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GEOCHEMISTRY AND GEOLOGICAL FACTORS GOVERNING EXPLOITATION OF SELECTED CANADIAN OIL SHALE DEPOSITS

G. MACAULEY
L.R. SNOWDON
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CONTENTS

Illustrations

Figures

Figures

Tables

GEOCHEMISTRY AND GEOLOGICAL FACTORS GOVERNING EXPLOITATION OF SELECTED CANADIAN OIL SHALE DEPOSITS

Abstract

Organic and inorganic geochemical data (Rock-Eval pyrolysis, organic petrology and X-ray diffraction) are examined, along with a few results from hydroretorting, co-combustion and rock mechanics studies.

The Mississippian, lacustrine lamosites of the New Brunswick Albert Formation yield the largest amount of hydrocarbons (100 litres/tonne) and have a high potential in a linked retorting and co-combustion with coal process. The stellarite and associated coal of the Oil-Coal Seam at Pictou, Nova Scotia, may be a viable resource in the area.

The Kettle Point Formation and the Collingwood Member of the Lindsay Formation of southern Ontario yield moderate amounts of hydrocarbon on pyrolysis (40 litres/tonne), but both give significantly higher yields when hydroretorted. The Cretaceous Boyne and Favel formations in Saskatchewan probably represent the largest volumetric reserves of shale oil, but give modest yields, and face competition from the nearby heavy oils and oil sands to the west.

Résumé

Le rapport examine les données sur la géochimie organique et inorganique (pyrolyse Rock-Eval, pétrologie organique et diffraction des rayons X) ainsi que quelques-uns des résultats d'études d'hydropyrogénation, de co-combustion et de mécanique des roches.

Les lamosites lacustres du Mississippien de la formation d'Albert, au Nouveau-Brunswick, donnent la plus forte quantité d'hydrocarbures (100 litres/tonne) et pourraient être utilsées dans le processus combiné de pyrogénation et de co-combustion avec le charbon. La stellarite et le charbon associé du filon Oil-Coal à Pictou, en Nouvelle-Écosse, pourraient devenir une ressource utile dans la région.

La formation de Kettle Point et le terme de Collingwood de la formation de Lindsay dans le sud de l'Ontario produisent des quantités moyennes d'hydrocarbures par pyrolyse (40 litres/tonne); par contre, les quantités obtenues par hydropyrogénation sont beaucoup plus élevées. Les formations crétacées de Boyne et de Favel en Saskatchewan représentent vraisemblablement le plus gros volume d'huile de schiste argileux, bien que les quantités qu'elles donnent soient faibles. Les huiles lourdes et les sables pétrolifères de la région leur font concurrence.

Summary

Organic geochemical analysis using a Rock-Eval pyrolysis apparatus provides data for the comparison of the classification, thermal maturation and economic potential of eight Canadian oil shale deposits. Samples were selected for study because of their geographic locations close to market or tidewater, and for anticipated good hydrocarbon recovery potential. Some of the deposits were investigated further by organic petrology studies, including vitrinite reflectance, fluorescence, and maceral identification, and by detailed chemical and chromatographic analysis of the kerogens and pyrolyzates. Also, where available, exploitation research data, including hydroretorting, co-combustion with high sulphur coal to control SO_x emissions, and rock mechanics studies, are reviewed.

All major classes of oil shale deposits are recognized within this sample set, and thermal maturation levels range from immature to moderately mature (in the petroleum generation sense). Areas of overmaturity are also recognized.

The Type I continental, lacustrine, moderately mature lamosites of the Mississippian Albert Formation in New Brunswick are the most interesting of the deposits, because of highest yields (Albert Mines zone averages 100 litres/tonne) and the potential for linked retorting and co-combustion with coal for oil production and power generation in an energy deficient area. At Pictou, Nova Scotia, investigations for development of the Pennsylvanian Oil-Coal Seam, co-utilizing the coal and stellarite, a Type I low maturity continental bog torbanite, are recommended. The Type II marine, mixed, immature oil shales of the Devonian Kettle Point Formation, and the Ordovician, Collingwood, Type II marine, sapropelic, marginal to low maturity deposits, (both of medium yield potential, 40 litres/tonne), are of interest because of their locations near the industrialized and petrochemical areas of Ontario; these deposits respond well to hydroretorting. Although areally the largest, and probably containing the largest potential *in situ* reserves, the Type II marine, mixed, immature oil shales of the Cretaceous Boyne and Favel formations in the Pasquia Hills, Saskatchewan, face strong competition from the conventional heavy oil and oil sand deposits to the west.

Sommaire

L'analyse géochimique organique au moyen d'un dispositif de pyrolyse Rock-Eval a fourni des données pour une comparaison de la classification, de la maturation thermique et des possibilités économiques de huit gisements canadiens de schistes argileux bitumineux. Les échantillons ont été choisis en raison de leur emplacement près des marchés et de ports d'eau profonde et des possibilités qu'ils offrent en ce qui a trait à la récupération des hydrocarbures. Certain gisements ont été étudiés de façon plus détaillée, notamment par un examen de la pétrologie organique, y compris le pouvoir de réflexion de la vitrinite, la fluorescence, l'identification des macéraux et l'analyse chimique et chromatographique détaillée des kérogènes et des pyrolysats. Dans certains cas, les résultats des travaux de recherche sur l'exploitation, notamment l'hydropyrogénation, la co-combustion avec le charbon riche en soufre en vue de contrôler les émissions de SO_2 et la mécanique des roches, ont également été examinés.

Cette série d'échantillons comprend toutes les catégories principales de gisements de schiste argileux bitumineux; les degrés de maturation varient de faible à moyen (du point de vue de la génération du pétrole). Des zones de surmaturité sont également reconnues.

Les lamosites lacustres continentales modérément matures de catégorie I de la formation d'Albert du Mississippien, au Nouveau-Brunswick, sont les gisements les plus intéressants puisque les quantités qu'elles produisent sont élevées (la zone d'Albert Mines donne en moyenne 100 litres/tonne) et qu'elles pourraient être utilsées dans le processus combiné de pyrogénation et de co-combustion avec le charbon pour la production du pétrole et de l'énergie électrique dans une région pauvre en sources d'énergie. Les auteurs recommandent d'étudier la possibilité de mettre en valeur le filon Oil-Coal du Pennsylvanien à Pictou, en Nouvelle-Écosse, et d'utilser ensemble le charbon et la stellarite, torbanite de tourbière continentale à faible maturité de catégorie I. Les schistes argileux bitumineux marins immatures mixtes de catégorie II de la formation dévonienne de Kettle Point, et les gisements marins sapropéliques ordoviciens de catégorie II du membre de Collingwood, sont intéressants parce qu'ils se trouvent près de régions industrialisées et pétrochimiques en Ontario; leur production est moyenne (40 litre/tonnes) et ils répondent bien à l'hydropyrogénation. Les schistes argileux bitumineux marins mixtes immatures de catégorie II des formations crétacées de Boyne et de Favel, trouvés dans les collines Pasquia en Saskatchewan, forment le plus vaste gisement de ce type et représentent vraisemblablement les plus importantes réserves sur place. Toutefois, les gisements classiques d'huile et de sable pétrolifère situés à l'ouest leur font concurrence.

GEOCHEMISTRY AND GEOLOGICAL FACTORS GOVERNING EXPLOITATION OF SELECTED CANADIAN OIL SHALE DEPOSITS

INTRODUCTION

In their paper "Oil and Natural Gas Resources of Canada", Procter, Taylor and Wade (1983) assess Canada's petroleum supply, and anticipate a broad mix of petroleum sources for the future:

> *Oil and gas remain the major sources of Canada's primary energy requirements. Although requirements for these fuels have been reduced through energy conservation, and efforts to promote substitutes for oil, this dependence will continue . . . In addition to conventional resources, Canada is more richly endowed with non-conventional oil and gas resources than most countries. These resources dwarf the conventional category in terms of total quantity of in-place reserves, and have the added advantage of having already been discovered . . . Canada's future oil supply will derive from some mix of conventional, frontier, heavy oil and non-conventional sources. The proportion of each will depend on many factors, including comparative economic developments in technology, and investment strategies . . . Thus, there remains as a major requirement the 'need to know', in ever-increasing sophistication, the nation's endowment of petroleum resources.*

To meet the above knowledge requirements effectively, both industry and governments are continuously assessing conventional oil and gas reserves, frontier and off-shore potential, heavy oil deposits, and the nonconventional oil sands resource. A constant assessment of coal energy reserves is also being maintained.

Nonconventional oil shale resources are missing from these evaluations. As a step toward correcting this omission, in 1980, the Geological Survey of Canada, through the Institute of Sedimentary and Petroleum Geology (ISPG), Calgary, Alberta, contracted a review of Canadian oil shale deposits. That review encompassed all published and available unpublished information to that date, but did not incorporate any new research. Those results are available in "Geology of the Oil Shale Deposits of Canada" (Macauley, 1984a, GSC Paper 81-25). This paper served as a background source for new investigations, primarily oriented to geochemistry, but also to determining the mineralogy and organic petrology of the deposits, and, in some cases, the chemistry of the oil products. ISPG conducted these studies on oil shales of Nova Scotia, New Brunswick, the Prairie Provinces and the Queen Charlotte Islands (British Columbia), in part independently, and in part in cooperation with the Department of Natural Resources, Province of New Brunswick, and the Ministry of Energy, Mines and Petroleum Resources, Province of British Columbia.

Concurrent with the above program, the Ontario Geological Survey (OGS), Toronto, Ontario, carried out a major coring program to evaluate oil shales in that province. The analytical phase of the Ontario project was conducted at the Department of Earth Sciences, University of Waterloo, Waterloo, Ontario. Data have been made available by the Ontario Geological Survey for inclusion herein.

Research into the production and utilization of Canadian oil shales is currently in progress at the Research and Productivity Council (RPC), Province of New Brunswick, in Fredericton. The major RPC project involves co-combustion of oil shale with high sulphur coal for oil production and power generation, whereby sulphur emissions from the coal are controlled by reaction with the carbonate of the oil shale. Hydroretorting evaluations have also been carried out on several Canadian oil shales at RPC. Data from most of these projects have been made available to the authors.

This paper is thus an updated effort to bring knowledge of Canadian oil shales to the level where they can be included in estimates of the energy resources of our country. Macauley (1984a) outlined the geographic and geologic settings of these oil shales. We attempt here, in early 1985, to define their geochemical character and related productivity criteria, and to outline the further steps required to determine their economic potential.

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OIL SHALE: DEFINITION AND CONCEPTS

"Oil shale" has been one of the most abused of geological terms, partly because of usage long before understanding had been attained of the geology of the deposits in question or of the nature of the included organic components. Only long established usage, in conjunction with a present-day generally accepted definition, can justify the continued use of "oil shale", in describing a rock which does not contain oil and is not necessarily a shale.

Definition

Oil shale is a fine grained, sedimentary rock, containing indigenous, organic matter that is mainly insoluble in ordinary petroleum solvents, and from which significant amounts of shale oil can be extracted by pyrolysis (i.e. heating in a retort).

Concepts

"Significant amounts" is an open-ended phrase, but several general concepts are involved. The temperature of pyrolysis seldom exceeds 500° to 600°C as, above these temperatures, additional yield of shale oil is low, and breakdown occurs for some of the inorganic rock constituents, especially dolomite. The energy necessary to raise the rock temperature to 500°C is approximately 250 calories/gram of rock. The heat value of the indigenous organic material is generally 10 000 calories/gram; therefore, 2.5% by weight is the minimum organic content at which the amount of energy recovered as shale oil could theoretically balance the input energy. This value, then, becomes the minimum organic content needed to define an oil shale, but does not allow for other energy-equivalent input (mining, transportation etc.). U.S. literature often quotes 10 U.S. gallons/ton (42 litres/tonne) as a minimum shale oil yield for economic consideration, but this is an arbitrary value.

The understanding of oil shales has advanced significantly in the past decade, with various types of deposits recognized on the basis of both geochemistry and organic petrology; however, a standard classification is not yet in place. A second characteristic, the degree of thermal maturation (i.e. the degree of natural retorting that has already occurred), is presently defined only by imprecise terminology.

Classification

Kerogen is the organically insoluble, indigenous, organic matter of sedimentary rocks – the nature of the kerogen is the basis for oil shale classification. Both geochemistry and petrology are utilized in kerogen analysis. Neither technique is fully adequate in itself, but together they provide a comprehensive picture for most deposits.

Tissot and Welte (1978) divided kerogen into types, using the atomic hydrogen/carbon ratio. Type I ($H/C>1.4$) is derived from algae, and is usually a nonmarine deposit; Type II (H/C 1.4-1.2) is marine kerogen derived from phytoplankton; Type III ($H/C<1.0$) constitutes higher land plant forms. Types I and II are sapropelic, and form oil shales: Type III is humic, and creates coal.

Individual kerogen grains are termed macerals and generally can be defined within one of the three maceral groups: inertinite, vitrinite and exinite (International Committee for Coal Petrology, 1963, 1971, 1975). Inertinite and vitrinite are the prime macerals of coal, but generally have minimal oil generative capacity. Most oil shale kerogen belongs to the exinite group, which is algal in origin (alginite), and contains only minor quantities of spores (sporinite), pollen and cuticles (cutinite) from higher land plants. Exinite is a secondary component of most coal. The sapropel of oil shale (Types I, II) and the humus of coal (Type III) are independent of each other, and oil shales are not normally related to coal deposition and/or to coal terminologies and maturation definitions.

In studies of Australian oil shales, Hutton et al. (1980) recognized two distinct alginite forms of exinite. 'Alginite A' (telalginite) consists of discrete algal bodies, both colonial and unicellular, that are either ellipsoid or disc shaped, and are analogous to *Botryococcus*. 'Alginite B' (lamalginite) is finely banded, lamellar alginite intrinsically interbedded with mineral matter in well laminated (macroscopically and microscopically) deposits. These are the dominant kerogens of Type I deposits.

Type II kerogens are less easily defined by maceral analysis, as they can be admixtures of marine Type I algae and Type III humic detritus, or be dominantly Type II marine phytoplankton (Hutton et al. *ibid.*). Most of the macerals are termed unfigured or amorphous, and can be described as fine, organic material that appears to be bitumen but which fluoresces. Creaney (1980) used the term 'matrix bituminite' for this type of kerogen in a northern Canadian source rock.

The oil shale classification used herein (Fig. 1) follows, with some modification, that proposed by Hutton et al. (1980) for the Australian deposits.

Torbanite: synonymous with boghead coal, torbanite is a form of sapropelic coal containing telalginite derived from algae related to the extant genus *Botryococcus*. The majority of torbanites are geographically restricted, lenticular bodies occurring close to, or bounded by, coal beds. Because of the close association with coal, vitrinite and inertinite are common secondary macerals. The inorganic content is commonly a quartz-clay detritus, defining the rock as shale or claystone.

Lamosite: lamalginite is the dominant maceral of organic-rich, laminated lamosite, which can also contain significant amounts of sporinite, and minor telalginite, but which has minimal inertinite and vitrinite content. The anastomosing habit of the lamalginite may be indicative of mat-forming, bottom-dwelling forms deposited in fresh or saline lacustrine environments. Lamosite oil shales are not found in association with coals or sediments containing abundant humic kerogen. Carbonate minerals are common, particularly dolomite. In some cases, the sediment is a dolostone; in others, sufficient quartz-clay content, along with the carbonate, defines the rock as a marlstone.

Mixed: shallow marine conditions are indicated by the presence of the remains of fish and pelecypods, together with dinoflagellates, acritarchs, and planktonic foraminifera, which indicate open sea conditions. Calcite is abundant, commonly occurring in limestone interbeds, possibly relating to coccolith blooms. These blooms are considered to have been the source of much of the kerogen that was deposited as extremely fine, unfigured, amorphous sapropel. Layers of fine, indeterminate humic material may be discernible, representing the influx of comminuted terrestrial debris. Clay and clay-size quartz detritus, along with the calcite, can provide a range of rock types, basically shale but in part grading to limestone.

Amorphous (sapropelic): some shallow marine carbonate (limestone-dolostone) oil shales contain the remains of marine pelecypods, trilobites, acritarchs and conodonts that can be used for environment identification; however, the organic content occurs only as an indeterminate matrix. No humic content can be recognized either petrologically or geochemically. Atomic H/C ratios define the kerogen as sapropel. These deposits commonly occur as an end phase to a widespread, carbonate sequence.

Oil Shale Type	Continental		Marine	
	Torbanite	Lamosite	Mixed	Amorphous (sapropelic)
Dominant Kerogen Type	I	I	II	II
Secondary Kerogen Type	III		I, III	
Maceral	Telalginite (Alginite A)	Lamalginite (Alginite B)	Amorphous	Amorphous (sapropelic)
Non-algal components	vitrinite inertinite sporinite	sporinite	indeterminate humus vitrinite sporinite	
Environment	bog	lacustrine	marine	marine

Figure 1. *Classification of oil shales based on geochemical type, maceral composition, and environment.*

Thermal maturation

Because both the character and yield of retorted oil depends on the hydrogen/carbon ratio and on the relative aliphatic-aromatic structures within the kerogen macerals, recognition of kerogen type is essential in evaluating an oil shale. Equally important is an understanding of the thermal history of the deposit. Hydrocarbons are generated naturally within a limited temperature range that is generally exceeded as the sediment is buried and subjected to the earth's increasing geothermal heat. Local igneous effects may also be significant. The degree of prior natural heating of the oil shale (the level of thermal maturation) influences both the quantity and quality of retorted oil product.

Like oil shale classification, thermal maturation concepts and definitions are still imprecise. Because maturation levels must also be applicable to hydrocarbon source rock deposits, the broad terms "immature" (no oil as yet generated), "mature" (in the thermal range of oil generation), and "over-mature" (all possible oil has been generated) are in common usage. Marginal, low and moderate are terms used to modify mature. Based on the "oil generation window" defined by pyrolysis (Tmax temperatures in the range 435° to 465°C), these terms have been generally adequate for the petroleum industry assessment of source rock maturity, and, with better definition, will also serve for oil shale evaluation.

Several systems can be utilized for numerical representation of maturation levels. Of these, three are based on organic petrology. The Thermal Alteration Index, TAI, is defined by the colour of the organic macerals in transmitted light, ranging from immature yellow through orange, to brown and black where overmature. Both the Conodont Colour Alteration Index, CAI, and the Acritarch Colour Alteration Index, AAI, are more specific reflected light variations of the TAI technique. Vitrinite reflectance, derived from coal petrology, is useful, but becomes misleading where bitumen of the oil shale impregnates the vitrinite to reduce significantly the measured reflectance (Hutton and Cook, 1980; Kalkreuth and Macauley, 1984). Lower reflectance bitumen grains are also easily mistaken for the more reflective vitrinite particles. Thus, vitrinite reflectances are of value when measured from non-oil-shale beds (not bitumen impregnated) contained within or closely adjacent to an oil shale sequence. Fluorescence measurement, which deals directly with the kerogen macerals of oil shales, is the most appropriate petrologic technique of maturation evaluation, especially in the range of immature to mature. Fluorescence measurements are more difficult for the more mature to overmature source rock beds (an overmature oil shale is an obvious source rock).

Geochemical techniques initially involved direct measurements of the C, H, and O content of the kerogen to define types I, II and III. With the advent of the Rock-Eval pyrolysis equipment, a modified form of the van Krevelen atomic ratio diagram was prepared by Tissot and Welte (1978). The Rock-Eval equipment measures Tmax, a maturity indicator based on the temperature of the maximum hydrocarbon evolution rate during kerogen pyrolysis, and also measures the amount of free volatile hydrocarbon in the rock. Because not all generated hydrocarbons successfully migrate from the source, the Production Index, PI (ratio of free hydrocarbons to total recovered hydrocarbons), is a measure of oil generation (i.e. thermal maturity). Other pyrolysis techniques can be similarly interpreted.

Within the oil window range of temperatures, heavy bitumens (organically soluble, molecularly complex, semi-solid hydrocarbons) are first developed, followed by increasingly better quality oils, by wet gas in the final phase and dry gas in early overmaturity. The chemical character of the pyrolyzed oil can be indicative of both increasing maturity and the nature of the kerogen (Type I or II). Interpretations are inferred from the aliphatic-aromatic make-up of the oil, by analysis of the pristane/phytane content, and by other component concentrations.

Figure 2 outlines the described thermal maturation indicators; none is fully adequate by itself. If used comparatively and cooperatively, in conjunction with the knowledge of oil shale origins and related kerogen types, an optimum interpretation can be made of the history and ultimately the economic potential of an oil shale deposit. The mature phase is subdivided into low or marginal (bitumen generation), moderate (oil phase), and high maturity (wet gas phase). Although coal rank equivalents are shown to relate completely to vitrinite reflectance values, the use of coal rank terminology is inappropriate to oil shales and is not recommended.

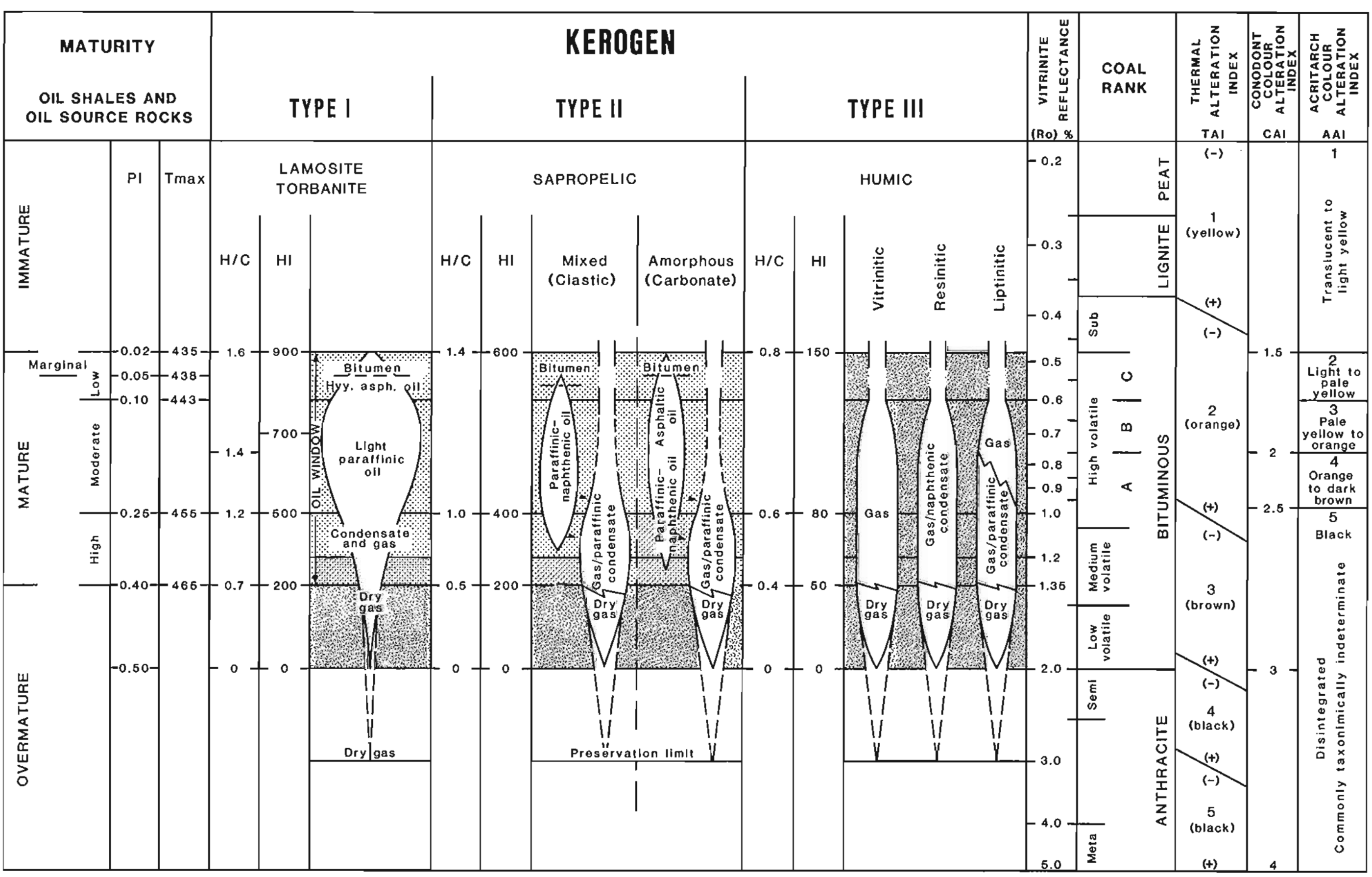


Figure 2. Maturation indices (Rock-Eval) for oil shales and source rocks compared with oil generation window and coal rank. (In part from Powell and Snowdon, 1983; in part from Dow, 1977; and in part from ISPG investigations.)

Analytical techniques

Because the various deposits are here interpreted and compared primarily on the singular geochemical basis of Rock-Eval pyrolysis, a brief description of the procedures, as used at ISPG, Calgary, is necessary. Background data are also required for the XRD analyses on which the comparative mineralogies are based. Techniques used in other laboratories can be reviewed from the references within the selected bibliography of this report.

Total Organic Carbon (TOC) Analysis: TOC content is an essential adjunct to the interpretation of Rock-Eval data. Samples were pulverized in a swing mill to approximately 150 micron sized particles. The crushed samples were then prepared, using dilute, cold, hydrochloric acid followed by 6N, hot hydrochloric acid treatments to remove mineral carbon occurring as carbonates – mostly calcite, dolomite and siderite. Sample sizes were 250 mg for TOC values less than 5% and 100 mg for samples with higher organic carbon (Corg) content, to ensure that the results were within the calibration range of the Leco WR12 carbon analyzer (Snowdon, 1984).

Rock-Eval Pyrolysis: in conjunction with the TOC value, Rock-Eval pyrolysis provides the following data points and interpreted values:

S1: the lower temperature peak that results from the distillation of the pre-existing volatile hydrocarbon component, measured as milligrams of hydrocarbon per gram of rock.

S2: the higher temperature peak resulting from the pyrolysis of organically insoluble kerogen and organically soluble bitumen, measured as milligrams of hydrocarbon per gram of rock.

S3: a measure of the CO_2 derived from the organic component as milligrams CO_2 per gram of rock. A temperature of 390°C has been selected as a cut-off for the collection of CO_2 to preclude measuring material from the breakdown of inorganic carbonate minerals.

Tmax: the temperature (°C) recorded at the maximum hydrocarbon evolution rate, defining the S2 peak; an indicator of thermal maturation.

Hydrocarbon Potential (S1+S2): the total of all hydrocarbon products pyrolyzable from the rock, and a direct indicator of economic potential. The relative quality of the organic matter in the deposits is best determined by comparing the ratios of total yield to organic carbon content [(S1+S2)/%Corg], whereas the overall economic potential of a deposit is a function of both the type and amount of organic matter.

Hydrogen Index (HI): the ratio of S2 hydrocarbon to the organic carbon content. This ratio has been correlated to the atomic H/C ratio (Espitalie et al., 1977) and provides an indicator of kerogen type and maturation when interpreted in conjunction with Tmax and the Oxygen Index.

Oxygen Index (OI): the ratio of the S3 (CO_2) peak to the organic carbon content, which correlates to the atomic O/C ratio (Espitalie et al., 1977), and is an indicator of kerogen type and maturity when interpreted with the Hydrogen Index and Tmax.

Production Index (PI): the ratio of volatile hydrocarbons (S1) to total, recoverable hydrocarbon (S1+S2), which is a direct indicator of thermal maturation and/or the presence of epigenetic (migrated) hydrocarbons.

A standard program was used for the Rock-Eval pyrolysis. The S1 peak was obtained at 300°C, and the S2 peak was measured during heating at a rate of 25°C/min. One set of results was obtained using a calibration standard (S2=3.38 mg/g, Tmax=459°C) that was established against a standard supplied with the instrument (S2=5.60 mg/g, Tmax=429°C). A second set of results was obtained using various alternative standards, with S2 yields ranging from 16 to 110 mg/g. These were calibrated directly against the standard at the Institut Francais de Petrole (IFP).

The Rock-Eval pyrolysis apparatus at ISPG responds to increasing S2 yields in a nonlinear fashion. If the instrument is calibrated with a sample of given pyrolysis yield and fixed sample size (typically 100 mg), then the richer samples yield disproportionately larger amounts of pyrolyzable material. Additional standards, with S2 yields much higher than the base IFP standard, were thus necessary. Three calibration standards were sufficient to cover the observed range of results for potential oil shale or very rich petroleum source rocks. Sample sets using 100 mg, 50 mg and 30 mg provided satisfactory results for the S2 yield ranges 0-50 mg/g, 35-65 mg/g, and 50-120 mg/g respectively. Extrapolation and discontinuity errors have not been eliminated, but have been reduced sufficiently to enable the data to be usefully interpreted (Snowdon, 1984).

Although the Rock-Eval parameters are shown to fall within specific phases of maturation level (Fig. 2), interpretations must be made within a broader spectrum of value ranges. Caution is warranted, especially where mixed kerogen types are recognized or suspected. Other factors, such as mineral matrix variations (Katz, 1983), must also be considered.

X-ray diffraction (XRD): the optimum recognition of clay mineral components was a prime concern, and prompted the use of cobalt radiation with an iron filter. One portion of powdered sample was pelletized on a cellulose substrate and X-rayed with Co kα radiation, iron filter, settings of 45Kv - 20 Ma, 1°2θ/min/2cm scanning speed, time constant 2, and range 2° to 40°. A second fraction was similarly X-rayed but with Cu kα radiation and a nickel filter. Mineral percentage compositions obtained from diffraction peak heights are semi-quantitative only, varying with the degree of crystallinity, crystal size, and the amorphous material present. Consequently, these data represent approximate relative concentrations and are not absolute values.

OIL SHALES IN CANADA: SELECTED APPRAISALS

Based on his investigations in late 1980, Macauley (1984a) outlined eighteen areas of known or potential Canadian oil shale deposits. These occur through much of the geologic column, including the Ordovician, Devonian,

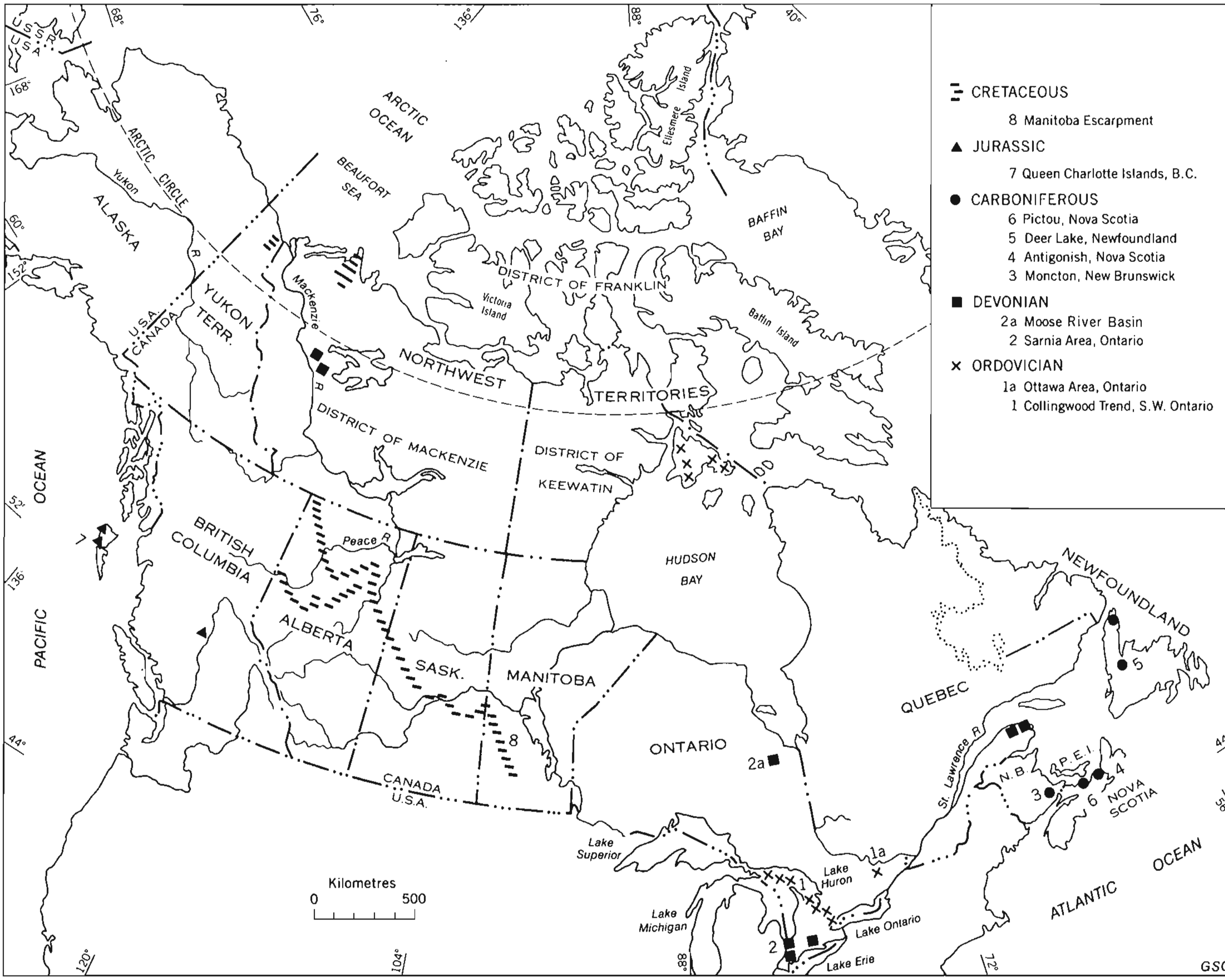


Figure 3. *Principal oil shale deposits of Canada; those selected for comprehensive geochemical investigation are numbered (from Macauley, 1984a).*

Carboniferous, Jurassic, and Cretaceous, and are found in every province and territory of the country, except Prince Edward Island.

Oil shale deposits of the Albert Formation in the Moncton Sub-basin, New Brunswick (Fig. 3, no. 3), were at that time the best studied of the known Canadian oil shale deposits (Macauley, 1984a), and a local deposit at Albert Mines appeared to be the most economically attractive. The Albert Mines deposit was recognized as requiring considerable additional geological study before any precise determination of shale oil potential could be made. A study, the results of which are published in Macauley and Ball (1982), was deemed essential to determine the most appropriate procedures for core evaluation and other exploration and development investigations. Those findings defined a basic procedure for evaluating the oil shale potential of the Albert Formation of New Brunswick, and deposits elsewhere in Canada. Comparable data could thus be made available for the selected Canadian oil shale occurrences described herein.

Other deposits chosen for study by ISPG were selected on the bases of apparent economic potential, geographic location relative to potential markets (including accessibility to tidewater), and their competitive distribution compared to other energy sources, especially conventional petroleum production. Had the Ontario Geological Survey not undertaken a major coring program over the past three years, much less data would be available for the Ontario oil shales. Fortunately, their results are available to complete this appraisal of Canada's most promising oil shale deposits.

Figure 3 is an index map showing the principal oil shale deposits that are here described, with emphasis on their geochemistry, and on both economic aspects and exploitation. Also shown, but not listed, are deposits that were not studied because of geographic remoteness, inaccessibility or known limited potential. In the following descriptive list of these oil shale areas, the numerical sequence corresponds to the locality numbers on the index map.

Ordovician

1. Manitoulin-Collingwood-Whitby trend, Ontario; Collingwood oil shale outcropping parallel to the base of the Niagara Esçarpment; thin, widespread, black limestone deposited as the final phase of a carbonate sequence on a shallow, restricted, marine platform; located in an area of limited conventional petroleum resources but in a region of major petroleum consumption.

1a. Ottawa area, Ontario; Billings shale, stratigraphically equivalent to the Collingwood to the west; studied to provide regional control for evaluation of the Collingwood deposits.

Devonian

2. Sarnia-Windsor area, southwestern Ontario; Kettle Point Formation; up to 75 m of black oil shale intercalated with grey to green, nonorganic shale; gross zone overlies carbonate with deposition in an apparently shallow, open marine environment; located in an area of low conventional oil reserves near the petrochemical complex at Sarnia.

2a. James Bay Lowland, Moose River Basin, northern Ontario; Long Rapids Formation; stratigraphic equivalent of the Kettle Point Formation; although geographically remote, must be included to complete the evaluation of the Windsor-Sarnia area deposits.

Carboniferous

3. Moncton Sub-basin, New Brunswick; Lower Mississippian, Frederick Brook Member of the Albert Formation, commonly referenced as the Albert oil shales; best known and discussed of all Canadian oil shales and economically the most attractive; continental lacustrine deposits up to 100 m thick but expanded by structural deformation to possibly 300 m at the Albert Mines location; considerable section yields in excess of 100 kilograms/tonne; in an area with limited petroleum resources, but with a small petroleum consumption that could be well served by a local, small, oil shale operation; economics will depend on competitive aspects of offshore oil (i.e. Hibernia).

4. Big Marsh-Antigonish area, Nova Scotia; Rights River Formation, stratigraphically equivalent to the New Brunswick Albert oil shale; probable lacustrine deposits ranging from 67 to 127 m in thickness; although of too low a yield potential for present interest, these were studied to attain a broader picture for further exploration relative to the New Brunswick Albert oil shales.

5. Deer Lake-Humber Valley, Newfoundland; Rocky Brook Formation of the Mississippian Deer Lake Group, which is younger than the New Brunswick deposit; scattered, thin, lacustrine oil shale beds; probably too thin to be economically significant, but included because of available geochemical data to provide a more complete review of the Carboniferous oil shales of the Atlantic Provinces.

6. Pictou area, Nova Scotia; the youngest Carboniferous oil shales in the Pennsylvanian Pictou Group; torbanite deposits in association with coal beds; areally restricted and thin; an Oil-Coal Seam may have potential for co-retorting or co-combustion in an energy-poor area, but in competition with high-cost offshore oil.

Jurassic

7. Graham Island, Queen Charlotte Islands, British Columbia; Kunga Formation; probable shallow marine, platform deposits interbedded with volcanically derived sediments; thin beds in structurally deformed sequences; of interest because of proximity to tidewater.

Cretaceous

8. Manitoba Escarpment and westward-extending outcrop trend across the Prairie Provinces; Boyne and Favel formations, informally the First and Second White Specks zones; up to 20 m and 40 m thick respectively; areally extensive marine shales, in part grading to limestones within a major sequence of open marine shale deposition; fair yields, good thickness and large areal extent indicate vast, potential hydrocarbon reserves, but must compete with the nearby Alberta oil sands deposits.

Ordovician: Collingwood oil shale, southern Ontario

Canada's first and only oil shale plant to achieve and maintain a continued period of oil production was erected in 1859 at Craigleith, near Collingwood, on the shores of Lake Huron, Ontario (Fig. 4). Although conventional crude oil had been discovered in 1858 at Oil Springs [a year before the Drake discovery in Pennsylvania (Powell et al., 1984)], the Craigleith plant managed several years of operation before succumbing to the economic competition of the lower priced conventional petroleum of the Oil Springs area.

The nomenclatural history of the Collingwood beds is complex (Macauley, 1984a). That history was thoroughly reviewed by Russell and Telford (1983), who defined the Collingwood beds as the uppermost member of the Lindsay Formation, recognizing the oil shales to be terminal beds of a carbonate sequence and separating them from the overlying blue-grey shales of the Blue Mountain Formation. Locally in the Whitby area, thin, organic shale beds of the Rouge River Member interfinger with nonorganic beds of the Blue Mountain Formation (figs. 4, 5).

Exposures of the Collingwood Member occur on the shores of Manitoulin Island, at the shoreline on Georgian Bay near Craigleith, and along the area bordering Lake Ontario near Whitby (Fig. 4). The intervening area of the outcrop trend from Craigleith to Whitby is thickly buried by drift; consequently, no data are available along this part of the trend.

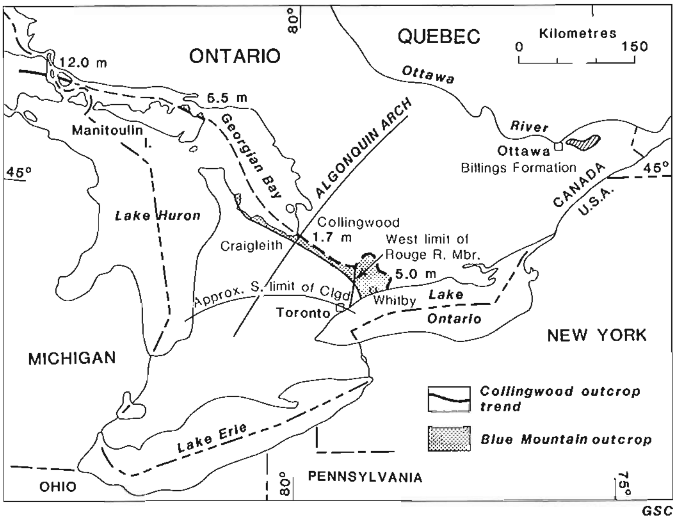


Figure 4. Outcrop distribution of Collingwood oil shales and equivalent Billings Formation in southern Ontario, with approximate thickness values for each outcrop area (expanded from Russell and Telford, 1983).

From examination of well records, Russell and Telford (1983, p. 1789) indicated a general southerly limit of Collingwood distribution in the subsurface (Fig. 4). From the core descriptions of Johnson et al. (1983a), the thinnest sections, averaging about 1.7 m, are encountered in the Collingwood area, with thicker sections to the southeast near Whitby (5.0 m), and to the northwest on Manitoulin Island (5.5 m) (Fig. 5). The maximum thickness encountered to date (12.0 m) was west-northwest of Manitoulin Island on St. Joseph Island (Johnson et al., in press). The thinnest sections overlie the Algonquin Arch (Legall et al., 1981, p. 494-495). The Arch defines the erosional pattern of Paleozoic beds in the area, and also may be reflected in the depositional pattern of the Collingwood, which thickens both northwest and southeast of the arch crest.

The stratigraphically equivalent Billings Formation is preserved locally near Ottawa (Fig. 3, no. 1a) in a partly fault-controlled feature (Baer et al., 1971).

Lithology and mineralogy

Collingwood oil shales are characteristically black, organic-rich, laminated, and fissile, with a rich invertebrate fossil fauna, characterized by abundant trilobites concentrated in thin, bioclastic beds. The oil shales have been variously described as shale, limestone and marl. The sharply overlying Blue Mountain Formation is a bluish grey, noncalcareous shale containing minimal organic carbon: where soft, brown to brown-grey organic shales of the Rouge River Member are developed, they can be calcareous (Russell and Telford, 1983), resembling Collingwood strata. The lower boundary is gradational downward (over variable thicknesses) to brownish grey and grey, sublithographic to very finely crystalline, nodular (in appearance) limestones of the Lindsay Formation. The gradational interval consists of interbedded limestone and argillaceous limestone with the argillaceous 'shaly' beds decreasing downward.

Snowdon (1984, Table III) provided eighteen XRD analyses of Collingwood shales. His results indicated calcite to be the prime mineral constituent (50%±), followed by quartz (35%±) and clays (15%±) with minor feldspar and pyrite (up to 4% each). Within the clays, illite predominates (10%±) over chlorite (5%±). Zones having almost complete replacement of the calcareous material by dolomite can be inferred from scattered samples at Collingwood and are more prominent on Manitoulin Island.

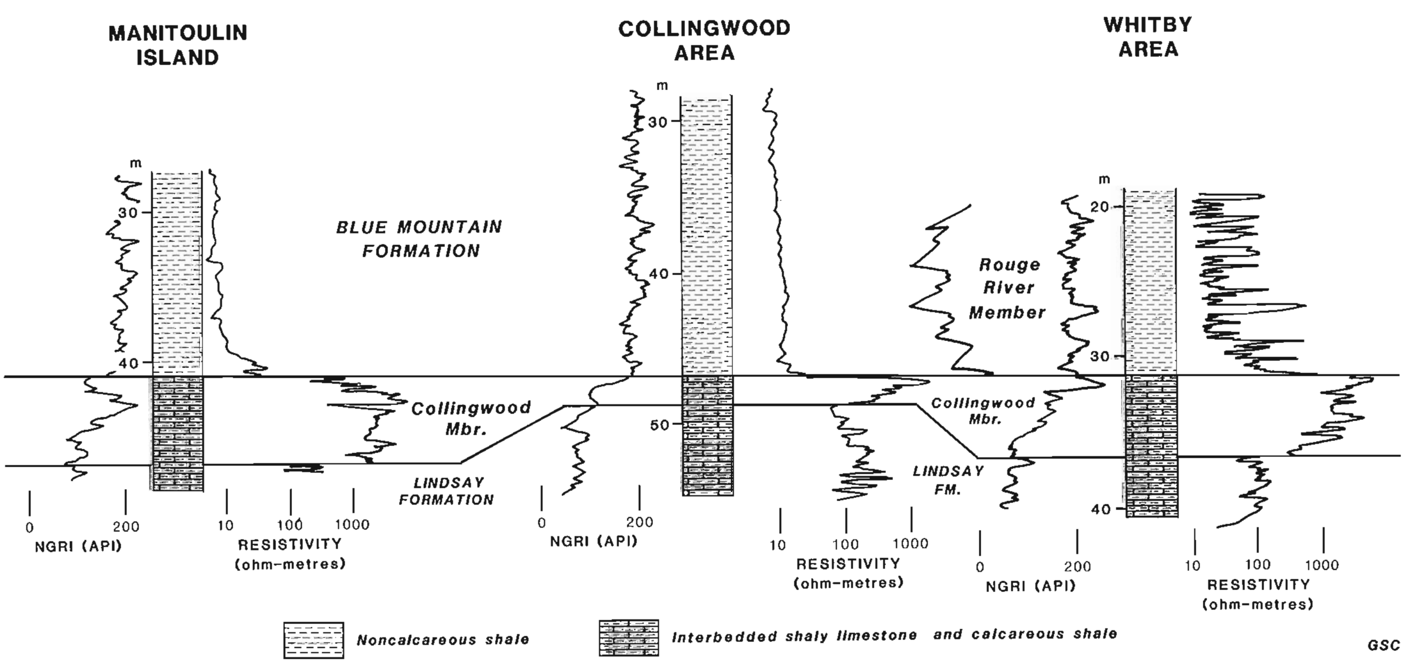


Figure 5. Gamma-resistivity-lithology plots illustrating the relationship of the Collingwood oil shale beds to overlying and underlying strata (logs and lithologies from Russell and Telford, 1983).

From determinations of total inorganic carbon (Barker et al., 1983), Russell and Telford (1983) considered the Collingwood oil shales to be, lithologically, marl or limestone. Marlstone is an appropriate term where no mineral assemblage predominates, but in this case calcite is sufficiently abundant to be the grain support mineral of the sediment, and thus define the rock as a limestone.

Organic geochemistry

In order to be directly comparable with data from the other Canadian oil shale deposits, most of the geochemical data discussed here are from the Rock-Eval results reported by Macauley and Snowdon (1984). Additional data from geochemical studies at the University of Waterloo have been included and are referenced. Table I summarizes the pertinent data for the interpretations of kerogen type, thermal maturation and hydrocarbon potential. All data are from Macauley and Snowdon (1984) except TOC values, which were averaged from Barker et al. (1983a). These numerous additional TOC values permit a more precise evaluation.

Total Organic Carbon (TOC): averaged values of total organic carbon (Table I) indicate an easterly decrease in organic content. Maximum TOC content is invariably less than 10%.

Tmax: from Tmax data (Table I), Collingwood oil shales can be defined as immature to only marginally mature (435°C average) in the Collingwood area; of marginal to very low maturity on Manitoulin Island; of low thermal maturity in the Whitby area (444°C); and overmature at Ottawa (466°C).

Hydrogen-Oxygen Indices (HI-OI): HI-OI data for the four areas plot into distinct groups (Fig. 6) with increasing maturation. HI and OI decrease directly with the increase in maturation levels indicated by Tmax. Snowdon (1984, Table II) indicated similar Tmax and HI distributions from a separate suite of samples.

Atomic H/C ratios in the range 1.2 to 1.6 were reported by Barker et al. (1983a), and are in general agreement with the range of HI from the Rock-Eval analyses.

Production Index (PI): low PI ratios (0.06) at both Manitoulin Island and the Collingwood area indicate marginal to very low maturation, increasing into the range of moderate maturation at Whitby (0.23) and high maturation to overmaturity at Ottawa (0.57).

Organic petrology

Barker et al. (1983b), on the basis of visual examination of a limited number of sample slides, described most of the kerogen as amorphous, and basically indeterminate in character, in the Manitoulin Island-Collingwood-Whitby areas. However, the Manitoulin and Whitby areas contained exinite detritus, cutinite and resinite, in addition to the amorphous sapropel. The decreasing yield/%Corg ratio (Table I) was attributed to the changing character of the kerogen.

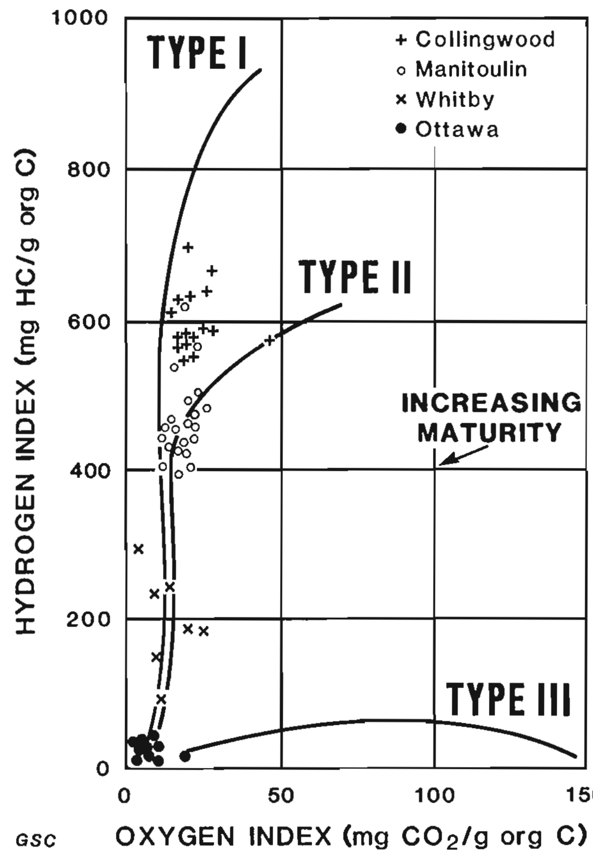


Figure 6. *Relative plots of Hydrogen and Oxygen indices, Collingwood oil shales, southern Ontario (from Macauley and Snowdon, 1984); (Types I, II and III refer to the three kerogen types).*

Vitrinite reflectance values at Whitby range from 0.44 to 0.57 per cent and at Ottawa are 1.38 per cent (Barker et al., 1983b). The values at Whitby are much lower than anticipated from other maturation indicators and possibly represent measurement on a bitumen particle, not on humic debris. Overmature bitumen in the Billings Formation at Ottawa has reflectance values commensurate with the geochemical indicators.

Both Conodont Colour Alteration indices (CAI) and Acritarch Colour Alteration indices (AAI) were described by Legall et al. (1981). These define a similar maturation pattern as Tmax values for the Ordovician beds, a pattern in which values increase eastwards and are higher in the Whitby area than at Collingwood-Manitoulin. Overmaturity values

Area	TOC Aver. %	Tmax Aver.°C	HI Aver.	PI Aver.	Yield/C Ratio Av. kg/t/1% Corg	Refl.	CAI	Prist/ Phyt	Prist/ nC_{17}
Collingwood	4.1	435	563	.06	6.41		<2	1.24	1.34
Manitoulin Is.	5.1	439	470	.06	5.04		<2	1.26	1.02
Whitby	3.8	444	195	.23	2.51	.44-.57	2+	1.54	0.50
Ottawa	2.6	466	26	.57	0.57	1.38	2.5		

TABLE I

Averaged geochemical data pertinent to classification and maturation interpretations, Collingwood oil shales were mapped at Ottawa. Acritarch values are based largely on *Leiosphaeridia*, a simple, spherical, or disc-shaped (after compaction), unornamented leiosphere. These possibly produce some of the vitrinite-resinite forms of exinite reported by Barker et al. (1983b).

Kerogen-pyrolyzate-oil characteristics

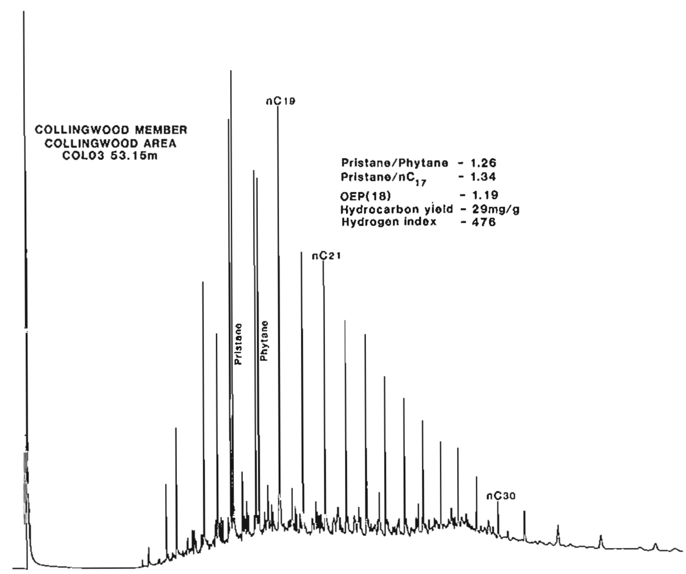
Cambrian and Ordovician oils from fields in southern Ontario show distinctive characteristics in their saturate, aromatic and isotopic compositions, with the only potential source identified as the Collingwood Member of the Lindsay Formation (Powell et al., 1984). The saturate fractions have characteristic odd-to-even predominance of the n-alkanes in the range nC_{14} to nC_{20}. Aromatic fractions are dominated by substituted naphthalenes. Extracts from the Collingwood show the same characteristics.

A combination of gas chromatography and mass spectrometry was used by Barker et al. (1983b) to analyze the pyrolyzates from Collingwood-Blue Mountain kerogens. Alkene-alkane pairs, imposed on a background of polysubstituted benzenes, dominate up to at least C_{15}. Above C_{15}, alkylbenzenes, possibly including diterpenoids, are dominant. Although oxygen and sulphur-containing bridge groups are found in the infrared spectra of the kerogen, these are missing from the residue and the pyrolyzate, apparently being released as CO_2 and H_2S on pyrolysis. From the infrared adsorption spectra, Barker et al. (1983a), noting stronger OH adsorption bands in the kerogen of the Whitby area, interpreted a more aromatic character for that kerogen in comparison to kerogen from the Collingwood-Manitoulin areas.

During evaluation of the Rock-Eval pyrolysis equipment, Snowdon (1984) discussed the hydrocarbon yield based on both solvent extraction and pyrolysis. Both Snowdon (*ibid.*) and Barker et al. (1983b) found that the solvent extractable hydrocarbon was much greater than that represented by the Rock-Eval S1 peak; considerable soluble bitumen was pyrolyzed in the S2 peak along with the kerogen.

Gas chromatograms of Collingwood solvent extracts indicated a predominance of odd/even normal alkanes in the C_{16} to C_{22} range of 1.07 to 1.32, with the lower values coming from the higher maturity Whitby area (Snowdon, 1984). Pristane/phytane ratios range from 1.2 to 1.6, increasing from Collingwood to Manitoulin Island to Whitby (Fig. 7). Pristane/nC_{17} ratios decrease commensurately from 1.34 to 1.02 to 0.50. These values confirm the changing maturation level indicated by the Hydrogen indices.

Although analyses of kerogen pyrolyzates and solvent extracts are excellent product indicators, data are sparse for the retorted oil products. Fischer Assay specific gravity values range from 0.893 to 0.942 (Barker et al., 1983b), but these specific values were not identified by area. Published data do not yet allow the correlation between specific gravity and maturity to be attempted, although some relationship is anticipated.



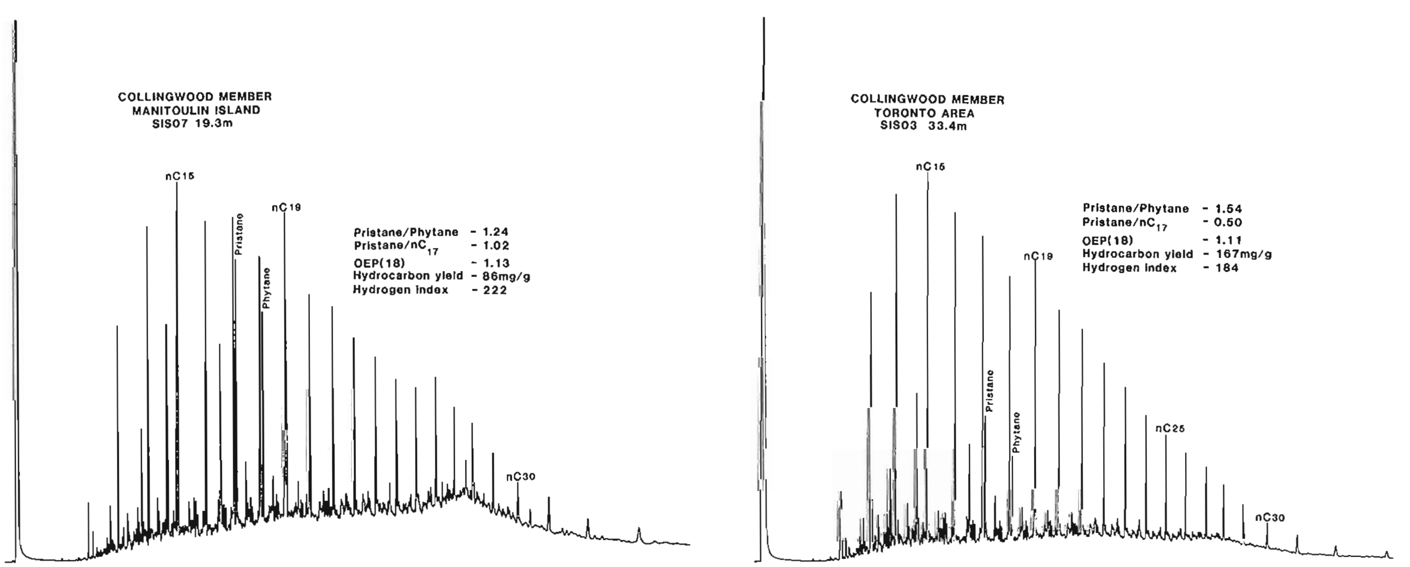


Figure 7. Gas chromatograms of representative saturate fractions, Collingwood oil shales, southern Ontario (from Snowdon, 1984).

Classification and maturation

Collingwood oil shales are marine Type II, amorphous, sapropel deposits, occurring as a thin but widespread unit, and representing the end phase of a period of carbonate deposition.

The maturation level is variable across the area. Oil shales at Collingwood are of marginal maturity, having generated early stage bitumen but little if any volatile hydrocarbons. Maturity is low at Manitoulin Island, with Collingwood beds possibly having generated slightly more bitumen there than at Collingwood, but still without generation of any significant amount of light hydrocarbons. In the Whitby area, maturity is well into the moderate range. This area has been the source of generated and migrated oils, and some generating capacity still remains. Beds at Ottawa (Billings Formation) are on the edge of thermal overmaturity; generated oils of this area have either migrated to reservoir beds or have been thermally destroyed in the source beds. Table I summarizes the significant data for maturation interpretations.

Some of the indicated maturation changes could also result from significant variations in the kerogen type across the areas, as suggested by Barker et al. (1983b). These differences are sufficiently large that to explain them by kerogen type would necessitate a major terrestrial component, something not anticipated in Ordovician strata. The small content of acritarch type material, if humic in nature, would be insufficient to effect these differences. Such change should also not be evident in Tmax values. Although further organic petrology studies, especially fluorescence, may be warranted, no change of maturation concepts is anticipated from further recognition of maceral composition.

Economic potential

Three factors are basic to the economic evaluation of an oil shale deposit: thickness (figs. 4, 5), Total Organic Carbon content, and yield per 1% organic carbon (Table I). Figure 8 plots the petroleum potential (yield) per 1% Corg from the Rock-Eval pyrolyses, and Figure 9 shows the relationship of Fischer Assay results to TOC, independent of area. The Rock-Eval data (Fig. 8) are indicative of the increasing maturation across the studied areas.

Barker et al. (1983b) indicated a maximum yield of 60 litres/tonne (55 kilograms/tonne at an averaged sp. gr. of 0.91), or 14 US gallons/ton. Because exploitation of only the best zones is seldom possible, maximum hydrocarbon yields are interesting, but are only partly indicative of economic potential. An average anticipated yield can be acquired from the average TOC and average yield/% Corg values. Petroleum potentials would thus be: Collingwood area, 26.3 kg/t (28.9 l/t, 6.9 US gals/ton); Manitoulin Island, 25.7 kg/t (28.2 l/t, 6.8 US gals/ton); Whitby area, 9.5 kg/t (10.4 l/t, 2.5 US gals/ton). Although the maturation level is slightly greater at Manitoulin Island relative to the Collingwood area, the petroleum potential is almost identical because of greater kerogen content at Manitoulin Island.

According to Johnson et al. (1983a), the Collingwood beds are approximately 5.5 m thick at Manitoulin, three times thicker than the 1.7 m generally encountered at Collingwood. The upper parts of the sections on Manitoulin Island may also contain (based on a perusal of data only) a higher average TOC content, which would increase recovery values for that part of the zone.

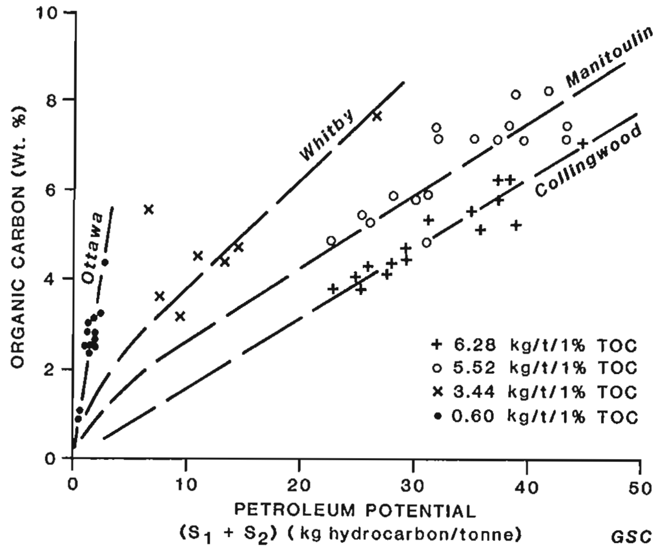


Figure 8. *Representative plot of petroleum potential against organic carbon content, defining yield/%Corg ratios, Collingwood oil shales (from Macauley and Snowdon, 1984).*

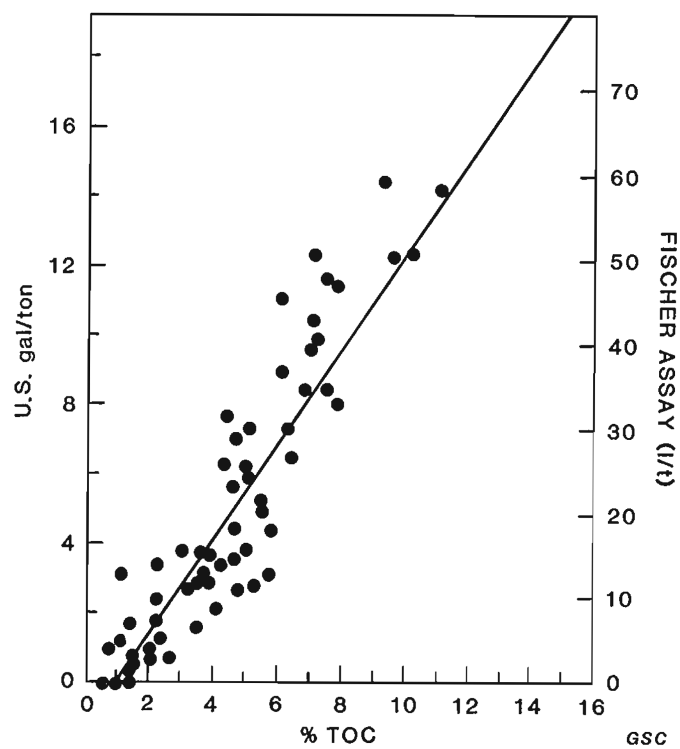


Figure 9. *Fischer Assay recoveries versus organic carbon content, Collingwood oil shales and Blue Mountain shale (from Barker et al., 1983b).*

At the University of Waterloo, pyrolysis of shale (YP) - plus gas liquid - yielded many hydrocarbon values. Five to ten milligrams of sample were heated in a helium stream to a temperature in excess of 600°C using a Chemical Data Systems quartz tube pyroprobe. The hydrocarbons were measured with a flame ionization detector and results expressed as weight per cent carbon (methane equivalents) (Barker et al., 1983b). Two empirical relationships were established for all data, independent of area:

Fischer Assay yield (l/t) = 5.6 TOC - 3.9
Fischer Assay yield (l/t) = 15.0 YP + 0.680

The analyses are reported in Barker et al. (1983) and Barker (in prep.) and can be used to provide more detailed information for each cored location. Many of the TOC values (Fig. 9) represent samples of the overlying organic carbon-poor Blue Mountain Formation.

Both the thickness distribution (thinnest) and maturation level (lowest) at Collingwood can be related to location near the crest of the Algonquin Arch and thus to the tectonic history of the area. A search for thicker local deposits near Collingwood can be justified because the shales of that area have the greatest hydrocarbon yields and the most aliphatic oil product. The greater zone thickness on Manitoulin Island may offset these qualitites. If areas of thin drift cover can be found southeast of Collingwood, but near enough to stay within the low maturity range, additional prospective area is possible.

Because of the limited thickness and average yield potential of only 28.9 l/t (6.9 US gals/ton), which is considerably below the rule-of-thumb minimum 10 US gals/ton required for economic consideration, the Collingwood Member does not presently appear to be a major oil shale resource. Exploitation research could change this conclusion.

Exploitation

Research into techniques for exploitation of the Collingwood oil shales is still minimal; only limited investigations of retorting in a hydrogen atmosphere (hydroretorting) have thus far been conducted.

Furimsky, Soutar et al. (1983) retorted seven samples at the CANMET facilities in Ottawa. Five samples were from cores of the Collingwood area, and one each from Manitoulin Island and the Whitby area. All samples had initial atomic H/C ratios of 1.1 to 1.2 with a ratio of 1.6 in the final oil product. The liquid product specific gravities of Fischer Assays were 0.913 at Collingwood, 0.922 at Manitoulin, and 0.879 in the Whitby area. The low specific gravity from the Whitby core should be anticipated because of the greater thermal maturity of the Whitby area beds. The Manitoulin-Collingwood gravities are not in direct agreement with the indicated maturations, but the number of samples is too small for conclusive results.

The yield under hydroretorting assay conditions ranges from 1.73 to 2.74 times greater than that under normal Fischer Assay techniques, indicating a possible doubling of hydrocarbon potential. Although yields are increased significantly, the economics are closely tied to the cost of hydrogen generation for this process.

Devonian: Kettle Point Formation, southwestern Ontario

The Kettle Point Formation (Fig. 3, no. 2), currently being investigated for oil shale potential by the Ontario Geological Survey, is the equivalent of the extensive black shale deposits (Antrim, Ohio, Geneseo, New Albany, Chattanooga) of the eastern United States (Fig. 10). The Findlay and Algonquin arches separate the Michigan and

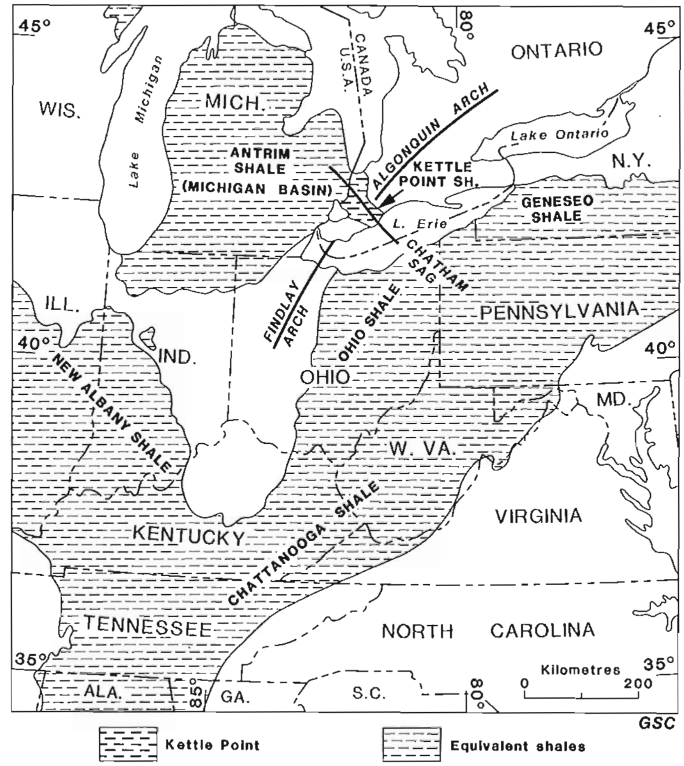


Figure 10. *Surface distribution of Kettle Point and equivalent shales, with pertinent tectonic features (compiled from Russell and Barker, 1983).*

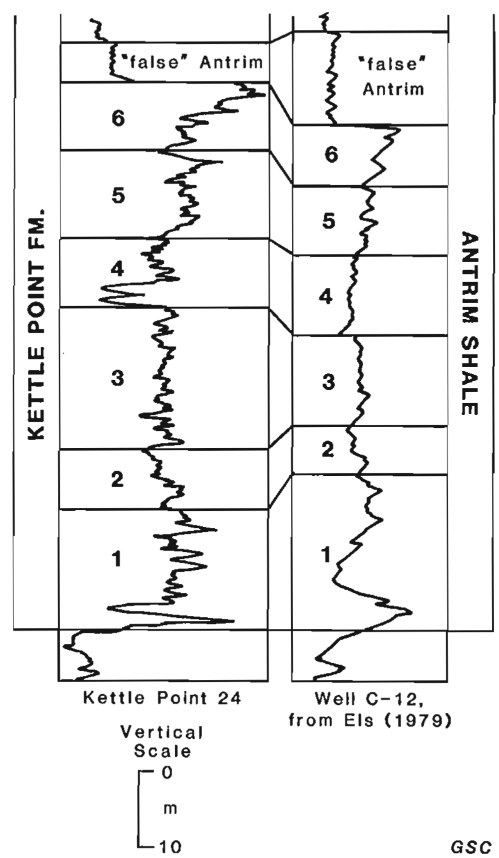


Figure 11. *Gamma ray log correlation between Michigan (Sanilac County) well C-12 and Ontario OGS well KP24 (from Russell and Barker, 1983).*

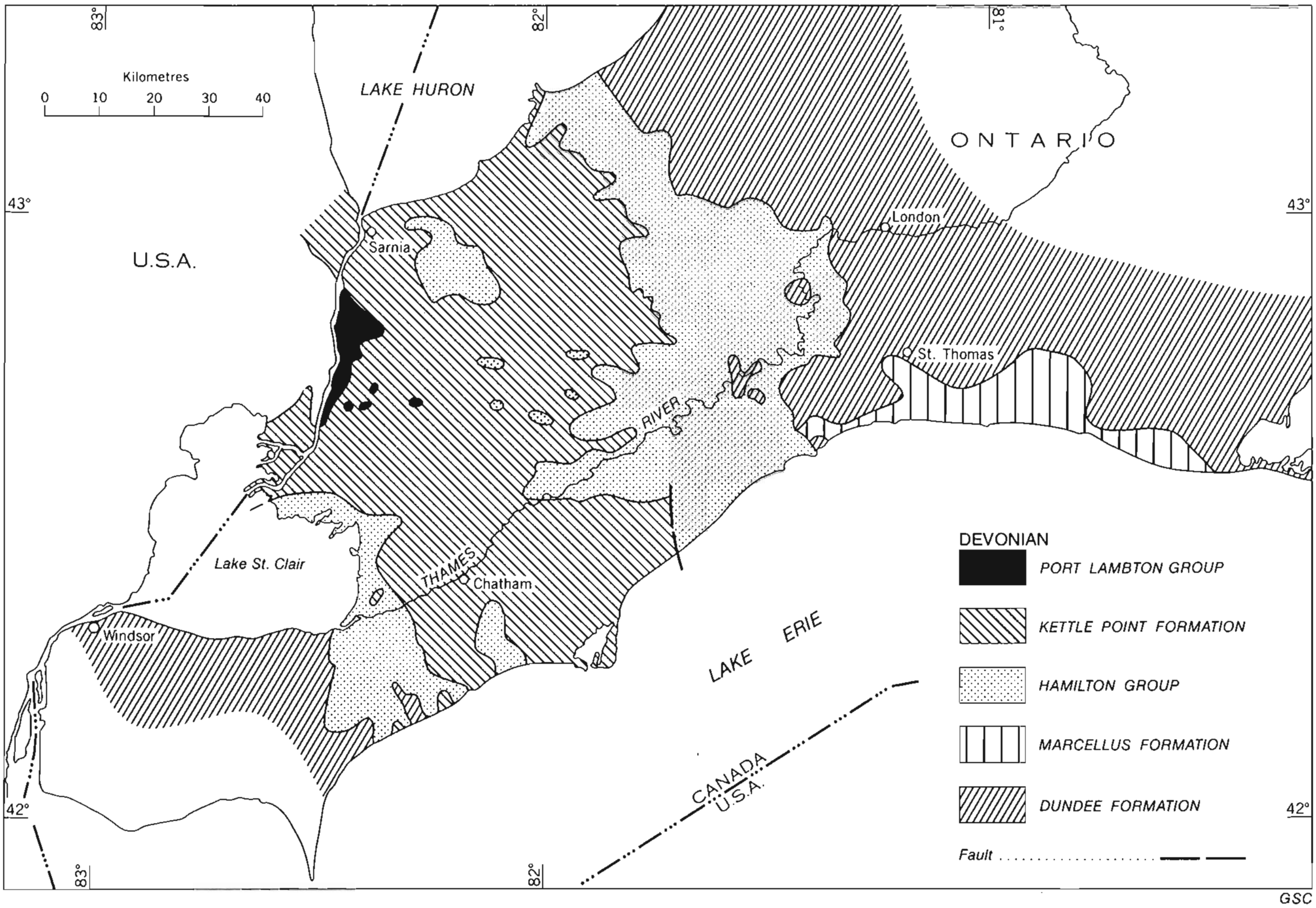


Figure 12. *Outcrop distribution of Devonian Marcellus and Kettle Point formations, southwestern Ontario (from Sanford, 1969).*

Appalachian basins. Beds of the Kettle Point Formation are preserved in the Chatham Sag, which separates the two arch areas.

Russell and Barker (1983) recognized six subunits within the Kettle Point on the basis of gamma ray log characteristics, and correlated these directly with the Antrim shale of the Michigan Basin to the west-northwest (Fig. 11). Correlations to the southeast with the Ohio shale were less distinct because of incomplete sections in the adjoining parts of the areas, and changes in the stratigraphic succession caused by the variation in depositional environments across the arch (Russell, in press). These regional correlations are important if maximum use is to be made of the considerable research (University of Kentucky, 1981, 1983a, 1983b) into the utilization of the eastern United States deposits.

Complete sections of Kettle Point Formation, which are present along the St. Clair River (locally underlying "Refinery Row") south of Sarnia, are covered by strata of the Port Lambton Group (Fig. 12). Where complete, the unit has a maximum thickness of 75 m, but averages 28 m across the area of distribution. Kettle Point strata are almost everywhere drift covered, but well logs contribute sufficient data to make an irregular distribution pattern apparent. Numerous erosional inliers of the Hamilton Group are present within the general Kettle Point subcrop area. The drift cover (Russell and Barker, 1983) is generally less than 100 m, and is typically 30 m.

Geology of the Long Rapids Formation in the Moose River Basin, near James Bay (Fig. 3, no. 2a) is only poorly known. This unit is stratigraphically equivalent to the Kettle Point Formation. As the units have been described as lithologically similar, concepts gained from the Kettle Point investigations may be directly applicable to the more northern deposits; however, Russell (pers. comm.) has identified some significant lithologic differences.

Lithology and mineralogy

Dark grey, brown-grey to black, silty, argillaceous shale characterizes the Kettle Point strata. Within the southern and central areas, there is an abundance of green shale interbeds (Barker et al., 1983). Large (up to 2 m), spherical concretions of radiating, impure limestone comprise the "kettles" after which the unit is named.

Snowdon (1984) indicated quartz to be the primary mineral, with secondary amounts of clay minerals (mostly illite, lesser chlorite, occasional kaolinite) and minor feldspar, pyrite and calcite. These shales are essentially noncalcareous. Most of the quartz occurs in clay size grains, although siltstone laminae were indicated by Russell and Barker (1983) to be present in the lower half of the section (Fig. 13).

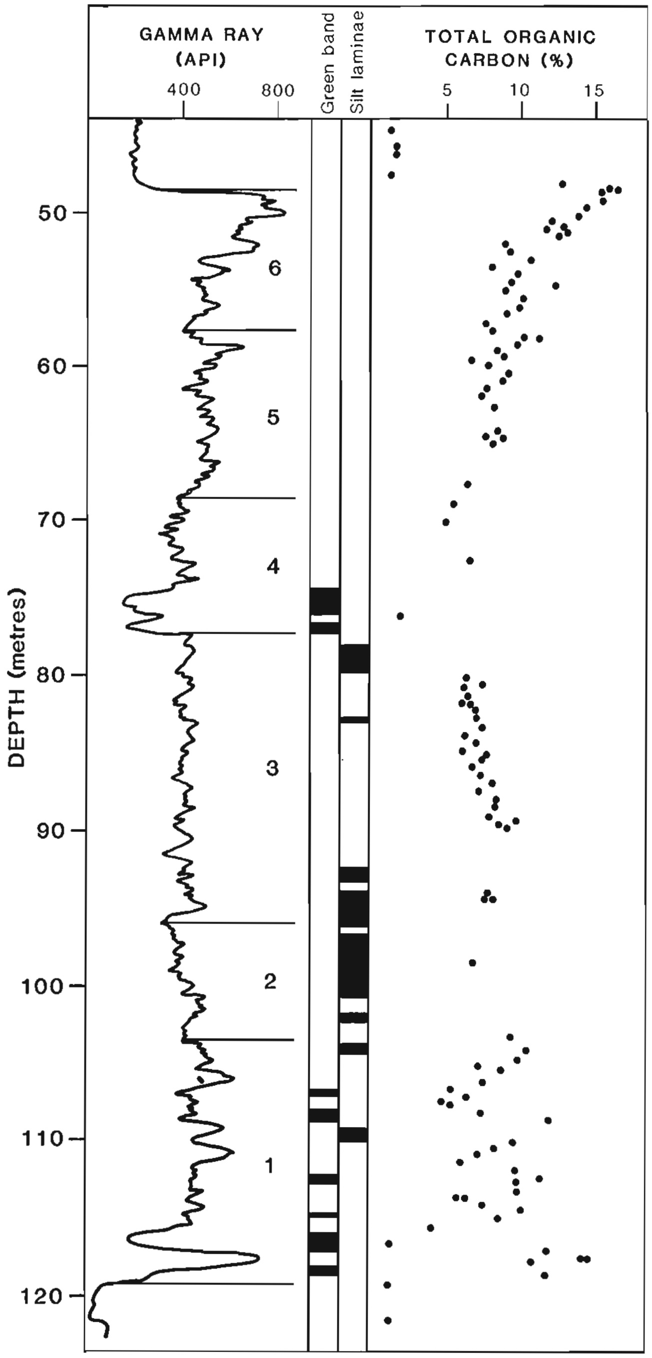


Figure 13. *Gamma ray log, lithologic variation, and Total Organic Carbon values for OGS well KP24 (from Russell and Barker, 1983).*

Kettle Point and equivalent strata are all poorly fossiliferous, containing the algal form *Tasmanites*; the widepread, short duration algal(?) form *Foerstia* (which provides the basis for many of the regional correlations); and scattered leiospheres and conodonts. Data are sufficient to define the deposit as marine in origin.

Organic Geochemistry

Only ten samples have been analyzed at ISPG (unpublished) by Rock-Eval pyrolysis, but Russell and Barker (1983) provided sufficient Total Organic Carbon and Fischer Assay data to provide the necessary detail for geochemical interpretations.

Total Organic Carbon (TOC): Total Organic Carbon content generally ranges from 5 to 8 per cent (Fig. 13), but two higher carbon intervals are recognized. A thin zone (1 m), at the base of Unit 1, ranges from 10 to 14 per cent TOC, but a more significant unit (10 m), occurs at the top of Unit 6, immediately below the inorganic shales of the Port Lambton Group, and averages greater than 10 per cent TOC. Because of the erosional pattern, this high carbon interval is of limited areal distribution, but is primely located within the area of the petrochemical complex at Sarnia.

The apparent relationship (Fig. 13) of gamma ray response to organic carbon content is confirmed by a direct comparison of the two characteristics (Fig. 14). This justifies the extensive use of the gamma ray response for unit correlations of the equivalent shales throughout southwestern Ontario and the Eastern United States.

Tmax: of the ten samples analyzed, the average Tmax was 430°C, below the generally accepted oil generation window (435° to 465°C). The maximum recorded Tmax, 437°C, is just within the window.

Hydrogen-Oxygen Indices (HI-OI): Hydrogen indices fall in the range of 277 to 431, averaging 363. From the cross-plot of Hydrogen versus Oxygen indices (Fig. 15), a partially matured Type I or Type II kerogen can be interpreted; however, Tmax values cannot support this interpretation. HI-OI values must be interpreted as representing an admixture containing Type III kerogen, and therefore creating lower values than those produced by Type I and/or Type II components alone.

Powell et al. (1984) reported atomic H/C ratios of 1.08 to 1.17, commensurate with Type II kerogen and this general range of Hydrogen indices.

Production Index (PI): the Production Index averages 0.04, indicating possible marginal maturity. Snowdon (1984), comparing hydrocarbon yield and total extract yield, (essentially defining PI), considered the zone to be immature. Barker et al. (1983b) reported a transformation ratio (i.e. PI) of <0.03 from the two peaks of their pyroprobe analysis. Thus, all three reports are in close agreement.

Organic petrology

The low level thermal alteration of the Kettle Point is also confirmed by various petrographic analyses. Legall et al. (1981) reported a Conodont Colour Alteration Index (CAI) of 1.5 and an Acritarch Colour Alteration Index (AAI) of 2-. The light yellow acritarchs are predominantly

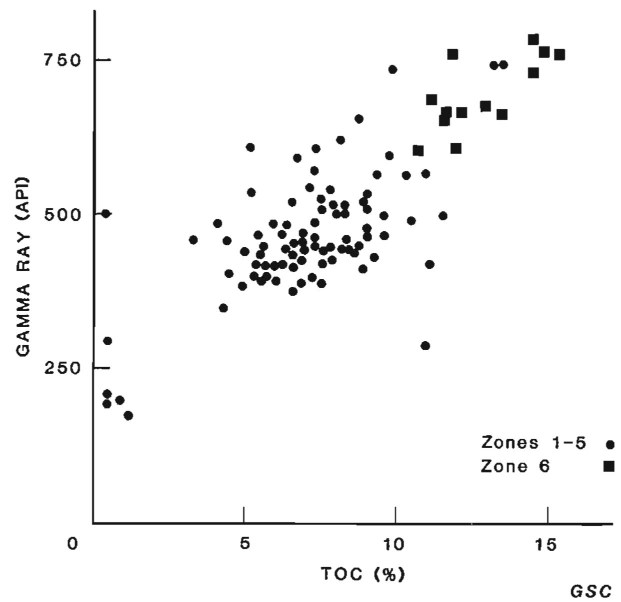


Figure 14. Comparison of gamma ray response to organic carbon content, Kettle Point Formation, OGS well KP24 (from Russell and Barker, 1983).

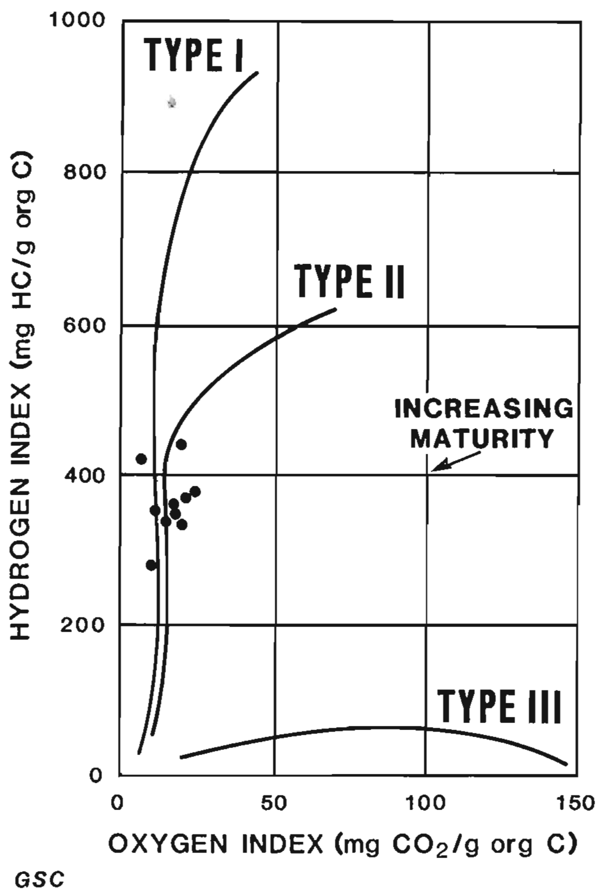


Figure 15. Hydrogen-Oxygen Index relationship, Kettle Point Formation (from data in Snowdon, 1984).

leiospheres, especially the genus *Liosphaeridia*. Vitrinite reflectance was determined by Barker et al. (1983b) to be .39 per cent R_o.

There are no data currently available defining the maceral content. Various publications, describing the equivalent zones in the United States, consider that both sapropel and humus are present. Type III humic debris can apparently be discerned at some locations, and the presence of Type II phytoplankton is confirmed by the acritarchs and conodonts.

Kerogen-pyrolyzate-oil characteristics

Kerogen of the Kettle Point Formation is dominated by aliphatic and aromatic adsorption bands, with a minor OH band from infrared absorption spectra (Barker et al., 1983).

Gas chromatograms were provided by Snowdon (1984) for the saturate fractions of the solvent extracts (Fig. 16). The extractable component from the Kettle Point samples is negligible. The pristane/nC_{17} ratio, at 1.69, is indicative of thermal immaturity. The pristane/phytane ratio is high (1.70) for immature oil shale, but this may reflect an input of terrestrial material rather than increased maturity. The predominance of odd/even numbered normal alkanes in the C_{16}-C_{22} range was about 1.1±.03 for the Kettle Point samples. The preponderance of acyclic isoprenoids over alkanes is indicative of immaturity (Powell et al., 1984) and possibly of some oxidation of the Kettle Point organic matter (Snowdon, 1984).

Williams (1919) indicated the specific gravity of recovered oil to be 0.88, considerably lower than the value of 0.94 reported by Martison (1966) for equivalent Long Rapids oil shale. Because of the immature nature of these oil shales, the higher value, 0.94, is considered to be the more realistic. Barker et al. (1983b) quoted a range of from 0.896 to 0.956 for the specific gravity.

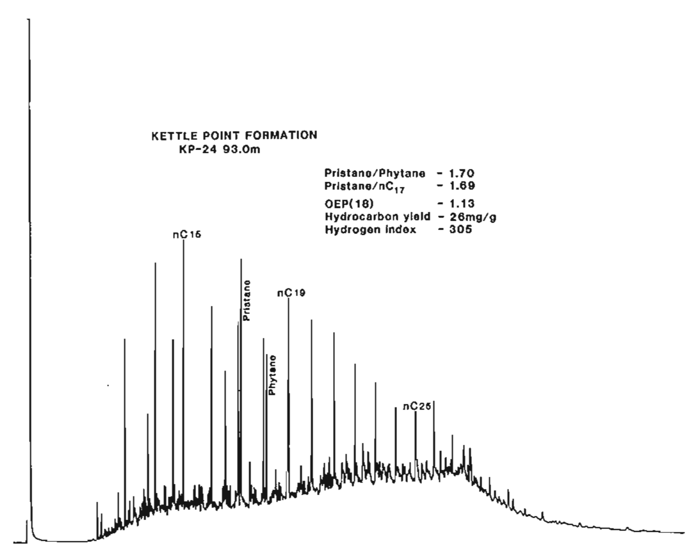


Figure 16. Typical gas chromatogram of Kettle Point saturate fraction (from Snowdon, 1984).

Classification and maturation

Kettle Point oil shales are marine Type II mixed, and were deposited in the clastic environment characteristic of this type, probably in a broad, shallow sea. They are immature to verging on marginally mature, and have not been the source for any conventional oil accumulations.

Economic potential

Hydrocarbon yield/%Corg, a basic parameter for oil shale evaluation, has been determined by both Rock-Eval pyrolysis (Fig. 17) and Fischer Assay (Fig. 18). Recovery values from the two sources are almost identical, at slightly greater than 4 l/t/%Corg. The linearity of these relationships indicates uniform kerogen type throughout the deposit. Using 10 per cent average TOC (Russell and Barker, 1983) for the uppermost Unit 6 (Fig. 13), 10 m of section will yield an average 41 l/t (10 U.S. gals/ton).

Further details of hydrocarbon yields are available in Barker (in prep.), where the results from the pyroprobe pyrolysis at the University of Waterloo can be utilized by the conversion ratio FA (Fischer Assay equivalent) = 17.2YP - 1.56.

Although basal Unit 1 has numerous carbon values in excess of 10 per cent, the range of values is wide (from 5 to 12 per cent, Fig. 13), sporadic, and only the thin, one metre thick zone near the base has continuously high carbon content. This zone is separated from the rest of Unit 1 by low carbon, green shale bands.

Although areally restricted because of erosion, the uppermost unit shows the greatest potential to date. Because of the discontinuity of the green shale interbeds, Unit 6, geographically the most widespread, may exhibit more continuous high carbon content in local areas.

Loftsson (1984) quoted an average bulk density of 2.59 Mg/m^3 for Kettle Point shales. Using this density value, 10 m of ore zone thickness, and pyrolysis-Fischer Assay values of 41 litres/tonne, then one km^2 of Kettle Point Unit 6 would contain 3 186 000 cubic metres (20 358 000 barrels) of *in situ* oil reserves. If hydroretorting were successful, *in situ* reserves would approximate 8 000 000 m^3 (50 000 000 bbls) per km^2 of surface area.

Exploitation

Telford (in press) stated that the upper 10 m of the Kettle Point Formation (Unit 6), under optimum conditions of hydroretorting, might yield an average 100 l/t (25 U.S. gals/ton) of hydrocarbon, a yield of 2.5 times the Fischer Assay recoveries. Telford also indicated that samples with anticipated equivalent yields have been obtained from the Long Rapids Formation in the Moose River Basin. Exploitation there may be facilitated by other potential resource development in the area.

The "rock mechanics" properties of the oil shale must be understood for any surface and/or underground mining operation, and also for any *in situ* combustion process. The engineering geology of the Kettle Point oil shales is reported

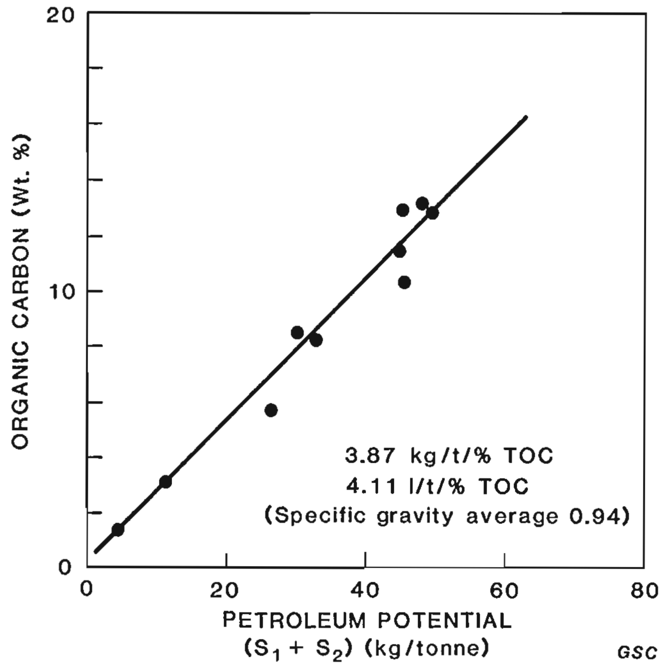


Figure 17. *Petroleum potential plotted against organic carbon content to define yield/% Corg ratio, Kettle Point Formation (from data in Snowdon, 1984).*

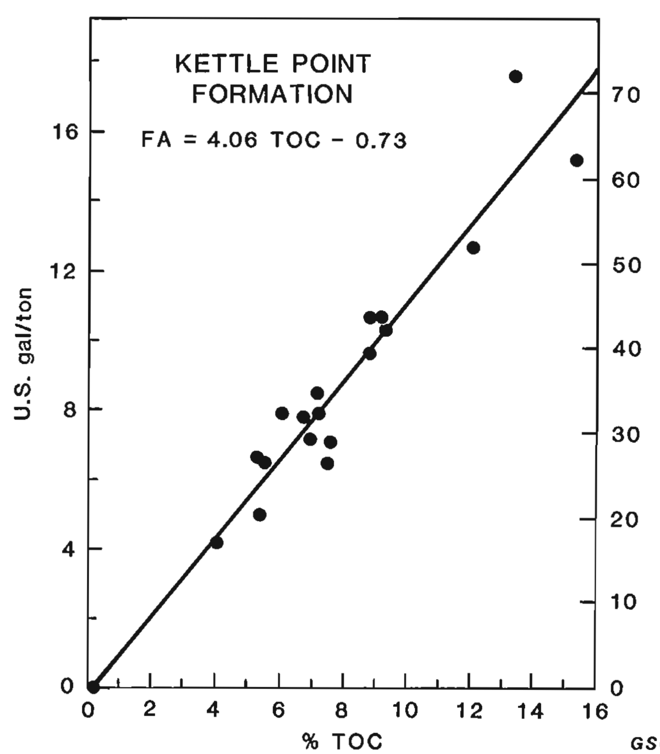


Figure 18. *Fischer Assay yields plotted against organic carbon content, Kettle Point Formation (from Barker et al., 1983b).*

in detail by Loftsson (1984) in an M.Sc. thesis at the University of Waterloo. The results are more readily available and more precisely presented by Dusseault and Loftsson (in press).

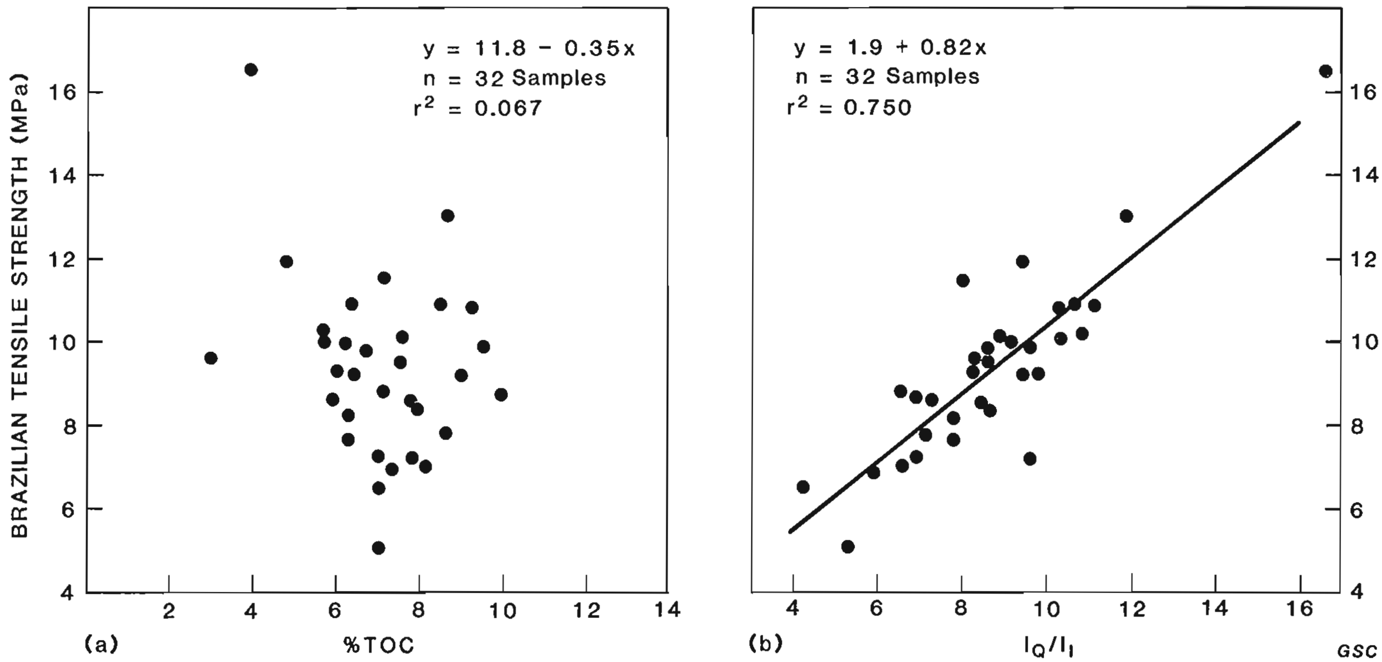


Figure 19. Brazilian tensile strength of Kettle Point oil shale contrasted with (a) organic carbon content, and (b) ratio of quartz to illite (from Loftsson, 1984).

According to Loftsson's investigations, Kettle Point shales are a medium strength material of low modulus ratio. They are highly anisotropic, and in places are characterized by low tensile strength across the bedding planes. Franklin and Gruspier (1983) proposed an Ontario shale strength rating system with values ranging from 0.0 to 9.0, where the higher numbers indicate stronger and more durable material. Loftsson indicated that under this system, the Kettle Point has a strength of 7.5 to 8.5.

Kerogen in oil shales may or may not, depending on quantity, influence the mechanical qualities of the rock. Loftsson concluded that kerogen content is sufficiently lean in the Kettle Point so as not to be a supporting part of the rock framework (Fig. 19a), and thus it has no influence on the rock's mechanical properties. Quartz and illite, which commonly comprise more than 85 per cent by weight of the total mineral matter, are the grain support minerals. A decreasing quartz-illite ratio reduces grain interlocking and mineral-to-mineral friction, thus reducing rock strength (Fig. 19b).

Specific measurements of Brazilian tensile strength (a measure of rock stability) best illustrate the above conclusions. Observed values of Brazilian tensile strength ranged from 5.1 to 16.5 MPa, and increased linearly with increasing quartz/illite ratio.

A knowledge of the uniaxial and triaxial compression strengths of these shales is important in developing surface excavation techniques and for designing pillar requirements in underground mines. The uniaxial compressive strength is approximately 9.5 times the Brazilian tensile strength. The ratio of the modulus of deformation to the uniaxial compressive strength is about 100, thus classifying the rock as being of low modulus ratio. The above parameters all vary directly with the quartz-illite ratio.

Direct shear tests, important for estimating blasting characteristics and slope stabilities, indicate that roughness of a fracture surface, independent of mineral or organic matter, has the greatest effect on the ultimate strength of the fracture.

The extreme inherent weakness of the bedding planes may be a problem at mine openings.

Loftsson (1984) also noted that the high quartz content may be extremely abrasive, a fact which could be significant when using drag-line and/or bucket wheel excavators.

Carboniferous: Albert Formation, New Brunswick

Interest in the oil shales of New Brunswick began, not with the oil shales themselves, but with the discovery of a black, vertical vein of albertite, 0.3 to 5 m thick, that intersected the associated oil shale strata. The vein was mined during the years 1860-1879, and excavations reached a depth of 335 m, at which time the major reserves had been exhausted.

Oil shales of the Albert Formation, of lower Mississippian (Tournaisian) age, are found in the Moncton Sub-basin, a component basin of the major tectonic Fundy Succession Basin (Fig. 20). The Albert Formation is exposed around the margins of the Moncton Sub-basin (Fig. 21), which is bounded on the south by the Caledonia Mountains, and contains the Kingston Uplift along its northwest margin. Oil shales occur in the medial Frederick Brook Member of the Albert Formation, and are best developed along the southern margin of the basin. Oil shales are only locally recognized along the Kingston Uplift; Synnott and Salter (1983) reported one Fischer Assay of 6.5 U.S. gallons/ton from Indian Mountain northwest of Moncton. The topography consists essentially of rolling hills that are largely forest covered. Consequently, outcrop exposures, primarily found along stream beds, are few and small. Thicknesses are difficult to estimate from surface data alone, especially for the oil shale interval.

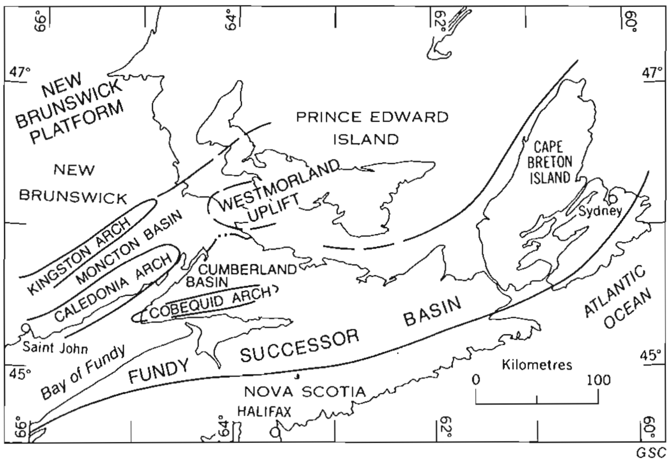


Figure 20. Tectonic elements of the Fundy Basin, New Brunswick and Nova Scotia.

Most of the interpretations of geology and geochemistry are based on core available from the Albert Mines area (Fig. 21), the location of the earlier-mined albertite deposit. Cores are also available from the Boudreau and Dover areas, both east of Albert Mines, and from the Rosevale and Urney areas to the west. The results of a detailed investigation, based on these cores, are published in "Oil Shales of the Albert Formation, New Brunswick" (Macauley and Ball, 1982). St. Peter (1984) has compiled an excellent source of mineralogical and chemical data for the Albert oil shales.

The Albert Formation is a grey coloured sequence of terrigenous clastics, conglomerates, sandstones, siltstones, shales and oil shales, deposited between sequences of red, terrigenous clastics, with shales, sandstones and conglomerates of the Memramcook Formation below and fine grained clastics of the Weldon Formation, or coarser grained conglomerates and lesser sandstone of the Hillsborough Formation, above. Within the Albert Formation, oil shales (mostly marlstones and dolostones of the Frederick Brook Member) separate the shales, sandstones and conglomerates of the overlying Hiram Brook and underlying Dawson Settlement members (Fig. 22). Where the oil shales are not developed, for example along the Kingston Uplift and in the extreme southwest near Norton-Apohaqui (Fig. 21), the Albert Formation cannot be subdivided into these members (Macauley, Ball, and Powell, 1984). At both Albert Mines and Boudreau, grey conglomerates interfinger with the oil shale beds.

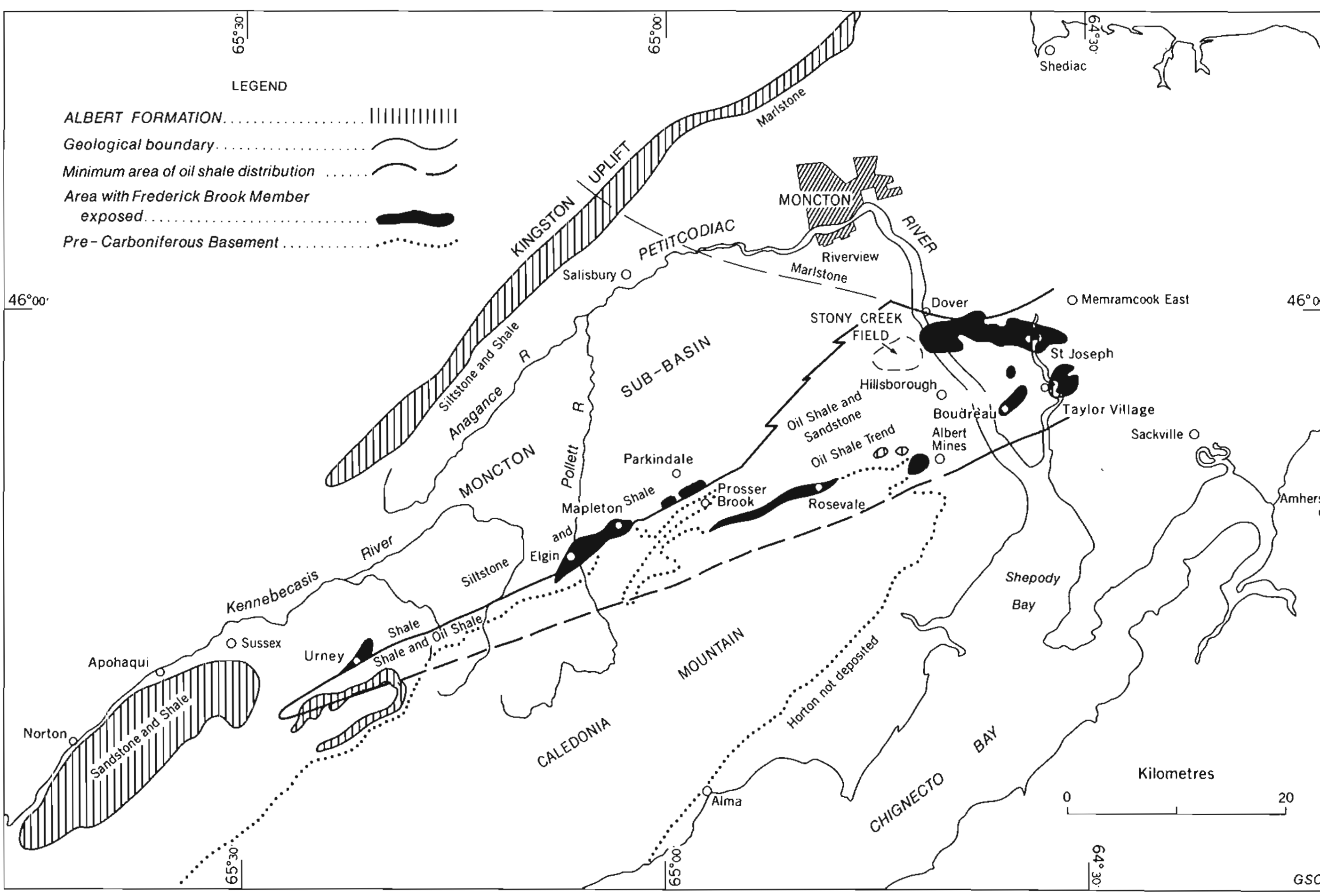


Figure 21. Outcrop areas of Albert Formation, New Brunswick, with interpreted lithologies of the Frederick Brook Member (as interpreted and generally modified from Greiner, 1962; Howie, 1980 and Pickerill and Carter, 1980).

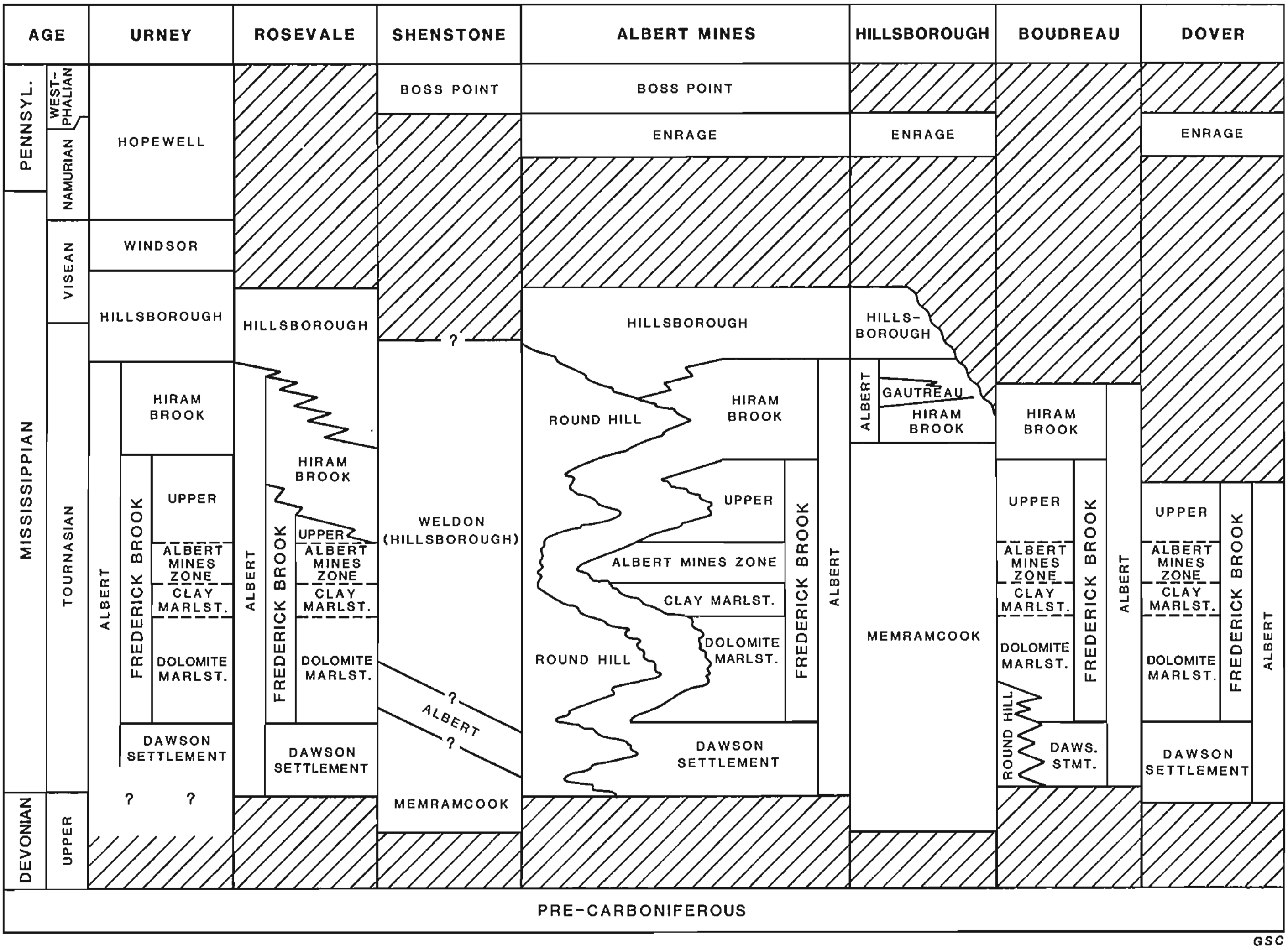


Figure 22. *Carboniferous nomenclature and correlations, Moncton Sub-basin, New Brunswick (from Macauley and Ball, 1982).*

All rock types of the above sequence are continental deposits within a complex of alluvial-deltaic-lacustrine environments (Pickerill and Carter, 1980). Initially thought to represent a layered sequence, the red-grey colour distribution is now considered to be a result of both lateral and vertical transitions (Macauley and Ball, 1982), although not all authors adhere to this concept. Grey to red represents a change from subaqueous to subaerial deposition. Within any sequence containing such complex lithofacies variations, and barren of any correlatable faunal component, interpretation of oil shale distribution is most difficult.

Lithology and mineralogy

Three marlstone lithotypes form the oil shale deposits of the Albert Formation. They are laminated marlstone, clay marlstone and dolomite marlstone (grading to dolostone). The lithotypes are interlaminated, interbedded and intergradational. They are defined by variations in the relative abundances of their three major components: dolomite (including calcite and siderite), clay (mostly montmorillonite-illite) and kerogen. In addition, the amounts of quartz and feldspar present modify the three primary rock types, especially the dolomite marlstone. The dominance of each rock type within specific sections of the gross oil shale interval provides for subdivision of the Frederick Brook Member at the Albert Mines deposit. The upper unit consists of all three lithotypes and is underlain by the Albert Mines zone, which is dominated by laminated marlstone, and is itself underlain by a clay marlstone unit. Dolomite marlstone is the lowermost unit. Although distinct at Albert Mines, this subdivision is somewhat less obvious to the east and west.

Laminated Marlstone: the laminated marlstones have the highest shale oil yields. Lamination results from alternating deposits of kerogen and carbonate (dolomite and calcite), ranging from 30 to 40 per cent of each, and which impart a light/dark varved appearance (Fig. 23a-b). Kerogen laminae are resistant to weathering even though they are finely laminated and fissile. The intervals richest in kerogen are "blocky" in appearance, but split easily along bedding planes to produce thin sheets of oil shale.

Kerogen laminae act as planes of structural weakness, and make the organic-rich, laminated marlstones susceptible to structural deformation (Fig. 23c). The numerous microfolds, faults and slickensided surfaces associated with this rock type appear to be tectonically induced.

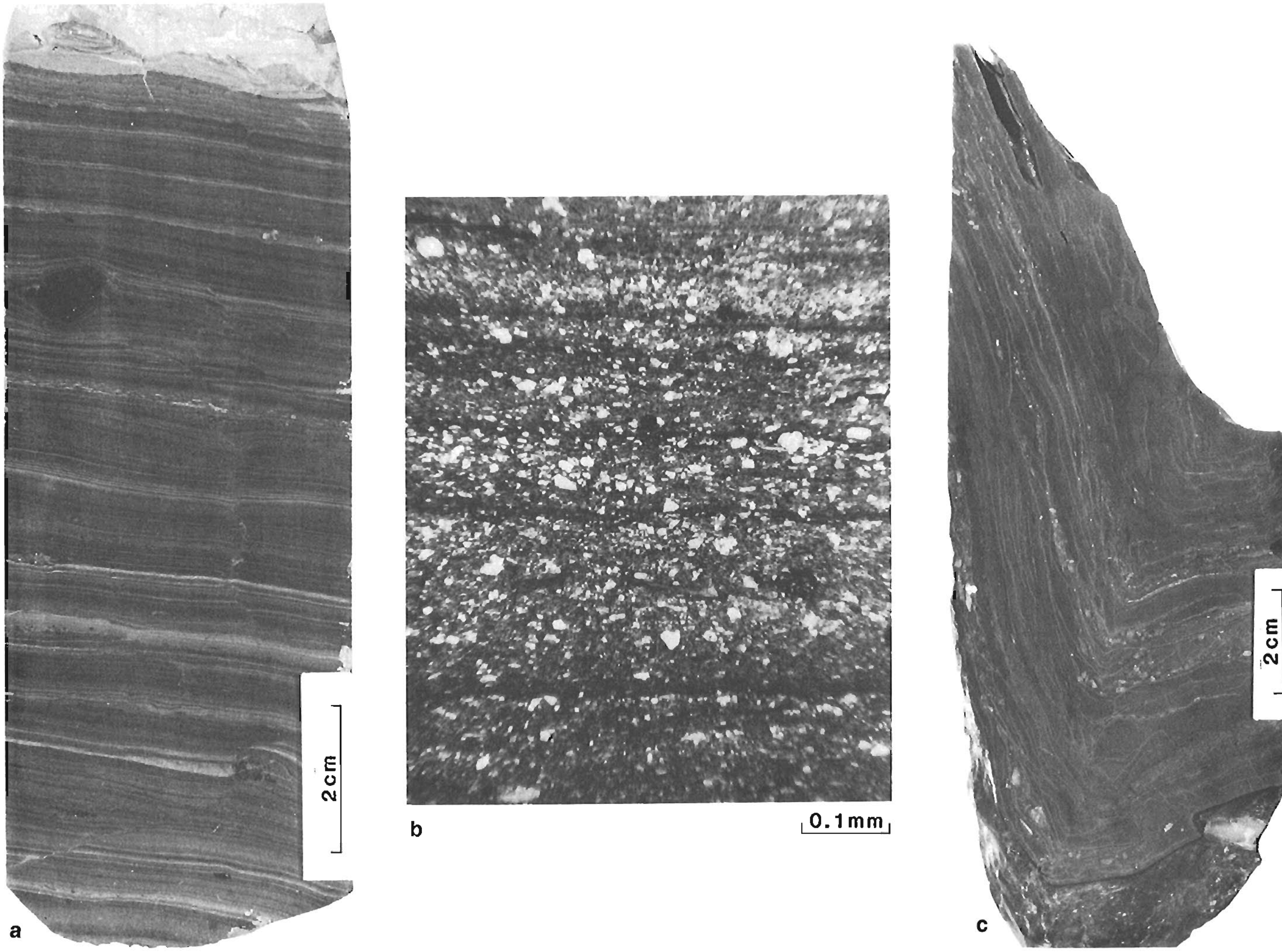


Figure 23. Laminated marlstone zone, Albert Mines deposit: (a) varved appearance, (b) photomicrograph showing kerogen laminae (black), (c) structurally contorted (from Macauley and Ball, 1982).

The laminated marlstone beds may grade to dolomite marlstone by an increase in dolomite content, or to clay marlstone by an increase in the amount of clay. In either case, the kerogen content decreases as the inorganic minerals increase.

Where coarser grained, clastic detritus is present, quartz predominates over feldspar, and analcime is present as the weathering product of the sequence feldspar→clay→analcime.

Clay Marlstone: the clay marlstones are greyish brown to brown in colour, reflecting kerogen content. They are dolomitic, and are laminated. Clays are the dominant mineral, followed by dolomite and kerogen. Beds of organically lean, grey, slightly dolomitic, laminated, fissile shale progressing to massive claystone are gradational from the clay marlstones. Because of the lower organic content, the clay marlstones are only poorly varved.

Virtually all the structures encountered in clay marlstones are considered to be tectonically induced. Although present, micro-faults, dragfolds, convolute contortions and ptygmatic folds are less evident than in the laminated marlstones.

Dolomite Marlstone: the dolomite marlstone is a composite of massive, dolomitic marlstone grading to sandy dolostone. Varying kerogen content can be recognized by colour variation – the natural light brown of the dolomite darkens with increasing organic content. Kerogen can occur as continuous to discontinuous wavy laminae (Fig. 24), or may be present only as parallel flecks or discontinuous groundmass (Fig. 25) as the dolostone lithologic end-member is reached.

Sand and silt content (quartz and feldspar) varies greatly, from virtually zero, to 40 per cent of the rock. In places the marlstone grades to barren siltstone, sandstone and dolostone beds.

Dolomite is the primary carbonate mineral of the dolomite marlstone; siderite occurs in minor amounts; calcite is virtually absent. The terrigenous clastic content is a quartz-feldspar mixture in the sand-silt phase, with feldspar exceeding quartz in quantity. Clays are predominantly illite, with some montmorillonite. In contrast to the laminated marlstone, analcime is absent. The quartz-feldspar input was probably similar for all zones, but inhibition of diagenetic alteration of the feldspars to quartz, clay and analcime in the dolomite marlstone has produced a markedly different end ratio relative to those of the clay and laminated marlstones.

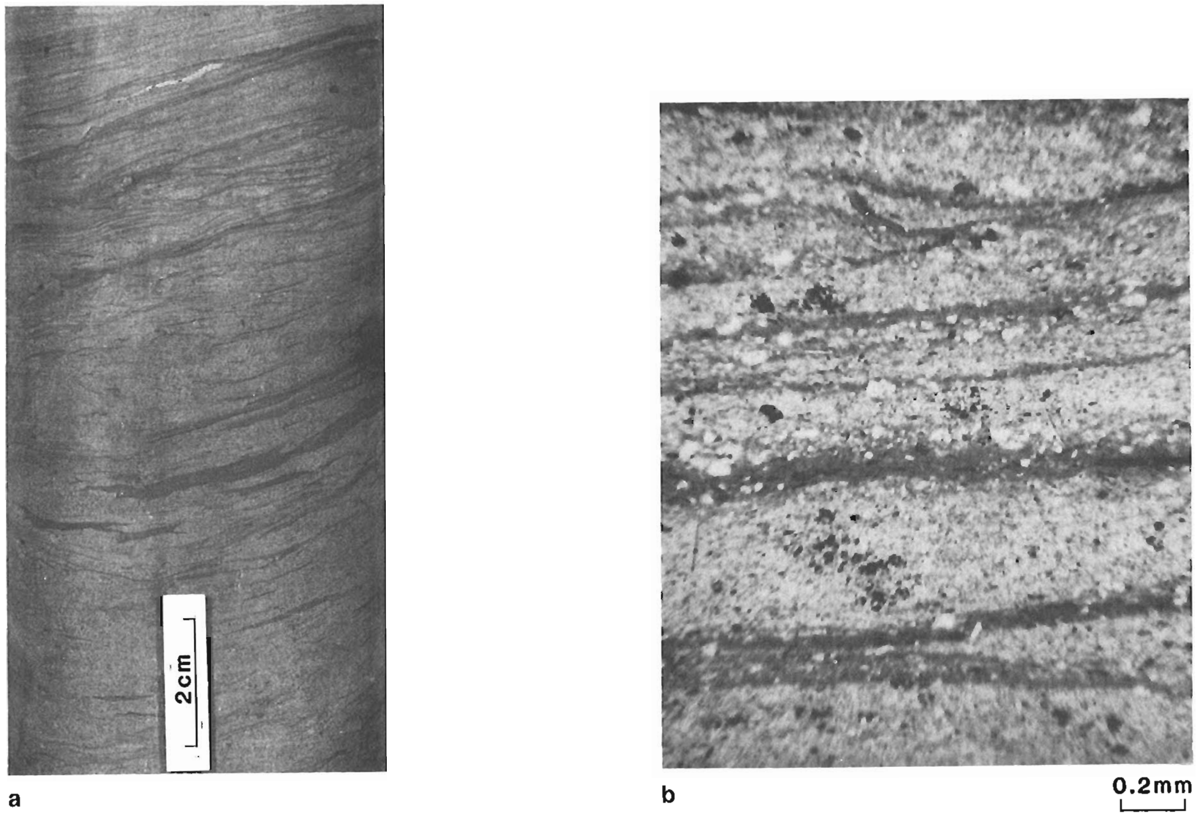


Figure 24. *Dolomite marlstone, continuous to discontinuous kerogen laminae: (a) core, (b) photomicrograph (from Macauley and Ball, 1982).*

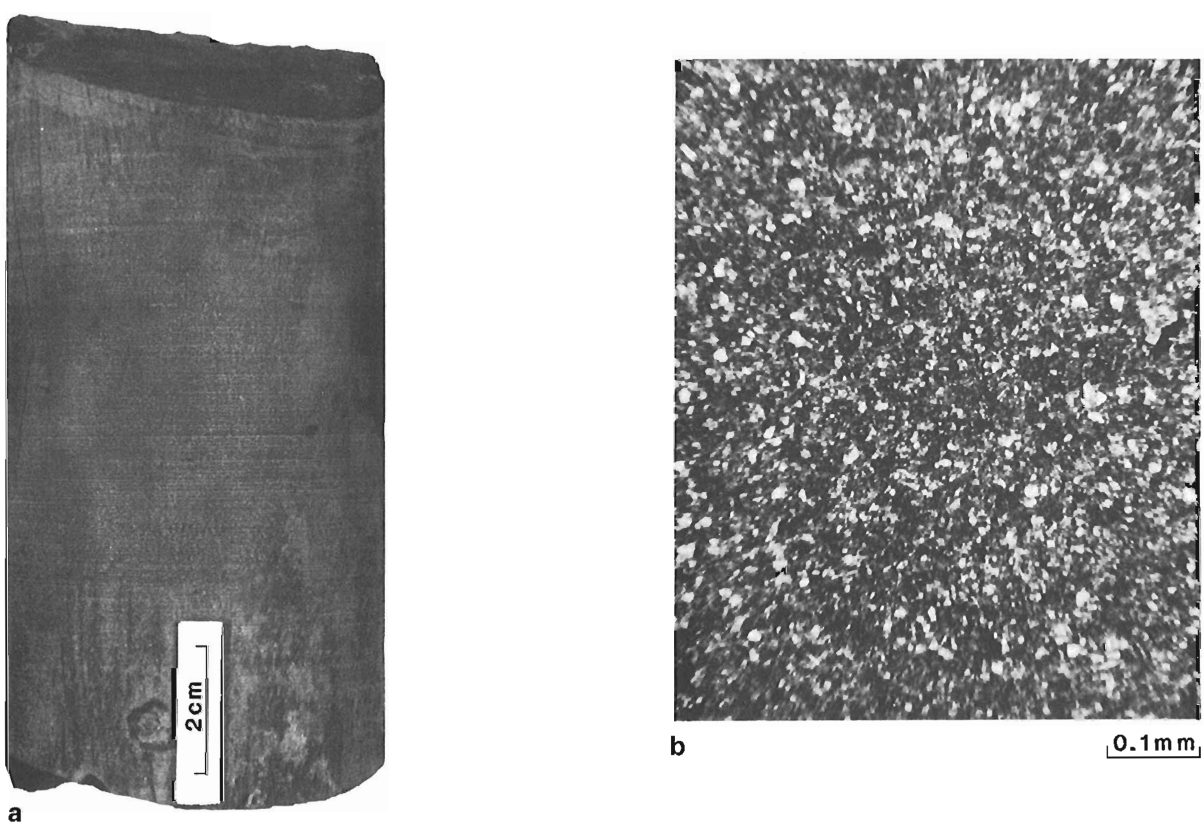


Figure 25. *Massive dolostone showing disseminated, amorphous kerogen: (a) core; (b) photomicrograph (from Macauley and Ball, 1982).*

Area	No. of Samples	Rock-Eval Pyrolysis							Fischer Assay						Industry Fischer Assays
		TOC Wt%	Tmax °C	HI mg/g	PI	Yield Ratio kg/t/%Corg	Yield		Yield l/t	Yield Ratio l/t/% Corg	Oil Spec. Gravity	Water Wt%	Rock Density gm/cc	
							kg/t	l/t						Yield l/t
Albert Mines U	10	5.94	443	820	.15	8.99	53.4	61.2	61.5	10.35	.872	1.77	2.24	35.3
AM	31	9.95	447	846	.10	9.36	93.2	106.0	105.5	10.60	.879	1.25	2.05	93.5
CM	11	6.28	442	788	.16	9.57	60.1	66.7	59.3	9.44	.901	2.05	2.09	38.4
DM	33	8.10	441	836	.20	7.90	64.0	71.4	70.1	8.65	.896	0.53	2.33	56.5
Boudreau U	3	1.67	447	439	.10	6.50	10.9	11.9	12.0	7.18	.912	1.80	2.53	6.7
AM	5	7.04	444	898	.06	9.41	66.2	72.2	64.8	9.20	.917	0.72	2.30	28.4
CM														13.8
DM	4	7.75	443	908	.07	10.11	78.4	85.5	74.6	9.62	.917	0.58	2.29	35.2
Dover U	2	4.99	440	751	.07	8.91	44.5	49.5	40.5	8.19	.909	2.45	2.37	17.8
AM														26.0
CM														8.6
DM	3	5.29	443	813	.07	9.45	50.0	55.0	47.4	8.96	.909	1.63	2.35	17.0
Rosevale U	2	2.07	437	709	.25	4.76	9.5	10.7	19.8	9.56	.889	0.50	2.52	18.2
AM	1	4.13	448	939	.07	10.15	4.2	46.6	53.4	12.92	.884	0.20	2.43	32.2
CM	2	3.35	444	806	.09	9.20	30.9	34.8	35.9	10.71	.887	1.40	2.48	14.0
DM														36.0
Urney U														6.5
AM	3	1.53	443	690	.08	7.60	11.6	9.2	9.2	6.01	.906	0.33	2.27	8.5
CM														5.1
DM	1	4.51	443	987	.05	10.36	46.7	33.8	33.8	7.49	.898	0.40	2.40	10.1

(analyses from Macauley and Ball, 1982)

TABLE II

Averaged geochemical data pertinent to classification and maturation interpretations and to evaluation of economic potential, Albert oil shales

Many pressure solution sedimentary structures and rip-up breccias are common. The tectonically induced structures of the other marlstone types are absent in the massive dolomite marlstones and dolostones, which are much more resistant to structural distortion.

Organic geochemistry

Geochemical data are more complete for the Albert Formation oil shales than for any other Canadian oil shale deposit. Organic carbon analyses, Rock-Eval pyrolysis, Fischer Assays, organic petrology and the chemistry of the petroleum extracts are all available for a single suite of samples. Table II summarizes the organic carbon, Rock-Eval, and Fischer Assay data as derived from Macauley and Ball (1982) for the four units of the Albert formation in the five areas examined.

Fischer Assays: in addition to those of the comparative geochemical study of Macauley and Ball (1982), many additional Fischer Assays were performed by private interests (Table II). The lithologic zonation of the shales at Albert Mines is well illustrated by a typical plot of Fischer Assay oil yields and water recoveries (Fig. 26). The sequence of high oil yield beds (average 93.5 litres/tonne) typifying the laminated marlstones is readily apparent; the other lithologic zones are not defined distinctly by yield alone.

The clay marlstone is characterized at Albert Mines by high water recoveries, also evident in the organic-poor shales and claystones of the upper unit. Increased water content can be related directly to clay content. In contrast, the water content of the dolomite marlstone zone is negligible. High water yield has been used to recognize the clay marlstone in areas other than Albert Mines, where oil yield alone does not readily define the Albert Mines unit.

Total Organic Carbon (TOC): according to all Albert Mines data, the average organic carbon content is 7.09 per cent, ranging to a maximum of 29.40 per cent; the sample containing this maximum assayed at 263 litres/tonne. The content varies with the zone. A maximum of 9.95 per cent is the average in the Albert Mines laminated marlstones, and 8.10 per cent in the dolomite marlstones. These are averaged across all coreholes and vary laterally within the deposit in a range of 9 to 13 per cent for the Albert Mines zone, and 6 to 9 per cent for the dolomite marlstones. Total organic carbon in the clay marlstone, and in the upper unit, averages approximately 6 per cent.

In none of the other known occurrences of these oil shales in New Brunswick were the encountered values of kerogen content and oil shale thickness equal to those at Albert Mines. Oil shales at Boudreau and Dover, east of Albert Mines, appear to have greater kerogen potential than do those at Rosevale and Urney to the west (Table II).

Tmax: Tmax values are almost everywhere identical, ranging from 440° to 448°C, but not in any specific pattern (Table II). Tmax for the Albert Mines zone may be slightly higher than for the other units, perhaps reflecting the increased kerogen content. The Tmax values would normally be interpreted on the borderline of low to moderate maturity, having generated bitumens and heavy oils, and possibly some lighter oils (Fig. 2). Recent results of Espitalié et al. (1984, Fig. 9) indicate that even immature Type I kerogen (Ro<0.5%) never has a Tmax less than approximately 440°C, and that this parameter is not useful until higher levels of maturity have been reached in such deposits.

Hydrogen-Oxygen Indices (HI-OI): average Hydrogen indices (Table II) are all in the range of 690 to 987, everywhere indicating Type I kerogen, which is also indicated by low oxygen content (Fig. 27). One low value of HI at Rosevale (Fig. 27b) and two at Boudreau (Fig. 27c) are from the overlying upper member and Hiram Brook Formation respectively. Humic detritus was recognized in the Boudreau samples (Macauley and Ball, 1982). Estimates of thermal maturity from HI/OI range from immature to low.

Production Index (PI): Production indices are uniformly less than 0.10 for the Boudreau-Dover and Rosevale-Urney areas, with one exception (0.25) in the upper zone at Rosevale. This value probably represents hydrocarbon migration into a zone of normally low yield beds. Values are slightly higher at Albert Mines, doubling from 0.10 in the laminated marlstones to 0.20 in the dolomite marlstones, indicating increasing maturation downward in the section. Again, the higher, upper zone value would represent minor migration of volatile hydrocarbon.

The PI values at Albert Mines indicate probable generation of some light gravity oils from the moderate thermal maturity range. Elsewhere, hydrocarbon generation would result in bitumen and possible heavy oil within the stage of low maturation.

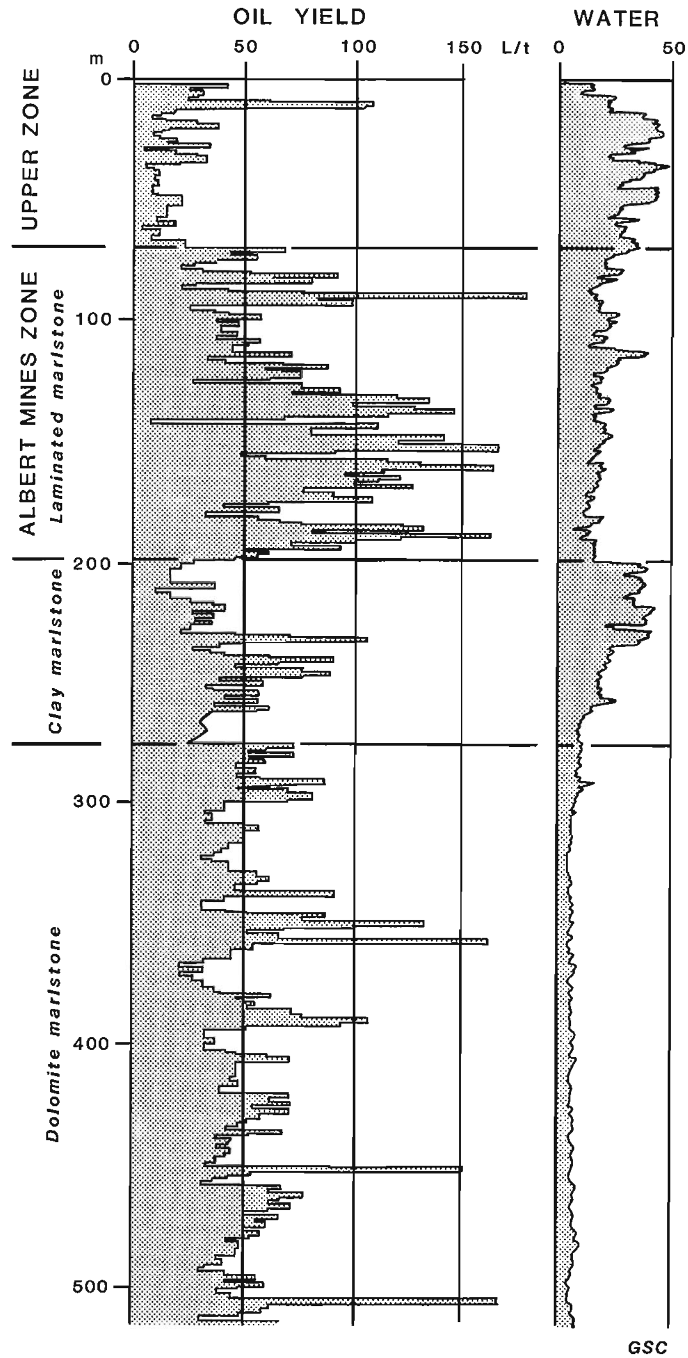


Figure 26. *Shale oil and water yields, Atlantic Richfield Albert Mines 1A (from Macauley and Ball, 1982).*

Organic petrology

King (1963) described the transmitted light colour range of the organic matter in the Albert Mines oil shales as lemon-yellow in the high grade, laminated marlstones, taking on a reddish tinge in sandy dolomite zones, and reddish-brown in dolomite marlstones. He did not recognize the descending sequence of these rock types or the possible relationship to increasing thermal maturation. There were no further publications on that subject until Kalkreuth and Macauley (1984) outlined the maceral content, vitrinite reflectance values and fluorescence spectra, and correlated them with Rock-Eval and Fischer Assay recoveries.

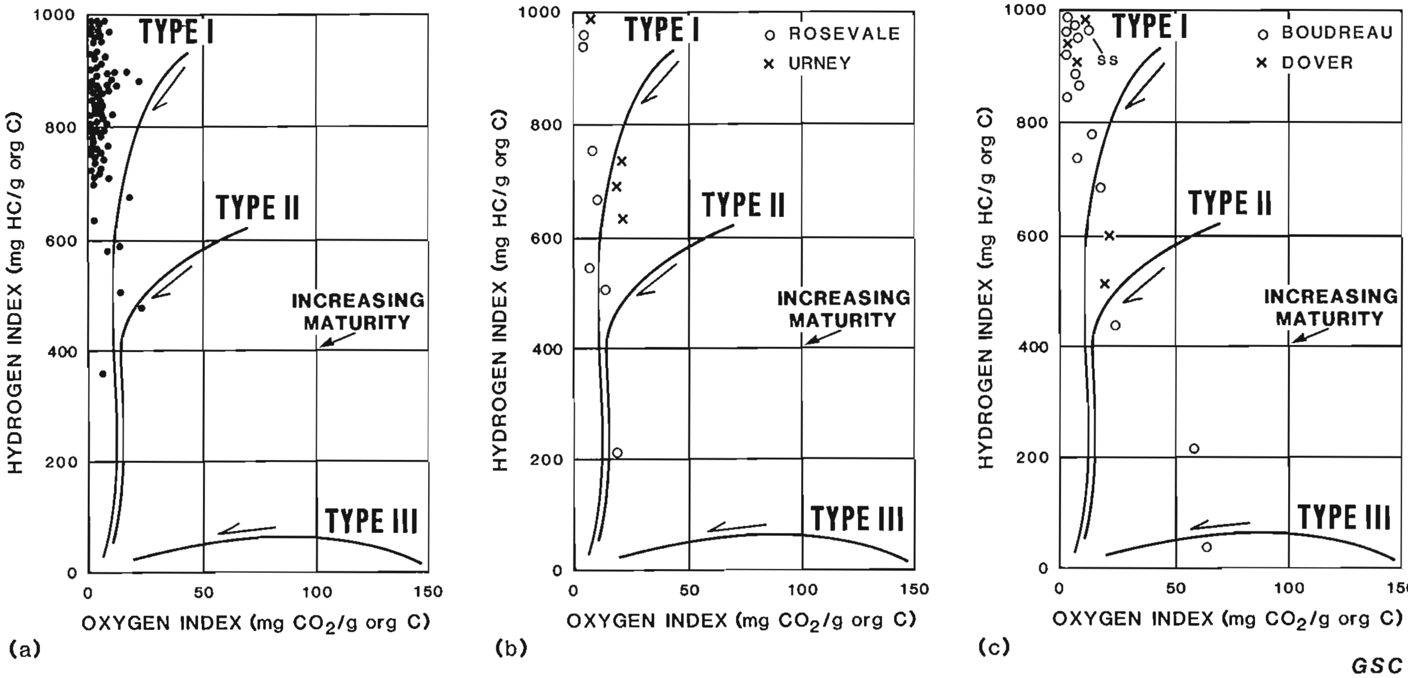


Figure 27. Hydrogen Index versus Oxygen Index, Rock-Eval analyses: (a) Albert Mines area, (b) Urney-Rosevale area, (c) Boudreau-Dover area (from Macauley and Ball, 1982).

Within the oil shale beds at Albert Mines, vitrinite reflectance values range from 0.43 to 0.50 per cent, indicative of thermal immaturity much below that interpreted from the Rock-Eval data. A sample from an overlying, dominantly humic, non-oil shale bed at Boudreau had a vitrinite reflectance of 0.86 per cent, which is much more compatible with the other data. Kalkreuth and Macauley (*ibid.*) concluded, as others had done in similar circumstances (Hutton and Cook, 1980) that the vitrinite reflectance was severely depressed, by as much as 50 per cent, because bitumen had impregnated the vitrinite particles in the oil shale. Vitrinite reflectance is thus an inadequate tool for maturation evaluation in these oil shales.

Maceral analysis showed the organic matter to be almost entirely lamalginite (alginite B) with considerable bituminite (probably albertite) and trace quantities of sporinite and telalginite (alginite A).

Fluorescence values were measured in the lamalginite, including determination of the wavelength where the highest intensitites are recorded (λmax, nm), and the Red-Green Quotient (Q=intensity at 650 nm/intensity at 500 nm). These values measure changes in spectral intensities during ultraviolet irradiation. At Albert Mines, λmax increased downward, from 544 nm in the upper unit to >700 nm (the limit of accurate measurement), below 598 m in the dolomite marlstone. The Red-Green intensity Quotient similarly increased from 0.95 to 1.48 at 737 m depth.

The lamalginite occurs as layers alternating with the mineral matrix, where the rock unit is characterized by a lamellar structure (the fusiform bodies of King, 1963), or as thin coatings surrounding mineral grains, especially detrital quartz and calcite crystals. Within massive dolostone beds, the organic matter appears as irregularly disseminated, unfigured kerogen or bitumen (Fig. 25b). The fluorescence results indicate that there is no significant difference between the unfigured macerals and the lamalginite; therefore, even though not everywhere laminated, the entire deposit is composed dominantly of a single "lamalginite" algal kerogen.

Fluorescence values at Urney (λmax=545 nm; and Q=0.95) are similar to the shallow section values at Albert Mines.

The single sample, not an oil shale, at Boudreau, contains huminite/vitrinite, inertinite and liptodetrinite (terrestrial). None of these was present in the oil shale beds.

Kerogen-pyrolyzate-oil characteristics

King (1963) stated that the bulk of the organic matter has a low index of adsorption, and is generally translucent and structureless. Where the organic matter of the kerogen transmits yellow, associated albertite is a dark reddish brown. King separated kerogen from the samples and produced comparative data for kerogen and albertite (Table III). All data show that the albertite, a definite product from thermal maturity of the oil shale, is more aromatic than the parent oil shale, although the albertite is not strongly aromatic.

More recently, Khavori-Khorasani (1983) utilized spectral response of optical parameters and X-ray diffraction to study the albertite. Because of weak adsorption in the visible spectrum, and a decline of the refraction index toward longer wavelengths, Khavari-Khorasani reported a lack of any substantial amounts of condensed aromatic systems in the molecular structure of the albertite. X-ray studies revealed a dominant reflection band (spacing 0.454 nm) consistent with aliphatic and/or alicyclic structures. The albertite, with a high proportion of volatile matter, and an atomic H/C ratio of 1.2:1 (slightly lower than, but comparable to King's determinations), must have originated from aliphatic and/or alicyclic material. The low aromaticity of the albertite indicates that severe diagenetic changes in the structure of the bitumen have not taken place.

As part of the ISPG concept of oil shale analysis by comparative techniques, Altebaeumer (1984) chemically analyzed some of the samples from Kalkreuth and Macauley's (1984) organic petrology study. Her investigations included elemental analysis (N, C, H) and gas chromatography of both solvent extracts and rock pyrolyzates. The eighteen samples cover all units and lithotypes of the oil shale, selected from two locations over as wide a depth range as possible. TOC, Rock-Eval and Fischer Assay results are also available for comparison.

At the Albert Mines location, the atomic H/C ratio remains relatively constant at about 1.45 (1.42 to 1.52) for the upper three units (including the laminated and clay marlstones) comprising the top 300 m, but is considerably lower, averaging 1.16 (1.03 to 1.27) over the lowermost 360 m of dolomite marlstone. From fluorescence microscopy studies, Kalkreuth and Macauley (1984) indicated increasing maturity downward in this section, and Macauley and Ball (1982) reported downwardly decreasing average yield/per cent Corg. Altebaeumer (1984) recorded an average atomic H/C for the Boudreau area of 1.40 (range of 1.33 to 1.45) independent of zone or depth. A sample from Boudreau, identified by Rock-Eval and organic petrology as humic Type III kerogen, shows an abnormally high (1.40) atomic H/C ratio for that type of kerogen, as is noted by Altebaeumer (*ibid.*).

Extract yields were high for Albert Mines, ranging from 12 645 to 25 255 ppm, or 115.0 to 979.2 mg/g Corg. In contrast, extracts for Boudreau were considerably lower, ranging from 1582 to 9450 ppm, or 61.2 to 337.6 mg/g Corg. These confirm the production indices (or transformation ratios) of 0.10 to 0.20 at Albert Mines and the lower (0.06 to 0.10) values at Boudreau (Macauley and Ball, 1982).

From Altebaeumer's data, saturates represent 41.1 per cent (37.1 to 54.0 per cent) and aromatics 14.0 per cent (6.2 to 18.0 per cent) of the extract at Albert Mines, a saturate/aromatic ratio of 3.16. At Boudreau, saturates average 33.3 per cent (24.9 to 39.6 per cent) and aromatics 12.85 per cent (8.8 to 19.9 per cent) for a saturate/aromatic ratio of 2.71. The higher propertion of saturates at Albert Mines results from greater thermal maturation. Figure 28 is a typical gas chromatogram for the Albert Mines area.

Altebaeumer (*ibid.*) noted that the extract yield could not be correlated to TOC content, and concluded that extract variations result from enrichment and depletion through primary migration of hydrocarbons in the oil shales, with such migration more pronounced at Albert Mines than at Boudreau. Extract yields are also noncorrelative with the S1 and S2 Rock-Eval peaks, because the S2 peak contains irregular amounts of soluble bitumen.

Kerogen type indices [m(+p)-xylene/n-octene], as proposed by Larter and Douglas (1980), were calculated by Altebaeumer to range from 0.23 to 0.59 at Albert Mines, with a poorly indicated increase of values downward in the section. Indices for whole sediment were lower, ranging from 0.21 to 0.39, also increasing downward. At Boudreau, isolated kerogen indices ranged from 0.18 to 0.37, independent of zone and depth. Alginites have kerogen indices <0.4, sporinites 0.4 to 1.3, and vitrinites >1.3. Altebaeumer (1984) described the indices of the isolated kerogen at Albert Mines as typical of lacustrine and marine algal kerogens; however, one must consider that higher values

	Kerogen (Oil Shale)	Albertite
Density	1.006	1.078
CHEMICAL PROPERTIES		
Carbon - wt %	82.1	84.1
Hydrogen	10.7	9.4
Nitrogen	1.2	2.0
Sulphur	1.4	0.3
Oxygen	4.6	4.2
Atomic H/C	1.56	1.34
Aromaticity	0.29	0.41
Refraction Index	1.55	1.65
INFRARED DATA Aliphatic		
3.42 μ, CH_2	1.23	0.72
7.27μ, CH_3	0.05	0.09
13.9μ, CH_2 chain	0.067	0.031
Aromatic CH		
11-14μ total	0.27	0.52
Carboyl 5.87μ	0.13	0.23
Aromatic C=C 6.27μ	0.10	0.26
Background at 5μ	0.05	0.14
Background at 8-10μ		stronger

TABLE III

Comparative oil shale-albertite chemical characteristics, Albert Mines area (from King, 1963)

(i.e up to 0.59) would also result from increasing maturation as lighter components migrate from the sources. Kerogen indices at Boudreau indicate the material to be alginitic. From the gas chromatograms, Altebaeumer noticed little difference for the vitrinite Type III sample defined by organic petrology except for the presence of more isoprenoids, especially the C_{13} isoprenoid alkene. If, as Altebaeumer suggests, the liptodetrinite of Kalkreuth and Macauley (1984) was derived from algal rather than terrestrial debris, the compounds derived from the vitrinite may be masked by the liptodetrinite derivatives. This is quite probable. Variations of isolated kerogen in whole rock pyrograms were interpreted by Altebaeumer to be due to the influence of mineral matter on the formation of petroleum hydrocarbons during pyrolysis.

Both Salib (1983) and Synnott and Salter (1983) provided elemental analyses of the product shale oil, and included numerous gas chromatograms of the derived oils for several cycles of retorting. There is no discussion of the characteristics definable from their chromatograms, but Altebaeumer's rock pyrolyzate investigations have produced similar results. For the Albert Mines deposit, sulphur content approximates 0.5 per cent by weight, nitrogen 0.25 per cent, carbon 81 per cent, and the weight %C/H ratio ranges from 6.70 to 7.10 (atomic H/C 1.7 to 1.8). This value is somewhat lower than the 7.2 to 7.4 range for Colorado shale oil, reflecting the better quality product at Albert Mines.

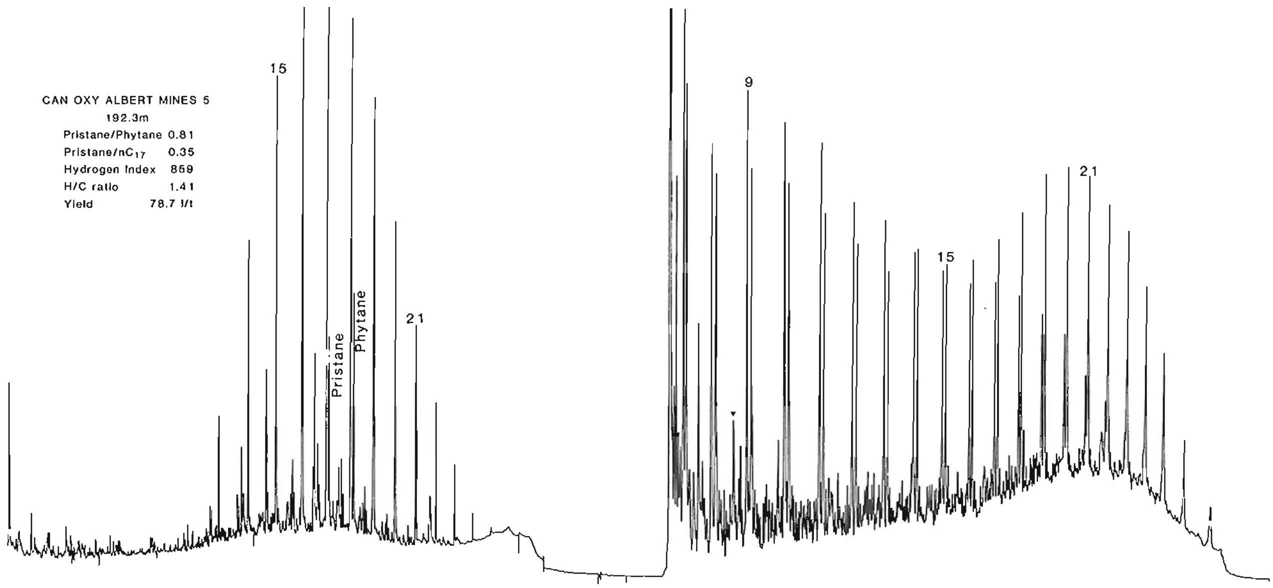


Figure 28. Typical gas chromatogram of whole rock pyrolyzate, Albert Mines deposit (from Altebaeumer, 1984).

Fischer Assay results reveal that oil specific gravities (Table II) are lightest at Albert Mines, approximately 0.88 average, and are elsewhere closer to 0.91. Rosevale may be an exception, with lower specific gravity values (0.887) for five samples; however, industry analyses (Macauley and Ball, 1982) place the specific gravity closer to 0.907 at Rosevale.

Classification and maturation

All indicators define the Albert formation oil shales of the Moncton Sub-basin to be continental, lacustrine, Type I lamosites. The Albert Mines deposit is at an optimum stage of thermal maturation, within the range of moderate maturity. Bitumens and heavy oils have essentially been generated and some, such as those that produced the albertite vein, have migrated from the source. The kerogen, bitumen and heavy oil products are at the specific stage where lighter hydrocarbon generation may occur. Such lighter products are recognizable from the petroleum odor emanating from freshly broken surfaces of dolomite marlstone beds (Macauley and Ball, 1982). Although the oil shales are at the point of initial generation of lighter gravity crude oils, no major amount of light gravity oil appears to have been generated; consequently most of the potential yield is still available to the oil shale retort.

Other known oil shale areas – Dover-Boudreau to the east, and Rosevale-Urney to the west – are less thermally altered, and in a stage of low thermal maturation, having generated bitumen and possibly a heavy oil component still within the source beds. The lesser maturity results in the production of a heavier, slightly more aromatic oil in these areas than that recovered at Albert Mines.

Albert oil shales, if present, have been more deeply buried in the central part of the Moncton Sub-basin on a line from Sussex to Moncton. There is considered to be small risk in identifying Albert oil shales, which interbed with some of producing sandstone reservoirs, as the source for the oil of the Stony Creek field (Fig. 21).

Economic potential

Because of variations in average organic content and in the development of the lithotypes across the known outcrop areas of Albert oil shales, as well as major differences in structural configuration, the economic potentials are best discussed as specific site evaluations.

Albert Mines Deposit. The oil shales and albertite vein, cropping out along Frederick Brook, approximately 4 kilometres west of the village of Albert Mines in southwestern New Brunswick (Fig. 21), have been the focus of repeated interest since the mid-nineteenth century. Unfortunately, the cores from thirty-six drillholes of the Canada Department of Mines program in 1942 have all been discarded. However, the Atlantic Richfield Company's (one drillhole in 1968), and Canadian Occidental Petroleum Company's (seven drillholes in 1976 and three drillholes in 1981) cores from eleven locations have been retained. Detailed lithologic and geochemical logs from six of these drillholes (Macauley and Ball, 1982) in conjunction with field notes made by McLeod (1980), are the basis for the geological interpretation of bedrock geology (Fig. 29) and the lithofacies relationships illustrated by the stratigraphic cross-section (Fig. 30).

The interdigitation of Round Hill conglomerate, and of the sandstones, siltstones and nonorganic shales of the overlying Hiram Brook Member and the underlying Dawson Settlement Member, is particularly evident in the west (Fig. 30). Across this local area, with increasing eastward distance from source, the Albert Formation becomes finer grained.

McLeod (1980) described the Albert Formation at Albert Mines as being in fault contact with the pre-Carboniferous rocks of the Caledonia Uplift to the west and the Hillsborough conglomerates to the south and northeast (Fig. 29). The Pennsylvanian Enrage Formation unconformably overlies Albert beds to the east; Frederick Brook oil shale beds are considered to extend eastward below the Enrage strata, which may add to the oil shale potential of the area.

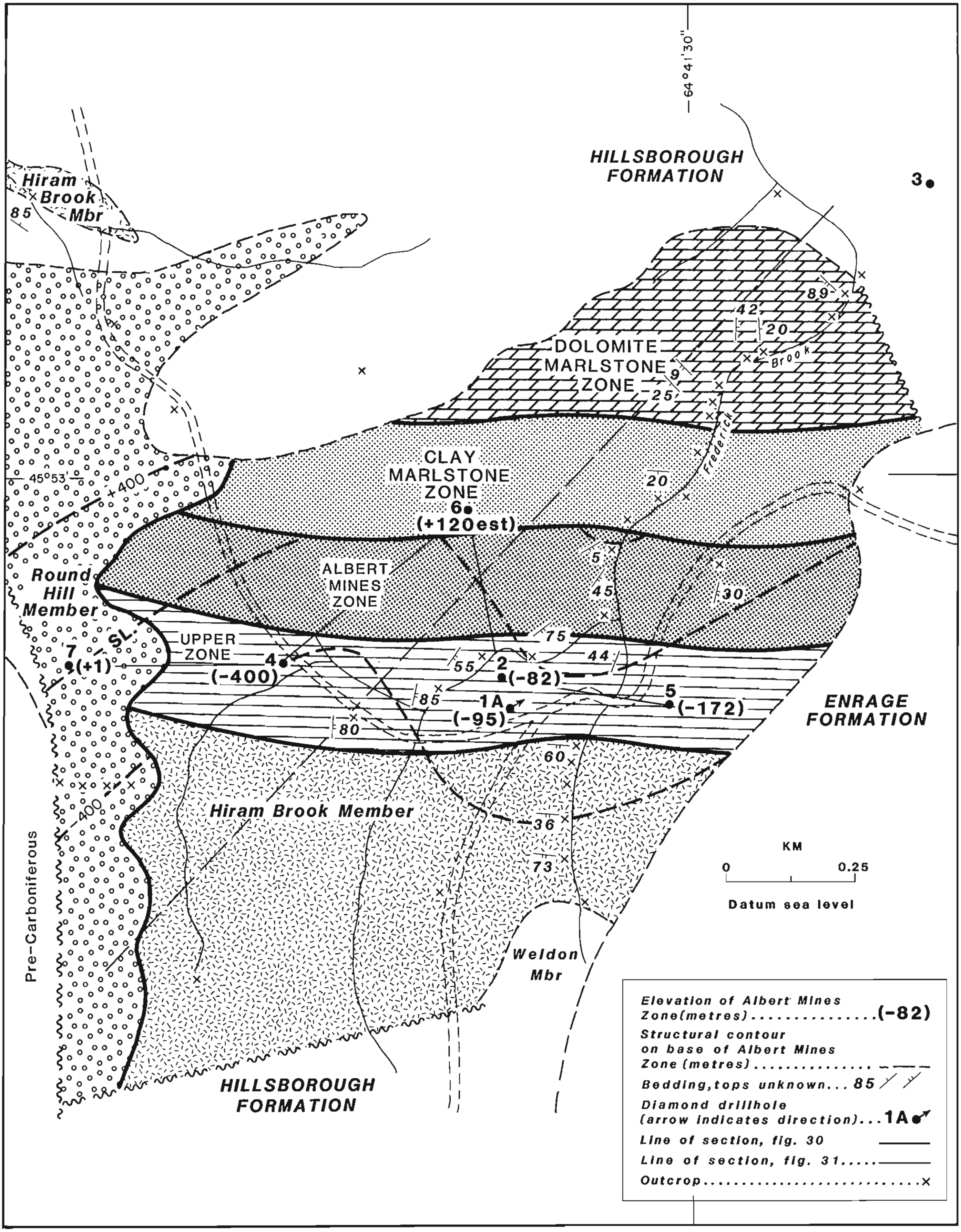


Figure 29. Interpreted surface geology, Albert Mines area, with subsurface contours for base of the Albert Mines zone (from Macauley and Ball, 1982).

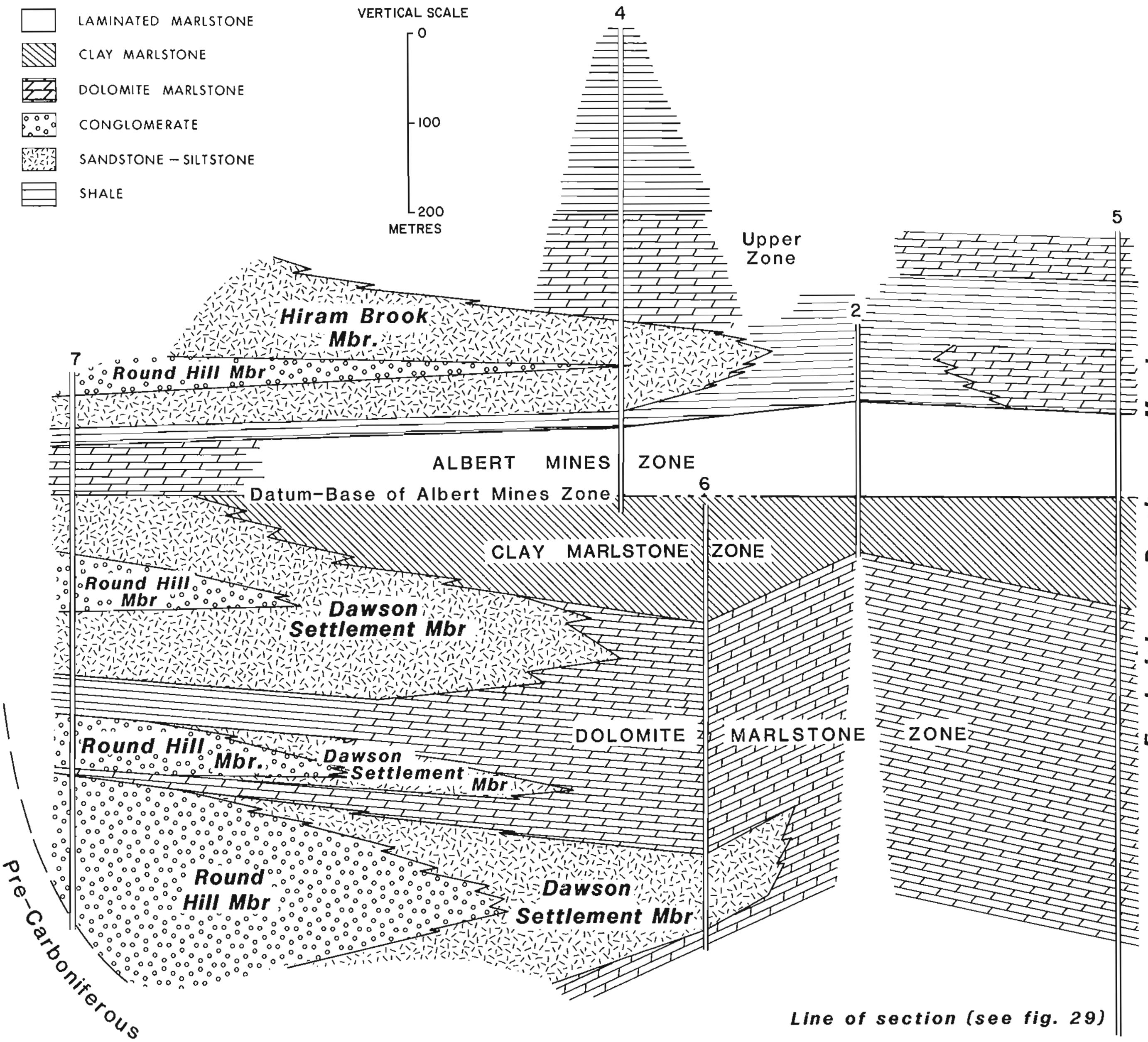


Figure 30. *Lithologic correlation section, Albert Mines area, uncorrected for structural distortion (from Macauley and Ball, 1982).*

The complexity of the local structure at Albert Mines has been mapped in increasing detail by successive geologists. Initially, the feature was interpreted as a simple southwesterly plunging anticline with its crest along Frederick Brook. Wright (1922) more fully recognized the structural complexity when he mapped the surface exposures and abandoned adits of the albertite mine. Macauley and Ball (1982) illustrated the feature as a possible south to north thrust (Fig. 29). Within the thrust sheet, the laminated marlstones, and in part the clay marlstones, have been thickened by disharmonic folding of the incompetent members because of extreme slippage and convolution along the kerogen planes. Because of the contortions caused by folding within these beds, specific surface dips are not considered reliable data on which to base a gross structural analysis. Structure contours for the base of the Albert Mines zone (Fig. 29), as mapped from corehole data, indicate a general east-west strike and a minimum, southerly, average dip of 55°. The dolomite marlstone zone is not thickened by folding and/or faulting. Prepared from the map presentations and structural attitudes shown on the corehole logs (Macauley and Ball, 1982, Fig. 4), Figure 31 diagrammatically represents this more complex structural interpretation. Geological factors will be most significant for any development of this deposit, whether by surface and/or underground mining, or by *in situ* retorting.

Recovery factors/% organic carbon vary with the zone, decreasing downward from a maximum 9.67 l/t/%Corg in the laminated marlstones of the Albert Mines zone, to 9.00 l/t/%Corg in the clay marlstones, and a lowest yield of 8.51 l/t/%Corg in the dolomite marlstone. These recovery factors have been derived from the line slopes of the Fischer Assay results (Fig. 32), and are slightly lower than those calculated

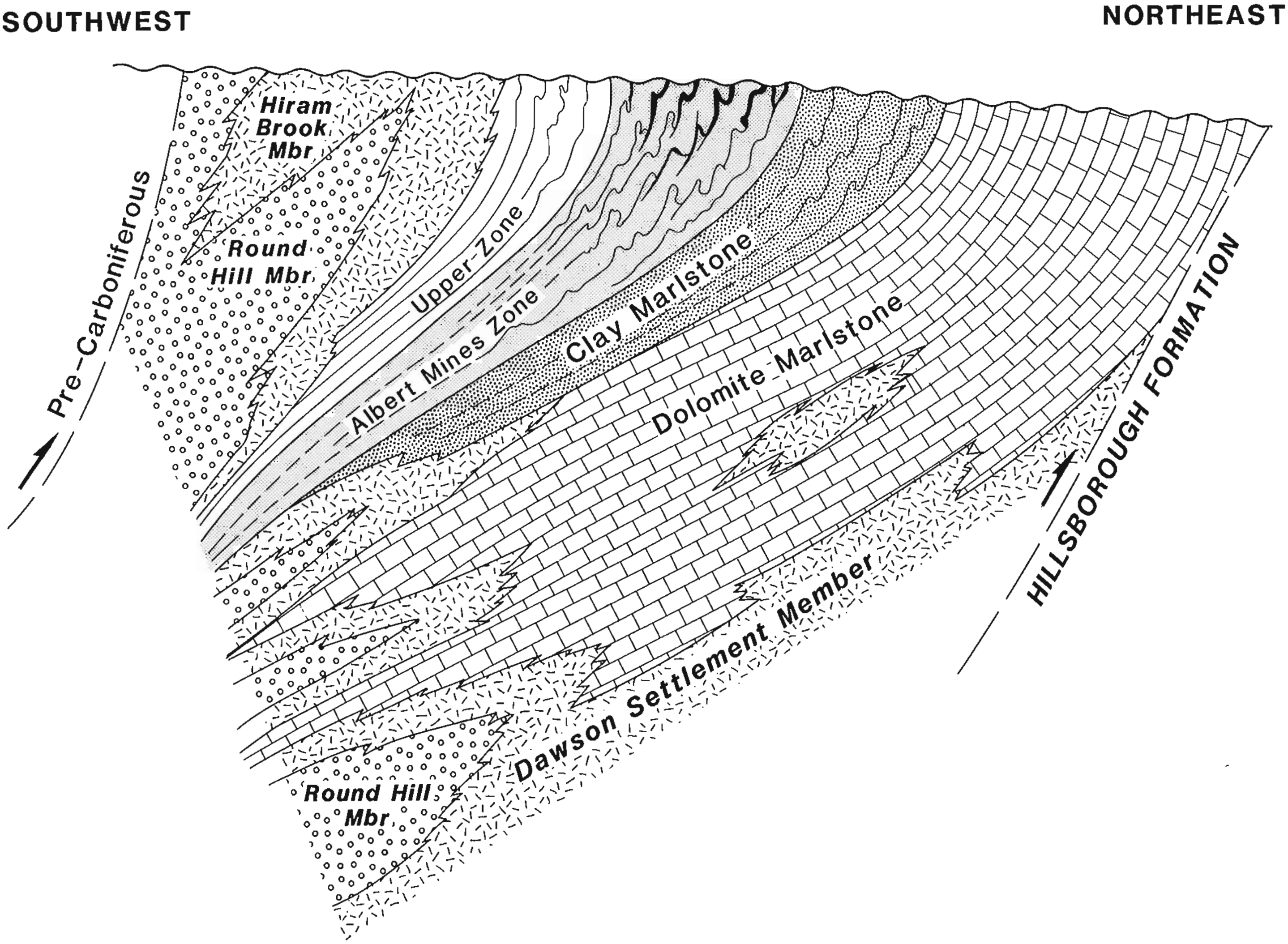


Figure 31. *Diagrammatic structure section of Albert Mines deposit.*

by averaging the values, as reported in Table II, but they are more comparable to the industry assay values (Macauley and Ball, 1982, p. 63). The upper zone is approximately an average of the other units as is expected by its multi-lithotype content. The downward decreasing yield may in part relate to the increasing maturity (Kalkreuth and Macauley, 1984), but is probably also influenced by the variable mineralogy (Macauley and Ball, 1982), especially in the upper unit. Altebaeumer (1984) found no differences in the kerogen-pyrolyzates that can be attributed to increased maturation in this local area.

Detailed chemical studies of the Albert Mines Formation extracts, kerogens and kerogen-pyrolyzates (Altebaeumer, 1984) have confirmed that essentially all of the organic matter has had a similar algal precursor and has undergone moderate catagenetic alteration. Liquid hydrocarbon generation has occurred within the oil shale, and migration can be inferred from the apparent enrichment and depletion of bitumen in various samples.

A significant spread in the yield/%Corg ratio is particularly noticeable for the Albert Mines zone (Fig. 32b). Macauley and Ball (1982) attributed this to migration of bitumen within the zone and possible overmaturation along slickensided zones.

At the surface, the Albert Mines zone appears to occupy a band approximately 100 metres wide by 1500 metres east-west. Because the structural thickening appears to decrease downward, Macauley and Ball (1982), assigned an average of 60 m thickness to this zone. Reducing the exposed east-west length to 1200 m because of possible easterly development of the Round Hill facies in the subsurface, 114.6×10^6 tonnes of oil shale are calculated for a depth of 600 metres. At an estimated 55° southerly dip, 600 metres drilled depth equates to 730 metres on the zone surface. At an average yield of 93.5 litres/tonne (industry values), Macauley and Ball (*ibid.*) estimated 10.71×10^6 cubic metres/67.35 million barrels of *in situ* shale oil reserves for the Albert Mines zone.

Their calculations for the other units of the Albert Mines area are presented in Table IV: 42.84×10^6 cubic metres/270 million barrels of *in situ* shale oil are estimated for these deposits. These estimates do not include postulated additional oil shale deposits beneath Enrage beds to the east, and make only minor allowance for the influx of Round Hill,

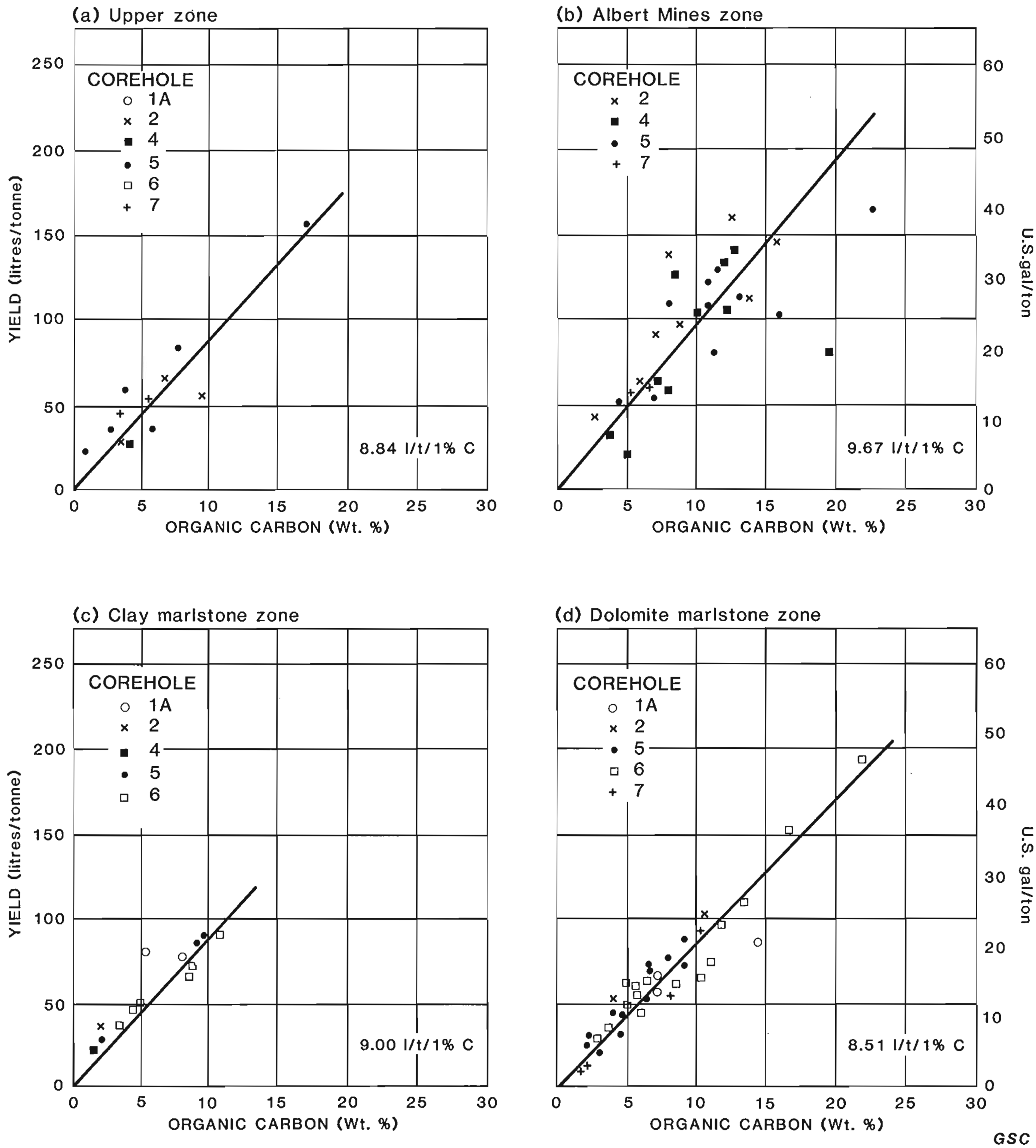


Figure 32. *Fischer Assay yield versus organic carbon content, Albert Mines area: (a) upper zone, (b) Albert Mines zone, (c) clay marlstone zone, (d) dolomite marlstone zone (from Macauley and Ball, 1982).*

Hiram Brook and Dawson Settlement clastics into the oil shale environment in the west. An indicated easterly improvement in shale oil yields may also be significant to that unexplored area below Enrage beds.

Because of the excellent quality of the shale oil (approximately 0.88 sp. gr.) and the high yield of the laminated marlstones, this specific part of the Albert oil shales is probably the most economically attractive of all Canadian oil shale deposits. Three important factors must be investigated before a proper economic assessment can be made. Firstly, the exact nature of the structural deformation must be determined; secondly, the distribution of the apparent higher and lower yield intervals, especially in

Zone	Thickness m	Length m	Yield l/t	Density g/cc	Mass t/10⁶	*In Situ* Reserves	
						$m^3.10^6$	$bbls.10^6$
Upper	75	1000	35.3	2.40	131.4	4.64	29.17
Albert Mines	60	1200	93.5	2.18	114.6	10.71	67.35
Clay marlstone	45	1200	38.4	2.37	93.4	3.59	22.56
Dolomite marlst.	180	1400	56.5	2.30	423.1	23.90	150.35
Total	360				762.5	42.84	269.43

TABLE IV

Estimated *in situ* reserves to a depth of 600 metres vertical, Albert Mines deposit

the clay and dolomite marlstones (Fig. 26) must be defined; and thirdly, the differences of the lithotypes must be examined for all exploitation procedures, including mining, crushing and retorting.

Boudreau-Dover (eastern Moncton Sub-basin). Yield ratios/%Corg at Boudreau and Dover (Fig. 21) are only slightly less than at Albert Mines (Table II), but kerogen content (TOC) is considerably less (7 to 7.75 per cent at Boudreau, 5 per cent at Dover). The lower yield ratio possibly relates to the slightly lower level of maturation in these areas compared to that at Albert Mines.

Only a few, thin, high-yield beds are present in the Boudreau and Dover cores. Macauley and Ball (1982) correlated these areas on the basis of high water intervals (the clay marlstones) and readily recognizable dolomite marlstones. The laminated marlstones may not be well developed in these areas. The structures are much less complex, lacking the major thickening of the Albert Mines zone equivalents (figs. 33, 34), although some disharmonic thickening is present at Dover.

From all Fischer Assay data on the coreholes of these areas, total hydrocarbon potential averages 30 to 35 litres/tonne at Boudreau and only 20 to 25 litres/tonne at Dover. Although these numbers are discouraging, they represent only a limited data base. The lateral facies distribution of the oil shale lithotypes is virtually unknown because of minor and sporadic outcrop control and a minimal number of coreholes. Spot samples do yield in excess of 100 litres/tonne (25 U.S. gals/ton). Macauley and Ball (1982) suggested that higher yield intervals occur near the base of the Albert Mines equivalent and near the top of the dolomite marlstone unit, and that such intervals are sufficiently thick to warrant exploratory interest even though completely barren zones occur within the total oil shale interval. Although the cores have been destroyed, good recoveries were also recorded at the Taylor Village and St. Joseph areas (Fig. 21) (Macauley and Ball, 1982). The potential for thicker, high-yield oil shale zones is certainly present in this most easterly part of the Moncton Sub-basin, but will be recognized and defined only by much additional corehole exploration.

Rosevale-Urney Trend. Outcrops of oil shales occur west-southwest of Albert Mines along the southern edge of the Moncton Sub-basin. Cores from Rosevale and Urney (Fig. 21) were studied by Macauley and Ball (1982). Scattered data from the intervening outcrop areas were reported by Macauley (1984a).

A simple, northwest dipping structure along the basin margin is mapped at Rosevale (Fig. 35). In contrast, the

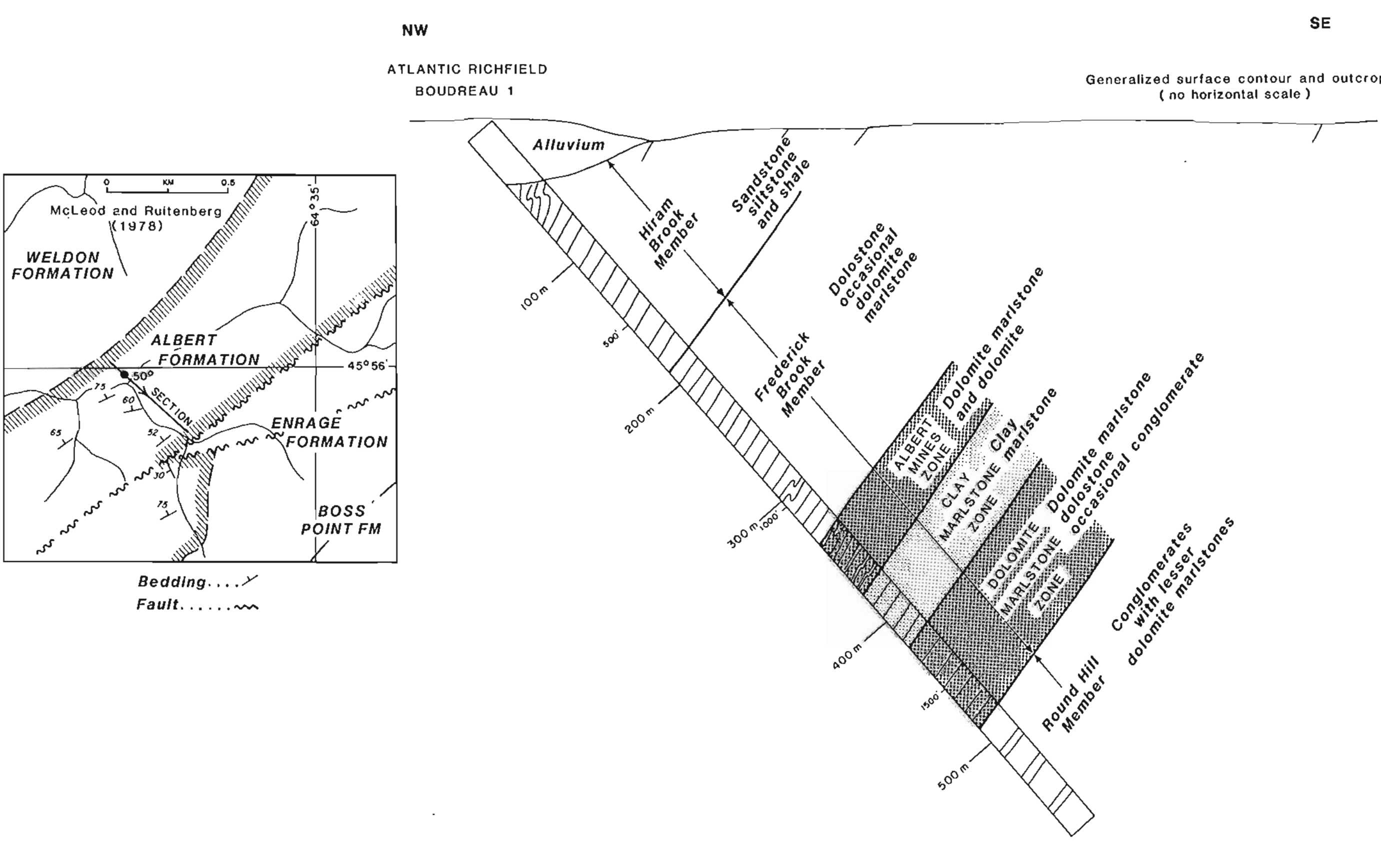


Figure 33. *Structural interpretation, Boudreau area (from Macauley and Ball, 1982).*

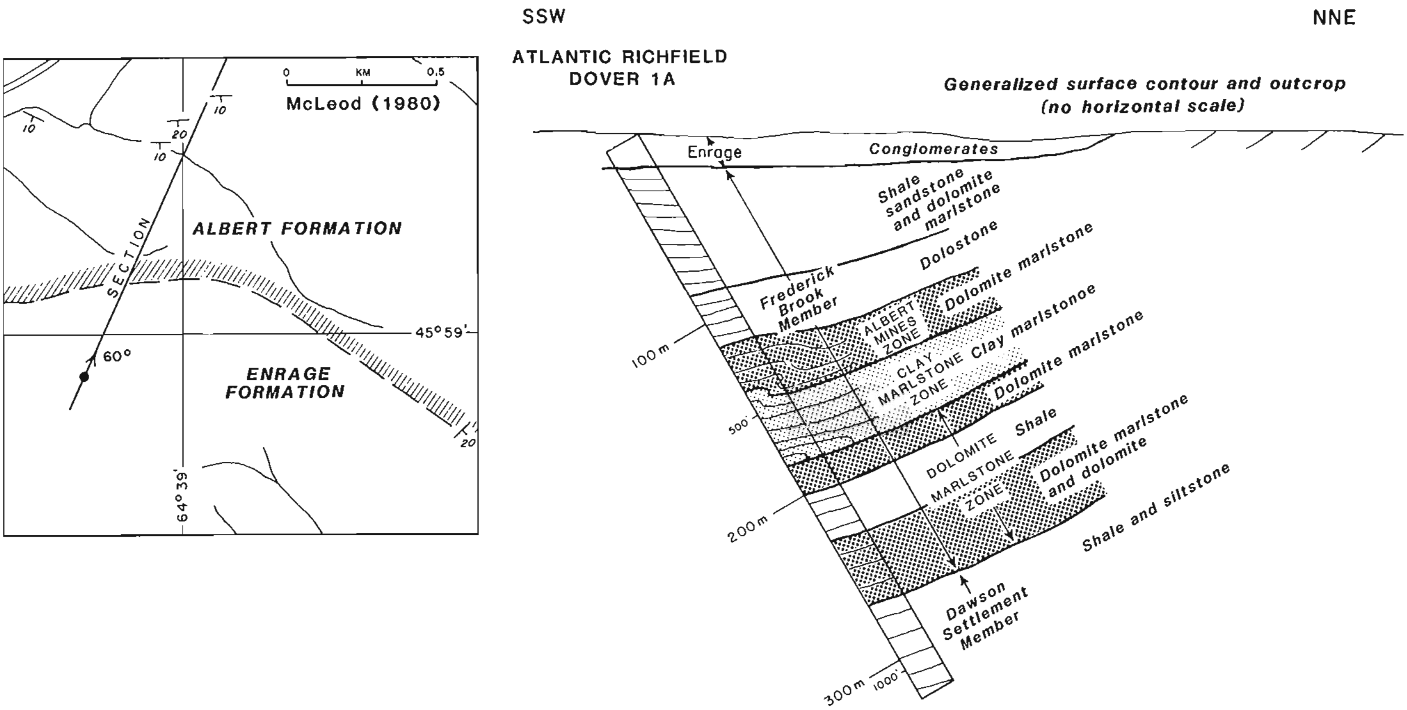


Figure 34. Structural interpretation, Dover area (from Macauley and Ball, 1982).

Albert Formation in the Urney area is folded into a tight anticline (Fig. 36). Similar to the Albert Mines area, fold contortions promoted by kerogen laminae and brecciated, slickensided zones are associated with the Urney anticline.

Yield ratios/%Corg and low to moderate maturation indices (Table II) are comparable to those in the Boudreau and Dover areas. The organic carbon contents are lower than in other areas, and generally average less than 5 per cent even for the best intervals; consequently, yield potential is less. At Rosevale, Macauley and Ball (1982) indicated that the Albert Mines zone could exceed 50 litres/tonne (12.5 U.S. gals/ton) over an interval of 15 m, which is certainly sufficient to be economically interesting.

The lower recoveries/%Corg in areas outside the Albert Mines deposit were attributed by Macauley and Ball (1982) to greater maturation levels. The additional investigations now relate the lower potential to lesser maturation at Boudreau-Dover and Rosevale-Urney, where the shales are within the bitumen-heavy oil generation stage. In contrast, the oil shales at Albert Mines have matured to a stage of lighter oil generation.

C. St. Peter (pers. comm.), of the New Brunswick Department of Natural Resources, is able to recognize lithofacies changes along the Rosevale outcrop trend. As these facies changes are mapped, for this and other outcrop areas, a better understanding of hydrocarbon potential will be possible and future exploratory coreholes will be located more effectively.

Exploitation

Mining requires considerable knowledge of the ore for both exploration and development. Continuous coring is an effective but expensive technique for providing the necessary data; geophysical logs of drilled holes can often produce equivalent information. Macauley and Ball (1982) investigated the relationship of rock density to yield potential for each lithotype, and compared the representative averaged lines (Fig. 37). Because of the variable mineralogy, density values cannot be related directly to anticipated yield without knowledge of the rock type. Ball (1984) found the zones to be recognizable during conventional rotary drilling through variations in the rate of drilling (increasing clay means faster drilling; increasing dolomite means slower drilling). The quality and quantity of sample returns, technical problems, such as wall collapse and bit plugging, and drilling fluid characteristics, also vary with different lithotypes. Thus, drillhole data can be used in part for evaluations by combining density logs, good logging of the samples and the lithological characteristics determined from drillhole conditions.

Hydroretorting of seventeen Albert Mines samples has produced positive results (Furimsky, Synnott et al., 1983), increasing the yield relative to Fischer Assay yields by 1.06 to 2.04 times (average 1.7 times). Carbon conversion was increased 1.5 times to produce liquid products with atomic H/C ratios near 1.64, considerably higher than the average 1.45 reported by Altebaeumer (1984) from pyrolysis, for the upper three zones. Furimsky, Synnott et al. (1983) attributed the beneficial effect of hydroretorting as the result of stabilization of unstable intermediates that would otherwise polymerize and remain in the spent shale residue. Additional background data are available, on procedures in Brown and Abbott (1982), and on results in Synnott and Salter (1983).

Initial rock mechanics studies are in progress at the University of Waterloo (Dusseault, pers. comm.), although optimum results are not expected, as only older core in poor condition was available. Loftsson (1984) discussed in considerable detail the changes in rock properties related to the proportions of kerogen, clay minerals, and harder mineral components (quartz, carbonate) that form the matrix support for the rock. By analogy to Loftsson's summary and

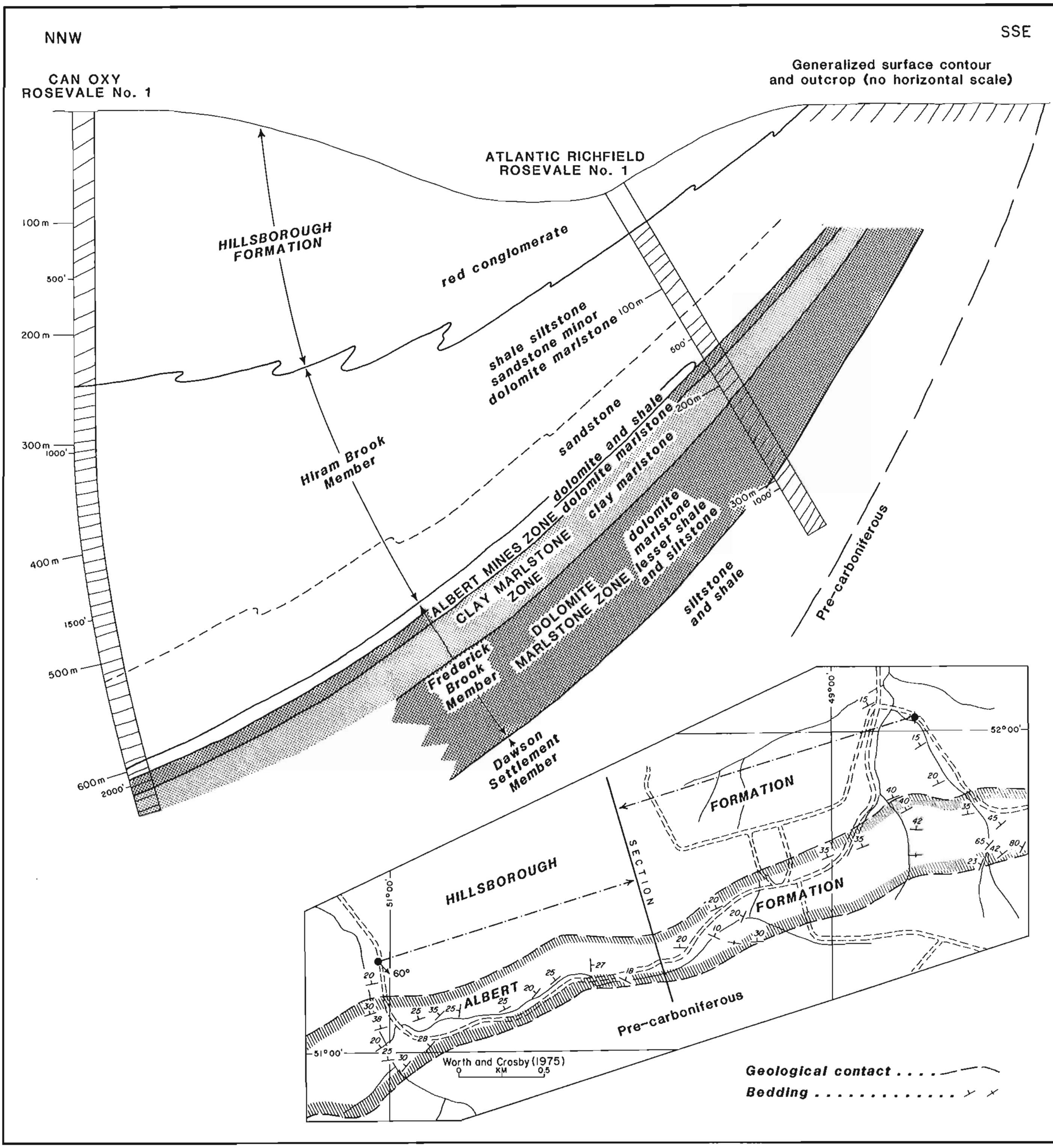


Figure 35. Correlation section with structural interpretation, Rosevale area (from Macauley and Ball, 1982).

examples, kerogen is anticipated to be the matrix control in the laminated marlstones, and clay in the clay marlstones. Both will be structurally much weaker than the dolomite controlled matrix of the dolomite marlstones. Because of the intergradation and interdigitation of these lithotypes, rock strengths are expected to vary considerably over short distances, both laterally and vertically. The extremely different effects of the structural deformation of the three lithotypes can be related directly to the indicated differences in rock strengths because of kerogen and mineral component distribution.

New Brunswick is an energy deficient province, where electricity is generated from the high sulphur (7%) coalbeds of the Minto area. The use of this coal is in part limited because of the high cost of SO_2 emission control, mining cost

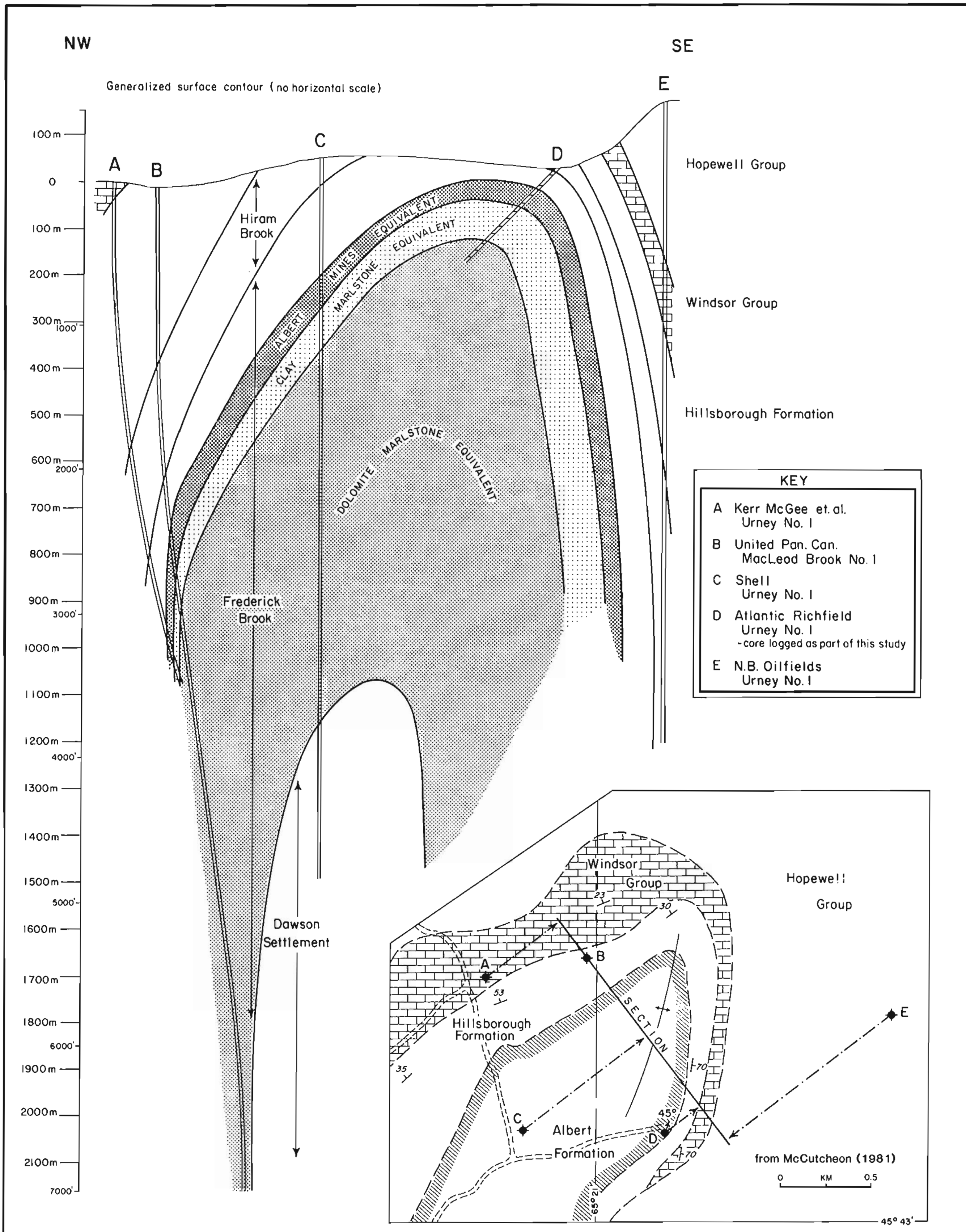


Figure 36. *Correlation section with structural interpretation, Urney area (from Macauley and Ball, 1982).*

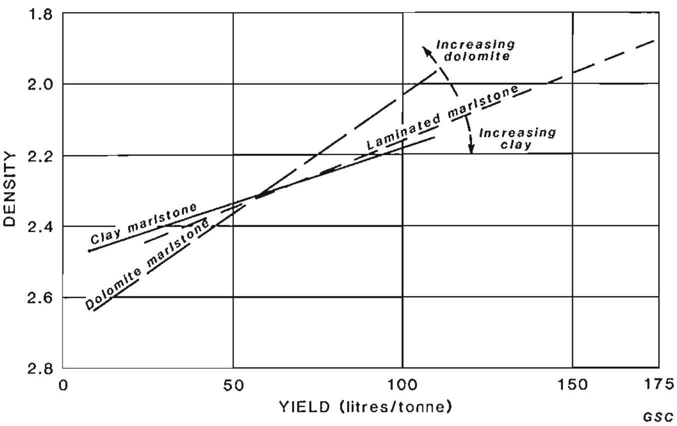


Figure 37. *Comparative densities versus yield averages for lithologic units, Albert Mines area (from Macauley and Ball, 1982).*

and the depletion of total resources available. Limestone can be used to trap the sulphur emissions resulting from coal combustion, but this is a direct cost without useful product yield. Gilders and Salter (1981) and Boorman et al. (1982) described from experimental research at the Research and Productivity Council, New Brunswick, the fluidized bed co-combustion of coal and oil shale as a route to SO_2 emission control. The Albert oil shales contain considerable carbonate capable of reacting with the sulphur, and also, unlike limestone, oil shale adds to the thermal balance during combustion. An oil shale/coal ratio of 2.6:1 reduces the SO_2 emissions by >90% and brings the SO_X discharge level below the Canadian Government Clean Air Act requirements. Although twice as much oil shale as limestone is required to achieve the same emission control, the additional energy from the oil shales very much offsets the additional quantities required.

Several systems for the co-use of high sulphur coal and oil shale were proposed by Gilders and Salter (1981). All involve recovery of energy from the oil shale as steam for electricity or for direct distribution to steam processes (i.e. paper mills), or for a combination of steam plus recovery of liquid refineable fuels. The latter, a retort interlock system, overcomes the losses of a standard retort system, as shale fines and "char" residues can be used in the fluidized bed combustor-scrubber with the coal. Figure 38 is the Research and Productivity Council's conceptual design for such a system, which has been successfully bench tested (Salib, 1983). Hydroretorting within the oil shale retort system can be beneficially effected by generating hydrogen from the recycled gas by partial reforming and/or by initiating gasification reactions inside the retort (Salib and Abbott, in press).

Preliminary capital and operating cost estimates have been made for several options (Research and Productivity Council, 1982; Salib and Boorman, 1983) and are summarized in Table V. Cases one and two are retrofits to a conventional 200 Megawatt (MW) coal-fired boiler at Dalhousie, New Brunswick; cases three and four are retort modifications to the Dalhousie generation plant; cases five and six are for the development of new plants in Albert County; case seven is for emission control of SO_2 by combustion of coal and limestone at Minto. Case six, the co-combustion of coal and oil shale with a retort interlock, does not include costs of the retort; presumably, they would be recovered in the marketing of the oil products.

Case	Location	MW	Capital Cost		Annual Cost (mills/Kwh)		
			$,000	$/kw	Capital	Operating	Total
1	Dalhousie Coal Plant	200	176,600	883	15.6	28	44
2	Dalhousie limestone scrubber	200	176,600 53,422 230,022	1150	20.4	28 8.5 36.5	57
3	Dalhousie Oil shale scrubber	200 90 290	176,600 104,110 280,710	968	17.1	35.3	52
4	Dalhousie Oil shale scrubber with retort interlock	200 ?	176,600 ?		15.6 ?		?
5	Albert Co. coal/oil shale fluid bed combustor	290	218,986	755	13.6	27.2	41
6	Albert Co. fluid bed combustor, retort interlock	290	241,129	831	14.7	28.0	43
7	Minto - Coal/limestone fluid bed combustor	290	218,986	755	13.6	37.6	51

TABLE V

Comparative cost estimates for various power generation options utilizing Albert oil shales (derived from the Research and Productivity Council, 1982, and from Salib and Boorman, 1983)

From these preliminary estimates, oil shale is a more attractive scrubber than limestone for SO_2 emission control, because of the energy generated by the oil shale. Additional cost reduction can be attained by locating plants to take advantage of a minimal material handling cost. Locations should be nearer the oil shale site because of the 2.6:1 ratio of oil shale to coal for optimum SO_X reductions. Fluidized bed combustors are the most economical option for any new generating capacity.

The New Brunswick Electric Power Commission, with funding from the Federal Department of Energy, Mines and Resources, is currently in the early stages of a project aimed at application of the RPC co-combustion research to a pilot plant study at the Chatham, New Brunswick thermal electric power station. Although Chatham is located at quite a distance (175 km) north of Albert Mines, the study site is appropriate because of the available generating facilities.

Carboniferous: Big Marsh (Antigonish) deposit, Nova Scotia

Oil shales of the Big Marsh area, approximately 11 km north of Antigonish, Nova Scotia (Fig. 3, no. 4), have been of interest because of their almost certain stratigraphic equivalence to the Albert Formation oil shales of New Brunswick (Macauley and Ball, 1984). The surface distribution of the beds near Big Marsh settlement (Fig. 39) was mapped by Mazerolle and MacGillivary (1974). Based on the surface geology, nine coreholes were located and drilled (Fig. 39). Macauley and Ball (1984) presented the results of Rock-Eval analysis of samples from six of the cored locations. Tournaisian aged Big Marsh oil shales were deposited within a sequence of grey and red polymictic conglomerate, feldspathic sandstone and shale, with minor, thin, freshwater limestones in the sequence. Like the Albert oil shales, they are continental lacustrine deposits, but the "grey" zonation is not so applicable at Big Marsh as it is in the Moncton Sub-basin.

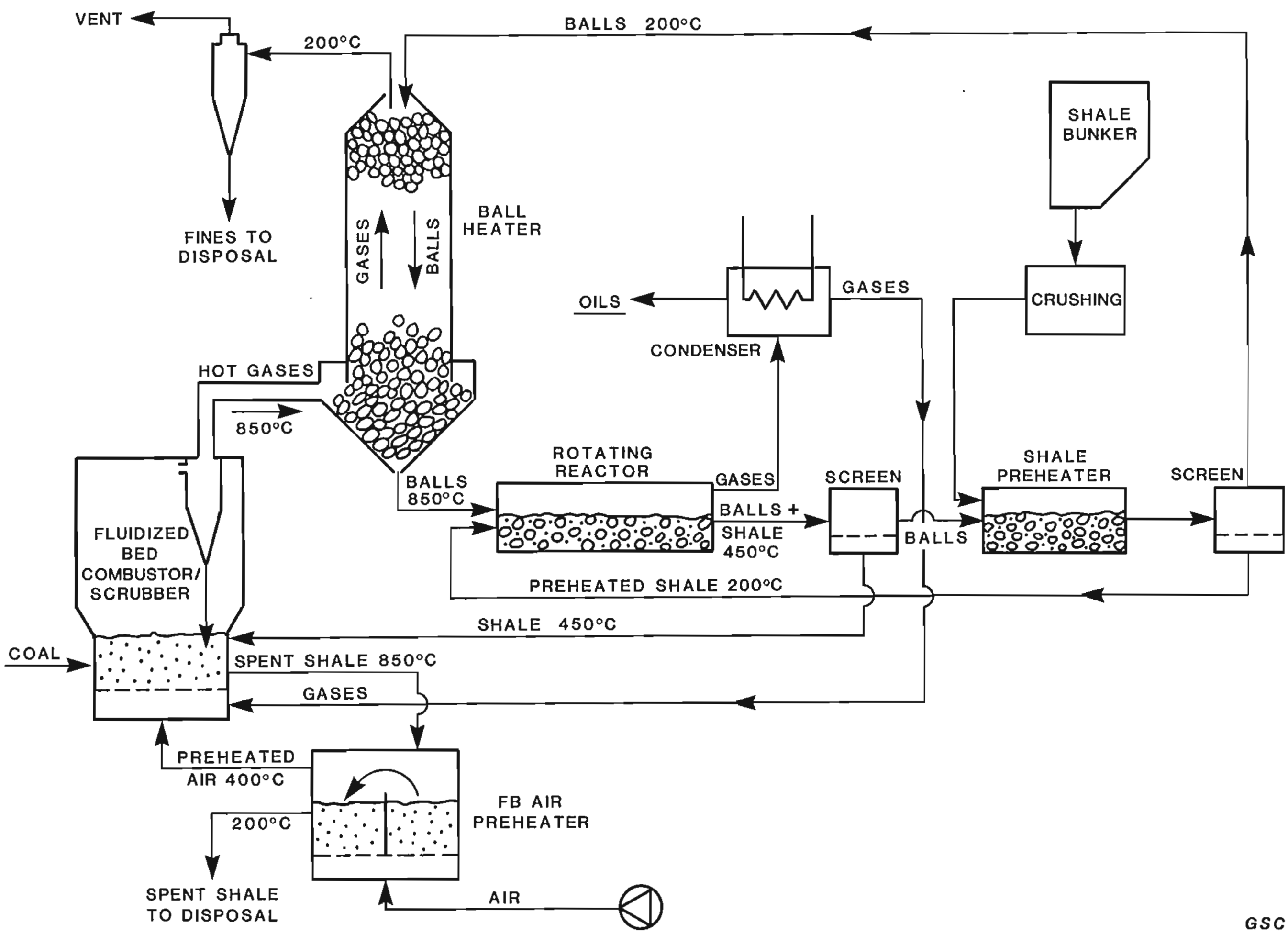


Figure 38. *Conceptual design for integrated fluidized-bed combustor and indirect shale retorting (from Salib and Boorman, 1983).*

Oil shale thickness almost doubles, from 67 m at the northernmost, no. 4 corehole, to 125 m at no. 9 corehole (figs. 39, 40). The efforts to directionally drill across the bedding were successful. With no apparent structural distortion, the penetrated sections represent true depositional thicknesses.

Lithology and mineralogy

Big Marsh oil shales are black, do not exhibit banding or lamination, and have poor to good fissility. The organic content is defined by a distinctive, brownish coloured streak, although the beds do not normally ignite or smoke in a flame. Fish and plant remains were noted as minor components. Of the two, plant remains are more common, varying from microscopic, carbonaceous debris to plant imprints, commonly pyritized. The oil shales grade upward and downward to nonorganic, grey to greenish and reddish shale and siltstone, sandstone and conglomerate.

Only a limited mineral assemblage is present. Quartz comprises approximately one half of the rock and is almost equalled in quantity by clay minerals, including kaolinite/chlorite, expandable/mixed layer clays, and illite. Of these, the kaolinite/chlorite is slightly more abundant than the others; kaolinite is interpreted to be much more prevalent than chlorite. Feldspar can be a significant component of shale but is here only a minor constituent, averaging less than 5 per cent, and commonly occurring as albite. Minor pyrite is ubiquitous.

Carbonates were not noted during sampling. The XRD results indicate that the average calcite content is less than 3 per cent, and that dolomite is essentially absent, but that siderite is present throughout in small but significant amounts. A second iron-bearing carbonate, ankerite, is sporadically encountered in minor amounts.

Organic geochemistry

A geochemical analysis for the area is provided by data from samples taken from the four coreholes (nos. 4, 5, 8, 9), which penetrate complete oil shale sections: Figure 40 illustrates the inter-relationship of the geochemical factors in these coreholes from south to north across the area.

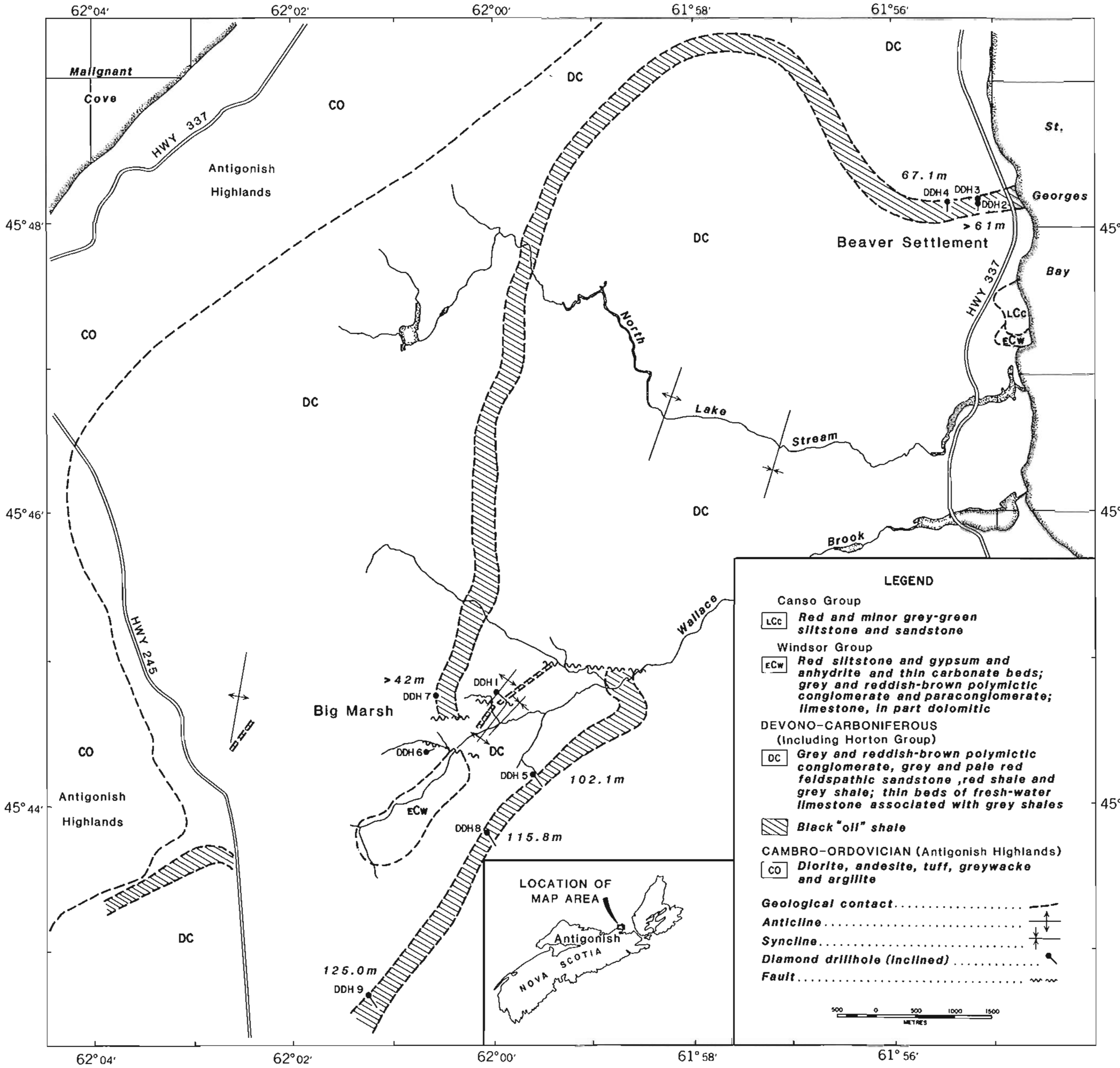


Figure 39. *Surface distribution of oil shale beds, Big Marsh (Antigonish) area, showing corehole locations and oil shale intersection thicknesses (after Mazerolle and MacGillivary, 1974).*

Total Organic Carbon (TOC): Total Organic Carbon decreases north to south, although the No. 8 hole deviates from this pattern. The range of average TOC content is small – 4.03 to 5.62 per cent – and the maximum average is somewhat lower than desired for a good oil shale deposit. Many individual values exceed 8 per cent, occasionally 10 per cent, but not over any significant thickness range.

Tmax: Tmax values (Fig. 40) all indicate low to marginal maturity. There is insufficient range to define any significant maturation change across the area, except that the southernmost beds are theoretically the least mature. This lower Tmax value could reflect difficulty in S2 peak definition, as S2 yields are low at the No. 9 location, and thus may not be a correct maturity indicator.

Hydrogen-Oxygen Indices (HI-OI): Hydrogen indices decrease uniformly southward (Fig. 40). Cross-plots of the Hydrogen and Oxygen indices (Fig. 41) can be variously interpreted. An increasing southward maturation of Type II marine deposits is possible, but this interpretation is rejected because of the continental environment of the deposits, and the known presence of Type III humic debris. Thus, these cross-plots are considered to represent an admixture of Type I and Type III kerogens, with the relative amount of Type III kerogen increasing southward. The abnormally high Oxygen indices reflect the humic kerogen. Because the oxygen has not been reduced relative to decreasing hydrogen values, a varying kerogen admixture is reflected rather than increasing maturity southward. A change to domination by Type III kerogen may be reflected in the lower Tmax value at No. 9 corehole.

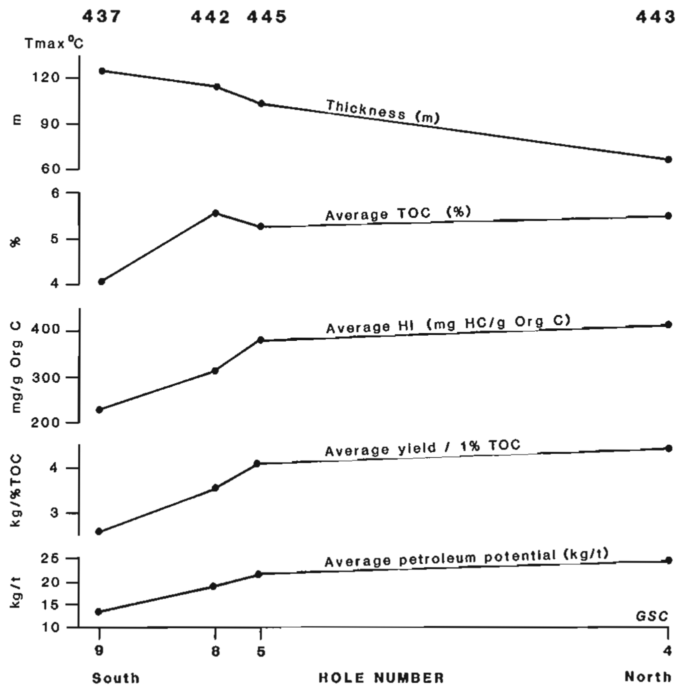


Figure 40. *Comparisons of pertinent oil shale data, Big Marsh area (from Macauley and Ball, 1984).*

Production Index (PI): Production indices are 0.02 to 0.03 except at the southernmost, No. 9 location, where the PI is 0.13. Maturity levels may actually be greater than the marginal maturity indicated, because, during production, the humic component would generate gas rather than petroleum product. Contrary to the other geochemical data, a possible southward increase of maturation level is suggested.

Kerogen-pyrolyzate-oil characteristics

Ells (1909) reported seven analyses from the Big Marsh oil shales, with specific gravities ranging from 0.890 to 0.917, and an average value of 0.903. These are generally within the same range observed for the New Brunswick, Albert Mines shale oils.

Preliminary, detailed, chemical studies (Altebaeumer, in prep.) on both the Big Marsh and Stellarton area (discussed below) oil shales indicate a large contribution of Type I kerogen that is genetically similar to that of the Albert Mines Formation. The range of organic matter type and thermal maturity may be considerably wider in this area, reflecting the contribution of significant amounts of higher land plant debris to some of the samples.

Classification and maturation

Big Marsh oil shales are continental, admixed, Type I and III deposits. Although the environment appears to be lacustrine, it is not known, without organic petrology studies, whether the Type I component is lamalginite or telalginite. The sediments could be poorly developed humic torbanite indicating a bog environment, although the thickness is much greater than would be anticipated for torbanite. Because of the high mineral content, these strata cannot be placed in the coal series, but must be classed as a humic or carbonaceous oil shale deposit.

The maturation level is low to possibly marginally mature, and appears to be fairly uniform across the deposit. Although the north-south change of indicators may in part reflect some southward maturation increase, this change is considered more likely to result from an increasing ratio of humic to sapropelic kerogen in that direction.

Economic potential

The yield per 1 per cent organic carbon decreases uniformly southward (Fig. 40) across the four coreholes (Fig. 42). The decreasing yield, from a maximum of 4.47 kg/t1%TOC to a minimum of 2.58 kg/t/%TOC, is considered to reflect the decreasing relative quantity of sapropelic Type I kerogen, although the effect of some increased maturation may be present.

Hydrocarbon yields at Big Marsh decrease from north to south from a best average of 24.56 kg/t (6.54 US gals/ton) in the north (BM no. 4) to 12.73 kg/t, in the south. This is mostly a reflection of the diminishing yields per % TOC, but a decreasing TOC content may exert a minor influence.

There is little potential for commercial development of the Big Marsh oil shales under present economic conditions and known mining and retorting procedures. The even distribution of the kerogen throughout the unit, without apparent, continuous, thicker zones of high yields, is discouraging. Mazerolle and MacGillivary (1974) mapped a more northerly extension of possible oil shale outcrop (Fig. 39) that has not been drilled. They projected this extension largely on the distribution of oil shale float, which Macauley and Ball (1984) agreed was an excellent indicator for near-exposures of these beds. Because of the increasing quality of the deposit northward, this area warrants further investigation.

Carboniferous: Pictou (Stellarton) deposits, Nova Scotia

Pennsylvanian age oil shales of the Pictou Group (Fig. 3, no. 6) occur in the Pictou coalfield area in the vicinity of the towns of New Glasgow and Stellarton (Fig. 43). The coalfield occupies a fault bounded graben structure running approximately 17.7 km on an east-west axis and 4.8 km north-south.

Oil shales are encountered throughout the upper, Division II, coal-bearing sequence of the Pictou Group (Fig. 44). During coreholing to evaluate the coal deposits, many of the oil shale beds were penetrated. Macauley and Ball (1984) presented the geochemical results from Rock-Eval analysis of samples from these cores and also from outcrop areas.

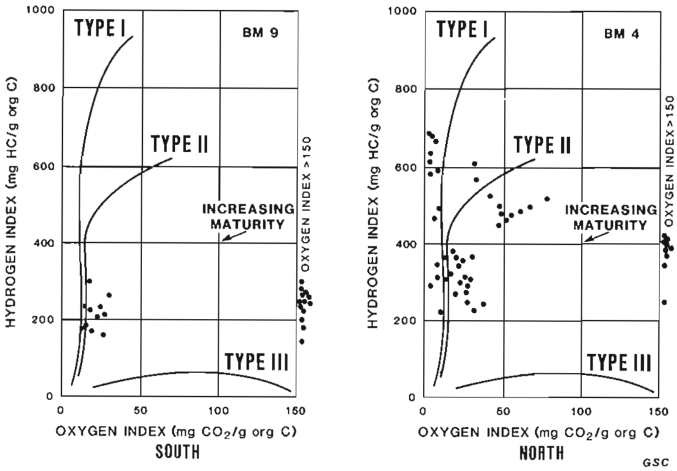


Figure 41. *Plots of Hydrogen versus Oxygen indices, Big Marsh area (from Macauley and Ball, 1984).*

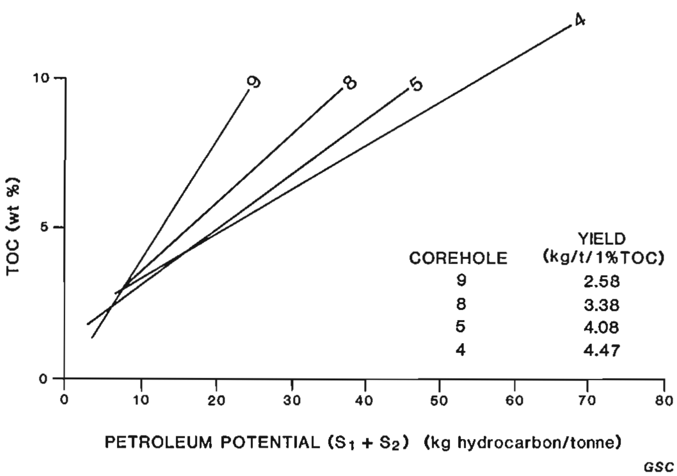


Figure 42. *Average yield/% TOC lines for Big Marsh coreholes (from Macauley and Ball, 1984).*

In the past, three types of deposit have been described for this area: low-yield oil shales, higher yield torbanite, and highest yield stellarite. Stellarite burns with "stars of fire", and is uniquely present as the lower half of the approximately 3 m thick Oil-Coal Seam, in which the stellarite is abruptly overlain by coal. The Oil-Coal Seam occurs near the base of the major sequence of coal-bearing strata (figs. 43, 44).

Lithology and mineralogy

The lower yield oil shale beds are black, massive to poorly laminated, sub-fissile, and are differentiated from enclosing, similar, nonorganic black shales, by having a brown as opposed to a grey streak. The sub-fissility produces a horizontal semi-cleavage on breaking. The torbanites are lithologically similar to the oil shales, but are much more massive, show little lamination or fissility, are lighter in weight, and break with a conchoidal fracture.

Beds of the Oil-Coal Seam are distinct from the lower yield oil shale beds and the torbanites. Dark grey, inorganic shale grades downward into black shale, black coaly shale, and then coal. The coal sharply overlies laminated, black oil shale (stellarite) that grades downward into contorted, slickensided oil shale, and then to black, contorted, friable, organic shale. Medium grey, inorganic shale underlies this kerogen-bearing interval. The oil shale (stellarite) is black with a distinctive brown streak; the coal and coaly zones are black with a grey streak. The presence of brittle, humic kerogen also readily defines the coaly intervals. The total unit averages about 3 m (10 ft) in thickness. In contrast to the other oil shales of the area and the torbanites, the stellarite is distinctively laminated, may be contorted and can be ignited.

Mineral composition defines all three types of deposits (lower yield oil shales, torbanites, and stellarite) as shales. Quartz comprises approximately half of the inorganic mineral component, with clay minerals representing most of the other half. Expandable and mixed layer clays, kaolinite-chlorite (dominantly kaolinite), and illite are clay groups that vary somewhat in their relative proportions, but do not distinctly define any specific oil shale type. The stellarite beds contain a somewhat higher proportion of kaolinite-chlorite than do the oil shales, and kaolinite-chlorite is the least represented clay group of the torbanites. Feldspars are present in small amounts in the oil shales and torbanites (2 to 5%), but are less common (about 1%) in the stellarite. Carbonates are rare, especially calcite and dolomite, but siderite ($FeCO_3$) is commonly present in a range of approximately 2 to 5 per cent, in the three oil shale types. Minor pyrite is common.

Organic geochemistry

Although How (1868) recognized coal-stellarite-oil shale lithologies on the basis of organic ash content, few further attempts have been made to differentiate the types and interpret their origins. Attempts to evaluate suspected torbanite beds have often resulted in recoveries much lower than those anticipated from the sample appearance.

Total Organic Carbon (TOC): within oil shales of the Coal Brook Member (Fig. 44), sampled in coreholes P-26 and P-29 (Fig. 43), TOC averages 6 to 7 per cent, and seldom exceeds 10 per cent, although local values may reach 20 per cent. In contrast, the torbanite beds at Shaw Pit (Fig. 43) average almost 28 per cent TOC, in contrast to the value of 6.7 per cent for the oil shale beds at that exposure. At McLellan Brook (Fig. 43), beds of mapped oil shale and torbanite were both sampled, but could not be differentiated from each other on the basis of TOC content, which ranged from 10 to 12 per cent.

At four coreholes penetrating the Oil-Coal Seam (Fig. 43: P-23, P-20, P-25, P-55), beds can be differentiated into coal, coaly shale and stellarite on the basis of lithology, TOC content, and Rock-Eval data. Coal beds generally exceed 50 per cent TOC, but coaly shales, and black shales defined as coaly, range from a minimal value to 20 per cent or better TOC. For the stellarite, average TOC values range from 7 to 18 per cent across the four locations, and encompass a wide range of specific values from 3 per cent to greater than 23 per cent.

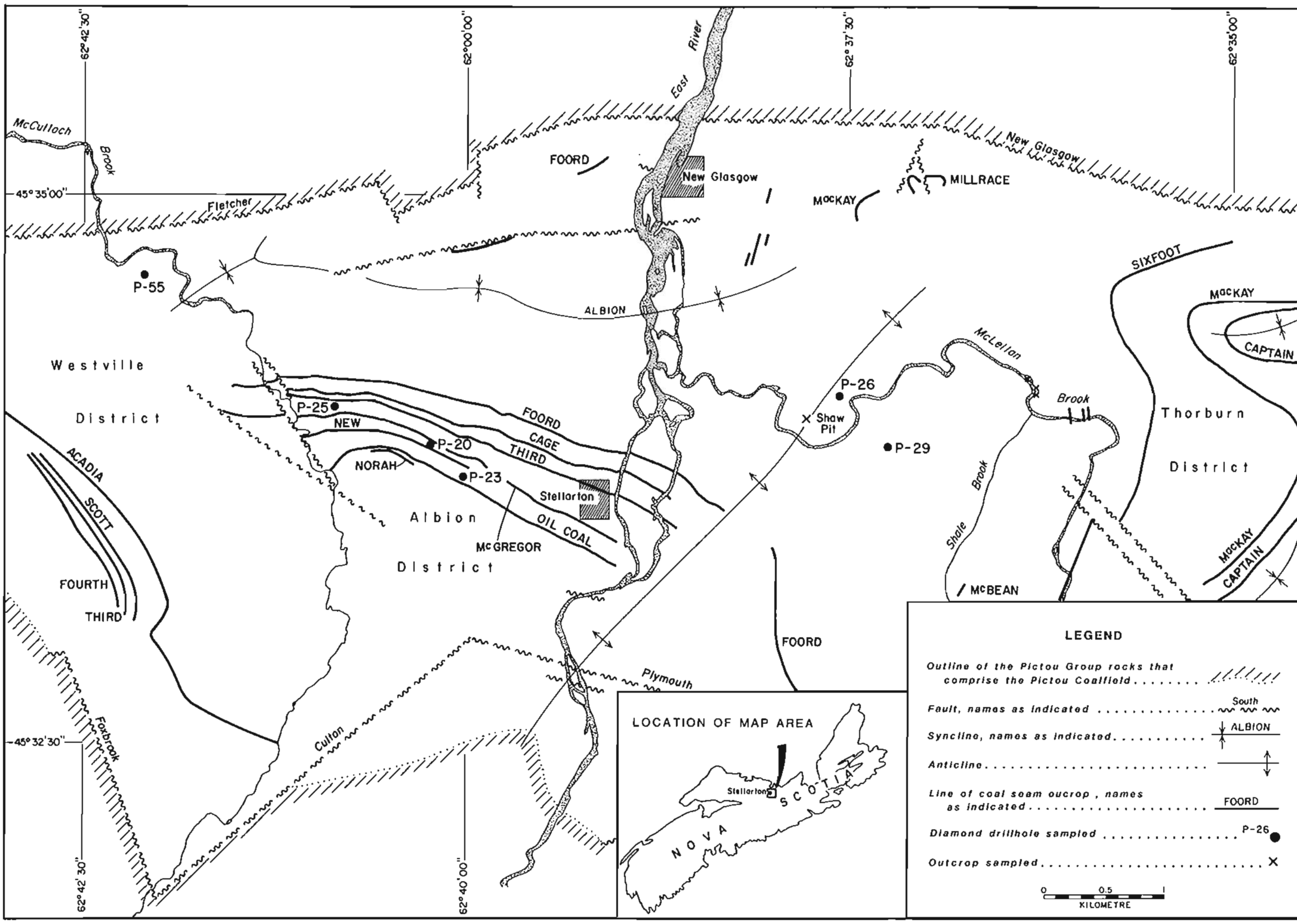


Figure 43. Surface distribution of coal seams in the Pictou coalfield, with pertinent corehole and surface outcrop locations (after Bell, 1940).

Although the oil shale beds do exhibit generally lower values, the overlap of the ranges encountered is such that TOC cannot by itself be used to differentiate oil shale, torbanite and stellarite.

Tmax: stellarite beds have the highest average Tmax values (about 450°C,) followed by most of the oil shales, the torbanites, and the coal beds (near 447°C). The youngest oil shales, at McLellan Brook and above the torbanites at Shaw Pit, have Tmax averages near 440°C. From these values, most beds may be classified as being in the moderate thermal maturity range within the oil generation window. Tmax values for the coal in the Oil-Coal Seam may be as much as 10°C lower than those of the stellarite.

Hydrogen-Oxygen Indices (HI-OI): the presence of humic kerogen is known from the existence of coal beds, as well as by minor, carbonaceous debris and scattered plant remains visible through microscope examination of the cores. From the Hydrogen-Oxygen indices of the stellarite (Fig. 45c) Type I kerogen may be assumed to be definitely present. Because of the known presence of Type I and Type III kerogens, both continental in origin, and the continental depositional environment of the entire sequence, the existence of marine, Type II kerogen is not anticipated.

Almost all the oil shale samples and the torbanites fall within a limited area on the HI-OI plots (Fig. 45a, b). Kerogen of the oil shale - torbanite lithotypes is considered to be a composite of Type I and Type III kerogens. If this is so, the relative concentrations of kerogen types is similar for both rock types. There also may be some distortion of kerogen type on the HI-OI diagram because of thermal maturation.

The hydrogen-oxygen relationships indicate that the oil shales and the torbanites are organically identical except for the amount of kerogen present. HI values for the oil shales and the torbanites fall in the range of 260 to 370 mgHC/g org. C; those for the stellarite are from 360 to 730 mgHC/g org. C; coal HI values range from 100 to 167 mgHC/g org. C. These HI values distinctly define the stellarite, oil shale-torbanite and coal rock types. The high stellarite HI values (Fig. 45c) represent low thermal maturity, less than that indicated by the 450°C Tmax average. Lower Hydrogen indices for the other two organic rock types are probably more indicative of a change in the type of organic content rather than increasing thermal maturation.

Production Index (PI): the concept of oil generation at moderate thermal maturity is not confirmed by the Production indices (PI), as there is virtually no free

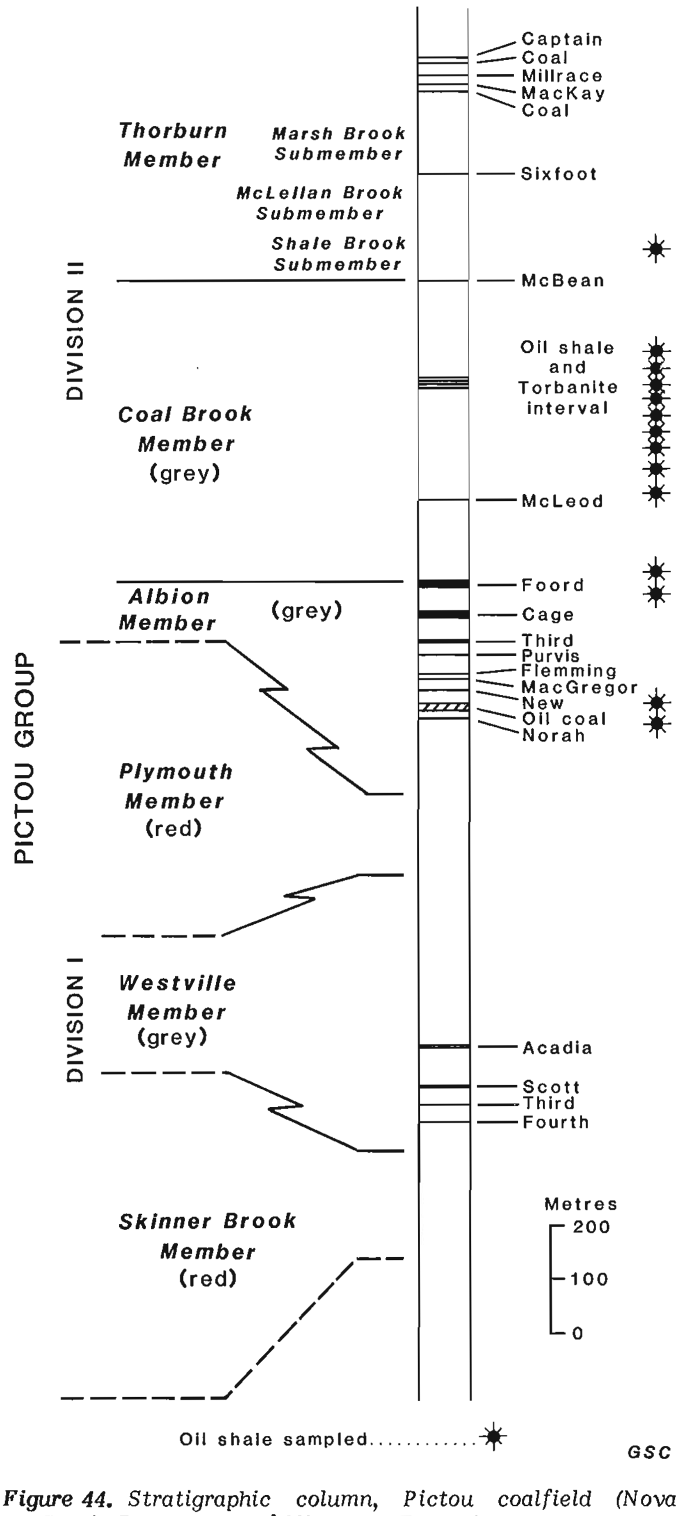


Figure 44. *Stratigraphic column, Pictou coalfield (Nova Scotia Department of Mines and Energy).*

hydrocarbon content in any of the sampled sections. PI values average near 0.10 for the oil shales, 0.07 for the torbanites, 0.07 for coal beds, and a minimum 0.02 for the stellarites – all indicative of only marginal maturity. The Type III kerogen content of the oil shale-torbanite beds would contribute little free hydrocarbon to the S1 peak; consequently, PI values may be disproportionately low because they are calculated against all organic carbon, not just that of the Type I kerogen. The low S1 peak and hence low PI of the Type I stellarite beds is inconsistent with the observed Tmax of about 450°C, but this is thought to be due to the insensitivity of Tmax for this type of kerogen (Espitalié et al., 1984).

Organic petrology

Coal rank data (vitrinite reflectance measurement) have been reported by Hacquebard (1978) and indicate that the coals of the Pictou coalfield are high volatile A bituminous at the surface in the Albion District (Fig. 42).

Samples of the coal associated with the stellarite of the Oil-Coal Seam were taken from the four coreholes of this study in the Albion District and were analyzed by Kalkreuth at ISPG. The reflectance data for the coal range from 0.85 to 0.96 per cent Rmax, indicating high volatile A bituminous rank at all four locations.

The reflectance values obtained from vitrinite particles within the associated stellarite are considerably lower (ranging from 0.38 to 0.41 per cent Rmax) than those of the overlying coal. This is a reduction of approximately 50 per cent, similar to the decrease of vitrinite reflectance in the Albert oil shales of New Brunswick, which was attributed to bitumen impregnation of the vitrinite particles (Kalkreuth and Macauley, 1984).

From his studies using transmitted light microscopy, Flynn (1926) described the stellarites as being composed of large yellow bodies, with outwardly radiating cells, in a black matrix. In contrast, the torbanites contain orange-red particles, the remains of laminated vegetable humus. According to Flynn, the stellarites can be identified by crushing a sample on a glass with a knife blade; the kerogen particles are discernible as amber colored beads, having the wrinkled surface of a walnut shell.

Preliminary results of fluorescence microscopy by Kalkreuth at ISPG indicate that the organic material of the stellarite consists primarily of the remains of a *Botryococcus*-type algae, typical of Type I torbanite deposits. The described torbanites and oil shales also contain significant amounts of *Botryococcus*-type telalginite (alginite A) as well as vitrinite, fusinite, inertinite and possible sclerotinite. Although coal macerals are common, mineral content is much too high for these to be placed in a coal series. Petrologically, the stellarite is an almost pure torbanite. The other low grade (oil shale) and high grade (torbanite) occurrences are similar. They are impure torbanites, either humic or carbonaceous. Occasional telalginite bodies can be discerned in the coal beds of the Oil-Coal Seam. The term "stellarite" is useful in defining the pure torbanites of this sequence.

Kerogen-pyrolyzate-oil characteristics

Flynn (1926) noted the specific gravity of the stellarite oil to be 0.86; at 0.91, that of the torbanite is slightly higher. Stellarite yielded 22 to 26 cu. ft. gas/bbl., whereas the impure torbanites, with a significant humic content, produced 56 to 59 cu. ft. gas/bbl. of shale oil, during Flynn's investigations. All oils were paraffinic. As noted above,

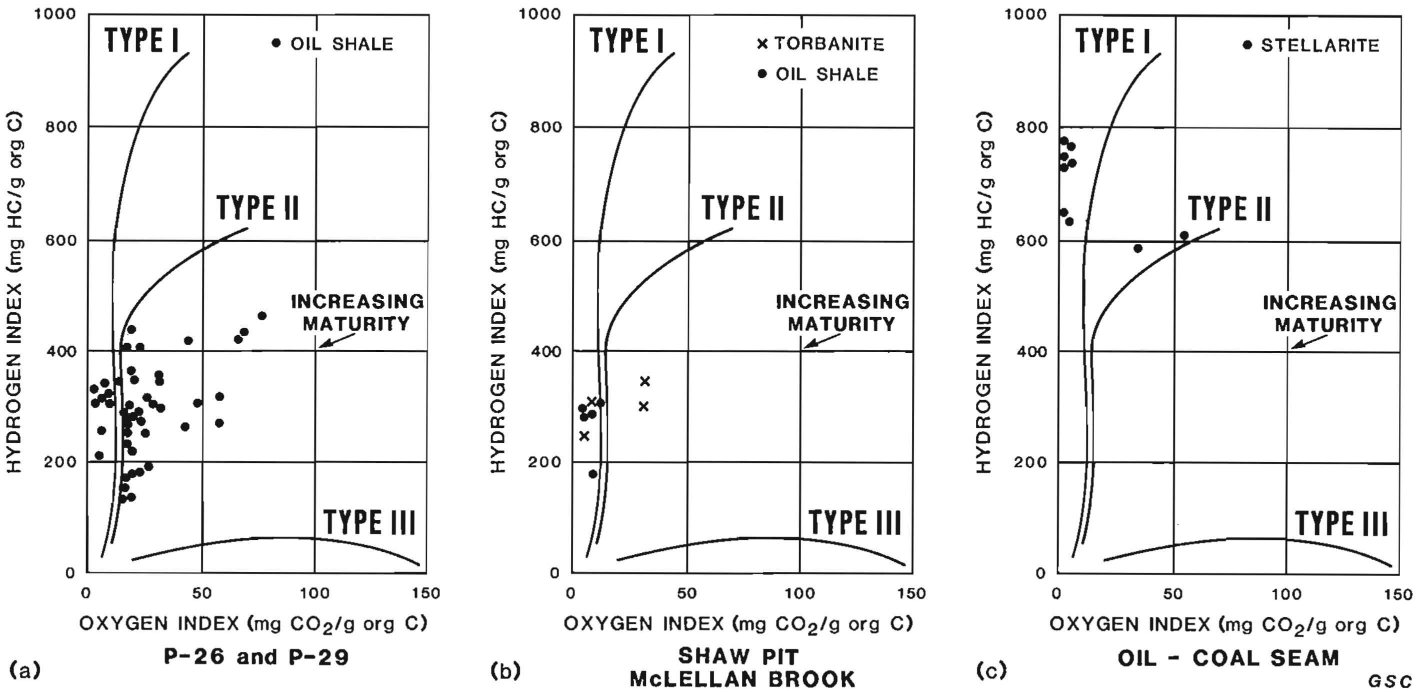


Figure 45. *Plots of Hydrogen versus Oxygen indices for three grades of torbanite: (a) low yield oil shale, (b) better yield torbanite and oil shale, (c) high yield stellarite bed of the Oil-Coal Seam (from Macauley and Ball, 1984).*

Altebaeumer (in prep.) observed that paraffinic yields from pyrolysis gas chromatography of the samples are dominated by Type I kerogen.

Classification and maturation

All oil shale deposits within the Pictou Group are classifiable as Type I torbanites – bog deposits – of which the stellarite represents essentially pure torbanite, composed predominantly of *Botryococcus*-type telalginite algal remains. The other oil shales are impure, carbonaceous or humic torbanites, comprising an admixture of telalginite and coal macerals. The lithologically differentiated oil shales and torbanites are geochemically and petrologically identical. Although kerogen content varies with the apparent lithologic variations, there is no distinct cut-off level at which to separate the two previously described oil shale types.

Tmax values indicate some degree of thermal maturation into the oil generation window, a concept confirmed by the coal grades and by the orange-red colour of the humic component in this section. The yellow colour of the stellarite algal component suggests minimal thermal alteration.

The oil generation window, 435-465°C for Rock-Eval pyrolysis investigations, is a concept which is now being defined in greater detail (Snowdon, 1984). All kerogens do not mature equally at identical temperatures. Mineral matrix differences may alter maturation rates for similar kerogens, and variable kerogen admixtures may affect maturation levels for specific components.

Thermal maturation may have been limited to the Type III kerogen content of these torbanites, producing gas rather than oil. This would explain the minimal S1 component and consequent low PI ratios. Even though Tmax approximates 450°C in the stellarite, there may not have been significant oil generation from this unit. In contrast, the excellent specific gravity (0.86) of stellarite oil is probably indicative of some maturation.

Economic potential

Even though the lower grade torbanites attain considerable thicknesses, as much as 13 m, and up to 50 m (Potter, 1975), where intervening, poorly organic, black shales are included, these zones are not presently of economic interest because of low organic content (7% or less) and an average yield of 3.5 kg/t/%Corg (Fig. 46). Except for the few occurrences of higher grade torbanite, and the stellarite of the Oil-Coal Seam, both kerogen type and content throughout the remaining oil shale sections are discouraging because of uniform low-yield characteristics.

At Shaw Pit, the higher-yield torbanites represent only approximately half of a total three metre thick oil shale interval. Although the TOC of these torbanites is high, and hydrocarbon yields can approach 100 kilograms/tonne (116 litres/tonne, 28 US gals/ton), a large area would be required to provide the necessary rock volume for shale oil production. In the P-26 corehole, only 250 m from Shaw Pit, the torbanite beds are barely discernible, or absent. In general, as the kerogen content of the torbanite beds increases, the zone thickness and areal extent appear to decrease. Wherever exploratory and development drilling for coalfields is continued, torbanite beds should be evaluated, in case thicker, geographically more extensive zones are present.

Stellarite beds vary considerably in kerogen quantity; the average organic carbon content increases from 7.5 per cent in the east to over 17.6 per cent at the westernmost of

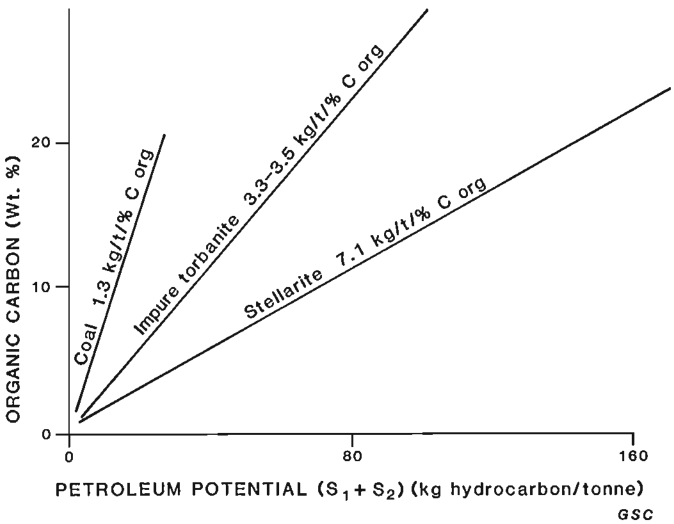


Figure 46. *Relative yield ratios of hydrocarbons/% Corg for Pictou oil shales and coal (from Macauley and Ball, 1984).*

the four coreholes. However, the recovery remains fairly constant, near 7 kg/t/% Corg (Fig. 46), approximately 8.1 litres/tonne/%Corg.

Although How (1868) reported stellarite yields in the range of 53 to 129 Imp. gallons/ton (approximately 230 to 580 kg/t), these high yields were seldom repeated. In most subsequent investigations, recoveries ranged from 4 to 50 Imp. gallons/ton (18 to 220 kg/t). In his specific studies of the retorting properties of stellarite and torbanite, Flynn (1926) reported stellarite recoveries covering this entire yield spectrum. The variable kerogen content (TOC) explains this wide range of hydrocarbon potential.

Macauley (1984a, p. 100) inferred that the stellarite and coal together could be a hindrance, as the stellarite contained too much ash to be used as a coal resource. Macauley and Ball (1984) indicated that the hydrocarbon yield from the coal beds may be sufficient for the entire Oil-Coal Seam to be retorted for liquid hydrocarbons and gas, and the residue burned for generation of electrical energy. At 0.35% (Flynn, 1926), the sulphur content of the stellarite is low and the oil quality is good (0.86 sp. gr.): the equivalent characteristics of the coal need to be defined so that its potential contribution to a retorting process may be evaluated.

Exploitation

Although no recent exploitation studies have been reported for the Pictou stellarite-torbanite oil shales, Flynn (1926) outlined the results of retorting research at the Nova Scotia Technical College, Halifax. Although the retorting apparatus was made in-house, and may not be directly comparable to present bench equipment, the comparative aspects of the results are still valid. Two significant differences in the retorting characteristics of stellarite and torbanite were recognized. Gas generation occurs continuously beyond the oil generation phase for the torbanite (Fig. 47a), but is coincident with the oil for the stellarite (Fig. 47b). This must reflect the Type III humic component of the torbanite that is absent from the stellarite. Although the clay contents are not appreciably different, torbanites produce more water (Fig. 47a), a characteristic possibly related to the humic kerogen component.

The rate of heating during retorting had a considerable effect on the product recovery, as is indicated for a stellarite example (Fig. 48). Actual oil yield decreased, specific gravity of the oil decreased (i.e. better quality oil was recovered) and gas yield increased as retorting time was increased over the 600-900°F (315-482°C) oil generation temperature range. Flynn recognized that the relative economics of the retorting and refining processes would ultimately control whether the most efficient process would be fast (yielding lower quality oil) or slow (yielding higher quality oil).

Carboniferous: Deer Lake region, Newfoundland

Oil shales in the Deer Lake region of western Newfoundland (Fig. 3, no. 5) are contained in the Viséan (early Mississippian), Rocky Brook Formation of the Deer Lake Group, and were deposited as lacustrine beds between fluvial deposits of the overlying Humber Falls and underlying North Brook formations. Hyde (1984) summarized the stratigraphy and structural geology of the area.

Two sections of oil shale exposures are present in the Deer Lake region: along the Humber River, and along Rocky Brook (Fig. 49) where they are brought to the surface in a synclincal feature. Better oil shales were once exposed at Grand Lake (Hatch, 1919), but these are now under water as a result of dam construction.

The oil shales occur as thin interbeds, generally 2 to 5 cm thick, within sequences of allochemical dolostones, stromatolitic carbonates, dolomitic siltstones and marlstones. In one of the better exposures along Rocky Brook, 1.6 m of oil shale are present within a 2.0 m thick stratigraphic interval.

Lithology and mineralogy

Kerogen occurs intimately intermixed in fine grained dolostone. From X-ray diffraction, the clay component may be interpreted to be chlorite and smectite, possibly interstratified, with subordinate illite. Illite can become dominant in nonorganic shales. Quartz, feldspar and analcime are also present, indicating a mineral assemblage similar to that of the New Brunswick, Albert oil shales. Lithologically, the Deer Lake oil shales are dolostones or dolomite marlstones.

Organic geochemisty

Sixteen samples from surface exposures were analyzed at I.S.P.G., Calgary, and the results were reported in Hyde (1984).

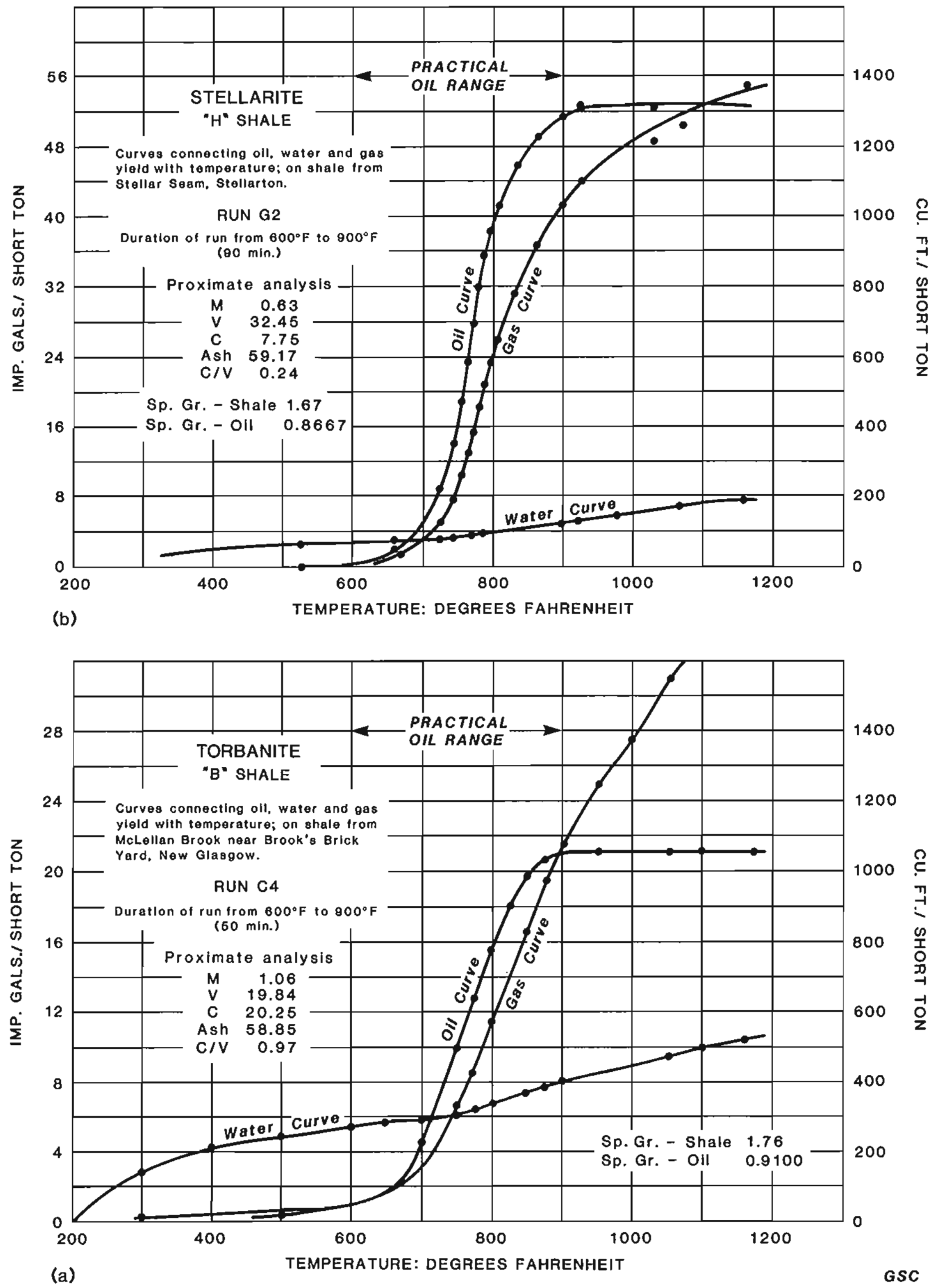


Figure 47. *Relationship of gas-oil-water yields on retorting of (a) stellarite, and (b) torbanite (from Flynn, 1926).*

Total Organic Carbon (TOC): Total Organic Carbon averages 7.5 per cent for the sixteen samples, ranging from 2.77 to 15.93 per cent, with two samples having greater than 14 per cent TOC content. Sufficient kerogen is present for these beds to be of economic interest.

Tmax: Tmax averages 444°C, within a range of 438° to 451°C, placing these oil shales on the border between low and moderate maturity.

Hydrogen-Oxygen Indices (HI-OI): HI values average 625, including several low values which may result from humic beds or samples impregnated by bitumen. Coupled with low Oxygen indices (Fig. 50), the Hydrogen indices indicate that the deposit contains immature Type I kerogen.

Production Index (PI): Production Index values associated with the higher HI values are generally 0.01 to 0.03, indicating virtual immaturity, as almost no volatile hydrocarbon is present. Within the lower HI range (<400 for four samples), PI values are as high as 0.10, indicating either hydrocarbon migration or maturation of humic content.

Organic petrology

Hyde (1984) indicated that the kerogen is orange-brown and amorphous in transmitted light. A few dolomite grains appear to have a replacement form of *Botryococcus*-type telalginite.

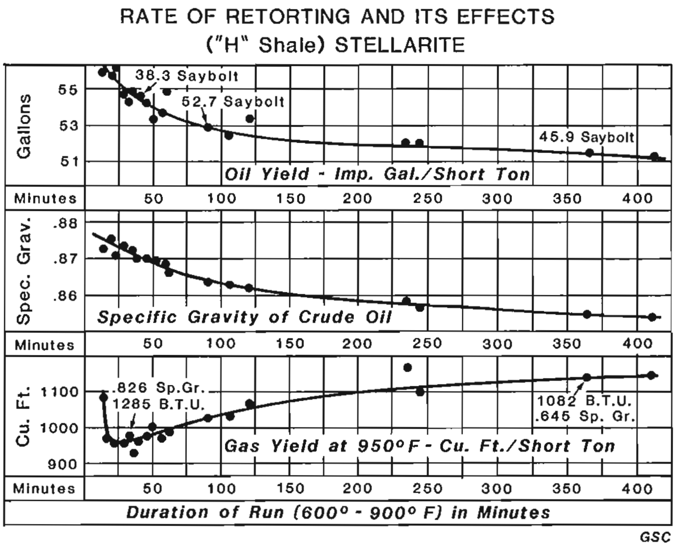


Figure 48. *Affect of retorting rate on yields of oil and gas and on quality of oil from stellarite (from Flynn, 1926).*

Vitrinite reflectance values range from 0.60 to 1.04 per cent, both in agreement with, and high, relative to the Tmax and HI values. The limited organic petrology data indicate a higher level of thermal maturation than is interpreted from the Rock-Eval data. Some humic content may explain these differences.

Classification and maturation

Deer Lake oil shales are primarily Type I lacustrine deposits, probably lamosites, but most likely dominated by lamalginite (alginite B) rather than telalginite (A). There may be interbeds of, or zones containing, Type III humic kerogen.

From a general average of oil indicators, the thermal maturation level is in the range of low to moderate, but can be interpreted as either immature or moderately mature.

Economic potential

Excluding the four abnormally low yields, an average 7.0 to 7.3 kg/t/%Corg can be expected (Fig. 51). No specific gravity data are available, but 0.91 is a realistic estimate for Type I kerogen at the low to moderate maturation level. This translates into a recovery level of 7.7 to 8.0 l/t/%Corg, only slightly lower than the excellent yields of the Albert Mines area.

Although some recovery grades are excellent, up to 155 litres/tonne, such grades are not sustained over sufficient thicknesses for mining to be contemplated. The quality is good, but quantity is still not adequate. Optimistically, there is a large, unexplored region on the western side of the Deer Lake Basin where Rocky Brook oil shales may be thicker. With simple stratal dips of less than 10°, the beds are close to the surface, overlain only by a thin cover of Pleistocene till.

Jurassic: Kunga Formation, Queen Charlotte Islands

On the Queen Charlotte Islands, off the west coast of mainland British Columbia (Fig. 3, no. 7), oil shales occur in the uppermost argillite member of the Kunga Formation (Sutherland-Brown, 1968), but organic carbon also is present in the overlying Maude Formation and in the underlying Kunga black limestones (Macauley, 1983). The best oil shales occur in the upper Kunga strata.

The best outcrops of Kunga strata occur along the western side of the Islands in the Queen Charlotte Ranges (Fig. 52). Investigations by Chamney (1977) indicate that strata of this area are entirely overmature and that the areas with the most potential lie south-centrally within the Skidegate Plateau (Yakoun Lake area) and at Kennecott Point, both on Graham Island. Most of the geochemical data of Macauley (1983) were obtained from outcrops and coreholes of the Yakoun Lake area, westward at the mouth of Rennell Sound, and south of Maude Island (Fig. 52).

Because of structural complexity, oil shale thicknesses are difficult to ascertain. In the southern islands, thicknesses of 500 m are probably attained (Sutherland-Brown, 1968), but Macauley (1983) estimated 100 m of oil-shale bearing strata in the upper Kunga Formation as a general maximum for sections on Graham Island.

Lithology and mineralogy

Upper Kunga strata comprise several distinct lithotypes, of which black, hard claystone to siltstone (argillite) is predominant in bands 1 to 10 cm thick. The rock is internally laminated but not fissile, and contains some organic carbon. Locally, these claystones and siltstones grade to limestone and silty limestone. Less common rock types include thin beds of light green claystone, greenish volcanic ash, and greenish, calcareous sandstones that rapidly decrease in grain size upward to claystones. Minor, dark brown to black, thin beds (1 cm or less) of organic-rich, laminated, fissile oil shale are also present. These oil shales comprise only a small part of the gross section.

Quartz and feldspar (mostly albite), are the dominant minerals of all upper Kunga rock types, except for increased calcite in the limestone intervals. Sandstone mineralogy is similar to that of the fine claystones, although the sandstones contain much larger rock fragments. All the detrital grains are of volcanic origin.

Both mixed-layer clays and undifferentiated chlorite-kaolinite are present, with the mixed-layer clays more common. Illite is virtually absent.

Carbonates, other than calcite, are not significant. Only scattered traces of dolomite and siderite were noted, as are possibly related trace occurrences of gypsum. Traces of several zeolites attest to the volcanic origin of the detritus in the Kunga and Maude intervals.

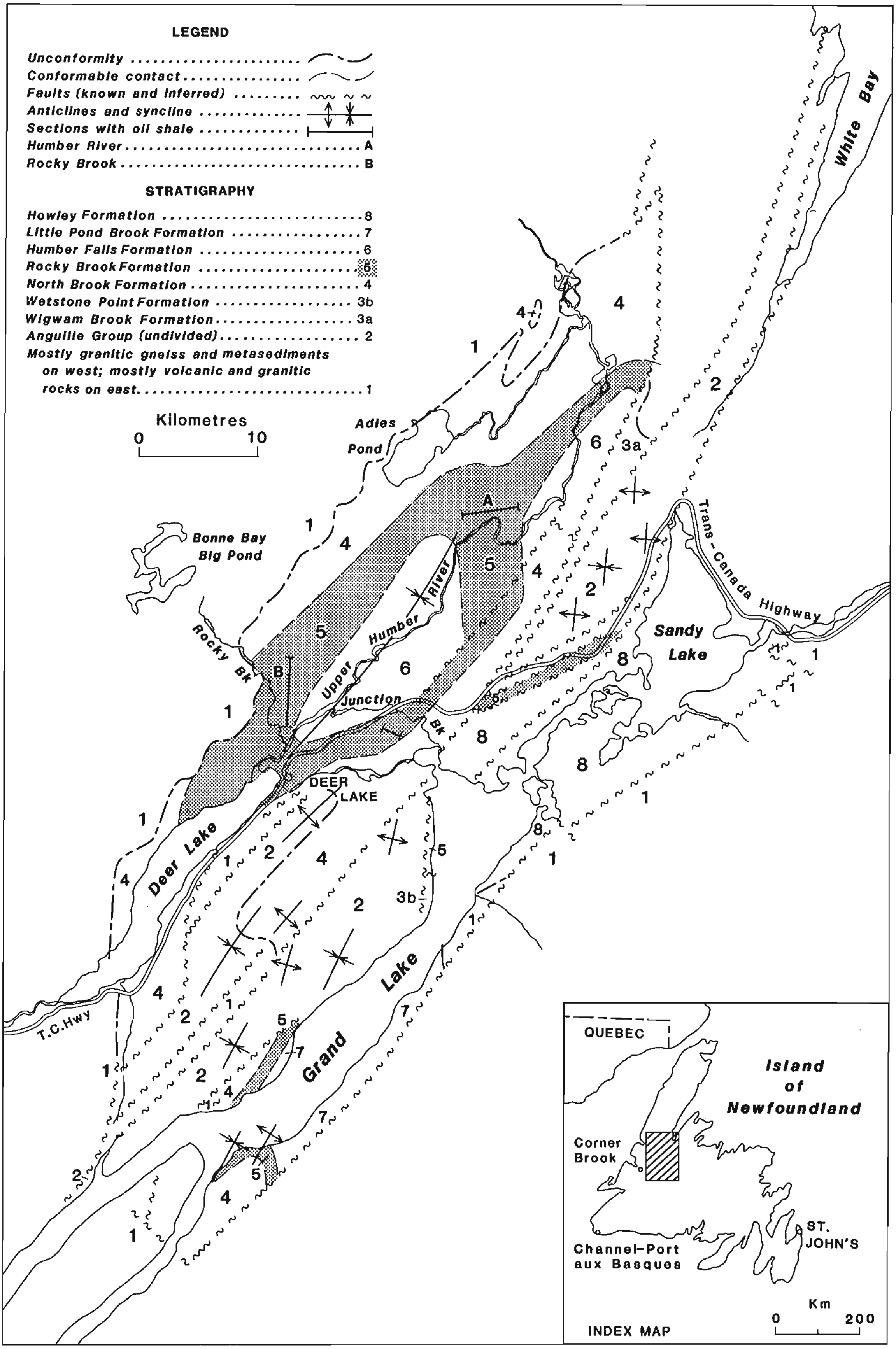


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Figure 49. *Simplified geologic map of Deer Lake Basin showing surface sections with oil shale (from Hyde, 1984).*

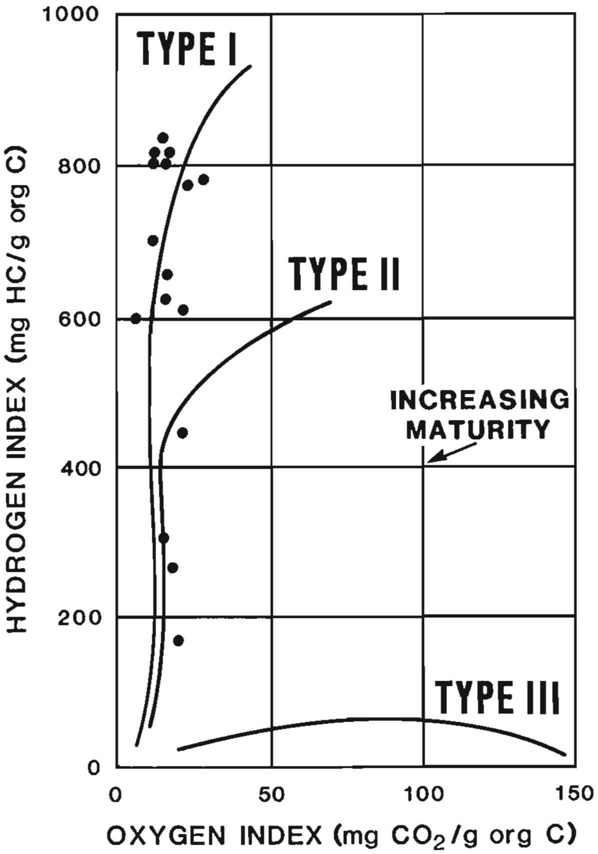


Figure 50. Plot of Hydrogen Index against Oxygen Index for Deer Lake oil shales (from Hyde, 1984).

Organic geochemistry

Although Macauley (1983) indicated that the Jurassic Kunga and Maude formations are more significant as oil source rocks than as oil shales, the geochemistry of these units is included herein because the results play an important role in the understanding of classification, maturation and economic potential of all the Canadian oil shale deposits discussed in this report.

Total Organic Carbon (TOC): throughout most of the sampled corehole and surface sections, the TOC content averages about 2 per cent, ranging to a maximum of 5 per cent. At one quarry, near Ghost Creek north of Yakoun Lake, approximately 55 m of exposed upper Kunga averaged 4.75 per cent TOC, with individual values as high as 8.7 per cent. Virtually all high-yield samples reported for Kunga beds appear to have come from this quarry.

Tmax: two distinct suites of Tmax values are recognized. At Maude Island and at Rennell Sound, Tmax averages range from 473° to 479°C for the various measured sections, all in the overmature range. In these sections, where yields of S2 were extremely low because of the overmaturity, many abnormally low and high Tmax values resulted.

For two coreholes and seven surface sections in the Yakoun Lake area, averaged Tmax values range from 446° to 455°C, all in the moderate to high maturity range.

Macauley (1983) reported an anomalous Tmax range at a third corehole, increasing downward from 445° to 470°C along a uniform gradient through a depth change of 230 m.

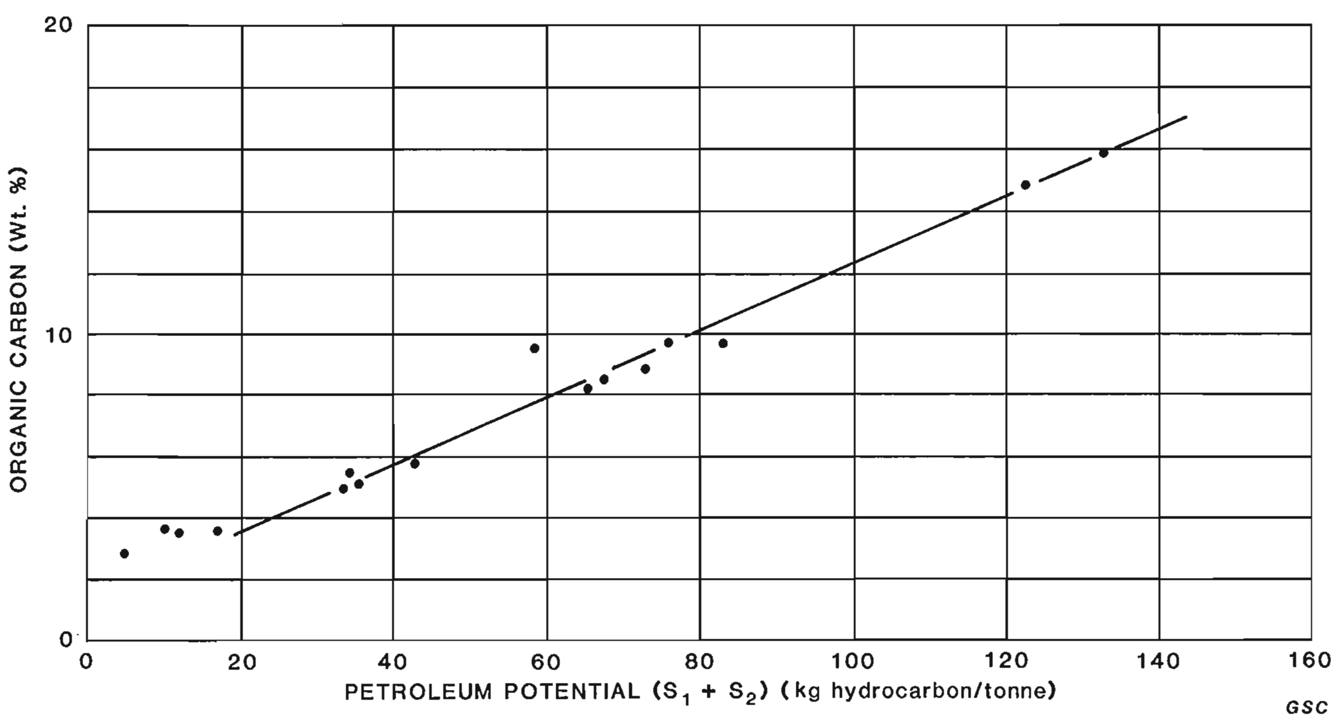


Figure 51. Petroleum potential (hydrocarbon yield) versus Total Organic Carbon, Deer Lake oil shales (from Hyde, 1984).

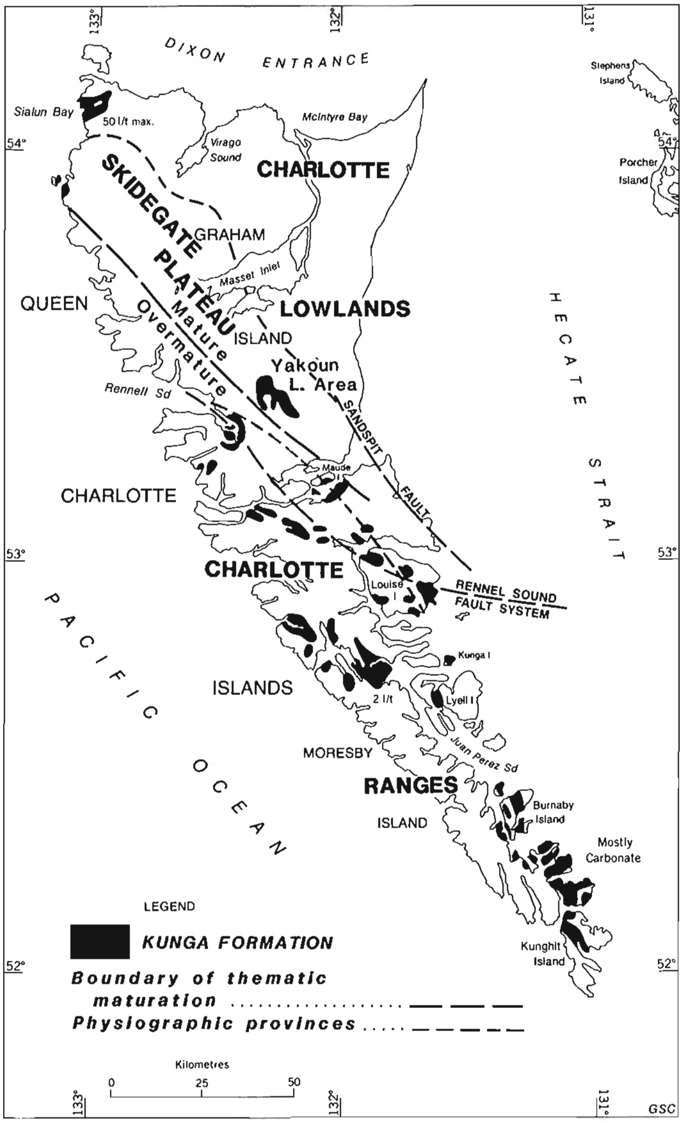


Figure 52. Outcrop distribution of Kunga Formation, Queen Charlotte Islands (after Sutherland-Brown, 1968).

This is an abnormally rapid rate of maturation with depth. Increased maturation levels also occur near the border of an igneous dike intersecting Kunga strata at another corehole; consequently, thermal alteration by igneous activity is a significant factor, probably more important than depth of burial, in this area.

The distance from the Yakoun Lake area to the Rennell Sound sections is only 10 km. The westward increase in thermal maturation is greater than can normally be attributed to depths of burial over this distance. The Queen Charlotte Ranges have an igneous core that accounts for the overmaturity of all the Kunga beds within the southwestern region of the Queen Charlotte Islands.

Hydrogen-Oxygen Indices (HI-OI): because of initial linearity problems in the Rock-Eval equipment (Snowdon, 1984), some of the yield data and Hydrogen indices reported by Macauley (1983) are incorrectly high. Data believed to be incorrect have been omitted for this review. Average Hydrogen indices for sections at Maude Island and Rennell Sound range from 5 to 53 (Fig. 53a), whereas those of the Yakoun Lake area vary from 207 to 385 (Fig. 53b), confirming the maturation levels of the Tmax values. Even with the reduced HI values, OI remains significant, probably representing some humic content in the kerogen.

Production Index (PI): Production indices do not indicate any pattern over the area, with averages ranging from 0.13 to 0.51, and individual values extending over a broad range for each section or corehole. Considerable migration of both volatile hydrocarbons and bitumens has occurred everywhere. In one corehole, a section overlain and underlain by zones of higher, irregular PI values is almost barren of volatiles (S1 peak). Macauley (1983) interpreted this to reflect complete migration of the light component from this part of the corehole.

Organic petrology

Organic petrology data are available only from an internal company report (Chamney, 1977).

Vitrinite reflectance values of 0.51 to 0.55 per cent were obtained from samples in the Yakoun Lake area, and a value of 0.25 per cent from a sample from Kennecott Point on northwestern Graham Island. These samples contain "alginite" and indicate a degree of maturity much lower than that anticipated from other geochemical data.

Samples were examined from two areas in the Queen Charlotte Ranges. Most of the vitrinite had values near 1.7, but other particles measured nearer 0.5 to 0.6 per cent. In Chamney's report, these were interpreted as reworked high reflectance vitrinite in low maturity samples. From other analytical evidence, the low reflectance particles are here considered to be bitumen saturated and anomalous in an overmature sediment.

At Sialun Bay, near Kennecott Point, upper Kunga beds are not exposed, but vitrinite reflectance of Kunga limestone is measured at 2.18 per cent, indicating a very overmature rock. The existance of the low, 0.25 per cent value at Kennecott Point must be doubted, although the Sialun Bay values do seem abnormally high.

Some kerogen of the Yakoun Lake area is reportedly yellow in transmitted light, indicating a thermal alteration index in the 1+ to 2- range. This suggests lower maturity than is indicated by other parameters.

Kerogen-pyrolyzate-oil characteristics

Although some variations occurred, a specific gravity of 0.920 was reported by Chamney (1977) for the aromatic-naphthenic oil of the Yakoun Lake and Kennecott Point areas.

The $C_{15}+$ hydrocarbon character indicates a mature geothermal state, equivalent to 2+ on the TAI scale. There is no odd carbon preference, and the normal paraffin components are skewed to the light end (Fig. 54). The hydrocarbon content of the extract is high compared to the total extract, indicating moderate to high maturity, or "staining". The kerogen related to this oil is described as amorphous. Most of the light hydrocarbon (C_1-C_7) is methane. The content of wet gas and gasoline components is low.

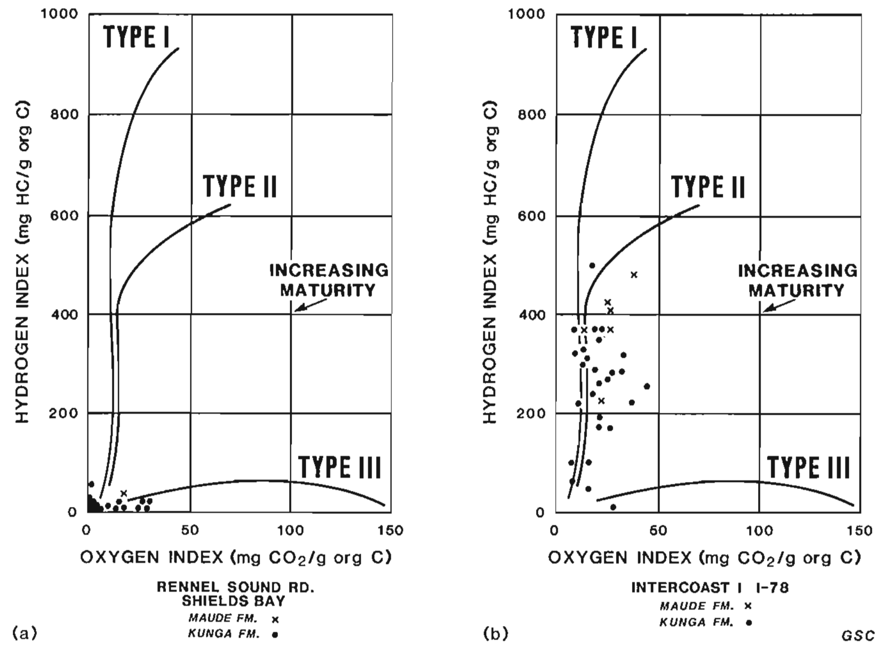


Figure 53. Typical Hydrogen versus Oxygen Index plots for (a) overmature, and (b) mature Kunga oil shales (from Macauley, 1983).

The specific gravity and character of the oil are indicative of a mature, mixed, Type II and III source.

Classification and maturation

Paleontological data define the Kunga Formation to be marine. Both amorphous sapropel and humic kerogen are definitely present in a basic marine, Type II, mixed oil shale deposit. Within the Queen Charlotte Range, the unit is overmature, but is variously of moderate to high maturity in the Yakoun Lake area and at Kennecott Point on the Skidegate Plateau (Fig. 52). Within the thermally mature area, local variations of maturity probably reflect igneous activity rather than differences in depth of burial. Almost all maturation effects, including the overmaturity along the backbone mountain range of the islands, can be easily attributed to heat effects from almost continuous intrusive and extrusive activity in the area.

Economic potential

Within the Yakoun Lake area, hydrocarbon yield/TOC ratios generally range from 4 to 7kg/tonne/%TOC (Fig. 55). However, the low carbon content restricts total petroleum potential to less than 30 kg/t (33 litres/tonne) at most locations. A sharp bend of the ratio line at 1 per cent Corg reflects either a degree of inert carbon (possibly related to the humic content), or a mineral-matrix effect. At the quarry near Ghost Creek, average TOC is higher (4.75 per cent) and yield ratios could approach 10 kg/t/% TOC, although this estimate is probably too high, as Rock-Eval linearity problems were not compensated for in that area. Maximum yield in the high kerogen beds (TOC near 8 per cent) may approach 80 kg/t (87 l/t, 21 U.S. gals/ton), but these beds are generally less than 1 cm thick, representing only a fraction of the total zone.

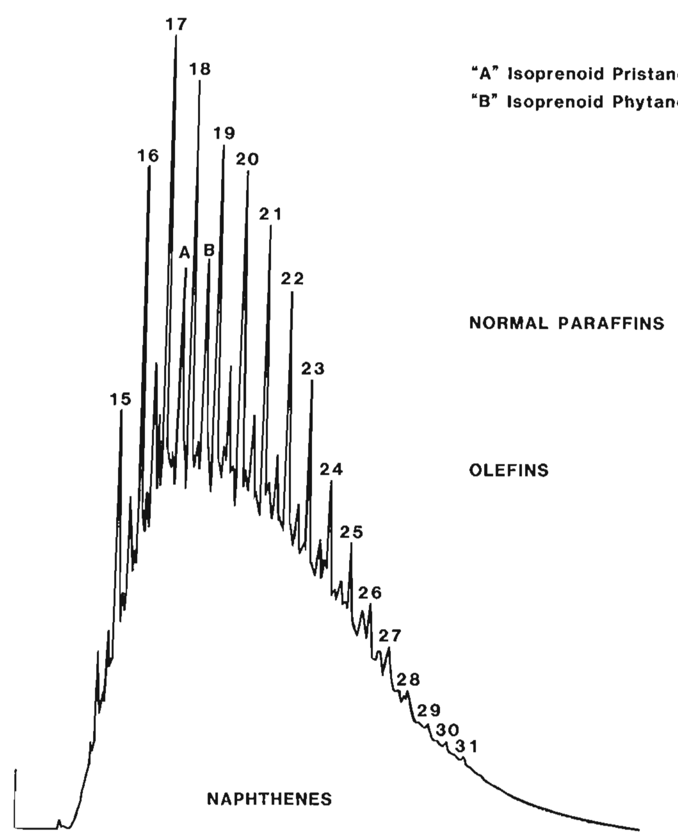


Figure 54. Typical gas chromatogram of saturate fraction, Kunga oil shale (from Chamney, 1977).

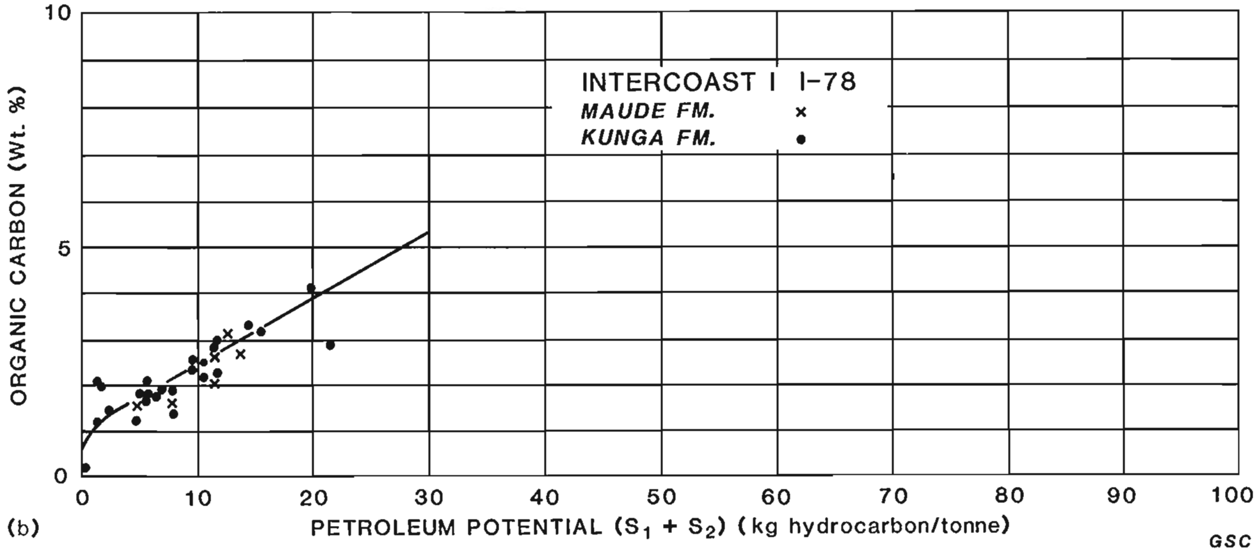


Figure 55. *Petroleum potential versus organic carbon content for oil shales of the Kunga and Maude formations, Queen Charlotte Islands (from Macauley, 1983).*

Because of the variation of maturation due to the irregularity of the igneous effects, local areas could be somewhat less mature, and one quarry is probably at the optimum maturation level for yield and oil quality (sp. gr. 0.920). However, unless an unforeseen area of more vertically continuous high kerogen strata is encountered, there is limited economic potential given present knowledge. In this aspect, the Queen Charlotte Islands and Newfoundland deposits are similar.

Cretaceous: Boyne and Favel (White Specks), Prairie Provinces

Two oil shale zones, an upper in the Boyne Formation and a lower in the Favel Formation, are present along the Manitoba Escarpment (Fig. 3, no. 8). They are separated by a non-oil shale interval, the Morden Formation. Both zones are similarly composed of white, speckled shale; foraminiferal debris and coccoliths make up the white specks. The three units are traceable across the three Prairie Provinces, except for a central area of Saskatchewan where the medial Morden Formation is poorly defined to absent, resulting in an apparently single speckled shale unit (Fig. 56). Within the subsurface of Alberta and western Saskatchewan, these zones are informally defined as the First and Second White Speckled shale zones.

West-northwest of the Pasquia Hills, the bedrock distribution is indistinct, because that area has dominantly low-relief, drift covered topography.

Park (1965) illustrated the westward thinning of the intervening Morden shale in Saskatchewan, and outlined the area where only one speckled shale unit is readily apparent (Fig. 56). Within this area, thin beds of probable Morden strata can often be picked on geophysical logs and confirmed by geochemical analyses. The Boyne/Morden speckled shale/nonorganic shale sequence is macroscopically identical to the underlying Favel/Ashville sequence; however, Boyne and Favel strata can be differentiated by micropaleontology (Park, 1965; North and Caldwell, 1975; McNeil and Caldwell, 1981).

The Boyne Formation ranges in thickness from 30 to 45 m along the Manitoba Escarpment, thins to approximately 15 to 18 m in central Saskatchewan where it is contiguous with Favel beds, and thickens again to a range of 35 to 60 m in the Alberta subsurface.

Favel beds attain a general maximum thickness of 30 to 40 m along the Escarpment, thin westwards to only a few metres in central Saskatchewan, and again thicken to 35 to 60 m in the subsurface area of Alberta.

The intervening Morden Formation thins westward from 45 m at the eastern outcrops to essentially zero in central Saskatchewan, and thickens to more than 100 m of unnamed beds in the Alberta subsurface, and 300 m in the Alberta Foothills belt. Park (1965) illustrated these relationships in regional correlation sections across Saskatchewan.

Although not evaluated here because of geographic remoteness, Cretaceous oil shales of northernmost Yukon and Northwest Territories (Fig. 3), bordering the Beaufort Sea, are stratigraphic equivalents of the Boyne-Favel oil shale strata (Macauley, 1984a).

Lithology and mineralogy

Both oil shale zones consist of identical lithotypes, dark to medium grey to brownish grey shale, with a variable degree of white speckling produced by coccolithic and possible foraminiferal debris. The shales are finely laminated to fissile, but fissility decreases as carbonate content increases toward pure limestone. The calcareous shales grade to marls in which fossil debris becomes the dominant rock component (Macauley, 1984b).

Bands of noncalcarous shale, barren of fossil debris, are present within the speckled intervals. Also, beds of

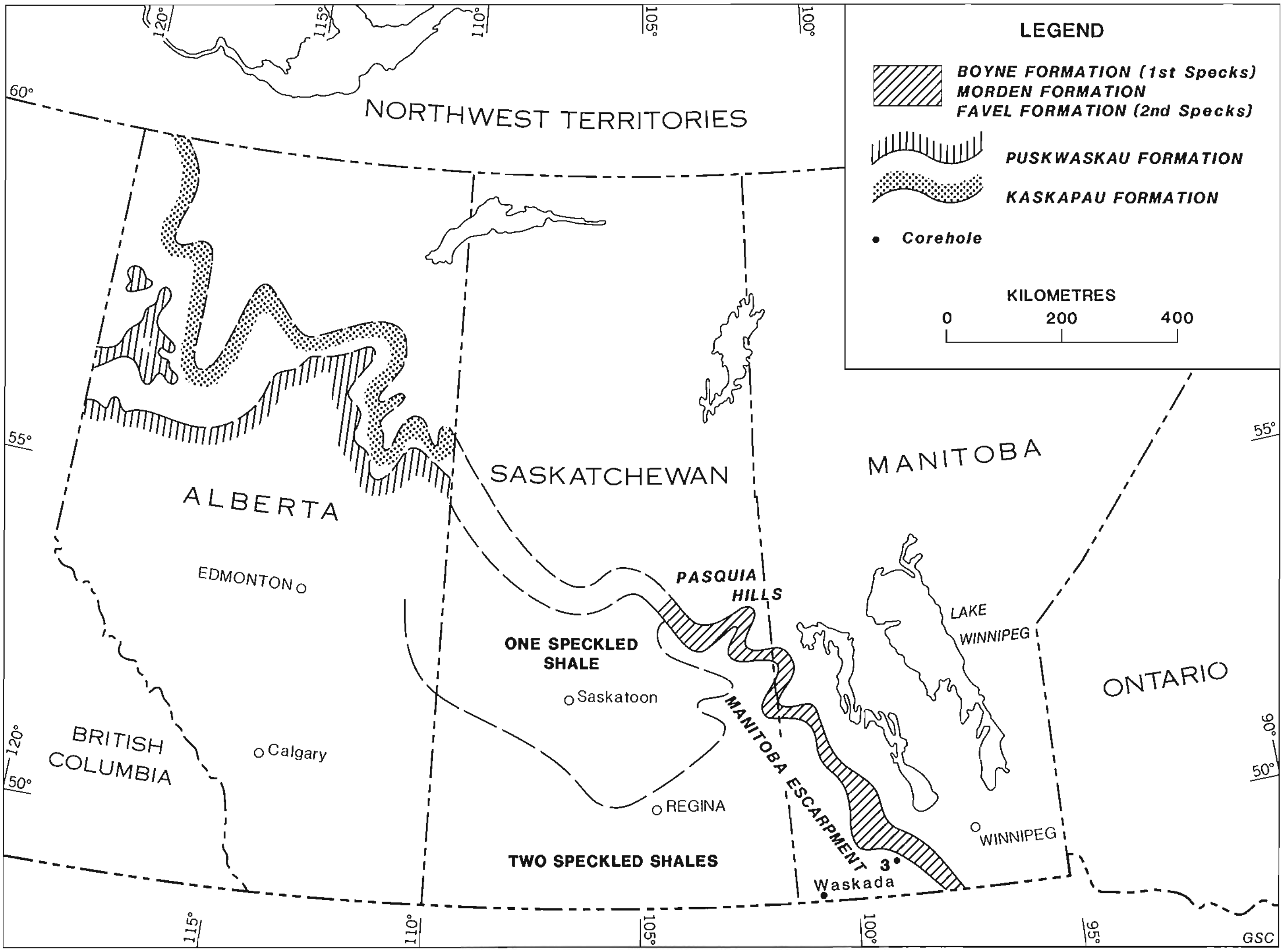


Figure 56. *Outcrop distribution of Upper Cretaceous oil shale zones, Prairie Provinces (from Macauley, 1984b).*

noncalcareous shale, normally included within the overlying and underlying stratigraphic units, may contain significant organic carbon and thus be included geochemically within the Boyne and Favel intervals. Consequently, geochemically defined limits may differ slightly from those based on calcareous distribution and/or geophysical log characteristics.

A quartz-clay-feldspar grouping defines the majority of the rock as a shale, in the sense of a fine grained, laminated, clay sediment. Quartz is the dominant component; clays are significant, and are present, in order of decreasing percentages, as: mixed-layer clays, illite, and chlorite-kaolinite. Feldspars are recorded in only minor amounts and are commonly absent.

Calcite, with only minor dolomite, is the second major mineral component. The abundance of calcite is apparently inversely proportional to the quartz-clay-feldspar content. Dolomite is present in amounts that range from only a trace to a few per cent. In effect, most of the oil shale beds may be classified as calcareous shale grading to argillaceous limestone.

The inter-relationship of quartz-clay-feldspar and calcite may be economically significant. No direct correlation, on a single value basis, can be made for hydrocarbon potential and mineral content, but an averaged value does indicate maximum yields at approximately 40 per cent calcite in the Boyne Formation and 60 per cent calcite in the Favel Formation. As calcite content increases above these values toward pure limestone, hydrocarbon potential decreases markedly.

Both Boyne and Favel mineralogies differ markedly from the other oil shale deposits discussed, in the presence of a prominent suite of secondary minerals (Macauley, 1984b), including zeolites, nonhydrous silicates, phosphates, sulphates, carbonates, Fe minerals, and oxides. Some minerals occur in more than one of the above groups. Some thirty-six secondary minerals were identified. Many of the oxide and sulphate forms differ only in the degree of hydration, although differences in Fe valency are also significant. Water of crystallization is common to almost all of the secondary mineral groups. Sun Oil company (1965) noted that more water was recovered on their bench retort assays when additional care was taken to prevent desiccation of the samples in the time between sampling and retorting.

This large water content is of possible economic significance. Almost all assays yield a minimum 40 kilograms/tonne (10 US gallons/ton) water, with many ranging to 80 kg/t (20 US gallons/ton) and some as high as 120 kg/t (30 U.S. gallons/ton). These yields reflect the hydrated water of clay minerals, zeolites, sulphates and oxides.

Organic geochemistry

Data from analyses of Total Organic Carbon and Rock-Eval pyrolyses are the basis for most of the geochemical interpretations (Macauley, 1984b).

Total Organic Carbon (TOC): the distribution of organic carbon content is similar for both the Boyne and Favel formations (Fig. 57a, b). Two north to northeast trends of greater organic carbon content (Boyne: possibly to 7 per cent, Favel: 7 per cent), offset a lower content area centered near Saskatoon, somewhat coincident with the thinnest area of sedimentation, where intervening Morden beds are poorly developed to absent (Fig. 56).

Tmax: Tmax values across Manitoba, Saskatchewan and eastern Alberta range from 405° to 425°C, all below the Rock-Eval oil generation window (435° to 465°C), and they therefore indicate thermal immaturity.

Hydrogen-Oxygen Indices (HI-OI): immaturity is also indicated by the plots of Hydrogen against Oxygen indices (Fig. 58a, b). Although values vary considerably for the Hydrogen indices, oxygen is not lost as hydrogen decreases; consequently, the distribution of points reflects variable kerogen components rather than maturation changes. An admixture of Type II and Type III kerogens is interpreted from the hydrogen-oxygen distribution (Macauley, 1984b).

Production Index (PI): Production indices at the Manitoba-Saskatchewan control points range from 0.02 to 0.06, invariably below 0.10 for the Boyne and Favel beds, indicating immaturity to marginal maturity at most for these deposits.

Organic petrology

According to Hutton (1981a, 1981b), the Boyne-Favel oil shales contain abundant, fine grained, nonfluorescing, black to brown humic detritus in lenses and layers up to 0.55 mm thick. Each humic layer contains fined grained fluorescing liptodetrinite and phytoplankton. Amounts of liptodetrinite vary from near zero (rarely), to approximately 30 per cent by volume. Dinoflagellates and/or acritarchs occur within the humic layers and also in the mineral layers.

Other fluorescing organic matter includes sporinite, lamellar bodies of one to several lamellae, and granular brown bitumen (up to 0.5 mm) that may be an amorphous sapropel. Some of the apparent humic layers contain abundant fluorescing liptodetrinite, indicative of sapropel content as well as humus. Vitrodetrinite and inertinite are present in small quantities. Hutton's description indicates an admixture of Type II and Type III kerogens.

Most of the sapropelic kerogen fluoresces yellow to green, generally indicating immaturity, although specific λmax and Red-Green quotient data were not reported by Hutton.

In a study of source potential of the stratigraphically equivalent Boundary Creek Formation (Macauley, 1984a) of the Mackenzie Beaufort Basin, Snowdon (1980) stated, "Although algal and other marine organisms contributed much to the organic debris, terrestrial matter also makes up a significant proportion of the total". Creaney (1980) identified vitrinite, inertinite, faunal remains, sporinite, resinite, alginite, liptodetrinite and bituminite in the Boundary Creek Formation. This lithologically and stratigraphically comparable zone contains the same macerals identified by Hutton for the Boyne-Favel oil shales.

Kerogen-pyrolyzate-oil characteristics

The specific gravity of the oil recovered is in the poorer range of shale oil types, averaging 0.952 at the south end of the Manitoba Escarpment, and becoming heavier northward (0.965 to 0.970) in the Porcupine and Pasquia hills.

Sun Oil Company (1965) investigated the content of bench retorted oil from the Pasquia Hills. The oil was low quality (11.5°API), highly aromatic, and hydrogen-deficient, containing between 1.18 per cent and 6.87 per cent N_2 by weight. Table VI outlines the basic components within the major oil generation temperature ranges.

The high aromaticity of the shale oil might be significant for petrochemical feedstock, as well as any olefin content.

Classification and maturation

The Boyne-Favel oil shales are marine, Type II, mixed deposits that are immature along both the Manitoba Escarpment and the more poorly defined drift covered trend across Saskatchewan, and are also immature across almost the entire subsurface area of the Prairie Provinces.

Economic potential

Any economic potential for oil shale development depends on the distribution of Total Organic Carbon (Fig. 57), and on hydrocarbon yield relative to organic carbon content (Fig. 59 a, b). For the Boyne and Favel oil shales, the latter relationship is not first order linear, as is indicated by the curve of the average line. The Favel line (Fig. 59b) shows a break in slope at 3 to 4 per cent organic carbon, above which the yield ratio improves. This, in combination with the HI/OI plots and the Tmax variations, is interpreted as a reflection of the varying distributions of Type II and Type III kerogens. All sampled locations show a similar change of slope. The entire area is considered to contain an average of 3 to 4 per cent organic carbon derived from Type III humic kerogen within the organic beds. Zones with lesser organic carbon

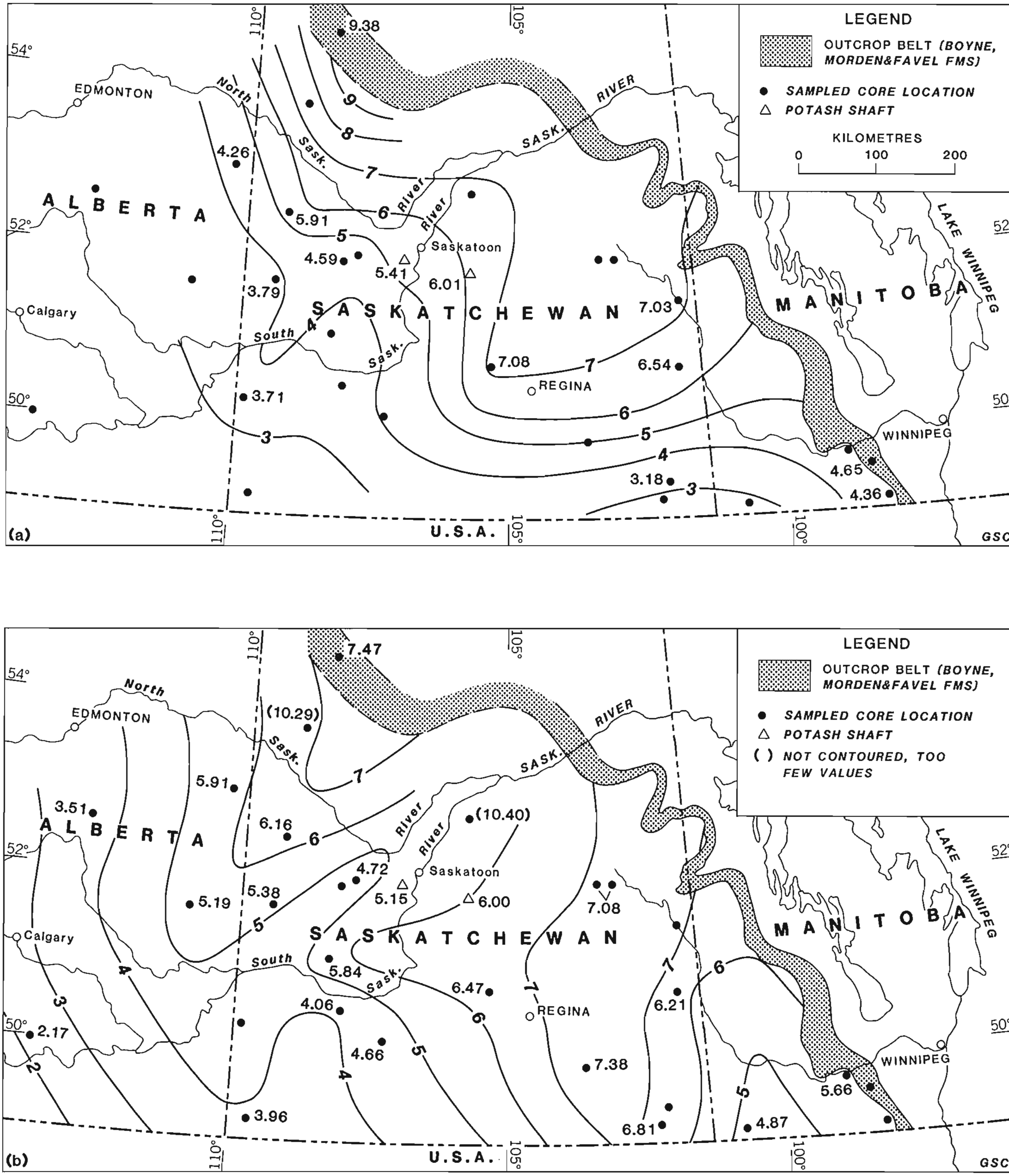
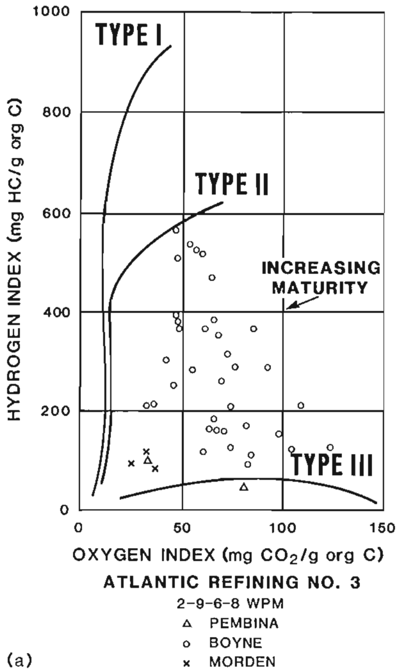


Figure 57. *Regional distribution of Total Organic Carbon content: (a) Boyne Formation, (b) Favel Formation (from Macauley, 1984b).*



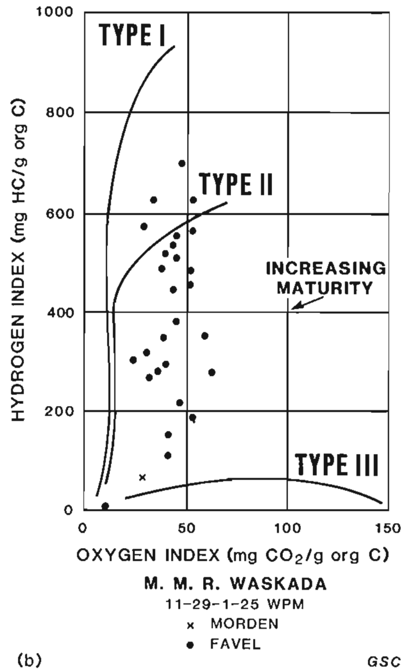


Figure 58. *Typical plots of Hydrogen Index, HI, against Oxygen Index, OI: (a) Boyne Formation, (b) Favel Formation (from Macauley, 1984b).*

Temperature		Saturates Vol %	Aromatics Vol %	Olefins Vol %	Resins	Ashphal-tenes
°C	°F					
0-190	0-375	11	68	21		
190-280	375-535	3	89	6		
280-450	535-834	3	61	6	30	
450+	834+	3	26		28	43

TABLE VI

Oil characterization during retorting of Pasquia Hills shale oil

may contain almost entirely humic material. Where organic carbon exceeds 3 to 4 per cent, the increase results from the presence of Type II sapropel, and is reflected by higher hydrocarbon recoveries with this change of kerogen (Macauley, 1984b).

Average yields per 1% organic carbon range from 3.5 to 4.5 kg/t over the total interval of either oil shale unit, but increase within the units to beds yielding up to 6 kg/t, where Type II kerogen predominates.

From the distribution of average hydrocarbon yield, two areas of better potential are recognized, one trending north in the eastern part of Saskatchewan, and a second trending northeast along the Alberta-Saskatchewan border, separated by a low potential area trending north-northeast through Saskatoon (Fig. 60a, b). These trends directly reflect the TOC distribution pattern (Fig. 57).

From these maps, it appears that the area in the northwest along the outcrop trend in Saskatchewan should be economically interesting, but some caution must be advised, as the three key control points contain only a few analytical values that may have been selected from higher-yield beds. This area is also covered by considerable drift, is virtually barren of rock exposures, and consequently will be difficult to explore.

The eastward trend is currently of more interest because of the Fischer Assay data available from the Sun Oil core program of 1964-1965 in the Pasquia and Porcupine hills. These analyses are on file at the Geological Survey of Saskatchewan.

Elevations for the base of the Boyne oil shale unit were calculated from the Sun Oil data, as defined by oil yields. Most of these elevations appear to be regionally compatible, and are mapped herein as contours on the Morden Formation (Fig. 61). Four values, one at the east end of the Porcupine Hills, one at the eastern extremity of the Pasquia Hills, and two to the east of Duck Mountain, are approximately 30 to 45 m (100 to 150 ft) low relative to the contours on the Morden Formation. Consequently, these cores are interpreted to have penetrated the Favel Formation. Irregularities of the contours on the north flanks of the Pasquia and Porcupine hills reflect distribution of organic material downward in the section. Based on organic content, the Boyne-Morden contact is in part a lateral facies relationship.

Because oil gravities (generally 0.965 in this area) are known, Fischer Assay yields have been converted to kg/t (Fig. 62). An area of optimum yield, in the range of 40 to 50 kg/t, in the Boyne Formation, is mapped on the north flank of Pasquia Hills, with recoveries decreasing both east and west of the optimum area. These detailed trend lines and

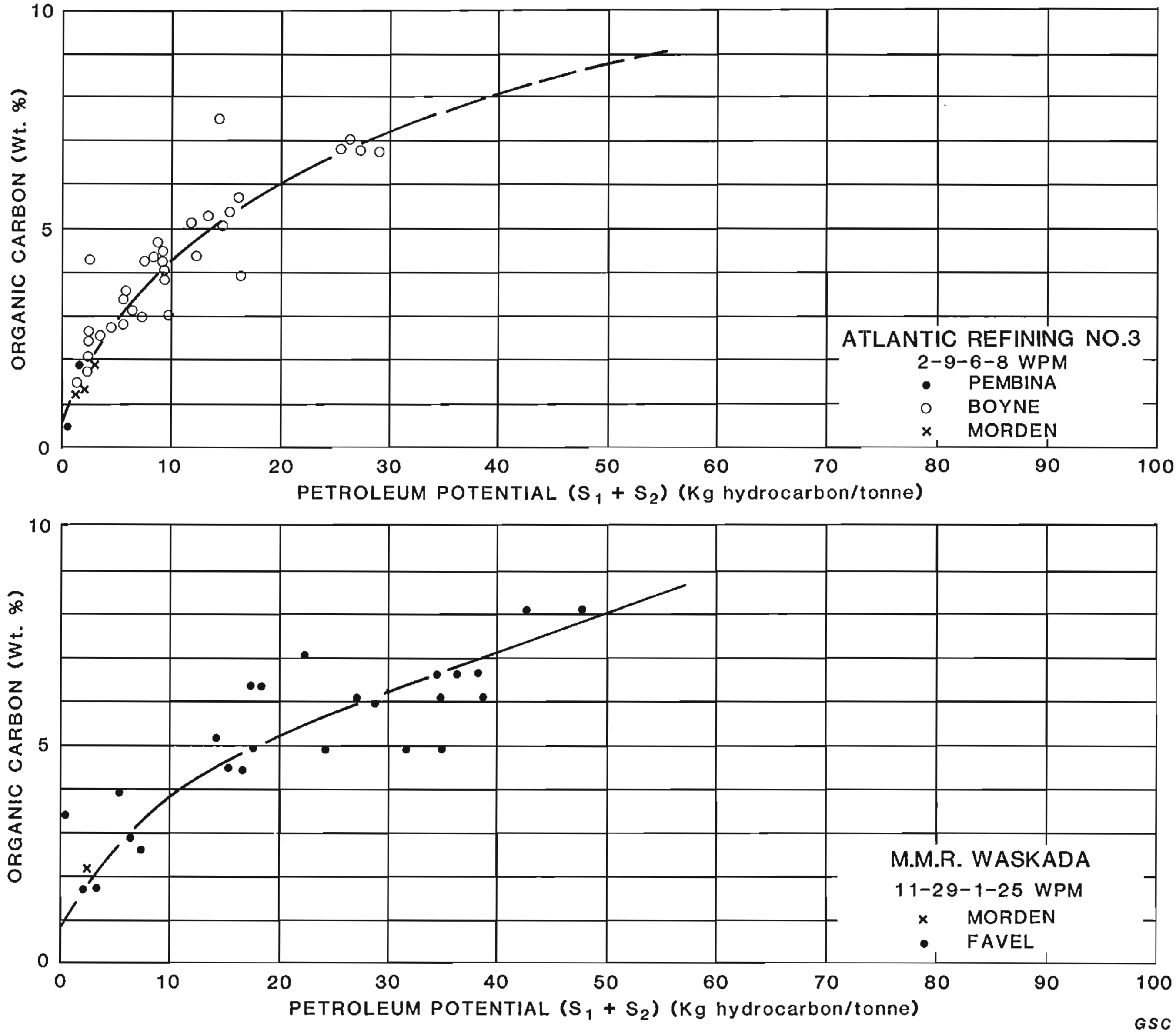


Figure 59. *Typical plots of Total Organic Carbon against Hydrocarbon Potential: (a) Boyne Formation, (b) Favel Formation (from Macauley, 1984b).*

data have been incorporated into the more regional hydrocarbon yield maps for both the Boyne (Fig. 60a) and Favel (Fig. 60b) formations. As contoured, the north slope of the Pasquia Hills is the most attractive area for oil shale development along the Manitoba Escarpment. This is in agreement with Beck (1974).

Because of the thick deposit, and the large geographic area, potential oil reserves in the Pasquia Hills are vast. Beck (1974) estimated that a zone, 1.6 to 19 km (1-12 miles) in width, by 56 km (35 miles) in length, could be mineable on the northwest flank of the hills. Using an average thickness of 30 m, and a grade of 32 kilograms/tonne (8 US gals/ton), Beck estimated 413 million cubic litres (2.6 billion barrels) of *in situ* oil. Macauley (1984) suggested a reduction of the average pay zone to 14 m (45 ft), because of lower grade intervals at the top and base, with a resultant decrease in *in situ* reserves to 200 million cubic metres (1.25 billion barrels) for the area.

Exploitation

On recognizing the extremely aromatic nature of the retorted oil, Sun Oil Company (1965) considered hydrogeneration of the oil during retorting, with a hydrogen source from a steam hydrocarbon process. Available hydrogen from the retorting process was 110 cu. ft. /barrel of shale oil produced, nearly half of the hydrogen estimated as necessary to upgrade this shale oil to gasoline products.

Sun Oil Company also determined that the retort char (spent shale) contained an average of 12 per cent carbon by weight, much more than the 2.5 per cent required to produce the heat necessary for the retorting process. Burning the spent shale could produce all the energy requirements of the system, including the steam for hydrogen generation. The 12 per cent figure for the residue may be questionable, as this is considerably greater than the anticipated whole rock carbon content.

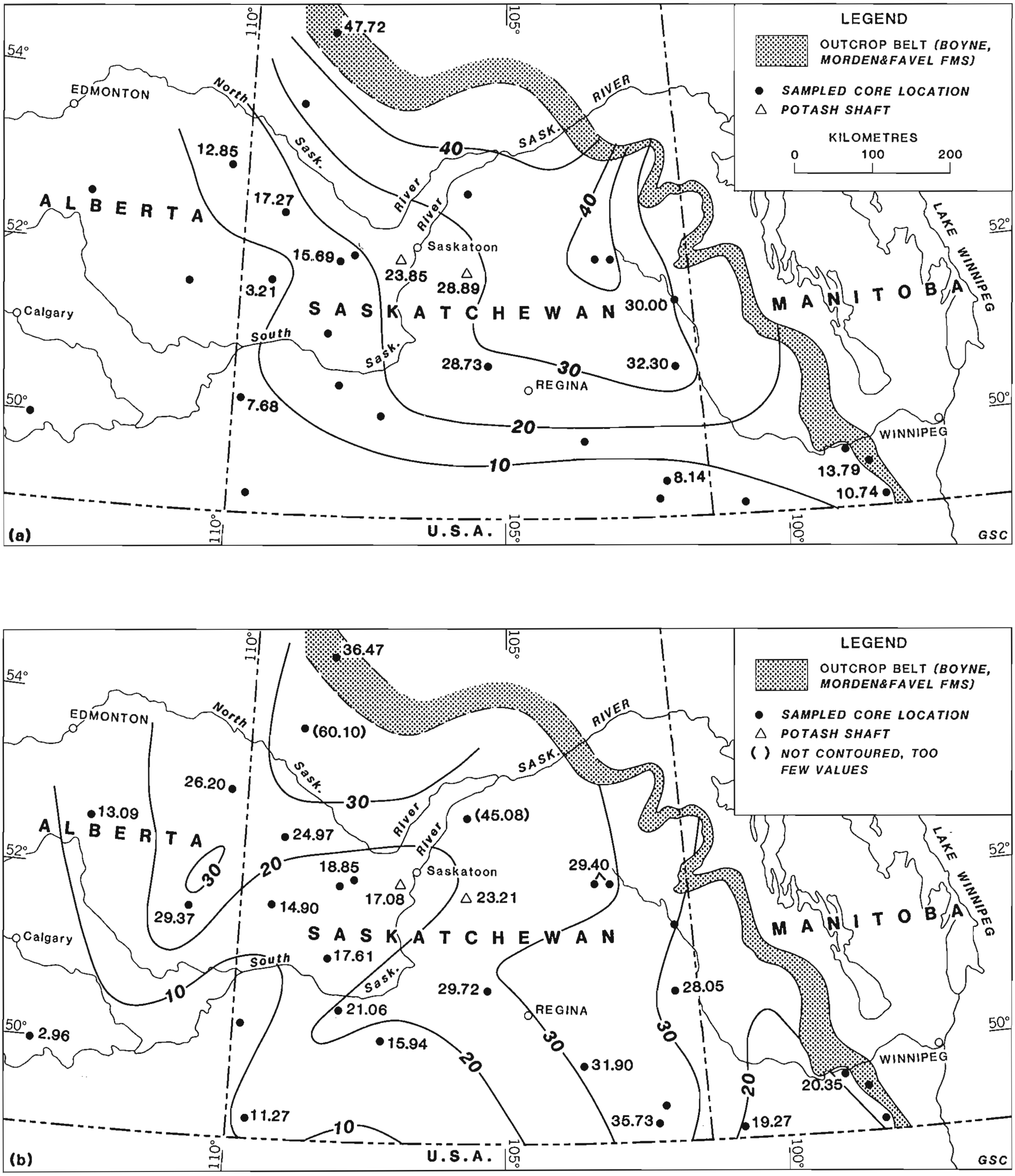


Figure 60. Regional distribution of averaged hydrocarbon yields: (a) Boyne Formation, (b) Favel Formation (from Macauley, 1984b).

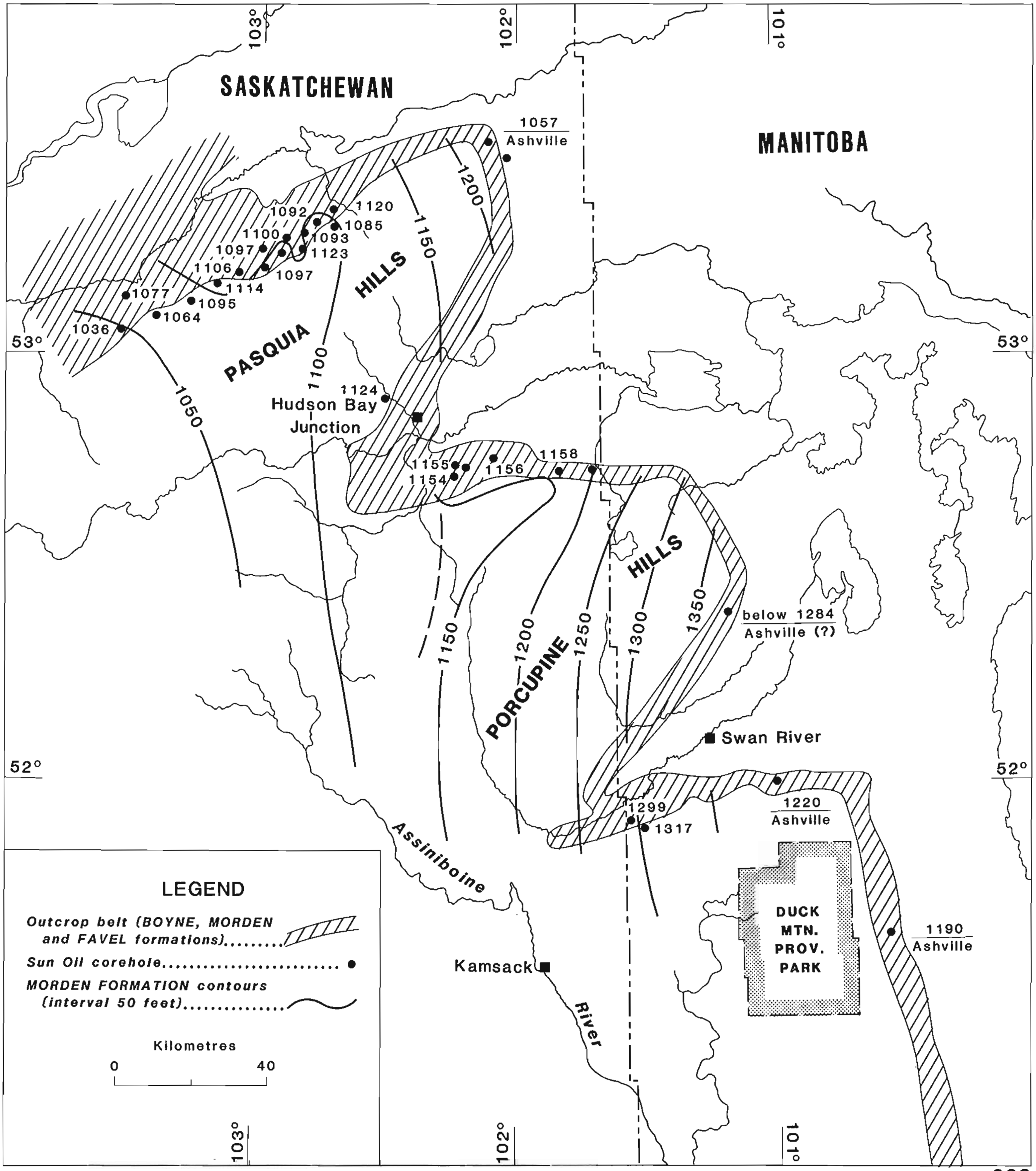


Figure 61. *Morden Formation contours from Sun Oil Company corehole data, Pasquia Hills -Porcupine Hills - Duck Mountain area (from Macauley, 1984b).*

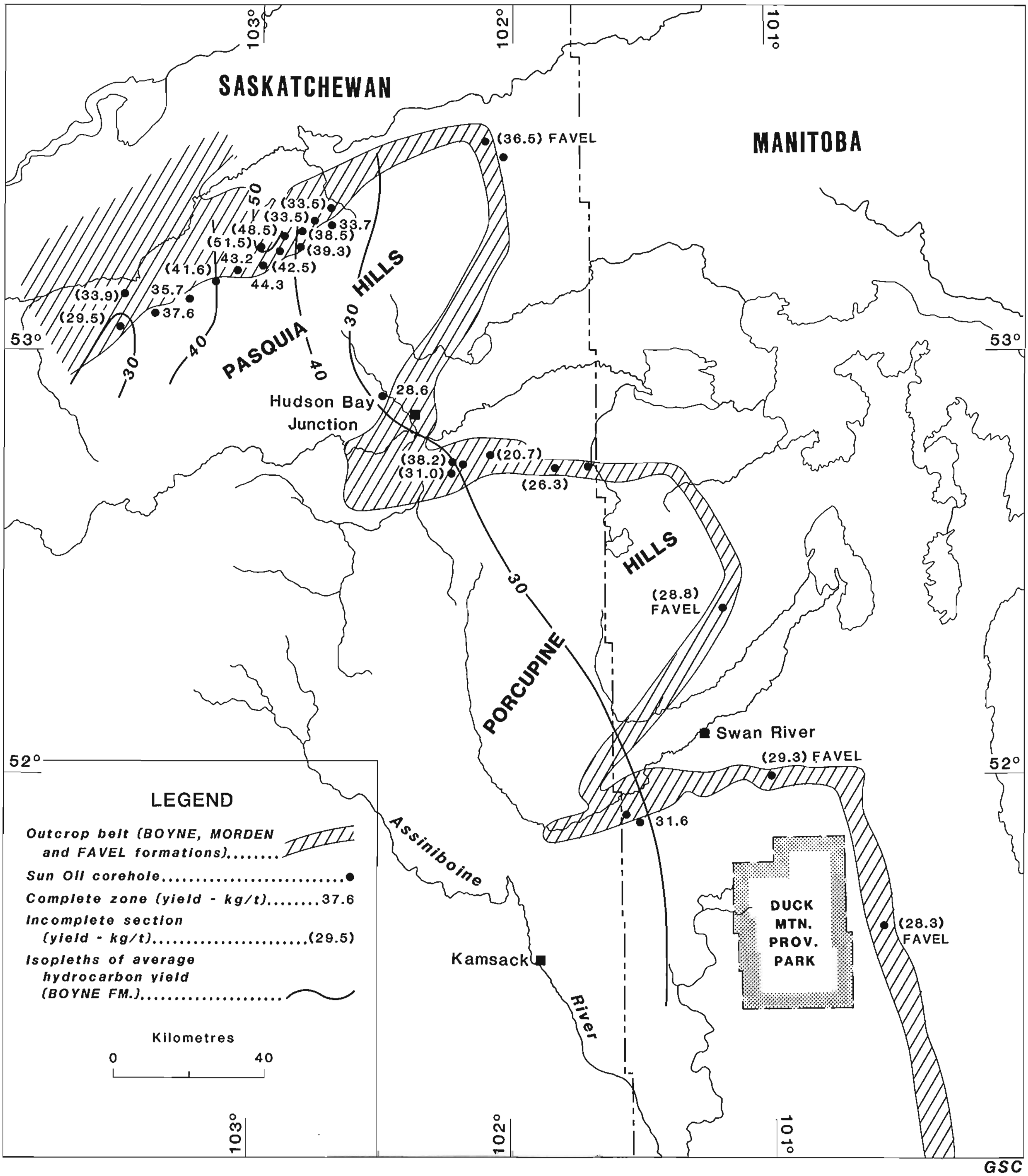


Figure 62. Average hydrocarbon yield from the Boyne Formation, Sun Oil Company corehole data, Pasquia Hills - Porcupine Hills - Duck Mountain area (from Macauley, 1984b).

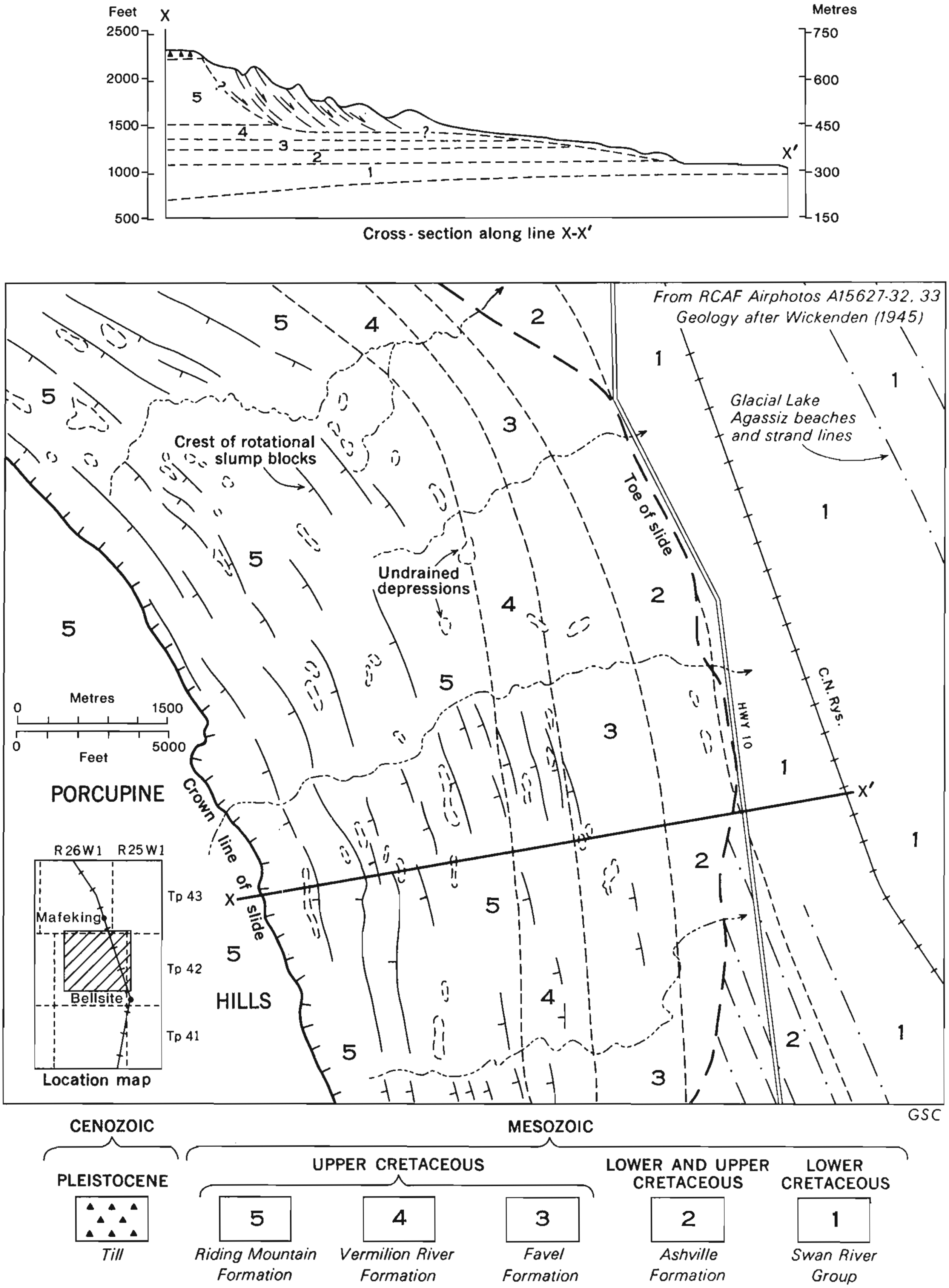


Figure 63. *Slope instability (landslide area) in beds overlying the Boyne oil shale zone, Porcupine Hills, Manitoba Escarpment (from Scott and Brooker, 1968).*

Because of the quantity of water-bearing clay minerals, and the large number of mineral forms containing water of hydration, the heating process in a retort may require more energy than normally anticipated. The generated steam may be beneficial, if usable in a hydrogen generation process, or could be a detriment to the efficiency of retorting.

No rock mechanics studies have been conducted on the oil shale beds. Scott and Brooker (1968) studied slumping in the overlying Riding Mountain beds in the Porcupine Hills (Fig. 63). The extreme potential for slumping in the Riding Mountain beds may present a problem in pit slopes, where these beds must be removed, or for roof stability in an underground process.

SUMMATION

Canadian oil shale deposits represent all basic classification types, including Type I, continental torbanites and lamosites, and Type II marine, both mixed and sapropelic. All ranges of thermal maturity are recognized, from immature to overmature (source rock rather than oil shale at this level). Table VII summarizes the classification and maturation of these deposits.

Of the Canadian oil shale deposits, those of the Frederick Brook Member of the Mississippian, Albert Formation at Albert Mines, New Brunswick, have the most attractive potential at present. Some 42.84×10^6 cubic metres (270 million barrels) of *in situ* shale oil are estimated from an area 1.6 km square (1.6 x 1.6) and 600 m deep. Of these reserves, 10.11×10^6 cubic metres (67.35 million barrels) are contained in the most prolific Albert Mines zone. The greatest plus factor of this deposit is the potential for linked retorting and co-combustion with high sulphur coal deposits, the oil shale carbonate reacting with the sulphur to reduce SO_X emissions to an environmentally acceptable level. Because the region is hydrocarbon energy-deficient, and dependent on imported oil, the economic competitiveness of the oil shale is enhanced. Even if successfully brought to production, offshore Canadian energy (i.e. Hibernia) will be expensive. Although in a scenically attractive area, the deposit can be developed without destroying unique land, and no commercial development (farming, foresty) is now in place. Of the complicating factors, the extreme structural complexity of the deposit, coupled with anticipated variations in the mechanical properties of the rocks, will create severe mining difficulties. Numerous additional coreholes will be required to define both the geological and engineering parameters for either open pit or underground mining operations, and to determine potential retort and co-combustion feedstock materials.

Age	Unit	Location	Classification	Maturation	Thickness (m)	Petroleum Potential Avge. l/t	Oil Sp. Gravity
Upper Cretaceous	**Boyne Favel**	Pasquia Hills Saskatchewan	Marine II mixed	Immature	40 30	40±	0.965
Jurassic	**Kunga**	Q.C.I. British Columbia	Marine II mixed	Mature to overmature	thin (cms)	35 max.	0.920
Pennsylvanian	Stellarite Torbanite Oil Shale	Pictou coalfield Nova Scotia	Continental I (bog) Torbanites	Moderate Low?	1.5 1.5 13	60-140 105 25	0.86 0.91 0.91 (estimate)
Mississippian Tournaisian	**Deer Lake**	Deer Lake Newfoundland	Continental I (lacustrine) Lamosite	Low to moderate	thin (cms)	60	0.90 (estimate)
Mississippian Viséan	**Big Marsh**	Antigonish, Nova Scotia	Continental I (lacustrine) Lamosite	Low	60-125	25 max	0.90
	Frederick Brook Member **Albert Formation**	Albert Mines, New Brunswick	Continental I (lacustrine) Lamosite	Moderate	360	35-95	0.87 to 0.88
		Boudreau-Dover New Brunswick		Low	25	30, up to 50	0.91
		Rosevale-Urney New Brunswick		Low	15	20, up to 50	0.91
Upper Devonian	**Kettle Point**	Sarnia and S. Ontario	Marine II mixed	Immature	10	41	0.94 (estimate)
Upper Ordovician	**Collingwood**	Manitoulin Island S.W. Ontario	Marine II sapropel	Low	5.5	28	
		Collingwood S.W. Ontario		Marginal	1.7	29	0.89 to 0.94
		Whitby S.W. Ontario		Moderate	5.0	10	

TABLE VII

Classification, maturation and pertinent data for economic potential, selected Canadian oil shale deposits

Elsewhere in the Moncton Sub-basin, the Albert oil shales east of Albert Mines, in the Boudreau-Dover-St. Joseph outcrop areas, are only minimally explored. Local high-yield zones may be present, although they may be much more limited in thickness than the Albert Mines deposit.

The higher yield zone (10 m thick) in the uppermost section of the Kettle Point Formation near Sarnia, in southwestern Ontario, is interesting because of its location in the heart of the petrochemical industrial area. The increased yield potential from hydroretorting may improve the economic attractiveness of this deposit, although its areal extent appears to be limited. This area is developed as farmland, industrial complexes, and as urban and rural habitat. Resistance to mining may come from any or all of these factions.

Although geographically widespread and continuous downdip of outcrop areas, the thin, Ordovician, Collingwood oil shales are economically inhibited by lack of major reserves in a small area. Outcrops occur along the shores of Georgian Bay and on Manitoulin Island, both established scenic resort areas; development probably will be environmentally unacceptable for a considerable period in the future.

Although the petroleum potential is on the margin of economic interest (i.e. a minimum of 40 litres/tonne, or 10 US gals/ton), the Boyne and Favel oil shales in the Pasquia Hills are attractive because of their thickness (40 and 20 m respectively), widespread distribution, and structural simplicity. The Pasquia Hills are scenically attractive, but are not within defined park areas, as are the Porcupine Hills and Duck Mountain southward along the Manitoba Escarpment. The area is only sparsely settled and minimally developed as farmland. Extreme economic competition exists from the Alberta oil sands and from the increasing recovery potential and upgrading of heavy oil deposits in the subsurface of eastern Alberta and western Saskatchewan.

The stellarite of the Oil-Coal Seam in the Pictou area, Nova Scotia, is most difficult to assess. Neither the coal nor the stellarite is thick enough to be economically attractive alone, but the combined zone may represent an economic deposit in this energy deficient region. The petroleum potential of the stellarite is excellent; the coal also yields significant oil on pyrolysis. Research into the co-utilization of the coal and stellarite of the Oil-Coal Seam is an obvious necessity.

One might wonder about the wisdom of oil shale investigations at a time when the world has a momentary glut of petroleum and other energy sources. Canada has now only scratched the surface of oil shales knowledge in this country – even at Albert Mines, the best assessed of our deposits, major geological investigation is still required before any exploitation can commence. Unfortunately, geological and geochemical investigations, to be done properly, require time. After that, the development of the mine and related refining (retorting) systems also require years for emplacement. Hopefully, this progress report will be beneficial in guiding ensuing, more complex geological-geochemical studies of all deposits and the economic-exploitation assessments of the more attractive deposits. Time is now available, before conventional hydrocarbon sources are depleted, to prepare methodical, complete assessments of these deposits, so that when we do need the oil shales, we will be able to develop them to their fullest potential.

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