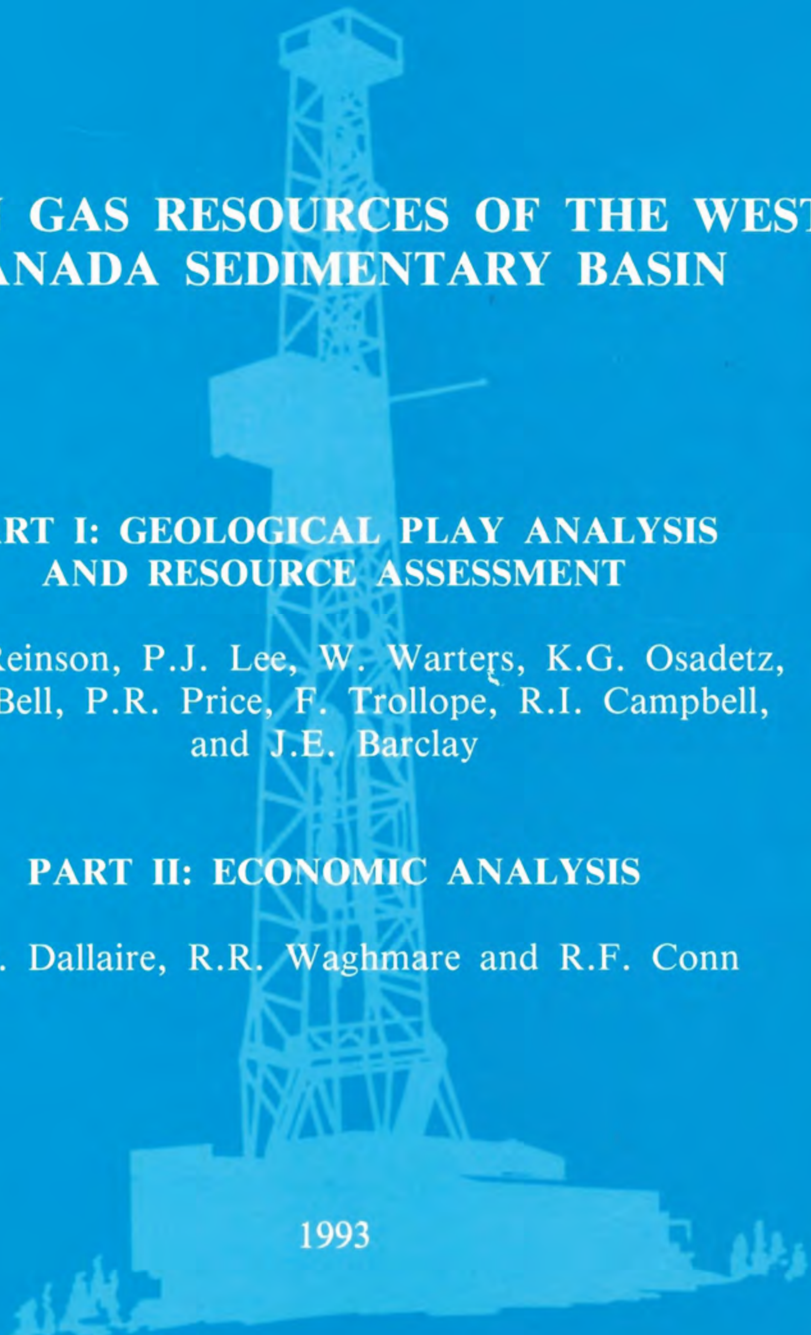
GEOLOGICAL SURVEY OF CANADA
BULLETIN 452



DEVONIAN GAS RESOURCES OF THE WESTERN CANADA SEDIMENTARY BASIN

PART I: GEOLOGICAL PLAY ANALYSIS AND RESOURCE ASSESSMENT

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PART II: ECONOMIC ANALYSIS

S.M. Dallaire, R.R. Waghmare and R.F. Conn

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Energy, Mines and Resources Canada
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Available in Canada through authorized
bookstore agents and other bookstores

or by mail from

Canada Communication Group–Publishing
Ottawa, Canada K1A 2A7

and from

Geological Survey of Canada offices:

601 Booth Street
Ottawa, Canada K1A 0E8

3303 - 33rd Street, N.W.
Calgary, Alberta T2L 2A7

100 West Pender Street
Vancouver, B.C. V6B 1R8

A deposit copy of this publication is also available
for reference in public libraries across Canada

Cat. No. M42-452E
ISBN 0-660-14994-X

Price subject to change without notice

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Manuscript submitted: 92.06.26
Approved for publication: 92.06.30

Cette publication est aussi disponible en français.

PREFACE

Appraisals of oil and gas resources existing in each of the major sedimentary basins of Canada are prepared on a regular basis by the Department of Energy, Mines and Resources Canada. These appraisals provide objective estimates of Canada's oil and gas resources, and also serve as a basis for efficient resource management and planning for future supply. Priorities for resource appraisal are set by the Petroleum Resources Appraisal Panel (PRAP), a joint organization of the Geological Survey of Canada and Energy sectors of the Department.

While conventional crude oil has been the mainstay of Canada's petroleum industry since the discovery at Leduc in 1946, the industry can be expected increasingly to shift investment to exploring for natural gas. Extensions to the continental gas transportation systems have opened new markets for Western Canadian natural gas at a time when reserves of conventional crude oil have been declining. Furthermore, natural gas is viewed as a preferred fuel for many applications because it is environmentally more acceptable than other fossil fuels. The PRAP, therefore, considers it a priority to estimate systematically both the amount of undiscovered natural gas likely to remain in the Western Canada Sedimentary Basin and the economic conditions under which it may be discovered, developed and produced.

Part I of this study describes the petroleum geology of Devonian exploration plays, and provides an assessment of remaining natural gas potential. The geological analysis and resource assessment were undertaken by the Institute of Sedimentary and Petroleum Geology (ISPG), Geological Survey of Canada. The potential estimates have been prepared using statistical techniques developed by the ISPG over the past two decades. Resource estimates are expressed in probabilistic terms.

Part II of this study is an economic analysis undertaken by the Energy Sector. It uses selected information from Part I and applies an investment decision methodology to estimate the quantity of economically recoverable resources under a set of assumptions pertaining to technology, costs and future economic parameters.

This report is the first in a series of publications on the natural gas resources of Western Canada. The information provided in these studies should assist in identifying investment opportunities for exploration and development in Western Canada. The studies also will contribute to the science of resource appraisal and methodologies of economic evaluation. These reports will be of particular interest to those who require an overview of the petroleum geology of Western Canada, and a comprehensive view of its gas resources and economics.

E.A. Babcock
Assistant Deputy Minister
Geological Survey of Canada

D. Oulton
Assistant Deputy Minister
Energy Sector

PRÉFACE

Le ministère de l'Énergie, des Mines et des Ressources (EMR) du Canada produit régulièrement des évaluations des ressources en pétrole et en gaz contenues dans chacun des principaux bassins sédimentaires du Canada. Celles-ci constituent des estimations objectives des ressources en pétrole et en gaz du Canada, en plus d'être fondamentales à la gestion efficace des ressources et à la planification de l'offre future. Les priorités en cette matière sont établies par le Comité de l'évaluation des ressources en pétrole et en gaz naturel (CERPG), relevant des secteurs de la Commission géologique du Canada et de l'énergie d'EMR.

Le pétrole brut conventionnel a été le pilier de l'industrie pétrolière canadienne depuis la découverte du gisement de Leduc en 1947; toutefois, on peut s'attendre à ce que l'industrie investisse de plus en plus dans l'exploration pour le gaz naturel. Le prolongement des réseaux de transport continental du gaz naturel a ouvert de nouveaux marchés pour ce combustible de l'Ouest canadien, à un moment où les réserves de pétrole brut conventionnel commencent à diminuer. De plus, on choisit très souvent le gaz naturel du fait qu'il est moins polluant que d'autres combustibles fossiles. Par conséquent, l'estimation systématique des quantités de gaz naturel non découvertes qui devraient exister dans le bassin sédimentaire de l'Ouest canadien, mais aussi l'évaluation des conditions économiques dans lesquelles elles peuvent être découvertes, mises en valeur et extraites sont prioritaires pour le CERPG.

La partie I du présent document contient une description de la géologie des zones gazéifères du Dévonien et une estimation des ressources non découvertes en gaz naturel. L'analyse géologique et l'évaluation des ressources ont été réalisées par l'Institut de géologie sédimentaire et pétrolière (IGSP) de la Commission géologique du Canada. L'estimation du potentiel a été préparée en utilisant des techniques statistiques mises au point par l'IGSP au cours des deux dernières décennies. Les résultats sont présentés en termes probabilistes.

La partie II présente une analyse économique réalisée par le Secteur de l'énergie. On y utilise des données choisies de la partie I ainsi qu'une méthode fondée sur les décisions d'investissement pour estimer la quantité de ressources économiquement récupérables, sur considération d'un ensemble d'hypothèses relatives à la technologie, aux coûts et aux conditions économiques futures.

Le présent ouvrage est le premier d'une série de publications portant sur les ressources en gaz naturel de l'Ouest canadien. Le contenu de ces documents devrait permettre de déterminer les possibilités d'investissement en matière d'exploration et de mise en valeur dans ce coin de pays. Cette série contribuera également à faire progresser la science de l'évaluation des ressources et à améliorer les méthodes d'évaluation économique. Elle sera particulièrement utile à toute personne souhaitant obtenir un aperçu de la géologie pétrolière de l'Ouest canadien et un panorama complet de ses ressources en gaz et de son potentiel économique.

E.A. Babcock
Sous-Ministre adjount
Commission géologique du Canada

D. Oulton
Sous-ministre adjoint
Secteur de l'énergie

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Abstract

The assessment of Devonian gas potential in the Western Canada Sedimentary Basin involved geological delineation and statistical evaluation of the established mature plays, and statistical evaluation of conceptual plays using the 25 identified established mature plays as a representative population of all Devonian gas plays. Results of the assessment suggest that the total Devonian gas resource in the Basin is in the order of 3 528 000 x 10^6m^3 (126 TCF). Fifty-six per cent of this gas volume remains to be discovered; 40 per cent is contained in conceptual plays and 16 per cent in established mature plays. The estimate of potential of the established mature plays is not overly optimistic; nonetheless some 17 gas pools, larger than 3 000 x 10^6m^3, are predicted to be present in the mature plays. This indicates that several of the mature plays still have a significant upside potential with respect to undiscovered gas volumes, particularly the Slave Point reef complexes and platform carbonates in northeast British Columbia and northwest Alberta, the Leduc/Nisku reef complexes in the Alberta "Deep Basin", and the Swan Hills shelf margin play in west-central Alberta.

Economic analysis of the Devonian gas potential estimates indicate that 16 per cent of the volume of recoverable gas is economic at a price of \$1.25 per MCF (\$44.13 per 10^3m^3), and 43 per cent at a price of \$2.50 per MCF (\$88.25 per 10^3m^3). Sensitivity analysis indicates that the economic potential of undiscovered gas is not greatly affected by cost changes, but can be very sensitive to exploration success rates and distance of discoveries to gathering systems. Estimates of the volume of economic gas potential for the entire Devonian (established and conceptual plays) are 240 000 x 10^6m^3 (8.5 TCF) at a price of \$1.25 per MCF (\$44.13 per 10^3m^3) and 634 000 x 10^6m^3 (22.4 TCF) at a price of \$2.50 per MCF (\$88.25 per 10^3m^3). These last numbers suggest that less than 32 per cent of estimated in-place potential (1 960 000 x 10^6m^3/70 TCF) will be economic unless gas prices rise above \$88.25 per 10^3m^3 (\$2.50 per MCF).

Résumé

L'estimation du potentiel en gaz dévonien du bassin sédimentaire de l'Ouest canadien a nécessité une délimitation géologique et une évaluation statistique des zones prouvées bien explorées, mais aussi une évaluation statistique des zones gazéifères possibles en utilisant, comme population représentative de toutes les zones de gaz dévonien, vingt-cinq zones prouvées bien explorées. Les résultats indiquent que les ressources totales en gaz dévonien dans le bassin sont de l'ordre de 3 528 000 x 10^6 m^3 (126 Tpi^3). Cinquante-six pour cent de ce volume n'a pas encore été découvert; 40 % est contenu dans des zones gazéifères possibles et 16 %, dans des zones prouvées bien explorées. L'estimation du potentiel des zones prouvées bien explorées n'est pas des plus optimistes; néanmoins, quelque 17 gisements de gaz de plus de 3 000 x 10^6 m^3 seraient contenus dans ces zones. Cela signifie que plusieurs des zones bien explorées présentent encore un fort potentiel à la hausse en ce qui concerne les quantités de gaz non découvertes, en particulier dans les complexes récifaux et les roches carbonatées de plate-forme de Slave Point (partie nord-est de la Colombie-Britannique et partie nord-ouest de l'Alberta), dans les complexes récifaux de Leduc et de Nisku («Deep Basin» en Alberta) et dans la zone de la marge de la plate-forme continentale de Swan Hills (centre ouest de l'Alberta).

L'analyse économique des ressources non découvertes en gaz dévonien indique que 16 % du volume de combustible récupérable est économiquement rentable au prix de 44,13 \$ par 10^3 m^3 (1,25 \$ par Mpi^3) et que 43 % de ce volume l'est au prix de 88,25 \$ par 10^3 m^3 (2,50 \$ par Mpi^3).

Une analyse de sensibilité révèle que le potentiel économique du gaz non découvert n'est pas tellement affecté par les variations de coût, mais qu'il peut l'être considérablement par le taux de succès des travaux d'exploration et, dans une moindre mesure, par la distance entre les découvertes et les réseaux collecteurs. Les estimations du potentiel en gaz économiquement rentable de tout le Dévonien (zones prouvées et possibles) sont de 240 000 x 10^6 m^3 (8,5 Tpi^3), au prix de 44,13 $ par 10^3 m^3 (1,25 $ par Mpi^3), et de 634 000 x 10^6 m^3 (22,4 Tpi^3), au prix de 88,25 $ par 10^3 m^3 (2,50 $ par Mpi^3). Ces chiffres signifient que moins de 32 % de l'estimation du potentiel en place (1 960 000 x 10^6 m^3 ou 70 Tpi^3) sera économique, à moins que le prix du gaz ne monte à plus de 88,25 $ par 10^3 m^3 (2,50 $ par Mpi^3).

Summary

The gas resources contained in Devonian strata of the Western Canada Sedimentary Basin are described in two sections. Part I contains the detailed geological play analysis and numerical assessment of undiscovered gas potential. Part II is an economic analysis of the undiscovered potential predicted in Part I. This overall appraisal of the natural gas potential of the Devonian forms the first of a series of reports resulting from an ongoing comprehensive assessment of the entire gas resources within Western Canada. Several reports on other play groups, similar to this volume, are anticipated.

In Part I, the natural gas potential of both established and conceptual plays is dealt with using a numerical assessment technique, termed the *discovery process model*, which is based on the size (volume) of individual pools or plays within a natural population of pools or plays. Established plays are defined as those that are demonstrated to exist by virtue of discovered pools with established reserves. Conceptual plays are defined as those plays that do not yet have discoveries or reserves, but which geological analyses indicates may exist. Established plays require geological analysis to delineate the type and extent of the pool population for each play, prior to statistical analysis. In contrast, no prior geological evaluation is required to undertake a statistical assessment of the conceptual plays.

With regard to established plays, the pools within a specific play form a natural geological population that is governed by one or more geological controls such as depositional style, structure, geometry, etc. (e.g., carbonate plays may be characterized as barrier reef, isolated reef, shelf margin, and platform). The play boundary is also controlled by geological factors and, in turn, governs the distribution of pools within that play. Once the play was defined, numerical evaluation was undertaken using the discovery process model. Twenty-five mature Devonian plays were geologically defined and statistically analyzed.

Results of the established mature play analysis indicate that four plays have a high upside potential for containing significant additional amounts of gas. These are: 1) Slave Point reef complexes situated north of the Peace River Arch and characterized by the Cranberry gas field; 2) Leduc/Nisku reef complexes such as Windfall, in the 'Deep Basin' region of west-central Alberta; 3) the Swan Hills shelf margin play of western Alberta, which is typified by the Kaybob South and Caroline fields; and 4) the Slave Point platform play of northeast British Columbia in which the Adsett field is the primary example.

The total estimated in-place gas potential for the 25 mature plays is 564 478 x $10^6 m^3$ (20 TCF). This number compares with a discovered in-place volume of 1 568 606 x $10^6 m^3$ (56 TCF). The total expected potential is not an overly optimistic number, and suggests that only 26 per cent of the total gas resource in mature plays remains to be discovered. Furthermore, no undiscovered pools of 28 317 x $10^6 m^3$ (1 TCF) in size or larger were predicted to be present in any of the 25 mature plays. Conversely, 17 undiscovered pools with in-place gas volumes of 3 000 x $10^6 m^3$ (~100 BCF) or larger are predicted to be present in the 25 mature plays. This suggests substantial upside potential in several of the mature plays, and makes continued exploration attractive.

Estimates of the potential and size of conceptual plays were derived by the discovery process model using the 25 mature plays as the 'pool' database. A discovery sequence of the 25 mature plays from 1946 to 1979 was generated, with each play size being the sum of the discovered in-place volume and estimated potential. The discovery date of each mature play was taken as the date when the first pool in that play was discovered. A play size-by-rank plot was then generated in a similar manner as the pool size-by-rank plots for the mature plays.

The estimated undiscovered potential for conceptual plays is 1 394 900 x $10^6 m^3$ (50 TCF). This estimate includes the volumetric sum of 23 conceptual plays out of the largest 40 Devonian plays.

This volume of 1 394 900 x $10^6 m^3$ compares with the discovered in-place volume of 1 568 600 x $10^6 m^3$. When compared with conceptual plays, mature plays have a much lower overall potential.

The total Devonian gas resource in the Western Canada Sedimentary Basin is estimated at 3 528 000 x $10^6 m^3$ (126 TCF). Fifty-six per cent of the Devonian gas resource remains to be discovered; 40 per cent is contained in conceptual plays and only 16 per cent in mature plays. It is stressed here that 56 per cent is a statistically estimated value of in-place gas resources. Only a portion of this 56 per cent will likely be booked as commercial reserves as discussed in Part II of this report.

Three important conclusions can be drawn from the above numerical estimates:

1. The geological analysis and statistical assessment of Devonian gas resources in the Western Canada Sedimentary Basin suggest that over one half (56 per cent) of the total gas resource remains to be discovered.

2. Of this undiscovered Devonian gas potential, 28 per cent is considered to be present in established mature plays. This is not an overly optimistic estimate for mature plays; nonetheless some 17 undiscovered pools, larger than 3 000 x $10^6 m^3$ are predicted to be present in mature plays.

3. Seventy-two per cent of the total Devonian gas potential is predicted to occur in conceptual plays. This is an extremely large value compared with established mature play potential, and thus should be taken for what it is; a statistical estimate of what is in-place with no implication for the economic viability of its discovery. Furthermore, the sizes of individual pools in specific conceptual plays will determine the extent to which these plays will ever be developed.

Part II contains estimates of the portion of undiscovered gas potential that can be expected to be economic over the long-term. This is accomplished by taking into consideration the major technical and economic constraints to exploration, development and production. This constrained portion is defined as *economic potential*, and is measured as a function of the plant gate price of natural gas. Economic potential is measured for both full-cycle and half-cycle analyses. The full-cycle case is defined to include all exploration, development, production and overhead costs, but excludes the cost of land rights. The half-cycle case excludes all pre-development costs and is relevant to development investment decisions when exploration costs are already incurred. The full-cycle and half-cycle analyses are undertaken in both fiscally burdened and unburdened contexts. Burdened and unburdened cases are provided to increase the relevance of the work to both the private and public sectors of the economy. Burdened economic potential measures potential under an assumed fiscal regime, while unburdened economic potential excludes the fiscal regime. The difference between the burdened and unburdened cases measures the impact of the fiscal regime on the ultimate discovery of natural gas resources.

The economic analysis was undertaken on each of the 25 established mature plays, for which undiscovered pool size estimates and other geological information are available. The 25 plays were assigned to five groups in order to reflect cost differences. Exploration, development and production costs, and production profiles, were estimated for each undiscovered pool. The resulting estimates of cost and production schedules were used to estimate plant gate pool supply prices using project discounted cash flow analysis. Supply curves for each play group were constructed from supply price estimates for each undiscovered pool in the plays belonging to that group. Similarly, supply curves for the total of all established Devonian plays were constructed from the play group supply curves. Although detailed economic analysis was not undertaken for conceptual plays, results for the mature plays were extended to conceptual plays to provide some estimate of their economic potential.

The supply curves estimated in this study are based on the following reference case conditions and assumptions: i) mean resource estimate for each undiscovered pool; ii) play-specific geological and engineering parameters and weighting factors; iii) play-specific economic exploration success rates; iv) current federal and provincial fiscal regimes; v) 1990 costs; and vi) a minimum required discounted cash flow real rate-of-return of 10 per cent on investment.

The reference case is based on data available at the time of the analysis. It does not consider improvements in economic success rates due to increased knowledge of exploration plays, reductions in development costs due to expansions of pipeline networks, or possible decreases in cost due to technological changes and improvements in company practices. Consequently, economic potential for the reference case should be considered closer to the current economics of exploration. It is likely a downward-biased estimate of long-term exploration fundamentals.

The major conclusions of the reference case and associated sensitivity analysis are as follows:

1. On a burdened full-cycle basis, economic potential as a percentage of recoverable gas-in-place volume ranges from 16 per cent at a plant gate price of \$44.13 per 10^3m^3 (\$1.25 per MCF), to 43 per cent at a price of \$88.25 per 10^3m^3 (\$2.50 per MCF). For the half-cycle case, the corresponding percentages range from 45 to 75 per cent.

2. The supply curve is elastic in the price range of \$17.65 per 10^3m^3 to \$88.25 per 10^3m^3 (\$0.50 to \$2.50 per MCF). At prices higher than \$88.25 per 10^3m^3, the supply curve is relatively inelastic.

3. There is little difference between burdened and unburdened economic potential. This occurs because the fiscal system is, in part, sensitive to the profitability of investment. Since the supply curves estimated trace marginal investments which, by definition, have a minimum level of profitability, it follows that altering or eliminating fiscal burden would have little impact on economic potential at any given price.

   This suggests that the combined federal and provincial fiscal regimes do not significantly reduce the profitability of finding and developing marginally economic resources. This does not suggest that more profitable investments are not paying significant taxes and royalties, or that activity would not be stimulated by a reduction in fiscal burden. This study does not consider the pace of activity and, therefore, conclusions cannot be drawn with regard to changes in rates of discovery as a result of changes in fiscal burden.

Sensitivity analyses were undertaken to estimate the impact on burdened economic potential of changes in costs, exploration drilling success rates, and distance of a discovery to a gathering system. Results of the sensitivity analyses are:

1. Estimates of the economic potential are not highly sensitive to changes in total costs. An increase in total costs of 20 per cent, relative to the reference case, reduces economic potential by approximately 10 per cent at a plant gate price of \$44.13 per 10^3m^3, and by 6 per cent at \$88.25 per 10^3m^3. Decreasing total costs by 30 per cent increases economic potential by 11 per cent at \$44.13 per 10^3m^3, and by 3 per cent at \$88.25 per 10^3m^3.

2. Economic potential is highly sensitive to exploration success rates. For example, doubling exploration success rates increases total economic potential by 38 per cent at a plant gate price of \$44.13 per 10^3m^3, and by 20 per cent at a plant gate price of \$88.25 per 10^3m^3. Improvements in drilling success rates can, therefore, have a significant impact on economic potential.

3. Reducing pipeline distance from discovery to gathering system to 2.5 km increases full-cycle economic potential by 16 per cent at \$44.13 per 10^3m^3. Similarly, in the half-cycle analysis, economic potential increases by 17 per cent. This relatively large increase in economic potential occurs because, at these lower prices, it is the relatively large pools, with higher

pipeline costs, that contribute to economic potential. At \$88.25 per 10^3m^3, full-cycle economic potential increases by 3 per cent. This increase is modest because, for small pools, exploration costs are a relatively larger component of total costs than are pipeline costs. In the half-cycle analysis, economic potential increases by 6 per cent.

Results of the 25 mature Devonian plays were extended to conceptual plays using a simple and straightforward procedure. The addition of economic potential of conceptual plays to estimates of economic potential of mature plays increases burdened full-cycle economic potential from 68 x 10^9m^3 (2.4 TCF) to 240 x 10^9m^3 (8.5 TCF) at \$44.13 per 10^3m^3, and from 180 x 10^9m^3 (6.4 TCF) to 634 x 10^9m^3 (22.4 TCF) at \$88.25 per 10^3m^3.

Sommaire

Les ressources en gaz contenues dans les couches dévoniennes du bassin sédimentaire de l'Ouest canadien sont décrites dans deux sections. La première (partie I) présente l'analyse géologique détaillée des zones gazéifères et l'évaluation numérique du potentiel en gaz non découvert; la seconde (partie II) se veut une analyse économique du potentiel non découvert estimé dans la partie I. Cette étude globale du potentiel en gaz naturel du Dévonien constitue le premier document d'une série qui sera publiée dans le cadre d'une évaluation complète et continue de toutes les ressources en gaz que recèle l'Ouest canadien. Plusieurs ouvrages semblables sur d'autres groupes de zones gazéifères sont prévus.

Dans la partie I, le potentiel en gaz naturel contenu dans les zones gazéifères prouvées et possibles est déterminé à l'aide d'une technique d'évaluation numérique appelée le *modèle du processus de découverte*; cette technique est basée sur la dimension (volume) de chacun des gisements ou de chacune des zones gazéifères au sein d'une population naturelle de gisements ou de zones gazéifères. Les zones prouvées sont définies comme étant celles dont l'existence est démontrée par la découverte de gisements contenant des réserves prouvées. Les zones possibles correspondent à celles dans lesquelles aucune découverte n'a encore été faite et pour lesquelles il n'existe pas encore de réserves, mais où l'analyse géologique indique des possibilités. Dans le cas des zones prouvées, il convient de réaliser une analyse géologique, afin de déterminer le type et l'étendue de la population de gisements de chaque zone, avant de se lancer dans une analyse statistique. Par contre, dans le cas des zones possibles, cette étape n'est pas nécessaire pour entreprendre une analyse statistique.

Les gisements au sein d'une zone gazéifère prouvée forment une population géologique naturelle gouvernée par un ou plusieurs facteurs géologiques comme le style de sédimentation, la structure, la géométrie, etc. Par exemple, les zones caractérisées par la présence de roches carbonatées peuvent être classées selon qu'il s'agit d'un milieu récif barrière, de récif isolé, de marge de plate-forme continentale et de plate-forme. Les limites de la zone gazéifère dépendent également de facteurs géologiques et gouvernent à leur tour la répartition des gisements au sein de cette zone. Une fois qu'une zone gazéifère a été définie, on procède à l'évaluation numérique en appliquant le modèle du processus de découverte. Vingt-cinq zones dévoniennes bien explorées ont été géologiquement définies et statistiquement analysées.

Les résultats de l'analyse des zones prouvées bien explorées montrent que quatre d'entre elles présentent un fort potentiel à la hausse relativement à la présence d'importantes quantités additionnelles de gaz. Ce sont les zones suivantes : 1) celle des complexes récifaux de Slave Point, située au nord de l'arche de Peace River et caractérisée par le champ de Cranberry; 2) celle des complexes récifaux de Leduc et de Nisku, située dans la région du «Deep Basin» dans le centre ouest de l'Alberta et caractérisée par le champ de Windfall; 3) celle de la marge de la plate-forme de

Swan Hills, située dans l'ouest de l'Alberta et caractérisée par les champs de Kaybob South et de Caroline; et 4) celle de la plate-forme de Slave Point, située dans le nord-est de la Colombie-Britannique et caractérisée par le champ d'Adsett.

L'estimation du potentiel de gaz en place dans les 25 zones gazéifères bien explorées atteint un total de 564 478 x 10^6 m^3 (20 Tpi^3), en comparaison avec un volume en place découvert de 568 606 x 10^6 m^3 (56 Tpi^3). Le potentiel total prévu n'est donc pas des plus optimistes et il indique que seulement 26 % de toutes les ressources en gaz dans les zones bien explorées n'ont pas encore été découvertes. En outre, il a été prévu qu'aucun gisement non découvert de 28 317 x 10^6 m^3 (1 Tpi^3) ou plus en volume n'existait dans l'une ou l'autre des 25 zones bien explorées. Par contre, on prévoit l'existence de 17 gisements non découverts d'au moins 3 000 x 10^6 m^3 (env. 100 Gpi^3) dans les 25 zones bien explorées, ce qui signifie un bon potentiel à la hausse dans plusieurs de ces zones et rend intéressante une exploration continue.

Les estimations du potentiel et de la dimension des zones possibles ont été réalisées au moyen du modèle du processus de découverte, en utilisant les 25 zones bien explorées comme base de données sur les gisements. Une séquence de découverte 25 zones gazéifères bien explorées s'échelonnant de 1946 à 1979 a été produite, la dimension de chaque zone correspondant à la somme du volume en place découvert et du potentiel estimé. La date de découverte de chaque zone bien explorée est celle de la découverte du premier gisement dans cette zone. On a ensuite produit un diagramme du volume des zones gazéifères selon leur rang, de la même façon que dans les zones bien explorées, on établit les diagrammes du volume des gisements selon leur rang.

L'estimation du potentiel non découvert dans les zones possibles est de 1 394 900 x 10^6 m^3 (50 Tpi^3); ce chiffre correspond à la somme des volumes de 23 zones possibles parmi les 40 zones dévoniennes les plus vastes. Ce volume est de 1 394 900 x 10^6 m^3, tandis que le volume en place découvert atteint 1 568 606 x 10^6 m^3. Par rapport aux zones possibles, les zones bien explorées ont un potentiel global beaucoup plus faible.

Les ressources totales en gaz dévonien dans le bassin sédimentaire de l'Ouest canadien sont évaluées à 3 528 000 x 10^6 m^3 (126 Tpi^3). Cinquante-six pour cent de ce volume n'a pas encore été découvert; 40 % est contenu dans des zones gazéifères possibles et seulement 16 %, dans des zones bien explorées. Il faut souligner que le 56 % cité ci-haut n'est qu'une estimation statistique des ressources en gaz présentes en place; seule une partie de ce 56 % sera un jour classée dans la catégorie des réserves commerciales, comme il le sera précisé dans la partie II du présent document.

Trois conclusions importantes peuvent être tirées des estimations numériques ci-dessus :

1. L'analyse géologique et l'évaluation statistique des ressources en gaz dévonien du bassin sédimentaire de l'Ouest canadien indiquent que plus de la moitié (56 %) des ressources totales en gaz restent à découvrir.

2. De ce potentiel en gaz dévonien, seulement 28 % est associé à des zones prouvées bien explorées. Ce chiffre n'est pas des plus optimistes pour des zones bien explorées; néanmoins, quelque 17 gisements non découverts de plusde 3 000 x 10^6 m^3 et plus en volume devraient exister dans des zones bien explorées.

3. Selon les prévisions, 72 % du potentiel total en gaz dévonien devrait se trouver dans des zones possibles. Cettevaleur est très élevée par rapport au potentiel des zones prouvées bien explorées; elle devrait donc être considérée pour ce qu'elle est, c'est-à-dire une estimation statistique des quantités en place sans implication quant à la viabilité économique de la découverte. De plus, l'ampleur de la mise en valeur dans certaines zones possibles sera établie d'après la dimension des différents gisements qui la composent.

La partie II contient des estimations de la fraction du potentiel de gaz non découvert qui pourrait être économiquement rentable à long terme, lesquelles prennent en compte les principales contraintes techniques et économiques à l'exploration, à la mise en valeur et à la production. Cette fraction du potentiel est définie comme le *potentiel économique* et est mesurée en fonction du prix à la sortie d'usinedu gaz naturel. Le potentiel économique est évalué pour le cycle complet et pour le demi-cycle. Dans le cas du cycle complet, on inclut les coûts totaux d'exploration, de mise en valeur et de production, mais on exclut les coùts d'acquisition des terres. Dans celui du demi-cycle, on exclut tous les coûts engagés préalablement à la mise en valeur et on ne considère que les décisions d'investissement pour la mise en valeur une fois les dépenses d'exploration engagées. Les analyses du cycle complet et du demi-cycle sont réalisées avec et sans fardeau fiscal. Les deux situations ont été examinées de façon que le travail ait un intérêt tant pour le secteur privé que pour le secteur public de l'économie. Dans le cas de l'analyse avec fardeau fiscal, on estime le potentiel en tenant compte d'un régime fiscal hypothétique. La différence entre les potentiels calculés avec et sans fardeau fiscal mesure les répercussions du régime fiscal sur la découverte ultime des ressources en gaz naturel.

L'analyse économique a porté sur les 25 zones prouvées bien explorées pour lesquelles on dispose de données sur le volume des gisements non découverts et sur d'autres aspects géologiques. Les 25 zones ont été classées dans cinq groupes de façon à faire ressortir les différences de coûts. Les coûts (d'exploration, de mise en valeur et de production) ainsi que les profils de production ont été établis pour chaque gisement non découvert. Les estimations des coûts et des délais de production ont été utilisées pour évaluer les prix d'offre à la sortie d'usine associés aux gisements, à l'aide de l'analyse de la marge brute d'autofinancement actualisée. Des courbes d'offre ont été établies pour chaque groupe de zones à partir d'estimations du prix de l'offre pour chaque gisement non découvert dans les zones faisant partie de ce groupe. De même, des courbes d'offre pour l'ensemble des zones dévoniennes prouvées ont été tracées à partir des courbes d'offre des groupes de zones. Les zones possibles n'ont pas fait l'objetd'une analyse économique détaillée, mais leur potentiel économique a pu être estimé en extrapolant les résultats obtenus dans le cas des zones bien explorées.

Les courbes d'offre estimées dans le présent document sont basées sur le cas de référence suivant : i) estimation moyenne des ressources pour chaque gisement non découvert; ii) paramètres relatifs à la géologie et à l'ingénierie et facteurs de pondération spécifiques à chaque zone gazéifère; iii) taux de succès économique de l'exploration spécifiques à chaque zone gazéifère; iv) régimes fiscaux provinciaux et fédéral actuels; v) coûts de 1990 et vi) taux minimal de rendement réel des ressources d'autofinancement actualisées de 10 % sur l'investissement.

Le cas de référence est basé sur les données disponibles au moment de l'analyse. Il ne tient pas compte des améliorations dans les taux de succès économique découlant d'une meilleure connaissance des zones d'exploration, des réductions dans les coûts de mise en valeur en raison du prolongement des réseaux de gazoducs ou des diminutions de coût associées aux changements et aux améliorations techniques apportés par les gazières. Par conséquent, on peut considérer que le potentiel économique calculé dans le cas de référence se rapproche du potentiel économique correspondant aux conditions économiques actuelles de l'exploration. À long terme, il constitue probablement une sous-estimationdu potentiel réel.

Les principales conclusions tirées de l'analyse du cas de référence et de l'analyse de sensibilité associée sont les suivantes :

1. Dans le cas du cycle complet avec fardeau fiscal, le potentiel économique exprimé en pourcentage du volume de gaz en place récupérable varie de 16 %, à un prix à la sortie d'usine de 44,13 $ par 10^3 m^3 (1,25 $ par Mpi^3), à 43 %, à un prix de 88,25 $ par 10^3 m^3 (2,50 $ par Mpi^3). Dans celui du demi-cycle, les pourcentages correspondants sont de 45 % et 75 %.

2. La courbe d'offre est élastique entre 17,65 $ par 10^3 m^3 et 88,25 $ par 10^3 m^3 (entre 0,50 $ et 2,50 $ par Mpi^3). Au-delà de 88,25 $ par 10^3 m^3, la courbe d'offre est relativement inélastique.

3. Le potentiel économique avec ou sans fardeau fiscal varie peu du fait que le régime fiscal est, en partie, sensible à la rentabilité des investissements. Étant donné que les courbes d'offre estimées suivent les investissements marginaux qui, par définition, présentent un niveau de rentabilité minimal, il s'ensuit que la modification ou l'élimination du fardeau fiscal aurait peu de répercussions sur le potentiel économique, quel que soit le prix.

Ces faits suggèrent que les régimes fiscaux combinés du fédéral et des provinces ne réduisent pas de façon importante la rentabilité d'une découverte et de la mise en valeur de ressources marginales du point de vue économique. Ils n'indiquent pas que les taxes et les redevances ne sont pas importantes dans le cas des investissements plus rentables ni qu'une réduction du fardeau fiscal ne stimulerait pas l'activité. La présente analyse fait abstraction du rythme de l'activité et, partant, il est impossible de tirer des conclusions au sujet des variations du taux de découverte consécutives à des modifications du fardeau fiscal.

Le but des analyses de sensibilité était d'estimer les répercussions des changements dans les coûts, dans le taux de succès du forage d'exploration et dans la distance des découvertes par rapport aux réseaux collecteurs, sur le potentiel économique avec fardeau fiscal. Les résultats des analyses de sensibilité sontles suivants :

1. Les estimations du potentiel économique ne sont pas très sensibles aux changements dans les coûts totaux. Une augmentation de 20 % des coûts totaux, par rapport au cas de référence, a pour effet de réduire le potentiel économique d'environ 10 %, à un prix de sortie d'usine de 44,13 \$ par 10^3 m^3, et de 6 %, à un prix de 88,25 \$ par 10^3 m^3. Une diminution de 30 % des coûts totaux a pour effet de faire augmenter le potentiel économique de 11 %, à un prix de 44,13 \$ par 10^3 m^3, et de 3 %, à un prix de 88,25 \$ par 10^3 m^3.

2. Le potentiel économique est très sensible au taux de succès des travaux d'exploration. Par exemple, si le taux de succès de l'exploration est multiplié par deux, le potentiel économique total augmente de 38 %, à un prix à la sortie d'usine de 44,13 \$ par 10^3 m^3, et de 20 %, à un prix à la sortie d'usine de 88,25 \$ par 10^3 m^3. L'amélioration du taux de succès du forage peut donc avoir des répercussions importantes sur le potentiel économique.

3. La réduction de la longueur des gazoducs entre le gisement et le réseau collecteur à 2,5 km a pour effet de faire augmenter le potentiel économique pour le cycle complet de 16 % à un prix de 44,13 \$ par 10^3 m^3. De même, dans le cas de l'analyse du demi-cycle, le potentiel économique augmente de 17 %. Cette augmentation relativement importante du potentiel économique est due au fait que, à ces bas prix, ce sont les gisements relativement vastes, pour lesquels les coûts de transport par gazoducs sont élevés, qui contribuent au potentiel économique. À 88,25 \$ par 10^3 m^3, le potentiel économique dans le cas du cycle complet avec fardeau fiscal augmente de 3 %. Cette augmentation est modeste parce que, dans le cas des petits gisements, les coûts d'exploration représentent une composante relativement plus importante des coûts totaux que les coûts reliés aux gazoducs. Dans l'analyse du demi-cycle, le potentiel économique augmente de 6 %.

Les résultats obtenus avec les 25 zones dévoniennes bien explorées ont été étendus aux zones possibles à l'aide d'une relation simple et directe. L'ajout du potentiel économiquedes zones gazéifères possibles aux estimations du potentiel économique des zones bien explorées a pour effet d'augmenter le potentiel économique dans le cas du cycle complet avec fardeau fiscal, le faisant passer de 68 x 10^9 m^3 (2,4 Tpi^3) à 240 x 10^9 m^3 (8,5 Tpi^3), à un prix de 44,13 \$ par 10^3 m^3, et de 180 x 10^9 m^3 (6,4 Tpi^3) à 634 x 10^9 m^3 (22,4 Tpi^3), à un prix de 88,25 \$ par 10^3 m^3.

PART I: GEOLOGICAL PLAY ANALYSIS AND RESOURCE ASSESSMENT

INTRODUCTION

Purpose

This report documents a detailed analysis of the conventional natural gas resources estimated to be contained in Devonian strata of the Western Canada Sedimentary Basin. It is the first in a series dealing with conventional gas resources of the entire Western Canada Sedimentary Basin south of 62° latitude. Estimates of regional resource potential have been prepared periodically by the Geological Survey of Canada (i.e., Dixon et al., 1988; Podruski et al., 1988; Wade et al., 1989; Sinclair et al., 1992), using systematic geological basin analysis and statistical resource evaluation methods. The initial computer-based statistical evaluation methods were developed within the Geological Survey of Canada by Lee and Wang (1983a, b, 1984, 1985, 1986), and subsequently refined into the present PETRIMES system (Lee and Tzeng, 1989; Lee and Wang, 1990), which is employed here for estimating the resource potential of established plays.

Because of the enormity of the well and pool database, the number of plays, and the geological and economic complexities associated with those plays, the assessment of the natural gas resource potential of Western Canada is the most difficult single project of its kind to be undertaken to date by the Geological Survey of Canada. Hence the assessment is divided into major play groups on the basis of geological criteria, primarily major stratigraphic time-rock units or structural/tectonic provinces, each having a distinct set of geological factors that controls the size, distribution and type of hydrocarbon play or reservoir. The major play groups set up for the Western Canada gas project are the Devonian, Permo-Carboniferous, Triassic, Deformed Belt, Lower Cretaceous (Jurassic to Mannville), Colorado Group, and Upper Cretaceous–Tertiary.

The Devonian assessment was undertaken first because of the existing comprehensive geological database, and also because there is an upside potential for finding significant reserves in relatively large economic pools. The Devonian System is the most prolific hydrocarbon-producing interval in the Western Canada Sedimentary Basin, even though major reserves are contained in upper Paleozoic and Mesozoic rocks. Devonian oil accounts for over 60 per cent of recoverable conventional crude in Alberta (Alberta Energy Resources Conservation Board, 1989). Furthermore, approximately one quarter of the total in-place gas reserves in the Western Canada Basin are contained in Devonian rocks (Fig. 1).

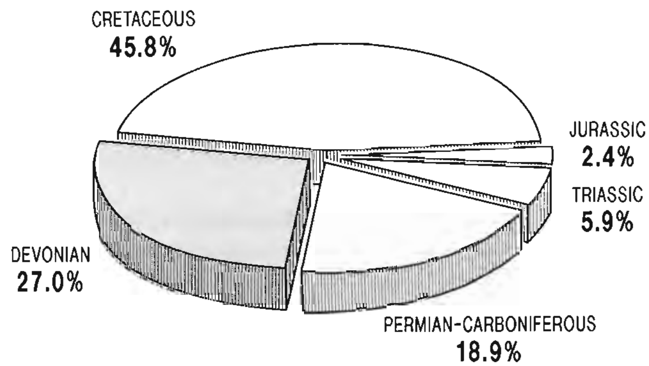


Figure 1. *Distribution of Western Canada gas resources by geological system. (Based on data from the Alberta Energy Resources Conservation Board, 1989, and the British Columbia Ministry of Energy, Mines and Petroleum Resources, 1990.)*

The objectives of this study are threefold: i) to estimate the total amount of gas that might exist in the Devonian System of Western Canada, regardless of whether all of it will ever be discovered or be economically exploitable if it is discovered; ii) to outline the principal geological gas plays in the Devonian System in a manner that will enable industry to utilize our data for exploration; and iii) to provide the necessary geological and resource potential information to allow industry and government agencies to undertake economic viability studies with respect to exploration, producibility and ultimate marketability.

Terminology

The term natural gas, as used in this report, is defined as any gas (at standard pressure and temperature of 14.73 psia and 60°F/101.33 kPa and 15°C, respectively) of natural origin, producible from a borehole, and composed primarily of hydrocarbon molecules (Potential Gas Committee, 1990). Natural gas may contain non-hydrocarbon components in significant amounts (i.e., H_2S in Devonian gas of the Alberta Deep Basin). In estimating potential, it was not feasible to separate such components from the total potential. It is recognized, however, that certain components, particularly H_2S, must be accounted for in any economic analysis of potential supply from sour gas sources.

Raw gas is unprocessed natural gas, containing methane, inert and acid gases, impurities, and other hydrocarbons, some of which may be recoverable as liquids. *Sales gas* or *marketable gas* is natural gas that meets specifications for end use, usually requiring processing to remove acid gases, impurities and liquid components. *Nonassociated gas* is natural gas that is not in contact with crude oil in a reservoir. *Associated gas* is natural gas that occurs in crude oil reservoirs as free gas. *Solution gas* is natural gas that is dissolved in crude oil under reservoir conditions.

In making the estimates of potential of Devonian natural gas, it was not practical to separate non-associated, associated and solution gas resources. Where designated as discrete entities within a pool, solution and associated gas volumes were added together. Pools discussed in this report may be composed of nonassociated (NA) gas or of various combinations of nonassociated, associated (A) and solution (S) gas. The potential estimates reported here reflect only total natural gas resources. However, within the description of each mature play, the principal mode of gas occurrence is indicated in the pool-rank table. In addition, within the written discussion, amounts of nonassociated gas are given for those plays that have substantial associated and/or solution gas volumes occurring within them.

The terms *resource, reserve,* and *potential* as defined by the Geological Survey of Canada (Podruski et al., 1988) are retained in this report. *Resource* is defined as all hydrocarbon accumulations that are known, or are inferred, to exist. The terms *resource, resource endowment* and *endowment* are synonymous and may be used interchangeably. *Reserves* are that portion of the resource that has been discovered, and the term *potential* describes that portion of the resource that is inferred to exist but is not yet discovered. The terms *potential* and *undiscovered* resources are synonymous and may be used interchangeably. It should be noted that the term *reserve* can also refer to initial marketable gas volume, so, to avoid confusion, *discovered in-place volume* has been used rather than *reserve*.

The term *gas-in-place* refers to the volume of gas found in the ground, regardless of what portion may be recoverable. *Inital in-place volume* refers to the gross volume of raw gas prior to production, while *recoverable in-place volume* is the portion of raw gas expected to be recovered with current technology costs.

The terms *prospect, play, field, pool,* and *strike area* have the following designated meanings in this report. A *prospect* is defined as an untested exploration target within a single stratigraphic interval; it may or may not contain hydrocarbons. A prospect is not synonymous with an undiscovered pool. A *play* consists of a family of pools and/or prospects that share a common history of hydrocarbon generation, migration, reservoir development and trap configuration (Energy, Mines, and Resources Canada, 1977). The term *gas field* is used to designate an area that produces gas without stratigraphic interval restrictions. Any number of discrete pools, at varying stratigraphic levels, may exist within a field. A gas *pool* is defined as a discovered accumulation of gas, typically within a single stratigraphic interval, that is hydrodynamically separate from another gas accumulation. A *strike area* refers to a well that is producing gas but has not been assigned to a specific pool or field (Alberta Energy Resources Conservation Board, 1989). In British Columbia the term *other area* is synonymous with strike area.

Plays are grouped into two categories: *established plays* (those that are demonstrated to exist by virtue of discovered pools with established reserves) and *conceptual plays* (those that do not yet have discoveries or reserves but which geological analysis indicates may exist). Established plays are grouped further into *mature* and *immature* plays on the basis of adequacy of the play data for statistical analysis. Mature plays are those plays in which the profile of the discovery sequence is adequate for analysis using the *discovery process model* utilizing the PETRIMES assessment procedure (discussed below). Immature plays are those in which the discovery sequence profile is inadequate for application of this model and corresponding assessment procedure.

Method and content

The assessment of Devonian gas resources has two essential components: geological analysis and statistical analysis. The geological analysis is the fundamental component, and involves characterization of the exploration play. Pools and prospects within a play form a natural geological population that can be delimited areally. Once the play is defined, a numerical resource assessment can be undertaken using pool and prospect data from that specific play (see Resource assessment procedure, below).

The analysis of Devonian gas potential entailed delineating and systematically evaluating some 28 established plays. Twenty-five plays were classified as mature; three were considered immature. This report contains a description of all established mature plays, including definition, geology, exploration history and numerically estimated resource potential, with supporting figures. Each play is designated by geological formation/member, depositional or trap type, and characteristic gas pool. Conceptual plays are treated in a separate section in a descriptive manner, and conceptual play potential is estimated using the 25 mature plays as the *pool* database.

The pool and well data used in the assessments are based on data sets of the provincial agencies of Alberta (Alberta Energy Resources Conservation Board, 1989) and British Columbia (British Columbia Ministry of Energy, Mines, and Petroleum Resources, 1990).

Acknowledgments

The authors have drawn upon the work of, and benefitted greatly from interchange with numerous colleagues in the petroleum industry and the Institute of Sedimentary and Petroleum Geology. Special acknowledgments are extended to J. Podruski, who was instrumental in the initial planning and undertaking of this project; T. Bird, who provided input on the Northwest Territories Devonian plays while an employee of COGLA and later with ISPG; and P. Tzeng, who assisted with the assessment and helped several authors to understand and use the statistical methodology programs. Staff of the Petroleum Geology Branch, British Columbia Ministry of Energy, Mines and Petroleum Resources, particularly J. MacRae and K. MacAdam, were most co-operative in assisting with data and input regarding the northeast British Columbia plays. C. Gemeroy and K. Goble, National Energy Board, advised on various aspects of reserves calculations and pool volumes. R. Chapman, K. Drummond, N. Fischbuch, G. Tebbutt and J. Wendte critically reviewed the preliminary manuscript, and provided many useful suggestions for its improvement.

The report could not have been completed without the enthusiastic and professional input of Peter Gubitz, who is responsible for drafting all figures; the ISPG Cartography unit (in particular J. Thomson, D. Wallace, and B. Ortman) who assisted with cartographic and production procedures; and W. Ell and E. Gordon, who were responsible for the word processing. Special thanks are extended to P. Greener and H. King for compugraphic processing, and to J. Monro for production editing of the manuscript.

RESOURCE ASSESSMENT PROCEDURE

Numerous methods exist for estimating the quantity of hydrocarbons that may exist in a play, region or basin. The method used depends on the nature and amount of data available. White and Gehman (1979), Masters (1984), and Rice (1986), have described approaches currently in use. For the assessment of the Devonian gas resources of the Western Canada Sedimentary Basin, the *discovery process model* (Lee and Wang 1985, 1990) was employed.

The underlying assumption of the discovery process model is that discoveries made in the course of an exploration program represent a biased sample of the underlying population of pools for that play. The process is biased in the sense that the largest prospects in a play tend to be tested first; therefore, the largest pools tend to be found early in a play's exploration history. The process model makes use of the two most reliable pool data sets - pool size and discovery date - to produce estimates of play potential and individual pool sizes. The volumes of individual pools are then summed to give an estimate of the total gas resource in that play.

The resource assessment procedure using the discovery process model is best described by outlining the various steps that were undertaken during analysis of the Devonian gas plays, using one of the mature plays as an example.

Play definition

The definition of play type and play area are the primary objectives of the basin analysis studies that precede the resource evaluation. The specific areal extent of the play is contained within a *play boundary or play polygon* (Fig. 2). The extent of the play boundary is governed by the distribution of pools within that play. By definition, pools in a specific play form a natural geological population that is characterized by one or more of the following: depositional model, structural style, type of trapping mechanism, geometry, or diagenesis.

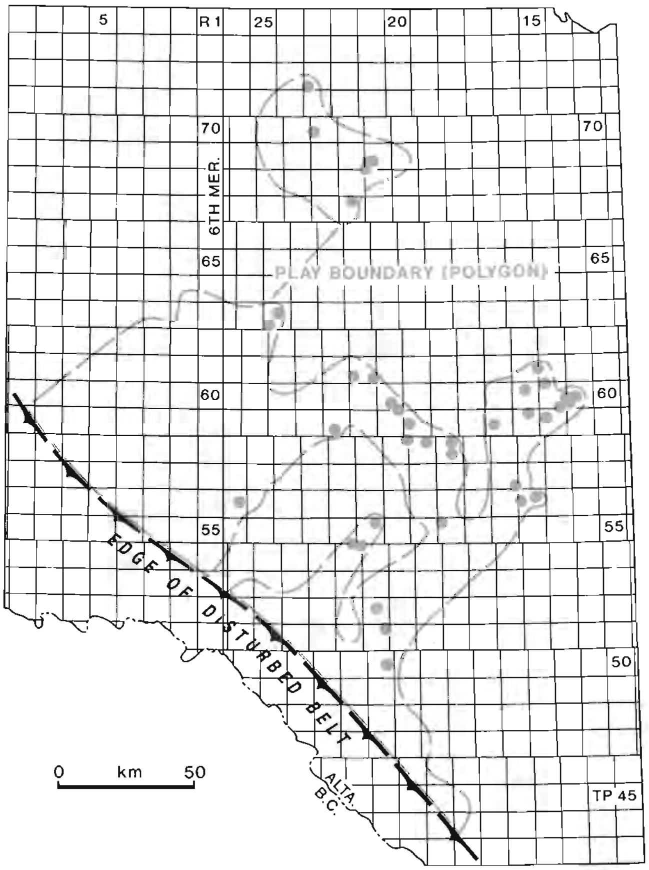


Figure 2. Example of a play boundary (play polygon) using the Leduc/Nisku reef complexes play. Dots indicate pools in the play.

The importance of a properly defined play is that it will correspond to a single statistical population, and thus satisfy the statistical assumptions required for the application of the evaluation models. A mixed population, resulting from an improperly defined play, will adversely impact on the quality of the resource estimates derived from the statistical evaluation.

Compilation of play data

Once a play is defined and the play boundary has been outlined as a closed polygon (Fig. 2), all the wells and pools within the formation(s) identified as part of that play are retrieved from the PETRIMES well and pool database. The well and pool lists are then examined to ensure that they are consistent with the play definition and play boundary. Drill-stem tests from exploratory wells are sometimes utilized to supplement the pool lists when pool numbers are insufficient. The pool lists are then used to produce an exploration discovery-time series (Fig. 3). This is the basic input data required by the discovery process model for estimating the quantity of undiscovered petroleum resources.

Discovery process model

As exploration of a specific play progresses through time, the pools discovered represent samples from the underlying pool population of that play. The discovered pools are not random samples, but are biased because explorationists tend to drill the best, and therefore largest, prospects first. This biased nature of the sample population poses a problem for estimation of petroleum resources using standard statistical methods.

The discovery process model was devised to account for the biased element within the sample population. Kaufman et al. (1975) and Lee and Wang (1985) incorporated this biased element into a probabilistic model in order to estimate the mean and variance of an underlying natural geological population. Two assumptions are inherent in this model: i) the probability of discovering (sampling) a pool is proportional to its size; and ii) sampling occurs without replacement; that is, a pool will not be discovered twice. The first assumption is supported by plotting discovery sequence in a time series (Fig. 3). The second assumption is self-evident. The biased nature of the sample obtained from the exploration process contains information not only about mean and variance of the pool size population but also about the total number of pools within the play. A further consequence of the model is the inverse relation between number of pools and mean of the pool size distribution. That is, the more undiscovered pools that are expected for a play, the smaller will be their sizes and the greater will be their number (Table 1, Appendix I*).

Unlike previous resource assessments, there now exists the option of choosing a probability distribution for the underlying pool size distribution during the estimation process. Both the parametric (log-normal in this report) and non-parametric (no prior probability distribution is assumed) discovery process models were applied on all play data sets. In most cases, both estimation procedures yielded similar results. However, in a few cases the parametric approach failed to give a satisfactory result, either because of numerical errors associated with the computational algorithm, or because of an inadequacy of the lognormal distribution in approximating the data set. Use of the log-normal assumption can be validated by plotting the pool size data in logarithmic scale against probability, or by

*Tables 1 to 40 are included in Appendix I following Part I of this report.

using a quantile–quantile plot. A truly log-normal population should show a linear relation. Deviations from linearity reflect problems either with the sample (mixed population) or with the log-normal assumption. The log-normal assumption holds true for all Devonian gas plays analyzed in this study except the Swan Hills isolated reef play, which was evaluated using a non-parametric approach.

Gas occurrences in a specific exploratory well may take different forms, ranging from a discovery of "commercial" size, or a significant recovery from a drill-stem test, to a few gas bubbles in the drilling mud and/or recovery of gas-cut water. All of these "shows" of gas could be considered as a pool by definition. In practice, a gas accumulation is considered to be a pool if and only if it is commercial at the time of discovery. However, imposing such a restricted definition on the underlying pool population severely truncates the pool size distribution and adversely impacts on the validity of the resource estimate. For example, if some of the small "pools" have been omitted from the sample, then the exploration times series (Fig. 3) may not reveal enough information to determine the total number of pools within a play. Consequently, within each play, wells that had significant gas shows on drill-stem testing were examined to determine whether these tests indicated a new pool, and if so, what resources should be allocated to that pool.

It should be noted that given the possible truncation of the pool-size data set, estimates of the resources in a play should not be considered as the ultimate resource for that play. The results of an assessment are based on the pool-size data set utilized; the model only predicts the existence of undiscovered pools based on that data set. The model does not account for appreciation in reserves of the pools within the data set.

Pool size distribution

The discovery process model generates estimates of the mean, variance, and total number of pools in the underlying pool population or play. An additional

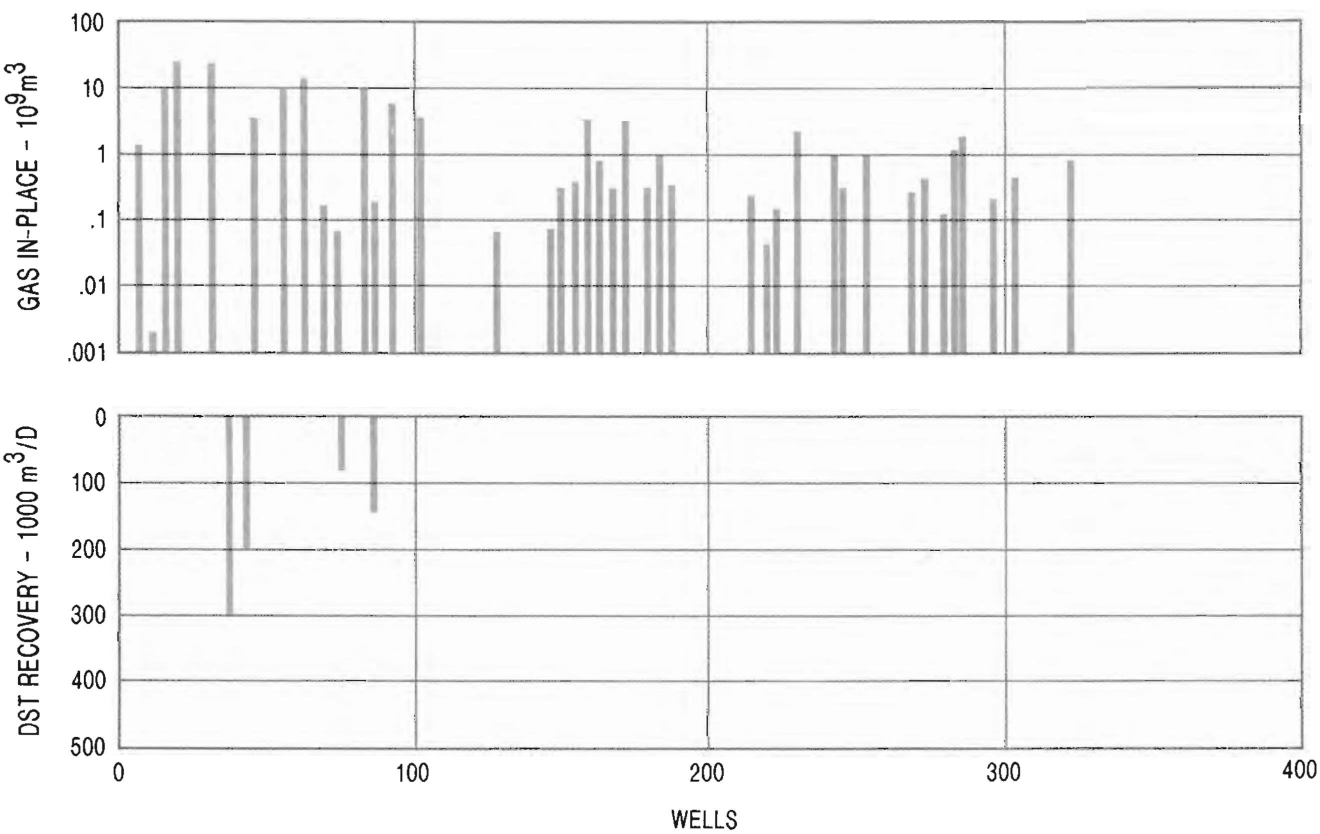


Figure 3. Exploration discovery-time series for the Leduc/Nisku reef complexes play. Horizontal axis is the discovery sequence, upper vertical axis indicates discovered pool volumes, and lower vertical axis indicates drill-stem test flow rates.

output of the model is the *beta* value, which can be considered as a measure of the exploration efficiency; that is, an indicator of how strong the relation between pool size and discovery sequence is.

The individual pools predicted by the model are represented in graphic form by bars indicating the range of possible sizes from largest to smallest (Fig. 4a). The graph plots individual pool size against pool rank. The individual pool-size ranges are in the form of cumulative frequencies greater than percentage. A bar with a frequency interval of 25 to 75 indicates there is a 50 per cent chance that the pool will fall somewhere within the size range constrained by the interval. A bar with a frequency interval of 5 to 95 indicates there is a 90 per cent chance that the pool will fall somewhere within the size range constrained by the interval.

After the individual pool sizes have been estimated, the discovered pool sizes are matched to the estimated pool sizes. The matched pools are indicated in graphic form by dots and the unmatched (undiscovered) pools by bars. The sizes of the undiscovered pools are further constrained by the fact that their size ranges cannot exceed or be less than any discovered (matched) pools that are ranked greater or less than the unmatched pool (Fig. 4b).

Estimate of play potential

The play potential can be estimated from the total number of pools and from the pool size distribution. Summation of the mean of all undiscovered pool sizes yields the mean of the play potential, defined as the *expected potential*. The play potential can also be derived by conditioning the play resource distribution (Fig. 5) on the total sum of the discovered resource for the play, defined as the *probable potential.*

The expected value of the potential is governed by an estimated range of values for each of the individual pool sizes, and the assigned pool ranks. Both the range of individual pool sizes and the pool ranks are controlled by the quality of the database of discovered pools. If the discovered pool sizes are incorrectly estimated, appreciated or depreciated, or if the rankings are altered, then the expected value of the potential will be altered. Provided that the geology of the play is well understood and documented, the expected value should provide a reliable estimate of the potential of that play. Thus expected values for the potential are the values most often adopted for economic analysis.

The probable value of the potential is best explained by considering the following question: how much additional play resource exists, given an amount of the play resource that has been discovered? This is a conditional probability statement. If our conditional probability is set at some value (i.e., 0.10), then the amount of additional resource that may exist can be determined utilizing the conditional probability statement and the play resource distribution.

Estimate of conceptual play resources

In previous assessments the resources of conceptual plays were determined using a "subjective probability" approach (Roy, 1979; Lee and Wang, 1990). In this assessment the discovery process model is utilized. The number and size of conceptual plays that exist in a mature basin can be estimated by the discovery process model without assuming log-normality. Thus, after compiling the expected values of the play potential for each mature play and their respective discovery dates (the date of discovery of the first pool in each play), a play resource discovery sequence is generated for all the mature plays (Fig. 6). If it is assumed that the mature plays belong to a single population, the *discovery process model* can be used to estimate both the number and individual sizes of conceptual plays within the basin (Fig. 7).

GEOLOGICAL FRAMEWORK

Depositional setting and tectonic elements

The Western Canada Sedimentary Basin occupies an area of 1.4 x 10^6 km^2, and encompasses southwestern Manitoba, southern Saskatchewan, Alberta, northeastern British Columbia, and the southwestern corner of the District of Mackenzie (Fig. 8) (Podruski et al., 1988). The portion of the basin extending into the United States occupies an additional area of 0.3 x 10^6 km^2. The basin consists of a wedge of sedimentary rocks that tapers from zero thickness in the east to greater than 6 km thick west of Calgary. This sedimentary succession, which represents the past 600+ million years, lies on the westward extension of the Precambrian continental craton (Porter et al., 1982). The basin is bounded on the north by the Tathlina Arch, on the east by the Canadian Shield (Fig. 8), on the south by the Transcontinental, Sioux, and Central Montana arches, and on the west by the edge of the folded and faulted thrust belt. The Western Canada Sedimentary Basin is subdivided by the Sweetgrass Arch into the Alberta and Williston basins.

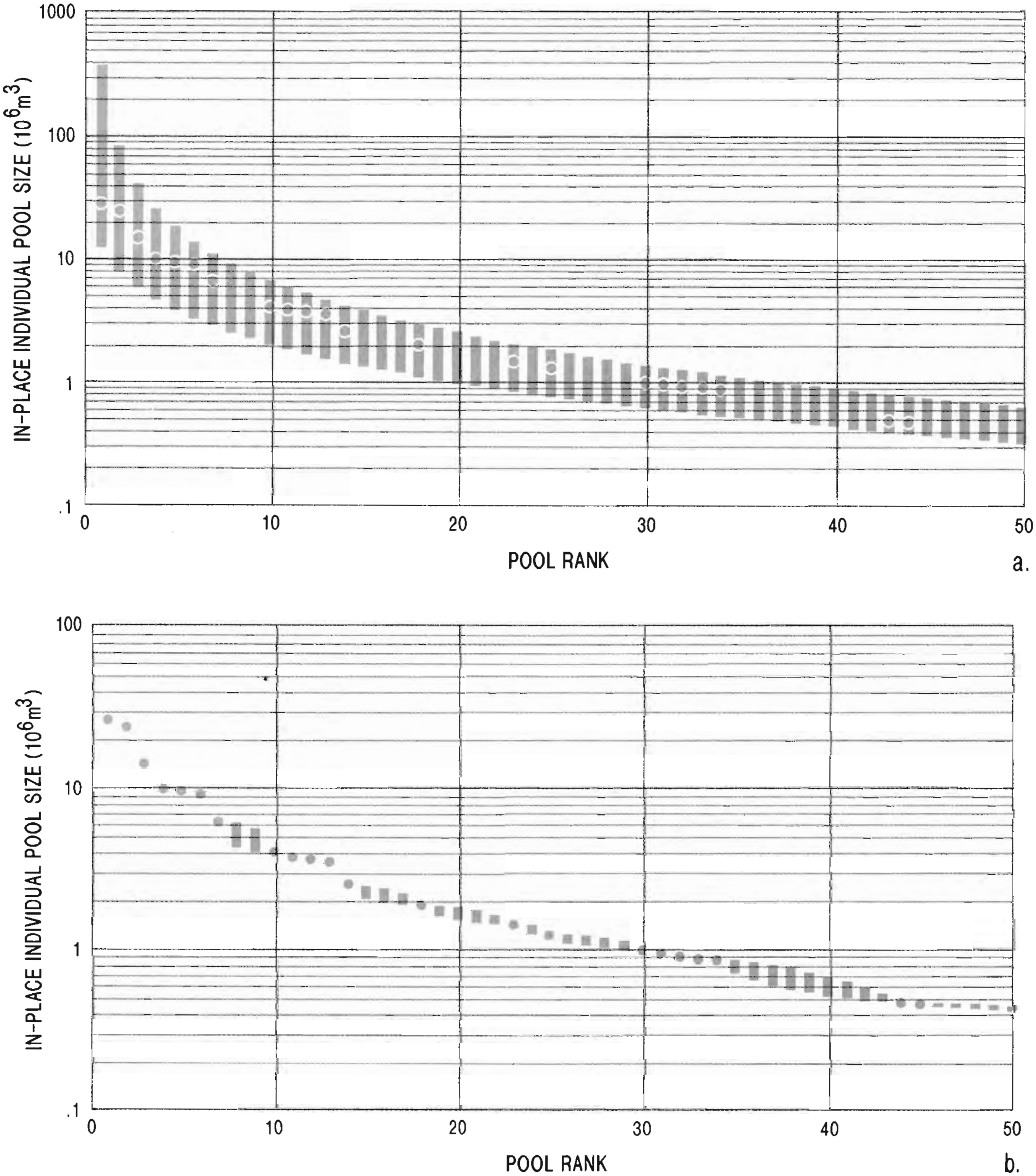


Figure 4. *Example of how a pool size-by-rank plot is generated, using the Leduc/Nisku reef complexes - Windfall play.* ***a.*** *Unconditioned pool sizes.* ***b.*** *Pool size-by-rank plot generated by conditioning pool sizes on the rank of matched discovered pools. (Sizes of discovered pools are represented by dots and estimated sizes of undiscovered pools by bars.)*

The tectonic evolution of the Western Canada Sedimentary Basin as it affected the Phanerozoic sedimentary wedge was discussed in detail by Porter et al. (1982), and reviewed by Burrowes and Krause (1987) and Podruski et al. (1988). The tectonic history of the basin and how it affected basin architecture during the Devonian is briefly reviewed here. Tectonic activity had a profound effect on the number and distribution of major, discontinuity-bounded sequences in the Devonian succession of Western Canada (Moore, 1988, 1989).

Middle Devonian sedimentation was preceded by major tectonic uplift and profound erosion. Devonian strata were deposited on a highly bevelled surface of Precambrian to Upper Silurian rocks. The pre-Devonian surface developed a "basin and arch" topography through gentle folding. This paleotopography greatly affected subsequent Devonian sedimentation.

The principal positive topographic elements were the Tathlina, Peace River and Western Alberta arches, and the Meadow Lake Escarpment (Figs. 8, 13). The Tathlina and Peace River arches have a core of Precambrian granitic basement, whereas the Western Alberta Ridge and the Meadow Lake Escarpment are cored by an eroded lower Paleozoic sequence. The Meadow Lake Escarpment is a north-facing topographic feature that corresponds to the northern erosional limits of Ordovician–Silurian strata contained within the Williston Basin.

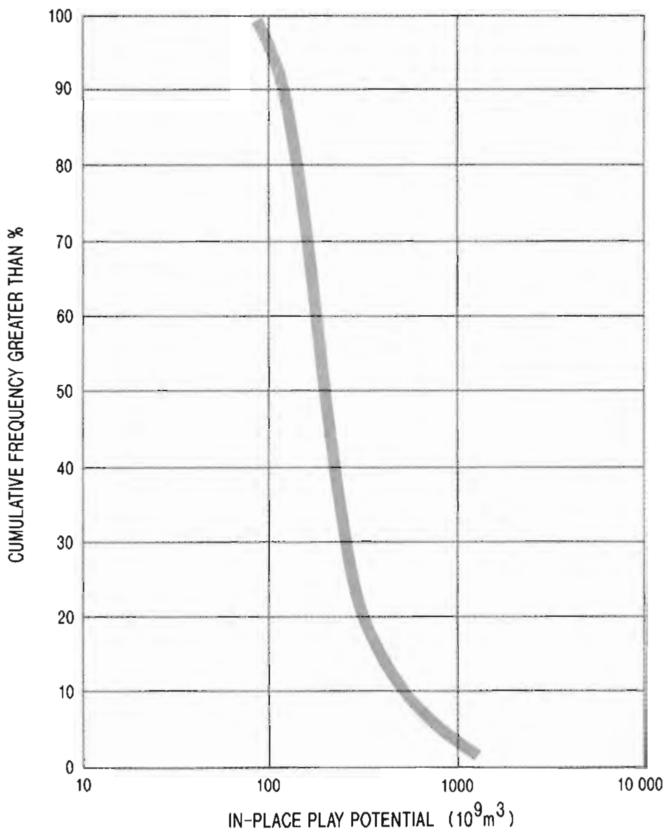


Figure 5. Example of the play resource distribution using the Leduc/Nisku reef complexes - Windfall play.

The major impact of the sub-Devonian intracratonic arches and depressions was to restrict marine incursion onto the craton from the west. An elongate northwest-trending basin developed, which opened seaward to the north and northwest but became extremely restricted to the south and southwest. This basin topography was prevalent throughout much of Devonian time. In the Late Devonian, the positive features were gradually covered with sediment, leaving only the emergent Precambrian Peace River High. The Western Alberta Arch was onlapped during latest Middle Devonian, and by the late Late Devonian, open-marine influence was virtually unrestricted from the west.

Regional stratigraphy

Subsurface reservoir stratigraphy and paleogeography in the Western Canada Sedimentary Basin have been given comprehensive treatment by Basset and Stout (1967), and more recently by Burrowes and Krause (1987), Moore (1988, 1989), Stoakes (1988), and Wendte et al. (1992). The brief summary presented here draws upon all of these articles, primarily Burrowes and Krause (1987), while stressing the principal cyclic stratigraphic sequences within an overall basin framework.

Moore (1988, 1989) divided the Devonian of Western Canada into five major sequences bounded by discontinuities, and referred to them as the Delorme, Bear Rock, Hume–Dawson, Beaverhill-Saskatchewan, and Palliser (Table 2, Fig. 9). The Devonian strata constitute the transgressive part of the Kaskaskia sequence of Sloss (1963), but the transgression was pulsatory as it inundated eastward over the craton. Moore (1988, 1989) fitted the several major and minor transgressive–regressive pulses to the eustatic fluctuations of sea level proposed by Johnson et al. (1985) for North America. These major sequences more or less correspond to the group-level lithostratigraphy already established and in use throughout the basin (Table 2). The Devonian is discussed below in terms of the seven depositional cycles shown in Table 2, and illustrated in Figures 10 and 11.

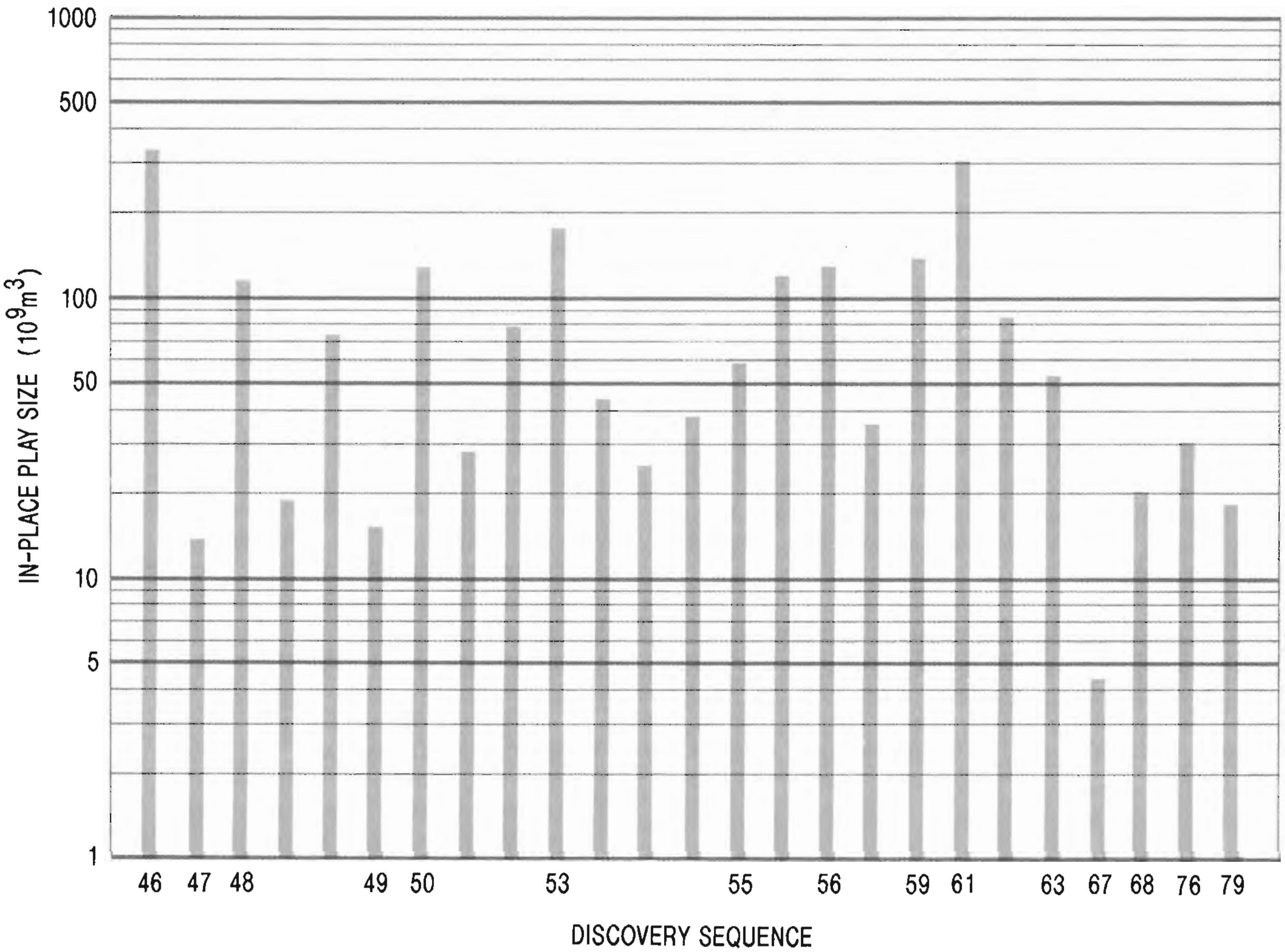


Figure 6. Discovery sequence plot of the 25 mature Devonian plays, dating from 1946 to 1979. Vertical axis includes the total of discovered in-place and expected potential volumes.

Lower Elk Point (Cycles C_1 and C_2)

Rocks of the Lower Elk Point consist of interbedded redbeds, evaporites (dominantly halite), shallow-marine clastics, and minor carbonates. The cycles include the succession from the Basal Red Beds to the base of the Keg River Formation (Fig. 9). This succession was deposited within a restricted, shallow, epicontinental sea that terminated in the south at the Meadow Lake Escarpment. The basin and arch paleotopography is well illustrated by the distribution of Lotsberg Salt (Moore, 1989) and the isopach map of the Cold Lake Salt (Meijer Drees, 1986). Within the sub-basins, Lower Elk Point deposits attain thicknesses of 300 m, but thin through depositional onlap to nearly zero over the Tathlina Arch, Peace River Arch, and Western Alberta Ridge.

Upper Elk Point Group (Cycle 3)

The transition from Lower to Upper Elk Point deposits is marked by an abrupt change from the restricted evaporites, dolostones, and siliciclastic rocks of the Chinchaga Formation to the relatively open-marine, fossiliferous carbonates of the Lower Keg River Formation. This change accompanied a major transgression that gave rise to basinwide deposition of these carbonates in a ramp-to-platform setting.

With continued subsidence and marine transgression, an extensive upper Keg River barrier-reef complex (Pine Point Formation of Presqu'ile Barrier Complex) developed near the northern limit of the basin in northeastern British Columbia and the southern District of Mackenzie (Fig. 10). Southeast of

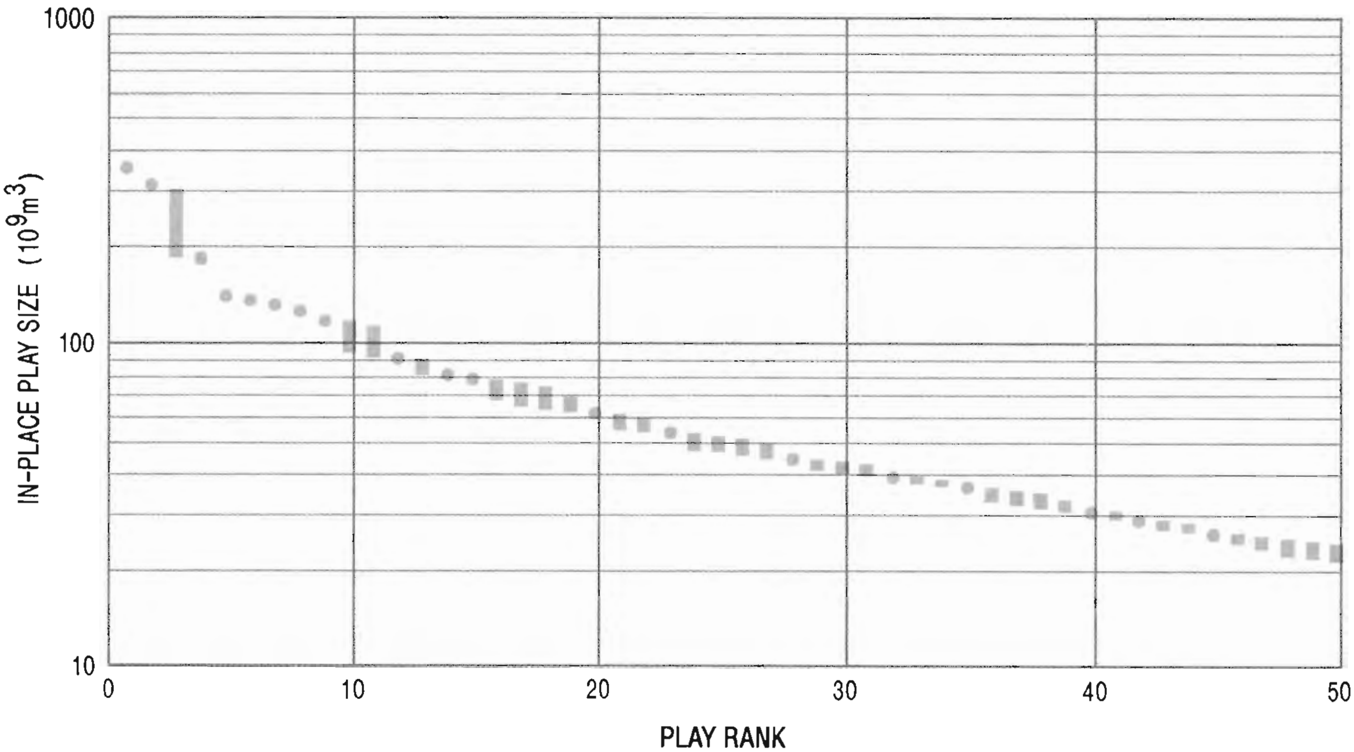


Figure 7. Play size-by-rank plot of 25 mature Devonian plays.

the barrier, isolated pinnacle reefs and reef mounds of the upper Keg River developed on a lower Keg River platform. In the Rainbow–Zama area hundreds of pinnacle reefs, up to 250 m thick, grew in discrete sub-basins.

Within the central and southern part of the basin, reefoid mounds and banks up to 60 m thick developed over lower Keg River platform deposits. These buildups extend from north-central Alberta into southeastern Saskatchewan (Winnipegosis Formation).

Following the upper Keg River phase, normal marine sedimentation was confined to the region north of the Presqu'ile Barrier Complex. In the Rainbow–Zama basins of northwestern Alberta, evaporitic deposition occurred as halite, anhydrite, and evaporitic dolostone of the Muskeg Formation. Southeastward, increasingly evaporitic conditions resulted in abundant halite deposits, which predominate in the Muskeg/Prairie Evaporite formations.

Near the end of upper Elk Point deposition, a minor marine incursion in northwestern Alberta resulted in the deposition of peritidal to shallow-marine carbonates of the Sulphur Point Formation. Upper Elk Point deposition was terminated by a pronounced base-level drop that resulted in the widespread occurrence of coastal-marine and continental shales and sandstones of the Watt Mountain Formation.

Beaverhill Lake Group (Cycle 4)

Beaverhill Lake Group sedimentation began with gradual marine transgression over the relatively flat surface of the Watt Mountain Formation. Throughout most of Alberta, the initial deposits of the Beaverhill Lake Group were peritidal anhydrites and carbonates of the Fort Vermilion Formation. This formation is only a few metres thick in central and southern Alberta, but thickens north and northwest to more than 50 m in northern Alberta.

The Fort Vermilion Formation is overlain by open-marine platform carbonates of the Slave Point Formation. Along the flanks of the Alberta Ridge and the Peace River Arch, the Slave Point carbonates form a widespread coral- and stromatoporoid-bearing shallow-marine platform ranging from 20 to 35 m thick. To the east of this platform the Slave Point thins

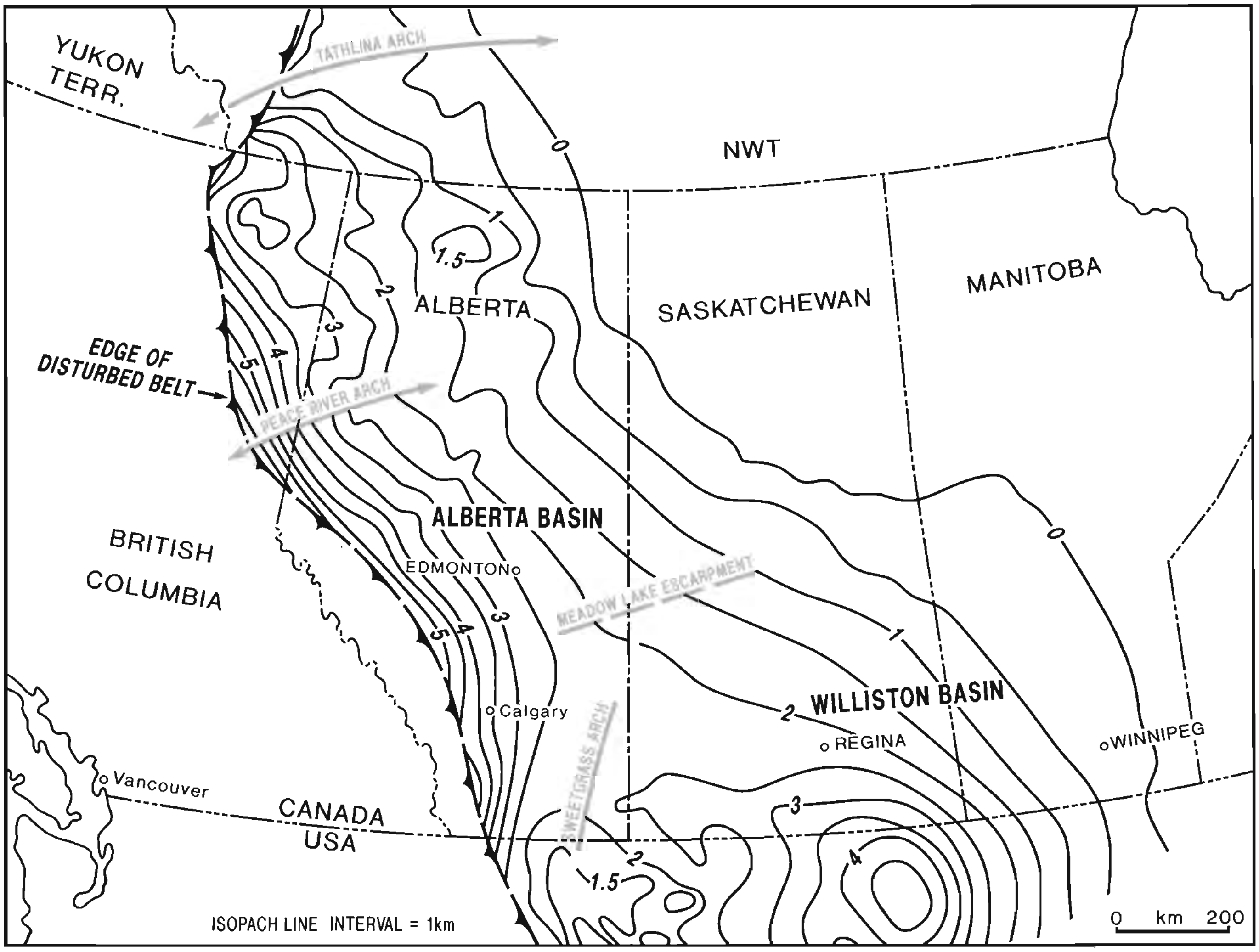


Figure 8. Basin-fill map, Western Canada Sedimentary Basin. (After Porter et al., 1982.)

and changes to somewhat deeper water facies. North and northwest of the Peace River Arch the Slave Point thickens progressively to 150 m near the Presqu'ile Barrier Complex (Fig. 10).

Further marine transgression over the Slave Point surface resulted in the development in west-central Alberta of an extensive reef-rimmed carbonate platform and the atoll-like reef complexes of the Swan Hills Formation (Fig. 11; Fischbuch, 1968). Basinal shales and argillaceous limestones of the Waterways Formation overlie the Swan Hills reef complexes. In southern Alberta, the Waterways interfingers with shelf carbonates and evaporites of the Southern Alberta Shelf Complex. In northern Alberta, the Waterways onlaps Slave Point reef complexes that fringe the Peace River Arch.

Woodbend Group (Cycle 5)

The transition from the Beaverhill Lake Group to the overlying Woodbend Group is conformable and resulted from renewed marine transgression and deepening of the entire basin. It appears that maximum marine incursion of the craton occurred sometime during this cycle. In contrast, the last two cycles (Winterburn and Wabamun) are characterized by regressive conditions and widespread basin filling (Stoakes, 1988).

Over the central and northern parts of Alberta, shelf limestones of the upper Waterways Formation are overlain by deep-water, organic-rich limestones and shales of the Duvernay, Majeau Lake and Muskwa formations (Fig. 9). Across southern and southeastern

Alberta, extensive platform carbonates of the Cooking Lake Formation, up to 100 m thick, comprise shallow-water equivalents of the Majeau Lake and basal Duvernay formations. Equivalents of these platform carbonates also overlie Swan Hills shelf deposits and reef complexes situated along the Western Alberta Ridge.

Ongoing marine incursion eventually resulted in drowning of the Cooking Lake platform in northern and north-central Alberta. In southern and southeastern Alberta, however, shallow-water and evaporitic carbonate deposition of the Leduc Formation and equivalents kept pace with sea-level rise, producing an extensive reef-rimmed shelf complex (Southern Alberta Shelf Complex). In the 'Deep Basin' area of Alberta, isolated Leduc reef complexes up to 250 m thick developed on the Cooking Lake and Beaverhill Lake platforms (Fig. 11). Woodbend reefs also formed an arcuate fringe around the Peace River Arch.

The upper Woodbend cycle began with sequential infilling of the basin by Ireton shales, progressing from the northeast toward the south and southwest. Ireton fine grained clastic deposition successively engulfed the stratigraphically younger Leduc reefs in the "East Shale Basin" (Stoakes, 1988). The Grosmont shelf-platform reef complex developed over the prograding Ireton shales in northeastern Alberta.

During Ireton deposition, organic-rich shales and limestones of the Duvernay Formation were accumulating in deeper water basinal environments. In northwestern Alberta, the Ireton interval is represented by the Muskwa Formation (Burrowes and Krause, 1987). The Muskwa Formation is overlain by thick upper Woodbend Group shales of the Fort Simpson Formation. At the end of Ireton–Fort Simpson deposition the Ireton basin in central Alberta was nearly filled, and the remaining clinoform slopes formed the Cynthia basin, which was the site of pinnacle reef development during later Winterburn Group deposition.

Winterburn Group (Cycle 6)

Winterburn Group rocks were deposited during shallowing conditions even though overall inundation of the craton was continuing. The regressive sedimentation patterns during Woodbend time resulted in

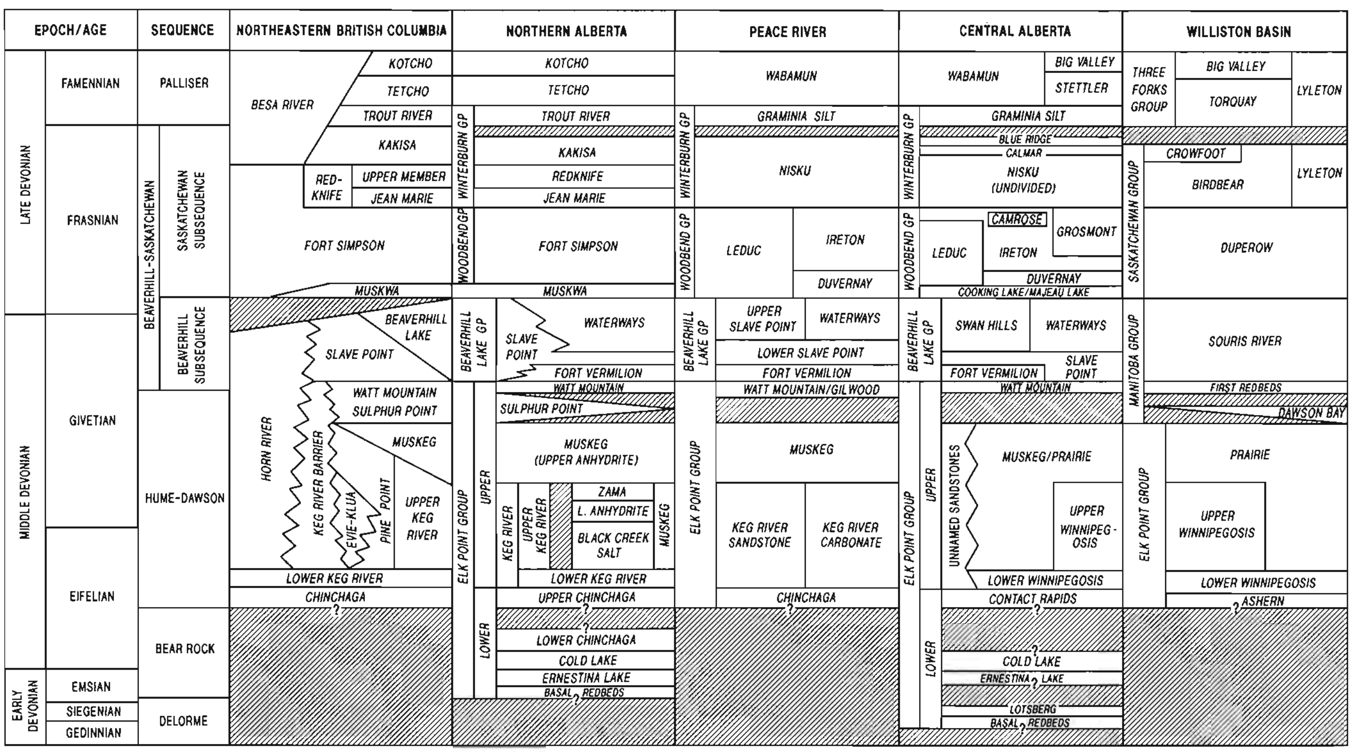


Figure 9. Table of formations, Devonian subsurface of the Western Canada Sedimentary Basin (Modified from Podruski et al., 1988, and British Columbia Ministry of Energy, Mines and Petroleum Resources, 1989.)

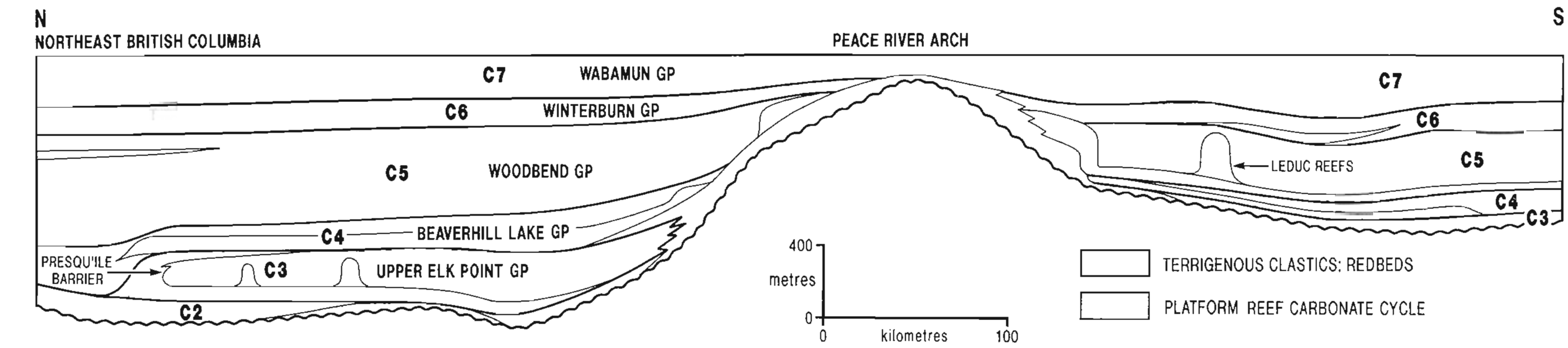


Figure 10. *North-south cross-section illustrating the major depositional cycles in the Devonian of the Western Canada Sedimentary Basin. (Modified from Moore, 1989.)*

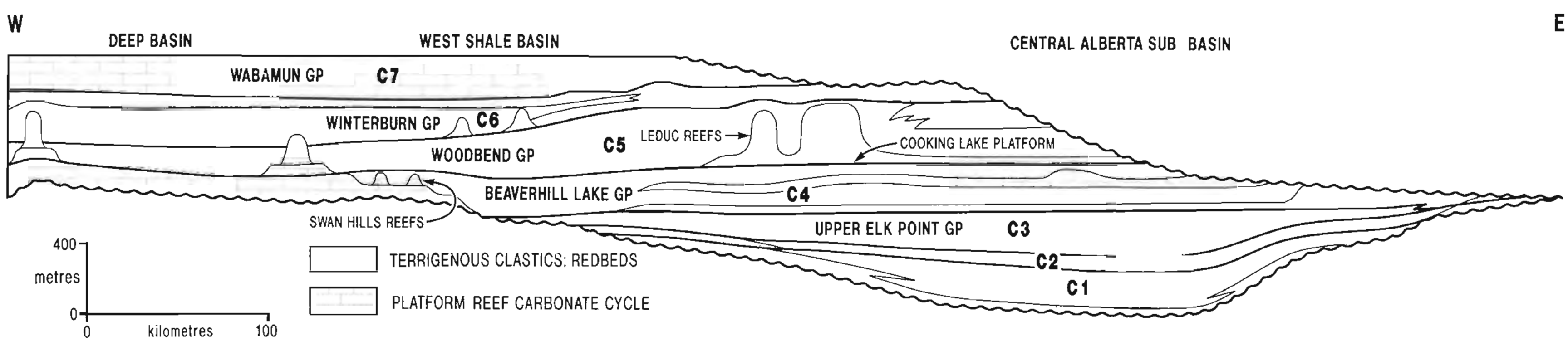


Figure 11. *East-west cross-section illustrating the major depositional cycles in the Devonian of the Western Canada Sedimentary Basin. (Modified from Moore, 1989.)*

the widespread shelf carbonates of the Nisku Formation. To the north, carbonates were silty and argillaceous, but in eastern and southeastern Alberta, and rimming the Cynthia basin, fossiliferous shelf and reef carbonates were widespread. Numerous small pinnacle reefs developed in the West Pembina area, along the southeastern flank of the Cynthia basin (Watts, 1987).

Nisku sedimentation was terminated by a major regression marked by terrigenous deposits of the Calmar Formation. Subsequently, shallow-marine incursion resulted in deposition of shelf carbonates of the Blue Ridge Member, which pinches out to the southeast, but thickens to over 50 m in western Alberta. A second major regression, which occurred at the close of Winterburn deposition, deposited a northwestward-thickening wedge of terrigenous clastics known as the "Graminia Silt". The Graminia Silt marks the Frasnian–Famennian boundary.

Wabamun Group (Cycle 7)

The transgression that initiated Wabamun deposition occurred over a broad, flat surface, resulting in an extensive, low-gradient, prograding carbonate ramp (Stoakes, 1988). This carbonate ramp covered most of central and northern Alberta and northeastern British Columbia. With continued ramp accretion, intertidal–supratidal conditions evolved in southeastern Alberta. Wabamun group strata average 300 m in thickness in western Alberta, conformably overlie Winterburn deposits, and consist mainly of shallow-marine to peritidal platform carbonates. In southeastern Alberta, these carbonates interfinger with evaporites of the Stettler Formation. In northeastern British Columbia, deeper water shale equivalents occur within the Besa River Formation.

Two transgressive episodes are recognized in the prograding Wabamun ramp-platform. The first transgression resulted in the shoal carbonates of the Crossfield Member, which forms a lenticular wedge that pinches out into evaporites of the Stettler Formation (Eliuk and Hunter, 1987). The second transgressive episode, near the end of Wabamun deposition, formed the open-marine, fossiliferous limestone deposits of the Big Valley Formation.

Carbonate reservoirs - depositional morphology and trap styles

During the Devonian, Western Canada was situated in equatorial latitudes and covered by an epeiric sea, resulting in extensive deposition of carbonates and evaporites. Consequently, Devonian reservoirs and play types follow standard carbonate depositional models. However, there is some redundancy and confusion in the terminology used to describe the morphological shapes of carbonate bodies on a local and a regional scale. Wilson (1975), James (1983), and James and Geldsetzer (1988) have defined carbonate buildups for both local organic bodies and large, regional features. The specific terms used here to describe carbonate morphology have been adapted from Wilson (1975), and are defined below.

A *carbonate buildup* is a locally formed (laterally restricted) body of carbonate sediment possessing topographic relief.

A *carbonate mass* is a carbonate localization with only slight relief, which develops as a result of a facies change from compactible argillaceous strata to noncompactible pure limestone.

A *stratigraphic reef* is a general term for a carbonate body that encompasses both of the above concepts and includes both local mound-like and regional curvilinear trends. No inference as to origin or internal composition is included.

Definitions based on configuration of regional features include the following:

Carbonate ramps. Large carbonate bodies built away from positive areas and down gentle regional paleoslopes. No striking break in slope exists, and facies patterns commonly are wide and irregular belts with the highest energy zone relatively close to the shore (Fig. 12).

Carbonate platform. Large carbonate bodies with a relatively horizontal top and abrupt shelf margins where "high energy" sediments occur. The normal processes of carbonate sedimentation effectively and rapidly evolve from ramps to platforms and create narrow, steep, shelf-margin ridges. Slopes on some ramps may be so gentle as to make them indistinguishable from platforms. Consequently, these terms commonly are used interchangeably.

Major offshore banks. Complex carbonate buildups that are large and thick and occur well offshore from coastal ramps or platforms.

Shelf. An area on top of a ramp or platform.

Shelf margin. The edge of the shelf on a platform.

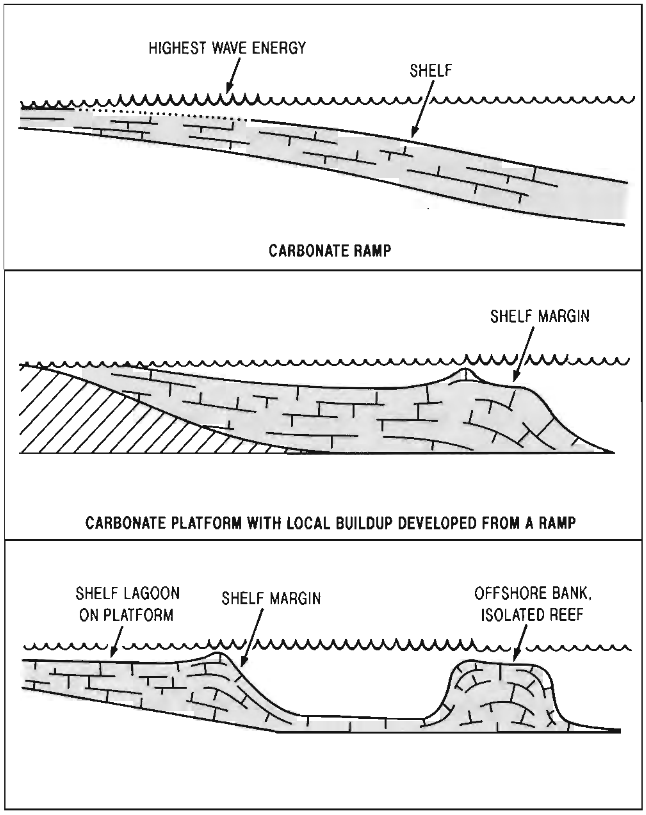


Figure 12. Carbonate platforms, shelf margins and offshore banks. (After Wilson, 1975.)

Shelf lagoon. Shallow neritic shelf seas on a platform.

Definitions for configuration of local carbonate features (implying organic accumulation rather than purely mechanical accumulation), include the following:

Pinnacle. A conical or steep-sided, upward-tapering mound or reef.

Patch reef. An isolated, circular area of organic, frame-constructed buildups.

Atoll. A ring-like organic accumulation in offshore or oceanic position surrounding a lagoon of variable depth.

Barrier reef. A curvilinear belt of organic accumulation located offshore and separated from the coast by a lagoon.

Fringe reef. A curvilinear belt of organic accumulation built directly out from the coast.

There often is confusion between the usage of platform and shelf when carbonates are discussed, but the difference between the two should be clear from the definitions of Wilson (1975) and Figure 12. *Shelf* refers to the environment and *platform* to the carbonate rock body. Localized organic carbonate features such as fringing and barrier reefs generally occur at shelf margins, patch reefs on shelves away from the margins, and pinnacle and atoll reefs in offshore basinal areas.

The above terms generally describe the shapes of carbonate bodies, but several definitions used in this paper also refer to internal composition, implying a genetic connotation. *Bioherm* refers to a lens-like body of organic origin within rocks of different lithology; *biostrome* refers to a bedded unit comprising a concentration of generally in-place carbonate skeletons (James, 1983). The term *organic bank* refers to a buildup that is formed predominantly of detrital organic sediment accumulated in place by trapping or baffling, but also in part through mechanical piling by waves and currents (Wilson, 1975). An *organic framework reef* (ecological reef) is a buildup formed in part by a wave-resistant framework constructed by organisms (Wilson, 1975).

There are several classification schemes used for describing internal textures of carbonate rock bodies. The most widely accepted classification, which is used in this paper, is that of Embry and Klovan (1971), a modification of Dunham's classification of limestones by depositional texture (Dunham, 1962).

The depositional cycles discussed in the previous section and illustrated in Figures 10 and 11 are characterized by both transgressive and regressive phases, which in general contain carbonate-rich and shale-rich strata, respectively. The carbonate-rich strata consist of large carbonate shelf platforms and reef complexes, with smaller and isolated patch and pinnacle reefs of the Keg River, Swan Hills, Leduc and Nisku formations. The shale-rich strata are the calcareous basin-fill deposits that surround the reefs. Carbonate shelf platforms and reefs form the reservoirs, and basin-fill deposits are the source and seal rocks. Gas is usually trapped along the updip (northeast) edges of the broad carbonate shelves and reef complexes, in patch and pinnacle reefs adjacent to shelf margins, and in subtle intrashelf traps. Podruski et al. (1988) discussed the various trap styles in Devonian rocks, and considered the updip terminating, isolated reef or shelf-margin reef complexes to be the most prevalent stratigraphic type. Subtle facies changes in, and seal-forming channels cutting through, carbonate platform deposits form other stratigraphic trap types. Structural traps include those caused by differential compaction with subsequent draping of younger carbonate deposits over Leduc and Swan Hills reefs, drape caused by underlying block faulting, and actual block faulting that produces an updip seal. Combination structural-stratigraphic traps are also present. The most obvious example is an erosional unconformity or paleotopographic subcrop trap caused by updip erosion and subsequent burial of Upper Devonian subcrop edges by Carboniferous deposition.

When trap styles and play types are considered within a depositional framework it becomes apparent that play types differ somewhat between specific cycles. This is particularly so for the Upper Devonian cycles (Beaverhill Lake, Woodbend, Winterburn and Wabamun, Table 2), which contain most of the mature plays defined in this study. As alluded to by Stoakes (1988), the Beaverhill Lake and Woodbend cycles are composed predominantly of transgressive deposits with widespread development of platforms and platform reef complexes. In contrast, the Winterburn and Wabamun cycles consist largely of regressive-phase deposits with a loss of pronounced reef and basin topography; they are dominated by small reefs, carbonate ramps and argillaceous basin-fill deposits. The mature plays have been grouped with these depositional constraints in mind in order to qualitatively assess conceptual play trends and trap types (discussed in a later section).

Composition and origin of Devonian gases

A methane-dominated mixture of hydrocarbon gases that includes progressively decreasing amounts of ethane, propane and butane, is broadly referred to as "natural gas". However other compounds, such as hydrogen sulphide, carbon dioxide, nitrogen, helium and argon can be significant components of a natural gas accumulation. In the Western Canada Sedimentary Basin there is commonly an association of CO_2 and H_2S (Hitchon, 1963b) that suggests the most important mechanism for the generation of both acid gases is thermochemical sulphate reduction (Orr, 1974; Eliuk, 1984; Eliuk and Hunter, 1987; Krause et al., 1988). Not only are CO_2 and H_2S products of this reaction, but the resulting H_2S can act as a catalyst for the subsequent reduction of sulphate by hydrocarbons (Toland, 1960).

Hitchon (1963a–c) described the composition of Devonian gases in the Western Canada Sedimentary Basin as follows. Gases in Middle Devonian strata are between 75 and 95 per cent hydrocarbons; methane constitutes between 50 and 90 per cent. The composition of Beaverhill Lake Group gases varies with geographic location. In northwestern Alberta and the Peace River Arch region, associated gases in the Swan Hills Formation are between 88.8 and 96.9 per cent hydrocarbons, while nonassociated gases are between 67.8 to 95 per cent hydrocarbons. In comparison, the nonassociated Beaverhill Lake gases from southern Alberta and southwestern Saskatchewan vary between 2.6 and 14.9 per cent hydrocarbons. Woodbend Group gases exhibit a wide range of hydrocarbon content (3–96.3%). The lowest hydrocarbon concentrations occur in southern Alberta, but Hitchon (1963b) also described a systematic geographic variation in the hydrocarbon content of Leduc reef gases that decreased with increasing depth along reef trends. Decreases in hydrocarbon content of Woodbend Group gases follow increases in acid gases, particularly H_2S and CO_2. Winterburn Group gases are hydrocarbon rich (between 65 and 97%), and nonassociated gases at the subcrop edge are predominantly methane. Wabamun Group gases exhibit a progressive decrease in hydrocarbon concentration with increasing depth and distance from the subcrop edge. Decreases in hydrocarbon content in Wabamun gases are compensated for by increases in acid gases, similar to those of the Woodbend Group.

The association of increasing CO_2 and H_2S with decreases in the proportion of hydrocarbon gases, and the pattern of their variation, are consistent with the current model of gas compositional control by thermochemical sulphate reduction. Because much CO_2 and most H_2S in Devonian reservoirs are formed by thermochemical sulphate reduction, it is important to consider these gases with the hydrocarbon gases when calculating in-place reserves. This is because the amount of such gases results from the reaction of hydrocarbon gases with reservoir sulphates.

Creaney and Allan (1990) identified four regionally significant potential petroleum source rocks in the Devonian succession of Western Canada and mapped their general thermal maturity patterns. Significant potential sources are present in the Lower Keg River Formation, Duvernay Formation, Cynthia Member and Exshaw Formation. A sedimentological model for Devonian source rock accumulation has been proposed by Stoakes and Creaney (1985) using the Duvernay source rocks in the Woodbend Group. No significant sources have been identified in the Beaverhill Lake Group, and Beaverhill Lake oils are similar to Woodbend Group oils. Creaney and Allan (1990) inferred that the Beaverhill Lake interval also was sourced from the Duvernay Formation. Devonian source rocks remained immature until burial by Foreland Basin sediments during Cretaceous time. Present maturity patterns increase progressively westward following increasing depth of burial. Many associated and nonassociated gas plays occur well updip of the 1.2 per cent Ro isomaturity contour. This indicates that some gas plays were sourced from lateral migration pathways.

ESTABLISHED PLAYS: GEOLOGICAL DEFINITION AND RESOURCE ASSESSMENT

Exploration regions

Podruski et al. (1988) considered there to be four petroleum exploration districts in the Devonian of the Western Canada Sedimentary Basin: Northern Alberta, the Peace River Arch region, Central Alberta, and the Williston Basin. These were defined on the basis of unique geography, oil source and migration paths, trap mechanism and trap stratigraphy. The Williston Basin presently contains no gas reserves, so this is not considered a major exploration region for established plays.This report basically adheres to a similar division of exploration regions, except that the Peace River Arch region is grouped with the Northern District. The Central District includes the "Deep Basin" of west-central Alberta, and the Southern District encompasses the expansive and thick Devonian carbonate–evaporite succession of the Southern Alberta Shelf Complex (Fig. 13, Table 3). This geographic division of play types has both geological (Fig. 8) and technical merit, as will be seen in the discussion of individual plays. Substantial overlapping and duplication is inherent in such a geographic division. The boundaries of the exploration regions are somewhat arbitrary, but certainly provide a comparative framework for discussion purposes. Natural gas reserves in the Northern District and Peace River Arch region occur mainly in Keg River (Pine Point) and Slave Point carbonate reefoid complexes of northeast British Columbia and the northern flank of the Peace River Arch. Gas reserves are associated with major reserves of oil in central Alberta, the Upper Devonian erosional subcrop edges of eastern Alberta, and the large carbonate shelves and reef complexes of the "Deep Basin" area in western Alberta. Central District and Deep Basin gas reserves occur in all of the Upper Devonian cycles (Beaverhill Lake, Woodbend, Winterburn and Wabamun). Gas reserves in the Southern Alberta Shelf are mainly confined to platform carbonates in the uppermost Devonian cycle (Wabamun Group).

A total of 25 mature and three immature plays have been defined in the Devonian of the Western Canada Sedimentary Basin. Each play is discussed sequentially, in terms of definition, geology, exploration history, and expected potential (if estimated), under the appropriate exploration region as outlined in Table 3.

Northern District and Peace River Arch

Middle Devonian clastics

Play definition. This gas play includes all pools and prospects in structural and stratigraphic traps in Middle Devonian sandstone and conglomerate reservoirs that mantle the flank of, and feather-out away from, the Peace River Arch (Figs. 14, 15). Although nonassociated gas pools have been discovered, none are significant enough in size to designate as typifying the play (Table 4).

Geology. Middle Devonian clastics, particularly the Granite Wash and Gilwood sandstones, are primarily oil-bearing reservoirs. The geology has been described by Shawa (1969), Alcock and Benteau (1976), and Chevron Canada Resources (1990). Regional relations of these Middle Devonian clastics to the Peace River Arch, and the enclosing onlapping carbonate–evaporite strata have been discussed by Jansa and Fischbuch (1974), Rottenfusser and Oliver (1977), Trotter and Hein (1988), and Podruski et al. (1988).

This play includes three distinct clastic wedges (Gilwood, Keg River and Chinchaga sandstones) that pinch out updip into associated shale and evaporitic sequences. The depositional environments of these clastic reservoirs ranged from alluvial and coastal plain to fan delta and shallow marine. The Middle Devonian sequence thins onto the Peace River Arch, and as the cyclical carbonate–evaporite units disappear, the clastic deposits amalgamate and cannot be differentiated from each other; these are collectively referred to as "Granite Wash". The Granite Wash overlies the Precambrian and its distribution appears to have been controlled mainly by structural movements of the basement (Fig. 15).

Hydrocarbon traps were formed by updip depositional pinch-out of the sandstone clastic wedges. 'Basement' block-faulting also contributed to the formation of traps by controlling the occurrence of locally thick sandstone deposits and by influencing the overall depositional pattern relative to updip closure. Reservoirs are generally of good to excellent quality since they consist of fine to coarse grained conglo-

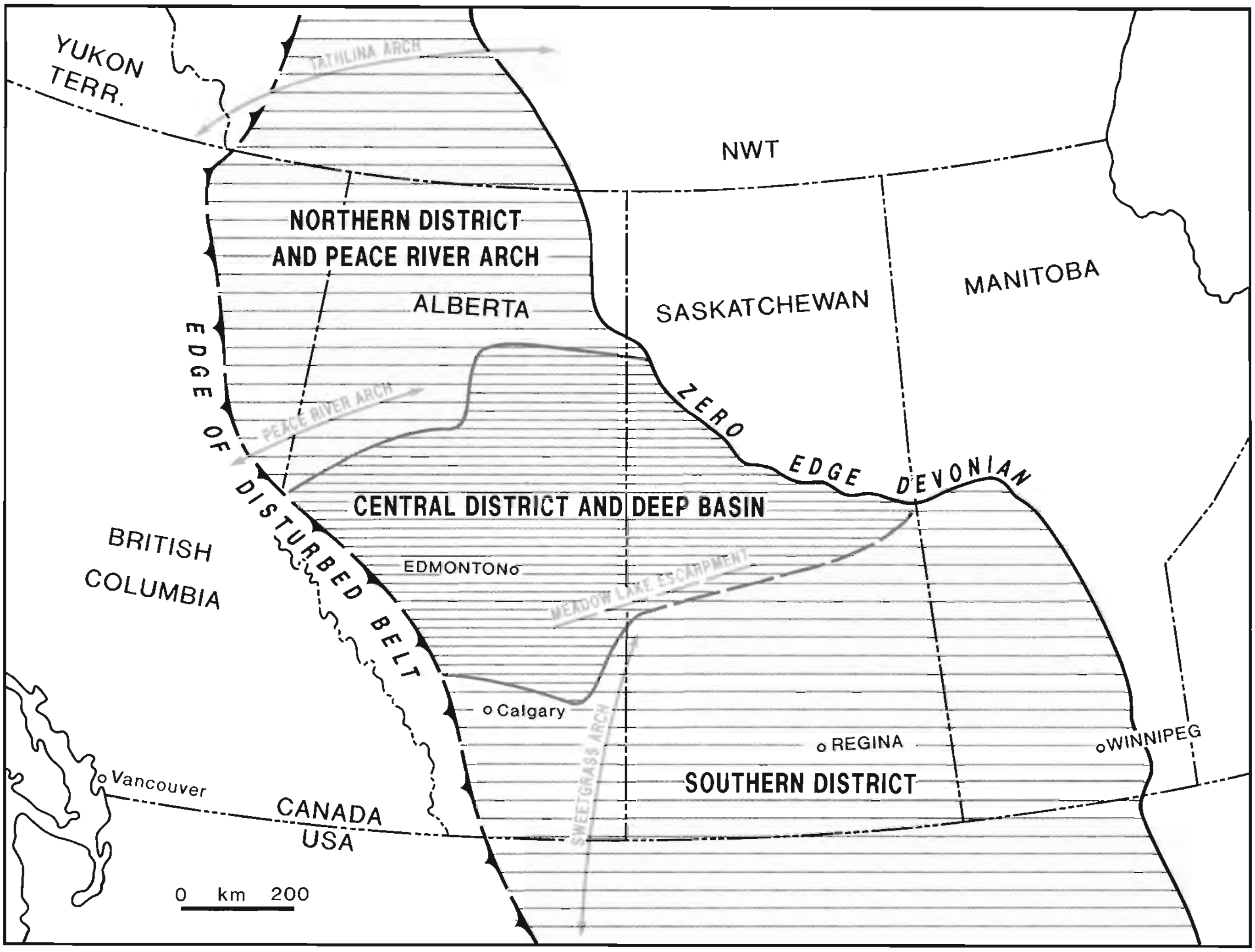


Figure 13. Geographic division of mature play regions.

meratic, arkosic sandstones with porosities ranging up to 30 per cent and permeabilities to 4000 md (Alcock and Benteau, 1976; Rottenfusser and Oliver, 1977).

Exploration history. This is primarily an oil play with gas commonly occurring as a cap or in solution. The initial oil discovery occurred in 1956 at Gilwood, and significant oil discoveries subsequently were made at Utikuma and Red Earth in the mid 1960s. The largest nonassociated gas pool was discovered in 1975 in the Gilwood sandstone at Cranberry (Table 4). To date, 44 pools have been discovered, with a total initial in-place volume of 25 665 x 10^6m^3. Of these 44 pools, only 17 are nonassociated gas, with a total initial in-place volume of 2 557 x 10^6m^3.

Play potential. Estimates of the potential for the Middle Devonian Clastics play indicate an initial in-place volume of 18 204 x 10^6m^3. This indicates that 42 per cent of the total gas reserves in this play is yet to be discovered. The estimate assumes a total pool population of 450, suggesting that, with only 44 pools discovered to date, this play is relatively immature. The largest undiscovered pool should have an in-place volume of 771 x 10^6m^3 (Fig. 16). The largest undiscovered pool is relatively small compared with other Devonian plays, yet there are over 406 pools still to be found. Consequently, this play is not very attractive from an exploration viewpoint, and the discovery of significant additional gas reserves is unlikely.

Keg River shelf basins - Rainbow, Zama, and Shekilie

Play definition. These plays include all associated, solution and nonassociated gas pools and prospects in drape structures formed by differential compaction

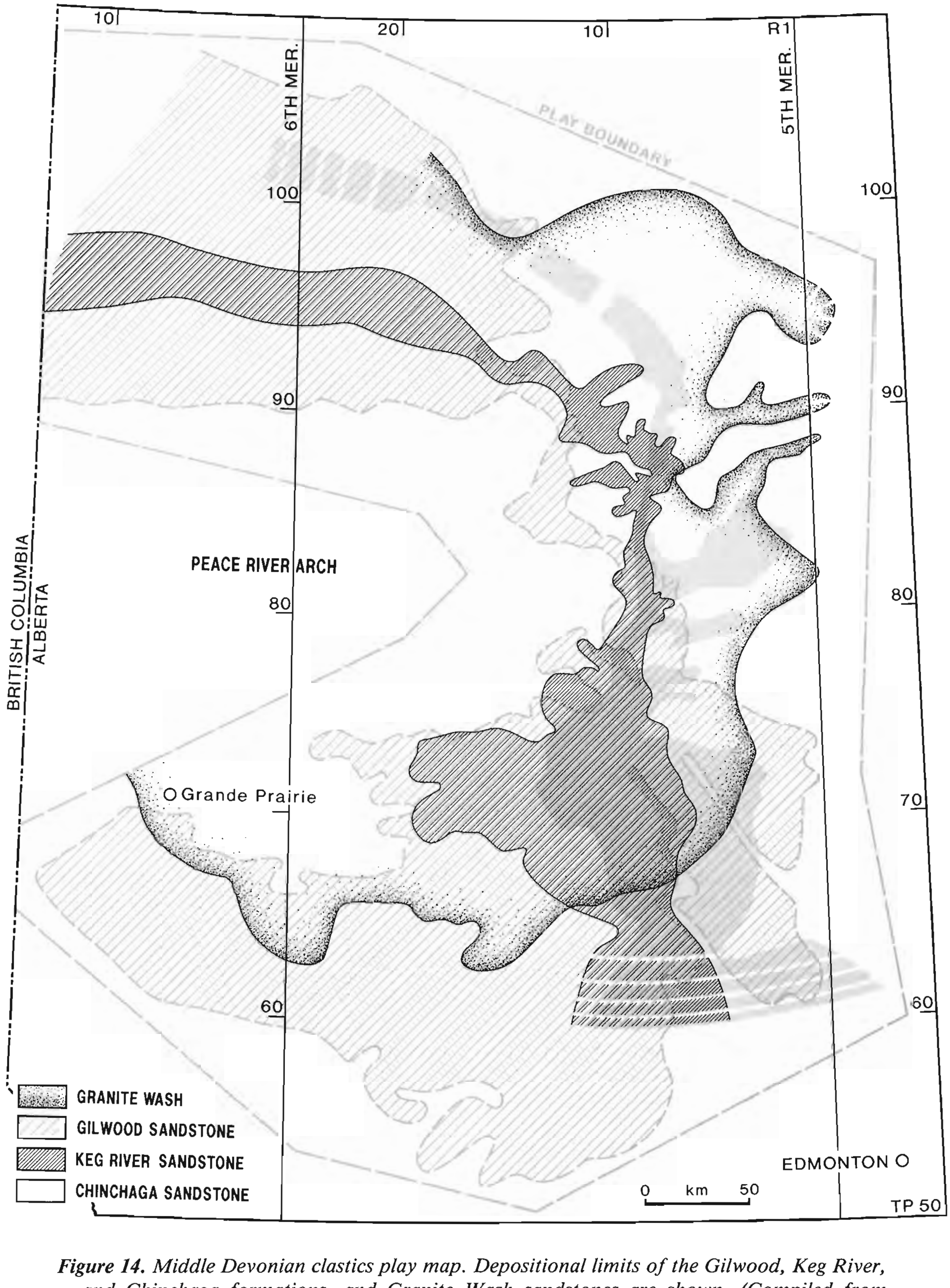


Figure 14. *Middle Devonian clastics play map. Depositional limits of the Gilwood, Keg River, and Chinchaga formations, and Granite Wash sandstones are shown. (Compiled from Trotter and Hein, 1988; Barclay et al., 1985; and Jansa and Fischbuch, 1974.)*

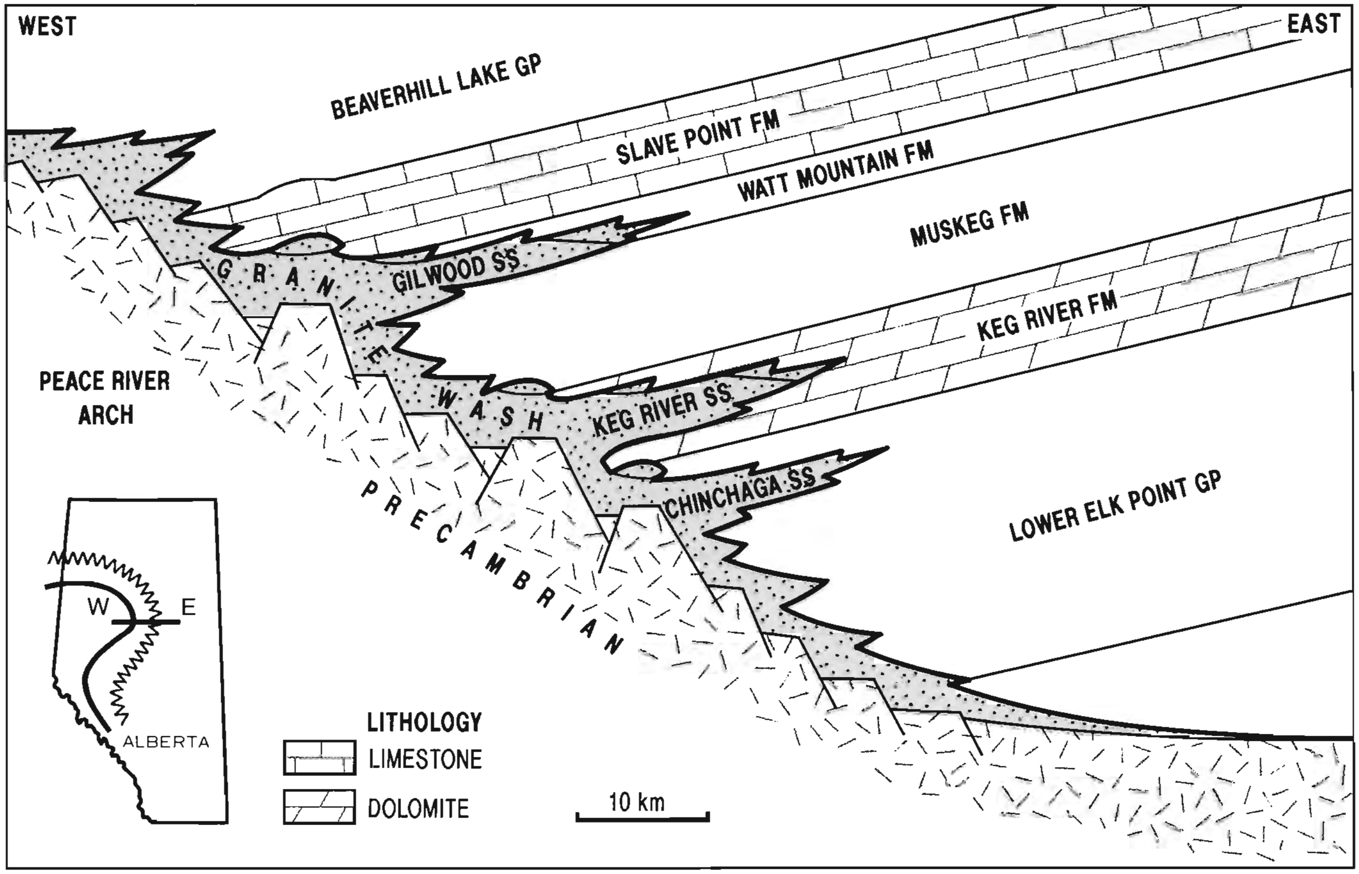


Figure 15. Schematic cross-section of Middle Devonian clastic units illustrating their relation to the Peace River Arch. (From Barclay et al., 1985.)

and salt dissolution-collapse in Slave Point, Sulphur Point, Muskeg, and Zama carbonate strata within the Shekilie, Rainbow and Zama shelf basins (Fig. 17). Gas associated with oil pools in Keg River reef buildups is also included in this play. Although resource evaluations were undertaken separately, the underlying geological controls defining these three basin plays are interrelated, and thus are discussed collectively.

Geology. The principal stratigraphic traps in this play are Keg River pinnacle reefs and bank-margin reef buildups that accumulated in small, deep basins, which were subsequently filled by Muskeg evaporites (McCamis and Griffith, 1967; Langton and Chinn, 1968; Barss et al., 1970). The Keg River reefs that developed on Lower Keg River ramp-platform carbonates (Fig. 18), range up to 200 m in thickness, yet occupy areas much smaller than a section (one square mile). The Muskeg evaporites form an ideal seal for these high-porosity reef buildups, which consist dominantly of dolomitized coral-stromatoporoid floatstones/bindstones capped by algal-rich grainstone-packestone shoal deposits.

Traps formed by structural drape occur in the Zama Member (Fig. 18), which represents deposition during marine incursion into the Muskeg evaporitic basin (McCamis and Griffith, 1967). The Zama Member is present primarily in the Zama Basin, to a lesser extent in the Shekilie Basin, and is absent in the Rainbow Basin. Porosity in the Zama Member is best developed over Keg River reefs, where higher energy conditions resulted in the formation of biostromal grainstones and packstones; dolomitization further enhanced the reservoirs.

Thin dolostone beds (<20 m) in the thick Muskeg evaporite section are commonly porous and form drape traps over underlying remnants of Black Creek Salt. Similarly, Sulphur Point dolostones (Bistcho Member) which consist of peritidal, algal-rich shoal deposits, form drape traps over some Keg River reefs. These dolostones form blanket-like deposits, ranging from 20 to 100 m in thickness, and are also gas bearing in facies-controlled stratigraphic traps outside of the Rainbow, Zama, and Shekilie basins (Fig. 42). Slave Point carbonates form the youngest reservoir unit in this structural drape, shelf basin play. Reservoirs in the

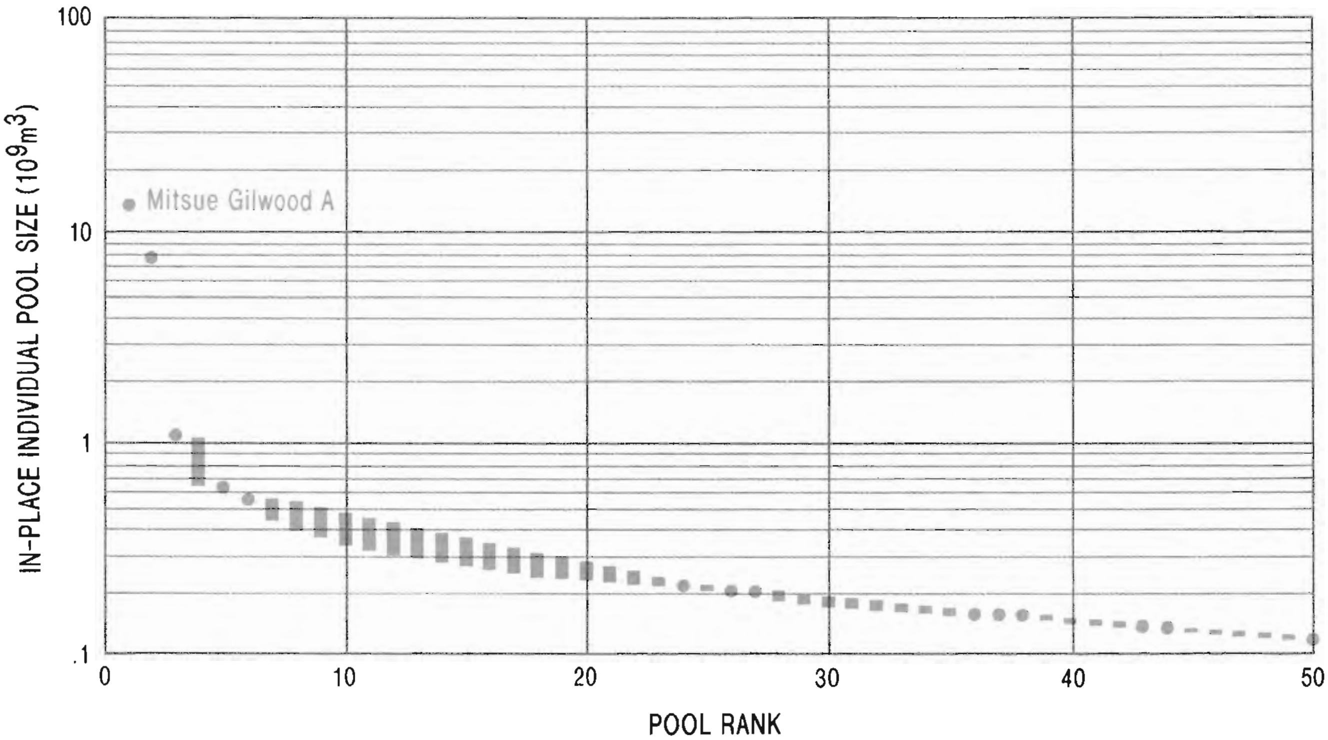


Figure 16. Pool size-by-rank plot for the Middle Devonian clastics play. The 20 largest discovered pools are listed in Table 4.

Slave Point are controlled by porosity related to low-relief biohermal development or carbonate shoal accumulation, with subsequent structural enhancement by drape resulting from compaction.

Exploration history. Exploration in this play has been the by-product of ongoing exploration (since 1965) for oil in the Keg River reefs of the Rainbow, Zama and Shekilie basins. Keg River reef buildups have been the primary targets, and overlying gas-prone drape structures have always been secondary. To date the number of pools discovered is 203, 582, and 105 in the Rainbow, Zama and Shekilie basins, respectively (Tables 5–7). The total initial in-place volumes for the Rainbow, Zama and Shekilie basins are 40 704 x 10^6m^3, 17 544 x 10^6m^3, and 7 084 x 10^6m^3, respectively. Of the total number of discovered pools in the three basins (890), only 533 contain nonassociated gas, with a total initial in-place volume of 23 160 x 10^6m^3. This compares with 65 332 x 10^6m^3 for the total undifferentiated in-place volume for all three basins.

Play potential. Estimates of the potential initial in-place volume of natural gas for the three basins are: Rainbow, 11 436 x 10^6m^3; Zama, 11 132 x 10^6m^3; and Shekilie, 13 858 x 10^6m^3. In the Rainbow Basin only 22 per cent of the total gas resource remains to be discovered, whereas in Zama, 38 per cent, and in Shekilie, 65 per cent of the remaining resource has not been discovered to date. This pattern reflects the relatively intense drilling for oil that has been undertaken in the Rainbow and Zama basins compared to the Shekilie Basin. Also, a large number of nonassociated gas pools lie within the Sulphur Point Formation in the Shekilie, suggesting an upside potential for finding additional significant reserves in this basin. However, the largest remaining undiscovered pool for each basin is relatively small compared with other Northern District and Peace River Arch plays. The projected in-place volumes for the largest undiscovered pool in Zama and Shekilie basins are 543 and 532 x 10^6m^3, respectively, while that predicted for the Rainbow Basin is 998 x 10^6m^3 (Figs. 19–21). From the standpoint of pool size and pool type (nonassociated, associated, solution, etc.) the shelf basin plays are not attractive in terms of discovering significant additional reserves of nonassociated natural gas (Tables 5–7).

Northeast British Columbia plays

Five, distinct, mature plays have been recognized in the region of the Keg River–Slave Point barrier carbonate

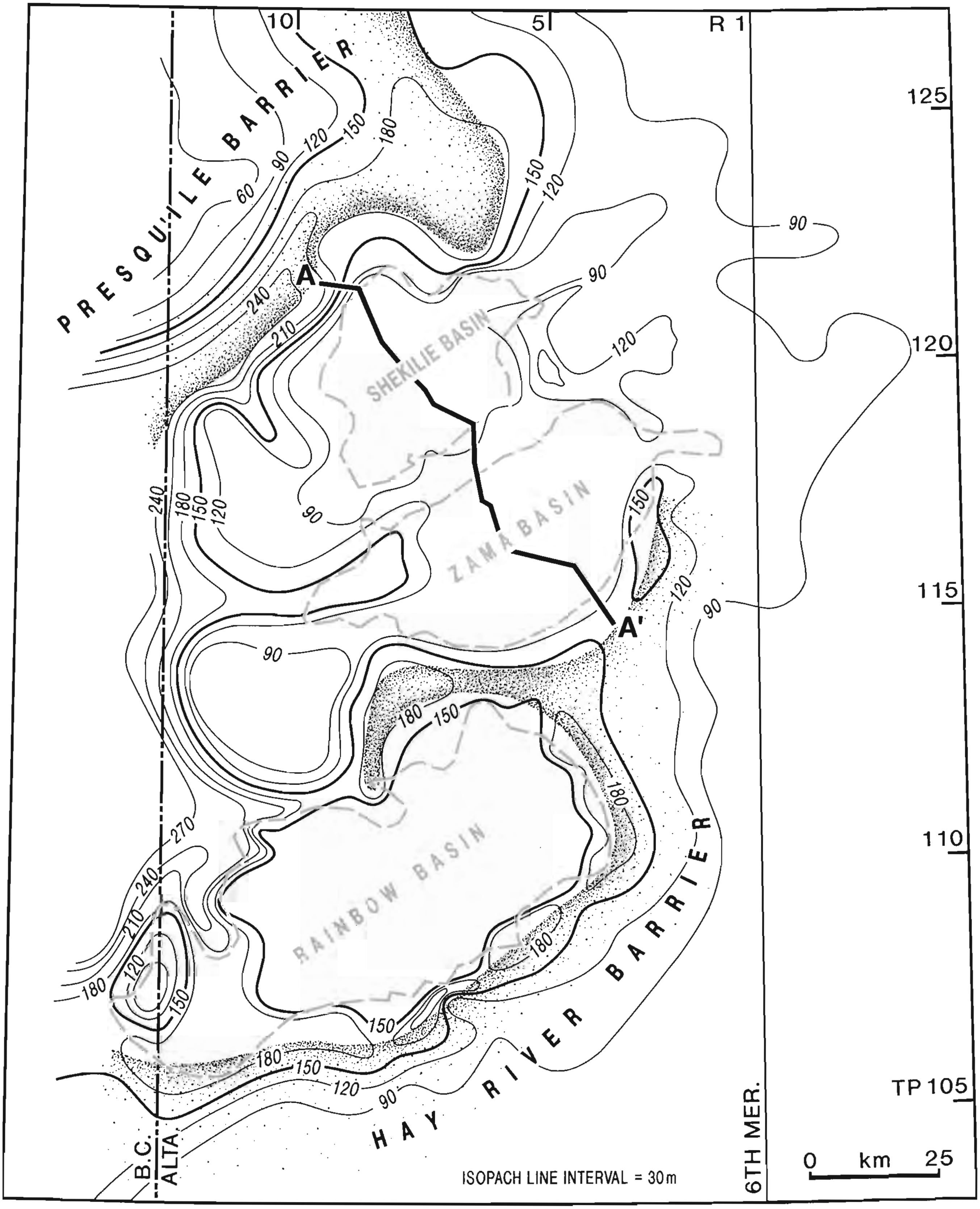


Figure 17. *Isopach map of the Keg River Formation, showing the Rainbow, Zama and Shekilie shelf basins. (See Fig. 18 for cross-section A–A'.)*

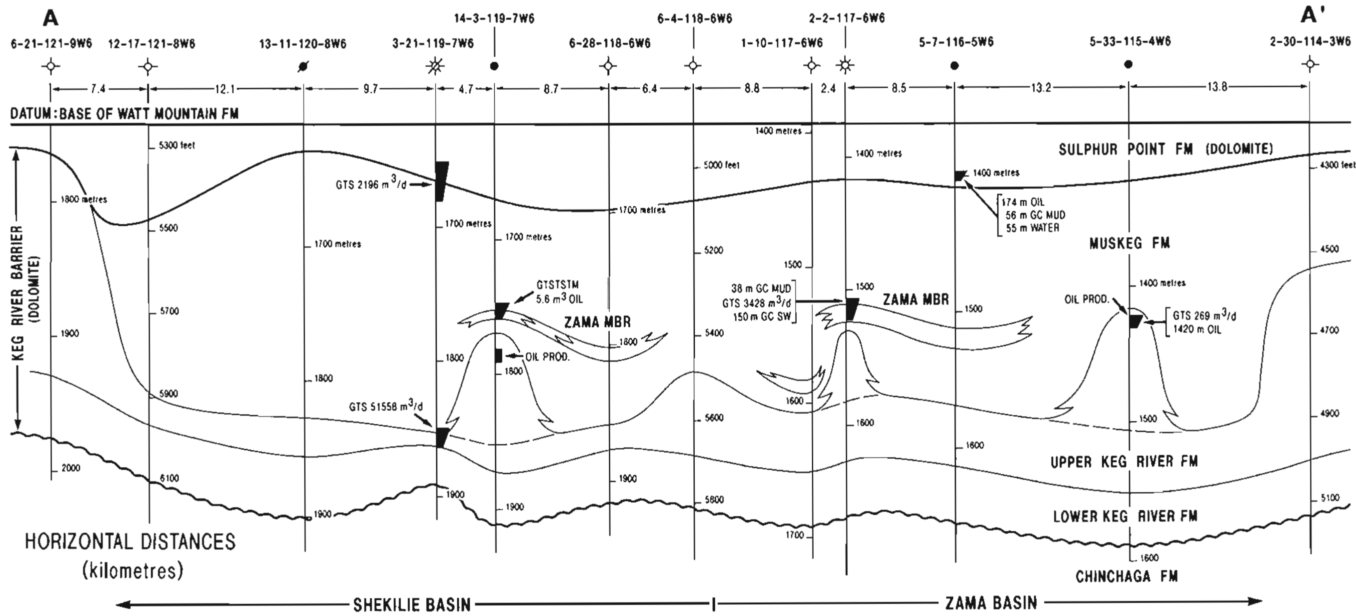


Figure 18. Cross-section A–A′ through Shekilie and Zama basins. (The cross-section location is shown in Fig. 17.)

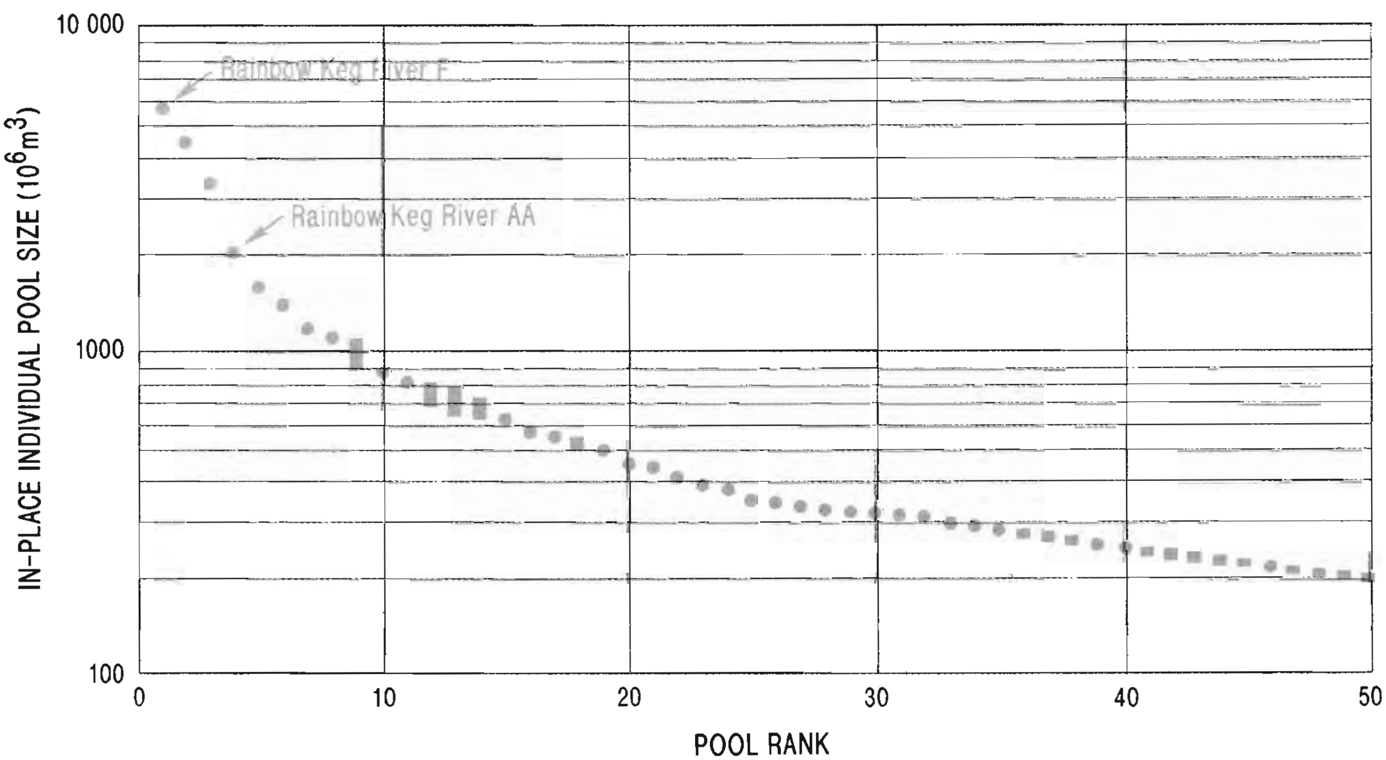


Figure 19. Pool size-by-rank plot for the Rainbow shelf basin play. The 20 largest discovered pools are listed in Table 5.

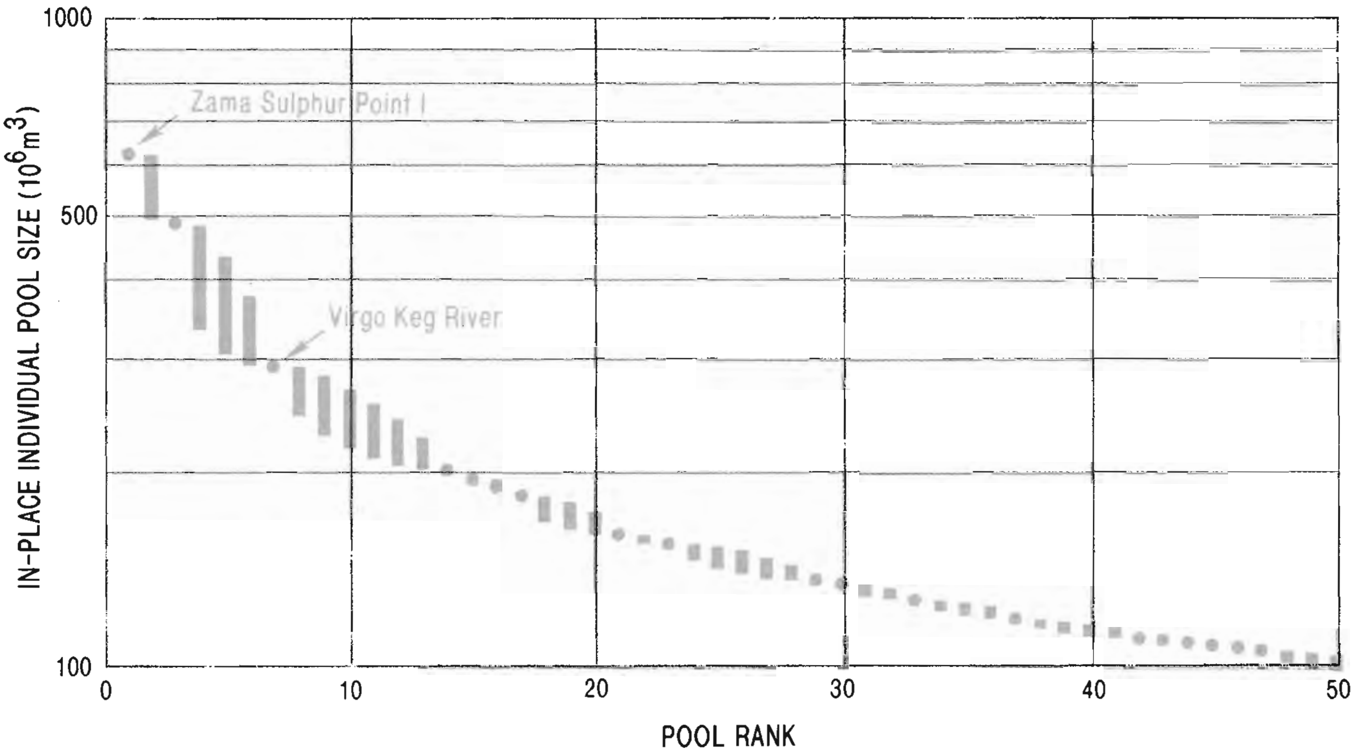


Figure 20. *Pool size-by-rank plot for the Zama shelf basin play. The 20 largest discovered pools are listed in Table 6.*

complex situated in northeast British Columbia (Fig. 22). These are: Keg River Isolated Reef (Yoyo), Keg River Platform (July Lake), Slave Point Barrier Reef (Clarke Lake), Slave Point Platform (Adsett), and Jean Marie Biostrome (Helmet North) (Table 3). The occurrence of the Keg River and Slave Point plays is directly related to the Keg River–Slave Point carbonate complex, whereas the occurrence of the overlying Jean Marie biostrome play is indirectly linked to the distribution of this carbonate complex (Fig. 29).

Because the Keg River and Slave Point plays are closely interrelated, it is necessary to clarify the stratigraphic nomenclature used to refer to the Middle Devonian barrier complex in northeast British Columbia and adjacent Northwest Territories. The existing nomenclature is extremely confusing. For example, all carbonate rocks of the entire barrier complex from the top of the Lower Keg River to the Watt Mountain Formation have been referred to as Keg River barrier (Fig. 9), Presqu'ile barrier (McCamis and Griffith, 1967), and Pine Point Group (Skal, 1975). However, Grayston et al. (1964) and Norris (1965) included the entire Keg River within the Pine Point. Furthermore, Gray and Kassube (1963) considered that the carbonate complex from the top of the Chinchaga to the base of the Slave Point consists of the Pine Point and overlying Presqu'ile formations. In this study, the term Keg River is preferred to that of Pine Point and Presqu'ile, and the nomenclature used follows that depicted in Figure 9.

The play maps and cross-sections illustrated in Figures 22 to 29 were compiled from the studies of Bell (1993), Fischbuch (1989a) and Williams (1981).

Keg River isolated reef – Yoyo

Play definition. This play was defined to include all gas pools and prospects in isolated dolomitized Upper Keg River (Pine Point) bioherms occurring in a narrow belt extending approximately 24 km basinward from the margin of the Middle Devonian carbonate complex in northeast British Columbia (Fig. 22a).

Geology. The isolated reefs that constitute reservoirs in this play occur in a broad bight formed in the Middle Devonian carbonate complex, referred to as the Utahn Embayment (Williams, 1981). The bioherms are encased in shales of the Evie and Otter Park members of the Horn River Formation, and are capped by shales of the Muskwa Member (Fig. 23).

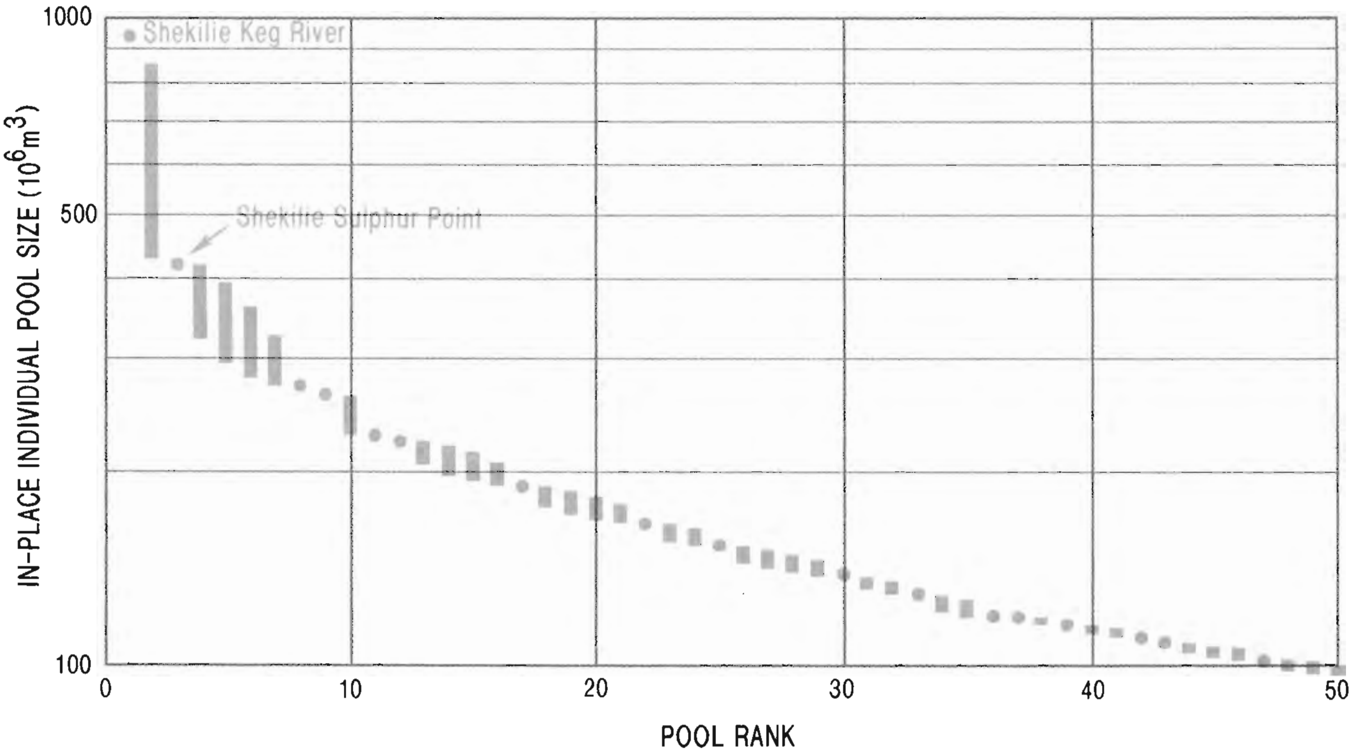


Figure 21. *Pool size-by-rank plot for the Shekilie shelf basin play. The 20 largest discovered pools are listed in Table 7.*

The extent of the reservoirs in the Keg River isolated reef play is governed by dolomite distribution. Keg River reefs are usually capped by the Slave Point Formation, but dolomitization is limited to the Keg River interval where the gas reservoirs are found (Fig. 23). In fact, in the Yoyo pool, the thickest gas plays are present where dolomite porosity is stratigraphically highest, toward the margins of the reef. In contrast, near the centre of the Yoyo pool, the dolomitized zone lies below the gas/water contact, rendering a large segment of the reef unproductive.

Exploration history. This is a nonassociated gas play, and the two largest pools, Yoyo Pine Point A and Sierra Pine Point A, were discovered in 1962 and 1965, respectively (Table 8). By 1978 most of the gas reserves in this play were established with the discovery of the Sahtaneh Pine Point B pool. To date the number of pools discovered is 31, with an initial in-place volume of 102 795 x 10^6m^3.

Play potential. Estimates of the potential for this play indicate an initial in-place volume of 35 146 x 10^6m^3. This number suggests that the Keg River isolated reef play is relatively mature, given that only 25 per cent of the total in-place potential remains to be discovered. The estimate assumes a total pool population of 300, but since only 31 have been discovered, most of the remaining resource likely is present in numerous small pools (Fig. 24). The largest undiscovered pool, however, has an initial in-place volume of 2 617 x 10^6m^3.

Keg River platform - July Lake

Play definition. This nonassociated gas play includes all pools and prospects in the Lower Keg River ramp-platform carbonates in the Cordova Bay region of northeast British Columbia extending into the Northwest Territories (Fig. 22a).

Geology. The Lower Keg River carbonate is a widespread and uniform unit up to 40 m thick. The gas reservoirs are formed by variations in the distribution of Presqu'ile dolomite porosity within the widespread carbonate, which acts as a base for later stages of reef growth.

There is no evidence of gas trapped in the Lower Keg River where the Upper Keg River (Upper Pine Point) reef is present. Established pools and shows only occur where the platform carbonate is overlain and trapped by shales of the Horn River or Klua formations (Fig. 23).

Exploration history. The initial gas discovery assigned to this play was made in 1967, at Helmet North. Additional pools in the July Lake area were found from 1977 to 1982. To date, the number of pools discovered is 14, with an initial in-place volume of 2 449 x 10^6m^3 (Table 9).

Play potential. Estimates of the potential for this play indicate an initial in-place volume of 2 055 x 10^6m^3 (Table 9). This number suggests that 46 per cent of the total gas resources in this play remains to be discovered. The estimate assumes a total pool population of 80, therefore most of the pools are yet to be discovered. The largest undiscovered pool should have an initial in-place volume of 232 x 10^6m^3 (Fig. 25). In order of play potential, this play ranks the lowest of all of the mature plays (Table 34). Even though the resource evaluation is not optimistic, one should not rule out the possibility of Lower Key River gas existing in substantial quantity, possibly in an extension of this play into the Northwest Territories.

Slave Point barrier reef - Clarke Lake

Play definition. This play includes all nonassociated gas pools and prospects in Slave Point dolomitized reef complexes along the margin of the Middle Devonian carbonate complex in northeast British Columbia and the southern Northwest Territories (Figs. 22b, 26).

Geology. Selective dolomitization of reefoid limestones near the edge of the barrier complex has resulted in the formation of a relatively narrow band of porosity lying between basinal shales and unaltered, dense, back-reef limestones. Gas pools in Slave Point bioherms tend to be smaller than, and are generally dwarfed by, the larger and more completely dolomitized Keg River reservoirs in the lower portion of the buildups.

The barrier reef reservoirs are sealed basinward by shales of the Otter Park Member of the Horn River Formation, and capped by the Muskwa shales (Fig. 26). The dolomites of the reef complex margin are confined shelfward by dense lagoonal micrites. The Muskwa shales, and those of the basal Horn River Evie Member, are highly bituminous, and likely sources for the gas in adjacent reservoirs.

Exploration history. The Clarke Lake field was discovered in 1956 and is now approaching depletion. Discoveries along the west side of the Arrowhead Salient followed in 1958, at Kotcho Lake and Petitot (Table 10). To date 49 pools have been discovered with an initial in-place volume of 103 317 x 10^6m^3.

Play potential. Estimates of the potential for this play indicate an initial in-place volume of 21 526 x 10^6m^3 (Table 10). Approximately 17 per cent of the total gas resource in this play is still to be discovered. This estimate assumes a total pool population of 425, with the largest pool, still to be discovered, having an initial in-place volume of 1 154 x 10^6m^3 (Fig. 27). These numbers indicate that the upside potential of this play is limited. Most of the pools remain to be discovered but they probably are very small, and consequently would be uneconomic.

Slave Point platform - Adsett

Play definition. This play includes all nonassociated gas pools and prospects that produce from Presqu'ile dolomite developed in otherwise dense lagoonal limestones of the Slave Point Platform behind the barrier margin (Figs. 22b, 26), primarily in northeast British Columbia.

Geology. The dolomitized reservoirs are stratiform lenses, probably following beds of increased susceptibility to dolomitization, or linear trends developed over the Keg River barrier. These linear trends may be localized as a result of fracturing resulting from differential compaction, in areas where the Slave Point overlaps the Keg River-Klua shale contact.

Exploration history. The largest pool assigned to this group is the Helmet Slave Point A pool, which was discovered in 1963. The Adsett A, B, C and D pools, considered to represent a single accumulation, were found from 1972 to 1982. Since the discovery of the Pesh A pool in 1982, no significant finds have been made. To date 45 pools have been discovered, with a total initial in-place volume of 19 467 x 10^6m^3 (Table 11).

Play potential. Estimates of the potential for this play indicate an initial in-place volume of 59 655 x 10^6m^3. Approximately 75 per cent of the total play resource remains to be discovered. Since a total pool population of 450 is predicted and only 45 have been discovered, this play can be considered to be relatively immature. Furthermore, the analysis predicts the largest undiscovered pool remaining should be in the order of 4 537 x 10^6m^3 (Fig. 28), which makes this play quite attractive.

Jean Marie biostrome - Helmet North

Play definition. This gas play includes all pools and prospects in biostromal shelf carbonates in the Jean

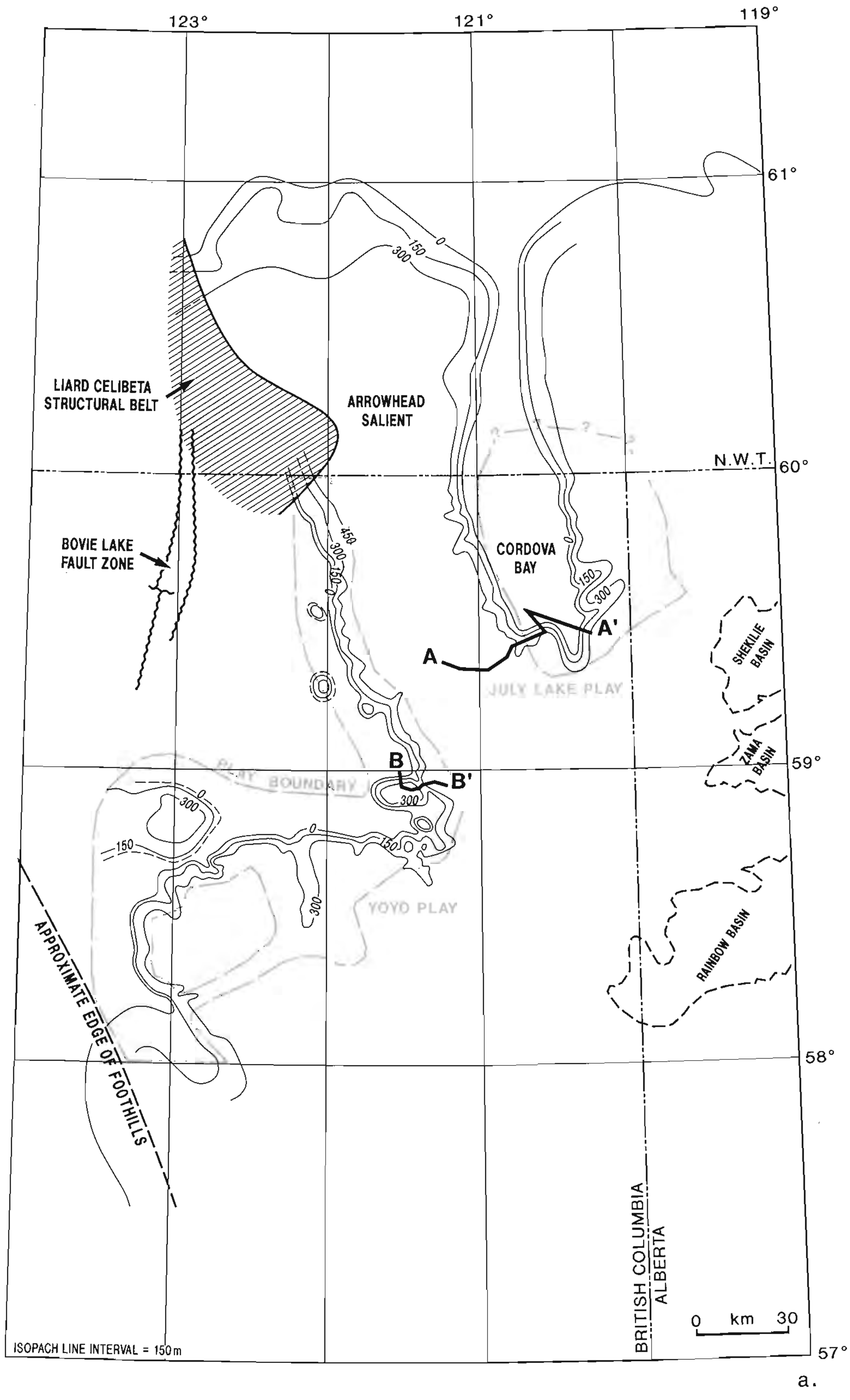


Figure 22. *Isopach map of the Slave Point–Keg River carbonate complex, northeast British Columbia.* ***a.*** *Boundaries of Keg River isolated reef (Yoyo) and Keg River platform (July Lake) plays.* ***b.*** *Boundaries of Slave Point barrier reef (Clarke Lake) and Slave Point platform (Adsett) plays. (See Fig. 23 for cross-sections A–A′ and B–B′ and Fig. 26 for cross-sections C–C′ and D–D′.)*

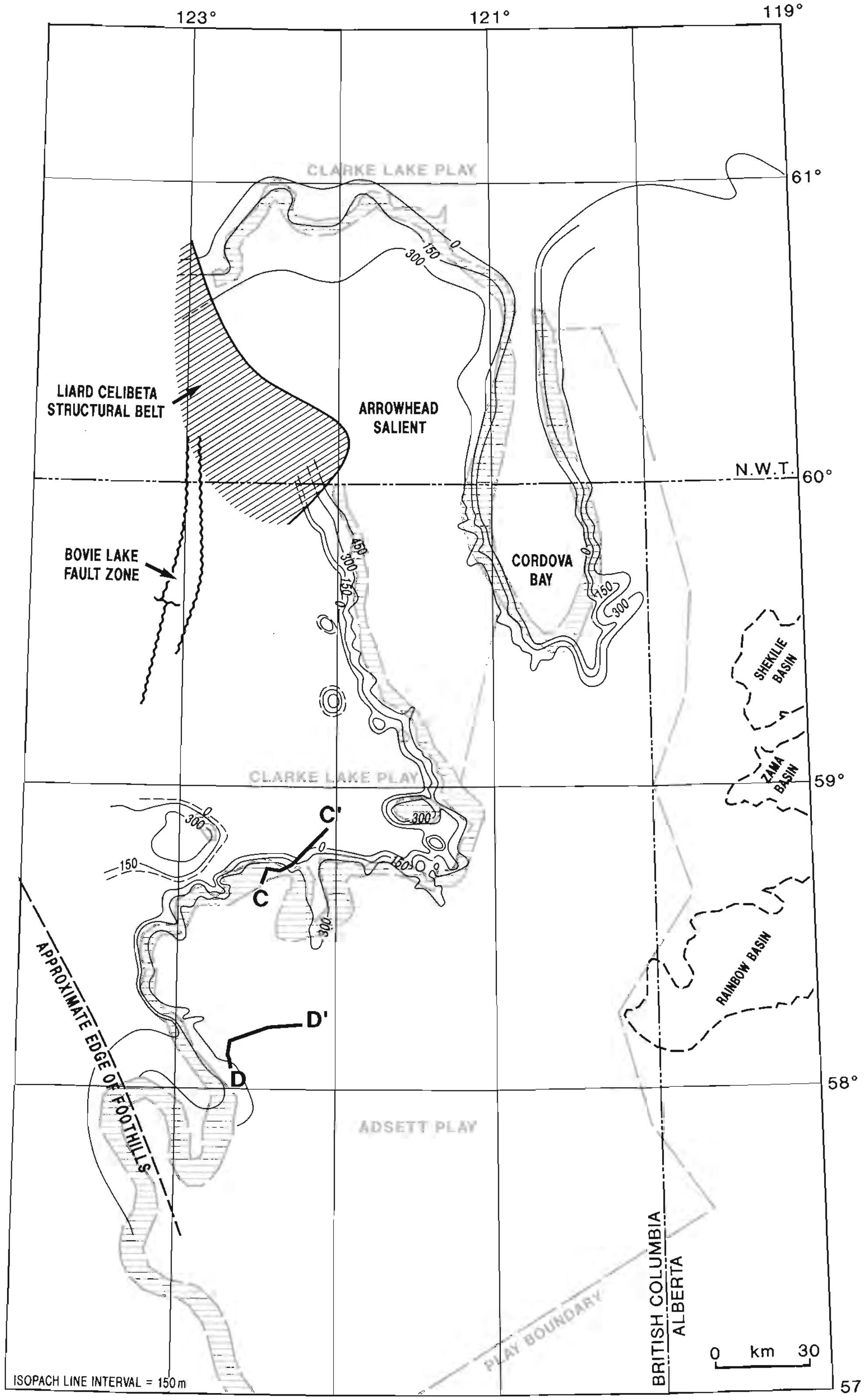


Figure 22. (cont'd)

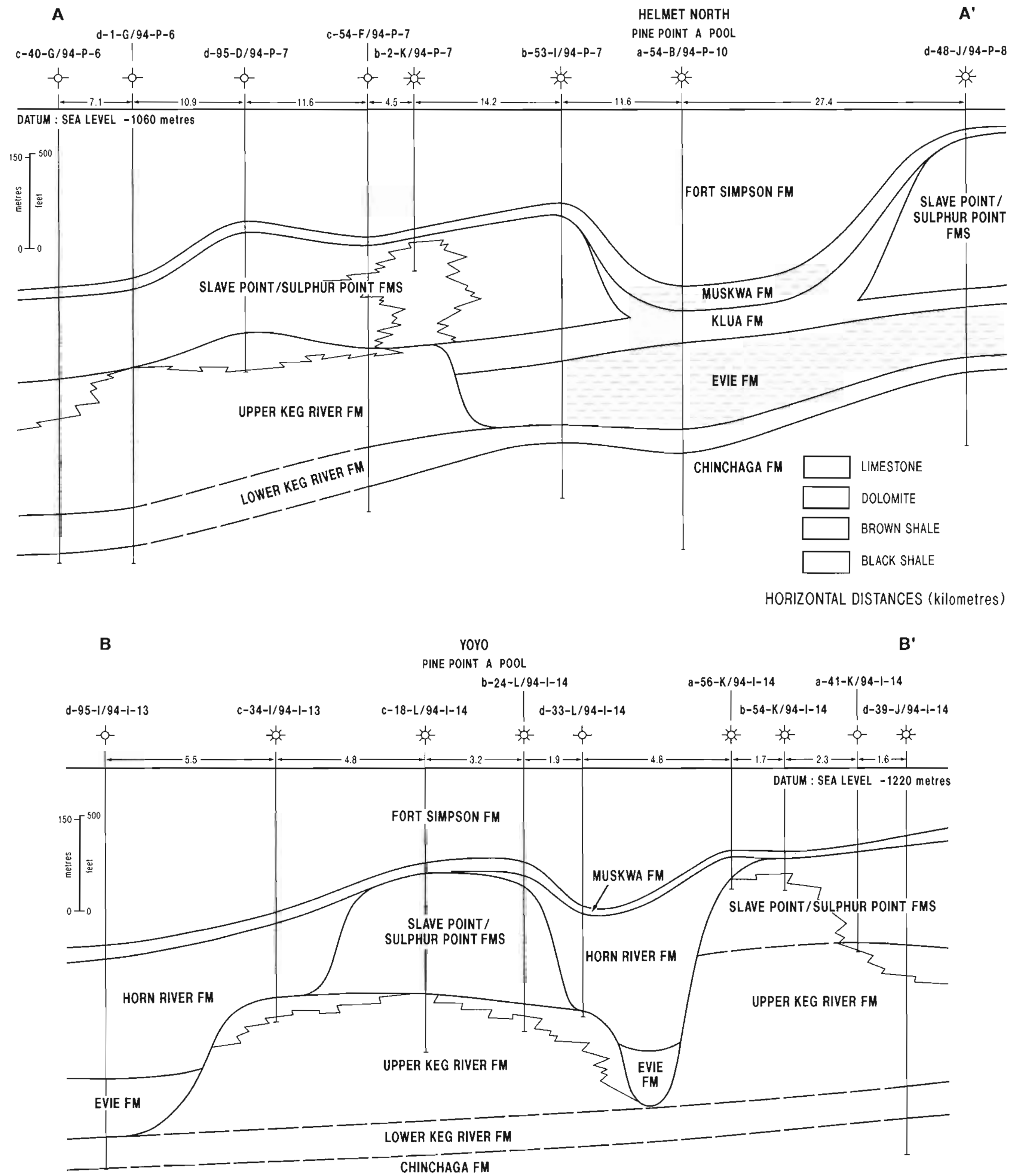


Figure 23. *Cross-sections of the Helmet area (A–A') illustrating the Keg River platform (July Lake) play, and of the Yoyo field (B–B') illustrating the Keg River isolated reef play. (Modified from Fischbuch, 1989a.) (Cross-section locations are shown in Fig. 22a.)*

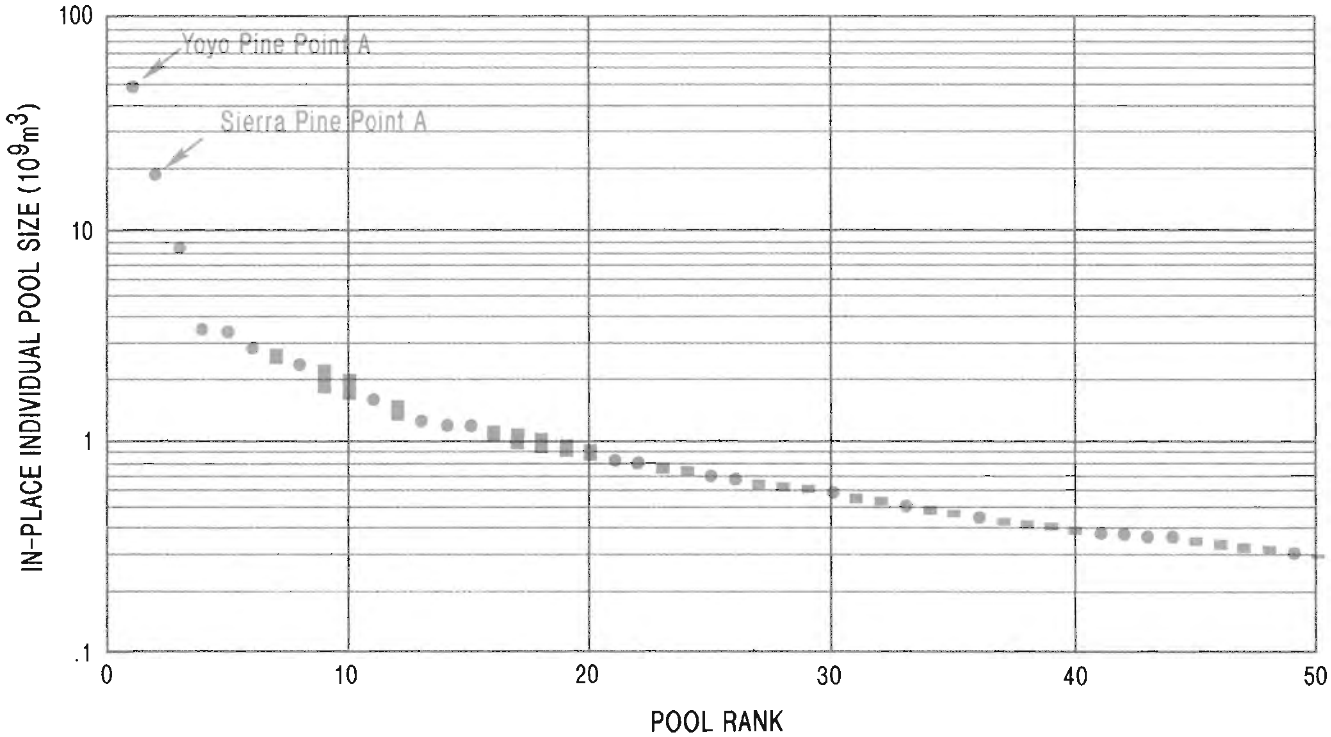


Figure 24. *Pool size-by-rank plot for the Keg River isolated reef (Yoyo) play. The 20 largest discovered pools are listed in Table 8.*

Marie Member of the Red Knife Formation, primarily in northeast British Columbia, extending northward into the Northwest Territories (Fig. 29).

Geology. The Jean Marie Member consists of silty to dolomitic limestones that form a shelf platform unit 13 to 25 m thick. The unit thickens to over 95 m to the west and then ''shales-out'' abruptly into the Besa River shale basin (Figs. 29, 30; Law, 1971; McAdam, 1981). Thickening of the platform unit may be related to the patchy occurrence of organic reefoid buildups (Law, 1971). Alternatively, the thickening could be due to sigmoidal progradation of the shelf margin (J. Wendte, pers. comm., 1991). Preliminary investigation of cores and logs in the July Lake area indicates the presence of flat, biostromal accumulations, up to 4.5 m thick, consisting of tabular, stromatoporoid-coral framestone-bindstones. These biostromes are encased in lime mudstones-wackestones. Other biostromal zones have been reported to consist predominantly of *Renalcis*-tabular stromatoporoid bindstones with lime mudstone matrix and shelter porosity developed in association with the stromatoporoid-*Renalcis* couplets (D. Sturrock, pers. comm., 1991).

The best reservoirs occur where relatively low primary porosities and permeabilities are enhanced in these biostromal zones by fracturing, dissolution and dolomitization (McAdam, pers. comm., 1991). Secondary fracture porosity apparently is related to differential compaction of the thick, Fort Simpson–Klua shale sequence, resulting in draping of the Jean Marie above the Slave Point bank margin (Fig. 30). Gas is pervasive throughout the Jean Marie Member and forms the continuous reservoir phase (Letourneau, 1991).

Exploration history. Gas shows were indicated in the Jean Marie in the 1950s but up until the late 1970s this play was not given high priority. Recent exploration activity suggests a renewed interest in this entirely nonassociated gas play. The largest discovered pool is Helmet North, with an initial in-place volume of 6 793 x $10^6 m^3$. To date the number of pools discovered is 18, with a total initial in-place volume of 11 636 x $10^6 m^3$. (Table 12).

Play potential. Estimates of the potential for this play suggest an initial in-place volume of 24 035 x $10^6 m^3$. This number indicates that 67 per cent of the total gas resource in this play remains to be discovered. The

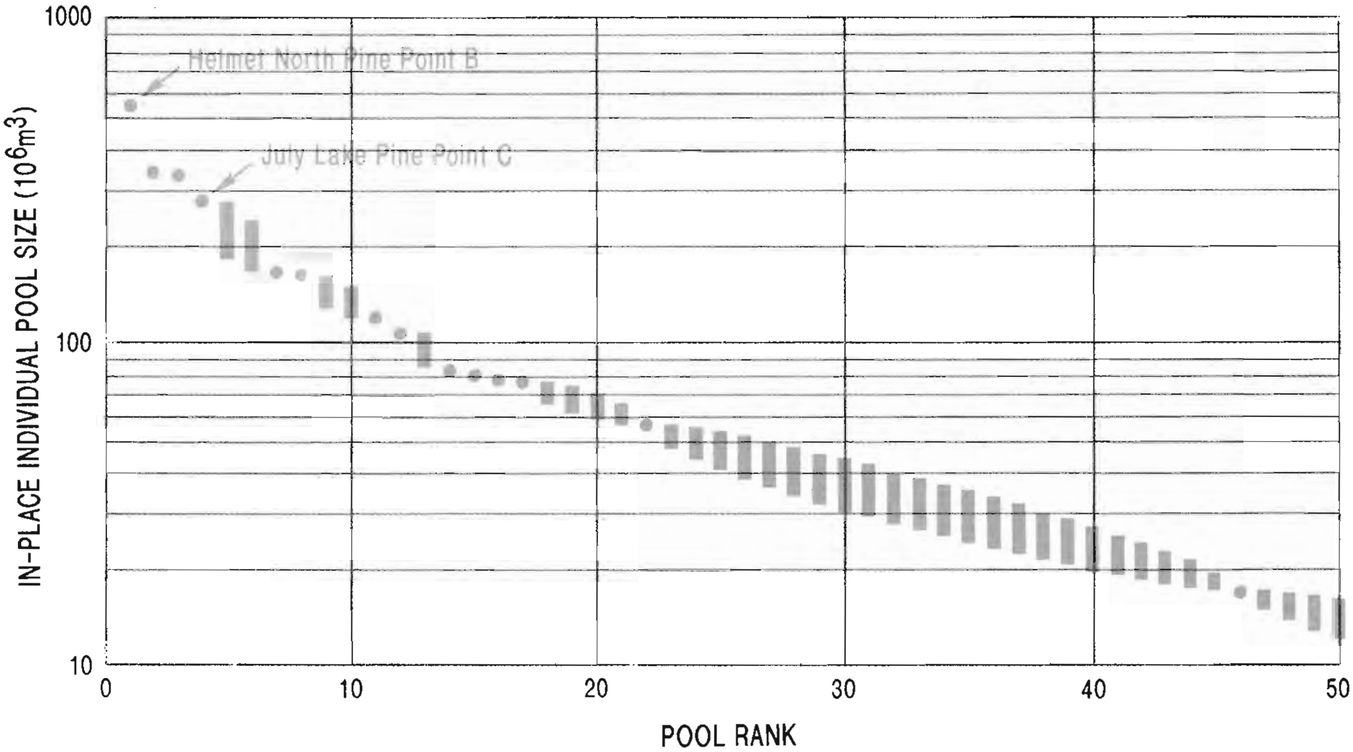


***Figure 25.** Pool size-by-rank plot for the Keg River platform (July Lake) play. Discovered pools in this play are listed in Table 9.*

estimate assumes a total pool population of 300, suggesting that the Jean Marie play is relatively immature, with only 18 pools having been discovered to date. The largest undiscovered pool should have an initial in-place volume of 3 110 x $10^6 m^3$ (Fig. 31).

Slave Point reef complexes - Cranberry

Play definition. This gas play was defined to include all pools and prospects in Slave Point reef complexes that occur in an arcuate trend around the north and east flanks of the Peace River Arch, and as isolated buildups within the widespread carbonate platform that extends northward into the southern Northwest Territories (Figs. 32, 33).

Geology. The Beaverhill Lake Group in the Peace River Arch area includes, in ascending stratigraphic order, the Fort Vermilion, Slave Point, and Waterways formations (Leavitt and Fischbuch, 1968). The Beaverhill Lake Group records an overall transgressive depositional cycle comprising shallow-water evaporites and carbonates of the Fort Vermilion and Slave Point formations and basin-filling shales and limestones of the overlying Waterways Formation.

The Fort Vermilion Formation consists of interbedded anhydrites, dolostones, limestones and shales representative of peritidal and shallow, restricted shelf environments. Anhydrites and evaporitic carbonates characterize the Fort Vermilion east of the sixth meridian, but westward, platform carbonates are more prevalent and not easily distinguishable from carbonates of the overlying Slave Point. This is particularly evident immediately north of the Peace River Arch in the Cranberry, Chinchaga and Hamburg areas (Fig. 33). In the oil-bearing areas east of the Peace River Arch (Red Earth, Loon, Otter), the Fort Vermilion is dominated by anhydrites and evaporitic dolostones, in contrast to the peritidal shelf carbonates of the overlying lower Slave Point Formation.

The Slave Point is a widespread, shallow-marine carbonate formation that extends from the central Alberta Basin southeast of the Peace River Arch northward to its type area near Great Slave Lake in the Northwest Territories. The Slave Point Formation is thickest near 60° latitude in northeast British Columbia and northwest Alberta, and thins progressively southward to a zero edge where it onlaps the Peace River Arch. Reef facies are developed at several stratigraphic levels around the margins of the Peace

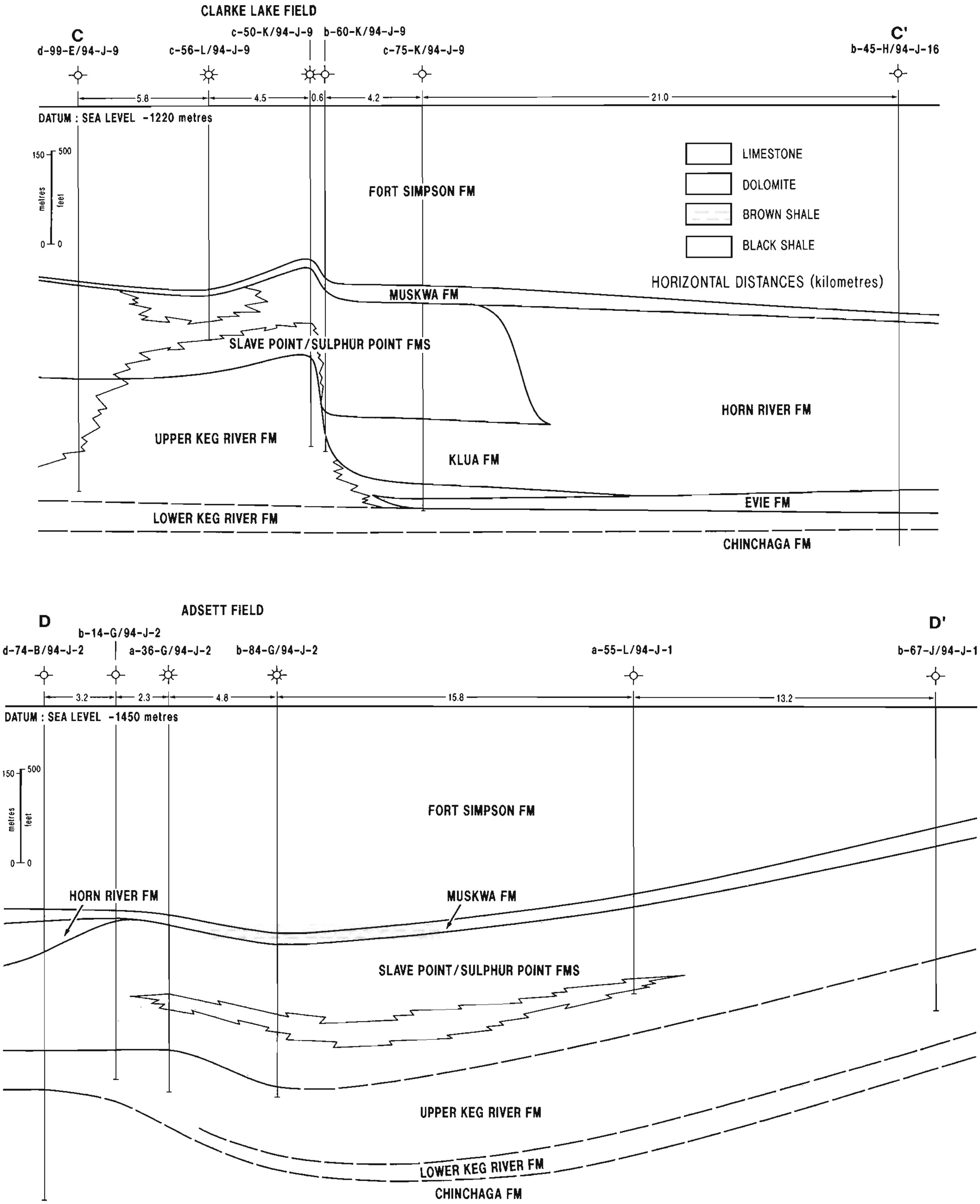


Figure 26. *Cross-sections of the Clarke Lake field (C–C') illustrating the Slave Point barrier reef play, and the Adsett field (D–D'), which typifies the Slave Point platform play. (Modified from Fischbuch, 1989a.) (Cross-section locations are shown in Fig. 22b.)*

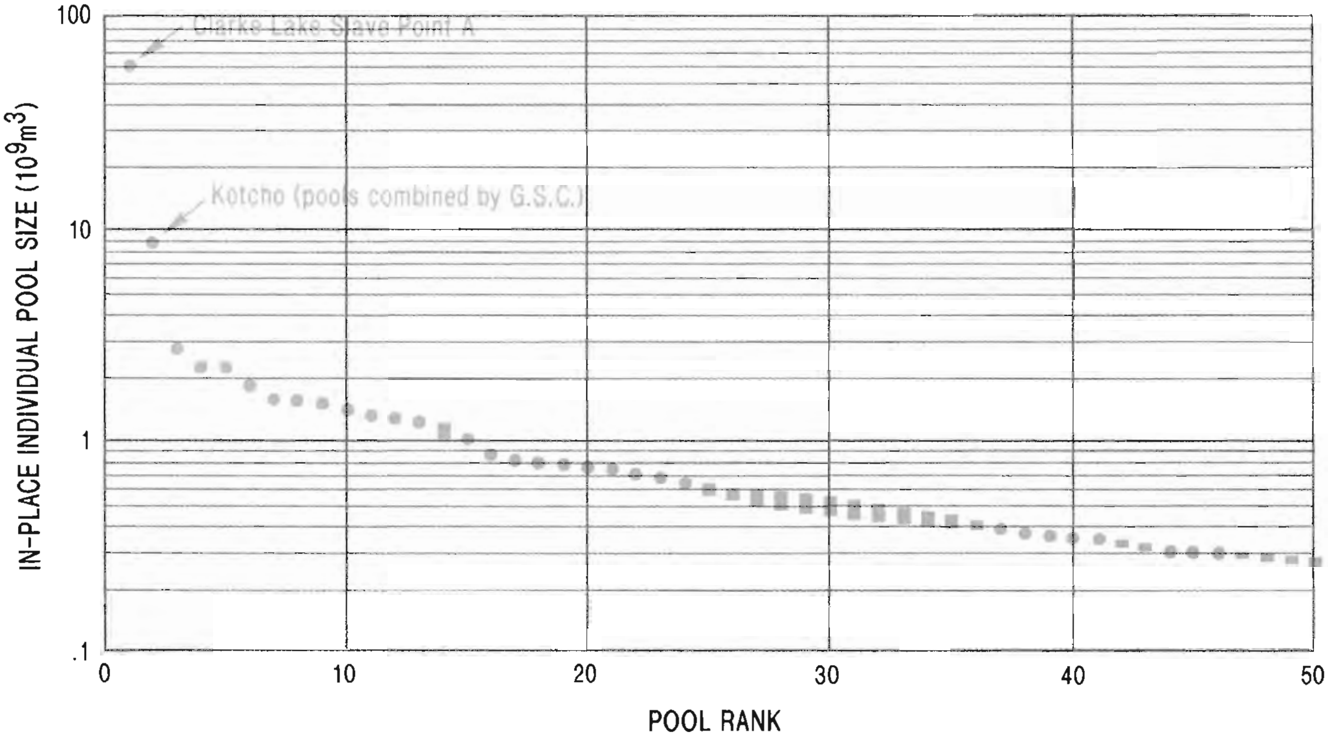


Figure 27. *Pool size-by-rank plot for the Slave Point barrier reef (Clarke Lake) play. The 20 largest discovered pools are listed in Table 10.*

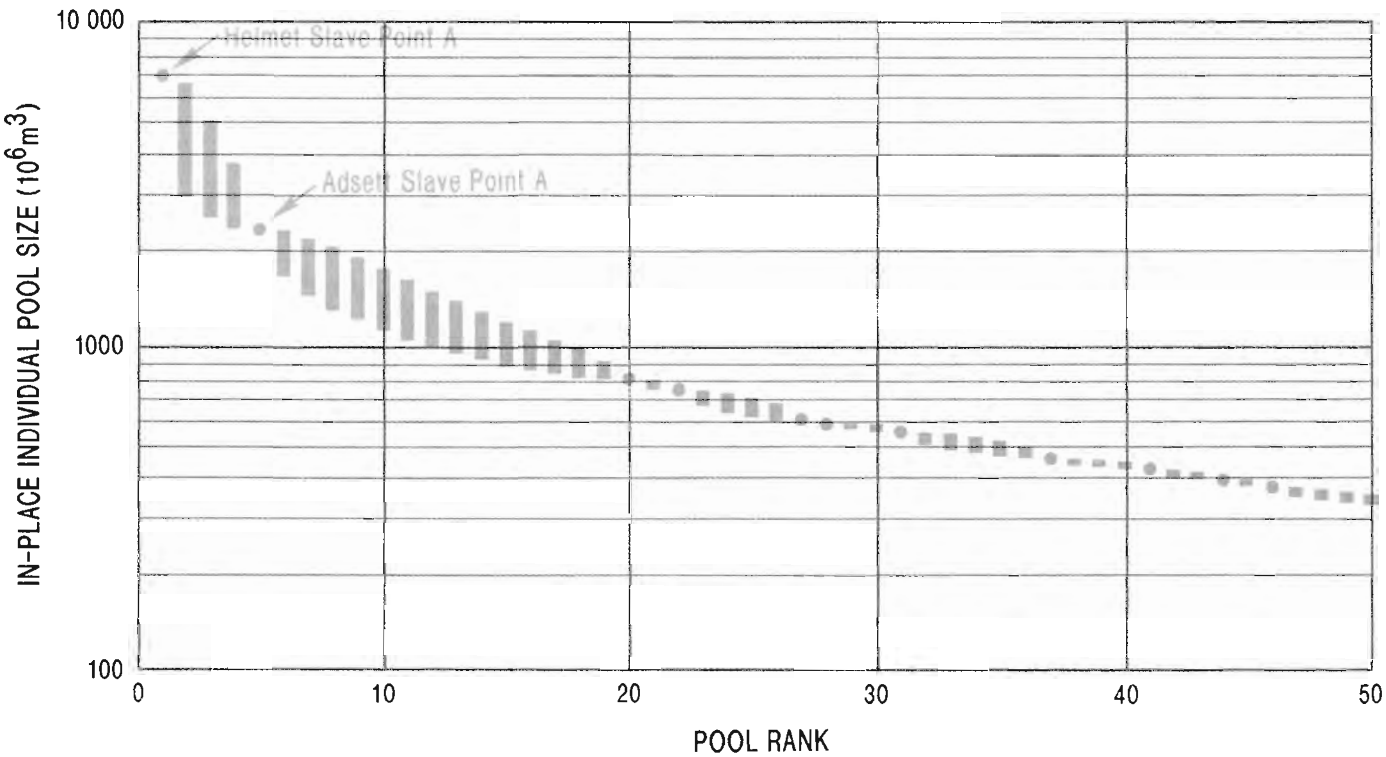


Figure 28. *Pool size-by-rank plot for the Slave Point platform (Adsett) play. The 20 largest discovered pools are listed in Table 11.*

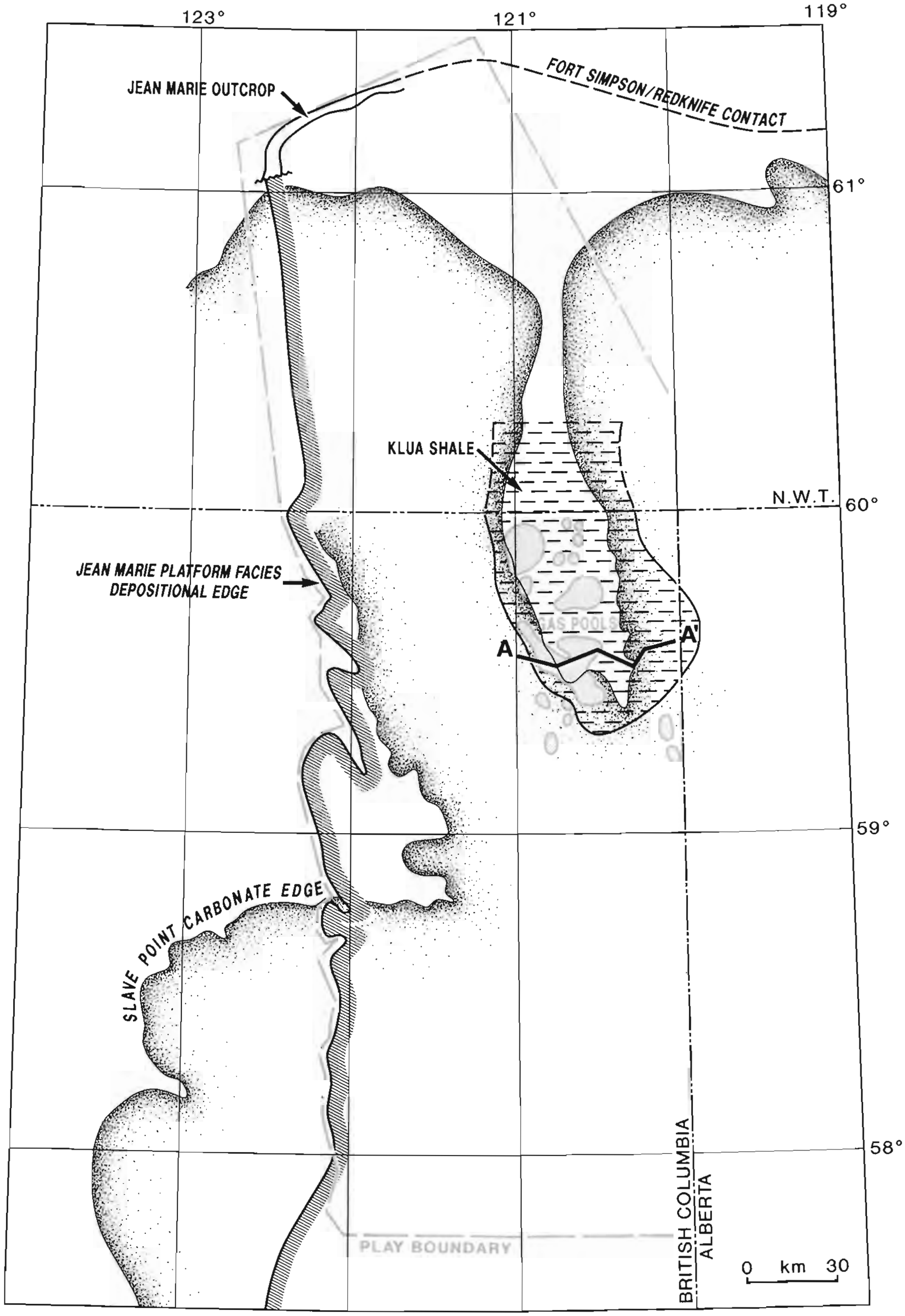


Figure 29. Map of the Jean Marie biostrome play. Note distribution of gas pools in the northeast corner of British Columbia relative to the underlying Slave Point carbonate edge. (Compiled using information from Williams, 1981, and McAdam, 1990.) (See Fig. 30 for cross-section A–A'.)

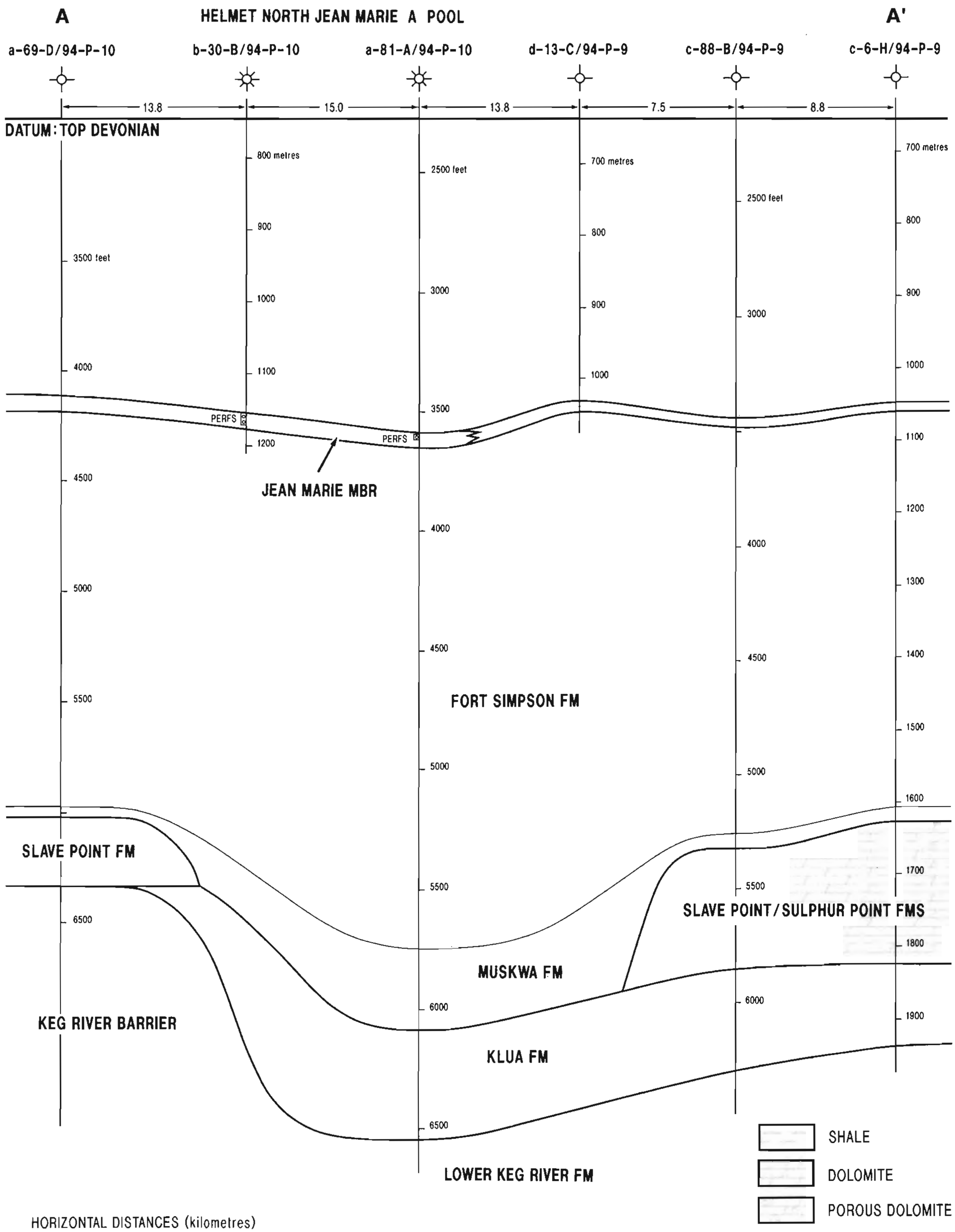


Figure 30. Stratigraphic cross-section A–A' through Jean Marie gas pools showing relation of gas occurrence to underlying Klua Shale and Slave Point carbonate edge. (Cross-section location is shown in Fig. 29.)

River Arch, reflecting a step-like sea-level rise and transgressive onlap of the Arch. Slave Point buildups occur in arcuate patterns around the flanks of the Arch (Podruski et al., 1988), and individual discontinuous reef complexes form isolated hydrocarbon reservoirs (Dunham et al., 1983; Craig, 1987; Tooth and Davies, 1988). In this study, the Slave Point Formation around the Peace River Arch is divided into a Slave Point platform (or lower Slave Point), and an upper Slave Point biohermal facies. The platform deposits are believed to equate with Division I and lower carbonates of the Swan Hills Formation, and the upper biohermal facies to Divisions II and III of the Swan Hills reef complexes (Fischbuch, 1968).

Several of the better producing oil pools such as Evi, Golden, Slave and Seal, occur within the "dolomite halo" that surrounds the Peace River Arch, and one of the major gas pools (Hamburg) also is, in part, a dolomitized reef complex. However, this gas play is facies controlled, whether dolomitization has occurred or not. Hydrocarbons are produced from skeletal stromatoporoid and interparticle matrix porosity of reef and backreef limestones in the Cranberry and Chinchaga gas pools, and in the Red Earth, Sawn and Loon oil pools. The lateral and upper seal rocks for these Slave Point reservoirs are Waterways shaly limestones and calcareous shales.

Although most of the known Slave Point reef buildups are present in the vicinity of the Peace River Arch, it is not unreasonable to expect similar patch reefs to occur within the thick Slave Point succession that blankets most of northern Alberta and extends into the Northwest Territories. Such reef complexes are difficult to identify as prospects because of low seismic contrast with the nonporous, open-marine, shelf limestones (Podruski et al., 1988). The Cranberry and Chinchaga reefoid buildups (Fig. 33) are also difficult to distinguish seismically because they are encased in open-marine limestones that have a velocity signature similar to the reefoid carbonates. Thus, the boundary map for this play extends north of 60° latitude to account for the possible occurrences of isolated Slave Point platform reef complexes in the Northwest Territories (Fig. 32). The gas pools and shows associated with Slave Point carbonates within the boundaries of the Keg River shelf basins are excluded from this play because they are considered to be controlled by structural drape rather than by stratigraphic trapping mechanisms.

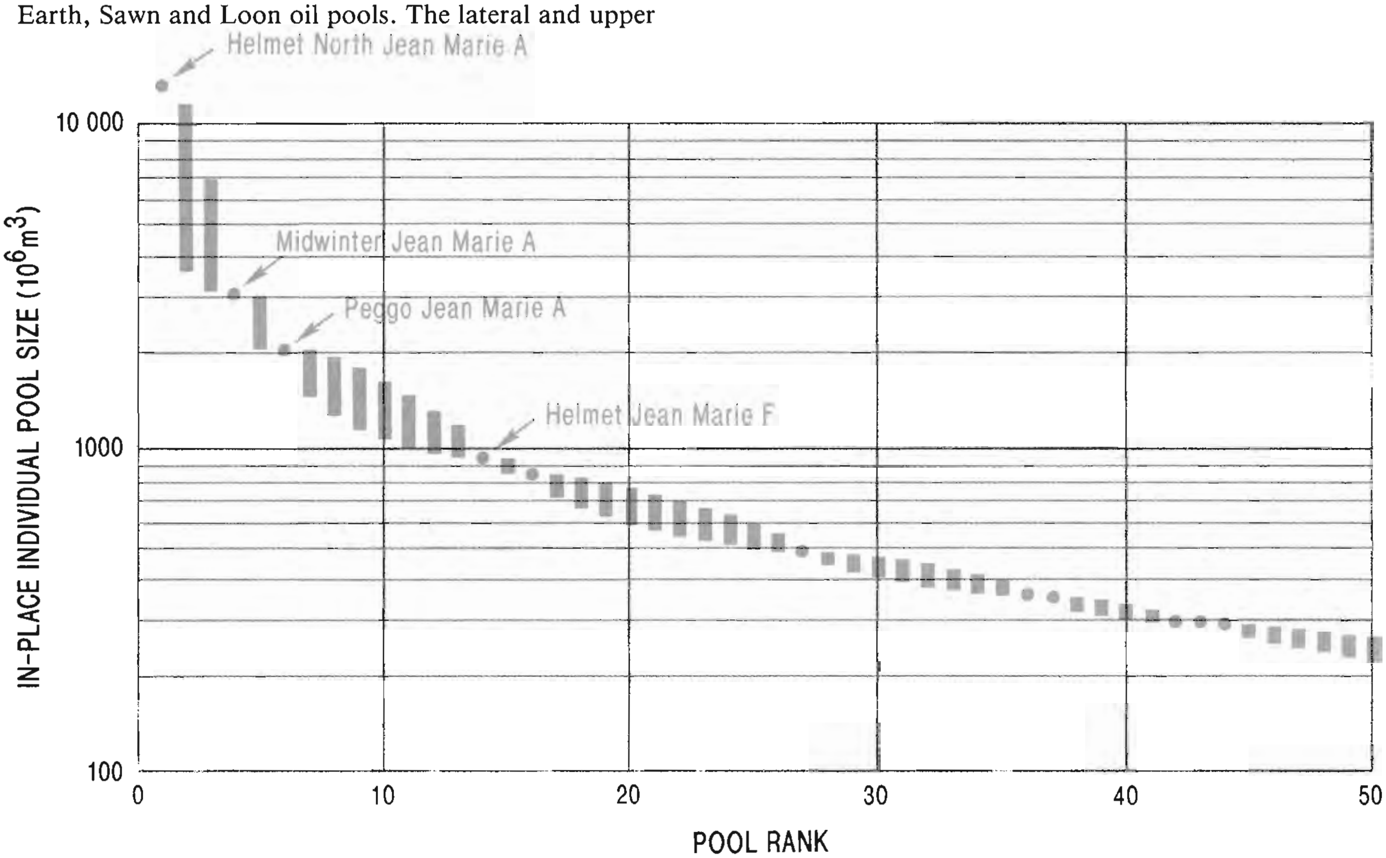


Figure 31. *Pool size-by-rank plot for the Jean Marie biostrome (Helmet North) play. All pools in this play are listed in Table 12.*

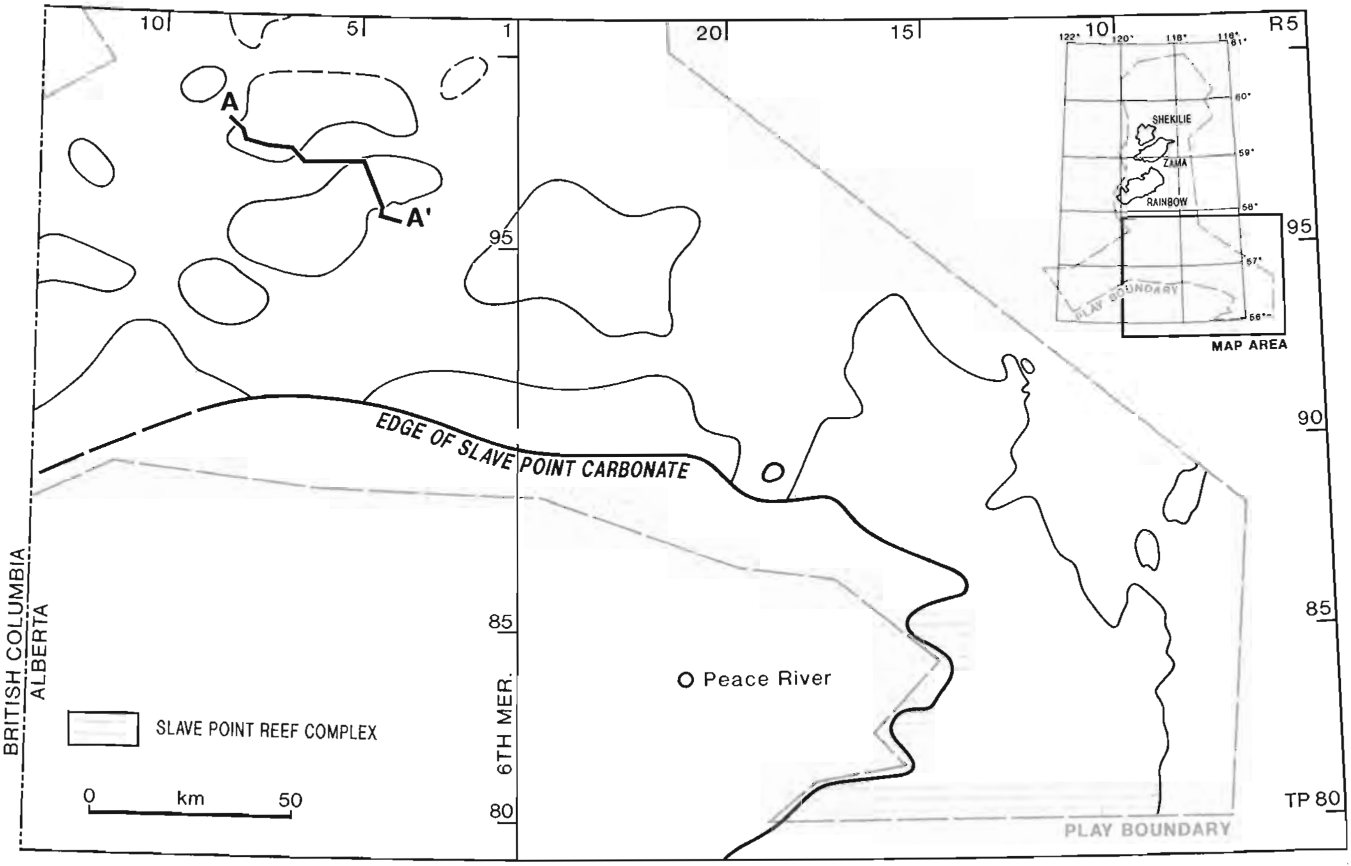


Figure 32. Map of Slave Point Reef complexes in the region of the Peace River Arch. Complete play boundary is shown on index map. (See Fig. 33 for cross-section A-A'.)

Exploration history. This is primarily a nonassociated gas play, and the largest pool, Cranberry Slave Point "A" (14 260 x 10^6m^3), was discovered in 1974. The earliest pool discovery of significant size was Rainbow in 1964 (341 x 10^6m^3). To date, the number of pools discovered is 37, with a total initial in-place volume of 21 100 x 10^6m^3 (Table 13). Of these 37, 26 are nonassociated gas with a total in-place volume of 20 484 x 10^6m^3.

Play potential. Estimates of the potential for this play indicate an initial in-place volume of 67 467 x 10^6m^3. This number suggests that 76 per cent of the total gas reserves in this play is still to be discovered. The estimate assumes a total pool population of 450, suggesting that, with only 37 having been discovered to date, this play is relatively immature (Table 13). The largest undiscovered pool should have an in-place volume in the order of 7 755 x 10^6m^3 (Fig. 34). The northern part of the play has no significant discoveries and is relatively underexplored. This area could have significant future potential, as could the area adjacent to, and west of Cranberry, extending into British Columbia (Fig. 32).

Leduc fringing reef - Worsley

Play definition. This play includes all gas pools and prospects occurring in upthrown fault blocks of the Leduc fringing reef complex that rims the Peace River Arch (Figs. 35, 36).

Geology. The Leduc reef chain forms the shelf margin of a carbonate-siliciclastic platform complex. The complex is a wedge-shaped body up to 250 m thick that thickens basinward from the Peace River Arch landmass to the shelf margin (Belyea, 1964; Bassett and Stout, 1967). The marginal reef chain is relatively narrow, ranging from 2 to 6 km in width, and separates basin-fill mudstone facies from landward, shelf-interior facies consisting of sandstone and dolomitic mudstone. Three main carbonate sequences are defined for the Leduc complex: the lowest sequence represents carbonate ramp development, the middle sequence is a locally rimmed shelf, and the uppermost sequence is a muddy carbonate ramp that grades into the overlying Winterburn Group (Dix, 1990).

"Granite Wash" arkosic, conglomeratic sandstones blanket the Peace River Arch landmass and form the innermost part of the shelf complex (Fig. 35). These sandstones underlie and interfinger with shelf-interior carbonates and fringing reef carbonates. The shelf-interior carbonates consist of nodular, brecciated, dolomitic mudstone and dolomitic floatstone containing fragments of corals, crinoids, brachiopods, tabular stromatoporoids, and dendroid stromatoporoids.

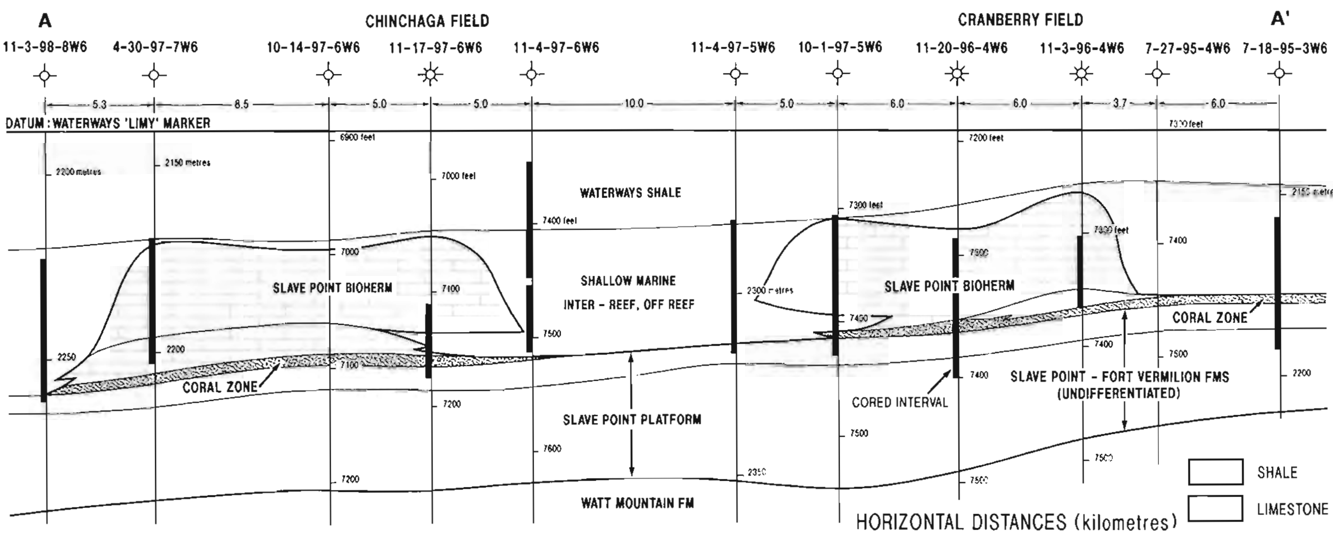


Figure 33. Lithological cross-section A-A' through the Cranberry and Chinchaga Slave Point reef complexes. Cored intervals are indicated by vertical bars. (Cross-section location is shown in Fig. 32.)

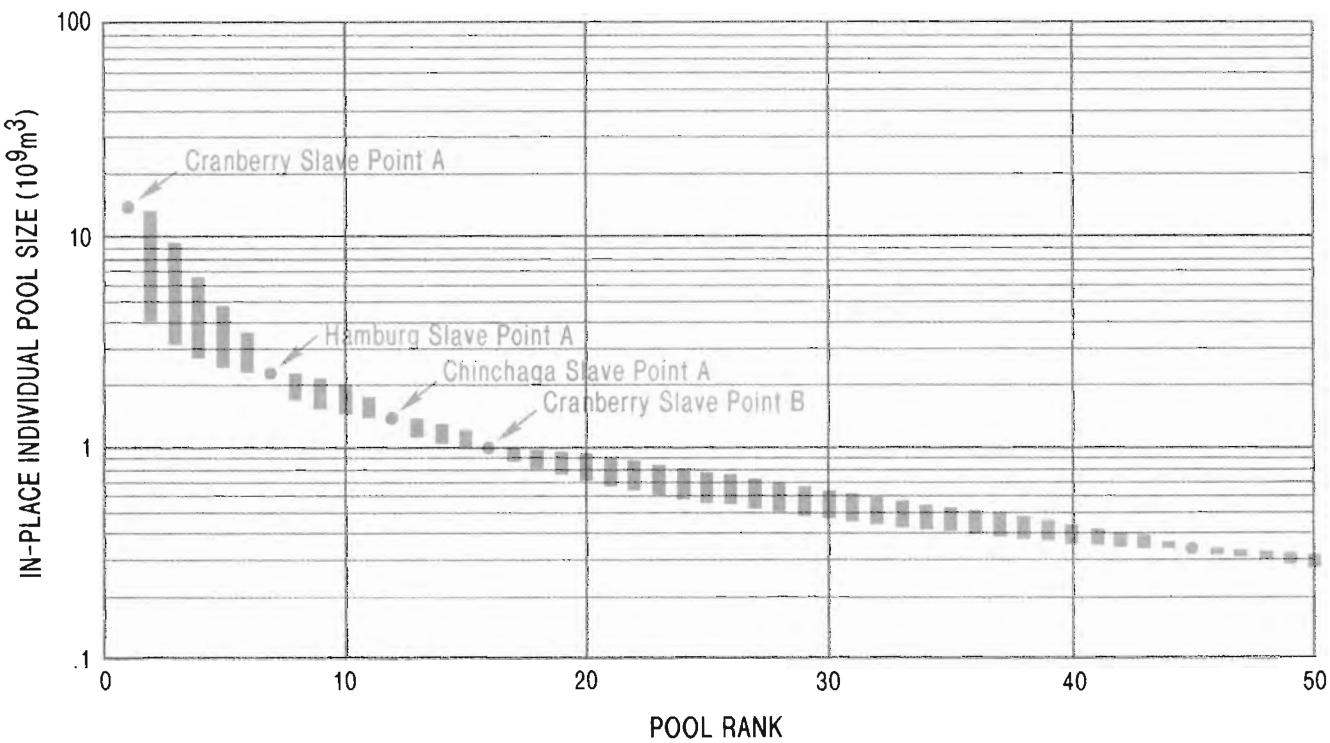
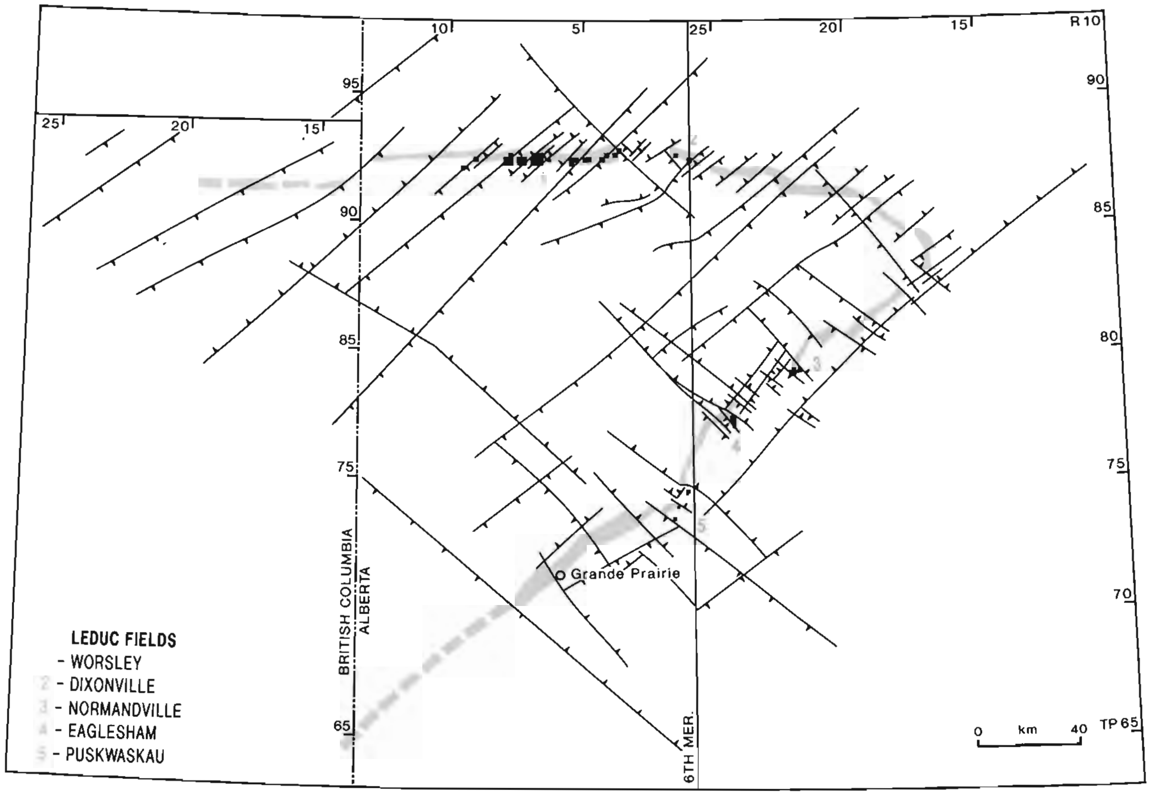
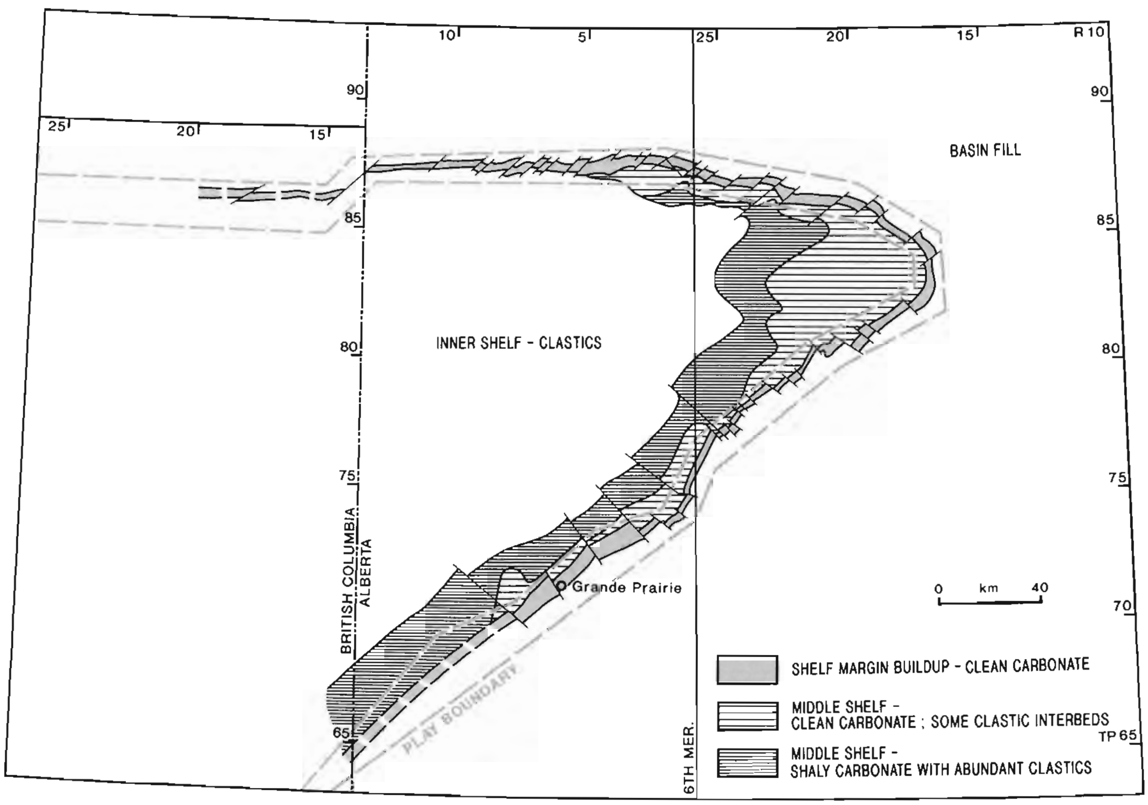


Figure 34. Pool size-by-rank plot for the Slave Point reef complexes (Cranberry) play. The 20 largest discovered pools are listed in Table 13.



a



b

Figure 35. Leduc fringing reef complex that rims the Peace River Arch.
***a.** Detailed block-faulting pattern. **b.** Facies distribution.*

Finely crystalline dolostone with vugs and fenestral fabric occur as a minor rock type in the shelf-interior facies.

The shelf margin facies that forms the reservoir is composed of dolomitic floatstone, which consists of 10 to 30 per cent coral fragments and a minor amount of tabular and dendroid stromatoporoid fragments in a matrix of dolomitic mudstone. Dissolution of the large fossil fragments coupled with pervasive matrix dolomitization appears to have controlled development of vuggy and biomoldic porosity in this facies.

The Leduc fringing reef complex is dissected by numerous fault blocks produced by pre-, syn- and post-reef movements on basement-rooted normal faults (Fig. 36). The faults have acted to displace reef blocks upward and laterally against the shaly carbonate seal rocks of the Winterburn Group and Nisku Formation.

Exploration history. Discoveries in this play belong to the post-1947 exploration phase of the Western Canada Basin. The first discovery was at Dixonville in 1949 (gas), followed by Normandville in 1958 (oil and gas), and Worsley (gas and oil) in 1960 (Table 14). To date the number of gas pools discovered is 17, with a total initial in-place volume of 7 035 x 10^6m^3. Of these 17 pools, 14 contain nonassociated gas with a total in-place volume of 6 929 x 10^6m^3.

Play potential. Estimates of the potential for this play indicate an initial in-place volume of 8 445 x 10^6m^3 distributed in 183 undiscovered pools that constitute 55 per cent of the total play resource (Table 14). The pool size by rank plot indicates that many of the larger pools are undiscovered, with the largest remaining pool estimated to have an in-place volume of 1 649 x 10^6m^3 (Fig. 37). Potential exists in additional undrilled fault blocks between established fields and at the west and southwest extremities of the play boundary (Fig. 35), or in updip (northeast) edges of previously drilled fault blocks.

Wabamun structural and stratigraphic - Parkland

Play definition. This play includes diagenetic-structural traps in the upper Wabamun Group and stratigraphic-structural traps in the middle Wabamun Group of northwest Alberta and northeast British Columbia (Figs. 38, 39).

Geology. The Wabamun Group consists of a sequence of shallow-water carbonates that were deposited in two major depositional settings: i) a broad carbonate ramp that extended across most of Alberta and into northeast British Columbia; and ii) a restricted shallow-water carbonate platform that fringed the Peace River Arch (Packard et al., 1990; Stoakes and Foellmer, 1987). The Wabamun Group grades laterally west-northwest into basinal shales of the Kotcho Formation and limestone-shale of the Tetcho Formation.

The Wabamun Group in the Peace River Arch area ranges up to 250 m in thickness. The lower and middle portions consist of a series of progradational platform carbonates that fringe the Arch. Small stromatoporoid patch reefs occur within the middle Wabamun Group (i.e., the Normandville area; Nishida, 1987). The upper Wabamun Group consists of deep-water crinoidal wackestones and mudstones deposited in a distal ramp setting. The upper Wabamun is a transgressive sequence overlain by the basinal anoxic shales of the Exshaw Formation (Stoakes, 1987; Stoakes and Foellmer, 1987; Halbertsma and Meijer Drees, 1987).

There are two distinct reservoir types in the Wabamun of the Peace River Arch area. The first type consists of partly dolomitized grainstone zones and stromatoporoid patch reefs in the middle Wabamun (i.e., Normandville). Dolomitization appears to have been an early diagenetic process but is not extensive (Halbertsma and Meijer Drees, 1987). The second reservoir type occurs in dolomitized distal ramp deposits of the upper Wabamun Group, such as at Tangent and Eaglesham North. These dolomitized zones occur in irregular, laterally discontinous, vertically oriented pods (Packard et al., 1990). This type of dolomitization is commonly associated with fault-generated breccia units that filled cavities created by hydrothermal fluid dissolution along fault zones. The breccia units range from 2 to 50 m in thickness and are present at various levels within the Upper Wabamun and overlying Exshaw Formation.

Exploration history. The first pool discovered in this play was the Parkland Wabamun A pool, which had an initial in-place volume of 6 300 x 10^6m^3 (Table 15). By the end of 1988, a total of 48 gas pools had been discovered, with a total initial in-place volume of 19 281 x 10^6m^3. Of these 48 pools, 24 contain non-associated gas with an in-place volume of 17 003 x 10^6m^3.

Play potential. The estimated potential for this play is 40 870 x 10^6m^3, indicating that 68 per cent of the total play resource is still undiscovered to date. The estimate assumes a total pool population of 900, with the largest undiscovered pool having an initial in-place volume of 2 022 x 10^6m^3 (Fig. 40).

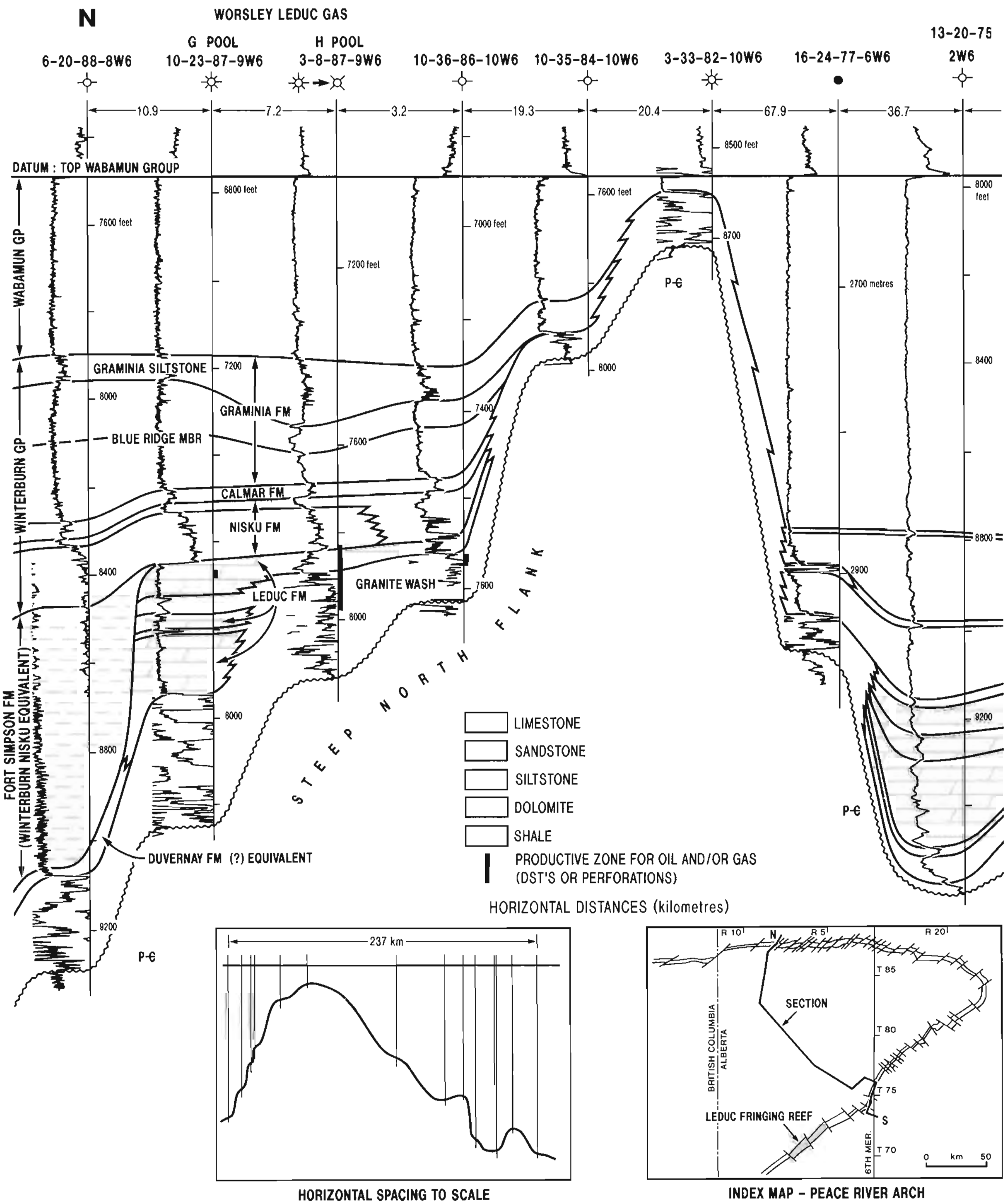


Figure 36. *Cross-section of the Peace River Arch showing the nature of the Leduc fringing reef play.*

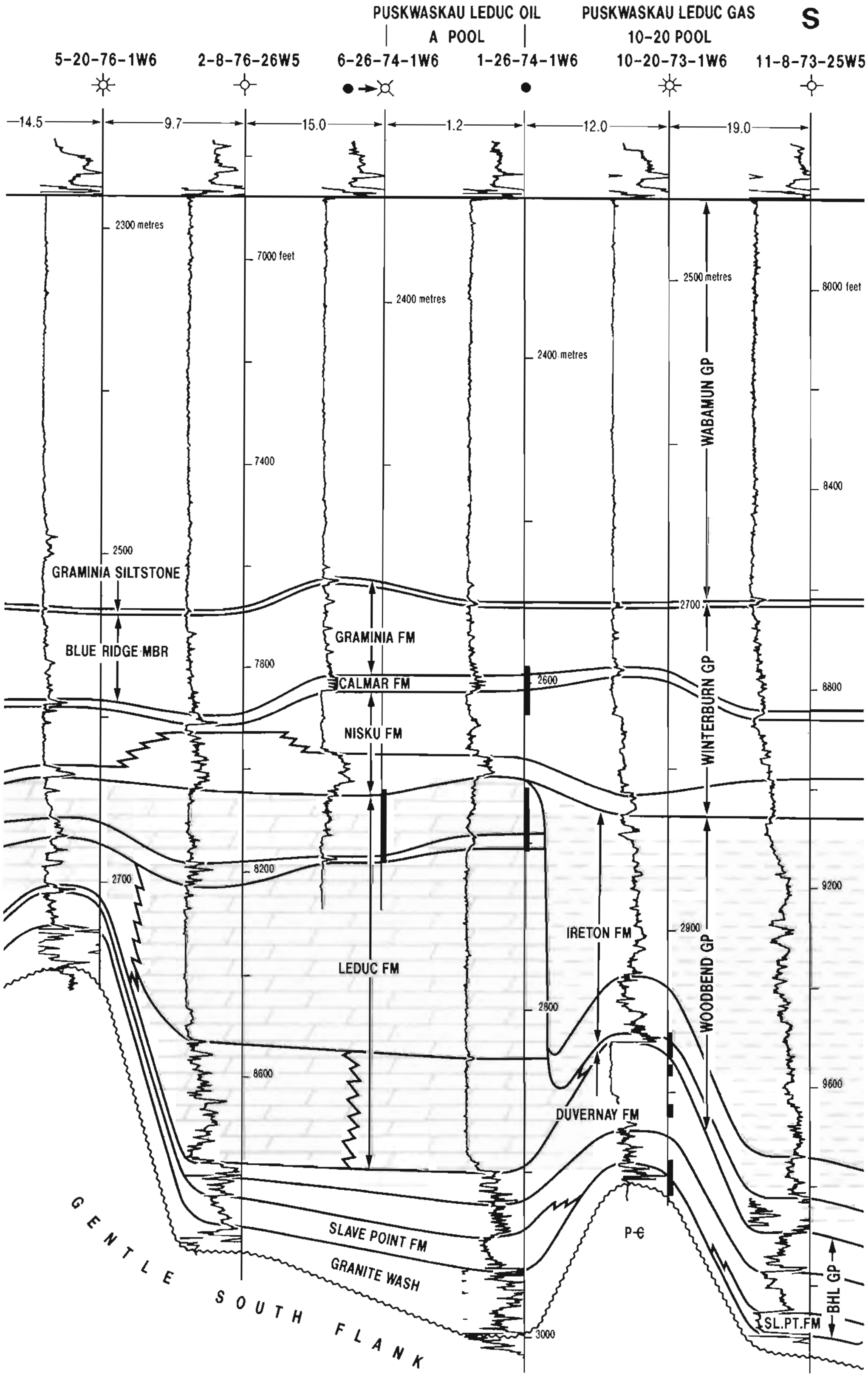


Figure 36. (cont'd)

Sulphur Point platform facies - Bistcho

Play definition. This immature play was defined to include all pools and prospects in stratigraphic traps of the carbonate shelf facies of the Sulphur Point Formation. The play extends northeast from Zama and Shekilie across the Alberta/Northwest Territories border to the northern edge of the Muskeg anhydrite (Fig. 41).

Geology. The Sulphur Point Formation consists of a shelf carbonate, 5 to 80 m thick, which disconformably overlies (and is laterally equivalent to) Muskeg evaporites (Fig. 42). It is unconformably overlain by the Watt Mountain Shale (Williams, 1981). Detailed correlations of uppermost Muskeg anhydrite/dolomite cycles with adjacent Sulphur Point carbonates suggest that a facies relation exists between the formations (McCamis and Griffith, 1967). McCamis and Griffith proposed the name Bistcho Member to be used in place of Sulphur Point Formation, but this has not gained acceptance.

Sulphur Point lithologies range from dolomitic mudstones/grainstones in the lower part, to lime mudstones in the upper part. The hydrocarbon reservoirs are formed from porous dolomitic grainstones or packstones that were deposited in peritidal channel environments. The reservoirs are sealed laterally by supratidal lime mudstones or anhydrites, and vertically by lime mudstones deposited in less restricted environments.

Exploration history. Hydrocarbon pools in this play were discovered by chance while drilling for Keg River reefs in northern Alberta during the 1960s. In the Northwest Territories the original Cameron Hills discovery, Cameron Hills A-05 (1968), was in the Sulphur Point Formation. At the time of writing, details regarding the Cameron Hills discoveries were confidential; hence Cameron Hills pools are excluded from Table 16. A total of 41 pools in northern Alberta have been designated in this play; these contain an initial in-place volume of 1 250 x $10^6 m^3$ of natural gas (Table 16).

Play potential. This is an immature play, consequently no numerical assessment was undertaken. Since the play area is quite large, there is potential for substantial gas reserves still to be found. The gas is likely to occur in many small pools near the edge of the Muskeg anhydrites (Fig. 41).

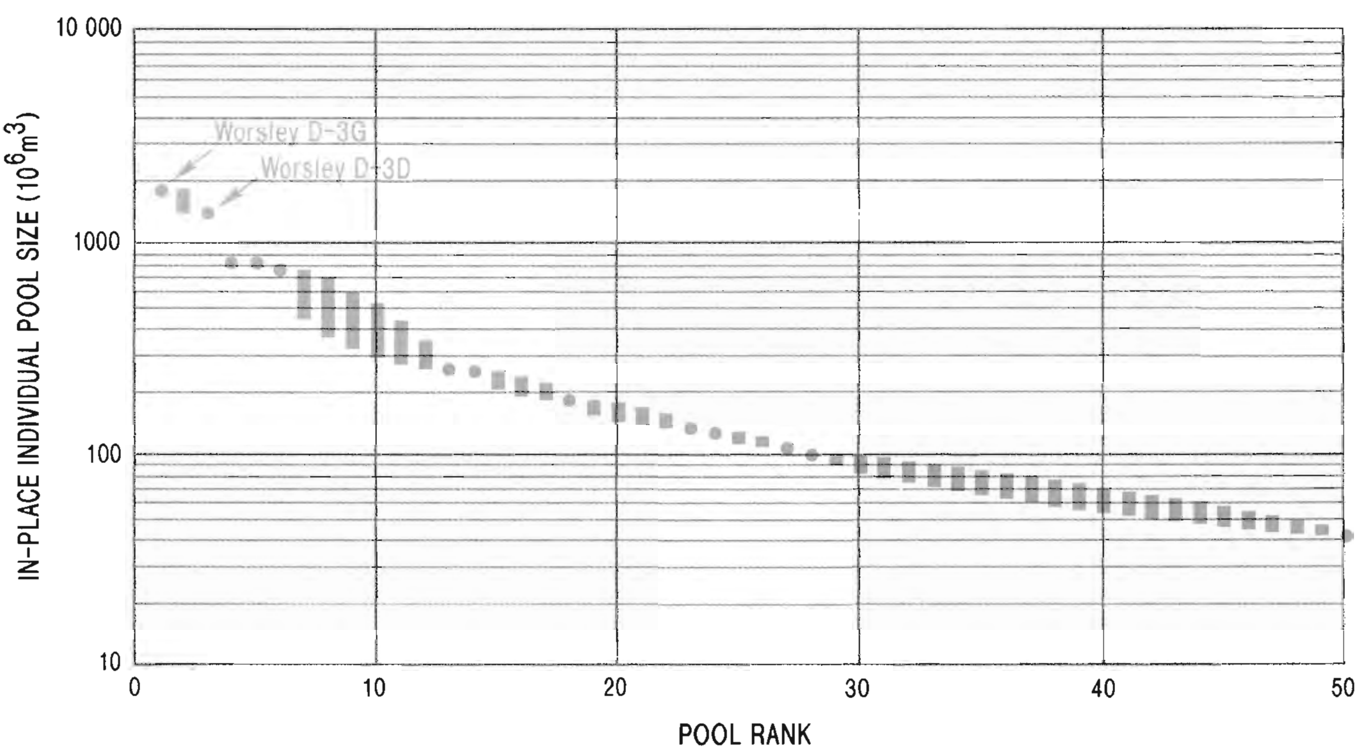


Figure 37. *Pool size-by-rank plot for the Leduc fringing reef (Worsley) play. The 17 discovered pools in this play are listed in Table 14.*

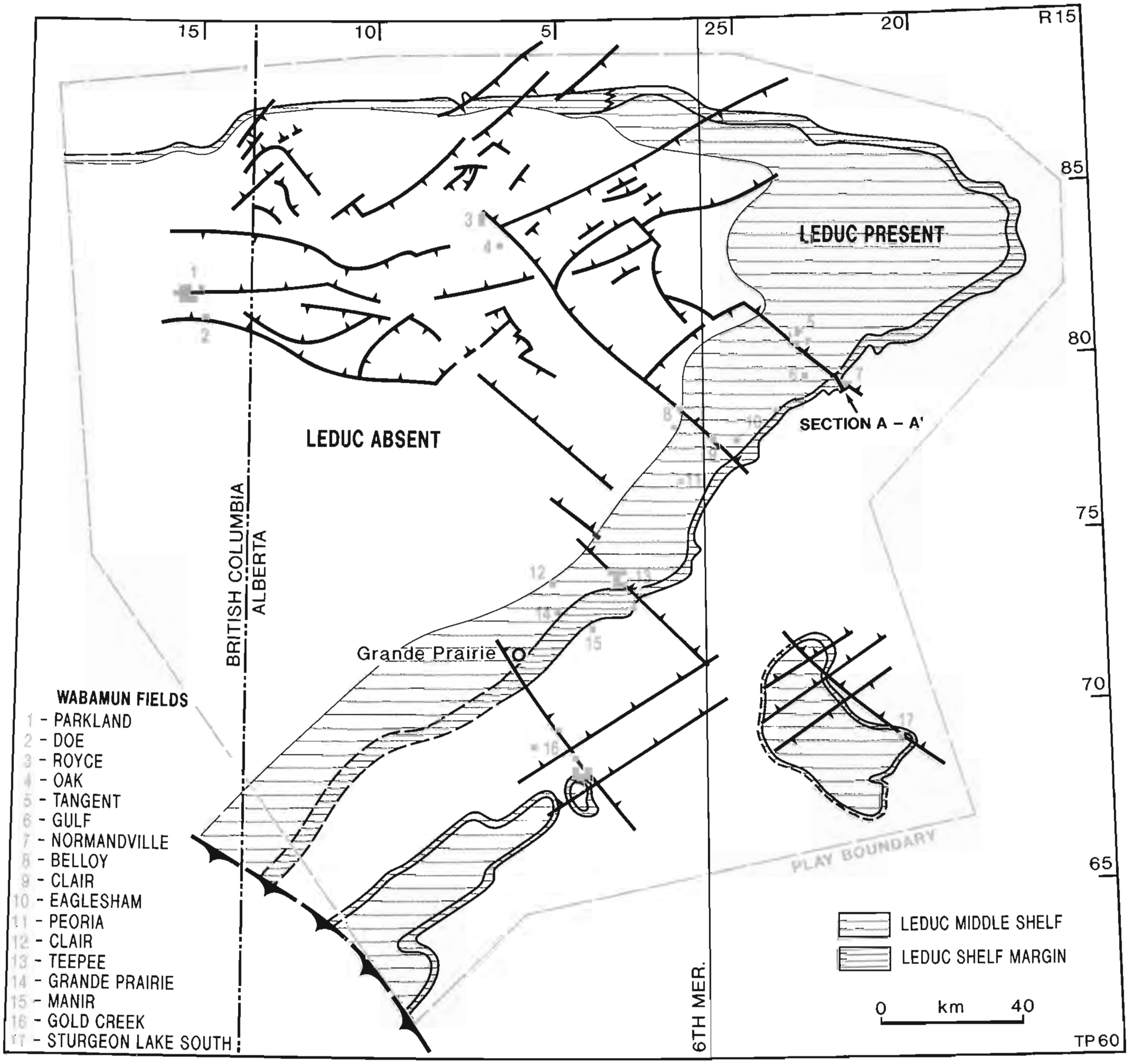


Figure 38. Map of Wabamun structural and stratigraphic (Parkland) play. Distribution of faults derived from Richards et al. (1984). (See Fig. 39 for cross-section A–A'.)

Central District and Deep Basin

Swan Hills shelf margin – Kaybob South

Play definition. This play includes all pools and prospects in stratigraphic traps within the carbonate shelf and platform of the Swan Hills Formation in west-central Alberta (Figs. 43–45).

Geology. The Beaverhill Lake Group in the area of the Swan Hills shelf margin play consists of the Swan Hills and Waterways formations. The Fort Vermilion Formation is absent and the Swan Hills Formation rests directly on the Watt Mountain Formation of the upper Elk Point Group. The Swan Hills Formation is divided into a lower platform (Divisions I to III, Fischbuch, 1968), and an upper, areally restricted, reef-rimmed shelf (Divisions IV to IX, Fischbuch,

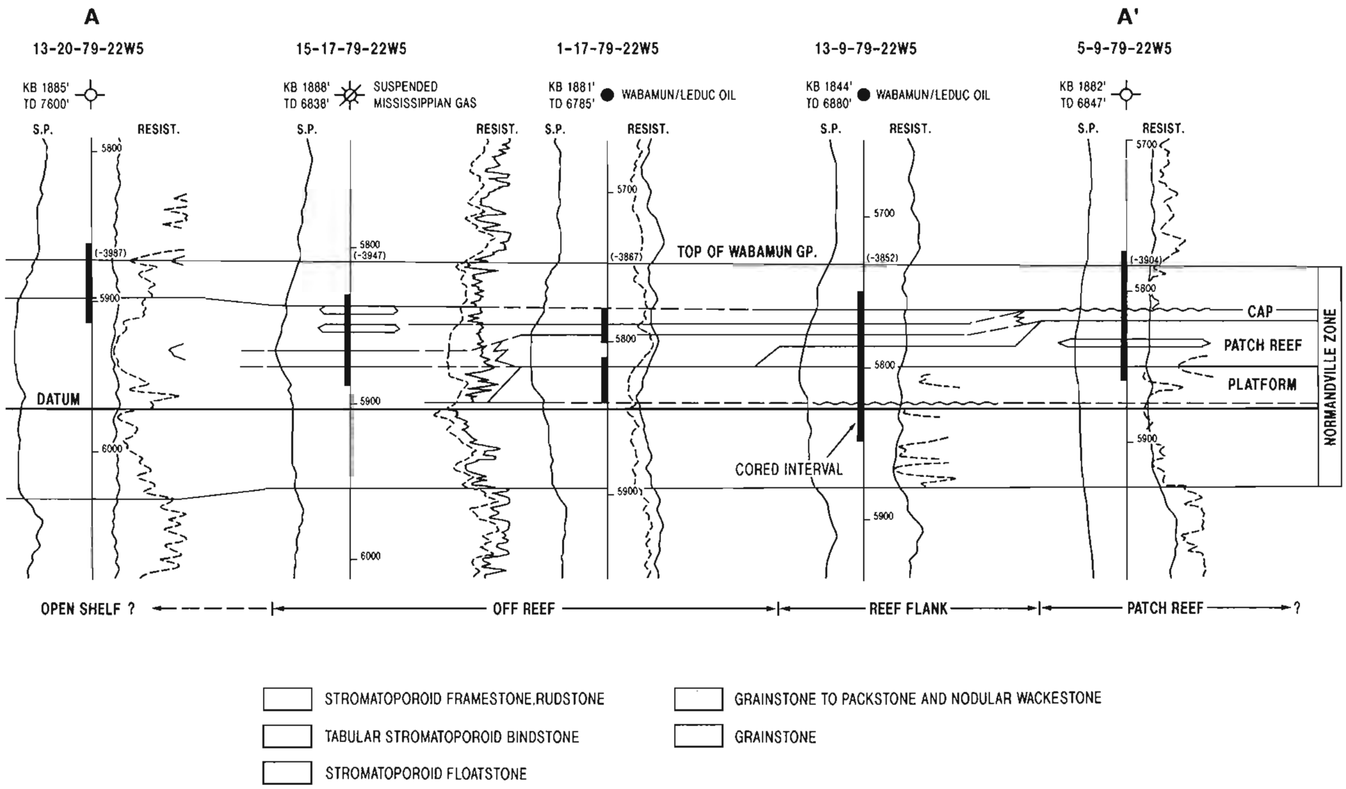


Figure 39. *Cross-section A–A′ through the Wabamun in the Parkland area illustrating internal facies variations. Modified from Nishida (1987). (Cross-section location is shown in Fig. 38.)*

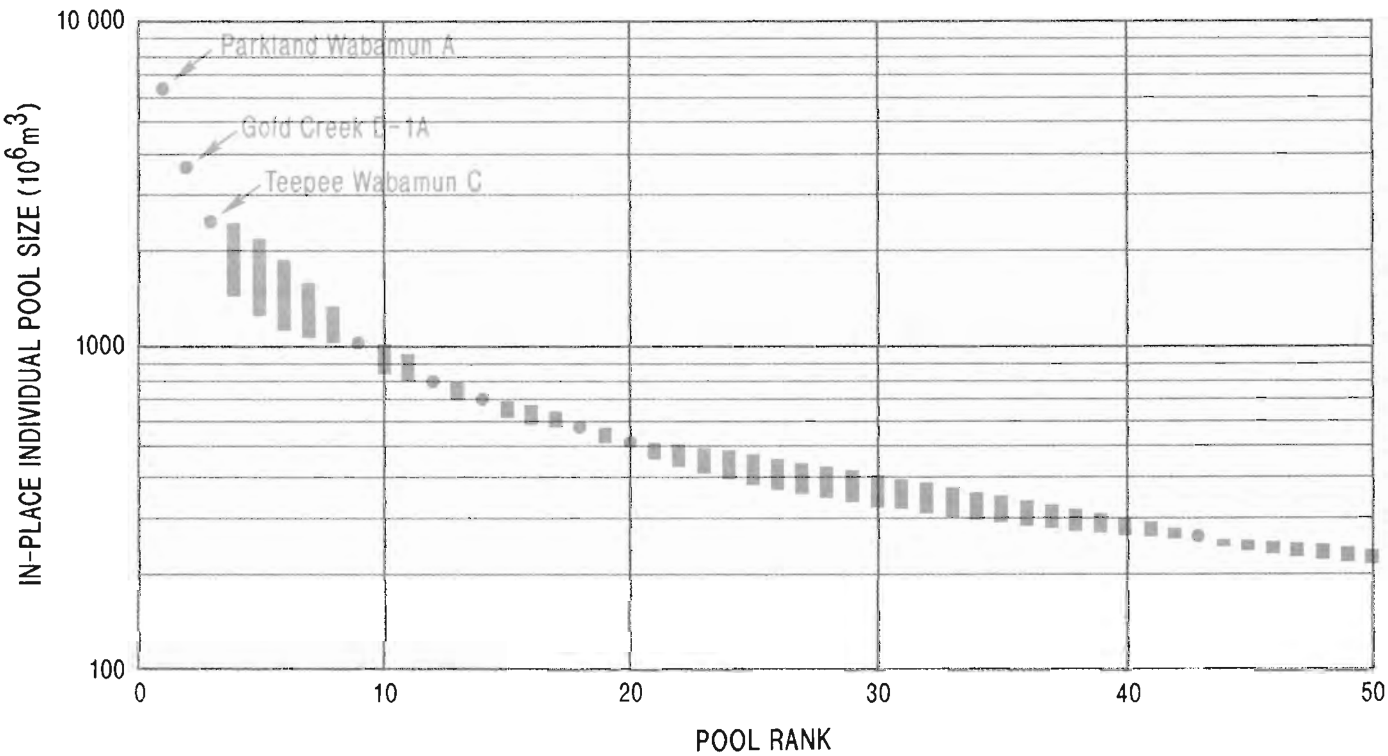


Figure 40. *Pool size-by-rank plot for the Wabamun structural and stratigraphic (Parkland) play. The 20 largest discovered pools are listed in Table 15.*

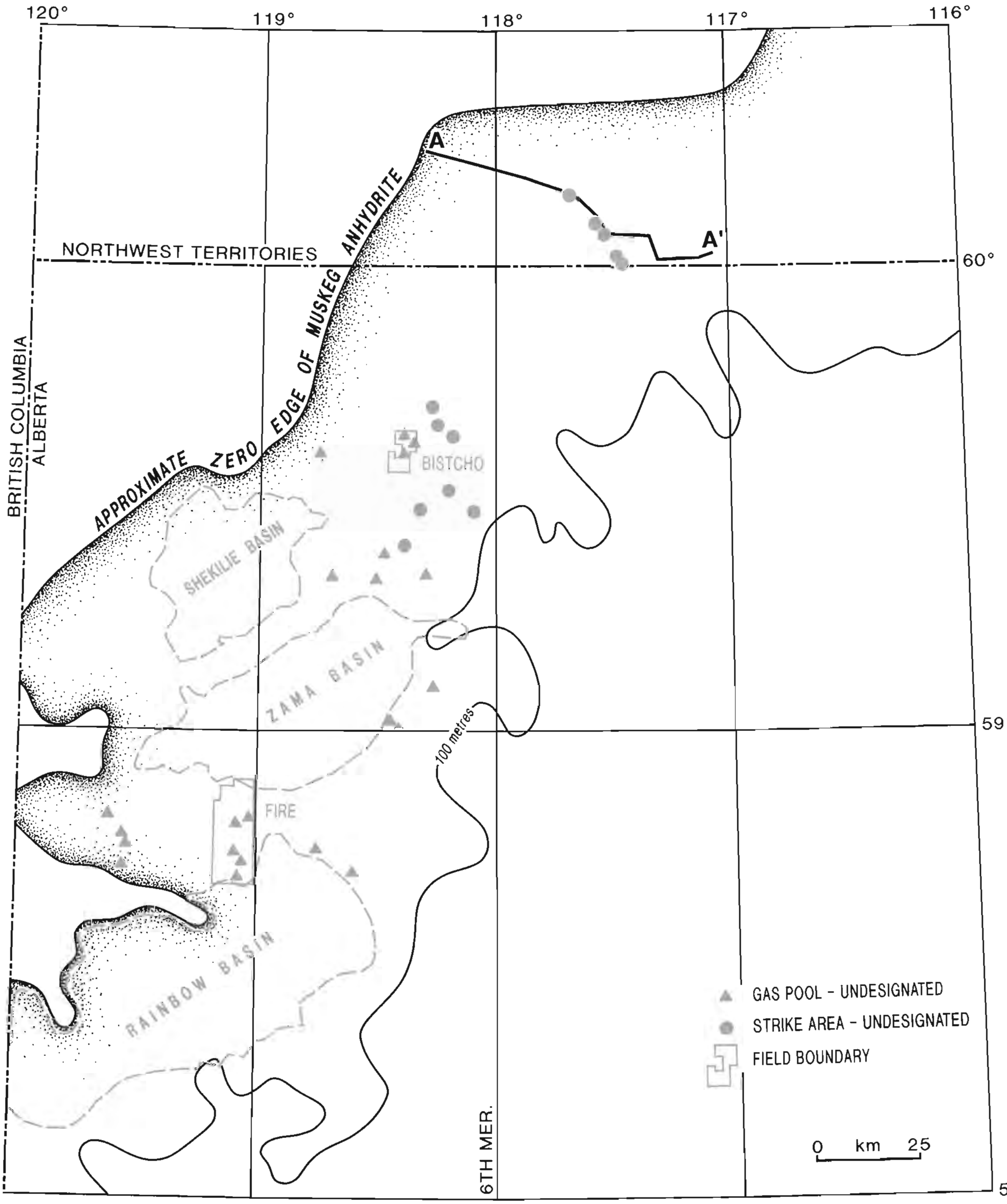


Figure 41. Map of immature Sulphur Point platform facies (Bistcho) play (zero and 100 m isopach lines of Muskeg anhydrite are shown). (See Fig. 42 for cross-section A–A'.)

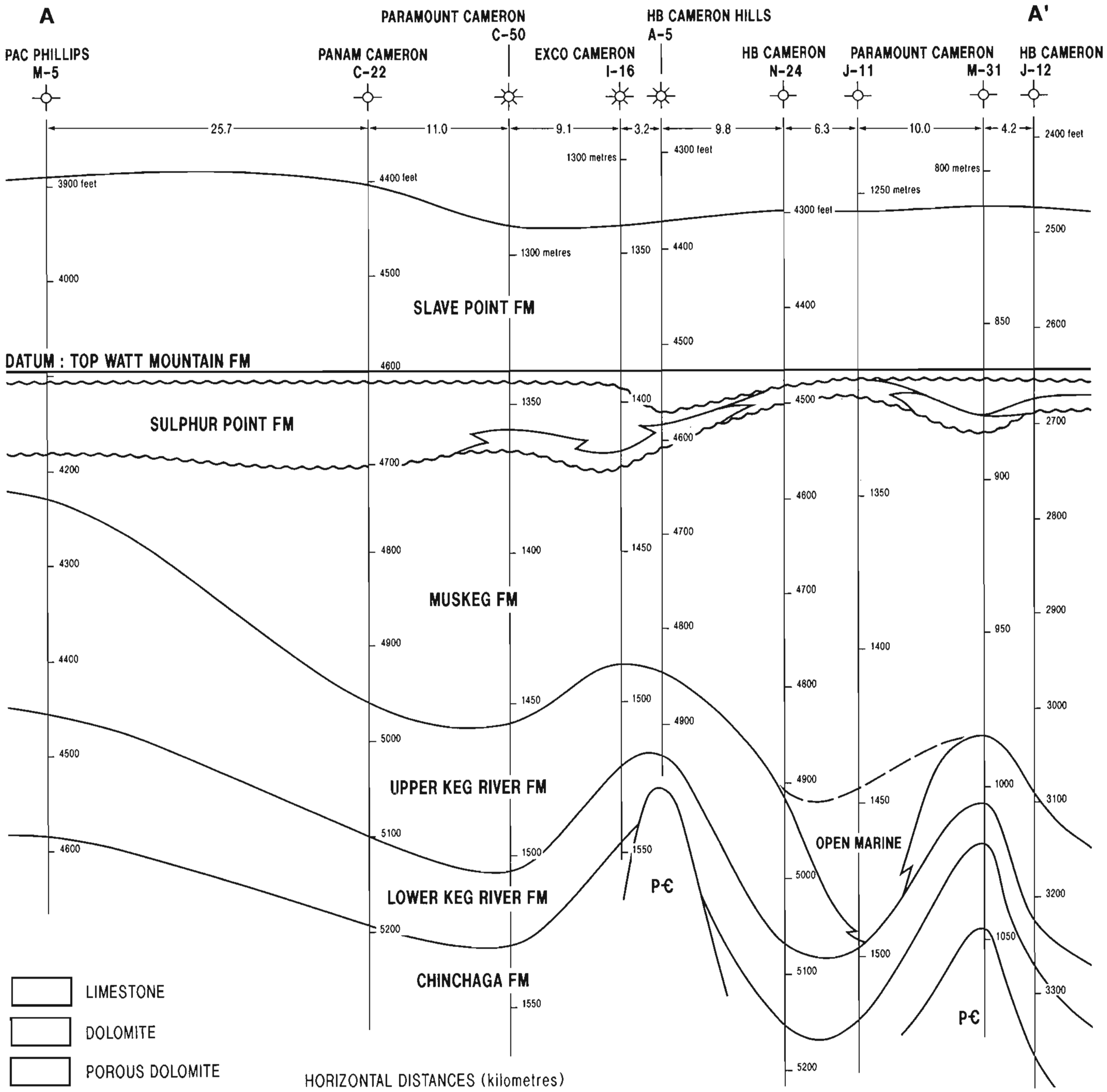


Figure 42. Cross-section A–A′ illustrating the nature of the immature Sulphur Point platform facies play. (Correlations derived from Williams, 1981, and Fischbuch, 1989b.) (Cross-section location is shown in Fig. 41.)

1968). The Swan Hills Formation ranges from 30 to 125 m in thickness, and is encased by shales and argillaceous limestones of the Waterways Formation. The Waterways Formation ranges up to 150 m in thickness but is totally absent where the Swan Hills is directly overlain by the Leduc Formation.

Most Swan Hills hydrocarbon reservoirs occur at the dolomitized northeast margin of the Swan Hills shelf and immediately adjacent to northwest-trending channels within the shelf (Fig. 43). The dolomitized shelf forms the reservoir, and the Waterways Formation forms the lateral and vertical seals. A second type of reservoir occurs in reefal limestones, also at the northeast shelf margin.

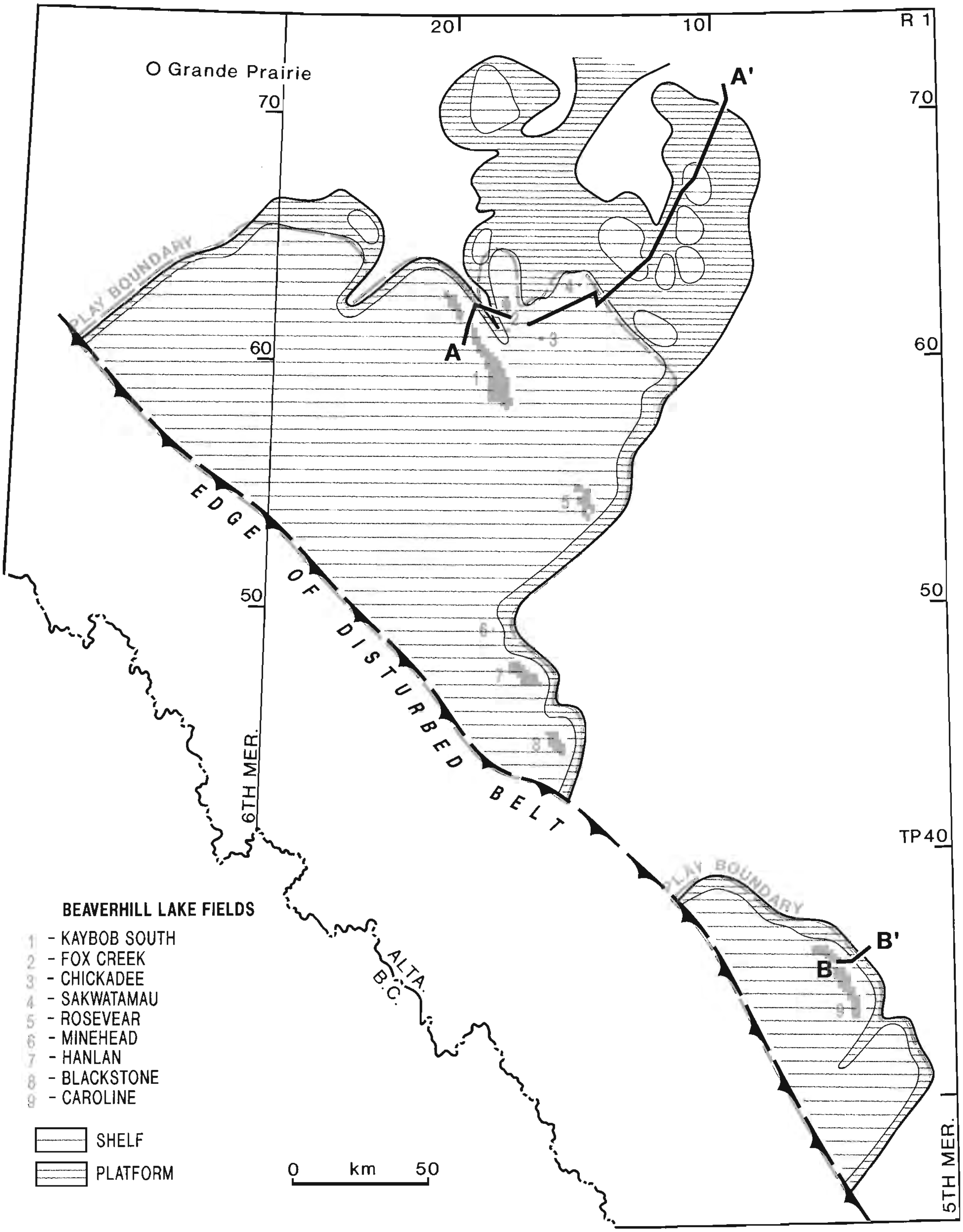


Figure 43. *Map of the Swan Hills shelf margin (Kaybob South) play. (See Fig. 44 for cross-section A–A' and Fig. 45 for cross-section B–B'.)*

All of the gas pools in this play contain H_2S except for Chickadee and Sakwatamau. The overlying Duvernay Formation is considered to have the most likely source rocks for that pooled gas.

Exploration history. The Kaybob South Beaverhill Lake A pool was the first and largest gas pool to be discovered in this play (Table 17). It has an initial in-place volume of 104 424 $x10^6m^3$ over an area of 20 015 hectares, with an average net pay of 31.1 m. Since Kaybob South was discovered, 14 additional gas pools have been found. The most recent discovery is the Caroline Beaverhill Lake A pool, which has resulted in renewed interest in exploration for gas in the Swan Hills Formation. Total initial in-place volume for the Swan Hills shelf margin (Kaybob South) play is 254 457 x 10^6m^3. Only two of the discovered pools contain associated or solution gas; these two pools account for less than one per cent of the discovered in-place volume for the entire play.

Play potential. Estimates of the potential for this play indicate an initial in-place volume of 52 541 x 10^6m^3, which means that 17 per cent of the total resource remains to be discovered. The estimate assumes a total pool population of 450, with the in-place volume for the largest undiscovered pool being 4 241 x 10^6m^3 (Fig. 46). The estimate of the potential for this play seems rather low when given as a percentage (17%), considering that the Caroline area has just begun its exploration phase.

Swan Hills isolated reef - Swan Hills

Play definition. This play includes all gas pools and prospects in the Swan Hills reef complexes of west-central Alberta (Figs. 44, 47).

Geology. The Beaverhill Lake Group in the Swan Hills isolated reef play area consists of the Fort Vermilion, Swan Hills and Waterways formations. The Fort Vermilion Formation consists of a sequence of carbonates and evaporites that conformably overlies the clastic deposits of the Watt Mountain Formation. The Swan Hills Formation overlies the Fort Vermilion

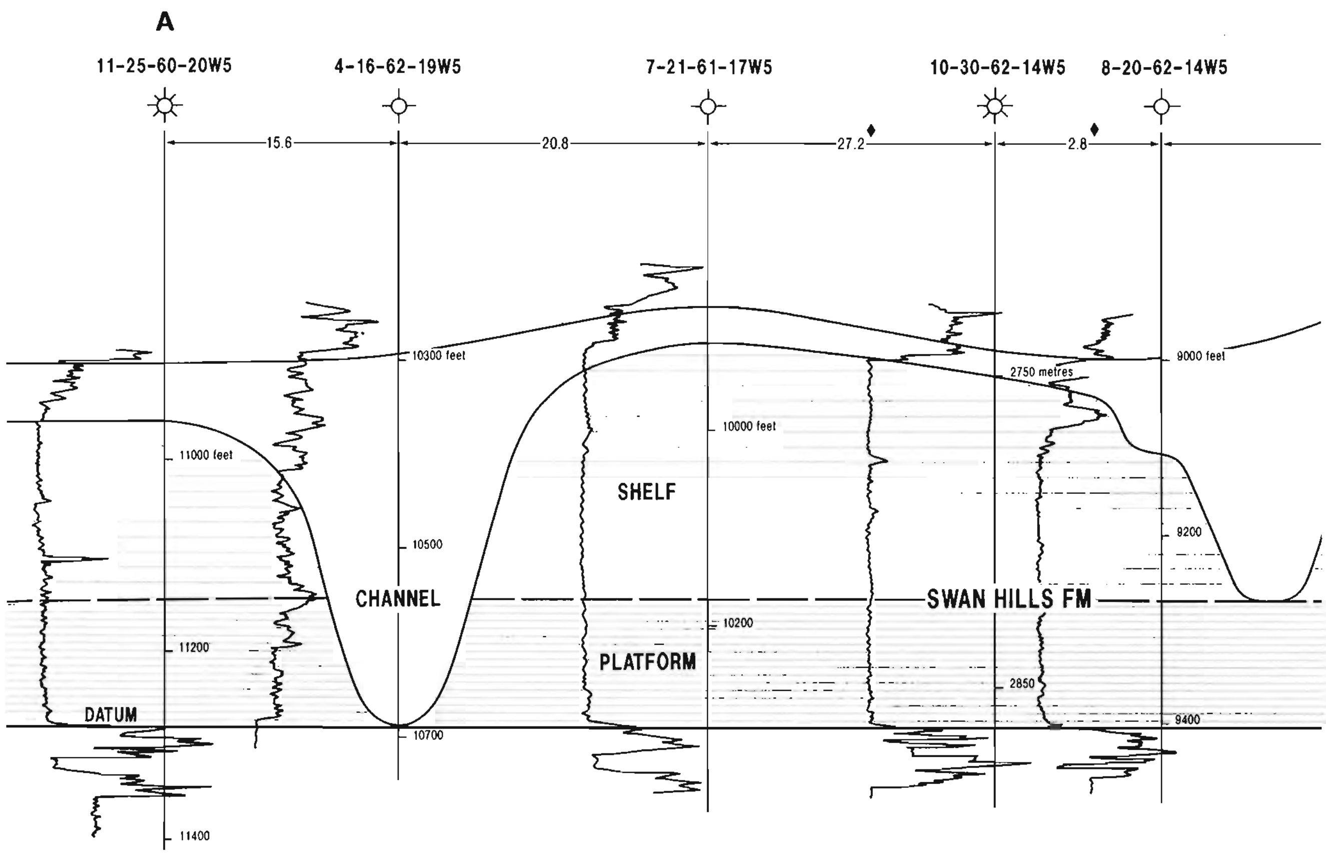


Figure 44. Northeast-southwest cross-section A-A′ illustrating relation between Swan Hills platform, reef-rimmed margin, and isolated reefs. (Cross-section location is shown in Fig. 43.)

and has been studied extensively by Fischbuch (1968), who subdivided it into nine informal divisions. The lower part (Divisions I to III), consists of an extensive, reef-rimmed platform. This platform is developed along the margin of the Western Alberta Ridge and can be correlated with the Slave Point Formation, which extends to the north around the Peace River Arch. Overlying the reef-rimmed platform are the isolated reef complexes of the upper Swan Hills Formation (Divisions IV to IX). Swan Hills reef complexes range up to 155 m in thickness, and are encased by limestone and shale of the overlying Waterways Formation.

The reef margins of the lower reef-rimmed platform form the reservoirs in the Swan Hills Beaverhill Lake C, House Mountain, and Gift Slave Point pools, and the northern part of the Virginia Hills Beaverhill Lake pool. The isolated reef complexes of the upper Swan Hills Formation form the reservoirs for the remaining pools in the Swan Hills isolated reef play. The basinal argillaceous limestones of the Waterways Formation act as the lateral and vertical seals. The Duvernay Formation is the most likely source for hydrocarbons trapped in the Swan Hills isolated reef complexes.

Exploration history. The Virginia Hills Beaverhill Lake pool, discovered in 1956, was the first pool found in the Swan Hills play (Table 18). The initial in-place volume for the Virginia Hills Beaverhill Lake pool is 6 709 x $10^6 m^3$ over an area of 13 098 hectares. The largest pool in the Swan Hills play is the combined Swan Hills Beaverhill Lake A and B pools, which have an in-place volume of 29 000 x $10^6 m^3$ over an area of 40 666 hectares. There have been 16 gas pools discovered in the Swan Hills isolated reef play, with a total, initial in-place volume of 125 835 x $10^6 m^3$. Only one of these pools contains nonassociated gas, with an initial in-place volume of 10 940 x $10^6 m^3$ (Table 18).

Play potential. Estimates of the potential for this play indicate an initial in-place volume of 7 758 x $10^6 m^3$. This number indicates that only 5 per cent of the total gas resources in this play remains to be discovered. The estimate assumes a total pool population of 60, with an in-place volume of 1 446 x $10^6 m^3$ (Fig. 48) for the largest undiscovered pool. The estimate of the undiscovered potential is very low because of the maturity of this play.

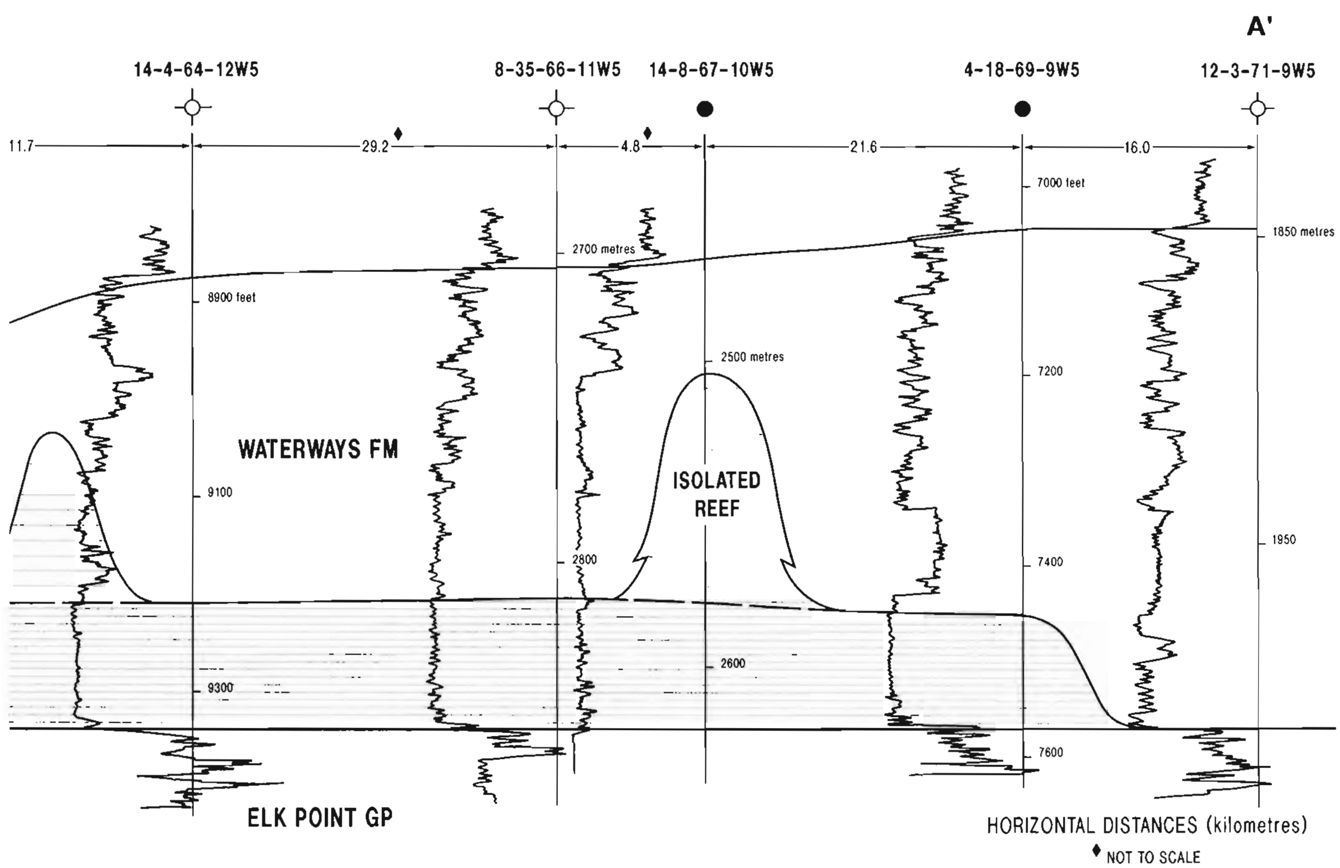


Figure 44. (cont'd)

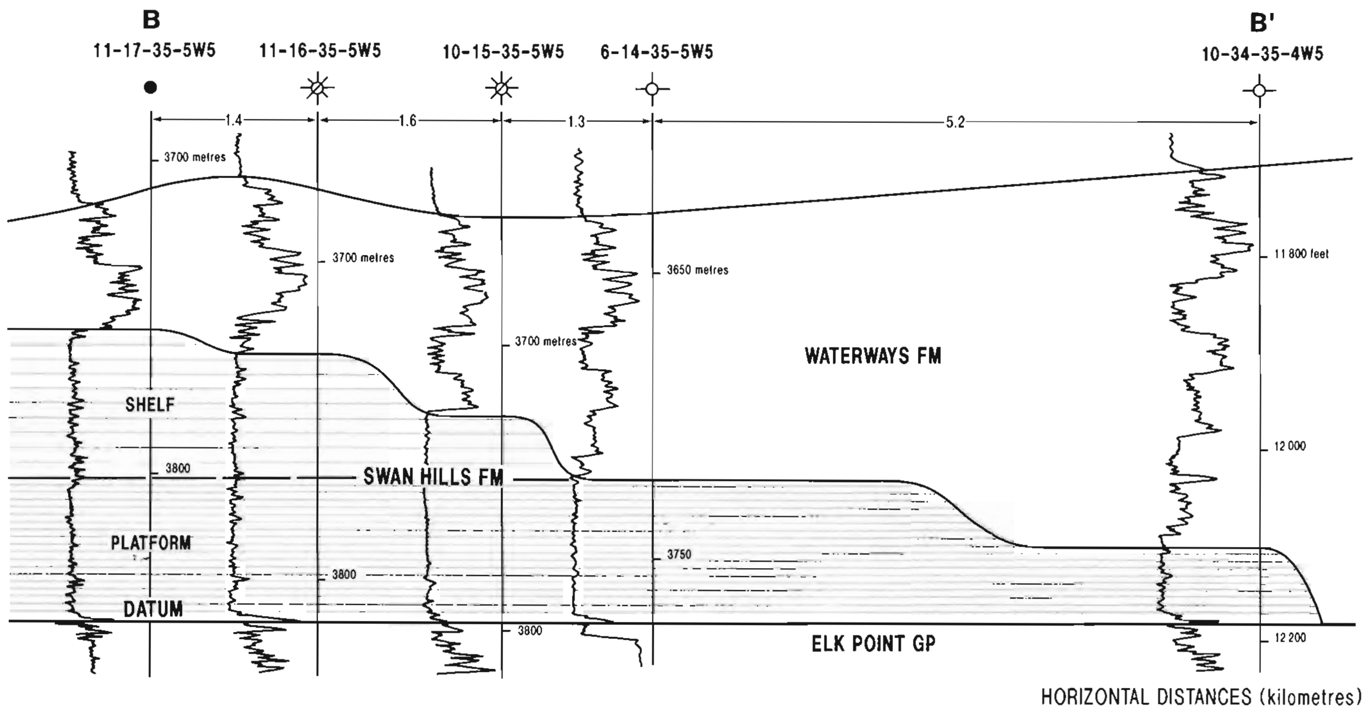


Figure 45. East–west cross-section B–B′ through Swan Hills shelf margin at Caroline. (Cross-section location is shown in Fig. 43.)

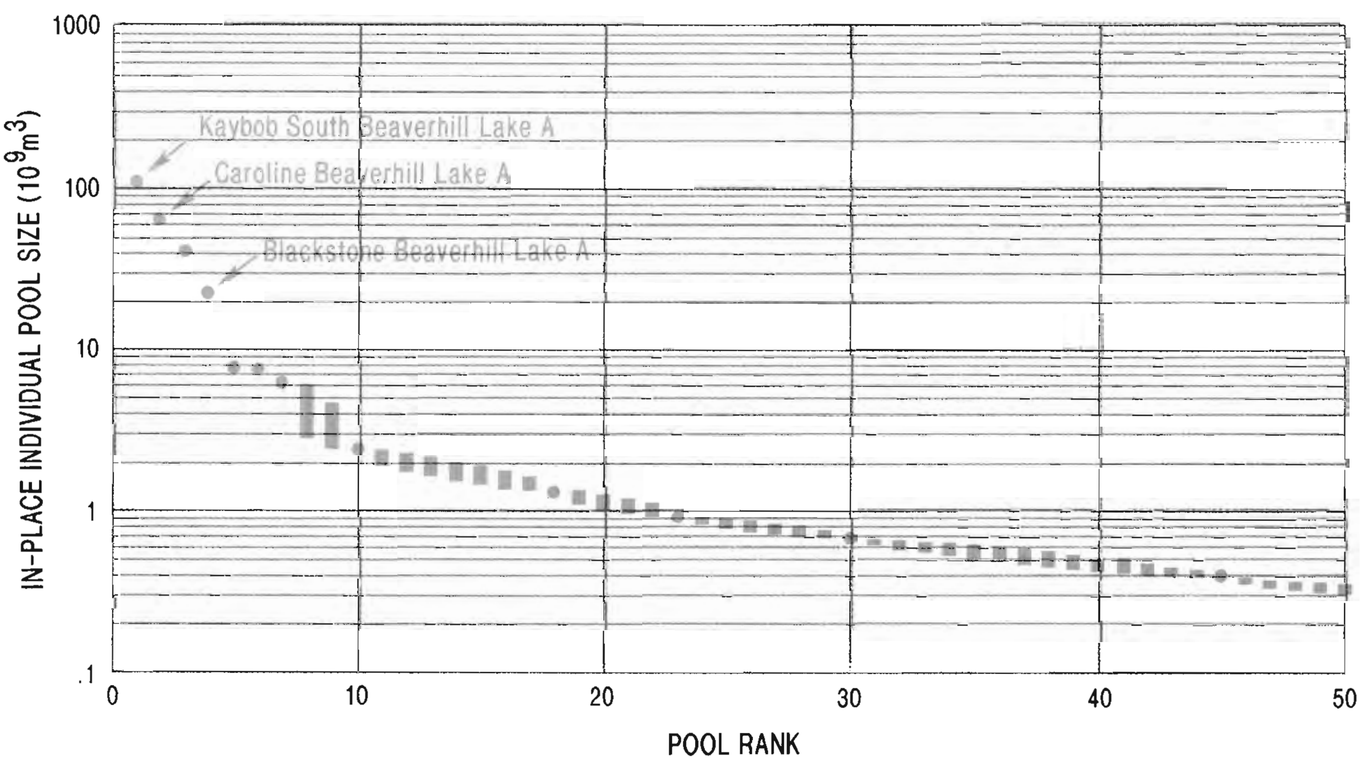


Figure 46. Pool size-by-rank plot for the Swan Hills shelf margin (Kaybob South) play. The 15 discovered pools in this play are listed in Table 17.

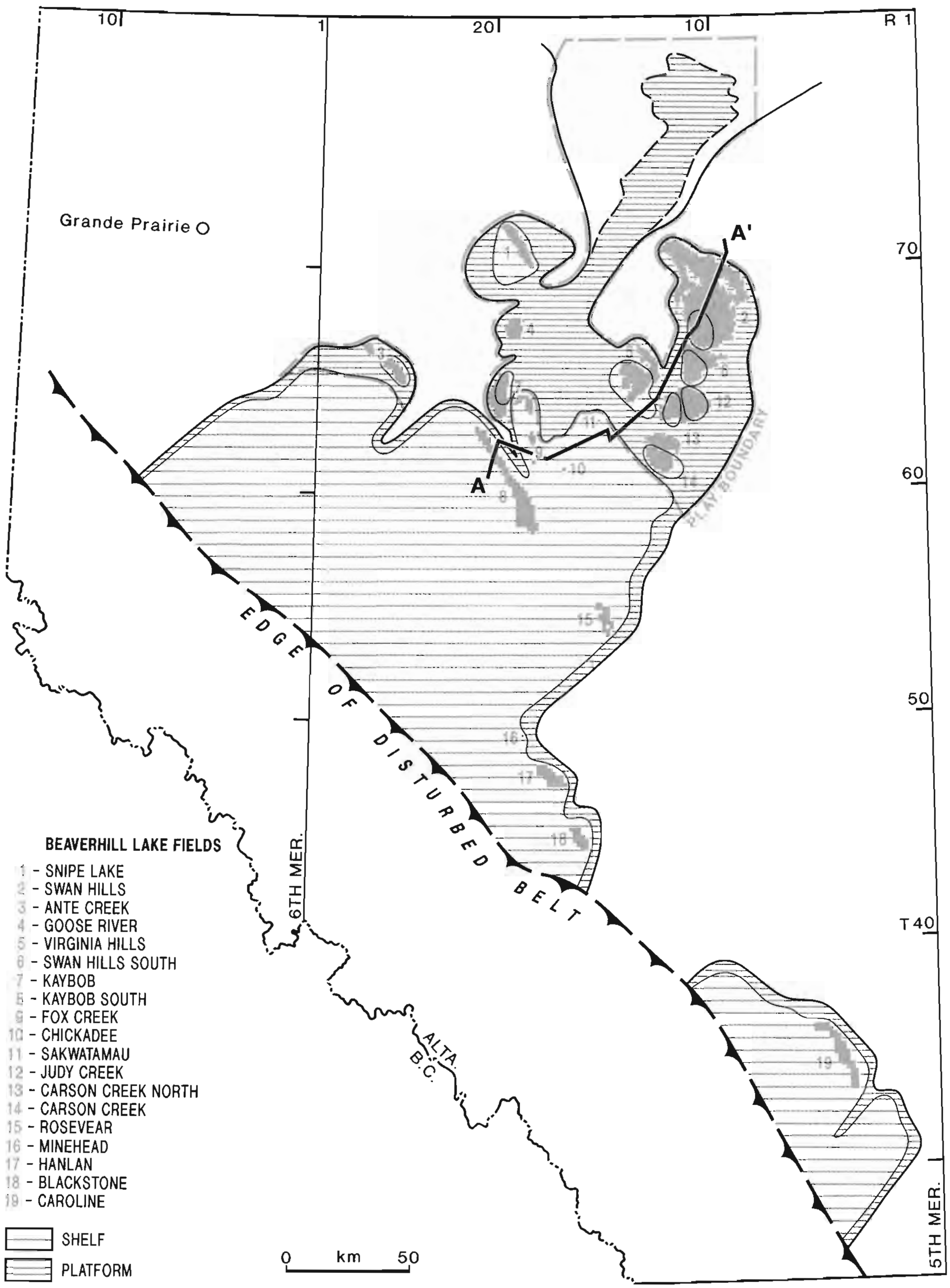


Figure 47. *Map of the Swan Hills isolated reef (Swan Hills) play. (See Fig. 44 for cross-section A–A'.)*

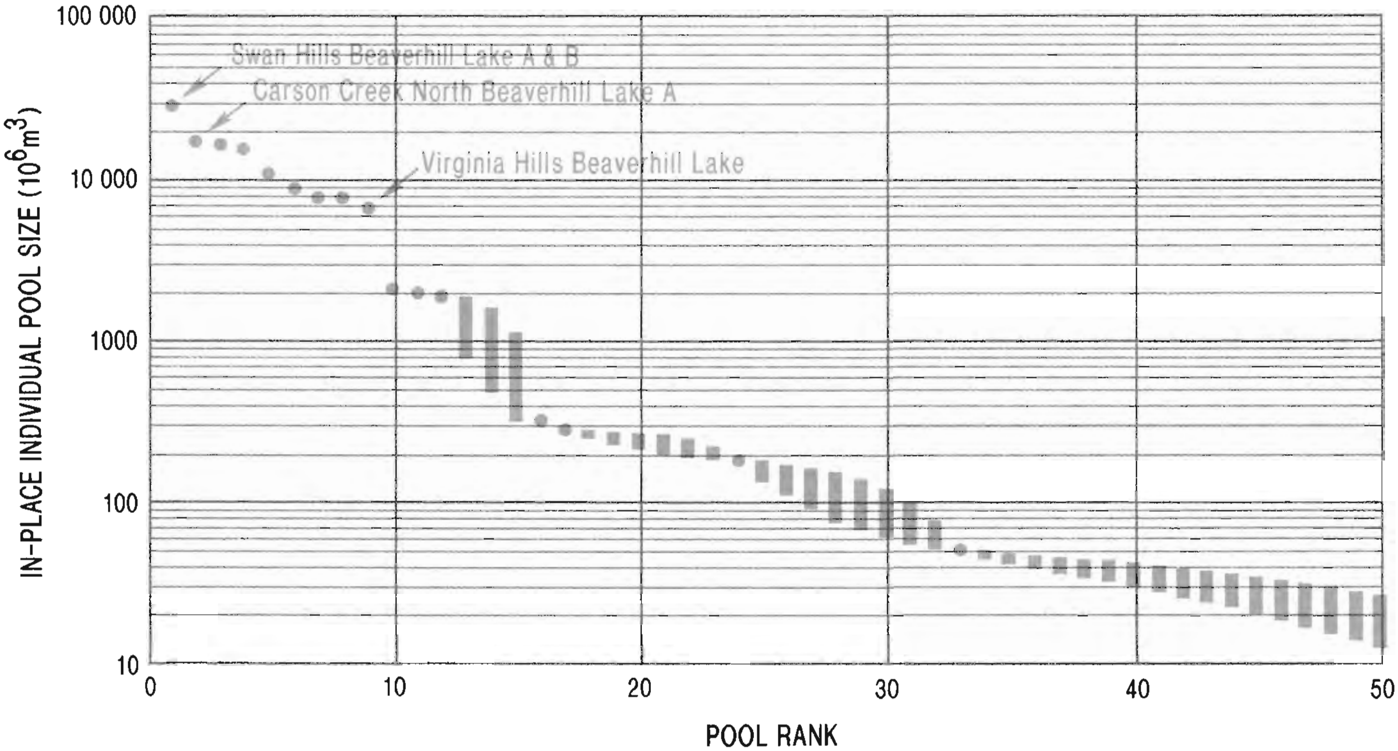


Figure 48. Pool size-by-rank plot for the Swan Hills isolated reef (Swan Hills) play. The discovered pools for this play are listed in Table 18.

Leduc/Nisku reef complexes - Windfall

Play definition. This play includes all gas pools and prospects in stratigraphic traps within the Leduc and Nisku reef complexes in west-central Alberta (Fig. 49). Excluded from this play are the Leduc and Nisku reefs in the Wild River Basin area (Fig. 75).

Geology. The Woodbend Group in west-central Alberta consists of the Leduc, Duvernay and Ireton formations. The Leduc Formation is a biohermal carbonate that was deposited in two distinct stages (Fig. 50). These two stages are referred to as the 'low' Leduc Formation and the 'high' Leduc Formation. A third stage of reef building continued during Winterburn deposition and is referred to as the Nisku Formation. The 'low' Leduc directly overlies the Swan Hills carbonate shelf and ranges up to 100 m in thickness. The 'low' Leduc is overlain by the thicker (140 m), more isolated 'high' Leduc reefs. The Nisku Formation ($\approx$75 m thick) overlies the 'high' Leduc, and in some places forms isolated reef complexes that are underlain by the basinal shales of Ireton Formation.

Most hydrocarbon reservoirs in this play occur in stratigraphic traps at the updip margin of the 'high' Leduc reefs. Both the Leduc and Nisku formations have been extensively dolomitized, which has resulted in the development of fossil-moldic and vuggy porosity. The basinal shales and limestones of the Duvernay and Ireton formations, and the basinal equivalents of the Winterburn Group, act as the lateral and top seals for the reservoirs.

All of the gas pools in this play contain significant concentrations of H_2S gas. The organic-rich shales of the Duvernay Formation are the most likely source for the hydrocarbons trapped in these Leduc/Nisku reef complexes.

Exploration history. The first pool, Sturgeon Lake D-3, was discovered in 1953, but the largest pool in this play is the Windfall D-3A pool, which was discovered in 1955 (Table 19). Forty-one gas pools have been discovered in the Leduc/Nisku reef complexes play and the total initial in-place volume is 127 776 x 10^6m^3. Of the 41 pools, 28 contain nonassociated gas with a total initial in-place volume of 80 200 x 10^6m^3.

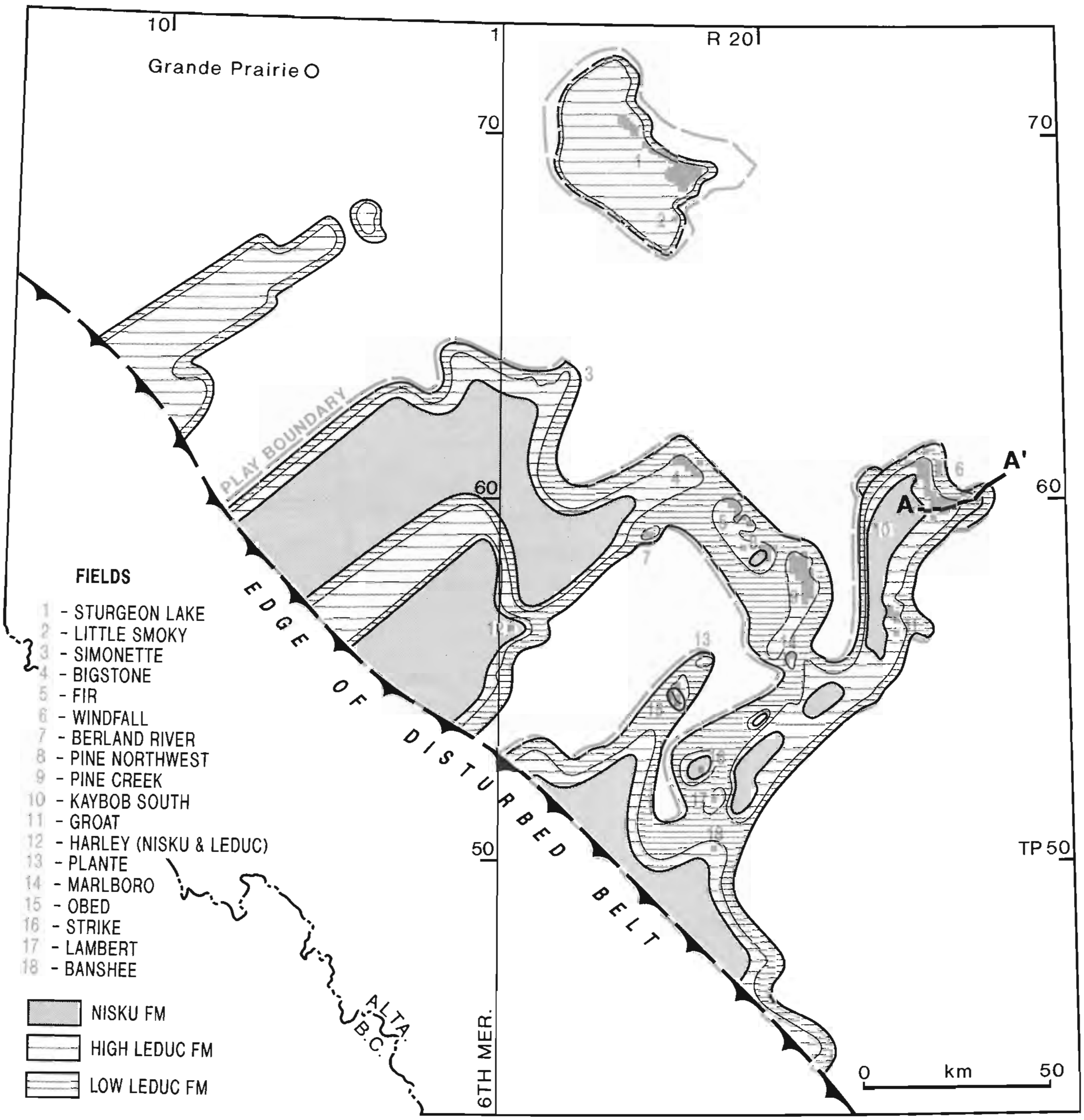


Figure 49. Map of the Leduc/Nisku reef complexes (Windfall) play. (See Fig. 50 for cross-section A–A'.)

Play potential. Estimates of the potential for this play indicate a value of 54 449 x 10^6m^3, which represents 30 per cent of the total play resource (Table 19). The estimate assumes a total pool population of 960, with an in-place volume of 5 245 x 10^6m^3 for the largest undiscovered pool (Fig. 51, Table 19). This estimate may be low considering the increased amount of exploration activity in this play. Future discoveries probably will occur in smaller isolated reefs of the Leduc Formation similar to the Berland River pool. The new Fir Leduc pool in section 34-57-21W5, which has an initial in-place volume of 2 360 x 10^6m^3, is evidence of this potential.

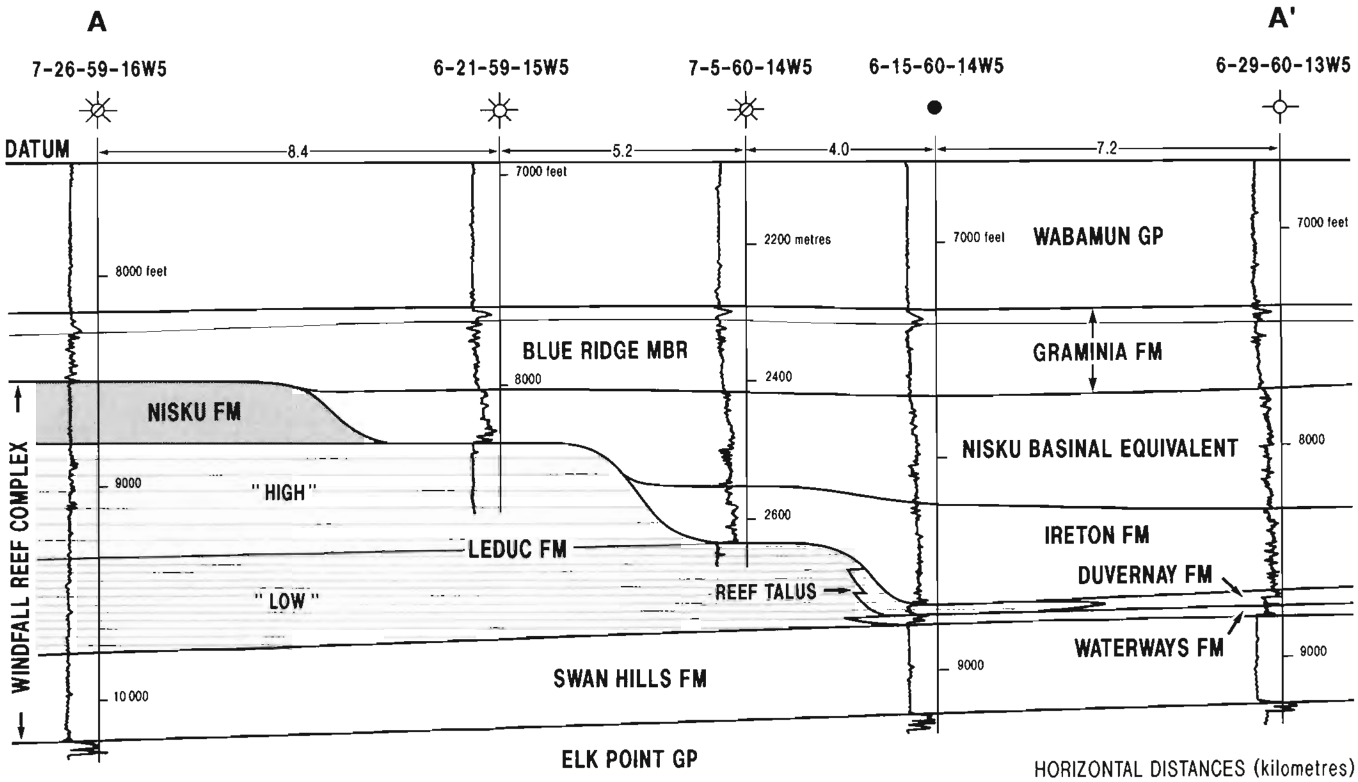


Figure 50. East-west cross-section illustrating depositional phases of the Leduc and overlying Nisku formations. (Cross-section location is shown in Fig. 49.)

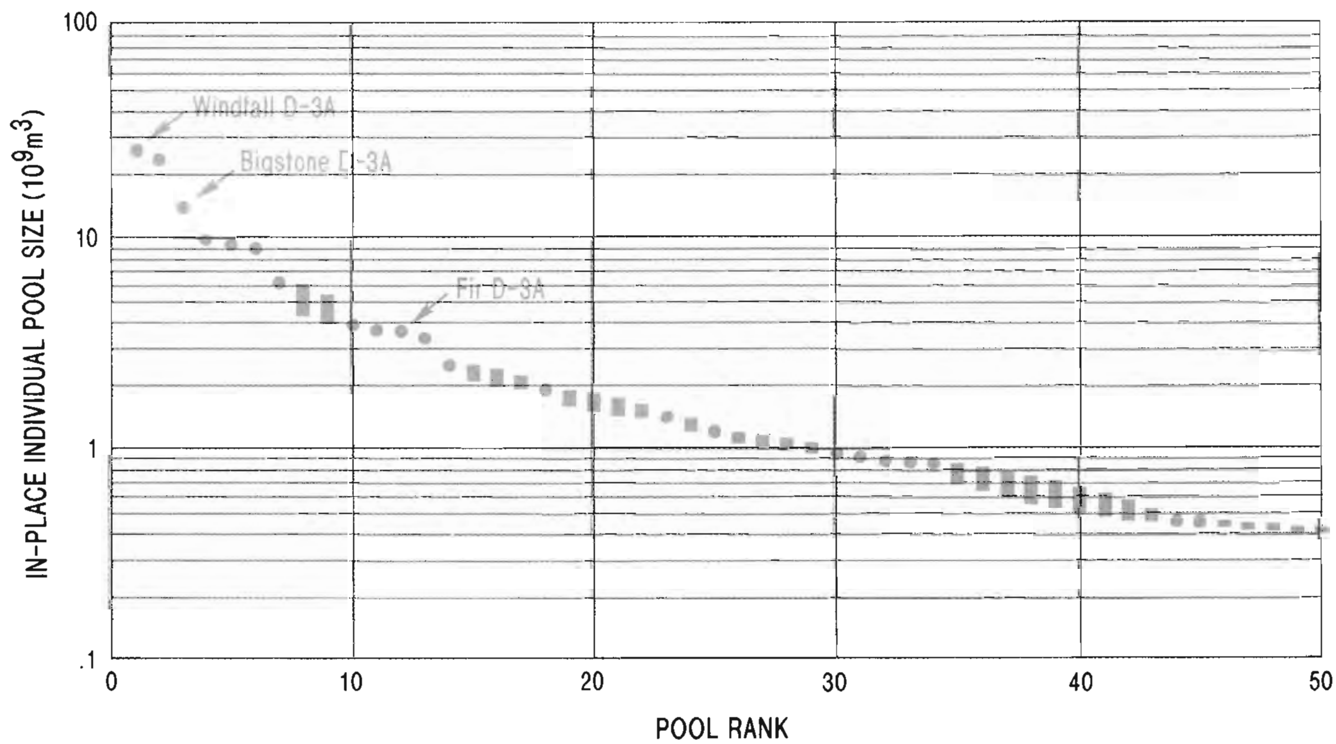


Figure 51. Pool size-by-rank plot for the Leduc/Nisku reef complexes (Windfall) play. The 20 largest discovered pools are listed in Table 19.

Leduc isolated reef - Westerose

Play definition. This play includes all gas-bearing pools and prospects involving reservoirs in Leduc reef complexes that developed near or on the western margin of the Cooking Lake platform. Reef bodies ranging from large complexes to small patch reefs form a linear north-northeast trend (Ricinus–Meadowbrook) that extends across central Alberta (Fig. 52).

Geology. This play is bounded on the southwest by the eastern margin of the "disturbed belt" and on the north by the overlying Grosmont Formation. The Leduc Formation is a thick, commonly dolomitized reefal development in the Upper Devonian Woodbend Group. In addition to the Leduc Formation, the Woodbend Group includes the Ireton, Duvernay, Cooking Lake and Grosmont formations (Fig. 9). Leduc carbonates developed as fringing reef complexes, linear chains of reefs, and isolated atolls and pinnacles. In the subsurface of central Alberta these buildups overlie the regional platform facies of the Cooking Lake Formation (Fig. 53). The Cooking Lake Formation generally consists of shallow-marine limestone; however, in the vicinity of the western margin of the Cooking Lake, partial to complete dolomitization is encountered. Consequently, the Cooking Lake and the overlying Leduc carbonates are in direct communication and form a common aquifer. This interconnected reservoir has acted as a conduit through which hydrocarbons were distributed throughout the Leduc Ricinus–Meadowbrook trend.

In central Alberta, the Leduc Formation is typically encased and sealed by the impermeable shales and argillaceous limestones of the Duvernay and Ireton formations. In contrast, the reefs to the northeast are capped by, and are in communication with, carbonates of the Grosmont Formation.

The Ricinus–Meadowbrook reef trend separates the eastern and western sectors of the Ireton shale basin. The Ireton Formation was laid down as basin fill during Woodbend deposition, and followed Leduc reef development and subsequent Duvernay shale and bituminous limestone deposition. The Duvernay shales, and to a lesser extent the Ireton Formation, are the primary source rocks for the hydrocarbons present in the Leduc reef complexes.

Exploration history. This play includes hydrocarbons discovered in 1946 in the Leduc–Woodbend field. This event initiated development of the oil and gas industry in Western Canada. The main Leduc pool in the Leduc–Woodbend field contained significant reserves of oil in addition to solution and associated gas; subsequently, a number of large oil and gas discoveries were completed along this trend. The largest gas field, Westerose South, was discovered in 1953. Of the larger Leduc reef gas accumulations in Alberta, five out of the top six are situated on this reef chain, and contain nonassociated gas. The distribution of natural gas in this play ranges from solution gas at shallow depths (i.e., Redwater, 975 m) through associated and solution gas at intermediate depths, to wet gas and eventually dry gas at depths of 3500 m or greater.

A total of 48 gas pools have been discovered to date (Table 20). Only one pool with an initial in-place volume greater than 1 000 x $10^6 m^3$ has been discovered since 1980. Total initial in-place volume for this play is 297 536 x $10^6 m^3$. Of the 48 pools, 25 contain nonassociated gas with an in-place volume of 180 428 x $10^6 m^3$.

Play potential. Estimates of the potential for this play indicate an initial in-place volume of 46 099 x $10^6 m^3$. This number indicates that 87 per cent of the total resource in this play has been discovered. The estimate assumes a total pool population of 210 of which 162 remain to be discovered. Although the largest undiscovered pool has an in-place volume of 4 340 x $10^6 m^3$, most of the undiscovered pools are predicted to be much smaller (Fig. 54). The Leduc isolated reef play is very mature, and several of the largest pools are near depletion (e.g., Westerose South). This is a result of early discovery combined with high deliverability. Leduc natural gas fields, consequently, have been some of the best gas producers in the province.

Leduc reef - Nevis

Play definition. This play includes all gas-bearing pools and prospects within the Leduc Formation of the Bashaw reef complex. This complex lies between the Ricinus–Meadowbrook linear reef trend on the west and the broad Southern Alberta shelf complex to the southeast (Fig. 55).

Geology. Porous Leduc reefs up to 275 m thick grew on the Cooking Lake regional platform facies. The Leduc Formation typically is encased and sealed by impermeable shales of the Duvernay and Ireton formations (Fig. 56). Stratigraphic and combined structural–stratigraphic traps associated with the Bashaw complex contain both gas and oil. Traps occur at the updip terminations of the large reef complex (Nevis), downdip of re-entrants in the reef complex (Clive), and in minor isolated atolls and pinnacles. In

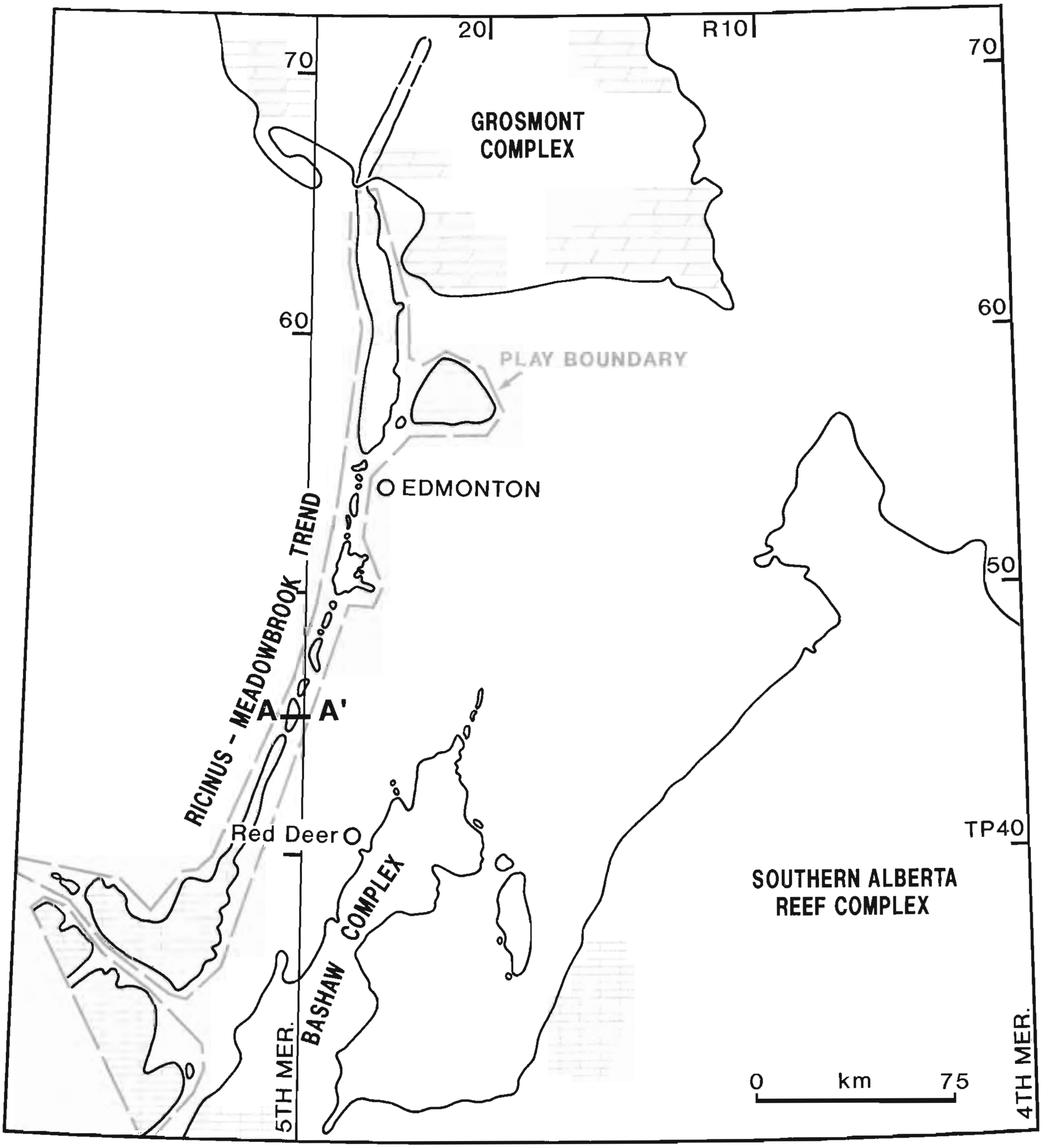


Figure 52. *Map of the Leduc isolated reef (Westerose) play. Boundary of play is confined to Ricinus–Meadowbrook trend. (See Fig. 53 for cross-section A–A'.)*

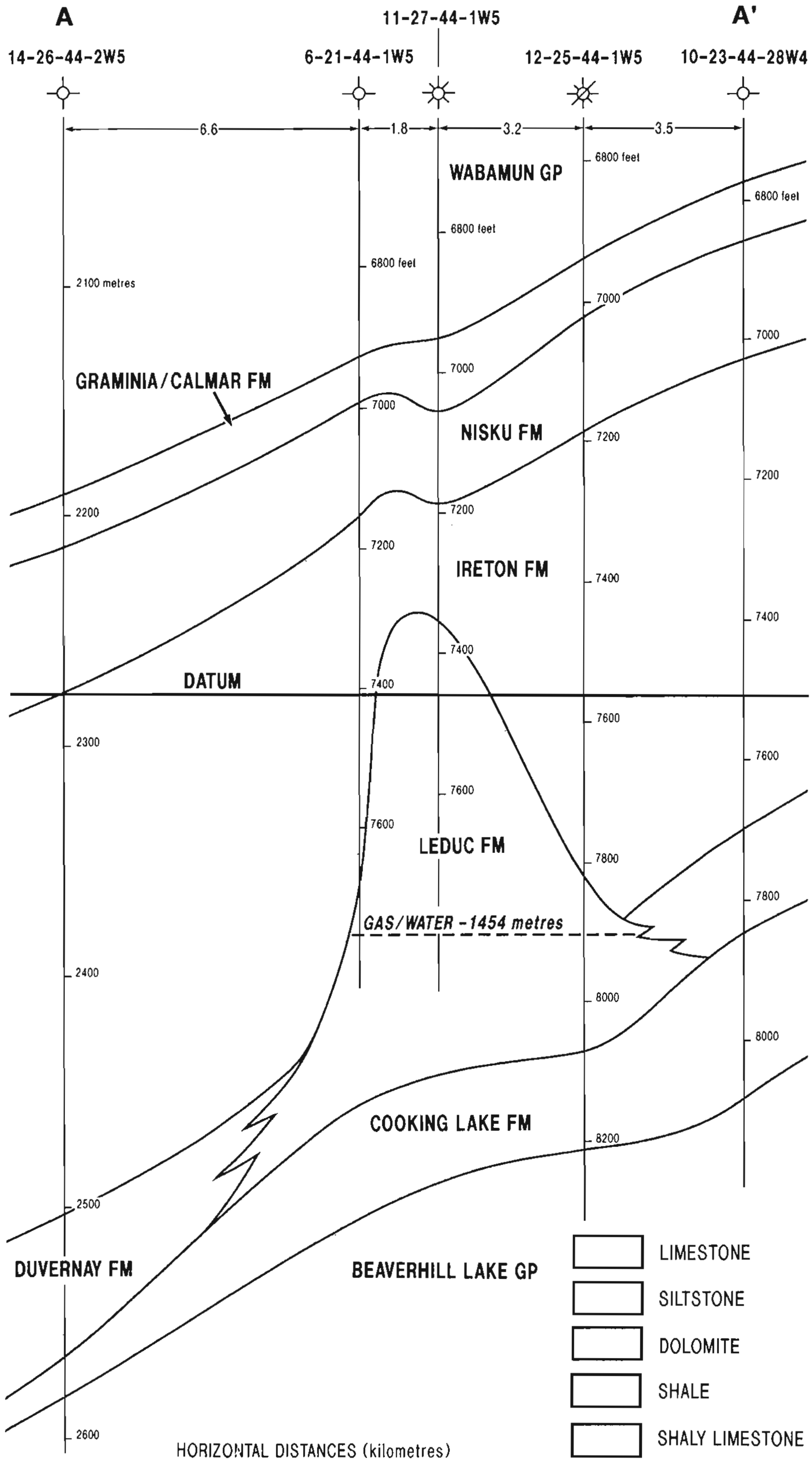


Figure 53. Cross-section A–A' illustrating the Leduc isolated reef and Nisku shelf drape plays in the Ricinus–Meadowbrook trend. (Cross-section location is shown in Fig. 52.)

the larger reef bodies, differential compaction between back-reef lagoonal carbonates, off-reef shales, and the more rigid dolomitized periphery of the buildups, commonly gives the larger features a broadly atoll-like shape, resulting in drape of overlying beds.

The reservoirs are all dolomitized except at Duhamel. Natural gas is restricted to the large reef masses regardless of whether it is nonassociated, associated, or in solution. The gases present in the reservoirs have a relatively high H_2S content, ranging between 10 and 20 per cent. Isolated reef pinnacles and atolls are more oil prone, with less H_2S in the solution gas.

Exploration history. Following the initial 1946 discovery of gas and oil at Leduc, Upper Devonian strata became the prime exploration target in Alberta. Oil and gas pools in this play were discovered during relatively continuous exploration from 1949 to 1970 (Table 21). The largest gas accumulation, the Nevis pool, was discovered in 1952, with Wimborne following two years later. Little gas has been discovered since 1960. Total initial in-place volume amounts to 66 954 x $10^6 m^3$ in 56 pools. This is primarily an associated/solution gas play, with only 13 pools containing a total of 2 711 x $10^6 m^3$ of nonassociated gas.

Play potential. The estimate of potential for this play indicates an initial in-place volume of 8 609 x $10^6 m^3$. This number suggests that only 11 per cent of the total gas resource in this play remains to be discovered. The estimate assumes a total pool population of 150, yet the largest remaining undiscovered pool is predicted to contain 1 102 x $10^6 m^3$ of natural gas (Fig. 57). This play is considered to be very mature, with limited potential.

Nisku shelf margin - Brazeau River

Play definition. This play includes all gas pools and prospects in the Zeta Lake reefs that developed at the outer shelf margin of the Nisku Formation in west-central Alberta (Figs. 58, 59).

Geology. The Nisku Formation of west-central Alberta consists of the Lobstick, Bigoray, Cynthia, Dismal Creek, Wolf Lake and Zeta Lake members. The Lobstick Member is 25 to 50 m thick on the Nisku

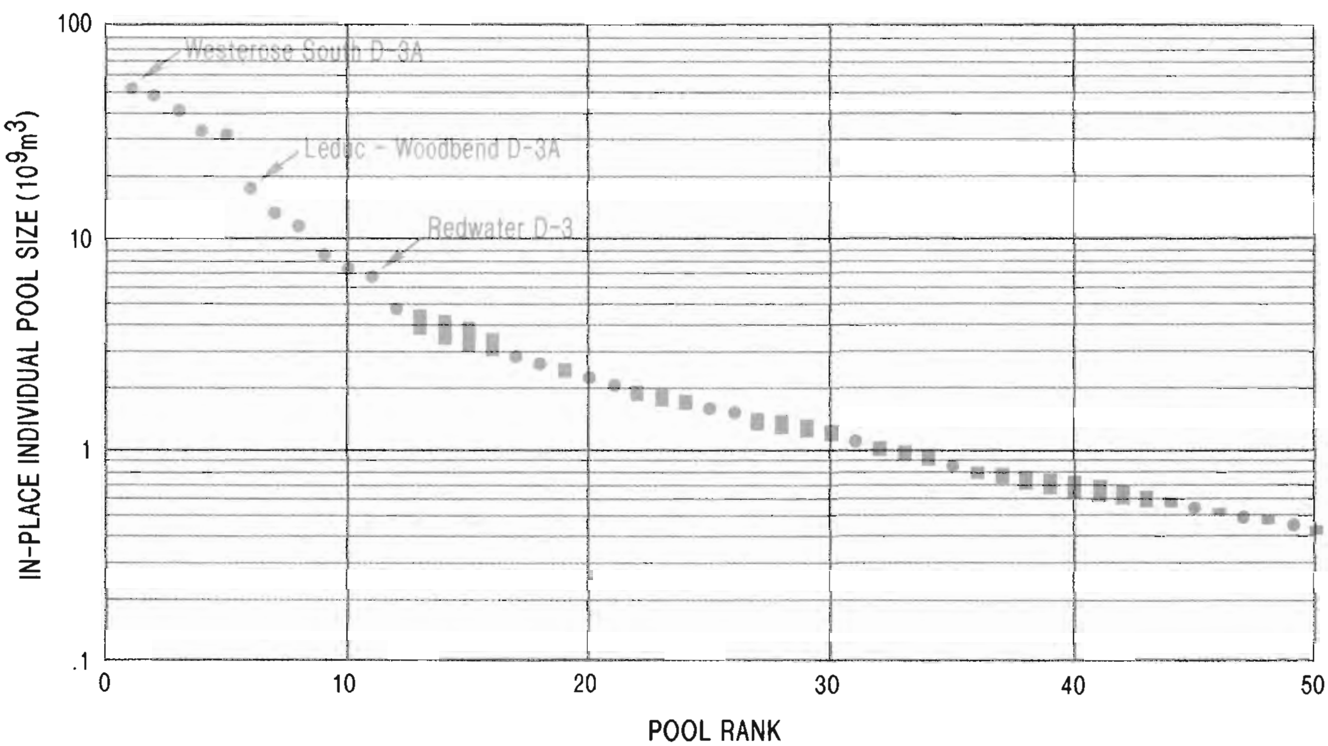


Figure 54. *Pool size-by-rank plot for the Leduc isolated reef (Westerose) play. The 20 largest discovered pools are listed in Table 20.*

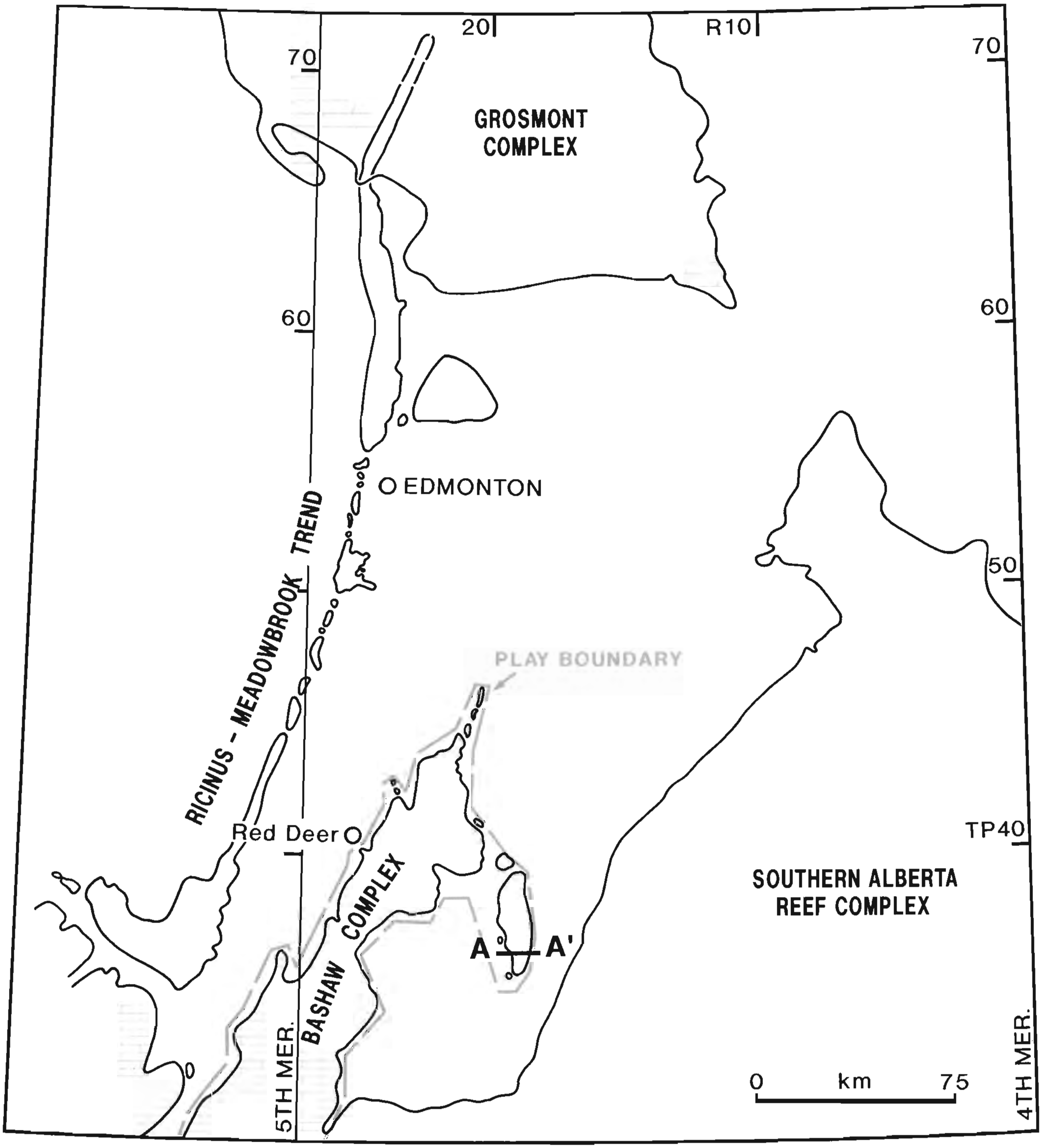


Figure 55. *Map of the Leduc reef (Nevis) play. Play area is confined to the Bashaw reef complex. (See Fig. 56 for cross-section A–A'.)*

shelf margin (Anderson and Machel, 1988). The Lobstick Member consists of a shallowing-upward sequence of subtidal ramp carbonates, and is in turn overlain by subtidal ramp deposits of the Bigoray Member. The Bigoray Member is up to 20 m thick and is divided into two units: a basal unit consisting of siltstones and minor carbonates, and an upper unit comprising silty, bioclastic carbonates. Near the end of

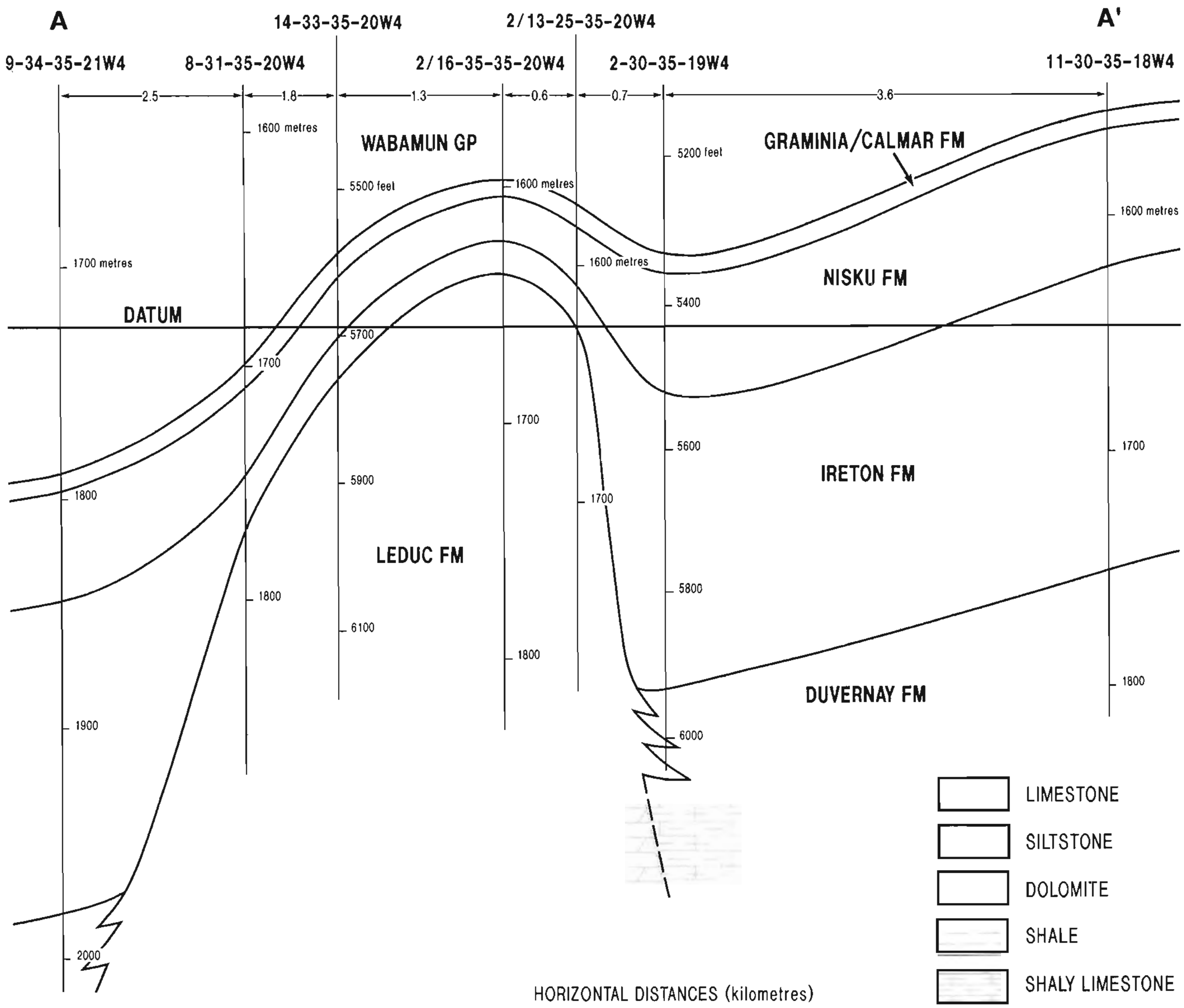


Figure 56. Cross-section A–A' illustrating the Leduc reef (Nevis) and Nisku shelf (Bashaw) plays. (Cross-section location is shown in Fig. 55.)

Bigoray deposition, there was a change in the profile of the basin from a ramp to a reef-rimmed shelf. This shelf is represented in Figure 58 as the outer shelf of the Nisku Formation. A Zeta Lake reef trend developed along the margin of this outer shelf and is typically thinner and more laterally continuous than the isolated Zeta Lake reefs that developed downslope. The Dismal Creek Member represents the shelf interior sediments that were deposited behind the Zeta Lake shelf margin reefs (Machel, 1985). The Cynthia Member contains a lower carbonaceous shale unit thought to be basinal, and an upper, fossiliferous, bioturbated carbonate unit thought to represent gradation to a deep ramp environment (Anderson, 1985). Machel (1985) found that both the Dismal Creek and Cynthia members interfingered with shelf margin Zeta Lake reef facies, and interpreted the Dismal Creek as being equivalent to the Cynthia Member (Fig. 59). The Dismal Creek and Cynthia members grade upward into tidal flat carbonates of the Wolf Lake Member (12 m thick), which is overlain by the Calmar Formation.

The Zeta Lake reefs of the shelf margin form the reservoirs in this play. The Cynthia Member and Calmar Formation are the vertical seals for the reservoirs, and the Cynthia and Dismal Creek members form the lateral seals. The source for the hydrocarbons

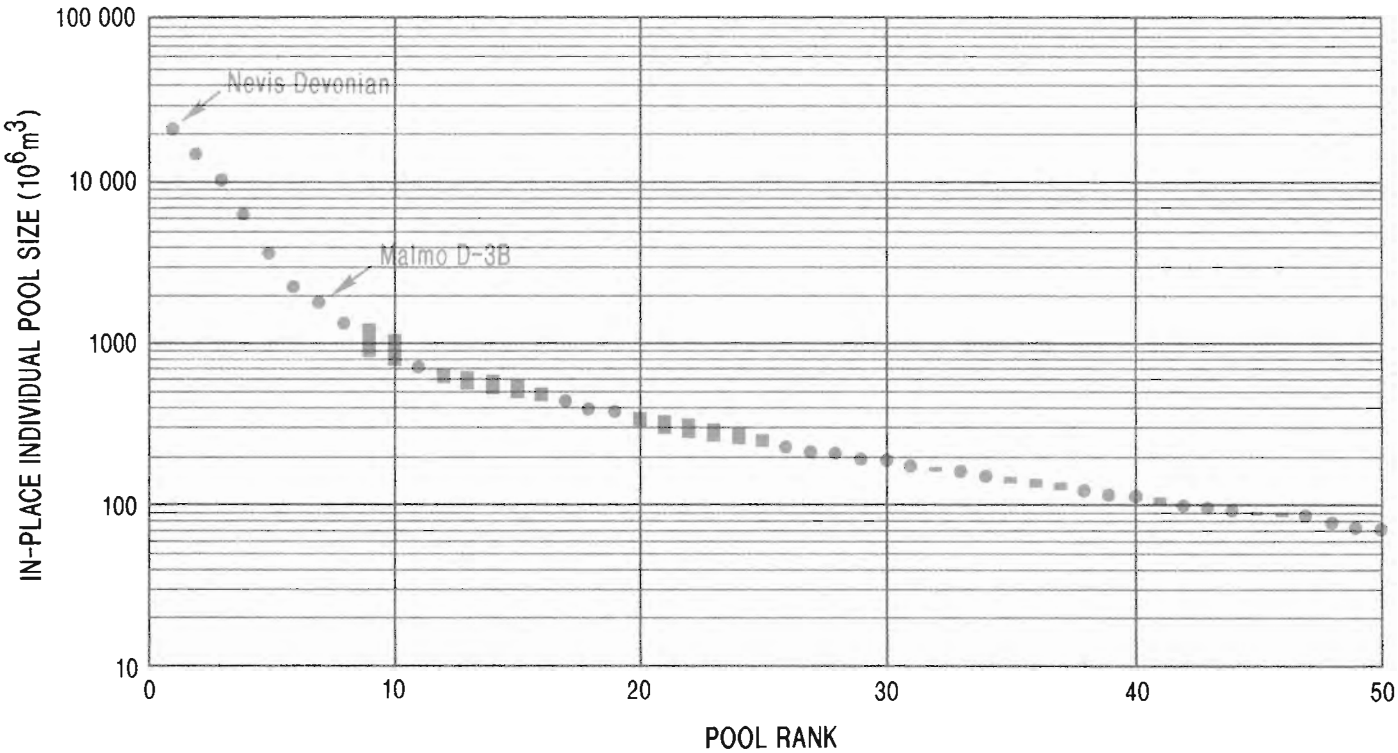


Figure 57. *Pool size-by-rank plot for the Leduc reef (Nevis) play. The 20 largest discovered pools are listed in Table 21.*

is thought to be the Cynthia Member or the underlying Ireton Formation (Chevron Standard Limited, 1979; Machel, 1985).

Exploration history. The Brazeau River Nisku P pool was the first and largest gas pool to be discovered in the Nisku shelf margin (Brazeau River) play. The initial in-place volume for Nisku P pool is 9 408 x 10^6m^3 covering an area of 3 761 ha, with an average net pay of 16.2 m. There have been a total of eight gas pools discovered in this play and the in-place volume is 10 970 x 10^6m^3 (Table 22). Seven of the eight pools contain nonassociated gas with an in-place volume of 10 722 x 10^6m3.

Play potential. Estimates of the potential for this play indicate an initial in-place volume of 7 481 x 10^6m^3, representing approximately 41 per cent of the total play resource. The estimate assumes a total pool population of 190 pools, with an in-place volume for the largest undiscovered pool of 2 553 x 10^6m^3 (Fig. 60). The potential gas resources will likely be found in small, one to two section-sized pools situated along the shelf margin where re-entrants create stratigraphic traps within the Zeta Lake marginal reef trend.

Nisku isolated reef - Brazeau River

Play definition. This play includes all gas-bearing pools and prospects in the downslope Zeta Lake Member reefs of the Nisku Formation in west-central Alberta (Fig. 61).

Geology. The stratigraphy of the Nisku Formation in west-central Alberta is discussed in the previous description of the Nisku shelf margin play (Fig. 59). The isolated reefs of the Zeta Lake Member developed at different levels on the downslope portion of the Lobstick and Bigoray ramps.

The isolated Zeta Lake reefs are the reservoirs in this play and the Cynthia Member and Calmar Formation act as the lateral and vertical seals. Similar to the Nisku shelf margin play, the source for the hydrocarbons in the Nisku isolated reef play is likely the Cynthia Member or the underlying Ireton Formation (Chevron Standard Limited, 1979; Machel, 1985).

There is a marked change in the diagenetic history of the Zeta Lake reefs along depositional strike. The

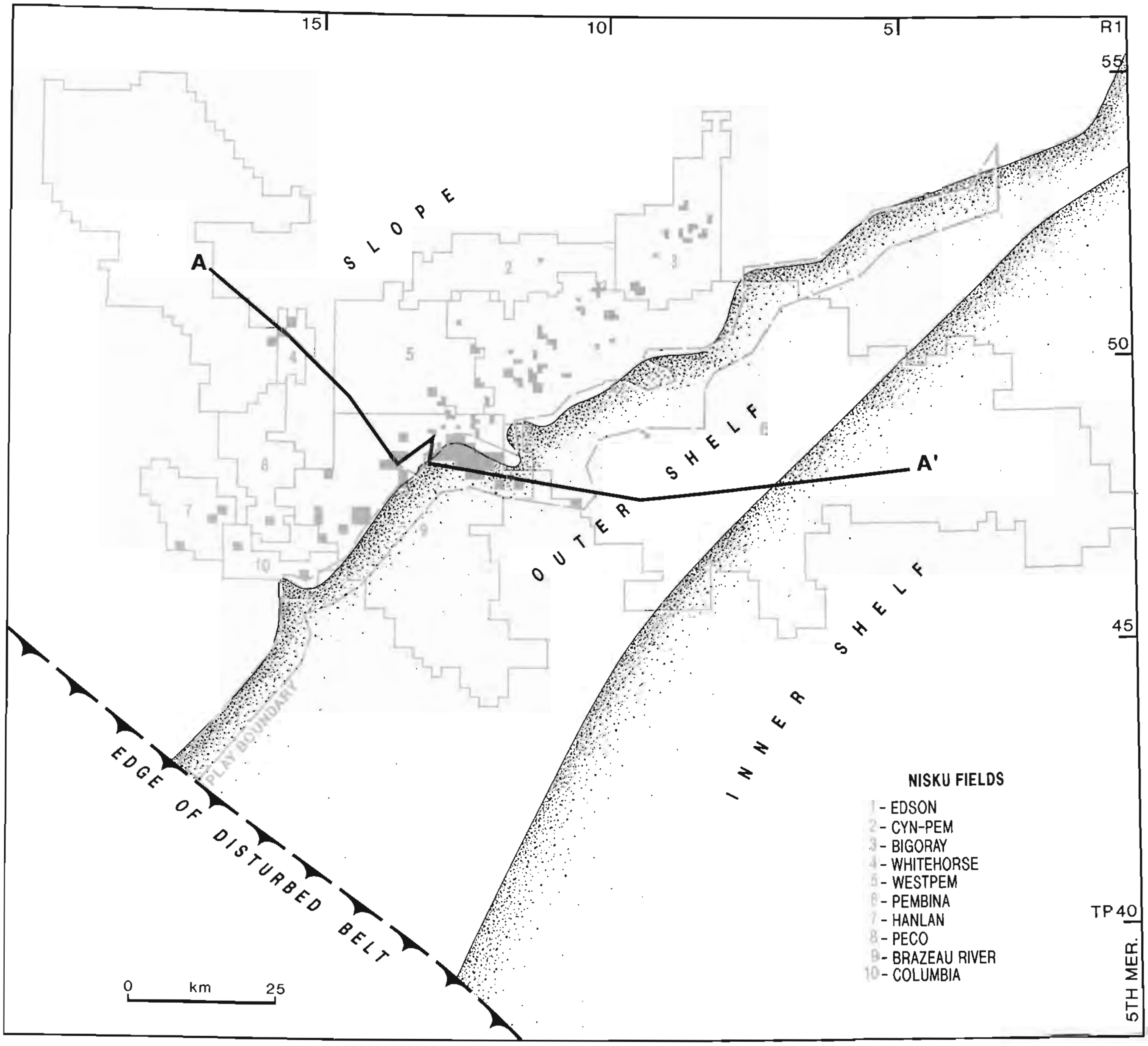


Figure 58. Map of the Nisku shelf margin (Brazeau River) play. (See Fig. 59 for cross-section A–A'.)

amount of dolomitization decreases from the southwest, where the reefs have been extensively dolomitized, to the northeast, where the reefs are predominantly limestone. Limestone reefs have porosities ranging from 3 to 5 per cent and permeabilities from 300 to 1000 md. Dolomitized reefs have porosities ranging from 5 to 11 per cent and permeabilties of 1000 md or greater (Anderson and Machel, 1988).

Exploration history. Chevron Standard Limited (1979) discovered the first Nisku reef (January, 1977) in the Brazeau River play area in the Nairb 11-22-49-12W5 well, which is now part of the Pembina Nisku A pool. The largest gas pool to be discovered in the Nisku isolated reef play is the Brazeau River Nisku M pool, which has an initial in-place volume of 1 489 x 10^6m^3 (Table 23). The number of gas pools that have been discovered in this play is 57, and the total initial in-place volume is 22 691 x 10^6m^3. Fourteen of these pools contain nonassociated gas with a total volume of 8 728 x 10^6m^3.

Play potential. Estimates of the potential for this play indicate an initial in-place volume of 8 041 x 10^6m^3. This represents 43 per cent of the total resource of this play. The estimate assumes a total pool population of 156 pools, with the largest undiscovered pool predicted to have an initial in-place volume of 639 x 10^6m^3 (Fig. 62).

Nisku shelf drape - Bashaw trend

Play definition. This play includes all gas-bearing pools or prospects in the porous, regressive-phase Nisku shelf carbonates that form combination drape-stratigraphic traps overlying the Bashaw reef complex (Fig. 56). The play area is essentially bounded by the margins of this complex (Fig. 63).

Geology. All the pools occur where the Nisku shelf deposits are draped over Leduc reefs of the Bashaw complex. East and southeast of the Ricinus-Meadowbrook reef trend, the Nisku Formation consists of carbonate muds, bioclastic carbonate banks and evaporites. In the Camrose-Drumheller area the Nisku is underlain by bioclastic carbonates of the Camrose dolomite. In the area of the Bashaw reef complex the Nisku consists of an upper, dense cryptocrystalline to finely crystalline dolomite and anhydrite zone, and a lower porous dolomite zone. The relative thickness of these two zones can vary considerably; some localities exhibit a full section of porous dolomite and others none.

Trapping is by structural drape over underlying Leduc reefs. However, the majority of the larger hydrocarbon accumulations display some aspects of stratigraphic entrapment.

Exploration history. The hydrocarbon pools in this play were discovered as early as 1949 (Table 24), soon after the original Nisku discovery at Leduc. All pools had been discovered by 1960. The initial in-place volume of 17 745 x 10^6m^3 is distributed in 47 pools; only six of these pools contain nonassociated gas, with a total in-place volume of 280 x 10^6m^3.

Play potential. The estimate of the potential for the Nisku shelf drape (Bashaw) play indicates an initial in-place volume of 4 934 x 10^6m^3. This number suggests that 22 per cent of the total gas resource is still to be discovered. The estimate assumes a total pool population of 300, suggesting that this play is somewhat immature given that only 47 pools have been discovered to date. However, the largest undiscovered pool is estimated to have an in-place volume of only 528 x 10^6m^3 (Fig. 64), indicating that this play is very mature, with little upside potential.

Nisku shelf drape - Ricinus-Meadowbrook trend

Play definition. This play includes all gas-bearing pools or prospects occurring in Nisku shelf carbonates in structural drape traps overlying the Ricinus-Meadowbrook reef trend. The play is essentially bounded by the margins of this reef trend (Figs. 53, 65).

Geology. All pools occur where Nisku shelf deposits drape over Leduc reefs in the Ricinus-Meadowbrook reef trend. The reservoir rock consists of fine to coarsely crystalline dolomite with intercrystalline and vuggy porosity. Although the entrapment mechanism is primarily structural drape, the larger gas pools commonly exhibit some stratigraphic control as well. For instance, oil and gas in the Leduc-Woodbend D-2 reef complex is trapped in the northeast updip edge by a combination of tight lithofacies and drape over the underlying Leduc reef.

Most of the natural gas contained in this play is associated with oil production; the largest pool, Leduc Woodbend D-2A (Table 25), contains large volumes of associated and solution gas. The gas/oil ratio in the oil pools increases toward the southwest reflecting increasing depth. Minor, nonassociated Nisku gas is found primarily in the southern part of this linear play trend (Fig. 65).

Exploration history. The first oil and gas discovered in the Leduc field in 1946 was from the Nisku Formation. Virtually all pools in this play were discovered by 1960. Several additional sour gas pools were encountered as a result of Leduc exploration in the Ricinus-Bearberry area in the late 1960s. To date the number of pools discovered is 19, with a total initial in-place volume of 8 754 x 10^6m^3 (Table 25). Only seven of these pools contain nonassociated gas, with a total initial in-place volume of 1 868 x 10^6m^3.

Play potential. The estimate of potential for this play indicates an initial in-place volume of 5 418 x 10^6m^3. This represents 38 per cent of the total estimated resource expected to occur in an additional 191 pools yet to be discovered. However, most of the undiscovered pools are relatively small; the largest has an estimated initial in-place volume of only 853 x 10^6m^3 (Fig. 66). Thus this play is considered to be very mature, with very little upside potential. The remaining potential is expected to occur as nonassociated gas situated in the southern portion of the play area.

Blue Ridge stratigraphic - Karr

Play definition. This play includes all gas pools and prospects in stratigraphic traps within the Blue Ridge Member of the Graminia Formation in west-central Alberta (Fig. 67).

Geology. The Blue Ridge Member is the lowermost member of the Graminia Formation and consists of a sequence of intertidal carbonates and siltstones. The Blue Ridge Member is over 50 m thick in the Winterburn Basin and thins to less than 7 m where it overlies the Nisku Formation in the West Pembina area. To the east, the Blue Ridge is indistinguishable from the overlying Graminia siltstone. The bedded anhydrite in the Blue Ridge Member suggests that isolated evaporitic basins were present, and stratigraphic traps could have formed on the downdip margins of these evaporitic pans. Hydrocarbon accumulations occur in stratigraphic traps in the intertidal carbonates of the Blue Ridge Member. However, the lack of detailed stratigraphic studies

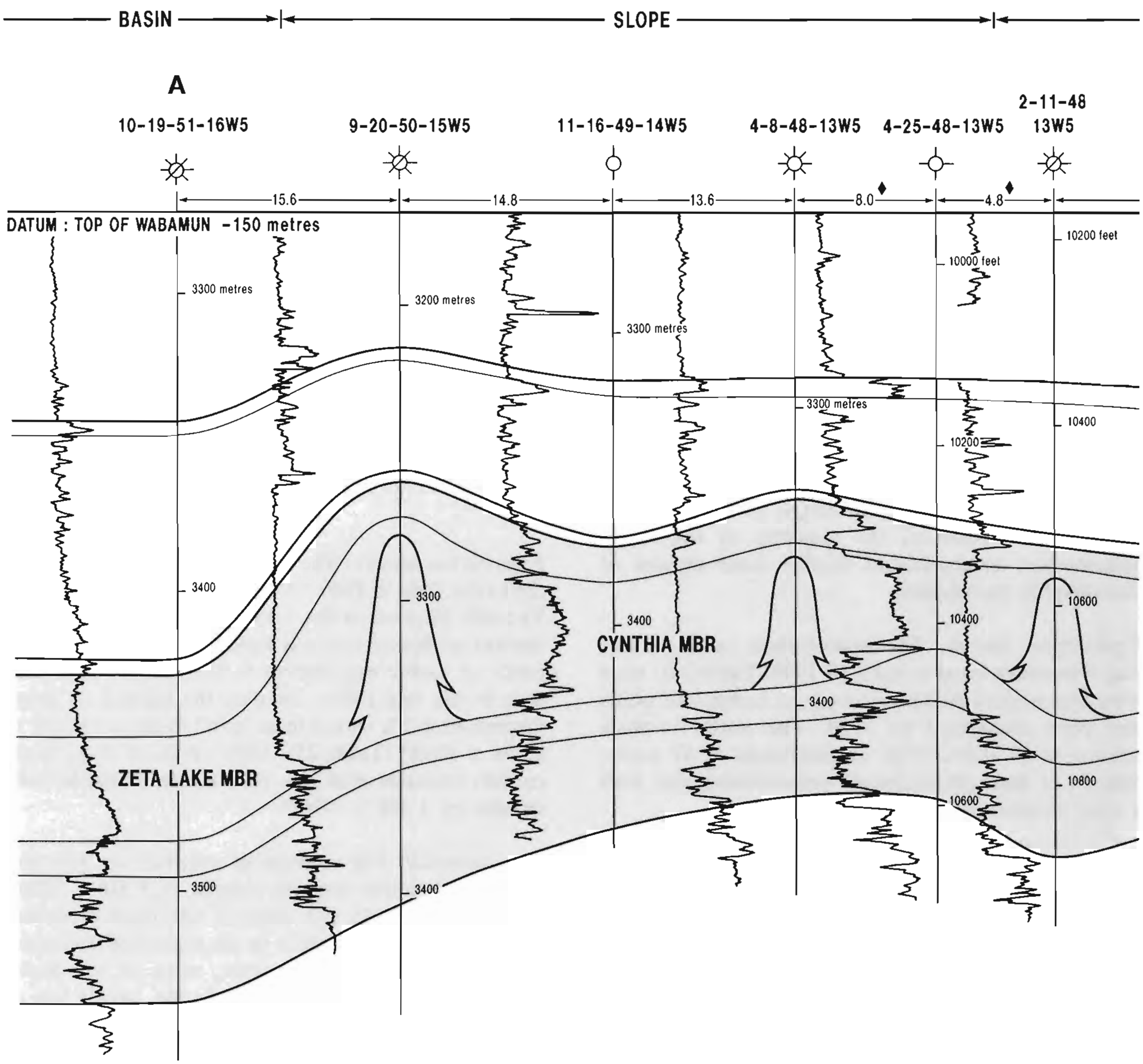


Figure 59. Cross-section A-A' illustrating relation between Nisku shelf margin and Nisku isolated reef plays. (Location of cross-section is shown in Figs. 58 and 61.)

makes it impossible to delineate the lateral distribution of these units; consequently, the trapping mechanism is poorly understood.

Exploration history. Hydrocarbons were first discovered in the Blue Ridge Member in 1954 (Location 5-14-58-8W5). The largest gas pool is the Skinner Blue Ridge A pool, which has an initial in-place volume of 1 799 x 10^6m^3 (Table 26). The total number of gas pools discovered in this play is 21, and the total initial in-place volume is 6 966 x 10^6m^3. Seventeen of the 21 discovered pools contain non-associated gas.

Play potential. Estimates of the potential for this play indicate an initial in-place volume of 19 190 x 10^6m^3, which equates to 73 per cent of the total play resource. The estimate assumes a total pool population of 460 with an in-place volume for the largest undiscovered pool of 2 629 x 10^6m^3 (Fig. 68). This play probably

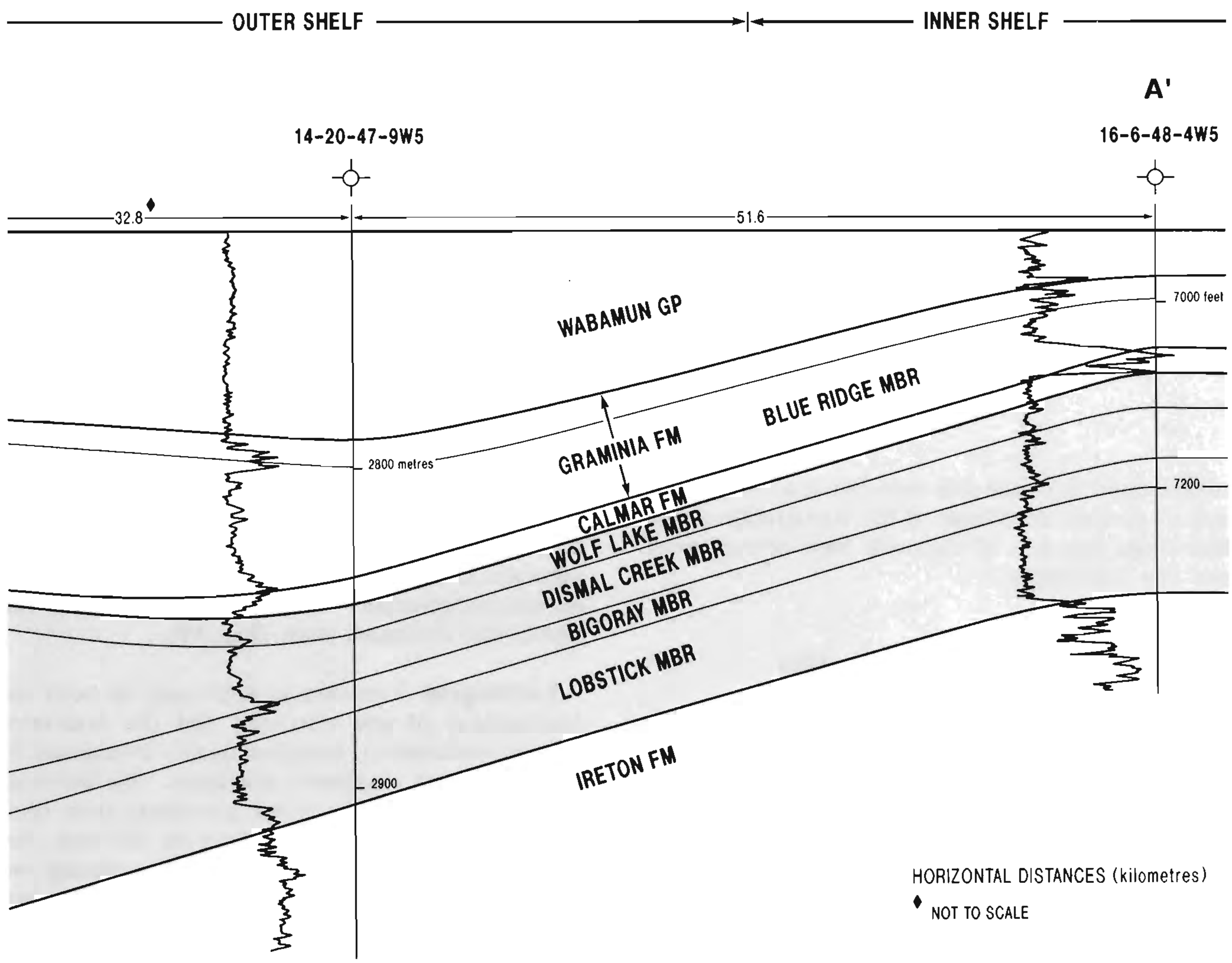


Figure 59. (cont'd)

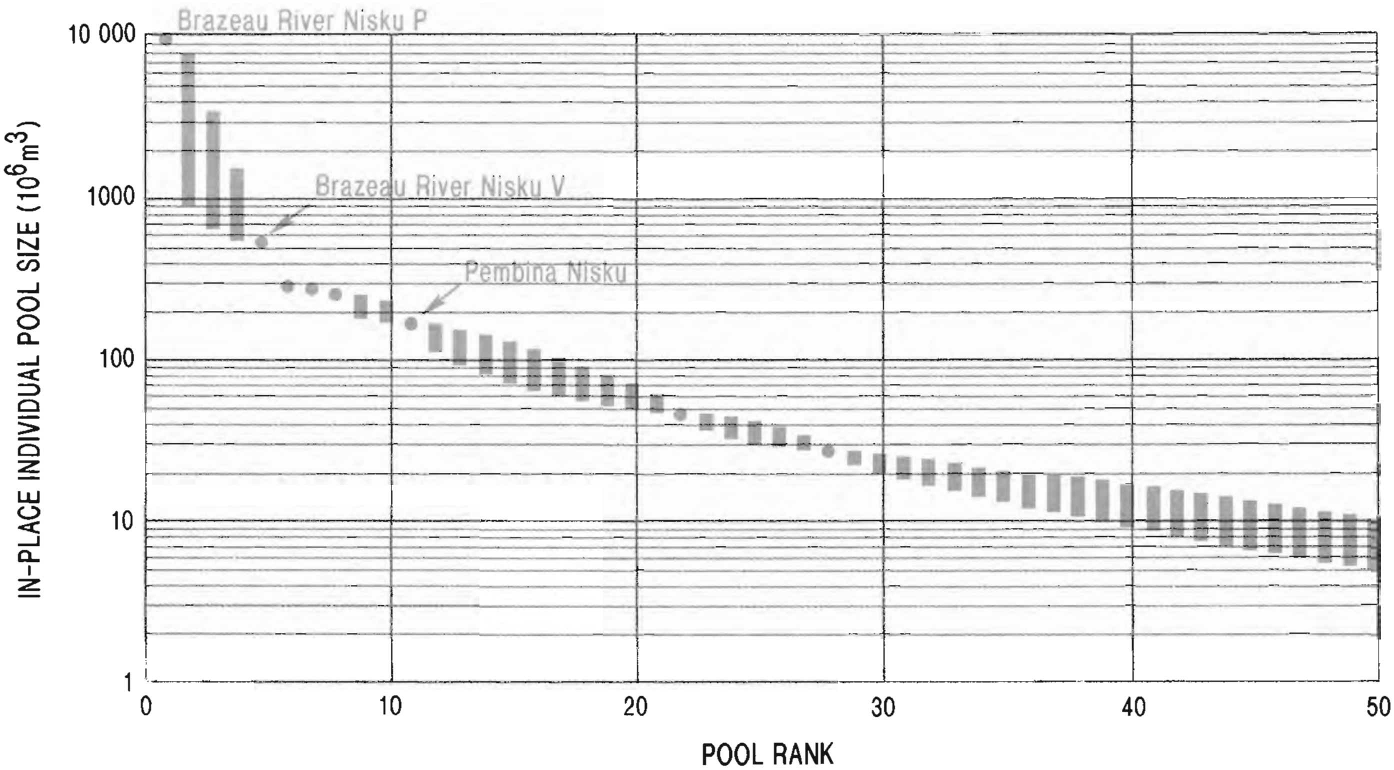


Figure 60. *Pool size-by-rank plot for the Nisku shelf margin (Brazeau River) play. The pools in this play are listed in Table 22.*

involves more than one play type, but as a result of the lack of detailed knowledge of the stratigraphy of the Blue Ridge Member, all the pools have been grouped into one population.

Upper Devonian subcrop - Marten Hills

Play definition. This play includes all gas pools and prospects in carbonate reservoirs of the Upper Devonian subcrop belt of eastern Alberta (Figs. 69, 70). The play is bounded on the west by the Mississippian erosional edge, on the east by a combination of erosional edges including the Leduc, Grosmont, and Nisku formations, and on the south by anhydritic lithofacies of the Nisku Formation and Wabamun Group. The northern boundary is the least well defined since it may involve either the Leduc or the Grosmont subcrop edge. An east-to-west facies change in the Wabamun, from porous dolomite to tight limestone, also complicates definition of the northern limits of this play.

Geology. This play primarily involves dolomite reservoirs encountered at the pre-Cretaceous unconformity surface. Because of truncation of increasingly older Upper Devonian strata eastward, the Wabamun Formation forms the uppermost reservoir unit, followed in an easterly direction by the Nisku, Camrose, Grosmont and Leduc carbonates. The major gas-bearing reservoirs are present in the Wabamun, Nisku, and Grosmont units (Fig. 69).

Lithological variation is important in both the development of the reservoirs and the associated trapping mechanisms. Reservoir quality is enhanced by dissolution and diagenetic alteration. The dolomite reservoirs have much higher porosities than their noneroded depositional equivalents to the west. For example, Nisku porosities in this play are generally two to three times the values encountered in the Bashaw area. The dolomites, by virtue of their greater stability (than limestones), are preferentially preserved at the paleotopographic erosional unconformity.

Exploration history. The largest gas pool in this play, Marten Hills Wabamun A, was discovered in 1960, some 12 years after minor gas shows were encountered in Wabamun reservoirs in the Leduc–Woodbend area. The larger gas accumulations in this play were discovered between 1960 and 1975 (Table 27). To date the number of pools discovered is 390, with a total

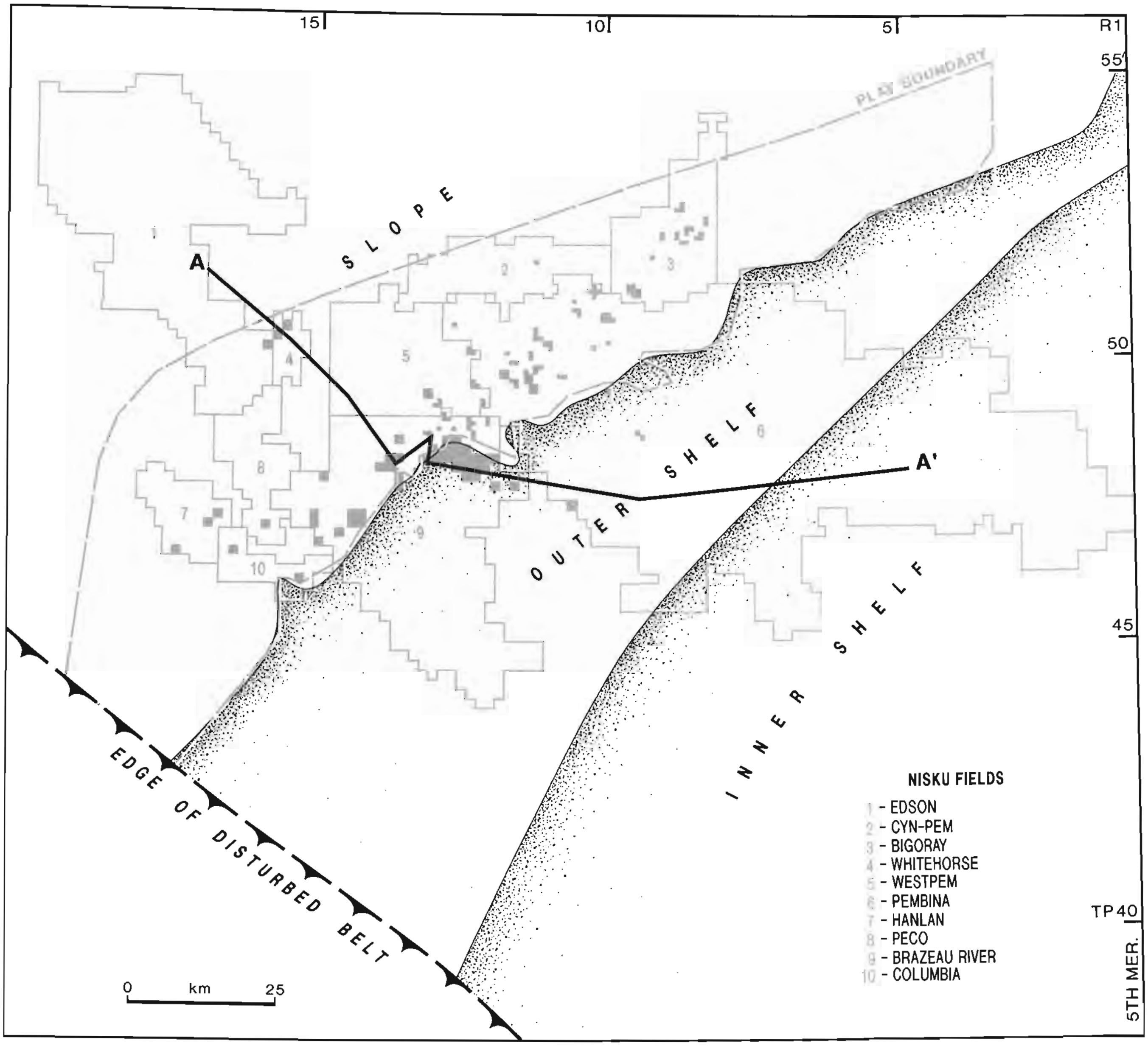


Figure 61. Map of the Nisku isolated reef (Brazeau River) play. (See Fig. 59 for cross-section A–A'.)

initial in-place volume of 101 734 x 10^6m^3. Gas occurs predominantly in nonassociated form (372 of the 385 pools contain nonassociated natural gas).

Play potential. The estimate of potential for this play indicates an initial in-place volume of 16 172 x 10^6m^3, suggesting that 14 per cent of the gas resource remains to be discovered. The estimate assumes a total pool population of 900; the largest undiscovered pool has an estimated in-place volume of 815 x 10^6m^3 of natural gas (Fig. 71). This play is very mature, but there is still potential in the northern sector of the area.

Wabamun platform facies – Pine Creek

Play definition. This play includes all gas pools and prospects in stratigraphic traps within the Wabamun Group in west-central Alberta (Fig. 72).

Geology. The Wabamun Group in Alberta consists of a sequence of shallow-water carbonates that were deposited on a broad carbonate ramp/platform. Stokes (1988) recognized that the Wabamun can be divided into two depositional systems: i) a lower transgressive platform system represented by the Crossfield Member in southeast Alberta; and ii) a

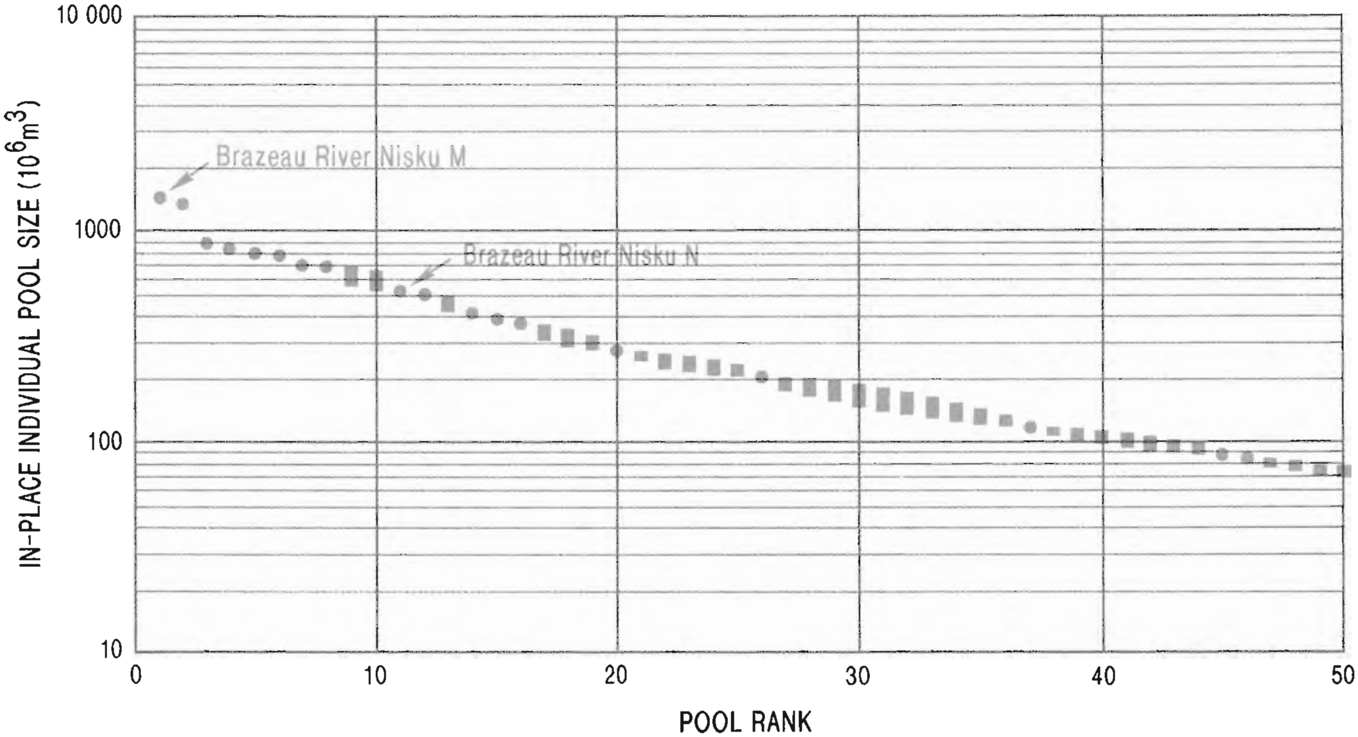


Figure 62. *Pool size-by-rank plot for the Nisku isolated reef (Brazeau River) play. The 20 largest discovered pools are listed in Table 23.*

regressive, regional, prograding ramp system. Detailed stratigraphy of the Wabamun Group in the play area has not been studied extensively. Subtle stratigraphic traps have been discovered in the Wabamun Group, and they tend to occur overlying Leduc reef complexes (Fig. 72). Reservoirs commonly are partly dolomitized peloidal grainstones that occur at different levels within the Wabamun platform succession (Fig. 73). Most of the Wabamun hydrocarbon reservoirs were encountered as a result of exploration aimed at the underlying Leduc Formation.

Exploration history. The Pine Creek Wabamun B pool was the first and largest natural gas pool discovered in the Wabamun platform facies (Pine Creek) play. The Pine Creek Wabamun B pool, discovered in 1955, has an in-place volume of 6 773 x $10^6 m^3$ (Table 28). The total number of gas pools in this play is 20 and the total initial in-place volume is 20 949 x $10^6 m^3$.

Play potential. Estimates of the undiscovered potential for this play indicate an initial in-place volume of 17 832 x $10^6 m^3$; this suggests that 46 per cent of the total resource remains to be discovered. The estimate assumes a total pool population of 450, with an in-place volume for the largest undiscovered pool of 2 279 x $10^6 m^3$ (Fig. 74). Future discoveries in this play probably will be in reservoirs overlying some of the smaller Leduc and Swan Hills reef complexes.

Leduc/Nisku isolated reef complexes - Wild River Basin

Play definition. This immature play includes all gas pools and prospects in stratigraphic traps in the Leduc and Nisku formations in the Wild River Basin area of western Alberta (Fig. 75).

Geology. The Swan Hills carbonate shelf is present in the entire Wild River Basin area, underlying the Leduc Formation. Deposition of the Leduc Formation occurred in two distinct stages: 'low' Leduc and 'high' Leduc (Fig. 75). In the Wild River Basin the 'low' Leduc Formation forms patch reef complexes on which 'high' Leduc reefs developed. Hydrocarbon reservoirs occur within the 'low' and 'high' Leduc and also in the overlying Nisku Formation (Fig. 76). The basinal shales and limestones of the Duvernay and Ireton formations, and the basinal equivalents of the Winterburn Group overlie and encase the Leduc reefs, acting as seals for the reservoirs. Hydrocarbon

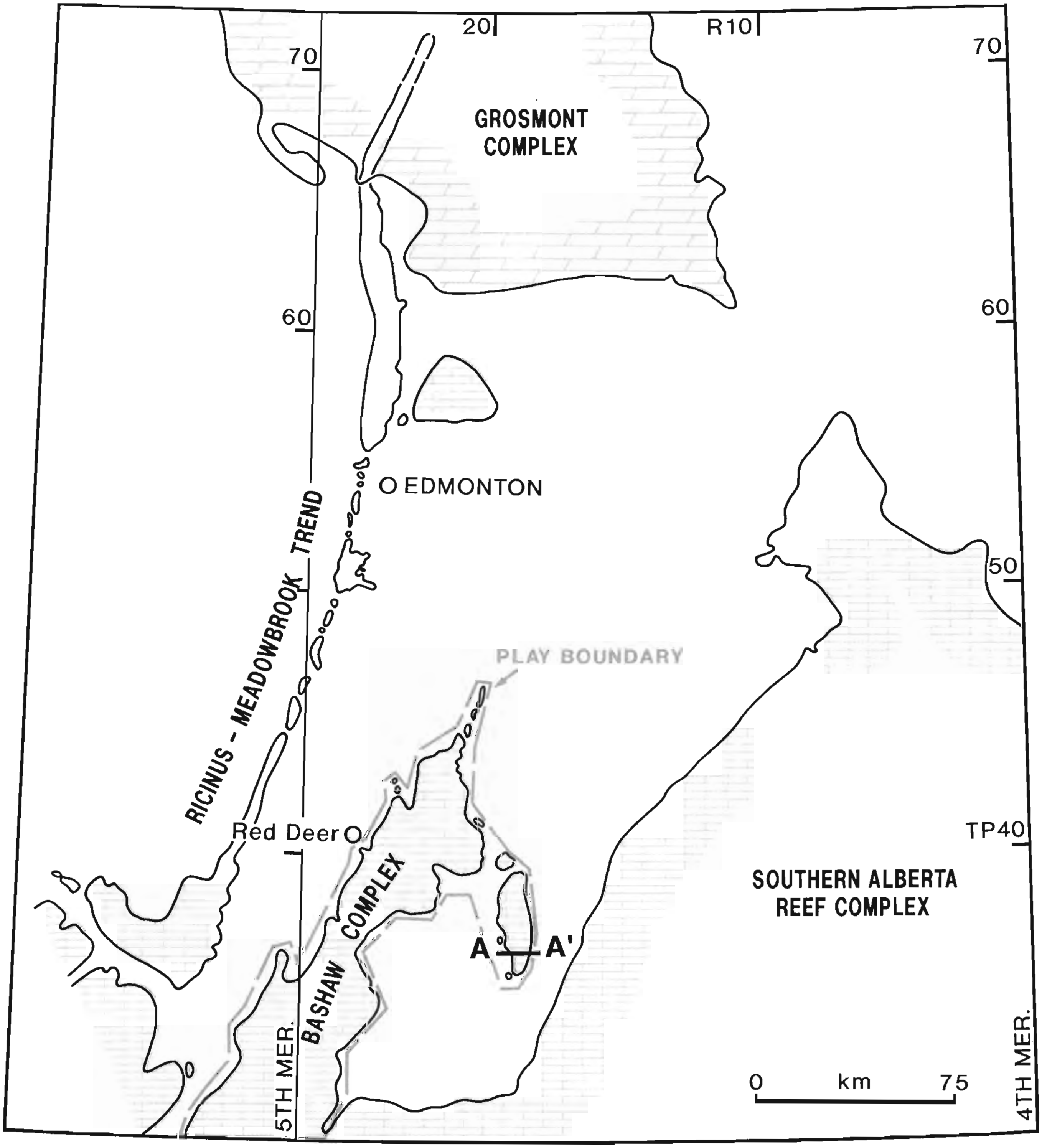


Figure 63. Map of the Nisku shelf drape (Bashaw) play. The cross-section illustrating this play type is shown in Figure 56.

reservoirs in the Leduc reef complexes of the Wild River Basin are overpressured relative to the regional pressure gradient. The organic-rich shales of the Duvernay Formation probably are the source for the natural gas trapped in the Wild River Basin area.

Exploration history. The first pool discovered in the Wild River Basin was in 1968 (Colt D-3 A pool, Table 29). The Colt D-3 A pool is a 'high' Leduc reef complex, which contains an initial in-place volume of 586 x 10^6m^3. The largest pool discovered in this play is Nosehill D-3 A, which has an initial in-place volume of 939 x 10^6m^3, and covers an area of 64 ha. There are a total of six pools in the Wild River Basin play; four of these are in the Leduc Formation and two are in the Nisku Formation. They contain an initial in-place volume of 3583 x 10^6m^3 (Table 29).

Play potential. This is an immature play, consequently no numerical assessment was undertaken.

Southern District

Wabamun platform facies - Crossfield

Play definition. This play includes all pools and prospects occurring in the Stettler Formation of the Wabamun Group in southern Alberta. Traps occur in porous dolomites stratigraphically associated with, but not restricted to, Crossfield Member carbonates, which are sealed updip by a change in lithology to nonporous dolomite and anhydrite (Figs. 77, 78).

Geology. The Crossfield Member, the primary reservoir zone, is up to 35 m thick in the play area, and thickens westward to approximately 100 m in the Foothills. Eastward it changes to nonporous facies of the Stettler Formation. The Crossfield Member comprises two predominant lithologies: i) light coloured dolomitic mudstones, deposited in restricted, shallow subtidal, intertidal, and supratidal environments; and ii) dark coloured dolomitic stromatoporoid–gastropod rudstones deposited in shallow, open-marine shoal environments. Eliuk (1984, 1990), Eliuk and Hunter (1987) and Richards et al. (1984) indicated that stromatoporoid rudstones correlative with the Crossfield Member can be recognized in the Palliser Formation throughout the southern Foothills and Front Ranges of the Rocky Mountains.

Despite the apparent wide distribution of carbonates at the Crossfield stratigraphic level, the play area is somewhat confined (Fig. 77). It appears to coincide with a north–south-trending structural feature that

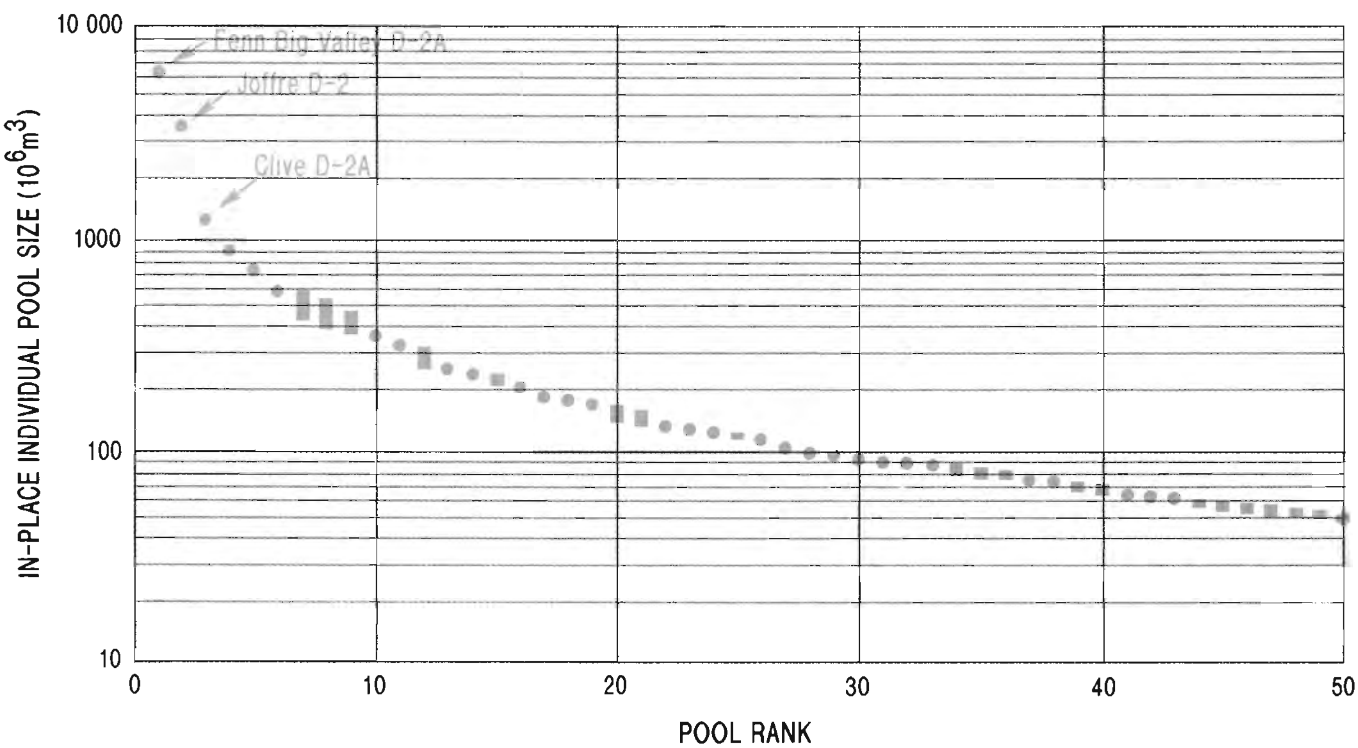


Figure 64. *Pool size-by-rank plot for the Nisku shelf drape (Bashaw trend) play. The 20 largest discovered pools are listed in Table 24.*

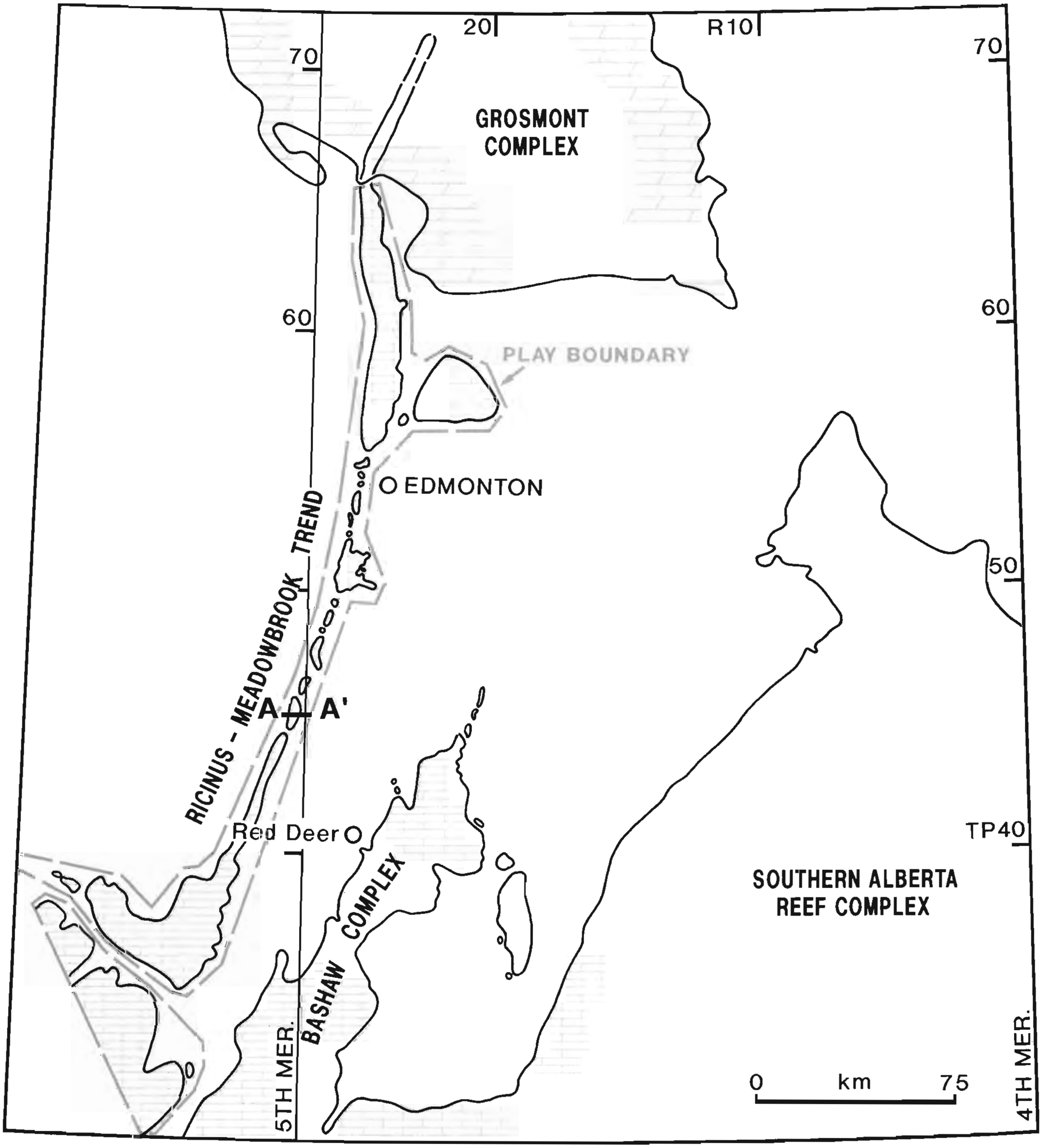


Figure 65. Map of the Nisku shelf drape (Ricinus–Meadowbrook) play. The cross-section illustrating this play is shown in Figure 53.

exerted subtle control on both Wabamun deposition and subsequent structure. Andrichuk (1960) indicated a more dolomitic, possibly shallower facies, in the basal Wabamun south of Township 35, straddling the 5th meridian. This coincides with a subtle structural hinge marked by a change in dip throughout the region (Mason and Riddell, 1959). Although structural influences are poorly documented, their presence in the productive area compared with the their absence throughout the broader region where Crossfield equivalents are unproductive suggests that the play should be limited to the area where structural controls are likely to occur.

Average pool porosities usually are only in the 5 to 6 per cent range. The light coloured dolomitic mudstones contain pinpoint intercrystal pores, and small vugs produced by leaching of clastic grains. The dark rudstone lithofacies contain moldic and vuggy pores as a result of leaching of primary bioclastic material. Fracture porosity also is significant. Caving of the Crossfield Member is commonly indicated by caliper logs and is usually associated with fractures (Eliuk, 1984).

Exploration history. The Crossfield Member was first identified in the Imperial Anglo Crossfield No. 1 well (9-11-28-2W5) which was drilled in May of 1946. The potential of this play was immediately recognized and in 1951, the Okotoks field (now Okotoks Wabamun B pool) was discovered by the Shell Mackid No. 1 well (1-19-21-28W4). With the end of the 1950s most of the major accumulations had been discovered and the play trend was well established. Discoveries continued to be made until 1980, although a number of these have been subsequently absorbed into larger fields. To date, 19 pools have been discovered with a total initial in-place volume of 128 162 x $10^6 m^3$ (Table 30). Only one of these pools contains associated/solution gas.

Play potential. Estimates of the potential for this play indicate an initial in-place volume of 2 125 x $10^6 m^3$. This number represents less than 2 per cent of the total resource of this play. The estimate assumes a total pool population of 60, with the largest pool still to be discovered having an in-place volume of 733 x $10^6 m^3$ (Fig. 79).

Since this play has been limited to the region delineated in Figure 77, it is important to distinguish it from conceptual plays in the Wabamun Group lying downdip and along the hydrocarbon migration pathway. The play, as now defined, is very mature and

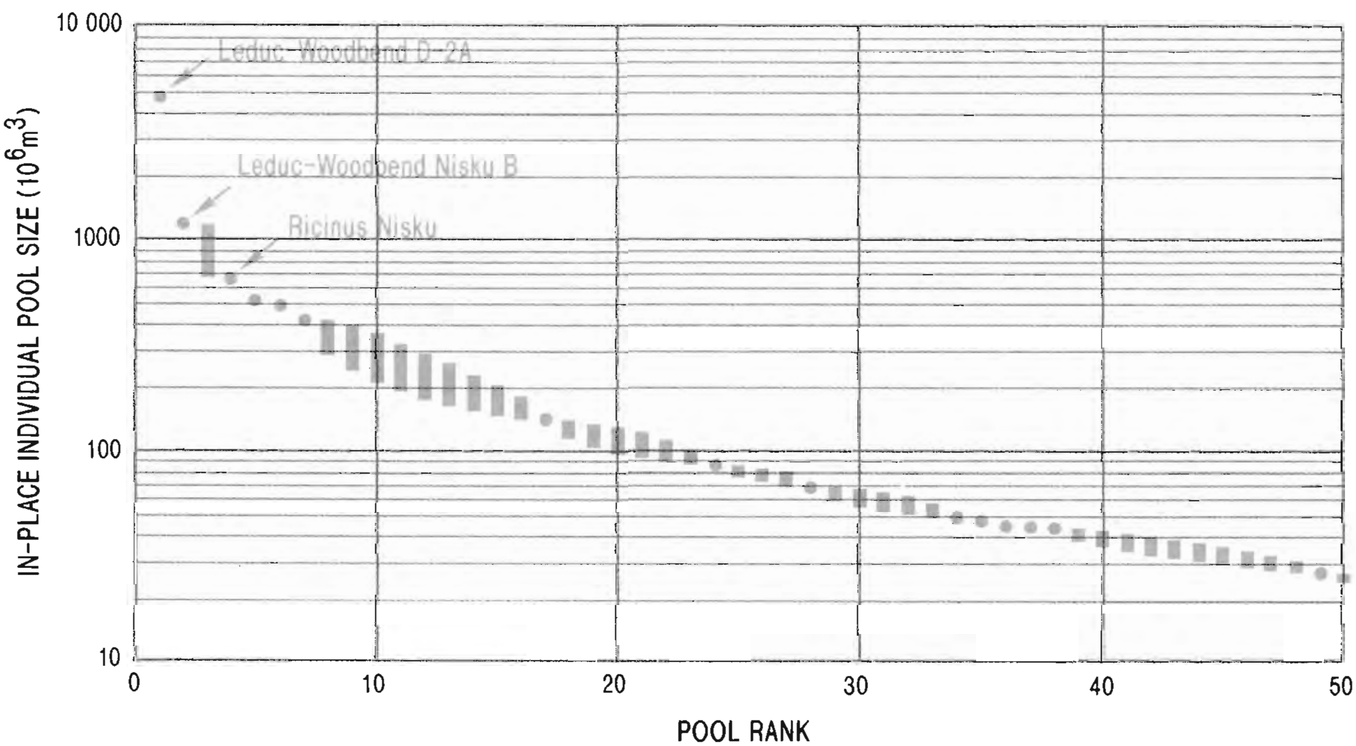


Figure 66. *Pool size-by-rank plot for the Nisku shelf drape (Ricinus–Meadowbrook trend) play. The 20 largest discovered pools are listed in Table 25.*

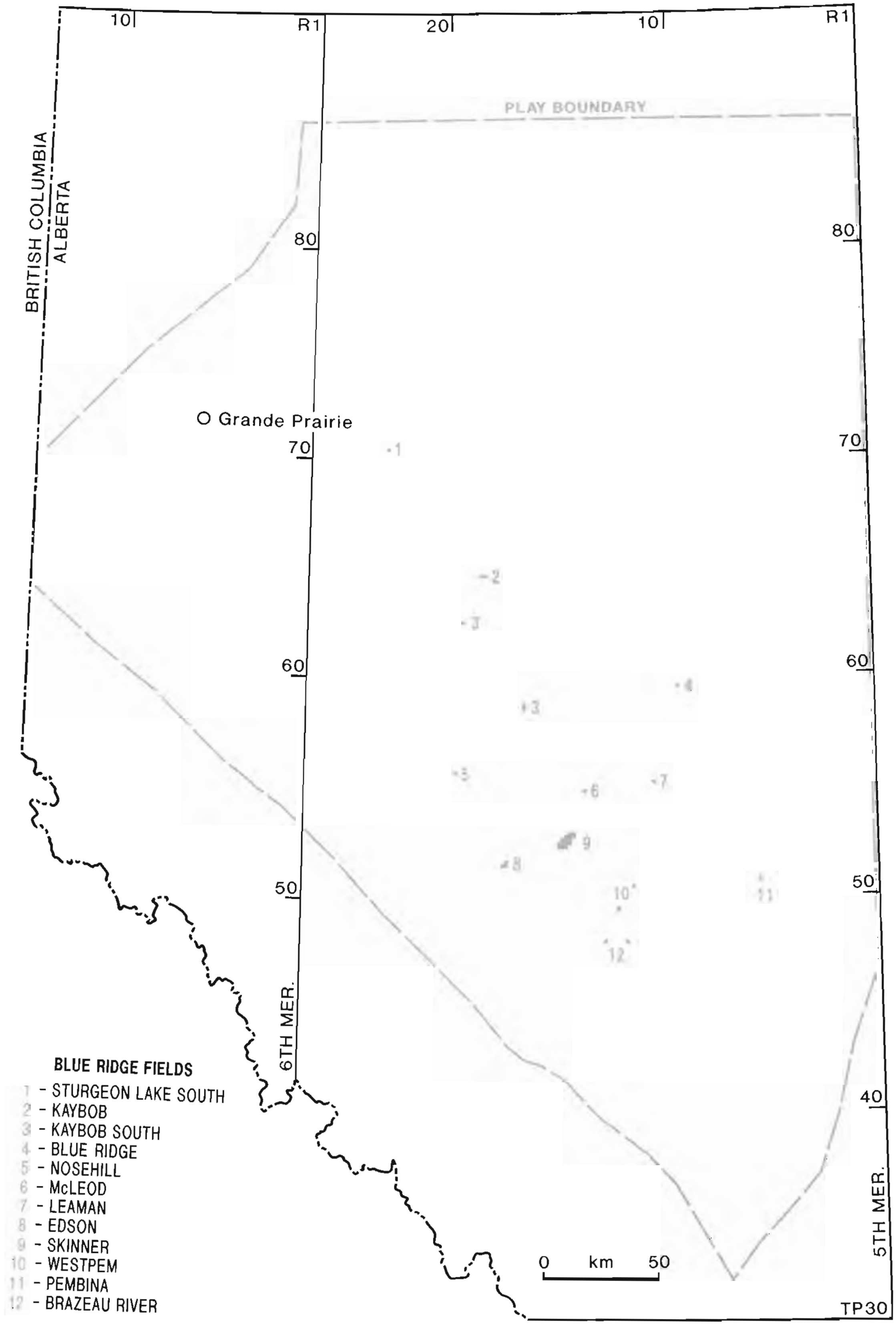


Figure 67. Map of the Blue Ridge stratigraphic (Karr) play.

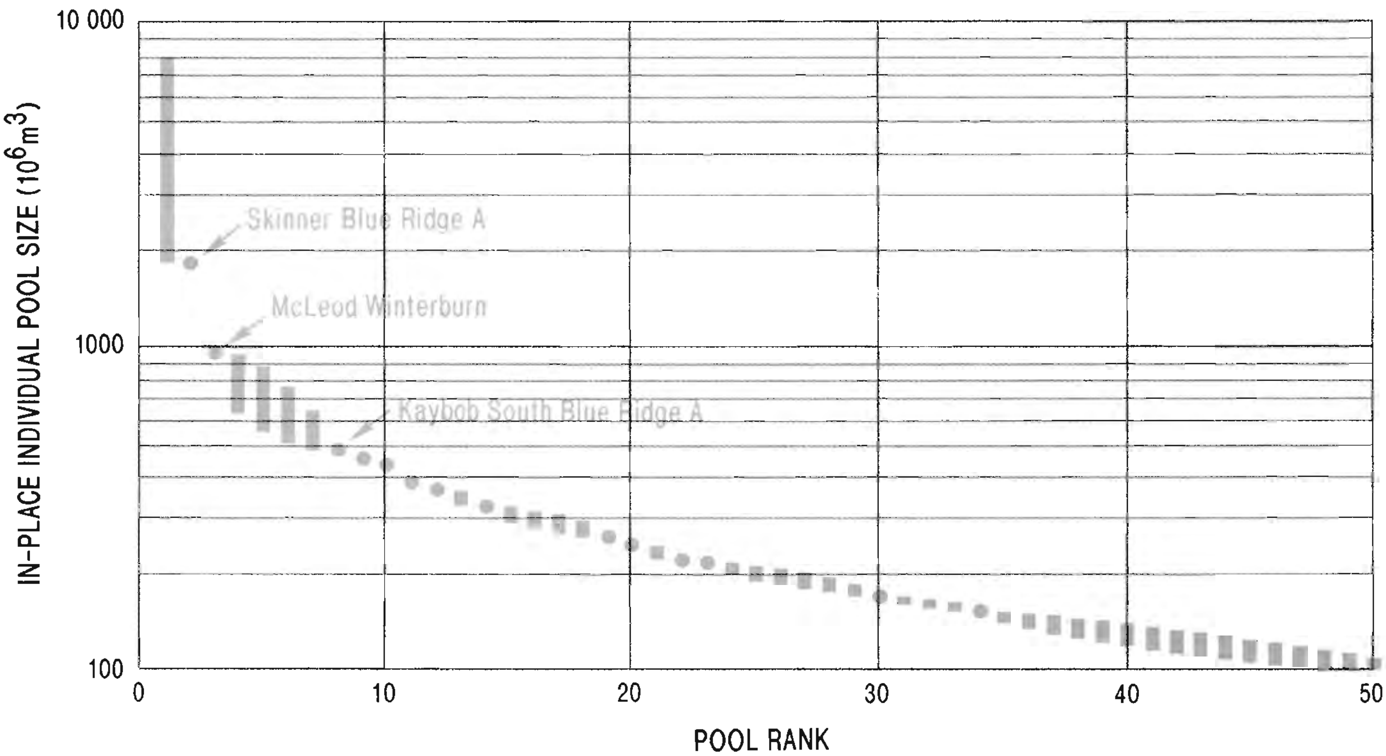


Figure 68. *Pool size-by-rank plot for the Blue Ridge stratigraphic (Karr) play. The 20 largest discovered pools are listed in Table 26.*

well explored. The largest pool has been found, providing a strong constraint on both the expected number of pools and the undiscovered resource potential.

Arcs structural - Princess

Play definition. This immature play includes all gas-bearing pools or prospects present in structural and/or stratigraphic traps in the Arcs Member (Nisku correlative) of southern Alberta.

Geology. Belyea (1957, 1964) considered the Arcs Member of the Southesk Formation in the subsurface of southern Alberta to be equivalent to the upper Nisku Formation in central Alberta, and the underlying Grotto Member to the Camrose Dolomite, also in central Alberta. The Arcs Member is a relatively thin (6–12 m) widespread unit, but locally it can be up to 45 m in thickness. The type subsurface section, in Lsd. 1-2-30-21 W4M (West Drumheller oil field) is 34 m thick. The Arcs Member consists of light coloured, fine to coarsely crystalline dolomite with bands of brown, granular dolomite and minor anhydrite. The porosity is vugular and intercrystalline with minor oblique fractures.

In the Enchant-Hays area (Fig. 80), the Arcs Member can be divided into two reservoir units separated by a thin shale bed. Dolomite, with interbeds of anhydrite, is the dominant lithology, and reflects a restricted peritidal to supratidal environment. Hydrocarbons are trapped in porous dolomites in structurally high closures (Fig. 81). The structures are believed to be a result of salt solution in older Upper Devonian carbonate-evaporite sequences (Slingsby and Aukes, 1989). The Arcs is relatively uniform in thickness over the entire Enchant-Hays region, indicating that structural deformation occurred after Arcs deposition. In addition, the isopach thickness of the Wabamun-to-Grotto interval indicates depositional thins over highs on the Arcs Member, suggesting that deformation occurred shortly after the Arcs carbonates were deposited.

Exploration history. The largest gas pool within this play, Princess Jefferson "B", was discovered in 1939 (Table 31). However, subsequent discoveries were quite sporadic, with oil discoveries (and associated natural gas) taking place in the general Drumheller area in the

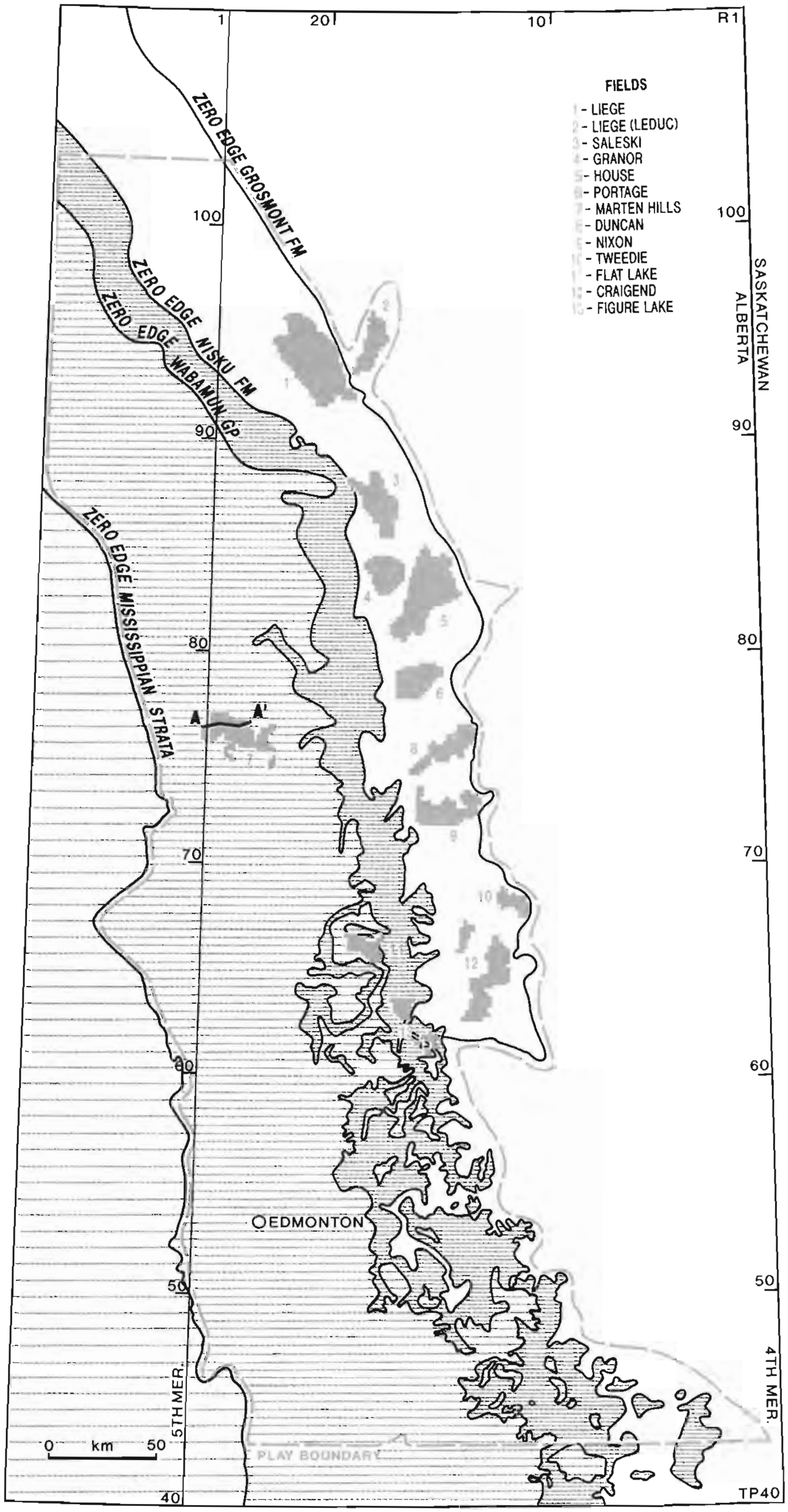


Figure 69. Map of the Upper Devonian subcrop play. (See Fig. 70 for cross-section A–A'.)

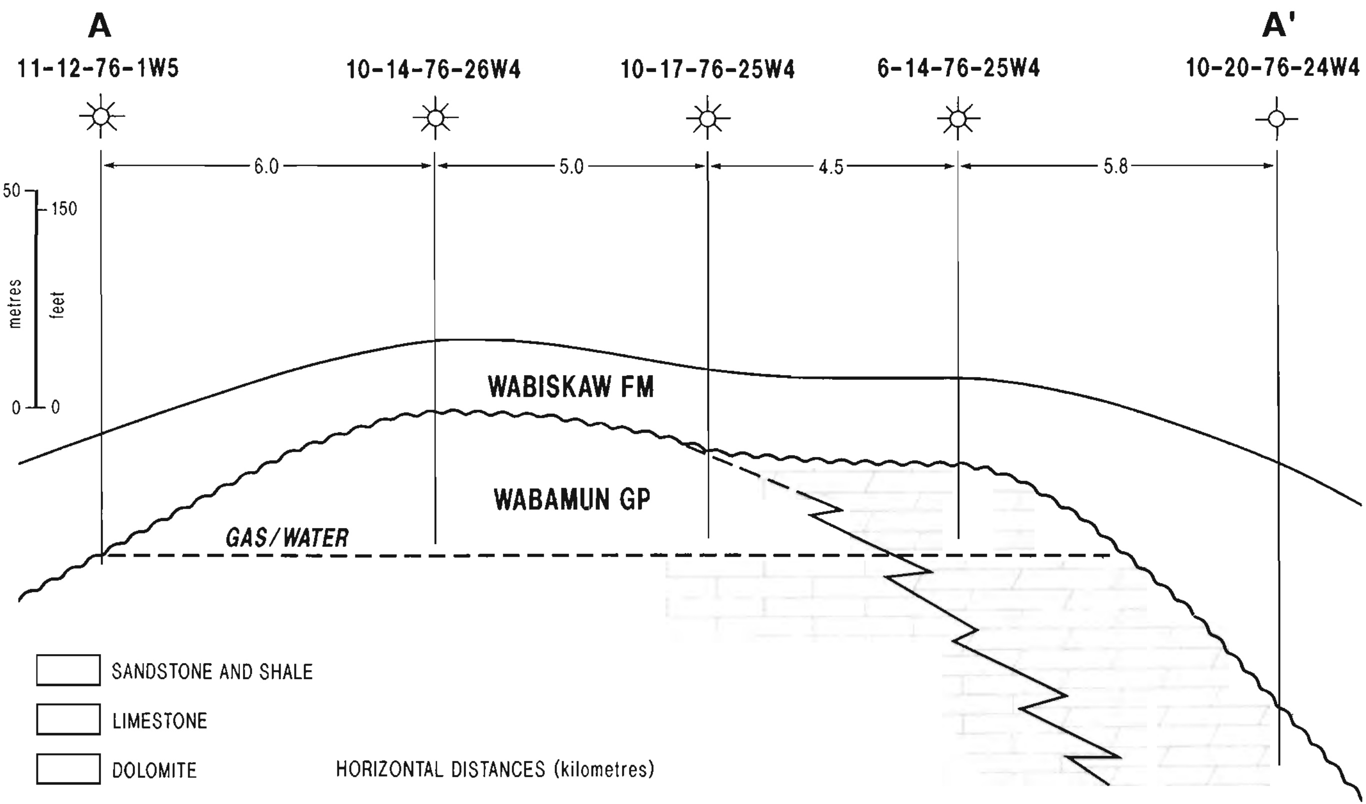


Figure 70. Cross-section A–A′ through Marten Hills illustrating one of the Upper Devonian subcrop play types. (Location of cross-section is shown in Fig. 69.)

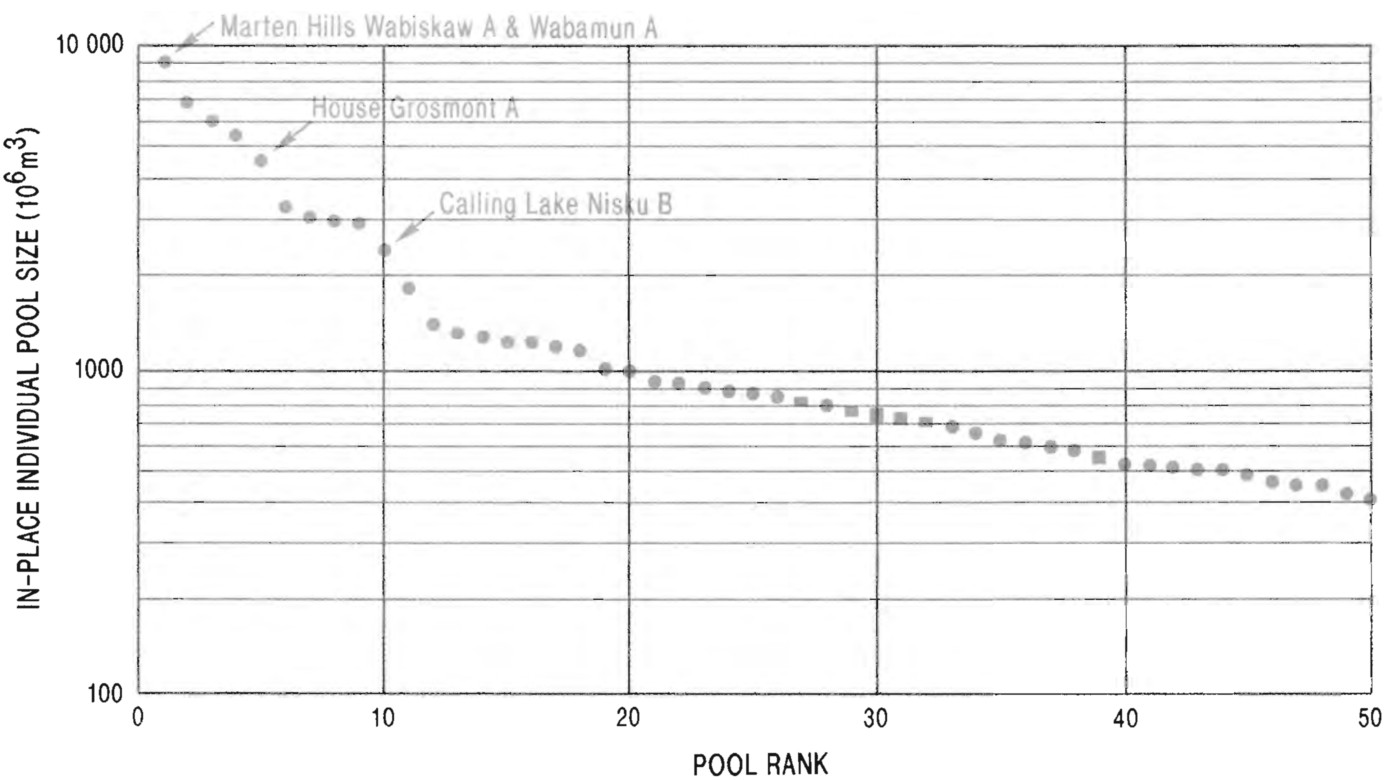


Figure 71. Pool size-by-rank plot for the Upper Devonian subcrop (Marten Hills) play. The 20 largest discovered pools are listed in Table 27.

early 1950s. The southern sector of this play became active after the discovery of oil and gas at Enchant in 1985. Subsequently, a number of pools, mainly oil with solution and associated gas, were discovered.

A total of 30 pools have been found, containing 5 844 x $10^6 m^3$ of gas (Table 31). The pools with the larger initial in-place volumes tend to contain nonassociated gas. These commonly are present in close proximity to oil pools and no obvious separation of hydrocarbons is apparent.

Play potential. This play is considered to be immature, consequently no assessment was undertaken. The individual designated pools are not large, but there appears to be considerable opportunity for the discovery of additional natural gas resources in this play.

Established play results

Discovered gas volumes, and expected and probable potential gas volumes for the 25 mature plays are listed in Table 32 (Appendix I). The total resource for each mature play is the sum of potential (either at the expected or probable level) and discovered volume. The expected potential is the more conservative value,

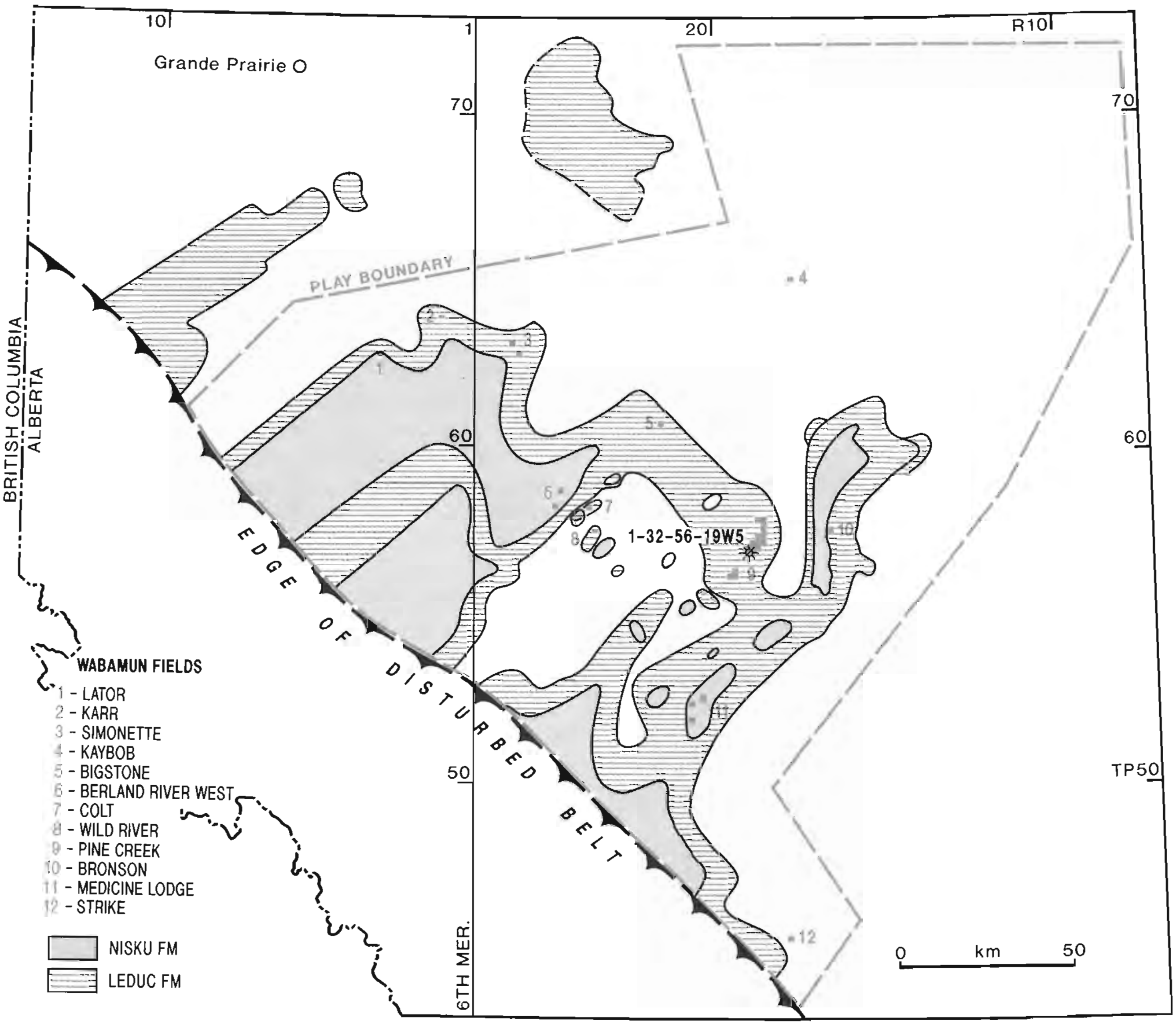


Figure 72. *Map of the Wabamun platform facies (Pine Creek) play. Depositional limits of the Leduc and Nisku formations (from Fig. 49) are shown relative to principal Wabamun gas pools.*

being constrained by the range of the individual discovered pool sizes, pool ranks and geological play definition. As defined in a previous section (Resource assessment procedure), probable potential is derived by conditioning the play resource distribution on the sum of all discovered pool sizes for that play (Fig. 5). In the discussion that follows, expected potential is emphasized for each play, but probable potential is also considered for comparative purposes.

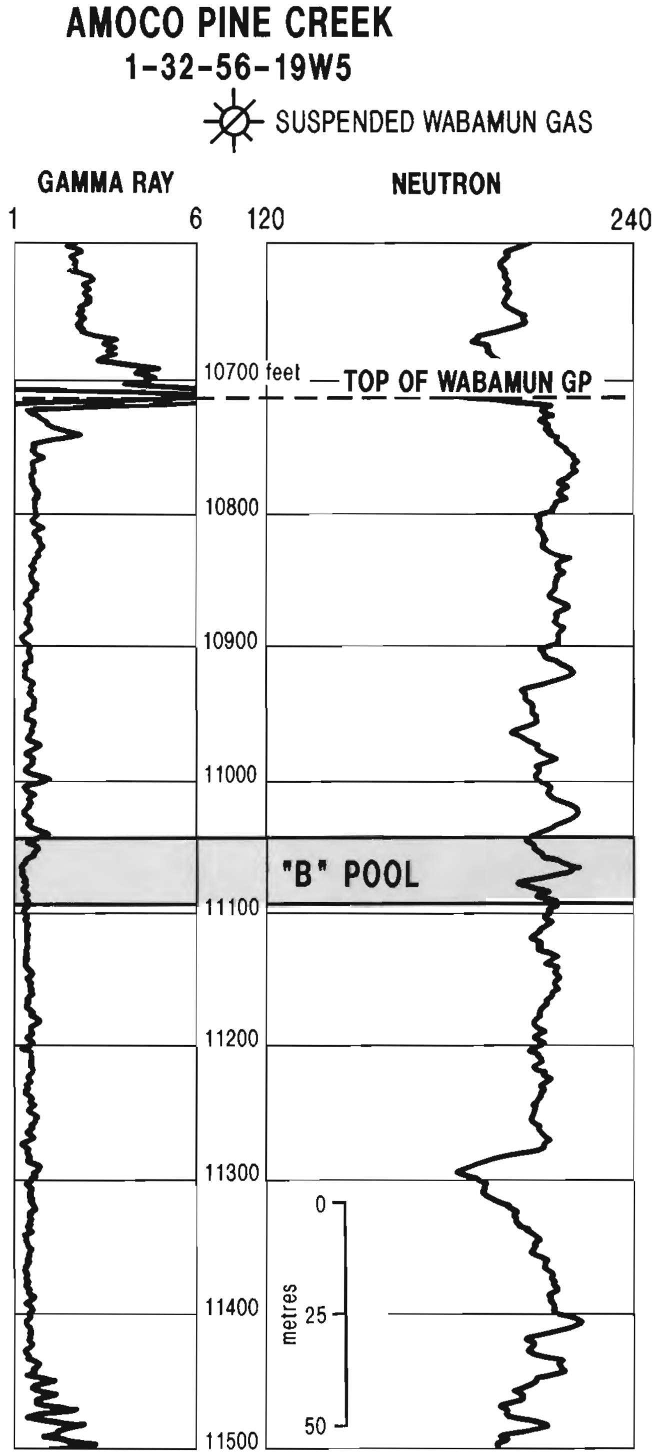


Figure 73. Well log demonstrating nondescript nature of the Wabamun platform facies (Pine Creek) play.

Mature plays are ranked according to discovered in-place volume, potential and largest undiscovered pool size in Tables 33-36. When comparing the different sets of numbers, interesting trends, which may be useful for planning exploration strategies, are evident. As expected, the very mature gas plays, Leduc isolated reef (Westerose) in central Alberta, and Swan Hills shelf margin (Kaybob South) in the "Deep Basin" area (Table 33), have the largest discovered gas resources. The large volumes in the Westerose play reflect its early discovery and subsequent intensive drilling, primarily for oil. Large discovered in-place volumes in the Kaybob South play reflect the recent Caroline gas discovery, which added substantial reserves to this still-expanding exploration play. The plays with the lowest discovered in-place volumes (Keg River platform - July Lake, Blue Ridge stratigraphic - Karr, Leduc fringing reef - Worsley, and Keg River shelf basin - Shekilie) reflect their relative immaturity, except for Shekilie, which is basically an oil play.

When the mature plays are ranked according to potential, a much different order than the discovered in-place volume ranking emerges (Tables 34, 35). The relation between discovered in-place volume and expected potential also illustrates some interesting comparative trends between plays (Fig. 82). The Cranberry, Adsett and Parkland plays have relatively low discovered in-place volumes but significant play potential. Furthermore, the Windfall and Kaybob South plays, although containing large discovered in-place resources, also have significant potential. Figure 82a appears to reflect a play maturity index, since the Cranberry, Adsett, Parkland and Helmet North plays have only recently (since 1975) attracted strong exploration interest.

Estimated largest remaining pools for each mature play, when ranked according to discovery size (Table 36), reflect the upside potential of the Cranberry, Adsett, Windfall, Kaybob South, and (surprisingly) the Westerose play. There should be a strong positive correlation between play potential and largest undiscovered pool for each play, and this is evident in Figure 82b.

When distribution of gas resources is examined according to exploration region (Table 37), it is apparent that largest discovered in-place volumes occur

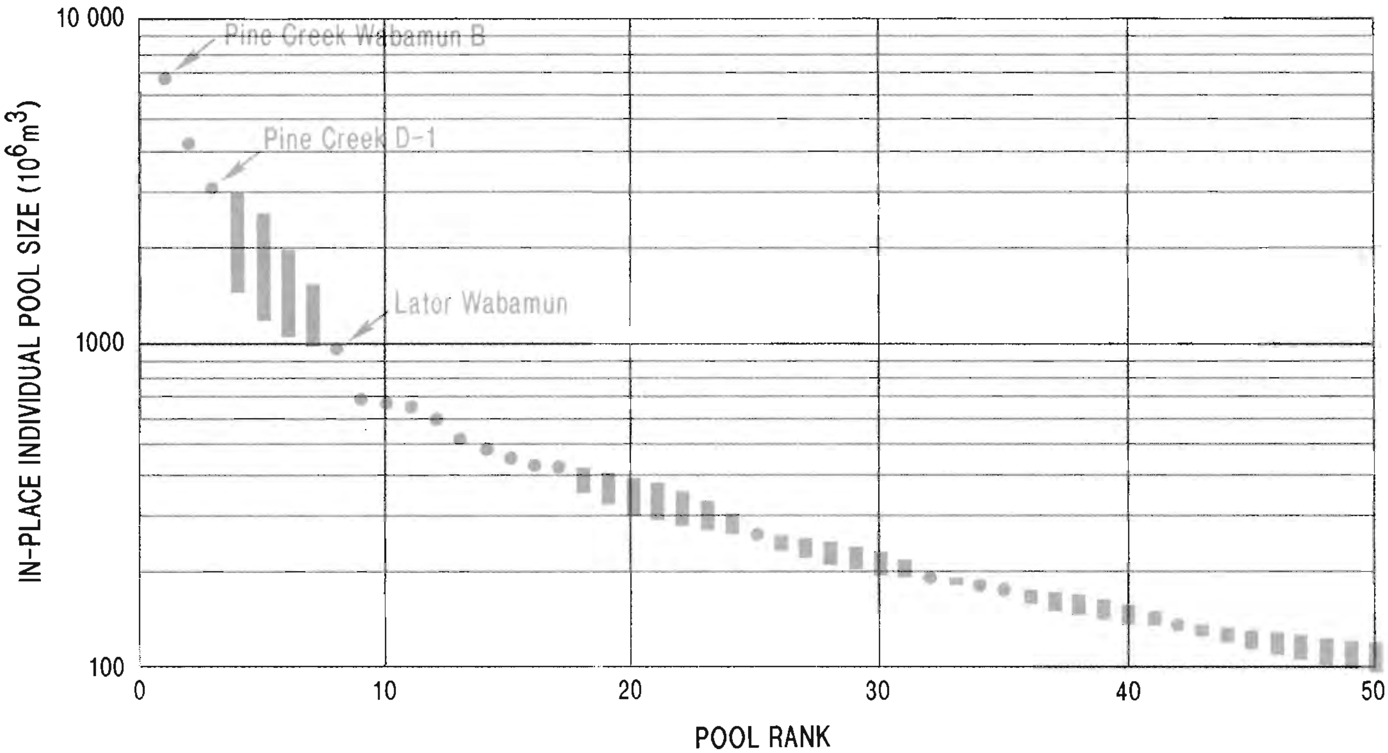


Figure 74. *Pool size-by-rank plot for the Wabamun platform facies (Pine Creek) play. The 20 largest discovered pools are shown in Table 28.*

close to highly populated areas where drilling activity has historically been the highest (Central District and Deep Basin region). The potential for discovering significant additional resources (at the expected level) is highest in the Northern District and Peace River Arch region. This reflects the relatively underexplored Slave Point reef complexes (Cranberry) and interior platform (Adsett) plays, and the Wabamun structural–stratigraphic (Parkland) play. Significant upside potential still exists in mature plays of the Central District and Deep Basin areas. The Swan Hills shelf margin (Kaybob South) and Leduc/Nisku reef complexes (Windfall) plays in the "Deep Basin" are in this upside potential, as is the Leduc isolated reef (Westerose) play. The relatively low discovered in-place volume and expected potential in southern Alberta are due to the fact that only one mature gas play has been identified in this exploration region. However, the analysis of conceptual plays (to follow) indicates that significantly more gas resources should be present in the Western Canada Sedimentary Basin; perhaps much of this occurs in as yet undefined plays in the Southern Alberta exploration region.

Natural gas potential at the probable level is markedly different from expected potential values for the three exploration regions (Table 37). In fact, there is far greater potential for finding significant additional reserves in the Central District and Deep Basin region than in the Northern District and Peace River Arch region. The Swan Hills Shelf Margin (Kaybob South) and Leduc/Nisku reef complexes (Windfall) plays of the Deep Basin area each have more than double the probable potential gas resources of the Slave Point reef complexes (Cranberry) play in northern Alberta (Table 35). It is noteworthy also that estimated probable gas potential in the Central District and Deep Basin region increases over 50 per cent of that estimated as expected potential, whereas the increase between expected and probable potential in the northern District and Peace River Arch region is less than 50 per cent (Table 37).

The total figures for the 25 mature plays are 1 568 606 x 10^6m^3 (56 TCF) of discovered in-place gas, with an additional 564 478 x 10^6m^3 (20 TCF) of potential estimated at the expected level and 1 822 463 (65 TCF) at the probable level (Table 32).

Discovered initial in-place gas volumes for the immature plays are listed in Table 38. As mentioned previously, immature plays are those in which the geology can be characterized, but the sample of the pool population is inadequate to undertake statistical evaluation with the discovery process model. Three immature plays were identified and characterized geologically (Table 3). Several other Devonian pools, or groups of pools, did not fall into any of the 28 plays (or natural geological populations) as defined in this study (an example of this is the Northern Alberta Wabamun [Wolverine] group of pools). These 'anomalous' isolated pools and pool groups must be accounted for in the discovered gas volumes, and therefore are amalgamated into an 'others' category (Table 38). The impact of this category and the three geologically defined immature plays on undiscovered potential is accounted for in the estimate of conceptual play potential, discussed in the following section.

CONCEPTUAL PLAY ANALYSIS

Estimation of conceptual play potential

Conceptual plays are defined as those plays that do not yet have discoveries or reserves, but which geological

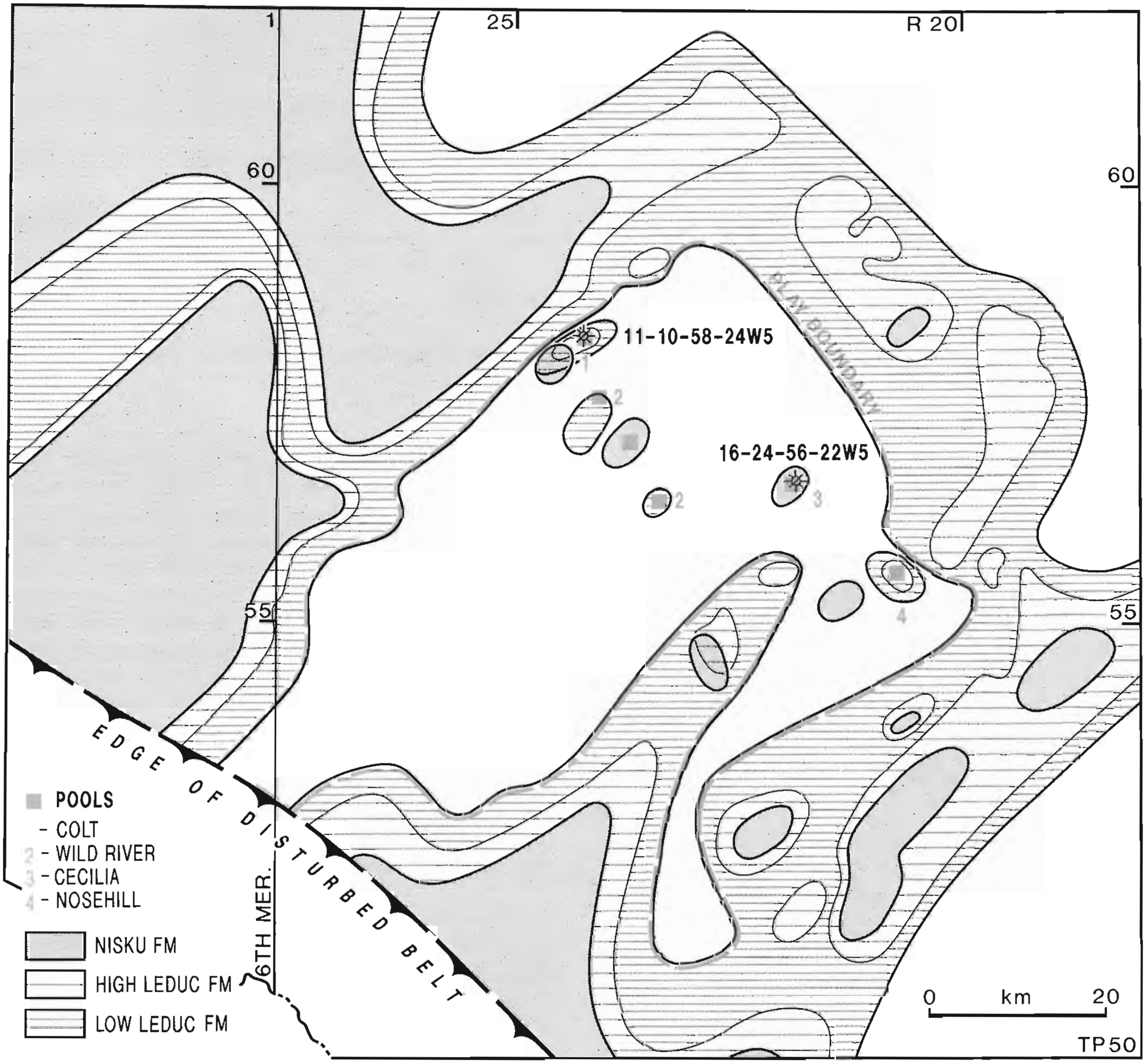


Figure 75. Map of the immature Wild River Basin play. Play boundary is illustrated relative to the surrounding Leduc/Nisku reef complexes (Windfall) play. (See Fig. 76 for well logs.)

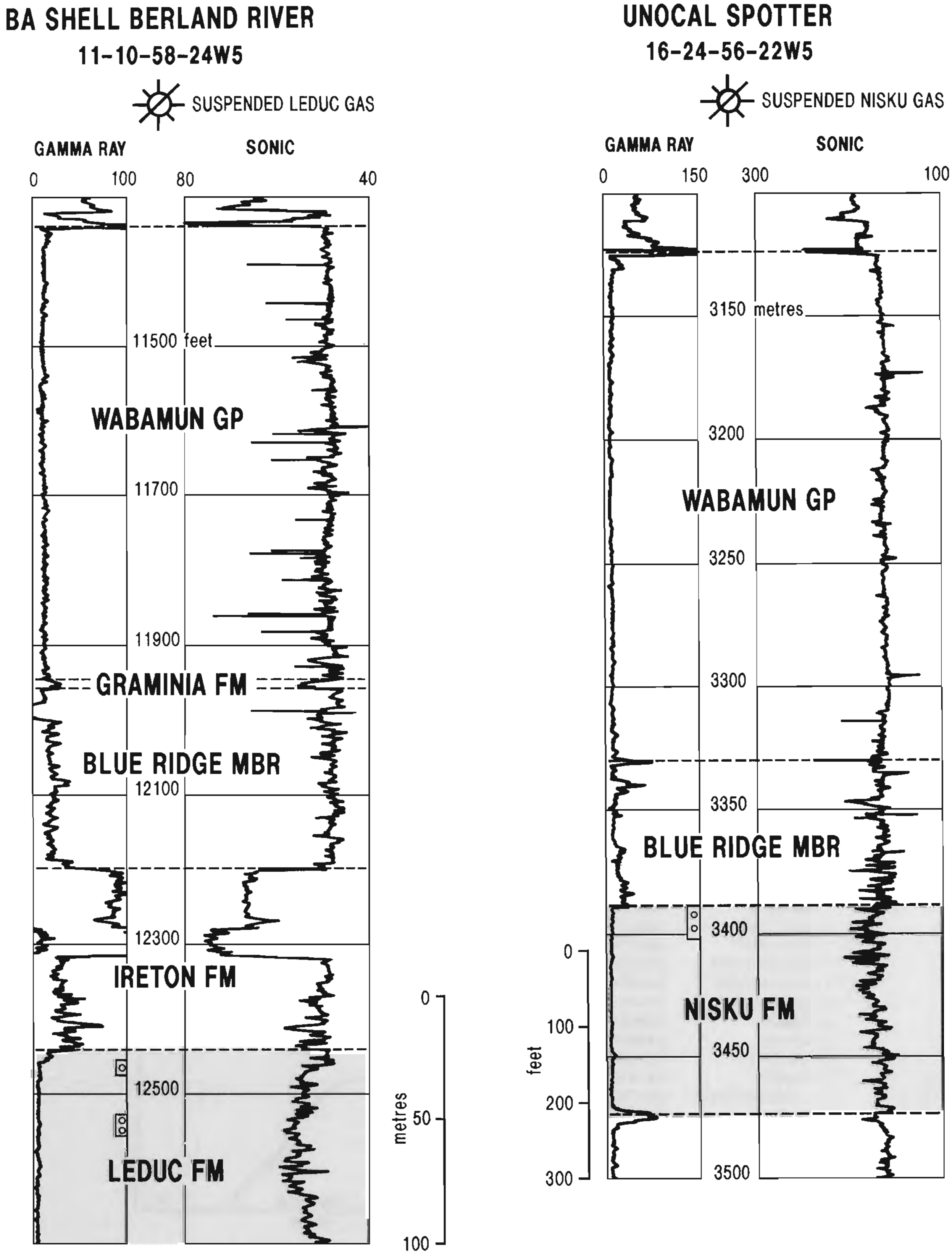


Figure 76. Illustrative well logs of the Leduc and Nisku gas wells, Wild River Basin play. (Well locations are shown in Fig. 75.)

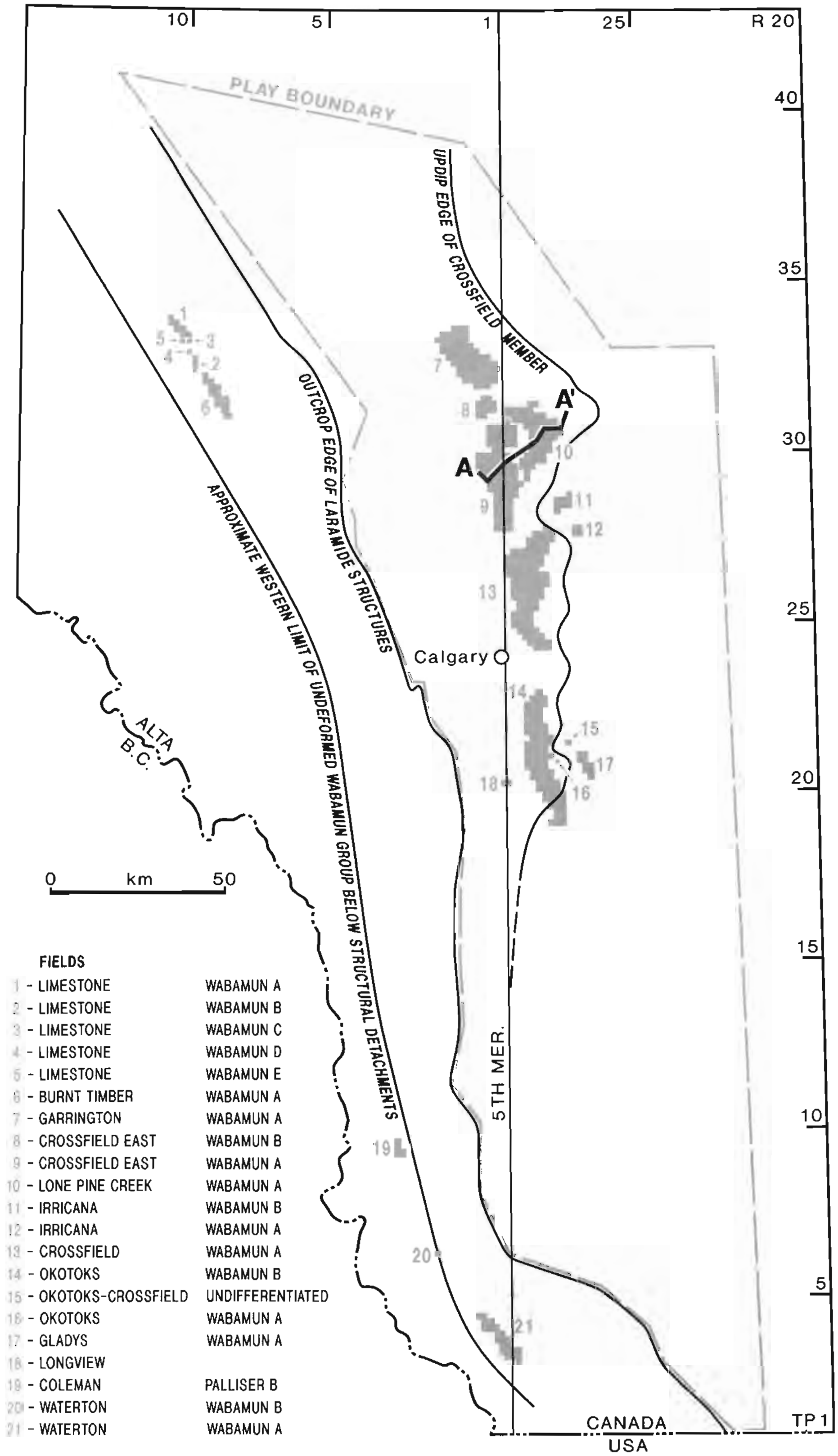


Figure 77. Map of the Wabamun platform facies (Crossfield) play. (See Fig. 78 for cross-section A–A'.)

analysis indicates may exist. Estimates of the potential and size of conceptual plays were achieved by the discovery process model using the 25 mature plays as the 'pool' database. A discovery sequence of the 25 mature plays from 1946 to 1979 was generated (Fig. 6), each play size representing the sum of the discovered in-place volume and expected potential (Table 39, Appendix I). The discovery date of each mature play is taken as the date when the first pool in that play was discovered. A play size-by-rank plot was then generated in a similar manner as the pool size-by-rank plots for the mature plays (Fig. 83). The rectangular bars in Figure 83 indicate plays that remain to be discovered, and the mean of all the undiscovered plays, when totalled, is an estimate of the conceptual play potential. The analysis suggests that there are a total of 100 Devonian gas plays in the Western Canada Sedimentary Basin; however, this estimate is difficult to accept given that it suggests that there are three times as many plays remaining to be discovered as have been discovered to date. When the discovery process model is used on a play basis, it is probably appropriate to apply a lower-end truncation to the generated play size-by-rank curve, since many of the very small plays will never be identified. A realistic estimate of play numbers and conceptual play potential is achieved when the play-size distribution is truncated at 30 000 x $10^6 m^3$ (Fig. 83), which corresponds to the largest 40 plays (this cut-off is approximately at 1 TCF). Of the 40 Devonian gas plays exceeding 30 000 x $10^6 m^3$, 17 are established, mature plays and three may be the immature plays that were geologically defined, but not statistically evaluated. The immature plays have to be considered conceptual since none were represented in the 'natural play-size population' used to generate the play size-by-rank plot (Fig. 83). Thus, it is estimated there are still 20 plays, exceeding 30 000 x $10^6 m^3$ in size, remaining to be discovered. Three of these conceptual plays are extremely large, in the order of 90 000 to 225 000 x $10^6 m^3$ (3-8 TCF). The number of undiscovered conceptual plays exceeding 30 000 x $10^6 m^3$ is not unrealistic given that these are not single pools but rather single plays comprising several pools. The sum of the mean volume of the 23 undiscovered conceptual plays, along with the volume for the entire nontruncated play population, is given in Table 40.

Geological analysis of conceptual plays

The credibility of the conceptual potential estimates (Table 40) depends to some degree on whether it can be demonstrated geologically that enough new plays actually exist to contain such additional gas volumes. Assuming that the conceptual potential is realistic, in what types of plays could one expect to find all of the conceptual gas? This is not a rhetorical question since conceptual plays by definition have to be 'new' plays. The last new Devonian play discovered was in 1979, the Nisku isolated reef (Brazeau River) play. The Caroline gas pool, discovered in 1986, is not a new play, but rather an extension of the Swan Hills shelf margin (Kaybob South) play. Thus, over the past decade, so-called 'new' plays have been relatively difficult to discover.

Conceptually, however, geological analysis based on stratigraphic models and comparison with established mature plays suggest that there are several possibilities for the existence of new plays containing significant undiscovered resources. These conceptual play possibilities are grouped into three types: i) carbonate facies belts based on the cyclicity and distribution of established mature plays, ii) deeply buried lowstand clastic deposits, and iii) structurally controlled drape or subcrop plays.

Cyclical carbonate facies belts

Possibly the best method to use for finding new plays is to compare type and distribution of established mature plays with the cyclical reef-platform model of Wilson (1975) (Fig. 84). As discussed above, the Devonian succession in Western Canada is composed of several carbonate depositional cycles, with each cycle more or less adhering to the carbonate facies belt model containing shelf, shelf margin and basinal-offshore environments (Fig. 84). Typical platform facies occur on the shelf's fringing and barrier reefs at the shelf margin, and isolated reef-bank buildups in the basin. The established mature plays are grouped into platform, shelf margin and isolated buildup play types; the absence of a facies-belt type within a specific cycle of established plays suggests the possibility of a conceptual play to fill that void (Fig. 84).

In the Upper Elk Point cycle, the isolated reef and platform plays have been delineated by the Keg River–Yoyo and Keg River–July Lake plays, respectively. However, the shelf margin reef play in the Upper Elk Point cycle remains to be clearly delineated, and potential for such fringing reef plays could exist at the Upper Winnipegosis platform margin, and in similar marginal positions in the Shekilie, Rainbow, Zama and as yet undelineated basins of this type. The Keg River barrier reef in northwest Alberta–northeast British Columbia forms a continuous reservoir with overlying Sulphur Point/Slave Point carbonates, and is therefore grouped in the Slave Point barrier reef complex (Clarke Lake) play.

In the Beaverhill Lake cycle, the fringing reef shelf margin plays are well documented by the Clarke Lake and Kaybob South types (Fig. 84), and isolated Swan Hills buildups are prolific hydrocarbon reservoirs in

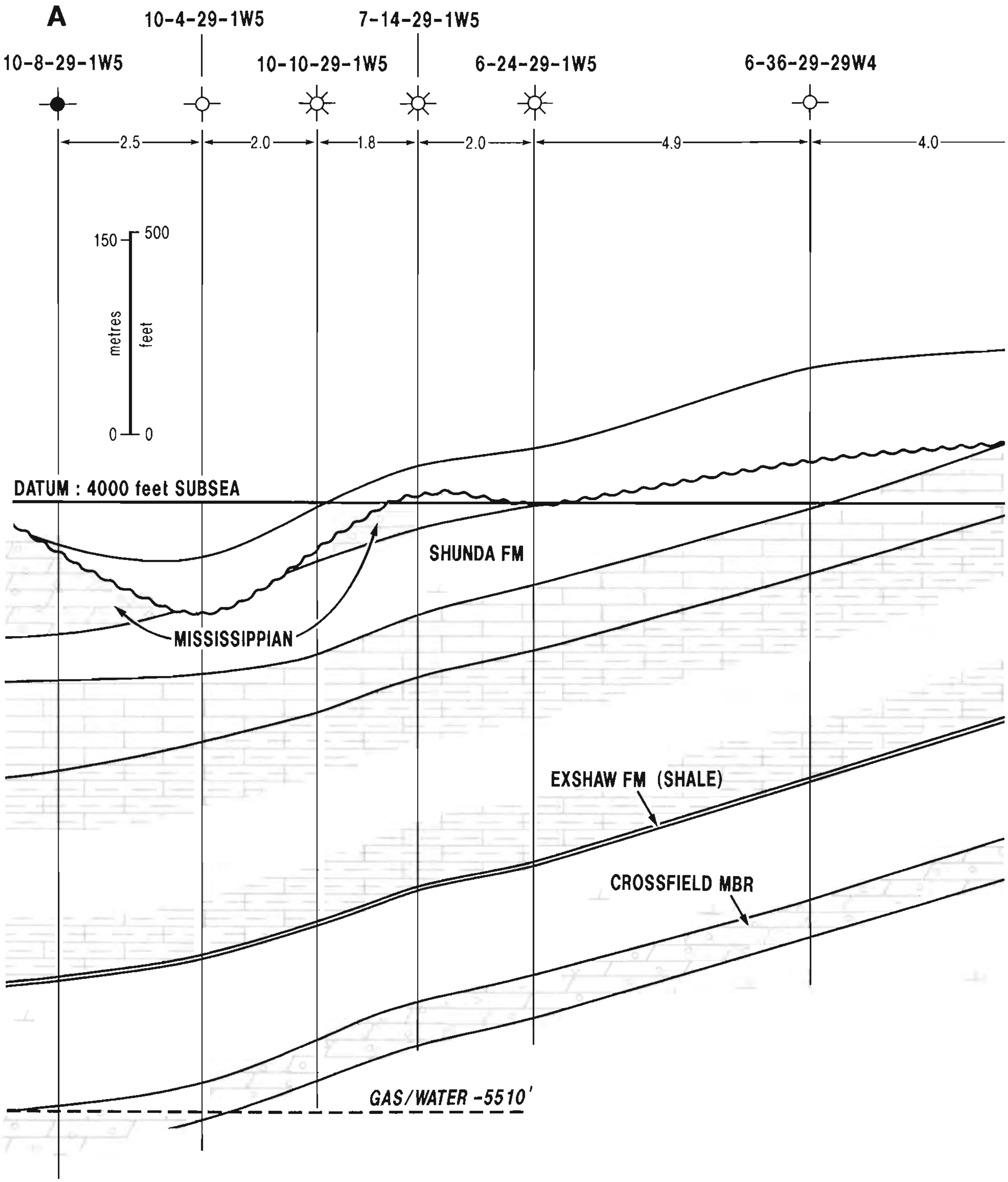


Figure 78. Cross-section A–A′ illustrating relation of Wabamun units and overlying Mississippian formations. (Cross-section location is shown in Fig. 77.)

central Alberta. Isolated reefs equivalent to the Clarke Lake shelf margin - Adsett platform cycles have not yet been delineated in the northern district. Similarly, the Beaverhill Lake platform play remains an unproven exploration concept in west-central and southern Alberta.

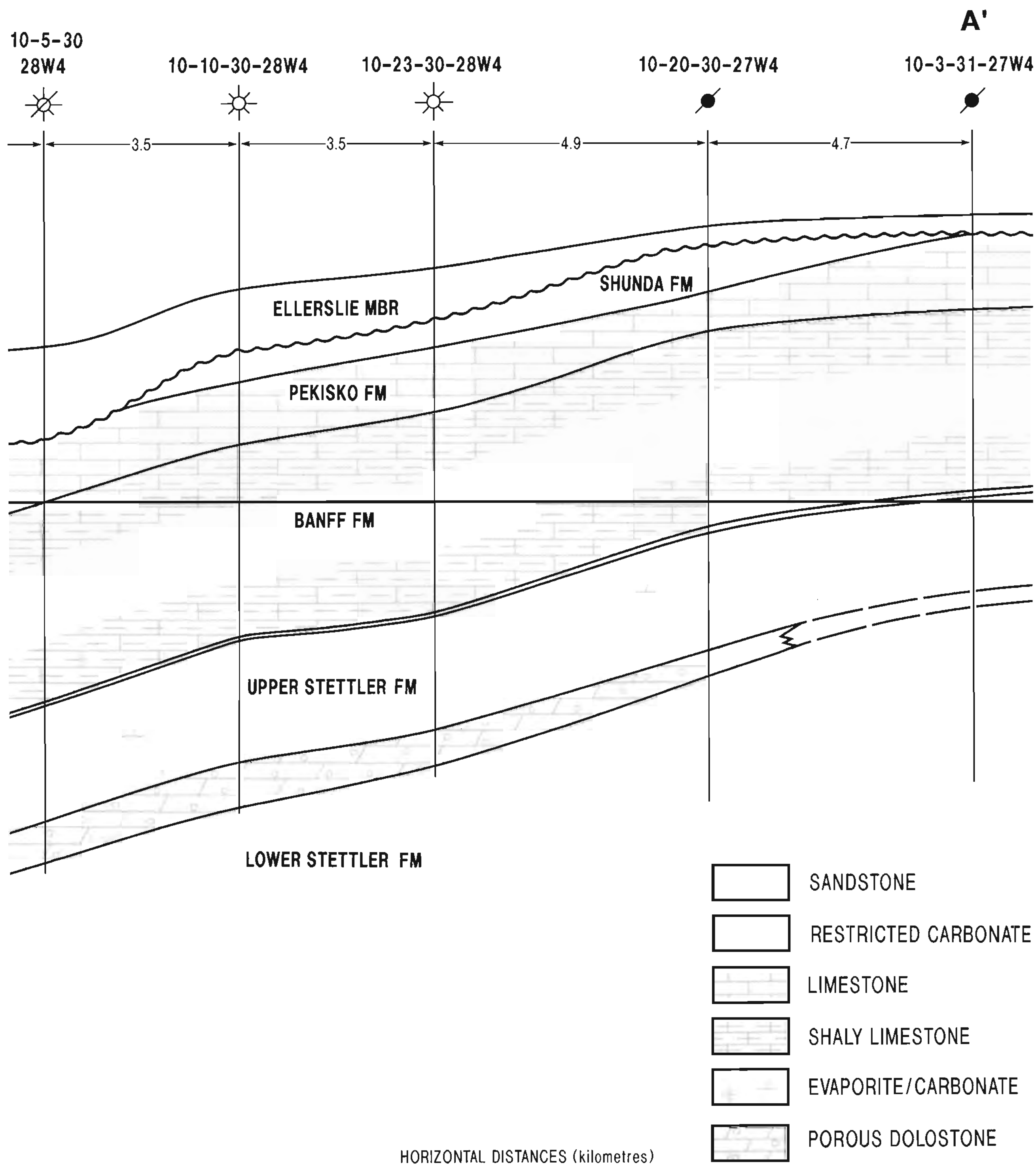


Figure 78. (cont'd)

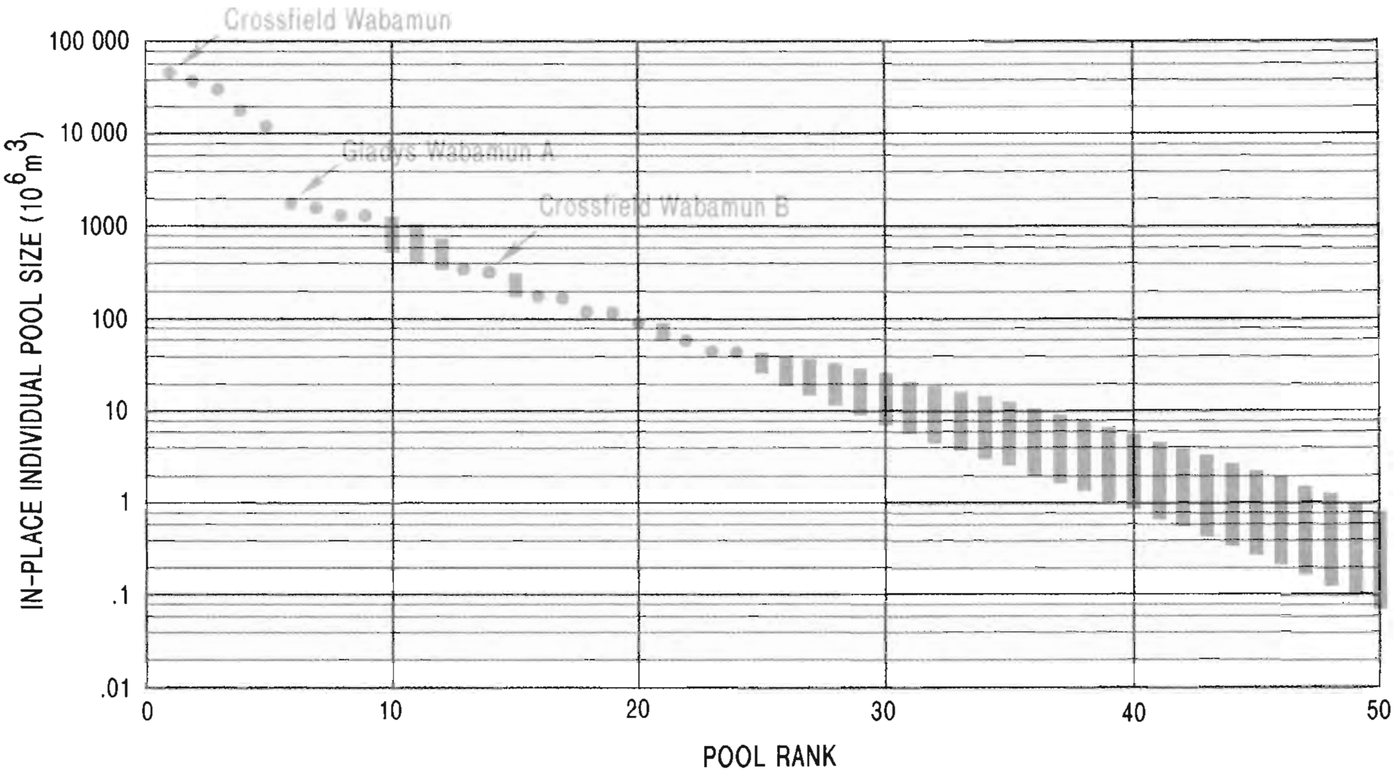


Figure 79. Pool size-by-rank plot for the Wabamun platform facies (Crossfield) play. The 20 largest discovered pools are shown in Table 30.

With respect to the Woodbend (D-3) cycle, platform margin and isolated reef buildup plays are well documented; however, the Woodbend platform play, with associated patch reefs, is yet to be discovered, most likely in the region of southern Alberta (Fig. 84).

All of the facies belt systems have been delineated in the Winterburn cycle plays, but in the Wabamun cycle, shelf-marginal and isolated-basinal reefs are yet to be discovered. This may be significant, particularly in southern Alberta, where the Stettler/Palliser facies transition is buried deep within the autochthonous Interior Platform succession below the Foothills. Adjacent to the Foothills, thick anhydrite sequences, inferred as having been deposited subtidally, characterize the lower Stettler succession (Andrichuk, 1960). Hence, the presence of a Stettler fringing reef complex between open-marine lower Palliser facies of the Foothills gas fields and evaporitic lower Stettler facies to the east, is entirely feasible.

Deeply buried lowstand clastic deposits

The second group of conceptual plays is termed "lowstand clastic deposits", and refers to the thick sandstone–conglomerate successions in the Upper Elk Point Group. These deposits are thought to extend from the Peace River Arch southward along the margin of the West Alberta Ridge (Grayston et al., 1964), but their lateral distribution is poorly understood. The possibility exists that thick shoreline sandstones are present adjacent and parallel to, and/or reservoir grade valley-fill deposits are situated perpendicular to, the West Alberta Ridge. Hydrocarbon accumulations may occur at the updip margins of these discrete sandstone units where they interfinger with evaporites of the Prairie Evaporite–Muskeg formations.

Structurally controlled drape and subcrop plays

This group of plays includes structural closure caused by draping due to differential compaction and/or salt dissolution/collapse, and subcrop erosional terminations of major stratigraphic–depositional units. The immature Arcs structural (Princess) play is viewed as a structural drape type caused by salt dissolution (Figs. 80, 81). There likely are several plays, analogous to the Arcs play, also occurring in platform phases of other Devonian depositional cycles. Additional subcrop plays could include those of the Beaverhill Lake cycle; furthermore, subcrop edges of subcycles within the Upper Elk Point, Woodbend and Winterburn cycles are also a distinct possibility. In particular, paleotopographic 'highs' adjacent to subcrop erosional edges provide a scenario for the occurrence of new plays, though individual pools of such plays may be relatively small.

Structural effects can play a significant role in controlling the dolomitization process and resultant formation of porous reservoirs. Examples are evident in several of the mature plays that were described earlier. However, diagenetic processes such as dolomitization are not viewed as a major control on the occurrence of conceptual play types, since such processes are seen to be active in immature and mature plays also.

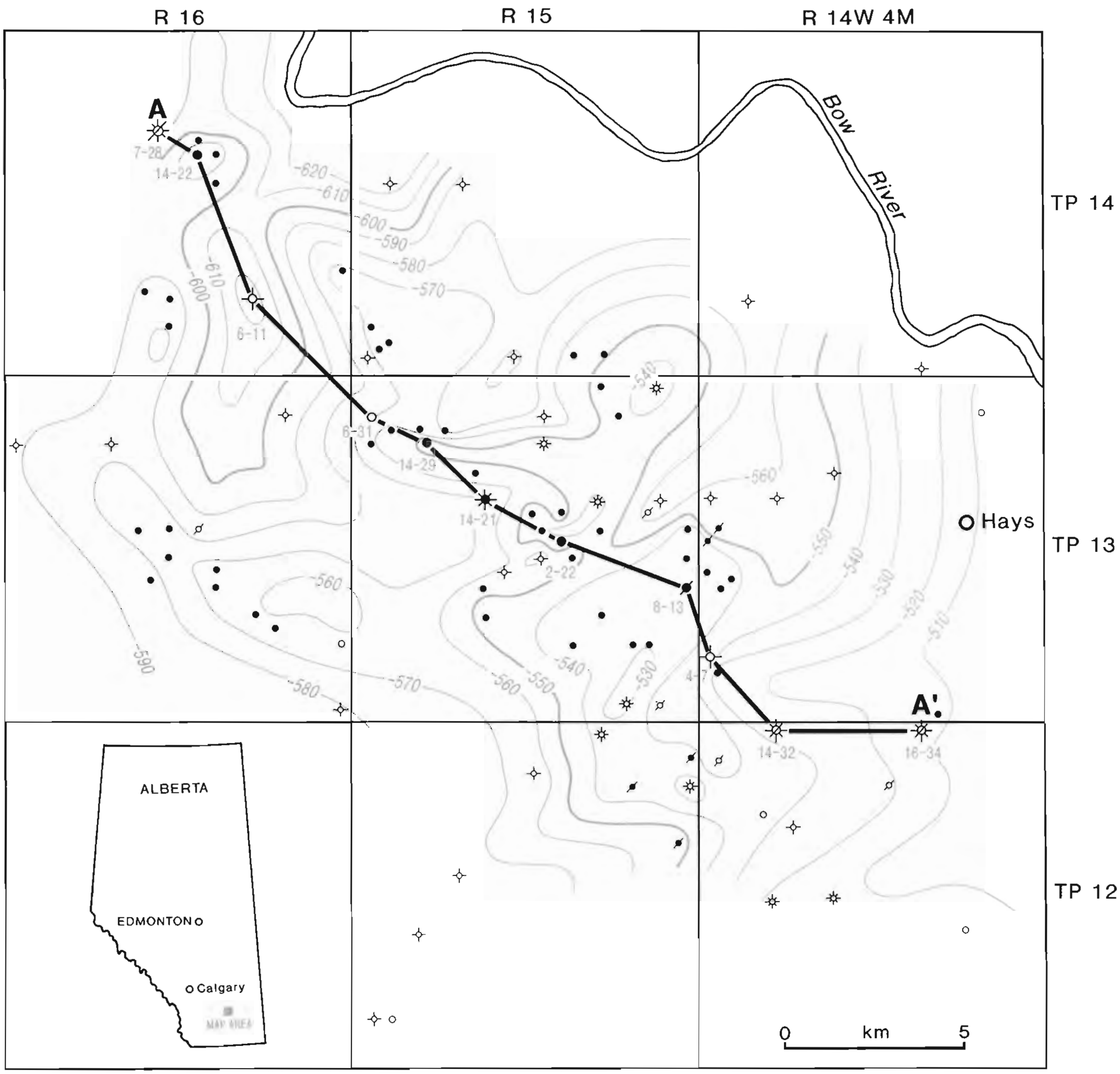


Figure 80. Structure contour map, top of Arcs Member (Nisku equivalent), Enchant–Hays area, Southern Alberta. Contour interval is 10 m. (See Fig. 81 for cross-section A–A'.)

DISCUSSION AND CONCLUSIONS

This report deals with assessment of natural gas potential of both established and conceptual plays in Devonian strata of the Western Canada Sedimentary Basin. Numerical assessment of these major play categories is undertaken with the discovery process model, which utilizes the size and discovery sequence of individual pools (plays) within a natural geological population of pools (plays). Established plays required geological analysis to delineate the type and extent of the pool population for each play, whereas the conceptual play analysis utilized the numerical results from the 25 mature plays with no prior geological evaluation. This difference should be remembered when comparing the potential gas volumes for mature and conceptual plays (Table 40).

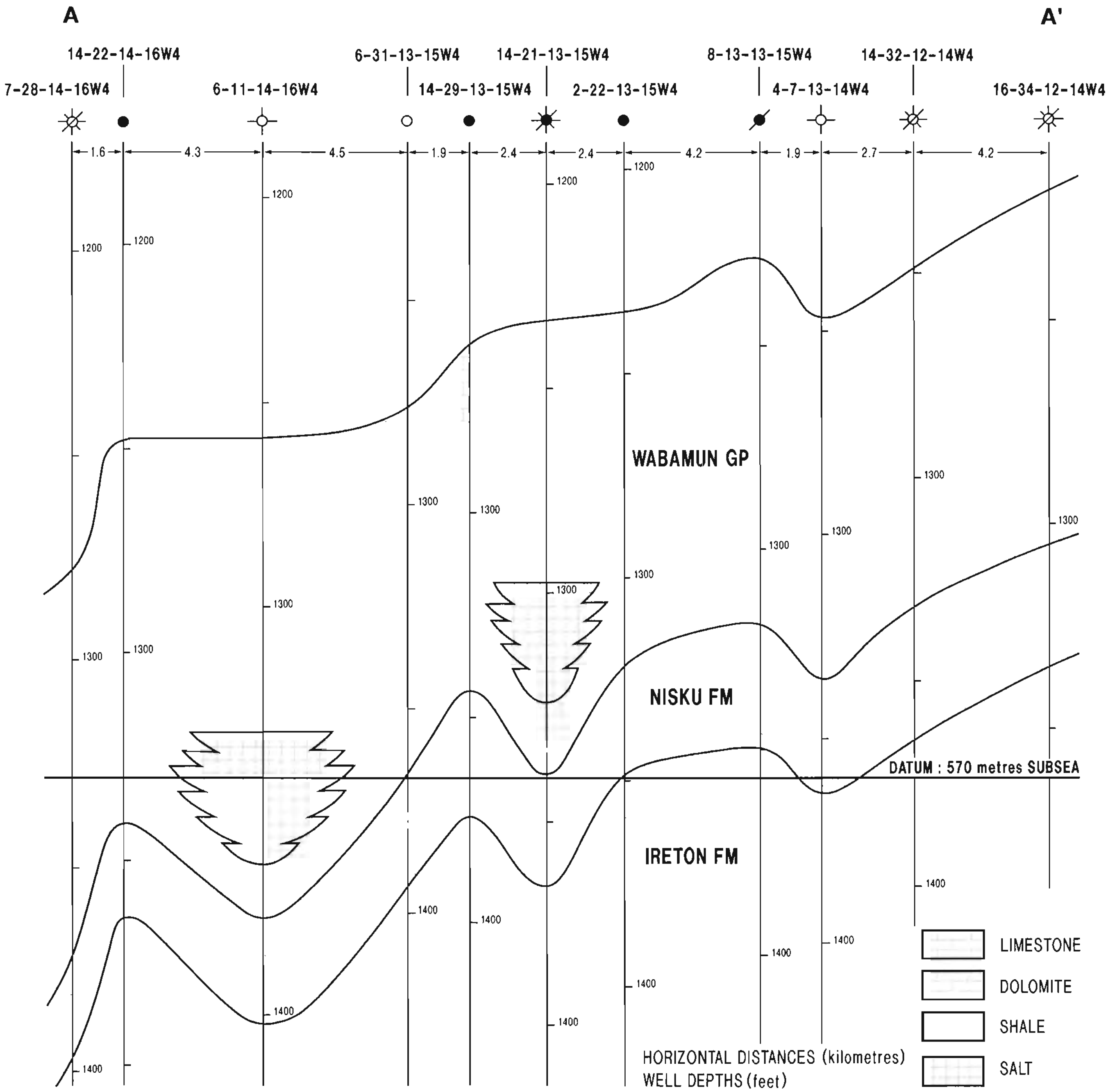


Figure 81. Cross-section A–A' illustrating structural control on the occurrence of hydrocarbons in the Arcs Member. (Cross-section location is shown in Fig. 80.)

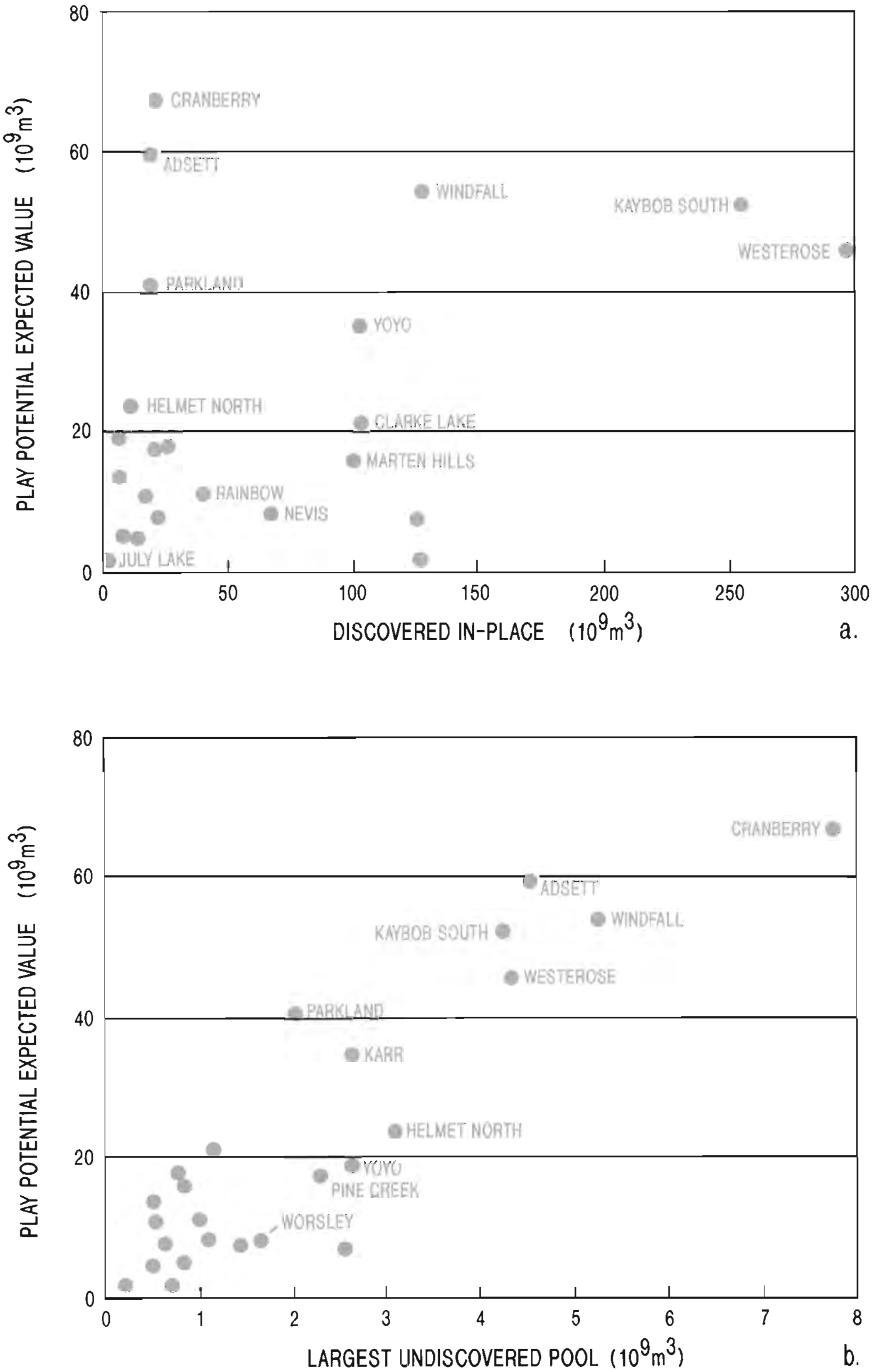


***Figure 82.** Graphs showing relation of expected play potential to discovered in-place volume (a), and to largest undiscovered pool (b). Names refer to characteristic pools used to designate each play.*

The significance of conceptual gas resources has been discussed, in general terms, as to where this undiscovered potential is likely to occur geologically, and more specifically, as to what types of plays these conceptual resources might occur in relative to existing mature play models. However, the geographic locations of conceptual gas resources are still very speculative compared to mature plays. This is because the occurrence and distribution of undiscovered gas potential in mature plays is confined (by the geologically derived play boundary) to a specific type of reservoir within a constrained area. Conceptual plays are not so constrained.

Three other points, which cannot be overemphasized, are important in the correct interpretation of the gas volumes reported in this study. These are as follows:

1. This report deals only with Devonian gas resources in the Western Canada Sedimentary Basin south of 61° latitude and east of the deformed belt. Major structural plays in the Foothills and Front Ranges are not considered here.

2. Estimates of mature play potential are given at two levels, expected and probable (Table 32). The expected values are thought to be conservative and more realistic than the probable values, because they are constrained by the discovered pool sizes and geological play delineations. Estimates of conceptual play potential were calculated only at the expected level.

3. The gas volume for conceptual plays is a total statistical estimate of the gas present 'in the ground', not the gas volume that is economically exploitable. The sizes of individual pools in specific conceptual plays will determine whether certain of these plays will ever be explored for. Many of the smaller conceptual plays (Fig. 83) will never be identified; thus the estimated total conceptual play resource is derived from the 40 largest plays (Table 40).

The total expected potential for the 25 mature plays is 564 478 x $10^6 m^3$ (20 TCF) (Tables 32, 40). This number compares with a discovered in-place volume of 1 568 606 x $10^6 m^3$ (56 TCF). The total expected potential is not an overly optimistic number, and suggests that only 26 per cent of the total gas resource in mature plays remains to be discovered. Furthermore, no undiscovered pools, 1 TCF (28 317 x $10^6 m^3$) in size or larger were predicted to be present in any of

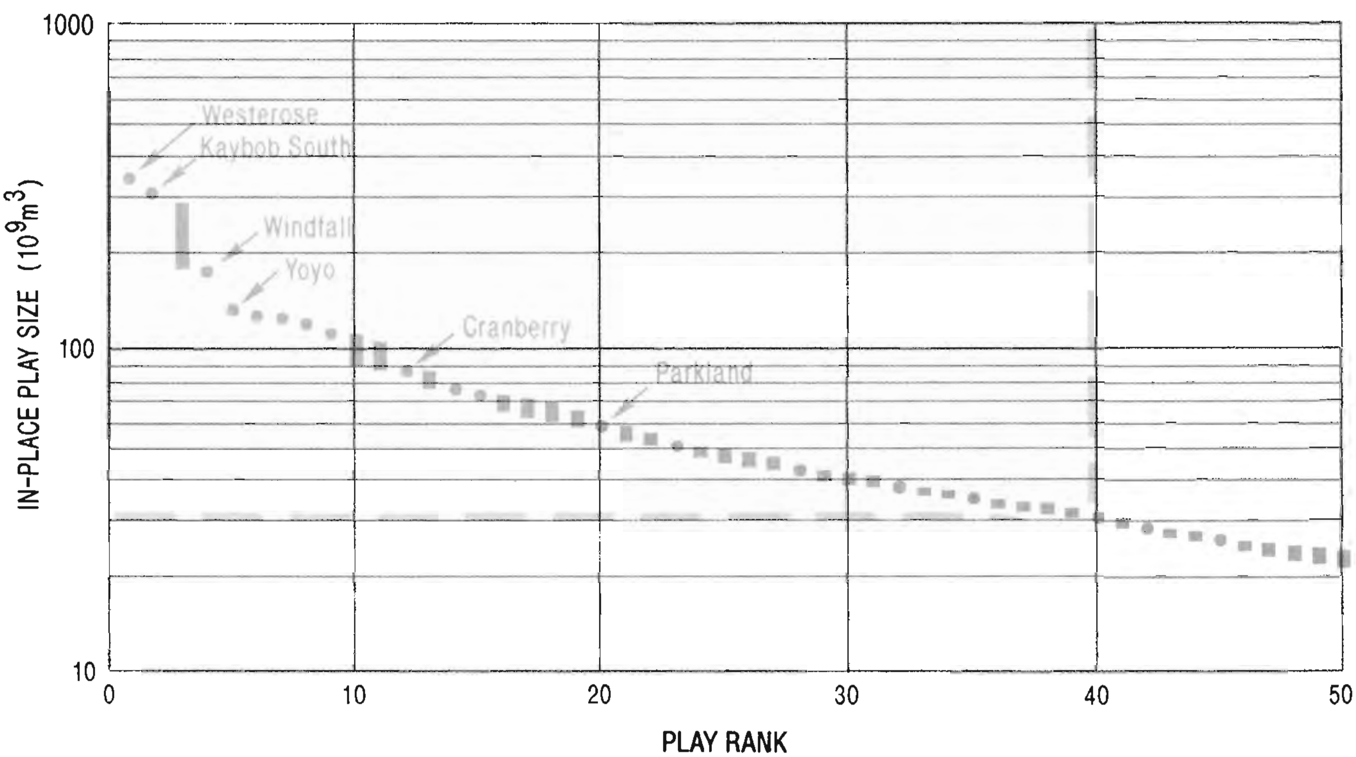


Figure 83. *Play size-by-rank plot for the conceptual play analysis. The largest 40 plays are highlighted by the dashed line. (See Table 39 for play resource data.)*

the 25 mature plays. Conversely, 17 undiscovered pools with in-place gas volumes of 100 BCF (3 000 x $10^6 m^3$) or larger, are predicted to be present in the 25 mature plays. This suggests substantial upside potential in several of the mature plays, and makes continued exploration attractive.

The estimated potential for conceptual plays is 1 394 900 x $10^6 m^3$ (50 TCF) (Table 40). This estimate includes the volumetric sum of 23 conceptual plays out of the largest 40 Devonian plays (Fig. 83). This volume of 1 394 900 x $10^6 m^3$ compares with the discovered volume of 1 568 606 x $10^6 m^3$. When compared to conceptual plays, mature plays have a much lower overall potential.

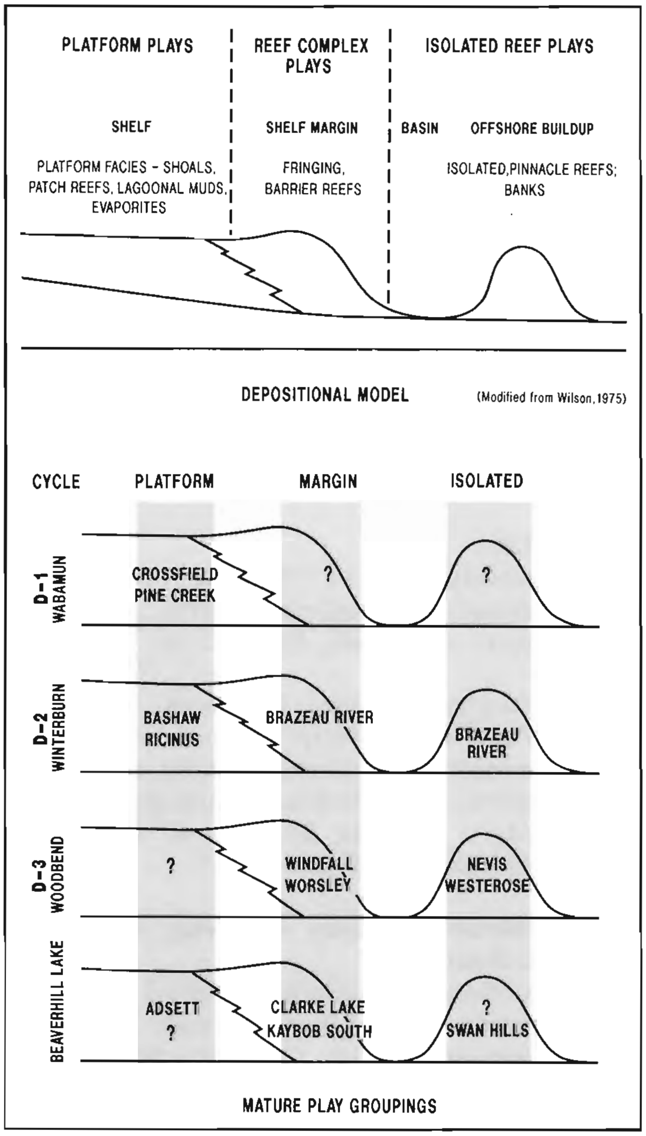


Figure 84. Generalized schematic diagram illustrating cyclicity of carbonate depositional model through Middle to Upper Devonian in Western Canada. Characteristic pool names are used to designate play types. Question marks suggest specific play types that have not yet been discovered.

The total Devonian gas resource in the Western Canada Sedimentary Basin is estimated at 3 528 000 x $10^6 m^3$ (126 TCF). Fifty-six per cent of the Devonian gas resource remains to be discovered (Fig. 85); 40 per cent is contained in conceptual plays and only 16 per cent in mature plays. It is stressed here that 56 per cent is a statistically estimated value of in-place gas resources; only a small part of this percentage will ever be classified as bonafide reserves.

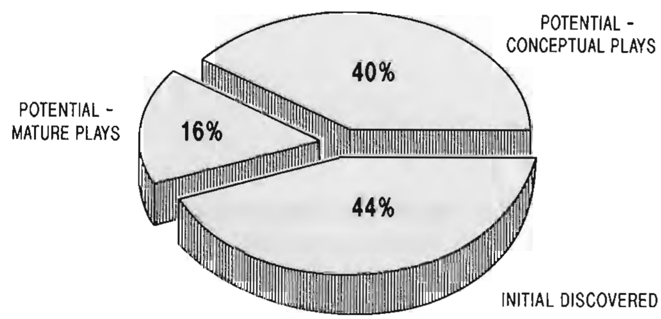


Figure 85. Pie diagram illustrating relation between discovered resources, mature play potential, and conceptual play potential (derived from data in Table 40).

In summary, four principal conclusions can be drawn from this report:

1. The geological analysis and statistical assessment of Devonian gas resources in the Western Canada Sedimentary Basin suggest that over one half (56%) of the total gas resource remains to be discovered.

2. Of this undiscovered Devonian gas potential, only 28 per cent is considered to be present in established mature plays. This is not an overly optimistic estimate for mature plays; nonetheless some 17 undiscovered pools, larger than 3 000 x $10^6 m^3$ are predicted to be present in mature plays.

3. Several established mature plays show a high upside potential. The most attractive plays with the highest potential are: i) Slave Point reef complexes situated north of the Peace River Arch and characterized by the Cranberry gas field; ii) Leduc/Nisku reef

complexes such as Windfall, in the 'Deep Basin' region of west-central Alberta; iii) the Swan Hills shelf margin play of western Alberta, which is typified by the Kaybob South and Caroline fields; and iv) the Slave Point platform play of northeast British Columbia, in which Adsett Field is the primary example.

4. Seventy-two per cent of the total Devonian gas potential is predicted to occur in conceptual plays. This is an extremely large value compared to established mature play potential, and thus should be taken for what it is - a statistical estimate of what is present in the ground, not what is economically exploitable. Furthermore, the sizes of individual pools in specific conceptual plays will ultimately determine whether any of these plays will ever be explored for and exploited to any degree.

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APPENDIX I: Tables 1 to 40

TABLE 1

Relations between the number of pools (N), mean, and log-likelihood values

N	Mean	Log-likelihood
100	2 462	-260.241
200	1 131	-258.791
300	785	-258.510
400	539	-258.259
500	434	-258.142
600	362	-258.079
700	285	-257.985
800	250	-257.985
900	223	-257.853

TABLE 2

Relation between major Devonian sequences and established lithostratigraphy in the Western Canada Sedimentary Basin

Devonian stage	Discontinuity-bounded sequences (from Moore, 1989)	Lithostratigraphic nomenclature (Podruski et al., 1988)	Depositional cycle (this paper)
Famennian	Palliser	Wabamun	C_7
Late Givetian to early Frasnian	Saskatchewan–Beaverhill Lake	Winterburn Woodbend Beaverhill Lake	C_6 C_5 C_4
Eifelian to early Givetian	Hume–Dawson	Upper Elk Point	C_3
Emsian to early Eifelian	Bear Rock	Lower Elk Point (Ernestina Lake, Cold Lake)	C_2
Lochkovian to Pragian	Delorme	Lower Elk Point (Lotsberg)	C_1

TABLE 3

MATURE DEVONIAN PLAYS		IMMATURE DEVONIAN PLAYS
NORTHERN DISTRICT AND PEACE RIVER ARCH Middle Devonian clastics Keg River shelf basin – Rainbow Keg River shelf basin – Zama Keg River shelf basin – Shekilie Keg River isolated reef – Yoyo Keg River platform – July Lake Slave Point barrier reef – Clarke Lake Slave Point platform – Adsett Jean Marie biostrome – Helmet North Slave Point reef complexes – Cranberry Leduc fringing reef – Worsley Wabamun structural and stratigraphic – Parkland **SOUTHERN DISTRICT** Wabamun platform facies – Crossfield	**CENTRAL DISTRICT AND DEEP BASIN** Swan Hills shelf margin – Kaybob South Swan Hills isolated reef – Swan Hills Leduc/Nisku reef complexes – Windfall Leduc isolated reef – Westerose Leduc reef – Nevis Nisku shelf margin – Brazeau River Nisku isolated reef – Brazeau River Nisku shelf drape – Bashaw trend Nisku shelf drape – Ricinus-Meadowbrook trend Blue Ridge stratigraphic – Karr Upper Devonian subcrop – Marten Hills Wabamun platform facies – Pine Creek	**NORTHERN DISTRICT AND PEACE RIVER ARCH** Sulphur Point platform facies – Bistcho **CENTRAL DISTRICT AND DEEP BASIN** Leduc/Nisku isolated reef complexes – Wild River Basin **SOUTHERN DISTRICT** Arcs structural – Princess

TABLE 4

Middle Devonian clastics

Rank	Field/Pool	Pool type	In-place volume ($10^6 m^3$)	Discovery date
1	Mitsue, Gilwood A	A&S	13 090	1968
2	Nipisi, Gilwood A	A&S	7 534	1964
3	Utikuma Lake, Keg River Sand A	S	1 105	1963
5	Cranberry, Gilwood Undefined	NA	618	1975
6	Worsley, Granite Wash A	NA	540	1975
24	Utikuma Lake, Keg River Sand N	S	216	1976
26	Bison Lake, Gilwood Undefined	NA	200	1959
27	Cornwall, Gilwood Undefined	NA	194	1983
36	Chinchaga, Gilwood Undefined	NA	154	1982
37	Nipisi, Keg River Sand A	S	153	1980
38	Puskwaskau, Granite Wash Undefined	NA	149	1980
43	Utikuma Lake, Keg River Sand U	S	136	1980
44	Cranberry, Gilwood Undefined	NA	133	1977
50	Botha, Gilwood Undefined	NA	120	1981
51	Rosevear, Gilwood Undefined	NA	117	1975
53	Nipisi, Keg River Sand E	S	113	1979
62	Utikuma Lake, Keg River M	S	99	1976
73	Strike Area, Gilwood Undefined	NA	84	1970
78	Puskwaskau, Granite Wash Undefined	NA	79	1955
82	Puskwaskau, Granite Wash Undefined	NA	75	1983
Initial in-place volume (discovered)			25 665	
Initial in-place volume (potential)			18 204	
Per cent play resources undiscovered			42	
Total pool population			450	
Total pools discovered			44	

TABLE 5

Keg River shelf basin - Rainbow

Rank	Field/Pool	Pool type	In-place volume ($10^6 m^3$)	Discovery date
1	Rainbow, Keg River F	A&S	5 775	1966
2	Rainbow, Keg River A	A&S	4 582	1965
3	Rainbow, Keg River B	A&S	3 403	1965
4	Rainbow, Keg River AA	A&S	2 071	1967
5	Rainbow, Keg River O	A&S	1 625	1966
6	Rainbow South, Keg River A	A&S	1 435	1965
7	Rainbow South, Keg River B	A&S	1 206	1966
8	Rainbow South, Keg River E	S	1 137	1966
10	Rainbow, Keg River I	A&S	891	1966
11	Rainbow, Keg River E	A&S	833	1966
15	Rainbow, Keg River FFF	NA	626	1966
16	Rainbow, Keg River II	S	586	1967
17	Rainbow, Keg River Q	NA	565	1966
19	Rainbow South, Keg River G	S	509	1974
20	Rainbow, Keg River G	A&S	468	1966
21	Rainbow, Keg River EEE	A&S	457	1968
22	Rainbow, Slave Point A	NA	425	1966
23	Rainbow, Sulphur Point Q	NA	400	1983
24	Rainbow South, Keg River C	A&S	387	1967
25	Rainbow, Muskeg O	S	358	1982
Initial in-place volume (discovered)			40 704	
Initial in-place volume (potential)			11 436	
Per cent play resources undiscovered			22	
Total pool population			460	
Total pools discovered			203	

TABLE 6

Keg River shelf basin – Zama

Rank	Field/Pool	Pool type	In-place volume ($10^6 m^3$)	Discovery date
1	Zama, Sulphur Point I	NA	628	1968
3	Zama, Sulphur Point H	NA	490	1966
7	Virgo, Keg River undefined	NA	294	1968
14	Amber, Sulphur Point undefined	NA	203	1983
15	Zama, Slave Point H	NA	196	1967
16	Zama, Sulphur Point P	NA	193	1968
17	Zama, Sulphur Point undefined	NA	185	1967
21	Amber, Keg River T	A	162	1984
23	Zama, Keg River undefined	NA	157	1983
29	Amber, Keg River undefined	NA	137	1982
30	Amber, Muskeg undefined	NA	135	1982
33	Zama, Muskeg undefined	NA	129	1981
37	Zama, Slave Point A	NA	121	1967
42	Virgo, Keg River undefined	NA	113	1983
43	Amber, Keg River P	A&S	112	1982
44	Virgo, Keg River F	A&S	110	1968
45	Zama, Slave Point K	NA	109	1967
46	Zama, Keg River ZZ	A&S	109	1967
47	Zama, Slave Point undefined	NA	108	1981
55	Virgo, Keg River QQQ	A&S	96	1969
Initial in-place volume (discovered)			17 544	
Initial in-place volume (potential)			11 132	
Per cent play resource undiscovered			38	
Total pool population			900	
Total pools discovered			582	

TABLE 7

Keg River shelf basin – Shekilie

Rank	Field/Pool	Pool type	In-place volume ($10^6 m^3$)	Discovery date
1	Shekilie, Keg River undefined	NA	944	1983
3	Shekilie, Sulphur Point undefined	NA	419	1969
8	Amigo, Keg River undefined	NA	270	1970
9	Amigo, Keg River undefined	NA	262	1983
11	Amigo, Keg River undefined	A	227	1983
12	Shekilie, Keg River J	A&S	223	1979
17	Strike Area, Slave Point undefined	NA	189	1983
22	Shekilie, Keg River undefined	A	165	1968
25	Shekilie, Keg River undefined	NA	152	1982
30	Amigo, Sulphur Point undefined	NA	137	1970
33	Amigo, Keg River undefined	NA	128	1983
36	Amigo, Keg River undefined	NA	118	1980
37	Shekilie, Keg River undefined	NA	118	1984
39	Shekilie, Sulphur Point undefined	NA	115	1978
42	Shekilie, Keg River TTT	S	110	1987
43	Shekilie, Keg River C	S	108	1971
47	Shekilie, Keg River I	A&S	101	1979
51	Shekilie, Muskeg undefined	NA	95	1969
52	Amigo, Keg River undefined	NA	94	1983
53	Shekilie, Keg River P	S	93	1980
Initial in-place volume (discovered)			7 084	
Initial in-place volume (potential)			13 858	
Per cent play resource undiscovered			65	
Total pool population			450	
Total pools discovered			105	

TABLE 8

Keg River isolated reef - Yoyo

Rank	Field/Pool	Pool type	In-place volume ($10^6 m^3$)	Discovery date
1	Yoyo Pine Point A	NA	49 820	1962
2	Sierra Pine Point A	NA	18 740	1965
3	Sierra Pine Point B	NA	8 809	1966
4	Sierra Pine Point C	NA	3 500	1977
5	Roger Pine Point A	NA	3 425	1975
6	Sierra Pine Point D	NA	2 853	1978
8	Sahtaneh Pine Point B	NA	2 421	1978
11	Sierra Pine Point E	NA	1 641	1979
13	Yoyo Pine Point B	NA	1 282	1978
14	Sierra W Pine Point A	NA	1 238	1979
15	Sahtaneh Pine Point A	NA	1 233	1976
21	Gote Pine Point A	NA	856	1972
22	d-54-A-94-D-09	NA	827	1967
25	d-1-I-94-D-09	NA	727	1979
26	Klua Pine Point A	NA	686	1973
30	b-86-K-94-J-02	NA	600	1977
33	d-18-B-94-J-11	NA	530	1968
36	Klua Pine Point B	NA	468	1978
41	d-50-D-94-J-08	NA	393	1983
42	d-77-H-94-J-08	NA	382	1972
Inital in-place volume (discovered)			102 795	
Initial in-place volume (potential)			35 146	
Per cent play resource undiscovered			25	
Total pool population			300	
Total pools discovered			31	

TABLE 9

Keg River platform - July Lake

Rank	Field/Pool	Pool type	In-place volume ($10^6 m^3$)	Discovery date
1	Helmet North, Pine Point B	NA	546	1979
2	Helmet North, Pine Point A	NA	340	1967
3	Other area, Pine Point	NA	333	1979
4	July Lake, Pine Point D	NA	280	1981
7	July Lake, Pine Point C	NA	165	1980
8	a-44-H-94-P-09	NA	164	1982
11	July Lake, Pine Point A	NA	120	1977
12	d-48-J-94-P-08	NA	109	1968
14	July Lake, Pine Point E	NA	84	1982
15	Other area, Pine Point	NA	81	1982
16	July Lake, Pine Point B	NA	78	1980
17	Other area, Pine Point	NA	76	1988
22	c-9-H-94-P-09	NA	56	1985
46	b-78-F-94-P-15	NA	17	1983
Initial in-place volume (discovered)			2 449	
Initial in-place volume (potential)			2 055	
Per cent play resource undiscovered			46	
Total pool population			80	
Total pools discovered			14	

TABLE 10

Slave Point barrier reef - Clarke Lake

Rank	Field/Pool	Pool type	In-place volume (10^6m^3)	Discovery date
1	Clarke Lake, Slave Point A	NA	62 025	1956
2	Kotcho (pools combined by GSC)	NA	9 022	1958
3	Petitot River, Slave Point A	NA	2 814	1958
4	Klua, Slave Point B	NA	2 310	1970
5	Cabin, Slave Point C, D, E	NA	2 295	1963
6	Yoyo, Slave Point A, C	NA	1 900	1962
7	Cabin, Slave Point A, B	NA	1 635	1963
8	Louise, Slave Point A	NA	1 630	1965
9	Klua, Slave Point C	NA	1 580	1972
10	Mel, Slave Point A	NA	1 453	1989
11	Tsea, Slave Point C	NA	1 365	1978
12	Klua, Slave Point D	NA	1 323	1977
13	Other area, Slave Point	NA	1 272	1986
15	Other area, Slave Point	NA	1 056	1967
16	Tsea, Slave Point B	NA	884	1964
17	Hoffard, Slave Point B	NA	831	1969
18	Other area, Slave Point	NA	813	1963
19	Tsea, Slave Point A	NA	795	1961
20	Sierra, Slave Point A	NA	777	1976
21	Netla (pools combined by GSC)	NA	775	1961
Initial in-place volume (discovered)			103 317	
Initial in-place volume (potential)			21 526	
Per cent play resource undiscovered			17	
Total pool population			425	
Total pools discovered			49	

TABLE 11

Slave Point platform - Adsett

Rank	Field/Pool	Pool type	In-place volume (10^6m^3)	Discovery date
1	Helmet Slave Point A	NA	6 817	1963
5	Adsett Slave Point A	NA	2 322	1971
20	Pesh Slave Point A	NA	800	1982
22	Helmet Slave Point B	NA	748	1971
27	Elleh N Slave Point A	NA	601	1978
28	b-58-L-94-J-07	NA	595	1968
31	d-18-K-94-P-02	NA	551	1967
37	c-4-E-94-I-15	NA	459	1974
41	d-99-H-94-P-08	NA	424	1980
44	Shekilie Slave Point A	NA	395	1965
46	a-16-J-94-I-06	NA	374	1964
51	Sextet Slave Point A	NA	326	1971
52	Ekwan Slave Point A	NA	317	1977
53	c-92-F-94-J-02	NA	314	1985
54	Junior Slave Point A	NA	308	1962
55	d-66-I-94-I-16	NA	305	1980
56	c-20-K-94-J-02	NA	303	1981
57	c-93-G-94-P-08	NA	303	1975
59	Junior Slave Point B	NA	288	1963
64	a-74-G-94-P-08	NA	267	1971
Initial in-place volume (discovered)			19 467	
Initial in-place volume (potential)			59 655	
Per cent play resource undiscovered			75	
Total pool population			450	
Total pools discovered			45	

TABLE 12

Jean Marie biostrome - Helmet North

Rank	Field/Pool	Pool type	In-place volume ($10^6 m^3$)	Discovery date
1	Helmet North, Jean Marie A	NA	6 793	1976
4	Midwinter, Jean Marie A	NA	1 559	1980
6	Peggo, Jean Marie A	NA	1 044	1981
14	Helmet, Jean Marie F	NA	479	1981
16	Other area, Jean Marie	NA	426	1970
27	Pesh, Jean Marie A	NA	245	1982
36	Other area, Jean Marie	NA	178	1959
37	Midwinter, Jean Marie C	NA	173	1979
42	Helmet, Jean Marie D	NA	146	1978
43	Other area, Jean Marie	NA	143	1981
44	Other area, Jean Marie	NA	141	1980
61	Helmet, Jean Marie A	NA	91	1976
78	Helmet, Jean Marie B	NA	63	1976
79	Helmet, Jean Marie E	NA	62	1978
97	Other area, Jean Marie	NA	45	1981
139	Pesh, Jean Marie B	NA	22	1982
153	Midwinter, Jean Marie D	NA	18	1980
203	Other area, Jean Marie	NA	8	1981
Initial in-place volume (discovered)			11 636	
Initial in-place volume (potential)			24 035	
Per cent play resource undiscovered			67	
Total pool population			300	
Total pools discovered			18	

TABLE 13

Slave Point reef complexes - Cranberry

Rank	Field/Pool	Pool type	In-place volume ($10^6 m^3$)	Discovery date
1	Cranberry, Slave Point A	NA	14 260	1974
7	Hamburg, Slave Point A	NA	2 276	1983
12	Chinchaga, Slave Point A	NA	1 389	1973
16	Cranberry, Slave Point B	NA	1 024	1980
45	Rainbow, Slave Point undefined	NA	341	1964
60	Strike area, Slave Point undefined	NA	235	1986
74	Golden, Slave Point A	S	179	1970
76	Black, Slave Point undefined	NA	170	1966
79	Slave, Slave Point H	S	163	1982
90	Strike area, Slave Point undefined	NA	133	1978
94	Slave, Slave Point S	S	125	1985
98	Strike area, Slave Point undefined	NA	117	1985
99	N.W.T. (pools combined by GSC)	NA	115	1968
150	Shekilie, Slave Point undefined	NA	56	1986
153	Shekilie, Slave Point undefined	NA	52	1985
154	Shekilie, Slave Point undefined	NA	52	1980
155	Strike area, Slave Point undefined	A	52	1968
158	Fire, Slave Point A	NA	50	1966
165	Black, Slave Point undefined	NA	46	1966
168	Slave, Slave Point L	S	44	1984
Initial in-place volume (discovered)			21 100	
Initial in-place volume (potential)			67 467	
Per cent play resource undiscovered			76	
Total pool population			450	
Total pools discovered			37	

TABLE 14

Leduc fringing reef - Worsley

Rank	Field/Pool	Pool type	In-place volume ($10^6 m^3$)	Discovery date
1	Worsley, D-3 G	NA	1 803	1969
3	Worsley, D-3 D	NA	1 520	1961
4	Worsley, D-3 B	NA	827	1960
5	Worsley, D-3 E	NA	817	1961
6	Worsley, D-3 A	NA	761	1960
13	Worsley, Leduc undefined	NA	258	1987
14	Worsley, D-3 K	NA	248	1977
18	Worsley, D-3 L	NA	185	1984
23	Dixonville, Leduc undefined	NA	136	1958
24	Worsley, D-3 H	NA	130	1972
27	Worsley, D-3 I	NA	111	1973
28	Dixonville, Leduc undefined	NA	103	1949
50	Normandville, D-3 B	S	43	1959
59	Normandville, D-3 A	S	32	1958
60	Worsley, D-3 F	S	31	1965
64	Worsley, D-3 C	NA	27	1960
142	Worsley, D-3 J	NA	3	1975
Initial in-place volume (discovered)			7 035	
Initial in-place volume (potential)			8 445	
Per cent play resource undiscovered			55	
Total pool population			200	
Total pools discovered			17	

TABLE 15

Wabamun structural and stratigraphic - Parkland

Rank	Field/Pool	Pool type	In-place volume ($10^6 m^3$)	Discovery date
1	Parkland, Wabamun A	NA	6 300	1955
2	Gold Creek, D-1 A	NA	3 600	1963
3	Teepee, Wabamun C	NA	2 465	1971
9	Gold Creek, Wabamun undefined	NA	1 021	1979
12	Manir, Wabamun undefined	A	793	1983
14	Doe, Wabamun A	NA	693	1978
18	Royce, Wabamun undefined	NA	571	1974
20	Gold Creek, Wabamun undefined	NA	511	1979
43	Royce, Wabamun undefined	NA	260	1974
53	Other area, Wabamun	NA	210	1988
56	Belloy, D-1 L	A	201	1988
63	Oak, Wabamun undefined	NA	179	1975
68	Gold Creek, Wabamun undefined	NA	164	1980
73	Tangent, D-1 Z	S	152	1987
75	Culp, D-1 A	A	148	1985
76	Tangent, Wabamun H	S	147	1983
77	Manir, D-1 A	NA	145	1984
83	Parkland, Wabamun B	NA	132	1977
87	Grande Prairie, Wabamun undefined	NA	127	1973
98	Tangent, Wabamun E	S	111	1983
Initial in-place volume (discovered)			19 281	
Initial in-place volume (potential)			40 870	
Per cent play resource undiscovered			68	
Total pool population			900	
Total pools discovered			48	

TABLE 16

Sulphur Point platform facies – Bistcho

Field/Pool	Pool type	In-place volume ($10^6 m^3$)	Discovery date
Strike area, Sulphur Point undefined	NA	42	1971
Strike area, Sulphur Point undefined	NA	75	1971
Strike area, Sulphur Point undefined	NA	30	1966
Bistcho, Sulphur Point A	NA	30	1971
Bistcho, Sulphur Point undefined	NA	6	1972
Bistcho, Sulphur Point undefined	NA	25	1966
Bistcho, Sulphur Point undefined	NA	94	1967
Bistcho, Sulphur Point undefined	NA	20	1966
Gator, Sulphur Point undefined	NA	56	1967
Fire, Sulphur Point A	NA	15	1966
Fire, Sulphur Point undefined	A	2	1987
Fire, Sulphur Point undefined	NA	45	1970
Fire, Sulphur Point undefined	NA	47	1970
Fire, Sulphur Point undefined	NA	73	1968
Fire, Sulphur Point undefined	NA	31	1970
Fire, Sulphur Point undefined	NA	39	1978
Fire, Sulphur Point undefined	NA	46	1970
Fire, Sulphur Point undefined	NA	35	1969
Fire, Sulphur Point undefined	NA	20	1968
Fire, Sulphur Point undefined	A	55	1969
Initial in-place volume (discovered)		1 250	
Initial in-place volume (potential)		–	
Per cent play resource undiscovered		–	
Total pool population		–	
Total pools discovered		–	

TABLE 17

Swan Hills shelf margin – Kaybob South

Rank	Field/Pool	Pool type	In-place volume ($10^6 m^3$)	Discovery date
1	Kaybob South, Beaverhill Lake A	NA	104 424	1961
2	Caroline, Beaverhill Lake A	NA	61 150	1985
3	Hanlan, Beaverhill Lake A	NA	40 000	1975
4	Blackstone, Beaverhill Lake A	NA	22 500	1978
5	Minehead, Beaverhill Lake undefined	NA	7 143	1973
6	Rosevear, Beaverhill Lake A	NA	7 095	1971
7	Rosevear, Beaverhill Lake B	NA	6 095	1974
10	Kaybob, Beaverhill Lake C	NA	2 326	1961
18	Hanlan, Beaverhill Lake B	NA	1 299	1979
23	Fox Creek, Beaverhill Lake A	S	901	1975
30	Kaybob, Beaverhill Lake B	A&S	668	1961
45	Chickadee, Swan Hills undefined	NA	381	1976
65	Kaybob South, Beaverhill Lake undefined	NA	219	1982
83	Sakwatamau, Swan Hills undefined	NA	143	1985
96	Kaybob South, Beaverhill Lake undefined	NA	111	1982
Initial in-place volume (discovered)			254 457	
Initial in-place volume (potential)			52 541	
Per cent play resource undiscovered			17	
Total pool population			450	
Total pools discovered			15	

TABLE 18

Swan Hills isolated reef - Swan Hills

Rank	Field/Pool	Pool type	In-place volume ($10^6 m^3$)	Discovery date
1	Swan Hills, Beaverhill Lake A&B	A&S	29 000	1957
2	Carson Creek North, Beaverhill Lake A	A&S	17 110	1958
3	Judy Creek, Beaverhill Lake A	A&S	16 040	1959
4	Swan Hills South, Beaverhill Lake A&B	A&S	15 230	1959
5	Carson Creek, Beaverhill Lake B	NA	10 940	1956
6	Kaybob, Beaverhill Lake A	S	8 756	1957
7	Judy Creek, Beaverhill Lake B	A&S	7 699	1959
8	Swan Hills, Beaverhill Lake C	S	7 601	1958
9	Virginia Hills, Beaverhill Lake	S	6 709	1956
10	Goose River, Beaverhill Lake A	A&S	2 083	1963
11	Ante Creek, Beaverhill Lake	A&S	2 028	1962
12	Snipe Lake, Beaverhill Lake	S	1 835	1962
16	Judy Creek South, Beaverhill Lake	S	293	1960
17	Ante Creek, Beaverhill Lake B	S	277	1966
24	Carson Creek North, Beaverhill Lake B	A&S	182	1960
33	Judy Creek, Beaverhill Lake C	S	51	1961
Initial in-place volume (discovered)			125 835	
Initial in-place volume (potential)			7 758	
Per cent play resource undiscovered			5	
Total pool population			60	
Total pools discovered			16	

TABLE 19

Leduc/Nisku reef complexes - Windfall

Rank	Field/Pool	Pool type	In-place volume ($10^6 m^3$)	Discovery date
1	Windfall, D-3 A	A&S	25 790	1955
2	Pine Creek, D-3	NA	23 510	1956
3	Bigstone, D-3 A	NA	13 810	1959
4	Simonette, D-3	A&S	9 706	1958
5	Sturgeon Lake South, D-3	A&S	9 300	1955
6	Pine Northwest, D-3 A	NA	8 991	1962
7	Marlboro, D-3 A	NA	6 123	1964
10	Berland River, D-3 A	NA	3 852	1957
11	Obed, Leduc undefined	NA	3 636	1965
12	Fir, D-3 A	NA	3 556	1974
13	Obed, D-2 A	NA	3 342	1956
14	Lambert, D-3 A	NA	2 451	1979
18	Windfall, D-3 E	NA	1 877	1984
23	Sturgeon Lake, D-3	S	1 401	1953
25	Groat, D-3 A	NA	1 220	1983
30	Banshee, Leduc undefined	NA	957	1977
31	Fir, D-3 B	NA	921	1980
32	Strike area, Nisku undefined	NA	873	1980
33	Harley, Leduc undefined	NA	861	1975
34	Plante, Leduc undefined	NA	850	1986
Initial in-place volume (discovered)			127 776	
Initial in-place volume (potential)			54 449	
Per cent play resource undiscovered			30	
Total pool population			960	
Total pools discovered			41	

TABLE 20

Leduc isolated reef - Westerose

Rank	Field/Pool	Pool type	In-place volume (10^6m^3)	Discovery date
1	Westerose South, D-3 A	NA	52 010	1953
2	Ricinus West, D-3 A	NA	49 490	1969
3	Strachan, D-3 A	NA	40 741	1967
4	Homeglen-Rimbey, D-3	A&S	33 050	1952
5	Bonnie Glen, D-3 A	A&S	31 730	1951
6	Leduc-Woodbend, D-3 A	A&S	17 538	1946
7	Harmattan-Elkton, D-3 A	NA	13 400	1961
8	Ricinus, D-3 A	NA	11 670	1968
9	Westerose, D-3	A&S	8 743	1953
10	Wizard Lake, D-3 A	A&S	7 303	1951
11	Redwater, D-3	A&S	6 831	1948
12	Golden Spike, D-3 A	A&S	4 767	1948
17	Strachan, D-3 C	NA	2 833	1972
18	Acheson, D-3 A	A&S	2 679	1952
20	Ricinus, D-3 B	NA	2 246	1971
21	Chedderville, D-3 A	NA	2 078	1967
25	Sylvan Lake, D-3 A	A&S	1 586	1961
26	Caroline, Leduc undefined	NA	1 516	1970
31	Chedderville, D-3 B	NA	1 123	1986
35	Garrington, D-3 D	A&S	866	1985
Initial in-place volume (discovered)			297 536	
Initial in-place volume (potential)			46 099	
Per cent play resource undiscovered			13	
Total pool population			210	
Total pools discovered			48	

TABLE 21

Leduc reef - Nevis

Rank	Field/Pool	Pool type	In-place volume (10^6m^3)	Discovery date
1	Nevis, Devonian	A	21 164	1952
2	Wimborne, D-3 A	A&S	14 855	1956
3	Nevis, Devonian	A	10 388	1952
4	Innisfail, D-3	A&S	6 163	1957
5	Lone Pine Creek, D-3 A	A&S	3 631	1962
6	Clive, D-3 A	A&S	2 242	1952
7	Malmo, D-3 B	NA	1 813	1959
8	Erskine, D-3	A&S	1 377	1952
11	Bashaw, D-3 A	A&S	721	1951
17	Stettler, D-3 A	S	441	1949
18	Clive, D-3 A	A&S	381	1952
19	Clive, D-3 A	A&S	378	1952
26	Joffre, D-3 B	S	233	1985
27	Fenn-Big Valley, D-3 F	S	219	1954
28	Malmo, D-3 A	A&S	217	1952
29	Bashaw, D-3 C	A	202	1985
30	Duhamel, D-3 B	A&S	194	1950
31	Malmo, Leduc undefined	NA	181	1980
33	Haynes, D-2 A & D-3 A	A	164	1968
34	Malmo, D-3 C	A	155	1965
Initial in-place volume (discovered)			66 954	
Initial in-place volume (potential)			8 609	
Per cent play resource undiscovered			11	
Total pool population			150	
Total pools discovered			56	

TABLE 22

Nisku shelf margin - Brazeau River

Rank	Field/Pool	Pool type	In-place volume ($10^6 m^3$)	Discovery date
1	Brazeau River, Nisku P	NA	9 408	1977
5	Brazeau River, Nisku V	NA	525	1978
6	Brazeau River, Nisku T	NA	280	1977
7	Brazeau River, Nisku Q	NA	269	1978
8	Brazeau River, Nisku X	S	248	1986
11	Pembina, Nisku undefined	NA	164	1981
22	Brazeau River, Nisku undefined	NA	48	1980
28	Brazeau River, Nisku U	NA	28	1979
Initial in-place volume (discovered)			10 970	
Initial in-place volume (potential)			7 481	
Per cent play resource undiscovered			41	
Total pool population			190	
Total pools discovered			8	

TABLE 23

Nisku isolated reef - Brazeau River

Rank	Field/Pool	Pool type	In-place volume ($10^6 m^3$)	Discovery date
1	Brazeau River, Nisku M	NA	1 489	1979
2	Brazeau River, Nisku S	NA	1 400	1979
3	Peco, Nisku undefined	NA	908	1979
4	Hanlan, Nisku B	NA	859	1979
5	Columbia, Nisku B	NA	800	1979
6	Pembina, Nisku P	A&S	791	1979
7	Brazeau River, Nisku J	NA	707	1979
8	Peco, D-2 A	NA	704	1981
11	Brazeau River, Nisku N	NA	519	1979
12	Whitehorse, Nisku undefined	NA	502	1981
14	Pembina, Nisku Q	A&S	420	1980
15	Brazeau River, Nisku L	S	386	1982
16	Brazeau River, Nisku W	NA	366	1986
20	Whitehorse, Nisku undefined	NA	279	1979
26	Pembina, Nisku C	S	207	1982
37	Edson, Nisku undefined	NA	122	1980
45	Pembina, Nisku S	S	89	1981
46	Pembina, Nisku I	S	86	1984
52	Brazeau River, Nisku R	NA	68	1981
56	Pembina, Nisku R	S	59	1980
Initial in-place volume (discovered)			22 691	
Initial in-place volume (potential)			8 041	
Per cent play resource undiscovered			43	
Total pool population			156	
Total pools discovered			57	

TABLE 24

Nisku shelf drape – Bashaw trend

Rank	Field/Pool	Pool type	In-place volume (10^6m^3)	Discovery date
1	Fenn-Big Valley, D-2 A	A&S	6 657	1952
2	Joffre, D-2	S	3 689	1956
3	Clive, D-2 A	A&S	1 304	1952
4	Clive, D-2 A	A	935	1952
5	Wimborne, Nisku B	A&S	760	1957
6	Stettler, D-2 A	S	594	1949
10	Malmo, D-2 A	A&S	368	1951
11	Alix, D-2	A&S	333	1956
13	Duhamel, D-2 A	A&S	249	1950
14	Bashaw, Nisku C	A	248	1988
16	Fenn West, D-2 A	S	211	1961
17	Lone Pine Creek, D-2 A	A	190	1976
18	New Norway, D-2	A&S	184	1951
19	Wood River, Nisku C	A&S	173	1972
22	Wood River, Nisku B	S	136	1984
23	Clive, Nisku B	A&S	134	1966
24	Nevis, Nisku undefined	NA	129	1985
26	Penhold, D-2 A	A	120	1984
27	Wimborne, D-2 A	S	109	1961
28	Stettler South, D-2	S	101	1951
Initial in-place volume (discovered)			17 745	
Initial in-place volume (potential)			4 934	
Per cent play resource undiscovered			22	
Total pool population			300	
Total pools discovered			47	

TABLE 25

Nisku shelf drape – Ricinus-Meadowbrook trend

Rank	Field/Pool	Pool type	In-place volume (10^6m^3)	Discovery date
1	Leduc-Woodbend, D-2 A	A&S	4 833	1947
2	Leduc-Woodbend, Nisku B	S	1 225	1950
4	Ricinus, Nisku undefined	NA	650	1977
5	Golden Spike, D-2 A	A&S	514	1948
6	Caroline, Nisku undefined	NA	492	1970
7	Ricinus, Nisku undefined	NA	420	1982
17	Homeglen-Rimbey, Nisku undefined	NA	145	1957
24	Acheson, Nisku undefined	NA	88	1972
28	Wizard Lake, D-2 A	A&S	71	1951
34	Acheson, D-2 A	S	50	1952
35	Leduc-Woodbend, Nisku E	S	49	1950
36	Leduc-Woodbend, Nisku C	S	45	1950
37	Westerose, Nisku undefined	NA	45	1952
38	Golden Spike, Nisku B	A&S	44	1951
49	Glen Park, Nisku undefined	NA	28	1983
58	Garrington, D-2 A	S	20	1986
63	Bonnie Glen, D-2 A	S	17	1952
67	Glen Park, D-2 A	A	15	1952
122	Acheson, Nisku B	A&S	3	1952
Initial in-place volume (discovered)			8 754	
Initial in-place volume (potential)			5 418	
Per cent play resource undiscovered			38	
Total pool population			210	
Total pools discovered			19	

TABLE 26

Blue Ridge stratigraphic - Karr

Rank	Field/Pool	Pool type	In-place volume ($10^6 m^3$)	Discovery date
2	Skinner, Blue Ridge A	NA	1 799	1978
3	Mcleod, Winterburn undefined	NA	988	1976
8	Kaybob South, Blue Ridge A	NA	486	1958
9	Nosehill, Winterburn A	NA	459	1971
10	West Pembina, Blue Ridge undefined	NA	447	1980
11	Brazeau River, Blue Ridge A	NA	392	1977
12	Edson, Blue Ridge A	NA	372	1980
14	Brazeau River, Blue Ridge undefined	NA	331	1977
19	Leaman, Blue Ridge undefined	NA	264	1972
20	Kaybob South, Winterburn undefined	NA	252	1980
22	Sturgeon Lake South, Blue Ridge A	A&S	227	1956
23	Blue Ridge, Blue Ridge undefined	NA	223	1955
30	Pembina, Blue Ridge undefined	NA	177	1977
34	Kaybob South, Winterburn undefined	NA	159	1978
54	Kaybob, Blue Ridge B	NA	99	1958
59	Pembina, Blue Ridge A	S	90	1977
61	Pembina, Blue Ridge D	S	86	1981
105	Kaybob South, Blue Ridge undefined	NA	45	1961
111	Brazeau River, Blue Ridge undefined	NA	42	1979
149	Kaybob, Blue Ridge A	NA	27	1957
Initial in-place volume (discovered)			6 966	
Initial in-place volume (potential)			19 190	
Per cent play resource undiscovered			73	
Total pool population			460	
Total pools discovered			21	

TABLE 27

Upper Devonian subcrop - Marten Hills

Rank	Field/Pool	Pool type	In-place volume ($10^6 m^3$)	Discovery date
1	Marten Hills, Wabiskaw A & Wabamun A	NA	9 069	1960
2	Liege, Grosmont B	NA	6 842	1975
3	Liege, Grosmont A	NA	5 895	1963
4	Craigend, Grosmont A	NA	5 380	1961
5	House, Grosmont A	NA	4 473	1973
6	Nixon, Grosmont A	NA	3 200	1969
7	Liege, D-3 A	NA	2 982	1980
8	Flat, Wabiskaw, Wabamun A	NA	2 919	1955
9	Duncan, Grosmont B	NA	2 871	1972
10	Calling Lake, Nisku B	NA	2 372	1964
11	Figure Lake, Upper Mannville B&D-2 B	NA	1 797	1955
12	Marten Hills, Wabamun C	NA	1 404	1966
13	Saleski, Grosmont A	NA	1 327	1977
14	Granor, Grosmont A	NA	1 290	1976
15	Baptiste, Wabamun E	NA	1 243	1959
16	Edwand, Nisku D	NA	1 240	1972
17	Tweedie, Grosmont A	NA	1 201	1961
18	Hoole, D-1 A	NA	1 163	1967
19	Viking-Kinsella, Nisku D	NA	1 021	1960
20	Plain, Camrose A	NA	1 011	1968
Initial in-place volume (discovered)			101 734	
Initial in-place volume (potential)			16 172	
Per cent play resource undiscovered			14	
Total pool population			900	
Total pools discovered			390	

TABLE 28

Wabamun platform facies – Pine Creek

Rank	Field/Pool	Pool type	In-place volume ($10^6 m^3$)	Discovery date
1	Pine Creek, Wabamun B	NA	6 773	1955
2	Pine Creek, Wabamun C	NA	4 231	1957
3	Pine Creek, D-1	NA	3 069	1957
8	Lator, Wabamun undefined	NA	980	1978
9	Medicine Lodge, Wabamun undefined	NA	675	1978
10	Berland River West, Wabamun undefined	NA	663	1958
11	Wild River, D-1 A	NA	648	1968
12	Simonette, D-1 A	NA	600	1959
13	Medicine Lodge, Wabamun undefined	NA	517	1977
14	Medicine Lodge, Wabamun undefined	NA	484	1977
15	Pine Creek, Wabamun D	NA	451	1957
16	Berland River West, Wabamun undefined	NA	422	1980
17	Karr, Wabamun undefined	NA	421	1967
25	Medicine Lodge, Wabamun undefined	NA	261	1980
32	Bigstone, D-1 A	NA	194	1962
34	Strike Area, Wabamun undefined	NA	181	1978
35	Bronson, Wabamun undefined	NA	174	1986
42	Colt, Wabamun undefined	NA	137	1967
93	Simonette, Wabamun B	NA	42	1960
121	Kaybob, D-1 A	NA	26	1960
Initial in-place volume (discovered)			20 949	
Initial in-place volume (potential)			17 832	
Per cent play resource undiscovered			46	
Total pool population			450	
Total pools discovered			20	

TABLE 29

Leduc/Nisku isolated reef – Wild River Basin

Field/Pool	Pool type	In-place volume ($10^6 m^3$)	Discovery date
Nosehill D-3 A	NA	939	1972
Wild River Leduc undefined (6-16-56-23W5)	NA	833	1980
Wild River Ireton A (7-6-57-23W5)	NA	622	1972
Colt D-3 A	NA	586	1968
Spotter Nisku undefined (16-24-56-22W5)	NA	484	1987
Wild River Leduc undefined (3-23-57-24W5)	NA	119	1968
Initial in-place volume (discovered)		3 583	
Initial in-place volume (potential)		–	
Per cent play resource undiscovered		–	
Total pool population		–	
Total pools discovered		6	

TABLE 30

Wabamun platform facies - Crossfield

Rank	Field/Pool	Pool type	In-place volume ($10^6 m^3$)	Discovery date
1	Crossfield, Wabamun A	NA	37 500	1954
2	Crossfield East, Wabamun A	NA	33 330	1960
3	Okotoks, Wabamun B	NA	25 660	1951
4	Lone Pine Creek, Wabamun A	NA	15 000	1955
5	Garrington, Wabamun A	A&S	10 460	1952
6	Gladys, Wabamun A	NA	1 500	1980
7	Irricana, Wabamun A	NA	1 333	1958
8	Crossfield East, Wabamun B	NA	1 091	1959
9	Irricana, Wabamun B	NA	1 070	1969
13	Okotoks, Crossfield	NA	269	1961
14	Crossfield, Wabamun B	NA	259	1966
16	Okotoks, Crossfield	NA	146	1978
17	Lone Pine Creek, Wabamun	NA	143	1980
18	Irricana, Crossfield	NA	103	1970
19	Lone Pine Creek, Crossfield	NA	102	1978
20	Irricana, Crossfield	NA	76	1967
22	Crossfield, Crossfield	NA	48	1967
23	Okotoks, Crossfield	NA	36	1979
24	Longview, Wabamun	NA	36	1966
Initial in-place volume (discovered)			128 162	
Initial in-place volume (potential)			2 125	
Per cent play resource undiscovered			2	
Total pool population			60	
Total pools discovered			19	

TABLE 31

Arcs structural - Princess

Field/Pool	Pool type	In-place volume ($10^6 m^3$)	Discovery date
Princess, Jefferson B	NA	1 014	1939
West Drumheller, D-2 A	S	860	1952
Hays, Arcs undefined	NA	633	1985
Jenner, Arcs A	NA	534	1981
Drumheller, Nisku B	S	403	1961
Hays, Arcs undefined	NA	388	1987
Grand Forks, Arcs undefined	NA	218	1986
Drumheller, D-2 A	S	185	1951
Enchant, Arcs E	A	181	1987
West Drumheller, D-2 A	A	173	1952
Enchant, Arcs undefined	NA	166	1986
Enchant, Arcs undefined	NA	158	1987
Grand Forks, Arcs undefined	NA	147	1985
Princess, Jefferson A	A	121	1939
Cessford, Arcs A	NA	100	1973
Hays, Arcs B	A	88	1987
Hays, Arcs undefined	NA	87	1985
Swalwell, D-2 A	A	81	1969
Grand Forks, D-2 A	NA	51	1957
Enchant, Arcs undefined	NA	46	1986
Initial in-place volume (discovered)		5 844	
Initial in-place volume (potential)		-	
Per cent play resource undiscovered		-	
Total pool population		-	
Total pools discovered		30	

TABLE 32

Discovered and potential gas volumes for mature Devonian plays

	Initial In-Place Volume ($10^6 m^3$)		
	Discovered	Expected Potential	Probable Potential
NORTHERN DISTRICT AND PEACE RIVER ARCH			
Middle Devonian clastics	25 665	18 204	27 306
Keg River shelf basin - Rainbow	40 704	11 436	26 115
Keg River shelf basin - Zama	17 544	11 132	16 698
Keg River shelf basin - Shekilie	7 084	13 858	15 631
Keg River isolated reef - Yoyo	102 795	35 146	84 024
Keg River platform - July Lake	2 449	2 055	4 619
Slave Point barrier reef - Clarke Lake	103 317	21 526	32 289
Slave Point platform - Adsett	19 467	59 655	82 967
Jean Marie biostrome - Helmet North	11 636	24 035	35 456
Slave Point reef complexes - Cranberry	21 100	67 467	108 080
Leduc fringing reef - Worsley	7 035	8 445	23 189
Wabamun structural and stratigraphic - Parkland	19 281	40 870	45 500
CENTRAL DISTRICT AND DEEP BASIN			
Swan Hills shelf margin - Kaybob South	254 457	52 541	421 830
Swan Hills isolated reef - Swan Hills	125 835	7 758	56 369
Leduc/Nisku reef complexes - Windfall	127 776	54 449	326 310
Leduc isolated reef - Westerose	297 536	46 099	188 901
Leduc reef - Nevis	66 954	8 609	97 078
Nisku shelf margin - Brazeau River	10 970	7 481	50 199
Nisku isolated reef - Brazeau River	22 691	8 041	22 029
Nisku shelf drape - Bashaw trend	17 745	4 934	16 871
Nisku shelf drape - Ricinus-Meadowbrook trend	8 754	5 418	19 756
Blue Ridge stratigraphic - Karr	6 966	19 190	25 856
Upper Devonian subcrop - Marten Hills	101 734	16 172	50 898
Wabamun platform facies - Pine Creek	20 949	17 832	41 304
SOUTHERN DISTRICT			
Wabamun platform facies - Crossfield	128 162	2 125	3 188
Total	1 568 606 (56 TCF)	564 478 (20 TCF)	1 822 463 (65 TCF)

TABLE 33

Mature plays ranked according to discovered initial in-place volume

Play	10^6m^3	Tcf
Leduc isolated reef - Westerose	297 536	10.561
Swan Hills shelf margin - Kaybob South	254 457	9.032
Wabamun platform facies - Crossfield	128 162	4.549
Leduc/Nisku reef complexes - Windfall	127 776	4.535
Swan Hills isolated reef - Swan Hills	125 835	4.467
Slave Point barrier reef - Clarke Lake	103 317	3.667
Keg River isolated reef - Yoyo	102 795	3.649
Upper Devonian subcrop - Marten Hills	101 734	3.611
Leduc reef - Nevis	66 954	2.376
Keg River shelf basin - Rainbow	40 704	1.445
Middle Devonian clastics	25 665	0.911
Nisku isolated reef - Brazeau River	22 691	0.805
Slave Point reef complexes - Cranberry	21 100	0.749
Wabamun platform facies - Pine Creek	20 949	0.744
Slave Point platform - Adsett	19 467	0.691
Wabamun structural and stratigraphic - Parkland	19 281	0.684
Nisku shelf drape - Bashaw trend	17 745	0.630
Keg River shelf basin - Zama	17 544	0.623
Jean Marie biostrome - Helmet North	11 636	0.413
Nisku shelf margin - Brazeau River	10 970	0.389
Nisku shelf drape - Ricinus-Meadowbrook trend	8754	0.311
Keg River shelf basin - Shekilie	7084	0.251
Leduc fringing reef - Worsley	7035	0.250
Blue Ridge stratigraphic - Karr	6966	0.247
Keg River platform - July Lake	2449	0.087
Total initial in-place volume - mature plays	1 568 606	55.677

TABLE 34

Mature plays ranked according to expected potential initial in-place volume

Play	10^6m^3	Tcf
Slave Point reef complexes - Cranberry	67 467	2.395
Slave Point platform - Adsett	59 655	2.117
Leduc/Nisku reef complexes - Windfall	54 449	1.933
Swan Hills shelf margin - Kaybob South	52 541	1.865
Leduc isolated reef - Westerose	46 099	1.636
Wabamun structural and stratigraphic - Parkland	40 870	1.451
Keg River isolated reef - Yoyo	35 146	1.248
Jean Marie biostrome - Helmet North	24 035	0.853
Slave Point barrier reef - Clarke Lake	21 526	0.764
Blue Ridge stratigraphic - Karr	19 190	0.681
Middle Devonian clastics	18 204	0.646
Wabamun platform facies - Pine Creek	17 832	0.633
Upper Devonian subcrop - Marten Hills	16 172	0.574
Keg River shelf basin - Shekilie	13 858	0.492
Keg River shelf basin - Rainbow	11 436	0.406
Keg River shelf basin - Zama	11 132	0.395
Leduc reef - Nevis	8 609	0.306
Leduc fringing reef - Worsley	8 445	0.300
Nisku isolated reef - Brazeau River	8 041	0.285
Swan Hills isolated reef - Swan Hills	7 758	0.275
Nisku shelf margin - Brazeau River	7 481	0.266
Nisku shelf drape - Ricinus-Meadowbrook trend	5 418	0.192
Nisku shelf drape - Bashaw trend	4 934	0.175
Wabamun platform facies - Crossfield	2 125	0.075
Keg River platform - July Lake	2 055	0.073
Total	564 478	20.036

TABLE 35

Mature plays ranked according to probable potential initial in-place volume

Play	10^6m^3	Tcf
Swan Hills shelf margin - Kaybob South	421 830	14.973
Leduc/Nisku reef complexes - Windfall	326 310	11.582
Leduc isolated reef - Westerose	188 901	6.705
Slave Point reef complexes - Cranberry	108 080	3.836
Leduc reef - Nevis	97 078	3.446
Keg River isolated reef - Yoyo	84 024	2.982
Slave Point platform - Adsett	82 967	2.945
Swan Hills isolated reef - Swan Hills	56 369	2.001
Upper Devonian subcrop - Marten Hills	50 898	1.807
Nisku shelf margin - Brazeau River	50 199	1.782
Wabamun structural and stratigraphic - Parkland	45 500	1.615
Wabamun platform facies - Pine Creek	41 304	1.466
Jean Marie biostrome - Helmet North	35 456	1.259
Slave Point barrier reef - Clarke Lake	32 289	1.146
Middle Devonian clastics	27 306	0.969
Keg River shelf basin - Rainbow	26 115	0.927
Blue Ridge stratigraphic - Karr	25 856	0.918
Leduc fringing reef - Worsley	23 189	0.823
Nisku isolated reef - Brazeau River	22 029	0.782
Nisku shelf drape - Ricinus-Meadowbrook trend	19 756	0.701
Nisku shelf drape - Bashaw trend	16 871	0.599
Keg River shelf basin - Zama	16 698	0.593
Keg River shelf basin - Shekilie	15 631	0.555
Keg River platform - July Lake	4 619	0.164
Wabamun platform facies - Crossfield	3 188	0.113
Total	1 822 463	64.689

TABLE 36

Mature plays ranked in order of largest undiscovered pool size

Play	Pool size (10^6m^3)	Rank (within play)
Slave Point reef complexes - Cranberry	7 755	2
Leduc/Nisku reef complexes - Windfall	5 245	8
Slave Point platform - Adsett	4 537	2
Leduc isolated reef - Westerose	4 340	13
Swan Hills shelf margin - Kaybob South	4 241	8
Jean Marie biostrome - Helmet North	3 110	2
Blue Ridge stratigraphic - Karr	2 629	1
Keg River isolated reef - Yoyo	2 617	7
Nisku shelf margin - Brazeau River	2 553	2
Wabamun platform facies - Pine Creek	2 279	4
Wabamun structural and stratigraphic - Parkland	2 021	7
Leduc fringing reef - Worsley	1 649	2
Swan Hills isolated reef - Swan Hills	1 446	13
Slave Point barrier reef - Clarke Lake	1 154	14
Leduc reef - Nevis	1 102	9
Keg River shelf basin - Rainbow	998	9
Nisku shelf drape - Ricinus-Meadowbrook trend	853	3
Upper Devonian subcrop - Marten Hills	815	27
Middle Devonian clastics	771	4
Wabamun platform facies - Crossfield	733	10
Nisku isolated reef - Brazeau River	639	9
Keg River shelf basin - Zama	543	2
Keg River shelf basin - Shekilie	532	2
Nisku shelf drape - Bashaw trend	528	7
Key River platform - July Lake	232	5

TABLE 37

Discovered, expected potential, and probable potential for mature plays in the three exploration regions (initial in-place volumes in $10^6 m^3$)

	Discovered	Expected potential	Probable potential
Northern District and Peace River Arch	378 077	313 829	501 874
Central District and Deep Basin	1 062 367	248 524	1 317 401
Southern District	128 162	2 125	3 188

TABLE 38

Discovered resources for immature Devonian plays

	Discovered initital in-place volume ($10^6 m^3$)
Sulphur Point platform facies - Bistcho	2 147
Leduc/Nisku isolated reef - Wild River Basin	3 464
Arcs structural - Princess	5 844
Others	5 884
Total	17 339

TABLE 39

Total play resource, mature Devonian plays (play resource = discovered + potential)

	Discovery date	Play rank	Play resource expected value ($10^6 m^3$)
NORTHERN DISTRICT AND PEACE RIVER ARCH			
Middle Devonian clastics	55/08/07	28	43 869
Keg River shelf basin - Rainbow	63/12/13	23	52 140
Keg River shelf basin - Zama	53/01/10	42	28 676
Keg River shelf basin - Shekilie	68/10/09	53	20 942
Keg River isolated reef - Yoyo	59/12/27	5	137 941
Keg River platform - July Lake	67/02/23	93	4 502
Slave Point barrier reef - Clarke Lake	56/01/23	8	124 843
Slave Point platform - Adsett	53/04/20	14	79 122
Jean Marie biostrome - Helmet North	59/12/15	35	35 671
Slave Point reef complexes - Cranberry	63/02/17	12	88 567
Leduc fringing reef - Worsley	49/05/16	63	15 480
Wabamun structural and stratigraphic - Parkland	55/12/20	20	60 151
CENTRAL DISTRICT AND DEEP BASIN			
Swan Hills shelf margin - Kaybob South	61/07/23	2	306 998
Swan Hills isolated reef - Swan Hills	56/11/28	6	133 593
Leduc/Nisku reef complexes - Windfall	53/07/16	4	182 225
Leduc isolated reef - Westerose	46/11/20	1	343 635
Leduc reef - Nevis	49/03/30	15	75 563
Nisku shelf margin - Brazeau River	79/05/03	57	18 451
Nisku isolated reef - Brazeau River	76/12/16	40	30 732
Nisku shelf drape - Bashaw trend	49/03/30	56	22 679
Nisku shelf drape - Ricinus-Meadowbrook	47/10/20	66	14 172
Blue Ridge stratigraphic - Karr	55/10/02	45	26 156
Upper Devonian subcrop - Marten Hills	48/11/25	9	117 906
Wabamun platform facies - Pine Creek	55/12/13	32	38 781
SOUTHERN DISTRICT			
Wabamun platform facies - Crossfield	50/10/12	7	130 287
Total			2 133 082 76 TCF

TABLE 40

Devonian gas resources (Initial In-Place Volume)

Plays		**Discovered**	**Expected Potential**
Mature		1 568 606 x $10^6 m^3$ (56 TCF)	564 478 x $10^6 m^3$ (20 TCF)
Conceptual	Total	–	2 079 200 x $10^6 m^3$ (74 TCF)
	Plays > 30 000 x $10^6 m^3$ (23 plays)	–	1 394 900 x $10^6 m^3$ (50 TCF)

PART II: ECONOMIC ANALYSIS

INTRODUCTION

Part I of this report provides estimates of the total natural gas resource within the Devonian System of the Western Canada Sedimentary Basin, unconstrained by engineering and economic considerations. The objective of Part II is to estimate the economic potential, the portion of the undiscovered resource that can be expected to provide economic investment opportunities over the long-term. By taking costs and other economic constraints into account, a more balanced description of the resource base is provided.

Terminology

Many of the terms applicable here were defined in Part I, and thus require no further explanation. With regard to the economic analysis, however, several new terms are introduced.

The term *supply price* refers to the plant gate price of natural gas and co-products required to recover all costs including a minimum discounted cash flow rate-of-return on investment. Supply price is synonymous with marginal cost. The *economic potential* of a play, at a given price, is the sum of resources of pools with estimated supply prices less than or equal to the given price. The price-economic potential relation is defined as the *supply curve* or *marginal cost curve*.

Full-cycle and half-cycle estimates of economic potential are made to provide estimates at different stages of the investment cycle. *Full-cycle* analysis includes all exploration, development, production and overhead costs, but excludes the cost of acquiring land rights. *Half-cycle* analysis excludes exploration costs and is relevant to development investment decisions when exploration costs are already incurred. Burdened and unburdened cases are provided to increase the relevance of the work to both the private and public sectors of the economy. *Burdened* economic potential measures potential under an assumed fiscal regime, while *unburdened* economic potential excludes the fiscal regime. The difference between the burdened and unburdened cases measures the impact of the fiscal regime on the ultimate discovery of natural gas resources.

Scope

The economic analysis was undertaken at the play level, and was limited to the 25 mature plays, as defined in Part I, for which undiscovered pool size estimates and other geological information are available. The 25 plays were assigned to five groups in order to estimate economic potential. Supply curves for each play group were constructed from supply price estimates for each undiscovered pool in the plays belonging to that group (Appendix IIb). Similarly, supply curves for the total of all mature Devonian plays were constructed from the play group supply curves (Figs. 88–93). Although detailed economic analysis was not undertaken for conceptual plays, results for the mature plays were extended to conceptual plays in order to provide some estimate of their economic potential. This extension is, by necessity, simple and straightforward. Any other approach would be speculative. The reader is advised to treat the estimates of economic potential for conceptual plays with caution.

Acknowledgments

This study was undertaken by the Energy Sector of Energy, Mines and Resources Canada (EMR) on behalf of the Petroleum Resources Appraisal Panel. The study has benefitted from advice from the Monitoring and Information Systems Division of the Economic and Financial Analysis Branch (EFAB), Energy Sector, EMR, which provided assistance on running and interpreting EFAB's cash flow simulation model. The Economic and Fiscal Analysis Division of EFAB provided advice on the application of federal and provincial fiscal systems. L. Roux and M. Boudreault of the Petroleum Resource Analysis Division, Energy Sector, EMR, conducted the analytical work for this study. P.J. Lee, ISPG, assisted in the interpretation of assessment information.

The engineering, production and costing model used in this work has drawn upon several studies contracted by the Energy Sector, EMR, with a number of firms. These include Confer Consulting, J.R. Eickmeier Engineering Ltd., N.W. Miller & Associates Ltd., Geo-Energy Consulting, Delta Projects Inc., and Computer Research Associates Ltd. Cost estimates were reviewed by Sproule Associates Ltd. The Energy

Sector appreciates the assistance provided by these firms, but is responsible for the interpretation, implementation and use of their work.

Presentations of preliminary results were made to the Canadian Petroleum Association, Independent Petroleum Association of Canada, Small Explorers and Producers Association of Canada, Alberta Energy Resources Conservation Board staff, Alberta Energy, British Columbia Ministry of Energy, Mines and Petroleum Resources, and National Energy Board staff. Comments and suggestions made by these organizations with regard to methodology, data, sensitivity analyses and presentation of results have shaped the present study. The Petroleum Resources Appraisal Panel, on behalf of Energy, Mines and Resources Canada, would like to thank each of these organizations for their contribution.

METHODOLOGY

The methodology (Fig. 86) developed to estimate the economic potential of undiscovered natural gas resources provides for a consistent treatment of the regional geology, resource assessment, engineering, costs, and economic considerations. The methodology allows for estimation of the plant gate supply price of marketable natural gas for each undiscovered pool and for the construction of supply curves for a given play or group of plays from these supply prices.

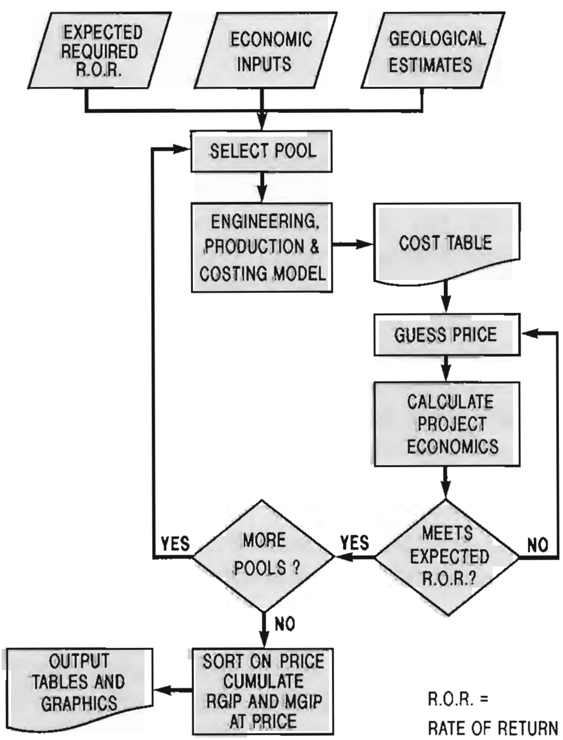

Figure 86. *Flow chart illustrating the methodology used for estimating economic potential of undiscovered gas resources. (RGIP and MGIP refer to recoverable and marketable gas-in-place, respectively.)*

Exploration, development and production of individual pools are treated as an investment opportunity (Fig. 87). Discounted cash flow (DCF) analysis is used to estimate the price that satisfies minimum profitability criteria. This estimated price is the pool supply price.

The estimated size of an undiscovered pool in the play, together with associated geological and reservoir parameters, are basic inputs. The expected exploration, development and production costs for a selected pool are estimated, as well as the expected production profile. These are provided as inputs to subsequent cash flow analysis. An initial supply price of natural gas is used to estimate gross revenue from natural gas and co-product sales. Royalty and taxes are calculated and net cash flow is estimated. The price is varied until the calculated rate-of-return is equal to the minimum required rate-of-return. The supply price is estimated for each pool in the undiscovered pool array, to a maximum price of \$300 per 10^3m^3 (\$8.50 per MCF). Prices in excess of \$300 per 10^3m^3 are considered to be beyond current price expectations.

For those plays in which significant quantities of natural gas are found as both nonassociated and in associated or solution gas forms, or in which both sour and sweet natural gas occur, a weighted average supply price is used as an appropriate measure of the play supply price. In order to calculate the weighted average price, the fractions of the resource base having the given attributes are estimated from the gas type and gas composition of existing discoveries in the play. Supply prices for each pool are calculated under the different sets of conditions. The reference case supply price for each pool is then calculated as the weighted average of the separate estimates using the estimated fractions.

As defined previously, the economic potential of a play, at a given price, is the sum of resources contained in pools with supply prices less than or equal to the given price. Similarly, economic potential of a group of plays is the sum of economic potential of the relevant plays. Supply curves were prepared for full-cycle and half-cycle economic potential, in both burdened and unburdened contexts (Figs. 88–93). The various cases are defined below.

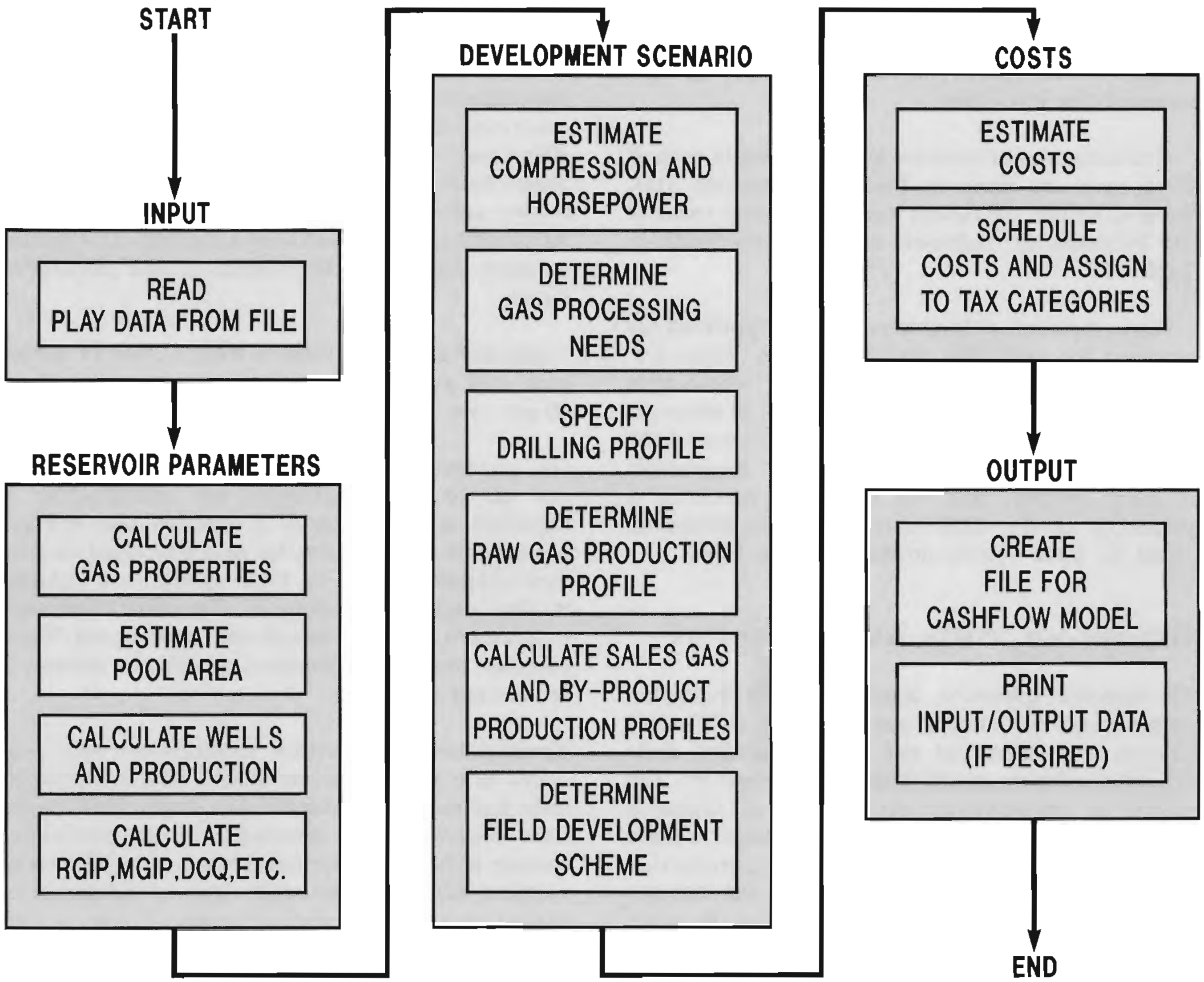

Figure 87. *Engineering, production and costing model. (DCQ refers to daily contract quantity.)*

Full-cycle analysis is defined to include all costs, including corporate overhead, that are required for exploration, development and production. Land acquisition costs are not included. This definition is consistent with the practice of estimating prospect profitability prior to acquiring land rights. Expectations of profits above the minimum acceptable profit may be used to prepare bids to acquire land rights. Thus, it would be inconsistent to include land costs in the full-cycle analysis. Full-cycle analysis is, therefore, appropriate for making exploration investment decisions prior to acquiring land rights.

In half-cycle analysis it is assumed that all exploration and pre-development costs are already incurred. This analysis is appropriate for investment decisions related to the subsequent development and production of a discovery. In this case, recovery of pre-development costs would have to come from the discovery and production of more profitable pools.

The burdened economic potential provides an estimate of economically recoverable resources assuming that the existing federal and provincial fiscal regime does not change over time. In the burdened case, pool profitability includes the net cost of taxes and royalties, and economic potential is obtained by summing recoverable potential in pools that earn a minimum required after-tax and royalty rate-of-return. When estimating unburdened economic potential, the fiscal regime is not included and pool profitability is based solely on estimates of costs and revenues. A comparison of burdened and unburdened economic potential provides a measure of fiscal impact on the volume of economically recoverable resources that may ultimately be discovered.

The categories of revenues and costs used in each of these cases are listed in Table 41 (Appendix IIa). Table 42 defines the various analytical cases in terms of the inclusion or exclusion of cost items listed in Table 41.

Three measures of long-term economic potential are prepared for each case described above. These are: i) the volume of economically raw recoverable gas-in-place (recoverable in-place volume); ii) economic raw recoverable in-place volume as a percentage of the total technical or unconstrained raw recoverable in-place volume; and iii) economic pools as a percentage of the total number of pools having an initial in- place volume greater than 1 x $10^6 m^3$.

TECHNOLOGY, COSTS, AND PRODUCTION

The expected exploration, development and production requirements for natural gas reservoirs in Western Canada were identified and their associated costs estimated using the model illustrated in Figure 87. The model is sensitive to differences in resource characteristics, such as estimates of initial in-place volume, gas composition, reservoir depth, production rates and drilling success rates. The model captures economies of scale and discontinuities in costs associated with development and production over the range of reservoir sizes relevant to this study.

Cost estimates include expenditures for exploration and development drilling, geological and geophysical activity, pipelines and roads, well site equipment, compression, and gas processing facilities. Separate operating costs were estimated for each of these capital items, and an allowance made for corporate overhead. Wherever possible, the estimated relations are play specific. Costs were estimated in 1990 dollars.

Technology and costs

Well requirements. The number of production wells required was estimated by dividing an estimated areal extent of the reservoir by a minimum well spacing. Current well densities were used for estimating minimum well spacing. Reservoir areas was estimated as a function of the initial gas-in-place. An allocation of dry and abandoned wells was estimated using separate exploratory and development drilling success rates. Capital costs for wells were estimated using separate correlations from drilling, completion and abandonment costs. These correlations are non-linear functions of depth, and reflect regional cost differences. Adjustments were made for exploration versus development drilling, the presence of sour gas, remote and/or difficult access, and winter drilling. Associated operating costs were estimated as a function of depth, and reflect the presence of sour gas and/or liquids.

Geological and geophysical activity. Costs of geological and geophysical activities were estimated as 40 per cent of exploratory drilling costs.

Gas processing. The technology required to process raw gas to meet marketable gas specifications is identified as a function of production rate and gas composition. Capital costs for each processing module were estimated separately. Plant utilities were included in final capital cost estimates. Operating costs were estimated to be 11 per cent of total capital costs. These costs are used in the economic analysis to estimate a fee for gas processing.

Compression. Compression requirements were estimated as a function of production rate, compression ratio and number of compression stages. Half of the total compression is installed prior to production start-up if the initial reservoir pressure is insufficient to sustain production at the initial rate, and the remainder in the year prior to production decline. For pools with less than an initial in-place volume of 30 x $10^6 m^3$, only one compression installation is scheduled. Capital costs for compressors were estimated as a linear function of installed horsepower. If compression were installed in two stages, 60 per cent of the estimated total cost was allocated to the initial installation and 40 per cent to the second installation. Operating costs were estimated as 7 per cent of cumulative capital costs.

Pipelines. The required length and diameter of pipelines were estimated separately for flow lines, common gathering lines and a transmission line to local processing facilities. Pipeline sizes were estimated such that the calculated pressure drop at the initial flow rate was at least ten psi per mile, with the further constraint that line pressure could not exceed maximum operating pressure. Pipeline costs were estimated using regional diameter inch mile cost correlations, adjusted to reflect difficult access and/or poor surface conditions, and the presence of sour gas. Pipeline operating and maintenance costs were estimated as 3 per cent of the capital cost of field pipelines (flow lines and common gathering lines), and 2 per cent of the capital cost of a transmission line connecting the reservoir to a main gathering system.

Roads. Road lengths were assumed to equal pipeline lengths. Road costs are a function of terrain and surface conditions. Operating costs were estimated to be 5 per cent of cumulative capital cost. In some areas, access to a well or pool was assumed to be by helicopter, eliminating the need for an all-season access road. The operating cost of a well or pool accessed by helicopter was assumed to be the same as the operating cost for an equivalent length of all-season road.

Well site equipment. Well site equipment includes metering and hydrate control. Hydrate control is provided by alcohol injection, line heaters or well site dehydration. Alcohol injection is selected if the gas is sweet and dry. Lines heaters are selected for sour gas, or for low flow rates. If line heaters are selected, flow lines and gathering lines are insulated to reduce heat loss. Capital costs for these systems are functions of production rate. Operating costs were estimated to be 5 per cent of capital costs.

Overhead. Corporate overhead cost was asumed to be equal to 30 per cent of total field operating cost.

Cost premium for British Columbia. Costs in northern British Columbia are higher than for similar activities in northwest Alberta, because of higher labour costs, less well developed road and pipeline infrastructure, and a less well developed service sector. A 15 per cent premium was added to account for these factors.

Solution gas recovery. In the economic analysis of solution gas production, all exploration costs and many development costs were assumed to have already been expended in the search for, development and production of crude oil reservoirs. Vapour recovery would therefore be considered an incremental or marginal investment decision. Local dehydration and compression at the oil battery and a raw gas transmission line to the local processing facility were considered to be the only cost components relevant to an investment decision to recover solution gas.

Drilling and development schedule. Capital expenditures are a function of the expected drilling and development schedule. Wells were assumed to be drilled according to a generic drilling profile. Twenty per cent of the successful wells were assumed to be needed to find and delineate reserves, and a further 20 per cent were assumed to be drilled to meet initial production requirements. The remaining 60 per cent were assumed drilled to maintain production prior to the onset of production decline.

It was assumed that all wells drilled prior to the startup year were connected in the year before startup and that subsequent wells were connected when completed. Connection includes flow lines and gathering lines, roads and well site equipment. An all-weather acccess road, if required, and a transmission line to the local gathering system, were assumed to have been constructed in the year prior to production startup.

Production estimates

Nonassociated gas reservoirs. The raw gas production profile was defined by assigning the pool to one of five size classes, depending upon the recoverable initial in-place volume. A typical production profile consists of a period of flat production, followed by a period of decline. The rate-of-take and period of constant production were defined so that 50 per cent of the recoverable gas is produced during the initial period of flat production. The remaining reserves are produced assuming an exponential rate of decline. The period of decline varies according to size class, from as short as five years for the smallest size class to thirteen years for the largest size class. Total productive life varies, therefore, from seven to nineteen years, depending on the pool size. The parameters defining the production profiles are provided in Table 43.

Solution gas reservoirs. Production profiles of solution gas from oil reservoirs were estimated by assuming a constant gas/oil ratio and a constant remaining-oil-reserves/production ratio of ten.

Sales gas and co-product production. Production profiles for sales gas and co-products (sulphur, liquified petroleum gases and/or condensate) were calculated from the raw gas production profile and gas composition. The profiles were adjusted to account for processing shrinkage due to removal of acid gases, recovery of liquid hydrocarbons and use of processed gas as fuel.

ECONOMIC ANALYSIS

The economic analysis provides an estimate of the plant gate price of natural gas and co-products that is required to recover all relevant costs, and also provide a minimum required rate-of-return on investment. The required price, or supply price, was estimated using project discounted cash flow modelling and analysis.

Discounted cash flow analysis

The economic analysis was initiated by converting all costs into current values using an assumed rate of inflation. Conversion into nominal values was necessary to ensure consistency with tax and royalty structures.

Pool supply prices were then calculated, for the burdened analysis, using the following, although not necessarily mutually exclusive, steps:

1. For each pool, an initial trial price of natural gas was assumed, and gross revenue from natural gas and co-products was calculated for each year over the expected life of the pool.

2. Consistent with the existing federal and provincial fiscal regimes, allowable deductions were calculated for capital expenses incurred for gas well equipment, exploration and development drilling.

3. A fee for gas processing was calculated as the sum of allowed depreciation on processing equipment, plant operating costs, and a specified rate-of-return on the total capital and operating base of the processing plant.

4. Where appropriate, any other deductions were calculated. For example, in British Columbia, the Producer Cost of Service (PCOS) was calculated to offset field costs associated with handling raw gas. This cost, specified in dollars per m^3, depends upon the location of the well and H_2S content of the gas.

5. After calculating the above deductions, net royalty payable was calculated using the appropriate provincial royalty regimes.

6. Following the calculation of net royalty, taxable income was calculated in two steps. First, Resource Profits for Resource Allowance (RPRA) was calculated as gross revenue less the sum of total operating costs and deductions allowed for gas well equipment. Taxable income was then calculated as RPRA minus a resource allowance of 25 per cent of RPRA, less deductions allowed for exploration and development expenditures.

7. The federal tax was calculated by applying the tax rate to taxable income. For provincial taxes, the tax amount obtained by applying the provincial tax rate to taxable income was reduced by an adjustment, which increases with royalty payable and decreases as resource allowance increases.

8. Net cash flow after tax was calculated by deducting capital cost allowances, operating costs, royalties and federal and provincial taxes from gross revenue.

9. The profitability of the investment at the trial price was calculated. If the resulting discounted cash flow rate-of-return were lower/higher than the minimum required rate, a higher/lower trial price was selected and the above steps repeated.

10. The iteration process stopped when the calculated rate-of-return equalled the minimum required rate-of-return at the trial price, which then became the estimated supply price for that pool. The price was then converted to constant 1990 dollars.

Economic assumptions and inputs

The major economic assumptions used in this study pertain to the fiscal systems, the appropriate exploration success rate, inflation rates, prices of co-products and minimum required discounted cash flow rate-of-return.

Fiscal systems. The current federal and provincial fiscal regimes were used in the determination of taxable income. Table 44 lists major fiscal parameters. It is assumed that all companies are fully taxable, and thereby able to claim all deductions in the year they become available.

Economic exploration success rate. The technical exploratory drilling success rate for each play was obtained by dividing the number of gas-bearing pools discovered by the number of exploratory tests. Only some of these pools, however, would earn the minimum required rate-of-return on investment to make them profitable to develop at expected prices. For exploration investment decisions, a measure of economic success is more relevant than technical success.

The economic success rate was estimated using the following method. The marginally economic pool for each play was defined as the smallest pool that provides an after-tax rate-of-return of 10 per cent at a plant gate price of \$88.25 per 10^3m^3, using half-cycle analysis. Costs used in the half-cycle analysis were those estimated for the reference case (as described below). The assumption was made that all discoveries larger than the defined marginal pool earn at least 10 per cent on a half-cycle basis, and are economic successes. Finally, the number of economic successes was divided by the number of exploratory tests to provide an estimate of the economic success ratio.

Inflation. The rate of inflation used to convert real costs and prices into nominal dollars was assumed to be 4 per cent per year.

Co-product prices. Co-product prices were estimated as a function of the price of natural gas or crude oil using historical correlations.

Minimum required rate-of-return. An expected real minimum after-tax and royalty rate-of-return of 10 per cent was assumed. The same rate was used for the burdened and unburdened cases to facilitate comparison.

ECONOMIC POTENTIAL OF MATURE PLAYS

Play groups

The 25 mature Devonian plays were assigned to five groups that reflect cost differences in exploration, development and production for different parts of Alberta and northeast British Columbia. The five play groups are:

1. Northwest Alberta, including Keg River shelf basin - Rainbow, Keg River shelf basin - Zama, Keg River shelf basin - Shekilie, Middle Devonian Clastics, and Slave Point reef complexes - Cranberry.

2. Peace River, including Wabamun structural and stratigraphic - Parkland, and Leduc fringing reef - Worsley.

3. West-central Alberta, including Swan Hills shelf margin - Kaybob South, Swan Hills isolated reef - Swan Hills, Leduc/Nisku reef complexes - Windfall, Nisku shelf margin - Brazeau River, Nisku isolated reef - Brazeau River, Wabamun platform facies - Pine Creek and Blue Ridge stratigraphic - Karr.

4. Southwest Alberta, including Leduc isolated reef - Westerose, Leduc reef - Nevis, Nisku shelf drape - Bashaw trend, Nisku shelf drape - Ricinus-Meadowbrook trend, Wabamun platform facies - Crossfield and Upper Devonian subcrop - Marten Hills.

5. Northeast British Columbia, including Keg River isolated reef - Yoyo, Slave Point barrier reef - Clarke Lake, Keg River platform - July Lake, Slave Point platform - Adsett, and Jean Marie biostrome - Helmet North.

Characteristics such as depth, recovery factor, gas composition, distance from gathering system, well spacing, and economic inputs for the reference case for each play in each group are given as an appendix in Dallaire et al. (1993). This appendix contains estimates of the proportions of resource expected to occur as nonassociated gas, solution gas or as sweet or sour gas. Estimates of the major cost components for the reference case are also provided.

Reference case assumptions

Economic potential was estimated for the reference case assuming the following: i) mean resource estimate for each undiscovered pool; ii) play-specific geological and engineering parameters and weighting factors; iii) play-specific economic exploration success rates; iv) current federal and provincial fiscal regimes; v) 1990 costs; and vi) a minimum required discounted cash flow real rate-of-return of 10 per cent on investment.

The reference case is based on data available at the time of the analysis. Improvements in economic success rates due to increased knowledge of exploration plays, reductions in development costs due to expansions of pipeline networks, or possible decreases in costs due to technological changes and improvements in company practices were not considered. Consequently, economic potential for the reference case should be considered to be closer to the current economics of exploration. It is likely an underestimate of long-term exploration fundamentals.

Economic potential estimates

Figures 88 to 93 depict supply curves for the mature Devonian plays. Figures 88 and 89 compare the full-cycle and half-cycle estimates of the volume of economically recoverable gas-in-place for the Devonian

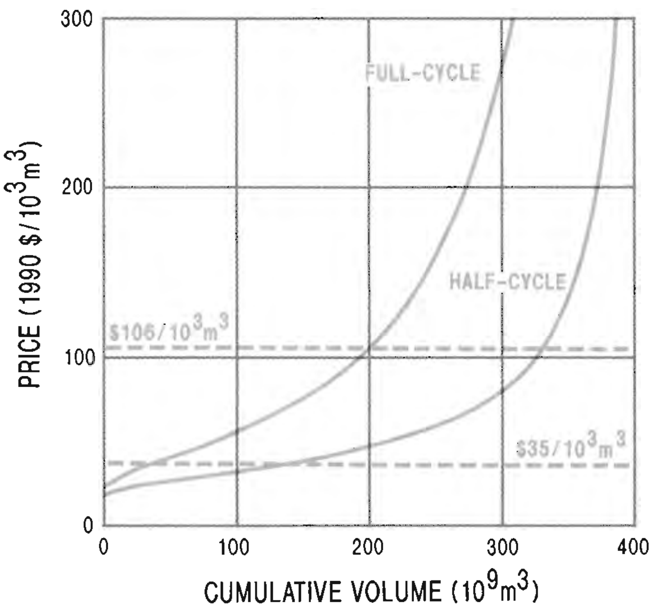

Figure 88. Burdened economic potential, all mature Devonian plays – cumulative recoverable gas-in-place volume.

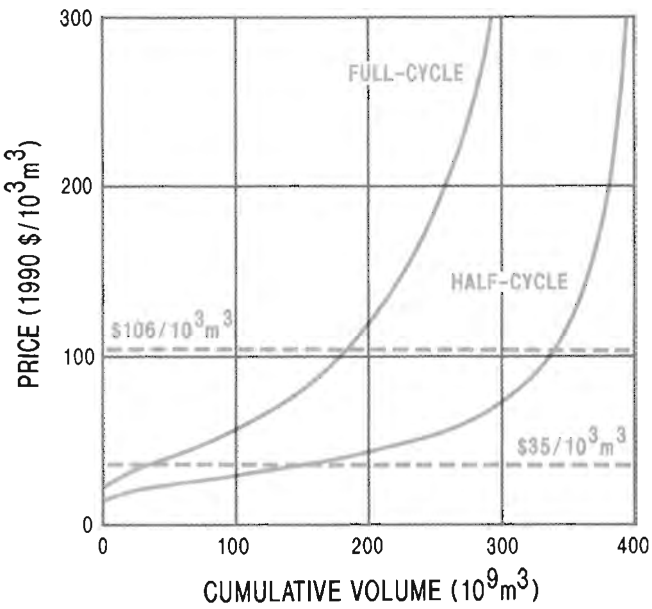

Figure 89. Unburdened economic potential, all mature Devonian plays – cumulative recoverable gas-in-place volume.

system, in burdened and unburdened contexts, respectively. Figures 90 and 91 present similar comparisons for economic potential measured in terms of percentage of total recoverable initial gas-in-place volume. The estimates of the percentage of undiscovered economic pools, in the total number of pools with a size greater than 1 x 10^6m^3 initial gas-in-place, are shown in Figures 92 and 93. Similar figures for each play group are given in Appendix IIb.

The supply curves depict a price range to $300 per 10^3m^3. A more realistic range for prices is $35 to $106 per 10^3m^3 ($1 to $3 per MCF). The bounds of this price range are shown with broken lines on each figure. For discussion purposes, results are referenced at two prices: $44.13 per 10^3m^3 ($1.25 per MCF), representing current prices, and $88.25 per 10^3m^3 ($2.50 per MCF), reflecting long-term price expectations.

The estimates of the volume of economic potential for the burdened full-cycle case at plant gate prices of $44.13 per 10^3m^3 and $88.25 per 10^3m^3 are summarized in Table 45. The unburdened full-cycle case, the burdened half-cycle case, and the unburdened half-cycle case are given in Tables 46, 47 and 48 respectively. Each table provides estimates of i) the volume of economic potential for recoverable and marketable gas, ii) economic potential as a percentage of the total technically recoverable potential, and iii) the number of economic pools and the percentage of economic pools to the total number of pools larger than 1 x 10^6m^3 initial gas-in-place. Results are presented for the total mature Devonian plays and separately for each of the five play groups.

Major conclusions with regard to economic potential are as follows:

1. Approximately 68 x 10^9m^3, or 16 per cent of the total recoverable gas-in-place volume is economic on a burdened full-cycle basis at $44.13 per 10^3m^3. Economic potential increases to 180 x 10^9m^3, or 43 per cent, at a price of $88.25 per 10^3m3.

2. Economic potential is significantly higher for the half-cycle case than for the full-cycle case. Economic potential on a burdened half-cycle basis is estimated to be 191 x 10^9m^3, or 45 per cent of the total recoverable gas-in-place volume at $44.13 per 10^3m^3, and 317 x 10^9m^3, or 75 per cent, at $88.25 per 10^3m^3. Half-cycle estimates are relevant because they are consistent with decisions to develop and produce pools that can earn the minimum required rate-of-return on marginal or incremental development and production costs. While pools that are economic on a half-cycle basis are not exploration targets, they are usually booked as reserves with provincial regulatory bodies.

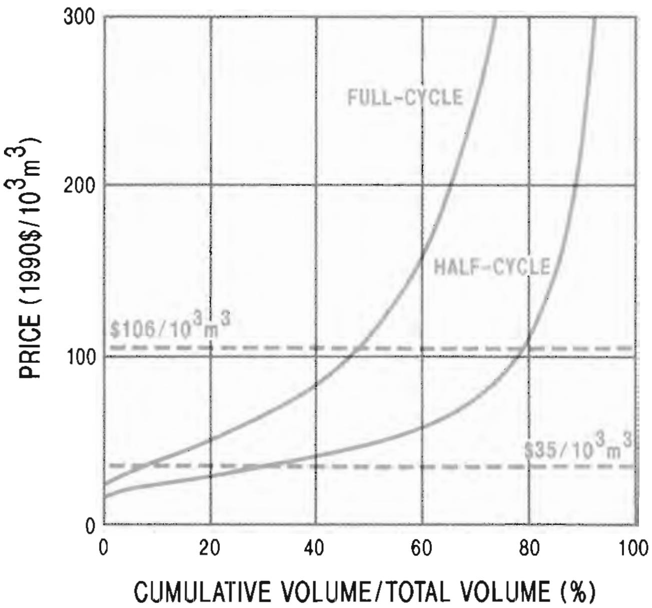

Figure 90. *Burdened economic potential, all mature Devonian plays – per cent of total recoverable gas-in-place volume.*

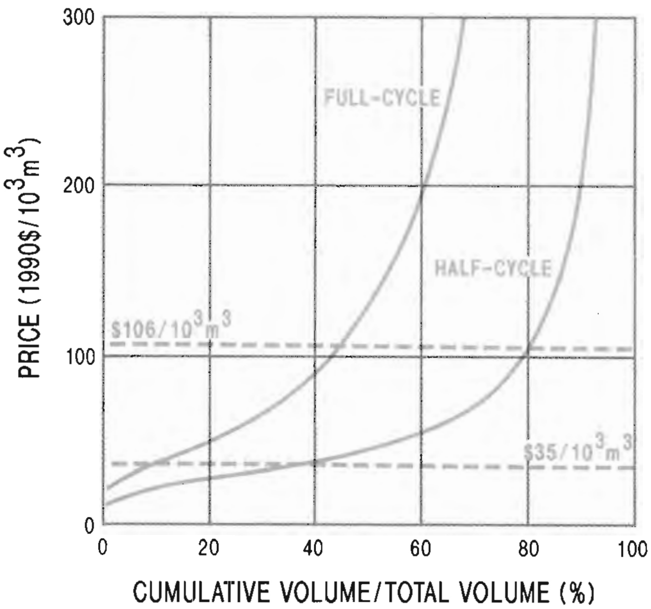

Figure 91. *Unburdened economic potential, all mature Devonian plays – per cent of total recoverable gas-in-place volume.*

3. Of the undiscovered pools estimated to have an initial gas-in-place volume larger than 1 x 10^6m^3, 1 per cent are economic on a burdened full-cycle basis at $44.13 per 10^3m^3. This percentage increases to 5 per cent at a price of $88.25 per 10^3m^3. Corresponding figures on a burdened half-cycle basis are 4 per cent and 16 per cent, respectively.

   The percentages should not be interpreted as exploration risk, which has already been taken into account in the analysis through the use of economic exploration success rates. The percentages are based on estimates of the number of pools having an initial in-place volume larger than 1 x 10^6m^3, which is the minimum size booked as reserves by the Alberta Energy Resources Conservation Board. Since many of these pools would never be considered as exploration targets because of their small size, these percentages would grossly underestimate the future economic drilling success rates.

4. There is little difference between burdened and unburdened economic potential. This is because the combined federal and provincial fiscal systems are, in part, sensitive to the profitability of investment. Since the supply curves estimated trace marginal investments that, by definition, have a minimum level of profitability, it follows that altering or eliminating the fiscal burden would have little impact on the economic potential at any given price.

   This suggests that the existing federal and provincial fiscal regimes do not significantly reduce the profitability of finding and developing marginally economic resources, but it does not mean that the more profitable investments are not paying significant taxes and royalties, or that activity would not be stimulated by a reduction in fiscal burden.

5. Estimates of economic potential vary among play groups. For example, at a plant gate price of $88.25 per 10^3m^3, the burdened full-cycle percentage of economic potential to total recoverable in-place volume varies from 23 per cent for the Peace River group to 57 per cent for the Southwest Alberta group. For the burdened half-cycle case, the corresponding percentage ranges from 69 per cent for the Northeast British Columbia group to 85 per cent for the Southwest Alberta group.

6. The supply curves are elastic in the price range of $17.65 to $88.25 per 10^3m^3 ($0.50 to $2.50 per MCF). That is, a given percentage increase in

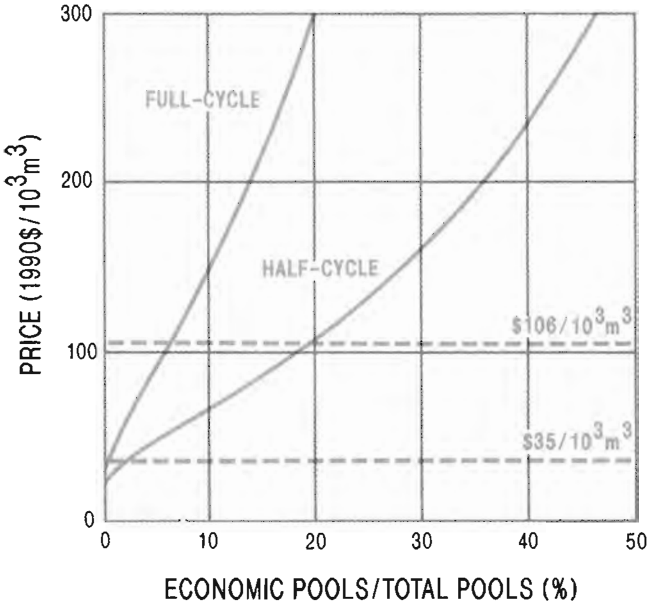

Figure 92. Burdened economic potential, all mature Devonian plays - per cent of total pools.

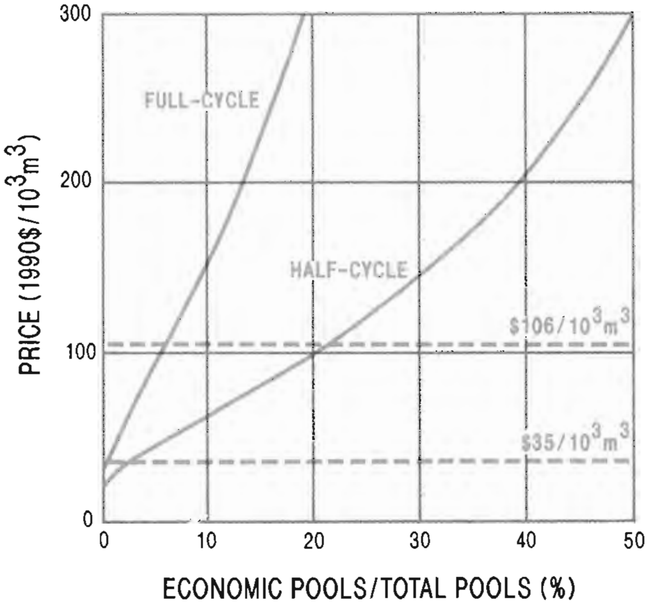

Figure 93. Unburdened economic potential, all mature Devonian plays - per cent of total pools.

supply price within this range leads to a more than proportional increase in economic potential. Above a price of $88.25 per 10^{3}m^3, the supply curve is relatively inelastic.

SENSITIVITY ANALYSIS

The economic potential estimates described in the previous section apply to the reference case. Significant variability and uncertainty, however, surround estimates of costs, exploration drilling success rates and the distance of discoveries to gathering systems. The impact of changes in these factors on economic potential is examined through sensitivity analysis. The analyses are described below.

Costs

Average exploration, development and production costs for each undiscovered pool were estimated in this study. Actual costs can be expected to vary significantly from these averages, reflecting differences in company practices, accessibility due to terrain and/or proximity to services, and costs of processing and transportation services. Technological changes in seismic techniques, drilling and processing, and improvements in company practices may result in significant future cost-savings. Total costs 20 per cent higher and 30 per cent lower than the reference case levels were examined in order to capture the impact of these differences and of future technological change.

Figure 94 shows the impact of changes in costs on the volume of economically recoverable gas-in-place. Table 49 compares the estimates of economic potential in terms of volume and in terms of the percentage of total recoverable gas-in-place between the reference case and the cost sensitivity cases. Comparisons are shown for aggregate results and for each play.

Observations on the impact of cost changes are as follows:

1. While changes in costs do affect the various measures of burdened full-cycle economic potential, the impact is modest. An increase in costs of 20 per cent, relative to the reference case, results in reductions in total economic potential of approximately 10 per cent at a plant gate price of $44.13 per 10^{3}m^3, and 6 per cent at a plant gate price of $88.25 per 10^{3}m^3. Decreasing costs by 30 per cent increases economic potential by 11 per cent at $44.13 per 10^{3}m^3, and 3 per cent at $88.25 per 10^{3}m^3.

2. The relatively small impact of cost changes on the volume of economic potential is attributed partly to the fiscal system, which provides a buffer to upward and downward cost changes.

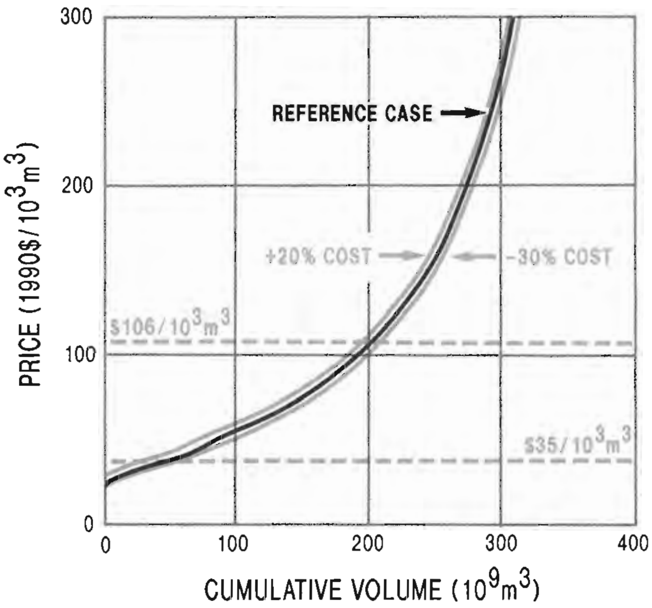

Figure 94. Sensitivity to cost, all mature Devonian plays - cumulative recoverable gas-in-place volume.

3. The smaller impact at higher prices is the result of the pool size distribution being skewed toward smaller pools. At high prices, only small pools are contributing to total economic potential. Hence, any changes in costs do not significantly change the volume of economic resources.

Exploration drilling success rates

The success rates are based on historical data. For some plays, the calculated technical success rates are likely biased downward because the number of exploratory tests attributed to the play are probably overestimated. The estimated number of exploration tests may include: i) wells drilled in the period prior to the current knowledge of the play; ii) wells that penetrated the formation, but are not in fact testing a prospect; and iii) wells targeted for oil.

To estimate the impact of drilling success on the economic potential estimates, economic drilling success rates for all plays were doubled, with the constraint that the revised economic success rates not exceed 50 per cent. This sensitivity analysis reflects an expectation that overall improvements in the economic success rates may be achieved over time through increased geological understanding.

Figure 95 compares the results of this case to the reference case, for the burdened full-cycle example. Table 50 provides the results at $44.13 per 10^3m^3 and $88.25 per 10^3m^3. Observations on the impact of increased drilling success rates are:

1. Doubling economic success rates for all plays increases total economic potential by 38 per cent at a plant gate price of $44.13 per 10^3m^3, and 20 per cent at $88.25 per 10^3m^3.

2. The sensitivity on success rates highlights the importance of pre-drilling investment in increasing economic potential.

Distance to gathering systems

Estimates of average distances of future discoveries from a gathering system were based on the location of the current pipeline network. It is reasonable to expect that discoveries considered uneconomic because they are too far from an existing transportation network may become economically viable as pipeline networks expand to serve new locations. To examine the impact of network expansion on estimates of economic potential, average distances of pools to a gathering system have been reduced to 2.5 km for all plays. Since pipeline costs to connect to a gathering system may be the dominant cost of development in some cases, the

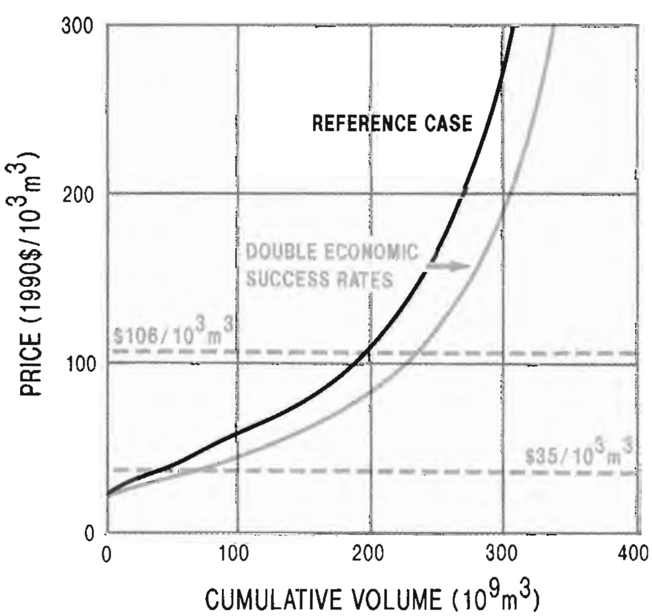

Figure 95. Sensitivity to drilling success rate, all mature Devonian plays - cumulative recoverable gas-in-place volume.

impact of this change on half-cycle economic potential was also examined. Figure 96 compares the results of these sensitivities to the reference case for the burdened full-cycle and half-cycle cases, and Tables 51 and 52 provide results for the full-cycle and the half-cycle cases, respectively.

Observations on the impact of changes in distance are:

1. At \$44.13 per 10^3m^3, burdened full-cycle economic potential increases by 16 per cent. In the half-cycle analysis, economic potential increases by 17 per cent. This relatively large increase in economic potential results from the fact that, at these low prices, it is the relatively large pools, with higher pipeline costs, that contribute to economic potential.

2. At \$88.25 per 10^3m^3, burdened full-cycle economic potential increases by 3 per cent. This increase is modest because for small pools, a greater number of which are economic at high prices, exploration costs are a relatively larger component of total costs than are pipeline costs. In the half-cycle analysis economic potential increases by 6 per cent.

3. The half-cycle result at \$88.25 per 10^3m^3 and 2.5 km indicate that almost 80 per cent of the total recoverable gas-in-place is economic. This result is consistent with the practice of treating the bulk of reserves booked with provincial regulatory bodies as economically recoverable, reflecting an expectation that price increases and/or reductions in development costs will make small pools economically viable.

EXTENSION OF ECONOMIC ANALYSIS TO CONCEPTUAL PLAYS

Approximately 70 per cent of the undiscovered resource for Devonian gas is estimated to exist in conceptual plays. Detailed geological characteristics of these plays are unknown and consequently, estimates of exploration, development and production costs are speculative. The economic potential of these resources was estimated by extending the results for mature plays to the resources estimated to exist in conceptual plays. This was accomplished by applying the proportion of economic potential to total recoverable gas-in-place volume for mature plays to the total estimated recoverable gas-in-place volume for conceptual plays. The recovery factor for conceptual plays was assumed to be 75 per cent.

Figure 97 shows the economic potential for the entire Devonian system, including conceptual plays. Table 53 provides estimates at \$44.13 per 10^3m^3 and

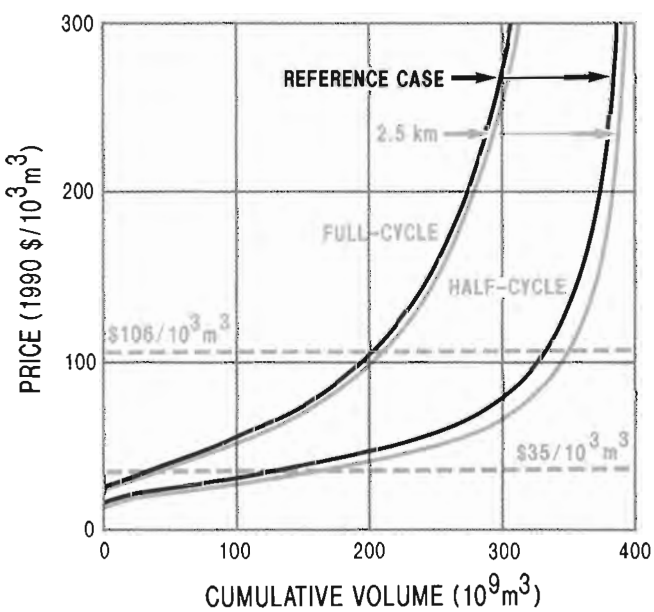

Figure 96. Sensitivity to distance to pipeline, all mature Devonian plays – cumulative recoverable gas-in-place volume.

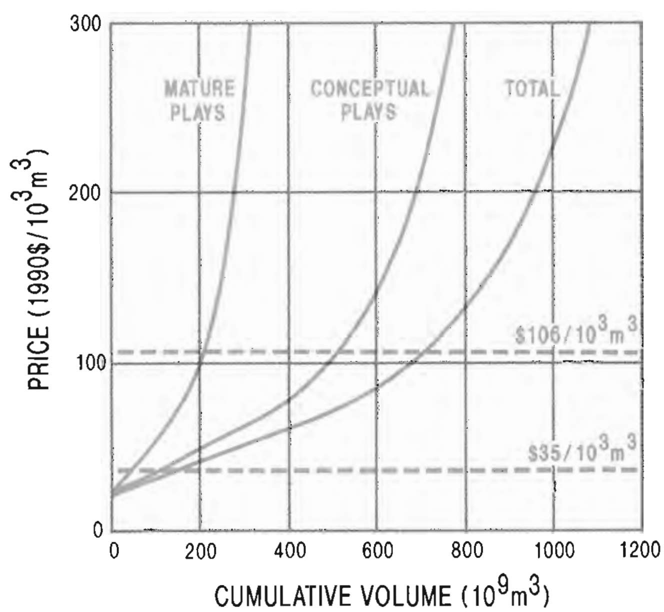

Figure 97. Burdened economic potential, mature and conceptual plays – cumulative recoverable gas-in-place volume.

\$88.25 per 10^3m^3. The addition of economic potential of conceptual plays to the estimates of economic potential of mature plays increases burdened full-cycle economic potential from 68 x 10^9m^3 to 240 x 10^9m^3 at \$44.13 per 10^3m^3, and from 180 x 10^9m^3 to 634 x 10^9m^3 at \$88.25 per 10^3m^3.

IMPACT OF LAND COSTS

The supply curves presented here do not consider land acquisition costs. In general, land acquisition costs are recovered from profits in addition to those required to recover all exploration, development and production costs and provide investors with the minimum required rate-of-return. Additional profits are realized when the sale price of gas exceeds the supply price. Estimates of high profitability likely result in premium land prices. Conversely, marginal profitability supports decisions not to acquire land rights.

For selected plays in each group, the impact of land costs on supply prices was estimated for pool sizes that are marginally economic at \$44.13 per 10^3m^3 and at \$88.25 per 10^3m^3 for the burdened full-cycle case. Land costs also include those associated with dry and abandoned drilling locations and are provided as regional averages in Table 54.

When land costs are included, the supply price increases by \$0.35 per 10^3m^3 (\$0.01 per MCF) to \$9.01 per 10^3m^3 (\$0.25 per MCF), depending on the play. These increases correspond to increases in supply prices of 1 to 10 per cent. This range indicates the extent to which all supply prices are likely to be underestimated.

CONCLUSIONS

This study provides an estimate of the economic potential of undiscovered Devonian natural gas resources by placing technical and economic constraints on the resource assessment contained in Part I. Major conclusions are:

1. On a burdened full-cycle basis, economic potential as a percentage of recoverable gas-in-place volume ranges from 16 per cent at a plant price of \$44.13 per 10^3m^3 (\$1.25 per MCF), to 43 per cent at a price of \$88.25 per 10^3m^3 (\$2.50 per MCF). For the half-cycle case, the corresponding percentages range from 45 per cent to 75 per cent.

2. Of the undiscovered pools estimated to have an initial gas-in-place volume larger than 1 x 10^6m^3, 1 per cent are economic on a burdened full-cycle basis at \$44.13 per 10^3m^3. This percentage increases to 5 per cent at a price of \$88.25 per 10^3m^3. Corresponding figures on a burdened half-cycle basis are 4 per cent and 16 per cent, respectively.

3. The supply curve is elastic in the price range of \$17.65 per 10^3m^3 to \$88.25 per 10^3m^3 (\$0.50 to \$2.50 per MCF).

4. There is little difference between the burdened and unburdened economic potential.

5. Estimates of the economic potential are not highly sensitive to changes in total costs. For example, a 20 per cent increase in total costs results in a reduction of economic potential of 10 per cent at \$44.13 per 10^3m^3, whereas a 30 per cent decrease in costs increases economic potential by 11 per cent at the same price.

6. Doubling the economic success rates increases economic potential by 38 per cent at a price of \$44.13 per 10^3m^3.

7. Reducing pipeline distance from a gathering system to 2.5 km increases burdened full-cycle economic potential by 16 per cent at \$44.13 per 10^3m^3 and by 3 per cent at \$88.25 per 10^3m^3. Half-cycle results show similar percentage increases in economic potential.

8. Extension of results of economic analysis for mature Devonian plays to the conceptual plays increases burdened full-cycle economic potential from 68 x 10^9m^3 to 240 x 10^9m^3 at \$44.13 per 10^3m^3, and from 180 x 10^9m^3 to 634 x 10^9m^3, at \$88.25 per 10^3m^3.

9. Including land costs increases the supply price for marginally economic pools by \$0.35 per 10^3m^3 (\$0.01 per MCF) to \$9.01 per 10^3m^3 (\$0.25 per MCF), depending on the play. These increases correspond to increases in supply prices of 1 to 10 per cent.

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APPENDIX IIa: Tables 41 to 54

TABLE 41

Revenues and costs considered in economic analysis

Revenues	Costs
(i) Natural gas (ii) Co-productions	(i) Overheads (ii) Exploration (including geological and geophysical costs) (iii) Development and gathering (iv) Production and gas processing (v) Taxes and royalities

TABLE 42

Type of economic analysis

Economic analysis	Full-cycle	Half-cycle
Burdened	(i)-(v)	(i), (iii)-(v)
Unburdened	(i)-(iv)	(i), (iii), (iv)

TABLE 43

Characteristics of production profiles by size class

Size class ($10^6 m^3$)	≤30	>30 and ≤100	>100 and ≤400	>400 and ≤2000	>2000
Constant production rate-of-take (days)	1460	2190	2920	3650	4380
No. years at initial rate	2	3	4	5	6
No. years on decline	5	7	9	11	13
Total prod. life (yrs.)	7	10	13	16	19
Decline rate (approx.)	38%	27%	21%	17%	15%

TABLE 44

Fiscal parameters

Canadian exploration expense (CEE)	100% write-off
Canadian development expense (CDE)	30% declining balance
Capital cost allowance (CCA)	25% declining balance, except for sales gas transmission line (if any), which is 4% or 20% declining balance, depending on useful life
Federal tax rate	28.84%
Provincial tax rates	15.50% Alberta 15.00% British Columbia

TABLE 45

Recoverable and marketable resources, burdened full-cycle case

Plant gate price: \$44.13 per 10^3m^3

	Undiscovered gas-in-place (10^6m^3)		Economic marketable gas (10^6m^3)		Economic marketable gas (10^6m^3)		Undiscovered pools (initial in-place volume >$1x10^6m^3$)		
	Initial	Recoverable	Total	% Recoverable in-place	Total	% Recoverable in-place	Total	Economic	Economic as % of total
All mature Devonian plays	563 912	422 934	68 143	16	56 757	13	6 843	66	1.0
Northwest Alberta plays	121 531	91 148	20 889	23	18 720	21	1 675	30	1.8
Peace River region plays	49 316	36 987	2 653	7	2 383	6	911	2	0.2
West-central Alberta plays	167 291	125 468	13 467	11	10 515	8	1 907	14	0.7
Southwest Alberta plays	83 357	62 518	16 956	27	13 297	21	1 027	13	1.3
Northeast B.C. plays	142 417	106 813	15 207	14	12 710	12	1 323	9	0.7

Plant gate price \$88.25 per 10^3m^3

	Undiscovered gas-in-place (10^6m^3)		Economic marketable gas (10^6m^3)		Economic marketable gas (10^6m^3)		Undiscovered pools (initial in-place volume >$1x10^6m^3$)		
	Initial	Recoverable	Total	% Recoverable in-place	Total	% Recoverable in-place	Total	Economic	Economic as % of total
All mature Devonian plays	563 912	422 934	180 252	43	149 411	35	6 843	334	4.9
Northwest Alberta plays	121 531	91 148	42 975	47	38 347	42	1 675	147	8.8
Peace River region plays	49 316	36 987	8 679	23	7 724	21	911	10	1.1
West-central Alberta plays	167 291	125 468	45 998	37	35 128	28	1 907	53	2.8
Southwest Alberta plays	83 357	62 518	35 634	57	28 525	46	1 027	61	5.9
Northeast B.C. plays	142 417	106 813	47 671	45	40 306	38	1 323	65	4.9

TABLE 46

Recoverable and marketable resources, unburdened full-cycle case

Plant gate price: $44.13 per 10^3m^3

	Undiscovered gas-in-place (10^6m^3)		Economic marketable gas (10^6m^3)		Economic marketable gas (10^6m^3)		Undiscovered pools (initial in-place volume $>1x10^6m^3$)		
	Initial	Recoverable	Total	% Recoverable in-place	Total	% Recoverable in-place	Total	Economic	Economic as % of total
All mature Devonian plays	563 912	422 934	73 404	17	61 287	14	6 843	77	1.1
Northwest Alberta plays	121 531	91 148	23 342	26	20 924	23	1 675	34	2.0
Peace River regions plays	49 316	36 987	2 653	7	2 383	6	911	2	0.2
West-central Alberta plays	167 291	125 468	14 110	11	11 060	9	1 907	16	0.8
Southwest Alberta plays	83 357	62 518	18 240	29	14 344	23	1 027	17	1.7
Northeast B.C. plays	142 417	106 813	15 207	14	12 710	12	1 323	9	0.7

Plant gate price: $88.25 per 10^3m^3

	Undiscovered gas-in-place (10^6m^3)		Economic marketable gas (10^6m^3)		Economic marketable gas (10^6m^3)		Undiscovered pools (initial in-place volume $>1x10^6m^3$)		
	Initial	Recoverable	Total	% Recoverable in-place	Total	% Recoverable in-place	Total	Economic	Economic as % of total
All mature Devonian plays	563 912	422 934	165 570	39	138 110	33	6 843	315	4.6
Northwest Alberta plays	121 531	91 148	41 146	45	36 960	40	1 675	131	7.8
Peace River region plays	49 316	36 987	9 204	25	8 188	22	911	11	1.2
West-central Alberta plays	167 291	125 468	31 960	25	24 450	19	1 907	48	2.5
Southwest Alberta plays	83 357	62 518	35 893	57	28 761	46	1 027	63	6.1
Northeast B.C. plays	142 417	106 813	48 009	45	40 589	38	1 323	65	4.9

TABLE 47

Recoverable and marketable resources, burdened half-cycle case

Plant gate price: \$44.13 per 10^3m^3

	Undiscovered gas-in-place (10^6m^3)		Economic marketable gas (10^6m^3)		Economic marketable gas (10^6m^3)		Undiscovered pools (initial in-place volume $>1x10^6m^3$)		
	Initial	Recoverable	Total	% Recoverable in-place	Total	% Recoverable in-place	Total	Economic	Economic as % of total
All mature Devonian plays	563 912	422 934	191 166	45	157 749	37	6 843	277	4.0
Northwest Alberta plays	121 531	91 148	37 230	41	33 398	37	1 675	46	2.7
Peace River region plays	49 316	36 987	19 387	52	17 218	47	911	53	5.8
West-central Alberta plays	167 291	125 468	57 869	46	43 970	35	1 907	59	3.1
Southwest Alberta plays	83 357	62 518	39 811	64	31 932	51	1 027	70	6.8
Northeast B.C. plays	142 147	106 813	37 807	35	32 113	30	1 323	51	3.9

Plant gate price: \$88.25 per 10^3m^3

	Undiscovered gas-in-place (10^6m^3)		Economic marketable gas (10^6m^3)		Economic marketable gas (10^6m^3)		Undiscovered pools (initial in-place volume $>1x10^6m^3$)		
	Initial	Recoverable	Total	% Recoverable in-place	Total	% Recoverable in-place	Total	Economic	Economic as % of total
All mature Devonian plays	563 912	422 934	317 107	75	262 413	62	6 843	1 096	16.0
Northwest Alberta plays	121 531	91 148	65 416	72	58 415	64	1 675	230	13.7
Peace River region plays	49 316	36 987	27 231	74	24 186	65	911	148	16.2
West-central Alberta plays	167 291	125 468	98 154	78	74 871	60	1 907	261	13.7
Southwest Alberta plays	83 357	62 518	53 013	85	42 742	68	1 027	215	20.9
Northeast B.C. plays	142 417	106 813	73 294	69	62 199	58	1 323	242	18.3

TABLE 48

Recoverable and marketable resources, unburdened half-cycle case

Plant gate price: $44.13 per 10^3m^3

	Undiscovered gas-in-place (10^6m^3)		Economic marketable gas (10^6m^3)		Economic marketable gas (10^6m^3)		Undiscovered pools (initial in-place volume $>1x10^6m^3$)		
	Initial	Recoverable	Total	% Recoverable in-place	Total	% Recoverable in-place	Total	Economic	Economic as % of total
All mature Devonian plays	563 912	422 934	206 976	49	171 123	40	6 843	336	4.9
Northwest Alberta plays	121 531	91 148	41 446	45	37 164	41	1 675	58	3.5
Peace River region plays	49 316	36 987	20 122	54	17 879	48	911	59	6.5
West-central Alberta plays	167 291	125 468	61 803	49	46 955	37	1 907	67	3.5
Southwest Alberta plays	83 357	62 518	43 141	69	34 737	56	1 027	95	9.3
Northeast B.C. plays	142 417	106 813	41 150	39	34 994	33	1 323	59	4.5

Plant gate price: $88.25 per 10^3m^3

	Undiscovered gas-in-place (10^6m^3)		Economic marketable gas (10^6m^3)		Economic marketable gas (10^6m^3)		Undiscovered pools (initial in-place volume $>1x10^6m^3$)		
	Initial	Recoverable	Total	% Recoverable in-place	Total	% Recoverable in-place	Total	Economic	Economic as % of total
All mature Devonian plays	563 912	422 934	325 303	77	269 497	64	6 843	1 200	17.5
Northwest Alberta plays	121 531	91 148	67 428	74	60 195	66	1 675	255	15.2
Peace River region plays	49 361	36 987	27 622	75	24 534	66	911	157	17.2
West-central Alberta plays	167 291	125 468	100 022	80	76 304	61	1 907	283	14.8
Southwest Alberta plays	83 357	62 518	53 213	85	42 910	69	1 027	222	21.6
Northeast B.C. plays	142 417	106 813	77 018	72	65 554	61	1 323	283	21.4

TABLE 49

Sensitivity of estimates of economic potential to changes in total costs, burdened full-cycle case

Plant gate price: $44.13 per 10^3m^3

	Reference case		20% increase in total costs			30% decrease in total costs		
	Recoverable in-place (10^6m^3)	% Recoverable in-place	Recoverable in-place (10^6m^3)	% Recoverable in-place	% Change	Recoverable in-place (10^6m^3)	% Recoverable in-place	% Change
All mature Devonian plays	68 143	16	61 369	15	-10	75 744	18	+11
Northwest Alberta plays	20 889	23	20 238	22	-3	23 957	26	+15
Peace River region plays	2653	7	2 653	7	0	3836	10	+45
West-central Alberta plays	13 467	1	13 303	11	-1	14 110	11	+5
Southwest Alberta plays	16 956	27	14 370	23	-15	18 472	30	+9
Northeast B.C. plays	15 207	14	14 342	13	-6	16 783	16	+10

Plant gate price: $88.25 per 10^3m^3

	Reference case		20% increase in total costs			30% decrease in total costs		
	Recoverable in-place (10^6m^3)	% Recoverable in-place	Recoverable in-place (10^6m^3)	% Recoverable in-place	% Change	Recoverable in-place (10^6m^3)	% Recoverable in-place	% Change
All mature Devonian plays	180 252	43	170 137	40	-6	184 841	44	+33
Northwest Alberta plays	42 975	47	41 003	45	-5	44 307	49	+3
Peace River region plays	8679	23	8 290	22	-4	9204	25	+6
West-central Alberta plays	45 998	37	43 717	35	-5	46 279	37	+1
Southwest Alberta plays	35 635	57	32 985	56	-2	36 066	58	+1
Northeast B.C. plays	47 671	45	42 942	40	-10	49 167	46	+3

TABLE 50

Sensitivity of estimates of economic potential to changes in drilling success rates, burdened full-cycle case

Plant gate price: $44.13 per 10^3m^3

	Reference case		Economic success rate double (Max. 50%)		
	Recoverable in-place (10^6m^3)	**%Recoverable in-place**	**Recoverable in-place (10^6m^3)**	**%Recoverable in-place**	**% Change**
All mature Devonian plays	68 143	16	94 296	22	+38
Northwest Alberta plays	20 889	23	25 010	27	+20
Peace River region plays	2 653	7	5 750	16	+117
West-central Alberta plays	13 467	11	21 938	17	+63
Southwest Alberta plays	16 956	27	23 518	38	+39
Northeast B.C. plays	15 207	14	18 244	17	+20

Plant gate price: $88.25 per 10^3m^3

	Reference case		Economic success rate double (Max. 50%)		
	Recoverable in-place (10^6m^3)	**%Recoverable in-place**	**Recoverable in-place (10^6m^3)**	**%Recoverable in-place**	**% Change**
All mature Devonian plays	180 252	43	216 182	51	+20
Northwest Alberta plays	42 975	47	48 628	52	+13
Peace River region plays	8 679	23	13 104	35	+51
West-central Alberta plays	45 998	37	59	47	+29
Southwest Alberta plays	35 634	57	43 308	69	+22
Northeast B.C. plays	47 671	45	51 953	49	+9

TABLE 51

Sensitivity of estimates of economic potential to changes in distance to pipeline, burdened full-cycle case

Plant gate price: $44.13 per 10^3m^3

	Reference case		Distance to pipeline set to 2.5 km		
	Recoverable in-place (10^6m^3)	% Recoverable in-place	Recoverable in-place (10^6m^3)	% Recoverable in-place	% Change
All mature Devonian plays	68 143	16	79 066	19	+16
Northwest Alberta plays	20 889	23	23 702	26	+13
Peace River region plays	2 653	7	2 653	7	0
West-central Alberta plays	13 467	11	13 962	11	+4
Southwest Alberta plays	16 956	27	17 220	28	+2
Northeast B.C. plays	15 207	14	22 094	21	+45

Plant gate price: $88.25 per 10^3m^3

	Reference case		Distance to pipeline set to 2.5 km		
	Recoverable in-place (10^6m^3)	% Recoverable in-place	Recoverable in-place (10^6m^3)	% Recoverable in-place	% Change
All mature Devonian plays	180 252	43	185 548	44	+3
Northwest Alberta plays	42 975	47	44 425	49	+3
Peace River region plays	8 679	23	9 204	25	+6
West-central Alberta plays	45 998	37	46 230	37	+1
Southwest Alberta plays	35 634	57	35 815	57	+1
Northeast B.C. plays	47 671	45	50 545	47	+6

TABLE 52

Sensitivity of estimates of economic potential to changes in distance to pipeline, burdened half-cycle case

Plant gate price: $44.13 per 10^3m^3

	Reference case		Distance to pipeline set to 2.5 km		
	Recoverable in-place (10^6m^3)	**%Recoverable in-place**	**Recoverable in-place (10^6m^3)**	**%Recoverable in-place**	**% Change**
All mature Devonian plays	191 166	45	224 235	53	+17
Northwest Alberta plays	37 230	41	47 319	52	+27
Peace River region plays	19 387	52	20 747	56	+7
West-central Alberta plays	57 869	46	64 914	52	+12
Southwest Alberta plays	39 811	64	43 036	69	+8
Northeast B.C. plays	37 807	35	48 536	45	+238

Plant gate price: $88.25 per 10^3m^3

	Reference case		Distance to pipeline set to 2.5 km		
	Recoverable in-place (10^6m^3)	**%Recoverable in-place**	**Recoverable in-place (10^6m^3)**	**%Recoverable in-place**	**% Change**
All mature Devonian plays	317 107	75	335 705	79	+6
Northwest Alberta plays	65 416	72	72 353	79	+11
Peace River region plays	27 231	74	28 246	76	+4
West-central Alberta plays	98 154	78	103 896	83	+6
Southwest Alberta plays	53 013	85	53 525	86	+1
Northeast B.C. plays	73 294	69	77 685	73	+6

TABLE 53

Estimate of economic potential for conceptual plays, burdened full-cycle case

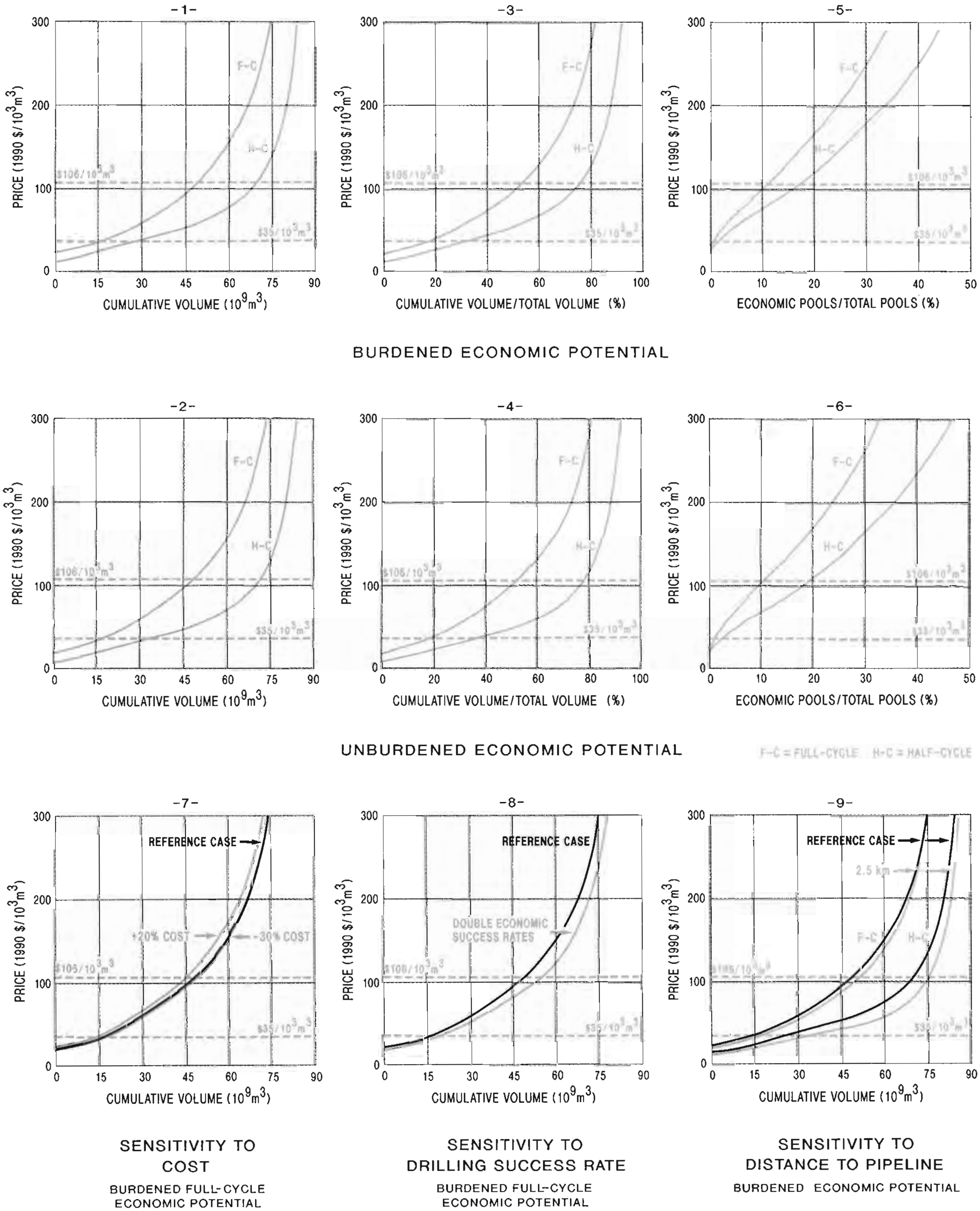
	Recoverable gas-in-volume (10^9m^3)	
	Plant gate price: \$44.13 per 10^3m^3	Plant gate price: \$88.25 per 10^3m^3
25 mature plays	68	180
Conceptual plays	171	453
Total plays	240	634

TABLE 54

Impact of land costs on supply prices

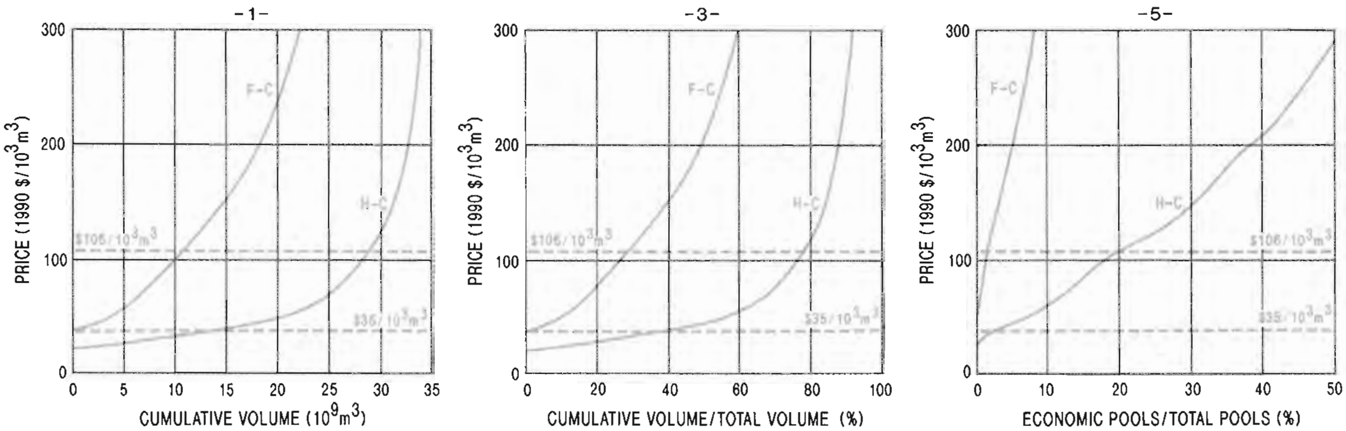
Play group	Play name	Land cost (\$ per hectare)	Pool size (10^6m^3)	Supply price without land (\$ per 10^3m^3) (1)	Supply price with land (\$ per 10^3m^3) (2)	%Increase $\frac{(2)-(1)}{(1)}$
Northwest Alberta	Zama	117	548	47.91	52.05	8.6
			173	88.15	95.99	8.9
Peace River region	Worsley	235	1653	40.40	44.28	9.6
			519	88.37	97.38	10.2
West-central Alberta	Kaybob South	275	4274	63.29	64.30	1.6
			2143	88.25	90.57	2.6
Southwest Alberta	Westerose	140	2452	44.17	44.52	0.8
			824	91.40	93.16	1.9
Northeast B.C.	Clarke Lake	205	1157	41.42	42.19	1.9
			319	88.04	91.26	3.7

APPENDIX IIb: Supply curves for the five play groups

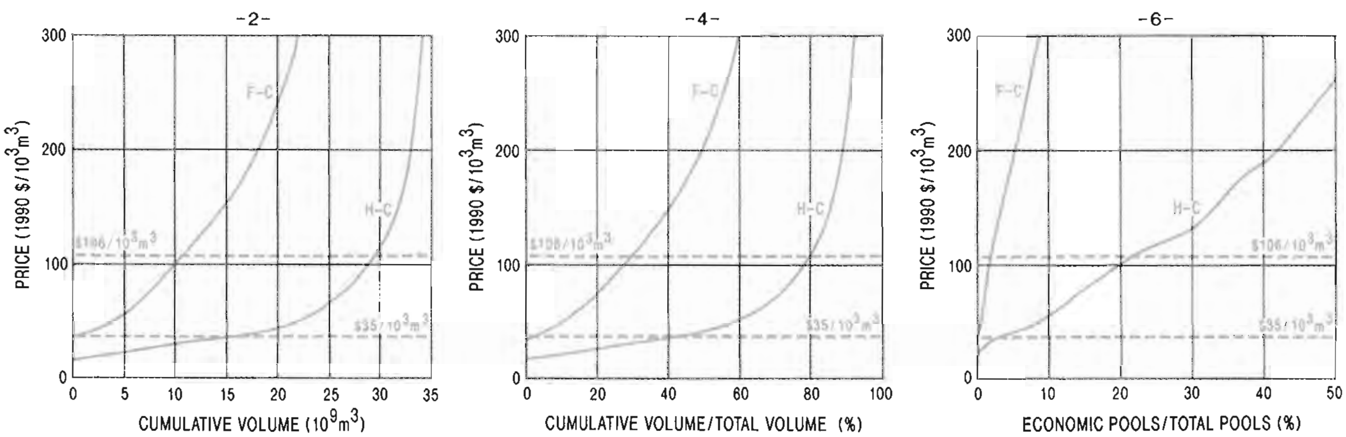


SUPPLY CURVES FOR NORTHWEST ALBERTA PLAY GROUP

FIGURE A

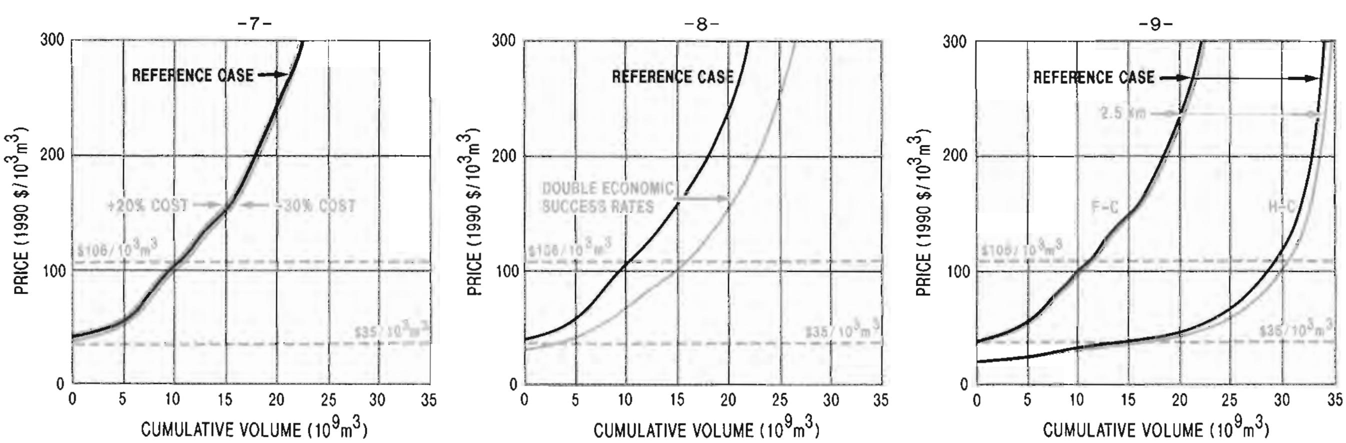


BURDENED ECONOMIC POTENTIAL



UNBURDENED ECONOMIC POTENTIAL

F-C = FULL-CYCLE H-C = HALF-CYCLE



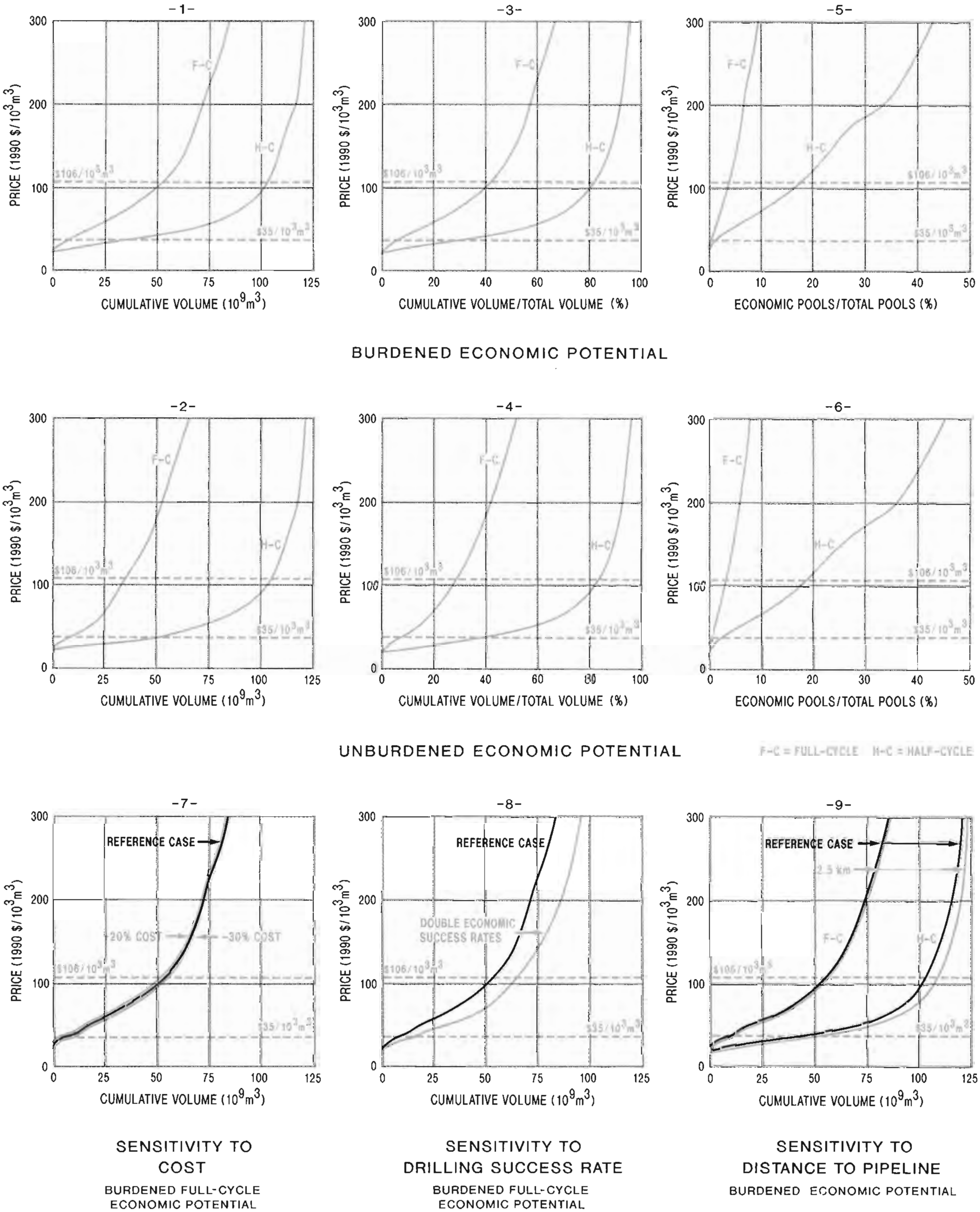
SENSITIVITY TO COST
BURDENED FULL-CYCLE ECONOMIC POTENTIAL

SENSITIVITY TO DRILLING SUCCESS RATE
BURDENED FULL-CYCLE ECONOMIC POTENTIAL

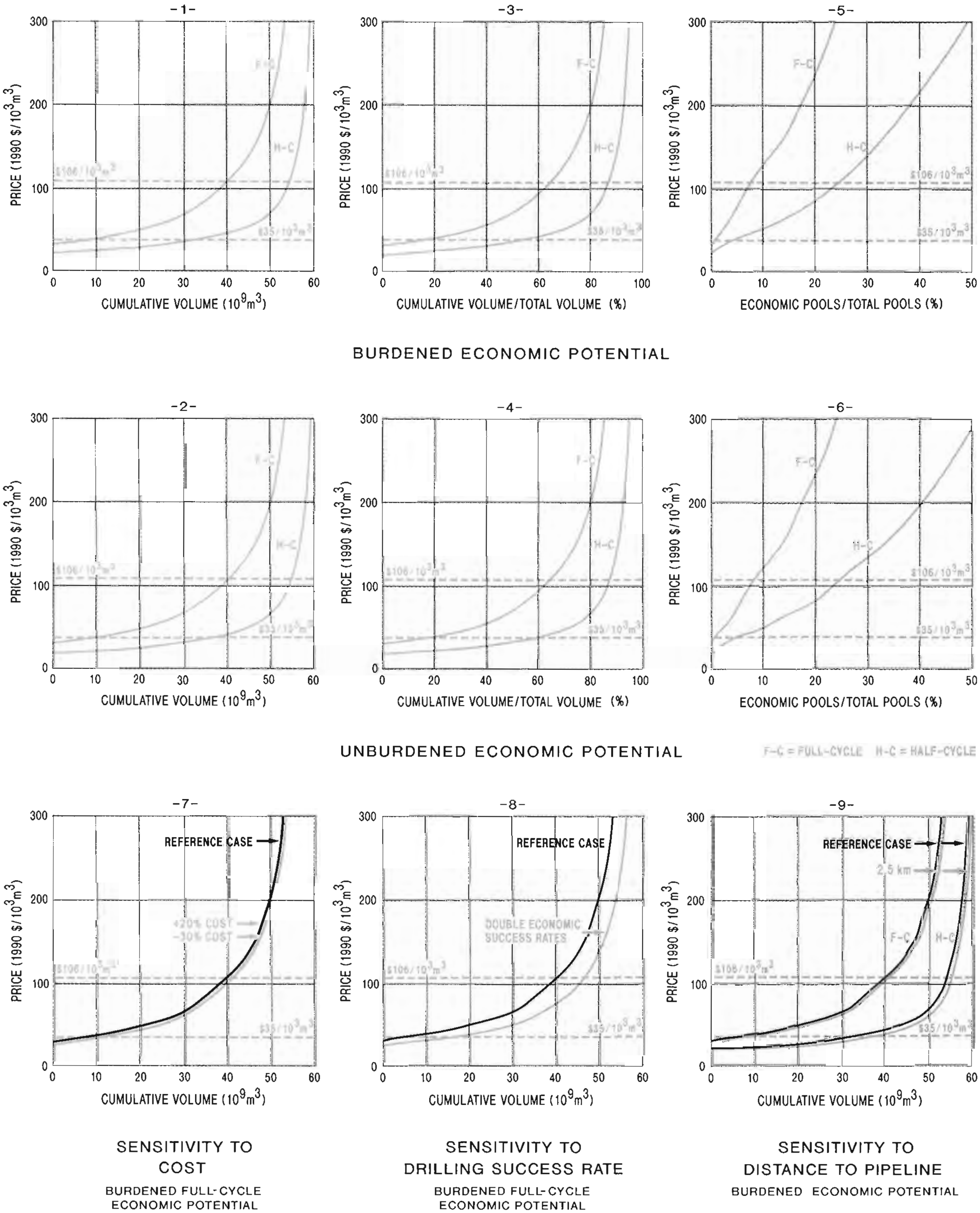
SENSITIVITY TO DISTANCE TO PIPELINE
BURDENED ECONOMIC POTENTIAL

SUPPLY CURVES FOR PEACE RIVER REGION PLAY GROUP

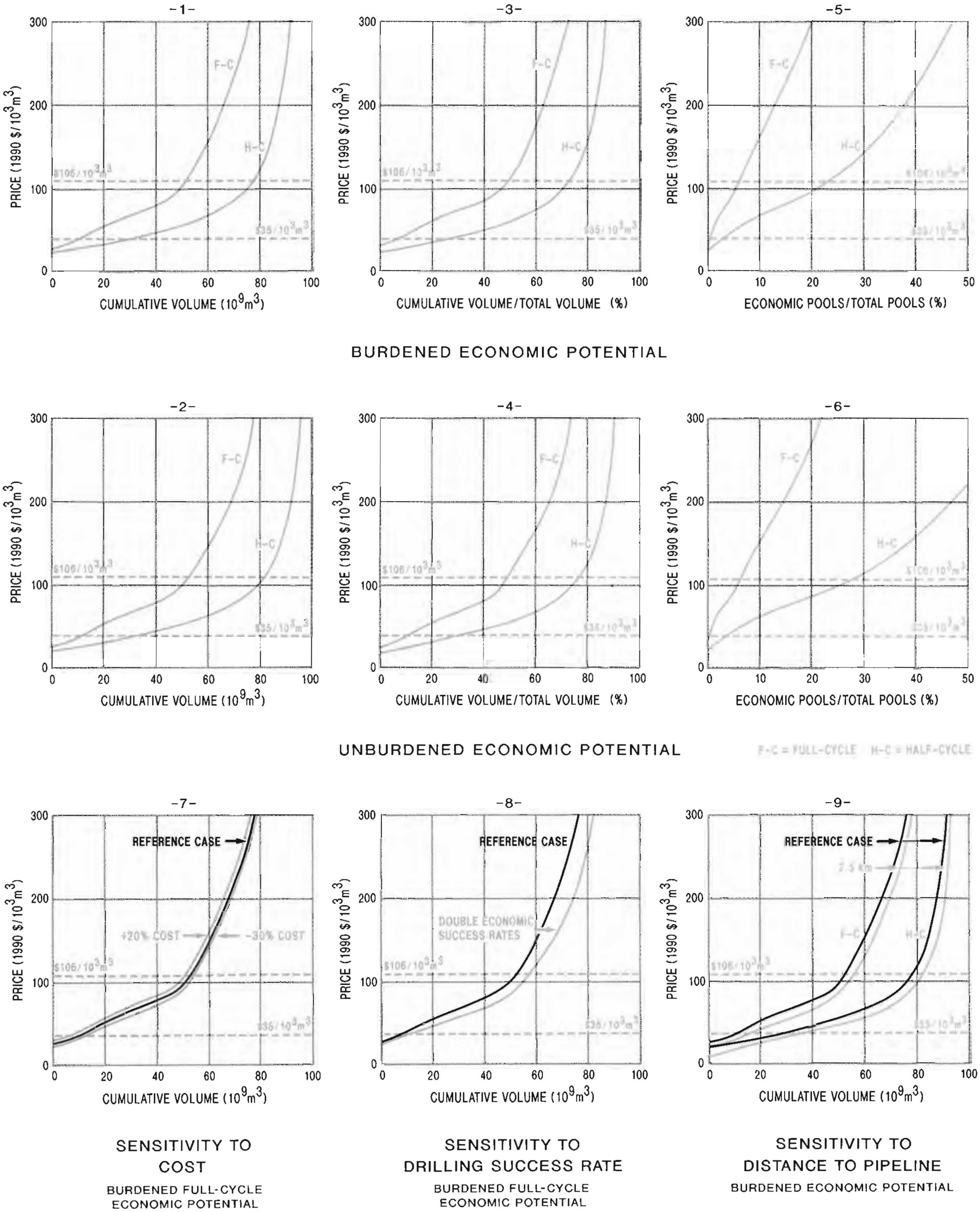
FIGURE B



SUPPLY CURVES FOR WEST-CENTRAL ALBERTA PLAY GROUP FIGURE C



SUPPLY CURVES FOR SOUTHWEST ALBERTA PLAY GROUP — FIGURE D



SUPPLY CURVES FOR NORTHEAST BRITISH COLUMBIA PLAY GROUP FIGURE E