THE UNIVERSITY OF CALGARY

OIL AND GAS EXPLORATION AS A FUNCTION OF CASH FLOW

by

Michael T. Waites

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The undersigned certify that they have read, and recommend to the Faculty of Graduate Studies for acceptance, a thesis entitled, "OIL AND GAS EXPLORATION AS A FUNCTION OF CASH FLOW" submitted by Michael T. Waites in partial fulfillment of the requirements for the degree of MASTER OF ARTS.

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ABSTRACT

This study examines the relationship between oil and gas exploration activity and industry cash flow. The hypothesis is that cash flow, as an indicator of both expected profitability and the industry's financial strength, is a major determinant of real exploration spending and hence, activity.

Exploration activity is first examined with a review of the supply theory of exhaustible resources. A simplified theoretical model is then postulated and tested empirically. Exploration spending is initially examined as a function of oil and gas netbacks and cash generation from producing operations. The model is then modified to relate spending solely to producing cash flow.

Two major data sets are used. The results using data obtained from Statistics Canada indicate there is a significant correlation between exploration spending and cash flow. Further, the results for the components of exploration expenditures are consistent with expectations. Land expenditures, for example, appear to be very responsive to cash flow levels.

The overall results obtained using the PMA data set are directionally consistent with those of Statistics Canada. However, the relationship is statistically weaker due, in part, to the limited sample of available data.

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CHAPTER 1 - INTRODUCTION

This study examines the relationship between oil and gas exploration activity and industry cash flow. Specifically, the hypothesis is that cash flow, as an indicator of both expected profitability and the industry's financial strength, is a major determinant of real exploration spending and hence, activity.

The overall level of exploration activity is clearly important from an economic and policy standpoint. Aside from the obvious issue of the discovery process and energy supply for Canadians, exploration activity influences employment levels in several sectors of the economy and significantly affects government receipts and hence, the management of its fiscal objectives. Total exploration spending in Western Canada approached $6 billion in 1985 and still exceeded $3 billion in 1986, a depressed year with plummetting crude prices.[1] Western Canadian land bonuses alone totalled about $790 million in 1987.[2] Land bonus payments combined with other resource revenues, notably Crown royalties, were expected to account for about 28 per cent of Alberta's General Fund revenues in the 1988-89 fiscal year.[3]

Exploration activity can be broken down into three functional activities: (1) land acquisition and retention; (2) geological and geophysical work; and (3) exploratory drilling.

Typically, the exploration process begins with a firm acquiring surface rights to undertake exploration activity on a given tract. The firm's interest on this tract could be triggered by many factors including

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1 Canadian Petroleum Association, Annual Report 1987, p. 7.
2 Ibid, p. 5.
3 The Honourable Dick Johnston, Provincial Treasurer, Budget Address 1988, in the Legislative Assembly of Alberta, p 32.

surface geological features, geophysical information or adjacent discoveries. The firm then undertakes an investigation of the subsurface geology, most often by conducting seismic operations. Seismic data are then processed and interpreted. If the data are encouraging, indicating the commercial presence of hydrocarbons, the next step is to drill an exploratory well. Prior to drilling the well, however, mineral rights must be obtained. If these rights are owned by the Alberta Government, for example, they are acquired on a competitive bid basis via government land sales. The firm ensures the target lands are posted for sale and then bids by offering land bonuses.

These three functional activities constitute the exploration component of the supply process. If the exploratory well is successful, the remaining steps are for the development and production of the newly discovered reserves.

The ensuing development stage involves the drilling of delineation and development wells and constructing process facilities and pipelines. If a gas field is discovered, then either a gas process plant is built or the gas is sent to a neighbouring facility for processing. At some point, secondary and tertiary recovery techniques may be employed to improve hydrocarbon recovery. Secondary recovery includes waterflooding and gas injection schemes designed to yield an additional 15 per cent or more of the oil in place compared to the natural depletion result from the primary recovery process. Tertiary recovery refers to methods other than those classified as secondary such as miscible flood techniques which yield an additional 10 to 20 per cent of the oil in place.

The sum of all exploration, development and production costs are referred to as "full cycle" costs. If expected revenues are sufficient to recover expected full cycle costs including a required return to financial capital, then investment will occur again and the cycle repeats itself with additional exploration activity. If, on the other hand, revenues merely recover production and development or "half cycle" costs, then exploration will cease over the long term as exploration costs are not fully recovered.

From this discussion it can be seen that the oil and gas supply process has several unique characteristics.

First, costs are largely incurred in the near term while revenues are realized for decades after a discovery. Revenue and profit expectations, therefore, play a large role in current investment decisions. If expected revenues exceed expected costs after discounting, investment will occur.

Second, there is a great deal of uncertainty involved in the supply process. Seismic data, no matter how encouraging, are not sufficient evidence of a discovery. Frequently, the ensuing exploratory wells are dry. Yet these unsuccessful well costs must be recovered from revenues from successful ventures and are included in the overall cost function.

Third, crude and gas are non-renewable resources, subject to depletion. As a result, there is an inverse relationship between the consumption of resources to date and the remaining resources to be consumed in future periods. Given some finite endowment of hydrocarbons, consumption today reduces resources available for consumption tomorrow. Accordingly, this depletion effect influences cost structures as the more accessible and less expensive reserves are typically discovered and consumed first.

The concept of depletion is discussed in some detail in Chapter 2. Depletion is first discussed in the context of a single ore body, examining the way in which supply quantities and prices could be expected to change over time.

The discussion is then expanded to the general supply framework for all resource deposits, a supply function in which exploration activity is one component. Chapter 2 also examines some selected empirical supply studies keying on exploration activity wherever possible. Considerable attention is given to the impact of time between when exploration and development investments are made and when returns are received. These studies highlight the fact that expected economic returns play an important role in supply activity for firms which are profit maximizers.
Chapter 3 presents an exploration activity model, positing that exploration activity is a function of expected returns and cash flow. The hypothesis holds that ultimately cash flow, as both a measure of expected profitability and the industry's ability to fund such activity, is a major determinant of exploration investment and hence activity. A theoretical unit profitability model is developed which is subsequently combined with an industry cash flow model. A brief discussion follows regarding limitations to financing exploration activity. A basic tenent in this discussion is that cash flow is a critical budget constraint to funding exploration activity both directly as well as indirectly via the industry's ability to attract and service the supply of equity financing that is available.

Chapter 4 presents the empirical findings of the model. Two major data sources are used. The first tests the theoretical relationship using aggregate industry data obtained from Statistics Canada. The other data set uses Petroleum Monitoring Agency data to examine the model within industry segments, e.g., the behaviour of large producers versus small producers.

Chapter 5 presents the conclusions of the empirical testing. In addition, some of the implicit assumptions of the model are reviewed and the strengths and weaknesses of the study are noted.

Finally, three appendices are provided. Appendix A summarizes the numerous data sources from which the data were obtained. Appendix B presents a discussion of the cash flow concept. The term "cash flow" can be defined, not incorrectly, in several ways. A conclusion of Appendix B is that oft presented measures of cash flow are overstated in absolute terms in that such estimates, while typically excluding pre-tax investment outflows, include the beneficial effect of credits to income tax expense relating to such investment spending.

Appendix C presents a limited review of the fiscal system as it pertains to oil and gas extraction income. Insofar as the provincial and federal governments have demonstrated a clear intent to exact significant economic rent from the industry over the last fifteen years, no discussion of profitability is complete without a review of this complex fiscal system.

The major contributions of this study are as follows:

1. Cash flow is measured in terms of actual cash generation from producing operations exclusive of investment activity. This measure is largely equivalent to cash generation from unit netbacks multiplied by total quantities produced. This derivation marks an improvement in assessing industry profitability compared to the alternative approach of multiplying production quantities by some estimated average unit netback.

2. The study formulates and tests a model relating exploration activity to cash flow. The specific argument holds that current cash flow is both an indicator of expected profitability and is crucial in funding exploration investment. The risky nature of the exploration process precludes debt financing and limits the extent of new equity financing. Moreover, any additional equity financing capacity is largely dependent on the level of existing cash flow, underscoring the importance of the latter in funding exploration investment.

CHAPTER 2 - OIL AND GAS SUPPLY THEORY

2.1 A BRIEF NOTE ON DEPLETION THEORY

Depletion theory provides the basis for the modern day supply theory of exhaustible resources in which exploration activity is one component.

The early depletion literature focused on the production of a fixed reserve or an exhaustible ore body such as a mine. The initial seminal work in this area was done by L. C. Gray and later developed mathematically by H. Hotelling.[4] After making several simplifying assumptions such as having a perfect knowledge of an exhaustible ore body and homogeneity of deposit, Gray's major contribution was illustrating that the mine owner, if indifferent between current and future production, may elect to operate at an output where average costs are minimized in order to maximize profitability over the life of the mine. This clearly provided an exception to the conventional profit maximizing notion of equating marginal cost to marginal revenue. Gray also observed that, if the mine were inexhaustible, the mine owner would revert to increasing production until the conventional marginal conditions were obtained.

Gray further illustrated that the rate of interest or discount is crucial to the production decision. Assuming all other conditions remained static over time, if the rate of interest used to discount future profitability is so great as to reduce the present value of profit by more than the cost of increasing current production (assuming the cost curve is currently rising due to diminishing returns), then the mine owner will favour current production at the expense of future production. However, given a sufficiently low discount rate, future production would be favoured.

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4 L. C. Gray, "Rent Under the Assumption of Exhaustibility," Quarterly Journal of Economics, v. 28 (1914), pp 466-489, and H. Hotelling "The Economics of Exhaustible Resources," Journal of Political Economy, v. 39 (1931), pp 137-175.

Obviously, conditions are not static over time and Gray went on to examine the effects of future changes in product prices and input costs. Rising future prices favour deferring production while rising future costs favour current production.

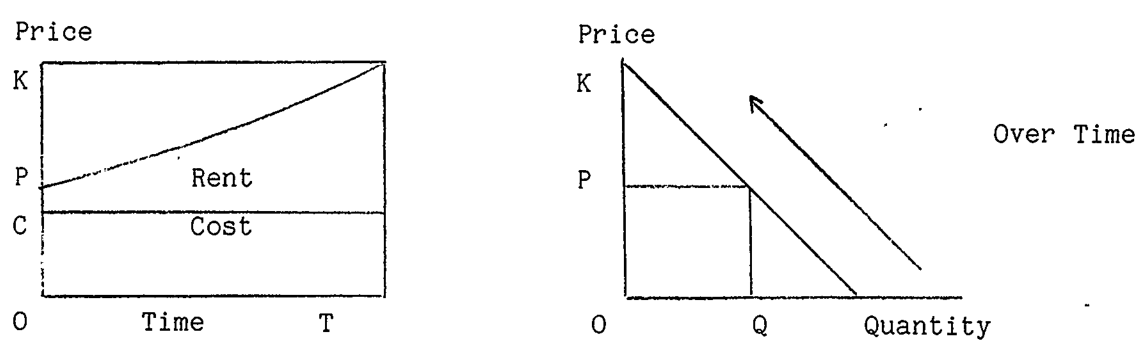
2.2 THE REFORMULATION OF DEPLETION THEORY

Others, notably Gordon, Scott, and Herfindahl, subsequently reviewed or expanded the framework developed by Gray.[5] Similar to Gray, both Scott and Herfindahl examined the effects of changing prices and costs deriving conclusions directionally consistent with those of Gray.

Herfindahl provided a particularly effective graphical illustration of the simplified depletion concept as follows:

FIGURE 2.2.1

A Graphical Illustration of the Depletion Concept



5 - R. L. Gordon, "A Reinterpretation of the Pure Theory of Exhaustion," Journal of Political Economy, v. 75 (1967), pp 274-286.
- A. D. Scott, "The Theory of the Mine Under Conditions of Certainty," in Extractive Resources and Taxation, ed. by Mason Gaffney (The University of Wisconsin Press, 1967), pp 25-62.
- O. C. Herfindahl, "Depletion and Economic Theory," also in Gaffney, Extractive Resources and Taxation, pp 63-90.

On the right, a price of P results in consumption of Q. As the price ultimately increases to K over time, production and sales will decrease with the commodity then only being used for critical applications, until the price will be sufficiently high to preclude any consumption and all of the resource will be used up. Herfindahl calls K the point of exploitation. If the rent or profit must increase at the real rate of interest (profit in each period is constant in present value terms so as to make production equally attractive over all points in time), then an initial price which is too low will increase the quantity demanded and the resource will be used up before the maximum price of K is obtained. Conversely, if the initial price is too high, the maximum price will be obtained prior to the point of total exploitation. This framework was subsequently used by Herfindahl to examine the outcome of changes in other factors potentially affecting production decisions including costs and revenues.

Herfindahl also examined the issue of exploration activity concluding that if one considers exploration activity to be a part of current costs, then exploration will be undertaken if prices are sufficient to recover such costs.

Herfindahl further attempted to reconcile observed price behaviour to the theory with the following four theoretical long run possibilities:

1. Prices are below costs (including exploration costs), precluding exploration activity - new discoveries are accidental.
2. Prices rise at an increasing rate until a maximum price is reached.
3. Prices are flat or rise moderately.
4. Prices rise to a level where a higher cost source of unlimited supply becomes economic.

Possibility one is dismissed because there are few, if any, commodities dependent entirely on accidental discoveries or discoveries stemming from the output of a more important product with which the commodity is found.

Possibility two is declared an empty set in that no such price behaviour has occurred. On the contrary, Herfindahl observed that improved technology and discoveries of more prolific sources of supply have resulted in lower, not higher, prices. With respect to depletion theory, this observation is explained in terms of the theory that market participants do not expect prices to rise over the intermediate term because of ample supplies and technological improvement and so there is little perceptible difference in current price because of depletion in the far distant future. If future costs were expected to rise as marginal deposits were developed, the theory would suggest that current costs and prices in each successive period would also rise. As Herfindahl states:

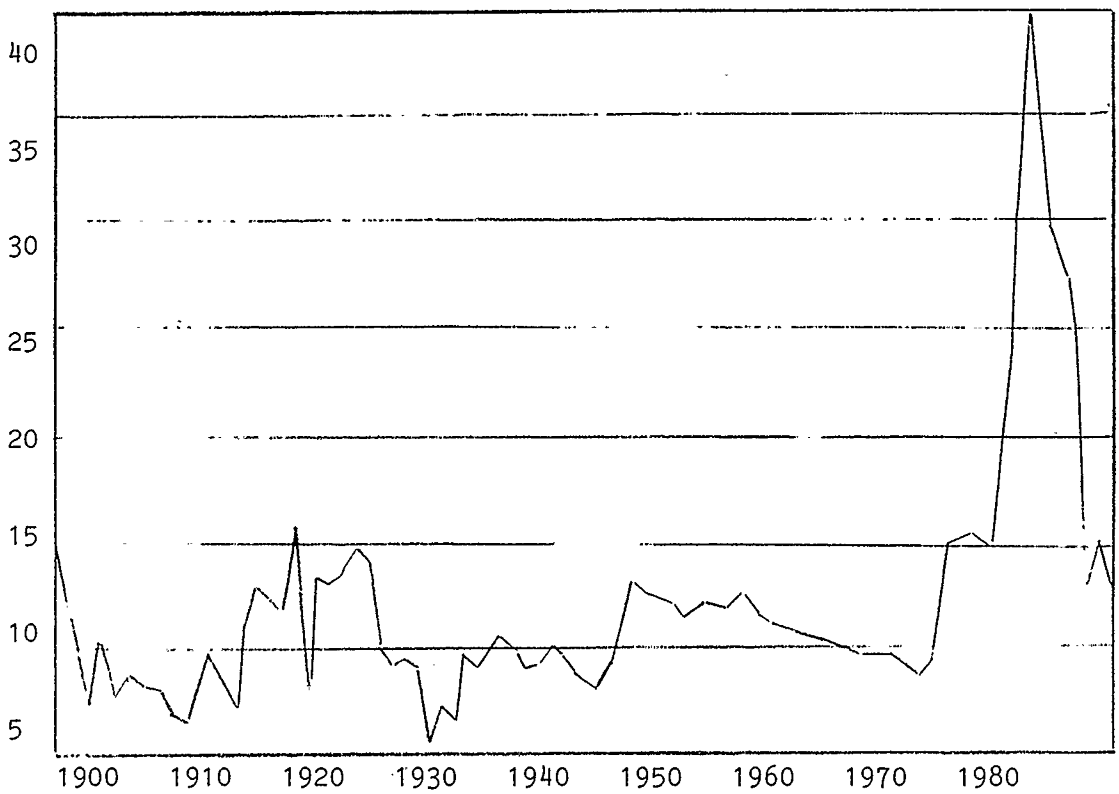
> A very large quantity of deposits exploitable at expected costs within reach of those now current is an observable feature of the world. In part this is a consequence of the fact that the earth - up to now, at least - has been very large in relation to the volume of materials consuming activity.[6]

The empirical evidence indicates that in a broader context, at least, a pure depletion driven case for rising prices has yet to be observed, as can be seen in Figure 2.2.2:

6 Ibid.,p. 85.

FIGURE 2.2.2

U.S. Crude Oil Price summary
1987 U.S. Dollars per Average Barrel



Source: Chevron Corporation, World Energy Outlook (San Francisco, 1987), p4.

Prior to OPEC's effective oligopoly control in the early 1970's, crude prices over the first 75 years of this century, fluctuated in the US $5 - 15/bbl range in constant 1987 US dollars and failed to exhibit a depletion driven upward trend. It is interesting to note that crude prices over most of 1988 were also in this range despite the cartel's efforts to artificially constrain supply.

Hence, we have the apparent contradiction. On the one hand, extending depletion theory to the future, we have a bleak picture of inexorably moving toward physical exhaustion at ever increasing costs and prices. Yet to date this has not been the case because of technological change and ongoing exploratory discoveries.

2.3 THE SUPPLY OF EXHAUSTIBLE RESOURCES

Adelman later undertook a comprehensive review of depletion theory providing a definitive link to modern day petroleum supply theory.[7] Starting from Gray's work, Adelman noted that there is a constant movement toward equating marginal cost to price citing the following five stages in the supply process:

1. The current operating margin, or rate of production, which is governed by the proportion of the reserve already depleted.

2. The intensive development margin which includes investment costs for the already known deposits.

3. The extensive development margin, where exploitation is begun of known but previously uneconomic deposits.

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7 M. A. Adelman, et al, Energy Resources in An Uncertain Future: Coal, Gas, Oil and Uranium Supply Forecasting (Cambridge, Massachusettes, Ballinger Publishing Co., 1983).

4. The exploration margin where a search for new deposits is conducted.

5. The technology margin which interacts with the first four.

Adelman concluded that the Gray-Hotelling theory is a special case which covers only the first three stages, setting four and five to zero. Adelman states the true supply paradigm as follows:

> At any given moment, mankind is unwillingly crawling up the leftward moving supply curve toward higher mineral costs and also pushing the curve over to the right toward lower costs.... Hence the pure theory of exhaustion, which deals with optimal use of dwindling stock, is at most a special or transitory case and should not be built into any scheme of calculating reserves.[8]

Adelman continued, examining the concept of an exploration model. He cited a simple example as the relationships between effort and yield. If the yield or expected yield increases, then exploratory effort should increase, pushing the supply curve out to the right. However, effort/yield models may fall short of explaining overall supply trends if it is not recognized that they imply certain assumptions regarding the quality of the resource base. Realistically, resource quality can vary dramatically, depending upon cumulative production, geological qualities and reserves location, and these factors should be considered. Nevertheless, assuming the point of total exploitation is far into the future, an increase in expected yield should directionally result in increased exploration activity. This increased activity, in turn, should manifest itself in the form of reserve additions.

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8 Ibid., p.9.

Other studies have empirically examined the many aspects of exploration activity in the context of overall supply theory. These studies generally fall into three categories: (1) supply cost studies; (2) performance-economic models; and (3) specific activity models. Although the complete conclusions of some of these studies are beyond the scope of this paper, it is worthwhile to examine how exploration activity has been dealt with in these broader contexts.

2.4 SUPPLY COST STUDIES

As a general observation, these studies often go beyond solely reviewing cost trends and frequently compare costs with observed revenue or profit to derive conclusions about supply prospects.

Bradley, in 1966, presented a sophisticated cost model which was based on observed investment behaviour.[9] Bradley sought to measure crude supply costs for various crude exporting regions and dealt extensively with the effect of time on the investment process and ultimate profitability over the long term. Bradley noted that near term investment costs may be imputed to future output to accurately determine overall profitability. This approach to assessing profitability is particularly useful if the objective is to relate investment costs to a range of future profit scenarios. In this respect, imputing investment cost to future output is a complementary approach to valuing initial investment outlays in terms of expected unit profitability and the term of asset expiration.

The following equation summarizes Bradley's valuation model:

$$(2.4.1) \qquad V = \int_{o}^{T} p(t)\, q(t)\, e^{-rt}\, dt - I$$

---

9 P. Bradley, The Economics of Crude Petroleum Production (Amsterdam: North Holland Publishing Co., 1967), pp 1-41.

where V is a measure of the net discounted value of the investment process, p(t) is the anticipated price level in period t net of extraction costs, q(t) is a function relating output at time t to investment I and continuous discounting is assumed. This equation states that if costs, together with the required return on investment, are to be recovered then V must be equal to or greater than zero for investment to occur. If one thinks of price as the minimum level of imputed development cost at which the investment is just repaid, then (2.4.1) can be reconciled to:

$$(2.4.2) \qquad I = \int_{o}^{T} Z\, q(t)\, e^{-rt}\, dt$$

or

$$(2.4.3) \qquad Z = \frac{I}{\int_{o}^{T} q(t)\, e^{-rt}\, dt}$$

where Z = constant development cost per barrel.

In allowing Z and I to relate solely to development costs, Bradley excluded exploration investment. Yet these costs must be recovered as part of the full cycle process and cannot be excluded. Bradley, however, argues that while exploration expenditures may affect the level of the other cost components, exploration costs cannot be imputed to any specific crude production. As will be seen later, several studies have since imputed such costs to production.

Before leaving Bradley, it is interesting to summarize the characteristics of (2.4.3). This expression can be viewed as the levelized cost of production and is determined by the investment, the production profile and life of the reservoir, and the cost of money. The investment is imputed to the units of production produced in later periods. In other words, this is the amount that must be charged to each unit of output over the life of the deposit in order to recoup the investment costs necessary for production.

This imputed levelized cost can be thought of as an annuity over the life of the reservoir which is needed for cost recovery. The levelizing process simply allows for costs and revenues (if also levelized) to be dealt with on a comparable basis, taking into account cash flow timing differences. Another way to assess profitability is to discount all costs and revenues to the present which is, of course, the play specific investment approach. The levelized approach is more useful if the orientation is to compare current costs to a range of expected profitability scenarios in order to evaluate the supply outlook, as is often the case with cost studies.

Eglington and Uffelman, in 1983, also employed a levelized cost approach as part of a finding cost study.[10] Although their main objective was to observe the unit finding and developing costs in Alberta over a set period, the analysis was extended, comparing levelized exploration and development costs to then current cash netbacks. The study yielded several noteworthy results, not the least of which was that in the late 1970's, the value of developed reserves was less than the levelized development and finding costs to put them in place. Yet exploration activity continued. The authors explain this incongruity in terms of three phenomenon.

First, the data used represented industry averages for which some successful companies were undoubtedly experiencing lower finding costs. Second, activity during that period was fueled by expected profitability, which was assumed to increase. Third, the discovery process is stochastic, causing firms to continue pursuing success despite depressed average conditions for the period.

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10 P. Eglington, and M. Uffelman, <u>Observed Costs of Oil and Gas Reserves in Alberta, 1957-1979</u> (Ottawa: Economic Council of Canada Discussion Paper No. 235, 1983).

Note that there are also two structural issues in the approach used by Eglington and Uffelman which would yield a conclusion of this kind. The major issue relates to the fact that pre-tax exploration expenditures are compared to the after-tax value of reserves acquisition. If oil and gas companies have other sources of income, exploration costs are deductible for federal income tax purposes subject to certain constraints. This means that after tax exploration expenditures would be on the order of one half to two thirds of pre-tax costs.

The extent to which exploration costs are deductible in a given year largely depends on the composition of the costs. More recently most geological and geophysical costs as well as exploratory drilling expenditures are eligible "Canadian Exploration Expenses" for tax purposes and are 100 per cent deductible in the year incurred. Land acquisition costs are generally categorized as "Canadian Oil and Gas Property Expense" and on a cumulative basis are deductible at 10 per cent per year.

The other issue with the Eglington and Uffelman study is the way in which finding costs are escalated in order to be compared to a reserves value. The cost of money is estimated using factored MacLeod Young Weir bond rates to approximate a weighted average cost of capital for a company with an average debt and equity capital structure. However, the interest cost component of this formula is deductible for tax purposes if debt proceeds are being used for the purpose of creating business income. Accordingly, the after-tax cost of money is somewhat lower than the estimates of Eglington and Uffelman. On a combined basis, escalating pre-tax costs at artificially high rates will naturally result in a comparatively overstated cost estimate. Hence, it is not surprising that these costs exceeded the value of reserves.

In contrast to Bradley, Eglington and Uffelman dealt with full cycle costs in their study, and went to great lengths to link total exploration expenditures to reserves discoveries. Due consideration was given to the lag effect between when expenditures are incurred and reserves discovered. Oil and gas investments were also segregated with exploratory drilling expenditures for oil being assigned, using oil intent ratios.

2.5 PERFORMANCE - ECONOMIC MODELS

Performance economic models take into account both technological and physical as well as economic considerations in assessing the supply outlook. While these models are, by definition, broader in scope than this study, two works, in particular, have focused on exploration activity.

Foat and MacFadyen, in 1983, undertook to develop a performance economic model for reserves additions in Alberta.[11] The model's components included behaviourial aspects - aggregate exploratory drilling effort and relative play specific exploratory effort - and a technological or performance component of cumulative discoveries for a given play. A play is defined as a group of pools or reservoirs with similar geological characteristics and the model sought to explain reserves additions on this disaggregated basis. Overall, the model's results were mixed although quite successful for selected plays.

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11 K. D. Foat, and A. J. MacFadyen, Modelling Exploration Success in Alberta Oil Plays (Calgary: Canadian Energy Research Institute Study No. 19, 1983).

An extension of their analysis, however, is of primary importance here; specifically, the question of what determines exploratory effort. Noting that from an economic standpoint, drilling activity is generated from expectations of economic profits, the authors proceeded to discuss the difficulties of measuring this behaviourial relationship. Several situations were cited, whereby a model misspecification may occur. For example, not all firms may be pure profit maximizers with some seeking to minimize risk instead. In addition, expectations regarding future profitability are based on past experiences, which differ. Also, individual tax positions may differ, subsequently affecting the after-tax cost of exploration activity.

After making several simplifying assumptions, Foat and MacFadyen tested a log-linear functional form relating the number of exploratory wells, W, to the real price of natural gas and oil (net of royalties), Pg and Po, and the average discovery size for oil and gas fields, Do and Dg.

The results for the period 1948 to 1970 are summarized below:

(2.5.1) $\ln W = 7.83 + 0.67 \ln Pg - 1.36 \ln Po - 0.06 \ln Do - 0.18 \ln Dg$

t values (10.40)(3.65) (-6.04) (-1.62) (-3.25)

$R^2 = 0.87$ Period = 1948 - 1976

D.W. = 1.72

It can be readily seen that the empirical result is not consistent with expectations. Specifically, the signs of the coefficients for the oil price and both discovery variables are negative. It was concluded that a single equation model was unlikely to prove useful, although some additional econometric testing was undertaken.

One variation of (2.5.1) substituted the price or value of oil and gas in the ground for the real price of oil and gas net of royalties. The major difference between these variables is that the value of reserves in the ground includes operating and developing costs as well as income taxes, whereas the real price of crude or gas formerly used simply nets royalties from realizations. However, this substituted variable retained its negative sign.

Other relationships were also tested, including the use of a lagged dependent variable as an independent variable to approximate a stock adjustment model, dummy variables for differing expectations over the period, and a success rate variable. None of these relationships yielded acceptable results.

Foat and MacFadyen noted that the historical development in the Alberta oil business "make the lack of good results for a simple exploratory drilling equation somewhat less surprising".[12] Considering that the major oil plays exhibited a depletion effect and that the real price of oil tended to fall until the early 1970's, these trends appear to be at odds with increasing activity. The inconsistency is categorically reconciled in terms of several observations, including:

1. The depletion effect within one oil play need not be generalized to the province.

2. Profitability is more important than the real price of oil or gas.

12 Ibid., p. 62.

3. Technological advancement makes it easier to discover reservoirs, reducing costs.

4. Expected prices and discovery size did not correspond to actual values observed.

5. There are drilling capacity limitations which results in less activity than desired.

6. Gas is also a valuable product, precluding the sole use of oil prices as an indicator of profitability for oil exploration.

7. There may have been changes in the number of market participants, making for increased competition.

The authors concluded that a more complex model is needed to explain total drilling effort in Alberta.

Uhler and Eglington, in 1986, sought to explain the process of reserves additions in terms of two factors, remaining geological potential and economic conditions.[13] Uhler and Eglington pointed out that drilling activity should be a function of the price of reserves. The price of reserves is the current value of the discounted flow of future after- tax cash netbacks and again is the complement of the levelized cost approach.

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13 R. S. Uhler and P. Eglington, The Potential Supply of Crude Oil and Natural Gas Reserves in the Alberta Basin (Economic Council of Canada, 1986).

Algebraically, Uhler and Eglington expressed the unit price of reserves as:

$$(2.5.2)\quad \frac{W}{Q} = \frac{\int_0^T \{p(t)\ [\ 1 - Ry\ ] - c(t)\}\ \{1 - \tau\}\ q(t)\ e^{-rt}\ dt}{Q} - Ps(1-\tau_1)$$

where W is the profit above a normal rate of return, Q is total production, p(t) is wellhead price in period t, c is the operating cost in period t, Ry is the royalty rate, τ is the statutory income tax rate, q(t) is the annual production rate, and r is the discount factor. The last term on the right is the price of reserves and is tax adjusted assuming that acquisition costs are tax deductible.

Allowing Pn to equal the after-tax cash netback and to remain constant as below:

$$(2.5.3)\quad Pn = \{p\ [\ 1 - Ry\ ]\} - c\}\ \{1 - \tau_1\}$$

and assuming q is constant and that excess profits are eliminated, (2.5.2) can be rewritten as:

$$(2.5.4)\quad Ps(1-\tau_1) = q\ Pn\ D_f\ ;\quad D_f = (\ 1 - e^{-rT}\ )\ /\ r$$

The authors noted that if r is fixed, the price of reserves is proportionate to the producer netback. Implicitly, (2.5.2) assumes that the reserves have already been developed and are ready for production and so, the only costs that are incurred are production costs. This price is referred to as the price of developed reserves and if one were to separate the exploration and development stages for analytical purposes, there would be a separate price for undeveloped reserves.

Uhler and Eglington subsequently discussed industry profit expectations insofar as the expected profit should determine current investment activity. In asking if there is any reason for forecasts of these quantities to be anything other than constant, they reviewed a history of wellhead price changes in Canada. The conclusion was that static price expectations for both oil and gas are reasonable up to 1973, after which time a growth rate is assumed until 1981.

Unfortunately, the reserves price variable ultimately turns out to be a poor explanatory factor in the aggregate reserves additions model due, in part, to fluctuations in observed discoveries around a declining cumulative trend and the relative stability of reserve prices over most of the sample period.

2.6 EXPLORATION ACTIVITY STUDIES

The work which has the most relevance for this study was prepared by B. L. Scarfe and E. W. Rilkoff in 1984. The authors examined the role of producer netbacks on internal cash generation in the financing of exploration and development activity.[14] Scarfe and Rilkoff attempted to explain overall industry activity, as measured by various categories of real exploratory expenditures, in terms of expected profitability and production trends.

Noting that planned reserve additions are partially a function of exploratory effort, the reverse relationship was examined; that exploratory effort would only be undertaken if it were profitable to do so. Hence, the optimal level of exploratory effort is a function of exploratory

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14 B. L. Scarfe, and E. W. Rilkoff, Financing Oil and Gas Exploration and Development Activity (Ottawa: Economic Council of Canada Discussion Paper No. 274, 1984).

additions and their value or their marginal revenue product.

An inventory theoretic notion was also postulated that, "producers invest with a view to maintaining some normal (though perhaps trended) relationships between production and reserve holdings...".[15] Essentially, the authors argue that the replacement process is critical to any extractive firm and so influences activity levels.

Because planned reserve additions cannot be observed, this variable is removed. As a result, optimal exploratory effort is linked directly to expected profitability and current production.

Scarfe and Rilkoff employed an exponential functional form for the postulated relationship, subsequently, transforming it into a log-linear equation:

$$(2.6.1) \qquad E^{*} = a\, P^{\beta}\, Q^{\gamma}$$

where E^{*} is the optimal level of exploratory effort, P is the value of undeveloped reserves in the ground, and Q is current production.

This relationship also incorporated a lag adjustment model as follows:

$$(2.6.2) \qquad \frac{E_t}{E_{t-1}} = \left(\frac{E^{*}_t}{E_{t-1}}\right)^{\delta} \qquad 1 > \delta > 0$$

15 Ibid., p.9.

Substituting for E* from (2.6.1) and natural log transforming:

$$(2.6.3)\quad \ln E_t = \delta \ln a + \delta \beta \ln P_t + \delta \gamma \ln Q_t + (1-\delta) \ln E_{t-1} + u_t$$

Exploratory effort is measured by real expenditures. The prices or values of undeveloped reserves were obtained from Uhler and Eglington, who worked back from oil and gas prices at the wellhead to derive discounted netbacks as reserve values.[16]

Scarfe and Rilkoff duly recognized the fact that exploratory additions are not homogeneous but consist of crude oil and natural gas reserves. The value of these reserves can differ significantly and so intent ratios are used to weight-average reserve prices and completion ratios are used to weight-average output.[17]

The empirical results obtained were fairly strong. Results for the primary model are summarized in Table 2.6.1. Estimates of the elasticities of the exploration equations are directionally as expected and statistically significant at the 5 per cent level. The price of undeveloped reserves has a strong influence on all categories of exploratory expenditures and most notably on land expenditures for land acquisitions. The lagged expenditure coefficient indicates that expenditures adjust at a moderate rate with land expenditures adjusting more quickly.

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16 R. S. Uhler, and P. Eglington, The Potential Supply of Crude Oil and Natural Gas Reserves in the Alberta Basin (Ottawa: Economic Council of Canada Discussion Paper No. 235, 1983).

17 Refer to P. Eglington, and M. Uffelman, Observed Costs of Oil and Gas Reserves in Alberta, 1957-1979 (Ottawa Economic Council of Canada Discussion Paper No. 235, pp A12-A18) for a discussion of intent ratios.

TABLE 2.6.1

Alberta Petroleum Industry Expenditure OLS Regressions, 1960-1981

ENDOGENOUS	EXPLANATORY VARIABLES				R^2	DW	N
1. GEOG 1	C	RESU	PRODW	GEOG1(-1)			
	-.7648	.1953*	.1259*	.6553*	.87	1.87	22
	(0.67)	(2.63)	(1.75)	(4.87)			
2. DRIL 1	C	RESU	PRODW	DRIL1(-1)			
	-1.791*	.1637*	.1284*	.8914*	.96	1.87	22
	(2.02)	(2.55)	(2.25)	(10.90)			
3. LAND 1	C	RESU	PRODW	LAND1(-1)			
	.6370	.3432*	.1227*	.5376*	.84	1.92	22
	(0.56)	(3.95)	(2.03)	(4.44)			
4. TOT 1	C	RESU	PRODW	TOT1(-1)			
	-.5165	.2495*	.1282*	.7328*	.85	1.81	22
	(0.72)	(4.47)	(2.97)	(8.95)			

*denotes significance at the 5% level.

GEOG 1 - log (geological and geophysical expenditures/ISPI)
DRIL 1 - log (drilling expenditures/ISPI)
LAND 1 - log (expenditures for land acquisitions and rentals/ISPI)
TOT 1 - log (total expenditures for exploration/ISPI)
ISPI - industrial selling price index
C - intercept term
RESU - INTo x log (URESo) + INTg x log (URESg)
INTo - oil intent ratio
INTg - gas intent ratio
URESo - price of undeveloped crude oil reserves/ISPI ($/bbl)
URESg - price of undeveloped natural gas reserves/ISPI ($/Mcf)
PRODW - COMo x log (PRODo) + COMg x log ($PROD_G$)
COMo - oil completion ratio
COMg - gas completion ratio
PRODo - crude oil production (bbls)
PRODg - natural gas production (Mcf)

Source: B. L. Scarfe and E. W. Rilkoff, Financing Oil and Gas, pp.18-19.

Scarfe and Rilkoff also tested the correlation of a cash flow variable to exploratory spending, observing that the hybrid production variable should be expected to correlate with cash flow. The cash flow variable was constructed as follows:

(2.6.4) Cash Flow = (oil production x oil netback/ISPI) + (gas production x gas netback/ISPI)

where ISPI refers to the Industrial Selling Price Index. This cash flow variable was then tested in the models with reserves price and adjustment variables. The regression results were not improved by including this variable, which usually reduced the significance of the reserve price variables. The authors noted this is a pairwise collinearity problem driven by the fact that reserve prices and netbacks are interconnected.

From the empirical study, Scarfe and Rilkoff concluded that the reserves price/production quantity relationship is the most useful way to proceed as opposed to the cash flow approach. However, they advised one should not conclude that cash flow is unimportant in the determination of industry activity levels because of the 0.94 correlation coefficient between the cash flow variable and the weighted production variable. The implication here is that financial constraints or capital availability may be an issue. This argument, however, is not developed further.

The authors summarized their conclusions as follows:

> When important incentive effects on exploration and development activity are captured in the equations by the inclusion of the stock prices of oil and gas reserves in the ground, current production volumes serve as robust proxies for cash flow variables. But production

volumes also belong in the investment equations for 'replacement investment' reasons when one is dealing with non-renewable resources, so that a fundamental identification problem remains. Although a similar identification problem commonly occurs in investment studies for other sectors as well, in the current context it implies that neither the neo-classical investment approach (more popular with Energy, Mines and Resources, Canada) nor the cash flow profitability approach (more popular with the Canadian Petroleum Association) appears to dominate the other from an empirical perspective.[18]

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18 B. L. Scarfe, and E. W. Rilkoff, Financing Oil and Gas Exploration and Development Activity, p.41.

CHAPTER 3 - AN EXPLORATION ACTIVITY MODEL

3.1 BACKGROUND

The postulated exploration activity model, which follows, is premised on the observed investment process employed by many firms in the oil and gas industry. Using an example, assume the decision at the margin is to drill an exploratory well. In determining how much the firm should pay in bonus to acquire mineral rights, it uses the standard yardsticks of discounted cash flows and rates of return to derive the appropriate bonus payment in current dollars. Risk factors and geological characteristics are incorporated in a play analysis to determine the potential value of a prospect. Estimates are also made for drilling, development and production costs to assess the profitability of the prospect and the amount of bonus (or from a public standpoint economic rent) which can be paid. Clearly, an increase in expected prices and hence, expected profitability will drive an increase in the bonus payment assuming excess profits in the industry are eliminated. If actual profitability exceeds expectations then the firm's stockholders benefit, ex post, assuming these additional benefits are not removed by government policy. Conversely, stockholders absorb the impact of lower than expected profits.

Although other cost components can also be expected to increase given increased profitability, the bonus payment is unique in that it acts as a barometer of expected profitability and should adjust quickly to changes in expected profitability. Theoretically, the bonus payment represents part of the economic rent which is expected to be available and which is voluntarily removed from profit by producers if excess industry returns are eliminated. If expected profitability over and above a normal return to financial capital is zero, then the bonus payments should be zero.

It can also be seen that the bonus payment forms a complement to other rent or quasi-rent collection mechanisms. For example, royalties at the production stage would reduce expected profitability and lower bonus payments. If production royalties were so high as to eliminate the recovery of exploration expenditures, then exploration would cease over the long run. In this respect, production royalties are mostly quasi-rents. Their imposition would affect long term supply although it is unlikely short term output would be affected.

3.2 THE GENERAL MICROECONOMIC MODEL

The investment decision occurs at the margin and it is helpful to revisit the simplified static theoretical model for profit maximization.

General microeconomic theory holds that profits are maximized when marginal cost is equated with marginal revenue. At this optimal level of output Q, there exists a production function which relates this output to a set of factor inputs under a given state of technology. For a production function Q, using factor inputs capital K, labour L and resources R, the relationship can be expressed algebraically as:

(3.2.1) $Q = f\ (K, L, R)$ where

$$\frac{\partial Q}{\partial K} > 0,\ \frac{\partial Q}{\partial L} > 0,\ \frac{\partial Q}{\partial R} > 0\ ;\ \text{and}$$

$$\frac{\partial^2 Q}{\partial K^2} < 0, \; \frac{\partial^2 Q}{\partial L^2} < 0, \; \frac{\partial^2 Q}{\partial R^2} < 0$$

That is, output Q, will increase for a given increase in each factor input but at a diminishing rate assuming diminishing returns to hold when other factor inputs are held constant.

The least cost conditions for producing a given output can be expressed in several ways including the following:

$$(3.2.2) \quad \frac{MPP_K}{P_K} = \frac{MPP_L}{P_L} = \frac{MPP_R}{P_R}$$

where MPP and P represent the marginal physical products and prices of each factor input. This condition simply states that in order to obtain a given output at least cost, the extra increments of output per dollar of input must be the same. Subject to physical and technology constraints, this relationship suggests a potential for substitution among factor inputs.

In addition, the following identity for marginal cost, MC,

(3.2.3) $$MC = \frac{P}{MPP}$$

can be substituted for MC in the profit maximizing condition MR = MC:

(3.2.4) $$MR = \frac{P}{MPP} \text{ or } P = MR \times MPP$$

It can be seen that to maximize profit, the marginal revenue product of a given factor input must be equal to the price of the input. In dollar terms, you must get out at least as much as you put in. Accordingly, if other factors remain unchanged and the marginal revenue associated with each unit of output increases, profit maximizing firms will increase their demand for and hence, the price of factor inputs until the equality is regained. However, if other factors do change then the relationship may not hold. For example factor input-prices may rise over time. In addition the MPP may also decline with quantities produced, particularly in an industry like oil and gas with diminishing returns.

3.3 THE APPLIED MODEL

Adopting the theoretical condition of maximizing profit by equating marginal cost with marginal revenue, the profit maximizing firm's costs at optimal output Q^* will include exploration costs, development costs and production costs.

If all costs and revenues for the project at the margin were incurred in the current period, replacement costs could be compared to current revenues to determine profitability and test for cost recovery. The unit replacement cost measure is defined as:

$$\frac{\text{Current production costs}}{\text{Barrels produced}} + \frac{\text{Current development costs}}{\text{Barrels added to proved reserves through extensions and revisions}} + \frac{\text{Current exploration costs}}{\text{Barrels added to proved reserves through discoveries}}$$

However, these costs should be viewed as occurring over two general periods. Exploration and development costs are typically incurred over the near term, while operating costs are subsequently incurred over a much longer period during which production is realized. The cash profit generated over the production period is referred to as the producer netback and is frequently expressed on a unit per barrel or cubic meter basis. A simplified unit netback for a single period can be expressed algebraically as:

$$(3.3.1) \quad N/Q = (R[1-\beta] - C)(1 - \lambda)/Q$$

where N is the producer netback, R is revenue, β is the royalty rate, C is the production or lifting cost, Q is total production for the period and λ is the income tax rate.

It should be noted that (3.3.1) is for illustration purposes and is a simplified expression of the netback concept. It does not disclose the complex fiscal arrangement which pertains to oil and gas production income. For example, (3.3.1) implies that royalties are deductible for income tax purposes, which has not been the case for provincial Crown royalties since 1974 following the federal-provincial dispute regarding resource taxation.[19]

19 Refer to Appendix C for a detailed discussion of the fiscal system applicable to oil and gas extraction income.

Further, it is important here to focus on profitability and not to look at prices as a proxy measure for profitability because fiscal regimes play an extensive role in determining ultimate cash profitability, as can be seen in the following example:

TABLE 3.3.1
Estimated Netbacks
Alberta Production - Old Oil, Crown Land

	Cdn $/bbl 1986-10	Cdn $/bbl 1985-04
Field Price	$ 20.00	$ 29.75
Production Operating Cost	(5.00)	(5.00)
	15.00	24.75
Crown Royalty	(8.00)	(12.50)
PGRT	-	(2.97)
Pre-tax Netback	7.00	9.28
Federal Income Tax @ 36%[20]	(4.05)	(6.68)
Provincial Income Tax @ 11%	(1.24)	(2.04)
Provincial Rebate	0.47	0.69
After-tax Netback	$ 2.18	$ 1.25

This example is instructive on many counts. For example, notwithstanding a 33 percent reduction in field price, the netback after the price fall is substantially higher than before, due to favourable changes in the industry's fiscal environment, notably the elimination of the Petroleum and Gas Revenue Tax (PGRT) on 1986-10-01. Clearly then, prices over this period

20 For the 1986 illustration, Federal Income Tax is computed at 36% of Taxable Income. Taxable Income is equal to the Field Price ($20) less Production Operating Cost ($5) less Resource Allowance ($3.75). Resource Allowance is equal to 25% of Resource Profit. Resource Profit is comprised of the Field Price ($20) less Production Operating Cost ($5). Refer to Appendix C for a detailed discussion of the fiscal system as it pertains to oil and gas extraction income.

would not be an acceptable proxy measure for profitability.

For any period T, the simplified netback can be expressed as:

$$(3.3.2) \quad N(t) = (R(t)\,[1-\beta] - c(t))(1-\lambda)$$

Discounting a continuous stream of netbacks over all periods yields a unit value of:

$$(3.3.3) \quad \int_{0}^{T} (\,R\,(t)\,[\,1-\beta] - c'(t)\,)\;(\,1-\lambda)\;\;q\,(t)\;e^{-rt}\;dt/Q$$

where T is the length of the realization period for the stream of netbacks and q is production in period t.

The present value of this future stream of netbacks or expected netbacks (future receipts are not known with certainty when investments are made) must be sufficient to recover all exploration and development costs if the latter are to occur over the long term. Algebraically, if E equals current period exploration costs and D equals current period development costs and excess profits are eliminated, then the marginal condition is:

$$(3.3.4)\; E\,(1-a\lambda) + D\,(1-b\lambda) = \int_{0}^{T} ((R(t)\,[1-\beta] - c(t))\,(1-\lambda)\,q(t)\,e^{-rt}dt$$

where the coefficients a and b are the discount factors applied to the income tax rate to adjust for the fact that certain costs are not fully deductible for income tax purposes when incurred.

Relationship (3.3.4) states that current after-tax exploration and development costs will equal the present value of a stream of expected netbacks. This relationship assumes that the markets are competitive and that exploration and development costs are incurred currently as opposed to over a one to three year period. The current period assumption is often valid for many of the exploration cost components, but is somewhat less accurate for development costs.

Substituting the expected netback N*(t) for the netback stream in the righthand side of (3.3.4):

$$(3.3.5) \quad E(1-a\lambda) + D(1-b\lambda) = \int_{o}^{T} N^*(t)q(t)e^{-rt}dt$$

Further, allowing q(t) to acquire an exponential decline rate c, from initial production q_0, then (3.3.5) becomes:

$$(3.3.6) \quad E(1-a\lambda) + D(1-b\lambda) = \int_{o}^{T} N^*(t)q_0 \; (e^{-ct}) \; (e^{-rt}) \; dt$$

If the price, fiscal environment and lifting costs are assumed constant over time, then N*(t) is constant (say N*) and (3.3.6) yields:

$$(3.3.7) \quad E(1-a\lambda) + D(1-b\lambda) = N^*q_0 \; (1-e^{-(c+r)T})/(c+r)$$

Finally, if the cost of money and development costs are assumed constant then after-tax exploration expenditures at the margin are proportional to the expected netback or:

(3.3.8) $E \alpha N$ *

The netback identified in (3.3.8) is the expected netback for the project at the margin. Since this variable cannot be measured, a simplifying assumption is made for empirical purposes that current average netbacks are a reasonable proxy measure for expected marginal netbacks. This assumption is not without its faults. For example, it can be argued that operating costs at the margin would undoubtedly be higher and so if prices remained constant, expected netbacks would be comparatively smaller. However, on the revenue side, expectation of real price increases during the 1970's might have increased netback expectations.

Although Uhler, among others, has argued that during the period 1973 to 1980, current profitability was a poor proxy for expected profitability, this may not be entirely valid.[21] For example, when assessing investment outcomes during the 1970's, many firms tested economics on their current as well as projected economic trends. Many projects that failed to meet the hurdle rate under then current conditions were cancelled, notwithstanding the fact they would have been economic with say, escalating crude prices. In reality, some combination of both methods likely drove investment activity.

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21 R. S. Uhler and P. Eglington, Crude Oil and Natural Gas Reserves, p.18.

Summarizing, a relationship between exploration investment activity and unit profitability has been postulated. An increase in expected profitability is expected to generate an increase in exploration activity given the simplifying assumptions which hold constant future netbacks, the cost of money, and development costs among other factors. All other factors remaining the same (notably the marginal productivity condition), this increased activity, in turn, should manifest itself in exploratory reserves additions.

3.4 THE ABILITY TO FUND EXPLORATION INVESTMENT

Up to this point little has been said about the industry's ability to fund exploration spending. However, a strong case can be made that the inherent risk of the exploration process requires the firm to generate a certain level of cash from operations in order to fund such activity. Algebraically, (3.3.8) can be expanded to:

(3.4.1) $E \alpha (N^*, Nq)$

or if current netbacks are used as a proxy measure for expected netbacks,

(3.4.2) $E \alpha (N, Nq)$

where Nq is a measure of cash generation from producing operations - unit netbacks multiplied by total production.

There are three major sources of conventional financing to fund investment activity. One method is to use internally generated cash or retained earnings (equity financing). Major considerations as to whether to use cash flow to fund capital programs include the firm's capital structure, cost and dividend constraints. The cost of such financing generally equates to the return that stockholders require on the firm's common stock, comprised of dividend yield and stock appreciation performance. If these funds were invested at a lesser rate, the market price of the firm's stock would decline.

Debt funding comprises another financing source for capital program funding. Debt financing might be obtained from the bank market with bank loans, the money market via the use of money market instruments such as commercial paper, or capital markets financing. A major feature of debt financing is that lenders assess the operating and financial risk of the borrower before loaning funds. For ventures such as developing an oil or gas field, lenders typically require some type of asset security to be posted as collateral. Hence, if the borrower defaults, the lender is able to secure on collateral and recover any principal amounts. As a practical matter, unless this collateral is posted, debt financing is simply unavailable to fund exploration investment due to risk.

External equity financing (issuing common or preferred stock) is the other source of funding available to finance exploration spending. However the riskiness of the exploration process limits the availability of such funding. The price of a share of common stock depends on the return investors expect to receive if they buy the stock and the riskiness of the expected cash flows. Given sufficiently high risk, financing via issuing new equity is extremely expensive and may be severely limited. In addition, the significant lags between when exploration investments occur and when oil and gas revenue is realized exacerbates the problem of equity financing because of earnings per share dilution. Briefly, if a firm issues equity today to acquire unproved properties, insofar as no incremental earnings are generated near term, earnings per share decline (there are now a greater number of shares outstanding sharing in comparable earnings),possibly exerting downward pressure on the stock price. Finally, to the extent equity financing can be obtained, such financing is dependent upon existing cash generation from operations to fund dividends.

The inherent nature of exploration risk and the associated financing problems have been recognized to some extent in some unique fiscal arrangements which have been placed by governments to provide equity financing alternatives. For example, Joint Exploration Companies (JEC's) benefit from an arrangement for income tax purposes which allows an investor or an investing company to make a payment to a JEC in return for resource related tax deductions. The JEC "renounces" these deductions to the investor. The main advantage of a JEC is that it provides an arrangement in which investors can fund exploration while spreading risk and cost factors among a number of parties.

Flow through share financing represents another unique financing arrangement designed to stimulate equity investment. Flow through shares are issued by a non-taxable oil and gas company to investors. The investors, in return, are purchasing equity in the company and access the company's tax deductions. While these programs are valuable, particularly to the smaller oil and gas companies, their impact in the larger context is small. For example, proceeds from flow through share financing were $115 million in 1987 and $80 million in 1986.[22] Total industry exploration expenditures in 1986 were $2.5 billion.

In summary, the inherent nature of exploration risk imposes definite financial capital constraints on the industry resulting in current cash generation playing a pre-eminent role in the financing of exploration spending.

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22 Petroleum Monitoring Agency, Canadian Petroleum Industry: 1987 Monitoring Report (Ottawa, 1987), p.30.

CHAPTER 4 - DATA AND MODEL ANALYSIS

4.1 DATA REVIEW - STATISTICS CANADA DATA

Industry expenditure and cash flow data are plotted in Figure 4.1.1. Additional information regarding summary cash flow data appear in Tables 4.1.1 and 4.1.2. Historical netback data appear in Table 4.1.3.

Cash flow data were derived from Statistics Canada publications and are expressed in constant 1987 dollars using the GDP Implicit Price Index in Figure 4.1.1.[23] It should be noted here that a significant attempt has been made to isolate a measure of cash flow from producing operations - a measure approximately equivalent to total cash flow from aggregate netbacks. This estimate goes beyond the relationship specified in (3.3.3) by incorporating the actual effects of all fiscal regimes in place. This measure also differs from conventional presentations of internal cash flow which, while similarly striving to exclude the effect of investment activity on cash flow from operations, typically include the current income tax credits associated with such activity. This issue is discussed in some detail in Appendix B. The point is that the measure of cash flow presented in Figure 4.1.1 and Tables 4.1.1 and 4.1.2 are, in absolute terms, a reasonably accurate measure of cash flow from producing operations exclusive of investment activity.

Exploration spending data, as a measure of exploration activity were similarly obtained from Statistics Canada publications and are also expressed in constant 1987 dollars. The expenditures are comprised of land acquisition and retention costs, geological and geophysical costs (G&G) and exploratory drilling spending. Details of how these expenditures were deflated appear in Appendix A. Note that these expenditures are pre-tax but have been reduced by the beneficial effect of Petroleum Incentive Program (PIP) grants over 1981 to 1984. This treatment of PIP grants is appropriate given the common practice in industry of viewing capital and exploratory expenditures net of the favorable PIP credits. Ideally, exploration expenditures would also be examined on an after tax basis. However, this

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23 Refer to Appendix A for detail on data sources.

would require some additional and not insignificant assumptions and investigation regarding an average industry expectation of the present value of tax deductions for a mix of expenditures each year. While it may be possible to measure this after tax effect, this study is limited to an examination of pre-tax expenditures. Notwithstanding this limitation, the study nevertheless makes a contribution of isolating producing cash flow exclusive of investment activity.

Insofar as historical activity trends may tell us something about the model's performance, it is beneficial to review this data prior to analyzing the model's results. By way of general observation, the period under review might be split into four chronologicial segments - 1971 to 1974, 1975 to 1978, 1979 to 1980, and 1981 to 1984. Noteworthy observations include:

. Industry expenditures over 1971 to 1973 were stable relative to cash flow.

. Industry cash flow jumped 123 per cent in 1987 dollar terms over the period 1974 to 1978, reflecting increases in Canadian and worldwide crude prices. OPEC crude prices quadrupled over 1973/74 in the wake of the 1973 Arab/Israel war as Arab nations imposed an oil embargo on the U.S.A. and cut crude production. While Canadian crude prices were controlled from 1973 to 1985, wellhead prices rose at fairly constant rates, stimulated by world price increases, with the price in mid-December 1973 of Cdn. $3.40/bbl. escalating to Cdn. $12.75/bbl. by January 1, 1979.

The slow initial rate of increase in Canadian cash flow relative to world crude price escalation was due to the imposition of this controlled price structure, significant increases in provincial royalty take in the wake of higher prices, and the federal/provincial fiscal dispute regarding the deductibility of provincial Crown royalties for federal income tax purposes.

TABLE 4.1.1

Sources and Uses of Funds Statement
for the Canadian Oil and Gas Industry, 1971 to 1984
(Millions of Nominal Dollars)

	Cash From Operations	Asset/Liabiity Account Changes and Other	Equity Financing	Debt Financing	Total Sources	Capital Spending	Dividends	Asset/Liability Account Changes & Other	Total Uses
1984	5 680	2 448	942	25	9 095	3 884	2 070	3 141	9 095
1983	3 975	2 518	2 503	139	9 135	5 695	1 820	1 620	9 135
1982	3 698	5 035	2 361	2 217	13 311	5 219	1 542	6 550	13 311
1981	3 200	2 325	3 406	4 407	13 338	5 990	599	6 749	13 338
1980	4 343	1 732	1 790	2 087	9 952	6 387	842	2 723	9 952
1979	3 944	2 375	1 370	1 755	9 444	5 665	764	3 015	9 444
1978	2 271	957	2 149	1 098	6 475	2 342	313	3 820	6 475
1977	1 993	1 658	144	518	4 313	2 456	233	1 624	4 313
1976	1 504	638	507	539	3 188	1 934	240	1 014	3 188
1975	1 026	471	144	401	2 042	558	146	1 338	2 042
1974	756	905	-110	130	1 681	486	121	1 074	1 681
1973	642	232	131	-2	1 003	116	89	798	1 003
1972	444	427	211	120	1 202	818	16	368	1 202
1971	394	105	515	2	1 016	357	57	559	1 016

Source: Analytically derived using accounting identities and income and balance sheet data from Statistics Canada data. Refer to Appendix A for additional information.

TABLE 4.1.2

Common Size Sources and Uses of Funds Statement
for the Canadian Oil and Gas Industry, 1971 to 1986
(percent)

	Cash From Operations	Asset/Liabiity Account Changes and Other	Equity Financing	Debt Financing	Total Sources	Capital Spending	Dividends	Asset/Liability Account Changes & Other	Total Uses
1984	63	27	10	0	100	43	23	34	100
1983	44	28	27	1	100	62	20	18	100
1982	28	38	18	16	100	39	12	49	100
1981	24	17	26	33	100	45	4	51	100
1980	44	17	18	21	100	64	9	27	100
1979	42	25	14	19	100	60	8	32	100
1978	35	15	33	17	100	36	5	59	100
1977	46	39	3	12	100	57	5	38	100
1976	47	20	16	17	100	61	7	32	100
1975	50	23	7	20	100	27	7	66	100
1974	45	54	-7	8	100	29	7	64	100
1973	64	23	13	0	100	12	9	79	100
1972	37	35	18	10	100	68	1	31	100
1971	39	10	51	0	100	35	6	59	100

This dispute caused a great deal of uncertainty in the context of the reinvestment process, but from the industry's standpoint, was somewhat resolved by 1976 with the Federal Government introducing the 25 per cent federal resource allowance which implicitly recognized a good portion of provincial Crown royalty expense. Nevertheless, the fallout from the dispute is still in effect today as this arrangement ensures that federal revenue is not subject to pre-emption by higher provincial royalty take.

Industry expenditures also rose over the 1974 to 1978 period, although it was not until 1976, after the Crown royalties dispute was resolved, that expenditures posted substantial increases. Total exploration expenditures increased 77 per cent in 1987 dollar terms over 1974 to 1978, indicating that prospects for improved profitability after 1975 drove a considerable increase in activity. G&G expenditures increased 17 per cent, drilling rose 58 per cent and land expenditures jumped 200 percent, the latter evidently reflecting some additional expected economic rent.

. Another period of improved profitability occurred over the period 1979 to 1980, partly reflecting increases in world crude prices which in turn provided the stimulus for increases in Canadian controlled prices in 1979. Spot crude prices soared to an excess of U.S. $40/bbl., following the 1978 Iranian oilfield labour strife, notwithstanding the fact that free world crude supply capacity remained ample.

FIGURE 4.1.1
Exploration Spending and Cash Flow for the Canadian
Oil and Gas Industry, Statistics Canada Data, 1987 $

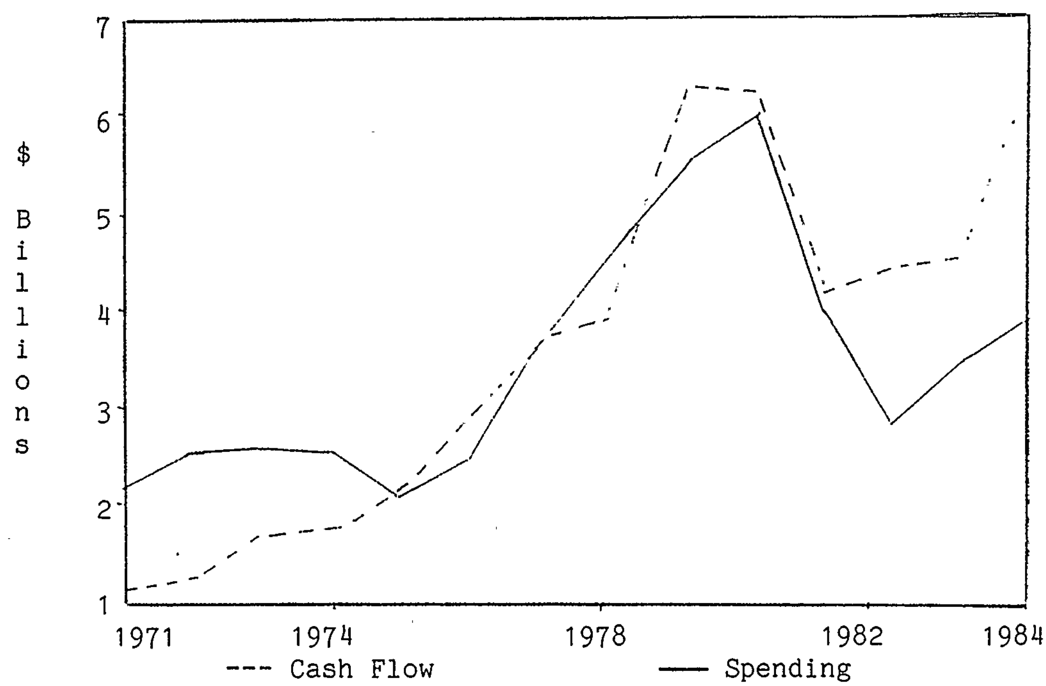
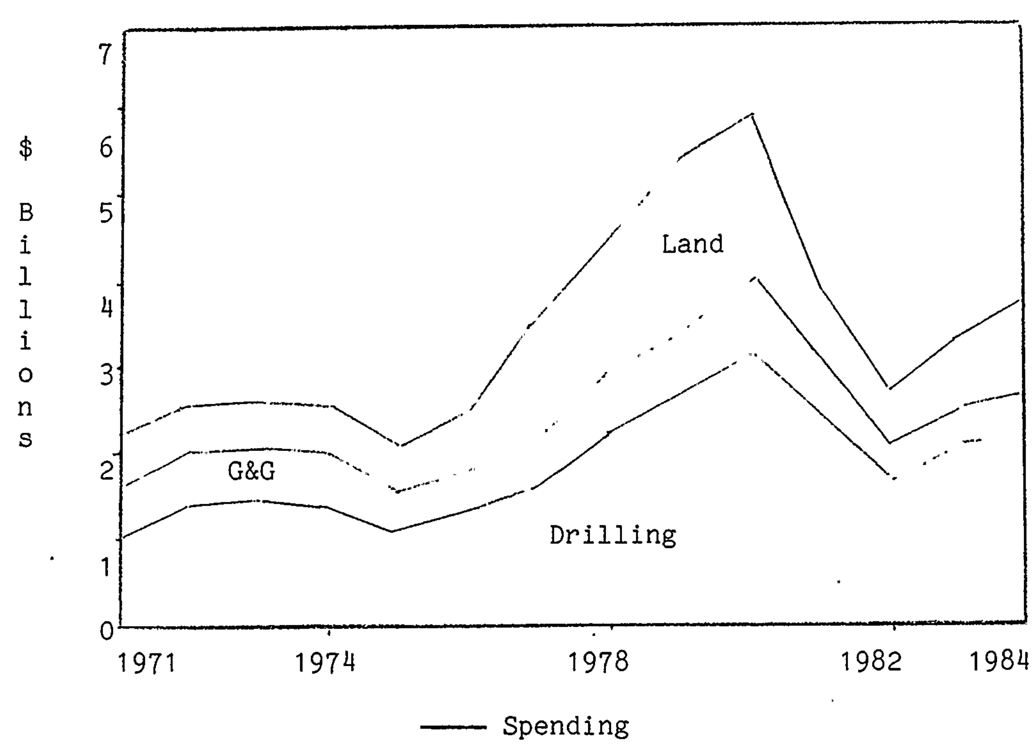


FIGURE 4.1.2
Exploration Spending by Function for the Canadian
Oil and Gas Industry, Statistics Canada Data, 1987 $



. Industry activity, as measured by expenditures, again responded vigorously, although somewhat less than proportionately to the increase in industry cash flow. Over the 1978 to 1980 period total exploration expenditures rose about 34 per cent in 1987 dollar terms. G&G expenditures edged up 20 per cent, land expenditures rose 23 per cent and drilling expenditures jumped 46 per cent.

. Total industry cash flow peaked in 1980 and dipped in 1981 with the imposition of the National Energy Program (NEP) on October 28, 1980. The NEP was essentially a four point program affecting taxes, energy prices, incentives and Canadianization regulations. Prices were controlled subject to a series of scheduled increases and formula based price ceilings for oil and natural gas.

Of particular note was the imposition of the confiscatory Petroleum and Gas Revenue Tax (PGRT) initially set at 8 per cent of oil and gas production revenue on January 1, 1981. This tax was not deductible for federal income tax purposes.

It is also noteworthy that during 1981, OPEC crude prices had started the year at U.S. $26/bbl. and ended the year at U.S. $36/bbl. as production by OPEC members was reduced. Yet, then current profitability for the Canadian oil industry plummetted due to the controlled price mechanism and the introduction of adverse fiscal measures. Hence, directionally at least, profitability was decoupled from price trends, underscoring the problem of using crude prices as a measure for profitability. This phenomenon subsequently repeated itself in 1983, when industry profitability jumped significantly while OPEC was reducing official selling prices in response to world oil market pressures.

TABLE 4.1.3

Historical Crude Oil and Natural Gas

Netbacks for the Canadian Oil and Gas Industry, 1971 to 1984

(Constant 1987 $ per bbl and $ per MCF)

	Crude Netback	Gas Netback
1971	2.91	0.12
1972	2.89	0.15
1973	3.79	0.16
1974	5.22	0.28
1975	3.76	0.47
1976	4.31	0.61
1977	4.79	0.52
1978	5.11	0.44
1979	5.71	0.48
1980	4.86	0.75
1981	3.56	0.51
1982	13.16	0.35
1983	7.84	0.32
1984	6.70	0.31

Source: Netback component data for 1971 to 1981 were derived from Uhler and Eglington (1986) and were tax adjusted by this author. Uhler and Eglington's data were derived from various sources, including Energy, Mines and Resources, and are for an average sized pool in Alberta. Data over 1982 to 1984 were estimated by this author using a "NORP" or new oil reference price (for oil discovered after 1981) netback. Under the 1981 Alberta - Ottawa agreement, NORP prices were allowed to reach 100 per cent of the international price compared to 75 per cent for old oil. The NORP price rose to in excess of Cdn. $40/bbl in 1982 and was responsible for the large increase in the netback. International crude prices subsequently fell accounting for the decline in netback in 1983.

Expenditure data indicate that activity dropped dramatically in the wake of the NEP. Figure 4.1.2 illustrates that land expenditures, primarily comprised of land bonus payments, fell below aggregate drilling expenditures in 1980 for the first time in recent history. This relationship continued on through 1984, suggesting that available economic rent was lower relative to other exploration costs than before. Land expenditures also posted the highest coefficient of variation over the sample period, supporting the contention that bonus payments tend to be the "shock absorber" accommodating and reflecting profitability trends. Operating cash flow comprised just 24 per cent of total industry fund generation in 1981 compared to an average of 43 per cent over the 1971 to 1984 period (See Table 4.1.2).

4.2 MODEL RESULTS AND ANALYSIS - STATISTICS CANADA DATA

The estimated equations relating exploration activity to netbacks and cash flow appear in Table 4.2.1. A straightforward linear functional form is used and lagged variables are specifically excluded. The assumption is that firms are quick to adjust to changing profit pictures and budget constraints given the exigencies of day to day cash management and stockholder demands for returns to capital.

It can be seen immediately from Table 4.2.1 that the sign of the coefficients for the oil netback variable are opposite that hypothesized - that an increase in current netbacks would stimulate additional activity. One possible cause of this relationship is that the netbacks estimated for 1982 through 1984 are for New Oil Reference Price or "NORP" Oil which, as can be seen from Table 4.1.3 were quite lucrative. Over this period, however, netbacks for oil discovered pre-1981 (The Conventional Old Oil Reference or "CORP" Oil) were very low. Notwithstanding these NORP netbacks, producers may have been uncertain regarding the likelihood of ever realizing such netback levels given the severity of the NEP's fiscal impact on their then existing profitability.

In an attempt to isolate the impact of the NEP years, the model was rerun over the period 1971 to 1980. The results appear in Table 4.2.2. The coefficientsfor the oil netbacks are still negative except for in the land expenditure equation, but at no time was the variable statistically significant at the 95 per cent confidence level.

TABLE 4.2.1

Exploration Expenditures, Netbacks, and Cash Flow,
OLS Regressions, 1971 to 1984

Explanatory Variables

Dependent Variable	Intercept	Oil Netback-No	Gas Netback-Ng	Cash Flow	R^2	Durbin Watson	Average Elasticities
Total Exploration Expenditures	1724.4 (3.6974)*	-132.73 (-2.3483)*	199.21 (0.17186)	0.65764 (5.1362)*	0.8266	1.2121	Cash 0.69293 No -0.21778 Ng 0.22669
Land Expenditures	253.24 (1.0747)	-57.113 (-1.9997)*	265.71 (0.45365)	0.26314 (4.0672)*	0.7677	1.1682	Cash 0.96424 No -0.32589 Ng 0.10516
G&G Expenditures	626.51 (7.1376)*	-27.336 (-2.5694)*	21.358 (0.097892)	0.034175 (1.4180)	0.4566	2.0349	Cash 0.20453 No -0.25475 Ng 0.013805
Drilling Expenditures	844.47 (3.1710)*	-48.282 (-1.4958)	-87.864 (-0.13273)	0.36032 (4.9279)*	0.8076	1.2982	Cash 0.70780 No -0.14769 Ng -0.018640

Source: Data were obtained from Statistics Canada. Refer to Appendix A for details. Note that T-values appear in parentheses below the explanatory variables. Asterisked values indicate significance at the 95 per cent confidence level. All equations have 10 degrees of freedom. Land expenditures include outlays for major bonus and land rentals. G&G expenditures are comprised of all direct expenditures relating to geological and geophysical activity. Drilling expenditures include all direct drilling outlays.

TABLE 4.2.2

Exploration Expenditures, Netbacks and Cash Flow,
OLS Regressions, 1971 to 1980

Dependent Variable	Intercept	Oil Netback-No	Gas Netback-Ng	Cash Flow	R^2	Durbin Watson	Average Elasticities
		Explanatory Variables					
Total Exploration Expenditures	1547.6 (2.0419)*	-52.430 (-0.23512)	-2041.7 (-1.8088)	0.92144 (6.2682)*	0.9393	2.7225	Cash 0.85047 No -0.066942 Ng -0.23936
Land Expenditures	100.90 (0.33146)	3.8252 (0.042709)	-745.99 (-1.7000)	0.38380 (6.5003)*	0.9489	1.6747	Cash 1.1753 No 0.016205 Ng -0.29014
G&G Expenditures	607.20 (3.6583)*	-16.704 (-0.34206)	-280.44 (-1.1721)	0.072863 (2.2633)*	0.5644	2.6162	Cash 0.35047 No -0.11115 Ng -0.17132
Drilling Expenditures	839.48 (1.5721)	-39.551 (-0.25173)	-1015.3 (-1.3190)	0.46477 (4.4873)*	0.8860	2.2809	Cash 0.84658 No -0.099659 Ng -0.23488

The gas netback coefficient is negative in all cases but again is not statistically significant. One major limitation with this sample is that it is extremely small with just ten observations and six degrees of freedom. This data limitation and the lack of significance of the oil netback coefficient make the exercise somewhat inconclusive regarding the explanatory power of the model over the smaller sample.

The negative sign of the netback coefficients and the lack of correlation between netbacks and cash flow (refer to Table 4.2.3) is clearly disappointing insofar as unit netbacks are one component of cash flow. Further note that real crude netbacks obtained from Uhler and Eglington fell significantly in 1975 and did not regain the 1974 level until 1979. Yet real cash flow more than tripled over the 1974 to 1979 period, a phenomenon which cannot be explained solely in terms of gas netbacks or production trends. Accordingly, there is some question here of data reconciliation which might be further investigated.

TABLE 4.2.3

Correlation Coefficient Matrix for Cash Flow and Netbacks

	Cash	Crude Netback	Gas Netback
Cash	1.00000	-0.51667	-0.64850
Crude Netback		1.00000	0.33537
Gas Netback			1.00000

One noteworthy feature in both samples though was the significance of the cash flow variable. Accordingly, activity was then modelled solely in terms of cash flow. This approach essentially assumes that firms generally have a slate of investment opportunities which based on current netbacks are expected to yield returns in excess of its cost of capital. Notwithstanding the data reconciliation issue above, the cash flow variable, being the product of netbacks and production, should theoretically capture the netback component as a proxy for expected profitability. In addition, cash flow provides a budget constraint to funding activity. Hence, this relationship was tested along with a dummy variable for the NEP period 1981 to 1984.

TABLE 4.2.4
Exploration Expenditures and Cash Flow,
OLS Regressions, 1971 to 1984

EXPLANATORY VARIABLES

Dependent Variable	Intercept	Cash Flow	NEP Dummy Variable	R^2	Durbin Watson	Average Elasticity	
Total Exploration Expenditures	1255.3 (3.7816)*	0.68286 (7.5058)*	-1022.9 (-2.8937)*	0.8371	1.5832	Cash	0.71951
Land Expenditures	58.306 (0.52081)	0.30794 (10.036)*	-647.79 (5.4337)*	0.9027	1.6546	Cash	1.1284
G&G Expenditures	523.71 (9.6365)*	0.040779 (2.7578)*	-233.59 (-4.0363)*	0.6137	1.6579	Cash	0.24405
Drilling Expenditures	673.30 (3.147)*	0.33414 (5.6984)*	-141.53 (-0.62120)	0.7697	1.5556	Cash	0.65637

It can be seen from Table 4.2.4 that the coefficients for the explanatory variables in all four equations are consistent with expectations. The cash flow coefficient is positive and as expected would increase with higher profitability. In addition, the sum of the individual cash flow coefficients is equal to the coefficient for total expenditures, indicating data consistency. The negative coefficient for the dummy variable is also consistent with the expectations with the negative impact of the NEP on investment activity. Further, most coefficients are highly significant at the 95 per cent level.

The explanatory power of the individual equations are mixed but for the most part indicative of a reasonably strong relationship between activity and cash flow. The equation relating land spending to cash flow performed the best, explaining about 90 per cent of the observed variations over the period. The drilling equation also performed reasonably well explaining over 75 per cent of the observed variations over the period. Overall, the model explained about 84 per cent of the observed exploration spending over the period.

The average elasticities of all variables are also consistent with expectations. The land expenditure elasticity of close to one makes sense bearing in mind that a major component of this spending - land bonus payments - represents the discounted expected profitability of investment returns. An increase or decrease in current cash flow should influence a commensurate change in expectations and provide the firm with the ability to fund a proportionate adjustment to land spending.

Drilling expenditures also exhibit some moderate elasticity at 0.66, suggesting that such expenditures are reasonably responsive to cash flow changes. Insofar as few oil companies operate and maintain their own drilling rigs, one would have expected some elasticity as companies could contract or release rigs on reasonably short notice. G&G expenditures, however, exhibit a relative inelasticity. One reason for this might be that a large component of these costs is for staffing, a factor input which tends to be fixed over the short to intermediate term.

In attempting to further investigate the observed behaviour of exploration activity a lagged dependent variable model was tested along the lines of the Scarfe Rilkoff model[24]. Using their lagged adjustment relationship,

$$(4.2.1)\quad \frac{E_t}{E_{t-1}} = \left\{ \frac{E^*}{E_{t-1}} \right\}^{\delta}$$

for optimal exploratory effort E_t^*, and our basic cash flow relationship expressed in an exponential functional form

$$(4.2.2)\quad E^* = a\ (Nq)^{\beta}$$

then substituting for E* from (4.2.1) with Nq representing cash generation from producing operations:

$$(4.2.3)\quad \ln E_t = \delta \ \mathrm{lna} + \delta\beta \ \ln\ (Nq) + (1-\delta)\ \ln E_{t-1}$$

The dummy variable can also be retained to account for the impact of the NEP years.

The empirical results for this model appear in Table 4.2.5. While the results in aggregate approach those in Table 4.2.2, none of the coefficients for the lagged variables in the individual activity equations were statistically significant. This finding tends to support the hypothesis that oil firms tend to react fairly quickly to changing cash flow conditions.

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24 B. L. Scarfe and E. W. Rilkoff, <u>Financing Oil and Gas,</u> p.37.

TABLE 4.2.5

Exploration Expenditures Cash Flow and Lagged Variables:
OLS Regressions, 1972 to 1984

Dependent Variable	Intercept	Cash Flow	Lagged Dependent Var.	Dummy Variable	R^2
Total Exploration Expenditures	1.4683 (1.2937)	0.41306 (3.2941)*	0.41788 (2.2578)*	-0.26112 (-2.4568)*	0.8297
Land Expenditures	-1.3830 (-1.6187)	0.82018 (5.2757)*	0.24806 (1.7166)	-0.49501 (-4.1463)*	0.9123
G&G Expenditures	2.9505 (2.0023)*	0.18721 (2.0236)*	0.31477 (1.5401)	-0.34274 (-3.2584)*	0.6531
Drilling Expenditures	2.5649 (2.0171)*	0.41088 (2.3668)*	0.21729 (0.98383)	-0.12624 (-0.71908)	0.6883

A further relationship was tested using lagged cash flow information as the independent variable. This relationship might be appropriate insofar as many oil and gas companies set their capital spending plans for a given year later in the fall of the previous year.

The overall results of this model were comparable to those in Table 4.2.4 although the performance of the individual equations were mixed. For example, the lagged cash flow variable explained approximately 76 per cent of the observed land expenditures compared to 90 per cent in Table 4.2.4. The lagged model, however, was superior for the G&G and drilling equations explaining 70 percent and 89 per cent of the observed activity respectively.

4.3 DATA REVIEW - PMA DATA

The Petroleum Monitoring Agency (PMA) provided the other major data source from which data were obtained to test the relationship between exploration spending and cash flow. Briefly, the PMA's data differ from that provided by Statistics Canada in that the PMA includes activities of crown corporations and merely samples (albeit on a significant basis) industry activity. Statistics Canada data cover a greater number of companies in the Canadian oil and gas industry and exclude the activities of crown corporations.

Table 4.3.1 presents aggregate PMA and Statistics Canada spending and cash flow data over the common period 1979 to 1984. Note that Statistics Canada data have now been adjusted to conform to the more conventional cash flow presentation used by the PMA. This presentation begins with net earnings and adds back non-cash accounting charges and capital and exploratory expenditures expensed. Non-cash accounting charges include depreciation, depletion, amortization and deferred income tax expense. It can be seen that the data correlate well over this period with a correlation coefficient of 0.99.

One attribute of the PMA data is that it is released in a more timely fashion and so the period under review can be extended through 1987. In addition, the PMA provides a breakdown of cash flow and spending activity by industry segment e.g. large producers versus small producers. On the downside, comprehensive PMA data are only available commencing with 1979.

TABLE 4.3.1

Exploration Expenditures and Cash Flow

PMA vs Statistics Canada (a)

(1987 $ Billions)

	Cash Flow		Exploration Spending	
	PMA	Statistics Canada	PMA	Statistics Canada
1979	8.2	9.4	4.7	5.6
1980	9.6	10.2	5.2	6.0
1981	6.8	7.4	3.6	4.0
1982	6.9	7.3	2.6	2.8
1983	8.3	7.5	3.0	3.4
1984	9.3	9.1	3.5	3.9

(a): Refer to Appendix A for details. Note statistics Canada cashflow data have now been adjusted to the PMA's method of displaying cash flow.

FIGURE 4.3.1
Exploration Spending and Cash Flow for the Canadian
Oil and Gas Industry, PMA Data, 1987 $

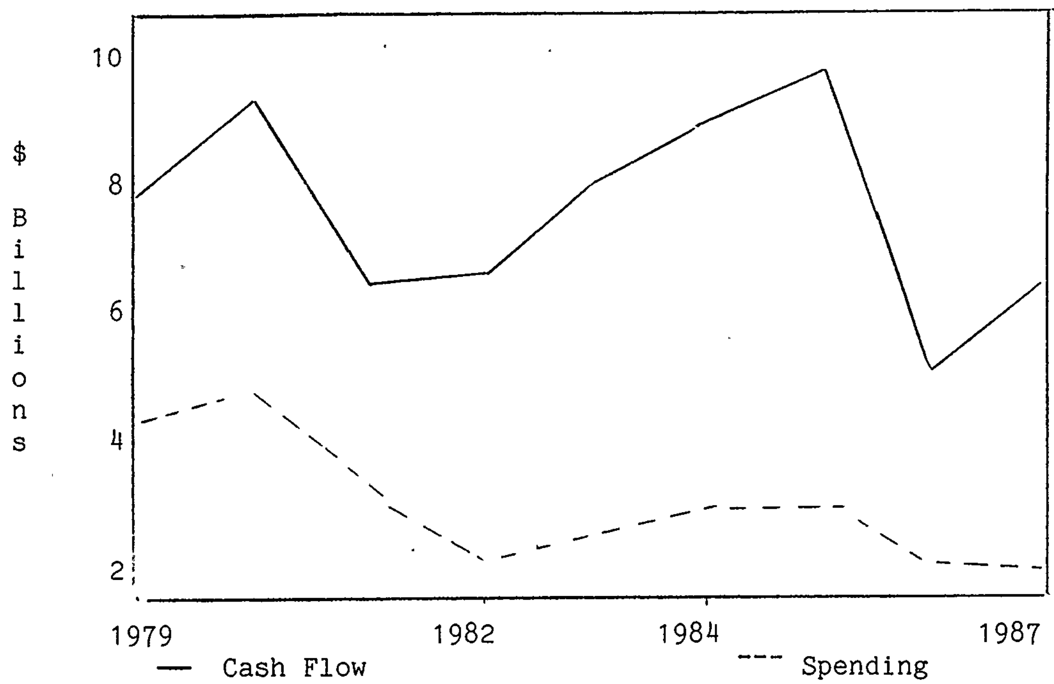


FIGURE 4.3.2
Exploration Spending and Cash Flow for the Upstream Arm
Of Integrated Cos., PMA Data, 1987 $

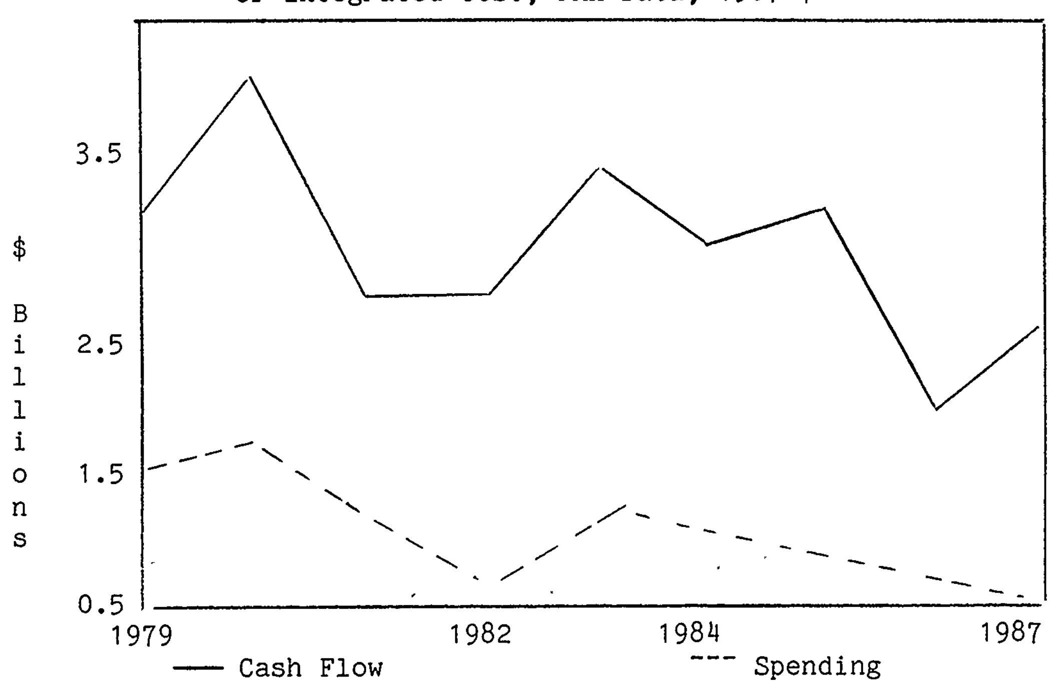


FIGURE 4.3.3
Exploration Spending & Cash Flow for Senior Producers, PMA Data, 1987 $

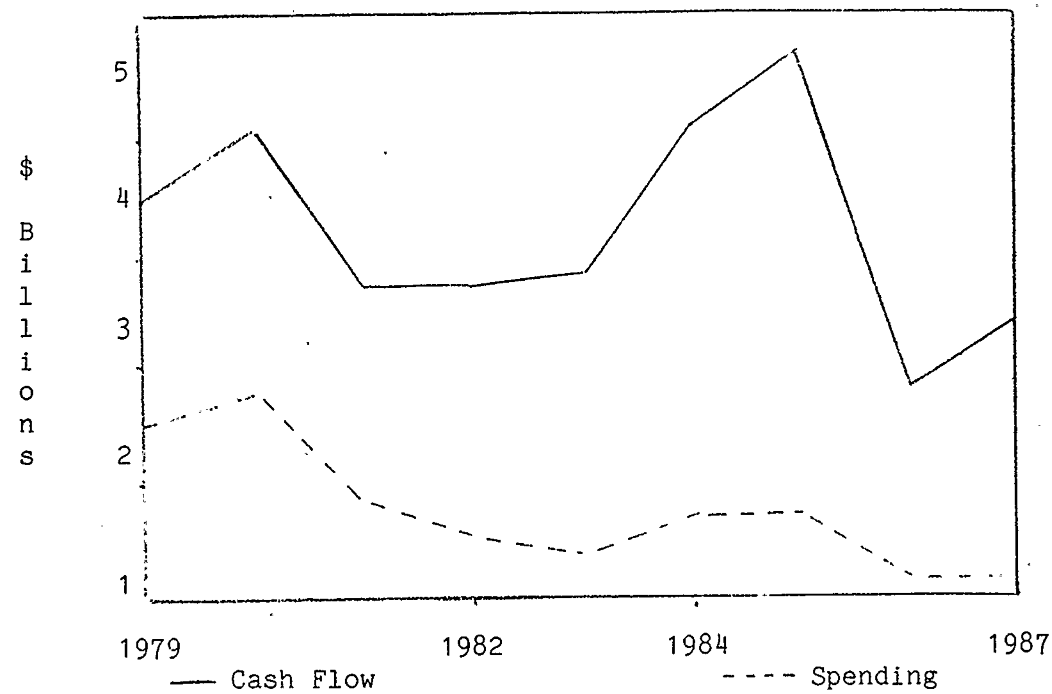
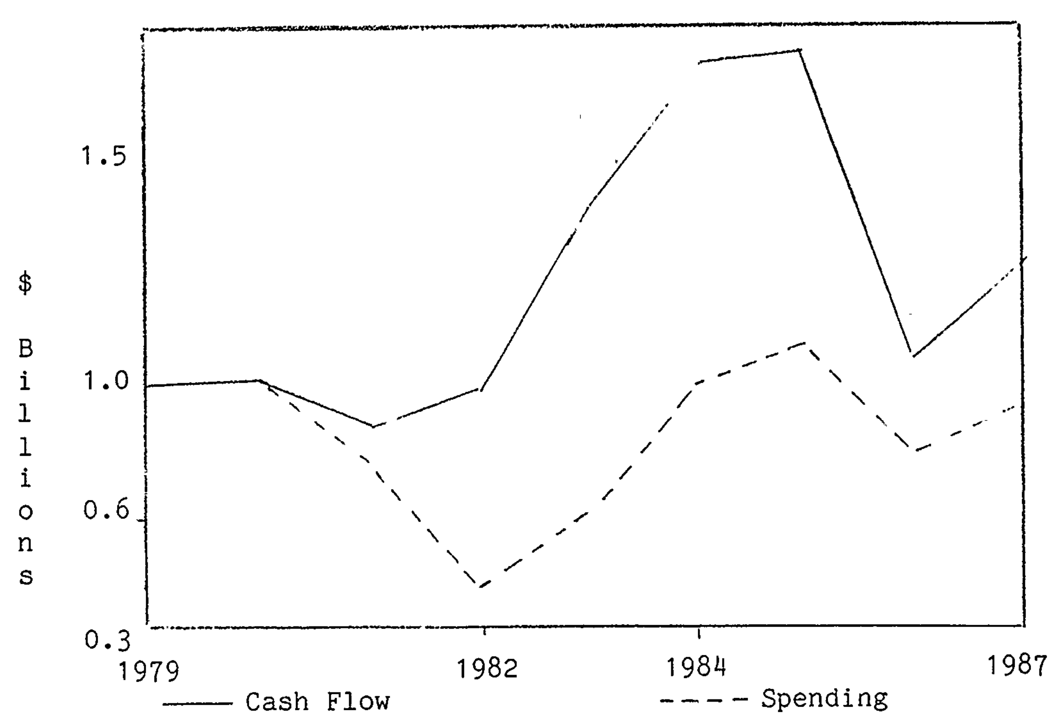


FIGURE 4.3.4
Exploration Spending & Cash Flow for Junior Producers, PMA Data, 1987 $



In addition, the functional breakdown in exploratory spending is limited to two categories, one for exploratory drilling and the other combining land expenditures and G&G costs. The land expenditure category, however, is of primary interest in assessing profit expectations manifested in bonus payments and the consolidation of this information with G&G costs is unfortunate.

PMA cash flow data were adjusted using the GDP Implicit Price Index. Exploration spending data are presented net of PIP grants. Unfortunately, PIP credit data were unavailable by industry segment. However, this information was available for Canadian controlled and foreign controlled companies. Further, revenue detail was available for Canadian and foreign companies by industry segment. Hence PIP credits were prorationed 100 per cent to Canadian companies (Canadian controlled companies accounted for in excess of 90 per cent of PIP grants received during much of the period that the PIP program was in place) on a revenue basis within each industry segment and netted against capital expenditures for those segments.[25] Clearly, this allocation process is less than perfect. For example, PIP eligible investment spending for Canadian Companies may not be proportional to revenues for those companies. Nevertheless, this allocation method might capture the significant impact of the PIP credits for each segment. Spending data were similarly deflated using weighted averages of the various CPA cost indices described in Appendix A.

4.4 MODEL RESULTS AND ANALYSIS - PMA DATA

Table 4.4.1 presents summary statistics for the model using PMA data. It can be seen immediately that the model does not perform as well as with Statistics Canada data.

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25 For example, Canadian controlled companies received in excess of 90 per cent of total PIP grants over 1982 to 1984 and 84 per cent in 1981. Refer to PMA's Monitoring Survey, under the "Sources of Funds" chapters for these years.

TABLE 4.4.1

Exploration Expenditures and Cash Flow, PMA Data,
OLS Regressions, 1979 to 1987

Dependent Variable	Intercept	Cash Flow	NEP Dummy Variable	R^2	Durbin Watson	Average Elasticities	
		Explanatory Variables					
Total Industry Expenditures	1414.4 (1.0126)	0.33363 (2.0491)*	-904.16 (-1.777)	0.5837	1.1911	Cash	0.76534
Senior Producer Expenditures	724.84 (1.0811)	0.33010 (2.0365)*	-486.79 (-1.7942)	0.5754	0.7766	Cash	0.75812
Junior Producer Expenditures	550.47 (3.0489)*	0.32896 (2.1158)*	-252.71 (-2.2890)*	0.5533	1.6222	Cash	0.50152
Integrated Co. Upstream Expenditures	-100.84 (-0.9259)	0.41123 (2.6828)*	-123.16 (-0.61943)	0.62244	1.9589	Cash	1.1765

There are several likely explanations for the inferior performance, one of which is the extremely limited sample size due to data limitations. Moreover, the beginning and ending sample years are non-NEP years while the interim is comprised of NEP years. In addition, this period was quite volatile for reasons separate from the introduction of the NEP. These include:

- the signing of the Western Accord on 1985-03-27 which eliminated many of the burdensome taxes and special charges that were introduced as part of the NEP in 1980. Under the terms of his agreement, crude prices were to be deregulated on 1985-06-01 and the reference prices for new oil (NORP) and old oil (COOP) would be eliminated. Also the Incremental Oil Revenue Tax (IORT) and the Petroleum Compensation Charge (PCC) were to be eliminated with price decontrol. The PGRT, however, was left in place although it was to be gradually phased out by the beginning of 1989. As it turns out, the PGRT was eliminated in late 1986.

- the mergers and acquisitions phenomenon appeared in full force. Mobil Canada merged with Canadian Superior in 1985-12. Other acquisitions and mergers were to follow including Encor purchasing Aberford Resources, Imperial purchasing Sulpetro's oil and gas assets and a host of other transactions. As a result, many companies were purchasing reserves rather than exploring them.

- World crude prices fell in early 1986 due to OPEC's inability to exercise production discipline. Canadian prices dropped from $33 per barrel in early 1986 to $22 per barrel by February. Prices were extremely volatile in 1986 dipping to a low of $14.50 per barrel in July before returning to the $20 per barrel range by year end. In an effort to respond, the federal government eliminated the PGRT on 1986-10-01. The Alberta government increased the Alberta Royalty Tax Credit to 95 percent of income and later announced reductions in royalties for old oil and gas (discovered pre-1974) averaging 2 percent to bring average rates to 31 percent and 25 percent respectively. New oil and gas royalties were reduced by an average of 4 per cent to 23 per cent and 19 per cent respectively.

The overall explanatory power of the model falls compared to using Statistic Canada data, explaining about 58 percent of the observed spending pattern. In addition, the T-values of the coefficients for the explanatory variables are weaker and there is evidence of autocorrelation in two of the equations which is not uncommon when dealing with time series data. Theoretically, this situation occurs when the error term, e_t, is dependent on the error terms in other periods, e_{t-1}, for example. However, the relationship e_t to e_{t-1} is often attenuated by some factor, say ρ where $-1 \leq \rho \leq 1$ as follows:

(4.4.1) $u_t = \rho u_{t-1} + V_t$

for the linear OLS regression:

(4.4.2) $Y_t = \alpha + \beta X_t + u_t$

Since the true residual terms u_t are not known a priori, ρ is estimated by applying OLS to the residuals e_t in the equation $y_t = \hat{\alpha} + \hat{\beta} x_t + e_t$:

(4.4.3) $e_t = \hat{\rho}\, e_{t-1} + V_t$

to obtain an estimate for ρ. The estimated coefficient ρ is then used to transform the original data in period t-1.

$$(4.4.4) \quad (Y_t - \hat{\rho}\, Y_{t-1}) = \hat{\alpha}\,(1-\hat{\rho}) + \hat{\beta}\,(X_t - \hat{\rho}\, X_{t-1}) + (e_t - \hat{\rho}\, e_{t-1})$$

Iterations occur until ρ converges to within some tolerance at which the error term is non-auto correlated. This technique generally follows the method suggested by C. Cochrane and G. H. Orcutt, a method which was applied to selected equations in this model with summary statistics presented in Table 4.4.2[26].

Application of this iterative technique to the equations for senior producers and all producers resulted in a moderate improvement in the explanatory power of the model. However, the T-values for the coefficients of the explanatory variables remained weak. One limitation here is the small sample size which ideally should be larger to test for serial correlation with the Durbin-Watson statistic.

As a further check on the data used, Statistics Canada data were retested over the larger Statistics Canada sample period adopting the more conventional cash flow format used by the PMA. If this data yielded comparable results to those in Table 4.2.3 then cash flow presentation could be eliminated as a reason for the poorer performance of the PMA data. The results of this exercise are presented in Table 4.4.3 which indicates the results are moderately superior to the results in Table 4.2.3. This development is disappointing considering the effort undertaken to derive a pure cash flow from operations measure. In any event, it appears that the cash flow data transformation is not the culprit for the poorer fit with the PMA data.

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26 See R. J. Wonnacott and T. H. Wonnacott, Econometrics (New York: John Wiley & Sons, Inc., 1970), pp.136-145.

TABLE 4.4.2

Exploration Expenditures and Cash Flow, PMA Data, 1979 to 1987
Selective Regressions Using Cochrane-Orcutt Iterative Technique

Dependent Variable	Explanatory Variables						
	Intercept	Cash Flow	NEP Dummy Variable	R^2	Durbin Watson	Rho	Average Elasticity
Total Industry Expenditures	1678.4 (1.3677)	0.25745 (1.9859)	-380.88 (-0.73957)	0.6913	1.1394	0.62613	Cash 0.59057
Senior Producer Expenditures	869.94 (1.7487)	0.24439 (0.7187)	-231.39 (-0.4069)	0.7999	0.9159	0.79100	Cash 0.56127

However, other data problems may exist. The PIP credit allocation mechanism described earlier may be underestimating the true extent of exploration investment by junior producers. This could be one reason why the outcome for the junior producer industry segment is somewhat surprising. For example, the junior producer might have been expected to have been the most responsive in spending levels to changes in cash flow considering the relatively higher costs of floating equity issues and being at a general name disadvantage compared to "blue-chip" stock market names. Yet the junior producers exhibited the lowest average elasticity for cash flow.

TABLE 4.4.3

Exploration Expenditures and Cash Flow, Statistics Canada Data, OLS Regressions, 1971 to 1984

	Explanatory Variables					
Dependent Variable	Intercept	Cash Flow	NEP Dummy Variable	R^2	Durbin Watson	Average Elasticity
Total Exploration Expenditures	1100.8 (4.1326)*	0.47438 (9.9443)*	-1269.8 (-4.4358)*	0.9002	1.9382	Cash 0.78506
Land Expenditures	24.875 (0.21831)	0.20643 (10.116)*	-736.93 (-6.0181)*	0.9041	1.6344	Cash 1.1881
G&G Expenditures	505.24 (9.8585)*	0.030239 (3.2947)*	-253.99 (-4.6116)*	0.6730	1.7636	Cash 0.28424
Drilling Expenditures	570.66 (3.2989)*	0.23771 (7.6731)*	-278.86 (-1.5000)	0.8567	1.8960	Cash 0.73341

CHAPTER V - CONCLUSIONS

The results of the model over the larger sample period using Statistics Canada data are mixed but with respect to cash flow are directionally consistent with expectations and are sufficiently strong to conclude that exploration activity is influenced by industry cash flow to a significant degree. As expected, land expenditures showed the greatest response to cash flow.

The results for the sample period 1979 to 1987 using PMA data are more tenuous. While the relationship between total exploration spending and industry cash flow is directionally supportive of the earlier findings, the industry segment relationship for junior producers is contrary to expectations. However, the extremely volatile period in terms of crude prices and fiscal changes and the limited sample size make a definitive conclusion difficult for the industry segment testing.

There may also be data problems present in the case of the junior companies. The PIP allocation process used, which is essentially based on comparative revenues may be understating the activity of the junior producers. If one hyothesizes that the juniors did not actually share proportionately in revenue terms in the PIP credits because these credits were weighted to higher cost, high risk frontier areas, then junior net spending activity may be understated. More work could be done here perhaps working directly with the PMA.

The need for simplifying assumptions because of data limitations also introduces a weakness to the model. The data used are aggregated and are not sufficiently sensitive to capture the empirical results of regional models and are not segregated by component for oil and gas. Yet theoretically, the data are also a strength of this study insofar as actual industry cash flow data have been derived and used in contrast to some subjectively estimated average netback measures.

From a theoretical standpoint, one of the larger weaknesses in this study is the assumption that current or total cash flow is equal to expected cash flow. Netback expectations were undoubtedly influenced by OPEC driven price increases during the 1970's. As pointed out, however, some firms managed to avoid the euphoria and required projects to generate satisfactory economic returns under then current netback assumptions. Moreover, in the wake of the significant increases in provincial crown royalties in the early 1970's and the NEP in 1980, it became clear that price driven exponential increases in profitability were simply not going to occur as governments sought to extract surplus rent. Efforts to assume some escalation factor for parts of the sample period have been avoided on the grounds the results would be spurious and arbitrary.

It is also important to note the implicit assumptions of the study. For example, it is assumed here that cash flow is completely dedicated to the reserves acquisitions process via exploratory effort. More recently, significant reserves or companies have been acquired via direct purchases from other companies although this had a greater effect on the sample period 1979 to 1987. Major acquisitions over this period included:

- Petro Canada's acquisition of Pacific Petroleum in 1978 for $1.5 billion
- Dome's acquisition of Mesa for $640 million in 1979
- Dome's acquisition of Hudson's Bay Oil and Gas for $4 billion in 1981
- Texaco's acquisition of Canadian Reserve for $495 million in 1984
- Gulf's acquisition of Hiram Walker for $3 billion in 1986
- TCPL's acquisition of Encor Energy for $1.1 billion in 1987.

Acquiring companies typically reduce exploration programs in the wake of an acquisition since they have purchased as opposed to found reserves.

Perhaps most importantly, the cash flow variable has been used partly to measure profit expectations. This is also a function of the marginal physical product of the factor inputs. If this incremental physical return is expected to remain constant then the model should perform well. However, if physical returns are expected to decline, say because of a regional depletion effect (finding costs increase), the model will fail to explicitly capture this phenomenon in explaining overall activity.

APPENDIX A

DATA SOURCES

Annual data were obtained primarily from the following three Statistics Canada publications:

	Catalogue Number[27]
Corporation Financial Statistics	61-207
Corporation Taxation Statistics	61-208
The Crude Petroleum and Natural Gas Industry	26-213

Data were collected for what is commonly referred to as the upstream segment of the oil industry, those companies principally involved in the exploration for and the production of crude oil, natural gas, and natural gas liquids. This industry segment is identified by Statistics Canada in its Standard Industrial Classification Manual (1970) as code 064.

Data were collected beginning with 1971. Prior to 1970, data for integrated producers - those involved in the upstream and downstream industry segments - were combined with upstream operators rendering cash flow measures as a proxy for upstream profitability meaningless. Revised and updated data for prior periods were used whenever possible.

CASH FLOW

Cash flow estimates were derived from balance sheet and income statements using accounting identities. See Appendix B for a detailed discussion of

27 These annual Statistics Canada publications can be obtained from Supply and Services, Ottawa, Canada.

this process. Cash flows are for the total upstream industry in Canada and materially originate from Alberta, British Columbia and Saskatchewan.

EXPLORATION ACTIVITY MEASURES

Exploratory drilling, geological and geophysical (G&G), and land acquisition expenditures were collected for all of Canada. Most expenditures occurred in Alberta over an area generally corresponding to the subsurface Western Canadian Sedimentary Basin.

Land acquisition activities and expenditures include the cost of bonuses, legal fees, filing fees, producing and non-producing acreage retention costs, bonuses paid for the acquisition of freeholders' mineral rights, and other related land costs.

PETROLEUM INCENTIVES PROGRAM (PIP) GRANTS

Commencing in 1981, qualifying companies carrying out exploration in Canada were eligible for certain PIP incentives. Statistics Canada's expenditure data are not reduced by these incentives. In order to derive net or actual expenditures, PIP payments were deducted from Statistics Canada expenditure data. PIP and Canadian ownership rate data were obtained by province/region from Petroleum Monitoring Agency (PMA) Annual Reports.[28] Incentives relating to each exploration activity (drilling for example) were estimated based on the percentage of those expenditures to total PIP eligible exploration expenditures.

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28 Petroleum Monitoring Agency, Monitoring Survey, for the years 1980 to 1987.

DEFLATORS

Cash flow and land expenditure data were deflated by the GDP Implicit Price Index. G&G expenditures were deflated using the Canadian Petroleum Association (CPA) Geological and Geophysical (Field) Index and exploratory drilling expenditures were deflated using the CPA's Exploration Drilling and Development Drilling Index.[29]

PETROLEUM MONITORING AGENCY (PMA) DATA

Cash flow and activity data can also be obtained from PMA Annual Reports where sources and uses of funds statements are presented. The chief limitation of PMA data is that comprehensive data are only currently available for 1979 to 1987 reflecting the PMA's creation in 1980.

Some differences exist between PMA data and Statistics Canada data. Statistics Canada covers a greater number of companies and excludes government business enterprises as well as the foreign activities of Canadian petroleum companies. In contrast, the PMA survey covers the global activities of all Canadian petroleum companies including Crown companies. Limited differences also occur in certain accounting presentations such as adjustments for extraordinary items.

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29 Canadian Petroleum Association, Alberta Oil & Gas Industry Cost Escalation Study Update, 1970-1986, Draft Report (Calgary, Alberta, December 1987), Table 3.

TABLE A1

Exploration Expenditure and Cash Flow Data
for the Canadian Oil and Gas Industry, 1971 to 1984
(Nominal $ Millions)

	Exploration Drilling Expenditures	Geological & Geophysical Expenditures	Land Expenditures	Total Expenditures	Cash Flow
1984	2 223	467	1 049	3 739	5 680
1983	2 047	382	760	3 189	3 975
1982	1 682	355	568	2 605	3 698
1981	2 336	477	691	3 504	3 200
1980	2 706	715	1 329	4 750	4 343
1979	1 840	518	1 286	3 644	3 944
1978	1 238	502	887	2 627	2 271
1977	784	353	752	1 889	1 993
1976	558	274	344	1 176	1 504
1975	402	226	256	884	1 026
1974	454	242	217	913	756
1973	403	209	195	807	642
1972	331	200	177	708	444
1971	208	191	182	581	394

Source: Statistics Canada

TABLE A2

Real Exploration Expenditure And Cash Flow Data for the Canadian Oil And Gas Industry, 1971 to 1984
(1987 $ Millions)

	Exploration Drilling Expenditures	Geological & Geophysical Expenditures	Land Expenditures	Total Expenditures	Cash Flow
1984	2 236	543	1 153	3 932	6 242
1983	2 121	449	864	3 434	4 517
1982	1 725	393	677	2 795	4 408
1981	2 498	563	895	3 956	4 145
1980	3 199	903	1 909	6 011	6 240
1979	2 702	714	2 041	5 457	6 260
1978	2 187	750	1 548	4 485	3 963
1977	1 620	613	1 395	3 628	3 698
1976	1 265	525	677	2 467	2 961
1975	1 041	485	547	2 073	2 192
1974	1 384	644	511	2 539	1 779
1973	1 460	615	524	2 599	1 726
1972	1 379	631	518	2 628	1 298
1971	967	635	563	2 165	1 220

Source: Statistics Canada

TABLE A3

Exploration Expenditure And Cash Flow Data For The
for the Canadian Oil and Gas Industry, PMA Data, 1979 to 1987
(Nominal $ Millions)

	Exploration Expenditures				Cash Flow			
	Senior Producers	Junior Producers	Upstream Integrateds	Total	Senior Producers	Junior Producers	Upstream Integrateds	Total
1987	1122	836	565	2522	3090	1222	2474	6787
1986	1102	701	718	2521	2496	941	1838	5275
1985	1641	1003	856	3499	4835	1631	3051	9517
1984	1520	835	959	3314	4472	1549	2701	8421
1983	1240	529	1065	2834	3038	1178	3082	7298
1982	1365	367	673	2404	2825	753	2217	5795
1981	1545	626	1033	3202	2590	618	2022	5230
1980	2056	728	1350	4135	3188	647	2869	6704
1979	1564	608	983	3165	2551	576	2022	5149

Source: PMA. Expenditures are after subtracting beneficial effect of PIP grants. "Upstream Integrateds" refers to the upstream arm of integrated companies.

TABLE A4

Real Exploration Expenditure And Cash Flow Data
for the Canadian Oil and Gas Industry, PMA Data, 1979 to 1987
(1987 $ Millions)

	Exploration Expenditures				Cash Flow			
	Senior Producers	Junior Producers	Upstream Integrateds	Total	Senior Producers	Junior Producers	Upstream Integrateds	Total
1987	1122	836	565	2522	3090	1222	2474	6787
1986	1111	707	724	2541	2581	973	1901	5455
1985	1617	988	843	3447	5149	1737	3249	10135
1984	1600	879	1009	3488	4585	1702	2968	9254
1983	1332	568	1144	3044	3452	1339	3502	8293
1982	1458	392	719	2568	3367	897	2642	6907
1981	1734	703	1159	3594	3355	801	2619	6775
1980	2583	915	1696	5195	4580	930	4122	9632
1979	2338	909	1469	4731	4049	914	3210	8173

Source: PMA

APPENDIX B

CASH FLOW

Cash flow data were derived from balance sheet and income statements using techniques commonly employed in a sources and uses of funds analysis.[30] Using accounting identities, this analysis and the resulting sources and uses of funds statement highlight changes in cash in terms of other asset, liability and stockholders' equity account changes.

The change in stockholders' equity, driven by net earnings performance, is of primary interest here. Starting with net earnings, non-cash items such as deferred income tax expense, and depletion and depreciation expenses are added back to obtain a cash generation from operations or cash flow estimate.[31] Theoretically, this is the underlying cash profitability of an enterprise before external financing.

Frequently, capital and exploratory expenditures expensed are also added back to cash generation in an effort to display cash generation before the deployment of capital during the period.[32] An example for 1983 appears at the end of this Appendix.

This data analysis can be taken one step further to isolate the effect of investment activity on cash generation. Briefly, a component of the current income tax provision will give rise to a tax offset due to capital and exploratory spending. This component can be eliminated to derive a reasonably good measure of industry's cash flow from producing operations.

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30 Refer to Sidney Davidson, Clyde P. Stickney, and Roman L. Weil <u>Financial Accounting: An Introduction to Concepts, Methods, and Uses</u> (Hinsdale, Illinois: Dryden Press, 1979), pp. 139-173.

31 This is still an approximation. For example, this figure could include undistributed income from affiliate interests accounted for under the equity method of consolidation.

32 This is the method adopted by the Petroleum Monitoring Agency.

For illustration, consider the following simplistic example:

1. (a) <u>Assumptions</u>

- Company A drills a dry hole for $100 in year 1.
- 100% of this cost is claimed as Canadian Exploration Expense for federal income tax purposes in year 1.
- there is no other income or expense activity for Company A in year 1.
- marginal tax rate is 50 per cent.

(b) Income Statement
Company A
Year 1

Revenue		$ -
Dry hole costs		(100)
Pre-tax loss		(100)
Income tax expense-	Current	50
	Deferred	---
Net loss		$(50)

(c) <u>Cash Flow Analysis</u>

After tax earnings (losses)	$(50)
Add back non-cash items	-
Add back exploratory expenditures expensed (dry hole costs)	$100
Net cash flow	$ 50

Now recall the objective is to isolate cash from operations before capital spending. In this example, this intuitively equates to zero. Company A has no other activity aside from drilling the dry hole. Yet the conventional cash flow presentation suggests cash generation of $50. This is because of the current income tax offset on drilling the dry hole

(technically, if there were no other income in Company A, a refund would not be received; rather this loss would be carried forward. However, if other income were realized, tax cash payments would be $50 lower.)

Hence, the following adjustment is required:

Net cash flow (from above)	$50
Subtract current income tax reduction due to exploration expenditures	(50)
Net cash flow	-

Now the cash flow algorithm eliminates all cash effects of capital spending activity. This was the approach used in this study in order to isolate aggregate producing cash income as a measure of current profitability.

Note that this algorithm also works for the alternate outcome of drilling a successful well. It works because regardless of success or failure, there will always be a current tax offset for the full amount of capital expenditures claimed for income tax purposes in any year. A deferred tax adjustment (which is also eliminated in the sources and uses of funds analysis as a non-cash item) is used to deal with timing differences between financial accounting and tax book depreciation.

Consider the earlier example but assume the exploratory well drilled was successful and hence capitalized and amortized over two years for financial accounting purposes:

Income Statement
Company A
Year 1

Revenue		$ --
Dry hole costs		--
Depreciation		(50)
Pre-tax loss		(50)
Income tax expense -	current	50
	deferred	(25)
Net loss		$(25)

Cash Flow Analysis

After tax earnings (losses)	$(25)
Add back non-cash items:	
Depreciation	50
Deferred income tax	25
Add back exploratory expenditure expenses (dry hole costs)	--
Subtract current income tax reduction due to exploration expenditures	(50)
Net cash flow	$--

An example for 1983 is presented in Table B1.

TABLE B1

Cash Generation From Operations Derivation for the Upstream Oil and Gas Industry In Canada Year Ended December 31, 1983

($ Millions)

Net earnings after tax	$2 281
Add back non-cash items:	
Depreciation	784
Depletion and Amortization	1 349
Deferred income taxes	1 188
Subtotal[33]	5 602
Add back capital items expensed[34]	956
Subtotal	$6 558
Subtract current income tax reduction due to capital spending[35]	(2 583)
Net cash flow	$3 975

33 All data to this point were obtained from Statistics Canada, Corporation Financial Statistics, 1983, Table 2B, "Detailed Income and Retained Earnings Statistics".

34 From Corporation Taxation Statistics, Table 5, "Reconciliation of Book Profit to Taxable Income for Corporations in the Petroleum and Natural Gas Industries".

35 This amount is derived by applying the effective tax rate on taxable income for the year to exploration and development expense deductions and the capital cost allowance deduction. See Table 5, Corporation Taxation Statistics

APPENDIX C

FISCAL OVERVIEW

This appendix provides a brief overview and chronological summary of the Canadian fiscal system as it applies to oil and gas extraction income. As mentioned in Chapter 3, the pervasive nature of the fiscal system has a significant effect on industry profitability with the following ramifications:

- industry profitability is largely dependent upon the fiscal regimes in place. Expected profitabiliity will be a partial function of the expected fiscal framework. The latter in turn, is influenced by existing fiscal conditions

- crude price changes, and to a lesser extent changes in costs, are absorbed to a great extent by the fiscal system

- depending upon the direction of fiscal changes, crude oil and natural gas prices may be poor proxies for profitability

- constantly changing fiscal terms introduce a significant element of uncertainty in projecting profitability.

The fiscal system is effectively a combination of sub-systems notably comprised of federal and provincial income taxation, provincial and federal royalties, other taxation, and subsidies. What follows is a very brief overview of how these sub-systems work for the Western Canadian producer with conventional production reinvesting in the business. A chronological summary is then provided highlighting major changes to the various systems since 1970.

INCOME TAXATION - FEDERAL AND PROVINCIAL

Oil and gas resource income is taxed by both the federal and provincial governments in Canada. In 1985, the federal rate of income tax on such income was 46 per cent with a 10 per cent abatement for provincial taxes. In Alberta, where most of this income was generated, the provincial rate of tax was 11 per cent. In addition, there was a federal 5 per cent income tax surtax on large corporations at this time which was introduced earlier in the 1985-05-23 federal budget. Hence, the marginal tax rate for large corporations with extraction income was at 48.8% (1.05 (36%) + 11%).

The average tax rate was lower reflecting exceptions for a variety of reasons including for non-extraction income, the so-called "M&P" deduction. This provision allowed for a deduction of up to 6 per cent for income from manufacturing and processing operations such as for the processing of natural gas.

In order to apply any rate structure, taxable income must be calculated. Excluding capital type items, the measure of taxable income largely coincides with pre-tax income computed in accordance with generally accepted accounting principles (GAAP). Capital type expenditures, however, have and generally continue to be accorded tax specific treatment as outlined below.

Canadian Oil and Gas Property Expense (COGPE) - means any outlay or expense made or incurred after December 11, 1979, that is for acquiring a Canadian resource property which includes any right, license or privilege to explore for, drill or take petroleum, natural gas or related hydrocarbons in Canada. Subject to certain limitations, a taxpayer may deduct up to 10 per cent of these costs annually.

Canadian Exploration Expense (CEE) - generally means geological and geophysical expenses incurred for the purpose of determining the existence, location, and extent and quality of a petroleum or natural gas deposit in Canada and the costs of drilling an exploratory well. Subject to limitations, a taxpayer may deduct up to 100 per cent of these costs annually.

Canadian Development Expense (CDE) - includes expenses incurred after May 6, 1974, for the drilling production, development, injection and disposal wells. Subject to limitations, a taxpayer may deduct up to 30 per cent of these costs annually.

Capital Cost Allowance (CCA) - this allowance provides for the taxpayer to deduct limited amounts of the capital costs of depreciable property each year. This allowance is computed on a pool basis with separate classes for various properties. Major classes relevant to the oil and gas industry in 1985 included:

- Class 2 (6 per cent)
  - Most pipelines
- Class 3 (5 per cent)
  - Most buildings
- Class 8 (20 per cent)
  - Fixed assets not specifically included in another class, including office equipment and similar assets not used in oil and gas production

- Class 10 (30 per cent)

  - Gas or oil well equipment, including equipment, structures, and pipelines acquired to be used in a gas or oil field in the production of natural gas or crude oil, and a pipeline acquired to be used solely for transmitting gas to a natural gas plant

- Automotive equipment

- Class 29 (50 per cent)

  - Machinery and equipment to be used to process natural gas or to refine crude oil

Resource Allowance - the resource allowance is a deduction which was introduced to give some recognition to the non-deductibility of crown royalties for income tax purposes in the wake of the federal-provincial tax dispute in 1974.

The Resource Allowance is 25 per cent of resource profits. Resource profits are defined as oil and gas production income. This is calculated by subtracting various operating costs from working interest income.

Provincial income taxation is generally based on the same rules as for federal taxation. In Alberta, the income tax rate had been 11 per cent for some time until 1987 when it was increased to 15 per cent. The two major benefits provided by Alberta relate to the Alberta Royalty Tax Credit (ARTC) and the Alberta Rebate.

The ARTC is a credit which gives limited provincial recognition to the fact that provincial crown royalties are not deductible for federal income tax purposes. This is a pure tax credit and for 1985 was limited to 50 per cent of Alberta royalties paid to a maximum of $2 million per year. The ARTC was subsequently increased and reached a maximum of 95 per cent to $3 million per year during much of 1986.

The Alberta rebate allows for a deduction in computing provincial taxable income for the difference between crown royalty expense and the 25 per cent resource allowance.

PROVINCIAL ROYALTY SCHEMES

Royalty schemes are administered by the various provinces in an attempt to exact available economic rent from producers. Individual schemes vary but are generally functions of the price of oil or natural gas, and the production rate of the well. It should be noted that freehold royalty arrangements are also in existence whereby individuals holding mineral rights receive royalties from the party operating the field or pool in question.

In Alberta, a sliding scale royalty is imposed for both "new" and "old" oil and is generally a function of production rate and price. The Alberta royalty formula in existence in 1985 was as follows:

Alberta Old and New Oil Royalty Formulae

$S = (\text{Production})^2/1271.28$, if monthly production is less than or equal to 190.7 M^3, and

$S = 28.6\ M^3 + (\text{Production} - 190.7\ M^3)$, if monthly production is greater than 190.7 M^3.

This basic royalty then enters into the appropriate royalty formula to determine the royalty payable in cubic metres, R, on any particular well. The royalty formula is:

$$R = S + KS\ ((A - B)/A)$$

Where: A is the par price (approximates the average wellhead price)

B is the select price

K is the royalty factor (varies according to the marginal rate - see below).

The royalty (K) factor varies with the oil and gas marginal rate as follows:

Old Oil and Gas Marginal Rate	Corresponding Royalty (K) Factor	New Oil and Gas Marginal Rate	Corresponding Royalty (K) Factor
45.0%	1.076923	35.0%	.615385
43.5%	1.007692	33.5%	.546154
42.0%	.938462	32.0%	.476923
40.0%	.846154	30.0%	.384615

As can be seen above, the maximum marginal royalty rate for old oil was as high as 45 per cent at the beginning or 1985. These rates have subsequently been reduced. The royalty for natural gas is essentially dependent on price and similarly distinguishes between "old" (discovered prior to 1974) and "new" gas.

CHRONOLOGICAL SUMMARY OF THE FISCAL SYSTEM APPLICABLE TO THE UPSTREAM OIL & GAS INDUSTRY IN CANADA, 1970-1987

1971 . The June budget set the federal corporate income tax rate at 50 per cent for 1972 and provided for reductions of one per cent annually to 46 per cent in 1976.

. Oil and gas rights were to be included in exploration and development expenses as a deduction in determining taxable income commencing in 1972.

1972 . The manufacturing and processing (M&P) deduction reduced the federal income tax rate for such income to 40 percent.

1973 . The Alberta government introduced major changes to its crude oil royalty system. Royalty rates were increased from 16.67 per cent to an average rate of over 20 per cent and rates were made price sensitive. Alberta indicated that these moves were made to defend its fiscal jurisdiction of oil and gas income in the wake of the federal government's oil price freeze and introduction of the oil export tax.

1974 . The federal government disallowed the deductibility of provincial crown royalty payments for federal income tax purposes in response to the significant increase in crown royalties in Alberta. The tax rate for production income was set at 50 per cent with a 10 per cent abatement for provincial income tax and a new 10 per cent resource profit abatement, the latter in partial recognition of the loss of the royalties deduction.

. Alberta introduced a new royalty system for gas which discerned "old" gas from "new" gas depending upon the year of discovery. The rates became price sensitive and were significantly increased.

. Later in 1974, the Alberta government reduced royalty rates for oil and gas production, introduced the Alberta Royalty Tax Credit (ARTC) and extended certain drilling incentives to the industry. The petroleum exploration plan was an attempt of Alberta to directionally offset the loss of deductibility of crown royalties for federal income tax purposes.

. In the November budget the federal government set the resource profit abatement at 12 per cent for 1975 and 15 per cent for 1976. In addition, exploration expenditures were deductible at 100 per cent in the year incurred beginning in May 1974. These expenditures were treated as "Canadian Exploration Expenses" and included geological and geophysical expenditures.

1975 . The federal corporate income tax rate was reduced to 46 per cent with a 10 per cent abatement. In recognition of the loss of the Crown royalty deduction, the government also introduced a 25 per cent Resources Allowance in place of the resource profit abatement.

1977 . A depletion allowance of 66.67 per cent (so called "superdepletion") became available for exploratory drilling costs for wells in excess of $5 million. This depletion allowance ultimately expired in March 1980.

1979 . The costs of acquiring oil and gas resource property, notably land bonus costs, were made deductible at a rate of 10 per cent per annum. These expenditures were treated as Canadian Oil and Gas Property Expenses (COGPE).

. A corporate surtax of 5 per cent of tax payable was introduced at year end, scheduled to be in place through the end of 1981.

1980 . The National Energy Program was introduced on October 28, 1980 which was subsequently modified in September 1981 with the Ottawa-Alberta agreement. The NEP essentially dealt with four major energy policy areas - pricing, taxation, incentives and Canadianization. In the area of taxation, the NEP notably introduced the Petroleum and Gas Revenue Tax (PGRT). This new tax of 8 per cent was applied to Canadian oil and gas production revenue net of lifting costs effective January, 1981. This tax was not deductible for income tax purposes and because of the controlled prices for oil and gas, the incidence was borne completely by producers.

- changes in depletion allowances including effective January 1981:

- the depletion allowance for domestic exploration expenditures were to be earned at 33.3 percent of qualifying expenditures incurred in 1981, net of any incentive payments.

- after 1981, the depletion allowance for domestic exploration expenditures both in and outside the Canada Lands was to be phased out.

- the depletion allowance for development expenditures were eliminated, effective January 1, 1981.

In addition, the Petroleum Incentives Program (PIP) was introduced in order to stimulate investment and compensate for the reduction and phase out of th earned depletion programs. This program enabled applicants to recover a portion of eligible exploration and development expenditures based on the location of the work and Canadian ownership rate and control status of the applicant.

1981 . The Alberta government increased the rate of the ARTC from 25 to 50 per cent and the annual maximum from $1 million to $2 million.

1982 . An update to the NEP was implemented. One of the major effects was a change in the PGRT rate which was earlier increased to 16 per cent less the 25 per cent resource allowance. The NEP update reduced he PGRT to 11 per cent commencing mid-year.

1985 . On March 27, 1985 the Governments of Canada, Alberta, Saskatchewan and British Columbia reached an agreement on changes to pricing and taxation of oil and gas production--the so-called "Western Accord." The agreement was a substantial reversal of the National Energy Program (NEP) and eliminated many of the burdensome taxes and special charges that were introduced as part of the NEP. For example, the PGRT rates were amended and the tax was to be phased out. In addition, the Incremental Oil Revenue Tax and Petroleum Compensation Charge, which were introduced as part of the 1981 Ottawa - Alberta agreement, were eliminated with crude price decontrol.

Aside from providing for specific crude price decontrol, effective June 1, 1985 and tax reductions the agreement was symbolic in that it represented a move toward a more market oriented arrangement for crude and natural gas transactions both within as well as outside of Canada. For example, the agreement incorporated the following major points.

- The National Energy Board was to no longer allocate light crude oil among eastern Canadian refineries.

- Producers were free to market their working interest oil. The Alberta Petroleum Marketing Commission, which formerly marketed all provincial crude, was to act as an agent for Crown oil only.

- New royalty incentives were to be developed to encourage offshore investment.

- The benefits of these fiscal change were to be flowed through to industry, including the net benefits of price decontrol.

Notably, in the area of taxation, the confiscatory PGRT was to be phased out by the beginning of 1989.

1986 . The PGRT was eliminated in October in the wake of the precipitous crude price declines earlier that year. The corporate income tax rate was to be reduced from 36 percent in 1986 to 33 percent by 1989. A surtax of 3 percent of business income was imposed commencing in January 1987.

. The Alberta government also increased the ARTC to 95 per cent from 75 per cent earlier in the year and announced the Exploration Drilling Assistance Program (EDAP) which extended a 50 per cent royalty credit to exploration wells. Later, Alberta introduced the Geophysical Assistance Program (GAP), the Well Servicing Assistance Program (WSAP) and the Development Drilling Assistance Program (DDAP).

. Finally in 1986, the Alberta government announced major reductions for oil and gas royalties as well as a royalty holiday program of up to five years for wells spudded between October 1986 and November 1987. The holiday was reduced to 3 years and 1 year respectively for the ensuing two year period. The average royalty rates fell by an average of 12 per cent to 31 per cent, for old oil, 23 per cent for new oil, and to 25 per cent for old gas and 19 per cent for new gas.

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