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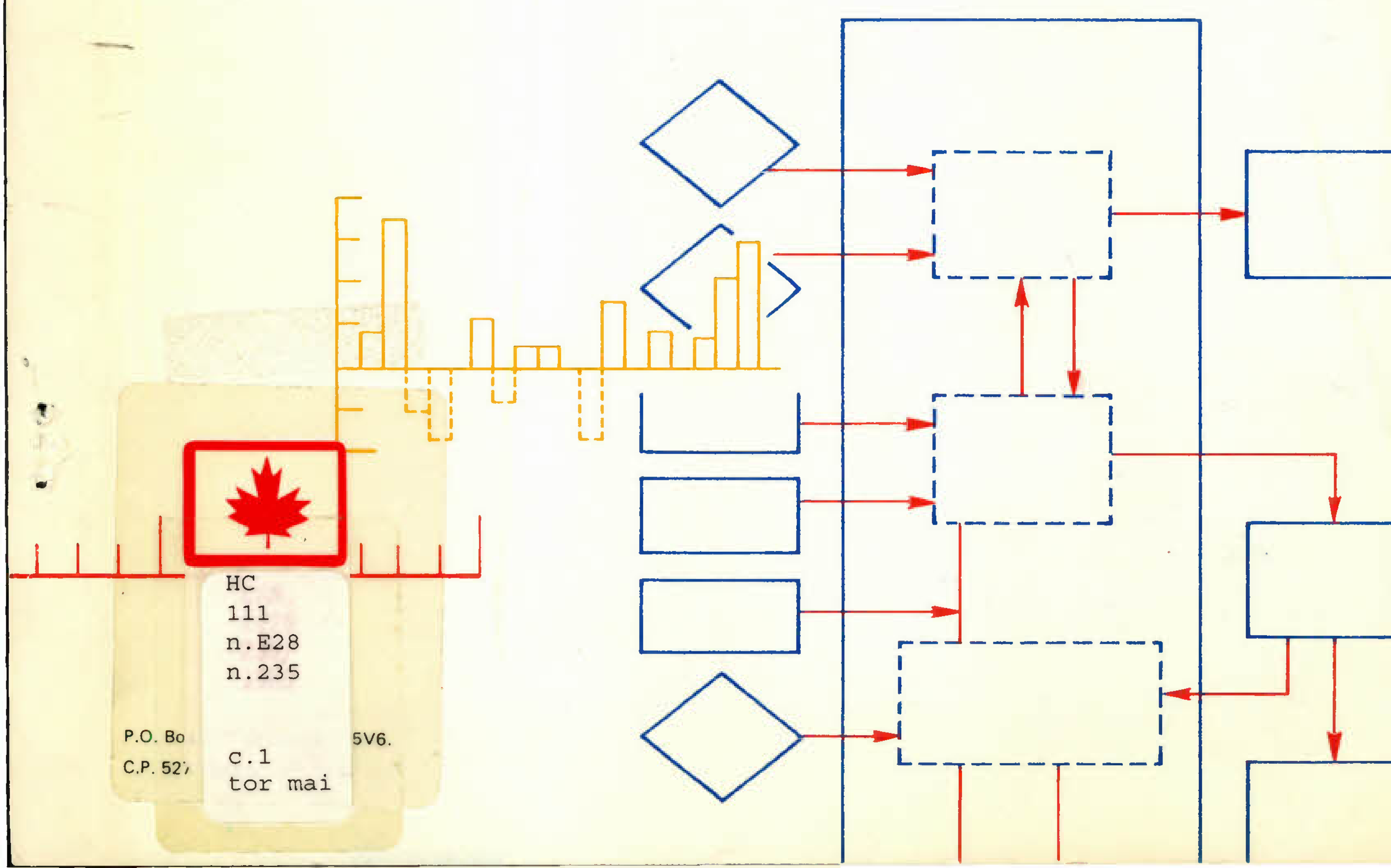

DISCUSSION PAPER NO. 235

Observed Costs of Oil and Gas Reserves in Alberta 1957-1979

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RÉSUMÉ

- L'objet de ce document est de présenter une évaluation des coûts unitaires d'exploration et de mise en valeur des réserves de pétrole et de gaz naturel de l'Alberta au cours de la période 1957 à 1979. Ces coûts sont exprimés en dollars de 1981.

- Les coûts correspondant aux nouvelles découvertes homologuées ont été comparés à la valeur estimée des réserves actuellement disponibles ainsi qu'à la valeur de celles de certaines années choisies au cours de la période considérée.

- Depuis le milieu des années 60, le coût réel des réserves pétrolières homologuées est passé d'un niveau compris entre 1,00 $ et 2,00 $ le baril en terre à 6,00 ou 7,00 $ en 1979, abstraction faite des dépenses que l'industrie doit effectuer au titre de l'acquisition des droits de prospection.

- De 1960 à 1979, la part correspondant aux dépenses de forages et d'exploration dans le coût total d'établissement de nouvelles réserves prouvées a progressé par rapport aux autres dépenses. Autrement dit, l'ensemble des coûts d'exploration (exploration, forage et travaux

géologiques) a augmenté plus rapidement que les autres coûts associés à l'établissement des réserves prouvées additionnelles.

. En 1965, les réserves homologuées dépassaient les 6 milliards de barils de pétrole et leur coût était inférieur à 1,00 $ le baril en terre. A la fin de 1970, un peu moins de neuf milliards de barils avaient été homologués, mais les coûts variaient alors entre 2,00 $ et 3,00 $ le baril. Depuis 1970, le coût en termes réels d'homologation d'un milliard de barils de réserves additionnelles, a remarquablement augmenté pour atteindre un niveau situé entre 7,00 et 10,00 $ le baril en terre.

. L'analyse des revenus nets avant impôt provenant de la production pétrolière au Canada à la fin des années 1970, montre que les coûts (de 7,00 à 10,00 $) excédaient la valeur des nouvelles réserves pétrolières qui était à cette époque d'environ 4,00 à 5,00 $ le baril. Même si l'anticipation de hausses du prix au point d'extraction a fait grimper la valeur des réserves, on estime que celle-ci n'a pas dépassé 9,00 $ le baril en terre. Nos calculs nous amènent à conclure qu'étant donné le contrôle exercé sur les prix pétroliers canadiens, la découverte et la mise en valeur de nouvelles réserves pétrolières n'étaient pas rentables vers la fin des années 70.

. Nous estimons, par ailleurs, en nous fondant sur l'ouvrage intitulé Mise à jour du programme énergétique national 1982, que les conditions dans lesquelles les petites sociétés exercent leurs activités de prospection pétrolière en Alberta, suffisent tout juste,au prix de référence du nouveau pétrole (PRNP), à garantir une rentabilité moyenne à leurs travaux d'exploration et de mise en valeur de nouveaux gisements pétrolifères. D'après nos calculs, la marge bénéficiaire de ces sociétés favorisées de l'industrie pétrolière canadienne semble plutôt faible.

. Nous constatons également que les revenus nets avant impôt provenant de la production d'ancien pétrole ne semblent pas, à l'heure actuelle, suffisamment élevés pour compenser le coût moyen des travaux de forage qu'il faudrait entreprendre, pour prouver des réserves additionnelles provenant de gisements connus de pétrole.

. Le coût, en dollars réels, de la découverte et de la mise en valeur de réserves de gaz, a grimpé proportionnellement plus que celui du pétrole depuis 1960, soit d'environ 14 cents le millier de pieds cubes en terre, jusqu'à environ 62 cents en 1979.

- En dépit de l'augmentation des coûts d'homologation des réserves de gaz, à peu près rien n'indique qu'il y ait eu une accélération de la hausse des coûts du gaz à mesure que des réserves additionnelles étaient homologuées.

- Dans les résultats mentionnés ci-dessus, les dépenses estimées d'homologation des réserves sont ajustées au taux général d'inflation. Nous présentons également d'autres formes d'ajustement pour rendre compte de l'augmentation particulière des prix des facteurs de production pour cette industrie durant les années 70.

- Même si la tendance à la hausse des coûts est un peu moins marquée lorsqu'on l'ajuste en fonction du taux général d'inflation et de l'accroissement des coûts des facteurs de production particuliers à l'industrie, les résultats restent essentiellement les mêmes. Les coûts d'homologation des réserves additionnelles de pétrole ont augmenté considérablement. Dans le cas du gaz, ils se sont accrus aussi, mais à un taux constant.

- En plus d'évaluer les coûts d'homologation séparément pour le gaz et le pétrole, et ce faisant, d'avoir à distinguer les activités d'exploration en fonction de leurs objectifs, nous avons aussi calculé une série de coûts d'homologation pour les réserves exprimées en barils d'équivalent-pétrole (BEP). Ils se situent quelque part entre les courbes de coûts du pétrole et du gaz. Cette méthode d'analyse, fondée sur l'équivalent-pétrole, présente toutefois certains problèmes particuliers que nous décrivons dans le texte et à l'annexe E.

. Par ailleurs, nous examinons la relation directe entre le forage de puits et l'homologation des réserves. L'analyse indique qu'une des principales causes de la hausse des coûts d'homologation a été l'augmentation du nombre de puits forés par unité de réserve homologuée. Nous pensons que cet accroissement reflète l'efficacité décroissante des forages et l'épuisement des ressources de l'Alberta.

. On trouve dans le texte une courte analyse de la théorie sous-jacente de l'offre, ainsi que de la méthode utilisée dans notre étude.

. Les annexes fournissent toutes les données numériques nécessaires pour reproduire les estimations de coûts.

ABSTRACT

- The paper provides calculations of the observed unit costs of finding and developing oil and natural gas reserves in Alberta, in the period 1957 to 1979. Throughout costs have been deflated to 1981 dollars.

- The calculated costs for "booking" developed reserves are compared to the estimated value of developed reserves, at the present time and at selected years during the past decade.

- Since the mid 1960's the real cost per barrel of booked oil reserves has risen from the $1.00 to $2.00 per barrel-in-the-ground range to some $6.00 to $7.00 in 1979, excluding the cost to industry of bonus payments.

- Over the 1960 to 1979 period the exploration drilling component of the cost of establishing new oil reserves has risen in importance relative to the other costs. That is, finding costs (exploration, drilling and geology) have risen faster than other cost components in proving up new oil reserves.

- By 1965 more than 6 billion barrels of oil had been booked and costs were no more than about $1.00 per barrel-in-the-ground. By 1970 slightly less than 9 billion barrels were booked but costs were in the $2.00 to $3.00 range. Since 1970 the real cost of proving up the next 1 billion barrels has risen dramatically, to the $7.00 to $10.00 per barrel-in-the-ground range.

- The level of costs in the late 1970's ($7.00 to $10.00) is above the value of new oil reserves (some $4.00 to $5.00) as indicated by the netbacks available for oil production in Canada, at that time. Even if expectations of wellhead price increases elevated the price of reserves they are estimated to have been worth no more than about $9.00 per barrel in the ground. On the basis of our calculations it appears to us that finding and developing new oil reserves was not a profitable endeavour in the late 1970's, given the controlled level of Canadian oil prices.

- We also estimate that the conditions for small oil companies, searching for oil in Alberta, as provided by the 1982 NEP Update, are just sufficient to provide average profitability in exploration and development for new oil

(NORP) reserves. By our calculations the profit margin for these favoured companies in the Canadian oil patch appears to be small.

. Our calculations suggest that the netbacks on old oil, at the present time, do not appear high enough to cover the average costs of proving up additional reserves through infill drilling of old oil pools.

. The real dollar cost of finding and developing gas reserves has risen by a slightly higher proportion than oil since 1960, from some 14¢ per mcf-in-the-ground to about 62¢ in 1979.

. Although the cost of booking gas reserves has risen there is little or no evidence of any acceleration in gas costs as additional reserves have been booked.

. In addition to adjusting the estimated costs of booking reserves for general inflation in the findings mentioned above, the paper also provides further price adjustments for the industry specific input price escalation which was experienced in the 1970's.

- Although the upward cost trends are somewhat less pronounced, when adjusted for both general inflation and industry specific input cost escalation, the findings are essentially similar. The booking costs for additional oil reserves have accelerated dramatically in the booking of the last 1 billion barrels. Gas costs have increased but at a steady pace per Bcf booked.

- In addition to calculating separate booking costs for gas and oil and thereby having to separate exploration activities as to intent, we have also calculated a series of costs for booking reserves of barrels of oil equivalent (BOE). The BOE cost series lies somewhere between the cost curves for oil and gas. However the BOE method of analysis does present particular problems which we describe in the text and in Appendix E.

- We also examine directly the physical input-output relationship between wells drilled and the booking of reserves. The analysis suggests that a major reason for the rise in booking costs was the rise in the number of wells drilled per booked reserve. We believe that the increase in the number of wells drilled reflects both the impact of declining drilling efficiency and the impact of the depletion of the Alberta resource base.

- A brief discussion of the underlying supply theory and the method of approach is provided in the text.

- The Appendices provide all the numerical details necessary to reproduce the cost estimates.

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1. INTRODUCTION

This paper provides calculations of the observed unit costs (cost per barrel in ground, and cost per mcf in ground) of finding and developing oil and gas reserves in Alberta, in the period 1957 to 1979. A considerable effort has been made to systematically and appropriately assign the observed total annual costs of the industry to either oil or gas activity, and ultimately to the annual bookings of oil and gas reserves by the Alberta Energy Resources Conservation Board (AERCB).

The calculations take into consideration the average delay times between bonus payments, geological expenditures, exploration drilling, development drilling and the booking of reserves. Each category of costs has been assigned either to oil reserves or to gas reserves in an attempt to estimate, insofar as possible, the real average unit cost of proving up developed oil reserves, separately, from gas reserves.

There are many complications which have to be included in the process of assigning costs and our methods and assumptions are set out in the appendix to this paper. It may be mentioned, however, that associated gas reserves have been included with non-associated gas without assigning to gas any portion of the oil exploration and development costs. For the period we have considered and especially since the mid 1960's we do not believe that this approach could significantly affect the results.

To consider the meaning of the observed costs we have discussed them in the context of the market for developed reserves. That is, we have compared the costs with the estimated value of developed reserves, as at the present time and at selected years during the past decade. As would be expected we find that the observed costs are approximately equal to the estimated value of reserves. This approach implicitly assumes that the market in the production and sale of oil and gas reserves is more or less competitive. The large number of small exploration and development companies and the wide variety of exploration and production sharing arrangements in the industry suggest that the competitive model is a reasonable approximation to reality although market "imperfections" related to the size of some purchasers probably exist.

The costs are also disaggregated in a number of ways, as in Figures 1 and 3, showing separately development drilling, exploration drilling, geology, and the cost of money tied up in the development and exploration activity. In particular bonuses are separated in that the private cost to industry can be distinguished from the real social cost of proving up reserves.

The observed unit costs, plotted against cumulative booked reserves, are shown in Figures 2 and 4. These graphs of historical costs may be interpreted as measures of the long run supply curves for oil reserves and for gas reserves. We stress, however, that the observed costs may not lie on the true long run supply curve, especially in recent years, because of rapid changes in market conditions for reserves. In addition, supply theory suggests that the observed costs are biased estimates of the true supply curve and also uncertainty in exploration and development may lead to the observed costs being above or below the expected supply function.

For the above reasons and because we have not formulated an explanatory model of the supply process in this paper we must caution against simply extrapolating the observed cost trends.

2. RESULTS

2.1 Results: Oil

Figure 1 shows our calculation of the observed costs per barrel, in 1981 dollars, of proving up oil reserves in Alberta, in the period 1957 to 1979. For various reasons discussed below these costs are calculated as 5 year moving averages.[1]

Before discussing these results it is important to comment on the units of measurement. First, to eliminate simple inflationary effects from the data we have converted to 1981 dollars using the industrial selling price index. Second, these costs refer to barrels of recoverable reserves in the ground. They do not refer to "levelized" unit cost applicable to oil production. To clarify, the full description of the units of measurement would be: 1981 dollar cost per barrel of developed recoverable oil reserves in the ground.

However, we note that the cost per barrel in the ground for exploration and development can be converted to a cost per barrel of production by multiplying by an appropriate factor, a function of the cost of money, the production profile, etc., which in January 1983 was about 2.125.[2] That is, a cost of $10 per barrel in the ground for exploration and development is equivalent to a levelized cost (for exploration and development) of about $21.25 per barrel produced. The derivation of the conversion factor is shown in Appendix B.

The levelized cost per barrel produced can be compared to the net back per barrel, after royalty, taxes and operating costs, which is available to the producer. At the present time a small new oil producer can expect a netback of some $21.83 per barrel.[3] This netback, if it is assumed to continue in real dollar terms implies a value or price for oil reserves in the ground of a little more than $10 per barrel in ground ($21.83 ÷ 2.125 = 10.27).

The balance between revenues and costs in the exploration and development of new oil reserves at January 1983 is approximately as follows. Consider first the revenues and netbacks from <u>new oil for a small</u> company with a PGRT holiday.

Wellhead price for New Oil (NORP) = 44.52 $/B produced
less:

Operating Costs	2.37	
Royalties	13.74	
Fed. Tax	5.48	
Prov. Tax	1.10	
PGRT	--	22.69
Approximate Netback		21.83 $/B produced

This implies a value for the underlying Developed Reserves of (21.83 ÷ 2.125) 10.27 $/B in ground

Average Cost of Booking Developed Reserves in 1979 without bonuses (Figure 1) 6.35 $/B in ground

Source: Netback are taken from the Ministry of Energy Mines and Resources, "Do Governments Take Too-Much?", September 1982. The reader may note that the EMR estimated netbacks are likely higher than those that will be realised in 1983. The above analysis assumes that the real dollar netback continues constant over future years.

The incentive to explore in the above example (which compares actual 1983 revenues with the estimated booking costs in 1979) is about $3.90 per barrel in the ground. The full PGRT payment would be equivalent to about $2.25 per barrel in the ground. We estimate that for Canadian companies PIP grants would subsidize the booking cost by about $1. Therefore the profit margin for Canadian companies would be larger. In addition royalties could be somewhat lower due to Alberta incentives.

It may also be noted that the cost per barrel in the ground is a calculation of the "full cycle" exploration and development cost of providing reserves, ready for production. Full cycle, a term used in the industry, means that the cost includes both pre-exploration, exploration and development costs, from the beginning of the process leading to the proving up of reserves, and taking consideration of the cost to the industry of tying up investment funds through the period until production may begin.

Looking now to the results; the overall impression of the trend in costs is obvious and striking. Since the mid 1960's the incremental real costs per barrel of booked reserves has risen from the $1.00 to $2.00 per barrel in the ground range to some $7.00 to $10.00 in the late seventies. The calculated social cost of reserves booked in 1979 is $6.35 per barrel, and bonuses added some $2.20, giving a total private cost of about $8.55. As previously noted the average value of developed reserves of new oil in 1983 is about $10 therefore it appears that the present regime is providing some positive stimulus to the search for and development of new oil, but the profit margin is small in view of the risks and uncertainties faced by the industry. We will discuss this further in the context of Figure 2 which presents costs in relation to cumulative reserves.

Figure 1 also shows that both development and exploration costs have risen. This would be expected as both the extensive and intensive "margins" to prove up new reserves were exploited by the industry, as the value of reserves has risen, especially during the 1970's.

It is interesting to look at the components of cost for representative years.

	Per Cent of Costs for Booked Oil Reserves		
	1960	1973	1979
	%	%	%
Development	46	34	36
Exploration drilling	14	16	26
Geology	12	14	6
Cost of Money	8	15	15
Bonuses	20	21	17
	100	100	100

It is significant that, while the absolute amounts of bonuses have grown substantially, their proportion in the total costs has tended to decline and they were only some 17% in 1979. We interpret this to mean that although the bonuses have been more visible during the 1970's because of their size, the expected profitability in oil exploration (and development) has declined and was low or negligible in the late 1970's.

The high costs in the period up to 1962 reflect the lean exploration years of 1958, 1960, 1961 and 1962 during which few reserves were booked. Bonuses, however, were running at some 20% of costs and a majority of exploration drilling was directed towards oil. Development costs were also high. It was only after the National Oil Policy was put in place in 1961, when production increased, that substantial reserves began to be booked from development.

There were also factors within Alberta which contributed to the appearance of high costs in the late 1950's but declining costs in the early 1960's. The 1964 changes in Alberta's prorationing system, where production allowables became based on established reserves, gave an incentive to industry to assure that all their previously discovered reserves were proved up and consequently booked by AERCB. In the same period the AERCB also introduced wider well spacing, as a norm, which had the effect of reducing the average costs of proving reserves.

In addition the Gilwood/Keg River plays led to lower exploration costs in 1964 to 1966. Overall, for the decade 1957 to 1967 it is perhaps reasonable to view total unit costs as being between $1.00 and $1.50 per barrel in the ground range - i.e., we may average the observed costs prior to 1962 with those between 1963 and 1966. It was after 1966 that real costs began their distinct upward course.

Like Figure 1, Figure 2 shows observed oil reserve costs but instead of being plotted against the year of observation they are shown with respect to cumulative booked oil reserves. Therefore Figure 2 shows the unit cost of incremental reserves. Bearing in mind the cautionary remarks made earlier it can be viewed as approximating the long run supply function of oil reserves.

By 1965 slightly more than 6 billion barrels had been booked and incremental private costs were less than $1.00 per barrel. By

1970 slightly less than 9 billion barrels were booked but private incremental costs were in the \$2.00 to \$3.00 range. Since 1970 the real cost of proving up the last 1 billion barrels has risen dramatically. This tremendous increase in observed social and private costs of booking reserves has been a real phenomena - there is no doubt. We would caution again, however, against using the most recent trend for extrapolating future costs.

The approximate value of developed oil reserves in 1970 was \$2.00 per barrel (\$1981) which was on average slightly less than the cost of proving up reserves. Hence it appears that it was not profitable or at least a break-even situation, on average, to find and develop oil reserves in Alberta at that time.[4] The value of new oil reserves had risen to some \$4.00 to \$5.00 per barrel (\$1981) in 1979 on the basis of netbacks at that time. If expectations of wellhead price increases of 10% per year were assumed, reserves would have been valued at about \$9.00. Our calculated private costs for that year are \$8.55 per barrel. Even social costs are estimated to have been some \$6.35 per barrel. There seems little doubt that finding and developing oil was not generally profitable in the late 1970's.

If oil directed exploration was not profitable one may ask why the industry continued to do it. There are three obvious explanations. First, the above data deals with industry averages and even if the average cost is higher than the average value of reserves there will be successful companies which find exploration profitable. Indeed this situation is likely to occur in a period of industry expansion such as the 1970's when many new companies were pulled into the market. However, we would not expect an average loss situation to continue for long because activity would eventually be reduced. A second factor is that companies were expecting considerably higher netbacks for Canadian oil than were permitted by Canadian policy which had kept prices below world levels. Thirdly, the extremely erratic nature of exploration results, i.e. the uncertainty in exploration, could lead the industry to continue exploring for long periods of time even if the average results at this level of their activity were not profitable. An example of this was during the many years when Imperial Oil and other companies continued exploration in Alberta before the Leduc discovery.

As we have previously mentioned the present new oil price provides for a value of about $10 per barrel of new oil reserves for a small company. Only since the NEP plus the Alberta Federal Agreement have prices been adequately high to stimulate the proving up of oil reserves. The margin for explorers, however, is not generous in the light of the cost trends in Alberta.

Finally, as a comment on these observed costs, it should be underlined that much of the booked reserves in each year stem from previously discovered reserves. The observed development (i.e. without exploration) costs of these reserves are about $3.00 per barrel in the ground which can be compared to their value of somewhat less than \$3 as indicated by the old oil netbacks for large producers (at full tax rates) under the present NEP price regime. Consequently old oil netbacks are not high enough to get the full infill development of existing reserves.

2.2 Results: Natural Gas

The calculations of natural gas reserves costs were made in much the same manner as for oil. Figure 3 shows the calculated costs for the period. While private oil reserve costs rose from some \$2.00 per barrel in 1957 to about \$8.55 per barrel in 1979, the gas costs have risen from about 14¢ per mcf to about 62¢ per mcf in 1979. That is, both oil and gas costs have risen about the same amount in real terms. Gas costs have increased by a slightly higher proportion than oil costs. Similar increases might be expected because incremental costs for both oil and gas should have more or less tracked the netbacks expected to become available. Actual netbacks for gas and oil however, have not increased in parallel. The most significant difference between the supply costs of gas and for oil show up in Figure 4 where we plot gas costs against cumulative gas reserves. For the gas reserves there is no evidence of an acceleration in the rise of unit cost as reserves have been accumulated, thus far.

The value of developed gas reserves was some 50¢ to 60¢ (\$1981) in the late 1970s.

2.3 Results BOE

In addition to calculating separate booking costs for oil and natural gas, and thereby having to separate drilling as to intent which presents some difficulties for exploration wells, we have also calculated a series of costs for booking of reserves of barrel of oil equivalent (BOE).

Converting to BOE introduces other problems. We have converted natural gas reserves to BOE reserves by using the estimated values of developed gas and oil reserves. The conversion is therefore a function of prices. The cost series is thus partly determined by the prices of oil and gas (and other revenue features including taxes and royalties), which is a mixing of revenue and cost elements that we had taken pains to avoid in developing the separate oil and gas cost series.

The results for BOE are shown in detail in Appendix E. The BOE cost series lies somewhere between our cost curves for oil and for gas, perhaps appearing more like the oil series. The BOE series is also more erratic which results from the conversion method at a time when the relative values of gas and oil reserves were changing significantly in the Canadian market, as was directionality in drilling.

Generally our conclusion is that while the BOE series may be of interest to explorationists and may be a useful cost series for government policy makers to examine in some circumstances (e.g., in comparing Canada and U.S.), it does not add to our understanding of cost trends in the context of this paper. In any event the interested reader is referred to Appendix E.

3. COMMENTARY

The most obvious finding of this study is that real booking costs have increased dramatically both for gas and oil over the past decade or so. In the case of oil the additional reserves booked have been relatively modest giving the appearance of accelerating costs for booking incremental oil reserves. For natural gas, costs have also increased but significant additional reserves have been booked.

As might be expected, booking costs have tended to rise in the wake of rising values for reserves, and generally it seems that costs have probably overshot reserves values. This raises a number of questions of explanation.

While we have allowed for general inflation in our cost estimates we may ask whether industry specific input cost increases might have been the cause of the observed rise of real booking costs. We show below that industry input price escalation was in fact higher than general inflation but that this factor does not explain the upward trend in booking costs. We may also ask whether the upward cost trends were largely a matter of less reserves being booked per well drilled; that is, that the physical productivity of wells in establishing reserves was declining. The analysis below shows that drilling productivity, in this latter sense, did decline markedly. The declining trend in reserves booked per well drilled closely parallels the observed upward trends in booking costs.

It has not been our intention in this paper to attempt an explanation, by econometrics or otherwise, of the true supply curve of the industry. Our cost findings, however, with the additional analyses below, suggest that a number of observations are noteworthy.

Firstly, the Canadian industry responded extremely quickly to the prospective incentives during the 1970's by very rapidly increasing the rate of drilling. We note that this is rather easy for the Canadian industry because a small proportion (10%) of all U.S. drill rigs can, by moving to Canada, double our drilling fleet in a matter of weeks. This, of course, can happen in both directions. Secondly, the rate of the rise in costs, and the corresponding decline in reserves additions per well, gives the strong impression that drilling was overextended relative to industry's knowledge of prospects. Many of the poorer (smaller, low quality reserves) prospects which had previously been put aside were dusted off and drilled. In the words of one company executive; it was a case of too much brawn and too little brain. This is one reason why the trend in costs in the late 1970's is probably not a good indicator of the long run path of costs in the future.

3.1 General Inflation and Industry Specific Input Price Escalation

In Figures 1 to 4 we have shown the costs for booking reserves of oil and gas, expressed in constant 1981 dollars by deflating the actual costs by the Industrial Selling Price Index (ISPI). This is an index that reflects the general behaviour of industrial selling prices across the entire economy. The use of a general price index for this purpose is an appropriate approach in view of our objective of showing the history of real dollar costs for booking new reserves and to make comparisons between real costs of establishing developed reserves and the value of reserves.

The decade of the seventies was clearly an inflationary period for the Canadian economy. But in addition the volume of activity that took place within the Alberta petroleum industry resulted in cost escalation within the industry that was greater than general inflation. The seventies were a boom period for the industry and as the demand for inputs into the industry rose, the prices for exploration, development and operating inputs were bid up even faster than general inflation.

For purposes of attempting to uncover as best as possible the underlying physical input-output relationships, however, we need to deflate industry costs by both general inflation and the particular input cost escalation faced by the industry.

The use of the ISPI to derive the constant dollar costs has allowed us to eliminate the effect of general inflation. Having done so, what remains are the real dollar costs incurred by the petroleum industry. In order to further eliminate industry specific input price escalation a further index is required.

In a 1981 study, "Alberta Cost Escalation Study", the Canadian Petroleum Association (CPA) derived a cost escalation index for Alberta conventional oil and gas industry for the period 1970-1980. We have adapted that index by linking it to the ISPI and noting the differences for the period 1970-1980. Deflated costs obtained by means of this new index will give a picture of how costs have evolved in the industry in terms of the physical input requirements for a given quantity of reserves. This measure eliminates the short-term pecuniary escalation effects on costs as well as the general inflationary effects, and therefore should be a better guide for long run cost trends.

The unit deflated costs for booking oil and gas reserves are re-calculated with the new index for the period 1970-1979. The results are given in Appendices C1 and C2 and are depicted in Figures 5 and 6. It can be seen that deflated costs still show a distinct upward trend, although not as steep as in Figures 2 and 4.

3.2 Wells Drilled Per Reserves Booked

We now turn our attention directly to a measure of the physical input-output relationship between wells drilled and the booking of reserves. Appendix D outlines the calculations that have been used.

It is customary to examine the ratio of reserves booked (or discovered) per well drilled. In the exploitation of a basin we expect this "finding rate per well drilled" to decline slowly as depletion of prospects forces industry to undertake the drilling of more risky or smaller targets. In this paper we have plotted the reciprocal of reserves booked per well drilled. Our series, shown in Figures 7 and 8 for oil and gas respectively, show wells drilled per reserves booked and therefore they tend to rise if more inputs (wells) are needed for a given output (reserves). These series therefore should track the real costs of booking reserves, separately from financial or price considerations.

The immediate impression from comparing our costs series, Figures 5 and 6, with Figures 7 and 8 in that the two sets of data move closely together.

The wells needed for booking incremental oil reserves increase rapidly during the 1970's. The graphs, considered together, strongly suggest that the rising unit costs during this period were closely related to the real phenomenon of significant declines in the effectiveness of drilling. Monetary factors, as discussed earlier, were present, but it appears that real input-output changes were very important in affecting cost trends.

The trends in our data series of wells drilled per gas reserves booked are quite similar to the trends in the real dollar costs of booking gas reserves (Figure 6). The gas wells drilled per reserve booked series does not accelerate during the 1970's as much as for oil but there is a distinct upward trend, which is the same conclusion we have previously discussed in regard to the cost series.

These data series suggest that a major reason for the rise in booking costs was the rise in wells drilled (or input effort) per reserves booked. However, we believe that the trends of declining well effectiveness reflect both a short term drop in drilling efficiency and productivity, caused by the overheated situation in the industry, as well as the long term decline in drilling effectiveness related to the depletion of the Alberta resource base.

In the short term the very rapid rise in the rate of drilling seemed to outrun the knowledge base of industry, and low drilling productivities ensued. Meanwhile expectations of rising oil and gas prices seemed to justify the drilling of low quality prospects. The consequence, in the short term, was an overshoot of activity wherein average booking costs went substantially higher than the real value of reserves in the ground.

In other research work it may be possible to separate short term factors and effects from those of a more long term nature.

3.3 Discussion of Supply Process and Method of Analysis

To explain further the oil and gas exploration and development process it is useful to set out the sequence of discovery and subsequent development as shown in Figure 9 below.

First, it may be noted that the whole process begins with the discovery of a pool. The discovery then sets in train a series of other drilling; to appraise the discovery and to put in place producibility; which comes under the general heading of development drilling. Enhanced oil recovery (EOR) may then be put in place.

The reserves from the discovery are "booked" by the AERCB in the categories identified by the boxes in the chart, at year-end as they occur.

The majority of studies of exploration or finding costs have related exploration costs in a given year (t) to the reserves found in that year as fully appreciated in subsequent years. That is, the reserves variable is the sum of the subsequently booked reserves, attributable to the discovery year t, assigned back to the year of discovery. This reserves variable is normally called "Appreciated Reserves by Year of Discovery". It can be seen that this measure, in some sense, attempts to get at the "true" size of the discovery and consequently the true finding cost of the reserve. It is argued that to relate the Booked New Discoveries (at year t) to that year's exploration costs would greatly overestimate the finding costs through underestimating the true size of the reserves. This procedure focuses on the finding costs and it ignores the development costs which are required to prove up the pool.

A complementary way of studying exploration costs, but also considering development costs, is to relate exploration plus development costs in a given year to the reserves booked in that year. The Booked New Discoveries represent exploration success, the Booked Reserves from "Appreciation" represent development success in proving up reserves (which had previously been found), and the Booked Reserves from EOR represent success in proving up reserves through enhanced oil recovery schemes.

Both approaches have their place in attempting to measure and understand the process of oil and gas reserves creation. The approaches, however, cannot be mixed -- i.e. it would <u>not</u> be appropriate to relate "Appreciated Reserves by Year of Discovery" to annual exploration plus development costs.

The Booked Reserves approach makes it possible to analyze development costs as well as exploration costs in the process of establishing reserves. It may also correspond more closely to the overall economics of reserves creation, year by year, than the other approach. In addition, given a model of the process of reserves creation, the Booked Reserves approach may be necessary for forecasting annual discoveries and concomitant industry activity.

Both approaches to the data, however, with suitable explanatory models can lead to estimates of ultimate reserves.

To summarize the above, we have two approaches as follows:

1) Appreciated Reserves by Year of Discovery	vs	Exploration Costs (or exploration footage, etc.)

to give "finding costs," $ per barrel in ground (or to give barrels per foot drilled, etc.).

2) Booked Reserves	vs	Exploration and Development Costs

to give "Cost of Establishing Reserves," $ per barrel in ground.

An example of the first method is in a recent AERCB "Gas Reserves Trends, December 1980" paper which related appreciated gas reserves to exploratory wells drilled, as below.

The second approach, while not without its own problems, is used in this paper. The basic idea is to estimate incremental annual unit costs of adding reserves to the productive reserves base. Such costs will have a correspondence with the long run reserves supply function for the industry.

We digress briefly to discuss the theoretical nature of the observed costs. We can illustrate the supply process by Figure 11.

The annual short run industry marginal and average costs are shown by the curves marked MC(i) and AC(i). The expected reserves in year one are R_1; in year two they are $(R_2 - R1)$; year three they are $(R_3 - R_2)$; and in year four they are $(R_4 - R_3)$. Notice that the expected annual additions to reserves are smaller and smaller, and that the annual producers' rent gets smaller until at R_4 it vanishes. It is the existence of the expected producers' economic rent (i.e., profits above normal costs of money) which keeps the exploration and development going in the region from year to year.

The long run supply curve may be viewed as being traced out by the minimum points on the average cost curves. In this example the region is fully explored and developed, at the demand price of $P_{R,o,t}$, after four years.

If the demand price for reserves were constant and the realized finding and development costs were the same as those expected we would observe a series of finding costs given by the intersection of the average cost curves and the lines indicating the quantities, as marked by the X's. The X's trace out the observed long run costs.

Of course, it is extremely unlikely that the realized finding and development costs would be the same as those expected. Each of the supply curves is really a stochastic curve distributed around curves like those indicated in Figure 11. Given a certain rate of drilling, larger than expected reserves may be proved up in which case larger than expected reserves with lower costs would be realized. Or, small discoveries may lead to smaller reserves with higher costs.

This discussion of the supply curve serves to remind us that extreme caution is required in extrapolating a series of observed costs. The observed costs are not likely to be on the industry's long run supply curve and secondly the stochastic nature of especially exploration means that observed costs may be above or below expectation and consequently they can be above the price or value of reserves, even for a number of years.

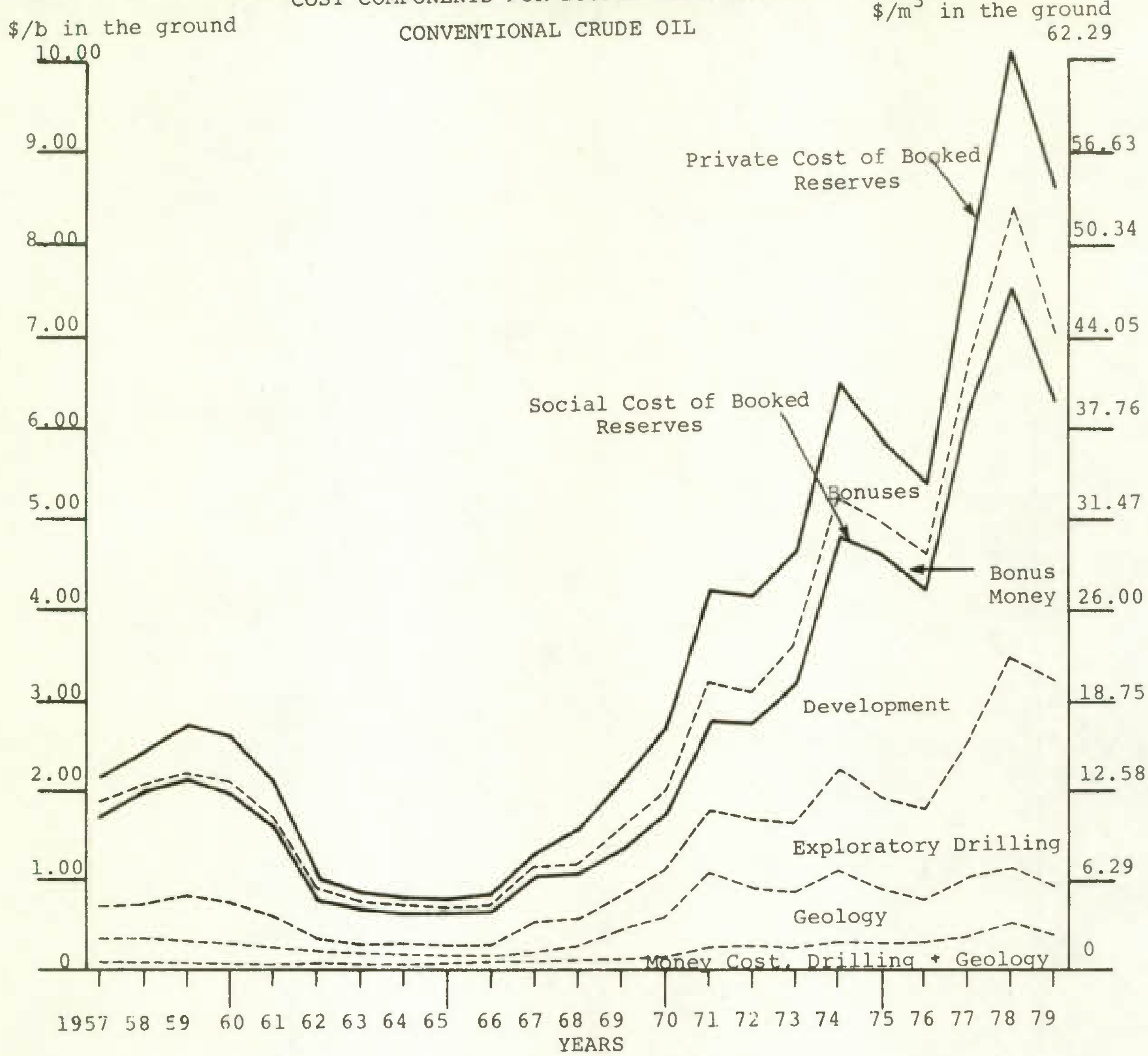
It should also be underlined once again that without a model of the finding and development process this study of the historical data cannot be used alone for forecasting, and furthermore there are other reasons why one must be cautious in interpreting the apparent trends. First of all, circumstances have changed so rapidly since 1974 and this suggests that the observed costs probably don't reflect the long run supply curve very well, and secondly, there are data biases which could overestimate costs.

One aspect which leads to cost overestimation can be explained by reference to Figure 9. It can be seen that development drilling leads to both the booking of new reserves and to the provision of productive capability -- i.e. producibility. In fact, a good deal of recent development drilling has been directed at improving or maintaining producibility but not leading to additional reserves being booked. These development costs were not undertaken to add reserves to the booked reserves base. Such expenditures, however, are necessary for the reserves to produce and they are properly associated with establishing productive capacity, although they have been made after the reserves had been booked.

One means of reducing the upward bias in the trend of costs from this feature (and from other problems), as the reserves base has matured, is to average the costs and the booked reserves over a number of years, thus in effect associating the later development drilling costs with the earlier exploration and development expenditure. This paper has used a 5-year moving average approach to the statistics.

FIGURE 1

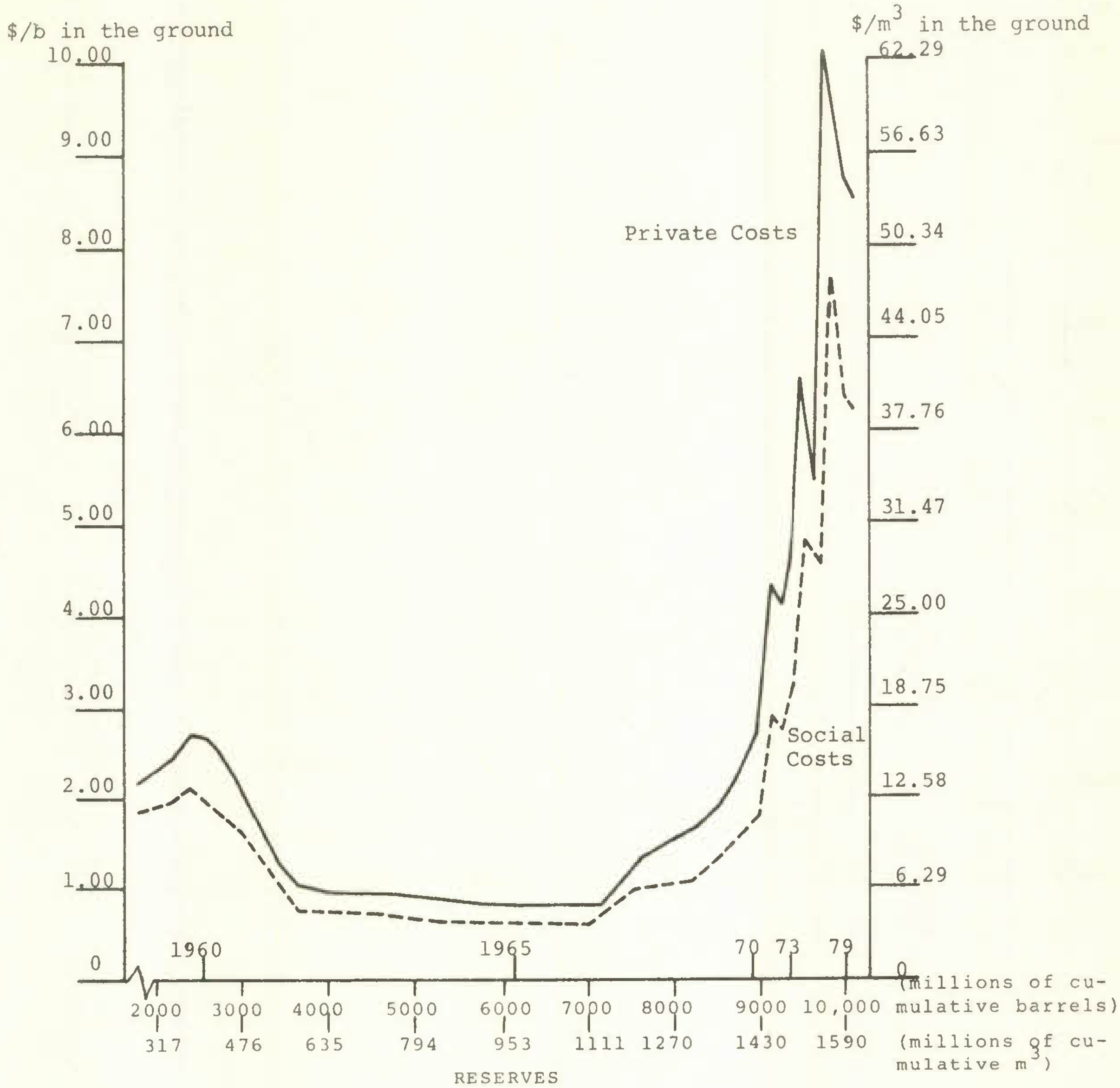
COST COMPONENTS FOR BOOKED RESERVES OF CONVENTIONAL CRUDE OIL



(in 1981 dollars)

FIGURE 2

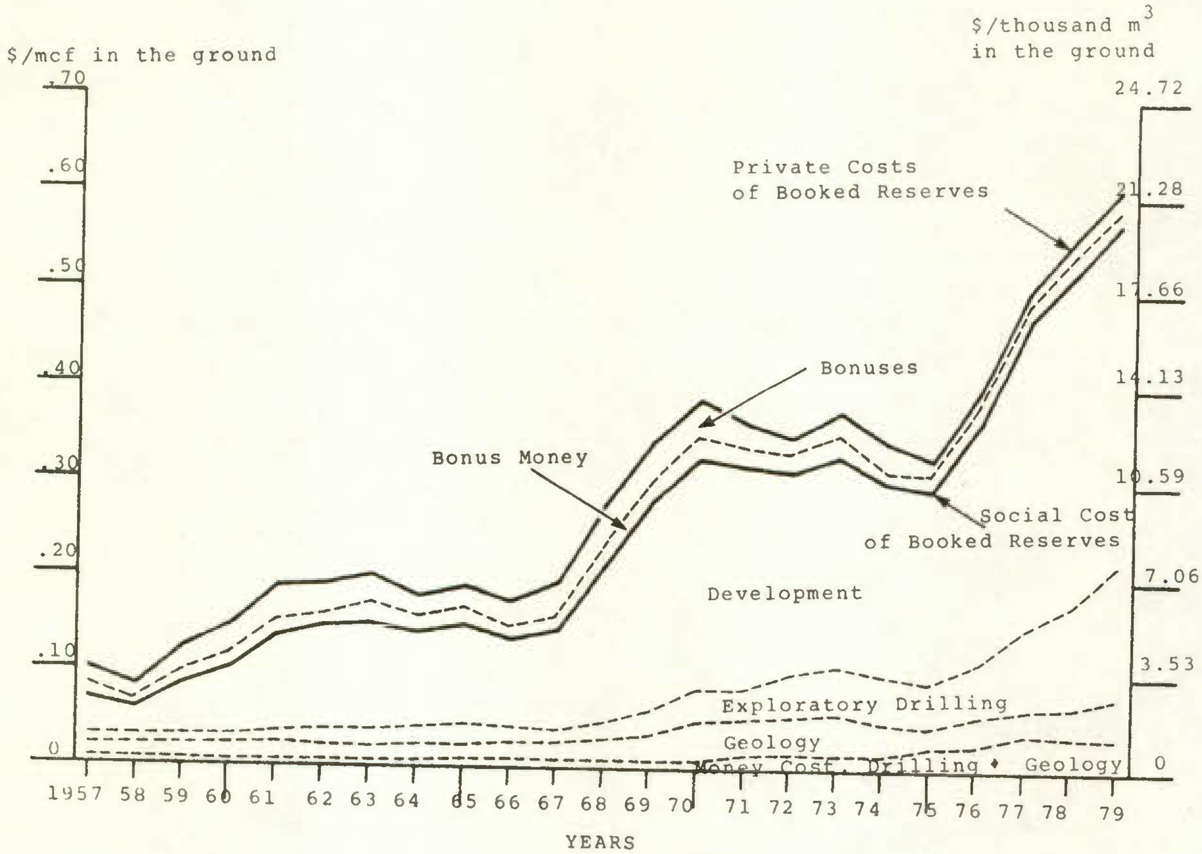
COSTS FOR CUMULATIVE BOOKED RESERVES OF CONVENTIONAL CRUDE OIL



(in 1981 dollars)

FIGURE 3

COST COMPONENTS FOR BOOKED RESERVES OF NATURAL GAS



(in 1981 dollars)

FIGURE 4

COSTS FOR CUMULATIVE BOOKED
RESERVES OF NATURAL GAS

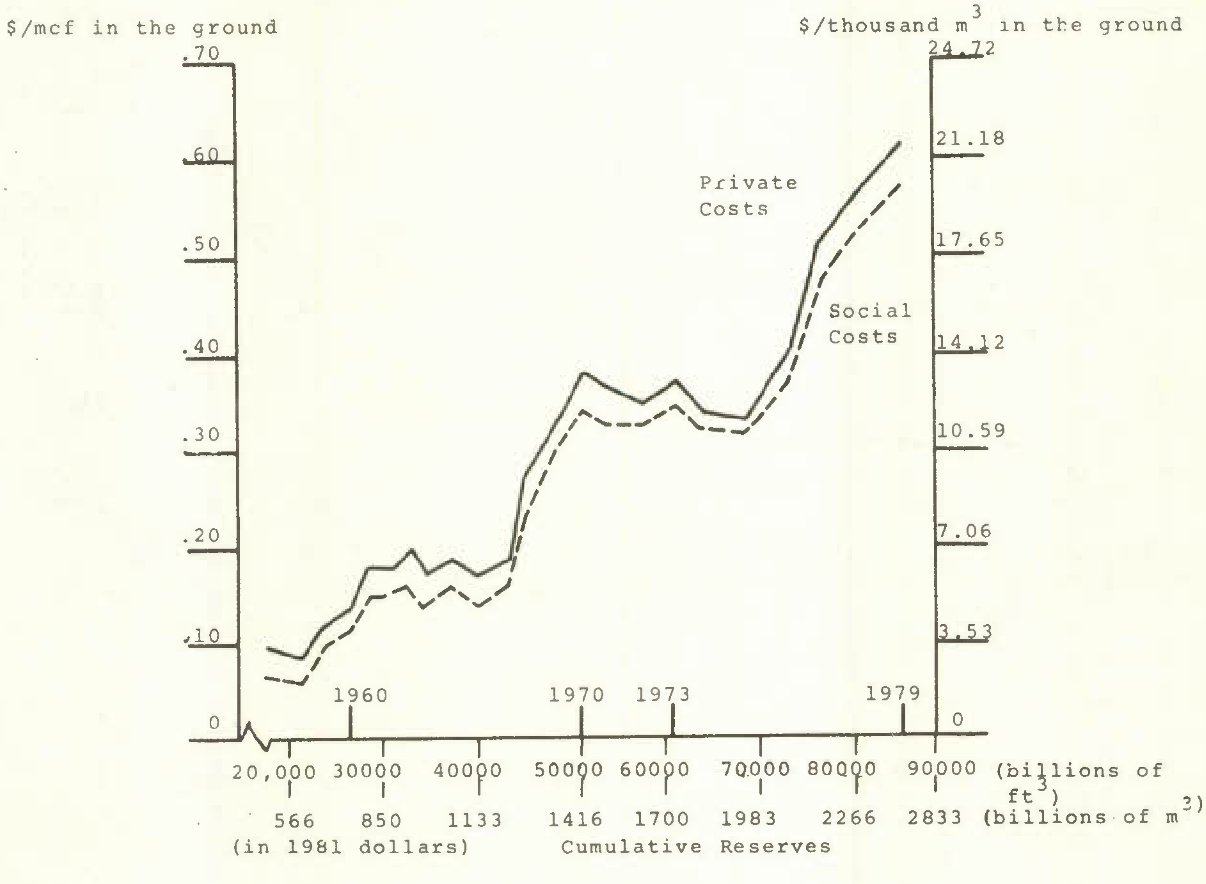


FIGURE 5

COSTS FOR CUMULATIVE BOOKED RESERVES OF CONVENTIONAL CRUDE OIL

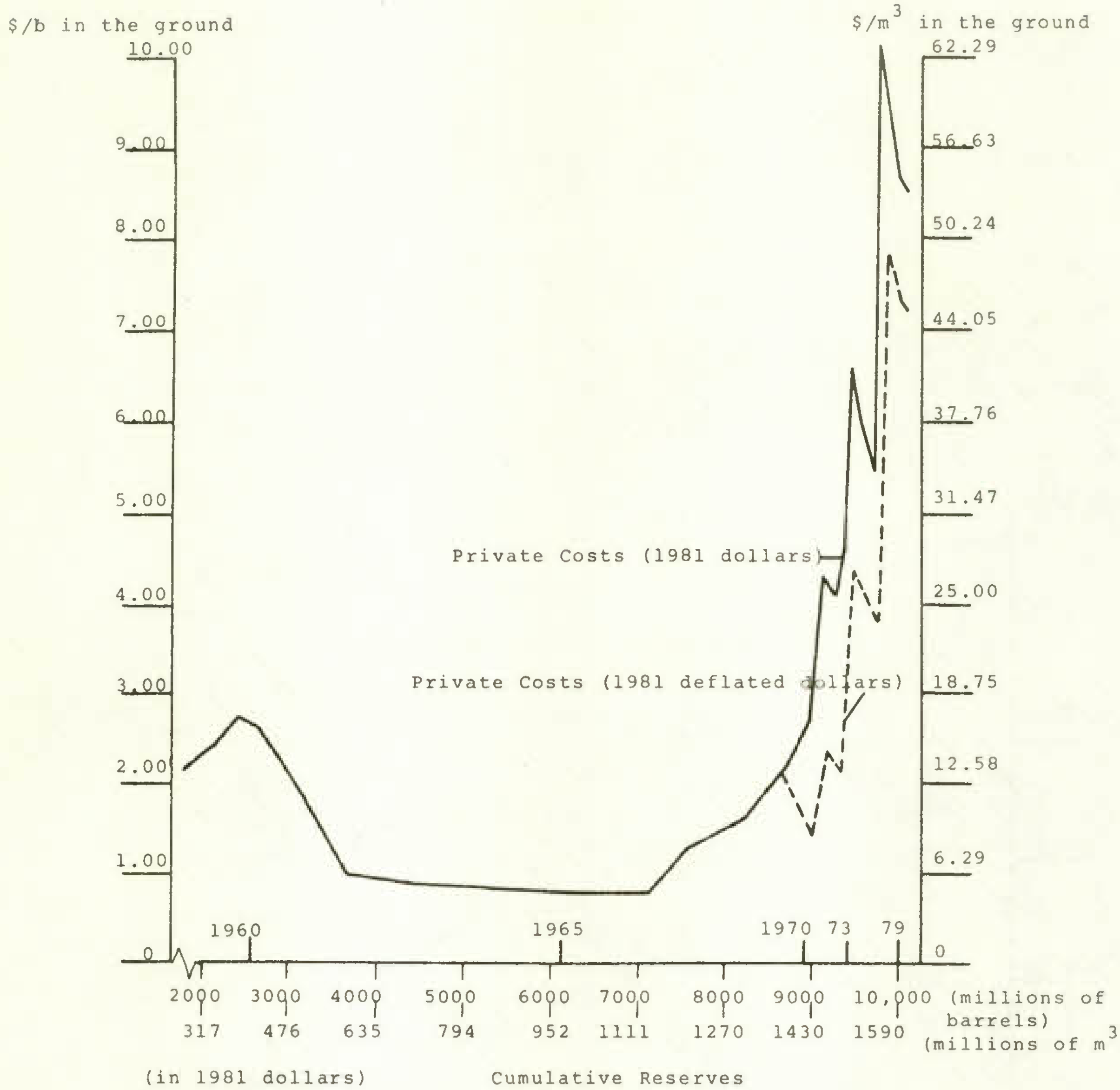


FIGURE 6

COSTS FOR CUMULATIVE RESERVES
OF NATURAL GAS

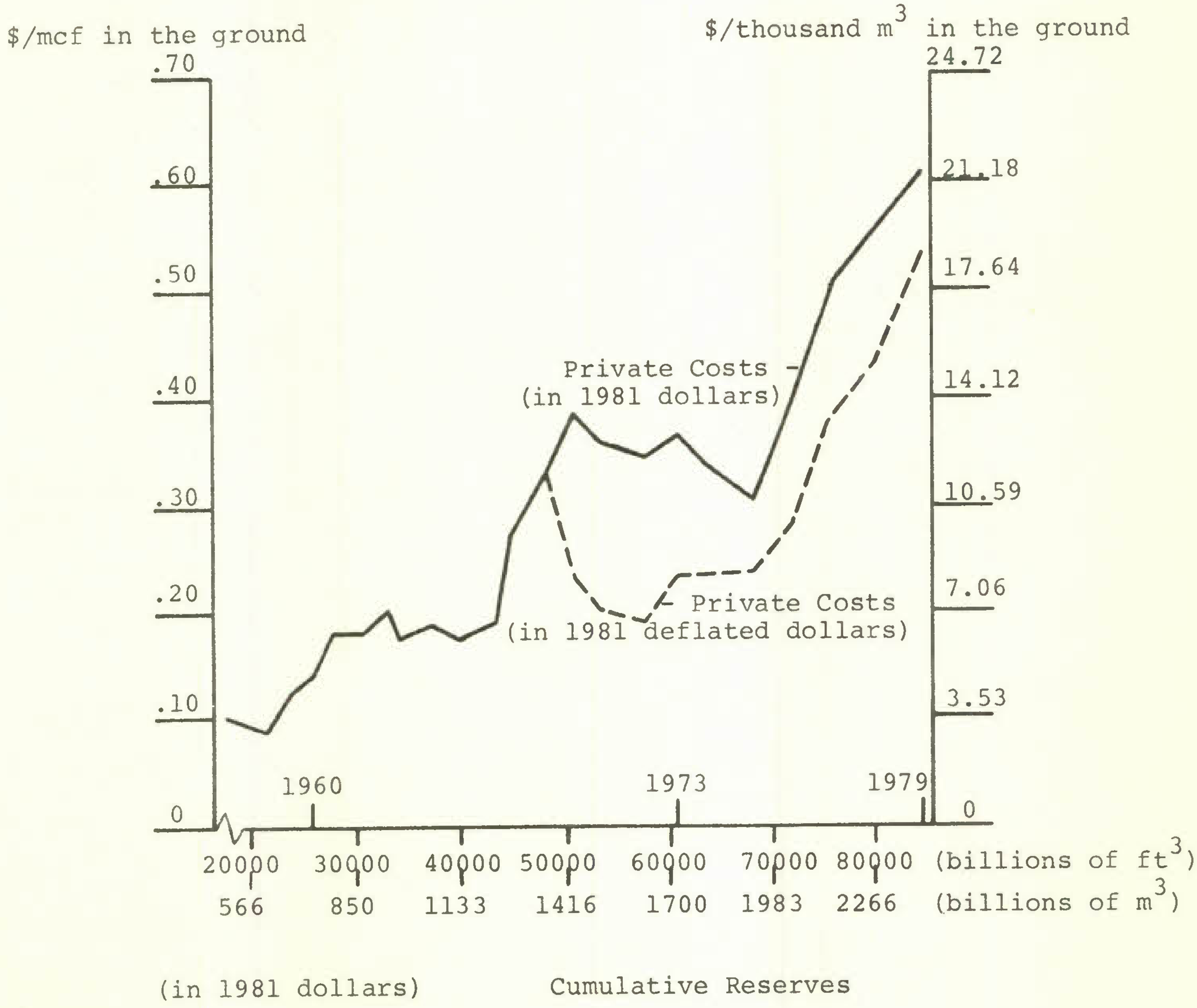


FIGURE 7

NUMBER OF WELLS FOR CUMULATIVE BOOKED RESERVES
OF CONVENTIONAL CRUDE OIL IN THE GROUND

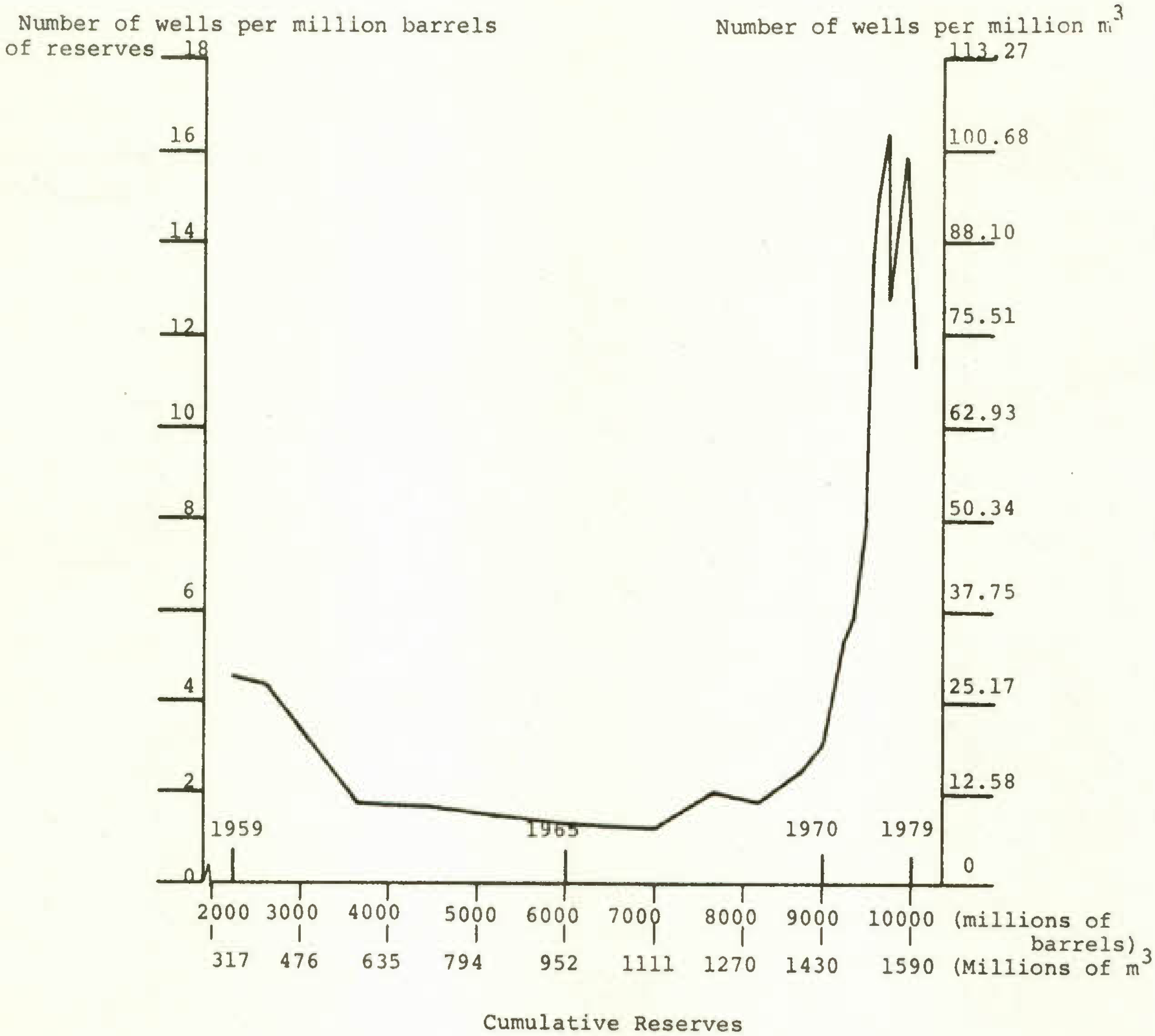


FIGURE 8

NUMBER OF WELLS FOR CUMULATIVE BOOKED RESERVES OF NATURAL GAS

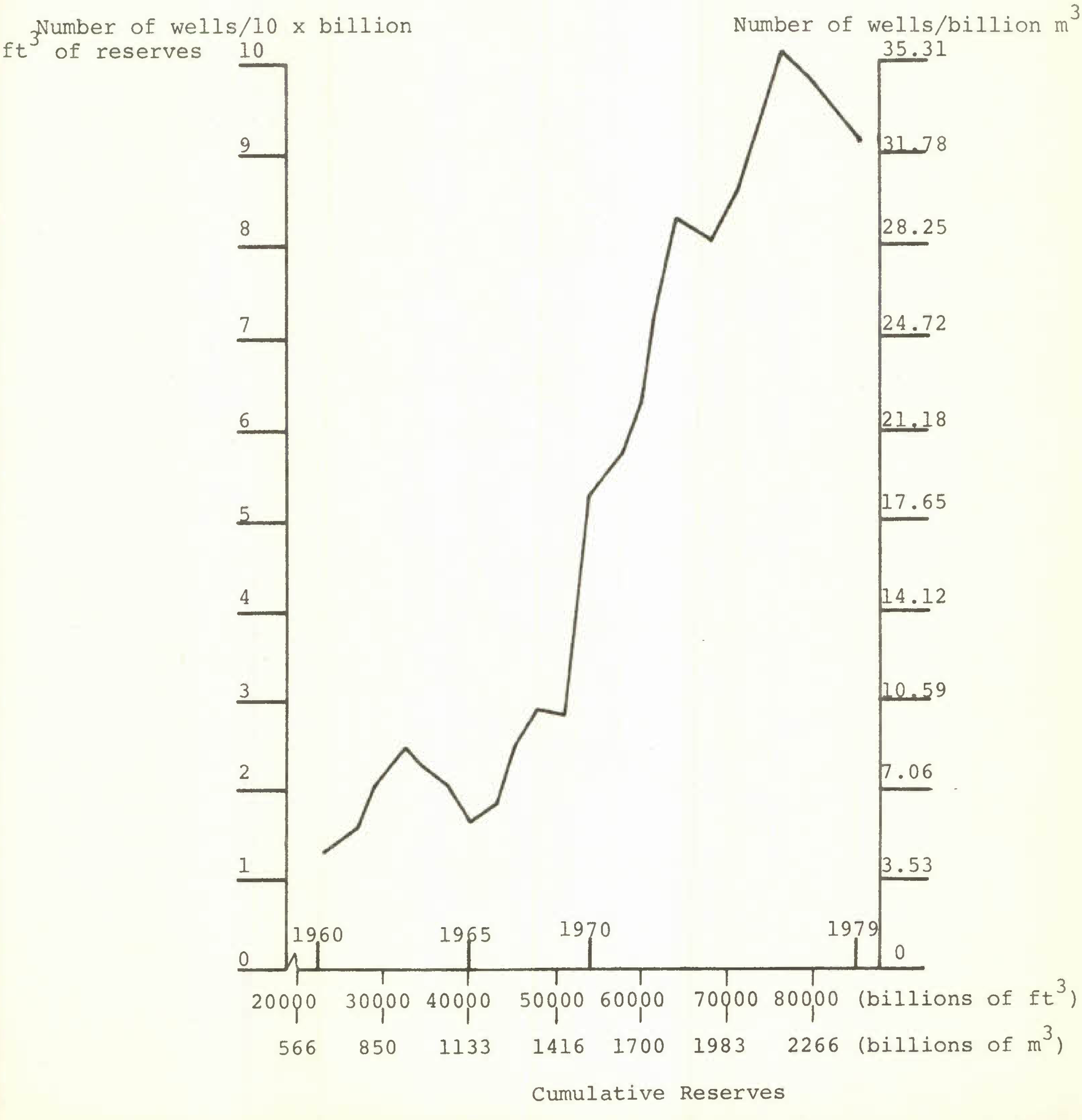


Figure 9

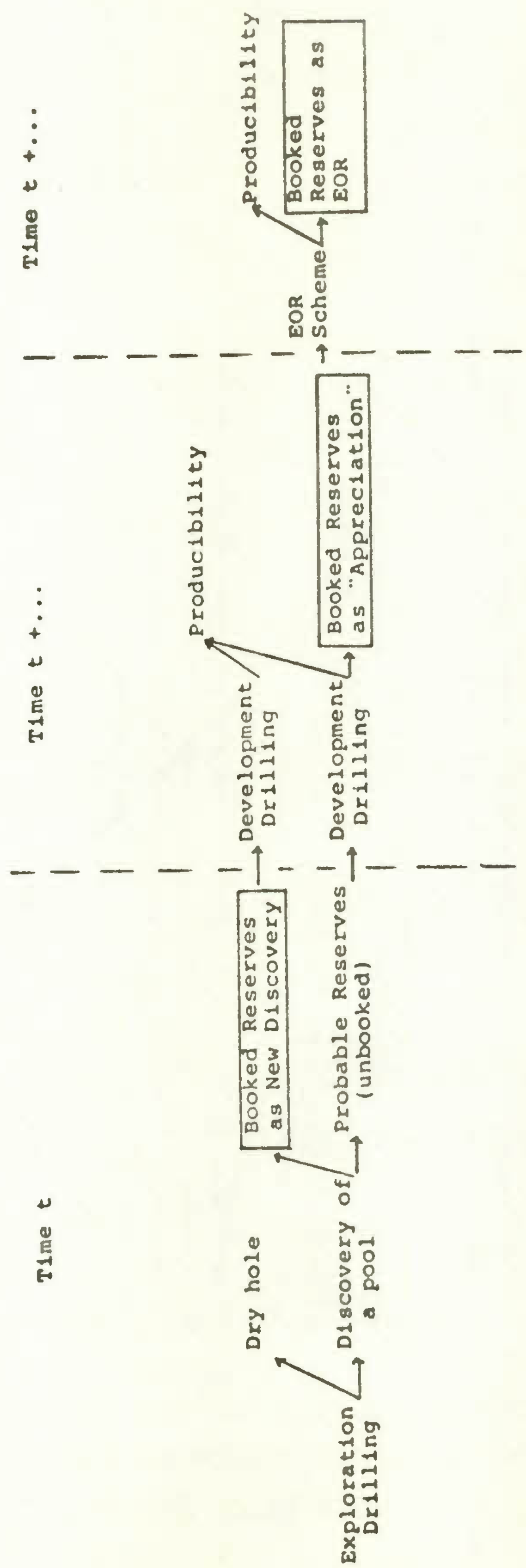
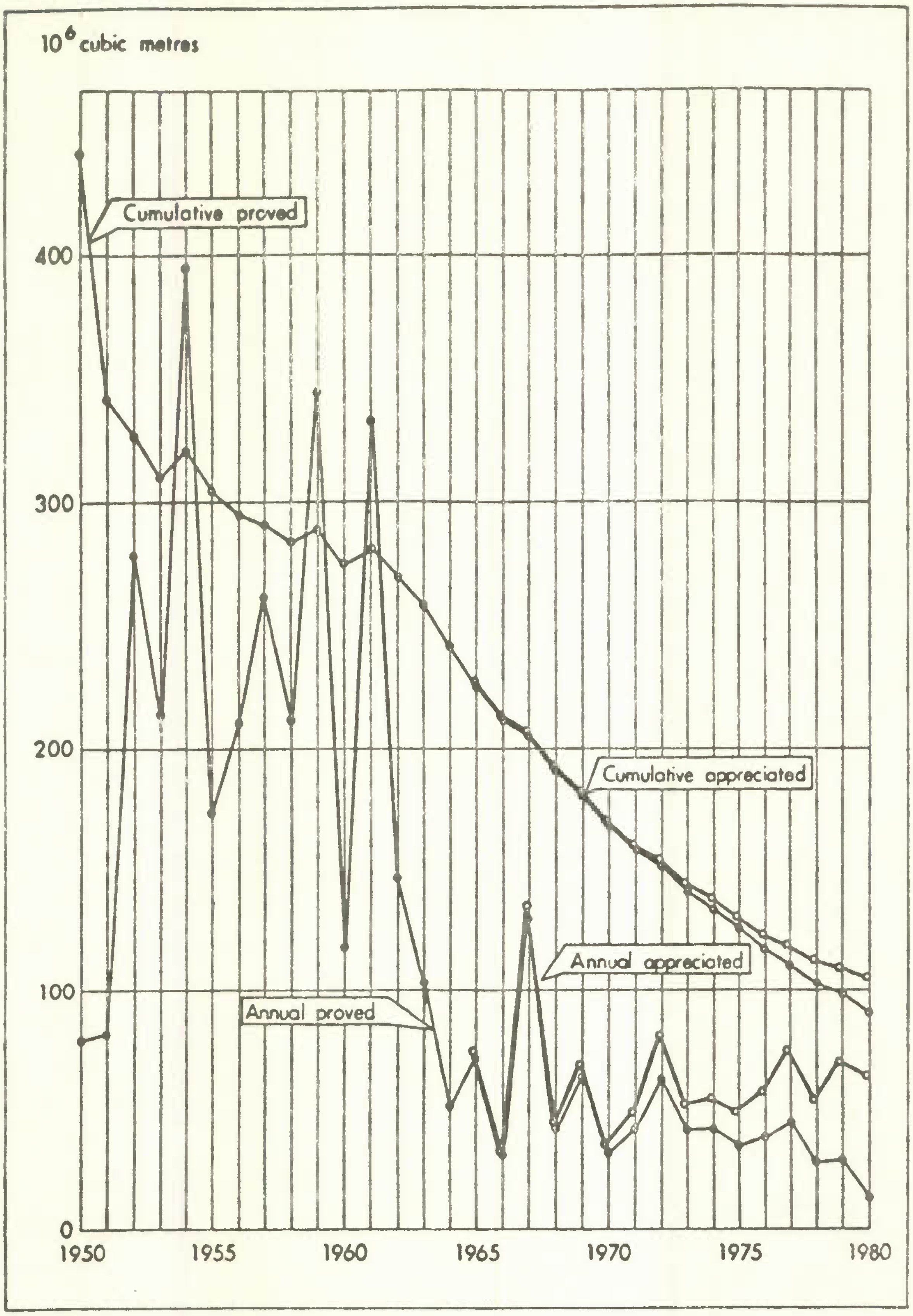

Time t
Exploration Drilling
Dry hole
Discovery of a pool
Booked Reserves as New Discovery
Probable Reserves (unbooked)
Time t +...
Development Drilling
Development Drilling
Producibility
Booked Reserves as "Appreciation"
Time t +...
EOR Scheme
Producibility
Booked Reserves as EOR

Figure 10

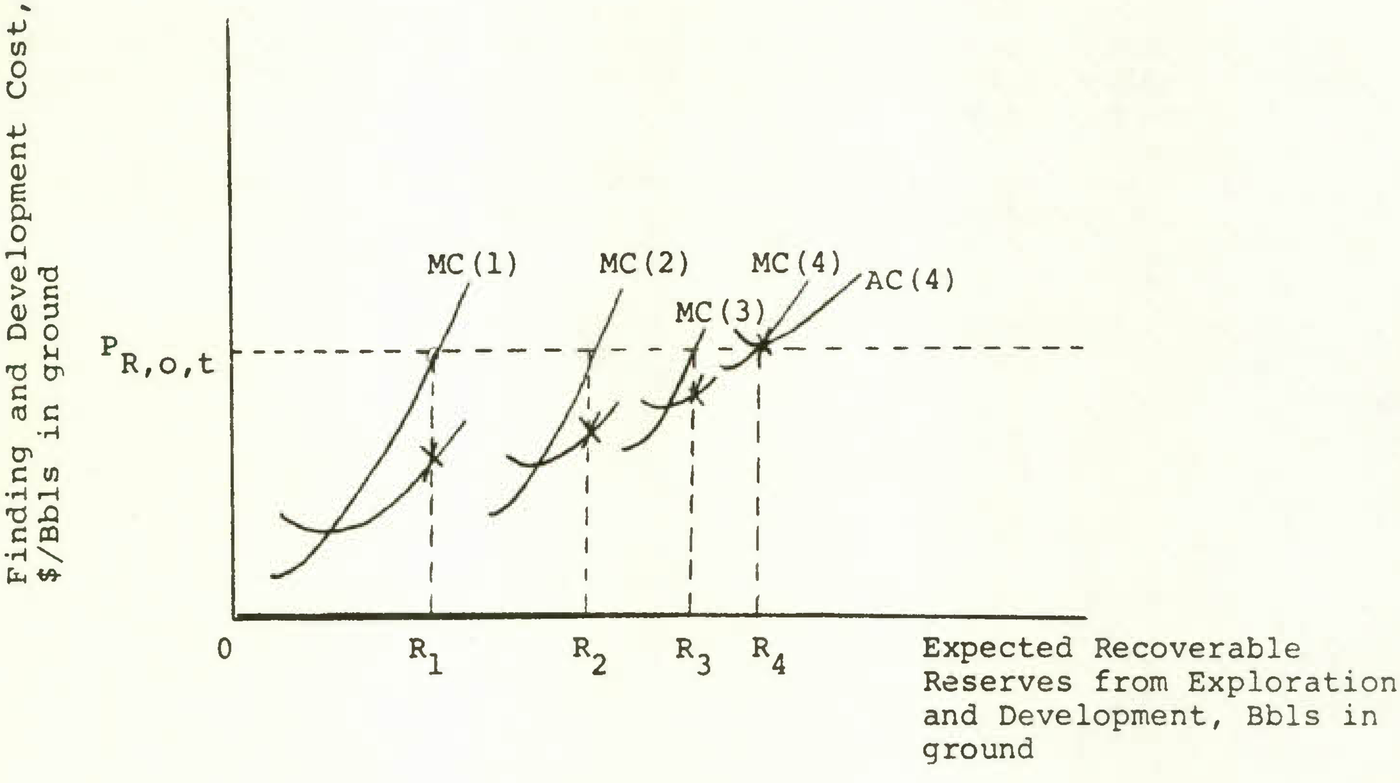


TRENDS IN THE DISCOVERY OF INITIAL ESTABLISHED RESERVES OF MARKETABLE GAS PER EXPLORATORY WELL

ENERGY RESOURCES CONSERVATION BOARD
ALBERTA, CANADA

Figure 11

Short Run and Long Run Supply



Notes

1. The unsmoothed costs are shown in Appendix A. Also shown in Tables A2 and A3 are the actual amounts of reserves booked each year by category of reserves.

2. See discussion in Appendix B.

3. Netbacks are based on a paper by the Financial and Fiscal Analysis Division at EMR, "Do Governments Take Too Much?", Sept. 13, 1982. It may be noted that in our paper the netbacks for oil do not reflect the extra profitability that may accrue because of revenues generated through the sale of joint products associated with oil. The extra value of the joint products has not been assigned to oil. However we have quoted estimated values for gas reserves that do include the value of co-products such as NGL's that are associated with natural gas.

4. A parallel study to this paper will report in detail on the estimated value of developed reserves during the past decade.

APPENDIX A

The appendix proceeds with a statement of the key variables that are calculated in the analysis, a detailed overview of the methodology used in the calculations, and a presentation of the raw data and equations. We conclude with a statement of the results.

I) VARIABLES

There are five key output variables that are calculated in the analysis. The first variable is the unit cost of adding to established petroleum reserves in a given year. This is the unit cost of booked reserves. Recall that annual additions to reserves result from new discoveries and the development of reserves. The unit cost of booked reserves is further broken down to reveal the unit exploration cost and the unit development cost of adding to established reserves. These variables are given by equations A1), A2) and A3).

A1) Unit cost of booked reserves = (development cost + exploration costs) / total booked reserves.

A2) Unit exploration cost for booked reserves = exploration costs / total booked reserves.

A3) Unit development cost for booked reserves = development costs / total booked reserves.

All results are given in 1981 dollars. The reserves data and the cost data are smoothed with a five year moving average thus the tabulated results are also smoothed. The justification for the averaging is given in the text.

The results of the equations are given for oil and gas in the tables in Appendix V.

II) METHODOLOGY

i) Reserves

The measurement of reserves is of particular importance in this type of analysis. The reserves data are taken from the Alberta Energy Resources Conservation Board (AERCB) 1981 Annual Reserves Report. Prior to 1976 the Board reported a value for the initial recoverable reserves for oil and for gas in each year as well as a value for the appreciated initial recoverable reserves in each year. The appreciated reserves value reported for each year took account of the fact that crude oil and natural gas reserves reported in a given year have historically increased beyond the initial reported value due to development and re-evaluation of the reserves. Oil reserves may further be increased through implementation of EOR schemes. This increase is called the normal appreciation of reserves.

Historical data for Alberta for the 1947-76 period provided the following equation for the appreciation factor:

$$A4)\ A = 1 + 6.98989(1-e^{-t4.4724})$$

where A is the appreciation factor and t is the number of years after the discovery year.[1] The asymptotic value for this factor during the period is approximately eight.

The appreciation factor for oil reserves discovered in the latter ten years of the period is believed by the AERCB to be considerably lower than the predicted value and thus not reflected in the appreciation equation. Use of this estimated appreciation factor is likely to create an upward bias in the estimate of the appreciation of the oil reserves discovered in the latter years. For this reason the AERCB changed its method of reporting annual oil reserve discoveries and increases. Gas reserves are still reported as appreciated reserves.

Currently the AERCB reports annual additions to established reserves of conventional crude oil.[2] Natural gas reserves are reported in both forms. Booked (reported) additions to reserves are now given for each year commencing in 1951 and running to

1981. The booked reserves are reported for a given year. They are not assigned back to previous years nor to particular pools.

Booked reserves are categorized as new discoveries and reserves acquired through development and re-evaluation and EOR. These reserve categorizations are used in this analysis.

The data for oil reserves are employed exactly as they are reported in the AERCB 1981 Annual Reserves Report, Table A4, p. A-9. Data are given for the period 1951-1981. The gas data are not complete as they are reported in Table A-5, p. A-11 of the same report. The data for new discoveries of gas and reserves of gas found by development are not available for the years 1952-1959 inclusive. Booked reserves of gas are reported from 1951-1981. Rather than shorten the period under analysis, the decision was made to substitute the missing data with appreciation data for gas as reported in the AERCB's 1980 publication Gas Reserves Trends, Table G-3.

This table shows appreciated gas reserves assigned back to the year of discovery. The appreciated reserves are reported according to the size of the reserves for each year following the discovery year. It is therefore possible to calculate the development that takes place in each year. This will be shown below.

A small section of the AERCB appreciation table is reproduced in Table A1.[3] It is important to note that figures given in the table pertain to about 63 per cent of the reserves in the province of Alberta as of December 31, 1980.[4]

TABLE A1

Discovery Year	Number of Years After the Discovery				
	0	1	2	3	 20
1951	6,508	11,016	14,706	17,094	....
1952	33,363	58,615	60,322	|	....
1953	27,229	54,391	|	|	....
|	|	|	|	|	....
|	|	|	|	|	....
1981	|	|	|	|	....

Source: AERCB Gas Reserves Trends.

Reserves are in millions of cubic metres.

The figures given in year 0 represent new gas discoveries for each year. In 1951, 6,508 million cubic meters of gas were discovered. An increase in the size of the reserve is reported in each year following the discovery. The reserve size is 11,016 million cubic metres one year following the 1951 discovery. Hence the development done in 1952 is given by the difference between the size of the reserve one year after discovery and the size of the initial discovery. The size of reserves found by development in 1952 was 4,508 million cubic metres.

The reserves found by development in 1953 are given by the increase in the size of the 1951 discovery from the first to the second year after the discovery and the increase in the size of the 1952 discovery one year after the discovery.

This method is used to determine the development done in each year from 1952 to 1959. The new discoveries for each year are given in column 0. The sum of the annual new discoveries and reserves by development yields the annual additions to reserves. This value is some fraction of the booked reserves that are reported in the AERCB 1981 Annual Reserves Report. A difference between the two values of booked reserves exists because the Gas Trends data do not represent all of the province's reserves. Recall that the AERCB appreciation table pertains to only 63 per cent of the province's gas reserves. To complete the calculations, the remaining annual booked reserves that are not yet categorized must be assigned to either new discoveries or reserves by development.

The allocation is done in the following way. The uncategorized booked reserves are assigned to new discoveries according to the ratio of unappreciated new discoveries to the sum of new discoveries and reserves by development for each year. These values are then added to the new discoveries reported in the Gas

Trends Table G-3. The resulting sums are used for new discoveries for the years 1952-1959 inclusive. They are given in Table A3, column 1 in Appendix V. The same procedure is used to calculate reserves by development. These results are given in Table A3, column 2 in Appendix V.

ii) Costs

The cost data for this analysis are taken from the 1980 Canadian Petroleum Association (CPA) Statistical Handbook. Exploratory costs are categorized into land acquisition and rental, geological and geophysical, and exploratory drilling expenditures. Development costs include expenditures for development drilling, secondary recovery and pressure maintenance, and field equipment. When development costs pertain to gas, expenditure for gas plants must also be included.

Each cost category except for land expenditures is employed exactly as it is reported in the CPA Handbook. The treatment of land expenditures is outlined in Section iii of this Appendix. The allocation of the expenditures to gas and oil is outlined in Section iv.

One of the key adjustments that must be made to the annually reported expenditures of the petroleum industry accounts for the production lags that characterize exploration activities.

Production lags necessitate the incorporation of a lag structure into the cost analysis.[5]

There is a very distinct delay between the time at which money is spent to acquire land for exploration and the time at which oil is actually discovered. Time lags also exist between investment into geological and geophysical activities and discovery, and between exploratory drilling and discovery.

The costs of acquiring land, undertaking geophysical activity and exploratory drilling are increased by the fact that funds are tied up during the delay period. This suggests that a cost of money must be incorporated into the lag structure. The longer the delay period is, the higher the cost of money will be. The lag structure used in this analysis assumes that on average land expenditures are made three years prior to the time of discovery, geophysical expenditures are made two years prior to discovery and exploratory drilling occurs one year prior to the discovery. The total cost of exploring for new reserves is therefore expressed as:

A5) $\text{TOTAL EXPLORATION COST}_{(\text{private})} = \text{Land expenditure}_{(t-3)} (1+r_{t-3})^3 + \text{geophysical expenditure}_{t-2}(1+r_{t-2})^2 + \text{exploratory drilling expenditure}_{t-1}(1+r_{t-1})$.

A6) TOTAL EXPLORATION COST$_{(social)}$ = Geophysical expenditure$_{t-2}$ $(1+r_{t-2})^2$ + exploratory drilling$_{t-1}$ $(1+r_{t-1})$.

where t is the current time period and r is the cost of money. The McLeod Young Weir bond yield for ten industrials is used to account for the cost of money. The bond rate is inflated by 40 per cent to account for the debt/equity ratio of the oil companies.[6] Petroleum companies can finance their investments either through equity or debt. The type of financing will affect the rate of return and this is captured by the ratio. The 40 per cent factor is considered to be a reasonable factor to account for the average mix of financial instruments that firms across the industry use. The exclusion of land costs in equation A6 is explained in Section iii.

iii) Land Expenditures

The land acquisition and rentals category in the CPA Handbook includes payments to the Alberta Government for the acquisition of rights to explore for oil and gas and to further develop these areas for the eventual production of any discoveries. These payments arise in the form of payments for exploration permits and licenses, crown drilling reservations, and petroleum and natural gas reservations. Payments are also made for the acquisition of production leases providing the right to produce gas and oil.[7] Rental fees are also included in the land expenditure category. These are payments made annually by the industry to procure on-going rights. However, these fees have been netted out of land expenditures in this analysis because they pertain primarily to production. Hence they are more accurately defined as operating expenses.

Payments made for the acquisition of exploration and production rights are made through bonus bidding. These bonus payments are of particular interest as they represent a component of economic rent on the natural resource. As economic rents they result in private costs to the petroleum explorationist and producer but they are not social costs. It is expected that when the profitability of the resource is perceived to be high, the bonus bids will be correspondingly high.

The economic cost of a resource from society's point of view is expressed in terms of the opportunity cost of using that resource in an alternative activity. It is generally considered that land used in petroleum activities does not have an opportunity cost insofar as it has no other use or petroleum activities do not preclude other activities from taking place simultaneously.[8] Bonuses however do represent a private cost as they do cause private funds to be tied up throughout the delay period.

When determining which bonus payments apply to exploration activities, a decision must be made in order to allocate exploration and production bonuses accordingly. Bonuses consist of permits, licenses and reservations which grant the right to explore for reserves and to develop them. They also consist of leases which grant the right to produce petroleum.

Upon first glance it seems obvious to relate production leases to production and payments for permits, licenses, and reservations to exploration. That division however becomes somewhat tenuous when one considers that production rights may be acquired through the purchase of leases for land that may never actually produce any oil. Further, historically reserves on Crown Lands have been obtained through the purchase of production leases. The prospects on Crown Lands are likely to have been more certain than other prospects however they were still undrilled upon purchase and would therefore require some exploratory drilling. For these reasons production leases are included as bonus payments made for exploration purposes in calculation of private land costs.

The bonus payments are taken from the CPA Yearbooks and Statistical Handbooks (1956-80). The CPA bonus categories include: payments to the Director of Mineral Rights and the Mining Recorder, payments for Crown Drilling Reservations, Petroleum and Natural Gas Drilling Reservations, Petroleum and Natural Gas Leases, Natural Gas Licenses and Leases, Block A Permits and Leases, Petroleum and Natural Gas Permits, Indian Lands, and Federal Lands. Over the years the number of bonus categories has declined and currently bonuses consist of Production Leases, Exploration Licences, Indian Lands and Federal Lands payments.

iv) The Allocation of Expenditures to Oil and Gas

The CPA reports overall industry expenditures made for both oil and gas. The procedure used in this analysis to allocate expenditures specifically to oil or gas is one that was developed by Peter Eglington in his 1975 PhD. Thesis, "The Economics of Industry Petroleum Exploration".

Exploration expenditures other than land expenditures are allocated to oil simply by multiplying the dollar amount by the oil intent ratio. The intent ratio simply expresses the number of exploratory wells drilled with the intent of finding oil as a fraction of the total number of exploratory wells drilled . Eglington presents data for the number of wells drilled for the purpose of finding oil for the period 1946-1970. The intent data was taken from the computer files of Imperial Oil (the Omega File). In this file the drilling intent was given by a one digit code that designates the purpose for which the well is being drilled. The intent of the well is assigned at the time of licensing and is determined by the Scouting and Geological Departments.[9] Intent data for the post 1970 era is not given in Eglington's paper.

In order to approximate the intent ratios for the past 1970 period without using actual oil well intent data, the assumption is made that the average value of the ratio of the number of exploratory oil well completions to the number of intent wells (the success ratio for oil) for the pre-1970 period remains constant until the mid-seventies. Beginning in 1975 the success ratio is assumed to rise until 1979 at which point it remains stable for the remaining three years of the period.

The success ratio for oil is then divided into the number of oil well completions (obtained from the CPA Handbooks, Section I, Table 5) for each year after 1970 to obtain the number of exploratory wells drilled for the purpose of finding oil. This is the number of oil intent wells.

To illustrate, the average value of the ratio of the number of total known oil well completions to the total number of exploratory oil intent wells for 1957-1970 is:

A7) $$\frac{1508}{7195} = .211$$

The total number of completions over the period is taken from the CPA Statistical Handbooks, Section I, Table 5 and the total number of intent wells is taken from Eglington, Tables 7.3 and 7.4. The ratio of .211 is assumed to remain constant until 1975 at which time it rises to .26. The assumed values for the success ratio for oil from 1976 to 1981 are as follows: .28, .30, .32, .34, .34, .34.

The success ratio for oil is assumed to increase during the seventies to account for the fact that rising netbacks prompted participants within the industry to go after known but poorer and less productive prospects. We note that rising netbacks may create an incentive to explore risky and more marginal prospects which put downward pressure on the success ratio. However, it is believed that during the period in question rising netbacks prompted industry participants to go after known prospects which ultimately put upward pressure on the success ratio for oil.

The assumed values of the success ratios are divided into the annual observed exploration oil well completion to obtain the number of calculated oil intent exploratory wells:

A8) 1971: calculated oil intent wells = 111/.211 = 526.

The number of calculated oil intent wells can then simply be taken as a fraction of the total number of exploratory wells drilled in a given year to obtain the oil intent ratio.

A9) 1971: 526/1007 = .52 = oil intent ratio.

This method is used to estimate the oil intent ratios for the 1970-1981 period. The gas intent ratio is simply one minus the oil intent ratio.

The method outlined above for obtaining the intent ratios without actual intent data is indeed a proxy method. Hence some discussion is warranted that addresses the sensitivity of the cost results to the assumed values of the success ratio for oil.

If the success ratio in any given year is lower than the assumed value, the intent ratio for oil will be higher and a higher portion of all petroleum expenditures must be allocated to oil. A higher success ratio will result in lower intent ratios for oil and a lower portion of petroleum expenditures will be allocated to oil.

The resulting trends are obvious. Higher oil intent ratios will result in higher unit costs for discovering oil and lower intent ratios will result in lower unit costs. The key issue however, concerning the assumption is the sensitivity of unit costs to changes in the assumed value of the success rate for finding oil. Different values for the success rate are tested to derive the intent ratio.

A high scenario for the oil success ratio is tested. In the test case the value of the success ratio for oil is assumed in 1970 to be .311. This value remains constant until 1975 at which point it rises to .36. The assumed values in the following years are as follows: .38 in 1976, .40 in 1977, .42 in 1978, and .44 in 1979, 1980, and 1981. The resulting intent ratios and unit costs for oil and gas are given in Tables A7 and A11. They are illustrated in Figures A1 and A2.

The scenario with higher success ratios for oil yields unit costs for booked reserves of oil that are 8-9% lower on average over the period than in the base scenario. The unit exploration costs for oil in the high scenario are about 12% lower on average over the period. The unit development costs are not affected as they are not allocated by means of the intent ratio.

The higher success ratios for oil imply higher intent ratios for gas. Hence a higher proportion of expenditures are allocated to gas. Accordingly, in this test scenario the unit costs for exploration and reserve bookings for gas increase.

The development costs are allocated to gas and oil by multiplying these costs by the ratio of the number of wells completed for gas or oil to the total number of completions. This is the completion ratio. Note that gas plant expenditures are allocated in entirety to gas.

The calculations of private exploration costs requires that land payments made for bonuses also be allocated to oil or to gas. It is not likely to be suitable to simply multiply bonus expenditures by the drilling intent ratio. It is not expected that the rate at which land bonuses are paid for oil will correspond to the rate at which oil wells are drilled with respect to gas wells.

By way of example, in a given year the profitability of drilling for oil may be around 100 million dollars and the profitability of drilling for gas is also around 100 million dollars. However, it may take far fewer oil wells to capture those profits than it will gas wells. Hence we would expect that the rate at which bonuses are obtained for oil with respect to total bonuses will exceed the rate at which wells are drilled for oil with respect to the total number of exploratory wells. Bonus payments are allocated to oil and to gas according to the procedure outlined in Eglington's 1975 work. The allocation was based on historical observation of bonus purchases.[10] The allocation for the period 1951-76 is as follows:

50 per cent of payments to the Mining Recorders, the Director of Mineral Rights, for Petroleum and Natural Gas Reservations, Indian Lands, Federal Lands, Block A Permits and Petroleum and Natural Gas Permit are allocated to oil.

66.6 per cent of Petroleum and Natural Gas Leases, and Block A Leases are allocated to oil.

100 per cent of Crown Drilling Reservations are allocated to oil.

The remaining bonuses are allocated to gas. In 1976 all bonus categories were assigned 50 per cent to oil and 50 per cent to gas. In the following years all categories were allocated 66.6 per cent to oil and 33.3 per cent to gas.

III) DATA

All reserves data come from the AERCB. The oil reserves data are taken from the AERCB 1981 Annual Reserves Report. The gas data are taken from the Reserves Report and from the AERCB's Gas Reserves Trends 1980. The cost data are compiled from the CPA 1980 Statistical Handbook and the Statistical Yearbooks 1956-1977. The intent ratios are compiled from intent data reported in Peter Eglington's 1975 work and from drilling data given in the CPA Yearbooks. The completion ratios are also compiled from CPA drilling data.

The price deflator used to put all costs in 1981 dollars is obtained by linking the General Wholesale Price Index for the year 1947 to 1956 with the Industrial Selling Price Index for the year 1957-1981. This yields an index where 1971=100. This index is then converted to let 1981=100. These indicies are taken from the Statistics Canada Cansim File. The MacLeod Young Weir bond rate for ten industrials is used for the cost of money. This series also comes from the Cansim File. The raw data for oil and gas are given in Tables A2 and A3.

IV) EQUATIONS

The following equations are used in the analysis:

A10) $GG_i = GG \times INTENT_i$ $\qquad$ i = gas, oil

A11) $XD_i = XD \times INTENT_i$

A12) $DC_i = DC \times CRATIO_i$ (if i = gas

$DCgas = DC \times CRATIO_{gas} + GPLANT$)

A13) $TFCP_i = BONUS_{i(t-3)} \times (1+r_{t-3})^3 + GGi_{(t-2)} \times (1+r_{t-1})^2 + XD_{i(t-1)} (1+r_{t-1}) + DCi$

A14) $TFCS_i = GG_{i(t-2)} \times (1+r_{t-2})^2 + XD_{i(t-1)} \times (1+r_{t-1}) + DC_i$

A15) $ECPB_i = [(TFCP_i - DC_i)/BR]/ISPI$

A16) $DCPB_i = (DC_i/BR)/ISPI$

A17) $TCPB_i = (TFCP_i/BR)/ISPI$

A18) $BC_i = (BONUS_{i(t-3)}/BR)/ISPI$

A19) $MCB_i = [(BONUS_{i(t-3)} \times (1+r_{t-3})^3 - BONUS_{i(t-3)})/BR]/ISPI$

A20) $GGC_i = (GG_{i(t-2)}/BR)/ISPI$

A21) $MCG_i = [(GG_{i(t-2)} \times (1+r_{t-2})2 - GG_{i(t-2)})/BR)]/ISPI$

A22) $XC_i = (XC_{i(t-1)}/BR)/ISPI$

A23) $MCX_i = [(XD_{i(t-1)} \times (1+r_{t-1}) - XD_{it-1})/BR]/ISPI$

where:

GG = geological and geophysical expenditures

CRATIO = completion ratio

XD = exploratory drilling expenditure

TFCP = total private cost for booked reserves

DC = development expenditure

TFCS = total social cost for booked reserves

INTENT = intent ratio

ECPB = exploratory cost of booked reserves (per unit)

BONUS = expenditures for bonuses

DCPB = development cost of booked reserves (per unit)

BC = bonus cost of booked reserves (per unit)

TCPB = total unit cost of booked reserves

MCB = money cost of bonuses (per unit)

BR = booked reserves

GGC = geology cost of booked reserves (per unit)

MCG = money cost of geology (per unit)

ISPI = industrial selling price index

XC = exploratory drilling cost (per unit)

MCX = money cost of drilling (per unit)

r = cost of money

V) RESULTS

The results are tabulated in the tables in this appendix. Tables A4 and A8 correspond to Figures 1, 2, 3 and 4 in the text. These results express all unit costs in terms of booked reserves.

Note that costs in these tables are private costs. Social costs are determined simply by excluding the cost of bonuses and the money cost of bonuses. Total unit costs for booked reserves are shown as well as the component costs: the development, bonus, geology, drilling and money costs for booked reserves.

Table A2

Raw Data for Oil

	m^3 of new (millions) discoveries	m^3 of reserves by (millions) development + reevaluation	m^3 of reserves by EOR (millions)	m^3 of booked reserves (millions)	Geological + geophysical expenditures (millions $)	Exploratory drilling expenditures (millions $)	Bonuses paid for oil (millions $)	Total development expenditures (millions $)	Oil Intent ratio	Oil completion ratio	Industrial Selling price index	McLoed, Young, Weir bond rate	Bond rate inflated by 40 per cent
YEAR= 1947	0.0	0.0	0.0	0.0	4.0	5.5	0.0	7.0	0.0	0.0	0.21	0.0	0.0
YEAR= 1948	0.0	0.0	0.0	0.0	10.5	7.5	2.1	29.0	0.0	0.0	0.25	0.0352	0.0492
YEAR= 1949	0.0	0.0	0.0	0.0	16.0	14.5	13.3	43.5	0.0	0.0	0.25	0.0356	0.0498
YEAR= 1950	0.0	0.0	0.0	0.0	24.5	11.0	24.3	64.0	0.0	0.0	0.27	0.0350	0.0490
YEAR= 1951	15.3	29.2	0.0	44.5	39.5	27.5	10.2	71.0	0.71	0.0	0.31	0.0396	0.0554
YEAR= 1952	14.4	48.2	0.0	62.5	53.5	27.0	14.9	83.0	0.74	0.0	0.29	0.0429	0.0600
YEAR= 1953	24.2	42.4	0.0	66.5	52.0	26.5	13.6	86.5	0.70	0.0	0.28	0.0449	0.0628
YEAR= 1954	1.9	53.7	0.0	55.6	44.5	35.0	39.6	74.5	0.70	0.0	0.27	0.0410	0.0574
YEAR= 1955	9.4	58.8	0.0	68.2	46.0	44.0	42.0	111.0	0.72	0.0	0.28	0.0399	0.0558
YEAR= 1956	3.5	78.5	0.0	82.0	40.5	46.0	49.1	153.5	0.74	0.0	0.29	0.0461	0.0645
YEAR= 1957	10.8	29.1	0.0	39.9	35.5	41.0	47.2	117.5	0.75	0.866	0.29	0.0536	0.0750
YEAR= 1958	1.3	-4.8	4.9	1.4	36.5	54.0	35.4	110.5	0.72	0.838	0.30	0.0499	0.0698
YEAR= 1959	14.9	37.2	16.0	67.5	31.5	48.0	51.1	121.5	0.73	0.779	0.30	0.0562	0.0786
YEAR= 1960	0.5	29.9	18.1	48.6	33.0	44.0	37.2	144.5	0.67	0.795	0.30	0.0574	0.0803
YEAR= 1961	1.7	31.5	24.5	57.5	30.5	52.0	32.7	149.5	0.64	0.721	0.30	0.0548	0.0767
YEAR= 1962	2.9	21.8	19.9	44.0	32.5	46.5	20.0	123.6	0.61	0.723	0.31	0.0544	0.0761
YEAR= 1963	14.6	12.6	29.2	56.6	28.0	50.2	41.2	136.5	0.69	0.787	0.31	0.0534	0.0747
YEAR= 1964	9.5	88.2	250.8	348.5	32.0	57.0	69.3	142.8	0.64	0.790	0.31	0.0549	0.0768
YEAR= 1965	28.6	42.6	-2.4	58.8	42.1	69.9	104.0	155.9	0.69	0.799	0.32	0.0557	0.0793
YEAR= 1966	89.1	13.5	38.3	140.8	68.1	75.7	80.6	134.3	0.63	0.714	0.32	0.0649	0.0908
YEAR= 1967	57.2	15.7	22.2	95.2	99.7	77.4	71.3	151.3	0.79	0.696	0.33	0.0709	0.0992
YEAR= 1968	62.0	14.8	42.9	119.8	87.2	87.6	78.4	159.5	0.75	0.585	0.34	0.0792	0.1108
YEAR= 1969	40.5	-44.5	58.5	54.5	86.4	89.8	86.9	179.6	0.68	0.515	0.35	0.0875	0.1225
YEAR= 1970	8.4	-7.6	36.1	36.7	80.3	83.8	24.2	165.4	0.49	0.330	0.36	0.0917	0.1283
YEAR= 1971	14.0	8.7	-0.8	22.1	65.5	80.8	28.2	152.1	0.52	0.343	0.37	0.0834	0.1167
YEAR= 1972	10.8	-5.6	14.8	20.0	71.2	102.1	33.8	223.3	0.27	0.337	0.38	0.0830	0.1162
YEAR= 1973	5.1	-6.0	10.2	9.2	70.7	131.4	48.0	284.4	0.31	0.283	0.43	0.0847	0.1185
YEAR= 1974	4.3	3.3	30.8	38.5	112.4	146.5	55.1	329.3	0.28	0.275	0.51	0.1016	0.1422
YEAR= 1975	1.6	2.1	3.3	7.0	99.0	149.1	53.5	438.2	0.23	0.255	0.56	0.1076	0.1506
YEAR= 1976	2.5	5.9	-27.0	-18.6	145.5	256.5	80.1	632.5	0.19	0.147	0.59	0.1048	0.1467
YEAR= 1977	4.8	5.1	9.2	19.1	223.4	394.7	284.5	717.4	0.26	0.193	0.64	0.0970	0.1358
YEAR= 1978	24.9	-1.9	1.4	24.4	350.3	644.5	409.6	963.4	0.31	0.234	0.70	0.1001	0.1401
YEAR= 1979	19.2	10.3	4.8	34.3	349.7	1027.5	683.9	1333.6	0.42	0.281	0.80	0.1098	0.1523
YEAR= 1980	9.0	5.1	8.6	22.7	452.3	1621.6	685.6	2099.6	0.45	0.292	0.91	0.1324	0.1853
YEAR= 1981	15.0	7.2	10.4	32.6	352.2	1543.7	292.0	2108.3	0.52	0.325	1.00	0.1622	0.2274

Table A3

Raw Data for Gas

	New discoveries (billions m^3)	Reserves from development (billions m^3)	Booked reserves (billions m^3)	Geological and geophysical expenditure (millions of $)	Exploratory drilling expenditure (millions of $)	Expenditure for bonuses (millions of $)	Development expenditure Net of gas plants (millions of $)	Intent ratio (gas)	Completion ratio (gas)	Industrial selling price index	Cost of money	Gas plant expenditure (in millions of $)
YEAR= 1947	0.0	0.0	0.0	4.0	5.5	0.0	7.0	0.0	0.0	0.21	0.0	0.0
YEAR= 1948	0.0	0.0	0.0	10.5	7.5	1.0	29.0	0.0	0.0	0.25	0.0492	0.0
YEAR= 1949	0.0	0.0	0.0	16.0	14.0	6.5	43.5	0.0	0.0	0.25	0.0498	4.0
YEAR= 1950	0.0	0.0	0.0	24.5	11.0	11.9	64.0	0.0	0.0	0.27	0.0490	3.5
YEAR= 1951	6.2	55.0	61.2	39.5	27.5	4.9	71.0	0.29	0.180	0.31	0.0554	2.0
YEAR= 1952	78.3	9.5	87.8	53.5	27.0	7.5	83.0	0.26	0.130	0.29	0.0600	2.0
YEAR= 1953	37.1	39.0	76.1	52.0	26.5	9.2	86.5	0.30	0.190	0.28	0.0628	1.0
YEAR= 1954	17.5	41.3	58.8	44.5	35.0	25.3	74.5	0.30	0.190	0.27	0.0574	2.5
YEAR= 1955	11.4	47.9	59.3	46.0	44.0	20.4	111.0	0.28	0.170	0.28	0.0558	6.0
YEAR= 1956	15.8	48.7	64.5	40.5	46.0	23.5	153.5	0.26	0.130	0.29	0.0645	18.5
YEAR= 1957	36.0	28.9	64.9	35.5	41.0	23.1	117.5	0.25	0.134	0.29	0.0750	6.0
YEAR= 1958	40.9	69.5	110.4	36.5	54.0	15.9	110.0	0.28	0.162	0.30	0.0698	29.0
YEAR= 1959	24.2	64.3	88.5	31.5	48.0	22.0	121.5	0.27	0.221	0.30	0.0786	12.5
YEAR= 1960	18.2	101.7	119.9	33.0	44.0	18.6	144.5	0.33	0.205	0.30	0.0803	20.5
YEAR= 1961	9.6	3.7	13.3	30.5	52.0	12.9	149.0	0.36	0.279	0.30	0.0767	61.0
YEAR= 1962	8.7	41.0	49.7	32.5	46.5	13.7	123.6	0.39	0.277	0.31	0.0761	20.0
YEAR= 1963	3.1	32.7	35.8	28.0	50.2	13.5	135.5	0.31	0.212	0.31	0.0747	36.0
YEAR= 1964	7.2	78.7	85.9	32.0	57.0	25.4	142.8	0.26	0.210	0.31	0.0768	29.0
YEAR= 1965	11.3	78.4	89.7	42.1	69.9	37.5	155.9	0.31	0.201	0.32	0.0793	32.1
YEAR= 1966	2.1	38.6	40.7	68.1	75.7	33.7	134.5	0.37	0.286	0.32	0.0908	44.3
YEAR= 1967	24.3	49.6	73.9	99.7	77.4	31.2	152.7	0.21	0.304	0.33	0.0992	88.0
YEAR= 1968	15.3	119.3	134.6	87.2	67.6	26.1	159.5	0.25	0.415	0.34	0.1108	87.0
YEAR= 1969	16.6	68.9	87.6	86.4	89.6	30.3	179.4	0.32	0.485	0.35	0.1225	91.2
YEAR= 1970	7.6	38.7	46.2	80.3	83.8	7.3	165.4	0.51	0.670	0.36	0.1283	162.3
YEAR= 1971	4.8	40.6	45.4	65.5	80.6	19.3	162.1	0.48	0.657	0.37	0.1167	214.0
YEAR= 1972	12.5	32.8	45.2	71.2	102.1	19.8	223.3	0.73	0.663	0.38	0.1162	109.7
YEAR= 1973	7.8	175.6	183.4	70.7	131.4	27.8	285.4	0.69	0.717	0.43	0.1185	65.3
YEAR= 1974	8.6	138.4	147.0	112.4	146.5	28.6	329.3	0.72	0.725	0.51	0.1422	126.1
YEAR= 1975	0.8	20.0	20.8	99.0	149.1	52.1	433.2	0.77	0.745	0.56	0.1506	123.8
YEAR= 1976	6.9	98.7	105.6	145.5	256.5	80.1	690.6	0.81	0.853	0.59	0.1476	155.0
YEAR= 1977	6.6	120.9	127.6	223.4	394.7	193.2	717.4	0.74	0.807	0.64	0.1358	143.8
YEAR= 1978	53.4	109.9	163.3	350.3	644.5	204.6	963.3	0.69	0.766	0.70	0.1401	165.9
YEAR= 1979	34.0	89.0	123.0	349.7	1027.5	341.9	1333.6	0.58	0.719	0.80	0.1523	204.7
YEAR= 1980	30.0	62.4	92.4	452.3	1621.6	543.4	2099.6	0.55	0.708	0.91	0.1853	241.1
YEAR= 1981	29.0	38.0	117.0	352.2	1543.7	196.1	2107.4	0.48	0.575	1.00	0.2274	310.9

Table A4

Private Costs for the Exploration and Development of Booked Reserves of Crude Oil (in 1981 dollars)

in dollars per m^3
(in dollars per barrel)

	Total Costs for Booked Reserves	Costs for Development	Costs for Exploration	Costs for Bonuses	Costs for Geology	Costs for Exploratory Drilling	Total Cost of Money
1957	13.94 (2.21)	6.85 (1.09)	7.09 (1.13)	2.1196 (0.3368)	2.0938 (0.3327)	2.1158 (0.3362)	0.7630 (0.1212)
1958	15.56 (2.47)	7.48 (1.19)	8.08 (1.28)	2.6664 (0.4237)	2.0488 (0.3256)	2.4398 (0.3877)	0.9275 (0.1474)
1959	17.27 (2.74)	7.92 (1.26)	9.34 (1.48)	3.3085 (0.5257)	2.1559 (0.3426)	2.6754 (0.4251)	1.2046 (0.1914)
1960	16.66 (2.65)	7.59 (1.21)	9.07 (1.44)	3.4216 (0.5437)	1.9479 (0.3095)	2.4053 (0.3822)	1.2995 (0.2065)
1961	13.33 (2.12)	6.25 (0.99)	7.08 (1.13)	2.6744 (0.4250)	1.4288 (0.2270)	1.9850 (0.3154)	0.9928 (0.1578)
1962	6.32 (1.01)	3.09 (0.49)	3.23 (0.51)	1.1830 (0.1880)	0.6434 (0.1022)	0.9278 (0.1474)	0.4801 (0.0763)
1963	6.00 (0.95)	3.04 (0.48)	2.96 (0.47)	1.0338 (0.1643)	0.5818 (0.0924)	0.9172 (0.1457)	0.4320 (0.0687)
1964	5.33 (0.85)	2.60 (0.41)	2.73 (0.43)	0.9315 (0.1480)	0.4959 (0.0788)	0.9261 (0.1472)	0.3787 (0.0602)
1965	5.09 (0.81)	2.41 (0.38)	2.68 (0.43)	0.9174 (0.1458)	0.4763 (0.0757)	0.9200 (0.1462)	0.3702 (0.0588)
1966	5.20 (0.83)	2.15 (0.34)	3.04 (0.48)	1.1124 (0.1768)	0.5319 (0.0845)	0.9677 (0.1538)	0.4299 (0.0683)
1967	9.07 (1.44)	3.24 (0.52)	5.83 (0.93)	2.0436 (0.3247)	1.2050 (0.1915)	1.7214 (0.2735)	0.8629 (0.1371)
1968	9.98 (1.59)	2.91 (0.46)	7.07 (1.12)	2.4108 (0.3831)	1.5568 (0.2474)	1.9861 (0.3156)	1.1128 (0.1768)
1969	13.62 (2.16)	3.50 (0.56)	10.12 (1.61)	3.5125 (0.5582)	2.3921 (0.3801)	2.4070 (0.3825)	1.8111 (0.2878)
1970	17.14 (2.72)	4.07 (0.65)	13.07 (2.08)	4.6446 (0.7381)	3.1297 (0.4973)	2.7037 (0.4296)	2.5870 (0.4111)
1971	27.00 (4.29)	6.80 (1.08)	20.20 (3.21)	6.5130 (1.0350)	5.2408 (0.8328)	4.1415 (0.6581)	4.3076 (0.6845)
1972	26.35 (4.19)	7.42 (1.18)	18.92 (3.01)	6.0537 (0.9620)	4.5097 (0.7166)	4.1387 (0.6577)	4.2228 (0.6710)
1973	29.01 (4.61)	9.94 (1.58)	19.06 (3.03)	6.0902 (0.9678)	4.1635 (0.6616)	4.5915 (0.7296)	4.2197 (0.6705)
1974	41.13 (6.54)	16.07 (2.55)	25.06 (3.98)	7.7977 (1.2391)	5.1036 (0.8110)	7.0104 (1.1140)	5.1466 (0.8178)
1975	37.78 (6.00)	16.92 (2.69)	20.86 (3.32)	6.1238 (0.9731)	4.1875 (0.6654)	6.2225 (0.9888)	4.3285 (0.6878)
1976	34.71 (5.52)	16.07 (2.55)	18.64 (2.96)	5.2629 (0.8363)	2.9620 (0.4707)	6.4379 (1.0230)	3.9732 (0.6314)
1977	48.58 (7.72)	22.47 (3.57)	26.11 (4.15)	6.3845 (1.0145)	3.8210 (0.6072)	10.0656 (1.5995)	5.8435 (0.9286)
1978	63.79 (10.14)	25.35 (4.03)	38.45 (6.11)	10.8705 (1.7274)	4.3357 (0.6890)	14.2504 (2.2645)	8.9886 (1.4283)
1979	53.68 (8.54)	19.13 (3.04)	34.55 (5.49)	9.2487 (1.4697)	3.4182 (0.5432)	14.2039 (2.2571)	7.6780 (1.2201)

Table A5

Private Costs for Booked Reserves of Crude Oil (without 5 year averaging) (in 1981 dollars)

in dollars per m^3 (in dollars per barrel)

	Total Costs for Booked Reserves		Costs for Development		Costs for Exploration	
1957	19.16	(3.05)	8.79	(1.40)	10.37	(1.65)
1958	496.73	(78.93)	219.48	(34.88)	277.26	(44.06)
1959	11.17	(1.78)	4.67	(0.74)	6.50	(1.03)
1960	16.56	(2.63)	7.88	(1.25)	8.68	(1.38)
1961	12.14	(1.93)	6.23	(0.99)	5.91	(0.94)
1962	15.77	(2.51)	6.55	(1.04)	9.22	(1.47)
1963	11.82	(1.88)	6.12	(0.97)	5.70	(0.91)
1964	1.98	(0.31)	1.04	(0.17)	0.93	(0.15)
1965	10.04	(1.60)	5.66	(0.90)	4.38	(0.70)
1966	4.95	(0.79)	2.13	(0.24)	2.82	(0.45)
1967	8.97	(1.41)	3.38	(0.54)	5.49	(0.87)
1968	8.40	(1.34)	2.29	(0.36)	6.11	(0.97)
1969	19.14	(3.04)	4.84	(0.77)	14.30	(2.27)
1970	22.59	(3.59)	4.13	(0.66)	18.46	(2.93)
1971	34.66	(5.51)	6.80	(1.08)	27.86	(4.43)
1972	39.21	(6.23)	9.90	(1.57)	29.31	(4.66)
1973	47.72	(7.58)	20.42	(3.24)	27.30	(4.34)
1974	10.15	(1.61)	4.61	(0.73)	5.54	(0.88)
1975	59.44	(9.45)	28.51	(4.53)	30.94	(4.92)
1976	-22.71	(-3.61)	-9.25	(-1.47)	-13.46	(-2.14)
1977	25.08	(3.99)	11.33	(1.80)	13.75	(2.19)
1978	26.92	(4.28)	13.20	(2.10)	13.72	(2.18)
1979	29.09	(4.62)	13.66	(2.17)	15.43	(2.45)

Table A6

Cumulative Additions to Established Reserves of Conventional Crude Oil

	in millions of m^3	(in millions of barrels)
1953	59.3	(374.43)
1954	126.4	(795.43)
1955	188.86	(1188.50)
1956	238.28	(1499.50)
1957	290.08	(1825.47)
1958	337.25	(2122.33)
1959	379.60	(2388.81)
1960	422.75	(2660.37)
1961	476.78	(3000.38)
1962	586.18	(3688.83)
1963	699.56	(4402.33)
1964	829.35	(5219.12)
1965	969.24	(6099.40)
1966	1121.57	(7058.04)
1967	1215.97	(7652.12)
1968	1304.05	(8206.40)
1969	1368.74	(8613.49)
1970	1418.61	(8927.33)
1971	1446.69	(9104.03)
1972	1471.62	(9260.89)
1973	1490.69	(9380.92)
1974	1501.74	(9450.48)
1975	1512.62	(9518.93)
1976	1526.49	(9606.23)
1977	1539.54	(9688.32)
1978	1555.68	(9789.88)
1979	1581.90	(9954.92)

Source Annual Reserves Report of the Alberta Energy Resources Conservation Board, 1981, Table A-4 p. A-9.

Conversion factor: $1 \text{ m}^3 = 6.293$

Table A7

<u>Private Costs for Booked Reserves of Crude Oil</u> (under the assumption of a higher success ratio for oil in 1971-1979)

in dollars per m^3 (in dollars per barrel) — in 1981 dollars

	Total Costs for Booked Reserves		Costs for Development		Costs for Exploration		Intent Ratio (oil)
1957	13.94	(2.21)	6.85	(1.09)	7.09	(1.13)	.75
1958	15.56	(2.47)	7.48	(1.19)	8.08	(1.28)	.72
1959	17.27	(2.74)	9.92	(1.26)	9.34	(1.48)	.73
1960	16.66	(2.65)	7.59	(1.21)	9.07	(1.44)	.67
1961	13.33	(2.12)	6.25	(0.99)	7.08	(1.13)	.64
1962	6.32	(1.01)	3.09	(0.49)	3.23	(0.51)	.61
1963	6.00	(0.95)	3.04	(0.48)	2.96	(0.47)	.69
1964	5.33	(0.85)	2.60	(0.41)	2.73	(0.43)	.64
1965	5.09	(0.81)	2.41	(0.38)	2.68	(0.43)	.69
1966	5.20	(0.83)	2.15	(0.34)	3.04	(0.48)	.63
1967	9.07	(1.44)	3.24	(0.52)	5.83	(0.93)	.79
1968	9.98	(1.59)	2.91	(0.46)	7.07	(1.12)	.75
1969	13.62	(2.16)	3.50	(0.56)	10.12	(1.61)	.68
1970	17.27	(2.74)	4.07	(0.65)	13.20	(2.09)	.49
1971	26.66	(4.24)	6.80	(1.08)	19.85	(3.15)	.35
1972	25.36	(4.03)	7.42	(1.18)	17.94	(2.85)	.18
1973	26.99	(4.27)	9.94	(1.58)	17.04	(2.71)	.21
1974	36.70	(5.83)	16.07	(2.55)	20.63	(3.28)	.19
1975	33.92	(5.39)	16.92	(2.69)	17.00	(2.70)	.16
1976	31.38	(4.99)	16.07	(2.55)	15.31	(2.43)	.14
1977	44.16	(7.02)	22.47	(3.57)	21.69	(3.45)	.19
1978	58.58	(9.31)	25.35	(4.03)	33.23	(5.28)	.24
1979	48.99	(7.78)	19.13	(3.04)	29.87	(4.75)	.33

Table A8

Private Costs for the Exploration and Development of Booked Reserves of Natural Gas

in dollars per thousand m^3
(in dollars per mcf)

	Total Costs for Booked Reserves		Costs for Development		Costs for Exploration		Costs for Bonuses		Costs for Geology		Costs for Exploratory Drilling		Total Cost of Money	
1957	3.58	(0.10)	1.52	(0.04)	2.06	(0.06)	0.7642	(0.0216)	0.5448	(0.0154)	0.5167	(0.0146)	0.2351	(0.0067)
1958	3.35	(0.09)	1.46	(0.04)	1.88	(0.05)	0.7549	(0.0214)	0.4154	(0.0118)	0.4891	(0.0139)	0.2255	(0.0064)
1959	4.39	(0.12)	2.19	(0.06)	2.20	(0.06)	0.9085	(0.0257)	0.4283	(0.0121)	0.5669	(0.0161)	0.2936	(0.0083)
1960	4.85	(0.14)	2.56	(0.07)	2.30	(0.07)	0.9158	(0.0259)	0.4280	(0.0121)	0.6196	(0.0175)	0.3324	(0.0094)
1961	6.37	(0.18)	3.38	(0.10)	2.99	(0.08)	1.1187	(0.0317)	0.5368	(0.0152)	0.9246	(0.0262)	0.4129	(0.0117)
1962	6.34	(0.18)	3.50	(0.10)	2.84	(0.08)	0.9796	(0.0277)	0.5641	(0.0160)	0.8844	(0.0250)	0.4117	(0.0117)
1963	6.98	(0.20)	4.05	(0.11)	2.93	(0.08)	0.9769	(0.0277)	0.6081	(0.0172)	0.9240	(0.0262)	0.4219	(0.0119)
1964	6.16	(0.17)	3.47	(0.10)	2.70	(0.08)	0.8626	(0.0244)	0.5509	(0.0156)	0.9148	(0.0259)	0.3695	(0.0105)
1965	6.55	(0.19)	3.88	(0.11)	2.68	(0.08)	0.8062	(0.0228)	0.5148	(0.0146)	0.9998	(0.0283)	0.3550	(0.0101)
1966	6.01	(0.17)	3.63	(0.10)	2.39	(0.07)	0.7577	(0.0215)	0.4997	(0.0141)	0.8055	(0.0228)	0.3264	(0.0092)
1967	6.83	(0.19)	4.35	(0.12)	2.48	(0.07)	0.8796	(0.0249)	0.5413	(0.0153)	0.6909	(0.0196)	0.3706	(0.0105)
1968	9.42	(0.27)	6.31	(0.18)	3.11	(0.09)	1.0851	(0.0307)	0.6858	(0.0194)	0.8482	(0.0240)	0.4935	(0.0140)
1969	11.49	(0.33)	7.81	(0.22)	3.69	(0.10)	1.1489	(0.0325)	0.8006	(0.0227)	1.1063	(0.0313)	0.6315	(0.0179)
1970	13.58	(0.38)	9.15	(0.26)	4.43	(0.13)	1.2442	(0.0352)	1.0564	(0.0299)	1.3096	(0.0371)	0.8157	(0.0231)
1971	12.61	(0.36)	8.61	(0.24)	4.00	(0.11)	0.8656	(0.0245)	0.9463	(0.0268)	1.4364	(0.0407)	0.7511	(0.0213)
1972	12.48	(0.35)	8.37	(0.24)	4.10	(0.12)	0.6545	(0.0185)	0.9791	(0.0277)	1.7306	(0.0490)	0.7405	(0.0210)
1973	13.24	(0.37)	8.76	(0.25)	4.48	(0.13)	0.5517	(0.0156)	1.0570	(0.0299)	2.1270	(0.0602)	0.7490	(0.0212)
1974	11.94	(0.34)	8.15	(0.23)	3.79	(0.11)	0.4082	(0.0116)	0.9924	(0.0281)	1.7722	(0.0502)	0.6143	(0.0174)
1975	11.43	(0.32)	7.80	(0.22)	3.63	(0.10)	0.3141	(0.0089)	0.8985	(0.0254)	1.8128	(0.0513)	0.6061	(0.0172)
1976	14.30	(0.40)	9.57	(0.27)	4.73	(0.13)	0.4433	(0.0126)	1.0036	(0.0284)	2.4353	(0.0690)	0.8495	(0.0241)
1977	17.98	(0.51)	11.52	(0.33)	6.45	(0.18)	0.6027	(0.0171)	1.2772	(0.0362)	3.3686	(0.0954)	1.2063	(0.0342)
1978	19.89	(0.56)	12.28	(0.35)	7.61	(0.22)	0.8914	(0.0252)	1.4140	(0.0400)	3.8646	(0.1094)	1.4394	(0.0408)
1979	21.97	(0.62)	12.54	(0.35)	9.43	(0.27)	1.1202	(0.0317)	1.6902	(0.0479)	4.8780	(0.1381)	1.7465	(0.0495)

Table A9

Private Costs for Booked Reserves of Natural Gas (without 5 year averaging) — in 1981 dollars

in dollars per m^3 (in dollars per mcf)

	Total Costs for Booked Reserves		Costs for Development		Costs for Exploration	
1957	4.18	(0.12)	1.16	(0.03)	3.03	(0.09)
1958	2.83	(0.08)	1.41	(0.04)	1.42	(0.04)
1959	3.55	(0.10)	1.48	(0.04)	2.06	(0.06)
1960	2.91	(0.08)	1.39	(0.04)	1.51	(0.04)
1961	37.00	(1.05)	25.71	(0.73)	11.29	(0.32)
1962	7.45	(0.21)	3.52	(0.10)	3.92	(0.11)
1963	10.87	(0.31)	5.85	(0.17)	5.02	(0.14)
1964	4.00	(0.11)	2.22	(0.06)	1.78	(0.05)
1965	3.71	(0.11)	2.21	(0.06)	1.50	(0.04)
1966	10.18	(0.29)	6.35	(0.18)	3.82	(0.11)
1967	8.69	(0.25)	5.51	(0.16)	3.18	(0.09)
1968	5.42	(0.15)	3.35	(0.09)	2.08	(0.06)
1969	8.86	(0.25)	5.81	(0.16)	3.05	(0.09)
1970	22.47	(0.64)	16.42	(0.46)	6.05	(0.17)
1971	26.32	(0.75)	19.08	(0.54)	7.24	(0.20)
1972	23.06	(0.65)	15.01	(0.42)	8.05	(0.23)
1973	5.11	(0.14)	3.42	(0.10)	1.69	(0.05)
1974	7.44	(0.21)	4.87	(0.14)	2.57	(0.07)
1975	56.60	(1.60)	38.66	(1.09)	17.95	(0.51)
1976	16.38	(0.46)	11.94	(0.34)	4.44	(0.13)
1977	13.53	(0.38)	8.85	(0.25)	4.68	(0.13)
1978	12.86	(0.36)	7.91	(0.22)	5.09	(0.14)
1979	20.37	(0.58)	11.82	(0.33)	8.86	(0.24)

Table A10

Cumulative Additions To Established Reserves of Natural Gas

(cumulative booked reserves)

	in billions of cubic meters	(in billions of cubic feet)
1957	503	17763
1958	593	20942
1959	572	23731
1960	748	26415
1961	809	28570
1962	870	30724
1963	923	32666
1964	985	34785
1965	1050	37080
1966	1135	40082
1967	1220	43084
1968	1297	45803
1969	1375	48558
1970	1447	51100
1971	1529	53996
1972	1623	57316
1973	1732	61165
1974	1832	64697
1975	1949	68828
1976	2062	72819
1977	1170	76633
1978	2293	80907
1979	2418	85391

Source Annual Reserves Report of the AERCB, 1981, Table A-5, p. A-11.

Conversion factor: $1\ m^3 = 35.3147\ ft^3$.

Table All

Private Costs for Booked Reserves of Natural Gas (under the assumption of a higher success ratio for oil in 1971-1979)

in dollars per m^3
(in dollars per mcf)

in 1981 dollars

	Total Costs for Booked Reserves		Costs for Development		Costs for Exploration		Intent Ratio (gas)
1957	3.58	(0.10)	1.52	(0.04)	2.06	(0.06)	.25
1958	3.35	(0.09)	1.46	(0.04)	1.88	(0.05)	.28
1959	4.39	(0.12)	2.19	(0.06)	2.20	(0.06)	.27
1960	4.85	(0.14)	2.56	(0.07)	2.30	(0.07)	.33
1961	6.37	(0.18)	3.38	(0.10)	2.99	(0.08)	.36
1962	6.34	(0.18)	3.50	(0.10)	2.84	(0.08)	.39
1963	6.98	(0.20)	4.05	(0.11)	2.93	(0.08)	.31
1964	6.16	(0.17)	3.47	(0.10)	2.70	(0.08)	.36
1965	6.55	(0.19)	3.88	(0.11)	2.68	(0.08)	.31
1966	6.01	(0.17)	3.63	(0.10)	2.39	(0.07)	.37
1967	6.83	(0.19)	4.35	(0.12)	2.48	(0.07)	.21
1968	9.42	(0.27)	6.31	(0.18)	3.11	(0.09)	.25
1969	11.49	(0.33)	7.81	(0.22)	3.69	(0.10)	.32
1970	13.70	(0.39)	9.15	(0.26)	4.55	(0.13)	.51
1971	12.70	(0.36)	8.61	(0.24)	4.24	(0.12)	.65
1972	12.36	(0.35)	8.37	(0.24)	4.24	(0.12)	.82
1973	13.42	(0.38)	8.76	(0.25)	3.99	(0.13)	.79
1974	12.00	(0.34)	8.15	(0.23)	3.88	(0.11)	.81
1975	11.65	(0.33)	7.80	(0.22)	3.88	(0.11)	.84
1976	14.83	(0.42)	9.57	(0.27)	5.30	(0.15)	.86
1977	18.36	(0.52)	11.52	(0.33)	7.06	(0.20)	.81
1978	20.48	(0.58)	12.28	(0.35)	8.12	(0.23)	.76
1979	22.95	(0.65)	12.54	(0.35)	10.24	(0.29)	.67

FIGURE A1

COSTS FOR CUMULATIVE BOOKED RESERVES OF CONVENTIONAL CRUDE OIL

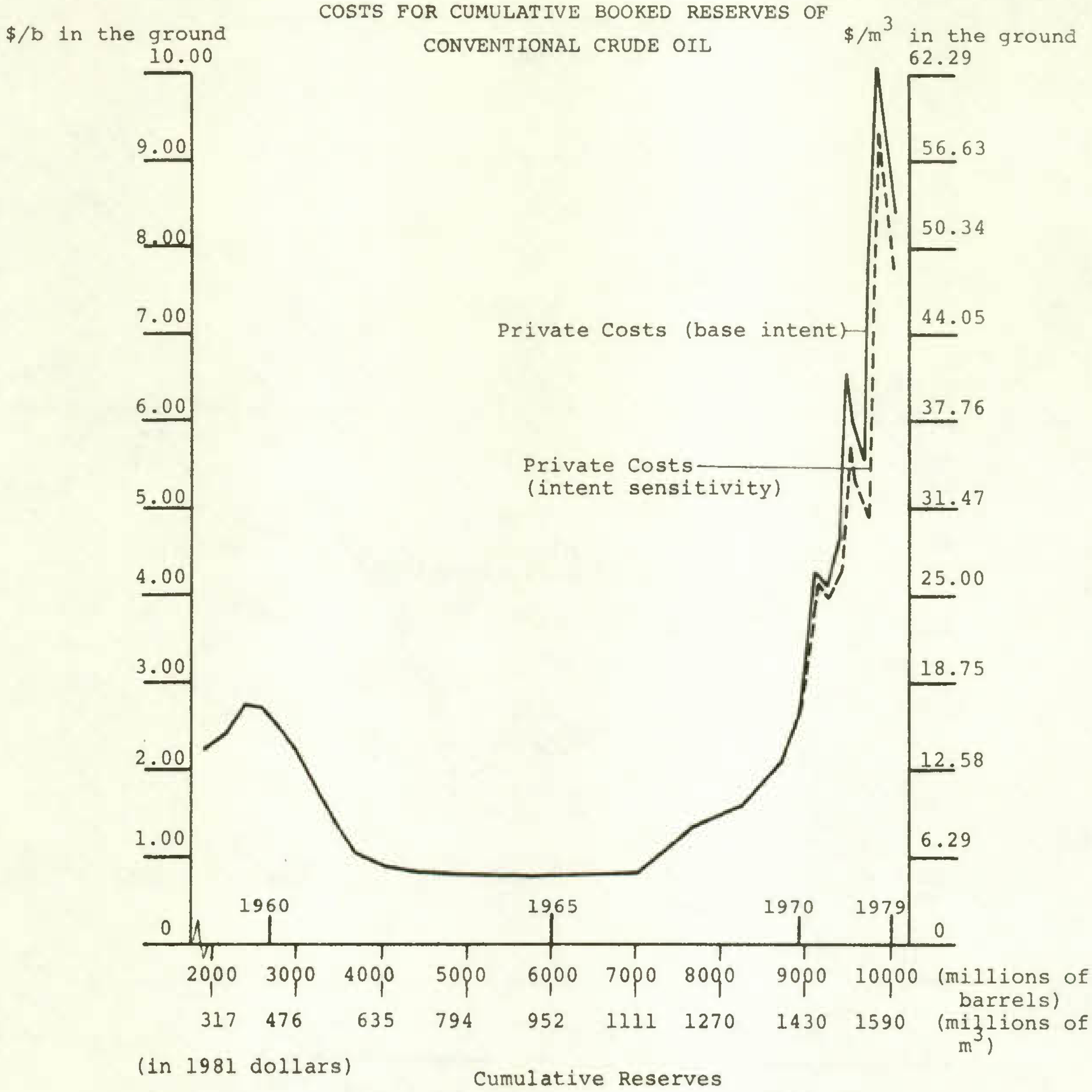
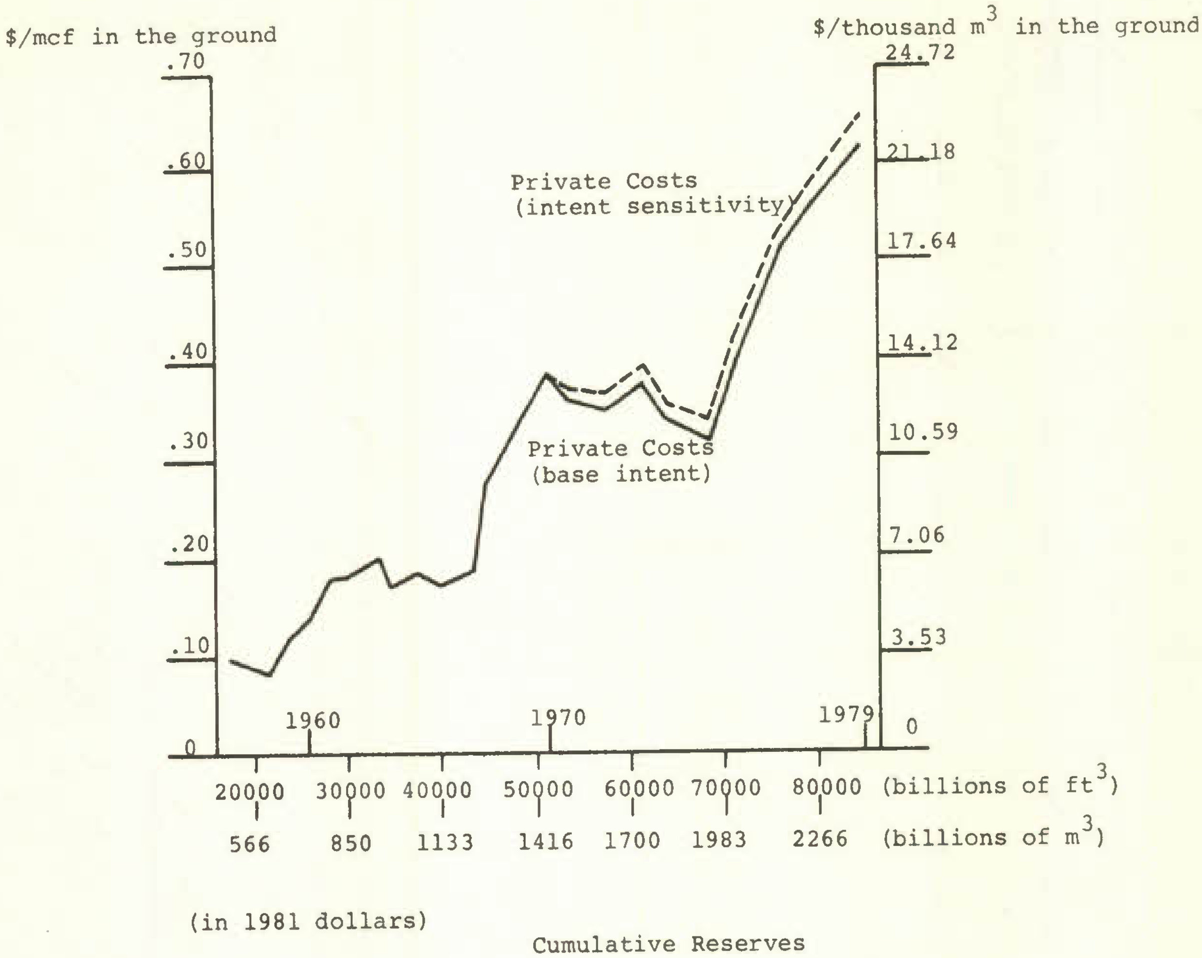


FIGURE A2

COSTS FOR CUMULATIVE BOOKED RESERVES
OF NATURAL GAS



Notes

1. AERCB Annual Reserves Report 1976, p. 9.3.

2. See Tables A2 and A3 in Appendix V.

3. AERCB, Gas Reserves Trends, 1980, Table G-3.

4. Ibid., p. 3.

5. W. Blackman, A. MacFadyen, "Provincial Royalties and Energy Sources", University of Calgary, 1975.

6. Peter Eglington, The Economics of Industry Petroleum Exploration, 1975, p. 5.38.

7. For further detail see M. Crommelin, P. Pearse, A. Scott, "Management of Oil and Gas Resources in Alberta: An Economic Evaluation of Public Policy", Natural Resources Journal 8, April 1978.

8. Russell Uhler, Finding Costs, Canadian Energy Research Institute, 1979, pp. 16-24.

9. Eglington, p. 161.

10. Eglington, p. 142-143.

APPENDIX B

In this appendix we derive the conversion factor which relates the booking costs for a stock of reserves in the ground to the booking cost component of a flow of barrels produced.[1] Recall that significant capital outlays for exploration and development must be made up front before a barrel of crude is produced. Hence the objective in establishing such a cost relationship is to assign the investments made for exploration and the development of reserves in the ground ($ per barrel in the ground) to a barrel of production ($ per barrel produced). In other words we want to determine the amount that must be charged to each barrel of crude produced in order to recoup the costs of the investment necessary to undertake exploration and development.

The annualized exploration and development cost is dependent upon the amount of investment, the cost of money, and the anticipated output profile. Expenditures for the exploration and development of reserves are assigned to barrels that are produced in later time periods. Recovered costs from barrels produced for these activities will therefore have to be discounted to the present. A first approximation of anticipated output can be expressed in terms of the rate of output in the initial period and the rate of production decline. The production decline rate accounts for the fact that as crude is produced in each period the amount of crude that remains to be produced declines and therefore production capacity declines.

A number of assumptions and formulations for the rate of production decline are used by petroleum engineers. A common assumption is that of an exponential decline which will be used in this analysis.

We can derive the factor that allows us to convert the stock exploration and development cost of reserves in the ground to the flow exploration and development cost of a barrel produced in the following way:

E = exploration and development expenditures (\$)[2]

r = the discount rate (McLeod Young Weir bond rate from Table A2 inflated by 40%)

R = additions to booked reserves (measured as barrels in the ground)

D = production decline rate (assumed to be 8% per year)[3]

q_0 = the rate of production in the initial period ($q_0 = D.R$)

X = the imputed finding cost of a barrel of crude produced

T = duration of the production period

q_t = the production in each time period

In order to equate the stock costs to the flow costs, the implied costs must equal the discounted initial investment:

1) $$X = E / {}_0\int^T q_t e^{-rt} \cdot dt$$

with the exponential decline assumption

2) $q_t = q_0 e^{-Dt}$ for any t, hence

3 $$X = E/{}_0\int^T (q_0 \cdot e^{Dt})\, e^{-rt} \cdot dt$$

4) $$X = E/{}_0\int^T q_0 e^{-(D+r)t} \cdot dt$$

upon integration

5) $$X = E\,(D+r)/q_0(1-e^{-(D+r)^T})$$

in the limit as $T \to \infty$

6) $$X = \frac{E}{q_0}\,(D+r) \text{ but } q_0 = R \cdot D$$

7) $$X = \frac{E}{R}\left(\frac{D+r}{D}\right)$$

Note that E/R is simply the unit exploration and development cost for a stock of reserves. Hence the conversion factor that we require to impute these costs to a barrel produced is given by: (D+r)/D. The results of this calculation for oil for the period under analysis are given in Table B1.[4]

If production does not take place at full capacity the above analysis which incorporates the exponential decline rate may be less appropriate than examining other decline patterns. This is likely to be the case when production is prorationed.

If limits are placed on production such as by prorationing, we can assume that production takes place at a constant rate over the life of the reservoir. Thus the production in each year is given by: R times 1/(period of production). To calculate factors on this basis estimates of production periods for the years 1957-1970 are taken from Eglington's 1975 Phd. Thesis. For the years following that period it is assumed that the production period drops to 20 years in 1971 and remains at that level. With these assumptions the annualized costs are derived as follows:

8) $$X = E/\int_0^T q_t e^{-rt}.dt$$

upon integration

9) $$X = (E \cdot r)/q_t (1-e^{-rT})$$

10) $$X = (E \cdot r)/q_t \cdot (i-e^{-rT}) \text{ but } q_t = R \cdot {}^1/_T$$

11) $$X = E/R \cdot r/({}^1/_T) \cdot (i-e^{rT})$$

Again E/R is simply the unit exploration and development cost for the stock of reserves in each period. The conversion factor in this instance is given by: $r/({}^1/_T) \cdot (1-e^{-rT})$. Calculations for this factor for oil are given in Table B2. The calculations for gas are given in Table B3.

The results in Table B1, B2 and B3 are given in nominal and real terms. In the latter case the real cost of money is defined as the nominal cost of money less the annual inflation rate in each year. The very low factors that result in 1973 and 1974 under both sets of assumptions can be explained by the very high rates of inflation and subsequent low real costs of money that prevailed in those years. The real cost of money in those years was .25% and -1.38% resulting in very low conversion factors.

It may be noted that the real dollar conversion factors are almost always less than those for nominal dollars. This is mainly because of the inflationary premium in the nominal cost of money. In some years the factors based on an exponential production decline are higher than those for an assumed flat production rate. In other years it is the contrary. Overall we prefer to use the set of factors based on an exponential decline, in real dollar terms.

Table B1

Alberta Oil Reserves and Production
Conversion Factors with an Exponential Decline

	i) in nominal terms	ii) in real terms
1957	1.94	1.94
1958	1.87	1.50
1959	1.98	1.98
1960	2.00	2.00
1961	1.96	1.96
1962	1.95	1.55
1963	1.93	1.93
1964	1.96	1.96
1965	1.99	1.60
1966	2.13	2.14
1967	2.24	1.83
1968	2.39	2.02
1969	2.53	2.18
1970	2.60	2.27
1971	2.46	2.12
1972	2.45	2.13
1973	2.48	1.03
1974	2.78	.83
1975	2.88	1.77
1976	2.83	2.20
1977	2.70	1.72
1978	2.75	1.68
1979	2.90	1.65
1980	3.32	1.82
1981	3.84	2.71

Example: In 1981, $10 per barrel in the ground is equivalent to $27.10 per barrel produced, in real dollars.

Table B2

Alberta Oil Reserves and Production
Conversion Factors with Flat Production Rates

	i) in nominal terms	ii) in real terms	iii) production period (years)
1957	2.29	2.290	33
1958	2.00	0.823	32
1959	2.25	2.240	31
1960	2.21	2.210	30
1961	2.01	2.010	29
1962	1.91	0.900	28
1963	1.75	1.750	27
1964	1.74	1.740	26
1965	1.70	0.847	25
1966	1.96	1.950	24
1967	2.07	1.200	23
1968	2.44	1.540	23
1969	2.53	1.830	22
1970	2.41	1.810	22
1971	2.10	1.490	20
1972	2.09	1.500	20
1973	2.14	0.0025	20
1974	2.67	-.363	20
1975	2.86	0.873	20
1976	2.77	1.620	20
1977	2.54	0.795	20
1978	2.63	0.714	20
1979	2.89	0.682	20
1980	3.62	0.956	20
1981	4.50	2.570	20

Example: In 1981, $10 per barrel in the ground is equivalent to $25.70 per barrel produced in real dollars.

Table B3

Alberta Gas Reserves and Production
Conversion Factors with Flat Production Rates

	i) in nominal terms	ii) in real terms	iii) production period (years)
1957	1.48	1.480	23.5
1958	1.29	0.490	23.0
1959	1.48	1.480	22.5
1960	1.47	1.470	22.0
1961	1.38	1.350	21.8
1962	1.33	0.590	21.6
1963	1.29	1.270	21.4
1964	1.31	1.020	21.2
1965	1.37	0.640	21.0
1966	1.60	1.590	20.8
1967	1.81	1.030	20.9
1968	2.02	1.360	20.4
1969	2.29	1.640	20.2
1970	2.37	1.810	20.0
1971	2.10	1.490	20.0
1972	2.09	1.200	20.0
1973	2.14	0.0025	20.0
1974	2.67	-.363	20.0
1975	2.86	0.873	20.0
1976	2.77	1.620	20.0
1977	2.57	0.795	20.0
1978	2.63	0.714	20.0
1979	2.90	0.682	20.0
1980	3.62	0.956	20.0
1981	4.50	2.57	20.0

Example: In 1981, $0.60 in the ground is equivalent to $1.54 per MCF produced in real dollars.

Notes

1. The following discussion relies heavily on the 1967 work done by Paul Bradley in his book, The Economics of Crude Petroleum Production.

2. $E = \Sigma_{o=1}^{T} E_o \, [(1/(1+r)]^{o}$

3. 8% is assumed to be a reasonable approximation for our purposes.

4. If the same decline rate is assumed for gas, the conversion factor for gas is the same as that for oil.

APPENDIX C

This appendix derives the index that is obtained by linking the ISPI and the CPA cost escalator.

The CPA cost escalator is an index which reflects the cost changes for conventional oil and gas exploration, development and production. Cost escalation indices are derived for capital costs and operating costs. Separate indices are also derived for the component capital costs including geological and geophysical costs, exploration and development drilling, lease and field equipment and gas plant construction.

The new linked index is derived by dividing the CPA cost escalation index by the ISPI. The indices for gas and oil are given in Table C3. Note that the CPA index for oil is the average of the indices for geological and geophysical costs, exploratory and development drilling and lease and field equipment. The CPA gas index is the index for total capital costs including gas plant construction.

These indices are used to put current expenditures into real deflated terms from 1970 onward. These results yield the deflated dollar costs which remain after the cost escalation effects and the inflationary effects are removed. For earlier years the ISPI is used. In these years the general inflationary effects are removed. These results are given in Tables C1 and C2.

Table C1

Private Costs for the Exploration and Development of Booked Reserves of Crude Oil (in 1981 deflated dollars)

in dollars per m^3
(in dollars per barrel)

	Total Costs for Booked Reserves	Costs for Development	Costs for Exploration	Costs for Bonuses	Costs for Geology	Costs for Exploratory Drilling	Total Cost of Money
1957	13.94 (2.21)	6.85 (1.09)	7.09 (1.13)	2.1196 (0.3368)	2.0938 (0.3327)	2.1158 (0.3362)	0.7630 (0.1212)
1958	15.56 (2.47)	7.48 (1.19)	8.08 (1.28)	2.6664 (0.4237)	2.0488 (0.3256)	2.4398 (0.3877)	0.9275 (0.1474)
1959	17.27 (2.74)	7.92 (1.26)	9.34 (1.48)	3.3085 (0.5257)	2.1559 (0.3426)	2.6754 (0.4251)	1.2046 (0.1914)
1960	16.66 (2.65)	7.59 (1.21)	9.07 (1.44)	3.4216 (0.5437)	1.9479 (0.3095)	2.4053 (0.3822)	1.2995 (0.2065)
1961	13.33 (2.12)	6.25 (0.99)	7.08 (1.13)	2.6744 (0.4250)	1.4288 (0.2270)	1.9870 (0.3154)	0.9928 (0.1578)
1962	6.32 (1.01)	3.09 (0.49)	3.23 (0.51)	1.1830 (0.1880)	0.6434 (0.1022)	0.9278 (0.1474)	0.4801 (0.0763)
1963	6.00 (0.95)	3.04 (0.48)	2.96 (0.47)	1.0338 (0.1643)	0.5818 (0.0924)	0.9172 (0.1457)	0.4320 (0.0687)
1964	5.33 (0.85)	2.60 (0.41)	2.73 (0.43)	0.9315 (0.1480)	0.4959 (0.0788)	0.9261 (0.1472)	0.3787 (0.0602)
1965	5.09 (0.81)	2.41 (0.38)	2.68 (0.43)	0.9174 (0.1458)	0.4763 (0.0757)	0.9200 (0.1462)	0.3702 (0.0588)
1966	5.20 (0.83)	2.15 (0.34)	3.04 (0.48)	1.1124 (0.1768)	0.5319 (0.0845)	0.9677 (0.1538)	0.4299 (0.0683)
1967	9.07 (1.44)	3.24 (0.52)	5.83 (0.93)	2.0436 (0.3247)	1.2050 (0.1915)	1.7214 (0.2735)	0.8629 (0.1371)
1968	9.98 (1.59)	2.91 (0.46)	7.07 (1.12)	2.4108 (0.3831)	1.5568 (0.2474)	1.9861 (0.3156)	1.1128 (0.1768)
1969	13.62 (2.16)	3.50 (0.56)	10.12 (1.61)	3.5125 (0.5582)	2.3921 (0.3801)	2.4070 (0.3825)	1.8111 (0.2878)
1970	9.21 (1.46)	2.19 (0.35)	7.02 (1.12)	2.4956 (0.3966)	1.6816 (0.2672)	1.4527 (0.2308)	1.3900 (0.2209)
1971	14.48 (2.30)	3.65 (0.58)	10.83 (1.72)	3.4925 (0.5550)	2.8103 (0.4466)	2.2208 (0.3529)	2.3099 (0.3671)
1972	13.71 (2.18)	3.86 (0.61)	9.85 (1.57)	3.1512 (0.5008)	2.3475 (0.3730)	2.1544 (0.3423)	2.1982 (0.3493)
1973	16.63 (2.64)	5.70 (0.91)	10.93 (1.74)	3.4917 (0.5549)	2.3871 (0.3793)	2.6325 (0.4183)	2.4193 (0.3844)
1974	27.97 (4.44)	10.93 (1.74)	17.04 (2.71)	5.3024 (0.8426)	3.4705 (0.5515)	4.7671 (0.7575)	3.4997 (0.5561)
1975	26.45 (4.20)	11.84 (1.88)	14.60 (2.32)	4.2867 (0.6812)	2.9312 (0.4658)	4.3557 (0.6922)	0.6194 (0.4815)
1976	23.81 (3.78)	11.03 (1.75)	12.79 (2.03)	3.6106 (0.5737)	2.0320 (0.3229)	4.4167 (0.7018)	0.6652 (0.4332)
1977	34.93 (5.55)	16.16 (2.57)	18.78 (2.98)	4.5911 (0.7296)	2.7477 (0.4366)	7.2382 (1.1502)	1.0619 (0.6677)
1978	48.54 (7.71)	19.29 (3.06)	29.25 (4.65)	8.2710 (1.3143)	3.2989 (0.5242)	10.8420 (1.7230)	1.4725 (1.0868)
1979	46.17 (7.34)	16.45 (2.61)	29.72 (4.72)	7.9559 (1.2642)	2.9404 (0.4672)	12.2184 (1.9416)	1.7118 (1.0495)

Table C2

Private Costs for the Exploration and Development of Booked Reserves of Natural gas (in 1981 deflated dollars)

in dollars per 1000 m^3
(in dollars per mcf)

	Total Costs for Booked Reserves		Costs for Development		Costs for Exploration		Costs for Bonuses		Costs for Geology		Costs for Exploratory Drilling		Total Cost of Money	
1957	3.58	(0.10)	1.52	(0.04)	2.06	(0.06)	0.7642	(0.0216)	0.5448	(0.0154)	0.5167	(0.0146)	0.2351	(0.0067)
1958	3.35	(0.09)	1.46	(0.04)	1.88	(0.05)	0.7549	(0.0214)	0.4154	(0.0118)	0.4891	(0.0139)	0.2255	(0.0064)
1959	4.39	(0.12)	2.19	(0.06)	2.20	(0.06)	0.9085	(0.0257)	0.4283	(0.0121)	0.5669	(0.0161)	0.2936	(0.0083)
1960	4.85	(0.14)	2.56	(0.07)	2.30	(0.07)	0.9158	(0.0259)	0.4280	(0.0121)	0.6196	(0.0175)	0.3324	(0.0094)
1961	6.37	(0.18)	3.38	(0.10)	2.99	(0.08)	1.1187	(0.0317)	0.5368	(0.0152)	0.9246	(0.0262)	0.4129	(0.0117)
1962	6.34	(0.18)	3.50	(0.10)	2.84	(0.08)	0.9796	(0.0277)	0.5641	(0.0160)	0.8844	(0.0250)	0.4117	(0.0117)
1963	6.98	(0.20)	4.05	(0.11)	2.93	(0.08)	0.9769	(0.0277)	0.6081	(0.0172)	0.9240	(0.0262)	0.4219	(0.0119)
1964	6.16	(0.17)	3.47	(0.10)	2.70	(0.08)	0.8626	(0.0244)	0.5509	(0.0156)	0.9148	(0.0259)	0.3695	(0.0105)
1965	6.55	(0.19)	3.88	(0.11)	2.68	(0.08)	0.8062	(0.0228)	0.5148	(0.0146)	0.9998	(0.0283)	0.3550	(0.0101)
1966	6.01	(0.17)	3.63	(0.10)	2.39	(0.07)	0.7577	(0.0215)	0.4997	(0.0141)	0.8055	(0.0228)	0.3264	(0.0092)
1967	6.83	(0.19)	4.35	(0.12)	2.48	(0.07)	0.8796	(0.0249)	0.5413	(0.0153)	0.6909	(0.0196)	0.3706	(0.0105)
1968	9.42	(0.27)	6.31	(0.18)	3.11	(0.09)	1.0851	(0.0307)	0.6858	(0.0194)	0.8482	(0.0240)	0.4935	(0.0140)
1969	11.49	(0.33)	7.81	(0.22)	3.69	(0.10)	1.1489	(0.0325)	0.8006	(0.0227)	1.1063	(0.0313)	0.6315	(0.0179)
1970	8.01	(0.23)	5.40	(0.15)	2.61	(0.07)	0.7343	(0.0208)	0.6235	(0.0177)	0.7729	(0.0219)	0.4814	(0.0136)
1971	7.18	(0.20)	4.90	(0.14)	2.28	(0.06)	0.4927	(0.0140)	0.5386	(0.0153)	0.8177	(0.0232)	0.4275	(0.0121)
1972	6.87	(0.19)	4.61	(0.13)	2.26	(0.06)	0.3605	(0.0102)	0.5392	(0.0153)	0.9531	(0.0270)	0.4078	(0.0115)
1973	8.02	(0.23)	5.30	(0.15)	2.72	(0.08)	0.3341	(0.0095)	0.6401	(0.0181)	1.2882	(0.0365)	0.4536	(0.0128)
1974	8.58	(0.24)	5.86	(0.17)	2.72	(0.08)	0.2932	(0.0083)	0.7129	(0.0202)	1.2730	(0.0360)	0.4412	(0.0125)
1975	8.42	(0.24)	5.75	(0.16)	2.68	(0.08)	0.2315	(0.0066)	0.6621	(0.0187)	1.3357	(0.0378)	0.4466	(0.0126)
1976	9.93	(0.28)	6.64	(0.19)	3.28	(0.09)	0.3077	(0.0087)	0.6966	(0.0197)	1.6904	(0.0479)	0.5896	(0.0167)
1977	13.22	(0.37)	8.48	(0.24)	4.75	(0.13)	0.4433	(0.0126)	0.9396	(0.0266)	2.4781	(0.0702)	0.8874	(0.0251)
1978	15.30	(0.43)	9.45	(0.27)	5.85	(0.17)	0.6857	(0.0194)	1.0877	(0.0308)	2.9727	(0.0842)	1.1072	(0.0314)
1979	19.11	(0.54)	10.90	(0.31)	8.20	(0.23)	0.9741	(0.0276)	1.4698	(0.0416)	4.2418	(0.1201)	1.5187	(0.0430)

Table C3

Index Used to Calculate the Deflated Dollar Costs

	Oil Index = $CPA_O/ISPI$	Gas Index = $CPA_G/ISPI$
1970	.67	.61
1971	.69	.65
1972	.73	.69
1973	.75	.71
1974	.75	.71
1975	.80	.76
1976	.86	.85
1977	.89	.87
1978	.92	.91
1979	.93	.92
1980	.96	.96
1981	1.00	1.00

CPA_O = The Canadian Petroleum Association Cost Escalation Index for Oil (excludes escalation for gas plant construction).

CPA_G = The Canadian Petroleum Association Cost Escalation Index for Gas (includes escalator for gas plant construction).

APPENDIX D

In order to calculate the well requirements for bookings reserves of oil and gas, the number of oil wells drilled in a given year for oil and the wells drilled for gas are divided by the number of reserves booked in that year for oil and gas respectively. The CPA provides annual drilling data for all exploratory and development wells drilled in the province of Alberta. The data includes both successful and unsuccessful wells.

The well data is allocated to oil and gas in the same way that industry expenditures are allocated. The number of exploratory wells drilled for oil are determined by multiplying the total number of exploratory wells by the intent ratio for oil. The development wells are allocated to oil by multiplying the total number of wells by the completion ratio for oil. The allocation of wells to gas is also carried out in this way. The results of the calculations are given in Table D1.

Table D1

Number of Wells Drilled per Booked Reserves of Conventional Crude Oil and Natural Gas

	number of oil wells		number of gas wells	
	per million m^3	(per million barrels)	per billion m^3	(per 10 x billion ft^3)
1959	28.3	(4.5)	4.6	(1.30)
1960	27.0	(4.3)	5.4	(1.52)
1961	21.3	(3.4)	7.1	(2.01)
1962	10.6	(1.7)	7.5	(2.12)
1963	10.6	(1.7)	8.8	(2.49)
1964	9.4	(1.5)	8.0	(2.26)
1965	8.8	(1.4)	7.2	(2.03)
1966	8.1	(1.3)	6.0	(1.69)
1967	12.5	(2.0)	6.5	(1.84)
1968	11.9	(1.9)	8.8	(2.49)
1969	15.7	(2.5)	10.3	(2.91)
1970	19.5	(3.1)	10.0	(2.83)
1971	33.3	(5.3)	18.6	(5.26)
1972	37.1	(5.9)	20.2	(5.71)
1973	50.3	(8.0)	25.4	(7.19)
1974	86.3	(13.8)	29.2	(8.26)
1975	93.8	(14.9)	28.7	(8.12)
1976	79.3	(12.6)	32.2	(9.12)
1977	103.2	(16.4)	35.9	(10.16)
1978	100.1	(15.9)	34.7	(9.83)
1979	71.1	(11.3)	32.6	(9.23)

APPENDIX E

In this Appendix the unit costs of booking petroleum reserves in the ground are recalculated. However the costs in this Appendix are determined on the basis of barrels of oil equivalent (BOE) and hence there is no assignment of costs to either oil or gas. In determining the unit cost of booking a BOE in the ground, the assignment process is done on the revenue side.

In this exercise we associate booked reserves in BOE terms to annual exploration and develpment expenditures across the petroleum industry. The BOE reserves data are calculated by summing annual reserves of oil in barrels with annual reserves of gas which are reported in mcf's. Of course barrels of oil and mcf's of gas cannot be directly added together. In order to come up with a BOE for gas, gas reserves are weighted according to the relative value of oil reserves and gas reserves.

The weights for the assignment process are derived from the Uhler price series for developed reserves in the ground of gas and oil. The value of the ratio of the price of oil reserves (Po) to the price of gas reserves (Pg) is calculated for each year and then divided into the annual number of booked reserves of gas. The relative price ratio reveals the number of gas reserves that are required to yield revenues equivalent to those yielded from one barrel of oil in the ground. The division of the annual relative price ratio into the annual booked gas reserve data expresses the gas reserves in terms of their relative value to oil reserves and hence in terms of barrels of oil equivalent.

The sum of the annual booked reserves of oil and the annual gas reserves expressed in BOE terms is divided into the annual exploration and development expenditures made by the petroleum industry in Alberta.

For example, the unit costs of booking a BOE in the ground is given by: Total industry exploration and development expenditures/Total BOE where;

$$\text{Total BOE} = [(\text{Booked Reserves of Oil in Barrels}) + (\text{Booked Reserves of Gas in mcf} \div Po/Pg)].$$

The result is the unit costs of booking a BOE in the ground. The values for the relative reserves price ratio, the unit costs of a BOE, and the cumulative BOE's booked over the period are given in Table E1. The unit costs are plotted against cumulative BOE's booked in Figure E1. The resulting curve reflects certain characteristics of the cost curve for oil and the cost curve for gas, Figures 2 and 4 respectively. The unit BOE costs clearly begin to rise after 1970. The unit BOE costs decline in 1975 and 1976 as they do for both gas and oil. The subsequent increase in BOE costs after this point is not as rapid as it is for oil costs but the BOE costs are clearly increasing at a faster rate than the unit gas costs.

Although this exercise yields a general indication of the behaviour of unit petroleum booking costs over the period, there are definite shortcomings with this approach with respect to its application to policy formulation. First, because costs are not divided between gas and oil there is no way of assessing individually the unit booking costs for oil vis-à-vis the unit booking costs for gas. This may in fact be important for policy considerations if for instance the supplies of one of the resources are being depleted faster than the other or if government has reason for directing activity away from one resource and toward the other. The required information for this type of decision making is not reflected in the BOE results.

Another shortcoming to this approcah lies in the fact that any changes in the relative values of oil and gas reserves in the ground are directly translated into changes in the amount of BOE of gas reserves. The gas reserves component of the unit cost equation changes as relative reserve prices change.

By way of illustration consider the period 1973 through 1975 where the unit BOE costs rise and then fall dramatically. The price of oil reserves (Po) rises in 1974 relative to the price gas reserves (Pg). Hence the relative price ratio, $Po/_{Pg}$ increases. As this occurs gas reserves are worth fewer barrels of oil reserves and the value of BOE on the denominator of unit BOE cost equation declines. What results in 1974 are higher unit costs for booking BOE reserves.

By contrast, in 1975 the price of gas reserves increase relative to oil reserve price. The relative reserve price ratio (Po/Pg) declines significantly as gas reserves are now worth more barrels of oil reserves. The total number of BOE reserves booked in 1975 then increases and the unit BOE costs decline. This is shown in Figure E1.

By reason of our BOE cost calculations a bias is introduced into the analysis. As outlined above an increase in the relative price of oil dictates a decline in the number of BOE booked and hence an increase in the unit booking costs. An increase in the relative price of gas reserves immediately dictates an increase in number of BOE reserves that are booked and a decrease in the unit booking costs.

Table E1

Barrels of Oil Equivalent

	Price of Oil Reserves / Price of Gas Reserves	Costs of Booked Reserves of BOE	Cumulative* BOE (in millions)
1957	119	1.24	344.2
1958	142	1.35	663.4
1959	103	1.46	957.1
1960	44	1.29	1289.1
1961	41	1.15	1682.8
1962	28	.59	2448.1
1963	27	.58	3232.4
1964	30	.50	4120.1
1965	23	.46	5100.5
1966	20	.42	6209.0
1967	18	.62	6970.4
1968	16	.64	7693.8
1969	21	.87	8231.2
1970	30	1.24	8629.5
1971	37	2.16	8884.0
1972	37	2.49	9130.0
1973	35	3.19	9339.2
1974	37	4.66	9605.7
1975	16	2.70	9870.6
1976	12	2.54	10266.7
1977	16	4.04	10603.1
1978	20	5.22	10932.3
1979	21	4.82	11306.8

* Due to data availability the reserves reported in 1957 do not reflect all previously discovered reserves.

Table E2

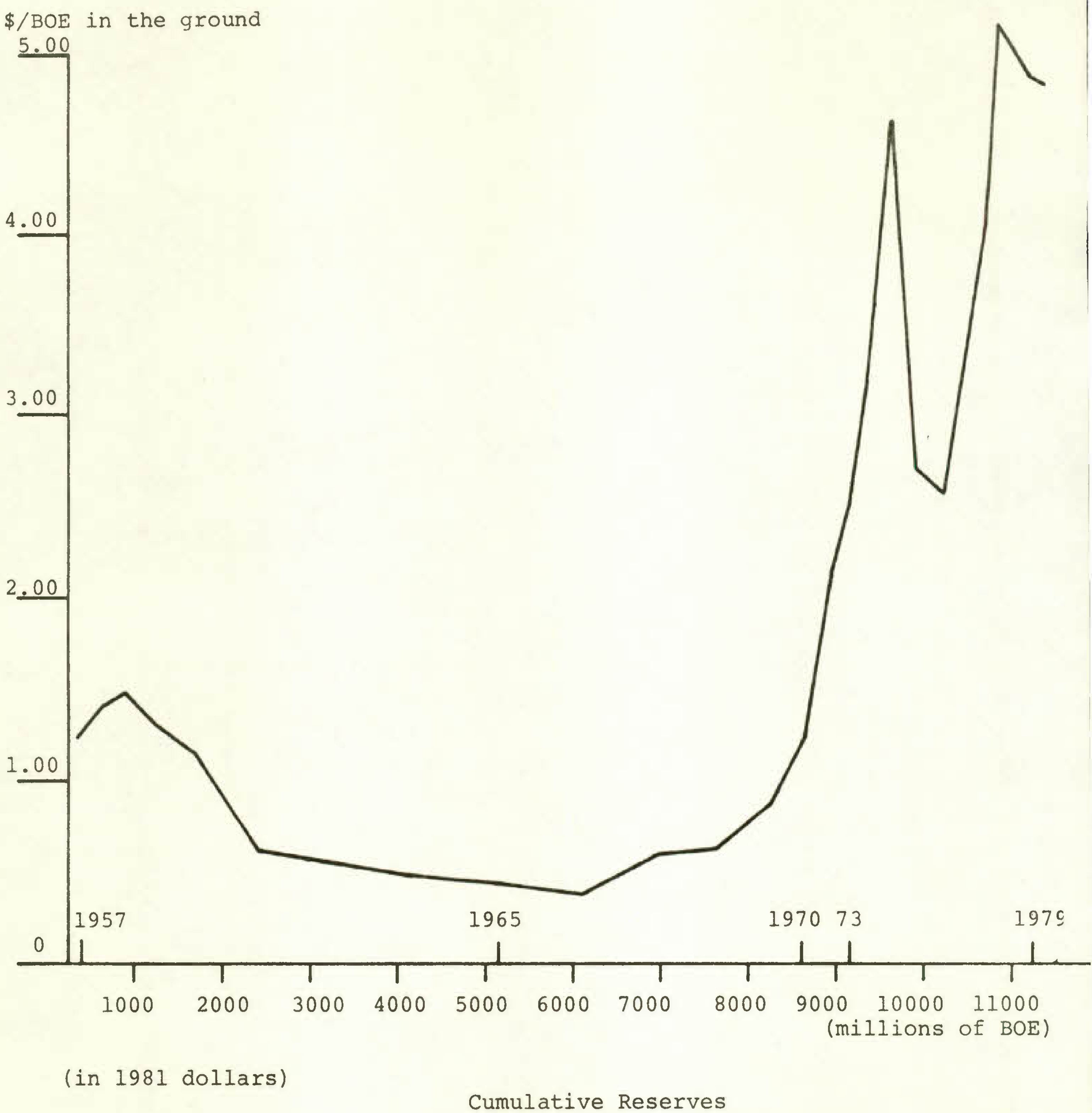
Prices of Oil and Gas Reserves in the Ground

	Price of Oil Reserves (in 1981 $ per barrel)	Price of Gas Reserves (in 1981 $ per mcf)
1957	2.38	.020
1958	2.13	.015
1959	2.17	.021
1960	2.00	.045
1961	2.07	.050
1962	2.23	.080
1963	2.32	.087
1964	2.42	.098
1965	2.34	.104
1966	2.31	.118
1967	2.15	.118
1968	1.91	.118
1969	1.80	.089
1970	1.61	.054
1971	1.95	.053
1972	2.03	.055
1973	2.44	.069
1974	5.75	.155
1975	4.54	.280
1976	7.69	.594
1977	8.41	.529
1978	9.01	.446
1979	8.85	.422

Source: These price estimates are those of Prof. Russell Uhler from work currently in progress for the Economic Council of Canada.

FIGURE E1

COSTS OF BOOKED RESERVES OF
BOE IN THE GROUND



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