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DISCUSSION PAPER NO. 251

Costs and Supply of Natural Gas from Alberta: An Empirical Analysis

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RÉSUMÉ

Cette étude traite d'une importante question, à savoir la capacité de production canadienne de pétrole brut et de gaz naturel. Son contenu empirique consiste en une analyse du coût de production du gaz naturel provenant des réserves connues de l'Alberta. Ses résultats sont susceptibles d'être importants en ce qui concerne l'analyse de l'offre de gaz naturel et même de pétrole brut. Ils montrent qu'il est possible d'introduire explicitement le facteur coût dans l'analyse de l'offre. En outre, il permettent de définir une structure, fondée sur des considérations d'ordre économique et géologique, susceptible de constituer un cadre d'analyse approprié des réserves potentielles.

De façon très générale, une courbe d'offre décrivant les additions aux réserves de pétrole devrait tenir compte des gains découlant des quatre activités suivantes:

(a) accroître la récupération des gisements au-delà des prévisions;

(b) mettre en valeur de nouveaux gisements déjà connus, mais non économiques;

(c) découvrir et exploiter de nouveaux gisements;

(d) faire progresser la technologie de façon à créer de nouvelles possibilités pour chacune des activités susmentionnées.

Les recherches dont il est fait état ici portent sur des réservoirs de gaz naturel connus et, par conséquent, se rattachent plus directement à l'activité décrite en b). Quant à l'analyse des coûts, elle est valable pour celle dont il fait état en c).

L'auteur aborde, dans ses éléments fondamentaux, la question de la sensibilité de l'offre de gaz naturel aux variations du revenu net réalisé au point d'extraction. Il cherche à établir s'il existe des régularités dans la structure des coûts de production pour des entités ou formations géologiques semblables. A cette fin, il procède à une estimation du coût unitaire de production de gaz naturel pour chaque gisement (coût de mise en valeur) d'un vaste échantillon de gisements connus de l'Alberta. Ces données sont ensuite utilisées conjointement avec d'autres ayant trait aux réserves établies, afin de déterminer la structure des coûts de mise en valeur de chaque formation géologique. L'auteur analyse ensuite les résultats en établissant un parallèle entre les stocks cumulatifs de réserves initiales récupérables et l'estimation de leur coût unitaire de mise en valeur.

La structure de coûts observée pour chaque formation constitue un élément essentiel du cadre utilisé pour procéder à l'analyse globale de l'offre de gaz naturel (ou de pétrole brut). Il est important de savoir comment les apports des diverses formations géologiques doivent se combiner pour déterminer l'offre globale. Si les coûts de production varient relativement peu à l'intérieur d'une même formation, il devient alors possible de s'en tenir à un seul niveau de coûts pour chaque formation. On pourrait alors obtenir une courbe globale des réserves potentielles représentant l'ensemble des stocks additionnels de réserves qui deviendraient disponibles à mesure que la hausse des prix rendrait les formations rentables dans un ordre de coûts ascendants. Les augmentations de l'offre proviendraient en grande partie de la mise en valeur de nouvelles formations. Par ailleurs, si les coûts d'importants volumes de gaz variaient de façon considérable entre les diverses formations, alors l'activité de mise en valeur destinée à identifier les formations serait aussi une source importante de nouvelles réserves au fur et à mesure que les prix augmenteraient.

La mesure utilisée pour estimer le coût de mise en valeur consiste à attribuer un coût à chaque volume de gaz produit, de telle sorte qu'une fois le plan de production exécuté, toutes les dépenses auront été remboursées. La littérature technique fait état de cette méthode et la qualifie de nivellement des coûts unitaires. Elle consiste à diviser la valeur actualisée des dépenses par la valeur actualisée de la production matérielle. L'estimation du coût exige que l'on ait recours à des données qui définissent certaines caractéristiques des gisements de gaz, ainsi qu'à des méthodes d'évaluation des dépenses de mise en production d'un gisement, compte tenu de ses caractéristiques physiques.

Les éléments les plus importants à prendre en considération afin de caractériser les gisements de gaz sont les suivants: les premières réserves commercialisables, la productivité moyenne des puits (fondée sur les résultats des essais), de même que la profondeur et l'emplacement du gisement tant du point de vue géographique que géologique.

De ces éléments, celui qui est le plus susceptible d'influencer la qualité des résultats, est celui des réserves, car si l'on s'attend à ce que le coût de mise en valeur d'un nouveau gisement soit élevé, le puit de découverte sera probablement fermé. De cette manière, seule une quantité minime de réserves, s'il en est, serait homologuée. Il a donc fallu établir une échelle de coûts qui soit telle que l'on puisse prétendre obtenir des estimations de réserves suffisamment fiables. La limite supérieure de l'échelle a été fixée à 60 cents le millier de pieds cubes. Les gisements dont les coûts dépassent ce niveau n'ont pas été pris en compte dans l'interprétation des résultats empiriques.

Lorsqu'on classe par ordre ascendant les coûts de mise en valeur des gisements d'une formation donnée, il s'en dégage une tendance très nette. A mesure que les coûts unitaires successifs augmentent, la taille moyenne des gisements diminue sensiblement. L'augmentation des coûts donne lieu, par conséquent, à une baisse rapide des réserves marginales additionnelles. La hausse des coûts unitaires est en grande partie attribuable à des livraisons de faibles montants par rapport au taux moyen de production des puits d'un gisement.

L'auteur analyse les résultats empiriques obtenus en reportant sur un graphique le coût relatif à chaque gisement ou groupe de gisements, en regard des réserves initiales cumulatives. Cette méthode est semblable à celle qui est utilisée pour caractériser les réserves potentielles d'un bassin ou d'une formation. Ici encore, une tendance fort nette se dessine entre les diverses formations. Dans la première partie de chaque courbe, pour une catégorie de coûts de mise en valeur n'excédant pas 20 cents le millier de pieds cubes, quelques très grands gisements pour lesquels ces coûts sont faibles confèrent aux courbes une assez grande élasticité en fonction du prix offert (soit des valeurs excédant l'unité), mais pour les coûts de 20 à 60 cents, l'élasticité se situe autour de 0,2.

Lorsque diverses formations se caractérisent par des coûts moyens, ceux-ci se situent le plus souvent au-dessous de 25 cents le millier de pieds cubes. Pour certaines formations, cependant, comme l'Upper and Middle Viking, ils sont sensiblement plus élevés. S'agissant de l'apparente similitude des coûts entre les diverses formations, il convient de souligner que certains facteurs connus pour leur influence sur les coûts n'ont pu être pris en considération dans cette analyse; il s'agit, par exemple, de la teneur en soufre et des différences de coût attribuables à l'emplacement géographique. Ces facteurs auraient en général un effet sur des formations entières, de sorte que leur inclusion conduirait à de plus grandes différences de coûts moyens. Quant à la formation plus coûteuse que nous venons de mentionner, le facteur important est sa capacité nettement plus faible de livraison.

Les résultats de cette étude pourront influencer les méthodes d'analyse des approvisionnements éventuels de pétrole et avoir une incidence encore plus directe sur la formulation des politiques en matière de gaz naturel. Les courbes qui mettent en corrélation les stocks de réserves et le coût de leur mise en valeur ont tendance à être relativement plates; autrement dit, à l'intérieur d'un étroit intervalle de coûts, l'offre est relativement élastique, mais au-delà, elle se montre très inélastique. Il en ressort qu'une fois obtenu un certain revenu net au point d'extraction, une bonne partie des gisements d'une formation peuvent être exploités économiquement. En outre, ces gisements renferment une part démesurément grande des réserves de la formation.

Cette dernière conclusion est encourageante pour l'estimation des réserves potentielles d'une formation, puisqu'elle vient appuyer la validité des résultats obtenus au moyen des modèles, plus généralement reconnus, du processus de découverte. Si l'on trouvait, cependant, dans une même formation, des réserves considérables à des coûts sensiblement différents, les données qui servent à estimer ces modèles seraient biaisées parce qu'on aurait omis de reconnaître le potentiel des réservoirs comportant des coûts plus élevés. Il s'ensuivrait alors une grave sous-estimation du total des réserves potentielles de n'importe quelle formation.

L'observation de la structure des coûts montre aussi que l'augmentation du revenu net au point d'extraction peut conduire à la mise en valeur de nouvelles formations, rendant ainsi disponibles de grandes quantités de réserves additionnelles. Mais, pour cela, il faudrait peut-être de fortes hausses de prix (ou réductions de redevances). Il en ressort, dans l'ensemble, que les réserves potentielles globales doivent être considérées comme la somme, suivant l'ordre des coûts, des réserves potentielles des diverses formations. Cependant, même si l'auteur a observé une régularité de la structure des coûts dans une même formation, rien ne permet de postuler qu'il existe une structure quelconque de coûts pour une région entière, c'est-à-dire pour l'ensemble des diverses formations. Il faut la déterminer empiriquement en combinant ces formations.

Il n'est pas possible d'évaluer le potentiel des nouvelles formations au moyen des techniques employées dans la présente étude. Ce potentiel n'en constitue pas moins, cependant, un bon indicateur de l'offre globale. Pour effectuer l'analyse de l'offre, il faudrait étudier individuellement chaque nouvelle formation tant du point de vue des coûts que du volume potentiel des réserves, ce qui serait d'ailleurs possible grâce aux techniques d'estimation des coûts qui sont d'ores et déjà disponibles ainsi qu'aux modèles connus du processus de découverte.

SUMMARY

This study relates to the broad question of Canada's ability to produce crude oil and natural gas. Its empirical content consists of an analysis of the cost of producing natural gas from known reservoirs in Alberta. The results of the study may have broad implications with regard to natural gas and even crude oil supply. They demonstrate the feasibility of explicitly introducing cost when analyzing supply. They also establish a structure, based on economic and geological considerations, within which to analyze reserves potential.

In most general form, a supply curve depicting additions to petroleum reserves would have to account for gains resulting from four activities:

(a) Increasing pool recovery above the level previously expected;
(b) developing new pools, previously known but uneconomic;
(c) finding and developing new pools;
(d) advancing the state of technology so that new opportunities are created for any of the preceding activities.

The research reported here concerns known natural gas reservoirs, and therefore relates most directly to activity (b). The cost analysis is relevant, however to activity (c), finding and developing new pools.

The question of the potential responsiveness of natural gas supply to changes in wellhead realization is approached at a very basic level. The aim is to establish whether, or to what extent, regularities exist in the structure of production costs within geologically similar entities, or formations. To do this, the unit cost of producing natural gas from known pools (development cost) is estimated, by pool, for a large sample of Alberta pools. This cost information is used together with information about established reserves in order to determine the structure of development costs for individual formations. The results are analyzed by relating cumulative stocks of initial recoverable reserves to estimated unit development cost.

The cost structure observed for individual formations is crucial as part of the framework advanced for the overall analysis of natural gas (or crude oil) supply. It is important to know how the contributions of individual formations should be combined in order to present the complete supply picture. If there is relatively little variation in production cost within a formation, it would be feasible to associate a level of cost with each formation. An overall reserves potential curve could then be obtained as the array of additional stocks of reserves becoming available as higher prices made formations with successively higher cost levels economic. Supply increases would be largely attributable to development activity in new formations. On the other hand, if costs for substantial volumes of gas vary over a significant range within formations, then development activity in establishing formations would also be an important source of reserves additions as prices rose.

The measure of development cost that was employed can be thought of as the attribution of a cost to each unit volume of gas produced, such that when the production plan is fulfilled all expenditures will have been repaid. This cost measure finds application in the engineering literature where it is sometimes referred to as levelized unit cost. The formula for its calculation takes the form of the quotient of the present value of expenditures and the present value of physical output. Cost estimation requires both data describing certain features of gas pools and methods for estimating the expenditures that must be made to produce a pool, given its physical characteristics.

Crucial input data describing gas pools include initial marketable reserves, average well productivity (derived from well test results), depth, and location (both geographical and with respect to the formation in which a pool occurs). Of these the measure which causes most concern as a possible source of bias in the results is that of reserves. This is because when the development cost of a newly discovered pool is expected to be high the discovery well is likely to be shut in. In this situation only a nominal quantity of reserves, if any at all, will be assigned. For this reason, it was necessary to define a cost range within which it could be expected that the reserves estimates were reliable. The upper bound of this range was set at 60 cents/Mcf; pools with costs above this level were ignored in interpreting the empirical results.

When development costs for pools in a given formation are classified according to increasing cost level, a consistent pattern emerges. With successively higher unit costs there is a marked decline in mean size of pool. As a result there is a rapid fall in incremental reserves additions as successively higher cost levels are attained. Increasing unit costs are largely attributable to lower values of deliverability, the mean production rate of wells in a pool.

The empirical results are analyzed by plotting the cost associated with each pool, or group of pools, against cumulative initial reserves. This is analagous to the format used when characterizing the reserves potential of a basin or formation. Again a consistent pattern emerges across formations. In the initial portion of each curve, for a category of development costs not exceeding 20 cents per Mcf, a few low-cost, very large pools cause the curves to be quite elastic with respect to supply price (values in excess of unity), but in the range of costs from 20 cents to 60 cents the elasticity is around 0.2.

When individual formations are characterized by average cost levels, most are below 25 cents per Mcf. Some, however, are significantly higher, notably the Upper and Middle Viking. In connection with the apparent similarity of cost levels among most formations, it should be noted that some factors known to have a bearing on cost could not be included in this analysis; examples are sulfur content and cost differentials relating to geographic location. These would generally affect entire formations, so that their inclusion would cause greater differences among average costs. For the higher cost formation just mentioned, the important factor is substantially lower deliverability.

The study results have implications with regard to the analysis of potential petroleum supplies as well as some more direct relevance to natural gas policymaking. The curves relating stocks of reserves to development cost tend to be relatively flat; in other words, within a narrow cost range supply is relatively elastic, but beyond this range it is very inelastic. This indicates that once a threshold wellhead realization has been obtained, a large share of the discovered pools in a formation becomes economic to produce. Furthermore, these pools contain a disproportionately large share of the reserves of the formation.

The conclusion just noted is encouraging with respect to the estimation of potential reserves within a formation, since it supports the validity of results derived using the more widely accepted discovery process models. If instead substantial volumes of reserves were found at significantly varying cost levels within a formation, the data which are used in estimating these models would be biased because of failure to recognize the potential of higher cost reservoirs. This would lead to severe understatement of the ultimate potential reserves of any formation.

A further implication of the observed cost structure is that increases in wellhead realization may result in the development of new formations, thus making available large quantities of additional reserves. For this to happen, price increases (and/or royalty reductions) may have to be substantial. The overall picture which emerges is that aggregate reserves potential must be visualized as the summation, ordered by cost level, of the reserves potential of individual formations. However, while a regularity of cost structure has been observed within formation, there is no basis for positing any particular cost structure for an entire region, that is for the aggregate of individual formations.

It must be established empirically, through the combination of individual formations.

The potential of new formations cannot be assessed by the techniques employed in the present study. However, it does provide a basis for approaching the analysis of aggregate supply. Such analysis will have to proceed by individually analyzing the newly emerging formations, both as to cost level and potential volume of reserves. Such a procedure is feasible, given the techniques of cost estimation which have been demonstrated together with already established discovery process models.

1. INTRODUCTION

This study relates to the broad question of Canada's ability to produce crude oil and natural gas. Its empirical content consists of an analysis of the cost of producing natural gas from known reservoirs in Alberta. The results of the study have implications with respect to the economics of securing additional reserves of natural gas and, by extension, crude oil. They demonstrate the feasibility of explicitly introducing cost considerations. They also establish a structure, based on economic and geological factors, within which to analyze potential reserves.

It will be useful to place the research which has been carried out in context by briefly discussing two matters: (1) the significance to policymakers of information of the sort conveyed by economists' supply curves; and (2) the difficulty of specifying such curves for a resource like petroleum. The remaining task of this introductory section will be to indicate the more specific questions addressed by the study.

The relationship between quantity of output forthcoming (or stock available to be produced) and price level -- the supply curve -- is fundamental to all market analysis. Supply curves can be flat; this occurs when a good is manufactured using inputs which are available in any desired quantity at unchanging price, assuming that adequate time is allowed to established productive capacity. In contrast, natural resource commodites are usually associated with upward-sloping supply curves, regardless of the time frame. This characterization, Ricardian scarcity, is derived from the premise of a fixed natural endowment within which there is quality variation. A distinction must be drawn between the true state of nature and man's knowledge of it, above all for petroleum. This distinction conditions the results of this study even though the study does not deal with the discovery process.

Much time is wasted by discussions of resource policy which implicitly assume a vertical supply curve, that is, that a resource endowment is a fixed amount -- petroleum at any price. As has been truly said about other resources in other places, crude oil or natural gas stocks in Alberta will never be exhausted. What matters is how much there is to be used before costs become so high that alternative materials are more attractive. More particularly, key policy issues converge on the extent to which a faster rate of utilization of crude oil or natural gas will force producers to turn to higher cost sources. Putting the matter the other way round, if producers were granted higher wellhead realizations, to what extent would reserves -- that is, producible stocks (and productive capacity) -- be expanded?

In concept, knowledge of crude oil or natural gas supply curves would make possible better decisions relating to a number of policy questions. The impact of the field prices allowed producers, in conjunction with the burden of royalties levied upon them, is determined by the underlying structure of costs. As recognized by the National Energy Board (NEB), the opportunity cost of exports depends not only upon recovery of expenditures related to production, but also upon the cost to Canada of an earlier need to turn to higher cost sources of supply. The Board's estimates of cost increases, however, are simply made on a trend basis. Unfortunately for policymakers, nature reveals her secrets grudgingly; supply curve information is costly to obtain.

In most general form, a supply curve depicting potential petroleum reserves would have to balance depletion against the additions resulting from four activities:[1]

(a) Increasing pool recovery above the level previously expected;

(b) developing new pools, previously known but not producing;

(c) finding and developing new pools;

(d) advancing the state of technology so that new opportunities are created for any of the preceding activities.

Each of the possible sources of new reserves requires investment, and in all cases the return, in the form of reserves additions, is uncertain. Dealing with uncertainty is a fundamental problem in specifying petroleum supply curves. The research reported here is based on known natural gas reservoirs; it relates to activity (b) but also to activity (c) as well. The uncertainty involved in gaining reserves additions from activity (b) is less than for activity (c), but uncertainty is still present. To be certain of the magnitude of reserves in a new pool and their unit production cost it is necessary to drill sufficient wells to delineate the pool. Normally, this only occurs when such wells can be immediately placed in production, since otherwise private producers cannot justify the expenditure. As a result, defining the supply curve relevant to decisions that involve future commitments (beyond the range of current production) always requires estimates of magnitudes which are not known with certainty.

Although presented as a problem of supply curve specification, this situation will be recognized in the large as the predicament of policymakers concerned with natural gas. Approval for output expansion, for example for exports, requires an increase in booked reserves, but the investment required to establish such stocks with the required certainty cannot be justified unless output opportunities -- in other words, markets -- are assured. The resolution of this dilemma lies in developing a more comprehensive analysis of supply.

Acceptance of established reserves as an appropriate supply measure, even though figures are periodically updated in accordance with economic conditions, effectively ignores the potential for increasing reserves stocks by the various investment activities just listed.

In this study, the question of the potential responsiveness of natural gas supply to changes in wellhead realization is approached at a very basic level. The aim is to establish whether, or to what extent, regularities exist in the structure of development costs within appropriately selected sample populations of reservoirs. The delineation of sample populations rests on geological considerations. That regular cost patterns do exist is implicitly or explicitly assumed by models used to forecast additions to reserves stocks. The study examines the nature of these regularities, or patterns, through the use of historical data from the province of Alberta. It is concerned, therefore, with establishing the geological-economic framework for analyzing additions to petroleum reserves.

The elemental unit of analysis is the reservoir, or pool. Reserves data are tabulated by pool, and well flow rates within a conventional pool are interdependent, even though they may differ markedly in magnitude. There are hundreds of pools in Alberta, and the development cost estimates by pool must be viewed in a statistical sense: general patterns are significant, and accuracy cannot be claimed for particular pools.

In the analysis pools are grouped according to formation, a classification which in concept reflects geological homogeneity. The grouping of pools by formation is a matter of considerable analytical significance, because the possibility of forecasting the magnitude and cost of uncertain stocks depends upon identifying populations where the characteristic of individual members vary in systematic fashion. For example, there is considerable literature which supports the hypothesis that within geologically homogeneous sediments, the size of petroleum deposits can be described by a lognormal probability distribution.[2]

A principal objective of the study is to examine how production costs vary within formations. In general, the more varied the physical characteristics of resource deposits (differing grade, size, or location), the greater the range of unit costs that might be associated with increasing supply. At present, there is only limited theoretical basis for predicting the range of cost variation within a gas-bearing formation or the pattern of variation. Thus these are matters for empirical investigation.

In the study, the unit development cost of producing natural gas from known pools is estimated, by pool, for a large sample of Alberta pools. This cost information is used in conjunction with information about established reserves in order to determine the structure of production costs for individual formations. The results are analyzed by relating cumulative stocks of initial recoverable reserves to estimated unit development cost. These schedules, or curves, are described more fully in Chapter 2. Because the reserves data cannot be presumed to be complete for reservoirs where development costs exceed 60 cents/Mcf, this upper limit is placed upon the reliability of the results. The nature of the data used is discussed in Appendix A.

The cost structures observed for individual formations are crucial as part of the framework advanced here for analysis of the natural gas (or crude oil) potential of a region. If there is relatively little variation in development cost within a formation, it would be feasible to associate a level of cost with each formation. The response of supply to economic incentives would in this case be visualized as the increments of reserves becoming available as higher realizations made it attractive to explore and develop formations which were previously uneconomic to produce. Established formations would contribute only insofar as higher realizations sustained exploration effort even though the average size of discoveries had become very small. By contrast, if costs for substantial volumes of gas vary over a significant range within formations, then established formations would be a much more important source of reserves with higher realizations. Large pools, previously uneconomic, could constitute very subtantial reserves increments.

Succeeding sections of the paper describe more completely the hypotheses about cost structures which have been examined and the principal results which have been obtained. Implications of the results are discussed with regard to the nature of reserves potential curves for individual formations and the significance of this for the analysis of the reserves potential of a basin or region. A comprehensive description of the costing methodology and the data used is provided in an appendix; appendices also provide more detailed reporting of the empirical results.

2. RESERVES POTENTIAL: POSSIBLE COST STRUCTURES

The manner in which costs vary across pools within a formation depends on such geological factors as size of pool, well productivity, and depth. The resulting pattern of costs determines the extent to which higher wellhead realizations make larger volumes of natural gas potentially profitable to produce. Alternative hypotheses may be advanced as to the nature of the cost structure, but before turning to these possibilities it is necessary to give careful consideration to the method of analysis utilized in this study.

The potential for natural gas reserves to be increased in response to economic incentives can best be expressed as the cumulative stock of reserves which are economic to produce at a given level of wellhead realizations. This response can also be described in terms of price elasticity: the percentage increase in stocks associated with a percentage increase in price. The results of this study are presented as both schedules and curves which show cumulative initial established reserves as a function of wellhead realizations; elasticity values are also estimated.

The distinctions between this analysis of the cost structure of petroleum stocks and conventional supply analysis should be emphasized. Supply curves typically depict rate of output at a given price level; that is to say, they are concerned with flows. For example, the rate of output of natural gas might be expressed as a function of supply price, or one might attempt to depict rate of reserves additions as a function of price. Secondly, supply curves normally depict availability, according to cost, at a point in time. The results presented here describe stocks of initial established reserves. "Initial" indcates that volumes of gas which have already been produced are not subtracted. "Established" indicates that the only reserves which are counted are those which have been identified with near certainty; reserves which might be present are not included. These results describe, therefore, the original state of nature with respect to stocks of gas in a particular formation as it has been revealed by the exploration which has taken place. Remaining reserves are briefly discussed in Appendix C.

The curves (or schedules) derived in this study are similar in concept to the reserves potential curves which have been used in petroleum industry studies to show the estimated reserves potential for unexplored basins.[1] The results here, however, describe <u>realized</u> potential. Where a particular formation has been well explored, the initial reserves which have been booked may comprise a good approximation of the potential reserves of the formation; for a lightly explored formation they will not. Inasmuch as forecasting the potential of a particular formation is beyond the scope of this study, it would be misleading to describe the derived curves as reserves potential curves. However, to the extent that this study has produced conclusions about the structure of costs, it will be relevant to forecasts of reserves potential.

The cost structure within formations will depend upon geological factors which condition cost. When different hypotheses are advanced in regard to geological patterns, different possibilities emerge with respect to the reserves potential-cost relationship for a given formation. To illustrate, two situations will be considered, which can be considered extreme, or polar, possibilities.[2] In the first case, assume that unit production costs are uniform for reservoirs within a formation, except for differences attributable to reservoir size. In this case there is minimal increase in incremental cost (or supply price) as successive pools are developed in a formation, but supply price will vary among formations. The second case relaxes this assumption, specifying unit cost within a formation to be a function of at least one other parameter beside reservoir size. A parameter that might be identified as being important is average well productivity.

In the literature on petroleum supply, attention focuses on the variable reservoir size. As noted in Section 1, empirical support has been developed for the hypothesis that pool sizes are distributed according to a skewed probability function, usually characterized as lognormal. Skewness implies that the bulk of all reserves will be found in a few pools, magnifying the importance of the size variable. Nevertheless, to specify reserves potential it is also necessary to know the incremental cost at which pools can be produced. Pool size is among the factors which influence cost, but it is not the only factor.

It is hypothesized that the size distribution of pools in a formation can be specified as shown in Figure 2.1, panel (a). Pools in the right-hand tail of this distribution would account for the bulk of the gas in place. Assuming pool size to be the <u>only</u> factor bearing on production cost, unit costs for these larger pools would be relatively low and approximately equal. This is shown in Figure 2.1, Panel (b), a reserves potential curve under these assumptions. With smaller pools production costs increase. However, since these pools contribute a relatively small fraction of the total recoverable gas in the formation, incremental development cost rises sharply only toward the rght-hand end of the supply curve when the smaller pools are exploited. As the formation becomes totally developed, the inventory of pools with proved reserves approaches the distribution in panel (a). Pools in the size range $S_0 S_1$ contribute the extra reserves $R_0 R_1$ shown in panel (b).

Next, assume unit production cost within a formation to be significantly affected by well productivity as well as pool size. This second case will be described with reference to Figure 2.2. It is assumed that pools within a formation have the same size distribution as in the previous case, so panel (a) has the same shape as the corresponding panel in Figure 2.1. However, suppose there is significant variation in the production costs of individual reservoirs within the formation attributable to differences in well productivity. To emphasize the possible distinction between the two cases, assume that well productivity is not highly correlated with reservoir size.

In these circumstances supply from the formation will be as shown in Figure 2.2, panel (b). It differs from the reserves potential curve of Figure 2.1 in that it is upward sloping over its entire range. Whereas in the former case the bulk of producible reserves in a formation would become economic once a threshold net wellhead realizaton was attained, now successively higher realizations are required in order to stimulate the production of larger shares of the potentially producible reserves. In Figure 2.2, panel (b), at the initial price P_0 reserves are forthcoming in the amount R_0 while at the higher price P_1 the stock of reserves will be R_1.

The situation with respect to pools can be seen in Figure 2.2, panel (a). With the higher price, reserves in the formation are augmented not just from the small pools in the S_1S_0 slice -- in addition, pools over the full size range now become economic. For example, a large reservoir, because of its low well productivity, may have high production costs which cannot be covered at the price P_0. If they are covered at price P_1, a large increment will be added to reserves.

The nature of actual cost structures -- whether similar to either of these extreme cases or somewhere in between -- is of vital concern when determining how to proceed with analysis of petroleum supply. In particular, if the cost estimations procedure proves robust and should the first case receive support (relative uniformity of development cost within formations), considerable impetus would be given to a disaggregate approach to petroleum supply estimation, one involving existing discovery process models together with development cost estimation. Should the second case receive support, the disaggregate approach would be much more complex. Not only would models describing cost variation within formations have to be developed, but doubt would be cast on the validity of estimates of reserves volumes arrived at using existing discovery process models.[3]

3. INITIAL ESTABLISHED RESERVES: OBSERVED COST STRUCTURES

Cost and reserves data have been organized to permit analysis by formation and across formations. To explain the results it will be helpful to make reference to several particular formations. Reserves by cost category for Viking Sandstone, Mannville, and Rundle are reported in Table 3.1. These formations are among the largest in terms of reserves; otherwise, their selection is arbitrary. Less detailed results are presented in Appendix B for twenty-one formations.

Column 1 of Table 3.1 classifies unit development costs by ten-cent intervals. The average cost figure reported in Column 2 is computed by weighting the cost figure for each pool in the particular category by that pool's share of total reserves. Column 3 shows the volume of known reserves in the data set which fall into each interval. The pattern that stands out in Table 3.1 is that with successively higher unit costs there is a sharp decline in mean size of pool (Column 10). This pattern is less pronounced for number of pools, but the number does decline substantially when unit costs rise about 50 cents/Mcf. The sharp decline in mean pool size, eventually reinforced by declining number of pools, causes a rapid fall in incremental reserves as successively higher cost levels are attained. This effect, seen in Column 3, is emhasized in Column 4 which reports cumulative reserves (expressed as a percentage of the total) producible at cost up to and including the given level.

Average well productivity (Col. 8), average depth (Col. 9), and mean size of pool (Col. 10) are all factors which were identified in the previous section as affecting cost. Average well productivity is derived from the well productivities calculated for each pool in a given category. These values are averaged, weighting each by the share of reserves in that pool. For each pool, average well productivity is simply the mean of the productivities of all wells in that pool for which there are data. Taking Viking Sandstone as an example, well productivity falls with perfect consistency as cost rises to 60 cents per Mcf, and the trend continues to the one dollar level. Except for the greater values observed in the 40 to 60-cent range, depth remains within a fairly narrow band. Productivity thus emerges as the predominant cost-determining factor, not surprising in light of the way the calculations are made. In the highest cost categories, pool sizes tend to be very small. Here scale effect relating to one-well indivisibility can lead to very high estimates of cost.

While the inverse relation between well productivity and cost was the most prominent one observed over the formations that were examined, depth and size effects may explain particular comparisons. A fact that must also be borne in mind is that the size measure differs from the other two in that individual pool values bear equal weight (unlike the size-weighted averages computed for productivity and depth). Consider, for example, in Table 3.1(a) that the inverse relation between productivity and cost appears to be violated when one reaches the 70 to 80-cent category. Average (weighted) well productivity is about the same as that of the 40 to 50-cent category, and average (weighted) depth is substantially less. The higher costs must, therefore, result from the much lower reserves per pool in the 70 to 80-cent category, which brings about for many of the pools the diseconomies of the underutilized single well. As a further example, note that the $1.20 to $1.30 category displays higher average poductivity than those preceding it. However, it is somewhat deeper; also, except for the immediately preceding category, it comprises smaller pools hence, the lumpiness effect again.

Table 3.1 provides some information about the production status of the pools in the different formations. Column 6 records the percentage share of pools never in production and Column 7 records those pools which began producing only after January 1, 1976. Higher cost pools could only have been profitably placed on production after wellhead realizations rose to levels that covered cost. When this happened there may still not have been opportunities to market the gas.

The cost figures in Table 3.1, expressed in 1980 dollars, may be compared to the returns that have been available to producers of natural gas in Alberta. Table 3.2 shows breakeven wellhead realizations, expressed in 1980 dollars, for the years from 1970 through 1980. This Table indicates, on average, the return available to cover development cost. The upward adjustment of the nominal values reflects the fact that capital and operating costs have escalated over the years. Thus a pool at the breakeven point in 1970, which would have had a development cost of 12.4 cents/Mcf, would have experienced a cost of 31.4 cents/Mcf in 1980 dollars.

Analyzing the production status of pools in a formation in light of price-cost circumstances provides a means of testing the reasonableness of the estimated costs. For example, one would expect that pools whose development costs are relatively high would be more likely to have been placed in production in the latter part of the 1970 to 1980 period, given the substantial increase in wellhead realizations. This type of analysis must, however, be restricted to general trends rather than being pool-specific. For example, the estimated wellhead realizations in Table 3.2 are net of gas processing costs, which were computed as an Alberta average. Therefore, where specific pools contain gas with a high sulfur content, this gas could be less valuable than indicated by the reported realization.

Furthermore, it should be reiterated that thus far primary attention has been devoted to the <u>variation</u> in costs attributable tn physical factors. With regard to the <u>level</u> of costs, the reported figures are probably low. For example, no allowance has been made for gathering costs. Perhaps more important, as discussed in Appendix A, the ratio between initial planned well productivities and AOF test results that was used was high relative to the estimate of industry experience; a more conservative assumption would raise the cost estimates significantly.

Information for analyzing the production status of pools is collected in Table 3.3. One would expect to observe a tendency for the percentage share of pools never in production to rise with higher cost categories. Very low cost pools would always have been economic to bring into production. However, some of these may only have been discovered in later years, so that they could only have been placed in production after 1976 or they may have yet to produce. The higher cost pools -- for example, categories between 60 cents and $1.40 -- would only have become economic to develop after 1974. Pools with development costs higher than $1.40 have always been only marginally economic.

Taking the figures for Viking as an illustration, the pattern of production status by cost category is generally as expected. Just twelve percent of pools in the 0 to 20 cent cost category have never been placed in production, while forty-two percent of pools in the highest cost category, greater than $1.40, have not been placed in production. Sixty-seven percent of pools with development costs in the category 60 cents to $1.00 were either placed in production only after 1976 or still awaiting producing status; the figure was about the same for pools in the $1.00 to $1.40 category.

Apparent anomalies appearing in Table 3.3 raise questions. As already noted, some low or intermediate cost pools may never have been produced because they were recent discoveries. There may not have been time to develop them, or there may not have been markets to justify development. One might wonder, however, why some intermediate cost pools (60 cents to $1.00, $1.00 to $1.40) were in production before 1976, or why pools with costs greater than $1.40 have ever been placed in production. There are several possible explanations. First, the allowance for sunk costs in one-well pools may be too small; where the actual incremental cost of placing a discovery well in production was low, it may have been worthwhile to produce a pool identified here as high cost. More generally, factors other than those taken into account may have affected costs for particular pools. For example, a pool may have been conveniently located for drilling operations or economies of scale may have been gained in a pool where a number of development wells were required. In either case the calculated cost would have been overstated.

Finally, there is uncertainty about reporting conventions; if small quantities of gas were produced for test purposes and then a well was shut-in, it may still have been classified as having been on production.

The discussion of development cost estimates for pools within a formation has been carried out with reference to Viking Sandstone, Mannville, and Rundle formations, but some comments should be made regarding the twenty-one zones for which results are reported in Appendix B. As shown in Table 3.4, the bulk of Alberta's reported reserves are found in a relatively small number of formations. Eighteen of the 21 zones described in Appendix B are part of the group comprising the largest twenty zones in Alberta; this group accounts for over 70 percent of reported reserves. Two zones in thhs group have not been included because of lack of data. These are Seags and Milk River and Medicine Hat. The latter because of its importance, will be discussed separately. The remaining three zones for which figures are given in Appendix B were included in the analysis inadvertently, but have not been discarded.

The results reported in Appendix B for the twenty-one formations generally display the features described for Viking Sandstone, but there are some differences. Consider first the similarities. Number of pools and mean size of pool usually decrease as cost rises. With regard to production status, the pattern across cost categories for the share of pools not on production is similar to that described for Viking. The same is true for the share of pools first produced in 1976 or later. The interplay of physical factors which determine unit cost also parallels that described for Viking. Average (weighted) productivity within a formation quite clearly declines as cost rises, while depth shows no consistent trend. Cost differences between particular categories can be explained when productivity, depth, and size are all taken into consideration. For example in Colony, the $1.00 to $1.25 category shows very high productivity and shallow depth, but the pool size is a much lower than previous categories. The same thing occurs in Wabamun, where the $1.25 to $1.50 category shows high productivity and low depth, and again mean pool size is very small.

Some interesting differences do appear among the formations described in Appendix B. For one thing, there is considerable variance in the degree to which the data set accounts for the reserves credited to particular zones by the AERCB (reported in Table A.2). Turning to differences in the physical features among formations, there are some that contain only a few large low-cost pools, for example, Beaverhill Lake. Then there are some formations where large volumes of gas at relatively high cost are counter to the usual pattern. Two examples are Bluesky Gething, which has a 74 BCF pool at $2.85, and Upper and Middle Viking, for which 1.98 TCF of reserves in commingled pools appear at $0.50; the data set shows a total of three pools for Bluesky Gething and five for Upper and Middle Viking. Of obvious interest is how average costs may vary among formations, but these comparisons will be deferred until the discussion of aggregate supply.

Figures 3.1 (a,b,c) are plots of pool development cost against cumulative reserves for Viking Sandstone, Mannville, and Rundle formations. In each case pools have been grouped to provide a convenient number of points. In the initial (lower left) portion of each curve a few very low-cost, very large pools make the curve appear nearly horizontal. Over the range from about 20 to 60 cents the curves rise rather rapidly. After this range they rise sharply. Of the three formations, Viking Sandstone displays the most pronounced intermediate range (the largest relative increase in reserves in the 20 to 60-cent cost range). On the other hand, for Rundle the increment of reserves in this range represents a very small share of total reserves present. The curves for these three formations are representative of those that would be observed if costs for the other formations reported in Appendix B were plotted in similar fashion.

A more precise description of the relation between incremental initial reserves and price, as depicted in Figure 3.1, is obtained by calculating elasticity values. Elasticity is defined in this instance as the percentage increase in reserves corresponding to a given percentage increase in wellhead realization. Results for the three formations under consideration are shown in Table 3.5.

The pattern of elasticity values for successively higher cost ranges is consistent for the Viking Sandstone, Mannville, and Rundle formations. In each case the price elasticity with respect to total reserves exceeds unity for the lowest cost category, under 20 cents, where most of the initial reserves are found. The elasticities tail off very rapidly, and are very low for cost categories above 60 cents. Again, however, it must be cautioned that the absolute level of these costs may be lower than in reality, and that it is the reserves with costs less than about 60 cents that we believe represent a reasonably unbiased sample of reality, whereas the reserves in higher cost categories were underrepresented in the AERCB data files in 1980.

So far the pool development cost estimates have been grouped by formation, showing how the cumulative stock of reserves increases as successively higher cost categories are included. The aggregate stock of reserves, summing across formations, is next considered. To do this incremental reserves of the lower cost formations are combined with incremental reserves attributable to pools in formations with higher costs. This is accomplished by summing reserves for each cost category, a process known as horizontal addition.

Table 3.6 has the same format as Table 3.1 and the tables in Appendix B. It reports reserves by five-cent cost categories when the data for the twenty-one formations which have been studied are combined. The same patterns occur in Table 3.6 as were typically seen for single formations. In particular, mean size of pool (Column 10) falls rapidly with higher costs, and beyond the first few cost levels number of pools per category (Column 5) also declines. The result is a steep drop in incremental reserves additions as successively higher cost levels are attained. One interesting exception is observed, the large incremental addition of reserves in the 50 to 55-cent category.

When one examines in Table 3.6 the cost figures and the averages which describe the physical determinants of cost, the relationships observed within formations again apply, though with some qualification. Average well productivity (Col. 8) declines sharply with rising costs. Mean pool size rapidly becomes quite small with the exception noted in the 50 to 55-cent range. Again depth shows great variation. It is notable, however, that average depths for pools in the very lowest cost categories are greater than anywhere else. This is offset by the extremely high productivities. On the other hand, there is a discernible tendency for average depths to be relatively low in the highest cost categories shown in the table. Very low well productivities, in the $1.25 to $1.50 cost range, can only be sustained where wells are shallower, hence cheaper.

When one next examines the information in Table 3.7 relating to the production status of pools in the aggregated data set, the broad trends are similar to those described for Viking Sandstone, and probably for the same reasons. Consider first the share, by category, of pools which have never been on production. For costs under 20 cents/Mcf it is 11 percent. In categories between 20 cents and $1.40 it averages about 25 percent. With costs above $1.40 it is 40 percent. As expected, the shares of pools never produced are larger at higher cost levels. For costs in the 60-cent to $1.00 range 82 percent of the pools observed either were placed in production subsequent to 1975 or have never been produced; the corresponding figure for the $1.00 to $1.40 range is 79 percent. One would not have expected to observe a large share of these pools in production prior to 1976.

For aggregated Alberta data as for a particular formation, the critical economic question is what potential incremental volumes of reserves become available as price (wellhead realization) rises. Again the reserves potential curve format is utilized, plotting pool development costs against cumulative initial established reserves. The result is shown in Figure 3.2.

The shape of the curve in Figure 3.2 appears much the same as the shape of the curves representing individual formations. An initial phase can be distinguished which is nearly horizontal. This is followed by a more steeply rising intermediate phase. Finally the curve rises nearly vertically. A description of the availability of initial reserves for the twenty-one formations using the elasticity measure is provided in Table 3.8. The elasticity with respect to supply price (development cost) follows a pattern similar to that observed for individual formations. It exceeds unity in the lowest cost range of between 1 cent/Mcf and 20 cents/Mcf but declines to 0.19 in the range of costs from 20 cents to 60 cents.

Closer examination of Figure 3.2 does reveal a feature not observed in the individual formation supply curves. There is a pronounced flat region at about the 50-cent level. This represents the gas (nearly 2 TCF) in the commingled pools of the Upper and Middle Viking formation. Were it not for a gap in the data set, a second plateau would be conspicuous in Figure 3.2, one considerably larger than the one which appears at the 50-cent level; this would represent the Milk River and Medicine Hat zone. It was not possible to match reserves figures with AOF data for this formation, and the AOF figures themselves have been questioned.

For the formations included in this study, the predominant pattern has been for the bulk of reserves to be producible with unit development costs of less than 24 cents. Viking Sandstone, Mannville and Rundle are typical. On the other hand, there are exceptions, formations with significantly higher threshold values, as just illustrated by Upper and Middle Viking and by Milk River and Medicine Hat. In connection with the apparent similarity of cost levels among most formations, it should be recalled that some factors known to have a bearing on cost could not be dealt with in this analysis. Two examples are sulfur content and cost differentials relating to location. These would generally affect entire formations, so that their inclusion would introduce differences among cost levels. With regard to the two formations cited as exceptions, the apparent cause of higher cost is substantially lower deliverability; Medicine Hat and Milk River has been described as borderline between conventional and tight gas.

The formations which have been studied are characterized by their average development costs in Table 3.9. They are listed in order of increasing cost. Specifically, the average cost figure is computed by weighting the unit cost for an individual pool by that pool's share of total reserves in the formation. Pools with unit costs above $1.50 per Mcf are excluded from these averages. For six of the formations this weighted average cost is five cents or less. The highest cost among the first twenty formations is Cardium at 27 cents. The "exception", Upper and Middle Viking, shows a weighted average development cost of about 50 cents. Again, well productivity and depth are identified as principal cost determinants. Weighted average values for these are shown in Columns 4 and 5, respectively. The cost figures reflect the interplay of the inverse relation with productivity and the direct (and nonlinear) relation with depth.

The empirical results which have been presented have related cumulative initial established reserves to development cost. Estimation of the reserves potential of Alberta is beyond the scope of the study, since reliance has been placed on reserves statistics and no forecasting of future discoveries or reserves appreciation was attempted. However, the sketch in Figure 3.3 endeavors to relate the study results to the possible reserves potential situation. The shape of the curve is that dictated by the observed results up to the 60 cents/Mcf level; beyond that the curve is judgmental and even speculative.

In Figure 3.3, up to the 60-cent range the reserve price elasticity falls from being greater than 1.0 at cost levels below 20 cents, to being about 0.2 for the cost range between 20 cents and 60 cents. Beyond the 60-cent cost level the sample data relates in large measure to shut-in pools which correspond to the more than 10,000 shut-in gas wells with minimally assigned reserves that now exist in Alberta. It is estimated that the 9.5 TCF of Milk River and Medicine Hat reserves, which were not covered in the sample, would fit into the reserves potential curve at costs ranging from a few cents upwards to about $1.60 and perhaps somewhat higher.

4. INTERPRETATION OF RESULTS

The curves which have been derived for individual Alberta formations relating stocks of initial established reserves to development cost (capital and operating) tend to be relatively flat, that is, to be confined to a narrow cost range. Specifically, although the simplified costing techniques used in this study may bias the cost results towards excessive uniformity, it seems clear that for most formations the reserve price elasticity is high in the lowest twenty-cent range of development cost but falls rapidly at supply prices beyond that range. This indicates that reserves potential curves for a given formation resemble the shape hypothesized in Figure 2.1(b) more closely than the shape in Figure 2.2(b). These results mean that once a threshold realization has been attained, a large share of the discovered pools in a formation becomes economic to produce with little further incease in field value. Moreover, these pools contain a disproportionately large share of the reserves in the formation.

Given the number of factors which influence development cost, considerable variation in observed costs might be expected. Moreover, the key cost determinant, average well productivity (or deliverability), assumes widely differing values for pools within a formation. In fact, considerable variation is observed in costs, but one point is noteworthy. Because of the apparent correlation between deliverability and pool size, costs or the bulk of reserves in a formation fall in a fairly narrow range. It should be noted that the study deals only with conventional gas, so that pools with extemely low deliverabilities (resulting from permeabilities of less than 0.1 millidarcy) are excluded. Potential reserves in the unconventional category exist in the tight formations of the Deep Basin, while reserves in the Medicine Hat and Milk River formation fall on the borderline between the two categories.

An implication of these results is the support provided for the validity of the more widely accepted discovery process models. These models,[1,2] with few exceptions, rely on measures of size, such as proved reserves, which are only established when development takes place. While the larger pools, as postulated in these models, may be found first, it is not evident *a priori* that they would always have sufficiently low development costs to warrant immediate exploitation. Until such time as they were developed and credited with reserves they might escape observation. In this situation, when prices were rising, discovery process models would understate the potential of formations. The empirical results here suggest that this form of bias is not usually serious.

The significance of the cost structure that has emerged from this study for predicted reserves additions attributable to new pools in an established formation can be emphasized with reference to the polar situations described in Figures 2.1 and 2.2. Figure 2.1 depicts the extreme case where reporting error would least affect the results of discovery process models. The pools likely to be ignored because reserves were not reported would be predominately very small. The observed distribution of pool sizes would be too low toward the left (small pool) side. Thus, although more small pools would actually be found than had been forecast, the additional contribution to reserves would be limited in amount. On the other hand, if a situation approaching the extreme case of Figure 2.2 had been observed, reporting error might result in substantial bias in the forecasts of reserves to be gained from new pools. Since high-cost pools, omitted from the data set, might be of any size, the comparison between the true size distribution and the one perceived when prices were low would be that portrayed in Figure 2.1(b). With higher prices, additions to reserves from new discoveries might be very substantial.

The further significance of the observed cost structure for policy purposes is that increases in wellhead realization may trigger development of new gas-bearing formations and thereby possibly make available large quantities of additional reserves. The quantity of reserves created when significant new pools in a formation like Upper and Middle Viking becomes economic appears substantial in comparison with the combined volume of reserves additions from established formations which might be attributed to higher wellhead realizations.[3] The potential of a new formation will, however, be difficult to forecast at an early date. Discovery process models cannot be applied until a body of information established by wildcat drilling has been accumulated. Furthermore, though perhaps not so obvious, reserves data for pools which have been discovered will not be reliable until development drilling has proceeded, and this usually is contingent upon actual or imminent production.

Aggregate supply comprises the summation of supplies from individual formations. This study was organized around the concept of pools grouped by geological formation, and hypotheses were advanced regarding the shape of formation reserves potential curves. The existence of a typical shape was based on the premise that, within a formation, cost and quantity-determining parameters would vary in systematic fashion, in accord with geological patterns. By contrast, there does not appear to be any basis for expecting systematic variation in the characteristics of formations over regions such as Alberta. Therefore, there is no basis for *a priori* hypotheses about the shape of the aggregate supply curve. It must be established empirically, formation by formation.

Many geologists and engineers believe that dramatic increases in reserves are possible from new formations. The analysis here does suggest that while development costs for conventional gas are contained in a relatively narrow band, development costs for new formations will be significantly higher. This is because -- although some new formations of the conventional sort will continue to be found (for example, the Elmworth Wapiti field, a "sweet spot" in the Deep Basin) -- the giant structures now known or predicted are markedly different (unconventional) in respect to the physical features which determine deliverability. Hence such formations only become economic to develop at higher threshold wellhead realizations.

The finding of relatively uniform unit development costs within formations suggests a method for approaching the analysis of aggregate supply. The observed cost behavior has two important implications. First, it is much easier to estimate a cost level than to develop and estimate a model which describes cost variation within a formation. Second, the application of existing discovery process models to establish quantities can be justified as has already been discussed. Hence the analysis would proceed by individually analyzing newly emerging formations, both as to cost level and potential volume of reserves. The number of formations that are the object of exploratory interest at any time is small enough for this procedure to be feasible. Indeed, it is possible that cost similarity would justify grouping formations within a horizon. When data describing Mannville horizon (a broader geological grouping comprising a number of formations) are aggregated in Appendix D, the resulting cost pattern resembles that of an individual formation.

Footnotes to Section 1

1. M.A. Adelman and J.C. Houghton, in M.A. Adelman, et al, Energy in an Uncertain Future: Reserves and Resources of Oil, Gas, Coal and Uranium (Ballinger Press, forthcoming). These authors list five sources of increased output. In the list below, which refers to stocks, Item (a) replaces two of their categories, increasing the rate of production from existing wells and drilling more wells to increase the rate of output of producing pools. They regard the Items (c) and (d) of the above list as "in the long run, far more important," relative to the others.

2. See, for example the work of R.G. McCrossan "An Analysis of Size Frequency Distribution of Oil and Gas Reserves of Western Canada," Canadian Journal of Earth Sciences, 6 (1969), 201-211, or Kaufman, Balcer and Kruyt ("A Probabilistic Model of Oil and Gas Discovery," in Studies in Geology No. 1, The American Association of Petroleum Geologists, 1975).

Footnotes to Section 2

1. For example see, Canada, Minister of Energy Mines and Resources, An Energy Policy for Canada, Phase I, Vol. II, pp. 82-84.

2. Portions of this discussion are based on an earlier paper: P.G. Bradley and A. Hansson, "The Price Elasticity of Natural Gas Supply: A Look at Causes and Their Implications for Forecasting," presented to the North American meetings of the International Association of Energy Economists, Denver, Colorado, November, 1982.

3. This is because in estimating such models the only pool attribute to be considered in size, usually measured by reported reserves. If some large pools in a formation were, because of other attributes (for example, low productivity), so high cost to produce as to be uneconomic, they would not be assigned reserves and would not enter the data set. Reserves estimated for the formation would therefore be understated; reserves that would be available at higher wellhead realizations would have been ignored.

Footnotes to Section 4

1. R.S. Uhler, Oil and Gas Finding Costs, Canadian Energy Research Institute, Study No. 7, September 1979, especially Chapter 3. This work is expanded and updated by Uhler as part of the present Economic Council study.

2. G.M. Kaufman, cited in Footnote 1 of Section II. For a thorough review of discovery process modelling see Kaufman, "Estimation of Undiscovered Resources of Oil and Gas," in Adelman, et al, cited in Footnote 1 of Section I.

3. It should be noted that the reserves potential curve of Figure 2.1 exaggerates in this regard, since it depicts only development cost. Higher prices will stimulate exploration, leading to the discovery of pools in established formations where development costs are at traditional low levels. Such pools are likely to be small, but they could be numerous.

Table 3.1(a)

Initial Established Reserves By Cost Category*

Formation: Viking Sandstone

(1) Development Cost	(2) Average Cost	(3) Reserves	(4) Reserves, Cum. %	(5) Number of Pools	(6) Pools Not Produced %	(7) Pools Producing After 76-1-1, %	(8) Average Well Productivity	(9) Average Depth	(10) Reserves Per Pool
0- .10	.07	964	38.4	11	0	27	2027	3100	88
.10- .20	.15	523	59.2	32	16	13	678	3926	16
.20- .30	.25	247	69.0	28	7	32	429	4552	9
.30- .40	.32	275	80.0	25	20	36	376	5392	11
.40- .50	.45	228	89.1	26	27	31	300	6474	9
.50- .60	.56	64	91.7	18	33	39	195	3513	4
.60- .70	.64	45	93.4	17	35	35	209	3769	3
.70- .80	.73	11	93.9	11	0	55	290	3349	1
.80- .90	.82	14	94.4	10	30	50	166	2848	1
.90-1.00	.95	15	95.1	10	20	40	106	2507	2
1.00-1.10	1.05	22	95.9	10	40	50	107	3219	2
1.10-1.20	1.12	4	96.1	5	20	80	115	3410	.9
1.20-1.30	1.25	6	96.4	7	14	0	271	3812	.9
1.30-1.40	1.33	2	96.4	3	0	67	96	3238	.5
1.40-1.50	1.46	10	96.8	5	0	60	198	3725	2
> 1.50	3.51	80	100	50	46	44	50	2821	2

* Development Cost in $/Mcf produced, Reserves in Bcf.
For definitions and for other units, see notes.

Table 3.1(b)

Initial Established Reserves By Cost Category*

Formation: Mannville

(1) Development Cost	(2) Average Cost	(3) Reserves	(4) Reserves, Cum. %	(5) Number of Pools	(6) Pools Not Produced %	(7) Pools Producing After 76-1-1, %	(8) Average Well Productivity	(9) Average Depth	(10) Reserves Per Pool
0- .10	.06	574	53.9	29	0	28	1586	3575	20
.10- .20	.14	192	71.9	24	4	42	948	3545	8
.20- .30	.23	80	79.4	19	11	47	456	3537	4
.30- .40	.35	37	82.9	17	24	41	531	3651	2
.40- .50	.44	30	85.6	9	44	33	266	3490	3
.50- .60	.55	23	87.8	8	12	88	131	2623	3
.60- .70	.64	21	89.8	9	22	56	224	3682	2
.70- .80	.75	5	90.2	6	17	67	346	2924	1
.80- .90	.83	7	90.9	6	17	83	231	3291	1
.90-1.00	.97	4	91.3	4	50	50	107	3156	1
1.00-1.10	1.03	3	91.5	4	0	75	316	3172	.6
1.10-1.20	1.16	3	91.8	3	33	33	380	2786	.9
1.20-1.30	1.26	8	92.5	4	0	75	77	2296	2
1.30-1.40									
1.40-1.50	1.46	1	92.6	2	0	50	209	3271	.5
> 1.50	2.02	79	100	25	36	36	104	6454	3

* Development Cost in $/Mcf produced, Reserves in Bcf. For definitions and for other units, see notes.

Table 3.1(c)

Initial Established Reserves By Cost Category*

Formation: Rundle

(1) Development Cost	(2) Average Cost	(3) Reserves	(4) Reserves, Cum. %	(5) Number of Pools	(6) Pools Not Produced %	(7) Pools Producing After 76-1-1, %	(8) Average Well Productivity	(9) Average Depth	(10) Reserves Per Pool
0- .10	.05	3838	49.6	19	5	32	3936	9125	202
.10- .20	.14	2924	87.4	13	15	15	1938	10863	225
.20- .30	.28	302	91.3	2	0	50	403	5416	151
.30- .40	.33	551	98.4	5	60	20	946	11893	110
.40- .50	.47	7	98.5	2	100	0	317	9580	3
.50- .60	.55	6	98.6	3	67	0	1535	6644	2
.60- .70	.66	24	98.9	2	0	100	292	10453	12
.70- .80	.77	46	99.5	2	50	50	340	11093	23
.80- .90									
.90-1.00									
1.00-1.10									
1.10-1.20	1.14	20	99.8	1	100	0	268	11863	20
1.20-1.30									
1.30-1.40									
1.40-1.50									
> 1.50	1.95	19	100	3	33	33	104	8372	6

* Development Cost in $/Mcf produced, Reserves in Bcf.
For definitions and for other units, see notes.

Notes to Table 3.1 (by column number)

2. The average across pools in the category of unit development costs. Each pool cost figure is weighted by that pool's share of total reserves.

8. The average across pools of average well productivity. Each pool figure is weighted by that pool's share of total reserves. Units: MMCF per year.

9. The average across pools of pool depth. Each pool figure is weighted by that pool's share of total reserves. Units: feet.

Table 3.2

Breakeven Wellhead Realizations

	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980
(1) Wellhead Netback, $ / $10^3 m^3$	3.67	3.09	3.14	4.11	9.20	17.42	22.72	25.33	25.74	31.15	49.99
(2) Average Operating Cost, $ / $10^3 m^3$	.70	.86	1.00	1.27	1.59	2.39	3.64	4.58	6.17	8.26	10.69
(3) (1) + (2) Nominal Wellhead Realization, 8 / $10^3 m^3$	4.37	3.95	4.14	5.38	10.79	19.81	26.36	29.91	31.91	39.41	60.68
(4) (3) x 2.832 Nominal Wellhead Realization, ¢ / Mcf	12.4	11.2	11.7	15.2	30.6	56.1	74.7	84.7	90.4	111.6	171.8
(5) Industrial Selling Price Index	100.	103.	106.	119.	142.	156.	164.	178.	194.	222.	253.
(6) (4) x 253 / (5) Breakeven Wellhead Realization, ¢ / Mcf **in 1980 dollars**	31.4	27.5	27.9	32.3	54.5	91.0	115.2	120.4	117.9	127.2	171.8

Notes to Table 3.2 (by row number)

(1) "Wellhead price is estimated value of gas at the input side of the gas plant having taken into account coproduct values and gas plant processing costs. Netback is wellhead price less operating costs and royalties." Source: R.S. Uhler and P. Eglington, The Supply of Oil and Gas Reserves in Western Canada, An Interim Report to the Economic Council of Canada, April 1983, p. 26.

(2) Source: R.S. Uhler, personal communication.

(6) Breakeven Wellhead realization indicates, on average, the return available to the producer to cover development cost. Nominal values are lower than constant dollar values in the earlier years. The upward adjustment is made to account for the fact that costs were also lower. A pool at the breakeven point in 1970, with development cost of 12.4 cents Mcf, would have experienced a development cost of 31.4 cents per Mcf in 1980 dollars.

TABLE 3.3

Production Status of Pools by Cost Category

(a) Viking Sandstone

Development Cost (¢ / MCF)	Number of Pools in Production:* Before 1976	1976 or Later	Never	
0-20	31	7	5	
	(72)	(16)	(12)	(100)
20-60	44	33	20	
	(45)	(34)	(21)	(100)
60-100	16	21	11	
	(33)	(44)	(23)	(100)
100-140	8	11	6	
	(32)	(44)	(24)	(100)
>140	7	25	23	
	(13)	(45)	(42)	(100)

*Percentages given in parentheses

	Development Cost (¢ / MCF)	Number of Pools in Production: Before 1976	1976 or Later	Never	
(b) Mannville	0-20	34 (64)	18 (34)	1 (2)	(100)
	20-60	16 (30)	26 (49)	11 (21)	(100)
	60-100	3 (12)	16 (64)	6 (24)	(100)
	100-140	3 (27)	7 (64)	1 (9)	(100)
	> 140	8 (30)	10 (37)	9 (33)	(100)
(c) Rundle	0-20	21 (66)	8 (25)	3 (9)	(100)
	20-60	3 (25)	2 (17)	7 (58)	(100)
	60-100	0 (0)	3 (75)	1 (25)	(100)
	100-140	0 (0)	0 (0)	1 (100)	(100)
	> 140	1 (33)	1 (33)	1 (34)	(100)

TABLE 3.4

Cumulative Share of Initial Marketable Gas by Formation

Number of Formations*	Share of Initial Marketable Gas
5	.385
10	.536
20	.705
30	.806
40	.864
50	.905
100	.980
230	1.00

*Arranged in descending order by reported volume of Marketable gas.

TABLE 3.5

Elasticity[1] of Initial Reserves Stocks with respect to Development Cost

	Cost Range (¢/MCF)	Elasticity	No. of Pools
(a) **Viking Sandstone**	4 - 20	1.46	43
	20 - 60	0.43	97
	60 - 100	0.07	48
	100 - 140	0.04	25
(b) **Mannville**	2 - 20	1.28	53
	20 - 60	0.20	53
	60 - 100	0.08	25
	100 - 140	0.04	11
(c) **Rundle**	1 - 20	1.11	32
	20 - 60	0.12	12
	60 - 100	0.02	4
	100 - 140	< 0.01	1

Notes to Table 3.5

1. Elasticity is defined as the ratio of percentage increase in initial reserves stocks to percentage increase in development cost,

$$\left(\frac{\Delta R}{R_{avg.}}\right) \Big/ \left(\frac{\Delta C}{C_{avg.}}\right)$$

Table 3.6

(1) Development Cost	(2) Average Cost	(3) Reserves	(4) Reserves, Cum. %	(5) Number of Pools	(6) Pools Not Produced %	(7) Pools Producing After 76-1-1, %	(8) Average Well Productivity	(9) Average Depth	(10) Reserves Per Pool
0- .05	.03	13027	33.8	57	12	23	6267	8384	229
.05- .10	.07	9756	59.0	175	12	35	3014	7915	56
.10- .15	.12	3677	68.6	144	9	33	1508	7271	26
.15- .20	.16	4378	79.9	130	12	46	1154	7877	34
.20- .25	.22	673	81.6	105	10	50	517	3972	6
.25- .30	.27	1127	84.6	101	18	51	400	4591	11
.30- .35	.33	1113	87.4	93	20	44	693	8303	12
.35- .40	.36	427	88.5	93	25	47	381	4647	5
.40- .45	.42	265	89.2	73	29	51	341	5168	4
.45- .50	.47	332	90.1	79	29	41	336	5744	4
.50- .55	.50	2138	95.6	60	22	47	136	2220	36
.55- .60	.57	242	96.3	53	26	51	268	4105	5
.60- .65	.62	121	96.6	47	40	43	724	4753	3
.65- .70	.67	127	96.9	54	20	68	210	4542	2
.70- .75	.72	61	97.1	32	13	59	193	2920	2
.75- .80	.77	94	97.3	35	23	63	247	6789	3
.80- .85	.82	68	97.5	42	33	50	214	3337	2
.85- .90	.87	82	97.7	34	21	62	188	5416	2
.90- .95	.91	50	97.8	23	26	61	149	2737	2
.95-1.00	.97	54	98.0	24	38	38	129	3283	2
1.00-1.05	1.02	43	98.1	18	22	67	154	4998	2
1.05-1.10	1.08	28	98.1	18	39	44	156	5891	2
1.10-1.15	1.13	62	98.3	21	29	71	235	7048	3
1.15-1.20	1.17	39	98.4	16	38	50	131	5477	2
1.20-1.25	1.22	13	98.4	17	18	47	160	3564	.8
1.25-1.30	1.27	19	98.5	15	7	27	360	3395	1
1.30-1.35	1.33	31	98.6	14	21	64	61	2360	2
1.35-1.40	1.36	48	98.7	12	50	33	121	6974	4
1.40-1.45	1.42	14	98.7	11	27	55	269	3668	1
1.45-1.50	1.47	12	98.8	12	25	50	201	3398	1
1.50	3.12	482	100	216	41	40	101	4681	2

* See notes for definitions and units.

Notes to Table 3.6 (by column number)

1. Units: $ per MCF produced

2. The average across pools in the category of unit development costs. Each pool cost figure is weighted by that pool's share of total reserves.

3. Units: BCF

8. The average across pools of average productivity. Each pool figure is weighted by that pool's share of total reserves. Units: MMCF per year.

9. The average across pools of pool depth. Each pool figure is weighted by that pool's share of total reserves. Units: feet.

TABLE 3.7

Production Status of Pools by Cost Category:

Twenty-one Formations

Development Cost	Number of Pools in Production :*			
(¢ / MCF)	Before 1976	1976 or Later	Never	
0 - 20	268	181	57	
	(53)	(36)	(11)	(100)
20 - 60	202	313	142	
	(31)	(48)	(21)	(100)
60 - 100	52	161	78	
	(18)	(55)	(27)	(100)
100 - 140	27	68	36	
	(21)	(52)	(27)	(100)
> 140	46	99	94	
	(19)	(41)	(40)	(100)

* Percentages given in parentheses

TABLE 3.8

Elasticity[1] of Initial Reserves Stocks

with respect to Development Cost:

Twenty-one Formations

Cost Range (¢/MCF)	Elasticity	No. of Pools
1 - 20	1.11	506
20 - 60	0.19	657
60 - 100	0.04	291
100 - 140	0.02	131

Notes to Table 3.8

1. Elasticity is defined as the ratio of percentage increase in initial reserves stocks to percentage increase in development cost,

$$\left(\frac{\Delta R}{R_{avg.}}\right) \Big/ \left(\frac{\Delta C}{C_{avg.}}\right) .$$

Table 3.9

	(1) Formation Name	(2) Average Unit Cost ($1Mcf)	(3) Number of Pools	(4) Volume of Reserves (BCF)	(5) Well Productivity (MMCF/Yr.)	(6) Pool Depth (Ft)
1	Rundle	.04	52	7609	2780	9858
2	Rundle Wabamun	.04	1	1727	6908	10974
3	Wabiskaw Wabamun	.04	2	860	1480	2185
4	Leduc	.04	43	6626	7530	10107
5	Beaverhill Lake	.045	4	2200	6520	11522
6	Elkton	.05	12	978	4745	8048
7	Mississippian	.12	7	671	2913	9284
8	Pekisko	.13	39	1469	1921	6500
9	Shunda	.14	3	91	986	7052
10	Wabamun	.15	78	2050	1481	7563
11	Mannville	.16	171	983	1187	3526
12	Debalt	.17	19	185	1035	3116
13	Colony	.19	191	740	698	1726
14	Glauconitic SS	.19	107	1459	993	5331
15	Bluesky Gething	.19	5	81	266	1012
16	Bow Island	.22	115	675	708	2649
17	Viking	.23	268	2423	1079	4027
18	Upper Mannville	.23	417	1757	790	2899
19	Lower Mannville	.24	263	1469	756	3790
20	Cardium	.27	28	551	1236	7819
21	Upper and Middle Viking	.50	5	2003	128	2087

* Explanatory notes on following page.

Notes to Table 3.9

Formations are ordered by estimated development cost.

The remaining notes refer to column number in the table.

2. The average across pools of unit development costs. Each pool cost figure is weighted by that pool's share of total reserves. Total reserves comprise those pools in the data set for which unit costs are less than $1.50 per MCF.

3. The number of pools contained in the date set.

4. The reserves represented in the data set.

5. The average across pools of average well productivity. Each pool figure weighted as in #2; same coverage as in #2.

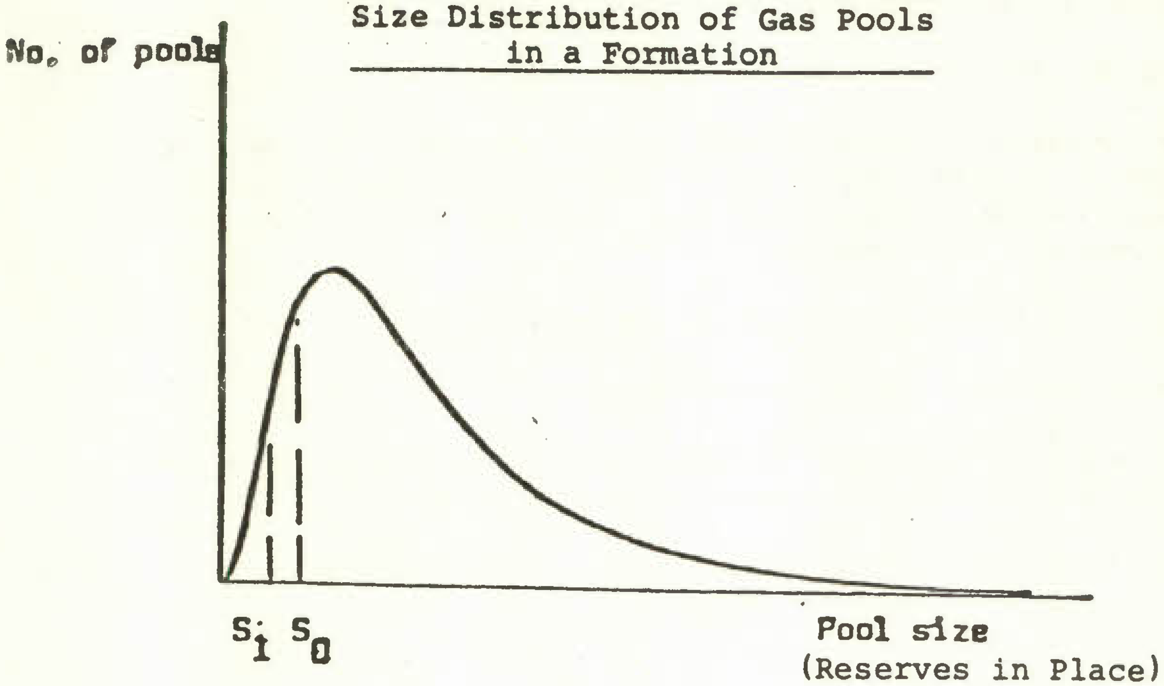
6. The average across pools of pool depth. Each pool figure weighted as in #2; same coverage as in #2.

Figure 2.1

Alternative Cost Structures (I)

(a)

Size Distribution of Gas Pools in a Formation



(b)

Gas Reserves Potential Curve

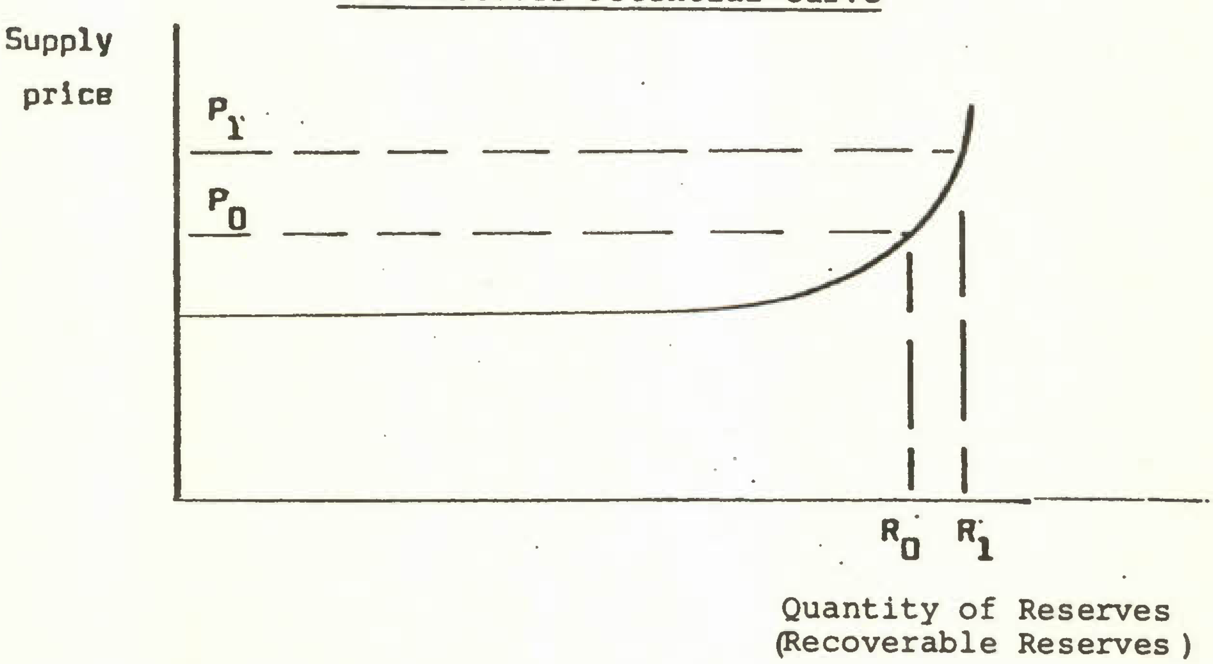
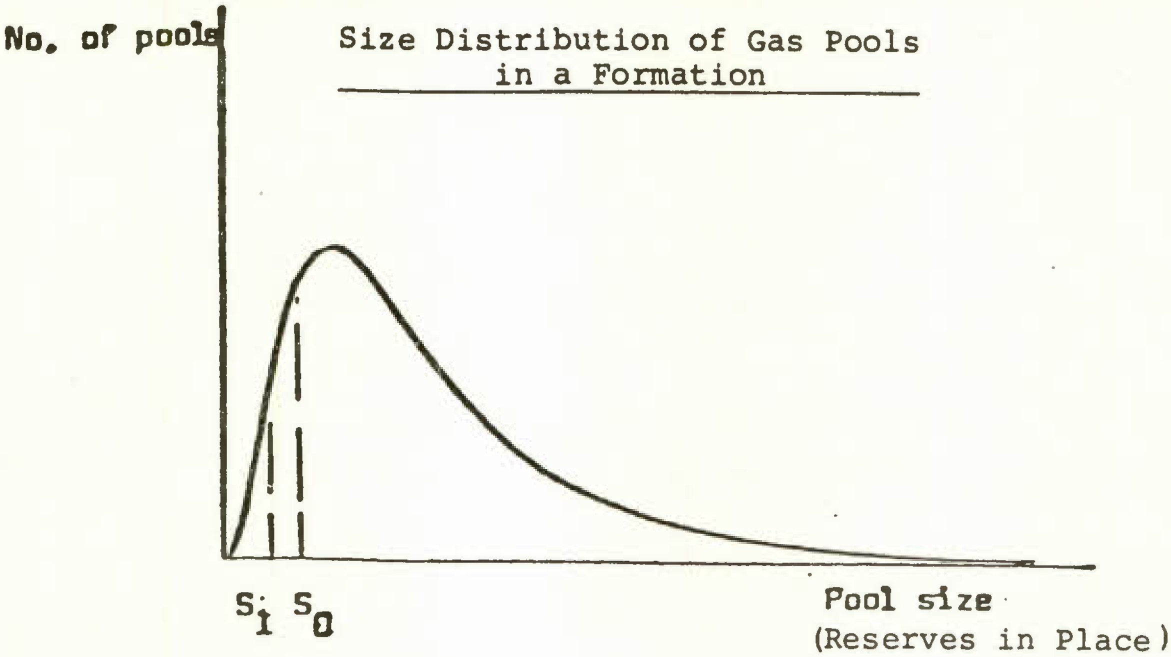


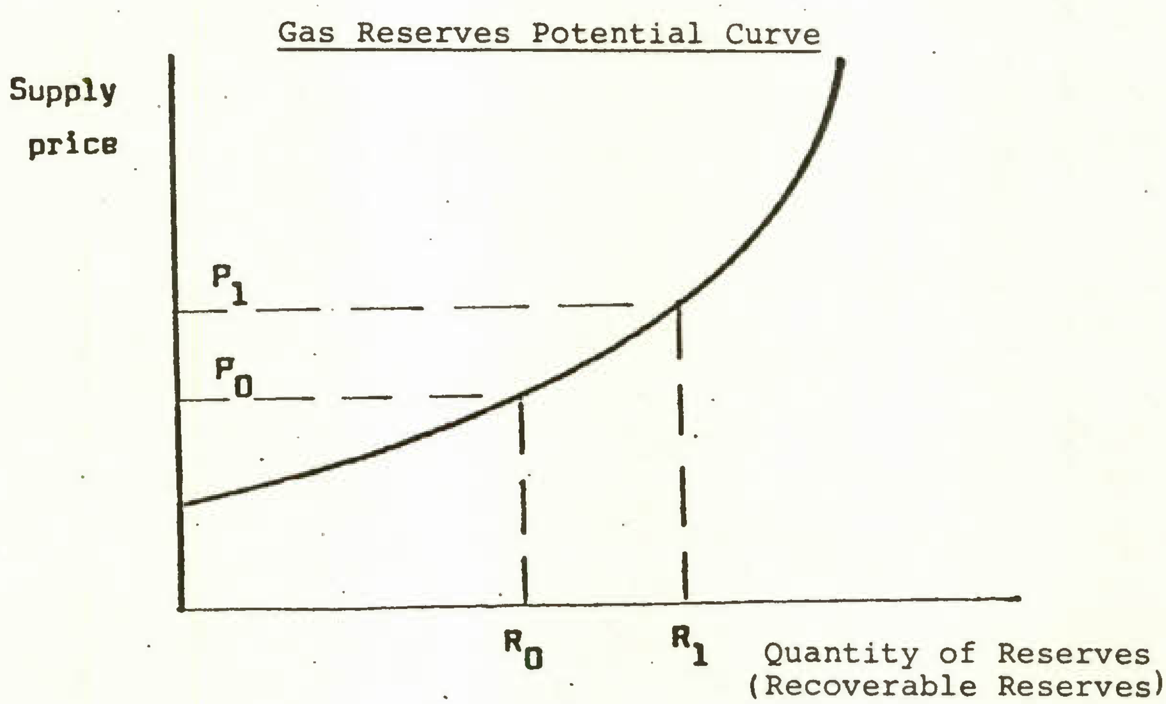
Figure 2.2

Alternative Cost Structures (II)

(a)



(b)

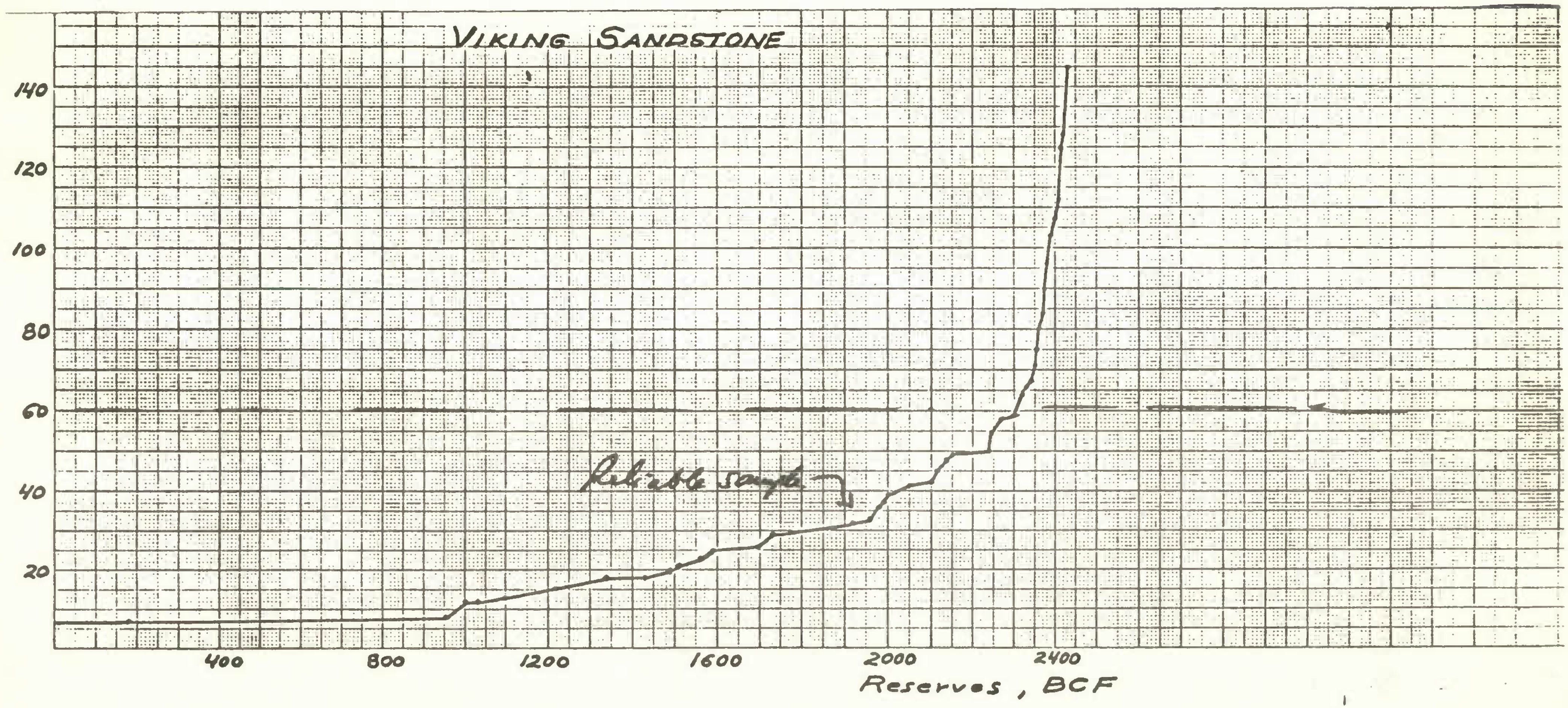


Cost, ¢/Mcf Produced

FIGURE 3.1(a)

Initial Established Reserves

At Development Cost



Cost, ¢/Mcf Produced

FIGURE 3.1(b)

Initial Established Reserves

At Development Cost

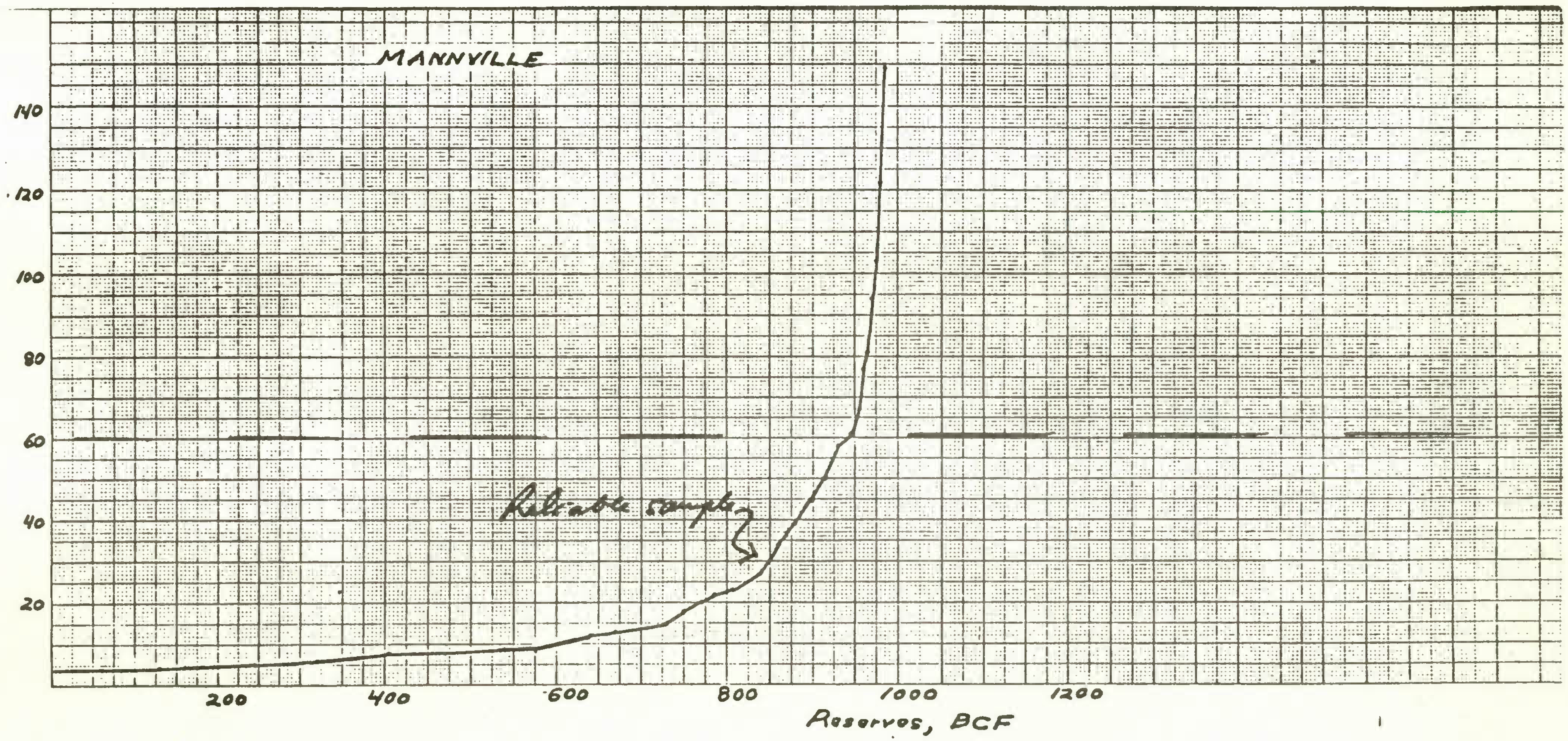
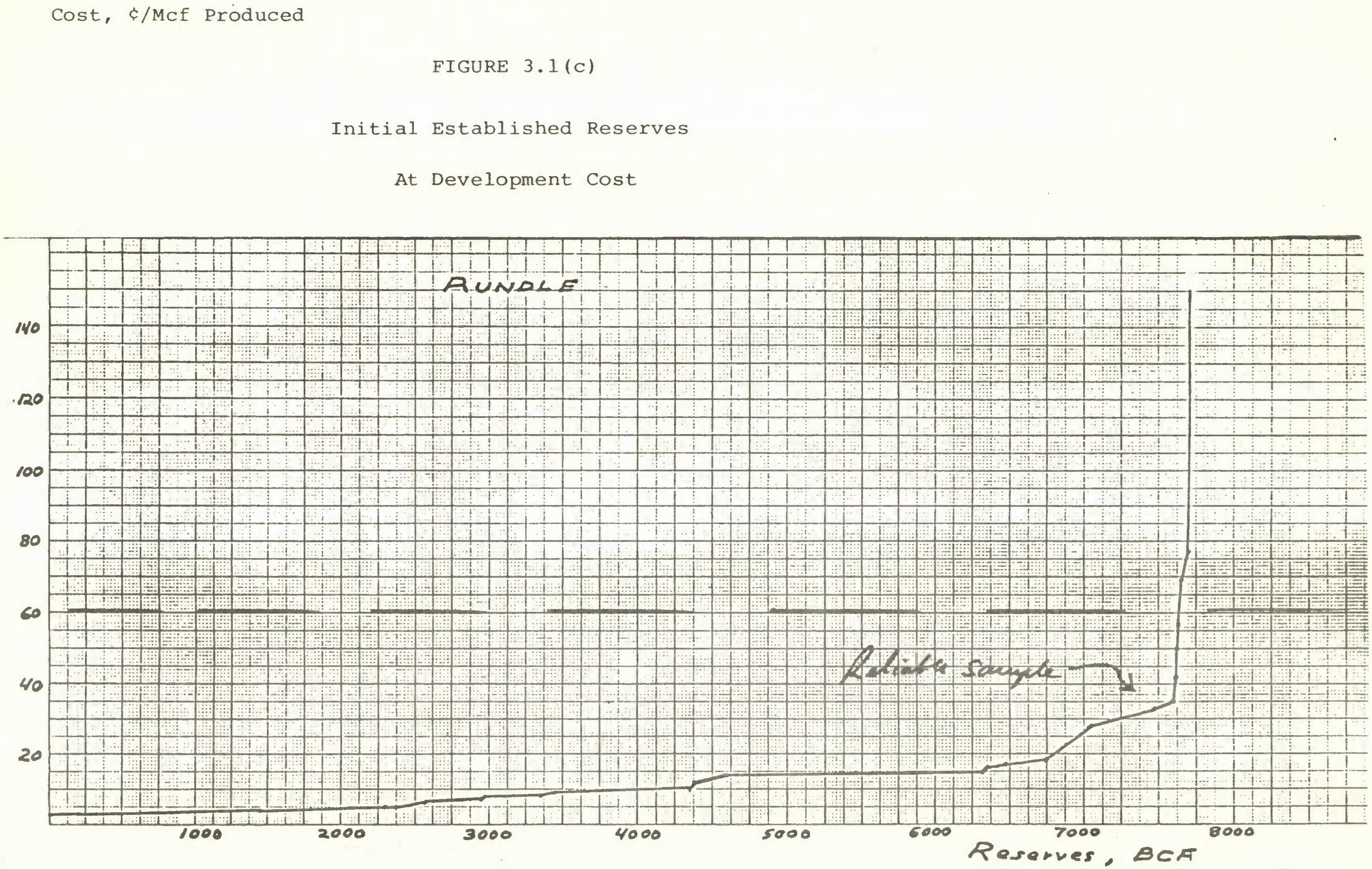


FIGURE 3.1(c)

Initial Established Reserves

At Development Cost



Cost, ¢/Mcf Produced

FIGURE 3.2

Initial Established Reserves

At Development Cost

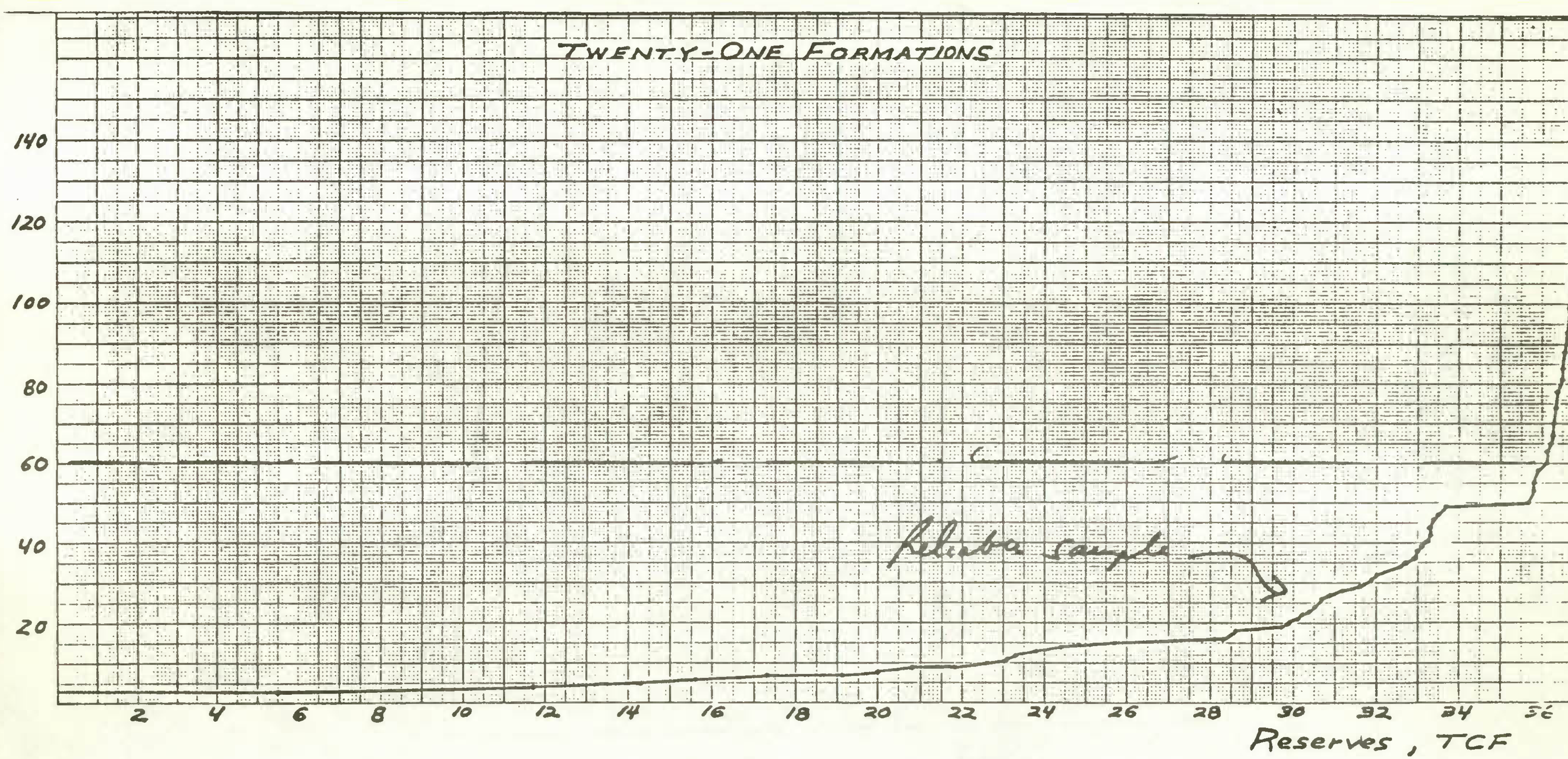
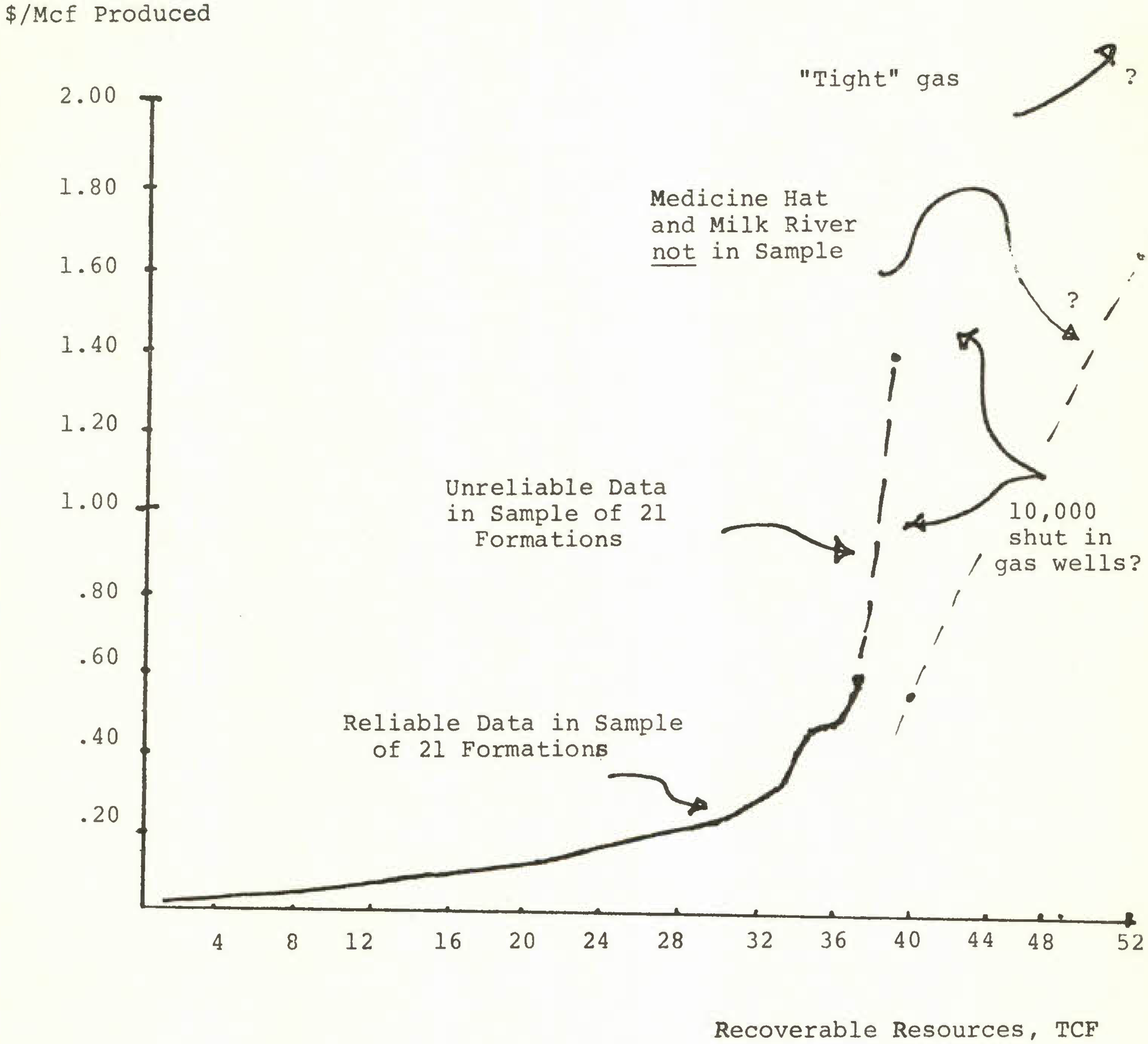


FIGURE 3.3

Approximate 50% Sample of

Possible Reserves Potential Curve for Alberta

(Initial Reserves at Development Cost based on 1980 Data)



APPENDIX A

COSTING METHODOLOGY AND DATA

COST ESTIMATION

A procedure for estimating development costs for natural gas must be selected in light of available data. While industry expenditures in the aggregate are reported by the Canadian Petroleum Association, there is no systematic reporting which breaks down the totals on a field or pool basis. Accordingly, it is necessary to estimate expenditures based on the physical characteristics of a pool. Furthermore, it is useful to have a figure for the cost of producing gas which is directly comparable to actual or expected wellhead realizations. Such a cost figure is derived using estimated expenditures in conjunction with an output forecast. Development cost, as defined here, represents the dollar amount per unit volume of gas produced that must be received in order to recover all the expenditures incurred in the production of that gas, including cost of capital. It is expressed in units of dollar per Mcf produced.

Production from a known pool requires completion of the exploratory well and, where the pool is large, the drilling and completion of additional production wells. Also, surface equipment must be installed on the leasehold. In addition to investment in capacity, operating outlays must be accounted for. The predicted operating expenditures are discounted over the productive life of the pool, and the resulting amount is treated as another investment component. Raw gas must be processed, but processing costs have not been included in the figures reported here. Information has not been compiled which would make it feasible to determine possible access to existing processing facilities, and no attempt has been made to analyze the manner in which clustering of small pools might permit joint use of a large new procesing plant. Consequently, the estimated development costs are compared with wellhead realizations net of a province-wide average processing charge.

LEVELIZED UNIT COST

The measure of development cost used here can be thought of as the attribution of a cost to each unit volume of gas produced, such that when the production plan is fulfilled all investment will have been repaid. This cost measure finds application in the engineering literature where it is sometimes referred to as levelized unit cost.[1] It is calculated by dividing the present value of expenditures (investment) by the present value of physical benefits, in this case the gas produced:

$$C = \frac{I}{Q_o b_{\overline{t|}r}} \qquad (1)$$

where I = total investment cost (present value of required expenditures),

Q_o = initial producing capacity

$b_{\overline{t|}r}$ = a factor which specifies the present value of output (over the period of production) per unit of initial capacity.

The subscripts to the b-factor denote that it depends upon the level of output at time t relative to initial capacity and the rate of discount r.[2]

Closer examination of Eq. 1 will show how certain physical features affect unit development costs and will make explicit some assumptions which have been used. It will be convenient to resolve investment into its two components, the part related to capital expenditures (to provide capacity) and the part related to operating outlays (the capitalized value of the stream of operating costs). Thus Equation 1 becomes:

$$C = \frac{I_c + I_o}{\int_o^T Q_t e^{-rt} dt}$$

where I_c = capacity investment.

I_o = operating cost (capitalized),

Q_t = pool output at time t,

T = productive life of pool.

It is assumed that the output profile for a pool is defined by institutional and physical constraints, that is, is specified. In particular, a ratio of initial daily production to marketable reserves (1:7300) is assumed. Production is maintained at this rate for ten years, after which it declines at ten percent per year. The production period ends after twenty years.[3]

The b-factor, previously defined as the factor which specifies the present value of output per unit of initial capacity, is:

$$b_{\overline{t}|r} = \int_o^T \frac{Q_t}{Q_o} e^{-rt}\, dt \qquad (3)$$

The quantity of reserves required to support a unit of initial output (for example, one Mcf per day) can be specified using the b-factor where the rate of interest r is zero:

$$b_{\overline{t}|o} = \int_o^T \frac{Q_t}{Q_o}\, dt \qquad (4)$$

Letting R = the initial volume of marketable reserves:

$$Q_o = \frac{R}{b_{\overline{t}|o}} \qquad (5)$$

Thus, on the assumption that all reserves are produced during the 20-year span, initial output is determined, given the volume of reserves in a pool.

Now consider the principal physical determinants of unit capacity cost:

$$C_c = \frac{I_c}{Q_o b_{\overline{t|}r}} \qquad (6)$$

Capital investment refers to well-related expenditures, so that:

$$I_c = N\{q_o\}\, W\{d,\ell\} \qquad (7)$$

where $N\{q_o\}$ = the number of wells, a function of average well deliverability,

$W\{d,\ell\}$ = the cost of a well, a function of depth and location

Since the required number of wells is determined by average well deliverability once the initial output of a pool is determined:

$$N = \frac{Q_o}{q_o} \qquad (8)$$

Eqs. 6 and 7 yield:

$$C_c = \frac{NW\{d,\ell\}}{Q_o b_{\overline{t|}r}} \qquad (9)$$

Next consider the principal physical determinants of unit operating cost:

$$C_o = \frac{I_o}{Q_o \, b_{\overline{t}|r}} \, , \qquad (10)$$

Operating expenditure, E, is assumed to be dependent on number of wells, their depth, and the location of the pool. Where number of wells is constant at its initial value:

$$E = k\{d,\ell\} \, N \qquad (11)$$

$$I_o = \int_0^T k\{d,\ell\} N e^{-rt} dt$$

$$I_o = Nk\{d,\ell\} \, a_{\overline{t}|r} \qquad (12)$$

where $a_{\overline{t}|r}$ = the annuity factor with rate of interest r for a period $t = T$.

Eqs. 10 and 12 yield:

$$C_o = \frac{Nk\{d,\ell\} \, a_{\overline{t}|r}}{Q_o \, b_{\overline{t}|r}} \qquad (13)$$

The several physical features which are crucial in establishing the development cost of natural gas can now be summarized. Combining Eqs. 9 and 13:

$$C = \frac{N}{Q_o \, b_{\overline{t}|r}} \left[W\{d,\ell\} + k\{d,\ell\} \, a_{\overline{t}|r} \right] \tag{14}$$

Eq. 14 is used in conjunction with Eqs. 5 and 8:

$$Q_o = \frac{R}{b_{\overline{t}|o}} \tag{5}$$

$$N = \frac{Q_o}{\bar{q}_o} \tag{8}$$

Average well productivity is a very important factor, acting through Eq. 8. As can be seen from Eq. 14, depth affects unit cost because it costs more to drill and operate deeper wells. Pool location also affects unit cost. In the estimates to be reported depth is taken into account but not location. Pools have been classified by Potter-Liddel area, but information on relative drilling and operating costs has not been obtained.

Required investment per well, (W + Ka) in Eq. 14, may be subject to economies of scale when larger pools are developed.

Gathering lines and surface equipment costs are subject to the type of economies commonly experienced in chemical processing. Drilling costs can be reduced when numerous wells are drilled in the same area. Account has not been taken of scale economies of this sort, which would be reflected in reduced unit development costs. It should be mentioned that pool size is critical in the usual methods of allocating finding costs, but finding costs are not of concern here.

Pool size does, nevertheless, affect the unit development cost estimates in one important way. This occurs when the volume of initial marketable reserves is not large enough to fully utilize the capacity of one well. Wells are not divisible, so investment and operating cost per unit of utilized capacity are higher than they would be for a larger pool with otherwise similar features, and this is reflected in a higher estimate of unit cost.[4] Note that if (and only if) there is no rounding involved in the number of wells, Eq. 14 simplifies, through substitution of Eq. 8, to a form where size of pool does not enter:

$$C = \frac{W\{d,\ell\} + k\{d,\ell\}\ a_{t\rceil r}}{q_o\ b_{t\rceil r}} \qquad (14A)$$

It was pointed out at the outset of this section that selection of a procedure for cost estimation had to be conditioned by data availability. Eq. 14, with Eqs. 5 and 8, relate unit development cost to certain physical features of gas pools. Cost estimation requires both the data describing these features, by pool, and methods for estimating the expenditures that must be made to produce a pool, given its physical characteristics. Consideration will first be given to the required data, then the problem of estimating expenditures.

DATA BASE AND SAMPLE

The Alberta Energy Resources Conservation Board (AERCB) is the source of the data describing gas pool in that province. In the Board's gas reserves file, initial marketable gas is reported for individual pools. These pools are identified by number, nine digits comprising a field and pool code. Four digits, written as part of the pool code, designate the formation in which the pool occurs, for example, Viking Sandstone or Lower Manville. Pools are grouped according to this formation classification. The formations studied are listed in Table A.2, each accompanied by its 4-digit zone code.

The use of initial marketable gas as the measure of quantities of recoverable reserves raises some serious issues. As defined by the AERCB, these figures describe "those reserves recoverable under current technology and present and critical level of development cost of 60 cents/Mcf has been designated. This represents a cost that would have generally been breakeven or better prior to 1975. The breakeven level rose substantially after 1975, but the normal lead time to develop reserves coupled with the lack of natural gas markets after 1975 suggest that the 60-cent figure, though probably conservative, is appropriate. Fewer than five percent of the reserves covered by sample data had unit development costs higher than 60 cents/Mcf.

Table 3.2 provided estimates of average breakeven wellhead realization for the years 1970 through 1980. It can be seen that these realizations (net of producer royalties) exceeded one dollar per Mcf after 1975. However, the market situation was deteriorating rapidly, with thousands of gas wells being shut in. Reserves for shut-in wells were typically booked as "assignments" by the AERCB; the assumed drainage area did not necessarily correspond to the pools potential. When these pools are developed, their reserves can be expected to be greater in quantity than would be predicted by the type of extrapolation which has been applied in the past to forecast reserves appreciation.

If the pools with costs above 60 cents are deficient with regard to reserves estimates, there may be concern about whether the sample of pools with lower costs might not be biased so as to color the conclusions which have been drawn.

Since the results are entirely derived from information about known pools, it is obviously important to take into account, for any particular formation, the extent to which the formation has been explored. Where a formation has been subjected to exploration drilling for some time, the likelihood that conclusions about cost structure have been distorted by inadequate reserves data seems small. This is believed to be the case even where the formation is still the subject of exploration activity, and hence cannot be categorized as thoroughly explored.

Logic and experience indicate that the largest reservoirs within a formation will be found early in the play. Even when the sample is limited to pools where costs are estimated to be 60 cents/Mcf of less, the very large pools are observed to be confined to the 0-20 cent range; they do not appear in the 20-60 cent range. It is not plausible that very large pools in this latter cost range would, first, escape detection, and, second, have been ignored throughout the 1970's, when efforts to find new reserves were proceeding, market conditions notwithstanding. A clear implication of the results is the existence of a positive correlation between pool size and productivity, the chief determinant of unit development cost.

It is unfortunate that the available data do not permit examination of the reserves-cost relationship above the 60-cent level. The frustration of not having adequate information about higher cost reserves, although they are known to exist, is inherent in the established procedures for reserves definition and description.

The coding system used by the AERCB makes it possible to use other data files compiled by the Board in order to assemble additional information about a pool. The data bank contains such pool statistics as average depth, pay thickness, geographical location (exact coordinates or Potter-Liddel region), and discovery year, as well as information about the wells drilled to each pool.

Of the required physical parameters, it has proved most troublesome to obtain information about average well productivity. In earlier work observed output rates were used, and this limited the data set to those pools which had been on production for several years at least. Aside from reducing the size of the sample of pools, use of average observed outputs to measure well capability was a matter of concern. Fortunately, with the availability of the AERCB's newly compiled file providing data on absolute open flow tests (AOF) for over 15,000 wells, there is now a direct measure of potential well productivity.

Use of this new file required matching pools for which well flow rates were reported (on the AOF file) with pools for which the other required information was available (on the existing reserves file). The resulting combined file, of necessity contains information on fewer pools than either of the constituent files. Table A.2 indicates the number of pool observations in the AERCB reserves file (Column 3) and the number of pools that survive in the matched file (Column 4). It also gives the corresponding total reserves figures, in the AERCB file (Column 5) and in the data set (Column 6). Column 7 indicates the fraction of AERCB reserves represented in the data set. For all but four zones, the data cover at least 50 percent of AERCB reserves. An explanation for low coverage in some formations may be that the gas is associated with crude oil so that AOF tests were not performed. Unfortunately, the data files are not at present set up to distinguish between associated and nonassociated gas; it would have been desirable to confine this study to nonassociated gas.

COST ESTIMATION PROCEDURES

Turning to the matter of expenditures, Eq. 14, while showing the dependence of development cost on various physical parameters, stops short of specifying formulas for estimating required investment. Eq. 8 oversimplifies the actual calculation of required number of wells. In fact, the procedure which was used for estimating expenditures closely parallels those outlined in engineering manuals dealing with gas pool development.[7]

The starting assumption in estimating development costs is that one or more wells have been drilled into a pool, AOF tests have been performed, and reserves estimated. It must be decided how many wells would be necessary to attain the required output from the pool. Initial daily production is specified as 1/7300 of initial marketable gas, a standard rate when the production of the pool is assigned to a long-term contract. The average well deliverability is fixed at 25 percent of the average of available AOF test values for wells in the pool. The 25 percent figure is an industry rule-of-thumb. When initial well deliverabilities derived from production data are compared with AOF test results, the ratio is 0.17, so the rule-of-thumb may impart a downward bias to the cost estimates.

The number of wells required to produce a pool is given by:

$$N = \left[1.25 \left(\frac{Q_o}{q_o} \right) \right] \qquad (15)$$

where Q_o = R / 7300,

q_o = average well deliverability.

The coefficient 1.25 implies a design capacity 25 percent in excess of the required daily rate. Square brackets signify that N is rounded up to 1 if less than 1, otherwise to the next higher integer from X.50 or the next lower integer from X.49.

The next task in the cost-calculation procedure is that of estimating the investment required for reservoir development; this depends not only on the number of wells needed but also on such factors as depth and location. It was necessary to develop cost formulas that could be applied to all pools. These formulas can at best yield cost estimates which are subject to considerable error. The attempt was made, however, to give appropriate recognition to the variation in costs across pools which arises because of differences in physical attributes of the pools.

Costs (on a per well basis) include contractor drilling costs, noncontractor costs, and operating costs. All three categories of cost have been estimated as depending on depth alone. More comprehensive analysis involving the effects of location and including the economies of scale achievable by the installation of several wells in a particular location has not been undertaken. The procedure for each category of cost is considered separately.

CONTRACTOR DRILLING COSTS

These costs, which form approximately 35% of total well drilling and completion costs, have been estimated by D. Wrean[8] with some modification in functional forms contributed by A. Hansson. The procedure is a two-stage one: (1) estimation of a daily rental rate for rigs dependent on target depth (which varies because of the different classes of rig required), and (2) estimation of drilling days required, also dependent on depth.

The estimation of daily rental rate was performed using data from a survey of rig operators who charge on a daily basis.[9] The data give average daily operating costs and rig replacement costs for five depth ranges. The replacement costs were converted to a daily rental fee and the total of the two costs was regressed on depth. A linear functional form was found to give the best fit. The regression results (t ratios in brackets) follow:

$$\text{Daily rental} = \underset{(12.0)}{3062} + \underset{(10.4)}{.344}\, D$$

$$R^2 = .9795$$

where D is the depth in feet, and rental is in 1980 dollars.

The estimation of days of drilling required was done using a subset of the AERCB Basic Well File. The elapsed time between the start of drilling and completion (with outlier points removed) was regressed on recorded depth. The best fit was obtained using a quadratic functional form:

$$\text{Drilling days} = \underset{(7.88)}{2.004} - \underset{(-.371)}{(.6262 \times 10^{-4})D} + \underset{(10.7)}{(.2646 \times 10^{-6})D^2}$$

$$R^2 = .9283$$

where D is depth in feet.

NONCONTRACTOR COSTS

These costs form approximately 65% of well costs. A breakdown by type of expenditure was found in a study by the Petroleum Services Association of Canada of six typical wells.[10] Expenditure categories from the PSCA study were divided into those that appeared to be depth dependent and those that depend on other factors. The latter were simply averaged, giving a value of $239,516 per well ($1981).

The depth dependent quantities were aggregated and regressed on depth. An exponential functional form was found to give the best fit:

$$\text{Non Contractor Costs} = \underset{(17.8)}{175\ 250} (e^{(1743 \times 10^{-7})} D_{-1})$$

$$R^2 = .9466$$

The exponent was estimated in a nonlinear procedure, thus a t ratio is not reported.

Combining the expressions for contractor and non-contractor costs, investment cost per well becomes:

$$w\{d\} = (.3062 + .344\ D)[2.004 - (.6262 \times 10^{-4})D + (.2646 \times 10^{-6})D^2]$$
$$+ 239{,}516/1.101 + 175{,}250/1.101(e^{(1743 \times 10^{-7})D}-1)$$

Division by 1.101 corrects 1981 dollars to 1980 dollars.

Operating Costs

Estimates of the cost of operating a natural gas well were obtained from a study by Sproule Associates Limited.[11] These costs are specified as linearly dependent on depth with a fixed component, as follows:

$$\text{Operating costs} = c(500 + .2\ D)$$

where costs are in 1979 dollars per well month, and c is a factor which assumes values of 1.0 for sour gas and 0.6 for sweet gas. Coefficients used were those for sour gas, since the basic data file contained no measure of sulplur content. Operating costs were assumed to be constant throughout the operating life of the well (here, 20 years). The present value of this 20 year stream of expenditures for one well is:

$$k\{d\}\ a_{\overline{t|}r} = \left(\frac{1 - e^{-rt}}{r}\right) 12\ (500 + .2\ D)$$

These costs are inflated from \$1979 to \$1980 using the Nelson refinery cost index taken from the Oil and Gas Journal.

Footnotes to Appendix A

1. A memorandum by Montreal Engineering Company Limited, entitled "Use of Levelized Unit Costs for Economic Analysis" was included in the direct evidence of Dr. Donald E. Armstrong on behalf of Alberta and Southern at the National Energy Gas Export Omnibus Hearing, 1982.

2. Table A.1 provides a summary of symbols used in this paper.

3. In practice production may continue for as long as 40 years. Because of the force of discounting, this would only alter the b-factor by a minor amount. For example, if production continues to decline at 10 percent per year and the rate of discount is 8 percent, the b-factor only increases by 1.9 percent when the production period is increased from 20 to 40 years.

4. This indivisibility also influences cost for pools with more than one well. However, the effect rapidly becomes small. The practice is to round the figure for required number of wells to the nearest integer. Thus if 1.5 wells would provide the required initial capacity, and this is rounded to 2, dollar investment per unit capacity is increased by at most 25 percent. When there is at least one well rounding downward also occurs, so (except for the

one-well case) the indivisibility is treated not as a source of scale diseconomies stemming from indivisibility. The exploration well can be utilized; completion but not drilling costs for this well are charged to development.

5. Energy Resources Conservation Board, Alberta's Reserves of Crude Oil, Gas, Natural Gas Liquids, and Sulphur, ERCB 79-18, December 1978, p.1-2.

6. The reserves data are the AERCB figures for initial marketable gas as of 1981. The appreciation factors were developed by the AERCB (Gas Reserves Trends, 1980) in order to adjust reserves credited to the most recently discovered pools toward more realistic values. The effect of the adjustment was quite small, an increase of less than 6 percent.

7. See, for example, F.W. Cole, Reservoir Engineering Manual (Gulf Publishing Company, 1969), or C.U. Ikoku, Natural Gas Engineering: A Systems Approach (Penwell, 1980).

8. D. Wrean, unpublished "Extended Essay," University of British Columbia, 1981.

9. Canadian Association of Oilwell Drilling Contractors, Cost Study, 1980.

10. Petroleum Services Association of Canada, Well Cost Analysis, April 1981.

11. Sproule Associate Limited, Evaluation of Canadian Oil and Gas Properties, Calgary, 1979.

TABLE A.1

List of Symbols Used in Appendix A

$a_{\overline{t|}r}$ = annuity factor

$b_{\overline{t|}r}$ = production discount factor (defined in paper)

C = total unit production cost ($/MCF)

C_c = unit capacity cost ($/MCF)

C_o = unit capacity cost ($/MCF)

d (or D) = depth

E = operating expenditure ($/unit time)

I_c = present value of capacity expenditure

I_o = present value of operating expenditure

ℓ = location

N = number of wells

q_o = average well productivity

Q_t = output of pool (MCF/unit time)

r = rate of interest

R = initial marketable reserves (BCF)

T = period of planned production

W = cost of a well

Table A.2

Formations Studied and Data Coverage*

	(1) Formation Name	(2) Zone Code	(3) Number of Pools with Reserves	(4) Number of Pools in Data Set	(5) Volume of Reported Reserves(BCF)	(6) Volume of Reserves in Data Set (BCF)	(7) Ratio: (6)/(5)
1	Rundle	6100	125	52	10566	7609	.72
2	Milk River & Medicine Hat	1581	57	0	9536	0	0
3	Leduc	7200	120	43	8323	6626	.80
4	Viking	2180	1327	268	4768	2423	.51
5	Beaverhill	7440	27	4	3733	2200	.59
6	Elkton Shunda	6390	20	3	3289	91	.03
7	Upper Mannville	2500	1600	417	3276	1757	.54
8	Lower Mannville	3100	952	263	2841	1469	.52
9	Wabamun	6580	202	78	2803	2050	.73
10	Cardium	1760	129	28	2338	551	.24
11	Glauconitic SS	3000	338	107	2087	1459	.70
12	Upper and Middle Viking	2191	11	5	2016	2003	.99
13	Mannville	2480	685	171	1930	983	.51
14	Pekisko	6420	116	39	1754	1469	.84
15	Rundle Wabamun	6110	1	1	1727	1727	1.00
16	Mississippian	6000	19	7	1403	671	.48
17	Debolt	6120	84	19	1342	185	.14
18	Seags	1861	6	0	1312	0	0
19	Bow Island	2130	452	115	1311	675	.51
20	Colony	2560	697	191	1298	740	.57
21	Elkton	6380	39	12	1168	978	.84
22	Wabiskaw Wabamun	3061	4	2	866	860	.99
23	Bluesky Gething	3041	6	3	83	81	.98

* Explanatory notes on following page.

Notes to Table A.2

Formations are ordered by total volume of reported reserves.

The remaining notes refer to column number in the table.

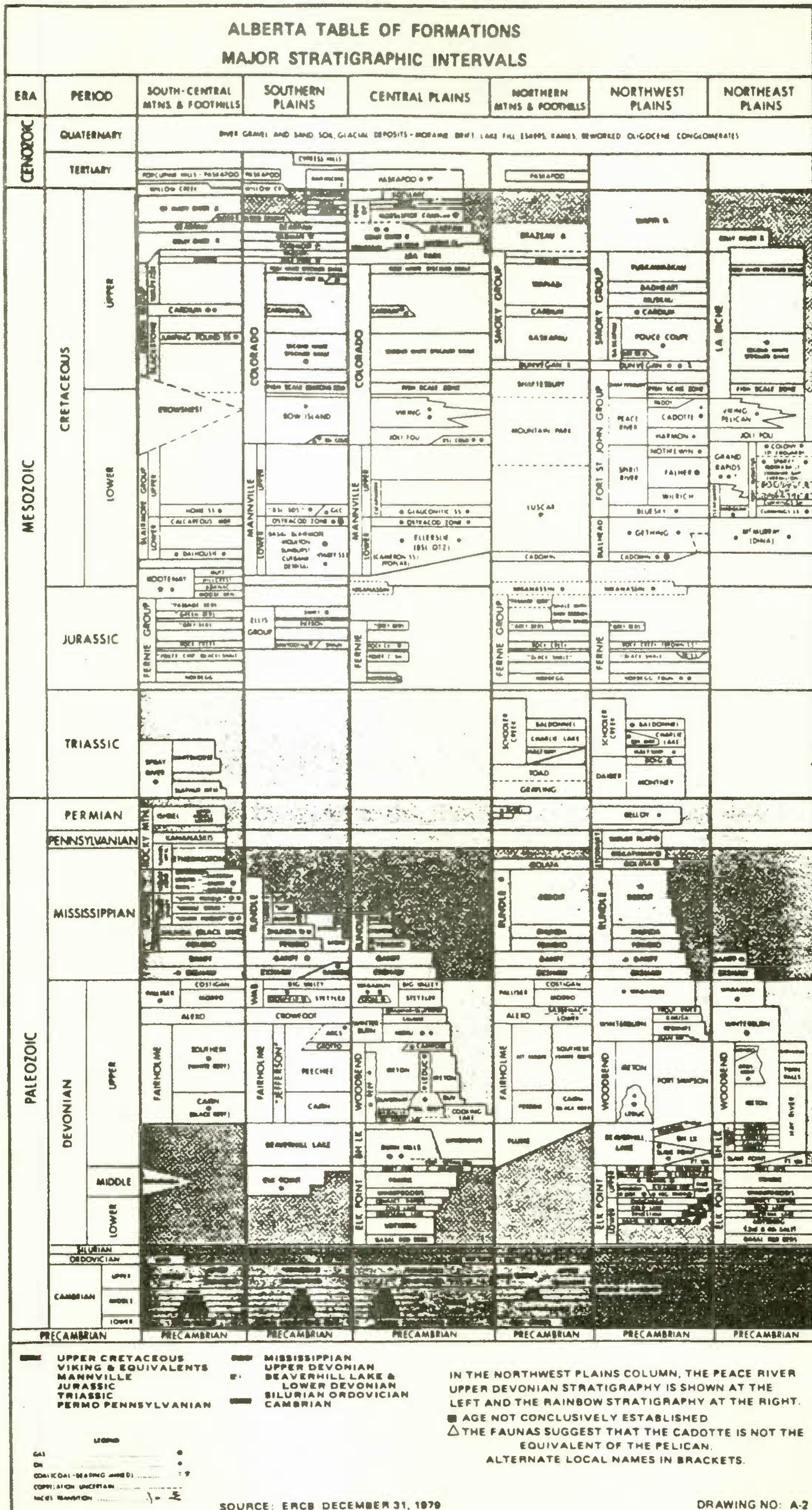
3. The number of pools for which reserves data are available in the file compiled by R.S. Uhler from the 1981 AERCB reserves file.

4. The number of pools contained in the data set (matched with AOF test results).

5. Reserves reported in Uhler file (#3 above).

6. Reserves represented in the data set.

FIGURE A.1


ALBERTA TABLE OF FORMATIONS
MAJOR STRATIGRAPHIC INTERVALS
ERA
PERIOD
SOUTH-CENTRAL MTNS & FOOTHILLS
SOUTHERN PLAINS
CENTRAL PLAINS
NORTHERN MTNS & FOOTHILLS
NORTHWEST PLAINS
NORTHEAST PLAINS
CENOZOIC
QUATERNARY
TERTIARY
MESOZOIC
CRETACEOUS
UPPER
LOWER
JURASSIC
TRIASSIC
PALEOZOIC
PERMIAN
PENNSYLVANIAN
MISSISSIPPIAN
DEVONIAN
MIDDLE
SILURIAN
ORDOVICIAN
CAMBRIAN
PRECAMBRIAN
COLORADO
SMOKY GROUP
LA BICHE
FORT ST JOHN GROUP
MANNVILLE
BLAIRMORE GROUP
FERNIE GROUP
FERNIE
ELLIS GROUP
SCHOOLER CREEK
ROCKY MTN
RUNDLE
FAIRHOLME
WOODBEND
ELK POINT
CARDIUM
BOW ISLAND
VIKING
JOLI FOU
MOUNTAIN PARK
LUSCAR
PEACE RIVER
CADOTTE
GRAND RAPIDS
VIKING PELICAN
JOLI FOU
GETHING
CADOMIN
BALDONNEL
CHARLIE LAKE
TOAD
GRAYLING
DAIBER
MONTNEY
BELLOY
ALEXO
CROWFOOT
PALLISER
COSTIGAN
MORRO
SOUTHESK
CAIRN
PEECHEE
BEAVERHILL LAKE
LEDUC
FORT SIMPSON
UPPER CRETACEOUS
VIKING & EQUIVALENTS
MANNVILLE
JURASSIC
TRIASSIC
PERMO PENNSYLVANIAN
MISSISSIPPIAN
UPPER DEVONIAN
BEAVERHILL LAKE & LOWER DEVONIAN
SILURIAN ORDOVICIAN
CAMBRIAN
IN THE NORTHWEST PLAINS COLUMN, THE PEACE RIVER UPPER DEVONIAN STRATIGRAPHY IS SHOWN AT THE LEFT AND THE RAINBOW STRATIGRAPHY AT THE RIGHT.
AGE NOT CONCLUSIVELY ESTABLISHED
THE FAUNAS SUGGEST THAT THE CADOTTE IS NOT THE EQUIVALENT OF THE PELICAN.
ALTERNATE LOCAL NAMES IN BRACKETS.
LEGEND
SOURCE: ERCB DECEMBER 31, 1979
DRAWING NO: A-2

APPENDIX B

COST RESULTS FOR EACH ZONE

Table B.1

Reserves By Cost Category*

Formation: Rundle

(1) Development Cost	(2) Average Cost	(3) Reserves	(4) Reserves, Cum. %	(5) Number of Pools	(6) Pools Not Produced %	(7) Pools Producing After 76-1-1, %	(8) Average Well Productivity	(9) Average Depth	(10) Reserves Per Pool
0- .25	.09	6762	87.4	32	9	25	3072	9877	211
.25- .50	.31	860	98.5	9	56	22	750	9601	96
.50- .75	.64	31	98.9	6	33	50	550	9476	5
.75-1.00	.77	45	99.5	1	100	0	330	11278	45
1.00-1.25	1.14	20	99.8	1	100	0	268	11863	20
1.25-1.50									
1.50	1.95	19	100	3	33	33	104	8372	6

* Development Cost in $/Mcf, Reserves in BCF.
For definitions and for other units, see notes.

Table B.2

Reserves By Cost Category*

Formation: Leduc

(1) Development Cost	(2) Average Cost	(3) Reserves	(4) Reserves, Cum. %	(5) Number of Pools	(6) Pools Not Produced %	(7) Pools Producing After 76-1-1, %	(8) Average Well Productivity	(9) Average Depth	(10) Reserves Per Pool
0- .25	.04	6638	99.1	31	16	10	7581	10098	214
.25- .50	.39	47	99.8	4	50	0	1014	11411	12
.50- .75	.65	9	99.9	3	33	0	5780	10056	3
.75-1.00									
1.00-1.25	1.23	1	99.9	1	0	0	345	7197	1
1.25-1.50	1.27	1	99.9	1	0	0	2633	9003	1
1.50	1.67	3	100	3	33	0	1800	10368	1

* Development Cost in $/Mcf, Reserves in BCF.
For definitions and for other units, see notes following these series of tables.

Table B.3

Reserves By Cost Category*

Formation: Viking Sandstone

(1) Development Cost	(2) Average Cost	(3) Reserves	(4) Reserves, Cum. %	(5) Number of Pools	(6) Pools Not Produced %	(7) Pools Producing After 76-1-1, %	(8) Average Well Productivity	(9) Average Depth	(10) Reserves Per Pool
0- .25	.11	1570	62.6	59	10	19	1493	3364	27
.25- .50	.35	666	89.1	63	21	35	362	5766	11
.50- .75	.60	116	93.7	42	29	38	211	3617	3
.75-1.00	.87	33	95.1	24	21	50	134	2687	1
1.00-1.25	1.06	27	96.1	16	31	56	112	3254	2
1.25-1.50	1.38	17	96.8	14	7	36	214	3723	1
1.50	3.51	80	100	50	46	44	50	2821	2

* Development Cost in $/Mcf, Reserves in BCF.
For definitions and for other units, see notes following these series of tables.

Table B.4

Reserves By Cost Category*

Formation: Beaverhill Lake

(1) Development Cost	(2) Average Cost	(3) Reserves	(4) Reserves, Cum. %	(5) Number of Pools	(6) Pools Not Produced %	(7) Pools Producing After 76-1-1, %	(8) Average Well Productivity	(9) Average Depth	(10) Reserves Per Pool
0- .25 .25- .50	.05	2402	100	4	50	25	6520	11522	600
.50- .75 .75-1.00									
1.00-1.25 1.25-1.50									
1.50									

* Development Cost in \$/Mcf, Reserves in BCF.
For definitions and for other units, see notes following these series of tables.

Table B.5

Reserves By Cost Category*

Formation: Elkton-Shunda

(1) Development Cost	(2) Average Cost	(3) Reserves	(4) Reserves, Cum. %	(5) Number of Pools	(6) Pools Not Produced %	(7) Pools Producing After 76-1-1, %	(8) Average Well Productivity	(9) Average Depth	(10) Reserves Per Pool
0- .25 .25- .50	.14	99	100	2	0	0	986	7052	50
.50- .75 .75-1.00									
1.00-1.25 1.25-1.50									
1.50									

* Development Cost in $/Mcf, Reserves in BCF.
For definitions and for other units, see notes following these series of tables.

Table B.6

Reserves By Cost Category*

Formation: Upper Mannville

(1) Development Cost	(2) Average Cost	(3) Reserves	(4) Reserves, Cum. %	(5) Number of Pools	(6) Pools Not Produced %	(7) Pools Producing After 76-1-1, %	(8) Average Well Productivity	(9) Average Depth	(10) Reserves Per Pool
0- .25	.10	1382	66.3	121	10	50	1022	2811	11
.25- .50	.34	426	86.8	112	19	54	341	3055	4
.50- .75	.60	98	91.5	67	13	63	269	2703	1
.75-1.00	.88	75	95.1	39	28	54	170	3963	2
1.00-1.25	1.11	15	95.8	16	13	81	189	3897	1
1.25-1.50	1.34	32	97.4	18	28	56	68	2260	2
1.50	3.45	55	100	44	23	61	56	3397	1

* Development Cost in $/Mcf, Reserves in BCF.
For definitions and for other units, see notes following these series of tables.

Table B.7

Reserves By Cost Category*

Formation: Lower Mannville

(1) Development Cost	(2) Average Cost	(3) Reserves	(4) Reserves, Cum. %	(5) Number of Pools	(6) Pools Not Produced %	(7) Pools Producing After 76-1-1, %	(8) Average Well Productivity	(9) Average Depth	(10) Reserves Per Pool
0- .25	.10	1228	69.8	81	12	44	922	3638	15
.25- .50	.35	232	83.0	67	21	57	445	4268	3
.50- .75	.61	132	90.5	35	29	49	340	4121	4
.75-1.00	.84	84	95.3	30	37	57	136	3187	3
1.00-1.25	1.12	23	96.6	15	47	47	124	4948	2
1.25-1.50	1.37	19	97.7	9	11	67	152	6759	2
1.50	3.48	41	100	26	38	35	86	4047	2

* Development Cost in \$/Mcf, Reserves in BCF.
For definitions and for other units, see notes following these series of tables.

Table B.8

Reserves By Cost Category*

Formation: Wabamun

(1) Development Cost	(2) Average Cost	(3) Reserves	(4) Reserves, Cum. %	(5) Number of Pools	(6) Pools Not Produced %	(7) Pools Producing After 76-1-1, %	(8) Average Well Productivity	(9) Average Depth	(10) Reserves Per Pool
0- .25	.14	1972	93.3	39	15	46	1529	7642	51
.25- .50	.39	61	96.2	18	22	67	664	5592	3
.50- .75	.56	37	98.0	5	20	40	315	7188	7
.75-1.00	.83	3	98.1	4	50	25	236	2487	.8
1.00-1.25	1.03	.6	98.1	1	0	100	462	2399	.6
1.25-1.50	1.44	.3	98.2	1	100	0	6716	1470	.4
1.50	2.06	39	100	10	40	40	246	10645	4

* Development Cost in \$/Mcf, Reserves in BCF.
For definitions and for other units, see notes following these series of tables.

Table B.9

Reserves By Cost Category*

Formation: Cardium

(1) Development Cost	(2) Average Cost	(3) Reserves	(4) Reserves, Cum. %	(5) Number of Pools	(6) Pools Not Produced %	(7) Pools Producing After 76-1-1, %	(8) Average Well Productivity	(9) Average Depth	(10) Reserves Per Pool
0- .25	.09	349	63.3	6	33	17	1728	8292	58
.25- .50	.35	104	82.0	5	80	0	377	6839	21
.50- .75	.62	14	84.6	4	75	25	214	6090	3
.75-1.00	.88	32	90.3	4	50	50	216	6929	8
1.00-1.25	1.13	23	94.5	2	100	0	126	7661	12
1.25-1.50	1.35	9	96.2	1	100	0	98	6984	9
1.50	2.64	21	100	6	66	17	70	7410	4

* Development Cost in \$/Mcf, Reserves in BCF.
For definitions and for other units, see notes following these series of tables.

Table B.10

Reserves By Cost Category*

Formation: Glauconitic SS

(1) Development Cost	(2) Average Cost	(3) Reserves	(4) Reserves, Cum. %	(5) Number of Pools	(6) Pools Not Produced %	(7) Pools Producing After 76-1-1, %	(8) Average Well Productivity	(9) Average Depth	(10) Reserves Per Pool
0- .25	.13	1468	80.2	27	11	15	1152	5459	54
.25- .50	.31	226	92.5	31	32	48	361	4953	7
.50- .75	.58	80	96.9	17	24	59	189	4496	5
.75-1.00	.91	11	97.5	8	13	38	385	3778	1
1.00-1.25	1.12	22	98.7	10	30	50	143	4620	2
1.25-1.50	1.34	3	98.8	5	40	20	313	3924	.6
1.50	7.66	21	100	9	56	22	71	6333	2

* Development Cost in $/Mcf, Reserves in BCF.
For definitions and for other units, see notes following these series of tables.

Table B.11

Reserves By Cost Category*

Formation: Upper & Middle Viking

(1) Development Cost	(2) Average Cost	(3) Reserves	(4) Reserves, Cum. %	(5) Number of Pools	(6) Pools Not Produced %	(7) Pools Producing After 76-1-1, %	(8) Average Well Productivity	(9) Average Depth	(10) Reserves Per Pool
0- .25	.08	8	.4	1	100	0	1261	2467	8
.25- .50	.36	4	.6	2	0	0	450	2600	2
.50- .75	.50	1991	100	2	0	0	123	2085	996
.75-1.00									
1.00-1.25									
1.25-1.50									
1.50									

* Development Cost in \$/Mcf, Reserves in BCF.
For definitions and for other units, see notes following these series of tables.

Table B.12

Reserves By Cost Category*

Formation: Mannville

(1) Development Cost	(2) Average Cost	(3) Reserves	(4) Reserves, Cum. %	(5) Number of Pools	(6) Pools Not Produced %	(7) Pools Producing After 76-1-1, %	(8) Average Well Productivity	(9) Average Depth	(10) Reserves Per Pool
0- .25	.09	834	78.2	67	3	37	1347	3573	12
.25- .50	.37	79	85.6	31	29	39	421	3487	3
.50- .75	.60	47	90.0	20	20	65	175	3134	2
.75-1.00	.86	13	91.3	13	23	77	251	3122	2
1.00-1.25	1.12	7	91.9	10	10	70	316	2788	.7
1.25-1.50	1.29	7	92.6	3	0	33	71	2470	2
1.50	2.03	79	100	25	36	36	104	6454	3

* Development Cost in $/Mcf, Reserves in BCF.
For definitions and for other units, see notes following these series of tables.

Table B.13

Reserves By Cost Category*

Formation: Pekisko

(1) Development Cost	(2) Average Cost	(3) Reserves	(4) Reserves, Cum. %	(5) Number of Pools	(6) Pools Not Produced %	(7) Pools Producing After 76-1-1, %	(8) Average Well Productivity	(9) Average Depth	(10) Reserves Per Pool
0- .25	.06	1237	81.5	15	20	7	2246	6510	82
.25- .50	.31	207	95.1	7	14	14	443	6545	30
.50- .75	.52	10	95.8	2	50	50	257	7307	5
.75-1.00	.93	5	96.1	2	0	100	81	3307	2
1.00-1.25	1.11	35	98.4	3	66	33	110	6222	12
1.25-1.50	1.43	4	98.7	1	100	0	76	5450	4
1.50	2.89	20	100	9	44	33	106	6289	2

* Development Cost in $/Mcf, Reserves in BCF.
For definitions and for other units, see notes following these series of tables.

Table B.14

Reserves By Cost Category*

Formation: Rundle Wabamun

(1) Development Cost	(2) Average Cost	(3) Reserves	(4) Reserves, Cum. %	(5) Number of Pools	(6) Pools Not Produced %	(7) Pools Producing After 76-1-1, %	(8) Average Well Productivity	(9) Average Depth	(10) Reserves Per Pool
0- .25 .25- .50	.04	1727	100	1	0	0	6908	10974	1727
.50- .75 .75-1.00									
1.00-1.25 1.25-1.50									
1.50									

* Development Cost in \$/Mcf, Reserves in BCF.
For definitions and for other units, see notes following these series of tables.

Table B.15

Reserves By Cost Category*

Formation: Mississippian

(1) Development Cost	(2) Average Cost	(3) Reserves	(4) Reserves, Cum. %	(5) Number of Pools	(6) Pools Not Produced %	(7) Pools Producing After 76-1-1, %	(8) Average Well Productivity	(9) Average Depth	(10) Reserves Per Pool
0- .25	.07	635	94.7	2	0	0	3063	9413	317
.25- .50	.28	5	95.5	2	0	0	726	3469	3
.50- .75	.64	9	96.8	1	100	0	296	9715	9
.75-1.00	.87	.8	96.9	1	0	100	798	3408	.8
1.00-1.25									
1.25-1.50									
1.50	1.37	21	100	1	100	0	102	6956	21

* Development Cost in $/Mcf, Reserves in BCF.
For definitions and for other units, see notes following these series of tables.

Table B.16

Reserves By Cost Category*

Formation: Debolt

(1) Development Cost	(2) Average Cost	(3) Reserves	(4) Reserves, Cum. %	(5) Number of Pools	(6) Pools Not Produced %	(7) Pools Producing After 76-1-1, %	(8) Average Well Productivity	(9) Average Depth	(10) Reserves Per Pool
0- .25	.09	158	72.2	6	33	33	1307	2578	26
.25- .50	.31	45	92.7	5	40	20	275	4671	9
.50- .75	.62	10	97.3	5	40	60	346	4806	2
.75-1.00									
1.00-1.25									
1.25-1.50	1.35	2	98.2	1	100	0	40	2916	2
1.50	1.54	4	100	2	100	0	103	5982	2

* Development Cost in $/Mcf, Reserves in BCF.
For definitions and for other units, see notes following these series of tables.

Table B.17

Reserves By Cost Category*

Formation: Bow Island

(1) Development Cost	(2) Average Cost	(3) Reserves	(4) Reserves, Cum. %	(5) Number of Pools	(6) Pools Not Produced %	(7) Pools Producing After 76-1-1, %	(8) Average Well Productivity	(9) Average Depth	(10) Reserves Per Pool
0- .25	.09	498	66.9	35	9	34	935	2680	14
.25- .50	.35	136	85.1	25	32	24	264	2674	5
.50- .75	.57	85	96.5	15	40	33	197	2438	6
.75-1.00	.86	7	97.4	8	38	38	175	2400	.9
1.00-1.25	1.12	5	98.1	9	22	44	288	2870	.6
1.25-1.50	1.36	6	98.9	6	33	50	88	2606	1
1.50	3.09	8	100	16	56	25	86	3046	.5

* Development Cost in $/Mcf, Reserves in BCF.
For definitions and for other units, see notes following these series of tables.

Table B.18

Reserves By Cost Category*

Formation: Colony

(1) Development Cost	(2) Average Cost	(3) Reserves	(4) Reserves, Cum. %	(5) Number of Pools	(6) Pools Not Produced %	(7) Pools Producing After 76-1-1, %	(8) Average Well Productivity	(9) Average Depth	(10) Reserves Per Pool
0- .25	.11	719	75.7	74	11	65	807	1666	10
.25- .50	.33	158	92.3	55	18	64	356	1911	3
.50- .75	.64	22	94.6	22	23	73	299	1875	1
.75-1.00	.85	32	97.9	22	23	64	152	2034	1
1.00-1.25	1.15	2	98.2	5	20	50	1578	1875	.5
1.25-1.50	1.38	1	98.3	3	0	100	361	1750	.4
1.50	5.25	16	100	10	50	50	34	1727	2

* Development Cost in $/Mcf, Reserves in BCF.
For definitions and for other units, see notes following these series of tables.

Table B.19

Reserves By Cost Category*

Formation: Elkton

(1) Development Cost	(2) Average Cost	(3) Reserves	(4) Reserves, Cum. %	(5) Number of Pools	(6) Pools Not Produced %	(7) Pools Producing After 76-1-1, %	(8) Average Well Productivity	(9) Average Depth	(10) Reserves Per Pool
0- .25	.04	961	98.0	5	0	0	4822	8063	192
.25- .50	.29	7	98.8	2	0	50	1026	5666	4
.50- .75									
.75-1.00	.97	5	99.4	2	0	50	290	8033	3
1.00-1.25	1.07	4	99.8	1	0	100	179	8789	4
1.25-1.50									
1.50	2.03	2	100	2	0	0	2961	9081	.9

* Development Cost in $/Mcf, Reserves in BCF.
For definitions and for other units, see notes following these series of tables.

Table B.20

Reserves By Cost Category*

Formation: Wabiskaw Wabamun

(1) Development Cost	(2) Average Cost	(3) Reserves	(4) Reserves, Cum. %	(5) Number of Pools	(6) Pools Not Produced %	(7) Pools Producing After 76-1-1, %	(8) Average Well Productivity	(9) Average Depth	(10) Reserves Per Pool
0- .25 .25- .50	.04	860	100	2	0	50	1479	2185	430
.50- .75 .75-1.00									
1.00-1.25 1.25-1.50									
1.50									

* Development Cost in \$/Mcf, Reserves in BCF.
For definitions and for other units, see notes following these series of tables.

Table B.21

Reserves By Cost Category*

Formation: Bluesky Gething

(1) Development Cost	(2) Average Cost	(3) Reserves	(4) Reserves, Cum. %	(5) Number of Pools	(6) Pools Not Produced %	(7) Pools Producing After 76-1-1, %	(8) Average Well Productivity	(9) Average Depth	(10) Reserves Per Pool
0- .25	.16	8	9.3	1	0	100	291	1043	8
.25- .50	.49	.9	10.4	1	100	0	49	742	.9
.50- .75									
.75-1.00									
1.00-1.25									
1.25-1.50									
1.50	2.85	74	100	1	100	0	16	766	74

* Development Cost in $/Mcf, Reserves in BCF.
For definitions and for other units, see notes following these series of tables.

Notes to Tables in Appendix B (by column number)

2. The average across pools in the category of unit development costs. Each pool cost figure is weighted by that pool's share of total reserves.

8. The average across pools of average well productivity. Each pool figure is weighted by that pool's share of total reserves. Units: MMCF per year.

9. The average across pools of pool depth. Each pool figure is weighted by that pool's share of total reserves. Units: feet.

APPENDIX C

REMAINING ESTABLISHED RESERVES

The curves reported in the main body of the text relate initial reserves to development cost. In analyzing the structure of costs for various producing formations it was appropriate to use reported initial reserves as a measure of the natural endowment of the resource. It was noted, however, that supply curves normally indicate outputs which are available. Where stocks are being considered in this context, one would therefore wish to exclude volumes that had previously been produced.

Curves relating remaining established reserves to development cost can be derived by subtracting cumulative production from the values reported for initial reserves. Remaining reserves are contained in pools which may or may not have been placed in production, and this must be taken into account in interpreting these quantities as a supply measure. Whether gas is available from producing pools to meet additional demand depends on the extent to which reserves in these pools are committed under existing contracts and on the possibility of increasing pool recoveries (the latter is the first of the reserve-creating activities listed in the text). Presumably gas contained in pools not yet in production is available to meet new demand (development of these pools is the second of the listed reserve-creating activities). However, as previously discussed, the quantities of reserves assigned to known but undeveloped pools are nominal amounts. The application of historical appreciation factors adjusts these figures in the correct direction, upward, but cannot be regarded as a very satisfactory procedure. The actual volumes in these pools could be estimated either using a pool-by-pool reservoir engineering approach or through the use of models of the exploitation of gas-bearing formations; both approaches require additional geological information and assumptions. Without expanded analysis, curves relating remaining reserves to development cost are not very helpful in analyzing the ability of a supplying region to meet new demand for natural gas.

Comparison of curves (or schedules) relating remaining reserves to development cost with corresponding curves in the text based on initial reserves is, nevertheless, of some interest. First, the basic shape of the curves is unchanged, as can be illustrated by comparing the curve for Rundle (Figure C.1) with Figure 3.1(c) in the text. It should be noted that the available data set only contained production figures from 1962, but this omission only affects a very small proportion of pools, and these to a limited degree. It does not, therefore, distort the comparison being made.

The data also confirm the tendency described in the text for relatively cheaper pools to be more heavily exploited. Thus when the share of initial reserves is arrayed according to cost category, it is observed that greater shares of the lower cost categories have been produced. This is shown in Table C.1. For three formations -- Viking Sandstone, Mannville and Rundle -- pools are divided into four groups containing roughly comparable total volumes of initial reserves. The group with lowest development cost in each case shows the greatest percentage produced. The group with the highest development cost shows the smallest percentage produced.

TABLE C.1

Percentage of Reserves Already Produced

By Development Cost Category

	Development Cost (¢ / MCF)	No. of Pools	Reserves Initial (BCF)	Reserves Remaining (BCF)	Percentage Produced
(a) Viking Sandstone	0 - 8	10	956	337	65
	8 - 18	35	389	196	50
	18 - 32	75	574	429	25
	> 32	268	591	482	18
(b) Mannville	0 - 6	15	323	153	53
	6 - 9	30	251	131	48
	9 - 18	50	178	86	52
	> 18	169	314	261	17
(c) Rundle	0 - 5	6	2302	677	71
	5 - 10	20	2051	1126	45
	10 - 15	26	1972	836	58
	> 15	52	1411	1222	13

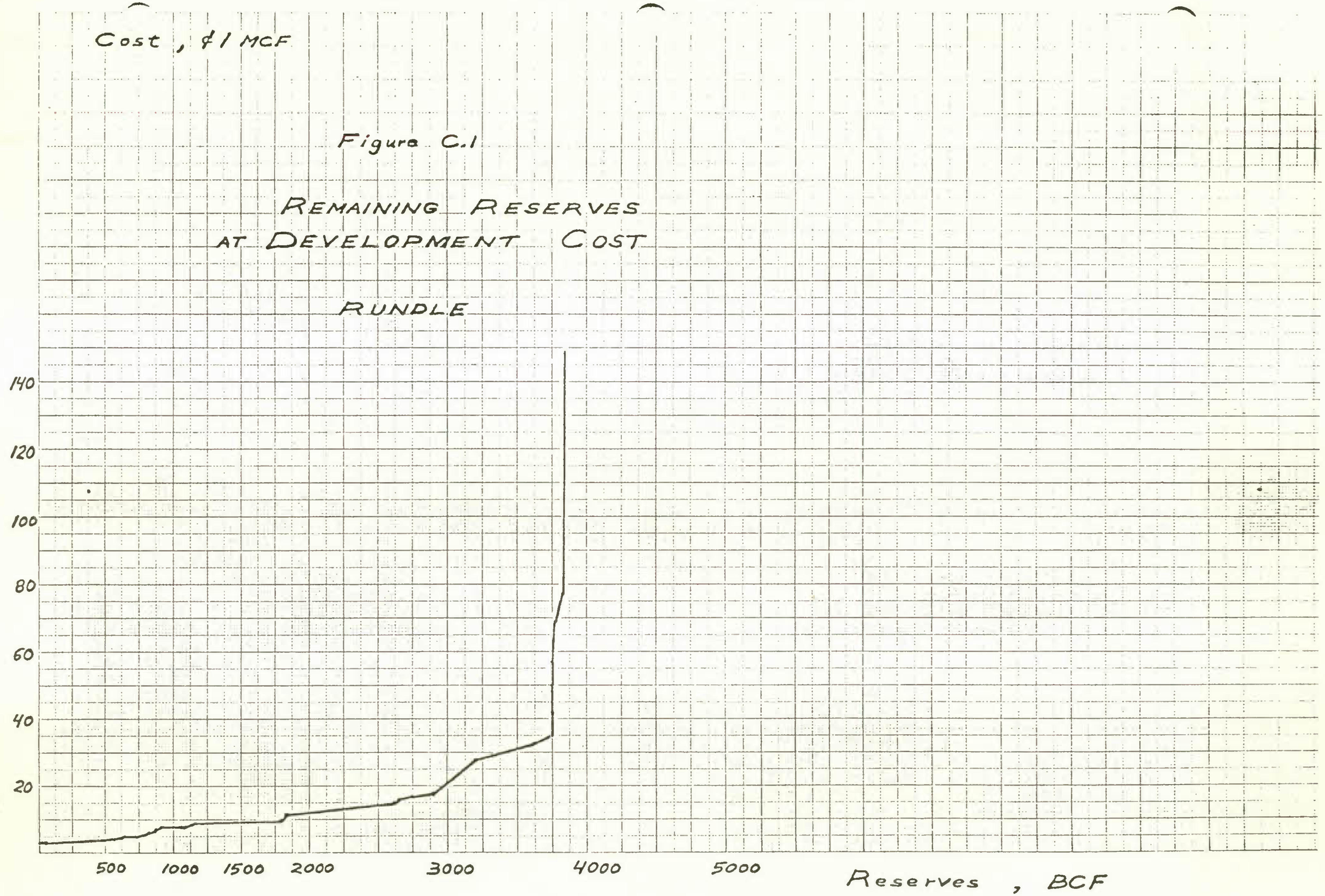


Figure C.1

REMAINING RESERVES AT DEVELOPMENT COST

RUNDLE

APPENDIX D

COST RESULTS FOR MANNVILLE HORIZON

A disaggregate approach to supply analysis would be facilitiated if it could be demonstrated that formations, the basic population unit for economic-geological modelling, could in certain circumstances be combined to form larger groupings. For this to be appropriate, evidence would be required that the larger population was still characterized by geological homogeneity. In the course of this research, formations identified as comprising the Mannville horizon were pooled, and the structure of development costs was examined. Tests to establish geological homogeneity were not carried out, so no firm basis for aggregation could be claimed. However, with respect to the relation between development cost and reserves stocks, Mannville horizon displayed the same pattern as was observed for individual formations.

Mannville horizon is specified as comprising the formations with ERCB code numbers between 2440 and 3501. Within this range there are about ninety listed formations, but in fact the bulk of pools containing reported reserves lie in only about a half-dozen formations. Table D.1 shows initial reserves by cost category for Mannville horizon and follows the same format as Table 3.1 in the text. It represents data from 1871 pools.

The pattern observed for individual formations, where a high fraction of total reserves is contained in the lowest cost pools, is repeated for Mannville horizon. For example, eighty percent of reserves are contained in pools where development cost is under forty cents. Again the relation between development cost and cumulative initial reserves is best conveyed by elasticity figures. These are presented in Table D.2, which is analogous to Table 3.5 in the text. As with individual formations, elasticity of reserves with respect to supply price is above unity for the cost range below 20 cents, and then falls sharply.

Table D.1

Reserves By Cost Category*

Formation: Mannville Horizon

(1) Development Cost	(2) Average Cost	(3) Reserves	(4) Reserves, Cum. %	(5) Number of Pools	(6) Pools Not Produced %	(7) Pools Producing After 76-1-1, %	(8) Average Well Productivity	(9) Average Depth	(10) Reserves Per Pool
0- .10	.05	5022	34.9	190	13	35	1409	2891	26
.10- .20	.14	4159	63.8	292	14	49	838	4369	14
.20- .30	.25	1614	75.1	214	17	53	473	4365	8
.30- .40	.35	734	80.2	192	22	49	387	4466	4
.40- .50	.44	421	83.1	162	28	52	363	3891	3
.50- .60	.55	479	86.4	126	21	56	310	4493	4
.60- .70	.64	450	89.5	117	26	57	219	4469	4
.70- .80	.75	154	90.6	75	25	59	271	3994	2
.80- .90	.86	188	91.9	76	33	51	182	4584	2
.90-1.00	.94	109	92.7	52	37	46	144	3253	2
1.00-1.10	1.06	294	94.7	40	38	40	154	7138	7
1.10-1.20	1.14	49	95.1	35	31	63	219	3810	1
1.20-1.30	1.24	31	95.3	31	23	55	162	4036	1
1.30-1.40	1.34	96	95.9	30	40	43	96	4725	3
1.40-1.50	1.45	36	96.2	29	31	48	142	5486	1
1.50	5.08	550	100	210	42	41	53	4191	3

* Development Cost in $/Mcf produced, Reserves in Bcf.
For definitions and for other units, see notes.

Notes to Table D.1 (by column number)

2. The average across pools in the category of unit development costs. Each pool cost figure is weighted by that pool's share of total reserves.

8. The average across pools of average well productivity. Each pool figure is weighted by that pool's share of total reserves. Units: MMCF per year.

9. The average across pools of pool depth. Each pool figure is weighted by that pool's share of total reserves. Units: feet.

TABLE D.2

Elasticity[1] of Initial Reserves Stocks
with Respect to Development Cost :

Mannville Horizon

Cost Range (¢ / MCF)	Elasticity	No. of Pools
2 - 20	1.22	482
20 - 60	0.30	694
60 - 100	0.14	320
100 - 140	0.10	136

Notes to Table D.2

1. Elasticity is defined as the ratio of percentage increase in initial reserves stocks to percentage increase in development cost,

$$\left(\frac{R}{R_{avg.}}\right) \Big| \left(\frac{C}{C_{avg.}}\right) .$$