The Impacts of the Market Pricing of Canadian Energy Resources on the Alberta Oil Industry

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Canada has recently enacted legislation that decontrols the price of domestically produced crude oil and natural gas. This study presents an analysis of the impacts of such decontrol via the use of an econometric model of the petroleum industry of the province of Alberta. The model developed in this study improves upon previous models in terms of the endogenizing of key variables associated with the exploration process. The model is estimated for 1958–79, and a simulation of the 1985–95 period is conducted.

Key words: econometric model, oil price decontrol, oil supply.

Between 1973 and 1985, the petroleum industry in Canada operated under a policy in which the domestic price of crude oil was to some degree set below international levels via the use of a complex set of pricing regulations. Over the 1980–84 period, Canadian oil pricing policy was largely a reflection of the National Energy Program (NEP) with its policy objectives of energy self-sufficiency, the equitable sharing of benefits of higher energy prices, and increased opportunity of Canadian participation in the petroleum industry (Energy, Mines and Resources, 1980, p. 2). These objectives were to be achieved through the implementation of tax incentives for exploration, holding the consumer price of domestic oil significantly below the imported price, and reducing foreign ownership of the industry to 50% by 1990 (Carmichael and Stewart, pp. 1–2).

Because of the low domestic oil price received under the NEP, the level of exploratory effort in terms of conventional petroleum sources was reduced. Recognizing this, the government of Canada entered into subsequent agreements with the producing provinces that established a two-tiered pricing system. Under these agreements, oil prices were determined according to whether the oil was classified as "old" or "new."

In order to simplify the pricing of Canadian oil resources and stimulate investment in the domestic oil industry, the federal government in cooperation with the governments of Alberta, Saskatchewan, and British Columbia enacted legislation in 1985 to decontrol the price of domestically produced crude oil. This legislation, known as the "Western Accord," represents a substantial departure from previous energy policy (see Economic Council of Canada, Daniel and Goldberg; and Doern and Toner). That is, investment in the Canadian energy sector was to be stimulated via the use of "market-sensitive" pricing and a fiscal regime based on "profit-sensitive" taxation (Energy, Mines and Resources 1985). Unfortunately, from the perspective of the federal government and the Canadian petroleum industry, the elimination of crude oil price controls has occurred at a time when the world price has been declining.

The main objective of this study is to analyze the possible impacts of recent changes in Canadian energy pricing on the level of oil exploration and production. This objective will

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be achieved via the development of an econometric model of petroleum exploration and production. This paper is organized as follows: First, we present a review of previous econometric models of petroleum supply and note how the model presented in this paper improves upon these studies. Next, the structure of the econometric model used in the industry simulations is presented. Because the province of Alberta has accounted for over 80% of Canadian crude oil production since 1973, this province will be the focus of the model developed in this paper. The model is estimated over the 1958–79 period and then validated via a dynamic simulation. Next, the model is evaluated in terms of its ability to provide forecasts over the 1980–84 period. Finally, a simulation of the oil and natural gas industry 1985–95 is provided under three oil pricing scenarios. Throughout the discussion of the econometric model reference will be made to variable names used in the empirical application and discussed in more detail in the appendix.

Review of Previous Econometric Models of Petroleum Supply

The model developed in this study improves upon previous econometric models of energy supply in terms of the endogenizing of key variables that are often assumed to be unaffected by changes in the economic environment (Clark, Coene, and Logan; Bohi and Toman). For example, Rice and Smith developed a model of the U.S. petroleum industry in which both the size of discovery and the success rate of exploratory drilling were treated as exogenous variables. Because the magnitude of these variables are affected in part by economic decisions, the present study specifically incorporates these variables.

As noted by Clark, Coene, and Logan, the development stage of resource supply is concerned with the installation of the necessary production capacity and infrastructure. In some models, development activity is lumped together with exploration activity, which implies that new discoveries and additions to productive capacity are generated within the models by a single process (Adelman and Paddock). Other studies make the assumption that development activity is automatic in the sense that once a resource is discovered, it is developed according to a predetermined profile (Epple, Uhler). Erickson and Spann; MacAvoy and Pindyck; and Pagoulatos, Debertin, and Pagoulatos view the role of development as one of generating information as to the extent of the reserves that have been discovered.

In the current model, the role of development activity is assumed not to be one of supplying more information as to the extent of previously discovered resources but rather one of generating an inventory of capable oil and gas wells. This assumption implies that the output of the exploration phase are appreciated reserves of crude oil and natural gas instead of booked reserves. The major reason for adopting this approach has been the relatively poor performance of the development components of previous models that explicitly model extensions and revisions to booked discoveries.

The role of resource depletion as a determinant of exploration or development activity is often ignored in models of oil supply. MacAvoy and Pindyck, and Pindyck develop models that incorporate such factors into the supply process. The present model improves upon their specification in that the effect of resource depletion is allowed to vary depending upon the degree to which the resource has been depleted.

In the models of oil and natural gas supply formulated by Bradley and Epple, oil and gas production is hypothesized as occurring along a given profile that is invariant to changing economic conditions. In other studies, such as those developed by Pindyck; and Pagoulatos, Debertin, and Pagoulatos, economic and physical variables determine the level of production. These latter two studies depict expected prices as being major determinants of oil and natural gas production. The major shortcoming with the use of expected prices is that it does not reflect the profitability of oil and natural gas production (Pagoulatos, Debertin, and Pagoulatos). The present study improves upon this by the inclusion of an after-tax profits (net back) variable in the crude oil and natural gas production equations.

General Structure of the Econometric Model

The energy supply process in the econometric model is assumed to consist of three stages: exploration, development, and production.

That is, with the discovery of new pools or fields of oil, the field must be developed before production can occur. This development activity involves the drilling of additional wells and the construction of the infrastructure necessary for production. A flow chart representing the general structure of the model is presented in figure 1. This flow chart is divided into three major sections, each concerned with one of the above stages. The following discussion will review this figure as it relates to the empirical model. The effect of key economic and resource variables on the important components of the econometric model will be discussed briefly.

Modeling Exploratory Activity

The exploration phase adopted in the present model is based on the structure used by Fisher in his early analysis of the U.S. petroleum industry and can be represented as

$$(1) \qquad TD_i = EXWELL \cdot PROB_i \cdot SIZE_i,$$

where TD_i represents the new discoveries of the ith resource (i = oil, gas), *EXWELL* is the number of exploratory wells completed, $PROB_i$ represents the proportion of exploratory wells finding the ith resource and $SIZE_i$ represents the average size of the ith resource discovered.

In figure 1, block (A) represents the values of lagged endogenous and exogenous variables that will have an effect on the system. Previous prices, when combined with the previous discovery sizes and the probabilities of such discoveries, results in an estimate of the expected gross returns (*EXPRET*) from drilling an exploratory well (block B). In the MacAvoy and Pindyck model of natural gas supply, it was shown that in addition to expected returns, the variation in those returns (*STDXRET*, block D) will also be a factor affecting the level of exploration activity where exploration activity can be represented by a number of exploratory wells completed (*EXWELL*) and their depth (*EXDEPTH*, block F). With risk-averse firms, an increase in the level of expected returns from exploration should result in an increase in the level of activity, while an increase in the variation in returns should result in decreased activity (Pindyck; MacAvoy and Pindyck; and Pagoulatos, Debertin, and Pagoulatos).

In addition to the size and variation of expected returns, the current level of oil and natural gas reserves (*OBEGRES, RGBEGRES*) are hypothesized to have an effect on exploration activity. The larger the size of the begining reserves, the larger the inventory of known deposits, which implies less of a need for undertaking activity designed to add to these inventories in order to meet future demands. In addition, large inventories have associated with them relatively high inventory costs. Therefore, the individual producer has an incentive to minimize the costs of holding inventories given the constraint of meeting near-term production requirements.

During the early stages of exploration, the most accessible deposits will be discovered. As less accessible areas are explored because of previous exploratory drilling (*CUMEXDR*), a larger number of exploratory wells needs to be drilled, with an increase in the average depth drilled in order to find new deposits. Thus, both measures of exploratory effort (*EXWELL, EXDEPTH*) are expected to be positively affected by an increase in cumulative drilling activity.

Given the expected returns from exploration, there will be a negative relationship between exploration costs (*EDREXP*, block E) and exploratory drilling. Exploration costs are seen as being determined by the number of exploratory wells drilled (+), their depth (+), and the exploration history of the region. The effect of the exploration history on costs depends on the degree to which an area has been explored. For areas that have only recently started to be explored, the effect of accumulated information, as represented by the variable *CUMEXDR*, may result in lower costs (i.e., the learning effect). As the region "matures" in the sense of having experienced greater amounts of past exploratory effort, the level of cumulative exploratory activity will have a positive (depletion) effect on exploration costs as less accessible areas need to be explored (Pakravan).

Estimation of Exploratory "Success" Rates

Expected returns from exploration not only have an effect on the level of exploration activity but also determine the direction of that activity. That is, the proportion of exploratory wells that are classified as finding oil (*OPROB*) or natural gas (*GPROB*) depends on the relative returns from exploring for these two resources (block C). Various authors refer to this

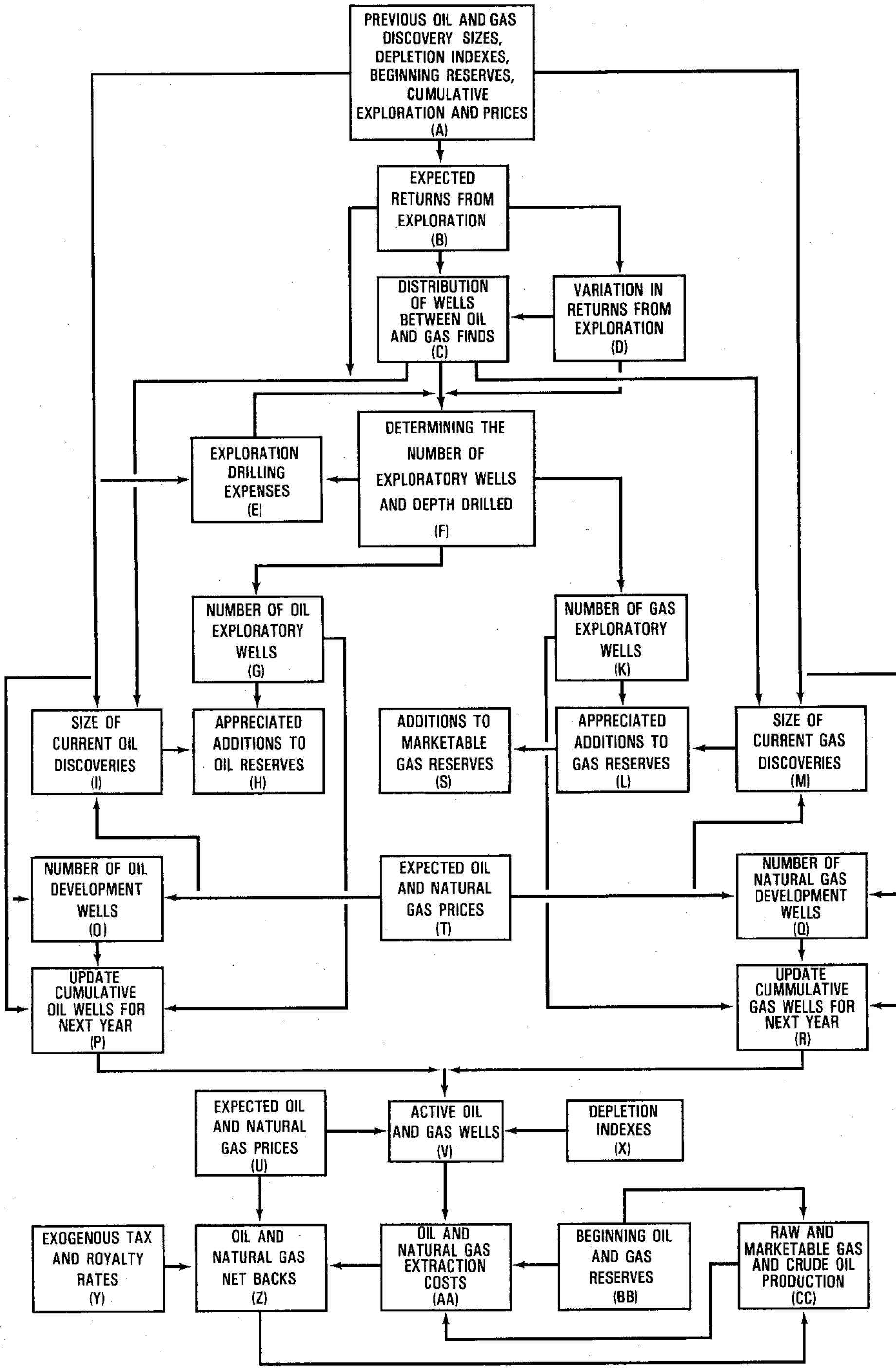

Figure 1. Flow chart of the petroleum supply model

proportion as the "success rate" of exploratory activity; but, as noted by Erickson and Spann, this variable is not a probability coefficient given by nature but reflects the distribution of prospects accepted (pp. 102–3). MacAvoy and Pindyck, in their study of the U.S. natural gas and petroleum industry, hypothesized lagged (expected) prices as affecting the magnitude of the distribution of exploratory wells between oil and natural gas finds. In the present study expected gross returns from discovering oil and natural gas are used to explain the direction of drilling activity, thus capturing the effect of changes in expected discovery sizes as well as expected prices. As the ratio of per-discovery expected returns from finding oil increases relative to that of natural gas (*RETRATIO*), the proportion of wells finding oil should increase. This positive relationship is caused by several factors. First, the above change may be the result of the shifting of exploration activity into areas where the likelihood of discovering oil is greater. Erickson and Spann provide a discussion of the factors affecting the location of exploration in the extensive versus intensive margins and note that "over time, there tends to accumulate an inventory of relatively small, relatively certain prospects. This inventory represents an aspect of the intensive margin in exploration" (p. 103). With higher prices, firms drill into this inventory. Second, given higher crude oil prices, the companies involved with exploration activity may simply use more resources to find oil, instead of gas, and thus generate a change in the relative proportions.

The level of undiscovered reserves has an impact on the probability of an exploratory well finding either oil or natural gas. As a region is explored and more of the resource is discovered, there will be a decrease in the discovery rate of new reserves because of the physical limits of the resource. This phenomenon is captured in the present model via the use of depletion index variables (*ODINDEX, MGDINDEX*), which are similar to those developed by MacAvoy and Pindyck. These depletion variables provide a measure of the proportion of the ultimate potential reserves left to be discovered, which implies a positive relationship between the value of this variable and the associated "success rate."

As exploration occurs in a region, information concerning the nature of deposits is obtained from both the successful and unsuccessful exploratory wells (*CUMEXDR*). As more information is obtained about the physical resource, exploratory efforts can be directed to those areas that are the most likely to result in a discovery. Thus, we would expect a positive relationship between cumulative exploration and the "success rates."

A successful exploratory well can be classified as discovering oil or gas but not both. With a given number of exploratory wells, an increase in the proportion of wells classified as finding one type of resource will result in a decrease in the proportion that are unsuccessful and/or a decrease in the proportion representing the other resource. Thus, in the logit equations used to describe the success rate variables, we include the variable representing the "success rate" of the other resource as an explanatory variable.

Estimation of the Average Size of Oil and Natural Gas Discoveries

In order to estimate the total level of discoveries, the average size per discovery needs to be estimated (*OILSIZE, RGSIZE,* blocks I and M). As noted by MacAvoy and Pindyck, and Fisher, the size of discoveries is affected by both physical and economic variables. Again, as a new region is explored, the usual case is that the largest and most easily accessible deposits will be discovered first. As exploration continues, the size of discoveries decreases. Expected resource prices (*EXOILPR, EXGASPR,* block T) will have an effect on the size of discoveries of crude oil and natural gas because average size of discovery is a reflection of the drilling opportunities undertaken by exploration firms due to changing economic variables (Fisher p. 7).

Previous studies have not been consistent in terms of the effects of price changes on the size of oil and gas discoveries. MacAvoy and Pindyck found a positive relationship between gas and oil discovery size and expected prices. In contrast, Pagoulatos, Debertin, and Pagoulatos found a negative relationship between oil size and oil price and a positive relationship between gas size and natural gas price. Fisher, in his study of the U.S. petroleum industry, found a negative relationship between the size of oil discovery and oil price. In their analysis of the U.S. petroleum industry, Erickson and Spann suggest that "if firms can at least roughly rank drilling prospects ex ante according to their expected size, then higher prices will justify moving through the distribution of prospects and accepting some prospects which would have been too small to drill at lower prices" (p. 103). Some of the above differences can be attributed to the definitions of discovery size and success rates used by various authors. For example, Fisher defines the size of oil discovery as the average size for successful (both oil and gas) wildcat wells.

Given the definition of intensive and extensive margin of exploration as proposed by Erickson and Spann, we would expect a negative relationship between "success" rates and the size of discovery. If a firm explores in the intensive margin, the size of discovery will be small while the success rate will be relatively high, *ceteris paribus*. The opposite will hold true for the extensive margin which has a few potentially large prospects. Thus, in the discovery size equations a "success" rate variable is used to explain the variation in discovery size.

The use of the depletion index variables in the size equations reflect the relationship between discovery size and exploration history of the region of concern. Because of the definition of these indexes, we expect a positive coefficient on the depletion index variables in the size equations.

With estimates of the number of exploratory wells finding oil or natural gas (blocks G and K) and of the average size of these discoveries, an estimate of the total level of reserve additions (blocks H and L) can be obtained via the use of equation (3.1). The above discussion has been concerned with raw natural gas and crude oil discoveries. In the empirical model the total discoveries of marketable natural gas are assumed to be based on two factors: (*a*) the level of raw gas discoveries and (*b*) the level of technology (block S).

Description of the Development and Production Components

The number of development wells (*ODEVWELL, GDEVWELL*) completed are hypothesized to be positively affected by expected prices (blocks O and Q). The effect of resource depletion on development activity depends on the stage of depletion. During the initial stages of resource discovery, development activity should be positively related to changes in depletion. As a region becomes more developed, the current level of development activity should decrease because of smaller amounts of new discoveries needing to be developed.

The number of active oil (*ACTOWELL*) or gas (*ACTGWELL*) wells are determined by the previous levels of successful exploratory and development wells (*CUMOWELL, CUMGWELL*, block V). Expected oil and natural gas prices (block U) will also have a positive impact on the number of active oil and gas wells, respectively. The impacts of cumulative oil or natural gas production (*CUMOPROD, CUMGPROD*) on the number of active oil or gas wells will depend on the stage of development of the region in terms of that resource. During the initial stages of exploitation, there should be a positive relationship between resource depletion and the number of active wells (i.e., the learning effect). As the use of the resource continues, the effect of continued resource extraction implies a negative effect on the number of producing wells (i.e., the depletion effect). The use of the depletion indexes in the active well equations captures the above effect (block X).

Expected net backs (*MOVEONB, MOVEGNB*, block Z) will have a positive impact on the level of natural gas and crude oil production (*RGPROD, OPROD*, block CC). In the calculation of the resource net backs, effective income tax rates, output prices, and royalty rates are assumed to be exogenous to the model (blocks U and Y), while the level of the production costs (*OOPERX, GOPERX*, block AA) are determined by the level of resource extraction (+), the number of active wells (+), and the level of beginning reserves. Because of the existence of associated natural gas deposits, the level of crude oil production will positively effect the level of raw gas production to the extent that there are associated gas deposits. Similar to the treatment of marketable raw natural gas discoveries, marketable gas production (*MGPROD*) in the empirical model is based on the level of raw gas production and technology.

MacAvoy and Pindyck; and Pagoulatos, Debertin, and Pagoulatos include the level of remaining reserves directly in their production equations and note that the marginal cost of production will be lower with relatively larger reserve levels. Thus, in their gas and oil production equations, beginning reserves had a positive impact on the level of production. Unlike the above, the present analysis allows for the presence of "learning" and "depletion" effects of remaining reserves on production levels.

Estimation and Validation of the Econometric Model

The econometric model of the Alberta petroleum industry consists of seventeen stochastic equations and twenty-six indentities.[1] A majority of the stochastic equations were estimated using a two-stage least squares estimator. Several equations contained within the model do not use endogenous variables as explanatory variables and were therefore estimated using ordinary least squares methods. In addition, the two equations used to explain the proportion of exploratory wells classified as finding crude oil or natural gas were estimated by use of the logit form of the regression, given that these proportions fall between zero and one. As noted by Intriligator (p. 174), the logit form of the regression equation poses heteroscedastic error terms and therefore must be estimated via generalized least squares (GLS) methods.[2]

The estimated model performs well given that over 78% of the estimated coefficients have t-statistics that are greater than two. The signs of these coefficients were as expected. For example, the *EXPRET* and *STDXRET* coefficients were positive and negative, respectively, in the exploratory well and exploratory depth equations. The after-tax net back variables were found to be positive and significant in the oil and raw natural gas production equations. The learning and depletion effects in terms of exploration expenses were captured by the use of a cost function similar to that used by Pakravan. In addition, the use of the oil and natural gas depletion index variables performed as hypothesized in terms of explaining discovery size, success rates, development activity, and the number of active oil and natural gas wells.

Validation of the model over the estimation period is based on a comparison of actual versus simulated values of the endogenous variables where the simulated values of lagged endogenous variables are obtained via a dynamic simulation. The statistics used in the validation process consist of Thiel's U_2 coefficient, the squared correlation coefficient between predicted and actual values, root mean square errors, and several error decomposition measures. Table 1 provides a listing of these statistics for key endogenous variables for the 1958–79 period. Given the above evaluation of the model over the estimation period, table 2 shows the values of several endogenous variables 1980–84. In terms of crude oil production, the largest absolute percentage error is the 8% underestimate in 1980. For natural gas production, the largest error is found in the model's estimate for 1983 production, 10%. The ending reserve estimates were relatively close for all three resources delineated in the model.

Simulation of the Alberta Oil Industry under Alternative Crude Oil Price Scenarios

This section presents forecasts of the impacts of three oil price scenarios on the Alberta oil industry. The assumption of decontrolled domestic oil prices will be used throughout the analysis. The unstable nature of the world petroleum market made the task of choosing future oil price paths extremely difficult. In order to cover the most likely situations, three price paths were chosen after discussion with Energy Mines and Resources (EMR) personnel and a review of recent studies concerned with the future prospects of world energy markets. Table 3 presents the data used in the derivation of the oil and gas prices for each of the scenarios. In addition to estimates of world oil prices, assumptions with respect to exchange rates and marketing costs were incorporated into the price calculation procedures.

The impacts of the three price scenarios on future levels of crude oil production are presented in figure 2.[3] Under all scenarios, the trend of decreasing levels of production, ob-

[1] A complete listing of the estimated econometric model and a more detailed discussion of the data used are available upon request from the author.

[2] An additional problem occurring in the gas and oil logit equations is the presence of the success rate of the other resource as an explanatory variable. In order to eliminate the simultaneity problem, two-stage least squares estimates of the parameters of each logit equation were calculated. From these equations estimated values of the gas and oil success rates were then used in the GLS estimation of the oil and natural gas logit equations, respectively, as dependent variables.

[3] When viewing figures 2 through 5, the simulation of the 1975–84 period is represented by the "Base" portion of each figure. The model was used to simulate the 1958–84 period.

Table 1. Comparison of Actual and Simulated Values of Selected Endogenous Variables, 1958–79

Variable	Mean	Γ	δ	β	Thiel's Coefficient	RMS Error	Source of Error U_m	U_r	U_d
OPROD	45,585	.451	.972	.988	.553	3,390	.007	.005	.988
RGPROD	46,422	.560	.989	.989	.630	2,737	.009	.011	.980
MGPROD	36,358	.564	.990	.991	.591	2,008	.007	.008	.985
OILSIZE	367.4	1.352	.888	.964	.274	163.6	.003	.011	.986
RGSIZE	515.4	1.040	.609	.780	.712	347.2	.000	.110	.889
GOPERX	129.5.	.810	.973	1.016	.675	17.1	.002	.008	.990
OOPERX	151.7	.445	.955	.986	.849	15.4	.172	.004	.824
RGBEGRES	2,141,150	.088	.973	.979	.495	36,400	.289	.011	.699
OBEGRES	1,255,500	.137	.973	.989	.523	30,060	.159	.004	.837
MGBEGRES	1,793,770	.092	.976	.976	.711	42,500	.642	.007	.351
EXWELL	1,140	.535	.917	.948	.767	179	.044	.031	.925
GPROB	.253	.458	.902	.869	.883	.039	.010	.172	.818
OPROB	.120	.423	.243	.589	.799	.048	.059	.127	.814
GASNB	4.06	.646	.948	.880	.837	.700	.065	.239	.697
OILNB	12.86	.171	.948	1.010	.523	.524	.118	.001	.880
ACTOWELL	9,740	.129	.971	.900	.707	272	.152	.243	.605
ACTGWELL	3,820	1.072	.993	.999	.323	347	.093	.000	.907
EXDEPTH	1,426	.190	.771	1.073	1.048	140	.170	.013	.817
ODINDEX	.351	.259	.988	.963	.509	.011	.043	.100	.857
MGDINDEX	.437	.231	.997	.994	.248	.005	.000	.013	.987
EXPRET	2,243	.843	.969	.989	.343	329	.004	.004	.992
STDXRET	1,211	1.2468	.808	1.106	.922	727	.180	.031	.790
GDEVWELL	751	1.130	.931	.972	.927	220	.004	.011	.985
ODEVWELL	597	.335	.707	1.006	.926	106	.001	.000	.999

Note: Refer to the appendix for the definitions of the variables used in this table and their units. Γ refers to coefficient of variation; δ is the squared correlation coefficient between actual and predicted values; β is the regression coefficient obtained when regressing the actual on the predicted values. Thiel's coefficient refers to Theil's inequality coefficient; U_m represents the proportion of the MSE due to difference in the means of the predicted versus actual series; U_r represents the proportion of the MSE due to the regression coefficient being different from one; U_d represents the proportion of the MSE that is due to the variance of the residuals obtained by regressing the actual on the predicted changes. For more detail refer to Madalla, pp. 344–45.

served since 1973, continues. Not surprisingly, the *HIGH* scenario initially resulted in relatively larger levels of crude oil production. The larger production levels occurring under this scenario 1985–93 result in substantially lower levels of beginning reserves, which in turn resulted in lower levels of output in 1994 and 1995 when compared to the *MEDIUM* and *LOW* scenarios.

Another factor that affected the level of production was the dramatic decrease in the level of crude oil net backs over the early 1990s in spite of relatively constant crude oil price levels. Over the 1985–95 forecast period, for most years, larger oil net backs were observed under the *HIGH* scenario (fig. 3). By 1995, this scenario generates a lower oil net back than under the *LOW* price scenario. The reason for this change in relative net backs are the higher average costs of extraction encountered for the later years under this scenario (fig. 4). From figure 4 we see that the average costs of extraction do not differ significantly between scenarios until 1992. After this year, the *HIGH* scenario generates significantly higher average costs. This result may be due to the lower reserve levels observed under this scenario (fig. 5).

Given the structure of the exploration component of the model, the effect of alternative levels of crude oil prices on (*a*) the level of production, (*b*) average discovery size, (*c*) the proportion of exploratory wells that find crude oil, and (*d*) the number of exploratory wells drilled in the previous period will determine the impacts on beginning reserve levels. Over the 1990–95 period, the level of exploratory drilling differed significantly across scenarios. Under the *HIGH* scenario, the level of exploratory wells completed increased by 94% in 1995 over the simulated 1984 level. This compares with a 71% increase observed under the *LOW* scenario. Under all three scenarios, there was a general upward trend in the level of ex-

Table 2. Comparison of Actual and Predicted Values of Selected Endogenous Variables

Variable	Units	1980		1981		1982		1983		1984	
		A	P	A	P	A	P	A	P	A	P
OPROD	1,000 c.m.	63,201	58,130	56,978	56,461	54,384	51,842	55,317	58,943	59,886	59,731
MGPROD	mil. c.m.	62,070	65,499	61,950	66,018	64,113	65,259	60,590	66,413	66,007	65,775
RGPROD	mil. c.m.	77,358	81,174	76,376	81,059	78,522	78,955	75,006	79,830	81,112	77,915
OBEGRES	mil. c.m.	886	877	854	849	833	858	812	823	780	785
RGBEGRES	bil. c.m.	2,324	2,260	2,303	2,240	2,341	2,249	2,296	2,228	2,269	2,209
MGBEGRES	bil. c.m.	2,005	2,001	1,993	1,991	2,036	2,007	2,003	1,996	1,984	1,987
GASNB	$/1,000 c.m.	12.32	12.92	8.15	8.25	8.28	7.83	8.59	7.96	8.22	7.61
OILNB	$/mil. c.m.	16.51	16.28	12.02	11.78	16.82	16.88	20.66	21.95	20.04	21.16
EXWELL	No. wells	2,599	2,751	2,352	2,766	1,768	1,762	1,370	1,504	1,933	1,733
ODINDEX	percent	23.3	24.2	23.0	23.3	22.0	22.2	20.9	20.0	19.5	19.1
MGDINDEX	percent	23.6	24.5	22.3	23.3	21.1	21.9	18.4	19.8	17.7	18.4
ACTGWELL	No. wells	16,661	17,247	18,797	19,874	20,611	22,201	21,300	23,314	24,740	24,006
ACTOWELL	No. wells	13,312	13,690	14,243	14,394	15,259	15,171	16,300	16,256	17,759	17,762
EXDEPTH	meters	1,533	1,387	1,464	1,361	1,472	1,732	1,590	1,731	1,551	1,753
ODEVWELL	No. wells	1,239	1,109	1,066	1,230	1,194	1,346	2,031	1,847	1,998	2,782
GDEVWELL	No. wells	2,672	2,248	2,004	2,170	1,810	1,996	813	1,606	936	1,222
OOPEREX	mil. $	318	306	314	324	360	340	425	377	420	420
GOPEREX	mil. $	426	398	421	438	433	471	412	489	508	498
OPROB	percent	15.4	10.8	17.7	13.3	24.0	42.1	31.0	34.7	31.9	37.4
GPROB	percent	49.9	57.2	46.0	53.2	39.0	32.0	27.4	30.0	23.1	24.8

Note: A refers to actual and P refers to predicted values. Refer to the appendix for a description of the above variables. All dollar figures are in terms of Canadian exchange; c.m. represents cubic meters. For more discussion refer to Gould.

Table 3. Derivation of Crude Oil and Natural Gas Prices Used for Simulations, 1985–95

Year	Price Scenario (1985 $U.S./bbl) LOW	MEDIUM	HIGH	Exchange Rate	Price Scenario (1971 $Cdn./c.m.) LOW	MEDIUM	HIGH	Gas Price (1971 $Cdn./ 1,000 c.m.)
1985	30	30	30	1.379	74.57	74.57	74.57	48.47
1986	15	15	15	1.321	42.74	42.74	42.74	45.00
1987	18	25	30	1.291	46.74	64.93	77.91	43.00
1988	20	25	30	1.279	51.21	64.68	77.67	47.00
1989	20	25	30	1.246	51.15	64.62	77.92	51.00
1990	20	25	35	1.246	51.08	64.55	87.36	55.00
1991	20	25	35	1.246	51.15	64.62	87.43	53.00
1992	20	25	35	1.246	51.24	64.71	87.51	51.00
1993	20	25	35	1.246	51.33	64.80	87.60	49.00
1994	20	25	35	1.246	51.42	64.74	87.70	47.00
1995	20	25	35	1.246	51.44	64.97	87.72	46.00

Note: The oil prices listed in columns 6–8 are wellhead prices and incorporate the various transportation costs, other marketing charges, and quality differentials. All oil price data is based on data obtained from EMR. The natural gas price data is based on price movements formulated by Rowse. Here, c.m. represents cubic meters.

ploratory wells completed. Concurrent with this trend of increased exploratory activity, the proportion of these wells classified as finding oil was forecast to decrease under all scenarios. In 1985, the model predicts that 40% of the exploratory wells will be classified as discovering crude oil. This percentage is forecast to decline to 15% in 1995 under the *MEDIUM* scenario.

With the above two countervailing trends, the number of new exploratory wells is projected to remain relatively constant 1986–89. Over the 1990–95 period, the number of new oil exploratory wells completed was projected to decrease under all scenarios. With the 1985 estimated oil exploratory well level of 794 wells, the number of new oil exploratory wells decrease by 21% to 626 in 1995 under the *HIGH* scenario as compared to 353 wells under the *LOW* scenario.

In terms of the size of crude oil discoveries, the *OILSIZE* variable was forecast to remain relatively constant 1989–95, with larger discovery sizes occurring under the *LOW* scenario. Over the 1985–95 period, the average size of oil discoveries was 44,000 cubic meters per well. This compares with 36 and 29 thousand cubic meters per well under the *MEDIUM* and *HIGH* scenarios, respectively.

An estimate of the level of reserve additions can be obtained by combining the trends observed in terms of new oil exploratory wells and average discovery size observed under the three price scenarios. Over the 1985–88 period, the level of reserve additions was increasing. For the remaining years, the level of new oil additions is estimated to decrease. Combining this trend with the oil production levels under the three scenarios results in the lower beginning reserve levels (fig. 5). Under the *HIGH* scenario, beginning crude oil reserves decrease the most rapidly. Given the relationship between reserve levels and production, the decreased beginning reserves may be one explanation for the pattern of lower production observed in the later years under the *HIGH* scenario.

Conclusions

This paper has presented an econometric model of the petroleum industry for the Province

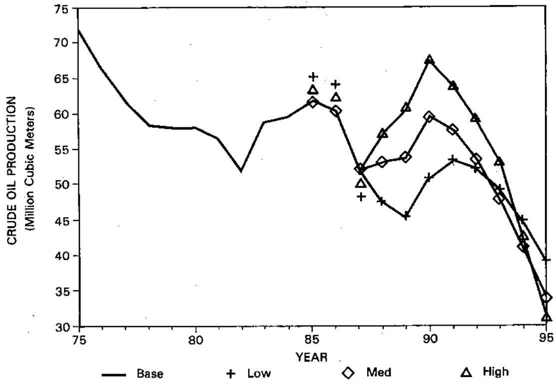

Figure 2. Crude oil production, Alberta, 1975–95

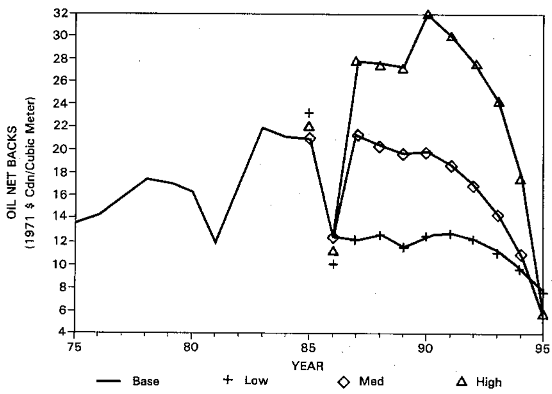

Figure 3. Crude oil net backs, Alberta, 1975-95

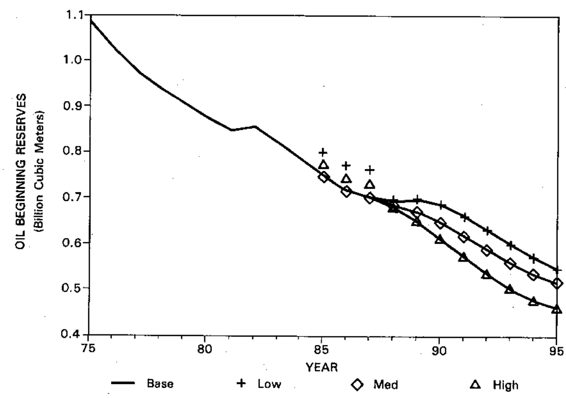

Figure 5. Crude oil beginning reserves, Alberta, 1975-95

of Alberta. The resources analyzed include the conventional sources of petroleum and natural gas. Gould has presented the results of these price changes on the natural gas sector. In this study the impacts on the oil sector are emphasized. This model of exploration and development follows the structure utilized by Fisher in his early analysis of the U.S. petroleum industry. The estimated model performs well, as shown by the various statistics used in the validation process. The model is estimated over the 1958–79 period and is used to simulate 1985–95 under three oil pricing scenarios.

In terms of crude oil production, except for the highest oil price scenario, the level of production is projected to continue to decline as it has since the mid-1970s. The level of oil net backs were projected to increase dramatically under the *HIGH* scenario and then drop quite rapidly after 1992. The *MEDIUM* oil price scenario resulted in relatively constant levels of net backs after the dramatic drop in 1986 until 1993. The *LOW* oil price scenario results in net backs that remain relatively constant at approximately the level received in 1986 ($12 per cubic meter).

The number of exploratory wells was forecast to remain relatively constant 1990–95 for all scenarios. Combining this trend with the movements of success rates and discovery sizes resulted in estimates of reserve additions that could not keep pace with the rates of extraction, which implies lower reserve levels under all scenarios. In summary, with the decontrol of oil prices in Canada, the continued decline in the level of oil production and reserve levels is expected to continue under the price and tax scenarios analyzed. The degree to which they decline will vary depending on the future oil price path.

One major limitation of this model is the exogenous nature of income taxes and royalty rates. With the development of a more detailed model with respect to the financial structure of the industry, the determination of the tax and royalty rates could be brought into the model. A second area of improvement that may be undertaken is to incorporate the various demand components into the model. Given the current situation in the oil markets, information as to the supply and disposition of crude oil is important from both a public policy as well as private decision-making perspective.

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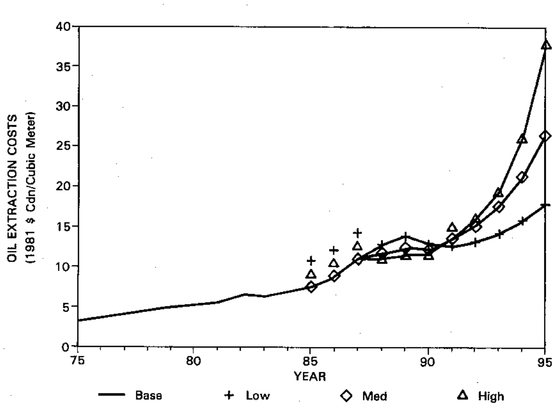

Figure 4. Crude oil extraction costs, Alberta, 1975-95

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Appendix

Listing of Key Variables

Exploratory, Development, and Active Well Variables:

ACTGWELL	Number of active gas wells as of 31 December
ACTOWELL	Number of active oil wells as of 31 December
CUMEXDR	Cumulative number of new field wildcats, new pool wildcats, deeper pool tests, shallower pool tests, and outpost wells completed as of the beginning of the year
CUMGWELL	Cumulative number of gas exploratory and development wells as of the beginning of the year
CUMOWELL	Cumulative number of oil exploratory and development wells as of the beginning of the year
EXDEPTH	The average depth per exploratory well (1,000 meters)
EXWELL	Number of exploratory wells completed as of 31 December
GDEVWELL	Number of gas development wells as of 31 December
GPROB	Proportion of completed natural gas exploratory wells
ODEVWELL	Number of oil development wells as of 31 December
OPROB	Proportion of completed oil exploratory wells

Prices, Costs, and Returns Variables:

EDREXP	Direct exploratory drilling expenses ($million 1971)
EXGASPR	Deflated expected natural gas price ($/1,000 cubic meters)
EXOILPR	Deflated expected crude oil price ($/cubic meter)
EXPRET	Expected exploratory drilling gross returns ($million 1971)
GASNB	Deflated natural gas net back ($/1,000 cubic meters)

GOPERX	Deflated natural gas operating expense ($million 1971)
NGPRICE	Deflated average plant gate raw natural gas price ($/1,000 cubic meters)
OILNB	Deflated crude oil net back ($/cubic meter)
OOPERX	Deflated oil operating expenses ($million 1971)
MOVEGNB	Moving average of gas net backs ($/1,000 cubic meters)
MOVEONB	Moving average of oil net backs ($/cubic meter)
PINDEX	Ratio of expected oil price and expected natural gas price
RETRATIO	Gross return ratio from finding crude oil and natural gas
STDXRET	The variation of deflated expected returns from exploratory drilling ($million 1971)

Crude Oil and Natural Gas Reserves Variables:

RGBEGRES	Raw natural gas beginning reserves (million cubic meters)
MGBEGRES	Marketable natural gas beginning reserves (million cubic meters)
MGDINDEX	Marketable gas depletion index (percentage)
OBEGRES	Crude oil beginning reserves (1,000 cubic meters)
ODINDEX	Crude oil depletion index
OILSIZE	Average size of oil discoveries (1,000 cubic meters)
RGSIZE	Average size of raw natural gas discoveries (million cubic meters)

Production Variables:

CUMMGPROD	Cumulative marketable natural gas production (million cubic meters)
CUMOPROD	Cumulative crude oil production (1,000 cubic meters)
MGPROD	Marketable natural gas production (million cubic meters)
OPROD	Crude oil production (1,000 cubic meters)
RGPROD	Raw natural gas production (million cubic meters)