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DISCUSSION PAPER NO. 274

Financing Oil and Gas Exploration and Development Activity

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Résumé

Le financement des travaux de prospection et de mise en valeur du pétrole et du gaz

La présente étude porte sur les facteurs principaux des dépenses d'investissement dans les activités de prospection et de mise en valeur, pour la production de pétrole et de gaz naturel. Les auteurs ont d'abord construit un modèle de l'activité pétrolière et gazière en Alberta, puis en ont fait l'estimation. Ils utilisent ensuite ce modèle ainsi que d'autres analyses de données financières pour tenter de répondre à cinq questions fondamentales énoncées dans l'introduction.

Plusieurs conclusions importantes se dégagent de l'étude. Premièrement, les flux de trésorerie découlant des activités actuelles d'extraction dans le secteur du pétrole et du gaz ont une grande influence sur l'aptitude de l'industrie à financer, tant par les sources internes qu'externes (emprunts), les travaux continus de prospection et d'exploitation. Les auteurs ont trouvé une certaine justification empirique au fait que l'industrie pétrolière et gazière doit financer, à même ses flux monétaires, une proportion plus élevée de projets que les autres genres d'entreprises. Cela semble d'ailleurs particulièrement vrai pour les travaux de prospection, où les risques sont élevés.

Mais le ratio d'endettement des entreprises situées en amont dans la structure industrielle, par rapport à ce qu'il était dans le passé et à celui d'autres industries comparables, a été anormalement élevé en 1981 et en 1982. On peut attribuer cette situation en grande partie aux acquisitions d'entreprises. Dans cet ordre d'idées, les auteurs ont trouvé, troisièmement, plusieurs preuves indirectes montrant que les mesures de canadianisation du Programme énergétique national (PEN) ont contribué à accroître le coût du capital pour les entreprises de l'industrie des hydrocarbures.

Quatrièmement, une grande part de la forte diminution, en 1981 et 1982, de l'activité de prospection et de mise en valeur dans le bassin sédimentaire de l'Ouest serait attribuable au fait que le PEN aurait entraîné une réduction des recettes nettes et des stimulants, bien qu'une autre partie soit nettement imputable à l'évolution des marchés mondiaux du pétrole, du marché du gaz naturel aux États-Unis et aux effets récessionnistes de la hausse des taux d'intérêt réels. Cinquièmement, cette répercussion du PEN indique, selon les auteurs, qu'une réduction des taxes que les sociétés pétrolières et gazières doivent payer "au départ" (particulièrement la taxe sur l'augmentation des recettes) devrait faire partie de toute entente future (ou renégociée) sur l'énergie, si l'on veut réaliser les objectifs fondamentaux de la sécurité d'approvisionnement et de l'efficience économique globale.

Les auteurs estiment que cette étude constitue l'une des premières tentatives en vue de modéliser le processus d'investissement des entreprises situées en amont dans la structure de l'industrie canadienne du pétrole brut et du gaz naturel. Les prix des réserves (développées ou non) sont utilisés comme principales variables explicatives qui captent ce que ce processus a de stimulant, mais les variables qui représentent les volumes de production (pondérés) ou les flux de trésorerie sont aussi des éléments importants. Les élasticités à long terme des dépenses globales réelles de prospection, en fonction des prix des réserves non développées et des volumes pondérés de production, sont estimés à 0,93 et 0,48, respectivement, tandis que celles des dépenses totales réelles de mise en valeur, par rapport aux prix des réserves développées et aux volumes pondérés de production, sont estimées respectivement à 0,46 et 0,52. Toutefois, ces deux fonctions d'investissement comportent d'importants retards, qui sont d'ailleurs un peu plus longs pour les activités de prospection que pour les travaux de mise en valeur.

Bien que les ajustements, à l'intérieur de l'échantillon, ainsi que les propriétés des simulations, soient un peu plus précis pour la prospection que pour la mise en valeur, l'aptitude prévisionnelle du modèle, hors échantillon, est loin d'être aussi bonne pour les travaux de prospection en 1982. Lorsque les aspects de la politique étrangère touchant une industrie se modifient sensiblement, comme la chose s'est nettement produite avec l'adoption du PEN, les changements dans les anticipations peuvent perturber sensiblement les anciens modes de comportement (prévus dans les équations économétriques). Nous croyons que ces changements dans les anticipations sont des facteurs qui expliquent avant tout pourquoi nos prévisions hors échantillon pour 1982, malgré leur juste orientation, sous-estiment fortement l'ampleur du déclin constant de la prospection en Alberta.

Executive Summary: Financing Oil and Gas Exploration and Development Activity

This study is concerned with the determinants of investment expenditure in the exploration and development phases of the crude petroleum and natural gas supply process. It constructs and then estimates an Alberta oil and gas activity model which is used, in conjunction with other financial data analysis, to provide tentative answers to five basic questions outlined in the introductory section.

The major conclusions arising from this study are, first, that the ability of the oil and gas sector to finance continued exploration and development activity from both internal and external (borrowed) sources is influenced importantly by cash flows from existing oil and gas extraction. Second, we found some empirical justification for the notion that the oil and gas industry needs to finance a larger percentage of its projects out of cash flow than is normal for other kinds of business. This appears to be especially true for the risky exploration stage. However, the debt/equity ratio for the upstream segment of the industry became abnormally high in 1981 and 1982 in relationship to both historical experience and other comparable industries due, in large part, to take-over activities. In conjunction with this, we found, third, considerable circumstantial evidence for suggesting that the 'Canadianization' aspects of the National Energy Program (NEP) increased the 'cost of capital' to firms in the industry.

Fourth, we attribute a considerable portion of the substantial 1981 and 1982 decline in exploration and development activity in the Western sedimentary basin to the netback-reducing and incentive-reducing impact of the NEP, though some portion is clearly attributable to events in world oil markets, in U.S. natural gas markets, and to the recession-inducing impact of high real interest rates. This consequence of the NEP leads us, fifth, to suggest that some reduction in the up-front taxation of the oil and gas industry (particularly through reductions in the petroleum and natural gas revenue tax) should be included in any subsequent (or re-opened) energy agreements if the basic objectives of security of supply and overall economic efficiency are to be achieved.

We believe that this study represents one of the first pioneering attempts to model the investment activity process in the upstream segment of the Canadian crude oil and natural gas industry. Reserve prices (both undeveloped and developed) serve as key explanatory variables that capture the incentive aspects of this process, but (weighted) production volumes and/or cash flow variables are also important elements in the story. The long-run elasticities of total real exploration expenditure with respect to undeveloped reserve prices and weighted production volumes are estimated to be 0.93 and 0.48, respectively, whereas the long-run elasticities of total real development expenditures with respect to developed reserve prices and weighted production volumes are estimated to be 0.46 and 0.52, respectively. Significant lags, however, exist in both of these investment functions, with the lags being somewhat longer for exploration activity than for development activity.

Although the within-sample fits and simulation properties are somewhat tighter on the exploration side than the development side, the out-of-sample forecasting ability for the year 1982 is not nearly as good for exploration activity. Whenever the external policy regime faced by an industry changes markedly, as clearly occurred with the introduction of the NEP, expectational shifts are likely to disturb previous behavioral modes (embedded in econometric equations) in a significant way. We believe these expectational shifts to be the main reason why our 1982 out-of-sample forecast, although directionally correct, understates the magnitude of the continuing downturn in exploration activity in Alberta by a considerable margin.

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I. Introduction

The five basic questions under investigation in this research study are the following:

1. What does an investigation of the financial requirements of the oil and gas sector tell us about the role of both buoyant and stable netbacks from existing oil and gas extraction in the ability of this sector to finance continued exploration and development activity from both internal and external (borrowed) sources?

2. What justification is there for saying that the oil and gas industry needs to finance a larger percentage of its projects out of cash flow than is normal for other kinds of business?

3. What justification is there for saying that the 'Canadianization' aspects of the National Energy Program (NEP) may have increased the 'cost of capital' to firms in the industry?

4. What has been the impact of the NEP and its aftermath on netbacks to the primary oil and gas industry, and the impact of reduced cash flows on exploration and development activity and potential supplies of oil and gas from the Western sedimentary basin?

5. What changes in fiscal arrangements for the industry should be included in subsequent (or re-opened) energy agreements if the basic objectives of security of supply and overall economic efficiency are to be achieved?

Early discussions with energy analysts at Alberta Energy and Natural Resources (AENR), the Alberta Energy Resources Conservation Board (AERCB), the Canadian Petroleum Association (CPA), the Economic Council of Canada (ECC), Energy, Mines, and Resources (EMR), Finance Canada, the Royal Bank's Global Energy & Minerals Group (GEG), and UBC's John Helliwell convinced us that we should begin our search for the answers to these five basic questions by trying to explain overall industry activity (or exploratory and development effort) as measured by various categories of real expenditures incurred over time in the Western sedimentary basin. To keep matters reasonably precise we decided to concentrate on the Alberta segment of the primary oil and gas industry, since fiscal variables do vary somewhat from jurisdiction to jurisdiction. The first two parts of this report therefore discuss the specification and estimation of an Alberta oil and gas activity model, as well as reporting on the empirical results thereby obtained. Later sections consider the specific financial constraints under which firms in the industry operate, and discuss the importance of financial considerations and expectational changes in explaining the 1981-1982 downturn in exploration and development activity in the Western sedimentary basin.

II. An Alberta Oil and Gas Activity Model

The pre-production activities of the primary oil and natural gas industry are ordinarily separated into two categories, exploration activities and development activities. The intensities with which each of these activities are carried out are referred to as exploration effort and development effort, respectively, and may be measured by real expenditures by the industry on these two activities. The outputs of the two activities are new additions to undeveloped reserves of oil and gas in the ground, and new additions to developed reserves, respectively. Of course, basic knowledge of the geological basin or formation to which exploration activity is directed is also an important output of the exploration process. Delineation drilling serves this knowledge-generating function as well at the development stage.

Given the choice of prospects to explore, actual new reserve additions are subject to natural or geological forces which determine the probability of success. Thus, there is no reason to suppose that in any one year planned or expected reserve additions and actual reserve additions are equal to one another for either crude oil or natural gas; evidently there is a stochastic or random element involved in the reserve-creation process. Moreover, the production technology that relates planned or expected reserve additions to exploration and/or development effort may well be subject to diminishing returns to overall effort as time proceeds if potential oil and gas lands become more fully explored and/or developed, a factor which would be reflected over time in increasing marginal finding costs.

Typically, in the exploration phase three categories of industry effort are combined to produce undeveloped reserves. These categories are (a) geological and geophysical expenditures, (b) exploratory drilling expenditures, and (c) land acquisitions and rentals. In the development phase, four categories of industry effort are combined to produce developed (and/or hooked up) reserves of oil and gas, namely (a) development drilling expenditures, (b) field equipment expenditures, (c) secondary recovery and pressure maintenance expenditures, and (d) expenditures on natural gas plants, though the last two of these categories of expenditure pertain at least as much to the production stage as they do to the development stage. Apart from natural gas plants, it is unfortunately not generally possible to get real expenditures in either the exploration or the development phase precisely separated into oil-related expenditures and gas-related expenditures. This implies that if one is to explain the volume of expenditures undertaken in each category, one must generally use hybrid measures (or weighted averages) of basic variables pertaining to crude oil supply and basic variables pertaining to natural gas supply, respectively. How this can be done using oil intent or completion ratios and gas intent or completion ratios will be demonstrated later in this section.

Given this background, our basic model consists of two ingredients. The first of these is a stochastic neoclassical production technology, whose expected value relates planned reserve additions A_t to industry effort E_t, where t refers to a particular year. The second ingredient is the inventory theoretic notion that producers only plan to replace or add to their stock of oil or gas reserves in the ground if it is expected to be profitable to do so. As we shall see, since reserve stock holdings are continuously depleted as extraction occurs, this implies that the main variables which influence exploration and development activity levels are current production volumes, Q_t, and reserve prices, P_t, although there may well be significant lags in the response process.

The prices of developed or undeveloped reserves of crude oil and natural gas in the ground, P_t, play a crucial linking role in the relationships among E_t, A_t, and Q_t. The price of developed reserves refers to the net present value of a unit of developed oil or gas reserves in the ground. Given a normal production profile, this price is essentially a discounted netback, where all taxes and production (or operating) costs are deducted from the wellhead price in calculating the netback. It is this price which is appropriate in most instances for explaining development activity levels. The price of undeveloped reserves refers to the net present value of a unit of undeveloped oil or gas reserves in the ground. Capitalised unit development costs are deducted from the price of developed reserves in obtaining this price. The price of undeveloped reserves is important in the explanation of exploration activity levels.

Given a stochastic neoclassical production technology which relates new reserve additions to industry effort, the optimal level of each of the three kinds of exploration effort is given by equating the marginal cost of one additional unit of effort to the expected marginal value of the undeveloped reserve additions that are thereby likely (in a probabilistic sense) to be created. If the industry experiences certain capacity limitations on the volume of exploratory effort sustainable at any one time, then the marginal cost of an additional unit of exploratory effort may be increasing as effort E_t is expanded. Since a neoclassical production technology will generally imply that the marginal undeveloped reserve additions that firms expect to acquire from one more unit of exploratory effort is decreasing as E_t expands due to diminishing returns, marginal finding costs (the ratio of the marginal cost of effort to its marginal productivity in terms of expected new reserve additions) are likely to be an increasing function of industry effort. Nevertheless, given that the optimum level of exploratory effort is obtained by a marginal condition of the usual sort, one may generally conclude that optimal exploratory effort, E^*_t, is a function of undeveloped reserve prices and planned undeveloped reserve additions which is non-decreasing in each of its arguments.

A similar reasoning process may be used for each of the four kinds of development effort, thus generating a functional relationship explaining optimal development effort in terms of developed reserve prices and planned additions to developed reserves, although it turns out in practise that netbacks are more useful than developed reserve prices in explaining the production related real expenditures on secondary recovery and pressure maintenance and natural gas plants. Once again, a standard marginal condition is used to establish this relationship.

In each case, the establishment of new reserves may be thought of as an investment in a newly-created capital asset. The quantity of this asset put in place in any given year may be related in a backward-looking way to the inputs of effort used up in its creation. These inputs will be larger, the higher is the value of the asset put in place. They are therefore positively related to the price of reserves which represents the unitised net value of the forward-looking stream of production outputs that the newly-created asset will help to provide. More explicitly, one may write

$$(1)\ E^*_t = h(A_t\ ,\ P_t)\ ,\ \delta h/\delta A>0\ ,\ \delta h/\delta P>0\ ,$$

as the generic expression which explains the optimal level of exploratory or development effort.

Although an active publicised market for reserves does not explicitly exist, in part because oil and gas pools are heterogeneous entities, the price of reserves (either developed or undeveloped) may be thought to be determined by equating the demand for the stock of oil or gas reserves in the ground to the existing supply as given by the current stock of reserve holdings. For a non-renewable resource like crude oil or natural gas, each year current production volumes deplete the existing stock of reserve holdings. On the other hand, new reserve additions created through exploration and development activity may be able to replace these stock losses.

An increase in demand which is reflected in higher reserve prices acts as an incentive for producers to find (or establish) a larger quantity of new reserves in relationship to the quantity of oil or gas they are currently producing, thereby adding to the stock of oil or gas reserves in the ground or at least preventing it from falling as quickly as it otherwise would. A decrease in demand which is reflected in lower reserve prices will generally induce producers to plan to find (or establish) a smaller quantity of new oil or gas reserves in relationship to their current production volumes, thereby in all probability running down their existing stock holdings. It follows from this that planned new reserve additions, A_t, will be positively related to both current production, Q_t, and reserve prices, P_t. This relationship may be expressed as follows

$$(2)\ A_t = g(Q_t\ ,\ P_t)\ ,\ \delta g/\delta Q>0,\ \delta g/\delta P>0\ .$$

Equation (2) may be interpreted to imply that producers invest with a view to maintaining some normal (though perhaps trended) relationship between production and reserve holdings, whether developed or undeveloped. The replacement investment process is vital to any extractive firm that wishes to remain in its traditional line of business.

Unfortunately, planned (as opposed to actual) new reserve additions are unobservable variables. However, since reserve prices are available to us, we choose to use P_t as our main linking variable, and thus eliminate the unobservable A_t across our two equations by substitution of equation (2) into equation (1). Hence, our basic relationship explaining optimal industry activity levels may be written as

$$(3)\ E^*_t = f(P_t\ ,\ Q_t)\ ,\ \delta f/\delta P>0,\ \delta f/\delta Q>0\ ,$$

where E^*_t refers to a particular optimal industry effort level, P_t is the appropriate reserve price and Q_t is the volume of production. E^*_t is stated in real terms by deflating by the all-industry selling price index. Similarly, P_t is also deflated by the all-industry selling price index to remove the effects of general inflation on reserve prices. The coefficients in this functional relationship may of course vary from activity category to activity category. Nevertheless, all partial elasticities are expected to be positive.

The simplest form of equation relating industry effort to reserve prices and production levels is the constant-elasticity relationship common to neoclassical investment theory. On this assumption, one may write

$$(4)\quad E^*_t = \alpha P_t^{\beta} Q_t^{\gamma}, \quad \alpha,\ \beta,\ \gamma > 0.$$

Assuming that the actual effort level E_t responds to the desired or optimal effort level via a partial adjustment model of the form

$$(5)\quad E_t/E_{t-1} = (E^*_t/E_{t-1})^{\delta}, \quad 1>\delta>0,$$

one may specify the following log-linear regression model,

$$(6)\quad \ln E_t = \delta \ln \alpha + \beta\delta \ln P_t + \gamma\delta \ln Q_t + (1-\delta)\ln E_{t-1} + \mu_t,$$

where μ_t is a stochastic error term distributed as $N(0,\sigma^2)$. This is our basic regression specification, where the undeveloped reserve price is used as a regressor when E_t refers to a component of exploratory effort (or its total), and the developed reserve price is ordinarily used as a regressor when E_t refers to a component of development effort (or its total).[1]

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[1] One way in which our basic relationship may be derived is as follows. Let planned reserve additions take the constant elasticity form

$$A_t = aP_t^{k}Q_t^{m}, \quad a>0,\ k>0,\ m>0,$$

where m may be approximately equal to unity. Let industry effort levels combine together to explain A_t by a relationship of the form $A_t = H(E^*_t$, other variables). The marginal conditions for cost minimization imply that $P_t \delta H/\delta E^*_t = c(E^*_t)$, where $c(E^*_t)$ refers to the (increasing) marginal cost of effort. If, for example, $A_t = H(E^*_t$, other variables) is a constant elasticity (Cobb-Douglas) function, then $\delta H/\delta E^*_t = hA_t/E^*_t$, where $0<h<1$ is the elasticity of planned reserve additions with respect to industry effort. Moreover, if $c(E^*_t)$ takes the form cE^{*d}_t with $c>0$, $d>0$, then one may write

$$hP_tA_t/E^*_t = cE^{*d}_t \text{ or } A_t = cE^{*(1+d)}_t/hP_t.$$

Equating the two definitions of A_t one has

$$aP_t^{k}Q_t^{m} = A_t = cE^{*(1+d)}_t/hP_t,$$

which may be solved for E^*_t to give

$$E^*_t = (ah/c)^{1/(1+d)}P_t^{(1+k)/(1+d)}Q_t^{m/(1+d)}.$$

Thus, on this hypothesis, E^*_t is an increasing function of reserve prices and output levels, where both the reserve

Industry output, however, consists of both crude oil and natural gas. In order to allow for this fact, in all cases except for expenditures on natural gas plants we have formed weighted average reserve prices and weighted average output measures using either oil and gas intent ratios (for reserve prices) or oil and gas completion ratios (for production) as weights. Thus, in general, and with an exception or two on the development side, we have constructed an intent ratio weighted or hybrid reserve price as

$$\ln P_t = i_o \ln P_{ot} + i_g \ln P_{gt} \ , \quad 1 > i_g = 1 - i_o > 0 \ ,$$

where P_{ot} is the appropriate price of oil reserves, and P_{gt} is the appropriate price of gas reserves; i_o is the oil intent ratio and $i_g = 1 - i_o$ is the gas intent ratio. In the case of development drilling, we discovered perhaps not surprisingly that a completion ratio weighted reserve price worked better in the regression. For secondary recovery and pressure maintenance, a completion ratio weighted netback proved most useful, and for natural gas plants, only the gas netback seemed important.

'(cont'd)price elasticity and the output elasticity are positive, but may be greater than or less than unity. Of course, actual effort E_t may respond to optimum effort E^*_t via a simple lagged adjustment process. We hasten to add, however, that this may not be the only way of deriving our basic relationship. We therefore do not use this model to interpret our regression coefficients in terms of underlying parameters along these lines, since in any case k, d and m would be under-identified unless one makes further a priori assumptions such as m=1 or d=0, assumptions which wind up implying different consequences for other parameters like k. Indeed, alternative explanations of our basic regression equations along cash flow lines are considered in later sections of this report.

Except in the case of natural gas plants, where only natural gas production seems important, we have constructed a completion ratio weighted or hybrid production measure as

$$\ln Q_t = c_o \ln Q_{ot} + c_g \ln Q_{gt} \ , \quad 1>c_g=1-c_o>0 \ ,$$

where Q_{ot} is crude oil output (in barrels per year) and Q_{gt} is natural gas output (in thousand cubic feet per year); c_o is the oil well completion ratio and $c_g=1-c_o$ is the gas completion ratio. Although this measure looks like it is adding together oranges and apples, it turns out to give eminently sensible regression results when used in conjunction with a hybrid reserve price in a log-linear regression formulation. These results are presented in the following section, along with some additional comments on both the nature of the hybrid reserve price and production measures, and the appropriate interpretation of the regression model itself.

III. Petroleum Industry Activity Levels

A. Data Sources and Manipulations

The regressions reported in Table I explain the components of petroleum industry exploration and development expenditures in terms of reserve prices, production, and a distributed lag adjustment process with geometrically declining weights. The production and expenditure data were obtained from the Canadian Petroleum Association, Statistical Handbook (1982). To account for the joint nature of oil and gas in the exploration and development phases, weighted averages of the reserve prices and production rates are used. The weights consist of either oil and gas intent or completion ratios. The exception is natural gas plant expenditures which pertain solely to gas.

The prices of undeveloped and developed oil and natural gas reserves were obtained from Uhler and Eglington (1983). The price that companies would pay through purchases or through their own exploration programs to find reserves is the price of undeveloped reserves. The price of developed reserves is the price that companies would pay for reserves ready for production. Their basic approach works backwards from oil and gas prices at the wellhead which are then used to determine netbacks and reserve prices. More specifically, when firms acquire reserves in the ground they acquire a revenue producing asset. The calculated unit profit on the acquisition is the difference between the discounted net revenue stream given by the wellhead price less operating costs, royalties, income and other taxes (or the netback) resulting from a standard (declining) production profile and the price of reserves. If a competitive environment is assumed, above-normal profits will be eliminated. Therefore, the price of developed reserves will equal the discounted value of the net return to their production. By further deducting the capital costs of development effort one is able to calculate the price of undeveloped reserves which is pertinent to the exploration phase. Uhler and Eglington incorporate the numerous complexities of the tax system in calculating the reserves prices and also factor a measure of industry expectations of future wellhead prices into their calculations.

The oil and gas intent and completion ratios were taken from Eglington and Uffelmann (1983). The intent ratios represent the number of exploratory intent wells drilled as a percentage of the total number of exploratory wells drilled. The oil intent data were obtained from Imperial Oil up to 1970 but due to a lack of data in the post-1970 period the authors used the following procedure. First, the pre-1970 oil success ratio (the ratio of the number of known oil well completions to the total number of exploratory oil intent wells) is divided into the observed exploratory oil well completions for the years 1971 to 1974 to give an estimate of the number of exploratory oil intent wells drilled up to 1974. The number of exploratory oil intent wells drilled for the post-1974 period is estimated using an oil success ratio that is assumed to rise until 1979 and then remain flat to 1981. These estimates of the number of exploratory oil intent wells drilled can then be taken as percentages of the total number of exploratory wells drilled in any given year to obtain the oil intent ratios. Gas intent ratios were taken as one less the oil intent ratios. The effect of the aforementioned assumption about the oil success ratio is implicitly to increase the gas intent ratios for the 1975 - 1981 period above where they otherwise might have been since 'joint intent' drilling is not categorised separately (see Eglington and Uffelmann, Appendix A). Completion ratios were calculated using Canadian Petroleum Association (CPA) drilling data.

A possible source of problems for our weighted average specifications arises from the potential link between intent and/or completion ratios and the relative reserve prices for oil and gas, either developed or undeveloped. A substantial increase in the relative reserve price of oil might have the effect of increasing the oil intent ratio, and perhaps also the oil completion ratio. We examined this possibility by comparing the intent ratio and completion ratio series with the developed and undeveloped reserve price series for oil relative to those for gas. Much to our surprise, we found very weak correlations between the intent and completion ratios and relative reserve prices, as illustrated by the following table of correlation coefficients.

Sample Correlation Coefficients

(mnemonics as defined in Table I)

	INTo	COMo	RESo/RESg	URESo/URESg
INTo	1.00	0.87	-0.09	0.05
COMo		1.00	0.04	0.25
RESo/RESg			1.00	0.91
URESo/URESg				1.00

It follows from these statistics that we do not believe that the variability of our intent and completion ratio weights causes spurious correlation to enter our regression results. Intent ratio weights are appropriate on incentive variables like reserve prices, especially on the exploration side, whereas completion ratio weights on production variables are appropriate if our inventory-theoretic replacement investment view of the world is valid.

Originally a separate cost of borrowing term was included in the equations but it proved to be statistically weak. This was likely due to the presence of a discounting term in the construction of the reserve price series. It should also be noted that in all cases, except gas plant expenditures, the Durbin h statistic, which is used to test for serial correlation with a lagged dependent variable, supported the null hypothesis of non-autocorrelation. Heteroscedasticity is unlikely to be a problem in the current form of time-series regression analysis.

B. Empirical Results

The estimates of the elasticities of the exploration equations are highly significant at the 5% level. The price of undeveloped reserves is important in influencing all categories of exploration expenditures, and especially land acquisitions (equation 3). This is a likely result since a fall in undeveloped reserve prices would be thought to have its greatest short-run impact on the first stage of the exploration process, land acquisitions. The short-run production elasticities are found to be of similar magnitude for all the exploration expenditure regressions. The estimated coefficients on the lagged endogenous variables indicate that exploration expenditures adjust relatively slowly. Land acquisitions and rentals adjust the fastest, then geological and geophysical expenditures, and finally expenditures for exploratory drilling. This is reassuring since the speed of adjustment occurs in the same sequence as the oil and gas exploration stages.

Table I
Alberta Petroleum Industry Expenditure Regressions

ENDOGENOUS	EXPLANATORY VARIABLES				R2	$\bar{R}2$	SSE	D.W.	DURBIN h	n	PERIOD
	Expenditures for Exploration										
1. GEOG1	C	RESU	PRODW	GEOG1(-1)							
	-.7648	.1953*	.1359*	.6583*	.87	.85	.7559	1.87	.38	22	1960-81
	(0.67)	(2.63)	(1.75)	(4.87)							
2. DRIL1	C	RESU	PRODW	DRIL1(-1)							
	-1.791*	.1657*	.1294*	.8914*	.96	.95	.4706	1.87	.32	22	1960-81
	(2.02)	(2.55)	(2.25)	(10.90)							
3. LAND1	C	RESU	PRODW	LAND1(-1)							
	.6370	.3432*	.1227*	.5376*	.84	.81	.8780	1.92	.22	22	1960-81
	(0.56)	(3.95)	(2.03)	(4.44)							
4. TOT1	C	RESU	PRODW	TOT1(-1)							
	-.5165	.2495*	.1282*	.7328*	.95	.94	.3571	1.51	1.25	22	1960-81
	(.72)	(4.47)	(2.97)	(8.95)							
	Expenditures for Development										
5. DRIL2	C	RESD2	PRODW	DRIL2(-1)							
	-2.136*	.1393	.1461*	.8760*	.93	.92	.4943	1.80	.60	25	1957-81
	(3.01)	(1.61)	(2.96)	(7.88)							
6. FIEL2	C	RESD1	PRODW	FIEL2(-1)							
	-5.725*	.2135*	.4198*	.4998*	.96	.95	.6878	2.26	-.96	25	1957-81
	(3.57)	(2.72)	(3.65)	(3.39)							
7. SEC2	C	NETW	PRODW	SEC2(-1)							
	-4.199*	.1853	.2873*	.5460*	.82	.79	2.274	1.62	1.42	25	1957-81
	(1.74)	(1.13)	(2.12)	(3.69)							
8. NAT2	C	LNETg+	LPROg+	NAT2(-1)							
	-1.148	.2045*	.2045*	.4292*	.74	.72	6.795	2.66	-2.78	28	1954-81
	(0.86)	(2.18)	(2.18)	(2.93)							
9. TOT2	C	RESD1	PRODW	TOT2(-1)							
	-1.413*	.1786*	.2058*	.6077*	.92	.91	.5100	2.27	-.95	25	1957-81
	(2.08)	(2.80)	(3.11)	(4.25)							

Notes to Table I

1. All regressions were performed using ordinary least squares.

2. The bracketed values are the absolute t-ratios.

3. * indicates significance at the 5% level.

4. + the coefficients of LNETg and LPROg are constrained to be equal, implying that gas cash flow is the important variable here.

5. Variable Names and Descriptions:

Endogenous Variables (all expenditure data are in $ millions)

GEOG1 - log(geological and geophysical expenditures/ISPI)
DRIL1 - log(drilling expenditures/ISPI)
LAND1 - log(expenditures for land acquisitions and rentals/ISPI)
TOT1 - log(total expenditures for exploration/ISPI)
DRIL2 - log(development expenditures for drilling/ISPI)
FIEL2 - log(development expenditures for field equipment/ISPI)
SEC2 - log(development expenditures for secondary recovery/ISPI)
NAT2 - log(development expenditures for natural gas plants/ISPI)
TOT2 - log(total expenditures for development/ISPI)
- when (-1) appears with the above this implies a one year lagged endogenous variable.

Exogenous Variables

C - intercept term
ISPI - industrial selling price index (1981=100)
INTo - oil intent ratio
INTg - gas intent ratio (1-INTo)
COMo - oil completion ratio
COMg - gas completion ratio (1-COMo)
RESo - price of developed crude oil reserves/ISPI ($/barrel)
RESg - price of developed natural gas reserves/ISPI ($/mcf)
URESo - price of undeveloped crude oil reserves/ISPI ($/barrel)
URESg - price of undeveloped natural gas reserves/ISPI ($/mcf)
PRODo - crude oil production (barrels)
PRODg - natural gas production (mcf)
NETg - gas netback/ISPI ($/mcf)
NETo - oil netback/ISPI ($/bbl)
RESD1 - INTo x log(RESo) + INTg x log(RESg)
- weighted price of developed reserves (based on intent ratios)
RESD2 - COMo x log(RESo) + COMg x log(RESg)
- weighted price of developed reserves (based on completion ratios)
RESU - INTo x log(URESo) + INTg x log(URESg)
- weighted price of undeveloped reserves (based on intent ratios)
PRODW - COMo x log(PRODo) + COMg x log(PRODg)
- weighted production variable (based on completion ratios)
NETW - COMo x log(NETo) + COMg x log(NETg)
- weighted netback variable (based on completion ratios)
LNETg - log(NETg)
LPROg - log(PRODg)
log - natural logarithm

6. Sources: The expenditure and production data were obtained from the 1981 Canadian Petroleum Association (CPA) Statistical Handbook. The intent and completion ratios were taken from Uffelmann and Eglington (1983). The reserves prices and netbacks were taken from Uhler and Eglington (1983), and the ISPI from Statistics Canada, Cansim #D 500000.

The components of development expenditures are more difficult to explain than those for exploration although the estimates for total development expenditures (equation 9) are fairly robust. The development drilling equation estimate of the reserve price elasticity (equation 5) is just under the critical point corresponding to the 5% level. Notice that the reserve price series used in this regression uses completion ratios rather than intent ratios to weight together the separate oil and gas components. Again, as in the exploratory drilling equation, the adjustment estimate is very large at .8760. A negative shock affecting oil and gas exploration and development would seem to have its slowest impact on both exploratory and development drilling.

For the field equipment regression (equation 6) production has the greatest elasticity as expected. The hybrid price for developed reserves using intent ratios was significant in this regression. Estimates for equations 7 and 8 were difficult to obtain as the results indicate. In the secondary recovery and pressure maintenance equation, a completion ratio weighted netback was used rather than a reserve price. This is because these expenditures are really related to production rather than to the establishment of developed reserves. In equation 8, the Durbin-Watson and Durbin h statistics are within the rejection bounds for non-autoregression. An adjustment for serial correlation, however, did not improve the equation so the problem is most likely that of omitted variables. The interesting observations on equation 8 are that gas netbacks and gas production are used as regressors, in fact in constrained (ie. multiplicative) cash flow form. Gas plant expenditures pertain only to gas production, and therefore the gas netback is the appropriate price variable to use. Evidently development expenditures for natural gas plants are sensitive to production levels.

Comparing the total expenditures for exploration and development three observations are readily apparent. First, reserve prices (undeveloped) are more important with respect to exploration expenditures. Second, expenditure levels are more sensitive to production on the development side. Finally, the adjustment process is somewhat slower for exploration. This is most likely the consequence of the large time lags between the exploration and production stages when proving up reserves. The size of these lags may have something to do with the existence of previously undertaken exploration commitments, especially with respect to exploratory drilling. Whether or not development expenditures are themselves responsive to previous exploration success is an hypothesis that we have not directly tested.

Table II

Long Run Expenditure Elasticities

	Reserve Price*	Production
Exploration		
geological and geophysical	0.57	0.40
	(2.35)	(2.68)
drilling	1.53	1.19
	(1.60)	(1.88)
land acquisition and rental	0.74	0.27
	(4.02)	(2.24)
total exploration	0.93	0.48
	(3.80)	(3.44)
Development		
drilling	1.12	1.18
	(1.72)	(1.41)
field equipment	0.43	0.84
	(3.19)	(9.94)
secondary recovery	0.41	0.63
	(1.11)	(3.38)
natural gas plants	0.36	0.36
	(3.78)	(3.78)
total development	0.46	0.52
	(2.81)	(5.40)

* The relevant price for secondary recovery is a (completion ratio) weighted netback and for natural gas plants is simply the gas netback.

+ t-ratios based on asymtotic variances are given in brackets.

Looking at the long run elasticities in Table II above it is apparent that the long run reserve price elasticities are larger on the exploration side whereas the long run production elasticities are somewhat larger on the development side. Overall, the long run price and output responses are relatively inelastic, with the exceptions of both exploratory and development drilling. This leads to an interesting observation, since in the short-run drilling expenditures are overall the least sensitive to prices and output and are the slowest to adjust. Over a longer time horizon, however, drilling expenditures have the largest price and output elasticities in both the exploration and development phases. Drilling activity seems to be very sensitive to the economic rents that may be left in the companies' hands.

As a check on the underlying aggregation involved, the regression estimates for equations 4 and 9 are compared to weighted estimates derived from equations 1 to 3 and 5 to 8, respectively, with weights based on the relative shares of each expenditure category in total expenditures on oil and gas exploration or development, as the case may be, on average over the sample periods used respectively in regression equations 4 and 9. The results are as follows:

TOT1	C	RESU	PRODW	TOT1(-1)
		.2469	.1279	.6991
		(.2495)	(.1282)	(.7328)
TOT2	C	RESD1	PRODW	TOT2(-1)
		.1776	.2504	.6534
		(.1786)	(.2058)	(.6077)

The unbracketed values are the weighted average estimates, whereas the bracketed values are the actual estimates taken from equations 4 and 9. The results show that the estimates do indeed compare reasonably well with those that would be obtained by weighting together the estimates from the underlying component regressions using average relative expenditure shares as weights.

There are two further considerations that should be addressed here. One problem arises because of the specification of our particular regression equations. That is, by estimating the equations by single equation methods it is assumed that the different components of total exploration and development expenditures are independent of each other. This may not be entirely correct since it is, for example, possible to substitute among the three kinds of exploration effort. Uhler (1981) estimated the partial elasticities of substitution between the exploratory inputs and found that drilling and geophysics were substitutes, land and geophysics were complements, and drilling and land were originally substitutes but are now complements. In the present study, no attempt was made to incorporate this type of analysis, largely because of the lack of reliable data on factor input prices.

Another problem that arises is caused by cross-equation error correlations on both the exploration and development sides. That is, the stochastic error components in each equation may not be independent of one another. This statistical problem is easily overcome by estimating each set of equations (1 to 3 on the exploration side and 5 to 8 on the development side) simultaneously using seemingly unrelated regression estimators (SURE). SURE results for the exploration and development models are presented in Table III. Comparing these estimates with the single equation ordinary least squares (OLS) estimates it is apparent that the coefficients remain relatively stable. This was to be expected as OLS estimates are unbiased and consistent even with cross-equation correlations among the error terms. The variances of the coefficient estimates improve only marginally using SURE so the gain in efficiency over OLS is not that large. For this reason, the original OLS estimates were used as the basis for the simulation analysis that follows.

Table III
Alberta Petroleum Industry Expenditure Regressions Using SURE

ENDOGENOUS	EXPLANATORY VARIABLES				SSE	D.W.	DURBIN h	n	PERIOD
	Expenditures for Exploration								
1. GEOG1	C	RESU	PRODW	GEOG1(-1)					
	-.7296	.1931*	.1315*	.6685*	.7561	1.89	.31	22	1960-81
	(0.71)	(2.88)	(1.90)	(5.63)					
2. DRIL1	C	RESU	PRODW	DRIL1(-1)					
	-1.789*	.1655*	.1291*	.8919*	.4706	1.87	.32	22	1960-81
	(2.25)	(2.88)	(2.58)	(13.00)					
3. LAND1	C	RESU	PRODW	LAND1(-1)					
	.7563	.3656*	.1354*	.4790*	.8894	1.86	.38	22	1960-81
	(0.73)	(4.71)	(2.49)	(4.63)					
	Expenditures for Development								
5. DRIL2	C	RESD2	PRODW	DRIL2(-1)					
	-2.232*	.1639*	.1528*	.8709*	.4981	1.81	.54	25	1957-81
	(3.44)	(2.17)	(3.49)	(9.03)					
6. FIEL2	C	RESD1	PRODW	FIEL2(-1)					
	-6.766*	.2618*	.5000*	.3910*	.7069	2.02	-.06	25	1957-81
	(4.84)	(3.82)	(5.05)	(3.11)					
7. SEC2	C	NETW	PRODW	SEC2(-1)					
	-4.058*	.1298	.2854*	.5259*	2.290	1.59	1.32	25	1957-81
	(1.90)	(0.87)	(2.40)	(4.18)					
8. NAT2	C	LNETg+	LPROg+	NAT2(-1)					
	-1.295	.2336*	.2336*	.3439*	6.050	2.17	-1.24	25	1957-81
	(0.98)	(2.54)	(2.54)	(1.83)					

Note: all mnenomics are as described in Table I.

C. Simulation Analysis

As a further check on the validity of our models, static (non-stochastic) and dynamic historical simulations were run on the nine expenditure equations. In this way, the forecasting accuracy or "fit" of the models can be judged through the examination of the ex-post forecast error. Several statistics are useful for this purpose.

One commonly used statistic is the root-mean-square (RMS) simulation error. This is simply a measure of the average deviation of the forecasted variable from its actual value. This statistic can also be decomposed into three terms, each of which represents a different type of forecast error. These include errors due to bias, regression, and disturbance. The bias component is the squared difference between the average predicted value and the average actual value. This represents prediction errors resulting from changes in central tendency and will be zero if average predicted values paralleled average actual values. The regression term is the squared difference between the standard deviations of the predicted series and the actual series. Therefore a value different from zero would represent prediction errors due to unequal variation. Finally, the disturbance term represents errors due to differences in covariation between the predicted and actual changes.[3] The optimal predictor would reduce the bias and regression components to zero so that all the error would be

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[3]H. Theil. Applied Economic Forecasting, Amsterdam: North-Holland Pub. Co., 1966, pp. 19-36.

due to random disturbances which cannot be known a priori (assuming of course that the error term does behave like white noise). Simple correlation coefficients are also often used to measure forecast accuracy. They, however, are not a perfect test since they do not account for systematic linear bias. A third statistic, the Theil inequality statistic, unlike the simple correlation coefficient, penalizes systematic linear bias and tends to zero for optimal forecasts. One final way in which forecasting accuracy can be measured is by simple reference to how well the model reacts to turning points in the actual data.

Table IV
Historical Expenditure Simulation Statistics

		Mean*	RMS*+	Proportion of error due to: bias	regression	disturbance	Correlation Coefficient	Theil Inequality Coefficient
Exploration Expenditures								
1. Geological and Geophysical	Static	207.2	1.20	0	0	1	.932	.017
	Dynamic	207.2	1.24	.005	.020	.975	.912	.020
2. Drilling	Static	329.9	1.16	0	0	1	.980	.013
	Dynamic	329.9	1.19	.013	.001	.986	.972	.015
3. Land Acquisition and Rentals	Static	485.0	1.22	0	0	1	.917	.016
	Dynamic	485.0	1.22	.004	.024	.972	.920	.016
4. Total Exploration	Static	1066.5	1.14	0	0	1	.972	.009
	Dynamic	1066.5	1.15	.001	.058	.941	.969	.010
Development Expenditures								
5. Drilling	Static	335.5	1.15	0	0	1	.962	.012
	Dynamic	335.5	1.25	.010	.001	.989	.900	.019
6. Field Equipment	Static	194.7	1.18	0	0	1	.979	.016
	Dynamic	194.7	1.17	.003	.001	.996	.981	.015
7. Secondary Recovery	Static	37.0	1.35	0	0	1	.904	.041
	Dynamic	37.0	1.43	.004	.007	.989	.863	.049
8. Natural Gas Plants	Static	135.2	1.64	0	0	1	.861	.049
	Dynamic	135.2	1.62	.000	.011	.989	.870	.048
9. Total Development	Static	843.9	1.15	0	0	1	.960	.011
	Dynamic	843.9	1.16	.005	.003	.992	.958	.011

* these estimates were derived by taking the appropriate antilogs and are expressed in millions of 1981 dollars.

\+ RMS refers to the root-mean-square forecast error.

The simulation results are illustrated in Charts III.1 through III.9 and the related forecast statistics are presented in Table IV above. The static simulations differ from the dynamic since they involve only the deterministic part of the model and therefore base the forecast on the previous period's actual value, not on its predicted value as in the dynamic case. In fact, the static forecasts are nothing more than the fitted values of the original regressions.

From the examination of the forecast statistics it is evident that the simulations "track" the actual data quite closely. For the total exploration series the RMS simulation errors are \$1.14 million and \$1.15 million for the static and dynamic simulations, respectively, as compared with a mean expenditure value of \$1066.5 million. Similarly, for total development expenditures the RMS errors are \$1.15 and \$1.16 million, compared with a mean value of \$843.9 million. Judging by the RMS, correlation coefficients, and Theil inequality statistics, the static simulations outperform the dynamic in all but three cases (equations 3, 6, and 8) although the difference is marginal. This result can be explained with reference to the breakdown of the RMS into the three subcomponents. Since the proportion of error attributable to the disturbance component is calculated by regressing the actual relative changes on the predicted relative changes, all the error will be explained by the disturbance component for the static simulations. In the dynamic case, a marginal proportion of the forecast error is due to bias and regression components. Thus the static simulations may be slightly superior. It should be noted that zero bias and regression error components are not sufficient conditions for an optimal predictor because the disturbance term may not be pure white noise because of errors due to omitted variables, autocorrelation, etc. The correlation coefficients are all quite close to unity and the Theil inequality coefficients are very close to zero indicating fairly robust prediction accuracy.

The only exceptions to these findings pertain to the dynamic simulations of three development expenditure categories: drilling, secondary recovery and pressure maintenance, and natural gas plants. In these cases the forecasted values performed poorly in tracking the turning points in the data. This is not surprising since difficulty was encountered earlier when trying to estimate the coefficients, especially those attached to the price variables. It is reassuring that the tracking ability of the total development expenditure simulation is very satisfactory.

Chart III.1
Simulated Geological Expenditures

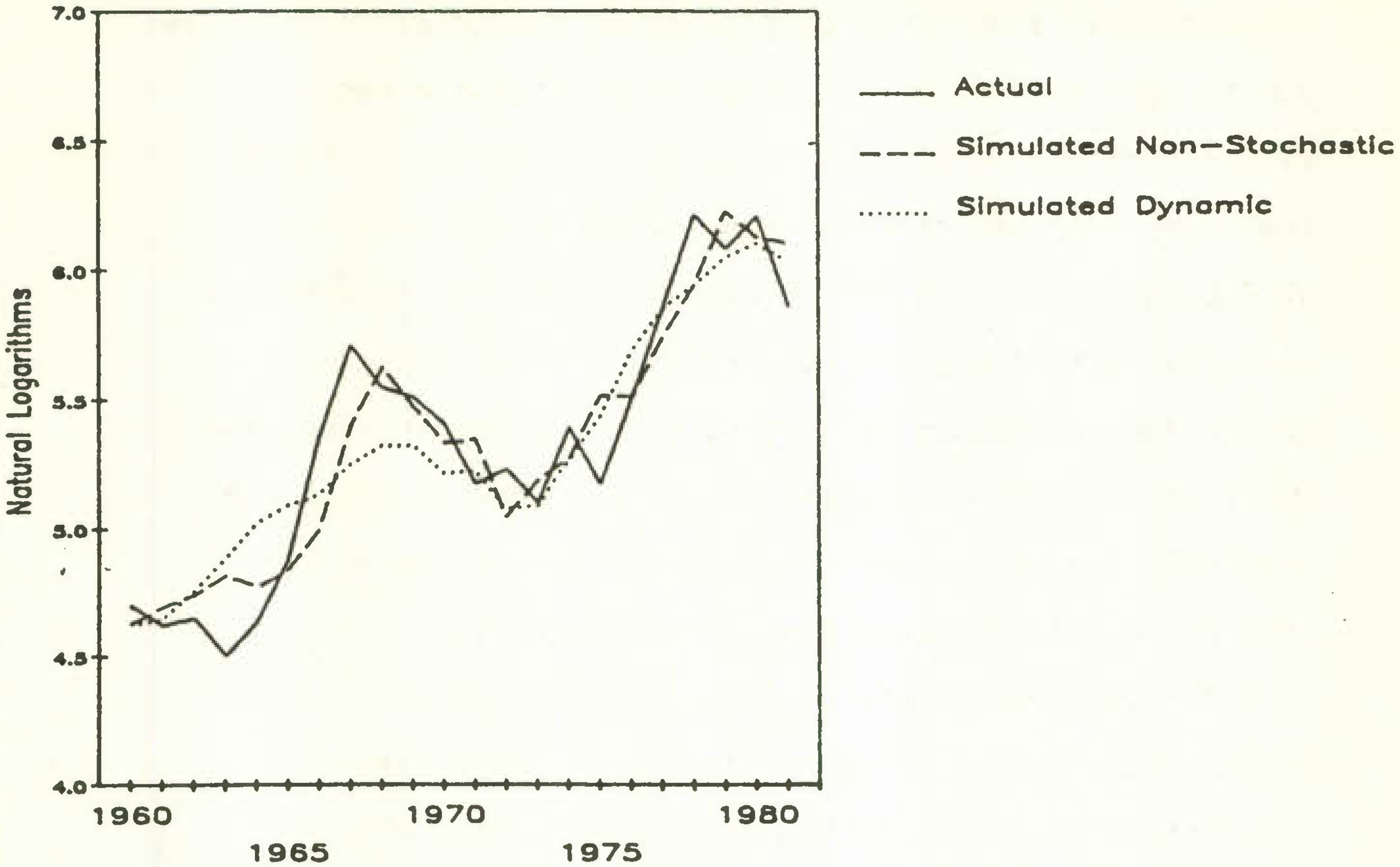


Chart III.2
Simulated Drilling Expenditures (Exploratory)

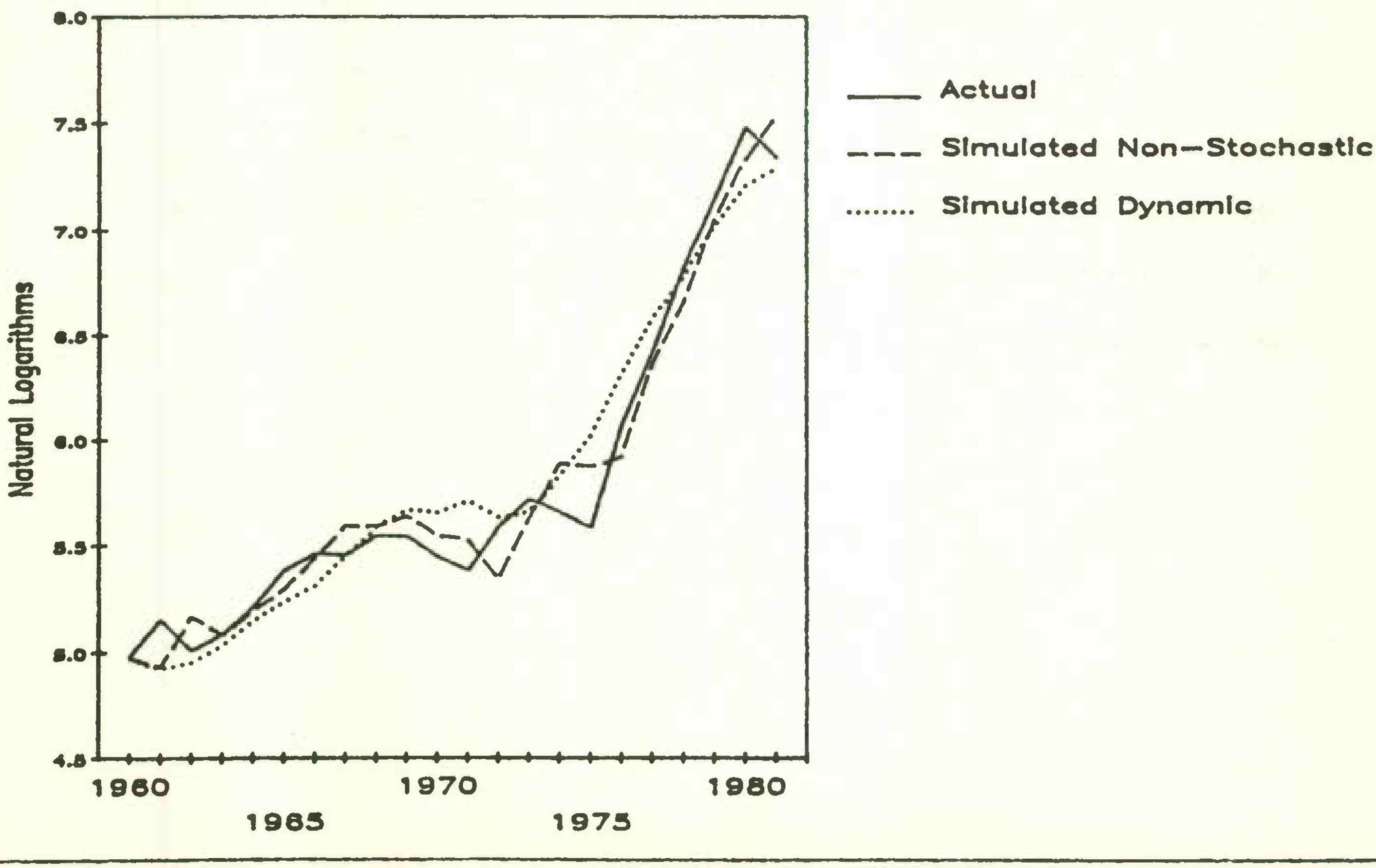


Chart III.3
Simulated Land Expenditures

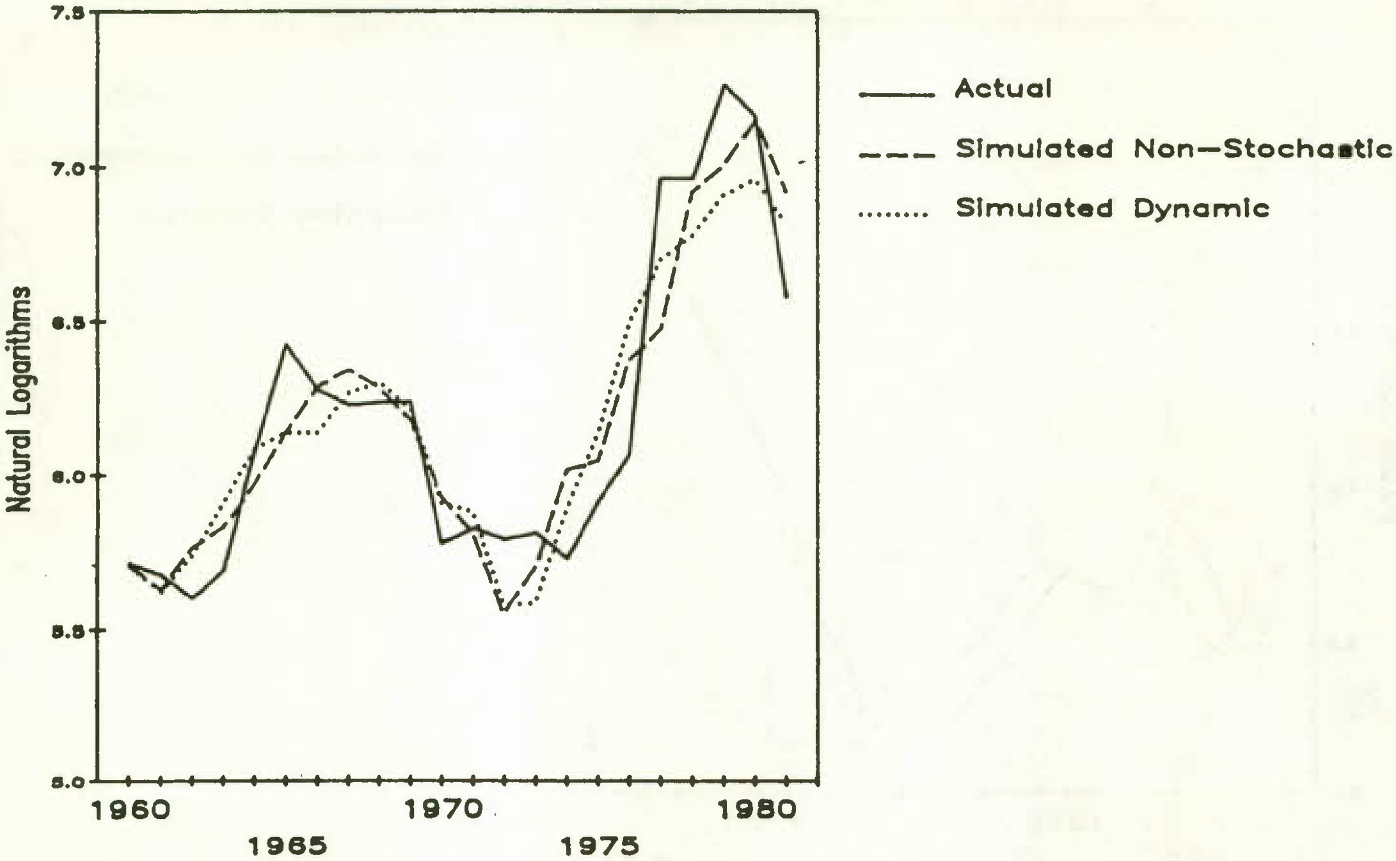


Chart III.4
Simulated Exploration Expenditures
(Total)

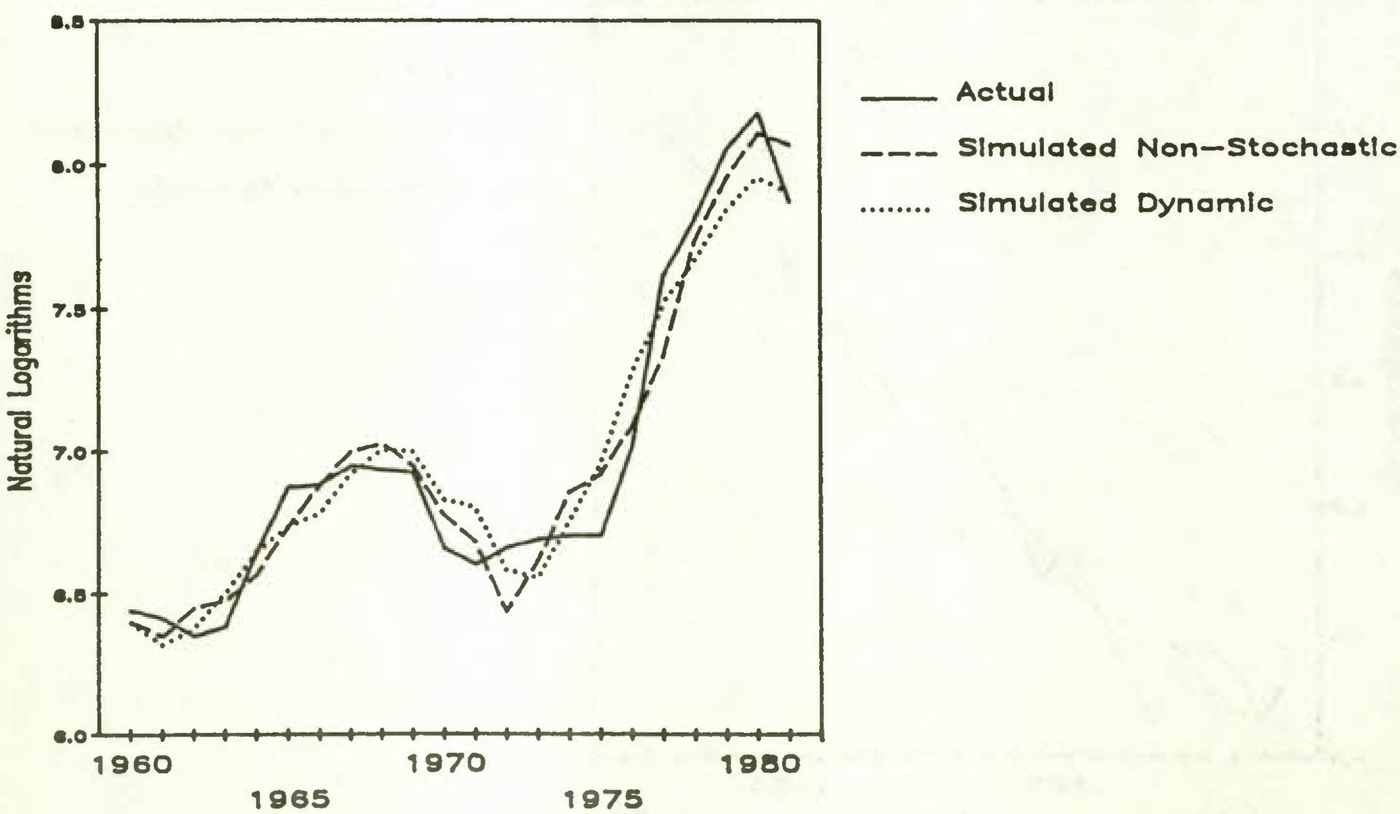


Chart III.5
Simulated Drilling Expenditures (Development)

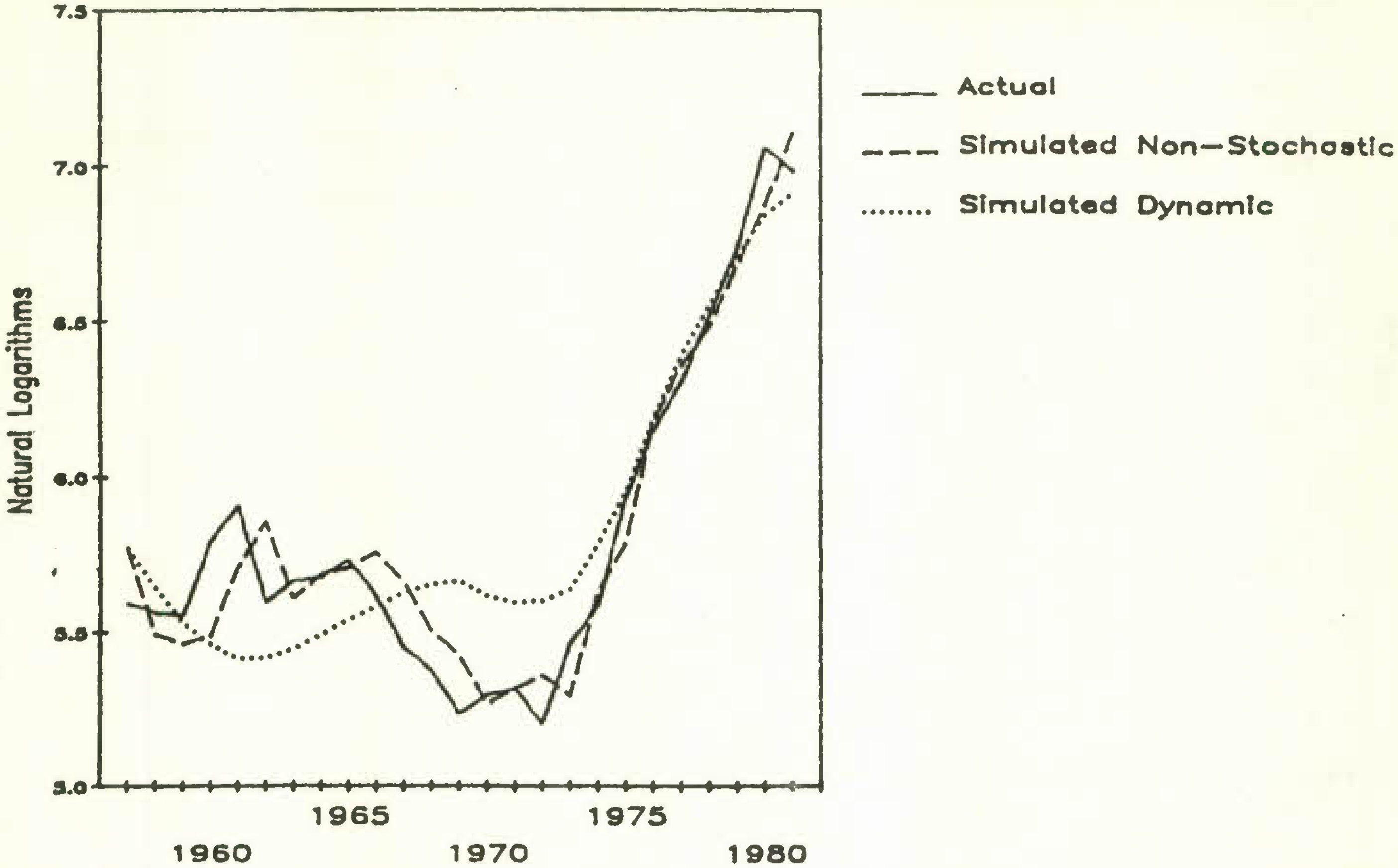


Chart III.6
Simulated Field Equipment Expenditures

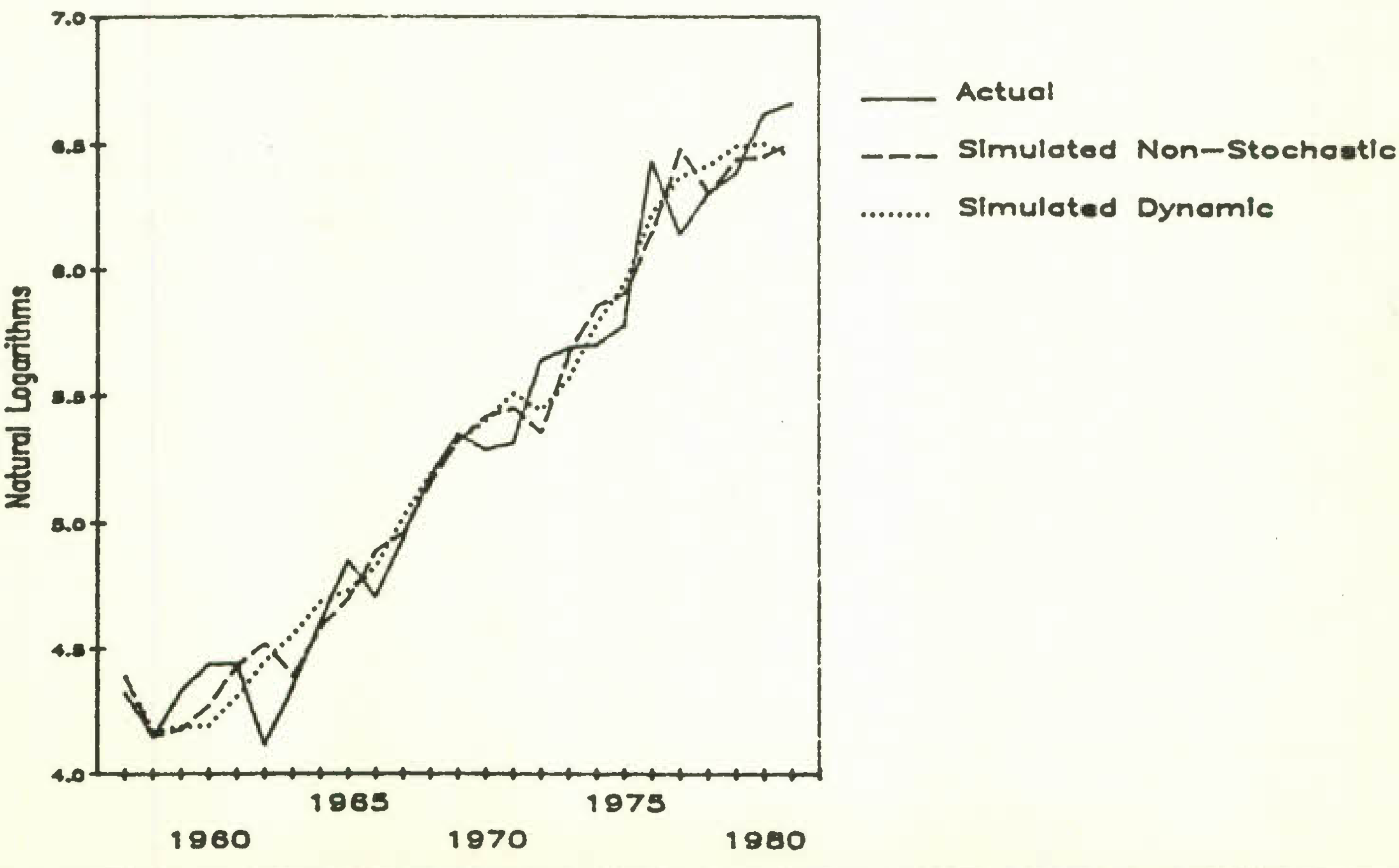


Chart III.7
Simulated Secondary Recovery Expenditures

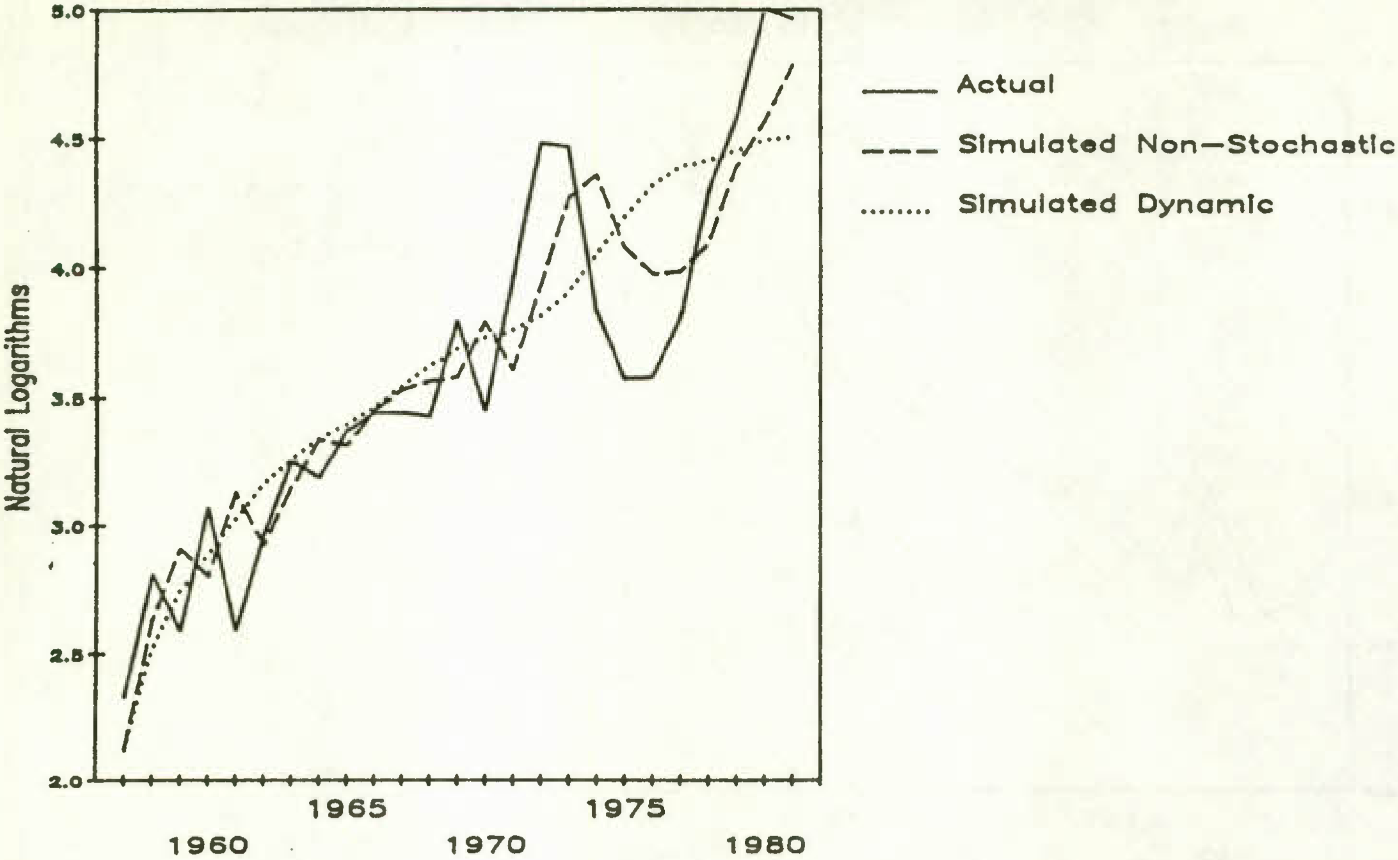
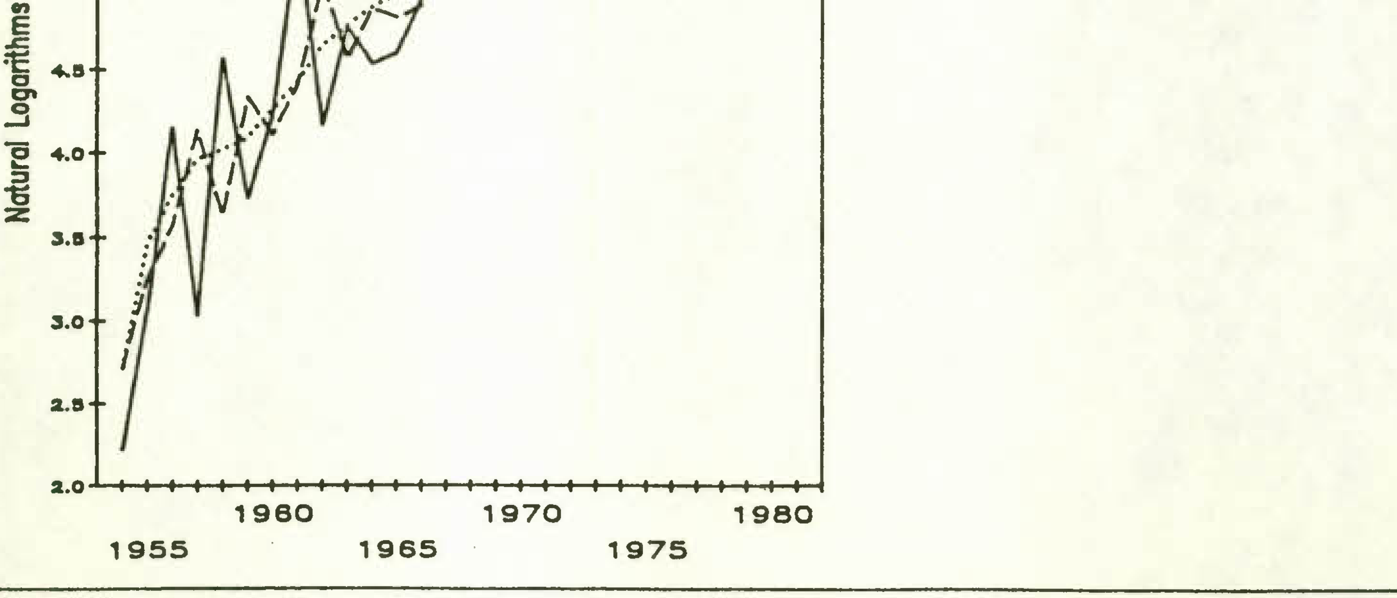


Chart III.8
Simulated Gas Plant Expenditures



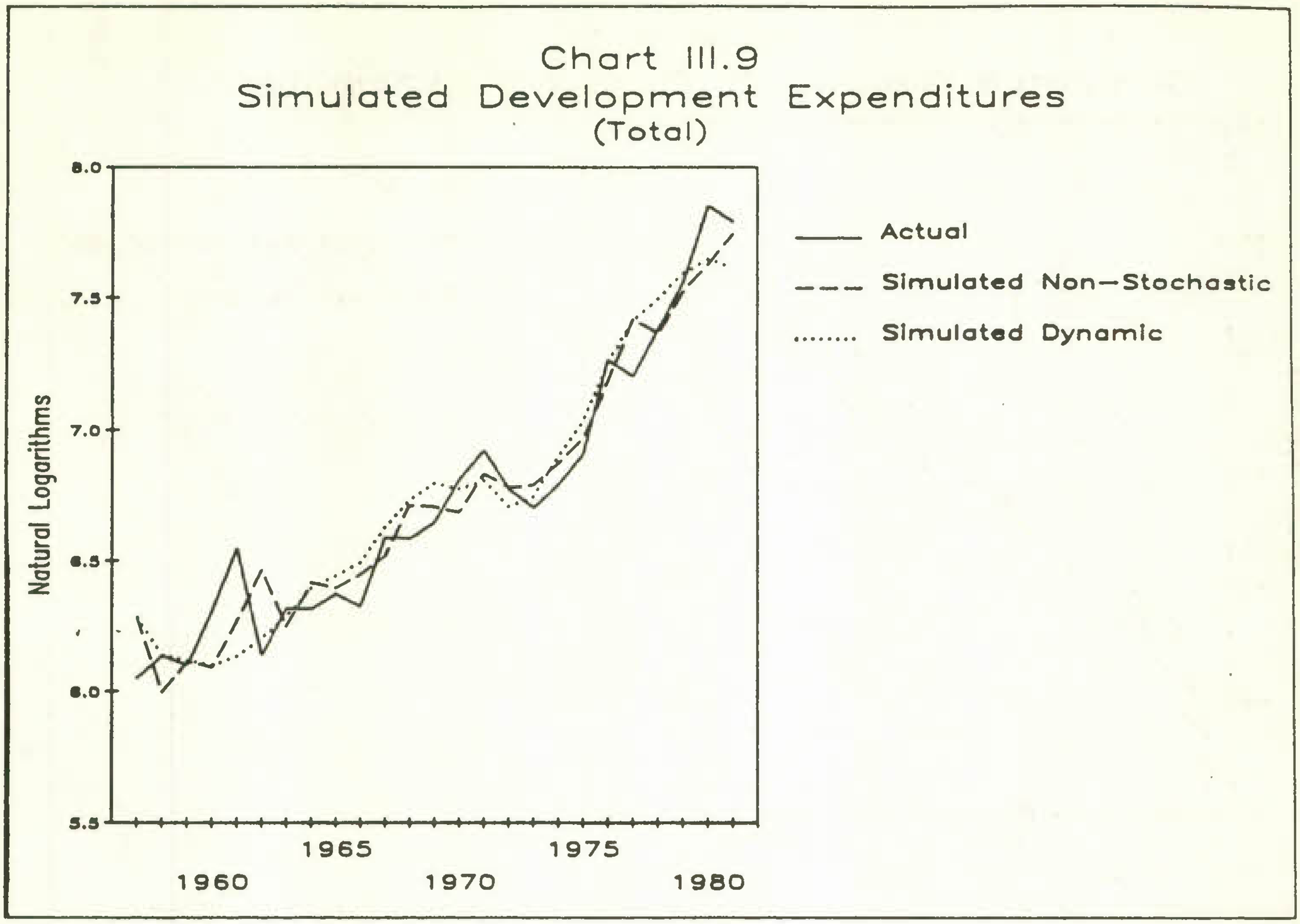


Chart III.9
Simulated Development Expenditures
(Total)
8.0
7.5
7.0
6.5
6.0
5.5
Natural Logarithms
1965
1975
1960
1970
1980
Actual
Simulated Non–Stochastic
Simulated Dynamic

D. Comparison With Cash Flow Models

In the process of obtaining the regression estimates presented in Table I, other variables were tested although in most cases the results were of little consequence. As mentioned earlier, the hybrid production variable used in the nine equations combined oil production in barrels and gas production in mcf. Since this variable is expected to be correlated with cash flow the contention that it was actually proxying cash flow was tested by constructing more elaborate cash flow variables.

The first of these was a straight cash flow variable which was constructed in the following manner,

Cash flow = log{(oil prodn. x oil netback/ISPI)+(gas prodn. x gas netback/ISPI)},

and was then tested in the models along with the reserves price and adjustment variables. Note that this specification eliminates the problem of adding together different units of measurement. These results are listed in Table V for comparison purposes. The regression coefficients were not improved and, in fact, the inclusion of the cash flow variables usually reduced the significance of the reserve price variables, especially on the development side. This pairwise collinearity problem can be explained by the strong intertemporal relationship between reserve prices and netbacks. After all, netbacks are one of the elements used in the construction of the reserve price series.

Table V
Cash Flow Regressions

ENDOGENOUS	EXPLANATORY VARIABLES				R2	$\bar{R}2$	SSE	D.W.	DURBIN h	n	PERIOD
	Expenditures for Exploration										
1. GEOG1	C	RESU	CASH	GEOG(-1)							
	-1.051	.1417*	.1332	.6821*	.86	.84	.7924	1.82	.56	22	1960-81
	(0.69)	(1.93)	(1.45)	(4.86)							
2. DRIL1	C	RESU	CASH	DRIL1(-1)							
	-2.487*	.1194*	.1586*	.8659*	.96	.95	.4882	1.82	.47	22	1960-81
	(1.94)	(1.96)	(2.06)	(9.00)							
3. LAND1	C	RESU	CASH	LAND1(-1)							
	.3565	.2986*	.1280*	.5329*	.83	.81	.9230	1.92	.24	22	1960-81
	(0.25)	(3.44)	(1.75)	(4.14)							
4. TOT1	C	RESU	CASH	TOT1(-1)							
	-1.001	.2027*	.1466*	.7155*	.94	.93	.3803	1.43	1.48	22	1960-81
	(1.10)	(3.71)	(2.68)	(7.87)							
	Expenditures for Development										
5. DRIL2	C	RESD2	CASH	DRIL2(-1)							
	-2.399*	.0860	.1543*	.8529*	.92	.91	.5096	1.74	.82	25	1957-81
	(2.97)	(1.12)	(2.81)	(7.05)							
6. FIEL2	C	RESD1	CASH	FIEL2(-1)							
	-8.030*	.0310	.5032*	.4739*	.95	.95	.7727	2.19	-1.11	25	1957-81
	(3.05)	(0.46)	(3.09)	(2.62)							
7. SEC2	C	NETW	CASH	SEC2(-1)							
	-4.317*	.0470	.2815*	.5352*	.82	.79	2.296	1.67	1.30	25	1957-81
	(1.70)	(0.03)	(2.06)	(3.46)							
8. NAT2	C	LNETg	LPROg	NAT2(-1)							
	-1.148	.2045*	.2045*	.4292*	.74	.72	6.795	2.66	-2.78	28	1954-81
	(0.86)	(2.18)	(2.18)	(2.93)							
9. TOT2	C	RESD1	PRODW	TOT2(-1)							
	-2.142*	.0890	.2167*	.6347*	.91	.90	.5796	2.20	-.89	25	1957-81
	(2.04)	(1.51)	(2.45)	(3.85)							

Note: all mnenomics are as described in Table I, with the addition of CASH = log((PRODo x NETo) + (PRODg x NETg))
CASH2 = log(PRODg x NETg) = LNETg + LPROg

A lagged cash flow variable of the aforementioned type was also tested in order to simulate the ostensible internal budget setting process of the industry. Although it produced slightly better results, these results were still inferior to those obtained using the weighted production variables, and the overall regression equations were not as robust as those we have reported in Table I. The fits were, nevertheless, quite reasonable.

As well, weighted cash flow variables were tried using oil and gas intent ratios and then completion ratios. These attempts did not prove fruitful; nor did lagged versions of them. The only improvement using a cash flow variable was to the natural gas plant expenditure equation which is based only on gas cash flow. In this equation the reserve price variable was omitted, and implicitly replaced by a netback variable.

One further experiment which was tried was to include reserve price variables, cash flow, and production variables. The results indicated a high degree of multicollinearity but, even so, the reserve price variable came through significantly in some of the regression equations (notably 3, 4, 9 and marginally in 1, 2 and 6) and the production variable came through significantly in others (notably 9 and marginally in 6) and was in most instances stronger than the cash flow variable. The following table of correlation coefficients gives some indication of the multicollinearity problem.

Sample Correlation Coefficients

(mnenomics as defined in Tables I and V)

	RESu	RESD1	RESD2	NETw	CASH2	CASH	PRODw
RESu	1.00	0.97	0.84	0.77	0.45	0.30	0.01
RESD1		1.00	0.85	0.81	0.36	0.20	-0.08
RESD2			1.00	0.96	0.02	-0.10	-0.41
NETw				1.00	-0.13	-0.27	-0.57
CASH2					1.00	0.97	0.88
CASH						1.00	0.94
PRODw							1.00

The table of correlation coefficients indicates that the cash flow variable and the weighted production variable are good proxies for each other, but that the production variable is on the whole less highly correlated with the reserve price variables than is cash flow. Thus, when cash flow variables (which include both production and netbacks) are placed in a regression with reserve prices (which are based on netbacks) and production, they tend to become insignificant. From this, one should conclude that the price/quantity separation we have imposed on the basic regression model underlying Table I is the most useful way to proceed.

One should, however, not conclude that cash flow is unimportant in the determination of industry activity levels. On the contrary, given the 0.94 correlation coefficient between the cash flow variable and the weighted production variable, we clearly have an acute identification problem between two alternative hypotheses about the determination of activity levels, the inventory-theoretic replacement investment hypothesis and the cash flow constraint hypothesis. Although we are unable to distinguish these hypotheses clearly, in all instances (except secondary recovery and pressure maintenance and natural gas plant expenditures where netbacks are more important) reserve prices appear to be essential incentive variables. The upshot of all this is that it is very difficult to test for the importance of financial constraints on industry activity levels using a cash flow variable. Nevertheless, while marginally preferring our own inventory-theoretic model, we believe that financial constraints on the industry are important and that our results support this conclusion to a considerable degree.

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.

E. Drilling Costs and Activity Levels

It may be argued, in order to portray petroleum exploration incentives more accurately, that the undeveloped reserve price be deflated by an appropriate cost of drilling index. This proves to be somewhat difficult since a suitable historical drilling cost series is not available. An implicit cost per foot drilled proxy was constructed by taking the ratio of exploratory drilling expenditures to well footage drilled. This was then used to deflate the undeveloped reserve price in the exploration expenditure equations. The resulting estimates, while generally significant at the 5% level, did not improve upon our earlier specificaton. One obvious flaw is that the development drilling expenditures are used as the dependent variable in equation 2 and are highly correlated with the other expenditure categories. Alternatively, of course, one might have double-deflated the expenditure series using this drilling cost proxy, though we decided to come at this question in the following rather different way.

An attempt was also made in this study to explain exploration and development effort using the number of exploratory and development wells drilled (in natural logarithmic form) as the activity variable. This number was separated into oil and gas components using the intent ratios as before. The explanatory variables in this model included the reserve price (either developed or undeveloped), exploration or development costs, and a geometrically distributed lag on wells drilled all in natural logarithmic form. The cost data were obtained from Eglington and Uffelmann (1983). The typical regression was of the form,

$$\ln(\text{Wells drilled})_t = \alpha + \beta_1 \ln(\text{Reserve price})_t + \beta_2 \ln(\text{Cost variables})_t + \beta_3 \ln(\text{Wells drilled})_{t-1} + \mu_t.$$

Estimation of the four equations (oil and gas exploratory drilling and oil and gas development drilling) overall did not produce very strong results so they are not reported here. Suffice it to say that the reserve prices did come through positively and with borderline significance in three of the regressions and a land cost variable came through negatively for the two natural gas regressions. (Land costs, of course, reflect potential economic rents. Since rents may be thought to be a residual category of income, it is not clear that land costs are a suitably predetermined regressor).

One reason the estimation of the model proved to be so difficult was due to a simultaneity problem between the wells drilled and cost variables. In specifying wells drilled as the dependent variable it is assumed that the direction of causality is from land and drilling costs to wells drilled. However, as industry activity increased, as it did in Alberta in the 1970s, input costs escalated; thus the direction of causality was from wells drilled to land and drilling costs. An attempt to correct for this using two-stage least squares proved unsuccessful although when exploration and development costs were regressed on wells drilled and land costs the coefficients were of the right sign and generally significant for natural gas. One further reason for the poor overall results may be due to the fact that wells drilled may be a poor indicator of industry effort. This is due to the obvious facts that all wells are not homogeneous and that costs vary as an increasing function of drilling depth. For this reason, many authors advocate the use of footage drilled as the measure of industry exploration and development effort; but this was not attempted here.

IV. Forecasting the Continuation of the Downturn in Industry Activity into 1982

A. The 1982 Out-of-Sample Forecast

The following table (Table VI) illustrates the decline in exploration and development activity that has occurred in the Alberta sector of the Western sedimentary basin since the announcement of the National Energy Program in the fall of 1980. On the exploration side, the numbers demonstrate that this decline has been nothing short of drastic. The significant 1981 decline in exploration activity worsened into a major tailspin in 1982. Industry development expenditures have also fallen, but to a lesser degree.

Although these numbers may overstate somewhat the real decline in exploration and development activity because real costs have also declined for certain categories of expenditure (and perhaps especially for drilling rig-days), this is of little consolation for those service sectors whose real incomes have been severely undermined in the process. Indeed, there can be no doubt that the decline in oil and gas exploration activity in the province has been one of the main reasons why the recession has been so deep in Alberta, and why the recovery in the provincial economy will lag behind that experienced elsewhere.

Table VI

Industry Activity Levels in Constant 1981 Dollars (millions)

	1980	% change	1981	% change	1982	1982 Nominal
Exploration						
geological	497.0	-29.1	352.2	-12.9	306.7	325.1
drilling	1782.0	-13.4	1543.7	-34.2	1015.4	1076.3
land	1292.9	-44.2	721.3	-39.1	439.2	465.6
total	3571.9	-26.7	2617.2	-32.7	1761.3	1867.0
Development						
drilling	1168.5	-7.3	1083.2	-17.9	889.2	942.5
field equip.	751.8	+4.1	782.7	+1.2	792.1	839.6
secondary rec.	149.1	-4.2	142.9	-12.5	124.9	132.4
nat. gas plants	264.9	+17.4	310.9	+49.8	465.8	493.7
total	2572.2	-6.0	2418.3	-6.1	2271.9	2408.2

Sources: The expenditure data were obtained from the CPA Statistical Handbook and the ISPI price deflators from Statistics Canada, Cansim #D 500000. On the development side, the omission of a small 'other expenditure' category implies that the individual items do not add exactly to total development expenditure.

In addition to running historical simulations on our nine expenditure equations, out-of-sample forecasts were made for 1982 to see whether the models would predict the further downturn in overall industry activity that had commenced in 1981. These forecasts were then compared to the actual expenditure figures for 1982.

Table VII

Assumptions Used in the Simulations

Explanatory Variable	1981	1982
RESo ($/bbl)	4.11	5.09
URESo ($/bbl)	2.43	3.01
RESg ($/mcf)	0.22	0.24
URESg ($/mcf)	0.07	0.08
NETo ($/bbl)	7.85	9.72
NETg ($/mcf)	1.02	1.09
....	.....	...
ISPI	100.0	106.0
INTo	0.52	0.60
INTg	0.48	0.40
COMo	0.325	0.393
COMg	0.675	0.607
PRODo (10^6bbls)	358.6	350.3
PRODg (bcf)	2711.0	2786.0

Sources: the intent ratios were supplied by Russell Uhler and Peter Eglington and the ISPI (1981=100) was taken from Statistics Canada, Cansim #D 500000. Completion ratios were calculated using drilling data taken from the CPA Statistical Handbook and the oil and gas production estimates were obtained from the Alberta Statistical Review, First Quarter, 1983. Notice that the 1982 dollar figures are in nominal terms in this table, and need to be deflated by the ISPI figure of 106.0 to get the corresponding real values.

The assumptions which underly the exploration and development forecasts are presented above in Table VII. There has been an important adjustment that has been made with reference to the Uhler/Eglington oil and natural gas netback series. In 1981, these netbacks were estimated at $10.87/bbl and $1.56/mcf (nominal) for oil and gas respectively. We believe, on the basis of EMR netback figures for old oil and old gas (see Table XII), that these estimates are overstated. Indeed, so much is implicitly admitted by Uhler and Eglington when they say on p.45 of their report that

"the tax changes associated with the NEP all became effective after 1981. Since our data analysis only extends through 1981 oil and gas reserve prices through 1981 are all that are needed for this analysis so we need not incorporate the effects of the NEP."

Whereas certain aspects of the 'agreement-amended NEP' such as NORP prices only began at the beginning of 1982, and certain taxation legislation related to the NEP was not passed until 1981 was almost over, it is incorrect to argue that netbacks and reserve prices in 1981 can be calculated without regard to the pricing and taxation measures contained in the NEP. Hence some adjustment to the 1981 (and implicitly 1982) data is clearly required.

We feel that more appropriate estimates of the 1981 netbacks would be in the $7.85/bbl and $1.02/mcf range. These estimates were derived by regressing the Uhler/Eglington netback series on the EMR netback series for 1975 to 1980 inclusive and then forecasting 1981 on this basis. Although simplistic, this procedure appears to be reasonable on the basis of goodness-of-fit, as measured by the coefficient of determination (R). For example, in the 1975 to 1980 sample period, the coefficients of determination between the EMR series and the Uhler/Eglington series were .80 and .83 for oil and gas, respectively. When the 1981 observations were included the goodness-of-fit dropped to .03 and .48. 1982 netback estimates were derived from the EMR data in a similar manner.

This revision also affects the 1981 undeveloped and developed reserve prices since they are, in effect, discounted netbacks. Re-estimated 1981 values were obtained by taking the ratios of the revised netbacks and the original Uhler/Eglington netbacks, and then multiplying by the 1981 Uhler/Eglington reserve price series. The 1982 reserve prices were also estimated from the 1982 EMR netback data by using a similar procedure. Notice that netbacks (not reserve prices) are the included price variables in the secondary recovery and natural gas plant equations.

With these changes to the 1981 reserve price and netback data, our basic regression equations were re-estimated to the end of 1981, giving the basic equations reported in Table VIII. It should be noticed, not surprisingly, that these re-estimated equations do not differ substantially from those reported in Table I. Static and dynamic within-sample simulations would however demonstrate that they track the 1981 downturn a little better than our original equations, at least on the side of overall exploration activity and its various component parts. We then proceeded to forecast the 1982 activity levels using these revised and re-estimated equations. This out-of-sample forecast uses the basic 1982 data contained in Table VII.

The resulting forecasts under the assumptions outlined above are presented in the following table (Table IX). As mentioned previously, static forecasts are based upon the previous period's actual value whereas dynamic forecasts are based upon the previous period's predicted value and, as such, incorporate a stochastic forecast error component. Overall, these figures are a striking contrast to those derived from the historical simulations in which the RMS forecast errors were between one and two million dollars.

Table VIII
Revised Expenditure Regressions

ENDOGENOUS	EXPLANATORY VARIABLES				R2	$\bar{R}2$	SSE	D.W.	DURBIN h	n	PERIOD
	Expenditures for Exploration										
1. GEOG1	C	RESU	PRODW	GEOG1(-1)							
	-.7691	.2026*	.1333*	.6709*	.87	.85	.7253	1.92	.24	22	1960-81
	(0.69)	(2.82)	(1.77)	(5.17)							
2. DRIL1	C	RESU	PRODW	DRIL1(-1)							
	-1.768*	.1680*	.1244*	.9060*	.96	.96	.4489	1.91	.23	22	1960-81
	(2.05)	(2.77)	(2.26)	(11.95)							
3. LAND1	C	RESU	PRODW	LAND1(-1)							
	.5125	.3506*	.1236*	.5568*	.85	.83	.8026	2.04	-.11	22	1960-81
	(0.47)	(4.34)	(2.15)	(4.97)							
4. TOT1	C	RESU	PRODW	TOT1(-1)							
	-.5968	.2500*	.1245*	.7561*	.95	.94	.3258	1.54	1.15	22	1960-81
	(.88)	(4.86)	(3.04)	(10.10)							
	Expenditures for Development										
5. DRIL2	C	RESD2	PRODW	DRIL2(-1)							
	-2.208*	.1376*	.1457*	.8902*	.93	.92	.4839	1.80	.58	25	1957-81
	(3.11)	(1.76)	(3.13)	(8.99)							
6. FIEL2	C	RESD1	PRODW	FIEL2(-1)							
	-5.364*	.1974*	.3908*	.5425*	.96	.95	.7147	2.26	-.93	25	1957-81
	(3.38)	(2.52)	(3.45)	(3.78)							
7. SEC2	C	NETW	PRODW	SEC2(-1)							
	-4.011	.1727	.2760*	.5605*	.82	.79	2.304	1.60	1.48	25	1957-81
	(1.66)	(0.99)	(2.05)	(3.80)							
8. NAT2	C	LNETg+	LPROg+	NAT2(-1)							
	-1.203	.2082*	.2082*	.4264*	.74	.72	6.794	2.66	-2.78	28	1954-81
	(0.88)	(2.18)	(2.18)	(2.89)							
9. TOT2	C	RESD1	PRODW	TOT2(-1)							
	-1.403*	.1720*	.1927*	.6458*	.92	.91	.5161	2.28	-.96	25	1957-81
	(2.05)	(2.73)	(2.99)	(4.72)							

Note: all mnenomics are as described in Table I.

Table IX

1982 Expenditure Forecasts in Millions of Constant 1981 Dollars

	Actual	Static	Dynamic
Exploration Expenditures			
1. Geological	306.7	355.5	387.1
2. Drilling	1015.4	1667.6	1595.9
3. Land Acquisition	439.2	751.1	819.0
4. Total Exploration	1761.3	2584.0	2587.7
Development Expenditures			
5. Drilling	889.2	1122.4	1048.0
6. Field Equipment	792.1	664.2	579.0
7. Sec. Recovery	124.9	110.1	82.4
8. Nat. Gas Plants	465.8	322.6	336.0
9. Total Development	2271.9	2255.5	2004.1

Note: The sums of the static and dynamic forecast elements on the exploration side are 2774.2 and 2802.0, respectively, even further out of line with actual total exploration activity than the static and dynamic forecasts for total exploration. The sums of the static and dynamic forecast elements on the development side are 2219.3 and 2045.4, respectively, not that far removed from the static and dynamic total development equation forecasts.

On the exploration side, real expenditures are grossly overstated. This may be the result of the overestimation of the reserve prices even after being adjusted downward for 1982, especially when high real interest rates are factored into the reserve price equation. But even if they are, the extent of the downturn remains seriously under-predicted by our regression equations. Also, in 1982 oil production dropped by 2.3% below its 1981 level, and gas production increased by 2.8% over 1981. Therefore, even though exploration expenditures continued to fall in 1982, the fall cannot be explained by changes in production volumes.

Looking to the development side, the forecasts are much better. Development drilling expenditures are over-predicted, but the remaining categories and total development expenditures are under-predicted. The static forecast for total development expenditures is not far off the mark. Note once again that Equations 7 and 8 (secondary recovery and natural gas plants) involve netback assumptions not reserve prices.

The static and dynamic forecasts differed by a substantial amount in all equations, indicating a large stochastic component in the 1982 forecast. This was due in part to the fact that the 1981 simulated values often differed substantially from their actual values and therefore augmented the dynamic forecast error for 1982. One further observation that is generally consistent in all the equations is that the equations with the slowest adjustment coefficients produced the largest (relative) forecast errors. This partly explains why the development expenditure forecasts were overall superior to the exploration expenditure forecasts. In normal times, petroleum industry activity levels seem to possess a strong 'inertia effect'. Strong negative shocks to the industry have apparently broken this effect and have caused our models to underpredict the fall in activity levels.

One hypothesis that leads one to suspect that the lag structure is not invariant over time, at least when there are substantial negative shocks, is the following. Suppose that firms have a particular view as to the total cumulative exploration activity on any given drilling site which is justified on the basis of current exploration cost and undeveloped reserve prices. Actual exploratory activity on the site is explained by a partial adjustment approach to its desired cumulative value. As long as reserve prices do not fall sharply, this process may work smoothly. However, a sharp decline in reserve prices will lead to a complete curtailment in exploration activity on some drilling sites since actual cumulative activity may suddenly exceed its desired level. Allowing for variability in the quality of drilling sites, this asymmetry may generate a sharp drop in aggregate exploration activity without activity completely ceasing on all sites. Our fixed parameter geometric lag structure clearly fails to capture this form of asymmetry if it occurs.

Finally, it is clear that we might more appropriately have based our undeveloped reserve price incentive variables in 1982 on NORP oil prices rather than the conventional crude oil prices. However, this clearly would not have generated more accurate out-of-sample forecasts for 1982 on the exploration side.

B. Commentary on the 1982 Forecast Results

Since our regression equations failed to forecast the depth of the downturn in industry activity in 1982, we can only speculate that the unexplained depth of this downturn (if not explained by asymmetrical lag patterns) reflects variables that were omitted from our equations. These variables are partly financial and partly expectational in nature. What, then, might some of these omitted variables be?

First, financial variables were very important in both 1981 and 1982. The build up of such a large volume of debt in the upstream portion of the industry after the NEP, coupled with unusually high interest rates, undoubtedly cut into exploration budgets. More specifically, the high interest charges facing the highly levered industry (especially the Canadian controlled companies) have induced the members of the industry to commit existing cash flows to putting their balance sheets in order, especially in the upstream (but also, to a lesser degree, in the downstream) segment of the industry. This is particularly evident in Charts V.3 and V.9 where the debt/equity ratios and interest/operating expense ratios peak in 1982-Q2 and 1982-Q3, respectively, and begin declining sharply thereafter. We shall have more to say about these data in the following section.

Table X

Ratio of Capital Expenditures to Internal Cash Flow (%)

	Upstream(a)		Petroleum-Related(b)	
	1981	1982	1981	1982
Integrated	94	72	84	106
Senior Companies				
Canadian Controlled	122	89	123	98
Foreign Controlled	80	64	80	63
Junior Companies				
Canadian Controlled	212	128	251	165
Foreign Controlled	266	189	260	185
Total Industry	116	85	110	104
Canadian Controlled	141	97	145	111
Foreign Controlled	99	77	90	100

Notes: (a) Upstream capital expenditures (net of PIP and other incentive payments) in Canada as a percentage of upstream cash flow.

(b) Petroleum-related (upstream plus downstream) capital expenditures in Canada as a percentage of internal cash flow generated by petroleum-related activities.

Source: Petroleum Monitoring Agency Canada, Canadian Petroleum Industry Monitoring Survey 1982, Ottawa: Supply and Services Canada, 1983, Appendix B-9.

Table X, which is taken from the PMA's 1982 Monitoring Survey, further shows that the industry's attempt to become less levered in 1982 led to a reduction of its ratio of capital expenditures to cash flow returns, or its re-investment ratio. This is especially true for the Canadian-controlled firms who were induced in 1981 to take on increasing debt loads to finance takeover activities under the 'Canadianization' aspects of the NEP.

Moreover, the implementation of discriminatory payments under the petroleum incentives program (PIPs) has caused higher cost frontier resource developments to be encouraged at the expense of potentially lower cost ones in the Western Canadian sedimentary basin. Indeed, exploration expenditures in the Canada Lands increased by 40% in 1982, while decreasing by 29% in the Western provinces for the same period.[3] Serious questions can be raised about the economic efficiency costs of going after more expensive sources of supply before cheaper sources have been fully explored and developed. But, in any case, the distortions caused by the PIP program would have important consequences for our 1982 expenditure forecasts. More generally, the 'opportunity cost' of exploration activity in the Western sedimentary basin in terms of foregone exploration activity elsewhere (including the United States) has not been properly modelled in our regression equations. However, insofar as this 'opportunity cost' effect is significant, it also must imply that cash flow (or possibly other) constraints on company-wide activities, regardless of location, are important.

Industry expectations are also a very important ingredient in explaining the downturn in exploration and development activity. Reserve prices were eroded not only because interest costs went through the roof shortly after

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[3] Petroleum Monitoring Agency Canada, Canadian Petroleum Industry Monitoring Survey 1982, Ottawa: Supply and Services Canada, 1983, Appendix B-7 and B-8.

the Canadian-controlled section of the industry was induced to become heavily leveraged by the excess borrowing generated by the 'Canadianization' aspects of the NEP, but also because the expectation that netbacks would expand along with world crude oil prices and with U.S. and domestic natural gas prices was dramatically falsified by both the original NEP and the fall 1981 Energy Agreements, as well as with the reversal in these price movements themselves. Although the NORP prices introduced under the Energy Agreements should have improved the incentive to find new oil reserves, the illiquid position in which many participants in the industry found themselves combined with the sluggish state of natural gas markets in the United States further undermined exploration activities. Gas discoveries which cannot be hooked up to any foreseeable market area for the next three or four years are unlikely to command much in the way of net present value.

Not only did the NEP falsify producers' expectations regarding their share of petroleum revenues, the long bitter battle between the federal and provincial governments, which eventually led to the signing of the September 1, 1981, Memorandum of Agreement between Ottawa and Alberta and the subsequent agreements with other producing provinces, not only increased speculation and uncertainty but in the end resulted in little improvement for the industry. Indeed, the agreement generated higher wellhead prices for oil and gas but further worsened the tax position faced by the industry.

The measures provided by the NEP Update and (more especially) the OGAP announcements in the spring of 1982 by themselves would have helped to reverse the downwards trend in industry expectations, but now the industry has had to face falling world oil prices and a diminishing export market for natural gas.

Finally, the Canada-Alberta amending agreement of June 30, 1983, should provide good stability to industry expectations. The main thrusts of that agreement were (a) to freeze the wellhead price of conventional crude oil (COOP) discovered before April 1, 1974, at $29.75 per barrel while this price lies within the 75-100% of world oil price band, (b) to freeze the Toronto city gate price of natural gas at 65% of the 'blended' price of oil, with the natural gas and gas liquids tax (NGGLT) being finally reduced to zero on February 1, 1984, to accommodate a smaller-than-scheduled increase (ie. more or less $.16 per mcf rather than $.25 per mcf) in the Alberta border price of natural gas, which will then remain unchanged until at least February 1, 1985, (c) to extend the new oil reference price (NORP) to all oil discovered after March 31, 1974 (SOOP oil), and to all production from infill drilling within pre-NORP entities, (d) to maintain a substantial petroleum compensation charge (PCC) and Canadian ownership charge (COSC) in effect until further notice, thereby providing a continuation of the sizeable wedge between the conventional wellhead price and the blended price of oil, and (e) to leave intact the existing provincial royalty rates and federal petroleum and natural gas revenue tax (PGRT) rates for the foreseeable future. The fact that this agreement took place with a minimum of public confrontation, and the fact that it represents to all concerned a reasonably sensible compromise on the difficult issues of oil and gas pricing and taxation, should reduce the uncertainty and instability of industry expectations. The main problems remaining are the pricing and marketing of natural gas for export to the various regions of the United States, the continuation of the tax wedge between old oil prices and new oil (or world) prices, and the current level of the PGRT, which will become increasingly onerous if (as projected in Table XII) real netbacks decline.

V. Financial Constraints on Oil and Gas Activity Levels

A. Historical Analysis of Financial Ratios

In order to further our understanding of the 1981-1982 downturn in industry activity, in this section we turn our attention to a number of background financial issues related to the petroleum and natural gas industry in Canada. We begin by studying an historical cross-industry comparison of five basic financial ratios, namely

(a) the liquidity (or working capital) ratio, that is current assets divided by current liabilities,

(b) the debt/equity ratio, that is total liabilities divided by total shareholders' equity,

(c) the net income/equity ratio, that is net income after taxes divided by total shareholders' equity,

(d) the base profit/equity ratio, that is base profit - or profit before taxes, interest charges, and certain non-cash expenses like depreciation or depletion - divided by total shareholders' equity, and

(e) the interest/operating expense ratio, that is the ratio of total interest expenses to total operating expenses.

The industries we use for comparative purposes are, first, the mineral fuels industry (which corresponds approximately to the upstream sector of the petroleum and natural gas industry, that is the exploration for and extraction of crude petroleum and natural gas), which we compare with the all industry aggregate statistics, and secondly the petroleum and coal products industry (which corresponds approximately to the downstream sector of the petroleum and natural gas industry, that is the refining and marketing of petroleum and natural gas products), which we compare with the all manufacturing industry aggregate statistics.

Annual averages of quarterly data on these five ratios for the years 1962-Q1 (1963-Q1 for some ratios in the mineral fuels industry) to 1983-Q1 (1982-Q4 for the all industry and all manufacturing aggregates) are plotted on the ten charts V.1 to V.10 that follow. The interest/operating expense ratio charts are shorter, since the data available only span the period from 1972-Q1. There is a rather small break in all the basic series in 1977 due to re-classifications carried out by Statistics Canada in that year. Accompanying these ten charts, we have the basic statistics contained in Table XI. This table shows the arithmetic mean, and in brackets the standard deviation, of each quarterly series over the complete time span of each data set, where for the link year 1977 we have used the new classification data rather than the old data. This lack of exact linkage cannot bias these average ratios very much at all.

Chart V.1
Corporate Liquidity Ratios
Mineral Fuels and All Industries

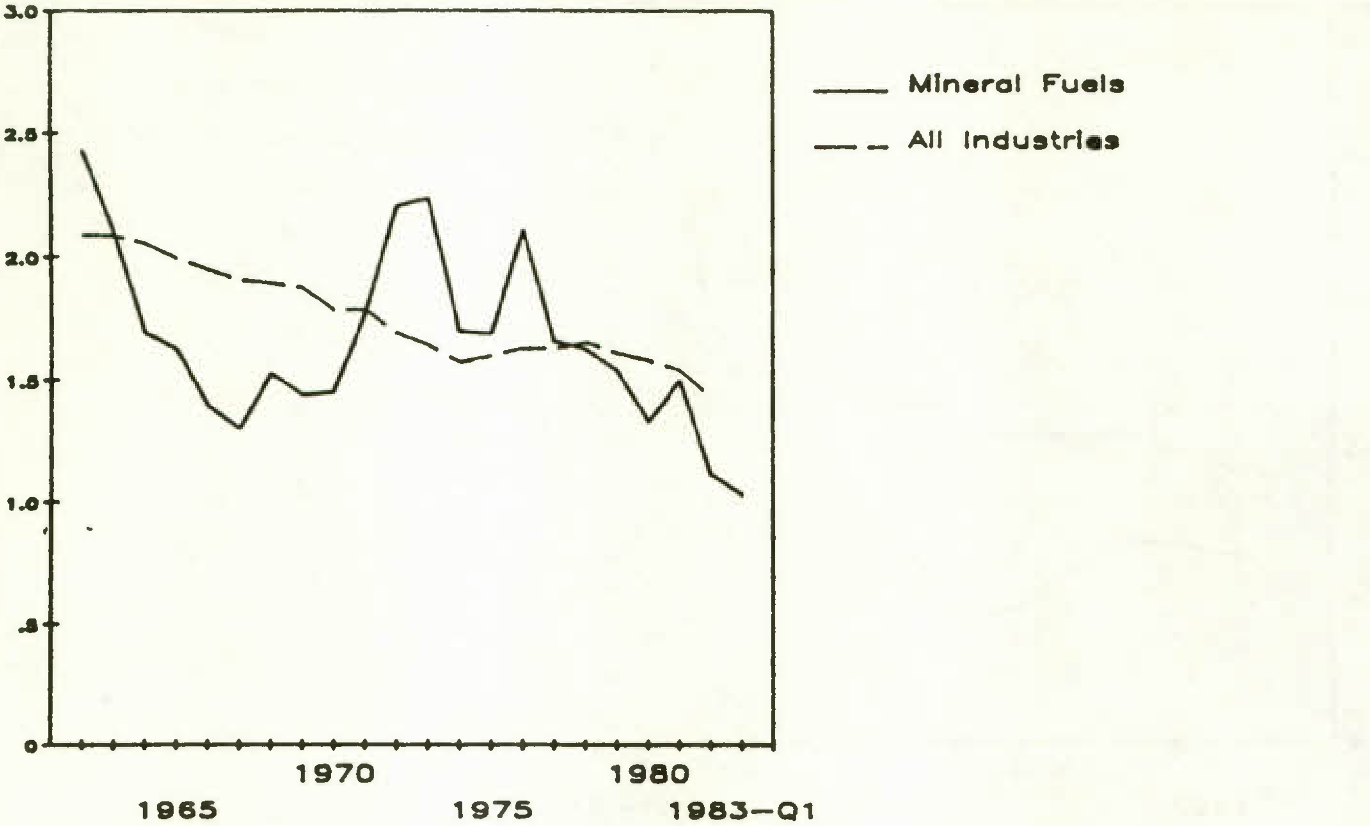

Chart V.2
Corporate Liquidity Ratios
Petroleum & Coal Products and Total Manufacturing

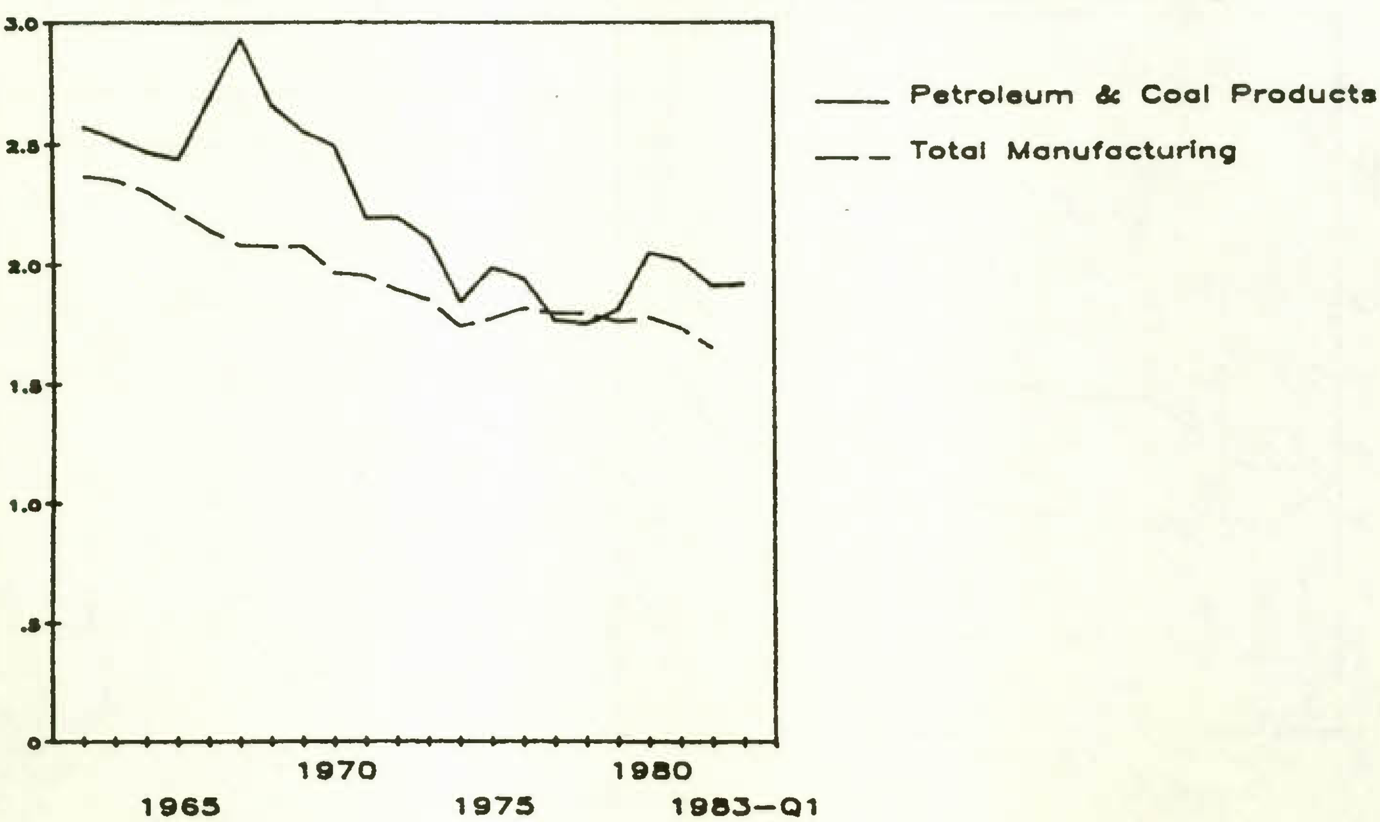

Chart V.3
Debt/Equity Ratios
Mineral Fuels and All Industries

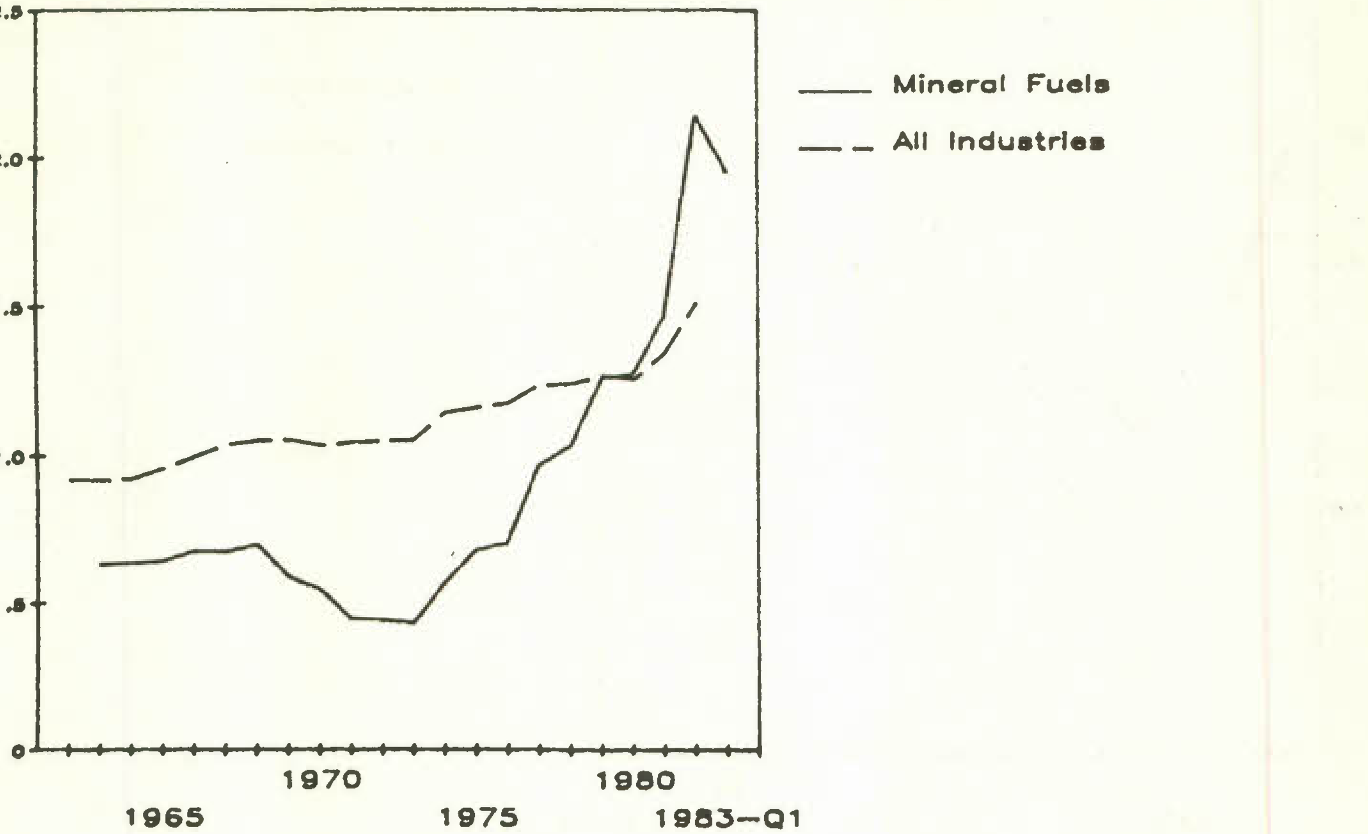

Chart V.4
Debt/Equity Ratios
Petroleum & Coal Products and Total Manufacturing

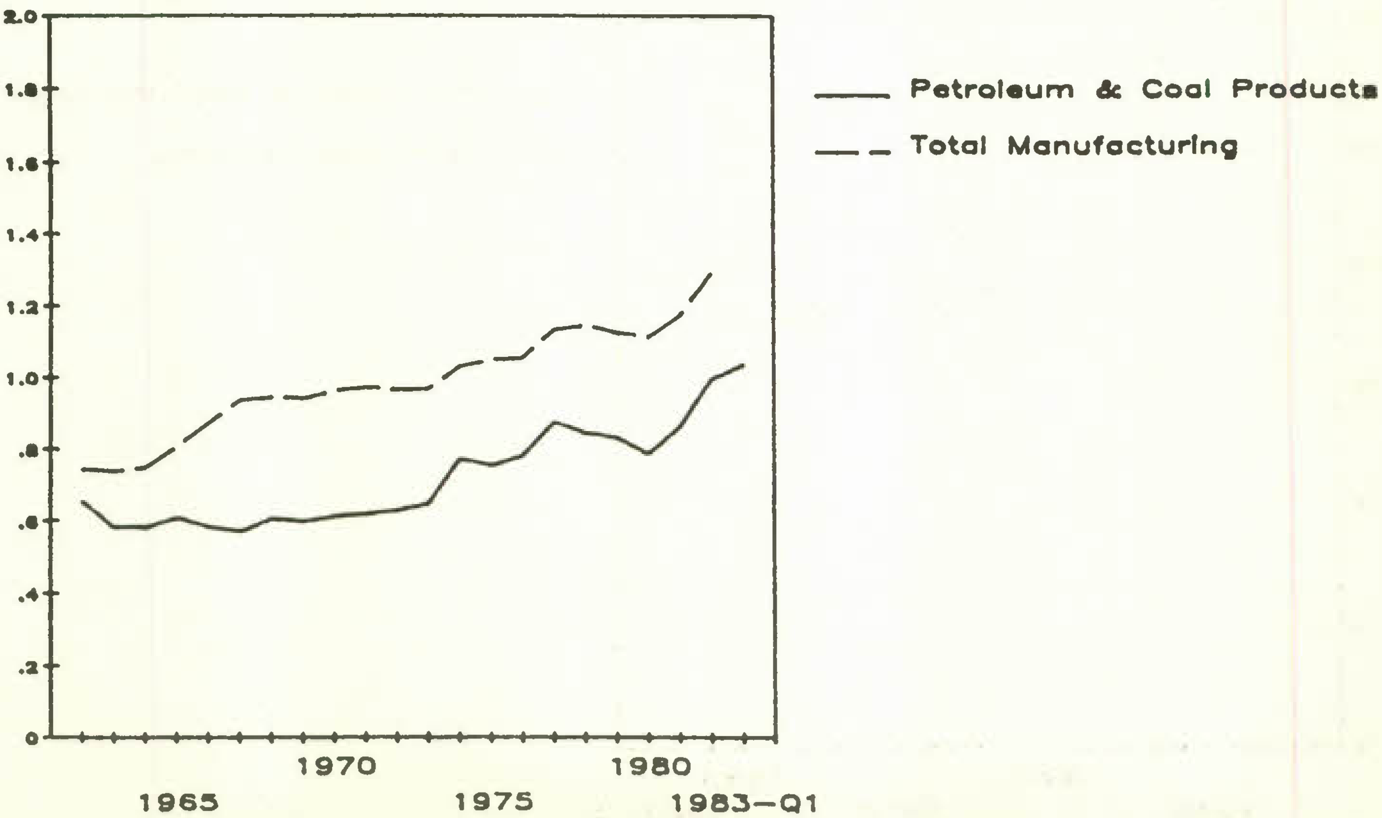

Chart V.5
Net Income/Equity Ratios
Mineral Fuels and All Industries

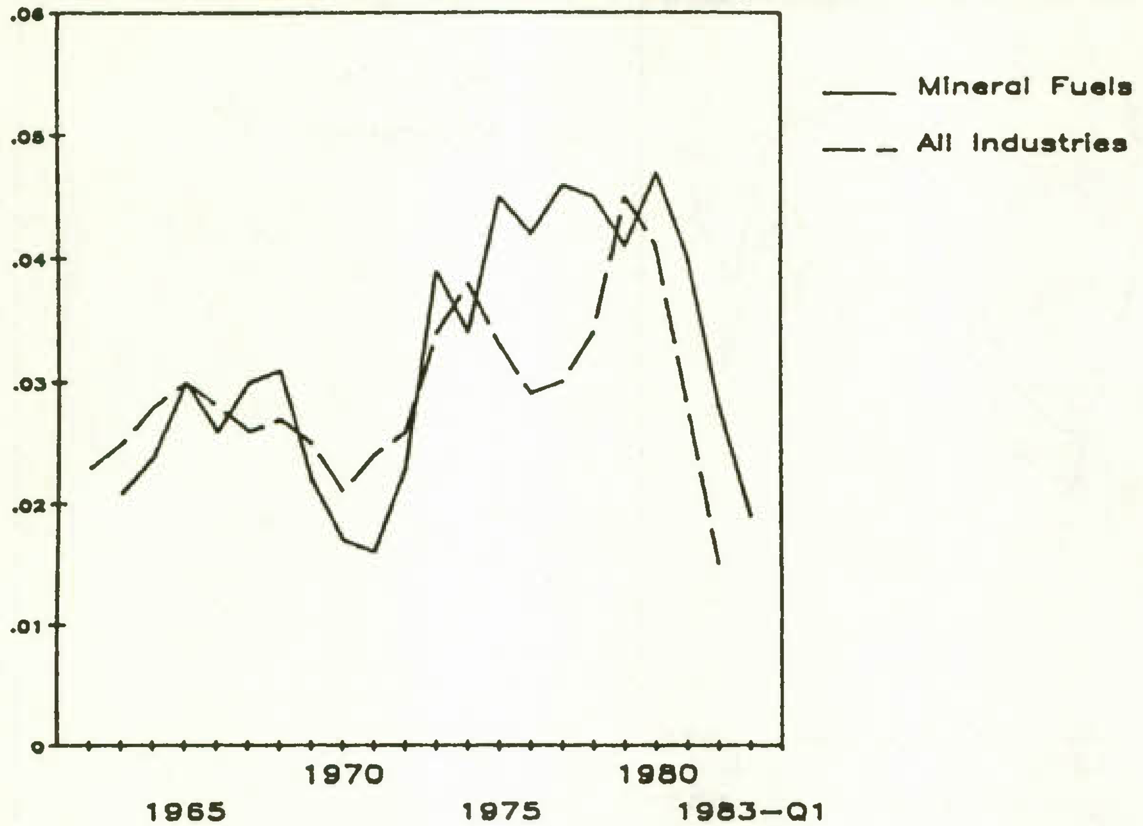

Chart V.6
Net Income/Equity Ratios
Petroleum & Coal Products and Total Manufacturing

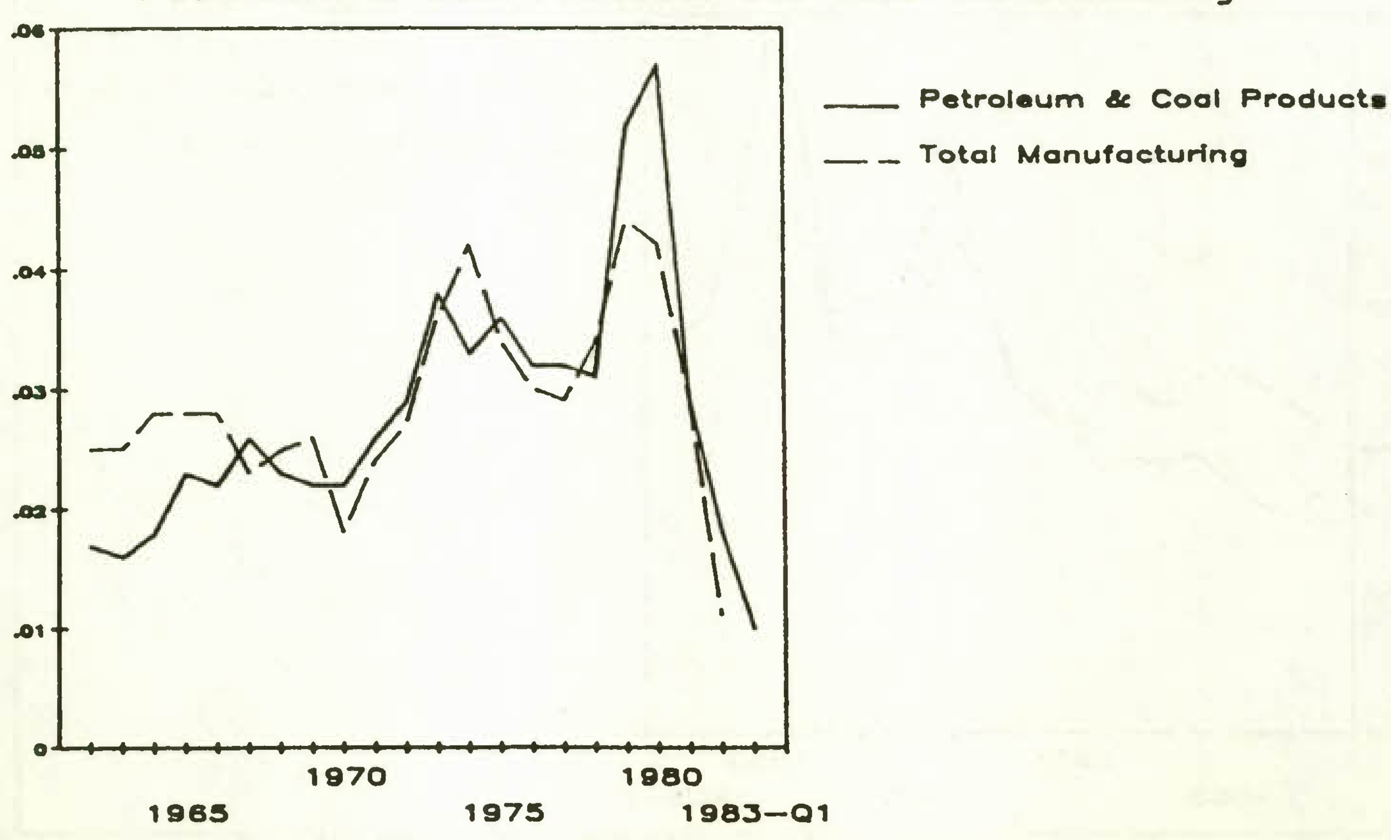

Chart V.7
Base Profit/Equity Ratios
Mineral Fuels and All Industries

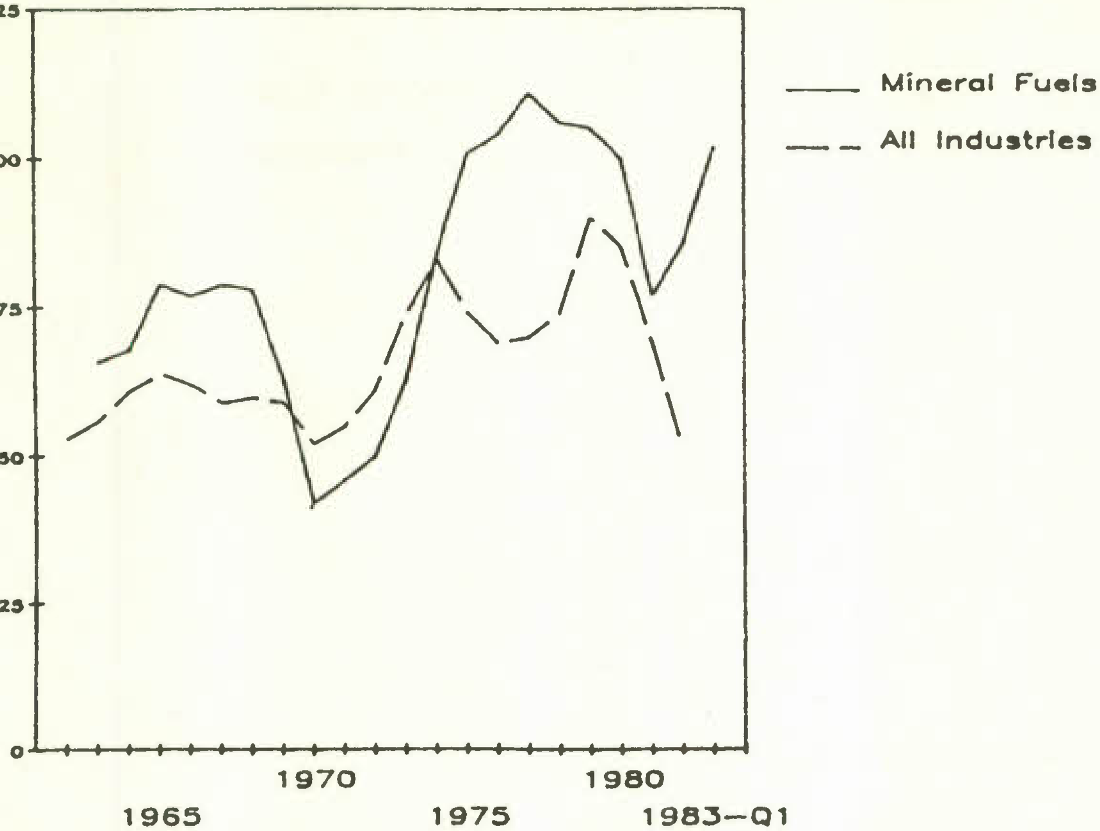

Chart V.8
Base Profit/Equity Ratios
Petroleum & Coal Products and Total Manufacturing

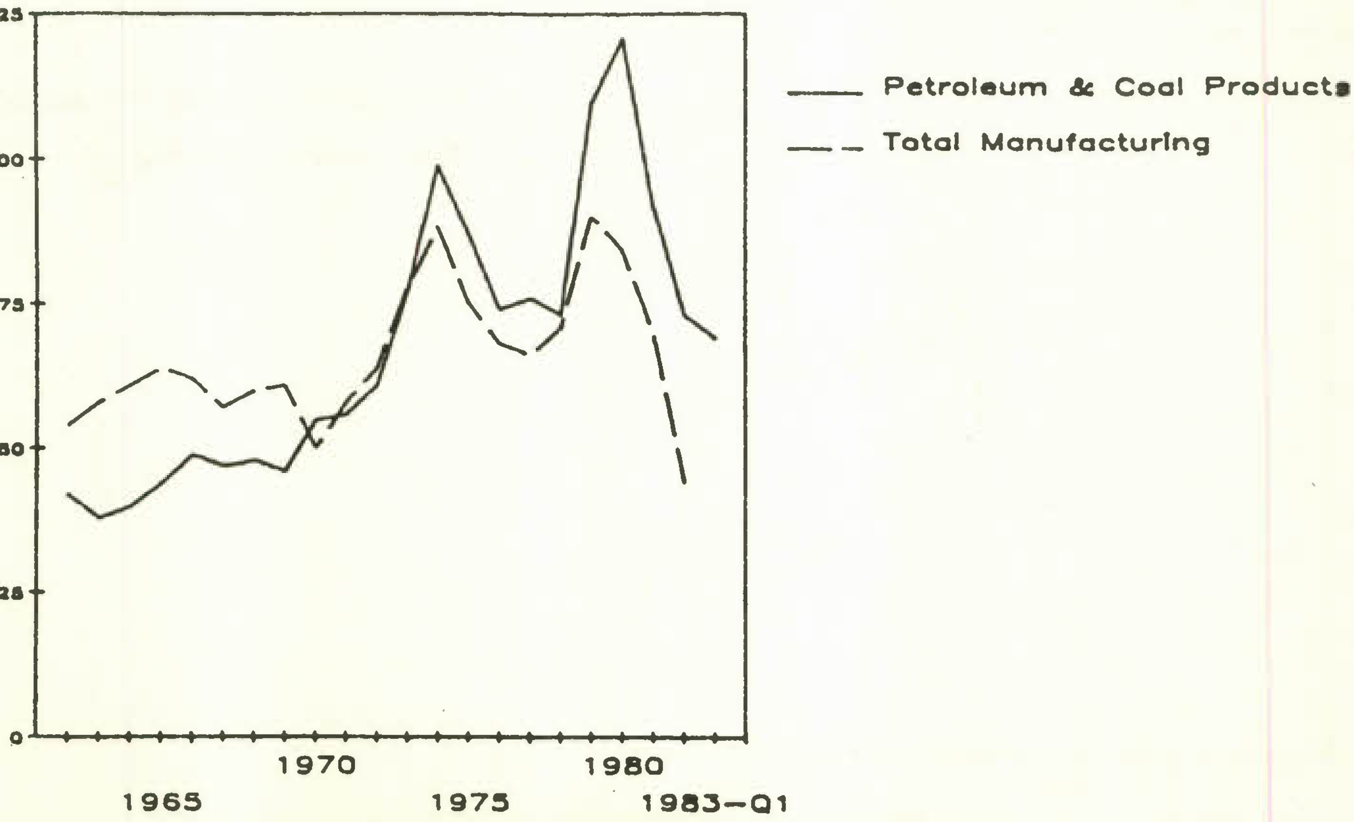

Chart V.9
Interest/Operating Expense Ratios
Mineral Fuels and All Industries

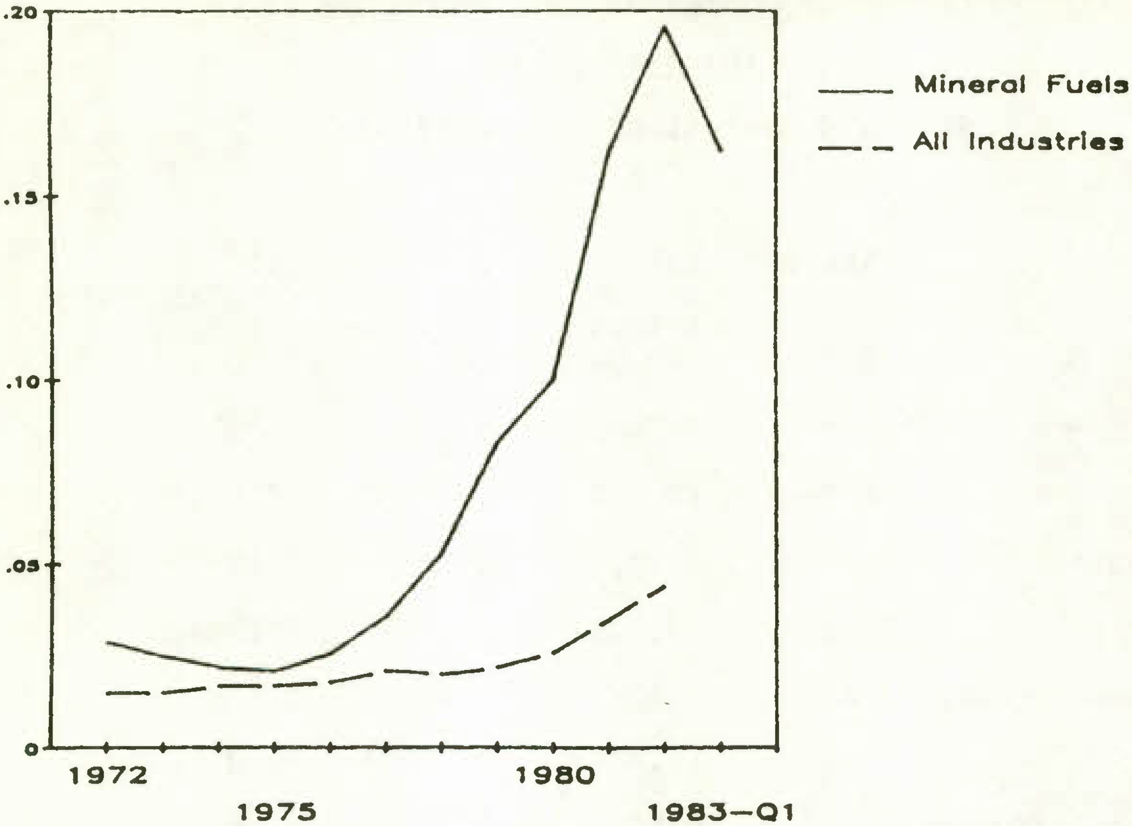

Chart V.10
Interest/Operating Expense Ratios
Petroleum & Coal Products and Total Manufacturing

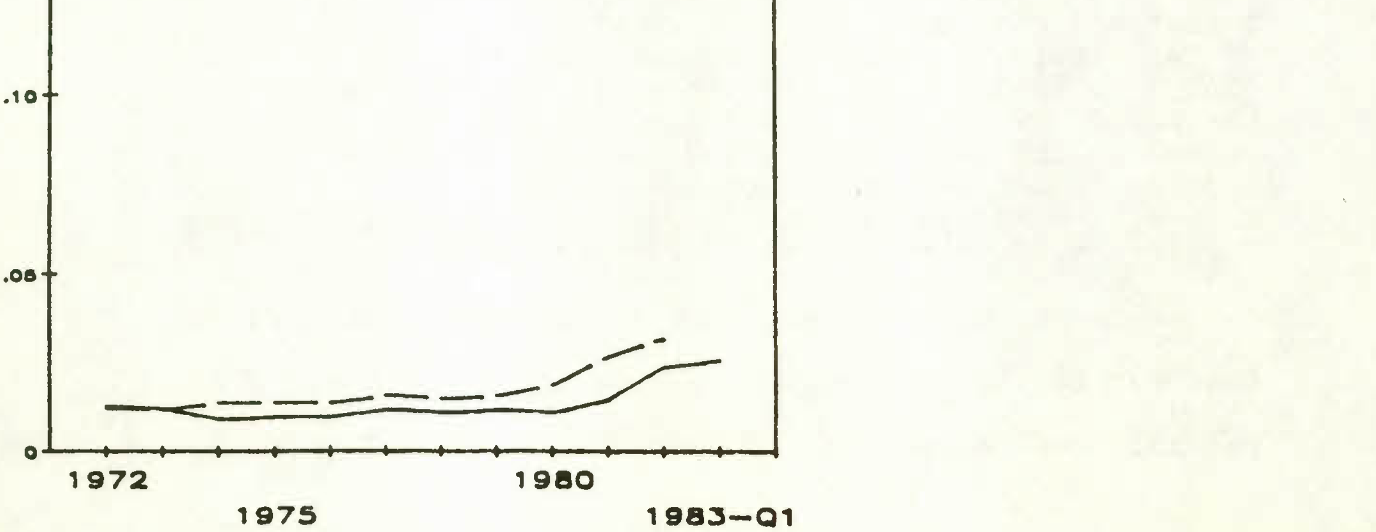

Table XI

Mean Financial Ratios

(Standard deviations in brackets)

	Mineral+ Fuels (1963Q1-1983Q1)	All Industries (1962Q1-1982Q4)	Petroleum and Coal (1962Q1-1983Q1)	All Manufacturing (1962Q1 1982Q4)
Liquidity++ Ratio	1.681	1.760	2.227	1.957
	(0.356)	(0.195)	(0.359)	(0.218)
Debt/Equity Ratio	0.842	1.116	0.711	0.985
	(0.428)	(0.153)	(0.132)	(0.148)
Net Income/Equity Ratio*	3.171	2.899	2.870	2.876
	(1.443)	(0.755)	(1.207)	(0.870)
Base Profit/Equity Ratio*	7.553	6.587	6.704	6.583
	(2.488)	(1.175)	(2.450)	(1.301)
Interest/Operating Expense Ratio++	7.055	2.260	1.270	1.726
	(6.052)	(0.853)	(0.457)	(0.634)

* The net income/equity ratios and base profit/equity ratios are quarterly flow/stock ratios; the equivalent annual ratios would be four times as large on average.
+ Some adjustments have been necessary to the published debt and equity data for the mineral fuels industry prior to 1970 due to the handling of 'debt owing to parent and affiliated companies' and 'paid capital'.
++ The liquidity ratio for mineral fuels spans the period 1962Q1 to 1983Q1. The interest/operating expense ratios span the period 1972-Q1 to 1983-Q1 for mineral fuels and petroleum and coal, and 1972-Q1 to 1982-Q4 for all industries and all manufacturing.
Source: Statistics Canada, <u>Industrial Corporations Financial Statistics</u>, Catalogue 61-003, Various Issues.

What do these various charts and statistics tell us? Consider first the liquidity ratios (Charts V.1 and V.2). For all four industries, the general trend in liquidity ratios has been downwards. Not surprisingly, the ratios for the narrower industries, mineral fuels and petroleum and coal products, are more volatile than those for all industries and all manufacturing industries, respectively. There is some tendency for the liquidity ratio for mineral fuels to be low when that for petroleum and coal products is high, which may have something to do with the statistical separation of recorded assets and liabilities between the upstream and downstream segments of the integrated companies which span both industries. The mineral fuels industry has suffered historically low and declining liquidity ratios since the announcement of the National Energy Program in the fall of 1980.

Consider next the debt/equity ratios (Charts V.3 and V.4). For all four industries, the general trend in debt/equity ratios has been upwards. The debt/equity ratio for the mineral fuels industry is more volatile than that of the other industries, and was escalated to historically high levels after the advent of the National Energy Program, continuing a trend which had begun somewhat earlier. A smaller tendency for a relative increase in the debt/equity ratio of the petroleum and coal products industry has also occurred during this period. Notice, however, that historically <u>both</u> the mineral fuels industry (the upstream end) and the petroleum and coal products industry (the downstream end) seem to operate with a lower debt/equity ratio than other industries. On these statistics, there appears to be some tendency for the upstream portion of the industry to need to finance a larger percentage of its projects out of cash flow than is normal for other kinds of business, and this may also be the case for the downstream portion of the industry. One reason for this may be that the commercial banks will never grant loans to companies purely for exploration purposes (I have this comment on the authority of the Royal Bank's Global Energy Group); indeed, they will only grant loans on the basis of demonstrated future cash flow from production operations. Thus, since equity capital is essential for risky undertakings like exploration activity, the upstream industry does normally operate with a lower debt/equity ratio than other industries; but the downstream industry seems to as well, for whatever reason, including possibly the degree of foreign ownership in this segment of the industry and/or the problem of separating statistically the upstream and downstream segments from the balance sheets of integrated petroleum companies. Once again, however, the mineral fuels industry was induced to generate inordinately and unusually high debt/equity ratios after the National Energy Program was implemented. These ratios have only recently begun to be corrected.

Consider now the net income to equity ratios (Charts V.5 and V.6) and the base profit to equity ratios (Charts V.7 and V.8). All four of these charts demonstrate (a) that there has been little trend in profitability in all four industries, and (b) that profitability has moved around substantially in a cyclical fashion, particularly during the past twelve years or so. Although profitability has historically been much the same in all four industries, it has been somewhat more volatile in the narrower industries, mineral fuels and petroleum and coal products, than in the broader aggregative industries, partly due to their larger riskiness. Noticeably, however, both the mineral fuels and the petroleum and coal products industries had become somewhat more profitable than the other industries in the late 1970's. This is noticeable from late 1974 to early 1980 for the mineral fuels industry, and from early 1979 to late 1980 for the petroleum and coal products industry. Profitability had already begun to trend downwards for both these industries (along with all industries and all manufacturing industries more generally) before the National Energy Program further eroded their profitability, particularly in relative terms for the upstream end of the business. In 1982, provincial royalty relief and, to a much smaller degree, federal tax changes have brought some re-emergence of profitability in this segment, but more to base profits than to the bottom line given the hangover of debt from which the upstream is still suffering.

This hangover effect is clearly demonstrated in the last two charts (Charts V.9 and V.10) which pertain to the ratio of interest expenses to total operating expenses. The trend in interest expenses as a proportion of total operating expenses has been upwards for all industries, especially between 1979 and 1982 during which period interest rates were at historically high levels. The increase in this ratio is, however, particularly pronounced for the mineral fuels industry, whose debt/equity ratio has shown the most dramatic increase over the period, especially since the advent of the National Energy Program in the fall of 1980.

B. Financial Variables in the Regression Analysis

In another set of regressions, the corporate financial statistics, compiled by linking Statistics Canada corporate financial data from 1962 to 1981 (1963 to 1981 for some variables) for the upstream sector of the petroleum industry, the mineral fuels industry, were added to our basic model (one at a time) in order to test for direct effects on industry activity levels. As already indicated, the first variable was a measure of corporate liquidity or the working capital ratio (current assets divided by current liabilities) available to the industry. Second, debt/equity ratios were tested to measure the impact of financial leverage on the activity variables. Next, two return on investment measures were constructed as the ratios of base profit (as described by Statistics Canada) to shareholders' equity and net income to shareholders' equity. Also, an interest/operating expense ratio was intended to be used to see if the interest burden had a significant impact on industry activity. Unfortunately, sufficient data were not available to test this although we believe that the results would be insignificant given that separate interest rate variables had already shown little significance in regressions that included a reserves price variable (which itself includes an interest or discount rate effect).

Unfortunately, this exercise proved to be of little statistical value. Indeed, none of these variables proved to be significant in historical regression analyses. These results may be due to the constrained size of our sample which afforded us only 14 or 15 degrees of freedom. Nevertheless, this does not prove that these variables were unimportant as determinants of the 1981-82 decline in exploration and development activity.

C. Canadianization and Capital Costs

Have the 'Canadianization' aspects of the National Energy Program increased the 'cost of capital' to firms within the industry? The financial evidence we have presented in the foregoing charts, and other evidence we have distilled from other analysts, lead us to conclude that the answer is yes.[4] 'Canadianization' has increased the cost

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[4]For other evidence on this point, see Bank of Montreal, "Canadian Corporate Takeovers: Some Economic Aspects", (mimeographed 1981); R.G.M. Sultan, "Canada's Recent Experiment in the Repatriation of American Capital", Canadian Public Policy, Vol. VIII, Special Supplement, October, (1982), pp.498-504; Carmichael, E.A., and Stewart, J.K., Lessons from the National Energy Program, Toronto, C.D. Howe Institute, (1983); and B.L. Scarfe, "The National Energy Program After Three Years: An Economic Perspective", Western Economic Review, Vol. 3, July (1984), pp. 2-31.

of capital in three distinct ways. First, the capital outflows generated in 1981 by the takeover wave in the industry clearly led to a softer Canadian dollar and to higher domestic interest rates than otherwise would have been the case. We estimate that long-term capital outflows generated by the National Energy Program may have amounted to $15 billion in the eighteen months subsequent to the NEP, peaking in the second quarter of 1981. The Canadian dollar fell by 4.5 cents U.S. over the two years subsequent to the NEP, and the uncovered interest rate differential widened from between 2 (for long term yields) and 3 (for short term yields) percentage points above its historic norm during a similar period (see Charts V.11 and V.12). Both the interest rate differential and the downwards pressure on the Canadian dollar have subsequently subsided. Nevertheless, in retrospect these and other data series suggest that the NEP increased the cost of capital to <u>all</u> economic agents in Canada, including those operating in the petroleum and natural gas producing sector of the economy. The takeover activity stimulated by the discriminatory tax and incentive system put in place under the NEP unfortunately came at a time when it was already difficult enough to manage our monetary and exchange rate policies in the face of record high (and inordinately volatile) U.S. interest rates. The resulting softness in the Canadian dollar added (albeit temporarily) both to our overall inflation rate and to our real interest rates.

Chart V.11
Long Run Yield Spreads, Canada/U.S.

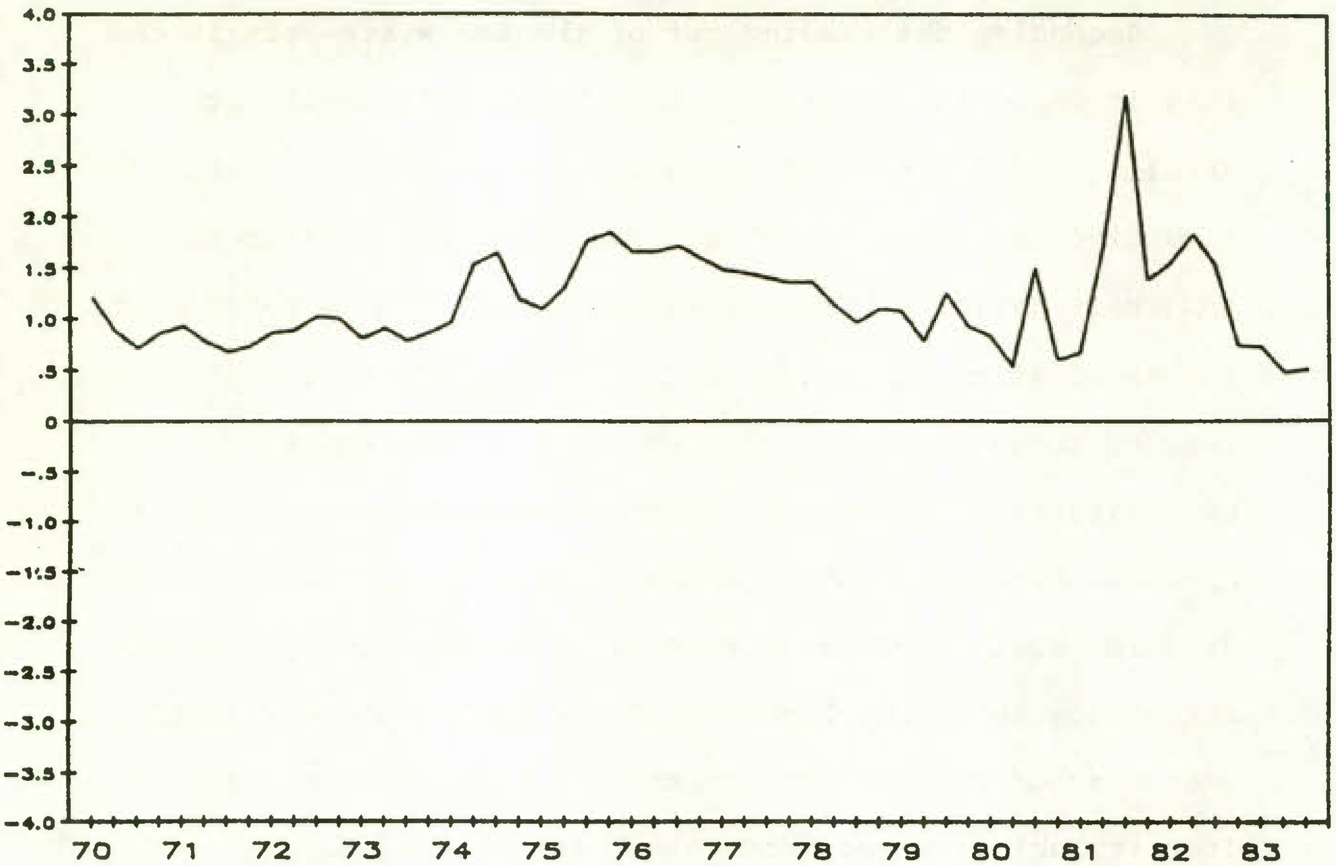
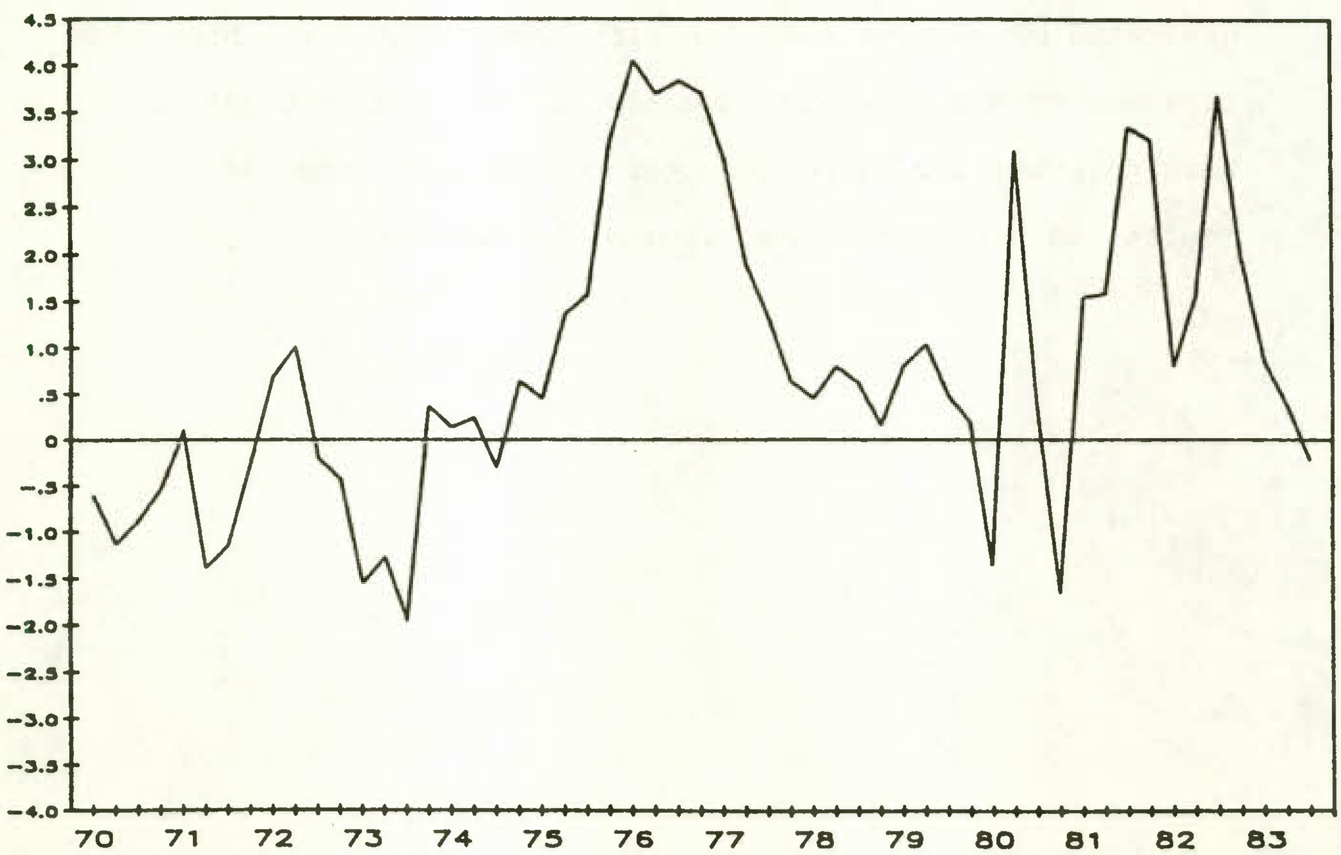


Chart V.12
Short Run Yield Spreads, Canada/U.S.



See Appendix Table A8 for data and sources.

Secondly, the phasing out of the tax write-offs in the form of depletion allowances and their replacement with drilling and other exploration incentives (PIPs or petroleum incentive payments), which are substantially greater for companies having a high percentage of Canadian ownership and for exploration on Canada Lands, may have increased the user cost of those forms of industry capital investment expenditures which are not eligible for PIP grants. It has also diverted exploration activity away from some lower cost drilling activities on provincial lands towards higher cost activities on Canada Lands. But the fact remains that the user cost of capital investment in some desirable forms of industry activity has been raised in the process.

Thirdly, and more generally, the reduction in real after-tax netbacks to the industry, the increased uncertainty generated by various energy policy changes, and the high cost takeover of assets which have now fallen in market value, have together increased the user cost of all forms of capital to producing firms within the industry.

D. Review of EMR Netbacks

The particular effect of reduced real netbacks can be deduced from the following table obtained from EMR in Ottawa. These netbacks were used in the reserve price approximations that were required for our 1982 activity level forecasts.

Table XII

Netback Calculations for Conventional Crude Oil and Natural Gas Produced in Alberta (Constant 1981 dollars)

Large Crown Producers

Year	Old-Old Oil ($/bbl)	New-Old Oil ($/bbl)	NORP Oil ($/bbl)	Old Gas ($/mcf)	New Gas ($/mcf)
1975	5.23	6.52		0.41	0.46
1976	5.09	6.57		0.59	0.72
1977	5.33	7.07		0.71	0.88
1978	6.07	8.08		0.80	1.01
1979	6.13	8.04		0.90	1.15
1980	6.49	8.53		1.05	1.36
1981	4.20	7.20	6.80	0.61	0.90
1982	5.88	9.35	13.49	0.70	0.92
1983	7.22	11.18	11.39	0.75	0.93
1984	6.33	10.82	9.82	0.71	0.89
1985	5.75	10.36	9.39	0.71	0.90
1986	5.00	10.93	9.45	0.74	0.94

Small Crown Producers

Year	Old-Old Oil ($/bbl)	New-Old Oil ($/bbl)	NORP Oil ($/bbl)	Old Gas ($/mcf)	New Gas ($/mcf)
1983	9.79	14.14	14.61	1.01	1.20
1984	8.80	14.00	12.77	0.98	1.16
1985	8.02	13.43	12.25	0.98	1.17
1986	7.08	14.01	12.36	1.02	1.22

[1] Source: These figures were obtained from officials at the Department of Energy, Mines, and Resources, Canada. These netbacks are calculated on an 'effective tax' basis and imply certain reinvestment assumptions that may not materialise and, indeed, could be quite misleading if interest rates are high and volatile. Netbacks on a full-tax basis (where the corporate profits taxation rates applied are considerably higher) are much lower than these numbers throughout. The lower portion of the table indicates that small producers receive larger benefits from the PGRT tax credit contained in the NEP Update 1982. The consumer price index has been used as a deflator throughout.

[2] Old-old (COOP) oil refers to oil discovered before March 31, 1974. New-old (SOOP) oil refers to oil discovered after March 31, 1974, but before January 1, 1981. The same March 31, 1974, break point divides old natural gas from new natural gas. NORP oil refers to all oil discovered after January 1, 1981, and to certain categories of tertiary and synthetic production begun before that date. Under the terms of the Alberta-Ottawa amending agreement of June 30, 1983, the new oil reference price (NORP) was extended to all oil discovered after March 31, 1974 (new-old oil), and to

production from infill drilling within pre-NORP oil entities. Alberta royalty rates differ on these five categories of primary energy, and it is notable that Alberta's Oil and Gas Activity Program (OGAP) of April 1982 allocated largest royalty reductions to old-old oil and to old natural gas, for which the NEP had the most severe netback eroding effects (35% and 42%, respectively) in real terms. Average Alberta royalty rates for these five categories of primary energy after OGAP are as follows: Old (Pre-1974) Oil 37%, Old (Pre-1974) Gas 41% (38% if low productivity well), New (1974-1980) Oil 25%, New (Post-1974) Gas 33% (30% if low productivity well), and NORP (Post-1980) Oil 23%.

[3] These netback calculations are based on the Amended Canada/Alberta Memorandum of Agreement of June 30, 1983, and therefore include the reclassification of SOOP to NORP as well as the important effects of Alberta's OGAP program. They therefore differ from the expected netbacks that may have been perceived by the industry from the vantage point of 1981 or 1982. As a check on these EMR netback figures, comparisons were made with those compiled in the latest (August 1983) Lewis Engineering Profitability Analysis Service report. Although there were numerous discrepancies, overall both series proved to be consistent with each other.

Real (and nominal) dollar netbacks for both oil and natural gas were seriously eroded in 1981 by the impact of the NEP, and especially the petroleum and natural gas revenue tax (PGRT), on the producing industry. Indeed, relative to 1980, and with the exception of 'new-old' oil, these netbacks on an effective tax rate basis were eroded in real terms by more than one-third on EMR's own estimates (see Table XII), and by somewhat more than this on Alberta Energy and Natural Resources' estimates. Even with all the new measures put in place, it is now estimated that netbacks on 'old-old' oil were not restored to 1980 levels in real terms until the latter half of 1983. On old and new gas real dollar netbacks are not restored until after the end of the energy agreement, if at all, unless there is a totally unexpected rebound in the marketability of Canadian gas in the U.S.A., which would affect netbacks through the revenue 'flow-back' system currently in place. Unless one believed that netbacks were much too large in the 1978-1980 period, and that the erosion of them would not affect producers' expectations and confidence, the consequences of the severe real netback erosion for exploration and development activity at a time of high real interest rates should have been anticipated. Cash flows from existing production are important for firms to extend their exploration and development activity, since these cash flows largely determine their ability to borrow on either debt or equity account.

The recent extension of NORP oil prices to SOOP oil and to oil produced from newly-drilled infill wells will provide greater cash flow to producers. Nevertheless, in so far as netbacks are gradually restored it will largely be through provincial royalty relief. Implicitly, therefore, the Alberta government is now paying a significant proportion of the PGRT out of its own revenues. Just as it bought back jurisdictional control over its own resources by agreeing to pay the Petroleum Incentive Payments (PIPs) on provincial lands in exchange for inducing the federal government to apply a zero rate of natural gas tax on exported gas (which if it had been kept level with the tax on domestic gas would now not be projected to earn much revenue in any case, indicating that Alberta paid a very heavy price for retaining jurisdictional control over the PIPs), the Alberta government has now attempted to buy back some moderate prosperity for the industry by providing royalty relief to assist in the restoration of real netbacks to the position at which they stood before the PGRT was unilaterally imposed by the federal government under the NEP. Given that the EMR netback figures peak in 1983 (except for NORP which peaked in 1982), if oil and gas prices remain flat into the mid-1980's as they are now projected, it will soon become time for the effective PGRT tax rates to be reduced if reasonably favourable real netbacks are to be maintained.

VI. Conclusions

Our evidence confirms that the driving force behind exploration activity is the quest for the potential economic rents that may accrue to new discoveries of crude petroleum and natural gas. These rents depend upon (a) the probability of exploration activity leading successfully to new discoveries, (b) the costs involved in this activity (finding costs), (c) the anticipated costs of extracting the new resources, (d) the anticipated date at which newly-extracted resources can be sold, (e) the anticipated prices at which these sales may occur, and (f) the anticipated taxation regime that will be imposed by federal and provincial authorities on the industry.

Since exploration activity is future-orientated, expectations and the uncertainty surrounding these expectations are of great importance to the exploration process. Indeed, given the geological uncertainties involved, a very strong case can be made for keeping fiscal uncertainties to a minimum. Government policy changes over the past three years have done little to reduce the fiscal uncertainties under which the crude petroleum and natural gas industry must operate. It is always possible to put in place a fiscal regime in which potential economic rents are perceived by exploring firms to be non-existent or even negative, in which case exploration activity will dry up altogether with spill-over effects on all those whose livelihoods are dependent upon its continuity.

To a considerable degree, when greater fiscal uncertainty is factored into the equation, our analysis suggests that this is what the original National Energy Program of 1980 appeared to have achieved, at least for exploration activity on provincial lands in the Western sedimentary basin. By seriously eroding existing real netbacks on current production, the federal government not only reduced the industry's cash flow available to finance exploration and development activity, but also it falsified producers' expectations that they might be permitted to retain a reasonable portion of the uncertain economic rents that could be generated from the marketing of new oil and gas discoveries. The new oil reference price (NORP) constructed in the fall 1981 Energy Agreements may have created better incentives for oil exploration activity, but the gloom and uncertainty overhanging the industry was not thereby redressed. For in exchanging higher prices, which no one in the industry believed were likely to be attained, for a continuing and increased taxation burden imposed by the federal government, the provinces did little in the fall of 1981 to buoy up producers' overall expectations that they would be treated to stable and favourable fiscal regimes in the future.

Subsequent royalty relief has clearly been helpful; but, in the meantime, the market situation for natural gas in the United States has lost its buoyancy, and the world oil market situation makes it unlikely that there will be any significant escalation in money prices in the foreseeable future. Hence real prices are likely to decline. If this is so, one can make the case that it is the federal government's turn to see that real after-tax netbacks do not decline faster than EMR numbers currently suggest, by backing off the petroleum and natural gas revenue tax (PGRT) gradually as required over the next few years. Significant royalty relief has already eroded the provincial share of rents on their own resources.

Although the firms in the industry do have an ability to borrow money with existing cash flows as security, it is clear from recent events that they cannot borrow imprudently without getting into serious financial difficulties. Many of the players are constrained by their existing cash flows, and new players must begin exploration activity from a solid base of equity since the banks generally will not lend directly for this purpose. Thus, our research suggests that both buoyant and stable netbacks from existing oil and gas extraction are important to the ability of the oil and gas sector to finance continued exploration and development activity from both internal and external (borrowed) resources.

Although good anticipated returns on the eventual extraction of potential newly-discovered reserves are necessary to generate a reasonable level of exploration and development activity, by themselves they are not sufficient. Reasonably favourable cash-flow netbacks on existing production are also required. For this reason, the public collection of rents obtainable from the production stage is never neutral in its effect on the exploration and development stage. Rent collection must be approached from an understanding of the nature of full-cycle (exploration, development, and production) returns on investment activity.

The most important incentive variables facing the firms' exploration and development decisions are the prices of undeveloped or developed oil and gas reserves in the ground.[8]

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[8] My research student, Farhed Shah, has prepared the following lengthy footnote on the relationship between reserve prices and exploratory effort, which relates the concept of reserve prices to the theoretical work of Pindyck (1978), Devarajan and Fisher (1982) and others. Suppose that a large number of firms in a regional oil industry have common access to all parts of the region as far as exploratory activity is concerned. Once a firm is able to discover a potential 'oil well', however, it is assumed to have property rights over that 'well'. That is to say, it can either extract from the 'well' and sell oil on the flow market, or it can decide to sell the 'well' in the asset market, or simply decide to hold on to its asset (ie. oil in the ground). If both asset and flow markets are in equilibrium at any point in time, the firm will be indifferent among each of these decisions at that point in time.

Assume now that both markets are always in equilibrium, and consider the exploratory behavior of a typical firm by focussing on the asset market. Since common access to the exploratory region has been assumed, the firm will not take into consideration any cost of 'depletion' or 'degradation' of the ultimately available regional resources. Under this assumption, the firm will obviously explore and discover oil until the cost of finding a potential 'oil well' is equal to the price of that 'well' obtainable in the asset market. (Assuming diminishing productivity in exploration activity, 'finding costs' rise as the level of exploratory effort increases in any given time period.) This asset price equals the undeveloped reserve price times the amount of oil in the 'well'. Thus the firm explores until the undeveloped reserve price equals the 'average' finding cost of a barrel of oil in the ground (where the 'average' pertains to the barrels contained in the particular 'well' in question).

These prices are crucially affected by gestation lags, interest rates and market price expectations, as well as all the parameters which affect producer netbacks. Their relation to oil and gas finding costs is what determines the size of competitive bids for exploration licenses and production leases. Indeed, the behavior of revenues and prices in this bidding process is one useful guide to the anticipated rents perceived by players in the industry. The fact that land sales prices and revenues collapsed in 1981 from their previous levels, and have not yet recovered, should be considered to be one indicator of the lack of buoyancy in producers' rent expectations, and of the likelihood that reserve prices on all classes of crude oil and natural gas remain insufficient in relationship to finding costs to generate any really significant recovery in exploration and development activity in the Western sedimentary basin.

'(cont'd) This relationship is a perfectly general one in so far as it does not depend upon the nature of the extraction cost function, and it allows one to model separately the exploration and extraction phases, using the reserve price as the linking variable. Observe that Pindyck (1978, p.843, fn.6) assumes away common access difficulties in the exploration stage. This assumption, however, is not followed by Devarajan and Fisher (1982, pp.335-6) who ignore the effect of cumulative discoveries on marginal finding costs. (One could, alternatively, posit the existence of relatively large amounts of ultimately discoverable oil; in both cases the objective is to enable one to set the shadow price of cumulative discoveries equal to zero from the firm's perspective.) Under these circumstances, if uncertainty is ignored, the shadow price of the resource in the ground (the reserve price) may be identified with the expected rent obtainable from the extraction of the resource. In equilibrium, therefore, firms will explore up to the point at which marginal discovery cost equals expected rent. Uncertainty, however, clouds this equilibrium condition.

If the basic objectives of security of supply and overall economic efficiency are to be achieved in any subsequent (or re-opened) energy agreements, it will be probably be essential for the federal government to lower its rates of PGRT taxation, and to unwind its PIP grant program in favour of a tax incentive scheme (for waste and efficiency reasons that we have documented elsewhere - see Scarfe 1983). Substantial changes in the fiscal regime, however, should only be made after detailed industrial (and provincial) consultation, since expectations, and the degree of certainty with which they are held, are vitally important to the behavior of an industry whose plans and activities cannot but be orientated very much toward the future.

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Data Appendix

List of Tables

TABLE A1

NET CASH EXPENDITURES OF THE ALBERTA PETROLEUM INDUSTRY

(millions of nominal $)

	EXPLORATION				DEVELOPMENT	
	GEOLOGICAL (GEOG1)	DRILLING (DRIL1)	LAND (LAND1)	TOTAL (TOT1)	DRILLING (DRIL2)	FIELD EQUIPMENT (FIEL2)
1947	4.0	5.5	7.5	18.5	4.0	1.0
1948	10.5	7.5	12.0	31.5	19.5	6.0
1949	16.0	14.0	32.0	64.5	28.5	8.5
1950	24.5	11.0	52.0	91.5	40.5	12.0
1951	39.5	27.5	32.5	107.0	47.0	11.0
1952	53.5	27.0	43.5	133.5	56.5	13.5
1953	52.0	26.5	47.0	136.5	61.0	15.0
1954	44.5	35.0	94.0	183.5	46.0	13.0
1955	46.0	44.0	93.0	198.5	73.5	17.5
1956	40.5	46.0	102.5	204.0	100.5	28.0
1957	35.5	41.0	104.5	203.5	78.0	22.0
1958	36.5	54.0	88.0	201.5	78.0	19.0
1959	31.5	48.0	109.0	208.5	77.5	23.0
1960	33.0	44.0	91.0	188.5	98.5	25.5
1961	30.5	52.0	87.5	183.0	110.5	25.5
1962	32.5	46.5	84.0	177.5	83.6	19.0
1963	28.0	50.2	92.0	184.2	89.5	24.0
1964	32.0	57.0	135.0	239.0	90.8	31.0
1965	42.1	69.9	197.7	309.7	98.9	40.9
1966	68.1	75.7	170.0	313.8	88.0	35.3
1967	99.7	77.4	167.0	344.1	76.9	46.1
1968	87.2	87.6	174.2	349.0	73.6	60.8
1969	86.4	89.8	179.6	355.8	67.6	73.8
1970	80.3	83.8	116.6	280.7	72.0	71.2
1971	65.5	80.8	125.9	272.2	75.5	75.5
1972	71.2	102.1	124.4	297.7	69.1	107.1
1973	70.7	131.4	144.3	346.4	101.7	127.4
1974	112.4	146.5	157.3	416.2	136.4	152.8
1975	99.0	149.1	207.9	456.0	212.3	181.0
1976	145.5	256.5	255.5	657.5	277.2	368.2
1977	223.4	394.7	679.9	1298.0	351.2	298.1
1978	350.3	644.5	740.5	1735.3	477.4	385.1
1979	349.7	1027.5	1144.7	2521.9	679.2	476.3
1980	452.3	1621.6	1176.5	3250.4	1063.3	684.1
1981	352.2	1543.7	721.3	2617.2	1083.2	782.7
1982	325.1	1076.3	465.6	1867.0	942.5	839.6

TABLE A1
NET CASH EXPENDITURES OF THE ALBERTA PETROLEUM INDUSTRY (CONT.)
(millions of nominal $)

	SEC. RECOVERY (SEC2)	NAT. GAS PLANTS (NAT2)	TOTAL (TOT2)	ISPI (1981=100)
1947	0.0	0.0	7.0	0.21
1948	0.0	0.0	29.0	0.25
1949	0.0	4.0	47.5	0.25
1950	0.0	3.5	67.5	0.27
1951	0.0	2.0	73.0	0.31
1952	0.0	2.0	85.0	0.29
1953	0.0	1.0	87.5	0.28
1954	1.0	2.5	77.0	0.27
1955	1.0	6.0	117.0	0.28
1956	1.0	18.5	172.0	0.29
1957	3.0	6.0	123.5	0.29
1958	5.0	29.0	139.0	0.30
1959	4.0	12.5	134.0	0.30
1960	6.5	20.5	165.0	0.30
1961	4.0	61.0	210.0	0.30
1962	6.0	20.0	143.6	0.31
1963	8.0	36.0	172.5	0.31
1964	7.5	29.0	171.8	0.31
1965	9.3	32.1	188.0	0.32
1966	10.0	44.3	178.8	0.32
1967	10.3	88.1	240.8	0.33
1968	10.4	87.0	246.5	0.34
1969	15.6	91.2	270.6	0.35
1970	11.3	162.3	327.7	0.36
1971	19.5	214.0	376.1	0.37
1972	33.6	109.7	333.0	0.38
1973	37.3	65.3	350.7	0.43
1974	23.6	126.1	455.4	0.51
1975	19.9	123.8	562.0	0.56
1976	21.1	155.0	845.6	0.59
1977	29.0	143.8	861.2	0.64
1978	51.7	165.9	1129.2	0.70
1979	78.2	204.7	1538.3	0.80
1980	135.7	241.1	2340.7	0.91
1981	142.9	310.9	2418.3	1.00
1982	132.4	493.7	2408.2	1.06

TABLE A2
EXOGENOUS VARIABLES - OIL
(all dollar figures are nominal)

	INTENT RATIO (INTo)	COMPLETION RATIO (COMo)	NETBACK ($/BBL) (NETo)	RESERVE PRICE ($/BBL) (RESo)	UNDEVEL. RES. PRICE ($/BBL) (URESo)	PRODUCTION (MILLIONS OF BBLS) (PRODo)
1947	0.0	0.0	1.74	0.90	0.81	6.38
1948	0.0	0.0	2.98	1.43	1.25	10.50
1949	0.0	0.0	2.29	0.98	0.86	19.77
1950	0.0	0.0	2.33	0.94	0.80	27.15
1951	0.71	0.0	2.07	0.85	0.73	45.84
1952	0.74	0.0	1.71	0.62	0.49	58.84
1953	0.70	0.0	1.60	0.61	0.48	76.70
1954	0.70	0.0	1.88	0.73	0.58	87.59
1955	0.72	0.0	1.74	0.76	0.62	112.90
1956	0.74	0.0	1.76	0.77	0.61	143.70
1957	0.75	0.866	1.84	0.69	0.49	136.80
1958	0.72	0.838	1.60	0.64	0.42	112.50
1959	0.73	0.779	1.64	0.65	0.41	128.80
1960	0.67	0.795	1.39	0.60	0.34	130.60
1961	0.64	0.721	1.56	0.62	0.35	157.60
1962	0.61	0.723	1.64	0.69	0.46	165.20
1963	0.69	0.787	1.69	0.72	0.50	168.70
1964	0.74	0.790	1.71	0.75	0.52	175.40
1965	0.69	0.799	1.69	0.75	0.53	183.70
1966	0.63	0.714	1.73	0.74	0.49	202.50
1967	0.79	0.696	1.75	0.71	0.44	230.80
1968	0.75	0.585	1.74	0.65	0.40	251.50
1969	0.68	0.515	1.74	0.64	0.36	286.70
1970	0.49	0.330	1.78	0.58	0.35	329.70
1971	0.52	0.343	1.93	0.72	0.55	357.30
1972	0.27	0.337	1.98	0.77	0.63	424.80
1973	0.31	0.283	2.76	1.06	0.93	522.40
1974	0.28	0.275	4.68	2.94	2.69	497.80
1975	0.23	0.255	4.77	2.55	2.18	424.80
1976	0.19	0.147	5.11	4.55	3.89	383.30
1977	0.26	0.193	6.13	5.39	4.67	380.80
1978	0.31	0.234	7.16	6.32	5.44	377.70
1979	0.42	0.281	8.40	7.09	6.10	431.20
1980	0.45	0.292	8.91	5.92	4.43	397.70
1981	0.52	0.325	10.87 (7.85)	5.69 (4.11)	3.36 (2.43)	358.60
1982	0.60	0.393	- (9.72)	- (5.09)	- (3.01)	350.30

Notes: Numbers in brackets are author estimates.
In this table, zeros imply data unavailable.

TABLE A3
EXOGENOUS VARIABLES - NATURAL GAS
(all dollar figures are nominal)

	INTENT RATIO (INTg)	COMPLETION RATIO (COMg)	NETBACK ($/MCF) (NETg)	RESERVE PRICE ($/MCF) (RESg)	UNDEV. RES. PRICE ($/MCF) (URESg)	PRODUCTION (MMCF) (PRODg)
1947	0.0	0.0	0.0	0.0	0.0	48.1
1948	0.0	0.0	0.0	0.0	0.0	56.5
1949	0.0	0.0	0.0	0.0	0.0	63.2
1950	0.0	0.0	0.0	0.0	0.0	72.0
1951	0.29	0.180	0.0	0.0	0.0	79.8
1952	0.26	0.130	0.0	0.0	0.0	91.3
1953	0.30	0.190	0.0	0.0	0.0	109.8
1954	0.30	0.190	0.0225	0.0045	0.0	129.0
1955	0.28	0.170	0.0386	0.0090	0.0	159.0
1956	0.26	0.130	0.0265	0.0059	0.0	188.0
1957	0.25	0.134	0.0352	0.0056	0.0	223.3
1958	0.28	0.162	0.0259	0.0045	0.0	271.5
1959	0.27	0.221	0.0265	0.0062	0.0	331.4
1960	0.33	0.205	0.0431	0.0135	0.0056	410.7
1961	0.36	0.279	0.0501	0.0149	0.0065	535.9
1962	0.39	0.277	0.0724	0.0245	0.0183	783.4
1963	0.31	0.212	0.0778	0.0268	0.0197	870.6
1964	0.26	0.210	0.0876	0.0301	0.0231	993.8
1965	0.31	0.201	0.0980	0.0332	0.0256	1083.0
1966	0.37	0.286	0.1223	0.0375	0.0293	1146.0
1967	0.21	0.304	0.1443	0.0386	0.0299	1255.0
1968	0.25	0.415	0.1648	0.0400	0.0307	1435.0
1969	0.32	0.485	0.1364	0.0301	0.0203	1678.0
1970	0.51	0.670	0.1034	0.0192	0.0107	1932.0
1971	0.48	0.657	0.0871	0.0194	0.0121	2115.0
1972	0.73	0.663	0.0885	0.0208	0.0130	2412.0
1973	0.69	0.717	0.1158	0.0287	0.0192	2613.0
1974	0.72	0.725	0.2592	0.0786	0.0645	2604.0
1975	0.77	0.745	0.4908	0.1561	0.1313	2643.0
1976	0.81	0.853	0.6401	0.3485	0.2967	2670.0
1977	0.74	0.807	0.7136	0.3370	0.2640	2787.0
1978	0.69	0.766	0.7252	0.3102	0.2062	2746.0
1979	0.58	0.719	0.8776	0.3361	0.2029	2910.0
1980	0.55	0.708	1.4084	0.4451	0.2693	2746.0
1981	0.48	0.675	1.5645 (1.02)	0.3282 (0.22)	0.1073 (.07)	2711.0
1982	0.40	0.607	- (1.09)	- (0.24)	- (.08)	2786.0

Note: numbers in brackets are author estimates.

In this table, zeros imply data unavailable.

TABLE A4

CORPORATE FINANCIAL RATIOS

MINERAL FUELS INDUSTRY
(ANNUAL AVERAGES OF QUARTERLY DATA)

	LIQUIDITY (CA/CL)	DEBT/EQUITY	NET INCOME/ EQUITY	NET PROFIT/ EQUITY	INTEREST/OPERATING EXPENSE
1962	2.430	0.0	0.0	0.0	0.0
1963	2.101	0.636	0.021	0.066	0.0
1964	1.695	0.642	0.024	0.068	0.0
1965	1.628	0.648	0.030	0.079	0.0
1966	1.395	0.682	0.026	0.077	0.0
1967	1.305	0.678	0.030	0.079	0.0
1968	1.530	0.702	0.031	0.078	0.0
1969	1.441	0.592	0.022	0.063	0.0
1970	1.455	0.548	0.017	0.042	0.0
1971	1.771	0.447	0.016	0.046	0.0
1972	2.207	0.441	0.023	0.050	0.029
1973	2.238	0.430	0.039	0.063	0.025
1974	1.698	0.570	0.034	0.084	0.022
1975	1.689	0.680	0.045	0.101	0.021
1976	2.109	0.706	0.042	0.104	0.026
1977	1.657	0.974	0.046	0.111	0.036
1978	1.626	1.037	0.045	0.106	0.053
1979	1.539	1.266	0.041	0.105	0.083
1980	1.330	1.282	0.047	0.100	0.100
1981	1.501	1.478	0.040	0.077	0.162
1982	1.113	2.150	0.028	0.086	0.196
1983-Q1	1.030	1.956	0.019	0.102	0.162

Note: in this table, zeros imply data unavailable.

TABLE A5

CORPORATE FINANCIAL RATIOS

ALL INDUSTRIES
(ANNUAL AVERAGES OF QUARTERLY DATA)

	LIQUIDITY (CA/CL)	DEBT/EQUITY	NET INCOME/ EQUITY	NET PROFIT/ EQUITY	INTEREST/OPERATING EXPENSE
1962	2.088	0.918	0.023	0.053	0.0
1963	2.084	0.917	0.025	0.056	0.0
1964	2.051	0.926	0.028	0.061	0.0
1965	1.991	0.960	0.030	0.064	0.0
1966	1.946	1.000	0.028	0.062	0.0
1967	1.903	1.040	0.026	0.059	0.0
1968	1.889	1.055	0.027	0.060	0.0
1969	1.872	1.055	0.025	0.059	0.0
1970	1.784	1.033	0.021	0.052	0.0
1971	1.784	1.046	0.024	0.055	0.0
1972	1.688	1.051	0.026	0.061	0.015
1973	1.641	1.054	0.034	0.074	0.015
1974	1.571	1.145	0.038	0.083	0.017
1975	1.598	1.163	0.033	0.074	0.017
1976	1.627	1.178	0.029	0.069	0.018
1977	1.628	1.238	0.030	0.070	0.021
1978	1.654	1.243	0.034	0.074	0.020
1979	1.607	1.271	0.045	0.090	0.022
1980	1.579	1.260	0.041	0.085	0.026
1981	1.537	1.347	0.028	0.069	0.035
1982	1.428	1.514	0.015	0.051	0.044
1983-Q1	0.0	0.0	0.0	0.0	0.0

Note: in this table, zeros imply data unavailable.

TABLE A6

CORPORATE FINANCIAL RATIOS

PETROLEUM AND COAL PRODUCTS
(ANNUAL AVERAGES OF QUARTERLY DATA)

	LIQUIDITY (CA/CL)	DEBT/EQUITY	NET INCOME/ EQUITY	NET PROFIT/ EQUITY	INTEREST/OPERATING EXPENSE
1962	2.573	0.656	0.017	0.042	0.0
1963	2.523	0.583	0.016	0.038	0.0
1964	2.468	0.584	0.018	0.040	0.0
1965	2.440	0.611	0.023	0.044	0.0
1966	2.687	0.585	0.022	0.049	0.0
1967	2.936	0.572	0.026	0.047	0.0
1968	2.659	0.610	0.023	0.048	0.0
1969	2.552	0.601	0.022	0.046	0.0
1970	2.493	0.617	0.022	0.055	0.0
1971	2.194	0.624	0.026	0.056	0.0
1972	2.196	0.634	0.029	0.061	0.013
1973	2.105	0.652	0.038	0.077	0.012
1974	1.844	0.777	0.033	0.099	0.009
1975	1.988	0.757	0.036	0.087	0.010
1976	1.940	0.787	0.032	0.074	0.010
1977	1.764	0.879	0.032	0.076	0.012
1978	1.751	0.847	0.031	0.073	0.011
1979	1.813	0.834	0.052	0.110	0.012
1980	2.050	0.790	0.057	0.121	0.011
1981	2.017	0.866	0.029	0.092	0.015
1982	1.909	0.997	0.018	0.073	0.024
1983-Q1	1.920	1.037	0.010	0.069	0.026

Note: in this table, zeros imply data unavailable.

TABLE A7

CORPORATE FINANCIAL RATIOS

MANUFACTURING INDUSTRY

	LIQUIDITY (CA/CL)	DEBT/EQUITY	NET INCOME/ EQUITY	NET PROFIT/ EQUITY	INTEREST/OPERATING EXPENSE
1962	2.367	0.742	0.025	0.054	0.0
1963	2.350	0.736	0.025	0.058	0.0
1964	2.304	0.747	0.028	0.061	0.0
1965	2.220	0.806	0.028	0.064	0.0
1966	2.140	0.871	0.028	0.062	0.0
1967	2.078	0.935	0.023	0.057	0.0
1968	2.072	0.944	0.025	0.060	0.0
1969	2.074	0.938	0.026	0.061	0.0
1970	1.961	0.962	0.018	0.050	0.0
1971	1.948	0.972	0.024	0.058	0.0
1972	1.888	0.962	0.027	0.064	0.012
1973	1.847	0.967	0.036	0.078	0.012
1974	1.736	1.030	0.042	0.088	0.014
1975	1.771	1.049	0.034	0.075	0.014
1976	1.814	1.054	0.030	0.068	0.014
1977	1.795	1.135	0.029	0.066	0.016
1978	1.792	1.148	0.034	0.071	0.015
1979	1.760	1.124	0.044	0.090	0.016
1980	1.776	1.112	0.042	0.084	0.019
1981	1.729	1.173	0.029	0.070	0.027
1982	1.648	1.290	0.011	0.044	0.032
1983	0.0	0.0	0.0	0.0	0.0

Note: In this table, zeros imply data unavailable.

TABLE A8

INTEREST RATES AND YIELD SPREADS, CANADA/U.S.

	McLeod, Young, Weir Wtd. Canadian Long-Term Corporate * (B14048)	Moody's U.S. Corporate Bonds, Ind Average (B54410)	Canada/U.S. Spread	Canadian 90 Day Prime Corporate Paper (B14017)	U.S. 90 Day Commercial Paper (B54412)	Canada/U.S. Spread
1970 1	9.28	8.07	1.21	8.44	9.03	-0.59
2	9.24	8.36	0.88	7.63	8.74	-1.11
3	9.16	8.44	0.72	7.34	8.19	-0.85
4	9.02	8.15	0.87	5.96	6.46	-0.50
1971 1	8.29	7.35	0.94	4.74	4.63	0.11
2	8.47	7.69	0.78	3.97	5.35	-1.38
3	8.43	7.75	0.68	4.70	5.83	-1.13
4	8.20	7.46	0.74	4.63	4.87	-0.24
1972 1	8.23	7.36	0.87	4.79	4.10	0.69
2	8.31	7.41	0.90	5.71	4.70	1.01
3	8.40	7.37	1.03	4.85	5.04	-0.19
4	8.27	7.27	1.00	5.06	5.48	-0.42
1973 1	8.20	7.39	0.81	5.08	6.61	-1.53
2	8.37	7.45	0.92	6.63	7.88	-1.25
3	8.61	7.82	0.79	8.46	10.40	-1.94
4	8.71	7.83	0.88	9.65	9.29	0.36
1974 1	9.07	8.09	0.98	9.03	8.90	0.13
2	10.16	8.61	1.55	11.44	11.20	0.24
3	10.94	9.28	1.66	11.48	11.78	-0.30
4	10.49	9.30	1.19	10.08	9.43	0.65
1975 1	10.19	9.09	1.10	6.86	6.40	0.46
2	10.65	9.33	1.32	7.34	5.96	1.38
3	11.09	9.31	1.78	8.38	6.79	1.59
4	11.12	9.26	1.86	9.16	5.92	3.24
1976 1	10.75	9.09	1.66	9.29	5.22	4.07
2	10.65	8.98	1.67	9.38	5.66	3.72
3	10.48	8.75	1.73	9.29	5.43	3.86
4	10.04	8.44	1.60	8.64	4.92	3.72
1977 1	9.82	8.33	1.49	7.90	4.87	3.03
2	9.72	8.26	1.46	7.25	5.35	1.90
3	9.61	8.20	1.41	7.33	6.00	1.33
4	9.75	8.39	1.36	7.42	6.78	0.64
1978 1	10.04	8.67	1.37	7.45	6.99	0.46
2	10.02	8.88	1.14	8.34	7.53	0.81
3	9.96	8.99	0.97	9.05	8.42	0.63
4	10.35	9.24	1.11	10.50	10.33	0.17
1979 1	10.55	9.47	1.08	11.13	10.31	0.82
2	10.39	9.60	0.79	11.17	10.12	1.05
3	10.84	9.58	1.26	11.80	11.31	0.49
4	11.91	10.98	0.93	14.18	13.99	0.19
1980 1	13.43	12.60	0.83	14.38	15.73	-1.35
2	12.37	11.83	0.54	12.98	9.87	3.11
3	13.47	11.96	1.51	10.72	10.35	0.37
4	13.85	13.24	0.61	14.53	16.18	-1.65
1981 1	14.27	13.58	0.69	17.13	15.56	1.57
2	16.00	14.31	1.69	18.57	16.96	1.61
3	18.36	15.15	3.21	21.02	17.65	3.37
4	16.65	15.26	1.39	16.62	13.39	3.23
1982 1	16.97	15.41	1.56	15.35	14.53	0.82
2	17.07	15.23	1.84	16.05	14.46	1.59
3	16.03	14.50	1.53	14.32	10.61	3.71
4	13.36	12.62	0.74	10.88	8.93	1.95
1983 1	13.00	12.27	0.73	9.62	8.76	0.86
2	12.33	11.85	0.48	9.32	8.95	0.37
3	12.90	12.38	0.52	9.33	9.55	-0.22
Mean	11.02	9.85	1.17	9.68	8.87	0.81
Variance	6.75	5.93	0.22	14.43	12.59	2.46
S.D.	2.60	2.44	0.47	3.80	3.55	1.57

* Due to changes in data reported by the Bank of Canada, this series is comprised of Statistics Canada Series B14016 through to Oct. 1977, then Series B14048 to Oct. 1983.

Source: Bank of Canada Review, Various Issues, Table S20.