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DISCUSSION PAPER NO. 258

An Economic Analysis of Hydrocarbon Developments in the Beaufort Sea

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Ce document est consacré à une évaluation économique de certains scénarios relatifs au développement de la production des hydrocarbures dans la mer de Beaufort. L'étude a été réalisée avec l'aide de deux compagnies déjà actives dans la mer de Beaufort, soit Gulf Canada Resources Inc. et Dome Petroleum Ltd.

Les auteurs désirent remercier les compagnies pour leur avoir fourni les données relatives aux coûts et à la production. Les résultats et les conclusions sont toutefois la responsabilité des seuls auteurs et non des compagnies qui ont fourni certaines des données utilisées. Les hypothèses relatives aux prix, à l'inflation et aux taux d'intérêt sont conformes à celles qui sont utilisées dans les monographies préparées par l'équipe sur l'énergie du Conseil économique du Canada. Elles n'ont été ni proposées ni endossées par Gulf ou par Dome.

Les auteurs notent également que les compagnies actives dans la mer de Beaufort réévaluent continuellement leurs positions et envisagent de nouvelles orientations. Par conséquent, les scénarios analysés dans les pages qui suivent peuvent en fait être très différents de ceux qui seront effectivement suivis au cours de la phase de développement dans la mer de Beaufort.

La région présente un intérêt particulier dans les perspectives d'avenir des approvisionnements pétroliers du Canada parce qu'elle constitue, au point de vue géographique, l'extension vers le Nord du bassin sédimentaire de l'Ouest. Compte tenu de la mise en production de Norman Wells, prévue pour 1986, on voit se réaliser la première étape, qui pourrait se révéler prophétique, vers le raccordement des ressources du Nord avec les marchés, par l'entremise du réseau nord-américain de pipelines. Le nombre de découvertes dans le delta du Mackenzie et la mer de Beaufort, compte tenu du nombre relativement faible de puits qui ont été forés, est encourageant, bien que d'autres travaux de délimitation soient nécessaires pour établir le seuil minimal s'appliquant à des plans particuliers de production et de transport.

Le delta du Mackenzie a été comparé aux grands bassins deltaïques d'hydrocarbures des autres parties du monde et il a été et reste encore attrayant pour les entreprises de prospection. L'éloignement et le climat, qui entraînent des coûts d'exploration très élevés, ont toutefois limité le rythme de prospection à quelques puits par année (habituellement moins d'une dizaine), que ce soit sur le continent ou au large des côtes. Par conséquent, les délais de démarrage sont plus longs qu'ailleurs.

Depuis le début des travaux, les compagnies ont cherché du pétrole plutôt que du gaz, mais, malheureusement, il semble y avoir surtout du gaz sur le continent et les recherches de pétrole se concentrent dans la mer de Beaufort. Les recherches visent non seulement à découvrir l'existence de pétrole, mais, bien sûr, la présence de grands réservoirs. Naturellement, les compagnies de prospection et leurs partenaires investisseurs, tout comme le gouvernement fédéral, qui subventionne fortement ces investissements, se demandent si l'entreprise a des chances d'être rentable.

Cette question nous paraît de toute première importance dans notre analyse de la politique relative aux Terres du Canada pour la région de la mer de Beaufort et du delta du Mackenzie. Par conséquent, nous traitons dans le présent document de trois thèmes.

1) Nous étudions, avec l'aide de deux compagnies actives dans la mer de Beaufort, Gulf Canada et Dome Petroleum, la taille minimale approximative des réserves de pétrole (l'échelle économique minimale) qui permettrait à la mise en exploitation d'une découverte, y compris la production et le transport du pétrole jusqu'à Montréal, d'être économiquement rentable. Notre analyse couvre la phase de "demi-cycle", c'est-à-dire les travaux de délimitation, de mise en exploitation et de production, plutôt

que le "cycle entier", qui comprend aussi les travaux de prospection.

2) Nous étudions, encore avec l'aide des deux compagnies, le potentiel de la mer de Beaufort en matière de pétrole à coût relativement faible. Dans cette analyse, nous nous demandons s'il existe des conditions favorables - bien que cela soit peu probable - qui permettraient de produire et de livrer du pétrole depuis la mer de Beaufort jusqu'à Montréal à un coût qui serait aussi faible que celui du pétrole de l'Alberta, par exemple.

3) Troisièmement, nous examinons, au moyen de l'analyse des mouvements de trésorerie d'industries particulières, la pertinence de diverses caractéristiques du régime fiscal actuel des Terres du Canada à l'égard du développement futur.

Le calcul de l'échelle économique minimale présente de l'intérêt pour un certain nombre de raisons; un projet "pilote" à petite échelle peut ouvrir la voie à une exploitation plus considérable d'une manière qui présente moins de risques pour l'environnement et soit plus acceptable au point de vue social; la taille de l'échelle économique minimale donne aussi une idée des risques économiques de la prospection, car il est généralement plus probable que l'on découvrira des petites réserves plutôt que des grandes, même si les structures sont grandes. Ainsi, en termes généraux, les estimations de l'échelle minimale peuvent aider à évaluer les possibilités de rentabilité d'un développement dans la mer de Beaufort.

Pour un développement à partir d'une seule "île de production" dans des eaux profondes d'environ 50 mètres, l'échelle économique minimale des réserves de pétrole se trouve dans la fourchette de 35 à 55 millions de mètres cubes avec une valeur médiane de 44 millions de mètres cubes (280 millions de barils), compte tenu de l'actuel régime fiscal des Terres du Canada et dans l'hypothèse de prix réels uniformes du pétrole. Si l'on exclut les impôts et les redevances, l'échelle minimale est estimée à 34 millions de mètres cubes en supposant un taux d'actualisation réel de 10 %. Ces résultats sont illustrés par les graphiques qui suivent le présent résumé.

Les prix ont un effet marqué sur l'estimation de l'échelle minimale. Lorsque les prix du pétrole sont réputés augmenter de 5 % par année, l'échelle économique minimale est réduite d'environ 45 %, soit de 44 à 24 millions de mètres cubes, au taux d'actualisation réel de 10 %. L'effet est encore plus grand lorsqu'on diminue les prix réels de 5 % par année, car il en résulte une augmentation soudaine de 70 % de l'échelle économique minimale.

Le prix de l'offre du pétrole (scénario de demi-cycle) à l'échelle économique minimale en eaux plus profondes est, par définition, égal au prix postulé du pétrole à Montréal, soit de 40 $ par baril.

Pour les développements à partir d'une seule "île" en eau moins profonde (environ 20 mètres), l'échelle économique minimale est estimée à quelque 25 % de moins, avec une valeur médiane d'environ 33 millions de mètres cubes, taxes et redevances comprises, ou à quelques 27 millions de mètres cubes si on exclut les impôts et les redevances.

Dans l'hypothèse de conditions qui nécessiteraient le développement à partir de plusieurs îles (5 îles), sans taxes ni redevances, l'échelle économique minimale serait d'environ 100 millions de mètres cubes, soit environ deux à trois fois plus que l'estimation pour le développement à partir d'une seule île de production. Les résultats des analyses portant sur plusieurs îles et sur une seule île ne sont pas entièrement comparables. Les hypothèses relatives aux paramètres des réservoirs dans les deux cas sont différentes et, par conséquent, les profils de coût et de production dans l'analyse portant sur plusieurs îles ne sont pas les mêmes que ceux qui servent à l'analyse portant sur une seule île.

Pour analyser le potentiel de pétrole à coût relativement faible, on postule que des réserves suffisantes ont été découvertes, de sorte la production est ainsi optimisée et le coût unitaire de production et de livraison du pétrole à Montréal est minimisé. Bien que la probabilité que tous les aspects (géographiques, techniques, administratifs, etc.) soient favorables est faible, nous croyons que les conditions que nous avons examinées sont possibles. L'estimation du prix de l'offre du pétrole à faible coût fixe donc un plancher pour les autres estimations de prix de l'offre.

Pour le pétrole à faible coût, nous estimons le coût social demi-cycle, c'est-à-dire sans taxes ni redevances, dans une fourchette de quelque 63 $ à 95 $ par mètre cube (de 10 $ à 15 $ le baril) pour produire le pétrole et le livrer à Montréal, ce qui correspond à un réservoir à forte productivité de 159 millions de mètres cubes (un milliard de barils), auquel on pourrait accéder par le développement à partir d'une seule île.

C'est donc dire qu'il existe un potentiel pour du pétrole à coût relativement faible et que, par conséquent, même si le réservoir de la mer de Beaufort présente beaucoup de risques, il est tout à fait possible que le coût du pétrole par mètre cube se révèle plus faible que celui des autres sources au Canada. Dans ce cas, bien entendu, la prospection et le développement des gisements de la mer de Beaufort seraient rentables. Les scénarios pour le pétrole à faible coût démontrent que le potentiel pétrolier de la mer de Beaufort peut offrir une importante rente économique, compte tenu des niveaux actuels des prix mondiaux du pétrole.

Le régime fiscal relatif aux Terres du Canada qui s'applique à la phase de délimitation et de développement de l'activité de l'industrie comprend la redevance de base de 10 % sur le revenu brut, la TPRG à 12 % du revenu d'exploitation, la redevance additionnelle progressive de 40 % sur les profits, l'option de participation gouvernementale à 25 % et les subventions de 20 % prévues par le programme d'encouragement du secteur pétrolier (PESP) pour les dépenses de développement intangibles. À cela s'ajoute, évidemment, l'impôt sur les bénéfices imposables des compagnies provenant du développement et de la production.

Au coeur du système fiscal proposé à l'origine pour les Terres du Canada se trouvait la redevance additionnelle progressive (RAP) frappant directement les bénéfices supérieurs à la normale tirés de l'exploitation d'un champ particulier ("délimité"). Depuis la conception de ce système au milieu des années 70, qui s'inspirait des régimes en vigueur au Royaume-Uni et en Norvège, on a superposé des caractéristiques fiscales qui ont donné lieu aux dispositions du PEN pour les Terres du Canada.

Tant la redevance de base de 10 % que la TRPG sont relativement insensiblement aux considérations de rentabilité et elles sont nettement en contradiction avec l'intention et l'esprit de la délimitation des champs aux fins de la RAP.

Quant aux subventions versées en vertu du PESP dans les Terres du Canada, elles équivalent à 80 % des dépenses de prospection et 20 % des dépenses d'exploitation intangibles. D'après nos recherches, lorsqu'une découverte a été faite et que les travaux d'exploitation se mettent en marche, la subvention de 20 % à l'égard des dépenses de développement ne semble pas jouer un rôle économique très important pour les projets de demi-cycle.

Il en va tout autrement pour la phase de prospection antérieure aux découvertes. Les subventions à l'exploration aident en effet les compagnies à poursuivre leurs travaux dans la mer de Beaufort. Si ces subventions soulèvent autant de problèmes qu'elles en résolvent, on peut dire que sans cette aide, les activités de prospection dans la mer de Beaufort n'en seraient pas à leur point actuel. Ce sont évidemment les compagnies qui forent constamment de coûteux puits de prospection qui bénéficient le plus de ces subventions.

Compte tenu du seuil rentable relativement peu élevé - entre 35 et 55 millions de mètres cubes (entre 220 et 350 millions de barils) -, à la condition qu'un réservoir puisse être atteint par forage directionnel à partir d'une seule île de production, et compte tenu de la possibilité que du pétrole à faible coût (entre 63 à 95 $ par mètre cube) puisse être obtenu dans la mer de Beaufort, il semble raisonnable que l'État encourage l'exploration et le développement dans cette région. De quelle manière cela devrait-être fait? Dans quelle mesure l'État doit-il prendre des risques avec les deniers publics?

Executive Summary

This paper provides an economic evaluation of some possible development scenarios for hydrocarbon production in the Beaufort Sea. The study has been carried out with the assistance of two Beaufort operating companies, Gulf Canada Resources Inc. and Dome Petroleum Ltd.

The authors wish to thank the companies for their provision of the cost and production data, however, the results and conclusions are the responsibility of the authors alone and not of the companies who have provided some of the input data. The price, inflation and cost of money assumptions are consistent with those being used in the Economic Council of Canada's Energy Group case studies. They have been neither suggested nor endorsed by Gulf or Dome.

The authors note also that the companies operating in the Beaufort are continually re-evaluating their positions and considering new directions. Consequently the scenarios assessed in this paper may in fact be very different from those that will actually be pursued once development gets under way in the Beaufort.

The Beaufort Sea - Mackenzie Delta region is one of the key areas in Canada's frontier that is being explored and delineated for possible oil and gas production. Some 180 wells have been

drilled in the area since exploration started in the early 1960s, costing about 2 billion dollars. Drilling has resulted in 12 oil discoveries, 11 gas discoveries, and 4 oil and gas, identifying close to 1 billion barrels of oil and about 9 TCF of gas.

The area is of particular interest in the unfolding of Canada's oil supply prospects because it is geographically the northward extension of the Western Sedimentary Basin and with Norman Wells scheduled to come on stream in 1986 the first step, which may prove to be prophetic, is being taken towards linking northern resources to market through joining them to the North American pipeline system. The number of discoveries in the Mackenzie Delta and the Beaufort Sea, with the relatively small number of wells that have been drilled is encouraging however further delineation is required to establish the threshold size for specific production and transportation plans.

The Delta has been compared to the great hydrocarbon delta basins of other parts of the world and it has been and still is tantalizing to explorationists. Remoteness and weather conditions, leading to very high exploration costs however, have restricted the pace of exploration to a few wells per year, usually less than ten or so either onshore or offshore. Lead times are consequently longer than elsewhere.

From the start of exploration the companies have been searching for oil rather than gas, but unfortunately the onshore appears to be gas prone and the focus of search for oil is now in the Beaufort Sea. Not only is the search aimed at oil prospects but of course it is for large oil reservoirs. Naturally the companies and their partners who are investing, and the federal government, which is heavily subsidizing the investment ask themselves whether the endeavour is likely to be worthwhile.

We view this question as central to our discussion of Canada Lands policy for the Beaufort Sea - Mackenzie Delta region. Accordingly this paper deals with three topics.

1) It considers, with assistance from two Beaufort operating companies Gulf Canada and Dome Petroleum, the approximate minimum oil reserve size, or minimum economic scale, that would allow development of a discovery to be economically viable including the production and transportation of oil to Montreal. The analysis deals with the "half cycle" phase of delineation, development and production rather than the"full cycle" which includes exploration.

2) It considers, again with assistance from the two companies, the potential for relatively low cost oil from the Beaufort. In this analysis it asks the question whether possible

(favourable) conditions, although unlikely, could exist which would allow for the production and delivery of Beaufort oil to Montreal at a cost, for example, as low as Alberta oil.

3) Thirdly the paper examines, through cash flow analysis of example oil developments, the appropriateness for future development of various features of the present Canada Lands fiscal regime.

An estimate of the minimum economic scale is of interest for a number of reasons; smaller scale "pilot" development may pave the way to larger scale development in a manner which is environmentally less risky and socially more acceptable; the size of the minimum economic scale also gives a sense of the riskiness of the exploration, from an economic viewpoint, because generally it is more likely that smaller reserves will be discovered rather than larger, even if the structures themselves are large. Thus in broad terms the estimates of minimum scale can assist in assessing the possibility of commercially successful of Beaufort development.

For a single island development in the offshore, with water depths around 50 metres, the minimum economic scale of oil reserve is in the range of 35 to 55 million cubic metres with a middle value of 44, (280 million barrels) under the present Canada Lands fiscal regime and assuming flat real oil prices. Without taxes and royalties the minimum scale is estimated at 34 million cubic metres, assuming a 10 per cent real discount rate. These results are illustrated by the graphs following this Executive Summary.

Price has a marked effect on the estimate of minimum scale. When oil prices are assumed to increase at 5 per cent per year the minimum economic scale is reduced by about 45 per cent, from 44 to 24 million cubic metres, at the 10 per cent real discount rate. The effect is even greater with declining real oil prices, a 5 per cent per year declining price leading to a 70 per cent jump in minimum economic scale.

The (half cycle) supply price for oil at the minimum economic scale in the deeper offshore is, by definition, equal to the assumed oil price at Montreal of $40 per barrel.

For single island developments in shallower water, at water depths around 20 metres, the minimum economic scale is estimated to be some 25 per cent less with a middle value of about 33 million cubic metres with taxes and royalties, or some 27 million cubic metres without taxes and royalties.

An approximation of minimum economic scale, assuming reservoir conditions which necessitate multi-island development (5 islands), without taxes and royalties is in the range of 100 million cubic metres, some two to three times as large as estimated for single island development. The results of the multi-island and single-island analyses are not entirely comparable. The assumed reservoir parametres in the 2 cases are different therefore the cost and production profiles that are used in the multi-island analysis are not the same as those used in the single-island analysis.

The analysis of the potential for relatively low cost oil assumes that adequate reserves have been discovered so that production is optimized and the unit cost for producing and delivering oil to Montreal is minimized. While the probability of all aspects being favourable, i.e., geographical, engineering, and project management etc., is small, the conditions examined are believed to be possible. The estimated supply price for low cost oil therefore puts a floor under alternative supply price estimates.

A (half cycle) social supply price, i.e., without taxes and royalties, in the range of some $63 to $95 per cubic metre ($10 to $15 per barrel) to produce and deliver oil to Montreal is estimated for low cost oil, corresponding to a high productivity reservoir of 159 million cubic metres (1 billion barrels), that could be accessed through a single island development.

This means that there is the potential for relatively low cost oil and thus although the Beaufort oil play is extremely risky it is entirely possible that the per cubic metre cost of oil will prove itself to be lower than other sources of oil in Canada. In this case, of course, Beaufort Sea exploration and development would be economically worthwhile. The low cost oil cases show that Beaufort oil potential may provide substantial economic rents at present levels of world oil prices.

The existing Canada Lands fiscal regime applicable to the delineation and development phase of industry activity includes the base royalty of 10 per cent on gross revenue, the PGRT at 12 per cent on operating revenue, the 40 per cent PIR (progressive incremental royalty) on profits, the 25 per cent government back-in provision and the 20 per cent PIPS on intangible development expenditures. Plus, of course, income tax on company taxable income from development and production revenues.

At the heart of the initially proposed fiscal system for Canada Lands was the PIR which is a royalty geared directly to above normal profits from a particular ("ring fenced") field. But since its design in the mid 1970's, taking much from the U.K. and Norwegian systems, one additional fiscal feature has been piled on another, culminating in the provisions of the NEP for Canada Lands.

The 10 per cent basic royalty and the PGRT both lack responsiveness to profitability and they are clearly in contradiction with the intent and spirit of ring fencing a field for the PIR.

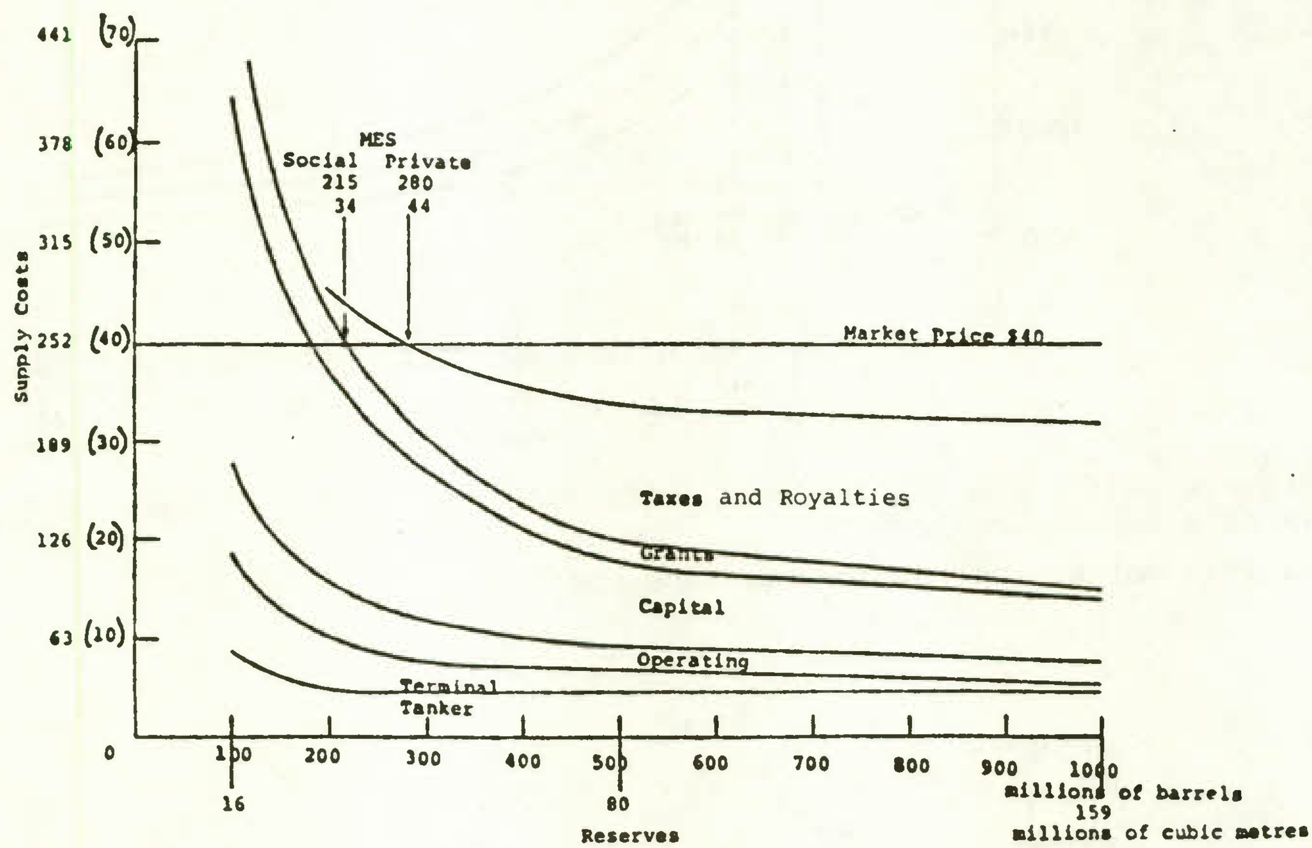
As for PIPS in the Canada Lands they are paid at a rate of 80 per cent towards exploration expenditures and at a rate of 20 per cent towards intangible development expenditures. Our findings suggest that once a discovery is made and development proceeds, the 20 per cent PIP grants on development expenditures do not appear to be enormously important in the half cycle project economics.

However this is not the case in the exploration phase prior to a discovery. Exploration PIPS are indeed of value to the companies in order to sustain activity in the Beaufort. While PIPS in their own right raise as many problems as they solve it can be argued that had there not been some equivalent form of assistance for exploration activities in the Beaufort these activities would not be proceeding as they are now. The PIPS, of course, are of most value to companies that continually drill costly wildcat exploration wells.

Considering the relatively small threshold reserve size of some 35 to 55 million cubic metres, (220 and 350 million barrels) provided that a reservoir can be accessed by directional drilling from a single island, and the potential that low cost oil in the \$63 to \$95 per cubic metre range might be available from the Beaufort Sea, it seems reasonable for the government to encourage Beaufort Sea exploration and development. In what manner should this be done? How much risk should the government take with public funds?

Half Cycle Component Costs for Beaufort Sea Oil at a 10% Real Discount Rate TANKER (single island development)

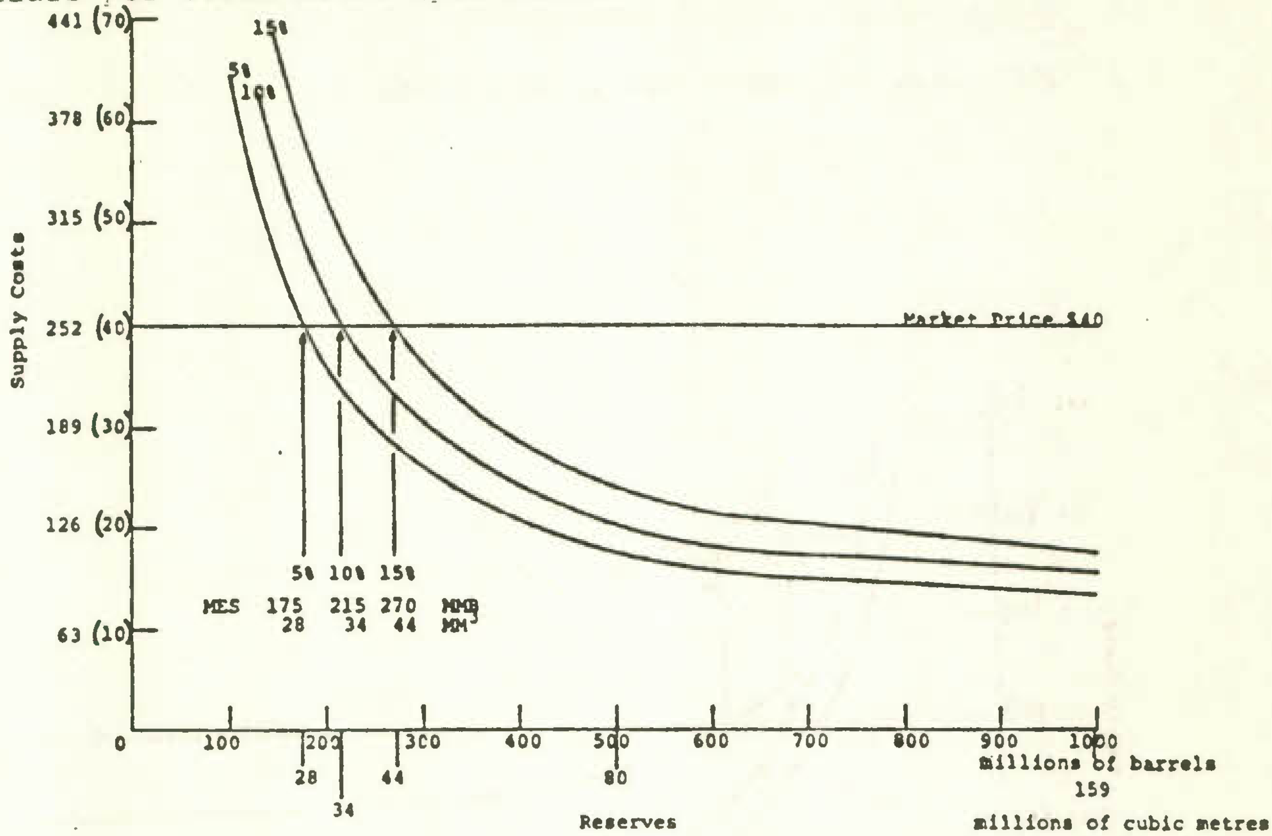
in 1983 dollars per cubic metre (per barrel)



Estimates by Dome Petroleum

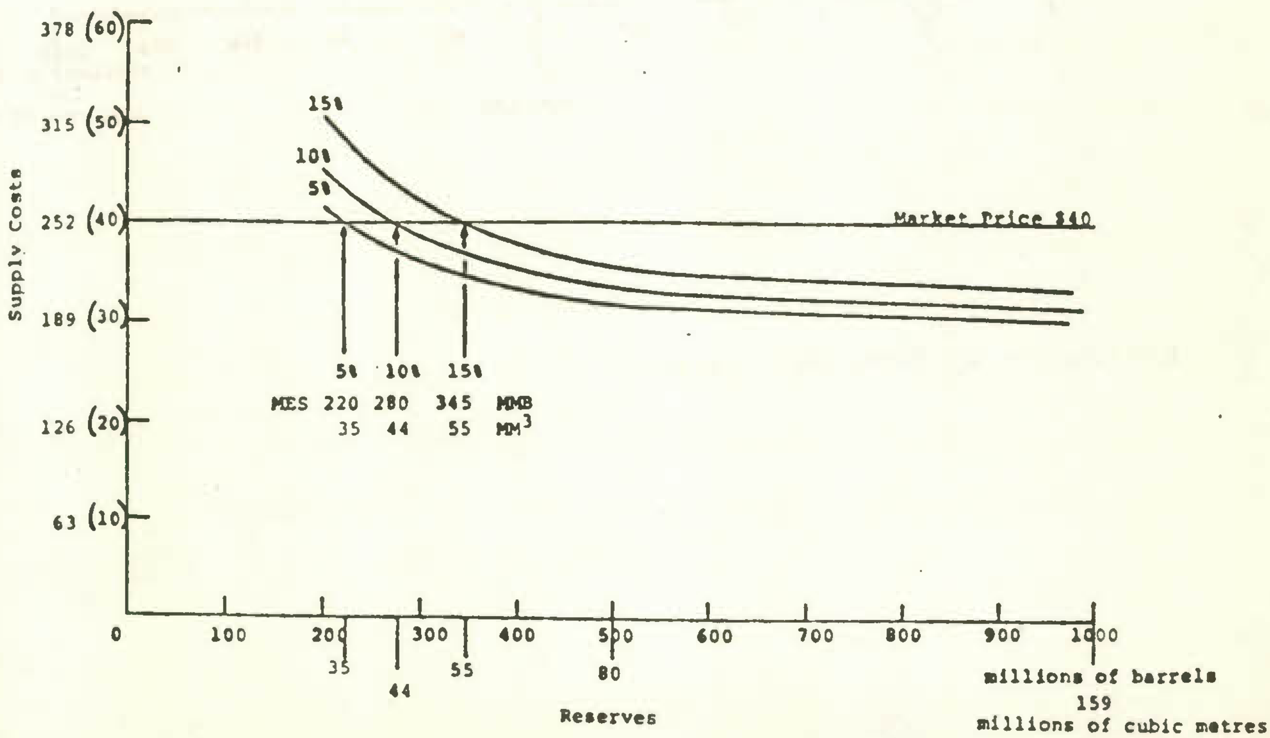
Social Half Cycle Supply Costs (without taxes and royalties) TANKER
(single island development)

in 1983 dollars per cubic metre (per barrel)



Private Half Cycle Supply Costs (with full taxes and royalties) TANKER
(single island development)

in 1983 dollars per cubic metre (per barrel)



Estimates by Dome Petroleum

1 INTRODUCTION

The Beaufort Sea-Mackenzie Delta region is one of the main areas in Canada's frontier that is being explored and delineated for the purpose of eventually producing hydrocarbons. This study provides an overview of possible development economics in terms of the required technologies and a possible range of economic factors bearing on Beaufort oil production.

To come to grips with the problem, potential development areas in the region are categorized in terms of reserve sizes, locations (whether onshore, inshore or offshore), and water depths. The analysis concentrates on the potential offshore development sites in shallow water depths and in the middle to deep waters. Two separate modes of transporting Beaufort oil to southern markets are considered in the development scenarios; a marine system of icebreaking tankers and an overland pipeline system.

The economic assessment of Beaufort oil development and production examines example projects under a number of conditions of price, fiscal terms, and the cost of money. One objective of the economic analysis is to show the effect of various fiscal measures and pricing assumptions on the corporate rate of return. A second objective is to investigate the share of revenues between the federal government and the private sector. Estimates of the social and private supply prices for oil from the projects are also reported. From the economic analysis and sensitivity tests, conclusions are drawn regarding the impact and appropriateness of the current taxation policies.

The paper proceeds with a description of the Beaufort Sea-Mackenzie Delta region and the technology that is required for hydrocarbon development in the area. A brief description and a general evaluation of the two transportation alternatives are also presented.

The discussion then deals with offshore development projects that are based on a single island. Two main objectives are sought in the examination of the single island development projects: the determination of the minimum reserve size, or minimum economic scale (MES) that would allow the development to be economically viable, including the production and delivery of Beaufort oil to Montreal, and an estimation of the potential for low cost oil from the Beaufort. Finally, sensitivity tests on the economics of these projects are provided.

Multi-island development projects are also examined and the economics of the projects are assessed in terms changing price and fiscal conditions.

The data for the single island analysis has been provided by Dome Petroleum Ltd. The multi-island analysis has been carried out with data that has been provided by Gulf Canada Resources Inc. In both cases the project descriptions and reservoir parameters have been set out by the respective companies.[1]

2 THE BEAUFORT SEA-MACKENZIE DELTA HYDROCARBON DEVELOPMENT REGION[2]

2.1 Location

Hydrocarbon reserves are presently being discovered in the Beaufort Sea-Mackenzie Delta (BSMD) sedimentary basin. The basin is located in the north-western portion of the North American continent and encompasses the north-eastern coastal region of Alaska, the north-western coastal region of the Northwest Territories and the Beaufort Sea. The triangular basin extends over a 420,000 square kilometre area, as shown in Figure 1. Approximately one-quarter of that area is currently being explored.

2.2 Geology

The sediments in the basin are mostly of a marine origin. Sedimentation began roughly 200 million years ago during the Triassic period. In the offshore areas of the basin sedimentation from three periods can be found: the Upper Cretaceous, the Paleocene and the Neocene. Geologists estimate this sedimentation to be up to eight kilometres thick and it is within these sections that the most promising oil bearing traps are believed to exist.

In the northern offshore reaches of the basin the main oil reservoirs are believed to have been created some 50-60 million years ago in the Paleocene age. Some of the oil in this area can be attributed to an ancestral river located where the Mackenzie River flows. The ancient river created a deep canyon under the ocean and erosional material funneled down into the waters of the canyon and flowed out in a fan shape at the base of the continental slope. Oil prospects are contained in these deep sea deposits. Figure 2 shows the stratigraphic relationships in the BSMD.

2.3 Exploration History

Two main spheres of exploratory activity have been in progress in the BSMD region. The activity in the offshore has tended to lag behind that in onshore areas. The initial phase of exploratory activity, the gathering of seismic data, began onshore in the late 1950s. Seismic activity in the offshore was carried out through the 1970's and is still in progress in prospective areas. About 140 onshore wells were drilled between 1965 and 1975.

Exploratory drilling began in the onshore areas in 1965 on Richards Island and wells have been drilled throughout the delta region. The oil and gas discovery locations are shown in Figure 3. Significant onshore oil finds occurred in 1970 at Atkinson Point and in 1971 at Mayogiak. Major onshore gas fields have been discovered at Parson's Lake and Taglu. A number of smaller gas pools including Niglintgak have also been found.

Exploratory drilling in the Beaufort Sea was initially carried out from artificial islands constructed in relatively shallow waters. The first offshore well was drilled in 1973 from an island constructed in three metres of water. Technology has advanced over the past decade and the islands can be constructed in water depths up to 65 metres. However to date the deepest water in which an island has been drilled has been about 30 metres for Uviluk (1983).

At the time that the Environmental Impact Statement (EIS) for the BSMD development was filed in 1982, 23 wells had been drilled from 23 artificial islands. The islands have been constructed in water depths up to 22 metres.

This drilling effort has resulted in major oil finds at Adgo (1973), Garry (1976), and Issungnak (1980) and gas finds at Netserk (1976), and Isserk (1978).

In addition to the artificial islands, reinforced drillships have also been used for exploration drilling. Two such drillships with the capability of operating in ice filled waters were brought to the Beaufort in 1976. Since then more ships have been added to the fleet. Drilling from these drillships has been carried out in water depths ranging from 23 metres to 68, leading to four oil discoveries; Nektoralik (1977), Kopanoar (1979), Tarsiut (1980), Koakoak (1981) and two gas finds; Nektoralik (1977) and Ukalerk (1977). By November 1983, 38 wells had been drilled from islands and drillships.

2.4 Hydrocarbon Reserve Estimates

Drilling activity to date suggests that the Beaufort Sea is oil prone whereas this has not been found to be the case onshore in the Mackenzie Delta. Recent estimates by the Geological Survey of Canada (EMR 1983) place potential recoverable oil reserves in the BSMD area at 1.3 billion cubic metres (8 billion barrels) and gas reserves at 1.8 trillion cubic metres (64 trillion cubic feet). Speculative estimates are almost 3 billion cubic metres (19 billion barrels) of oil and over 4 trillion cubic metres (140 trillion cubic feet) of gas. The Survey states that these estimates are high for a relatively small region but they are not inconsistent with the high success rate and early discovery of 3 very large gas fields. The largest potential for both oil and gas is estimated to exist in the Beaufort Sea in the area now being evaluated by drilling and in the area westward to the Canada - U.S. border.[3]

The Geological Survey says that less than 10 per cent of that potential can be considered established on the basis of drilling to date. Based on estimates of the various operators in the BSMD region, the EIS states that ultimate recoverable oil reserves range from 1.0 billion cubic metres (6.3 billion barrels) to 5.1 billion cubic metres (32 billion barrels).

3 THE TECHNOLOGY OF HYDROCARBON DEVELOPMENT IN THE BEAUFORT SEA

3.1 Introduction

A number of factors, and notably the climate and remoteness, cause the technological requirements for hydrocarbon development in the BSMD region to be significantly different from those required in Alberta and even in deep water offshore exploration and development in areas such as the Gulf of Mexico.

The harshness of the climate and the year round presence of ice necessitate uniquely designed systems for exploratory drilling, development, production and transportation. The weather also seriously curtails the rate at which exploration and development can take place. Only about one third of the year is suitable for drilling from drillships, however with the new units that have been introduced by Gulf and Dome the drilling time has been extended. The drilling units are described below. In addition the area's remoteness from population centres and from major markets has meant that all the infrastructure for exploration and development has had to be built from scratch. The production infrastructure and a long distance transportation system to remove the oil from the area has yet to be provided. These factors and others necessarily result in long lead times in all phases of the exploration to production full cycle sequence.

This section briefly describes some of the adaptations that have been made, and will have to be made, in order to discover, produce and transport oil from the BSMD area. The discussion will centre around activity in the offshore.

3.2 Platforms for Drilling and Production

Realization of oil and gas supplies from the Beaufort Sea requires the building of offshore structures that can accomodate drill rigs for exploration, delineation, and production wells. The structures must also house facilities that separate oil, gas and water and support transportation systems.

The Beaufort Sea can be distinguished from all other existing offshore hydrocarbon developments because of the year round presence of ice. The Sea is ice covered for about nine months of the year. In the summer the amount of open water is relatively small which tends to limit the size of the waves that occur. The tidal activity in the area is also quite small. There are no icebergs in the area as there are in the Newfoundland coastal waters. It is predominantly the sea ice that dictates the design of platforms in the Beaufort Sea.[4]

The physical characteristics of the Beaufort waters have led to the design and construction of artificial islands. The islands, if intended for development and production, must house the operating equipment over the life of the reservoir given the harsh environmental conditions.

Generally the design concepts attempt to provide the flexibility to adapt an island used for exploratory drilling to a production island. Given the uncertainty of exploration, temporary structures such as self eroding islands are best suited to the purpose. If however a discovery warrants development and production a permanent facility is required.

3.2.1 Exploration Systems

Drillships

Drillships are floating drilling systems that can be moved between various drilling sites. There are a number of limitations facing the use of conventional drillships in the Beaufort Sea. The presence of ice and rough seas restrict their year round use. In fact, drilling activities from drillships can only be carried out during about 100 days of the year. Conventional drillships are most feasible in water depths beyond the capability of bottom founded drilling rigs.

Mobile Drilling Units

A recently developed concept in platform design is the Semi-Submersible Drilling Caisson (SSDC). This semi-submersible unit can be moved to drillsites quite readily. The concept has been introduced by Dome Petroleum Ltd.

The unit is in fact a 225,000 tonne Very Large Crude Carrier (VLCC). The stern of the carrier is removed and the vessel is reinforced with concrete and steel. The unit is taken to a drillsite where it is ballasted down with 200,000 tonnes of water.

The SSDC was introduced in 1982 and operated through the winter of 1982-1983. During that winter a continuous ice-wake existed on the lee of the vessel. This may prove to be an added feature for future production islands allowing year round access for tankers and marine vessels.

Gulf Canada has designed a Mobile Actic Caisson for operation in relatively shallow water depths of 18 metres to 36 metres. The 30,000 tonne caisson will rest on a sub-surface berm. Its core will be filled with 150,000 cubic yards of sand for ballast. The sandcore can be removed in order to refloat and reposition the caisson. The unit is expected to arrive in the Beaufort in the summer of 1984.

Esso Resources has introduced a new mobile caisson which takes the shape of a 330 foot diameter doughnut. It can also be ballasted to a sub sea berm with sand. By removing the sand it can be re-floated and re-located.

Gulf Canada also has a conical drilling unit (drillship) that is designed to extend the possible days of operation in the Beaufort to 175 from the 100 days with drillships. The drilling season will extend from June to January. The unit commenced operation in August 1983 and is expected to allow the drilling and testing and completion of at least one well per season.

3.2.2 Island Design Concepts

Most of the island design concepts for the Beaufort Sea involve construction of berms (manmade islands) to form the main foundation of the island. The berms are reinforced either with rock and gravel or with encasements made of concrete or steel. The encased berm is known as a caisson-berm island and the encasement prevents the erosion of the berm slopes during severe fall storms.

The caissons can be quickly placed on top of the berm. The caisson generally extends 6 to 10 metres below the surface and provides a structure that resists ice forces. The caisson-berm can initially be constructed to house only exploration facilities.

However with expansion and reinforcement the structure can be made more permanent and used for production.

The EIS describes a large offshore platform known as the Artic Production and Loading Atoll (APLA).[5] The APLA is a 2 island system providing a protected harbour between the islands for the loading of tankers. However experience obtained through Tarsiut Island and the Mobile Drilling Caissons shows that the protected harbour concept shown in the EIS is no longer necessary. Current work suggests that berm mounted multi-unit caissons would be suitable in shallower waters (20 metres) whereas larger structures with open water tanker loading would be more applicable in deep water (40 metres and over).[6]

3.3 Production Drilling Systems

Production wells drilled in the Beaufort Sea are drilled directionally rather than vertically meaning that the angle at which the well is drilled deviates from the encasement which extends vertically below the wellhead. The technique is not new and angles ranging up to 50-60 degrees are normal. This technique allows a number of wells to be drilled from one platform and thereby minimizes platform costs. It enables the access of a reservoir over a large area from a single platform.

3.4 Storage Facilities

Somewhat larger than usual oil storage facilities will be required in the BSMD region because of possible interruptions caused by failures in the transportation system. A delayed arrival of a tanker or a pipeline breakdown might necessitate substantial temporary storage. Storage could be accomodated at the tanker loading facilities offshore in the case of a tanker delay or onshore at the northern pipeline terminal in the case of a pipeline breakdown.

3.5 Subsea Pipelines

Some of the potential development scenarios include satellite wells on artificial islands that will be situated around a central production facility. The oil would be transported to central production facilities via subsea pipeline networks. The pipelines would be small in diameter and would be used for oil gathering. Oil could be pumped through the subsea pipelines to tanker loading facilities or in the case of overland pipelines the oil would be transported to shore to the northern terminal of the overland pipeline.

4 TRANSPORTATION ALTERNATIVES

4.1 Introduction

There are two main transportation systems that are being considered for the transport of Beaufort Sea oil to markets. They are tankers and overland pipelines. Initially likely one system will be put in place but it is conceivable that at some point both transportation modes will be utilized. Currently both systems are considered to be feasible. The proposed routes are shown in Figure 4.

4.2 Tanker Systems

Although tankers are a long established mode of transporting crude oil, their feasibility in the Beaufort will depend upon success achieved in adapting them to ice infested waters. That technology is not yet proven although many advances have been made. Icebreaking tankers will be required to transport Beaufort oil year round.

Much of the experience for the Artic tanker has come the Kigoriak, Dome Petroleum's prototype icebreaker. The Kigoriak is a Canadian Artic Class 4 ship. A new icebreaker, the Robert Lemeur was introduced into the Beaufort in 1982. This icebreaker uses 60 per cent of the power required by the Kigoriak.

The standard tanker design proposal as it is outlined in the EIS calls for an arctic tanker that is about 400 metres in length and has a cargo capacity of about 200,000 tonnes. The cargo capacity translates to 238,000 cubic metres (1.5 million barrels) of crude oil which, given the proposed tanker routing, is approximately equivalent to 8,000 cubic metres (50,000 barrels) per day per tanker. Various Beaufort operators are likely to have their own variations for the proposed tanker design. In this analysis the tanker capacity is assumed to be about 10,300 cubic metres (65,000 barrels) per day.

Costs for the operation of a tanker transportation system include expenditures for the construction and operation of loading terminals, the purchase of the icebreaking tankers and the operation of those tankers. Fuel costs are a significant portion of the tanker operating costs. A more detailed discussion of the tanker assumptions is given in Section 5.2.

4.3 Pipeline Systems

There are a number of possible pipeline designs that could be used for a pipeline system that would originate at the northern end of the Mackenzie Delta and extend along the Mackenzie River Valley to a southern terminal near Edmonton where the pipeline would join existing lines. Two design options may be considered: a buried mode and an elevated mode.

The required size of the pipeline is a crucial question and will likely influence the choice between a buried or elevated pipeline. The choice of pipeline diameter will depend on the rate of throughput.

We note also that an overland pipeline system will require a system of subsea pipelines to transport oil from the offshore to the overland pipeline system. Subsea pipelines pose a number of problems because the technology required for adapting them to the subsea conditions in the Artic is not yet proven. The trenching of the pipelines to avoid ice scouring will be a difficult task as will temperature and pressure maintenance to keep the oil flowing.

4.3.1 Buried Pipeline

Because of the existence of permafrost, a line that is buried must be kept chilled in order to prevent the permafrost from melting. The practicality and efficiency of building buried lines that are chilled diminish rapidly as the diameter of the pipeline increases. It has been suggested to us that lines with diameters much in excess about 600 mm are likely to become uneconomic if they are buried and therefore must carry refrigerated oil.[7] For large throughput volumes twin buried lines each with a diameter that is smaller than 600 mm could be a solution.

4.3.2 Elevated Pipeline

An alternative to running chilled lines through the permafrost is to elevate the pipeline above ground. The cost of above ground pipelining is substantially higher than that of a buried line. One estimate suggests the cost of the elevated line is four times that of the buried line.[8] This pointedly suggests a quantum leap in investment costs as larger diameter pipelines that must be elevated are considered.

While larger diameter lines necessitate very high initial capital costs there are generally significant economies of scale in pipelining and there may in fact be a level of throughput that would justify a larger line. The Dome Submission to the Senate suggests that a 900 mm above ground pipeline could be justified with the development of a 320 million cubic metre (2 billion barrel) reserve. Such a pipeline would have a capacity of 160,000 cubic metres (1 million barrels) per day.

4.4 Relative Merits of Tankers and Pipelines

A general evaluation of the relative merits of the two transportation modes might suggest that due to the flexibility of the tanker system and because a lower proportion of the capital costs for tankers are expended in the pre-production years than in the case of the pipeline, a tanker system would be most efficient.

The relative merits will be discussed below but it is important first to note a number of caveats.

First and foremost it must be noted that a transportation system of icebreaking tankers is not a proven technology and experience might prove that the anticipated tanker productivity could not be realized. Being an unproven technology cost estimates are likely to be biased downwards. Secondly, the choice of a delivery system will in part be determined by the volume of reserves that will be developed and the throughput that will be demanded of the system. Thirdly, the location of developments will influence the choice of the system. It may in fact be economic to transport oil from offshore sites in deeper waters by tanker rather than move the oil by subsea pipeline to the northern terminal for transport by overland pipeline. Similarly, oil from inshore shallow water sites and from onshore sites is likely to be transported more efficiently by overland pipeline.

The tanker system is a more flexible system as it can be more readily adapted to changes in production levels. Tankers can be added or taken off stream as needed to ensure the efficient utilization of tankers that are in commission. In the pipeline case a minimum throughput is needed for operation and decreases in throughput below design capacity would cause a disproportionate increase in tariffs. Within limits increases in throughput cause unit costs to fall, but eventually the entire line would have to be looped, i.e., a new line would be built. In this regard it is a fact that tanker systems consist of smaller separate investment units.

Tanker systems may also be less susceptible to cost overruns than pipeline systems in the far north in part because shipyard contracts tend to be competitive and fixed price contracts can likely be obtained,[9] whereas onsite construction in the remote north can signficantly inflate costs.

Pipeline construction requires that roughly 90 per cent of pipeline capital expenditures be made prior to production start-up and before the generation of revenues. A tanker system requires that about 30 per cent of its capital expenditures be made in the early years.

On the other hand there are advantages that the pipeline system appears to have over the marine mode of transportation. First the required technology for the overland pipeline is developed. Secondly it currently appears to have economic advantages at very high levels of throughput. Thirdly a pipeline system of transportation has lower operating costs than a marine system primarily because the pipeline is more energy efficient. Fourthly, a pipeline system through the Mackenzie Valley would provide a conduit for any onshore oil development throughout the Valley and would parallel Norman Wells, and lastly it would connect the

Beaufort and the Mackenzie Valley into the whole North American pipeline system, via IPL or Trans Mountain pipelines.

These pipeline advantages adhere principally to an overland pipeline whereas subsea pipelining in the Beaufort raises other difficulties that would be minimized with a tanker system.

5 SINGLE ISLAND DEVELOPMENT PROJECTS

5.1 Introduction

This section provides a description and economic assessment of a number of offshore single island oil developments, in the middle depth waters of the Beaufort Sea. There are three main objectives sought in this analysis; determination of the approximate minimum economic scale for oil development in the Beaufort, estimation of the potential for low cost oil; and examination of oil development economics under various conditions of alternative prices and fiscal terms. It may be noted that all the analyses refer to development economics rather than exploration economics. They deal with the development "half cycle" only.

5.2 Cost Structures and Production Profiles of the Offshore Sites

Each development scenario is outlined separately in Appendix 1 however there is a general set of assumptions that applies to all cases:

1. The analysis refers to expenditures and revenues subsequent to a decision being made to proceed with delineation and development of a previously discovered oil pool. The year of discovery was 1980.

2. Expenditures, i.e., exploration costs, made prior to delineation expenditures are ignored for the purposes of this analysis.

3. Delineation occurs in the first three years of the project, capital expenditures for production facilities and a loading terminal begin in 1985, development expenditures begin in 1987, production commences in 1989, a subsea pipeline system is put in place in 1987-88 for the pipeline mode of transportation.

4. Project life is 19 years with production commencing in 1989, the 6th year, and terminating in 2001.

5. Production profiles, field costs and transportation costs are dependent upon reservoir parameters particularly reserve size.

6. The reservoirs in the single island scenarios are located in water depths of about 50 metres. Deep reservoir formations are assumed i.e., 3500-5000 metres subsea. Sand thicknesses range from 30-90 metres.

7. Delineation is done from drillships.

Transportation Assumptions:

8. Transportation systems are assumed to deliver the oil to an existing east coast refinery. They do not include additional costs to move the oil to Montreal but they do recognize a price differential between the landed Montreal and landed east coast prices.

9. The wellhead prices are determined by netting the 1983 real dollar transportation tariff from the assumed delivered-at-Montreal price of $40 (1983$).

10. Tanker system consists of arctic icebreaking VLCC's transporting produced oil from the terminal facilities at the Beaufort oil source to Point Tupper, Nova Scotia where it is assumed to be transferred to Montreal at a cost of some $8.90 per cubic metre (1.42 per barrel).

11. Operating and capital expenditures for the loading terminal under the tanker scenarios are allocated to field costs.

12. Tankers are assumed to be effectively 100% debt financed and capital costs are recovered on a mortgage type basis over the assumed field life of 13 years which is somewhat less than the expected tanker life. The tankers are

assumed to be mortgaged at a nominal rate of 12 per cent.

13. Fuel costs are directly proportional to throughput and on average represent about 15 per cent of the tanker tariff.

14. A single tanker capacity is about 10,300 cubic metres (65,000 barrels) per day.

15. The pipeline system consists of an offshore link from the field to Richards Island and then a new line down the Mackenzie Valley to Zama where existing pipeline systems (Rainbow and Interprovincial) can move oil to the east. The latter lines are assumed to have available capacity.

16. The pipeline rate base is depreciated to reflect the field life of 13 years, i.e., substantially faster than most pipelines.

17. The pipeline tariff calculation is based on an annual 13 per cent return to the rate base (a recent NEB assumption for the TQM pipeline) plus operating costs.

18. Two pipeline sizes are assumed: a 400 mm buried pipeline with a throughput of 12,000 cubic metres (75,000 barrels)

per day and a 600 mm buried pipeline with a throughput of 40,000 cubic metres (250,000 barrels) per day.

19. Transportation costs and tariffs are not optimized.

General Cost Assumptions:

20. The cost assumptions for a (middle size) reserve of 64 million cubic metres (400 million barrels) are as follows:

Total investment for production facilities is about $1340 million (1983$) including a 40% contingency.

Drilling costs are based on 69 wells costing $21.6 million each including a 20 per cent contingency.

Operating costs run at about $120 million per year and sum in total to $1556 million over a 13 year lifetime.

Terminal facilities are roughly $350 million including a 40 per cent contingency.

5.3 The Minimum Economic Scale (MES)

In this analysis we are interested in determining the approximate minimum scale at which development of Beaufort oil breaks even, assuming that an oil discovery has been made and therefore that most exploration costs are sunk. We further seek to determine whether this minimum scale occurs under a tanker mode of transportation or pipeline. We are interested in the minimum scale at which discovered Beaufort Sea oil can be economically developed, produced, and delivered to Montreal.

The MES is given by the level of production for which the present value unit cost (levelized cost) exactly equals the present value unit selling price (levelized price). Since the level of production depends upon the reserve size the private MES can be described as the volume of reserve of oil required to recover capital, operating and transportation costs, pay royalties and taxes, and recover a defined return to the producer. The MES is a function of the present value unit cost and the present value selling price, and therefore it will vary over a range of discount rates.

The MES will also be dependent upon the price of oil, the cost of producing and delivering the oil and the rate at which the oil is produced. The MES should not be confused with the economically most efficient level of output nor with the profit maximizing level of output, two other concepts often used in economic analysis.

At the economically most efficient scale of output the per unit average cost of production is minimized and reserves availability is not considered a constraint. The determination of this cost minimizing scale is dependent upon most effective capacity utilization which would be with reserves larger than the MES, and it would not be constrained by the price of the final output. The profit maximizing level of output occurs where the incremental revenue received for an additional unit produced exactly equals the incremental cost incurred to produce that unit; again reserve availability is not viewed as a constraint.

There are a number of reasons why the MES is of interest. The determination of the MES yields an upper limit for each category of unit costs for the recovery of all development, production and transportation costs given a fixed selling price. An increase in any one category of costs causes the project to become uneconomic at that scale of development. The MES also aids in the determination of what size of oil pool would have to be discovered before development could economically proceed. If smaller scales of development turn out to be environmentally less risky, which may not in fact be the case, knowledge of the MES could reveal whether or not the smaller developments would be economically viable.[10] In addition the MES gives a sense of the riskiness of exploration, from an economic viewpoint, because generally one is more likely to discover smaller reserves than larger, even if the structures themselves are large.

5.3.1 Results of the MES Analysis

Dome Petroleum Ltd. has assisted in the determination of the MES for a general base case and for a number of variations on the base case as specified by the Economic Council of Canada's Energy Group. Given a set of assumptions on price, inflation, royalties, taxation and discount rates, Dome ran a number of oil production simulations in order to determine the level of output for which the levelized selling price equals the levelized supply price.

A private MES and a social MES are determined for the base case. The private MES is the level of output for which the levelized selling price equals the levelized supply price including all taxes and royalties. In the determination of the social MES, the levelized supply price excludes any taxes and royalties. The base case assumes that prices and costs remain flat in real terms. A detailed description of the base case is given in Appendix 2. The fiscal regime is described in Appendix 3.

Further iterations were performed to determine the MES under scenarios of increasing real prices and declining real prices.

The MES is assessed separately under assumptions of a marine transportation system and a pipeline transportation system.

The reserve sizes determined in the MES analysis are summarized in Table 1. The MES for the private and social base cases under both modes of transportation are given for real discount rates of 5, 10, and 15 per cent. The minimum reserve sizes under increasing real prices (5 per cent annually) and decreasing real prices (5 per cent annually) are calculated for the tanker scenario only, at a real rate of discount of 10 per cent.

For a single island development in the offshore, with water depths around 50 metres, the minimum economic scale of oil reserve is in the range of 35 to 55 million cubic metres, with a middle value of 44, with the present Canada Lands fiscal regime. The MES under the social case is 34 million cubic metres, at a 10 per cent discount rate. It is estimated that the pipeline alternative would require an MES some 15 per cent larger. Price has a marked effect on minimum economic scale. The 5 per cent annual price increase reduces the private MES by about 45 per cent from 44 to 24 million cubic metres, at the 10 per cent discount rate. Incidentally, all of the economic analyses are extremely sensitive to the price assumptions.

5.3.2 Commentary

Comparison of the pipeline and tanker scenarios suggest that the tanker system is more sensitive to the imposition of the fiscal regime than is the pipeline system. At a real rate of discount of 10 per cent for the tanker scenario, the increase in the MES resulting from the imposition of taxes and royalties is greater than it is under the pipeline scenario. At that rate of discount the private MES is about 29 per cent higher than the social MES for the tanker assumption. For the pipeline the difference is about 23 per cent.

There are a number of reasons for this including the fact that cost savings in the tanker alternative vis-a-vis the pipeline are partially negated by the more complete "ring-fencing" of the pipeline expenditures. This may be an area for modification in the fiscal regime. Another partial explanation is that in the pipeline scenario economies of scale are more apparent in the transportation system. A 400 mm pipeline is used for the social MES reserve size of 39 million cubic metres and for the private MES reserve size of 48 million cubic metres. This suggests increased capacity utilization and a falling transportation tariff to offset the increased costs imposed by taxes and royalties.

In the tanker scenario the increase in production required to determine a new MES after the imposition of taxes and royalties necessitates an additional tanker. One tanker is required for the social MES reserve size of 34 million cubic metres. However during peak production two tankers are required for the private MES reserve size of 44 million cubic metres. Accordingly the tanker tariff is higher for the larger reserve size and a larger increase in production is required to arrive at the private MES for the tanker scenario than for the pipeline. Despite this larger increase the private MES is smaller for the tanker scenario than the pipeline.

Emphasis in this single island development analysis is on offshore sites in middle to deep water depths. However Dome also provides estimates for the social and private MES for pipeline and tankers scenarios of inshore development sites in shallower water depths of about 20 metres.

The MES estimates for inshore water depths of around 20 metres, both the social and private cases under both transportation scenarios, are approximately 25 per cent lower than the estimated reserve sizes for the offshore deeper water sites. The lower minimum reserve sizes mainly reflect the lower costs of island construction and operation in shallower water. Island construction costs are directly related to water depths. In the pipeline scenario a further cost saving results from having sites located closer to shore which may reduce the size of the subsea pipeline network which delivers oil to the northern pipeline terminal.

Further analysis of the MES results will be carried out in the subsequent section on sensitivity tests.

5.4 The Potential for Low Cost Oil

The potential for low cost oil at a large scale of production is investigated in this section under what could be deemed as near "perfect" conditions. The conditions are such that adequate reserves are assumed to be available so that production is optimized and the unit average cost for producing and delivering oil to Montreal is minimized. While the probability of all aspects being favourable, i.e., geological, engineering, and project management etc., is small, the conditions examined are believed to be possible. The estimated supply price therefore puts a floor under alternative estimates.

The determination of this potential was also estimated by Dome Petroleum Ltd. The minimum supply price is that which corresponds to a pool size which provides sufficient throughput to capture all economics of scale, under an optimum cost environment. In this analysis all contingencies have been removed from the cost estimates and no taxes or royalties are considered.

The supply prices in the low cost scenario are calculated for a reserve size of 159 million cubic metres (1 billion barrels) for both the marine and a pipeline transportation assumptions. The supply price is calculated by adding the real dollar discounted unit cost of producing oil at the wellhead to the real dollar discounted unit transportation cost.

This minimum possible supply price, in 1983 dollars for oil delivered to Montreal by tanker is around $75 per cubic metre (11.90 per barrel), assuming a 10 per cent discount rate, as shown in Table 5. The supply price under a pipeline scenario is about $96 per cubic metre ($15 per barrel).

The tanker tariff makes up about 34 per cent of the real supply price at the 10 per cent discount rate. In the pipeline case the tariff accounts for 45 per cent of the supply price delivered to Montreal. Supply prices will be discussed further in Section 5.6.4.

The pipeline scenario in the large reserve case assumes a 600 mm buried pipeline with an average throughput of about 40,000 cubic metres (250,000 barrels) per day. The tanker scenario assumes a tanker fleet of 5 during peak production years with each tanker carrying about 8,200 cubic metres (52,000 barrels) per day.

The findings in this analysis support a conclusion made by Dome in the 1982 Senate Submission where it is suggested that at low and medium levels of throughput a tanker system yields a lower tariff than the pipeline alternative. It is suggested that this is the case for a throughput rate up to about 110,000 cubic metres (700,000 barrels) per day.[11]

5.5 The Canada Lands Fiscal Regime

The details of the system of royalties and taxation for petroleum activities in Canada Lands are given in Appendix 3. In general terms the regime consists of a federal income tax of 46 per cent, a petroleum and gas revenue tax which is effectively 12 per cent, a basic royalty on gross revenues of 10 per cent and a progressive incremental royalty (PIR) which is 40 per cent of net profits. Net profits are defined such that a royalty is only levied to the extent of net annual profit in excess of a 25 per cent floor rate of return. If in fact the predetermined rate of profitability is not achieved in a given year, the PIR would not be applied and only the basic royalty would be payable. There is a PIR holiday available in cases where the original oil and gas discovery was made prior to 1981 or where the discovery was declared significant prior to December 1982. In these cases the license holder is exempt from the PIR for 3 conscentive years. This is the standard Canada Lands fiscal regime assumed in the private base case.

There is an additional feature of the Canada Lands fiscal regime that allows the federal government to back-in with a 25 per cent working interest to any project on Canada Lands. The back-in can take place at the time that the development phase begins. The details of this provision are outlined in Appendix 3.

The Crown back-in has not been incorporated into the cashflows due to the uncertainty of the timing of the projects and the uncertainty of who exactly the participants in the various projects will be.

5.6 Economic Analysis

5.6.1 Introduction

This analysis examines the economics of various development scenarios for single island development projects. The economics are assessed with and without taxes and royalties and under various assumptions for price and the system of royalties and taxation. Fiscal regime, price, inflation, and cost of money assumptions are given in the Appendices.

Some key questions that are of importance in this analysis are; How feasible is small scale development in the Beaufort? What are the gains to be made through the operation of a very large scale development? What mode of transportation will be most efficient for delivering oil to the southern markets? Is the current system of taxation appropriate or does it tax inefficiently? Finally, what are the relative merits of the various fiscal measures within the Canada Lands fiscal regime?

5.6.2 Results: Rates of Return

The discounted cash flow (DCF) rates of return for all of the single island development scenarios are given in Tables 2 and 3. It should be noted that these returns relate to the investment in the development and production of oil and not the investment in transportation facilities. The wellhead price is obtained by netting the 1983 real dollar transportation tariff from the $40 price received for oil delivered in Montreal.

Base Cases

The rates of return for the social and private base cases are given in Table 2. The results reveal a broad range between a low real rate of return of 10 per cent and high real return of 50 per cent. The lowest real return of 9.9 per cent corresponds to the social MES under a tanker scenario and a reserve size of 34 million cubic metres. Recall that this reserve size was estimated to represent the social MES at a 10 per cent real rate of discount.

The highest real return of 50.2 per cent corresponds to the scenario of potential low cost oil. In this case the reserve size is almost 5 times that of the social MES. A tanker system of transportation is assumed and there are no taxes and royalties in this case.

The potential for low cost oil scenario under the assumption of a pipeline system of transportation generates a real rate of return that is about 7 percentage points lower than under the tanker assumption. As will be shown in a subsequent discussion of supply costs, this is owing to a higher pipeline tariff. Clearly the low cost oil cases show that Beaufort oil potentially may provide substantial economic rents, at present levels of world oil prices.

The imposition of the fiscal regime reduces the real rate of return by about 6 percentage points for the 64 million cubic metre reserve and the 48 million cubic metre reserve, from some 25 per cent to about 19 per cent and from some 15 per cent to about 9 per cent respectively, as shown in Table 2.

Sensitivity Tests

Sensitivity tests on the assumptions for price and the fiscal regime indicate the degree to which the project economics are preserved under changing conditions. Variations in the fiscal regime reveal the relative impacts of the fiscal measures that make up the regime. The sensitivity results are reported in Table 3 for a test case only. This is the 64 million cubic metre reserve size with tankers.

Base

The real rate of return in this case is 19 per cent. It is worth noting that in this base case the profitability of the project does not prompt the imposition of the Progressive Incremental Royalty (PIR) until near the end of the project. The base for this royalty as defined in Appendix 3 does not become positive until the second last year of the project. The overall royalty payment is marginally higher than it would be if only the Basic Royalty was collected.

No PIPs

The base case assumes full PIPS are available but in this sensitivity no PIP grants are paid to offset capital expenditures causing the real rate of return to fall 4 percentage points. PIPs are valuable to the company for this particular discovery. They are paid at the rate of 80 per cent towards exploration (delineation) in the earlier years and at rate of 20 per cent to intangible development expenditures. Delineation carried out from drillships in the first 3 years of the project is categorized as exploration therefore the present value worth of the 80 per cent PIP grants to the company is quite high. Because PIPS are reduced the PIR is not levied in this scenario and therefore a trade-off is affected, imposing heavier costs to the private sector earlier but lower costs towards the end of the production life.

It may be noted that PIPS are of most value to companies that are actively drilling wildcat exploration wells.

No Taxes or Royalties Until Payout, and No PIPS

In this case no royalties or taxes are paid until the cumulative cash flow becomes positive. This takes place during the ninth year. PIPs are excluded in this case. The real return falls 3 percentage points below the base case return primarily because of the absence of PIPs. However the real return is only 1 percentage point higher than the return earned in the case with no PIPs. Because payout occurs shortly after start-up (in the third year of production) there are only three years when the company is free from taxation.

No PGRT

The PGRT is levied at a rate of 12 per cent of net operating revenues and allows for no capital deductions. As a result, the impact of removing it is substantial. The real return in this case is 24 per cent, 5 percentage points above the base case return.

The profitability of the project in the absence of the PGRT, warrants the earlier imposition of the PIR. The PGRT is deductible from the PIR base of net profits. Without any PGRT deduction the PIR base becomes positive in the fourth year of production and the PIR is levied at that point in time and remains over the life of the project. The total royalty payment is 22 per cent higher in undiscounted terms than in the base case. The higher royalty payment serves to dampen the improvement gained in the absence of the PGRT, but overall the earlier imposition of the PIR seems a more robust fiscal arrangement.

PGRT Relief

PGRT relief as it is defined for Enhanced Oil Recovery projects in the April 1983 federal budget is granted in this case. The PGRT is not payable until payout when the accumulated value of the PGRT base becomes positive (PGRT base = Gross Revenues - Operating Costs - Capital Costs). At that point the PGRT equals 12 per cent of the PGRT base.

No PGRT is collected until the project begins to earn profits causing the real return to increase by more than 2 percentage points. The provision of capital deductibility for purposes of the PGRT makes the PGRT more akin to the profit sensitive PIR rather than the basic royalty.

The PIR in this case is imposed in the later few years of the project. At the time that it is levied capital expenditures are no longer being made. The overall royalty payment in undiscounted terms is about 5 per cent higher than in the base case.

No Basic Royalty

The 10 per cent royalty levied on gross revenues is removed in this case. The impact is virtually the same as the removal of the PGRT. The real return increases by slightly less than 5 percentage points. The PIR is levied in the fourth year of production, but there is a period of 3 years in the middle of the production period where no royalty is collected.

Increasing Real Prices

Wellhead prices increase at an annual real rate of 5 per cent in this case. While this assumption may appear to be unlikely it does attempt to bracket an extreme limit for a range of future oil prices which at best are clouded in uncertainty. The 5 per cent real increease is not presented as a forecase and should be considered as a tool that is used for analytical pruposes only in order to see how the fiscal regime performs. The impact of rising real prices is dampened by the resulting increases in the fuel cost component of the tanker tariff. The fuel cost component is roughly 15 per cent of the tanker tariff hence that portion of the tariff also increases in real terms.

The increased tanker tariff dampens the increase in the wellhead price. It is a lower wellhead price that is allowed to increase at 5 per cent in real terms than would be the case if the fuel component were ignored.

The real rate of return is about 10 percentage points higher than it is in the base case. When the fuel cost component is ignored and the tanker tariff remains unchanged the real return increases a further 1 to 2 percentage points. The profitability of the project warrants the levying of the PIR in the second year of production. The PIR is collected over the life of the project. The overall royalty payment is 15 per cent higher in undiscounted terms than in the base case.

The fact that the results do not go through the roof suggests that without drastic price changes the interacting and offsetting features of the fiscal regime and the changing fuel costs tend to mask the effect of rising prices. A lower real price increase was tested and the results fell between the base case results and the extreme case as would be expected.

Decreasing Real Prices

Declining real prices cause the real return to fall over 12 percentage points below the base case return. Two factors help to dampen this decline. As was the case in the rising price case, the fuel cost component affects the impact. In this case the fuel cost component of the tanker tariff falls in real terms causing the tanker tariff to fall. Therefore a higher wellhead price results and it is that wellhead price that declines in real terms.

A second factor that helps to dampen the impact of falling prices is the absence of the PIR. The profitability of the project is not high enough for the PIR to be levied on the project. The total royalty paid is exactly 10 per cent of total revenues, equal to the basic royalty.

The proportional decrease in the real return as prices fall is greater than the proportional increase under rising price. This suggests that the fiscal regime, because of the basic royalty, only cushions the private sector price risks in a limited way. This will also be seen in the discussion of net revenues.

Stand-Alone Taxation

In this final sensitivity the assumption that taxation is done on a full flow-through basis is removed. Under the full flow-through assumption of the base case the company is in a fully taxable position and is able to take advantage of all available tax deductions.

In this case taxation is done on a stand-alone basis. The company is assumed not to be in a taxable position at the time that the project expenditures begin meaning it has no external income in the pre-production years against which it can apply the available tax write-offs.

Under this assumption the project economics are diminished in comparison to the base case. The real return declines by nearly 3 percentage points suggesting that the present worth of the tax deductions in the early years is quite important to the company.

Conclusions to the Sensitivity Tests

The sensitivity tests help to reveal the relative impacts of various fiscal measures and price conditions. The findings suggest that under base case assumptions the project economics are affected significantly by the PGRT and the Basic Royalty. Changing real prices impact on the project returns quite heavily but the overall affect is dampened by corresponding changes in the fuel cost component of the transportation tariff and the PIR payments.

The PIR is designed to collect revenues only if a certain level of profitability is achieved. The PIR base is a check on the project's profitability. If the base is not positive the royalty is not levied. In cases where the PIR is levied throughout most of the project, the royalty payment is found to be significantly higher than would be the case if only the Basic Royalty is collected.

The analysis does not include a sensitivity on the capital costs however rising costs would impact directly on the cash flow and further effects would be felt through the PGRT and the Basic Royalty take. Capital costs are not deductible for the purposes of these measures therefore there is no protection offered in the case of rising capital costs. The proportion of total net revenues that is captured by the PGRT and the Basic Royalty increases as capital costs rise.

It must be stressed that this rate of return analysis should not be used to assess the <u>absolute</u> levels of return which may be realized by companies in the Beaufort Sea, but of most importance are the relative values of the returns under different development and economic assumptions. The technologies that are assumed are for the most part new, having limited or no historical performance data to draw from, and the reserviors production characteristics could differ substantially from those assumed. Cost figures and production profiles are also estimates which may in fact be altered as development proceeds and experience and information is gained. In any event the particular size and productivity of a reservoir will largely dictate its absolute level of profit ability.

5.6.3 Results: Net Revenue Shares

The share of each participant of present value net revenues serves as an indication of the effectiveness of the fiscal regime. The project net revenues, above a normal cost of money, also serve as an indication of potential economic rent that is available for distribution between the federal government and the company.[12] It must be cautioned, however, that this analysis deals essentially with the half cycle of delineation, development and production. All the preceeding exploration costs are ignored. Some of the present worth of the half cycle must be retained by the private sector in order to sustain exploration.

Base Case

As shown in Table 4, in the base case the federal government receives the largest share of the net revenues generated in the project. The government share increases as discount rates increase. The company share declines over the higher discount rates because its significant positive cash flows are received later in the project life, after the front end expenditures are made. The federal government foregoes tax and royalty collection in the pre-production years and allows tax writeoffs but relative to the companies investments and subsequent revenues the government gives away less in the earlier years.

Increasing Real Prices

When prices increase in real terms the net revenue shares are not significantly altered in comparison to the base case. The share of net revenues taken by the royalty which includes the PIR, remains about the same as the share taken in the base case. In the base case the PIR is collected only in the final two years however the impact of the PIR is minimal in that case. This increasing price case suggests that the PIR does not allow the federal government to collect a higher share of rents from more profitable projects but only maintain its share.

Decreasing Real Prices

Under declining real prices the company's share is vastly diminished. At real discount rates over 7 per cent the company incurs losses while the government collects positive revenues. Regardless of the project's profitability the government will always be able to collect revenues through its Basic Royalty on gross revenues and the PGRT, although in the circumstances they would have to be waved or reduced by the minister if companies are to continue their activities.

Conclusions

The rigidity of some aspects of the fiscal system appears to offer little protection to the company's share of net revenues under worsening economic conditions. While the structure of the PIR is efficient to the extent that it is only levied if a certain level of profitability is achieved, profitability is not a factor which determines the collection of the PGRT and the basic royalty. Under worsening conditions the PGRT is very damaging to the company's share even in the absence of the PIR.

Under more favourable conditions of increasing real prices the fiscal regime does not appear to capture a larger share of the net revenues. This may be a reasonable design feature bearing in mind that the analysis deals essentially with the half cycle under conditions of extreme uncertainty in exploration. The PIR is the only mechanism (aside from the income tax) in the regime that is responsive to the project's profitability. However its efficiency is undone by the Basic Royalty and PGRT; its ability to capture a growing portion of excess profits is hampered by the deduction of the Basic Royalty and the PGRT. A combination of the PIR and a modified PGRT relief would perhaps be more symmetrically responsive to the project's profitability. This suggests that a replacement of the PGRT by PIR that would be based on a lower profit floor and imposed at an earlier time would be efficient for the frontier.

5.6.4 Results: Supply Costs

The real dollar supply cost ("supply price") to produce a cubic metre of crude oil from a project is given by the total discounted real cost divided by the total discounted production. From society's point of view, the supply cost of a cubic metre of oil ignores taxes and royalties. The supply costs for the base cases at a real discount rate of 10 per cent are given in Table 5. The supply costs at Montreal are broken down to show the wellhead component and the transportation component. The supply costs delivered to Montreal are shown over a range of discount rates in Appendix 4.

In the context of the foregoing discussion of net revenue shares, it should be noted that the difference between the real supply cost without taxes and royalties and the real price received is an indication of the amount of half cycle economic rent that is available for distribution between the owner's of the resource and the company.

Development scenarios whose reserve sizes correspond to the MES at a 10 per cent real discount rate should in fact have supply costs that equal the \$252 per cubic metre (\$40 per barrel) price for oil delivered at Montreal. These cases are; the social case 34 million cubic metre reserve with tankers, the private case 44 million cubic metre reserve with tankers and the private case 48 million cubic metre reserve with a pipeline. In all of the MES cases the supply cost is approximately \$252 per cubic metre (\$40 per barrel) in 1983 dollars. In these social cases there is no economic rent. The projects just break even, that is to say that they just earn 10 per cent real return on the funds invested.

As reserve sizes expand above the MES levels, the supply costs per cubic metre to deliver oil to Montreal fall. This can be seen by comparing the two private cases of 44 and 64 million cubic metres with the tanker system, or the three social cases of 34, 64 and 159 million cubic metres with tankers.

Looking at the transportation tariffs separately an increased reserve size and increased throughput generally causes the tariff to decrease. This is not always the case however for relatively small changes in reserves and production throughput because an additional tanker may be needed that would not be used at capacity. We note that the transportation systems are not assumed to be optimized.

5.7 Conclusions to the Single Island Development Analysis

1. What is most important in the economic analysis of the single island projects is the approximate range of reserve sizes that may potentially be developed and under what conditions rather than the absolute reserve sizes. Further, it is the relative impact of various changes in conditions that is of importance rather than the absolute impact or the absolute returns generated by the example development projects.

2. The MES for both the private and social cases is smaller under a marine mode of transportation than a pipeline mode.

3. The range of reserve sizes for which development remains economic without taxes and royalties goes down to about 34 million cubic metres which is the esimated minimum economic scale, assuming a 10 per cent discount rate.

4. The sensitivity tests reveal that the PGRT and the basic royalty affect the project economics significantly.

5. Given the conditions set in the base case for the single island development projects, the fiscal regime does not capture an increasing share of economic rents generated

under improved conditions. It does however, through the PIR, maintain most of the government's share. The downside risk to the company is aggravated by the PGRT and basic royalty.

6 MULTI-ISLAND DEVELOPMENT PROJECT

6.1 Introduction

In this section we describe a multi-island development project for a 100 million cubic metre reserve size. The field is located in a water depth of about 20 metres. The economics of the development are assessed under a pipeline system of transportation. Only one development scenario is examined in this section.

The intent of this analysis is to examine the economics of developing a shallow field requiring the construction of 5 production islands.

The results of the multi-island and single island analyses are not directly comparable. The assumed reservoir parametres in the two cases are different therefore the cost data and the production profiles that are used in the multi-island analysis are not the same as those used in the foregoing single island analysis.

6.1.1 Island Requirements

The number of islands that are required for commercial production in the offshore is driven by the geometry of the reservoir. In the Beaufort Sea drilling takes place from single surface locations and is done directionally. Directional drilling can allow oil to be accessed up to a distance of about 5 kilometres from the drilling platform.

The reach of the wells drilled directionally from a production island will in part be determined by the reservoir depth. As discussed in Section 3.3, directionally drilled wells are drilled at an angle that deviates from the encasement that extends vertically below the wellhead. The deviation from the vertical can be as great as 60 degrees.[13] Thus the deeper the reservoir is the greater the horizontal reach can be. The ease with which oil can be accessed from a single surface location declines as the depth of reservoir declines.

The assumed reservoir in the multi-island analysis is long and narrow in shape (approximately 32 km x 3 km). Its depth is less than half that of the reservoir assumed in the single island case. The assumed reservoir parametres are such in the multi-island case that only 20 million cubic metres of oil are producible from a single production island therefore 5 islands are required to produce the 100 million cubic metre reserve. However in the single island base case 64 million cubic metres of oil are producible from a single production island given the reservoir parametres. Therefore only one island is required for the reserve size.

The economics of offshore projects in the Beaufort will read very differently depending upon the development requirements. The geometry of the reservoir under development will determine the location of islands and the number of islands required. The island requirements will be a major determinant of the cost structures of the developments. While the results of the single island and multi-islands scenarios examined in this paper may not be directly comparable due to differences in the technical assumptions general conclusions can be reached as to the impact of the reservoir geometry and the development requirements on the economics of offshore oil production in the Beaufort Sea.

The economic assessment of the multi-island development involves a cash flow analysis of the project and sensitivity tests on the project economics.

6.2 Cost Structure and Production Profile

The development scenario corresponds to the first shallow field that is described in the EIS,[14] but it has been altered somewhat, principally in that the timing for the development has been set back 6 years to reflect changing perceptions of possible start-up dates.

The following assumptions apply to the multi-island development scenario:

1. The analysis begins at a time when the decision is made to proceed with development. Expenditures begin in 1991 however for discounting and deflation purposes the start year is 1983.

2. Once the decision to develop is made in 1991 further delineation is done until 1993. Expenditures prior to 1991 are ignored.

3. Five production islands are built with the construction of the first beginning in 1991. Capital expenditures for production facilities begin in 1991 and continue to 1995. Capital expenditures for the gathering system are incurred between 1991 and 1995.

4. The project life (from time of first expenditures) is 20 years terminating in 2010. Production starts in 1992.

5. The reserve size is 100 million cubic metres (630 million barrels). The assumed recoverable reserves per island are 20 million cubic metres (126 million barrels).

6. The water depth is about 20 metres and the depth of the reservoir is shallow (less than 1500 metres).

7. Two drilling rigs are used per production island. Each rig drills 8 wells per year. A total of 80 wells are drilled in the 8 years of the development phase.

Transportation Assumptions:

8. The transportation system is a pipeline which delivers oil to Montreal. The average peak production throughput is about 22,000 cubic metres (140,000 barrels) per day.

9. The transportation tariff is $38.32 per cubic metre ($6.09 per barrel) in 1983$ over the life of the project.

10. The wellhead price is determined by netting the 1983 real dollar transportation tariff from the assumed delivered at Montreal price of $40 (1983$).

General Cost Assumptions:

11. Total capital costs for production islands are about $1500 million (1983$).

12. Total expenditure for development wells is approximately $2000 million (1983$).

13. Operating costs are in total about $6100 million (1983$). In the last 10 years of production operating costs are about $360 million annually (1983$).

14. Total capital costs for the production facilities are about $3780 million (1983).

15. Total capital costs for the gathering system are $250 (1983$).

16. Total capital costs are about $7800 million (1983$).

Commentary

While stressing that the costs for the single island and multi-island developments are not directly comparable, there are a few general comments that can be made. Capital expenditures for similar scales of development will be much higher in the multi-island case simply because 4 additional islands are being constructed. Because of the additional islands the number of rigs and wells can be expanded which calls for higher drilling expenditures. Operating expenditures will also be higher than those that would be made for a similar development with one island.

6.3 Economic Analysis

6.3.1 Introduction

This analysis examines the economics of the multi-island development project under various price conditions and fiscal terms. The economics are assessed with and without taxes and royalties. The detailed assumptions for the fiscal regime, prices, inflation and cost of money are those used in the single island analysis and are given in the Appendices.

The key questions that are of importance in this analysis are; How does the current system of taxes and royalties affect the economics of the project? Is that system appropriate and does it tax efficiently? Finally, what are the relative merits of the various fiscal measures within the Canada Lands fiscal regime.

As in the preceding single island analysis it is important to stress that it is the relative impacts of changing price conditions and fiscal terms that are of importance rather than the absolute supply costs incurred or the absolute returns earned. The technologies that are being used are for the most part new technologies that have limited or no historical data to draw from. Cost figures and the production profiles that are used are estimates which may in fact be altered as development proceeds and experience and information is gained.

6.3.2 The Canada Lands Fiscal Regime

The details of the system of royalties and taxation for petroleum activities in the Canada Lands is outlined in Section 5.5 and detailed in Appendix 3. The same fiscal regime is assumed here.

6.3.3 Results: Rates of Return

The discounted cashflow (DCF) returns for the multi-island case are given in Table 6 and 7. The returns are generated by the company's cashflow based on field costs for the development and production of oil at the wellhead and the wellhead price received. The wellhead price is obtained by netting the 1983 real dollar transportation tariff from the $40 price received for oil delivered in Montreal.

Base Case

The returns earned by the private and social base cases are given in Table 6. The results reveal that the project economics are poor given the base case assumptions. The real return earned in the social case where no taxes or royalties are imposed is just over 10 per cent, i.e., no economic rent exists. In the private case the real return is 3.7 per cent. The imposition of the fiscal regime impacts heavily on the project economics causing the real return to fall by more than 6 percentage points. Evidently the fiscal system over-reaches its purpose because taxes and royalties are collected although the private sector return earns less than a normal profit on investment.

Sensitivity Tests

The degree to which various fiscal measures affect the project economics can be revealed through sensitivity testing. The sensitivity tests are carried out on the assumptions for price and the fiscal regime. Sensitivity analysis also reveals the degree to which the project economics are preserved under changing conditions. The results of the analysis are reported in Table 7.

Base

Variation in the base case real return of 3.7 per cent to the private sector as assumptions are changed, reveal the impact of those assumptions on the project economics. In the base case the profitability of project is not great enough to prompt the imposition of the Progressive Incremental Royalty (PIR) - a desirable feature. The 10 per cent basic royalty is the only royalty paid throughout the life of the project.

No PIPs

In the base case PIP grants are paid at a rate of 80 per cent towards exploration expenditures (delineation) in the first 3 years of the project and 20 per cent towards intangible development expenditures. However in this case no PIPs are earned causing the real return to decrease by just under 2 percentage points. The economics of the project are diminished further.

Again, only the Basic Royalty is payable throughout the project as the level of profitability is not high enough for the PIR to be levied.

No Taxes or Royalties Until After Payout

The base case is altered in this case such that no taxes or royalties are levied until the cumulative cash flow becomes positive. This takes place during the ninth year after production start-up. The real return increases to over 8 per cent with the 9 year tax and royalty holiday. In this case it is assumed that the project is only taxed from the point in time at which it becomes profitable. Only the Basic Royalty is payable in this case.

No PGRT

The effect of removing the PGRT is quite significant. The real return increases to just under 8 per cent, 4 percentage points above the base case return. The PGRT is levied at an effective rate of 12 per cent on net operating revenues. No capital deductions are allowed.

The project's profitability improves in this case but not to the point that the PIR is levied.

PGRT Relief

PGRT relief as it is defined in Section 5.2 is tested in this case.

The absence of PGRT until profits are generated causes the real return to increase by more than 2.5 percentage points to over 6 per cent. The provision of capital deductibility for the purposes of PGRT lessens the similarity between the tax and a royalty on revenues.

The revised PGRT improves the project economics although they still remain poor. The PIR is not levied in this case.

No Basic Royalty

In the absence of the 10 per cent Basic Royalty on revenues the real return increases to over 8 per cent. The impact of the Basic Royalty is very similar to the PGRT in terms of the overall economics of the project. In the absence of this royalty, no royalty is collected over the project life.

Increasing Real Prices

Wellhead prices increase at an annual real rate of 5 per cent which significantly improves the project. The explanation for this price sensitivity is given in Section 5.6.2. The real return is about 21 per cent, an increase of about 17 percentage points. Six years before the project's termination the project's profitability is such that the PIR is levied and is payable for the remaining years.

With the imposition of the PIR the total royalty payment in undiscounted terms is about 30 per cent higher than would be the case if only the Basic Royalty was payable over the project's life. The imposition of the PIR dampens the increase in net revenues to the company through rising real prices.

Decreasing Real Prices

In this case of declining real prices few conclusions can be drawn except that the economics are severely diminished, and investments do not give any positive rate of return.

Stand-Alone Taxation

In this final sensitivity taxation is no longer assumed to be done on a full flow-through basis. The full flow-through assumption of the base case considers that the company is in a fully taxable position and is able to take full advantage of all available tax deductions.

The company is assumed to be a stand-alone corporation in this case. The company is not in a taxable position at the time that project expenditures begin. This means that the company has no external income in the pre-production years against which it can apply the available tax write-offs.

The project economics are diminished under this assumption in comparison to the base case. The real return is reduced to about 2 per cent suggesting that the present worth of the tax deductions in the early years is quite important to the firm.

Conclusions to the Sensitivity Tests

The relative impacts of various fiscal measures and price conditions are revealed in the sensitivity tests. The findings suggest that under the base case assumptions the project economics are affected significantly by the PGRT and the Basic Royalty. Changing real prices affect the project economics significantly. There is some upside potential to the company under rising real prices however it is dampened to some degree by the levying of the PIR. When the PIR is levied the royalty payment under rising real prices is significantly higher than would be the case if only the Basic Royalty is payable. Under falling real prices the economics of the project are greatly diminished.

We stress again that it is not the absolute values of the return earned in the project that is of most importance but rather the relative returns earned under changing conditions.

6.3.4 Results: Net Revenue Shares

The present value share of the net revenues collected by each participant gives an indication of the effectiveness of the fiscal terms and especially whether government take is closely related to the realized economic rent. Net revenues are defined as total revenues less operating and capital expenses. They serve as an indication of the economic rent that is available for distribution between the company and the federal government.

The present value net revenue shares for the multi-island case are shown in Table 8.

Base Case

With each of the discount rates the federal government earns positive revenues because it is able to collect the PGRT and the Basic Royalty regardless of the project's profitability level. In fact the company incurs losses in the base case over all discount rates presented in Table 8.

Furthermore the share collected by the federal government increases over higher discount rates while the company experiences growing losses over higher rates. The company's gains are made later on in the project after the front-end expenditures are made, production has begun and positive cash flows begin.

It is of interest to note that the Basic Royalty levied on gross revenues (the only royalty paid in the base case) captures 252 per cent of the available net revenues at a 10 per cent real discount rate. The PGRT captures 220 per cent and the income tax captures 50 per cent.

Increasing Real Prices

Under increasing real prices net revenues are somewhat more evenly distributed in comparison to the base case. The company earns a positive share of revenues over all discount rates. Similar to the base case, the federal government's share increases over higher discount rates.

In this case the total royalty payment captures 20 per cent of the available net revenues at a 10 per cent real discount rate. The PGRT and the federal income tax capture 19 and 37 per cent respectively.

The share distribution is greatly affected by the fact that under increasing prices net revenues are a much greater proportion of gross revenues than in the case in the base case. As a result, fiscal measures that are based on gross revenues or even net operating revenues are much less damaging to the company's share than is the case under the base case assumptions.

However, a more efficient system of taxation would be one that would be able to capture increasing rents generated under more favourable conditions while attempting to preserve the project economics under less favourable conditions.

Decreasing Real Prices

The economics are such under declining real prices that positive net revenues are not earned over the reported range of discount rates. The government incurs losses because its royalty and PGRT collections are not great enough to offset the negative federal income tax collection. The government's losses are less than half of those incurred by the company.

Conclusions

The fiscal regime appears to offer little in the way of protection to the company's share of net revenues under worsening economic conditions. The structure of the PIR is efficient to the extent that it is levied only if a certain level of profitability is achieved. However profitability is not a factor which determines the PGRT. Revenue based measures such as the Basic Royalty and the PGRT can be very damaging to company shares even in the absence of the PIR.

6.3.5 Results: Supply Costs

The real dollar supply cost to produce a cubic metre of crude oil from a project is given by the total discounted real cost divided by total discounted production. This measure is also called the "supply price".

From society's point of view, the supply cost of producing crude oil ignores taxes and royalties. In this analysis a distinction is made between the social supply cost and the private supply cost which does include taxes and royalties.

The 1983 dollar supply costs for oil delivered to Montreal are given in Table 9 discounted at a real rate of 10 per cent. The wellhead component and the pipeline transportation component are also shown in this table. The delivered costs over a range of discount rates are shown in Appendix 5.

The difference between the discounted selling price and the discounted social supply costs gives an indication of the amount of half cycle economic rents that are available for distribution. In the social case supply cost is slightly below the selling price at a real discount rate of 10 per cent indicating that the project generates a small amount of rent. Recall that the real social rate of return is 10.6 per cent. In fact this scale of reserves, some 100 million cubic metres, is approximately the minimum economic scale for multi-island development.

Once taxes and royalties are imposed the supply cost delivered at Montreal is well above the $252 per cubic metre ($40 per barrel) selling price. In the social case the pipeline tariff is about 16 per cent of the delivered cost. In the private case it is about 14 per cent.

6.4 Conclusions Multi-Island Development Analysis

1. The economic analysis of the Multi-Island Development suggests that the economics of the project are poor under the base case assumptions. However the relative impacts that changing price and fiscal conditions have on the project tell us more than the absolute returns earned. The cost structures and production profiles are to some extent still speculative.

2. The multi-island development results are not directly comparable to the single island analysis because

differences may exist in their technical assumptions and hence in the assumptions for cost and production potential.

3. Although the reserve size used in the multi-island analysis does not correspond exactly to the single island cases some general comparisons can be made. Additional islands significantly increase the capital expenditures that are required as do the increased number of drilling rigs and wells accommodated by the additional islands.

4. The decision to construct a multi-island production system suggests that the reservoir parameters are such that there is insufficient oil within the area that can be reached from the platform to justify commercial production from one island.

5. The sensitivity tests reveal that the royalties and PGRT affect the project economics significantly.

6. From the company's point of view there appears to be some upside potential, under improved conditions such as increasing prices. However, under less favourable conditions the downside risk is high.

7 TABLES

Table 1

Minimum Economic Scale Reserve Sizes[1]
in millions of cubic metres (in millions of barrels)

Transportation	Real Discount Rate	Mimimum Economic Scale[2] Social Case	Mimimum Economic Scale[2] Private Case
Base Case			
Tanker	5%	28 (175)	35 (220)
	10%	34 (215)	44 (275)
	15%	43 (270)	55 (345)
Pipeline	5%	32 (220)	45 (280)
	10%	39 (245)	48 (300)
	15%	46 (290)	56 (350)
Increasing Real Prices			
Tanker	10%	-	24 (150)
Decreasing Real Prices			
Tanker	10%	-	75 (475)

1 As calculated by Dome Petroleum Ltd.

2 In the private case full taxes and royalties are imposed. In the social case no fiscal regime is included.

Table 2

Rates of Return - Base Cases

Case	Nominal	Real
Single Island Development Projects	Return %	Return %
1. 34 million cubic metre reserve: social MES, tanker (no taxes or royalties)	17.1	9.9
2. 44 million cubic metre reserve: private MES, tanker (full taxes and royalties)	16.3	9.2
3. 64 million cubic metre reserve: social, tanker (no taxes or royalties)	33.6	25.1
4. 64 million cubic metre reserve: private, tanker (full taxes and royalties)	27.1	19.2
5. 159 million cubic metre reserve: potential for low cost oil, tanker (no taxes or royalties)	60.6	50.2
6. 48 million cubic metre reserve: social, pipeline (no taxes or royalties)	22.0	14.6
7. 48 million cubic metre reserve: private MES, pipeline (full taxes and royalties)	15.7	8.7
8. 159 million cubic metre reserve: potential for low cost oil, pipeline (no taxes or royalties)	53.0	43.0

Table 3

Rates of Return - Sensitivity Tests

Case	Nominal	Real
Single Island Development Projects	Return	Return
1. 64 million cubic metre reserve: private, tanker		
1.1 Base (full taxes and royalties, with full PIPs)	27.1	19.2
1.2 No PIPs	22.8	15.2
1.3 PIPs reversed	28.0	20.0
1.4 No PIPs, no taxes or royalties until payout	23.8	16.1
1.5 No PGRT	32.5	24.2
1.6 PGRT Relief	29.7	21.6
1.7 No Basic Royalty	32.2	23.9
1.8 Prices Increasing (5 per cent real per year)	37.1	28.6
1.9 Prices Decreasing (5 per cent real per year)	14.0	6.9
1.10 Base Case Done on a Stand-Alone Basis	24.2	16.5

Table 4

Present Value Net Revenue Shares: Single Island Developments
in millions of 1983 dollars (per cent of total)

Real Discount Rate	Total Net Revenue	Federal Government	Company
64 million cubic metre reserve, full taxes and royalties, PIPs, tanker			
5%	4555 (100%)	2938 (65%)	1617 (35%)
7%	3475 (100%)	2294 (66%)	1181 (34%)
10%	2298 (100%)	1584 (69%)	714 (31%)
15%	1098 (100%)	846 (77%)	252 (23%)
increasing real prices			
5%	10074 (100%)	6604 (66%)	3469 (34%)
7%	7864 (100%)	5204 (66%)	2660 (34%)
10%	5452 (100%)	3670 (67%)	1782 (33%)
15%	2978 (100%)	2084 (70%)	894 (30%)
decreasing real prices			
5%	1215 (100%)	1038 (85%)	178 (15%)
7%	795 (100%)	769 (97%)	26 (3%)
10%	346 (100%)	474 (137%)	-128 (-37%)
15%	-91 (100%)	170* (-187%)	-261 (287%)

* Note that when total net revenues are negative, a negative share percentage indicates that the party did not incur a portion of the loss: i.e., this is the case for the federal government at the 15% discount rate under falling prices.

Table 5

Supply Costs - Base Cases
in 1983 dollars per cubic metre (per barrel)

Case	Real Rate of Discount	Supply Cost at the Wellhead	Transportation Tariff	Supply Cost Delivered to Montreal
Single Island			+	=
1. 34 million m^3, social, tanker	10%	224.00(35.60)	25.80(4.10)	249.83(39.70)
2. 44 million m^3, private, tanker	10%	216.00(34.33)	36.60(5.85)	252.60(40.18)
3. 64 million m^3, social, tanker	10%	119.25(18.95)	27.05(4.30)	146.31(23.25)
4. 64 million m^3, private, tanker	10%	192.00(30.51)	27.05(4.30)	219.00(34.78)
5. 159 million m^3, social, tanker	10%	49.71 (7.90)	25.17(4.00)	74.88(11.90)
6. 48 million m^3, social, tanker	10%	162.48(25.82)	50.39(8.00)	212.82(33.82)
7. 48 million m^3, private, pipeline	10%	205.34(32.63)	50.34(8.00)	255.72(40.63)
8. 159 million m^3, social, pipeline	10%	53.49 (8.50)	43.36(6.90)	96.91(15.40)

Table 6

Rates of Return - Base Case

Case	Nominal	Real
Multi-Island Development Projects	Return	Return
1. 100 million cubic metre reserves: social, pipeline (no taxes or royalties)	17.2	10.6
2. 100 million cubic metre reserve: private, pipeline (full taxes and royalties, full PIPs)	9.8	3.7

Table 7

Rates of Return - Sensitivity Tests

Case Multi-Island Development Projects	Nominal Return	Real Return
100 million cubic metre reserve: private, pipeline		
1.1 Base (full taxes and royalties, full PIPs)	9.8	3.7
1.2 No PIPs	8.2	2.1
1.3 PIPs reversed	14.1	7.6
1.4 No PIPs, no taxes or royalties until payout	14.7	8.3
1.5 No PGRT	14.3	7.88
1.6 PGRT Relief	12.4	6.04
1.7 No Basic Royalty	14.9	8.5
1.8 Prices Increasing (5 per cent real per year)	28.1	20.8
1.9 Prices Decreasing (5 per cent real per year)	NS	NS
1.10 Base Case Done on a Stand-Alone Basis	8.5	2.43

NS - No Solution

Table 8

Net Revenue Shares: Multi-Island Development
in millions of 1983 dollars (per cent of total)

Real Discount Rate	Total Net Revenue	Federal Government	Company
100 million cubic metre reserve, full taxes and royalties, No PIPs, pipeline			
5%	1676 (100%)	1860 (111%)	-184 (-11%)
7%	862 (100%)	1245 (144%)	-383 (-44%)
10%	165 (100%)	674 (408%)	-509 (-308%)
15%	-282 (100%)	221* (-78%)	-504 (178%)
increasing real prices			
5%	13067 (100%)	8743 (67%)	4325 (33%)
7%	8988 (100%)	6124 (68%)	2864 (32%)
10%	5170 (100%)	3653 (71%)	1517 (29%)
15%	2070 (100%)	1605 (77%)	466 (23%)
decreasing real prices			
5%	-3294 (100%)	-948 (29%)	-2346 (71%)
7%	-2742 (100%)	-791 (29%)	-1951 (71%)
10%	-2106 (100%)	-610 (29%)	-1497 (71%)
15%	-1388 (100%)	-403 (29%)	-985 (71%)

* Note that when total net revenues are negative, a negative share percentage indicates that the party did not incur a portion of the loss: i.e., this is the case in the base case at a 15% discount rate.

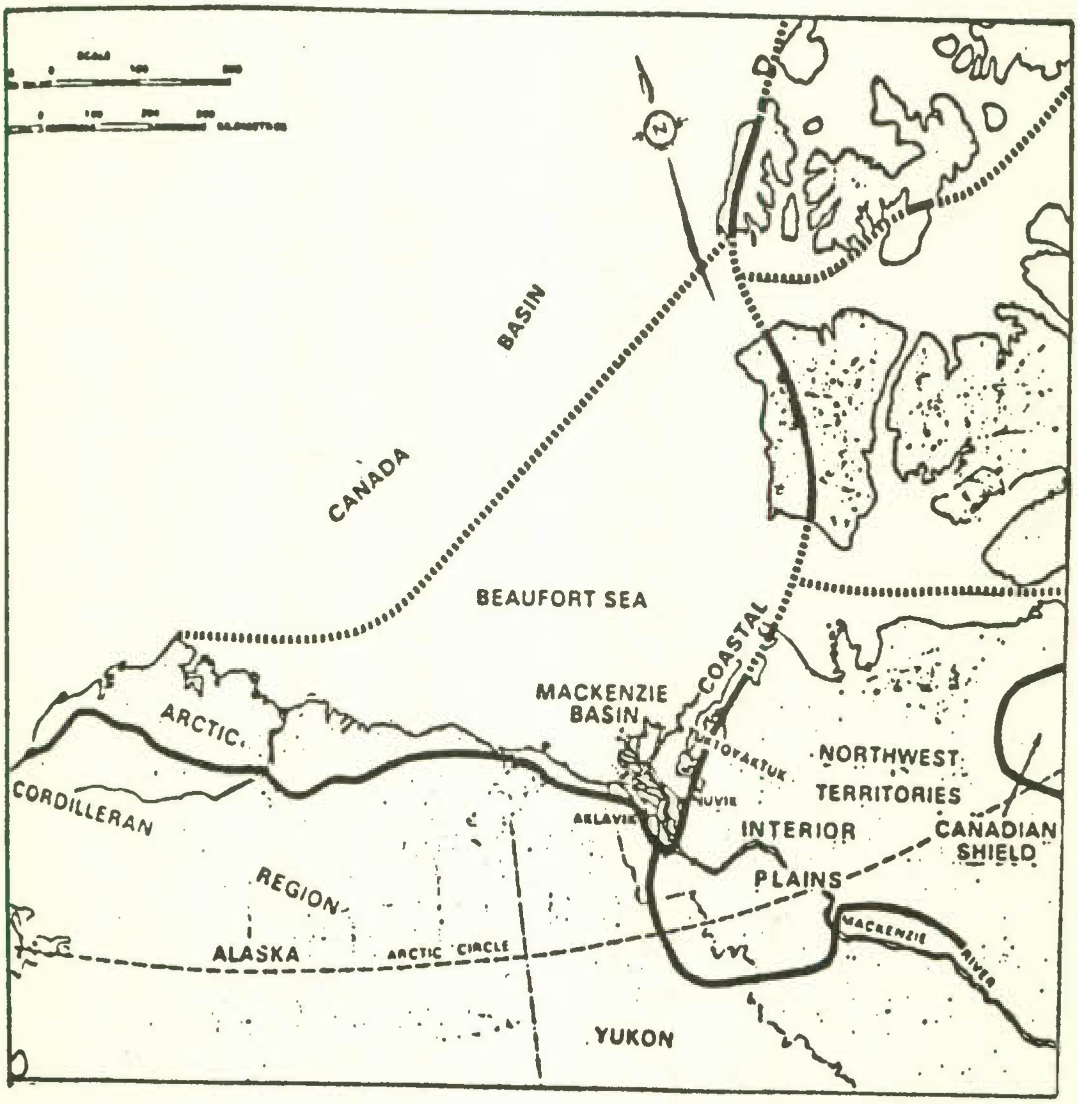
Table 9

Supply Costs - Base Cases
in 1983 dollars per cubic metre (per barrel)

Case	Real Rate of Discount	Supply Cost at the Wellhead	Transportation Tariff	Supply Cost Delivered to Montreal
Multi-Island			+	=
9. 100 million m^3, social, pipeline	10%	204.96(32.57)	38.38(6.10)	243.53(38.67)
10. 100 million m^3, private, pipeline	10%	239.45(38.05)	38.38(6.10)	277.83(44.15)

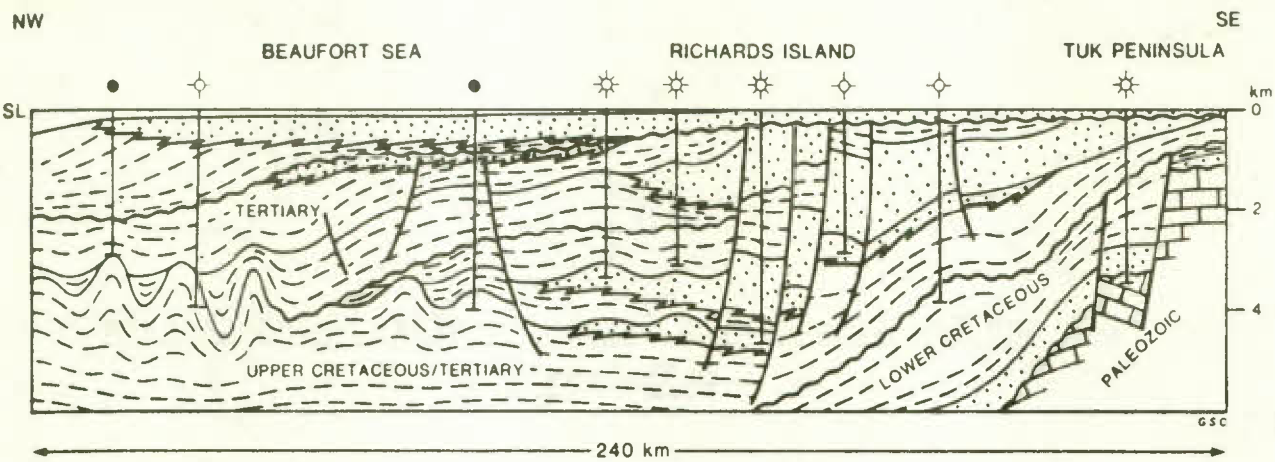
Figure 1

The Beaufort Sea-Mackenzie Delta Basin

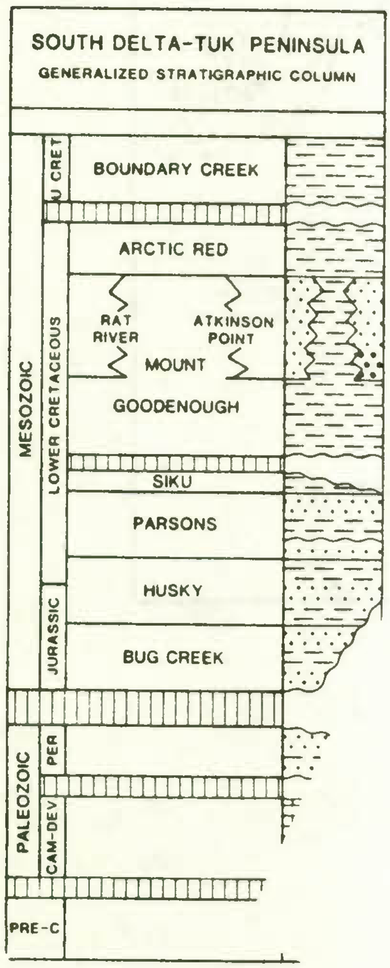


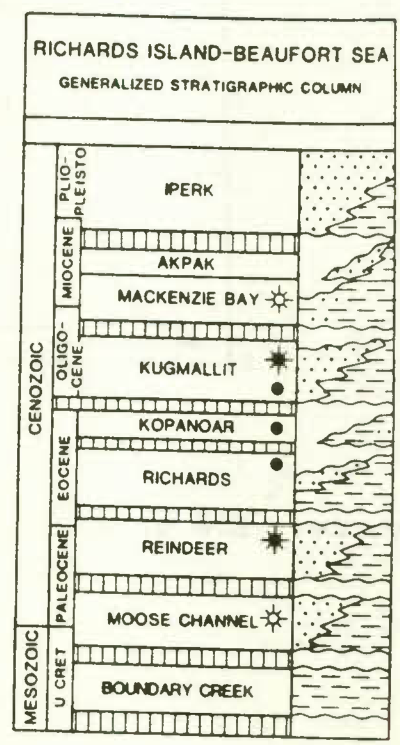
Source: EIS p. 2.3

Figure 2



Schematic stratigraphic relationships, Beaufort Sea-Mackenzie Delta

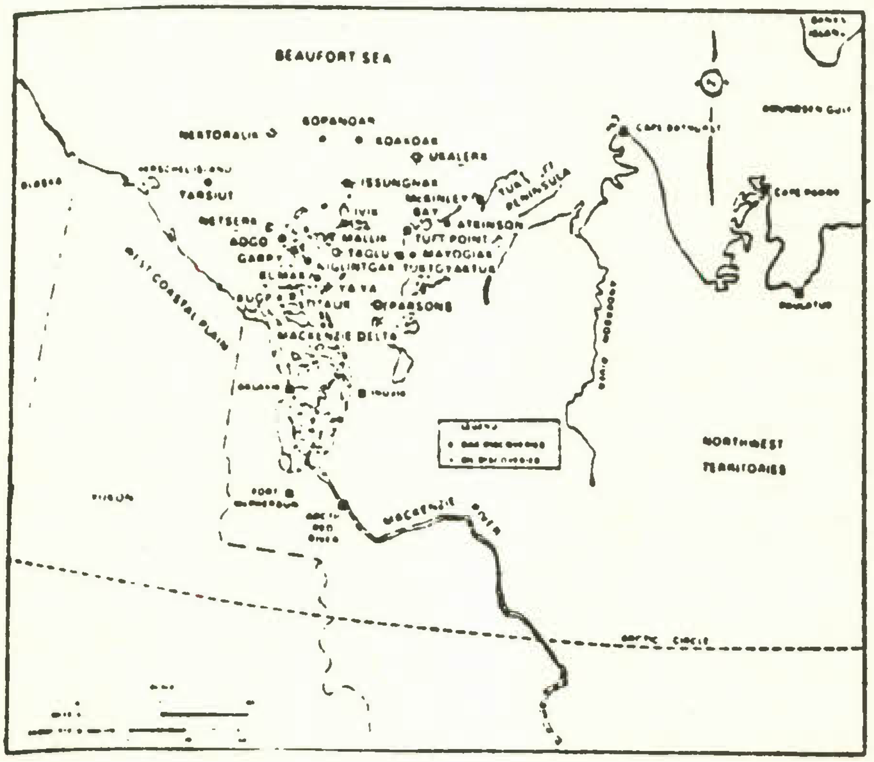




Source: Geological Survey of Canada

Figure 3

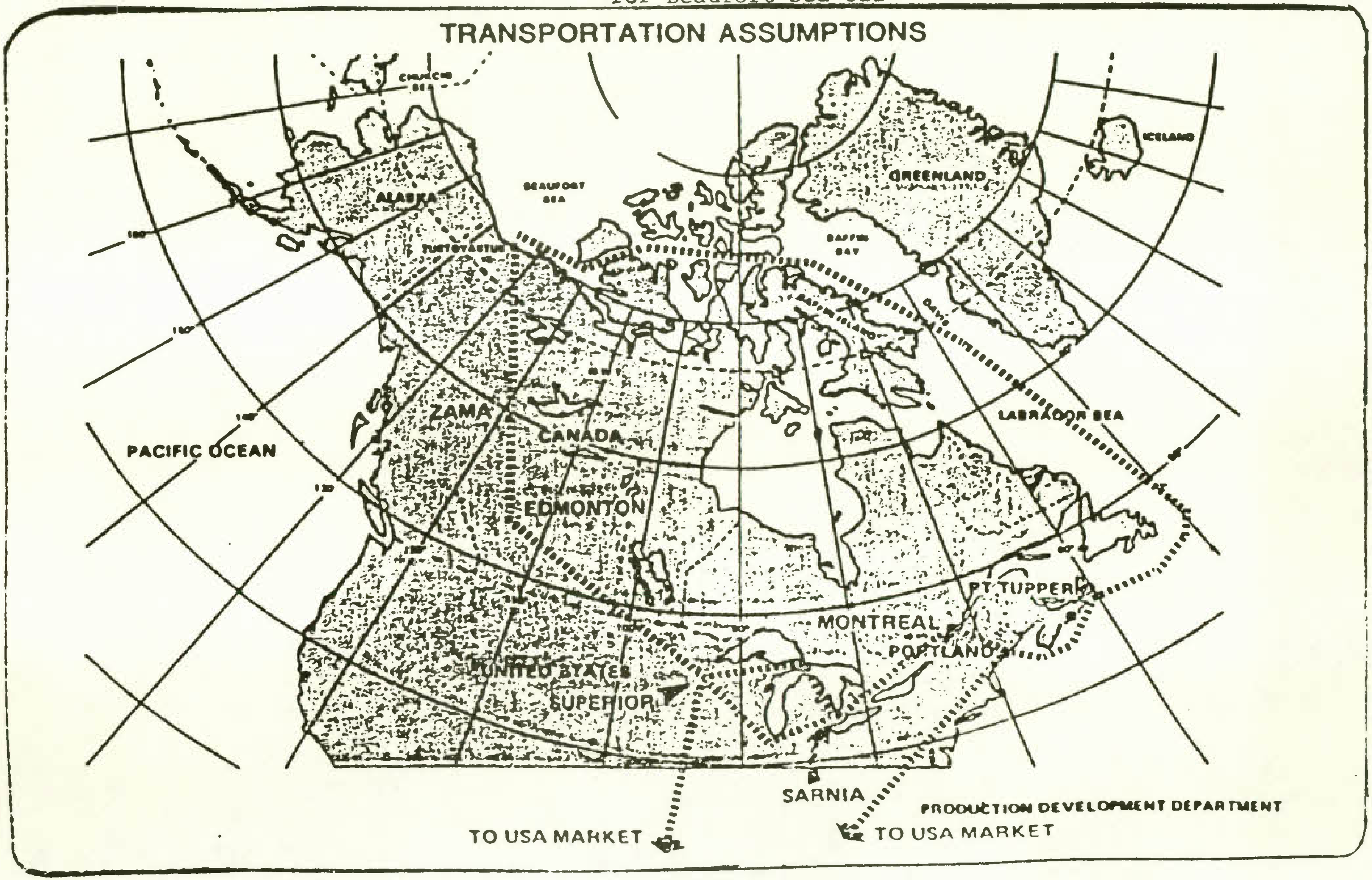
<u>Oil and Gas Discoveries in the Beaufort Sea-Mackenzie Delta Basin</u>



Source: EIS p. 3.21

Figure 4

Pipeline and Tanker Transportation Routes for Beaufort Sea Oil



Source: Dome Petroleum Ltd., Calgary

APPENDIX 1

Project Descriptions for Single Island Developments

1.	Case:	Social Minimum Economic Scale (MES)
	Field Type:	Offshore
	Reserve Size:	34 million cubic metres (215 million barrels)
	Transportation:	Single tanker over project life carrying 9,000 cubic metres per day at peak production
	Total Operating Costs:	$1,500
	Total Capital Costs:	$3,600
2.	Case:	Private MES
	Field Type:	Offshore
	Reserve Size:	44 million cubic metres (275 million barrels)
	Transportation:	Two tankers used over peak production years each carrying on average 6,000 cubic metres per day
	Total Operating Costs:	$1,550
	Total Capital Costs:	$3,600
3.	Case:	Sensitivity Case (social and private)
	Field Type:	Offshore
	Reserve Size:	64 million cubic metres (400 million barrels)
	Transportation:	Two tankers used over peak production years each carrying on average 8,000 cubic metres per day
	Total Operating Costs:	$1,560
	Total Capital Costs:	$3,600
4.	Case:	Social MES
	Field Type:	Offshore
	Reserve Size:	48 million cubic metres (300 million barrels)
	Transportation:	400 mm buried pipeline carrying 12,000 cubic metres per day peak rate
	Total Operating Costs:	$1,560
	Total Capital Costs:	$3,700

5. Case: Potential for Low Cost Oil
   Field Type: Offshore
   Reserve Size: 159 million cubic metres (1 billion barrels)
   Transportation: 5 tankers each carrying about 8,200 cubic metres per day peak rate
   Total Operating Costs: $1,700
   Total Capital Costs: $3,700

6. Case: Potential for Low Cost Oil
   Field Type: Offshore
   Reserve Size: 159 million cubic metres (1 billion barrels)
   Transportation: 600 mm buried pipeline carrying 40,000 cubic metres per day peak rate
   Total Operating Costs: $2,100
   Total Capital Costs: $4,100

Note: All dollar figures are in millions of undiscounted 1983 dollars. Capital Costs are before PIPs.

1 cubic metre = 6.293 barrels

Total capital and operating costs are the sum of those costs over all years.

APPENDIX 2

Price, Cost and Inflation Assumptions

1. Social Base Case

   - prices remain flat in real terms
   - costs remain flat in real terms
   - annual inflation in 1983 is 8.8% then 7.8, 7.2, 7.0, 7.3, 7.0, 6.9, 6.5 then 6.0 (forecast for 1983-87 is taken from the Economic Council's CANDIDE forecast, Nineteenth Annual Review)
   - price of oil delivered to Montreal is $40 in 1983
   - no taxes or royalties

2. Private Base Case

   - this case is the same as the Social Base Case but the Canada Lands fiscal regime is imposed
   - taxation is done on a full flow-through basis

3. Real Increasing Prices

   - base case assumptions are used but prices increase at an annual real rate of 5 per cent

4. Real Declining Prices

   - base case assumptions are used but prices decline at an annual rate of 5 per cent

APPENDIX 3

Canada Lands Fiscal Regime

1. Income Tax Rate: 46%

2. Depletion is earned at a rate of 33.3 per cent. Depletion on exploration is phased out by 1984. (Allowable to a limit of 25 per cent of resource profits).

3. Investment Tax Credit = 10 per cent for expenditures on tangible assets except CEE.

4. C.C.A.:

CEE	100%	
CDE	30%	
cl 10	30%	(drilling rigs and well equipment)
cl 2	6%	(pipeline with life expectancy greater than 15 years)

5. Resource Allowance: 25%

6. Petroleum Gas Revenue Tax (PGRT): 16% on operating revenues (effectively 12%)

7. Basic Royalty: 10 per cent on gross revenues

8. Progressive Incremental Royalty (PIR): 40 per cent of net profits

   where GROSS REVENUES
   less operating costs
   basic royalty
   federal income tax allowance
   investment allowance
   capital allowance
   PGRT
   equal NET PROFITS

<u>Federal Income Tax Allowance</u>: The allowance is equal to the amount of federal income tax that would be payable in the year. The notional deduction is calculated on the assumption that the firm is in a fully taxable separate entity situation.

<u>Investment Allowance</u>: 25 per cent of "total eligible investment" which includes costs for discovery, delineation, or development wells and other preproduction development activities, exploration costs prior to drilling a discovery well, and continuing developmental and delineation expenses. Deduction is given for current year costs plus prior year's depreciation at 10 per cent.

<u>Capital Allowance</u>: The amount of the allowance that may be claimed is equal to the lesser of:

- 1/6 of "total eligible investment" costs
- the unclaimed balance of "total eligible investment"

9. PIPs: when applied are given at of a rate of 80 per cent on exploration expenditures and 20 per cent on intangible development expenditures

10. Crown Back-in: The Canada Lands fiscal regime gives the federal government the option of becoming a 25 per cent working interest in petroleum operations in the Canada Lands. The option can be exercised at the time that the project enters the development phase. At that time the Crown incurs 25 per cent of all subsequent expenditures and receives 25 per cent of all production.

The Crown compensates the private interests for expenditures made prior to the back-in either through PIP grants or ex-gratia payments. For exploration expenditures made post 1980 the Crown contributes a minimum of 25 per cent of the expenditures made by companies with the minimum Canadian ownership rating (COR). An additional 55 per cent in contributed towards post 1980 exploration expenditures for a total contribution of 80 per cent for companies with the highest COR. Pre 1981 exploration expenditures made on a field declared significant by 1983 and which was drilled before 1981 qualify a company for an "ex-gratia" payment in lieu of a PIP grant. Ex-gratia payments are not based on Canadian ownership levels. The payments are equal to ¼ of 250 per cent of pre 1981 exploration costs grossed up 15 per cent per annum to the end of 1980. The 15 per cent gross up is intended to account for the impact interest and inflation. The payment is made to the company by federal government in the first year of production.

APPENDIX 4

Supply Costs for Oil Delivered at Montreal
in 1983 dollars per cubic metre (per barrel)

Case	Real Rate of Discount %	Supply Cost Delivered to Montreal
Single Island		
1. 34 million m^3, social, tanker	5 7 10 15	208.67 (33.16) 231.52 (36.79) 249.83 (39.70) 293.13 (46.58)
2. 44 million m^3, private, tanker	5 7 10 15	235.20 (37.37) 244.72 (38.90) 252.60 (40.18) 273.90 (43.52)
3. 64 million m^3, social, tanker	5 7 10 15	125.98 (20.02) 135.17 (21.48) 146.31 (23.25) 171.23 (27.21)
4. 64 million m^3, private, tanker	5 7 10 15	207.00 (32.90) 213.96 (34.00) 219.00 (34.78) 233.34 (37.08)
5. 159 million m^3, social, tanker	5 7 10 15	67.19 (10.67) 71.23 (11.32) 74.88 (11.90) 84.51 (13.43)
6. 48 million m^3, social, pipeline	5 7 10 15	183.06 (29.09) 195.84 (31.12) 212.82 (33.82) 248.30 (39.45)
7. 48 million m^3, private, pipeline	5 7 10 15	237.33 (37.71) 246.30 (39.14) 255.72 (40.63) 276.67 (43.96)
8. 159 million m^3, social, pipeline	5 7 10 15	86.02 (13.67) 91.12 (14.48) 96.91 (15.40) 110.40 (17.54)

APPENDIX 5

Supply Costs for Oil Delivered at Montreal
in 1983 dollars per cubic metre (per barrel)

Case	Real Rate of Discount %	Supply Cost Delivered to Montreal
Multi-Island		
100 million m^3, social, pipeline	5 7 10 15	211.33 (33.58) 223.40 (35.49) 243.35 (38.67) 280.85 (44.63)
100 million m^3, private, pipeline	5 7 10 15	256.12 (40.70) 264.36 (42.01) 277.83 (44.15) 264.83 (42.08)

Notes

1 The authors wish to thank Dome Petroleum Ltd. and Gulf Canada Resources Inc. for their contribution and direction given in the study.

2 This discussion is based on information given in the Environmental Impact Statement (EIS) for Hydrocarbon Development in the Beaufort Sea-Mackenzie Delta Region, Vol. 2, Development Systems, Part 2, 1982.

3 R.M. Proctor, G.L. Taylor, J.A. Wade, for the Geological Survey of Canada, Oil and Natural Gas Resources of Canada, Paper 83-31, 1983, p. 25.

4 EIS, p. 4.80.

5 EIS, pp. 4.111 - 4.130.

6 Dome Petroleum.

7 Dome Petroleum.

8 Dome Petroleum Ltd., A Sumbission to the Senate on the Northern Pipeline, 1982, p. 2.12.

9 Ibid., p. 3.22.

10 Path Economics Ltd. for the Beaufort Sea Alliance, "An Analysis of the Minimum Economic Scale of Developing Beaufort Sea Oil Reserves", 1983, p. 1.

11 Dome, Submission to the Senate, p. 3.25.

12 Economic rent is the payment to a factor of production over and above what is necessary to keep the factor in its current employment. It is, in other words, payment to the factor over and above its opportunity cost.

On an industry level we can think of rent as the surpluses earned by industry in excess of the revenues necessary to pay all costs: operating costs, investment cost plus an adequate return to risk taking and capital. Normal profits are earned when capital and risk taking earn returns just equal to their opportunity costs. In this case the payments are sufficient for these factors to remain in their current employment. Above normal profits are earned when capital and risk taking earn returns in excess of their opportunity cost.

13 EIS, p. 4-167.

14 EIS, pp. 3.11 - 3.13.