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GEOLOGICAL SURVEY OF CANADA  
BULLETIN 474

# PETROLEUM RESOURCES OF THE MACKENZIE DELTA AND BEAUFORT SEA

J. Dixon, G.R. Morrell and J.R. Dietrich  
G.C. Taylor and R.M. Procter  
R.F. Conn, S.M. Dallaire and J.A. Christie



1994



Natural Resources Canada  
Ressources naturelles Canada

Canada

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**PETROLEUM RESOURCES OF THE  
MACKENZIE DELTA AND BEAUFORT SEA**

**PART I: BASIN ANALYSIS**

J. Dixon, G.R. Morrell and J.R. Dietrich

**PART II: RESOURCE ASSESSMENT**

G.C. Taylor and R.M. Procter

**PART III: ECONOMIC POTENTIAL  
OF UNDISCOVERED GAS RESOURCES**

R.F. Conn, S.M. Dallaire and J.A. Christie

**1994**

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Available in Canada through authorized  
bookstore agents and other bookstores

or by mail from

Canada Communication Group-Publishing  
Ottawa, Ontario Canada K1A 0S9

and from

Geological Survey of Canada offices:

601 Booth Street  
Ottawa, Ontario K1A 0E8

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

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

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

Cat. Number M42-474  
ISBN 0-660-59108-1

Price subject to change without notice

**Reprinted January 2003**

**Critical readers**

*A.F. Embry*  
*D. Gardner*

**Authors' addresses**

***J. Dixon, J.R. Dietrich,  
G.C. Taylor, and R.M. Procter***  
Geological Survey of Canada  
Institute of Sedimentary and  
Petroleum Geology  
3303 - 33rd Street N.W.  
Calgary, Alberta  
T2L 2A7

***G.R. Morrell***  
National Energy Board  
311 - 6th Ave. S.W.  
Calgary, Alberta  
T2P 3H2

***R.F. Conn, S.M. Dallaire, and  
J.A. Christie***  
Energy, Mines and Resources  
Energy Sector  
580 Booth Street  
Ottawa, Ontario  
K1A 0E4

*Manuscript submitted: 90.05.31*  
*Approved for publication: 94.03.07*

## **PREFACE**

The Beaufort-Mackenzie region of Canada has proven reserves of oil and gas, and although at the present time their economic viability is debatable, this area may be a future petroleum producing province as the resources of western Canada decline. In the first part of this report a number of known and conjectured play types are defined. The second part assesses resource potential and the third comprises an economic analysis of the undiscovered gas potential. The authors conclude that when exploration is renewed, the onshore Mackenzie Delta and shallow-water offshore resources will likely be the focus of immediate attention.

Elkanah A. Babcock  
Assistant Deputy Minister  
Geological Survey of Canada

## CONTENTS

1	SUMMARY
1	Oil and Gas Resources
1	Onshore/Shallow Offshore Play Group
1	Offshore Delta Play Group
1	West Beaufort Play Group
2	Deep Water and Other Play Group
2	Total Regional Endowment
3	Resources of Current Interest
3	Onshore/Shallow Offshore Play Group
3	Offshore Delta Play Group
3	West Beaufort Play Group
4	Economic Analysis
4	INTRODUCTION
4	Foreword
5	Basin Study Group
5	Reserves Committees
5	Petroleum Resource Evaluation Committee
5	Scope of Evaluation

## PART I: BASIN ANALYSIS

6	GEOLOGICAL SETTING OF THE MACKENZIE DELTA-BEAUFORT SEA REGION
6	Stratigraphy
6	Inuvikian strata
7	Franklinian strata
7	Ellesmerian strata
12	Brookian strata
13	Structural setting
14	PETROLEUM GEOLOGY
14	Exploration history
14	Hydrocarbon discoveries
16	Exploration play groups
16	Onshore/Shallow Offshore Play Group
16	Parsons Play
17	Atkinson Point Play
18	Tuk Play
20	Taglu Play
21	Ivik Play
22	South Delta-Mesozoic Play
23	South Delta-Paleozoic Play
24	Mayogiak Play
25	Offshore Delta Play Group
25	Netserk Play
26	Amauligak Play
27	Tarsiut Play
29	Akpak Play
29	West Beaufort Play Group
29	Adlartok Play
31	Herschel Play
31	Demarcation Play
32	Deep Water and Other Play Group
32	Kopanoar Play
33	Deep-Marine West Play

34	Hinge Play
35	Imperial Clastics Play
36	Yukon Coastal Plain Play

## PART II: RESOURCE ASSESSMENT

37	OIL AND GAS RESOURCES
37	Drilling history
38	Oil and gas discoveries
39	Resource endowment
39	Onshore/Shallow Offshore Play Group
40	Offshore Delta Play Group
41	West Beaufort Play Group
41	Deep Water and Other Play Group
42	Total regional endowment
42	Resources of current interest
43	Onshore/Shallow Offshore Play Group
43	Offshore Delta Play Group
44	West Beaufort Play Group

## PART III: ECONOMIC POTENTIAL OF MACKENZIE DELTA- BEAUFORT SEA REGION

45	UNDISCOVERED NATURAL GAS RESOURCES
45	DEVELOPMENT REQUIREMENTS, PRODUCTION AND COSTS
46	ECONOMIC ANALYSIS
46	Objective
46	Methodology
46	Infrastructure
47	Marginal economic criteria
47	Fiscal system
47	Full cycle costs
47	Rate of return
47	Processing fees
47	Exploratory risk
47	BASE CASE
47	ANALYTICAL EXAMPLE — TAGLU PLAY
47	Marginal Pool vs. Price
48	Economic gas potential
49	ECONOMIC GAS POTENTIAL OF THE MACKENZIE DELTA-BEAUFORT SEA REGION
51	CONCLUSIONS
51	REFERENCES

### Figures

2	1. Map of significant discoveries
6	2. The area evaluated
8	3. Index map to wells drilled in the Mackenzie Delta-Beaufort Sea Region
11	4. Stratigraphic column, Mackenzie Delta-Beaufort Sea Region
14	5. The major structural elements in the region
16	6. The areal extent of the play groups
16	7. Schematic sketch of the trap types — Parsons Play
17	8. Sketch map locating the Parsons Play area
17	9. Schematic sketch of the trap types — Atkinson Play
18	10. Sketch map locating the Atkinson Play area

- 19 11. Schematic sketch of the trap types — Tuk Play
- 19 12. Sketch map locating the Tuk Play area
- 20 13. Schematic sketch of the trap types — Taglu Play
- 20 14. Sketch map locating the Taglu Play area
- 21 15. Schematic sketch of the trap types — Ivik Play
- 21 16. Sketch map locating the Ivik Play area
- 22 17. Schematic sketch of the trap types — South Delta-Mesozoic Play
- 22 18. Sketch map locating the South Delta-Mesozoic Play area
- 24 19. Schematic sketch of the trap types — South Delta-Paleozoic Play
- 24 20. Sketch map locating the South Delta-Paleozoic Play area
- 24 21. Schematic sketch of the trap types — Mayogiak Play
- 25 22. Sketch map locating the Mayogiak Play area
- 25 23. Schematic sketch of the trap types — Netserk Play
- 26 24. Sketch map locating the Netserk Play area
- 26 25. Schematic sketch of the trap types — Amauligak Play
- 27 26. Sketch map locating the Amauligak Play area
- 28 27. Schematic sketch of the trap types — Tarsiut Play
- 28 28. Sketch map locating the Tarsiut Play area
- 29 29. Schematic sketch of the trap types — Akpak Play
- 29 30. Sketch map locating the Akpak Play area
- 30 31. Schematic sketch of the trap types — Adlartok Play
- 30 32. Sketch map locating the Adlartok Play area
- 31 33. Schematic sketch of the trap types — Herschel Play
- 31 34. Sketch map locating the Herschel Play area
- 32 35. Schematic sketch of the trap types — Demarcation Play
- 32 36. Sketch map locating the Demarcation Play area
- 32 37. Schematic sketch of the trap types — Kopanoar Play
- 33 38. Sketch map locating the Kopanoar Play area
- 33 39. Schematic sketch of the trap types — Deep-Marine West Play
- 34 40. Sketch map locating the Deep-Marine West Play area
- 34 41. Schematic sketch of the trap types — Hinge Play
- 34 42. Sketch map locating the Hinge Play area
- 35 43. Schematic sketch of the trap types — Imperial Clastics Play
- 35 44. Sketch map locating the Imperial Clastics Play area
- 36 45. Schematic sketch of the trap types — Yukon Coastal Plain Play
- 36 46. Sketch map locating the Yukon Coastal Plain Play area
- 38 47. Discovered resources ranked by pool size.
- 39 48. Distribution of estimates of discovered gas resources
- 39 49. Distribution of estimates of discovered oil resources
- 40 50. Distribution of estimates of the gas endowment — Onshore/Shallow Offshore Play Group
- 40 51. Distribution of estimates of the oil endowment — Onshore/Shallow Offshore Play Group
- 40 52. Distribution of estimates of the gas endowment — Offshore Delta Play Group
- 40 53. Distribution of estimates of the oil endowment — Offshore Delta Play Group
- 41 54. Distribution of estimates of the gas endowment — West Beaufort Play Group
- 41 55. Distribution of estimates of the oil endowment — West Beaufort Play Group
- 41 56. Distribution of estimates of the gas endowment — Deep Water and Other Play Group
- 42 57. Distribution of estimates of the oil endowment — Deep Water and Other Play Group
- 42 58. Distribution of estimates of the gas endowment — Mackenzie Delta-Beaufort Sea Region
- 42 59. Distribution of estimates of the oil endowment — Mackenzie Delta-Beaufort Sea Region
- 43 60. Distribution of the gas endowment showing the impact of predicted pool sizes —  
Onshore/Shallow Offshore Play Group
- 44 61. Distribution of the oil endowment showing the impact of predicted pool sizes —  
Onshore/Shallow Offshore Play Group
- 44 62. Distribution of the gas endowment showing the impact of predicted pool sizes —  
Offshore Delta Play Group

- 44 63. Distribution of the oil endowment showing the impact of predicted pool sizes —  
Offshore Delta Play Group
- 44 64. Distribution of the oil endowment showing the impact of predicted pool sizes — West  
Beaufort Play Group
- 45 65. Sketch map of Mackenzie Delta–Beaufort Sea Region illustrating major discoveries, Play  
Group boundaries, proposed pipelines and gas plants
- 48 66. Marginally economic pool size — Taglu Play (burdened case)
- 48 67. Marginally economic pool size — Taglu Play (unburdened case)
- 48 68. Economic gas potential — Taglu Play (burdened case)
- 48 69. Economic gas potential — Taglu Play (unburdened case)
- 49 70. Economic gas potential — Mackenzie Delta–Beaufort Sea Region (burdened case)
- 49 71. Economic gas potential — Mackenzie Delta–Beaufort Sea Region (unburdened case)
- 49 72. Economic gas potential — Onshore/Shallow Offshore Play Group (burdened case)
- 50 73. Economic gas potential — Onshore/Shallow Offshore Play Group (unburdened case)
- 50 74. Economic gas potential — Offshore Delta Play Group (burdened case)
- 50 75. Economic gas potential — Offshore Delta Play Group (unburdened case)

**Tables**

- 43 1. Mean amounts of reserves (discovered resources) and potential for play groups
- 45 2. Economic Undiscovered Gas Resources
- 48 3. Marginal Pool Size—Taglu Play (burdened case)
- 48 4. Marginal Pool Size—Taglu Play (unburdened case)
- 49 5. Economic Gas Potential—Taglu Play (burdened case)
- 49 6. Economic Gas Potential—Taglu Play (unburdened case)
- 50 7. Economic Gas Potential—Mackenzie Delta–Beaufort Sea Region (burdened case)
- 50 8. Economic Gas Potential—Mackenzie Delta–Beaufort Sea Region (unburdened case)
- 50 9. Economic Gas Potential—Onshore/Shallow Offshore Play Group (burdened case)
- 50 10. Economic Gas Potential—Onshore/Shallow Offshore Play Group (unburdened case)
- 50 11. Economic Gas Potential—Offshore Delta Play Group (burdened case)
- 50 12. Economic Gas Potential—Offshore Delta Play Group (unburdened case)



## SUMMARY

Exploration in the Mackenzie Delta–Beaufort Sea Region has resulted in 48 significant oil and gas discoveries (Fig. 1). The total quantities of gas and oil discovered to date, plus the estimated remaining potential, make this region one of the most attractive petroleum provinces in North America today. The estimates presented in the following report are based on a thorough basin analysis by GSC and Canadian Oil and Gas Lands Administration (COGLA)<sup>1</sup> scientists, examining available geological, geophysical, geochemical and petroleum geology information.

From this analysis, 20 exploration plays were identified and quantified using advanced probability methods developed by the Geological Survey of Canada. The 20 exploration plays occur in four groups, distinguished by geographic, geological and developmental criteria. The **Onshore/Shallow Offshore Play Group** comprises eight plays that exist in the Richards Island, South Delta and Tuk Peninsula areas, plus their extensions into adjacent shallow water. The plays include Paleozoic, Mesozoic and Tertiary targets. The four plays of the **Offshore Delta Play Group** form a narrow fairway between the Tarsiut and Amauligak fields in which several major oil and gas discoveries have been made. This group occurs in about 25 m of water, and exists in rocks of similar Tertiary age and with similar structural style. The three plays of the **West Beaufort Play Group** differ significantly from the main delta plays in the structural style and grain of the area, the age of reservoirs, and a different oil generation regime. The **Deep Water and Other Play Group** consists of five plays, dominated by two Tertiary plays that occur in deep water beyond the Offshore Delta and West Beaufort groups. The two Tertiary plays rely on deep water sedimentation for reservoir opportunities. The other three plays are combined with this group because they are conceptual and will probably not attract serious exploration for some time.

### OIL AND GAS RESOURCES

Highlights from the analysis of discovery and potential include:

---

<sup>1</sup>Now part of the National Energy Board (NEB)

<sup>2</sup>6.2898 barrels = 1 m<sup>3</sup>

<sup>3</sup>35.5 cu. ft. = 1 m<sup>3</sup>

### *Onshore/Shallow Offshore Play Group*

About 24 per cent of the oil resources estimated for this group has already been discovered. The 251 million barrels<sup>2</sup> discovered exists in 14 fields, the largest being Adgo, Kumak, Ivik North and Atkinson. About 1 billion barrels remains undiscovered, dispersed in about 150 pools. For gas, more than one third of the total 20 TCF<sup>3</sup> has been discovered in 14 fields. These include the near-giant Taglu field, plus Parsons and Niglintgak, each of which contains more than 500 BCF of gas. More than 12.6 TCF of gas remains undiscovered, distributed in more than 170 pools. This play group has abundant geological diversity, is structurally complex, and is a challenge for modern seismic methods. Resources are expected to be dispersed in a large number of traps, compared to other play groups, but still constitute very attractive on-land exploration prospects relative to remaining conventional Western Canada Sedimentary Basin targets, provided a production infrastructure is developed in the area.

### *Offshore Delta Play Group*

The giant Amauligak oil discovery dominates this play group. More than 42 per cent of the 2.2 billion barrels of oil estimated to exist in this play group has been discovered in seven fields. Most of the oil discoveries have associated gas which, along with about 120 predicted but undiscovered pools, amounts to substantial gas resources of 12.7 TCF. The success rate in this group of plays is about 50 per cent, making this trend an outstanding area of opportunity by any standard. Remaining targets in this play are expected to include thick and highly productive pay zones in relatively simple faulted structures.

### *West Beaufort Play Group*

This is the least explored of the play groups but is estimated to contain about the same total oil resource as the Offshore Delta group. The discovery of a major oil field at Adlartok has identified a whole new family of potential opportunities, including at least one large accumulation. This series of plays will be the “new frontier” within the region, containing numerous structures in deeper water (50–100 m) than those of the main Offshore Delta group. All three plays extend into

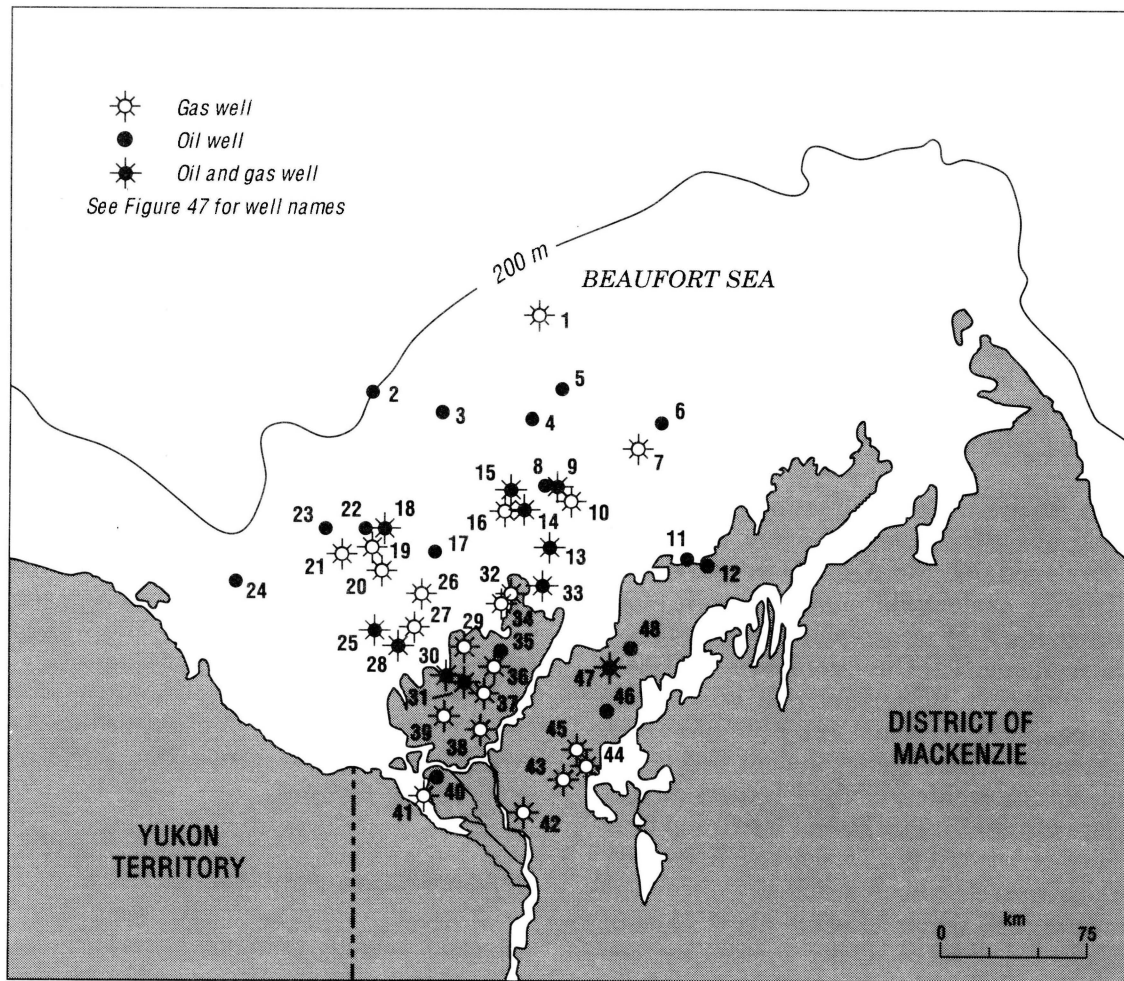


Figure 1. Map of significant discoveries.

Alaska, where one has been tested just west of 141° W longitude. The results of that test have been held confidential.

### Deep Water and Other Play Group

Only one of the five plays in this group has been tested, resulting in several oil and gas discoveries. The Kopanoar oil and Kenalook gas stand out as large discoveries but are probably beyond economic development for the foreseeable future. The problem is one of thin discontinuous pay zones in broad structures located in water depths greater than 50 m. The two deep water plays are expected to contain large resources estimated at mean expectations of 1.5 billion barrels of oil and almost 20 TCF of gas.

Given the uncertainties associated with the plays in this group, and the lack of comprehensive testing of structures, it is probably appropriate to look at

speculative levels of potential for this group such as 2 billion barrels of oil and more than 30 TCF of gas.

### TOTAL REGIONAL ENDOWMENT

The total endowment for oil is estimated to be between 6.2 and 7.8 billion barrels (75 to 25 per cent probability range) in the region. The mean expectation is 7.1 billion barrels. From 1.5 to 2.0 billion barrels, or about 25 per cent, of this endowment is discovered resources. A substantial undiscovered potential of between 4.7 and 5.8 billion barrels is possible. For gas, it is estimated that between 57.5 and 73.1 TCF of gas may exist in the region (75 to 25 per cent probability range). The mean expectation is 67 TCF. Approximately 18 per cent of this endowment is in the already discovered category, leaving a very large undiscovered potential of 47.1 to 60.5 TCF. Much larger values of undiscovered gas are shown at low probability levels.

The values quoted are those of the regional resource endowment based on our current geoscience knowledge. Although useful as a comparative measure of the total quantities that are estimated to exist in a basin, the values are not discounted for future economic viability, likelihood of discovery, or difficulty of exploitation. They assume only current levels of technology in terms of recovery of resources. This lack of “discounting” may render the regional endowment values misleading for planners and economists who have to be concerned about the size of individual fields and the likelihood of their discovery and development within a limited time. The manner in which the endowment estimates have been prepared facilitates this requirement while still retaining the scientific and statistical integrity of the process. To cast the results of the estimation process into a more useable product, the endowment’s dispersal in terms of size, and the elements of the endowment most likely to be of current interest, are shown.

## **RESOURCES OF CURRENT INTEREST**

Although it would be inappropriate to pre-judge the future economics of this region, one can recognize that some elements of the total resource will be the focus of exploration for the next 20 years, assuming some current level of exploratory activity. Accordingly, plays of the Onshore/Shallow Offshore, Offshore Delta and the oil plays of the West Beaufort play groups were identified as those most likely to receive attention in the near future. For each of these elements, the distributions of estimates have been examined in terms of the quantity of the resources existing within arbitrarily selected size ranges.

### ***Onshore/Shallow Offshore Play Group***

For this play group, one pool larger than 100 million barrels and 14 pools larger than 25 million barrels have been identified as potentially present. Together these 15 pools contain about one half of the total endowment. If those two size ranges were the only ones of current interest, it would reduce the mean endowment from 1.3 billion barrels to just 738 million barrels. The analysis indicates only three pools larger than 1 TCF, two of which (Taglu and Parsons) are already discovered. The second size range consists of 32 pools that contain between 8 and 10.7 TCF in total, suggesting that there are many potentially attractive targets for exploration in the onshore area. The remaining large number of small pools do not add significant resources. If one were to consider only the pools in the two larger size ranges to be of short term

interest then the mean gas endowment for the Onshore/Shallow Offshore Play Group would reduce from 22 to 15.7 TCF.

### ***Offshore Delta Play Group***

In the Offshore Delta Play Group, five major pools are anticipated in the larger than 100 million barrel range, one of which (Amauligak) has already been discovered. This size range constitutes almost one half of the endowment. A combination of the larger two size classes would include 18 pools containing between 1.5 and 2.0 billion barrels. Thus the overall mean endowment would reduce from 2.1 to 1.8 billion barrels in the current interest category. For gas, two pools larger than 1 TCF are indicated, including the one associated with the Amauligak oil discovery. The 28 pools of the second size range contain almost twice as much gas as the first. If only these two size groups were of current interest, then the mean endowment would reduce from 14.7 to 12.0 TCF.

### ***West Beaufort Play Group***

Only the oil resources of this play group were considered for size analysis. Four pools larger than 100 million barrels are estimated to exist, including the Adlartok discovery. Combined with the 12 pools in the 25 to 100 million barrel size range, the 16 pools contain between 1.2 and 2.2 billion barrels. This would reduce the mean regional oil endowment from 2.2 to 1.8 billion barrels in the current interest category.

In summary, the total resource endowment of the Mackenzie Delta-Beaufort Sea Region, when viewed in terms of current interest, reduces from 7.1 billion barrels of oil and 65 TCF of gas (mean values) to 5.6 billion barrels and 33 TCF, respectively. Of this restricted endowment, if one chose to consider only the amounts contained in oil pools larger than 25 million barrels and in gas pools larger than 100 BCF, then the resources would reduce to 4.4 billion barrels of oil distributed in about 50 pools and 28 TCF of gas distributed in about 65 pools. Of this, 3.0 billion barrels of oil and 17.2 TCF of gas remain to be discovered. The pool size limits used in this scenario are probably slightly larger than those that might support development if oil and gas production and transportation facilities existed in the region, therefore there is encouragement that abundant opportunity exists for future exploration and investment in the region. One should expect fairly intensive exploration for both oil and gas in the onshore areas as well as a continued search for major oil in the offshore

Amauligak to Tarsiut trend. The West Beaufort oil opportunities are also bound to be the focus of exploration. Initially, one would expect this future exploration to be tightly focused on existing plays while continuing the task of trying to understand the more complex conceptual plays. The Mackenzie Delta-Beaufort Sea Region is already recognized internationally as the petroleum province where exploration has been very successful, but the economic viability of the discoveries has yet to be established.

## **ECONOMIC ANALYSIS**

The economic analysis estimates the portion of the undiscovered natural gas resources of the Mackenzie Delta-Beaufort Sea Region that is economically viable for exploration and development over the long term. As well, new discoveries may extend the life of a lead development project. The analysis covers the undiscovered gas resources of two of the four exploration play groups, the Onshore/Shallow Offshore and Offshore Delta. Both can be developed with conventional technology and they contain the bulk of known reserves. The other two play groups, the West Beaufort and Deep Water and Other, are excluded from analysis because they are more sparsely explored and may require new production technologies to bring on stream.

A detailed analysis is presented for the Taglu play (Onshore/Shallow Offshore group) to illustrate the analytical approach and input. The analysis assumes that a lead gas development is in operation in the

Mackenzie Delta and delivering 1.2 BCF per day to southern markets. Additional reserves to maintain the pipeline at rated capacity would likely have to be connected 15 to 20 years after pipeline startup. New reserves established from presently undiscovered gas resources would not have access to the main pipeline until that time.

The economically viable portions of undiscovered gas resources assessed in the Mackenzie Delta-Beaufort Sea Region are estimated with and without a full burden of taxes and royalties. Assumptions made in the economic analysis in the base case are: full-cycle costing (includes exploratory drilling, geological and geophysical costs and overhead); a 1:7 exploration success; an expected 15 per cent real discounted cash flow (DCF) rate-of-return; a 25 km distance from discoveries to processing facilities; and an Alberta border price for natural gas of \$4.00 per MCF. This last assumption provides for a plant-gate price of \$3.00 per MCF and a pipeline toll of \$1.00 per MCF. In the base case, additional commercially viable discoveries totalling 8.1 TCF ( $228 \times 10^9 \text{ m}^3$ ) of new natural gas resources are estimated to exist as a mean expectation. Analysis shows that the fiscal burden does not significantly reduce this total and, by implication, there is little scope to encourage activity through tax or royalty reductions. The 8.1 TCF represents about 40 per cent of the undiscovered gas resources of 22 TCF in the two play groups analyzed and about 15 per cent of the 53 TCF for the four play groups. Access to significantly greater quantities of the region's endowment will require lower development costs and/or higher natural gas prices.

## **INTRODUCTION**

### **FORWARD**

Estimates of the oil and gas resources of various regions of Canada are prepared periodically by the Petroleum Resource Appraisal Secretariat of the Geological Survey of Canada, with the assistance of geologists and geophysicists from COGLA. The estimates are prepared using a probability methodology in which each of the individual exploration plays of a region are examined for opportunities for the existence of gas and oil resources. The method incorporates objective data derived from exploration drilling,

geophysics, and various forms of mapping, with the subjective opinion of informed experts. This systematic approach to the evaluation of Canada's resources has been conducted since 1973 and the last series of estimates for the Mackenzie Delta-Beaufort Sea Region were prepared in 1983.

The present report on resources of the Mackenzie Delta-Beaufort Sea Region marks a new variation in the evaluation process. In the early years of the activity, the primary focus was on the preparation of a gross estimate of the total resources of the region. A

small number of people (six to nine) were able to effectively extract an appropriate amount of information and opinion from a variety of sources for the evaluation. Over the years the evaluation process has matured, the methodology has evolved, and the focus has expanded from the simple estimation of resource abundance to one of producing the input data for economic analysis and supply projection. The number of plays also increased as the data base grew, and the need was recognized for an improved method of developing the geological foundation upon which the estimates are based.

Because the quality and validity of the estimates are ultimately dependent on a correct perception of the geological opportunities for oil and gas accumulation that exist in any given area or basin, the decision was made to restructure components of the Geological Survey of Canada into basin study groups. The basin study group integrates all of the various types of information for a basin — geological, geophysical, geochemical, sedimentological and other information — and analyzes and synthesizes the historic development of the basin. When dealing with frontier basins, the study group is commonly augmented with scientists from COGLA who have additional expertise in petroleum geology. By this process, the sedimentological, structural, and stratigraphic models, which are the basis of exploration plays, become apparent. With the assistance of the Petroleum Resource Appraisal Secretariat, play definitions are developed and members of the basin study group compile data on a variety of reservoir characteristics appropriate for each play.

For each major resource evaluation a Petroleum Resource Evaluation Committee is nominated by the Secretariat. This committee is responsible for approving the original play definitions and for reaching consensus on the various input data before final estimates are prepared. In practice, the basin studies team provides a review of all relevant geology, exploration history, geochemistry etc. to the evaluation committee. In this exercise the lead role passes to the petroleum geologists in charge of play definition or play quantification who recommend preliminary values for each variable to the committee. They become the focus of questions aimed at testing the degree to which the estimates reflect the fundamental geology presented, as well as determining the appropriate level of confidence attached to the values of each variable. Eventually consensus is reached by the committee, which takes responsibility for the final estimates such as those contained in the present report.

## **BASIN STUDY GROUP**

The basin study group for the Mackenzie Delta-Beaufort Sea Region project consisted of J. Dixon, J.R. Dietrich, D.H. McNeil, and L.R. Snowdon of ISPG, and G. Morrell, M. Fortier, and U. Schmidt of COGLA. In addition a number of other scientists at ISPG and COGLA contributed information, directly and indirectly, based on years of experience in a variety of disciplines relevant to our understanding of the geology of the region. The technical support of N. Spooner, D. Duggan, and A. Larabie to the COGLA effort is acknowledged in particular.

## **RESERVES COMMITTEES**

An often unrecognized contribution to the total effort of any particular assessment is the contribution made by the Reserves Committee chaired by A. Hiles. An understanding of the nature of the discovered resources is the base from which assessments are produced. The work of K. Goble, C. Gemeroy (NEB), D. Smith, W. Ward, and L. Richards (COGLA) on the geology, and of S.B. Young, T. Baker, and S. MacMullin (COGLA) on the engineering aspects is gratefully acknowledged.

## **PETROLEUM RESOURCE EVALUATION COMMITTEE**

The committee struck for this evaluation of the Beaufort Sea-Mackenzie Delta Region consisted of G.C. Taylor (chairman), G.R. Campbell (COGLA), J.P. Hea (EMR), P.J. Lee, J.A. Podruski, and R.M. Procter (GSC). Able assistance to the committee was rendered by P.R. Price (GSC) who operated most of the computer assessment programs.

## **SCOPE OF EVALUATION**

In this report the focus is on a re-evaluation of the oil and gas resources of the Mackenzie Delta-Beaufort Sea Region (Fig. 2). In 1983, all plays in the region were reviewed and estimates were updated. Since that time, significant additional data resulting from exploratory drilling, seismic exploration, and geochemistry have been added to the database. In addition, the development of a new concept of the depositional model and the application of sequence stratigraphic analysis has permitted a better definition of the petroleum opportunities. Because of new Tertiary

discoveries, and particularly the need to provide better definition of pool sizes and reservoir characteristics for cost and supply analysis, the Mackenzie Delta-Beaufort Sea Region study group was requested to undertake the detailed studies that are summarized in this report.

In the report that follows, the regional geology of the Mackenzie Delta-Beaufort Sea Region is described with emphasis on the sedimentation of the Tertiary sequences as it relates to petroleum geology. This description, along with the following discussion of the definition of the plays used in the current assessment, represents the basin analysis contribution (Part I) to the report. Part II deals with the total resource estimates for the Mackenzie Delta-Beaufort Sea Region, incorporating the newly updated plays, and is the work of the assessment committee. Implications of the new estimates in terms of discovery rate and future supply (Part III) conclude the report.

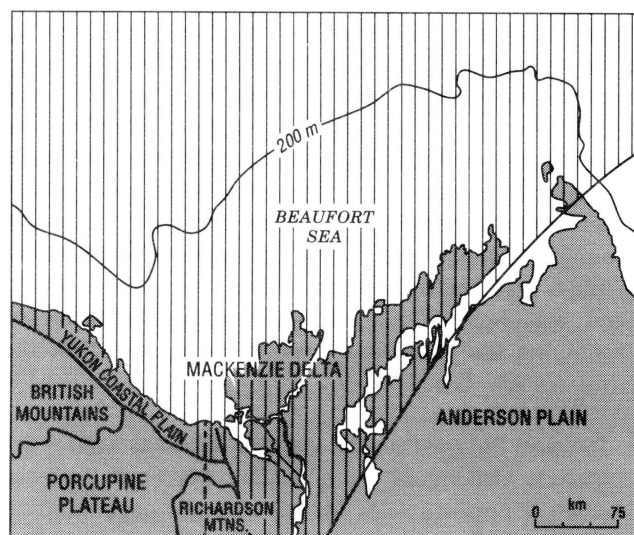


Figure 2. The area evaluated.

## PART I: BASIN ANALYSIS

### GEOLOGICAL SETTING OF THE MACKENZIE DELTA-BEAUFORT SEA REGION

The area of the petroleum evaluation extends from the head of the Mackenzie Delta to the southern limit of the permanent ice pack in the Beaufort Sea, and from 127° to 141°W. The onshore areas include Mackenzie Delta, Tuktoyaktuk Peninsula, and the coastal plain of northern Yukon. The bulk of the evaluation area lies under the Beaufort Sea. Within this area over 200 exploration wells have been drilled (Fig. 3) and many tens of thousands of kilometres of seismic reflection data are available. These data, plus studies of exposed strata on land, are the basis for the geological interpretations and the exploration play concepts summarized in this report.

#### Stratigraphy

The known strata in the Mackenzie Delta-Beaufort Sea Region can be divided (Fig. 4) into several large-scale tectono-stratigraphic assemblages (Lerand, 1973; Norris and Yorath, 1981), these are:

1. Inuvikian: Proterozoic strata,
2. Franklinian: Cambrian to Devonian strata,

3. Ellesmerian: Mississippian to upper Hauterivian strata, and
4. Brookian: upper Hauterivian to modern strata.

These assemblages are separated from each other by major regional unconformities. The unconformities generally reflect significant changes in the tectonic regime. The Brookian can be subdivided into lower and upper Brookian, based on the presence of a significant unconformity between Upper Cretaceous and underlying strata. The bulk of the oil and gas discovered in the Mackenzie Delta-Beaufort Sea Region is present in upper Brookian strata; discoveries have been made in lower Brookian, Ellesmerian and Franklinian strata but they are generally smaller.

#### *Inuvikian strata*

Unnamed Proterozoic strata outcrop near Inuvik, in the Campbell Lake Uplift. Recent studies of seismic deep-reflection data in the vicinity of Inuvik (Cook et al., 1987) clearly show that the area is underlain by a succession of thrust faulted Proterozoic strata 13 to 15 km thick. A belt of presumed Proterozoic strata can be traced in the subsurface from Campbell Lake northeastward along the length of the Tuktoyaktuk Peninsula (Wielans, 1987). Proterozoic strata

apparently thin dramatically towards the Beaufort Sea (Cook et al., 1987).

Sandstone, shale, and carbonates are present in the Campbell Lake Uplift. In the subsurface occurrences along the Tuktoyakyuk Peninsula, quartzite interbedded with shale is the most common rock type penetrated. Volcanic rocks are locally present in the subsurface. In the British Mountains, presumed Proterozoic strata consist of highly deformed argillites, sandstones, and argillaceous limestones and all are assigned to the Neruokpuk Formation (Norris, 1985). Recent studies indicate that some Neruokpuk strata are early Paleozoic in age (Lane and Cecile, 1989).

Detailed information concerning the internal stratigraphy and distribution of Proterozoic strata in the Mackenzie-Beaufort area is lacking due to limited exposures and few borehole penetrations. However, the petroleum potential is considered to be very minor in these strata, based on our knowledge of the high levels of organic maturity, poor source rock quality, and the poor reservoir characteristics of known Proterozoic strata in this area.

### *Franklinian strata*

Franklinian rocks, Cambrian to Devonian in age, are known from the onshore and nearshore areas, and are present in both outcrop and the subsurface. In the eastern areas, Cambrian to Middle Devonian strata outcrop in the Anderson Plains and extend into the subsurface under the Tuktoyaktuk Peninsula. They are predominantly carbonates, although significant successions of Lower to Upper Cambrian clastics, associated with salt and anhydrite, are present in the subsurface of the Anderson River area (Pugh, 1983). In ascending order, these basal clastics and evaporites consist of the Old Fort Island, Mount Cap, and Saline River formations. These Cambrian clastics appear to pinch out towards the Eskimo Lakes area and they have not been identified with any degree of confidence in the subsurface of the Mackenzie-Beaufort area. Extensive occurrences of Upper Cambrian to Middle Devonian carbonates have been identified under the Tuktoyaktuk Peninsula, although stratigraphic subdivisions in these thick carbonates are not always obvious. In the outcrop belts, the Upper Cambrian to Middle Devonian stratigraphic divisions are, in ascending order: Franklin Mountain, Mount Kindle, Peel, Tatsieta, Arnica, Landry and Hume formations (Pugh, 1983). Dolostone is dominant in most formations except the Landry and Hume, which are limestone formations. In the Campbell Lake Uplift

there is a limestone succession that has been correlated with the Cambrian-Silurian Vunta Formation and a dolostone succession originally identified as Gossage Formation, which is approximately equivalent to the Arnica and Landry formations (Norris, 1981). The carbonates underlying the eastern part of the evaluation area are mostly shallow water, shelf sediments.

Westward, the carbonates are laterally replaced by shale, chert, and sediment gravity-flow deposits of the Road River Formation. Outcrops of these lithotypes are present in the Richardson and Barn mountains, and are known in the subsurface from wells on the east flank of the Richardson Mountains (Pugh, 1983). Within the British Mountains, Cambrian volcanic rocks have been identified, and some of the phyllites of the Neruokpuk Formation are equivalent to Road River strata (Lane and Cecile, 1989).

Upper Devonian strata form a thick wedge of clastic sediments which rest abruptly on the underlying carbonates. Generally a distinct black, radioactive shale, the Canol Formation rests on the carbonates, in turn overlain by the much thicker Imperial Formation. The latter consists of interbedded conglomerate, sandstone and shale, deposited principally as sediment gravity-flow beds. Canol and Imperial clastics are present east of the Richardson Mountains and underlie considerable areas of the Tuktoyaktuk Peninsula.

Franklinian rocks underlying Anderson Basin dip gently and become more folded and faulted to the west and northwest. Under the Tuktoyaktuk Peninsula the subcrop pattern of the Paleozoic carbonates suggest that they are either folded or that thrust faults repeat the section (Wielans, 1987). In the Barn Mountains, Lower Paleozoic strata are isoclinally folded.

### *Ellesmerian strata*

Ellesmerian strata are Carboniferous to middle Hauterivian in age. Carboniferous strata are extensively exposed around the perimeter of the British Mountains (Bamber and Waterhouse, 1971) and are known to have been locally penetrated under the southwestern part of Mackenzie Delta. On the east flank of Richardson Mountains, the clastic Tuttle Formation is present south of Fort McPherson, and extends eastward into the subsurface.

In northwestern Yukon the lowest Carboniferous units are clastics of the Kekiktuk and Kayak formations. The Kekiktuk unconformably overlies older strata and consists of interbedded conglomerate

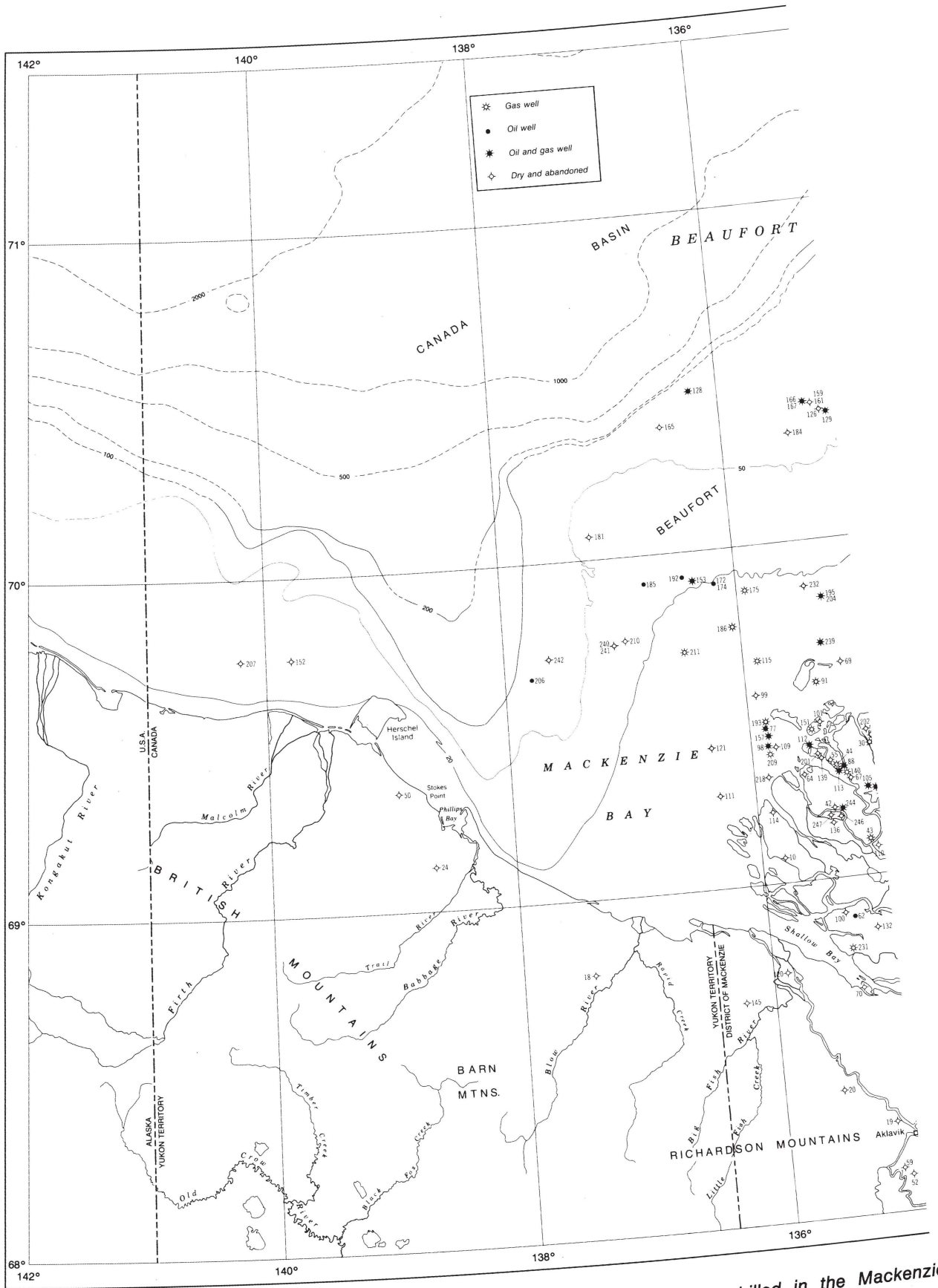


Figure 3. Index map to wells drilled in the Mackenzie Delta-Beaufort Sea Region.

kilometres 10 0 10 20 30

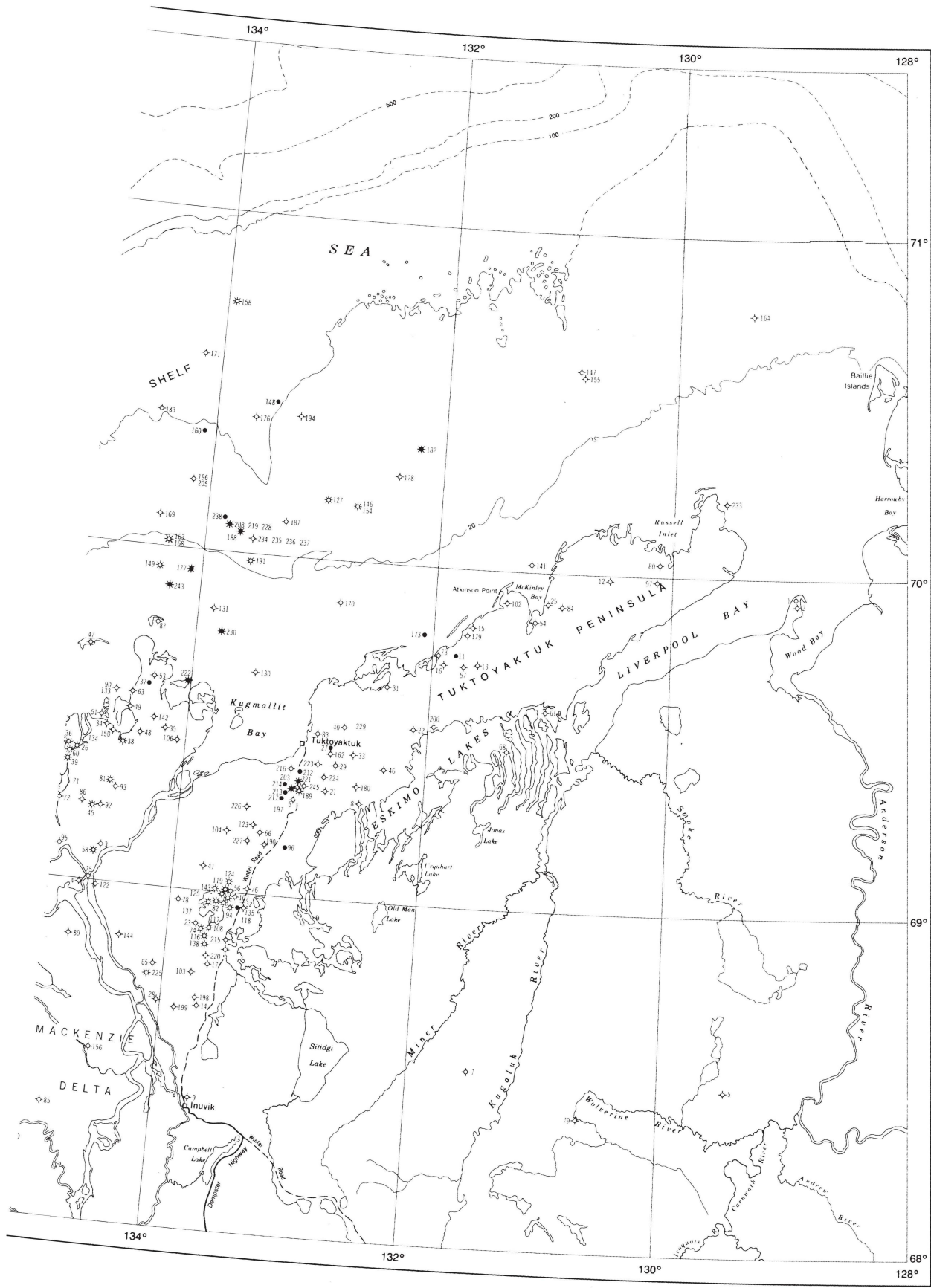


Figure 3. (cont'd).

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53. Imp. Ivik N-17	114. SOBC North Ellice J-23	176. Dome et al. Aiverk 2I-45	238. Gulf et al. Amauligak D-86
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**Figure 3. (con't).**

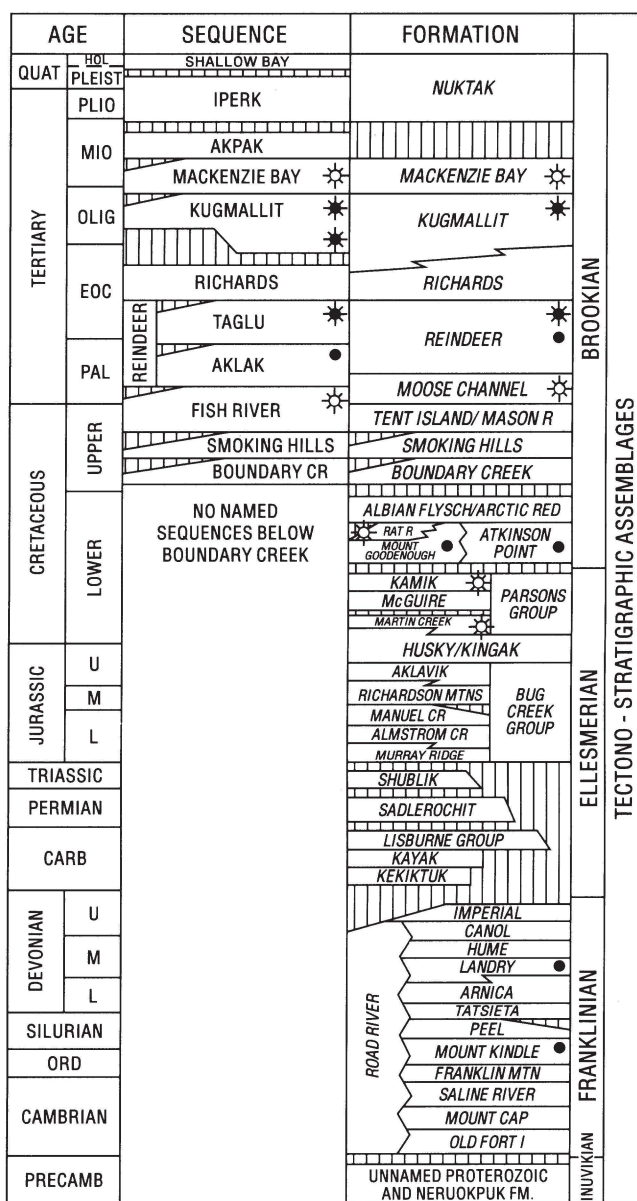


Figure 4. Stratigraphic column, Mackenzie Delta-Beaufort Sea Region.

and sandstone. The overlying Kayak Formation consists of interbedded shale, coal and limestone. Both formations are predominantly nonmarine in origin, although the Kayak contains a significant proportion of marine beds. Carbonates of the Lisburne Group gradationally overlie the Kayak Formation. The Lisburne Group consists of interbedded limestone and dolostone in its lower part and mostly limestone in its upper part.

Shale, sandstone and minor amounts of limestone of the Permian Sadlerochit Group disconformably

overlie Carboniferous strata. Sadlerochit strata crop out in the British Mountains, and eastward, in the Cache Creek Uplift, correlative and considerably thicker Permian strata are present and extend under the southwestern part of the Mackenzie Delta. These eastern Permian strata are predominantly marine sandstone and shale, although, on the east flank of the Richardson Mountains, nonmarine Permian strata are present.

Only local occurrences of Triassic strata are known on the northern flank of the British Mountains. There, Triassic strata consist of interbedded limestone, sandstone and shale and are correlated with the Shublik Formation of adjacent Alaska. Only about 150 m of strata are preserved.

Beginning with Jurassic sedimentation, the depositional style and paleogeography changed dramatically from Permo-Triassic time. A series of northwestward prograding wedges of clastic sediment characterizes Jurassic to Hauterivian deposition. The bulk of the coarser materials (sands and gravels) form a southwest to northeast trending arenaceous belt extending along the Tuktoyaktuk Peninsula, through the northern Richardson Mountains, and along the Keele Range. At the north end of the Ogilvie Mountains this trend shifts to a north-south orientation. Within the arenaceous belt, the vertical succession consists of alternating shale- and sandstone-dominant formations. The sandstone units grade laterally into shale-dominant strata toward the northwest and west.

In ascending order, the formations within the arenaceous belt are: Bug Creek Group (mostly sandstone), Husky Formation (shale-dominant), Martin Creek Formation (sandstone-dominant), McGuire Formation (shale), and Kamik Formation (mostly sandstone). In northwestern Yukon, the Bug Creek to McGuire interval is represented by a single shale succession, the Kingak Formation. Some local variations in the stratigraphy are present, for example the Porcupine River and North Branch Formation are sandstone facies equivalents of the lower Husky Formation.

The bulk of the preserved record of Jurassic to Hauterivian strata consists of shoreline to shelf sediments with a significant nonmarine component in the lower part of the Kamik Formation (Poulton, 1982; Dixon, 1986). In the latter formation the nonmarine beds are present principally under the Tuktoyaktuk Peninsula and south Mackenzie Delta. The source of the clastics during Jurassic to Hauterivian time was the stable craton to the east and southeast.

## *Brookian strata*

Brookian strata consist of Barremian to Holocene sediments and are separated from underlying strata by a major regional unconformity at the base of the Mount Goodenough Formation. Within the Brookian assemblage, a major regional unconformity below Upper Cretaceous strata divides the succession into a lower and upper assemblage.

Barremian strata are represented by the shale-dominant Mount Goodenough Formation. This unit is present throughout northern Yukon, northern Richardson Mountains, and in the subsurface of the Mackenzie Delta and the Beaufort Sea. A basal sandstone is locally developed, especially adjacent to, or on, tectonic uplifts such as the Cache Creek and Romanzof uplifts. Interbedded sandstones and shales of the Rat River Formation gradationally overlie the Mount Goodenough Formation. Rat River strata outcrop in the northern Richardson Mountains but have been eroded west of Rapid Creek. In the subsurface they occur in the southwest part of the Mackenzie Delta. Most of the preserved Rat River interval consists of marine strata, commonly arranged in a series of shale-to-sandstone, coarsening-upward cycles.

Under the central part of the Tuktoyaktuk Peninsula there is a relatively thin succession of sandstone and conglomerate that is equivalent to both the Mount Goodenough and Rat River formations. These are strata of the Atkinson Point Formation. Atkinson Point strata have a limited distribution adjacent to the northwest flank of the Eskimo Lakes Arch and rapidly change facies into siltstone and shale (Dixon, 1979). The localized distribution and rapid lateral facies changes suggest that the Atkinson Point Formation was deposited as a small fan delta on the northwest flank of the active Eskimo Lakes Arch.

Late Aptian and Albian strata are mostly shales and consist of the Martin House and Arctic Red formations east of the Richardson Mountains, and the informally designated Albian flysch west of the mountains. Local, thin, basal sandstone beds are present along the Eskimo Lakes Arch, especially where Arctic Red strata rest unconformably on older rocks. In the Albian flysch, shale is dominant but there are also significant intervals of sandstone and conglomerate, especially in the basal part of the succession (Young, 1977). A local ironstone unit, the Rapid Creek Formation (Young and Robertson, 1984), occurs on the northwest flank of the northern Richardson Mountains. Albian flysch beds underlie much of the Yukon coastal plain but plunge rapidly under a thick Tertiary cover in the nearshore areas. The flysch beds are at least 4000 m thick within the Rapid Depression and may be considerably thicker.

The flysch beds west of the Richardson Mountains were deposited in the Blow Trough as sediment gravity-flow deposits in slope, submarine fan and basinal environments.

Martin House strata consist of interbedded shale, siltstone and sandstone, with local coquinas. They have been identified only on the east flank of the Richardson Mountains. They represent deposition during a late Aptian/early Albian transgression on to the cratonic areas of northern Canada. Arctic Red strata consist of shale with thin interbeds of siltstone and very minor amounts of sandstone. Arctic Red strata were deposited as shelf sediments south and southeastward of the Eskimo Lakes Fault Zone. Northwestward of the zone, within the Kugmallit Trough, Arctic Red strata were deposited as slope and basinal deposits.

The unconformity between Albian and younger strata is especially prominent west of the Richardson Mountains, where weakly consolidated, low-density shales and thin interbeds of bentonite of the Boundary Creek Formation abruptly overlie dense, brittle Albian shales. East of the Richardson Mountains, the contrast is not as marked but the Cenomanian–Turonian Boundary Creek strata are generally absent and Campanian–Santonian shales of the Smoking Hills Formation rest disconformably on Albian shales. Both the Boundary Creek and Smoking Hills shales are rich in organic matter, averaging 3 to 5 per cent, and locally as high as 12 per cent in the Smoking Hills succession. Smoking Hills strata are eroded west of the Richardson Mountains, where Maastrichtian rocks of the Tent Island Formation rest erosionally on Boundary Creek shales. Boundary Creek and Smoking Hills strata were deposited on outer shelf to slope environments.

Late Maastrichtian to Holocene strata consist of a series of basinward prograding deltaic complexes which, cumulatively, consist of 12 to 14 km of strata under the central Beaufort Sea. Under the Mackenzie Delta, and in outcrops, the succession consists of alternating shale- and sandstone-rich intervals which have been divided into conventional lithostratigraphic units (Fig. 4; Young, 1975; Young and McNeil, 1984). Basinward, the sandstone-dominant units begin to be replaced by shale. Consequently, in some parts of the offshore areas, many thousands of metres of section are shale-dominant and correspond to several units in the nearshore areas. This creates a major problem for realistic correlations and paleogeographic reconstructions. Consequently, Dietrich et al. (1985) advocated the use of the depositional sequence concept (Mitchum et al., 1977) to identify basin-wide, genetically related, packages of sediment. This concept does not rely solely upon lithology to identify the

stratigraphic units, instead, basin-wide stratigraphically significant surfaces are identified. The surfaces are unconformities or their basinward correlative conformities, and are identified principally from seismic reflection as well as from geophysical logs in exploration holes. The unconformities/conformities form the bounding surfaces of depositional sequences. Most of the Tertiary sequences can be up to 4000 m thick at their depocentres. Others have used similar approaches to basin analysis (e.g. Willumsen and Cote, 1982; Gardner and Bates, 1987).

The sequences identified to date are (from oldest to youngest):

- a) Boundary Creek: Cenomanian–Turonian;
- b) Smoking Hills: Santonian–Campanian;
- c) Fish River: late Maastrichtian–Paleocene (contains the Tent Island Formation and sandstone member of the Moose Channel Formation);
- d) Reindeer supersequence: this can be divided into two sequences — Aklak (late Paleocene–early Eocene) and Taglu (early–?middle Eocene);
- e) Richards: middle–late Eocene;
- f) Kugmallit: Oligocene (this sequence now contains the previously separated Kopanoar sequence) (Dietrich et al, 1985);
- g) Mackenzie Bay: Oligocene–Miocene;
- h) Akpak: Miocene;
- i) Iperk: Plio–Pleistocene;
- j) Shallow Bay: late Pleistocene–Holocene.

Each of the major Tertiary sequences consists of a thick succession of interbedded sandstone and shale at the basin margins, deposited in delta plain and delta front environments. In the distal delta front environment the amount of shale increases and sandstone decreases. In the prodelta and shelf environments shale is dominant, although isolated sand-rich intervals may be present where delta lobes prograded onto the shelf. Slope and basinal deposits tend to be mud-dominant but when deltaic deposits built out to the shelf edge, or when there was a relative sea level drop, coarser material could have been deposited in the deep water environments.

The deltaic facies of the Fish River and Aklak sequences are centred over the western part of the Beaufort Sea and both form a large belt of sandstone-rich strata. In early Eocene time the delta depocentres switched to the east, centering Taglu and Kugmallit deltaic strata under Richards Island and the central Beaufort shelf respectively. To date we have not been able to identify the Mackenzie Bay and Akpak deltaic facies, either because they have been eroded at the basin margins or they are present west of the study area. The Iperk depocentre is located beneath the

eastern Beaufort Sea shelf. Holocene deltaic deposition has shifted back to the central Beaufort Sea.

During the late Eocene there was a major drop in relative sea level and the previously formed shelf was subaerially exposed. During this period of exposure, submarine canyons formed on the slope and shelf, feeding sediment to a large submarine fan. These low-stand submarine fan deposits form the basal part of the Kugmallit sequence (ex-Kopanoar sequence). During deposition of the succeeding Kugmallit delta, significant quantities of sediment were shed directly from the delta front into deep water. The vertical stacking of these two deep water intervals has resulted in a thick, muddy, interval of Oligocene sediment gravity-flow deposits within the central offshore area of the Beaufort shelf.

### Structural setting

The area can be divided into four large-scale structural terrains:

1. Stable Craton. East of the Peel River and south of the Tuktoyaktuk Peninsula, Paleozoic and Mesozoic strata are only moderately deformed. However, these strata are underlain by a thick, highly deformed succession of Proterozoic strata that appears to have been part of a Precambrian fold belt. Paleozoic strata are part of a westward thickening, homoclinal wedge which becomes more deformed toward the Richardson Mountains and on the north side of the Eskimo Lakes Fault Zone. The thin Mesozoic cover tends to be flat-lying to gently warped into broad synclines and anticlines.
2. Faulted southeast margin of the Canada Basin. Under the Tuktoyaktuk Peninsula, a zone of large-scale, listric normal faults, which have had minimal offset in Upper Cretaceous and Tertiary strata, extends northeastward into the offshore through Lower Cretaceous and older strata (Cook et al., 1987). The bulk of the stratigraphic displacement is within Jurassic and Lower Cretaceous units, placing the main fault activity in the early Mesozoic. These faults are interpreted to be the result of rifting and opening of the Canada Basin during the Mesozoic.
3. Cordilleran Foldbelt. The area west of the Richardson Mountains and extending into the western Beaufort Sea is underlain by highly deformed strata. Compressional and strike-slip structures formed during late Cretaceous and early Tertiary deformation. Within this terrain there are features of older origin, such as the Cache Creek

Uplift, White Uplift, and Rapid Depression (Fig. 5) — all of which probably originated as Mesozoic fault-bounded structures. Undoubtedly some features have even older origins, such as the White Uplift, which was an isolated carbonate bank during early Paleozoic time.

4. Canada Basin. Oceanic crust underlies the Canada Basin, which was formed from continental rifting and seafloor spreading during the Cretaceous. A thick cover of Tertiary sediment overlies the oceanic crust. The transition from continental to oceanic crust has not been identified with certainty, but initial studies of refraction and gravity data suggest that the transition underlies the Beaufort shelf.

Under the Beaufort Sea, Tertiary strata have been deformed by compression and gravity-induced faulting. Most of the Lower Tertiary strata in the western Beaufort Sea have been folded into an arcuate fold belt that dies out oceanward and to the northeast. The intensity of folding varies geographically. In the nearshore areas the anticlines tend to be asymmetric, verging oceanward, and are commonly cut by high-angle reverse faults on the oceanward limb. Basinward the folds tend to become more symmetric and less faulted. The folds show repeated thinning of strata onto the structures, indicating intermittent growth, associated with episodic compression. In the central Beaufort, under Richards Island and the nearshore areas, the folds are crosscut by younger, gravity-induced listric faults. These listric faults usually face oceanward, although in the Tarsiut area there are large landward-facing listric faults. A zone of very pro-

minent listric faults (Tarsiut–Amauligak Fault Zone) extends from Tarsiut, northeastward through the Ukalerk area. Oceanward from the zone, the section is essentially unfaulted. The thick Plio-Pleistocene Iperk sequence unconformably overlies older Tertiary strata and truncates underlying structures. Deformation within the Iperk sequence is minor, although equivalent strata in the northeastern part of Alaska are involved in folding.

West of the Mackenzie Delta there are several prominent large-scale structural features (Fig. 5). The Blow River and Herschel highs are areas cored by closely spaced anticlines. Flanking the southern margin of Herschel High is the Demarcation Subbasin, a large synclinal structure filled with middle Eocene and younger strata.

## PETROLEUM GEOLOGY

### Exploration history

The fragile, but harsh environment, presence of semi-permanent ice, permafrost, overpressured reservoirs and extremes of climate experienced in the Mackenzie Delta–Beaufort Sea Region has necessitated the development of new and modified exploration techniques and equipment. In general, onshore drilling is restricted to periods when the ground surface is frozen, offshore drilling in water depths up to 25 m is done from artificial islands, and drilling in depths greater than 25 m is done from ice-reinforced drillships and floating platforms.

The favourable stratigraphic section and existence of large structures defined by seismic exploration in the early 1960's led to the drilling of the first exploratory wells in 1962. Texcan Nicholson G-56 and N-45 were drilled on the coast of the Beaufort Sea east of the Tuktoyaktuk Peninsula.

Exploration moved offshore in 1973 with the drilling of Imperial Immerk B-48 and Imperial Adgo F-28 on gravel islands built in 2 to 3 m of water. In 1976, summer drilling from ice-strengthened drillships commenced allowing exploration to proceed in deeper waters.

### Hydrocarbon discoveries

Hydrocarbons have been recovered from Paleozoic carbonates, Lower Cretaceous sandstones and Tertiary sandstones. All the Paleozoic and Lower Cretaceous

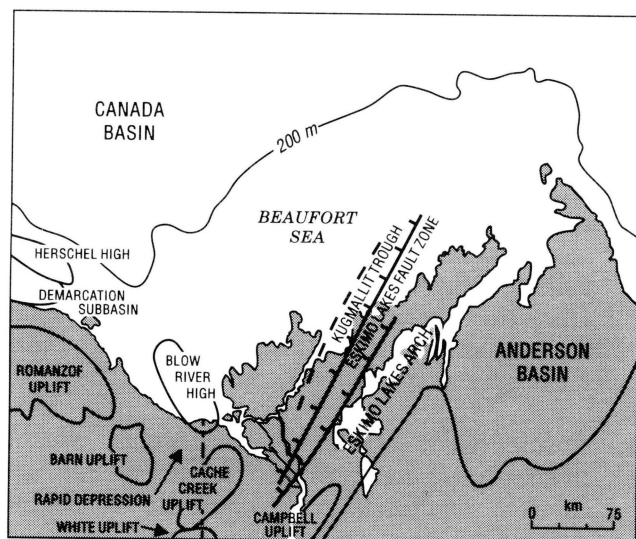


Figure 5. The major structural elements in the region.

reservoirs are located in the southern Mackenzie Delta and along the Tuktoyaktuk Peninsula. Discoveries in Tertiary reservoirs are concentrated in the central area of the Beaufort-Mackenzie Basin, reflecting the focus of drilling activity. Recent drilling in the relatively unexplored western Beaufort Sea indicates that hydrocarbons are present (e.g. the Adlartok P-09 oil discovery).

Only three hydrocarbon accumulations in carbonate reservoirs have been discovered: one at Mayogiak J-17, the second at West Atkinson L-17, and the third at Unak L-28. In the Mayogiak and West Atkinson wells, oil was recovered from Lower Paleozoic carbonates and the geochemical properties of the oil indicate that it was derived from the Upper Cretaceous Smoking Hills Formation. In both localities the reservoirs are on small fault blocks and the porosity is enhanced by fractures. Presumably, oil generation occurred within the adjacent Kugmallit Trough and the oils migrated updip along fault planes into the carbonate reservoirs. Overlying Jurassic and Cretaceous shale would provide the seal to the carbonates. In Unak L-28 the reservoir is in Carboniferous carbonates. Gas has been recovered in Unak L-28, which could be derived from Jurassic-Cretaceous shales but the exact source is unknown. The Unak trap appears to be related to closure against a thrust fault.

Both oil and gas have been trapped in Lower Cretaceous sandstones throughout the Tuktoyaktuk Peninsula and south Mackenzie Delta. Oil has been recovered from Parsons Group sandstones at Kugpik O-13 and Kamik D-48, from the Barremian-Aptian Atkinson Point Formation, and a minor amount from a sandstone in the Mount Goodenough Formation at Imnak J-29. With the exception of the Kamik discovery, the oil appears to have been generated from Smoking Hills shale (Snowdon and Powell, 1979; Brooks, 1986). The origin of the Kamik oil remains unresolved. Trapping is in fault blocks adjacent to the Kugmallit Trough, in which it is presumed the oil was generated and migrated updip along fault planes.

Gas is present in large volumes in the Parsons Group at the north and south Parsons gas field. The source of the gas has not been positively identified. The associated liquids are not correlatable with oil from the Smoking Hills Formation. Langhus (1980) suggested that the gas was derived from the Jurassic-Cretaceous Husky Formation. The terrestrially dominant organic matter in the Husky shale is consistent with a gas-prone source rock for the Parsons gas. At the Unak L-28 well, gas was recovered for the first time from Lower Cretaceous Rat River

strata. The source of the Unak gas is not known but it could be the thick Jurassic-Cretaceous shales in the area of Unak L-28.

Most of the hydrocarbon discoveries in the Beaufort-Mackenzie area are in Tertiary strata. Oil and gas have been recovered from the Fish River, Aklak, Taglu, Kugmallit and Mackenzie Bay sequences. Deltaic strata of the Taglu and Kugmallit sequences account for the bulk of the discoveries, with lesser volumes in deep water sediments of the Kugmallit sequence. While there is a general trend for the trapped hydrocarbons to be more oil-prone in a basinward direction, there is no identifiable pattern to the type of hydrocarbons discovered. Oil-to-source rock correlations indicate that the liquid hydrocarbons are derived from two possible Tertiary sources. Oils from the central Beaufort area contain a biomarker compound that has only been found in the basal part of the Richards shale (Brooks, 1986), suggesting that the Richards shale is the source rock. In the oil discovery at Adlartok P-09, in the west Beaufort, the Richards-type biomarker is not present and the geochemistry of the oil appears to indicate a possible source rock in Paleocene shales (L.R. Snowdon, pers. comm., 1987).

Even though drilling has reached depths of 4000 to 4500 m, the Tertiary section in the central Beaufort area is generally thermally immature. Vitrinite reflectance values rarely reach 0.7 per cent Ro. In the west Beaufort, where the Natsek and Edlok wells have been drilled, higher levels of thermal alteration are attained and values of 0.8 per cent Ro have been measured in Paleocene strata. In the Blow River E-47 well, located on the Yukon coastal plain, very high levels of thermal alteration have been noted in the near-surface Albian strata, with values up to 2.0 per cent Ro, well beyond the oil window.

The Tertiary succession is dominated by type III (terrestrial) organic matter. Using a conventional hydrocarbon generation model, this type of organic matter would tend to produce mostly gas. While the Beaufort-Mackenzie succession does contain large volumes of gas, there is an unusually large volume of liquids that cannot be accounted for by the terrestrial dominance of the organic matter. Normally such volumes of oil are generated from organic matter that is more marine in character. As a possible explanation for this anomalous situation, Snowdon and Powell (1979) postulated that the oils were generated from resin-rich terrestrial sediments. Resin is a common component of the Beaufort-Mackenzie deltaic sediments and it is not uncommon to find small globules in the cutting samples from exploration wells. This type of organic matter has the added advantage of

generating hydrocarbons at lower levels of thermal alteration, which would be consistent with the Beaufort–Mackenzie thermal regime.

### Exploration play groups

The revised estimates presented in the following report are based on a thorough basin analysis by GSC and COGLA scientists. From this analysis, 20 exploration plays were identified and quantified using advanced probability methods developed by the Geological Survey of Canada. The 20 exploration plays occur in four groups, distinguished by geographic, geological and developmental criteria (Fig. 6). The **Onshore/Shallow Offshore Play Group** comprises eight plays that exist in the Richards Island, South Delta and Tuktoyaktuk Peninsula areas, plus their extensions into adjacent shallow water. The plays include Paleozoic, Mesozoic and Tertiary targets. The four plays of the **Offshore Delta Play Group** form a narrow fairway between the Tarsiut and the Amauligak fields in which several major oil and gas discoveries have been made. This group occurs in about 25 m of water, and the plays exist in rocks of similar Tertiary age and with similar structural style. The three plays of the **West Beaufort Play Group** differ significantly from the main delta plays in the structural style and grain of the area, the age of reservoirs, and a different oil generation regime. The **Deep Water and Other Play Group** consists of five plays, dominated by two plays that occur in deep water beyond the Offshore Delta and West Beaufort play groups. These two Tertiary plays rely on deep water sedimentation for reservoir

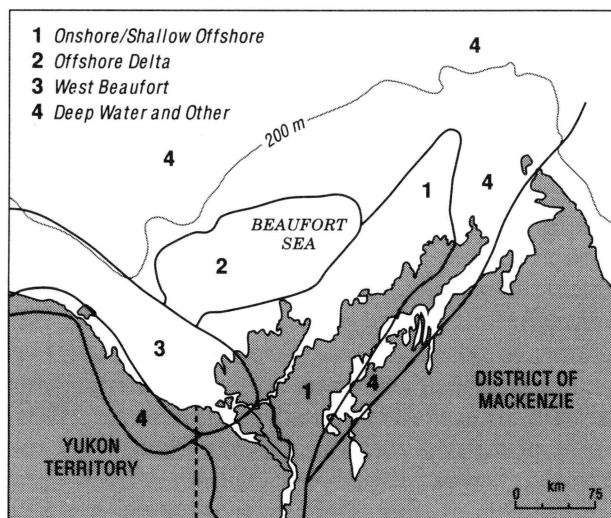


Figure 6. The areal extent of the play groups.

opportunities. The other three plays are combined with this group because they are conceptual and will probably not attract serious exploration for some time.

### Onshore/Shallow Offshore Play Group

The Onshore/Shallow Offshore Play Group is a collection of eight plays that have the common parameter of being either located on land or only marginally overlapping into very shallow water (less than 15 m) of the adjacent Beaufort Sea. Although the geological controls for the various plays encompass a broad spectrum of variables, the logistics of exploration, including drilling and seismic acquisition have a common character. Drilling onshore is restricted to periods when the ground is frozen, and drilling offshore, to artificial islands in water depths of less than 25 m. Seismic acquisition over the play areas, particularly in the very shallow waters near shore, is difficult and expensive.

### Parsons Play

**Play Definition.** This play was defined to include all pools and prospects in the Lower Cretaceous Parsons Group along the southern Tuktoyaktuk Peninsula (Fig. 7). Gas is the principle hydrocarbon in this play but significant amounts of oil may be present. The play area extends from the Caribou Hills, northeastward to the area of Tuktoyaktuk (Fig. 8). Southeast and east of the Eskimo Lakes Fault Zone, Parsons strata are eroded.

**Geology.** Where fully developed, the Parsons Group consists of the sandstone-dominant Martin Creek

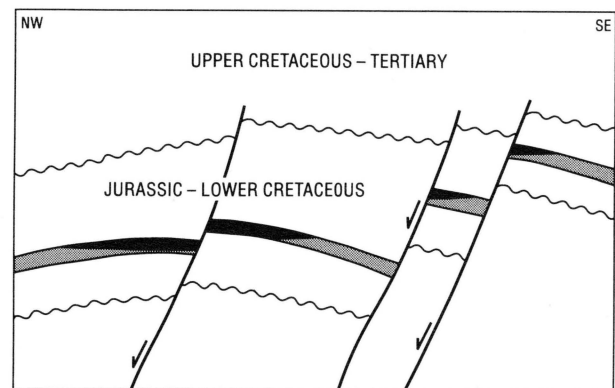
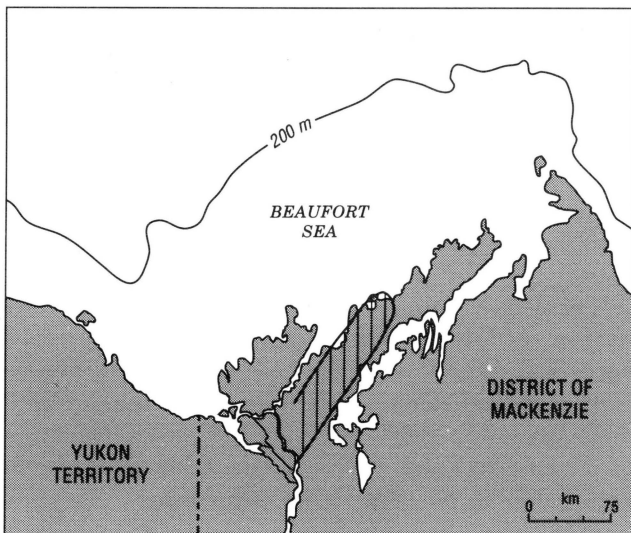


Figure 7. Schematic sketch of the trap types — Parsons Play.



**Figure 8.** Sketch map locating the Parsons Play area.

Formation, abruptly overlain by shale of the McGuire Formation, in turn gradationally overlain by the Kamik Formation. The Kamik Formation has a distinctive twofold division: a lower sandstone-rich interval that contains fluvial and marginal marine beds, and an upper interval consisting of a series of coarsening-upward cycles of barrier bar origin (Dixon, 1982).

The Parsons Group is up to several hundred metres thick in the Kugmallit Trough, thinning depositionally and erosionally to the east, northeast, and southeast, onto the Eskimo Lakes Arch. Southwest of the Caribou Hills, pre-Mount Goodenough erosion has removed considerable amounts of Parsons strata.

Porosity values are variable but generally in the 15 to 20 per cent range for the quartz arenites and less for more argillaceous sandstones.

Included in this play is a sandstone unit that occurs within the Mount Goodenough Formation, immediately above the Siku shale. The sandstone unit can be correlated throughout the subsurface but it is of highly variable quality and thickness. Generally it is only a few metres to a few tens of metres thick and can range from a very argillaceous, silty sandstone to a fine grained, relatively clean, quartz arenite. Porosity values in this sandstone are usually less than 15 per cent.

Structures associated with this play are closures against normal faults of the Eskimo Lakes Fault Zone and have a wide range of sizes, from the large faulted

anticline at Parsons gas field to the small fault blocks of the Tuk area. The thick overlying succession of Lower Cretaceous and Upper Cretaceous shales provide an efficient seal.

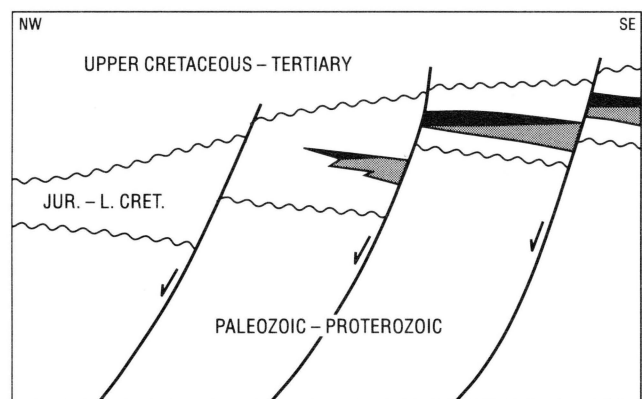
Source rocks for this play may include the Husky Formation which has a terrestrially derived organic content and is gas-prone (Langhus, 1980). Other Lower Cretaceous shales, such as in the Mount Goodenough and Arctic Red formations could be potential source rocks, the former is gas-prone and the latter has more oil-prone intervals. The Upper Cretaceous Smoking Hills Formation is a rich, oil-prone source rock that appears to have been the source for some of the oils in the Parsons Group.

*Exploration History.* The Parsons gas field was first drilled in 1972, and subsequent step-out drilling has indicated that there is 1.4 TCF of recoverable gas in two main pools. Subsequent exploration has resulted in a gas condensate discovery in Tuk L-09, a small oil discovery in Kamik D-48 (both in the Kamik Formation), and a minor oil discovery at Imnak J-29 in a Mount Goodenough sandstone. About 13 separate prospects have been drilled into Parsons Group strata.

### *Atkinson Point Play*

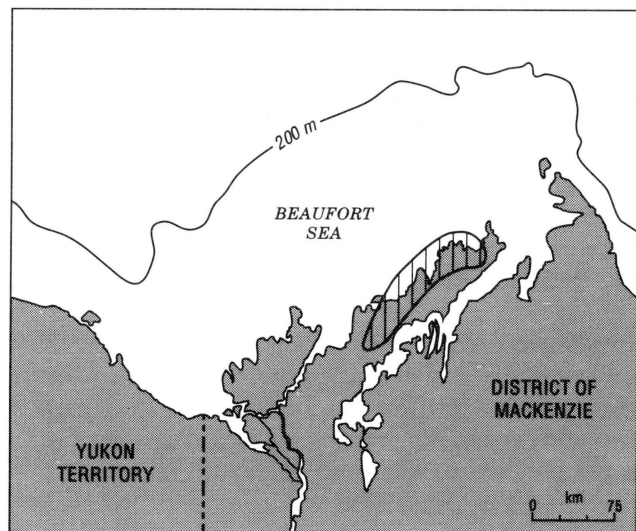
*Play Definition.* The Atkinson Point play was defined to include all pools and prospects in the Hauterivian to Aptian Atkinson Point Formation along the northwest margin of the Tuktoyaktuk Peninsula (Fig. 9). Oil is the principal hydrocarbon.

The play area extends from about the central part of the Tuktoyaktuk Peninsula to its northernmost point,



**Figure 9.** Schematic sketch of the trap types — Atkinson Play.

but the Atkinson Point Formation is limited to the western side of the peninsula. Some nearshore areas on the Beaufort Sea side of the peninsula are included in the play area (Fig. 10).



**Figure 10.** Sketch map locating the Atkinson Play area.

**Geology.** At its eastern limits, strata of the Atkinson Point Formation consist of interbedded conglomerate and sandstone. These grade laterally into sandstone and siltstone and then into the marine shale and siltstone of the Mount Goodenough Formation (Dixon, 1979; Dixon et al., 1989). Dixon (1979) interpreted the Atkinson Point Formation as a local, small, fan delta deposit grading laterally into marine strata.

The type area is in the vicinity of the original discovery, Atkinson H-25, where the thickest and best reservoir facies are developed. A few kilometres to the west, at West Atkinson L-17, equivalent strata consist of silty and argillaceous sandstone of poor reservoir quality. Thin successions of Atkinson Point strata to the northeast and south of the type area may well represent deposits of the transgressive phase that terminated Atkinson Point deposition. As well as facies changes limiting the area of distribution, a mid-Cretaceous unconformity truncates Atkinson Point and equivalent strata south of the Eskimo J-07 well, on the Eskimo Lakes Arch. Within the Kugmallit Trough, from the Mayogiak area southwestward, equivalent strata are shale-dominant.

Porosity and permeability is highly variable, and generally facies dependent. The best porosity/

permeability values occur in clean sandstones and conglomerates in the vicinity of Atkinson H-25 well (15-20%).

Thick, overlying Albian and Upper Cretaceous shales provide adequate top seal. Lateral seals could be fault planes or facies change to finer grained or argillaceous strata.

There is a strong correlation between the distribution of the Atkinson Point Formation and Jurassic-Cretaceous faults bounding the western margin of the Eskimo Lakes Arch. The Atkinson H-25 discovery is in a small, tilted fault block on the margin of the Eskimo Lakes Arch and remaining prospects are anticipated to be of a similar trap type.

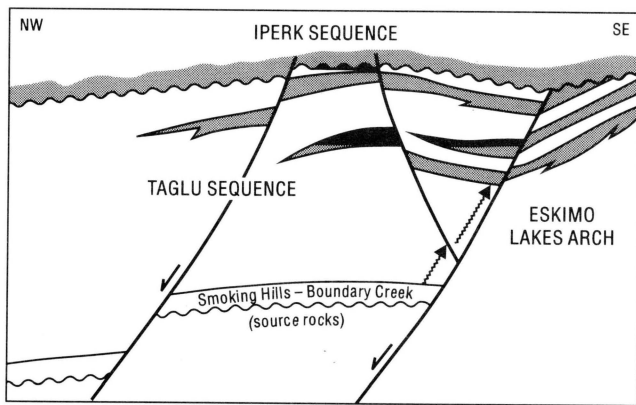
Oil in the Atkinson H-25 was apparently derived from the organic-rich Upper Cretaceous Smoking Hills Formation. Maturity levels of Smoking Hills strata on the Eskimo Lakes Arch is low, consequently the oil must have migrated from deeper levels in the adjacent Kugmallit Trough to the west, probably facilitated by the numerous faults.

**Exploration History.** The Atkinson H-25 oil discovery was drilled in 1970. Subsequent drilling in the immediate area failed to find another discovery. Not until 1982, when West Atkinson L-17 was drilled, were more hydrocarbons found in the Atkinson Point Formation. However, in L-17 the reservoir was so poor that the well was not recognized as an Atkinson Point discovery, rather the underlying fractured Paleozoic carbonates were the principal producing interval. Altogether, 21 wells have penetrated Atkinson Point strata.

### *Tuk Play*

**Play Definition.** This play was defined to include all the pools and prospects within the Paleocene-Eocene succession along the southern Tuktoyaktuk Peninsula (Fig. 11). It is an oil and gas play.

The play area (Fig. 12) is limited to the southeast by truncation of the potential reservoir, to the northeast by shale-out of the delta front reservoir facies, and to the southwest by the overwhelmingly sandy character of the deltaic sequence. The northwestern boundary with the Taglu play is arbitrary and reflects the limits of the structural influence of the Eskimo Lakes Arch and the likelihood of effective Upper Cretaceous oil source rocks.

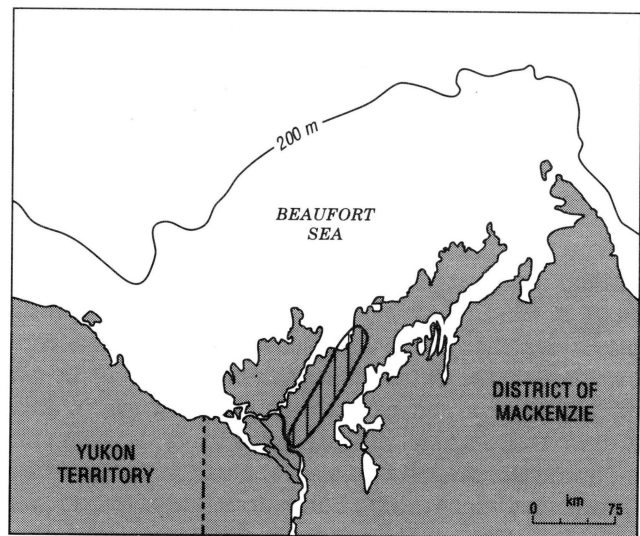


**Figure 11.** Schematic sketch of the trap types — Tuk Play.

**Geology.** The Eskimo Lakes Arch is a positive structural element which confines the southeastern flank of the Beaufort-Mackenzie Basin. Delta front sandstones of the uppermost Aklak and lower Taglu sequences onlap the arch along much of its length. These sandstones follow a thick succession of shale and siltstone of the Aklak and Fish River sequences which in turn overlie the pre-Tertiary core of the arch. The Taglu Sequence is overlain in this area by thick sandstones of the Iperk Sequence and is progressively truncated onto the arch by the strongly erosive basal Iperk unconformity with consequent increased risk to trap integrity.

Taglu delta front sandstones occur in coarsening-upward cycles 15 to 45 m thick, commonly capped by several metres of massive sandstone. Where the massive sandstone is absent, the delta front packages are thin bedded, at a decimetre scale, with individual sandstones unresolved on most conventional logs. Porosity is typically in excess of 27 per cent in these relatively shallow sandstones. Delineation of the Tuk J-29 discovery has indicated that individual delta front sandstones are not extensive and pinch-out between closely spaced delineation wells.

The flank of the Eskimo Lakes Arch is formed by major down-to-basin listric faults of the Eskimo Lakes Fault Zone. Many of these faults have a long history of reactivation extending into the Neogene. Fault displacements in Tertiary rocks are, however, much less than in older rocks and are in the order of tens of metres. Smaller faults crosscut the major lineaments producing a large number of small, compact, fault-bounded prospects. Pool sizes are further reduced by stratigraphic pinch-out. This pinch-out, however,



**Figure 12.** Sketch map locating the Tuk Play area.

benefits the updip seal in this play, where cross fault leakage is a problem.

Oils in this play are probably derived from organic-rich shales of the Upper Cretaceous Smoking Hills and Boundary Creek formations. Considerable vertical migration up fault planes and minimal lateral migration are required to place hydrocarbons in the shallow Tertiary reservoirs.

Pervasive flushing of thick sandstone units by meteoric waters has resulted in degradation of oils. A wide variation in oil gravity is observed between zones. As a general rule, the thick, shallow sandstones host heavy oil of less than 20° API; the thin, deep sandstones contain higher gravity oils. A risk factor for heavy oil has been included in the prospect risk.

Deep burial of the Upper Cretaceous source rocks may have resulted in gas generation on the downthrown side of the Eskimo Lakes Fault Zone. An older (Jurassic?) source is, however, the more likely explanation for gas occurring as pools and associated with oil in this play. Reservoirs in this play are normally pressured.

**Exploration History.** Esso PCI Home et al. Tuk J-29 was drilled in 1985 as a delineation to the Lower Cretaceous gas/condensate discovery at Tuk L-09. Lower Cretaceous strata contained water but tests of several uphole zones in the Tertiary section showed substantial flows of both oil and gas. A flurry of drilling followed, directed exclusively at testing the Tertiary. Most wells tested in the vicinity of the

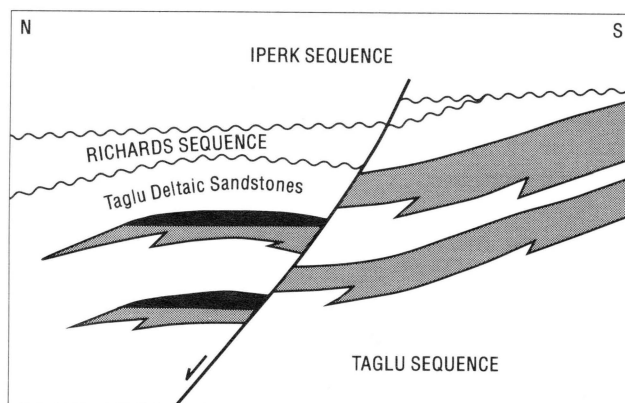
original discovery contained hydrocarbons, although from different zones and with minimal recoveries of low gravity oil from the shallow zones. The wells of this follow-up program indicate a complex faulted structure and rapid lateral changes in many lithological units.

The play has been tested along the strike of the Eskimo Lakes Arch both to the northeast and southwest. A total of 14 wells have been drilled to test the play since the Tuk J-29 discovery. These wells have been tested for 9 separate prospects resulting in two discoveries; oil and gas at Tuk play and gas in Ikhil K-35. Delineation drilling around Tuk play has indicated the existence of several pools in the Tuk field which are separated both stratigraphically and geographically. Wells originally drilled to test Lower Cretaceous targets may have failed to evaluate the shallower Tertiary sandstones which, in many instances, were cased without logging.

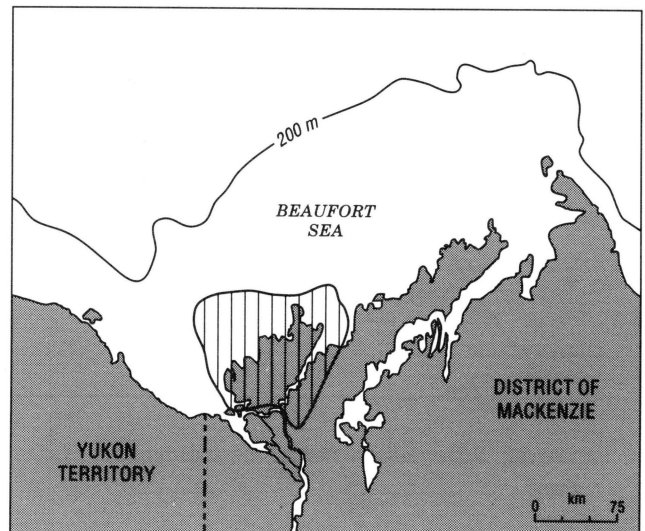
### Taglu Play

**Play Definition.** This play was defined to include all pools and prospects within the Taglu sequence occurring under the outer Mackenzie Delta and nearshore areas (Fig. 13). It is principally a gas play although a small proportion of pools contain significant quantities of oil.

The play area is confined by erosion beneath the basal Kugmallit and Iperk unconformities to the southwest, shale-out of deltaic facies to the north and northeast, and a change in structural style along the flank of the Eskimo Lakes Arch to the southeast (Fig. 14).



**Figure 13.** Schematic sketch of the trap types — Taglu Play.



**Figure 14.** Sketch map locating the Taglu Play area.

**Geology.** The deltaic sandstones of the Taglu sequence were deposited in a spectrum of delta front and delta plain depositional subenvironments. A proximal assemblage of coarsening-upward delta front sandstones overlain by distributary mouth bar and distributary channel deposits characterizes the central area of this play. Sandstone packages are up to 50 m in gross thickness with most falling in the range of 15 to 30 m. Sandstones in the coarsening-upward delta front strata occur in beds 1 to 3 m thick, interbedded with mudstones. Overlying sandstones related to more proximal depositional environments are generally massive and form the prominent Taglu reservoir. Porosity and permeability are good. Lateral continuity of sandstones varies in this play, with thin sandstones likely to be of restricted areal extent. Thicker series of stacked channel sandstones extend laterally over considerable distances (in excess of 5 km at Taglu Field).

Top seal of the Taglu sequence is provided by shales of the Richards sequence. Unconformities at the base of the Kugmallit and Iperk sequences truncate both Richards and Taglu sequences across some of the higher structures. The Kugmallit and Iperk sequences are sandy and no top seal can be expected where erosion to the level of the Taglu reservoirs occurred.

Traps in this play are mainly structural and involve northward plunging anticlines segmented by numerous east-west trending down-to-basin listric faults. Some of these faults exhibit large throws sufficient to completely offset the Taglu sequence (e.g. at Taglu Field) and hence delineate separate prospects. More commonly, faults are of lesser throw and the entire

anticline has been regarded as a single prospect. Faulting significantly increases the number of pools per field, hence the number of wells required to drain a prospect.

Many prospects in this play are truncated by an unconformity near the base of the Richards sequence, lending a stratigraphic component to trapping. Poor seal over this unconformity is a possibility and is expressed by increasing prospect risk.

The source of the abundant gas in this play is unknown. The oils are believed to be derived from shales of the lower Richards sequence. The relative quantity of oil and gas for this play was expressed as net gas pay and net oil pay probability curves based on the ratios in the significant number of discovered pools in the play.

The Taglu sequence is not overpressured where drilled. However, it overlies a transition zone into overpressured strata. In prospects deeper than 3500 m, overpressuring may be expected within the Taglu sequence. This is a situation that may prove particularly common in the northeastern area of the play.

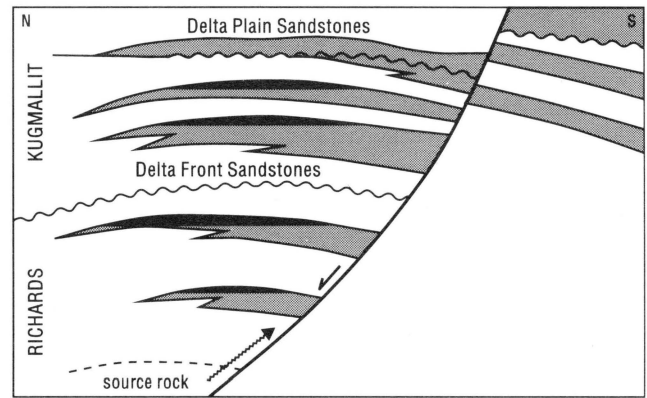
The majority of undrilled prospects in this play lie in shallow water around the fringes of the subaerial Mackenzie Delta. Water depths for the play do not exceed 15 m.

*Exploration History.* Taglu field, discovered in 1971, is the largest gas field in this play. Median value for gas reserves is estimated to be 3 TCF. Subsequent to the discovery of Taglu, 10 additional but smaller discoveries were made in a further 27 exploration wells, for a discovery ratio of 0.370. With the exception of the 1986 gas test at Minuk, discoveries in this play have been onshore in the Mackenzie Delta, or in extremely shallow waters of the delta fringe. Three discoveries contain significant oil reserves associated with gas.

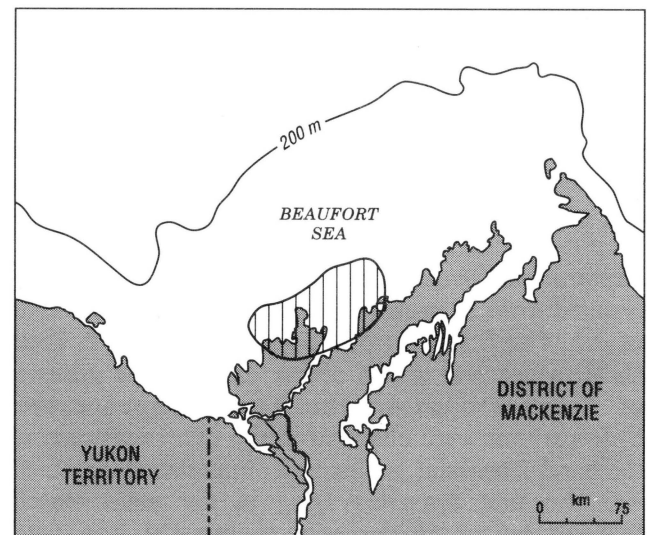
### *Ivik Play*

*Play Definition.* The Ivik play was defined to include all pools and prospects in delta front sandstones of the upper Richards and lower Kugmallit sequences present under the outer Mackenzie Delta and nearshore areas (Fig. 15). It is an oil and gas play.

The play area is limited to the south and west by erosion beneath the Kugmallit sequence and to the northeast by pinch-out of potential reservoir sandstones (Fig. 16). The northern boundary is with the Amauligak play. Different structural type, higher



**Figure 15.** Schematic sketch of the trap types — Ivik Play.



**Figure 16.** Sketch map locating the Ivik Play area.

risk of top seal, thinner potential reservoir, and lower sandstone continuity serve to distinguish between the Ivik and Amauligak plays.

*Geology.* Within the area of this play, delta front sandstones are present beneath the thick succession of Kugmallit delta plain sediments. The delta front deposits are characterized by coarsening-upward packages of siltstone and sandstone, separated by shales. Similar sandstones occur both above and below the sequence boundary between Richards and Kugmallit sequences and are grouped together in this play.

Coarsening-upward packages are typically 30 m thick with 40 per cent net sandstone. Most wells encounter a series of these packages separated by

shales that are effective seals. Lateral pinch-out of delta front sandstones is expected.

Traps in this play are structural and are created by rollover into northeastward-trending listric faults. Syndepositional growth on these faults is likely. Faults commonly juxtapose the upper Kugmallit delta plain sandstones against potential reservoir units with an attendant high risk of cross fault leakage.

The source of gas in this play is unknown. Oils are from a Tertiary source, probably in the lower Richards sequence. The stratigraphic proximity of potential reservoir rocks in the upper Richards and basal Kugmallit sequences to a possible oil source in the lower Richards enhances the prospects for oil migration.

Reservoirs in this play are expected to have normal pressure.

Pools and prospects are within a compact area; they underlie the northeastern Mackenzie delta and are in shallow waters immediately offshore. Water depths do not exceed 12 m.

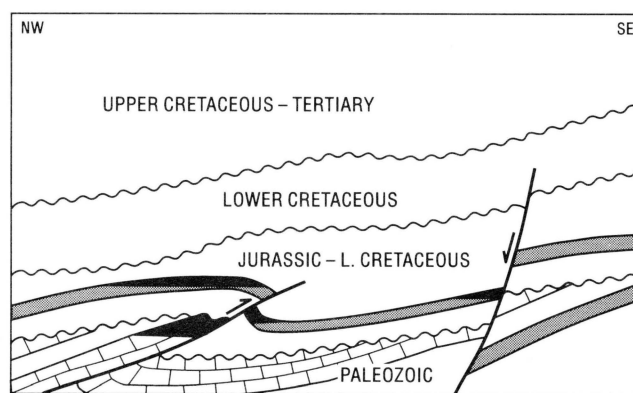
**Exploration History.** Six significant discoveries have resulted from 12 prospects tested, for a discovery ratio of 0.5. The first well to test this play was IOE Taglu G-33, which was drilled deeper to prove the presence of hydrocarbons in the Taglu sequence. No hydrocarbons were observed in the thin sandstones of the basal Kugmallit in this well. Imperial Mallik L-38 was the first discovery (gas) in the play, closely followed by an oil discovery at Imperial Ivik J-26, 12 km to the northeast. Recent discoveries are oil with associated gas at Arnak K-06 and gas with minor oil and condensate at Hansen G-07.

### *South Delta-Mesozoic Play*

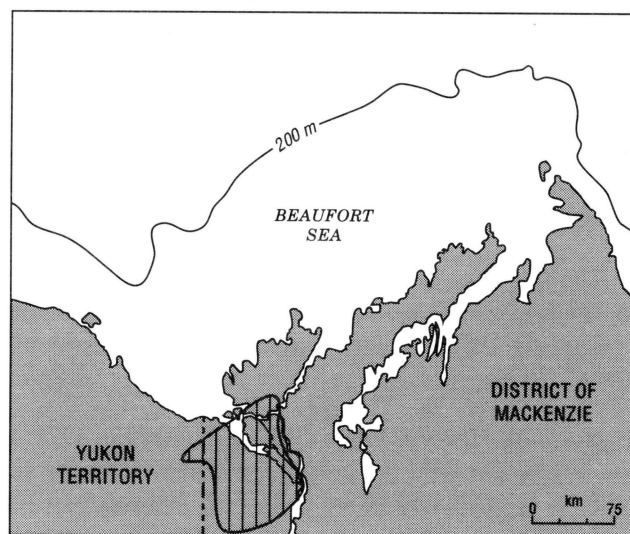
**Play Definition.** This play was defined to include all pools and prospects in Jurassic and Lower Cretaceous sandstones underlying the southern part of the Mackenzie Delta (Fig. 17). It is a gas and oil play.

The play area is between the Caribou Hills in the east, the northern Richardson Mountains in the west, the Eskimo Lakes Fault Zone in the south, and near the Kugpik area on the Mackenzie Delta in the north (Fig. 18).

**Geology.** Within the play area there is a thick succession of Jurassic and Lower Cretaceous strata,



**Figure 17.** Schematic sketch of the trap types — South Delta-Mesozoic Play.



**Figure 18.** Sketch map locating the South Delta-Mesozoic Play area.

consisting of alternating shale- and sandstone-dominant formations. The principal potential reservoirs are the Bug Creek Group, Parsons Group, basal sandstone of the Mount Goodenough Formation, and the Rat River Formation.

Two major unconformities truncate some of the reservoir horizons. An unconformity at the base of the Mount Goodenough Formation has eroded significant amounts of Lower Cretaceous and Jurassic strata. The most pronounced effect has been the truncation of the Parsons Group in the southern half of the play area, especially adjacent to and across from the Eskimo Lakes Fault Zone, and on and adjacent to the Cache Creek Uplift. The Parsons Group is commonly absent

on the upthrown side of the Eskimo Lakes Fault Zone. Adjacent to the Cache Creek Uplift, the Martin Creek and part of the Kamik formations are commonly preserved below the unconformity. In the latter situation, the basal Mount Goodenough sandstone cannot be differentiated from the Kamik sandstones.

The second unconformity separates Lower and Upper Cretaceous strata and is well illustrated in the Kugpik area. There, Upper Cretaceous shale rests erosionally on a truncated Kamik Formation at Kugpik O-13, whereas about 2 km to the west, Upper Cretaceous strata rest erosionally on Permian rocks at Kugpik L-24.

The Lower to Middle Jurassic Bug Creek Group (Poulton et al., 1982; Dixon, 1982) is present throughout the area but its distribution is also affected by the two previously mentioned unconformities, as well as an apparent depositional pinch-out to the east. The Bug Creek Group consists of alternating sandstone and shale units.

The Berriasian to Hauterivian Parsons Group, which consists of the Martin Creek, McGuire, and Kamik Formations, is the thickest and most widespread of the potential reservoir intervals. It originally underlied the whole play area but subsequent erosion (explained above) has modified thickness trends.

Rat River strata are late Barremian to early Aptian in age and consist of a series of coarsening-upward units deposited as marine bars/shoals. Three factors limit its distribution to the northwestern part of the play area: late Aptian/early Albian erosion in parts of the Kugmallit Trough, facies change to a more argillaceous succession to the north and northeast, and truncation by Late Cretaceous and Tertiary events.

The potential reservoirs in the Jurassic-Lower Cretaceous succession are mostly quartz arenites with variable degrees of cementation, although in most places porosity seems to be generally low because of widespread silica cementation. The bulk of the strata are marine in origin, with some local lagoonal and delta plain deposits in the basal part of the Kamik Formation.

Adequate seals are present in the thick shale successions separating the sandy formations.

Trap types are dominantly structural, consisting of closure against faults. Normal faults are the most common type but the Unak L-28 well, in the northern

part of the area, penetrated a repeated Mesozoic section, indicating the presence of thrust faults. The thrust faults are believed to be present only in the northwestern part of the play area. Generally poor quality seismic reflection data in parts of the play area make it difficult to map thrust faults and the related closure.

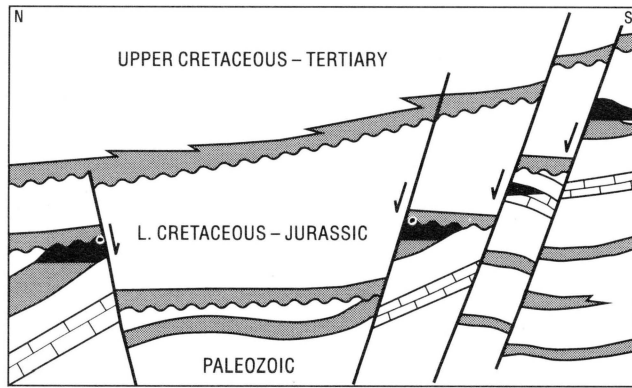
Potential source rocks are present in the extensive Jurassic and Lower Cretaceous shale successions, although terrestrially derived organic matter is dominant, indicating a gas-prone source. Some parts of the Albian Arctic Red Formation contain good marine source rocks, although levels of maturity of this shallowly buried interval are not generally high. The Upper Cretaceous Boundary Creek and Smoking Hills formations are the richest, oil-prone source rocks in the play area but due to Tertiary and Quaternary erosion they are limited to the northern part of the play area.

*Exploration History.* Approximately 14 wells in the play area penetrated Jurassic and Cretaceous strata, of which two were discoveries. Kugpik O-13 was drilled in 1973 and recovered oil from a truncated Parsons Group. The source rock is believed to be the Smoking Hills Formation, which directly overlies the Parsons Group at Kupik O-13. The second discovery was Unak L-28, drilled in 1986, in which gas was recovered from the Rat River Formation.

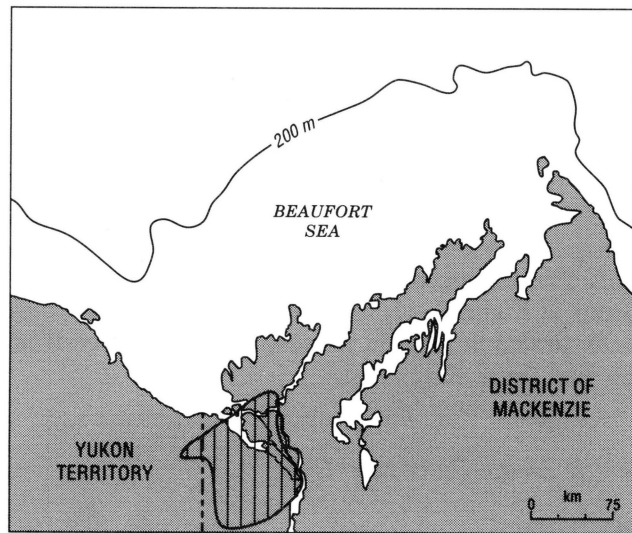
### *South Delta-Paleozoic Play*

*Play Definition.* This play was defined to include the pools and all the prospects in Upper Paleozoic strata underlying the southern part of Mackenzie Delta (Fig. 19). The play area is between the Caribou Hills in the east, the northern Richardson Mountains in the west, the Eskimo Lakes Fault Zone in the south, and near the Kugpik area on the Mackenzie Delta in the north (Fig. 20). Gas may be the principal hydrocarbon.

*Geology.* Our understanding of Upper Paleozoic stratigraphy in this part of Mackenzie Delta is poor. Only 11 wells have penetrated Upper Paleozoic strata, most of which have only minimal penetration. Permian strata are mostly clastics, predominantly interbedded shale and sandstone, with some local coarser strata. The Permian strata presumably correlate with the Sadlerochit Group in the British Mountains to the west. Presumed Carboniferous strata contain a mixture of clastics and carbonates and probably correlate with the Lisburne Group of the British Mountains and northeast Alaska.



**Figure 19.** Schematic sketch of the trap types — South Delta-Paleozoic Play.



**Figure 20.** Sketch map locating the South Delta-Paleozoic Play area.

Porosity and permeability in the penetrated Upper Paleozoic section is generally poor, and poor reservoir quality may be widespread. Fracturing in the carbonates could enhance porosity and permeability.

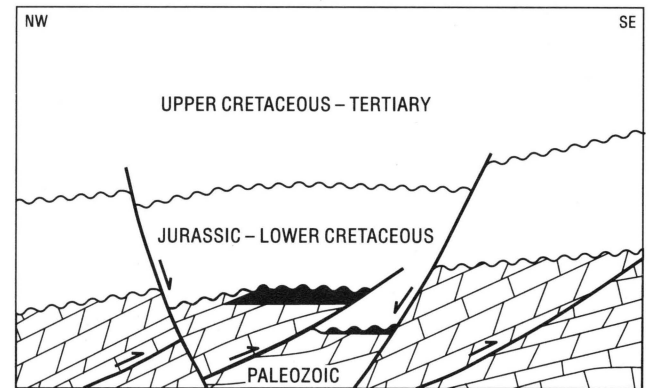
Structural traps consisting of closure against faults are readily recognized. Normal faulting is present throughout the play area but thrust faults are also present, at least in the northwestern part of the play area. The thrust faults are difficult to identify with presently available seismic data.

Potential Upper Paleozoic source rocks have not been identified but juxtaposition of Paleozoic reservoirs against Mesozoic source rocks could provide good trapping situations.

**Exploration History.** No significant discoveries or shows were recorded from Upper Paleozoic strata until Unak L-28 was drilled in 1986. There, gas was recovered from Upper Paleozoic limestones.

### *Mayogiak Play*

**Play Definition.** This play was defined to include all pools and prospects in Paleozoic carbonates underlying the Tuktoyaktuk Peninsula and the southern part of the Mackenzie Delta (Fig. 21).

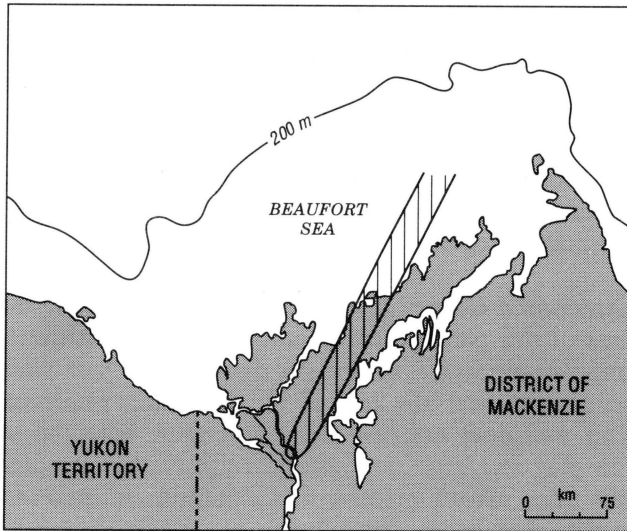


**Figure 21.** Schematic sketch of the trap types — Mayogiak Play.

The play area extends from the southern part of the Mackenzie Delta along the northwest side of the Tuktoyaktuk Peninsula into the shallow water areas of the Beaufort Sea (Fig. 22).

**Geology.** Fine to coarsely crystalline dolostone, bioclastic limestone and peloidal limestone are present in the poorly understood carbonates that subcrop under the Tuktoyaktuk Peninsula. Wielans (1987) compared them to the Lower Paleozoic succession in the Interior Plains to the south, based on lithological similarity and a limited amount of paleontological data. The north to north-northeast striking subcrop pattern of these carbonates indicates that the strata were faulted or folded prior to Mesozoic deposition (Wielans, op. cit.).

The limited lithological information indicates that the penetrated successions are mostly platform carbonates with generally poor porosity. Fractures enhance the porosity, and are present in the Mayogiak J-17 and West Atkinson L-17 reservoir strata.



**Figure 22.** Sketch map locating the Mayogiak Play area.

Overlying Jurassic–Cretaceous strata contain thick shale units that provide adequate seal.

Traps are anticipated to be tilted fault blocks along the northwestern flank of the Eskimo Lakes Arch.

The two discoveries to-date have been oil, apparently derived from the Upper Cretaceous Smoking Hills Formation. Both discoveries are located on the northwest flank of the Eskimo Lakes Arch, in a good position to trap migrating hydrocarbons from the deeply buried section in the Kugmallit Trough. No indigenous potential source rocks are known within the Paleozoic carbonates, although throughout the area the carbonates are capped by the Canol shale, an organic-rich unit. However, the Canol shale is usually thermally overmature in the play area and may be expected to be a gas source.

**Exploration History.** Eighteen separate tests have penetrated Lower Paleozoic carbonates, although there are as many more penetrations on the Parsons structure. Only two discoveries have been made, one at Mayogiak J-17 and another at West Atkinson L-17, both are oil in fractured carbonates. At J-17 the reservoir is in dolostone, presumed to be equivalent to the Ronning Group, and at L-17 the reservoir is in limestone of presumed Landry equivalence.

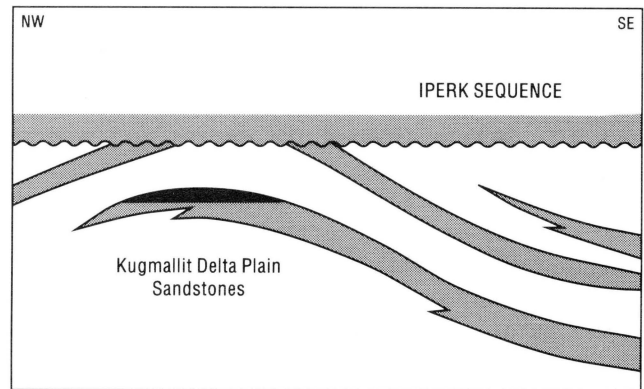
### **Offshore Delta Play Group**

The Offshore Delta Play Group consists of four plays confined to a narrow fairway located over the

conjunction of a series of major listric faults and the front of the Tertiary deltas. Average water depth for the plays is about 25 m. Drilling is most commonly done from ice reinforced drillships and floating platforms, or from specially designed caisson reinforced islands. Acquisition of seismic information over the play areas is by conventional marine methods.

### **Netserk Play**

**Play Definition.** The Netserk play was defined to include the pools and all the prospects in the delta plain facies of the Kugmallit sequence and the transgressive sandstones at the base of the Mackenzie Bay sequence that underlie the inner shelf areas offshore from Mackenzie Delta (Fig. 23). It is primarily a gas play.

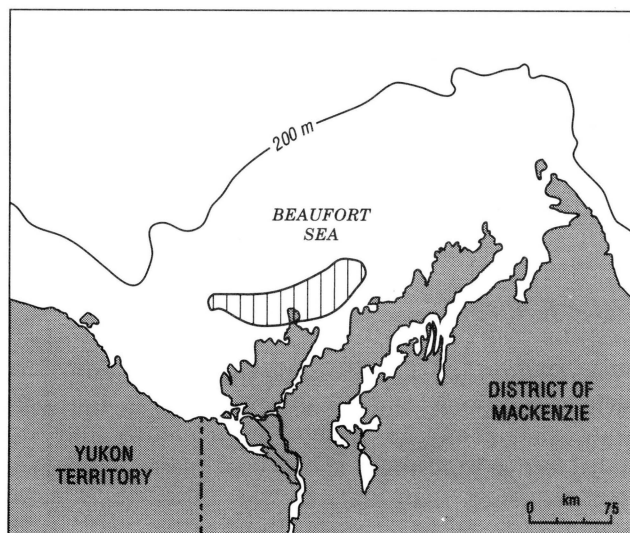


**Figure 23.** Schematic sketch of the trap types — Netserk Play.

The water is less than 10 m deep across much of the play area, increasing to 18 m in the northeastern corner of the play. About half of the play area is in water less than 5 m deep with prospects accessible from offshore islands.

The play is bounded on the northern side by a facies transition to delta front strata (Amauligak play) and to the east and west by limits of sand deposition (Fig. 24). The southern limit is controlled by sub-Iperk erosion of Mackenzie Bay shales. The play is underlain by strata of the Ivik Play over most of its extent.

**Geology.** This play is characterized by thick potential reservoir sections of high porosity and permeability. Net sand thickness varies from 200 m in areas of the delta plain which were remote from preferred river tracts, to more than 1000 m along an axial thick



**Figure 24.** Sketch map locating the Netserk Play area.

running south to north through the central area of the play. The sand-to-shale ratio is commonly between 0.5 and 0.7, declining toward the eastern and western limits of the play. Sandstones are blocky in log profile, and occur in units 50 to 200 m thick. The sandstones are fine to medium grained with coarse to conglomeratic channel lags common. Few shales are present within the sandstone units. In general, the sandy nature of the section increases the risk of absence of a seal for this play.

Deposition of sandstones occurred in stacked channel tracts on the delta plain. Orientation of the axes of these tracts varied between northwesterly and northeasterly. The pinch-out of sandstone units characterizes the flanks of the channel tracts. The orientation of channel tracts coincides with the orientation of anticlinal axes in this area of the basin. The updip pinch-out of a channel tract on the flanks of these anticlines is a potentially effective trap and constitutes the principal trapping mechanism in this play.

Channel sandstones that extend across the crests of anticlines create purely structural traps. Crestal erosion of anticlines has resulted in prospects of this type being few and they have been included in this play as having a high risk equivalent to the flanking stratigraphic trap.

The potential hydrocarbon in this play is expected to be gas, possibly from a source within the Kugmallit sequence or migrating vertically from deeper units. Oil

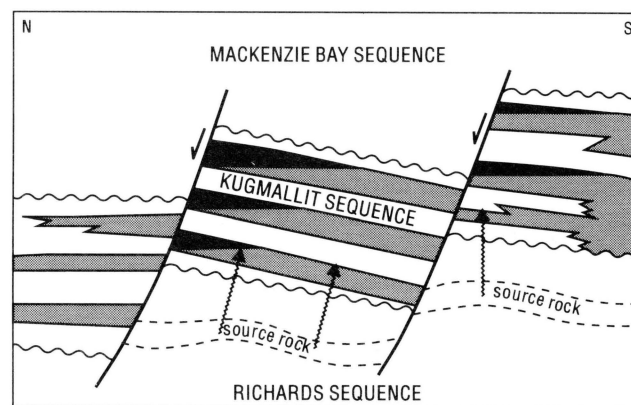
from the underlying Richards sequence and present in pools in the basal Kugmallit and upper Richards sequences is unlikely to have migrated in sufficient volume through the thick delta plain succession to form significant accumulations. Prospects in this play are elongate in a north-south direction. Drainage characteristics of pools are likely to be excellent. Normally pressured reservoirs are anticipated.

**Exploration History.** Ten wells have been drilled in the area of this play, generally on the crests of anticlines. Imperial Netserk F-40 is a gas discovery in delta plain sandstones near the top of the Kugmallit sequence. This well does not test the stratigraphic potential of this play and is on the western fringe of the play area but does afford positive confirmation of reservoir quality and hydrocarbon type.

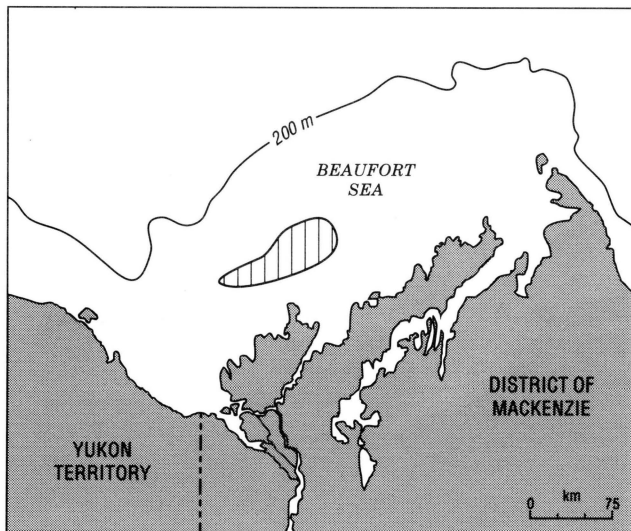
### *Amauligak Play*

**Play Definition.** The Amauligak play was defined to include all pools and prospects within proximal delta front sandstones of the Kugmallit sequence that underlie the mid-shelf area of the Beaufort Sea immediately north of Mackenzie Delta (Fig. 25). It is an oil and gas play.

Vertical stacking of depositional environments during Kugmallit deposition enables facies boundaries to be used to delineate the play area (Fig. 26). The play is bounded to the south by the facies boundary with the delta plain facies of the Kugmallit sequence (Netserk), and to the north by the facies boundary with the distal delta front and shelf facies (Tarsiut and Akpak). The play area is entirely offshore in water depths between 15 and 35 m.



**Figure 25.** Schematic sketch of the trap types — Amauligak Play.



**Figure 26.** Sketch map locating the Amauligak Play area.

**Geology.** The proximal delta front facies of the Kugmallit sequence is characterized by coarsening-upward sandstone units, generally capped by a thick sandstone, indicative of high-energy processes operating in the shallow marine environment. Wells drilled within the area of this play encountered numerous sandstones of this type, separated by shales and siltstones. The overall net sand varies between 20 and 30 per cent of the Kugmallit sequence.

Evidence for the dissolution and removal of clay minerals and the development of secondary porosity has been noted in Kugmallit sandstones from several wells and is expected to characterize this play (Schmidt, 1987).

Pools in this play are characterized by reservoir sandstones between 5 and 15 m thick, an average porosity of 21 per cent, but with 30 per cent common, and recovery factors estimated (in the absence of sustained production statistics) to be 30 per cent. The larger fields contain numerous stacked pools with different water lines. Reservoir sandstones are expected to have good continuity across most prospects.

Thick interbedded shales and the overlying Mackenzie Bay shale succession provide good seals. A cross fault seal can be a problem where the throws are insufficient to completely juxtapose the Kugmallit sequence against the Mackenzie Bay shales.

Major post-depositional movements of faults of the Tarsiut-Amauligak Fault Zone have resulted in the

development of large rotated fault blocks, which comprise the class of structural trap envisaged in this play. The throw of these faults can be very large (in the order of thousands of metres) and sufficient to juxtapose reservoir sandstones with older source rocks of the lower Richards sequence.

Source rocks for this play have produced both oil and gas in large quantities with oil and gas being typical of the large discoveries and gas typical of the smaller discoveries. A general increase in the relative quantity of oil occurs with depth below the top of the Kugmallit sequence: the higher zones tend to be filled with gas, and the lower zones, with much less gas and more oil. This phenomenon can be rationalized in terms of differential segregation of the lighter and heavier hydrocarbons during migration.

Reservoirs in the Kugmallit sequence are generally normally pressured although increasing formation pressures occur toward the base of the Kugmallit sequence in some wells. Overpressured reservoirs in the deeper prospects are a possibility.

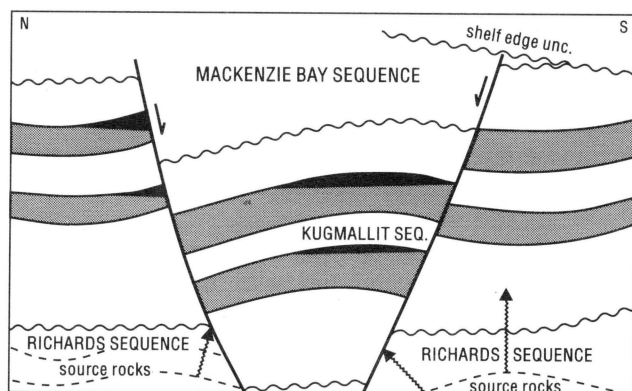
Discovered pools and prospects are elongate along the strike of the controlling fault but not excessively so: length to breadth ratios of 1:3 are typical.

**Exploration History.** Of a total of nine prospects tested in this play, six are regarded as significant discoveries resulting in an excellent discovery ratio of 0.71. However, of these discoveries five are oil and gas discoveries (Nipterk, Issungnak, Itiyok, Amauligak and West Amauligak), the remaining two (Amerk and Isserk) are small gas discoveries. Failures have occurred at North Issungnak and Kaubvik (suspect closures), and Kogyuk (suspect closure or failure of updip migration?). The low trap-fill typical of the small gas discoveries is probably the result of inadequate vertical migration.

The first well drilled in this play was Imperial Isserk E-27. A series of exploration wells followed through the early eighties, all drilled from artificial islands, which culminated in the 1984 discovery of the Amauligak field by Gulf Canada Ltd. and partners.

### *Tarsiut Play*

**Play Definition.** The Tarsiut play was defined to include all pools and prospects within distal delta front strata of the Kugmallit sequence located in the mid-shelf areas offshore from the Mackenzie Delta (Fig. 27). The play includes both gas and oil.



**Figure 27.** Schematic sketch of the trap types — Tarsiut Play.

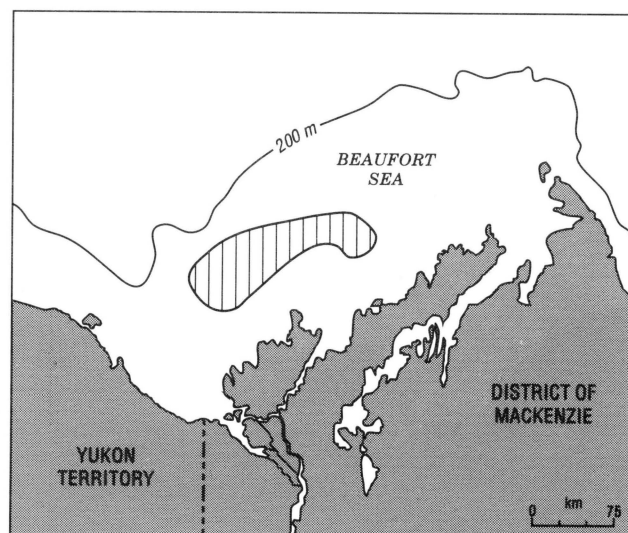
The play area (Fig. 28) is bounded to the south by a facies change to proximal delta front (Amauligak Play), to the north by the Kugmallit shelf edge, and to the east and west by the disappearance of a potential reservoir at the fringes of deltaic influence. The play is entirely offshore in water depths varying from 15 to 35 m.

**Geology.** The distal delta front facies of the Kugmallit sequence is characterized by packages of interbedded sandstone and siltstone separated by thick shales. The sandstone/siltstone packages generally exceed 50 m in thickness and reach 200 m in some of the more proximal wells. Although most wells have encountered several stacked sandstone/siltstone packages, there is increasing risk of absence of reservoir toward the northern and western (distal) limits of the play.

The incidence of sandstone beds increases upward through these packages giving an overall appearance on logs of coarsening-upward. Bed thicknesses seldom exceed 2 m and are more commonly 1 m or less. Net clean sandstone within the sandstone/siltstone packages averages 20 per cent. Individual sandstone beds commonly have an abrupt base and exhibit some fining-upward with increasing lamination and silt content. Excellent porosity occurs in the coarse and medium grained sandstones and may be partially due to secondary dissolution. The thin bedded nature of the reservoir is recognized as adversely affecting the recovery factor.

The thick interbedded shales and overlying shale succession of the Mackenzie Bay sequence provide good seals.

The majority of traps in this play are structural and were created by major post-depositional movement on



**Figure 28.** Sketch map locating the Tarsiut Play area.

faults of the Tarsiut–Amauligak Fault Zone. These faults are long, sinuous, and trend east-northeast. Throws are commonly large and variable along the fault and may be down-to-basin or antithetic. Resulting pools and prospects tend to be elongate along the strike of the fault with length-to-breadth ratios commonly exceeding 4:1.

Pinch-out of the sandstone/siltstone packages adds a stratigraphic component to trapping. These pinch-outs are visible seismically and have influenced the location of some wells. For this reason, the stratigraphic component is not considered to increase risk of reservoir absence across prospects, rather it leads to an increased number of smaller prospects.

A relatively small number of prospects in this play require a subunconformity seal as a trapping component. The unconformity in question occurs near the edge of the Kugmallit paleo-shelf and progressively truncates the Kugmallit sequence to the north. This truncation affects the northern limit of the play where reservoirs are anticipated to be poor or absent. These prospects are not, therefore, considered to be important components of the play.

Hydrocarbon source rocks for this play occur in the lower Richards sequence. Discoveries to date have been either gas or oil. The gas discoveries may reflect high maturity in the source rock gas generation in the southwest and vertical migration of gaseous hydrocarbons only in discoveries with very low trap-fill. Oil discoveries require long vertical migration routes, probably up fault planes from lower Richards source rocks within the oil window. With no adequate

model available for predicting the types of hydrocarbons generated and their migration routes, a simple split of predicted pools into oil or gas was made on the basis of the current ratio of oil to gas discoveries.

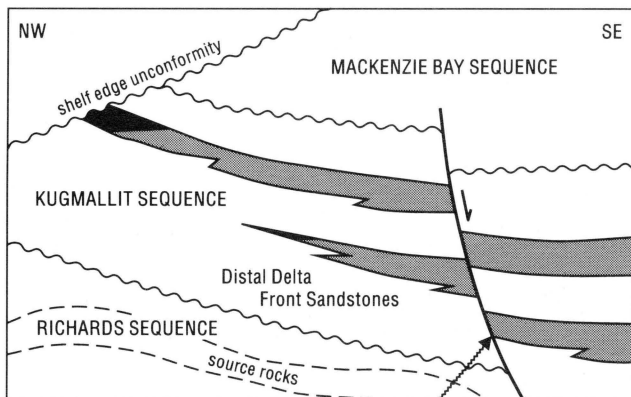
Reservoirs in this play are expected to be normally pressured.

**Exploration History.** The first well drilled in this play was Dome et al. Tingmiark K-91. It was abandoned prematurely after encountering a gas kick at the top of the Kugmallit sequence and was not fully evaluated. The Ukalerk gas discovery followed. The first oil in the play was discovered in Dome et al. Tarsiut A-25. A total of seven prospects have been adequately tested resulting in six significant hydrocarbon discoveries for an extremely high discovery ratio of 0.857. Of these, two are oil discoveries and four are gas.

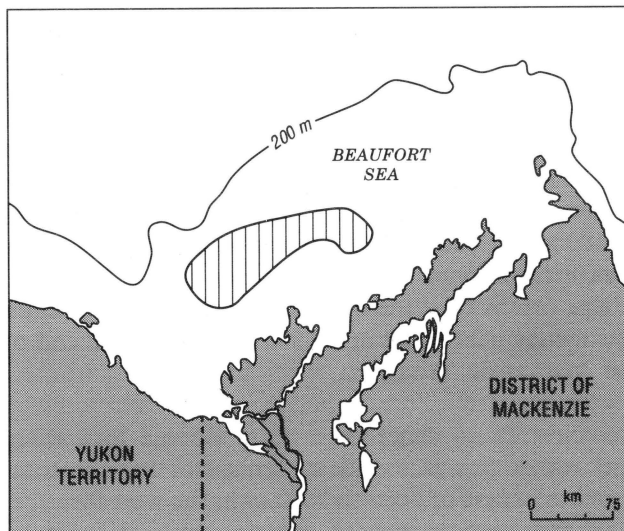
### Akpak Play

**Play Definition.** The Akpak play was defined to include all prospects in distal delta front strata of the Kugmallit sequence that underlies a shelf edge unconformity under the mid- to outer-shelf of the Beaufort Sea (Fig. 29). It is an oil and gas play. The play area (Fig. 30) parallels the Kugmallit paleo-shelf edge distal to the Tarsiut play. Prospects lie in water depths between 35 and 55 m.

**Geology.** The distal delta front facies of the Kugmallit sequence has been described for the Tarsiut play. Sandstones are generally thin bedded and thick vertical sequences of potential reservoir are not expected in this distal area of the delta front.



**Figure 29.** Schematic sketch of the trap types — Akpak Play.



**Figure 30.** Sketch map locating the Akpak Play area.

A reversal of regional dip toward the shelf edge, combined with a downcutting unconformity present at the shelf edge have created a unique trapping configuration which characterizes this play. Updip reservoir sites for hydrocarbons terminate beneath this unconformity and also at delta front sand pinch-outs.

The play is characterized by a relatively small number of prospects although some are of large size. High risks are assigned to the presence of sandstones of reservoir quality and to hydrocarbon migration.

**Exploration History.** Gulf et al. Akpak 2P-35 is the only well to have been drilled into this play. The well was dry and abandoned. A high recovery of formation fluids from a 7 m sandstone within the Kugmallit sequence indicates good permeability. In general, however, the Kugmallit was sand-poor in the well.

### West Beaufort Play Group

The West Beaufort Play Group consists of three plays that differ significantly in their geological context from the Offshore Delta Play Group. Their plays are located mainly west of the Mackenzie Trough and lie offshore from the Arctic Wildlife Refuge. These two geographic factors severely impact upon the economics of transporting the products of potential discoveries.

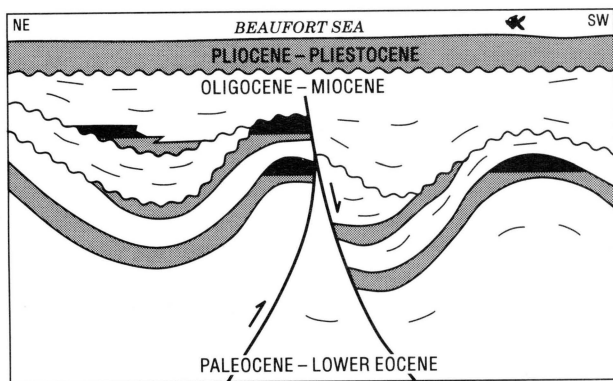
### Adlartok Play

**Play Definition.** This play is defined to include all prospects and the one pool in the large anticlinal

structures that involve Paleocene and Eocene deltaic sandstones in the west Beaufort Sea Region. Secondary targets include unconformity-related stratigraphic traps in sandstones on the flanks of the folds (Fig. 31). The play area extends from the Yukon coastline north and northeastward to the (interpreted) depositional limits of the lower Tertiary deltaic facies (approximately 80 to 100 km offshore). The eastern boundary of the play area extends onto western Richards Island (Fig. 32). Water depths over the offshore prospects vary from a few metres near shore up to 300 m at the north end of the Mackenzie Trough.

**Geology.** The Paleocene to Early Eocene Fish River and Aklak (lower Reindeer) sequences have a combined thickness of 5000 to 7000 m in the west Beaufort area and both sequences contain thick and areally extensive successions of delta plain and delta front strata. The delta plain deposits consist of 10 to 40 m thick fining-upward and coarsening-upward sandstone and conglomerate sections interbedded with thin shale and coal beds. The delta front deposits consist of 50 to 100 m thick coarsening-upward sandstone sections separated by thick shale beds. Sandstone porosity in these successions varies from 10 to 20 per cent. The lower porosity values result from carbonate and silica cementation within the sandstones. Other potential hydrocarbon reservoirs in the play area include shallow marine transgressive sandstones. The transgressive deposits occur above major erosional unconformities of Early and Middle Eocene age, which locally truncate substantial sections of subunconformity strata.

Oligocene and Miocene sediments throughout most of the West Beaufort area are mudstone dominant and should provide adequate seals for many of the structural prospects.



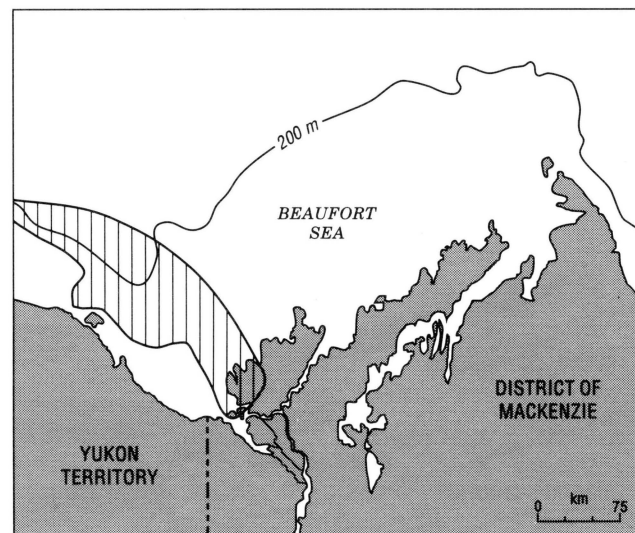
**Figure 31.** Schematic sketch of the trap types — Adlartok Play.

Structural traps in the play area exist on large, asymmetric anticlines oriented in an arcuate array extending from Mackenzie Bay around to the Canada-U.S. border. The anticlines are compressional structures and are locally cored by thrust or high-angle reverse faults. In addition to the anticlinal structures, the play area also contains numerous normal listric faults, most of which are oriented in a northeast direction. The normal faults modify or form part of many of the structural closures.

Potential hydrocarbon source rocks include the Tertiary shales of the lower Richards and lower Fish River sequences and the oil-prone shales of the Boundary Creek Formation. The distribution of Boundary Creek strata beneath the western Beaufort Sea is not known and its potential as a major oil source remains in question. Coal beds within the Tertiary deltaic sections may have some gas source potential. The Lower Tertiary sequences in the west Beaufort Sea Region are at higher levels of thermal maturation than seen elsewhere in the basin. The maturation conditions appear to be very good for significant hydrocarbon generation in at least parts of the play area.

**Exploration History.** The 1985 oil discovery at Adlartok P-09 is the only discovery in the west Beaufort fold belt.

The uppermost portion of the prospective Fish River-Aklak deltaic section has been unsuccessfully tested in 2 offshore wells and 4 onshore wells. Most of these partially tested prospects still have hydrocarbon



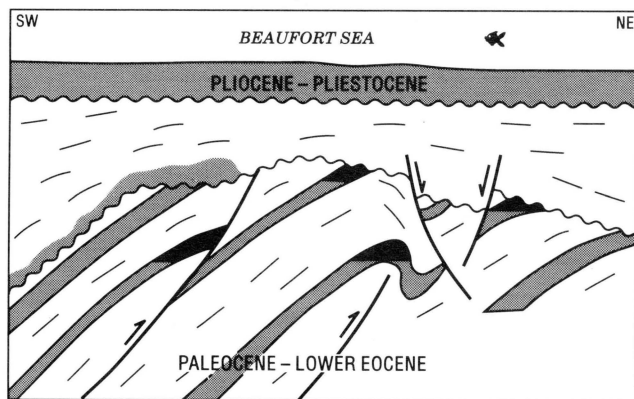
**Figure 32.** Sketch map locating the Adlartok Play area.

potential in deeper reservoir sections (typically below 3500 m) which were not penetrated by the individual wells. The stratigraphic targets have been unsuccessfully tested by one well (Natsek E-56). At least 60 large structural prospects remain completely untested along with a number of stratigraphic targets in the play area.

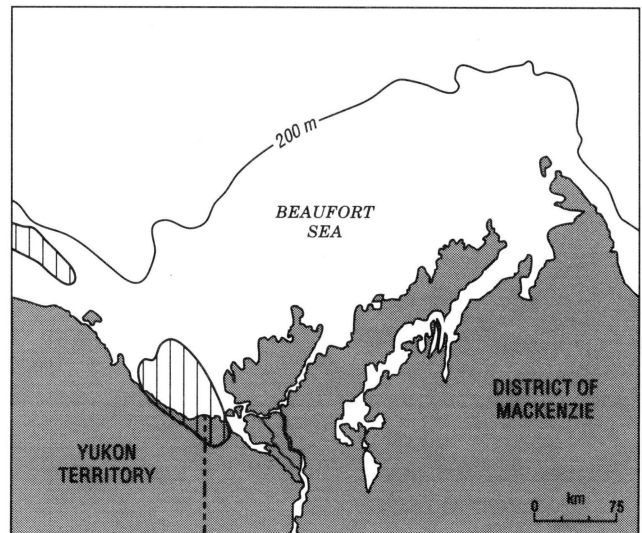
### Herschel Play

**Play Definition.** This play is defined to include all prospects in the complexly deformed Paleocene–lower Eocene strata within the Herschel and Blow River highs (Fig. 33). The two structural complexes occur beneath shallow waters of the southwestern Beaufort shelf (Fig. 34). The Blow River High extends on shore beneath the coastal plain near the Yukon–N.W.T. border.

**Geology.** The Paleocene to Early Eocene Fish River and Reindeer sequences are intensely folded and faulted within the cores of two structurally elevated complexes that form components of the west Beaufort Tertiary fold belt. Potential reservoirs within the deformed Lower Tertiary sequences include delta plain and delta front sandstones, similar to those in the Adlartok play. The Hershel and Blow River highs are cored by high amplitude, closely spaced folds and reverse faults (Fig. 33). Significant erosion of submiddle Eocene strata occurs over the crests of the two highs. Steep (internal) structural dips and crest erosion limit the potential of both complexes. Potential traps will be relatively small areally, confined to the crests of the folds, and may include sandstones that subcrop the unconformity. Potential hydrocarbon sources may include Paleocene and Upper Cretaceous shales.



**Figure 33.** Schematic sketch of the trap types — Herschel Play.



**Figure 34.** Sketch map locating the Herschel Play area.

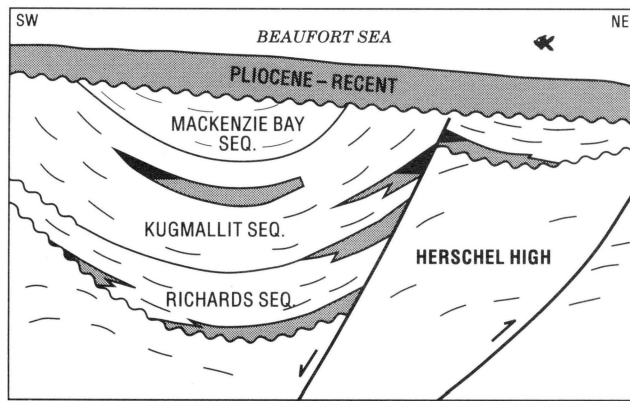
**Exploration History.** No wells have been tested in either of the Herschel or Blow River highs. Only two wells (Natsek E-56 and Adlartok P-09) delimit the stratigraphy for this large area.

### Demarcation Play

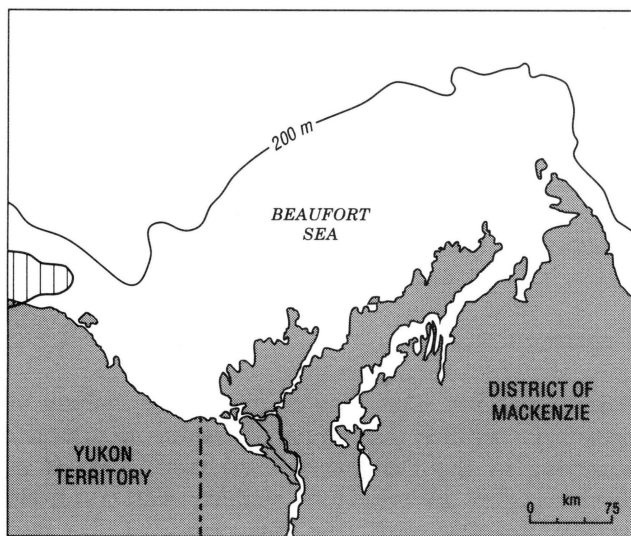
**Play Definition.** This play is defined to include all prospects within the Upper Tertiary depocentre occurring in the Demarcation subbasin. This is an offshore play in relatively shallow waters of the western Beaufort shelf (Fig. 36).

**Geology.** The Demarcation subbasin is an east–west trending, asymmetric syncline containing up to 7 km of post-middle Eocene sediments within the Richards, Kugmallit and Mackenzie Bay sequences. Potential reservoirs within the subbasin fill include transgressive sandstones above the base-Richards unconformity at the subbasin floor and turbidite and shelf sandstones within and along the subbasin margins (Fig. 35). Porosity in the sandstones of the Upper Tertiary sequences averages 25 to 30 per cent.

The structure of the Demarcation subbasin is relatively simple with little internal deformation. A normal fault along the north margin of the subbasin may contribute a structural component to the (otherwise) stratigraphic subbasin traps. Hydrocarbon sources may occur in the deeper portions of the subbasin or in adjacent Lower Tertiary strata of the Herschel High complex.



**Figure 35.** Schematic sketch of the trap types — Demarcation Play.



**Figure 36.** Sketch map locating the Demarcation Play area.

**Exploration History.** The Demarcation subs basin has been partially penetrated by one well (Edlok N-56) along the eastern basin flank. This well was dry and abandoned, but did encounter reservoir quality sandstones. Analysis of seismic reflection data indicates that the most prospective portion of the subs basin occurs northwest of the Edlok location.

### Deep Water and Other Play Group

Five plays are recognized in this group (one real, four conceptual). Two of the plays dominate the group's resource endowment and occur in deep water, beyond the Offshore Delta Play Group. These two plays share a common problem of potentially thin reservoirs on

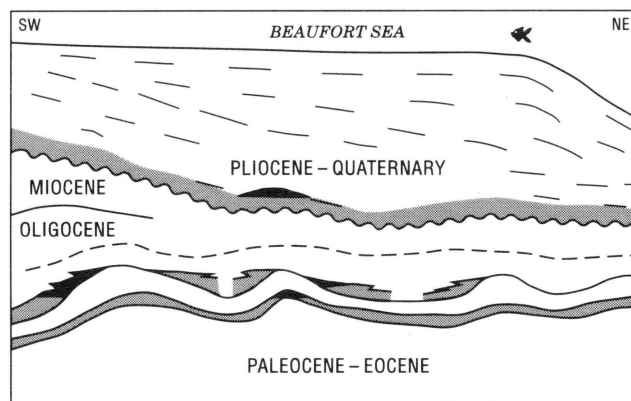
large structures, that would then require more development wells per given field size, thus significantly increasing project costs. Prospects in these deeper water plays are normally drilled from ice-reinforced drillships. The three remaining conceptual plays will probably not attract serious exploration until a viable infrastructure based on more attractive prospects becomes established.

### Kopanoar Play

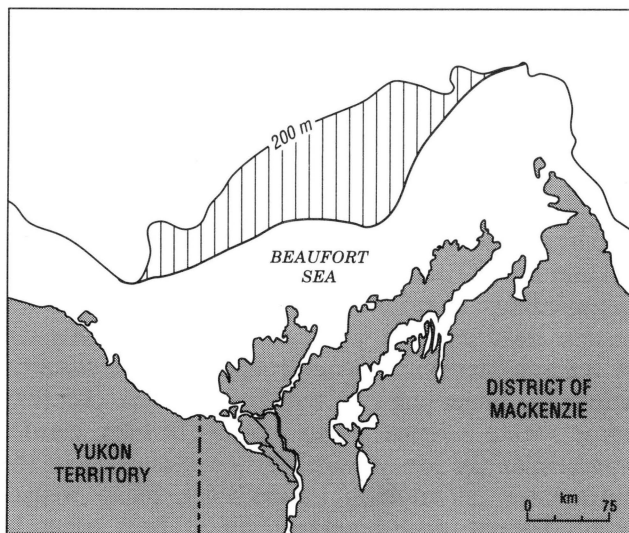
**Play Definition.** This play was defined to include all pools and prospects involving deep water sandstones deposited on the continental slope, rise and basin plain as components of submarine fans. The principal trap type is a structural drape with a strong component of stratigraphic pinch-out (Fig. 37). The play contains pools with a varied mixture of oil and gas.

The southern margin of the Kopanoar play is the shelf to slope transition of Oligocene strata. The play extends northward beneath the outer portions of the modern shelf (Fig. 38). The northern limit is arbitrary and is drawn at the present day shelf edge. Reservoir targets are principally Oligocene and Miocene strata and are restricted to the eastern Beaufort-Mackenzie Basin. Most prospects in this play lie in water depths between 60 and 100 m.

**Geology.** Reservoirs assigned to this play have been encountered in the Mackenzie Bay, Akpak, Kugmallit, and possibly older sequences. The Kugmallit sequence, in particular, contains strata equivalent in age to sand-rich deltaic deposits on the adjacent shelf. Potential reservoir sections in this play comprise packages of thin bedded sandstone up to several hundred metres in overall thickness. Individual sandstone beds are less



**Figure 37.** Schematic sketch of the trap types — Kopanoar Play.



**Figure 38.** Sketch map locating the Kopanoar Play area.

than 1 m thick and interbedded with siltstone and shale. The sandstones have a higher clay and silt content, and a correspondingly reduced porosity and permeability, than those on the shelf.

Sandstone units between 5 and 30 m thick are rarer than the thin bedded sandstone packages. These are fine to medium grained, with a fining-upward log profile, an average porosity of 15 per cent, and more homogeneous permeability. These sandstones can be attributed to deposition by channel processes on submarine fans, whereas the finer grained, thin bedded units would represent the product of interchannel processes.

Wide variation in thickness is evident within seismic sequences beneath the area of this play. The mounded appearance on seismic sections suggests rapid change in the thickness of lithological units. Delineation drilling at Kopanoar has revealed a complex situation of pinch-out and/or local erosion, and a partial drape of reservoir units across a large anticline. Thus reservoir continuity, both on a large scale across structures and on the smaller scale of individual sandstone beds, must be given a high risk factor.

Most remaining mapped prospects are distal to existing discoveries. However, a diversity of stratigraphic traps are undoubtedly present within the proximal area of the play and may become viable drilling targets.

Oils and condensates in this play are sourced from the Richards sequence and are characterized by a very

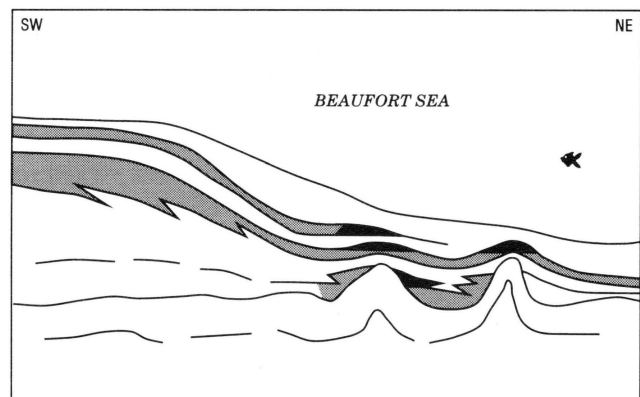
low level of maturity. Gas may well have originated in several unidentified source rocks within the play area. The absence of oil in the most distal discovery at Kenalookak may be an indication that the Richards oil source is ineffective in this portion of the area.

**Exploration History.** Thirteen wells have been drilled in this play with most tests in the proximal area of the play. With six significant discoveries, the success ratio is high. However, the characteristics of very thin sandstone beds, broad structures, and inconsistent pay distribution within the reservoirs reduces the volume of entrapped hydrocarbons that could be considered recoverable from most of these discoveries. However there does exist the possibility that local conditions could have created above average reservoir characteristics which, coupled with the large size of the prospects, would result in very large accumulations.

### *Deep-Marine West Play*

**Play Definition.** This conceptual play was defined to include all hydrocarbon prospects with traps in turbidite sandstones of Tertiary age. The play is similar in nature to the turbidite play to the southeast, but includes older (Paleocene–Eocene) potential reservoirs and is located in an area of deeper water. Water depths over the slope and rise increase from 200 m at the shelf edge to 2700 m at the northern limit of the play area. The traps occur along the flanks of, or are draped over, low-relief folds of large areal extent (Fig. 39).

The play area is bounded on the west by the 141st meridian of west longitude, and underlies the present day continental slope and rise of the western and central Beaufort Sea (Fig. 40).



**Figure 39.** Schematic sketch of the trap types — Deep-Marine West Play.

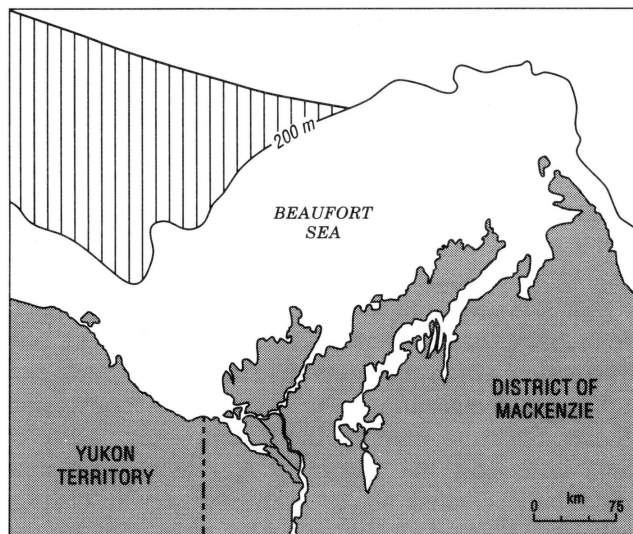


Figure 40. Sketch map locating the Deep-Marine West Play area.

*Geology.* Potential reservoirs in the northern areas include turbidite sandstones within the Aklak and Fish River sequences and, to a lesser extent, younger Tertiary sequences of Oligocene to Pliocene age. Most of the Tertiary section in this northern play area is expected to be mudstone-dominant basinal (or slope) facies.

The anticlines within the Deep-Marine West play area form the northern extension of the west Beaufort fold belt. Structures within the fold belt become more symmetrical, less faulted and more diapiric (in appearance) in a northward direction.

The nature and thermal maturation conditions of potential hydrocarbon source rocks are unknown, but it does appear that at least some gas has been generated and trapped in the play area. Seismic reflection profiles across several of the anticlinal structures display direct seismic hydrocarbon indicators, indicating local gas accumulations.

*Exploration History.* No wells have been tested in the play area. The deep water over most of the structures may slow the pace of exploration in this region.

### Hinge Play

*Play Definition.* This conceptual play was defined to include any pooled hydrocarbons associated with two onlapping seismic sequences that overlie two distinct flexures or hinge lines in underlying bedded sequences (Fig. 41). The potential reservoir sequences are believed

to represent Lower Tertiary and Lower Cretaceous sandstones. The play occurs (Fig. 42) beneath the eastern Beaufort Sea shelf, north of the Tuktoyaktuk Peninsula, in water depths from 20 to 60 m. The play probably extends to the northeast, to offshore Banks Island (and beyond).

*Geology.* The offshore (northeast) extension of the Eskimo Lakes Fault Zone is represented by two major tectonic hinge lines (and associated faults) beneath the eastern Beaufort Sea. The basinward (northwest) dip of the sub-Mesozoic unconformity increases abruptly across the hinge lines or fault zones. Reservoirs may occur within Cretaceous or Lower Tertiary clastics which onlap the sub-Mesozoic strata, basinward of the hinge lines. In addition to the thick onlap wedge, small, normal, fault-bounded half grabens occur in

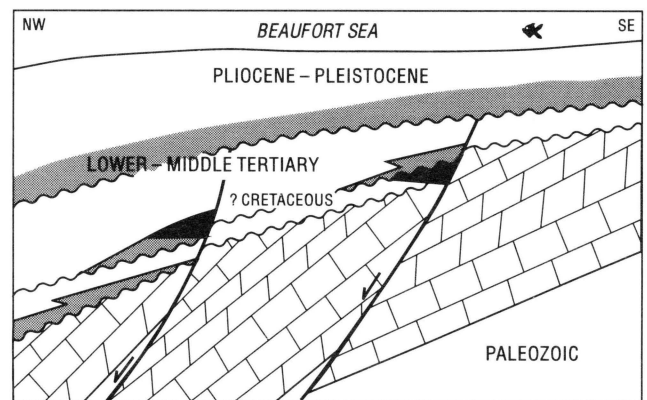


Figure 41. Schematic sketch of the trap types — Hinge Play.

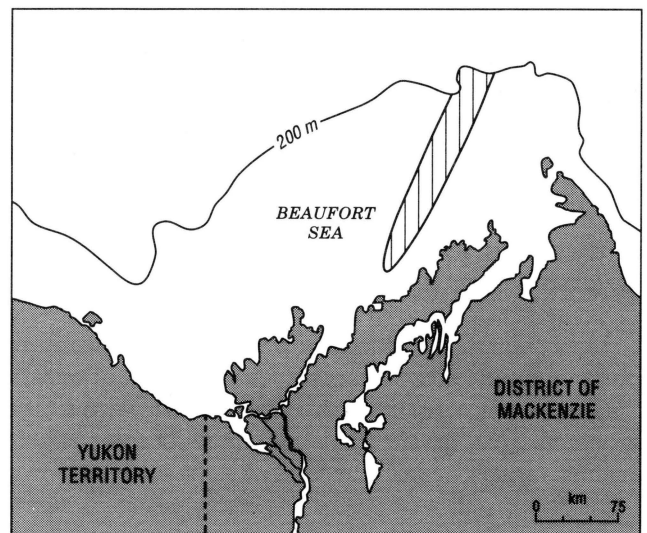


Figure 42. Sketch map locating the Hinge Play area.

some areas along the hinge zone. The grabens may locally contain Mesozoic strata up to several hundred metres thick. Potential reservoirs within the graben fill or onlap wedge include rift-related Lower Cretaceous sandstones and post-rift Lower Tertiary (turbidite) sandstones.

Limited seismic coverage has been inadequate to define individual prospects and the stratigraphic nature of the play can allow for areally very large hydrocarbon accumulations.

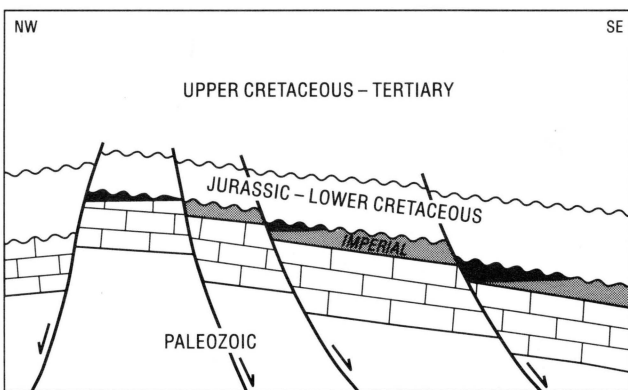
Trap seals would be provided by Albian to Lower Tertiary basinal shales. Potential hydrocarbon source rocks would be similar to those for the Parsons or Atkinson Point plays.

*Exploration History.* No wells have been tested in this play and it remains conceptual in nature. A portion of the onlap wedge section occurs below conventional drilling depths of 5 or 6 km.

### *Imperial Clastics Play*

*Play Definition.* This conceptual play was defined to include all prospects within the Imperial Formation clastic reservoirs in structures associated with the Eskimo Lakes Fault Zone (Fig. 43). The play area extends from the northern end of the Tuktoyaktuk Peninsula into the shallow waters of the Beaufort Sea, to the northeast (Fig. 44). Closures against normal faults are the main trap types and natural gas is expected to be the principle hydrocarbon.

*Geology.* The Upper Devonian Imperial Formation consists of interbedded shale and sandstone of sediment-gravity flow origin, with many of the



**Figure 43.** Schematic sketch of the trap types — Imperial Clastics Play.

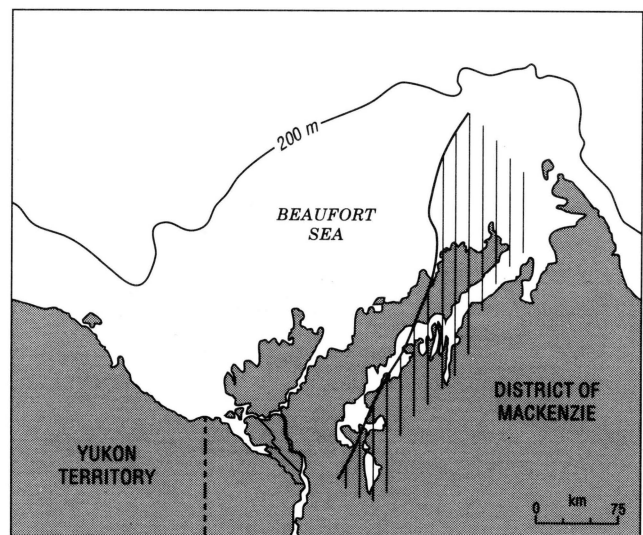
sandstone beds deposited as turbidites. Some conglomerate beds are present under the northern part of the Tuktoyaktuk Peninsula and there is a general tendency to become more argillaceous with thinner sandstone beds to the southwest. Penetrated sections of the Imperial Formation are several hundred metres thick, but the formation is present on only the east flank of the Eskimo Lakes Arch where the formation is erosionally truncated.

The cherty sandstone and conglomerate beds are extensively cemented with silica, consequently porosity is very low, usually less than 10 per cent.

The Imperial Formation occurs on the highly faulted Eskimo Lakes Arch, and potential traps will probably be associated with the normal faults. Overlying Cretaceous shales would provide a seal.

Terrestrially derived organic matter is common within the formation and high levels of organic maturity have been attained. The underlying Canol shale, which tends to be more marine in its organic matter content, is also at a high level of maturity. The thermal maturity would suggest gas as the product of the source rocks. Migration of hydrocarbons from younger source rocks could be invoked but the wide separation of the Imperial subcrop from the Kugmallit Trough, where Cretaceous strata could be expected to be thermally mature, would tend to reduce this possibility.

*Exploration History.* Only nine wells have penetrated Imperial strata, of which the Kapik K-39 recovered gas-cut mud.



**Figure 44.** Sketch map locating the Imperial Clastics Play area.

## Yukon Coastal Plain Play

**Play Definition.** This conceptual play was defined to include all prospects in which hydrocarbons are trapped in pre-Cenomanian rocks. The play extends from the northern end of the Richardson Mountains, westward along the Yukon coastal plain to the British Mountains and includes a narrow strip of the inshore waters of the Beaufort Sea (Fig. 45). The play area extends southward to the Barn Mountains and the upper reaches of Blow River. All pre-Cenomanian strata are included in the play. Gas would be the principle hydrocarbon in structural traps (Fig. 46).

**Geology.** A thick Mesozoic succession fills the Rapid Depression and Proterozoic to Paleozoic strata are exposed within the surrounding mountains. Lower Paleozoic strata are exposed in the Barn Mountains where they consist of basinal shale, some sandstone, thin bedded carbonates, and chert. Carboniferous strata are represented by the clastics of the Kayak and Kekiktuk formations and the carbonate and clastic Lisburne Group. Permian strata are mostly clastics, with some carbonates, in the Sadlerochit Group. A thin succession of Triassic strata, consisting of interbedded sandstone, shale and carbonate (Shublik Formation), crops out on the flanks of the British Mountains.

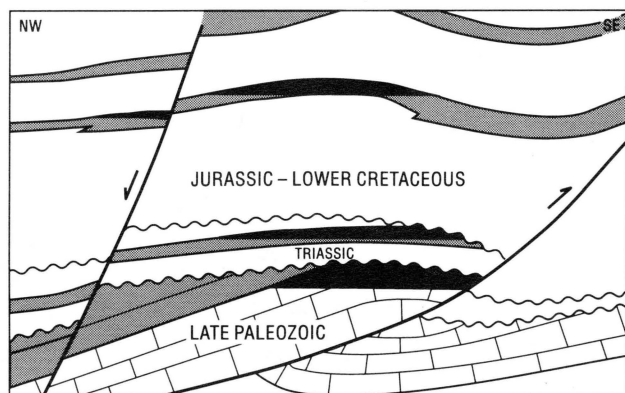
Jurassic to Albian strata consist of shale- and sandstone-dominant formations that are probably between 5000 and 10 000 m thick in the Rapid Depression. Jurassic through Valanginian strata are mostly shale of the Kingak Formation. The sandstones of the Bug Creek Group, Porcupine River, and Martin Creek formations shale-out west of Rapid Depression. Kamik Formation sandstones are present but they also

contain more shale towards the British Mountains. Also, the Kamik Formation is truncated under Mount Goodenough strata along the northeastern flank of the British Mountains. The latter formation is shale dominant, although a local basal sandstone is present adjacent to the British Mountains. Late Barremian–Aptian Rat River strata are present only on the eastern side of the Rapid Depression, to the west they have been eroded. Albian strata form a thick succession (up to 5000 m in the Rapid Depression) of sediment-gravity flow deposits, consisting of interbedded conglomerate, sandstone and shale, with local ironstone beds. A local coarser facies that loses its identity to the north and east is present on the western flank of the Rapid Depression.

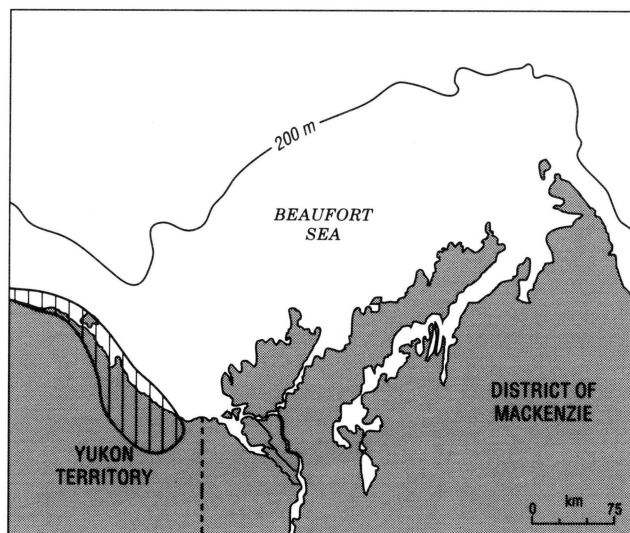
Although potential reservoir intervals should be numerous, the clastics are generally well cemented with silica, resulting in poor quality, low-porosity reservoirs. Carbonates also tend to have low porosity, although fracturing is extensive.

The play area is structurally complex with thrust faults, normal faults and some strike-slip faults, and associated folds. Late Cretaceous and Early Tertiary deformation created the bulk of the present structural configuration, although older events have influenced present trends.

Throughout the thick Mesozoic shale successions, the thermal alteration of the rocks is very high, therefore any potential source rock, regardless of its organic type, would probably produce only dry gas.



**Figure 45.** Schematic sketch of the trap types — Yukon Coastal Plain Play.



**Figure 46.** Sketch map locating the Yukon Coastal Plain Play area.

*Exploration History.* Only three wells have been drilled in the play area, Blow River E-47, Roland Bay L-41 and Spring River N-58, all drilled in the early 1970's. None of the wells encountered hydrocarbons. Since

these wells were drilled there has been a moratorium on drilling in this area, and since 1987 there has been a National Park from the Babbage River westward to the US border.

## PART II: RESOURCE ASSESSMENT

### OIL AND GAS RESOURCES

#### Drilling history

In general, onshore drilling has been restricted to periods when the ground surface is frozen; offshore drilling in water depths from 0 to 25 m has been done from artificial islands, and drilling in water depths greater than 25 m has been accomplished from ice reinforced drillships and floating platforms. In 1988, a total of 237 wells had been drilled, including those that had been spudded that year; 30 exploratory and 29 delineation wells had been drilled on land; and 59 exploratory and 19 delineation wells offshore (Fig. 3).

Exploration activity was initiated in 1962 by the drilling of the Texcan Nicholson G-56 and N-45 tests on the coast of the Beaufort Sea east of the Tuktoyaktuk Peninsula. Drilling in the Mackenzie Delta proper commenced with the spudding of B.A. et al. Reindeer D-27 in 1965, undoubtedly encouraged by the discovery that year of the giant Prudoe Bay oil field in Alaska. Three more dry holes were drilled in the winter of 1968-69 and five more in 1969-70, prior to the initial oil discovery at Imperial Atkinson H-25, which was spudded in December of 1969 and completed in February 1970. The Taglu gas field was discovered in June 1971. The discovery well, IOE Taglu G-33, flowed gas at 28 MMCFD from Eocene sands at approximately 2480 m. The Gulf et al. Parsons F-09 well, discovery well in the Parsons gas field, spudded in December of 1971, penetrated Lower Cretaceous gas bearing sandstones at 2682 m.

Drilling onshore continued at an accelerated pace with ten wells spudded in 1970, 11 in 1971, and 16 in 1972, all of which resulted in several small oil and gas discoveries, including: Reindeer, Kugpik, Kumak, Mayogiak, Mallik, Ivik, Niglintgak and Ya Ya. Onshore drilling activity peaked in 1973. Delineation drilling at previously indicated discoveries came into effect at that time in response to the continued rise in world oil prices. Twenty-four tests were spudded in

1973, 18 in 1974, 18 in 1975, and 14 in 1976. Onshore drilling during this period resulted in only minor additions to reserves. Since 1978, one or two wells have been drilled each winter; these have been concentrated on Esso acreage on the Tuktoyaktuk Peninsula in search of "Tuk type" oil plays.

Exploration moved offshore in 1973 with the drilling of Imperial Immerk B-48, and Imperial Adgo F-28 on gravel islands built in 2 to 3 m of water. The Adgo F-28 test resulted in the discovery of the Adgo oil and gas field (Figs. 3, 47).

Esso pioneered drilling offshore wells from islands in water shallower than 20 m. Two types of island designs have been used in water up to 20 m deep. These are sandbag retained, and sacrificial beach types. Secondary slope protection is provided in both types by sandbags and filter cloth. Issungnak, the largest, was started in 1978 and required two seasons to build. It was built in 20 m of water and required over four million cubic metres of sand fill.

As water depths increased and exploration moved towards the western Beaufort Sea, where the seabed is silt and clay, a different island design was needed that would reduce required volumes of sand and prevent erosion of the islands in heavy open sea conditions. The caisson retained island (CRI) was introduced to serve the need. Tarsiut was the first caisson retained island; it was built in 1980-81 in 21 m of water by placing four interlocked, steel reinforced concrete blocks on an underwater berm to provide a stable drilling platform to allow delineation of the Tarsiut accumulation. The original discovery, Tarsiut A-25 was drilled from a drillship between 1978 and 1980. Later CRI types were improved with a higher freeboard and better resistance to storms and ice.

The successful use of the Tarsiut island as a drilling platform led to the development of three new types of artificial islands. The Dome Semi-submersible Drilling Caisson (SSDC) is a converted, ice strengthened

GAS (billion cubic feet)						
	>2000	1000-2000	500-1000	100-500	10-100	<10
ONSHORE	29 TAGLU	43 PARSONS 45	30 NIGLINTGAK	25 ADGO 27 GARRY N. 28 GARRY S. 33 HANSEN 47 TUK M-09 37 YA YA S.	42 IKHIL 35 MALIK 21 MINUK 26 PELY 38 REINDEER 39 TITALUK 41 UNAK a 41 UNAK b 36 YA YA N.	
		9 AMAULIGAK 15 ISSUNGNAK	1 KENALOOAK	21 MINUK 20 NETSERK 7 UKALERK	10 AMERK 13 ARNAK 16 ISSERK 14 ITIYOK 19 KADLUK 18 KIGGAVIK 2 NEKTORALIK	5 NERLERK 8 W. AMAULIGAK
OFFSHORE						
OIL (million barrels)						
	>500	100-500	25-100	10-25	<10	
ONSHORE			25 ADGO 12 ATKINSON 32 IVIK N. 31 KUMAK	28 GARRY S. 34 IVIK S. 46 IMNAK 40 KUGPIK 30 NIGLINTGAK 47 TUK TERTIARY 11 W. ATKINSON	44 KAMIK 48 MAYOGIAK	
	9 AMAULIGAK	24 ADLARTOK 3 KOPANOAR	6 HAVIK 15 ISSUNGNAK 4 KOOKOAK 17 NIPTERK 23 PETSUULIK 22 TARSUUT	2 NEKTORALIK	13 ARNAK 14 ITIYOK 5 NERLERK 8 W. AMAULIGAK	
OFFSHORE						

Figure 47. Discovered resources ranked by pool size. Number indicates location on Figure 1.

supertanker which rests on an underwater sand berm. It is movable and has relief well capability. The SSDC was used during the 1982–83 winter season to drill the Uviluk P–66 dry hole. The Esso “steel doughnut” CRI features eight separate 43 m long steel segments fitted with ballast tanks. The vessel is towed to the location and ballasted onto a 4 m high subsea berm. The third type is Gulf’s conically shaped drilling structure called Molikpak, which rests on a submarine berm.

The construction of artificial islands has been the key element allowing exploration in the Beaufort Sea in water shallower than 25 m and in allowing multi-well delineation programs to occur on a timely and cost effective basis. However, for exploratory wildcat wells, particularly in deeper waters, ice strengthened drillships have a technological and economic advantage; ice breaking vessels extend the limited open water season in which drillships can operate.

In 1976, drilling operations from drillships were permitted during the summer months. Explorer I, II and III were used to spud four wells in 1976 at Kopanoar, Tingmiark, and Nektoralik. Major oil accumulations were discovered at Kopanoar in 1978,

and Tarsiut in 1979. Explorer IV joined the drillship fleet in August 1979. A new generation of floating exploration drilling equipment was introduced by Gulf in the summer of 1983 when the Kulluk spudded the Pitsiulak A–05 discovery. The Kulluk, a floating cone shaped unit moored by twelve anchor cables, is designed to better withstand the extreme environmental forces in the Beaufort Sea thereby extending the drilling season. Two new Class 4 Gulf ice breakers, the Kalvik and the Terry Fox — the two largest privately owned and operated ice breakers in the world — were brought into the Beaufort to support the Kulluk.

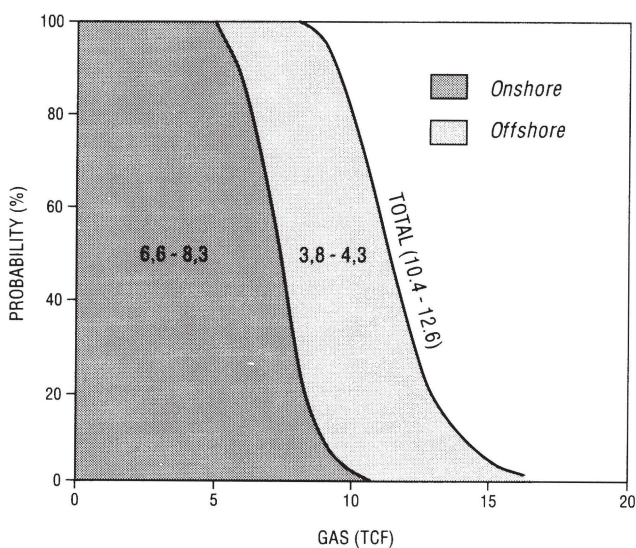
### Oil and gas discoveries

The drilling of 130 exploratory wells onshore and 59 offshore has resulted in 48 significant discoveries. The discoveries are listed in Figure 47 arranged by size class and onshore versus offshore location. The size of individual discoveries at the present level of pre-production delineation is highly subjective. The values given were derived from frequency distribution curves for each discovery reflecting different confidence levels provided by the Reserves Committee,

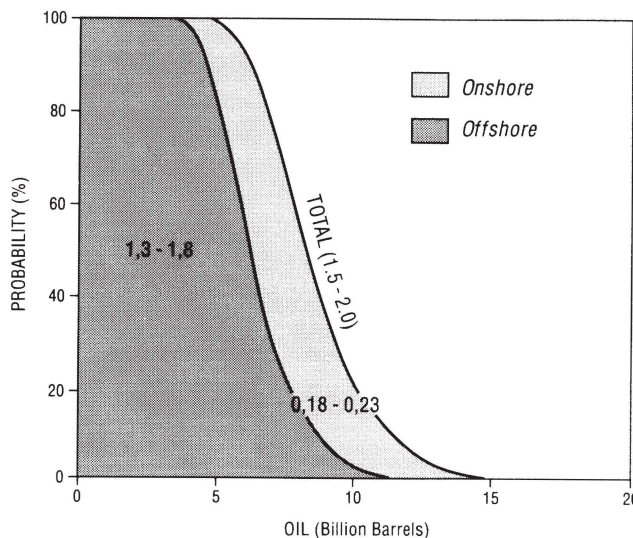
augmented in some cases by industry estimates from trade journals. Many discoveries have significant “up-side” potential, that is there is a small possibility of much higher values than the average if net pay turns out to be thicker or more extensive areally than current drilling or geophysics can confirm with confidence. These “up-side” values tend to produce mean values that are larger than those commonly used, but they more accurately reflect the consensus regarding the size of discoveries.

Figures 48 and 49 illustrate the total quantities of discovered gas and oil. For gas it is estimated that between 10.4 and 12.6 TCF (75 to 25 per cent probability range) have been discovered. About two thirds of this quantity exists in the Onshore and Shallow Offshore group of plays (6.6 to 8.3 TCF), whereas Offshore Delta discoveries total from 3.8 to 4.3 TCF. The total quantity of oil discovered (Fig. 49) is estimated to be between 1.5 and 2.0 billion barrels (75 to 25 per cent probability range). In contrast to the location of gas discoveries, the offshore plays dominate the discovery record with 1.3 to 1.8 billion barrels. This is the result of much larger individual discoveries in the offshore, dominated by the giant Amauligak field.

It should be noted that the term “reserves”, although used in some figures in this report, is inappropriate. By current definition, the expression “reserves” has specific requirements of current or foreseeable economic viability and a high degree of confidence in terms of quantity. The usage in this report is only in the sense of the technically recoverable



**Figure 48.** Distribution of estimates of discovered gas resources (numerical values are for the 25 to 75 per cent confidence limits).



**Figure 49.** Distribution of estimates of discovered oil resources (numerical values are for the 25 to 75 per cent confidence limits).

portion of the discovered oil in place by means of primary and normal enhanced (i.e. gas re-injection, water flood) recovery techniques. Properly the quantities of discovered oil and gas for this region should be regarded only as “discovered resources”.

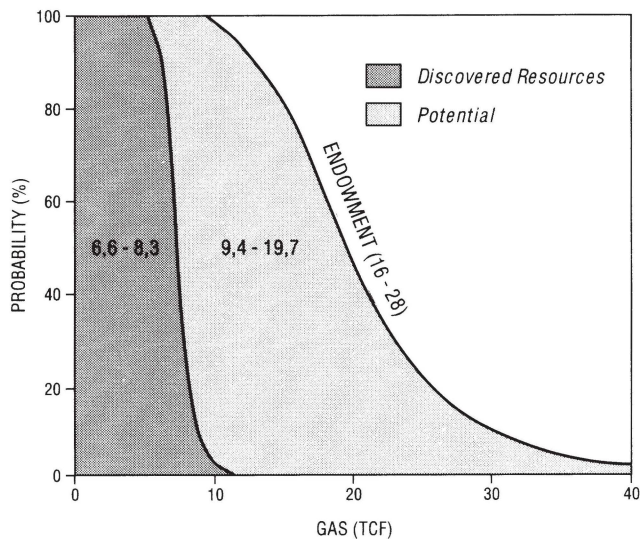
### Resource endowment

Each of the 20 exploration plays identified within the Mackenzie Delta-Beaufort Sea Region were evaluated using methods developed by the Geological Survey of Canada (Podruski et al., 1988, p. 8-13). Only a few plays had enough discoveries to make effective use of the discovery process method; the remainder were analysed using the subjective probability play approach. For each play the procedure resulted in a pool size distribution, a number of pools distribution, a distribution of the total gas and oil endowment for the play, and size ranges for the predicted oil and gas pools that would be statistically appropriate for the analysis. The results were aggregated by play groups and are illustrated by a series of cumulative frequency curves.

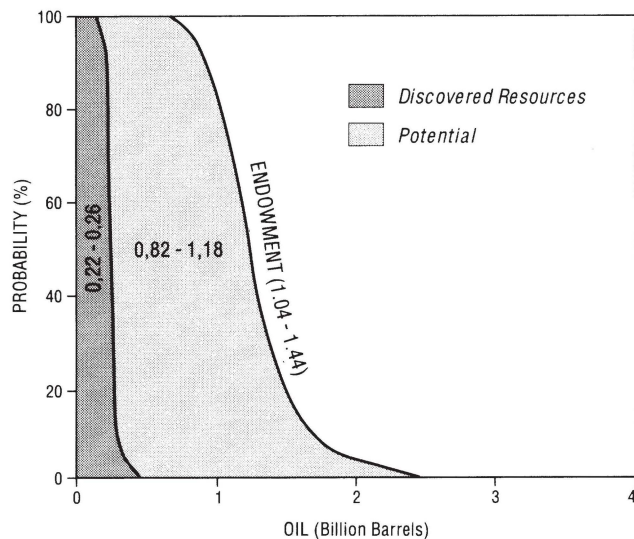
### Onshore/Shallow Offshore Play Group

The eight exploration plays in this group were estimated to contain 16 to 28 TCF of gas and 1.04 to 1.44 billion barrels of recoverable oil. The range reported represents the 75 and 25 per cent probability ranges respectively, from the distributions shown as Figures 50 and 51. Figure 50 also shows much larger

possible values of gas endowment at speculative levels. The estimates indicate that about one third of the gas but only one fifth of the oil has already been discovered. Remaining gas potential is concentrated in the Taglu, Parsons and Ivik plays. Although oil potential is more dispersed, the Taglu and Ivik plays are the most important. This play group has the highest ratio of gas-to-oil, about 16,900 cubic feet/barrel, (compared to 9700 for the region as a whole) reflecting the relatively shallow burial of source rocks.



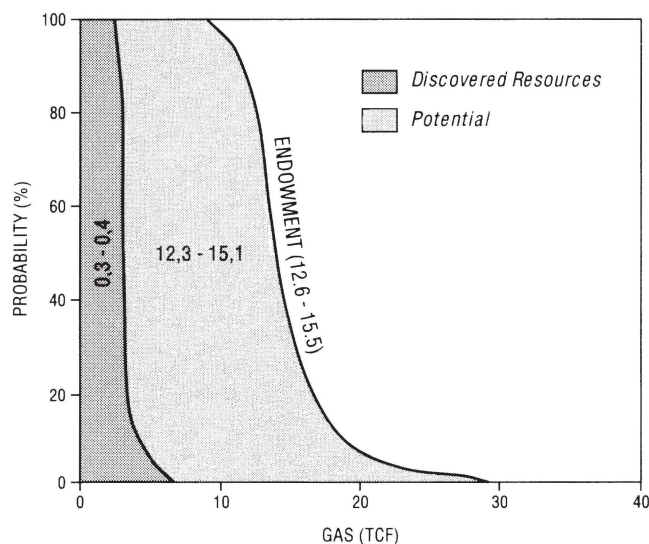
**Figure 50.** Distribution of estimates of the gas endowment — the Onshore/Shallow Offshore Play Group.



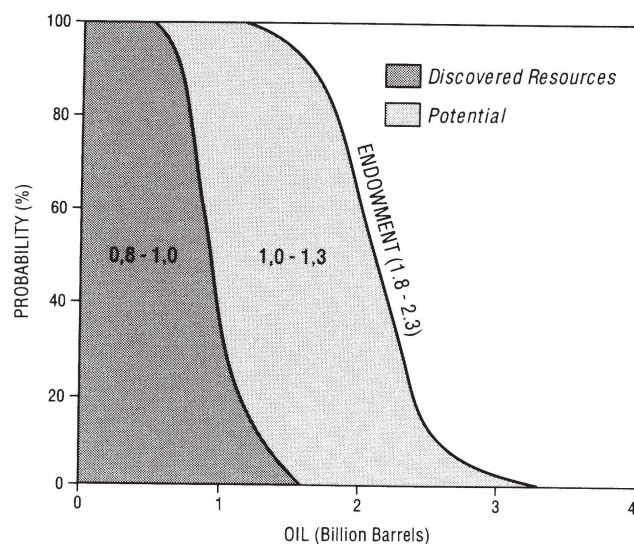
**Figure 51.** Distribution of estimates of the oil endowment — Onshore/Shallow Offshore Play Group.

### Offshore Delta Play Group

This group of four exploration plays, dominated by the Amauligak play, was estimated to contain between 12.6 and 15.5 TCF of gas and 1.8 to 2.3 billion barrels of technically recoverable oil. Both sets of estimates (Figs. 52, 53) have speculative values that are almost double those at the median. Although only a small portion of the total gas endowment has been discovered, more than 40 per cent of the oil is shown as discovered. This relatively high per centage of discovered oil reflects the major accumulation at Amauligak and a trend of associated fields extending to Tarsiut, as



**Figure 52.** Distribution of estimates of the gas endowment — Offshore Delta Play Group.



**Figure 53.** Distribution of estimates of the oil endowment — Offshore Delta Play Group.

well as a fairly mature level of exploration. The Offshore Delta Play Group has a low gas-to-oil ratio (7000 cubic feet/barrel) consistent with the Committee's opinion that this relatively small part of the basin is in an oil-preferred part of the hydrocarbon generation system.

### West Beaufort Play Group

The three exploration plays in this group are estimated to contain between 8.6 and 14.3 TCF of gas and from 1.4 to 2.5 billion barrels of oil. The distributions of estimates of endowment (Figs. 54, 55) are highly skewed, with long tails in the low probability or speculative ranges. These curves are consistent with the uncertainty of estimates in a largely unexplored area. The only discovery in the area is the oil at Adlartok. The size of this discovery is expressed with a relatively wide range, but is most certainly of major significance. The West Beaufort Play Group is regarded as having high oil potential because of the number of large untested structures and geochemical indications of better thermal maturity than other play groups.

### Deep Water and Other Play Group

This group of five exploration plays is estimated to contain between 13.6 and 20.1 TCF of gas and from 1.1 to 1.7 billion barrels of oil. Figures 56 and 57 indicate very large amounts of resource endowment at the speculative or low probability levels, particularly for gas. The discoveries and potential are dominated by the Kopanoar and Deep Marine West plays, which

also have the largest areal extent of all the plays in the Mackenzie-Beaufort region. Although there have been more oil than gas discoveries to date, the analysis suggests that the play group will have a high gas-to-oil ratio (13,300 cubic feet/barrel) compared to the region as a whole. There are large numbers of untested structures in the plays of this group, many of them in deep water and in areas of permanent ice cover. The smaller plays in the group do not have well-defined targets at this time because of poor geophysical definition.

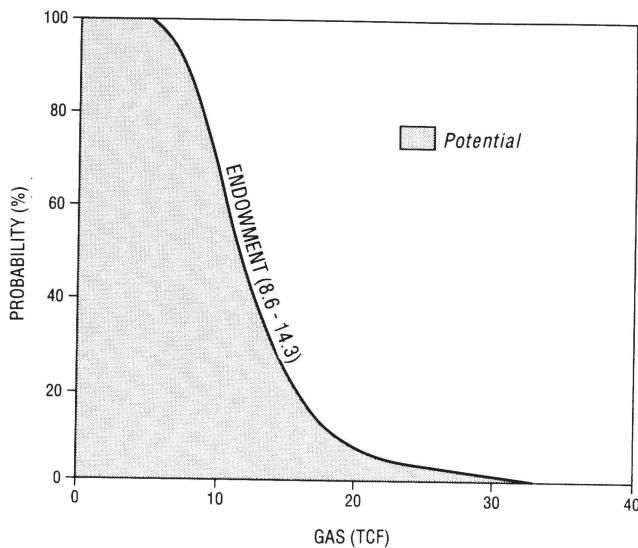


Figure 54. Distribution of estimates of the gas endowment — West Beaufort Play Group.

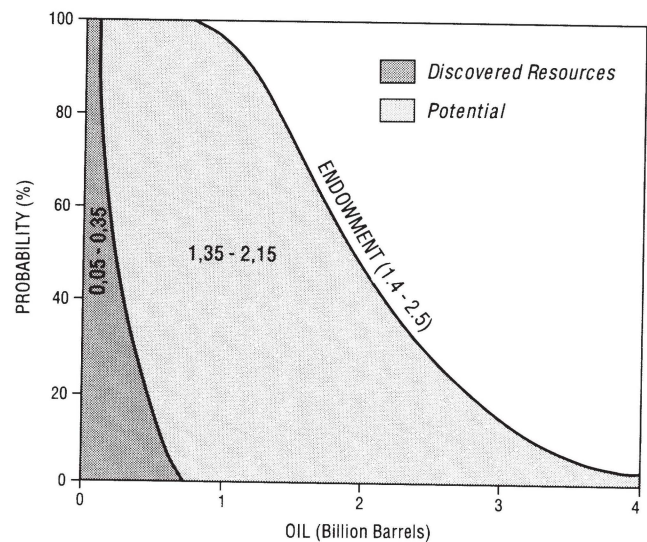


Figure 55. Distribution of estimates of the oil endowment — West Beaufort Play Group.

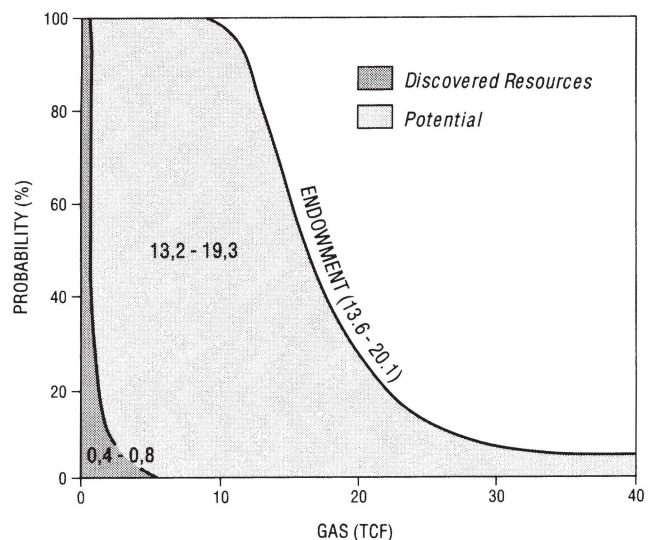
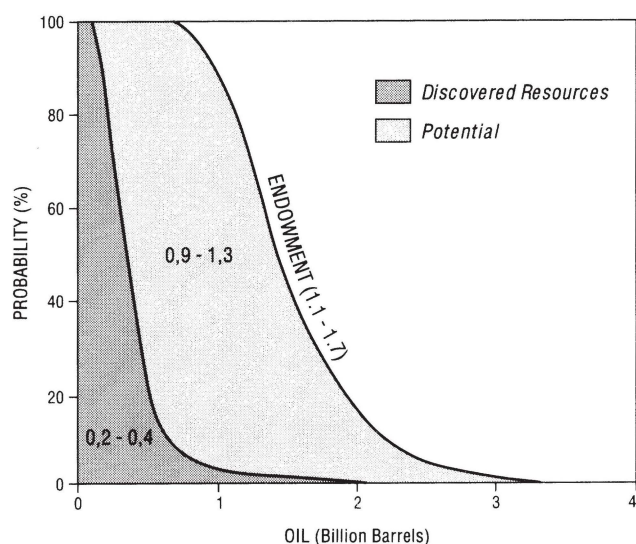
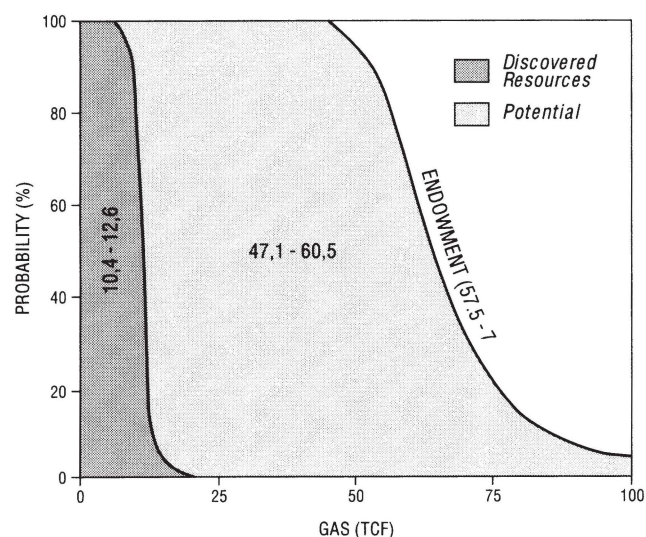


Figure 56. Distribution of estimates of the gas endowment — Deep Water and Other Play Group.



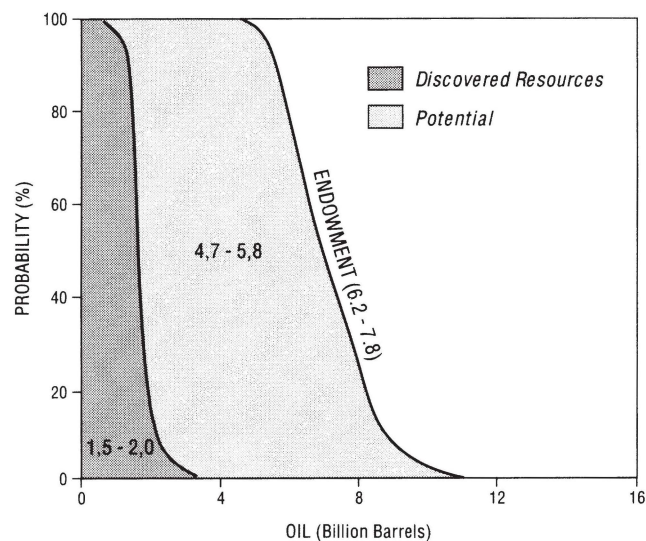
**Figure 57.** Distribution of estimates of the oil endowment — Deep Water and Other Play Group.



**Figure 58.** Distribution of estimates of the gas endowment — Mackenzie Delta-Beaufort Sea Region. Values given are for the 75 and 25 per cent probability levels.

### Total regional endowment

Figures 58 and 59 show the total quantities of gas and oil estimated to exist in the 20 exploration plays of the Mackenzie Delta-Beaufort Sea Region. The distributions are obtained by statistically summing the estimate curves for each play, by play grouping. For gas (Fig. 58), it is estimated that between 57.5 and 73.1 TCF of gas may exist in the region (75 to 25 per cent probability range). The mean expectation is 65 TCF. Approximately 18 per cent of this endowment is in the already discovered category, leaving a very large undiscovered potential of 47.1 to 60.5 TCF. Much larger values of undiscovered gas are shown at low probability levels. For oil (Fig. 59), it is estimated that between 6.2 and 7.8 billion barrels (75 to 25 per cent probability range) may exist in the region. The mean expectation is 7.1 billion barrels. From 1.5 to 2.0 billion barrels, or about 25 per cent, of this endowment are shown as discovered resources. The figure also indicates a substantial undiscovered potential of between 4.7 and 5.8 billion barrels. The mean values of the oil and gas endowment are shown in Table 1.



**Figure 59.** Distribution of estimates of the oil endowment — Mackenzie Delta-Beaufort Sea Region. Values given are for the 75 and 25 per cent probability levels.

### Resources of current interest

Expressions of total regional endowment of oil and gas resources are useful in the sense of identifying the total inventory range that may exist for the region. These values are not discounted for current or future economic viability, technical exploitability, or likelihood of discovery. As such they may be misleading for planners and for those who prepare forecasts of supply. For

these purposes one needs information on where the resources are concentrated, the sizes of future discoveries and some limited reference time frame. In Table 1 the resource endowment of the Mackenzie Delta-Beaufort Sea Region are summarized by play groups. If one were to consider which groups would be the focus of exploration for the next 20 years, one might conclude that the Deep Water and Other oil and gas plays, and the West Beaufort gas plays could be

**TABLE 1**

Mean amounts of reserves (discovered resources) and potential for play groups

Play Group	Oil (billion barrels)		Gas (TCF)	
	Mean Recoverable		Mean Recoverable	
	Discovered	Potential	Discovered	Potential
Onshore/Shallow Offshore	0.251	1.05	7.57	12.6
Offshore Delta	0.910	1.25	3.29	9.4
West Beaufort	0.226	1.93	–	12.5
Deep Water and Other	0.357	1.16	0.88	18.8
<b>Total</b>	<b>1.744</b>	<b>5.39</b>	<b>11.74</b>	<b>53.3</b>

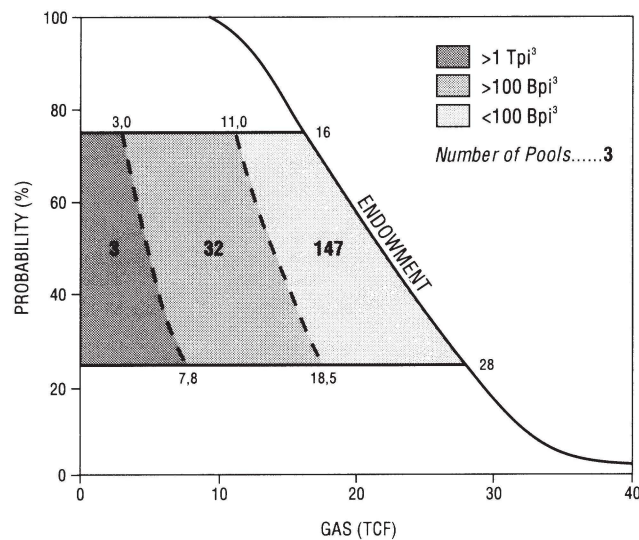
classified as “beyond current interest” because of their remoteness and probable excessive cost of exploitation. In order to provide some discounting of the regional resource endowment values for the current study, those assumptions were used. As a result the total mean oil expectation for the region is reduced from 7.1 to 5.6 billion barrels, and the mean gas expectation from 65 to 33 TCF. Each of the play groups included in the discounted endowment was then examined in terms of how much of the resource existed in given size ranges. The results of this analysis are shown in Figures 60 to 64.

**Onshore/Shallow Offshore Play Group**

Figure 60 shows how much of the total gas endowment of 16 to 28 TCF occurs in pools larger than 1 TCF, in

pools from 100 BCF to 1 TCF, and in pools smaller than 100 BCF. Also shown are the expected number of pools in each size category. The analysis indicates only three pools larger than 1 TCF, two of which (Taglu and Parsons) are already discovered. The second size range consists of 32 pools that contain from 8 to 10.7 TCF in total. This suggests that there are many potentially attractive targets for exploration in the onshore area. As seen in Figure 60, the remaining large number of small pools do not add significant resources. If one were to consider only the pools in the larger two size ranges to be of short term interest, then the mean gas endowment for Onshore/Shallow Offshore Play Group would reduce from 22 to 15.7 TCF.

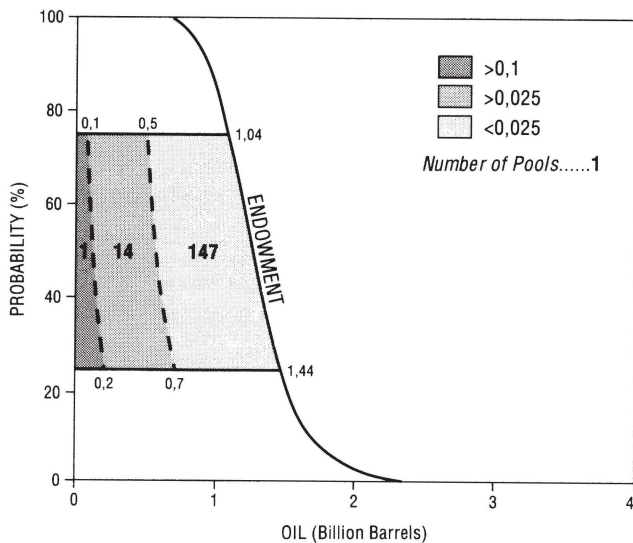
The portion of the total oil endowment for this group of plays that occurs in pools larger than 100 million barrels, between 25 and 100 million barrels, and in pools smaller than 25 million barrels is shown in Figure 61. Only one pool greater than 100 million barrels and 14 pools greater than 25 million barrels are indicated. Together these 15 pools would contain about one half of the total, reducing the mean endowment from 1.3 billion barrels to just 738 million barrels, if those two size ranges were the only ones of current interest.



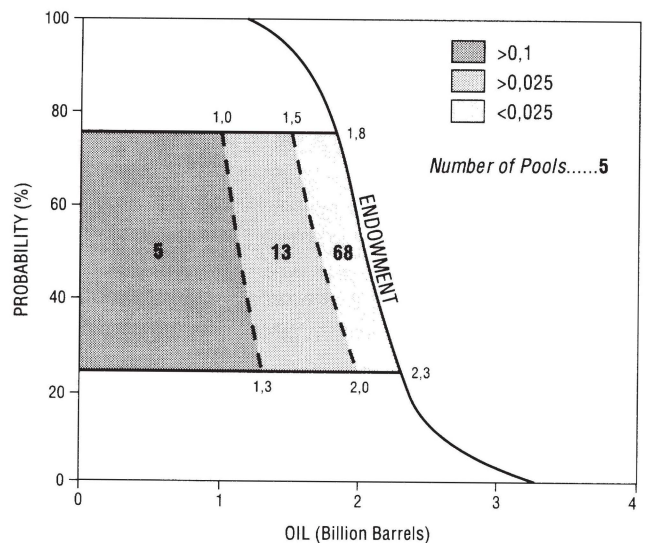
**Figure 60.** Distribution of the gas endowment showing the impact of predicted pool sizes — Onshore/Shallow Offshore Play Group.

**Offshore Delta Play Group**

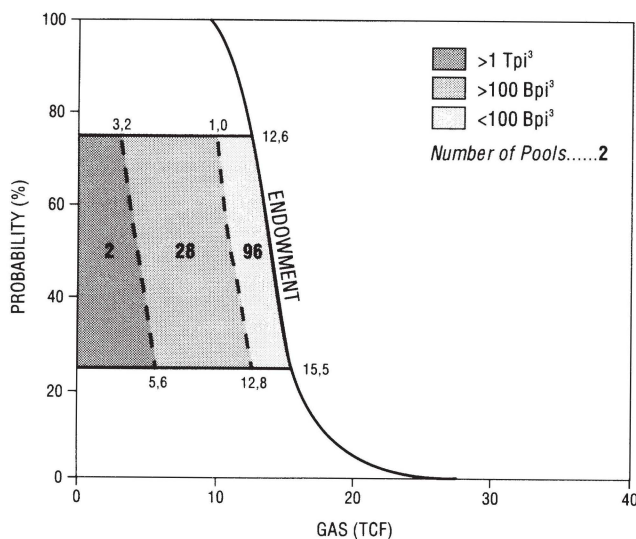
Using the same criteria as described above, the gas and oil resources of the Offshore Delta Play Group are shown in Figures 62 and 63. For gas, two pools greater than 1 TCF are indicated, including the one associated with the Amauligak oil discovery. The second size range includes 28 pools that contain almost twice as much gas as the first. If only these two size groups were of current interest, then the mean endowment would reduce from 14.7 to 12.0 TCF.



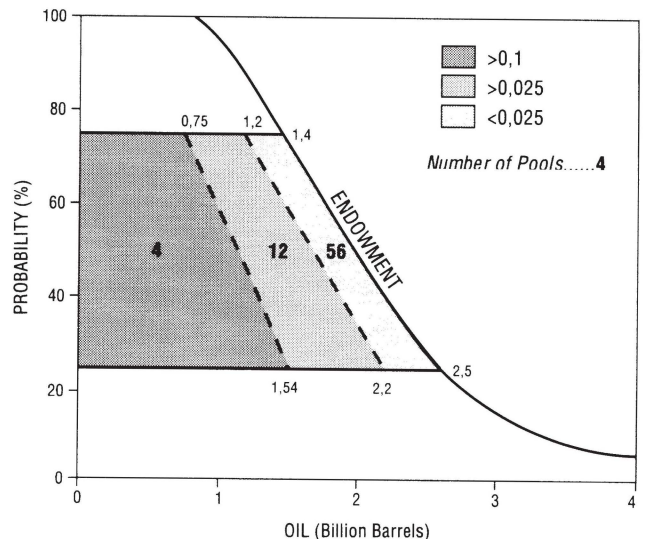
**Figure 61.** Distribution of the oil endowment showing the impact of predicted pool sizes — Onshore/Shallow Offshore Play Group.



**Figure 63.** Distribution of the oil endowment showing the impact of predicted pool sizes — Offshore Delta Play Group.



**Figure 62.** Distribution of the gas endowment showing the impact of predicted pool sizes — Offshore Delta Play Group.



**Figure 64.** Distribution of the oil endowment showing the impact of predicted pool sizes — West Beaufort Play Group.

Figure 63 shows how the oil endowment is distributed by size. Five major pools are anticipated in the larger than 100 million barrel range, one of which (Amauligak) is already discovered. This size range constitutes almost one half of the endowment. A combination of the larger two size classes would include 18 pools containing from 1.5 to 2.0 billion barrels. Thus the overall mean endowment would reduce from 2.1 to 1.8 billion barrels in the current interest category.

### West Beaufort Play Group

Only the oil resources of this group of plays was considered for size analysis. Figure 64 shows that four pools larger than 100 million barrels are estimated to exist, including the Adlartok discovery. Along with the 12 pools in the 25 to 100 million barrel size range, these 16 pools would contain between 1.2 and 2.2 billion barrels. This would reduce the mean regional oil endowment from 2.2 to 1.8 billion barrels in the current interest category.

## PART III: ECONOMIC POTENTIAL OF MACKENZIE DELTA-BEAUFORT SEA REGION

### UNDISCOVERED NATURAL GAS RESOURCES

As described in Parts I and II of this report, 20 exploration plays aggregated into four play groups are defined for the region and have a total natural gas potential of 53 TCF ( $1.5 \times 10^{12}$  m<sup>3</sup>). At this time, economic analysis is undertaken on the Onshore/Shallow Offshore and Offshore Delta play groups which contain ten exploration plays and are estimated to contain 22 TCF ( $620 \times 10^9$  m<sup>3</sup>) of undiscovered gas resources (Table 2). The technology required to develop and produce gas from the West Beaufort and Deep Water and Other play groups (containing a potential of 31 TCF or  $882 \times 10^9$  m<sup>3</sup>) is speculative and as a consequence these groups are excluded from the analysis.

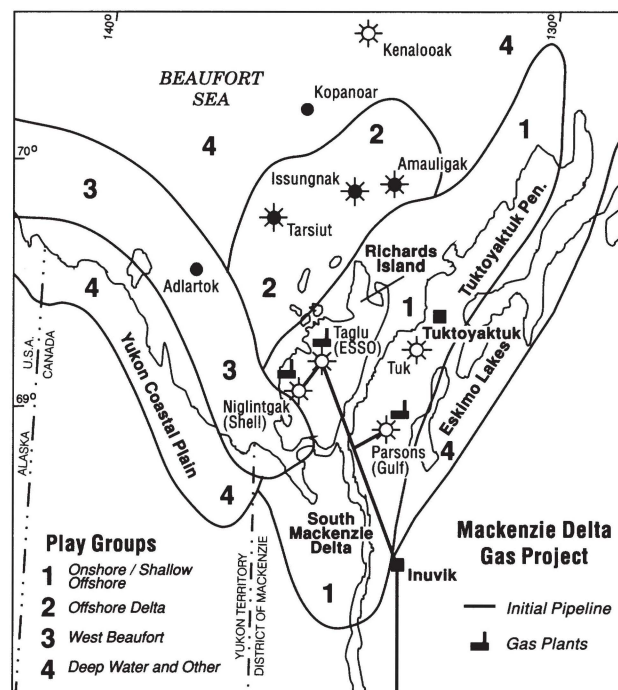
**TABLE 2**

Economic Undiscovered Gas Resources  
Trillion Cubic Feet (TCF)

Alberta Border Price	Burdened	Unburdened
\$5.00	11.2	12.0
\$4.00	8.1	8.6
\$3.00	5.9	6.3

Existing discoveries are considered to the extent that they support development of a gas gathering network and processing facilities in the Mackenzie Delta and the construction of a sales gas pipeline to southern markets (Fig. 65). The current export applications by Esso, Shell and Gulf, now awaiting federal government approval, will require a pipeline capable of transporting 1.2 BCF ( $34 \times 10^6$  m<sup>3</sup>) per day for twenty years. Reserves supporting these applications total 9.2 TCF ( $259 \times 10^9$  m<sup>3</sup>). Production from these reserves will begin to decline about fifteen years after startup; new reserves will need to be brought on stream to maintain pipeline throughput at maximum capacity.

Estimates of economic gas potential are relevant to questions regarding the availability of reserves to back-up current applications for export licences, extension of the useful life of the pipeline, appropriate pipeline size and capacity, and, in general, to any issue relating to a lead gas development project in the Mackenzie Delta-Beaufort Sea Region.



**Figure 65.** Sketch map of Mackenzie Delta-Beaufort Sea Region illustrating major discoveries, Play Group boundaries, proposed pipelines and gas plants.

The analysis is conducted at the exploration play level to best utilize geological and reservoir information. The economic analysis itself considers both fiscally burdened and unburdened cases. Detailed analysis on the Taglu play is provided to illustrate this approach. Other results presented are aggregates of the results of individual plays.

Data for the economic analysis of the undiscovered resources for this region come from Part II of this report and supporting data from an electronic file from the Institute of Sedimentary and Petroleum Geology. The Geological Potential Committee provided estimates of potential for resources that are technically recoverable without regard to economic viability.

### DEVELOPMENT REQUIREMENTS, PRODUCTION AND COSTS

Petroleum Resource Analysis Division, with assistance from COGLA's Engineering Branch, has constructed an engineering and costing model to support the economic analysis. The model provides a generalized

and consistent means of specifying the technology required for gas field development and production, generating expected production profiles, and estimating the associated costs and investment schedules. Two sources were used to construct the model: a) COGLA's April 1989 review of the likely development scenarios and costs for the existing discoveries in the Mackenzie Delta; and b) preliminary development plans and costs by Esso, Shell and Gulf in support of their recent export applications to the National Energy Board.

The development and production requirements include production wells, field processing facilities, pipelines to an existing processing plant, and field compression to delay the onset of production decline. A production platform is also included for plays located off shore. The number of wells required for the development of a gas pool is calculated by dividing the recoverable reserves by the average reserves per well. Production is estimated by assigning the pool to one of four classes on the basis of recoverable reserves. A characteristic production profile for each class defines the initial production rate, number of years at that rate, decline profile and productive life of the pool. The accelerated production usually associated with smaller reserves is, therefore, explicitly considered in the economic analysis. Field processing facilities and compressors are sized using the initial reservoir production rate as the design rate. Exploratory well costs are assumed constant, reflect high mobilization (fixed) costs, and depend on whether drilling is on land or off shore.

Geological and geophysical costs are estimated to be 20 per cent of exploration drilling costs. Development well costs are estimated as a function of reservoir depth. Capital costs of field processing facilities and compression are calculated as a function of the initial production rate of the pool. Pipeline costs are determined by distance and terrain. Overhead charges related to development are calculated as a fixed percentage of the facilities and pipeline costs. Operating costs associated with capital items are calculated as fixed percentages of cumulative capital costs.

For purposes of cash flow analysis, it is assumed that exploration costs (including geological and geophysical) are spread over three years. Capital expenditures for development are assumed to begin in the year following the discovery. Development takes place over one to three years depending on the number of wells required. For example, for one- and two-well pools, all

development costs are assumed incurred in a single year, while for three- and four-well pools, costs for wells and facilities are spread over two years. The pipeline to processing facilities is built in the year prior to production, and compression is installed in the year prior to production decline.

## ECONOMIC ANALYSIS

### Objective

The resource assessment provided by the Geological Potential Committee estimates the technically recoverable potential, unconstrained by economic considerations. The following economic analysis estimates the portion of the potential which may be expected to provide economic investment opportunities, under a set of specified assumptions, over the long term, defined as the **economic potential**. The present study considers both fiscally burdened and unburdened economic potential cases.

### Methodology

Estimates of economic potential are sensitive to price and are presented as a functional relationship to plant-gate prices. The analysis compares prices available on natural gas production with expected minimum required prices (supply prices). The available price is based on plant-gate outlets in the Mackenzie Delta.

Analysis is micro-economic and at the play level. Account is taken of geological, engineering and economic factors with regard to the basic unit of investment decision analysis — the prospect. Results for the basin are a summation of results of individual plays.

### Infrastructure

The fundamental assumption in the economic analysis of the remaining undiscovered potential is that a lead gas development project from existing discoveries, having processing facilities and a sales gas pipeline to southern markets, is in operation. Natural gas liquids are assumed to be extracted at processing plants and shipped to Norman Wells by oil pipeline or dedicated natural gas pipeline. For purposes of estimating tolls, pipelines are assumed to be largely depreciated. Spare processing capacity is assumed once production from initial reserves has declined.

## **Marginal economic criteria**

Discounted cash flow analysis is used to identify the minimum recoverable pool size necessary to cover all full-cycle costs at a given price. All costs are in dollars of 1988 purchasing power. For accuracy in tax and royalty calculations, costs and prices are inflated at 4 per cent annually for purposes of cashflow analysis, and subsequently deflated to 1988 dollars. Other assumptions in the cashflow analysis follow:

### ***Fiscal system***

The long-term fiscal system is identical to that currently in place. It is assumed that all companies are fully taxable. The Exploration Tax Credit is assumed to have expired.

### ***Full cycle costs***

All overhead, geological, geophysical and exploratory drilling costs are included in the cashflow analysis.

### ***Rate of return***

An expected real after-tax DCF rate of return of 15 per cent is assumed on all costs.

### ***Processing fees***

A Standard Jumping Pound formula was used to estimate the facilities' processing fees for the recent export applications of Esso, Shell, and Gulf. Fees were assumed constant at the initial levels.

### ***Exploratory risk***

Six exploratory dry holes are allocated to each successful exploratory well to give an economic success ratio of 1:7. This ratio takes into account all costs associated with discovery including marginal return on investment. This compares with a technical success ratio of 1:3 for having found some oil and gas in the exploratory wells of the region. The economic success ratio is within acceptable limits for a Mackenzie Delta plant-gate gas price of \$3.00 per MCF and the price range under consideration.

## **BASE CASE**

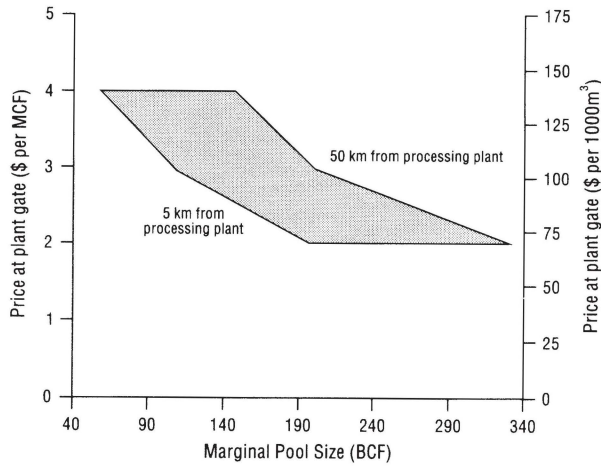
Natural gas prices and distance to processing facilities are key variables in identifying marginally economic pool sizes. Prices available to Mackenzie Delta producers are estimated by subtracting an appropriate transportation toll from prices assumed to be available at the Alberta-Saskatchewan border. Applicable prices for undiscovered potential will be those prevailing in the later life of the mainline transportation system. In this long-term view, border prices are estimated to be approximately \$4.00 per MCF. The base case Mackenzie Delta plant-gate price is assumed to be \$3.00 per MCF — the border price minus \$1.00 per MCF toll. The distance to processing facilities is an important, but variable factor. Undiscovered resources may be located as close as 5 km and as far as 50 km from a processing plant. An average distance of 25 km has been chosen for the base case.

## **ANALYTICAL EXAMPLE — TAGLU PLAY**

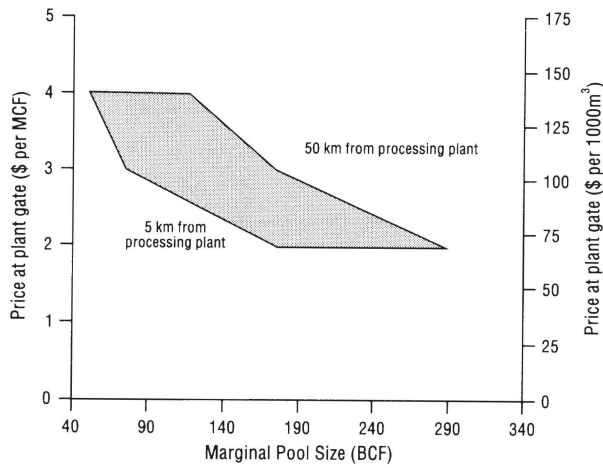
The results of the economic analysis of the Taglu play are presented to illustrate the methodology used in the economic analysis. The geology and resource assessment for the play are described in Parts I and II of this report. Reservoir depth for the economic analysis is assumed to average 2000 m. The producing pool is assumed to be accessible from land or shallow water drill sites. Exploratory well costs are estimated at \$6.0 MM per well and geological and geophysical costs are estimated as \$1.2 MM (20 per cent of exploratory well costs). Development well costs are estimated at \$6.0 MM per well of which 40 per cent is for completion. Pipeline costs average \$3.0 MM per mile. Surface facility and compression costs are determined by initial production rate and as a result vary by the size of pool reserves.

### **Marginal Pool vs. Price**

Figures 66 and 67 show the marginally economic pool sizes for the Taglu play for burdened and unburdened cases at varying distances from processing facilities. Data used to prepare the curves are in Tables 3 and 4. As expected, pool reserves required to justify exploration and development decrease as price increases and distance from processing decreases. Figure 66 shows that at \$3.00 per MCF, a pool needs recoverable reserves of 105 BCF ( $3 \times 10^9$  m<sup>3</sup>) to be marginally



**Figure 66.** Marginally economic pool size — Taglu Play (burdened case).



**Figure 67.** Marginally economic pool size — Taglu Play (unburdened case).

**TABLE 3**

Marginal Pool Size (BCF)  
Taglu Play  
(burdened case)

Price	5 km	25 km	50 km
\$2.00	195.4	265.9	330.0
\$3.00	105.7	145.0	199.3
\$4.00	55.8	80.0	145.0

**TABLE 4**

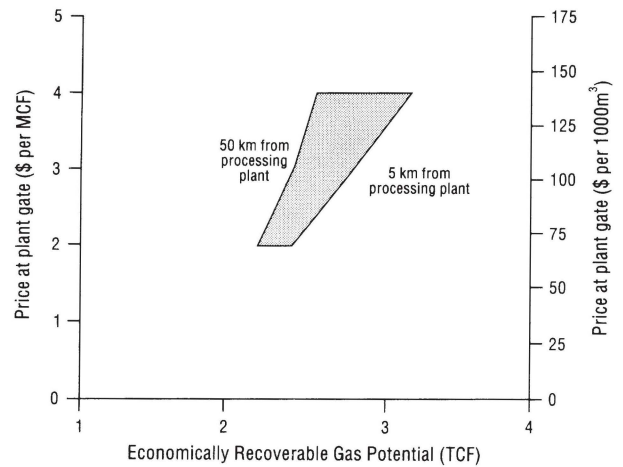
Marginal Pool Size (BCF)  
Taglu Play  
(unburdened case)

Price	5 km	25 km	50 km
\$2.00	176.0	226.0	289.9
\$3.00	72.9	127.7	172.8
\$4.00	49.6	68.6	116.5

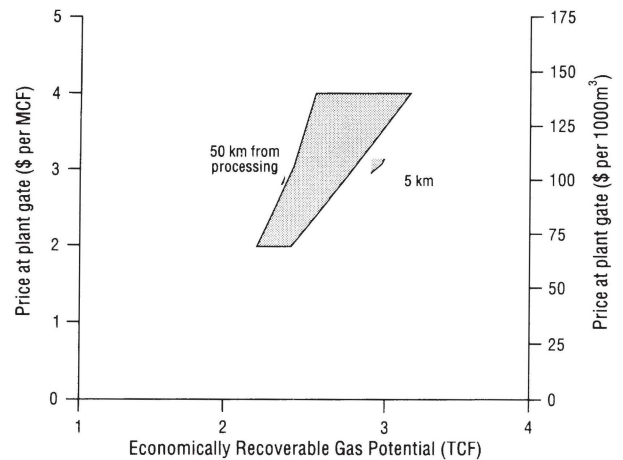
economic with full fiscal burden if located 5 km from processing facilities. At the same price, the marginal reserves increase to 145 BCF ( $4.1 \times 10^9 \text{ m}^3$ ) and to 200 BCF ( $5.6 \times 10^9 \text{ m}^3$ ) if the pools are located at 25 and 50 km. Comparison of the marginal pool size shows that burdened and unburdened cases are similar which confirms that the existing fiscal regime does not significantly burden marginal project investments.

### Economic gas potential

Figures 68 and 69 show supply-price curves for burdened and unburdened cases. Tables 5 and 6 provide supporting data. Economic potential increases as price increases, and decreases as distance from processing increases. For example, at \$3.00 per MCF



**Figure 68.** Economic gas potential — Taglu Play (unburdened case).



**Figure 69.** Economic gas potential — Taglu Play (unburdened case).

**TABLE 5**

Economic Gas Potential (BCF)  
Taglu Play  
(burdened case)

Price	5 km	25 km	50 km
\$2.00	2406.7	2179.6	2179.6
\$3.00	2825.2	2571.6	2406.7
\$4.00	3203.7	3010.9	2571.6

**TABLE 6**

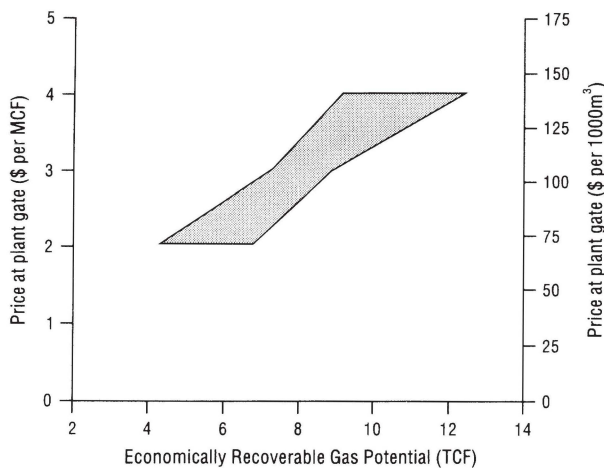
Economic Gas Potential (BCF)  
Taglu Play  
(unburdened case)

Price	5 km	25 km	50 km
\$2.00	2406.7	2406.7	2179.6
\$3.00	3010.9	2714.7	2406.7
\$4.00	3256.4	3081.7	2714.7

and a distance of 25 km, pool reserves of 2.6 TCF (73x10<sup>9</sup> m<sup>3</sup>) are viable for exploration, when burdened with taxes. At the same price, economic potential decreases by 0.17 TCF (4.9x10<sup>9</sup> m<sup>3</sup>) if found 50 km from processing facilities.

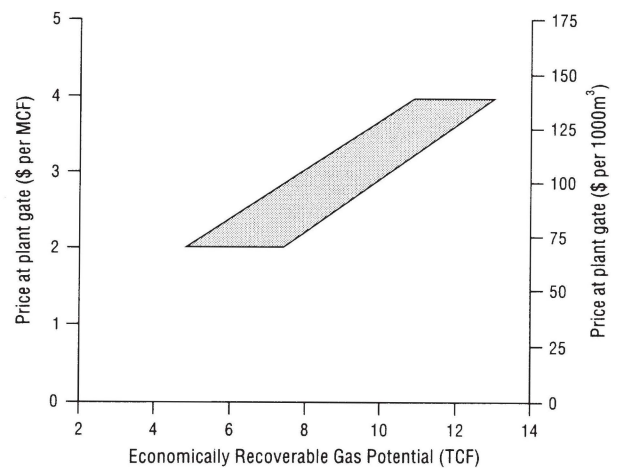
**ECONOMIC GAS POTENTIAL OF THE MACKENZIE DELTA-BEAUFORT SEA REGION**

The economic gas potential of the Mackenzie Delta-Beaufort Sea Region is the summation of potential estimates for individual exploration plays. Figures 70

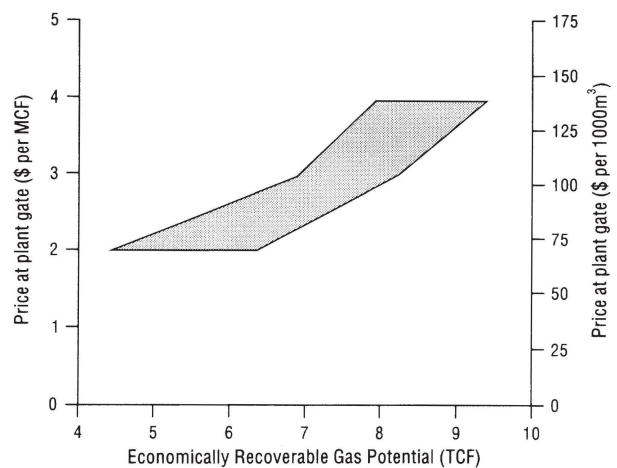


**Figure 70. Economic gas potential — Mackenzie Delta-Beaufort Sea Region (burdened case).**

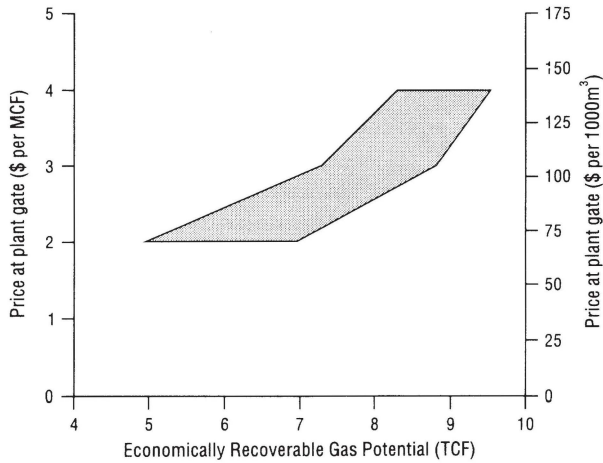
and 71 show the relationship of economic gas potential to price for both burdened and unburdened cases. Figures 72 and 73 show similar curves for the Onshore/Shallow Offshore Play Group and Figures 74 and 75 for the Offshore Delta Play Group. Tables 7 to 12 provide the supporting data. A comparison of the two play groups demonstrates that over 90 per cent of their total economic resource in the base case belongs to the Onshore/Shallow Offshore Play Group. Most of the resources in the offshore plays are uneconomic unless they are located very close to an existing gathering system and processing facilities or gas prices approach \$4.00 per MCF. This is shown by the supply curves of the two play groups. The Onshore/Shallow Offshore Play Group shows diminishing increments in potential as price increases while the Offshore Delta Play Group has greater elasticity to price increases.



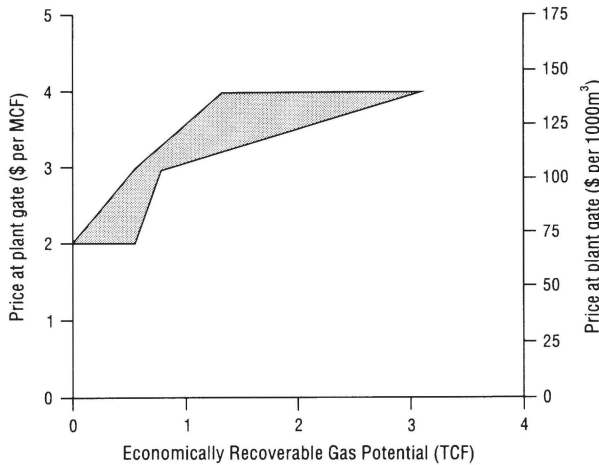
**Figure 71. Economic gas potential — Mackenzie Delta-Beaufort Sea Region (unburdened case).**



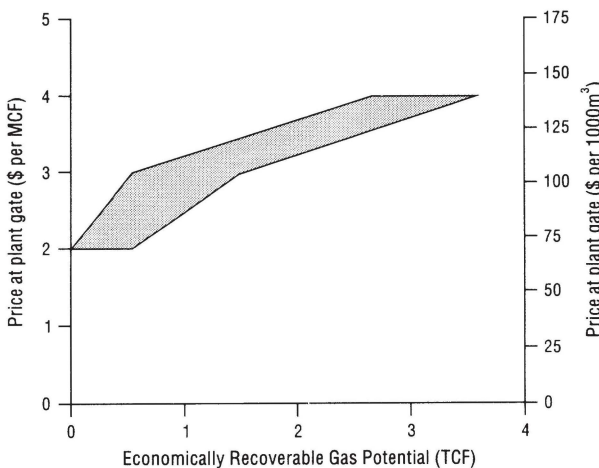
**Figure 72. Economic gas potential — Onshore/Shallow Offshore Play Group (burdened case).**



**Figure 73.** Economic gas potential — Onshore/Shallow Offshore Play Group (unburdened case).



**Figure 74.** Economic gas potential — Offshore Delta Play Group (burdened case).



**Figure 75.** Economic gas potential — Offshore Delta Play Group (unburdened case).

**TABLE 7**  
Economic Gas Potential (BCF)  
Mackenzie Delta–Beaufort Sea Region  
(burdened case)

Price	5 km	25 km	50 km
\$2.00	6869.9	5878.8	4427.4
\$3.00	8960.3	8125.0	7409.1
\$4.00	12 498.3	11 167.9	9270.0

**TABLE 8**  
Economic Gas Potential (BCF)  
Mackenzie Delta–Beaufort Sea Region  
(unburdened case)

Price	5 km	25 km	50 km
\$2.00	7471.6	6332.4	4920.1
\$3.00	10299.1	8605.2	7808.6
\$4.00	13 070.4	11 979.3	10 933.3

**TABLE 9**  
Economic Gas Potential (BCF)  
Onshore/Shallow Offshore Play Group  
(burdened case)

Price	5 km	25 km	50 km
\$2.00	6332.4	5878.8	4427.4
\$3.00	8178.3	7587.5	6871.6
\$4.00	9424.6	8870.9	7924.7

**TABLE 10**  
Economic Gas Potential (BCF)  
Onshore/Shallow Offshore Play Group  
(unburdened case)

Price	5 km	25 km	50 km
\$2.00	6934.1	6332.4	4920.1
\$3.00	8809.9	8067.7	7271.2
\$4.00	9522.5	9066.9	8265.5

**TABLE 11**  
Economic Gas Potential (BCF)  
Offshore Delta Play Group  
(burdened case)

Price	5 km	25 km	50 km
\$2.00	537.5	0.0	0.0
\$3.00	782.1	537.5	537.5
\$4.00	3073.8	2297.0	1345.3

**TABLE 12**  
Economic Gas Potential (BCF)  
Offshore Delta Play Group  
(unburdened case)

Price	5 km	25 km	50 km
\$2.00	537.5	0.0	0.0
\$3.00	1489.2	537.5	537.5
\$4.00	3547.9	2912.4	2667.8

In summary, the analysis shows that, of the total undiscovered resource of 22 TCF (620x10<sup>9</sup> m<sup>3</sup>) in the two play groups, 8.1 TCF (228x10<sup>9</sup> m<sup>3</sup>) (burdened) and 8.6 TCF (242x10<sup>9</sup> m<sup>3</sup>) (unburdened) is economic to find, develop and produce, assuming a price of \$3.00 per MCF at the plant gate and an average distance of 25 km. The economic potential is nearly 40 per cent of the total undiscovered resources in the two groups ("resources of current interest") but only 15 per cent of the total undiscovered gas resources of 53.3 TCF (1.5x10<sup>12</sup> m<sup>3</sup>) estimated by the GSC for the four play groups of the Mackenzie Delta-Beaufort Sea Region.

## CONCLUSIONS

The economic analysis of the Onshore/Shallow Offshore and Offshore Delta play groups concludes: a) Economically viable undiscovered resources exist to back-up initial development. b) For the base case (Alberta border price of \$4.00 per MCF), it would be economic to explore for 8.1 TCF (228x10<sup>9</sup> m<sup>3</sup>) of undiscovered potential in a burdened context. At \$5.00 per MCF, the profitable undiscovered potential increases to 11.2 TCF (315x10<sup>9</sup> m<sup>3</sup>). c) Comparable estimates in an unburdened case are 8.6 TCF (242x10<sup>9</sup> m<sup>3</sup>) and 12.0 TCF (338x10<sup>9</sup> m<sup>3</sup>), respectively. d) Approximately 40 per cent of the total undiscovered resources in the two play groups of current interest for the analysis is economic at a plant-gate price of \$3.00 per MCF (Alberta border price of \$4.00 per MCF). e) This economic potential is approximately 15 per cent of the total undiscovered resource potential of the entire Mackenzie Delta-Beaufort Sea Region. f) The current export application requires one-half of the total economic resource (9 of 19 TCF, 253 of 535x10<sup>9</sup> m<sup>3</sup>). g) Fiscal burdens do not significantly reduce economic potential. h) Price is more important than fiscal burden in determining the expected economic viability of exploration investments.

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