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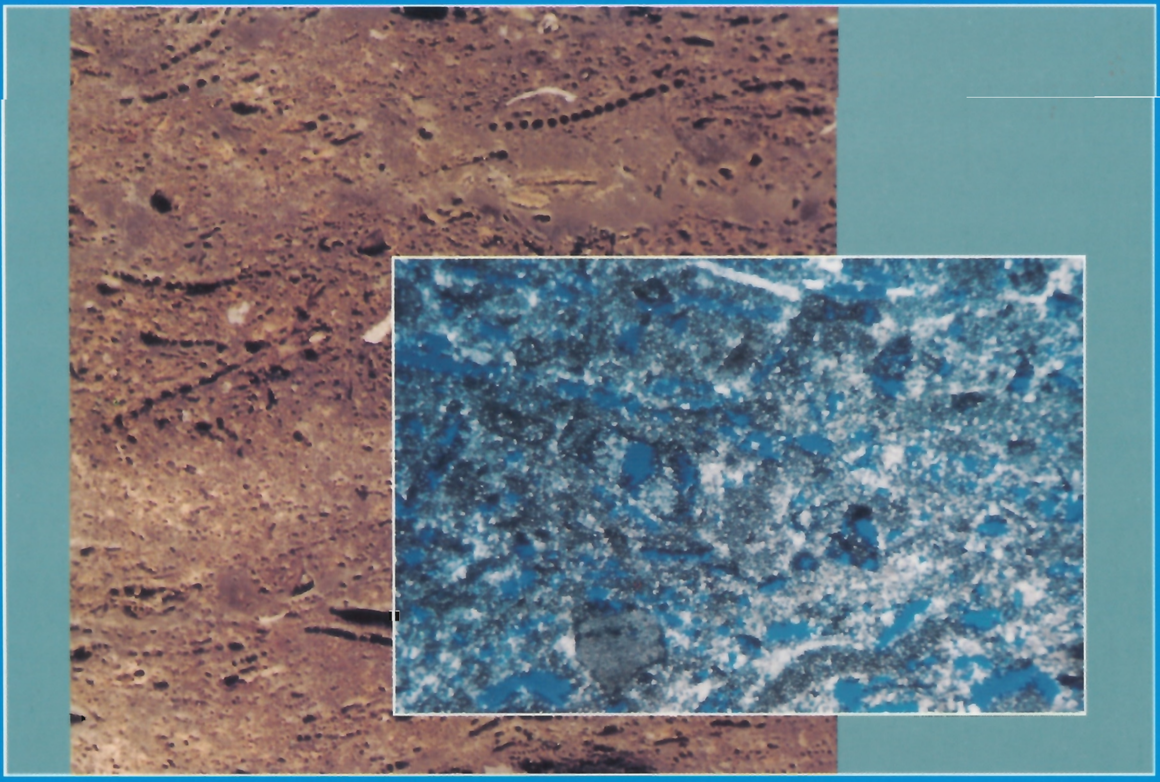
BULLETIN 515

CARBONIFEROUS AND PERMIAN GAS RESOURCES OF THE WESTERN CANADA SEDIMENTARY BASIN, INTERIOR PLAINS



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CARBONIFEROUS AND PERMIAN GAS RESOURCES OF THE WESTERN CANADA SEDIMENTARY BASIN, INTERIOR PLAINS

PART I: GEOLOGICAL PLAY ANALYSIS AND RESOURCE ASSESSMENT

J.E. Barclay, G.D. Holmstrom, P.J. Lee, R.I. Campbell, and G.E. Reinson

PART II: ECONOMIC ANALYSIS

S.M. Dallaire, R.R. Waghmare, L. Roux, M. Boudreault, and R.F. Conn

1997

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Cover illustration

Sandy bioclastic bryozoan-brachiopod dolo-grainstone, 12-15% visible biomouldic and intercrystalline porosity provides reservoir for gas production, Permian Belloy Formation (see Belloy Peace River structural - Eagle play in text). Photograph of drill core provided by J.E. Barclay, Springtide Energy Ltd.
Inset: Crinoid-brachiopod dolo-grainstone with 23% intercrystalline and biomouldic porosity and 800-1000 millidarcies permeability. From gas-producing reservoir in the Mississippian Elkton Formation in the Crossfield Field area (see Mississippian subcrop - Edson/Harmattan play in text). Thin section photomicrograph provided by A. Gordon, GR Petrology Consultants Inc.

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PREFACE

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

Although conventional crude oil has been the mainstay of Canada's petroleum industry since the discovery of Leduc in 1947, the industry can be expected increasingly to shift investment to exploring for natural gas. Extensions to continental gas transportation systems have opened new markets for western Canadian natural gas while 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. PRAP considered 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 exploration plays in Carboniferous and Permian strata, and provides an assessment of the remaining natural gas potential. The geological analysis and resource assessment were undertaken by the GSC, Calgary. The estimates have been prepared using statistical techniques developed by the GSC 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 third 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 will also 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.

M.D. Everell
Assistant Deputy Minister
Earth Sciences Sector

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PART I: GEOLOGICAL PLAY ANALYSIS AND RESOURCE ASSESSMENT

Abstract

Part I of this paper describes the discovered gas resources of the major Carboniferous and Permian gas plays in flat-lying strata beneath the Interior Plains of western Canada. It presents a prediction for their undiscovered gas resources based on geological and statistical analysis. In Carboniferous strata in the plains, 587.208 x 10^9 m^3 (20.8 TCF) total discovered gas occurs in five established, mature Carboniferous plays, present in 241 fields with 883 pools. This represents 53 per cent of the in-place gas volume for the Carboniferous and Permian plays (plains plus Foothills). The potential of initial volume in-place gas in these five plays is 142.041 x 10^9 m^3 (5.0 TCF), predicted to occur within 3177 undiscovered pools. Thus, 19 per cent of the Carboniferous (plains area) gas-in-place resource in mature plays remains to be discovered. There are four immature plays identified for the Carboniferous in the plains and they contain 2.711 x 10^9 m^3 (0.1 TCF) of initial volume in-place gas in 10 gas fields, each consisting of one pool. The potential in the immature plays was incorporated in the conceptual play analysis.

For the Permian in the plains, 39.943 x 10^9 m^3 (1.4 TCF) occurs within one established mature play, in 48 fields with 93 pools. This represents 96 per cent of the gas-in-place total for the Permian (plains plus Foothills). The expected potential of initial volume in-place gas in the plains is predicted to be 72.783 x 10^9 m^3 (2.6 TCF), within 907 undiscovered pools in the established play. The total number of discovered and predicted Permian pools (plains area) is 1000. Almost 65 per cent of the Permian gas-in-place resource in the plains remains to be discovered. No immature plays were identified for the Permian.

The potential gas volume in the conceptual and immature plays within the Carboniferous and Permian of the plains is 285.909 x 10^9 m^3 (10.1 TCF). This statistical analysis predicts about 22 plays in the Carboniferous and Permian, representing six mature plays, four immature plays, and 12 conceptual plays. For comparison, at least 5 to 10 conceptual plays are suggested on the basis of our regional geological analysis.

For the Carboniferous and Permian of the plains, the discovered initial volume in-place gas for all established, mature and immature plays is 629.862 x 10^9 m^3 (22.4 TCF), within 296 fields and 986 pools. The total initial volume in-place gas resource (discovered and undiscovered) for all mature, immature and conceptual plays is 1130.595 x 10^9 m^3 (40.1 TCF), predicted to occur in 5070 discovered and undiscovered pools within the mature plays, plus an undetermined number of undiscovered pools in the conceptual and immature plays. The undiscovered potential of 500.733 x 10^9 m^3 (17.8 TCF) for all play types represents 44 per cent of the total gas resource in the plains area.

Summary

This paper presents an analysis of the major gas plays and the discovered and undiscovered gas resources of the Carboniferous and Permian in the Interior Plains portion of the Western Canada Sedimentary Basin. The analysis forms part of the ongoing Geological Survey of Canada's (GSC) Western Canada Gas Assessment Project. Part I of this paper contains the geological play analysis and numerical assessment of undiscovered gas potential and Part II contains an economic analysis of the predicted potential.

Total discovered in-place gas in the Carboniferous of the Interior Plains, Rocky Mountain Foothills, and Front Ranges is 1108.507 x 10^9 m^3 (39.3 TCF) in 322 gas fields with 1064 pools. In this paper gas resources are given as initial volume in-place, i.e., gross volume of raw natural gas, unless noted as marketable. Associated, nonassociated and solution gas are included and aggregated in this analysis). Approximately 702 x 10^9 m^3 (24.9 TCF), or 63 per cent, of this in-place gas is marketable, and represents about 16 per cent of the total marketable gas reserves in all strata of the plains and Foothills.

The total discovered initial volume in-place gas in the mainly Permian Belloy Formation and equivalent strata in the plains and Foothills is 41.706 x 10^9 m^3 (1.5 TCF), which occurs within 51 gas fields and 96 pools. Approximately 29.8 x 10^9 m^3 (1.1 TCF) is marketable gas, and represents about 0.8 per cent of the total marketable gas reserves of western Canada.

In-place gas for the Carboniferous and Permian plays in the study area, which includes the plains area but not the Rocky Mountain Thrust Belt, is 629.862 x 10^9 m^3 (22.4 TCF), present in 986 pools within six major, mature exploration plays. The undiscovered resource (expected potential) for these mature plays is predicted to be 214.824 x 10^9 m^3 (7.6 TCF). This is predicted to occur in 4084 pools of varying sizes, including numerous small pools, many of which may be uneconomic to develop. In addition to the six mature plays, four immature plays are identified, which have only 10 discovered single-pool fields. Also, 12 conceptual plays are identified in the Carboniferous and Permian. The predicted undiscovered gas volume for the conceptual and immature plays is estimated to be 285.909 x 10^9 m^3 (10.1 TCF).

Regional geological analysis provided criteria for dividing the 893 discovered pools in Carboniferous strata into two main groups of established, mature and immature, geologically defined, plays: 1) stratigraphic subcrop plays, which contain the bulk of the discovered gas, and 2) stratigraphic facies pinchout and structural plays, which have less discovered gas but significantly more potential than the subcrop plays (see Tables 1, 2). The 93 pools in the Permian[1] Belloy Formation were grouped into one established play type consisting mainly of pools in structural traps but also with many traps controlled by internal and external unconformities. Quantitative methods based on the exploration discovery history of pools and their sizes within the geologically defined plays were used to assess play potential.

For Carboniferous strata only, marketable gas reserves in the cratonic Interior Platform (within the Interior Plains) and the Rocky Mountain Thrust Belt (mainly within the Rocky Mountain Foothills) are approximately 702 x 10^9 m^3 (24.9 TCF), occurring in 322 fields with 1064 pools. This represents about 16 per cent of the total marketable gas reserves in all strata of the Western Canada Sedimentary Basin. The total volume of discovered gas-in-place within Carboniferous strata is 1108.507 x 10^9 m^3 (39.3 TCF; plains plus Foothills), of which 587.208 x 10^9 m^3 (20.8 TCF), or 53 per cent of the total, occurs in five mature plays in the plains and an additional 2.711 x 10^9 m^3 (0.1 TCF) occurs in four immature plays within the plains.

The Carboniferous of the plains has five established mature plays with 241 fields comprising 883 pools, and four established immature plays with 10 single-pool gas fields. The expected potential of gas-in-place in the mature plays is 142.041 x 10^9 m^3 (5.0 TCF), contained within 3177 undiscovered pools. The total number of discovered and undiscovered pools in established mature plays is 4060. The total discovered plus undiscovered gas-in-place volume in established mature plays is 729.249 x 10^9 m^3 (25.9 TCF), of which 19 per cent remains to be discovered.

Of the Carboniferous plays, the mature play with the largest discovered gas-in-place volume and second largest gas-in-place potential is the Mississippian

[1]The Belloy Formation was thought to be mainly Permian, based on brachiopods and foraminifers (see Naqvi, 1972; Henderson, 1989). However recent biostratigraphic work using conodonts has indicated that the lower part of the Belloy Formation may be Upper Carboniferous (Moscovian stage) (Chung, 1993; Chung and Henderson, 1993a, b; Henderson et al., 1994; Richards et al., 1994). In this report we have generally referred to the Belloy Formation as Permian, but where appropriate, we note the suggested Upper Carboniferous assignment to the lower part of the Belloy Formation.

Table 1

List of Carboniferous–Permian plays

Established Mature Plays
1. Mississippian subcrop–Edson/Harmattan play (597 pools)
2. Bakken stratigraphic/subcrop–Loverna play (37 pools)
3. Rundle/Sweetgrass structural–Black Butte play (44 pools)
4. Peace River carbonate–Dunvegan play (90 pools)
5. Kiskatinaw clastics–Pouce Coupe play (115 pools)
6. Belloy/Peace River structural–Eagle play (93 pools)

Established Immature Plays
1. Mattson structural–Windflower play (3 pools)
2. Banff downdip stratigraphic — Ferrier/Willesden Green play (2 pools)
3. Banff/Rundle drape–Windfall (2 pools)
4. Williston Basin (associated gas) subcrop–Alida play (3 pools)

Conceptual Plays: (no pools)
1. Rundle downdip stratigraphic play:
   a. Central Alberta Pekisko-Shunda-Elkton shoals, stratigraphic play
   b. Wabamun Crossfield-type major facies change
   c. Peace River carbonate stratigraphic play
   d. Diagenetic, hydrodynamic traps
   e. Rundle slope-facies
   f. Reef-like buildups and Waulsortian-type mounds
2. Mattson delta stratigraphic play (e.g. on west side of Bovie Fault
3. Williston Basin stratigraphic play
4. Williston Basin structural play

Table 2

Brief descriptions of mature Carboniferous–Permian plays

Mississippian subcrop–Edson/Harmattan play
- carbonate with porosity enhanced at various Rundle and Banff subcrop edges
- outliers, hills, structures, promontories
- seals: Mesozoic shale or tight sandstone
- e.g., Minnehik–Buck Lake, Crossfield, Hotchkiss, Desan fields

Bakken stratigraphic/subcrop–Loverna play
- marine sandstone
- erosional edge trap
- subtle erosional highs, shoals, folds
- e.g., Driver, Hudson, Antelope fields

Rundle/Sweetgrass structural–Black Butte play
- Sweetgrass Arch horsts, highs
- facies and diagenetic changes
- e.g., Vulcan, Aden, Parkland N.E. fields

Peace River carbonate–Dunvegan play
- Rundle, Banff carbonate, upthrown Peace River Arch blocks
- some facies and diagenetic controls on reservoirs
- e.g., Normandville, Belloy, Culp fields

Kiskatinaw clastics–Pouce Coupe play
- fluvioestuarine, marine sandstone
- facies changes, horsts, erosional pinchouts
- e.g., Boundary, Blueberry, Gordondale fields

Belloy/Peace River structural–Eagle play
- Permian shoreline, marine sandstone, carbonate, coquinas
- composite play: horsts, drapes, facies and erosional pinchouts (internal, edge), Deep Basin
- e.g., Stoddart, Boundary, Progress, Wapiti, Virginia Hills fields

subcrop–Edson/Harmattan play, with 499.115 x 10^9 m^3 (17.7 TCF) of gas-in-place in 597 discovered pools and an expected potential of 52 351 x 10^6 m^3 (1.9 TCF) in an estimated 343 undiscovered pools. Within the plains area, the play contains 80 per cent of the discovered Carboniferous and Permian gas-in-place volume in the mature plays and 24 per cent of the expected potential.

The established mature Carboniferous and Permian plays, in order of expected potential are as follows:

Belloy/Peace River structural–Eagle play
Expected potential (undiscovered): 72 783 (10^6 m^3) (2.6 TCF)
Discovered gas-in-place volume: 39 943 (10^6 m^3) (1.4 TCF)
Undiscovered: 65 per cent
Largest undiscovered pool[1]: 1644 (10^6 m^3) (58 BCF)
Discovered pools: 93
Undiscovered pools: 907
Per cent of Carboniferous–Permian mature play potential: 34

[1]Largest undiscovered pools are reported at their median values which represent the best estimate of their predicted size. Note that the economic analysis in Part II uses mean values because they can be summed for a whole play, whereas median values cannot be summed, i.e., the sum of the medians of members of a population is not necessarily the median of the population.

Kiskatinaw clastics–Pouce Coupe play

Expected potential (undiscovered): 54 322 (10^6 m^3) (1.9 TCF)

Discovered gas-in-place volume: 29 015 (10^6 m^3) (1.0 TCF)

Undiscovered: 65 per cent

Largest undiscovered pool: 581 (10^6 m^3) (21 BCF)

Discovered pools: 115

Undiscovered pools: 1085

Per cent of Carboniferous–Permian mature play potential: 25

Mississippian subcrop–Edson/Harmattan play

Expected potential (undiscovered): 52 351 (10^6 m^3) (1.9 TCF)

Discovered gas-in-place volume: 499 115 (10^6 m^3) (17.7 TCF)

Undiscovered: 9 per cent

Largest undiscovered pool: 1893 (10^6 m^3) (67 BCF)

Discovered pools: 597

Undiscovered pools: 343

Per cent of Carboniferous–Permian mature play potential: 24

Peace River carbonates–Dunvegan play

Expected potential (undiscovered): 16 640 (10^6 m^3) (0.6 TCF)

Discovered gas-in-place volume: 48 895 (10^6 m^3) (1.7 TCF)

Undiscovered: 25 per cent

Largest undiscovered pool: 2900 (10^6 m^3) (102.9 BCF)

Discovered pools: 90

Undiscovered pools: 130

Per cent of Carboniferous–Permian mature play potential: 8

Bakken stratigraphic/subcrop–Loverna play

Expected potential (undiscovered): 12 233 (10^6 m^3) (0.4 TCF)

Discovered gas-in-place volume: 3290 (10^6 m^3) (0.1 TCF)

Undiscovered: 79 per cent

Largest undiscovered pool: 341 (10^6 m^3) (12.1 BCF)

Discovered pools: 37

Undiscovered pools: 1063

Per cent of Carboniferous–Permian mature play potential: 6

Rundle/Sweetgrass structural–Black Butte play

Expected potential (undiscovered): 6495 (10^6 m^3) (0.2 TCF)

Discovered gas-in-place volume: 6893 (10^6 m^3) (0.2 TCF)

Undiscovered: 49 per cent

Largest undiscovered pool: 306 (10^6 m^3) (10.9 BCF)

Discovered pools: 44

Undiscovered pools: 556

Per cent of Carboniferous–Permian mature play potential: 3

The total discovered plus undiscovered gas-in-place volume for each of the six Carboniferous and Permian mature plays (plains area) were used as data points for a statistical prediction of the undiscovered initial gas-in-place volume in conceptual plays. The predicted potential of the conceptual plays is assumed to include some unspecified potential for the four established immature Carboniferous plays. These immature plays were excluded as data points because they have inadequate discovered resources and no directly predicted potential. The predicted potential for conceptual plays (those with no discovered pools but predicted to exist on the basis of geological and statistical analyses) and immature plays in the Carboniferous and Permian of the plains is 285.909 x 10^9 m^3 (10.1 TCF). The Carboniferous and Permian gas resources in the plains comprise 841.975 x 10^9 m^3 (29.9 TCF) of discovered and potential gas-in-place for the established mature plays, in 5060 pools. Another 285.909 x 10^9 m^3 (10.1 TCF) of potential gas occurs in an unknown number of undiscovered pools in the conceptual and immature plays. In the immature plays, 2.711 x 10^9 m^3 (0.1 TCF) of discovered gas is present, occurring in 10 pools. The total gas-in-place volume for the Carboniferous and Permian is 1130.595 x 10^9 m^3 (40.1 TCF), occurring in more than 5070 pools.

In addition to the six established mature plays and four established immature plays, we predict on the basis of a geological analysis, at least five Carboniferous and/or Permian conceptual plays, and possibly up to 10 conceptual plays, if the major conceptual plays are split into five subplays. This geologically based prediction of play numbers is similar to, and provides credibility to, the 12 statistically predicted conceptual plays. The geologically predicted conceptual play thought to have the most potential is the Rundle down-dip stratigraphic play in which hydrocarbons are trapped by internal facies pinchouts or diagenetic changes down-dip from the subcrop edge.

Ongoing drilling activity and significant gas and oil discoveries in the stratigraphic and structural plays such as at Alces, Bilawchuk, Boundary Lake, Craigmyle/Michichi, Desan, Doe, Ghost Pine, Goodwater, Hoosier, Mica and Pouce Coupe indicates significant gas potential in Carboniferous strata. Although relatively thin and areally restricted in comparison to most Carboniferous deposits, Permian strata have significant potential, as indicated by the gas discovery at Boundary Lake in 1987. We consider that our predicted potential for gas in the Carboniferous and Permian strata provides additional justification for continued exploration in these units.

INTRODUCTION

This study was undertaken to evaluate the discovered and undiscovered, conventional natural gas resources in the generally flat-lying Carboniferous and Permian strata within the Interior Plains area of the Western Canada Sedimentary Basin (WCSB) (Figs. 1, 2). The objectives of this study are: 1) to document the volume of existing discovered gas-in-place in the Carboniferous and Permian, with respect to the plays in which they occur, 2) to estimate the total amount of undiscovered gas-in-place that might exist in the Carboniferous and Permian strata of the Western Canada Sedimentary Basin, 3) to outline the geology of the major gas plays in Carboniferous and Permian strata to enable industry to use the data for exploration, and 4) to provide the

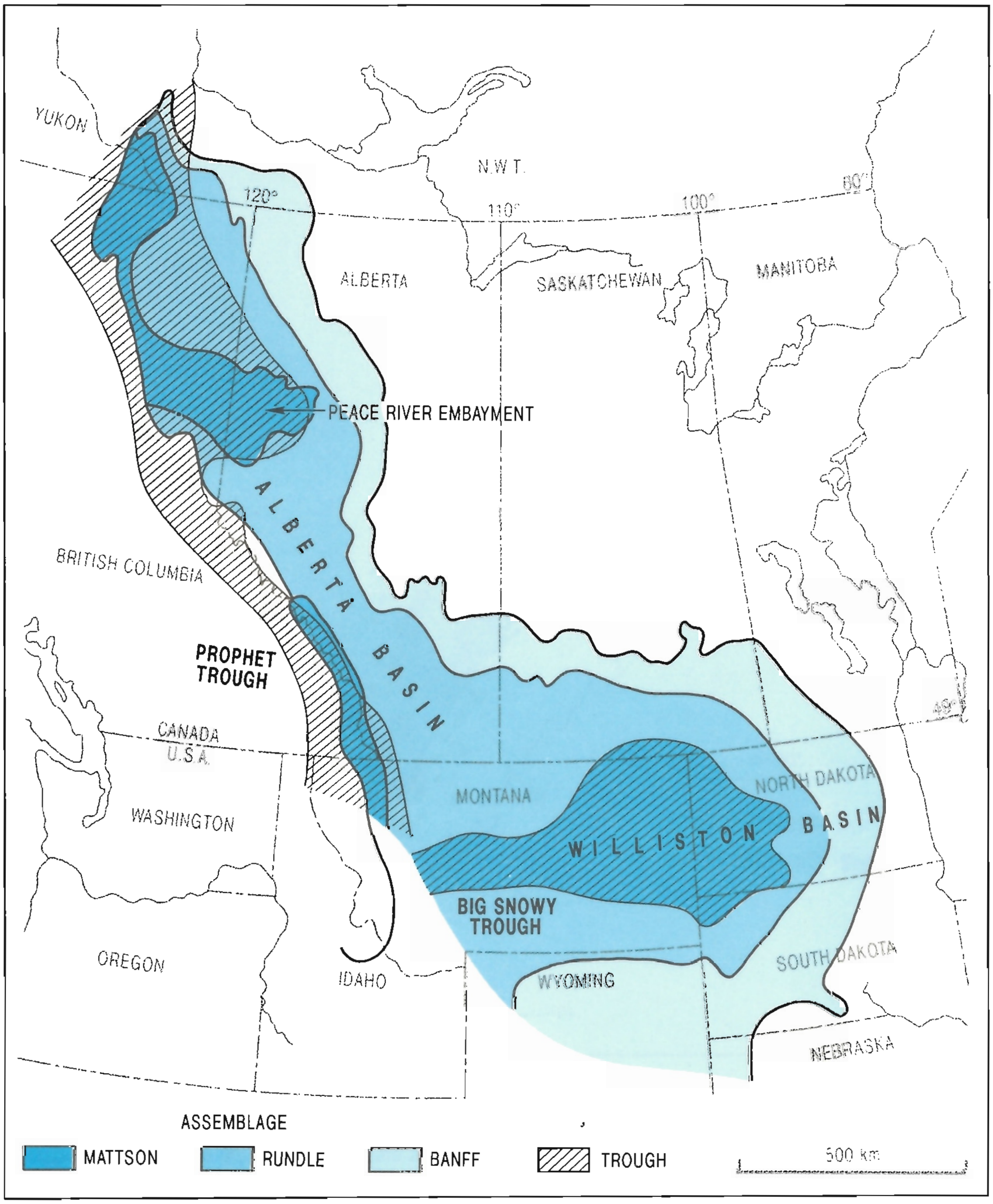


Figure 1. Distribution of Carboniferous strata, Western Canada Sedimentary Basin (after Podruski et al., 1988; Richards et al., 1993).

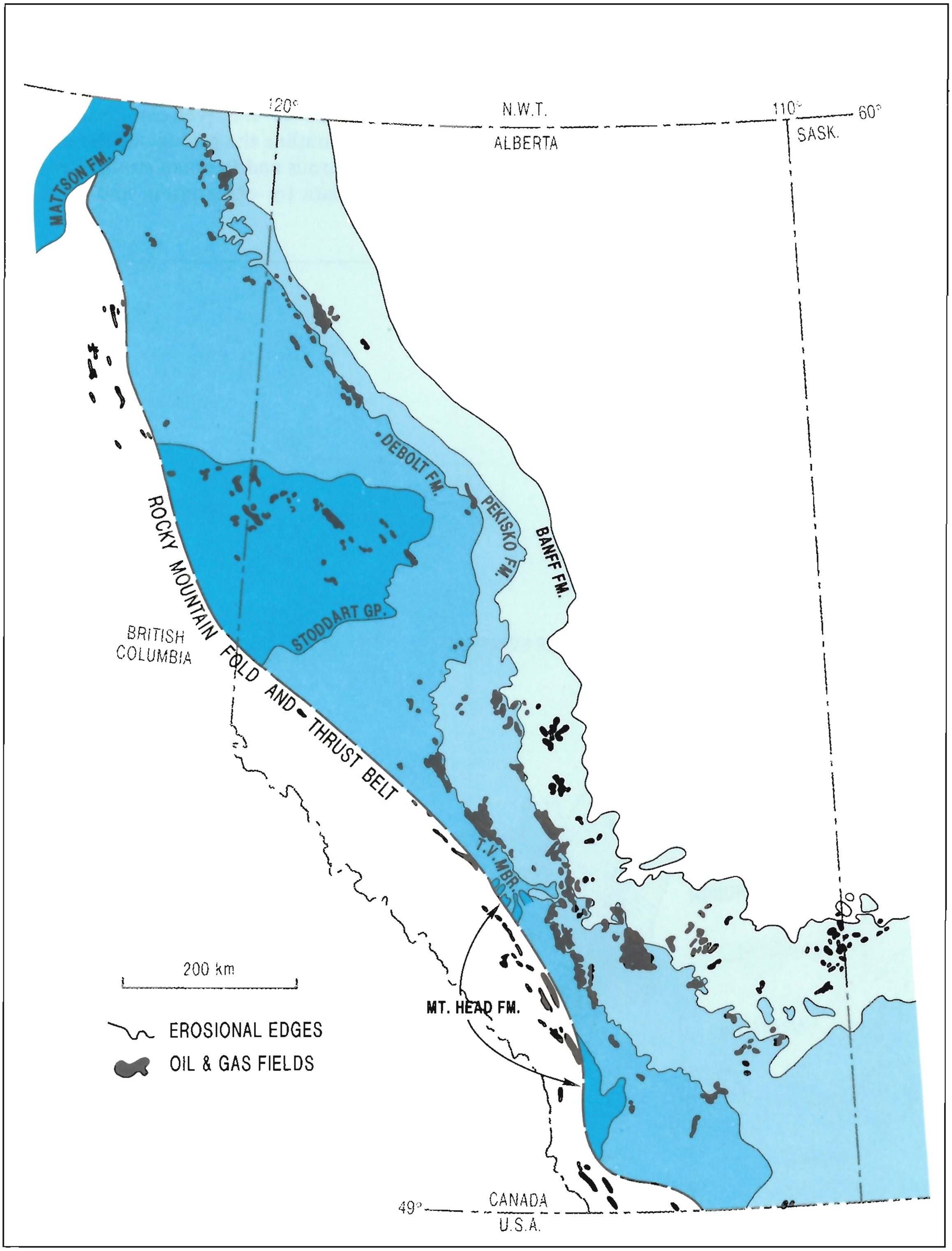


Figure 2. *Major oil-and-gas producing areas in Carboniferous strata based on a plot of Carboniferous producing wells in western Canada. Map provides approximate field boundaries. Erosional edges (subcrops) of major Carboniferous units also shown and the occurrence of fields along the subcrop edges emphasizes the dominance of the discovered gas in the Mississippian subcrop–Edson/Harmattan play (information compiled from Law, 1981; English, 1986; Podruski et al., 1988; Barclay et al., 1990; Alberta Energy Resources Conservation Board, 1991; British Columbia, Energy Resources Division, 1991; Saskatchewan Energy and Mines, 1989).*

necessary geological and resource potential information to allow industry and government agencies to undertake economic viability studies in exploration, producibility and marketability. The numerical and geological analyses prepared by the Geological Survey of Canada (GSC) is presented as Part 1 of this paper, and an economic analysis of these gas plays by the Energy Sector of the Department of Natural Resources Canada follows as Part II.

This study forms part of the GSC's Western Canada Gas Assessment Project. Seven major play groups were defined for western Canada on the basis of geological criteria. These were primarily major stratigraphic units or structural/tectonic provinces, each with a distinct set of geological factors controlling size, distribution and type of hydrocarbon play or reservoir. The major play groups include the Devonian, Carboniferous–Permian, Triassic, Jurassic to Lower Cretaceous, Middle Cretaceous, Upper Cretaceous–Tertiary, and the Rocky Mountain Thrust Belt (see Reinson et al., 1993a, b; Bird et al., 1994; Osadetz et al., in prep.; other reports are also underway). This paper describes the Carboniferous and Permian exploration plays and assesses their discovered and undiscovered gas resources in the Western Canada Sedimentary Basin south of latitude 61N. The study area (Fig. 1) covers the generally unfolded and unfaulted plains area but does not evaluate the important Carboniferous gas plays in the thrust belt of the Foothills (see Osadetz et al., in prep).

Estimates of hydrocarbon potential throughout parts of Canada have been prepared periodically by the Geological Survey of Canada, (e.g., Procter et al., 1984; Dixon et al., 1988; Podruski et al., 1988; Wade et al., 1989; Sinclair et al., 1992; Reinson et al., 1993b) using geological basin analysis and statistical resource evaluation methods. The present gas assessment follows the format and approach of the earlier oil and gas assessments of western Canada (Podruski et al., 1988; Reinson et al., 1993b) and incorporates modified portions of those publications in the text. In particular, the gas-play definitions and geological descriptions are modelled after the play descriptions in Podruski et al. (1988). This is because, in the Western Canada Sedimentary Basin, most Carboniferous and Permian oil plays do not differ geologically from the gas plays in the same strata. The initial mainframe-computer-based statistical evaluation methods and petroleum information management systems were developed by the GSC (Lee and Wang 1983a, b, 1984, 1985, 1986), and were subsequently refined into the personal-computer-based system called "PETRIMES" (Lee and Tzeng, 1993; Lee and Wang, 1990), which was employed to estimate resource potential of exploration plays in Carboniferous and Permian strata.

Terminology

The terminology and assessment procedure used in this study follows that in Podruski et al. (1988) and Reinson et al. (1993b) and terminology was also adapted from that used by the Alberta Energy Resources Conservation Board (e.g., Alberta Energy Resources Conservation Board, 1991).

Natural gas is defined as any gas (at standard pressure and temperature of 14.73 psia and 60F/101.33 kPa and 15°C) of natural origin that is composed primarily of hydrocarbon molecules producible from a borehole (Potential Gas Committee, 1990). Natural gas may contain significant amounts of nonhydrocarbon components (e.g., H_2S, CO_2 and He). In our study of potential gas, it was not feasible to separate such components from the total potential but it is recognized, however, that certain components, particularly H_2S, must be accounted for in any detailed economic analysis of potential gas.

Raw gas is unprocessed natural gas, containing methane, inert and acid gases, paraffins, hydrocarbons and impurities, and is recoverable from a well tapping an underground reservoir. Some of the hydrocarbons may be recoverable as liquids. Our assessment analyzed only raw natural gas and assessed the discovered *initial volume in-place* natural gas (Alberta Energy Resources Conservation Board, 1991) attributed to pools. *Initial volume in-place* gas is raw natural gas calculated or interpreted to exist in a reservoir before any volume has been produced and refers to the volume of gas in the ground regardless of what portion may be recoverable (Alberta Energy Resources Conservation Board, 1991). We have evaluated and aggregated associated, nonassociated, and solution gas. Other phrases we have used in the text to refer to this gas in discovered pools include *discovered in-place volume*, *gas-in-place*, *raw natural gas* and *raw gas*. We used the phrase *in-place gas potential* to refer to predictions of undiscovered raw natural gas. Note that the term *reserves* does not apply to the in-place amounts, as reserves refers to the amount of gas that is recoverable or marketable; such gas reserves were not evaluated in our assessment.

Established reserves are hydrocarbon accumulations that are recoverable with current technology and under present and anticipated economic conditions. Established reserves are reported by the Alberta Energy Resources Conservation Board (1991) as *marketable gas*, which is natural gas that meets specifications for end use, usually requiring processing to remove acid gases, impurities and liquid components (Alberta Energy Resources Conservation Board, 1991). *Nonassociated gas* is a natural gas not in contact with crude oil in a reservoir and *associated gas* is natural gas that occurs in crude oil reservoirs as free gas, typically as a gas cap overlying the oil zone. *Solution gas* is natural gas that is dissolved in crude oil under reservoir conditions. *Condensate* is a mixture of hydrocarbons that are gaseous in the underground reservoir but mainly liquid at the surface.

All gas volumes are reported in metric units. Imperial units were added in the abstract, summary and discussion using the following conversions: 1 TCF $= 10^{12}$ cubic feet $= 28\ 175.55 \times 10^6\ m^3$; 1 BCF $= 10^9$ cubic feet $= 28.17555 \times 10^6\ m^3$.

Resource is defined as all hydrocarbon accumulations that are known, or inferred, to exist and thus includes both discovered and undiscovered hydrocarbons. *Discovered resource* usually refers mainly to gas-in-place resources and occasionally refers to reserves (i.e., recoverable marketable gas quantities). The term *potential* refers to that portion of the resource that is inferred to exist, but is not yet discovered. In this paper, play potentials are reported as the *expected potential*, defined as the mean of the play potential obtained by summing the mean of all undiscovered pool sizes. The terms *potential* and *undiscovered resource* are synonymous and are used interchangeably here.

The terms *prospect, gas field, gas pool, play* and *other area* have the following meanings in this report. A *prospect* is defined as an untested exploration target that may or may not contain hydrocarbons (note: oil explorationists also call a prospect a "play"). A prospect may not necessarily be synonymous with an undiscovered pool. The term *gas field* is used to designate an area that produces gas without stratigraphic interval restrictions. A *gas pool* is defined as a discovered accumulation of gas, typically within a single stratigraphic interval, that is thought to be hydrodynamically separate from other gas accumulations. Any number of discrete pools, commonly at varying stratigraphic levels or in different geographic parts of the field, may exist within a field. The word *play* is used here to refer to a group of fields, pools or prospects that share a common history of hydrocarbon generation, migration, reservoir development and trap configuration (Energy, Mines, and Resources Canada, 1977). In British Columbia, the term *other area* refers to a pool not yet assigned a pool name (British Columbia, Energy Resources Division, 1991).

Plays are grouped into two categories: *established plays* that are demonstrated to exist by virtue of discovered pools with established reserves, and *conceptual plays* that do not yet have discoveries or reserves, are inferred from geological or statistical analysis. Established plays are classed as either *mature* or *immature* 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, the number of pools and the geographic distribution of discovered pools are appropriate for analysis using a discovery process model with the PETRIMES assessment procedure (discussed below). Mature plays typically have many discovered pools, up to hundreds or thousands in some instances. *Immature plays* are those in which there are very few pools and the discovery sequence profile is inadequate for application of the discovery process model.

Method and content

This assessment of Carboniferous and Permian gas resources has two essential components: geological analysis and statistical analysis. The geological analysis is the fundamental component and involves characterization of the exploration plays and their pools. The regional geology and geological play analysis of Carboniferous and Permian strata is similar to that outlined by Podruski et al. (1988) and includes observations from recent geological publications, such as Henderson (1989), Richards (1989a), Barclay et al. (1990), Henderson et al. (1993, 1994), and Richards et al., (1993, 1994).

Pools and prospects within a play form a natural geological population and occur within a specific geographic area that can be delimited areally using the results of geological analysis. Once the play is defined, a numerical resource assessment is undertaken using pool data from that specific play (see Resource Assessment Procedure, below). Six established mature plays and four established immature plays were defined and evaluated numerically in this analysis. This report contains a description of the mature plays, including play definition, geology, exploration history and numerically estimated resource potential, with supporting figures. Brief descriptions of the immature plays are presented. Each play is named by the main geological unit or geographic area containing the reservoirs, the depositional or trap type, and characteristic gas pool or pools (e.g., Belloy/Peace River structural-Eagle play).

Conceptual and immature plays are treated separately, in a shorter descriptive manner, with their potential estimated by using the six mature plays as the pool database. This statistical analysis identified 12 conceptual plays. A geological analysis of conceptual plays was performed independently of the statistical analysis to evaluate the credibility of the statistical analysis. At least five, and possibly ten, conceptual plays were identified geologically.

In making the estimates of potential natural gas, nonassociated, associated, and solution gas resources were added together wherever they were designated within provincial government databases as discrete entities within a gas pool. Pools may be composed of nonassociated gas or of various combinations of nonassociated, associated, and solution gas. The potential gas estimates reported here reflect the total (raw gas-in-place) natural gas resources of all gas types. The principal mode of gas occurrence is indicated in the pool-rank table for each mature play.

The discovered pool volumes and well data used in the assessments are based on data sets of the provincial agencies of Alberta (Alberta Energy Resources Conservation Board, 1991), British Columbia (British Columbia, Energy Resources Division, 1991), and Saskatchewan (Saskatchewan Energy and Mines, 1989) and represents data collected by them to the end of December 1990. Corrections were made where necessary to selected pools, either to update the pool sizes, using newer data provided by these agencies or by the National Energy Board, or to split or group pools based on significant changes made to pool data by the provincial agencies since the provincial data tapes were issued.

Acknowledgments

Ping Tzeng provided help and advice on using the PETRIMES resource assessment computer programs. Kirk Osadetz provided helpful comments on the Carboniferous geology, particularly concerning southern Alberta and Saskatchewan. Barry Richards and Wayne Bamber, Charles Henderson and Federico Krause discussed various aspects of Carboniferous and Permian geology with the authors. Byron Abrahamson compiled maps of Permian pools and prepared cross-sections of Permian strata. Peter Hannigan and Kirk Osadetz provided preliminary results of the Foothills gas assessment to help separate pools in the plains from those in the Foothills, and for comparison with results presented here. Kirk Osadetz also provided a thorough critical review of this paper, which helped improve the final version. Tim Bird and Gerry Reinson provided access to their manuscripts on Triassic and Devonian gas assessment and gave guidance in making this Carboniferous report consistent with their reports (Bird et al., 1994; Reinson et al., 1993b). Peter Gubitz (GSCC) drafted the figures. Lorne Samson and others at the Alberta Energy Resources Conservation Board provided advice on the use of their data tapes. Geologists from the National Energy Board provided pool parameters for selected pools and also provided advice on play definitions.

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. Data such as basin and rock volume, pool characteristics, source rock characteristics, pool discovery history are used (e.g., White and Gehman, 1979; Masters, 1984; Rice, 1986; Lee, 1993). Discovery process models were employed (Lee and Wang, 1990) for this assessment of gas resources in the Carboniferous and Permian, in which the predictions are based mainly on the use of the discovery history and sizes of pools in a play.

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 complete population of pools for that play. The discovery process is thus biased statistically in the sense that the largest pools tend to be found early in a play's exploration history. The discovery process model both handles and incorporates the statistically biased sampling (discovery) of pools and also makes use of the two most reliable pool data—sets pool size and discovery date—to produce estimates of play potential and individual undiscovered pool sizes. This model is thought to incorporate some, or all, of the accumulated knowledge and strategy in the exploration process. The mean volumes of undiscovered individual pools are then summed to give an estimate (expected value) of the total gas potential in that play. One advantage of this assessment method over others is that it provides a prediction of sizes of individual undiscovered pools. This information can then be used to evaluate economic viability of exploration plays. The resource assessment procedure using the discovery process model is described below by outlining the various steps in geological and numerical analysis that were undertaken during assessment of the Carboniferous and Permian gas plays, using the Mississippian subcrop–Edson/Harmattan mature play as an example.

Geological play definition

The definition of play type and play area, and sorting discovered pools into appropriate plays, are the primary objectives of the geological basin analysis studies that precede and provide the framework for the numerical resource evaluation. By definition, pools in a specific play form a natural geological population characterized by one or more of the following: age, depositional model, geographic distribution, structural style, trapping mechanism, geometry and diagenesis. In each case, a play is defined by its most important characteristics. Each pool is then assigned to the play that best describes it. The importance of a properly defined play is that it has a single statistical population of pools, thus satisfying the statistical assumptions required for the discovery process evaluation models. A mixed population, resulting from an improperly defined play, would adversely impact on the quality of the resource estimates derived from the statistical evaluation. A play area boundary encompasses pools discovered within the play and also defines the prospective area for reservoir development and petroleum entrapment in that play. Play areas are established using geological knowledge of the plays (Fig. 3).

Compilation of play data

Once a play is defined and the play boundary has been outlined as a closed polygon (Fig. 3), all the wells and pools within that play are retrieved from the PETRIMES well and pool database. The well and pool lists are then examined to ensure they are consistent with the play definition and play boundary and are then used to produce an exploration discovery sequence (Fig. 4). These are the basic input data used in the discovery process model for estimating the quantity of undiscovered petroleum resources. Details of the procedure for defining and analyzing plays is summarized as follows, in approximate sequence:

1. Assemble provincial government well data, pool data and pool lists pertinent to Carboniferous and Permian strata (Alberta Energy Resources Conservation Board, 1991; British Columbia, Energy Resources Division, 1991) using PETRIMES and SWELLS (Geological Survey of Canada programs) software. Assemble available literature on the formations of interest and their fields, pools, petroleum geology and stratigraphy.

2. Obtain or generate regional facies, isopach, structure and subcrop edge maps and well-log cross sections as required, to establish play definitions and play boundaries. Maps were obtained from published literature or generated using SWELLS software, which accesses provincial databases.

3. Assign initial play definitions based on stratigraphic interval and, using the simplest convenient formation groupings, begin to sort gas pools into appropriate plays. Separate the folded and faulted Foothills plays and pools from the stratigraphic/ structural plays and pools of the plains (typically unfolded and unfaulted).

4. Generate local cross-sections over pools that have possible affinities to several plays, in order to sort pools into appropriate plays.

5. Revise initial play definitions as required, based on the dominant gas-trapping mechanism as determined from mapping.

6. Plot all wells penetrating Carboniferous and Permian zones, including full and partial penetrations, in order to evaluate the proportion of undrilled areas.

7. Plot "Discovery" or "Identifying" and listed "producing" wells for each pool by stratigraphic interval chosen in step 3 against the geographic distribution of pools within the play.

8. Assemble pools in geographic clusters and check for geological affinities using PETRIMES cross-plots of reservoir parameters. Spot-check pools for parameters in common and check that pools which fall outside clusters do not belong to another play type.

9. Assemble a pool list for each group of pools. Check associated and nonassociated-solution gas in database and check for double-counted and unnamed pools.

10. Place remaining unsorted pools into appropriate plays.

11. Check pools for natural population distributions with cross-plots of discovery sequence versus pool volume (gas-in-place).

Discovery process model

The pools discovered in a specific play represent biased samples from the total pool population of that play. The discovered pools are not random samples, but are the result of a selective process as oil and gas exploration progresses through time, and because explorationists tend to drill the best prospects and typically find the largest fields earliest in the discovery process (e.g., Fig. 3). This biased nature of the sample

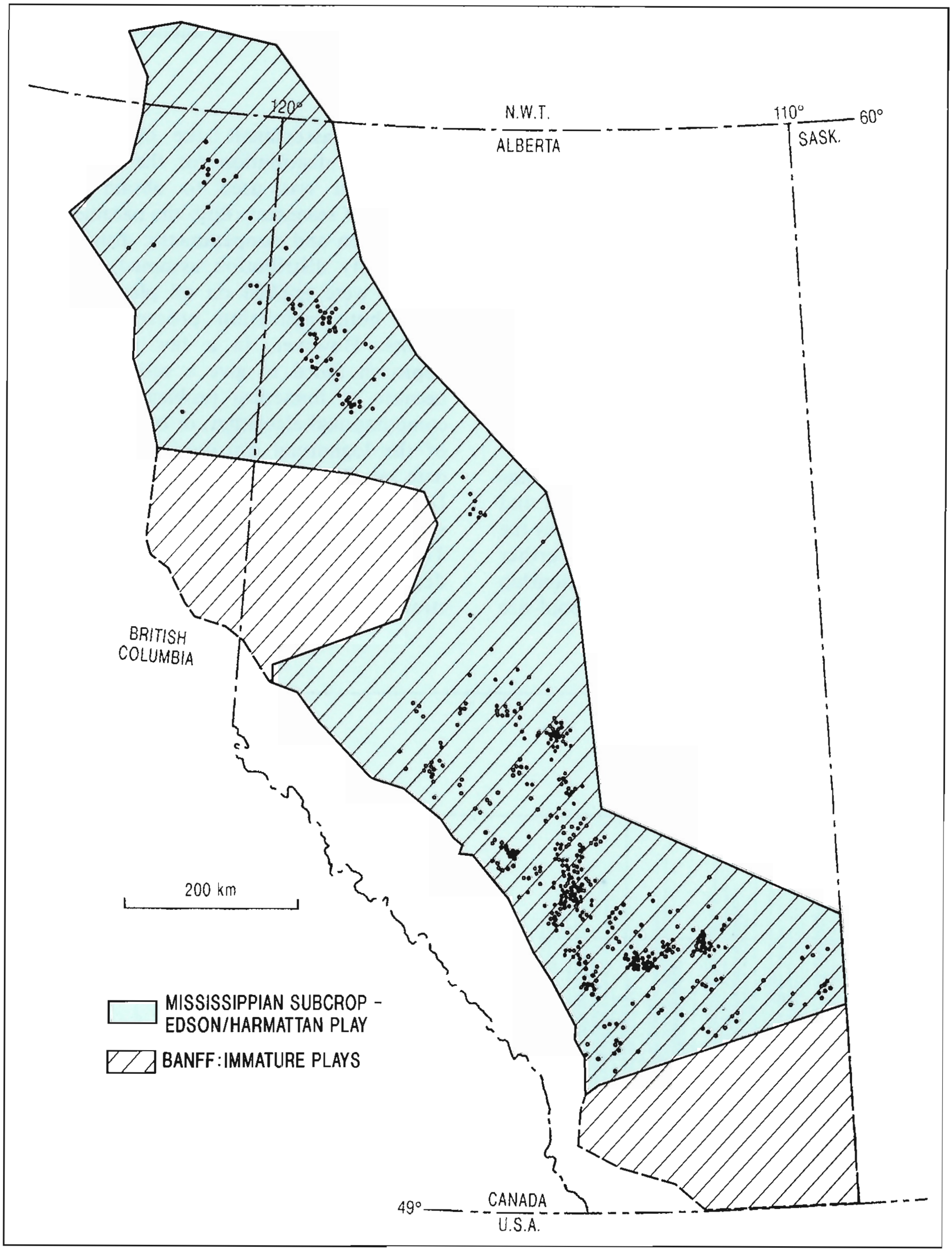


***Figure 3.** Example of a play boundary (play polygon) map, Mississippian subcrop–Edson/Harmattan play. Note that the immature Banff–Rundle drape and Banff stratigraphic plays occupy the same area as the subcrop play, as well as areas indicated by diagonal lines. Location of discovery wells and wells typifying the play-type indicated.*

population poses a problem for estimating petroleum resources using standard statistical methods. The discovery process model was devised to account for the biased element contained within the sample population. Lee and Wang (1985, 1990) incorporated this biased element into a probabilistic model in order to estimate the mean and variance of an underlying natural geological population and the number of pools in that population. Two assumptions are inherent in this probabilistic model. The first assumption is that the probability of discovering (sampling) a pool is proportional to its size. In other words, the largest pools are more likely to be discovered in the early exploration stages. This is supported by plotting a discovery sequence as a time series (Fig. 4). The second assumption necessary in the statistical evaluation is that sampling occurs without replacement. That is, a pool will not be discovered twice. The biased nature of the sample obtained from the exploration process contains information not only about the 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 relationship between number of pools and the mean of pool-size distribution. That is, the more undiscovered pools expected for a play, the smaller their size and greater their number.

In this assessment, the option of choosing a probability distribution for the underlying pool-size distribution was used to obtain the appropriate estimate of resources. Both the parametric (lognormal) distribution and nonparametric distribution (no prior probability distribution 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 problems associated with the computational algorithm, or because of an inadequacy of the lognormal distribution in approximating the data set. For example, in the Peace River carbonates–Dunvegan play, the three largest pools deviate from a straight line on the quantile-quantile plot (Fig. 5). These deviations may be the result of variation in the degree of structural trapping control versus stratigraphic trapping control in the play.

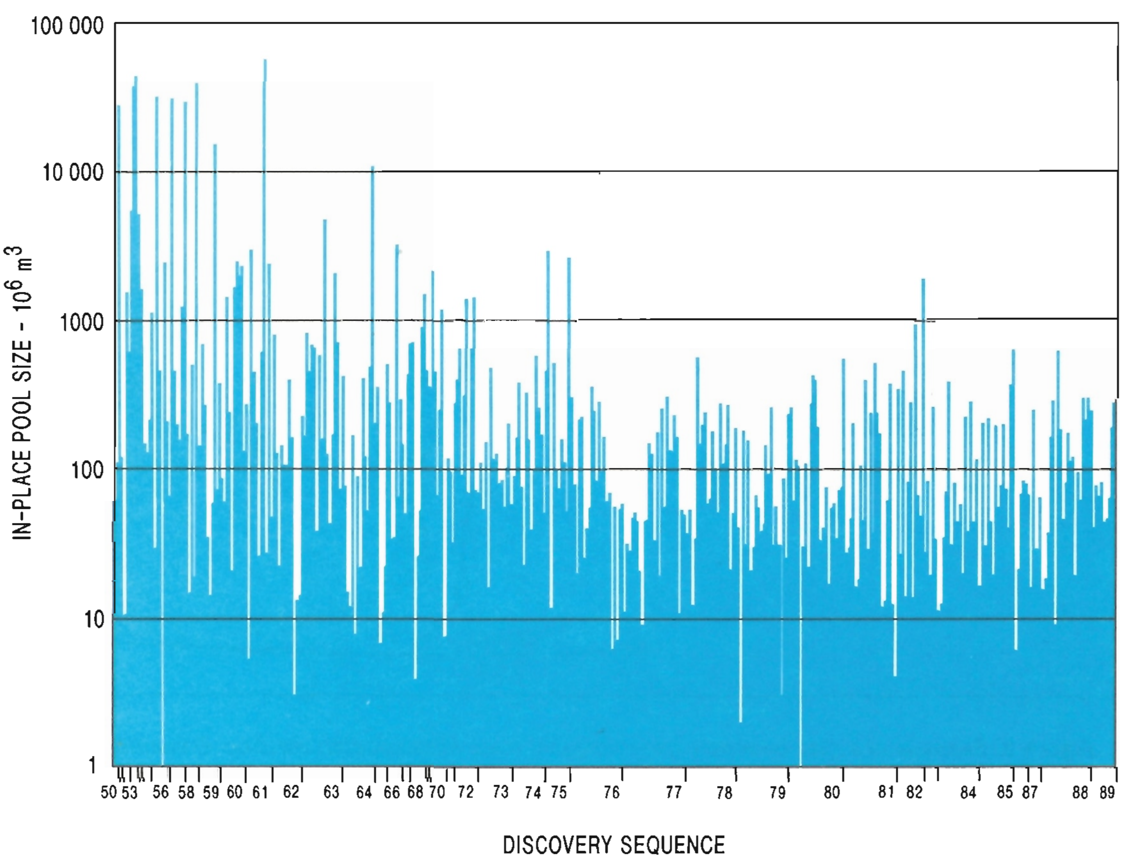


***Figure 4.** Example of exploration discovery sequence plot for all pools in a play, Mississippian subcrop–Edson/Harmattan play. Note the general decrease in size of discoveries with time.*

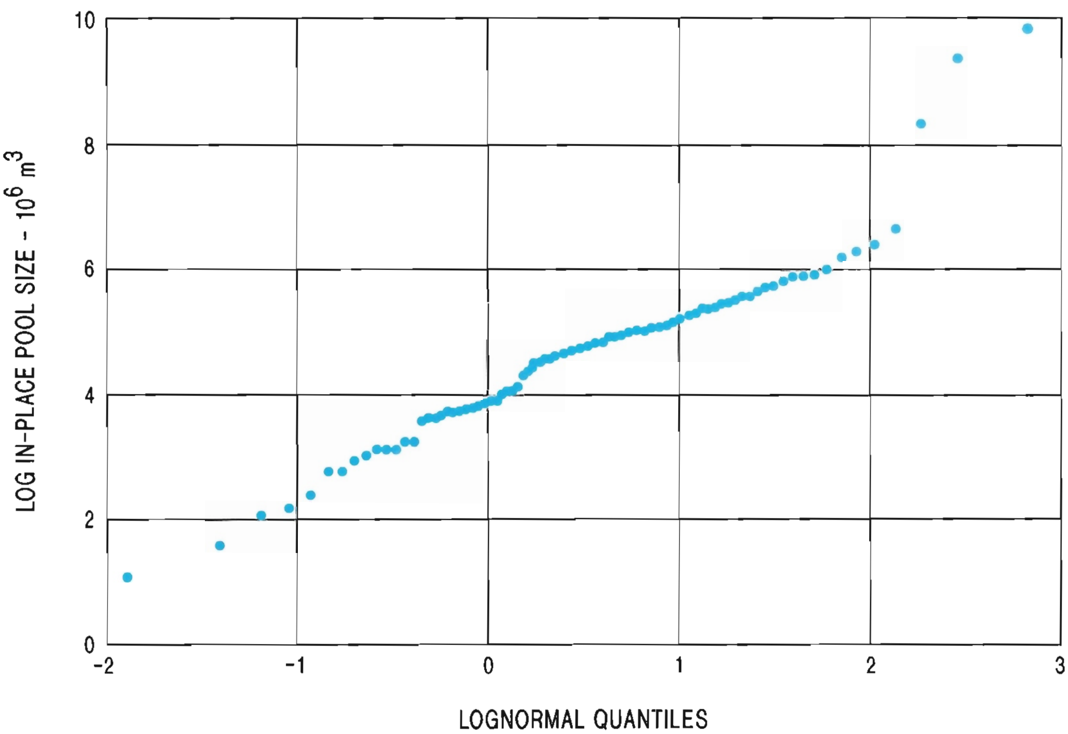


***Figure 5.** Example of pool sizes deviating from straight line on a quantile–quantile plot, suggesting variation in trapping control on a pool population, Peace River carbonates–Dunvegan play.*

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 gas pool. In practice, however, and in this analysis, a gas accumulation is considered to be a pool, if and only if, it is commercial at the time of discovery and is listed in the provincial pool databases. 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 discovery sequence may not reveal enough information to determine the total number of pools within a play. Given the possible truncation of the pool-size data set, estimates of the resources in a play should not be considered necessarily as the ultimate resource for that play. The results of an assessment are based on the pool-size data set used, which includes typically only commercial pools; the model only predicts the existence of undiscovered pools based on that data set. Also, the model does not account for any future appreciation of gas-in-place volumes of pools within the data set.

Total number of pools and 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. The information about the total number of pools (discovered and undiscovered) can be plotted as a relation between the number of pools and the log likelihood value for a specific number of pools (Fig. 6). For the illustrated case, the maximum value is attained when N = 940; this value is used for the play assessment.

The individual pools predicted by the model are represented in graphic form by vertical bars on a graph that plots individual pool size against pool rank (Fig. 7). A bar with a frequency interval of 5 to 95 indicates there is a 90 per cent chance that the predicted 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. In Figure 7 the matched pools are indicated in graphic form by dots and the unmatched (undiscovered) pools by vertical 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 ranked, respectively, greater or less than the unmatched pool (Fig. 8).

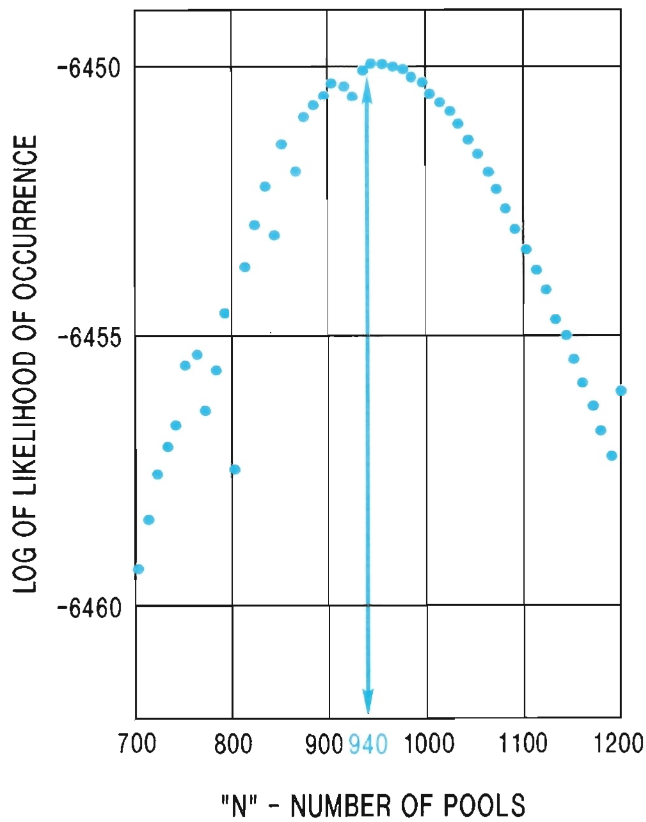


Figure 6. *Relation between various values for the total number of pools (N) and the likelihood of occurrence (as a log value) of the various values of N, Mississippian subcrop–Edson/Harmattan play. This type of plot was used to choose the most likely N value for most plays; in this play, a value of 940 was chosen.*

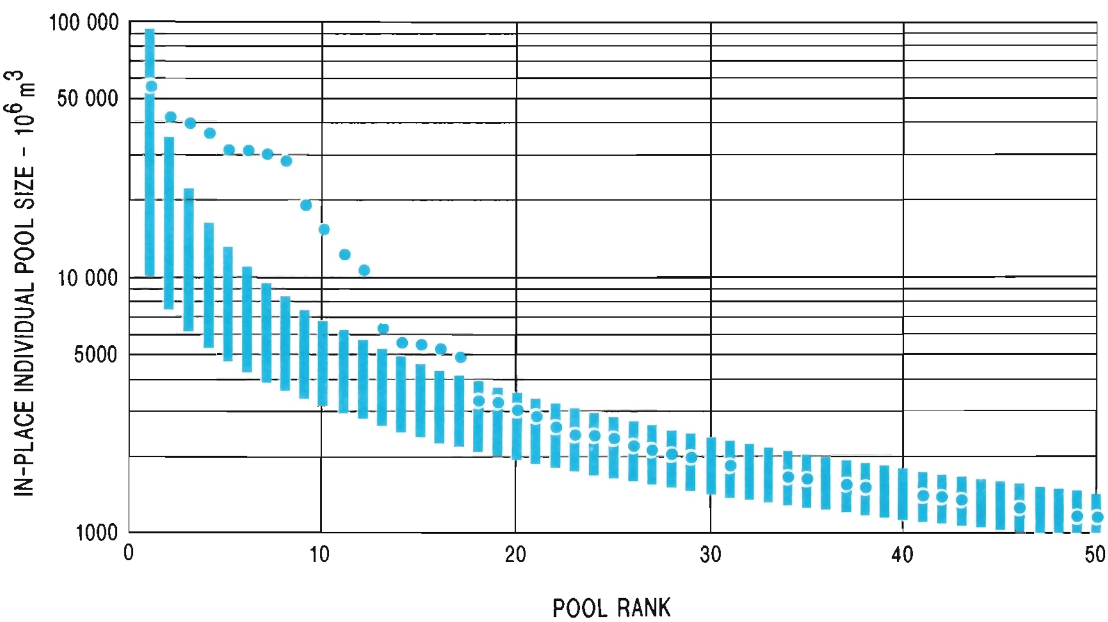


Figure 7. *Example of pool-size-by-rank plot — unconditioned by discovered pools; Mississippian subcrop–Edson/Harmattan play.*

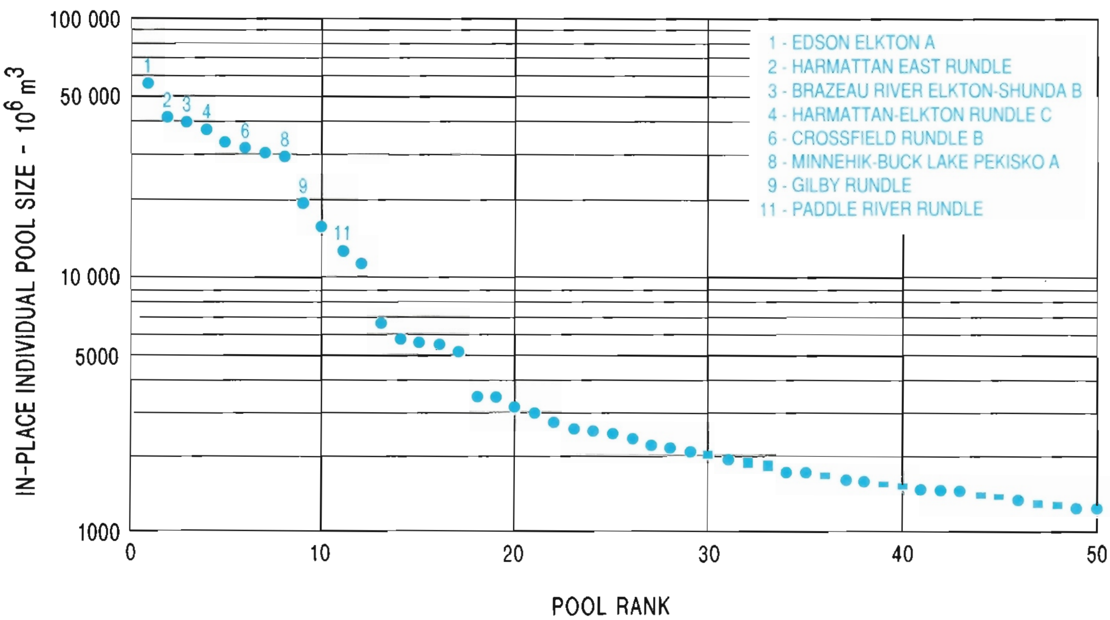


Figure 8. *Example of pool-size-by-rank plot — conditioned by discovered pools (dots), Mississippian subcrop–Edson/Harmattan play (predicted undiscovered pools shown by rectangles).*

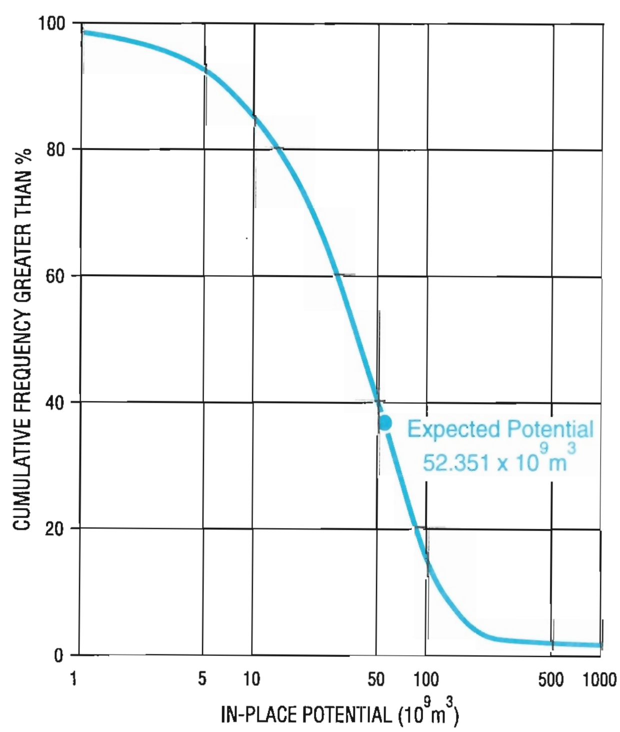
Estimate of play potential

The play potential can be estimated from the total number of pools and from the pool-size distribution (Fig. 9). Summation of the mean of all undiscovered pool sizes yields the mean of the play potential, reported here as the expected potential.

The value of the expected 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 sizes of discovered pools are incorrectly estimated, appreciated or depreciated, or if the rankings are altered, then the value of the expected potential will be altered. The expected potential can be considered as an estimate with a relatively high probability of being reliable—a more speculative or optimistic estimate is also provided for the total potential, termed the "probable potential", but it has a lower probability of being accurate.

Estimate of conceptual play resources

In other assessments of the potential of conceptual plays, (Roy, 1979; Lee and Wang, 1990) a "subjective probability" approach was used. Reinson et al. (1993b) used the discovery process model to estimate the potential of conceptual plays by applying it to established mature plays; this method is adopted here. After compiling the expected potential values for each



(Barclay, Holmstrom, Lee, et al.)

Figure 9. *Example of the distribution of the predicted play potential, Mississippian subcrop–Edson/Harmattan play. Predicted expected potential is 52.351 x 10^9 m^3 gas-in-place.*

mature play and adding that to the discovered resource to give a total estimated play resource and compiling 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. 10). Assuming the mature plays belong to a single, large population, the discovery process model can be used to estimate the number and individual sizes of conceptual plays within the basin (Fig. 11). As the potential of established immature plays cannot be estimated reliably or directly, their total resource is unknown and cannot be used in the data set for conceptual play analysis. However, we consider that the results of conceptual play analysis include an unspecified and unknown potential that should belong to the known immature plays. The small amount of known discovered in-place gas volume of the immature plays is presumed to be incorporated within the potential predicted in the conceptual play analysis. The discovered gas volume for immature plays should therefore be subtracted from the aggregate potential value predicted for all conceptual and immature plays.

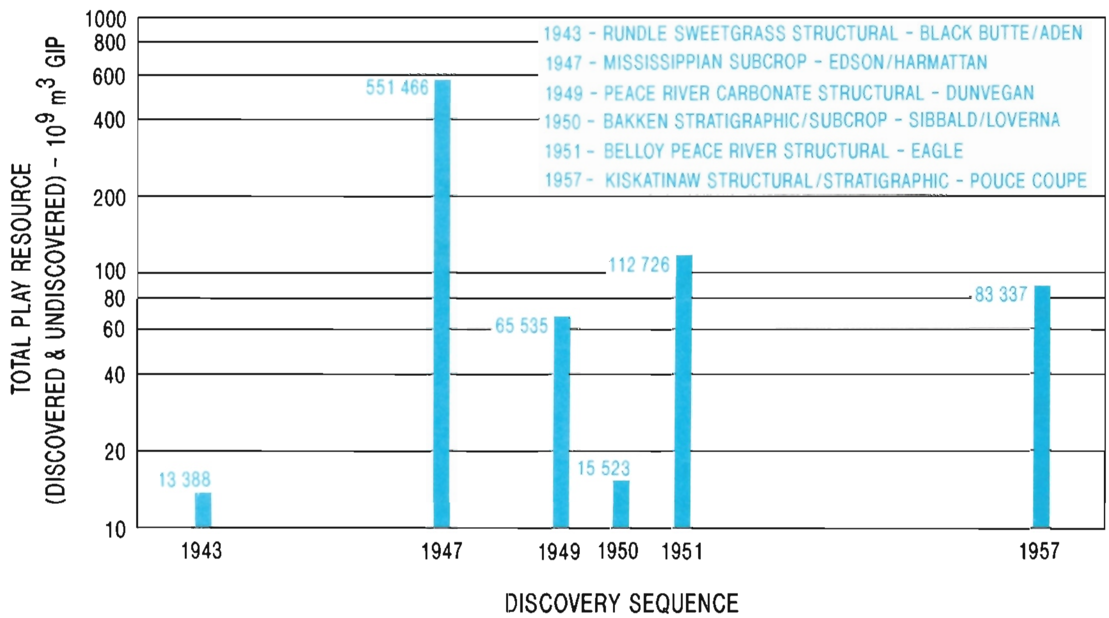


Figure 10. *Play size (discovered and undiscovered resources) versus discovery sequence for the six established mature Carboniferous and Permian plays.*

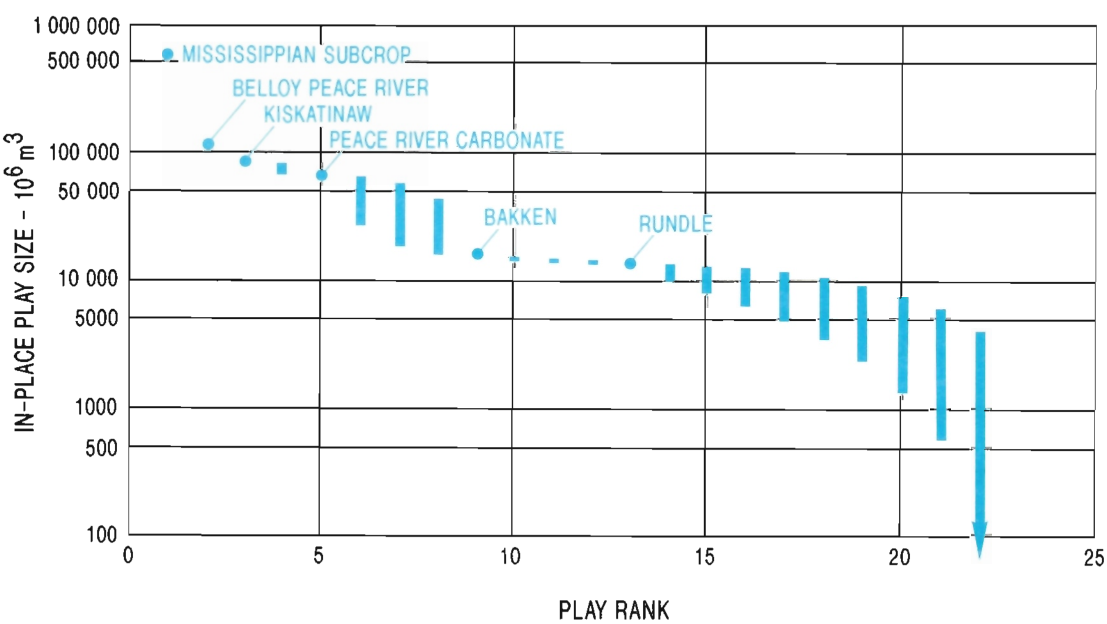


Figure 11. *Play-size-by-rank plot for the conceptual plays.*

GEOLOGICAL FRAMEWORK

The following summary is derived mainly from the literature and is intended to provide the basic geological background for the exploration plays discussed later. More extensive summaries of regional aspects of Carboniferous and Permian petroleum geology and stratigraphy in western Canada can be found in Sikabonyi and Rodgers (1959), Macauley et al. (1964), McGugan et al. (1964), Nelson (1970), Douglas (1970), Naqvi (1972), Podruski et al. (1988), Henderson (1989), Richards (1989a, b), Henderson et al. (1993, 1994) and Richards et al. (1993, 1994), and references therein.

Geological and tectonic setting

Regional Geographic Setting: The Western Canada Sedimentary Basin occupies an area of 1.4 x 10^6 km^2 and lies within southwestern Manitoba, southern Saskatchewan, Alberta, northeastern British Columbia and the southwestern District of Mackenzie of the Northwest Territories (Fig. 1; Podruski et al., 1988). The United States part of the basin occupies an additional area of 0.3 x 10^6 km^2 (not evaluated in our study). The basin consists of a wedge of Proterozoic to Tertiary sedimentary rocks that taper from a zero edge in the east, where they onlap the Precambrian Canadian Shield, to greater than 6 km thick, west of Calgary. Approximate geological basin boundaries consist of the Tathlina Arch to the north, the Transcontinental, Sioux and Central Montana arches to the south, and the folded and faulted Rocky Mountain Thrust Belt to the west. The Sweetgrass Arch subdivides the Western Canada Sedimentary Basin into the Alberta Basin to the northeast and the Williston Basin to the southwest.

Most of the Carboniferous and Permian gas pools and plays evaluated here occur within the Alberta Basin, in the subsurface of the present-day Interior Plains (Figs. 1, 2). Prolific Carboniferous gas pools and plays (and minor Permian pools) also occur in the Rocky Mountain Thrust Belt of the Rocky Mountain Front Ranges and Foothills (physiographic subdivisions and geological provinces from North and Henderson, 1954; Douglas, 1970). In contrast to the mainly stratigraphic plays in flat-lying beds of the Interior Platform, the Cordilleran plays comprise mainly folded and thrust-faulted structural traps and will be evaluated a separate Geological Survey of Canada gas assessment study (Osadetz et al., in prep.).

Tectonic Setting: Carboniferous sedimentation in the Western Canada Sedimentary Basin was preceded by generally quiet tectonic activity during the Devonian, when the basin was filled from the north with mainly carbonate sediments. The Western Canada Sedimentary Basin was segmented by the locally active Peace River, Tathlina and West Alberta arches into several partially protected basins surrounded by extensive reef-rimmed shelves, including the well-known reefs that contain much of western Canada's oil in facies pinchout traps (see e.g., Podruski et al., 1988; Reinson et al., 1993b). By the end of the Devonian, the basins were essentially filled, the arches had been covered with sediment (except for small parts of the Peace River Arch crest) and the basins became essentially tectonically inactive.

The combination of relatively flat paleotopography and a Late Devonian extinction of reef-building stromatoporoid organisms, allowed carbonate ramp sedimentation (i.e., no reefal shelf-margin barriers) to develop throughout the basin during the Late Devonian. These broad shallow-water ramps covered most of the Western Canada Sedimentary Basin and persisted through the Early Carboniferous. The ramps opened to the west, into the Prophet Trough where slope to basinal deposits accumulated (Fig. 1; Richards, 1989a). The former Peace River Arch began to downwarp, forming a broad westward-opening depocentre called the Peace River Embayment that contained deeper water open marine deposits than the surrounding ramps (Douglas, 1970; Richards, 1989a; Barclay et al., 1990; O'Connell, 1990; O'Connell et al., 1990; Richards et al., 1993, 1994). The embayment was a large lozenge-shaped basin that existed from the Carboniferous to Triassic, inboard from the western North America cratonic margin. During the Early Carboniferous, the Sweetgrass Arch was a mildly positive feature that partially separated the Alberta and Williston basins. Williston Basin was a region of marked subsidence during the Early Carboniferous, in which terrestrial and shallow-marine sediments accumulated. Petroleum traps within the extensive, relatively uniform, carbonate ramps are not typically facies pinchout traps, as is the case for the Devonian, but instead are traps relying mainly on seals along the erosional (subcrop) edges of the ramps or, less commonly, on structural traps developed over underlying local structural highs, such as fault blocks or Devonian reefs.

During the late Early Carboniferous (Viséan and Serpukhovian; Richards, 1989a; Richards et al., 1994) and the Late Carboniferous (Chung, 1993; Chung and Henderson, 1993a, b), sediment deposition was localized in the Peace River Embayment and Prophet Trough. During this time, the Peace River Embayment was much more deeply downwarped than the rest of the Western Canada Sedimentary Basin. The block-faulted embayment formed a more rapidly subsiding feature than adjacent areas, as well as creating the central, highly faulted, Dawson Creek Graben Complex (Barclay et al., 1990). The subsiding embayment acted as a sediment sink, capturing mainly siliciclastic sediments mixed with some carbonates (the Stoddart Group). Petroleum traps in the embayment are mainly structural, related to the active block faulting.

In the Western Canada Sedimentary Basin, Permian rocks occur throughout much of the eastern Cordillera. Permian sediments were also deposited on the cratonic Interior Platform within the Peace River Embayment and Liard region (Fig. 12; Henderson, 1989; Henderson et al., 1994). These strata were deposited along the plate margin of western North American in west-southwest (present-day) facing facies belts. Mainly shallow-water, marine facies sediments were deposited on the cratonic platform, passing westward into outer shelf, slope, and basinal siltstone and shale of the Ishbel Trough. Ishbel Trough is an elongate trough within the Eastern Cordillera overlying the Carboniferous Prophet Trough and extending from southeastern British Columbia to northern Yukon (Henderson, 1989). West of the Ishbel Trough, pericratonic terranes such as the Cariboo and Cassiar, may represent uplifted highlands that formed the western rim of the Ishbel Trough.

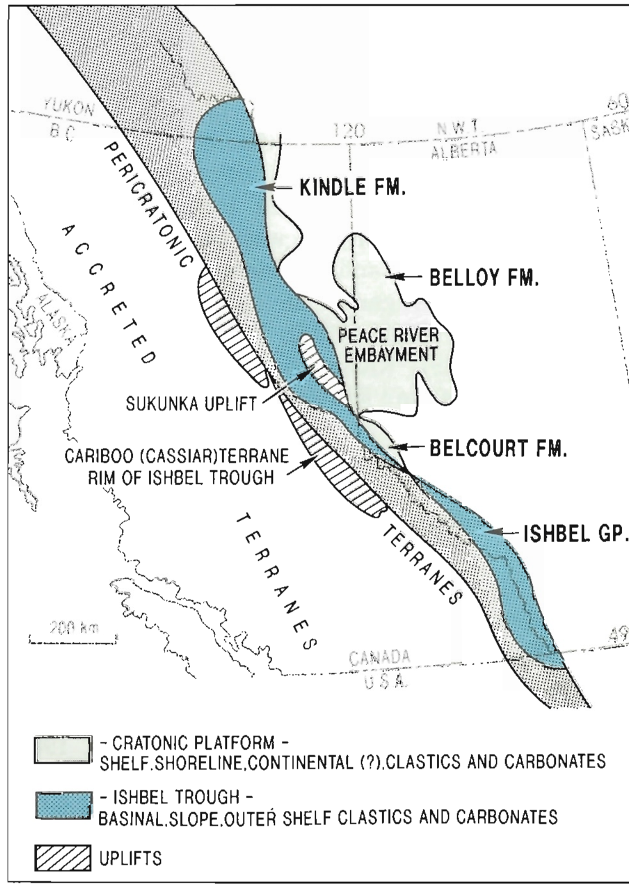


Figure 12. *Distribution and tectonic setting of Permian strata in western Canada (modified from McGugan et al., 1964; Ziegler, 1969; Rascoe and Baars, 1972; Henderson, 1989).*

The major Permian exploration play occurs in the Belloy Formation, which is restricted to the Peace River Embayment (Fig. 12; Barclay et al., 1990; Richards et al., 1994). The Belloy Formation blanketed and extended beyond the relatively dormant Dawson Creek Graben Complex (Naqvi, 1972; Henderson, 1989; Barclay et al., 1990; Henderson et al., 1994). However, some fault rejuvenation and anomalous subsidence in central parts of the graben complex reflect continued but subdued tectonic activity. These faults have small displacements and associated uplifts, and provide structural control on petroleum trapping in this regionally porous formation. Also, the faulting has isolated reservoirs in stratigraphic traps along the erosional edge of the Belloy Formation.

Carboniferous–Permian depositional setting

Facies packages and transgressive–regressive cycles of the Carboniferous–Permian are described in this section. They are relevant to gas distribution because reservoir-quality units are deposited at specific positions vertically and laterally within these packages. Petroleum reservoirs are preferentially developed toward the top of individual shallowing-upward (progradational) cycles, in porous, open marine, grainstone facies and also in dolomitized, lagoonal to supratidal carbonates. In addition, these carbonates provide a suitable facies for the enhancement of porosity at their erosional subcrop edges, where stratigraphic traps can develop.

Carboniferous strata comprise a thick succession of mainly shelf carbonate rocks with lesser siliciclastics, and occur throughout the Western Canada Sedimentary Basin (i.e., Rundle, Madison, Stoddart groups and related strata; Figs. 1, 13). The less common siliciclastics occur in the lowermost Carboniferous (Exshaw, Banff and equivalent formations) and uppermost Carboniferous (Stoddart and Mattson groups, and equivalent beds) strata and are interbedded with some carbonate. Permian strata comprise a mix of sandstone, siltstone and dolomitic carbonate (Belloy Formation and Ishbel Group; Fig. 12).

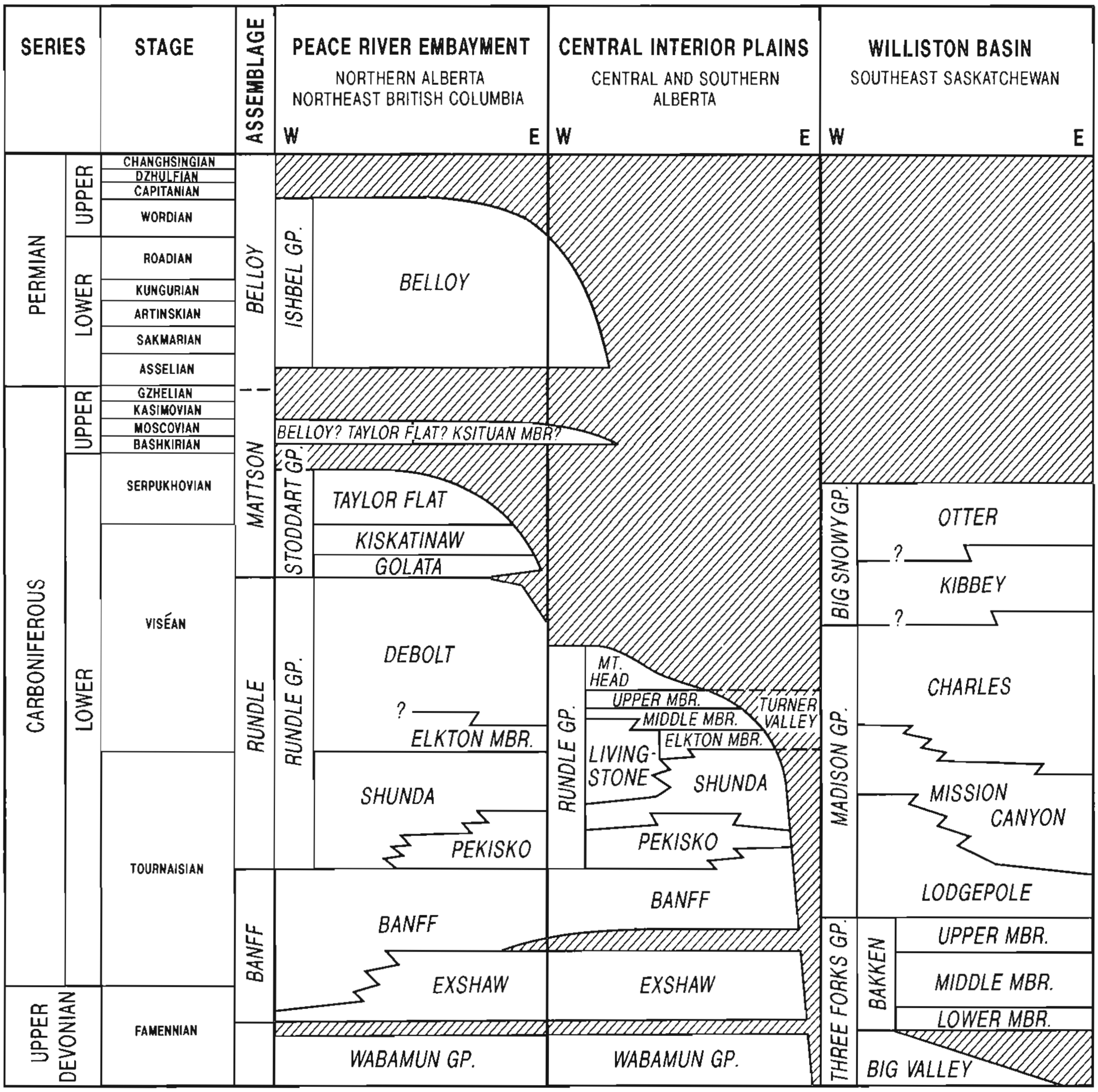


Figure 13. *Table of Carboniferous and Permian formations, subsurface of Western Canada Sedimentary Basin (modified from Podruski et al., 1988; Henderson, 1989; Richards, 1989a, 1993; Chung, 1993; Henderson et al., 1993, 1994; Richards et al., 1993, 1994).*

Carboniferous and Permian strata are overlain unconformably by Mesozoic strata throughout most of the basin and rest with minor unconformity on underlying Devonian strata. The present eastern and northern limits of Carboniferous and Permian strata were formed by several Late Paleozoic and Mesozoic events. These events produced several sub-parallel erosional edges of various Carboniferous and Permian strata trending roughly northwest-southeast, parallel to depositional strike. Reservoir quality is enhanced along these erosional edges (Fig. 14). Increased tilt of the basin to the southwest during the Late Mesozoic and Tertiary orogeny resulted in oil and gas being trapped at the northeast, updip, parts of the erosional edges.

The Belloy Formation was deposited within the Peace River Embayment in a relatively tectonically stable, shallow-water, marine, shelf setting (Naqvi, 1972), characterized by mixed carbonate and siliciclastic deposition. Burton et al., (1990) interpreted an eastern facies assemblage of dolomitic sandstone and dolostone coquinas (both reservoir facies) as belonging to tidal shoreline environments. Thicker deposits consisting of siltstone and limestone in the western parts of the Peace River Embayment are interpreted as deeper water, outer shelf to basinal sediments (Henderson, 1989; Burton et al., 1990). Exposure and erosion at the Permian–Triassic unconformity caused an influx of chert and silica cements into the uppermost Permian units and also

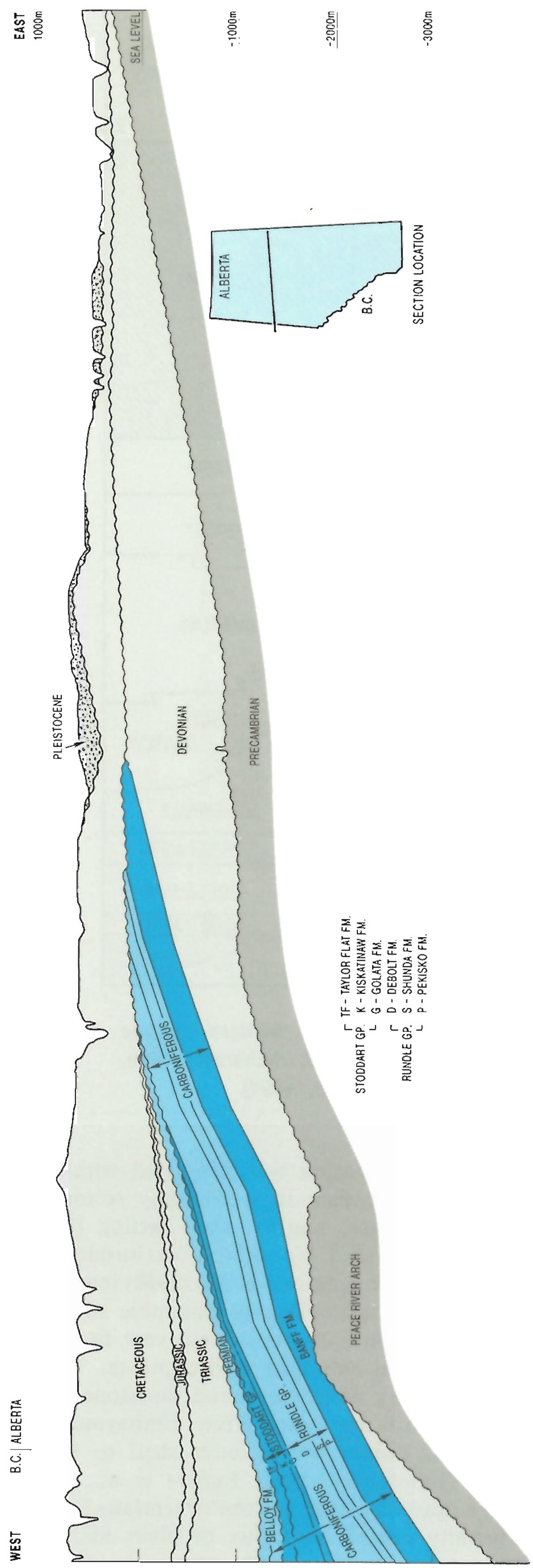


Figure 14. *West—east cross-section illustrating stratigraphic position of Carboniferous and Permian units in the Western Canada Sedimentary Basin. Note narrow belts of subcrop edges below Mesozoic strata (modified from Gussow, 1962; Wallace-Dudley, 1982; Wright, 1984).*

caused the isolation of reservoir units at the top of the Belloy Formation.

Regional stratigraphy

Carboniferous: The Carboniferous succession can be subdivided into three major shallowing-upward (progradational) units, which, in turn, form an overall shallowing-upward succession (Macauley et al., 1964; Podruski et al., 1988; Richards et al., 1993; 1994).

1. **Lower Unit (''Banff Assemblage'')**: deep-water basin to slope shale, sandstone and muddy limestone (Exshaw, Bakken, Banff and Lodgepole formations; approximately Late Famennian to middle Tournaisian) (Fig. 13).

   The Lower Unit consists of two shallowing-upward, transgressive–regressive cycles, separated by a disconformity (Podruski et al., 1988). The lower cycle (Exshaw Formation and part of the Banff Formation) consists of black, organic-rich, deep-water, marine shale overlain regressively by nearshore sandstone. The upper cycle (upper Bakken Formation, Lodge and Banff formations) consists of deep-water, black shale and muddy carbonate overlain by shelf, higher energy, lime grainstone, in turn overlain by low-energy, tidal, muddy carbonate and clastic. Petroleum reservoirs are preferentially developed in the porous grainstone and dolomitized tidal carbonate. Also, porosity in these carbonate reservoirs is enhanced at their erosional subcrop edges.

2. **Middle Unit (''Rundle Assemblage'')**: slope, ramp, rimmed shelf and nearshore carbonate (lower and middle, or all, of the Rundle Group, middle and upper Madison Group; approximately middle Tournaisian to Late Viséan).

   The Middle Unit is an overall shallowing-upward succession. The unit consists of deep-water slope and basinal carbonate overlain successively by shelf lime grainstone and finally by shallow-water, restricted marine, muddy carbonate. There are several internal unconformities that divide the unit into numerous smaller, transgressive–regressive cycles. On the shelf, the small-scale cycles consist of open marine bioclastic or oolitic grainstone overlain by lagoonal to supratidal mudstone, packstone, shale, and evaporite. The open marine grainstone and dolomitized, tidal, muddy carbonate form petroleum reservoirs.

3. **Upper Unit ("Mattson Assemblage")**: deltaic and nearshore siliciclastics with some marine carbonate [Stoddart Group, Etherington (upper Rundle Group), Mattson, Golata, and Kibbey (lower Big Snowy Group)] formations; approximately Late Viséan to Serpukhovian, or younger Carboniferous) (Richards et al., 1993; Podruski et al., 1988).

The Upper Unit is restricted geographically to three areas: the Peace River Embayment, Williston Basin, and Liard River region, in contrast to the basin-wide Lower and Middle units (Fig. 1). In the Peace River Embayment, the Upper Unit consists of black marine shale (Golata Formation) overlain successively by fluvio-estuarine, tidal and shallow marine, sandstone and shale (Kiskatinaw Formation), and open marine limestone (Taylor Flat Formation) (Rutgers, 1958; Halbertsma, 1959; Barclay, 1988; Barclay et al., 1990; Richards et al., 1994). This succession forms an overall transgressive sequence. Fluvio-estuarine sandstone at the base of the Kiskatinaw Formation form the main gas reservoirs in structural–stratigraphic traps related to block-faulting in the Peace River Embayment. In the Liard River region, the Upper Unit consists of prodeltaic shale of the Golata Formation overlain by fluviodeltaic sandstone and shale of the Mattson Formation. Limited amounts of gas occur in the Mattson sandstone within structural traps along the Bovie Fault Zone (Richards, 1983, 1989b). In the Williston Basin, the Upper Unit consists of intertidal to marginal marine siliciclastics, evaporite, and carbonate of the Kibbey Formation, which do not host any known gas pools in Canada, although the Kibbey Formation does produce oil in Montana (Hansen, 1972).

Permian: The Upper Carboniferous to Permian Belloy Formation in the Peace River Embayment mainly consists of thin, widespread, marine, supratidal to basinal, siliciclastics, and silty to sandy carbonate (Henderson, 1989; Chung, 1993; Chung and Henderson, 1993a, b). This succession forms a fourth depositional assemblage overlying the three Carboniferous assemblages (Fig. 13). The Belloy Formation lacks the extensive, thick carbonate that characterize much of the underlying Lower Carboniferous and Devonian, and also lacks basinal shale and well defined continental deposits (Henderson, 1989). The Belloy Formation can be subdivided into a broad, eastern, sandstone-dolostone facies belt and a localized, western, limestone-siltstone facies package (Naqvi, 1972; Henderson, 1989; Burton et al., 1990).

The eastern facies belt is dominated by shallow-water, marine platform, shoreface and tidal, cherty sandstone and dolostones, with subordinate limestone and shale. It is widespread in the eastern parts of the Peace River Embayment (Barclay et al., 1990; Bloy and Scott, 1993; Leggett et al., 1993). Sandstone is most common near the embayment margins and passes laterally into less porous dolostone toward the centre of the embayment. A basal phosphatic chert conglomerate is common (Henderson, 1989). Locally, the eastern assemblage of the Belloy Formation can be divided into three members (Halbertsma, 1959) and is described as follows (from Halbertsma, 1959; Naqvi, 1972; Henderson, 1989). The Lower Carbonate member consists of fine grained, glauconitic quartz arenite, siltstone, and sandy and cherty dolomitic limestone. Fossiliferous, white chert occurs toward the top of the Lower Carbonate member. The overlying, coarsening-upward Sand member consists of medium grained, quartz arenite with glauconite and phosphate, and some interbedded carbonate and chert. The Upper Carbonate member consists of dolomitic limestone, dolostone, glauconitic sandstone, and bedded chert. A karst zone, consisting of dissolution collapse breccia, chert, and sandstone extensively cemented with chert and silica, is common at the top of the Belloy Formation where it underlies, and was created during development of, the Permian–Triassic unconformity.

The western facies package occurs in the thickest development of the Belloy Formation, within the western and most deeply subsided parts of the Peace River Embayment. It consists of siltstone and fossiliferous carbonate (Naqvi, 1972; Henderson, 1989; Barclay et al., 1990; Burton et al., 1990). Sponge spicules, brachiopods, corals, and crinoids occur in this facies assemblage. This assemblage represents deposition in carbonate platform and outer shelf settings.

Units within the Belloy Formation are flat-lying, indicating a mainly stable tectonic setting post-dating the main subsidence and block-faulting episodes of the Dawson Creek Graben Complex (Naqvi, 1972; Barclay et al., 1990). Block faults that disrupt the underlying Carboniferous Stoddart Group appear to have caused only minor and local offset of units within the Belloy Formation, typically near the margins of the Peace River Embayment.

ESTABLISHED MATURE AND IMMATURE PLAYS: GEOLOGICAL DEFINITION AND RESOURCE ASSESSMENT

This section describes the geology and gas resources of the plays that have discovered pools. These plays are termed established plays and were split into two groups: 1) the established mature plays with numerous pools — this permits a full discovery process analysis of their potential, and 2) the established immature plays with too few pools to permit a full analysis of their potential. The results of the discovery process analysis of gas potential for the mature plays are reported in this section.

Established immature plays — play definitions and descriptions

The four identified immature plays have a total of 10 single-pool gas fields that host a total of 2.711 x 10^9 m^3 discovered gas-in-place, which represents 0.4 per cent of the discovered gas-in-place in the Carboniferous–Permian of the plains. In contrast to the established mature plays, the established immature plays have too few discoveries to allow detailed numerical analysis using the discovery process model. Their potential is incorporated within the analysis of conceptual plays and we believe that the 16 predicted conceptual plays and their resources include the four immature plays

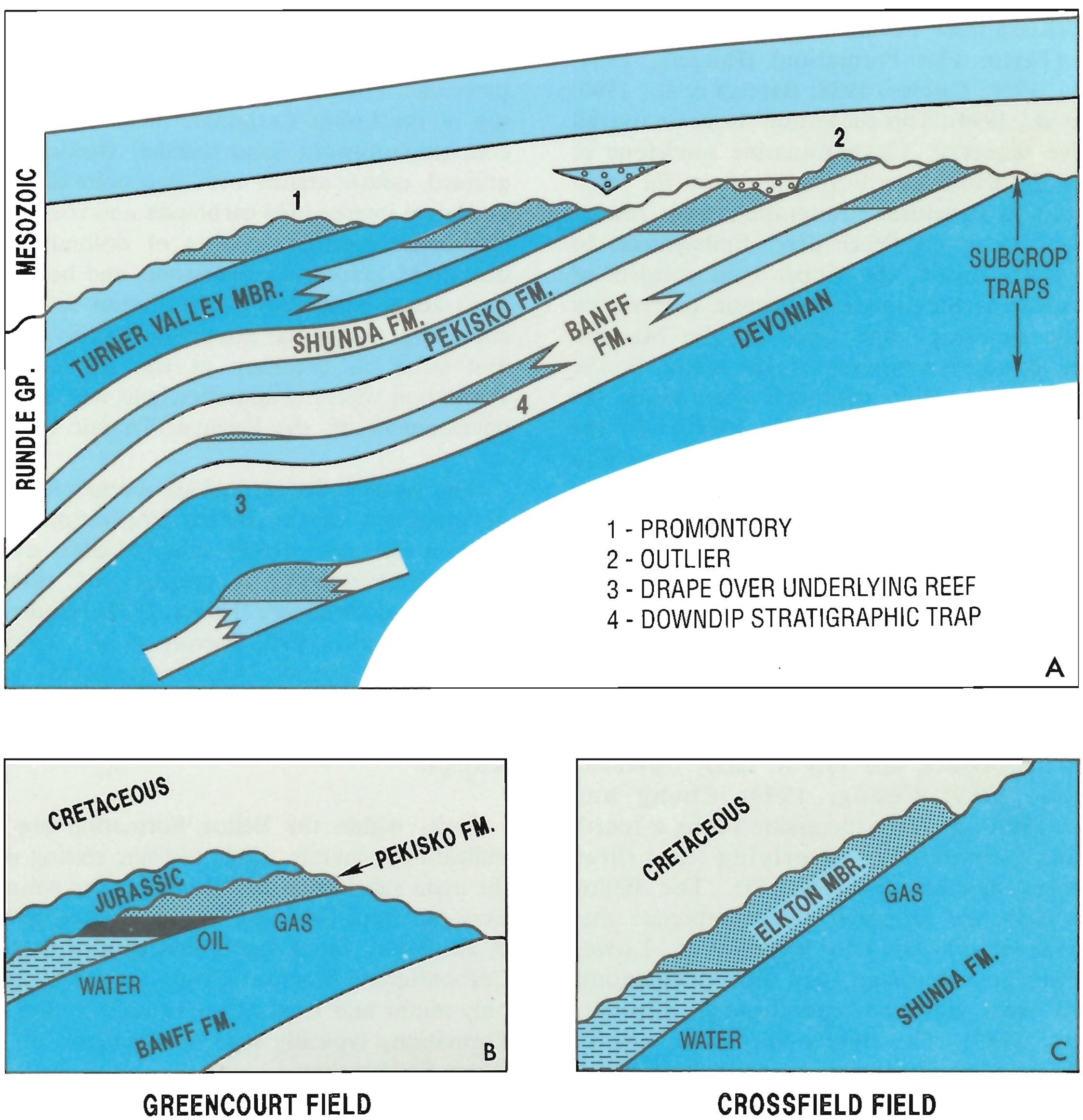


Figure 15. *Mississippian subcrop–Edson/Harmattan play:* ***A:*** *schematic diagram of play types.* ***B:*** *Greencourt Field;* ***C:*** *Crossfield field (examples modified from Callow, 1969; Whitman, 1969).*

and their predicted resources (Fig. 11). In other words, 12 purely conceptual plays (with no known discoveries) are predicted.

Banff downdip stratigraphic–Ferrier/Willesden Green play

The two pools in this immature play occur in the Banff Formation at Ferrier and Willesden Green, with pool sizes of 0.210 x 10^9 m^3 and 0.225 x 10^9 m^3 respectively, and a total discovered gas-in-place volume of 0.435 x 10^9 m^3. The first pool found in this play was the Ferrier–Banff pool, discovered in 1967. These pools occur downdip of the Banff Formation erosional edge and the reservoirs are due to updip facies changes within the Banff Formation (Fig. 15A, B). These two pools were the only ones found in our analysis that had been formed entirely due to facies pinchouts. They do not appear to have been influenced by trapping and reservoir enhancement along subcrop edges. Similar traps in facies pinchouts are likely to exist in the overlying Pekisko, Shunda, and Turner Valley formations of the Rundle Group (Fig. 15A, B, C) and form an important, purely conceptual play, or set of conceptual plays, in addition to the Banff downdip stratigraphic play. This play is analogous to the Oungre and Sherwood plays in the American portion of the Williston Basin.

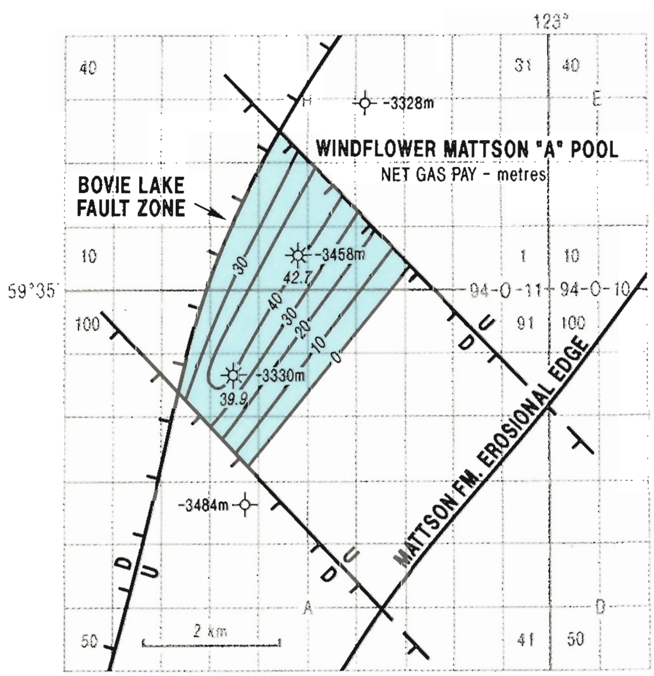


Figure 16. Mattson structural play (immature): net gas pay map, Windflower pool (modified from Province of British Columbia, 1991).

In general, reservoir quality is poor and contacts between reservoir and nonreservoir facies are poorly defined within the extensively developed platform carbonate of the Banff Formation and Rundle Group. However these deposits occur over a large, inadequately explored area (Fig. 3). Although our assessment methods do not permit a numerical prediction of potential in immature plays, we feel that the downdip play within the Banff Formation and Rundle Group may have the most potential in Carboniferous and Permian strata of the plains. For example, Speranza (1993) outlined trends of prospective fairways and patches of Banff Formation carbonate sand shoals in southern Alberta.

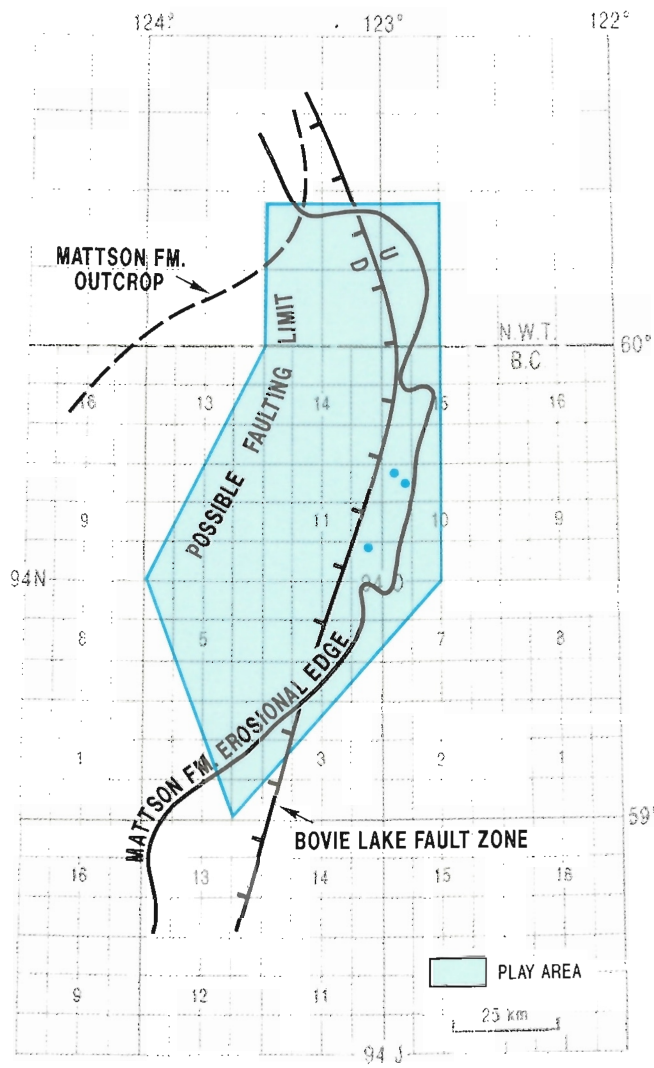


Figure 17. Mattson structural play (immature): play area and location of discovery wells (geological information from Richards, 1989b; Macauley et al., 1964). Location of discovery wells and wells typifying the play-type indicated.

Banff/Rundle drape-Windfall play

The two pools in this immature play are the Windfall Banff A and Little Smoky Pekisko pools, with pool sizes of 0.242 and 0.061 x 10^9 m^3, respectively. The total discovered gas-in-place volume is 0.303 x 10^9 m^3. The Little Smoky Pekisko pool was the first pool found in this play and was discovered in 1954. Traps occur on local structural highs caused by drape over underlying Devonian reefs (Fig. 15A).

Mattson structural-Windflower play

The three pools in this immature play are the Windflower Mattson A pool (Fig. 16) and two unnamed pools termed "Other Area, Mattson", all found in 1973. Pool sizes are 0.684, 0.158 and 0.058 x 10^9 m^3, respectively (rounded-off values). The total discovered gas-in-place volume is 0.899 x 10^9 m^3 (using nonrounded pool sizes). This play consists of fluviodeltaic sandstone reservoirs of the Mattson Formation in anticlines or along normal faults at the eastern upthrown side of the Bovie Lake Fault Zone (see Richards, 1983, 1989b). The play area lies between the Mattson erosional edge to the north, east and south and the western limits of the Bovie Lake Fault Zone to the east (Fig. 17).

Williston Basin (associated-gas) subcrop-Alida play

The three pools in this immature play are associated-gas pools in the Mission Canyon Formation of southeastern Saskatchewan. The pools are the Alida East Frobisher-Alida, Alida West Frobisher-Alida, and the Nottingham Alida pools, with pool sizes of 0.688, 0.081 and 0.304 x 10^9 m^3, respectively. The total discovered gas-in-place volume in the play is 1.073 x 10^9 m^3. The Alida East Frobisher-Alida was the first pool discovered in this play and was found in 1954. The pools occur in shallow-water, shelf, subtidal to intertidal, carbonate along the oil-prone erosional edge of the Alida Member (Figs. 18, 19; Edie, 1958; Lake, 1989).

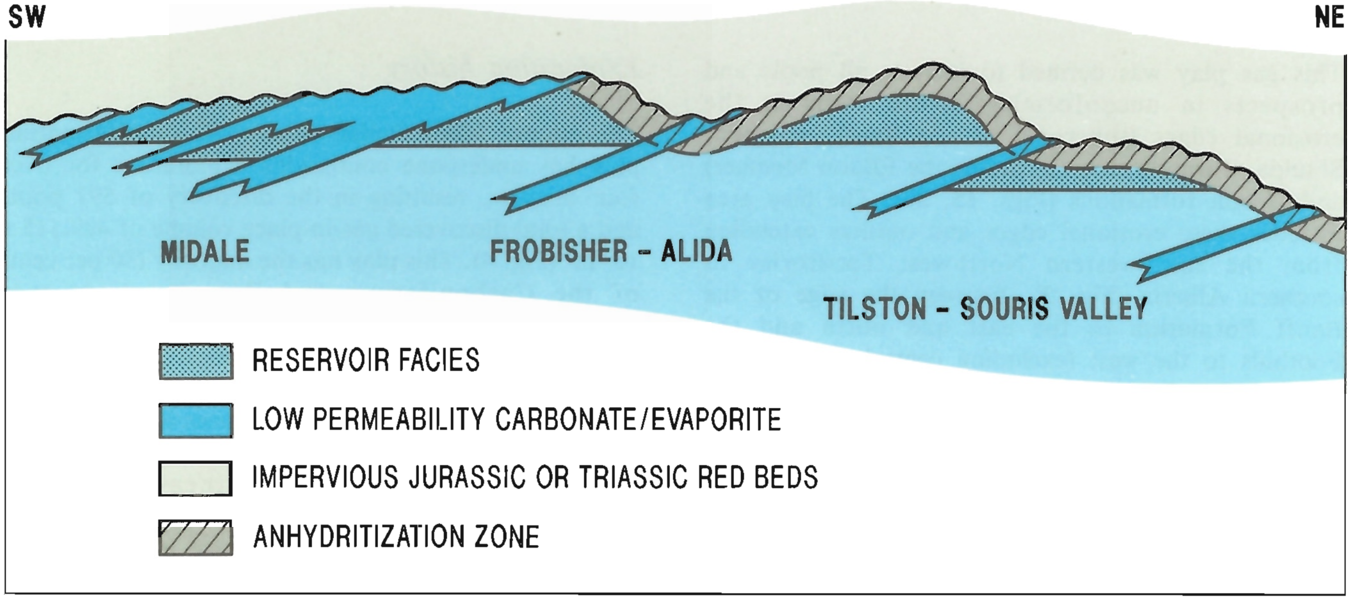


Figure 18. *Schematic diagram of the Alida subcrop play (immature) (modified from Kent, 1984; Podruski et al., 1988).*

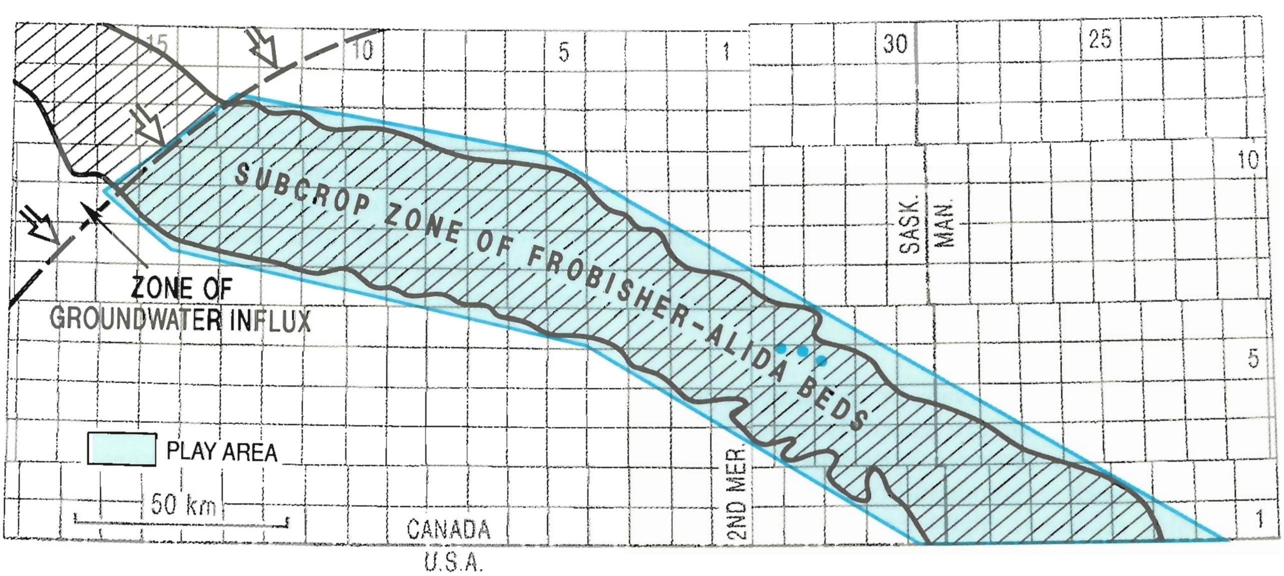


Figure 19. *Alida subcrop play (immature): play area. Location of discovery wells and wells typifying the play-type indicated.*

Established mature plays — geological definition and resource assessment

Mississippian subcrop-Edson/Harmattan play

Play definition

This gas play was defined to include all pools and prospects in unconformity-related traps at the erosional edges (subcrops) of the Banff, Pekisko, Shunda, Turner Valley (including the Elkton Member) and Debolt formations (Figs. 15, 20). The play area includes these erosional edges and outliers extending from the southwestern Northwest Territories to southern Alberta (Fig. 3), between the edge of the Banff Formation to the east and north and the Foothills to the west (excluding central parts of the Peace River Embayment area, which lacks major subcrop edges and is dominated by structural plays).

Geology

Carbonate of the Banff (particularly the middle Banff "Clarke's Member"), Pekisko, Shunda, Turner Valley (lower Elkton Member) and Debolt formations have undergone diagenesis along their eastern subcrop edges to produce reservoirs with vuggy, pinpoint, and intercrystalline porosity. A variety of traps occur at the angular unconformities, either over paleotopographic highs or as erosional salients and outliers (Fig. 14; Podruski et al., 1988). A stratigraphic component of trapping occurs near the erosional surface in some fields, caused by facies and diagenetic changes, such as variations in porosity-enhancing dolomitization. Overlying Mesozoic shale typically provides the seal rock, either as a blanketing seal or filling channels around outliers or salients (Fig. 21). The source rocks are probably the underlying shale of the Exshaw and Bakken formations. Other possible source rocks include Banff Formation shale and carbonate and overlying Mesozoic shale.

The gas producing intervals in the subcropping formations listed above are generally dolomitized carbonate. The typical reservoir facies consists of open marine, middle shelf, echinoderm-bryozoan grainstone that probably represents high-energy shoal deposits. Restricted, shallow-water marine, muddy subtidal to supratidal dolo-packstone to dolo-mudstone of the Shunda Formation also form reservoirs along the Shunda subcrop edge. The Turner Valley (lower Elkton Member) and Pekisko formations contain the most prolific reservoirs in this play, such as at the Harmattan (Fig. 21), Sundre, Sylvan Lake (Elkton Member), Twining, and Medicine River (Pekisko Formation) fields.

Exploration history

The mature Mississippian subcrop-Edson/Harmattan play has undergone continuous exploration for over four decades, resulting in the discovery of 597 pools and a total discovered gas-in-place volume of 499.115 x 10^9 m^3 (Fig. 4). This play has the majority (80 per cent) of the Carboniferous and Permian discovered gas-in-place in mature plays. The first discovery was in 1947, at the Hanna Banff A pool. Most of the discoveries from 1950 to 1970 were made in south-central Alberta, while discoveries since 1970 have been made further north, in the subcrop areas of northwestern Alberta and northeastern British Columbia. Pool volumes range from less than 1 x 10^6 to 56 x 10^9 m^3 gas-in-place. Average net pay ranges from 0.3 to 36.6 m, porosity from 1 to 31 per cent, and pool area from 5 to 45 364 ha (0.019 to 175.15 sections).

Play potential

The expected potential for this play is 52.351 x 10^9 m^3 gas-in-place (Table 3), predicted to occur in 343 undiscovered pools. In contrast to its discovered resource, this play is predicted to contain only 24.4 per cent of the Carboniferous and Permian expected potential in mature plays. This relatively low potential reflects the advanced exploration maturity of the play and the restriction of reservoir trends to long, narrow belts within the play area. The potential however is quite significant because this play has the third best total potential of the Carboniferous–Permian mature plays. The largest remaining undiscovered pool is predicted to be 1.893 x 10^9 m^3 gas-in-place (Fig. 8). The less explored northern part of the subcrop edge is expected to have the most potential, even though gas potential here is limited by facies changes to shalier rocks with poor quality reservoirs, particularly in the Peace River Embayment (see Richards, 1989a; O'Connell, 1990), by heavy oil in the reservoirs of certain areas, and by the lack of good seal and source rocks in the overlying Cretaceous sandstone-dominated strata (Fig. 20).

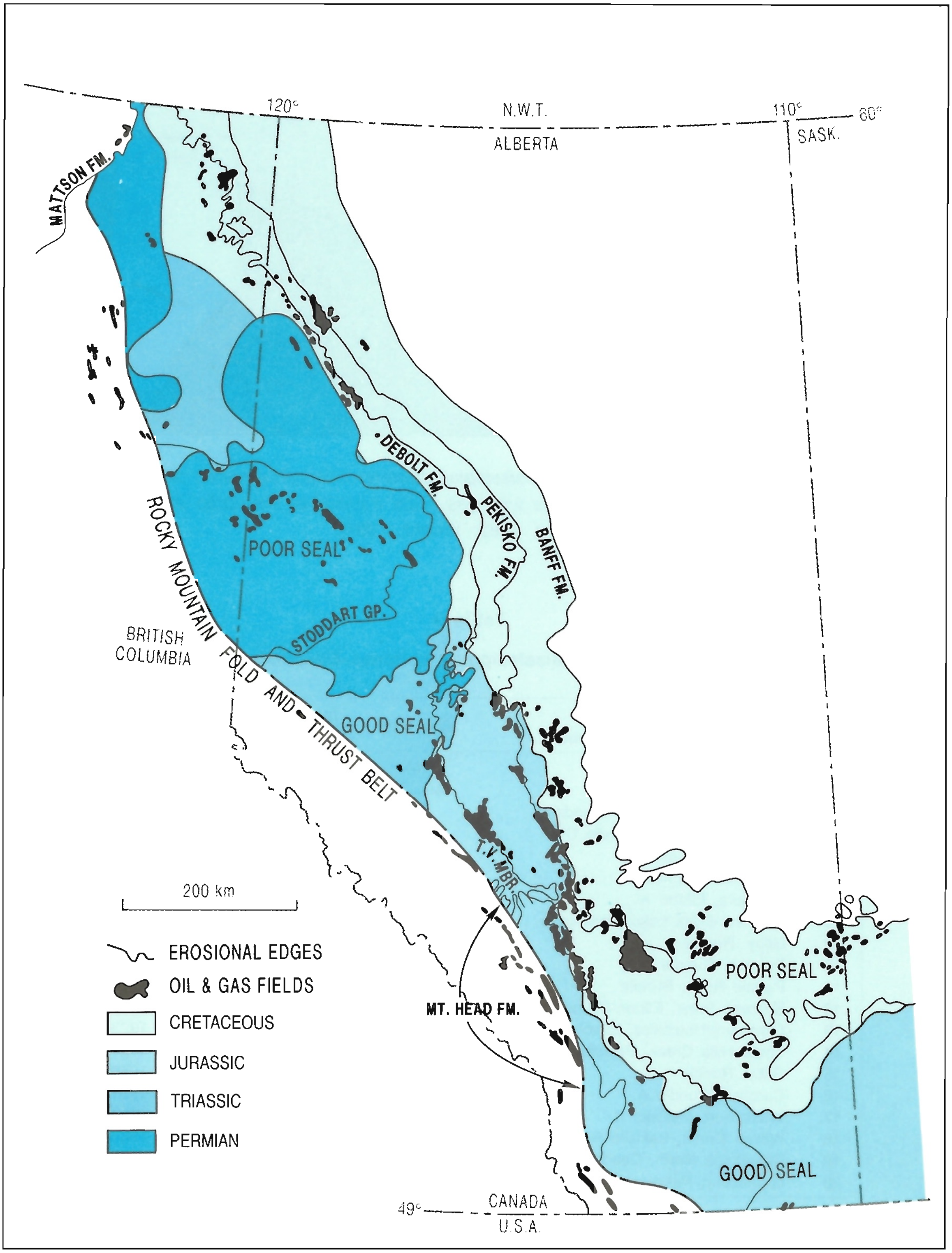


Figure 20. *Distribution of strata overlying the Carboniferous. Trapping potential and access to gas source rocks is best for reservoirs in the top-Carboniferous that lie beneath the impermeable and organic rich, shale-dominated Triassic and Jurassic strata, and poorer beneath sandstone-dominated, organic-poor permeable Permian and Cretaceous strata.*

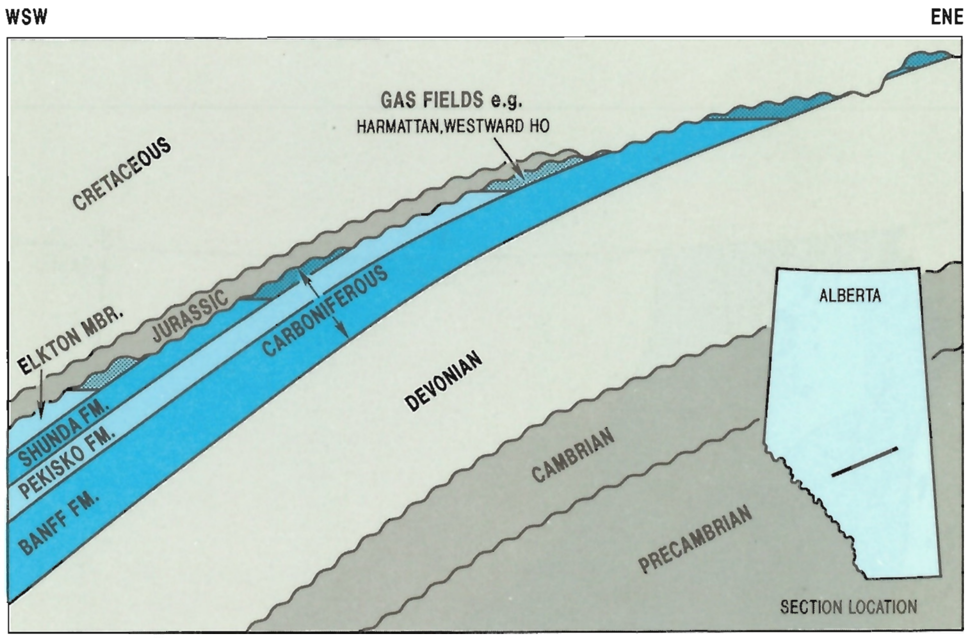


Figure 21. *Schematic diagram of the Mississippian subcrop–Edson/Harmattan play illustrating several Carboniferous subcrop edges with gas fields trapped at the updip limits (modified from Gussow, 1962; Wallace-Dudley, 1982; Wright, 1984).*

Table 3

Largest 20 pools of the Mississippian subcrop–Edson/Harmattan play

Rank	Field/Pool (top 20 discovered pools)	Gas type	In-place volume (10^6 m^3)	Discovery year
1	Edson, Elkton A	NA	55 633	1961
2	Harmattan East, Rundle	AG, SG	41 876	1954
3	Brazeau River, Elkton-Shunda B	NA	39 463	1959
4	Harmattan–Elkton, Rundle C	AG, SG	36 469	1953
5	Crossfield, Rundle A	NA	31 235	1956
6	Crossfield, Rundle B	NA	31 096	1957
7	Carstairs, Elkton A	NA	29 728	1958
8	Minnehik-Buck Lake, Pekisko A	NA	28 105	1952
9	Gilby, Rundle	AG, SG	18 850	1954
10	Twining, Rundle A	AG, SG	15 277	1959
11	Paddle River, Rundle	AG	12 183	1957
12	Brazeau River, Elkton-Shunda A	NA	10 668	1965
13	Cranberry/Hotchkiss, Debolt Pool No. 1	NA	6 230	1973
14	Three Hills Creek, Pekisko	AG	5 434	1953
15	Gilby, Rundle	NA	5 366	1956
16	Caroline, Rundle A	AG, SG	5 194	1955
17	Whitecourt, Pekisko E	NA	4 741	1963
18	Wilson Creek, Pekisko B	NA	3 161	1966
19	Chinchaga North, Debolt-Detrital A	NA	3 158	1978
20	Greencourt Pekisko A	AG, SG	2 910	1961
Initial in-place volume (discovered) (10^6 m^3)			499 115	
Initial in-place volume (potential) (10^6 m^3)			52 351	
Per cent of play resources undiscovered			10	
Total pool population (discovered and undiscovered)			940	
Total pools discovered			597	
Total pools undiscovered			343	
Largest undiscovered pool			1 893	
Total undiscovered pools >140 x 10^6 m^3			67	

NA, nonassociated gas; AG, associated gas; SG, sour gas

Bakken stratigraphic/subcrop–Sibbald/Loverna play

Play definition

This play was defined to include all pools and prospects in stratigraphic, structural, and unconformity-related traps in shallow-water, marine sandstone in the middle part of the Bakken Formation (Fig. 22). The play area straddles the Alberta/Saskatchewan border between latitude 51°N and 52°N, with the Bakken erosional edge to the north and east, and the depositional limits of the reservoir sandstone to the west and south (Figs. 23, 24).

Geology

The fine grained sandstones of the Bakken Formation (also informally called the Coleville or Banff sandstones) of southwestern Saskatchewan and southeastern Alberta are interpreted as nearshore to offshore, marine bar, deposits (Grassby and Pelletier, 1990). Good quality reservoirs exist where carbonate cement has been leached along the erosional edge. Trap types include: erosional edge traps in the northeastern part of the play area; stratigraphic traps, such as shoal facies downdip of the subcrop edge; structural traps caused by gentle folding and faulting, or meteorite impact, and combination stratigraphic-structural traps, caused by drape over Devonian salt-solution remnants (K.G. Osadetz, pers. comm., 1992). The source rock is probably the underlying Exshaw Formation.

Exploration history

The first discovery in this play was made in 1950, at the Sibbald Bakken A pool (Table 4). Other than the latter and three other pre-1970 pools, all pools were discovered between 1970 and 1990. Thirty-seven pools have been discovered, resulting in a total discovered gas-in-place volume of 3.29 x 10^9 m^3. This forms 0.5 per cent of the Carboniferous and Permian (plains area) discovered gas-in-place volume for mature plays. Data from the pools indicates average net pay ranges from 0.5 to 12.5 m, porosity ranges from 11 to 35 per cent, and pool area ranges from 8 to 1613 ha (0.03 to 6.2 sections).

Play potential

The expected potential for this play has a mean of 12.233 x 10^9 m^3 gas-in-place, predicted to occur in 1063 undiscovered pools and represents 5.7 per cent of the expected potential in Carboniferous-Permian (plains area) mature plays (Table 4, Fig. 25). The largest remaining undiscovered pool is predicted to be 0.341 x 10^9 m^3 (Table 4).

The northeastern part of the play area is dominated by low API (low gravity) oil and associated gas and oil, while the southwestern part of the play area is dominated by gas. Potential is limited in the southwest by the occurrence of poor reservoir-quality siltstone and argillaceous sandstone.

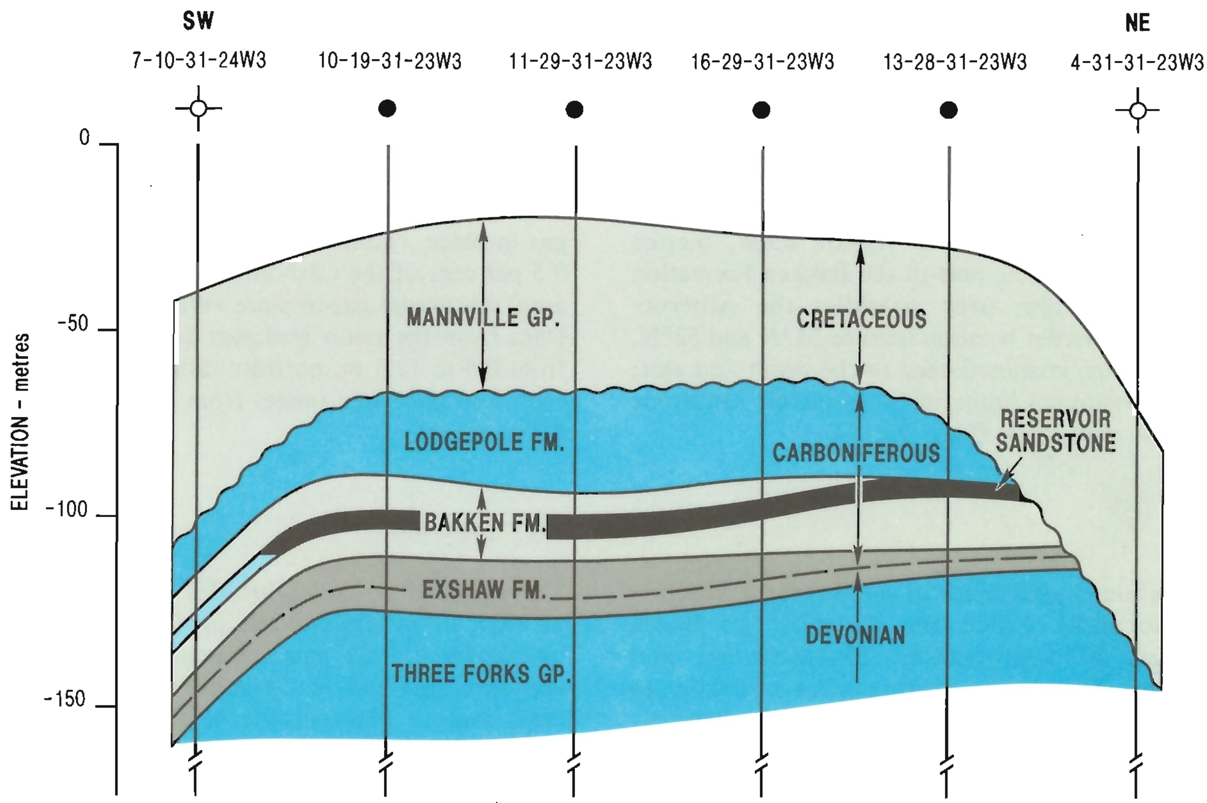


Figure 22. *Example of a trap in the Bakken stratigraphic/subcrop–Loverna play: Coleville–Bakken Formation (oil pool) (after Grassby and Pelletier, 1990).*

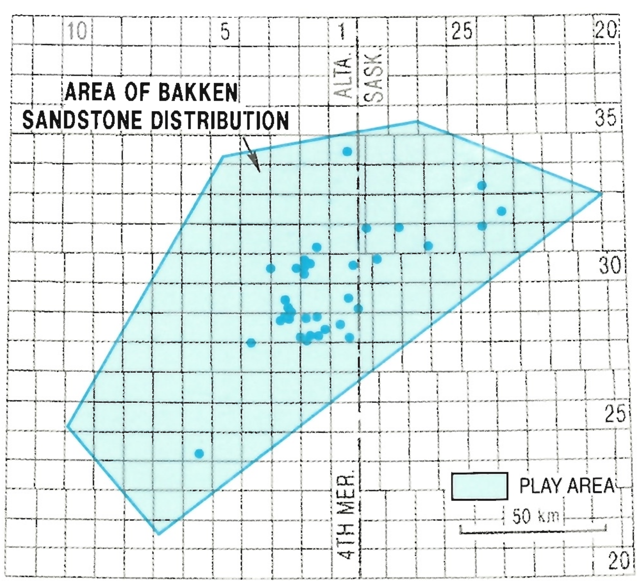


Figure 23. *Bakken stratigraphic/subcrop–Loverna play: play area and location of discovery wells. Location of discovery wells and wells typifying the play-type indicated.*

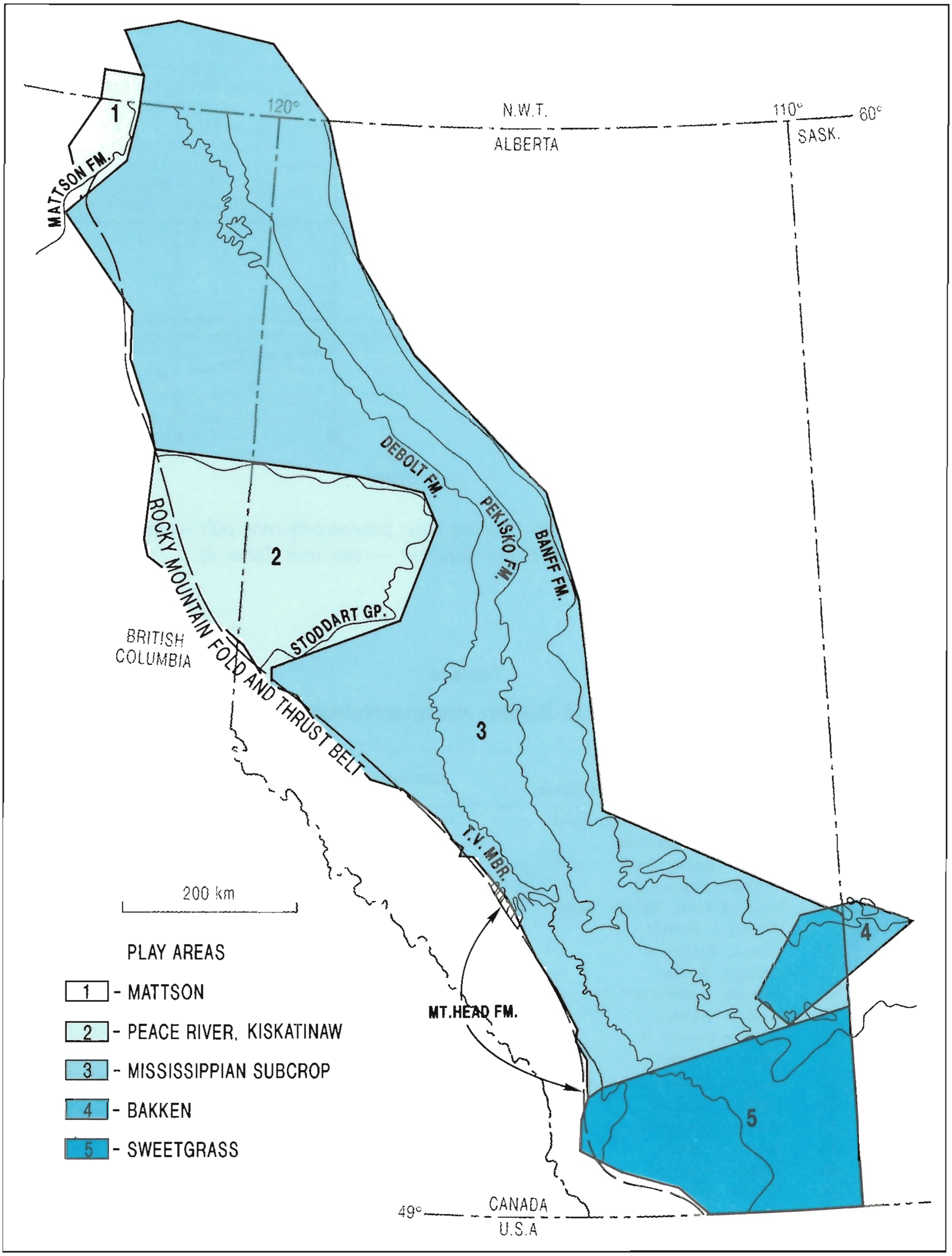


Figure 24. Mature Carboniferous play areas (polygons used in numerical analysis).

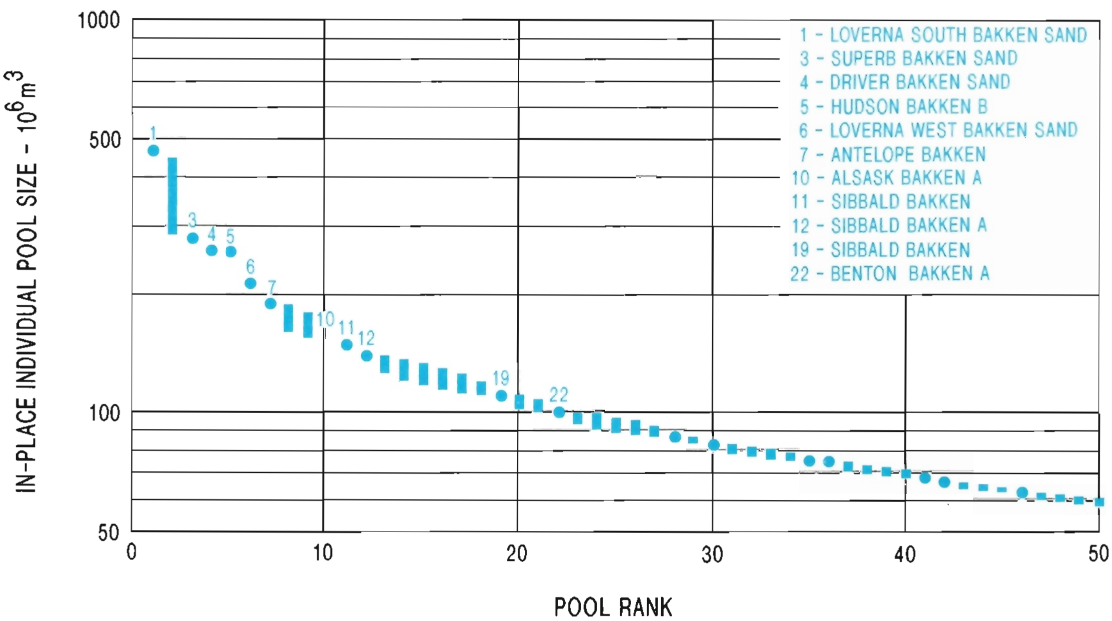


Figure 25. *Bakken stratigraphic/subcrop–Loverna play: pool-size-by-rank plot — conditioned by discovered pools (larger discovered pools identified — see also Table 4).*

Table 4

Largest 20 pools of the Bakken stratigraphic/subcrop–Loverna play

Rank	Field/Pool (top 20 discovered pools)	Gas type	In-place volume (10^6 m^3)	Discovery year
1	Loverna South, Bakken Sand	NA	468	1973
3	Superb, Bakken Sand	NA	282	1965
4	Driver, Bakken Sand	NA	260	1985
5	Hudson, Bakken B	NA	259	1972
6	Loverna West, Bakken Sand	NA	214	1980
7	Antelope, Bakken	NA	190	1978
10	Alsask, Bakken A	NA	155	1977
11	Sibbald, Bakken	NA	149	1989
12	Sibbald, Bakken A	NA	140	1950
19	Sibbald, Bakken	NA	110	1989
22	Benton, Bakken A	NA	101	1981
28	Benton, Bakken	NA	86	1981
30	Hudson, Bakken D	NA	82	1988
35	Hudson, Bakken	AG	75	1972
36	Hudson, Bakken A	NA	74	1973
41	Benton, Bakken	NA	68	1989
42	Sibbald, Bakken	NA	66	1989
46	Benton, Bakken	NA	62	1988
51	Hudson, Bakken C	NA	58	1987
66	Hoosier, Bakken Sand	AG	48	1972
Initial in-place volume (discovered) (10^6 m^3)			3 290	
Initial in-place volume (potential) (10^6 m^3)			12 233	
Per cent of play resources undiscovered			79	
Total pool population (discovered and undiscovered)			1 100	
Total pools discovered			37	
Total pools undiscovered			1 063	
Largest undiscovered pool			341	
Total undiscovered pools >140 x 10^6 m^3			3	

NA, nonassociated gas; AG, associated gas

Rundle/Sweetgrass structural–Black Butte/Aden play

Play definition

This gas play was defined to include all prospects and pools in Rundle Group carbonate (Pekisko, Shunda, Turner Valley, Livingstone, and Mt. Head formations) in structural and combination stratigraphic–structural traps. The play area extends across southernmost Alberta, from the Sweetgrass Arch to the eastern limits of the Rocky Mountain Thrust Belt, and is bounded on the north by the limit of normal faulting (Figs. 24, 26).

Geology

Structural traps are developed on block faults and anticlines related to Laramide tectonics on, and west of, the Sweetgrass Arch (Fig. 27; Podruski et al., 1988). This deformation also enhanced or created reservoirs by inducing local fracturing of the shelf carbonate. Unconformity-related processes also enhanced porosity in reservoirs of the Livingstone Formation. Shale of the Exshaw or Bakken formations may be the source rocks. Gas migration from the shale was facilitated by fracture systems (Podruski et al., 1988).

Exploration history

The first commercial gas pool in Carboniferous strata in the plains of western Canada was discovered in this play, at Black Butte in 1943 (Table 5). Total gas-in-place volume discovered in this play is 6.893 x 10^9 m^3, occurring in 44 pools. This represents 1.1 per cent of the discovered gas-in-place volume in Carboniferous and Permian (plains area) mature plays (Table 5). Data from the pools indicates average net pay ranges from 0.4 to 21 m, porosity from 3 to 20 per cent, and pool area from 16 to 2011 ha (0.06 to 7.76 sections).

Play potential

The expected potential for this play has a mean of 6.495 x 10^9 m^3 gas-in-place volume, predicted to occur in 556 undiscovered pools, and represents 3.0 per cent of the Carboniferous and Permian (plains area) expected potential in mature plays. The largest remaining undiscovered pool is predicted to be 0.306 x 10^9 m^3 (Fig. 28; Table 5).

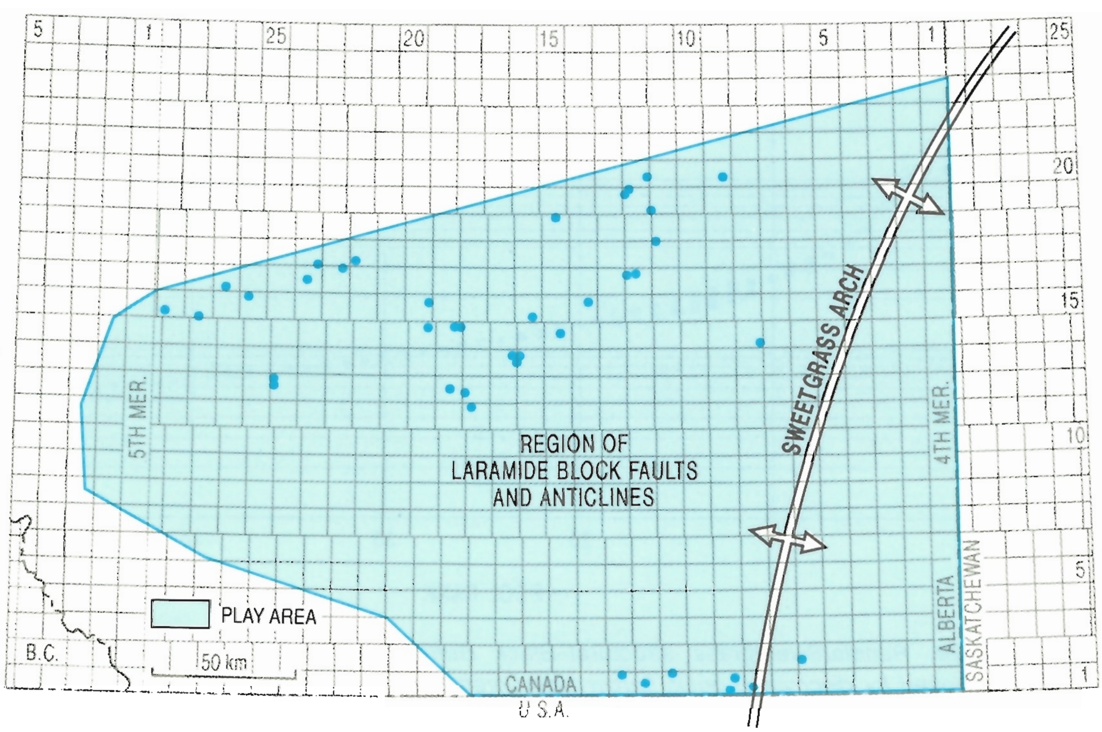


Figure 26. *Rundle/Sweetgrass structural–Black Butte play: play area and location of discovery wells. Location of discovery wells and wells typifying the play-type indicated.*

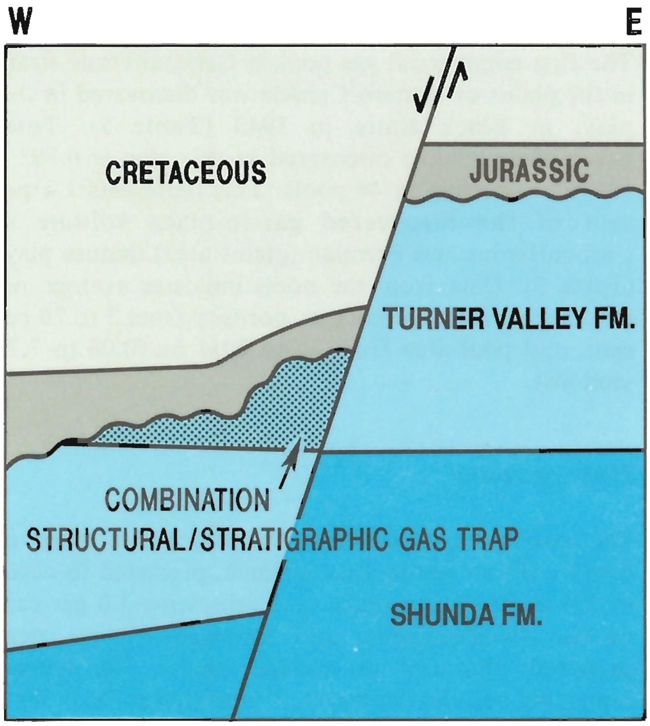


Figure 27. *Rundle/Sweetgrass structural–Black Butte play: trap example, Vulcan–Turner Valley Formation field (modified from Fraleigh and Fekete, 1969).*

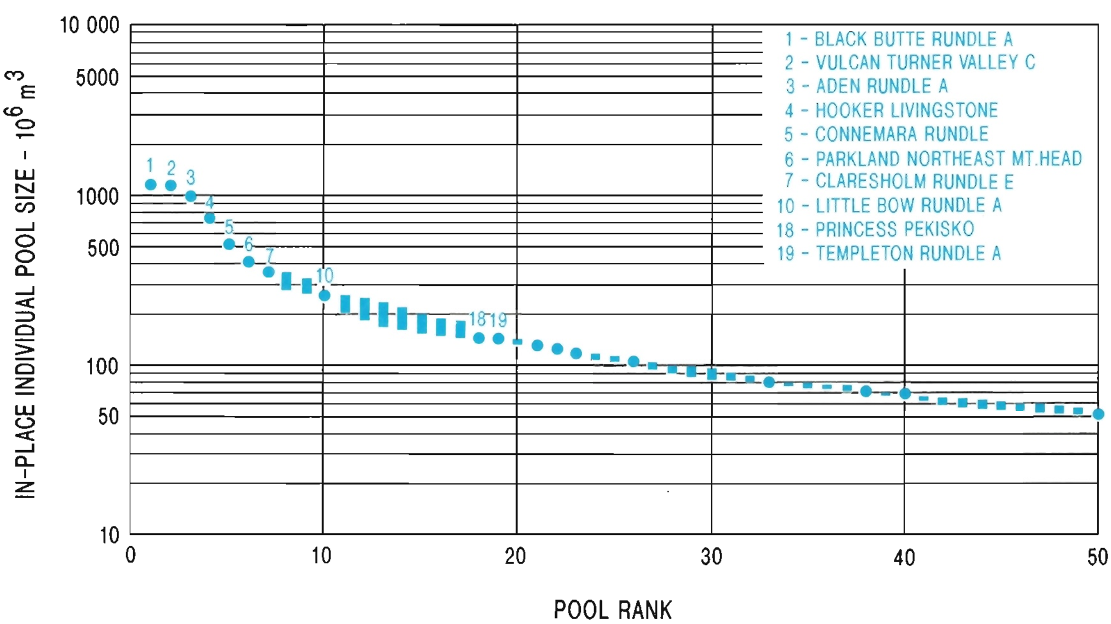


Figure 28. *Rundle/Sweetgrass structural–Black Butte play: pool-size-by-rank plot — conditioned by discovered pools (larger discovered pools identified — see also Table 5).*

Table 5

Largest 20 pools of the Rundle/Sweetgrass structural–Black Butte play

Rank	Field/Pool (top 20 discovered pools)	Gas type	In-place volume (10^6 m^3)	Discovery year
1	Black Butte, Rundle A	NA	1 105	1943
2	Vulcan, Turner Valley C	NA	1 094	1960
3	Aden, Rundle A	NA	958	1960
4	Hooker, Livingstone	NA	711	1980
5	Connemara, Rundle	NA	498	1955
6	Parkland Northeast, Mount Head	NA	389	1953
7	Claresholm, Rundle E	NA	338	1971
10	Little Bow, Rundle A	NA	249	1963
18	Princess, Pekisko	NA	138	1974
19	Templeton, Rundle A	NA	137	1955
21	Claresholm, Rundle D	NA	128	1972
22	Retlaw, Livingstone	NA	122	1981
23	Enchant, Pekisko	NA	114	1987
26	Enchant, Elkton A	NA	101	1952
33	Vulcan, Turner Valley	NA	78	1989
38	Long Coulee, Rundle A	NA	69	1975
40	Little Bow, Turner Valley	NA	64	1981
50	Parkland, Turner Valley	NA	50	1955
52	Enchant, Elkton	NA	48	1953
52	Long Coulee, Turner Valley	NA	48	1983
Initial in-place volume (discovered) (10^6 m^3)			6 893	
Initial in-place volume (potential) (10^6 m^3)			6 495	
Per cent of play resources undiscovered			49	
Total pool population (discovered and undiscovered)			600	
Total pools discovered			44	
Total pools undiscovered			556	
Largest undiscovered pool			306	
Total undiscovered pools $>140 \times 10^6$ m^3			9	

NA, nonassociated gas

Peace River carbonate structural–Dunvegan play

Play definition

This gas play was defined to include all pools and prospects in carbonate mainly of the Debolt Formation but also of the Banff, Pekisko, Shunda, and Taylor Flat formations in structural-stratigraphic traps associated with faulted structures in the Peace River Embayment. The play area is defined by the eastern edge of the Rocky Mountain Thrust Belt on the west and structural deformation to the north, east and south of the Peace River Embayment (Figs. 24, 29).

Geology

The Debolt Formation in the Peace River Embayment was deposited in shallow-water, open marine to restricted marine (subtidal to supratidal), settings. Dolomite reservoirs are associated with horst blocks and grabens. Secondary porosity development occurred in carbonates fractured by faulting and folding, or exposed at an unconformity surface. Several intra- and interformational unconformities exist. Primary (depositional) porosity also occurs in packstone or grainstone (Packard and Al-Aasm, 1993). Gas fields occur mainly in northern parts of the Peace River Embayment, within the Fort St. John Graben and related satellite grabens, which outline the area of most intense Peace River-type block faulting (see Barclay et al., 1990). No pools have been found, so far, in the less intensely faulted southern part of the play area (i.e., south of Township 74).

The middle unit in the Banff Formation appears to have the most reservoir potential in the area. One pool occurs at the top of the Pekisko Formation, in a carbonate that differs from the more shaly Pekisko Formation of this area. The Shunda Formation in the Earring pool appears to be trapped along a block fault. A stratigraphic component to some traps occurs in the Debolt Formation where anhydrite overlying the dolostone reservoir creates part of the seal, such as at the Normandville field (van Biezen, 1969; Fig. 30). The Taylor Flat Formation forms local reservoirs in open marine, bioclastic, sandy limestone to calcareous, bioclastic sandstone (Barclay et al., 1990), such as at the Monias field in northeastern British Columbia.

Exploration history

The Normandville-Mississippian D was the first pool discovered in this play and was discovered in 1949 (Table 6, Fig. 10) during exploration for deeper targets in the Devonian Leduc reefs (see van Biezen, 1969; Dix, 1990; Reinson et al., 1993b). The largest fields in the play were discovered from 1951 to 1955, namely the Belloy, Dunvegan, Eaglesham, Fort St. John and Puskwaskau gas fields. The Dunvegan gas field in the Debolt Formation contains about 85 per cent of the discovered gas in this play and occurs on the upthrown side of the large ''Dunvegan'' normal fault. The rest of the fields are generally small and were found between 1973 to 1989 and only the Culp field is as large as some of the earlier discovered fields. Ninety pools have been discovered in this play and the total discovered gas-in-place volume is 48.895 x 10^9 m^3, which represents 7.8 per cent of the Carboniferous and Permian (plains area) discovered gas-in-place volume in mature plays. Data from the pools indicates average net pay ranges from 0.8 m to 14.7 m, porosity from 5 to 27 per cent, and area from 50 to 13 200 ha (0.19 to 51 sections).

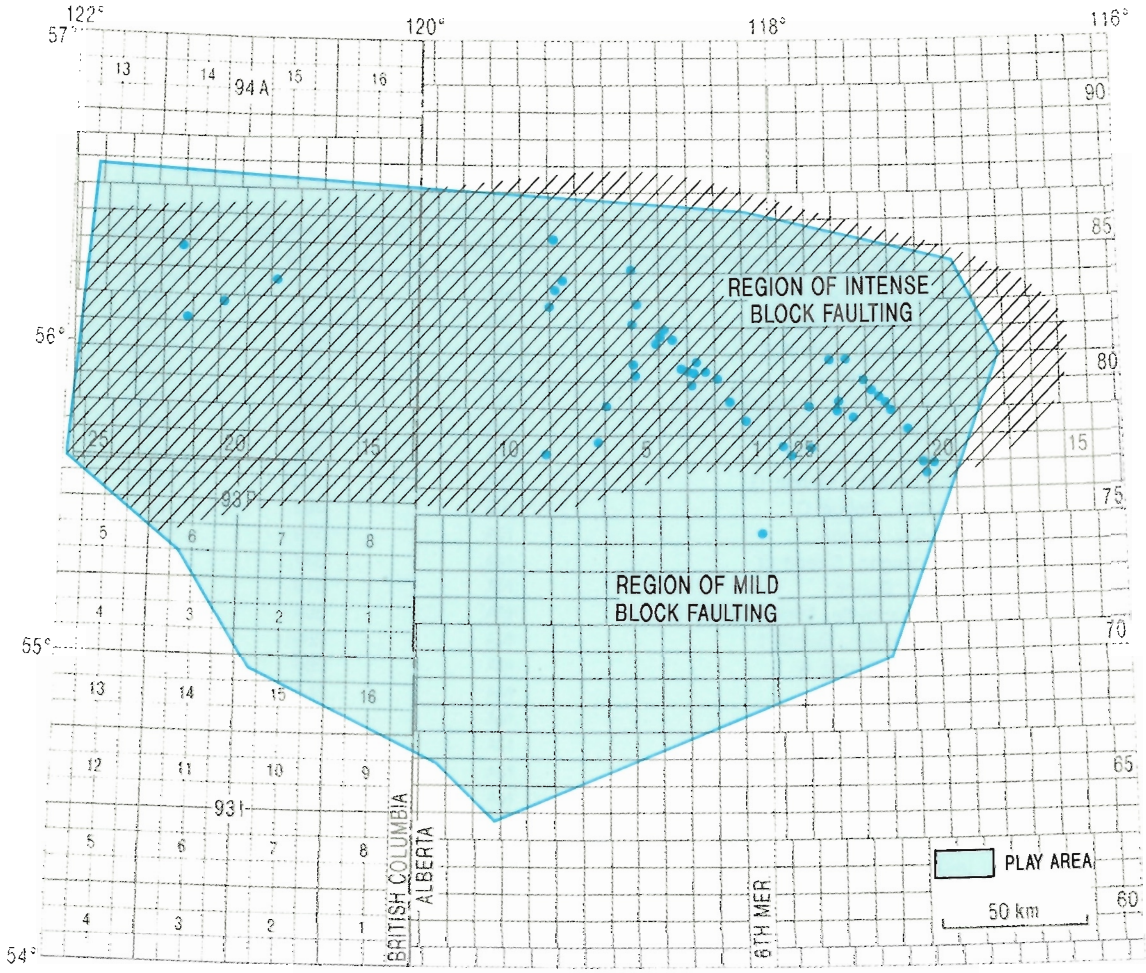


Figure 29. *Peace River carbonates–Dunvegan play: play area and location of the discovery wells.*

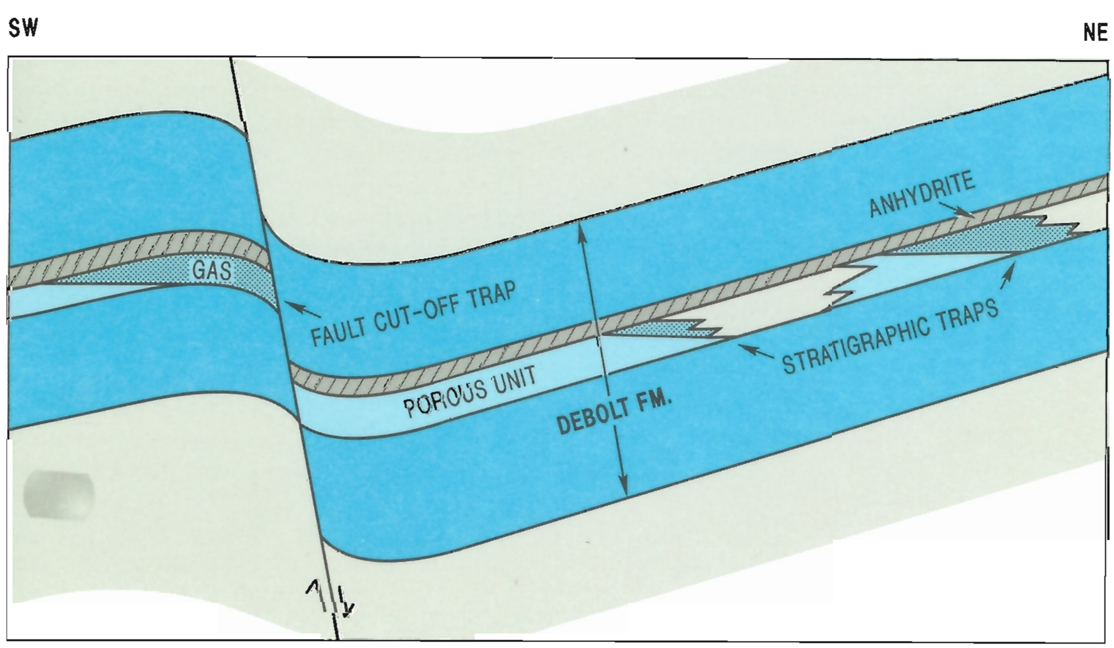


Figure 30. *Peace River carbonates–Dunvegan play: trap example, Normandville–Debolt gas field (modified from van Biezen, 1969). Also shows possible stratigraphic trap in the Peace River Arch carbonate stratigraphic conceptual play.*

Table 6

Largest 20 pools of the Peace River carbonate–Dunvegan play

Rank	Field/Pool (top 20 discovered pools)	Gas type	In-place volume (10^6 m^3)	Discovery year
1	Dunegan, Debolt B	NA	19 736	1963
2	Dunvegan, Debolt C	NA	12 158	1952
3	Dunvegan, Debolt A	NA	4 355	1963
11	Culp, Debolt A	NA	778	1973
14	Normandville, Mississippian A	NA	605	1956
16	Eaglesham, Debolt A	NA	542	1958
17	Belloy, Debolt B	NA	494	1951
21	Eaglesham, Debolt G	NA	375	1952
22	Belloy, Debolt C	AG	362	1951
23	Belloy, Debolt	NA	359	1988
24	Dunvegan, Debolt Q	NA	337	1975
25	Culp, Debolt	NA	313	1973
26	Normandville, Mississippian D	NA	304	1949
27	Eaglesham, Debolt I	NA	289	1980
28	Belloy, Debolt A	NA	266	1951
29	Culp, Debolt	NA	264	1985
30	Dunvegan, Debolt	NA	250	1974
31	Dunvegan, Debolt D	NA	241	1972
32	Fort St. John, Debolt A	NA	237	1953
33	Eaglesham, Debolt H	NA	222	1959
Initial in-place volume (discovered) (10^6 m^3)			48 895	
Initial in-place volume (potential) (10^6 m^3)			16 640	
Per cent of play resources undiscovered			25	
Total pool population (discovered and undiscovered)			220	
Total pools discovered			90	
Total pools undiscovered			130	
Largest undiscovered pool			2 900	
Total undiscovered pools >140 x 10^6 m^3			13	

NA, nonassociated gas; AG, associated gas

Kiskatinaw clastics–Pouce Coupe play

Play potential

The expected potential for this play is 16.640 x 10^9 m^3 gas-in-place, predicted to occur in 130 undiscovered pools, and represents 7.7 per cent of the Carboniferous and Permian (plains area) expected potential in mature plays (Fig. 31). The largest remaining undiscovered pool is predicted to be 2.900 x 10^9 m^3 (median value) (Table 6). There are few wells that penetrate the complete Carboniferous section in the Peace River region, particularly in the southern parts. This play can consequently be considered to have low exploration maturity. Although no pools occur in southern parts of the play area, at least one gas test (in 72-10W6) indicates some potential. Any pools in the southern area are likely to be smaller than those in the Dunvegan area because of the smaller faults and lesser intensity of faulting. Another negative factor is that the overlying Stoddart Group and Belloy Formation are quite sandy and porous here and provide poor seal rocks above the Debolt Formation.

Play definition

This gas play was defined to include all pools and prospects in fluvioestuarine to shallow-water, marine sandstone of the Kiskatinaw Formation in structural, stratigraphic, and combination structural-stratigraphic traps. The play area is defined by the limits of the Rocky Mountain Thrust Belt to the west and the Kiskatinaw Formation erosional edge to the north, east and south (Figs. 24, 32).

Geology

Structural traps occur where porous sandstone is laterally truncated by normal faults (Fig. 33A). Stratigraphic traps result from facies changes (e.g., from nonporous siltstone or shale to porous sandstone, Fig. 33A, B) and porous sandstone trapped up against Taylor Flat Formation or Belloy Formation seal rocks overlying the Kiskatinaw erosional edge. Combination structural-stratigraphic traps occur where sandstone is draped over horst blocks or Devonian reefs, or where channel sandstone fills fault-controlled valleys. Most pools in the Kiskatinaw Formation are in some way associated with fault-bounded structures in the Peace River district. Some gas pools occur at the updip edges of downthrown graben blocks where the updip edge is resting against a seal facies in a neighbouring upthrown horst block (Fig. 33C) (Hinds et al., 1993).

Exploration history

The first pool discovered in this play was the Mica Creek Lower Kiskatinaw A pool in 1957. Discovered gas-in-place volume in this play is 29.015 x 10^9 m^3 in 115 pools (Table 7). This play contains 4.6 per cent of the Carboniferous and Permian (plains area) discovered gas-in-place volume in mature plays. Most of the pools were discovered between 1970 and 1990. The lull in discovery since Mica Creek probably reflects the difficulty in identifying Kiskatinaw Formation prospects with 1960s vintage seismic. Renewed exploration success can be attributed to improvements in seismic, particularly recent 3-D seismic technology. Some of the larger fields in this play include Boundary Lake South, Blueberry, Pouce Coupe, Josephine and Gordondale. Data from the pools indicates average net pay for the play ranges from 0.5 to 22.46 m, porosity from 4 to 25 per cent, and pool area from 32 to 2334 ha (0.12 to 9 sections).

Play potential

The expected potential for this play is 54.322 x 10^9 m^3 gas-in-place, predicted to occur in 1085 undiscovered pools (Table 7, Fig. 34). This play is predicted to contain 25.3 per cent of the Carboniferous and Permian (plains area) expected potential in mature plays. The high potential relative to discovered gas resources reflects both the immature exploration status of the play and the risk associated with finding reservoirs and favourable structural locations in this complex unit. The largest remaining undiscovered pool is predicted to be 0.581 x 10^9 m^3 (median size) (Table 7).

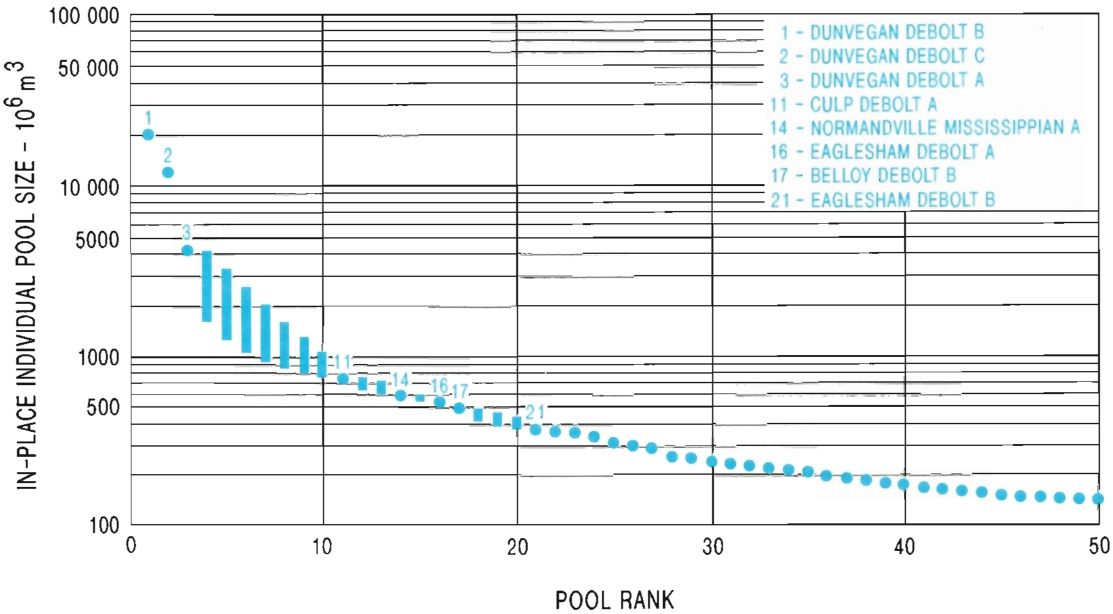


Figure 31. *Peace River carbonates–Dunvegan play: pool-size-by-rank plot — conditioned by discovered pools (larger discovered pools identified — see also Table 6).*

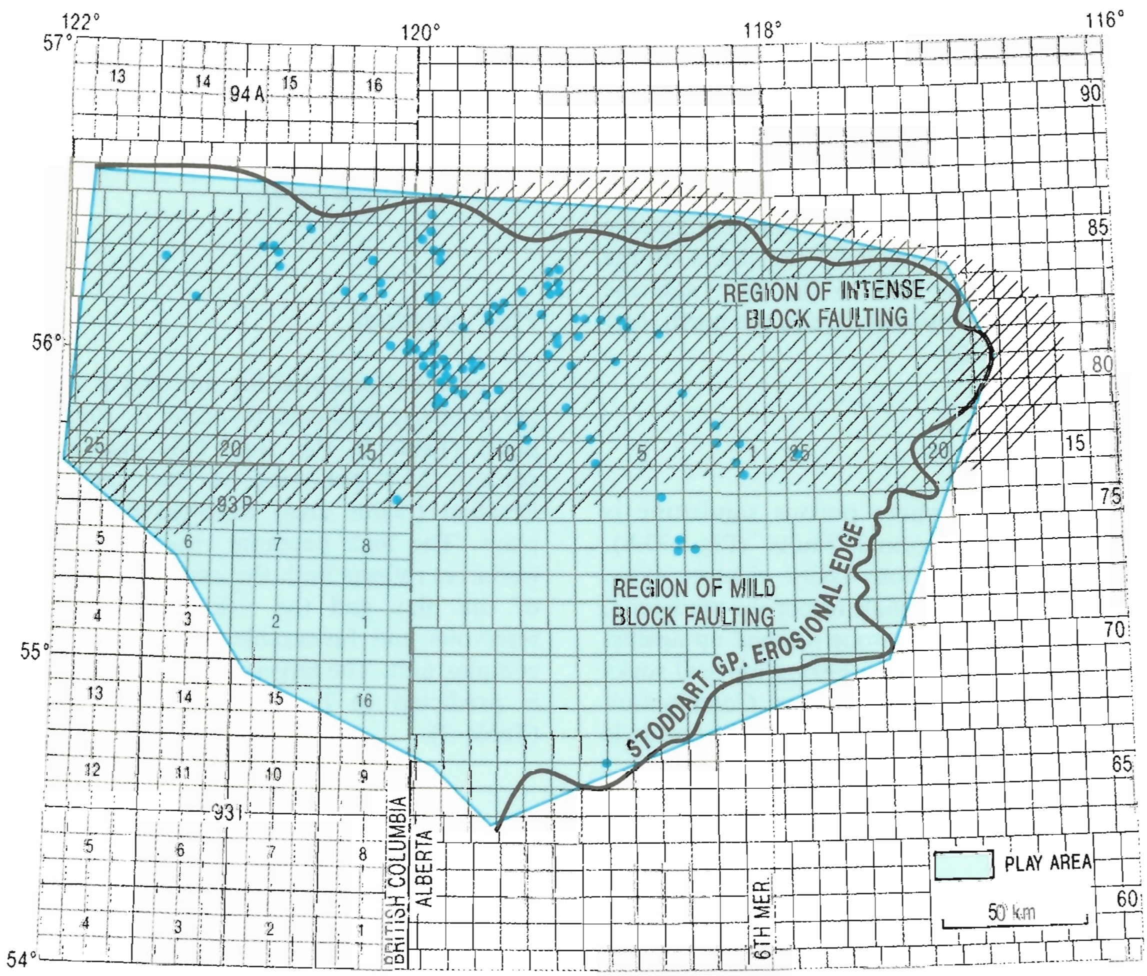
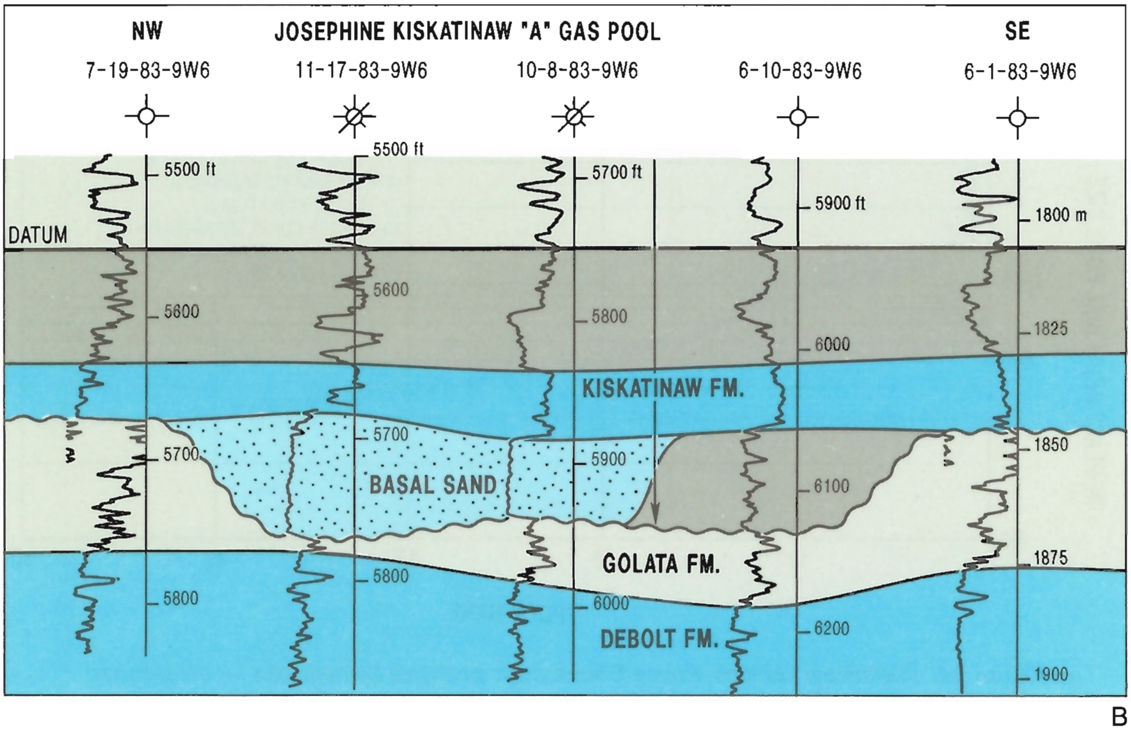
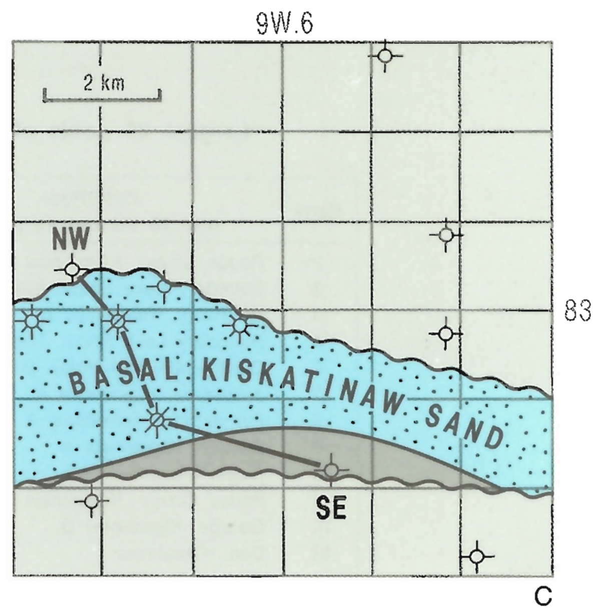


Figure 32. *Kiskatinaw clastics–Pouce Coupe play: play area and location of discovery wells. Location of discovery wells and wells typifying the play-type indicated.*





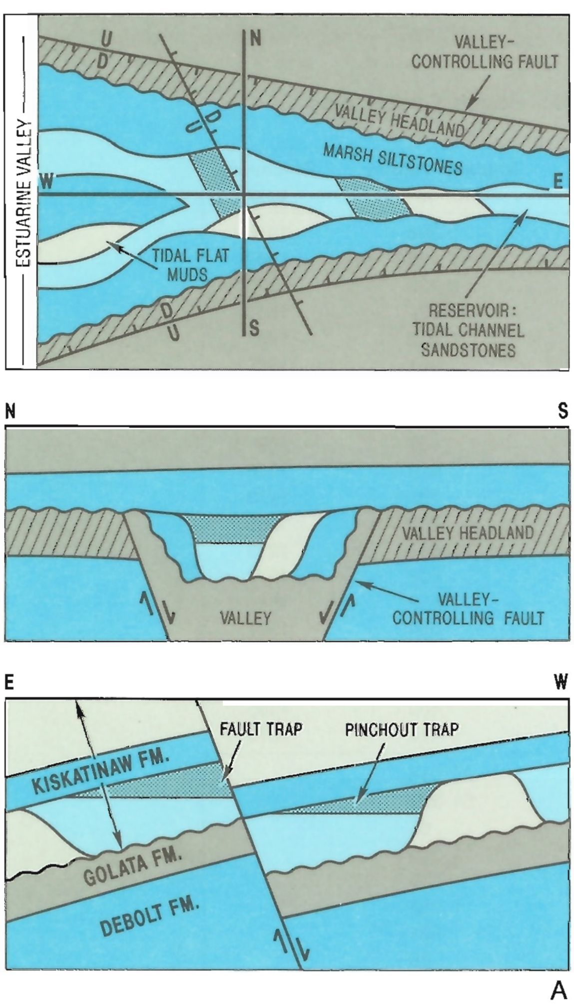


Figure 33. *Kiskatinaw clastics–Pouce Coupe play:* ***A.*** *schematic diagram of trap types.* ***B.*** *example of trap-type, cross-section of Josephine field–Kiskatinaw A pool;* ***C.*** *map of Josephine field–Kiskatinaw A pool.*

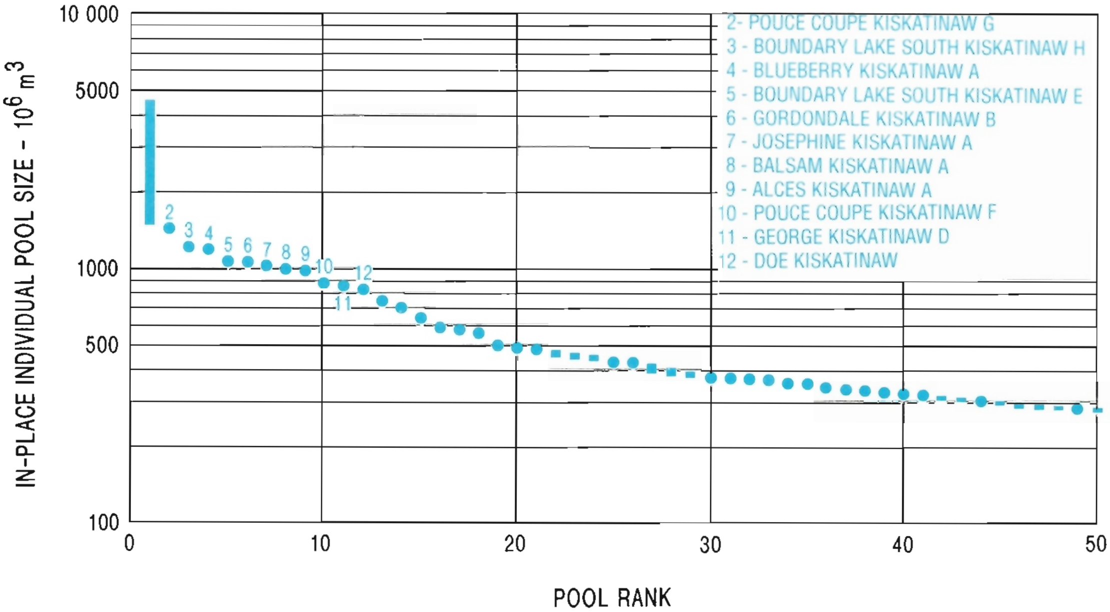


Figure 34. *Kiskatinaw clastics–Pouce Coupe play: pool-size-by-rank plot — conditioned by discovered pools (larger discovered pools identified — see also Table 7).*

Table 7

Largest 20 pools of the Kiskatinaw clastic–Pouce Coupe play

Rank	Field/Pool (top 20 discovered pools)	Gas type	In-place volume (10^6 m^3)	Discovery year
2	Pouce Coupe, Kiskatinaw G	NA	1 388	1976
3	Boundary Lake South, Kiskatinaw H	NA	1 169	1964
4	Blueberry, Kiskatinaw A	NA	1 139	1973
5	Boundary Lake South, Kiskatinaw E	NA	1 020	1963
6	Gordondale, Kiskatinaw B	NA	1 012	1981
7	Josephine, Kiskatinaw A	NA	991	1974
8	Farmington, Kiskatinaw A	NA	952	1977
9	Balsam, Kiskatinaw A	NA	945	1974
10	Alces, Kiskatinaw A	NA	852	1981
11	Pouce Coupe, Kiskatinaw F	NA	828	1976
12	George, Kiskatinaw D	NA	785	1973
13	Doe, Kiskatinaw	NA	713	1989
14	Other area, Kiskatinaw	NA	652	1979
15	Pouce Coupe, Kiskatinaw B	NA	606	1977
16	Pouce Coupe, Kiskatinaw H	NA	558	1988
17	Boundary Lake, Basal Kiskatinaw	NA	549	1987
18	Pouce Coupe, Kiskatinaw	NA	517	1974
20	Attachie, Basal Kiskatinaw A	NA	470	1971
21	Doe, Kiskatinaw A	NA	460	1965
25	Teepee, Kiskatinaw	NA	415	1973

Initial in-place volume (discovered) (10^6 m^3)	29 015
Initial in-place volume (potential) (10^6 m^3)	54 322
Per cent of play resources undiscovered	65
Total pool population (discovered and undiscovered)	1 200
Total pools discovered	115
Total pools undiscovered	1 085
Largest undiscovered pool	581
Total undiscovered pools >140 x 10^6 m^3	89

NA, nonassociated gas

Belloy/Peace River structural-Eagle play

Play definition

This gas play was defined to include all pools and prospects in nearshore sandstone and dolostone of the Permian Belloy Formation in structural and unconformity-influenced traps. The play area is defined by the limits of the thrust belt to the west and the Belloy Formation erosional edge to the north, east and south (Fig. 35).

Geology

This play was the only one identified for the Permian in the plains because all pools had common features, such as the strong influence of structural (Figs. 36, 37) and erosional controls, and all occur within the relatively thin, localized strata of the Belloy Formation (e.g., Fig. 38A, B). No immature plays were identified. The play can be subdivided into a series of related subplays, as follows: structural traps created by block faulting in the Peace River Embayment; trapping at the erosional edge; erosion at the Permian-Triassic unconformity; and stratigraphic traps, such as facies changes or diagenetic changes (Figs. 39, 40). However, this subdivision is difficult to apply without detailed mapping and is not consistent with the broader play definitions used in this and other Geological Survey of Canada assessments (e.g., Podruski et al., 1988; Reinson et al., 1993b; Bird et al., 1994).

The Belloy Formation typically consists of a thin but extensive sheet of porous sandstone and dolostone (Fig. 41), with gas and oil usually trapped where these reservoirs are draped over small-throw Peace River Embayment-related horst blocks (Fig. 36). In southern parts of the play area, the fields at Kaybob and Sturgeon occur where the Belloy Formation is draped over deeper Devonian reefs. Trapping at fields in the Monias region of northeastern British Columbia, such as Stoddart and Eagle, are affected by a large anticlinal structure called the Monias High (Barclay et al., 1990). Some fields are influenced by trapping near or along the Belloy Formation erosional edge (e.g., Stoddart, Eagle fields, Fig. 42). Belloy Formation sandstone outliers at Virginia Hills form two erosional remnant oil pools (Podruski et al., 1988). Other traps may be found along the erosional edge within salients that are sufficiently isolated to form traps. Other fields involve subtle stratigraphic or porosity pinchouts. Because the Belloy Formation is typically quite thin and overlain everywhere by the Permian-Triassic unconformity, reservoir development is strongly influenced by leaching at the unconformity.

Exploration history

The first gas field discovered in this play was the Belloy gas field (Belloy A pool), found in 1951. Nineteen other gas fields were discovered from then until 1959, with the largest gas fields found at Stoddart, Fort St. John Southeast, Braeburn, and Wapiti (Table 8). Five gas fields were discovered in the 1960s, including the large fields at Stoddart West and Virginia Hills. Fifteen gas fields were found in the 1970s, with larger fields at Eagle West, Eagle, Roxana and Monias. Eight gas fields were found in the 1980s, including the large field at Progress. Also, eight new large pools were discovered in the Boundary Lake area from 1987 to 1989. The relatively continuous discovery pattern in this play suggests that discoveries will continue to occur in the future. The discovered gas-in-place volume is 39.943 x 10^9 m^3, occurring in 48 gas fields with 93 pools (Fig. 43). This play contains 6.4 per cent of the Carboniferous and Permian (plains area) discovered gas-in-place volume for mature plays.

Play potential

The mean expected potential of this play is 72.783 x 10^9 m^3, predicted to occur in 907 undiscovered pools (Table 8, Fig. 43). This is 33.9 per cent of the Carboniferous and Permian (plains area) expected potential and the play is the most prospective of the mature plays evaluated in this assessment. The largest remaining undiscovered pool is predicted to be 1.644 x 10^9 m^3 (Table 8). Wells penetrating this play are relatively evenly distributed throughout the play area, except for southern parts of British Columbia townships. However, most of the wells in the play area were drilled for underlying targets, such as the Kiskatinaw Clastics-Pouce Coupe play, Peace River carbonate play, Devonian carbonate, or sandstone targets. Thus the Belloy play has not been adequately evaluated and the potential gas is probably distributed throughout the play region, although the southern areas are less well known. The discovery of the large Boundary pool in 1987, near the large Stoddart and Eagle fields, attests to the potential of this play.

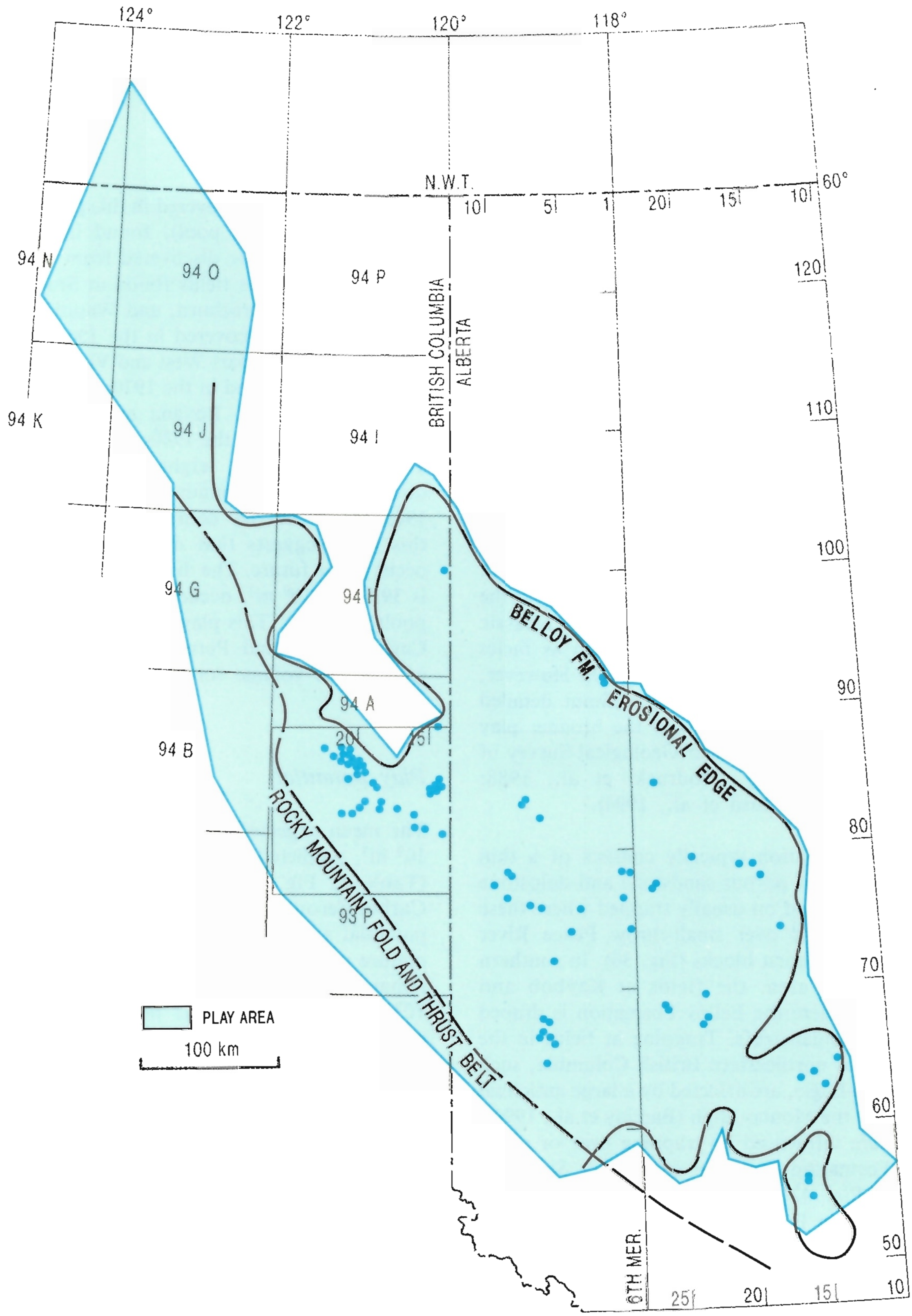


__Figure 35.__ Belloy/Peace River structural–Eagle play: play area and location of discovery wells. Location of discovery wells and wells typifying the play-type indicated.

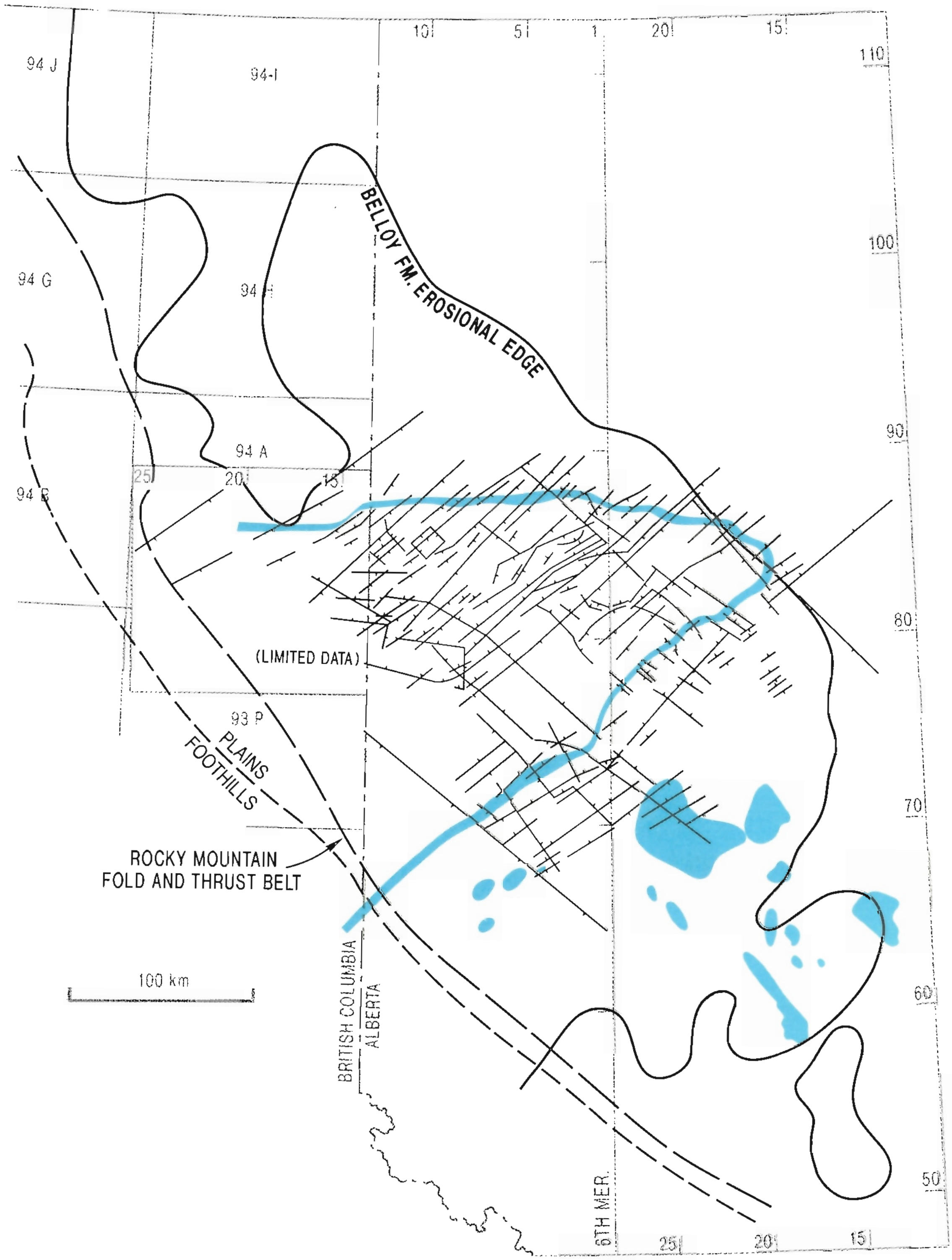


Figure 36. Faults on the Peace River Arch/Peace River Embayment interpreted to affect Carboniferous and Permian plays by offsetting reservoir units (faults derived from unpublished work by J.E. Barclay and from Sikabonyi and Rodgers, 1959; Cant, 1988; Halbertsma, pers. comm., 1989; outlines of Devonian reef from Jansa and Fischbuch, 1974; Reinson et al., 1993b).

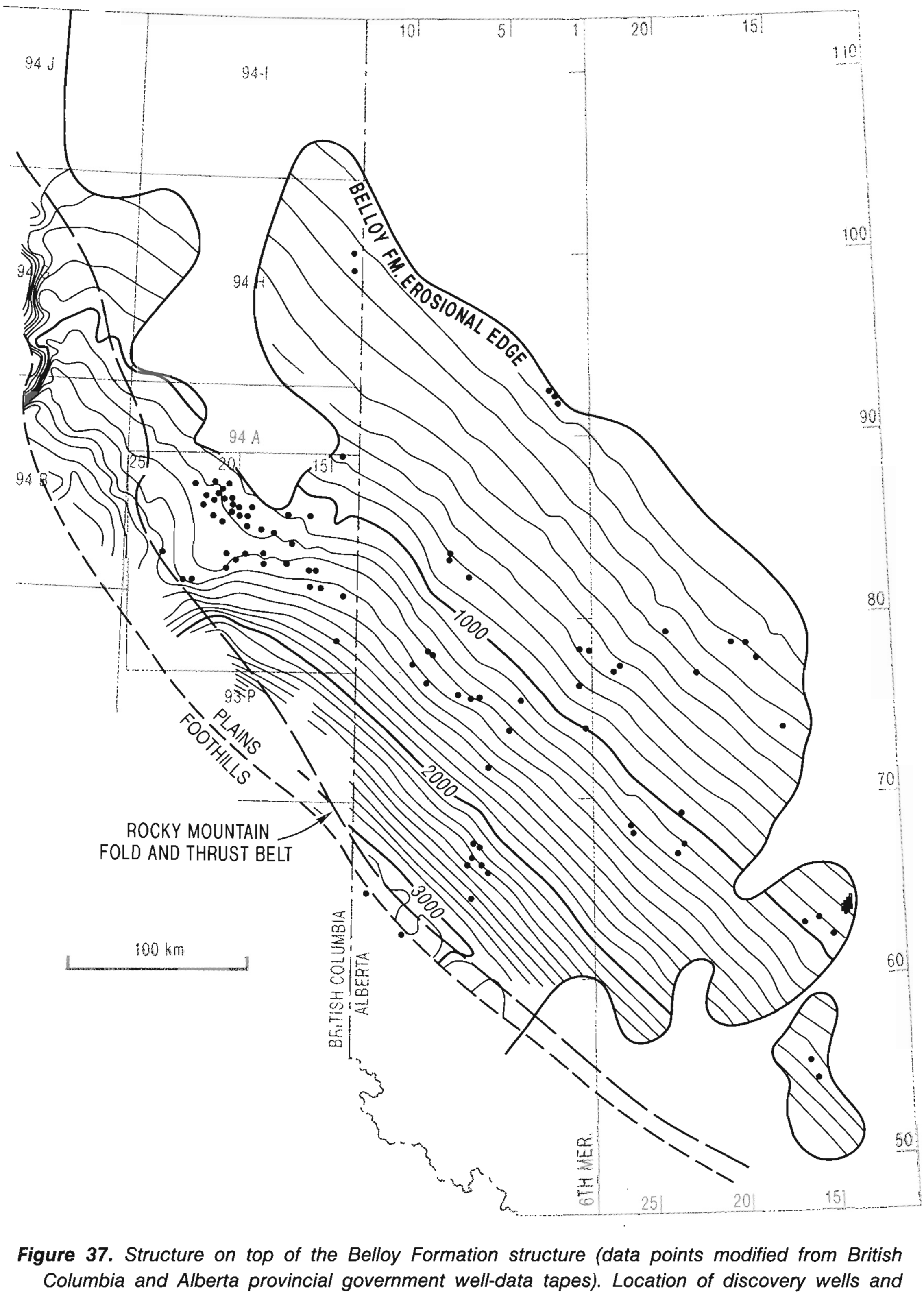


Figure 37. *Structure on top of the Belloy Formation structure (data points modified from British Columbia and Alberta provincial government well-data tapes). Location of discovery wells and wells typifying the play-type indicated. Note that most fields are associated with small structures.*

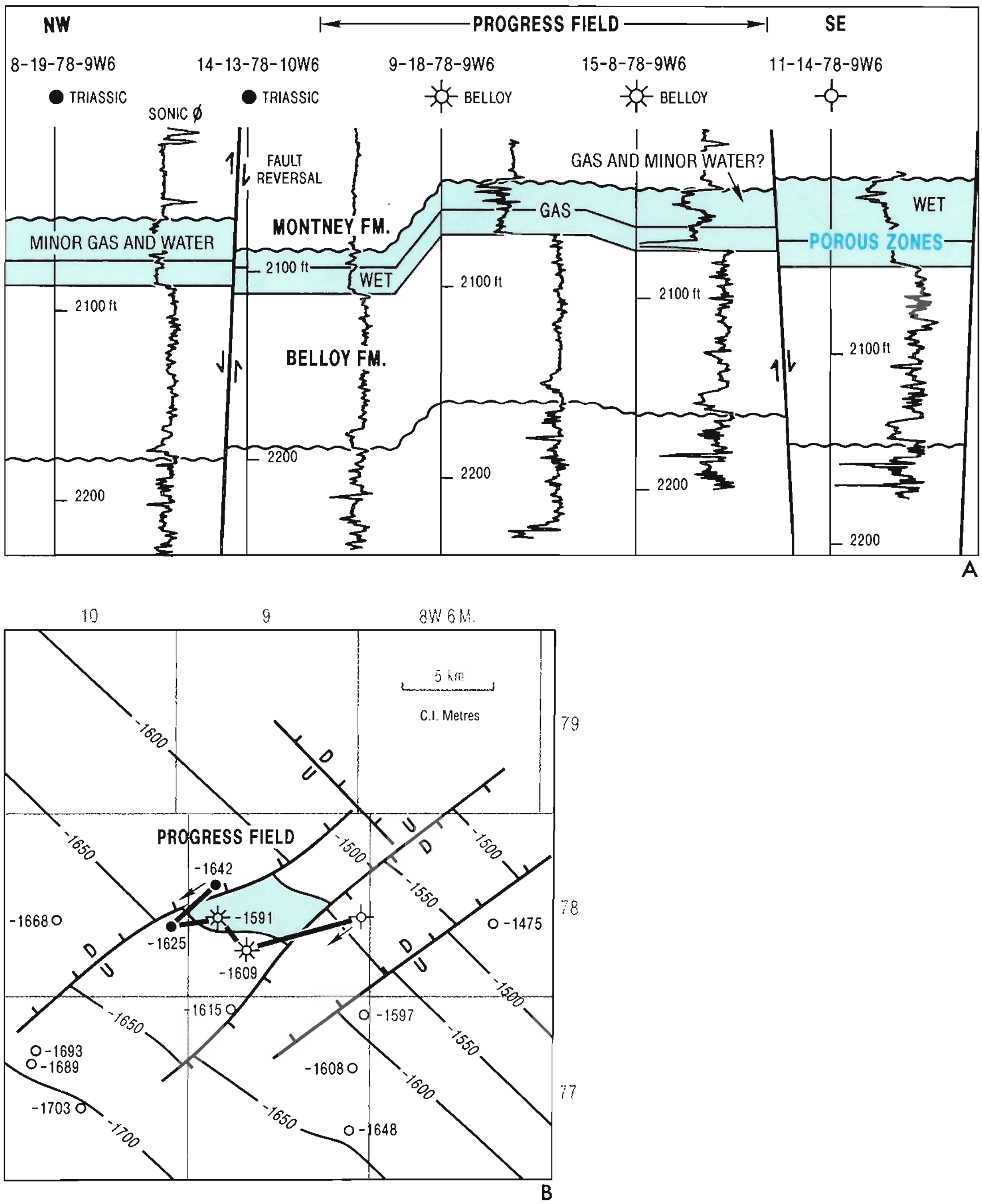


Figure 38. Example of trapping at Progress Field (Belloy Formation play) showing the combination of structural, stratigraphic and erosional controls on trapping. ***A****. cross-section;* ***B****. structure contours map (contours drawn on top of the Belloy Formation).*

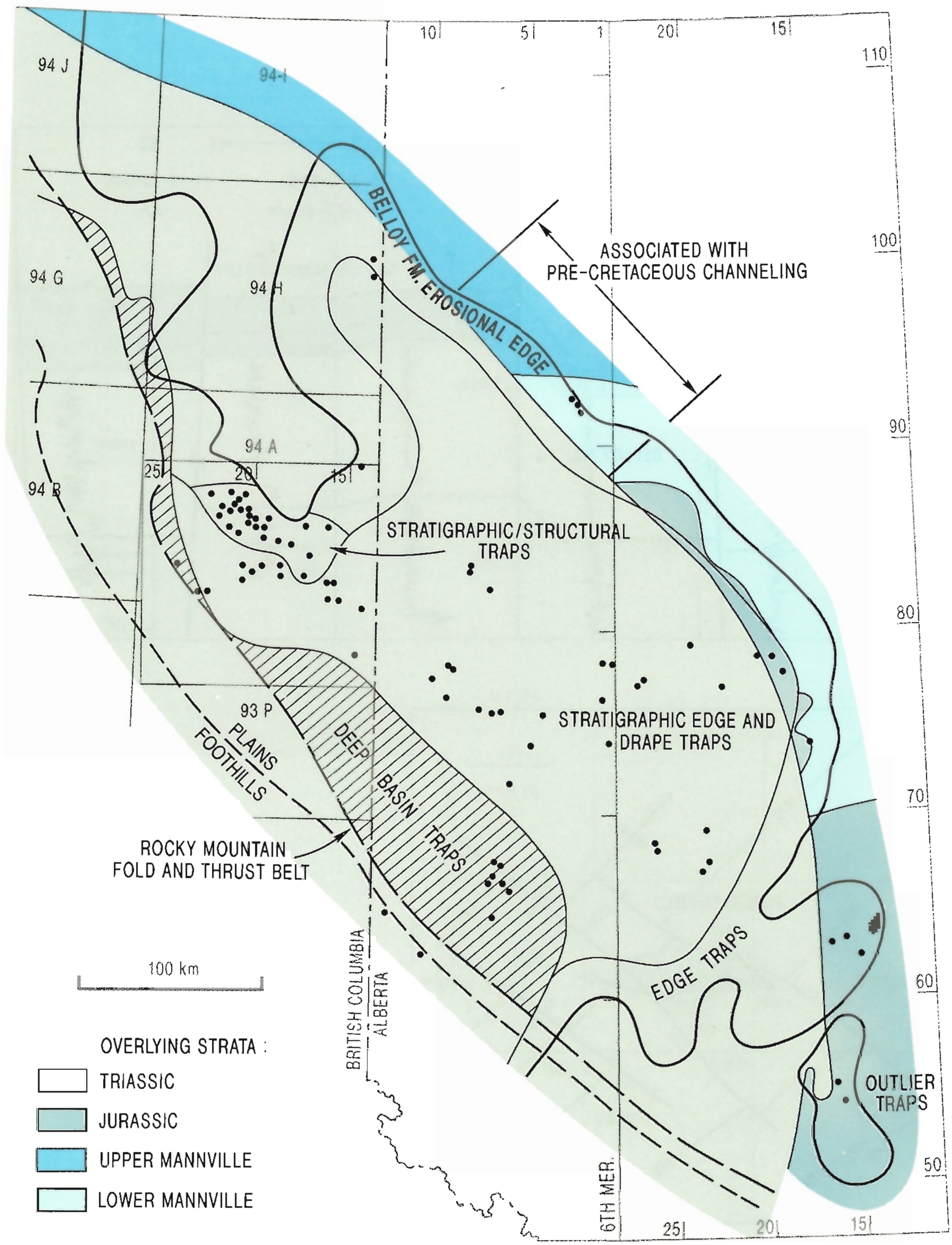


Figure 39. *Petroleum trapping regimes within the Permian Belloy Formation. Cover cap rocks are shaded. The best seal rocks over the Belloy Formation are Triassic and Jurassic shale.*

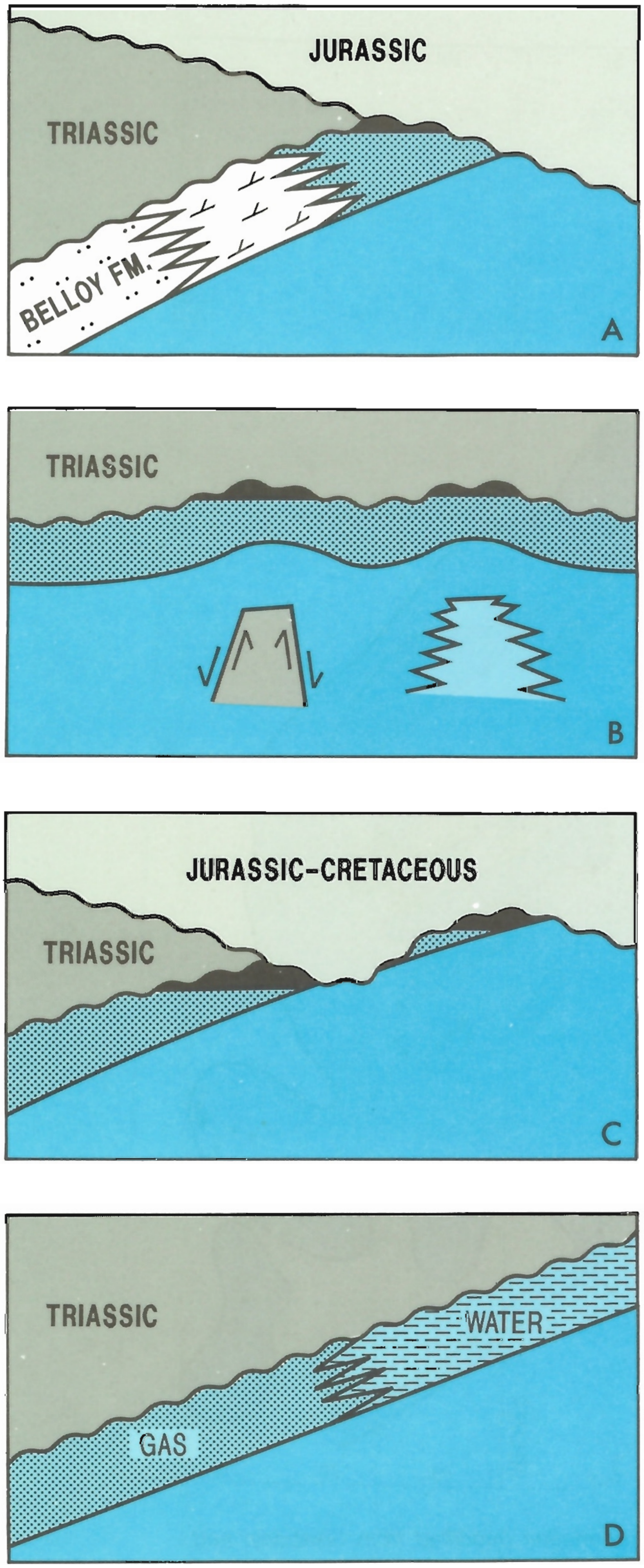


Figure 40. *Belloy/Peace River structural–Eagle play:* ***A.*** *updip facies change with pinchout at erosional edge;* ***B.*** *drape over Devonian reefs and Peace River Arch horsts;* ***C.*** *trapping and porosity enhancement along the erosional edge;* ***D.*** *unconventional Deep Basin trap in gas-saturated region downdip of water.*

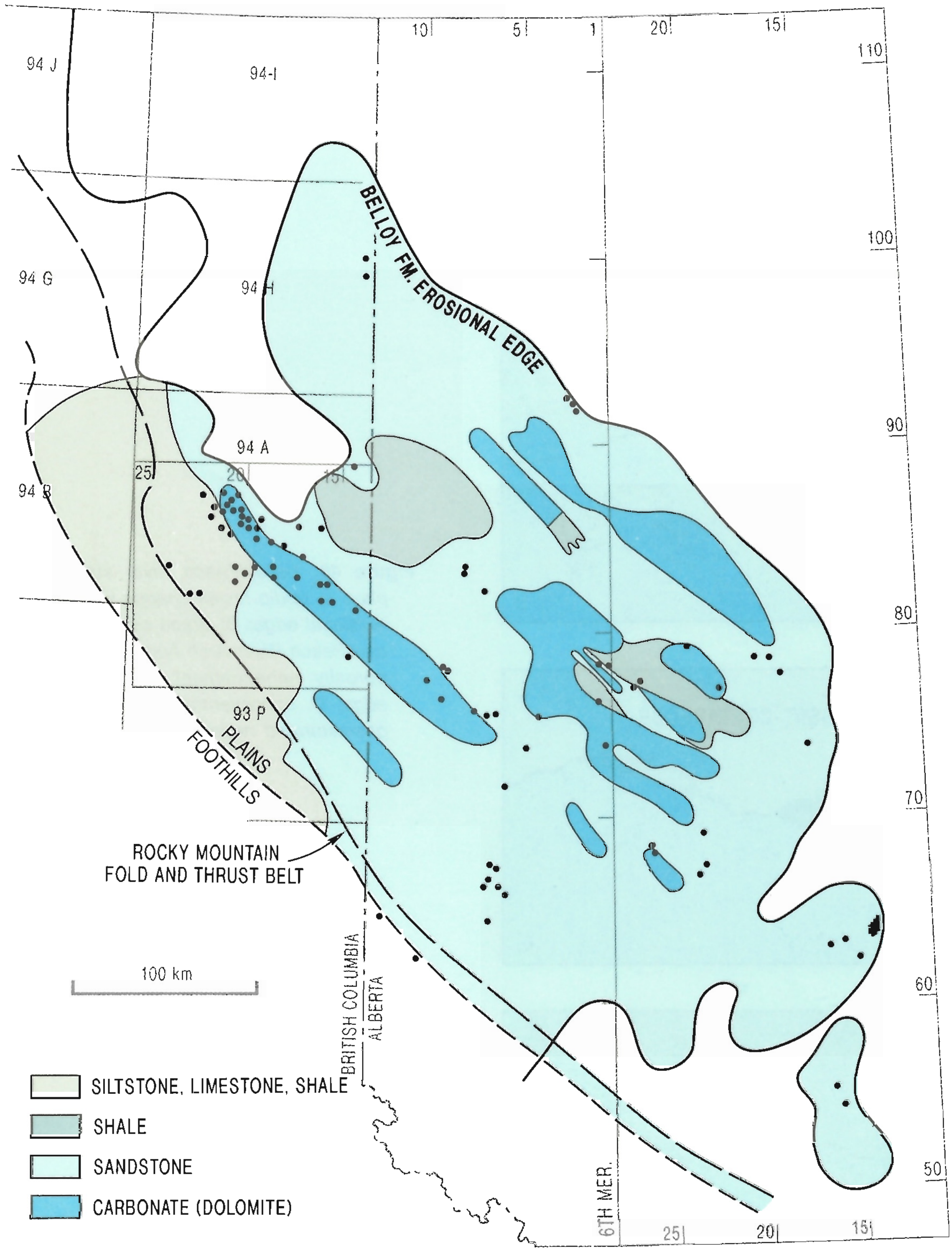


Figure 41. *Dominant lithofacies in the Belloy Formation (modified from Sikabonyi and Rodgers, 1959; McGugan et al., 1964; Naqvi, 1969, 1972; Barclay et al., 1990).*

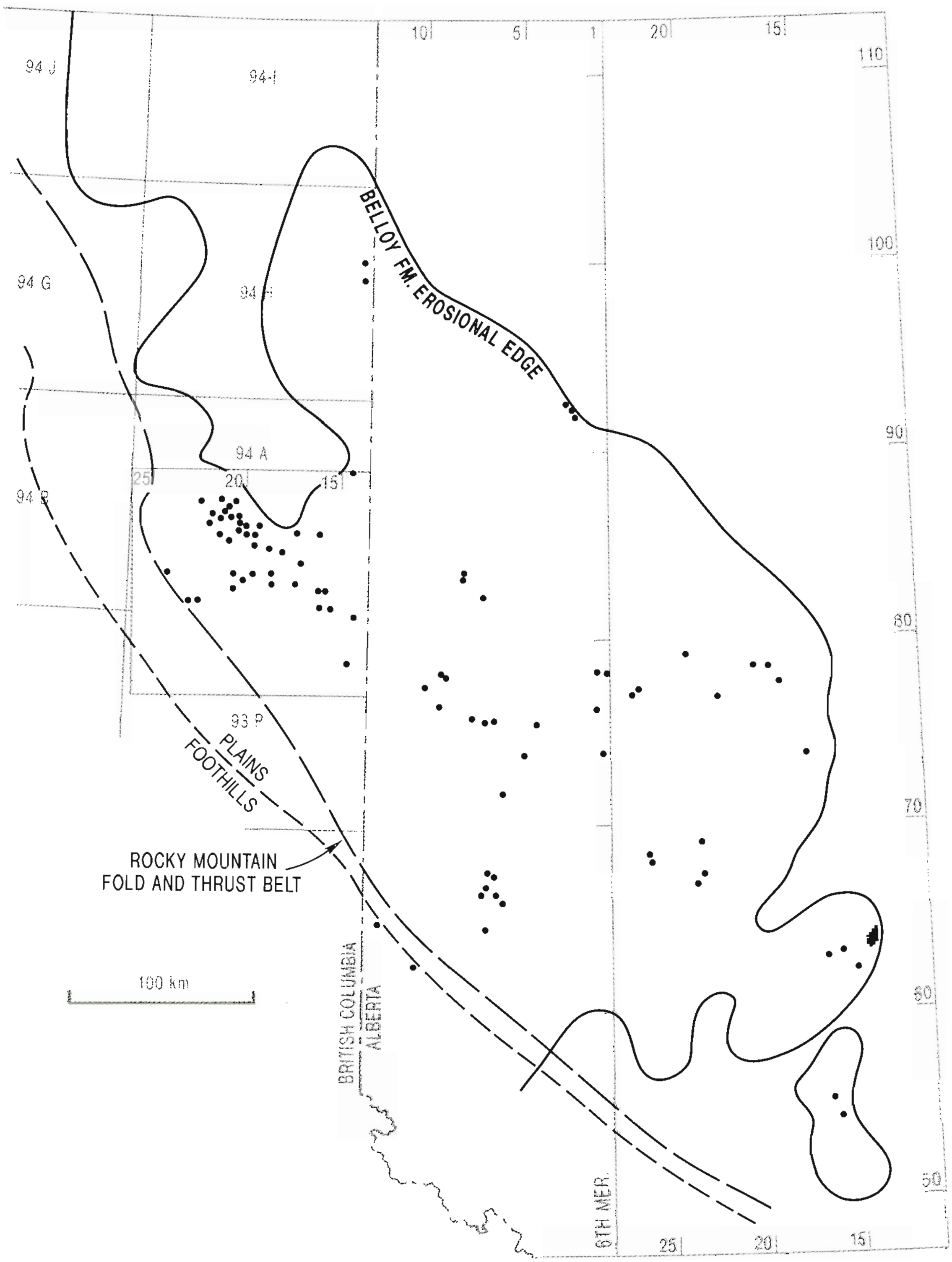


***Figure 42.** Oil and gas fields in the Belloy Formation. Location of discovery wells and wells typifying the play-type indicated.*

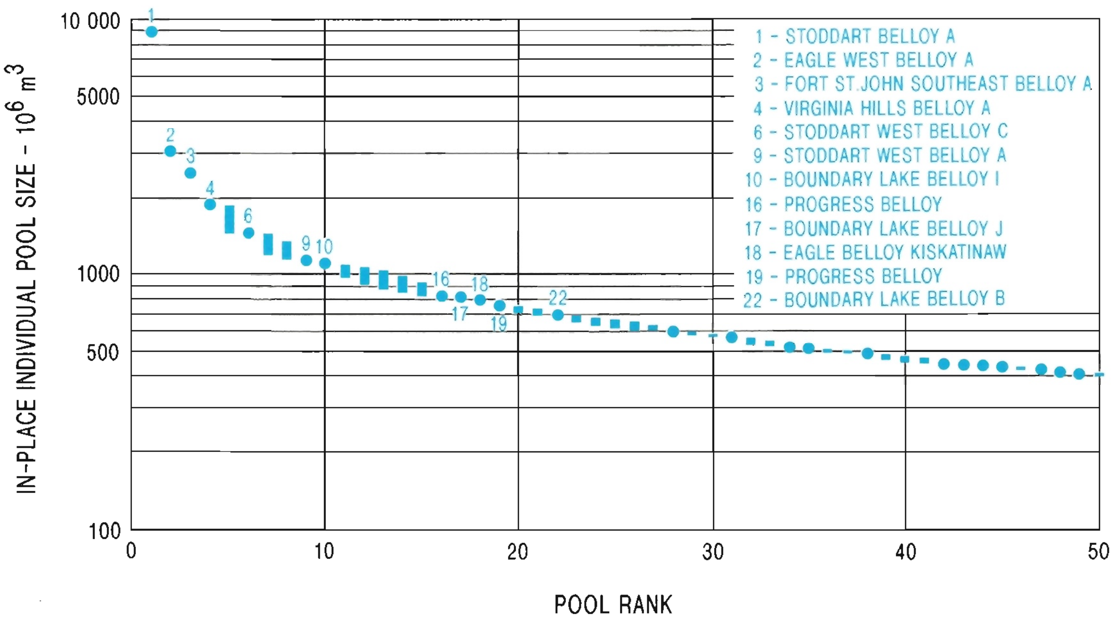


Figure 43. *Belloy/Peace River structural–Eagle play: pool-size-by-rank plot — conditioned by discovery record (large discovered pools identified — see also Table 8).*

Table 8

Largest 20 pools of the Belloy/Peace River structural–Eagle play

Rank	Field/Pool (top 20 discovered pools)	Gas type	In-place volume (10^6 m^3)	Discovery year
1	Stoddart, Belloy A	NA	9 039	1957
2	Eagle West, Belloy A	AG, SG	3 082	1976
3	Fort St. John Southeast–Belloy A	NA	2 536	1952
4	Virginia Hills, Belloy A	AG, SG	1 910	1961
6	Stoddart West, Belloy C	AG	1 461	1970
9	Stoddart West, Belloy A	NA	1 140	1967
10	Boundary Lake, Belloy I	NA	1 119	1988
16	Progress, Belloy	NA	843	1980
17	Boundary Lake, Belloy J	NA	834	1989
18	Eagle, Belloy–Kiskatinaw	SG	810	1972
19	Progress, Belloy	NA	766	1980
22	Boundary Lake, Belloy B	NA	707	1987
28	Stoddart West, Belloy H	NA	608	1968
31	Wapiti, Permo-Penn System	NA	575	1956
34	Braeburn, Belloy A	NA	528	1954
35	Roxana, Belloy A	NA	526	1974
38	Fort St. John, Belloy A	NA	499	1952
42	Boundary Lake, Belloy K	NA	453	1989
43	Blueberry, Belloy	NA	451	1973
44	Boundary Lake, Belloy G	NA	449	1988
Initial in-place volume (discovered) (10^6 m^3)			39 943	
Initial in-place volume (potential) (10^6 m^3)			72 783	
Per cent of play resources undiscovered			65	
Total pool population (discovered and undiscovered)			1 000	
Total pools discovered			93	
Total pools undiscovered			907	
Largest undiscovered pool			1 644	
Total undiscovered pools $>140 \times 10^6$ m^3			132	

NA, nonassociated gas; AG, associated gas; SG, sour gas

CONCEPTUAL PLAY ANALYSIS

To evaluate the possibility of discovering entirely new exploration plays, two independent methods of analysis were applied to the numerical and geological data. The first method was numerical and used the discovery process model with the discovery history and total play resource information for individual plays as a database. It modelled the distribution of resources, as for pools in individual mature plays. The second method used a subjective geological approach, in which we defined new plays based on our knowledge of the existing Carboniferous and Permian plays and regional geology (see Table 1). In other words, we tried to imagine what could be, based on what is (G.K. Williams, pers. comm., 1985). The geological analysis was also used to evaluate the credibility of the numerical prediction.

Numerical analysis of conceptual play potential

Conceptual plays are defined as those plays in which discoveries or reserves have not yet been proven, but according to geological analysis, may exist. Estimates of the potential and size of conceptual plays were done using the nonparametric discovery process model, using the six mature Carboniferous and Permian gas plays as the database. This method uses the individual, mature-play total resources (i.e., discovered plus undiscovered gas-in-place volumes) as data points, in the same way that individual pool volumes were used as data points in the individual play assessments reported above (Fig. 44).

A discovery sequence of the six mature plays was generated (Fig. 10), each play size representing the total play resource, that is, the sum of the discovered gas-in-place volume and in-place potential. 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 generated in the same manner as the pool-size-by-rank plots for the six mature plays (Fig. 11). The numerical analysis suggests that there is a total of at least 22 Carboniferous and Permian gas plays, which includes the six mature plays, four immature plays and 12 conceptual plays. The rectangular bars in this figure represent the range in potential of the four immature plays and 12 conceptual plays. The sum of the 16 means from these plays is the expected potential for conceptual and immature plays. The analysis indicates that the 12 conceptual plays will combine with the total resource from the four immature plays (unspecified potential) to give an expected potential of 285.9 x 10^9 m^3 gas-in-place.

Geological analysis of conceptual plays

The credibility of the estimates for the conceptual plays (Table 9) depends on whether it can be demonstrated

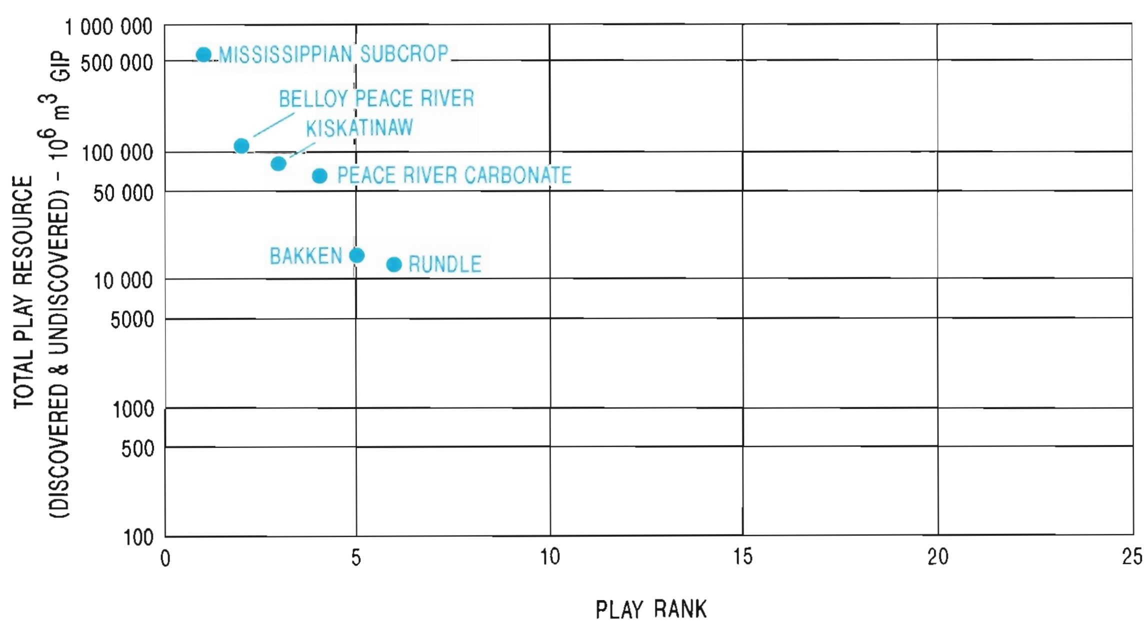


Figure 44. *Total play-in-size — discovered and undiscovered resources — of the six established mature Carboniferous and Permian plays.*

Table 9

Summary of total resources: Carboniferous and Permian plays

	Initial in-place gas volume (10^6 m^3)			
	Discovered	Expected potential (undiscovered)	Total gas resource	% undiscovered
Carboniferous mature plays (5)	587 208	142 041	729 249	19
Carboniferous immature plays (4)	2 711	*	>2 711*	*
Carboniferous subtotal	589 919	>142 041	>731 960*	>19*
Permian mature play (1) (no Permian immature plays)	39 943	72 783	112 726	65
Carboniferous and Permian subtotal	629 862	214 824	>844 686*	>25*
Carboniferous and Permian conceptual plays (10)	0	285 909*	285 909*	100
Carboniferous and Permian plays total (20 plays)	629 862	500 733	1 130 595	44

*immature play potential incorporated within conceptual plays potential

geologically that enough new plays might actually exist to contain the additional volume. The plays described below were derived by considering the possible trap types that may occur in Carboniferous and Permian strata and which have not yet been discovered. We examined nonproductive or poorly productive Carboniferous and Permian units and speculated on whether those units had the potential for reservoir development, seal geometry, and access to source rocks. We also speculated on whether those units had the ingredients for play types found in other parts of the Carboniferous and Permian of western Canada, or in other basins.

Rundle downdip stratigraphic play

This play consists of stratigraphic traps that consist of subtle facies or diagenetic changes forming reservoirs downdip from subcrop edges within the generally impermeable Rundle Group carbonate (Fig. 15A-C). The development of these reservoirs was not related to the processes, such as leaching and dolomitization, which enhanced and created reservoirs at the subcrop edge in the mature subcrop play. Although we did not classify any discovered Rundle Group pools as belonging to this play concept, it is possible that some pools placed in the Mississippian subcrop–Edson/Harmattan play have elements of stratigraphic trapping in their development and belong to this play concept. This play is similar to the immature, Banff downdip stratigraphic play, in which two pools occur.

Examples of potential reservoirs in this play include high- energy, oölitic-skeletal grainstone, such as those present at shelf-margin barriers (e.g., Majid, 1987; Speranza 1984; 1993); where diagenetic changes have enhanced porosity; Waulsortian-type, crinoid-rich, mud-mounds at shelf margins (e.g., Morgan and Jackson, 1970; Edwards, 1988; Davies et al., 1989; Kirkby, 1992); dolomitized, restricted-marine mudstone (e.g., Illing et al., 1967); fractured carbonate; reservoirs isolated and enhanced by internal Carboniferous unconformities; and peloidal limestone shoals at seaward edges of sabkha environments (e.g., Illing et al., 1967). Subtle underlying structures could also assist in reservoir development by creating shoaling conditions in a particular location (e.g., Majid, 1987; Speranza, 1993).

This play is difficult to assess because the extent of reservoir development and access to hydrocarbon migration pathways are unknown (Podruski et al., 1988). Also, the contrast between such reservoirs and surrounding seal rocks may be poor and thus difficult to see on conventional seismic. Many wells do not penetrate the entire Rundle Group and those that do so are rarely cored, consequently it is difficult to evaluate lithological or diagenetic changes in the section. However, modern seismic techniques, detailed drill cutting examination, and detailed well-log sequence stratigraphy may provide a means of identifying trap geometry and reservoir development. The numerous individual shoaling-upward cycles within the Rundle Group (see e.g., Richards, 1989a) provide a favourable juxtaposition of reservoir and seal-rock facies. This play hinges on the extent of reservoir development within the generally impermeable Rundle Group strata; should this development be significant, this widespread play could contain major amounts of hydrocarbons. The Rundle downdip stratigraphic play also does not rely on the distribution of seal-rock facies overlying the Carboniferous, such as Jurassic or Triassic shale, as does the subcrop play (e.g., Figs. 15, 20). Areas in which the Carboniferous has not been thoroughly tested include northern parts of Alberta and British

Columbia, southernmost Alberta, and the Deep Basin area.

Peace River carbonate stratigraphic play

This play concept is related to the Peace River carbonate–Dunvegan structural play and concerns the possibility of stratigraphic trapping (i.e., not directly related to horst blocks) in Rundle Group carbonate of the Peace River area (Fig. 30). The play also can be considered a subplay of the Rundle downdip stratigraphic play. In the Peace River Embayment, the Debolt Formation contains alternating permeable dolostone and impermeable anhydrite beds and this may provide a suitable geometry for hydrocarbon entrapment (Podruski et al., 1988; Packard and Al-Aasm, 1993). Law (1981) reports that porosity and permeability in the Debolt Formation are usually poor, but locally reach 6 per cent and 200 mD, and that the Debolt Formation commonly displays open fractures.

Mattson delta stratigraphic play

This play concept concerns the possibility of stratigraphic traps caused by facies changes in fluviodeltaic deposits of the Mattson Formation (Podruski et al., 1988; Richards, 1989a, b). Such changes are likely to occur in a fluviodeltaic setting because of the complex interplay of marine and fluvial processes resulting in a complex stratigraphy and interbedding of reservoir-quality sandstone with impermeable mudstone. In addition, the deposits were influenced by active tectonism, which may have added to the frequency of facies changes. Such stratigraphic traps may exist on either the upthrown east side of the Bovie Lake Fault Zone (Figs. 16, 17), where reservoirs are known in the three pools in structural traps of the immature, Mattson structural play, or on the downdropped west side, where no pools are known.

Williston Basin stratigraphic play

Stratigraphic traps may exist in the Mission Canyon and Charles formations, downdip of their erosional edges (Podruski et al., 1988). These formations are productive, particularly for oil, at their erosional edges, where porosity has been enhanced and suitable seals exist. Diagenetic or depositional facies changes away from the subcrop edges could provide seals for reservoirs. This play is analogous to the immature, Banff downdip stratigraphic play in Alberta and British Columbia, in which only two pools exist downdip of the prolific Mississippian subcrop play, which has 597 discovered pools and is also analogous to the Rundle downdip stratigraphic play (e.g., Fig. 15).

Williston Basin structural play

This play concept involves structural traps in Bakken Formation or Madison Group carbonate reservoirs affected by post-Carboniferous deformation, or drape over underlying salt solution, meteorite impact, or local structural deformation features (Podruski et al., 1988).

DISCUSSION

Results of Carboniferous and Permian gas assessment

Total gas resources of Carboniferous–Permian plays–Plains area

The discovered gas-in-place volume for the six mature Carboniferous and Permian plays of the plains area is 627.151 x 10^9 m^3 (22.3 TCF), in 976 discovered pools, and the undiscovered resource (potential) is 214.824 x 10^9 m^3 (7.6 TCF), i.e., 26 per cent of the total mature play resource (i.e., 841.975 x 10^9 m^3 in 5060 pools, 29.9 TCF) remain to be discovered in the mature plays (Table 10, Fig. 45). The four immature Carboniferous plays have a discovered gas-in-place volume of 2.711 x 10^9 m^3 (0.1 TCF) in 10 pools (Table 11; no immature Permian plays were identified). The total resource for the established, mature and immature, Carboniferous and Permian plays of the plains area (i.e., discovered plus undiscovered gas-in-place) is 844.686 x 10^9 m^3 (30.0 TCF) gas-in-place, in 5070 discovered and undiscovered pools, plus the 285.909 x 10^9 m^3 (10.1 TCF) predicted for the conceptual and immature plays in an unknown number of pools, for an aggregate total of 1130.595 x 10^9 m^3 (40.1 TCF) gas-in-place (Fig. 45). For all mature, immature, and conceptual plays (Fig. 45), 500.733 x 10^9 m^3 (17.8 TCF), or 44 per cent of the total resource, remains to be found. This is the expected potential value. The more optimistic total probable potential value is 2141 x 10^9 m^3 (76 TCF), in which 1352 x 10^9 m^3 (48 TCF) occurs in the mature plays and 789 x 10^9 m^3 (28 TCF) in the immature and conceptual plays. For the mature plays, 1127 x 10^9 m^3 (40 TCF) is the probable potential for the Mississippian subcrop play, suggesting that there may be significantly more or about 6.2 per cent of the total potential for all conceptual plays in the Western Canada Sedimentary Basin (see Reinson et al., 1993a). The total potential

Table 10

Discovered and potential gas resources for mature Carboniferous-Permian plays (ranked by discovered initial gas-in-place volume)

		Initial gas-in-place volume (10^6 m^3)			
	Discovery date	Discovered resource	Expected potential	Total resource	% undiscovered
Mississippian subcrop-Edson/Harmattan	47/01/17	499 115	52 351	551 466	9
Peace River carbonates structural-Dunvegan	49/05/16	48 895	16 640	65 535	25
Belloy-Peace River structural-Eagle	51/06/14	39 943	72 783	112 726	65
Kiskatinaw structural/stratigraphic-Pouce Coupe	57/01/23	29 015	54 322	83 337	65
Rundle Sweetgrass structural-Black Butte/Aden	43/11/02	6 893	6 495	13 388	49
Bakken stratigraphic/subcroup-Loverna	50/10/30	3 290	12 233	15 523	79
Total		627 151	214 824	841 975	26

Table 11

Discovered gas resources for immature Carboniferous plays

	Discovered initial gas-in-place volume (10^6 m^3)	Number of pools	Discovery date
Williston Basin (associated gas) subcrop-Alida	1 074	3	54/00/00
Mattson structural-Windflower	899	3	73/01/13
Banff down-dip stratigraphic-Ferrier/Willesden Green	435	2	67/02/03
Banff-Rundle drape-Windfall	303	2	54/02/21
Total	2 711	10	

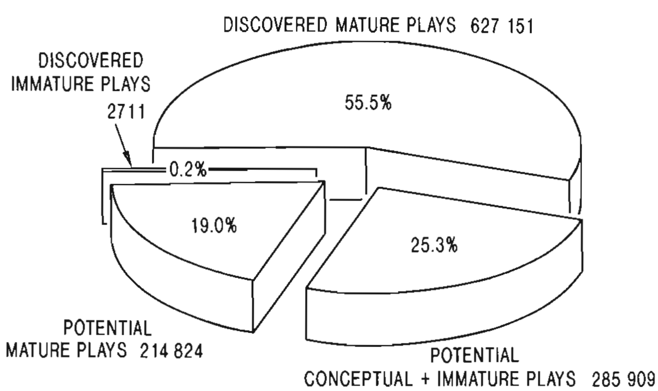


Figure 45. *Relation between discovered gas-in-place resources for mature and immature plays, undiscovered gas-in-place resources (potential) for mature plays, and conceptual plus immature plays.*

for Carboniferous and Permian (plains area) mature and conceptual (plus immature) plays is 7.7 per cent of the total potential in mature conceptual (plus oror potential than predicted by the expected potential results for that play.

The mature and immature plays constitute 629.862 x 10^9 m^3 (22.4 TCF), or 9.7 per cent of the total discovered gas-in-place for mature, immature, and conceptual plays in the Western Canada Sedimentary Basin (inclusive of the Foothills), and also constitute 500.733 x 10^9 m^3 (17.8 TCF), or 7.7 per cent, of the total undiscovered gas-in-place (expected potential) (Table 9; Reinson et al., 1993a). The mature Carboniferous-Permian (plains area) plays make up 6.8 per cent of the gas potential for all mature plays in the Western Canada Sedimentary Basin (Fig. 46) and the conceptual plays (including gas potential for immature plays) make up 285.909 x 10^9 m^3 (10.2 TCF), or about 6.2 per cent of the total potential for all conceptual plays in the Western Canada Sedimentary Basin (see Reinson et al., 1993a). The total potential for Carboniferous and Permian (plains area) mature and conceptual (plus immature) plays is 7.7 per cent of

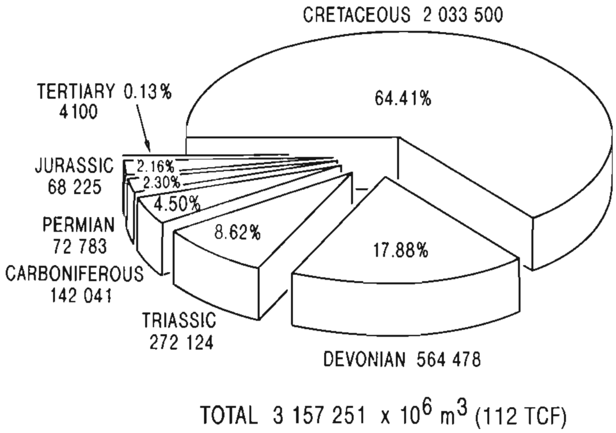


Figure 46. *Gas-in-place (10^6 m^3) for expected potential (undiscovered resources), established mature plays, all geological systems, for the plains area, Western Canada Sedimentary Basin (data in part from Reinson et al., 1993a; note: Cretaceous gas-volume provided by K. Drummond, National Energy Board, September, 1993. This gas volume includes an amount attributable to conceptual plays. The Cretaceous slice cannot be easily compared to the other slices — removal of the Cretaceous conceptual portion would reduce the Cretaceous slice and expand each of the other slices).*

the total potential in mature conceptual (plus immature) plays for the Western Canada Sedimentary Basin (see Reinson et al., 1993a). The total resources of all Carboniferous and Permian (plains area) plays (discovered plus undiscovered, mature, immature, and conceptual) is 1130.595 x 10^9 m^3 (40.1 TCF), or 10.8 per cent of the gas resource in the plains of western Canada (1045.43 x 10^9 m^3 = 37.1 TCF), and 8.7 per cent of the gas resource in the plains and Foothills (1204.63 x 10^9 m^3 = 42.8 TCF; Reinson et al., 1993a).

Gas resources of individual, mature Carboniferous-Permian plays-Plains area

In terms of Carboniferous-Permian potential, three mature plays have the highest and most similar gas potentials. They are the Belloy/Peace River structural-Eagle play (72 783 x 10^6 m^3; 2.6 TCF potential), the Kiskatinaw clastics-Pouce Coupe play (54 322 x 10^6 m^3; 1.9 TCF), and the Mississippian subcrop-Edson/Harmattan play (52 351 x 10^6 m^3; 1.9 TCF; Figs. 47, 48). The Mississippian subcrop play contains the majority (79.6 per cent; 479 115 x 10^6 m^3; 17 TCF) of the discovered Carboniferous-Permian (plains area) gas resource (Fig. 49) and although it has low potential relative to its discovered resources, the potential is still significant (Fig. 50). The Belloy and Kiskatinaw plays have discovered gas resources of 39 943 x 10^6 m^3 (1.4 TCF) and 29 015 x 10^6 m^3 (1.0 TCF), respectively. Their potentials are similar to their discovered gas resources, reflecting immature exploration. The remaining three mature plays form a group of plays with smaller potentials than those listed above: 16 640 x 10^6 m^3 (0.6 TCF), 12 233 x 10^6 m^3 (0.4 TCF), and 6495 x 10^6 m^3 (0.2 TCF) for the Peace River carbonate-Dunvegan play, the Bakken stratigraphic/subcrop-Loverna play, and the Rundle/Sweetgrass structural-Black Butte play, respectively (Figs. 47, 48). The Peace River carbonate play has significant discovered resources of 48 895 x 10^6 m^3 (1.7 TCF), while the Bakken and Rundle/Sweetgrass plays have smaller discovered amounts, of 3290 x 10^6 m^3 (0.1 TCF) and 6893 x 10^6 m^3 (0.2 TCF), respectively (Fig. 49).

The total potential of a play is only one numerical measure of its prospectivity and the plays can be ranked differently by a variety of criteria. For example, ranking the plays by their largest undiscovered pool sizes shows that the Peace River carbonate play, the Mississippian subcrop play and the Belloy play have the largest predicted undiscovered pool sizes, of 2900 x 10^6 m^3 (103 BCF), 1893 x 10^6 m^3 (67 BCF), and 1644 x 10^6 m^3 (58.3 BCF), respectively (Fig. 51). The other three plays have much smaller largest undiscovered pools (Fig. 51). Figure 52 shows that there is a general positive correlation between the largest undiscovered pool size and the play potential, reflecting the significant contribution of the predicted largest pool to the potential, compared with the contribution of the many small predicted pools.

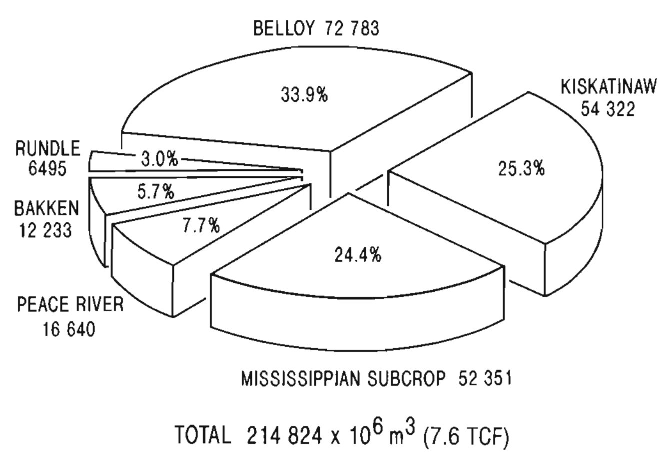


Figure 47. *Gas-in-place volume (10^6 m^3) for expected potential (undiscovered resources) established mature Carboniferous-Permian plays.*

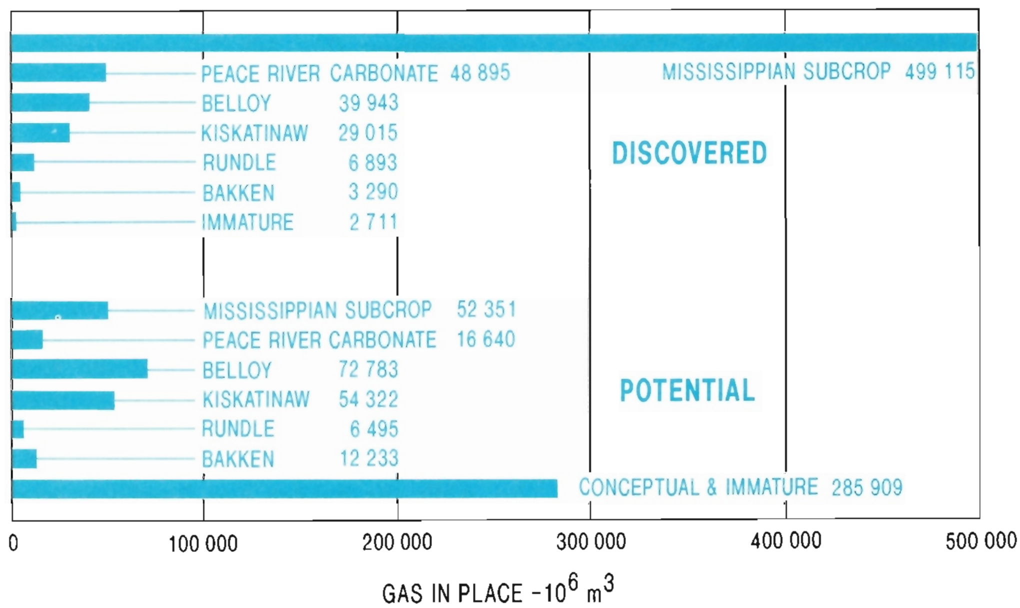


Figure 48. *Gas-in-place volume (10^6 m^3) for mature, immature and conceptual Carboniferous–Permian plays, ordered by discovered gas-in-place volume (discovered resources, top) compared to expected potential (undiscovered resources, bottom).*

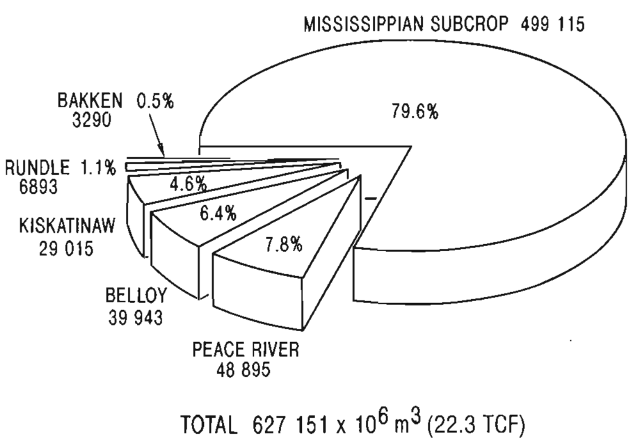


Figure 49. *Gas-in-place volume (10^6 m^3) for established mature Carboniferous–Permian plays, discovered resources.*

Ranking the plays by the total number of undiscovered pools shows that the Kiskatinaw clastics, Bakken stratigraphic/subcrop, and Belloy/Peace River structural plays are the best, with 1085, 1063, and 907 undiscovered pools, respectively, followed by the Rundle/Sweetgrass structural, Mississippian subcrop, and Peace River carbonate plays, with 556, 343, and 130 undiscovered pools (see Tables 3–8). However, this ranking of plays does not evaluate the size of the pools. If this were done by, for example, listing the number of pools greater than 140 x 10^6 m^3 (approximately 5 BCF), it would show that the Belloy/Peace River structural, Kiskatinaw clastics, and Mississippian subcrop plays contain most of these larger, potentially economic pools — 132, 89 and 67 pools, respectively. The Peace River carbonate, Rundle/Sweetgrass, and Bakken stratigraphic/subcrop plays form a group with relatively few pools greater than 140 x 10^6 m^3 (5 BCF), having 13, 9, and 3 of these pools, respectively. The 140 x 10^6 m^3 (5 BCF) pool size is used as it would be economic for many companies. However, there are many important factors controlling the economic potential of these undiscovered pools, such as company finances, pool location, infrastructure, and gas price. Part II of this paper provides a full economic analysis of these plays using such factors. The analysis indicates, among other things, that the Peace River carbonate, Mississippian subcrop and Kiskatinaw clastics plays generally are the most economic (e.g., see Part II).

Comparison with gas resources in the Foothills

Carboniferous–Permian: The resources of the Carboniferous–Permian plays in the plains can be compared to the significant Carboniferous–Permian resources (mainly Carboniferous) in the folded and faulted strata of the Foothills (using the initial results

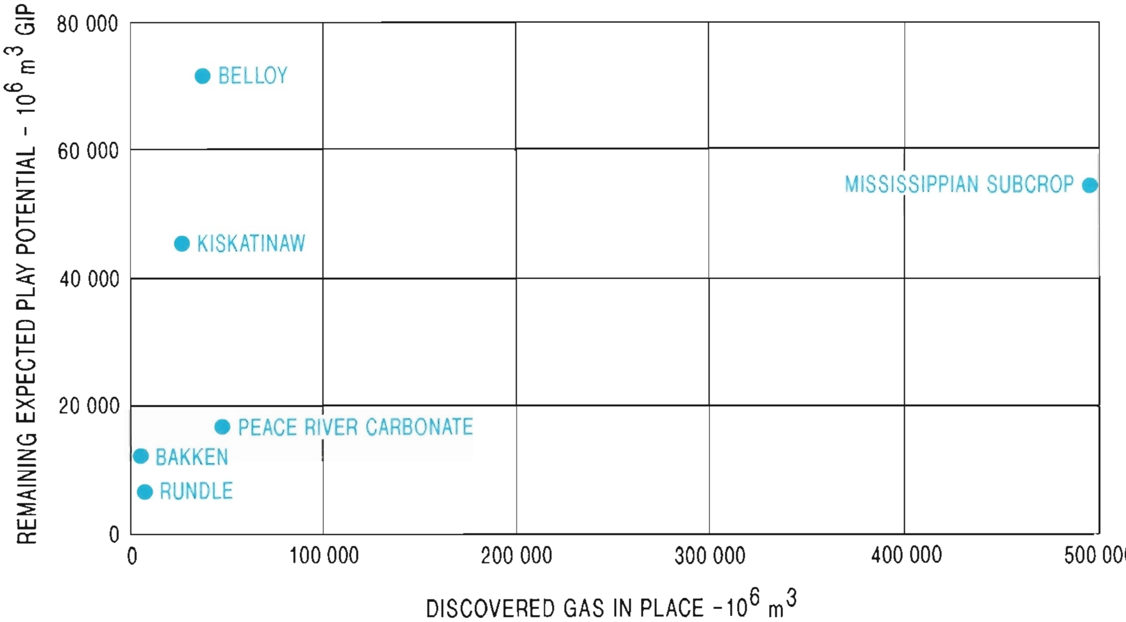


Figure 50. *Plot of remaining expected play potential and discovered gas-in-place volume for the mature plays.*

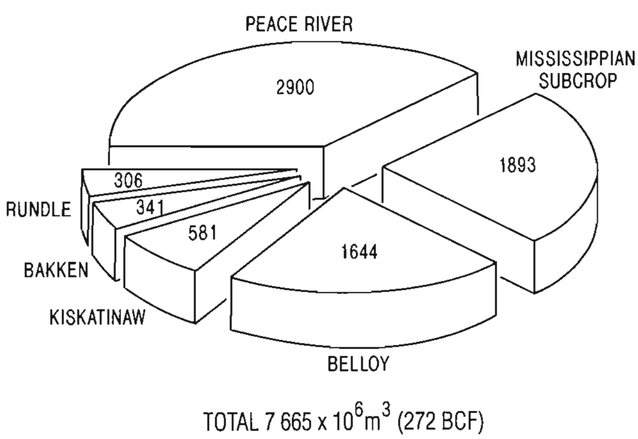


Figure 51. *Gas-in-place volume (10^6 m^3) within the largest undiscovered pools established mature Carboniferous–Permian plays (Note: as a rough approximation, 100 x 10^6 m^3 perhaps would be economic to explore; 3000 x 10^6 m^3 would be a significant discovery, and 50 000 x 10^6 m^3 would be a large discovery, for example, as large as the Devonian Caroline gas discovery).*

from Osadetz et al., in prep.). The Foothills plays contain about 520.351 x 10^9 m^3 (18.5 TCF) discovered gas-in-place for mature and immature plays, and about 672.948 x 10^9 m^3 (23.9 TCF) undiscovered resource (potential) for mature plays (these values include an unspecified small contribution from reservoirs in the Devonian Wabamun Group, particularly those in the Waterton Field area, because Devonian and Carboniferous gas-in-place values are reported together in provincial databases). Immature and conceptual plays (values not determined) form a significant portion of the total potential in the Foothills (approximately 850 x 10^9 m^3; 22 TCF gas-in-place volume). The mature and immature Carboniferous and Permian plays in the plains (629.862 x 10^9 m^3; 22.4 TCF) form 54.8 per cent of the plains plus Foothills discovered resource. The potential in the mature plays of the plains (214.824 x 10^9 m^3; 7.6 TCF) forms 31.9 per cent of the plains plus Foothills potential for mature plays. The potential of the conceptual and immature plays in the plains (285.909 x 10^9 m^3; 10.1 TCF) is probably less than the immature and conceptual plays in the Foothills.

Carboniferous: An estimated 589.919 x 10^9 m^3 (20.9 TCF) of gas occurs in the Carboniferous of the plains (Fig. 53), which is 53 per cent of the total discovered resources in the Carboniferous of the Western Canada Sedimentary Basin (gas volume for the Foothills after Osadetz et al., in prep.; gas volume for the Carboniferous are approximated assuming that the Rundle Group part of Waterton Rundle/Wabamun play contains about two thirds of the discovered gas-in-place volume for the play). The discovered resources in the plains occur in 883 known pools (see Fig. 54), in five established mature plays that contain 587.208 x 10^9 m^3 (20.8 TCF) of the discovered gas-in-place, and in four established immature plays with 10 pools constituting 2.711 x 10^9 m^3 (0.1 TCF) of the discovered gas-in-place volume (Fig. 53). The

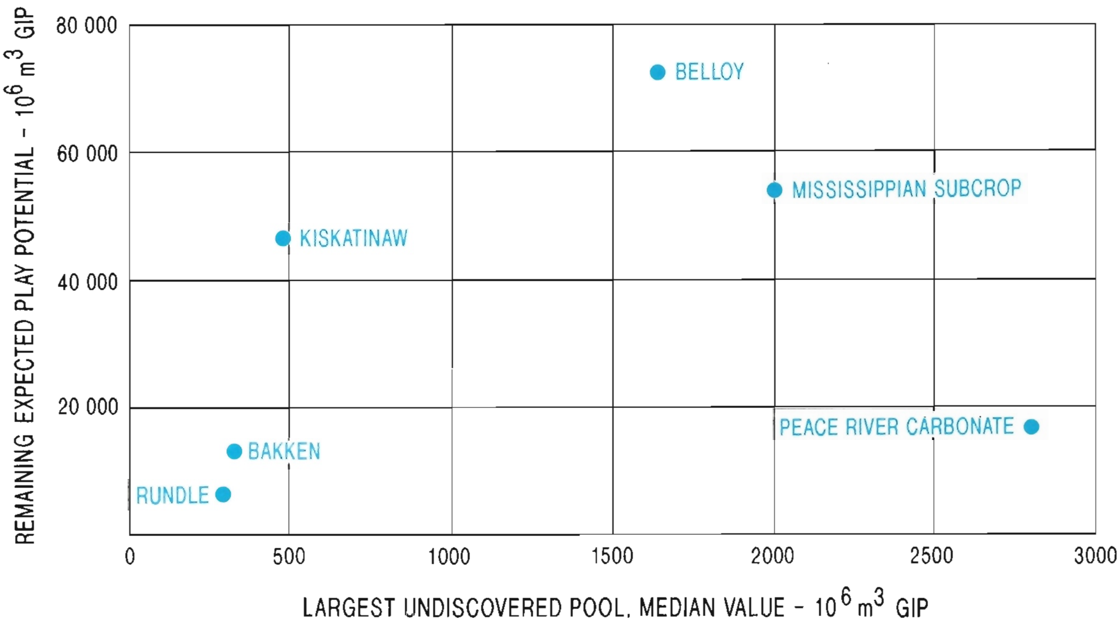


Figure 52. *Plot of remaining expected play potential and largest undiscovered pool for each play type.*

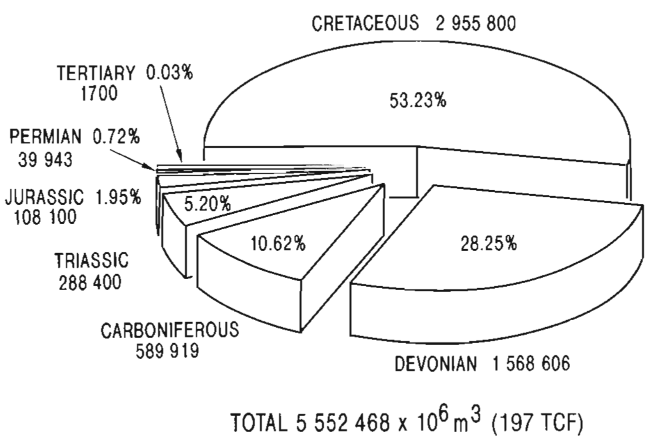


Figure 53. *Gas-in-place volume (10^6 m^3) of discovered resources in established mature and immature plays for all geological systems, plains area of Western Canada Sedimentary Basin (data in part from Reinson et al., 1993a).*

expected potential of Carboniferous gas-in-place for mature plays in the plains is predicted to be 142.041 x 10^9 m^3 (5.0 TCF), contained in 3177 undiscovered pools (Fig. 46). The total number of discovered and undiscovered pools is 4070.

Permian: The total gas resources (discovered gas-in-place volume) discovered in the Permian of the Western Canada Sedimentary Basin (gas volume for the Foothills, after Osadetz et al., in prep.) is 41.663 x 10^9 m^3 (1.5 TCF), of which 39.943 x 10^9 m^3 (1.4 TCF), or 96 per cent, occurs in 93 pools of the established, mature, Belloy/Peace River structural-Eagle play (Figs. 49, 54). The expected gas-in- place potential in the Permian of the plains is predicted to be 72.783 x 10^9 m^3 (2.6 TCF), contained within 907 undiscovered pools (Fig. 47). The total number of discovered and undiscovered pools is 1000. No immature plays were identified in the geological analysis of the Permian. As Permian pools in the Foothills were included in plays with other, mainly Carboniferous, strata, the potential of Permian strata in the Foothills cannot be easily specified (see Osadetz et al., in prep.).

Comparison to other western Canada gas-play groups

The results of this assessment can be compared to other gas assessments in the Western Canada Sedimentary Basin in order to provide another context for evaluating the relative significance of the Carboniferous-Permian plays. Assessments of Devonian, Triassic, and Foothills gas resources have been completed or are near completion (Reinson et al., 1993a, b; Bird et al., 1994; Osadetz et al., in prep.;

note that the values for the Cretaceous cited below, provided in part by K. Drummond of the National Energy Board, pers. comm., 1993, and in Reinson et al., 1993a, cannot be compared directly to our results for mature plays because their values include unspecified amounts attributable to mature, immature, and conceptual plays). The following tables provide a series of comparisons of the Carboniferous and Permian plays with the plays in other geological systems. These tables indicate that the Carboniferous and Permian plays of the plains are a small, but significant, part of the total discovered and undiscovered gas resources of the Western Canada Sedimentary Basin. Also, a few of the mature plays have some of the highest total gas-potential and discovered gas in the basin. Some of the larger undiscovered pools in the Western Canada Sedimentary Basin also occur in the Carboniferous and Permian plays. The Carboniferous and Permian plays have a total of 4084 predicted undiscovered pools in mature plays of the plains. The Carboniferous and Permian plays have a relatively small potential compared to their immature plays or immature plays in other strata (e.g., Devonian, Reinson et al., 1993b), but the potential in the conceptual plays, however, is quite significant. The potential in the conceptual plays probably reflects the increased potential in the deeper, less drilled, or more complex, strata.

Geological systems ranked by discovered gas-in-place volume for mature and immature plays, plains area (10^9 m^3; TCF in brackets, see Fig. 53):

1.	Cretaceous	2955.8 (104.9)	
	(n.b., includes immature and conceptual plays, see Reinson et al., 1993a)		
2.	Devonian	1568.6 (55.7)	
3.	Carboniferous	589.9 (20.9)	(10.6% of total)
4.	Triassic	288.4 (10.2)	
5.	Jurassic	108.1 (3.8)	
6.	Permian	39.9 (1.4)	(0.7% of total)
7.	Tertiary	1.7 (0.06)	
	Total	5552.4 (197.1)	

Geological systems ranked by discovered gas-in-place volume for mature and immature plays: plains and Foothills areas (10^9 m^3; TCF in brackets, see Fig. 55):

1.	Cretaceous	3053.7 (108.4)	
	(n.b., includes conceptual plays, see Reinson et al., 1993a)		
2.	Devonian	1710.4 (60.7)	
3.	Carboniferous	1108.5 (39.3)	(17.2% of total)
4.	Triassic	435.3 (16.1)	(0.7% of total)
5.	Jurassic	109.1 (3.9)	
6.	Permian	41.7 (1.5)	
7.	Tertiary	1.7 (0.06)	
	Total	6460.4 (229.3)	

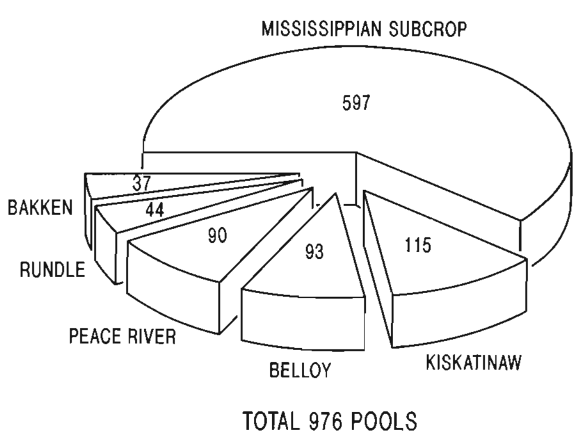


Figure 54. *Number of discovered pools in established mature Carboniferous–Permian plays.*

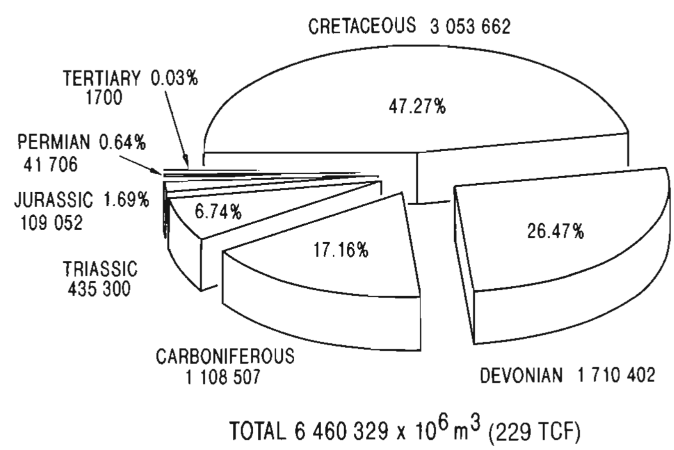


Figure 55. *Distribution of total discovered gas-in-place volume (10^6 m^3) by system within the plains and Foothills of the Western Canada Sedimentary Basin (in part from Reinson et al., 1993a; Osadetz et al., in prep).*

Geological systems ranked by gas-in-place expected potential for mature plays (10^9 m^3; TCF in brackets):

1.	Cretaceous	2033.5	(72.2)	
	(n.b., includes immature and conceptual plays, see Reinson et al., 1993a)			
2.	Foothills	804.2	(28.5)	
	(includes various systems)			
3.	Devonian	564.5	(20.0)	
4.	Triassic	272.1	(9.7)	
5.	Carboniferous	142.0	(5)	(3.5% of total i.e., plains only)
6.	Permian	72.8	(2.6)	(1.8% of total i.e., plains only)
7.	Jurassic	68.2	(2.4)	
	Total	3957.3	(140.5)	

Geological system ranked by gas-in-place total resource in mature plays (10^9 m^3; TCF in brackets):

1.	Cretaceous	4989.3	(177.1)	
	(n.b., includes immature and conceptual plays, see Reinson et al., 1993a)			
2.	Devonian	2133.1	(75.7)	
3.	Foothills	1449.3	(51.4)	
4.	Carboniferous	729.2	(25.9)	(7.2% of total)
5.	Triassic	536.8	(19.1)	
6.	Jurassic	175.5	(6.2)	
7.	Permian	112.7	(4.0)	(1.1% of total)
8.	Tertiary	1.7	(0.06)	
	Total	10 127.6	(359.4)	

Largest mature play of each geological system play-group ranked by discovered gas-in-place volume (10^9 m^3; TCF in brackets):

1.	Carboniferous	499.1	(17.7)
2.	Foothills	355.1	(12.6)
3.	Devonian	297.5	(10.6)
4.	Triassic	66.6	(2.4)
5.	Jurassic	42.0	(1.5)
6.	Permian	39.9	(1.4)
(?)	Cretaceous	(not available)	
(?)	Tertiary	(not available)	

Play groups ranked by gas-in-place expected potential of the largest mature play of each play group (10^9 m^3; TCF in brackets):

1.	Foothills	184.0	(6.5)
2.	Triassic	88.9	(3.2)
3.	Permian	72.8	(2.6)
4.	Devonian	67.5	(2.4)
5.	Carboniferous	54.3	(1.9)
6.	Jurassic	25.4	(0.9)
(?)	Cretaceous	(not available)	
(?)	Tertiary	(not available)	

Play groups ranked by the largest undiscovered pool in their mature plays (10^9 m^3; BCF in brackets, median values):

1.	Foothills	11.5	(408)
2.	Devonian	7.8	(277)
3.	Triassic	3.2	(114)
4.	Carboniferous	2.9	(103)
5.	Permian	1.6	(57)
6.	Jurassic	1.6	(57)
(?)	Cretaceous	(not available)	
(?)	Tertiary	(not available)	

(note: The largest undiscovered pool in the Lewis/Waterton-Rundle/Wabamun play is estimated to be about 8.3 x 10^9 m^3 (approximately 300 BCF) and although classed as immature it is one of the more mature immature plays. However, this pool could have gas from the Devonian Wabamun Group, in addition to, or instead of, gas from the Carboniferous Rundle Group. Also, the Limestone Fairholme and Chinook Ridge Permo-Carboniferous immature plays could have large undiscovered pools, but the assessment is not yet complete (Osadetz et al., in prep.).

Play groups ranked by number of discovered pools and compared to number of total pools (i.e., number of discovered + undiscovered pools, mature plays):

		Discovered Pools/Total Number of Pools
1.	Cretaceous	approx. 20 000/unknown
2.	Devonian	1945/9321
3.	Carboniferous	883/4060
4.	Triassic	614/3915
5.	Foothills	602/5610
6.	Jurassic	435/2240
7.	Permian	93/1000

Play groups ranked by number of undiscovered pools in mature plays:

1.	Devonian	7376
2.	Foothills	5008
3.	Triassic	3301
4.	Carboniferous	3177
5.	Jurassic	1805
6.	Permian	907
(?)	Cretaceous	(not available)
(?)	Tertiary	(not available)

Total of immature plays in each geological system ranked by discovered gas-in-place volume (10^9 m^3; TCF in brackets):

Foothills	215.5	(7.6)	(13 plays, 77 pools)
Triassic	23.7	(0.8)	(2 plays, 8 pools)
Devonian	17.3	(0.6)	(3 plays, 77 pools)
Carboniferous	2.7	(0.1)	(4 plays, 10 pools)
Jurassic	0.8	(0.03)	(2 plays, 9 pools)
Permian	0.0		(0 plays, 0 pools)

Cretaceous (unspecified amount within 2955.8 (104.9), see Reinson et al., 1993a)

Tertiary (not available)

Conceptual plays ranked by gas-in-place expected potential (includes an unspecified amount attributable to discovered gas-in-place volume and potential of immature plays) (10^9 m^3; TCF in brackets):

1.	Devonian	1394.9	(49.5)
2.	Foothills	846.4	(30.0)
3.	Carboniferous + Permian	285.9	(10.1)
4.	Triassic	33.8	(1.2)
5.	Jurassic	10.1	(0.4)
(?)	Cretaceous	(not available)	
(?)	Tertiary	(not available)	

CONCLUSIONS

1. Five established mature plays with 883 discovered pools and four established immature plays with 10 discovered pools were identified in Carboniferous strata within the Interior Plains portion of the Western Canada Sedimentary Basin. One established mature play with 93 pools was identified in the Permian of the plains. No immature Permian plays were identified. Twelve conceptual plays (i.e., plays with no discovered pools) were predicted for the Carboniferous and Permian.

2. The five established mature Carboniferous plays and their discovered resources and potential are (discovered/undiscovered, 10^6 m^3 gas-in-place, TCF in brackets):

   i) Mississippian subcrop–Edson Harmattan play, 499 115/52 351 (17.7/1.9)

   ii) Peace River carbonate–Dunvegan play, 48 895/16 640 (1.7/0.6)

   iii) Kiskatinaw clastics–Pouce Coupe play, 29 015/54 322 (1.0/1.9)

   iv) Rundle/Sweetgrass structural–Black Butte play, 6893/6495 (0.2/0.2)

   v) Bakken stratigraphic/subcrop–Loverna play, 3290/12 233 (0.1/0.4)

   The established mature play in the Permian is the Belloy/Peace River structural–Eagle play which has a discovered gas-in-place resource of 39 943 x 10^6 m^3 (1.4 TCF) and a predicted potential of 72 783 x 10^6 m^3 (2.6 TCF). The four established immature Carboniferous plays have discovered resources of 2.711 x 10^9 m^3 (0.1 TCF) and their potential was included, but unspecified, in the conceptual play analysis. The Belloy and Kiskatinaw plays have the greatest predicted potential. The largest predicted undiscovered pool occurs in the Peace River carbonate–Dunvegan play and has 2900 x 10^6 m^3 (0.1 TCF) gas-in-place.

3. Total discovered gas-in-place resources for the mature and immature Carboniferous plays is 589.919 x 10^9 m^3 (20.9 TCF) and the undiscovered resource (potential) for the mature plays is 142.041 x 10^9 m^3 (5.0 TCF). The discovered resource of the Permian is 39.943 x 10^9 m^3 (1.4 TCF) and potential is 72.783 x 10^9 m^3 (2.6 TCF). The potential resource for the conceptual and immature Carboniferous and Permian plays is 285.909 x 10^9 m^3 (10.1 TCF). 500.7 x 10^9 m^3 (17.8 TCF), or 44 per cent of the total Carboniferous and Permian (plains area) resource of 1130.6 x 10^9 m^3 (40.1 TCF), remains to be discovered. Nineteen per cent of the total resource remains to be found in the undiscovered pools of the mature plays.

4. The discovered resources of the Carboniferous and Permian plays are concentrated in the Mississippian subcrop–Edson/Harmattan play, in fields along several major erosional edges, yet the gas potential in Carboniferous–Permian plays appears to be concentrated in structural or stratigraphic traps downdip of those edges. The potential resource is predicted to occur in 4084 pools in the mature plays and in an unknown but probably large number of pools in the conceptual and immature plays.

5. The Carboniferous–Permian plays of the plains constitute 9.7 per cent of the total discovered gas-in-place resource of the Western Canada Sedimentary Basin and 7.7 per cent of the total undiscovered resource.

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PART II: ECONOMIC ANALYSES

Abstract

Undiscovered raw gas-in-place estimates for exploration plays in the Carboniferous and Permian systems of the Interior Plains region of the Western Canada Sedimentary Basin (provided in Part I of this study) do not reflect technological and economic constraints related to the exploration, development and production of the resource. Part II of this study provides this complementary economic analysis.

Supply curves, describing the relation between the plant gate price of natural gas and the economically recoverable volumes of undiscovered gas and the economically recoverable portion of the undiscovered resource base are provided. Supply curves are presented, with and without a fiscal burden, for full- cycle, half-cycle and weighted cases. The weighted case, a weighted average of the full- and half-cycle results, is regarded as the reference case in this study. In the weighted case, 32 per cent of the volume of recoverable gas (or 25 per cent of the undiscovered initial gas-in-place estimates) is estimated to be economic at \$88.25 per 10^3 m^3 (\$2.50 per MCF), in 1990 dollars. Economic potential for established and conceptual plays in the Carboniferous and Permian systems is estimated as 126 x 10^9 m^3 (4.5 TCF) at \$88.25 per 10^3 m^3. Further analysis shows the sensitivities of economic potential to changes in costs, exploration success ratios, distances of discoveries to gathering systems, and pool size estimates. Finally, economic potential and marginal pools sizes are compared for each play.

Summary

Part I of this study described the petroleum geology and natural gas exploration plays of the Carboniferous and Permian systems in the Interior Plains region of the Western Canada Sedimentary Basin. It also provided estimates of the discovered and undiscovered natural gas resources in these plays. The estimates of undiscovered resources did not reflect technological and economic constraints.

This report estimates the portion of the undiscovered initial gas-in-place expected to be economic over the long term by considering the major technical and economic constraints to exploration, development and production. This constrained portion, defined as *economic potential*, is measured as a function of the weighted full- and half-cycle estimate of the plant gate supply price of natural gas. The weighted estimate recognizes that some discoveries in a play may be made with wells drilled to targets in deeper plays. The use of a weighted estimate is appropriate in the economic analysis of resources in the Carboniferous and Permian systems because exploration targets are expected to exist above and below those strata. The weighted case is, therefore, the reference case for this study.

The full-cycle case includes all exploration, development, production and overhead costs. Cost of land rights has been excluded from this analysis in order to estimate prospect profitability prior to acquiring land. The half-cycle case excludes all pre-development costs. Economic potential is given for both the full-cycle and half-cycle cases to provide estimates at major decision points in the investment cycle, and to address single target exploration drilling.

Estimates of economic potential were prepared with and without a fiscal burden. Burdened economic potential measures potential under the existing fiscal system, while unburdened economic potential excludes the fiscal system. The difference between the burdened and unburdened cases measures the impact of the fiscal system on the discovery, development and production of natural

gas resources. For each case, two estimates of economic potential are provided: the volume of economic initial raw recoverable gas, and the percentage of the total initial raw recoverable gas that is economic.

Undiscovered pool size estimates and other required information are available for mature plays only. Therefore, economic analysis was undertaken for each of the five mature Carboniferous plays and the single mature Permian play. Exploration, development and production costs, together with production profiles, were estimated for each undiscovered pool. The resulting cost and production schedules were used to estimate minimum required plant gate supply prices using discounted cash flow analysis. Supply curves, relating economic potential to prices, were constructed from the above estimates. Because of a lack of relevant information, it was not possible to apply the methodology used for the economic analysis of mature plays to the resources estimated for immature and conceptual plays. In order to provide some measure, however speculative, of the economic potential of this resource, results for the mature plays were extended to the conceptual resources.

Economic potential was estimated under the following reference case conditions and assumptions: 1) mean resource estimates of undiscovered pools; 2) play-specific geological and engineering parameters; 3) play-specific economic success ratios; 4) federal and provincial fiscal systems as of June 1993; 5) 1990 costs; and 6) minimum real discounted cash flow rate-of-return of 10 per cent on investment.

The reference case is based on data available at the time of analysis. It does not consider: 1) possible decreases in costs due to technological changes and improvements in company practices; 2) reductions in development costs as a result of expansions of pipeline networks; 3) improvements in economic success ratios; and 4) increases in undiscovered pool size estimates because of increased knowledge of exploration plays. Consequently, economic potential for the reference case reflects the current economics of exploration. It is likely an underestimate of the long-term exploration fundamentals.

Economic potential is estimated as a function of prices up to \$300 per 10^3 m^3 (\$8.00 per MCF). However, for the purposes of discussion, results are provided at a plant gate price of \$88.25 per 10^3 m^3 (\$2.50 per MCF). Major conclusions for the mature Carboniferous and Permian plays, for the reference case, are:

1. In the weighted case, burdened economic potential is estimated as 54 x 10^9 m^3 (1.9 TCF). This volume corresponds to 32 per cent of the total initial raw recoverable gas, and 25 per cent of the undiscovered initial gas-in-place volumes estimated in Part I of this study.

2. On a full-cycle basis, burdened economic potential is 32 x 10^9 m^3 (1.1 TCF), corresponding to 19 per cent of the total initial raw recoverable gas.

3. On a half-cycle basis, burdened economic potential increases to 99 x 10^9 m^3 (3.5 TCF), corresponding to 59 per cent of the total initial raw recoverable gas.

4. There is a 16 per cent difference between burdened and unburdened economic potential, indicating the impact of the fiscal system.

5. The supply curves are generally elastic in the price range of \$35 to \$106 per 10^3 m^3 (\$1.00 to \$3.00 per MCF).

Approximately 57 per cent of the undiscovered Carboniferous and Permian gas resources are estimated as being in immature and conceptual plays. Results of the economic analysis for the six mature plays were extended to this portion of the resource. The inclusion of resources in immature and conceptual plays increases the estimate of the burdened weighted economic potential from 54 x 10^9 m^3 (1.9 TCF) to 126 x 10^9 m^3 (4.5 TCF) at \$88.25 per 10^3 m^3.

Significant variability and uncertainty surround estimates of costs and other factors. Sensitivity analyses were undertaken to gauge the impact of changes in key factors on estimates of burdened weighted economic potential. Results of the sensitivity analyses, at a plant gate price of \$88.25 per 10^3 m^3, are:

1. An increase in total costs of 20 per cent, relative to the reference case, reduces the weighted economic potential by 45 per cent. A reduction in total costs of 30 per cent increases economic potential by 29 per cent.

2. Doubling the exploration success ratio increases the weighted economic potential by 26 per cent. In the full-cycle case, economic potential increases by 52 per cent.

3. Reducing the pipeline distance to the gathering system to 2.5 km increases the weighted economic potential by 16 per cent. The estimate of economic potential increases by 9 per cent for the half-cycle case.

4. The combined impact of both cost reductions and expansions to the pipeline system was examined. A 30 per cent reduction in total cost and a reduction of the pipeline distance to 2.5 km shows an increase in weighted economic potential of 45 per cent.

5. Increasing the mean estimates of undiscovered pool sizes by 10 per cent increases economic potential by almost 20 per cent.

The relative attractiveness of exploration plays was compared by using the full-cycle and half-cycle supply curves and marginal pool size curves for each play. Major conclusions for this comparison are:

1. In the full-cycle case, the Peace River carbonate–Dunvegan play and the Mississippian subcrop–Edson/Harmattan play have the most economic potential at \$88.25 per 10^3 m^3.

2. The ranking of plays according to economic potential at \$88.25 per 10^3 m^3 does not show a positive correlation with the ranking according to the expected volumes of total initial recoverable gas, particularly in the full-cycle case.

3. The supply curves for the Mississippian subcrop–Edson/Harmattan play are the most elastic up to \$106 per 10^3 m^3 (\$3.00 per MCF). Supply curves for the Belloy/Peace River structural–Eagle and Kiskatinaw clastics–Pouce Coupe plays are also elastic.

4. The Mississippian subcrop–Edson/Harmattan play and the Belloy/Peace River structural–Eagle play have similar exploration economics, as do the Bakken stratigraphic/subcrop–Loverna play and the Kiskatinaw clastics–Pouce Coupe play. The Peace River carbonate–Dunvegan play has the largest pools with relatively low supply prices.

5. In the full-cycle case, 36 pools are economic at \$88.25 per 10^3 m^3. The smallest economic pool size in this case is 260 x 10^6 m^3 (9.2 BCF). In the half-cycle case, 325 pools are economic at \$88.25 per 10^3 m^3. The smallest economic pool size in the half-cycle case is 52 x 10^6 m^3 (1.8 BCF).

INTRODUCTION

Part I of this study described the petroleum geology and natural gas exploration plays in the Carboniferous and Permian systems of the Interior Plains region of the Western Canada Sedimentary Basin. Estimates of undiscovered natural gas resources in these plays were provided. These estimates were not constrained by engineering and economic considerations.

This report presents estimates of economic potential, defined as the portion of the undiscovered resource that can be expected to be profitable in the long term. Estimates of economic potential are prepared by taking engineering constraints, costs and other economic factors into consideration. This estimate is relevant to exploration and development decisions, strategic planning, supply forecasting and the analysis of resource management issues.

This is the third in a series of studies on the economic potential of undiscovered gas resources in the Western Canada Sedimentary Basin. The first study, Part II of GSC Bulletin 452, provided estimates of the economic potential of the gas resources of the Devonian System (Dallaire, Waghmare and Conn, 1993). The second study, Part II of GSC Bulletin 483, examined gas resources of the Triassic System (Waghmare, Dallaire and Conn, 1994).

Terminology

Stacked resources refers to resources found in oil and gas plays that are vertically superimposed, in whole or in part. Where stacked resources exist, oil and gas resources in shallower plays (or *uphole resources*) may be discovered with wells drilled to targets in deeper plays. Total exploration costs are shared between the prospective strata. The current analysis avoids the resulting problem of double-counting costs by constructing a weighted full- and half-cycle supply curve that recognizes shared costs. The *full-cycle* analysis includes all exploration, development and production costs, including overhead. Land acquisition costs are excluded from the full-cycle analysis, which is consistent with the practice of estimating prospect profitability prior to making expenditures for land. The *half-cycle* analysis excludes all pre-development and land costs. The half-cycle analysis provides an approximation of the quantity of undiscovered resource that may ultimately be booked as reserves with provincial regulatory bodies.

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. Supply prices are prepared for the full-cycle and half-cycle cases. When the play being evaluated is one of a set of stacked oil and gas plays in a region, the *weighted supply price* (a weighted average of the full-cycle and half-cycle supply prices) is estimated for each undiscovered pool. Estimates of the full-cycle and half-cycle supply prices are made with and without fiscal burden. The *burdened* analysis includes net taxes and royalties, and is relevant to private sector investment decisions. The *unburdened* analysis excludes fiscal burden and is, therefore, relevant to public sector resource management.

Initial raw recoverable gas refers to the volume of raw gas that can be extracted from pools using current technology but without explicit consideration of costs and other economic constraints. Total initial raw recoverable gas is calculated as the sum for all plays of the mean resource estimate multiplied by the average play recovery factor. *Initial marketable gas*, or sales gas, is the volume of natural gas that meets specifications for end use, usually requiring processing to remove acid gases, impurities and liquid components. *Economic potential*, at a given price, is the sum of recoverable resources with estimated supply prices less than or equal to the given price. The relationship between price and economic potential is defined as the *supply curve* or marginal cost curve.

Scope

The economic analysis was limited to six mature plays, as defined in Part I of this study, for which detailed undiscovered pool size estimates and other geological information were available. For these plays, the total undiscovered gas-in-place was estimated as 215 x 10^9 m^3 (7.6 TCF). The total initial raw *recoverable* gas was estimated as 169 x 10^9 m^3 (6.0 TCF), of which 109 x 10^9 m^3 (3.9 TCF) were estimated as being part of the Carboniferous System, and 60 x 10^9 m^3 (2.1 TCF) as being part of the Permian System.

An additional 286 x 10^9 m^3 (10.1 TCF) of undiscovered gas-in-place were estimated as existing in immature and conceptual plays. The recoverable portion of this volume was estimated as 226 x 10^9 m^3 (8 TCF). Because of a lack of relevant information, it was not possible to apply the methodology used for the economic analysis of mature plays to this resource. In order to provide some measure, however speculative, of the economic potential of this resource, results for the mature plays were extended to the resources estimated for the immature and conceptual plays.

METHODOLOGY

Since most of the methodology and assumptions used in this report are the same as those used in GSC Bulletins 452 and 483, only a summary is presented here. Changes to the methodology are, however, described in detail.

General description

The economic analysis was undertaken at the play level. This allowed the consistent treatment of geological, engineering and economic factors. Undiscovered pools in a play were treated as a set of investment opportunities. Basic inputs to the model were the estimated size of an undiscovered pool in the play and parameters describing the characteristics of the play. Exploration, development and production costs for the selected pool, together with the expected production profile, were estimated. These estimates were used as inputs to subsequent discounted cash flow analysis. An initial supply price of natural gas was then used to estimate gross revenue from natural gas and co-product sales. Royalties and taxes were calculated, and a discounted cash flow rate-of-return estimated. The price was varied until the calculated rate-of-return equalled the minimum required rate-of-return. The supply price was estimated for each pool in the undiscovered pool array, to a maximum price of $300 per 10^3 m^3 ($8.50 per MCF) in 1990 dollars. Supply prices were then sorted and economic potential calculated at each price. Figure 56 illustrates the methodology.

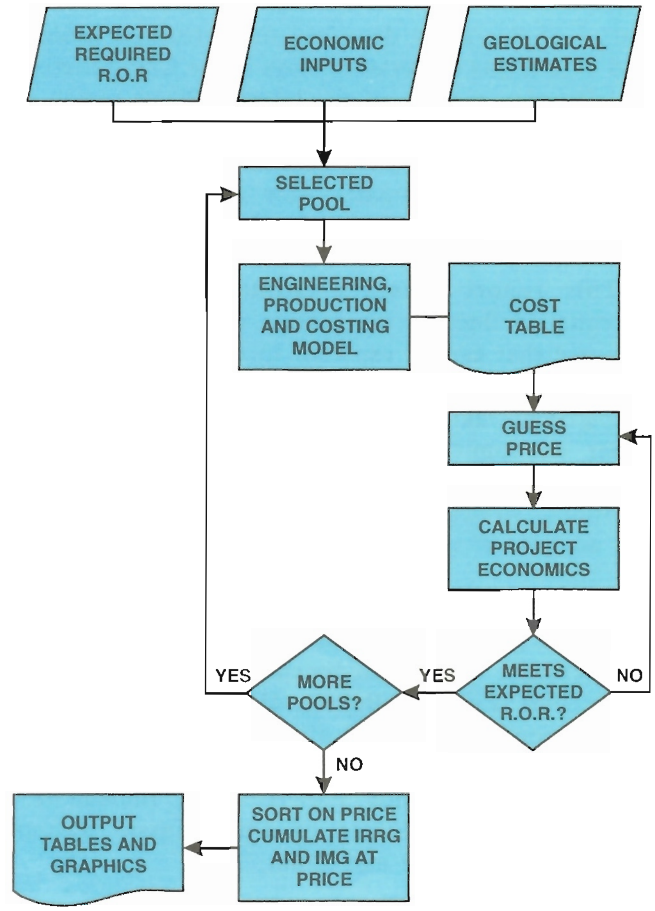

Figure 56. *Flow chart illustrating the methodology used for estimating economic potential of undiscovered gas resources.*

Supply curves were constructed for weighted, full-cycle and half-cycle economic potential, with and without a fiscal burden. Two measures of economic potential were prepared: 1) the *volume* of economic initial raw recoverable gas; and 2) the *percentage* of the total initial raw recoverable gas that is economic.

Technology, costs and production

The exploration, development and production requirements for natural gas pools and associated costs depend upon variables such as the volume of gas-in-place, pool area, pool depth, drilling success ratios, gas composition, production rates, etc. The engineering and costing model developed to support the economic analysis reflects the impact of these factors. It also allows for economies of scale and discontinuities in development and production costs over the full range of estimated undiscovered pool sizes. Wherever possible, the estimated relationships are play-specific and are based on industry experience and practices.

Table 12 lists the major capital and operating costs used in the analysis. The following is a brief description of these items. Full details regarding the technological assumptions and the estimation of associated costs are provided in GSC Bulletins 452 and 483.

Well requirements. Reservoir area was estimated as a function of the initial-gas-in-place. The number of production wells required was estimated by dividing the areal extent of the reservoir by an estimate of the minimum well spacing. Current well densities were used to estimate minimum well spacing. The number of associated D&A wells was estimated using separate exploratory and development drilling success ratios. Capital costs for wells were estimated using separate correlations for drilling, completion and abandonment costs.

Table 12

Summary of costs considered in engineering and costing model

	Capital cost	Operating cost
Geological and geophysical	●	N/A
Wells		
Exploration		
D&C	●	●
D&A	●	N/A
Development:		
D&C	●	●
D&A	●	N/A
Well site equipment	●	●
Pipelines		
Flow lines	●	●
Gathering lines	●	●
Transmission line	●	●
Roads		
Lease roads	●	●
Access road (optional)	●	●
Compression	●	●
Gas processing*	●	●
Corporate overhead	N/A	●

***Note:** Capital cost used to estimate gas processing fee.

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

Gas processing. Gas processing costs were estimated as a function of production rate and gas composition.

Compression. Compression requirements were estimated as a function of production rate, compression ratio and number of compression stages.

Pipelines and roads. The required length and diameter of pipelines were estimated separately for flow lines, common gathering lines and a transmission line to local processing facilities. Road costs were estimated as a function of terrain and surface conditions. Road lengths were assumed to equal pipeline lengths.

Well site equipment. Well site equipment includes metering and hydrate control. Hydrate control is provided by alcohol injection, line heaters or well site dehydration. Capital costs for this equipment are functions of production rate.

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

Solution gas recovery. In the economic analysis of solution gas resources, all exploration costs and many development costs were assumed to be already spent on exploration, development and production of crude oil pools. As a result, solution gas recovery was considered as an incremental or marginal investment decision, and only the costs of a gas conservation scheme and of a raw gas transmission line to a local processing facility were included in the economic analysis of solution gas resources.

Production estimates. For nonassociated gas pools, the raw gas production profile was defined by assigning each pool to one of five size classes, depending upon the volume of initial raw recoverable gas. A typical production profile consists of an initial period at a constant production rate, followed by a period of production on exponential decline. It was assumed that 50 per cent of the recoverable gas would be produced during the period of constant production. The time periods for constant and declining production were chosen to reflect accelerated production usually associated with smaller reservoirs. The size classes and parameters for each class are listed in Table 13. For solution gas produced from crude oil pools, gas production profiles were estimated by assuming a constant gas/oil ratio and a constant remaining-oil-reserves/production ratio of 10. In both cases, the raw gas production profiles were converted to sales gas and co-product production profiles.

Using weighted average supply prices. As mentioned earlier, the technology required and cost estimates included in the analysis were dependent on several variables, including the type of gas found and its composition. Existing discoveries in a play were reviewed in order to determine whether natural gas was

Table 13

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 prod. 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 (years)	7	10	13	16	19
Decline rate (approx. %)	38	27	21	17	15

found as nonassociated or solution gas, or as sour or sweet gas—whether the gas contained H_2S or not. When the existing discoveries included significant quantities of both nonassociated and solution gas and/or both sour and sweet gas, a supply price was estimated for each case. If necessary, a unique set of geological parameters was used in the estimation of the supply price for each gas type, using data from existing discoveries. Using these supply prices, weighted average prices were calculated for both the full-cycle and half-cycle cases, using as weights the fractions of the discovered resources with the given attributes.

Regional cost differences were incorporated into the analysis by assigning plays to different cost regions in the provinces of Alberta and British Columbia. Plays were generally assigned to one cost region, but when a significant portion of the play area was found in other regions, separate supply prices were calculated assuming pools were found in those regions. Again, a weighted average supply price was calculated as representative of the play.

Economic analysis

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

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

Exploration success ratios. The number of exploratory wells required for each discovery was estimated using economic success ratios instead of technical success ratios (Wilson, 1991a, b; Conn and Christie, 1988; Conn, et al., 1991; Dallaire, Waghmare and Conn, 1993).

The technical success ratio for each play was determined as the ratio of the number of drilled and completed wells to the number of exploratory tests. On the other hand, the economic success ratio was defined as the ratio of economic discoveries to the number of exploratory tests. Economic discoveries were defined as gas pools that earn an after-tax-and-royalty real rate-of-return of at least 10 per cent at a plant gate price of \$88.25 per 10^3 m^3 (\$2.50 per MCF), on a half-cycle basis.

In past studies (Dallaire, Waghmare and Conn, 1993; Waghmare, Dallaire and Conn, 1994), the economic success ratio was assumed constant for all cases examined. However, the number of economic discoveries used to determine the economic success ratio depends upon the underlying estimates of costs. Whenever costs increase or decrease, the number of economic discoveries and the economic success ratio will correspondingly decrease or increase. For this reason, economic success ratios were calculated separately for the burdened and unburdened cases, and for all sensitivity analyses.

Inflation rate. Application of the fiscal system required conversion of all real costs into current values using an assumed rate of inflation. The rate of inflation was assumed to be 4 per cent per year. Inflation was subsequently removed from the estimates in order to calculate supply prices in constant 1990 dollars.

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 minimum after-tax-and-royalty real rate-of-return of 10 per cent was assumed.

The same rate was used for the burdened and unburdened cases to facilitate comparison.

Fiscal system. The current Canadian federal and provincial (British Columbia and Alberta) fiscal systems as of June 1993 were used in the determination of fiscal burden. It was assumed that all companies were fully taxable, and that they would claim all deductions in the year they become available. It was also assumed that companies would take advantage of Alberta Royalty Tax Credit.

It is not unusual for plays to be vertically superimposed in a region. In these cases, discoveries in the play being evaluated may be the result of drilling to targets in the play or to targets in deeper plays. Discoveries in the play with wells drilled to that play were assumed to be full-cycle discoveries. Discoveries in the play with wells drilled to targets in deeper plays were assumed to be half-cycle discoveries. When estimating the economics of undiscovered resources, however, it is not known whether future discoveries will be made with wells drilled to targets in the play or with wells drilled to targets in deeper plays. Consequently, the weighted full- and half-cycle average supply price was considered to be a more relevant estimate of the supply price required to find, develop and produce undiscovered pools when stacked resources exist (Dallaire, 1994). The weight to be applied to the full-cycle supply price for each undiscovered pool was calculated by dividing the number of existing discoveries in the play being evaluated *with wells drilled to targets in that play* by the total number of discoveries in the play. The weight applied to the half-cycle price was the residual; that is, the number of pools discovered in the play *with wells drilled to targets in deeper plays* divided by the total number of discoveries in the play.

The weighted supply curve is constructed using the weighted supply prices. It avoids double-counting of exploration costs by assigning exploratory drilling costs to only one play. It is the appropriate supply curve to use when summing individual play curves to construct aggregate supply curves where stacked resources exist, either for the geological system, for a given region, or for the entire Western Canada Sedimentary Basin.

ESTIMATES OF ECONOMIC POTENTIAL

Reference case assumptions

The six Carboniferous and Permian plays were assigned to five cost regions in order to incorporate regional differences in exploration, development and production costs, and the impact of different provincial fiscal systems in British Columbia and Alberta. The Belloy/Peace River structural-Eagle and Mississippian subcrop-Edson/Harmattan plays were assigned to multiple regions, since significant portions of these plays are located in more than one area. The play assignments were:

Eastern British Columbia: the Belloy/Peace River structural-Eagle play (70 per cent weight).

Peace River (Alberta): the Belloy/Peace River structural-Eagle play (30 per cent weight); the Kiskatinaw clastics-Pouce Coupe play, and the Peace River carbonate-Dunvegan play.

Southwest Alberta: the Rundle/Sweetgrass structural-Black Butte play, the Bakken stratigraphic/subcrop-Loverna play, and the Mississippian subcrop-Edson/Harmattan play (34 per cent weight).

West-central Alberta: the Mississippian subcrop-Edson/Harmattan play (33 per cent weight).

Northwest Alberta: the Mississippian subcrop-Edson/Harmattan play (33 per cent weight).

Economic potential was estimated for a reference case using the mean resource estimate for each undiscovered pool. Figure 57 compares the resource distributions for the six plays. In this figure, the undiscovered pool size arrays for each play are arranged in decreasing order of estimated pool size.

The reference case used play-specific geological and engineering parameters, nonassociated/solution gas and sour/sweet gas weighting factors, economic exploration success ratios, and full-cycle/half-cycle weighting factors. Table 14 provides the reference case data and selected cost estimates.

Costs and supply prices were estimated in 1990 dollars to facilitate comparison with results provided in GSC Bulletins 452 and 483.

The reference case was based on data available at the time of the analysis. It did not consider: 1) improvements in economic success ratios or upward revisions to the resource estimates due to increased knowledge of exploration plays; 2) reductions in development costs because of expansions of pipeline networks; or 3) possible decreases in costs as a result of 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 an underestimate of the long-term exploration fundamentals.

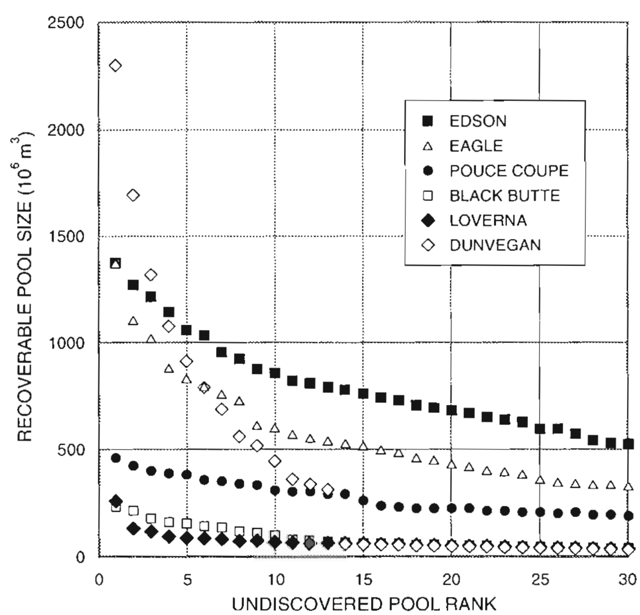

***Figure 57.** Undiscovered pool size arrays for mature Carboniferous and Permian plays.*

Table 14

Reference case input data and selected cost estimates for mature Carboniferous–Permian plays

Play description and play name	Kiskatinaw Clastics Pouce Coupe	Rundle Sweetgrass Structural Black Butte		Bakken Stratigraphic/ Subcrop Loverna	Peace River Carbonates Dunvegan	Mississippian Subcrop Edson/ Harmattan						Belloy Peace River Structural Eagle			
Province															
Alberta	area 3	area 1		area 1	area 3		area 1			area 2	area 4	area 3			
British Columbia														area 5	
Undiscovered gas-in-place															
Undiscovered resource estimate	54 322	6495		12 233	16 640	52 351						72 783			
Largest undiscovered pool	581	304		351	2906	1893						1658			
Gas type	NA	NA	NA	NA	NA	NA	NA	SG	SG	NA	NA	NA	NA	NA	NA
	sweet	sweet	sour	sweet	sweet	sweet	sour	sweet	sour	sour	sweet	sweet	sour	sweet	sour
Fraction of total resource	1.00	0.17	0.83	1.00	1.00	0.05	0.12	0.12	0.05	0.33	0.33	0.12	0.18	0.16	0.54
Average recovery factor	0.80	0.77	0.79	0.74	0.79	0.75	0.77	0.68	0.69	0.78	0.68	0.74	0.73	0.87	0.87
Average depth (metres)	2023	1041	1525	902	1485	1707	2355	1724	2511	2746	659	1727	2178	1920	1891
Drilling data															
Exploratory well success rate	0.281	0.043		0.206	0.144	0.146						0.158			
Development well success rate	0.95	0.95		0.95	0.95	0.95						0.95			
Success rate in zone	0.321	0.100		0.201	0.153	0.315						0.280			
Proportion of full-cycle discoveries	0.299	0.810		0.794	0.518	0.821						0.379			
Average well spacing (ha/well)	256	256		256	256	256						256		512	
Well costs															
Costs of D&A dev. well (10^3 $)*	389	133	212	123	248	224	504	0	0	1033	231	298	508	406	442
Costs of D&C dev. well (10^3 $)*	576	224	353	206	389	356	717	0	0	1420	349	458	740	610	673
Operating costs (10^3 $/well/mo.)	2.5	1.8	3.4	1.7	2.3	2.1	4.1	0.0	0.0	4.7	2.1	2.4	4.3	2.9	4.7
Surface facilities															
Well site equipment:															
Alcohol injection				X							X				
Dehydration	X	X													
Line heaters			X		X	X	X			X		X	X	X	X
Vapour recovery								X	X						
Cost (10^3 $/well)	184	184	81	27	81	81	81	3197	3879	81	27	81	81	93	93
Roads															
Terrain	Parkland	Farmland		Farmland	Parkland	Farmland				Forest	Muskeg	Parkland			
Unit costs (10^3 $/km)															
a) Lease/field roads	26	20	20	20	26	20	20	0	0	30	52	26	26	30	30
b) All-weather access	52	40	40	40	52	40	40	0	0	60	104	52	52	60	60
Pipelines															
Average distance to existing gathering system (km)	8	8	8	5	10	10	10	10	10	5	12	8	8	10	10
Unit costs (10^3 $/km) for 2″	39	26	34	26											
Unit costs (10^3 $/km) for 3″	50	35	46	35	59	42	46			76	59	59	64		
Unit costs (10^3 $/km) for 4″										91		71	76	82	88
Unit costs (10^3 $/km) for 6″					92	68	74	57	63		71			106	114

*Add 10% for exploration wells

Reference case estimates of economic potential

Figures 58 and 59 show, respectively, estimates of economic potential in terms of *volumes* of economic initial raw recoverable gas and in terms of *percentages* of the total initial raw recoverable gas for the burdened case. In these figures, supply curves are given for the weighted, full-cycle, and half-cycle cases. Figures 60 and 61 compare the burdened and unburdened weighted estimates of economic potential, measured as volumes and percentages, respectively.

Estimates of economic potential for the Carboniferous and Permian resources at plant gate prices of \$44.13 (\$1.25 per MCF) and \$88.25 per 10^3 m^3 (\$2.50 per MCF) are given in Table 15. Also shown in Table 15 are estimates of the economically recoverable initial marketable gas.

For the purposes of discussion, estimates of economic potential will be presented at a long-term price expectation of \$88.25 per 10^3 m^3 (\$2.50 per MCF). An analysis of Figures 58 to 61 and Table 15 leads to the following major conclusions regarding economic potential for the mature Carboniferous and Permian plays, at a plant gate price of \$88.25 per 10^3 m^3:

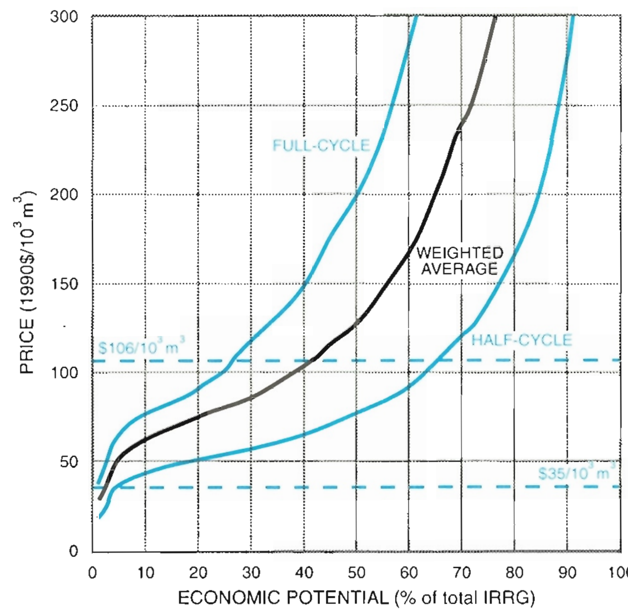

Figure 59. Supply curves showing the reference case estimates of burdened economic potential, measured as percentage of total initial raw recoverable gas (IRRG), for all mature Carboniferous and Permian gas plays.

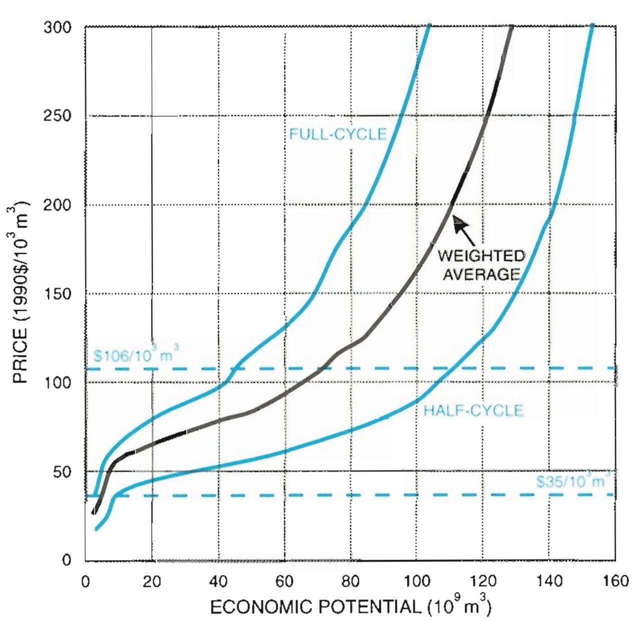

Figure 58. Supply curves showing the reference case estimates of burden economic potential, measured as a volume of initial raw recoverable gas, for all mature Carboniferous and Permian gas plays.

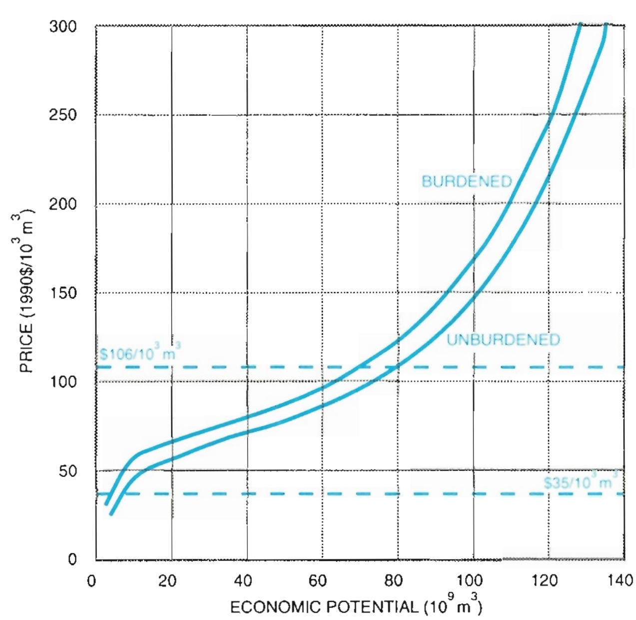

Figure 60. Supply curves showing the difference between the weighted reference case estimates of burdened and unburdened economic potential, measured as a volume of initial raw recoverable gas, for all mature Carboniferous and Permian gas plays.

Table 15

Reference case estimates of economic potential and initial marketable gas for undiscovered natural gas resources in all mature Carboniferous–Permian plays

Type of analysis	Economic potential				Initial marketable gas			
	Volume (10^6 m^3)		% of total initial raw recoverable gas		Volume (10^6 m^3)		% of total initial raw recoverable gas	
	\$44.13/ 10^3 m^3	\$88.25/ 10^3 m^3	\$44.13/ 10^3 m^3	\$88.25/ 10^3 m^3	\$44.13/ 10^3 m^3	\$88.25/ 10^3 m^3	\$44.13/ 10^3 m^3	\$88.25/ 10^3 m^3
Burdened estimates:								
Full-cycle	3 981	31 582	2	19	3 665	28 477	2	7
Half-cycle	18 634	99 058	11	59	16 944	89 632	10	53
Weighted full- and half-cycle	5 300	54 224	3	32	4 880	49 072	3	29
Unburdened estimates:								
Full-cycle	5 300	40 224	3	24	4 880	36 322	3	21
Half-cycle	38 448	106 651	23	63	34 678	96 537	20	57
Weighted full- and half-cycle	8 666	63 900	5	38	7 969	57 870	5	34

Total initial raw recoverable gas: 169 217 10^6 m^3

1. For the weighted case, burdened economic potential is estimated as 54 x 10^9 m^3 (1.9 TCF). This volume corresponds to 32 per cent of the total initial raw recoverable gas, and 25 per cent of the undiscovered initial gas-in-place estimated in Part I of this study.

2. On a full-cycle basis, burdened economic potential is estimated as 32 x 10^9 m^3 (1.1 TCF), corresponding to 19 per cent of the total initial raw recoverable gas.

3. On a half-cycle basis, burdened economic potential increases to 99 x 10^9 m^3 (3.5 TCF), corresponding to 59 per cent of the total initial raw recoverable gas.

4. There is a 16 per cent difference between the burdened and unburdened estimates of weighted economic potential, indicating the impact of the fiscal system.

5. The various supply curves are generally elastic in the price range of \$35 to \$106 per 10^3 m^3 (\$1.00 to \$3.00 per MCF).

The supply curves shown in Figures 58 to 61 have an irregular shape, rising quickly at lower prices and more slowly at prices above \$60 per 10^3 m^3. This is a consequence of the resource distributions for the plays. As shown in Figure 62, only the Peace River carbonate–Dunvegan play has any economically recoverable resource at prices less than or equal to \$44.13 per 10^3 m^3. In this play, several large undiscovered pools are predicted. Their relative sizes, though, decline quickly, as is shown in Figure 57. As a result, the supply curve for the Dunvegan play rises quickly. At somewhat higher prices, resources in the Mississippian subcrop–Edson/Harmattan, Belloy/Peace River structural–Eagle, and Kiskatinaw clastics–Pouce Coupe plays provide significant contributions to supply. The supply curves for these plays are elastic between \$40 and \$106 per 10^3 m^3. The

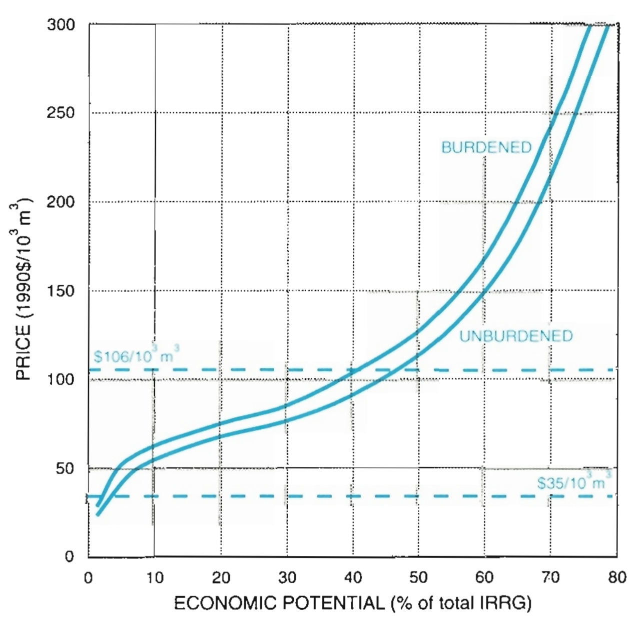

Figure 61. *Supply curves showing the difference between the weighted reference case estimates of burdened and unburdened economic potential, measured as a percentage of total initial raw recoverable gas (IRRG), for all mature Carboniferous and Permian gas plays.*

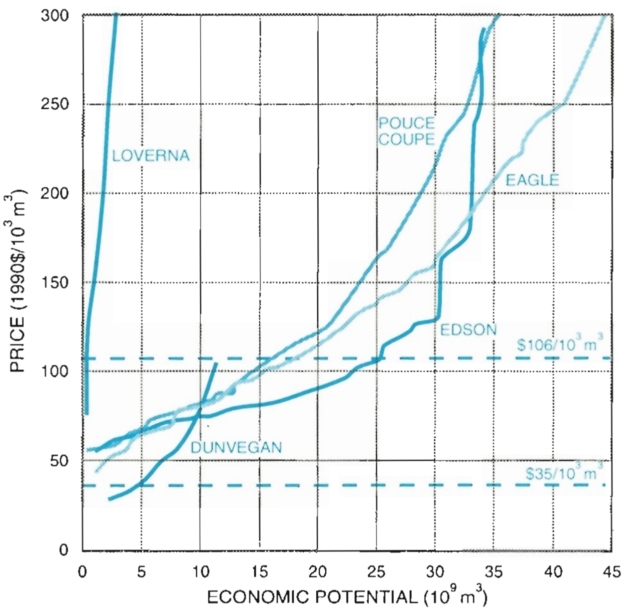

Figure 62. *Supply curves showing the reference case weighted estimates of burdened economic potential, measured as a volume of initial raw recoverable gas, for the five Carboniferous and Permian gas plays having economic resources at prices less than $106/10^3 m^3$.*

Figure 63 shows the weighted economic potential for the entire Carboniferous and Permian systems, including all established (mature and immature) and conceptual plays. The inclusion of resources in immature and conceptual plays in the estimates of economic potential increases the burdened weighted estimates from 54 x 10^9 m^3 (1.9 TCF) to 126 x 10^9 m^3 (4.5 TCF) at $88.25 per 10^3 m^3.

Initial marketable gas estimates

Economic potential is calculated in terms of initial raw recoverable gas. Figure 64 shows supply curves for the volumes of economic initial raw recoverable gas (for both established and conceptual resources) and the corresponding volumes of initial marketable gas. The latter curve estimates the volumes of natural gas that would be available for sale to end-users at various prices, after the removal of acid gases (such as CO_2 and H_2S), impurities and liquid components (water and heavier hydrocarbons), and the use of a small portion of the processed gas as fuel in gas processing plants. At a price of $88.25 per 10^3 m^3, 114 x 10^9 m^3 (4.0 TCF) would be available for sale. This estimates includes resources in immature and conceptual plays.

lower portion of the aggregate supply curves, then, reflects the contribution to supply of the Dunvegan play, while the upper portion reflects the additional contributions of the other plays.

Extension of results to immature and conceptual plays

Approximately 57 per cent of the total undiscovered natural gas-in-place estimated for the Carboniferous and Permian systems in Part I of this study, or 286 x 10^9 m^3 (10.1 TCF), are expected to be found in immature and conceptual plays. Since geological characteristics and undiscovered pool size estimates were not available for these plays, economic potential of these resources was obtained by simply extending the results for mature plays to the resources estimated for the immature and conceptual plays. This was done by applying the percentage of the total initial raw recoverable gas that is economic at a given price to the resource estimate for immature and conceptual plays. A recovery factor of 79 per cent, equal to the average recovery factor for mature plays, was assumed for this resource.

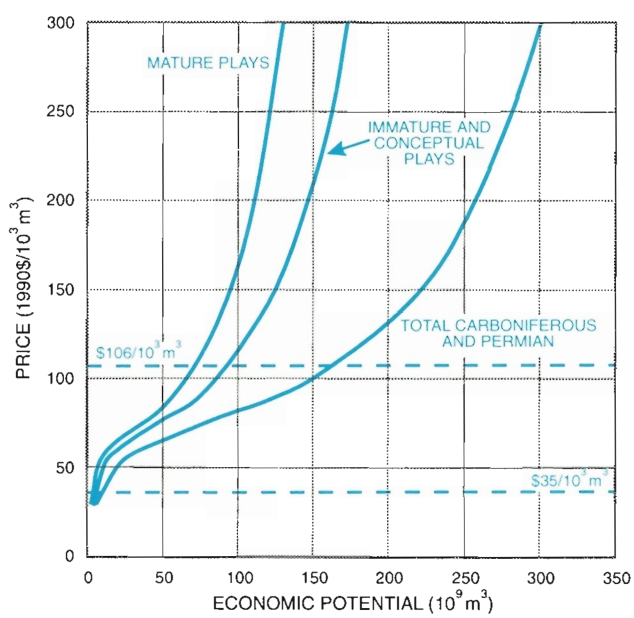

Figure 63. *Supply curves showing the reference case weighted estimates of burdened economic potential, measured as a volume of initial raw recoverable gas, for undiscovered natural gas resources in mature, immature and conceptual plays in the Carboniferous and Permian.*

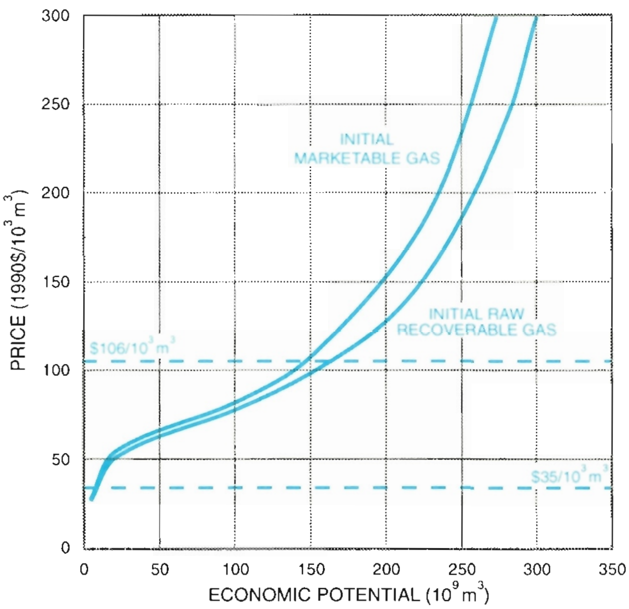

Figure 64. *Supply curves showing the volumes of initial raw recoverable gas and initial marketable gas for the reference case weighted estimates of burdened economic potential.*

SENSITIVITY ANALYSES

Significant variability and uncertainty surround estimates of costs, exploration drilling success ratios and the distance of discoveries to gathering systems. Although this analysis did not explicitly consider time, it is reasonable to expect that over time costs will be reduced, success ratios in general will increase, and gathering systems will expand as exploration and development continue in the Western Canada Sedimentary Basin. In addition, advances in drilling and seismic technology, coupled with a continuous increase of geological information related to oil and gas plays, have resulted over the years in regular upward revisions to estimates of in-place potential (Armstrong and Calantone, 1990; Reinson, et al., 1993). It is likely that current estimates of potential could again be increased in the future.

The impact of changes in these factors on economic potential was examined through sensitivity analyses. The specific sensitivities examined were: 1) total costs 20 per cent above and 30 per cent below the reference case; 2) economic success ratios double those of the reference case, with a constraint that the ratio not exceed 1:2; 3) distance of pools to gathering system reduced to an average of 2.5 km for all plays; 4) a combined 30 per cent reduction in total cost and a reduction in the average distance of pools to gathering system to 2.5 km; and 5) a 10 per cent increase in the mean size estimates for undiscovered pools. As noted earlier, where the sensitivity analysis resulted in either increases or decreases in costs, the economic success ratios were recalculated.

In general, sensitivity analyses were undertaken on the burdened weighted estimates of economic potential in the reference case, with some exceptions. The first exception was with regard to the doubling of economic success. Since the weighted estimates include the half-cycle case, which excludes exploration costs, the impact of doubling the success ratio is significantly diminished. To demonstrate the full impact of doubling economic success, the full-cycle case is also shown. The other exceptions were the impact on the half-cycle case of reducing the pipeline distance to 2.5 km, and the combined impact of a 30 per cent reduction in cost and a reduction in the pipeline distance to 2.5 km. These half-cycle sensitivities provide some measure of the impact of these changes on the reserves that may ultimately be booked with regulatory bodies.

Table 16 compares the estimates of economic potential between the weighted reference case and the corresponding sensitivity cases in terms of volume and percentage of total initial raw recoverable gas. For the purposes of discussion, results are provided at a plant gate price of \$88.25 per 10^3 m^3.

Costs

Figure 65 shows the impact of changes in total costs on the volume of economic initial raw recoverable gas for all mature Carboniferous and Permian plays.

Given the relatively high costs of developing the majority of Carboniferous and Permian plays, increases and decreases in costs significantly affect the economics of these plays. A 20 per cent rise in costs relative to the reference case leads to a 45 per cent decline in the weighted estimate of economic potential at a price of \$88.25 per 10^3 m^3. For a 30 per cent reduction in costs, the economic potential increases by 29 per cent at this price.

The greater impact of cost increases compared to cost reductions is attributed to the fact that resources in oil and gas plays are typically distributed among a relatively small number of large pools and a large number of small pools. As a result, when compared to the reference case, the resources in pools that would become uneconomic when costs increase are generally greater than the resources in pools that would become economic when costs decrease.

Table 16

Sensitivity analyses measuring impact of changes in key variables on estimates of economic potential for all mature Carboniferous–Permian plays

Type of sensitivity analysis	Economic potential (10^6 m^3)		% of total initial raw recoverable gas		% Change	
	$44.13/ 10^3 m^3	$88.25/ 10^3 m^3	$44.13/ 10^3 m^3	$88.25/ 10^3 m^3	$44.13/ 10^3 m^3	$88.25/ 10^3 m^3
Sensitivity analyses on weighted average estimates:						
Reference case – weighted average	5 300	54 224	3	32		
20% increase in total costs	3 981	29 611	2	17	-25	-45
30% decrease in total costs	10 560	69 956	6	41	+99	+29
Drilling success ratio doubled (max. 1:2)	7 754	68 400	5	40	+46	+26
Distance to pipeline set to 2.5 km	7 754	63 028	5	37	+46	+16
Pool size at 10% probability level	14 998	78 612	9	46	+183	+45
30% decrease in costs and 2.5 km pipeline distance	8 530	64 757	5	38	+61	+19
Mean pool size increased by 10%						
Sensitivity analysis on full-cycle estimates:						
Reference case – full-cycle	3 981	31 582	2	19		
Drilling success ratio doubled (max 1:2)	5 300	48 097	3	28	+33	+52
Sensitivity analysis on half-cycle estimates:						
Reference case – half-cycle	18 634	99 058	11	59		
Distance to pipeline set at 2.5 km	28 050	108 297	17	64	+51	+9
30% decrease in costs and 2.5 km pipeline distance	60 776	124 045	36	73	+226	+25

Total raw recoverable gas: 169 217 10^6 m^3

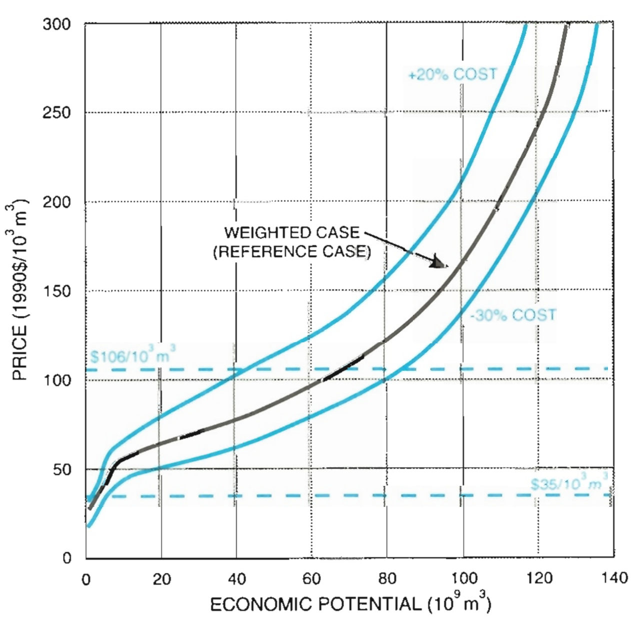

Figure 65. *Supply curves showing the impact of changes in total costs on weighted estimates of burdened economic potential, for all mature Carboniferous and Permian gas plays.*

Exploration drilling success ratio

Technological advances in seismic surveying and data interpretation, together with an increased knowledge of the resource base, should enable companies to find a larger proportion of economic pools for a given number of exploration wells. In order to capture the likely impact of future increases in exploration success, economic success ratios for all plays were doubled, but with the constraint that the revised ratio not exceed 1:2.

Figures 66 and 67 show the impact of doubling economic success ratios on economic potential in the weighted and full-cycle cases, respectively. Doubling economic success for all plays increases weighted economic potential in the burdened case by 26 per cent at a price of $88.25 per 10^3 m^3. This impact is similar to the case of a 30 per cent reduction in costs. In the full-cycle case, doubling the economic success ratio increases economic potential by 52 per cent.

Distance to gathering system

Estimates of average distances of future discoveries from a gathering system were based on the location of

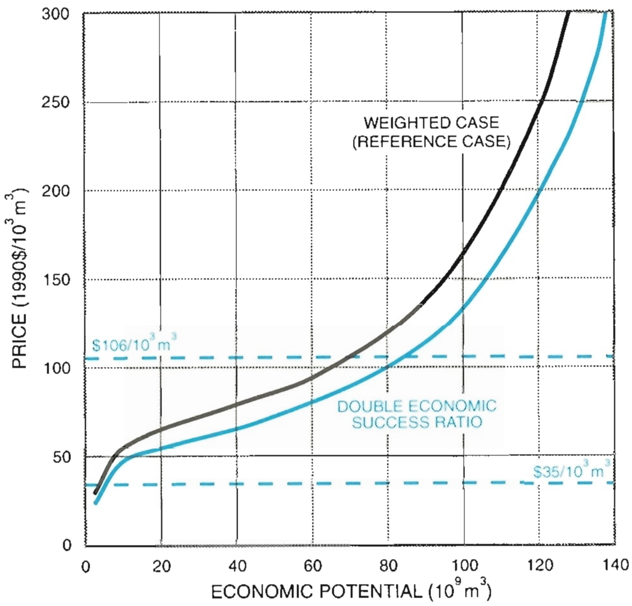

Figure 66. Supply curves showing the impact of doubling the economic success ratio on weighted estimates of burdened economic potential, for all mature Carboniferous and Permian gas plays.

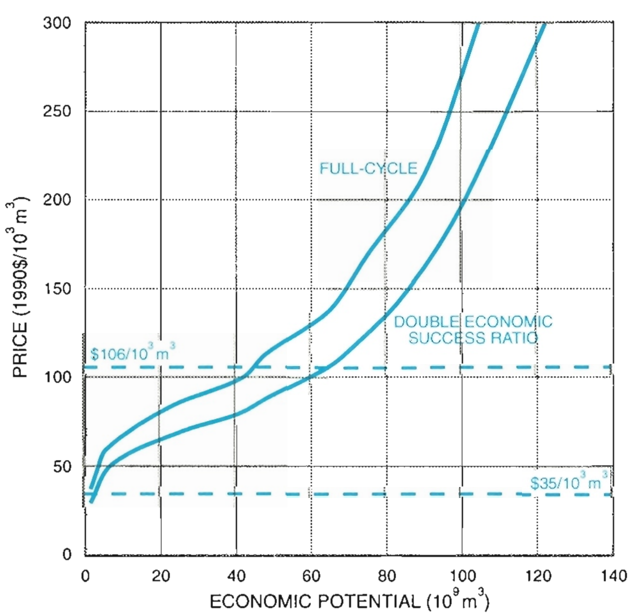

Figure 67. Supply curves showing the impact of doubling the economic success ratio on the full-cycle estimates of burdened economic potential, for all mature Carboniferous and Permian gas plays.

the current pipeline network. As the pipeline network expands over time, it is likely that more plays or pools, which were initially determined to be uneconomic to develop and produce because of their distance from a gathering system, would then become economic. The impact of expansion of gathering and transmission systems on economic potential was examined by assuming that the average distance of all pools from the pipeline network is reduced to 2.5 km.

Figure 68 shows the impact of this change on the weighted and half-cycle estimates of economic potential. When the average distance from future discoveries to the gathering network is reduced to 2.5 km, the weighted economic potential increases by 16 per cent at $88.25 per 10^3 m^3. For the half-cycle case, the corresponding percentage is 9 per cent.

Reduction in costs and distance to gathering system

In the long term, exploration economics can be expected to benefit from both reductions in cost due to technological advances and reductions in distances to gathering systems that can be expected with continued exploration and development of the Western Canada Sedimentary Basin. The combined impact of these changes was examined with a 30 per cent decrease in total cost and a reduction in distance to the pipeline network to 2.5 km.

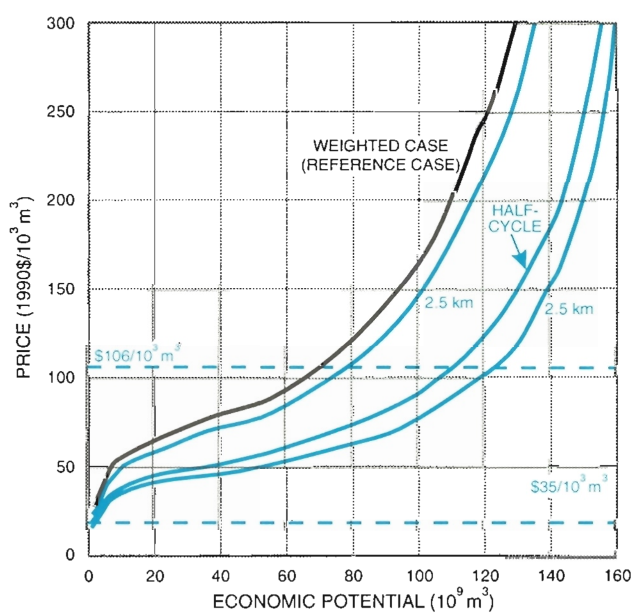

Figure 68. Supply curves showing the impact of reducing the average distance of pipelines from future discoveries to gathering system to 2.5 km.

Figure 69 shows the combined impact of these changes on the volume of economic initial raw recoverable gas for all mature Carboniferous and Permian plays. The weighted economic potential increases by 45 per cent at a price of \$88.25 per 10^3 m^3.

Also shown in Figure 69 is the impact on the half-cycle estimates of economic potential of both cost reductions and reductions in the pipeline distance. Note that in this case, economic potential in the Carboniferous and Permian systems is 73 per cent of the total initial raw recoverable gas, at \$88.25 per 10^3 m^3, as shown in Table 16. This suggests that, in the long term, reserves bookings with provincial regulatory bodies may be significantly greater than the current economic climate would indicate.

Estimated size of undiscovered pools

Experience has shown that estimates of the resource endowment tend to increase with time, as increased exploration and development lead to a greater knowledge of the petroleum geology and the resource base. The current estimates may also increase. To measure the impact of possible upward revisions in the resource estimate, economic potential was estimated using pool sizes 10 per cent larger than the mean pool sizes estimated.

Figure 70 shows the impact of this change. Increasing the mean estimates of undiscovered pool sizes by 10 per cent increases economic potential by almost 20 per cent at \$88.25 per 10^3 m^3.

To conclude, the sensitivity analyses confirm that the long-term economic potential is significantly larger than the current exploration environment indicates. Reductions in costs, expansions of the pipeline network, and improvements in geological understanding and exploration practices will likely result in significant reductions in supply prices of undiscovered pools. This will lead to an increase in the proportion of the resource that is economic.

COMPARISON OF INDIVIDUAL PLAYS

The estimates of economic potential provided above are useful for issues related to supply and long-term resource management. The relative attractiveness of individual plays as exploration targets, however, is best evaluated by examining supply curves and marginal pool size curves for each play. In this context, plays either are or are not of exploration interest. Useful comparisons between plays, therefore, are between the full-cycle and half-cycle cases. A comparison of weighted supply prices and weighted supply curves is not appropriate.

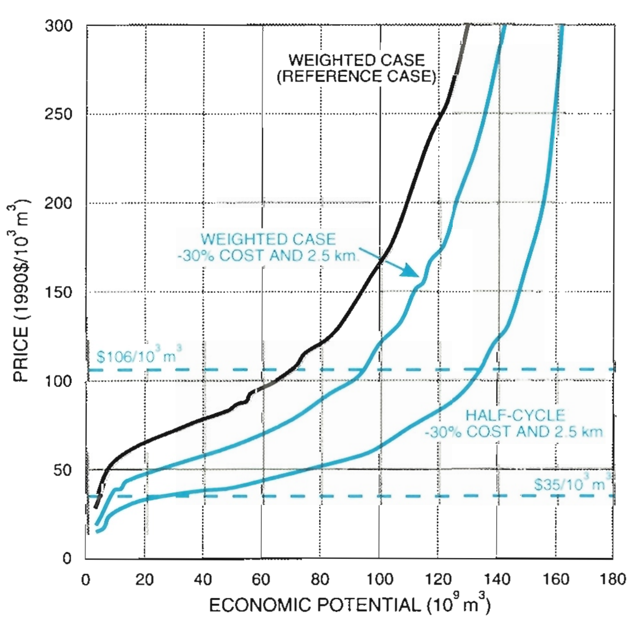

Figure 69. *Supply curves showing the impact of a combined reduction of 30 per cent in total costs of a reduction in the average distance to the gathering system to 2.5 km.*

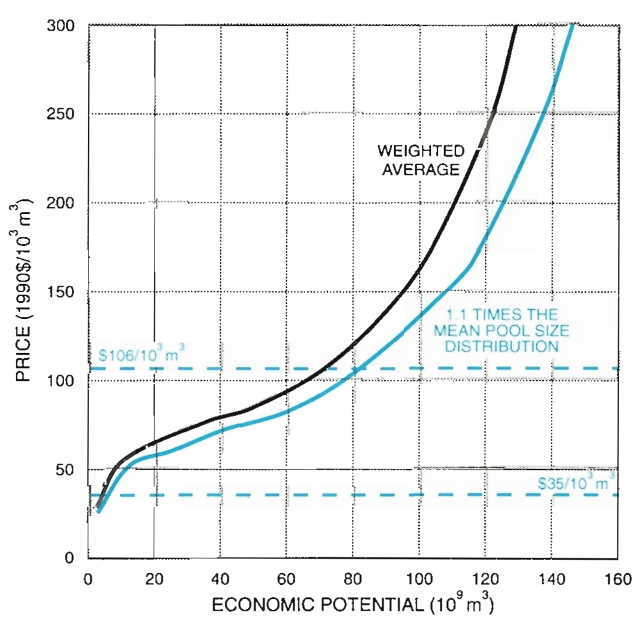

Figure 70. *Supply curves showing the impact of a 10 per cent increase of the mean pool size estimate, for the weighted estimates of burdened economic potential, for all mature Carboniferous and Permian gas plays.*

To ensure that the comparison was between Carboniferous and Permian plays only, the economic impact of resources found in other strata was excluded from this analysis. All wells without discoveries in the Carboniferous and Permian systems were regarded as dry and abandoned, even if resources were discovered in shallower strata.

Economic potential estimates by play

Figures 71 and 72 show the economic potential in the Carboniferous and Permian plays for the burdened full-cycle and half-cycle cases, respectively. Supply curves for five of the six Carboniferous and Permian plays are shown in Figure 71, because the economic potential of the remaining play was too small to be illustrated on the figure. Table 17 summarizes the results at a price of \$88.25 per 10^3 m^3.

Major observations with regard to the supply curves for these plays, at a plant gate price of \$88.25 per 10^3 m^3, are:

1. In the full-cycle case, the Peace River carbonate-Dunvegan and Mississippian subcrop-Edson/Harmattan plays are the most attractive exploration plays. In the case of the Dunvegan play, 67 per cent of the initial raw recoverable gas is economic, and in the Edson/Harmattan play, 39 per cent is economic. About three quarters of the total full-cycle economic potential for mature plays is contained in these two plays.

2. In the half-cycle case, 86 per cent of the resources in the Peace River carbonate-Dunvegan play and 90 per cent of the resources in the Mississippian subcrop-Edson/Harmattan play are economic. Half of the undiscovered recoverable gas in the Belloy/Peace River structural-Eagle and Kiskatinaw clastics-Pouce Coupe plays is also economic.

3. In the half-cycle case, economic potential in the Carboniferous and Permian is more evenly distributed over various plays, relative to the full-cycle case.

4. The ranking of plays according to economic potential at \$88.25 per 10^3 m^3 does not show a positive correlation with the ranking according to the expected volumes of total initial recoverable gas, particularly in the full-cycle case. This is attributable to the interplay of a number of factors, including differences in the resource

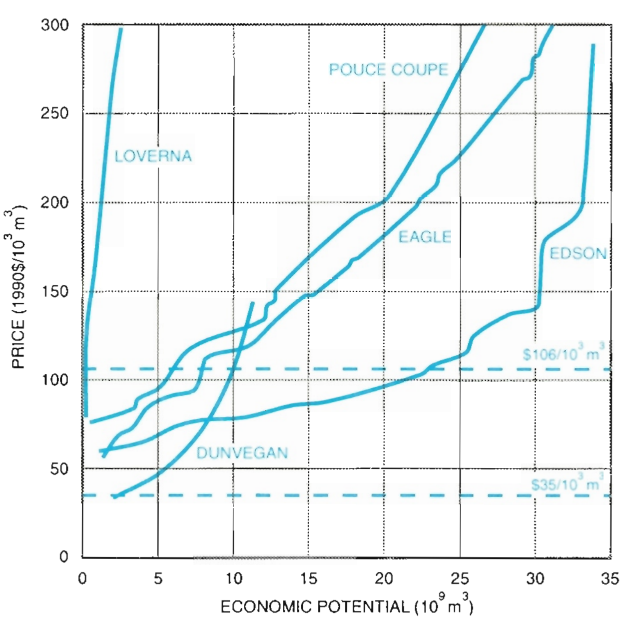

Figure 71. *Supply curves showing the reference case full-cycle estimates of burdened economic potential for the five Carboniferous and Permian plays having economic potential at prices equal or less than \$106/10^3 m^3.*

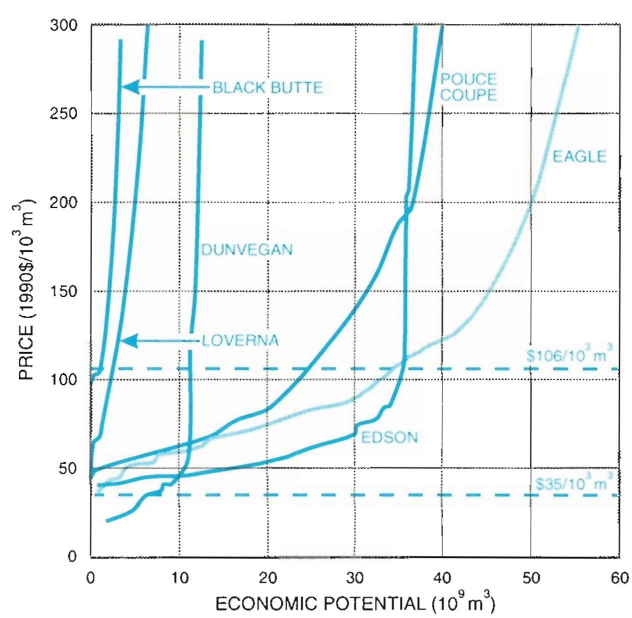

Figure 72. *Supply curves showing the half-cycle reference case estimates of burdened economic potential for mature Carboniferous and Permian gas plays.*

Table 17

Reference case estimates of economic potential for individual Carboniferous–Permian plays at $88.25 per 10^3 m^3

Play	Initial raw recoverable gas (IRRG) (10^6 m^3)	Full-cycle			Half-cycle		
		Economic potential (10^6 m^3)	% of IRRG	# pools	Economic potential (10^6 m^3)	% of IRRG	# pools
Belloy Peace River Structural–Eagle	60 352	4 381	7	4	29 802	49	85
Kiskatinaw Clastics–Pouce Coupe	43 457	3 470	8	9	21 550	50	136
Mississippian Subcrop–Edson/Harmattan	38 101	14 702	39	15	34 370	90	67
Peace River Carbonates–Dunvegan	13 146	8 769	67	7	11 321	86	13
Bakken Stratigraphic/Subcrop–Loverna	9 053	260	3	1	2 014	22	24
Rundle Sweetgrass Structural–Black Butte	5 109	0	0	0	152	3	1

distribution for undiscovered pools in the play, depth, gas composition, and economic success ratios.

5. The supply curves for the Mississippian subcrop–Edson/Harmattan play are the most elastic over a realistic range of expected natural gas prices up to \$106 per 10^3 m^3 (\$3.00 per MCF). Supply curves for the Belloy/Peace River structural–Eagle and Kiskatinaw clastics–Pouce Coupe plays are also elastic. The supply curve for the Peace River carbonate–Dunvegan has approximately unit elasticity.

Marginally economic pool sizes

A comparison of supply prices as a function of pool size offers an alternative comparison of the exploration and development economics. Figures 73 and 74 show supply prices for pools in the Carboniferous and Permian plays for the full-cycle and half-cycle cases, respectively. These curves are, essentially, marginal pool size curves (Conn et al., 1991; Conn and Christie, 1988).

Despite differences in resource distribution and geological characteristics, supply prices for pools of the same size in the Mississippian subcrop–Edson/

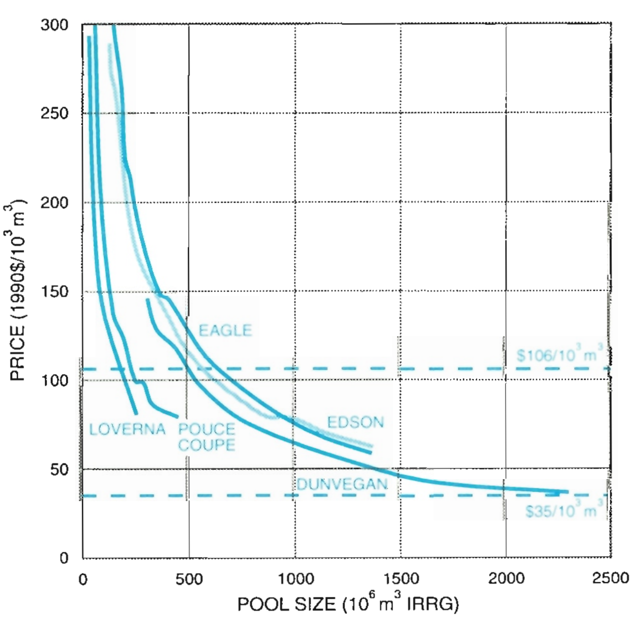

Figure 73. Full-cycle marginal pool sizes curves for mature Carboniferous and Permian plays.

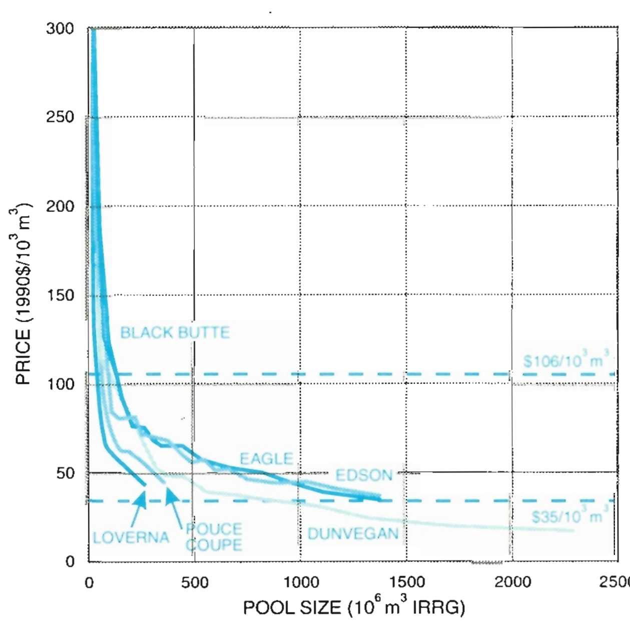

Figure 74. Half-cycle marginal pool size curves for mature Carboniferous and Permian plays.

Harmattan and the Belloy/Peace River structural-Eagle plays are similar, indicating that these plays have similar exploration economics. The Bakken stratigraphic/subcrop-Loverna play and Kiskatinaw clastics-Pouce Coupe play are also similar. The Peace River carbonate-Dunvegan play has the largest pools with relatively low supply prices.

Number of economic pools

The number of economic pools and their size distribution are important indicators of investment opportunities for exploration companies. Figures 75 and 76 show the number of economic pools with a minimum size equal to a given size at selected prices ranging from \$35 to \$300 per 10^3 m^3, for the full-cycle and half-cycle cases, respectively.

For each of the curves in these figures, the smallest pool size shown represents the marginally economic pool at the specified price. As expected, the marginal pool size varies inversely with price. The curves for various prices do not merge with one another to form a continuous curve because at various prices the marginally economic pool is found in different plays having different geological and cost characteristics. The "no price constraint" curve represents the distribution of undiscovered pool sizes, in terms of initial raw recoverable gas volumes. Major conclusions with regard to the number of economic pools are:

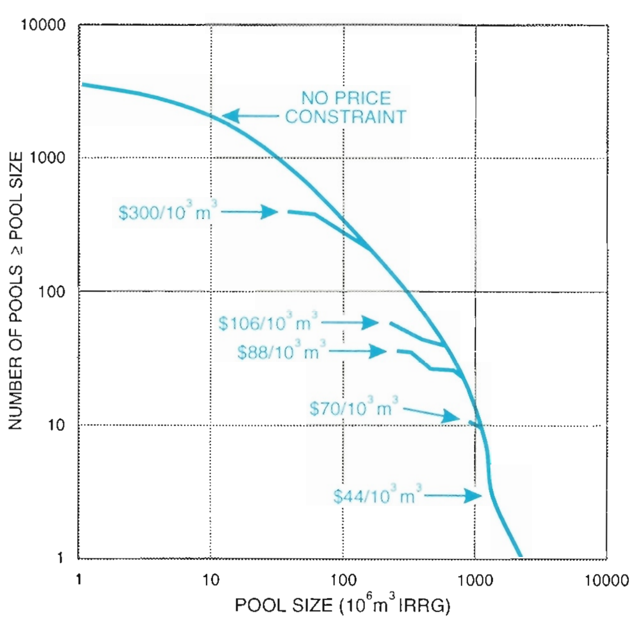

Figure 75. Family of curves showing the number of pools equal to or greater than a given pool size at selected prices ranging for \$44/10^3 m^3 to \$300/10^3 m^3 for the burdened full-cycle case.

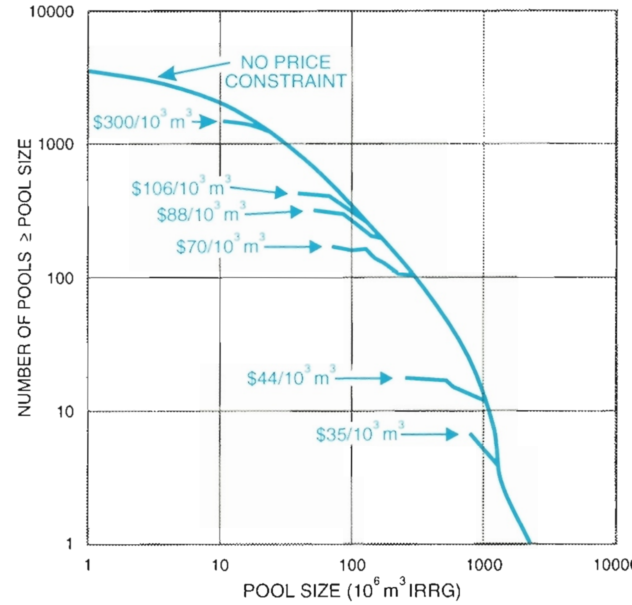

Figure 76. Family of curves showing the number of pools equal to or greater than a given pool size at selected prices ranging from \$35/10^3 m^3 to \$300/10^3 m^3 for the burdened half-cycle case.

1. In the full-cycle case, 36 pools are economic at \$88.25 per 10^3 m^3. Thirteen of these pools are greater than or equal to 1000 x 10^6 m^3 (35 BCF) initial raw recoverable gas. The smallest economic pool size in this case is 260 x 10^6 m^3 (9.2 BCF) initial raw recoverable gas.

2. In the half-cycle case, 325 pools are economic at \$88.25 per 10^3 m^3. There are 13 undiscovered pools greater than or equal to 1000 x 10^6 m^3 initial raw recoverable gas. An additional 240 pools in the size range of 100 to 1000 x 10^6 m^3 (3.5 to 35 BCF) initial raw recoverable gas are economic. The smallest economic pool size in the half-cycle case is 52 x 10^6 m^3 (1.8 BCF) initial raw recoverable gas.

CONCLUSIONS

This study provides an estimate of the economic potential of undiscovered Carboniferous and Permian natural gas resources by placing technical and economic constraints on the resource assessment in Part I of this study. It also compares the exploration potential of individual plays.

With regard to the aggregate estimates of economic potential, major conclusions at a price of \$88.25 per 10^3 m^3 (\$2.50 per MCF) are:

1. For the weighted case, burdened economic potential for mature plays is estimated as 54 x 10^9 m^3 (1.9 TCF). This volume corresponds to 32 per cent of the total initial raw recoverable gas, and 25 per cent of the undiscovered initial gas-in-place estimated in Part I of this study.

2. On a full-cycle basis, burdened economic potential for mature plays is estimated as 32 x 10^9 m^3 (1.1 TCF), corresponding to 19 per cent of the total initial raw recoverable gas.

3. On a half-cycle basis, burdened economic potential for mature plays increases to 99 x 10^9 m^3 (3.5 TCF), corresponding to 59 per cent of the total initial raw recoverable gas.

4. The inclusion of resources in immature and conceptual plays in the estimates of economic potential increases the burdened weighted estimates to 126 x 10^9 m^3 (4.5 TCF). The marketable gas associated with these resources is 114 x 10^9 m^3 (4.0 TCF).

5. There is a 16 per cent difference between the burdened and unburdened estimates of weighted economic potential, indicating the impact of the fiscal system.

6. The aggregate supply curves are generally elastic in the price range of $35 to $106 per 10^3 m^3 ($1.00 to $3.00 per MCF).

7. Sensitivity analyses show that estimates of economic potential are sensitive to the following factors: i) total costs; ii) economic success ratios; iii) average distance of future discoveries to the gas gathering system; and iv) increases in undiscovered pool size estimates.

With regard to the comparison of individual plays, major conclusions are:

1. In the full-cycle case, the Peace River carbonate-Dunvegan play and the Mississippian subcrop-Edson/Harmattan play have the most economic potential at $88.25 per 10^3 m^3.

2. The ranking of plays according to economic potential at $88.25 per 10^3 m^3 does not show a positive correlation with the ranking according to the expected volumes of total initial recoverable gas, particularly in the full-cycle case.

3. The supply curves for the Mississippian subcrop-Edson/Harmattan play are most elastic over a realistic range of expected natural gas prices up to $106 per 10^3 m^3 ($3.00 per MCF). Supply curves for the Belloy/Peace River structural-Eagle and Kiskatinaw clastics-Pouce Coupe plays are also elastic.

4. The Mississippian subcrop-Edson/Harmattan play and the Belloy/Peace River structural-Eagle play have similar exploration economics, as do the Bakken stratigraphic/subcrop-Loverna play and Kiskatinaw clastics-Pouce Coupe play. The Peace River carbonate-Dunvegan play has the largest pools with relatively low supply prices.

5. In the full-cycle case, 36 pools are economic at $88.25 per 10^3 m^3. The smallest economic pool size in this case is 260 x 10^6 m^3 (9.2 BCF). In the half-cycle case, 325 pools are economic at $88.25 per 10^3 m^3. The smallest economic pool size in the half-cycle case is 52 x 10^6 m^3 (1.8 BCF).

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