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INTERNATIONAL

OIL TAX COMPARISON

STUDY

Prepared for

the Alaska State Legislature

and

the Alaska Department of Revenue

April 1990

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OIL TAX COMPARISON

STUDY

PART I THE ECONOMIC ANALYSIS: ALASKA, UNITED KINGDOM, NORWAY, INDONESIA, & AUSTRALIA

by

Alexander Kemp
David Rose

Aberdeen University
Petroleum and Economic Consultants
Aberdeen, Scotland

and

Peter Gaffney

Gaffney, Cline and Associates
Energy Advisors
Houston, Texas
Alton, Hampshire, England

PART II FINANCIAL AND OTHER ASPECTS OF OIL INDUSTRY INVESTMENT

by

H. Motamen Scobie

Chief Editor of "Energy Economics" and
"Economic Modelling"
London

ABOUT THE AUTHORS

Alexander Kemp and **David Rose**, the principals of Aberdeen University Petroleum and Economic Consultants, are widely regarded as the leading academic figures on economic rents and discounted cash flow analysis in the oil industry. They also do extensive consulting, primarily to governments. Among the numerous papers and books they have written (many jointly), Petroleum Rent Collection Around the World, the Institute for Research on Public Policy, Canada, 1988 has become a standard reference.

Peter Gaffney is a principle of Gaffney, Cline and Associates, energy advisors based in Houston, Texas and Hampshire, England. This is a premier firm in the appraisal of oil assets and oil prospects. Mr Gaffney, who grew up in an industry family, does some teaching in addition to his demanding consulting schedule. He has been on assignment to virtually every oil region in the world.

H. Motamen Scobie, a consultant to governments, oil companies, and the financial sector, comes from a background of teaching and international banking. Ms. Scobie is chief editor of two academic journals: "Energy Economics" and "Economic Modelling." Among her publications are Macroeconomics of North Sea Oil in the United Kingdom, Heinemann, London, 1983.

INTERNATIONAL TAX COMPARISON STUDY

Prepared for

THE STATE OF ALASKA

AUPEC

Aberdeen University Petroleum
and Economic Consultants

GCA

Gaffney, Cline and Associates

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INTRODUCTION

The State of Alaska has undertaken a project to develop a model that will enable the State to compare the climate for investment in Alaska vis-à-vis other oil and gas provinces.

In the past few years a controversy has arisen between the oil industry and the State of Alaska. The Industry believes that its investors are not receiving a rate of return commensurate with the risks inherent in the exploration and development of new and existing fields. The State of Alaska contends that it is incumbent upon the State to pursue an aggressive oil royalty and taxation policy. The development of a comparative model is desired to increase the reliability of information available to the Alaska Legislature for use in the decision-making process in legislation on oil taxation.

The work was carried out under the aegis of a joint Senate/House Committee under the chairmanship of Senator Bettye Fahrenkamp. The consultants were selected in such a way as to represent a broad spread of expertise in the industry. Meetings were held with the Committee in Anchorage in November and in Juneau in January, at which the key questions raised by the Committee at their initial internal deliberations were addressed at some length. During the meetings and after subsequent work by the consultants the scope of the consultants' work was adjusted slightly to incorporate carrying out the actual tax comparisons in conjunction with the Revenue Department.

Four key Alaskan fields were chosen. It was decided to model historical Prudhoe Bay as well as to forecast its performance, together with hypothetical developments at the West Sak, North Star and Niakuk discoveries. The performance of an incremental project at Prudhoe Bay was also examined.

In addition to meetings with the Committee, extensive discussions were held with the Revenue Department and various tax models from other jurisdictions were made available. The Revenue Department prepared the four field economic cases under the Alaskan legislation and worked with the consultants to ensure the model would provide a framework for future ongoing work by the Department. Legislative comparisons were made with the UK, Norway, Indonesia and Australia. The study was carried out by, in effect, translating these four legislations to Alaska and examining the economic performance of the Alaskan fields as though that legislation had been in place in Alaska. The models used included provisions to examine, among other things sensitivity to oil price, costs, exploration programs, and differences between current and new investors.

The State of Alaska has requested the consultancy Gaffney Cline and Associates (GCA), in co-operation with AUPEC (Aberdeen University Petroleum and Economic Consultants), and Dr. Motamen Scobie, Economic Consultant, to prepare a report covering the methodology and results of the comparative modelling.

The division of work was as follows:

AUPEC Group

Professor Alex Kemp and David Rose, AUPEC, carried out the cashflow/country model computer runs.

GCA

GCA was to be an arbitrator of fairness in the analysis and be responsible for the reporting and also for the inclusion of the prospectivity analysis.

AUPEC and GCA worked together to select relevant criteria and to assess the validity of comparisons.

Dr. Motamen Scobie

Dr. Motamen Scobie was to examine the financial aspects of comparative legislation in terms of investor credibility, and was to review other legislations not included in the current group. Dr. Motamen's work is the subject of a separate presentation.

Department of Revenue

The oil group of the Department of Revenue carried out the historical and forecast assessment of the Prudhoe Bay field together with forecasting the performance under Alaskan legislation of the three new Alaskan fields which were to be considered. All base data for the Alaskan modelling were provided by the Department, and the

Department worked with the Consultants to ensure a compatible and appropriate comparison. The basic field data provided by the Department provided the base data for the comparisons.

A draft report was presented in mid March to the Committee and at separate meetings to the Senate Finance and House Finance Committees in addition to a discussion with Industry.

Although the industry was most helpful in general no direct information regarding for instance specific development plans or allocated exploration expense or their appropriateness was made available directly to consultants in time to be incorporated.

The following presentation reflects the work of AUPEC and GCA in this phase of the study. It was not the intention of these comparisons to mirror the industry's exact performance as each company will handle its tax arrangements differently and they will, indeed, be in a different position. The attempt was to try and compare on a "reasonably level playing field" how particular projects would have looked if they had been carried out in Alaska under different tax legislation environments.

Insufficient time was available to adequately cross check the material validity of the hypothetical development plans or to assess the impact of a realistic incremental project on Prudhoe Bay. With the current results to hand it would also be prudent to ensure that the base case Alaska cashflow analysis was also carried out under the same identical system as the comparison fields to ensure more complete compatibility. In these senses the work should be considered preliminary.

Nevertheless recognising that the original objective of this work was to set up a 'model' with which to make comparisons, a basic approach has been selected, models made available and a first pass of comparisons carried out.

Acknowledgements

The not inconsiderable help of the Revenue Department in Anchorage, the Revenue Commissioner's Office in Juneau and the Committee members and their staff is acknowledged. We are also grateful for material provided by industry and the opportunity to see the North Slope operations on site. No multiple organisation operation of this type works without cooperation and that cooperation provided by both State and Industry made possible the completion of this study.

SUMMARY OF RESULTS

Broad comparisons are possible and useful. While these comparisons show that both the State and the companies did well from Prudhoe Bay they do not necessarily suggest that the State could have done much better as the returns under all the other legislations which were not designed for a Prudhoe Bay sized field appear punitive.

The comparisons do show the new projects on the North Slope are marginal especially if sunk exploration costs are included. These projects look better especially under the U.K. and Norwegian systems, of course, the field sizes are more in line with the size of fields more typical of the North Sea region, so these comparisons are reasonable.

Being a current investor helps substantially and all the new projects look much worse from a new player's point of view.

It is important to stress that unlike other countries Alaska is disadvantaged as it only controls a part of total taxation and gains only very indirectly from employment, services and manufacture occurring in the lower 48.

In examining the many subjective perceptions that drive investments in the industry, it is clear that Alaska's image is one of being more difficult in many respects than the other countries concerned. Indeed the perceptions are reinforced by the results of the new projects mentioned above.

In summary we have answered a number of the initial questions raised by the committee including the usefulness and methodology of making some comparisons.

We have provided a framework for comparison and provided model capability. The first phase of model comparisons has been completed and some comments on the Alaskan legislation relative to other legislations have been made. Some observations have also been made on how in very general terms it might be possible to achieve one or more of a series of potential goals if these goals were indeed the State's objectives.

RESULTS OF COMPARISONS

Method of Approach

In order to present effectively and concisely the results of what amounts to a large volume of information, it has been necessary to adopt a summary approach in the following presentation. Full details of the economic analysis have been made available to the Department of Revenue. Essentially the key comparative components are shown on the attached graphs with a brief written summary of the results.

The basic analysis has consisted of establishing the value of each project by calculating the Net Present Value (NPV) on a 12.5% real basis (17% nominal), a measure of the size of each project in each country. This was carried out for both the company and government share.

Among other factors considered were:

Internal Rate of Return (IRR), a relative measure of return on investment, typically we would expect projects to stand some chance of proceeding if rates of return were at least 10% (real) or about 15% nominal.

Payout from initial development, a measure of how long the total funds were exposed.

Prospectivity, a series of very subjective judgements on the relative attraction of a Country for investment.

In addition, the sensitivity to changes in oil price, costs and the impact of exploration costs were also examined together with the effect of being a new investor as apposed to an existing one with tax sheltering capability.

The base case factors were as follows: real discount rate 12.5% (equivalent to a 17% nominal rate), oil prices US$14.50 per barrel for Prudhoe wellhead, prices adjusted for quality and transportation for other fields, and inflation of 4.5% p.a. The base case also assumed an existing investor and takes account of some of the allocatable sunk past exploration costs. The Prudhoe Bay field was examined through its history and appropriate inflation rates were used for the prior period.

Net Present Value (NPV)

Net Present Value is an approach to illustrating the worth of a project after taking into account the time value of money. Typically the oil industry uses this approach to get a true idea of the value of the project and to compare the project with others. In carrying out our analysis we first brought past costs forward, using the US inflation rates of the day, so that $1,000 spent 10 years ago in a particular country might represent the equivalent of $2,000 today. Similarly, in examining future income, $1,000 received ten years hence might be worth only $500 today.

Next, we have to discount the stream of net income - to allow comparisons with other projects and give a yardstick as to how far above or below we are from our minimum return. The discounts applied to obtain Net Present Value in oil are commonly in the range of ten to fifteen percent above inflation. However, from time to time, financial institutions, in particular, may use higher percentage discounts in order to try and use the discounting approach to assess some sort of project related risk. For our purposes we have chosen a medium 12.5% real discount rate (i.e. 17% if there is 4.5% inflation) for the base case valuations but have also examined the projects at discounts of 10% and 15% in the detailed results which have been made available.

It is also clear that even a very large project which is carried out long into the future and evaluated with a high discount rate might have a very low Net Present Value. On the other hand a very small successful project occurring in the near future and evaluated perhaps with the same discount rate might appear to be a much more attractive project.

Net Present Value is a good indicator of project size but it in fact gives no indication of duration. Project payout on the other hand is a good indication of how long funds are at risk from the point of major investment but gives no indication of return on investment or project size. Rate of Return gives an indication of project success but no indication of timing or size.

While there are many performance criteria we can use in the interests of simplifying the results, we have limited our analysis to comparing the government and company Net Present Values, in real dollars, Internal Rate of Return in % terms and payout in years for each field, for each of the five legislative scenarios.

In order to present the most meaningful comparisons on the graph, anomalously high values have been capped. This is shown by the value of the bar being fully extended to the margin of the graph at its maximum or minimum value.

Company Net Present Value (NPV at 12.5%) Results

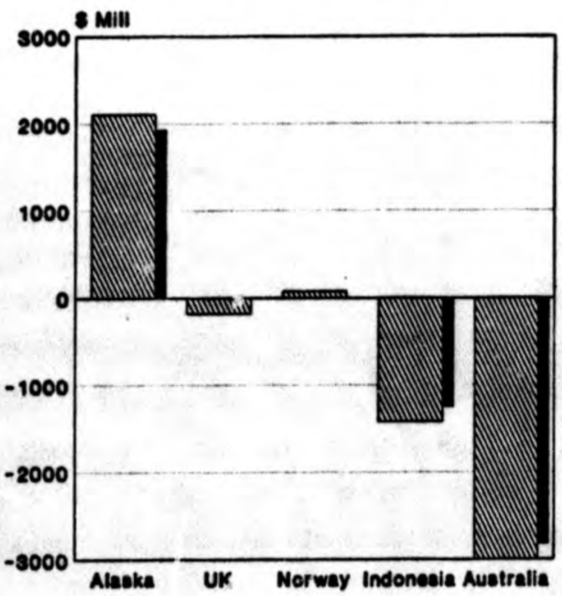
Company NPV for Prudhoe Bay is higher under the Alaskan legislation than under any others but it is unlikely that development could have proceeded under the Indonesian and Australian legislations. Note that this analysis looks at Prudhoe Bay as of 1975 - all other analysis uses 1990.

The remaining Net Present Value of Prudhoe Bay was also examined under each legislation in 1990 terms. This remaining NPV analysis does not include all likely necessary new investments typical of such situations and probably overstates the company position.

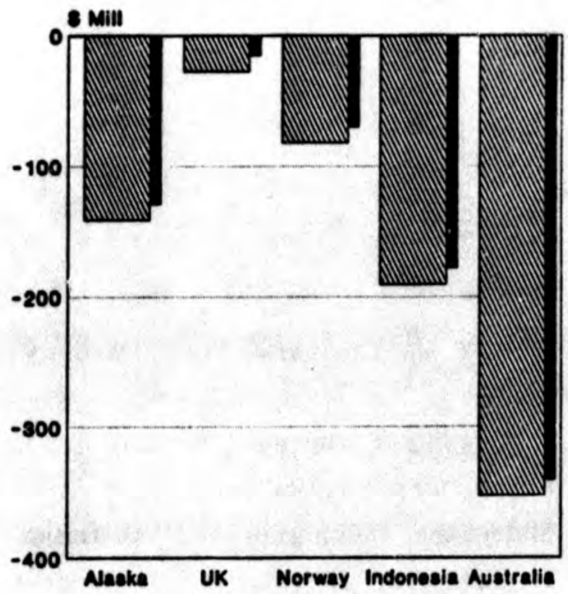
The remaining Prudhoe Bay Net Present Value is shown separately comparing government and company shares at zero discount and at the standard 12.5%. On the bar chart showing the relatively high remaining U.K. government NPV it must be remembered that while the marginal tax rate is very high, the U.K. allows offset of very significant exploration and some development costs against current production taxes.

For the other three fields only Niakuk in the U.K. appears positive, indeed all three fields would do better under both U.K. and Norwegian legislation. The high front end exploration and the low effective oil price make these projects all look unsuccessful under Indonesian and Australian legislation as these legislations are particularly geared to higher oil price regimes. Removing exploration costs, of course, makes all three projects look better and indeed viable in the model cases under some legislations.

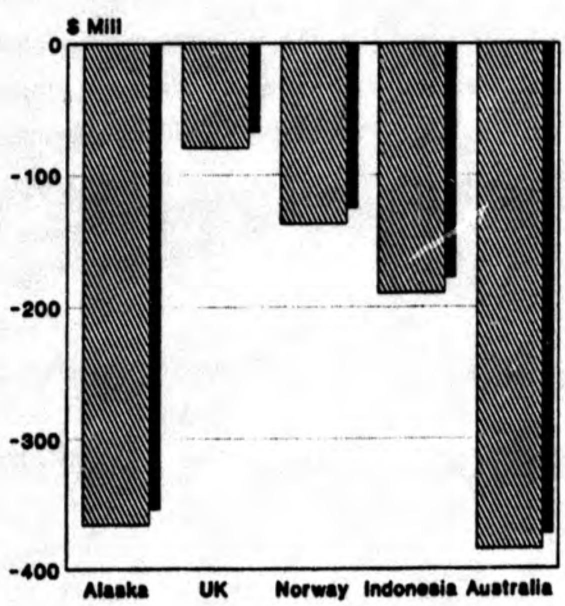
COMPANY NPV $ REAL
Prudhoe Bay
Base Case at 12.5%



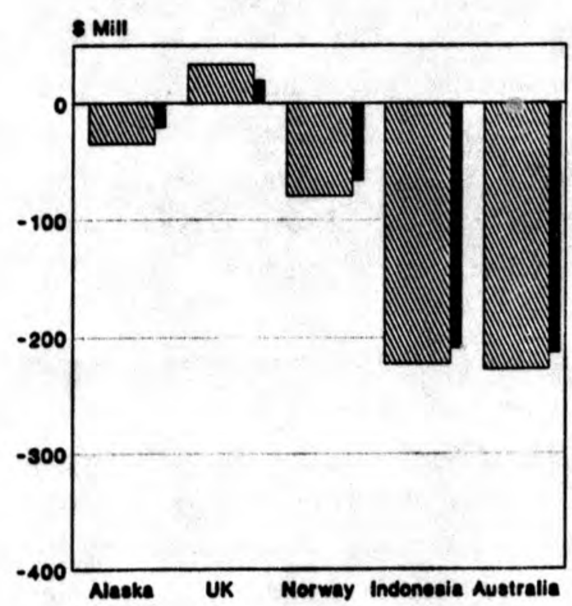
COMPANY NPV $ REAL
West Sak
Base Case at 12.5%



COMPANY NPV $ REAL
North Star
Base Case at 12.5%



COMPANY NPV $ REAL
Niakuk
Base Case at 12.5%



Government Net Present Value (NPV at 12.5%) Results

Prudhoe Bay

Apart from Australia where the revenues would have been so high as to negate the project, Alaska appears to have received somewhat less present value from the project than if the project had been under the other three legislations. Timing of revenues affects this type of analysis as funds received later will be worth less when present valued back to 1975 as was done in this case. Note that Prudhoe Bay government NPV shows the split between State and Federal taxes.

West Sak

Government NPV's look good in all cases except U.K. but the project is marginal from an investment point of view.

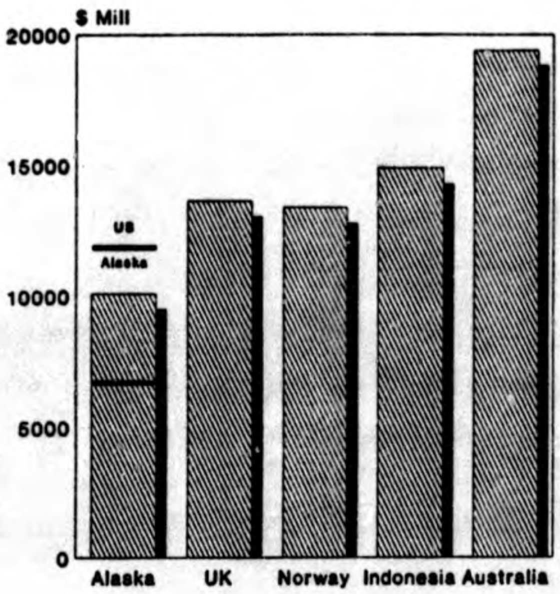
North Star

This project which is marginal appears to have a positive government NPV only in Alaska suggesting that, by comparison, it would be treated more favourable elsewhere.

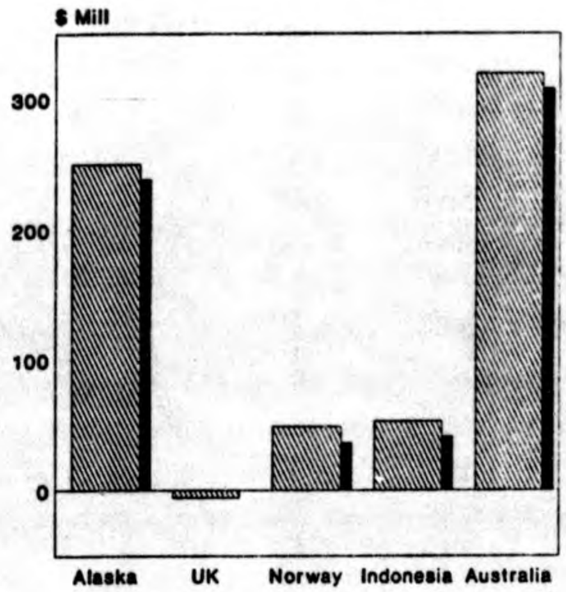
Niakuk

As in North Star, Alaska government's NPVs are much higher and indeed positive.

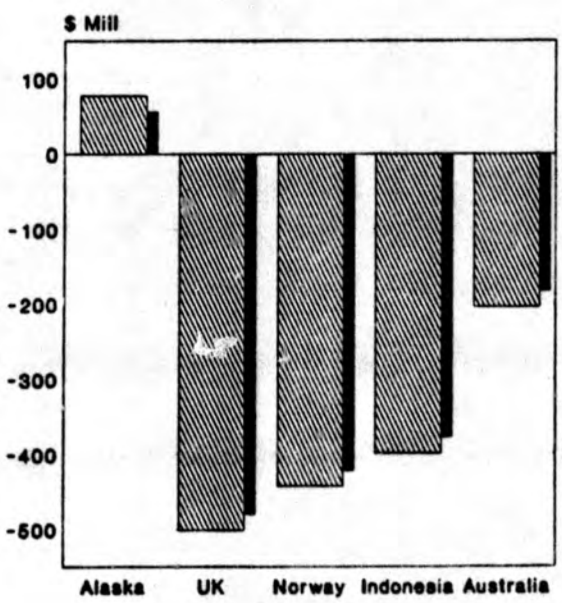
GOVERNMENT NPV $ REAL
Prudhoe Bay
Base Case at 12.5%



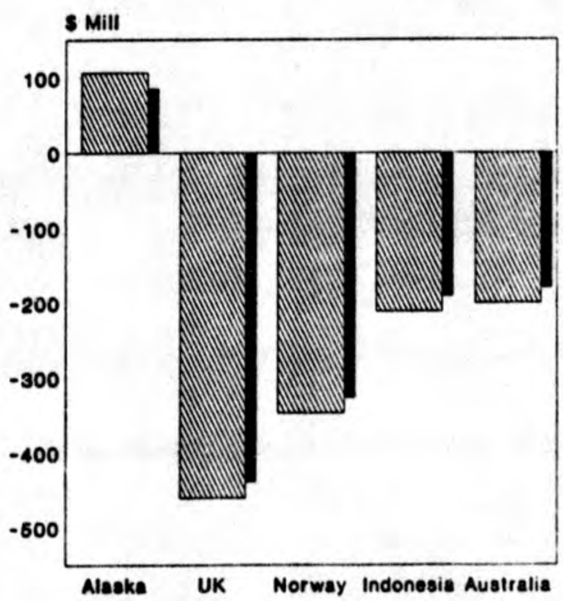
GOVERNMENT NPV $ REAL
West Sak
Base Case at 12.5%



GOVERNMENT NPV $ REAL
North Star
Base Case at 12.5%



GOVERNMENT NPV $ REAL
Niakuk
Base Case at 12.5%



Company and Government Prudhoe Bay NPV and Government Take - Various Discounts

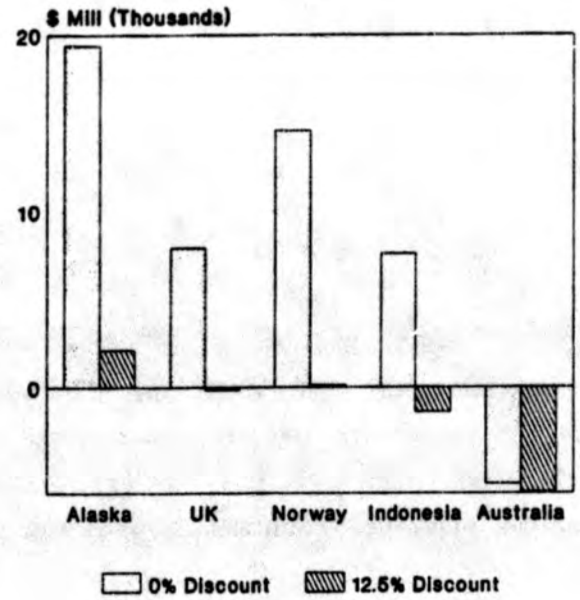
The following charts illustrate Prudhoe Bay Net Present Value from a government and company view based on different discount rates.

The government chart also shows the split between State and Federal taxes for Prudhoe Bay.

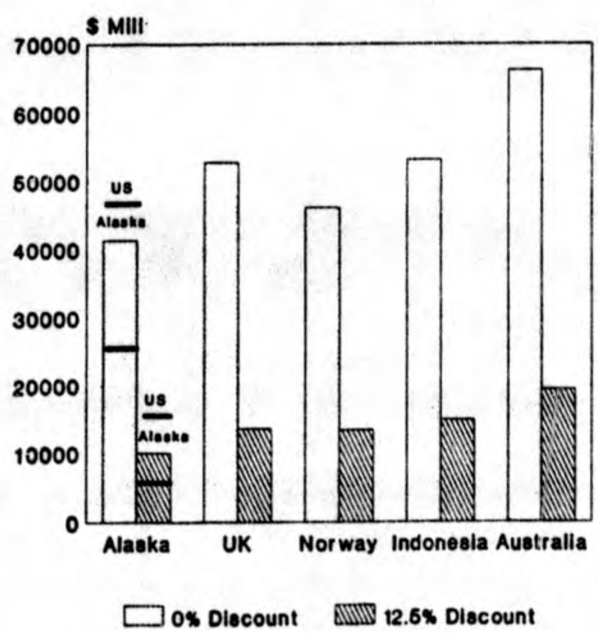
The government take chart shows the percentage government take for Prudhoe Bay over and above a 12.5% discount.

In Alaska this is just over 80% rising to over 100% for the other legislations. In other words this represents the percentage of what is referred to as the Economic Rent which is taken by the government. It can be seen that at 12.5% the take would be unreasonably high in all other countries giving grounds to the concept that their legislation was not geared to a Prudhoe Bay field.

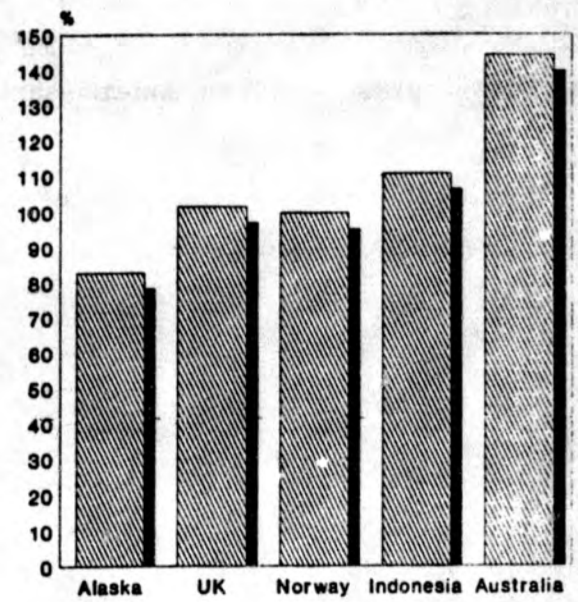
COMPANY NPV $ REAL
Prudhoe Bay
Base Case Varying Discount



GOVERNMENT NPV $ REAL
Prudhoe Bay
Base Case Varying Discount



GOVERNMENT TAKE %
Prudhoe Bay
Base Case at 12.5%

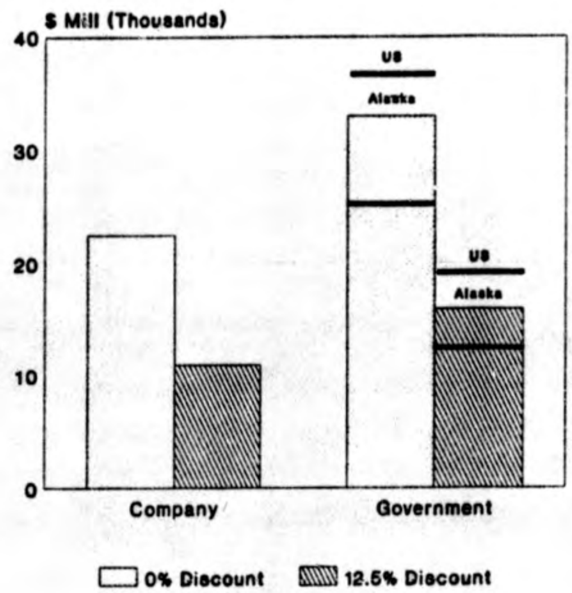


Prudhoe Bay Remaining Net Present Value (1990)

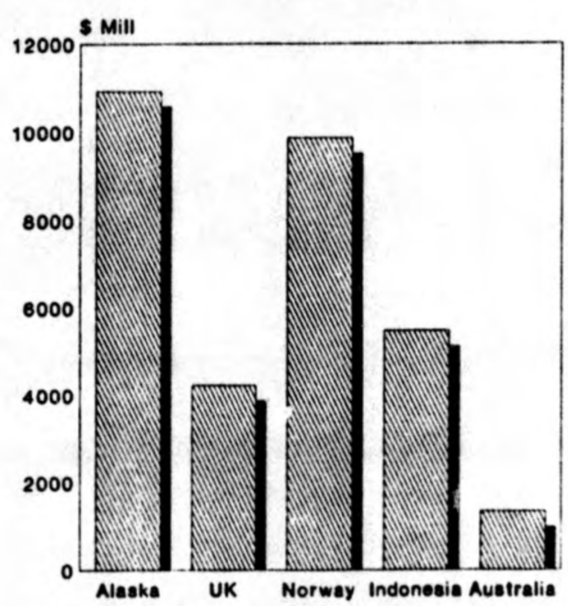
The remaining Net Present Value of Prudhoe Bay was also examined under each legislation in 1990 terms. This remaining NPV analysis does not include all likely necessary new investments typical of such situations and probably overstates the company position.

The remaining Prudhoe Bay Net Present Value is shown separately comparing government and company shares at zero discount and at the standard 12.5%. On the bar chart showing the relatively high remaining U.K. government NPV it must be remembered that while the marginal tax rate is very high, the U.K. allows offset of very significant exploration and some development costs against current production taxes.

REMAINING NPV COMP+GOV
Prudhoe Bay- Alaska
Base 1990$ Varying Discount



REMAINING NPV COMPANY
Prudhoe Bay
Base Case 1990 $ at 12.5%



Rate of Return (ROR) and Internal Rate of Return (IRR)

These are measures, typically quoted as percentages, of the amount of the investment which is recovered on an annual basis. Thus if we invest $100 and get $10 back within a year this might be referred to as a 10% return.

Internal Rate of Return is more typically used in the oil industry. It is the percentage rate of return which could still be achieved if the project was to only break even, i.e. the rate of return at which the Net Present Value (NPV) of a project is zero. Rates of Return are excellent comparative tools but they give no indication of size or duration of the project. Thus a very small investment with a correspondingly small Net Present Value might have a very high Rate of Return. Correspondingly, a very large project with a very large NPV could also have a very small Rate of Return. It is important to stress that these performance measures cannot be considered in isolation, and a series of the various project performance tools must be used.

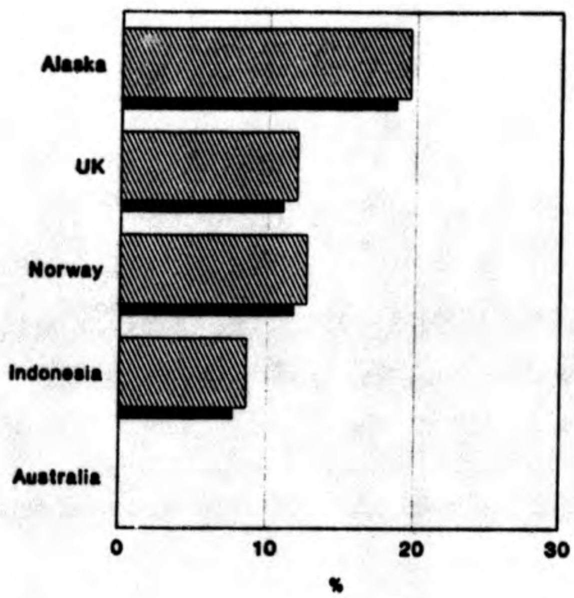
For rate or return purposes, only positive Internal Rate of Return (IRR) values were shown so that the lowest value in the rate of return is zero. Negative IRR values can be misleading.

Internal Rate of Return Results

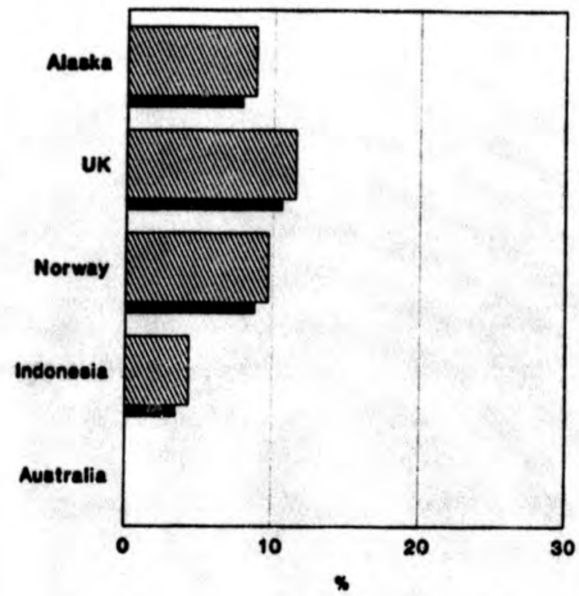
Prudhoe Bay IRR% is higher in Alaska than in all the other countries. This is partially so because other countries tightened their legislation significantly as prices rose in the late Seventies/early Eighties. Indeed the U.K. was at its most aggressive with high rate Petroleum Revenue Tax (PRT), Supplimental Petroleum Duty (SPD) and Advanced Petroleum Revenue Tax (APRT) payments all occurring in the late Seventies and adversely affecting the early production of Prudhoe Bay under that simulated legislation.

All three new fields look better under U.K. legislation, while North Star only has a positive rate of return under U.K. and Norwegian legislations.

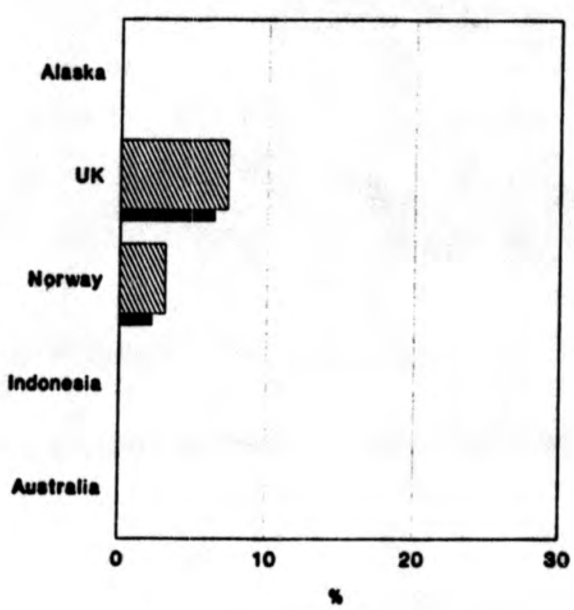
COMPANY IRR % REAL
Prudhoe Bay
Base Case



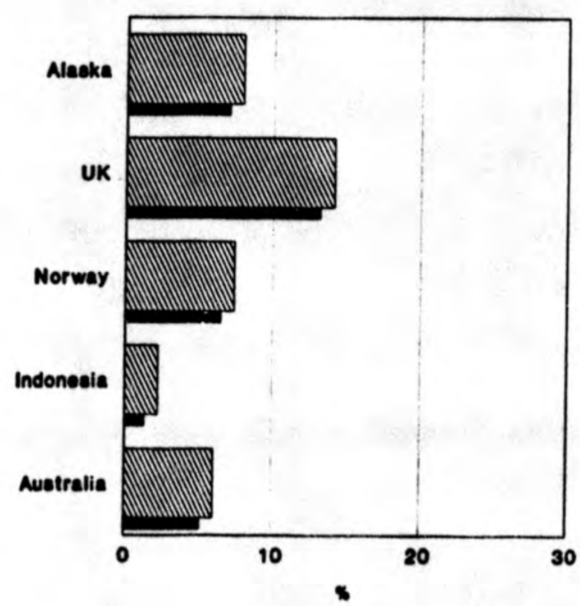
COMPANY IRR % REAL
West Sak
Base Case



COMPANY IRR % REAL
North Star
Base Case



COMPANY IRR % REAL
Niakuk
Base Case



Years to Payout

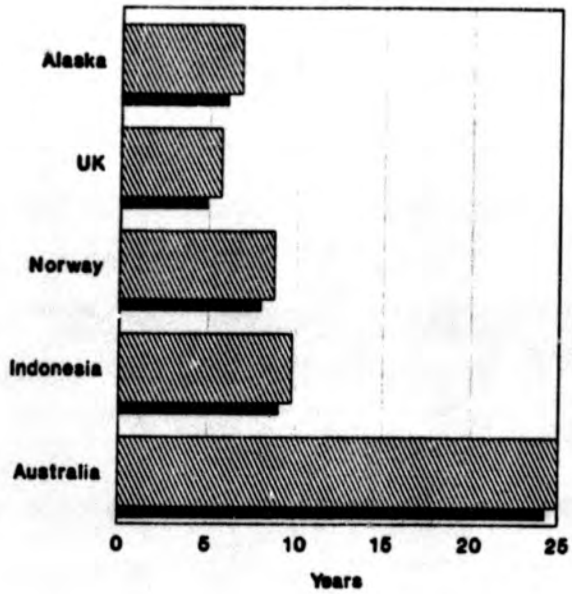
This is defined as the time required to recover the original investment including a full exploration program.

How soon payout was achieved from the beginning of each of the projects at the development stage was examined. It should be noted that payout, of course, would take rather longer if the period from the beginning of the exploration stage had been taken; but payout as calculated does incorporate repayment of the inflation- adjusted exploration costs no matter how long ago they had been expended.

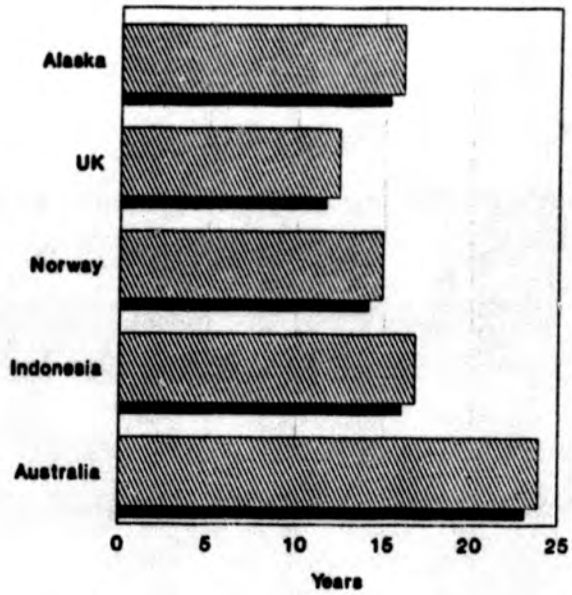
Years to Payout Results

Prudhoe Bay would have paid out sooner under U.K. legislation but Alaska, Norway and Indonesia were all of the same order of magnitude. North Star and Niakuk payout earlier under U.K. legislation.

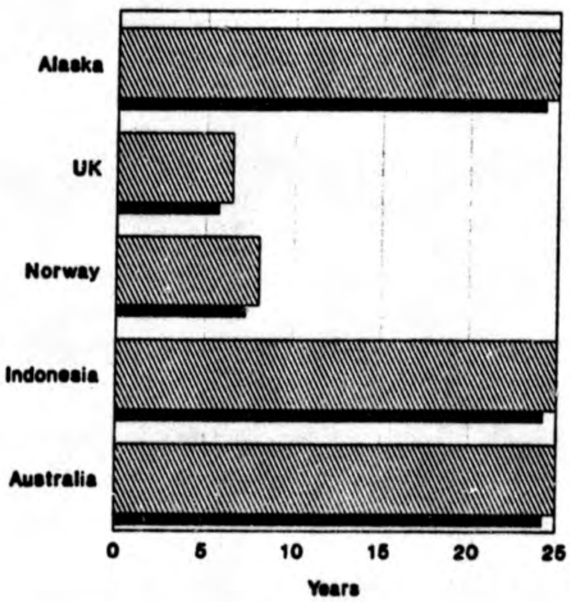
YEARS TO PAYOUT
Prudhoe Bay
Base Case



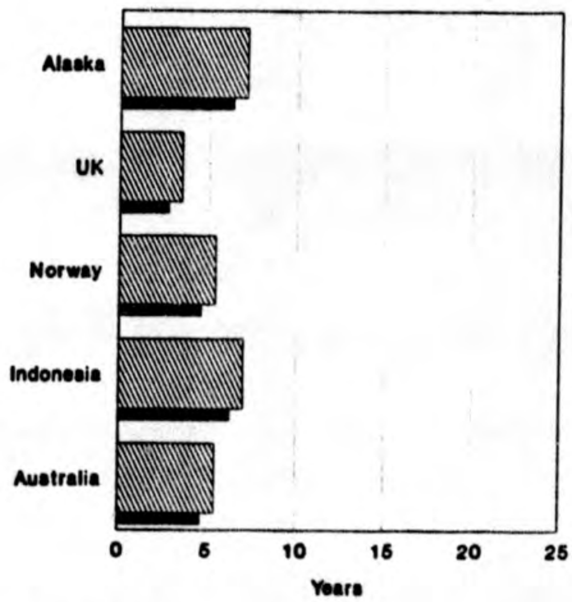
YEARS TO PAYOUT
West Sak
Base Case



YEARS TO PAYOUT
North Star
Base Case



YEARS TO PAYOUT
Niakuk
Base Case



Net Present Value for Incremental Prudhoe Bay Project

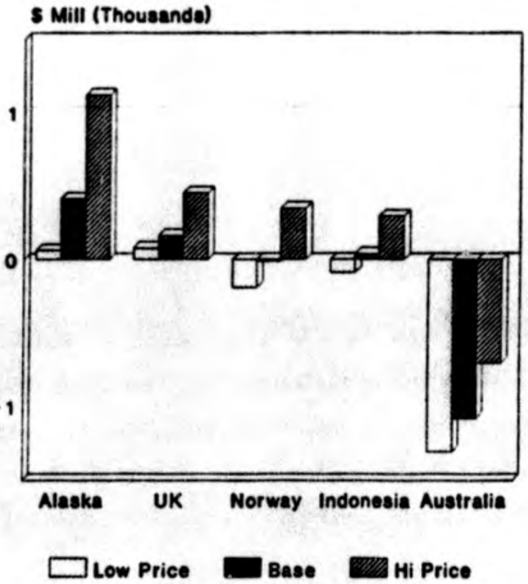
We have examined for Prudhoe Bay, in each legislative scenario, the impact of a late-life incremental project (i.e. additional reserves, additional revenues and additional costs) on the Net Present Value of the overall project.

Net Present Value for Incremental Project Results

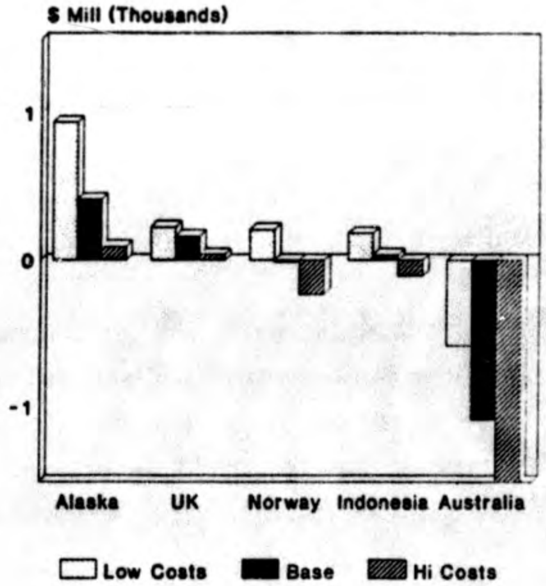
The incremental project (Hurl State Analogy) looks better under Alaska legislation than it does under any of the others.

However, this incremental project was a Hurl State Analog and insufficient time was available to evaluate its appropriateness as an incremental project. Indeed it is clear that it does not adequately simulate some likely aspects of typical late life field investments and costs.

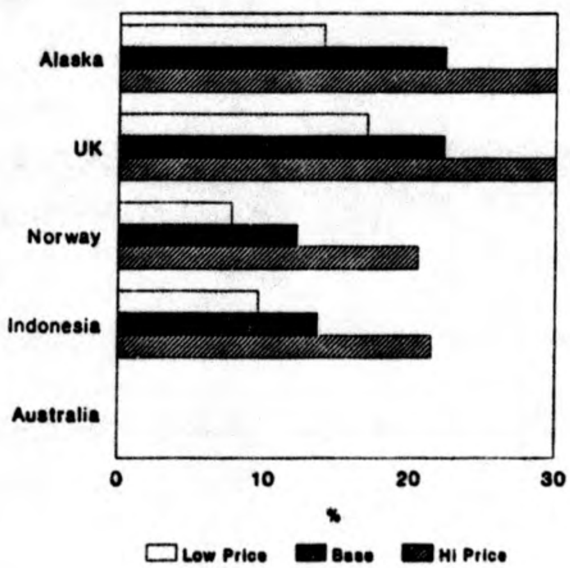
COMPANY NPV $ REAL
Prudhoe Bay Increment
Sensitivity to Oil Price



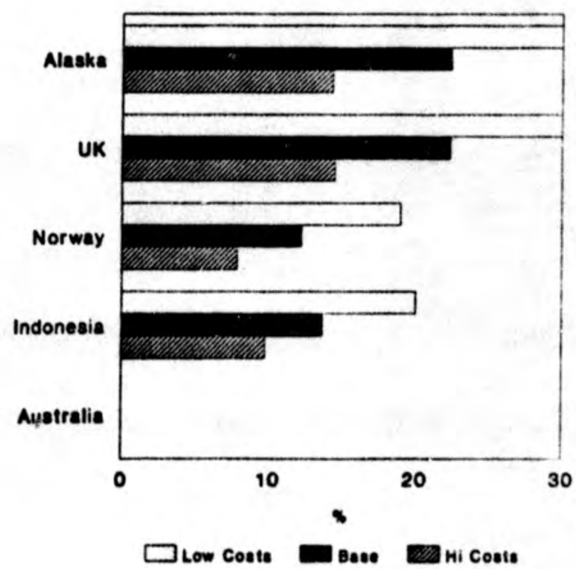
COMPANY NPV $ REAL
Prudhoe Bay Increment
Sensitivity to Costs



COMPANY IRR % REAL
Prudhoe Bay Increment
Sensitivity to Oil Price



COMPANY IRR % REAL
Prudhoe Bay Increment
Sensitivity to Costs



Prospectivity

It is well recognised within the industry that decisions are made on the basis of more than just the previously mentioned economic criteria. It is the combination of criteria that allows proper assessment of the opportunity. No one company at any one time will be driven by the same influences or use the same performance yardsticks yet, from time to time, the industry as a whole may rush to a new or revitalised area, for instance, offshore China in the early 1980s.

Companies which want to invest in exploration have to perceive that the geological prospects are good and that the combination of resources and technology available to them make it possible for them to expect economic success.

Included among the key criteria in what we might generally call prospectivity is the perception of how good the geological prospects are, the size of those prospects, the logistics, costs, legislative and political environment, the time to do a deal, the time to get on production, the market, and what we might generally describe as the hassle factor. Of course, in addition to these are the availability of capital within the company and issues of pricing and costs which are largely taken care of in the economic analysis.

In reviewing the prospectivity charts one must accept that this is a subjective judgement made at a precise moment. Such an assessment will vary with time, with company, with prospect and with opportunity levels. The charts are given solely to give an idea of some of the factors which have a very real bearing on initial and reinvestments.

Geology

The geological prospects for oil or gas have to be reasonable.

Field or Opportunity Size

Large companies will rarely look in areas where the potential field size is very small. They have limited staff resources and their way of doing business is such that their costs will form too high a burden on small fields. For any given area the geological prospectivity will suggest the types of field sizes which might be possible. These field sizes have to be large enough in the particular logistical and economic climate to be viable for the type and size of organisation that is investing in them.

Logistics

Difficult logistics, for instance in transport, environment, the lack of existing pipelines or a simple method of extracting the crude, will dictate that much larger fields have to be found to make the ultimate project viable. In such situations, longer periods of time are necessary and hence exploration funds are exposed at risk for a longer period. Poor logistics in combination with other marginal factors can lead to a company deciding not to invest. Good logistical factors are a major plus, for instance, in many parts of the North Sea.

Costs

There will be a perception of costs in each particular area. Major variations will depend among other factors upon the logistics, environment and the nature and depth of the potential prospects. If the operation is perceived extremely costly then naturally one has to be looking for larger fields. To the extent that costs are high this will tend to mitigate against the involvement of smaller, less adequately financed concerns and favour larger companies who can handle major longer term expenditures.

Legislative and Political Risk

Legislative and political risk is mainly a perception of potential change which might affect the company's ability to recover an investment. If the prospects and economic returns look good the industry frequently takes on board what are huge risks, investing in volatile legislative scenarios and where there may be very real potential risk exposure.

Time to Do a Deal

To many companies an important aspect is their perception of whether it would be possible to do a deal and get exploration acreage in a reasonable finite period. How long will it take to obtain the opportunity in the first place? If the prospects are excellent and the perceived field sizes large, companies will be quite happy to wait around for years, all other things being largely positive. If, on the other hand, the current returns appear marginal they may be more inclined to be impatient and at the very least place the opportunity on the back burner.

Time to Get Production (Time to Product)

Smaller companies and indeed larger ones are frequently concerned about how long it will take once they have found production to get it on stream and begin to make a return. The nature of the legislation itself can define how fast they can make their return and these items are dealt with in the economic criteria presented elsewhere. If the combination of logistics, environment, location etc. indicate in the end a very long time to get production on stream, then this has a negative impact.

Markets

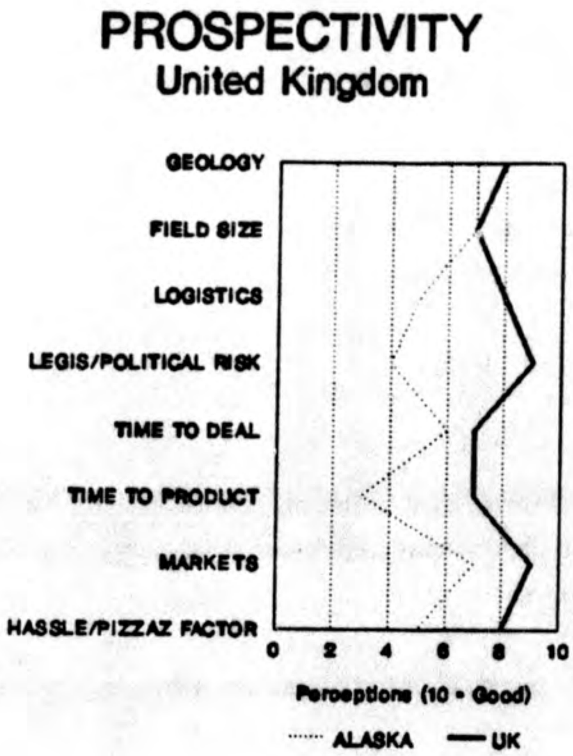
Availability of a market, particularly today for gas and also for instance heavy oil, can be a major factor in the timing and ability to carry out both exploration and development. With long lead-times, (exploration through to discovery and development) particularly in the more harsh environments, companies must make judgements on oil and gas prices and markets well into the future. To the extent that there appears some other element of market risk this will downgrade attractiveness of the project. To the extent that there appears to be no significant market risk, projects get upgraded.

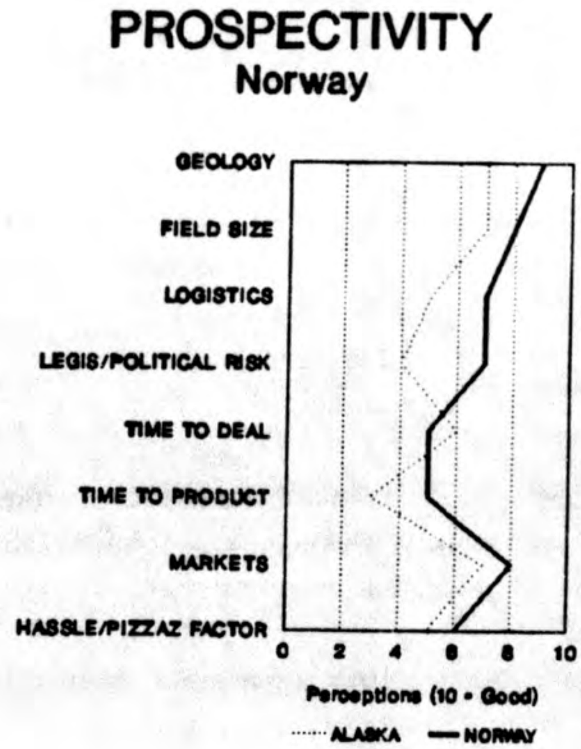
Hassle/Pizzaz Factor

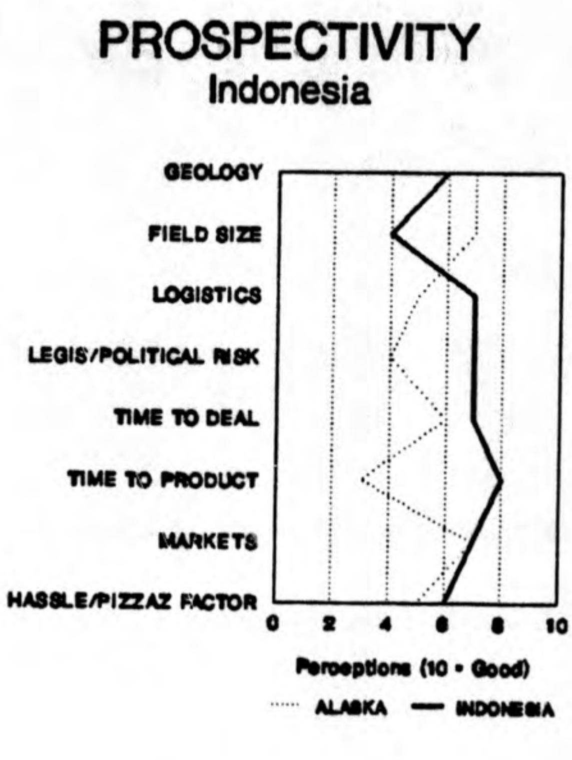
Industry is frequently driven, like any exploration-based natural resource concern, on what we might call the gold-rush concept. Is there a new place where a new series of large or even small discoveries appears imminent? Is there an old area we can revisit with new technology and do well? So from time to time we see the industry move suddenly to new pastures where there is a perception of major new opportunity. The industry moved to the North Sea in the early 70s with successful results and moved to offshore China in the early 80s with very poor results. Regions and indeed countries become fashionable even though particular countries and environments may have large problems. Environmental aspects may cause substantial delays; there may be difficulties in getting expatriate staff in place or with approvals for the importing of equipment. There may even be concerns of terrorist activity. The combination of these makes up what we might generally refer to as the hassle and/or pizzaz factor. If there are high hopes and it is a fashionable area, the industry will frequently cope with quite exceptional circumstances. On the other hand if the prospects are less attractive, the industry is less inclined to invest in the first place.

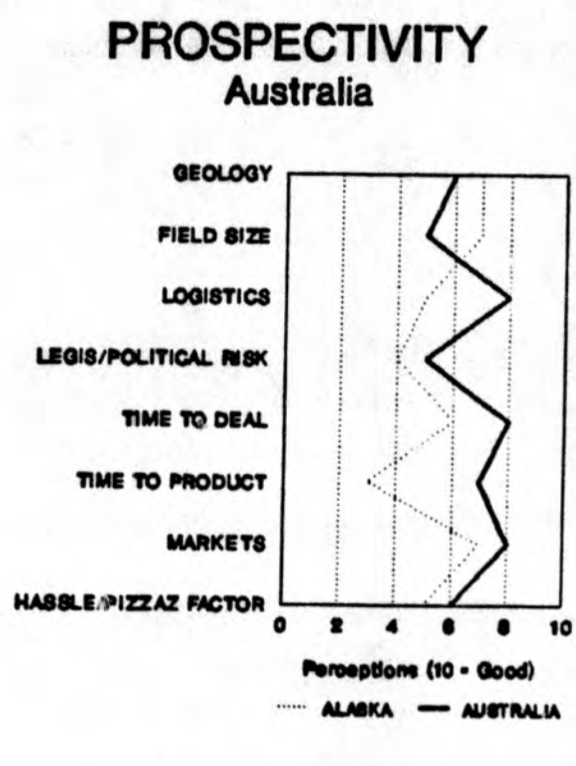
Prospectivity Results

Generally, Alaska looks less attractive under the scenario's examined at this "snap-shot" in time. Legislative/political risk appears higher in Alaska because among other reasons, the UK, Norway and Indonesia have all made material improvements in their legislation in more recent times. Recognising the subjective nature of the approach, overall Alaska appears similar to Norway and generally less attractive than the U.K. North Sea.


PROSPECTIVITY
United Kingdom
GEOLOGY
FIELD SIZE
LOGISTICS
LEGIS/POLITICAL RISK
TIME TO DEAL
TIME TO PRODUCT
MARKETS
HASSLE/PIZZAZ FACTOR
0 2 4 6 8 10
Perceptions (10 = Good)
ALASKA
UK


PROSPECTIVITY
Norway
GEOLOGY
FIELD SIZE
LOGISTICS
LEGIS/POLITICAL RISK
TIME TO DEAL
TIME TO PRODUCT
MARKETS
HASSLE/PIZZAZ FACTOR
0 2 4 6 8 10
Perceptions (10 = Good)
ALASKA
NORWAY


PROSPECTIVITY
Indonesia
GEOLOGY
FIELD SIZE
LOGISTICS
LEGIS/POLITICAL RISK
TIME TO DEAL
TIME TO PRODUCT
MARKETS
HASSLE/PIZZAZ FACTOR
0 2 4 6 8 10
Perceptions (10 = Good)
ALASKA
INDONESIA


PROSPECTIVITY
Australia
GEOLOGY
FIELD SIZE
LOGISTICS
LEGIS/POLITICAL RISK
TIME TO DEAL
TIME TO PRODUCT
MARKETS
HASSLE/PIZZAZ FACTOR
0 2 4 6 8 10
Perceptions (10 = Good)
ALASKA
AUSTRALIA

Sensitivities

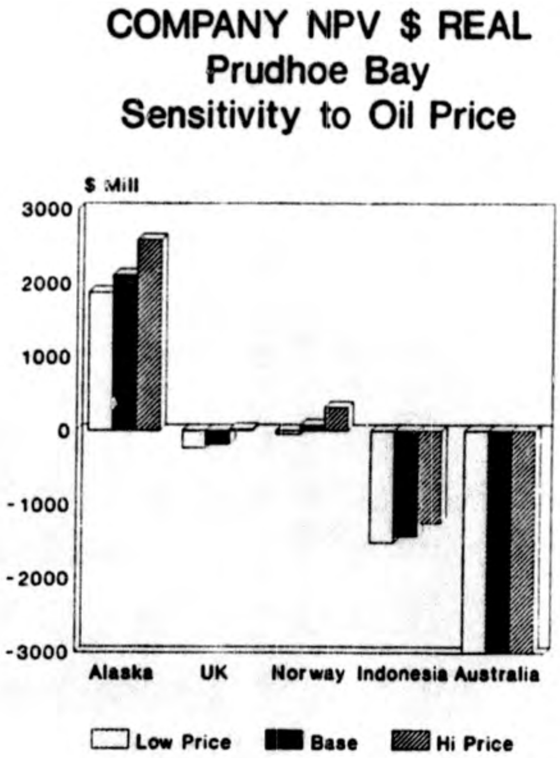
Sensitivities to Prices

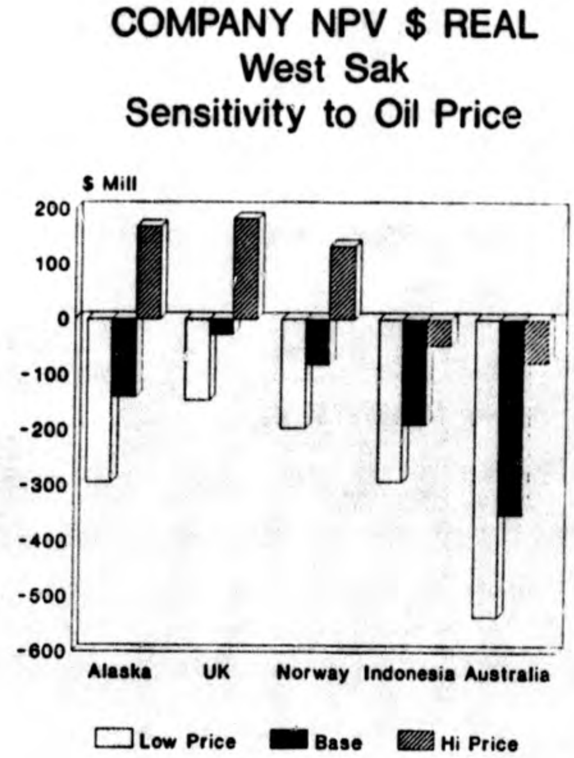
The following two pages of charts show the sensitivity to a high and low price, US$3 down (US$17/Bbl sale price) and US$6 up (US$26/Bbl sale price) from our base case (US$20/Bbl sale price - US$14.40 well head).

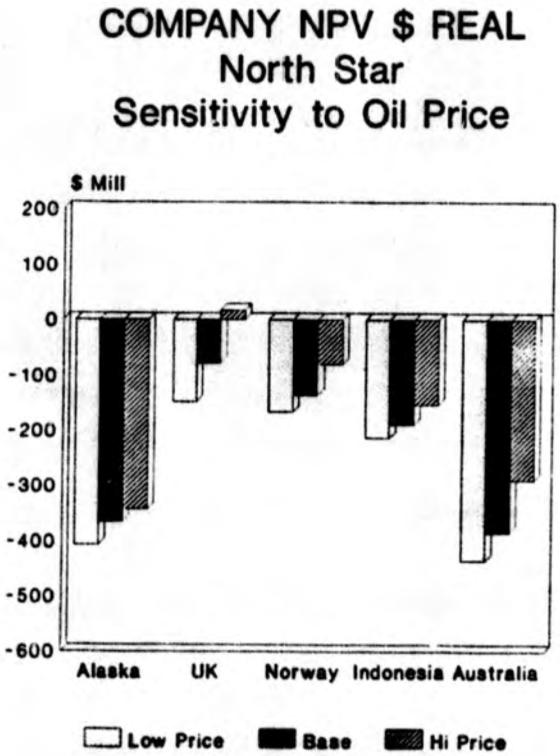
The sensitivity on the Net Present Value and on the internal rate of return is illustrated.

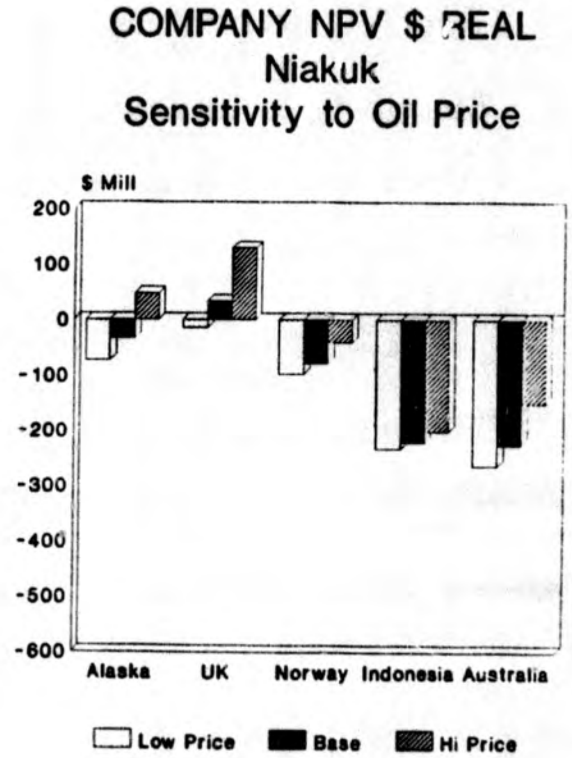
Prudhoe Bay historical rate of return is extremely insensitive to future prices when looking back from 1975. This is, of course, because a large part of the production is already at a market established price.

High prices put West Sak and Niakuk into a better looking scenario rate of return wise but only under U.K. legislation does North Star look to reach an even marginally acceptable internal rate of return. The rate of return on Niakuk demonstrates quite clearly the difference between the U.K. and Alaskan legislation, as even under a low price the rate of return is above 10% in U.K. versus 2% for Alaska. While under a high price the Alaskan return exceeds that in the U.K.

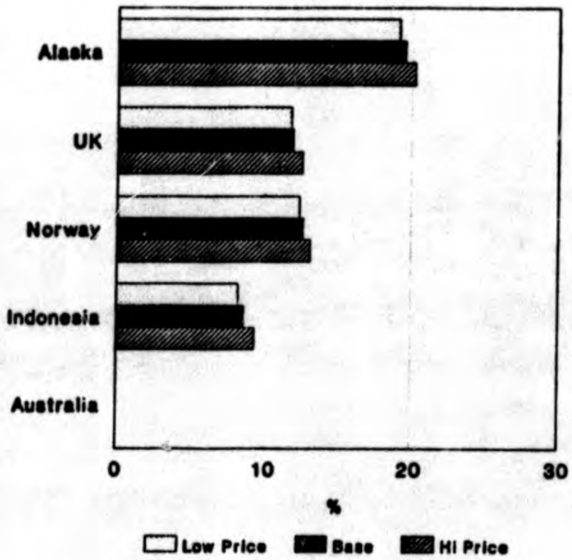

COMPANY NPV $ REAL
Prudhoe Bay
Sensitivity to Oil Price
$ Mill
3000
2000
1000
0
-1000
-2000
-3000
Alaska
UK
Norway
Indonesia
Australia
Low Price
Base
Hi Price


COMPANY NPV $ REAL
West Sak
Sensitivity to Oil Price
$ Mill
200
100
0
-100
-200
-300
-400
-500
-600
Alaska
UK
Norway
Indonesia
Australia
Low Price
Base
Hi Price

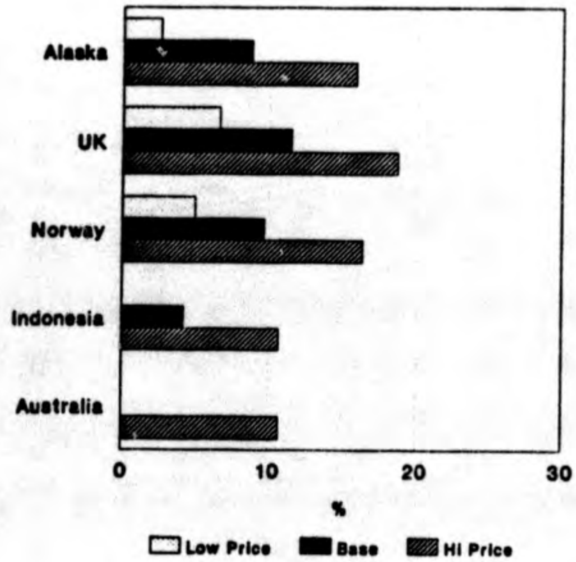

COMPANY NPV $ REAL
North Star
Sensitivity to Oil Price
$ Mill
200
100
0
-100
-200
-300
-400
-500
-600
Alaska
UK
Norway
Indonesia
Australia
Low Price
Base
Hi Price


COMPANY NPV $ REAL
Niakuk
Sensitivity to Oil Price
$ Mill
200
100
0
-100
-200
-300
-400
-500
-600
Alaska
UK
Norway
Indonesia
Australia
Low Price
Base
Hi Price

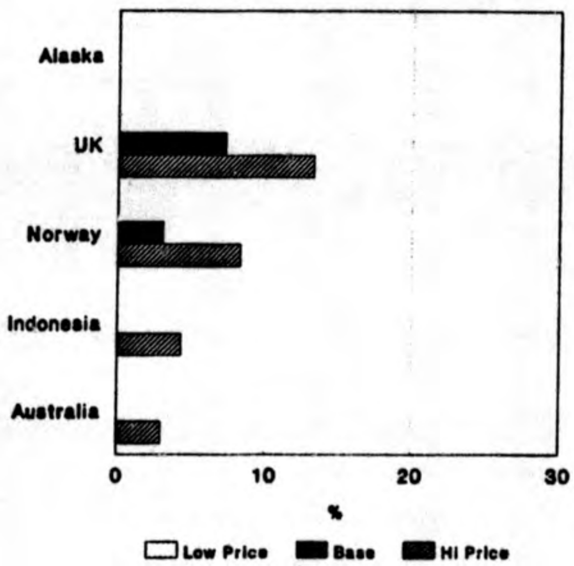
COMPANY IRR % REAL Prudhoe Bay Sensitivity to Oil Price



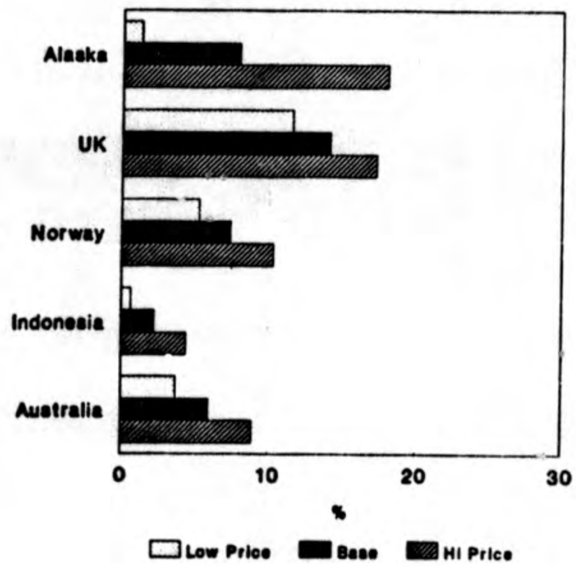
COMPANY IRR % REAL West Sak Sensitivity to Oil Price



COMPANY IRR % REAL North Star Sensitivity to Oil Price



COMPANY IRR % REAL Niakuk Sensitivity to Oil Price



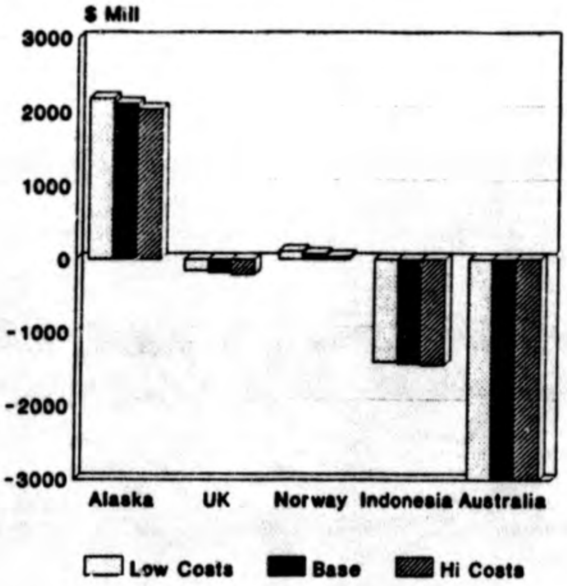
Sensitivity to Costs

The following two pages of charts show the sensitivity to a high (+25%) and low (-25%) cost scenario. The sensitivity on the Net Present Value and on the internal rate of return is illustrated.

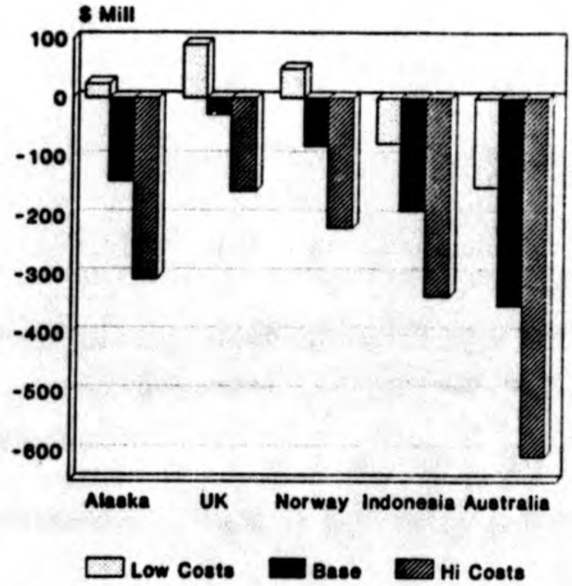
Again Prudhoe Bay is very insensitive to future cost changes when viewed from 1975. A low cost case makes West Sak and Niakuk look more attractive. Even North Star gets up in the range of potential investment consideration under U.K. legislation if costs can be reduced by 25%.

Sensitivity to costs is more marked in rate of return numbers in Alaska than say in U.K. or Norway.

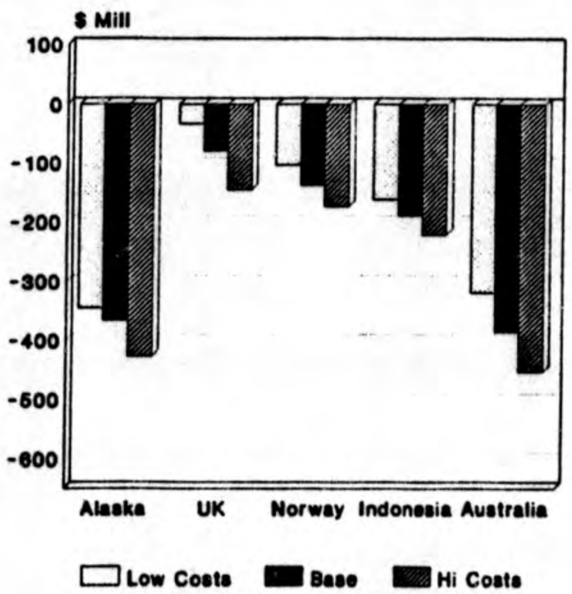
COMPANY NPV $ REAL
Prudhoe Bay
Sensitivity to Costs



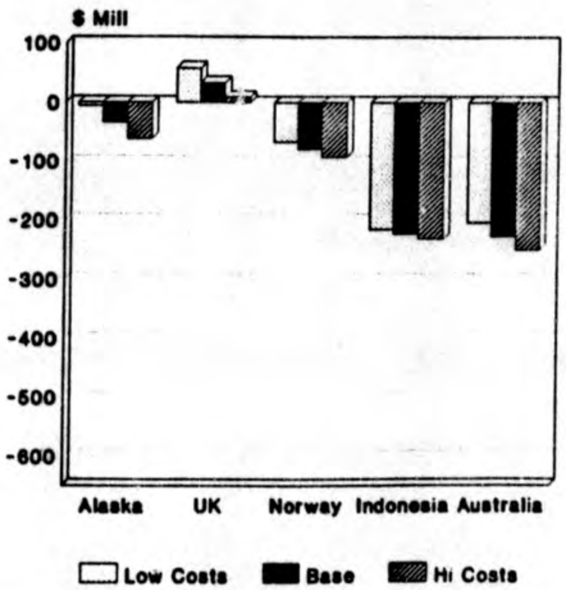
COMPANY NPV $ REAL
West Sak
Sensitivity to Costs



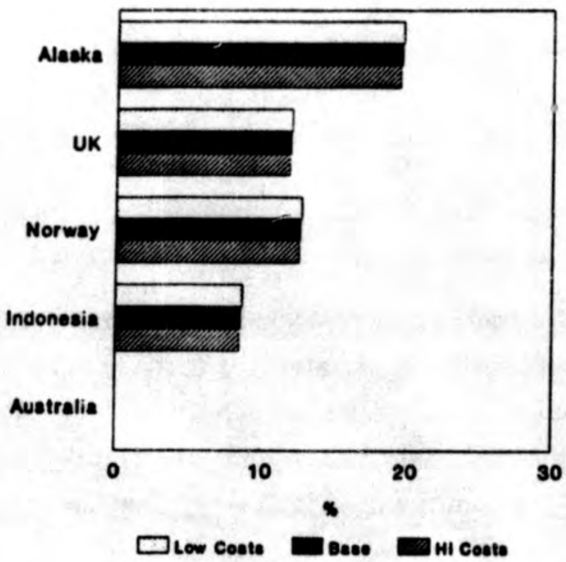
COMPANY NPV $ REAL
North Star
Sensitivity to Costs



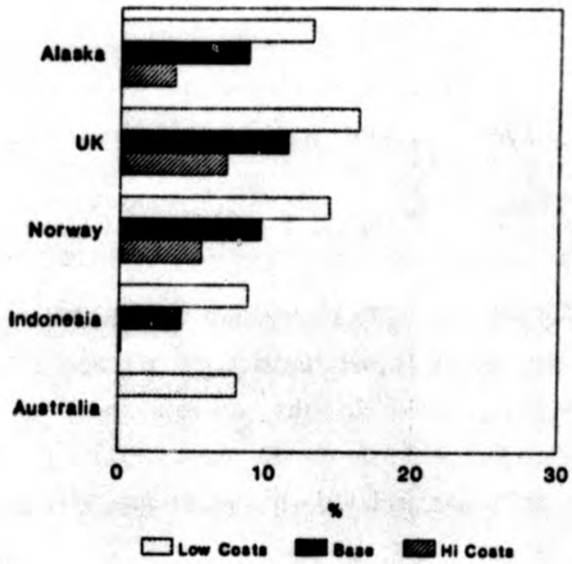
COMPANY NPV $ REAL
Niakuk
Sensitivity to Costs



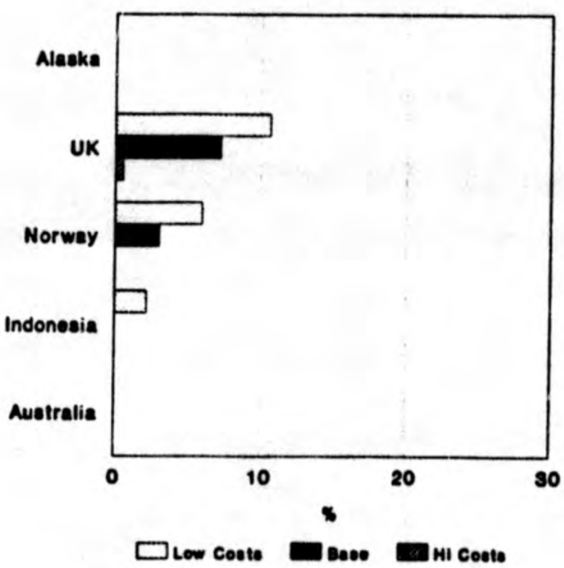
COMPANY IRR % REAL
Prudhoe Bay
Sensitivity to Costs



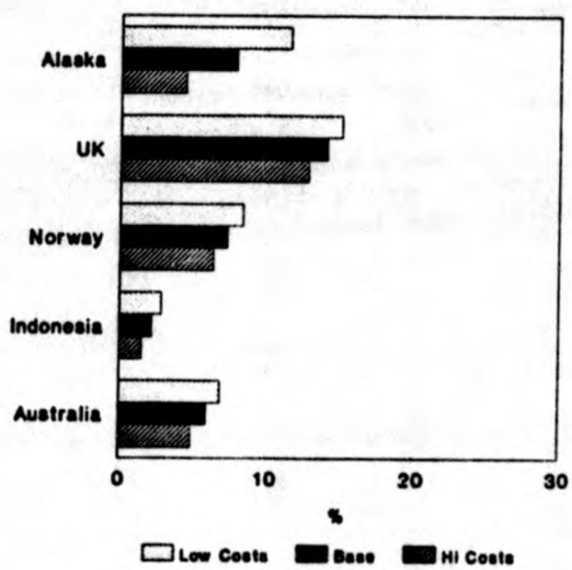
COMPANY IRR % REAL
West Sak
Sensitivity to Costs



COMPANY IRR % REAL
North Star
Sensitivity to Costs



COMPANY IRR % REAL
Niakuk
Sensitivity to Costs



Sensitivity to Exploration and New Investment

The following two pages of charts show the sensitivity to the sunk exploration costs on the Net Present Value and internal rate of return of the four fields.

Also shown on the same two pages is the effect of being a new player and not having the benefit of exploration write off against other projects.

Sunk Exploration Costs

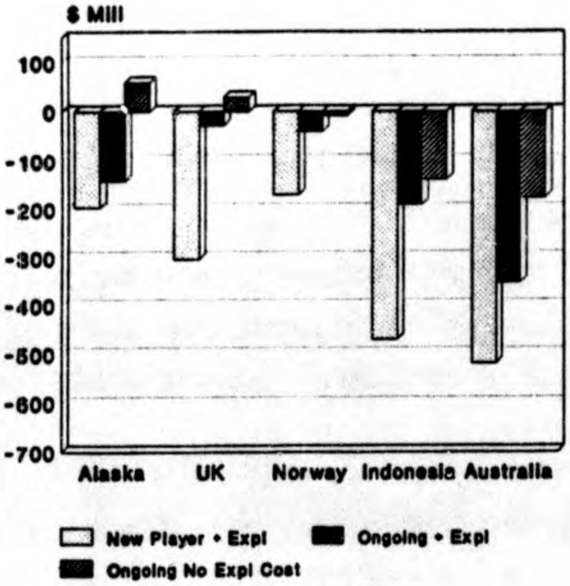
The decision to explore implies a commitment to later development of attractive opportunities. Unrecovered unsuccessful exploration effort has to be incorporated in the overall industry economics. So while a new area may look attractive from a development point alone the necessary front end exploration costs including related unsuccessful efforts must be considered in early assessments of going ahead on a new exploration venture. The exploration bill has to be paid somewhere.

Having made a discovery the analysis of the development economics may well take place without allocating sunk costs of exploration and development in the basic decision to proceed. However to the extent that such costs are not notionally recoverable against the project regardless of whether previously offset against past tax, the industry is simply cutting its losses rather than investing in a sensible project. It is clear that taking out the sunk exploration costs made Niakuk and West Sak especially more attractive projects.

New Player Versus Ongoing Investors

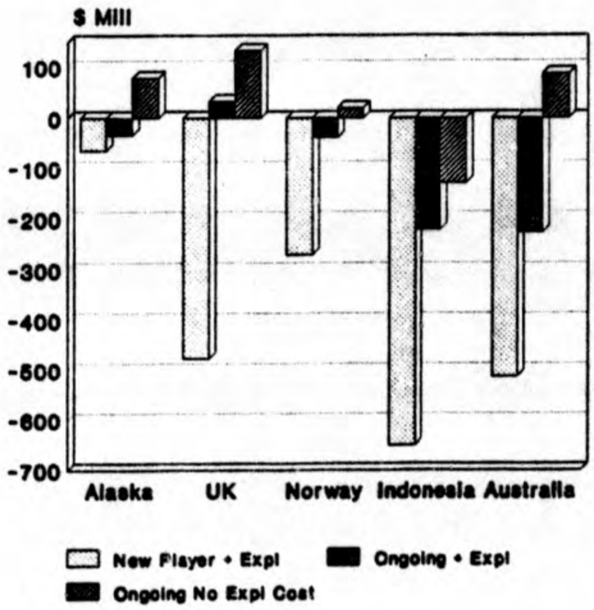
The impact of being a new player is also shown in the "Exploration" Sensitivity charts. As is to be expected, a new player would find the three new developments much less attractive than a current player, indeed none of the projects would look viable with the possible exception of West Sak.

COMPANY NPV $ REAL West Sak Sensitivity to Exploration



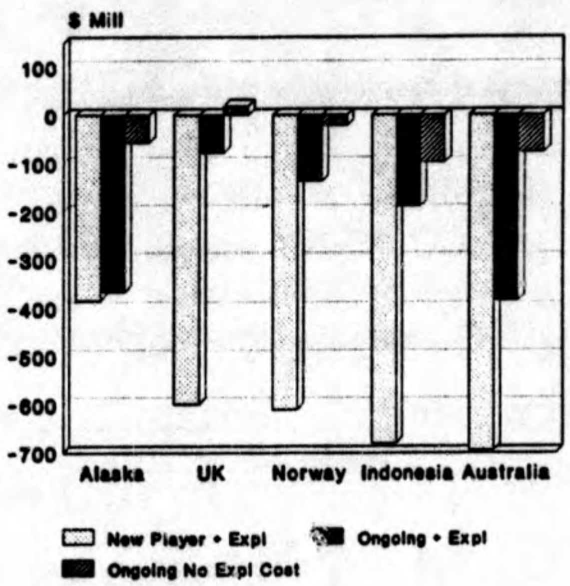
Ongoing + Expl Costs is Base Case

COMPANY NPV $ REAL Niakuk Sensitivity to Exploration



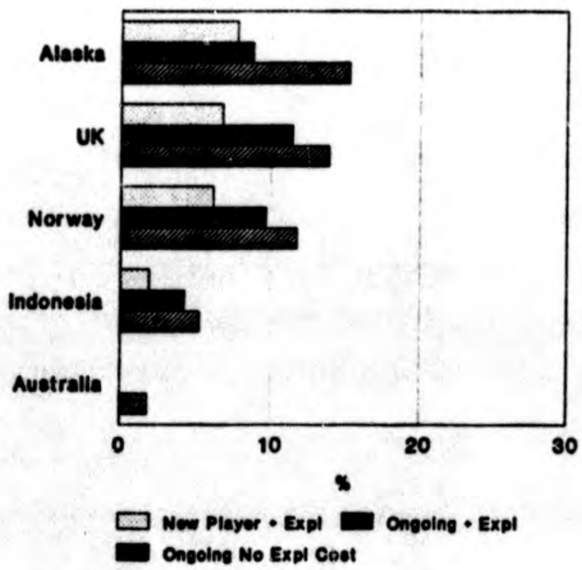
Ongoing + Expl Costs is Base Case

COMPANY NPV $ REAL North Star Sensitivity to Exploration



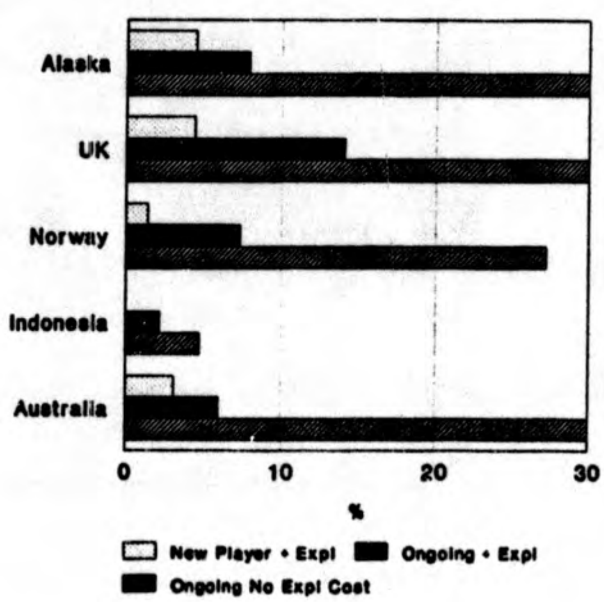
Ongoing + Expl Costs is Base Case

COMPANY IRR % REAL
West Sak
Sensitivity to Exploration



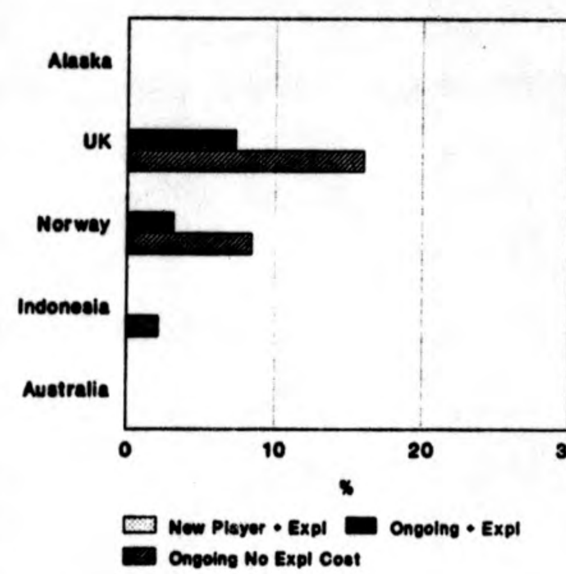
Ongoing + Expl Costs is Base Case

COMPANY IRR % REAL
Niakuk
Sensitivity to Exploration



Ongoing + Expl Costs is Base Case

COMPANY IRR % REAL
North Star
Sensitivity to Exploration



Ongoing + Expl Costs is Base Case

Encouraging Activity

Whether it be under concession arrangements such as in the United Kingdom or production-sharing agreements such as in Indonesia, these two governments have certainly used a pragmatic approach to adjust relative returns to the industry. This has been achieved by modifications to the contract conditions and/or to tax accounting guidelines. If encouraging exploration and development are objectives, the most successful approach has been that in the U.K. where the tax write-offs are significant enough to continue to encourage major exploration effort so that high marginal tax rates are offset by substantial exploration offset provisions. A similar, if somewhat more restricted approach, is taken under the Indonesian Production-Sharing Contract. Any government, of course must make a decision on the extent to which it wishes to encourage further exploration, investment in existing fields or new developments based relative to its need for current or longer term revenue from the industry, in addition to aspects such as employment and infrastructure which are critical in many jurisdictions.

While from a purely Alaskan view much of the employment and equipment manufacturing benefits may occur elsewhere, they do for the most part occur within the same government jurisdiction, i.e. the United States. Thus major projects, particularly on the North Slope or elsewhere, can have a significant impact in relative terms on the whole of the U.S. oil industry environment.

Certainly, governments in other countries have sought to encourage development and indeed domestic employment and domestic manufacture, but they are, of course, more concerned that such employment occurs within the country rather than a particular State. In the U.K., however, the emphasis has been more localised and significant efforts have been made to ensure that much of the offshore benefits accrue to Scotland.

Policy Goals

While the goal in Australia has been to maximise revenue the perception has been that prospects were not good for finding major new fields. In Indonesia while foreign currency and revenue were key issues the government has recognised a need to continue encouraging the industry for long term benefits of revenue, foreign exchange, employment and infrastructure.

In Norway the goal has been to maximise both revenue and local involvement and at the same time control development so as not to allow it to get out of hand.

The United Kingdom has pursued a varied policy over the last several years but overall it can be said to have wanted first to reduce or eliminate the oil deficit by encouraging exploration and development, then encouraging domestic industry with the resulting employment. Those two planks, maximising production and local involvement continue to be key driving forces, although it must be recognised that the U.K. marginal tax rate on large fields is one of the harshest in the world. This in turn is offset by generous exploration offsets to encourage further exploration.

How does the Government control industry in other countries?

The industry is largely controlled in most countries by a combination of the equivalent or a Ministry or Department of Energy and an appropriate Department of Revenue. Basically, the Ministry is responsible for issuing of new licences, exploration/production (the equivalent of lease sales), the approval of appropriate permits and for the general regulation and control of the industry, and will typically have involvment in the basic terms and conditions affecting the return to the industry. The revenue authorities typically will be involved in adjustments to the tax code and the general guidance of the government and the ministry or equivalent to encourage/discourage further investment by way of tax enhancements/disincentives.

To the extent that some countries have separated aspects of basic petroleum control and taxation into more than one or two groups, there has definitely been some reduction in effectiveness and there appears to be an increased likelihood of litigation.

The Legislative Dilemma

We must recognise the long time between encouraging exploration or reinvestment on the one hand and seeing the results in terms of taxation revenues in a remote and costly location on the other. This time gap makes it difficult for governments to establish a reasonable basis for judging the level of appropriate benefits today as opposed to what one should encourage for a tomorrow which could be more than a decade away. While the oil industry is not unique in this regard, because much of it is so visible - it continues to present all legislators with very difficult choices.

The median view would seem to be to continue to encourage re-investment and development and exploration at the expense of current revenues to the extent necessary while reasonable prospects and opportunities appear to exist in the future. Industry itself provides the barometer of the reality of those opportunities since they are unlikely to invest even small percentages in a tax-efficient manner if the opportunities are indeed poor. To achieve this happy, and perhaps ideal mean, does require the government to have its own ongoing and reasonable analysis of prospects and opportunities and to be close enough to the industry to recognise their own driving forces and to encourage them accordingly.

As indicated in discussions with the Committee we are dealing with a worldwide industry and other opportunities will cause the limited capital resources to move away from one area to another. This will require governments of the day to adjust their revenue-sharing arrangements if they wish to continue to attract risk funds.

Similarly, from time to time it may well be that the existing structure, as we have seen in the U.K. and in other parts of the world, is no longer appropriate and it may be necessary to increase the tax share. Logically, how one treats the industry will be different if it forms a high proportion of government revenues, than how the industry is treated where it is but a small fraction. The principles may well be the same but the approach will be different.

Ideally from both governments' and industry's point of view a tax system which seeks to increase the state take as the project becomes more attractive, be it because of price, improved performance or whatever reason, is one that seems to find the most favour with all parties. Unfortunately, most systems are not even-handed in how they treat and encourage re-investment, development of marginal fields or encouragement of exploration, especially under lower oil price scenarios. However, it is fair to say that there is no panacea in defining legislation, for each country has particular circumstances which both require and justify somewhat different handling.

Some Observations

We must recognise that the analysis carried out is by no means exhaustive in terms of examining a full spectrum of opportunities for Alaska. Nevertheless, it may be helpful to examine the possible direction in which legislation might achieve one or another end, based on what has been carried out in other countries. A significant amount of additional study on the Alaskan Legislation and the appropriateness and application of necessary directions would be needed to recommend specific detailed tax policies and indeed the Legislature would need to define objectives accordingly.

Let us suppose that the hypothetical objective was to encourage domestic employment to the extent that such approaches were acceptable under federal regulations. It might be possible to grant some relief on future development to those concerns which demonstrated in all their operations an increase in Alaskan domiciled employees (e.g. perhaps those who qualify for payouts from the permanent fund).

If we assume that a longer term objective might be to maximise the State revenue to reduce the potential fiscal gap as much as possible, then we might proceed as follows. Carry out a reasonable assessment preferably with industry's help of remaining potential exploration, development and incremental projects. Then modify the fiscal legislation to make it more progressive so as to encourage a reasonable amount of exploration and development on an ongoing basis.

An efficient fiscal system applied to petroleum exploitation may be defined as one which collects a share of any economic rents to the State while at the same time maintaining incentives for (a) continued exploration, (b) new field developments, and (c) incremental investments. Account should be taken of the risks involved in petroleum exploitation, and the lead times between initial expenditures and income from production. In assessing investment opportunities oil companies employ discount rates which reflect their costs of capital and the perceived risks. A well-designed tax system should take these factors into account.

In practice an efficient fiscal system should be related to the profitability of petroleum exploitation. It should be sensitive to the variations in the factors determining project viability, such as oil prices and development costs.

A profits-related system is better able to satisfy these conditions than one based on production or gross revenues. Thus, when oil prices fall impositions based on gross revenues can render marginal fields uneconomic. The impact of profits-based taxes also depends upon the timing of the reliefs for exploitation costs. A slow rate of relief brings earlier revenue to government but reduces the post-tax returns in present value terms. A delicate balance is required to maintain incentives. This issue is especially important when there are very long lead times between expenditure and income.

Should the objective be to maximise oil production and the discovery of the maximum resource, then the recommended approach adopted in the previous case must be relaxed to greater extent to ensure that exploration development and investment funds are encouraged to move toward Alaska preferentially. Ideally this would mean providing early relief from higher rates of State tax, but in a more general sense doing whatever is possible at State level to minimise the impact of whatever environmental legislation is in place so as to reduce at least the time delay inherent in the current systems.

Overall legislation should be a blend of the various competing objectives. Achieving that blend is no easy task but will be facilitated by bringing the various alternative objectives into plain view where they can be discussed by all interested parties. It seems reasonable to assume that a significant number of potentially attractive exploration, development and re-investment opportunities remain in the North Slope area onshore and offshore and it would seem prudent to try and encourage the necessary activities to produce these resources.

APPENDIX

Base Case Summary

Ongoing operator (i.e. not a new player)

Includes allocated exploration and bonus costs

Government take includes state and federal revenues but not bonuses except in the case of the analysis of the effect of the 900 million bonus

NPV's and IRR's are for Real $ Cashflows

Discount Rate is 12.5% real (i.e. 17% if there is 4.5% inflation) (except where stated)

Prices and Costs were escalated at 4.5% p.a.

Oil price was $14.50 a barrel wellhead price Prudhoe Bay, with quality and transportation adjustments for the other fields as necessary. This is equivalent to a sale price of about US$20.00/Bbl

The Prudhoe Bay base case is for a full life cycle of the field from 1975 though 2016 and the Real $ are 1975 dollars for Prudhoe Bay as against 1990 dollars for the analysis of the remaining Prudhoe Bay production and all other fields

Analysis Details and Comments

The base case for each field in each legislation was taken from 1990 with a median oil price, median costs, inclusive of an exploration program and assuming an existing investor. In addition a number of sensitivities were run.

As indicated elsewhere the discount rate chosen for the valuation was 12.5% real 17% and ranged about 10-15%. The oil price chosen for the base case was $14.50 per barrel wellhead price Prudhoe Bay, with quality and transportation adjustments for the other fields as necessary. Prices were escalated at 4.5% p.a. as were capital and operating costs. High and low oil price cases at the equivalent of minus $3.00, that is $11.50 per barrel Prudhoe Bay, and plus $6 which is $20.50 per barrel, were also examined to note price effects. The impact of different operating and capital costs from the base case was evaluated by examining the effects of increasing or decreasing such costs by 25%.

The net present values and rates of return determined for type fields, were not meant to reflect exactly what companies achieve but instead to provide a base for comparison. Some companies may have incorporated additional exploration costs in their assessment of the Alaskan fields, others may allocate costs differently.

Indeed, the base data may not reflect exactly how the new projects might be carried out in future. We have examined some measure of the impact of exploration by considering the allocation of some, but by no means all, unsuccessful efforts. Similarly the analysis has been carried out at the wellhead and does not attempt to evaluate the impact on, for instance, the TAPS pipeline. Further it should be clear that this analysis is centred around developments and production in the North Slope region. production using the TAPS Pipeline for export. It is not meant to give comparisons with other parts of Alaska where transportation methods are more or less costly and where other factors could be more relevant.

Sensitivity analyses to price, cost, the impact of whether one was a new investor or was an existing investor and therefore had ongoing tax right-offs, were carried out to give some idea of the impact of these aspects. The benefits of an existing player, particularly in the United Kingdom, are very significant under current legislation and this has no small impact in attracting new capital to explore for and indeed develop existing discoveries.

Extensive analysis was carried out to compare the value of North Slope crude to other market crudes in the key countries considered. However, bearing in mind the complexities involved, the decision was to treat the analysis as though the legislation had been moved to Alaska rather than to bring in the impact of different crude price and market regimes.

Similarly, extensive investigation was carried out to look into the allocated costs for discoveries in the countries considered with a view to using different exploration costs for each region, but again in the interests of making comparisons on basis of legislation alone, this approach was left for consideration if necessary at some later stage.

Other measures of performance.

Marginal Tax Rates on Prudhoe Bay

In order to make an assessment of historical taxes, it was necessary to make a judgement on marginal tax rates. To be conservative relatively high marginal tax rates were assumed to apply for the past period. This almost certainly overstates the relative amount of tax that the government might have obtained and also overstates the amount of tax the companies would have paid. The time and the complexities involved did not justify running this analysis significantly further at this time.

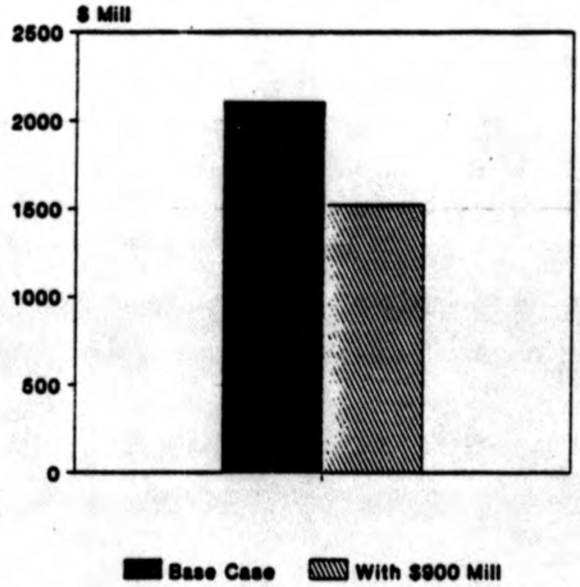
$900 Million (1969) Bonus

Impact of allocating full $900 Million (1969) Bonus payments to Prudhoe Bay is shown in the following charts.

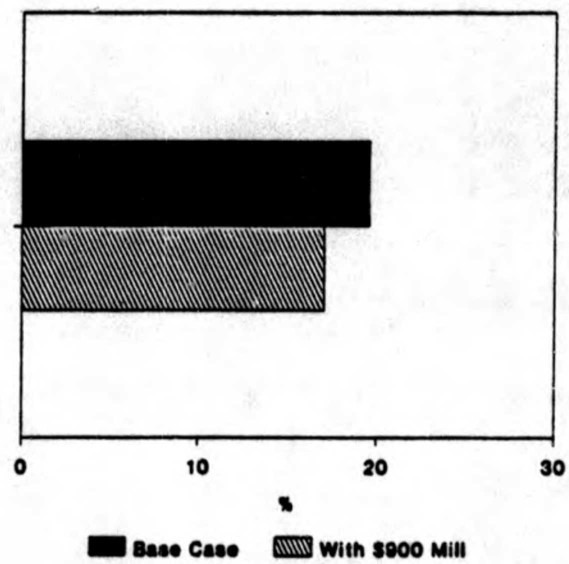
Base Data Note

In the data presented by the revenue group some fields were kept in production after they had a negative cash flow - this was necessary in order to present a full data set for use under the other regimes. For comparative purposes it was necessary to "produce" these fields where possible to similar points although an economic cut-off was used. This aspect produces some inconsistencies but it is believed these are not meaningful in the broader-brush comparisons illustrated.

COMPANY NPV $ REAL
Prudhoe Bay Alaska
Sensitivity to $900 Mill Bonus



COMPANY IRR % REAL
Prudhoe Bay Alaska
Sensitivity to $900 Mill Bonus



Countries and Fields Selected for Comparison

The countries selected for comparison were the United Kingdom, Norway, Indonesia and Australia. They have been chosen because they represent jurisdictions where the legislation has either led to continued industry attention, or where there have been problems in maintaining investment.

U.K.

The United Kingdom was chosen in view of the very considerable proportion of major exploration funds which continue to be spent in the North Sea. This has occurred partly as a result of the very attractive tax driven exploration policy adopted by the government, where at the margin some 83-87% of costs of exploration are borne by the government by way of tax. However, these tax concessions combined with prospects still have to be good for the industry to invest. Continuing high success ratios, albeit with smaller fields, have continued to make the United Kingdom an attractive exploration and development arena.

Norway

Norway was included in the comparison mix because of the large size of its fields and also because it had demonstrated a more aggressive approach to legislation than that of the United Kingdom. Larger and more expensive projects and long periods before development can take place have made a number of international companies recently offer for sale their interests in Norway. This has confirmed the view that Norway largely remains an arena for the long term players with requirements for large producing volumes and one where it is difficult for companies not currently involved to justify investment.

Indonesia

Indonesia was incorprated in the assessment as it has remained an attractive arena over the last 15 or more years. Offshore field sizes, of course, are small by comparison with both the North Sea and Alaska but the production-sharing contracts and pragmatic government approach have continued to encourage investment.

Australia

The Australian Bass Straits area largely contain older fields which represent a large proportion of Australia's production. This production has been subject to special tax handling (excise tax), and new development has been plagued by stop/start industry policy as perceived returns under the then current legislation/price scenarios became more or less attractive.

Thus in general, the United Kingdom and Indonesian legislations demonstrably were situations where industry was investing and has continued to invest heavily during the recent period, while the Australian and Norwegian legislations were of a more aggressive type where industry was less able to justify continued investment.

Alaskan Fields Selected for Comparison

The four Alaskan fields selected for comparison were Prudhoe Bay, West Sak, North Star (Seal Island) and Niakuk.

Prudhoe Bay

Prudhoe Bay is a large mature oil field. It was developed in the mid 1970s, with first production in 1977. Current estimates of ultimate reserves are in excess of 11 billion barrels.

West Sak

West Sak is a relatively large higher cost oil field with estimated recoverable reserves of 633 million barrels, with first production due in 1992.

North Star (Seal)

North Star is a medium sized higher cost oil field with estimated recoverable reserves of 178 million barrels. Development expenditure is due to commence in 1997, with first production in 2000.

Niakuk

Niakuk is a smaller or relatively lower cost oil field with estimated recoverable reserves of 58 million barrels. Development expenditure is taken to start in 1990, with first production in 1994.

UNITED KINGDOM

In the United Kingdom the state owns any oil or gas in place that is discovered. The Government has the power to award licences which permit exploration or development in the areas covered by the licences.

Exploration licences entitle the holder to conduct preliminary exploration activities in the area and have recently been issued every 2 years. The exploration period is typically 6 years. A production licence entitles the holder to appraise and develop fields subject to the consent of the Department of Energy. Consent is usually obtained following the submission of a detailed development plan.

The Government take from oil and gas revenues is essentially made up of the following elements

- Government Royalties
- Petroleum Revenue Tax (PRT)
- Corporation Tax (CT)

Government Royalties - on the first to fourth Round Licences (i.e. pre 1972) royalty is payable at 12.5% on the wellhead value of the petroleum, i.e. certain costs of conveying and initial treatment are deducted from the landed value of production. On fifth and later Round Licences (i.e. post 1976) royalty is payable at 12.5% of the market value of the petroleum. On fields given development approval after April 1st 1982 there is no royalty charged. Royalty where applicable is taken in cash.

Petroleum Revenue Tax (PRT) is assessed on a field basis for six-monthly chargeable periods at 75% of the assessable net profits.

Net Profit	=	Market Value of Oil Sales
	+	tariff receipts less allowance
	+	Asset disposal receipts
	+	Conveying and treating receipts
	-	Royalty payable
	-	Allowable Field Expenditure

- Uplift
- Exploration and appraisal expenditure
- Research and development expenditure
- Cross field allowance

Allowable field expenditure essentially means any expenditure relating to the search for, production of, transportation of, treatment and storage of petroleum. Uplift is a supplementary allowance intended to compensate for the inability to offset loan interest against tax. It is set at 35% of expenditure mainly related to the appraisal and development of the field and is allowed only prior to payback. The oil allowance is currently set to 500,000 tonnes per chargeable period up to a maximum of 10 million tonnes for fields given development consent after April 1st, 1982*. Crossfield allowance gives an opportunity for 10% of the development costs of a field incurred after March 1987 outside of the Southern Basin to be offset against the PRT payment on existing U.K. production.

Corporation Tax (CT) is charged on a company basis at a rate of 35% of trading profits.

Trading Profits	=	Gross revenues
	-	Royalty
	-	PRT
	-	Operating Costs
	-	Capital allowances

Capital allowances are essentially depreciation on plant and machinery assessed at 25% of the prior year's written down balance. Most development drilling is 100% for first year. CT is payable in that year following the chargeable period.

* This means in effect that smaller fields pay little or no PRT.

NORWAY

In Norway the state participates in each licence through Statoil (the 100% state- owned oil company). The requirement for foreign companies to carry the state through the exploration and appraisal stage was removed for licences issued after January 1st, 1987. The state awards production licences which allow for an exploration period of 6 years and a production period of 30 years. Field development requires the approval of the Storting (Parliament).

The government take from oil and gas revenues consists of the following elements:

- Government Royalties
- Income tax
- Special Petroleum Tax (SPT)

Royalty - Fields receiving development approval after January 1st, 1986 are exempt from Royalty payments. Post 1972 licences have a varying rate for oil between 8% and 16% of the wellhead value depending on the rate of production. Gas and NGL are subject to a constant rate of 12.5% of the wellhead value. On new fields the royalty is zero. The market value 'norm' is fixed for each field for each calendar quarter by a board appointed by the Ministry of Energy.

Income Tax - this includes	Municipal Tax	23%
	State Tax	27.8%
	Capital Tax	0.3%

Municipal tax is levied at the rate of 23% of Profit before Tax. The State Tax is levied at the rate of 27.8% of Profit Before Tax less dividends paid. Capital Tax is paid at the rate of 0.3% of net worth. Net worth is Book Asset value less debt (excluding income tax).

Special Petroleum Tax (SPT) is assessed at a rate of 30% of profits adjusted for 'norm' price. For fields given development approval before January 1st, 1987 an annual uplift deduction from profits is allowed. The uplift is calculated as 6.666% of total assets used in oil production and pipeline transportation and lasts for a period of 15 years. For fields given development approval after January 1st, 1987, SPT is calculated on net income exceeding a production allowance'. The production allowance is set at 15% of the value of produced petroleum based on 'norm prices'. Depreciation for both income tax and special tax is on six year straight line basis.

INDONESIA

In Indonesia the state participates in oil and gas activity through the use of Production-Sharing Contracts. The exploration period lasts for 6-8 years and should a commercial discovery be made, the contract period is extended to 30 years.

The Government take from oil and gas revenues is made up of the following elements.

- Bonus Payment
- Production-Sharing Contract (PSC)
- Income Tax

Bonus Payment - A negotiable signature bonus of several million U.S. Dollars is payable on signing the contract. In addition, production bonuses may be payable when specified rates of production are reached.

Production-Sharing Contract - the PSC allows a sliding scale government share (between 51.9 to 80.77%) dependent of the age and area of the contract and type of development. In this study the pre-tax government share is 71.1538% on new fields.

The Contractor is allowed to recover his costs from production but the maximum annual cost recovery is now limited to 80% of annual production. Allowable costs include exploration costs, capital costs depreciated on a declining balance, plus an uplift of 17% of oil field development costs and operating expenses. Any costs in excess of the annual allowable cost recovery may be carried forward for up to five years. The PSC also obliges the Contractor to supply the state with up to 25% of total field production for which it is paid the market price for the first five years of production and thereafter 10% of the export price, but of course the company then recovers all costs associated with the domestic obligation under the cost recovery program.

Income Tax - Corporation tax is charged at an effective rate of 48% of the total value of the Contractor's taxable income (35% income tax and 20% dividend tax). The depreciation rules under the post 1984 time permits some assets to be reserved at 50% declining balance, some at 25% and some at 10%.

AUSTRALIA - BASS STRAIT AREA

In Australia, offshore permits are administered by the Australian Commonwealth Government under the control of the Petroleum (Submerged Lands) Act of 1967. The permits take two forms, exploration permits which have an initial duration of 6 years with possible extension of 5 years up to a total of 26 years and production permits having an initial period of 21 years with an extension of 21 years so long as the field is commercial. The Government take for the Bass Strait area consists of

- Royalty
- Excise Tax
- Corporation Tax (CT)

Royalty - for production from an exploration permit or initial production permit royalty is levied at the rate of 10% of wellhead value. For production from an extended production permit, royalty is levied at a rate between 11% to 12.5% of wellhead value fixed by the Government.

Excise Tax - The Excise Tax is on sliding scale levy based on field oil production rates. The applicable rates are dependent on the timing of the discovery and development of the individual field. There are three categories of crude oil - old, middle and new. Applicable Excise rates are shown below:

Annual Production	Excise Rate, %		
000s Bbls	Old oil	Middle oil	New oil
0 - 315	0	0	
315 - 629	5	0	0
629 - 1259	15	0	0
1259 - 1888	20	0	0
1888 - 2517	40	15	0
2517 - 3146	70	30	0
3146 - 3776	75	50	10
3776 - 4405	75	55	20
4405 - 5034	75	55	30
5034 +	75	55	35

Corporation Tax - CT is charged on a company basis at the rate of 39% of trading profits. Depreciation of developments costs can be either under fiscal terms for "prescribed petroleum operations", in which case the rate is currently 10 year straight line or under normal tax rates. In the latter case the rate for plant and machinery is 20% straight line basis and 33.3% for drilling plant and downhole equipment.

FINANCIAL AND OTHER ASPECTS OF OIL INDUSTRY ACTIVITIES AND INVESTMENT

Outline

Executive Summary

One - Financial Aspects of Oil Industry Activities:
A cross-country comparison

Two - Other Aspects of Oil Industry Investment:
A comparative analysis
(both across countries and within countries)

Three - Interaction of Government and Oil Industry:
Some relevant case studies

Four - Coordinated Government Policy

Five - Encouragement/Role of Independents

Six - Concluding Remarks

Table of Contents

EXECUTIVE SUMMARY

This part of the study, prepared for the International Tax Comparison Committee of the State of Alaska Legislature, focusses on the financial and other dimensions of oil industry activities and investment.

An attempt is made to show that, while tax is an important factor, there are others which play a part in any investment decision-making process, in particular when a company considers entering a new area. Thus, a comparison of different petroleum fiscal regimes would not be complete without reference to these specific aspects.

Accordingly, the factors highlighted in Parts One and Two can be applied as a checklist when the superiority of one region over another is being assessed. The components of this checklist are featured in sections 1.6, 1.7, 1.8, 1.9, 2.2 and 2.3 of this part of the study. Going through the checklist, Alaska scores favourably as an investment climate.

The interaction between industry and government in the countries chosen for comparison is examined in Part Three. Here are shown cases where relationships have deteriorated to the point of exodus of industry, and situations where relationships have improved over time.

The importance of coordinated government policy is stressed in Part Four where examples are given from other countries, and the encouragement and role of independents is discussed in Part Five.

Finally, in Part Six, it is concluded that in the current climate of the oil industry there would be neither a lack of finance nor a shortage of companies willing to enter Alaska, should the opportunities present themselves. The international petroleum industry today is both cash-rich and highly acquisitive.

One - FINANCIAL ASPECTS OF OIL INDUSTRY ACTIVITIES

Preface

This part of the report is written for a wide readership including the non-expert. Those with some knowledge of the oil industry may well be familiar with some or indeed most of the points raised here. They are mainly intended to help demonstrate various facets of the industry for international comparisons.

1.1 - Introduction

Traditionally the oil industry has been characterized as one of extremes, with giants and very small players and few in between. Either a company had adequate cash flow and did not require long-term finance or it simply wasn't large enough to obtain such funding.

This pattern has changed substantially over time and today the international petroleum industry accommodates all sizes of companies. Large amounts have been raised externally in the last two decades for major capital expenditure programmes and for acquisition financing in the oil and gas sector.

The interplay of finance and the activities of the international petroleum industry are, thus, quite significant. Indeed this dimension is so vast that the comparative analyses of the countries chosen for this report could be the subject of a separate study (given the mixture of companies in operation in these regions). Nevertheless, an overview is presented here of some of the financial issues and other aspects of industry investment (discussed in Section Two below) that have direct relevance for this particular report. This should form a checklist that can be used when examining complaints from industry about the tax structure.

In short, when international comparisons are drawn, two key questions have to be the guiding principle: i) Is there ready finance available for the development of oil and gas projects in the area chosen for comparison? ii) What are the comparative advantages and limitations of sinking funds in the region?

1.2 - Sources of Finance

Finance for the development of the oil and gas industry is made available through three major sources: i) internal finance; ii) external finance through bank loans; and iii) external finance through the issue of shares (or some other instruments such as royalty units, etc.) in the case of publicly quoted companies. Further details on modes of financing are given in section 1.10 below.

1.3 - Industry Background

In the context of this particular report, it is worth pointing out some of the day to day workings of industry and its interaction with the financial world.

Companies with public ownership of shares are always interested in attracting new shareholders as well as convincing existing ones to buy more of their stock. Usually when a company gives an account of its activities to the financial community it tends to draw attention to the more positive aspects of its future prospects - highlighting information that makes investment in the company as attractive and profitable as possible. For instance, they would point out development of new fields that will enhance their oil and gas production in future years, or an increase in their exploration activities, etc.

Conversely the same company lobbying the government for tax reduction or for prevention of a tax revision would place the emphasis elsewhere. Both pieces of information are wholly accurate. They are made available to the public and are not in the least false. The question is, which statistics are highlighted at which presentation. Indeed, the legislature has to look at both sides of the story when in receipt of evidence of a loss on the basis of an ad hoc calculation for a single oil field.

Usually, for a publicly quoted company, the annual report is a good starting point to form an overview of the profitability of a subsidiary (such as one based in Alaska) and its future prospects. The size of a company's profit for each segment of its activities (in relation to the assets) provides some basis for consistency of argument.

For ultimately, if in the light of the tax revisions the subsidiary becomes unprofitable for a period of time, corporations have a responsibility to their shareholders to pull out of a loss-making operation. They either have to sell off or shut down the subsidiary. The reader should be cautioned here, though, not to interpret every sale of assets as a consequence of high taxes - for it could be the result of company rationalisation decisions. This aspect will be further discussed in section 2.1 below.

1.4 - Structure of Petroleum Industry

Oil companies are run in a decentralised manner. It tends not to matter how large or small each subsidiary unit or outfit is. The rule is that each subsidiary must stand on its own by producing a positive net return (unless the operation is set up purely as a tax vehicle). Thus, when a new subsidiary starts, ample time is given by the parent company to recover initial investment and produce a positive cash flow.

After an initial gestation period, however, an operation has to be profitable. If it continues making losses which are not caused by exogenous factors such as the sudden collapse of oil prices or a stock market crash, then the parent looks closely at the operation. Persistent losses call for a shutdown of the entire operation of the subsidiary or for submerging it under another subsidiary to reduce overheads. In particular, if the company in question is a publicly quoted company, its stockholders would require it to secure the maximum return.

In the final analysis one can ask how far can oil taxes rise before companies put their oil and gas operations up for sale, and what would be the asking price? Alternatively, a real test would be at what price would a company be willing to depart from the area and give up its entire operations.

1.5 - Categories of Companies

To gain further insight into the financing of petroleum industry activities, one can break oil companies into four separate categories:

a) The oil majors - with public ownership of their shares (nearly all such companies seem to have a presence in Alaska)

b) The independents - with public ownership of their shares (noticeably absent from Alaska)

c) The private, smaller type, firms - with no public ownership of their shares (again noticeably absent from Alaska)

d) The state oil companies

Examples of category d are Statoil in Norway, Pertamina in Indonesia, and Petrocanada - the last of which is to be privatised soon.

1.6 - Freedom of Investment by Non-indigenous Companies

When international comparisons are drawn, a premium has to be attached to investment in a location where no barriers to investment exist for foreign oil companies who wish to enter the region. In this respect Alaska (being part of the United States) contrasts sharply with countries such as Canada, for instance, where a foreign oil group can hold only 30% of an existing oil and gas company, unless the Canadian firm being acquired is in grave financial difficulty.

When a company invests in Alaska, they have the implicit assurance that at any time they can sell their entire assets and investments in Alaska without any government interference. Hence, their sale to a foreign (i.e. non-US company) would not be prevented, should a favourable offer be presented. For it could prolong the sale considerably if the vendor has to wait for an indigenous buyer. Moreover, it would dampen the price if there is an absence of global competition.

This aspect is a significant advantage for Alaska and makes it clearly a superior region compared to its neighbour Canada, or Australia, as an investment climate in which to operate. Barriers to foreign investment as imposed by the government body "Investment Canada" are further discussed in Section 3.2. Furthermore, an account will be given of the harrowing experience of a Canadian oil and gas company with the Government of Canada at the time when a British firm was acquiring half of their corporation.

1.7 - Foreign Exchange Control

The absence of foreign exchange control in Alaska is an advantageous factor for industry and as an investment climate can command a premium. For when a country restricts the outward flow of foreign exchange it is always a worry for the company concerned whether they can repatriate their entire post-tax profit or capital if need be. This imposes an implicit limit on the company, forcing it to reinvest its profit within the country concerned.

Such a restriction exists in many parts of the world where there are petroleum reservoirs. It is not confined to the Third World, where export earnings fall short of their import requirements; it is prevalent in certain OECD countries where oil exploration and production take place.

In Australia there was an element of foreign exchange control up to 1982. It was monitored by a government agency known as the Foreign Investment Review Board. Any transfer of sums larger than A$10,000 out of Australia had to be cleared by FIRA.

In France, to take another example, until the beginning of 1990 a foreign oil firm operating in the Paris Basin would need to get clearance from the French Treasury in order to repatriate profits and assets to the parent company. The law has been more stringent for companies whose parents are not regarded as part of the European Community, such as a US group. Of course it should be pointed out that within the European Community there are plans to phase out all foreign exchange controls before 1992. In the UK, as in the United States, at present there is no foreign exchange control.

In most of the less developed countries, however, such as practically all of Africa, parts of the Middle East and parts of the Far East, there is some element of foreign exchange control. This in turn prohibits the availability of finance. Hence, bank loans are either not available for smaller companies or are not advanced on a non-recourse basis.

There have been cases when, even if the World Bank acts as a backer and provides a guarantee for such companies, most financial institutions are not willing to provide loans for investment in oil projects. Examples are countries such as Senegal, Gabon and the like.

Occasionally an oil company can access 'blocked funds' in exchange controlled countries, such as India or parts of Africa. These funds can be acquired for less than the principal of the loan. Here the owner of such funds is willing to release them for a lower amount in order to get them out of the country. But these are exceptions rather than the rule.

1.8 - Premium for Political Stability

Political stability is a crucial factor for lending purposes. In recent years many banks have lost a great deal of money on Third World debts which have had to be written off. So banks at board level have made a conscious decision not to finance projects in certain parts of the world that have 'Country Risks'. They treat them as restricted zones for funding purposes.

This in reality means: no matter how good the geology of the field or how handsome the prospects of the cash flow, when the request for finance for development of a field is placed in front of the credit department of a bank, the loan is turned down. Also this has been applicable to date to most of the centrally planned areas, for example Hungary.

[This is based on the consultant's personal experience. In May 1988, the Chairman of the Council of Ministers of Hungary paid a visit to Britain as a guest of the Prime Minister. At that time I was executive director of an investment bank in London. The Hungarian Council Chairman paid me a visit at the bank and invited me to advise them on their macroeconomic modelling efforts. I mentioned his visit to the chairman of our bank and asked if he was interested in meeting him. The answer was, "We wouldn't be prepared to lend such countries a penny. So what would be the point of meeting him?" (Incidentally, it should be pointed out that Hungary has a certain amount of oil and gas assets and Occidental has been the chief foreign investor.)]

Broadly speaking, in areas where 'Country Risks' exist for the purpose of external finance, oil companies have to use their internal finance. This factor tends to limit the industry to the oil majors or very large independents wherever there is an element of political instability.

Again, for Alaska this is an advantageous factor being excluded from such zones and as an investment climate it is a superior region.

1.9 - Stability of the Currency

Another factor is the stability of the currency of the country. A fair amount of hedging is required for the forward sale of the oil concerned when a currency is unstable. Usually, the more volatile the currency, the more the cost of the hedging.

For instance, the Australian dollar is regarded as internationally more unstable compared with the US dollar, and, hence, there has always existed a degree of concern about debt-financing in foreign currency.

The escalation of the Australian interest rate in 1989 to around 20% has created an overvalued currency. This implies once interest rates fall (though currently they have been reduced marginally to the current range of 17½ to 19%), a downturn in the Australian dollar is to be expected. Since the sale of crude oil is denominated in US dollars, a depreciation in the Australian dollar will in turn mean a decline in revenue for the Australian oil and gas companies.

This problem does not arise so much in the case of Alaska. The prices of crude oil and related petroleum products (being internationally traded commodities) are denominated in dollars. At the same time the revenues on oil industry activities in Alaska are earned in dollars. If the parent of a company is based outside the United States, however, and wants to repatriate the profits, some degree of hedging against movements in the dollar would be undertaken by the company.

1.10 - Modes of Oil Industry Finance

External financing for the oil industry has become more and more sophisticated over the years. New ideas have been emerging - perfecting the techniques of finance to suit the needs of the industry more closely.

It is preferable for companies to seek long term external funds - matching the life of their debt to their future production profile. This is not, of course, always feasible but companies try to get as close to it as possible. Modes of finance are many. A brief account of some of the different options for external finance open to companies is given below.

i) Equity Finance

This is when a company raises funds by way of an issue of its stock to finance a specific acquisition or development project. It is carried out through either a rights issue or treasury issue and is usually underwritten by one or a group of investment banks.

ii) Private Placement

Through this method both equity finance and debt finance can be arranged for specific purposes, e.g. the construction of a cross-country pipeline for oil and gas. For equity finance the private placement market comprises mainly large pension funds and insurance companies. This enables companies to raise cash without resort to public quotation.

Loans of fixed maturities can be secured whereby an issue of interest-bearing debt is privately placed with financial institutions without resort to public issues in capital markets. For example, a UK independent completed a $75 million five-year loan in 1987 through a private placement with seven Japanese trust and banking institutions.

iii) Bonds

A company can raise finance through an issue of a long-term (ten years, say) bond from a financial market. Where the bond is issued in a foreign market, the currency exposure is usually hedged.

iv) Banking Facility

This is a special arrangement with a bank where a fixed amount of credit is granted for a fixed period of time. The longer the maturity of the facility the better for the company. For instance, the European Investment Bank in December 1987 granted an oil company a £50 million facility of up to 14 years.

v) 'Charter' or Contractor Finance

This is one of the more innovative type of financing for field development that has taken place in the UK recently. Under this scheme the development of the an oil field is subcontracted to a contractor who in turn takes out the finance. The loan is then repaid out of the cash flow of the field by the contractor. In other words the finance is for 'renting' of the equipment such as chartering a drilling rig, etc. Thus the repayment of the capital is limited to the production levels of the field.

For every barrel the company pays the contractor a sum agreed a priori and the contractor in turn pays the financier.

This method was tried for the development of the Emerald field in the North Sea. Emerald has reserves of around 30 million barrels and a life of 5-7 years with a development cost of around £120 million. The contractor's finance was guaranteed by the UK government through the Department of Trade and Industry. Moreover, in the case of Emerald, the oil was forward sold to another company with a minimum agreed price.

The purpose of mentioning this type of funding is not for its frequent use. But it is intended to bring to the attention of the Legislature the most up-to-date information about the more creative types of financing for the development of some of the more marginal fields.

vi) Project Financing

"Project financing" is a form of loan increasingly used for natural resource development. As far as definition is concerned, it is a type of funding which must meet the following requirement: a) it is used primarily for the purchase of equipment, knowhow and machinery associated with a certain project, b) the duration of the loan is linked to the capability of the project to produce adequate cash flow for repayment of the loan, c) if the loan is in foreign currency, the project should produce adequate foreign exchange to meet repayments.

Effectively, this method enables reliance upon a free-standing investment such that its cash flow is isolated and specifically assigned to the project. The revenue is used for the payment of the project and does not accrue to the parent. This allows the lender to liquidate a mortgaged security in the case of default or cash flow interruption.

The move into expensive offshore production and other costly areas has created the need for such loan finance, and the oil majors have been able to raise their funds on the finest terms.

vii) Limited Recourse Finance

Under this scheme there is no recourse to the other assets of the company. It has gained increasing prominence as a preferred method for the funding of very large natural resource projects involving substantial capital investment. The assigned cash flow and associated costs are not included in the profit and loss account of the company. Also the related assets are excluded from the balance sheet.

This is a financing method used for the UK Brae fields (South, Central and North Brae).

1.11 - Interaction of Banks with the Oil Sector

In recent years the international financial sector has become a great deal more sophisticated, as well as aggressive, in its interaction with the oil and gas industry. A large number of major banks (both corporate and investment banks) have developed extensive in-house expertise and capabilities in this area. Thus, the initiation of finance is no longer a one-way route where an oil company first approaches the financier. Rather, it has developed into a two-way system. In fact more and more the direction of approach is reversed and the first steps are taken by the banks to initiate deals.

A bank can now 'create a deal' and plant the seeds of a transaction within the oil companies. Hence, a company is presented with both the asset and the financing that would accompany it as a package. Such oil assets can be in the form of a producing field, proven and undeveloped reserves, or exploration acreage, as well as shares of a particular company. Thus, companies in many cases simply respond to opportunities presented to them. The term 'opportunities' in this instance embraces a variety of activities, viz. development of a field, farm-ins, acquisition of a producing asset, or even exploration.

If a banker, say, approaches an oil company with a financial package to invest in Alaska (be it in the form of any of the above activities), the company may not instantaneously respond and quite possibly may turn down the deal. But the information regarding the deal acts as a reminder for the company of the existence of some potential opportunities in the region. It triggers further thought and awareness and may later lead into another completely different transaction.

In the case of Alaska there isn't the same frequency of such reminders presented to the rest of the world's oil and gas industry (as, say, in the UK).

1.12 - Comments on the Financing of Individual Fields in the Countries under Comparison

For the development of a field as large as Prudhoe, there would be ready finance available in all the four countries concerned. We shall concentrate on financing of fields which have to be developed, namely West Sak, Niakuk and Seal Island.

i) UK

A comparable field in the UK to Prudhoe, though much smaller in reserve size, would be the Forties field offshore in the North Sea. It should be pointed out the British government's policy of enhancing activity in the North Sea has been such that all exploration expenditure can be offset against Petroleum Revenue Tax.

Thus, when the Forties field became PRT-paying the operator of the field sold a small number of ½% and ¼% units of the field. These so-called 'Forties Units' were attractive as tax shelter and were bought by companies who could offset their exploration expenditure against the PRT liabilities of these small units. Forties Units have been ideal for foreign petroleum companies entering the UK for the first time or for independents wishing to expand their exploration activities.

The reserve estimates of the Forties field were raised in 1988 from 2,391 to 2,470 million barrels. By the end of 1988, approximately 1,909 million barrels had been extracted, leaving 561 million barrels. The average daily production of the Forties field in 1988 was 290,000 barrels per day. Thus a ½% unit held by an independent company amounted to 1,450 barrels per day of production. The Forties Units were traded at between £5 million and £3.5 million during 1988.

For the other fields, finance would be available on a 40 : 60 basis, whereby 60 per cent of the required finance would be available on a limited recourse basis. For the Seal Island field which has considerable risk one could attain 'Charter finance' if the price of oil rose considerably from its current level.

ii) Australia

Before discussing the financing of the smaller fields in Australia , it may be useful to give some background to the Australian oil and gas scene. It is a combination of a large number of junior oil companies with a market value of less than A$25 million and a small number of major oil companies.

The current economic climate, while adversely effecting the indigenous sector, has created favourable conditions for foreign investors. A cash-rich company has abundant opportunities for farm-ins with generous terms. There are also attractive acquisition possibilities of oil and gas assets.

The most likely financing route available for the development of the smaller fields by the independent companies would be through venture capital on the basis of 20 : 80. That is to say, 20% would be laid down by the owner of the reserves and 80% by the venture capitalist. If the development of the fields is undertaken by an oil major, an issue of medium-term notes seems to be the preferred route. In December 1989 a subsidiary of one of the oil majors offered to the market A$100 million of corporate bonds maturing in 1995 with a coupon rate of 14%. This was part of the company's financing package for their investments in 1989 and 1990. The gearing of this subsidiary is around 40%.

iii) Indonesia

Finance available for foreign companies to invest in the fields in Indonesia would be primarily granted on a corporate basis rather than localised to the assets in the country. Foreign companies who have invested in Indonesia over the past years have raised their loans on a corporate basis and have not obtained them on the basis of non-recourse limited finance. In fact, the financial community ranks Indonesia last for funding purposes, behind the UK, Norway and Australia. In this respect, Japanese banks have a different attitude. Their behaviour is more unique to themselves and differs to some extent from the rest of the financial community.

iv) Norway

The Norwegian banking sector has suffered major losses in the past three years. The collapse of oil prices in 1986 brought about losses on both loans and guarantees. The tide is just beginning to turn as a result of a great deal of rationalisation within the banking sector. The national oil company Statoil holds most of its long-term debt in foreign currency.

Recent acquisitions in the oil sector have been financed through internal cash flow of the companies. For instance in March 1990 a Finnish oil company, acquired the Norwegian arm of an American oil company.

Two - OTHER ASPECTS OF OIL INDUSTRY INVESTMENT

It is essential for politicians and civil servants not to review a tax structure in isolation from other aspects of petroleum industry investment. These 'other' aspects throw light on why companies may leave a certain area, and what other factors may influence their investment decisions besides tax.

2.1 - Strategic Decisions of Companies

The exiting of a company from a region may be construed by some as the result of excessive taxes. However, if one looks beneath the surface, it may turn out to be a strategic issue.

If one is led to believe that a certain oil major, say, is leaving Alaska, one has to closely examine the nature of the assets they are selling. Is it just downstream (namely refining and marketing), as it was in the case of one company recently, or is it upstream (exploration and production)? As far as is known the company concerned was planning to maintain its exploration acreage in Alaska. The production it was intending to sell (which it subsequently withdrew), was small and could have been part of its restructuring strategy. Companies periodically undertake a program of rationalisation and pull out of certain areas in order to consolidate some of their other activities. If they have a small operation in a particular region, it makes economic sense to withdraw and consolidate their resources and efforts in areas where they have bigger production and leases.

This does not mean that oil and gas activities in that area are inherently undesirable for the entire oil industry - or that the undesirability of the tax is the prime factor responsible for the exodus of a particular oil company.

Example: In 1988 one of the largest independent oil companies in the UK examined its international portfolio of assets and decided to sell its small interests in countries such as Holland, Ireland, etc. It chose to consolidate its assets in the UK North Sea. So when it put up for sale its Dutch exploration interests, it was faced with a very keen interest from a European company who had made a decision at board level to expand their Dutch activities.

In fact the European firm was so keen to acquire the interest and conclude the deal that they bid considerably above the initial price the British independent had in mind. In the end, however, the British independent did not sell. It arranged a swop of the Dutch assets with another company. This made sense, for the cash receipts would have been subject to capital gains tax.

In short the British independent's decision to exit the Netherlands was in no way a reflection on the Dutch oil and gas taxation regime. On the contrary, the Netherlands has become quite an attractive area for the industry to enter in recent years (further explained in section 2.5 where we look at two more tax jurisdictions relevant for comparison with Alaska).

2.2 - Existence of Production Quotas

Another element is production control imposed by OPEC within the thirteen member countries. For a company to operate in any one of these countries where production quotas are imposed is anything but the best investment climate. Any given field has an optimal depletion rate with which one should not interfere, as far as optimal reservoir management is concerned. This was confirmed by the reservoir engineers during the consultants' visit to Prudhoe Bay. [In Iran, for example, as a result of continuous cutbacks (due either to the Gulf War or OPEC quotas) and, hence, poor reservoir management, a great deal of the country's reserves have diminished.]

Clearly, an OPEC member country with a quota system, such as Indonesia, is an inferior region compared to Alaska where no production restriction exists.

2.3 - Consequences of Cutbacks in Production

Within the non-OPEC countries chosen, Norway has in the past three years been trying to help OPEC with some self-imposed "cutbacks". This voluntary restraint during 1989 was 7.5%. For 1990 Norway has restricted oil companies to producing at 95% capacity.

Although the effective cutback has been on the growth of production and not on the actual level of production, this again is both destabilizing and undesirable from the oil industry's viewpoint. Once an oil company has undertaken the investment in a field it should be allowed to produce at the optimal rate. Cutbacks would be simply eating into the profits of the industry.

2.4 - Mixture of Companies Active in an Area

In drawing up tax comparisons between different countries, it is essential that one also looks at the mixture of different companies active in the petroleum sector of those regions. For any changes in the oil taxation could affect them differently. It is important to study how many lose and how many gain.

This dimension of the analysis is particularly relevant if the government is conscious of the absence of oil independents and wants to encourage investment in the area by smaller companies.

The distribution and mixture of the licence holders for some of the countries examined in this study are given here. These tax jurisdictions are: the UK, Norway, Australia and the Netherlands.

i) In the UK there are a total of 118 licence holders of which 39 companies hold around 94% of the total licences. These companies would be categorised as the principal licence holders. What is significant is that the remaining 6% of the total area leased is held by 79 licence holders. This reflects the large number of independents active in the UK part of the North Sea.

ii) In Norway there are a total of 38 licence holders of which 17 companies hold over 96% of the total leases as the principal licence holders. Less than 4% of the total area leased is held by 21 licence holders. The number of independents in Norway is substantially below that of the UK. This is significant - considering that Norway will be the largest oil and gas producer in Europe after 1994.

iii) There are over two hundred participants in the Australian industry of which less than a hundred are actual owners of oil and gas reserves. Despite the large number of players, 86% of the oil and gas reserves is in the hands of nine companies. Among these nine significant owners of the reserves are three Australians and the rest are international majors.

iv) In the Netherlands there are a total of 64 licence holders of which 20 companies hold around 85% of the total leases as the principal licence holders. Less than 15% of the total area leased is held by 44 licence holders. What contrasts Holland with the other two is the lower concentration of the principal licencees - 85% against 94% in the UK and 96% in Norway.

The consultant has not been able to obtain the comparable distribution figures for Alaska. This comparison could be carried out perhaps at a later date with the help of the Department of Natural Resources.

2.5 - A Look at Two More Tax Jurisdictions Relevant for Comparison with Alaska: The Netherlands and Canada

At the January meeting of the International Tax Comparison Committee it was requested that the comparative study of taxation for Alaska should include a brief review of the tax and industry activities in two more regions: The Netherlands and Canada.

i) Dutch Petroleum Taxes and Environment

Although Dutch offshore activities can be regarded as being in the mature phase, the oil industry has witnessed a growing number of takeovers. Moreover, assets have been changing hands more frequently in recent years. It is evident that interest in the Netherlands is rising and oil companies, both large and small, have paid premium prices for the purchase of assets in this area. A good example is the purchase of such assets by a British independent in October 1988.

Furthermore, when the Dutch seventh round of licensing took place during 1988 (over the period 1 October to 30 December), 115 applications were received from 23 different consortia amounting to 59 different companies. A brief overview of the Dutch taxation system is given below.

Netherlands Fiscal Regime

The Dutch Petroleum Tax Regime has two main components which are mutually dependent. Thus the computation of the tax liability is in a way similar to the solution of a simultaneous equations system. There are two types of licences - 'old' and 'new'. This distinction essentially amounts to a ring fence whereby losses from one group cannot be offset against profits from another.

a) Royalty:

Royalty is charged on a field depending on its production rate and the time when the licence was first awarded. The rate is halved if there is state participation in a given licence. Royalty rate does not exceed 16%.

b) Profit Share Tax (PST):

Due to the simultaneity problem mentioned above, it becomes imperative to compute provisional values of profit share tax and corporation tax (explained below). Thus, the provisional PST estimate is income less royalty, operating cost, depreciation and uplift. Uplift is at the rate of 70% for new licences and 50% for old licences. When the provisional corporation tax calculation has been made the final liability of PST can be computed taking the provisional CT into account. PST is paid in two instalments with on average a delay of about seven months.

c) Corporation Tax (CT):

Corporation Tax is provisionally calculated on approximately the same basis as PST and is not subject to any ring fence provisions. Once the final PST calculation has been made, liability for CT can be calculated with the PST incurred removed from the income liable for taxation. CT is payable on average 18 months after liability is incurred. From March 1988 Corporation Tax has been 35%.

ii) Canadian Petroleum Taxes and Environment:

When examining the Canadian system it is important to note that the country has a very heterogeneous mixture of fields located in different parts of the country. There are considerable variations in field sizes and field costs.

The oil and gas fiscal system underwent major revisions from the mid-1980s which were introduced by both the Provincial Governments of Canada and the Federal Government. The prime intention of this revision was to devise a system that was geared to market forces in the oil and gas industry.

Most significant was the abolition of Petroleum & Gas Revenue Tax (PGRT) both for new fields (with effect from 1985), and for fields already in production (with effect from 1988). The PGRT on the latter category was gradually reduced to zero over a period of three years.

Parallel to the cut in taxes was the removal of investment tax credit in 1988. By the summer of 1989 Corporate income tax became 33%. Currently no provincial taxes exist for offshore oil production.

FINANCIAL AND OTHER ASPECTS OF OIL INDUSTRY ACTIVITIES AND INVESTMENT

Prepared for

THE INTERNATIONAL TAX COMPARISON COMMITTEE,

THE STATE OF ALASKA

By

Dr. H. Motamen Scobie

Chief Editor of the Academic Journals

Energy Economics & Economic Modelling

In Alberta, the current provincial royalty formula takes account of three major factors: i) the time of discovery, ii) the level of oil prices, and iii) the volume of well production. The major tax reliefs are royalty holiday, royalty tax credit and royalty rebates.

The reformed tax system (after the National Energy Program of 1985) applied to Alberta is quite complex and details of the structure of the tax are beyond the scope of this report. [For further information see Dept. of Energy, Mines & Resources of Canada Report (1985): The National Energy Program (Ottawa, Canada).]

The tax scheme introduced after the National Energy Program provides incentives for further exploration particularly in Alberta. Indeed, compared to most oil producing regions of the world, the Canadian tax system is more conducive to exploration activities.

Three - INTERACTION OF GOVERNMENT AND OIL INDUSTRY

It has happened in many regions that at the time licences for exploration and development of fields are given, the government of a particular region has had a fairly lax attitude towards taxes and royalties. Once the industry has taken all the risks and sunk funds into investment - having found it profitable on the basis of the initial calculation - the government then revises the tax upward (sometimes gradually and sometimes more steeply) and prevents the investors from acquiring the rewards for which they took the initial risks. This happened in the 1970s in Britain as a result of decisions taken by the Labour Government which was in power between 1974 and 1979.

3.1 - BRITAIN

The deterioration of relations between the British Government and the oil industry during the 1970s can best be explained through the experiences of an American oil independent called Mesa Petroleum [as narrated by the company chairman T. Boone Pickens Jr. in Boone (1978), Hodder & Stoughton Ltd., Great Britain, pp 112 - 121]. Mesa Petroleum, now worth around $3 billion, both entered and exited the UK North Sea during that decade.

After the discovery of oil in the North Sea in 1965, the British Government gave 50,000-acre tracts free to any company who undertook to carry out exploration in that region. Mesa Petroleum obtained two licences in the early 1970s and explored for two years. By the mid-1970s they had a discovery. This was the Beatrice field, named after the chairman's wife.

While the American independent was exploring and spending millions of dollars, a new Labour Government came into power in 1974 and the rules changed. They created a state oil company named the British National Oil Corporation (BNOC). Oil companies were told then that they had to negotiate with BNOC who wanted "participation".

Mesa protested to the UK Government that they had signed an agreement with their company. The response they received was, says the chairman of the company, "If I didn't like the terms, they could make things a lot worse for us".

Mesa entered into a series of long and arduous negotiations with the UK Department of Energy and was finally told by an official there, "You might as well give up. This has been decided." BNOC took a twenty percent interest in the field. To Mesa this was an unusual 'collaboration', since the new partner had no financial risk but had a veto power on everything. This included Mesa's expenditure. They discovered that "the original partners of the field would continue to share all the risks and costs of developing the field". As Mesa's chairman put it, "This was the British idea of partnership".

The BNOC representatives were present at all the operator meetings and applied their veto power wherever they chose.

The Labour Government's treatment of the industry worsened with successive upward revisions of taxes in those years to the point that the oil companies felt they left little reward for taking risks.

In 1978 Mesa complained to an official of the Department of Energy how they were wasting their money on the one hand and increasing their taxes on the other, leaving them with little profit. This could force them to leave.

The official replied, "Oh you'll stay. We have studied people like you. You are an entrepreneur. You have to keep risking your money, because that's the way you are". That statement turned out to be the straw that broke the camel's back. Mesa at that point made a final decision to leave the UK and sell off their North Sea operation. "If there is no profit, an entrepreneur isn't going to be interested very long," said the chairman of Mesa to the DOE official.

BNOC had the option to buy the production from any field, should a partner wish to sell. This proved another arduous and agonising ordeal for Mesa when negotiating a price with the state oil company. Mesa finally left Britain in 1979 with $31.2 million profit. But to them this was not such a good deal, for they sold their largest discovery at a wholesale price.

When the Conservatives came to power in 1979, after an initial phase of tax increases, the petroleum fiscal policy was reversed and the system became more profit oriented. Downward revisions were introduced year after year. Accordingly, exploration and development activities in the UK side of the North Sea responded positively as shown in Fig. 1 and Fig. 2.

Parallel to the increased level of activities was a reduction in UK government revenue from the oil and gas sector as portrayed in Table 1. This decline in revenue, which is partly due to the collapse of oil prices in 1986 and partly due to reduced production, reflects the magnitude of exploration costs offset against taxation. Moreover, Fig. 3 shows that the substantial drop in UK government revenue is not matched by a significant fall in oil and gas production during the years 1986,'87 and '88. The fall in production in 1988 was partly due to the shutdown of fields caused by accidents such as that of the Piper Alpha field.

In 1988 at a gathering organised by the consultant, the Labour Party Spokesman for Energy addressed some two hundred senior executives of the oil industry. His only message seemed to be "Tell us what you want and we shall act upon it." This was interpreted by the attendants as a sign that the Labour Party had no clear direction. Many of the participants left the meeting relieved that the Labour Party were not in power, not having forgotten the party's grim policies of the mid- and late 70s.

Presently the UK is one of the most attractive regions for exploration and development from a taxation point of view. Suffice it to say, the shortfall in revenue from the oil and gas sector could be readily absorbed by the government, for it coincided with its privatisation of many large corporations, such as British Gas, British Telecom, British Airports Authority, etc.

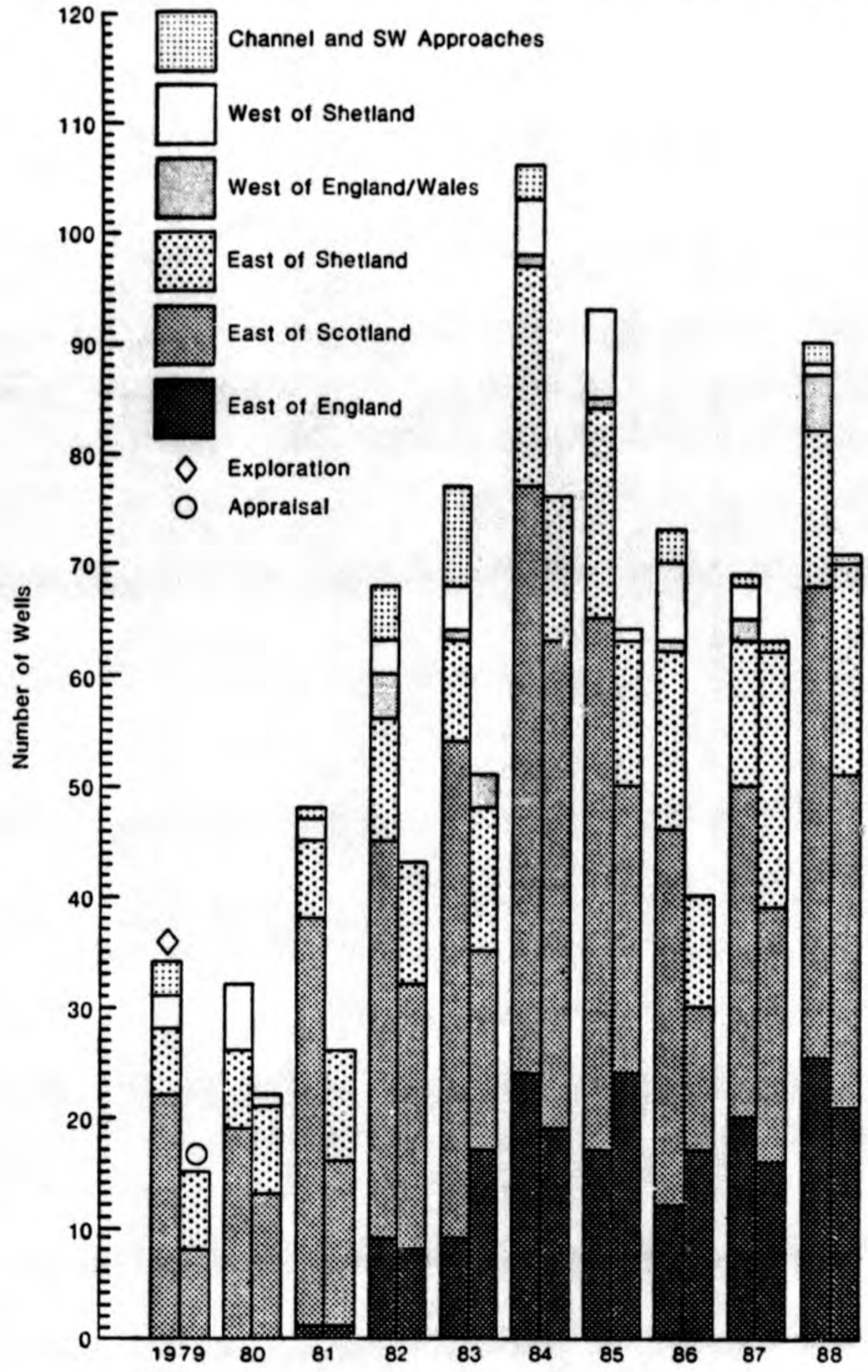
If one looks at forecasts made for the UK future oil production profile made in the early 1980s, a sharp decline was foreseen for the end of the decade with the peak projected for 1984/5. In fact this trend proved incorrect and the decline has been much less severe. This can to some extent be attributed to the continual revision of taxes and, hence, encouragement given towards further investment by the government.

Table 1: TAXES AND ROYALTIES ATTRIBUTABLE TO UK AND UKCS OIL AND GAS

Financial Year	1979/80	1980/1	1981/2	1982/3	1983/4	1984/5	1985/6	1986/7	1987/8	1988/9 (prov)
(£ Million)										
Royalty	628	992	1396	1632	1904	2426	2057	919	1024	600
Supplementary Petroleum Duty	-	-	2025	2395	-	-	-	-	-	-
Petroleum Revenue Tax	1435	2410	2390	3274	6017	7177	6375	1188	2296	1300
Corporation Tax	250	341	681	521	877	2425	2917	2683	1350	1300
Total Revenues	2313	3743	6492	7822	8798	12028	11349	4790	4670	3200

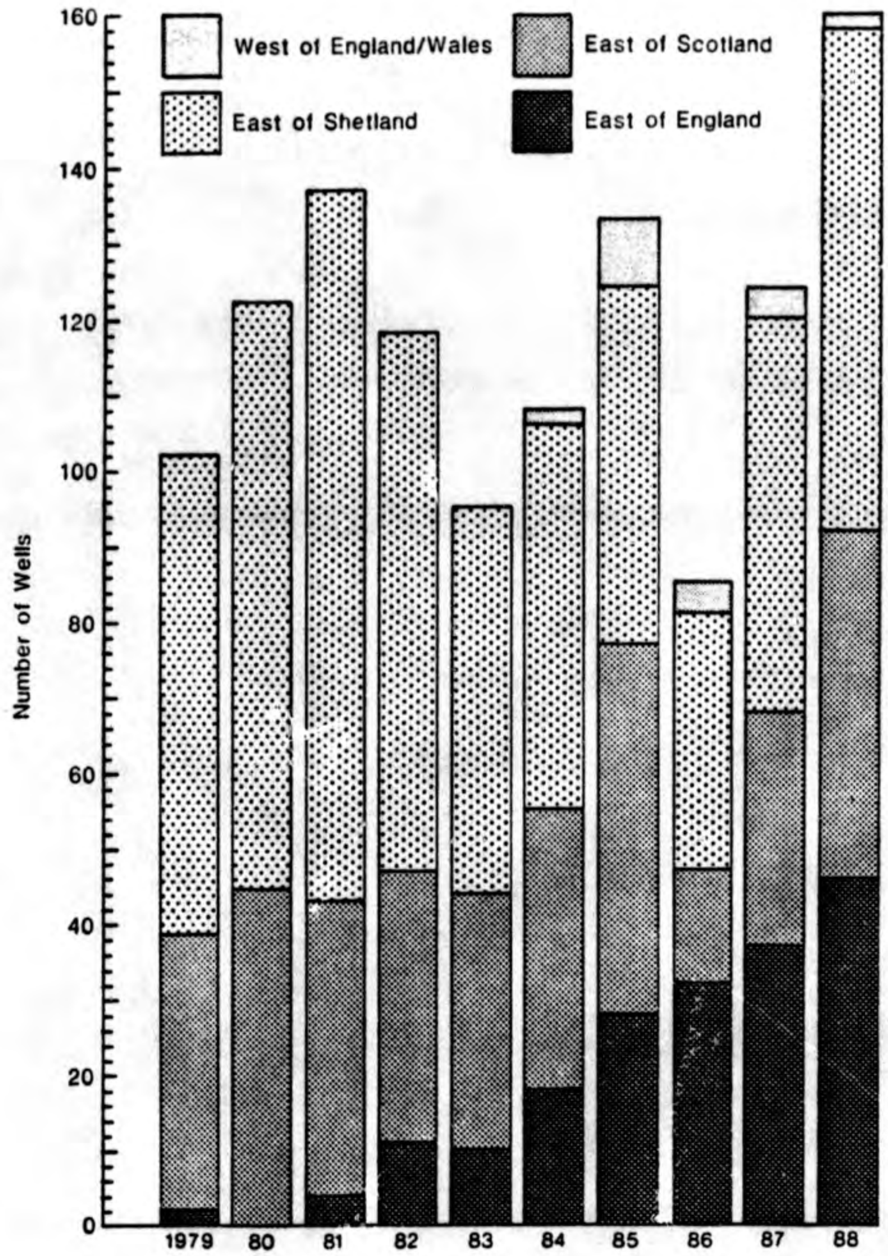
Source: UK Department of Energy, The Development of Oil & Gas Resources of the United Kingdom, London, HMSO, April 1989.

Fig. 1: OFFSHORE EXPLORATION AND APPRAISAL WELL DRILLING



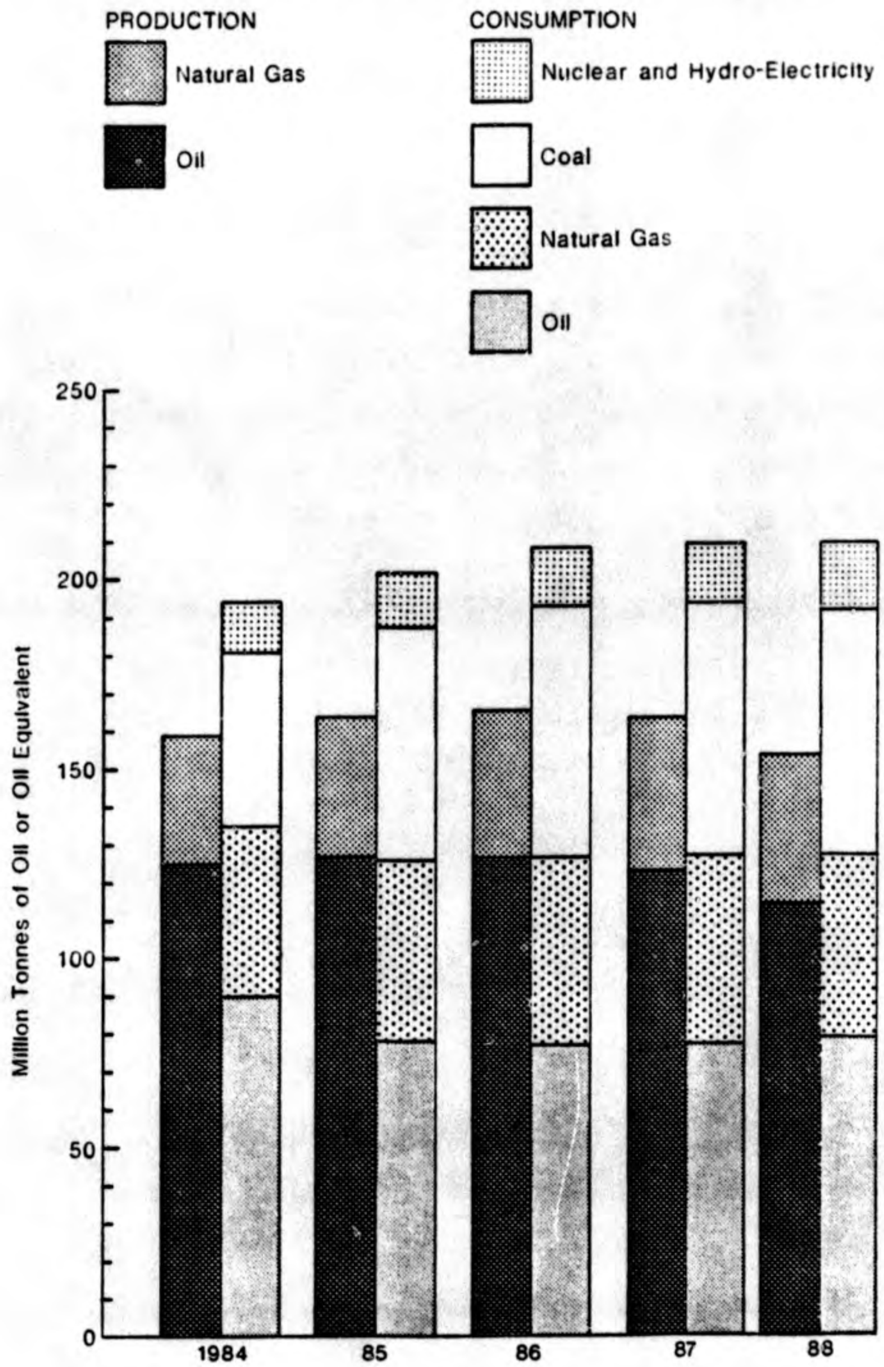
Source: UK Department of Energy, The Development of Oil & Gas Resources of the United Kingdom, London, HMSO, April 1989.

Fig. 2: OFFSHORE DEVELOPMENT WELL DRILLING



Source: UK Department of Energy, The Development of Oil & Gas Resources of the United Kingdom, London, HMSO, April 1989.

Fig. 3: UKCS AND ONSHORE OIL AND GAS PRODUCTION COMPARED WITH UK TOTAL PRIMARY FUEL CONSUMPTION



Source: UK Department of Energy, The Development of Oil & Gas Resources of the United Kingdom, London, HMSO, April 1989.

3.2 - CANADA

In July 1987 a British company made an offer to purchase 50 per cent of the shares of a publicly quoted Canadian oil and gas company. The company, worth then about C$800 million, was based in Alberta and owned substantial assets in the UK North Sea, which were of interest to the large British company.

The offer was approved by the Board of Directors of the Canadian company and the British firm was led to believe that the acquisition would be approved by the Canadian Government.

About a year prior to the offer, the Canadian Government had decided to reverse its interventionist policies and had opted to actually encourage foreign investment in Canada. It changed the name of the quango hitherto called "FIRA" (a foreign investment review body) to "Investment Canada". Indeed, the name itself had the connotation that the state was in favour of the flow of capital to the country. But this turned out not to be the case when the British firm's offer was presented for government approval. The former was given a great deal of trouble having already announced the deal to its shareholders.

The executives of the Canadian firm had to carry out many tiresome negotiations trying to untangle the bureaucracy in Ottawa while at the same time maintaining the interest and goodwill of the British investing firm.

In the end the government in Ottawa did not give in and the British company had to split its 49% shareholding to 30% voting shares and the remaining 19% non-voting Z shares.

Following this incidence, and to avoid further adverse publicity, the Canadian Government attempted to regenerate interest and encourage the flow of investment from abroad.

In November 1987 a Belgian oil and gas company attempted to enter Canada by making acquisitions. Again the barriers posed by the government forced the company to return empty-handed.

The Canadian protectionist policies have indeed been damaging and counter-productive. Presently the government is in severe financial difficulty suffering from a large budget deficit. Somehow the policy-makers seem to ignore the economic reality that the lower the level of investment, the lower the level of activity, and, hence, the less tax revenue available for government. Today the public sector debt-servicing burden in Canada is ten times higher than in 1975. Thus, to reduce the deficit a 7 per cent goods and services tax is to be introduced from January 1991.

3.3 - AUSTRALIA

Australia is a federation of six States and two Territories (Canberra, known as the Australian Capital Territory, and the Northern Territory).

In an effort to improve the mounting balance of payments deficit, the Australians imposed a revenue tax on production at the time of high oil prices. This tax has not been reduced proportionally as the price of oil halved.

In June 1987, the Australian government introduced some tax concessions where the excise tax was to be cut from 80% in 1986/87 to 75% in 1989/90.

These modifications were not, however, considered adequate. For the combination of the excise tax and the corporation tax brought the government take on a barrel of oil to 88%. The industry tried to exert further pressure on the government to ease oil taxation.

In November 1988 some 25,000 barrels of production in the Bass Strait was shut down. Following this, in January 1989, the Australian government proposed a new sliding scale of taxes for certain fields in the Bass Strait (regarded as a mature area for so called "old oil").

The new arrangement was announced as a "non-negotiable" sliding scale to replace the existing 77% rate that applied to half of the Bass Straight oil. The range of the sliding scale was between 77% at an oil price of above A$21 a barrel and a minimum of 55% if the price dropped to A$8.

In May 1989 a European oil giant put up for sale all its Australian oil and gas production assets, after 27 years of exploration search. A statement made by the head office of the company said these assets were no longer within the international policy of the group.

The sale of the above assets coincided with another divestment: that of a UK independent of its Eastern Australia assets, although it should be pointed out that the company in question has simultaneously been expanding its North Western Australian activities.

Finally, another burden imposed by the state has been the policy of high interest rates pursued in Australia since last year. Thus, oil and gas investments that have required corporate financing or project financing have had to be postponed.

In June 1989 the government in Canberra launched a review of Australia's crude oil tax. The study is to be completed by mid-1990.

Table 2: AUSTRALIAN GOVERNMENT REVENUE FROM CRUDE OIL, NATURAL GAS & LPG

(A$million)	1983/4	84/5	85/6	86/7	87/8
COMMONWEALTH					
Crude oil excise	3593.6	4041.8	4310.6	2195.4	-
LPG excise	92.9	69.4	81.9	37.6	-
Crude oil & LPG total	3686.5	4111.2	4392.5	2233.0	2193.7
Crude oil & LPG refunds	12.5	3.5	102.1	236.6	71.0
Total	3699.0	4114.7	4494.6	2469.6	2264.7
VICTORIA					
Royalties on production	173.7	197.5	202.8	147.3	144.1
Total	173.7	197.5	202.8	147.3	144.1
QUEENSLAND					
Royalties crude oil	2.2	18.9	32.6	17.6	22.7
Royalties natural gas	2.5	2.6	3.2	2.3	3.6
Royalties LPG	-	-	-	-	0.2
Total	4.7	21.5	35.8	19.9	26.5
SOUTH AUSTRALIA					
Royalties on production	11.1	24.3	47.5	26.3	28.8
Total	11.1	24.3	47.5	26.3	28.8
WESTERN AUSTRALIA					
Royalties crude oil	14.8	13.8	29.3	21.9	23.8
Royalties natural gas	3.4	3.8	3.6	4.8	4.9
Royalties condensate	-	-	-	-	1.3
Total	18.2	17.6	32.9	26.7	30.0
NORTHERN TERRITORY					
Royalties crude oil	-	0.8	2.1	1.3	0.6
Royalties natural gas	-	0.1	0.1	0.5	1.0
Total	-	0.9	2.2	1.8	1.6
TOTAL AUSTRALIA	3906.7	4376.5	4815.8	2691.6	2495.7

Source: Australian Bureau of Statistics (annual reports and budget papers of relevant State and Northern Territory departments).

3.4 - NORWAY

Oil and gas production commenced in 1971 when the Ekofisk field started production. In Norway the state (through Statoil) participates directly on the investment side of the business. Statoil has gone through a change of organisation and after a period of overrunning cost, the company is quite profitable now. However, privatising this company is not likely to happen in the near future.

The former Norwegian Minister (of the Labour Party) who was in power until Autumn 1989, was a strong advocate of regulating the offshore oil and gas developments and carried out interventionist policies. For instance, the sales of Norwegian gas are negotiated only by three domestic companies. These restricting policies brought about a reduction in activity in Norway and reduced exploration activities. Compared to the UK North Sea, where on average 160-170 wells are drilled each year, in Norway the number has been dwindling rapidly from 50 exploration wells in 1985 to around 25 in 1989.

Table 3: ROYALTIES IN 1987 AND 1988 (NOK MILLION)

		1987	1988
OIL	Ekofisk/Valhall/Ula	1190.8	1029.1
	Statfjord	4832.6	3321.9
	Murchison	14.5	21.5
	Heimdal	-12.4	-0.3
	Oseberg	33.0	12.9
	Gullfaks	82.5	165.2
GAS/NGL	Ekofisk Fields	545.3	415.7
	Valhall	14.7	0.4
	Ula	-2.6	-1.2
	Frigg/Ne Frigg/Odin	785.0	521.4
	Statfjord	5.6	0.0
	Murchison	-0.3	0.2
	Heimdal	27.8	-6.0
	Gullfaks	0.0	0.0
TOTAL ALL FIELDS		7516.7	5480.9

Source: The Norwegian Petroleum Directorate, Annual Report 1988.

Table 4: CENTRAL GOVERNMENT INCOME FROM OIL ACTIVITIES IN NORWAY, 1981-1988

Year	1981	1982	1983	1984	1985	1986	1987	1988
(Million kroner)								
Royalty	3639	5308	7663	9718	11626	8211	7517	5481
Special tax on oil income	4955	8062	8870	11078	13013	9996	3184	1072
Ordinary tax on property, capital and income	9912	13804	14232	18333	21809	17308	7137	5129
Area tax, etc.	63	69	75	84	219	237	243	184
Total	18569	27243	30840	39213	46667	35752	18081	11866

Source: Norwegian Central Government Account.

In 1987/88 there were major revisions to the Norwegian tax regime in order to induce development of new fields. But a suspicion has existed on the part of industry that the Norwegian government had simply modified the tax law with a view to making certain petroleum development projects more attractive. Industry has felt that the modification would disappear as soon as the projects had been developed and profitable production started flowing.

Whereas in the UK part of the North Sea the relationship between industry and the government has been quite good in the '80s, in Norway there are cases of litigation between the government and the oil industry. For example, in December 1989 partners of the state oil company on the Ula field took their claim regarding excessive pipeline tariffs to arbitration. The field's operator, a British company, pleaded that the tariffs charged by the state oil company for the use of its pipeline (i.e. the Ula/Ekofisk line) are unreasonably high. Thus, the partners are demanding a 50% reduction on the tariffs on the grounds that they were set when the price of oil was around $30 a barrel. The state oil company, on the other hand, argues that the alternative of buoy-loading or construction of a line owned by all the Ula partners was presented to the partners. Yet, they all opted for the state oil company to build the entire pipeline alone.

A new Minister of Petroleum and Energy was appointed in October 1989 when the Centre Party came into power (as part of a new non-socialist coalition). Following his appointment some oil companies began to lobby the government for modifications in licensing terms enabling them to take greater risks. In November 1989 the new minister indicated that he would be "open to companies' creativity, if this can stimulate exploration which otherwise would not have taken place". Subsequently, he introduced revisions to the terms of some of the existing licences. At the end of November 1989 he confirmed "the dropping of the state's right to have its exploration costs met - or carried - by other partners in the block".

3.5 - INDONESIA

Indonesia produces 1.7 million barrels per day in line with its OPEC quota. During the fiscal year 1988/89 the government revenue from oil and LNG (as shown in Table 5 below) comprised 41% of the total domestic revenues collected. With the weaker oil prices during 1988 the hydrocarbon revenue for the year 88/89 fell by 5%. This income is expected to rise by 36% in the year 89/90.

Table 5: INDONESIAN DOMESTIC REVENUE FISCAL YEAR 1988/89

	(in trillion rupiah)		(billion US dollars)	
Hydrocarbon revenues		9.5		5.6
Oil	8.3		4.9	
LNG	1.2		0.7	
Non-hydrocarbon		13.5		8.0
Total domestic revenue		23.0		13.6

Daily average production of oil during 1989 was 809,050 and the yearly production of liquefied petroleum gas has been 18.5 million of LNG.

A split of 85 : 15 (between government and industry) existed until August 1988. But for frontier areas the government offered a revised profit-sharing arrangement. Under this scheme, at lower quantities of oil production, a bigger share was to be attributed to the company and the reverse was to take place at higher production.

This change was necessary because the 85 : 15 split did not differentiate between the high cost and low cost fields.

In February 1989, the government improved the production sharing agreement further by giving an investment credit for deep sea contracts. At the same time the gas pricing policy was changed and was based on the production cost of different fields instead of the previous basis, namely, the type of the end user.

Although these revisions were welcomed by industry, the general reaction is that a great deal more revisions would be required to attract significant expenditure on exploration. There is a belief by current producers that the improved terms have to apply to existing contract areas where actual production and enhanced recovery take place. Nevertheless, the number of foreign companies keen to sign contracts has been rising. There are altogether more than forty foreign companies active in Indonesia.

3.6 - MECHANISMS THAT IMPROVE INDUSTRY/GOVERNMENT RELATIONS

The relationship between industry and government improves only through closer contacts and frequent informal meetings. In the UK the Secretary of State for Energy or the Junior Ministers of the Department of Energy are often invited to informal lunches by both industry and the financial community. On these occasions companies are able to express their views freely and the government is able to 'hear'.

Usually when the invitation is from industry it is arranged by a single company and its views, which contain information of a proprietary nature, can be expressed openly without the presence of competitors. Government officials (be it Ministers or Members of Parliament concerned with the oil industry) are accompanied by their advisors who would supply them with necessary information should a specific issue be raised. In addition Ministers are accompanied by their Parliamentary Private Secretary who is another Member of Parliament.

There seems to be a lack of such opportunities in Alaska. It is helpful to allow industry the chance for such meetings on a single company basis due to the confidential nature of the business information. Moreover, opportunities have to be given to the financial community to host lunches with both government officials and representatives of industry present. This eases the flow of information and forward movement of activity. Moreover, the private sector can gain useful knowledge and advice from the government.

In Norway there is a government body, the Norwegian Petroleum Directorate, which acts as coordinator between different departments. It was set up in 1973 and has regular meetings with both industry and different government departments. With the expertise, experience and interdisciplinary insights it represents, it evaluates economic, technological and safety-related aspects of the petroleum resources.

As far as attraction of overseas companies is concerned there seems to be a perception on the part of the Government of Alaska that it cannot be seen to promote investment from abroad into the state. This is in sharp contrast with most countries where public sector officials actively promote foreign investment. In the UK even the Prime Minister makes frequent trips abroad specifically discussing the issue of the flow of investment into the United Kingdom. The same is true of Norway, Australia and Indonesia.

Four - COORDINATED GOVERNMENT POLICY

A striking feature of the Alaskan oil and gas scene is the lack of coordination between different government agencies active in the sector. It has been clear to the consultant through various contacts with representatives of the state government that there is an absence of an exchange of information and ideas on a constructive basis.

In the United Kingdom the Inland Revenue is under the direct auspices of the Treasury which in turn determines the taxation structure.

The former also works very closely with the Department of Energy (DOE) in formulating taxation policy. Naturally the Inland Revenue is privy to confidential information which it does not divulge to the DOE. However, it is able to receive the advice and recommendations of the latter as to what type of tax relief could further stimulate activity in the oil and gas sector. This is then fed to the Treasury through the computations put forward by the Inland Revenue. Finally the the Chancellor of the Exchequer decides upon the necessary tax revisions and announces them in the Budget each year in March.

An official of the Inland Revenue or the Treasury is often present at the meetings of the Department of Energy with the financial community or industry. Moreover, there is a liaison between the Department of Trade and Industry (DTI) and the Department of Energy. Where an oil development project cannot get off the ground because the contractors require financial guarantees, the DTI undertakes the necessary guarantees.

An example is the development of the Emerald field. Following the approval of the Annex B (i.e. the development consent) by the Department of Energy, assistance came from the Department of Trade and Industry. As the chairman of the operator of the field stated in their 1988 Annual Report, "The contractor's finance could not have been completed without the support of the Department of Trade and Industry, who guaranteed a £94 million package of equipment and service from British suppliers." This created 2,000 jobs for the industry in the UK.

As far as the relationship between the Alaskan Department of Natural Resources (DNR) and the Department of Revenue, there should be more coherence between their respective policies for the best interests of the state. Specifically, the former can formulate tax policies with the help of the latter to achieve the highest level of exploration and development. Accordingly, the DNR can encourage further development of the petroleum sector by the awarding of licences through a merit system. Companies acting in the best interests of the state would be given preference in the granting of new licences.

Moreover, the entry of the smaller explorers would be brought closer by relaxing some of the terms stipulated for new acreage releases. Many junior oils are looking at investment outside their own countries, having found their domestic opportunities dwindling, e.g. in Australia.

It would be useful if there were a review of work commitments by the Alaskan Department of Natural Resources as to how companies have utilised their exploration licences and how much actual drilling has been performed. There seems to be a belief in the Department of Natural Resources in Alaska that everything should be left to the market and the companies know best. If companies are not exploring, there must be a good economic reason for it. This is not necessarily true. What holds at microeconomic level does not necessarily hold at macroeconomic level, and, in a competitive market, what is good for one company may not be good for another.

Five - ENCOURAGEMENT/ROLE OF INDEPENDENTS

As far as encouragement of the independents into Alaska is concerned, perhaps there are some lessons to be learnt from the UK.

A Select Committee was set up by the UK Government in 1988 which examined the future of the British independents. The main finding of the study was that the independents have made a significant contribution to the development of oil and gas in Britain. Furthermore, the report recognised the importance of their ongoing role. The committee concluded that they wished to see an enhanced capability for the independents.

The UK Department of Energy has been encouraging the development of small British independents by granting them approval to act as field operators. This is a change of policy on the part of the government in recent years, for historically the responsibility of acting as an offshore field operator has been placed in the hands of the oil majors.

Six - CONCLUDING REMARKS

There would be a great many petroleum companies worldwide who would be interested in entering Alaska. Thus, if faced with the threat of closure or departure by some companies, the government of Alaska should be reassured that there would be others willing to enter the region should the opportunity present itself. In addition there would be abundant external finance available for investment.

In the international petroleum scene today there are always companies who are willing to offer prices over and above what would be classed as 'commercial terms'. They pay such prices in order to achieve their longer term objectives of expanding their upstream positions.

Furthermore, it would be just as effective to introduce the foreign banking community to Alaska, as it is to expose the industry worldwide to Alaska. For the bankers themselves would carry out half the task of encouraging further investment into Alaska through their own fervour for initiating deals, as explained in detail in section 1.11.

This should not be misinterpreted as saying the State of Alaska is short of capital and, hence, so few oil companies are active in the region. Rather, the call for energy-oriented bankers is for their ability to circulate further information about opportunities in Alaska among the international oil industry. The stimulus the financial community is able to make can be quite effective for the encouragement of newcomers into Alaska. The term 'opportunities' in this instance embraces a variety of activities, viz. development of a field, farm-ins, acquisition of a producing asset, or even exploration. Accordingly the investment by the newcomer would be undertaken to suit the company concerned.

It would be up to the Government of Alaska to bring the opportunities to the attention of both foreign oil companies and the foreign banking communities. One possible way would be through sponsoring various conferences on 'The Oil and Gas Scene in Alaska' - inviting both a large number of oil companies absent from Alaska as well as the energy-oriented international banking community. The desired result would not be instantaneous. Such an initiative would be a starting point that can bring about further awareness for outsiders. But the reminders have to continue in a frequent manner if the momentum is not to be lost.

All the government would be doing in this case would be to create the environment - reminding the independents that their presence would be desirable. The rest of the thinking would be done by industry if the environment is found conducive to investment.

The superiority of Alaska as an investment region can be summarised by way of a checklist, itemised in Sections 1.6, 1.7, 1.8, 1.9, 2.2, and 2.3 above.

For funding purposes the ranking given by the financial community is the following: 1) UK, 2) Norway, 3) Australia and 4) Indonesia.

Suffice it to say when an oil company considers entering a new area tax is but one factor out of many. When it contemplates exiting, tax may be the only factor.

In examining Alaskan taxes one has to ask the question: does the fiscal system guarantee a maximum tax payable on a given field? This guarantee exists in the British system by way of a tax clause known as "safeguard". Such a provision acts as a check between the flow of income in relation to the capital sunk in the project and, hence, the payment of tax.

Another factor when examining the Alaskan Tax system is to see whether there is consideration for profitability of a field by specifically looking at the payback period, i.e. when it breaks even. This provision is met in the UK tax system by allowing uplift of 35% on capital expenditure until the field reaches payback.

In analysing the effect of a change in oil taxes it is important to study the different characteristics of the companies active in the State and compare the mixture with other areas. Any changes in the oil taxation have to be examined in relation to the balance of the losers and gainers (see Section 2.4).

If the government is concerned about its immediate income as well as the future of oil activity in Alaska, there is one strategy that can be considered. That is a tax change which is revenue neutral and at the same time makes the tax system more related to profits of a given field. This can ensure that there is no immediate loss of revenue. At the same time it gives the industry the comfort that if profits decline (as a result of oil price falls or cost escalation), they pay less tax.

The neutrality of revenue can be achieved through, say, abolition or reduction of royalty and simultaneous reduction of allowances. In the case of the UK it was done through halving of oil allowances. If Alaska does not have an oil allowance, then it can be done through perhaps reduction of cost allowances.

A key question is whether there is any evidence that the current Alaskan fiscal regime has deterred investment from the State. Have there been opportunities to invest which have been refused by industry?

The state government should have the authority to reduce the royalty/tax if it believes this would lead to the recovery of petroleum which would otherwise not materialise. This happens in other jurisdictions, e.g. in Australia the Commonwealth Government has such a power.

Finally, an issue of concern is how much has the state of Alaska helped the oil industry tax-wise since the collapse of oil prices in 1986 up to the present compared to other tax jurisdictions. As everyone knows, the price of oil went from the mid-twenties dollar a barrel in 1985 down to as low as $8 in 1986 and oscillated between $22 and $12 since then. Has there been a downward revision of tax or up-front relief during this period?

Although since the collapse of oil prices in 1986 there haven't been much external funds available for pure exploration (particularly for start up positions), this picture is expected to change in the 1990s.

It is almost inevitable that the commercial interests of a company may differ periodically from that of the state. Tension may arise from time to time between the government of the country in which it operates (in particular the Department of Revenue) and the company.

The Group Managing Director of the Royal Dutch Shell Group, John Jennings, made an interesting statement in a recent speech which has an important message for both the industry and for governments. "Mechanisms are available," he said, "which effectively meet the legitimate aims and aspirations of all, without any of them [resource holders or investors] being required to forego what they have come to regard as essential rights and controls". In the opinion of this consultant one of the most effective methods is the continual dialogue between the state and the industry.