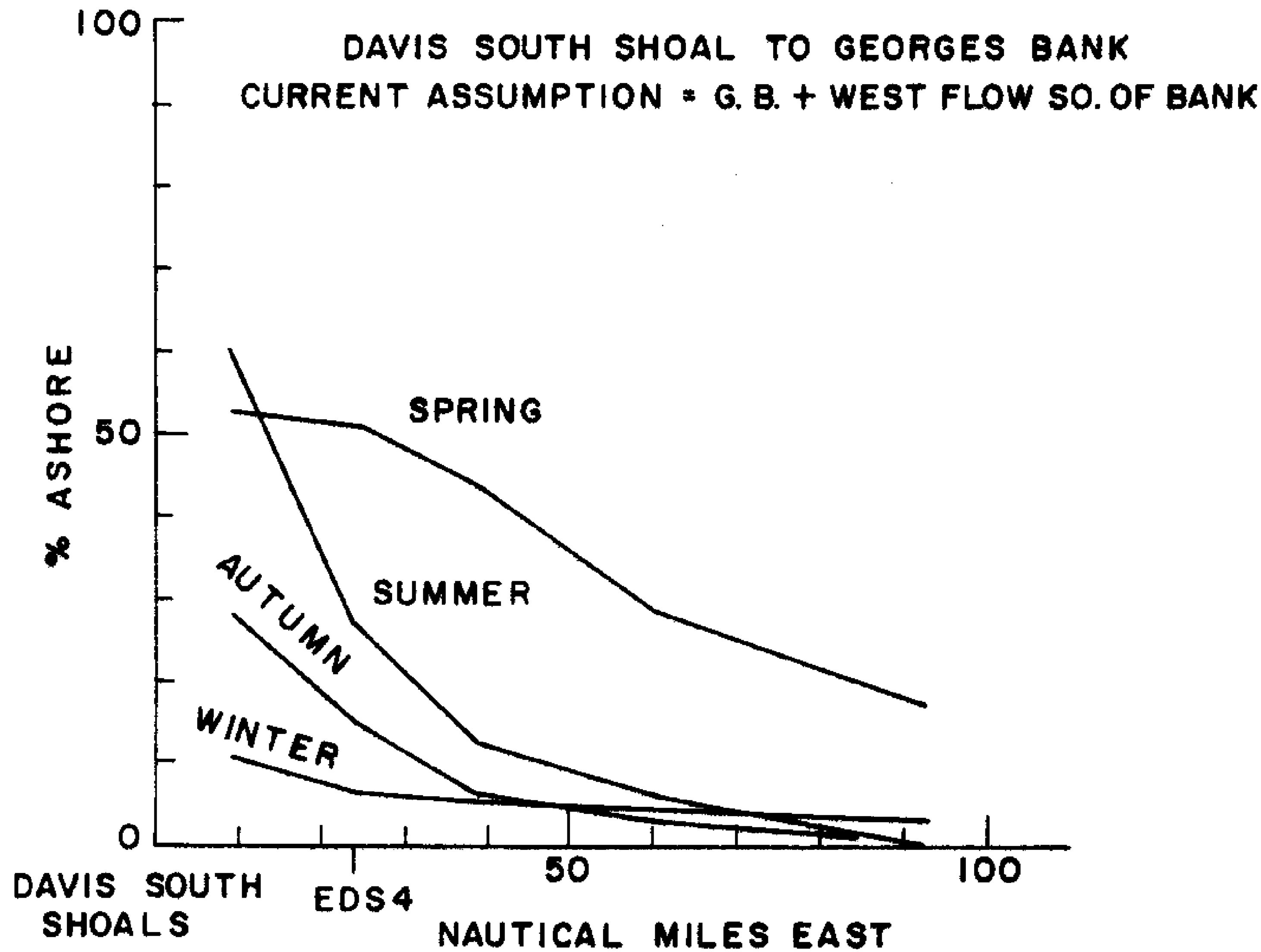


FIGURE 3-13 DEPENDENCE OF THE PROBABILITY OF A SPILL IMPACTING SHORE

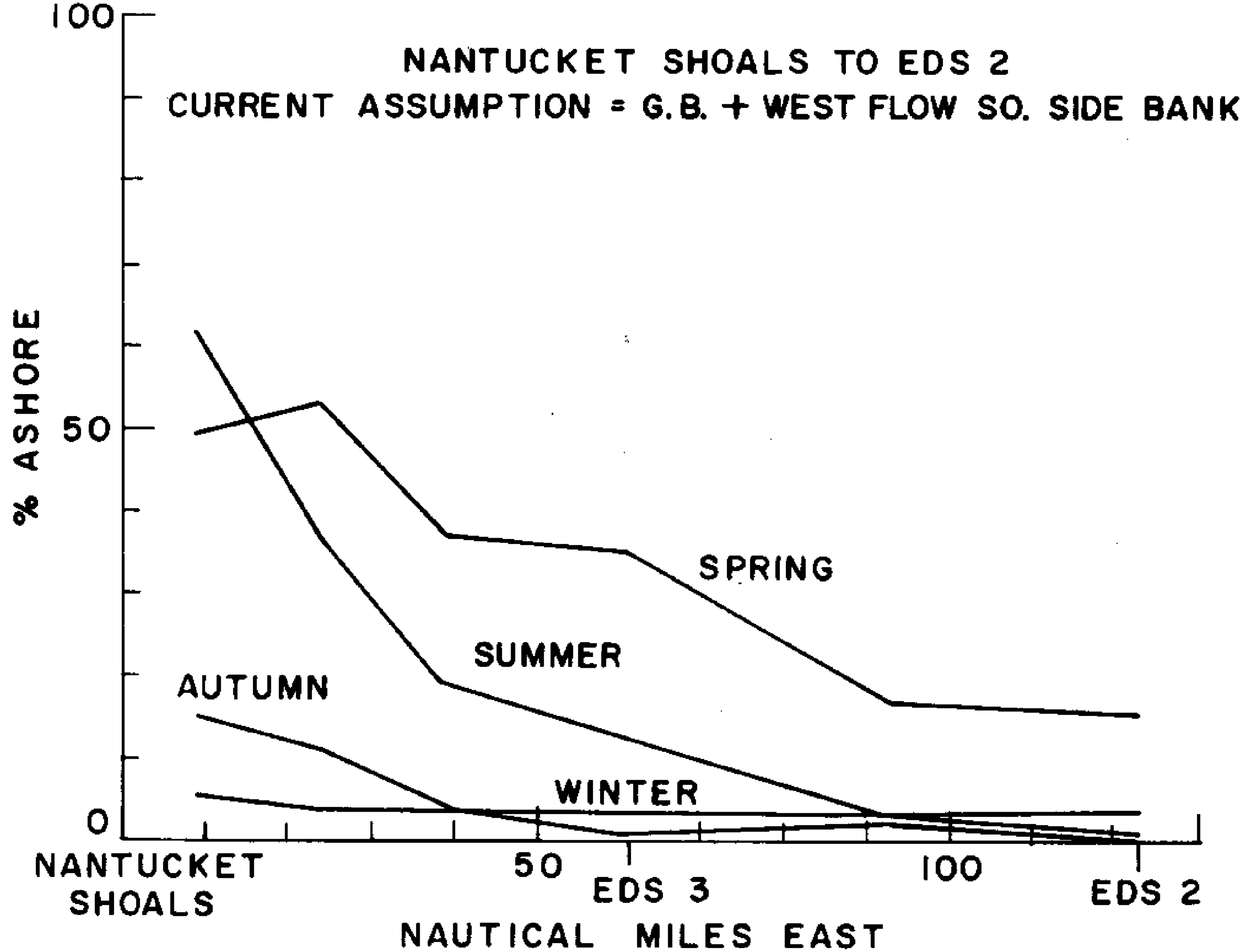


FIGURE 3-14 DEPENDENCE OF THE PROBABILITY OF A SPILL IMPACTING SHORE ON THE DISTANCE EAST OF NANTUCKET SHOALS OF THE SPILL LAUNCH SITE

we have depicted and only if the wind drift coefficient is 0.03. However, it is not unreasonable to expect that the wind drift coefficient and the current are nearly correct and, on this basis, we can accept the results as presenting at least the right qualitative picture.

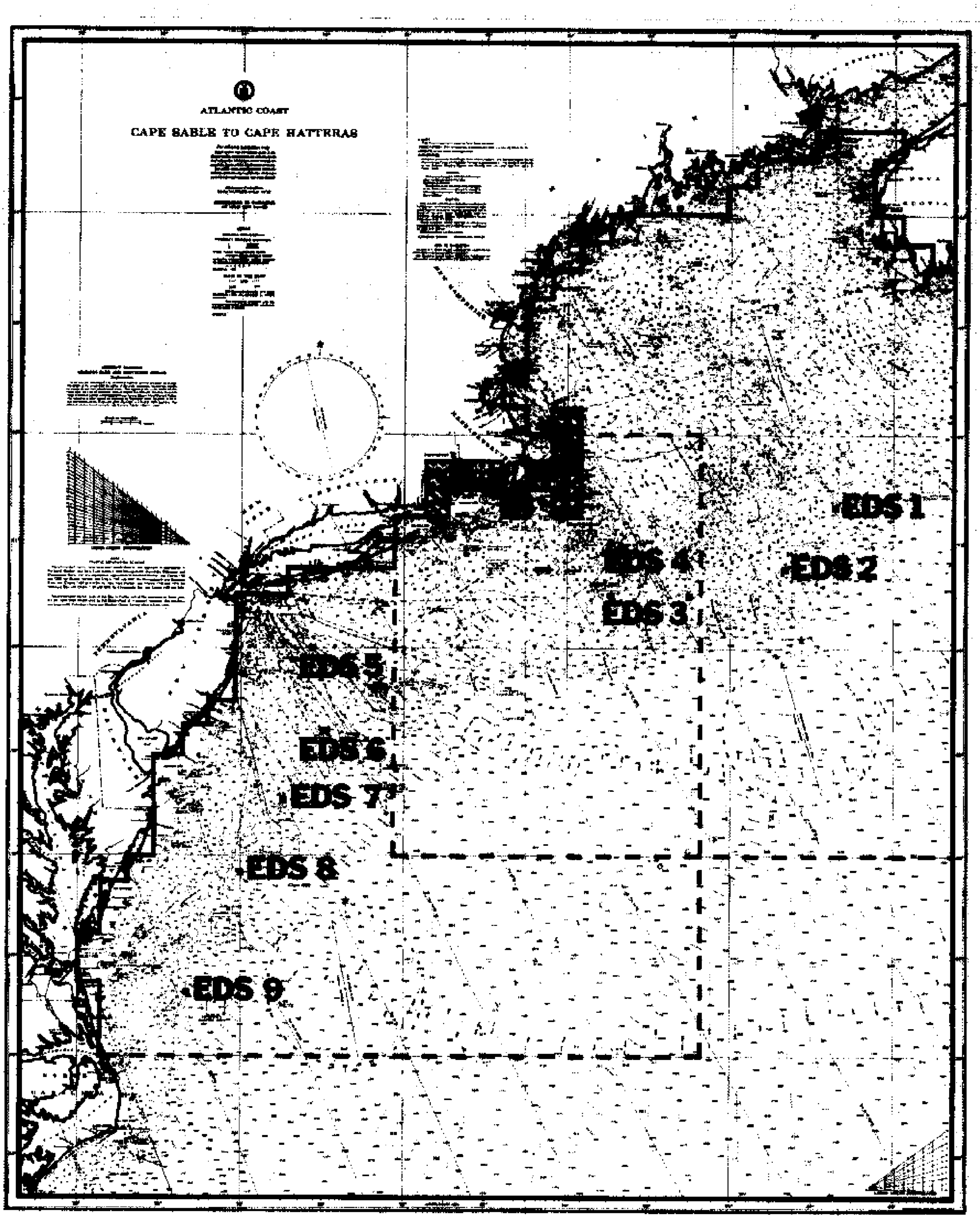
Figure 3.15 indicates the regions that have the greatest exposure to spill impact for all spills released from the EDS 4 region. The high percentage shown for the northern part of Cape Cod is probably an artifact caused by the particular selection of the grid square representation of the land area.

Conclusion

We have established that the selection of the hypothesized current pattern is consistent with our (admittedly sketchy) information of currents in this area. Based on this current pattern and the wind simulation, we have shown that it is possible to reconcile drift bottle data with our predictions. This, of course, serves as a validation of our model only if we believe that drift bottles obey the same drift equations.

The conclusions that can be drawn are rather straightforward. First, the drilling site closest to Nantucket Island presents the greatest risk to the southern New England area of having a spill go ashore. EDS 2 and EDS 3 appear to present a lesser risk and EDS 1 presents the least risk. The average time to shore for the drilling sites run from 40 to 120 days, however, so we may be reasonably confident that spills arriving from at least the three outermost drilling sites will be well weathered. As in the Georges Bank study, it still appears unlikely that a Georges Bank spill will ever impact on the northern area of New

Figure 3.15--Percentage impacts in Georges Bank area for spills released from EDS 4 on an annual basis.



< 0.5%

0.5% to 1%

1% to 3%

3% to 5%

> 5%

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England or Nova Scotia, and the behavior is highly seasonal.

The critical parameters that must be verified before we can have complete confidence in this analysis are the deep, non-wind-related currents lying on Georges Bank; in the vicinity immediately north of Georges Bank; and in the region lying south and west of Georges Bank.

Short of determining these currents, it would be most helpful to run an intensive drift card release program in the area of EDS 4, because it is in this area we would expect to get the best results. This, however, would only be partially successful in resolving the uncertainties, because we would still have the fundamental problem of verifying that drift cards behave like oil spills.

Mid-Atlantic region

Figure 3.16 shows the grid representation of the mid-Atlantic region and the drilling site locations. Also shown are the traverses used in determining impact sensitivities to launch point position. Figure 3.17 shows the ambient current pattern used in the simulation. This current pattern is consistent with the measured westward flow in the region south of Nantucket Shoals (Webster, 1969) and in the region just south of Long Island (Baylor, 1974). The .5-knot Gulf Stream is positioned on the southern boundary in accordance with Figure 3.18, which was provided by VIMS (Welch, 1974). Its direction was taken to be northeasterly and its speed was set at the value of .5 knots as a conservative estimate. The southward flow along the New Jersey coast was deduced from dynamic height contours provided by VIMS and the region of no current was introduced as an approximation to what appeared to be a very complex flow area in which the dynamic height contours adopted no consistent pattern.

The drift bottle launch and recovery results are summarized in Figures 3.19 through 3.23. Notice that EDS 5 and 6 appear to have the greatest number of recoveries. Also note that the recoveries from EDS 5 extend from the northeastern portion of Long Island all the way south to Delaware Bay, with the greatest concentrations occurring in western Long Island and middle and northern New Jersey. EDS 6, on the other hand, tends to have its recoveries localized to the west and south; only a few bottles were recovered to the north.

EDS 9 shows the next greatest concentration of recoveries, and here the recoveries tend to group to the south and west.

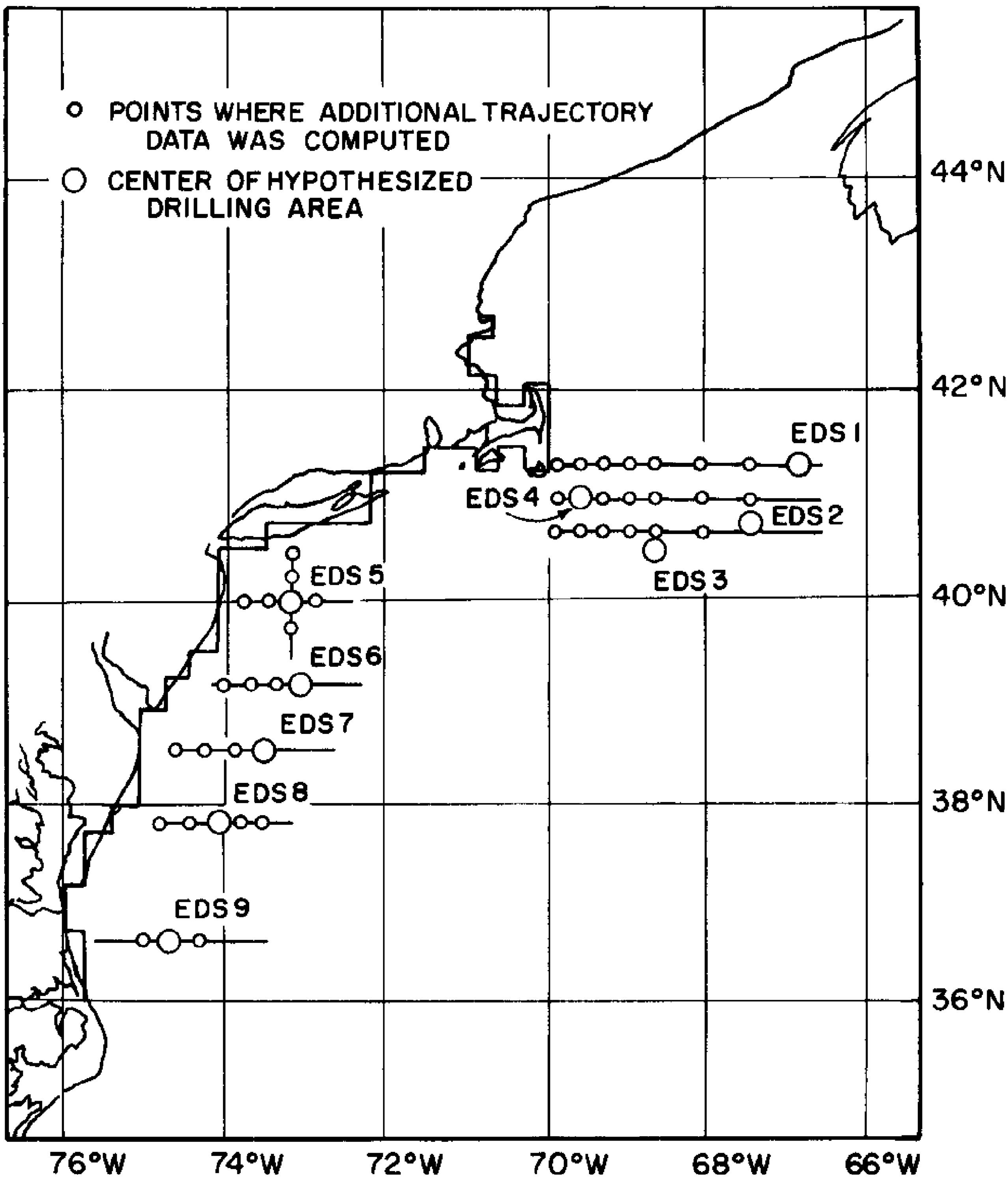


FIG. 3.16 LOCATION OF POINTS IN THE MID-ATLANTIC BIGHT GEORGES BANK REGION FOR WHICH DETAILED TRAJECTORY CALCULATIONS WERE MADE

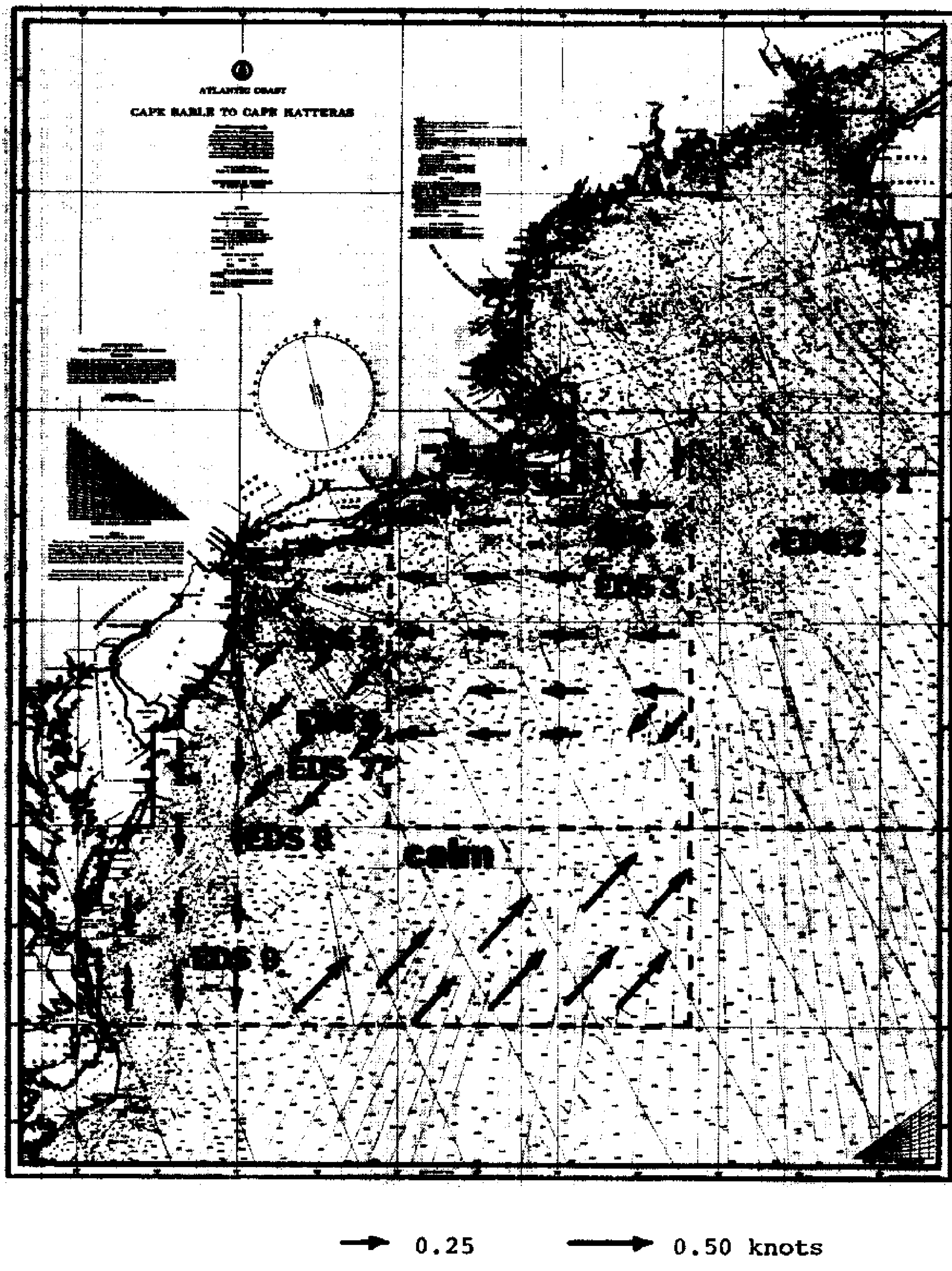


Figure 3.17--Hypothesized current pattern for Mid-Atlantic region.

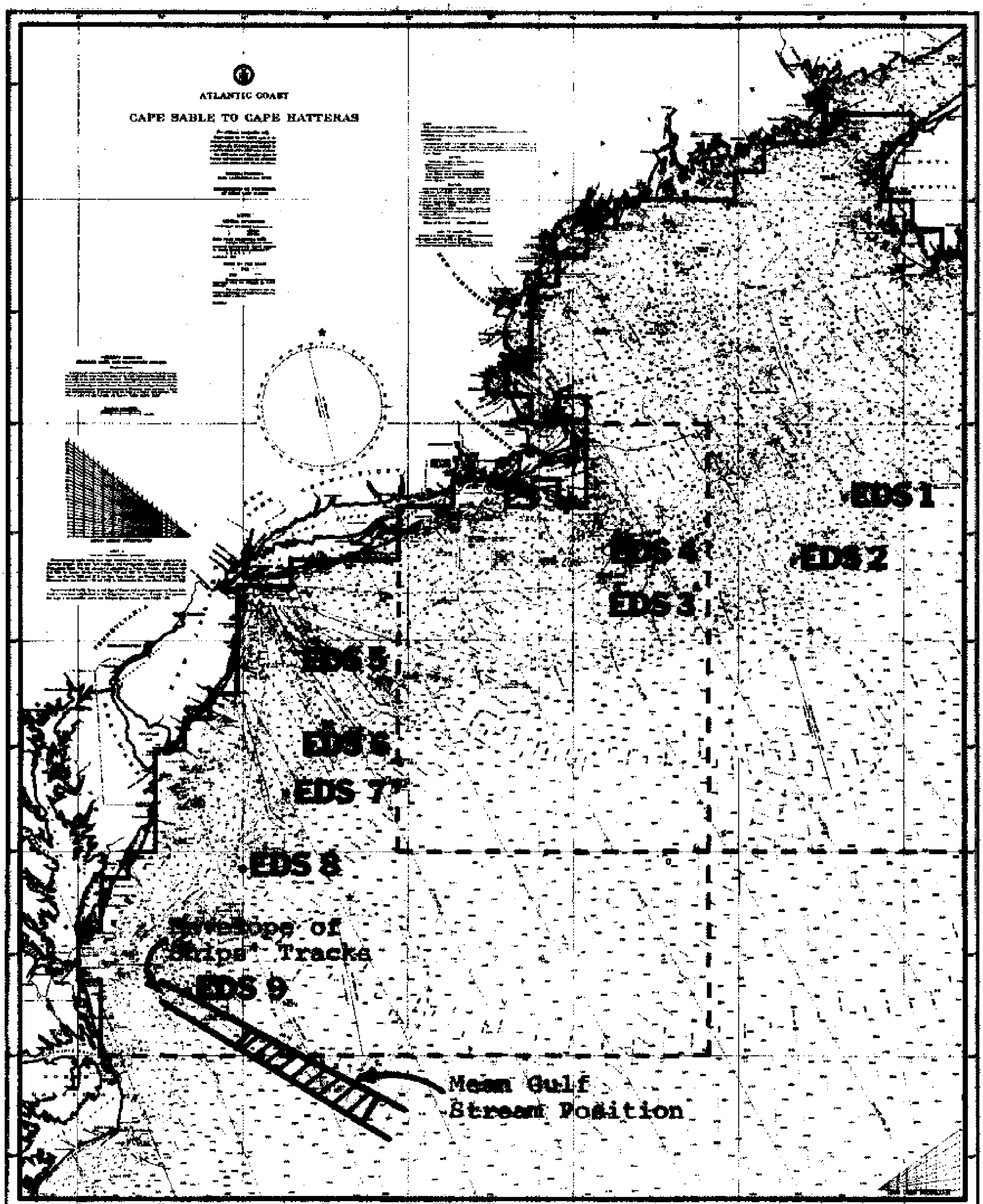


Figure 3.18--Observed Gulf Stream position based on XBT casts by NOO. (From Gulf Stream Monthly Summary, December, 1972.)

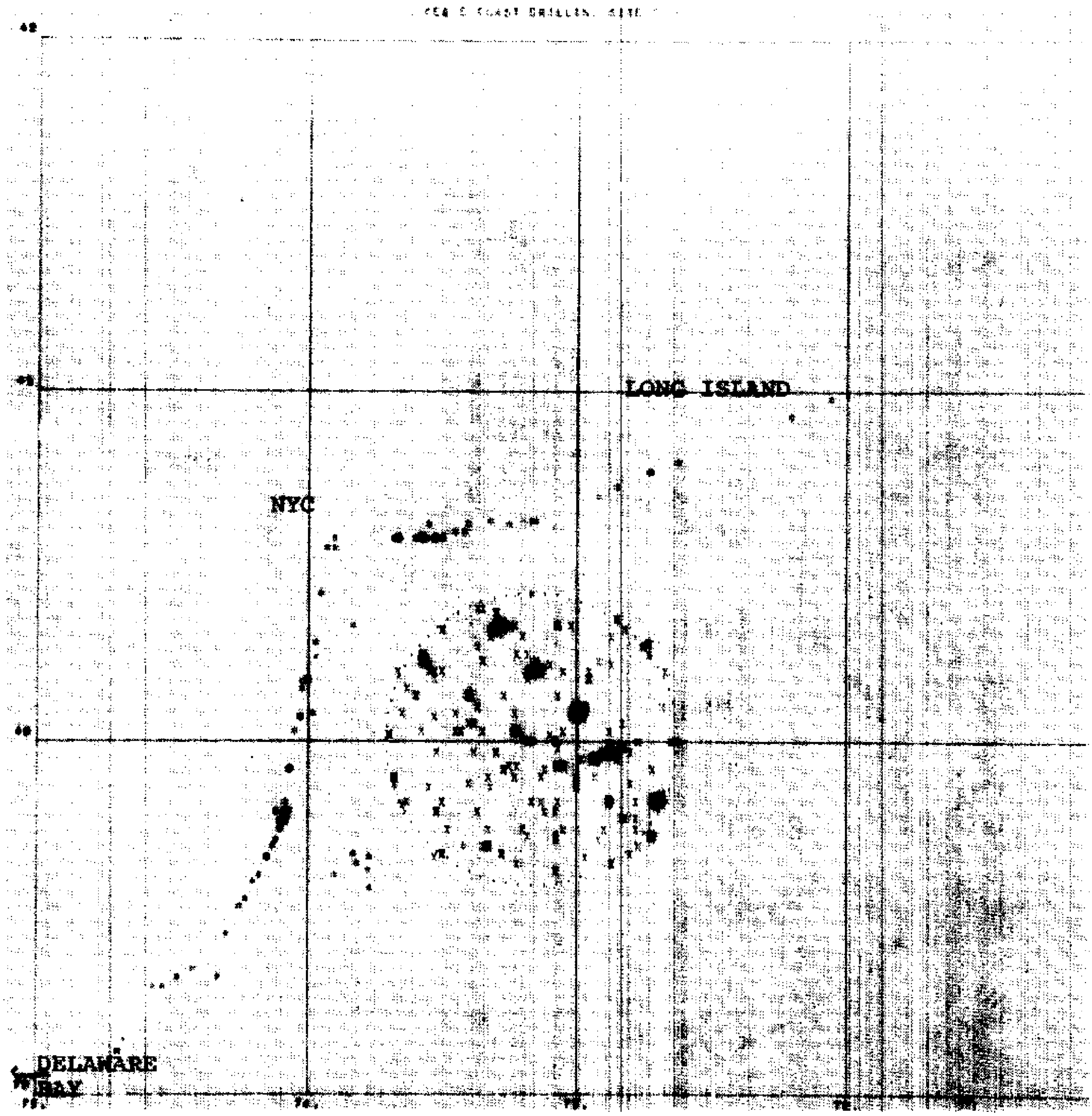


Fig. 3.19--Summary of drift bottle release and recovery results for EDS 5.

x Indicates release location for a launch group

* Indicates reported recovery location

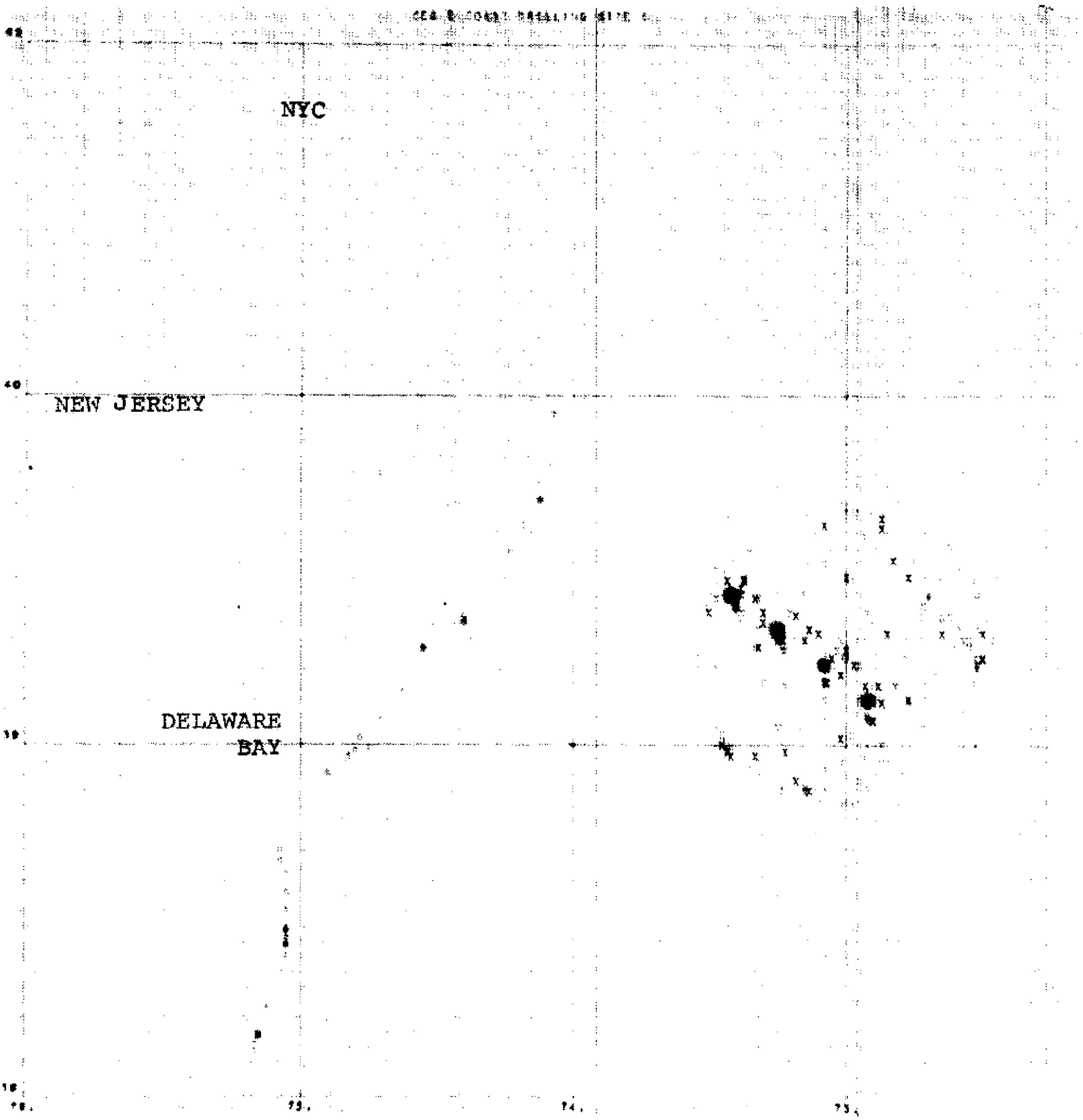


Fig. 3.20 Summary of drift bottle release and recovery results for EDS 6.

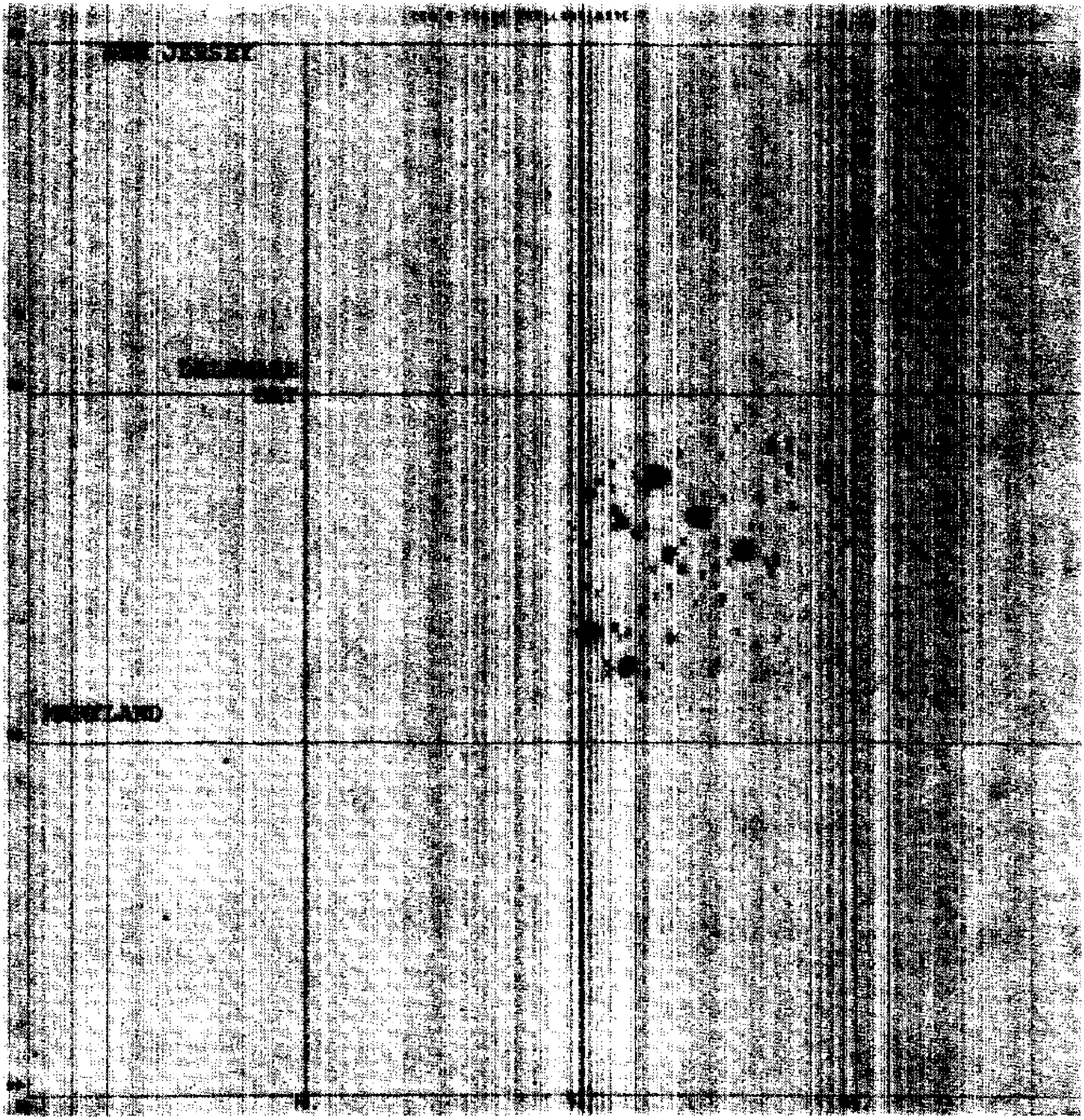


Fig. 3.21--Summary of drift bottle release and recovery results for EDS 7.

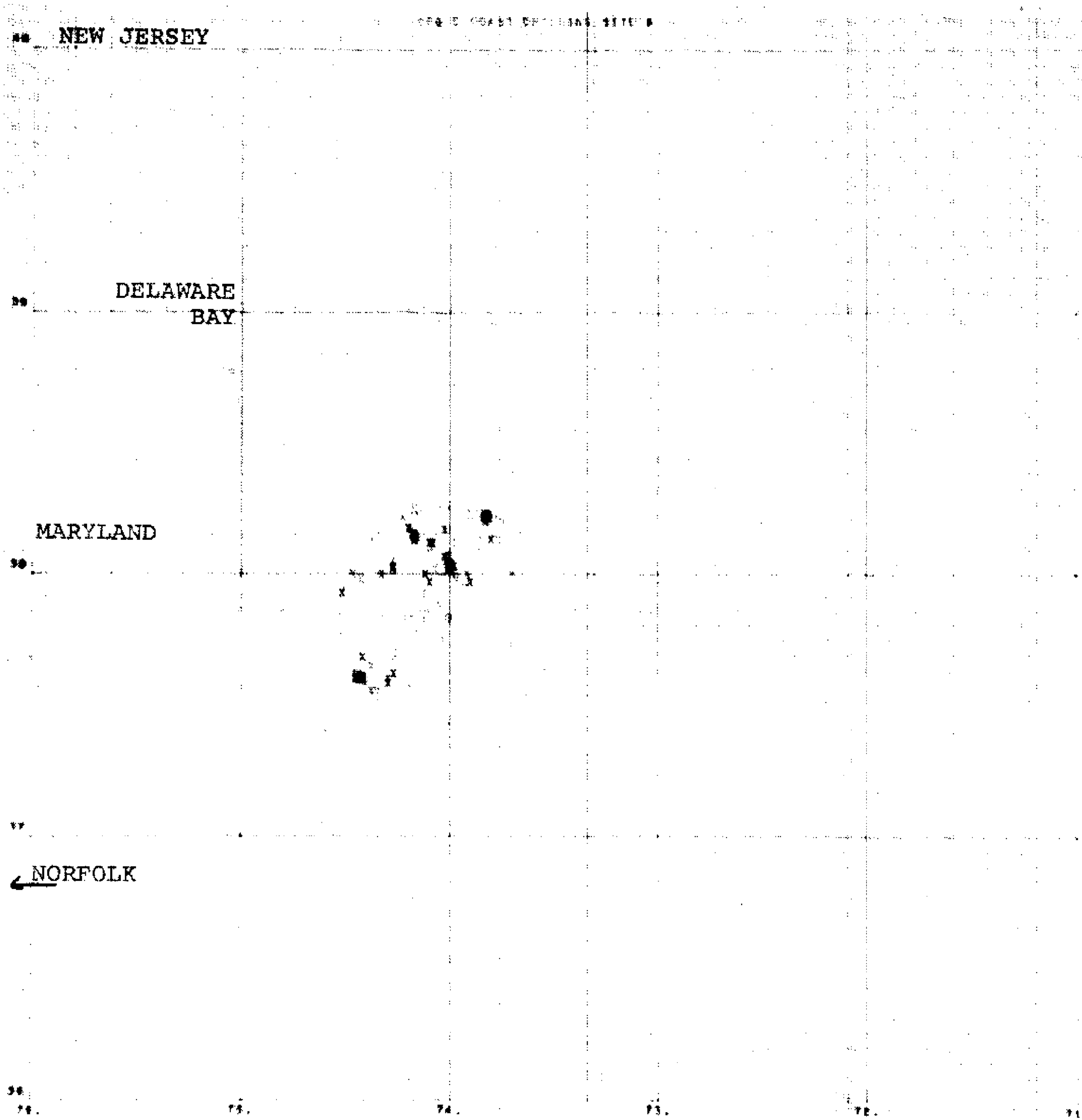


Fig. 3.22--Summary of drift bottle release and recovery results for EDS 8.

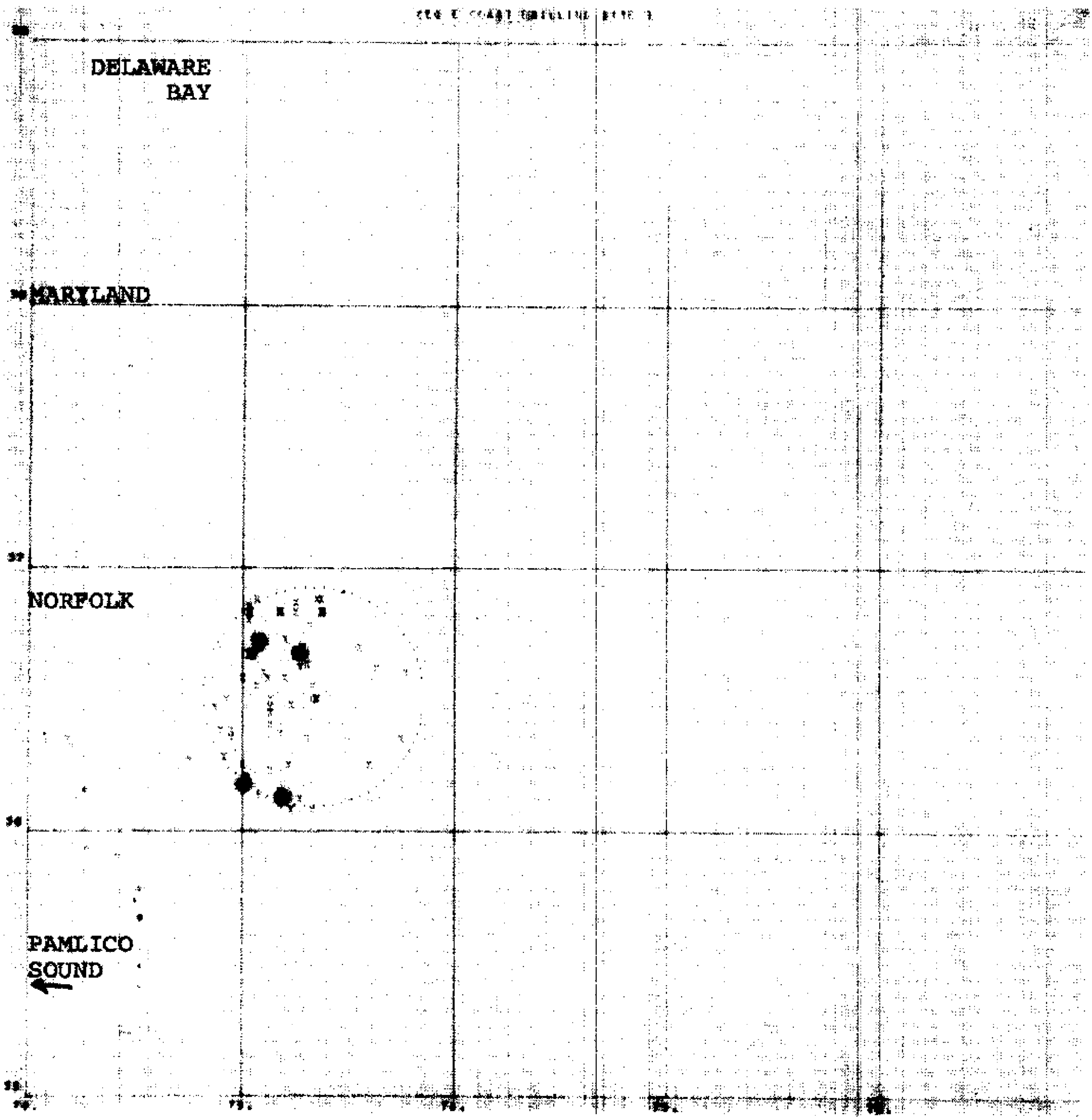


Fig. 3.23--Summary of drift bottle release and recovery results for EDS 9.

Both EDS 7 and EDS 8 are notable for their lack of recoveries, although this may be due in part to the relative dearth of launches.

The percentage recovery of ballasted drift bottles and the average and minimum times to shore are shown in Table 3.5. Again, the statistic we prefer to use for the percent recovery is the conservative one of the recovery groups/launch groups x 100 ("PERCENT GROUP RECD" in Table 3.5).

Figures 3.24 and 3.25 compare our model predictions for percent ashore and time to shore to the drift bottle data for the region. The critical point to be made here is that the drift bottle data and the model do not agree very well in each of EDS sites 6, 7, 8, and 9 in one season. It is possible to attribute some of the variance in the EDS 9 site to the apparent concentration of launches in the southwestern quadrant of the drilling site. These launches would be 25 nautical miles closer to shore than the drilling site location and, as we have seen in the EDS 4 region, such a distance can significantly enhance the chance of impact. However, if we believe that our model ought to duplicate drift bottle data, then the large difference may imply that during at least one season there is some sort of change to the ambient current system which would not be accounted for in our model, since we retained the one current pattern for all four seasons.

Some additional insight into the source of the discrepancy between our simulated drift statistics and the drift bottle data can be gained from a comparison of the location of the principal impact zones. As we have noted above, the drift bottles tend to land south and west of the launch site. The

Table 3.5

DRIFT BOTTLE STATISTICS FOR THE MID-ATLANTIC REGION

Summary of EDS 5 Recovery Statistics

	Winter	Spring	Summer	Autumn	Overall
Num. Rel. Grp:	66	66	71	110	313
Tot. Bot. Reld:	380	391	368	536	1675
Num. Rec. Grps:	0	6	9	1	16
Tot. Bot. Recd:	0	7	12	1	20
Percent Bot. Recd:	0.00	1.79	3.26	0.19	1.19
Percent Group Recd:	0.00	9.09	12.68	0.91	5.11
Minimum Time	182	3	13	4	3
Average Time		98	68	332	79

Summary of EDS 6 Recovery Statistics

	Winter	Spring	Summer	Autumn	Overall
Num. Rel. Grp:	65	62	75	92	294
Tot. Bot. Reld:	356	336	398	479	1569
Num. Rec. Grps:	0	4	4	0	8
Tot. Bot. Recd:	0	5	5	0	10
Percent Bot. Recd:	0.00	1.49	1.26	0.00	0.64
Percent Group Recd:	0.00	6.45	5.33	0.00	2.72
Minimum Time	N/A	15	9	N/A	9
Average Time	N/A	60	94	N/A	93

Summary of EDS 7 Recovery Statistics

	Winter	Spring	Summer	Autumn	Overall
Num. Rel. Grp:	55	50	50	64	219
Tot. Bot. Reld:	305	261	258	325	1149
Num. Rec. Grps:	0	5	3	0	8
Tot. Bot. Recd:	0	5	5	0	10
Percent Bot. Recd:	0.00	1.92	1.94	0.00	0.87
Percent Group Recd:	0.00	10.00	6.00	0.00	3.65
Minimum Time	N/A	17	34	N/A	17
Average Time	N/A	120	61	N/A	85

Summary of EDS 8 Recovery Statistics

	Winter	Spring	Summer	Autumn	Overall
Num. Rel. Grp:	22	28	33	28	111
Tot. Bot. Reld:	140	159	177	149	625
Num. Rec. Grps:	0	0	4	1	5
Tot. Bot. Recd:	0	0	5	1	6
Percent Bot. Recd:	0.00	0.00	2.82	0.67	0.96
Percent Group Recd:	0.00	0.00	12.12	3.57	4.50
Minimum Time	N/A	N/A	33	19	19
Average Time	N/A	N/A	53	27	46

Table 3.5 (continued)

Summary of EDS 9 Recovery Statistics

	Winter	Spring	Summer	Autumn	Overall
Num. Rel. Grp:	21	42	38	21	132
Tot. Bot. Reld:	120	286	215	169	790
Num. Rec. Grps:	0	0	6	0	6
Tot. Bot. Recd:	0	0	9	0	9
Percent Bot. Recd:	0.00	0.00	4.19	0.00	1.14
Percent Group Recd:	0.00	0.00	4.19	0.00	4.55
Minimum Time	N/A	182	13	N/A	13
Average Time	N/A	182	54	N/A	62

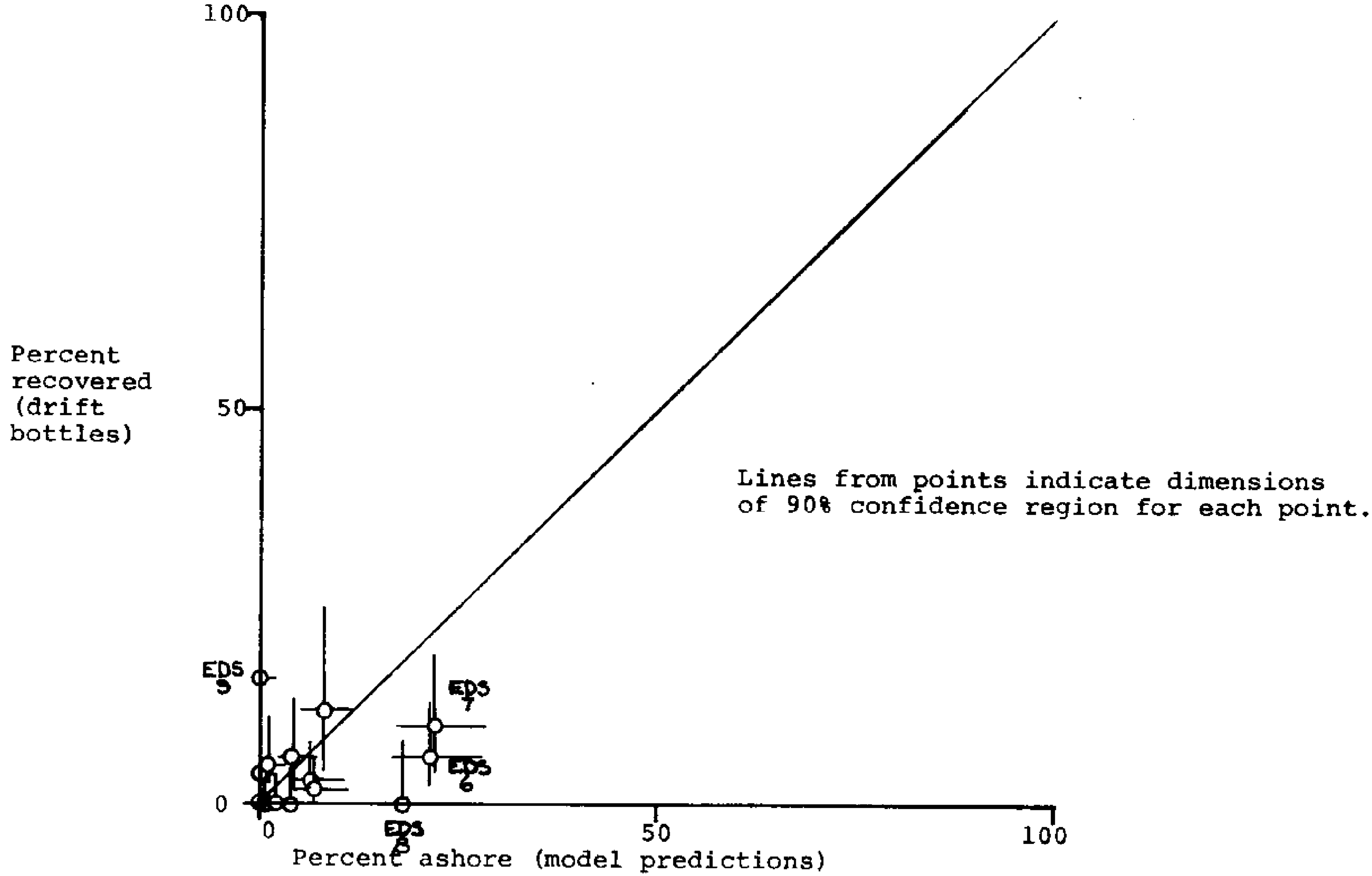


Figure 3.24--Mid-Atlantic region--comparison of total percentage recovery of drift bottles vs. model predictions of percentage of spills ashore. (Note: Drift bottle pecentage recovered is based on launch groups and recovery groups.)

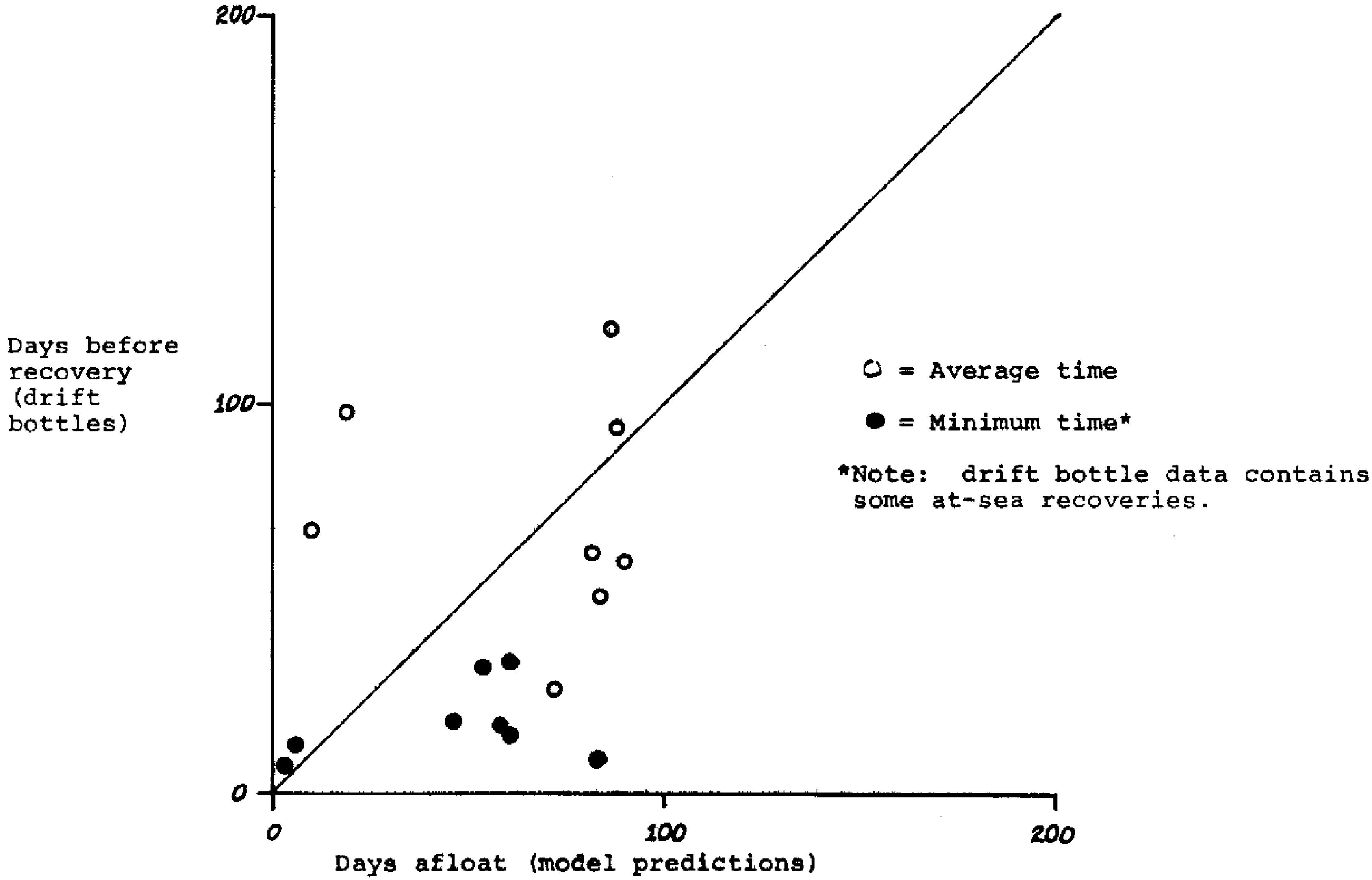


Figure 3.25--Mid-Atlantic region--time afloat: drift bottle data for EDS region and season vs. model predictions for EDS point and season.

model predicts landings to the north and west. The season in which this discrepancy is most pronounced is spring for EDS 6, EDS 7, and EDS 8. The model predicts average trajectory times on the order of three months and minimum times on the order of one and a half to two months. Based on the time required to complete the trajectory, it is plausible to suppose that the simulated trajectories are being carried by the wind north and perhaps east through the hypothesized null current area and into the westward flow presumed off the south coast of Rhode Island, Connecticut, and Long Island. Once in this current they are then carried into the central part of the New York Bight region where they impact shore. If the area of presumed null current were actually to have a slight eastwardly current, then these trajectories might very well never impact shore, but rather be swept up by the Gulf Stream and carried out of the region. As we can see in Figures 8, 10, and 11 of Welch (1974), it is possible to justify the assumption of some eastwardly drift in this region for the spring-summer months based on the dynamic height contours. Thus, the discrepancy suggests that the current specification in the central area of the Mid-Atlantic Bight is of critical importance in the modeling problem for the drilling sites off New Jersey and Delaware. Somewhat mitigating the problem, however, is the observation that the predicted chances of impact are still so small as to make these areas attractive candidates. The possibility that even the small chance of hitting shore is an overestimate makes them even more attractive.

The launch point sensitivity studies are shown in Figures

3.26 through 3.31. The primary features to notice are the high sensitivity to distance south of Long Island, as shown in the EDS 5 southerly traverse. As we have seen previously, the position of this dropoff is probably a function of the wind drift coefficient, but even with the 0.04 value the same effect would be observed, although not in the same place nor to the same degree.

The general pattern that emerges from this simulation is that spills originating anywhere in the region lying within 20 to 30 miles of Long Island would appear to have a reasonably good chance of striking shore. With the exception of spills from EDS 6, 7, and 8 occurring in the spring, the remainder would tend to be carried south. In traveling south, the eastward component of the average wind drift is sufficient to carry them to the point where they are swept up by the Gulf Stream and removed from the region. An example of the shoreline region affected by spills from EDS 5 is shown in Figure 3.32.

Conclusions

In the mid-Atlantic, the governing features appear to be the presence of the Gulf Stream in the offshore area. Based on the essentially null results from the central EDS sites, it would appear that the westward and northward component of the wind drift is weak and variable at best (except in spring and summer), and any component of drift that tends to inject spills from these areas into the Gulf Stream will reduce dramatically the percentage going ashore.

While our results must necessarily be treated with some caution due to the hypothetical nature of the ambient current

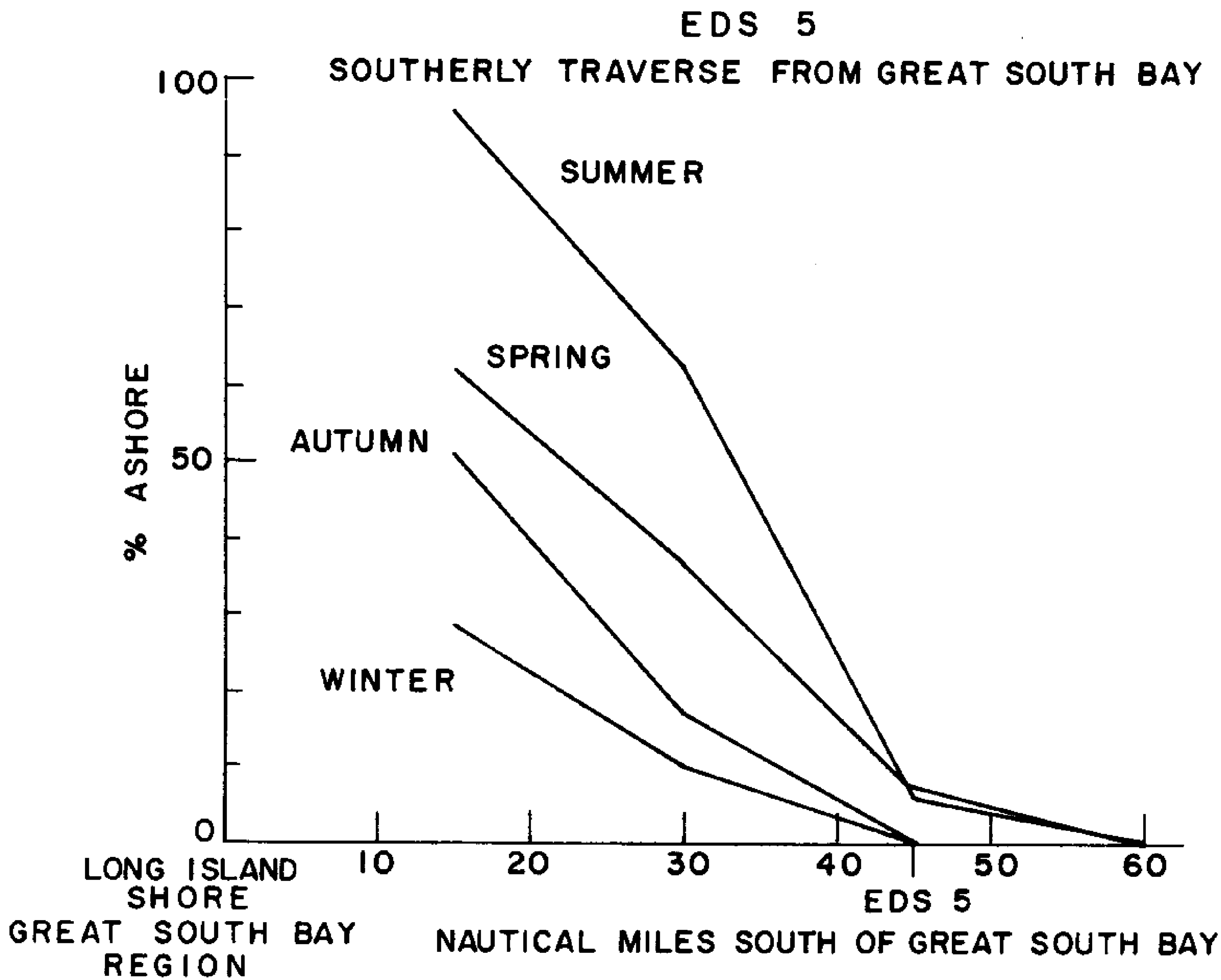


FIGURE 3-26 DEPENDENCE OF THE PROBABILITY OF A SPILL IMPACTING SHORE ON THE DISTANCE FROM SHORE OF THE SPILL LAUNCH SITE

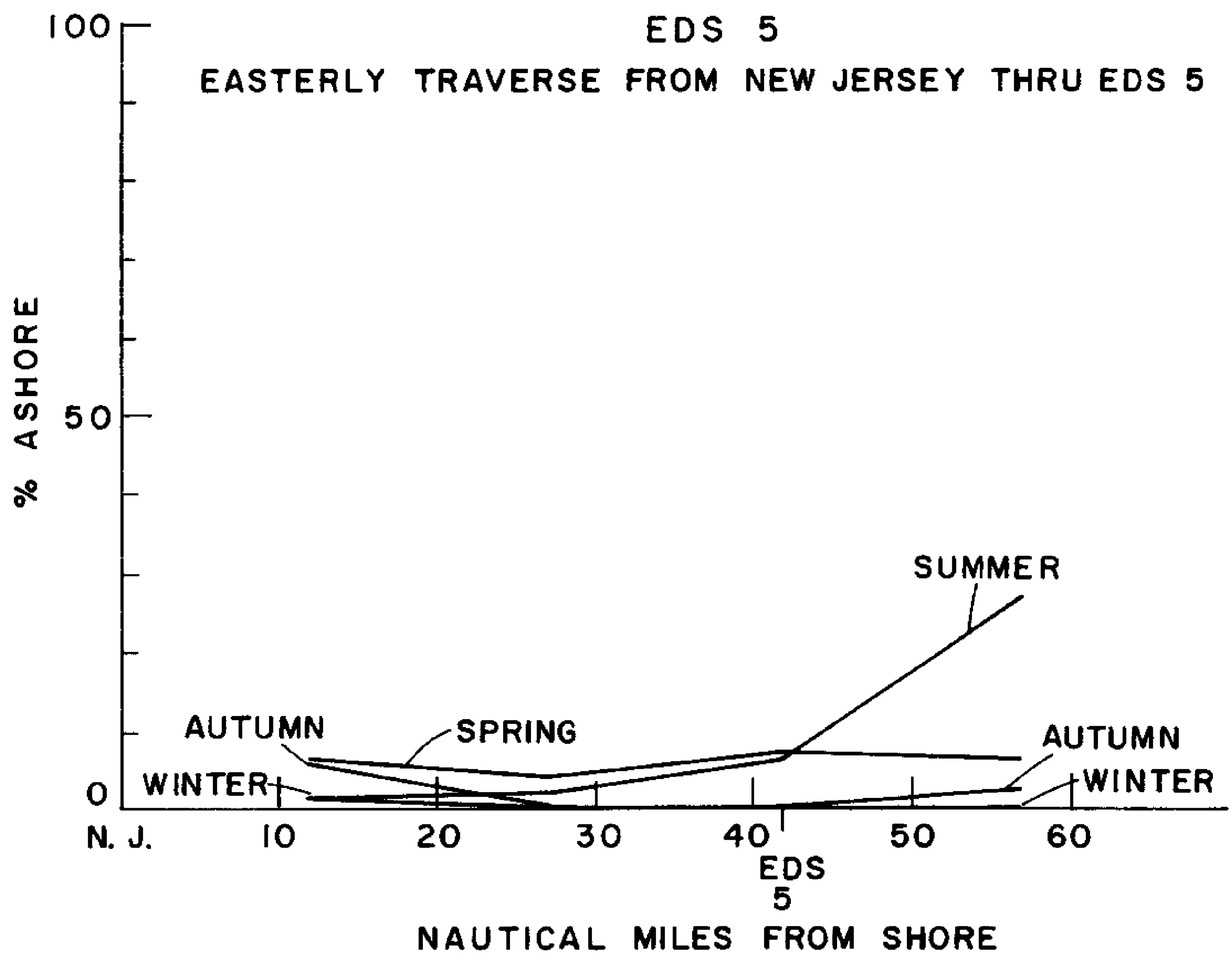


FIGURE 3-27 DEPENDENCE OF THE PROBABILITY OF A SPILL IMPACTING SHORE ON THE DISTANCE FROM SHORE OF THE SPILL LAUNCH SITE

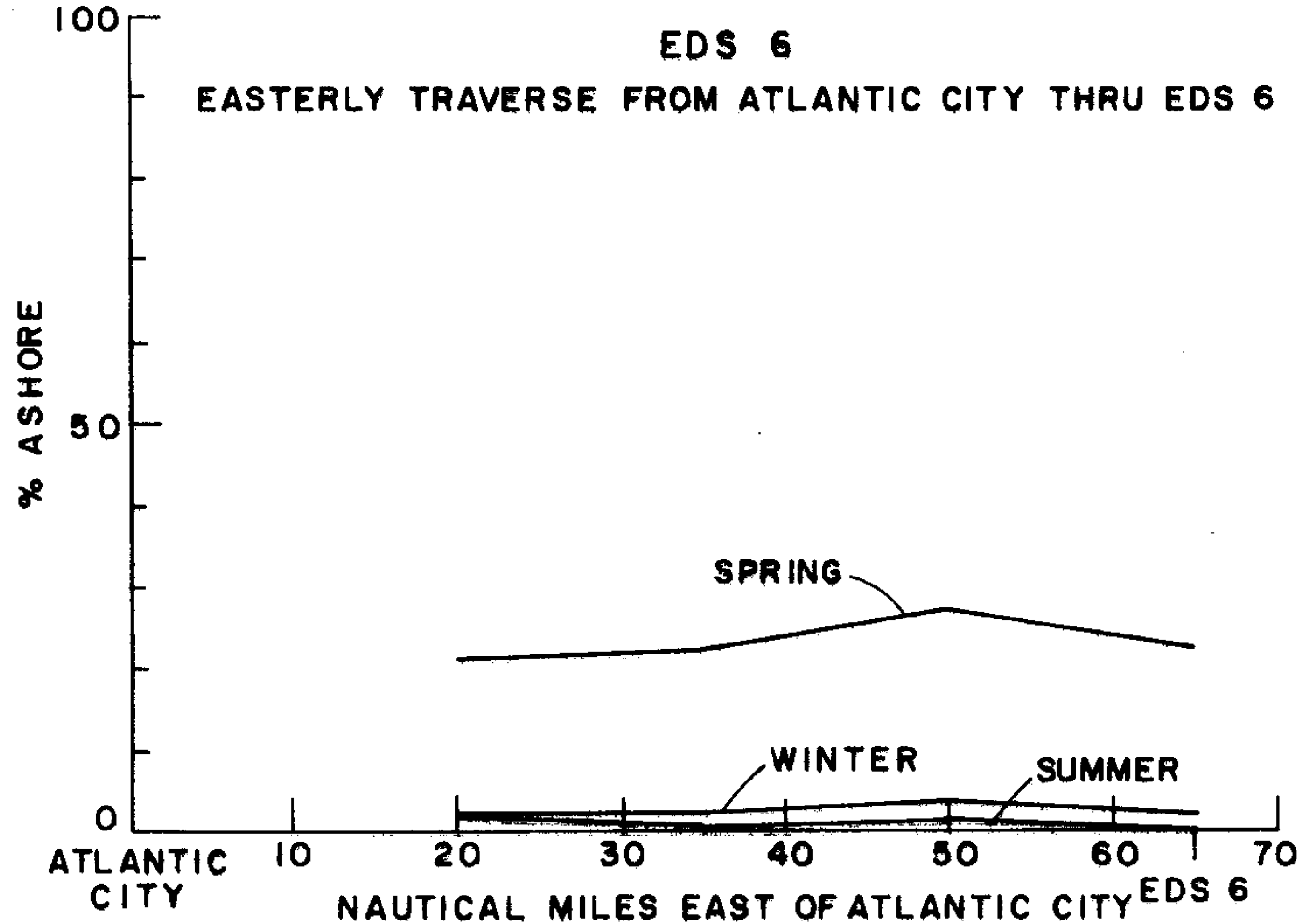


FIGURE 3-28 DEPENDENCE OF THE PROBABILITY OF A SPILL IMPACTING SHORE ON THE DISTANCE FROM SHORE OF THE SPILL LAUNCH SITE

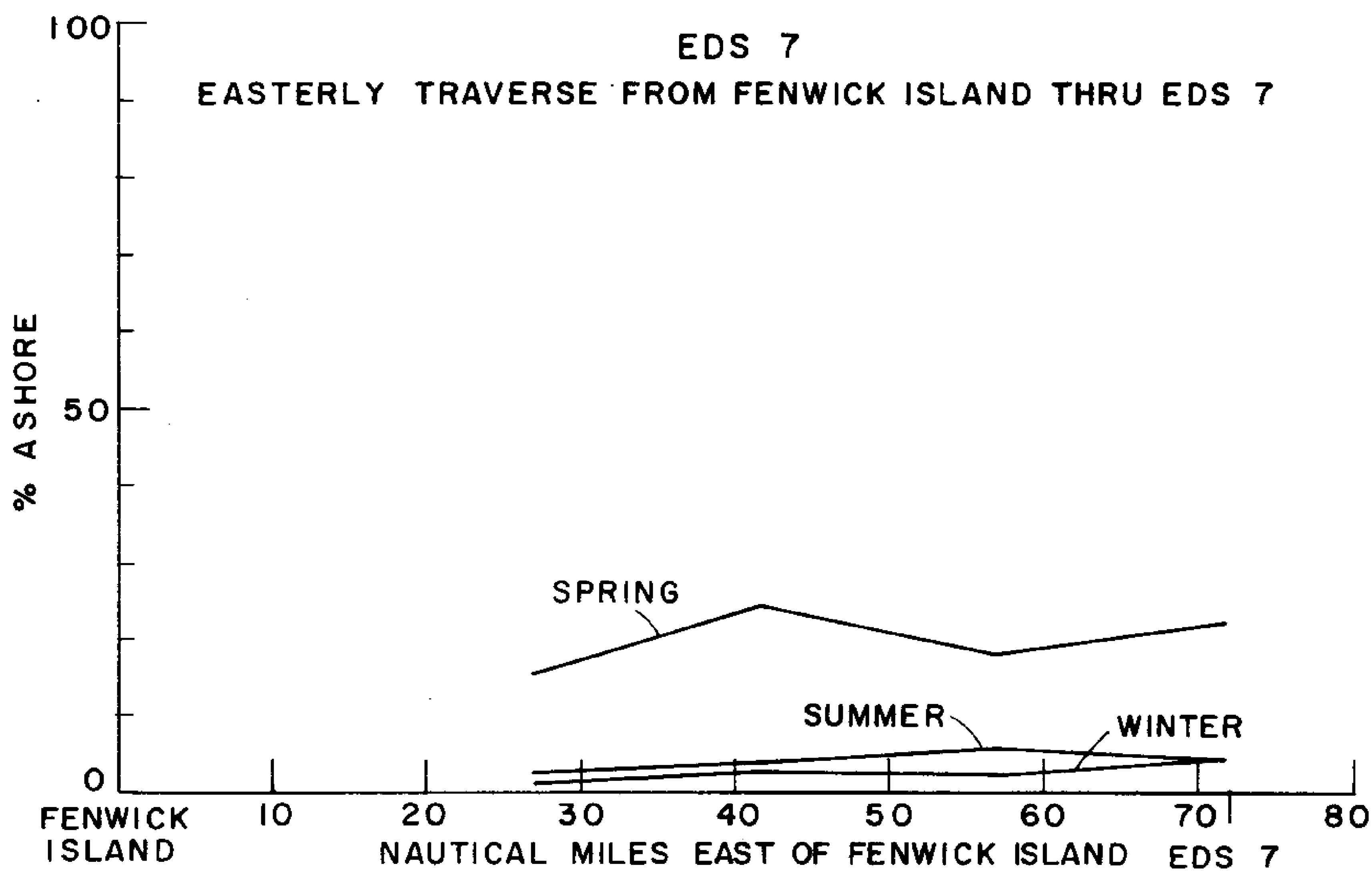


FIGURE 3-29 DEPENDENCE OF THE PROBABILITY OF A SPILL IMPACTING SHORE ON THE DISTANCE FROM SHORE OF THE SPILL LAUNCH SITE

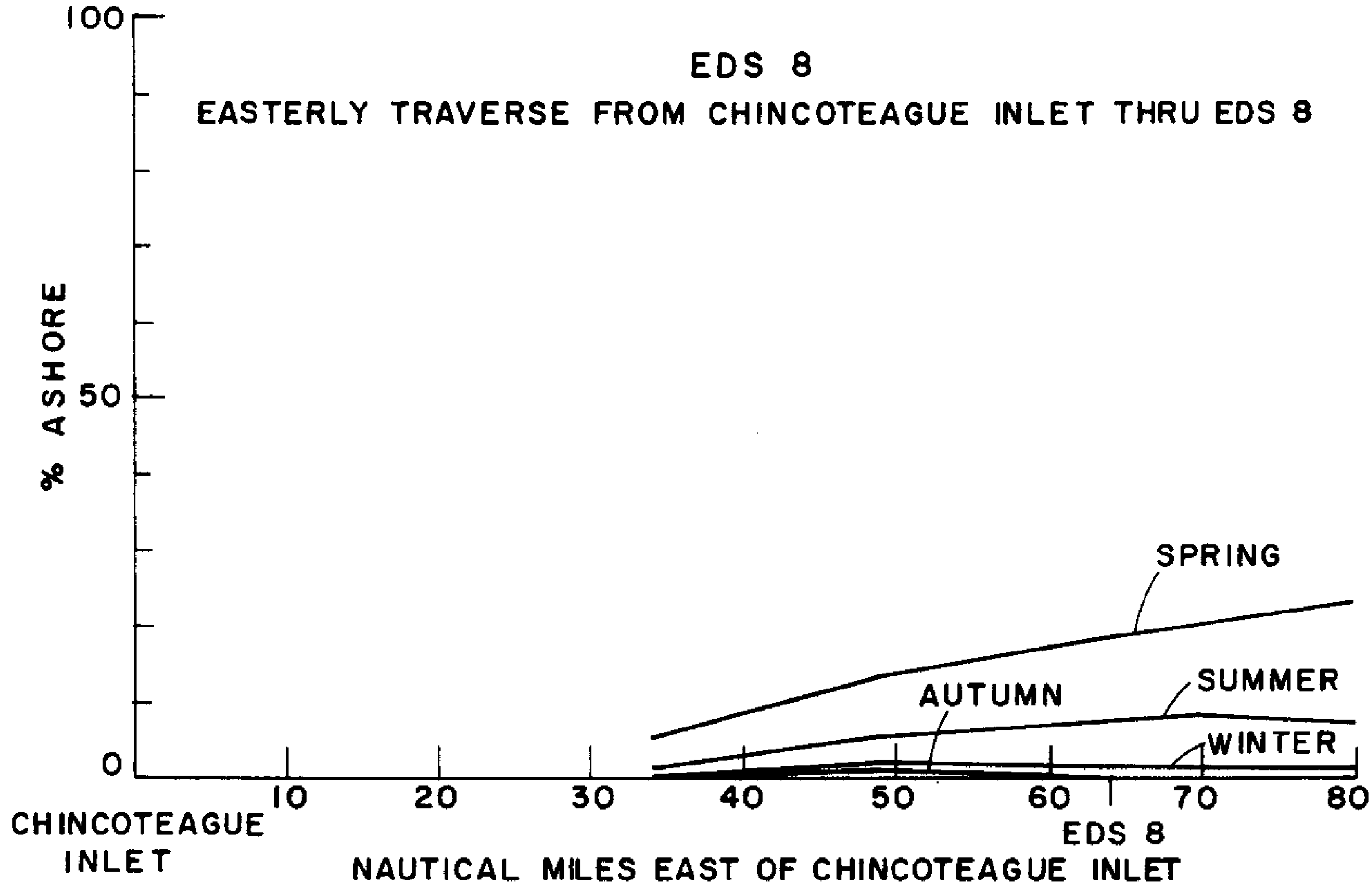


FIGURE 3-30 DEPENDENCE OF THE PROBABILITY OF A SPILL IMPACTING SHORE ON THE DISTANCE FROM SHORE OF THE SPILL LAUNCH SITE

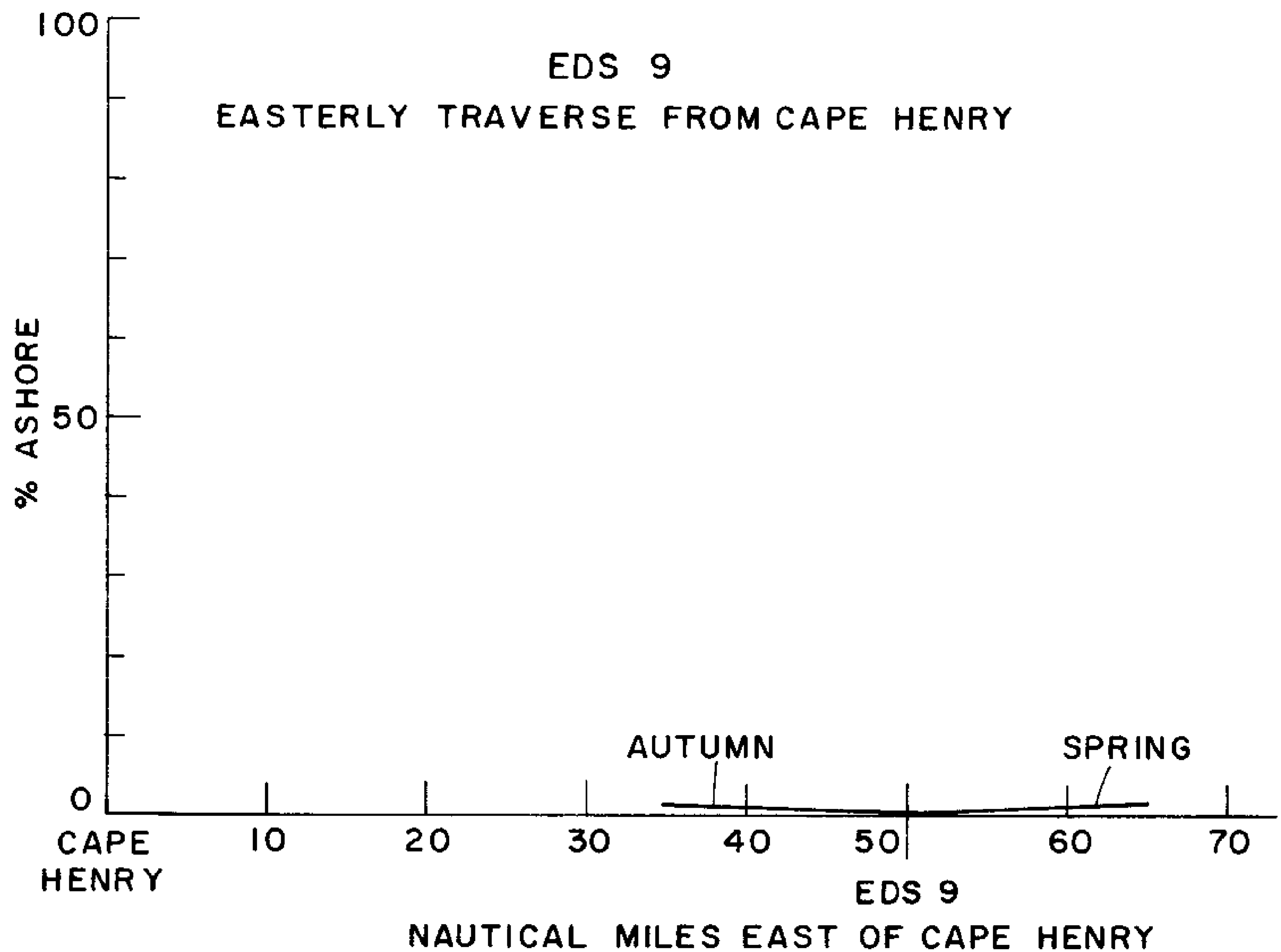
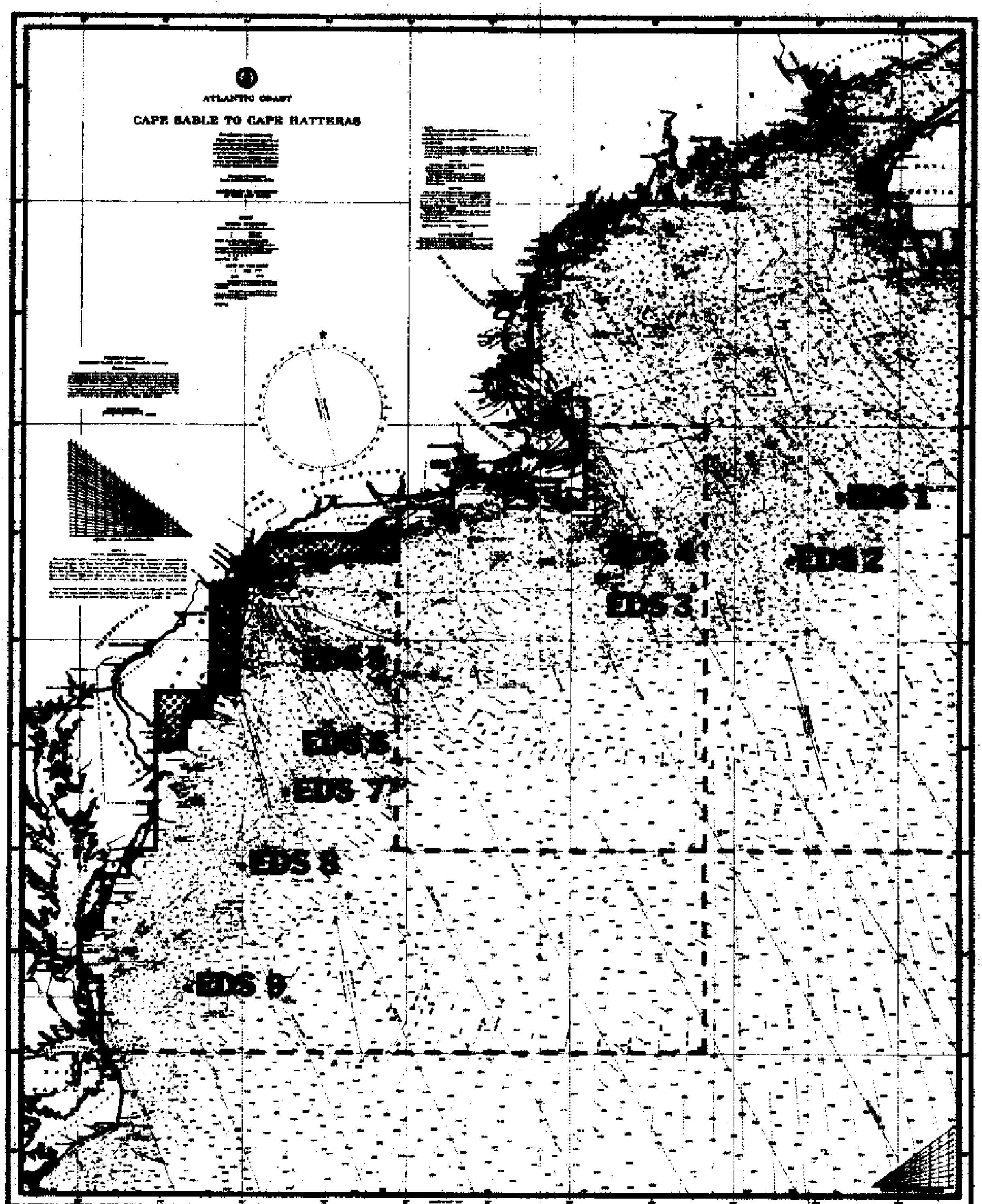


FIGURE 3-31 DEPENDENCE OF THE PROBABILITY OF A SPILL IMPACTING SHORE ON THE DISTANCE FROM SHORE OF THE SPILL LAUNCH SITE

Figure 3.32--Average annual percent chance of a spill impacting shore from EDS 5.



< 0.1%

0.1% to 0.3%

0.3% to 0.5%

0.5 to 1%

> 1%

specification, it seems reasonable to state that EDS 7 and 8 are the drilling site selections that would pose the least risk of having a spill go ashore. Certainly, EDS 5 presents the greatest risk followed perhaps by EDS 6; although on the point of naming EDS 6 ahead of EDS 9, it would be well to delve a little more deeply into the unusually high drift bottle percentage recovery in the summer in the EDS 9 area. It could be that in our broad-brush approach we have failed to recognize some critical facet of the wind or current behavior in this southern area.

South Atlantic region

The grid representation of the South Atlantic region is shown in Figure 3.33. As can be seen from this sketch of the area, there are no offshore islands. Nor is there an offshore ocean station position. Consequently, we were unable to identify any offshore wind data sources for this region, so this area is the one area in which all wind drift is calculated using strictly shore-based data.

The presumed current pattern is shown in Figure 3.34. It was derived in part from dynamic height contours provided by VIMS (Welch, 1974) and in part from current arrows shown in USCGS Chart 1001. Figure 3.35 shows the median and extremes of the monthly average position of the Gulf Stream. It can be seen that there is a relative lack of variance in position of the Gulf Stream; consequently, we felt justified in using just this one current hypothesis through the year.

The drift bottle launch and recovery records are summarized in Figures 3.36 through 3.39. Note that, of the four East Coast drilling sites in this region, only EDS 10 has a relative lack of recoveries. Table 3.6 summarizes the launch and recovery statistics for this area, and, by comparing the statistics from each area, we can see that this low recovery record wasn't for lack of bottles released. However, we can see that, on the whole, the bulk of the releases for the EDS 10 area took place in the outer portion of the region, whereas the other drilling sites tended to have a more even coverage of launch sites. This could be an indication that distance from shore is of critical importance in determining drift behavior in this area.

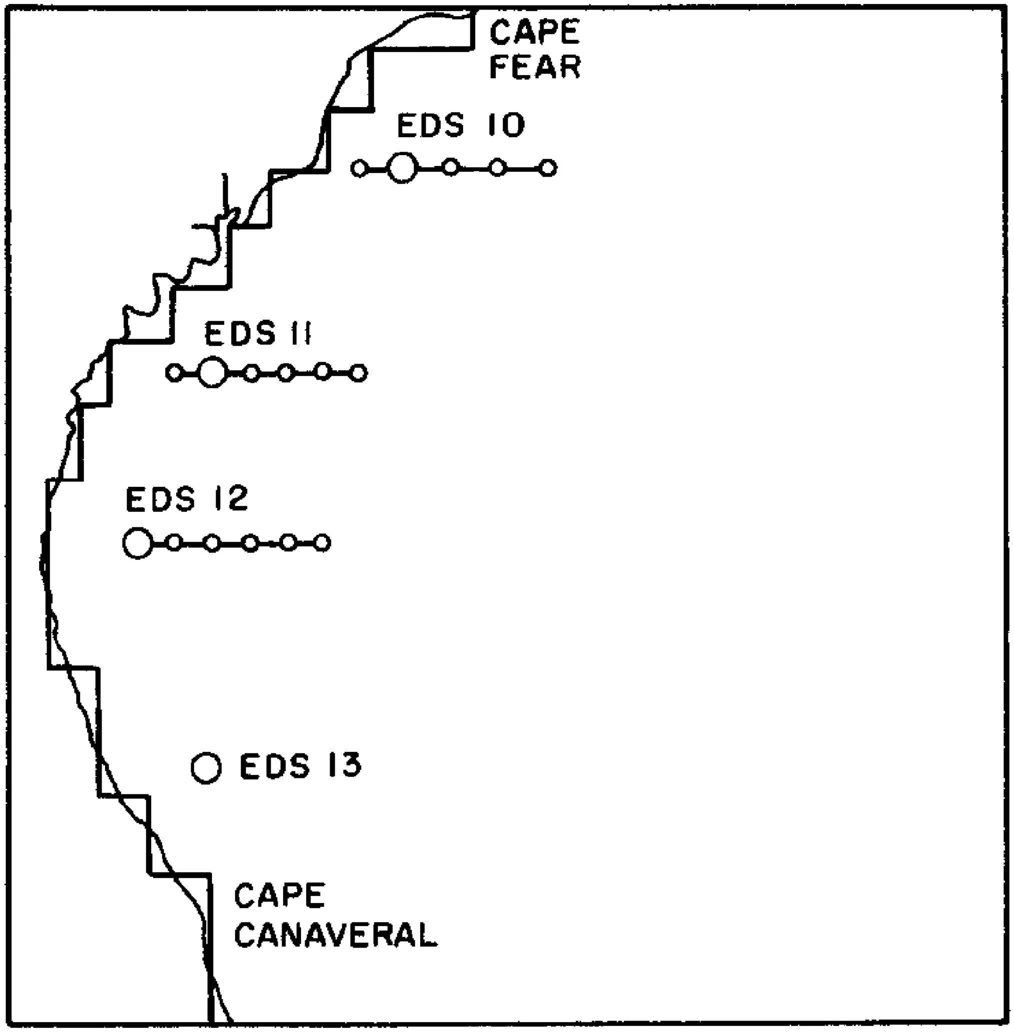


FIG. 3.33 LOCATION OF POINTS IN THE GEORGIA EMBAYMENT REGION FOR WHICH DETAILED TRAJECTORY CALCULATIONS WERE MADE

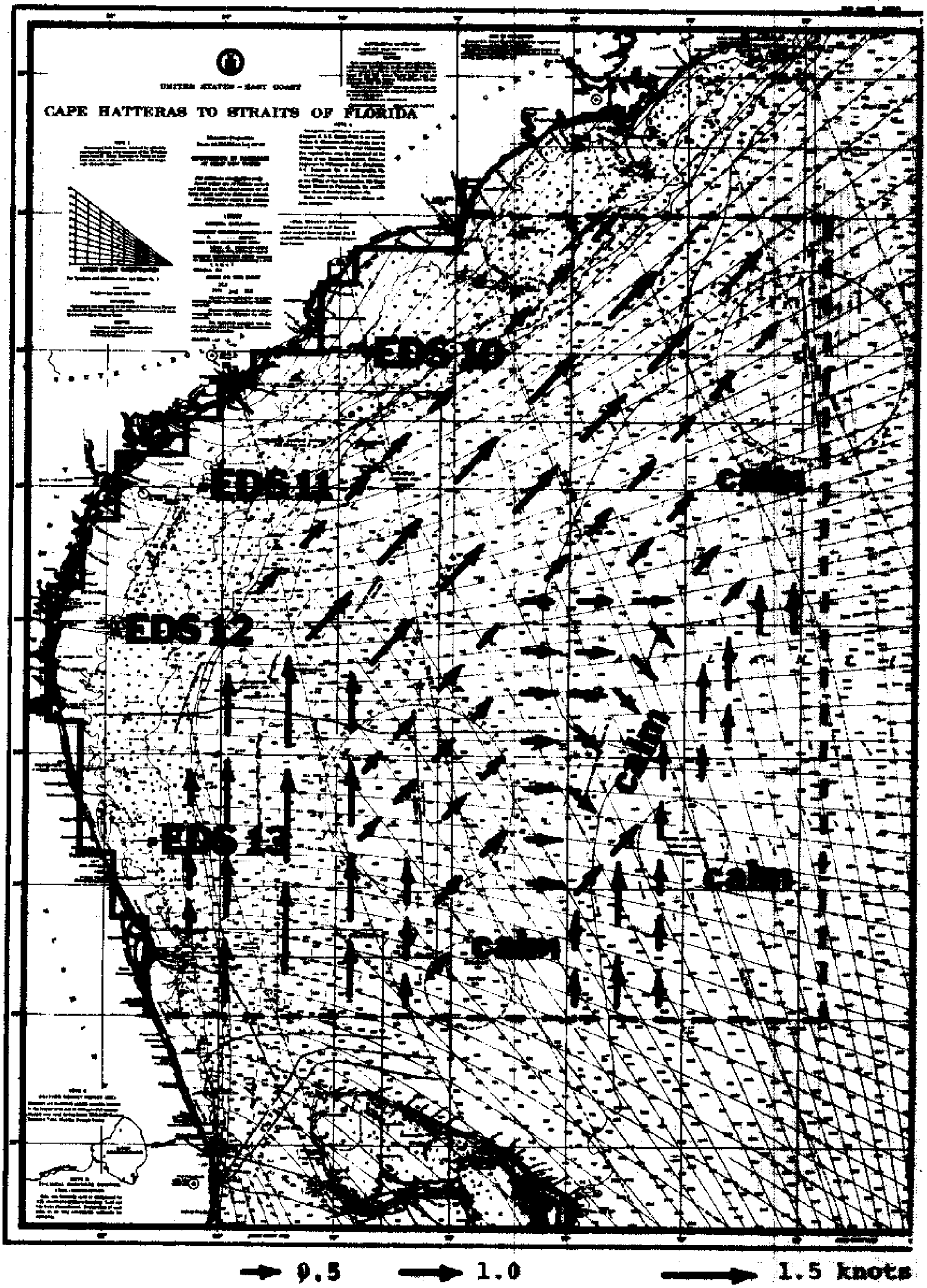


Figure 3.34--Hypothesized current pattern for Georgia Embayment region.

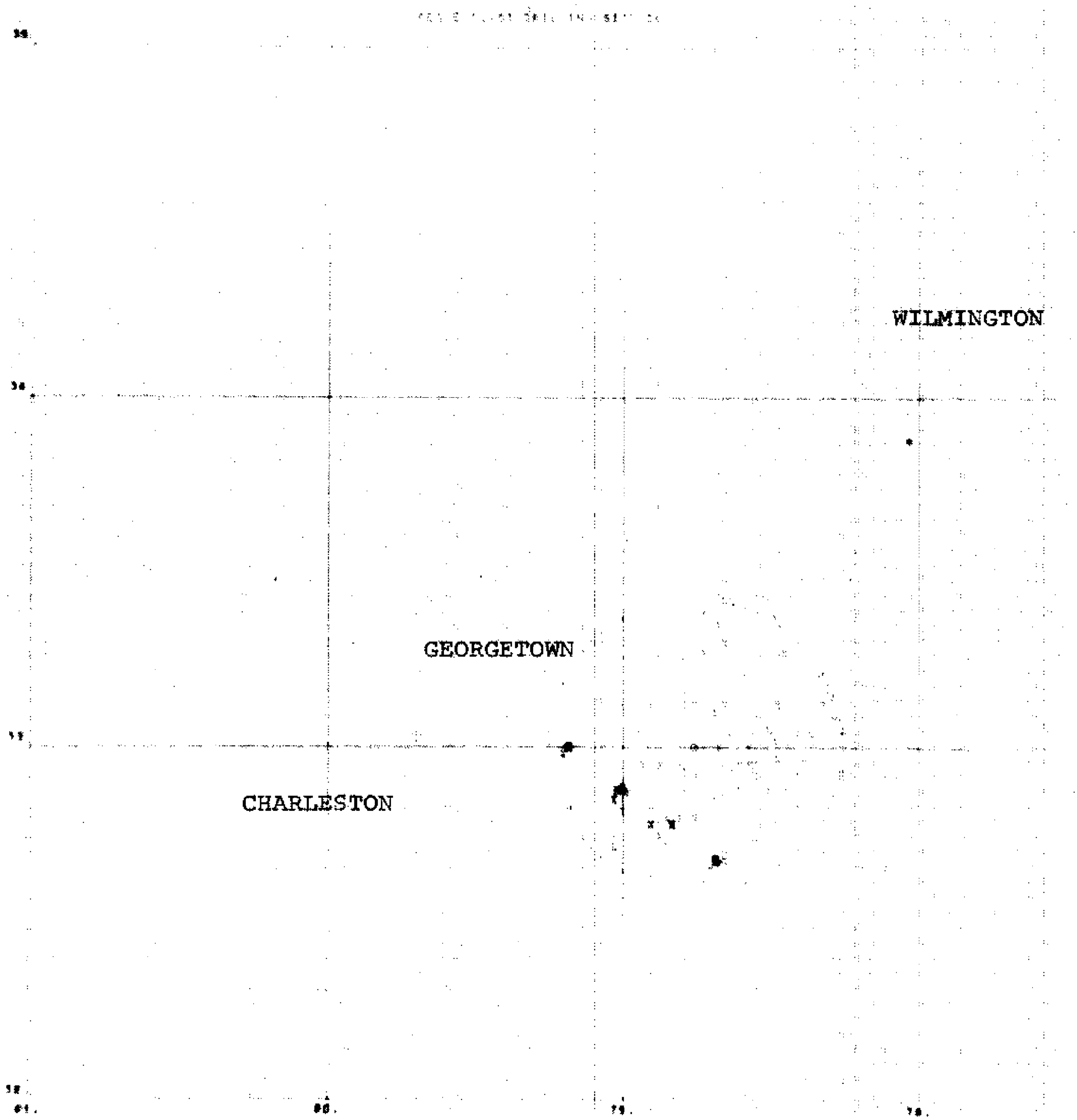


Fig. 3.36--Summary of drift bottle release and recovery results for EDS 10.

x Indicates release location for a launch group

* Indicates reported recovery location

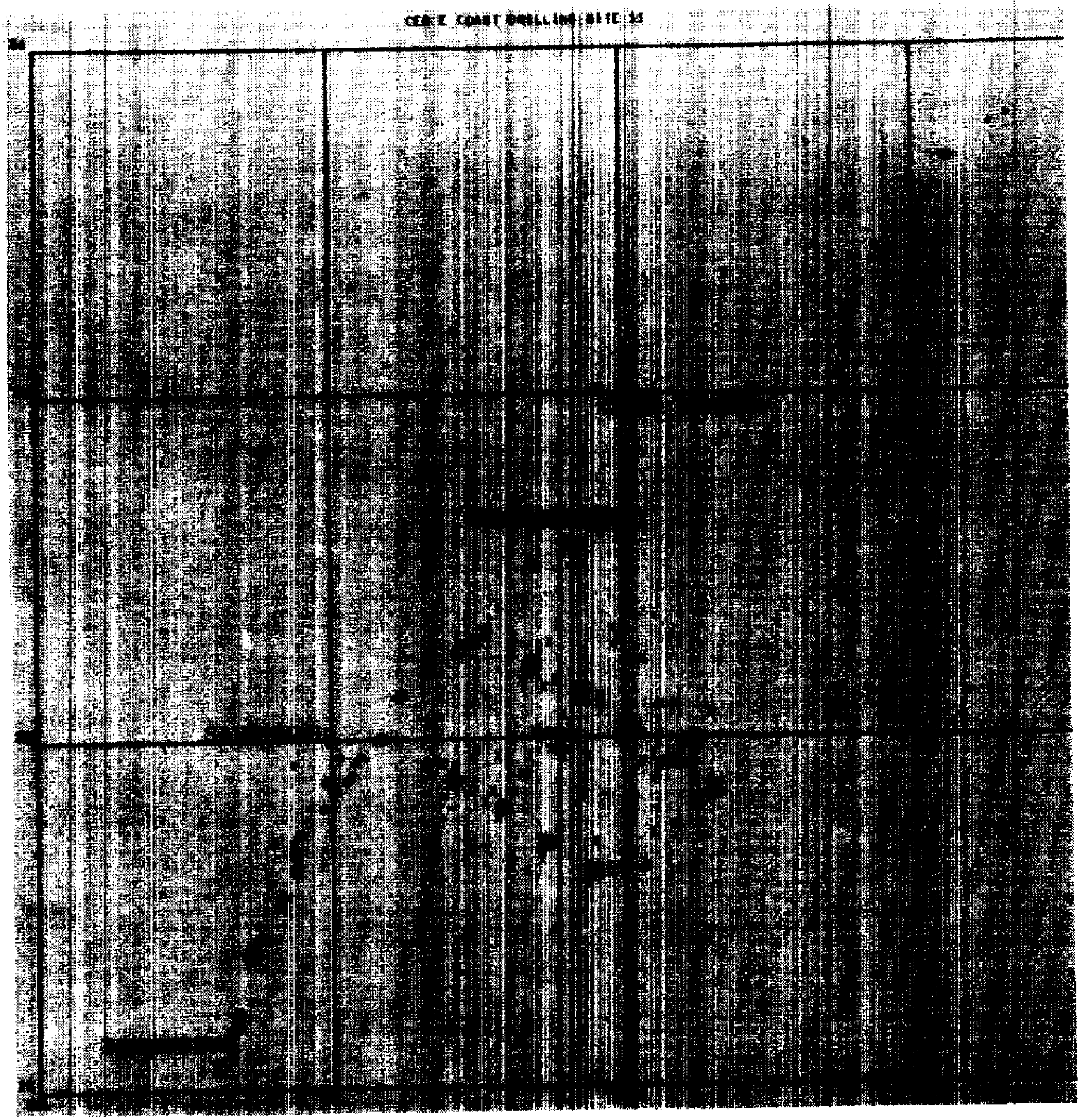


Fig. 3.37 -- Summary of drift bottle release and recovery results for EDS 11.

x Indicates release location for a launch group

* Indicates reported recovery location

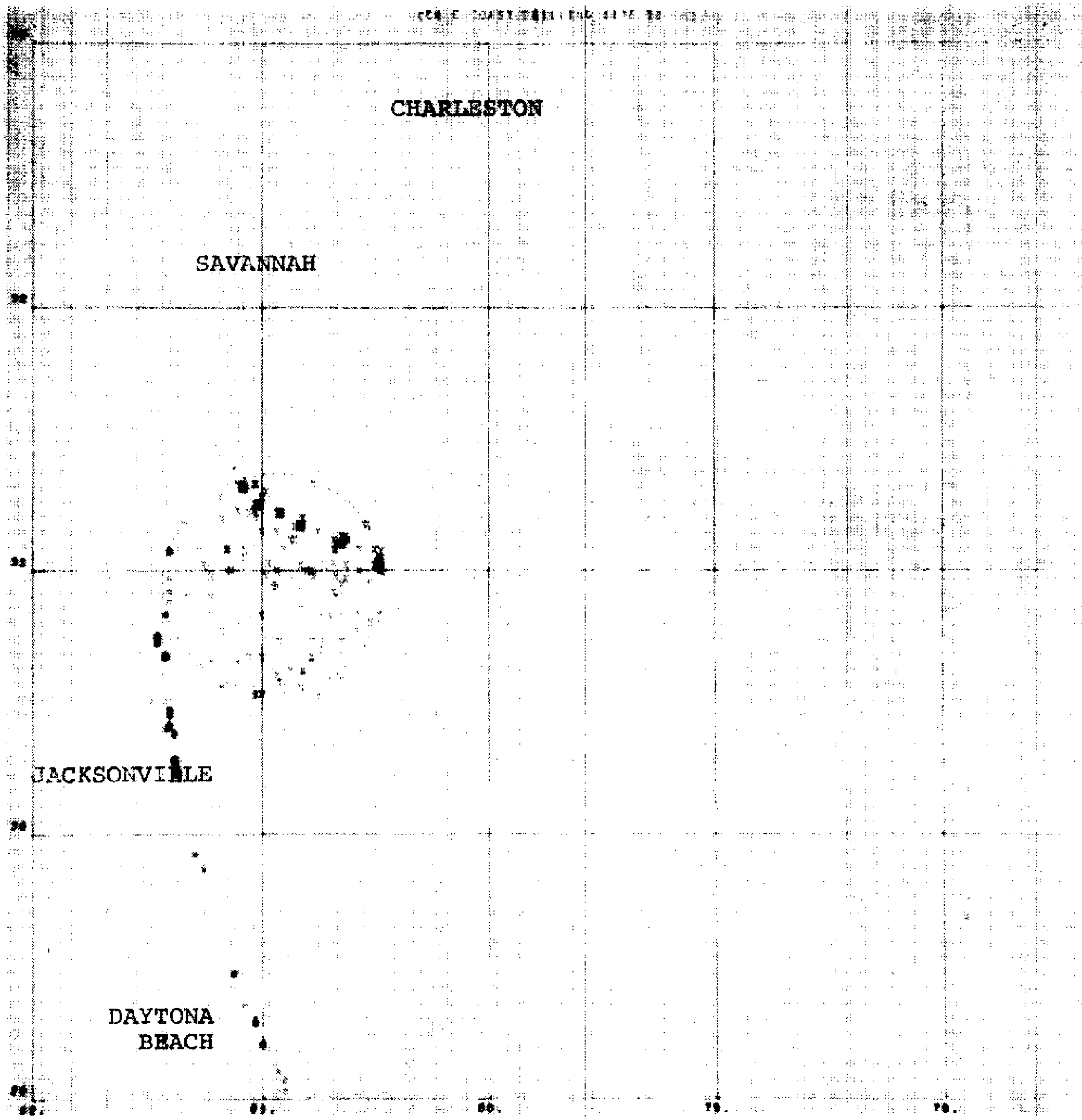


Fig. 3.38-- Summary of drift bottle release and recovery data for EDS 12.

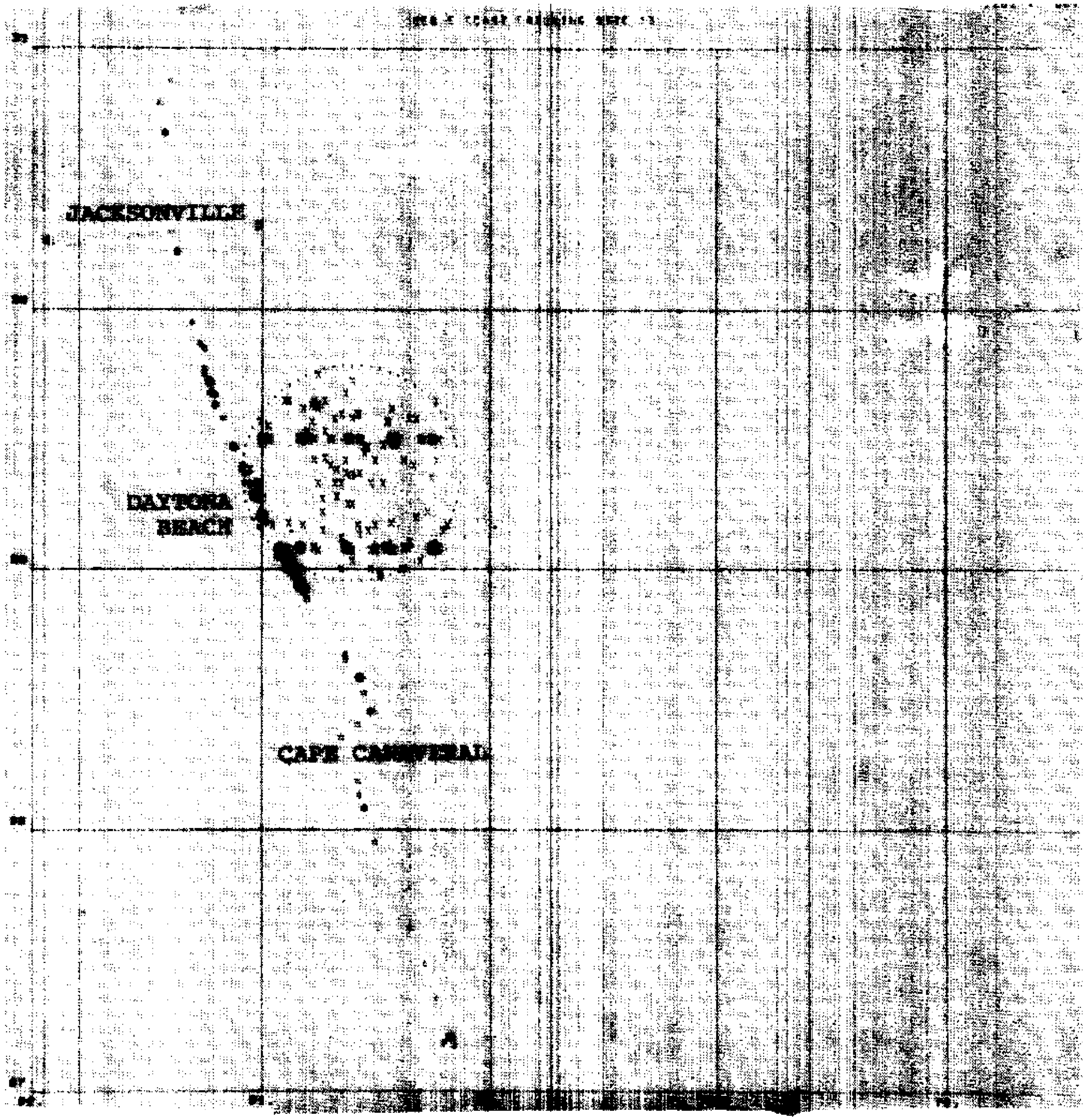


Fig. 3.39 --Summary of drift bottle release and recovery results for EDS 13.

Table 3.6

SUMMARY OF DRIFT BOTTLE RELEASE AND RECOVERY STATUS
FOR THE SOUTHERN ATLANTIC COASTAL REGION

Summary of EDS 10 Recovery Statistics

	Winter	Spring	Summer	Autumn	Overall
Num. Rel. Grp:	31	36	23	19	109
Tot. Bot. Reld:	160	179	125	95	559
Num. Rec. Grps:	1	0	2	0	3
Tot. Bot. Recd:	1	0	2	0	3
Percent Bot. Recd:	0.63	0.00	1.60	0.00	0.54
Percent Group Recd:	3.23	0.00	8.70	0.00	2.75
Minimum Time	N/A	N/A	12	N/A	12
Average Time	N/A	N/A	27	N/A	27

Summary of EDS 11 Recovery Statistics

	Winter	Spring	Summer	Autumn	Overall
Num. Rel. Grp:	42	54	20	23	139
Tot. Bot. Reld:	210	270	100	115	695
Num. Rec. Grps:	0	7	5	3	15
Tot. Bot. Recd:	0	15	5	3	23
Percent Bot. Recd:	0.00	5.56	5.00	2.61	3.31
Percent Group Recd:	0.00	12.96	25.00	13.04	10.79
Minimum Time	38	7	N/A	3	13
Average Time	38	100	92	66	78

Summary of EDS 12 Recovery Statistics

	Winter	Spring	Summer	Autumn	Overall
Num. Rel. Grp:	34	55	29	19	137
Tot. Bot. Reld:	163	279	139	91	672
Num. Rec. Grps:	3	19	7	8	37
Tot. Bot. Recd:	4	36	15	13	68
Percent Bot. Recd:	2.45	12.90	10.79	14.29	10.12
Percent Group Recd:	8.82	34.55	24.14	42.11	27.01
Minimum Time	22	2	3	8	2
Average Time	N/A	61	30	133	85

Summary of EDS 13 Recovery Statistics

	Winter	Spring	Summer	Autumn	Overall
Num. Rel. Grp:	33	86	25	46	190
Tot. Bot. Reld:	165	426	125	230	946
Num. Rec. Grps:	5	21	2	27	55
Tot. Bot. Recd:	10	60	3	61	134
Percent Bot. Recd:	6.06	14.08	2.40	26.52	14.16
Percent Group Recd:	15.15	24.42	8.00	58.70	28.95
Minimum Time	15	1	5	4	1
Average Time	29	56	9	24	38

Using the hypothesized current and comparing the total percentage ashore per season under this hypothesis to the percent ashore under the null hypothesis, we determined a rough cut at the sensitivity to the current specification for the trajectory simulation. The results of this comparison are shown in Figure 3.40. Note that the model appears to be relatively insensitive to the selection of either the null current or the rather vigorous current we've hypothesized.

Next, we compared the model predictions of percent ashore with the drift bottle data on percent recovered. This is depicted in Figure 3.41. Note that the model consistently overpredicts the percent ashore with respect to the drift bottle data. Next, we looked at the sensitivity of the percent ashore to the offshore position and the results of the analysis are shown in Figures 3.43 through 3.45. (Note that EDS 13 is not depicted, as it is already at the point where the bottom drops off rapidly into the Atlantic Basin; thus exploration in the region lying farther offshore of EDS 13 is unlikely.)

These results give us some explanation for the overestimation of the percent ashore, because we can see that the percent ashore drops off rapidly as we go just another 20 or 30 miles farther out from each drilling site. This is probably an indication that either our wind drift coefficient is not properly chosen, or that our current field does not go close enough to shore, or that there is a significant offshore flow not accounted for in the current model. At any rate, the disparity is relatively academic because, from a decision-maker's point of view, the option to move the sites for leasing and exploration farther

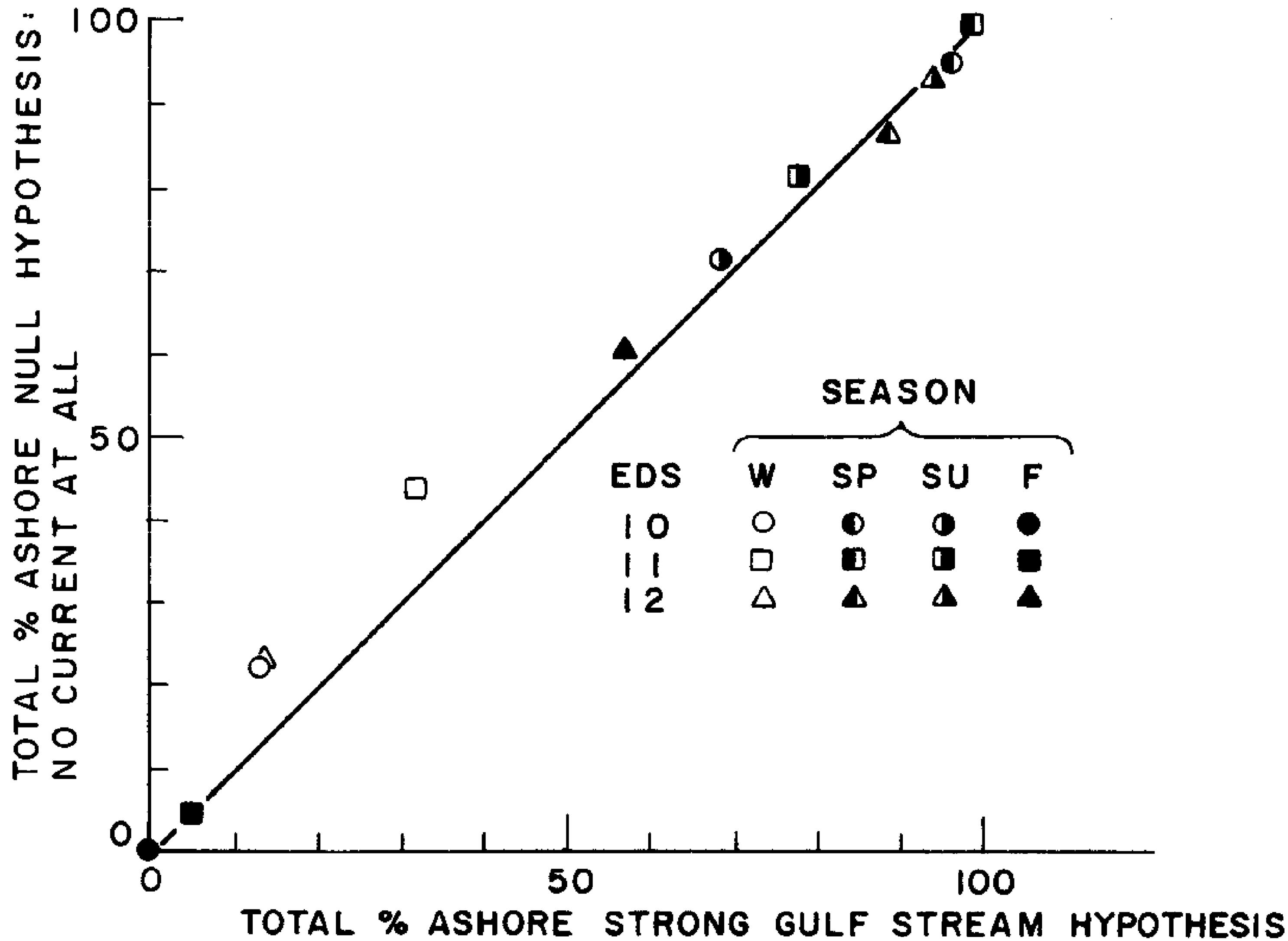


FIGURE 3-40 SENSITIVITY TO CURRENT SPECIFICATION
SOUTH ATLANTIC REGION

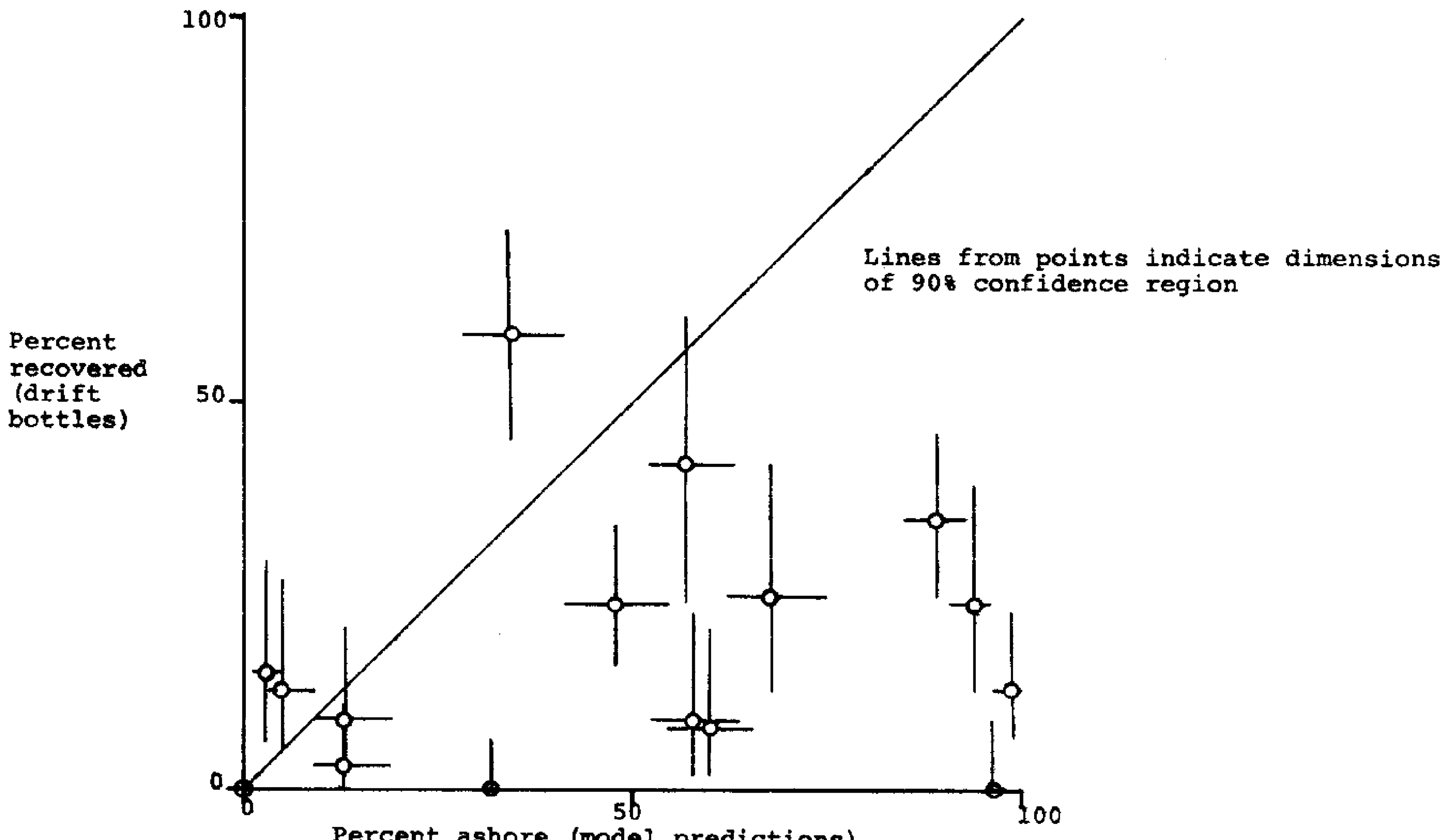


Figure 3.41--South Atlantic region--comparison of total percentage recovery of drift bottles vs. model prediction of percentage of spills ashore. (Note: drift bottle percentage recovered is based on launch groups and recovery groups.)

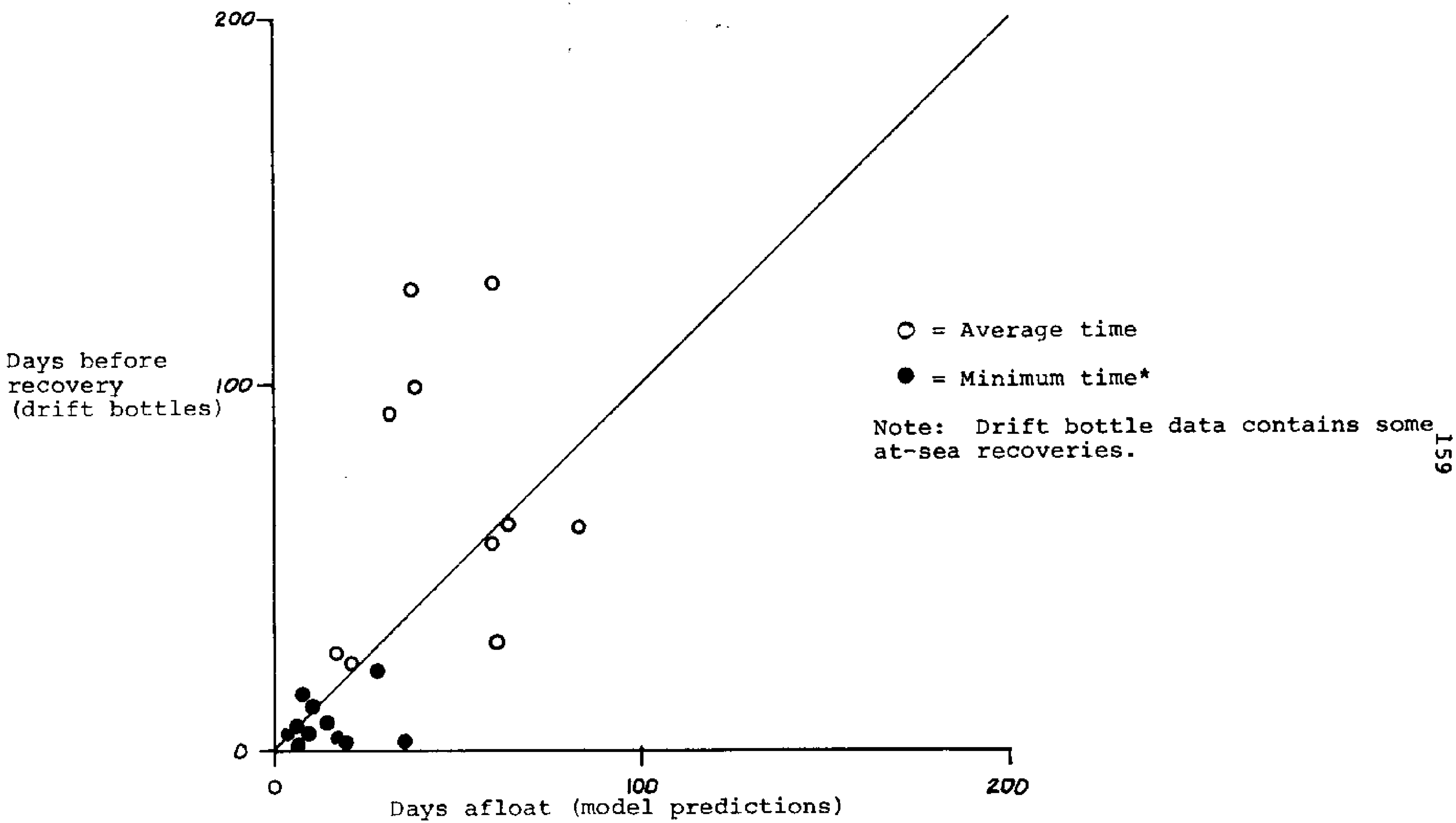


Figure 3.42--South Atlantic region--time afloat: drift bottle data for EDS region and season vs. model predictions for EDS point and season.

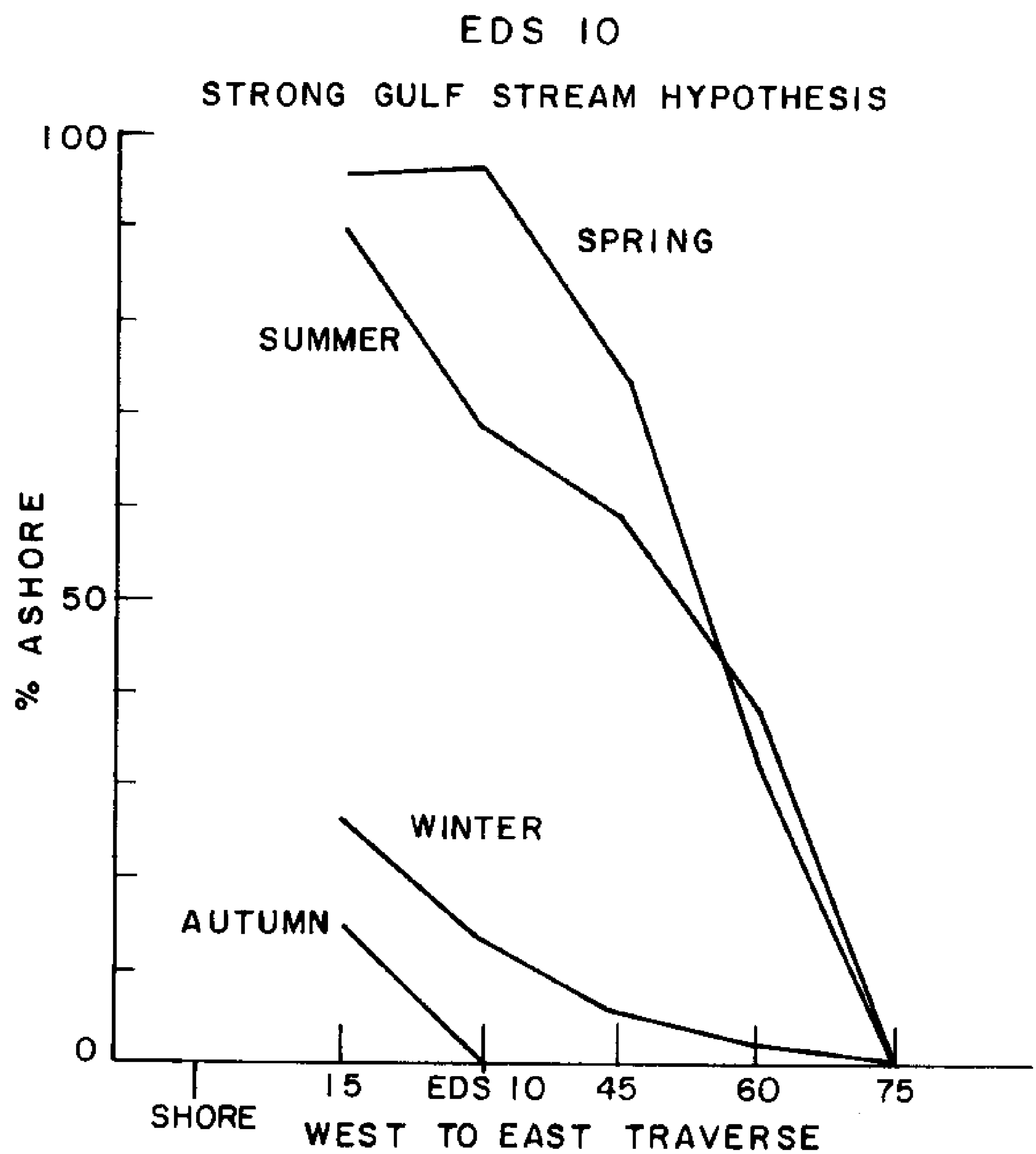


FIGURE 3-43 DEPENDENCE OF THE PROBABILITY OF A SPILL IMPACTING SHORE ON THE DISTANCE FROM SHORE OF THE SPILL LAUNCH SITE

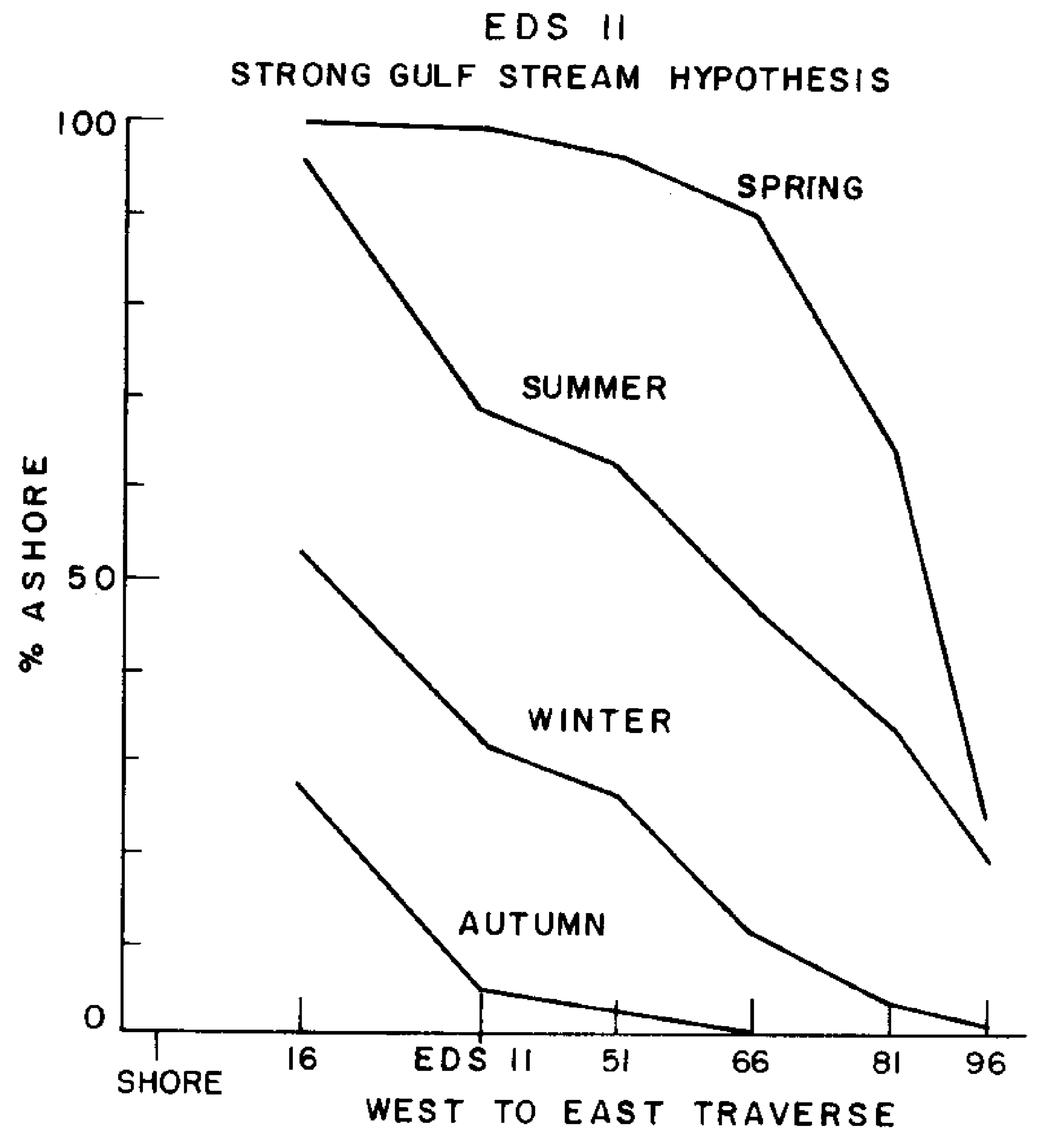


FIGURE 3-44 DEPENDENCE OF THE PROBABILITY OF A SPILL IMPACTING SHORE ON THE DISTANCE FROM SHORE OF THE SPILL LAUNCH SITE

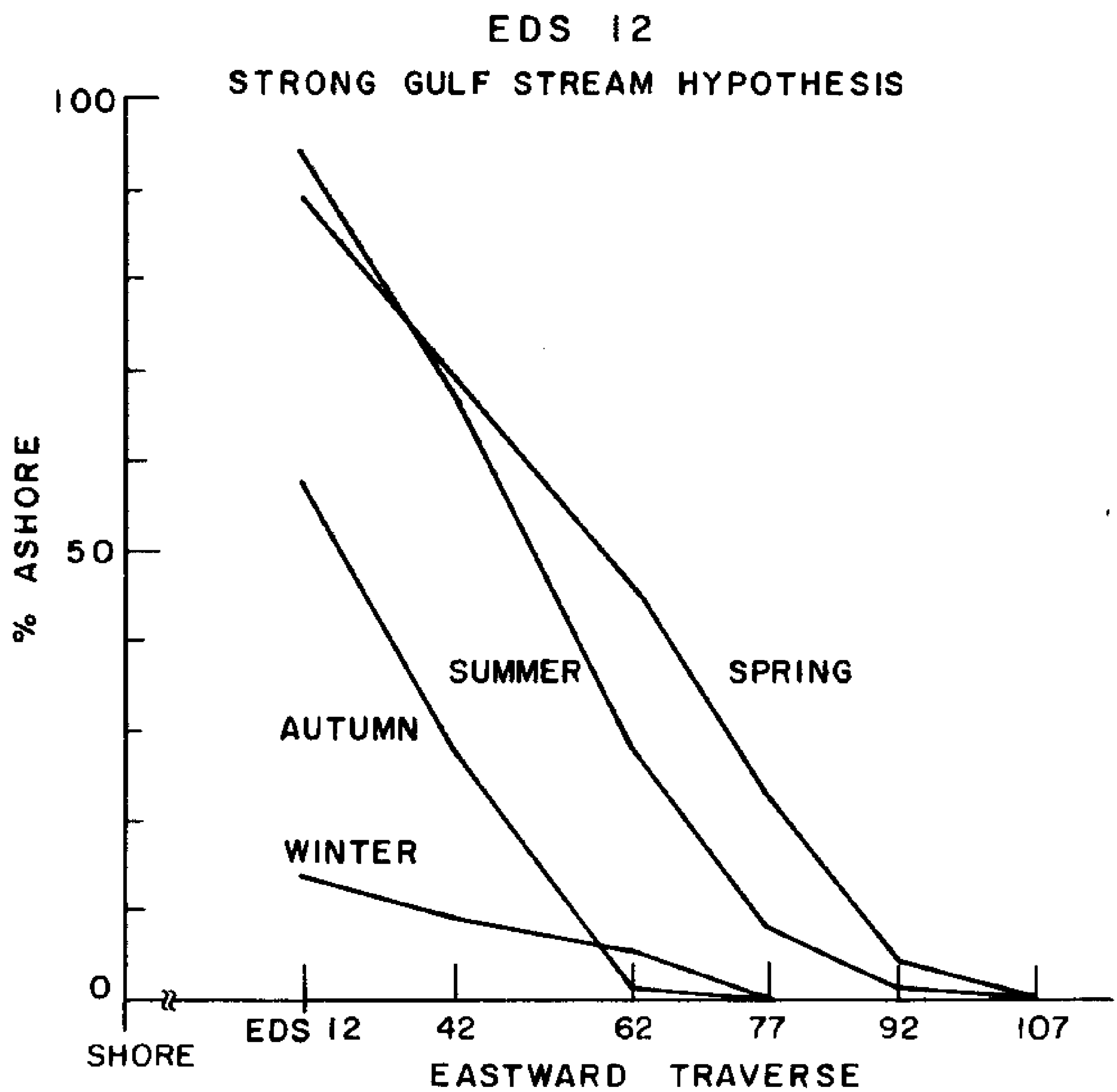


FIGURE 3.45 DEPENDENCE OF THE PROBABILITY OF A SPILL IMPACTING SHORE ON THE DISTANCE FROM SHORE OF THE SPILL LAUNCH SITE

out is available, and can be exercised if the disagreement between the drift bottle results and the model cannot be satisfactorily resolved.

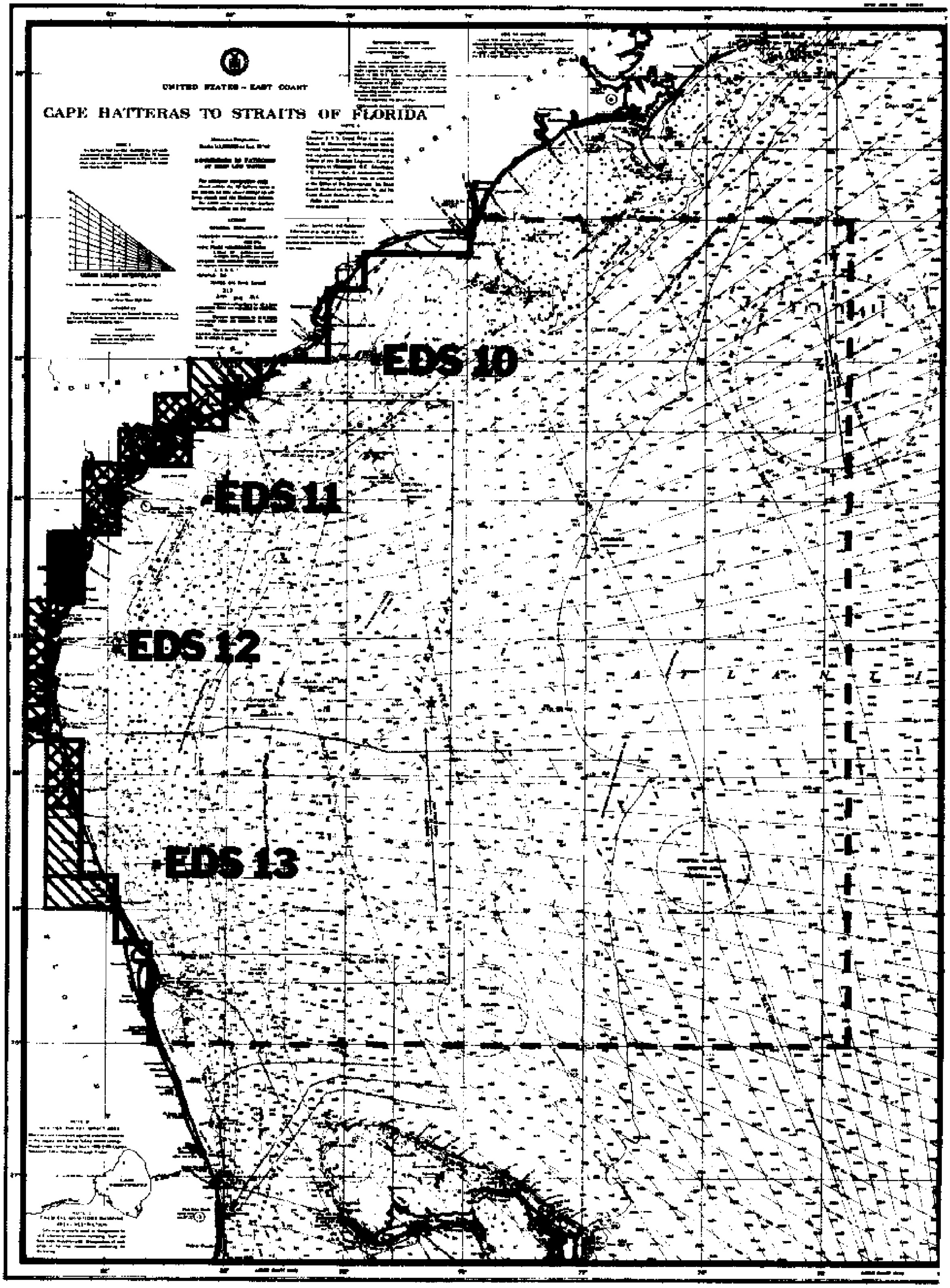
Figure 3.46 summarizes the predicted percent ashore on an annual basis for spills released from EDS 12. This figure also gives us a clue that all is not right with the current specification as it now stands because the drift bottle data tended to have a predominance of recoveries south of the drilling site, not north as in the figure.

Conclusion

Spills occurring at the outer edges of the proposed drilling site areas will almost certainly be relatively unlikely to come ashore. As we get closer to shore, the degree of certainty of our predictions is reduced because we find that our drift bottle data disagree with our simulation model results. The differences are most pronounced in the EDS 10 region. However, over most of the region considered, this should be of relatively minor importance because it would appear that the option to move the leasing areas outwards is viable (geological considerations not considered!).

Should it be desirable to lease in the area closer to shore, then it would appear to be desirable to conduct some intensive drift card studies coupled with some long-term, bottom-mounted current meter deployments in the nearshore area.

Figure 3.46--Average annual percent chance of a spill impacting shore from EDS 12.



< 0.5%

0.5% to 1.0%

1% to 3%

3% to 5%

> 5%

Gulf of Alaska area

Wind

As in the Georges Bank region, there appears to be a marked difference in the behavior of the wind between the spring-summer months and the fall-winter months. Over most of the region, the predominant wind direction is offshore, but in the spring and summer months, this behavior is modified in the nearshore region by the creation of a diurnal onshore sea breeze that typically establishes itself by 10 or 11 in the morning and persists into the late afternoon. The predominant winter wind is from the northeast direction, with the sea breeze typically coming from the southwest during spring and summer.

The importance of this observation is that we should expect the possible trajectories of an oil spill or a drift bottle to exhibit a much broader variation in the spring and summer than in the fall and winter, due to the more strongly varying wind behavior. That is, just as the summer southwesterly that is normally found in the southern New England region provided a mechanism for modifying the usually seaward path of an oil spill or drift bottle released from Georges Bank, so too will the Alaskan sea breeze provide a means for transporting an oil spill against the normally offshore drift established by the non-diurnal portion of the prevailing wind.

Non-wind-related currents

The studies of the geostrophic currents in the Gulf of Alaska provide us with a good estimate of the direction of the long-term flow patterns established by the distribution of mass and surface wind stress in the region (Rosenberg, 1972). The current pattern is typically considered to be composed of two flows, the Alaska Current, and the Subarctic Current. The Alaska Current is found in the northern and western parts of the Gulf of Alaska. It parallels the shoreline, flowing from east to west. It persists up to 200 miles away from the shore or more. Farther offshore, in the region lying from about 47°N to 52°N, the easterly flowing Subarctic Current is found. The strength of these flows is not calculable due to the basic nature of geostrophic calculations. However, reasonable values for this current would appear to be on the order of 1 knot in the region just off Kodiak, and 0.1 knot to 0.5 knot over the rest of the area.

As an added complication to this counterclockwise gyre behavior, Dr. Favorite and his colleagues have noted a strong intrusion of low salinity surface water well out into the central portion of the eastern Gulf (Favorite, 1973). This is indicative of some kind of counterflow to the Subarctic Current. This could be caused by a northward swing of the Subarctic Current such that it traveled toward Yakutat, where it diverged. Part of the flow would then merge with the Alaska Current, while the remainder would head south and perhaps swing out to sea again. This behavior was limited to the winter, apparently, and it seems likely that would not affect the flow off Kodiak or in the region just south of Prince William Sound. Consequently, we limited our range of hypothetical currents to a strong counterclockwise gyre and the null hypothesis. The counterclockwise gyre is depicted in Figure 3.47. Figure 3.48 shows the sensitivity of the total percentage ashore to these assumptions. Note that only the sites off Kodiak appear to be affected. This is

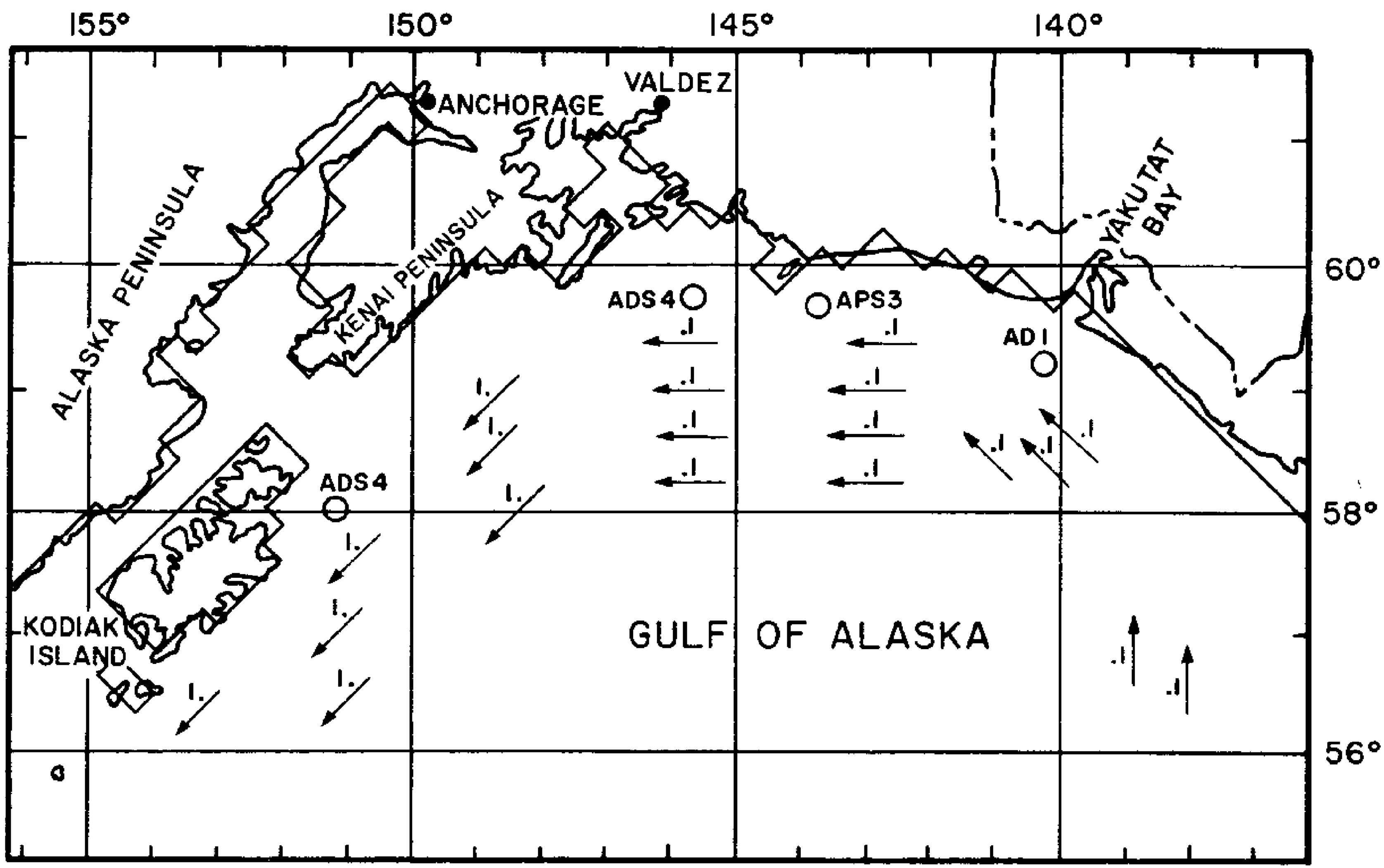


FIG. 3.47 COUNTER CLOCKWISE CURRENT PATTERN USED FOR GULF OF ALASKA SPILL DRAJECTORY PREDICTIONS

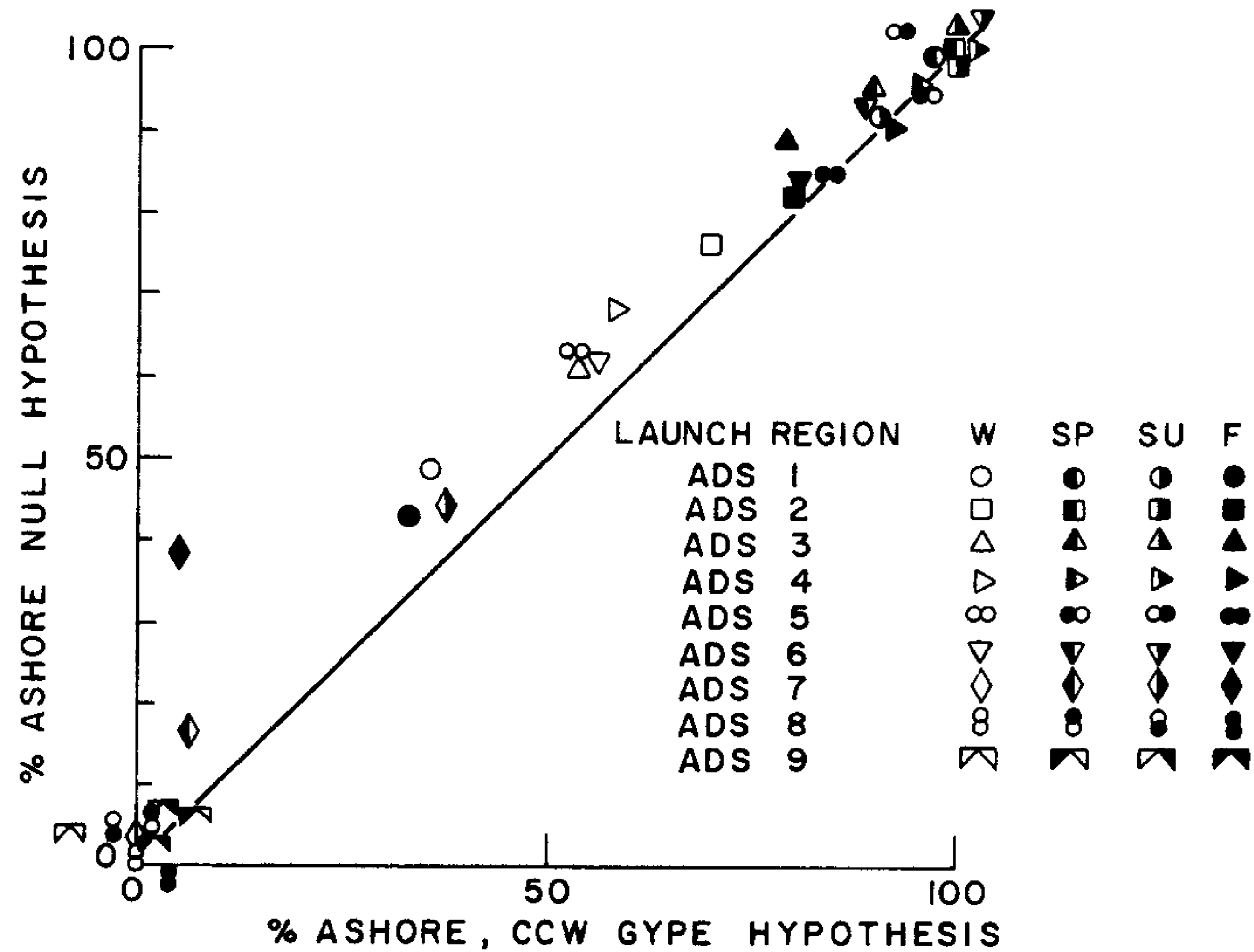


FIGURE 3-48 SENSITNITY TO CURRENT SPECIFICATION
GULF OF ALASKA

comforting because we are most sure of the persistence, direction, and strength of the currents in this area.

Drift bottle data

The most superficial examination reveals that the Gulf of Alaska does not have the wealth of drift bottle information common to many areas on the East Coast. Consequently, the possibility of making impact zone predictions based solely on drift bottle results is denied us; and the degree of validation we can expect for our Monte Carlo simulation is somewhat reduced. However, it is possible to discern some central tendencies in what data there are.

The data base is composed solely of drift bottle experiments conducted in the Gulf of Alaska during the years 1930, 1933, 1934, and 1957. For the purposes of this discussion, the release stations are grouped into geographic regions, as indicated in Figure 3.49 and Tables 3.7, 3.8, and 3.9. These are further divided according to month of release. In addition, there are 11 recovery regions, described in Table 3.10.

The dominant characteristic is the westward movement in the northern regions, in agreement with the generally accepted theory of counterclockwise motion of the primary current in the Gulf. Superimposed on this flow, however, is an apparent seasonal variation of bottle trajectories, as we might expect, based on our discussion of the spring and summer onshore diurnal breeze.

This variation is exhibited in Release Region A. Bottles were released in March 1933 from Stations 42 to 47 near Cape Spencer (Group A_1). Of the 10 bottles returned, eight were recovered in locations east of the Kenai Peninsula (Recovery Regions

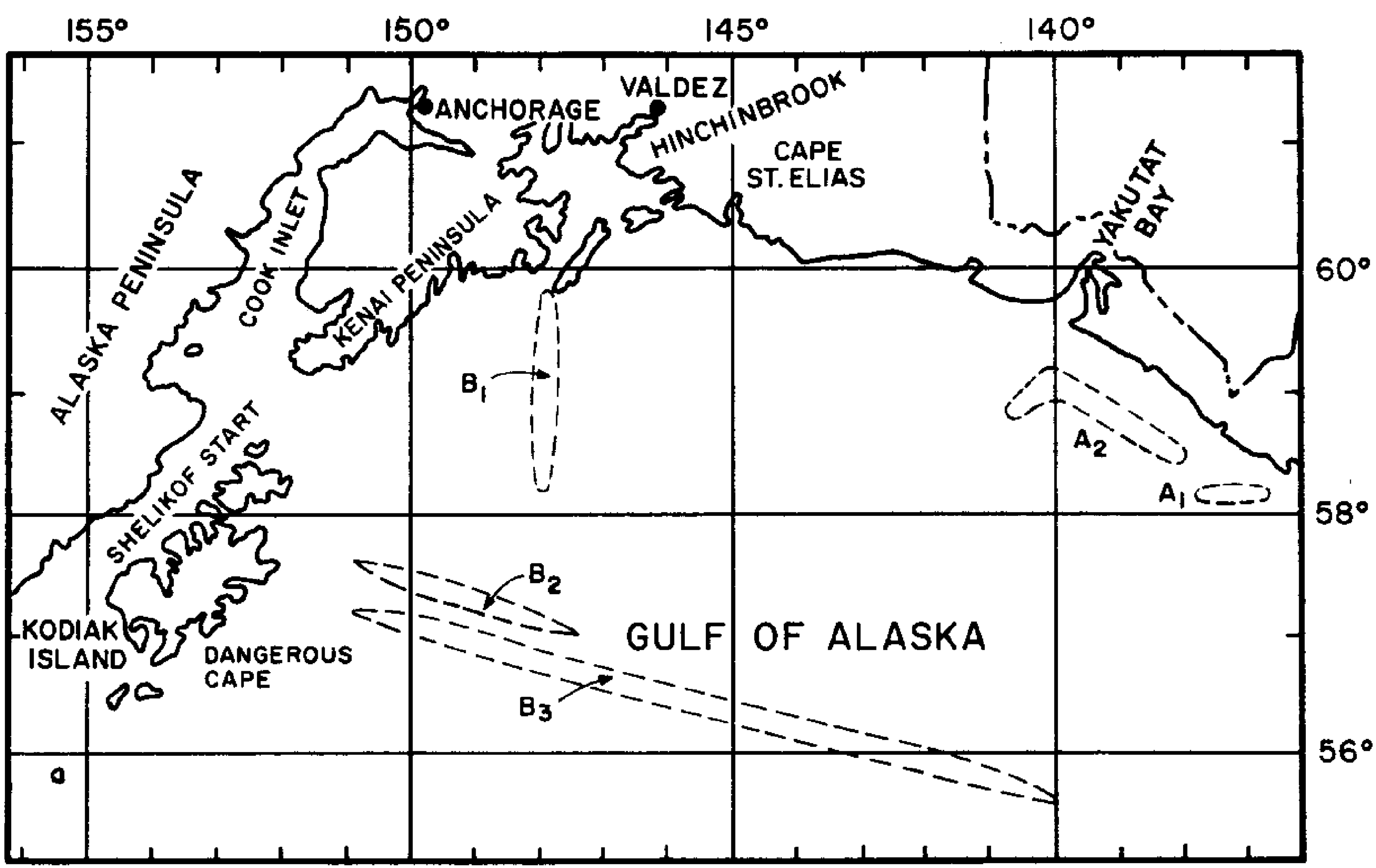


FIG. 3.49 SKETCH OF DRIFT BOTTLE RELEASE AND RECOVERY AREAS IN THE GULF OF ALASK

Table 3.7a

RECOVERIES

Group	Release Locations	Primary Recovery Locations
A_1 (March)	Cape Spencer	Prince William Sound Montague Island Yakutat Bay to Cape Fairweather
A_2 (January)	Yakutat Bay to Cape Spencer (within 70 miles from shore)	Kodiak Island Lower Alaska Peninsula

Table 3.7b

RELEASE REGION A

	Release Station	Recovery Region	Date of Release
	42	11	3/7/33
	42	8	"
	43	3	"
	43	7	"
	43	7	"
A_1	44	5	"
	46	8	"
	46	11	"
	46	11	"
	47	11	"
	23	3	1/26/33
	24	2	1/30/33
	24	3	"
A_2	24	3	"
	53	2	1/29/34
	53	2	"
	54	4	"

Table 3.8a

RELEASE REGION B

Release Station	Recovery Region	Date of Release
25	3	2/16/33
26	3	2/20/33
59	4	2/20/34
59	3	"
62	3	2/25/34
29	2	3/2/33
29	2	"
30	3	"
33	2	"
35	3	3/3/33
35	1	"
36	3	"
39	1	3/4/33
1	2	5/19/30
1	4	"
2	10	"
3	6	"
5	5	"
5	6	"
5	3	"
6	3	5/20/30
6	5	"
7	5	"
7	3	"
7	5	"
8	5	"
10	2	5/21/30
10	10	"
12	1	"
12	2	"
12	2	"
12	2	"
12	2	"
12	2	"
12	4	"
12	2	"

Table 3.8b

RECOVERIES

Group	Release Location	Primary Recovery Locations
B_1 (February)	Along the line extending from the point 30 miles south of Port Bainbridge, southward to the point 120 miles east of Kodiak	Lower Alaska Peninsula
B_2 (March)	From 30 miles east of Kodiak, to 240 miles east of Dangerous Cape	Kodiak Island Alaska Peninsula
B_3 (May)	From 60 miles west of Cape Ommaney to 40 miles east of Dangerous Cape	Kodiak Island Cook Inlet Lower Kenai Peninsula

Table 3.9

RELEASE REGION C

Release Date: 2/17/57
Location: 55°35'N 142°40'W

Recovery Region	Number Recovered
1	20
2	4
3	32
4	1
5	1
6	1
10	1
11	1
Washington	3
Oregon	2
California	2
Charlottes	1
Wake	1

Release Date: 8/17/57
Location: 55°43'N, 142°21'W

Recovery Region	Number Recovered
1	1
2	1
3	1
5	1
6	2

Table 3.10

RECOVERY REGIONS

Region Number	Description
1	Kodiak Island, north of the line from Uyak Bay to Dangerous Cape
2	Remainder of Kodiak Island (southern portion)
3	Alaska Peninsula and Aleutian Islands, south and west of Cape Igvak
4	Shoreline of Alaska Peninsula along the Shelikof Strait, between Cape Douglas and Cape Igvak
5	Shores of Cook Inlet from Cape Douglas to the southwestern tip of Kenai Peninsula
6	Southern shore of Kenai Peninsula, to Port Bainbridge
7	Shores of Prince William Sound from Port Bainbridge to Cape Hinchinbrook, excluding Montague Island
8	Montague Island
9	Shoreline from Cape Hinchinbrook to Cape St. Elias
10	Cape St. Elias to Yakutat Bay
11	Shoreline south and east of Yakutat Bay

7, 8, and 11). Bottles of Group A_2 were released from Stations 23 and 24 in January 1933 and Stations 53 and 54 in January 1934. All recoveries in this group were made south and west of Kenai Peninsula (Recovery Regions 2, 3, and 4). So in the spring there is apparently some enhanced onshore component of the bottle motion, while in the winter this behavior is absent, thus allowing the bottles to be carried southwestward toward Kodiak Island and beyond.

Bottles of Group B_1 were released in February from the area shown in Figure 3.49. Five recoveries were made; four of these were in Region 3, along the Alaska Peninsula beyond Kodiak Island. The bottles of Group B_2 were released in March. Of eight recoveries, five were made on Kodiak Island. The other three drifted to Region 3.

Group B_3 is composed of bottles released in May 1930 from stations across the entire width of the Gulf. Nineteen of the 23 recoveries were made in the area from Kodiak Island to the southern end of Kenai Peninsula and Cook Inlet. Three bottles were recovered from Region 3, and one was found near Cape St. Elias.

From these data, it appears that in February bottles released from as far north as Montague Island were carried south and around Kodiak. In March about half the bottles were carried due west. By the end of May the onshore drift was well developed, and some bottles attained a northerly component of drift.

The third series of releases to be considered is that of February 17 and August 17, 1957, from the position shown in Figure 3.49. Six recoveries were made from the August experiment; five were found in the vicinity of Kodiak Island and Kenai Peninsula, and one was recovered on Chirikof Island, south of Kodiak.

There were 71 returns from the February experiment. Thirty-two were from Region 3, 24 from Kodiak Island. The rest were scattered with no substantial number from any particular area.

While a number of hypotheses may be developed to explain this behavior, it is clear that our hypothesis relating the onshore drift to the presence (or absence) of the onshore sea breeze does explain qualitatively the behavior. Further, the drift was invariably to the west, in agreement with the known behavior of the Alaska Current.

Impact assessment

It was found that the counterclockwise gyre current hypothesis best matched the observed drift bottle behavior. Consequently, the launch site sensitivity assessment was based on this current hypothesis. Figures 3.50 through 3.53 show the seasonal probabilities that an oil spill will impact shore somewhere in the Gulf of Alaska as a function of the distance from shore. ADS 1, 3, 4, and 7 were selected for these traverses as they appeared representative of adjacent drilling sites. Notice that only the launch site off northeastern Kodiak (Figure 3.53) shows an appreciable dependence on distance from shore. This is due to the strong southward flow imparted by the Alaska Current and the rather limited southward extent of Kodiak Island and the Trinity Islands. If the current is able to drive the spills south quickly enough, only a few will have time to travel to the west and strike these shorelines.

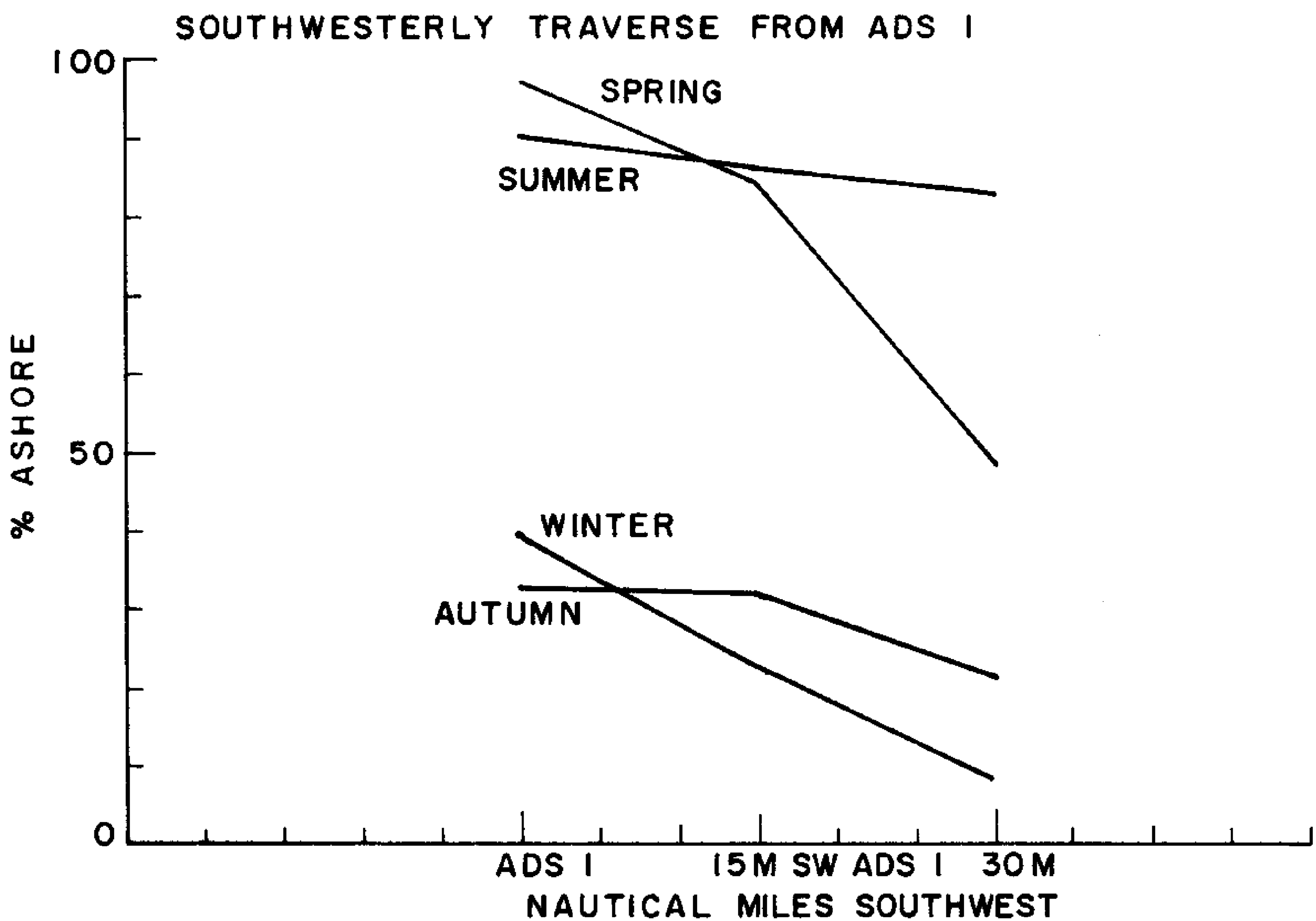


FIGURE 3.50 DEPENDENCE OF PROBABILITY OF A SPILL IMPACTING SHORE ON THE DISTANCE FROM SHORE OF THE SPILL LAUNCH SITE

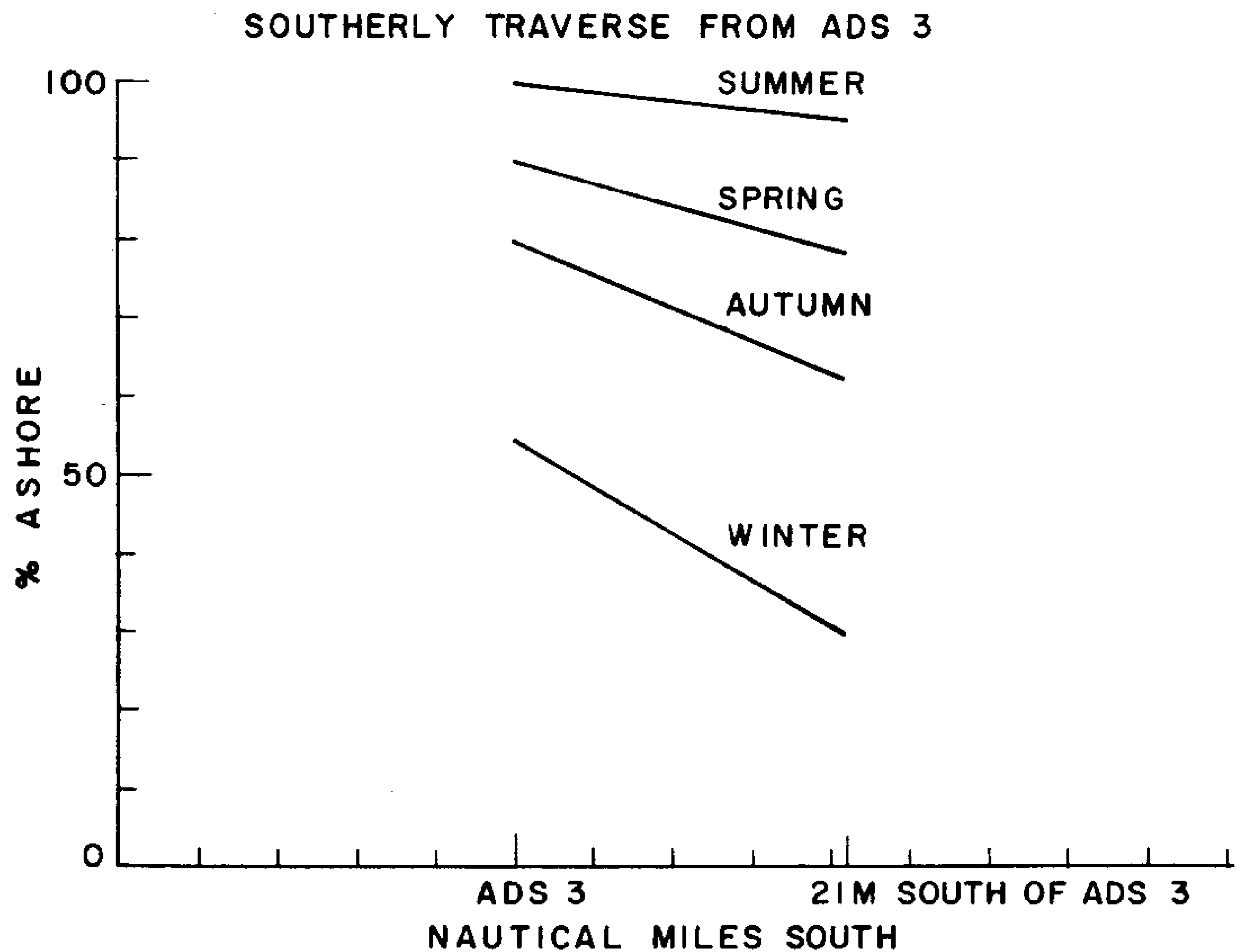


FIGURE 3.51 DEPENDENCE OF PROBABILITY OF A SPILL IMPACTING SHORE ON THE DISTANCE FROM SHORE OF THE SPILL LAUNCH SITE

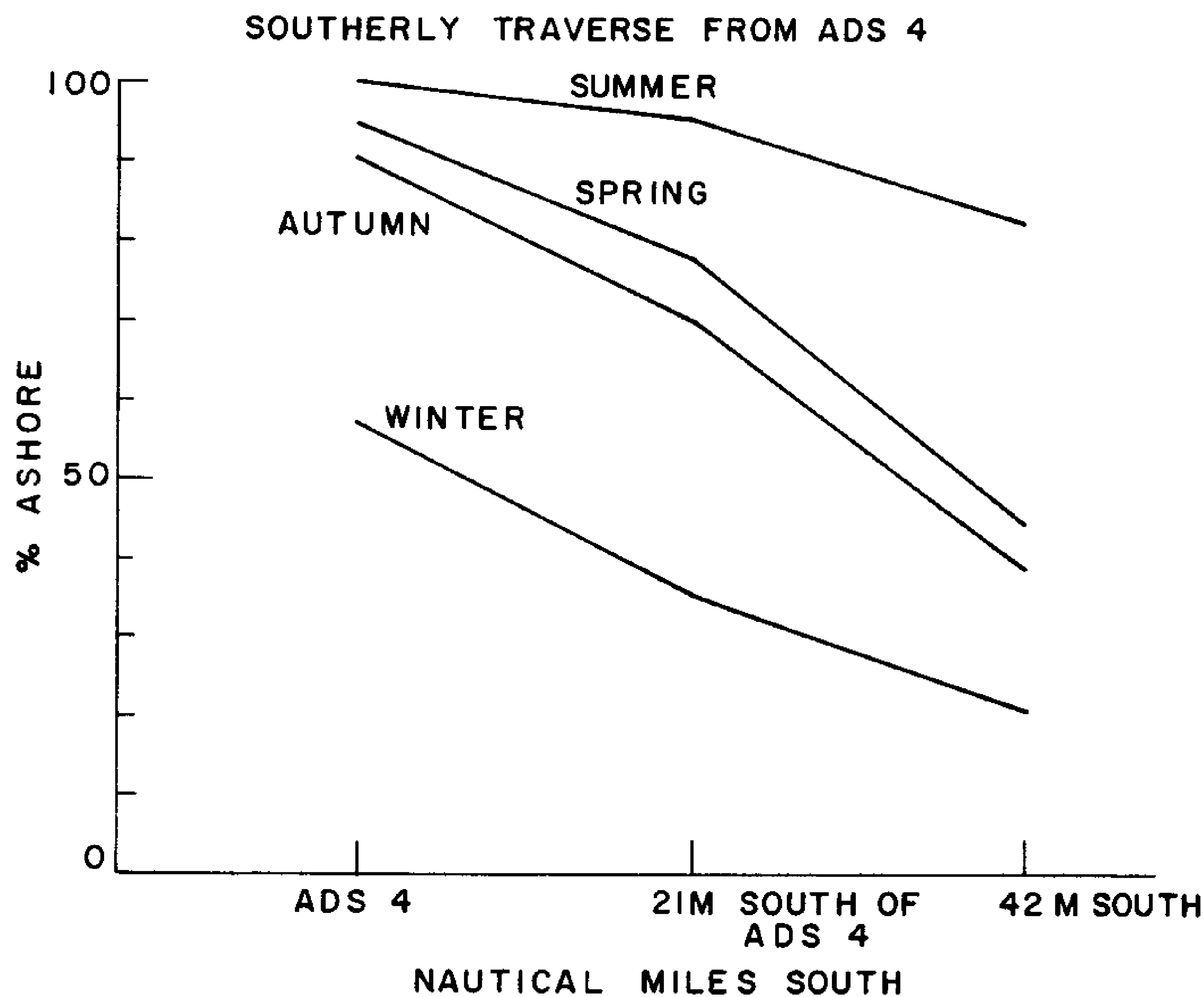


FIGURE 3.52 DEPENDENCE OF PROBABILITY OF A SPILL IMPACTING SHORE ON THE DISTANCE FROM SHORE OF THE SPILL LAUNCH SITE

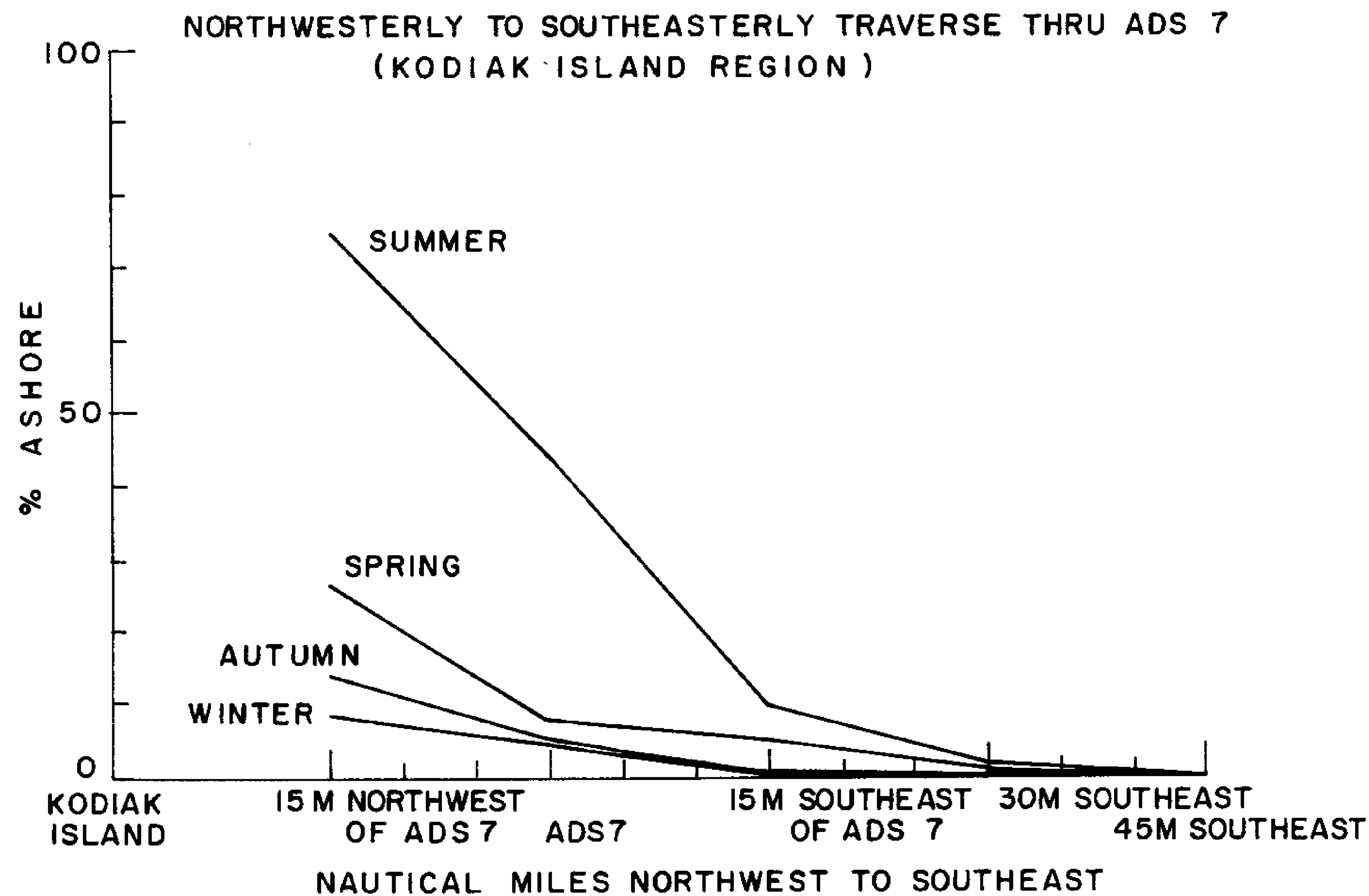


FIGURE 3.53 DEPENDENCE OF PROBABILITY OF A SPILL IMPACTING SHORE ON THE DISTANCE FROM SHORE OF THE SPILL LAUNCH SITE

Figure 3.54 indicates the probability on an annual basis that an oil spill released from ADS 4 will impact the boundaries of one of the 15 nautical mile square grid elements used to represent the land area in the Gulf of Alaska. This is a rather typical picture for the six easternmost drill sites. Notice the rather dispersed pattern of impacts in the regions lying to the west and north. Minimum times to shore for this region run in the three- to 20-day range, while average times to shore run in the neighborhood of 20 to 30 days. The model did predict some difference between seasons in the time to shore and the location of impact zones, but they were not very pronounced. The probability of hitting shore is, of course, highly seasonal as we can see from Figures 3.50 to 3.52.

The trajectory behavior for the drilling sites off Kodiak is somewhat different, as we might expect. Here we get both strong seasonal differences, and a very pronounced localization of the impact areas. This localization is depicted in Figure 3.55, which is the probability on an annual basis that a spill released from ADS 7 will impact the boundaries of one of the 15 nautical mile square grid elements representing the Alaskan shoreline.

Figure 3.56 depicts the geographical location of the launch points utilized in Figures 3.52-3.53.

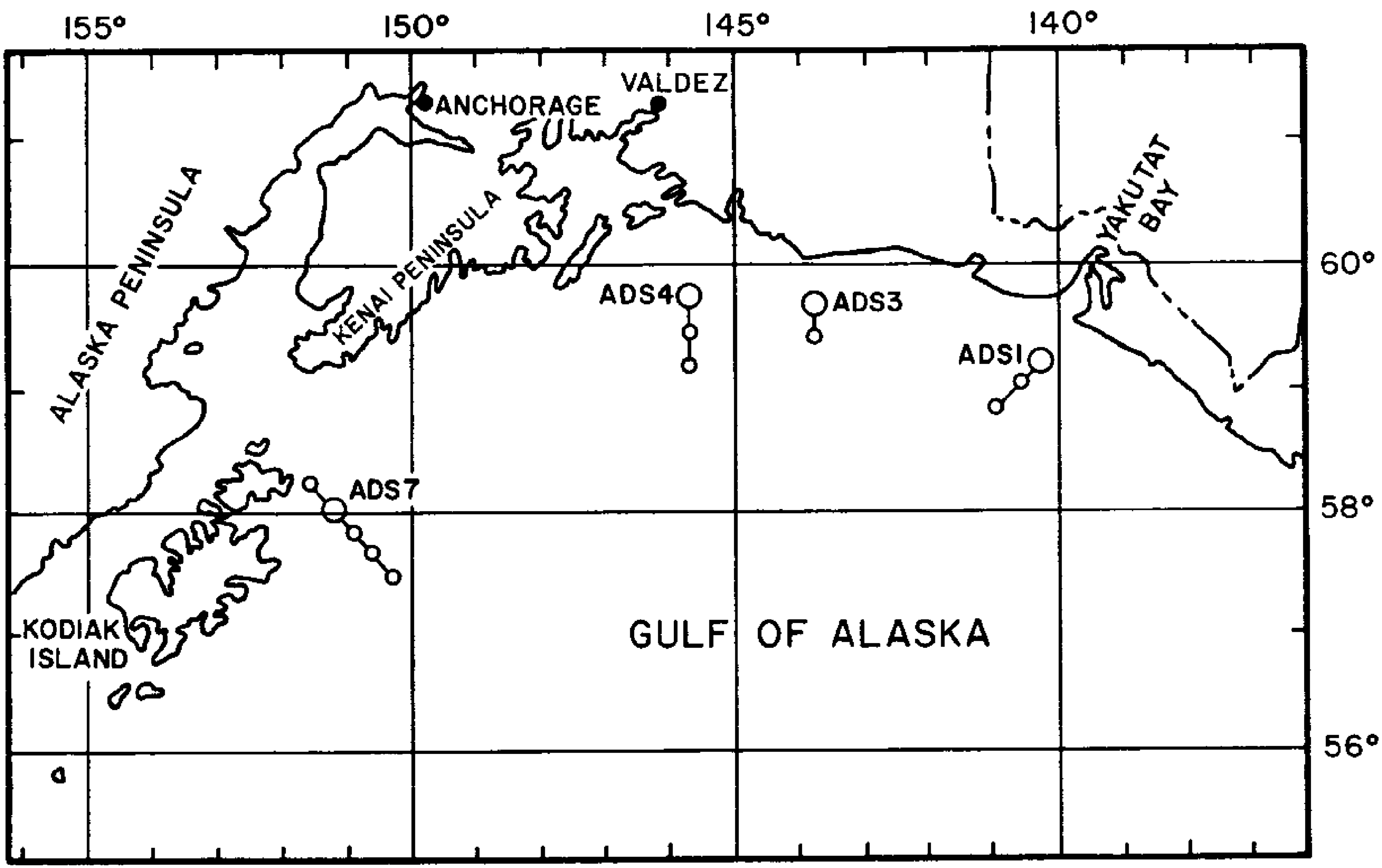


FIG.3.56 LOCATION OF POINTS IN THE GULF OF ALASKA REGION FOR WHICH DETAILED TRAJECTORY CALCULATIONS WERE MADE.

BLANK

Other considerations: time dependence

The analysis to this point has dealt solely with the problem of determining where the spill will go due to the combined actions of the wind, waves and currents. There are, however, natural processes that, given sufficient time, tend to mitigate the effect of a spill upon beaching on a coast or entering an estuary. These processes are principally the evaporation of the lighter fractions into the atmosphere, the dissolution of the soluble fraction into the water, and the breakdown of the larger oil slicks into ever smaller and more numerous patches by the action of the ambient turbulence.

Unfortunately, the relative importance of these processes in any given spill may only be determined once we have some idea of the volume of oil spilled, the rate at which the oil was released, and the chemical and physical properties of the oil.

As Devanney et al. discuss in the spill probability section of this report, the volume of a spill can vary widely. Not discussed, but equally true, is the fact that the rate at which the oil is released may vary widely, from the near-instantaneous release of oil from a badly ruptured tank to the steady release of oil from an uncapped subsurface well. Moreover, the variability in the composition of crude oil is so great that some of the very light crudes might be expected to volatilize completely within a few days to several weeks. Other crudes are very much like asphalt and are barely buoyant. These will remain intact over very long periods of time. Thus, it is difficult to fix upon any particular spill scenario that would allow us to generalize on the problem. Perhaps the most sweeping generalization we can justify is that, if spills take a very long time to reach shore, then, under some circumstances, the weathering processes could ameliorate the effect of the oil on beaching. Thus the time required for a spill to reach shore is of general importance, but the specific implications are dependent on several other parameters.

The minimum and average times for spills beaching for each of the seasons are shown in Table 3.11. The minimum observed times for the Atlantic coast sites run in the neighborhood of five to seven days for EDS 4 (nearly all seasons), EDS 5 (spring and summer), EDS 11 (spring), and EDS 13 (most seasons). This minimum value is a fairly crude estimate of the true minimum due to the rather limited sample sizes. However, the values are certainly in the right ballpark and they do illustrate the problem.

Within such a one-week period we can reasonably expect smaller spills (less than 10,000 gallons, say) to be well dispersed and fairly well weathered, at least with respect to the low boiling fractions in the oil. In fact, there are some crudes that are composed of such low boiling fractions that most visible traces of these spills might be gone within this time. On the other hand, if the oil is made up of very high boiling fractions, or if a very large amount is spilled, then the oil might still be concentrated in a few large patches and identification of the spill would still be possible.

If we can shift our time frame from one week to many weeks or several months, then we can be reasonably confident that, except for the very largest spills, the oil will be substantially dispersed over a large area, and the larger patches will have been replaced by tar balls and other remnants. These

Table 3.11

Minimum and Average Times to Shore for
Hypothesized OCS Drilling Sites
(days)

OCS Drilling Site	Winter		Spring		Summer		Fall	
Atlantic Coast	Min	Ave	Min	Ave	Min	Ave	Min	Ave
EDS 1	88	126	56	106	-	-	83	83
2	109	126	57	99	106	112	-	-
3	110	129	20	77	32	77	24	38
4	7	91	7	54	9	40	6	35
5	-	-	6	20	6	12	-	-
6	46	76	61	90	82	88	-	-
7	46	87	59	86	61	82	-	-
8	55	87	54	85	47	73	-	-
9	-	-	-	-	-	-	-	-
10	22	64	10	40	11	29	-	-
11	20	85	6	36	9	33	54	73
12	35	110	21	81	18	60	17	43
13	8	62	7	64	9	57	5	16
Gulf of Alaska	Min	Ave	Min	Ave	Min	Ave	Min	Ave
ADS 1	39	88	23	70	19	64	39	80
2	11	30	11	25	9	29	11	33
3	3	27	4	34	5	21	3	30
4	7	30	8	29	6	26	7	22
5	5	28	6	28	8	27	6	22
6	4	22	5	22	6	25	6	20
7	5	13	16	36	12	27	8	15
8	-	-	7	19	26	43	-	-
9	4	5	6	11	13	17	7	9

spills will have a somewhat reduced impact upon beaching.

As we can see from the table, with the exception of the four sites mentioned and EDS 10, all the remaining Atlantic drilling sites exhibit fairly large minimum times to shore. Thus, we can make a fairly clear distinction between EDSs 4, 5, (10), 11, and 13 and the remaining Atlantic coast sites on the basis of the minimum time to shore. Notice also that the average times to shore for these same sites are systematically lower than for the other sites. Since these same sites also exhibit the highest probability of a spill beaching, it is fairly clear that they represent the least desirable selection on the Atlantic coast from the standpoint of oil spill impact on the neighboring shoreside communities.

In the Gulf of Alaska we find that all of our time scales are greatly reduced. Minimum times commonly run in the range of one week, although two- to four-week minimum times are observed for ADSs 1, 7 and 8. Average times run from two weeks to three months with a typical value being around 30 days. Here we can expect a good percentage of the oil spills to come ashore while still reasonably intact.

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THE ROLE OF MASS TRANSPORT IN OIL SLICK WEATHERING

by

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Report to
Council on Environmental Quality

April 1974

THE ROLE OF MASS TRANSPORT IN

OIL SLICK WEATHERING

TABLE OF CONTENTS

THE ROLE OF MASS TRANSPORT IN OIL SLICK WEATHERING

1. Introduction

This report examines the present state of knowledge with respect to mass transport and its effect on the composition of petroleum in an oil slick. In this document we do not address photochemical and biochemical changes in the compounds themselves. Generally speaking, these chemical processes operate on time scales which are at least an order of magnitude longer than the processes with which we will be dealing.

2. Spreading

The only coherent model of oil spill spreading of which we are aware is the Fay-Hoult description (Hoult, 1972), which treats the oil as a fluid of homogeneous density, viscosity and surface tension. The Fay-Hoult model identifies three regimes of spreading: in order, the inertial, the viscous, and the surface tension; and develops rates of spreading for each of these three regimes. This model has proven useful in developing engineering estimates of the overall size of a spill of a given volume as a function of time and order-of-magnitude estimates of the size of a spill after spreading ceases. Figure 2.1 shows the estimates for three spill sizes on the Georges Bank: 30 million gallons (approximately "Torrey Canyon"), 3 million gallons (approximately Santa Barbara), and 3 hundred thousand (approximately three times West Falmouth). Figure 2.2 shows these same final areas close to shore.

Unfortunately, when we consider the effect of spreading on weathering, we require a more detailed description of the phenomenon. It is an experimental fact that oil does not spread as a single homogeneous liquid; rather, it appears to fractionate on the surface. Often this phenomenon takes the form of a single central "glob" surrounded by a "film". The thickness of the glob may be three orders of magnitude that of the surrounding film. Sometimes the phenomenon takes the form of a number of individual globs, each surrounded by its own film. When dispersant is added, still more complicated phenomena are observed. This surface fractionation is important to spill weathering for several reasons:

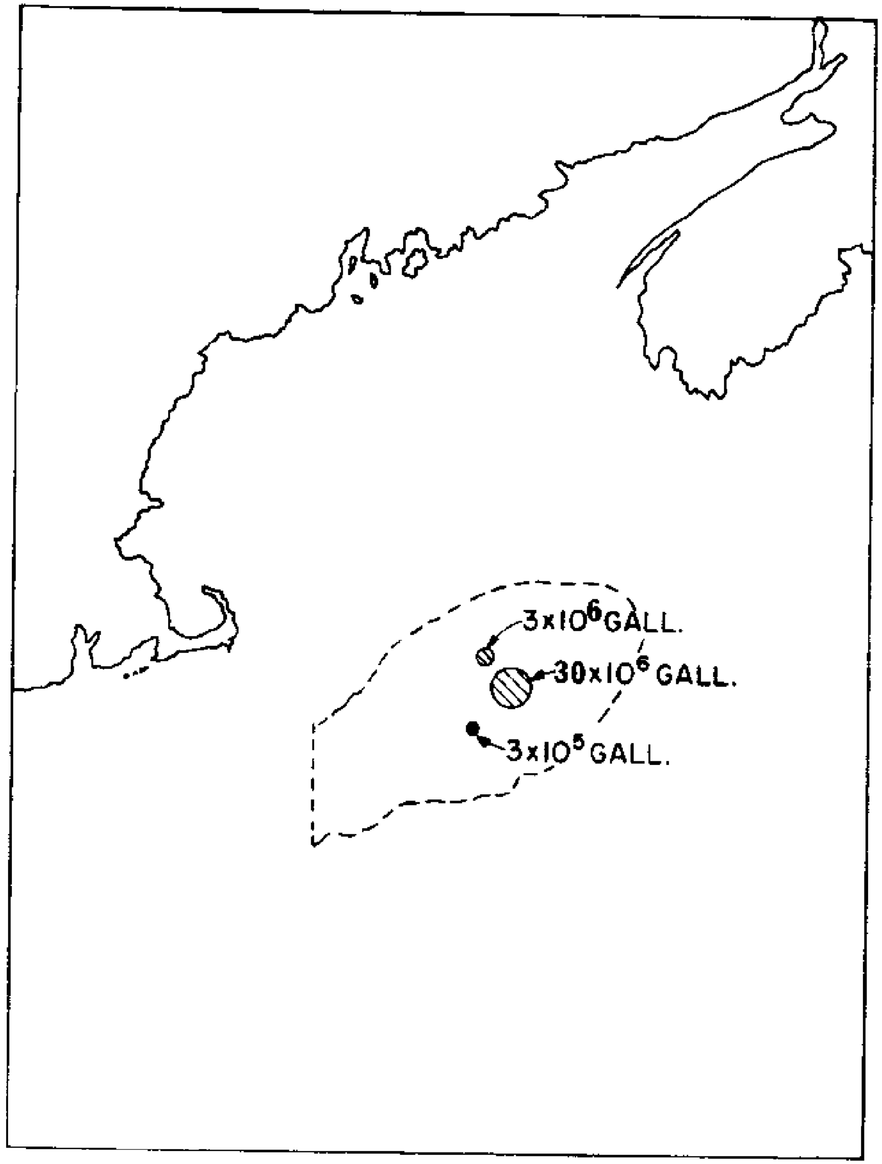

Figure 2.1
Example of the areal extent of spills after spreading ceases.

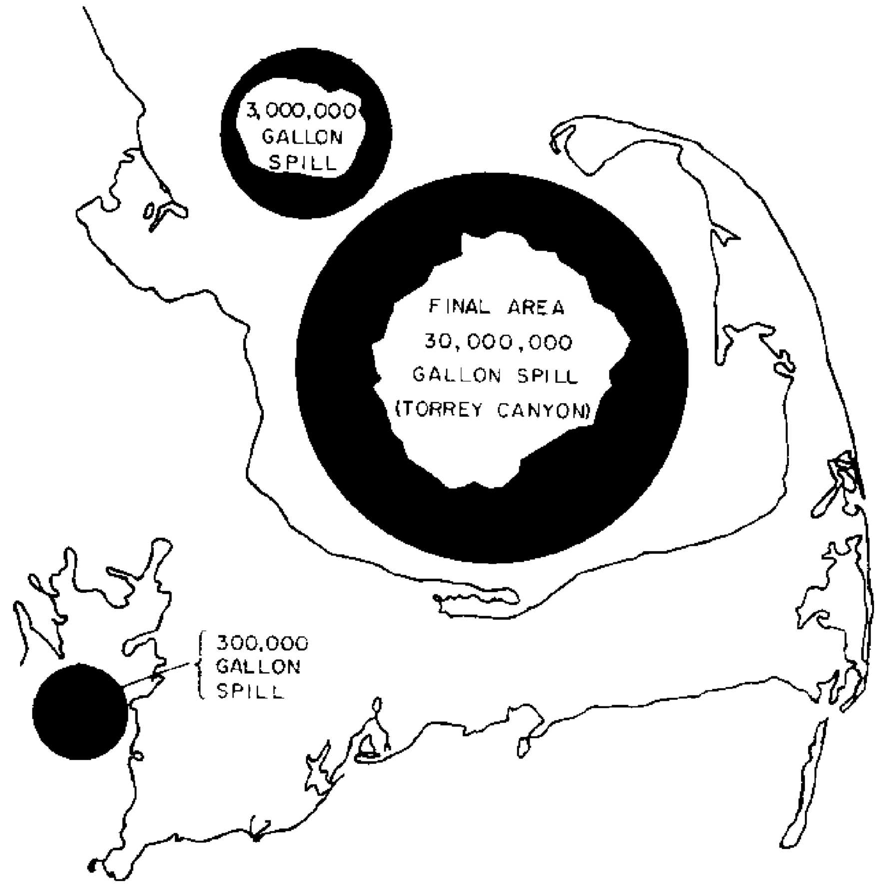

Figure 2.2
Examples of the areal extent of spills after spreading ceases.

1. Whether or not the compounds in the film are the low surface tension, highly soluble constituents, as we suspect, will make a great difference in the time history of the concentrations of these more toxic compounds which the biota will face.

2. Since the slick thickness will be markedly different from that which would result under homogeneous spreading, the evaporation and diffusion into the water column will be different from that without the fractionation.

With respect to 1, we have, with the aid of the Coast Guard, attempted to sample the glob and the film. However, our film samples were not trustworthy, so no real evidence is available as to the relative composition of the thicker and thinner parts of the slick. Experimental work in this area is definitely indicated. We will address Issue 2 in the next section.

3. Vertical diffusion

3.1 Introduction

Systematic, quantitative data on the biological effects of various constituents of petroleum are just beginning to become available. However, Moore et al. (1973) and the Offshore Oil Task Group (1973) have surveyed the available data and concluded that except for coating, it is the soluble aromatic fraction in the oil which is the most harmful. Recently, Anderson (1973) has done experiments corroborating this conclusion.

In this section, we concentrate on two such compounds: benzene and naphthalene. A simple model has been developed to gain insight into the process of diffusion of these two compounds from an oil slick.

3.2 Formulation

The system is modeled as shown in Figure 3.1. The air, oil slick, and water consist of five regions of different properties. The top layer of air is assumed to be turbulent, reflecting atmospheric winds and currents. Just above and below the slick are thin laminar boundary layers in which there is molecular diffusion. The slick itself is also assumed to be laminar. The bottom region is turbulent water where bulk mixing is the predominant means of diffusing dissolved hydrocarbons.

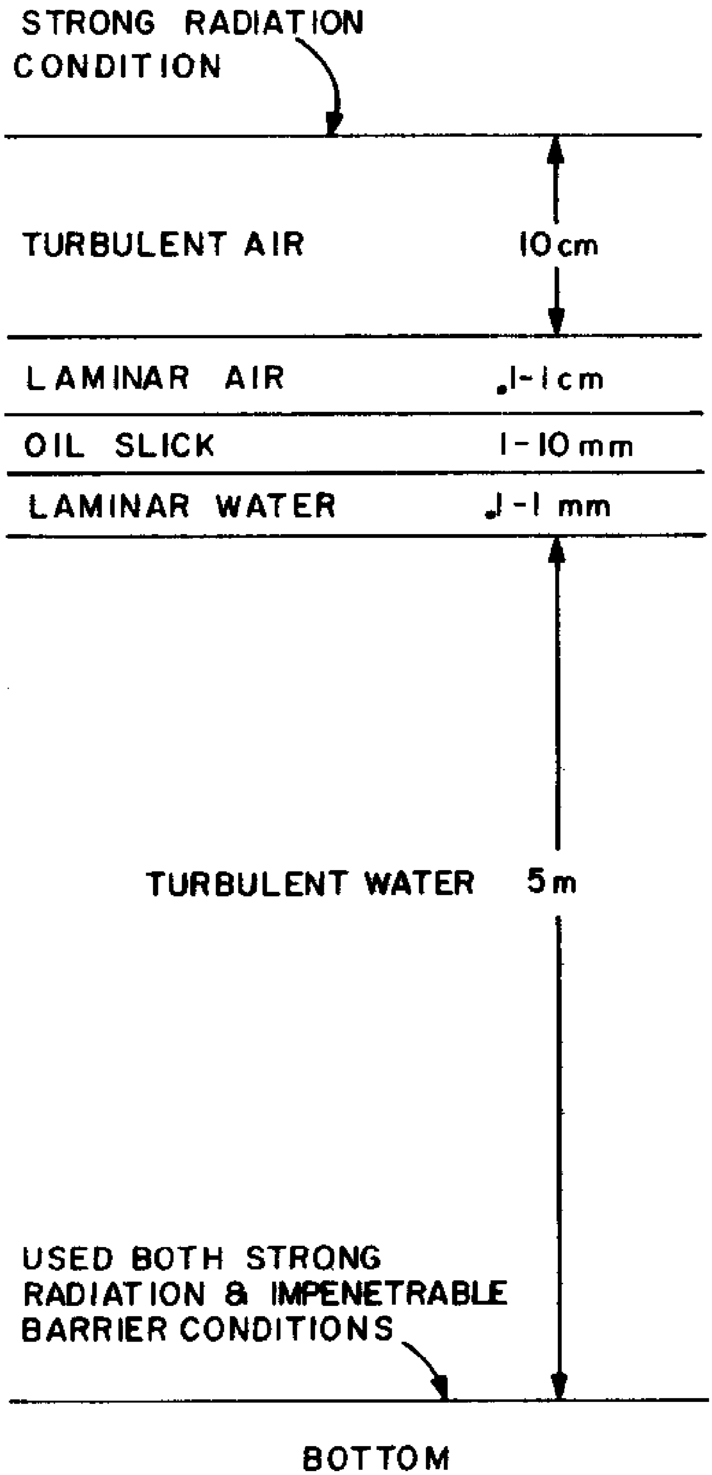

FIGURE 3.1 SCHEMATIC OF DIFFUSION MODEL

Within each region the governing partial differential equation is the diffusion equation,

$$\frac{\partial c}{\partial t} = D \frac{\partial^2 c}{\partial x^2}$$

where c is the concentration and D is the diffusivity coefficient. At the top and bottom boundaries it is assumed that the rate of mass transfer is proportional to the difference in concentration across the boundary (Crank, 1964):

$$D \frac{\partial c}{\partial x} = -h(c_a - c_b)$$

The atmosphere and water column are modeled as infinite media in this manner. If finite depth is desired for the water, then at the bottom h is set equal to zero. It will be shown that the solution in the water is insensitive to a wide range of h.

Two conditions must be specified at each interface (Crank, 1964). One is mass continuity,

$$D_a \frac{\partial c_a}{\partial x} = D_b \frac{\partial c_b}{\partial x}$$

The other deals with the concentration on both sides of the interface,

$$c_a = kc_b$$

where k is the relative solubility of the hydrocarbon in the two media. Therefore, at the air-air and water-water interface k equals 1.

The method of numerical solution is described in the appendix.

3.3 Physical constants

The diffusion of benzene and naphthalene from an oil slick is to be simulated. Benzene was selected because of its high solubility, naphthalene because of its high toxicity. In order to implement the model outlined in section 3.2, we require values for the thickness of each layer, the diffusivities within each layer, the solubility ratios between oil and water and oil and air for the constituents of interest, and the evaporation (absorption) rate controlling transport across the outermost boundaries. Research is needed to determine these values, especially the boundary layer thickness and the solubility ratios. In the meantime, the arguments outlined below were used to obtain ballpark estimates of the needed parameters.

Preliminary trial runs revealed that the thickness of the air boundary layer thickness did not have a critical effect on water column concentrations. The effect of an order of magnitude change in this thickness after one hour of simulated diffusion was less than 10% in the slick concentration and less than 5% in the water. Since computation costs increase inversely as the square of this distance (Salvadori et al., 1961), it was fixed at 1 cm.

The other thicknesses used were: turbulent air, 10 cm; oil slick, 1 mm; turbulent water, 5 m. The diffusion coefficient of gases in turbulent air is certainly greater than 10 cm^2/sec, the value chosen for the runs. Trial runs indicated that the turbulent air was nearly homogeneous for this value, so any greater value would not result in a significant change. The minimum value for the diffusion coefficient of gases in quiescent air was 0.089 cm^2/sec (Hodgman, 1960). Minimum values for all the air diffusion coefficients were chosen because they represent the worst case from the point of view of the biota in the water column. For the slick, laminar water, and turbulent water the diffusivities were put at 1.0×10^{-5}, 0.44×10^{-5} (Witherspoon et al., 1969), and 0.2 cm^2/sec (Ichiye et al., 1972) respectively.

The least sensitive of all the variables were the h's, controlling the evaporation rate at the uppermost and lowest boundaries. As long as the evaporation rate was large on the top of the turbulent air, simulating strong radiation to an infinite atmosphere, there was no change in the solution for the slick or water. The evaporation rate on the bottom of the turbulent water was generally set to zero, simulating an impermeable sea floor, but sensitivity runs were made with this variable quite large. Only small differences in water column concentrations were observed.

In order to arrive at an estimate for the solubility ratios it was assumed that these ratios are independent of concentration. From Dalton's law of partial pressure we can arrive at an estimate of the molar density of an equilibrium mixture of either benzene or naphthalene in air:

$$\frac{n}{v} = \frac{p}{RT} \text{ gmole/cm}^3$$

Under these assumptions, the equilibrium density in air in gm/cm^3 is the above molar density multiplied by the molar weight of the substance. The vapor pressures of benzene and naphthalene at 15°C are approximately 60 mm Hg and 1 mm Hg respectively (Rossini et al., 1953). This implies that above a pure mixture of either substance we would observe an equilibrium density of 3×10^{-4} gm/ml (benzene) and 6×10^{-6} gm/ml (naphthalene). The assumption is that this ratio of densities in the air to that in the pure benzene (naphthalene) slick will remain constant, whatever the actual density of benzene (naphthalene) in the slick is. The quotient of these two densities is the solubility ratio.

The same assumptions are used with respect to the slick-water interface. The solubility of benzene in sea water is approximately 1.25×10^{-3} gm/ml (McAuliffe, 1966 and 1973) and of naphthalene is 3×10^{-5} (Hodgman, 1960). Therefore, the range of ratios of the solubility in water is 700 to 38,000.

Two theoretical approaches lead to approximations for the water boundary layer thickness. The first is the solution to the boundary layer thickness of a flat plate oscillating at frequency ω (Batchelor, 1967),

$$\ell = \sqrt{2\nu/\omega}$$

where ν is the kinematic viscosity of the fluid, 0.012 cm^2/sec for sea water (Mandel, 1969). For capillary waves in the ocean, the maximum frequency is approximately 100 rad/sec. For these values, $\ell \geq 0.011$ cm.

The second approach was from a dissipation of energy standpoint (Kraus, 1972). Assume that the boundary layer thickness is that distance below the slick where the dissipation of energy in the turbulent field is equal to the dissipation in the laminar field. For a turbulent field,

$$\epsilon_t = \frac{\rho u^3}{kz}$$

where ε is the dissipation, ρ is the density, κ is Van Karman's constant, z is depth, and u is the shear velocity,

$$u = \sqrt{\frac{\tau}{\rho}}$$

where τ is the shear stress. For a laminar field,

$$\varepsilon_\ell = \frac{u\mu}{\ell}\frac{\partial u}{\partial z}$$

where μ is the viscosity and ℓ is measured in the z-direction. Equating the two and presuming a constant stress boundary layer (Kraus, 1972), so $u = \beta\ell$,

$$\beta^2\mu = \frac{\rho u^3}{\kappa\ell}$$

Substituting the above expression for u and making use of a constant stress boundary layer,

$$\ell = \nu\kappa\sqrt{\frac{\rho}{\tau}}$$

The density of sea water is approximately 1 gm/cm^3, $\kappa = 0.4$ and a typical shear stress in the boundary layer is 1 $dyne/cm^2$ (Dorman, 1971). The second approach leads to an approximation of 0.005 cm for the boundary layer thickness.

Runs were made using 0.01 and 0.1 cm as the range of the boundary layer thickness because of the excessive cost of going down to 0.005 cm. Table 3.1 is a summary of the constants used for the runs.

Figure 3.2 shows the concentration profiles in the water column through time for the first 12 hours for benzene given our best estimates of the solubility ratios and diffusivities for a water boundary layer thickness of .1 cm and an oil slick thickness of .1 cm. The horizontal axis shows concentration relative to the initial concentration in the slick, that is, the reduction in concentration. The diffusion

	D, cm^2/sec	L, cm
Turbulent air	10	10
Air boundary layer	0.089	1
Oil slick	1×10^{-5}	0.1
Water boundary layer	0.44×10^{-5}	0.01-0.1
Turbulent water	0.2	500

Solubility ratios:

air/oil	$3 \times 10^{-4} - 6 \times 10^{-6}$
oil/water	38,000 - 700

Table 3.1
Values Used in Simulations

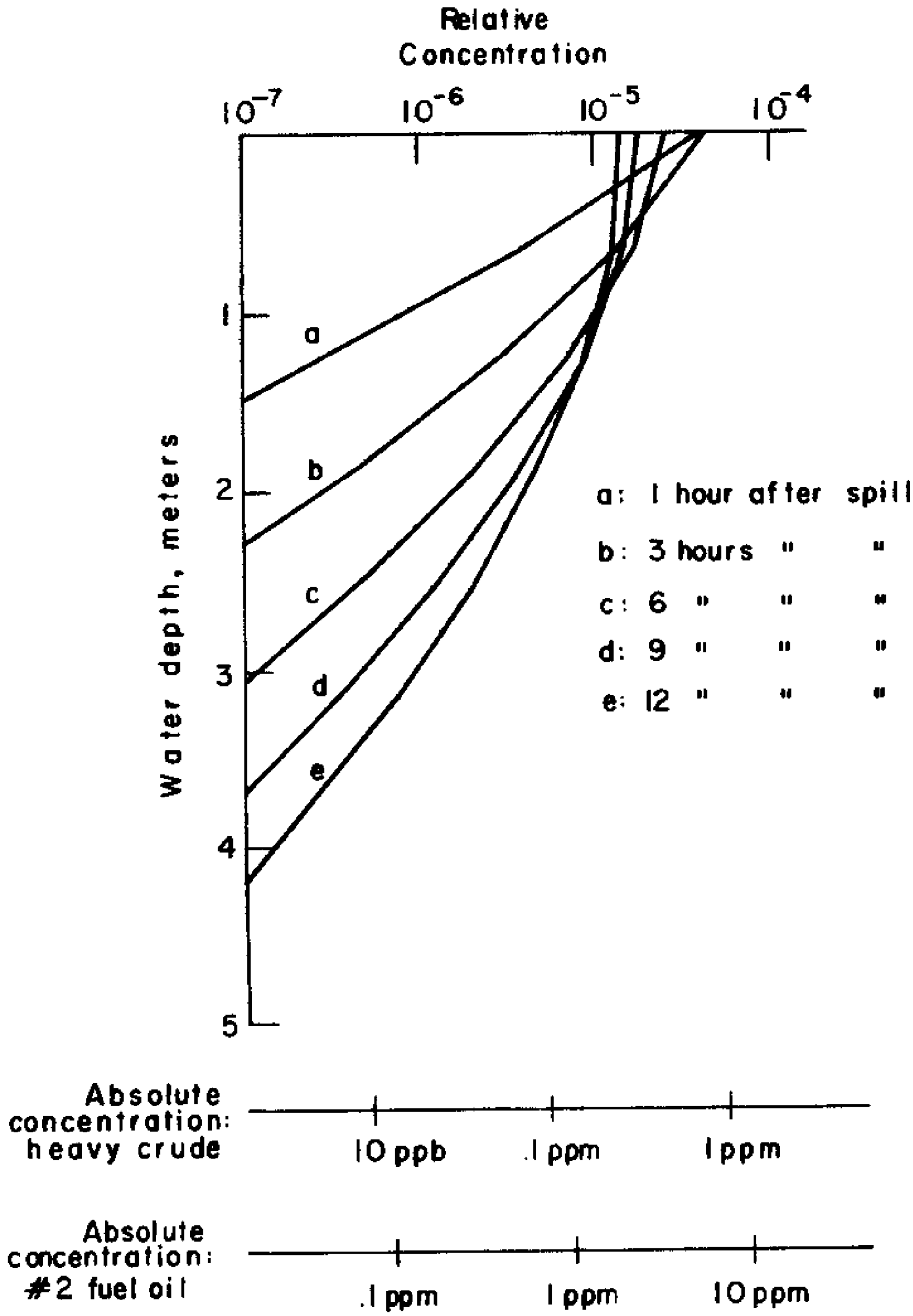

Figure 3.2--Concentration profiles of benzene, water boundary layer thickness .01 cm. (Absolute concentrations based on typical initial slick concentrations given in Table 3.2)

model is linear in the initial concentration. In order to interpret this number, typical initial concentrations of benzene and naphthalene are shown in the following table. These initial concentrations have been reflected in the absolute concentration axes shown at the bottom of Figure 3.2 and succeeding graphs.

TABLE 3.2

TYPICAL CONCENTRATIONS OF BENZENE AND NAPHTHALENE

	Heavy Crude	Medium Crude	#2 Fuel Oil
Benzene	2	5	15
Naphthalene	6	3	5

Thus, for crudes, Figure 3.2 indicates concentrations of about 1 ppm immediately under the slick, dropping off to about 10 ppb 3 meters deep. These concentrations, while small, are still definitely of interest to biologists. Moore (1973) estimates the sublethal range of benzene to reach as low as 10 ppb to 1 ppm and the lethal range as low as 10 ppm.

Under our model, these concentrations can persist for some time. In Figure 3.3, we show the long-range behavior assuming an impenetrable bottom at 5 meters. Figure 3.4 shows the same behavior assuming the bottom absorbs all benzene it comes in contact with. This is an attempt to simulate infinite depth. As indicated, the bottom assumption is of little or no importance. In both cases, after about 2 days the concentration is practically constant top to bottom and then, very slowly, begins dropping at the top as benzene gets sucked from the water column through the slick into the air. The

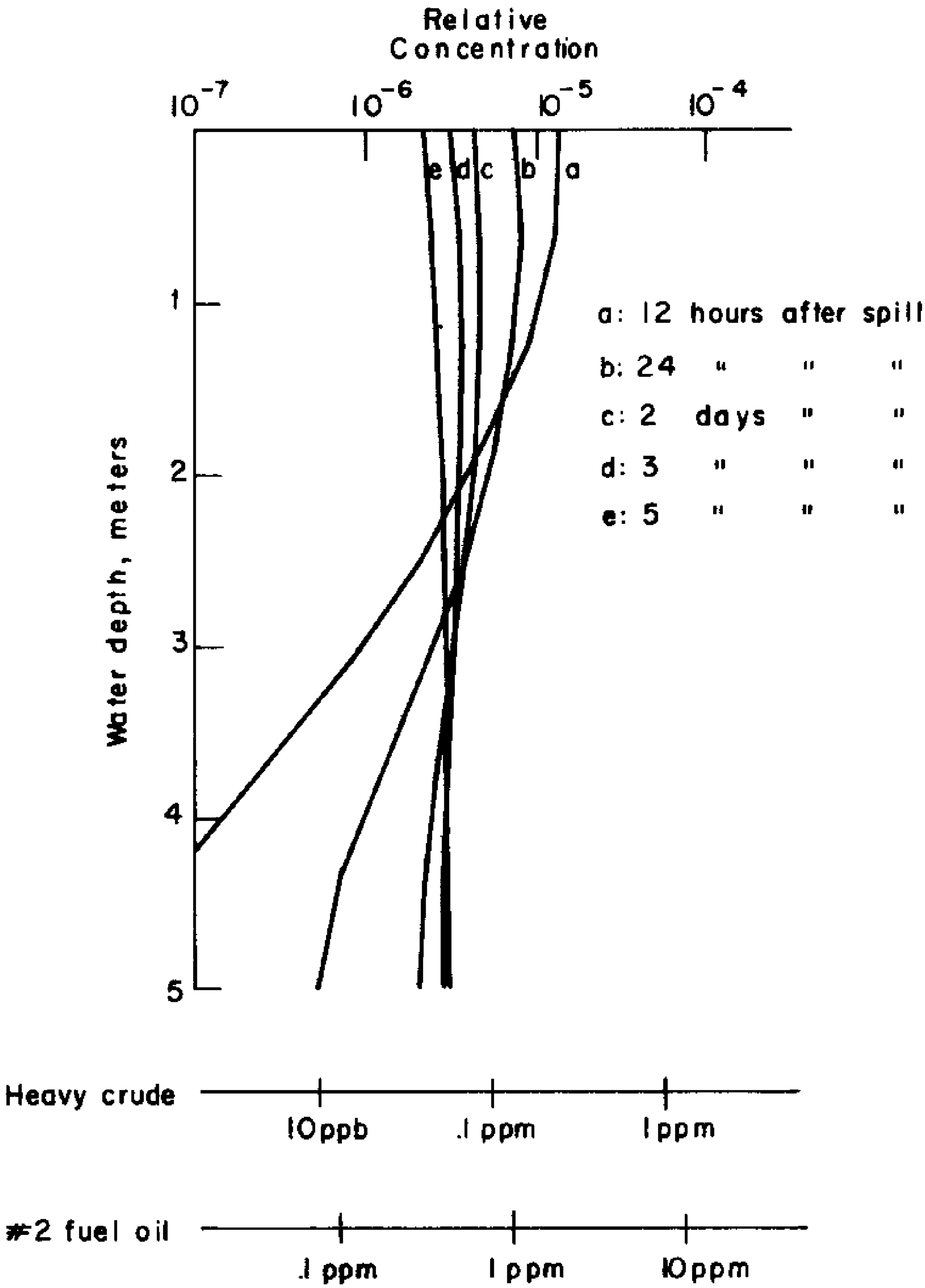

Figure 3.3 -- Concentration profiles of benzene, long simulation, impermeable sea floor.

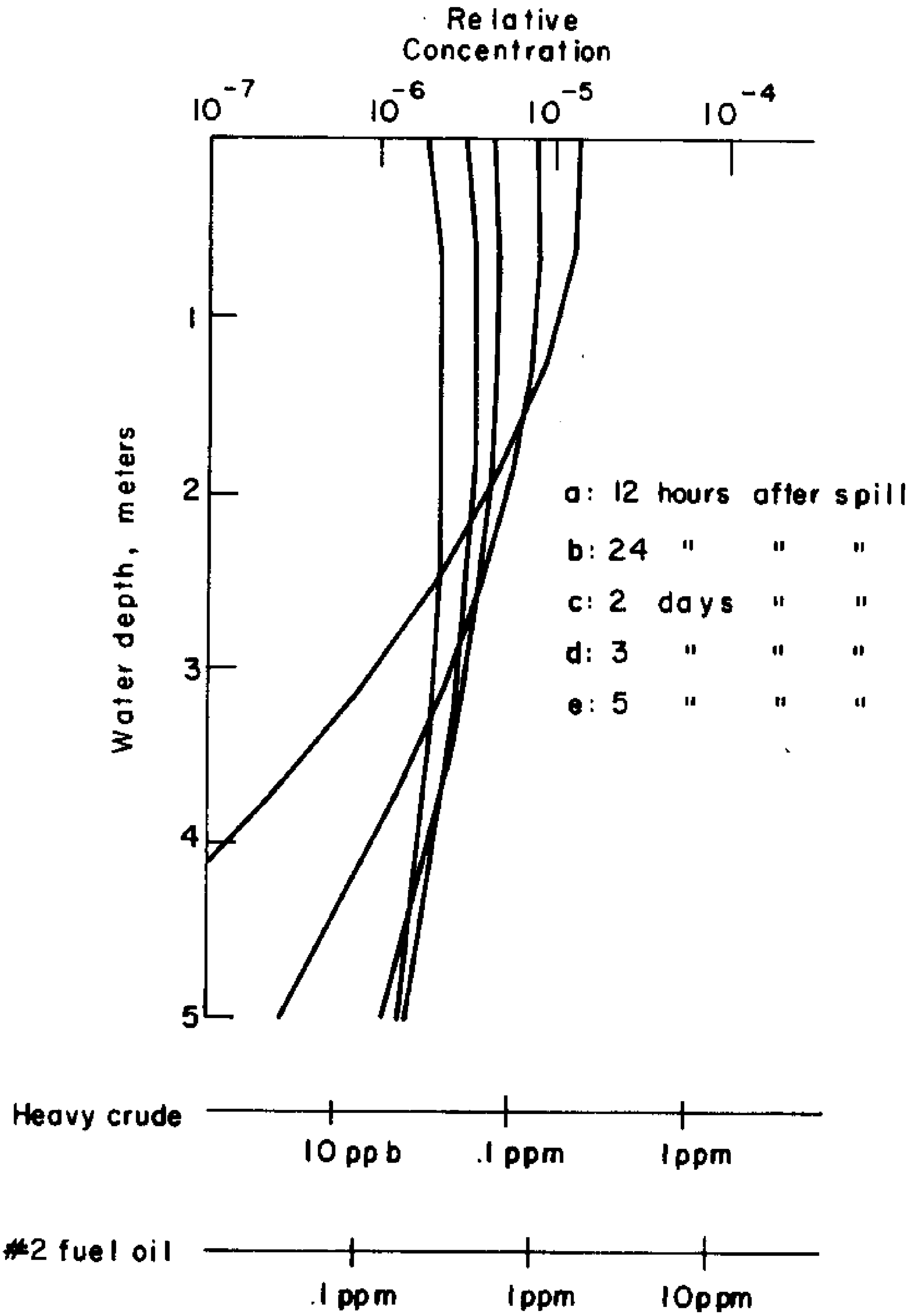

Figure 3.4 -- Concentration profiles for benzene, long simulation, infinite depth.

model undoubtedly loses a great deal of accuracy at the longer times. For one thing, it is unlikely that a slick will be over one point for five days. Secondly, it is unlikely that a slick will cover such a wide area that horizontal diffusion will not be important over a five-day period.

Figure 3.5 attempts to give us some insight into the effect of the slick moving away. In this run, the same situation as Figure 3.2 was posited for the first 12 hours. Then the slick together with the laminar boundary layer was instantaneously removed. As indicated in Figure 3.5, the upper layers of the water column are rather quickly purged, but relative concentrations of 10^{-6} (.1 ppm for #2 fuel oil) can persist at lower levels for some time. Once again, this figure does not account for the horizontal diffusion. The smaller the original spill, the more important this horizontal dispersion will be in reducing concentrations.

Figure 3.6 shows benzene concentrations for the first 12 hours given a slick 10 times as thick as that in Figure 3.2. The effect of the additional thickness is to increase concentrations in the water column by an order of magnitude. It also retards the onset of the phenomenon shown in Figure 3.2, where after about 6 hours, benzene is no longer flowing from the slick to the water column, but from the water column to the slick. Figure 3.6 indicates that this doesn't start happening for the thicker slick until some time in the neighborhood of 9 to 12 hours. In short, slick thickness is of great importance; this in turn implies that studies of the

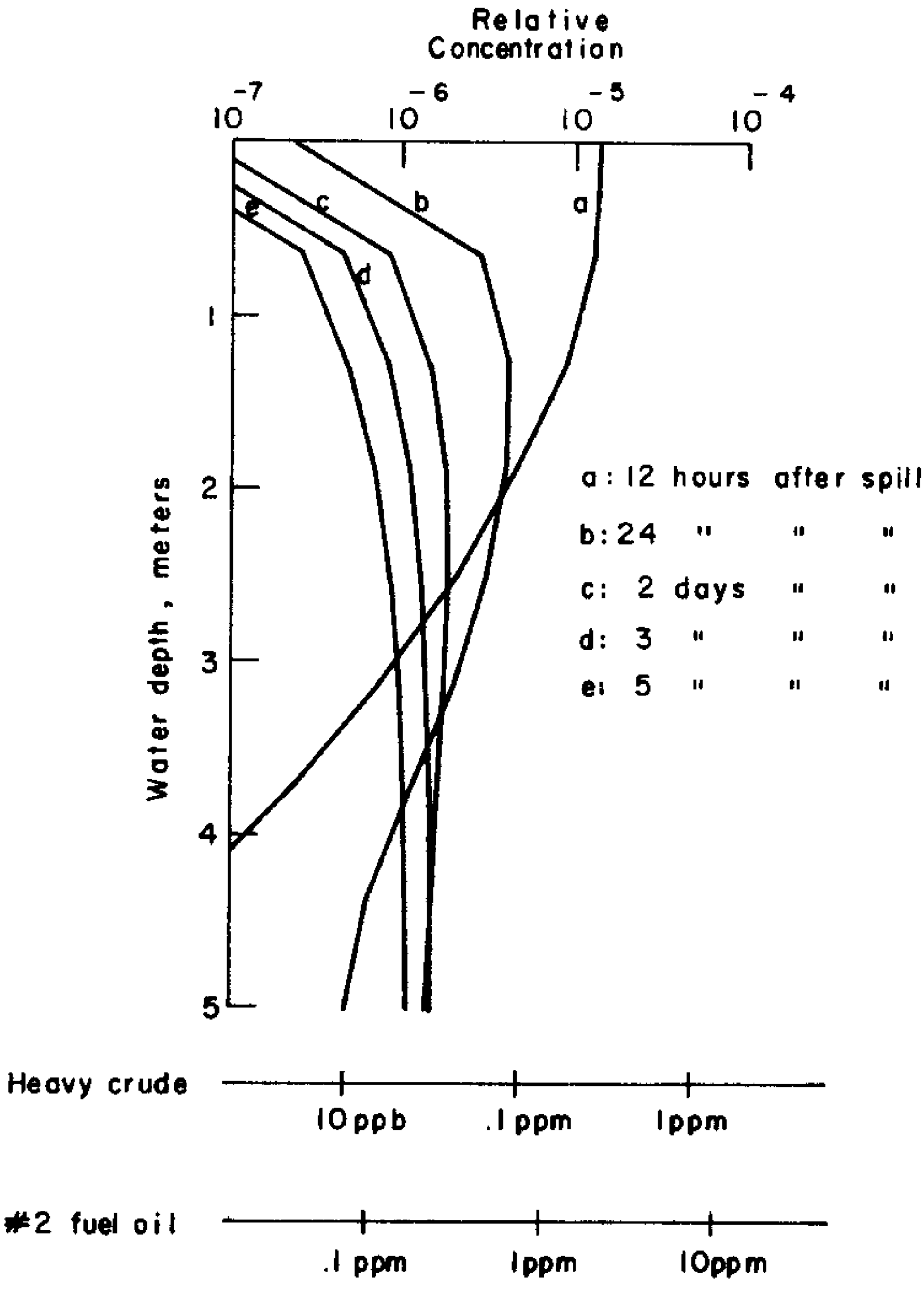

Figure 3.5 --Concentration profiles for benzene, slick disappears at 12 hours.

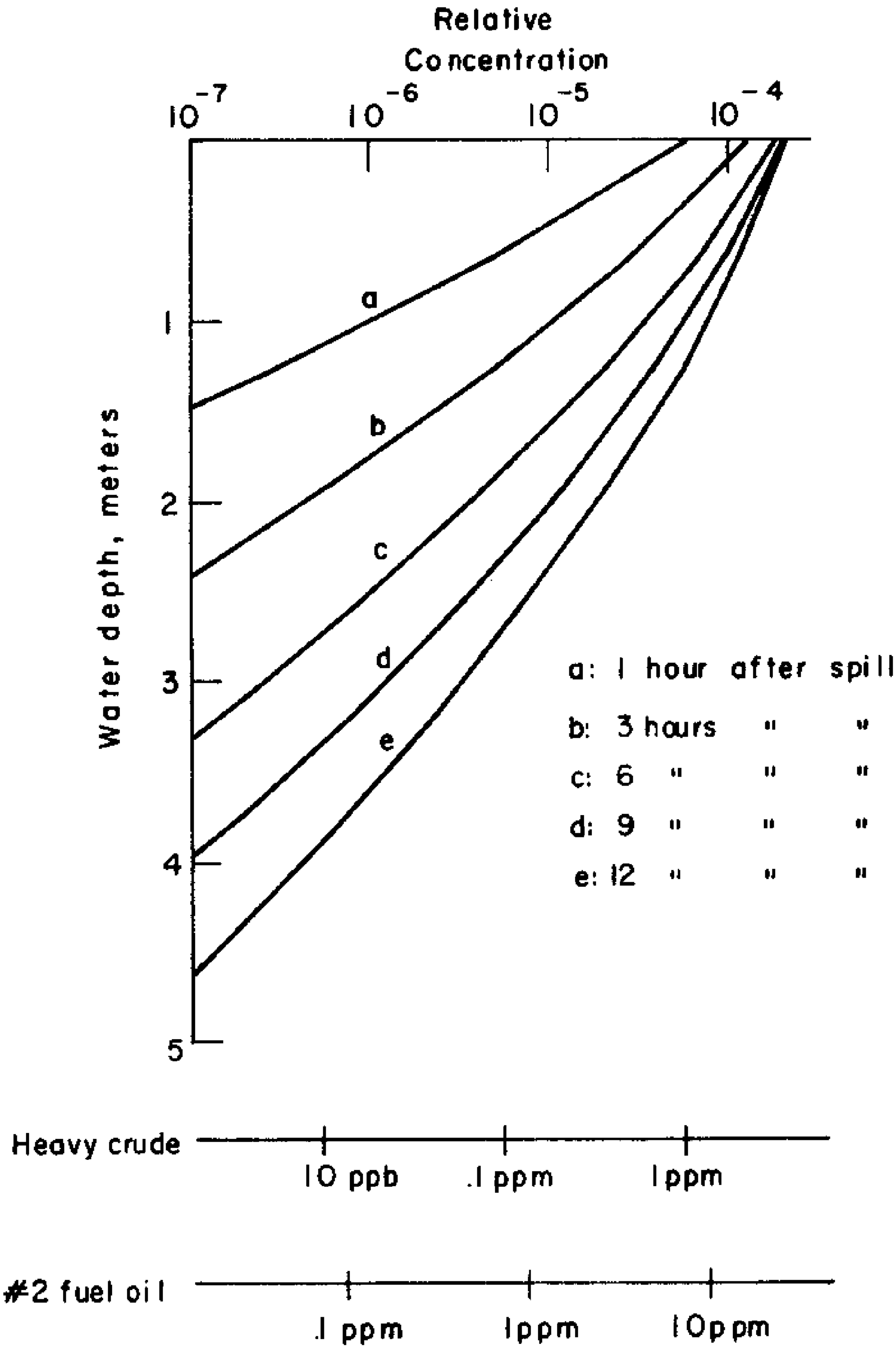

Figure 3.6--Concentration profiles of benzene, water boundary layer thickness .01 cm, slick thickness 1.0 cm.

surface fractionation phenomenon discussed in Section 2 are definitely needed.

Another key variable is the thickness of the boundary layer below the slick. The benzene concentrations obtained by this diffusion model are quite sensitive to this boundary layer thickness, a variable about which almost nothing is known. As Figure 3.7 indicates, an order of magnitude increase in this thickness results in approx. ately an order of magnitude less concentration throughout the simulation. Much more work addressed at determining this variable is indicated.

The concentration is also strongly dependent on the partial pressure of the compound. Figure 3.8 indicates the effect of dropping the partial pressure of the benzene to that of naphthalene. The 1 to 3 hour concentrations are quite similar to that of the base case 3.2. However, from that point on, the concentrations diverge as benzene continues to be pumped down from the slick in the slow evaporation case, while benzene is drawn out of the water into the slick in the base case. Fortunately, partial pressures are relatively well known. Figure 3.9 shows the combined effect of low boundary layer thickness and slow evaporation. The effects, very roughly speaking, are additive.

Figure 3.10 shows the relative concentrations in the water column for naphthalene for our "best" estimates of the physical parameters governing the process. The reduction in concentration is an order of magnitude greater than that for benzene as the much lower solubility more than compensates

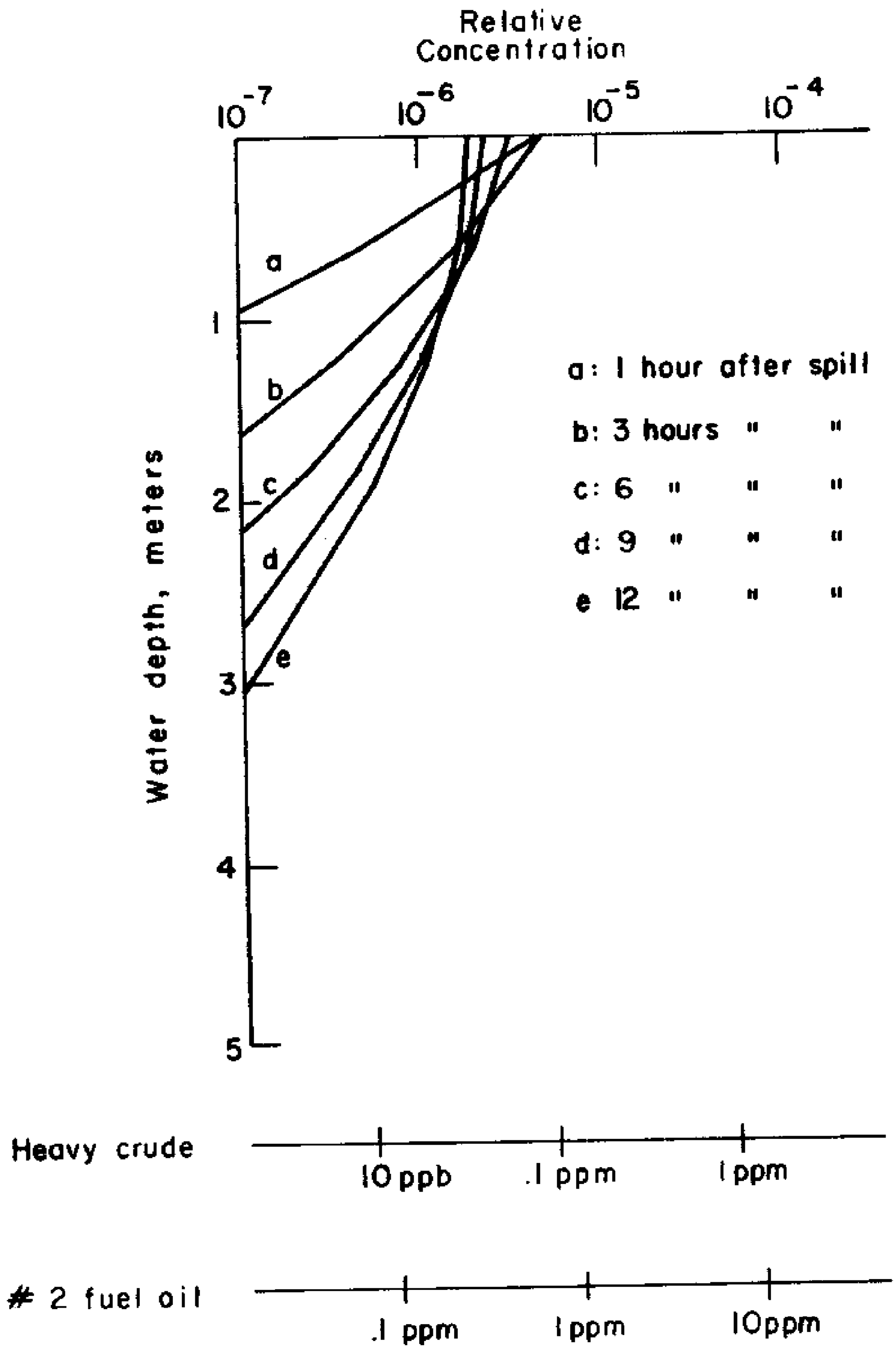

Figure 3.7 --Concentration profiles of benzene, water boundary layer thickness .1 cm.

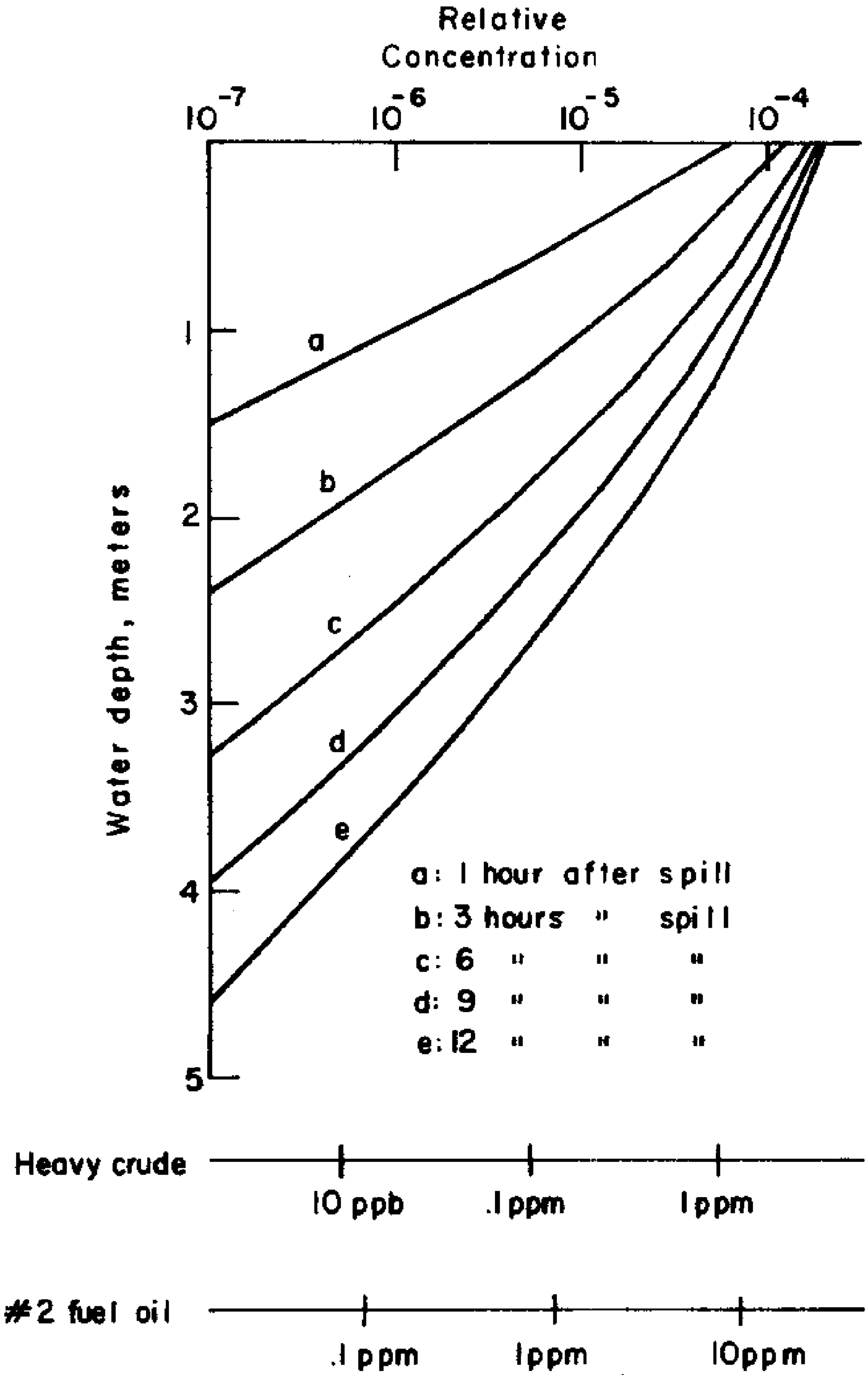

Figure 3.8 -- Concentration profiles of benzene, water boundary layer thickness .01 cm., slow evaporation

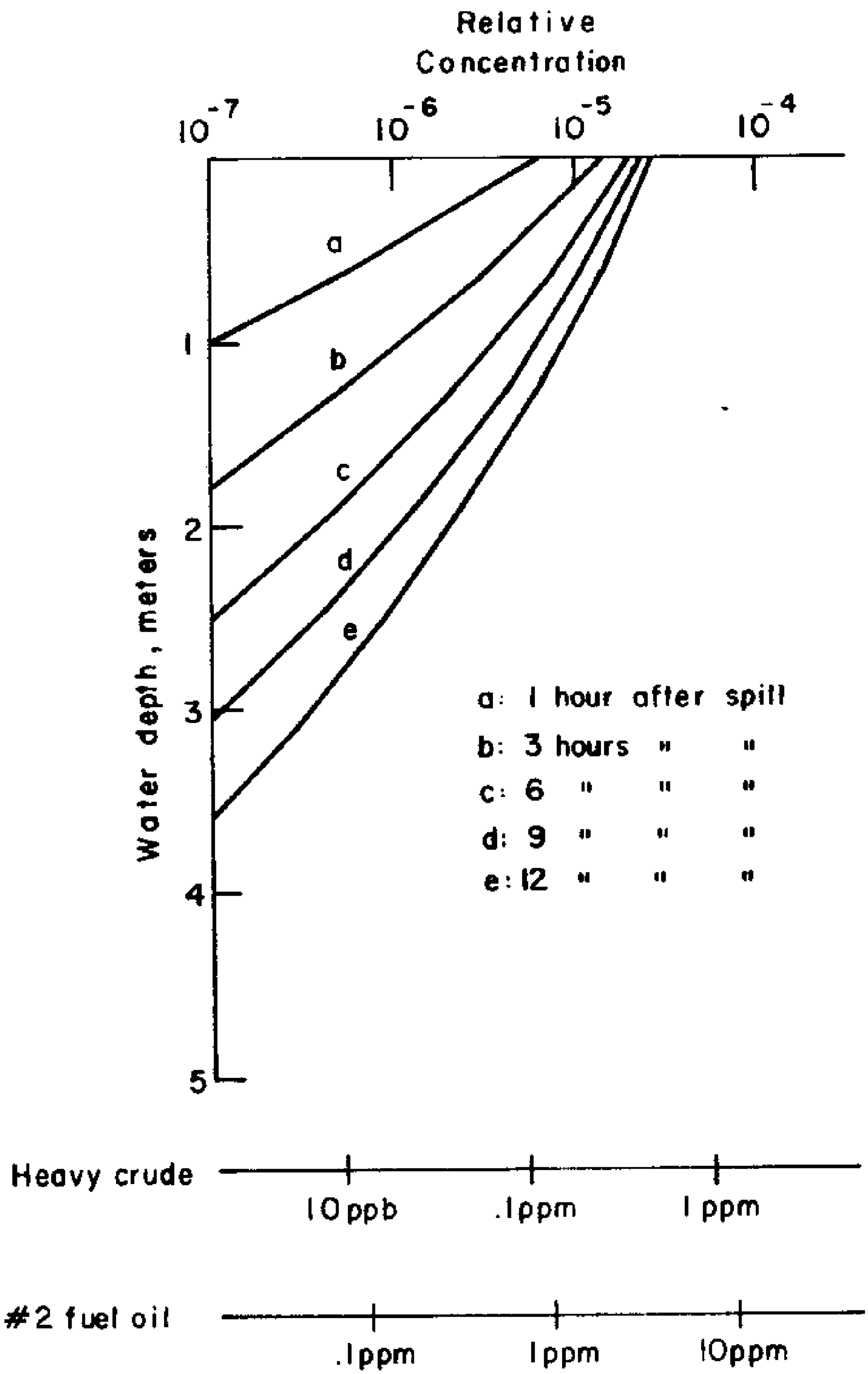

Figure 3.9 -- Concentration profiles of benzene, water boundary layer thickness .1cm., slow evaporation

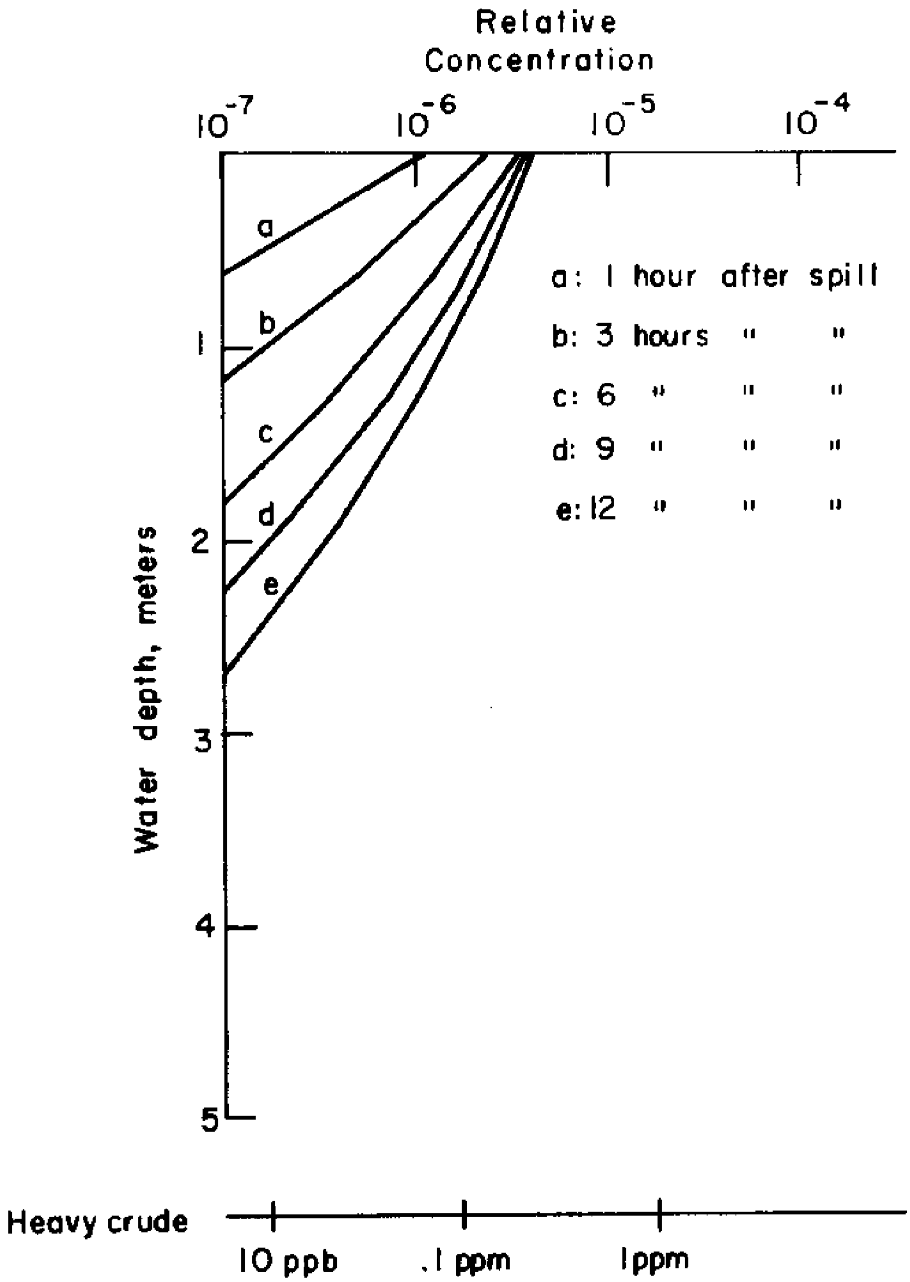

Figure 3.10 -- Concentration profiles of naphthalene, water boundary layer thickness .01 cm.

for the lower partial pressure. In fact, because of the lower evaporation rate and lower diffusion, naphthalene remains in the slick much longer than benzene, as shown in Figure 3.11. More than 76% of the initial naphthalene remains in the slick after 12 hours, while less than 10% of the initial benzene is left at 3 hours and less than 1% at 6 hours.

Figure 3.11 also shows the percentages of 3 alkanes remaining in a 1 mm thick slick as a function of time according to the diffusion model. Almost all of these compounds which leave the slick do so to the atmosphere.* Nonetheless, the results are of interest. They indicate that everything below C_9 will be gone from the slick in a matter of hours, while everything above C_9 will remain in the slick for much longer periods of time. From the point of view of the diffusion model, this is comforting, because chromatographs of oil that has weathered for any length of time invariably show little or no compounds whose carbon numbers are less than 9, while the peaks for C_{12} and above show little difference from the fresh petroleum. It indicates we are in the right ballpark, at least. For a medium weight crude, about 20% of the total composition will be compounds whose carbon numbers are 9 or less. In short, except for lighter products and very light crudes, evaporation and diffusion does not appear to be the driving mechanism in the breaking up of the slick itself.

Returning to the aromatics, the effects of varying water boundary layer thickness and evaporation rate on naphthalene

*Relative concentrations of n-pentane greater than 10^{-7} were limited to the top meter of the water column and persisted for less than 12 hours. Relative concentrations of n-octane and n-nonane were always less than 10^{-7}.

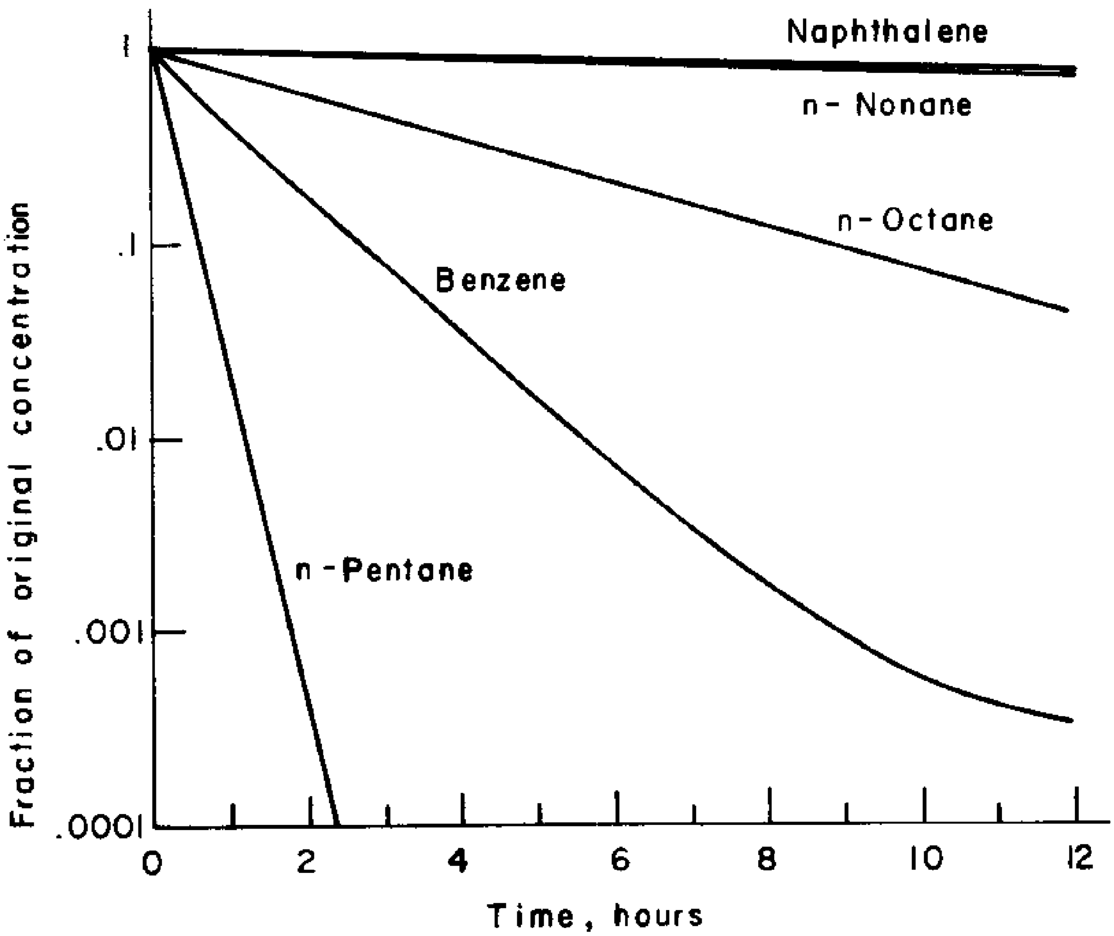

Figure 3.11--Fraction of hydrocarbon remaining in oil slick as a function of time. Slick thickness 1 mm.

are relatively speaking the same as they were in the case of benzene, Figures 3.12 and 3.13.

It is of considerable interest to study the detailed behavior of the concentration gradient in the slick itself as a function of slick thickness. The solid lines in Figure 3.14 are for benzene in a 1 mm slick; the dotted lines are for benzene in a 1 cm slick. Obviously, the figure is not drawn to scale vertically. Notice for the thin slick the concentration gradient across the slick itself is practically constant and that after 3 hours and especially after 6, the concentration in the boundary layer immediately below the slick is lower than that in the water column, indicating that benzene is being drawn up out of the water and through the slick. For the thick slick, on the other hand, the concentration gradient within the slick is not constant, as benzene is being drawn off the top faster than it's being replaced, no reversal below the slick occurs and close to the initial concentration is maintained in the slick for 6 hours. Figure 3.15 indicates that in the case of naphthalene, there are no qualitative differences between the thick slick and the thin slick.

3.4 Summary

The vertical dispersion of soluble hydrocarbons beneath an oil slick has been modeled mathematically as a classical diffusion problem. The solution to this diffusion problem has been obtained numerically by the explicit evaluation of the associated finite-difference equations. Our results

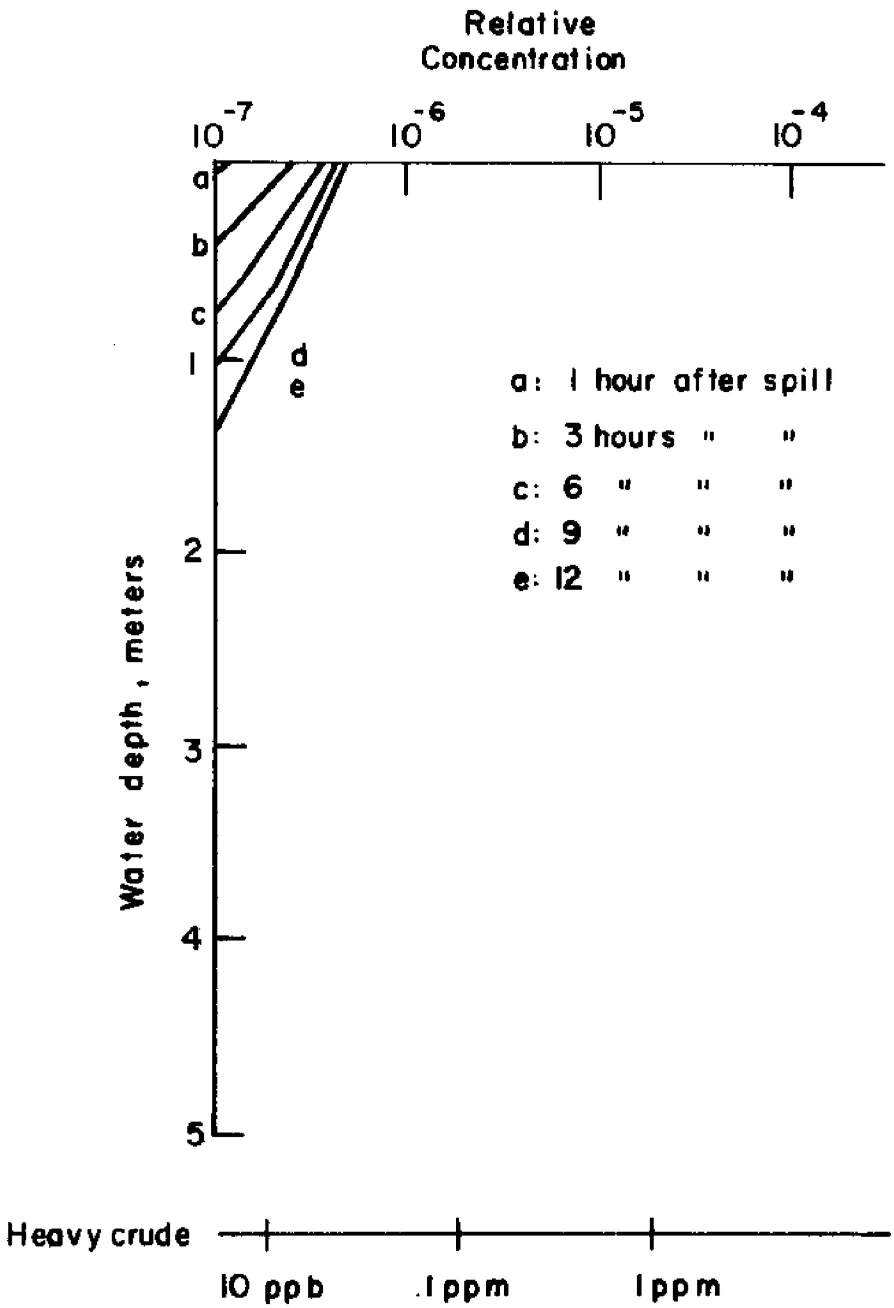

Figure 3.12 -- Concentration profiles of naphthalene, water boundary layer thickness .1 cm.

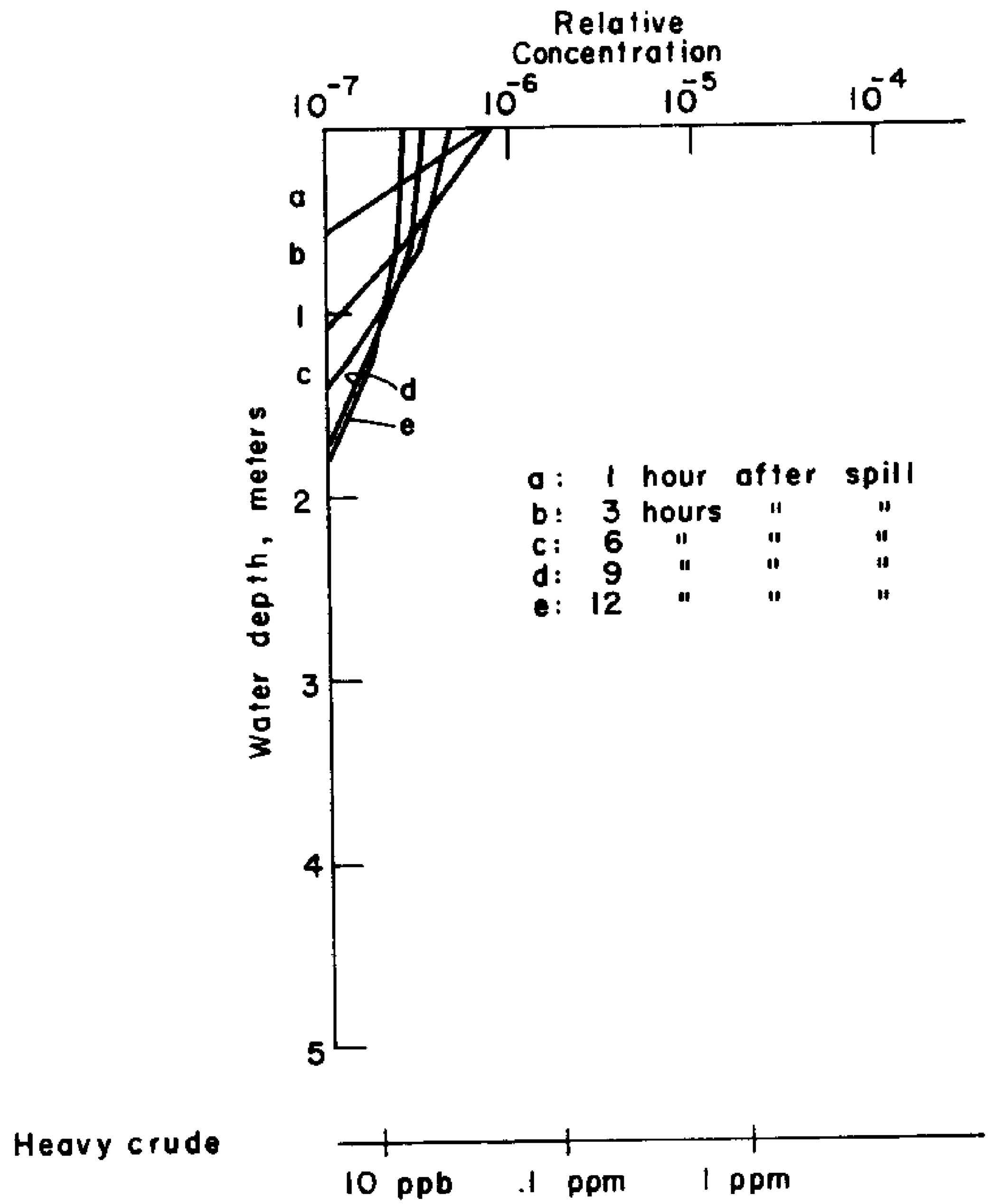

Figure 3.13 Concentration profiles of naphthalene, water boundary layer thickness .01 cm., fast evaporation

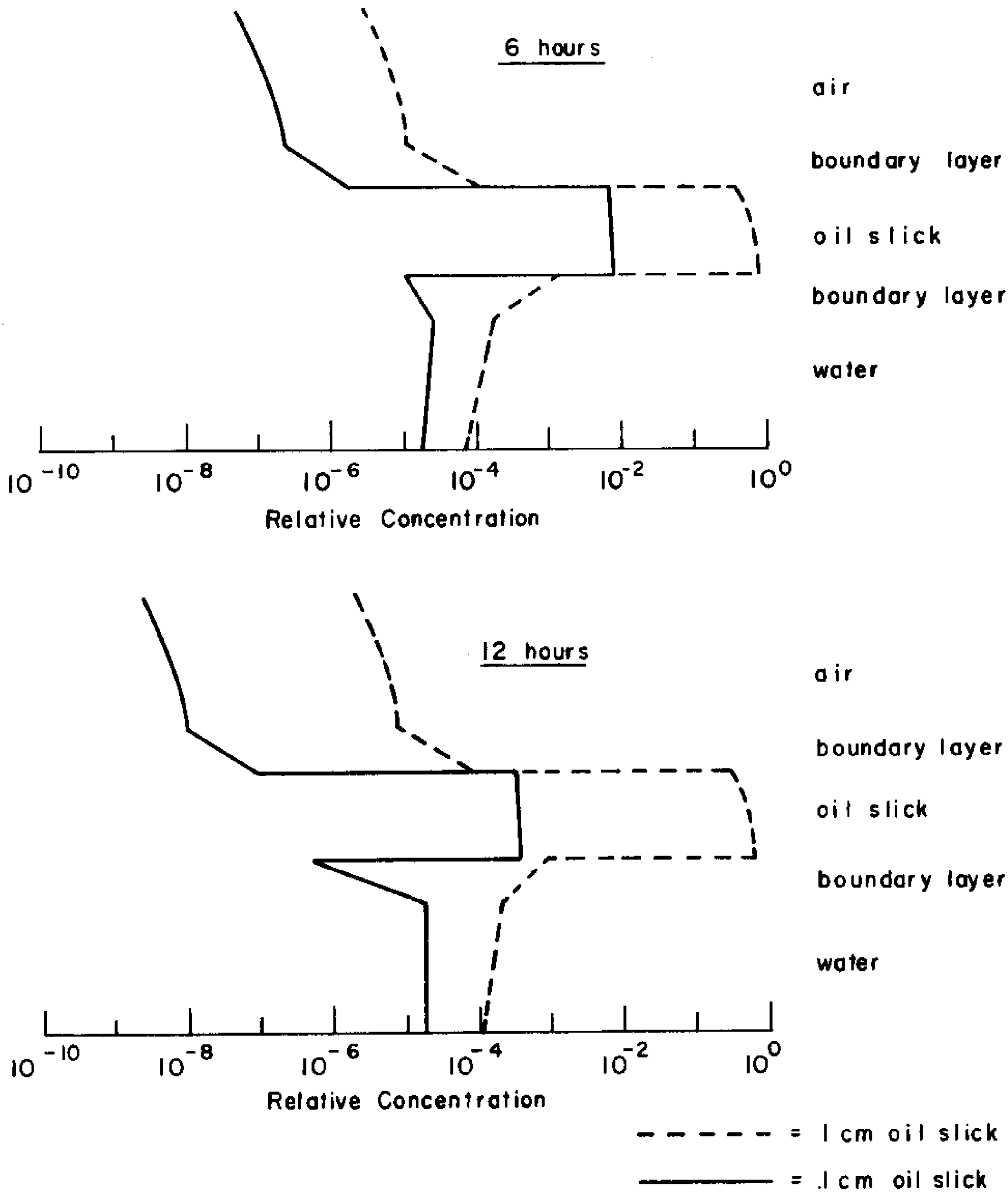

Figure 3.14 --Concentration profiles for benzene with varying oil slick thickness, 6 and 12 hours.

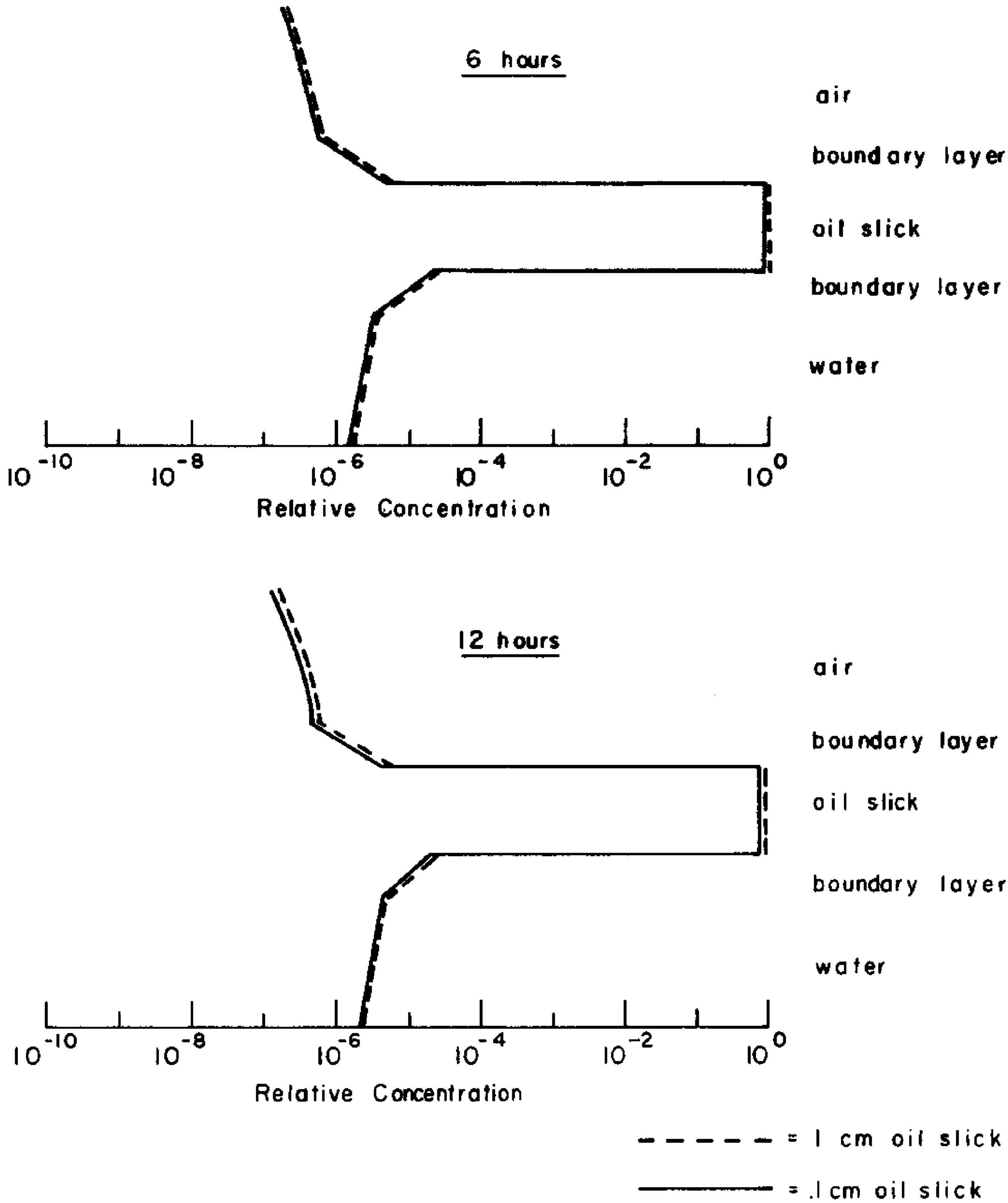

Figure 3.15 --Concentration profiles for naphthalene with varying oil slick thickness, 6 and 12 hours.

indicate that the mass transfer of light aromatics from an oil slick progresses through three stages. During the first stage, soluble hydrocarbons from the upper layers of slick are evaporated into the adjacent air while soluble hydrocarbons from the lower layers of the slick are dissolved into the adjacent water. During the second stage, evaporative loss of hydrocarbon from the slick into air halts the flow of hydrocarbons into the water while hydrocarbons continue to diffuse from immediately beneath the slick into the bulk water column. During the third stage, evaporation draws soluble hydrocarbons from the water back through the slick and into the adjacent air.

Our results for benzene indicate that for slicks of 1 mm thickness, the first stage lasts approximately 3 hours, the second stage perhaps another 3 hours. During this 6-hour period, over 95% of the benzene has left the slick. For thicker slicks, the process takes considerably longer. Our results further indicate that biologically important concentrations of benzene can be obtained through diffusion to a depth of 3 or 4 meters and that these concentrations can persist for surprisingly long times after the surface slick has disappeared. All these results could stand some empirical investigation.

Our results for naphthalene indicate that naphthalene departs from the slick very slowly and that biologically important concentrations of naphthalene can be obtained to a depth of only a meter or so as a result of diffusion. The very slow diffusion of naphthalene combined with the fact that it's present in the surface slick for much longer times makes it much more available to other mechanisms, such as sedimentation and breaking waves, indicates that these other mehcanisms are probably more important than diffusion as far as the vertical dispersion of naphthalene is concerned.

Our computer studies of alkanes indicate that all compounds with carbon numbers of less than 9 will be gone from the slick in a matter of hours. The great bulk of these lighter alkanes evaporate into the atmosphere and biologically interesting concentrations of alkanes do not appear to be attainable in the water column through diffusion. The model predicts that alkanes with carbon numbers of 9 and above will remain in the slick for much longer times. These results are in rough agreement with actual analyses of slightly weathered oil.

Appendix to Section 3

Method of Solution

A numerical method was chosen to solve this boundary-balue problem because of difficulties in formulating an analytical solution. The explicit method uses a set of finite-difference equations to determine the solution at the end of a time interval in terms of the solution at the beginning.

Let a region be divided vertically into an equal number of intervals δx and time into intervals δt. If we denote the concentrations at the point $i\delta x$ at time t by c_i and at time $t + \delta t$ by c_i^+, then the diffusion equation written as a finite-difference equation becomes

$$\frac{c_i^+ - c_i}{\delta t} = \frac{D}{(\delta x)^2}\left[c_{i+1} - 2c_i + c_{i-1}\right] .$$

Solving for c_i^+ yields

$$c_i^+ = c_i + \frac{D\delta t}{(\delta x)^2}\left[c_{i+1} - 2c_i + c_{i-1}\right] .$$

This equation holds throughout the region, but it must be modified at the boundaries. It is assumed that the air above the top region and the water below the bottom are sufficiently turbulent that whatever mass is transferred across the boundary is immediately swept away,

$$C_{inside} >> C_{outside} .$$

Applying this to the top region, the boundary condition becomes

$$\frac{D_1}{2\delta x_1}\left[c_{i+1} - c_{i-1}\right] = -h_i c_i .$$

Solving for the fictitious c_{i-n} and substituting into the general expression,

$$c_1^+ = c_1 + \frac{2D_1\delta t}{(\delta x_1)^2}\left[c_2 - \left(1 + \frac{h_1\delta x_1}{D_1}\right)c_1\right] .$$

Similarly, the expression for the bottom boundary is

$$c_N^+ = c_N + \frac{2D_5\delta t}{(\delta x_5)^2}\left[c_{N-1} - \left(1 + \frac{h_5\delta x_5}{D_5}\right)c_N\right] .$$

Mass continuity must be preserved at the interfaces,

$$\frac{D_a}{2\delta x_a}[c_{i+1} - c_{i-1}] = \frac{D_b}{2\delta x_b}[c_{i+1} - c_{i-1}] = F .$$

Solving for the fictitious concentrations, c_{i+1} in a and c_{i-1} in b,

$$c_{i+1} = c_{i-1} + 2\delta x_a F/D$$

$$c_{i-1} = c_{i+1} - 2\delta x_b F/D .$$

Substituting these into the diffusion equation,

$$\frac{\partial c_a}{\partial t} = \frac{2D_a}{(\delta x_a)^2}\left[c_{i-1} - c_a + \frac{\delta x_a F}{D_a}\right]$$

$$\frac{\partial c_b}{\partial t} = \frac{2D_b}{(\delta x_b)^2}\left[c_{i+1} - c_b - \frac{\delta x_b F}{D_b}\right] .$$

At the interface $c_a = kc_b$. When the grid point i represents the interface, let c_i equal c_b, which means $c_a = kc_i$. Substituting these into the above expressions and eliminating F,

$$c_i^+ = c_i + \frac{2\ t}{k\delta x_a + \delta x_b}\left[\frac{D_a}{\delta x_a}(c_{i-1} - kc_i) + \frac{D_b}{\delta x_b}(c_i - c_{i+1})\right] .$$

This completes the formulation of the problem as an explicit set of finite-difference equations. The solution is stable and will converge to the true solution within a discretization error of order $(\delta x/L)^2$ provided that the minimum ratio $(\delta x)^2/D\delta t$ is less than 0.5 (Carnahan et al., 1969). The value used for these solutions was 0.25.

4. Sedimentation

The oil in a slick eventually goes somewhere, and undoubtedly the major mechanism in removing the heavier compounds from the surface of the water is sedimentation. Very little is known about the sedimentation of oil in water. We do know that oil has been found as deep as 240 m after a spill in Nova Scotia (Forrester, 1971) and recently some interesting information was taken in conjunction with a spill in the Gulf. In this spill, which flowed for several weeks, stations were set about a month after the flow had ceased and bottom sediments sampled. These sediments registered an average of 80 ppm hydrocarbons and a high of 300 ppm. Rough calculations from these stations indicate that some 10% of all the oil which was spilled became part of the top 1.5 cm of the bottom sediments within 5 miles of the spill. This was in 40 ft of highly turbid water, so it may be an extreme case. In any event, the example indicates the importance of sedimentation.

Practically all the hydrocarbons found in these sediments were C_{12} and above. One year later, it was reported that all stations were registering hydrocarbon concentrations of about 15 ppm, which is the background level in these rather heavily loaded waters.

In short, sedimentation is important. It appears that a great deal of sedimentation starts taking place shortly after the oil is introduced into the water. But almost nothing is known about rates, fractional composition, etc. Most observers feel that sedimentation takes place by adsorption of oil onto particulate matter in the water, which would indicate that the amount and distribution of size of this matter is of importance. Other than that, almost nothing is known. Sedimentation certainly deserves more attention than it has been given.

5. Breaking waves

The third mechanism for introducing slick oil into the water column is the physical folding in of the slick by breaking waves. Almost nothing is known about this mechanism. Once introduced into the water column, oil can be carried as deep as 25 meters by orbital motions, depending on the severity of the sea state. This mechanism has the biological disadvantage that it operates on fresh oil as readily as on weathered and may be a prime culprit along the shoreline. Blumer (1971) observed naphthalene in 20 ft of water in Buzzards Bay. Since our earlier analyses indicated that diffusion is unlikely to be the cause, it is possible this was due to breaking waves.* However, no quantitative description of how oil will act in breaking waves is presently available. Research in this area should be able to build upon the work on bubbles in breaking waves done in conjunction with sonar applications.

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*It could also be due to sedimentation. Naphthalene is only very slightly lighter than seawater as a liquid.

6. Summary

1. Oil does not spread as a homogeneous fluid, but rather appears to fractionate on the surface. Almost nothing is known about this phenomenon, which is almost certainly of great importance to oil slick weathering. Empirical work is definitely indicated.

2. A diffusion model attempting to simulate the vertical dispersion of the lower boiling aromatics into the atmosphere and into the water column was constructed. Two specific compounds, benzene and naphthalene, were chosen for study.

3. With respect to benzene, using best guesses of the required physical parameters, the results indicate that, for a slick .1 cm in thickness, 90% of the benzene will have left the slick in 3 hours and 99% in 6 hours. The bulk of this benzene goes into the atmosphere.

4. However, sufficient benzene diffuses into the water column to generate concentrations of concern to biologists. According to the model, a diesel oil slick could generate concentrations of 1 ppm to depths of 3-4 meters for 12 hours or so under the slick. Further, these concentrations appear to persist for surprisingly long periods.

5. The key unknown in the above results is the thickness of the boundary layer beneath the slick. Research here is definitely indicated.

6. According to our model, much less naphthalene gets into the water column through diffusion than benzene. The

reduction in concentration in the original slick to that in the water is about 5 orders of magnitude, or one order of magnitude greater than that for benzene.

7. Naphthalene remains in the slick for much longer periods than benzene and this is available to other mechanisms for entering the water column for a much longer period. Such mechanisms are sedimentation and breaking waves.

8. The results for benzene are rather sensitive to slick thickness. Thicker slicks retard evaporation in the early history of the slick and then greatly slow the process of concentrations in the water column being drawn from the column through the slick in the later stages of the process. Thus, the interrelationship between spreading, horizontal fractionation, and vertical dispersion appears to be of considerable importance to oil weathering.

9. Diffusion studies of alkanes indicate that all compounds with carbon numbers less than 9 will depart from the slick in a matter of hours, the great bulk by evaporation. Biologically interesting concentrations of these lighter alkanes do not appear to be attainable in the water column through diffusion.

10. Our computer studies indicate that alkanes with carbon numbers of 9 or above will persist in the slick for much longer periods of time. These results are in rough agreement with analyses of semi-weathered oil which indicate the breakpoint is in the C_{10} range.

11. For naphthalene and all compounds above about a carbon number of 9, sedimentation and possibly breaking waves appear to be more important phenomena than diffusion. Little is known about these mechanisms, and research is indicated.

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