THE POTENTIAL SUPPLY OF CRUDE OIL AND NATURAL GAS RESERVES IN THE ALBERTA BASIN

Russell S. Uhler

with the collaboration of
Peter C. Eglington

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The Potential Supply of Crude Oil and Natural Gas Reserves in the Alberta Basin

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Contents

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1 Introduction

It is common for studies of the supply of oil and gas reserves to be based on the exploitation of geological data on the volume of sediments or to use probability distributions of pool characteristics to estimate the ultimate supply potential of a basin. Such methods provide useful information and are probably the only ones possible when a history of actual drilling results is not available. In this study, the potential supply of primary conventional light and medium oil and natural gas reserves is examined from a different perspective. Interest focuses on the remaining potential in those geological formations in which oil and gas have already been discovered and for which there exists a past history of drilling results. Moreover, the supply of reserves is believed to depend upon the economic conditions that are faced by the industry, and thus a primary objective of the study is to determine how the supply of reserves responds to changes in these economic conditions.

This objective is accomplished by studying the data at two different levels of aggregation with respect to the geological formations and geographical areas in which oil and gas have already been found. The first level of aggregation consists of eight groups of geological formations and areas. This grouping accounts for 98 per cent of conventional oil and 93 per cent of non-associated natural gas discovered in the Alberta basin. It turns out that this grouping is very close to what are commonly considered the major oil and gas plays in the basin. The second level of aggregation is over all formations and areas and is thus the entire basin.

The study of the data at these two levels of aggregation is accomplished using two different approaches. The first approach is applied at both levels of aggregation and focuses on the study of how reserve additions, in each year, respond to drilling activity with the objective being to determine the ultimate amount that firms in the industry want to drill given the prices of reserves and drilling costs. These prices and costs can then be associated with the reserve additions produced by the desired level of drilling to yield a supply relationship of ultimate reserves. The other approach is only applied to the aggregate data and focuses on the discoveries-appreciation process. The yearly amount of initial discoveries is explained by economic and other variables, and these initial discoveries are then appreciated according to a formula which makes appreciation depend upon the time since discovery and the price of reserves.

In Chapter 2, the methodology used in the data analysis is set out and links are established with work done elsewhere. Special attention is given to showing how methods, which in engineering literature are referred to as performance methods, can be integrated with economic analysis to produce what is called a performance-economic model. In fact, this is the basic model used in the analysis of the disaggregate data. In explaining this model, it quickly becomes obvious that reserves prices play a key role in the decision-making process.

Since reserves prices are not generally available in published form such as, for example, are wellhead prices, they must be derived from the available data. Chapter 3 is devoted to explaining the rationale behind the derivation of these prices and to presenting the price series. Since reserves prices are unit asset prices that are based on future wellhead prices they respond to changes in wellhead price expectations. Unlike wellhead prices, reserves prices respond to changes in royalty rates, income tax rates, various categories of development costs, delays between discovery and production, etc., and thus can be expected to diverge from wellhead prices. This divergence is shown by graphs of the price ratios. It is found, for example, that oil reserves prices fall with respect to wellhead prices until the mid-1970s at which point they rise sharply. Natural gas reserve prices also rise sharply at this time. It is not a coincidence that this is a period when drilling activity also rises sharply. Also shown in this chapter is the relationship between reserves prices and what in the industry are commonly called netbacks.

In Chapter 4, the results of the analysis of the disaggregate data are presented. These results indicate that only one geological horizon for which substantial amounts of drilling data are available, the Upper Devonian, shows any substantial remaining oil potential. It is estimated that the remaining potential for primary recoverable oil is somewhere in the range of 60 to 160 million cubic metres (378 million to 1 billion bbls). The prospects for additional oil reserves in the other seven horizons studied are not particularly bright with perhaps 6 to 20 million cubic metres (38 to 126 million bbls) likely to be forthcoming. Table 1-1 summarizes and compares estimates of potential additional light and medium crude oil reserves in the

Table 1-1

Potential Light and Medium Oil Reserve Additions in the Alberta Basin

	In Devonian	Primary and waterflood ($10^6 m^3$) Without deep basin	With deep basin
This study[1]	60-160[1]	66-180[1]	n.a.
Petro-Canada	122	190	285
National Energy Board	n.a.	n.a.	280
Esso[2]	126	177	317
ERCB[3]	100	n.a.	250

1 Primary reserves only at $70/m³ reserves price. On average waterflood adds about 8 per cent to reserves in the Upper Devonian.
2 Appreciated discoveries only.
3 The Alberta Energy Resources Conservation Board.

Alberta basin made in this and other recent studies. The range of estimates from this study are broadly consistent with those from the other studies noted in Table 1-1. This range of estimates is produced from two models that represent polar cases in assumptions about the ability of firms to complete wells to a particular hydrocarbon, for example, oil, when the intent of the well is to find that hydrocarbon, as opposed to the case where drilling effort has no specific intent. This concept of "directionality" and its role in the development of the two models is discussed in detail in Chapter 2.

One of the purposes of this study is to estimate the responsiveness of the supply of ultimate reserves to price changes. This is done by determining the optimal amount of cumulative drilling effort, and the resulting reserves, at various levels of the price of reserves. Since at higher prices more cumulative drilling will be undertaken and more reserves will be discovered, it is possible to quantitatively estimate the magnitude of this response to price increases. Estimates of this price responsiveness are obtained for each of the horizons of interest. The oil reserves estimates and the way in which these estimates respond to changes in the price of reserves for the disaggregate analysis are summarized in Table 4-23 of Chapter 4.

It has already been indicated that the Upper Devonian is the only horizon studied that shows significant remaining conventional light and medium oil potential. As expected, this potential is somewhat responsive to the level of reserves prices, but the estimates of this responsiveness depends upon the treatment in the model of the ability of firms to successfully discriminate between oil and gas prospects (directionality). In the extreme case in which firms cannot discriminate between these prospects (no directionality), the price elasticity of reserve additions is estimated to be about 0.20. This estimate establishes a minimum benchmark. In the other extreme case where discrimination among prospects is possible (perfect directionality), price responsiveness is expected to be higher, possibly about 0.60.

It is not surprising that the results of the analysis of the disaggregate data show that the prospects for additional non-associated natural gas reserves are very bright indeed. For the major gas horizons, the 1981 gas reserves prices, unit drilling costs and gas reserves additions rates were such that there was an incentive to drill additional wells. Since the gas additions rates in these horizons are fairly high and nearly constant with respect to cumulative drilling, estimates of ultimate non-associated gas reserves are difficult to make. However, it seems quite possible that another 727 billion cubic metres of non-associated gas reserves might be added with most of this coming from the Mannville, Viking, Mississippian and Upper Devonian horizons. This is an increase of 30 per cent above the 1981 total in the level of non-associated gas reserves and brings the ultimate total for the Alberta basin to 3,056 billion cubic metres (109 TCF). These estimates do not include the gas potential of such horizons as the Deep Basin nor do they include associated gas. The natural gas reserves estimates and the way in which these estimates respond to changes in the price of reserves for the disaggregate analysis are summarized in Table 4-24 of Chapter 4.

In Chapter 5, the results of the analysis of the aggregate data are presented. Two models are used to analyze these data, one which studies the supply process from the standpoint of reserve additions, and the other which studies it from the standpoint of initial discoveries and their subsequent appreciation. The results from the aggregate reserve additions model are thus more directly comparable to the disaggregate results since they both focus on the explanation of total reserve additions. In making this comparison, one is struck by the differences in the estimates of the oil and non-associated gas supply potential of the basin. The aggregate analysis indicates no oil potential at 1981 prices and only a small increase at higher oil prices. The difference in the oil results in the disaggregate and aggregate analysis is probably due to the aggregate data being dominated by the lack of oil prospects in all of the horizons, except for the Upper Devonian, and points out the dangers of aggregate analysis when there are important outliers in the aggregate data.

In Chapter 5, the supply of oil and gas reserves is also studied from the perspective of initial discoveries and their subsequent appreciation. Particular attention is given to the base upon which to measure appreciation, and it was decided to use as initial discoveries the amounts booked in the discovery year and the year following. This, of course, lowers the appreciation factors but it serves to stabilize them over time. The impact of increases in the price of reserves on appreciation factors is also examined, and it is found that price increases seem to have increased gas appreciation factors but have had no effect on oil appreciation factors.

The estimated discoveries equations which make up a part of this model indicate that the ability to determine price effects directly from the aggregate data is severely limited. The discoveries portion of the model requires adjustments to changes in prices and costs, resulting in predictable outcomes which are not likely within the one year periods which make up the data set. But studying various lag patterns of adjustment were also fruitless. Possible reasons for the disappointing results from this model are reviewed in Chapter 5.

2 Methodology

In this chapter is set out the planned approach to the study of the supply of conventional crude oil and natural gas reserves in the Alberta basin. Although the objective is to determine how ultimate reserves respond to changes in the price of reserves for the basin as a whole, this can be done by studying the data at different levels of aggregation. The easiest and most obvious approach is to study the data aggregated for the basin as a whole. It has been suggested, however, that studying oil and gas supply at this level of aggregation provides a poor understanding of the supply process and leads to inferior estimates of aggregate supply, a suggestion that will be examined carefully in the course of this study.

An alternative is to study supply at the level of geological zones and geographical areas, and to build up the aggregate supply picture in this way. This study carries out the analysis at both levels of aggregation. The results from the disaggregate analysis will be used to build up a picture of basin-wide supply which can then be compared with the results from the direct study of the aggregate data.

Methodology of the Disaggregate Analysis

Over an extended period of time, oil and gas reserves have been discovered in various geological formations located in different parts of the Alberta basin. These geological formations in major stratigraphic intervals, and in six geographical areas of the Alberta basin, are shown in a table called the "Alberta Table of Formations: Major Stratigraphic Intervals" (available from the Alberta Energy Resources Conservation Board). However, rather than attempt to deal with each of these formations separately, they are collected into 10 relatively homogeneous groups called *geological horizons*. The 10 horizons are listed in Table 2-1, and except for the breakdown of the Lower Cretaceous period into the Mannville and Viking and Equivalents horizons, they correspond to formations grouped by a standard geological period. Table 2-1 also lists the formation zone codes used by the Energy Resources Conservation Board (ERCB) for these horizons.

Table 2-1

Geological Horizons and Corresponding ERCB[1] Zone Codes

Horizon	ERCB Zone Code
Upper Cretaceous	1000 - 2080
Viking and Equivalents	2100 - 2420
Mannville	2440 - 3501
Jurassic	4000 - 4500
Triassic	5000 - 5499
Permian and Pennsylvanian	5500 - 5800
Mississippian	6000 - 6499
Upper Devonian	6500 - 7400
Beaverhill Lake and Lower Devonian	7440 - 8000
Silurian, Ordovician, Cambrian and Precambrian	8200 -

1 The Alberta Energy Resources Conservation Board.

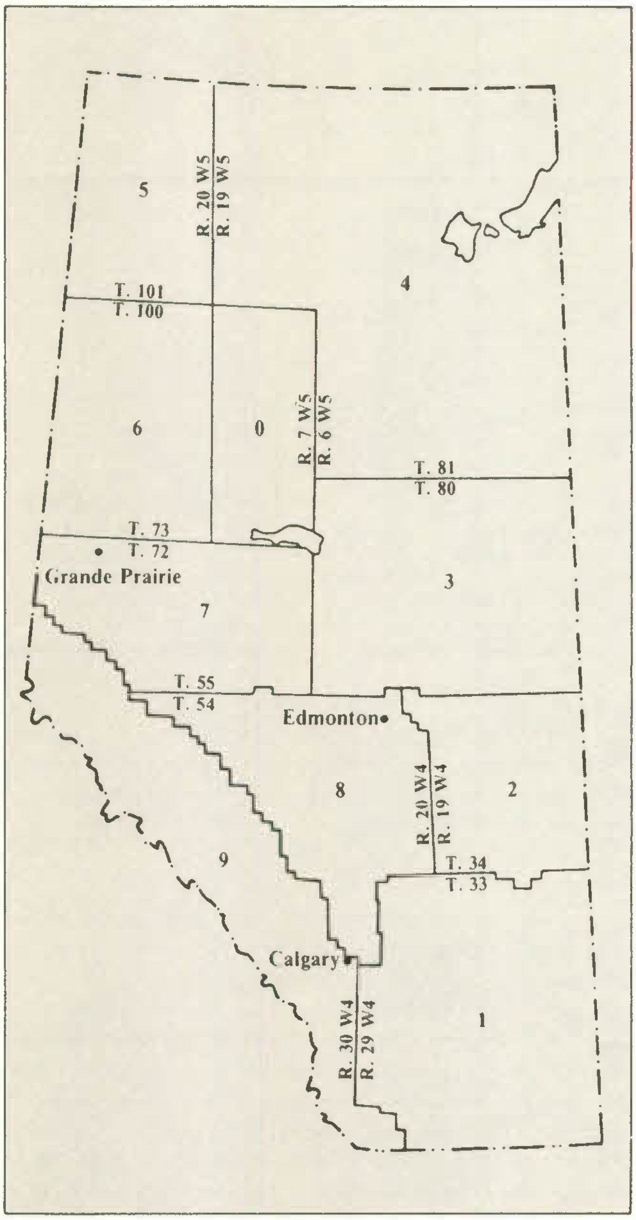
Instead of using the geographical areas shown in the Alberta Table of Formations, the Alberta basin has been divided into the 10 areas shown in Figure 2-1. These are the standard Potter-Liddle areas and were chosen because much of the data which are required for this study are only available for this area division. Thus, these 10 geographical areas combined with the 10 horizons provide one hundred possible regions to examine in the disaggregated part of the study.

A question which naturally arises at this point is: why study oil and gas discoveries at this level of disaggregation, what are the benefits? For one thing, it is well known that oil and gas discoveries tend to come in waves of activity directed at specific horizons and that *relatively* regular patterns of reserve additions can be detected within each of these "plays," whereas the aggregate data are much more complex and difficult to analyze. If the objective is to evaluate the remaining supply potential of alternative regions then a disaggregated analysis is, of course, mandatory. It is probably, at least partly because of their natural interest in such evaluations that engineers and geologists, who study these issues, have tended toward disaggregated analyses of oil and gas supply.

The justification for the area breakdown is less compelling, but it helps provide a more accurate measure of drilling effort and better estimates of the cost of drilling. The cost of drilling varies both with respect to depth and area within the basin. Although the capability exists to analyze the supply data over an extended period of time in each of a hundred regions (horizons and areas), it does not mean that this is the

Figure 2-1

Potter-Liddle Areas of Alberta



most natural level of aggregation in which to carry out the disaggregate analysis. It may be that upon examination of the data, a more appropriate level of aggregation will emerge. Presumably, the best level will not turn out to be a basin-wide aggregation.

A model is needed to carry out the quantitative analysis of the disaggregate data in order to eventually obtain a supply relationship for each region. To arrive at an appropriate model, it is useful to review some of the earlier work on oil and gas supply, and it is particularly important to trace the evolution of supply models which have come from the geology-engineering literature since these models form a basis for more recent efforts, including some of those models used by economists.

One of the first models of oil supply was developed by Hubbert (1962), who in criticism of volumetric analysis[1] stated that:

> The only possible way we have of determining how much oil the United States will produce is by pure empiricism, based on our actual experience in exploration and production of petroleum. The United States experience can then be used to estimate what may be expected from other comparable regions.[2]

Hubbert decided to see if there was an empirical relationship between cumulative reserves discovered and time for the United States as a whole.[3] His plots of the data indicated that cumulative discoveries seemed first to grow at an increasing rate and then pass through a point of inflexion and continue to grow at a decreasing rate with respect to time. This evidence led him to propose a logistic model with parameters that could be estimated from the available data. The asymptote parameter is of particular interest in this model since it provides an estimate of ultimate reserves. The general shape of the cumulative discoveries and discovery rate curves in Hubbert's model is shown in Figures 2-2 and 2-3.

Figure 2-2

Hubbert's Model

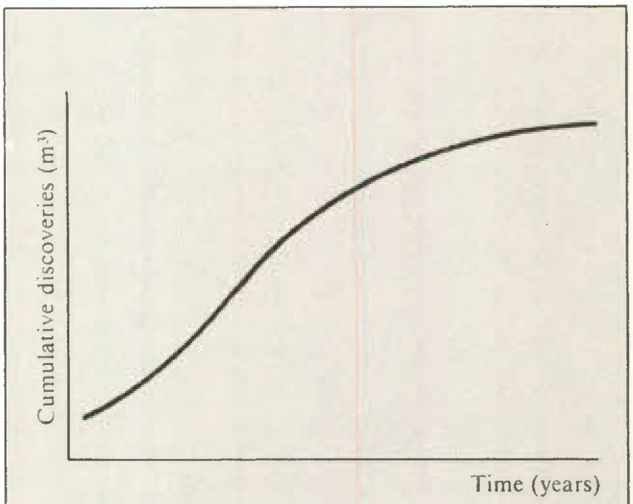
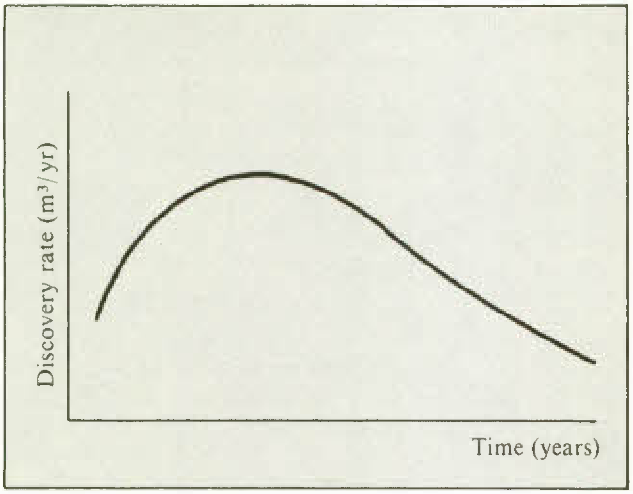


Figure 2-3

Hubbert's Model



Further progress in the analysis of oil and gas supply was reported in Arps, Mortada and Smith (AMS) (1970). They state:

> Methods for estimating future potential reserves for a geological basin or area in more mature stages of exploration are analogous to performance methods used for estimating proved reserves during the later stages of the life of a reservoir. Past trends in exploration performance are used, in effect, to delineate the most likely trends in the future which relate to estimates of ultimate recovery from incremental exploratory efforts.

This *performance* model clearly evolves more from engineering concepts than from geological concepts. The model itself consists of two stages: one to explain the discovery of initial reserves, and the other to explain the subsequent growth in these reserves due to delineation and development of initial discoveries. The discussion of the second stage will be taken up again later in the study.

In developing the first stage of their model to explain cumulative initial discoveries, AMS considered the use of several possible measures of effort, including time. They eventually settled on cumulative exploratory footage, rejecting time on the grounds that time and effort are not always linearly related. This choice marked a major departure from earlier models and, as we will see, paved the way for improved formulations of the discovery process. To further illustrate this departure, it is useful to consider the diagramatical comparison with Hubbert's model given by a comparison of Figures 2-2 and 2-3, with 2-4 and 2-5 which illustrate the AMS model. These diagrams are based on empirical evidence and illustrate the relationship between both cumulative discoveries and effort, and the rate of discovery and effort. Both models suggest that eventually, as time passes and cumulative effort grows, there will be a decline in the discovery rate although Hubbert sees this rate as first rising and then declining.

Figure 2-4

AMS Model

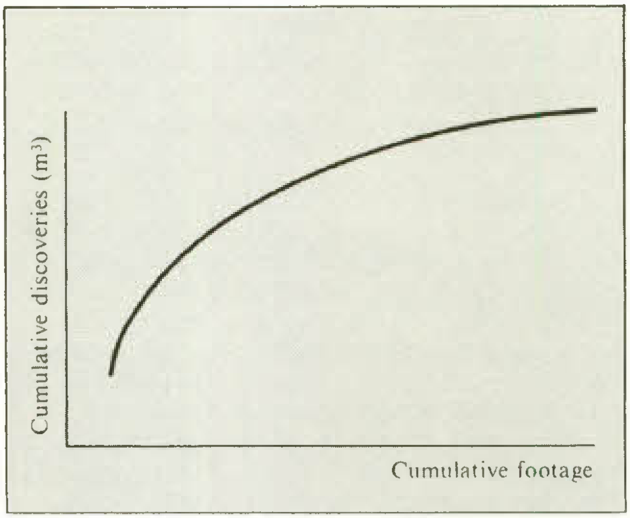
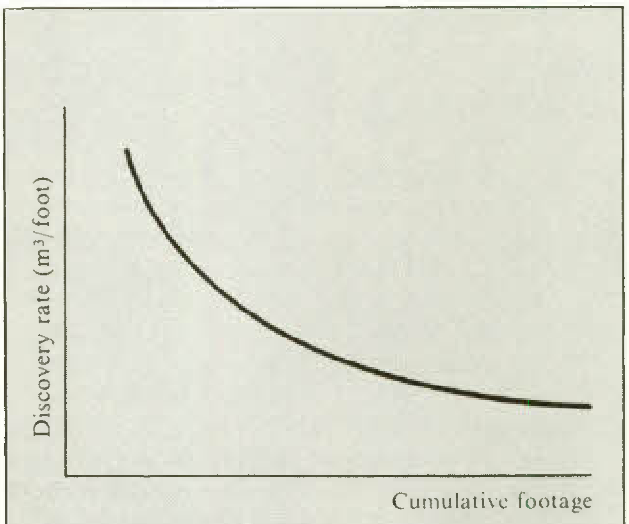


Figure 2-5

AMS Model



AMS also recognize the concept of the economic limit which indicates that economic conditions will set a limit on the level of effort. In fact, they suggest that the economic limit would be at that level of effort where the value of additional reserves discovered equals the incremental cost of the effort but do not make full use of this concept in their analysis. As will be seen shortly, only some relatively minor adjustments which introduce economic factors explicitly are required to convert this model into a fully integrated performance-economic model.

A variation of the performance model just discussed has recently been used by Kleopfer, Coles, Nikiforuk and Pennell (KCNP) (1980), in a major study of natural gas supply in Alberta. Like AMS, economic factors are recognized as obviously important in determining supply but are not included as an integral part of the model.

Although these models are adequate for estimating supply for a given set of economic conditions, their lack of integration of prices prevents them from being supply models in the usual sense in which economists think of supply, but modifications will be proposed to allow integration of economic factors. Although this is only done explicitly for the model used by KCNP, it is clear that this integration is easily accomplished for similar models. First, some of the basic concepts and assumptions used by KCNP will be established to see how their approach differs from those considered previously.

The first concept is that all categories of drilling (exploratory, delineation and development) result in reserve additions. KCNP believe that this is a more useful way to view the process of reserve additions than one involving two stages in which exploratory drilling results in initial discoveries, and reserve growth occurs subsequently as a result of delineation and development drilling. They also believe that it is necessary to consider reserve additions, for a basin as large as Alberta, by geological horizon and area (call this a region) because of the nonhomogeneity of conditions across regions.

Reserve additions in a region occur as a result of drilling in that region where drilling effort is measured by the number of feet actually penetrating the horizon. Thus, wells drilled in the area dimension do not count unless they have actually probed the geological horizon in question. If a well passes through the horizon, in quest of a deeper one, the footage drilled in the horizon still counts even though the intent of the well may not have been to investigate that horizon.[4]

The ratio of the time rate of reserve additions (m^3/year) to the time rate of drilling effort (ft/year) is called the reserve additions, or simply, the additions rate. Since the additions rate is the cornerstone of the model, it seems useful to consider its specification in more detail. To do this the following quantities are defined:

$R_{ha}(t)$ = cumulative reserves discovered in geological horizon h, in area a, in year t.

$\dot{R}_{ha}(t)$ = time rate of reserve additions in geological horizon h, in area a, in year t.

$D_{ha}(t)$ = cumulative drilling in horizon h, in area a, in year t.

$\dot{D}_{ha}(t)$ = time rate of drilling in horizon h, in area a, in year t.

The reserve additions rate is defined as $\dot{R}_{ha}(t) \,/\, \dot{D}_{ha}(t)$, i.e., the ratio of reserve additions in year t to total drilling in year t. In the KCNP model, for example, these rates are calculated for a number of years for each region and plotted against cumulative footage. Except for the difference in the definition of drilling effort and the level of aggregation in the two models, the reserve additions rate is the same as what AMS called the effectiveness of exploration illustrated in Figure 2-5.

The relationship between the additions rate and cumulative footage could be written as:

$$\dot{R}_{ha}(t)/\dot{D}_{ha}(t) = f[D_{ha}(t)]. \tag{2.1}$$

But instead of assuming that $\dot{R}_{ha}(t)/\dot{D}_{ha}(t)$ is a constant function of $D_{ha}(t)$ as in KCNP, or a negative exponential function as in AMS, equation 2.1 can be written more generally as:

$$\dot{R}_{ha}(t) = g[\dot{D}_{ha}(t), D_{ha}(t)]. \tag{2.2}$$

This relationship is what economists call a production function. It relates the output, the time rate of reserve additions, $\dot{R}_{ha}(t)$, to the input, the time rate of drilling effort, $\dot{D}_{ha}(t)$, and to cumulative drilling effort $D_{ha}(t)$, which serves as a measure of the degree to which the region has been drilled and thus is a proxy for the remaining potential of the region. The advantage of this formulation is that it allows but does not require the drilling rate to be linearly related to the rate of reserve additions.

In the KCNP model, remaining gas reserves in a horizon and area are estimated as a product of the finding rate (reserve additions rate) and estimated remaining footage. Three quantities are needed to calculate remaining footage: (1) volume of sediments (mi^3), (2) the ultimate drilling density (mi^3/mi drilled), and (3) footage drilled to the present. The word *ultimate* in "ultimate drilling density" is used in the context of current economic conditions. In other words, this is the estimated drilling density which is worthwhile to undertake given the current economic conditions. What is not so clear is how such a drilling density is actually determined in the light of current economic conditions. The Mannville horizon in Area 2 can be used to illustrate the confusion. In the economics section of their study, KCNP concluded that finding rates in 1978 and 1979 were insufficient to justify the cost of exploratory programs, and that "it is likely that Area 2 will see a drop off in activity" as a result. But if there is to be a drop off of activity because of uneconomic prospects in Area 2, why would the ultimate drilling density in this area be expected to reach a value of nearly twice what it is at the current time? Presumably such a density would require improved economic conditions.

Such confusion can be eliminated by using a more straightforward approach to the economic analysis of drilling decisions; one which explicitly introduces output prices and costs yet preserves the basic features of the model. The production function which was just discussed states the relationship between reserve additions, the drilling rate, and cumulative drilling. If a value can be placed on these reserve additions and drilling costs can be determined, then it is possible to estimate the amount of drilling which firms will want to undertake. The value of the reserves is determined by the present value of the production revenue stream net of taxes, royalties, etc. If p is the price of these reserves[5] then $p\,\partial \dot{R}_{ha}(t) \,/\, \partial \dot{D}_{ha}(t)$ is the value of reserve additions due to an increment of drilling effort. Firms will want to add reserves until the value of these additions equals the cost of drilling. Actually, the situation is more complicated than this in that successful drilling effort will result in three possible outcomes: (1) oil reserves are added, (2) both oil and associated gas reserves are added, or (3) only non-associated gas reserves are added. However, these can be consolidated into two outcomes by assuming that when oil and gas are discovered together in a region, they will be discovered in a fixed gas-oil ratio.[6] This allows us to define a compound unit of oil reserve additions which also involves associated gas.

Firms in the industry will maximize their profits by allocating drilling effort within a region to the level where the value of its marginal product equals its cost. But what is the value of the marginal product of drilling in a region where either oil (including associated gas) or non-associated gas is found? One view is that although firms can allocate drilling effort amongst regions to equate marginal returns because they have a choice between oil-prone and gas-prone regions, this is not as easily accomplished within a region because of the difficulty in determining if a target is an oil or gas pool. In this case, the value of the marginal product of drilling within a region is simply the sum of the values of the marginal products of oil and gas reserve additions.

In order to formalize these notions, the following simple model of profit maximization is proposed. First, assume that within a region the gas-oil in ($10^3 m^3/m^3$) oil pools is a constant k. The subscripts o and g are added to the previous notation to indicate oil and non-associated gas reserve additions. The variables p_o and p_g are the prices of oil and gas reserves and $c_{ha}(t)$ is the unit cost of drilling in horizon h, in area a. The profit from drilling in the region is given by:

$$\Pi(t) = (p_o + kp_g)\dot{R}_{oha}(t) + p_g\dot{R}_{gha}(t) - c_{ha}(t)\dot{D}_{ha}(t) \qquad (2.3a)$$

When firms cannot direct drilling effort to permit a choice between oil and non-associated gas reserve additions, profits are maximized by equating the sum of the marginal oil and gas product of drilling to its unit cost. Since reserve additions are inversely related to cumulative drilling effort, it is possible to determine the supply relationship between ultimate reserves and their price. To do this, one simply notes that the level of cumulative effort and the resulting associated reserve additions, which equates the sum of the value of the marginal oil and gas product to drilling cost, depends on the price of reserves. Thus, different reserves prices produce different amounts of ultimate reserves.

The view taken above is that firms in the industry cannot easily choose the desired mix of oil and non-associated gas discoveries because they cannot easily identify oil and gas targets and thus cannot direct their drilling effort. This is commonly called drilling under complete non-directionality. Another view, and the other polar case, is where firms can direct their drilling effort by identifying oil and gas targets. In this case, that of complete directionality, profit maximization is to choose oil intent drilling and gas intent drilling to equate the value of the marginal product of each of these drilling categories to the unit cost of drilling. In this case, the profit relation is given by:

$$\Pi(t) = (p_o + kp_g)\dot{R}_{oha}(t) + p_g R_{gha}(t) - c_{ha}(t)\,[\dot{D}_{oha}(t) + \dot{D}_{oha}(t)] \qquad (2.3b)$$

where $\dot{D}_{oha}(t)$ and $\dot{D}_{gha}(t)$ are the oil and non-associated gas drilling rates in horizon h, in area a, and where

$$\dot{R}_{oha}(t) = R_o\,[\dot{D}_{oha}(t),\, D_{oha}(t)]$$

$$\dot{R}_{gha}(t) = R_g\,[\dot{D}_{gha}(t),\, D_{gha}\ (t)]\,.$$

These equations show that oil reserve additions depend on oil drilling and gas reserve additions depend on gas drilling rather than each depending on total drilling, as is the case of complete non-directionality. In the data analysis presented in Chapter 4, both of these cases are examined.

The performance-economic model which has just been outlined specifies a relationship between reserve additions and drilling effort in a region. We now want to focus on the problems of measuring drilling effort in a region. In their study of natural gas supply in the Alberta basin, KCNP measured yearly drilling effort in a region by the amount of footage which actually penetrates the region. A similar alternative measure would be the number of wells which actually penetrates the region. However, the weakness of this measure is that it gives equal weight to wells which penetrate several horizons within an area regardless of the targeted horizon. In other words, if the targeted horizon is deep and a well is completed to that horizon but other horizons are penetrated on the way down, one unit of drilling effort is assigned to each horizon. Surely this is a misassignment of intended drilling effort. Even though such a well may count for something toward effort in the shallower horizons, if it came to a choice between counting a unit of effort in these horizons and not counting effort in them at all, the choice would be not to count it at all. In other words, a better measure of effort in a region is the amount of drilling which is specifically directed at testing geological structures in (that) region. Although data on *targeted* well penetrations cannot be observed directly, if one is willing to assume that wells which pass through a specific horizon are not targeted there then the available data can be used to estimate targeted well penetrations.[7] The methods and data to be used in estimating targeted wells in various regions will be discussed in Chapter 4 of this study.

The general nature of the performance-economic model which focuses on reserve additions at the disaggregate level of analysis has been outlined. At this point it is appropriate to consider a specific model of reserve additions that can be used in the analysis of the data. It would be useful to have a model which was flexible enough to accommodate the AMS, effectiveness of exploration, and the KCNP, finding rate models as special cases. Towards this end, the following functional form is proposed to explain the time rate of reserve additions in a region.

$$\dot{R}_{ha}(t) = A\,\dot{D}_{ha}(t)^{\alpha}\,exp[-\beta D_{ha}(t)] \tag{2.4}$$

where A, α and β are parameters. If $\alpha = 1$ this is the AMS model. If $\alpha = 1$ and $\beta = 0$ then the reserve additions rate is independent of $D_{ha}(t)$, and it is the specification used by KCNP.[8]

It is perhaps instructive to examine the short-run and long-run features of this model. If $\alpha < 1$, then diminishing returns to current drilling effort exist so that the optimal level of current drilling effort can be determined. If, in addition, $\beta > 0$, then the level of current drilling effort should decline steadily over time. On the other hand, if $\alpha = 1$ and $\beta > 0$, then constant returns to current drilling effort exists and the rate of reserve additions, $\dot{R}(t)/\dot{D}(t)$, declines exponentially with increases in cumulative effort. In this case, the level of current drilling effort, and hence the level of current reserve additions, is indeterminant. Nevertheless, so long as $\beta > 0$ the value of the marginal product of drilling declines with respect to cumulative effort, and it will be economically worthwhile to continue drilling so long as the value of the marginal product of drilling exceeds its unit cost. In other words, there is some level of cumulative drilling, and hence cumulative reserves found, which is economically worthwhile to undertake. The higher the price of reserves the larger the amount of this cumulative drilling, and the larger the amount of reserves that will be discovered so that the amount of ultimate reserves supply depends upon the price of reserves and, of course, on any factors that affect this price. The response of the ultimate supply to price changes allows the determination of the price elasticity of ultimate reserves supply. It is clear that this supply relationship, which might be called the "long-term" supply relationship, can be determined regardless of the magnitude of α so long as $\beta > 0$.

If the case where $\alpha \geq 1$ and $\beta > 0$ occurs so that the supply rate of reserves in the short run is indeterminant then the question arises of what keeps all prospects from being drilled immediately. In other words, what factors limit the current level of drilling activity when diminishing returns are not observed? A number of possible explanations exist. One is that instead of being constant, as has been assumed, unit drilling costs actually rise with the level of drilling activity, particularly at high levels of activity. Another possibility is that if the current value of the marginal product of drilling exceeds its economic cost then firms receive rents that are at least partially transferred to resource owners in the form of payments for land acquisition. Since land acquisition is a cost from the point of view of the firm, these costs may serve to limit the amount of current activity. Eventually, as the value of the marginal product of drilling declines with increases in cumulative effort, these rents will also decline and thus so will the payments for land acquisitions. But so long as these payments absorb most of the rents, costs from the perspective of the firms in the industry will nearly equal the value of the product added. For any given price of reserves, the final limit to cumulative drilling and reserves supply is reached when the value of the marginal product of drilling equals its cost, so that these rents are eliminated and it is no longer worthwhile to acquire land.

In the model discussed in this section, the amount of current and cumulative drilling effort explains the amount of reserve additions. It is, of course, recognized that drilling effort is not the only input into the process of adding new reserves of oil and gas. Of particular importance is geophysical effort in that it is of primary importance in locating and selecting oil and gas prospects. However, the inclusion of a measure of geophysical effort in explaining reserve additions presents formidable problems; not least among them being a measurement itself. The most common published data on geophysical effort is given by: number of active geophysical crews x number of days or months these crews are active in the year. This is referred to as crew-days or crew-months of geophysical effort.

The first problem with such a measure of geophysical effort is that technological change has made the comparison of a crew-day of effort today with a crew-day of effort even 10 years ago meaningless. The same problem would arise if it were necessary to measure drilling effort by the number of days spent in drilling when it is clear that improvements in technology have increased drilling rates dramatically.

Another problem in using the available geophysical effort data is that of matching effort and reserve additions. Geophysical effort normally leads drilling and thus reserve additions but has the feature that it provides information to be used over an extended period of time. This feature makes it very difficult to establish a relationship between geophysical effort and reserve additions.

For these practical reasons geophysical effort is not included in the explanation of reserve additions. Insofar as it is excluded, it effects the calculation of the economic limit to reserve additions, but even if some way was to be found to include it, the results would not be substantially changed since it makes up such a small proportion of total expenditures on the effort involved in oil and gas reserve additions.

Methodology of the Aggregate Analysis

Another approach to studying the supply of oil and gas reserves in a basin is to examine the aggregate data for the basin as a whole directly rather than examining certain regions and then aggregating at a later stage. In this section, two models for examining the aggregate data directly are outlined. The first model is similar to the one used in the disaggregate analysis in that it focuses on reserve additions resulting from all categories of drilling. The second model separates reserve additions into new discoveries and their subsequent appreciation. This model could also be applied to the disaggregate data.

Aggregate Analysis – Model 1

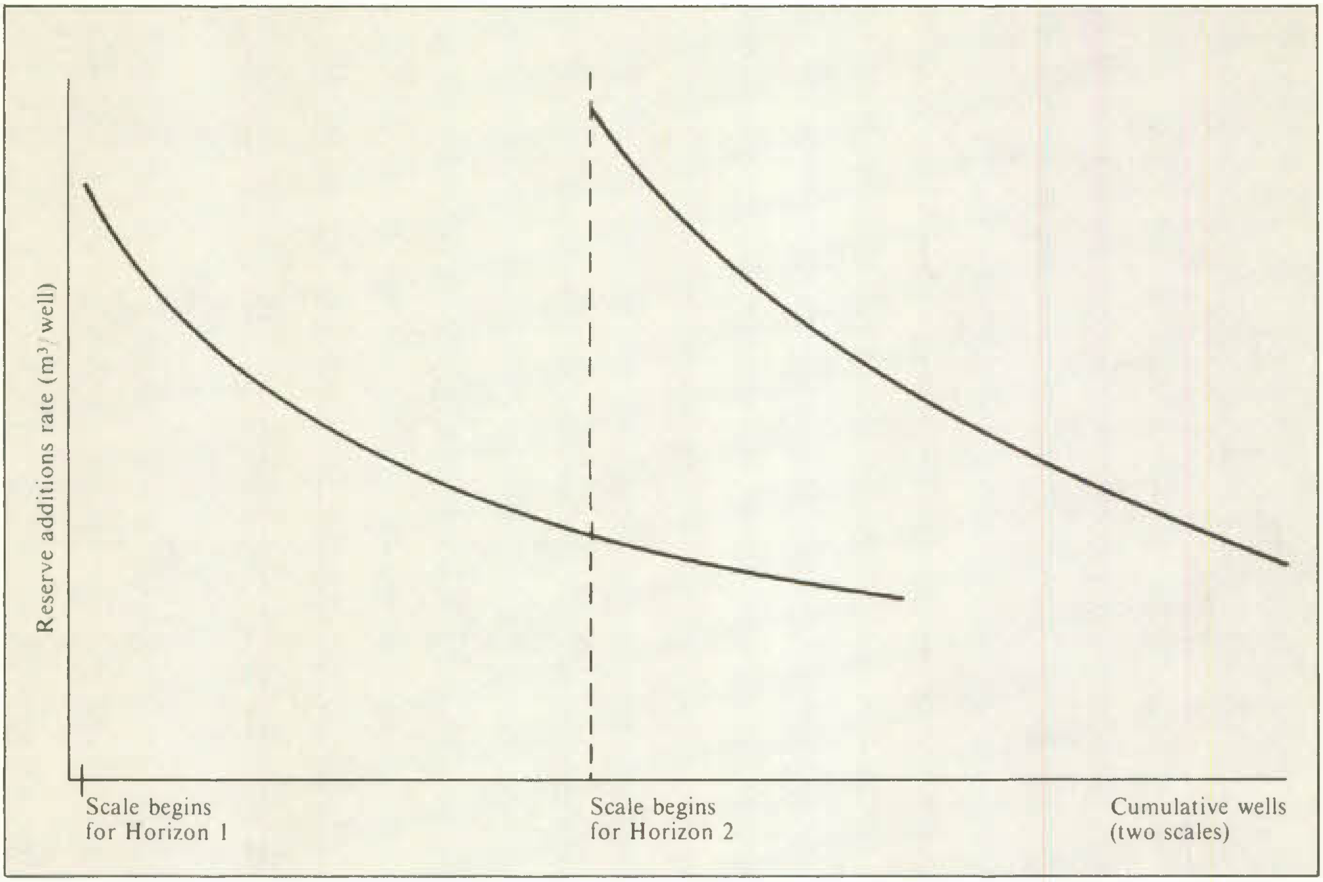
As noted earlier, when oil and gas supply is examined by region, two important problems arise with respect to the measurement of effort. The first is the conceptual problem of how to weight wells which are not targeted to the horizon, and the second is the actual determination of targeted wells. One of the advantages of studying aggregated oil and gas supply data is that drilling effort measurement problems are considerably reduced. In the aggregate case, total wells drilled is a reasonably good measure of the amount of drilling effort in all regions. There is clearly a trade off, however, since the gains that are made on effort measurement are offset by the losses caused by the aggregation of reserve additions across regions. It is the recognition of these losses that have encouraged the examination of the disaggregate data because of the belief that our models of the supply process are not likely to perform very well when reserve additions in any period can come from several regions (plays) simultaneously. This assertion will now be examined in further detail.

It is useful to consider this issue in terms of a simple example. Consider two producing horizons (plays) which were discovered at different times. Also assume that the reserve additions rate (reserve additions/targeted wells) follows exponential decline with respect to cumulative wells. With such data the parameters of an exponential decline model for each horizon could be estimated separately and these estimates could be used to make forecasts of the reserve additions rate in each horizon. This is, of course, the ideal situation since in this example targeted well data are presumed to be available whereas in reality only a rough estimate can be made.

Figure 2-6 depicts this example in graphical terms. The horizontal axis contains two scales, one for the cumulative wells in region 1, and the other for cumulative wells in region 2. If estimated separately each curve would fit the data accurately. Now aggregate over the two horizons as depicted in Figure 2-7. Now if we were to fit a single curve to the data, as it appears in Figure 2-7, we obviously would not get a very good fit. The fitted curve would overestimate the additions rate in the first period (before region 2 was discovered) and underestimate it thereafter. However, one way to

Figure 2-6

Reserve Additions versus Cumulative Wells in Two Horizons



overcome this weakness and still be able to use the aggregate effort data is to include a dummy variable in the model which switches on at the time region 2 is discovered. With a dummy variable specification that captures both intercept and slope changes, one might expect the aggregate model to work reasonably well, especially in view of the fact that measurement of aggregate drilling effort is so much easier than measurement of horizon-targeted effort. However, if the data situation involves several plays where the reserve additions rate responds differently to increases in play-specific cumulative effort, then the aggregate analysis including dummy variables may not work so well. The data analysis presented in Chapters 4 and 5 will provide additional information for choosing between the aggregate and disaggregate analysis.

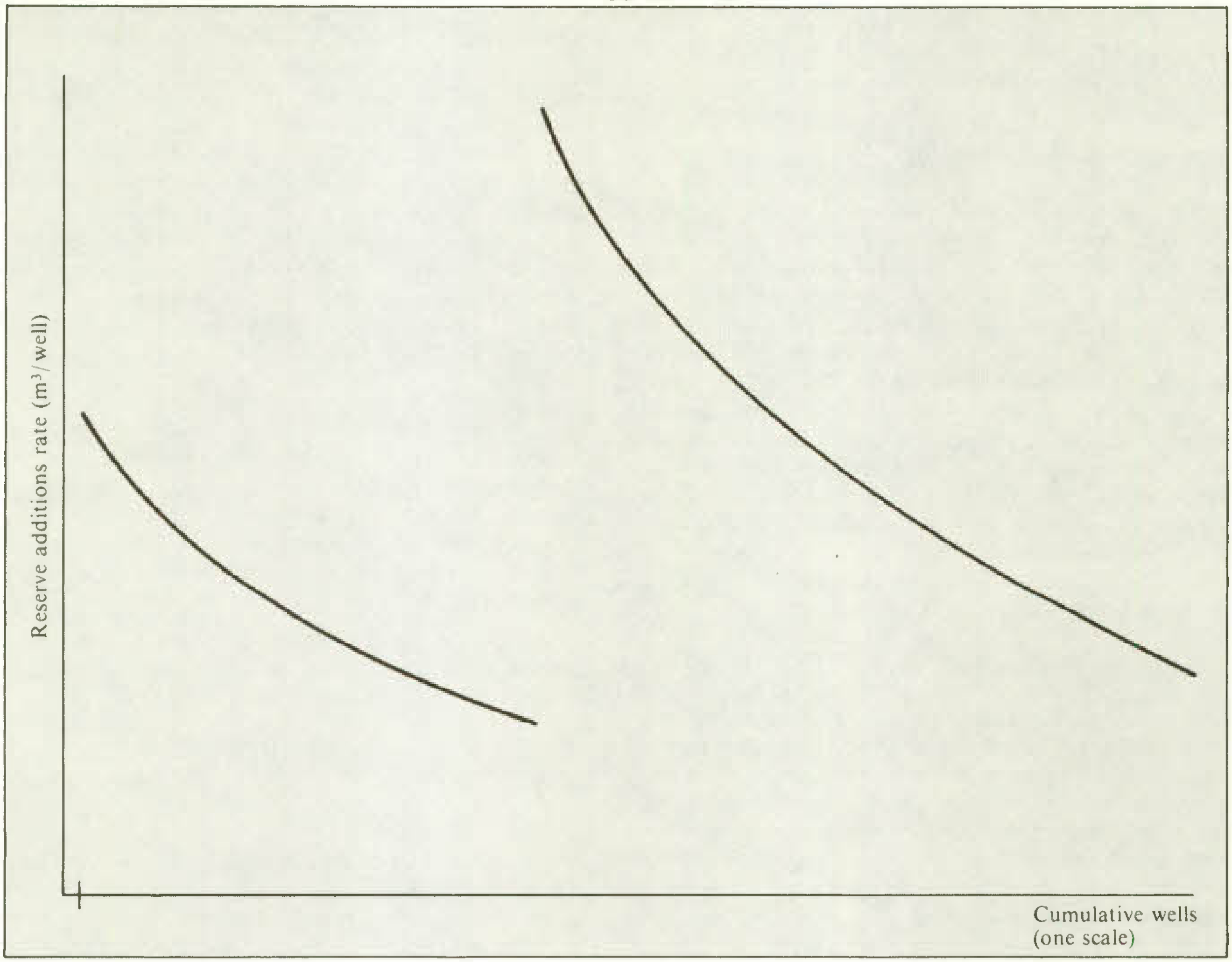
In order to formalize these notions and more clearly distinguish between the disaggregate and aggregate reserve additions models, let us assume that firms in the industry want to maximize aggregate profits associated with their drilling programs in all regions. These profits are given by:

$$\Pi(t) = \sum_{ha}\sum [(p_o + kp_g)\dot{R}_{oha}(t) + p_g\dot{R}_{gha}(t) - c_{ha}(t)\dot{D}_{ha}(t)] \qquad (2.5)$$

Besides variation over time, the profit function given in equation 2.5 implies two additional kinds of variation: (1) variation in the cost of wells, and (2) variation in the oil and gas reserve additions relationships. As noted earlier, depending upon directionality assumptions, profits are maximized by setting drilling effort in each region such that either the sum of the value of the marginal product of oil and non-associated gas equals the unit cost of drilling, or setting it such that the value of the marginal product of oil drilling equals that of gas drilling and equals the unit cost of drilling. In the first case, firms are assumed not to be able to allocate

Figure 2-7

Reserve Additions versus Cumulative Wells Aggregating Over Two Horizons



drilling between oil and gas prospects, whereas in the second case, they are assumed able to make such an allocation.

In the aggregate model, the Alberta basin is viewed as a single large region so that the only variation remaining in the model is with respect to time. If unit drilling costs are taken as constant at $\bar{c}$ for all regions, then aggregate profits are given by:

$$\Pi_A(t) = (p_o + kp_g)\dot{R}_{oA}(t) + p_g\dot{R}_{gA}(t) - \bar{c}\dot{D}_A(t) \tag{2.6}$$

where

$$\dot{R}_{oA} = \sum_{h}\sum_{a}\dot{R}_{oha}, \dot{R}_{gA} = \sum_{h}\sum_{a}\dot{R}_{gha}, \text{ and } \dot{D}_A = \sum_{h}\sum_{a}\dot{D}_{ha}.$$

If it is also assumed that aggregate reserve additions depend upon aggregate drilling in the following way,

$$\dot{R}_{ja}(t) = R_j[\dot{D}_A(t), D_A(t)] \quad j = o,g \tag{2.7}$$

then aggregate profits are maximized by choosing the aggregate level of drilling such that the value of the sum of its oil and gas product equals the average unit cost of drilling. This condition assumes no drilling directionality. However, because of the existence of oil- and gas-prone regions, it is probably more reasonable in this case to assume directionality and allow the allocation of drilling activity so that the profit maximizing condition is that drilling be at that level which equates the value of the marginal product of oil and gas drilling to their unit cost. Of course, the implementation of this model requires the measurement of oil and gas drilling effort separately.

Aggregate Analysis – Model 2

The previous approach to modelling the reserves supply process took the point of view that the sources of reserve additions need not be distinguished so that all categories of drilling should be combined. Although this approach has the advantage of simplicity, it assumes that a single aggregated reserves supply process can adequately represent the separate processes associated with new discoveries and reserve appreciation and, therefore, has important implications for determining the long-run elasticity of supply. However, if these two sources of additional reserves respond to changes in both economic and physical conditions in different ways, then such an aggregate model might break down and therefore it would be preferable to model the two sources separately.

In a model suggested by Uhler (1982*a*), the discovery and appreciation processes are modelled separately and then they are integrated to determine the impact of price changes on total reserves additions. It is useful to consider this model in some detail since it will be used to provide one of the estimates of potential oil and gas supply in this study. Moreover, it is important to understand the connection of this model with those that have been examined so far if the supply estimates are to be evaluated adequately.

The first requirement of this model is to determine how initial discoveries of reserves respond to changes in reserves prices, in other words, to determine the supply function of initial discoveries. In order to do this, it is possible to employ a model similar to the one just discussed for the case of aggregate reserve additions by simply substituting initial discoveries for reserve additions and exploratory drilling effort for total drilling effort. Instead, it was decided to employ an alternative model which allows estimation of price effects on initial discoveries directly. Although the direct approach is in many ways much easier to apply, it makes some strong assumptions about the behaviour of firms in the industry. Amongst other things, it is assumed that firms adjust quickly to changes in economic conditions and these adjustments are reflected in the data.

To begin, the aggregate discoveries function is written in a more general form than in the case of the aggregate reserve additions function. It is given by:

$$Z[y_o(t), y_g(t), \dot{x}(t), x(t)] \tag{2.8}$$

where $y_o(t)$ and $y_g(t)$ are aggregate discoveries of *initial* reported reserves of oil and gas, respectively in year t, and $\dot{x}(t)$ and $x(t)$ are the exploratory drilling rate and cumulative exploratory drilling, respectively. Equation 2.8 is a general function relating the discoveries of oil (including associated gas) and non-associated natural gas to current and cumulative exploratory drilling effort. This function is assumed to have the property that firms can allocate drilling effort in favour of oil-prone and gas-prone regions. In other words, it assumes directionality which allows firms to discriminate between oil and non-associated gas targets.

If an appropriate joint output functional form for equation 2.8 could be specified then we could proceed along the lines used before; equating the value of the marginal product of drilling to its unit cost and then using this to determine the supply curve of initial discoveries. But this is a joint output function and this makes the approach too difficult to apply.

Another way to proceed is to assume that firms in the industry maximize profits subject to equation 2.8, so that the maximized profit function is given by:

$$\Pi^* [p_o(t), p_g(t), c(t), x(t)] \tag{2.9}$$

where $c(t)$ is the unit cost of exploratory drilling. This function is derived by maximizing over the outputs and inputs leaving the maximized profit function which depends only on prices and cumulative effort. The derivatives of $\Pi^*(\,.\,.\,)$, with respect to the prices, produce the relevant output supply and input demand equations. However, to obtain quantitative results it is necessary to specify a functional form for the maximized profit function or the supply equations themselves. A common procedure, and the one followed here, is to specify an appropriate functional form for the maximized profit function and then derive the supply equations which are then estimated directly using the price and output data. A quadratic functional form will be chosen for the maximized profit function which produces supply equations which are then linear in prices.

So far the model has only been concerned with the supply of reserves from new discoveries which arise from exploratory effort. However, as has been noted earlier, once a reservoir is discovered then appraisal drilling will often occur, and if the reservoir is commercially viable then development will proceed. Appraisal and development drilling results in reserve additions in a process is called appreciation. Once a reservoir is discovered the decision to undertake appraisal and development drilling is clearly affected by economic conditions. If product markets are strong and input prices make development profitable, then aggregate reserve additions due to appreciation will occur at a higher rate than would otherwise be the case.

It is easy enough to describe the appreciation process and the expected impact of economic conditions, but what is required is a model of the process which will allow quantitative estimates of the impact of changes in economic conditions. One such approach is outlined in Uhler (1982), which now will be summarized.

Let $y_{t\tau}$ be the reserves which in time period τ are associated with the reserves which were discovered in period t. Also let y_t be the reserves which are reported as being discovered in period t, and let $A(\tau-t,p_\tau)$ be an appreciation function. Thus,

$$y_{t\tau} = y_t A(\tau-t,p_\tau) \tag{2.10}$$

and cumulative appreciated discoveries viewed from the perspective of time τ is:

$$R_\tau = \sum_{t=1}^{\tau} y_{t\tau}. \tag{2.11}$$

In terms of the earlier discussion y_t is unappreciated discoveries in period t, and $A(\tau-t,p_\tau)$ is the function which appreciates them over time and which depends upon the prevailing price in period τ, p_τ. Equation 2.11 simply states that cumulative discoveries consists of the sum of the appreciated discoveries of each vintage.

The effect of an increase in the price of reserves at time τ on cumulative discoveries is given by:

$$\partial R_\tau / \partial p_\tau = \sum_{t=1}^{\tau} y_t \partial A / \partial p_\tau + A\, \partial y_\tau / \partial p_\tau \ . \tag{2.12}$$

The first τ terms on the right measures the rise in reserves of each vintage due to the rise in appreciation caused by the price increase, and the last term measures the effect of the price increase on discoveries at time τ.

There are clearly other ways to model the appreciation process. Instead of making appreciation depend on time, it could be related to the categories of drilling effort that result in reserve additions through appreciation. There are several ways to proceed along these lines. One would be to trace the development drilling associated with each vintage of discoveries and make appreciation depend upon the level of development drilling. Economic effects could be integrated in the usual way by having an appreciation function show declining marginal returns to cumulative development drilling, so that for any given set of economic conditions development drilling of each vintage would reach an economic maximum. Changes in economic conditions would change the ultimate level of development drilling and thus the ultimate level of reserves additions from this source. In other words, the level of development of each vintage of discoveries would be expanded up to the point where the value of the marginal product of additional development drilling equalled its cost. The advantage of keeping track of each vintage of reserves and their subsequent appreciation due to development drilling is that this provides a model which is similar to the earlier model, which used the appreciation function given in equation 2.10, and thus has all the advantages of this formulation.

An alternative way to incorporate development drilling explicitly into the appreciation process is to associate development drilling in any particular year with appreciation from all vintages of previous discoveries rather than trying to keep track of that which is associated with each vintage. In this formulation, reserve additions due to new discoveries and appreciation would still be separate processes explained by exploratory and development drilling, respectively. However, there would be an advantage to maintaining such a separation only if these supply processes were substantially different in their response to the physical inputs, or if the choice of inputs responded differently to changes in economic conditions. If such differences are insignificant then a model that combines drilling categories to explain total reserve additions is suggested. It is thus clear that the importance of separating initial discoveries from appreciation depends mainly on how one expects each of these sources of reserve additions to respond to categories of drilling effort, and how drilling effort is expected to respond to economic conditions.

3 The Price of Oil and Gas Reserves

In Chapter 2, the price of oil and gas reserves was repeatedly used to evaluate the product of drilling activity. In this chapter, the concept of the price of reserves is developed further and it is related to more familiar prices such as the wellhead price and the producer netback. A time series of these prices is estimated which will be used subsequently in the analysis of oil and gas supply.

To make the concept of the reserves price clear, consider a simple example which involves production from a single pool.[1] Suppose that the wellhead price, $p(t)$, and unit operating costs, $c(t)$, can be forecast over the production life, T, of the pool and its production rate is given by, $q(t)$. A simple tax system includes a royalty at rate, R_y, and an effective income tax at rate, τ_1. First, let us define the producer netback as the wellhead price less operating costs and royalties.[2] In terms of this example, the netback is given by:

$$Pn(t) = p(t)[1 - R_y] - c(t) \tag{3.1}$$

The price of reserves will now be defined and under certain conditions it is shown to be nothing more than the producer netback multiplied by a discount factor. When a firm acquires reserves in the ground either through outright purchase or through its own exploration program, it acquires an asset which produces a stream of revenue over a period of time. In the example, this period is of length T. The unit profit, above a normal rate of return that the firm makes from the acquisition is:

$$W/Q = \int_0^T \{p(t)[1 - R_y] - c(t)\} \{1 - \tau_1\} q(t)e^{-rt}dt/Q - p(1 - \tau_1). \tag{3.2}$$

The first term on the right side of this expression is the discounted value of production net of royalties and income taxes divided by Q, where Q is the sum of all production. Under the assumption that the price of reserves acquisition is tax deductable, the second term is the price of reserves, p_s, net of income tax. It is clear from this expression that if competition eliminates economic profits the income tax rate will not have an effect on the price of reserves, but if economic profit occurs then an increase in the tax rate will depress the price of reserves.[3] Although this will be considered again below, the role of industry price expectations on the price of reserves is immediately apparent from equation 3.2. Note that wellhead price, $p(t)$ is a function of time so that if $p(t)$ is expected to grow the current price of reserves will be higher than otherwise.

If, in fact, profits are eliminated so that the price of reserve acquisition is equal to the discounted value of the net return to production, and the wellhead price, operating costs and the output rate are assumed to be constant over time then,

$$p_s = p_n D_f; \;\; D_f = (1 - e^{-rT})/rT \tag{3.3}$$

so that if r is also fixed, the price of reserves is proportional to the producer netback. It should be emphasized that this is only true under the circumstances just outlined, including the simple tax system provided in this example.

In the example just given, capital costs were not included. Had this been done under the conditions that capital expenditures are not immediately tax deductable, the reserves price would not have been proportional to the netback. Had capital costs been introduced explicitly into the example, a different reserves price would have been obtained. This price is called the price of undeveloped reserves and the one that was calculated in the example is called the price of developed reserves. It is instructive to provide further detail regarding these two prices to see how they relate to the two approaches to the analysis of oil and gas supply which are undertaken in this study.

When capital costs are not deducted, as in the example above, the implicit assumption is that the reserves have already been developed and are ready for production. The only costs incurred are operating costs. Thus, the price of these reserves is the price of developed reserves. It is easy to see how developed reserves might be acquired through outright purchase, but how can they be acquired through drilling activity, how can drilling activity find developed reserves? One of the supply models that is used in this study does not distinguish between exploration and development drilling activity in the process of acquiring reserves. In this view of reserve addition, productive capacity is put in place through both categories of drilling. It is as if developed reserves are being added, and thus the price of developed reserves is the appropriate price incentive under these conditions. On the other hand, if one uses a model framework which clearly separates exploration and development into two stages, then there is a need for a price which is called a price of undeveloped reserves. It is this price incentive which is relevant to the explorer searching for undeveloped reserves.

Industry Price Expectations

It is clear from the previous discussion, and especially from equation 3.2, that reserves prices depend upon the time path of wellhead prices and operating costs. It might now be asked if there is any reason for industry forecasts of these quantities to be anything other than that they will remain constant. In an attempt to answer this question, the history of wellhead price changes in Canada will be examined.

During the 1950s and 1960s, the wellhead price of crude oil was fairly stable. Oil prices were even protected during the 1960s by the National Oil Policy as world oil prices declined. Natural gas prices rose in the 1960s from their very low levels in the 1950s, but their growth certainly stabilized by 1965 and remained fairly constant until 1974. All in all, one would be hard pressed to argue that the industry could have expected significant changes in nominal prices before 1973, if such expectations are at all dependent upon the recent past.

However, in 1973, the Organization of Petroleum Exporting Countries (OPEC) began to exercise its price setting power and world oil prices rose dramatically in several stages from that year. Even though the policy of the Government of Canada was to keep domestic oil prices below world levels, wellhead prices in Canada began to rise sharply in 1973. Natural gas prices started their sharp upward movement a year later. Moreover, in each year, starting in 1973, the industry would have reasonably expected future domestic prices to rise as pressures mounted to allow them to rise along with world prices. The lag in domestic prices behind world prices due to government policy decisions would have made such expectations even stronger. Thus, during most of the 1970s, it would be unreasonable to assume expectations of static nominal wellhead prices of oil or gas in Canada.

In summary, the analysis of industry price expectations in Canada suggests that static expectations for both oil and gas are in order up to 1973, after which we must include in our calculations of reserves prices some assumptions about the expected growth in both oil and gas prices, at least through 1981. After 1981, the effects of the world recession and the glut of oil and gas require further revisions of price expectations. The current view is that they will not rise in nominal terms, at least in the intermediate future.

The Price of Crude Oil Reserves

In estimating the price of crude oil reserves from the available data, use is made of the basic concepts outlined in the example for a single pool. The values used for the basic variables such as the wellhead price and operating and capital costs are industry averages, so that the reserves prices and netbacks are also industry averages.[4] But aside from the data being based on industry averages, the main difference between the calculations in the example and those which will be presented and discussed in this section of the study is the complexity of the tax system. Not only is it necessary to account for royalties and income tax, as in the example, but also to account for depletion allowances, resource allowances, tax rebates, tax credits, etc. A definition of various cost components and an indication of how they were treated by the tax system prior to May 6, 1974, along with various changes which affect reserves prices and netbacks, is given below:

Well operating costs per barrel of oil – These costs are obtained by apportioning total operating costs for both oil and gas wells on the basis of operating oil wells relative to total operating wells. These costs are fully deductible for tax purposes in the period in which they are incurred.

Development drilling and other development costs per barrel of oil – These are based on estimates of costs per well divided by production per operating well. They are fully deductible in the period in which they are incurred.

Field equipment costs per barrel of oil – In calculating undeveloped reserves price these costs are charged immediately at their full value, but since they are depreciable for tax purposes, a tax saving is realized in future periods resulting in a decline in the present value cost of these assets. Since the method of depreciation applied to these assets is declining balance, each dollar of capital outlay will have an after tax present value of $1 - a_1\tau_1/(a_1+r)$, where a_1 is the depreciation rate, τ_1 is the effective income tax rate, and r is the rate of interest.

Land rental and provincial taxes (excluding income taxes) per barrel of oil – These costs are fully deductible in the period in which they are incurred.

Oil and gas royalties – Royalties are fully deductible in the period in which they are incurred.

After May 6, 1974, land rentals, provincial taxes and royalties were no longer deductible for income tax purposes, but the federal government reduced the income tax rate to 25 per cent, making the income tax rate applicable to the petroleum industry in Alberta equal to 36 per cent. The province of Alberta introduced two tax schemes designed to help the industry.

The first was a royalty tax rebate which was 11 per cent of land rental, provincial taxes and royalties, and the second was a royalty tax credit which was 25 per cent of Alberta royalties but with an upper limit of $1 million. This upper limit makes the overall impact of this part of the program relatively small.

Development expenses and land acquisition expenses had been treated as current expenses but after May 6, 1974, development expenses were capitalized and written off at a maximum annual rate of 30 per cent, and land acquisition expenses were capitalized and written off at a 10 per cent rate. This change in the tax law introduced asymmetry into the tax treatment of reserve acquisition which had not existed since 1962. The outright purchase of reserves would no longer be treated as a current expense but would have to be capitalized as mentioned, whereas exploration expenses were still treated as current expenses. Also, prior to May 1974, the depletion allowance had the effect of reducing the income tax rate by one-third. Subsequently, the concept of "earned depletion" was introduced and the depletion allowance was calculated as one-third of land acquisition expenses, development expenses and exploration expenses, with an upper limit of 25 per cent of income net of operating and depreciation expenses.

On January 1, 1976, the taxation of the oil and gas industry was changed again. The federal government increased the income tax rate to 36 per cent so that in Alberta it became 47 per cent. At the same time, it introduced a resource allowance which was deductible at a rate of 25 per cent of income net of operating expenses and capital consumption allowance.

The tax treatment of the industry remained stable until the federal government introduced the National Energy Program (NEP) in October 1980. This was followed by the Agreement with the Alberta government in September 1981 which set forth a price schedule for oil and for gas and a taxation arrangement which was to last for five years. But "Update 82" to the NEP was later introduced which lowered the Petroleum and Natural Gas Revenue Tax (PGRT) and eliminated the Incremental Oil Royalty Tax for a period of time. In 1982, the Alberta government also introduced an industry relief package which involved royalty rate reductions and an extension of tax credits. The tax changes associated with the NEP all became effective after 1981. Since our data base only extends through 1981, oil and gas reserves prices through 1981 are all that are needed for this analysis so we have not incorporated the effects of the NEP.

For the period 1947-81, Table A-1 in Appendix A shows wellhead prices, producer netbacks, and the prices of both developed and undeveloped crude oil reserves in nominal terms. Various costs and royalties used in these calculations are shown in Table A-2. A detailed example of the calculation of the reserves prices is also shown in Appendix A.

The pre-1973 period is unremarkable in that all price categories remain relatively constant, especially after 1951. The post-1973 period is, of course, more interesting. During this period wellhead prices quintupled, netbacks also rose but to a lesser degree, and reserves prices increased relative to wellhead prices. To illustrate these relative price changes during the entire period, the price ratios based on five-year averages are plotted in Figure 3-1.

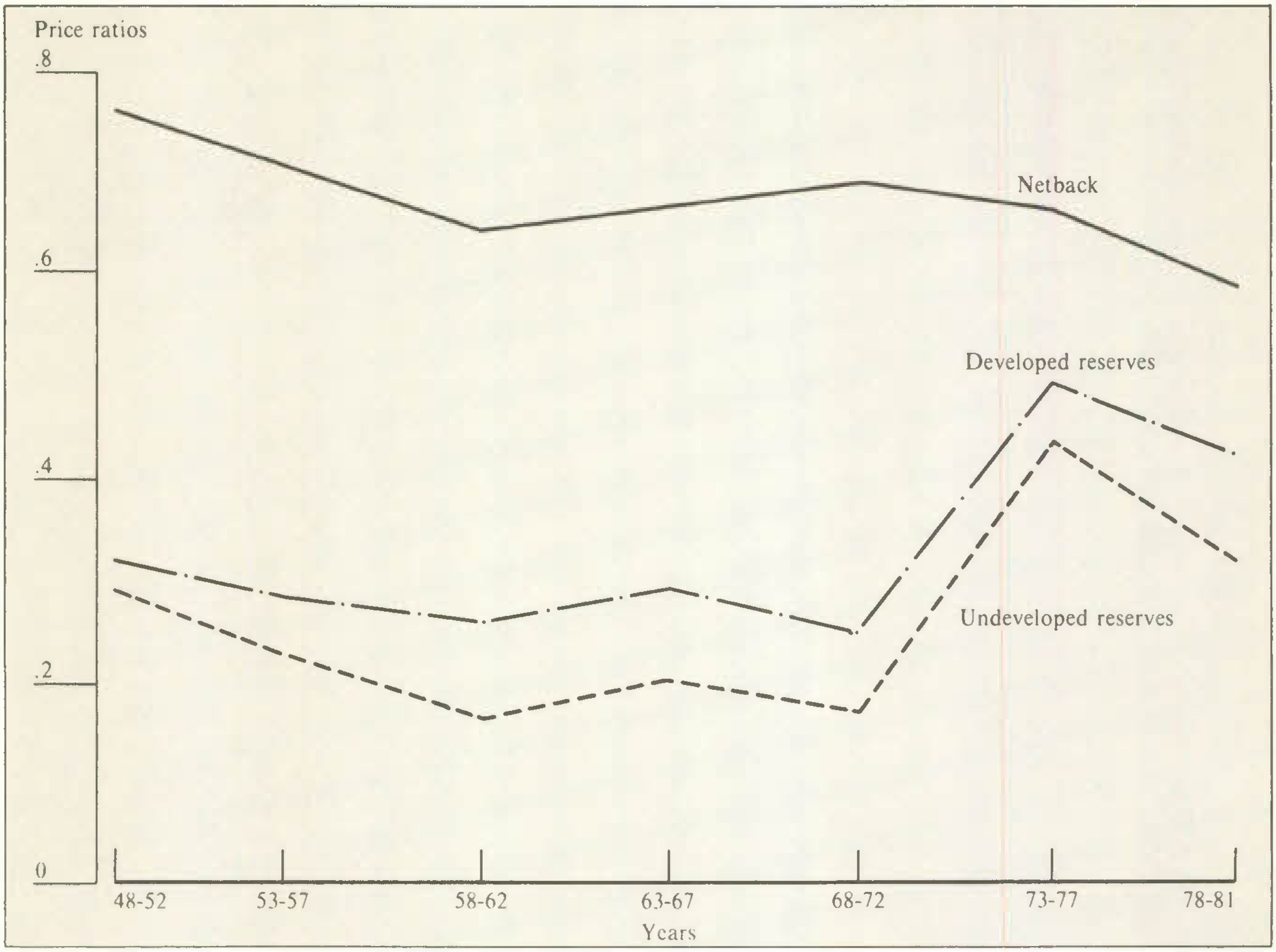
Figure 3-1 shows that in the earlier period netbacks and reserves prices remained a relatively constant proportion of wellhead prices. In the later period, netbacks decline as a proportion of wellhead prices, but what is most striking is the sharp increase in relative reserves prices. The main reason for this increase is the price expectations which are included in determining reserves prices for this period. Beginning in 1974, a 5 per cent per year continuous increase in the wellhead price, that in 1976 was increased to a 10 per cent yearly increase, was incorporated into the reserves price calculation. Since these are treated as continuous increases, they enter as exponential growth for this period and thus have the effect of lowering the discount rate by an equivalent amount. This is illustrated in the detailed example in Appendix A where the effective discount rate is lowered from 0.23 to 0.13 because of a 0.10 continuous growth in expected wellhead prices. As is evident from Table A-1, in 1980 and 1981 the price of reserves declined from their earlier higher levels. The primary reason for this was the sharp increase in interest rates that was not offset by a similar increase in wellhead price expectations. The reason the price of undeveloped reserves was hit particularly hard is because, in addition to the effect of higher interest rates, current capital costs also rose in these years.

The Price of Natural Gas Reserves

The methodology for determining the price of natural gas reserves is the same as the one used to determine the price of crude oil reserves. There are, however, some special features of determining natural gas reserves prices which have not yet been encountered. The first involves the definition of the product itself. Most people think of the price of natural gas as its price at some distribution point such as the Toronto City Gate or the Alberta Border. Even the field price is generally thought of as the price of processed gas at the gas plant. But the product which appears at the wellhead is unprocessed gas containing various amounts of natural gas liquids (NGLs) and sulphur which, after separation at the gas plant, are valuable

Figure 3-1

Ratios of Netbacks and Reserves Prices to Wellhead Prices: Crude Oil, Alberta



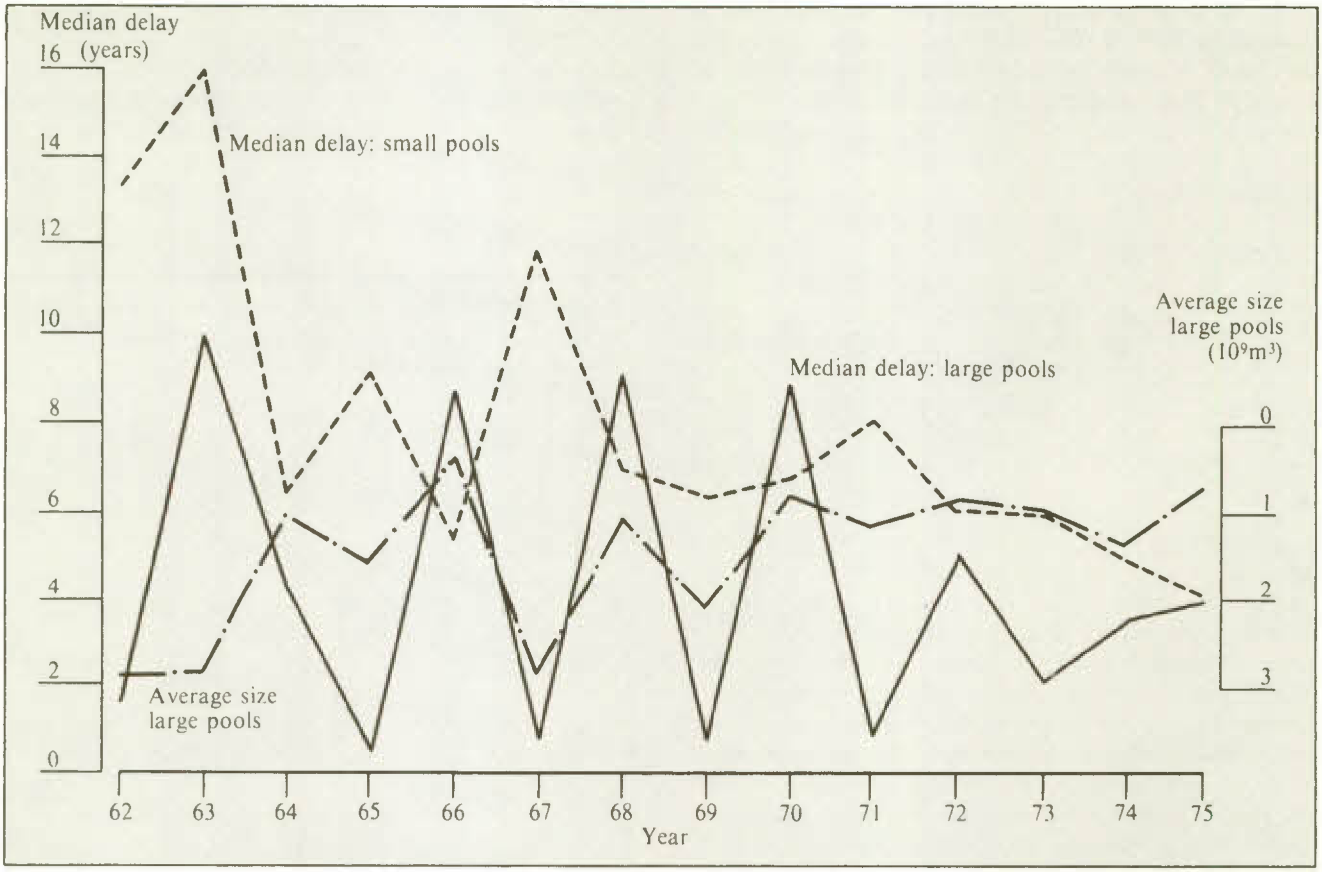
products in their own right. Since the methodology for determining the reserves price requires that one work backwards from the wellhead price, the first objective is to value unprocessed gas at the wellhead. This is done by considering the value of all products which emerge from the gas plant. They are then imputed to gas production. After deducting gas plant costs, what is called the composite price of gas at the wellhead is obtained. One then works backwards from this value to determine netbacks and reserves prices as described earlier.

The second feature of reserves price determination which was not encountered earlier involves the effects of delay between discovery and initial production. This has not typically been a problem in the case of oil discoveries since most discoveries have begun production shortly after they were found. But this is certainly not true for natural gas in the Alberta basin. Evidence of such delays by discovery year and by size of reservoir is presented in Figure 3-2. In this graph, the median delay between discovery and initial year of production is presented for the period 1962-75; a period in which natural gas production grew by nearly 2.5 times.[5] The graph shows that even for large pools (greater than 280 x $10^6 m^3$) median delay can be substantial. It also shows clearly that delays for smaller pools are typically much larger than for large pools.

Two other features of the graph are noteworthy. The first is the much greater variation in the median delay

Figure 3-2

Median Delay Between Year of Discovery and the Beginning of Production and Average Size of Large Pools: 1962-75



for large pools and the rather unusual cycle of large and small values of median delay. This unusual result can be explained by considering the average size of discoveries in this group. A plot of the average size of large pools is also shown in Figure 3-2 (right scale). It is mainly true that when the median delay is large the average size of the discoveries in that year is small. Since large discoveries usually have low production costs, the delay involved in bringing them into production is typically shorter. The other feature to notice is that the median delay for small pools has a definite downward trend. In fact, there seems to be a convergence of median delay in the large and small pool groups. Although the downward trend in the delay for small pools would have increased their value and thus provided an incentive to search for them, there is little evidence to suggest that this trend has continued to the current time. It is well known that one of the important problems in the industry today is its inability to market established gas reserves.

It is also interesting to note that if lowering natural gas prices at the wellhead was required to improve gas marketability, such a wellhead price reduction would not necessarily lower the price of gas reserves. If delay time was reduced enough the price of reserves might even increase as a result of a decrease in the wellhead price. It can be shown that under reasonable assumptions the elasticity between the delay time and the wellhead price, that leaves the price of reserves unchanged, is inversely proportional to the product of the discount rate and the delay time. If the discount rate is 0.10 and the delay time is five years, then a 1 per cent decrease in the wellhead price must result in more than a 2 per cent decrease in the delay time if the reserves price is to rise due to this effect.

In Table A-3 of Appendix A, the calculations of nominal natural gas wellhead prices, netbacks and reserves prices are presented. Various costs and royalties used in these calculations are given in Table A-4. Unlike oil prices, gas prices in the early period show some surprises. First, there are the negative values for netbacks and reserves prices which require explanation.[6] The negative reserves prices indicate that the net present value of acquiring reserves is negative so that in these circumstances it would not pay to carry out a program of gas reserve acquisition. But in these years one does in fact observe gas reserve additions. Why would this be? One explanation is that the most of these additions to gas reserves were as a result of the industry searching for oil. What is more difficult to explain, however, is the production of gas in a period in which average gas netbacks were negative. Now certainly most gas production came as a result of the production of oil but some also came from non-associated gas pools. At present, no good explanation for this observation is available except to note that the netbacks are very small negative numbers, and small data errors may easily be large enough to explain this result.

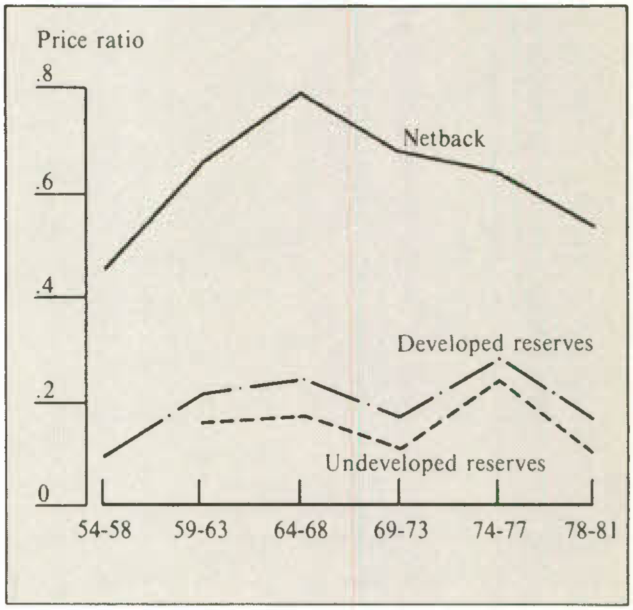
In the late 1950s, netbacks began to grow even though the price incentive to search for more gas was nil so that there was, on average, an incentive to produce gas which had already been found. Our calculations also show that it was not until 1960 that the price of undeveloped reserves reached a level indicating a positive *price incentive* to explore for additional gas reserves. However, this does not mean that it would have been economically worthwhile to do so. Only if finding costs were below this amount would there have been an economic incentive to actually search for additional reserves.

The price of developed reserves is positive as early as 1954. It may be noted that the reserves prices are netted back from the wellhead price and therefore if the price of developed reserves is nil or negative, then the price of undeveloped reserves will be negative. Indeed, if the price of developed reserves is less than the cost of development (about 28 cents in 1960), then the price of undeveloped reserves will be negative. These two price series are calculated because they serve as the appropriate prices in each of the models which are used in this study. In the first model, both exploratory and development drilling result in reserves additions so that the price of developed reserves measures the value of additions, whereas in the other model exploratory drilling finds undeveloped reserves which are developed and brought into production as a result of development drilling.

In Figure 3-3, the ratio of average netbacks and average reserves prices to average wellhead prices are grouped in several subperiods. The fluctuation in the ratio of the reserves price to wellhead price indicates that wellhead price serves as a poor proxy variable for the reserves price. This is not at all surprising given that reserves prices have responded to changes in industry expectations of future prices, delays between discovery and initial production, and changes in fiscal terms.

Figure 3-3

Ratios of Netbacks and Reserves Prices to Wellhead Price: Natural Gas, Alberta



It is apparent from this chapter that wellhead prices are calculated from yearly, industry-wide data and are thus yearly averages of various regions (horizons and areas) in the Alberta sedimentary basin. Of course, in reality reserves prices vary from region to region and, indeed, from pool to pool because of differences in development, operating, and capital costs so that it is a simplification to value reserve additions in all regions, in a given year, at the same price. However, because of data limitations it was not possible to recognize regional variation in reserves prices, and the results of this study are poorer because of this limitation.

4 The Supply of Oil and Gas Reserves: The Disaggregate Analysis

In Chapter 2, the basic features of the oil and gas supply process and the data requirements for supply estimates were discussed. It was indicated that the maximum level of disaggregation that this study could accommodate was one hundred regions consisting of 10 geological horizons and 10 geographical areas. These horizons and areas are shown in Table 2-1 and Figure 2-1. Oil and gas reserve additions and appreciation data for each of these regions have been assembled and presented in Appendix B.[1]

If the tables of data presented in Appendix B are examined, it soon becomes clear that for many of the one hundred regions the amounts are so small that a supply analysis using historical data is infeasible. In view of this situation it was decided to carry out the supply analysis at a more aggregate level as given by the following horizons and areas:

1) Upper Devonian – All Areas. The majority of pools are in Area 8 but a major pool, Redwater, is in Area 3.

2) Upper Cretaceous – Area 8. The Pembina Field accounts for virtually all of the oil reserves in this region.

3) Beaverhill Lake and Lower Devonian – All Areas except for Area 5. Most of the pools are in Areas 0 and 7.

4) Beaverhill Lake and Lower Devonian – Area 5. This is the Rainbow-Zama play.

5) Mannville – All Areas. A large number of small oil and gas pools in Areas 1, 2 and 8.

6) Viking – All Areas. Oil is mainly in Area 8. Gas is more widespread. Relatively high gas-oil ratio in oil pools.

7) Upper Cretaceous – Area 1. Major shallow gas horizon with large number of commingled pools in Medicine Hat and Milk River.

8) Mississippian – All Areas. Pools are mainly in Areas 8 and 9. Primarily a gas horizon with high gas-oil ratio in oil pools.

Primary and enhanced reserve additions-appreciation tables for these regions are provided in Appendix C.[2] Furthermore, associated and non-associated gas have been separated and tables for each are provided. For purposes of the supply analysis, it is assumed that all gas in small pools is non-associated gas. The regions listed above account for 98 per cent of all oil discoveries and 93 per cent of all non-associated gas discoveries in the Alberta basin.

To illustrate the use of the data contained in Appendix C, Table C-1 is reproduced below as Table 4-1. It shows primary oil reserve additions and appreciation in the Upper Devonian horizon for the entire Alberta basin. The entries in the first column labelled DISC refer to booked discoveries in each year starting in 1946. For example, 5.99 x $10^6 m^3$ of primary oil and booked as discovered in 1947 and this was also the recorded reserve addition in 1947 as shown in the Total column at the far right of the table. The entries in columns between DISC and Total refer to appreciation of discoveries made in the year indicated at the column head. For example, in 1950, discoveries made in 1947 were appreciated by 12.04 x $10^6 m^3$, and in that same year discoveries made in 1948 were appreciated by 15.10 x $10^6 m^3$, and discoveries made in 1949 were appreciated by 13.06 x $10^6 m^3$. Thus, total reserve additions in 1950 were 45.5 x $10^6 m^3$ of which 5.3 x $10^6 m^3$ were booked discoveries in 1950 and the remainder was appreciation of earlier discoveries. Thus, in any year, total reserve additions consists of new discoveries and appreciation of earlier discoveries, and this is given by the sum of the numbers in each row of the table. It is these totals that supply the data on reserve additions for the models discussed earlier that require such data.

These data tables also permit the analysis of the discoveries data from another point of view. Notice that each column, headed by a year, provides data on the historical appreciation of discoveries made in that year. Thus, the column totals give the total appreciation of each vintage of discoveries. These data, along with the data in the DISC column, are used in estimating the parameters of model 2 used for the aggregate analysis.

In addition to the reserves price data presented in Chapter 3 and the reserve additions data just described, data are needed on drilling effort and unit drilling costs in order to estimate oil and gas supply relationships for the eight regions listed above. In Chapter 2, certain properties of the drilling data were discussed and it was concluded that the best measure of drilling activity is that which is targeted to the horizon in question. It was indicated that even though the available drilling data only provides information on

Table 4-1

Oil Reserve Additions and Appreciation in the Upper Devonian Horizon, Primary Reserves, All Areas

	DISC	1946	1947	1948	1949	1950	1951	1952	1953	1954	1955	1956	1957	Total
1946	0.05													0.05
1947	5.99													5.99
1948	0.25													0.25
1949	5.01		0.05	95.09										100.15
1950	5.30		12.04	15.10	13.06									45.50
1951	34.09		20.29	7.79	4.35	1.81								68.34
1952	3.54		-3.83		4.83	11.75	-7.75							8.54
1953	4.80		-0.02		-0.76	11.13	21.00	10.95						47.12
1954	0.77		0.44		0.41	1.42	9.90	0.74	11.51					25.20
1955	0.13		1.95	4.13	-0.37	0.12	1.07	-0.76	-1.12	0.60				5.76
1956	3.11		2.80	-10.33	0.97	8.43	27.88	7.45	5.95	-0.00				46.26
1957	6.30		2.07	11.60	0.45	1.57	5.08	0.41	-0.43	0.13	0.02	2.05		29.25
1958	1.01		-0.95	0.48	-3.44	0.14	1.32	-1.06	2.56	0.08		3.48	2.05	5.66
1959	0.30			0.79	0.51	0.07	2.87	2.97	-3.09	0.67		-0.26	-0.43	5.60
1960	0.13		0.48	-1.59	8.53	1.56	-1.14	0.11	2.91	-0.12	-0.01	-1.75	1.64	12.71
1961	0.72		-3.18	-0.01	0.04	2.74	-0.22	0.22	0.09	-0.21	0.10	-0.00	-0.00	0.65
1962	0.44		-1.75		-2.55	0.31	0.04	-0.21	1.43	0.02	0.15			-0.97
1963	0.24		0.64				0.41	0.29	0.09	-0.01		0.59	0.32	3.63
1964	0.74		0.11	1.71	0.22	2.30	6.57	1.45	4.62	0.42	0.14	0.17	1.03	22.27
1965	1.17				12.37	7.31	3.69	1.07	0.79	0.58	0.01	-0.00	0.28	28.65
1966	0.05				-0.00	0.00	7.51	5.95			0.09			13.84
1967	0.46		0.02	0.03	0.48	0.03	0.01		0.21	0.05	0.00			1.16
1968	1.06			0.02	0.06	0.01	0.26	0.45	0.00			4.47		6.39
1969	0.15			0.33		0.04	1.55					0.31	0.14	4.18
1970	0.90				0.84	0.01	-2.44	0.01				0.02	1.98	4.48
1971	0.03			4.13	-0.06	0.03	2.79	0.34	2.83		0.01	0.23	0.12	11.51
1972	0.51				0.32		6.05	-0.54	0.11			0.84	-0.02	7.63
1973	0.03		3.34	-0.24		-0.52	-0.27	-0.24	0.07	-0.01		0.07		0.91
1974	0.05		0.64			-0.00					0.01	0.02		1.01
1975	0.00					0.05	0.95		-0.01			0.08	-0.01	1.02
1976					-4.93	0.38	0.01			0.04	0.00	0.30		-4.26
1977					-2.76			0.03	-0.08	-0.12	-0.00		0.41	-2.35
1978	2.46		-0.03	-0.08	3.36	0.01	0.11	0.04	-0.05	0.11	0.00	0.45	-0.02	8.64
1979	0.08					4.00	10.10		0.46					25.54
1980			0.50		-0.04	0.00	0.50	0.02		0.25	0.01	0.04	0.51	10.57
1981					0.04	0.01	0.36	0.02	0.01			0.63		3.53
Total			35.61	128.94	35.95	54.70	98.21	29.72	28.85	2.48	0.51	11.72	8.00	

	DISC	1958	1959	1960	1961	1962	1963	1964	1965	1966	1967	1968	1969	Total
1958	1.01													5.66
1959	0.30	0.20												5.60
1960	0.13	1.97	0.01											12.71
1961	0.72	0.34	0.02	0.01										0.65
1962	0.44	-0.05	0.01	0.22	0.96									-0.97
1963	0.24	0.40		0.13	0.07	0.45								3.63
1964	0.74	2.90	-0.02	-0.01	0.14	-0.24								22.27
1965	1.17	0.25		0.93	0.06	0.10		0.03						28.65
1966	0.05			0.27				-0.04						13.84
1967	0.46			-0.09	0.00	-0.03	-0.02		-0.00	0.04				1.16
1968	1.06	0.04	0.00		0.16	-0.01	-0.01	-0.05	-0.03		-0.05			6.39
1969	0.15		0.19	0.02	-0.17	0.72	0.14	-0.01		0.72	0.01	0.04		4.18
1970	0.90								-0.00	2.75		0.06	0.36	4.48
1971	0.03	1.59	-0.00							-0.72		-0.03	0.22	11.51
1972	0.51		0.00	0.18	-0.00	0.26		-0.00	0.00	0.01				7.63
1973	0.03		-0.02		-0.03	-0.03	-0.12	-0.29	-0.00	-0.83		0.11	-0.07	0.91
1974	0.05	0.06										0.12		1.01
1975	0.00			0.03						0.01		-0.04		1.02
1976							-0.06					0.00		-4.26
1977					-0.03			0.01	0.00	0.01	-0.05	0.05		-2.35

Table 4-1 (concl'd.)

	DISC	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	Total
1978	2.46	0.01	-0.15	-0.00	-0.00	0.00		0.00	0.00	0.01	-0.00	0.00		8.64
1979	0.08	-1.62							0.00	0.04			-0.00	25.54
1980									0.01		-0.01		-0.45	10.57
1981			0.03		0.25			0.00			0.01			3.53
Total		7.10	0.07	1.69	1.41	1.22	-0.07	-0.34	-0.02	2.05	-0.09	0.31	0.06	

	DISC	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	Total
1970	0.90													4.48
1971	0.03													11.51
1972	0.51	-0.07												7.63
1973	0.03	-0.13	-0.01	0.09										0.91
1974	0.05			0.12										1.01
1975	0.00				-0.03									1.02
1976														-4.26
1977				0.18										-2.35
1978	2.46	0.00		-0.00		0.01		0.01	2.38					8.64
1979	0.08	0.03		-0.04					-0.10	12.59				25.54
1980				-0.41				-0.01	0.36	1.76	7.54			10.57
1981				0.01	0.05	-0.01		0.00	0.06	0.36	0.38	1.32		3.53
Total		-0.16	-0.01	-0.05	0.02	0.00		0.00	2.70	14.71	7.92	1.32		

well penetrations it might still be used to estimate the number of targeted wells. In Tables D-1 to D-10 of Appendix D, the raw drilling data on well penetrations by year, horizon, and area are presented. If the methodology outlined in Chapter 2 is followed, and one only counts as drilling effort those wells in an horizon that do not proceed to penetrate a deeper horizon, then targeted wells can be estimated by simply subtracting the total number of wells which penetrate the next deepest horizon from the number that have penetrated the horizon in question. Although this procedure has inaccuracies, it provides a better measure of drilling effort in a particular horizon than just counting the number of well penetrations. This is particularly true for the shallower horizons which have been penetrated by many non-targeted wells.

Estimates of targeted drilling effort in each of the regions listed above appear in various data tables in Appendix E. These estimates are based primarily on the targeted drilling method just described but a number of adjustments have been made based on other information. For example, the method indicates a large number of Mississippian targeted wells in Area 1 yet there is other evidence that most of these wells were actually targeted for Mannville. The wells were probably targeted to Mannville but extended to penetrate the first paleozoic formation for licensing or for information purposes and, in this area, the first paleozoic horizon is the Mississippian. Based on this information, most of these wells have been allocated to the Mannville horizon. Other problems with the targeted drilling estimation procedure also exist. In some areas wells will not penetrate all of the horizons, especially Jurassic, Triassic, Permian, and Pennsylvanian so that it is difficult to estimate targeted wells in these horizons. Fortunately, these horizons do not play an important role in the supply estimates. Another inaccuracy arises because many exploration wells will be drilled to deeper horizons simply for information purposes. This is especially true of exploratory wells with shallow targets. But even with these shortcomings, the determination of targeted drilling in this way provides a better measure of horizon-specific drilling effort than does total well penetrations.

The remaining data needed for the supply estimates are unit drilling costs by region. These costs are determined in the following way. Estimated cost-depth relationships for completed development wells for each area in the basin were used in conjunction with data on the average depth of pools in each horizon and area, the current proportion of total wells drilled which are actually completed, and the proportion that are development wells. Using the information that completed wells cost about 50 per cent more than abandoned ones and exploration wells about 15 per cent more than development wells, weighted unit costs of wells in each region were estimated. These unit costs appear in various tables later in this chapter in connection with the estimates of ultimate oil and gas supply.

Oil and Gas Supply in Upper Devonian

The Upper Devonian horizon in all areas of the Alberta basin has supplied about 43 per cent of primary oil reserves and 12 per cent of non-associated gas reserves with the majority of these reserves coming from pools in Area 8. In Table E-1 of Appendix E, smoothed oil and gas reserve additions and targeted drilling data in this horizon is presented which has been extracted from Tables in Appendices C and D. If the reserve additions in Table E-1 are compared with those from Table C-1, it will be noticed that in some years the amounts differ. This is due to minor smoothing of the data to avoid negative reserve additions and to recognize major appreciation which was later recinded. For example, the 1965 amount was adjusted downward and the 1976-77 amounts were adjusted upward because of substantial re-evaluation in these years of 1949 vintage discoveries. In 1965, substantial reserves were added to these discoveries but withdrawn in 1976-77. The reserve additions data for other regions in the disaggregate analysis was also smoothed in this way so that the data used in estimating the parameters are not identical to the data which appear in the tables in Appendix C.

Examination of Table E-1 shows a fairly typical pattern of oil reserve additions in a major producing horizon. These additions tend to build up quickly after discovery of the initial pool and then drop off slowly and irregularly over time. However, what is rather unusual about the pattern of reserve additions in this horizon is the sharp rise in recent years. This rise is due to discoveries in the Nisku formation in West Pembina and has been attributed to improved seismic technology. Whether this rise in the discovery rate will persist in this horizon is hard to say, but if it does then it will be the case of new technology causing a significant and permanent shift in the level of reserve additions. Although one cannot hope to explicitly model the impact of this technology because of the small number of observations in the sample over which it is present, one view is that these observations should be given equal weight with all others in the sample. Another view is that this rise in the additions rate is likely to be non-persistent and non-recurring. Although new technology may act to keep the additions rate from falling as fast as it might otherwise, this has always been the case and the more recent technology is not likely to be special in this respect. To present both of these views with respect to the supply prospects in the Upper Devonian horizon, forecasts are provided based on estimates of the reserve additions equation which includes and excludes these sample observations.

Table 4-2 is divided into two parts containing ordinary least squares parameter estimates of oil reserve addition equations and non-associated gas reserve additions equations. These estimates are made under the assumption of no drilling directionality. They are also made using a sample that both includes and excludes the Nisku observations. Furthermore, estimates are presented when the parameter α is restricted to equal one and when it is left free to vary. It is noted that the unrestricted estimate of α is not significantly different from one using standard statistical tests. In all cases presented in Table 4-2, the estimates show that the oil reserve additions rate declines as the level of cumulative drilling effort rises but, as expected, the decline rate is greater when the Nisku observations are excluded from the sample.

Two sets of restricted estimates of the non-associated gas equations are included in the lower part of Table 4-2. The first set indicates that the non-associated gas additions rate is actually increasing with respect to cumulative drilling effort. The reason is that in the early years of the sample period large numbers of wells were drilled, directed primarily at finding and developing oil reserves thus yielding small amounts of non-associated gas reserve additions. This, of course, made the gas additions rate quite low since total wells drilled is the effort variable. Later in the period total drilling dropped off but, at the same time, more was directed toward finding gas and since significant

Table 4-2

Parameter Estimates of Oil and Gas Reserve Additions Equations in the Upper Devonian Horizon, All Areas

Parameter	Unrestricted[1]	Restricted[1]	Unrestricted[2]	Restricted[2]
		Oil		
log A	2.645 (2.702)	3.980 (0.052)	3.693 (2.865)	4.136 (0.535)
α	1.225 (0.446)	–	1.074 (0.468)	–
$\beta(\times 10^{-3})$	–0.136 (0.078)	–0.146 (0.075)	–0.180 (0.086)	–0.184 (0.080)
R^2	0.31	0.11	0.34	0.15
		Non-associated gas[3]		
log A	1.389 (0.527)		3.736 (0.921)	
$\beta(\times 10^{-3})$	0.234 (0.527)		–0.048 (0.119)	
R^2	0.26		0.007	

Note Standard error in parentheses.
1 Including recent Nisku observations.
2 Excluding recent Nisku observations.
3 First set of estimates for whole period and second set for years 1956-79.

amounts of gas were discovered, the additions rate rose. The estimates over the whole period simply reflect this general trend and point out one of the difficulties of using total drilling effort in trying to explain oil reserves and non-associated gas reserves additions separately.

The second set of estimates of the non-associated gas reserves additions equations are based on the 1956-79 sample period in an attempt to reduce the impact of oil directed drilling in the earlier part of the period. Although these estimates indicate a small decline in the additions rate with respect to cumulative drilling effort, in a statistical sense, cumulative effort does not have a significant impact on this rate. Since a clear pattern of decline in the non-associated gas reserves additions rate with respect to cumulative drilling effort does not emerge from any of these estimates, for purposes of subsequent calculations it is taken to be constant at the average rate achieved in the last five years.

The restricted estimates of the oil reserve additions equations, reported in Table 4-2, have been used to calculate the value of the marginal product of drilling in the Upper Devonian horizon for various levels of cumulative effort. These results are reported in Table 4-3. The upper part of the table shows the estimates including the Nisku observations and the lower part shows the estimates when they are excluded. In calculating the marginal oil product, the value of associated gas is incorporated using the average gas-oil ratio in this horizon as outlined in Chapter 2. At the estimated level of cumulative effort in 1981 the point estimate of the marginal oil product when the Nisku observations are included is about $0.385 million per well and the marginal non-associated gas product is about $0.25 million per well. Based on an estimate of drilling costs of $0.37 million per well there is an economic incentive to continue to drill in this horizon. If the estimates which exclude the Nisku observations are used, then the point estimates indicate that there is a weaker but still positive economic incentive to drill in this horizon.

The calculations based on the point estimates including Nisku show that so long as the reserves prices and unit drilling costs remain constant at the levels given, it will be worthwhile to drill another 8,000 wells in this horizon, at which point the sum of the values of the marginal oil and gas products will decline to equal the unit cost of drilling. It is estimated that this additional drilling should discover another 47.7 x 10^6m^3 of oil and 172.6 x 10^9m^3 of non-associated gas.

The results provide a reasonably optimistic forecast for a horizon that up to now has accounted for over 40 per cent of total primary oil discoveries in the Alberta basin. Table 4-3 reports estimates of the value of the marginal oil product based on additions equations which exclude the recent Nisku observations. Although the value of the marginal oil product, the ultimate level of cumulative drilling, and ultimate reserves are reduced, the effect of deleting these observations is not as strong as one might have expected. Calculations show that it is still worthwhile to drill an additional 4,800 wells that are expected to discover an additional 35.0 x 10^6m^3 of oil in this horizon.

In Table 4-4 the response of oil and gas reserves to changes in the price of oil reserves is given. An increase in this price also increases gas reserves because they are complements in the supply process.

Table 4-3

The Value of the Marginal Product of Drilling in the Upper Devonian Horizon, All Areas[1]

Cumulative wells	Value of marginal oil product	Value of marginal gas product	Cost per well	Oil reserves	Non-associated gas reserves
		($x 10^6)		(x 10^6m^3)	(x 10^9m^3)
			Including Nisku observations		
11,422[2]	0.385	0.251	0.370	554.4	283.3
19,418	0.120	0.251	0.370	602.1	455.9
			Excluding Nisku observations		
11,422	0.291	0.251	0.370	554.4	283.3
16,239	0.120	0.251	0.370	589.4	387.4

1 Based on restricted estimates without directionality; 1981 prices and costs. Gas – oil ratio = 0.20.
2 Estimates wells in 1981.

The table shows that the optimal number of cumulative wells to drill in the horizon rises with the price of oil reserves. But even with a 40 per cent increase in the price to \$50.00/m³, ultimate oil reserves increase by only 5.9 x 10^6m^3 beyond what would have been added had the price of reserves remained unchanged. A doubling of the price to \$70.00/m³ adds another 10.2 x 10^6m^3.

These data provide points on the supply curve of ultimate oil reserve additions. As the price of oil reserves rises, holding all other things equal, the quantity of ultimate oil reserve additions also rises. The reserve additions supply elasticity over price returned \$35/m³ – \$70/m³ is about 0.20.

Just as increases in the price of oil reserves will increase gas reserve additions so will increases in gas reserves prices increase oil reserve additions. In the lower part of Table 4-4, the results of these calculations are reported. What is particularly noteworthy about the results is the relatively strong response of both oil and gas reserve additions to increases in gas reserves prices. These results should be viewed with caution, however, because they rely on the gas reserve additions rate remaining constant with respect to cumulative drilling effort and this is unlikely to be the case for such large increases in total drilling effort in the horizon. A rise in the price of gas reserves to only \$15.00/10^3m^3 has a greater impact on oil additions than a doubling of the price of oil reserves.

In Chapter 2, the situation of complete directionality where drilling could be allocated between oil and gas drilling was discussed, and it was shown that profit maximizing behaviour involved equating the value of the marginal products of oil and gas drilling to the unit cost of drilling. It was also noted that empirical implementation of this case required that yearly oil and gas intent drilling be determined. Since these drilling categories could not be observed directly they were estimated from the available data. The method used was to assume that the oil success ratio (ratio of oil well completions to oil intent wells) is the same as the success ratio in all drilling (ratio of total well completions to total targeted wells). If this is approximately true then since oil well completions, total well completions, and total targeted wells are observable, oil intent wells can be estimated.

The parameter estimates of the oil and non-associated gas reserve additions equations using oil and gas intent drilling are presented in Table 4-5. As in Table 4-2, the unrestricted and restricted estimates of the oil equation that includes and excludes the Nisku observations are presented. The restricted non-associated gas estimates are shown for two samples of the data. What is particularly noteworthy about the oil results is that the reserve additions rate is not declining with respect to cumulative oil intent drilling, so that if the value of the marginal product of oil drilling exceeds its cost there is no way of determining ultimate

Table 4-4

Oil and Gas Reserves Supply in Response to Reserves Price Changes in the Upper Devonian Horizon, All Areas[1]

	Cumulative wells	Oil reserves added	Oil reserves	Gas reserves added	Gas reserves
		($x10^6m^3$)		($x10^9m^3$)	
Oil reserves price[2] (\$/m³)					
35.78	19,418	47.7	602.1	172.6	455.9
40.00	20,138	49.9	604.3	188.2	417.5
45.00	20,903	51.9	606.3	204.7	488.0
50.00	21,592	53.6	608.0	219.7	503.0
70.00	23,810	57.9	612.3	267.5	550.8
Gas reserves price[3] (\$/10^3m^3)					
11.65	19,418	47.7	602.1	172.6	455.9
13.00	21,390	53.1	607.5	215.2	498.5
15.00	25,991	61.0	615.4	314.7	598.0
25.00	---	69.3	623.7	---	---

1 Table based on restricted estimates without directionality including Nisku observations.
2 Oil reserves price constant at \$35.78/m³.
3 Gas reserves price constant at \$11.65/10^3m^3.

Table 4-5

Parameter Estimates of Oil and Gas Reserve Additions Equations in the Upper Devonian Horizon, All Areas[1]

Parameter	Unrestricted[2]	Restricted[2]	Unrestricted[3]	Restricted[3]
		Oil		
log A	3.596 (1.942)	3.586 (0.553)	4.018 (2.051)	3.654 (0.566)
α	0.999 (0.292)	---	0.943 (0.306)	---
$\beta(\times 10^{-3})$	0.014 (0.120)	0.014 (0.095)	-0.022 (0.130)	-0.007 (0.100)
R^2	0.36	0.0007	0.37	0.0002
		Non-associated gas[4]		
log A	5.466 (0.266)		4.692 (0.488)	
$\beta(\times 10^{-3})$	-0.932 (0.194)		-0.530 (0.289)	
R^2	0.46		0.17	

Note Standard errors in parentheses.
1 Results are for oil intent and gas intent drilling.
2 Including recent Nisku observations.
3 Excluding recent Nisku observations.
4 First set of estimates for the period 1952-79 and second set for years 1961-79.

supply from these data using this model. When the Nisku observations are excluded, the sign on the cumulative drilling variable becomes negative but it is highly insignificant so that the conclusion remains unaffected. Using the restricted estimates including the Nisku observations gives a reserve additions rate of 40.35 x 10^3m^3 which, as shown in Table 4-6, makes the value of the marginal product of oil drilling about $1.5 million when evaluated at a reserves prices of $38.11/$m^3$. Since wells are estimated to cost only about $0.37 million in this horizon there is a strong economic incentive to continue drilling for oil with no way of determining within the context of this model the ultimate supply of oil. If it is assumed that the reserve additions rate remains constant at the level noted above for another 4,000 oil intent wells, another 160 x 10^6m^3 of primary recoverable reserves could be expected from this horizon. Whether a 50 per cent increase in cumulative oil intent wells could be expected to occur without a decline in the additions rate is problematical, however. Additional data will be necessary before a decline can be observed. It is also noteworthy that this prediction would not be very different if based upon the estimates that excluded the Nisku observations, as is evident from the estimates in the lower part of Table 4-6.

Even though the estimates in Table 4-5 indicate that the reserve additions rate has not declined significantly with respect to increases in cumulative oil intent drilling, it is hard to accept this as a condition that will continue indefinitely and is the reason for arbitrarily setting an upper limit on cumulative oil drilling in the calculations just presented. However, it may be useful to use some of the results presented in Table 4-5 but to impose a decline rate that is smaller than the one obtained earlier for the model without directionality but still not zero. For purposes of illustration a decline rate of 0.10 x 10^{-3} is chosen. The calculations show that under this scenario it would be worthwhile to add another 62.3 x 10^6m^3 of oil reserves in the Upper Devonian if the price of reserves is $35.78/$m^3$. At higher prices of $50.00/$m^3$ and $70.00/$m^3$ it would be worthwhile to add 85.4 x 10^6m^3 and 106.5 x 10^6m^3, respectively. The price elasticity of reserve additions between these latter two prices is calculated to be 0.62. It should be emphasized again, however, that these calculations are for illustration only and not based on

Table 4-6

The Value of the Marginal Product of Oil and Gas Drilling in the Upper Devonian Horizon, All Areas[1]

Cumulative wells	Value of marginal oil product	Oil reserves	Cost per well	Value of marginal product of gas drilling	Non-associated gas reserves
	($x10^6^)	(x10^6m^3)		(x10^6$)	(x10^9m^3)
8,175[2]	1.537[3]				
12,175	1.537	715.4	0.370	---	---
8,175	1.392[4]	554.4	0.370	---	---
12,175	1.392	700.6	0.370	---	---

1 Results based on restricted estimates, 1981 prices, and assume directionality in drilling.
2 Estimated wells in 1981.
3 Including Nisku observations.
4 Excluding Nisku observations.

any specific set of empirical estimates. Nevertheless, they serve to illustrate a realistic case in which there is a slow decline in the reserve additions rate with respect to increases in cumulative oil intent drilling.

Combining these results, which assume perfect directionality with those that assume complete non-directionality, the estimates range between 60 to 160 million cubic metres of additional primary recoverable oil depending upon the price of oil and gas reserves. As noted earlier, these two sets of estimates might be viewed as extremes in that one assumes no possibility of allocation of drilling between oil and gas prospects and the other assumes perfect allocation. The truth probably lies somewhere between these two extremes so that a more reasonable estimate of ultimate supply from this horizon might be closer to 110 or 120 million cubic metres.

The non-associated gas results presented in Table 4-5 are the restricted estimates for two periods of time, 1952-79 and 1961-79. The first set of estimates show that the non-associated gas additions rate is declining significantly with respect to cumulative gas intent drilling. This is not a surprising result when it is noted that throughout the 1950s the level of gas intent drilling in this horizon was very low, with gas pools being discovered primarily as a result of oil drilling. This made the gas additions rate with respect to gas intent drilling quite high. When one starts the analysis of the data in 1961, there is still evidence of decline but it is no longer statistically significant. Although the results are not presented in Table 4-5, if the analysis starts in 1966 the decline in the additions rate with respect to cumulative gas intent drilling is even less apparent.

As is evident from Table 4-6, the value of the marginal product of gas intent drilling is lower than the cost of drilling in the Upper Devonian horizon. This is true for both sets of parameter estimates shown for the non-associated gas reserve additions equation in Table 4-5. Unless the price of gas reserves were to rise to above $25 per thousand cubic metres, gas intent drilling is not economically worthwhile in this horizon.

Oil and Gas Supply in Beaverhill Lake and Lower Devonian

The supply analysis of this horizon includes all areas of the Alberta basin except for Area 5 which will be studied separately. Oil reserves discovered in this horizon account for about 18 per cent of total primary oil reserves and about 4 per cent of non-associated gas reserves and are mainly in Areas 0 and 7. In Table E-2 of Appendix E, oil and gas reserve additions and targeted drilling data which have been taken from Appendixes C and D are listed. As in Table E-1, the reserve additions data that appear in this table have been smoothed. In Table 4-7 the unrestricted and restricted estimates of the reserve additions equation are presented. In this horizon, the restricted oil equation fits the data relatively well and shows a strong and significant downward trend in the additions rate with respect to cumulative drilling effort.

The non-associated gas situation in this horizon is dominated by the Kabob South pool. Discovered in 1961, it had substantial reserve additions in 1968 and 1969 followed by substantial downward revisions in 1975, 1978 and 1980. Table C-5 of Appendix C shows how these adjustments have dominated total reserve additions in each of these years so this data has been smoothed using the method described earlier. But even this smoothing has not produced very good results for the non-associated gas equations. Since the main gas discoveries tended to come later in the development of this region, the results for the full observation set shows an increasing gas additions rate with respect to cumulative effort. However, when the last 14 years are analyzed separately this changes to a small but insignificant decline with respect to cumulative effort. In view of these results, the forecast of the gas additions rate is based on its average of the last five years of the adjusted data.

In Table 4-8, the calculations of the value of the marginal oil and gas product and of cumulative drilling in this horizon are shown. With unit well costs at around $0.690 million, this approach indicates that the value of the oil and gas product of drilling is not large enough to warrant further drilling in the horizon. Even though the estimates indicate that at 1981 reserves

Table 4-7

Parameter Estimates of Oil and Gas Reserve Additions Equations in the Beaverhill Lake and Lower Devonian Horizon, All Areas Except Area 5

	Oil		Non-associated gas[1]	
Parameter	Unrestricted	Restricted	Unrestricted	
log A	7.66 (2.92)	5.41 (0.68)	-1.05 (1.13)	2.75 (4.45)
α	0.57 (1.54)	---	---	---
$\beta(\times 10^{-3})$	-0.85 (0.22)	-0.84 (0.21)	0.82 (0.36)	-0.075 (1.14)
R^2	0.47	0.42	0.20	0.0004

1 First column based on full observations set and second column based on last 14 observations.

Table 4-8

The Value of the Marginal Product of Drilling in the Beaverhill Lake and Lower Devonian Horizons, All Areas Except Area 5[1]

Cumulative wells	Value of marginal oil product	Value of marginal gas product	Unit well cost	Oil reserves	Non-associated gas reserves
		($x10⁶)		(x10⁶m³)	(x10⁹m³)
5,260[2]	0.104	0.495	0.690	236.8	84.5
7,000	0.024	0.495	0.690	239.3	158.4

1 Based on restricted estimates without directionality; 1981 prices and costs.
2 Estimated wells in 1981.

prices further drilling in the horizon is not economically worthwhile, as a matter of interest, Table 4-8 shows the value of the marginal oil and gas products and the reserve for a higher amount of cumulative drilling. The table shows that an additional 1,700 wells would only be expected to add 2.5 x $10^6 m^3$ of primary oil reserves. It shows more gas potential but this is based on tenuous parameter estimates.

If oil and gas reserves prices rise enough then an incentive to drill additional wells will exist. If the price of gas reserves is held constant then the price of oil reserves must rise to nearly $72.00/m³ to create an economic incentive to drill additional wells. Thus, the oil reserves supply curve in this region is essentially vertical up to this price. However, because of the high gas reserves additions rate the price of gas reserves does not have to increase very much to make additional drilling worthwhile. If it were to rise above about $13.80/10³m³ then the total value of the marginal product of drilling at the current level of cumulative wells rises above the unit cost. Since the gas additions rate is constant, it is not possible to determine the economic limit of the number of cumulative wells, but if they were to rise to 7,000 then about 2.5 x $10^6 m^3$ of additional oil and about 74.0 x $10^9 m^3$ of additional non-associated gas would be found. These responses to changes in oil and gas prices are summarized in Table 4-9.

The oil reserves supply situation in this horizon has also been analyzed on the basis that drilling with complete directionality. Since most of the drilling in the horizon has been directed at oil prospects, the parameter estimates of the oil reserve additions equation presented in Table 4-10 are very similar to those presented in Table 4-7. At the estimated 1981 level of cumulative oil drilling, the reserve additions rate is 4.24 x $10^3 m^3$ per oil well which gives a value of the marginal product of about $0.162 million when evaluated at a price of $38.11/m³. Since wells cost about $0.690 million in this horizon there appears to be no economic incentive to drill for oil. Even if the

Table 4-9

Oil and Gas Reserves Supply in Response to Reserves Price Changes in the Beaverhill Lake and Lower Devonian Horizon, All Areas Except Area 5[1]

	Cumulative wells	Oil reserves added	Oil reserves	Gas reserves added	Gas reserves
		(x10⁶m³)		(x10⁹m³)	
Oil reserves price[2] ($/m³)					
35.78	5,260	0	236.8	0	84.5
70.00[3]	5,260	0	236.8	0	84.5
Gas reserves price[4] ($/10³m³)					
11.65	5,260	0	236.8	0	84.5
14.00	7,000	2.5	239.3	73.9	158.4

1 Based on restricted estimates without directionality.
2 Oil reserves price constant at $35.78/m³.
3 At a price of $72.00/m³ additional drilling becomes profitable.
4 Gas reserves price constant at $11.65/10³m³.

Table 4-10

Parameter Estimates of Oil and Gas Reserve Additions Equations in the Beaverhill Lake and Lower Devonian Horizon, All Areas Except Area 5[1]

Parameter	Oil		Non-associated gas[2]
	Unrestricted	Restricted	unrestricted
log A	8.363	5.414	4.966
	(2.765)	(0.725)	(1.237)
α	0.444	---	---
	(0.503)		
β (x10^{-3})	−0.880	−0.824	−2.333
	(0.244)	(0.240)	(5.656)
R^2	0.44	0.36	0.014

1 Results are for oil intent and gas intent drilling.
2 Based on 1966-79 period.

price of oil reserves were doubled to near \$75.00/m^3, there still would not be an incentive to add oil reserves. Thus, as in the earlier analysis, it is concluded that the remaining oil potential of this horizon is small, even if reserves prices rise substantially.

The non-associated gas estimates based on gas intent drilling are also presented in Table 4-10. Only the data beginning in 1966 could be used because before this year all of the drilling was oil intent drilling. The estimates show that the non-associated gas reserve additions rate is declining with respect to cumulative gas intent drilling but that the decline is not significantly different from zero. The additions rate is about 54 x 10^6m^3 per well which makes the value of the marginal product of drilling about \$0.630 million per gas intent well. Thus, it would appear that only a small an increase in the price of gas reserves is required to make gas drilling economically worthwhile. These results should be viewed with caution, however, since they are dominated by a single pool, the Kabob South Pool. Moreover, they are very much influenced by the data smoothing referred to earlier. If one examines the unsmoothed non-associated gas data for this horizon, the later part of the data period is actually featured by some rather large downward revisions in reserves. Thus a slightly different smoothing procedure could lead to dramatic changes in the gas results.

Oil and Gas Supply in Mannville

The Mannville horizon contains a large number of relatively small oil and gas pools which account for about 7 per cent of oil reserves and 38 per cent of non-associated gas reserves discovered in the Alberta basin. It has been particularly important in yielding large amounts of non-associated gas in recent years, accounting for about 53 per cent of total reserve additions in the five years preceding 1981. In all likelihood, many of these pools will account for further reserve additions in the future.

Table E-3 of Appendix E brings together the oil and gas reserve additions and targeted drilling data which has been taken from Appendixes C and D. Table 4-11 presents the estimated reserve additions equations based on these data. To conserve space, estimates using both directionality assumptions are included. In this table, and similar tables to come, only the restricted estimates are reported since they will be used in determining the marginal product of drilling and ultimate supply and are typically similar to the unrestricted estimates. These results show a slow but significant decline in the oil additions rate with respect to increases in cumulative drilling. The gas additions rate is essentially constant with respect to cumulative drilling.

In Table 4-12, the calculations of the value of the marginal oil and gas products and unit cost of drilling are reported. It shows that the values of the marginal gas product exceeds the unit cost of drilling. Since the gas additions rate exceeds the unit cost of drilling and there is no evidence that it is declining as cumulative effort rises, an economic limit on gas supply cannot be determined since additional drilling is always profitable. Again it is noted that it is unlikely that a constant gas additions rate can continue indefinitely so that placing an upper limit on cumulation drilling is reasonable. The oil and gas additions rate equation has been evaluated at an additional 12,240 wells to bring the total in this horizon to 40,000 mainly to determine the effect on additional oil reserves. As shown in Table

Table 4-11

Parameter Estimates of Oil and Gas Reserve Additions Equations in the Mannville Horizon, All Areas

	Oil[1]		Non-associated gas[2]	
log A	1.67	2.317	3.25	4.098
	(0.30)	(0.310)	(0.14)	(0.143)
β (x10^{-3})	−0.117	−0.218	−0.012	−0.052
	(0.032)	(0.066)	(0.015)	(0.030)
R^2	0.31	0.27	0.02	0.09

Note Standard errors in parentheses.
1 Second column shows results for oil intent drilling.
2 Second column shows results for gas intent drilling.

Table 4-12

The Value of the Marginal Product of Drilling in the Mannville Horizon, All Areas[1]

Cumulative wells	Value of marginal oil product	Value of marginal gas product	Unit well cost	Oil reserves	Non-associated gas reserves
		($x 10^6)		(x 10^6m^3)	(x 10^9m^3)
27,761[2]	0.008	0.292	0.200	87.5	678.8
40,000	0.002	0.292	0.200	88.8	987.5

1 Based on restricted estimates without directionality.
2 Estimated 1981 wells.

4-12, the additional wells only add another 1.3 x 10^6m^3 of oil and these oil reserve additions take place due to the drilling incentive created by the return due to gas discoveries. If the gas additions rate holds constant, as assumed, then another 310 x 10^9m^3 might be expected from this horizon.

In view of the magnitude of recent discoveries in the Mannville horizon these estimates of the oil supply potential in this horizon may seem low. But even if one takes a more optimistic view and assumes that the average additions rate in the last five years will continue for a time, Mannville oil prospects are still not overly bright. The 1977-81 average additions rate is about 1.2 x 10^3m^3/well. If this continues, and it is doubtful that it will, the additional 12,239 wells shown in Table 4-12 would add another 14.7 x 10^6m^3. This is substantially above the 1.3 x 10^6m^3 predicted by the additions rate equation whose parameters are shown in Table 4-13, but still not large in the total scheme of things. Since 1980-81 discoveries in this horizon were relatively large, it was decided to estimate another additions rate equation which included these observations. This resulted in a slightly more optimistic forecast of 4.1 x 10^6m^3 of oil reserve additions.

The parameter estimates of the reserve additions equation with oil intent drilling and the non-associated gas reserve additions equation with gas intent drilling are also presented in Table 4-11. At the 1981 level of cumulative oil drilling, the estimated oil reserve additions rate is about 0.60 x 10^3m^3 per well which when evaluated at a reserves price of $39.86/$m^3$ (includes the value of associated gas) yields a value of the marginal product of $0.023 million per well. Since wells cost about $0.200 million in this horizon, the price of oil reserves would have to increase nearly tenfold to make drilling for oil economically worthwhile.

The non-associated gas situation in this horizon is entirely different. The gas additions rate is estimated to be about 28.8 x 10^6m^3 per well which when evaluated at a price of $11.65/$10^3m^3$ yields a value of the marginal product of gas drilling of $0.340 million so there is a clear incentive to drill for gas at this price. Gas prices would have to fall by nearly 50 per cent to eliminate this incentive.

Since the gas additions rate is declining with increases in gas drilling, it is possible to determine a supply relationship of ultimate non-associated gas reserves from this horizon although it should be noted that the coefficient on cumulative gas drilling is relatively unstable. Table 4-13 reports these results. If the price of gas reserves were to remain at its 1981 level of $11.65/$10^3m^3$ another 223.0 x 10^9m^3 can be expected from this horizon. If the price of gas reserves rose to higher levels then larger additions would be expected as shown in the table. At $25/$10^3m^3$ an additional 400 x 10^9m^3 might be expected.

The estimates in Tables 4-12 and 4-13 explain the oil and gas supply picture in the Mannville horizon quite clearly. There is already a drilling incentive in this horizon because of natural gas prospects and, with no drilling directionality, some oil will be found in the course of drilling for gas; perhaps another 2-3 x 10^6m^3. If drilling directionality is perfect an incentive to drill for oil does not exist so that no additional amounts can

Table 4-13

Non-Associated Gas Reserves Supply in Response to Price Changes in the Mannville Horizon, All Areas

Gas reserves price	Cumulative gas wells	Gas reserves added	Gas reserves
($/ 10^3m^3)		(x 10^9m^3)	
7.00	14,176	0	455.9
11.65	24,099	223.0	678.9
15.00	28,951	296.6	752.5
25.00	38,757	399.0	854.9

be expected. Under both directionality assumptions the prospects for additional gas discoveries are very bright.

Oil and Gas Supply in Beaverhill Lake and Lower Devonian – Area 5

This horizon contains the well-known Rainbow-Zama oil play and has yielded about 10 per cent of discovered oil reserves but an insignificant percentage of gas reserves discovered in the Alberta basin. It is treated separately from the rest of the Beaverhill Lake and Lower Devonian horizon because of its geographical separation and the unique character of its pools. One of the features of the reserve additions data for this horizon is the number of years of negative reserve additions. The typical pattern was to assign large reserves to pools initially and then to revise them downward in subsequent years that yielded an uncharacteristic depreciation rather than appreciation in pool reserves. In order to use these data in estimating the reserve additions equations, they have been smoothed in the way discussed earlier; that is, by offsetting negative additions against earlier positive additions for pools discovered in years 1967 to 1973.

The smoothed oil reserve additions data and the targeted drilling data for this horizon are shown in Table E-4 of Appendix E. There is not enough non-associated gas in this horizon to include in the study. The estimates of the restricted oil reserve additions equation, the value of the marginal oil product, and the unit cost of drilling are shown in Table 4-14. Since at the current level of cumulative effort the value of the marginal oil product is less than the unit cost of drilling, there is no economic incentive to continue drilling in this region. The price of oil reserves would have to rise to $67.51/m³ and unit drilling costs remain constant for an economic incentive to emerge. Thus the supply curve for the horizon is vertical up to the price of $67.51/m³ after which point it would have positive slope, but even if the price rose significantly above this level, the estimates show that very little additional oil could be expected even though an incentive would exist to drill some additional wells.

Since almost all of the drilling in this horizon has been oil intent drilling and little non-associated gas has been discovered, the separate oil and gas drilling results are not reported here. The estimated oil reserve additions equation using oil intent drilling is thus virtually identical to that reported in Table 4-14.

Table 4-14

Parameter Estimates of the Oil Reserve Additions Equations and Value of Marginal Oil Product in the Beaverhill Lake and Lower Devonian Horizon, Area 5[1]

Parameters of additions equations	
log A	5.990
	(0.533)
β (x10⁻²)	-0.378
	(0.067)
R^2	0.72
Oil product of drilling	
Cumulative wells	1,109[2]
Value of marginal oil product ($x10⁶)	0.220
Cost per well ($x10⁶)	0.412

Note Standard errors in parentheses.
1 Results are for the case in which no directionality is assumed but since virtually all drilling was oil intent drilling then results also apply for the case of complete directionality.
2 Estimated 1981 wells.

Oil and Gas Supply in Upper Cretaceous – Area 8

Oil supply in the Upper Cretaceous horizon in Area 8 is made up largely of discoveries in the Cardium formation which is dominated by a single pool, the Pembina pool. This horizon has supplied about 13 per cent of primary oil reserves discovered in the Alberta basin. The fact that oil supply in this horizon has been dominated by a single pool which has been subject to large upward and downward revisions in reserve estimates makes supply analysis difficult. As noted before, the model of reserves additions cannot accommodate negative additions and there have been several years of large negative additions in the Pembina pool. This difficulty has been overcome by smoothing the data by offsetting negative and positive additions. These smoothed data along with the targeted drilling data are presented in Table E-5 of Appendix E. Non-associated gas reserve additions are not included in this table because they are so insignificant in the region. Thus, the economic incentive to drill additional wells depends exclusively on oil and associated gas prospects.

In Table 4-15, the parameter estimates of the oil reserve additions equation, the value of the marginal product of drilling and the unit cost of drilling are reported. This table shows that there has been a significant decline in the oil additions rate with respect to increases in cumulative drilling. It also shows that the value of the marginal oil product (including associated gas) is below the cost of drilling so that it does not appear to be economically worthwhile to continue to drill in this horizon. The price of oil reserves would have to nearly triple in order to provide an economic incentive to add reserves. Thus, the supply curve is expected to be nearly vertical for reserves prices between the current value of $35.78/m³ and $112/m³.

Table 4-15

Parameter Estimates of the Oil Reserve Additions Equations and Value of Marginal Oil Product in the Upper Cretaceous Horizon, Area 8

Parameters of additions equations	
log A	4.503
	(0.880)
β ($\times 10^{-3}$)	-0.494
	(0.179)
R^2	0.23
Oil product of drilling	
Cumulative wells	7,137[1]
Value of marginal oil product ($\$\times 10^6$)	0.106
Cost per well ($\$\times 10^6$)	0.310

Note Standard errors in parentheses.
1 Estimated 1981 wells.

The analysis of the ultimate supply potential of this horizon which is dominated by the Pembina pool brings up some interesting questions regarding pool spacing and its effect on the reserve additions and drilling data, and hence, on the parameter estimates. The ERCB administers minimum pool spacing regulations which, in pools where oil does not pass easily through the pore structure of the rock, may not permit full recoverability. If the data are generated under a specific set of spacing regulations and these regulations are then changed to recognize less than full economic recovery then the parameter estimates will produce misleading results. This may be the case in this horizon because changes in well spacing regulations for the Pembina pool, or parts of it, may enhance its supply potential beyond what the historical data analysis would indicate.

Again, since nearly all of the drilling in this horizon has been oil intent drilling, separate results for this case are not presented. They are essentially identical to those shown in Table 4-15.

Oil and Gas Supply in Viking and Equivalents

This horizon has supplied about 2 per cent of total primary oil reserve discoveries in the Alberta basin and about 12 per cent of non-associated natural gas. It also has a high average gas-oil ratio which serves to increase the value of oil discoveries. Shown in Table E-6 of Appendix E are the smoothed oil and gas reserve additions and targeted drilling data for this horizon. These data were used to estimate additions rate equations and their parameter estimates appear in

Table 4-16

Parameter Estimates of Oil and Gas Reserve Additions Equations in the Viking Horizon, All Areas

Parameter	Oil[1]		Non-associated gas[2]	
log A	1.845	2.847	3.705	4.199
	(0.555)	(0.562)	(0.617)	(0.552)
β($\times 10^{-3}$)	-0.401	-0.486	-0.113	-0.235
	(0.240)	(0.697)	(0.267)	(0.365)
R^2	0.09	0.02	0.066	0.014

Note Standard errors in parentheses.
1 Second column shows results for oil intent drilling.
2 Second column shows results for gas intent drilling.

Table 4-16. The estimates indicate a decline in the oil additions rate with respect to increases in cumulative drilling effort but the fit of the equations to the data is poor. Like most of the other horizons that have been studied, the non-associated gas finding rate is nearly constant with respect to increases in cumulative effort. This is due to some large reserve additions of gas that have occurred in recent years.

In Table 4-17, the calculations of the value of the marginal oil and gas products of drilling in the Viking horizon are presented. As long as gas reserves prices and drilling costs do not change they indicate a clear incentive to continue drilling, but nearly all of the incentive is due to the value of non-associated natural gas additions. Of course, it should be noted again that the gas additions rate is unlikely to remain constant indefinitely. There is even some evidence of this from the parameter estimates in Table 4-16 in that the gas additions rate declines with cumulative drilling. However, in this, like in most of the other horizons, the decline parameter is so unstable that a constant rate has been used in projecting gas reserve additions.

In Table 4-17 oil and non-associated gas reserves for cumulative drilling of 10,000 wells are shown. Thus a near doubling of targeted drilling in this horizon only adds another 1.6 x $10^6 m^3$ of oil reserves but another 106 x $10^9 m^3$ of non-associated gas. In the table, two well costs are indicated. Since Viking oil pools, mainly in Area 8, are relatively deep the first cost applies to them. On the other hand, Viking as pools that are mainly in other areas are shallower so that the second cost indicated in parentheses is more applicable to these pools. Under these cost conditions there is an incentive to drill additional wells with the incentive coming totally from the incentive to drill for gas. But if the gas additions rate is constant with respect to

Table 4-17

The Value of the Marginal Product of Drilling in the Viking Horizon, All Areas[1]

Cumulative wells	Value of marginal oil product	Value of marginal gas product	Unit well cost: Oil	Unit well cost: Gas	Oil reserves	Non-associated gas reserves
		($x10⁶)			(x10⁶m³)	(x10⁹m³)
5,257[2]	0.044	0.261	0.343	(0.200)	29.6	267.6
10,000	0.007	0.261	0.343	(0.200)	31.2	374.6

1 Based on restricted estimates without directionality; 1981 prices and costs.
2 Estimated 1981 wells.

cumulative effort, the value of the marginal gas product must be below the unit cost of drilling if there is to be a supply response to a change in the price of gas reserves. If it is higher, then a rise in price does not lead to higher ultimate gas reserves.

When perfect drilling directionality is assumed so that effort is allocated between oil and gas intent wells, the results obtained for this horizon are altered. The parameter estimates for the reserve additions equations using oil intent and gas intent drilling are also given in Table 4-16. At the estimated 1981 level of cumulative oil drilling, the additions rate is about 8.0 x 10^3m^3 per well which when evaluated at a reserves price of $57.10/m^3$ (the gas-oil ratio of pools in this horizon averages 1.83) yields a value of the marginal product of oil drilling of about $0.457 million. Since oil wells cost $0.343 in this horizon, drilling under perfect directionality indicates that there is an incentive to drill for oil.

The additions equation can be used to determine ultimate oil supply at various reserves prices, but the instability of the estimated coefficient on cumulative oil intent wells should be noted. Results of the calculations for several prices are given in Table 4-18. At the 1981 price of reserves, taking into account the value of associated gas, an additional 3.95 x 10^6m^3 of oil can be expected. At $70.00/m^3$ this amount would rise to 8.58 x 10^6m^3. Although these amounts are not large in absolute terms they are surprisingly large in view of the amounts of oil found to date in the Viking horizon. It is also somewhat surprising that this horizon shows so much more oil potential than Mannville. Part of the reason may be in the assignment of targeted wells. It was noted earlier that it was sometimes difficult to determine targeted wells in the shallower horizons and that it was especially difficult to distinguish between Viking and Mannville targeted wells. An over assignment of wells to Mannville and an under assignment to Viking would produce overly optimistic results for Viking and overly pessimistic results for Mannville. But even though this might have occurred, it is clear that even at very high levels of oil reserves prices the ultimate supply potential of either of these horizons is not very large.

Like oil additions, non-associated gas reserve additions also respond positively and significantly to targeted gas intent drilling. The restricted estimates are given in Table 4-16 and show that the gas additions rate declines with cumulative gas intent drilling but that the decline coefficient is very unstable. Nevertheless, the estimated equation is used to determine the gas additions rate at the estimated 1981 level of cumulative gas intent wells. This yields a gas additions rate of 27.97 x 10^3m^3 per well so that the value of the marginal product of gas drilling in the Viking horizon is $0.326 million. It is noteworthy that this amount is close to the value of the product of gas drilling in the Mannville horizon. This suggests that the concern expressed earlier about the allocation of wells between the two horizons may be unfounded given the optimality condition that the value of the marginal product of drilling should be equated across horizons.

Since the cost of Viking gas wells averages about $0.200 million there is an incentive to drill additional wells at the 1981 price of gas reserves. The price would

Table 4-18

Oil Reserves Supply in Response to Price Changes in the Viking Horizon, All Areas[1]

Oil reserves price	Cumulative oil wells	Oil reserves added	Oil reserves
($/m³)		(x10⁶m³)	
35.78	1,600	3.95	33.6
50.00	2,628	6.41	36.0
70.00	3,137	8.58	38.2

1 Results based on reserve additions equation with oil intent drilling.

Table 4-19

Non-Associated Gas Reserves Supply in Response to Price Changes in the Viking Horizon, All Areas[1]

Gas reserves price	Cumulative gas wells	Gas reserves added	Gas reserves
($/ 10^3m^3)		($x10^9m^3$)	
7.00	3,687	0	268.6
11.65	5,776	46.0	314.6
15.00	6,852	62.3	330.9
25.00	9,028	85.1	353.7

1 Results based on reserve additions equation with gas intent drilling.

Table 4-20

Parameter Estimates of Oil and Gas Reserve Additions Equations in the Mississippian Horizon, All Areas

Parameter	Oil[1]		Non-associated gas[2]	
log A	3.029	4.169	5.180	6.083
	(0.668)	(0.829)	(0.392)	(0.291)
$\beta(x10^{-3})$	-1.167	-2.209	-0.345	-1.048
	(0.291)	(0.641)	(0.171)	(0.281)
R^2	0.36	0.29	0.12	0.32

Note Standard errors in parentheses.
1 Second column shows results for oil intent drilling.
2 Second column shows results for gas intent drilling.

have to decline to around $7.00/10^3m^3$ to remove this incentive. In Table 4-19, ultimate non-associated gas reserves supply is estimated at various prices of gas reserves. At the 1981 price there is an incentive to add another 46.0 x 10^9m^3 in this horizon. At a price of $25.00/10^3m^3$ there is an incentive to add another 85.1 x 10^9m^3.

Oil and Gas Supply in Mississippian

The Mississippian horizon has produced about 5 per cent of primary oil reserves and about 23 per cent of non-associated gas reserves discovered in the Alberta basin. It has also yielded significant amounts of associated gas. Oil discoveries are dominated by the Turner Valley pool which accounts for about 30 per cent of primary reserves in this horizon.

Table E-7 presents the yearly data on oil, associated and non-associated gas reserve additions along with targeted drilling data. The targeted drilling data for some areas in this horizon were difficult to determine so that the drilling totals are probably less accurate than for most of the other horizons in this study. The parameter estimates of the reserve additions equations are shown in Table 4-20. These estimates show that there has been a significant decline in the rate of oil reserve additions with respect to increases in cumulative drilling effort. This result is consistent with the findings for the other geological horizons in this study except that the rate of decline is somewhat larger in this horizon. Furthermore, unlike the other horizons which have contained significant amounts of non-associated natural gas, the gas reserve additions rate is also declining with respect to cumulative drilling effort. But even though there is strong statistical evidence of a decline of the gas additions rate, evaluated at current levels of cumulative drilling the additions rate is still quite high.

As before, the results from these equations are used to determine the value of the marginal oil and gas product of drilling in the horizon. These estimates are given in Table 4-21. Again, the value of the marginal oil product is negligible and currently the entire incentive to drill is due to the prospect of gas discoveries. However, this incentive is relatively small in magnitude and, combined with the evidence that the gas additions rate is declining with respect to cumulative drilling, suggests that drilling many more wells would quickly bring profitability to zero. Without regard for the decline in the marginal oil product the level of drilling at which profits are eliminated is 5,380 wells; only a small increase above the current level.

The results reported in Table 4-21 are for the Mississippian horizon in all areas of the basin. In Area 9 the picture is quite different. Although wells may cost more than twice as much in this area as in Area 8, where many Mississippian pools are also located, reserve additions per well have more than compensated for the extra cost. For example, for the period 1975-79 gas reserve additions were about 23.8 x 10^6m^3 from only 70 targeted wells. Evaluated at a reserves price of $11.65/10^6m^3$ this yields a value of nearly $4.0 million per well. Even though wells may cost upwards of $1.0 million in this area, the payoff has been high. Thus, it might be expected that many of the remaining wells to be drilled in the Mississippian horizon will be concentrated in this area.

It is evident from Table 4-21 that the oil additions rate in this horizon is so low that even a substantial rise in the price of oil reserves will not raise the ultimate level of drilling effort very much. Thus, it is concluded that the oil supply curve for this region is essentially vertical. On the other hand, a rise in the price of gas

Table 4-21

The Value of the Marginal Product of Drilling in the Mississippian Horizon, All Areas[1]

Cumulative wells	Value of marginal oil product	Value of marginal gas product	Unit well cost	Oil reserves	Non-associated gas reserves
		($x10⁶)		(x10⁶m³)	(x10⁹m³)
5,190[2]	0.003	0.346	0.325	66.1	535.1
5,380	0.002	0.322	0.325	66.2	540.7

1 Based on restricted estimates without directionality; 1981 prices and costs.
2 Estimated 1981 wells.

reserves will provide a substantial incentive to drill for additional gas and some oil would likely be discovered from this drilling. In Table 4-22 the effect of increases in gas reserves prices both on oil supply and on non-associated gas supply is shown. As expected, oil additions increase in response to gas price increases but the amount is very small due to the very low oil additions rate. An increase in the price to $\$25.00/10^3m^3$ causes another $42.7 \times 10^9m^3$ of gas to be added.

Parameter estimates of the reserve additions equations have also been obtained for the case of perfect drilling directionality where total drilling effort has been divided between oil and gas intent drilling. These estimates are presented in Table 4-20. Both equations show a significant decline in the additions rate with respect to cumulative drilling. At the estimated 1981 level of cumulative oil intent wells, the predicted oil reserve additions rate is only $0.14 \times 10^3m^3$ per well which, when evaluated at a reserves price of $\$53.37/m^3$ (the gas/oil ratio in this horizon is 1.51), gives a value of the marginal product of oil drilling of only $0.008 million per well. Thus, the estimates indicate that the oil reserves price would have to rise significantly to warrant drilling for additional reserves. This is consistent with the results for the case when total drilling is used in the analysis.

At the 1981 level of cumulative gas intent drilling and price of reserves, the non-associated gas additions rate is estimated to be $26.54 \times 10^6m^3$ per well with a value of $0.309 million. Unlike the earlier case, this value is slightly below the cost of drilling in this horizon. However, at higher prices there is an incentive to add non-associated gas reserves although the amounts added are estimated to be lower than those given in Table 4-22. The reason is that the coefficient on the cumulative gas intent wells variable is relatively large thus leading to a sharp decline in the additions rate with respect to this variable. At a price of $\$25.00/10^3m^3$ these estimates indicate that only another $13.00 \times 10^9m^3$ can be expected. However, if gas intent drilling and the resulting gas reserve additions in Area 9 are examined separately, the conclusions are similar to the earlier conclusions that indicated significant remaining economic potential for this region.

Gas Supply in Upper Cretaceous – Area 1

The other geological horizons that were studied accounted for about 98 per cent of total primary oil reserves and 80 per cent of non-associated gas reserves discovered in the Alberta basin. The Upper Cretaceous

Table 4-22

Oil and Gas Reserves Supply in Response to Gas Reserves Price Changes in the Mississippian Horizon, All Areas[1]

Gas reserves price	Cumulative well	Oil reserves added	Oil reserves	Gas reserves added	Gas reserves
($/10³m³)		(x10⁶m³)		(x10⁹m³)	
11.65	5,380	0.01	66.11	5.6	540.7
13.00	5,691	0.02	66.12	8.0	548.7
15.00	6,100	0.03	66.14	17.5	558.2
25.00	7,575	0.03	66.14	42.7	583.4

1 Based on restricted estimates without directionality.

horizon in Area 1 is the only remaining horizon to have significant amounts of non-associated natural gas. These reserves are contained in a complex formation of shallow commingled pools that have been known to exist since the earliest years of the exploration and development of the Alberta basin. But because of their low productivity, they only became economically viable ventures when gas prices began to rise in the early 1970s. This improvement in economic conditions led to large drilling programs in this region which caused the recognized level of reserves to grow dramatically. This is a clear case of price induced appreciation referred to in Chapter 2 in connection with the discoveries-appreciation model and it will be discussed in more detail in Chapter 5.

In Table E-8 of Appendix E, the yearly data on gas reserve additions and targeted drilling in this region are reported. The same method used earlier could be used to determine the value of the marginal product of drilling and estimate ultimate gas supply. However, because of the unusual physical characteristics of the pools and their unusual history of discovery and development, it was decided to slightly alter the method of analysis in this region. Instead of using the year by year additions rate and targeted drilling data contained in Table E-8 to estimate the additions rate equation and the value of the marginal product of drilling, somewhat broader trends are studied. Five-year average additions rates are calculated which are also included in Table E-8. Examination of these rates shows that there is a definite downward trend with a sharp dip in the middle period. In the last period gas reserve additions per well were an average of 14.6 x 10^6m^3. When evaluated at a reserves price of $\$11.68/10^3m^3$ the average well yields about \$0.170 million. Since wells in this region only cost about \$0.120 million there is an economic incentive to continue to drill and add to reserves. This presumes of course that the reserve additions rate does not decline too rapidly. If it continues on the downward trend established in the last two five-year periods then significant additional reserves would not be expected from this region.

Summary of the Disaggregate Analysis

In this section, two tables are presented that summarize some of the findings of Chapter 4. Table 4-23 shows estimated reserve additions and price elasticities in various horizons for the model with and without directionality. Table 4-24 is a similar summary table for the natural gas.

Table 4-23

Summary of Disaggregate Results for Light and Medium Oil in the Alberta Basin

		Without directionality		With directionality	
Horizon	Area	Potential reserve additions[1]	Reserve additions price elasticity[2]	Potential reserve additions[1]	Reserve additions price elasticity[2]
Upper Cretaceous	1	(Note 1)			
	8[3]	Minimal	(Note 2)	Minimal	(Note 2)
	Deep Basin	(Note 1)			
Lower Cretaceous					
Viking and equivalent	All	2.0	(Note 3)	9.0	0.70
Mannville	All	1.5–4.0	(Note 3)	Minimal	(Note 2)
Mississippian	All	Minimal	(Note 2)	Minimal	(Note 2)
Upper Devonian	All	58.0	0.20	160.0	0.60[4]
Lower Devonian and Beaverhill Lake	5	Minimal	(Note 2)	Minimal	(Note 2)
	All except 5	3.0	(Note 3)	Minimal	(Note 2)
Total		66.0		169.0	

Note 1 Horizon and area not examined for oil potential.
2 Rise in oil reserves price to $\$70/m^3$ not large enough to yield any significant additional oil reserves.
3 Additional oil reserves due largely to incentive to drill for gas at a reserves price of $\$15/10^3m^3$.

1 10^6m^3 at 1983 new oil price of about $\$70/m^3$.
2 Percentage change in ultimate oil reserve additions/percentage change in oil reserve prices. All other prices and costs constant.
3 Based on the presumption of no changes in the minimum oil spacing in the Pembina pool.
4 Elasticity based on illustrative example in text.

Table 4-24

Summary of Disaggregate Results for Natural Gas in the Alberta Basin

		Without directionality		With directionality	
Horizon	Area	Potential reserve additions[1]	Reserve additions price elasticity[2]	Potential reserve additions[1]	Reserve additions price elasticity[2]
Upper Cretaceous	1	(Note 1)			
	8	Minimal	(Note 2)	Minimal	(Note 2)
Lower Cretaceous					
Viking and equivalent	All	106.0	(Note 3)	62.0	1.2
Mannville	All	309.0	(Note 3)	297.0	1.1
Mississippian	All	18.0	7.3	10.0	(Note 4)
Upper Devonian	All	315.0[3]	2.8	Minimal	(Note 2)
Lower Devonian and Beaverhill Lake	5	Minimal	(Note 2)	Minimal	(Note 2)
	All except 5	74.0	(Note 4)	74.0	(Note 3)
Total		804.0		443.0	

Note 1 Commingled pools in Milk River and Medicine Hat account for nearly all of the gas in this horizon and areas. Additional potential not estimated.
2 Rise in gas reserves price to $\$15/10^3m^3$ not large enough to yield any significant additional reserves.
3 Price elasticity cannot be calculated because the decline in the additions rate with respect to increases in cumulative drilling is not significant. Estimate of reserve additions therefore comes from an assumed upper limit on cumulative wells.
4 Elasticity cannot be calculated because reserve additions at base price are zero.

1 10^9m^3 at gas reserves price of about $\$15/10^3m^3$.
2 Percentage change in ultimate gas reserve additions/percentage change in gas reserve prices. All other prices and costs constant.
3 Gas reserve additions in Upper Devonian are due primarily to the incentive to drill for oil at the 1981 base price of oil reserves.

The most striking result in Table 4-23 is that of all the horizons studied only the Upper Devonian indicates substantial remaining oil potential. The results also indicate some response of additional reserves to increases in reserves prices. It should be emphasized, however, that these results do not include some regions, such as the Deep Basin, that are considered by industry to hold significant remaining potential.

Table 4-24 indicates significant prospects for additional gas reserves in the Upper Devonian when the model without directionality is estimated and only minimal prospects when it is estimated with directionality. The reason is that without directionality the oil prospects are such that significant amounts of additional drilling are indicated and the gas reserve additions rate is high enough so that substantial amounts of gas are expected to be found. However, when directionality is allowed then most of the drilling is oil intent drilling which results in no non-associated gas discoveries; either oil is found (including associated gas) or nothing is found.

5 The Supply of Oil and Gas Reserves: The Aggregate Analysis

In Chapter 2, two models designed to study the aggregate data were outlined. The first model is similar to the one used in the disaggregate analysis in that it uses all categories of drilling effort to explain the rate of reserve additions. The only difference is that instead of being applied to individual horizons and areas it is applied to the entire Alberta basin. Applying this model to the entire basin has the advantage that the problem of measuring targeted drilling effort does not arise since, in the aggregate setting, total drilling effort in all horizons and areas is the relevant effort variable. On the other hand, fitting the model to the wave-like pattern of the aggregate reserve additions data may be difficult and, moreover, a single average value for the unit cost of drilling wells must be used. If, for example, reserve additions in one region of the basin dominated the total but the unit cost of drilling in this region was higher than the average, the aggregate model would tend to be too optimistic in its forecasts of reserves supply.

The second aggregate model is different in two important ways: (1) rather than trying to explain total reserve additions (new discoveries plus appreciation of past discoveries) by total drilling effort, it attempts to explain new discoveries by *exploratory* drilling effort and then allows these initial discoveries to appreciate over time, in accordance with an appreciation function which depends on economic factors, and (2) rather than estimating this discoveries relationship and then using economic variables to determine the supply relationship via the marginal product conditions, the supply relationship is estimated directly as a function of all of the relevant prices.

Aggregate Data Analysis – Model 1

It will be recalled from the discussion of this model in Chapter 2 that two specifications were mentioned. One involves not recognizing the occurrence of new plays and estimating the aggregate oil reserve additions equation excluding dummy variables. The other is designed to explicitly recognize new plays using dummy variables that switch on in the year in which the new play begins. In terms of fitting the wave-like pattern of reserve additions, the first specification cuts off the crests of the waves and only picks up the general trend of any decline in the additions rate with respect to cumulative drilling that might be observed. It will estimate a function that will project oil plays to unfold more or less as they have in the past. The second specification explicitly recognizes the occurrence of oil plays through the use of dummy variables. Thus, forecasts based on this specification cannot anticipate new plays but will provide a better fit to the observed data. In other words, it will tend to follow the wave-like pattern rather than cut through it.

Since the non-associated gas play situation is muddled at best and one might even argue that only in the 1970s has an economic climate existed which would generate anything like a play in natural gas, the aggregate gas model will use the specification that excludes dummy variables.

It was noted in Chapter 2 that even though one could take the point of view that in some cases firms cannot easily discriminate between oil and gas prospects, this was much less valid in the aggregate than in the disaggregate analysis. Since certain regions of the Alberta basin are obviously oil prone and others are gas prone, firms can respond and do respond to changes in the relative returns to oil and gas drilling by allocating their resources among regions. In view of this, only the results of the aggregate analysis that use oil and gas intent drilling are reported.

In Table 5-1, the aggregate reserve additions, drilling data, and the oil completions proportion used to allocate drilling effort are presented. The reserve additions data are the total of the smoothed data in the various regions studied in Chapter 4. Because these data are the total of the smoothed data in these regions, it does not quite correspond to the aggregate reserve additions data shown in the additions-appreciation data tables in Tables C-25 to C-28. In Table 5-2, the parameter estimates for the two specifications of the aggregate oil model and one specification of the non-associated gas model are reported. Only the restricted estimates are presented so that the dependent variable is the rate of reserve additions.

Examination of the oil equations in Table 5-2 shows that model specification 1 gives a decline rate with respect to cumulative drilling which is much smaller than specification 2 so that it behaves as expected. Model specification 2 uses dummy variables D_1 – D_4 which switch on at the beginning of oil plays in the Upper Cretaceous Area 8 (Pembina), Beaverhill Lake and Lower Devonian, excluding Area 5 (Swan Hills),

Table 5-1

Oil and Gas Reserve Additions and Drilling Activity in the Alberta Basin

Year	Oil	Associated gas[1]	Non-associated gas[1]	Targeted wells	Oil completion fraction
	(10^6m^3)	(10^9m^3)			
<1947	26.76	--	--	1,592	0.44
1947	6.58	--	--	225	0.54
1948	7.88	--	--	379	0.91
1949	100.52	26.1	64.1	798	0.93
1950	46.89	0.1	6.3	1,053	0.94
1951	74.30	22.4	78.0	1,276	0.82
1952	23.56	26.7	20.4	1,676	0.79
1953	76.97	44.3	37.5	1,410	0.80
1954	48.60	24.3	30.9	1,186	0.81
1955	53.36	18.6	35.1	1,625	0.84
1956	72.48	42.8	47.5	1,890	0.88
1957	49.63	-1.5	56.8	1,433	0.82
1958	33.75	0.4	121.4	1,668	0.82
1959	52.54	18.0	42.5	1,603	0.73
1960	67.92	31.7	91.0	1,655	0.75
1961	22.91	13.9	32.5	1,563	0.70
1962	22.93	13.3	50.8	1,562	0.69
1963	19.84	1.9	32.2	1,676	0.76
1964	53.25	8.8	72.3	1,840	0.76
1965	46.13	18.1	85.7	2,043	0.72
1966	82.28	29.4	35.4	1,667	0.65
1967	76.87	-2.0	60.9	1,653	0.62
1968	30.23	2.7	104.1	1,910	0.55
1969	14.55	13.0	83.1	1,878	0.45
1970	11.06	3.5	62.0	1,859	0.29
1971	22.64	-2.4	61.9	2,040	0.30
1972	14.86	3.4	44.0	2,687	0.28
1973	4.01	18.5	176.1	3,534	0.24
1974	8.44	10.4	142.4	3,516	0.24
1975	5.04	-8.2	13.4	3,680	0.23
1976	3.08	5.5	143.2	5,066	0.13
1977	0.01	2.7	128.6	5,175	0.12
1978	17.64	8.4	160.6	5,625	0.15
1979	31.92	5.9	127.0	5,818	0.21

1 First observation is for all years prior to 1950.

Beaverhill Lake and Lower Devonian Area 5 (Rainbow-Zama), and Upper Devonian (Nisku Reefs). Thus, in this specification the recent Nisku discoveries are treated as a separate play from the main Upper Devonian (Leduc) which began in 1947. Each of these play-dummy variables has a significant impact on the oil additions rates.

At the estimated 1981 level of cumulative oil intent wells, the oil reserve additions rate is 5.90 x 10^3m^3 and 5.85 x 10^3m^3 per well, respectively, for model specifications 1 and 2. The results from specification 1 will be used in the remaining calculations involving the estimation of ultimate aggregate oil supply because it is felt that even though the fit is inferior, specification 1 provides a better forecasting model since it does not require the prediction of future plays. The value of the marginal product of oil drilling is $0.228 million when evaluated at the 1981 level of the price of oil reserves. Table 5-3 presents the aggregate supply estimates of ultimate oil reserves at various reserves prices when wells are estimated to cost $0.350 million. These results show that there is no incentive to drill oil wells at a reserves price of less than about $60.00/m³, and even when price is as high as $90.00/m³, there is an incentive to add only about 30 million cubic metres. This is in contrast with the findings in the disaggregate analysis in Chapter 4 which indicated that between 70 and 160 million cubic metres of additional primary oil reserves might be expected depending upon the level of oil and gas reserves prices. Why should this aggregate model yield such different results? Obviously the reason must have something to do with the aggregation of the data since the aggregate model is very similar to that used in Chapter 4. The explanation is believed to be that the oil reserve additions rate observed in the Upper Devonian, which has led to virtually all the

Table 5-2

Parameter Estimates of the Two Specifications of the Aggregate Oil and Gas Reserve Additions Equations Using Oil and Gas Drilling

Parameter	Oil[1]		Non-associated gas[2]
log A	4.278 (0.419)	4.338 (0.466)	5.005 (0.136)
β (x10^{-3})	-0.069 (0.021)	-0.323 (0.082)	-0.059 (0.011)
D1	--	1.799 (0.859)	--
D2	--	1.994 (0.961)	--
D3	--	2.647 (1.073)	--
D4	--	2.646 (1.016)	--
R^2	0.25	0.47	0.54

1 Column 1 is model specification 1 and column 2 is model specification 2.
2 Specification 2.

Table 5-3

Oil Reserves Supply in Response to Changes in Reserves Prices

Oil reserves price	Cumulative oil wells	Oil reserves added	Oil reserves
($/m^3)		(x10^{6}m^3)	
35.78	36,085	0	1,295.9
50.00	36,085	0	1,295.9
70.00	38,473	12.96	1,308.9
90.00	42,096	28.98	1,324.9

forecasted oil reserve additions, is swamped in the aggregate analysis. Relative to the other horizons in the Alberta basin, the Upper Devonian is clearly an outlier in terms of its ability to sustain a high rate of oil reserve additions as cumulative effort grows. But when this horizon is included with all of the others in an aggregate analysis its oil prospects are overshadowed by the negative oil prospects of the others. It is perhaps for this reason that the analysis of the aggregate data yields more pessimistic conclusions.

The parameter estimates of the aggregate non-associated gas reserve additions equation are presented in Table 5-2. When evaluated at the estimated 1981 level of cumulative gas intent drilling the additions rate is only about 11.16 x 10^{6}m^3 per well which, even when evaluated at \$25.00/10^{3}m^3, is only about \$0.280 million. This suggests that future gas reserve additions are not likely to be of substantial magnitude yet the disaggregate analysis has already indicated that several horizons appear to offer significant additional potential. Again the aggregate analysis gives results that seem to be overly pessimistic.

Aggregate Data Analysis – Model 2

In this section the aggregate data are studied from the perspective of initial discoveries and their subsequent appreciation rather than from the perspective of total reserve additions. This difference in perspective can be best explained with reference to Table 4-1. Although this table refers to oil data for the Upper Devonian, a similar table has been prepared for the entire Alberta basin and also appears in Appendix C (available separately). In the previous part of the study the row totals of the data matrices illustrated by Table 4-1, the reserve additions, were of primary interest. In this part of the study the initial booked discoveries and the column totals, the appreciation of each vintage of discoveries, will be of primary interest. Thus it can be viewed as a two-staged model. The first stage attempts to explain the rate of supply of initial discoveries of oil and gas with reserves prices, drilling costs, and cumulative drilling effort as regressors in a regression equation. Thus, instead of estimating the reserves supply relationship indirectly via estimation of the production function and use of the marginal product conditions, the supply equation is estimated directly with the relevant price variables as regressors. The second stage attempts to explain the appreciation of these discoveries based on elapsed time since discovery and the price of reserves. In the first stage, the appropriate price is the price of undeveloped reserves whereas in the second, it is the price of developed reserves. However, before going on to estimate the two stages of this model from the data, it is useful to consider the process of reserve appreciation in more detail.

The Appreciation of Oil and Gas Reserves in the Alberta Basin

If the first well in a prospective pool encounters hydrocarbons in promising amounts, it is common practice to drill appraisal wells to test and delineate the pool. This additional drilling may take two or more years depending upon the pool's location and its geological complexity. If the test of the discovery well is promising then, in the case of the Alberta basin, the ERCB will probably assign some amount of initial and recoverable reserves to the pool. Subsequently, the

ERCB evaluates the information from the additional drilling and revises its initial estimates of reserves. There is a natural tendency for this revision to be in the upward direction because subsequent drilling and tests usually provide information upon which to assign additional reserves. Since the reserve estimates are published on a yearly basis, the amount of reserves which are assigned on "booked" depends on the time of the year the pool was discovered and on the rate of appraisal and development drilling. If the discovery well was completed near the end of the year so that there is not enough time for additional drilling to be completed, then it is likely that fewer reserves would be booked than if it had been drilled near the beginning of the year. In some cases no reserves will be booked in the discovery year and may not be booked for several years. This is particularly true for natural gas discoveries in the earlier years of the exploration and development of the Alberta basin.

The most widely used measure of appreciation is the "appreciation factors" given by:

1.0 + (amount of appreciation)/(amount of reserves booked in the discovery year).

Such factors have been calculated from past observations of the growth of reserves from their initial recorded amounts in order to estimate the ultimate reserves associated with more recent discoveries which have not had time to fully appreciate. But this application has been the subject of considerable debate. It is often argued that appreciation factors based on past data may not be applicable to current discoveries for a number of reasons including:

1) The size of pools has been declining over time and appreciation factors are a function of pool size.

2) Appreciation factors are dependent on the particular geological horizon in which the discoveries are made.

3) Appreciation factors are affected by the time delay between discovery and booking and it is certainly true, at least in the case of gas discoveries, that this delay has decreased with the passage of time.

Since aggregate model 2 relies heavily on the use of appreciation estimates it is important to consider some of these concerns. Even though the reserve additions-appreciation tables in Appendices B and C permit the study of appreciation factors for various geological horizons, the issue of variation in these factors across horizons will not be taken up here. Instead, attention will focus on variation in aggregate appreciation factors over time.

Column one of Table 5-4 lists booked discoveries in each year for oil pools for which a complete history of appreciation is available.[1] Also reported in the table are total reserves booked in the discovery year and the year following discovery. Counting reserves which are booked in the first two years as initial discoveries is a departure from usual practice but it has merit. It picks up those cases for which there has been insufficient time to properly evaluate drilling results in the discovery year although it also gives time for extra appreciation in those pools discovered near the beginning of the year. A casual glance at the appreciation factors based on discoveries measured in this way indicates some improvement in their stability. For the years preceding the unusual appreciation situation in the Rainbow-Zama play, the average appreciation factor is 7.96 with a standard deviation of 3.26 when based on first year booked amounts. When the first two years are used as a base, then the average appreciation factor for the same period is 4.04 with a standard deviation of 2.31. The years since 1964 were not included in the average because of the unusual results for the pools in the Beaverhill Lake and Lower Devonian in Area 5 which dominated the totals in the mid to late 1960s. In the 1970s, discoveries have either been too sparse or too recent to yield useful data for appreciation calculations. Both sets of appreciation factors reported in Table 5-4 indicate a downward trend over time.

In Table 5-5 natural gas appreciation factors are reported. Like oil, they are based on a subset of pools for which reserve histories are available which in this case are all pools with reserves greater than $0.28 \times 10^9 m^3$ in 1981. Appreciation factors are calculated for discoveries measured as booked reserves in the first year and in the first two years. The first measure produces an average value for the pre 1950-74 period of 6.33 with a standard deviation of 2.82. For the second measure of discoveries the average is 3.89 with a standard deviation of 2.13. It is noteworthy that the oil and gas average appreciation factors are very similar when the second measure of initial discoveries is used. These results indicate that the gas appreciation factor has remained relatively constant over time.

Estimating the Oil and Gas Appreciation Functions

In Chapter 2, the role of the appreciation function in aggregate model 2 was outlined. The function was to be dependent on the time since the discovery and to have the capability of responding to changes in the price of developed reserves, the rationale being that the ultimate appreciation of a pool's primary reserves might be responsive to changes in these prices. To test this hypothesis it is necessary to specify a functional form for the general appreciation function given in Chapter 2 that has these features. The following candidate is proposed.

Table 5-4

Oil Reserve Discoveries and Appreciation in the Alberta Basin

Year	Booked discoveries in first year	Booked discoveries in first two years	Appreciation factor based on column 1	Appreciation factor based on column 2
1947	5.99	5.99	6.94	6.94
1948	0.25	95.34	516.76	1.36
1949	5.11	19.50	10.80	2.83
1950	5.30	7.11	11.32	8.44
1951	34.09	26.34	3.88	5.02
1952	3.51	14.46	9.47	2.30
1953	34.19	70.47	4.93	2.39
1954	1.13	2.48	12.99	5.92
1955	0.18	0.18	5.06	5.06
1956	2.75	4.78	6.12	3.52
1957	9.75	34.07	9.26	2.65
1958	2.58	4.16	7.82	4.85
1959	14.65	40.74	4.83	1.74
1960	0.25	0.26	8.12	7.81
1961	1.18	2.14	2.33	1.29
1962	0.63	5.15	12.79	1.57
1963	1.22	5.80	10.71	2.25
1964	10.17	22.34	3.03	1.38
1965	22.52	59.53	2.76	1.04
1966	24.43	42.17	1.76	1.02
1967	51.93	40.30	0.59	0.76
1968	43.37	20.38	0.24	0.51
1969	33.81	10.04	0.30	0.99
1970	5.31	3.37	0.68	1.07
1971	11.94	4.91	0.46	1.12
1972	6.16	3.07	0.32	0.64
1973	1.96	1.20	0.92	1.50
1974	0.05	0.05	12.60	12.60
1975	0.0	0.0	1.00	1.00
1976	0.0	0.0	1.00	1.00
1977	0.21	4.92	41.38	1.77
1978	2.46	18.04	9.48	1.29
1979	0.20	12.31	78.05	1.27

$$A(\tau-t,\ p_T) = 1 + \eta\left\{1 - exp[-\phi\cdot(\tau-t)]\right\}p_T^{\lambda} \quad (5.1)$$

where η, ϕ, and λ are parameters to be estimated and p_T is the price of developed reserves at time τ. This equation says that for pools discovered in year t the appreciation factor grows as time elapses between the discovery year and the year the factor is calculated. But besides depending on this time difference it also depends on the price of developed reserves at time τ. Instead of the asymptote of this function being $1.0 + \eta$ as in the usual specification it also depends upon the price and is given by $1.0 + \eta p_T^{\lambda}$. This price effect is illustrated in Figure 5-1. The effect is simply to shift the curve upward so that it asymptotically approaches a higher level. The price elasticity of the ultimate appreciation function is λ.

The estimation of the function is accomplished in the following way. For each vintage of discoveries the appreciation factor for each year since discovery is calculated. On a scatter diagram of A versus $\tau-t$ this gives a number of values for A for each $\tau-t$ that has a different price associated with it. If the higher values of A tend to be associated with higher p_T's then price will show up as having a positive effect on A. Looking at it in another way, if one were to fit a function like equation 5.1 without the price variable, then for each value of $\tau-t$ the points above the fitted function would, on average, have higher prices associated with them.

Because of the improved stability, the appreciation factors calculated from the booked amounts in the discovery year and the year following are used in the estimation of the subsequent discoveries equations. The estimates of the parameters of the oil and non-associated gas appreciation functions that includes and excludes the price variable are shown in Table 5-6. Those estimates that exclude and the price variable are

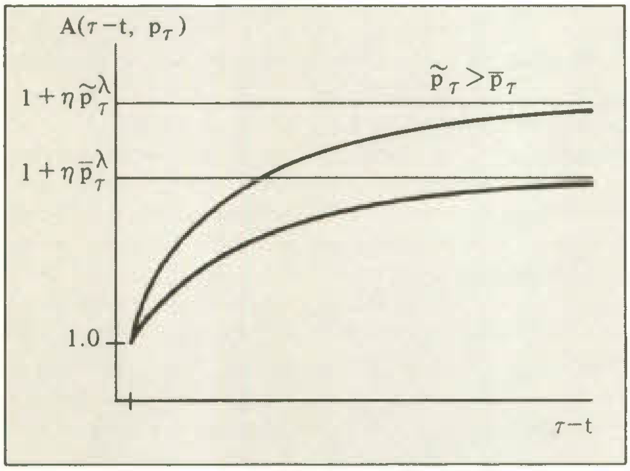
Table 5-5

Gas Reserve Discoveries and Appreciation in the Alberta Basin

Year	Booked discoveries in first year	Booked discoveries in first two years	Appreciation factor based on column 1	Appreciation factor based on column 2
<1951	52.4	117.7	8.5	3.8
1951	4.1	6.8	5.4	3.3
1952	9.8	17.5	6.5	3.6
1953	3.8	7.5	6.4	3.2
1954	10.3	15.9	8.8	5.7
1955	4.4	7.3	11.0	6.7
1956	9.0	13.5	7.7	5.2
1957	27.0	43.9	3.3	2.1
1958	35.9	51.3	1.9	1.3
1959	16.5	31.5	7.2	3.8
1960	17.3	18.7	2.0	1.9
1961	10.1	16.5	11.6	7.1
1962	8.3	30.8	6.4	1.7
1963	5.4	6.5	7.8	6.5
1964	4.2	19.8	4.0	0.8
1965	2.5	3.7	9.4	6.4
1966	1.5	1.8	6.7	5.6
1967	7.5	36.8	9.2	1.9
1968	8.0	9.2	3.2	2.8
1969	13.1	36.4	3.1	1.1
1970	1.7	2.0	10.2	8.7
1971	5.5	6.4	4.5	3.9
1972	9.7	11.3	5.6	4.8
1973	14.4	20.4	2.8	2.0
1974	6.2	9.1	5.0	3.4
1975	0.4	12.1	56.3	1.9
1976	5.0	14.0	7.2	2.6
1977	6.9	31.2	8.6	1.9
1978	2.8	17.6	7.7	1.2
1979	1.4	8.9	10.1	1.6

Figure 5-1

Appreciation Factors and the Price of Reserves



as expected. The asymptote (ultimate appreciation) of the oil function is about 4.5 and that of the gas function is about 3.6. These values may seem low in comparison to other calculations of ultimate appreciation but it is because discoveries have been measured as the amounts booked in the discovery and following year.

The most surprising result is that when the price variable is included in the oil appreciation function the parameter estimates indicate that higher prices of reserves reduces ultimate appreciation. Although this result is difficult to accept it is easy to explain. Recall from Table 5-4 that appreciation factors seemed to trend downward over time. This is most likely due to improved ability to estimate primary reserves on the basis of early information. In other words, learning from experience has improved ERCB estimates of recoverable reserves made on the basis of information in the first two years of the discovery of a pool. This will naturally tend to reduce appreciation. Combine this with the rising trend in reserves prices and it is understandable that reserves prices would be negatively related to ultimate appreciation yet no causality is involved. Any tendency for higher reserves prices to raise appreciation has been swamped by technical and

Table 5-6

Parameter Estimates of Oil and Non-Associated Gas Appreciation Functions

Parameter	Oil[1]		Non-associated gas[1]	
η	3.462 (0.344)	6.818 (2.144)	2.608 (0.152)	2.071 (0.162)
ϕ	0.101 (0.024)	0.053 (0.021)	0.169 (0.029)	0.229 (0.043)
λ	--	-0.145 (0.044)	--	0.120 (0.030)

1 Column 1 excludes price and column 2 includes it.

informational factors that have led to more accurate initial estimates of ultimate recoverable reserves.

The parameter estimates of the gas appreciation function are as expected and similar to those reported in Uhler (1982). The effect of gas reserves price increases is to shift the appreciation function upwards but the price effect has strong diminishing returns. The price elasticity of the ultimate appreciation factor is given by the estimate of λ which is 0.12. For example, an increase in the price of gas reserves from $\$15.00/10^3m^3$ to $\$20.00/10^3m^3$ will raise the ultimate appreciation factor from 3.87 to 3.97.

Even though the response of the ultimate appreciation factor to increases in price does not seem to be large, when it is applied to a large base of reserves total reserve additions from this source can be significant. If the small gas pools that have accounted for most of the recent discoveries of non-associated gas appreciate by this factor then the volumes involved are very large indeed. The magnitude of these volumes will be considered later.

Estimating the Oil and Gas Discoveries Equations

In the previous section, the appreciation equations were estimated using as a measure of discoveries reserves booked in the discovery year and the year following the discovery year. This same measure of discoveries is also used in the discoveries equations which will be estimated in this section and an attempt will be made to explain both the rate and ultimate level initial discoveries with reserve prices, drilling costs, and cumulative discoveries. Cumulative discoveries serves the same purpose in this model as does cumulative drilling in the other model. As cumulative discoveries rise prospects become more scarce so that, other things equal, the discovery rate declines. Eventually cumulative discoveries are large enough so that the discovery rate declines to a small value. Thus for given prices some ultimate amount of discoveries can be determined. However, if the prices of reserves should rise or drilling costs should decline, the discovery rate would be expected to rise which would then imply a higher level of ultimate discoveries.

The data used to estimate the oil discovery equation is different than that in Table 5-4 because it also includes those pools for which reserve histories are not available. The reserves of these pools are included at their appreciated amount as of the year 1981. The gas discoveries data have a similar feature and thus are also different from the data reported in Table 5-5. All pools smaller than $0.28 \times 10^9m^3$ are recorded in the discovery year at their appreciated amounts. But since it has been only recently that small gas pools have accounted for a large portion of total discoveries and since most of these pools have not yet been developed, the gas discoveries-appreciation picture is not seriously distorted by this treatment.

In order to estimate the oil and non-associated gas discoveries equations a functional form for these equations must be specified. It was noted in Chapter 2 that one procedure is to specify an appropriate functional form for the maximized profit function and then derive the discoveries (supply) equations from the profit function. In Uhler (1982), a normalized quadratic profit function was used that yields linear discoveries equations in the relative prices. Cumulative discoveries and its squared value entered the equations as shift variables. The results in that study were that the natural gas discoveries equation – the study only dealt with gas supply – proved to be statistically inferior to an equation which was simply linear in prices. It was also noted that this equation was no longer homogeneous of degree zero in prices nor could it be derived from a linear homogeneous profit function but that these properties would be sacrificed for better explanatory power.

In this study the linear discoveries equations in relative prices were also inferior to other specifications so the results are not reported or used here. Reported in columns one and two of Table 5-7 are estimates of both a linear and a partial log-linear oil discoveries equation. Both of these equations show that discoveries are declining with respect to cumulative discoveries. The linear equation shows that all price effects have the expected sign but that the estimated coefficients are so unstable that these effects must be taken as not significantly different from zero. In the second equation, the logarithm of the discovery rate is regressed on the logarithm of the prices and on cumulative discoveries. Thus, the discoveries rate in this equation is presumed to exhibit exponential decline with respect to

Table 5-7

Parameter Estimates of the Oil Discoveries Equations in the Alberta Basin

Variable	Parameter estimates[1]	
Oil reserves price, $p_o(t)$	0.221 (1.593)	---
Gas reserves price, $p_g(t)$	-0.606 (4.383)	---
Drilling price, $\bar{c}$	-0.020 (0.107)	---
Cumulative discoveries (10^{-2})	-3.876 (2.372)	-0.460 (0.195)
Constant	41.418 (10.771)	4.146 (2.870)
log $p_o(t)$	---	-0.440 (0.300)
log $p_g(t)$	---	0.282 (0.197)
log $\bar{c}$	---	0.373 (0.637)
	$R^2 = 0.17$	$R^2 = 0.27$

Note Standard errors in parentheses.
1 Observations = 33.

cumulative discoveries. As in the linear case, the downward trend with respect to this variable provides most of the explanation of the discovery rate. The price variables all have the wrong signs but are again so unstable that they must be taken as having no significant effect on the level of oil discoveries.

An elementary way to help interpret these statistical results is as follows. If the relationship between the discovery rate and cumulative discoveries is estimated, excluding the other variables, then in each year there will be a residual which is the difference between the value on the estimated relationship and the observed value. In order for prices and cost to show up as important in a fully specified relationship, they must show some association with these residuals. For example, if the price of oil reserves is to have a significant positive effect on the discovery rate then for years in which prices are high, observed discoveries must be above the fitted curve, and when prices are low, observed discoveries must fall below it. However, given the fluctuation in observed discoveries around this downward trend and the relative stability of prices over most of the sample period, it is not surprising that price shows very little association with these residuals and therefore does not show up as significant in the estimates shown in Table 5-7. The same is also true for the other prices in the model. One is led to the conclusion that year to year price changes play an insignificant role in the explanation of oil discoveries. It is noteworthy, however, that over the last 10 years there has been a stronger positive association between oil reserve prices and discoveries with the main discoveries coming from the Nisku Reefs. But the period over which these data are observed is so short that one could not be very confident in the estimates of a discoveries equation. It should again be emphasized that the lack of response to price changes is not related to a failure to account for the importance of price expectations. The reserves price data depend upon price expectations in that the wellhead prices used in calculating reserves prices contain an explicit growth pattern (see Chapter 3 and Appendix A).

Had the prices turned out to be stong predictors of discoveries then the model could have been used to determine the oil reserves supply relationship in the following way. For a given set of prices, say those that prevailed in the last data period, the discovery rate would decline with the growth in cumulative discoveries. Eventually cumulative discoveries would reach some ultimate amount so that after applying the appropriate appreciation factor one point on the supply curve of ultimate reserves would be obtained. The same calculation could then be made for a higher oil reserves price yielding a higher value of ultimate supply, etc. In this way the entire supply relationship is traced out. But since the effect of reserves prices is so unreliable it does not seem worthwhile to make these calculations because the forecasted amounts could not be taken seriously. Thus, oil reserves supply forecasts using this method are not reported in this study.

The results of the estimates of both forms of the non-associated gas discoveries equations are shown in Table 5-8. As in the case of oil, the yearly prices are not significant predictors of the yearly levels of gas discoveries in either of the equations. But unlike the oil equation, cumulative discoveries does not have an important influence on the rate of gas discoveries. This is consistent with some of the earlier results that show that cumulative drilling effort did not have an important effect on gas reserve additions. Even if prices had played a more important role in affecting discoveries, it would not have been possible to estimate ultimate non-associated gas supply under these circumstances because a limiting mechanism for reducing the rate of gas reserve discoveries does not exist.

Because of possible collinearity between oil and gas reserves prices, regressions were estimated excluding the oil reserves price. In the linear model, the gas price

Table 5-8

Parameter Estimates of the Non-Associated Gas Discoveries Equations in the Alberta Basin

Variable	Parameter estimates[1]	
Oil reserves price, $p_o(t)$	0.191 (1.060)	---
Gas reserves price, $p_g(t)$	2.742 (2.797)	---
Drilling price, $\bar{c}$	0.026 (0.070)	---
Cumulative discoveries (10^{-2})	0.489 (1.544)	−0.016 (0.113)
Constant	22.450 (7.434)	1.998 (1.410)
log $p_o(t)$	---	0.149 (0.173)
log $p_g(t)$	---	0.069 (0.115)
log $\bar{c}$	---	0.289 (0.329)
	$R^2 = 0.47$	$R^2 = 0.34$

Note Standard errors in parentheses.
1 Observations = 29.

becomes a more stable predictor of discoveries but cumulative discoveries remains unstable and thus renders the model ineffective for estimating ultimate supply. In the partial log-linear model, the results were even poorer than those presented in Table 5-8 when this variable was excluded.

The failure of the discoveries equations to yield evidence of short-run price effects is consistent with the results from the reserve additions model. It will be recalled that in most cases the parameter α in the reserve additions equation was not significantly different from one in which case the short-run relationship between the price of reserves and the amount of reserves added was indeterminant. Thus, it is not surprising that short-run price effects are also not observable in the discoveries equations.

6 Implications for Canadian Energy Policy

Major Canadian energy policy issues in the 1980s, and possibly beyond, will continue to be: (1) the dependence of Canada on imported oil, and (2) export volumes and pricing of Canadian natural gas. Future dependence on imported oil became an energy policy issue in the 1970s as a consequence of world oil price increases and the Arab oil embargo, combined with the belief that Canada had the potential to become self-sufficient in oil consumption. In setting forth the National Energy Program (NEP) in 1980, the federal government expected that self-sufficiency could be achieved by the early 1990s, by exploiting the potential of both conventional and non-conventional sources of oil and by the substitution of natural gas and electricity for oil consumption. The NEP and its subsequent revisions set forth pricing schedules and taxation schemes directed toward this end. However, the pricing schedules in the finalized program which followed the agreement with Alberta greatly overestimated future new oil reference prices (NORPs) because of the overestimation of future international oil prices which set an upper limit to the NORPs.[1] It is now generally believed that international oil prices will remain fairly stable or decline in real terms over the next few years. This means that in the absence of a reduction in oil production taxes the price of new oil reserves can also be expected to remain relatively stable. But, as outlined in Chapter 3, a reduction in production taxes would result in an increase in the reserves price even though the wellhead price remained constant. Such a decrease in taxes would therefore provide an improved incentive to search for and discover new reserves of conventional oil and develop known reserves of non-conventional oil. However, the important question is: How much additional reserves and hence additional deliverability could be expected from a reduction in taxes? The results of this study can help to provide an answer to this question for conventional sources of oil in the Alberta basin.

It will be recalled that using the results of the disaggregate analysis it was found that between 60 and 160 million cubic metres of additional recoverable conventional oil reserves might be expected from those geological horizons that have already accounted for 98 per cent of reserves in the Alberta basin with the bulk of these additions coming from Upper Devonian sediments. It will also be recalled that the lower estimate came from a model with no directionality in drilling and was based on a reserves price of $70.00/m^3$ which is approximately what the average NORP for reserves is today. The upper bound on the estimate came from a model in which complete directionality was assumed. The Upper Devonian estimates for this case were such that no decline in the reserve additions rate with respect to cumulative drilling could be detected. Since drilling was determined to be profitable in the Upper Devonian at a reserves price well below $70.00/m^3$, combined with the lack of evidence of a decline rate did not permit the determination of a unique solution for ultimate supply. Thus, the upper limit of oil reserve additions was determined by assuming an upper bound on the level of cumulative drilling in the Upper Devonian. Although this may seem somewhat arbitrary, it is justified on the grounds that a decline in the additions rate will occur eventually. This belief is examined further by imposing a small, non-zero, decline rate on the estimates in which case oil reserve additions of about 105 million cubic metres were estimated to occur at a reserves price of $70.00/m^3$. Although none of the models in this study attempt to predict the time pattern of these reserve additions, if yearly drilling levels remain similar to the 1981 level then the estimated additions should occur by the early 1990s.

The methodology used in Chapter 4 to determine the response of ultimate supply to increases in the price of reserves can also be used to determine the impact of lower taxes on ultimate supply. Lower taxes have the effect of raising the price of reserves even though the wellhead price may remain constant. Suppose, for example, that taxes were lowered so that the price of reserves rose from their approximate average current value of $70.00/m^3$ to $90.00/m^3$. If one uses the model without drilling directionality, the results from the disaggregate analysis indicate that such a price increase would cause primary recoverable reserve additions to be about 2.5 million cubic metres (15.7 million bbls) higher than at the $70.00/m^3$ price. On the other hand, the model using complete directionality with a small decline rate imposed indicates that such a price increase would cause primary recoverable reserve additions to be about 12.0 million cubic metres (75.5 million bbls) higher than would otherwise be the case.[2] With no directionality the price elasticity of reserves supply is about 0.15 whereas with complete directionality it is about 0.40. Since these two sets of results represent polar cases with respect to drilling directionality one might reasonably suppose that the truth is somewhere in between.

In any case, the results indicate that increases in additions to conventional reserves can be expected from such an increase in the price of oil reserves. Still higher reserves prices would bring forth some additional amounts but, again, they are not expected to be large quantities. Thus, it can be concluded that tax relief which serves to increase the price of oil reserves would result in higher ultimate conventional primary oil reserve additions and that these amounts are expected to be between 2.5 and 12.0 million cubic metres with most of this coming from the Upper Devonian. In the range of values considered above, a 1 per cent increase in the price of oil reserves results in an increase in *primary* recoverable reserve additions of somewhere between 0.15 and 0.40 per cent.

However, it must be stressed again that the study estimates of primary reserve additions have necessarily been only for those geological horizons and areas in Alberta for which a statistical drilling history exists. There are horizons in the basin that have little or very limited drilling history which industry considers highly prospective of additional oil reserves. In particular, various sediments in the Alberta Deep Basin are viewed by industry as having substantial light and medium oil potential but the realization of such potential will be influenced by after-tax economic incentives in exploration and development.

It may be remarked that the study has found that some geological horizons and areas offer only marginal net economic incentive for oil development. Each horizon and area has its unique performance and cost characteristics, as well as its particular level of uncertainty so that there is a need for taxation which is geared to *profitability* of the full-cycle exploration and development activity. Economically efficient new oil policy cannot prejudge the "adequacy" of netbacks, but should simply be to provide the highest new oil netback that is feasible for any given world oil price.

A second major policy issue cited at the beginning of this chapter concerns the export volume and pricing of natural gas. The results of this study have a bearing on this issue in that allowable gas exports depend upon estimates of the supply of gas reserves which in turn depend upon the price of these reserves. Excluding the Milk River and Medicine Hat formations and the Deep Basin, this study estimates that at a gas reserves price of $\$15/10^3m^3$ the potential for non-associated gas reserve additions in the Alberta Basin is between 443 and 804 billion cubic metres. Added to the 1981 level of proven marketable reserves gives an ultimate potential of between 1,953 and 2,314 billion cubic metres of non-associated gas. At the 1981 level of deliveries of both associated and non-associated gas, this is a 25 to 30 year supply of *non-associated* gas reserves alone.

The response of reserve additions to increases in the price of reserves are estimated to be greater for gas than for oil. In those cases where they could be determined, the price elasticities were greater than one so that a 1 per cent increase in the price of gas reserves would be expected to yield at least a 1 per cent increase in the ultimate level of additions. Thus, the results tend to confirm the generally held belief that Canada's potential supply of natural gas reserves is large and is a high multiple of current deliveries. They also suggest that Canada could go far toward independence from oil imports if substitution possibilities between natural gas and oil are great enough. But obviously, domestic substitution possibilities depend upon the relative domestic prices of these two sources of energy and, in the short run, on energy using technology. The current policy in Canada is to keep the domestic price of natural gas at 65 per cent of the price of oil on an energy equivalent basis. This policy is based on the desire to encourage gas-oil substitution and on the presumption that if unregulated, the price of gas would rise to the energy equivalent price of oil. But this would only happen under the questionable assumption that these two sources of energy are energy-perfect substitutes. Given current gas supply conditions, rather than rise in price, it may be that if left unregulated natural gas prices would fall relative to their current level which would serve to expand the domestic market and thus help reduce the "lack of markets" problem. Moreover, it is not even clear that if the wellhead price of gas declined under such deregulation that the price of reserves would fall. A reduction in the delay between discovery and production due to market expansion may more than offset the effect of a decline in the wellhead price. But if the price of gas reserves were to decline, the results of this study show that the ultimate potential supply is still large even under the lower reserves price scenario.

The export market is the other major market for Canada's natural gas. Current export volumes are considerably below authorized amounts partly because of high export price. Recent policy decisions have allowed some price discounting in order to expand the export market and it seems likely that further discounting would add significantly to sales. Even though the particular pricing strategies which might be employed in this market are beyond the scope of this study, it should be pointed out that reducing the export price in order to expand export markets will not necessarily lead to a reduced price incentive to explore for natural gas for the same reason given earlier with respect to a reduction in the domestic price of natural gas at the city gate. Expanding sales will tend to reduce the delay time between discovery and production which, as we already know from Chapter 3, raises the price of reserves in the ground. Thus, a reduction in the wellhead price which leads to an increase in sales could increase the price of reserves and enhance the incentive for additional exploratory effort and reserve additions. It can be shown that under reasonable assumptions that the elasticity between the delay time and the wellhead price which leaves the price of reserves unchanged is inversely proportional to the product of the discount rate and the delay time. Thus, if the discount rate is 0.10 and the delay time is 5 years then a 1 per cent decrease in the wellhead price must result in a 2 per cent decrease in the delay time in order for the price of reserves to remain unchanged. Any greater decrease in the delay time under these conditions results in an increase in the price of reserves in the ground.

Another reason for government policy to stimulate the search for natural gas reserves is that it results in the discovery of oil because drilling directionality is not perfect. In Chapter 4, it was shown that when the model without directionality was used oil reserve additions responded strongly to increases in the price of gas reserves. Thus, the desire to achieve oil independence through the discovery of additional conventional reserves is affected by the price of natural gas reserves.

Appendixes

Appendix A

Tables A-1 and A-3 show wellhead prices, netbacks, developed reserves prices and undeveloped reserves prices for oil and gas, respectively, as discussed in Chapter 3. Tables A-2 and A-4 show costs, taxes and land rents, and royalties which are used in the calculation of the results shown in Tables A-1 and A-3. This appendix also provides further details on the calculation of reserves prices.

Further Details on the Calculation of Reserves Prices

As indicated in Chapter 3, the computation of the price of reserves in the ground is carried out by deducting various costs and taxes from the wellhead price and then discounting the flow of expected net unit returns. Here, an example of this calculation is provided for the 1981 price of oil reserves. It should be noted that this price is not for the reserves in any specific pool in Alberta but for an "average" pool that is discovered in 1981 and produced at a constant rate over a 15 year period. The calculations are in 1981 dollars.

Wellhead price of oil		\$18.61/bbl(\$117.12/m^3)
Less:		
Well operating and other costs –	\$1.38/bbl	
Provincial taxes (excluding income taxes) and land rental and lease costs –	\$0.27/bbl	
Provincial royalties –	\$6.09/bbl	
Netback (excluding income taxes)		\$10.87/bbl(\$68.41/m^3)
Less:		
Income tax –	\$8.10/bbl	
Plus:		
Resource allowance –	\$1.52/bbl	
Provincial tax rebate –	\$0.53/bbl	
Netback (including net income tax) (p_{nn})		\$4.82/bbl(\$30.33/m^3)

The price of both developed and undeveloped reserves can be calculated from this netback.

$$\text{Price of developed reserves} = [\int_0^T p_{nn} q \exp(-(r-i)t)dt] \times F$$

where

P_{nn} is the second netback computed above.

q is a constant production rate.

r is the nominal rate of interest.

i is the rate of oil price increase expected by the industry.

T is the length of the production period of the average pool.

F is a tax factor recognizing that reserve acquisition through exploration is tax deductible.

$$F = 1.0/(1.0 - \tau_1 - \tau_1/3.0) \text{ where } \tau_1 \text{ is the income tax rate.}$$

$$\text{Price of developed reserves} = [\,4.82(1.0 - exp(-15(0.23 - 0.10)))/15(0.23 - 0.10)\,]\ 2.68$$

$$= 4.82(0.44)(2.68) = \$5.69/\text{bbl}(\$35.78/\text{m}^3)$$

To obtain the price of undeveloped reserves the cost of development must be deducted. These costs are assumed to be incurred in the first year of the production period. Thus,

$$\text{Price of undeveloped reserves} = [\,4.82\ (0.44) - 0.87\,]\ 2.68$$

$$= \$3.35/\text{bbl}(\$21.13/\text{m}^3)$$

Table A-1

Crude Oil Wellhead Prices, Netbacks and Reserves Prices in Alberta, 1947-81

			Reserves prices	
Year	Wellhead	Netback	Developed	Undeveloped
		(Nominal dollars/m³)		
1947	12.52	10.93	5.68	5.07
1948	21.84	18.77	8.98	7.91
1949	19.01	14.38	6.18	5.40
1950	19.45	14.68	5.91	5.01
1951	18.12	13.03	5.35	4.57
1952	15.98	10.74	3.88	3.09
1953	15.04	10.10	3.81	3.02
1954	16.80	11.81	4.59	3.66
1955	15.54	10.97	4.81	3.93
1956	15.67	11.09	4.84	3.87
1957	16.74	11.58	4.37	3.07
1958	16.36	10.10	4.01	2.62
1959	15.92	10.35	4.09	2.61
1960	14.73	8.72	3.79	2.13
1961	14.79	9.84	3.88	2.23
1962	15.48	10.32	4.33	2.89
1963	16.11	10.65	4.55	3.15
1964	16.11	10.73	4.70	3.26
1965	16.05	10.62	4.73	3.35
1966	16.17	10.91	4.66	3.11
1967	16.11	11.01	4.45	2.77
1968	16.17	10.96	4.09	2.49
1969	16.17	10.96	4.00	2.24
1970	16.17	11.18	3.68	2.22
1971	17.62	12.13	4.52	3.45

Table A-1 (concl'd.)

Year	Wellhead	Netback	Reserves prices: Developed	Reserves prices: Undeveloped
		(Nominal dollars/m³)		
1972	17.94	12.48	4.84	3.96
1973	21.96	17.38	6.64	5.86
1974	36.25	29.48	18.49	16.95
1975	45.69	30.02	16.03	13.72
1976	53.49	32.17	28.63	24.48
1977	64.32	38.55	33.89	29.40
1978	77.09	45.08	39.77	34.22
1979	86.85	52.87	44.59	38.38
1980	96.98	56.05	37.23	27.88
1981	117.12	68.43	35.78	21.13

Note Netback is wellhead price less operating costs and royalties. Reserve prices are calculated on the assumption that the acquirer of reserves pays income taxes on subsequent production.

Table A-2

Crude Oil Costs, Taxes and Royalties, 1947-81

Year	Well and other operating costs	Provincial taxes and land costs[1]	Royalties	Development costs
		(Nominal dollars/m³)		
1947	0.72	0.36	0.52	0.49
1948	1.89	0.24	0.94	0.86
1949	2.61	0.85	1.16	0.61
1950	2.36	1.08	1.33	0.71
1951	2.34	1.11	1.64	0.54
1952	2.22	1.33	1.70	0.52
1953	2.17	1.28	1.49	0.53
1954	2.13	1.21	1.65	0.62
1955	1.90	1.00	1.68	0.60
1956	1.96	0.85	1.77	0.67
1957	2.12	1.01	2.03	0.90
1958	3.08	1.34	1.85	0.96
1959	2.81	1.20	1.57	0.99
1960	3.31	1.21	1.49	1.12
1961	2.43	1.07	1.45	1.10
1962	2.41	0.89	1.86	0.96
1963	2.61	0.85	2.00	0.94
1964	2.47	0.87	2.04	0.96
1965	2.45	0.88	2.11	0.92
1966	2.34	0.81	2.12	1.04
1967	2.08	0.75	2.27	1.13
1968	2.16	0.74	2.32	1.08
1969	2.10	0.74	2.37	1.18
1970	1.93	0.66	2.41	0.98
1971	2.16	0.63	2.70	0.72
1972	1.98	0.52	2.95	0.58
1973	2.03	0.45	2.10	0.52
1974	2.36	0.79	3.62	0.80
1975	3.43	1.02	11.23	1.20
1976	4.56	1.22	15.55	1.55
1977	4.42	1.09	20.26	1.68
1978	5.28	1.17	25.56	2.07
1979	5.84	1.12	27.01	2.32
1980	7.62	1.44	31.87	3.49
1981	8.69	1.70	38.30	5.47

1 Excluding income taxes.

Table A-3

Natural Gas Wellhead Price, Netback and Reserves Prices in Alberta, 1949-81[1]

Year	Wellhead price	Netback	Reserves prices: Developed	Reserves prices: Undeveloped
		(Nominal dollars/ 10^3m^3)		
1949	0.28	---	---	---
1950	0.45	---	---	---
1951	0.78	---	---	---
1952	1.38	---	---	---
1953	1.47	---	---	---
1954	2.22	0.80	0.16	---
1955	2.59	1.37	0.32	---
1956	2.14	0.94	0.21	---
1957	2.42	1.25	0.20	---
1958	2.14	0.92	0.16	---
1959	2.01	0.94	0.22	---
1960	2.60	1.53	0.48	0.20
1961	2.70	1.78	0.53	0.23
1962	3.38	2.57	0.87	0.65
1963	3.76	2.76	0.95	0.70
1964	4.13	3.11	1.07	0.82
1965	4.67	3.48	1.18	0.91
1966	5.57	4.34	1.33	1.04
1967	6.41	5.12	1.37	1.06
1968	7.32	5.85	1.42	1.09
1969	6.27	4.84	1.07	0.72
1970	5.05	3.67	0.68	0.38
1971	4.63	3.09	0.69	0.43
1972	4.84	3.14	0.74	0.46
1973	6.29	4.11	1.02	0.68
1974	12.48	9.20	2.79	2.29
1975	23.63	17.42	5.54	4.66
1976	34.44	22.72	12.37	10.53
1977	45.43	25.33	11.96	9.37
1978	52.93	25.74	11.01	7.32
1979	63.82	31.15	11.93	7.20
1980	90.05	49.99	15.80	9.56
1981	98.74	55.53	11.65	3.81

Note Wellhead price is estimated value of gas at the input side of the gas plant having taken into account co-product values and gas plant processing costs. Netback is wellhead price less operating costs and royalties. Reserve prices are calculated on the assumption that the acquirer of reserves pays income taxes on subsequent production.

1 Negative prices not shown.

Table A-4

Natural Gas Costs, Taxes and Royalties, 1947-81

Year	Well and other operating costs	Provincial taxes and land costs[1]	Royalties	Development costs
		(Nominal dollars/ 10^3m^3)		
1947	0.24	0.12	0.0	0.18
1948	0.66	0.08	0.0	0.38
1949	0.97	0.32	0.0	0.32
1950	0.80	0.36	0.0	0.40
1951	0.79	0.38	0.02	0.29
1952	0.87	0.52	0.06	0.32
1953	0.89	0.52	0.07	0.32
1954	0.84	0.47	0.10	0.36
1955	0.72	0.38	0.12	0.32
1956	0.77	0.33	0.10	0.37

Table A-4 (concl'd.)

Year	Well and other operating costs	Provincial taxes and land costs[1]	Royalties	Development costs
		(Nominal dollars/10^3m^3)		
1957	0.73	0.35	0.09	0.43
1958	0.78	0.34	0.10	0.34
1959	0.68	0.29	0.10	0.32
1960	0.69	0.25	0.13	0.32
1961	0.54	0.24	0.14	0.32
1962	0.43	0.16	0.22	0.22
1963	0.53	0.17	0.30	0.25
1964	0.51	0.18	0.33	0.25
1965	0.59	0.21	0.39	0.26
1966	0.58	0.20	0.45	0.30
1967	0.57	0.20	0.52	0.34
1968	0.66	0.23	0.59	0.38
1969	0.67	0.24	0.52	0.42
1970	0.70	0.24	0.44	0.39
1971	0.86	0.25	0.43	0.32
1972	1.00	0.26	0.43	0.33
1973	1.27	0.28	0.63	0.41
1974	1.59	0.53	1.16	0.54
1975	2.39	0.71	3.11	0.84
1976	3.64	0.98	7.10	1.24
1977	4.58	1.13	14.39	1.73
1978	6.17	1.37	19.65	2.42
1979	8.26	1.59	22.82	3.27
1980	10.69	2.02	27.35	4.90
1981	11.68	2.28	29.25	7.35

1 Excluding income taxes.

Appendix B

A technical paper published separately from this study includes the tables of Appendix B. This paper is available on request from the Information Division, Economic Council of Canada, P.O. Box 527, Ottawa, Ontario, K1P 5V6.

List of Supplementary Tables

Appendix C

A technical paper published separately from this study includes the tables of Appendix C. This paper is available on request from the Information Division, Economic Council of Canada, P.O. Box 527, Ottawa, Ontario, K1P 5V6.

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Appendix D

Tables D-1 to D-10 are well penetrations by geological horizon, geographical area and year in the Alberta basin. These data are the basis of the calculation of targeted drilling. The source is KCNP (1980).

Table D-1

Well Penetrations by Horizon and Year in Area 0

Year	Upper Cretaceous	Viking and Equivalent	Mannville	Jurassic	Triassic	Permian and Pennsylvanian	Mississippian	Upper Devonian	Beaverhill Lake and Lower Devonian	Silurian, Ordovicain, Cambrian and Precambrian
1945	1	1	1	0	0	0	0	0	0	0
1946	0	0	0	0	0	0	0	0	0	0
1947	0	0	0	0	0	0	0	0	0	0
1948	0	0	0	0	0	0	0	0	0	0
1949	1	1	1	0	0	0	1	1	1	0
1950	2	2	2	0	0	1	2	2	2	1
1951	6	6	6	0	0	3	6	6	3	3
1952	15	14	15	0	0	3	14	15	12	11
1953	6	5	6	0	0	5	5	6	6	5
1954	6	6	6	0	0	2	6	6	6	6
1955	6	6	6	0	0	4	6	6	3	4
1956	15	15	15	0	0	4	14	15	12	12
1957	21	21	21	0	0	4	20	19	17	18
1958	36	32	36	0	0	6	25	35	32	33
1959	19	15	19	0	0	5	12	19	17	17
1960	19	16	19	0	0	2	12	19	18	19
1961	8	6	8	0	0	1	5	8	7	7
1962	13	14	14	0	0	1	14	14	14	12
1963	33	33	33	0	0	3	32	29	29	29
1964	41	38	41	0	0	3	37	39	37	35
1965	152	151	154	0	0	5	149	150	149	106
1966	170	161	171	0	0	5	161	167	166	103
1967	97	89	99	0	0	7	86	93	91	66
1968	75	67	75	0	0	3	62	71	68	56
1969	71	64	70	0	0	1	64	69	69	44
1970	49	44	52	0	0	2	40	48	48	33
1971	51	48	51	0	0	2	42	47	46	37
1972	71	64	71	0	0	4	62	59	59	30
1973	64	58	65	0	0	11	56	47	46	36
1974	64	60	63	0	0	7	60	53	51	39
1975	48	42	48	0	0	5	43	36	34	26
1976	93	72	92	0	0	2	72	75	53	51
1977	115	93	116	0	0	6	83	90	64	55
1978	81	62	85	0	0	7	63	68	48	43
1979	89	84	94	0	0	6	81	80	66	53
1980	66	60	66	0	0	3	61	62	53	46

Source KCNP (1980).

Table D-2

Well Penetrations by Horizon and Year in Area 1

Year	Upper Cretaceous	Viking and Equivalent	Mannville	Jurassic	Triassic	Permian and Pennsylvanian	Mississippian	Upper Devonian	Beaverhill Lake and Lower Devonian	Silurian, Ordovicain, Cambrian and Precambrian
1945	437	314	261	176	0	0	201	49	3	3
1946	38	34	29	16	0	0	24	9	0	0
1947	65	52	27	10	0	0	23	7	1	1
1948	41	37	33	14	0	0	29	5	0	0
1949	39	30	28	9	0	0	27	16	3	2
1950	49	43	38	12	0	0	35	17	3	2
1951	145	129	111	29	0	0	98	40	5	3
1952	178	168	153	48	0	0	136	70	12	4
1953	253	236	219	48	0	0	176	113	2	1
1954	195	177	160	29	0	0	128	56	0	0
1955	174	159	142	40	0	0	123	50	4	1
1956	173	160	145	39	0	0	130	42	2	0
1957	158	148	132	36	0	0	122	47	6	6
1958	204	164	152	28	0	0	104	38	7	5
1959	353	284	269	36	0	0	243	34	4	2
1960	264	226	207	42	0	0	187	26	8	5
1961	261	223	209	41	0	0	195	32	12	9
1962	323	287	257	33	0	0	241	21	4	2
1963	407	329	311	87	0	0	296	29	5	4
1964	448	420	411	102	0	0	393	23	9	6
1965	510	473	458	195	0	0	402	27	2	0
1966	324	286	273	132	0	0	239	21	1	0
1967	364	321	306	103	0	0	262	23	4	3
1968	452	368	352	139	0	0	292	34	16	7
1969	475	329	315	130	0	0	282	56	16	4
1970	672	358	329	117	0	0	282	41	9	1
1971	779	448	420	174	0	0	368	33	7	3
1972	1,185	588	550	223	0	0	473	34	3	2
1973	1,558	721	660	187	0	0	596	63	0	0
1974	1,594	633	585	255	0	0	514	53	5	5
1975	1,483	508	459	174	0	0	394	30	0	0
1976	2,142	699	615	146	0	0	542	45	4	3
1977	2,164	881	782	254	0	0	704	50	4	4
1978	2,561	1,154	1,052	326	0	0	942	85	22	23
1979	2,258	1,001	910	291	0	0	766	67	2	0
1980	734	361	314	93	0	0	256	22	1	0

Source KCNP (1980).

Table D-3

Well Penetrations by Horizon and Year in Area 2

Year	Upper Cretaceous	Viking and Equivalent	Mannville	Jurassic	Triassic	Permian and Pennsylvanian	Mississippian	Upper Devonian	Beaverhill Lake and Lower Devonian	Silurian, Ordovicain, Cambrian and Precambrian
1945	262	259	215	0	0	0	1	42	3	1
1946	60	60	37	0	0	0	0	10	3	2
1947	88	88	82	0	0	0	0	5	2	0
1948	108	108	105	0	0	0	0	31	4	1
1949	68	67	61	0	0	0	4	28	9	4
1950	96	96	87	0	0	0	14	30	7	3
1951	167	167	149	0	0	0	13	43	7	1
1952	252	252	226	0	0	0	10	63	11	1
1953	212	212	170	0	0	0	11	74	10	1

Table D-3 (concl'd.)

Year	Upper Cretaceous	Viking and Equivalent	Mannville	Jurassic	Triassic	Permian and Pennsylvanian	Mississippian	Upper Devonian	Beaverhill Lake and Lower Devonian	Silurian, Ordovicain, Cambrian and Precambrian
1954	140	140	95	0	0	0	5	25	2	0
1955	157	157	128	0	0	0	4	43	7	0
1956	167	167	157	0	0	0	3	46	7	1
1957	198	198	192	0	0	0	11	74	3	0
1958	201	201	185	0	0	0	3	61	3	0
1959	156	156	142	0	0	0	16	82	13	2
1960	95	95	77	0	0	0	13	58	3	1
1961	80	80	59	0	0	0	18	44	3	0
1962	95	95	72	0	0	0	6	43	5	0
1963	83	83	72	0	0	0	2	32	7	0
1964	124	124	110	0	0	0	7	46	3	0
1965	191	185	160	0	0	0	11	55	1	0
1966	211	211	138	0	0	0	10	28	6	0
1967	274	273	149	0	0	0	11	32	4	4
1968	336	336	210	0	0	0	18	84	8	2
1969	354	354	244	0	0	0	12	101	6	0
1970	347	347	293	0	0	0	19	141	21	12
1971	393	393	312	0	0	0	27	222	17	3
1972	405	403	311	0	0	0	13	204	8	7
1973	627	627	474	0	0	0	25	328	5	0
1974	564	562	485	0	0	0	42	176	4	0
1975	747	745	656	0	0	0	38	214	2	0
1976	980	973	873	0	0	0	62	463	4	0
1977	942	941	895	0	0	0	75	547	11	0
1978	911	910	875	0	0	0	74	543	8	1
1979	975	971	933	0	0	0	66	605	6	0
1980	181	181	178	0	0	0	21	116	1	0

Source KCNP (1980).

Table D-4

Well Penetrations by Horizon and Year in Area 3

Year	Upper Cretaceous	Viking and Equivalent	Mannville	Jurassic	Triassic	Permian and Pennsylvanian	Mississippian	Upper Devonian	Beaverhill Lake and Lower Devonian	Silurian, Ordovicain, Cambrian and Precambrian
1945	16	15	14	0	0	0	0	8	3	0
1946	7	7	7	0	0	0	0	7	6	2
1947	9	9	8	0	0	0	0	5	2	2
1948	31	31	31	0	0	0	7	26	7	5
1949	392	392	389	0	0	0	183	377	27	6
1950	545	546	545	0	0	0	120	540	18	3
1951	263	265	265	0	0	0	29	221	9	1
1952	215	214	204	0	0	0	18	125	15	0
1953	140	140	125	0	0	0	4	53	13	2
1954	77	77	75	0	0	0	8	44	4	0
1955	67	67	66	0	0	0	8	51	5	2
1956	39	38	38	0	0	0	7	27	9	7
1957	43	40	43	0	0	0	7	30	15	10
1958	50	50	49	0	0	0	5	35	19	10
1959	42	42	43	0	0	0	4	28	15	5
1960	40	40	40	0	0	0	6	32	11	2
1961	66	66	65	0	0	0	2	43	18	1
1962	73	73	71	0	0	0	9	48	14	3
1963	60	60	60	0	0	0	6	41	10	1
1964	162	162	161	0	0	0	86	144	109	19
1965	285	285	285	0	0	0	136	239	175	10

Table D-4 (concl'd.)

Year	Upper Cretaceous	Viking and Equivalent	Mannville	Jurassic	Triassic	Permian and Pennsylvanian	Mississippian	Upper Devonian	Beaverhill Lake and Lower Devonian	Silurian, Ordovicain, Cambrian and Precambrian
1966	232	232	234	0	0	0	79	200	94	14
1967	137	136	137	0	0	0	36	95	59	12
1968	196	196	196	0	0	0	45	129	41	5
1969	189	191	191	0	0	0	56	144	38	3
1970	198	198	200	0	0	0	27	143	15	4
1971	220	222	223	0	0	0	19	171	20	0
1972	292	294	293	0	0	0	61	236	21	2
1973	434	440	439	0	0	0	51	368	32	0
1974	380	392	393	0	0	0	54	299	53	1
1975	518	524	522	0	0	0	41	421	40	2
1976	718	729	729	0	0	0	67	573	29	1
1977	628	640	639	0	0	0	63	473	61	1
1978	605	618	637	0	0	0	78	463	95	3
1979	621	637	667	0	0	0	86	451	138	2
1980	345	348	350	0	0	0	47	217	67	0

Source KCNP (1980).

Table D-5

Well Penetrations by Horizon and Year in Area 4

Year	Upper Cretaceous	Viking and Equivalent	Mannville	Jurassic	Triassic	Permian and Pennsylvanian	Mississippian	Upper Devonian	Beaverhill Lake and Lower Devonian	Silurian, Ordovicain, Cambrian and Precambrian
1945	1	0	3	0	0	0	0	0	2	0
1946	0	0	0	0	0	0	0	0	0	0
1947	0	0	0	0	0	0	0	0	0	0
1948	0	0	0	0	0	0	0	0	0	0
1949	2	0	3	0	0	0	0	1	4	4
1950	2	2	5	0	0	0	0	5	4	3
1951	4	4	6	0	0	0	0	8	6	6
1952	3	2	3	0	0	0	0	5	5	3
1953	3	3	3	0	0	0	0	3	1	0
1954	0	0	0	0	0	0	0	0	0	0
1955	0	0	0	0	0	0	0	0	0	0
1956	1	2	2	0	0	0	0	1	2	1
1957	15	11	26	0	0	0	0	13	18	17
1958	18	15	23	0	0	0	0	13	22	17
1959	11	9	16	0	0	0	0	12	15	9
1960	9	8	20	0	0	0	0	22	19	7
1961	11	7	12	0	0	0	0	12	12	5
1962	8	5	8	0	0	0	0	9	9	1
1963	4	0	11	0	0	0	0	10	6	2
1964	2	1	7	0	0	0	0	7	4	4
1965	15	13	15	0	0	0	0	14	8	3
1966	31	26	38	0	0	0	0	32	27	20
1967	17	13	22	0	0	0	0	17	14	11
1968	18	15	31	0	0	0	0	39	38	37
1969	24	41	52	0	0	0	0	60	64	52
1970	17	15	23	0	0	0	0	28	29	19
1971	15	13	16	0	0	0	0	21	19	9
1972	14	14	17	0	0	0	0	15	10	3
1973	28	33	42	0	0	0	0	21	17	4
1974	61	58	79	0	0	0	0	50	24	4

Table D-5 (concl'd.)

Year	Upper Cretaceous	Viking and Equivalent	Mannville	Jurassic	Triassic	Permian and Pennsylvanian	Mississippian	Upper Devonian	Beaverhill Lake and Lower Devonian	Silurian, Ordovicain, Cambrian and Precambrian
1975	34	44	58	0	0	0	0	38	20	0
1976	23	32	47	0	0	0	0	30	20	1
1977	40	49	66	0	0	0	0	54	16	2
1978	22	29	63	0	0	0	0	48	21	2
1979	32	40	68	0	0	0	0	43	36	1
1980	29	26	39	0	0	0	0	31	6	1

Source KCNP (1980).

Table D-6

Well Penetrations by Horizon and Year in Area 5

Year	Upper Cretaceous	Viking and Equivalent	Mannville	Jurassic	Triassic	Permian and Pennsylvanian	Mississippian	Upper Devonian	Beaverhill Lake and Lower Devonian	Silurian, Ordovicain, Cambrian and Precambrian
1945	0	0	0	0	0	0	0	0	0	0
1946	0	0	0	0	0	0	0	0	0	0
1947	0	0	0	0	0	0	0	0	0	0
1948	0	0	0	0	0	0	0	0	0	0
1949	0	0	0	0	0	0	0	0	0	0
1950	1	1	1	0	0	0	0	1	1	1
1951	3	1	5	0	0	0	1	5	5	5
1952	1	1	1	0	0	0	0	1	1	1
1953	2	0	2	0	0	0	2	2	2	2
1954	6	2	8	0	0	0	5	8	8	7
1955	1	1	2	0	0	0	2	2	2	1
1956	5	2	7	0	0	0	5	7	7	6
1957	4	4	4	0	0	0	2	4	4	3
1958	9	3	12	0	0	0	3	12	10	8
1959	4	2	5	0	0	0	2	3	3	1
1960	6	2	6	0	0	0	5	6	6	4
1961	6	1	6	0	0	0	6	6	6	5
1962	6	1	6	0	0	0	6	6	6	1
1963	11	1	11	0	0	0	8	10	10	2
1964	14	2	15	0	0	0	12	15	14	4
1965	33	5	31	0	0	0	27	32	32	11
1966	105	13	118	0	0	0	105	121	120	46
1967	287	29	309	0	0	0	287	324	323	73
1968	291	27	310	0	0	0	282	320	319	87
1969	161	10	161	0	0	0	156	174	173	26
1970	79	7	78	0	0	0	79	86	85	15
1971	73	9	77	0	0	0	54	76	75	5
1972	63	6	65	0	0	0	57	65	64	2
1973	60	16	63	0	0	0	54	53	50	2
1974	67	20	66	0	0	0	63	26	17	1
1975	82	12	84	0	0	0	70	41	9	0
1976	173	31	191	0	0	0	135	88	9	0
1977	227	28	233	0	0	0	185	91	14	1
1978	96	25	105	0	0	0	90	43	24	0
1979	90	14	110	0	0	0	81	64	36	1
1980	68	12	83	0	0	0	51	49	20	1

Source KCNP (1980).

Table D-7

Well Penetrations by Horizon and Year in Area 6

Year	Upper Cretaceous	Viking and Equivalent	Mannville	Jurassic	Triassic	Permian and Pennsylvanian	Mississippian	Upper Devonian	Beaverhill Lake and Lower Devonian	Silurian, Ordovicain, Cambrian and Precambrian
1945	12	11	12	1	1	4	4	0	0	–
1946	1	1	0	0	0	0	0	0	0	–
1947	1	1	1	0	0	0	0	0	0	–
1948	2	2	0	0	0	0	0	0	0	–
1949	4	4	2	2	2	2	2	2	1	2
1950	15	15	14	11	10	12	13	13	8	13
1951	34	35	35	33	29	31	28	12	6	11
1952	38	38	37	31	27	20	20	10	3	8
1953	29	29	24	17	17	14	11	5	2	4
1954	22	22	17	8	10	10	10	6	4	6
1955	19	19	16	12	11	12	12	9	6	9
1956	44	41	37	30	28	24	25	10	5	7
1957	49	48	45	34	29	23	32	15	8	13
1958	39	37	37	25	25	21	30	20	10	13
1959	38	36	35	29	29	23	25	16	6	10
1960	28	28	27	24	24	22	23	18	5	16
1961	28	27	26	19	22	13	17	10	6	10
1962	46	43	43	35	36	23	22	16	13	11
1963	29	30	28	24	24	15	15	13	5	10
1964	37	32	32	28	26	14	12	5	2	2
1965	27	26	27	17	19	15	20	11	6	6
1966	21	18	21	12	13	12	17	13	9	10
1967	27	23	24	18	18	8	10	8	6	7
1968	37	34	36	31	32	20	24	15	9	12
1969	37	37	36	33	33	15	19	13	8	9
1970	51	47	52	44	42	19	25	18	13	15
1971	78	76	79	67	69	41	48	18	8	10
1972	129	131	131	105	112	68	85	23	9	11
1973	124	123	122	98	96	62	74	34	14	14
1974	141	142	141	101	109	84	104	34	11	16
1975	146	145	149	109	107	93	119	44	13	27
1976	192	186	195	126	130	99	153	34	8	27
1977	213	215	214	133	132	82	144	37	22	22
1978	175	178	182	116	104	53	102	29	17	10
1979	193	196	198	150	150	66	87	28	15	13
1980	74	65	65	48	54	20	32	10	8	3

Source KCNP (1980).

Table D-8

Well Penetrations by Horizon and Year in Area 7

Year	Upper Cretaceous	Viking and Equivalent	Mannville	Jurassic	Triassic	Permian and Pennsylvanian	Mississippian	Upper Devonian	Beaverhill Lake and Lower Devonian	Silurian, Ordovicain, Cambrian and Precambrian
1945	0	0	0	0	0	0	0	0	0	0
1946	0	0	0	0	0	0	0	0	0	0
1947	1	1	1	1	0	0	1	1	1	0
1948	0	0	0	0	0	0	0	0	0	0
1949	2	2	2	2	2	2	2	2	1	1
1950	1	1	1	1	1	1	1	1	1	0
1951	4	4	4	3	3	3	3	1	1	0
1952	5	5	5	4	3	3	5	5	2	2

Table D-8 (concl'd.)

Year	Upper Cretaceous	Viking and Equivalent	Mannville	Jurassic	Triassic	Permian and Pennsylvanian	Mississippian	Upper Devonian	Beaverhill Lake and Lower Devonian	Silurian, Ordovicain, Cambrian and Precambrian
1953	12	12	12	12	12	12	12	12	1	1
1954	41	37	37	33	25	25	33	31	13	9
1955	75	72	72	70	64	60	72	70	21	19
1956	95	90	90	83	71	67	82	70	15	12
1957	85	79	76	64	46	36	71	55	14	9
1958	116	111	111	78	63	35	94	88	71	15
1959	229	229	229	109	77	49	228	228	210	27
1960	386	385	385	150	6	36	377	373	351	22
1961	409	408	408	140	55	33	395	386	365	15
1962	226	226	226	82	35	25	219	207	197	9
1963	434	432	430	249	207	149	394	351	321	22
1964	427	423	421	190	163	119	377	349	337	31
1965	303	300	300	115	92	61	286	271	246	43
1966	137	137	137	74	56	30	128	111	92	11
1967	79	73	70	49	36	23	58	46	33	3
1968	146	145	142	118	80	67	126	99	84	12
1969	139	138	138	104	66	47	123	100	90	17
1970	130	129	129	106	70	42	118	90	72	11
1971	151	150	148	124	57	36	122	98	61	14
1972	147	141	138	111	73	33	112	84	53	10
1973	165	160	159	127	82	46	126	94	70	8
1974	175	172	172	110	53	27	143	95	78	8
1975	125	122	121	91	49	35	92	51	37	6
1976	155	151	148	125	84	47	110	84	75	22
1977	184	181	179	148	84	36	110	76	61	21
1978	291	270	256	195	93	50	133	86	70	16
1979	364	327	327	235	125	55	162	102	81	12
1980	127	125	122	95	45	14	59	42	27	3

Source KCNP (1980).

Table D-9

Well Penetrations by Horizon and Year in Area 8

Year	Upper Cretaceous	Viking and Equivalent	Mannville	Jurassic	Triassic	Permian and Pennsylvanian	Mississippian	Upper Devonian	Beaverhill Lake and Lower Devonian	Silurian, Ordovicain, Cambrian and Precambrian
1945	7	0	0	0	0	0	1	1	0	1
1946	1	1	1	1	0	0	1	1	0	0
1947	45	45	44	0	0	0	6	44	5	0
1948	156	156	156	2	0	0	49	151	8	1
1949	257	257	253	4	0	0	123	239	12	0
1950	309	309	283	1	0	0	144	263	13	0
1951	589	589	514	2	0	0	224	480	24	3
1952	917	915	715	5	1	0	281	618	26	1
1953	717	713	577	14	0	0	373	536	21	2
1954	687	495	373	35	0	0	275	317	22	3
1955	1,107	425	241	61	0	0	201	177	17	3
1956	1,318	415	275	99	1	0	210	147	8	2
1957	821	325	284	105	1	0	248	175	8	0
1958	957	346	327	59	1	0	286	232	11	3
1959	723	240	225	74	0	0	200	118	15	4
1960	760	237	227	100	0	0	201	86	19	2
1961	658	313	308	118	0	0	271	146	17	2
1962	745	431	422	178	5	0	381	210	21	6
1963	593	315	306	148	9	0	268	127	13	3

Table D-9 (concl'd.)

Year	Upper Cretaceous	Viking and Equivalent	Mannville	Jurassic	Triassic	Permian and Pennsylvanian	Mississippian	Upper Devonian	Beaverhill Lake and Lower Devonian	Silurian, Ordovicain, Cambrian and Precambrian
1964	557	303	294	115	11	0	248	152	11	4
1965	507	274	266	99	12	0	197	145	10	1
1966	394	248	244	66	13	0	206	165	8	1
1967	294	162	160	51	5	0	135	110	4	2
1968	282	174	173	43	3	0	137	120	12	6
1969	336	215	209	71	9	0	165	130	15	5
1970	247	170	166	77	8	0	141	99	19	0
1971	236	180	168	64	3	0	131	79	16	5
1972	324	214	211	80	4	0	146	105	19	2
1973	417	282	270	105	13	0	188	122	16	1
1974	382	272	258	113	13	0	188	94	8	1
1975	408	301	280	103	17	0	177	63	11	2
1976	474	356	329	114	10	0	198	99	10	7
1977	535	418	404	139	10	0	283	184	19	8
1978	699	526	512	227	10	0	400	304	25	7
1979	859	635	613	260	4	0	434	240	11	7
1980	241	189	183	88	2	0	128	53	4	2

Source KCNP (1980).

Table D-10

Well Penetrations by Horizon and Year in Area 9

Year	Upper Cretaceous	Viking and Equivalent	Mannville	Jurassic	Triassic	Permian and Pennsylvanian	Mississippian	Upper Devonian	Beaverhill Lake and Lower Devonian	Silurian, Ordovicain, Cambrian and Precambrian
1945	575	437	503	423	4	2	430	13	6	4
1946	20	19	19	21	0	1	21	3	1	0
1947	11	11	11	11	0	0	10	2	1	0
1948	13	9	11	13	1	0	12	1	1	0
1949	8	7	10	9	0	0	10	3	0	0
1950	3	3	3	3	0	0	4	0	0	0
1951	5	4	5	5	0	0	1	0	0	0
1952	4	3	4	2	0	0	1	0	0	0
1953	9	8	9	8	0	0	7	3	0	2
1954	6	4	4	2	0	0	1	1	0	0
1955	8	5	7	4	0	0	5	3	0	0
1956	12	8	10	10	2	0	8	2	0	1
1957	18	10	15	16	0	2	12	2	0	1
1958	15	12	17	13	2	3	12	4	1	2
1959	15	12	15	13	0	0	10	4	1	1
1960	28	21	29	27	9	4	25	7	4	5
1961	24	19	24	26	3	3	22	5	2	2
1962	21	14	16	16	2	0	15	3	2	3
1963	9	6	7	8	1	0	5	2	0	1
1964	11	8	11	11	3	2	8	4	1	1
1965	6	5	5	4	1	0	2	1	0	1
1966	5	4	5	5	0	1	5	2	0	0
1967	11	10	11	9	0	0	5	1	0	0
1968	20	18	18	17	2	1	17	3	0	1
1969	21	17	20	17	1	1	14	4	2	2
1970	27	20	23	23	3	0	21	12	7	7
1971	19	14	16	14	1	0	9	5	2	0
1972	30	21	25	23	4	3	22	7	4	2
1973	21	15	18	17	8	2	16	6	2	4
1974	31	23	30	27	3	1	20	5	3	2

Table D-10 (concl'd.)

Year	Upper Cretaceous	Viking and Equivalent	Mannville	Jurassic	Triassic	Permian and Pennsylvanian	Mississippian	Upper Devonian	Beaverhill Lake and Lower Devonian	Silurian, Ordovicain, Cambrian and Precambrian
1975	31	22	31	25	4	2	21	3	2	3
1976	32	18	29	30	6	3	24	10	6	9
1977	45	31	38	35	6	0	28	19	11	14
1978	36	28	30	28	7	3	27	12	8	8
1979	35	27	24	26	4	2	27	13	8	8
1980	10	10	9	8	1	1	7	2	2	1

Source KCNP (1980).

Appendix E

Tables E-1 to E-8 present oil and gas reserve additions and drilling data for the regions (horizons and areas) chosen for the disaggregate analysis.

Table E-1

Oil and Gas Reserve Additions and Targeted Drilling in the Upper Devonian, All Areas, 1947-79

Year	Oil	Associated gas[1]	Non-associated gas[1]	Targeted wells
	(10^6m^3)	(10^9m^3)		
1947	6.00			52
1948	0.25			194
1949	100.15	2.5	1.3	612
1950	45.50	0.1	0.4	809
1951	68.34	21.5	1.7	742
1952	8.54	19.0	7.7	818
1953	47.12	25.5	6.4	744
1954	25.20	3.3	5.9	433
1955	5.76	2.7	2.3	343
1956	46.26	21.2	13.1	296
1957	29.25	-7.0	13.0	339
1958	5.66	-0.9	36.9	349
1959	5.60	0.8	9.7	238
1960	10.16	6.0	17.4	187
1961	0.65	0.8	3.4	240
1962	1.58	0.8	3.5	289
1963	3.63	1.5	3.3	226
1964	22.27	1.9	11.5	250
1965	20.96	3.2	18.1	305
1966	13.84	4.0	2.7	327
1967	1.16	0.3	8.8	205
1968	6.39	-0.8	23.7	202
1969	4.18	-0.1	27.0	222
1970	4.48	0.1	14.8	190
1971	11.51	2.6	0.6	185
1972	7.63	0.4	11.4	211
1973	0.91	4.2	3.9	253
1974	1.01	1.2	3.9	236
1975	1.02	-4.2	2.2	172
1976	0.67	1.0	5.5	230
1977	0.41	-0.7	12.2	355
1978	8.64	3.3	12.0	464
1979	25.54	0.9	4.7	396

1 First observation is total prior to 1950.

Table E-2

Oil and Gas Reserve Additions and Targeted Drilling in the Beaverhill Lake and Lower Devonian, All Areas Except Area 5, 1957-79

Year	Oil	Associated gas	Non-associated gas	Targeted wells
	(10^6m^3)	(10^9m^3)		
1957	3.61	3.0	1.1	30
1958	22.63	8.0	0.01	91
1959	35.84	5.2	0.01	227
1960	45.64	10.9	0.6	374
1961	18.46	-1.3	0.6	398
1962	16.26	2.9	0.4	242
1963	6.97	-1.4	0.1	334
1964	26.85	2.9	0.3	410
1965	5.37	-1.3	0.01	432
1966	17.24	4.6	2.3	253
1967	8.90	0.7	7.3	100
1968	3.91	—	13.0	164
1969	1.50	—	4.5	171
1970	1.99	0.9	2.8	140
1971	7.85	0.1	2.0	143
1972	3.97	0.8	0.01	106
1973	.01	5.8	7.1	153
1974	3.73	2.9	0.01	172
1975	1.15	-1.2	0.2	115
1976	1.82	1.1	7.9	124
1977	1.02	-0.1	4.8	163
1978	.05	—	12.2	220
1979	1.45	-0.2	8.6	172

Table E-3

Oil and Gas Reserve Additions and Targeted Drilling in the Mannville Horizon, All Areas, 1950-79

Year	Oil	Associated gas	Non-associated gas	Targeted wells
	(10^6m^3)	(10^9m^3)		
pre 1950	15.73	0.3	5.8	766
1950	0.06	—	3.7	96
1951	3.89	0.4	6.7	246
1952	2.01	0.8	6.8	425
1953	0.56	0.2	6.1	318
1954	0.49	—	7.2	270
1955	0.15	0.6	6.4	232
1956	9.73	1.4	7.6	311
1957	5.14	3.2	11.8	286
1958	0.99	0.8	11.1	321
1959	1.76	0.9	6.4	326
1960	0.77	-0.0	16.4	238
1961	0.21	0.6	18.2	261
1962	0.93	-0.7	17.4	334
1963	4.51	0.4	13.0	441
1964	2.78	-0.1	23.4	559
1965	1.72	0.5	12.3	653
1966	1.98	0.8	6.6	446

Table E-3 (concl'd.)

Year	Oil	Associated gas	Non-associated gas	Targeted wells
	(10⁶m³)	(10⁹m³)		
1967	2.43	0.4	8.2	484
1968	3.16	0.7	14.9	631
1969	1.60	1.7	13.3	664
1970	0.54	0.1	6.8	746
1971	1.30	-0.2	16.6	905
1972	0.47	0.2	16.3	1,152
1973	3.24	2.0	31.3	1,565
1974	1.58	0.7	25.2	1,498
1975	0.67	2.0	24.2	1,777
1976	2.29	0.4	70.8	2,398
1977	0.20	1.7	62.0	2,501
1978	5.99	3.8	97.8	2,664
1979	2.03	2.6	47.8	2,813

Table E-4

Oil and Gas Reserve Additions and Targeted Drilling in the Beaverhill Lake and Lower Devonian Horizons, Area 5, 1965-78

Year	Oil	Associated gas	Targeted wells
	(10^6m^3)	(10^9m^3)	
1965	9.03	5.2	21
1966	43.04	5.4	74
1967	44.78	-0.3	250
1968	9.40	0.1	232
1969	4.72	-0.6	147
1970	1.75	---	60
1971	1.89	1.4	70
1972	1.21	0.2	62
1973	0.75	-2.3	48
1974	0.33	---	16
1975	0.03	-1.7	9
1976	0.01	-0.0	9
1977	0.13	-0.0	24
1978	1.46	-0.3	35

Table E-5

Oil and Gas Reserve Additions and Targeted Drilling in the Upper Cretaceous Horizon, Area 8, 1953-79

Year	Oil	Associated gas	Targeted wells
	(10^6m^3)	(10^9m^3)	
1953	28.76	8.4	4
1954	17.72	15.7	192
1955	33.42	2.3	682
1956	16.48	-6.1	903
1957	0.80	0.1	496
1958	3.79	-8.4	611
1959	9.28	1.7	483

Table E-5 (concl'd.)

Year	Oil	Associated gas	Targeted wells
	(10^6m^3)	(10^9m^3)	
1960	8.01	2.4	523
1961	3.25	6.1	345
1962	3.99	1.9	314
1963	2.07	-0.1	278
1964	1.10	---	254
1965	1.32	10.0	233
1966	5.25	9.3	146
1967	18.85	-6.7	132
1968	3.84	---	108
1969	1.54	11.1	121
1970	2.05	1.8	77
1971	0.01	-4.3	56
1972	1.00	0.9	110
1973	0.01	3.4	135
1974	0.92	0.3	110
1975	0.80	-1.0	107
1976	2.15	0.6	118
1977	0.01	2.0	117
1978	1.99	1.1	173
1979	1.24	1.8	224

Table E-6

Oil and Gas Reserve Additions and Targeted Drilling in the Viking Horizon, All Areas, 1950-79

Year	Oil	Associated gas	Non-associated gas	Targeted wells
	(10^6m^3)	(10^9m^3)		
pre 1950	0.10	2.0	32.6	181
1950	1.33	---	2.0	41
1951	2.07	0.5	9.5	111
1952	5.89	7.0	4.8	251
1953	0.53	10.1	12.2	210
1954	2.19	1.9	12.0	186
1955	2.16	6.0	6.7	231
1956	0.01	5.4	10.6	165
1957	0.01	0.8	8.5	73
1958	0.68	0.8	4.6	48
1959	0.06	1.6	2.1	44
1960	0.79	0.2	4.8	47
1961	0.34	3.1	0.4	41
1962	0.28	0.1	4.4	64
1963	0.01	1.4	1.9	40
1964	0.25	0.8	3.3	35
1965	0.04	2.2	2.4	48
1966	0.93	4.3	6.9	90
1967	0.75	4.2	0.01	144
1968	3.53	0.6	0.5	146
1969	1.01	0.1	0.01	130
1970	0.25	0.9	5.8	112
1971	0.40	-3.8	10.8	189
1972	0.58	0.3	12.3	159
1973	0.12	2.1	21.9	303
1974	0.87	0.1	8.3	225
1975	1.37	0.2	7.4	309
1976	1.07	0.9	13.9	530

Table E-6 (concl'd.)

Year	Oil	Associated gas	Non-associated gas	Targeted wells
	(10^6m^3)		(10^9m^3)	
1977	0.03	0.3	13.9	358
1978	0.84	0.4	26.0	323
1979	0.2	-0.1	9.9	172

Table E-7

Oil and Gas Reserve Additions and Targeted Drilling in the Mississippian Horizon, All Areas, 1950-79

Year	Oil	Associated gas	Non-associated gas	Targeted wells
	(10^6m^3)		(10^9m^3)	
< 1950	19.46	21.4	11.3	502
1950	0.01	---	0.2	12
1951	0.01	---	48.1	23
1952	7.12	---	0.8	18
1953	0.01	---	3.1	16
1954	2.96	3.4	5.2	13
1955	11.87	7.0	17.4	28
1956	0.20	21.0	1.2	101
1957	10.82	-1.6	20.3	124
1958	0.27	---	50.7	85
1959	0.13	9.3	21.9	118
1960	1.08	12.2	47.3	158
1961	1.22	3.8	3.2	174
1962	2.44	7.0	14.3	223
1963	2.65	0.3	26.6	216
1964	0.03	0.0	29.0	172
1965	0.52	0.1	33.9	115
1966	1.84	0.3	3.2	87
1967	0.11	0.2	21.1	67
1968	0.56	2.3	20.2	93
1969	0.15	-0.9	18.2	97
1970	0.01	-1.8	3.8	110
1971	0.01	0.9	19.8	144
1972	0.13	0.6	9.1	190
1973	0.35	3.8	28.2	202
1974	0.44	5.0	18.2	310
1975	0.01	-3.0	5.0	313
1976	0.02	1.9	19.0	359
1977	0.02	0.3	9.8	406
1978	0.09	0.2	5.5	364
1979	0.60	0.8	17.7	414

Table E-8

Gas Reserve Additions, Targeted Drilling and Average Additions Rates in the Upper Cretaceous Horizon, Area 1, 1950-79

Year	Non-associated gas reserve additions	Targeted wells	Average gas reserve additions rate
	(10^9m^3)		(10^6m^3/well)
< 1950	9.7	153	–
1950	–	6	–

Table E-8 (concl'd.)

Year	Non-associated gas reserve additions	Targeted wells	Average gas reserve additions rate
	(10^9m^3)		(10^6m^3/well)
1951	10.1	16	–
1952	–	10	–
1953	8.4	17	139.60
1954		18	–
1955	0.4	15	–
1956	11.5	13	–
1957	–	10	–
1958	9.1	40	218.75
1959	0.1	69	–
1960	1.2	38	–
1961	0.9	38	–
1962	–	36	–
1963	0.8	78	11.58
1964	3.3	28	–
1965	4.3	37	–
1966	–	38	–
1967	9.4	43	–
1968	–	84	34.76
1969	4.4	146	–
1970	2.4	314	–
1971	13.0	398	–
1972	4.2	738	–
1973	72.0	1,177	34.62
1974	84.2	1,311	–
1975	1.0	1,368	–
1976	19.2	2,118	–
1977	10.6	1,779	–
1978	5.9	1,764	–
1979	18.2	1,229	14.53

Notes

Chapter 2

1 This technique estimates reserves by measuring the volume of sediments in a region multiplied by an oil recovery factor per unit volume of sediments.

2 Uhler (1977) argues that such criticism of the volumetric method is too strong in that the method is also based on empirical evidence.

3 Although Hubbert applies this model to the United States as a whole, it is more appropriately used at a disaggregated level of study since aggregation tends to reduce the goodness of fit. Ample evidence of this aggregation effect is presented later.

4 This measure of drilling effort will be discussed in more detail later.

5 The determination of the price of reserves in the ground is discussed in detail in Chapter 3.

6 Since oil deposits within a particular geological horizon in a particular geographical area are relatively homogeneous in character, this assumption is reasonable.

7 Of course, some wells will be drilled below the targeted horizon in order to test deeper structures so that this approach will incorrectly measure targeted drilling effort. This is particularly true for the shallower horizons.

8 This functional form can be used for both models of directionality discussed earlier.

Chapter 3

1 For a more detailed examination of these price calculations see Uhler (1982*b*).

2 A producer netback is often defined in other ways. Probably the most common alternative is to also deduct income tax but this deduction is more difficult to make than many people realize.

3 If reserves acquisition is not tax deductable then, of course, the tax rate influences their price. Currently, acquisition through exploration is tax deductable but if acquired by outright purchase must be depreciated over time like any other capital asset. This treatment introduces an asymmetry which encourages firms to be vertically integrated in exploration and production.

4 Before the Agreement between the Government of Canada and the government of Alberta, all oil of a given quality received the same price, in which case it is reasonable to use the average wellhead price in determining the value of reserves. However, the agreement sets the price of oil discovered in 1981 and thereafter at the world price and the price of oil discovered earlier at a lower level not to rise to more than 75 per cent of the world level. Thus, from the date of the agreement, average wellhead price should not be used in calculating the value of new discoveries. The agreement was amended later to allow discoveries subsequent to 1973 to receive the world price.

5 This is the number of years until one-half of the reserves discovered in a particular year are brought into production. The median is used rather than the mean because in all years some discoveries had not yet begun to produce in 1979.

6 They are shown as nil value in Table A-3.

Chapter 4

1 Appendix B is provided as a separate document and is available on request. Tables B-1 to B-28 are the oil data, Tables B-29 to B-66 are the gas data in pools larger than 0.28 x $10^6 m^3$, and Tables B-67 to B-121 are gas data in smaller pools.

2 Appendix C is also presented as a separate document and is available on request.

Chapter 5

1 These pools account for about 70 per cent of initial booked discoveries. For purposes of estimating the supply relationships, the remaining reserves in pools without a complete history of appreciation are included in the yearly discoveries data at their 1981 estimated amounts.

Chapter 6

1 For example, instead of a January 1, 1984 NORP price of $\$378.73/m^3$ as set out in the September 1, 1981 Agreement with Alberta, the actual price was about $\$236/m^3$ because of the ceiling set by the international price.

2 If the decline rate is zero then the price response cannot be measured.

List of Tables and Figures

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