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DYNAMICS OF PETROLEUM INDUSTRY

INVESTMENT IN THE NORTH SEA

By

Arthur Oren Beall, Jr.

M.I.T. Sloan School of Management Master's Thesis

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Ph.D., Stanford University
(1964)

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Submitted to the Alfred P. Sloan School of Management on May 1, 1976 in partial fulfillment of the requirements for the degree of Master of Science.

ABSTRACT

This investigation has attempted to provide a current estimate of the oil potential of the northern North Sea from which estimates of exploration investment, development investment, and accruing cash-flows can be derived. Current proven reserves are estimated at 29.4 billion barrels oil equivalent, of which 22.6 billion barrels are oil. Of the 59 discoveries documented, 8 can be classed as true gas accumulations.

Undiscovered potential for the area of study is estimated at 24.3 billion barrels, giving a most probable ultimate recoverable reserve of 53.7 billion barrels oil equivalent. Depending on minimum commercial field size, recoverable oil reserves should vary between 33.7 and 39.2 billion barrels.

Current development of 14.8 billion barrels of recoverable oil involves an estimated capital investment of $16.8 billion dollars. Peak daily production is estimated to occur in 1981 at 4.12 million barrels daily. An additional 4.6 billion barrels of recoverable oil is in various stages of evaluation and will probably be developed, yielding a total of 19.4 billion barrels of reserves and a total peak production of 4.95 million barrels per day in 1981. Capital investment is estimated at $27 billion dollars for the total.

In order to develop current plus discovered plus future discoveries, private industry is estimated to require between $56 and $70 billion dollars. Most of this investment, including approximately $6 billion additional outlay for exploration, is anticipated to occur between now and 1985. Peak production of 6.58 to 7.85 million barrels per day is estimated to occur around 1986, representing a total reserve development of approximately 34.4 to 38.4 billion barrels of oil. Private industry is anticipated to earn between $30 and $56 billion dollars whereas government take, assuming a lower discount rate, is estimated to run between $83 and $222 billion dollars.

Critical to this analysis are assumptions about host-government tax policy and the world price of crude oil, especially as pertaining to "marginal" North Sea fields. Utilizing an econometric model developed by the Supply Analysis Group of the M.I.T. World Oil Project, investigation of discounted cash-flow profiles for various field sizes indicates that access to crude supply and development of subsequent discoveries appear to be the primary economic incentives for continuing to operate smaller fields after peak production is obtained. Tax policy and high operating costs relative to productive capacity tend to make small fields less attractive investments. Finally, it is patently obvious that very high per-well productivity is essential for viable development of North Sea fields under current economic, political, fiscal, and technical constraints.

Thesis Supervisor: Morris A. Adelman

Title: Professor of Economics

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Thirdly, I would like to acknowledge the many individuals who helped me accomplish the multitude of tasks required to complete this work. I am especially indebted to Mr. Dan DeBouf, who persisted in aiding my efforts to conquer a recalcitrant computer terminal.

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INTRODUCTION

CHAPTER I

Petroleum exploration can be characterized as being related to the willingness of investors to participate in high-risk, large investments, with long-term exposure to financial loss. The objectives of this study are to analyze a currently active exploration arena, the northern North Sea, in terms of economic return to the petroleum industry as well as to the host government. In order to do so, three main factors must be evaluated: (1) estimation of current North Sea petroleum reserves as well as future discoveries, (2) economic analysis of current industry investment in the North Sea, and (3) estimation of future industry investment as based upon current expectations of profitability.

The estimation of current reserves and future discoveries is based on a complex source of published information, personal communications, analytical approaches, and geological insight furnished by the writer. A perspective on the Exploration Process is furnished to the interested reader as a means of better understanding the approach utilized.

Central to the study is a computational scheme developed by Eckbo[1] which takes current estimates of investment costs, reserves, and accessory parameters, and calculates cash-flow to the private company and to the host-government on a yearly basis. Separate discount rates can be utilized, and figures for both Norway and the U.K. are automatically printed out. This tool was utilized for various sensitivity tests as well as to develop a numerical basis for the minimum field size required for development, as discussed in Chapter IV.

The area of study is confined to a geographic area between 56° and 62° North latitude, the offshore boundary between Norway and Denmark, and published geologic features as shown in figure 1. A discussion of the criteria utilized to delimit the area of study is contained in Chapter II. It should be pointed out at the outset that this area is commonly considered to represent the "oil area" of the North Sea by industry writers.

Although not included herein, this investigation was originally conceived as a systems dynamics analysis of industry investment where manipulation of government policy, eg. tax policy, as well as imposed price and supply controls, various government participation schemes, and other elements of potential impact on industry investment could be evaluated. As work progressed, however, it became evident that considerable additional work would be required in order to include such an analysis. Nevertheless, a number of conclusions regarding such elements as described above will be offered in the final chapter, as derived from the contained analysis. Further work on this aspect of the investigation should be undertaken by subsequent writers.

EXPLORATION IN THE NORTH SEA

CHAPTER II

A. A Perspective on the Exploration Process

During the early history of petroleum exploration, considerable amounts of commerical hydrocarbons were in "large" structures which were obvious on the basis of very limited information. As geological and geophysical tools became more sophisticated, the amount of commercial oil discovered by such advanced tools also increased. "Wildcatting" slowly gave way to technology and organizational decision-making. Likewise, the evoling geological and geophysical skills have converged towards a focused approach in petroleum exploration. Thus a "petroleum explorationist" is described variously as capable of synthesizing the complex exploration data currently available to the point of assessing probability of encountering commercial quantities of hydrocarbons on a "prospect".

Technology has continued to expand until today we stand on the thresh-hold of a new era in petroleum exploration. The complexity of processing overwhelming masses of data associated with current exploration has led to the development of a new type of decision-making. This is compounded by the fact that over large segments of the world, many of the large structures have been drilled, and decisions as to deployment of resources are no longer obvious. Disregarding for the moment the difficulty of assessing the external environment in which he must work, the modern explorationist remains primarily technologically oriented and will probably tend to become more so. Thus decisions regarding exploration will necessarily involve a broader organizational element than in the past. Communication between the explorationist and the economist or politician or engineer will have to improve in order for the exploration process to continue. The following paragraphs attempt to facilitate that understanding.

An exploratory "prospect" is basically conceptual, in that there exists a considerable latitude of prospect quality between operators in terms of creative input and sound geological processes. Within a basin, the problem of what comprises a prospect is strongly affected by the stage of exploration maturity, operating limitations, and the explorationist's perception of prospect composition. It is often observed that a large number of characteristics can be elucidated which are common for most fields within any one "play". Furthermore, it should be obvious that, beyond any communality of geologic parameters among oil fields, sheer size of reserves can easily demonstrate that particular basins of the world are much more prolific than others.

The most critical parameters vary from prospect to prospect, but fundamental to all are considerations as to size, both areally and vertically. The distribution of reservoir thicknesses, hydrocarbon-generating potential, and trapping mechanisms are undoubtedly lognormal and finite. Thus many prospects, purely on the basis of size, will not be drilled in an environmentally difficult area like the North Sea where minimum expectations require large reserves for development. This makes it difficult to explore for stratigraphic accumulations or test stratigraphic concepts unless they happen to coincide with large structural anomalies.

The ability to accurately interpret the "true state of nature" in light of real constraints on data quality and a clear understanding of processes at work is no where more apparent than in petroleum exploration.[2] Our ability to evaluate risk or probability of success for the purposes of arriving at decisions, eg. to invest or not to invest, lies at the core of the competitive process. Each entity interprets and converts any given set of data to its own investment decisions. Those interpretations of geological and geophysical data are the subjective deduction of individual's ideas as to what the basic data mean. Interpretations often turn out to be in error, as evidenced by a large number of dry blocks for which funds have been expended in order to evaluate invalid interpretations.

The preceeding can be summarized by saying that a so-called "high-risk industry" operates with a highly subjective decision-making process, especially in terms of exploratory investment decisions. If that risk is not rewarded then the risk will not be taken. Exploration and development must be a function of cost and resource availability. The said costs also pertain to greater conservation, trade imbalances, environmental costs, costs attendent to diminishing reserves, and cost of converting various resources to usable energy forms in an acceptable way.

A large number of long-standing contractural arrangements and resources have been expended towards gathering data pertaining to various offshore areas. A company often chooses to participate with others in joint ventures in order to share technical expertise and spread financial resources among a number of potential prospects rather than concentrating on a few. Jointly owned properties afford participation in more drilling and exposure to a variety of prospect types. Furthermore, by sharing the burden, necessary financial resources required for rapid development can be obtained. By way of illustration, consider a company in two situations: (1) operating a small area of acreage on 100 percent exposure, and (2) operating an area three times the previous size with an exposure of 33.3 percent. Assume that field size is log-normal within the basin, and that only some finite percentage of any acreage will be prospective. This allows the company under condition 2 above a greater probability of finding a larger than normal field. Furthermore, exposure to unanticipated success in unknown reservoirs is also greater. As shown in subsequent sections of this thesis, the larger fields are also the more profitable fields, and the discovery rate is not as critical to success as is the recoverable reserve size.

B. Estimation of North Sea Reserves

As shown in figure 1, the area of study, hereafter called the Area, has been delimited on the basis of exploration parameters which consist of: 1) selected depth contours on the base of the Paleocene,[3,4] 2) the primary structural elements of the North Sea,[3,4,5] 3) discussions with explorationists and data from the literature,[6,7] and 4) geopolitical

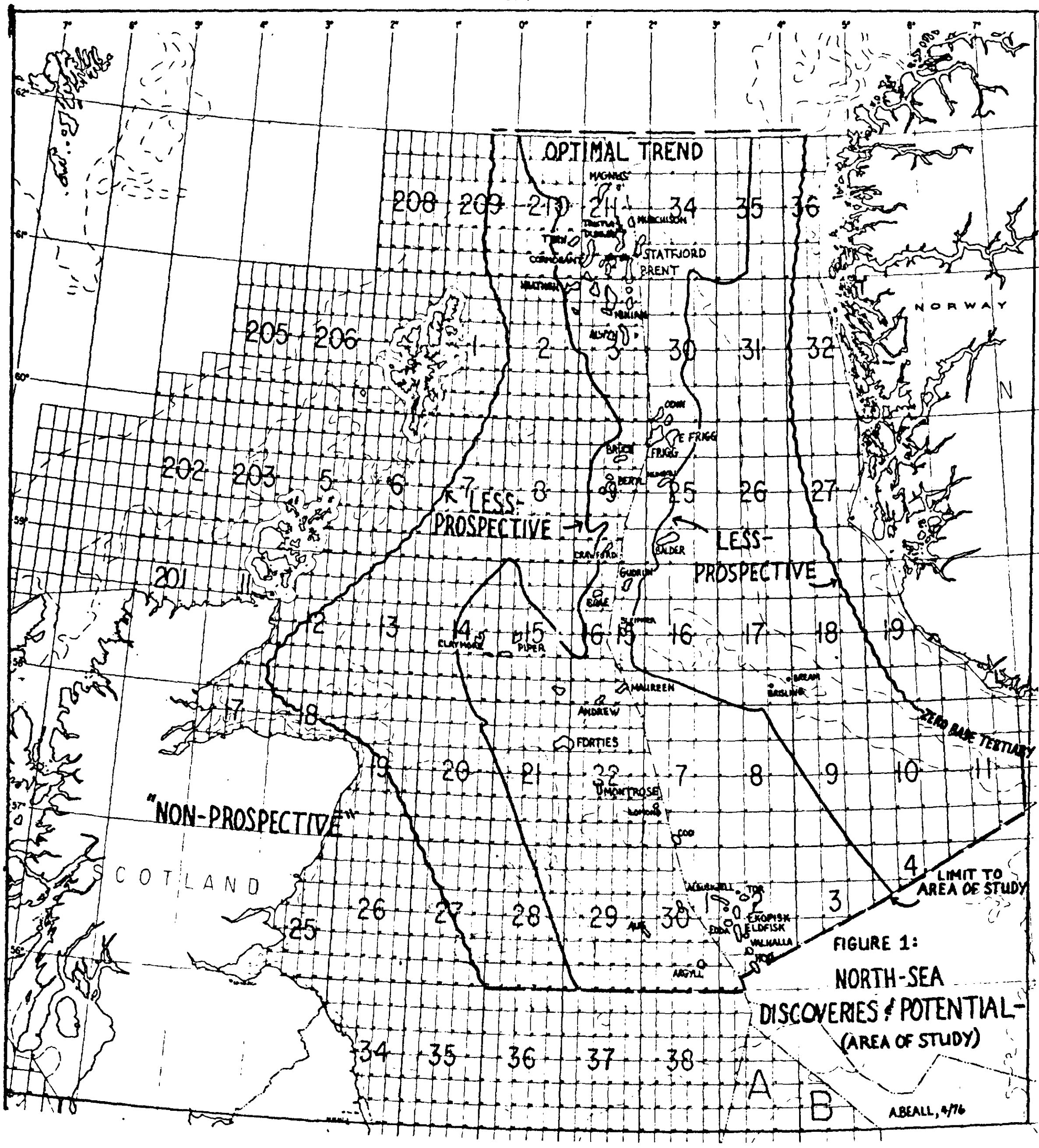

Figure 1: North Sea Discoveries and Potential - (Area of Study)

considerations. The Area is defined between 56° and 62° North latitude, the boundary of Norway and Denmark, and the zero Paleocene depth contour. Areas outside these approximate boundaries are considered poorly to non-prospective for the purposes of this investigation.

The various depth contours and structural elements define a central North Sea graben or down-faulted trough which generally contains the thickest sedimentary section, particularly of post-Jurassic sediments. It is this sedimentary section which contains most of the currently-known reserves. Production presently derives from three main horizons/intervals: 1) Tertiary Paleocene sands, (eg. Forties and Frigg), 2) Danian reservoirs, (Ekofisk complex), and 3) the major Jurassic producing horizon of the North Sea, (eg. Statfjord, Brent, and Piper).

Although the main productive horizons are geologically distinctive, it is considered impractical, for the purposes of this study, to attempt to identify separate potential fairways within the Area. Of the three horizons, the Ekofisk-type production appears to be limited most specifically to the deeply buried central basin. The reader is therefore advised that this latter region has the greatest Danian potential although statistical treatment to follow does not differentiate.

The Area, (figure 1), has been further differentiated into an "optimal or prime trend" and a "less prospective trend". While a discussion of the geologic basis for this differentiation is beyond the scope of this paper, it can be noted that the discovery rate within the prime trend of 24 percent is substantially better than the 6 percent rate within the less prospective trend. Finally, the boundary between the two trends is rather arbitrary in the southern part of the area of study, and is placed on the basis of the -3000 feet contour on the base of the Paleocene.[3,4,5]

At this stage of exploration, the northern North Sea has reached an intermediate stage of exploration evaluation. Considerable amounts of seismic data of post-1970 vintage are now available over the entire area of interest. This data, in conjunction with geologic data derived from boreholes and field studies, comprises the main body of data on which new prospects are generated.

Since the larger structures are finite in number and generally known, the question can be asked, "have they all been drilled?" This writer would suggest that the answer is no, purely on the basis that some areas may be characterized by data such that the true structural/stratigraphic picture has not been developed. At the same time, it appears unlikely that there are many such large anomalies, as evidenced by a prospect portfolio made available to this writer where the largest prospect has a potential for only 600 million barrels.

At the same time, additional drilling on large structures which do not, at the present time, appear to contain commercially large reserves will undoubtedly discover unanticipated new reserves in some instances. This was true in the Ekofisk area, is proving to be true in the Beryl and Brent area, and will surely hold in other areas. Such discoveries are not true exploration discoveries, but neither are they delineation discoveries.

Table 1 shows current assessment of recoverable reserves in the

TABLE I

NORTHERN NORTH SEA DISCOVERIES

Order of Discovery	Field Name or Location	Spud Date	Cumulative Wildcats	Recoverable Oil Equiv.	Reserves (oil)
1	Cod	2/68	16	159	(25)
2	Montrose	4/69	31	200	(200)
3	Ekofisk	9/69	46	1932	(1060)
4	Josephine	6/70	52	250	(250)
5	Tor	8/70	55	245	(150)
6	Eldfisk	8/70	56	927	(500)
7	Forties	8/70	58	1800	(1800)
8	W. Ekofisk	8/70	60	706	(350)
9	Auk	9/70	64	50	(50)
10	Frigg	4/71	70	1264	(0)
11	Brent	5/71	72	2375	(1750)
12	Argyll	6/71	74	75	(75)
13	Bream	12/71	89	75	(75)
14	Lomond	2/72	95	500	(500)
15	S.E. Tor	4/72	96	34	(25)
16	Beryl	5/72	100	550	(550)
17	Cormorant	6/72	103	400?	(400)?
18	Edda	6/72	104	126	(55)
19	Heimdal	7/72	107	414	(23)
20	Albuskjell	7/72	109	560	(150)
21	Thistle	7/72	111	450	(450)
22	Piper	11/72	123	800	(800)
23	Maureen	11/72	124	500	(500)
24	Dunlin	4/73	138	400	(400)
25	3/15-2	4/73	141	150	(150)
26	Hutton	7/73	153	300	(300)
27	Alwyn	7/73	154	500	(500)
28	E. Frigg	8/73	157	623	(0)
29	Heather	8/73	159	150	(150)
30	Brisling	8/73	160	75	(75)
31	Ninian	9/73	163	1200	(1200)
32	Statfjord	12/73	178	4595	(3900)
33	Odin	12/73	181	178	(0)
34	Bruce	3/74	188	450	(450)
35	Magnus	4/74	190	1080	(1080)
36	N.E. Frigg	4/74	191	71	(0)
37	Balder	4/74	193	100	(100)
38	Andrew	4/74	195	?	?
39	Claymore	4/74	196	400	(400)
40	E. Magnus	6/74	208	250	(250)

TABLE I - Continued

Order of Discovery	Field Name or Location	Spud Date	Cumulative Wildcats	Recoverable Reserves Oil Equiv.	(oil)
41	9/13-4	6/74	210	220	(220)%
42	15/6-1	9/74	223	150	(150)
43	Brae	9/74	226	185	(185)
44	Sleipner	9/74	227	50	(0)
45	Hod	11/74	237	75	(75)
46	211/27-3	11/74	238	450	(450)
47	Gudrun	11/74	239	450	(0)
48	2/10-1	11/74	240	100	(100)
49	3/4-4	12/74	244	100	(100)
50	14/20-1	1/75	245	75	(75)
51	Crawford	1/75	246	150	(150)
52	9/13-7	1.75	247	350	(350)
53	3/8-3	1.75	248	100	(100)
54	Tern	2/75	249	175	(175)
55	21/2-1	2/75	254	175	(175)
56	3/2-1A	3/75	260	200	(200)
57	Valhalla	4/75	264	50	(50)
58	3/4-6&3/9-1			200	(200)
59	15/13-2			200	(200)
60	211/26-4			175	(175)

boundary between, along with order of discovery, field name, spud date, and number of wildcats spudded up to that time. Gas reserves have been converted to oil-equivalent values using a conversion factor of 1 Trillion cubic feet of gas equals 178 million barrels of oil.

Examination of the table would seem to indicate a more or less random distribution of large-reserve discoveries. It should be noted that the record for 1975 is somewhat incomplete. Revision should not greatly affect the conclusions drawn herein. Classification of an announced discovery as "significant" is highly subjective during the early phases of evaluation in most instances. Table I is complicated by inclusion of some discoveries which undoubtedly are not commercial in themselves and exclusion of dry holes which "discovered" small accumulations. At the same time, in order to fully evaluate the amount of discovered hydrocarbons currently known as well as to be discovered, it appears important to assess the amount present in accumulations down to 50 million barrels in size. Current proven reserves are estimated at 29.369 billion barrels oil equivalent, of which 22.648 billion barrels, or 77.1 percent, is oil. Of the 59 discoveries, 8 of the discoveries can be classified as true gas accumulations with very little associated liquid.

Figure 2 illustrates the reserve data plotted cumulatively in terms of reserves and in terms of discovery size class. Note that both distributions are good approximations of a log-normal distribution as would be predicted by Kaufman.[8] The mean discovery size is 230 million barrels recoverable whereas the mean reserve size is significantly

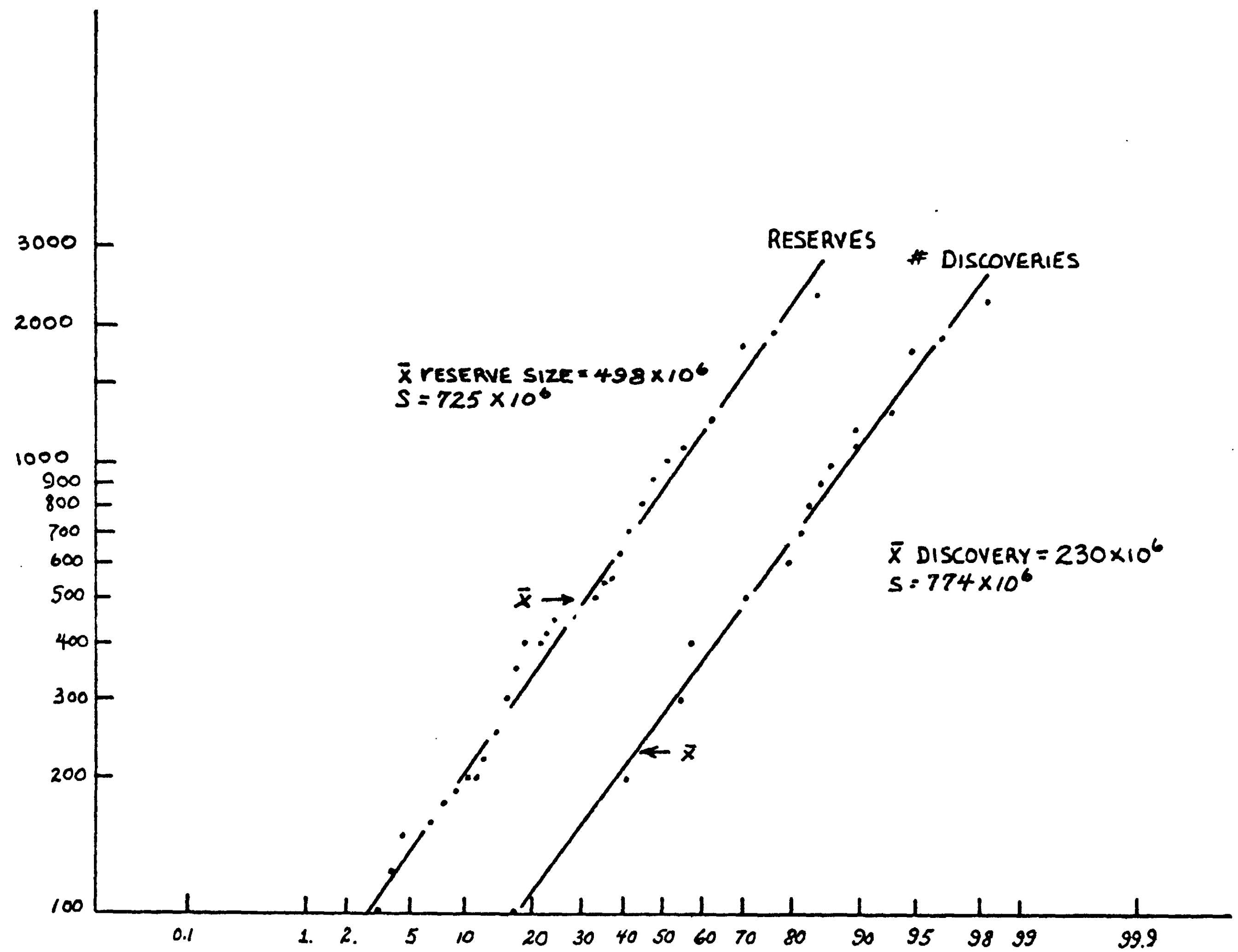

Figure 2: Cumulative Distribution, North Sea Oil and Gas Reserves and Discoveries

larger at 498 million barrels. These data are illustrated more graphically in figure 3. Some 37 percent of the discoveries contain 64 percent of the total reserves. The largest discovery, Statfjord, represents over 15 percent of the total North Sea reserves. From these data one could estimate that the probability of discovery of another Ekofisk is very low, (less than 5 percent), whereas the probability of encountering fields in the 500 million to 1 billion barrel class is relatively high. The following section discusses this aspect in more detail.

C. A Postulated Discovery Process

A number of approaches to estimation of undiscovered reserves have been advanced over the years and will not be reviewed here. In order to make such an estimation, one must make assumptions as to the likely drilling activity for some future period, the probability of success, the size of reserves discovered thus serving as an economic index of opportunity. Environmental factors, such as high cost or political stability, may impact both drilling activity and required reserve size.

The work of Kaufman, et al.,[8,9] has clearly been the most useful approach to prediction of future reserves, in that it attempts to predict discovery size as well as ultimate reserve addition. A key element in their model is a set of probabilistic assumptions which govern the behavior of additions to oil/gas in place as a function of the number of wells drilled. The postulates they utilize are:

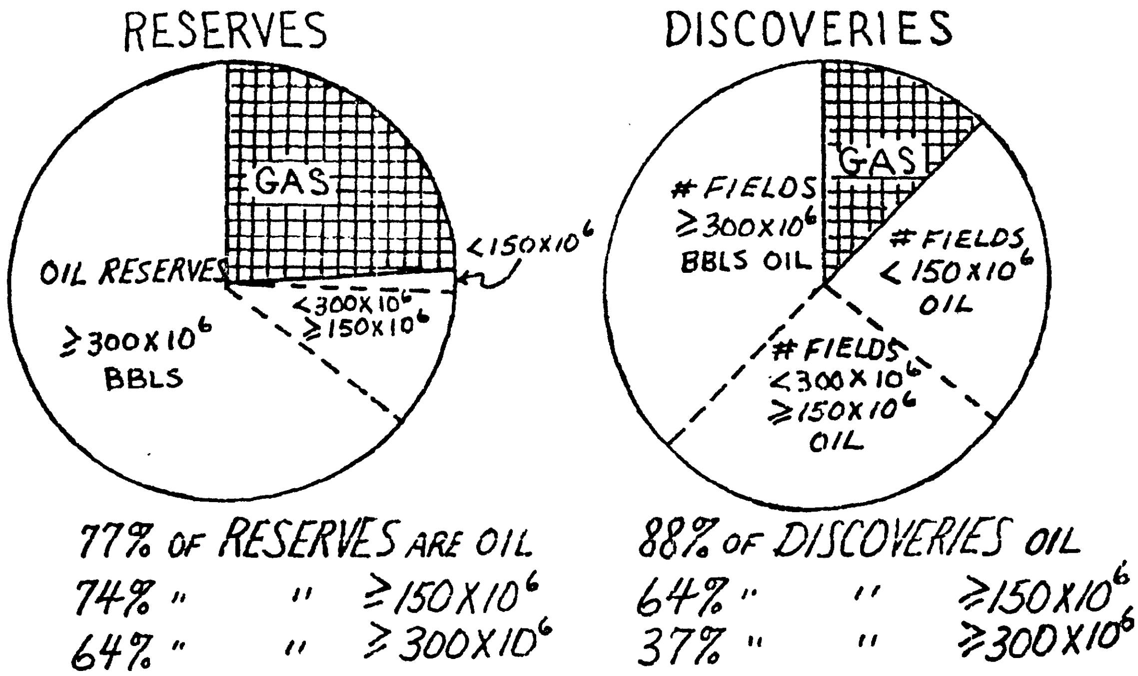

Figure 3: North Sea Reserves and Discoveries Summary Comparison

1) "the size distribution of petroleum deposits in pools within a subpopulation is lognormal", 2) "within a subpopulation, the probability of the "next" discovery will be of a given size is equal to the ratio of that size to the sum of sizes of as-yet-undiscovered pools within the subpopulation". The model essentially predicts that the largest pools will be discovered early, leading to a decline in average size as exploration proceeds. Although the analytical approach used by Barouch and Kaufman[9] is not utilized here, work in progress appears promising in developing a more elegant analytical tool for such prediction.

The approach utilized here is to take a more subjective approach. Utilizing the log-normal distribution of North Sea discoveries to-date, and making assumptions as to the probability of discovering general size classes of recoverable reserves, it then became necessary to estimate industry activity and perception of opportunity over the next decade. The first step thus became an analysis of past discovery success rates, the amount of prospective acreage remaining and undrilled, and potential impact of exploration costs.

Within the prime trend, approximately 51 discoveries were made with a wildcat effort of 210 wells. The less prospective area yielded only 3 discoveries out of 49 attempts. Success rates of 24 and 6 percent are thus derived from this data. The average success rate is 21 percent for all 259 wildcats. An independent assessment by CONOCO personnel estimates 31 "commercial" discoveries out of 139 attempts, for a success rate of 22 percent.[7]

An inventory of acreage within the designated area of investigation has been assembled in Table II. Note that Norway blocks, due to their larger size, have been converted to U.K. size for purposes of analysis. The total number of blocks, (U.K. size), is 995 Within the prime area of exploration, there are 431 blocks. Industry has held some 358 blocks, with subsequent relinquishment of 50 blocks, and currently holds approximately 308 blocks. Within the less prospective area, there are approximately 564 blocks. Industry has held approximately 153 blocks, with subsequent relinquishment of 51 blocks. Of the blocks currently held, 75 percent are in the prime area and 25 percent in the less prospective area, a significant change from the original holding of 70 percent and 30 percent respectively. This trend will continue, as most of the prime acreage in U.K. waters is held by industry. Norway, by way of contrast, still has some 62 blocks considered to lie in the prime area which have never been awarded. An additional 12 blocks of the industry sector are held by the Norwegian national oil company, Statoil.

In order to estimate the undiscovered potential of industry held acreage, it has been necessary to establish what percentage of that acreage is considered "prospective" under current industry interpretation. One approach utilizes the concept of a prospect "portfolio" wherein a typical company holds interests in 18 blocks within the area of study.[7] Some 40 percent, or 7 blocks, are not currently considered prospective, whereas the remaining 11 blocks are interpreted to have a mean potential of 500 million barrels per block, (with a standard deviation of 415 million barrels). This distribution of potential

TABLE II

NORTH SEA EXPLORATION ACREAGE

A. On the basis of Host-Government:

PRIME AREA

	U.K.	Norway
Blocks Never Awarded----------------------------------	11	62
Blocks Relinquished by Industry----------------------	13	37
Blocks Retained by Industry--------------------------	215	93*
TOTALS	239	192

* includes Statoil

LESS PROSPECTIVE AREA

	U.K.	Norway
Blocks Never Awarded----------------------------------	222	189
Blocks Relinquished by Industry----------------------	12	39
Blocks Retained by Industry--------------------------	48	54
TOTALS	282	282

B. On the Basis of Acreage-Type and Combined Host-Government:

	PRIME AREA	LESS PROSPECTIVE
Blocks Held by Industry--------------------	308	102
Blocks Relinquished by Industry------------	50	51
Blocks Retained by Industry----------------	73	411
TOTALS	431	564

C. Prime Area Discovery Rate = .24
Less Prospective Area Rate = .06
Conglomerate Discovery Rate = .21

reserve size is very comparable to the distribution of reserve size shown in figure 2. Furthermore, there are no prospects in the portfolio which fall in the less prospective area. Utilizing this type of prospect distribution as typical for the region as a whole, we can then attempt to ascertain hydrocarbon potential.

Using a mean block potential of 500 million barrels and 60 percent of the prime area blocks as prospective, applying the 24 percent chance of discovery yields a potential of 22.5 billion barrels. The less prospective area is more difficult to estimate. If we apply the same criteria to this acreage with a 6 percent chance of discovery, we gain another 1.8 billion barrels, for a total of 24.3 billion barrels of undiscovered reserves. Addition of this figure to current reserves of 29.369 billion barrels yields an ultimate potential of 53.669 barrels. The assumptions that the relatively high success rate will continue without decline into the future and that the less prospective area contains a relatively high percentage of prospects appears unrealistic, however. It is a commonly observed fact that discovery rates decline over time, along with mean field size.

One can attempt to evaluate host-government-retained acreage utilizing comparable criteria. There are 73 prime area blocks, mostly in Norwegian waters, which would thus have a potential for 5.3 billion barrels. Assuming that the relatively large amount of acreage in the less prospective area, currently held by government, contains an estimated 10 percent prospective possibility, we can add another 1.2 billion barrels potential. We can thus derive a total grand ultimate potential for the North Sea of 60.2 billion barrels oil and gas. Using the previously cited percentage of oil reserves, we derive 46.3 billion barrels of oil reserves. As cited in Table III, however, this figure should be taken as highly optimistic.

Table III compares other estimates of North Sea potential with the current work. Ultimate reserves on the order of 40 to 50 billion barrels do not appear to be unreasonable, although O'Dell cites a significantly greater potential for the "Scottish sector" of the North Sea.[15] Finally, a figure of 53.669 billion barrels, as derived from the following discussion, will be used as this writers' best estimate. Reasoning is as follows.

An essential input required for this investigation was derivation of anticipated field size, on a year by year basis, assuming a finite number of prospects remain to be evaluated. Within the prime area, there are 308 blocks, 61 percent of which are prospective, with a 24 percent chance of discovery, yielding 45 potential discoveries. The less prospective area might yield another 4 discoveries, and a total of approximately 49 discoveries of roughly 250 prospects drilled. Current estimates of 1976 exploratory rig activity are based on announced drilling plans utilizing approximately 20 rigs, down 10 rigs from previous years.[7] This translates into approximately 80 exploratory wells during 1976. In order to relate this to exploratory activity as used in this study, it is necessary to separate wildcat activity from "infield" exploratory activity. Based on prior statistics, it would appear that about 50 percent of the so-called exploratory wells are

TABLE III

ESTIMATES OF NORTH SEA POTENTIAL
(all figures are billions of barrels)

British Petroleum[10]	18.0	Current plus 24.0	Future ---------	=	42.0 Bbls.
Oil and Gas Journal[11]	23.0	Current			
King[12]	17.5	Current plus 16.0	Future (U.K.)---	=	33.5 Bbls.
Birks[6]	39.	Commercial plus 8.5	Subcommercial---	=	47.5 Bbls.
This Study(1976):					
Industry Acreage:	29.369	Current plus 24.3	Future----------	=	53.669 Oil + Gas
Fields $\geq 150\times10^6$:	21.645	Current Oil plus 17.6	Future Oil------	=	39.245 Oil
Fiels $\geq 300\times10^6$:	18.69	Current Oil plus 15.0	Future Oil------	=	33.69 Oil
Ultimate Potential including Government Acreage-------------------------------				=	53.669 Oil + Gas
			Plus		6.5
					60.169 Oil + Gas
			Total (X .77)	=	46.3 Oil

truly wildcats, the remainder being "significant" extensions or infield delineation wells across block boundaries from prior discoveries.

A drilling rate of 40 wildcats per year would require approximately 6.3 years in order to drill 250 wildcats, yielding about 8 discoveries per year. If we apply judgment and assume that the discovery rate will decline over time, a discovery table such as shown in Table IV can be derived. Using our previously cited discovery data, 24.3 billion barrels reserves would be discovered with 49 discoveries. As noted in Table IV, this reduces to 18.8 billion barrels oil in 43 discoveries. Some 15.6 billion barrels of reserves would be found in 18 of the discoveries. Utilizing a non-rigorous approach to distribution of field size in fields greater than 300 million barrels of oil, this writer assigned 8 fields to the 500 million barrel class, 9 fields to a 1 billion barrel class, and 1 field of 2 billion barrels. As shown in Tables IV and V, these field sizes form the basis for subsequent economic analysis reported in subsequent sections of this thesis.

As shown in Table IV, the distribution of field sizes is randomly distributed although biased towards the earlier years of exploration. Thus the derived additions to reserves on a yearly basis reflect this writer's anticipation of reduced success in 1980 and 1981. In order to evaluate the plausibility of development of fields less than 300 million barrels, 13 fields of the 200 million barrel class were distributed over the 6 year period. This size class is one of convenience, since the utilization of a larger number of smaller fields would have complicated the necessary computations. As is shown in Table V, inclusion of fields

TABLE IV

PREDICTED DISCOVERIES - 1976 THROUGH 1981, NORTH SEA OIL

	1976	1977	1978	1979	1980	1981	SUM
Discoveries -----	10	9	8	8	7	7	49
Oil Discoveries--	9	8	7	7	6	6	43
# 60 x 10^6 bbls.-	2	2	2	2	2	2	12
#200 x 10^6 bbls.-	3	2	2	2	2	2	13
#500 x 10^6 bbls.-	1	2	1	2	1	1	8
# 1 x 10^9 bbls.--	1	2	2	1	2	1	9
# 2 x 10^9 bbls.--	0	0	1	0	0	0	1
Sum Reserves at 150 x 10^6 Minimum Field Size-------	$2.1E^9$	$3.4E^9$	$4.9E^9$	$2.4E^9$	$2.9E^9$	$1.9E^9$	17.6×10^9 BBLS
# Fields----------	5	6	6	5	5	4	31
Sum Reserves at 300 x 10^6 Minimum Field Size-------	$1.5E^9$	$3.0E^9$	$4.5E^0$	$2.0E^9$	$2.5E^9$	$1.5E^9$	15.0×10^9 BBLS
# Fields---------	2	4	4	3	3	2	18

RESERVES	# DISCOVERIES
24.3×10^9 bbls oil + gas	49
18.8×10^9 bbls oil	43
18.0×10^9 bbls oil $\geq 150E^6$	31
15.6×10^9 bbls oil $\geq 300E^6$	18

TABLE V

OBSERVED AND PREDICTED DISCOVERIES AND RESERVES,
NORTH SEA OIL, 1968-1981

Year	'68	'69	'70	'71	'72	'73	'74	'75	'76	'77	'78	'79	'80	'81	SUM
# Discoveries, Oil + Gas-----	1	2	6	4	10	10	16	11	10	9	8	8	7	7	109
Reserves, Billions BBls.	.15	2.1	4.0	3.8	4.3	8.1	4.1	2.7	3.1	4.5	5.9	3.4	3.9	2.9	53.669
Reserves in Fields $\geq 150x10^6$ bbls oil-----------		1.3	3.1	1.8	3.4	6.6	3.2	2.5	2.1	3.4	4.9	2.4	2.9	1.9	39.245
# Discoveries $\geq 150x10^6$ bbls oil-----------		2	5	1	7	7	8	8	5	6	6	5	5	4	69.0
Reserves in Field $\geq 300x10^6$ bbls oil-----------		1.1	2.7	1.8	3.2	6.3	2.4	1.4	1.5	3.0	4.5	2.0	2.5	1.5	33.69
# Discoveries $\geq 300x10^6$ bbls oil-----------		1	3	1	6	5	4	2	2	4	4	3	3	2	40

greater than or equal to 150 million barrels, (all of 200 million barrels in the years post 1975), would increase the number of "commercial" fields from 40 to 69, and the amount of recoverable oil reserves from 33.69 billion barrels to 39.245 billion barrels, or some 16 percent of total recoverable oil reserves.

As previously discussed, it is this writer's opinion that the North Sea is in "an intermediate stage of evaluation". As exploration proceeds, one can assume that a transition into a "mature" stage of exploratory activity will ensue. As illustrated by figure 4, we are currently projecting an absolute discovery rate which captures remaining potential reserves in a relatively short time. One might logically assume that discovery rates will decline more rapidly than shown in figure 4, thus yielding a lower absolute potential for the North Sea. The subsequent scenarios should thus be considered as optimistic evaluations of future potential for the North Sea. It should also be pointed out that government-retained acreage is not included here or in subsequent sections, due to uncertainties regarding future release of said acreage for industry exploration.

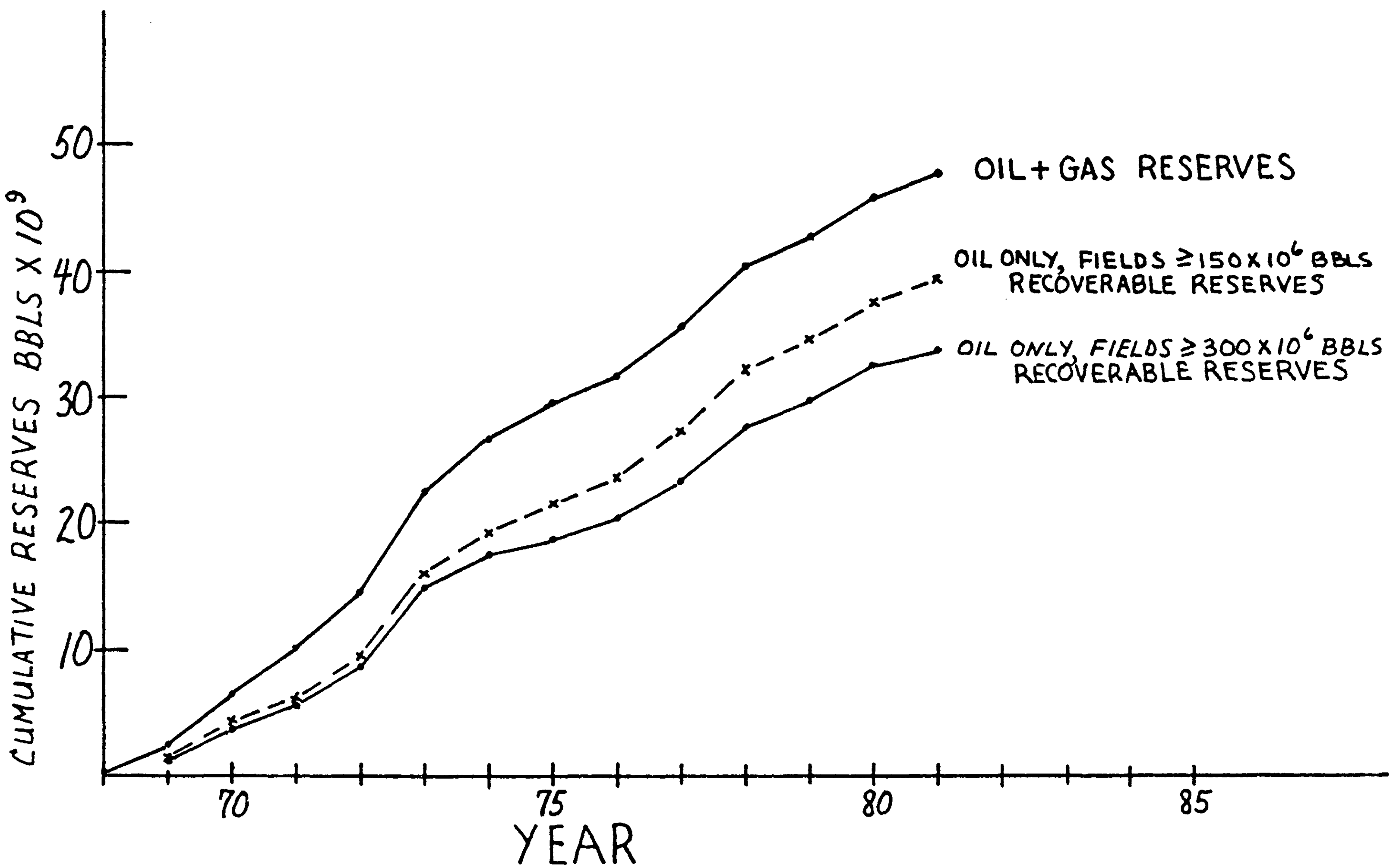

Figure 4: Northern North Sea Postulated Recoverable Reserves

CURRENT INDUSTRY INVESTMENT IN THE NORTH SEA

CHAPTER III

A. Introduction

There is only limited information available at the present time concerning the number of projects, and their associated investments, undergoing development in the North Sea. Published information concerning capital expenditure and operating costs have been summarized from consulting firms and published accounts.[14] This writer presently estimates that some 14.8 billion barrels recoverable oil reserves are undergoing active development with an estimated capital investment of $16.8 billion dollars. Peak daily production is estimated to occur in 1981 at 4.12 million barrels daily, which translates to a cost of $4087./daily barrel of production without accounting for operating costs.

It can be further estimated that an additional 4.6 million barrels of reserves are in various stages of evaluation and will probably be developed. Addition of this development to the above would yield a total of 19.4 billion barrels of reserves and a peak production of 4.95 million barrels per day in 1971 at a capital investment of $27.018 billion dollars. The higher cost of this latter production raises the overall cost per barrel of daily production to $5458.

The enormous expenditures by private industry cited here should serve to dramatize the magnitude of capital investment in the North Sea. Before entering into a detailed discussion of that investment and the potential benefits to be derived, a brief discussion is inserted here on the costs of North Sea exploration as well as the operating environment. From this discussion it is hoped that a better understanding of the exposure to risk by said private companies might be gained. Following that discussion, sections of reserves and production forecasts, investment costs, tax law and government policy, and a cash-flow analysis will be presented.

B. North Sea Exploration Costs

There is no accurate way to establish total expenditure towards exploration in the northern portion of the North Sea other than to attempt to estimate the important components. Most of this information comes from the literature or trade journals. Up to 1972, it was estimated by Birks[6] that some 625,000 miles of geophysical data in U.K., Norway and Dutch waters had been shot. Assuming approximately 60,000 miles/year as average acquisition since 1972, the total line mileage through 1975 would be on the order of 800,000 miles. Excluding early mileage devoted largely to the southern U.K. and Dutch gas area, mileage in the northern areas is probably on the order of 600,000 line miles as a conservative estimate. The acquisition and process cost of these data would thus be on the order of \$120 million dollars, with geophysical interpretation and additional processing of another \$120. million. Geological interpretation expenditures would account for an estimated \$60 million dollars or more, thus bring total geological/geophysical costs to approximately \$300 million dollars. On the basis of the number of blocks drilled to date, the average expenditure per block is approximately \$600 thousand dollars.

By the end of 1975, it has been estimated that some 562 exploration and delineation wells had been drilled where oil was the primary objective. Assuming that at least a portion of these oil programmed wells were drilled in the gas fields of the northern area, we can estimate that at least 520 wells should logically be allocated towards the "oil play" of the northern area. Using a current figure of $4.6 million per well plus a 10 percent management overhead fee to account for research and development costs, we arrive at a figure of $3 billion dollars plus as the industry exploration expenditure.

If we use the above approach as a basis for estimating expenditures over the next five years, total industry outlay for exploration could easily approach $6 billion dollars. Assuming some 250 wildcats discover 18 commercial fields requiring 6 wells each to delineate, we can easily project costs of 1.6 billion dollars. Another 13 fields of smaller size would require an additional $360 million dollars to evaluate. Recent escalation of geophysical and geological costs, for which I have no current estimates, would thus bring the total cost to approximately $2.5 to $3. billion dollars.

Exploration costs have not been included in the development outlays of the projects analyzed. Present values of the discounted cashflows for each project should, therefore, exceed the average exploration expenditure for each project. There are currently 22 fields which appear to be commercially viable. The average industry expenditure to date is thus $136 million dollars per project although not all fields are thoroughly delineated. Alternatively, one can estimate that an expenditure of $600,000 for geophysics and geology along with an average

6 exploration/delineation wells at $4.6 million per well yields a minimum exploration expenditure of approximately $30. million dollars.

C. The North Sea Environment and Cost Escalation

The North Sea represents one of the most severe marine environments yet encountered by the petroleum industry. As might be expected, early designs and construction-cost estimates were, in retrospect, highly optimistic. Subsequent high rates of inflation, lack of construction capacity, shortages of drilling and construction materials, and labor problems led to higher investment and operating costs as development plans proceeded. It is now anticipated that inflation rates in the North Sea sector will moderate during the next years. Reduced pressures on available resources resulting from the present recession, anticipated slowdown in North Sea drilling activity, and construction capacity catching up with demand should account for most of the reduction.

The cost data cited in the following sections represents estimates of inflation on all post-1975 outlays. The figures used were 30 percent for 1975, 25 percent for 1976, 20 percent for 1977, and 10 percent for all years thereafter.[14] The use of inflated costs for the analysis represents this writer's conservative approach plus a lack of confidence that the acquired cost figures had been treated consistently. This problem will be discussed further in the Chapter on Minimum Field Size Required for Development where cost data is most critical.

D. Current Development Capital Investment

As documented in Appendix I, cost data for 15 development projects have been used for the initial analysis. These projects represent oil development only. Total capital investment ranges from $280 million in the Montrose Field to $3.5 billion at Statfjord. Cost data is shown as (1) platform and installation costs, (2) platform equipment costs, (3) development drilling costs, and (4) transportation and pipeline costs, which include onshore terminal costs. Miscellaneous costs have been arbitrarily allocated almost entirely to platform and installation costs. Miscellaneous costs generally run about 3 percent of total investment.

Large projects such as Ekofisk and Forties, which had an early start-up in terms of North Sea development, have relatively low costs as compared to later projects. If these projects were translated into 1976 dollars the converse would be true. The Ekofisk development is probably the most expensive development of the entire North Sea when viewed in that context.

Total operating costs vary between approximately $40 million dollars per year for the smaller projects to $165 million per year for Statfjord. As shown in Appendix I, operating costs are broken down into platform operating and transportation operating costs.

Standard investment and production profiles, expressed as a percentage per year since discovery, were used for all analyses undertaken in this study. As shown in Table VI, all fields with reserves less than 300 million barrels use a six year profile for investment, whereas the larger fields use a nine-year profile. Production profiles range from a

TABLE VI

Investment and Production Profiles, North Sea

Investment Profiles: (CIPFL)

"Small" (<300E6)		"Large" (>300E6)	
Year 1	.04	Year 1	.04
Year 2	.44	Year 2	.12
Year 3	.27	Year 3	.20
Year 4	.11	Year 4	.24
Year 5	.08	Year 5	.16
Year 6	.06	Year 6	.07
		Year 7	.06
		Year 8	.06
		Year 9	.05

Production Profiles (PNPFL):

RESV	< 300E6	300E6 to 1500E6	> 1500 E6
Year 1	.09	.03	.01
2	.13	.08	.04
3	.15	.10	.06
4	.13	.11	.09
5	.13	.10	.10
6	.11	.10	.10
7	.08	.10	.10
8	.06	.10	.10
9	.05	.08	.10
10	.03	.06	.08
11	.02	.05	.07
12	.02	.04	.05
13	0	.03	.03
14	0	.02	.03
15	0	0	.02
16	0	0	.01
17	0	0	.01

12 year profile for small fields to a 14 year profile for fields in the 300 to 1500 million barrel range, and a 17 year profile for large fields. The only exception to this practice was the Thistle Field, where an abnormally rapid production profile of 7 years was used. Such a high rate of extraction may be unrealistic in view of the rates projected by other operators in the area. Figure 5 illustrates approximate timing of investment and production relative to year of discovery. Timing for current development projects is given in Appendix I.

E. Computation of Taxes and Government Policy

Both Norway and the United Kingdom have recently enacted new tax laws to increase government take from anticipated North Sea production. After describing the laws for the two countries, which have quite comparable effects on cash-flow, a brief discussion of government participation and potential future changes in tax policy are included. Bonus payments and various types of fees have not been included in the discussion or the analysis. Bonus payments for North Sea blocks have not been used extensively, and various license fees do not approach the magnitude or importance of costs considered herein.

United Kingdom:

The new tax laws became effective in November of 1974.[13] The government revenues are comprised of the following measures: (1) royalty payments, (2) petroleum revenue tax, (P.R.T.), and (3) corporate tax.

Royalty is calculated as a percentage of gross oil production on a per field basis. The current rate is 12.5 percent. The Energy

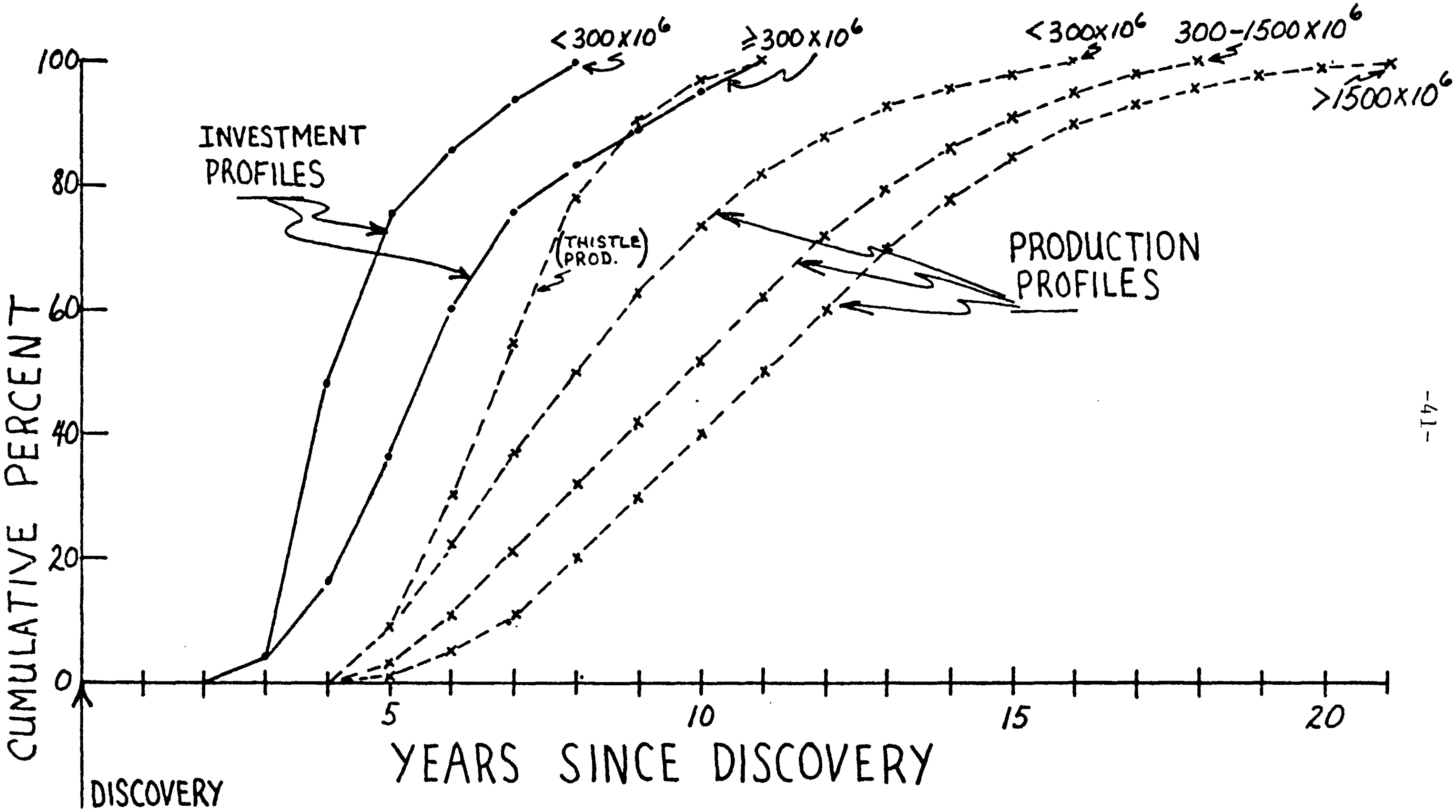

Figure 5: Investment and Production Profiles versus Time, North Sea

Ministry has the power to refund royalty wholly or in part, presumably during periods of emergency. "Emergency" could be construed as a period of low crude prices or operator distress from adversity.

The Petroleum Revenue Tax considers that an investment fence extends around each field, and includes pipelines and terminal facilities allocated to that field. A "fence" includes all areas within 5000 meters of the field boundary. Exploration or delineation costs, even if abortive, are allowed as expense if within this fence with "uplift" on investment.

Field by field computation of P.R.T. is required, thus current losses on one field cannot be offset against profits on another field. P.R.T. is payable at 45 percent of corporate taxable income on each field reduced by the following deductions:

1) Investment is multiplied by an "uplift" factor of 1.75 for the putpose of calculating taxable income.
2) The operator receives an oil allowance or the cash equivalent of 7.3 million barrels of oil per year of production subject to (a) 73 million barrels maximum over the field life, (b) a carry-forward of unused amounts but still subject to 7.3 million barrels per year maximum deduction, and (c) the allowance does not start until uplift on the investment has been recovered.
3) The maximum P.R.T. liability in any year is 80 percent of the difference between the taxable income for P.R.T. before oil allowance, and 30 percent of investment.

4) Interest costs are not allowed as expense for P.R.T. calculations.

5) P.R.T. is not payable on gas fields with signed contracts to the British Gas Corporation as of June 30, 1975.

6) Although not in the legislation, it is apparently the government's intention that the rate of P.R.T. can/will be changed if crude prices change substantially in real terms. P.R.T. can thus be construed as an excess profits tax.

The Corporate Tax computation is relatively straight-forward and payable at a rate of 52 percent subject to the following deductions. The tax rate is legislated on a yearly basis.

1) Operating costs, royalty payments, interest costs, and P.R.T. are fully deductible from revenue.

2) Depreciation is fully deductible and can be written off as incurred if a tangible investment. Intangible investment is written off over the project life.

3) Loss carry-forward is deductible and written off as fast as income is available.

4) Deficits anywhere in the U.K. North Sea can be applied against income in the North Sea, but not against onshore income. Deficits onshore can be applied against North Sea income. Corporate tax payment lags by one year whereas P.R.T. is paid as accrued. The tax price of crude, (the Norm Price), will probably be set as equal to the average U.K. North Sea realized price.

Norway:

The new petroleum tax low became effective in January of 1975.[13] The government revenues are comprised of the following measures: (1) royalty payments, (2) corporation tax, (3) state tax, (4) local tax, (5) special tax, (6) withholding (source) tax on distributed dividends, and (7) capital tax. All taxes are deferred one year.

Royalty is calculated as a percentage of gross oil production on a per field basis. For blocks allocated in the first licensing round, the royalty is fixed at 10 percent. For all subsequently licensed blocks, royalty is computed on the basis of production rates as follows:

40,000 barrels/day or less	= 8 percent
40,000 to 100,000 bbls/day	= 10 percent
100,000 to 225,000	= 12 percent
225,000 to 350,000	= 14 percent
350,000 and greater	= 16 percent

Once the royalty rates reaches 12 percent, it does not decline with subsequently lower production levels.

The Corporation Tax is payable at a rate of 50.8 percent on the basis of revenue less operating costs, royalty, depreciation, loss carry-forward, interest costs, and distributed dividends. Payment is deferred one year. Deductions are explained as follows:

1) Depreciation of production and transportation facilities will be linearly over a period of six years from the year the plant was taken into ordinary use, or when petroleum is produced.

2) Carried-forward losses can be deducted provided they arise from offshore operations during the past 15 years. The losses must be spread over a 3-year period on a straight-line basis. All offshore

losses, if so required, can be offset against other company profits derived from Norwegian activities. Only 50 percent of losses derived from other Norwegian activities can be offset against offshore profits. For purposes of calculation, we must ignore the possibility of external losses in this study.

3) Interest costs may be deducted for computing taxable income whether it is a parent company loan or a third-party loan. Interest is deductible for both corporate and special tax.

State tax is payable at a rate of 26.5 percent of net taxable income less distributed dividends. Distributed dividends are available earnings less tax liability, and will probably vary between 30 and 60 percent of net taxable income.

Local tax is computed as 24.3 percent of net taxable income.

The Special Tax can be essentially construed as an excess profits tax. The special tax is computed at a rate of 25 percent of taxable revenue less operating cost, royalty, intangibles expensed, depreciation, interest, losses carried-forward, and tax-free income. Tax free income is 10 percent of tangible investment that has been put into operation in the preceding 15 years but purchased prior to the end of the preceding year. The unused portion may be carried forward.

The Withholding (source) Tax is computed on the basis of 10 percent of distributed dividends. Payment is deferred one year.

The Capital Tax is calculated at a rate of 0.7 percent of the net capital, (i.e. after depreciation where relevant), that the company is carrying on its books. Taxable capital includes production, transport and storage facilities as well as other equipment used in the company's activities. The same applies to stocks of products produced, securities and bank deposits. The capital tax is not regarded as deductible in the assessment of other taxes. Payment is deferred one year.

Participation and Government Policy:

In Norway waters, current government participation varies from 5 to 50 percent on selected blocks. The Ministry of Industry is attempting to work out a Norwegian standard contract with active government participation for future awards. The government's share will vary from 20 to 50 percent, and will be exercised per discovery. Statoil will not share in costs until a commercial discovery is made, and will take its share in kind. The private participants will, in turn, have to market Statoil's share if this is desirable. Current developments in Norway indicate that Statoil intends to become an internationally integrated oil company as rapidly as possible.

U.K. intentions regarding participation have been considerably less aggressive as compared to Norway. Agreements reached to date primarily involve loan guarantees on the part of the government in return for agreements on an option to purchase a significant share of production on a per field basis. The government has repeatedly emphasized that private companies would be no better or no worse off than before signing of participation agreements. One could interpret that the main thrust of the participation agreements is to provide sharing of risk in order to facilitate development of some of the smaller, possibly marginal fields. Possibly the most significant effect of the government's intention to push participation is the pronouncement that any new licenses to be issued will require majority U.K. government participation in any discoveries as a condition of the license.

F. Cash-Flow Analysis of Current Development

Utilizing the computational program developed by Eckbo, a series of discounted cash-flows to the private company and the host-government have been generated for current oil field development projects. The $7 price represents a conservative approach to evaluation in which the price of crude can be construed as a constant price in current dollars and a declining price in terms of real dollars. Costs, on the other hand, can be thought of as constant in real terms, reflecting inflation beyond worldwide inflation. For the two prices of crude, a discount rate of 10 percent has been used both for the private sector and the host-government. The resulting cash-flows thus represent accrual on investment after worldwide inflation is removed. See Chapter IV for further discussion. At the $7 price of crude, only fields greater than 300 million barrels recoverable reserves have been included in the summary, whereas fields down to 150 million barrels reserves have been included in the $12 price scenario.

Table VII presents pertinent Present Values for the projects studied. Results range from $5. billion to the company and $10.9 billion for the Norwegian government at the $12 price to $3. billion to the company and $5.7 billion for the government for the Ekofisk complex. Conversely, the Cormorant Field results range from $211 million to the

TABLE VII

SUMMARY OF PRESENT VALUES, CURRENT NORTH SEA OIL DEVELOPMENT

Field	Reserves in Billion BBLS.	Time after (Disc.) to Prod. Start	Discount Rate	$ Oil Price	PVC $ Billions	PVG $ Billions
1. Ekofisk Complex	3.8	('70) 4 years	.1	12	4.82	11.14
				7	2.94	5.76
2. Statfjord	3.0	('74) 4	.1	12	4.02	7.18
				7	2.53	2.99
3. Montrose	.20	('69) 8	.1	12	0.21	0.25
				7	0.10	0.08
4. Forties	1.80	('70) 6	.1	12	1.99	3.74
				7	1.21	1.69
5. Brent	1.75	('71) 6	.1	12	1.98	3.25
				7	1.25	1.24
6. Cormorant	0.16	('72) 6	.1	12	0.21	0.16
				7	0.03	0.05
7. Beryl	0.40	('72) 5	.1	12	0.74	1.26
				7	0.46	0.53
8. Thistle	0.45	('72) 6	.1	12	0.74	1.26
				7	0.46	0.53
9. Piper	0.80	('73) 4	.1	12	1.19	2.46
				7	0.72	1.25
10. Dunlin	0.40	('73) 5	.1	12	0.63	0.73
				7	0.35	0.25

TABLE VII CONTINUED

Field	Reserves in Billion BBLS.	Time after (Disc.) to Prod. Start	Discount Rate	$ Oil Price	PVC $ Billions	PVG $ Billions
11. Alwyn	0.50	('73) 6	.1	12	0.57	0.90
				7	0.33	0.35
12. Heather	0.15	('73) 6	.1	12	0.20	0.18
				7	0.04	0.04
13. Ninian	1.0	('74) 5	.1	12	1.59	1.63
				7	0.80	0.49
14. Claymore	0.40	('74) 5	.1	12	0.58	0.89
				7	0.34	0.37
15. Hutton	0.30	('73) 7	.1	12	0.40	0.36
				7	0.15	0.09

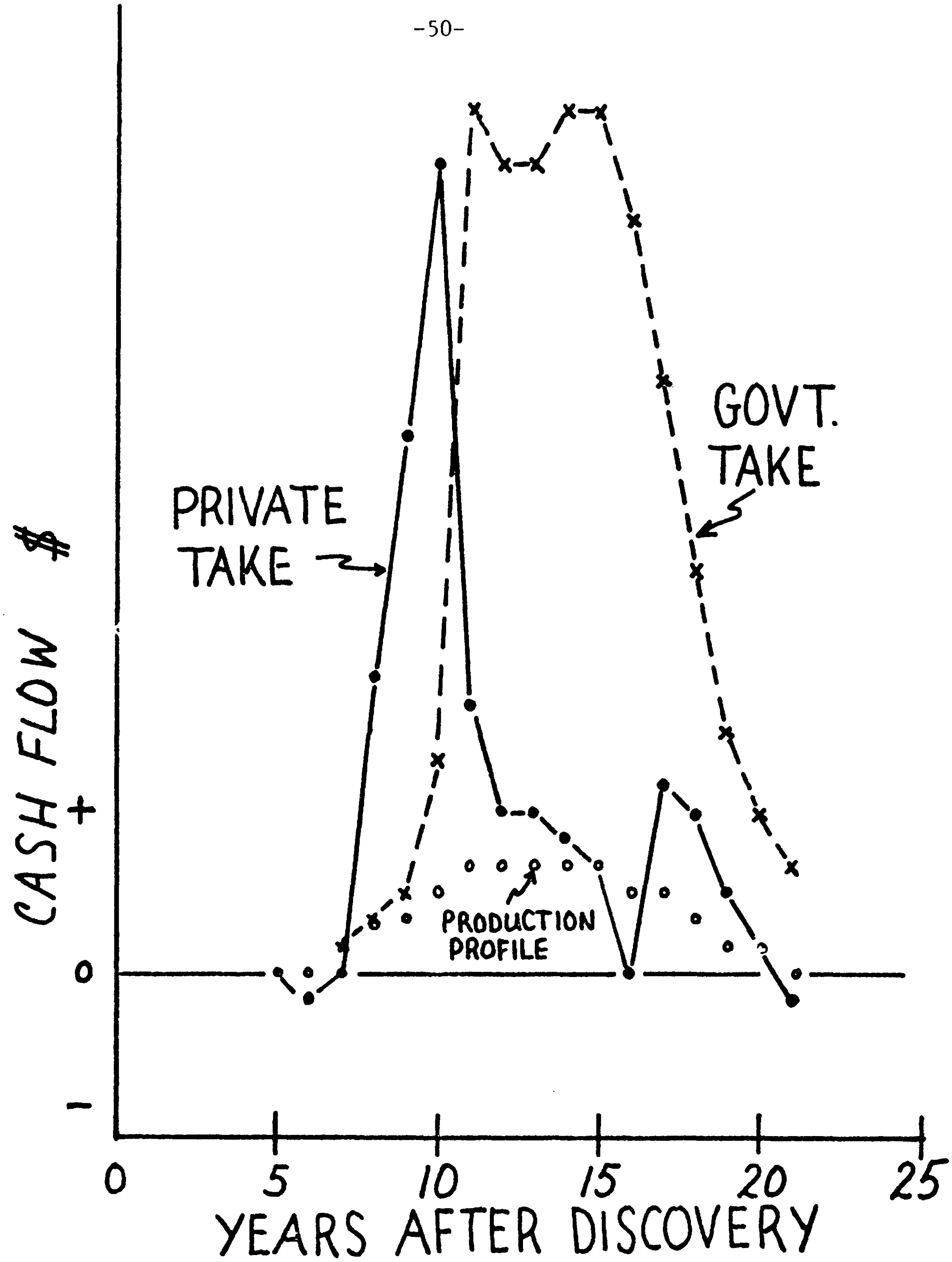

Figure 6: Cash-Flow Profile Over Time Since Discovery, British Tax System

company and $164 million to the U.K. government at the $12 price down to $29 million for the company and $45 million for the government at the $7 price.

Table VIII shows a summary of pertinent data for current development under the two prices utilized.

TABLE VIII

SUMMARY OF PERTINENT DATA FOR CURRENT DEVELOPMENT

Price:	$7	$12
Peak Production, millions bbls/day/year:	4.12(1981)	4.22(1981)
Total Reserves Developed, billions bbls:	14.8	15.1
Development Investment, $ billions:	16.84	17.8
Discounted Cash-Flow, $billions:	27(Co)-47.2(Gvt)	46.3(Co)-104.(Gvt)

It is readily observed that the higher price increases government take relative to private company take. Figure 6 illustrates the basis for this relationship, in that private company cash flow peaks rapidly in the early years of production, declining rapidly as investment is recovered. Government take, deferred until investment is recovered, then dominates the remaining years of the project. At the $7 price, discounted government take averages 64 percent, where as at the $12 price, discounted government take averages 69 percent.

In conclusion,analysis of cash-flow data from development currently under way demonstrates a number of interesting relationships: (1) a relatively high crude price is advantageous to all parties, (2) at a price of $7./bbl., fields of less than 200 million barrels do not appear attractive, (3) fields of 300 million barrels, e.g., Hutton, have present values, at a 10 percent discount rate, close to the industry average exploration outlay, and an overestimation of recoverable reserves would reduce cash-flow to a net loss. Finally, it is readily apparent that only in the larger fields will there be a net inflow of cash in the latter years of a project which accrue to the private company. Two main factors are involved relative to the small field: 1) the volume allowance may not be fully utilized prior to P.R.T. takeover due to limited production capacity of the field, and 2) operating costs, relative to production revenue obtained during subsequent years, may not allow for a positive cash-flow to the private company. Thus access to crude supply and development of subsequent discoveries appear to be the only economic incentives for continuing to operate the smaller fields after peak production is obtained.

CHAPTER IV

FUTURE DEVELOPMENT OF NORTH SEA OIL

A. Introduction

After formulating an approach to estimation of future North Sea discoveries, and establishing an analytical method to generate cash-flow data for current development projects, it thus becomes possible to estimate the contribution of known North Sea discoveries as well as future North Sea discoveries. Necessary elements required for this analysis include (1) assumptions pertaining to development costs for reserves of various size, (2) the future price of crude, and (3) the minimum field size required for development investment under those projected assumptions.

Assumptions about the future price of crude are relatively straightforward. This writer has taken the approach that prices, at least in the short run, will remain constant in current terms, and thus decline in real te-ms. Use of the \$12 and \$7 prices represents two points on a spectrum of potential prices which can be envisioned as potential conservative high prices, (e.g. \$12), and minimum acceptable low prices, (e.g. \$7). Attempts by the western governments to establish a floor price of approximately \$7/bbl. also influenced this writer. It does appear unlikely that prices might erode to a level below \$7/bbl. at any time in the near future.

The use of an apparently low discount rate of 10 percent deserves additional comment. Considering that this study utilizes the inflated cost data previously discussed, it was thought that the use of a 10 percent discount rate would adequately account for a reasonable return on investment. This may or may not be true in the case of current development projects. Uncertainties regarding reserve size, well productivity, platform durability and safety, and future government policy tend to push private industry to use much higher discount rates when evaluating projects. Secondly, by virtue of the approach taken in this study, future development projects utilize discounted cash-flows back to the time of their discovery, not to January, 1976. Thus the contribution of discounted cash-flow to the present value of future discoveries as well as current discoveries where development is speculative is overly large. The final section of this chapter attempts to deal with this problem by discounting the cumulative cash-flow of the North Sea as an additional 10 percent as representative of a more conservative estimate of the present value of North Sea oil production.

B. Minimum Field Size Required for Development

This writer has taken two approaches to the problem of establishing the minimum field size required for development. The first approach involves taking available cost data from ongoing North Sea development and attempting to analyze that data in terms of future development costs on a disaggregated basis.[14] Assumptions and limitations of that analysis are given in the following section. The second approach involves a much simpler empirical analysis of the same data by attempting to relate reserve size with total development cost using "selected" fields.

Miminum Field Size Using Disaggregated Costs:

Cost categories used to generate cash-flows for various fields have been investigated for correlation with reserve size, distance from shore, depth of production, water depth, and well capacity. The cost categories, as previously cited, consist of: (1) platform cost and installation, plus most of the miscellaneous fund, (2) platform equipment, (3) development drilling, (4) transportation costs, e.g. S.B.M., pipelines, and terminals, and (5) annual operating costs for both platform and transportation. The relationships developed were vague and poorly defined by standard statistical measures. Conclusions from this approach are thus stated in the form of assumptions regarding various cost categories.

Assumption I: Platform and installation costs are herein considered as simple functions of water depth, and no consideration has been given to design differences, environmental requirements, (as in the more hazardous northern area), or future technological improvements. It should be obvious that as areal extend of a field increases there is a concomittant increase in the number of platforms required. Under optimal trapping conditions one platform should be able to adequately service a 500 million barrel field. Alternatively, relatively long, linear reservoirs with less than one hundred million barrels may not be adequately drained by one platform. Statfjord will require at least three platforms. For the purposes of this study, it is assumed that reservoir geometry is such that efficient drainage by one platform is not a significant problem. Table IX illustrates the derived relationships used to establish platform and installation costs.

TABLE IX

PLATFORM AND INSTALLATION COST

Water Depth	Platform Cost	Installation Cost	Total
300'/less	$ 50 million	$25 million	$ 75 million
400'	100 "	37.5 "	137.5 "
500'	150 "	50. "	200. "
600'	200 "	62.5 "	262.5 "

Assumption II: Platform equipment appears to be independent of water depth, and more or less a function of reserve size. This is assumed to reflect the greater volume of liquids to be processed on the platform for larger reservoirs. No consideration has been given to different gas/oil mixtures and the problems associated with high-pressure reservoirs. Both are common problems in the North Sea.

Assumption III: Development drilling is a function of reserve size, but does not appear to be particularly cost sensitive on a project by project basis. There is an implicit assumption that smaller reservoirs will require more redrills. There is obviously a big jump in cost when going from one platform to two or more.

Assumption IV: S.B.M., terminal, and pipeline costs are relatively fixed and basically reflect reserve size as well as distance from shore. Where small fields will often use a S.B.M. in conjunction with higher transportation operating costs, it is anticipated that a number of small fields will be in close proximity to larger reserves such that spur lines can be connected with the larger pipeline systems which will be developed.

Assumption V: Miscellaneous costs appear to run about 3 percent of the gross investment outlay. A figure of 3 percent will be used for all projects formulated here, with 97 percent allocated to platform and installation costs and the remainder to transportation.

From these assumptions a field size of 150 to 200 million barrels recoverable reserves would require the following investment outlays:

TABLE X

ESTIMATED INVESTMENT FOR 150-200 MILLION BBL. FIELD

Platform and installation	$75 million to $262.5 million
Platform Equipment	50 million to 200 million
Development Drilling	125 million
S.B.M. and Terminal	45 million
Miscellaneous	9 million to 20 million
Total Investment	$300 million to $653 million

Total operating costs for fields in this size category appear to run between $35 and $40 million dollars per year. Approximately 3/4 of the operating costs is normally allocated to the platform operation. The following section discusses operating costs in more detail.

It can be readily determined from the figures cited above that platform cost and equipment are the most critical to our analysis of minimum required field size for development. Unfortunately, we must also make assumptions about probable water depth for future discoveries as well as some averaging assumptions about the cost of platform equipment required. For these reasons the following empirical approach was chosen instead.

Minimum Field Size Using Empirical Relationships:

Figure 7a shows the results achieved by plotting the log of reserve size as a function of investment per barrel of reserves and as a function of total annual operating costs. Only selected fields were used, omitting earlier projects such as Ekofisk and Forties Fields, and concentrating on developing a relationship which would emphasize financial risk. With the exception of Alwyn, Claymore, and Montrose, the function shown in Figure 7a approximates a good fit to the data. The linear function used is:

$$\text{Log Reserves} = 4.12 - .61 \text{ (Cap. Inv./bbl. Reserves)} \qquad (1)$$

Extra weight was attached to Statfjord, Brent, Hutton, and Cormorant in order to achieve this fit to the data, and the standard error is large if all data are considered. Again, this relationship can be considered as a conservative approach by attaching high investment costs to the smaller fields.

Operating costs for the smaller fields generally range between #35 and $40 million dollars per year. Statfjord, Brent, and Ninian form the basis for establishing operating costs for the larger fields. The curve for operating cost shown in Figure 7b is adequate for purposes of this investigation and is an "eye-ball" fit.

Table XI summarizes the cost data as formulated on the basis of the preceeding discussion. As shown in the table, the previous figures of #300 to #635 million investment costs for a field in the 150 to 200 million reserve category is comparable to the figures of $346 to $594 million for fields of 100 and 200 million barrels arrived at with the

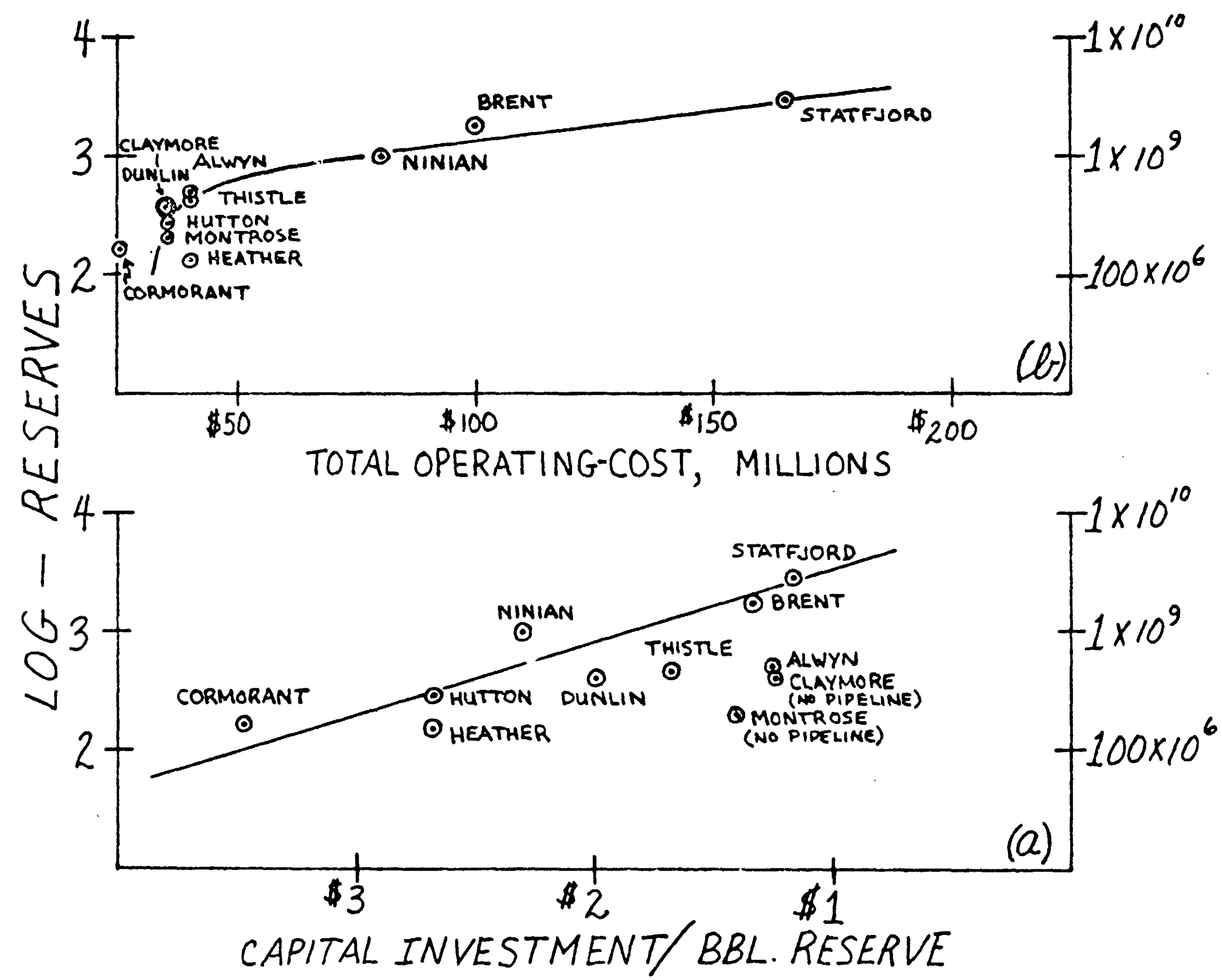

Figure 7: Capital Investment (a), and Operating Costs (b), as a Function of Reserve Size, North Sea

empirical approach. Operating costs for the smaller fields do not vary significantly from the $35 to $40 million per year previously cited. The ratio of platform to transportation operating costs range from 1:1 to 4:1, and a ratio of 3:1 appears to represent a good average.

TABLE XI

DERIVED FIELD DEVELOPMENT COSTS

Reserves (RESV)	Investment (CINV)	Platform Op. Cost (COPN)	Transportation Op. Cost (COTN)
100 $X10^6$	\$346 $X10^6$	\$26 $X10^6$	\$ 9 $X10^6$
200 "	594	26	9
300 "	819	30	10
500 "	1195	30	10
1000 "	1880	60	20
2000 "	2760	98	32

The investment and production profiles previously cited in Table VI are also used here to investigate minimum field size. These profiles represent current industry expectations and should be valid for our purposes. As previously discussed, selection of an appropriate production profile represents a thorny problem. Production profiles range from 7 to 17 years, and although the smaller fields tend to have a shorter duration, there is considerable overlap. As has been discussed in a previous section, the small fields will maximize cash-flow to the private company if the peak production is rapidly achieved. Large per-well flow rates would naturally be advantageous in such situations. Unfortunately, not all reservoirs in the North Sea can be expected to possess optimal yield characteristics such that high flow rates can be sustained. Furthermore, it would seem foolhardy to justify investment on the basis of abnormally high flow rates if the production profile selected would make the difference between commercial and non-commercial investment. Therefore all relatively small fields of 300 million barrels or less are assigned to a 12-year production profile as a somewhat conservative approach to the problem.

The average duration between discovery and time of production start is approximately 5 years, ranging from 3 to 7 years. The decision to start development investment averages approximately 3 years. Those averages are used herein. Again the smaller fields may have longer delays due to uncertainty on the part of the operators as to commercial feasibility of development.

Utilizing the computational program previously cited, cash-flows and net present values at various crude prices and various discount rates were generated using the British Tax System. The present values are shown in Table XII. In order to formulate a minimum field size for development, one must first select an acceptable discount rate and a crude oil price. Two discount rates were chosen: 10 percent and 25 percent. The question can then be asked as to what present value is necessary in order to satisfy the investor. As previously discussed in the Chapter on current industry development, a figure in excess of exploration investment must be obtained, but it seems unrealistic to use the relatively high hurdle of $136 million dollars, which is the average industry expenditure for 22 apparently viable fields. Alternatively, this writer has used a figure of $50 million dollars, which is the average exploration cost per 59 discoveries.

TABLE XII

SUMMARY OF PRESENT VALUES
FOR HYPOTHETICAL NORTH SEA OIL FIELDS
(British Tax System)

Bbls. Reserves Recoverable in Millions	Discount Rate	$ Price CRUDE	Present Value Private $ Millions	Present Value Govt. $ Millions
100	.1	12	106.	83.
	.1	10	59.	50.
	.1	7	-42.	30.
	.1	16	185.	166.
	.25	16	71.	166.
	.25	12	40.	86.
200	.1	12	303.	266
	.1	10	229.	179.
	.1	7	98.	68
	.1	5	-41.	46
	.25	12	115.	266.
	.25	7	35.	68.
	.25	16	160.	474.
	.1	16	417.	474.
300	.1	12	422.	364.
	.1	7	157.	107.
	.25	7	43.	107.
	.25	12	127.	364.
500	.1	12	638.	632.
	.1	7	280.	207.
1000	.1	12	1193.	1521.
	.1	7	640.	506.
2000	.1	12	2244.	3679.
	.1	7	1398.	1393.

Figure 8 illustrates the derived relationships using the two discount rates cited above. At a price of $12/bbl., minimum field size varies between 85 and 110 million barrels, whereas at a price of $7/bbl., minimum field size varies between 150 and 400 million barrels. The current industry assessment of minimum field size is variously cited between 250 and 300 million barrels recoverable reserves. Utilizing figure 8, this writer has concluded that the minimum acceptable field size at a price of $12 is thus 150 million barrels, which reflects the minimum acceptable size if price did fall to the lowest level anticipated. The minimum acceptable field size at a price of $7 is arbitrarily set at 300 million barrels, reflecting a more pessimistic scenario of high risk and a lowest expected price. Furthermore, one should point out that these small projects are so price and time sensitive, that a one to two year depression of prices below those used in these calculations would have disastrous effects on profitability.

C. <u>Future Development Scenarios</u>

Utilizing the concepts developed for minimum field size acceptable for development, we can not turn to known discoveries where development is speculative, as well as to future discoveries and subsequent development. A series of cash-flows, using the British tax system as a basis for calculation of private and government take, were generated at the two prices of $7 and $12 per barrel. In the $7 scenario, only fields of 300 million barrels or greater are included, whereas the $12 scenario includes fields down to the minimum size of 150 million barrels. The results of this calculation are summarized in Appendix II.

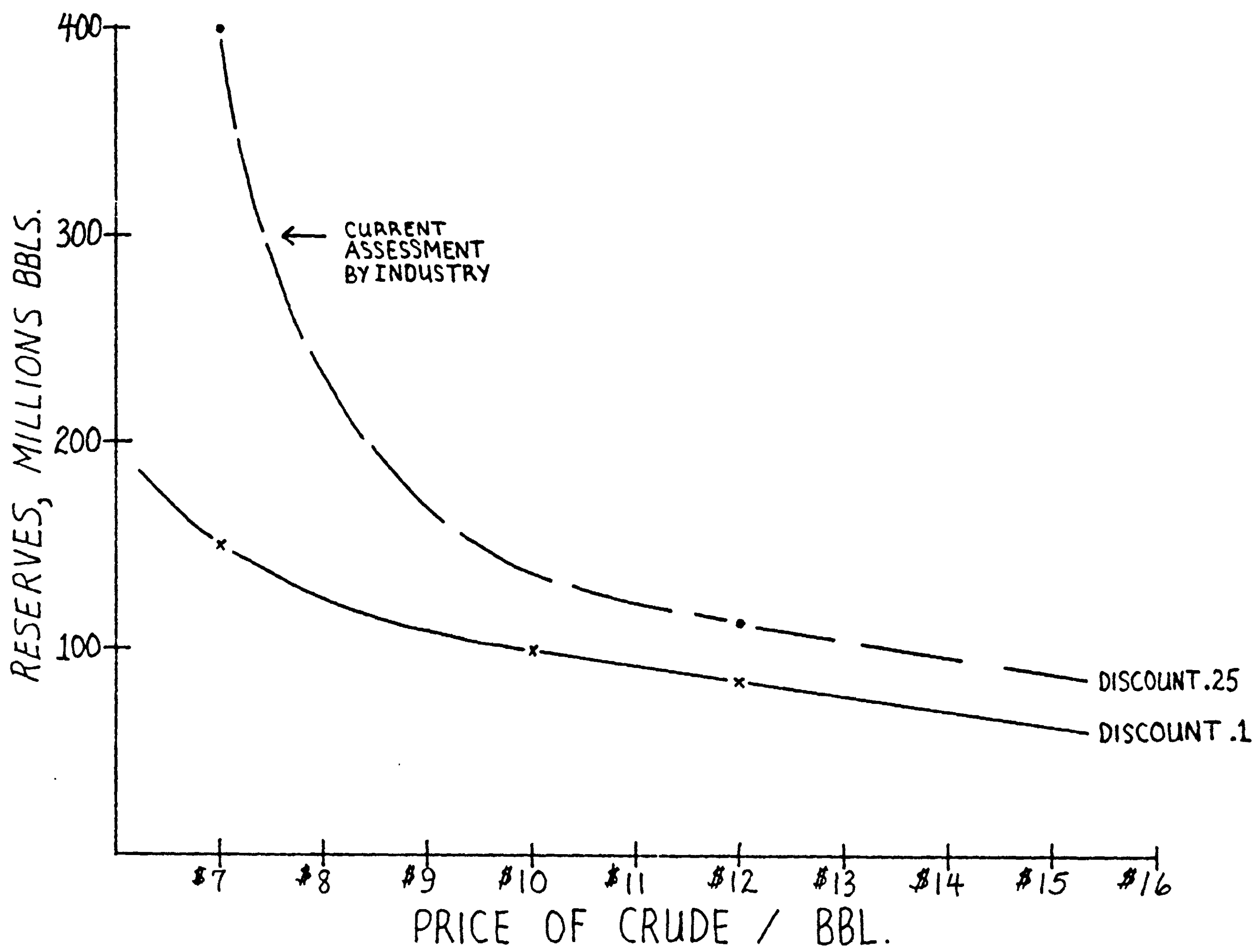

Figure 8: Minimum North Sea Field Size to Develop as a Function of Recoverable Reserves, Price, and Discount Rate

Table XIII summarizes the discounted cash-flows into the present values of current development, speculative development and future discovery development. As discussed previously, a 10 percent discount rate was used throughout, on a project basis, and does not take into account future discovery or speculative development timing. Thus the last two figures shown at the bottom of Table XIII attempt to account for timing by using another 10 percent discount to derive the present value of North Sea oil to the private sector.

TABLE XIII

DISCOUNTED CASH-FLOW SUMMARY

	$7 Price		$12 Price	
(in billions of dollars):	Private	Govt.	Private	Govt.
Current Development ----------------	27.04	47.25	46.34	103.98
Plus Development, Speculative------	35.11	55.14	66.76	132.96
Plus Future Discovery Development--	61.52	83.33	122.48	222.38
Discounted Additional 10% to 1/76--	30.58		56.25	

Figure 9 illustrates the yearly production of oil obtained under the two price scenarios. Peak production is estimated to occur in 1986 at 6.58 million barrels/day, (the $7 scenario), and could reach as high as 7.85 million barrels/day, (the $12 scenario).

Figures 10 and 11 illustrate the cash-flow data previously cited. At the $7 price, peak profits are obtained in 1979 and 1987 for private investment. Reduced cash flow from 1982 to 1984 is partially the result of timing of new production and partially an affect of relatively large outlays for new development. Government cash flow peaks in 1982, and is considerably less variable as compared to private industry cash flow.

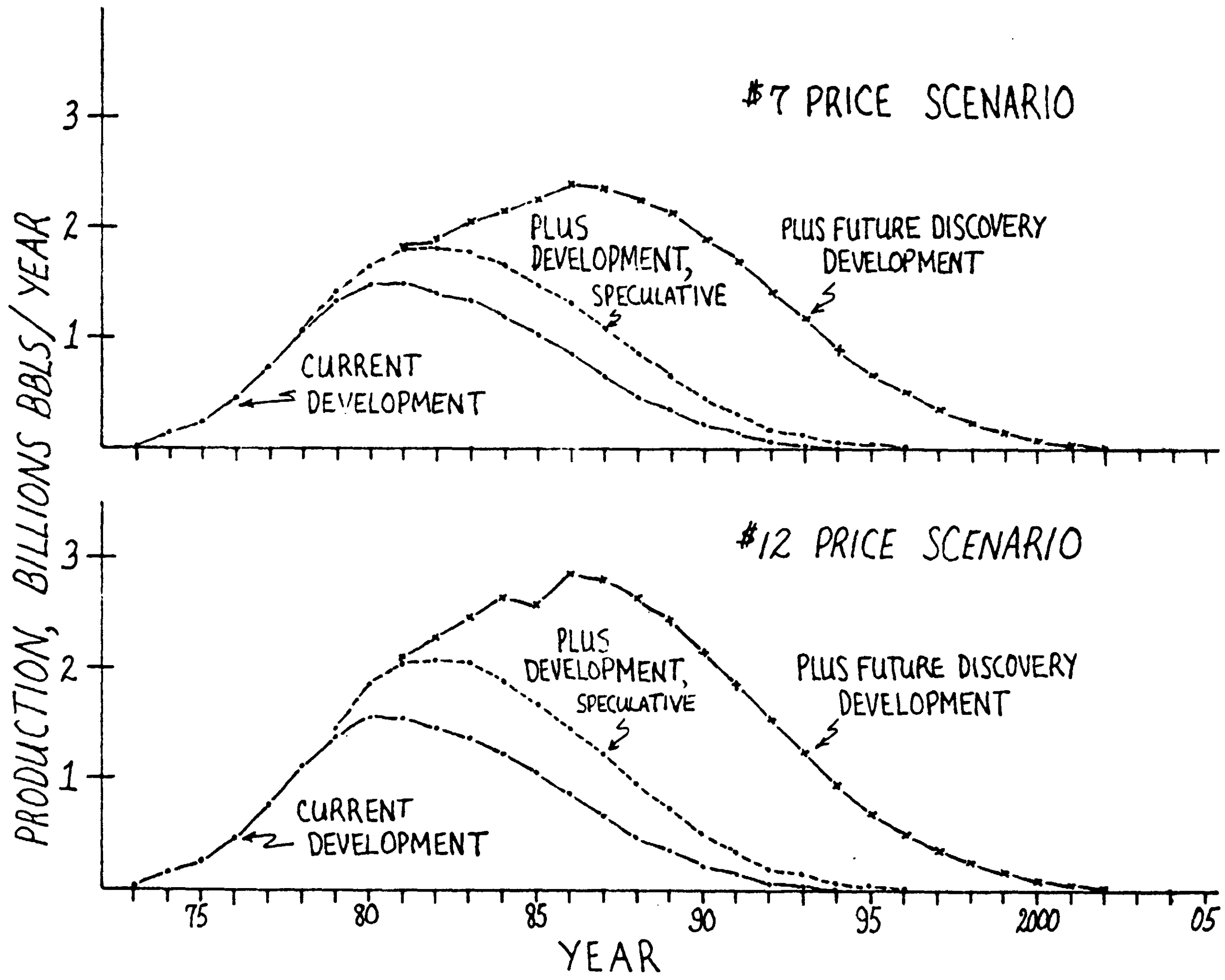

Figure 9: North Sea Yearly Production at $7 and $12 Price

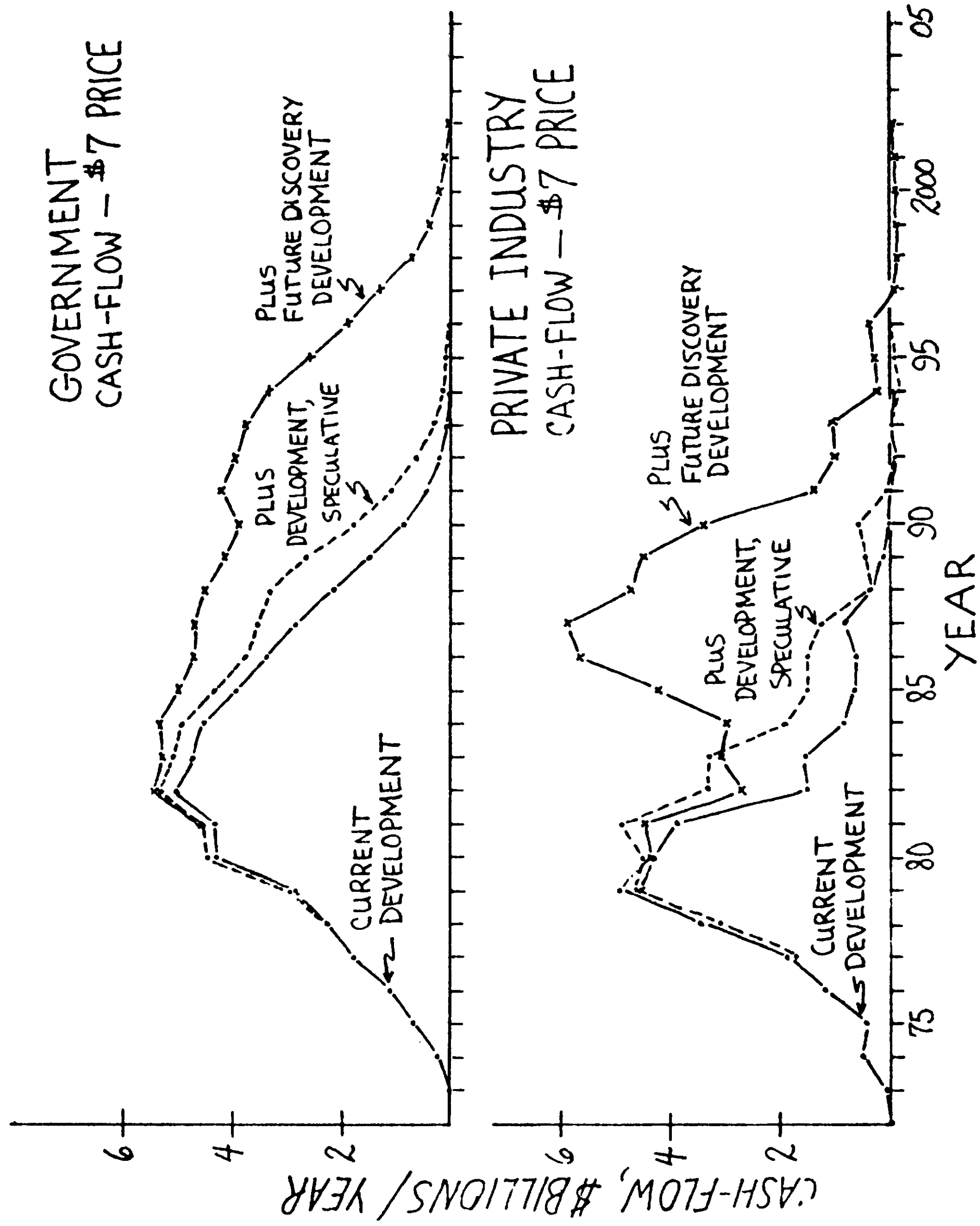

Figure 10: Government and Private Industry Cash-Flow at a $7 Price

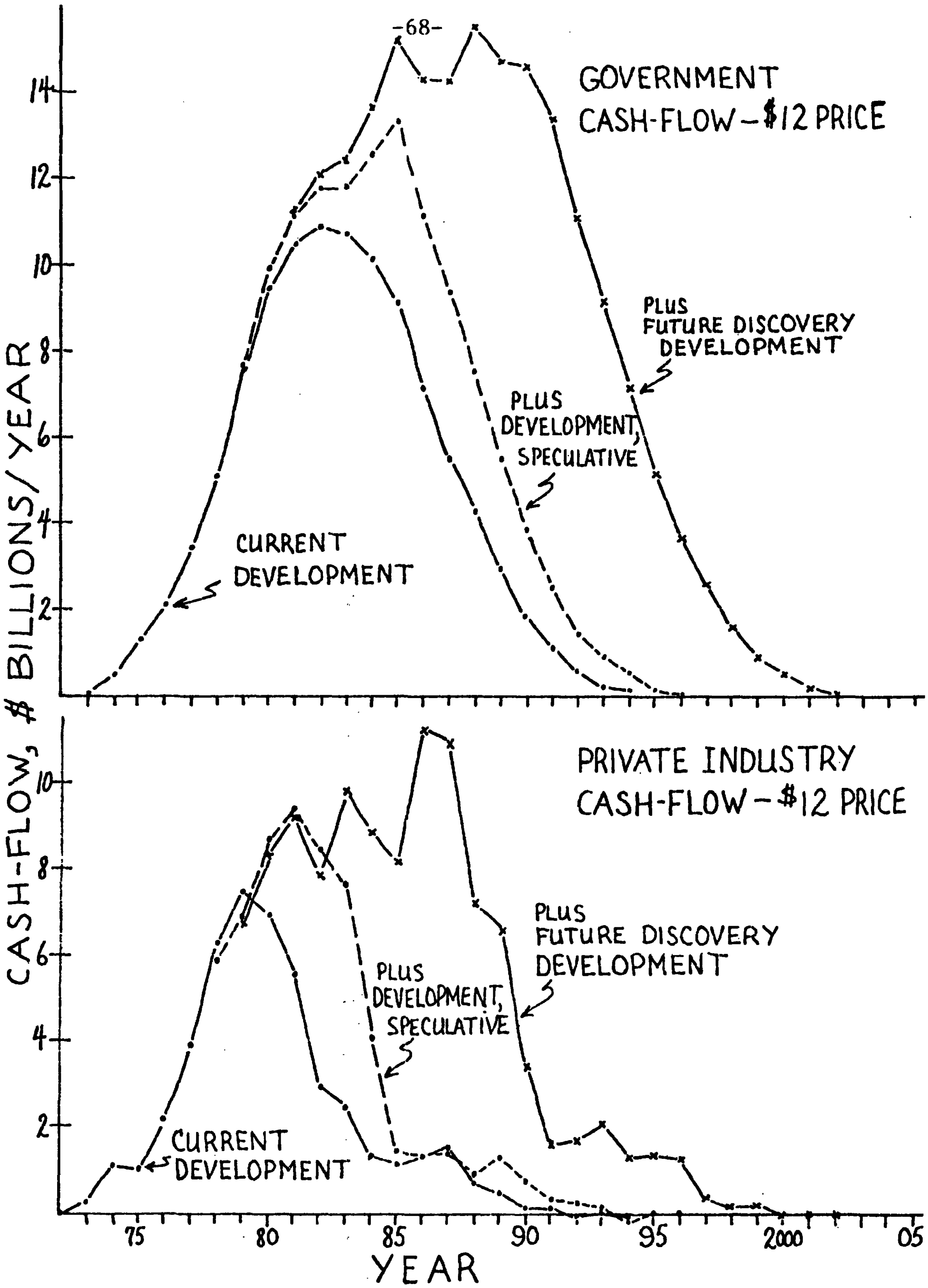

Figure 11: Government and Private Industry Cash-Flow at a $12 Price

as compared to private industry cash flow. The contribution of new discovery development is obviously substantial in both instances, thus forming the basis for a more stable utilization of resources by both government and industry.

At the $12 price, peak profits are obtained in 1986 by private industry and 1988 for the host-governments. The relatively greater contribution to government is obvious from the data plots, emphasizing the benefit that accrues to the government by virtue of the current tax policy. From these data one could infer that the host-governments have an obviously vested interest in maintaining a relatively high crude price as well as encouraging development of the smaller fields.

It should be interjected here that these scenarios account for oil development only. Of considerable interest would be comparable data for gas development along with reasonable projections of investment in new recovery technology. The latter contribution to longevity of petroleum production in the North Sea should surely extend private industry involvement into the 21st century.

Table XIV summarizes pertinent data regarding production, developed reserves, and required industry investment for the scenarios developed in this study. In addition to the estimated $6 billion dollars projected for exploration outlays, private industry is anticipated to require between $56 and $70 billion dollars for development of North Sea oil reserves. Most of this investment is anticipated to occur between now and 1985, or appoximately ten years duration.

TABLE XIV

SUMMARY OF NORTH SEA OIL DEVELOPMENT

Current Development:		
Peak Production (million bbls/day(year)---	4.12(1981)	4.22(1981)
Total Reserves Developed (billion bbls)---	14.8	15.1
Development Investment ($ billions)-------	16.84	17.8
Current Plus Discovered Development:		
Peak Production (million bbls/day(year)---	4.95(1981)	5.70(1982)
Total Reserves Developed (Billion bbls)---	19.4	20.8
Development Investment ($ billions)-------	27.02	33.17
Current Plus Discovered Plus Future:		
Peak Production (million bbls/day(year)---	6.58(1986)	7.85(1986)
Total Reserves Developed (billion bbls)---	34.4	38.4
Development Investment ($ billions)-------	56.26	70.13
Total Anticipated Industry Outlay for Exploration not Included above ($ billions) ------------------------------	6.0	

D. Summary

The preceeding discussion leads to the conclusion that enormous outleys of investment capital will be required to develop North Sea petroleum reserves. Assuming reasonable crude prices, i· is anticipated that private industry will generate very acceptable returns on the required investment. One might also assume that a considerable segment of this return will be reinvested in down-stream opportunities which arise from this significant new source of petroleum supply.

Private industry investment is estimated to require between $56 and $70 billion dollars in order to earn between $30 and $56 billion dollars. Government take, assuming a lower discount rate, is estimated to run between $83 and $222 billion dollars. Peak production of 6.58

to 7.85 million barrels/day is estimated to occur abour 1986, representing a total reserve development of approximately 34.4 to 38.4 billion barrels of oil. Natural gas and oil recovered by tertiary methods are not included in this total, and can be expected to contribute a substnatial amount in all respects to both private industry and host-governments.

The price of crude and the incentive, by private industry, to develop smaller, apparently marginal fields will substantially affect both private industry and host-government cash-flow. At the same time, it should be pointed out that current estimates of ultimate North Sea potential are highly speculative and may be highly optimistic, especially regarding undiscovered pool sizes.

CHAPTER V

CONCLUSIONS

This investigation has attempted to provide a current estimate of the oil potential of the northern North Sea from which estimates of exploration investment, development investment, and accruing cash-flows can be derived. The following findings are cited as the product of that effort:

(1) By the end of 1975, the northern North Sea has reached an intermediate stage of exploration. Current proven reserves are estimated at 29.369 billion barrels oil equivalent, of which 22.648 billion barrels, or 77.1 percent, is oil. Of the 59 discoveries, 8 can be classified as true gas accumulations.

(2) Undiscovered potential for the area of study is approximately 24.3 billion barrels, giving a most probable ultimate reserve of 53.7 billion barrels. Depending on minimum commercial field size, recoverable oil reserves should vary between 33.7 and 39.2 billion barrels. Ultimate potential, including currently retained government acreage, could reach approximately 60 billion barrels although considered unlikely.

(3) This writer estimates that some 14.8 billion barrels recoverable oil reserves are undergoing active development with an estimated capital investment of $16.8 billion dollars. Peak daily production is estimated to occur in 1981 at 4.12 million barrels daily.

(4) It can be further estimated that an additional 4.6 billion barrels of reserves are in various stages of evaluation and will probably be developed. This would yield a total of 19.4 billion barrels of

reserves and a peak production of 4.95 million barrels per day in 1981 with a capital investment of $27 billion dollars.

(5) This writer estimates that current industry expenditure for exploration is on the order of $3 billion dollars, and should reach $6 billion dollars by the end of 1981. Most of the North Sea reserves should be discovered by that time.

(6) Cash-flows discounted at a 10 percent rate for current development should range between $27 and $46 billion for private industry and $47 and $104 billion dollars for host-governments. At a $7 price of crude, discounted government take averages 64 percent, whereas at a $12 price, discounted government take averages 69 percent.

(7) Analysis of cash-flow profiles indicate that access to crude supply and development of subsequent discoveries appear to be the only economic incentives for continuing to operate the smaller fields after peak production is obtained in a field. Tax policy and high operating costs relative to productive capacity tend to make small fields less attractive from N.P.V. comparisons with large fields.

(8) This writer has concluded that the minimum acceptable field size at a price of $12/bbl is 150 million barrels, which reflects the minimum acceptable size if price did fall to the lowest level anticipated. The minimum acceptable field size at a price of $7 is arbitrarily set at 300 million barrels, reflecting a more pessimistic scenario of high risk and a lowest expected price.

(9) In order to develop current plus discovered plus future discoveries, private industry is estimated to require between $56 and $70 billion dollars. Most of this investment, including approximately

$6 billion additional for exploration, is anticipated to occur between now and 1985.

(10) Peak production of 6.58 to 7.85 million barrels per day is estimated to occur around 1986, representing a total reserve development of approximately 34.4 to 38.4 billion barrels of oil. Private industry is anticipated to earn between $30 and $56 billion dollars whereas government take, assuming a lower discount rate, is estimated to run between $83 and $222 billion dollars. Natural gas and oil recovered by tertiary methods are not included here, and can be expected to make a significant contribution to both private industry and host-government cash-flow.

(11) Host-government tax policy and the world price of crude will greatly influence the development of marginal North Sea fields. Stability of both factors over the next decade will stabilize North Sea benefits to both private industry and the host-governments.

(12) Although not specifically discussed as a separate section within the thesis, comments on risk seem appropriate here. Private industry perception of increased risk include: a) cost inflation at a higher rate than crude price inflation, b) imposition of a possibly more restrictive tax policy on the part of the host governments, c) operator overestimation of recoverable reserves or per-well productivity, and d) vulnerability of offshore production facilities to sabotage or natural disasters.

Conversely, private industry might perceive reduction of risk as consisting of the following elements: a) guarantees of host-government leveraging via participation agreements, b) securing of royalty rebates in critical situations, c) non-recourse loan arrangements, and d) a perception of time as a stabilizing factor where the investment climate in North Sea petroleum activity allows the preceding variables to establish continuity.

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Appendices

APPENDIX I

CURRENT DEVELOPMENT COST SUMMARY
(Amounts in $ Millions)

Field	Reserve Recov. Billions Bbls.	# Delin. Explor. Wells	Invest. Start Yrs. After Disc.	Prod. Start Yrs. After Disc.	Platform Op.Cost /Year	Transpor. Op. Cost /Year	Platform +Instal. Cost	Platform Equip. Cost	Develop. Drilling Cost	Transport. &Pipeline Cost
Ekofisk	3.80	26	4	4	67.	23.	900.	390.	380.	580.
Statfjord	3.00	7	2	4	130.	35.	1385.	460.	700.	955.
Montrose	0.20	3	6	8	17.	18.	104.	45.	90.	41.
Forties	1.80	6	3	6	67.	13.	793.	235.	355.	367.
Brent	1.75	8	4	6	89.	21.	843.	385.	645.	577.
Cormorant	0.16	6	4	6	20.	5.	274.	120.	120.	41.
Beryl	0.40	6	3	5	22.	23.	160.	65.	145.	60.
Thistle	0.45	6	4	6	27.	13.	248.	120.	200.	182.
Piper	0.80	7	1	4	19.	11.	160.	45.	100.	195.
Dunlin	0.40	5	3	5	28.	7.	313.	105.	235.	147.
Alwyn	0.50	3	4	6	27.	13.	292.	90.	160.	88.
Heather	0.15	5	3	6	22.	18.	164.	65.	125.	46.
Ninian	1.00	7	2	5	60.	20.	848.	310.	445.	697.
Claymore	0.40	8	3	5	25.	10.	249.	75.	145.	31.
Hutton	0.30	6	4	7	28.	7.	360.	125.	170.	145.

Note: Data from Reference 14.

APPENDIX II

CASH-FLOW TO COMPANY (CFC) AND GOVERNMENT (CFG), AND PRODUCTION ON A YEARLY BASIS (PN), FOR NORTH SEA OIL (In Millions)

A. CURRENT DEVELOPMENT

Year	$7 Price			$ 12 Price		
	CFC	PN	CFG	CFC	PN	CFG
72	-17.5	0	0	-17.5	0	0
73	57.0	38.0	38.0	213.0	38.	72.9
74	527.7	152.0	245.7	1073.1	152.	469.7
75	415.7	246.	705.9	999.8	246.	1330.8
76	1208.7	465.5	1155.4	2198.4	465.5	2153.0
77	1869.3	732.	1795.6	3946.	743.2	3424.8
78	3435.4	1069.	2275.7	6254.7	1100.1	5083.3
79	4958.1	1340.	2917.3	7445.1	1387.7	7555.6
80	4298.3	1495.5	4277.1	6930.2	1533.6	9437.3
81	3872.3	1504.	4324.	5495.7	1451.1	10446.6
82	1469.0	1403.5	5017.5	2894.4	1440.6	10830.
83	1579.7	133715	4674.5	2424.1	1370.	10688.6
84	839.1	1192.	4513.4	1286.	1215.2	10088 5
85	667.3	1024.	3919.4	1149.	1042.6	9067.
86	638.	851.5	3371.	1271.9	865.4	7096.5
87	832.8	649.5	2840.5	1527.2	658.8	5439.7
88	357.5	469.5	2149.	655.3	477.3	4227.3
89	140.3	336.5	1462.5	433.9	342.7	2881.5
90	41.8	211.	838.2	155.	214.2	1813.4
91	3.9	144.	445.6	138.3	144.	1053.7
92	-141.8	56	213.2	-56.6	56.	511.6
93	7.6	35.	52.9	25.9	35.	189.1
94	-17.1	5.	20.9	-103.5	5.	123.5

APPENDIX II (Continued)

B. DISCOVERED, DEVELOPMENT SPECULATIVE

Year		$7 Price				$12 Price	
	CFC	PN	CFG		CFC	PN	CFG
76	-23.9	0	0				
77	-122.6	0	0		-84.2	0	0
78	-317.5	10.	8.4		-393.9	0	0
79	-333.3	69.	57.5		-631.9	66.	93.9
80 ----	192.8	183.	152.4	-------	1743.6	319.	458.2
81	1067.6	304.	253.1		3889.9	497.	713.2
82	1852.5	403.	335.7		5520.9	640.	920.7
83	1764.9	453.	377.4		5177.1	476.	1084.
84	1071.7	460.	383.3		2724.5	475.	2432.8
85 ----	834.5	360.	383.3	-------	261.4	640.	4220.
86	904.4	360.	383.8		64.0	593.	3953.7
87	400.6	434.	739.4		-121.9	555.	3865.
88	19.	372.	1156.3		196.8	462.	3158.5
89	297.	303.	1164.3		889.2	376.	2557.
90 ----	551.2	227.	960.8	-------	619.	282.	2015.
91	72.9	161.	654.1		180.4	189.	1407.6
92	62.5	125.	412.5		312.5	137.	896.5
93	-24.1	86.	266.1		132.	96.	660.
94	-111.4	50.	141.4		-119.9	50.	399.9
95 ----	-77.5	30.	47.6	-------	33.6	30.	126.4
96	-18.4	10.	8.4		25.4	10.	14.6

APPENDIX II (Continued)

C. FUTURE DISCOVERY DEVELOPMENT

Year	$7 Price CFC	$7 Price PN	$7 Price CFG	$12 Price CFC	$12 Price PN	$12 Price CFG
79	-30.8	0	0	-48.6	0	0
80 ----	-153.8	0	0 -------	-361.7	0	0
81	-452.9	15.	12.5	-185.	69.	99.7
82	-601.3	90.	75.2	549.4	204.	295.7
83	-253.4	255.	213.	2205.7	433.	628.9
84	1079.3	515.	430.1	4817.8	741.	1077.7
85 ----	2722.5	795.	664. -------	6747.3	913.	1859.
86	4149.3	1090.	910.4	9883.9	1408.	3178.9
87	4661.1	1290.	1077.4	9491.	1601.	4892.7
88	4371.8	1415.	1182.3	6351.7	1691.	8066.1
89	4101.9	1485.	1487.1	5230.9	1719.	9181.3
90 ----	2831.	1470.	2043.1 -------	2643.	1660.	10659.3
91	1320.	1395.	3094.8	1286.6	1539.	10816.2
92	1094.	1245.	3265.6	1431.6	1353.	9610.6
93	1049.1	1070.	3430.7	1909.6	1142.	9239.9
94	358.9	850.	3206.3	1528.6	898.	6580.1
95 ----	377.2	650.	2535.3 -------	1313.7	648.	4962.3
96	442.3	497.	1867.7	1238.5	486.	3619.2
97	-66.4	345.	1291.3	385.6	353.	2587.9
98	-156.2	235.	721.2	189.4	235.	1558.1
99	-117.	160.	397.	219.1	160.	861.
00 ----	-155.8	75.	200.8 -------	-43.8	75.	463.8
01	-107.2	40.	67.2	-0.4	40.	160.4
02	-27.5	15	12.5	38.1	15.	21.9

APPENDIX III

Eckbo's Reservoir Development Submodel -- A Brief Description[1]

The reservoir development submodel is essentially a net present value calculator. It uses reservoir characteristics as explanatory variables in a set of functional relationships that determine the development and extraction costs associated with producing a given reservoir. A set of production and tax regulations is then applied to determine the cash flow for the reservoir. In this manner the submodel checks the economic viability of a discovered field.

Basic elements included in the submodel include: 1) development costs by categories, 2) estimates of recoverable reserves, 3) formulation of production and tax policies of host-governments, 4) assumptions regarding investment and production profiles of the reservoir, 5) estimates of annual operating costs, and 6) assumptions regarding the world price of crude oil. Options include separate discount rates for private investment and host-governments.