Thomas Frisch

GEOLOGICAL SURVEY OF CANADA

COMMISSION GÉOLOGIQUE DU CANADA

PAPER 78-12

AN ASSESSMENT OF THE HYDROCARBON SOURCE ROCK POTENTIAL OF THE CANADIAN ARCTIC ISLANDS

T.G. POWELL

Energy, Mines and Resources Canada

Énergie, Mines et Ressources Canada

1978

GEOLOGICAL SURVEY
PAPER 78-12

AN ASSESSMENT OF THE HYDROCARBON SOURCE ROCK POTENTIAL OF THE CANADIAN ARCTIC ISLANDS

T.G. POWELL

1978

available by mail from

Printing and Publishing
Supply and Services Canada,
Hull, Québec, Canada K1A 0S9,

and

The Geological Survey of Canada
601 Booth St., Ottawa, K1A 0E8

or

Through your bookseller.

Catalogue No. M44-78/12	Price: Canada: $4.50
ISBN - 0-660-01539-0	Other Countries: $5.40

Price subject to change without notice

CONTENTS

	Page
Introduction	1
Acknowledgments	2
Geological setting	2
Geological provinces of the Arctic Islands	2
Stratigraphy and geological history (outline)	3
Hydrocarbon occurrences	3
Samples and methods	5
Analytical procedure	5
Data base	8
Recognition of contamination	8
Maturation and source rock criteria	8
Definition of maturation levels	8
Source rock criteria	13
Basis of an interpretative diagram for assessment of source rock potential	18
Sverdrup Basin	29
Regional maturation trends	29
Maturation and source rock potential of stratigraphic units	34
Isachsen and younger formations	34
Deer Bay, Awingak and Wilkie Point Formations	38
Savik and Jaeger Formations	42
Borden Island and Heiberg Formations	44
Schei Point and Blaa Mountain Formations	46
Bjorne and Blind Fiord Formations	48
Permo-Pennsylvanian	52
Summary of source rock potential and oil-source correlation	57
Arctic Platform and Parry Island Fold Belt	58
Regional maturation trends	58
Maturation and source rock potential of stratigraphic units	60
Hecla Bay Formation and Griper Bay Supergroup	60
Weatherall, Bird Fiord, Blackley, Cape de Bray and Eids Formations	62
Blue Fiord Formation	63
Bathurst Island and Stuart Bay Formations	63
Read Bay, Allen Bay, Cape Phillips and Kitson River Formations	64
Thumb Mountain, Bay Fiord, Copes Bay and Parrish Glacier Formations	66
Summary of source rock potential and oil-source correlation	66
Banks Island	67
Maturation and source rock potential	67
Mesozoic and Tertiary strata	67
Paleozoic strata	70
Quantitative estimates of oil yields	70
Schei Point Formation	70
Weatherall and Bird Fiord Formations	76
Timing of hydrocarbon generation	76
Sverdrup Basin	76
Franklinian Geosyncline	79
General conclusions	80
References	81

Illustrations

Table	1.	Sverdrup Basin - location of wells sampled and extent of analysis	6
	2.	Franklinian Geosyncline and Arctic Platform - location of wells sampled and extent of analysis	7
	3.	Banks Island - location of wells sampled and extent of analysis	7
	4.	Extract and kerogen data for the Isachsen, Christopher, Hassel and Kanguk Formations	31
	5.	Extract and kerogen data for the Deer Bay, Awingak and Wilkie Point Formations	36
	6.	Extract and kerogen data for the Savik and Jaeger Formations	37
	7.	Extract and kerogen data for the Borden Island and Heiberg Formations	40
	8.	Extract and kerogen data fot the Schei Point Formation	41
	9.	Extract and kerogen data for the Blaa Mountain Formation	50
	10.	Extract and kerogen data for the Bjorne and Blind Fiord Formations	53
	11.	Extract and kerogen data for Permian and Pennsylvanian formations	62-63
	12.	Reflectance data for the BP *et al.* Hotspur J-20 and Panarctic Tenn. *et al.* Bent Horn N-72 wells	64
	13.	Atomic hydrogen to carbon ratios of pyrobitumen in the Blue Fiord Formation on Cameron Island	64
	14.	Extract and kerogen data for the Hecla Bay Formation and Griper Bay Supergroup	64

Page

Table 15. Extract and kerogen data for the Weatherall, Bird Fiord, Cape de Bray and Eids Formations 66
16. Extract and kerogen data for the Blue Fiord, Bathurst Island, Peel Sound and Stuart Bay Formations 66
17. Extract and kerogen data for the Cape Phillips, Kitson River, Read Bay and Allen Bay Formations 67
18. Extract and kerogen data for the Irene Bay, Thumb Mountain, Bay Fiord, Eleanor River, Baumann Fiord, Copes Bay and Parrish Glacier Formations 75
19. Extract data for Mesozoic and Paleozoic strata on Banks Island 75
20. Volumes of in place and migrateable oil in the Schei Point source rock 79

Figure 1. Generalized and composite stratigraphic section of the Sverdrup Basin 2
2. Generalized and composite stratigraphic section of the Arctic Platform and Franklinian Geosyncline 3
3. Principal structural units of the Arctic Island and hydrocarbon occurrences and location of wells with geochemical data 4-5
4. Gas chromatograms of saturated hydrocarbons from diesel oil, pipe grease, core box wax and respectively contaminated samples 9
5. Geochemical results obtained for the Drake D-68 well 10
6. Geochemical results obtained for the North Sabine H-49 well 11
7. Geochemical results obtained for the Schei Point Formation 12
8. Diagrams to illustrate assessment of source organic matter quality, maturation state and anticipated hydrocarbon product from extract data 14-15
9. Organic metamorphic facies maps of three stratigraphic levels within the Sverdrup Basin .. 16-17
10. Cross-sections of the Sverdrup Basin showing relationship of gas and organic carbon logs to the major stratigraphic units and igneous intrusions 18-28
11. Extract and gas data for the Panarctic *et al.* Louise Bay O-25 well 29
12. Source rock potential and gas chromatograms of the saturated hydrocarbons of the Isachsen and younger formations 30
13. Source rock potential and gas chromatograms of the saturated hydrocarbons of the Deer Bay, Awingak and Wilkie Point Formations 32-33
14. Source rock potential and gas chromatograms of the saturated hydrocarbons of the Savik and Jaeger Formations 34-35
15. Source rock potential and gas chromatograms of the saturated hydrocarbons of the Borden Island and Heiberg Formations 38-39
16. Source rock potential and gas chromatograms of the saturated hydrocarbons of the Schei Point Formation 42-43
17. Source rock potential and gas chromatograms of the saturated hydrocarbons of the Blaa Mountain Formation 44-45
18. Source rock potential and gas chromatograms of the saturated hydrocarbons of the Bjorne and Blind Fiord Formations 46-47
19. Source rock potential and gas chromatograms of the saturated hydrocarbons of the Permian to Pennsylvanian strata 48-49
20. Correlation of crude oils with possible source rocks in the Sverdrup Basin based on stable carbon isotope distribution 51
21. Relationship of gas and organic carbon logs to the major stratigraphic units in the Franklinian Geosyncline and Arctic Platform 52-56
22. Per cent wet curves and extract data from the Zeus F-11, Apollo C-73, Dundas C-80, Eldridge Bay E-76, Hotspur J-20 and Bent Horn N-72 wells 57-59
23. Source rock potential and gas chromatograms of the saturated hydrocarbons of the Hecla Bay Formation and Griper Bay Supergroup 60-61
24. Source rock potential and gas chromatograms of the saturated hydrocarbons of the Weatherall, Bird Fiord, Cape de Bray and Eids Formations 68-69
25. Source rock potential and gas chromatograms of the saturated hydrocarbons of the Blue Fiord, Bathurst Island, Peel Sound and Stuart Bay Formations 70-71
26. Source rock potential and gas chromatograms of the saturated hydrocarbons of the Cape Phillips, Kitson River, Read Bay and Allen Bay Formations 72-74
27. Correlation of Bent Horn oil with possible source rocks based on stable carbon isotope distribution 76
28. Relationship of gas and organic carbon logs to the major stratigraphic units on Banks Island 77-78
29. Organic metamorphic facies map for the Schei Point Formation in the Western Sverdrup Basin showing areas used to calculate volumes of migrateable oil 79
30. Burial history curves for the Schei Point Formation and equivalent formations 80

AN ASSESSMENT OF THE HYDROCARBON SOURCE ROCK POTENTIAL
OF THE CANADIAN ARCTIC ISLANDS

ABSTRACT

Four facies of organic metamorphism have been recognized in the Mesozoic and Paleozoic sedimentary rocks of the Sverdrup Basin: undermature, marginally mature, mature and overmature. Hydrocarbon generation commences in the marginally mature facies, but only amorphous organic matter is likely to yield oil at this diagenetic level. The mature zone corresponds to the maximum phase of oil generation in both amorphous and woody-herbaceous organic matter but only the former will yield significant amounts of oil. Gaseous hydrocarbons were formed in the overmature zone by cracking of liquid hydrocarbons and kerogen. In the Sverdrup Basin, the onset of the marginally mature and mature zones occur at approximately 1500 and 3000 m maximum burial depth, respectively. The transition from mature to overmature occurs in the vicinity of 4300 to 4600 m maximum burial depth.

Due either to lack of maturity or source organic matter type, the majority of upper Paleozoic and Mesozoic rocks of the Sverdrup Basin are likely to have yielded only gas. The Schei Point Formation (Middle-Upper Triassic) is an exception and has probably been the source for the oil shows and "tar sands" on Melville Island. Oil generation is likely to have begun in the Schei Point Formation during the Early Cretaceous and migration probably occurred prior to the Eurekan Orogeny.

The gas in the Drake, Hecla and King Christian fields appears to have been formed at relatively low levels of maturation. In contrast, the gas in the Jackson Bay field was derived from the overmature facies.

All the boreholes in the Franklinian Geosyncline and Arctic Platform commence in the mature or overmature facies. The fine-grained sediments of the Devonian clastic wedge and the lower Paleozoic graptolitic shale facies can have excellent source potential for oil. The governing factor is the position of the mature to overmature transition where the hydrocarbon product changes from oil to gas-condensate or dry gas. The Bent Horn oil was probably derived from the fine-grained sediments of the Bird Fiord Formation of the clastic wedge. Maximum hydrocarbon generation in all prospective source rocks probably occurred in Middle to Late Devonian time.

In the case of Banks Island, the Paleozoic sediments are largely overmature whereas the Mesozoic sediments are undermature.

RESUME

On a étudié le potentiel roche-mère d'hydrocarbures qui caractérise les roches sédimentaires mésozoïques et paléozoïques de l'archipel Arctique canadien.

On a identifié dans le bassin Sverdrup quatre faciès d'une séquence métamorphique de caractère organique, à savoir un faciès jeune, un faciès de maturité commençante, un faciès mature, et un faciès de maturité avancée. La formation des hydrocarbures débute dans le faciès de maturité commençante, mais seule la matière organique amorphe peut donner du pétrole à ce niveau de diagenèse. La zone de maturité correspond à la phase maximale de formation du pétrole, à la fois dans la matière organique amorphe et la matière organique constituée de débris ligneux et herbacés, mais seule la première peut engendrer des volumes importants de pétrole. Les hydrocarbures gazeux se sont formés dans la zone de maturité avancée par cracking des hydrocarbures liquides et du kérogène. Dans le bassin Sverdrup, la limite supérieure de la zone de maturité commençante se situe à une profondeur maximale de 1500 m, celle de la zone mature à une profondeur maximale de 3000 m, la transition entre les zones mature et de maturité avancée à une profondeur maximale de 4300 à 4600 m.

Dans le bassin Sverdrup, en raison du faible degré de maturité, ou de l'absence de matière organique capable de produire des hydrocarbures, la majorité des roches d'âge paléozoïque supérieur et mésozoïque n'ont vraisemblablement donné naissance qu'à du gaz naturel. La formation de Schei Point (Trias moyen et supérieur) est une exception, et a probablement été la source des indices de pétrole et des "sables bitumineux" de l'île Melville. Le pétrole a sûrement commencé à exister dans la formation de Schei Point pendant le Crétacé inférieur, et la migration des hydrocarbures est probablement antérieure à l'orogenèse de l'Eureka.

Le gaz naturel des champs pétrolifères de Drake, Hecla et King Christian semble s'être formé à un degré relativement faible de maturation. Au contraire, le gaz du champ de Jackson Bay provient du faciès de maturité avancée.

Tous les sondages du géosynclinal franklinien et de la plate-forme de l'Arctique commencent par traverser les faciès matures ou de maturité avancée. Les sédiments de granulométrie fine rencontrés dans le prisme clastique dévonien et le faciès des argiles litées graptolitiques du paléozoïque inférieur ont un excellent potentiel roche-mère d'hydrocarbures. L'élément déterminant est la situation de la zone de transition du faciès mature au faciès de maturité avancée, où les condensats ou les gaz secs se substituent au pétrole. Le pétrole de Bent Horn, a probablement son origine dans les sédiments à grains fins de la formation de Bird Fiord qui fait partie du prisme clastique. C'est probablement entre le Dévonien moyen et le Dévonien supérieur que s'est formée la majeure partie du pétrole dans toutes les formations à potentiel de roche-mère.

Dans le cas de l'île Banks, les sédiments paléozoïques appartiennent surtout à un faciès de maturité avancée, tandis que les sédiments mésozoïques appartiennent à un faciès peu développé.

Critical Readers
N.E. HAIMILA
N.G. KOCH
L.R. SNOWDON

Technical Editor
E.R.W. NEALE

Artwork by CARTOGRAPHY SECTION,
Institute of Sedimentary and Petroleum Geology, Calgary

Manuscript received: October 10, 1977

Author's address: Institute of Sedimentary and Petroleum Geology
3303 - 33rd Street N.W.
Calgary, Alberta T2L 2A7

AN ASSESSMENT OF THE HYDROCARBON SOURCE ROCK POTENTIAL OF THE CANADIAN ARCTIC ISLANDS

INTRODUCTION

This report incorporates the results of petroleum geochemical studies carried out in the Arctic Islands by the Geological Survey of Canada during the period 1970 to 1977. The aim of these studies has been to define the levels of organic metamorphism in this area and their implication to the possible distribution of oil and gas: to identify potential hydrocarbon source rocks and to interpret what the expected hydrocarbon product might be, i.e. oil, gas, gas-condensate; to quantitatively estimate the volumes of migrateable oil a particular source sequence might have generated; and where possible to determine from which source sequence the presently known hydrocarbon accumulations were derived. The study falls into three parts:

1. The upper Paleozoic and Mesozoic sequence of the Sverdrup Basin.
2. The lower Paleozoic sequence of the Franklinian Geosyncline, the Arctic Platform and Boothia Uplift.
3. The lower Paleozoic and Mesozoic sequence of Banks Island.

To avoid possible deleterious effects of weathering, only subsurface samples have been used, so the study is restricted to those areas which have undergone exploration drilling.

Early work (to 1974) consisted chiefly of a reconnaissance geochemical study by analysis of cuttings for light hydrocarbon gases and organic carbon. A regional synthesis of levels of organic metamorphism based on these data has been made for the Sverdrup Basin by Snowdon and Roy (1975). They produced maps of the facies of organic metamorphism for the major stratigraphic units. Their interpretations will be reviewed and revised in the light of additional data. Since 1974, work has concentrated on the source potential of particular stratigraphic units both in the Sverdrup Basin and the Franklinian Geosyncline. Two published reports deal with the petroleum geochemistry of this area. Baker *et al.* (1975) suggested that the Triassic-Jurassic section in the Sverdrup Basin has good potential for gas but that certain intervals, particularly the Awingak-Savik (Jurassic), have a consistent potential for liquid hydrocarbon generation. Henao-Londoño (1977) has recently published a preliminary geochemical evaluation of the Arctic Islands which treats two aspects of the problem: a) source richness of critical units expressed in terms of organic carbon content; and b) maturation levels of these units expressed in terms of vitrinite reflectance. Several conclusions of this author, although largely unsupported in his text, are consistent with some of the conclusions expressed herein. These are:

a) Maturation levels vary greatly from immature to eometamorphosed, not only in the Sverdrup Basin but in the Franklinian Geosyncline.

b) In the Franklinian Geosyncline, favourable conditions exist for oil generation on Bathurst Island and along a large belt on the northern flank of the geosyncline on Melville Island. Everywhere else gas is the main product because of kerogen content or mainly because of high maturation levels.

c) The Sverdrup Basin is essentially a gas prone area. However, oil can be expected as a subsidiary product from Upper Triassic sources.

d) Migration from Upper Triassic sources appears to have taken place late in the history of the basin, probably not before late Early Cretaceous.

e) All gases found thus far are thermally derived.

f) At least four different types of oil have been identified thus far, three in the Sverdrup Basin, one in the Franklinian Geosyncline.

Some of Henao-Londoño's (1977) conclusions are not consistent with the present study. These are:

a) The main shale and siltstone formations in the Arctic Islands have enough organic carbon content to be considered potential source rocks. This potential ranges from excellent in the Upper Jurassic and Lower Devonian shales to good in most other fine-grained clastic units, except those of Middle to Early Devonian age which have only a marginal potential.

b) Oil can be expected as a subsidiary product from Jurassic sources over large portions of the western part of the basin or as a predominant product from the same source on small areas along the northern flank.

c) The largest volumes of hydrocarbons are to be expected from Triassic strata. Lower maturation levels limit locally the source of potential of the Jurassic shales and prevent the Lower Cretaceous formations from realizing their good source potential in the western part of the basins.

Differences between this study and that of Henao-Londoño (1977) can be traced to fundamentally different approaches to the problem of source rock evaluation which will be dealt with more fully below but can be summarized as follows.

A. In the study of Henao-Londoño (1977):
   1. A loose definition of a source rock or potential source rock.
   2. Use of carbon content as a guide to source richness.
   3. Use of general scheme of maturation in conjunction with descriptions of kerogen type.

4. Use of an assumed value of hydrocarbon content for all types of organic matter.

5. Assumption that all organic matter types respond to diagenesis in the same way and that hydrocarbon contents are the same throughout the mature zone.

B. In this study:

1. A precise definition of the term source rock or potential source rock.

2. Use of hydrocarbon yield (expressed as a proportion of the organic carbon) in conjunction with organic carbon content as a guide to source richness.

3. Use of a maturation scheme erected for use in the Arctic Islands.

4. Use of hydrocarbon concentrations with due regard to their variability and for their meaning in terms of source rock potential.

ACKNOWLEDGMENTS

L. R. Snowdon initiated geochemical work in the Arctic Islands and laid the ground work for the development of this project. Many people have contributed significantly by discussion of the geology, notably N.E. Haimila, D.G. Wilson, K.J. Roy, G.R. Davies, H.R. Balkwill, and A. Embry. The invaluable assistance of technicians, M. Northcott, M. Kahn and R. Evis, is gratefully acknowledged. The author wishes to thank N.E. Haimila, N.G. Koch and L.R. Snowdon for reviewing the manuscript.

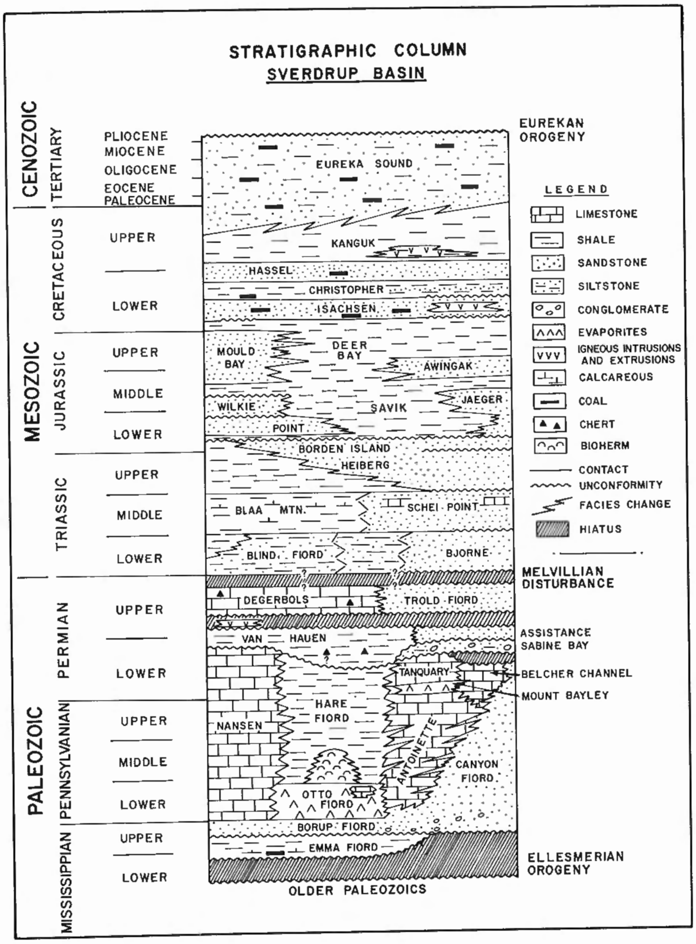


FIGURE 1. Generalized and composite stratigraphic section of the Sverdrup Basin (after Stuart-Smith and Wennekers, 1977, published with permission of AAPG Bulletin).

GEOLOGICAL SETTING

GEOLOGICAL PROVINCES OF THE ARCTIC ISLANDS

The regional geology of the Arctic Archipelago has been described by Thorsteinsson and Tozer (1970). The major geological provinces as defined by them are the Arctic Platform, Boothia Uplift, Franklinian Geosyncline, Sverdrup Basin, Prince Patrick Uplift and Arctic Coastal Plain (Fig. 3).

The Arctic Platform comprises flat-lying or little disturbed sedimentary strata overlying Precambrian basement. These strata are for the most part of Cambrian to Late Devonian age. The Boothia Uplift (including the Cornwallis Fold Belt) is composed of Precambrian rocks which are flanked by folded Cambrian and Lower Devonian sedimentary rocks, and it bisects the Arctic Platform. The Franklinian Geosyncline was the site of more or less continuous sedimentation between late Precambrian and Late Devonian times. It is now the site of a complex fold belt which is called the Parry Islands Fold Belt west of the Boothia Uplift. To the west, the Parry Islands Fold Belt is terminated by the Eglinton Graben which contains approximately 2100 m of Mesozoic strata (Miall, 1975) and is probably continuous with the Banks Basin to the southwest. Post-Paleozoic (Jurassic to Tertiary) sediment thicknesses are of the order of 1800 m in the Banks Basin (Miall, 1975). In contrast to the Sverdrup Basin, no Triassic strata are known from Banks Island. The Prince Patrick Uplift, as defined by Thorsteinsson and Tozer (1970), consisted of a series of Paleozoic and Precambrian inliers aligned in a northerly trend through Prince Patrick and Banks Islands. This definition has been modified by Miall (1975), who confined the term to the Paleozoic high on Prince Patrick Island. The structural high running through western Banks Island is termed the Storkerson Uplift (Miall, 1975).

The Sverdrup Basin is a regional depression superimposed on the Franklinian Geosyncline. It contains an essentially concordant succession of formations ranging in age from Early Carboniferous to Late Cretaceous. The basin today is a great synclinorium, the axis of which extends northeast for 900 km from northern Melville Island to northern Ellesmere Island. The Arctic Coastal Plain comprises a narrow strip of relatively undisturbed Pliocene and Pleistocene sediments that unconformably overlie the rocks of the Prince Patrick Uplift and Sverdrup Basin along the margin of the Arctic Ocean.

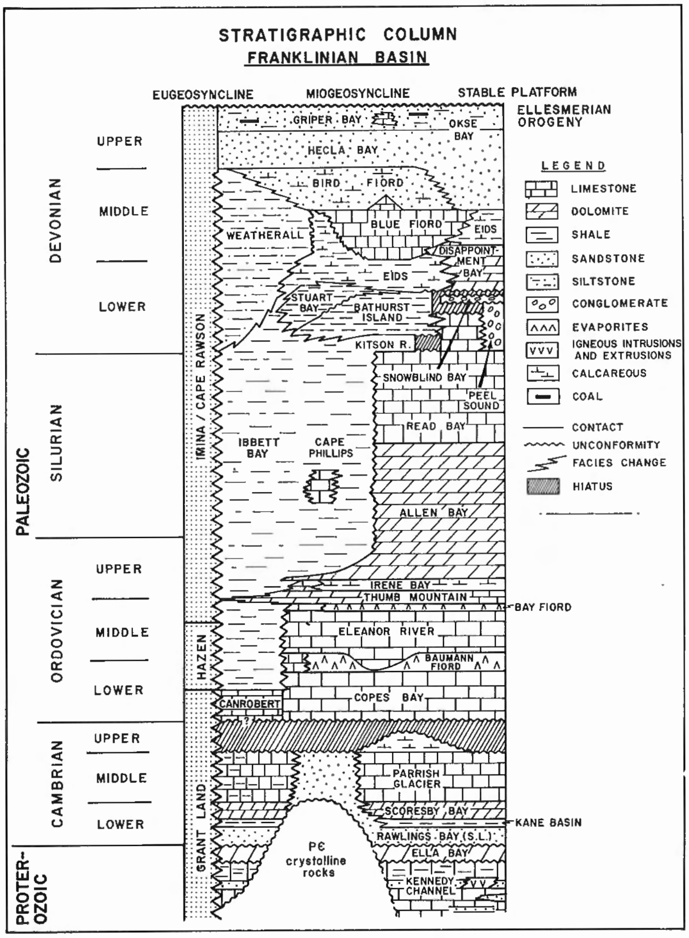


FIGURE 2. Generalized and composite stratigraphic section of the Arctic Platform and Franklinian Geosyncline (after Stuart-Smith and Wennekers, 1977, published with permission of AAPG Bulletin)

STRATIGRAPHY AND GEOLOGICAL HISTORY (OUTLINE)

A generalized and composite stratigraphic section of the Canadian Arctic Archipelago is shown in Figures 1 and 2. Drummond (1973) has succinctly described the tectonic and depositional history as follows:

1. Cambrian sedimentation is characterized by nearshore facies, zero to 457 m thick, mapped more or less continuously in a narrow belt fringing the shield. A miogeosynclinal sequence, with a lower sandstone unit and an upper carbonate unit, outcrops on northeastern Ellesmere Island, up to 2940 m thick. All these rocks are Lower and Middle Cambrian, with no known occurrence of Upper Cambrian beds.

2. Ordovician-Silurian-Lower Devonian sedimentation in the Franklinian Geosyncline is characterized by periods of carbonate shelf and/or bank deposition with equivalent evaporite and/or shale deposition. The section ranges in thickness from 1500 m on the basin margins to 5500 m in the axial area. Deposition was continuous through the Ordovician to Late Silurian. Beginning in Late Silurian and to the end of the Early Devonian, certain areas were locally uplifted during the mid-Paleozoic epeirogeny with the deposition of syntectonic clastics.

3. Widespread Middle Devonian deposition followed, after a period of erosion in areas affected by the mid-Paleozoic epeirogeny and without interruption in unaffected areas. Middle and Upper Devonian sediments up to 5200 m thick of variable lithologies grade upward in the section from marine carbonates and clastics to nonmarine clasitics. These sediments were subsequently deformed into the various structures of the Franklinian fold complex during the Ellesmerian Orogeny.

4. Following the Ellesmerian Orogeny, the Sverdrup Basin began its development during Mississippian time. There followed a period of continuous deposition from at least the Middle Pennsylvanian to the early Tertiary, characterized by the deposition of 12 200 to 13 700 m of an alternating succession of nonmarine and marine facies, reflecting periodic changes from nearshore to offshore conditions due to transgressions and regressions of the sea. The Sverdrup Basin sediments have been intruded by igneous dykes and sills during the Cretaceous and were subsequently deformed to a variable degree during the Eurekan Orogeny.

5. The final sedimentary phase in the Arctic was the deposition of nonmarine sediments of late Tertiary and Pleistocene age of the Arctic Coastal Plain.

HYDROCARBON OCCURRENCES

Stuart-Smith and Wennekers (1977) have provided a comprehensive review of the hydrocarbon occurrences in the Arctic Islands. Only the major occurrences will be mentioned here. The only oil encountered in lower Paleozoic rocks occurs in mid-Devonian carbonates (probably Blue Fiord Formation) in the Bent Horn Field on Cameron Island (Fig. 3). Several wells have encountered light oil (density 792.7 kg/m^3; 47° API) in this area. In the Sverdrup Basin, oil shows have been encountered in Lower and Middle Triassic rocks in the vicinity of the Sabine Peninsula of Melville Island (Fig 3). High density oils (946.4-921.8 kg/m^3; 18-22° API) were recovered from the Bjorne sandstone in the Drake L-67 and West Hecla P-62 wells (Fig. 1). Lower density oils (84.8 kg/m^3; 35.2° API) have been recovered from the Schei Point Formation in the North Sabine H-49 well. On northwestern Melville Island, sandstones assigned to the Bjorne Formation are saturated with tar over a significant area. Calculations of tar in place range from 16 to 41 x 10^6 m^3 (Stuart-Smith and Wennekers, 1977) but the grade of deposits is low (less than 6% bitumen by weight). In the Sverdrup syncline on Ellesmere Island, the Romulus C-42 well yielded hydrocarbons from four different horizons. Gassy oil (883.8 kg/m^3; 28.6° API) was recovered from a Jurassic sandstone whereas gas-condensate was encountered in the Schei Point Formation and the Bjorne sandstone. One well on Thor Island (Thor P-38) flowed light oil (825.0 kg/m^3; 40° API) to surface from the upper part of the Borden Island Formation.

Seven gas fields have been discovered to date in the Sverdrup Basin (Fig. 1) with total reserves in excess of 280 x 10^9 m^3. All the fields occur in the Borden Island-Heiberg sand complex (Lower Jurassic-Upper Triassic) and contain exclusively dry gas

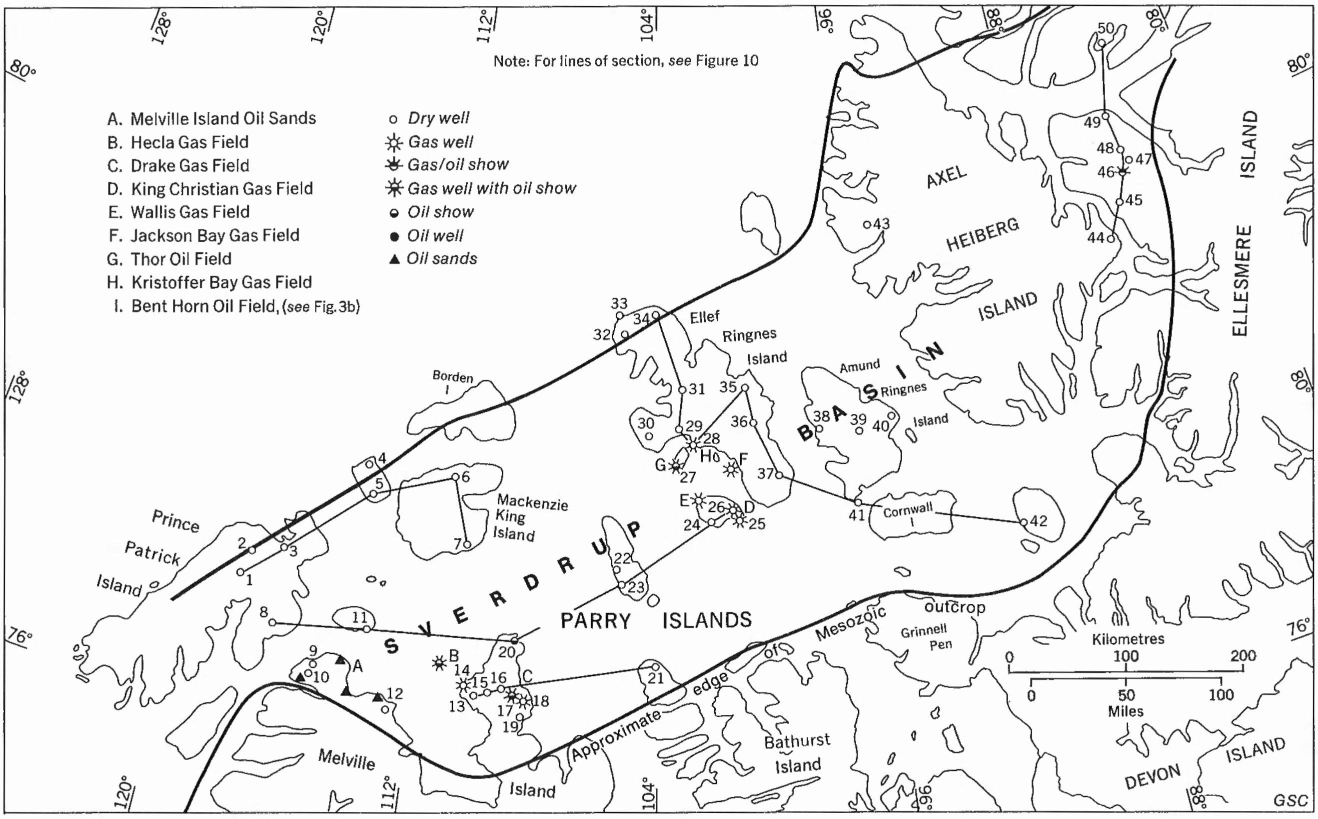


FIGURE 3A. Sverdrup Basin

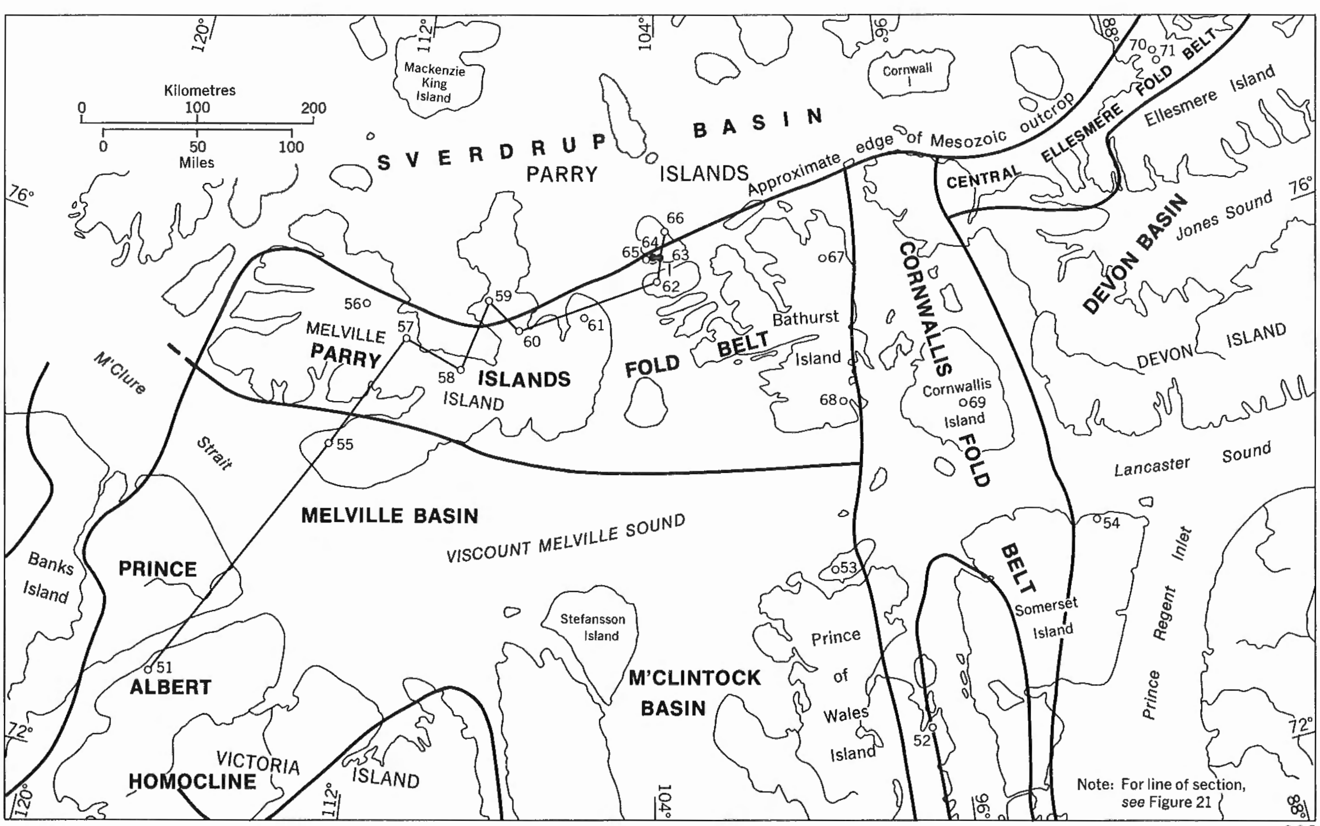


FIGURE 3B. Franklinian Geosyncline and Arctic Platform

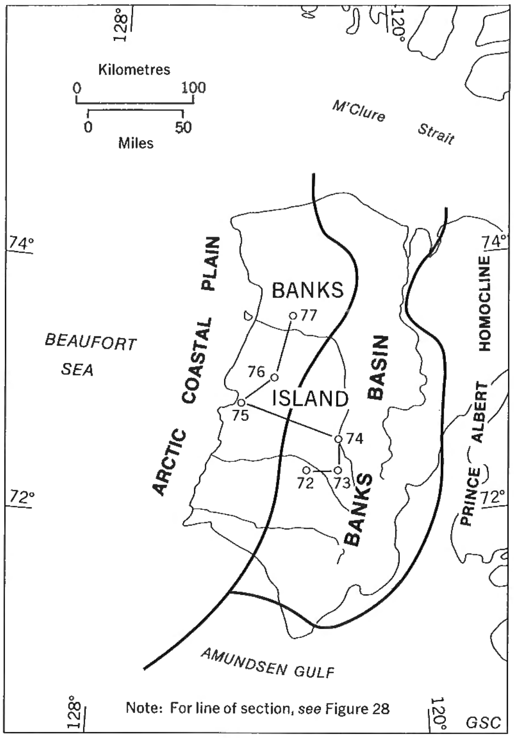


FIGURE 3C. Banks Island

(Drummond, 1973). Two large fields (Hecla and Drake) flank the Sabine Peninsula of Melville Island. They occur in structures draped over ancestral highs. The remainder of the fields (King Christian, Thor, Kristoffer, Wallis and Jackson Bay) occur in presumed halokinetic structures (Balkwill, in press) on western Ellef Ringnes Island and smaller adjacent islands.

SAMPLES AND METHODS

ANALYTICAL PROCEDURE

Reconnaissance geochemical analyses have been carried out routinely for the majority of exploration wells in the Arctic Island (Fig. 3). The method has been described by Snowdon and McCrossan (1973). Briefly, samples of cuttings which had been canned at the well site were homogenized in a gas tight blender. A sample of the blender headspace was analyzed for methane, ethane, propane and butanes. In certain of the wells, the can headspace was analyzed for hydrocarbon gases prior to analysis of the cuttings. In these cases (*see* Table 1), the concentrations of gases reported represent the sum of the two sets of analyses.

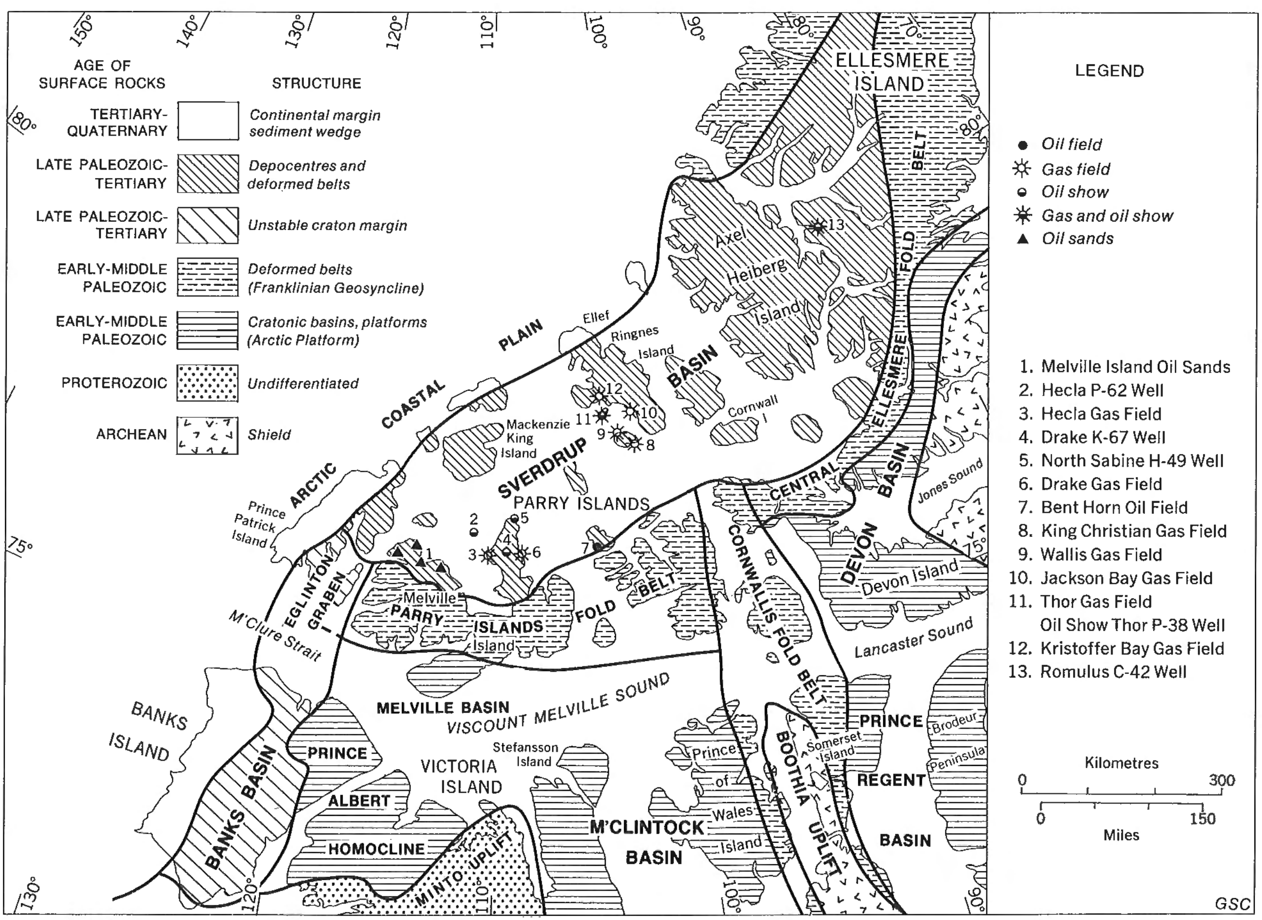


FIGURE 3D. Index map

FIGURE 3. Principal structural units of the Arctic Islands and hydrocarbon occurrences and location of wells with geochemical data (*see* Tables 1-3 for well names and locations)

TABLE 1

Sverdrup Basin - location of wells sampled and extent of analysis.

WELL NO.	WELL NAME	LOCATION		GAS LOG	CARBON LOG	NUMBER OF SAMPLES			
		LATITUDE N	LONGITUDE W			EXTRACT	KEROGEN H/C	KEROGEN MICRO-SCOPE	KEROGEN %Ro
1	Elf Intrepid Inlet H-49	76°58'26"	118°45'03"	X	X	2			
2	Elfex Andreason L-32	77°11'37"	118°14'14"	X	X	3			
3	BP *et al.* Panarctic Satellite F-68	77°17'27"	116°55'10"	X	X	8	2	1	1
4	Panarctic Brock I-20	77°59'40"	114°33'51"	X	X				
5	Panarctic *et al.* Brock C-50	77°49'00"	114°17'24"	X	X	3	1	1	
6	Elf Wilkins E-60	77°59'19"	110°21'45"	X	X	4	1	1	
7	Elf Cape Norem A-80	77°29'13"	110°27'05"	X	X	9	1	21	17
8	Elf Jameson Bay C-31	76°40'12"	116°43'45"	X	X	5	1	1	
9	Panarctic Sandy Point L-46	76°25'38"	115°18'14"	X	X	4	1	1	3
10	Panarctic Marie Bay D-06	76°21'01"	115°33'31"	X	X	1			9
11	BP *et al.* Emerald K-33	76°42'43"	113°43'21"	X	X	9	2	1	2
12	Sun KR Panarctic Kitson River C-71	76°10'12"	112°58'56"	X	X	4			
13	Panarctic Hecla J-60	76°19'37"	110°19'49"	X	X	3			
14	Panarctic Tenneco *et al.* POR Hecla F-62	76°21'17"	110°24'31"	X	X				
15	Panarctic *et al.* Chads Creek B-64	76°23'08"	109°54'21"	X+		9			
16	Panarctic Drake Point K-67	76°26'45"	108°55'13"						
16	Panarctic Drake Point L-67	76°26'36"	108°55'23"	X	X	6			2
17	Panarctic *et al.* Drake Point D-68	76°27'05"	108°55'43"	X	X	21	13	40	18
18	Panarctic Tenneco *et al.* POR Drake F-16	76°25'15"	108°35'38"	X	X				
19	Panarctic Dome *et al.* Sherard Bay F-14	76°13'20"	108°35'52"	X					
20	Panarctic Hmstd. POR N. Sabine H-49	76°48'15"	108°45'11"	X	X	23	6	30	18
21	Panarctic Tenneco Robert Harbour K-07	76°36'32"	104°02'14"	X	X	8	4	2	
22	Panarctic Tenneco *et al.* Pat Bay A-72	77°21'02"	105°26'57"	X+					
23	Sun KR Panarctic Skybattle Bay C-15	77°14'12"	108°05'57"	X	X	8	3	29	15
24	Dome Arctic Ventures Sutherland O-23	77°42'53"	102°08'39"	X	X	8			
25	Panarctic King Christian D-18	77°47'03"	101°07'06"	X	X				
26	Panarctic Tenneco *et al.* King Christian N-06	77°45'54"	101°02'19"	X	X	14	2	2	1
27	Panarctic Tenneco *et al.* Thor P-38	78°07'51"	103°15'13"	X	X	10	4	3	
28	Panarctic Tenneco *et al.* Kristoffer Bay B-06	78°15'18"	102°32'00"	X	X	13			
29	Panarctic Dome Tenneco *et al.* Dome Bay P-36	78°25'52"	103°47'54"	X	X	6			1
30	Panarctic Noice G-44	78°23'23"	104°21'39"	X	X	5			
31	Panarctic Dome Tenneco *et al.* Louise O-25	78°44'57"	102°41'58"	X	X	9			
32	Panarctic Tenneco *et al.* Pollux G-60	79°09'23"	104°57'23"	X	X	7			
33	Panarctic *et al.* Isachsen J-37	79°16'39"	105°16'35"	X	X				1
34	Panarctic Home Tenneco *et al.* Sirius K-28	79°17'34"	103°43'38"	X	X				
35	Panarctic Gulf Helicopter J-12	78°41'33"	100°36'49"	X	X	18	2	3	
36	Panarctic Gulf Dumbells E-49	78°28'24"	100°24'12"	X	X	13			
37	Panarctic Hoodoo Dome H-37	78°06'27"	99°45'38"	X	X	7	2	2	
38	Panarctic Gulf West Amund I-44	78°23'41"	97°50'16"	X	X				
39	Panarctic Amund Central Dome H-40	78°19'28"	96°15'51"	X	X				
40	Imp. Panarctic Union PPL E. Amund M-05	78°24'48"	95°04'24"	X	X				
41	Sun Gulf Global Linckens Is. P-46	77°45'47"	97°45'26"	X	X	3			1
42	BP *et al.* Graham C-52	77°21'14"	90°51'25"	X	X	6			
43	Horn River CCS Getty Mid Fiord J-73	79°52'37"	94°57'10"	X	X	2			
44	Panarctic CS May Point H-02	79°21'24"	85°00'47"	X	X	3			
45	Panarctic Fosheim N-27	79°36'54"	84°43'19"	X	X	2			
46	Panarctic Romulus C-42	79°51'04"	84°22'41"	X	X	8			
47	Panarctic Union Arco Taleman J-34	79°53'41"	83°46'53"	X	X	2			
48	Panarctic Gemini E-10	79°59'22"	84°04'10"	X	X	4			10
49	Panarctic Halcyon O-16	80°15'53"	84°06'40"	X	X	2			
50	Gulf WC *et al.* Neil O-15	80°44'45"	85°06'50"	X		3			

For wells *see* Figures 3a and 10

+ Gas analyses performed on can head space and cuttings

TABLE 2

Franklinian Geosyncline and Arctic Platform - location of wells sampled and extent of analysis.

WELL NO.	WELL NAME	LOCATION		GAS LOG	CARBON LOG	NUMBER OF SAMPLES			
		LATITUDE N	LONGITUDE W			EXTRACT	KEROGEN H/C	KEROGEN MICRO-SCOPE	KEROGEN %Ro
51	Murphy *et al.* Victoria Island F-36	72°45'18"	117°11'13"	X+	X	3			
52	KMG Decalta Young Bay F-62	72°41'23"	96°49'34"	X+					
53	Sun Panarctic Russel E-82	73°51'29"	98°56'48"	X	X	3			
54	Panarctic Deminex Garnier O-21	73°49'52"	90°36'45"	X	X				
55	Panarctic Dome Dundas C-80	74°39'02"	113°22'59"	X	X	8	2	2	
56	Panarctic Tenneco *et al.* Zeus F-11	75°50'22"	113°36'24"	X	X	3			
57	Panarctic Apollo C-73	75°32'00"	111°58'58"	X	X	6			
58	Panarctic, Standard Sabine Bay A-07	75°26'06"	110°00'49"	X+	X	4			
59	Panarctic Eldridge Bay E-79	75°58'21"	109°29'38"	X	X	8	3	2	
60	Dome Panarctic Texex Weatherall O-10	75°49'52"	108°31'50"	X	X	6	2	3	
61	Panarctic Towson Point F-63	75°52'17"	106°24'37"	X	X	3			
62	BP *et al.* Hotspur J-20	76°09'37"	104°04'43"	X	X	10	1		9
63	Panarctic Tenneco *et al.* Bent Horn N-72	76°21'51"	103°58'12"	X	X	7	4	3	8
64	Panarctic Bent Horn F-72/F-72A	76°21'27"	103°58'15"	X+			4		
65	Panarctic *et al.* West Bent Horn C-44	76°23'09"	104°17'10"	X+	X	12	6	5	
66	Panarctic Cape Fleetwood M-21	76°30'48"	103°40'37"	X+		12	5	2	
67	Sun KR Panarctic Young Inlet D-21	76°20'10"	98°40'30"	X	X	4			
68	Sun KR Panarctic Allison River N-12	75°11'52"	98°35'42"	X	X	4			
69	Panarctic Deminex Cornwallis Central Dome K-40	75°09'40"	96°43'13"	X	X	7			
70	Panarctic Tenneco *et al.* Eids M-66	77°25'58"	86°26'07"	X		6			
71	Panarctic ARCO *et al.* Blue Fiord E-46	77°15'27"	86°18'08"			6			

For wells *see* Figures 3b and 21

+ Gas analyses performed on can head space and cuttings

TABLE 3

Banks Island - location of wells sampled and extent of analysis.

72	Deminex CGDCFOC Amoco Orksut I-44	72°23'44"	122°42'08"	X	X	3			
73	Columbia *et al.* Amoco Ikkariktok M-64	72°23'46"	121°50'48"	X					
74	Elf Texaco Tiritchik M-48	72°47'51"	120°44'48"	X	X	3			
75	Elf *et al.* Storkerson Bay A-15	72°54'00"	124°33'29"	X	X	3			
76	Elf Nanuk D-76	73°05'13"	123°23'45"	X	X				
77	Elf Uminmak H-07	73°36'29"	123°00'30"	X	X	1			

For wells *see* Figures 3c and 28

The organic carbon content of the cuttings was also determined. Samples of cuttings from 9 to 15 m (30-50 ft) intervals from each well were analyzed. The results were plotted in a log against depth and record the variations in total gas content (ppm by volume of rock), per cent wet gas (C_2-C_4/C_1-C_4 x 100) organic carbon content (weight per cent) and, if appropriate, the iso- to normal butane ratio.

The cuttings gas and organic carbon data formed the basis for selection of samples for solvent extraction. Samples were selected where:

a) there was a high gas content; or
b) there was a high organic carbon content.

In addition, where possible, care was taken to ensure that formations containing appreciable amounts of organic carbon were sampled at all stages of maturity.

For the purposes of extraction, cuttings samples were washed to remove drilling mud, dried at 40°C overnight and crushed to less than 149 µm (100 mesh). The organic carbon content of the cuttings was determined and the sample extracted for 24 hours using a mixture of benzene and methanol (60:40) in a Soxhlet apparatus. Evaporation of the solvent yielded the extract as a brown gum. Elemental sulphur was removed by treatment with colloidal copper after the method of Blumer (1957). The extract was dissolved in a minimum amount of chloroform and the asphaltenes were precipitated by additions of n-pentane. The fraction soluble in pentane was chromatographed on alumina (Grade 1) which was eluted successively with pentane, benzene and methanol to yield the saturated hydrocarbons (paraffins plus naphthenes), aromatic hydrocarbons and oxygen-, nitrogen- and sulphur-bearing compounds. The saturated hydrocarbons were analyzed by gas chromatography using a 4.8 m x 3.2 mm stainless steel column packed with 30 per cent eutectic salt (54.5% KNO_3, 27.3% $LiNO_3$, 18.2% $NaNO_3$) (Snowdon and Peake, in press) on 177 to 149 µm Chromosorb W. N-alkanes and the C_{18}-C_{20} isoprenoid alkanes were quantitized using an internal standard technique.

On the basis of the extract data, a number of samples were selected for the isolation of the insoluble organic matter (kerogen) and subsequent elemental analysis for carbon, hydrogen and nitrogen. Samples were chosen to represent a number of pertinent formations containing a variety of types of organic matter. Kerogen isolation procedures were essentially those used by Powell *et al.* (1975), although treatment with sodium borohydride to remove pyrite was not attempted.

Kerogen types and vitrinite reflectance values have been determined on a limited number of samples by P.R. Gunther who has previously described the techniques (Gunther, 1976). In this report the following terms are used to describe the organic matter. Coaly refers to black, angular, opaque fragments of indeterminate origin. Woody organic matter comprises elongate internally structured material ranging from yellow to dark brown. Herbaceous refers to spores, pollen and membranous material ranging from yellow to dark brown. Amorphous refers to unstructured, fluffy and diaphanous material presumably derived from the decayed remains of algae and bacteria.

Crude oil samples were distilled to 210°C and the asphaltenes were removed from the residues. The asphaltene-free fractions were separated into saturated hydrocarbons, aromatic hydrocarbons and ONS compounds (oxygen-, nitrogen-, and sulphur-bearing compounds) by liquid chromatography. The saturated hydrocarbons were analyzed by gas chromatography using a eutectic salt column and n-alkanes and isoprenoids were quantitized using the internal standard technique. Stable carbons isotope ratios were determined on the saturated and aromatic hydrocarbons of the oils and selected extracts by Global Geochemistry Corporation of California and are quoted as δC^{13}°/∘∘ values relative to the PDB standard. Stable carbon isotope ratios of methane from natural gas from several fields in the Arctic have been determined by W. Stahl of the Geological Survey of West Germany.

DATA BASE

Gas analyses and organic carbon determinations have been made on 50 wells from the Sverdrup Basin (Table 1). On the basis of this data, 282 samples were selected for extraction and heavy hydrocarbon analysis. Kerogens were isolated from 45 samples for elemental analysis and 30 kerogen samples were prepared for microscopical examination. Vitrinite reflectance profiles have been obtained on four complete wells (sampled at approximately 150 m intervals) and vitrinite reflectance measurements have been made on an additional 59 samples from 12 wells. Visual kerogen data have also been obtained at approximately 150 m intervals in the 3 wells on which complete vitrinite reflectance data have been obtained.

In respect of the Arctic Platform and Franklinian Geosyncline, 21 wells have been analyzed for cuttings gas and organic carbon (Table 1). Heavy hydrocarbon analyses were conducted on 114 samples and elemental analyses were obtained on 27 kerogen samples of which 17 were examined microscopically. Vitrinite reflectance data have been obtained on 2 wells. Six wells from Banks Island have been analyzed for cuttings gas and organic carbon. Only 12 heavy hydrocarbon analyses have been made from this area.

RECOGNITION OF CONTAMINATION

Geological samples collected from boreholes are readily contaminated by refined products used in drilling operations. Diesel oil and pipe grease are commonly used to facilitate drilling. Contamination of cuttings samples with these hydrocarbons is not uncommon (Fig. 4). Diesel oil has a narrow distillation range and, since n-alkanes are not commonly present, a sharp narrow hump in the range C_{16} to C_{20} occurs in the gas chromatograms of the saturated hydrocarbons. If the contamination is severe, then the hydrocarbon yield may be excessive and the saturate to aromatic ratio will be high.

Pipe grease is the other common contaminant (Fig. 4). Again a hump of naphthenic alkanes is the point of recognition. In this case the hump is broader and reaches a maximum at nC_{26}. Contamination is rarely severe except in samples with very low hydrocarbon yields.

Another form of contamination has recently been recognized which applies only to cores. In this case the nC_{20} and nC_{21} alkanes are enriched (Fig. 4). This is due to absorption of the more volatile components of wax from the waxed cardboard core boxes in which cores are shipped and stored (Snowdon and Powell, in press). Again this is only severe in samples with low hydrocarbon yields.

MATURATION AND SOURCE ROCK CRITERIA

DEFINITION OF MATURATION LEVELS

Petroleum hydrocarbons are generated from the organic material in sedimentary rocks at elevated temperatures which reflect the geothermal gradient and depth of burial (e.g. Philippi, 1965; Tissot *et al.*, 1971). The degree of thermal diagenesis of sedimentary organic matter can be defined by a number of parameters: coal rank or reflectance (Teichmuller, 1971), spore colour (Staplin, 1969), cuttings gas analysis (Evans and Staplin, 1971), kerogen composition (McIver, 1967), and the nature of sedimentary hydrocarbons themselves (Philippi, 1965). In this study, cuttings gas analysis has been used extensively and has been supported by heavy hydrocarbon analysis, vitrinite reflectance and, to a lesser extent, kerogen composition.

At the immature stage of diagenesis (prior to the onset of hydrocarbon generation), methane is the sole gaseous hydrocarbon present in sedimentary rocks (Evans and Staplin, 1971; Snowdon and McCrossan, 1973). As diagenesis proceeds, the higher gaseous hydrocarbons (ethane through butanes) are generated by thermal reactions. A wet gas content of above 30 per cent (ΣC_2-C_4/ΣC_1-C_4 x 100) represents the beginning of the mature stage (zone of hydrocarbon generation) from the standpoint of gas analysis (Snowdon and McCrossan, 1973; Snowdon and Roy, 1975). When the wet gas content of the cuttings gas exceeds 60 per cent, the fully mature stage has been reached. As diagnesis proceeds, the organic matter continues to undergo cracking reactions. Liquid hydrocarbons are transformed to methane and the residual organic matter tends to become graphite. The transition from the mature to the overmature zone is determined by a decrease in wet gas content to below 30 per cent. It was on this basis

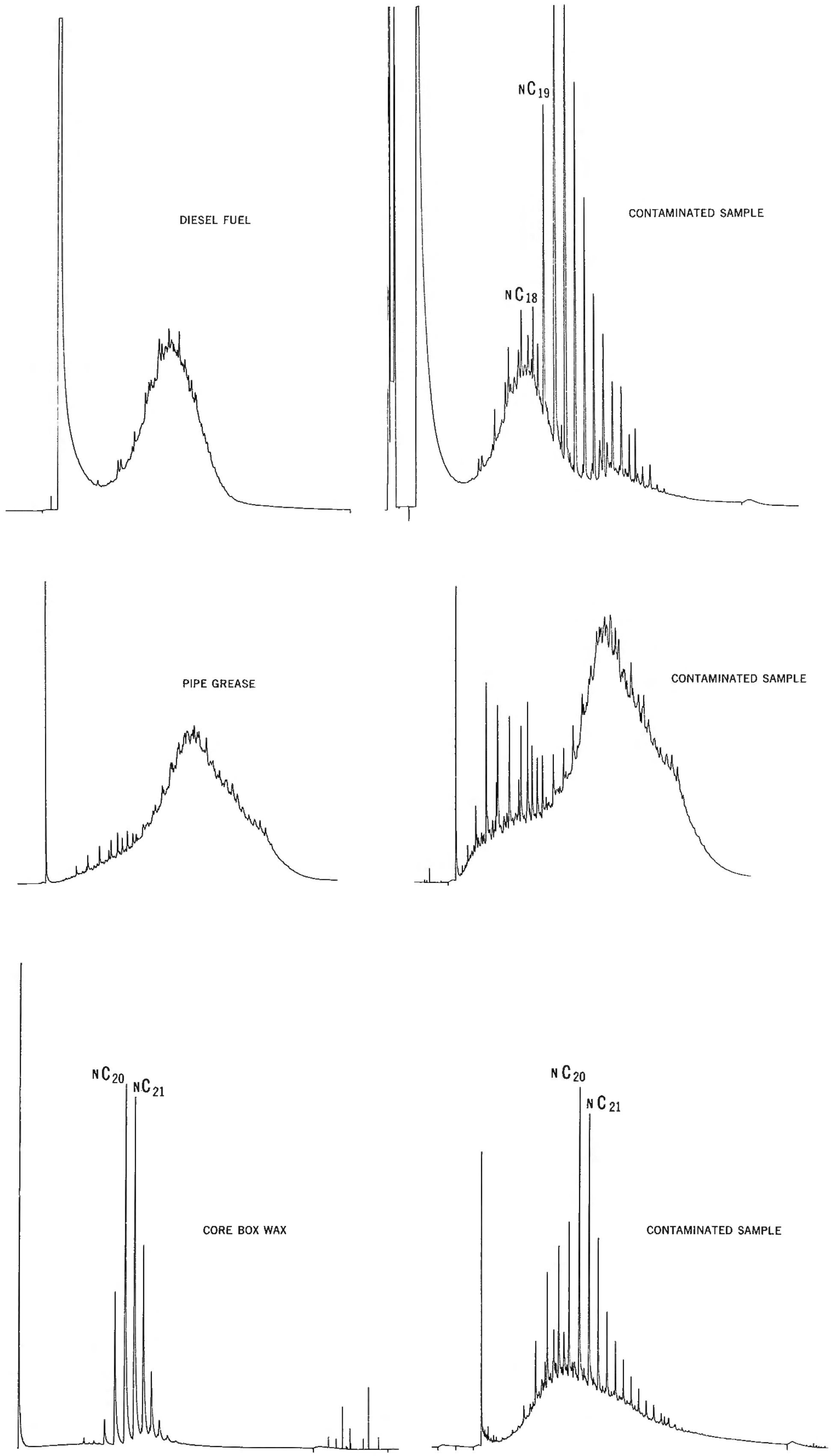


FIGURE 4. Gas chromatograms of saturated hydrocarbons from diesel oil, pipe grease, core box wax and respectively contaminated samples

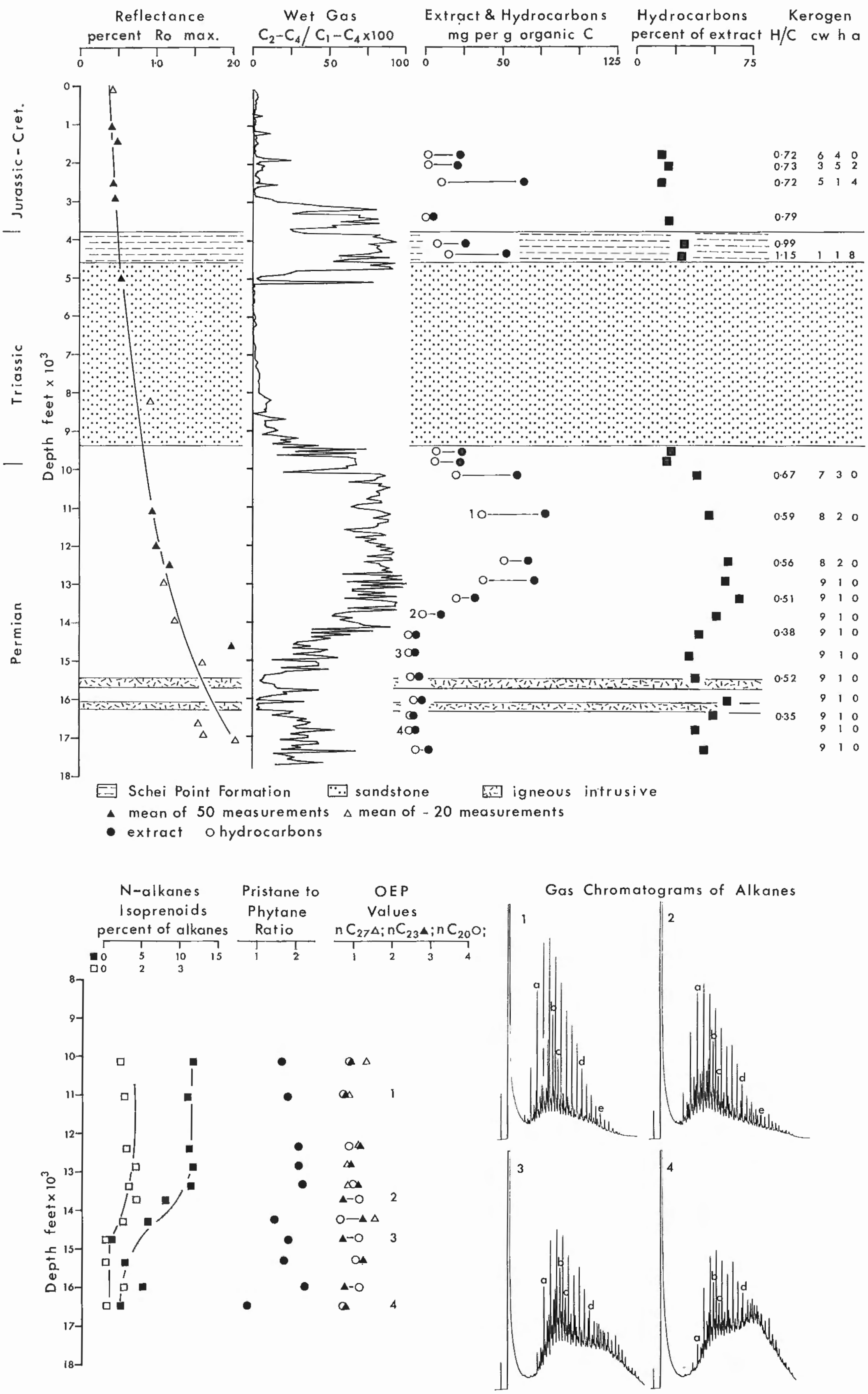


FIGURE 5. Geochemical results obtained for the Drake D-68 well. Kerogen: H/C = atomatic hydrogen to carbon ratio; CW = coaly woody; h = herbaceous; a = amorphous. Gas chromatograms: a = nC_{15}; b = pristane; c = phytane; d = nC_{23}; e = nC_{27}

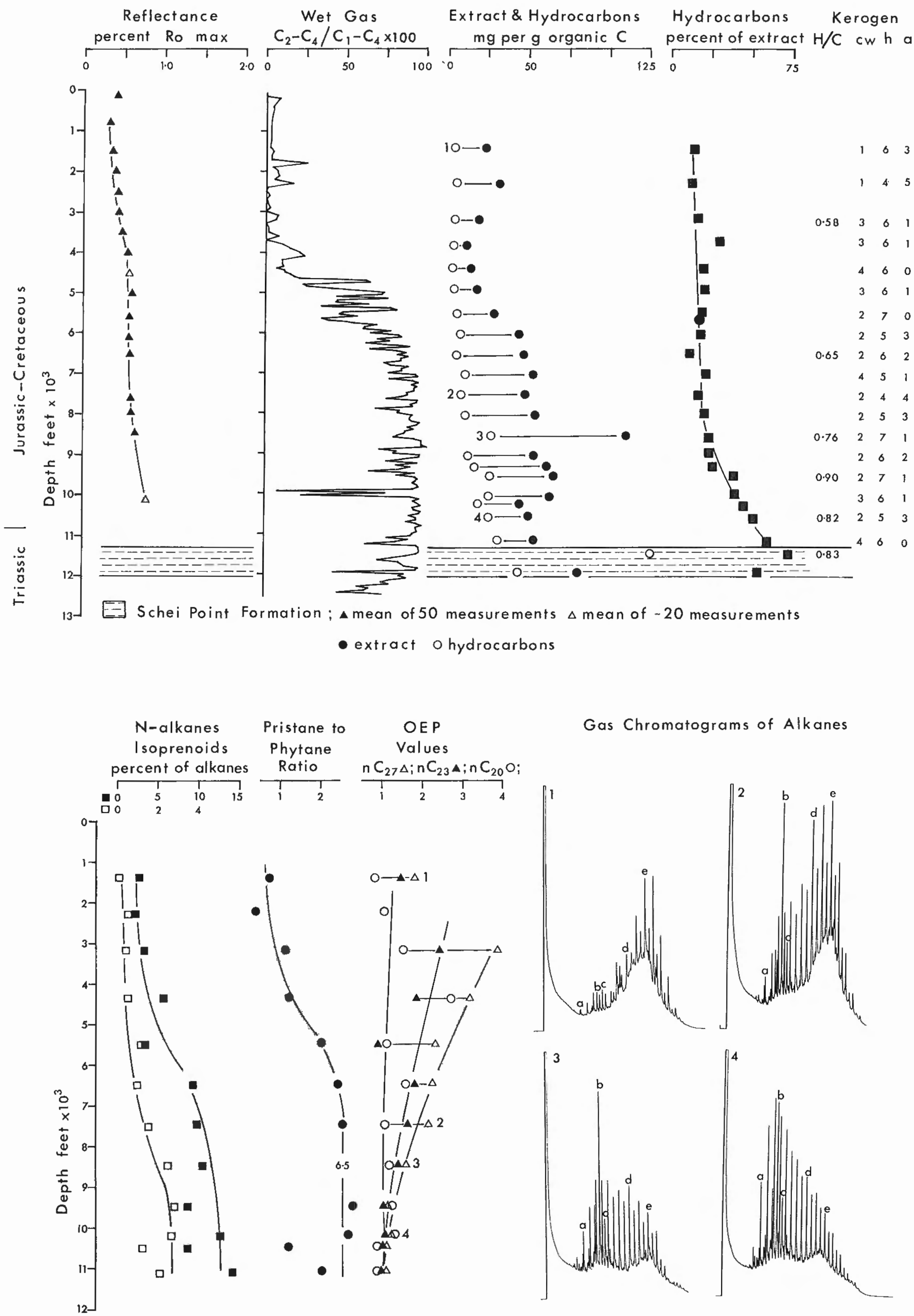


FIGURE 6. Geochemical results obtained for the North Sabine H-49 well (*see* Fig. 5 for key)

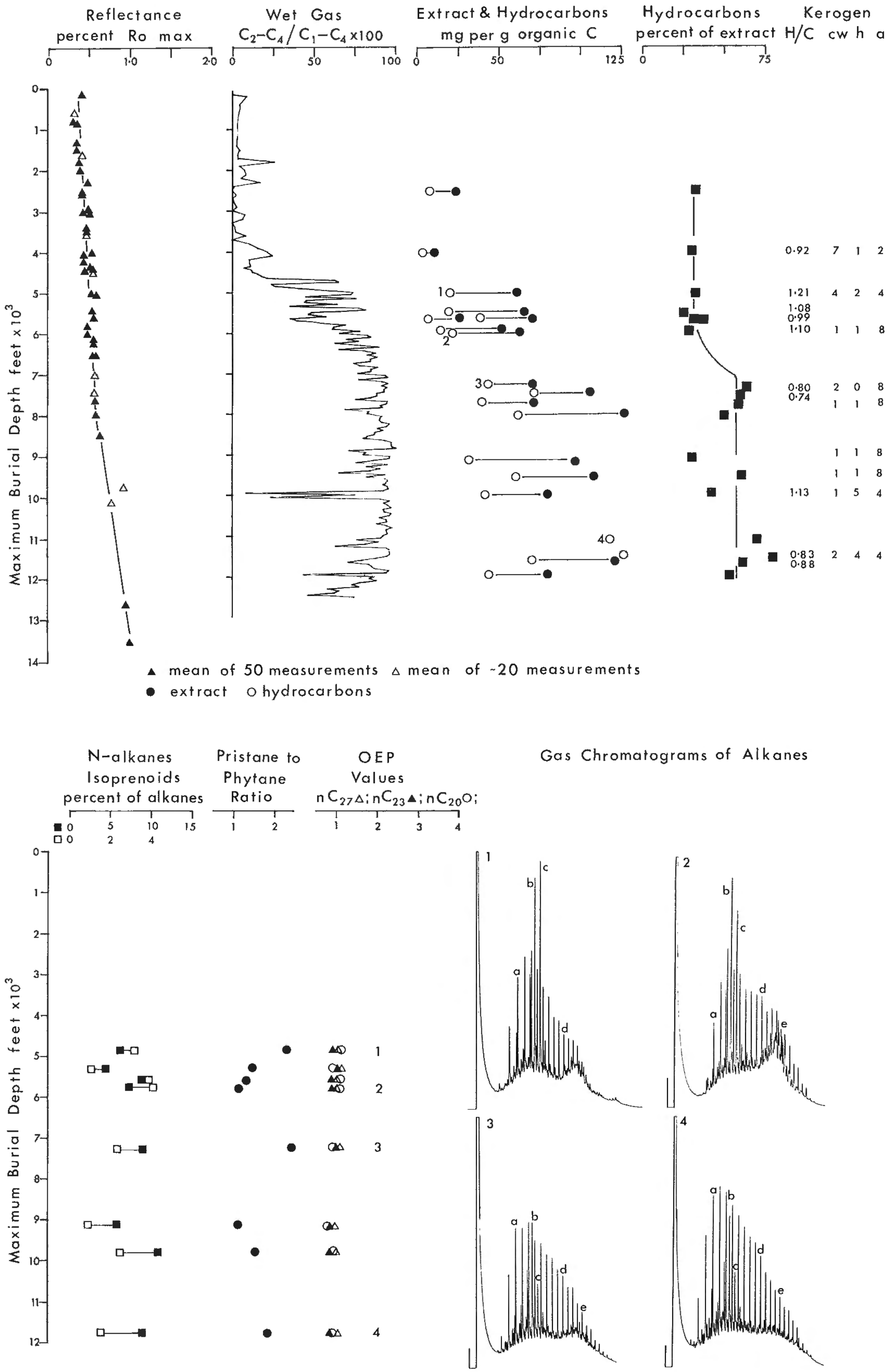


FIGURE 7. Geochemical results obtained for the Schei Point Formation. Gas log is that from the North Sabine H-49 well. Reflectance values are those obtained in the Drake D-68, North Sabine H-49, Cape Norem A-80 and Skybattle Bay C-15 wells

that Snowdon and Roy (1975) constructed maps of organic metamorphic facies for the bases of the major stratigraphic units in the Sverdrup Basin. It must be pointed out at this stage that certain rock types, sandstones, coals, and clean limestones, commonly yield relatively dry gas even within the mature zone. This phenomenon is related to the type of organic material in these rocks, namely coaly or highly proteinaceous, and may lead to misleading interpretations of maturation level.

As extract work continued, it became increasingly apparent that the onset of the wet gas zones occurred at an earlier stage of diagenesis than the generation of heavier hydrocarbons. Philippi (1965), Tissot *et al.* (1971), and Albrecht and Ourisson (1969) have demonstrated that, as thermal diagenesis proceeds, the yield of extractable organic matter expressed as a proportion of the organic carbon increases. The composition of the extractable hydrocarbons also changes. The predominance of odd carbon numbered n-paraffins over even carbon numbered n-paraffins in the range C_{23} to C_{33} disappears. The maximum in the n-alkane distribution shifts to lower carbon numbers and the steranes and triterpanes decrease in concentration relative to the lower molecular weight cyclo-alkanes. In order to establish the relationship between the cuttings gas data and other maturation indicators such as vitrinite reflectance, a detailed examination of two wells was undertaken. This aspect of the project forms part of a continuing study of the relationship between different maturation parameters (Foscolos *et al.*, 1976; Powell *et al.*, in prep.).

It is quite clear from the studies of the Drake D-68 and North Sabine H-49 wells (Figs. 5, 6) that the onset of the wet gas predominance in the cuttings gas does not coincide with an increase in the yield of extractable heavy hydrocarbons in these wells. The kerogens from most of the samples from these wells have atomic hydrogen to carbon ratios of less than 0.8 which is indicative of coal-like, poor source material (Tissot, Durand, Espitalié and Combaz, 1974). The gas chromatograms, particularly in the upper part of the two wells, show a pronounced odd over even predominance indicative of material derived from higher plants (Powell and McKirdy, 1973). The visual kerogen descriptions also point to a preponderance of woody and herbaceous (land plant derived) organic matter. Exceptions occur at relatively shallow depths in both wells.

In both wells, the onset of wet gas in the cuttings gas coincides with a vitrinite reflectance value of 0.45% Ro max. Thus the widely quoted figure of 0.5% Ro max for the onset of the mature zone (e.g. Shibaoka *et al.*, 1973) coincides very well with the gas data from the Sverdrup Basin. However the onset of maturity in the extractable hydrocarbons does not occur until several thousand metres below the onset of wet gas. This is shown particularly well in the North Sabine H-49 well. The onset of wet gas occurs at 1500 m whereas the hydrocarbon yields do not increase until a depth of 3000 m. In the Drake D-68 well, the Bjorne sandstone occupies this critical zone and yields relatively small amounts of dry gas and no extract.

The preponderance of organic material derived from land plants in many of these samples indicated that their source potential is less than would be the case for organic material of marine origin (Staplin, 1969). There is also the possibility that organic material of marine origin would respond more rapidly to diagenesis. The Schei Point Formation contains organic matter which has an amorphous appearance and a high atomic hydrogen to carbon ratio (Fig. 7). Both of these features are typical of the better quality organic matter from the standpoint of hydrocarbon generation (Staplin, 1969; Tissot, Durand, Espitalié and Combaz, 1974). In Figure 7, the data from the Schei Point Formation in the western Sverdrup Basin are plotted against restored maximum burial depth (supplied by K.J. Roy). From this figure it can be seen that amorphous organic matter of probable algal origin responds more readily to thermal diagenesis than organic matter of land plant origin. The extract yields increase in the vicinity of 1524 m corresponding to the top of the wet gas zone. The proportion of hydrocarbons in the extract exceeds 40 per cent at about 1800 m maximum burial depth. However the gas chromatograms still show signs of immaturity at this depth, namely a relatively high proportion of isoprenoids (particularly pristane and phytane) to n-alkanes and a pronounced hump in the base line in the C_{26} to C_{30} region, indicating the presence of large amounts of steranes and triterpanes. The maximum phase of oil generation (Vassoevich *et al.*, 1969) occurs in the intervals below 2700 m corresponding to a vitrinite reflectance level of about 0.7% Ro max. This coincides with the onset of the mature zone in respect of the organic matter derived from land plants.

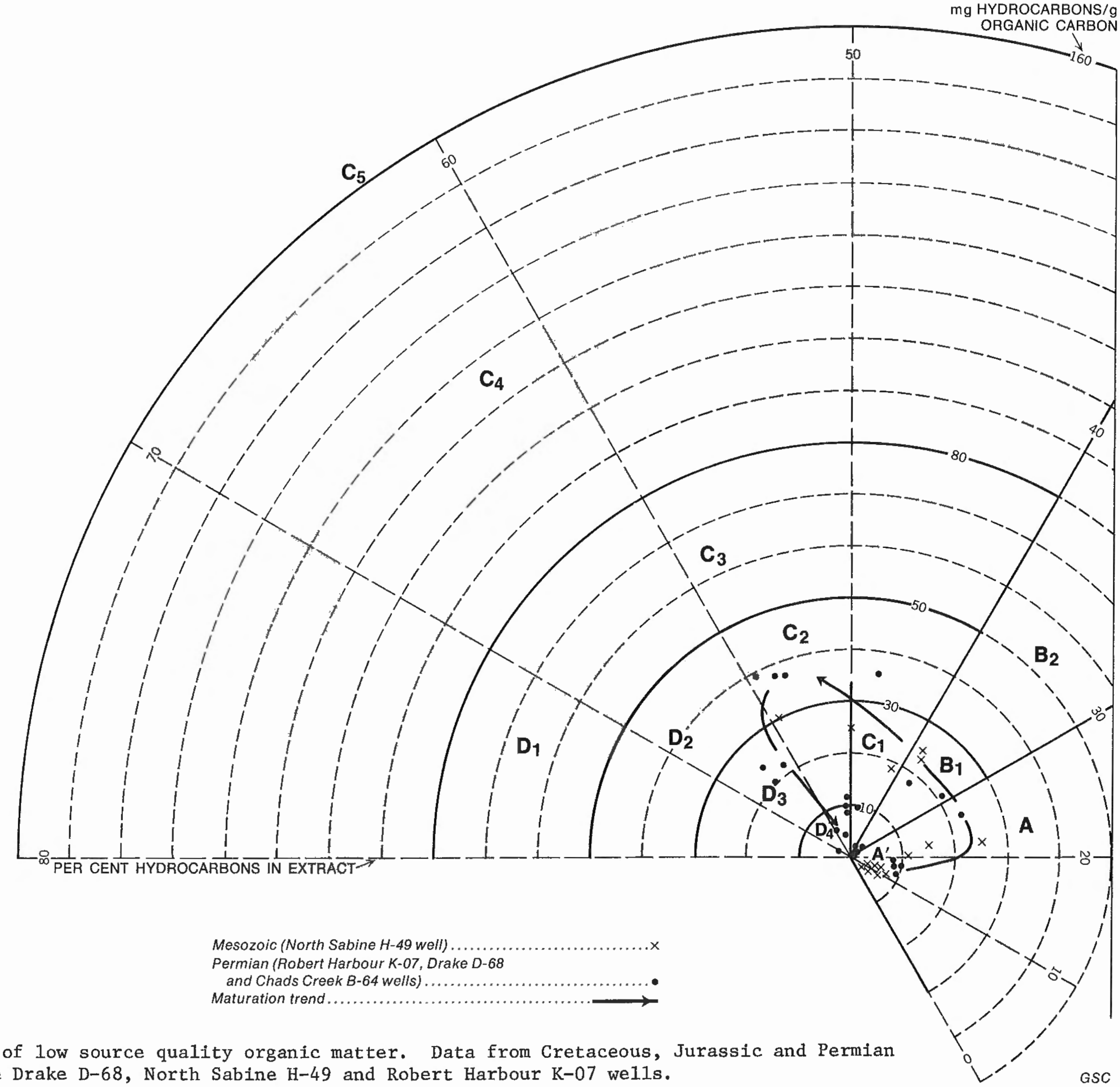
In the Sverdrup Basin, the onset of the wet gas zone defined above (i.e. approximately 0.5% Ro max in terms of vitrinite reflectance) is a good indicator for the onset of maturation for the amorphous component. However, in the case of woody herbaceous organic matter, higher levels of maturation are required before significant hydrocarbon generation occurs. This corresponds to a vitrinite reflectance level of 0.7% Ro max. Whether organic matter of the latter type can be a source for oil itself is another aspect which must be taken into consideration. Even in the case of amorphous organic matter, vitrinite reflectance levels of 0.7% Ro max must be reached before the maximum hydrocarbon potential is achieved.

In respect of the mature to overmature transition, the change from above 60 per cent wet gas to less than 60 per cent wet gas corresponds extremely well with the decrease in extract yield in the Drake D-68 well (Fig. 5). This transition corresponds to a vitrinite reflectance value of 1.0 to 1.2% Ro max. As would be expected from thermodynamic considerations, the transition from 60 per cent wet gas to lower values is offset downward from the decrease in extract yield. However, the offset is only of the order of 150 to 300 m so that the transition from 60 per cent wet gas to 30 per cent wet gas is an adequate definition of the oil-generating zone.

SOURCE ROCK CRITERIA

The only truly applicable definition of a source rock is "a rock that has demonstratably been the source for migrated oil and gas". This means that the correlation has been made between reservoired hydrocarbon and its source. In frontier areas where the necessary knowledge for this definition is not available, we are considering only potential source rocks. Potential source rocks, in this study, are considered to have all the attributes of source rocks. They contain a suitable organic matter type at the correct level of maturation. The distinction between the terms "source rock" and "potential source rock" is important because the all important step of migration has not been demonstrated in the latter case. It is also possible to recognize

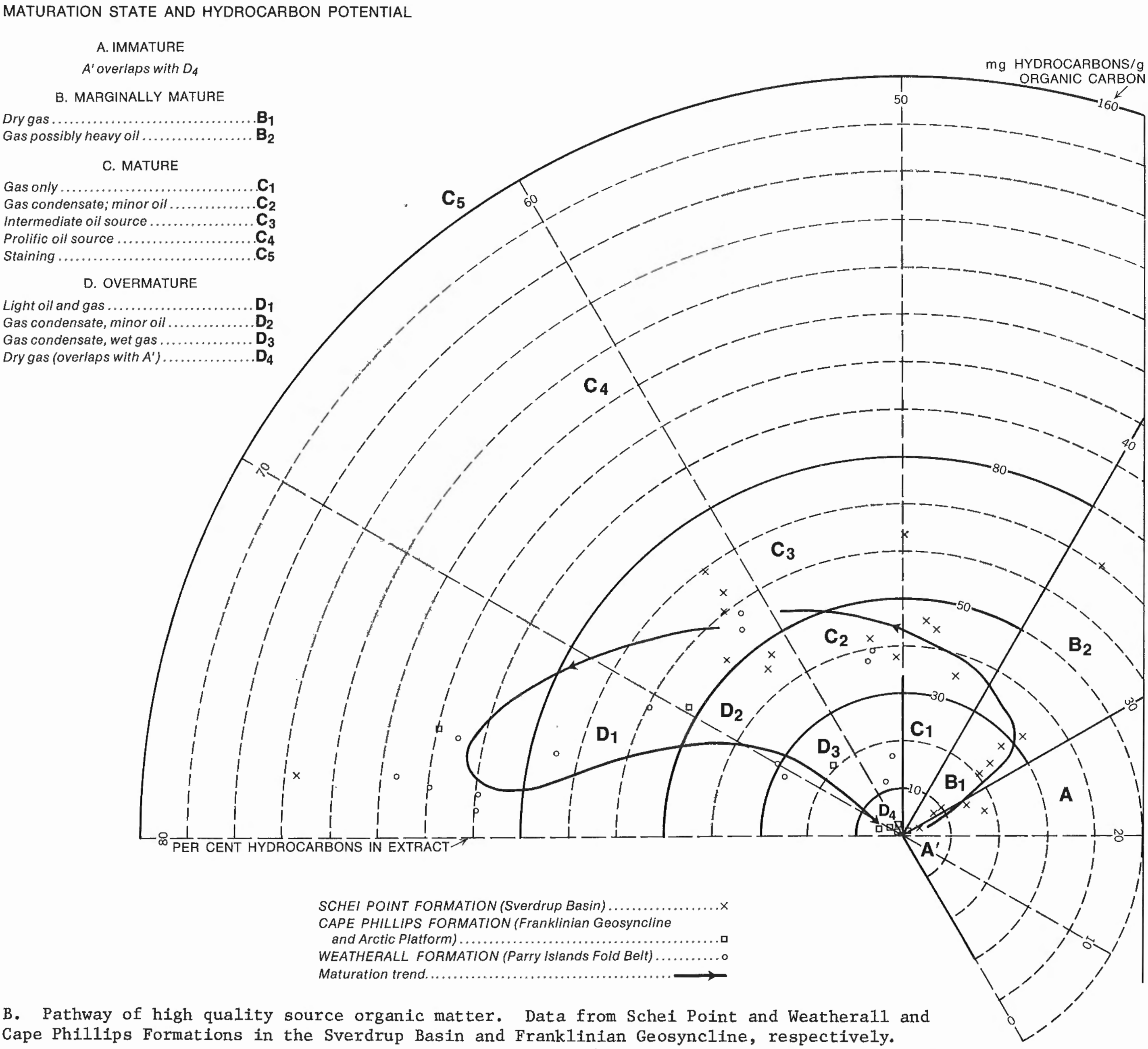
FIGURE 8. Diagrams to illustrate assessment of source organic matter quality, maturation state and anticipated hydrocarbon product from extract data.



A. Pathway of low source quality organic matter. Data from Cretaceous, Jurassic and Permian rocks in the Drake D-68, North Sabine H-49 and Robert Harbour K-07 wells.

"immature potential source rocks". These rocks have all the attributes of source rock except maturity. One might postulate that they could become potential source rocks given sufficient burial. However, it is necessary to have some knowledge of the basin configuration and to assume that the quality of the organic matter is constant throughout the area for this extrapolation to be valid.

Various criteria have been used to indicate the presence of potential source rocks, e.g. high content of amorphous organic matter (Staplin, 1969; Correia, 1971), high atomic hydrogen to carbon ratios of kerogen (Tissot, Durand, Espitalié and Combaz, 1974), content of hydrocarbons in ppm (Philippi, 1958), and high pyrolysis yield (Heacock and Hood, 1970). All, except hydrocarbon content, are empirical relationships which have been observed in good source rocks. Although they are useful in a general sense, they lack the specificity required for a quantitative evaluation of source content. The concentration of hydrocarbons in the source rock may be of use from the quantitative standpoint but, unless the organic carbon content and state of maturity are taken into consideration, then it is not possible to evaluate the source potential. Thus, a hydrocarbon concentration of 700 ppm in a rock containing 1 per cent organic carbon is far more significant in terms of source potential than the same hydrocarbon concentration in a rock with 5 per cent organic carbon. The degree of saturation of the insoluble organic matter is considerably higher in the former than the latter and hence will more readily yield hydrocarbons for migration. Hydrocarbon concentrations in coals can be very large but they do not form source rocks because the yield relative to organic carbon in low. Extremely high hydrocarbon concentration in shales may be attributed to staining.



B. Pathway of high quality source organic matter. Data from Schei Point and Weatherall and Cape Phillips Formations in the Sverdrup Basin and Franklinian Geosyncline, respectively.

Source rock quality is therefore a function of two variables: the yield of extractable hydrocarbons per unit weight of organic carbon and the amount of organic matter in the rock. Since it is not possible to determine a lower limit on the amount of organic carbon required for a rock to act as a source for hydrocarbons, the organic carbon content is regarded as a secondary consideration when the hydrocarbon potential of the organic matter within the rock has first been evaluated.

The quantities of NSO compounds and asphaltenes obtained during extraction of sedimentary rocks are extremely variable depending on the type of solvent system. In order to make comparisons with other workers, only hydrocarbon yields are considered since they are less susceptible to the influence of solvent type and are more relevant to hydrocarbon potential. In this regard, Albrecht *et al.* (1976) noted that a solvent system consisting of benzene and methanol extracted considerably more resins and asphaltenes from Douala Basin sediments than did chloroform. Our experience would suggest that this is particularly true where coaly organic matter is concerned.

Potential oil source rocks which are rated excellent in quality (e.g. Toarcian of the Paris Basin) contain 100 to 130 mg per gram organic carbon of hydrocarbons (i.e. 10-13% of the organic matter is hydrocarbon) in the optimum mature state (Tissot *et al.*, 1971). Similar figures can be inferred from Philippi's (1965) data on the Los Angeles Basin. Even higher values (130-160 mg per gram organic carbon) can be inferred for certain parts of the Leonard Formation in the Delaware Basin of West Texas and a Miocene shale from South Sumatra (Philippi, 1958); both are rated as excellent source rocks. Values obtained for different facies within the same formations and rated good by

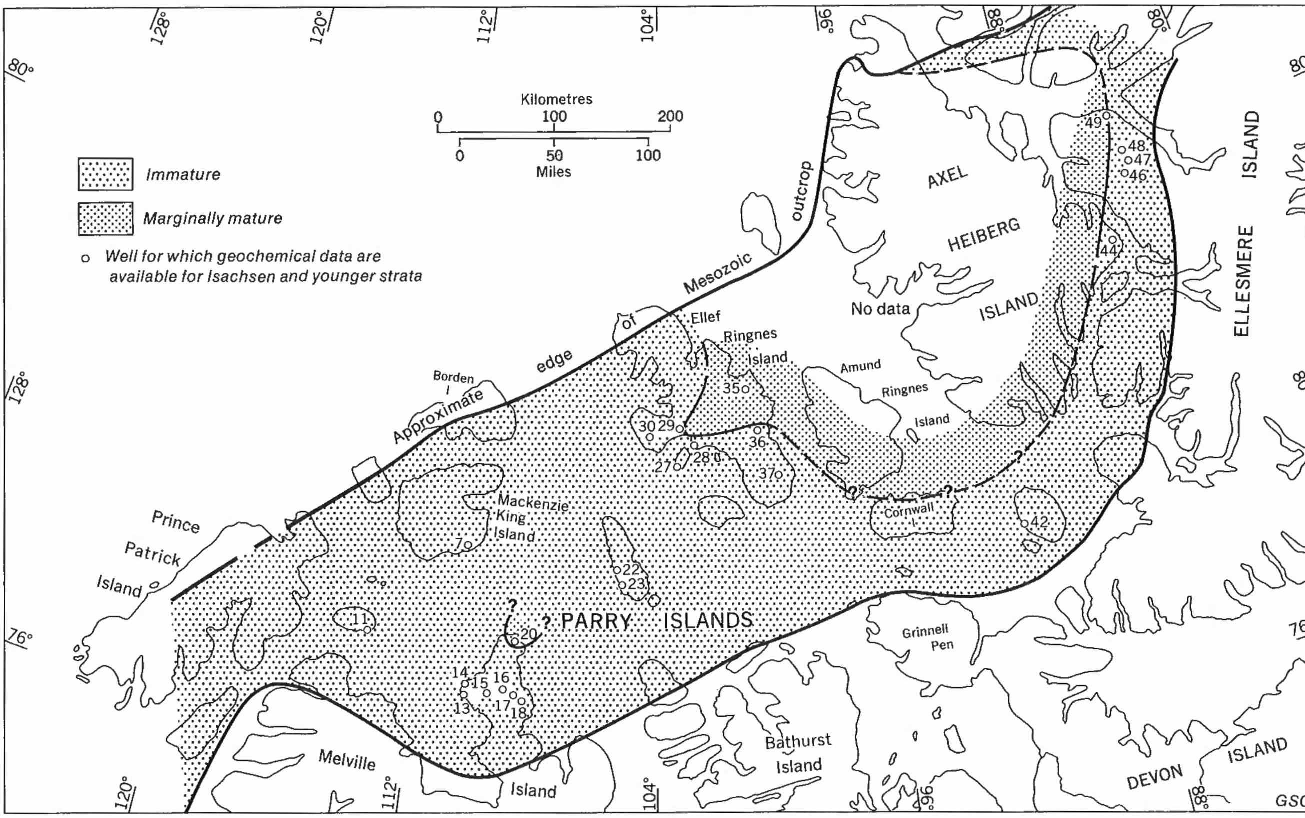


FIGURE 9A. Base of the Isachsen Formation

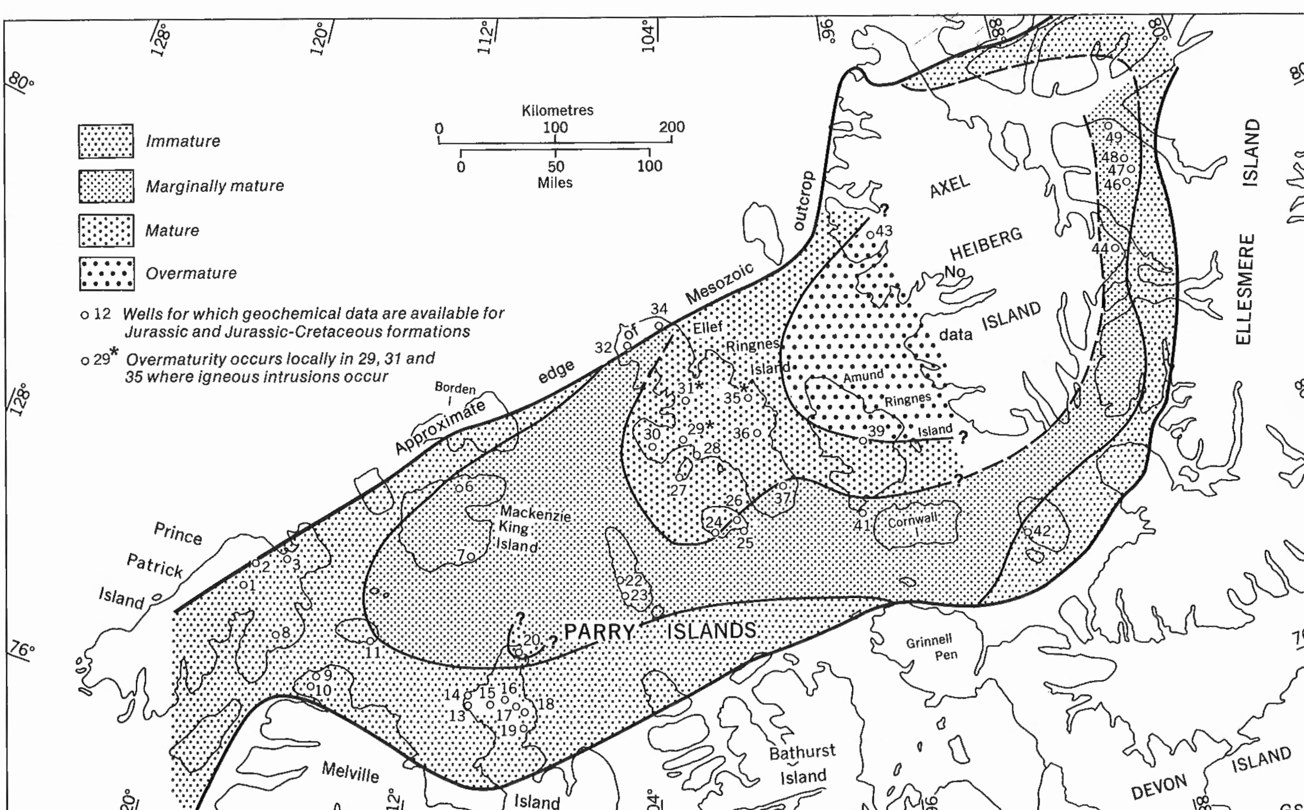


FIGURE 9B. Base of the Jurassic shale succession

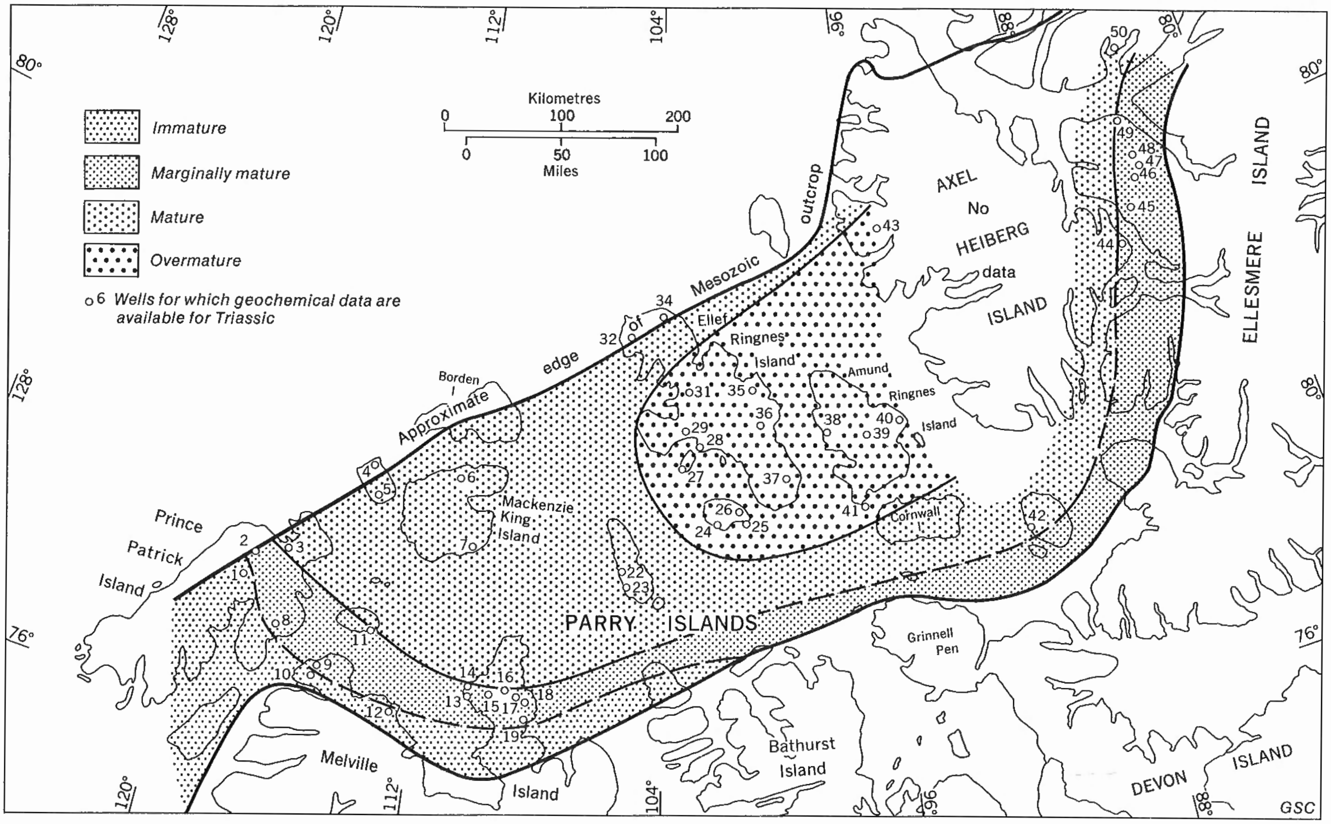


FIGURE 9C. Base of the Triassic strata

FIGURE 9. Organic metamorphic facies maps of three stratigraphic levels with the Sverdrup Basin

Philippi calculate to 60 to 80 mg per gram organic carbon. Values that calculate to below 60 mg per gram were rated fair to poor. Studies on the hydrocarbon contents of coals (Hood and Castaño, 1974; Allan, 1975) show that even at the optimum generation stage the hydrocarbon content of coals is less than 25 mg per gram organic carbon. At this stage it is worth noting the discrepancy between these coal results and the values obtained for "coal like" organic matter occurring in the sediments of the Douala Basin (Albrecht *et al.*, 1976; Durand and Espitalié, 1976). The atomic hydrogen to carbon ratios of the insoluble organic matter in these sediments were similar to coals (≃0.6-0.8) in the mature stage. Petrographic examination showed that 80 per cent of the organic matter consisted of 'organic cement' which was vitrinite-like but was not identified as vitrinite. At the optimum maturation stage, the hydrocarbon yields are of the order of 50 to 75 mg per gram organic carbon which are equivalent to values indicative of some source potential by Philippi (1958). Clearly the values are two or three times higher than those of coal. On the basis of extract data, identification of organic matter in sedimentary rocks as coaly does not necessarily imply that these rocks have no source potential. This is particularly true in the Upper Cretaceous-Tertiary sediments of the Mackenzie Delta where coaly organic matter gives hydrocarbon yields up to 140 mg per gram organic carbon (Snowdon, 1977). In this case, the coaly organic matter appears to contain a substantial amount of plant resins (resinite of coal maceral terminology) which may contribute the majority of the hydrocarbons (Snowdon, 1977). However, as a rule, the potential of coaly organic matter will be less than that obtained from purely amorphous organic matter.

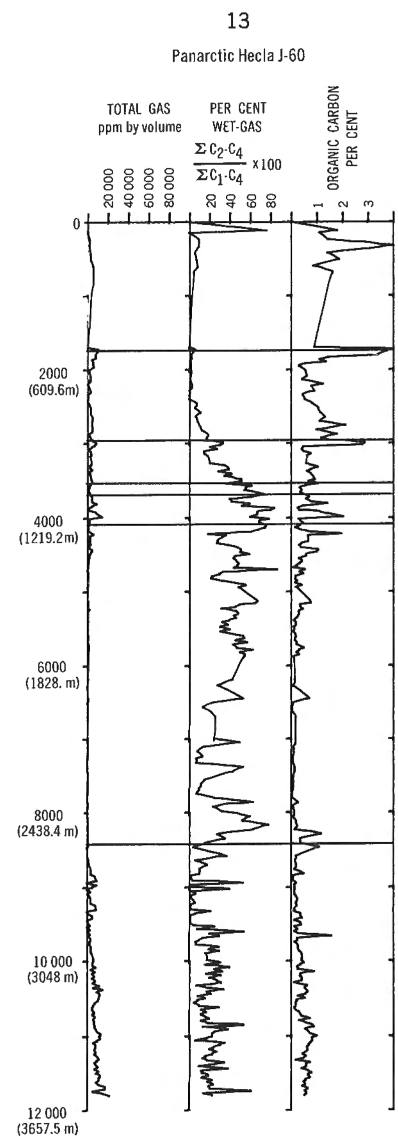
On the basis of the foregoing discussion, at the optimum mature stage the following criteria have been used in respect of oil potential. These criteria refer only to hydrocarbon yields per unit weight of organic carbon. The amount of organic matter present in a rock is a separate factor. Hydrocarbon yields (saturated hydrocarbons plus aromatic hydrocarbons) in excess of 80 mg per gram organic carbon are considered to indicate excellent source rock potential for oil. Values between 50 to 80 are considered to indicate good oil potential whereas values below 50 but above 30 are indicative only of marginal oil potential. Values below 30 are considered to indicate no potential for oil. It must be pointed out that the values obtained for a particular geologic unit may be variable. Quite apart from any heterogeneity in the deposits, migration may cause a depletion in hydrocarbon content.

On this basis, the Mesozoic rocks in the North Sabine H-49 well (hydrocarbon yields <30 mg per gram organic carbon) and the Permo-Pennsylvanian rocks in the Drake D-68 well (hydrocarbon yields <45 mg per gram organic carbon) have no potential or only marginal potential for oil. In contrast, the Schei Point Formation (hydrocarbon yields up to 130 mg per gram organic carbon) has good to excellent source potential for oil. The variation in extracts yields illustrates the danger in assuming a uniform value for the proportion of organic matter that is converted to hydrocarbons and is one of the reasons for the differences in conclusions between this study and that of Henao-Londoño (1977).

REFERENCE TO FORMATIONS

Beaufort, Eureka Sound, Kanguk, Hassel, Christoper, Isachsen 1
Deer Bay, Mould Bay, Awingak, Wilkie Point 2
Savik, Jaeger 3
Borden Island-Heiberg 4
Schei Point 5
Blaa Mountain 6
Bjorne and Blind Fiord 7
Degerbols, Trold Fiord, van Hausen, Assistance, Sabine Bay, Belcher Channel, Nansen, Hare Fiord, Canyon Fiord 8
Griper Bay, Hecla Bay 9
Bird Fiord, Weatherall, Cape de Bray, Blackley, Nanuk, Eids, Orksut 10
Blue Fiord 11
Stuart Bay, Bathurst Island, Peel Sound 12
Kitson River, Cape Phillips, Read Bay Allen Bay 13
Irene Bay, Thumb Mountain, Bay Fiord, Eleanor River, Baumann Fiord, Copes Bay 14
Parrish Glacier 15

Igneous intrusion .... ▬▬▬ ⅃ ⌐ v



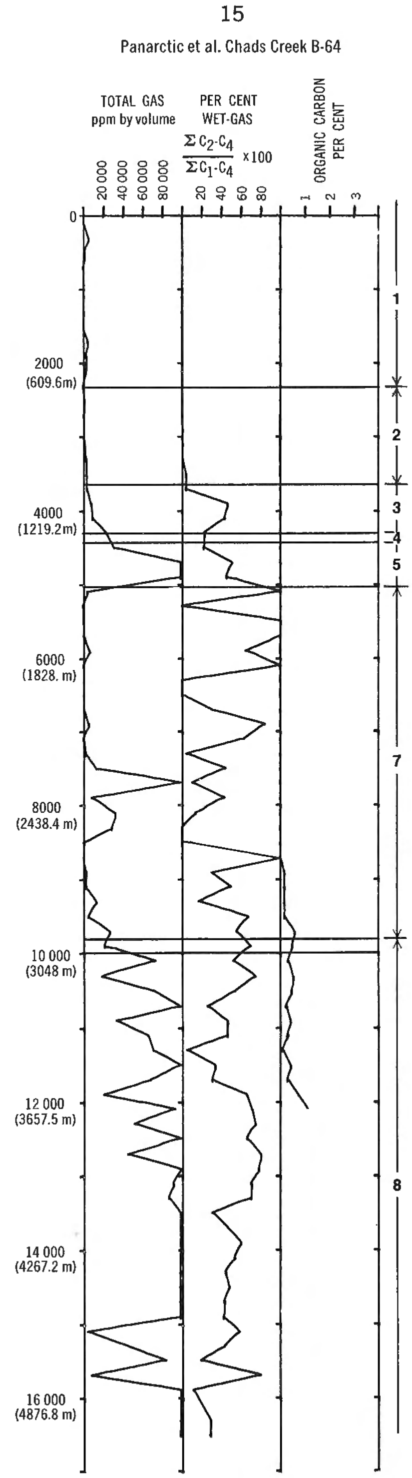
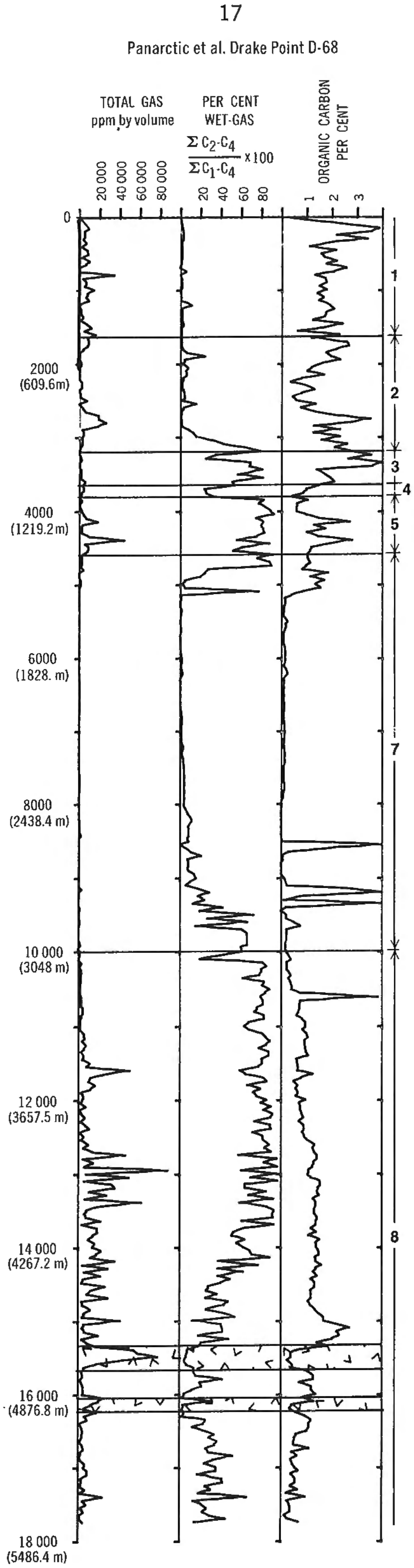


FIGURE 10.

Cross-sections of the Sverdrup Basin showing relationship of gas and organic carbon logs to the major stratigraphic units and igneous intrusions (*see* Fig. 3a and Table 1 for well locations).

BASIS OF AN INTERPRETATIVE DIAGRAM FOR ASSESSMENT OF SOURCE ROCK POTENTIAL

The extract data can be used to illustrate the state of maturation, organic matter quality and hydrocarbon product. The hydrocarbon yield and percentage of hydrocarbons in the extract are plotted on an interpretative diagram. The diagram is based on the observation that extracts obtained by a solvent system comprising benzene and methanol or chloroform and methanol change in a regular fashion with maturation. At the immature stage, the percentage of hydrocarbons in the extracts is relatively low (approximately 25% or less). With increasing diagenesis, the yield of extract and hydrocarbons increase and the proportion of hydrocarbons in the extract also increases (Figs. 5-7). The diagram is based on polar co-ordinates (Fig. 8). The radial distance from the origin represents the hydrocarbon yield in milligrams per gram organic carbon. The angle Θ is related to the percentage hydrocarbons in the extract. The horizontal axes have been arbitrarily set at 20 and 80 per cent. The transition from immature to mature is expressed in the diagram by a spiral line of data points curving out from the origin in a counter-clockwise direction. This is illustrated in Figure 8A by the diagenetic pathway for woody herbaceous organic matter with atomic hydrogen to carbon ratios in the range 0.6 to 0.8. The samples are from the North Sabine H-49 (Upper Triassic-Cretaceous), Drake D-68 (Permian), Robert Harbour K-07 (Permian) and Chads Creek (Permian) wells.



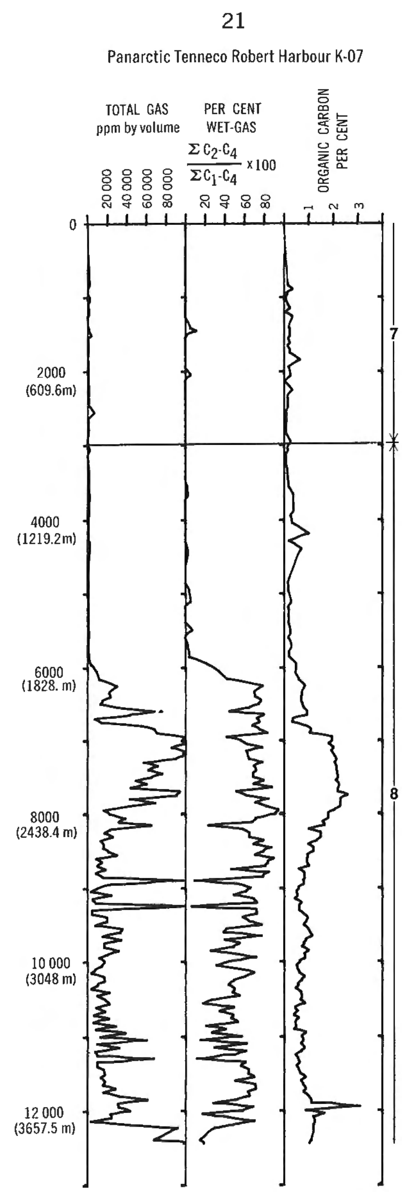
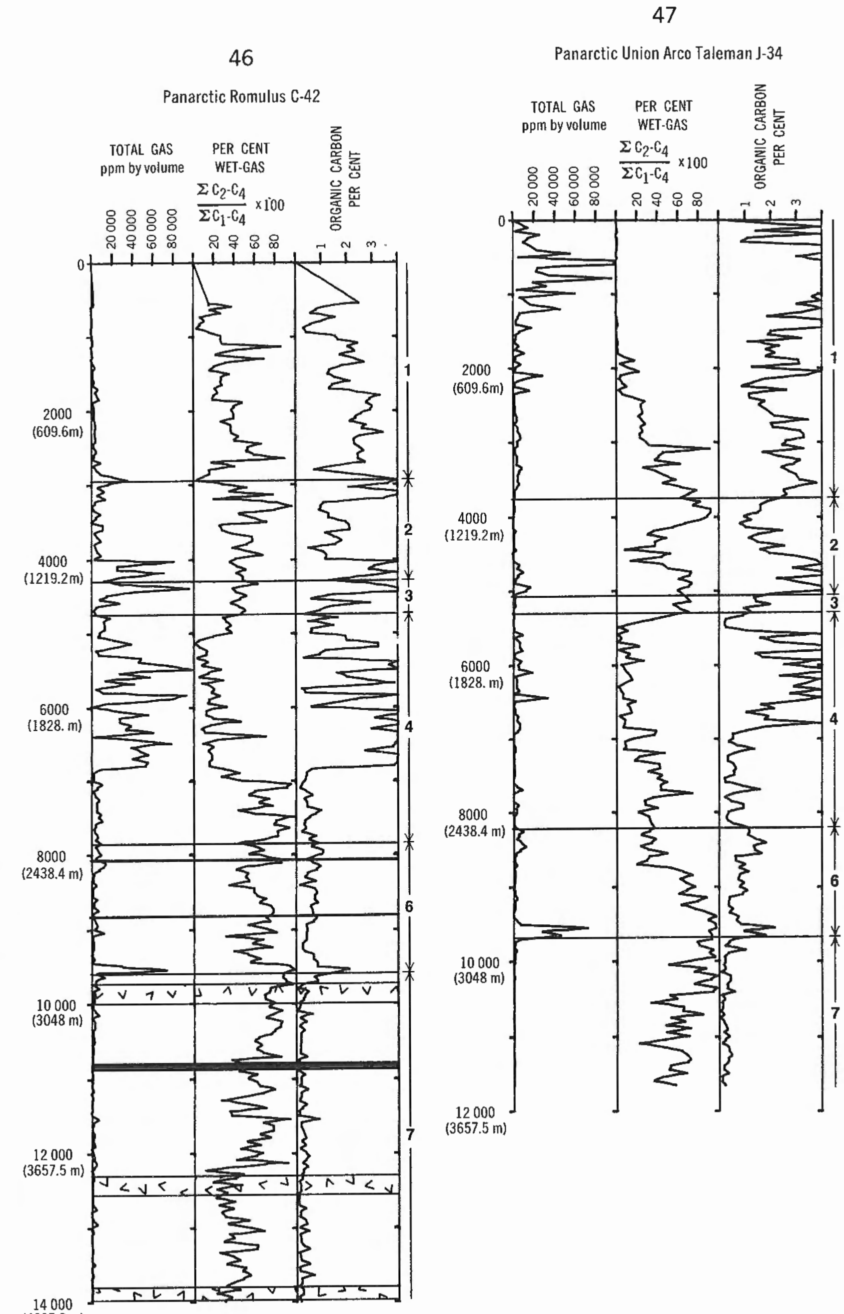
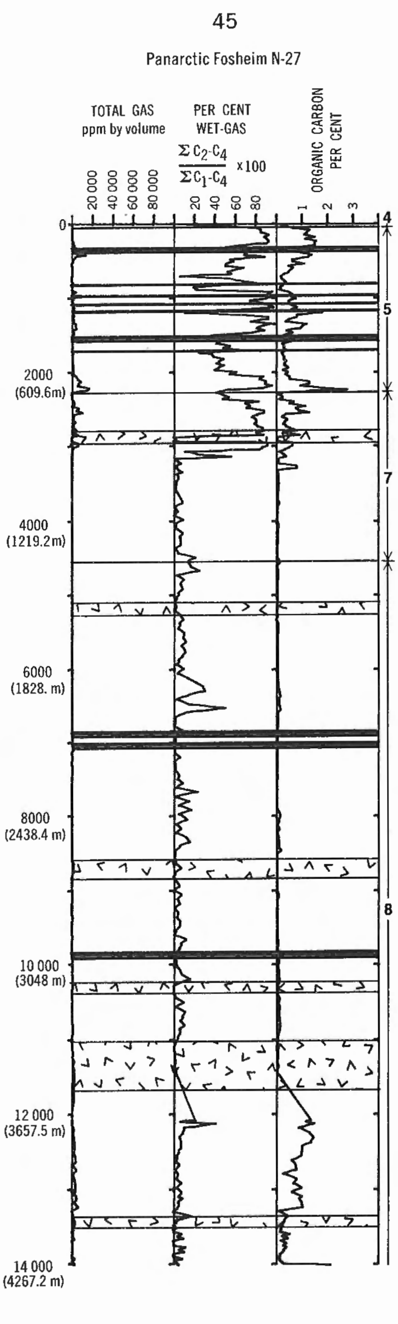


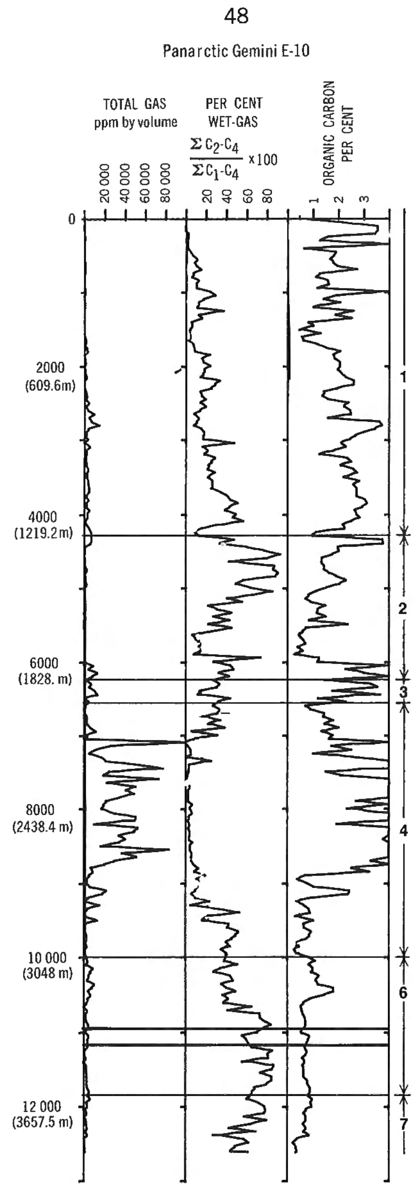
FIGURE 10. Continued

FIGURE 10. Continued





At the immature stage the hydrocarbon yields are low (Fig. 8A), being less than 8 mg per gram organic carbon and the percentage of hydrocarbons in the extract is less than 20 per cent. The samples plot close to the origin of the diagram (Fig. 7A). Gas chromatograms of the saturated hydrocarbons show a pronounced odd over even predominance in the n-alkanes and a pronounced hump of naphthenic alkanes. With increasing thermal diagenesis both the extract and hydrocarbon yields increase but the proportion of hydrocarbons in the extract remains the same. The proportion of n-alkanes in the saturated hydrocarbons increases however and pristane becomes very prominent (Powell *et al.*, in prep.). At greater depth, the proportion of hydrocarbons in the extract begins to increase. As the proportion of hydrocarbons in the extract increases from 30 to 40 per cent, the odd over even predominance in the n-alkanes diminishes to 1



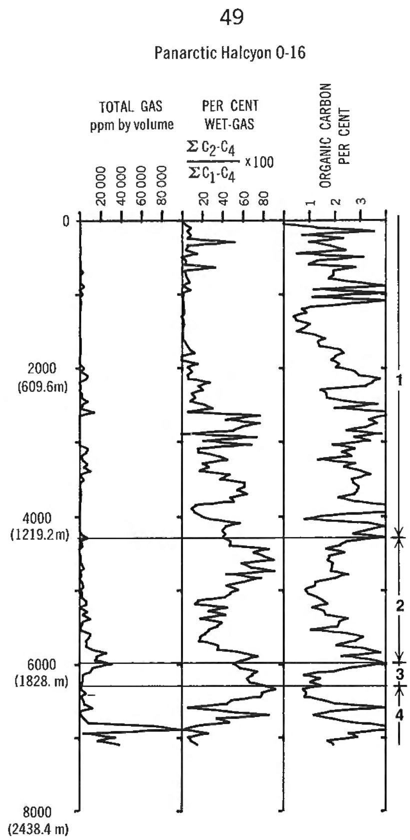
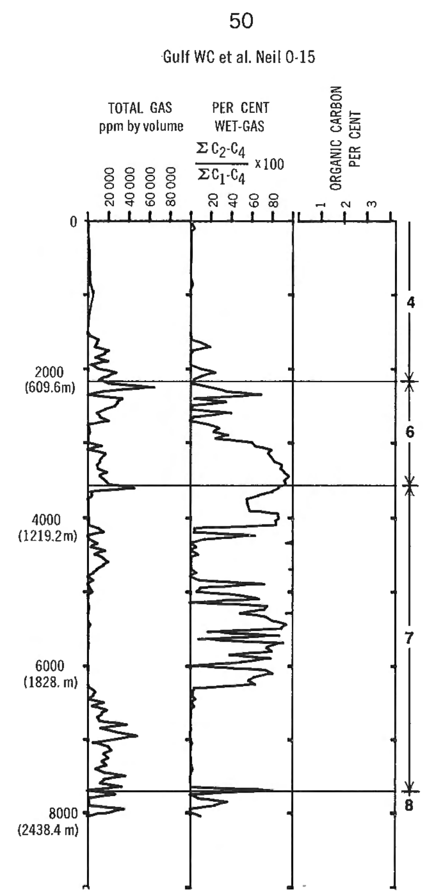


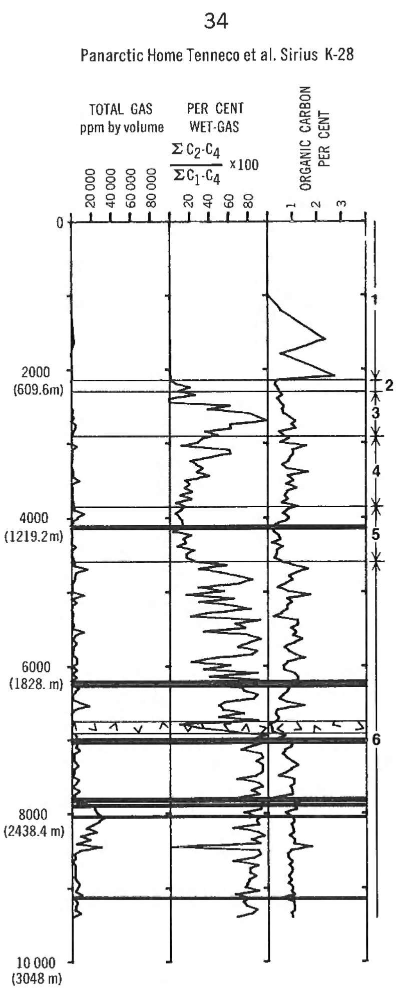
FIGURE 10. Continued

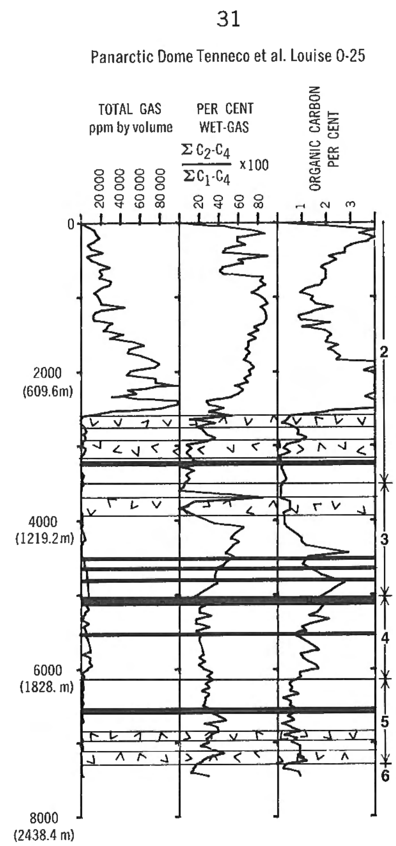


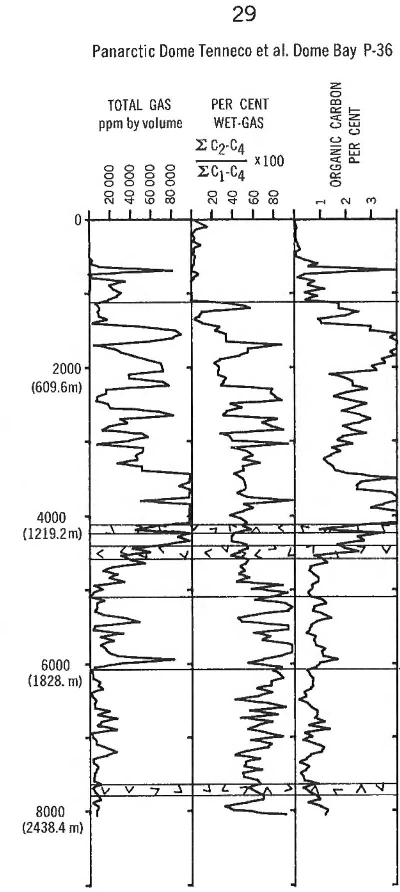
(Fig. 6). Similar trends were noted in extracts of the Toarcian of the Paris Basin (Tissot *et al.*, 1971) and the Mowry Shale (Nixon, 1973), namely that as the hydrocarbon content of the extract approached 40 per cent the odd over even predominance diminished. Where the hydrocarbon content of the extract has reached 40 per cent, it is reasonable to assume that the petroleum generation zone has been reached in respect of woody herbaceous organic matter since at this stage the hydrocarbon distribution of the rock extracts is petroleum-like. There is an intermediary zone between the immature stage (hydrocarbon content of extract less than 30%) and the fully mature stage (hydrocarbon content above 40%) which is termed marginally mature. In the North Sabine H-40 well this transition is rather rapid (Fig. 6).

The initial hydrocarbon content of extracts from the Schei Point Formation (containing amorphous organic matter) is higher (25-30%) than in extracts from woody-herbaceous organic matter. This contradicts the observation of Vandenbroucke *et al.* (1976) when comparing the extract data from the Douala Basin with those from the Toarcian of the Paris Basin. The contradiction between the results from the Sverdrup Basin and the French studies is probably attributable to the use of different solvent systems. The n-alkane distributions from the Schei Point Formation show no odd carbon number preference (Fig. 7) and reach a maximum in the C_{16}-C_{20} range even in the immature samples. This is typical of the distributions obtained from marine organic matter (Powell and McKirdy, 1973). A hump in the baseline of the gas chromatograms in the C_{30} region indicates the presence of steranes and triterpanes in significant concentration. The acyclic isoprenoid hydrocarbons pristane and phytane are commonly in higher concentration than any of the normal alkanes.

FIGURE 10. Continued







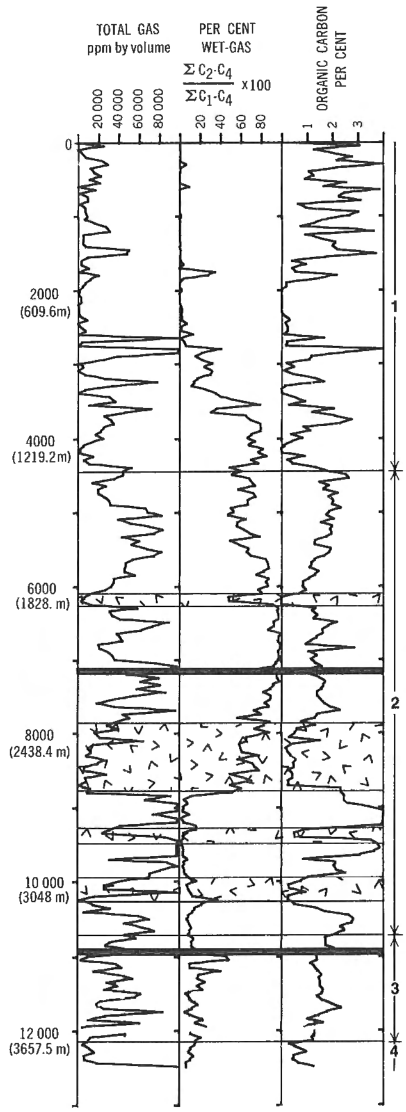
As maturation proceeds, there is an increase both in total extract and hydrocarbon yields. This is shown in the diagram (Fig. 8B) by a second spiral line of data points. Hydrocarbons form 40 per cent of the extract at a shallower depth than in the case of the woody herbaceous organic matter typified by the samples in the North Sabine well (Fig. 6). However at this stage, the full source potential of the amorphous organic matter has not been reached since the gas chromatograms still show a pronounced hump in the sterane and triterpane region (Fig. 7). The fully mature stage is reached below a maximum burial depth of 3000 m where hydrocarbon yields of between 110 and 130 mg per gram organic carbon are achieved and the gas chromatograms show a typical mature distribution of n-alkanes and an absence of sterane and triterpane hump (Fig. 7).

In contrast, the hydrocarbon yields from Mesozoic sediments (excluding the Schei Point Formation) in the North Sabine H-49 well never exceed 30 mg per gram organic carbon (Figs. 6, 8A). In the case of the Permian sediments in the Drake D-68 and Chads Creek B-64 wells, higher yields (up to 40 mg per gram hydrocarbon) were obtained. As the overmature zone is reached, the hydrocarbon yields begin to decrease and the trend lines in Figure 8A curve back toward the origin. Under these circumstances, the proportion of hydrocarbons in the extract may drop below 40 per cent. Thus the overmature samples may plot within the range of the very immature samples or very close to it. In these cases, gas-chromatography of the saturated hydrocarbons or maturation criteria allows a distinction to be made between the immature and overmature samples (Figs. 5, 6). The transition from mature to overmature for organic matter of the amorphous type is illustrated by samples from the Cape Phillips and Weatherall Formations from the Franklinian Geosyncline (Fig. 8B).

The diagram (Fig. 8) can be divided into zones, from which the anticipated hydrocarbon product of samples falling within these zones can be predicted. Area A is the zone in which most immature samples plot, i.e. a significant amount of liquid hydrocarbon has not been generated. The boundary of the zone is at the 30 per cent line although in many samples the proportion of hydrocarbons in the extract is less than 20 per cent and may be less than 10 per cent in some cases, e.g. Cretaceous samples from the North Sabine H-49 well. No oil is likely to reside in samples within this zone. The question of gas potential is problematical. During reconnaissance gas analysis, gas was encountered at all stages of maturity. In the immature zone it can consist entirely of methane or it can consist of wet gas even though the heavier hydrocarbons

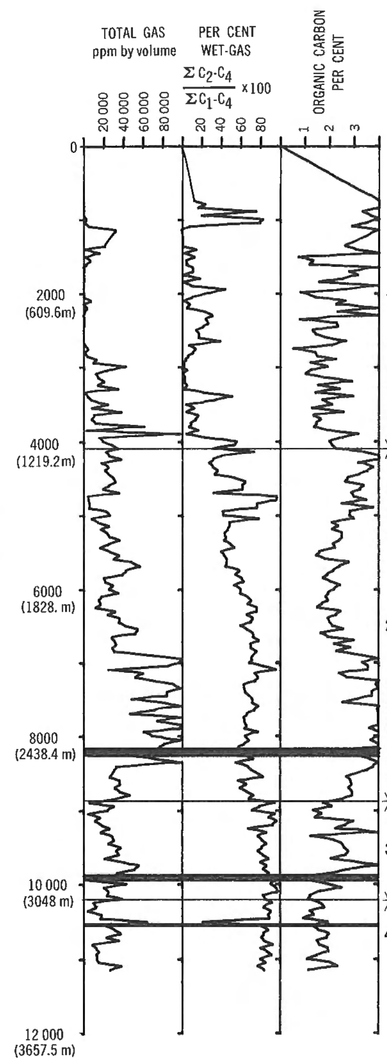
35

Panarctic Gulf Helicopter J-12



36

Panarctic Gulf Dumbells E-49



28

Panarctic Tenneco et al. Kristoffer Bay B-06

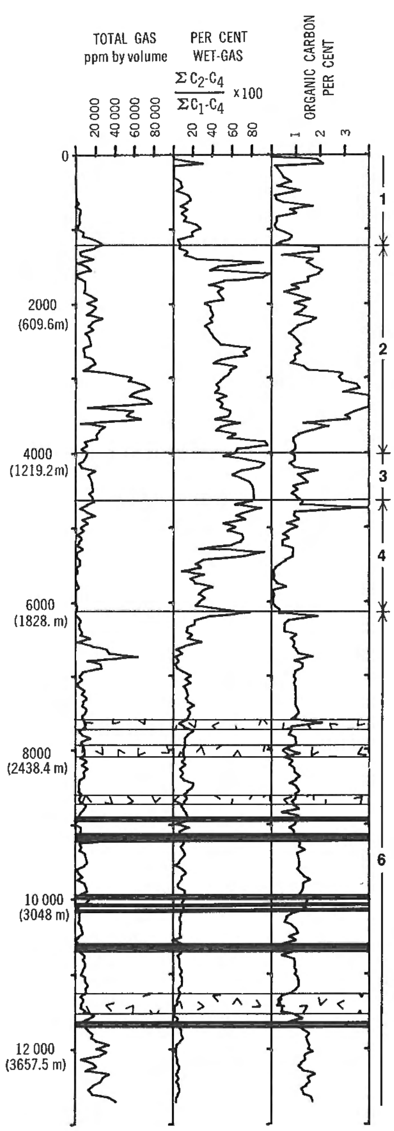
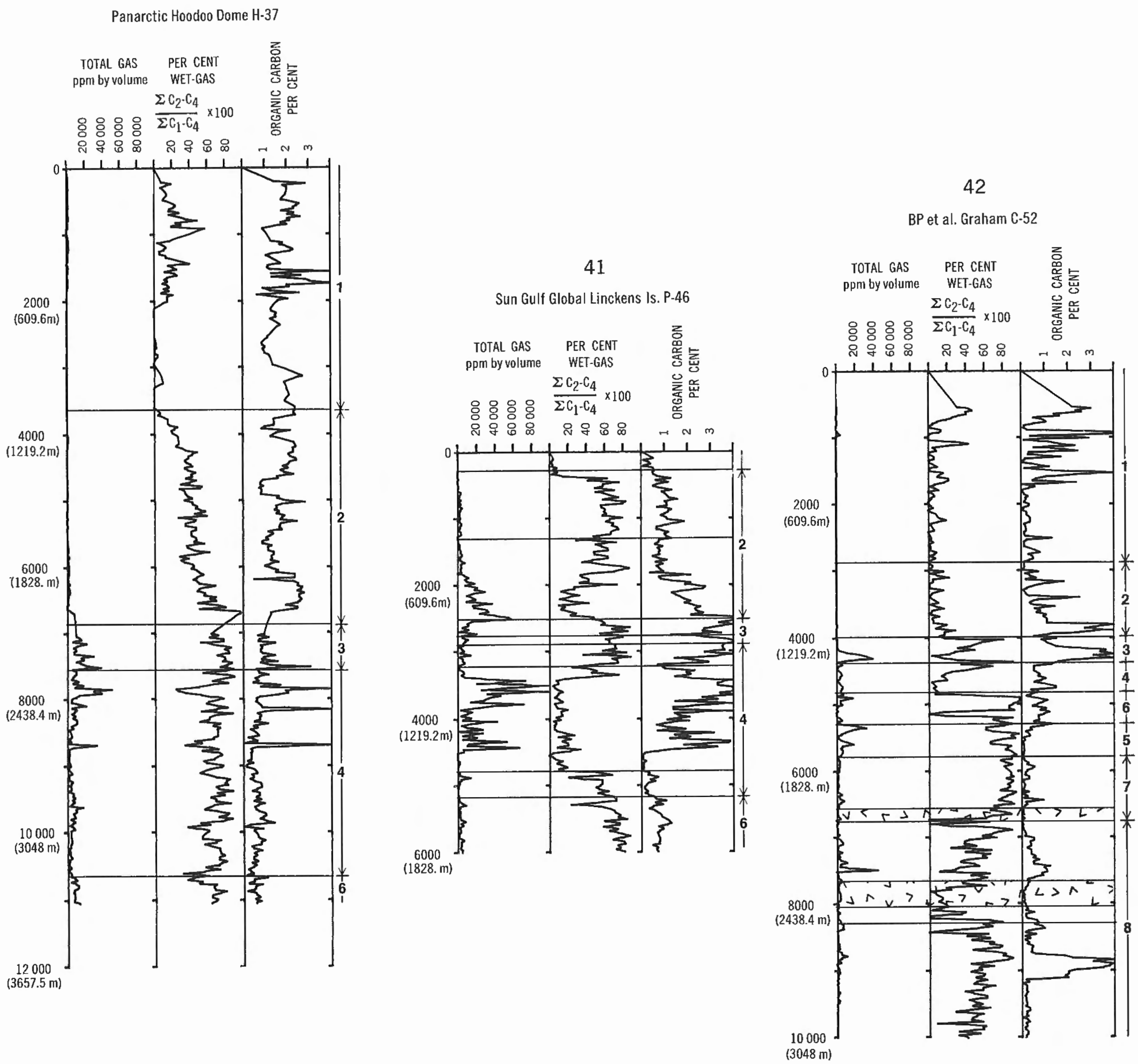


FIGURE 10. Continued

have not undergone thermal diagenesis. Some gas potential exists therefore at all stages of diagenesis but it is difficult to estimate quantitatively. Zone B contains those samples which are marginally mature, i.e. hydrocarbon generation has occurred but the optimum generation zone has not been achieved. There is a possibility that samples with high hydrocarbon yields in this zone may yield immature heavy asphaltic oil at this stage of diagenesis.

Zone C contains samples which have reached some degree of maturity in respect of the heavy hydrocarbons. The hydrocarbon content of the extract exceeds 40 per cent and the yield of hydrocarbons exceeds 10 mg per gram organic carbon. Sub-zone C_1 contains mature samples with organic matter of poor oil source potential such as coaly organic matter. Some gas potential is expected from these samples but probably does not reach a maximum until a late stage of thermal diagenesis.

FIGURE 10. Continued



Zone C_2 contains mature samples with a limited oil potential. Again the major hydrocarbon product is probably gas. Samples containing amorphous organic matter enter this zone at a lower level of maturation than samples derived from woody-herbaceous organic matter (*see* previous discussion). Any oil formed from amorphous organic matter at this stage may show indications of immaturity, namely a low gasoline yield and a relatively high content of steranes and triterpanes. The asphaltene content is still probably low. Zone C_3 contains samples which have a relatively good oil potential. Again in the case of the Schei Point Formation, the samples which fall in this zone have not reached their full source potential. Area C_4 is the zone which contains samples of excellent source potential. In the case of two samples from the Schei Point Formation (North Sabine H-49 and Cape Norem A-80), there are no signs of immaturity. Consideration must be given to the possibility of oil staining of samples which fall in this zone although commonly oil-stained samples have very high hydrocarbon yields and an extremely high proportion of hydrocarbons in the extracts (above 75%). In this case, staining refers to the presence of non-indigenous hydrocarbons brought about by oil migration.

As thermal diagenesis proceeds, cracking of existing hydrocarbons commences and the hydrocarbon yields begin to diminish (Zone D). Area D_1 corresponds to the zone in which excellent source material has undergone some cracking. The extract yields just begin to decrease and this zone overlaps with C_3. The oil potential is decreased relative to gas. Samples falling in zone D_2 have undergone more extensive cracking, and gas-condensate and light oil are the expected hydrocarbon products. Samples occurring in zone D_3 have undergone further cracking and the yields fall below 30 mg per gram organic carbon. The Drake D-68 well samples plotted in this zone contain large amounts of wet gas. The expected hydrocarbon product is therefore wet gas

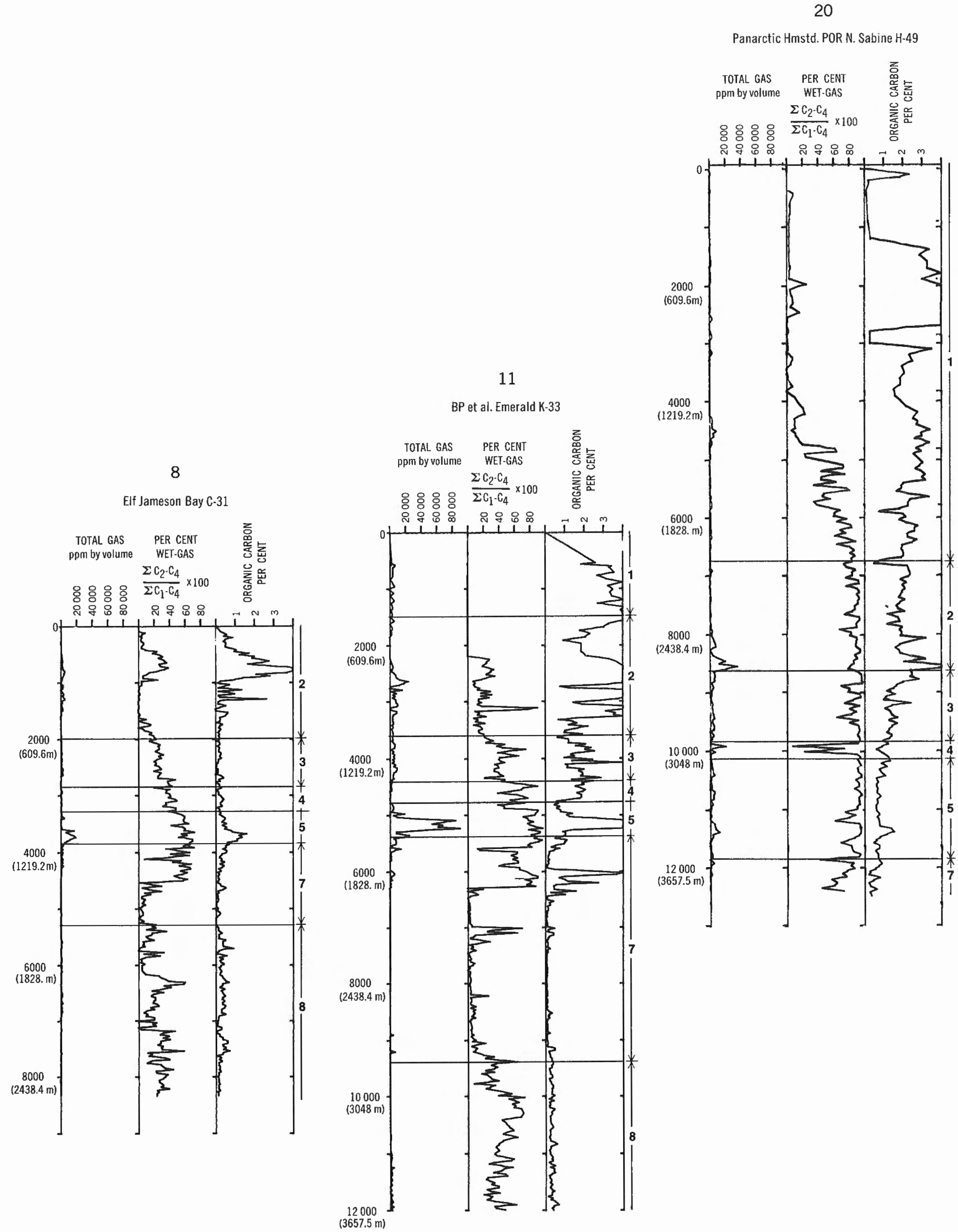
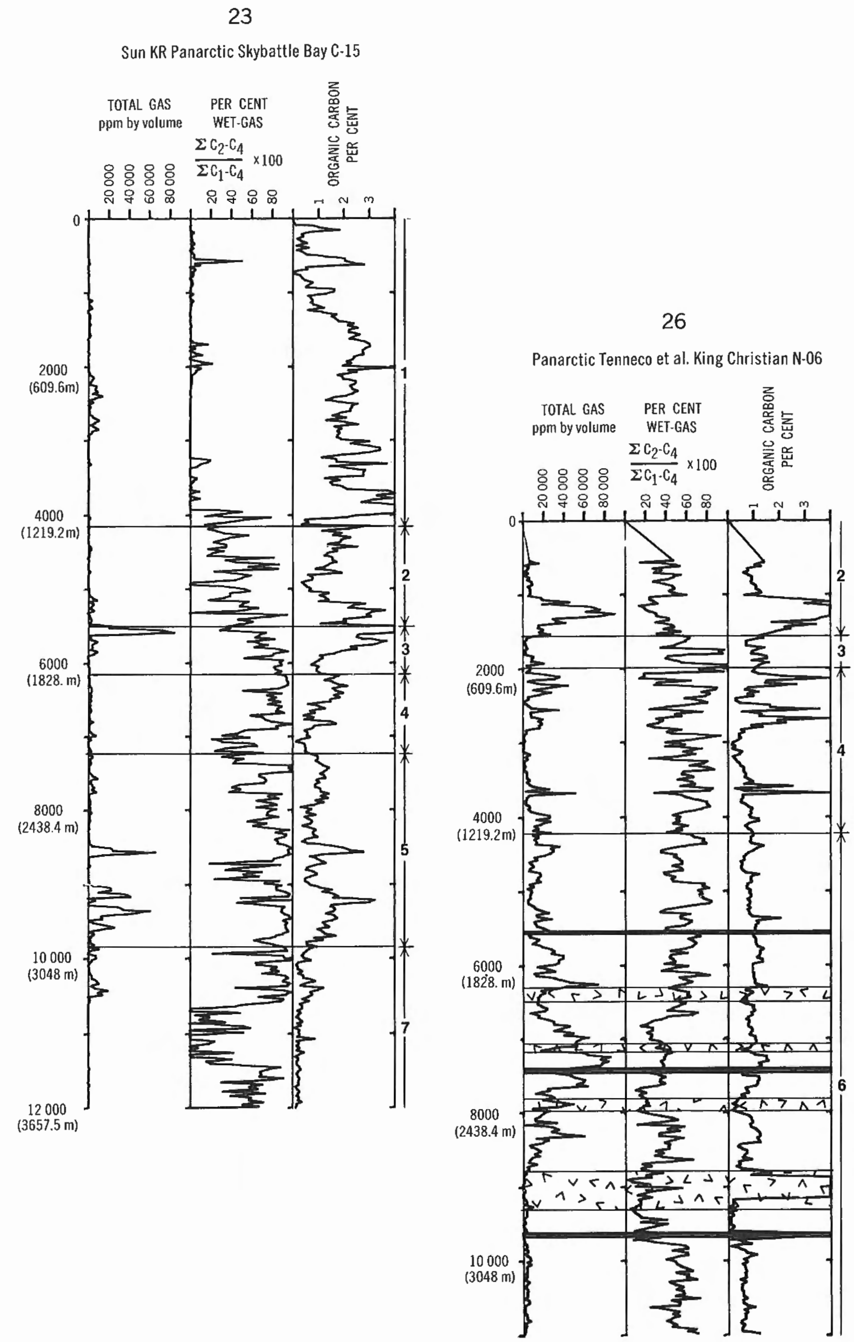


FIGURE 10. Continued

FIGURE 10. Continued



with some condensate. Samples in zone D_4 show no heavy hydrocarbon potential. Samples from the Drake D-68 well which plot in this zone have a high yield of relatively dry gas (30-40% wet) of which a substantial proportion is ethane.

Thus, from consideration of hydrocarbon content and other data, the nature of the source material, its level of maturation and hydrocarbon product can be inferred. It is evident from Figures 5, 6 and 7 that, where it occurs, the liquid hydrocarbon potential from woody-herbaceous organic matter is confined to a very narrow depth range. However amorphous organic matter is capable of yielding liquid hydrocarbons over a much greater range, but its full potential is not realized until the maturation level is reached at which woody herbaceous matter generates hydrocarbons.

It only remains for the organic carbon content to be considered to obtain data in respect of the richness of the source. The Cape Phillips Formation commonly has organic carbon values up to 5.0 per cent whereas the Weatherall Formation rarely has organic carbon contents above 0.4 per cent. Both formations have high hydrocarbon yields in terms of milligrams per gram organic carbon (Fig. 6B). Clearly, however, one would expect the Cape Phillips Formation to be a more prolific source rock since it contains approximately 10 times the amount of organic carbon and hydrocarbons than does the Weatherall Formation.

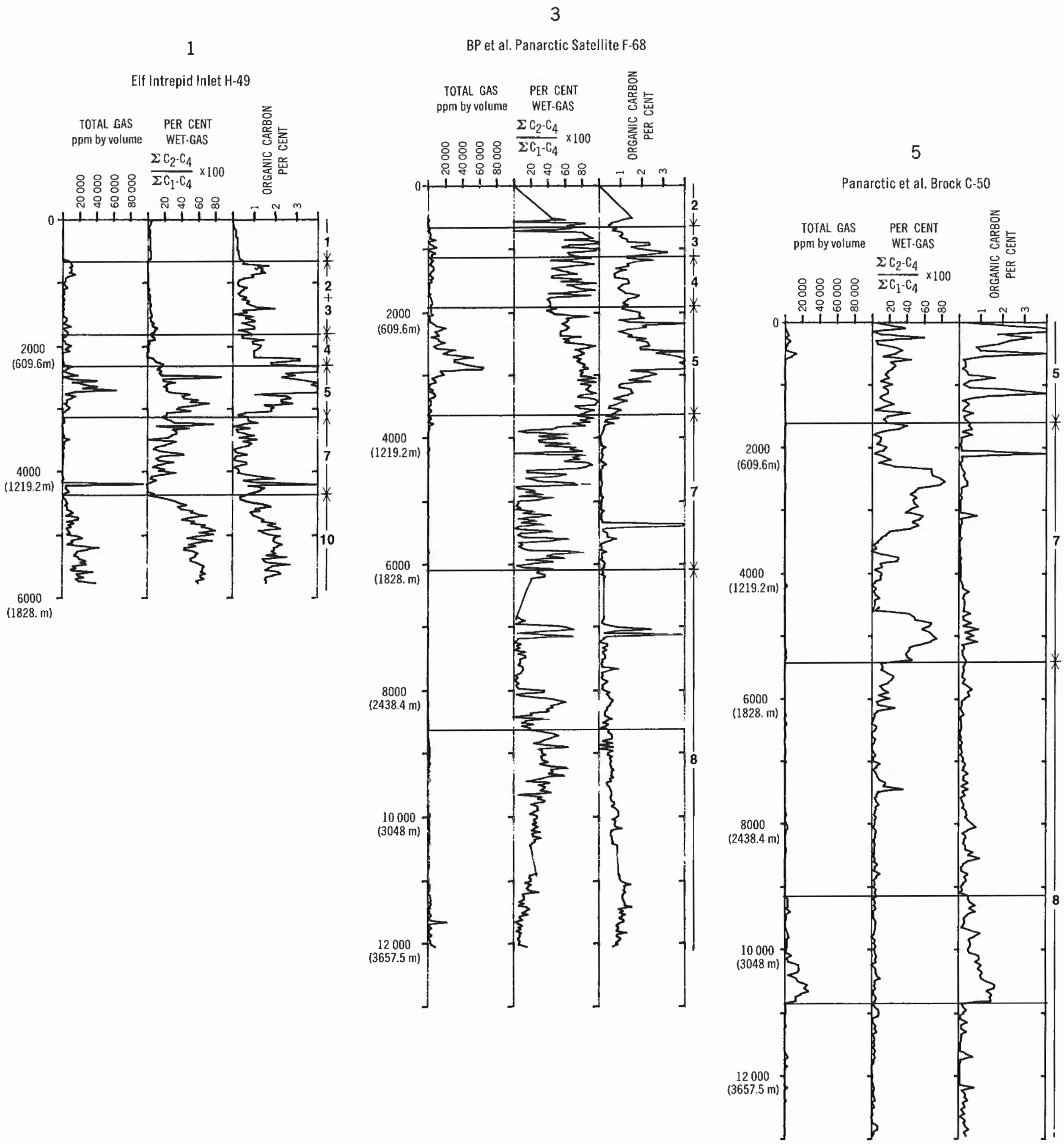
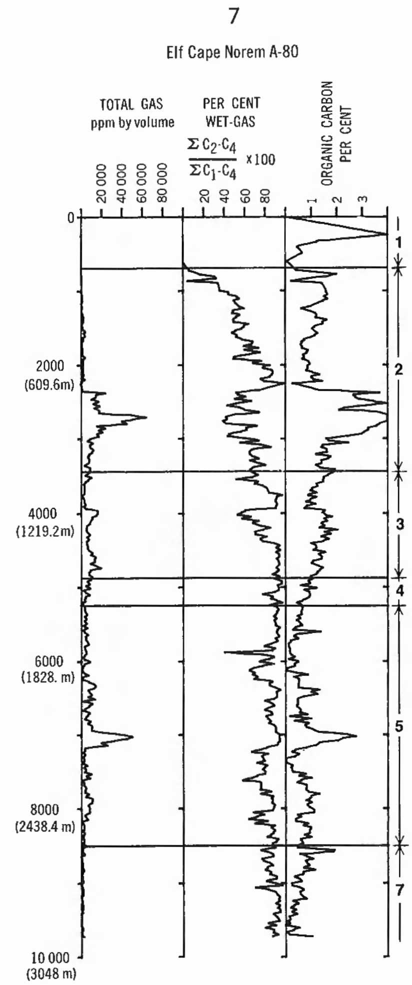
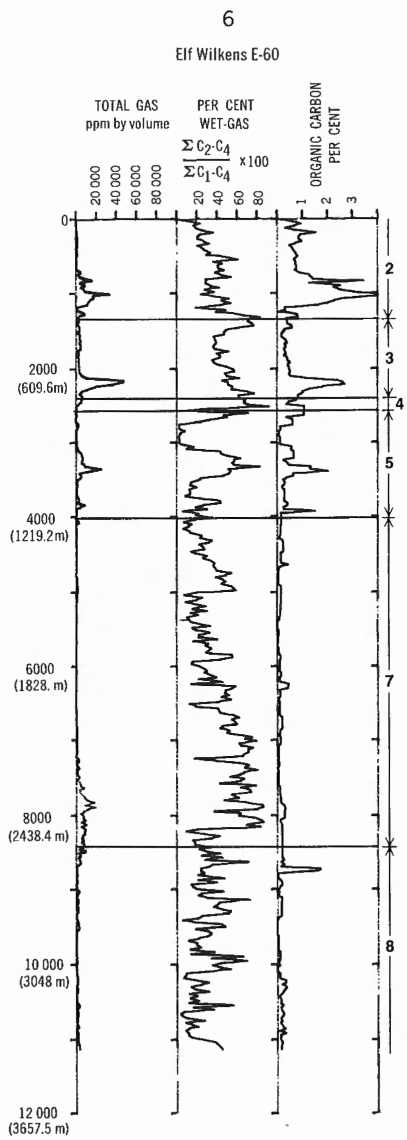


FIGURE 10. Continued


7
Elf Cape Norem A-80
TOTAL GAS
ppm by volume
PER CENT
WET-GAS
$\frac{\Sigma C_2\text{-}C_4}{\Sigma C_1\text{-}C_4} \times 100$
ORGANIC CARBON
PER CENT
20 000
40 000
60 000
80 000
20
40
60
80
1
2
3
0
2000
(609.6m)
4000
(1219.2m)
6000
(1828. m)
8000
(2438.4 m)
10 000
(3048 m)
1
2
3
4
5
7


6
Elf Wilkens E-60
TOTAL GAS
ppm by volume
PER CENT
WET-GAS
$\frac{\Sigma C_2\text{-}C_4}{\Sigma C_1\text{-}C_4} \times 100$
ORGANIC CARBON
PER CENT
20 000
40 000
60 000
80 000
20
40
60
80
1
2
3
0
2000
(609.6m)
4000
(1219.2m)
6000
(1828. m)
8000
(2438.4 m)
10 000
(3048 m)
12 000
(3657.5 m)
2
3
4
5
7
8

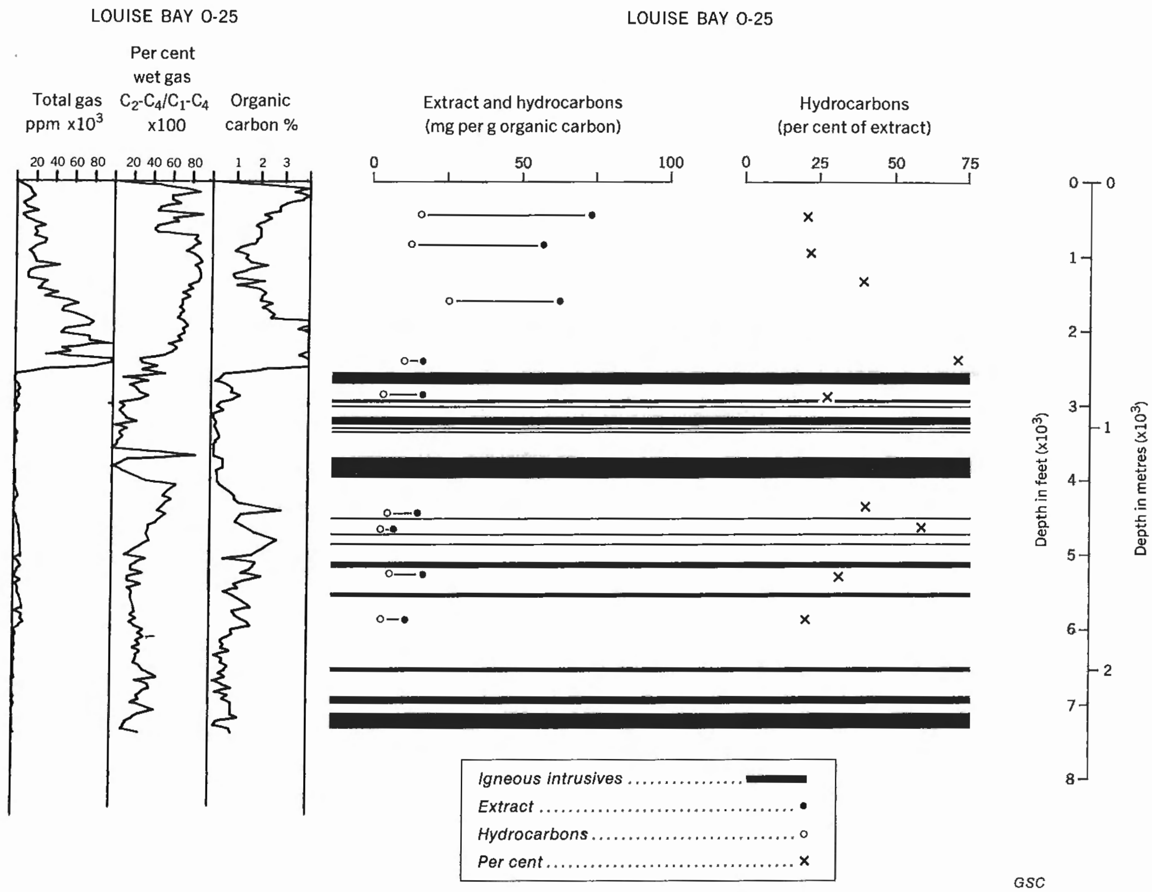


FIGURE 11. Extract and gas data for the Panarctic *et al.* Louise Bay O-25 well

SVERDRUP BASIN

REGIONAL MATURATION TRENDS

Snowdon and Roy (1975) have constructed organic metamorphic facies maps based on cuttings gas analysis for three major stratigraphic levels within the Sverdrup Basin, namely the base of the Isachsen Formation, the base of the Jurassic Shale succession and the base of the Triassic sequence. From the data which have been obtained subsequently, a number of significant modifications must be made to this overall pattern.

a) The transition from dry gas to wet gas [the immature to mature facies transition of Snowdon and Roy (1975)] indicates the very top of the oil-generating zone only when the best type of source organic matter is present.

b) The main phase of oil generation with respect to the best source organic occurs several thousand metres below the onset of the mature zone as defined by gas analysis.

c) Organic matter of lesser source potential does not become mature from the heavy hydrocarbon standpoint, until several thousand metres below the onset of wet gas. The onset of hydrocarbon generation in this case coincides with the main phase of oil generation in higher quality organic matter.

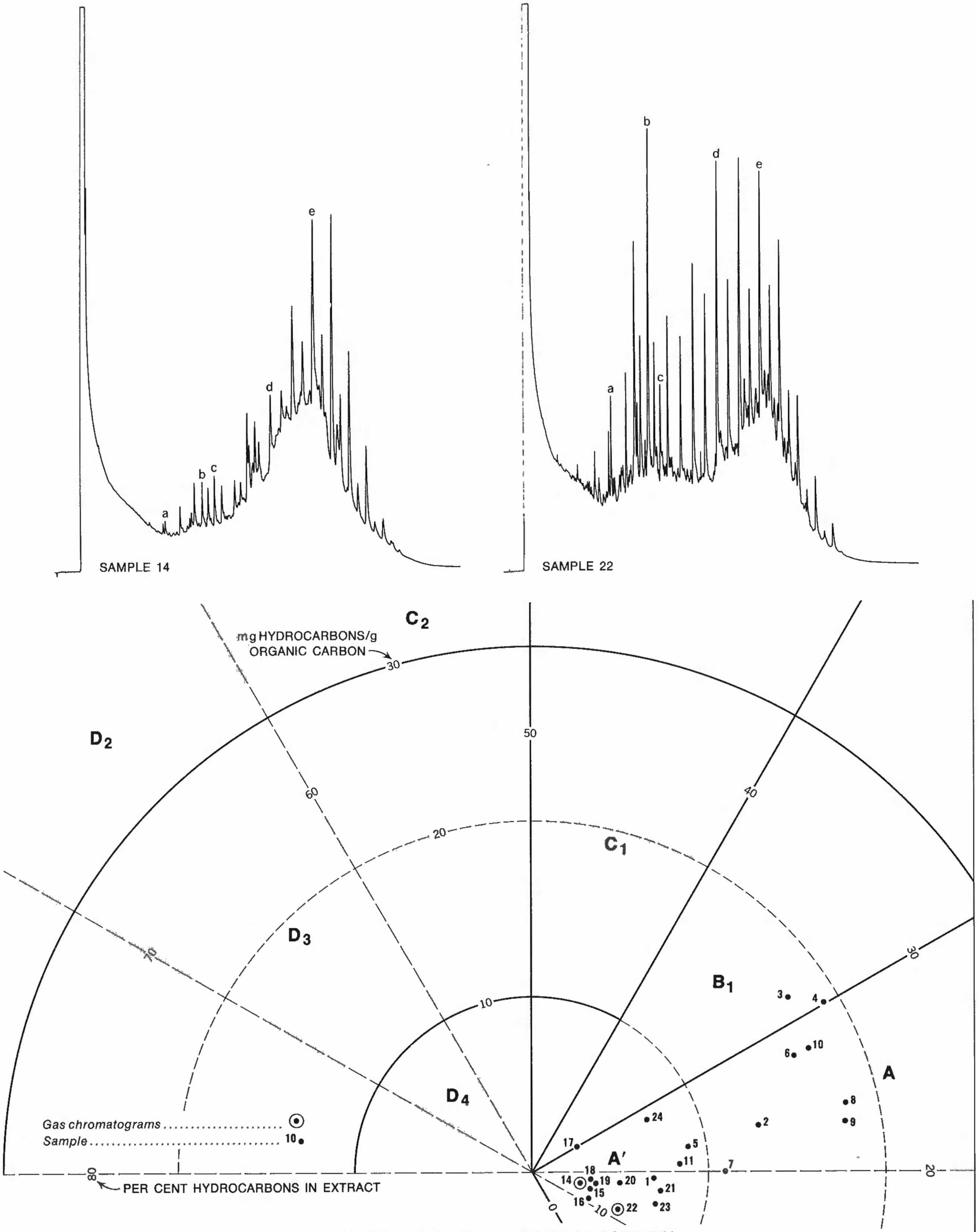
In the light of these considerations, the maps of metamorphic facies have been revised to reflect the large amount of extract data and the updated interpretation of the cuttings gas data (Fig. 9). Four facies are now recognized.

1. An undermature facies based on Snowdon and Roy's (1975) definition, i.e. wet gas content less than 30 per cent and a vitrinite reflectance level of less than 0.5% Ro max.

2. A marginally mature facies in which the wet gas content exceeds 30 per cent but the onset of the main phase of oil generation has not been reached. The main phase of oil generation is defined by the attainment of 40 per cent hydrocarbons in extracts of samples containing woody-herbaceous organic matter and a vitrinite reflectance level of 0.7% Ro max.

3. A mature facies corresponding to the main phase of oil generation. Per cent hydrocarbons in the extracts of woody-herbaceous organic matter exceed 40 per cent, or the distribution of saturated hydrocarbons is oil-like and vitrinite reflectance values lie between 0.7 and 1.4% Ro max.

4. An overmature facies which is indicated by a decrease in wet gas content below 60 per cent, a decrease in hydrocarbon yield below 30 mg per gram and vitrinite reflectance values in excess of 1.4% Ro max.



MATURATION STATE AND HYDROCARBON POTENTIAL

A. IMMATURE	B. MARGINALLY MATURE	C. MATURE	D. OVERMATURE
A' overlaps with D_4	Dry gas .... B_1	Gas only .... C_1	Light oil and gas .... D_1
	Gas possibly heavy oil .... B_2	Gas condensate; minor oil ... C_2	Gas condensate, minor oil ... D_2
		Intermediate oil source .... C_3	Gas condensate, wet gas ..... D_3
		Prolific oil source .... C_4	Dry gas (overlaps with A') .... D_4
		Staining .... C_5	

GSC

FIGURE 12. Source rock potential and gas chromatograms of the saturated hydrocarbons of the Isachsen and younger formations (*see* Table 4 for sample descriptions and Fig. 5 for key)

TABLE 4. Extract and kerogen data for the Isachsen, Christopher, Hassel and Kanguk Formations

							HYDROCARBONS		KEROGEN			
WELL NAME	SAMPLE NO.	DEPTH in metres	FORMATION	LITHOFACIES	ORGANIC CARBON %	EXTRACT mg/g org. C	mg/g org. C	% in extract	Atomic H/C	% Coal Wood	% Herbaceous	% Amorphous
Dumbells E-49 (36)	1	853	Isachsen	Shale, siltstone, sandstone	3.77	36.5	7.0	19.1				
	2	914-930	Isachsen	Carbonaceous sandstone, shale	3.85	53.9	13.1	24.2				
	3	1173-1189	Isachsen	Sandstone, shale	4.09	56.3	18.2	32.3				
	4	1219	Isachsen	Shale, siltstone, sandstone	2.50	65.2	19.5	29.9				
Emerald K-33 (11)	5	658	Isachsen	Shale	0.91	39.6	9.1	23.0				
Helicopter J-12 (35)	6	122-137	Isachsen	Siltstone, shale	2.13	57.6	16.3	28.3				
	7	213	Isachsen	Shale, sandstone, coal	4.82	54.6	11.0	20.2				
	8	427-442	Isachsen	Shale, siltstone, sandstone	4.38	75.5	18.2	24.1				
	9	884-899	Isachsen	Sandstone, shale, coal	2.79	77.5	18.1	23.3				
	10	1219-1234	Isachsen	Shale, siltstone	1.00	60.7	17.2	28.4				
Hoodoo Dome H-37 (37)	11	521-530	Isachsen	Sandstone, shale	1.80	39.4	8.3	21.0				
	12	576-594	Isachsen	Carbonaceous sandstone	3.20	45.1	14.8	32.9	0.74	30	40	30
May Point H-02 (44)	13	1829-1844	Christopher	Shale, siltstone	2.46	54.0	8.7	19.2				
North Sabine H-49 (20)	14	427-457	Kanguk	Shale	3.85	23.1	3.4	14.7				
	15	701-732	Hassel	Shale, sand	1.99	32.3	4.1	12.6				
	16	975-1006	Christopher	Shale, siltstone	2.07	18.5	3.0	16.2				
	17	1158-1189	Christopher	Shale, siltstone	1.64	10.5	3.1	29.0				
	18	1341-1356	Christopher	Shale	3.15	13.7	2.7	19.7	0.58	45	35	20
	19	1494-1509	Christopher	Shale	2.83	17.5	3.4	19.4				
	20	1676-1692	Christopher	Shale, siltstone	2.53	28.8	5.1	17.7				
	21	1829-1844	Christopher	Shale, siltstone	2.46	43.5	7.5	17.2				
	22	1981-1996	Isachsen	Sandstone, shale	3.12	45.9	5.4	11.7	0.65	35	65	
Romulus C-42 (46)	23	747-762	Christopher	Shale	3.05	49.2	7.4	15.0				
Thor P-38 (27)	24	229-244	Isachsen	Carbonaceous sandstone, shale	1.99	25.9	7.1	27.6				

Location of wells *see* Figure 3a, Table 1

Numbers in brackets *see* Figures 3a, 10

In detail, sub-zones can be picked in the transition from the mature facies to overmature facies since the decline in wet gas content is offset from the decline in hydrocarbon yield but for required mapping purposes the distinction is of little significance.

In contrast to the map shown by Snowdon and Roy (1975), the additional data from the central part of the basin show that the base of the Isachsen Formation lies in the undermature zone (Fig. 9). The only exception is the North Sabine H-69 well where the base of the Isachsen Formation lies just in the wet gas zone. This contrasts with data from the Emerald K-33 and Skybattle C-15 wells. The North Sabine H-49 well was drilled adjacent to a salt diapir. Salt is more highly conductive to heat than other rocks. As a result of the insulation properties of the overlying rocks, a halo of heat is formed in the vicinity of the diapir and results in a locally higher maturation level. Similar effects have been observed in the vicinity of salt domes on the Scotian Shelf (Rashid and McAlary, 1977). The local enhancement of maturation may have some implications for the area of salt diapirs lying in the vicinity of the Sabine Peninsula particularly at lower stratigraphic levels. This map is similar to that given by Henao-Londoño (1977) for the ovelying Christopher Formation.

In the two remaining facies maps (Figs. 9B, C), the transition from undermature to marginally mature as drawn by Snowdon and Roy (1975, Figs. 13, 14) appears to be correct on the basis of gas analysis with the exception of the North Sabine area where extract data show the base of Jurassic shale succession to be mature. Interpretation of the mature to overmature transition is more difficult. Data from two deep wells on the Sabine Penisula of Melville Island, namely Drake D-68 and Chads Creek B-64, indicate that the base of the Triassic in this area is still in the mature zone and that the mature to overmature transition occurs well into the Permian (Fig. 5). On Ellef Ringnes and farther to the east, the mature to overmature transition depends on the distribution of igneous intrusions. In the case of a single intrusion, only the sediments in the immediate vicinity (equivalent to the thickness of the intrusion) appear to be affected by its heat. In the case of multiple intrusions, thermal effects would be widespread in the surrounding sediments. This appears to have been the case in the Louise Bay 0-25, Helicopter J-12, Amund Central Dome H-40, Mid Fiord J-73, Kristoffer Bay G-06 and King Christian N-06 wells (Fig. 10). An extreme case is the Louise 0-25 well. Sediments in the upper part of the well, which are not intruded, are marginally mature on the basis of extract data whereas sediments from the lower part of the well,

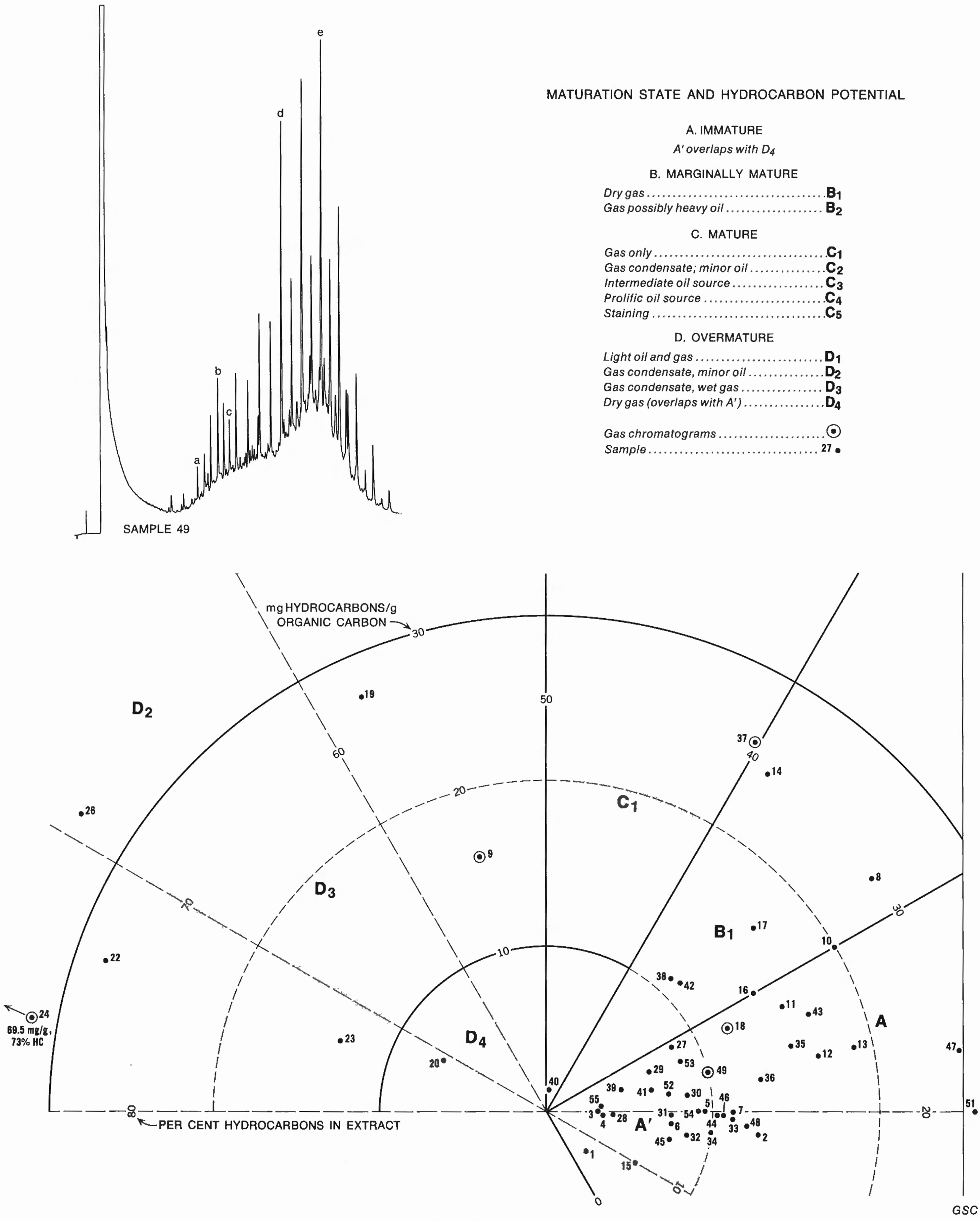
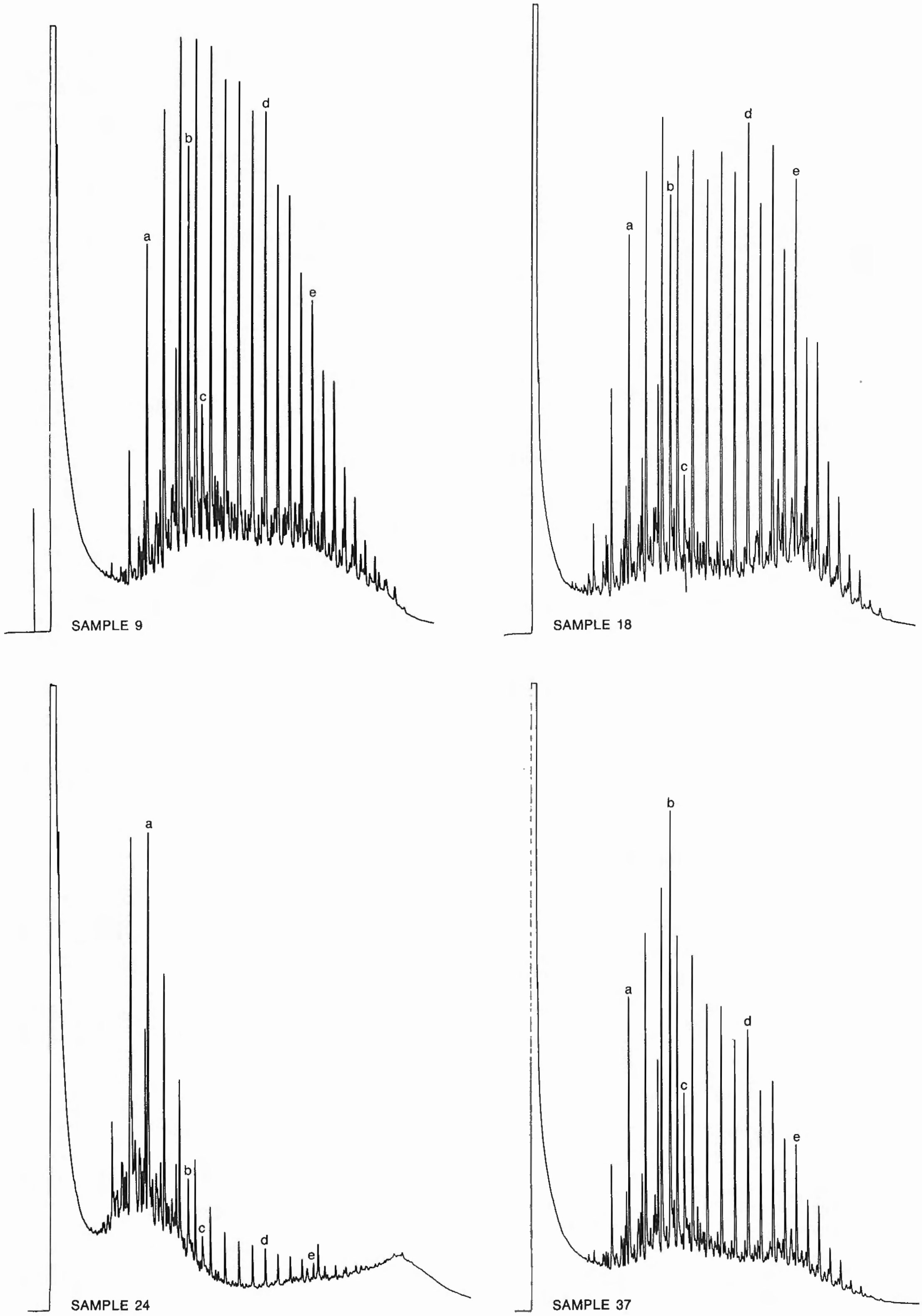


FIGURE 13. Source rock potential and gas chromatograms of the saturated hydrocarbons of the Deer Bay, Awingak and Wilkie Point Formations (*see* Table 5 for sample descriptions and Fig. 5 for key)

FIGURE 13. Continued



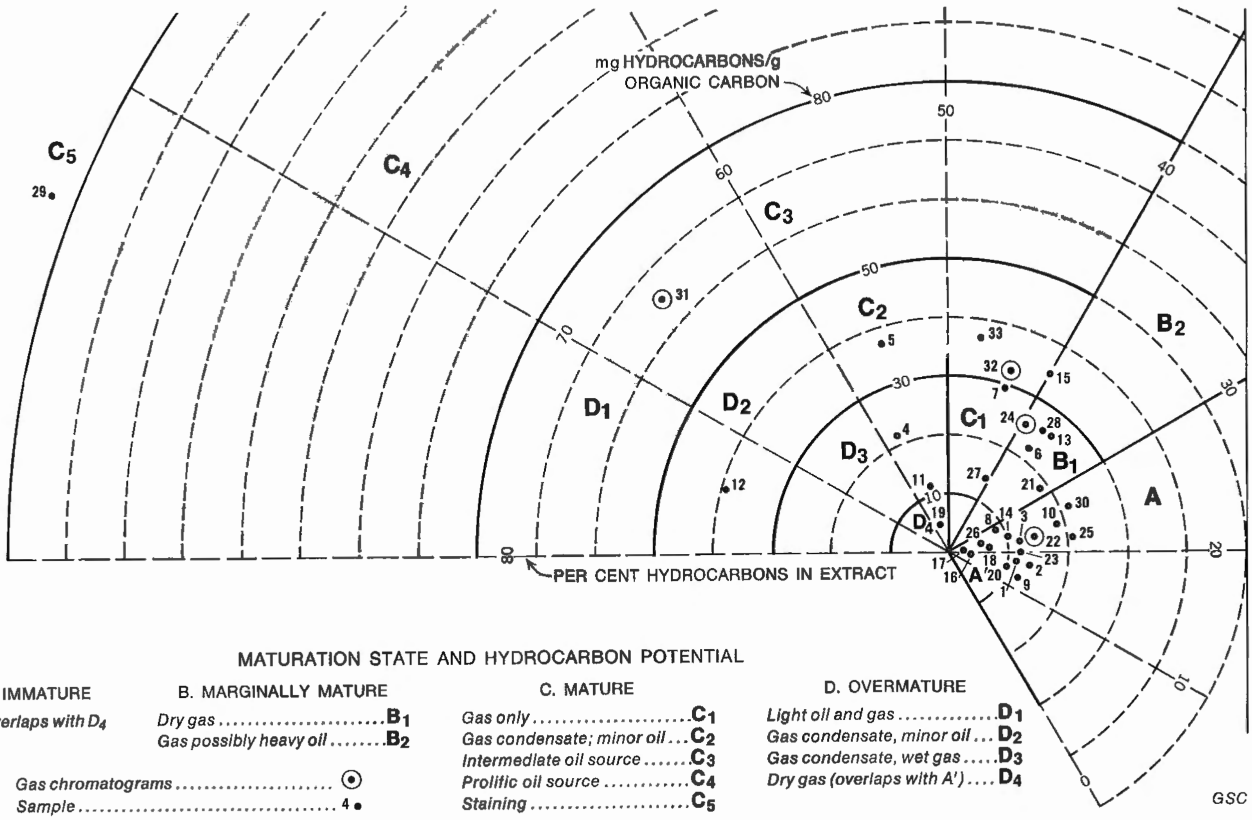


FIGURE 14. Source rock potential and gas chromatograms of the saturated hydrocarbons of the Savik and Jaeger Formations (*see* Table 6 for sample descriptions and Fig. 5 for key)

which are extensively intruded by sills and dykes, are overmature (Fig. 11). In contrast, in the Hoodoo Dome A-37, Dumbells E-43 and Dome Bay P-36 wells, intrusions are absent or are of insufficient density to affect a substantial part of the section. Projection of organo-metamorphic facies between the wells is therefore extremely difficult.

At Helicopter J-12, Louise O-25, Mid Fiord J-73 and Dome Bay P-36 the intrusions extend as high as the Jurassic strata (Fig. 10). An overmature interpretation for the base of the Jurassic is probably correct for all wells except Dome Bay P-36 where igneous activity has not been sufficiently intense to completely affect the lower part of the Jurassic section (Fig. 10). Data from Amund Ringnes suggest that the mature to overmature transition occurs beneath the base of the Jurassic shale zone. In respect of the Triassic strata, they are overmature where they are intruded by sills and dykes; e.g. King Christian N-06 below 1800 m, Kristoffer Bay G-06, and Amund Central Dome H-40. The base of the Triassic sequence is likely to fall in the overmature zone in the Ellef Ringnes region (Fig. 9C). The Blaa Mountain is considered to be at least 1800 to 2400 m thick, which would place the base of the Blaa Mountain Formation at a maximum burial depth of the order of 5500 to 6100 m which is well within the mature zone. In general, these two maps are similar to those given by Henao-Londoño (1977) for the Savik and Lower Blaa Mountian/Blind Fiord Formations. They differ in that the maturation levels in the Fosheim Peninsula area are interpreted to be lower in this study and no account of local effect of igneous intrusion has been considered by Henao-Londoño (1977).

MATURATION AND SOURCE ROCK POTENTIAL OF STRATIGRAPHIC UNITS

Isachsen and younger formations

The organo-metamorphic facies map at the base of the Isachsen indicates that the Isachsen and younger formations have undergone insufficient thermal diagenesis for significant hydrocarbon generation. The hydrocarbon yields and hydrocarbon content of the extracts are low (Table 4, Fig. 12). There is some suggestion of an increase in extract yield in the Isachsen of the Helicopter J-12 well but the percentage hydrocarbon content of the extract indicates marginally mature values and the gas chromatograms of the saturated hydrocarbons show a pronounced odd over even predominance. A limited amount of kerogen data shows that the sediments contain organic matter of predominantly terrestrial origin (Table 4). There is some evidence to suggest that the Kanguk and Hassel Formations may contain more hydrocarbon-prone organic matter. Visual kerogen descriptions of samples from these formations in the North Sabine H-49 well show a relatively high content of amorphous organic matter. A gas chromatogram of the saturated hydrocarbons from a sample in the same interval shows no heavy waxy paraffins, a preponderance of phytane over pristane and a relatively high content of steranes and triterpanes (Fig. 5). All these features are indicative of organic matter derived from micro-organisms. However, this group of sediments would have to undergo considerable burial and diagenesis before hydrocarbon generation could take place.

FIGURE 14. Continued

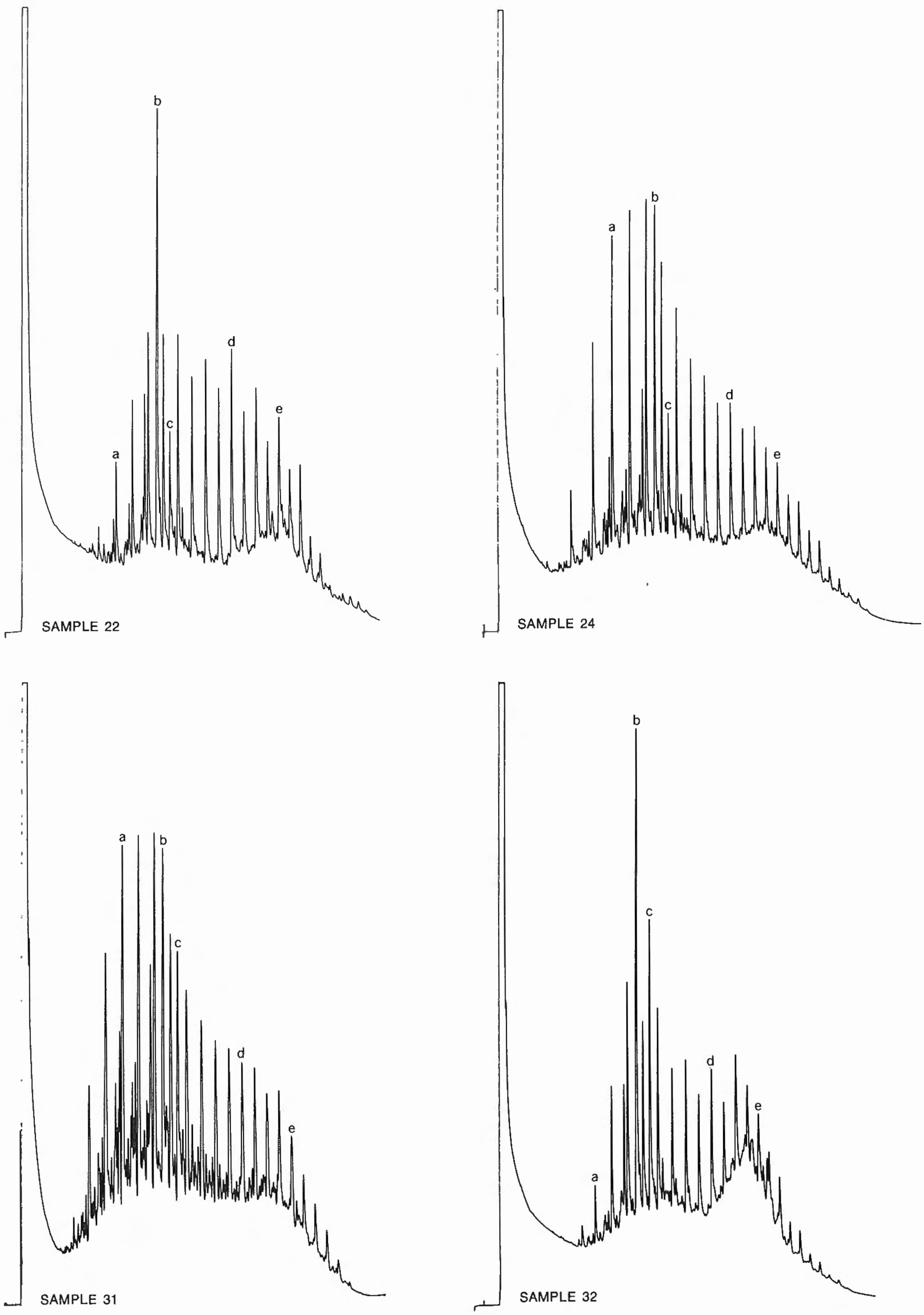


TABLE 5. Extract and kerogen data for the Deer Bay, Awingak and Mould Bay Formations

WELL NAME	SAMPLE NO.	DEPTH in metres	FORMATION	LITHOFACIES	ORGANIC CARBON %	EXTRACT mg/g org. C	HYDROCARBONS mg/g org. C	HYDROCARBONS % in extract	KEROGEN Atomic H/C	KEROGEN % Coal Wood	KEROGEN % Herbaceous	KEROGEN % Amorphous
Cape Norem A-80	1	853-863	Deer Bay	Bituminous shale	4.02	65.9	3.4	5.1				
(7)	2	908-917	Deer Bay	Shale (calcareous)	2.09	73.2	12.9	17.6				
Drake Point D-68	3	549-564	Deer Bay	Shale and siltstone	2.37	22.3	3.7	16.8	0.72			
(17)	4	610-625	Deer Bay	Shale and siltstone	1.81	19.5	3.5	17.7	0.73			
	5	808-823	Deer Bay	Siltstone, sandstone, coal	1.98	63.9	9.8	19.9	0.72			
Dome Bay P-36	6	457	Deer Bay	Shale, sandstone	3.44	43.3	7.6	17.5				
(29)	7	640-655	Deer Bay	Shale (carbonaceous)	1.84	57.4	11.3	19.7				
	8	1006	Deer Bay	Shale, siltstone	1.76	76.8	24.2	31.6				
	9	1402-1417	Deer Bay	Shale (carbonaceous)	1.80	28.8	15.9	55.2				
Dumbells E-49	10	1524	Deer Bay	Shale	2.96	64.8	19.8	30.6				
(36)	11	1707	Deer Bay	Shale	2.55	56.6	15.7	27.7				
	12	1890	Deer Bay	Shale	1.95	71.0	16.8	23.7				
	13	1981-1996	Deer Bay	Shale, sandstone	2.31	79.9	18.9	23.6				
	14	2332	Deer Bay	Shale (carbonaceous)	4.37	63.2	24.4	38.6				
Gemini E-10 (48)	15	1524-1539	Deer Bay	Siltstone	1.37	47.2	6.2	13.2				
Graham C-52 (42)	16	1167	Deer Bay	Sandstone, shale	3.20	46.0	14.5	30.5				
Halcyon O-16	17	1463-1478	Deer Bay	Shale	2.20	48.9	16.8	34.4				
Helicopter J-12	18	1524	Deer Bay	Shale	2.35	42.5	13.1	30.9		40	40	20
(35)	19	1768-1783	Deer Bay	Shale	2.07	47.3	27.5	58.3				
	20	1951-1966	Deer Bay	Shale	1.95	9.8	7.0	70.9	0.53	90	10	
	21	2073-2088	Deer Bay	Shale	3.59	494.5	323.8	65.5	0.80	90	10	
	22	2225-2240	Deer Bay	Shale	2.37	38.8	28.2	72.6				
	23	2469-2484	Deer Bay	Shale, igneous rock	1.98	17.8	13.1	73.5				
	24	2743	Deer Bay	Shale	4.40	95.2	69.5	73.0				
	25	2987-3002	Deer Bay	Shale, igneous rock	2.55	-	-	-				
	26	3200-3216	Deer Bay	Shale	2.92	48.7	33.5	68.8				
Jameson Bay C-31	27	165-201	Deer Bay	Shale	2.49	29.7	8.5	28.7				
(8)	28	238-256	Deer Bay	Shale (carbonaceous)	5.45	21.2	4.1	19.7				
King Christian N-06	29	411-421	Deer Bay	Shale	3.52	24.6	6.7	27.4				
(26)	30	439-448	Deer Bay	Shale	2.46	38.6	8.6	22.3				
	31	457-466	Deer Bay	Limestone, shale	2.04	38.7	7.6	19.5				
Kristoffer Bay B-06	32	610-625	Deer Bay	Shale	1.90	51.3	8.6	16.7				
(28)	33	792	Deer Bay	Shale	1.64	57.6	11.6	20.2				
	34	1128-1143	Deer Bay	Shale	2.08	54.0	10.0	18.0				
Louise Bay O-25	35	137	Deer Bay	Shale	1.70	74.2	15.3	21.4				
(31)	36	244	Deer Bay	Shale	1.80	57.0	13.1	23.0				
	37	488-503	Deer Bay	Shale	1.90	63.7	25.7	40.3				
	38	732-747	Deer Bay	Shale	5.13	16.1	11.2	69.3				
	39	869-884	Deer Bay	Shale	0.40	17.7	4.7	26.4				
Mid Fiord J-53 (43)	40	914-930	Deer Bay	Shale	1.28	3.6	1.5	47.8				
Noice G-44	41	366	Deer Bay	Shale	3.31	26.3	6.5	24.5				
(30)	42	655-671	Deer Bay	Shale	1.96	33.1	11.5	35.5				
	43	1006-1021	Deer Bay	Shale	1.98	61.9	16.9	27.3				
North Sabine H-49	44	2134-2149	Deer Bay	Shale	2.85	52.4	10.4	20.2				
(20)	45	2286-2301	Deer Bay	Shale, sandstone	2.53	47.4	7.6	16.0				
	46	2438-2454	Awingak	Shale, sandstone	2.31	54.2	10.7	19.7				
	47	2591-2606	Awingak	Shale (carbonaceous)	4.40	110.4	25.2	22.8	0.76	20	50	30
Romulus C-42 (46)	48	914-930	Deer Bay	Shale, siltstone	2.77	62.7	12.1	19.3				
Skybattle Bay C-15	49	1308-1317	Deer Bay	Shale	1.90	40.6	10.2	25.2	0.78	40	40	20
(23)	50	1399-1408	Deer Bay	Shale, siltstone	1.57	39.9	11.9	29.8				
	51	1664-1673	Deer Bay	Sandstone, coal	1.60	125.2	25.9	20.7	0.82	30	40	30
Thor P-38	52	290-305	Deer Bay	Shale, siltstone	2.41	31.6	7.3	23.1				
(27)	53	366-381	Deer Bay	Shale, siltstone	1.31	32.1	8.8	27.3				
	54	594-610	Deer Bay	Shale, siltstone	1.69	46.8	9.7	20.7	0.97	10	50	20
	55	671-686	Deer Bay	Shale (carbonaceous)	4.53	17.1	3.8	22.2	0.85	40	40	20

Location of wells *see* Figure 3a, Table 1

Numbers in brackets *see* Figures 3a, 10

TABLE 6. Extract and kerogen data for the Savik and Jaeger Formations

WELL NAME	SAMPLE NO.	DEPTH in metres	FORMATION	LITHOFACIES	ORGANIC CARBON %	EXTRACT mg/g org. C	HYDROCARBONS mg/g org. C	HYDROCARBONS % in extract	Atomic H/C	KEROGEN % Coal Wood	KEROGEN % Herbaceous	KEROGEN % Amorphous
Cape Norem A-80 (7)	1	1237	Savik	Shale, siltstone	1.93	67.5	11.9	17.2				
	2	1311	Savik	Shale	1.81	79.6	13.9	17.4				
Drake Point D-68 (17)	3	1036-1052	Savik	Shale, siltstone	2.52	5.9	1.2	19.9	0.66			
Dome Bay P-36 (29)	4	1570-1585	Jaeger	Sandstone, shale	1.83	37.6	21.7	57.9				
	5	1646-1661	Savik	Shale	1.10	66.1	36.8	55.8				
Dumbells E-49 (36)	6	2804	Jaeger	Shale, sandstone	2.87	59.5	22.1	37.2				
	7	2972-2987	Savik	Shale	2.28	71.9	31.3	44.4				
Emerald K-33 (11)	8	1229	Savik	Shale, siltstone	0.56	31.3	8.7	28.0				
Gemini E-10 (48)	9	1981-1996	Lower Savik	Shale, sandstone	1.77	94.5	12.6	13.3				
Halcyon O-16 (49)	10	1844-1859	Upper Savik-Jaeger	Shale, sandstone	2.50	77.3	19.1	24.7				
Helicopter J-12 (35)	11	3490-3505	Savik	Shale, trace igneous	1.63	22.4	12.3	54.9				
	12	3536	Savik	Shale, trace sandstone	1.76	52.9	39.4	74.4				
Hoodoo Dome H-37 (37)	13	2176	Savik	Shale, siltstone	1.32	71.4	26.0	36.4				
King Christian N-06 (26)	14	542-570	Savik	Shale, siltstone	0.57	41.5	10.0	24.2				
	15	579-597	Savik	Shale, siltstone	1.23	86.8	34.8	40.1				
Linckens Island P-46 (41)	16	786-796	Savik	Shale	2.47	18.1	3.4	18.9				
	17	914-924	Savik	Shale	2.71	19.3	3.8	19.6				
Louise Bay O-25 (31)	18	1356-1372	Savik	Shale, igneous rock	1.24	16.2	6.5	40.4				
	19	1417-1448	Savik	Shale, igneous rock	0.94	7.6	4.4	58.2				
May Point H-02 (44)	20	2499-2515	Savik	Shale, sandstone	2.59	61.8	10.2	16.6				
Noice G-44 (30)	21	1280	Jaeger	Shale, siltstone	2.60	58.1	18.7	32.2				
North Sabine H-49 (20)	22	2667-2682	Upper Savik	Shale	3.27	61.1	14.3	23.4		20	60	20
	23	2758-2774	Jaeger	Shale	1.12	52.9	11.9	22.5				
	24	2896-2911	Jaeger	Shale, sandstone	1.37	65.1	25.6	39.0		20	65	15
Romulus C-42 (46)	25	1311-1326	Upper Savik-Jaeger	Shale, sandstone	2.87	94.7	21.1	22.3				
Sandy Point L-46 (9)	26	602	Savik	Shale	0.81	26.5	5.9	24.2				
Sirius K-28 (34)	27	838-853	Savik	Shale	2.04	34.7	14.2	40.8				
Skybattle Bay C-15 (23)	28	1820-1829	Savik	Shale	0.76	65.8	24.8	37.7				
Sutherland O-23 (24)	29	232-241	Savik	Siltstone	0.54	228.4	164.2	71.9				
Thor P-38 (37)	30	991-1021	Savik	Shale, siltstone	1.02	80.8	21.5	26.6				
	31	1128-1143	Savik	Shale	3.03	97.9	64.9	66.3	1.06	60	40	
Wilkins E-60 (6)	32	661-680	Savik	Shale	2.67	70.2	32.9	42.9				
	33	698-725	Savik	Shale	1.43	75.4	37.3	47.4	1.16	10	20	70

Location of wells *see* Figure 3a, Table 1

Numbers in brackets *see* Figures 3a, 10

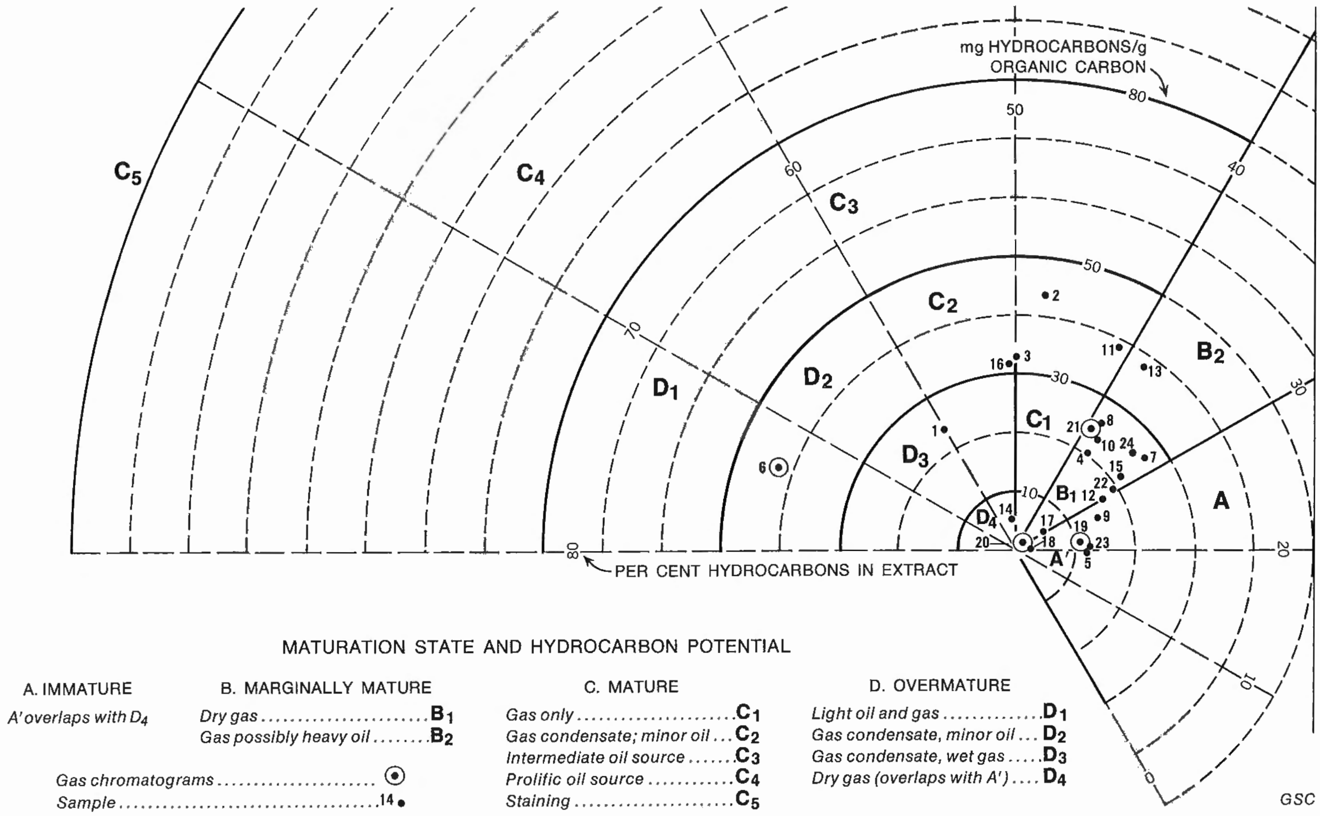


FIGURE 15. Source rock potential and gas chromatograms of the saturated hydrocarbons of the Borden Island and Heiberg Formations (*see* Table 7 for sample descriptions and Fig. 5 for key)

Deer Bay, Awingak and Wilkie Point Formations

These formations range from Early Jurassic to Early Cretaceous in age. The Awingak and Wilkie Point Formations are dominantly sandstones whereas the Deer Bay is a thick grey to black marine shale. The Deer Bay is largely immature to marginally mature except on central Ellef Ringnes Island (Helicopter J-12, Louise O-25 and Dome Bay P-36 wells) (Fig. 13, Table 5). The organic carbon logs show a characteristically high carbon content (up to 4%) at the base of the Deer Bay in many wells (Fig. 10). This is commonly accompanied by a high gas concentration which may be in excess of 100 000 ppm by volume in some wells on Ellef Ringnes (Fig. 10). West of Ellef Ringnes Island, the background gas levels are less than 5000 ppm. On western and southern Ellef Ringnes Island and adjacent smaller islands (King Christian and Thor Islands), the gas concentrations have increased to 10 000 to 20 000 ppm whereas in east-central Ellef Ringnes the background gas levels are in excess of 20 000 ppm reflecting the heating effects of igneous activity.

Extract data (Table 5, Fig. 13) show that the Deer Bay has generally not generated much in the way of liquid hydrocarbons. The high content of waxy n-alkanes in the saturated hydrocarbons with a pronounced odd carbon number preference (Fig. 13), atomic hydrogen to carbon ratios of the kerogen of less than 0.8 (Table 3), and the preponderance of woody organic matter in the slide preparations of the kerogen all indicate generally poor source material. Exceptions to the generally immature or marginally mature aspect of the Deer Bay Formation occur in the Helicopter J-12, Dome Bay P-36, Dumbells E-49 and Louise Bay O-25 wells. Some extracts from these wells contain a high percentage of hydrocarbons. This is particularly the case in the Helicopter J-12 well where the percentage of hydrocarbons in the extracts ranges from 31 to 73. A stained sample occurs at 2073 m in the Helicopter J-12 well and is attributed to the igneous activity causing local generation and migration of hydrocarbons. Despite their maturity, the samples from the Helicopter well generally have low yields of hydrocarbons (20-30 mg per gram organic carbon) and are rated as poor source rocks. An exception is the sample from 2743 m in the Helicopter J-12 well. It has a good yield of hydrocarbons (69.5 mg per gram organic carbon) and is rated as a good source rock. It differs from the other samples from this well in having a quite different distribution of saturated hydrocarbons. The distribution of hydrocarbons reaches a maximum at C_{15} (Fig. 13) and the higher molecular weight hydrocarbons are much less abundant than in the other samples. Since the gas-chromatogram peaks at C_{15} in this sample, the likely hydrocarbon product is gas-condensate or light oil. The proximity of the sample to a thick igneous sill (Fig. 10) probably explains these anomalous results. Below 2750 m in the Helicopter J-12 well, there is a dramatic decrease in the wet gas content (Fig. 10). At first one would suppose that this is due to thermal cracking associated with the occurrence of igneous activity. It also coincides with the zone of high organic carbon content in the Deer Bay Formation. Extract data from depths of 2987 and 3200 m (Table 5, Fig. 13) show no decline in extract yields as would be expected if the overmature zone had been

FIGURE 15. Continued

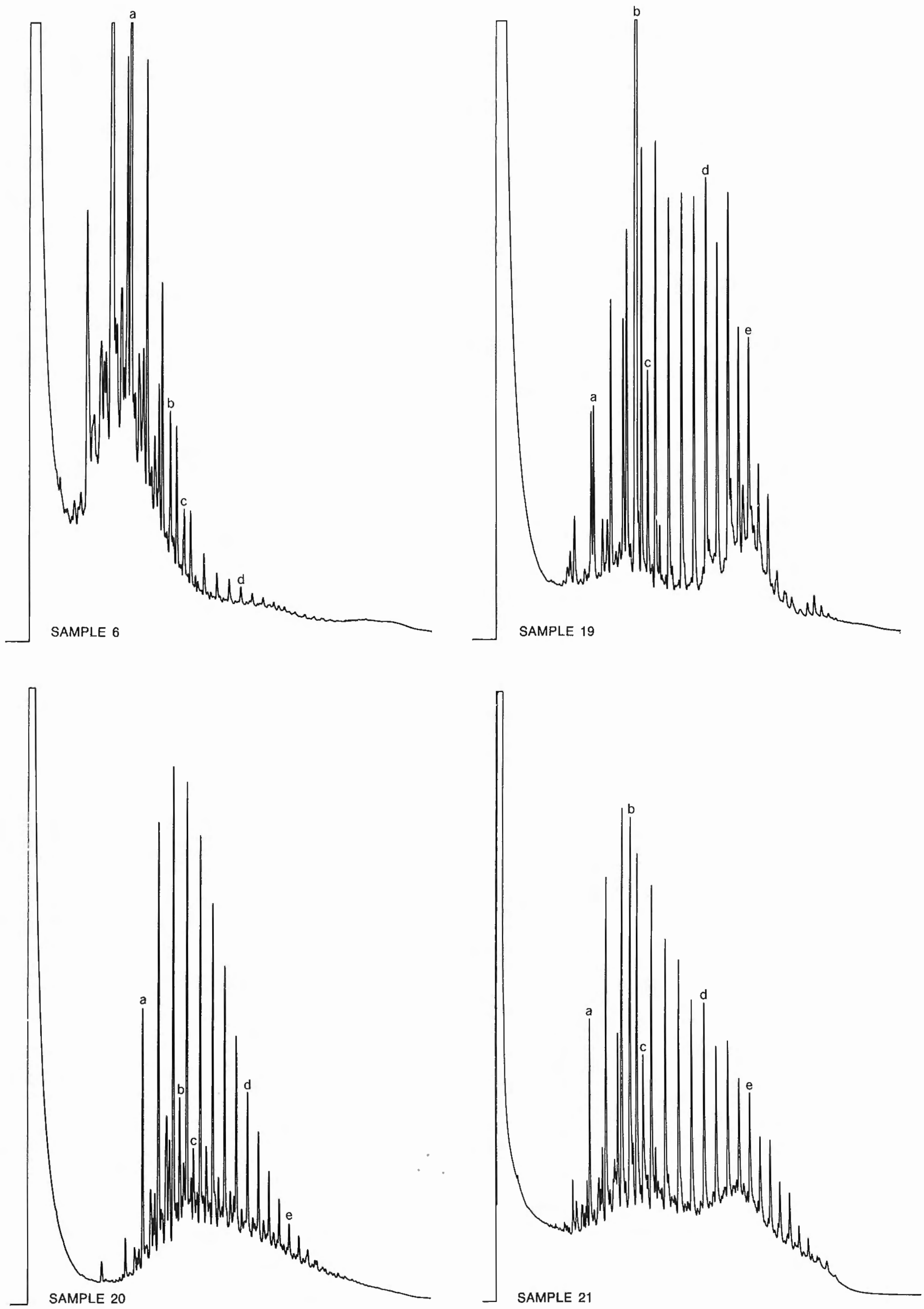


TABLE 7. Extract and kerogen data for the Borden Island and Heiberg Formations

WELL NAME	SAMPLE NO.	DEPTH in metres	FORMATION	LITHOFACIES	ORGANIC CARBON %	EXTRACT mg/g org. C	HYDROCARBONS mg/g org. C	HYDROCARBONS % in extract	Atomic H/C	KEROGEN % Coal Wood	KEROGEN % Herbaceous	KEROGEN % Amorphous
Dome Bay P-36 (31)	1	2042	Heiberg	Shale, siltstone, sandstone	1.22	40.4	24.0	59.5				
Dumbells E-43 (36)	2	3200	Heiberg	Sandstone, shale, coal	1.97	91.2	43.9	48.1				
	3	3322	Heiberg	Sandstone, shale	1.45	65.5	33.0	50.3				
Emerald K-33 (11)	4	1408-1426	Borden Island	Shale, siltstone	1.52	53.7	20.5	38.2	0.95			
Gemini E-10 (48)	5	2423-2438	Heiberg	Shale, siltstone, sandstone	5.04	62.7	12.1	19.3				
Helicopter J-12 (35)	6	3749	Heiberg	Siltstone (carbonaceous)	0.72	57.8	42.5	73.5				
Hoodoo Dome H-37 (37)	7	2377	Heiberg	Shale (carbonaceous), sandstone	2.81	82.2	26.5	32.2		30	50	20
	8	2405-2414	Heiberg	Shale, carbonaceous sandstone	3.14	66.9	26.0	38.9	0.97			
	9	2652	Heiberg	Sandstone, coal	12.96	54.4	14.9	27.4				
	10	2999-3008	Heiberg	Shale, sandstone	1.85	60.4	23.2	38.4				
King Christians N-06 (26)	11	835-853	Heiberg	Shale (carbonaceous), sandstone	3.60	94.0	38.6	41.0	0.86	30	70	
	12	1067-1085	Heiberg	Sandstone, shale	1.01	57.4	17.0	29.6	0.77	50	50	
	13	1213-1222	Heiberg	Shale (carbonaceous), siltstone	0.95	67.9	37.9	55.8				
Linckens Island P-46 (41)	14	1088-1097	Borden Island-Heiberg	Shale, coal	13.65	10.8	5.1	52.2				
Kristoffer Bay B-06 (28)	15	1478-1494	Heiberg	Sandstone, shale	1.57	69.0	21.9	31.8				
	16	1600-1615	Heiberg	Sandstone, siltstone	0.80	61.7	31.6	51.2				
Louise Bay O-25 (31)	17	1615-1646	Heiberg	Sandstone, carbonaceous shale	0.79	17.8	5.6	31.3				
	18	1798-1829	Heiberg	Shale, sandstone	0.79	10.8	2.3	21.6				
May Point H-02 (44)	19	2743-2758	Heiberg	Shale, sandstone	9.69	47.5	10.7	22.3				
Mid Fiord J-53 (43)	20	1829-1838	Heiberg	Siltstone, igneous rock	0.39	6.1	2.0	33.3				
North Sabine H-49 (20)	21	3048-3063	Borden Island	Siltstone, sandstone	0.83	62.5	24.5	39.0		25	60	15
Romulus C-42 (46)	22	1829-1844	Heiberg	Sandstone, coal, shale	3.16	61.9	18.7	30.3				
Taleman J-34 (47)	23	1829-1844	Heiberg	Shale, siltstone, shale	4.31	63.6	12.4	19.5				
Thor P-38 (27)	24	1234-1250	Heiberg	Shale (carbonaceous), sandstone	1.54	76.9	25.6	33.3				

Location of wells *see* Figure 3a, Table 1

Numbers in brackets *see* Figures 3a, 10

reached. The only possible alternate explanation is that substanial amounts of dry gas have been generated adjacent to the intrusions and have migrated and swamped the indigenous gas content of strata remote from the sills and dykes.

As mentioned previously, in the Louise Bay O-25 well the abundance of igneous intrusions has been sufficient to raise the level of thermal diagenesis of the Deer Bay Formation to the overmature stage.

Two immature samples were encountered from these formations which would probably have some hydrocarbon potential if more deeply buried. These are from 2591 m (Awingak) in the North Sabine H-49 well and from 1664 m (Deer Bay) in the Skybattle Bay C-15 well (Table 3). They have large extract yields (~110 mg per gram organic carbon) and a high hydrocarbon yield of 25 mg per gram organic carbon considering their immature state. Visual kerogen data indicate a lower coal content than many of the samples in this group although the atomic hydrogen to carbon ratios of the kerogen show no significant difference. In general, the overall lack of maturity and unfavourable organic matter type suggests the Deer Bay is an unfavourable source rock for oil. It may have considerable gas potential particularly on Ellef Ringnes Island. Henao-Londoño (1977) indicates some oil potential for this unit on eastern Ellef Ringnes Island. The difference in interpretation can be directly attributed to differences in the method of source rock evaluation.

TABLE 8. Extract and kerogen data for the Schei Point Formation

WELL NAME	SAMPLE NO.	DEPTH in metres	FORMATION	LITHOFACIES	ORGANIC CARBON %	EXTRACT mg/g org. C	HYDROCARBONS mg/g org. C	HYDROCARBONS % in extract	Atomic H/C	KEROGEN % Coal Wood	KEROGEN % Herbaceous	KEROGEN % Amorphous
Andreason L-32 (2)	1	1094-1103	Schei Point	Bituminous shale, limestone	1.27	206.6	72.1	35.1				
Brock C-50 (5)	2	91	Schei Point	Shale	1.75	70.3	44.6	63.3	0.80	0	20	80
Cape Norem A-80 (7)	3	2143-2152	Schei Point	Bituminous, calcareous shale	2.35	12.1	3.7	30.5				
	4	2353-2362	Schei Point	Limestone	0.53	175.6	118.3	67.4				
	5	2390	Schei Point	Siltstone	0.94	nd	nd	48.2				
	6	2518	Schei Point	Limestone, sandstone	0.87	215.5	70.9	32.9	0.88			
	7	2582-2591	Schei Point	Calcareous shale, siltstone	0.82	93.5	44.1	47.2				
Drake Point L-67A (16)	8	1443	Schei Point	Shale (calcareous)	0.60	1907.0	1609.0	84.4				
	9	1459	Schei Point	Siltstone (argillaceous)	0.11	313.0	247.0	79.0				
Drake Point D-68 (17)	10	1250-1265	Schei Point	Siltstone	1.66	25.3	7.8	30.8	0.99			
	11	1326-1341	Schei Point	Siltstone, limestone	2.33	51.6	15.1	29.2	1.15			
Emerald K-33 (11)	12	1536-1554	Schei Point	Shale	2.82	79.4	51.8	65.2				
	13	1600-1609	Schei Point	Shale, limestone	4.39	119.1	71.0	59.6	0.74	10	10	80
	14	1664-1673	Schei Point	Shale, sandstone	1.68	76.2	47.1	61.8				
Fosheim N-27 (45)	15	375-393	Schei Point	Siltstone	0.96	40.2	18.8	46.9				
	16	640-649	Schei Point	Siltstone, shale, limestone	0.83	141.8	112.0	79.0				
Hecla J-60 (13)	17	1207-1216	Schei Point	Siltstone	2.73	73.0	37.5	51.3				
Intrepid H-49 (1)	18	820-829	Schei Point	Bituminous shale	4.41	44.2	12.4	28.0				
Jameson Bay C-31 (8)	19	1058-1076	Schei Point	Calcareous shale	0.69	67.1	17.5	26.1		25	35	40
	20	1122-1131	Schei Point	Argillaceous limestone	1.49	73.6	27.7	34.9	1.08			
	21	1140-1149	Schei Point	Argillaceous limestone	1.63	68.9	22.9	33.2				
Marie Bay D-02 (10)	22	314-323	Schei Point	Sandstone, siltstone	0.31	26.0	8.7	33.3				
North Sabine H-49 (20)	23	3109-3124	Schei Point	Shale	1.12	42.8	18.3	42.7				
	24	3200-3216	Schei Point	Sandstone, siltstone	0.94	49.7	24.9	50.0	0.82	40	20	40
	25	3383-3398	Schei Point	Shale	1.08	52.2	30.9	59.0				
	26	3475-3490	Schei Point	Shale, limestone	1.90	163.9	127.8	78.0	0.83			
	27	3520-3535	Schei Point	Shale, limestone	0.95	nd	nd	63.0				
	28	3551	Schei Point	Shale, limestone						30	65	5
	29	3597	Schei Point	Shale	1.08	79.6	42.4	53.0				
Pollux G-60 (32)	30	1158-1173	Schei Point	Sandstone, bituminous shale	0.91	95.3	46.0	48.0	0.92			
Sandy Point L-46 (9)	31	775	Schei Point	Shale	2.51	10.0	2.5	25.0		70	10	20
Satellite F-68 (3)	32	640	Schei Point	Shale	0.97	28.6	7.5	26.0	0.84			
	33	750-759	Schei Point	Shale	1.40	61.3	20.4	33.0				
	34	868	Schei Point	Shale, limestone fragments	5.06	101.1	63.9	62.0	1.21			
Skybattle Bay C-15 (23)	35	2621-2640	Schei Point	Sandstone, shale	0.34	97.4	32.5	33.5				
	36	2694-2703	Schei Point	Sandstone, limestone	0.17	109.4	68.8	62.5				
	37	2838-2847	Schei Point	Siltstone	1.60	79.2	34.8	43.9	1.13	10	50	40
	38	2947-2957	Schei Point	Limestone	0.26	280.5	186.5	66.5				

Location of wells *see* Figure 3a, Table 1

Numbers in brackets *see* Figures 3a, 10

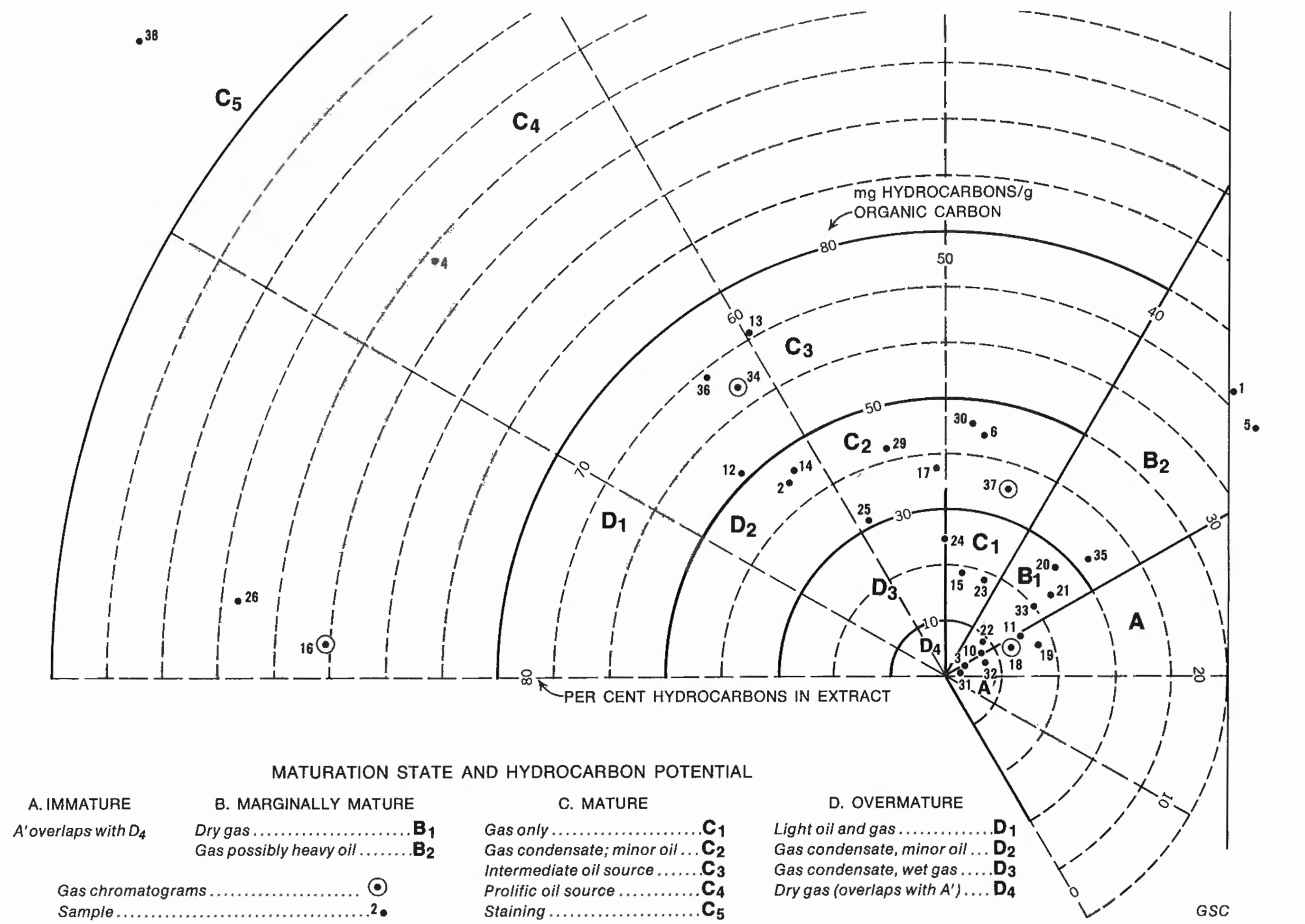


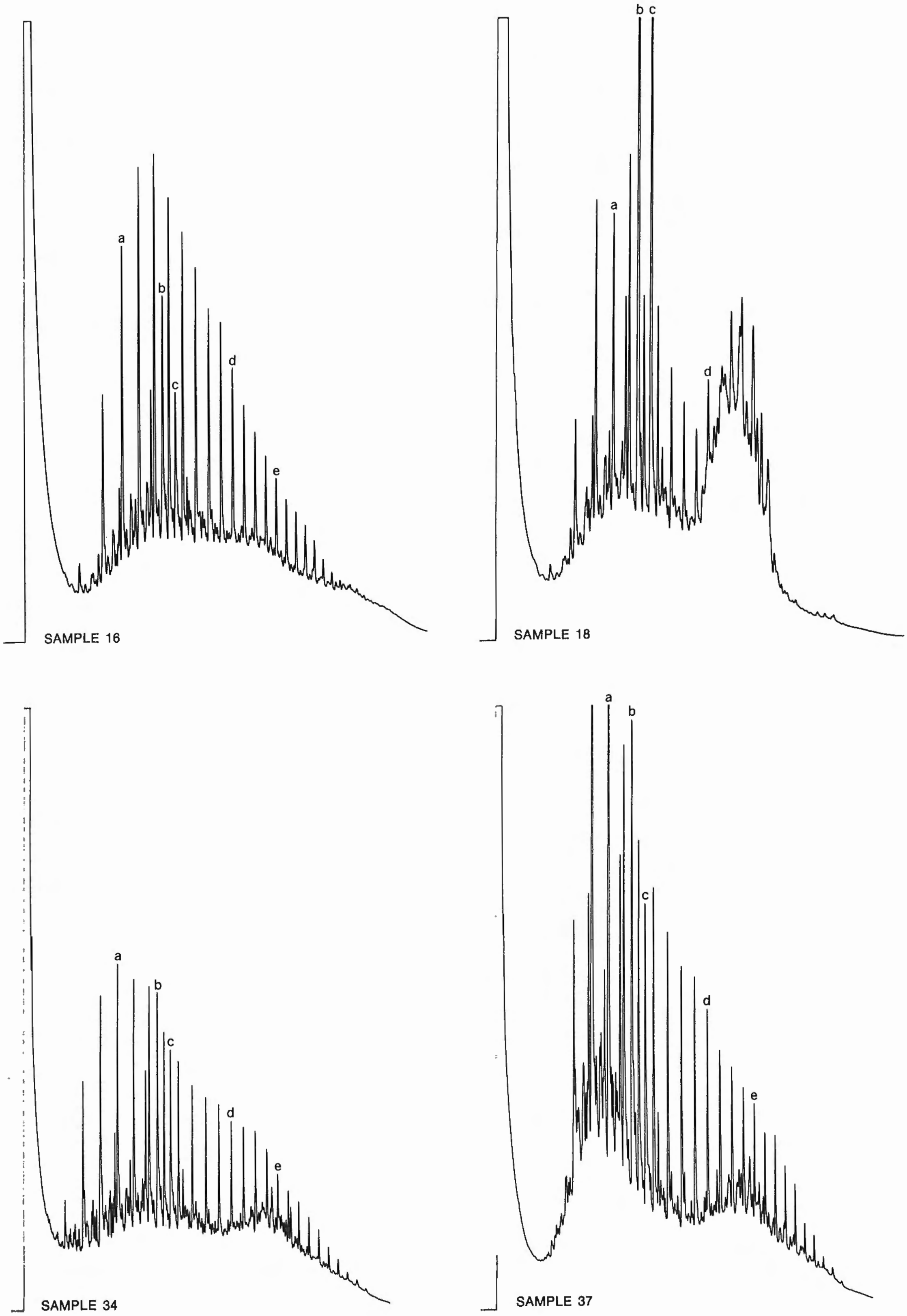
FIGURE 16. Source rock potential and gas chromatograms of the saturated hydrocarbons of the Schei Point Formation (*see* Table 8 for sample descriptions and Fig. 5 for key)

Savik and Jaeger Formations

The Savik Formation is a marine shale which is commonly divided into upper and lower units by a predominantly sandstone unit, the Jaeger. The organometamorphic facies map (Fig. 9) for the base of the Jurassic shale succession (base of Savik) indicates that these formations are undermature or marginally mature west of Ellef Ringnes Island. Again an exception is the area in the vicinity of the North Sabine H-49 well. These formations are mature to overmature on Ellef Ringnes. Snowdon and Roy (1975) indicated that the base of the Savik on central Ellef Ringnes, Amund Ringnes and Axel Heiberg Islands occurs in the overmature zone. The gas logs for the Amund Central Dome H-40 and Mid Fiord J-73 wells support this interpretation for Amund Ringnes and eastern Axel Heiberg. However the situation on Ellef Ringnes Island is complex. In the Dumbells E-49 well, the Savik and underlying Heiberg Formations contain a substantial proportion of wet gas (Fig. 10), whereas in the Helicopter J-12 well the per cent wet gas decreases drastically in the lower part of the Deer Bay Formation. This coincides with an increase in carbon content and a substantial increase in gas concentration. The reason for this is not apparent since, as noted in the previous section, there is no corresponding decrease in extract yields. Extract data (Table 6, Fig. 14) show that the Savik and Jaeger Formations are mature on northern and central Ellef Ringnes Island and tending to maturity in the vicinity of North Sabine H-49 well. The hydrocarbon content of the extracts approaches and exceeds 40 per cent. At Helicopter J-12, and Louise Bay O-25, this interval has been affected by igneous intrusions and is locally overmature (Fig. 10). The hydrocarbon yields within the mature zone are rather variable. In the Dumbells E-49, Dome Bay P-36 and Helicopter J-12 wells, the values fall between 30 and 50 mg per gram indicating minor oil potential (Fig. 14). The values of 64 and 164 mg per gram organic carbon in the Thor P-38 and Sutherland O-23 wells, respectively, are indicative of good source potential although the latter sample may be stained. In the North Sabine H-49 well, the lower part of the Savik Jaeger section is nearly mature. The hydrocarbon yields are low (20-25 mg per gram organic carbon), however, and indicate no oil source potential.

A marginally mature sample from the Wilkins E-60 well shows good potential for oil generation at higher levels of maturity. The hydrocarbon yields are fairly low at 35 mg per gram organic carbon but they represent 45 per cent of the extract. Visual kerogen examination shows a high content of amorphous organic matter (70%) and the kerogen has a high atomic hydrogen to carbon ratio of 1.2. The gas chromatogram of the saturated hydrocarbons shows its relatively immature state (Fig. 14). Pristane and phytane predominate over the adjacent normal alkanes; there is a pronounced hump in the sterane and triterpane region and an odd over even predominance amongst the higher n-alkanes. The visual

FIGURE 16. Continued



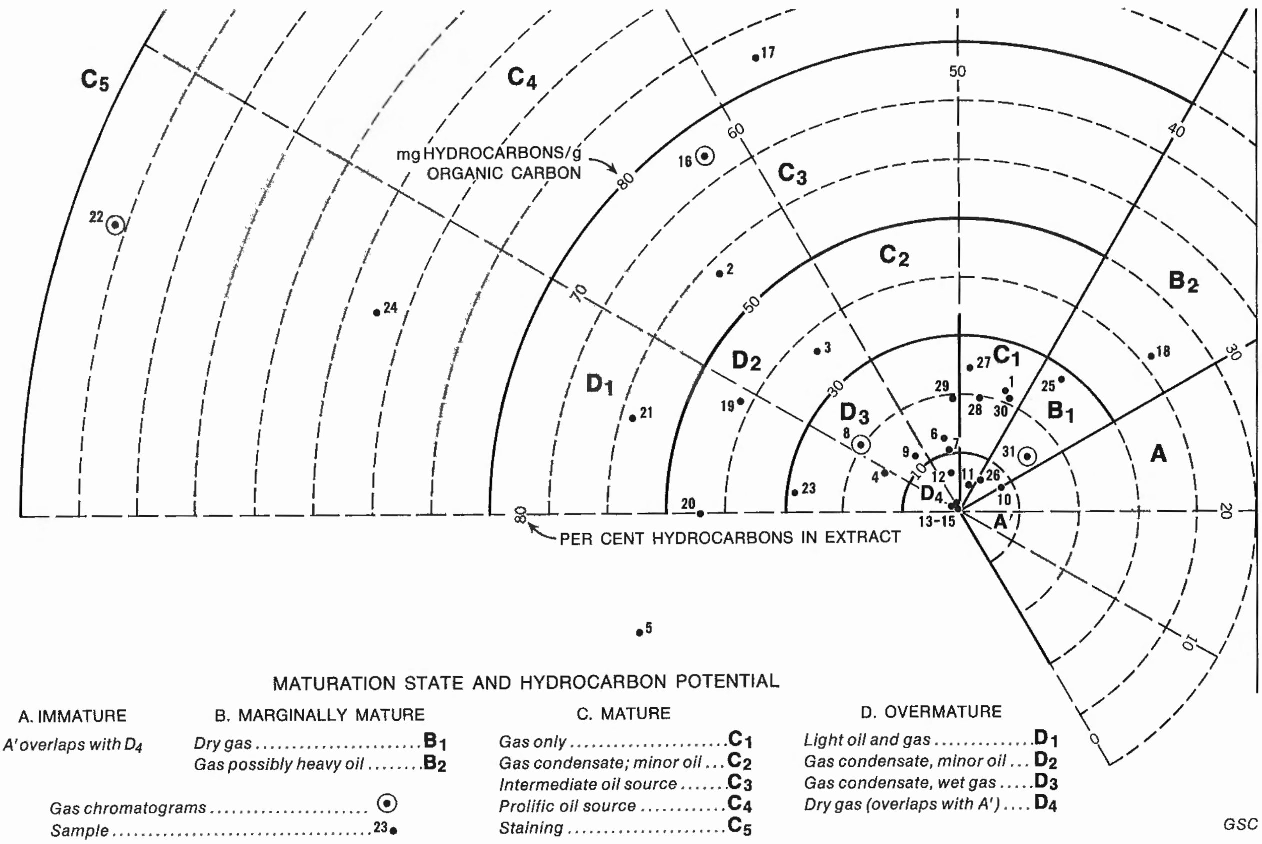


FIGURE 17. Source rock potential and gas chromatograms of the saturated hydrocarbons of the Blaa Mountain Formation (*see* Table 9 for sample descriptions and Fig. 5 for key)

kerogen and gas chromatographic data show a predominantly algal source with some input from terrestrial organic matter. At its present maturity level, it may yield minor amounts of oil (Fig. 14). Samples from the Thor P-38 and King Christian N-06 wells show a more mature type of saturated hydrocarbon distribution (Fig. 14). They have a smooth distribution of n-alkanes, no pronounced hump in the sterane and triterpane region, and pristane and phytane do no predominate over the adjacent n-alkanes. It is evident that the lack of maturity in many parts of the basin and the variability of the organic matter type reduce the source potential of this interval for oil. Again this interpretation differs from that of Henao-Londoño (1977).

Some consideration of gas yields from the Savik Formation is probably in order because of its proximity to the Borden Island sand which has proven to be a major gas reservoir in the Sverdrup Basin. West of Ellef Ringnes and associated islands, the gas yields in the Savik are low, generally less than 3000 ppm, but there is usually a high proportion of wet gas. On Ellef Ringnes and adjacent islands, the gas levels are of the order of 10 000 to 20 000 ppm with occasional surges to 80 000 ppm (e.g. Thor P-38 well). Again the gases are usually wet (60-80%). On Ellef Ringnes Island the Savik Formation could be a source for gas.

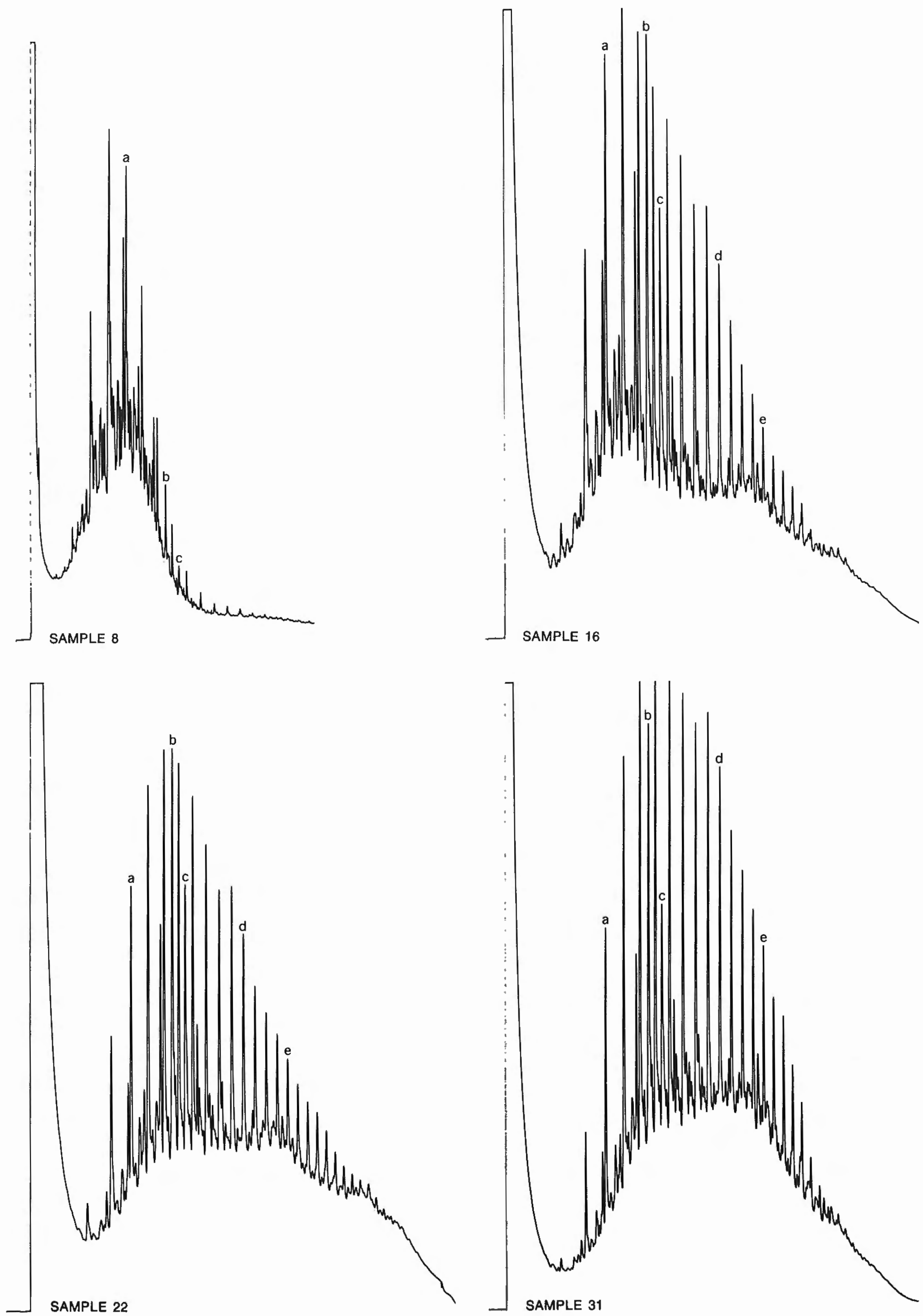
Borden Island and Heiberg Formations

The Borden Island Formation is a marine sandstone underlying the Jurassic shale succession. It is frequently difficult to distinguish it from the underlying Heiberg Formation which is also predominantly sandstone. In the latter, coal seams and carbonaceous shales are interleaved with the sandstones particularly in the southeast part of the Sverdrup Basin. Interleaving shales, carbonaceous silts and coaly partings were the subject for this geochemical study.

The interval ranges from undermature at the basin to overmature in certain wells on Ellef Ringnes. Throughout the area, the gas content is low (Fig. 10). It is uncertain whether these results are reliable since the highly porous and permeable sandstones would quickly de-gas during drilling and sample recovery operations. The carbon content is variable west of Ellef Ringnes Island and on Ellef Ringnes itself the carbon contents are approximately 1 per cent. In the southeastern part of the basin much higher carbon contents were recorded, reflecting the presence of coal seams and carbonaceous stringers within the Heiberg Formation (Fig. 10).

The samples from the Fosheim Peninsula (Gemini E-10, May Point H-02, Romulus C-42, and Taleman J-34) are not mature, having a low proportion of hydrocarbons in the extracts (*ca.* 20%) and an odd over even predominance in the saturated hydrocarbons (Table 7, Fig. 15). At Emerald K-33 and Hoodoo Dome H-37 wells, the Heiberg samples have generated some hydrocarbons but the fully mature stage has not been reached whereas, in Louise Bay O-25 and Kristoffer G-06, the samples are overmature because of the effects of igneous activity. The remainder of the samples from Ellef Ringnes Island

FIGURE 17. Continued



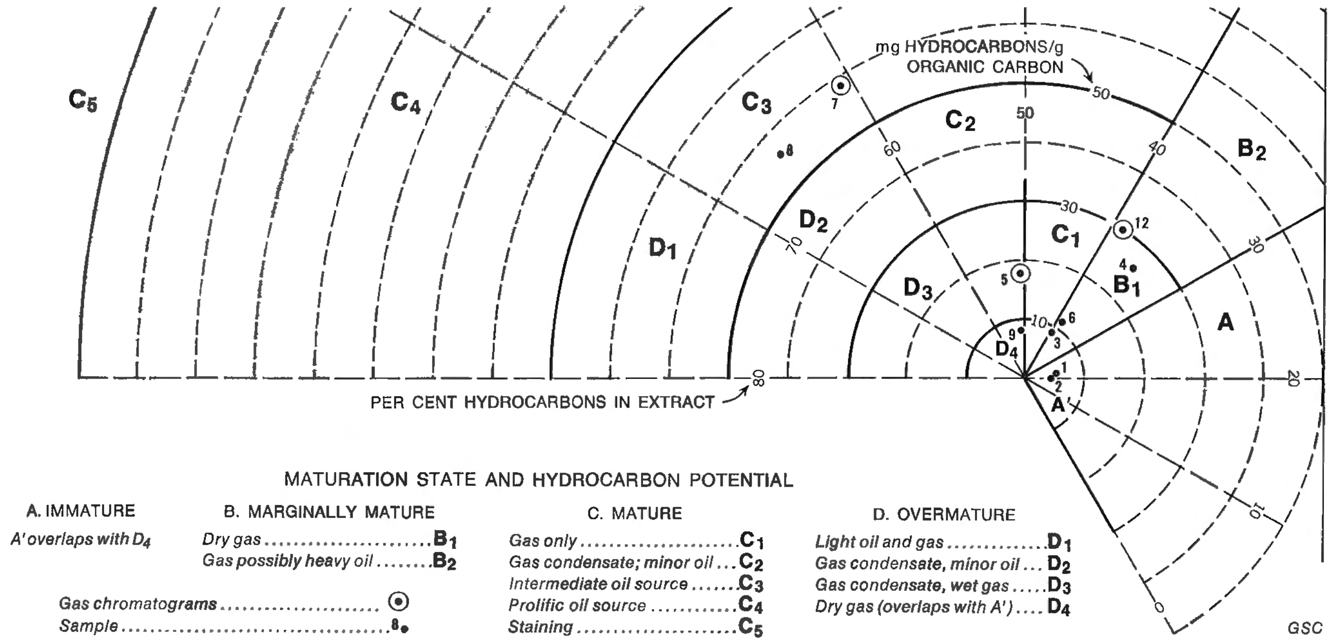


FIGURE 18. Source rock potential and gas chromatograms of the saturated hydrocarbons of the Bjorne and Blind Fiord Formations (*see* Table 10 for sample descriptions and Fig. 5 for key)

(North Sabine H-49 and Linckens Island P-46 wells) are mature. In most cases the hydrocarbon yields are low at less than 30 mg per gram organic carbon. Two samples have higher yields, namely Dumbells E-49 3445 m and Helicopter J-12 4035 m, with values of *ca.* 42 mg per gram organic carbon indicating minor oil potential. In both cases the gas chromatograms show a preponderance of light hydrocarbons which differs from the more normal mature distribution shown by the North Sabine H-49 sample (Fig. 15). The higher hydrocarbon yields and unique hydrocarbon distributions are probably the products of heating brought about by igneous activity and gas condensate would be the anticipated hydrocarbon product.

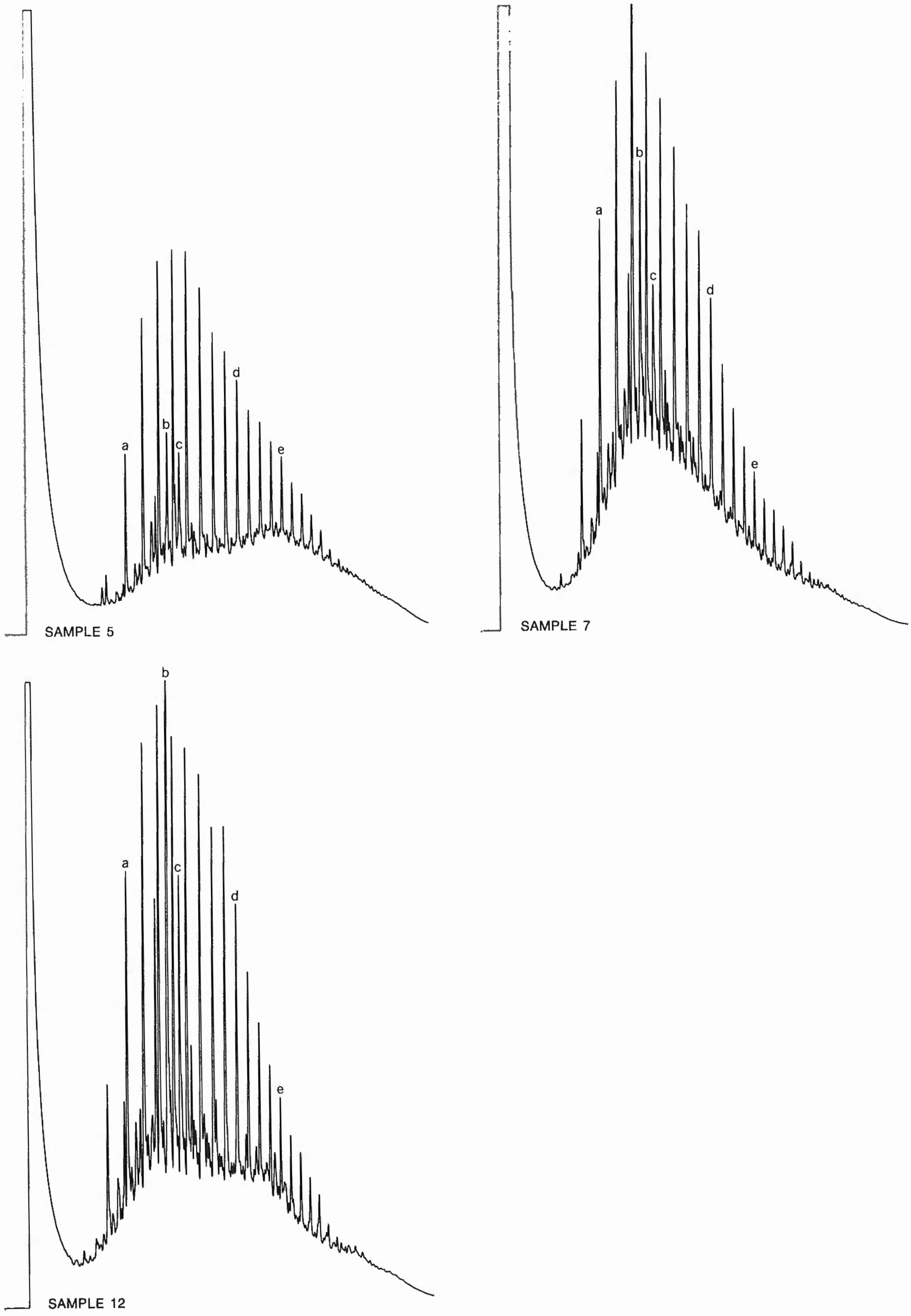
With the exception of the immature areas noted above, the interval does have some gas potential particularly in the regions where igneous activity has increased the diagenetic level to the late mature or overmature phase.

Schei Point and Blaa Mountain Formations

The Schei Point and Blaa Mountain Formations are interpreted as time equivalent units (Thorsteinsson and Tozer, 1970). As originally defined, the Schei Point is a marginal facies consisting of sandstones and limestones with the limestones forming coquinas. The Blaa Mountain Formation is a basinal shale equivalent. In the western Sverdrup Basin (Lougheed Island and farther west), the Schei Point as named in the subsurface consists of limestones, thin sandstones and bituminous shales and calcareous silts and shales which, strictly speaking, probably belong to the Blaa Mountain facies. For the purpose of source rock evaluation, it is convenient to discuss the two formations separately since the usage of the terms are geographically defined and their source rock characteristics are somewhat different.

The term Schei Point has been used in the subsurface west of Lougheed Island and in the northern and southeastern flanks of the basin. The Schei Point Formation is characterized on the gas logs by a substantial content of wet gas, up to 60 000 ppm (Fig. 10) and the higher values are commonly associated with high organic carbon values (up to 5% in the Satellite F-68 well). On the flanks of the basin, the Schei Point Formation coincides with the onset of the marginally mature zone (e.g. Drake D-68, Andreason L-32, Intrepid H-49, Jameson Bay F-31, Sirius K-28 and Pollux G-60). In the axial part of the basin and in the Brock C-50 well, it falls in the marginally mature or mature zones. Nearly all the samples from the Schei Point Formation (Table 8, Fig. 16) show a high percentage of hydrocarbons in the extracts and, as shown previously, they respond to diagenesis more readily than the majority of samples from the Jurassic and Permian. The gas chromatograms of the saturated hydrocarbons show considerable evidence of immaturity. Fully mature distributions were encountered only in samples from the North Sabine H-49 and Cape Norem A-80 wells, both of which have been the most deeply buried of the Schei Point samples (Fig. 7). The generally favourable aspect for hydrocarbon generation is shown by the high atomic hydrogen to carbon ratios of the kerogens and the high content of amorphous organic matter in many of the samples. Immature Schei Point samples show a distribution of saturated hydrocarbons which is typical of marine organic matter; namely, pristane and phytane predominate over adjacent n-alkanes; n-alkanes distributions peak in the C_{17} to C_{20} range with a pronounced hump in the sterane and triterpane region. With increasing diagenesis, the importance of the isoprenoids diminishes but the sterane-triterpane hump has disappeared only in the most mature samples (North Sabine H-49 and Cape Norem A-80). It is these samples which show excellent source rock quality. The remainder are rated only as marginal because of their lack of maturity. Heavy oil in limited amounts might be expected to have originated from samples of this

FIGURE 18. Continued



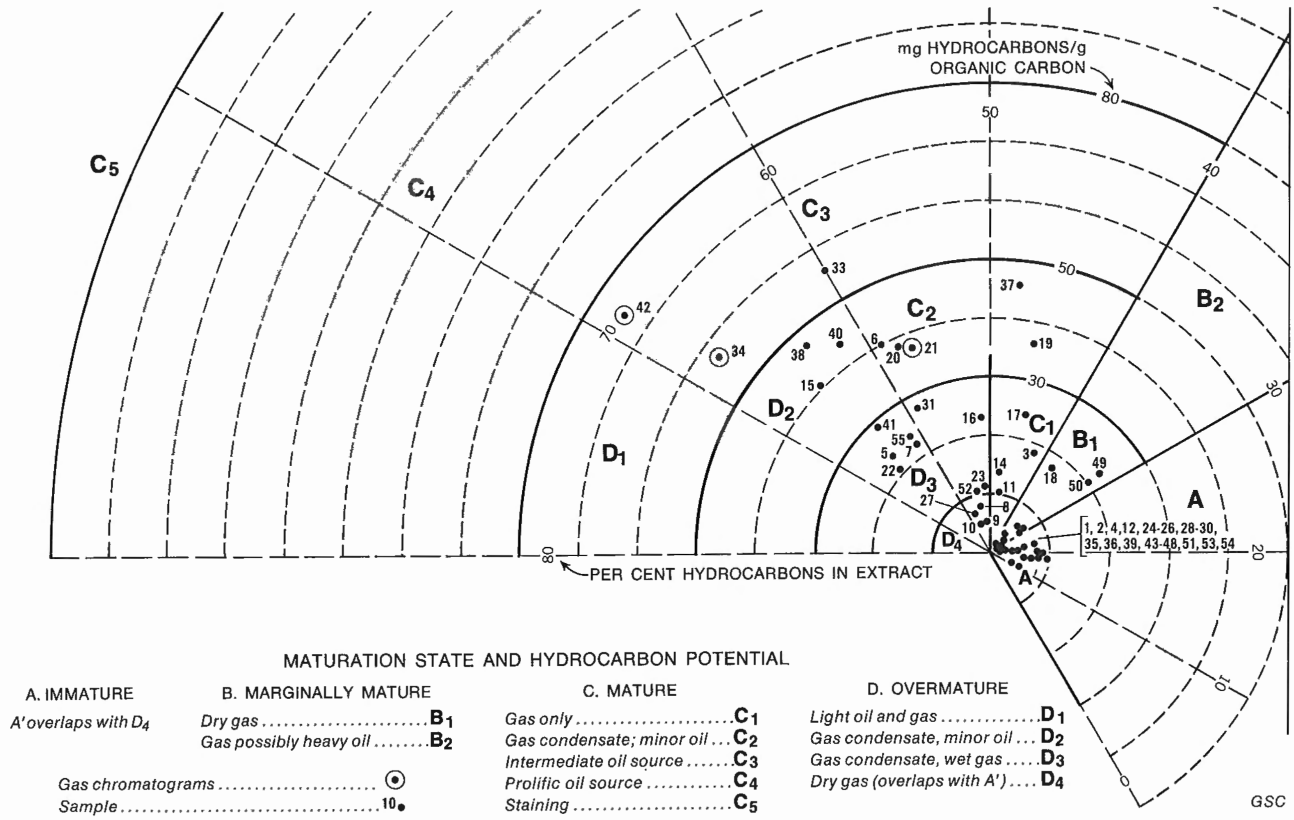


FIGURE 19. Source rock potential and gas chromatograms of the saturated hydrocarbons of the Permian to Pennsylvanian strata (*see* Table 11 for sample descriptions and Fig. 5 for key)

type. The sample from the Andreason L-32 well is unique in this set. It has very high extract and hydrocarbon yields (206 and 72 mg per gram organic carbon, respectively). The proportion of hydrocarbons in the extract (35%) and saturated hydrocarbon distribution show it to be relatively immature (Fig. 16) although slightly more mature than a sample from an adjacent well (Intrepid H-49) (Table 8, Fig. 16). Considerable amounts of heavy oil may be generated from a source rock of this type. Maximum depths of burial of the order of 3600 m are required for the full source potential of the Schei Point Formation to be realized. The favourable source potential for the Schei Point Formation in the western Sverdrup Basin is also recognized by Henao-Londoño (1977).

The Blaa Mountain Formation is considered to be the basinal shale equivalent of the Schei Point Formation and is encountered in the subsurface east of Lougheed Island. It is commonly intruded by sills and dykes which cause transformation to the overmature facies in many places (Fig. 10), notably the Blaa Mountain section in the Kristoffer G-06 well where the gas levels are relatively low (10 000 ppm) and the wet gas content is 20 per cent or less. In contrast, in the King Christian N-06 well there is a high gas content ranging up to 80 000 ppm and containing between 20 and 60 per cent wet gas. There is a gradual decline in the wet gas content with burial depth. The Dome Sutherland O-23 well penetrated a substantial thickness of the Blaa Mountain Formation. Below 3000 m in this well there is a dramatic decrease in the wet gas content from 80 per cent of the cuttings gas to less than 20 per cent. The extractable hydrocarbon yields are variable (Table 9, Fig. 17). In the Kristoffer Bay G-06 well, the Blaa Mountain Formation is overmature. Gas condensate is the anticipated hydrocarbon product to a depth of 2100 m, while below this depth only dry gas is expected. Gas source rocks with minor oil or condensate potential are encountered where the Blaa Mountain is penetrated by dykes and sills. Samples adjacent to the intrusions have higher extractable hydrocarbon yields, e.g. King Christian N-06 1835 and 2652 m, Sirius K-28 2454 m, and Sutherland O-23 2131 m. Samples showing excellent source potential occur in the Sutherland O-23 well at 2131 and 3316 m although their organic carbon content is relatively low (0.44 and 0.54%). Other good to excellent source rocks occur at 1082 m in the Neil O-15 well and at 1390 m in the Pollux G-60 well.

The effect of the igneous activity on the hydrocarbon distribution of samples in the Kristoffer G-06 well is seen in the gas chromatograms where the low boiling hydrocarbons predominate. The more normal mature distributions are represented by the remainder of the chromatograms (Fig. 17). No immature samples of this formation were encountered.

Bjorne and Blind Fiord Formations

The Bjorne Formation (Lower Triassic) consists mainly of quartzose and commonly crossbedded sandstone with conglomeratic interbeds. The Blind Fiord Formation is a fine-grained equivalent consisting of red and green silty shales (Thorsteinsson and Tozer, 1970). These formations are encountered in the subsurface west of Lougheed Island and at the basin margins, notably

FIGURE 19. Continued

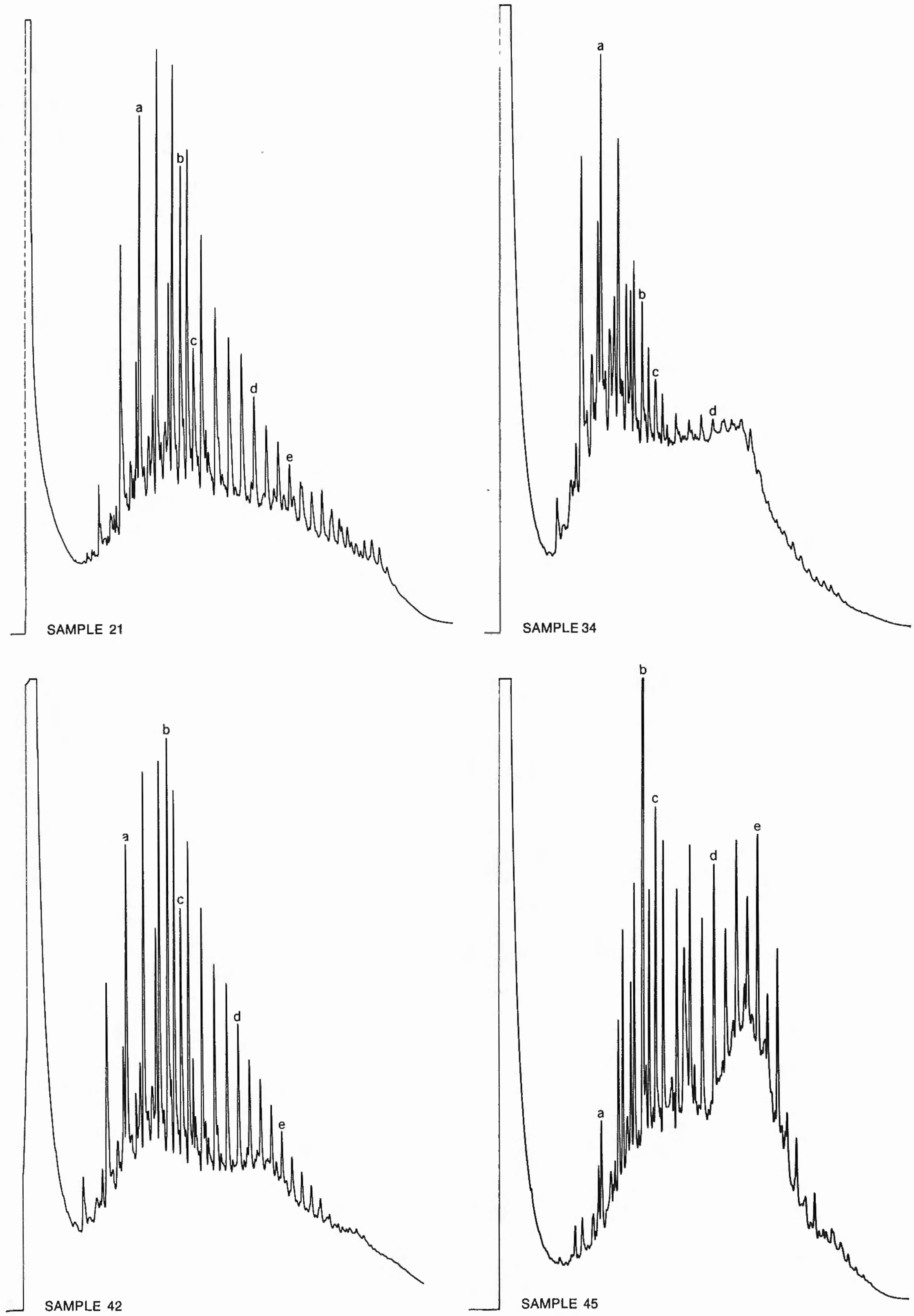


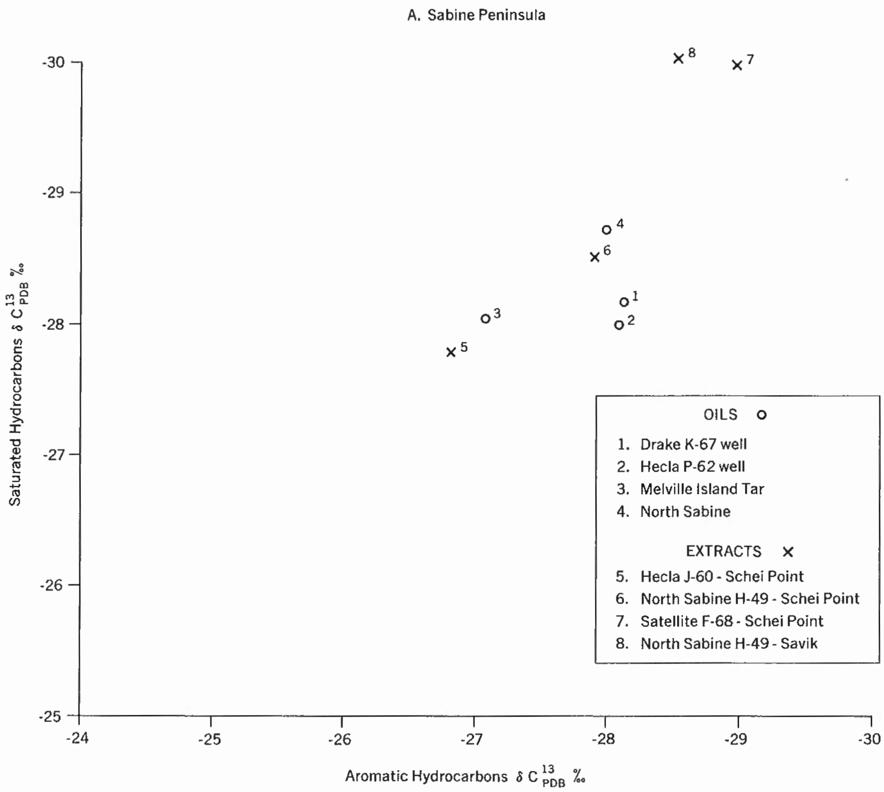
TABLE 9. Extract and kerogen data for the Blaa Mountain Formation

WELL NAME	SAMPLE NO.	DEPTH in metres	FORMATION	LITHOFACIES	ORGANIC CARBON %	EXTRACT mg/g org. C	HYDROCARBONS mg/g org. C	HYDROCARBONS % in extract
Gemini E-10 (48)	1	3368	Blaa Mountain	Shale	1.23	50.0	21.6	43.2
King Christian N-06 (25)	2	1835-1844	Blaa Mountain	Shale	0.97	89.2	57.7	64.7
	3	2118-2146	Blaa Mountain	Shale, siltstone	1.13	57.5	36.8	64.0
	4	2313-2323	Blaa Mountain	Shale, igneous rock	1.48	20.6	14.6	70.7
	5	2652-2661	Blaa Mountain	Shale, calcite veins	0.39	65.1	56.9	87.4
	6	2972-2981	Blaa Mountain	Shale, igneous rock	0.89	23.4	12.5	53.6
	7	3182-3191	Blaa Mountain	Shale	0.54	20.0	10.7	53.6
Kristoffer B-06 (28)	8	2042	Blaa Mountain	Shale, siltstone	1.93	29.5	20.3	78.9
	9	2103	Blaa Mountain	Shale, siltstone	2.09	18.6	11.8	63.4
	10	2164	Blaa Mountain	Shale	1.10	26.8	8.1	30.3
	11	2423-2438	Blaa Mountain	Igneous rock, shale	0.90	10.4	4.6	44.0
	12	2728-2743	Blaa Mountain	Shale	0.91	12.9	7.1	55.0
	13	3002-3018	Blaa Mountain	Shale (carbonaceous)	1.46	0	0	0
	14	3597	Blaa Mountain	Shale, calcite veins	2.20	0	0	0
	15	3658	Blaa Mountain	Shale, calcite veins	2.36	0	0	0
Neil O-15 (60)	16	1082-1097	Blaa Mountain	Shale	2.96	120.6	74.7	62.0
Pollux G-60 (32)	17	1390-1402	Blind Fiord-Blaa Mountain	Shale	1.55	144.9	84.3	58.1
	18	1676	Blind Fiord-Blaa Mountain	Shale, limestone, siltstone	0.95	126.6	41.8	33.0
	19	2134-2149	Blind Fiord-Blaa Mountain	Shale, siltstone	0.74	59.2	42.0	70.9
Sirius K-28 (34)	20	2454-2469	Blaa Mountain	Shale, sandstone	1.20	54.9	44.1	80.2
Sutherland O-23 (24)	21	1521-1530	Blaa Mountain	Shale	1.12	78.9	58.1	73.6
	22	2131-2140	Blaa Mountain	Siltstone	0.44	207.4	152.5	73.5
	23	2743-2752	Blaa Mountain	Shale	0.84	37.2	28.8	77.4
	24	3316	Blaa Mountain	Shale	0.54	144.2	105.0	72.8
	25	3490-3517	Blaa Mountain	Shale	0.28	74.6	28.0	37.6
	26	3636-3664	Blaa Mountain	Shale	0.39	14.5	6.8	41.2
	27	3719-3746	Blaa Mountain	Shale	0.20	50.7	24.8	48.9
Thor P-38 (27)	28	1722-1753	Blaa Mountain	Shale	1.13	42.6	20.1	47.1
	29	1768-1783	Blaa Mountain	Shale, sandstone	0.74	37.0	19.4	52.5
Romulus C-42 (46)	30	2438-2454	Blaa Mountain	Shale	0.86	51.2	21.5	42.1
	31	2499-2515	Blaa Mountain	Shale, igneous rock	1.26	43.9	14.6	33.3

Location of wells *see* Figures 3a, b, Tables 1, 2 — Numbers in brackets *see* Figures 3a, b, 10, 21

the Fosheim Peninsula. West of Lougheed Island, the organic carbon contents are uniformly low (<0.3%; Fig. 9), with occasionally higher values representing carbonaceous stringers. The gas yields are generally very low (1000-2000 ppm) and comprise mostly methane (e.g. Drake D-68 well). It is doubtful whether the gas yields for the Bjorne are truly representative since the formation is quite porous and gas would have been lost from the samples during drilling and recovery operations. Higher proportions of wet gas were encountered in the Skybattle Bay C-15, Romulus C-42, Taleman J-34 and Neil O-15 wells. In view of the low gas yield, these data must be considered suspect because of the possibility of contamination from cavings.

Because of the unfavourable aspect from gas analysis and organic carbon measurements, only a limited amount of extract data was obtained from both the Bjorne and Blind Fiord Formations (Fig. 18, Table 10). The extract data confirm the absence of source potential from these formations with the exception of two samples from the Romulus C-42 well at 3658 and 4252 m. The carbon contents are low at 0.32 and 0.27 per cent but the hydrocarbon yields indicate some marginal oil potential and the gas chromatograms show a mature distribution.



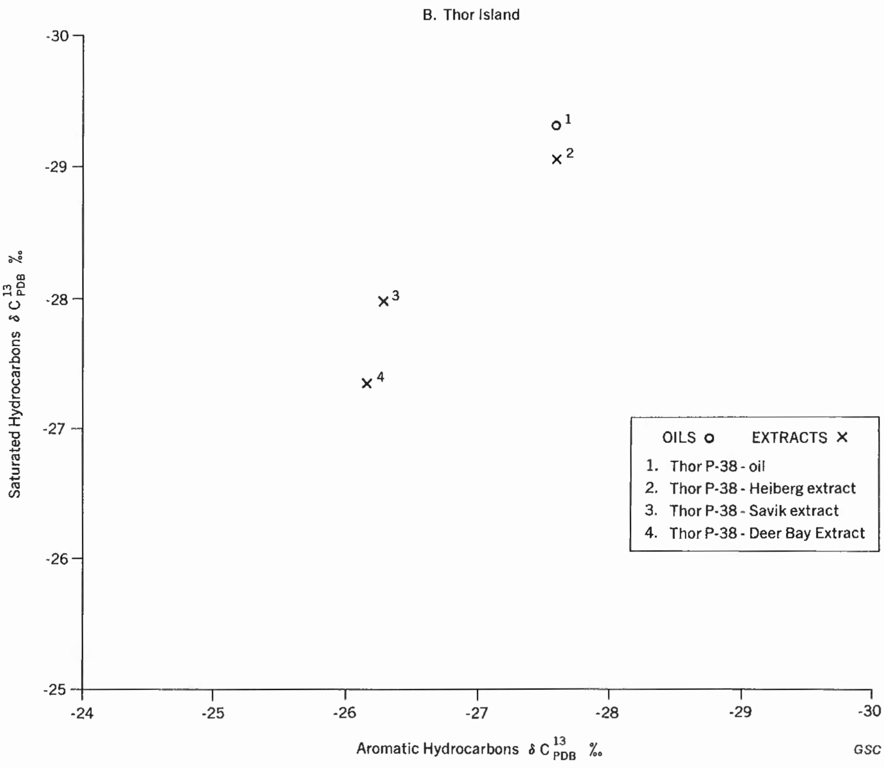


FIGURE 20. Correlation of crude oils with possible source rocks in the Sverdrup Basin based on stable carbon isotope distribution.
A) Sabine Peninsula. B) Thor Island

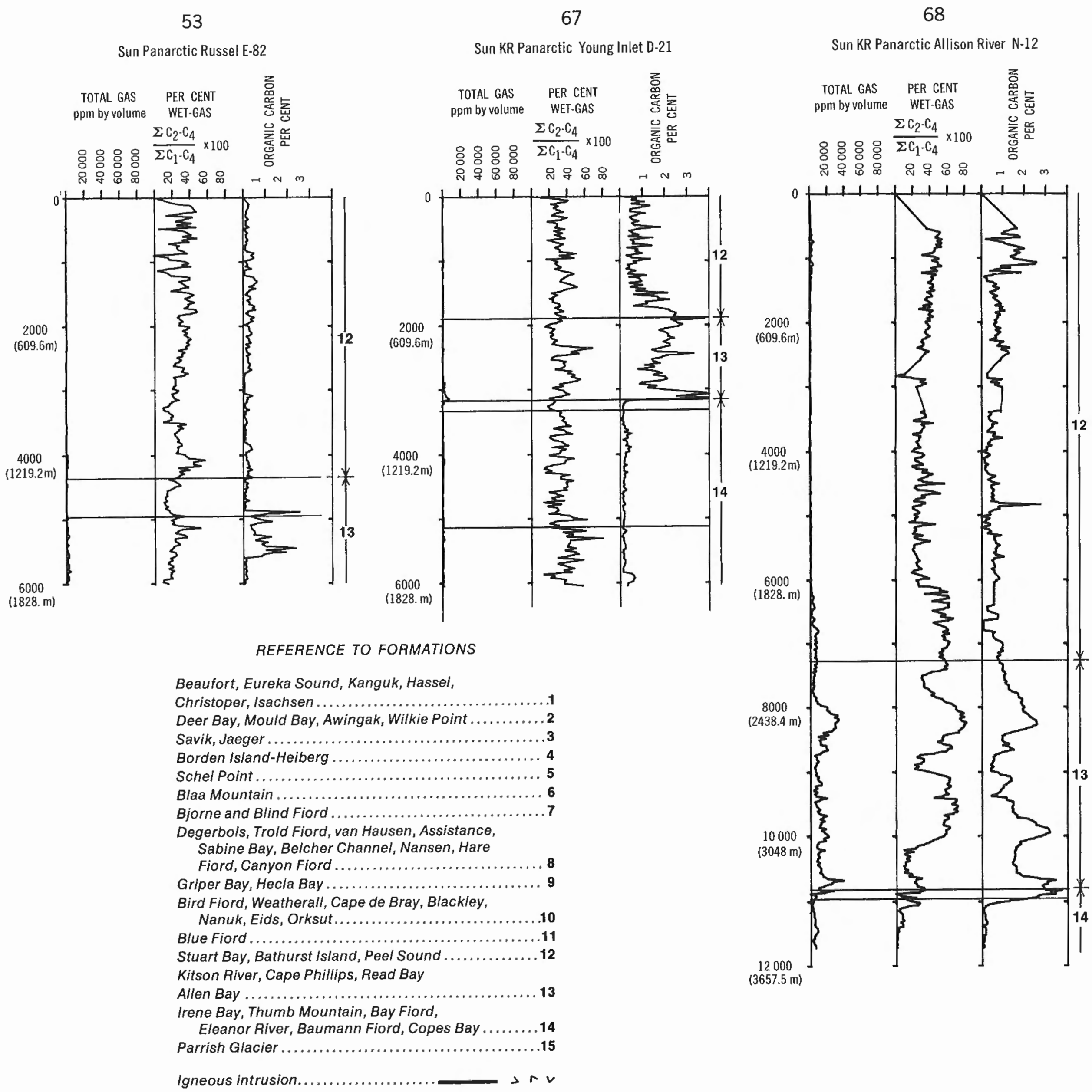


FIGURE 21. Relationship of gas and organic carbon logs to the major stratigraphic units in the Franklinian Geosyncline and Arctic Platform (*see* Fig. 3b and Table 2 for well locations)

Permo-Pennsylvanian

The Pennsylvanian to Permian sequence of the Sverdrup Basin is one of great complexity comprising intertonguing formations of conglomerate, sandstone, shale, limestones and evaporites (Thorsteinsson and Tozer, 1970). A regional unconformity in the upper part of the Lower Permian (Artinskian) separates the sequence into two convenient groups. The lower package can be separated into four facies belts arranged parallel to the northeasterly trending axis of the Sverdrup Basin. From southeast to northwest the belts are as follows:

1. A marginal facies developed on the south and east sides of the basin and characterized by clastic and carbonate rocks, respectively the Canyon Fiord and Belcher Channel Formations.

2. An eastern carbonate belt in which the principal rock units are the Antoinette, Mount Bayley, Tanquary and Belcher Channel Formations.

3. A central shale belt where the rocks are known as the Hare Fiord Formation and are mainly shale and siltstone.

4. A northwestern carbonate belt where the Nansen Formation is the principal unit.

Evaporitic rocks (Otto Fiord Formation) occur in the eastern carbonate central shale and northwestern carbonate belts. The generalized facies distribution of the Lower Pennsylvanian in the subsurface of the Sverdrup Basin has been illustrated by Meneley *et al.* (1975).

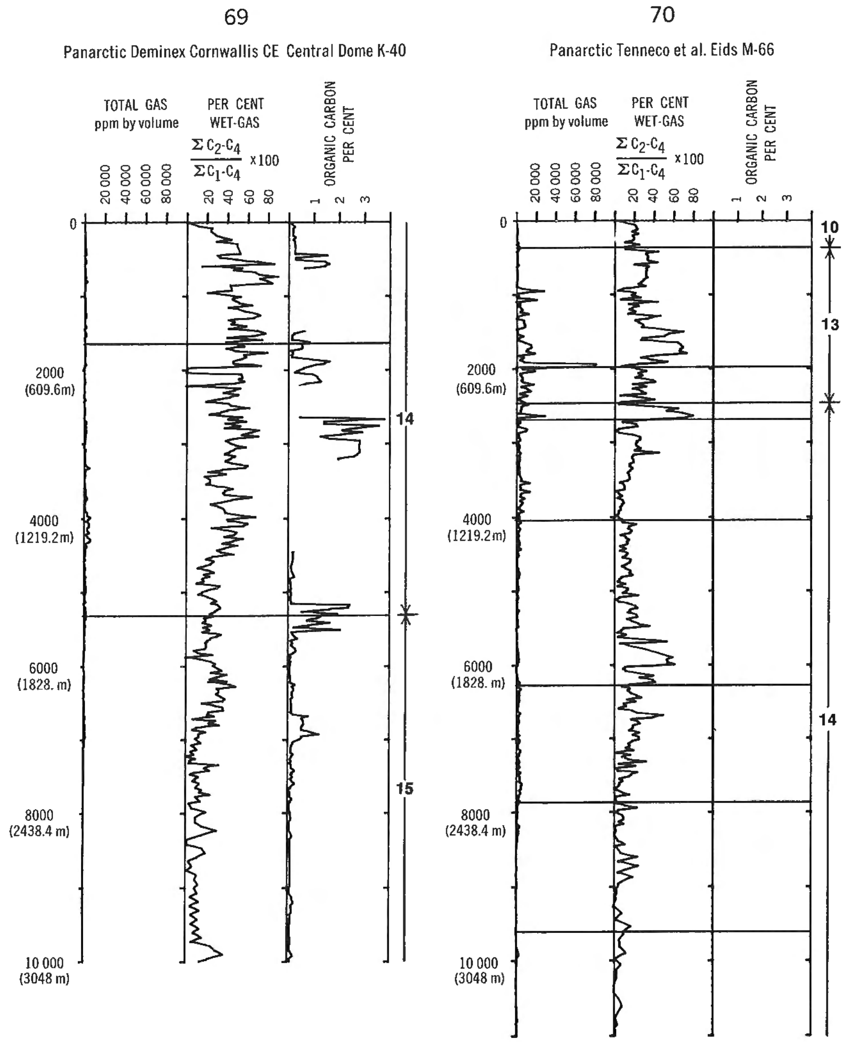


FIGURE 21. Continued

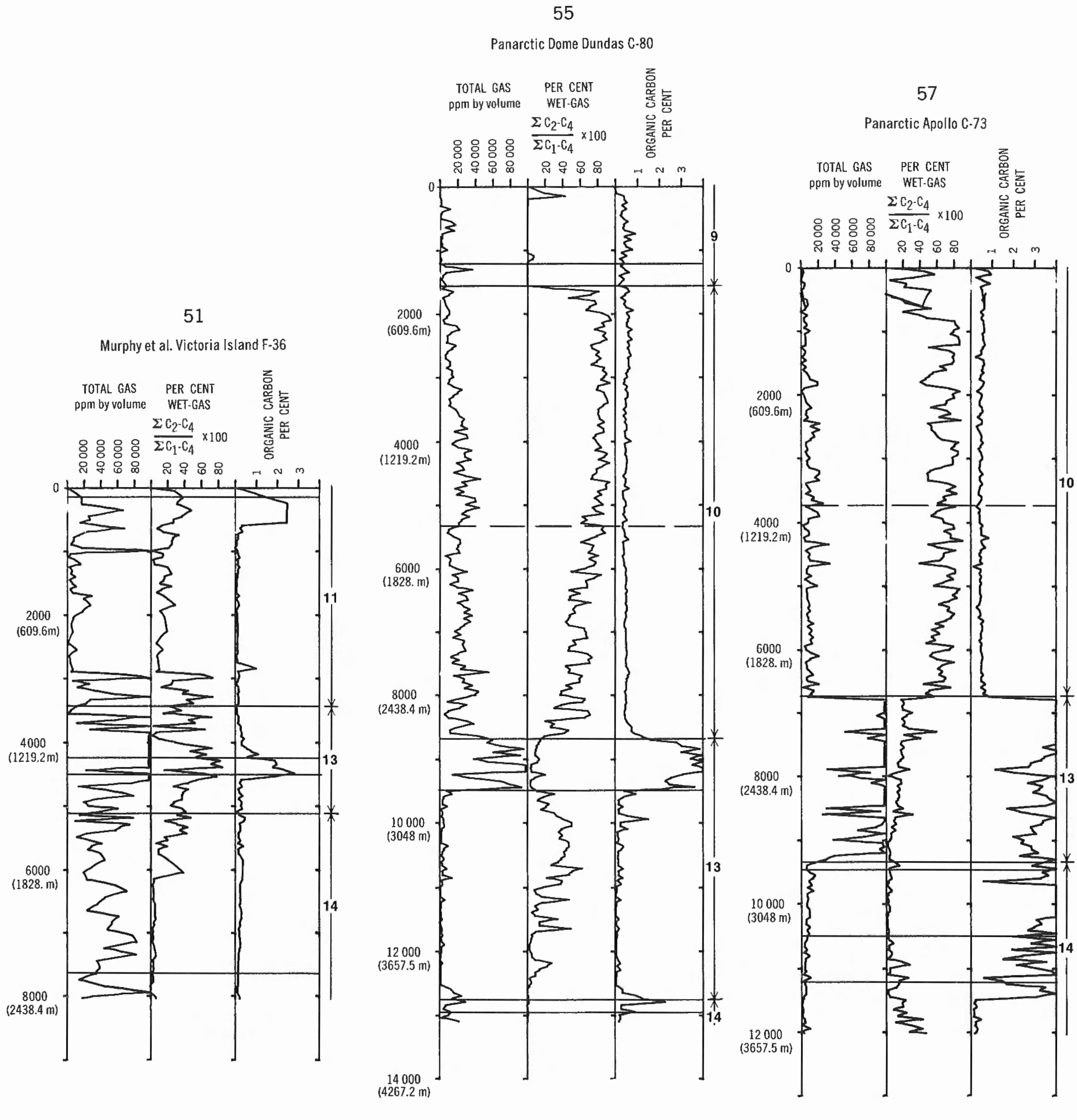
TABLE 10. Extract and kerogen data for the Bjorne and Blind Fiord Formations

Drake D-68	1	2896-2911	Blind Fiord	Siltstone	0.30	24.2	5.3	22.0
(17)	2	2957-2972	Blind Fiord	Siltstone, shale	0.32	21.8	4.3	19.7
Emerald K-33	3	1661	Bjorne	Sandstone	0.21	21.0	8.4	40.0
(11)	4	2177	Bjorne	Shale, siltstone	0.06	76.5	26.0	35.0
Neil O-15	5	1372-1387	Bjorne	Sandstone, siltstone	0.44	34.4	17.4	50.7
(50)	6	1676-1692	Bjorne	Siltstone, shale	0.52	26.8	10.6	39.6
Romulus C-42	7	3658-3673	Bjorne	Sandstone, minor shale	0.32	95.3	58.4	61.3
(46)	8	4252-4267	Bjorne	Sandstone, igneous rock	0.27	85.4	56.2	65.8
Sandy Point L-46 (9)	9	1090	Bjorne	Sandstone, shale	0.23	15.8	8.0	50.6
Satellite F-68	10	1123	Bjorne	Sandstone	0.11	20.2	nd	nd
(3)	11	1770	Bjorne	Sandstone	0.09	6.1	nd	nd
Taleman J-34 (47)	12	2957-2972	Bjorne	Sandstone	0.87	76.1	29.8	39.2

Location of wells *see* Figure 3a, Table 1

Numbers in brackets *see* Figures 3a, 10

FIGURE 21. Continued



Above the Artinskian unconformity, two regional facies belts can be distinguished. The basinal facies consists of fine-grained clastics and cherts of the Van Hauen Formation and is overlain by carbonates and cherts of the Degerböls Formation. The marginal facies, indicating near-shore conditions on the south and east edges of the Sverdrup Basin, consists of glauconitic sandstone divided into the Sabine Bay, Assistance, and Trold Fiord Formations.

The Permo-Pennsylvanian section has been encountered in the subsurface on the northwestern, southwestern and southeastern flanks of the basin. With the notable exception of the wells on the Sabine Peninsula and the Robert Harbour K-07 well, the gas yields and organic carbon values are extremely low (Fig. 10). Occasional higher values are encountered for example in the 3000 to 3350 m interval in the Brock C-50 well. The per cent wet values are erratic. In the Brock C-50 well, only methane is present whereas in the Pollux G-60 well values ranging up to 80 per cent wet were obtained. However the gas yields are very low and small changes in the concentration of wet gases would have a profound effect on the per cent wet values. The decline in the per cent wet values in the lower part of the Satellite F-68 well may indicate the onset of the overmature zone.

On the Sabine Peninsula high yields (up to 80 000 ppm) were encountered in Permian strata (Fig. 10). Above 4600 m, the gas contains a high proportion of wet components (*ca.* 80%). The proportion of wet gas begins to decline in both the Chads Creek B-64 and Drake D-68 wells below a depth of about 4400 m. The high yields of gas and decrease in wet gas indicate the onset of the overmature zone. It is unclear whether this can be attributed to normal geothermal processes or the effects

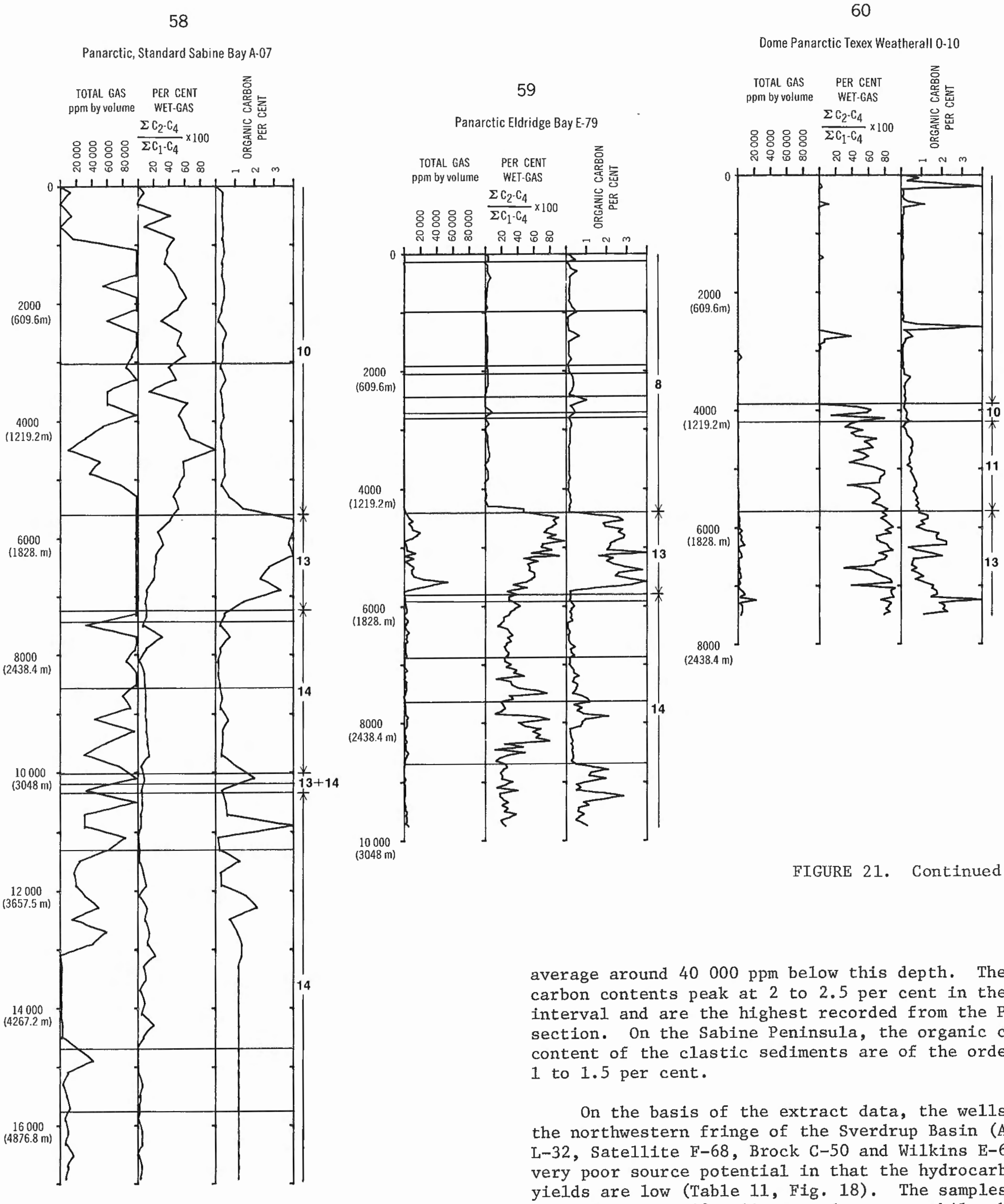
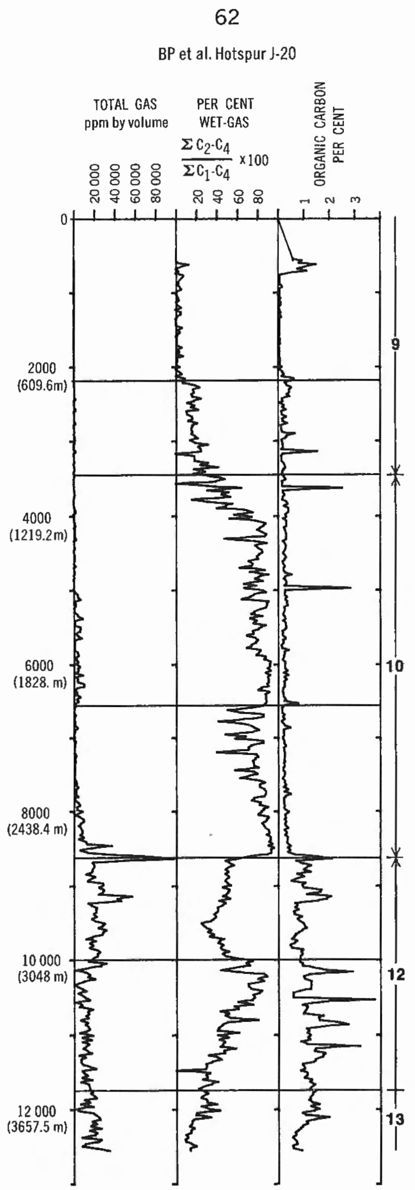


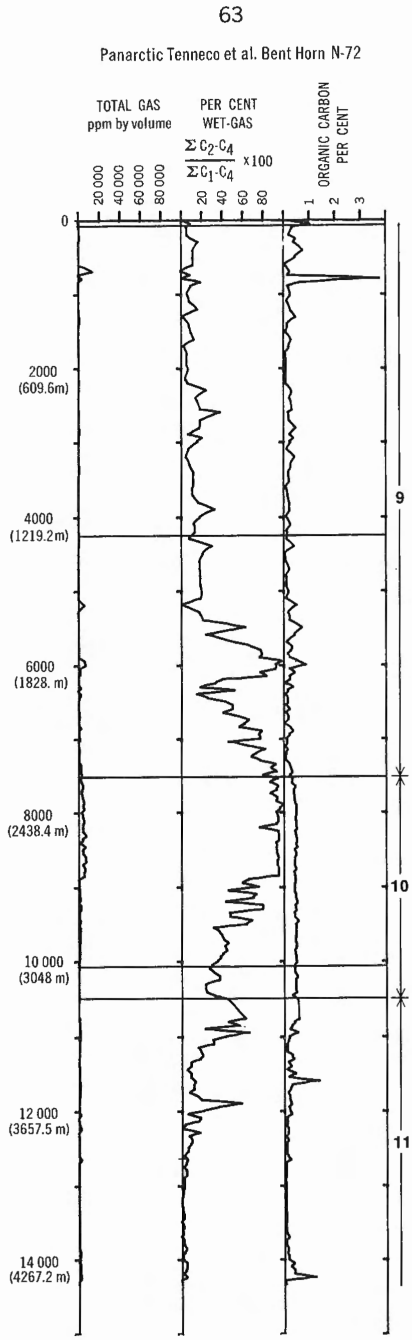
FIGURE 21. Continued

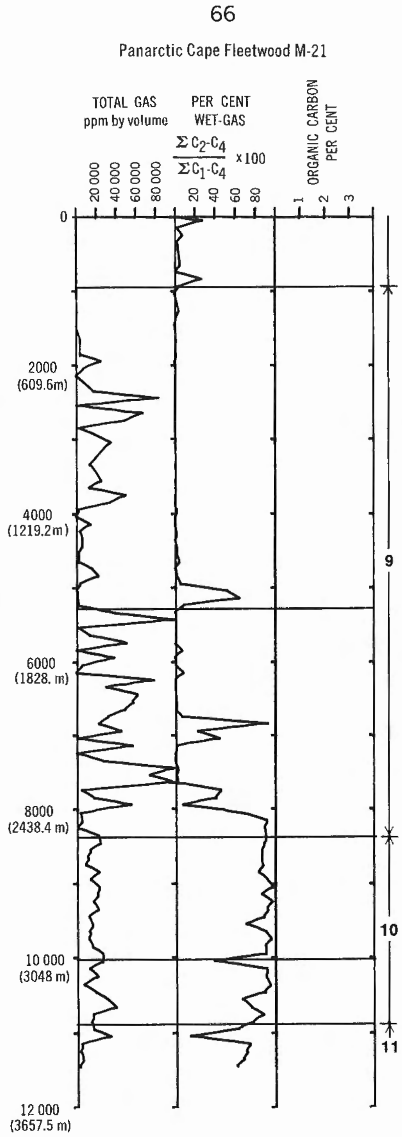
of igneous activity since two thick intrusions were encountered in the interval between 4700 and 4900 m in the Drake D-68 well. In complete contrast to the Sabine Peninsula of Melville Island, the Permian was encountered at 919 m in the Robert Harbour K-07 well on northern Cameron Island. There is a progressive increase in wet gas with depth indicating the onset of the marginally mature zone. The gas yields in the interval 1800 to 2400 m range up to 100 000 ppm but average around 40 000 ppm below this depth. The organic carbon contents peak at 2 to 2.5 per cent in the same interval and are the highest recorded from the Permian section. On the Sabine Peninsula, the organic carbon content of the clastic sediments are of the order of 1 to 1.5 per cent.

On the basis of the extract data, the wells on the northwestern fringe of the Sverdrup Basin (Andreason L-32, Satellite F-68, Brock C-50 and Wilkins E-60) show very poor source potential in that the hydrocarbon yields are low (Table 11, Fig. 18). The samples from the Andreason L-32 well are undermature while those from Brock C-50 and Wilkins E-60 are mature. As indicated from the gas data, the low yield at the bottom of the Satellite F-68 well may indicate the overmature facies. Higher hydrocarbons yields were obtained from the Belcher Channel Formation in the Graham C-52 well and the Degerböls and Canyon Fiord Formations in the Pollux G-60 well. In both cases the organic carbon content is low and the yield of hydrocarbons is sufficient only to be rated as marginal for oil. The

FIGURE 21. Continued







presence of two igneous intrusions in the Graham C-52 well may indicate excessive heating and the occurrence of the overmature facies below the maximum depth of this well.

The main phase of oil generation occurs above 3900 m in both the Drake D-68 and the Chads Creek B-64 wells. The hydrocarbon yields are low (30-40 mg per gram organic carbon) indicating little or no oil potential. This contrasts with the conclusion of Henao-Londono (1977) who indicates good oil potential for Permian rocks in the Sabine Peninsula area of Melville Island. Visual kerogen data and the kerogen atomic hydrogen to carbon ratios of the samples in the Drake D-68 well confirm the poor source of the organic matter. The gas potential of this section may however be considerable in view of the maturation level and the high recorded gas contents.

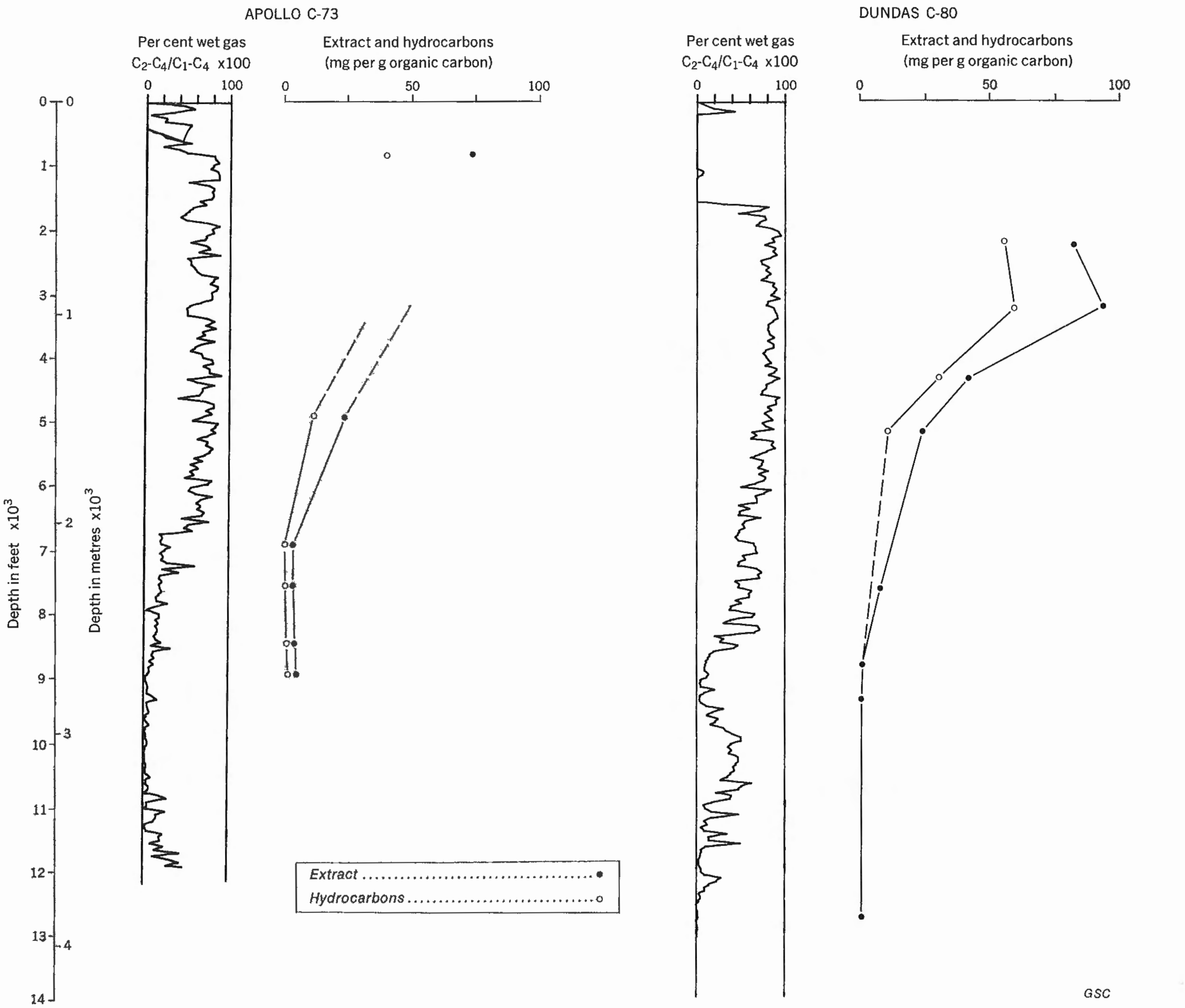


FIGURE 22. Per cent wet curves and extract data from the Apollo C-73, Dundas C-80, Eldridge Bay E-76, Zeus F-11, Bent Horn N-72 and Hotspur J-20 wells

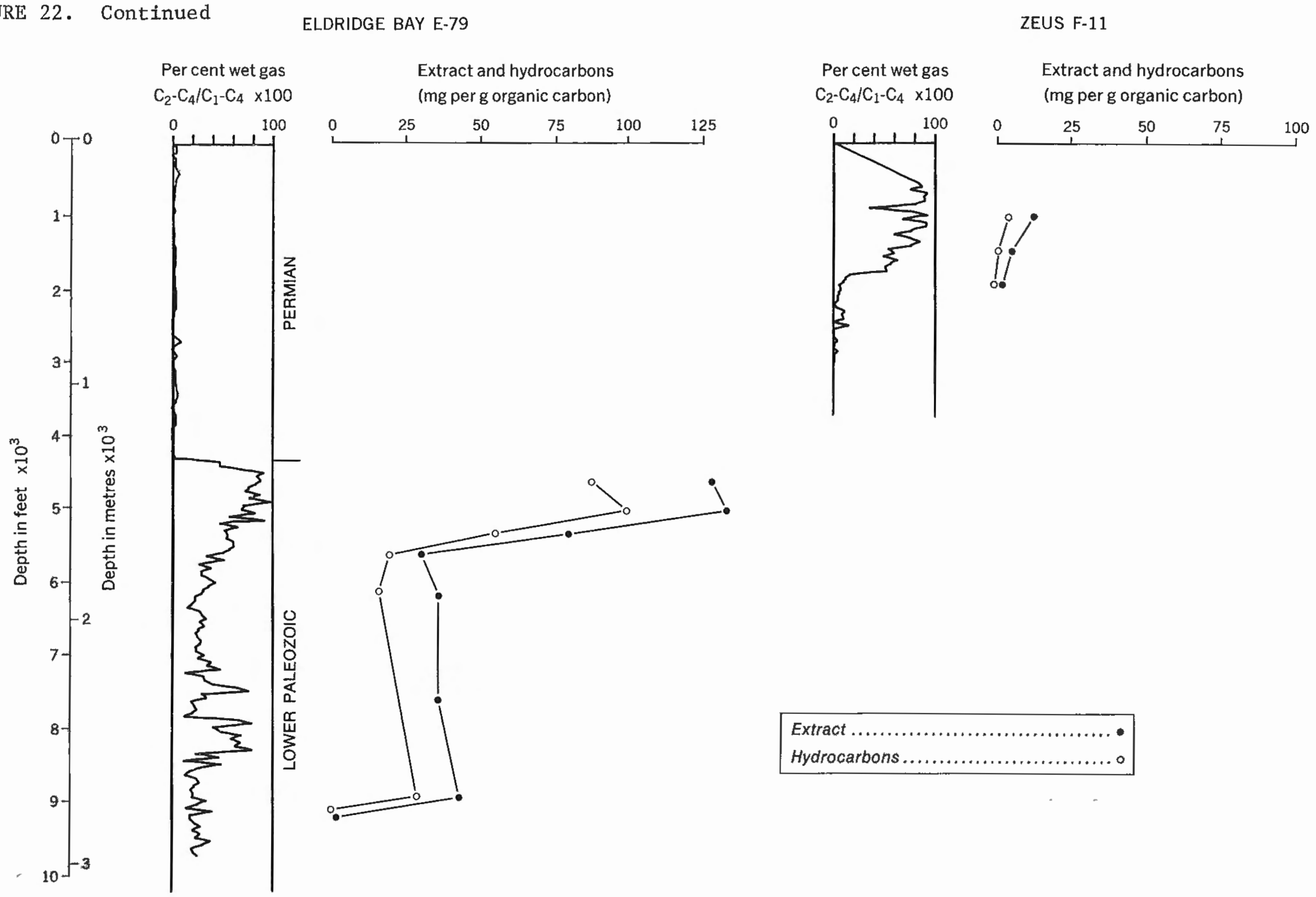
In contrast, the Permian in the Robert Harbour K-07 well is insufficiently mature to have generated liquid hydrocarbons. Again these data contradict the maturation map of Henao-Londoño (1977, Fig. 15). A high atomic hydrogen to carbon ratio in the kerogen from a sample at 2438 m indicates that, given sufficient burial, this part of the section may yield liquid hydrocarbons.

SUMMARY OF SOURCE ROCK POTENTIAL AND OIL-SOURCE CORRELATION

It is evident from the foregoing discussion that due either to lack of maturity or source organic matter type the majority of the strata in the upper Paleozoic and Mesozoic rocks of the Sverdrup Basin are likely to have yielded only gas. A notable exception is the Schei Point Formation west of Lougheed Island. It consistently contains organic matter of a suitable type for oil generation. The Savik and Blaa Mountain Formations occasionally show evidence of good source quality but the organic matter type is variable in character and it is difficult to predict the occurrences of the favourable source facies. These conclusions are in contradiction to those of Henao-Londoño (1977) who indicates considerable oil potential in the Deer Bay, Savik and Blaa Mountain Formations.

In contrast, gas has been obtained in various quantities from rocks of all ages and maturity levels. High gas yields (40 000 to 100 000 ppm) were recorded in the mature to overmature Permian section on Sabine Peninsula of Melville Island and in Triassic to Lower Jurassic rocks on Ellef Ringnes where igneous intrusions have penetrated the section. The existence of large gas fields (Drake and Hecla) at relatively shallow depth (900-1200 m) close to the onset of the mature zone means that the overmature facies is not a necessary prerequisite for the occurrence of reservoired gas in

FIGURE 22. Continued



the Sverdrup Basin. The prediction of gas sources therefore is uncertain and it is likely that accumulation of gas in such circumstances is mostly dependent on the availability of a trap for early generated gas.

Only small amounts of oil have been found within the Sverdrup Basin. The assessment of source rock potential does place some constraints on the source for this oil. In the Sabine Peninsula area, the most likely source for the oil in the North Sabine H-69 well (Schei Point Formation), Hecla P-62 (Bjorne Formation), Drake L-67/K-67 (Bjorne Formation) and Melville Island tar sands (Bjorne Formation) is the Schei Point Formation. The oil in the Thor P-38 well occurs in the Heiberg. The overlying Savik Formation contains good source organic matter but is not mature in the Thor P-38 well. Certain of the shale partings in the Heiberg Formation show some potential for oil in this well. The waxy nature of the Thor oil would tend to suggest a source in which there is a substantial contribution of land plant detritus (Powell and McKirdy, 1975). This fact would tend to support a source from within the nonmarine Heiberg Formation. Carbon isotope measurements on the saturate and aromatic fractions for the oils tend to support this assignment, although the correlations are by no means definitive (Fig. 20). Variation in the isotopic composition of the saturate fractions from the oils and tars on Melville Island can be attributed to varying degrees of biodegradation. Experimental results on oils from the Mackenzie Delta show that there is an increase in δ^{13}°/₀₀ values by 1°/₀₀ of the saturate fraction as a result of the removal of n-alkanes (unpublished results).

ARCTIC PLATFORM AND PARRY ISLANDS FOLD BELT

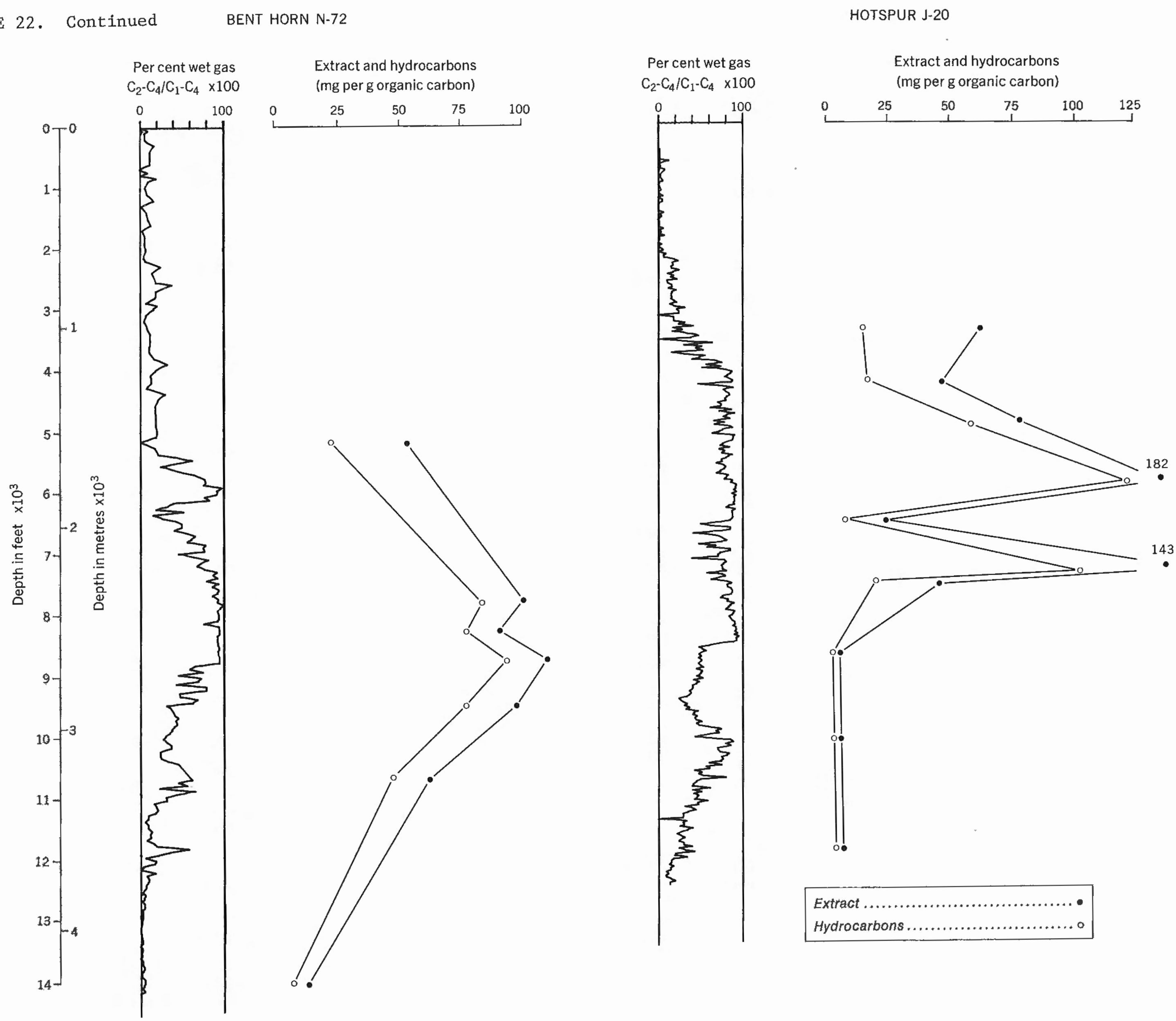
REGIONAL MATURATION TRENDS

Relatively few wells have been drilled in these geological provinces. Of the nineteen wells examined, eleven are confined to Melville and Cameron Islands (Fig. 3b) and the remainder are scattered over a wide area. The wells on Melville and Cameron Islands chiefly penetrate strata of the Middle to Upper Devonian clastic wedge (Embry and Klovan, 1977) and terminate in either Silurian or Upper Ordovician strata. The remainder of the wells penetrate a generally older section (Silurian to Lower Ordovician and, in one case, Cambrian).

The gas logs of the wells on Melville Island (Fig. 21) show that wet gas was encountered close to the surface. In contrast, the wells on Cameron Island encountered dry gas in the first few thousand metres in the Hecla Bay and Griper Bay Formations. Both formations comprise predominantly sandstones with minor coals but generally they have a low carbon content (Fig. 21). Reflectance measurements of coaly particles from these formations in the Hotspur J-20 and Bent Horn N-72 wells are in the range of 0.8 to 1.0% Ro max (Table 12) indicating that these formations are in the mature zone.

In several wells there is a decline in the percentage of wet gas with depth from above 60 per cent to 20 to 30 per cent. This is shown particularly in the Zeus F-11, Apollo C-73, Dundas C-80, Sabine Bay A-07, Eldridge Bay E-76 and Hotspur J-20 wells (Fig. 20). In

URE 22. Continued



each of these cases, the decline in wet gas is associated with a decline in extract yield indicating the onset of the overmature zone (Fig. 22). In the Bent Horn N-72 well, the decline in wet gas is not matched by a decline in extract yields. The hydrocarbon yields obtained from the Weatherall and Cape de Bray Formations in the Bent Horn N-72 well are high and may represent staining with oil from the underlying reservoir. The oil from the Bent Horn N-72 is remarkably undersaturated with respect to gas so that the absence of wet gas from the lower part of the Weatherall would not be too surprising if staining were the case. Additional data would tend to suggest that the Blue Fiord Formation in the Bent Horn N-72 well is still within the mature zone. Atomic hydrogen to carbon ratios were measured on "pyrobitumen" samples from the Blue Fiord Formation from several wells on Cameron Island. The values fall in the range 0.55 to 0.60 (Table 13) which is considered to indicate the mature zone (Rogers *et al.*, 1974). Conodont colouration studies also suggest that the overmature zone has not been reached (Uyeno, pers. com., 1977). The only well from Melville and Cameron Islands which does not show a decline in wet gas content with depth is the Weatherall O-10 well. The extract data also show that the overmature zone has not been reached.

In summary, all of the wells on Melville and Cameron Islands begin in the mature zone. The mature to overmature transition occurs in the lower part of the Weatherall (Cape de Bray) Formation at Apollo C-73, Zeus F-11, Dundas C-80, Sabine Bay A-07 or in the underlying Cape Phillips Formation (Eldridge Bay E-76). In the Hotspur J-20 well, the Eids/Cape de Bray Formation is probably overmature. On Cameron Island, the transition to the overmature zone lies within or below the Blue Fiord Formation (Bent Horn N-72, and F-72/F-72A, West Bent Horn C-44 and Cape Fleetwood L-21).

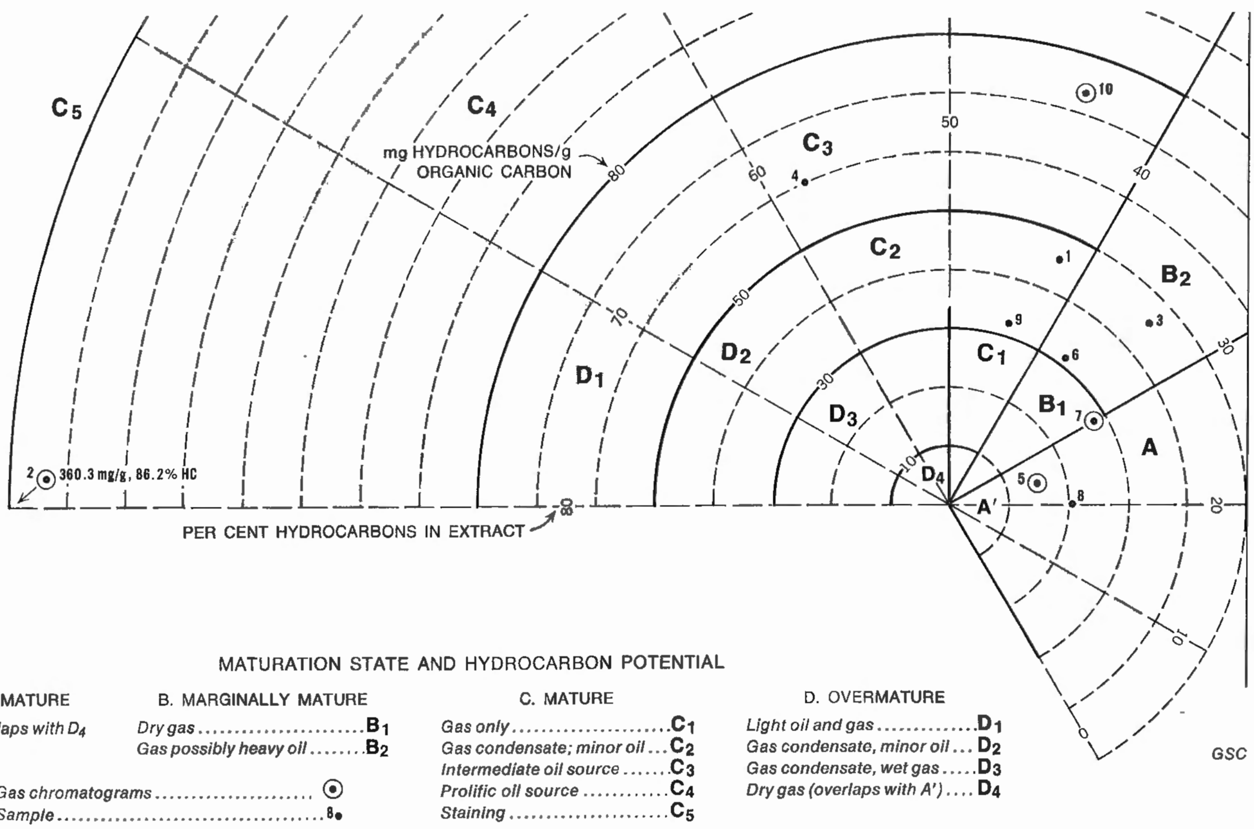


FIGURE 23. Source rock potential and gas chromatograms of the saturated hydrocarbons of the Hecla Bay Formation and Griper Bay Supergroup (*see* Table 14 for sample descriptions and Fig. 5 for key)

In the remainder of the wells, the wet gas content rarely exceeds 60 per cent (Fig. 21). In addition, the organic carbon content is very low in many of the limestones. Thus, it is difficult to determine the mature to overmature transition. Extract yields in the Allison River N-12 well decline with depth and the overmature zone is probably reached in the interval between 2300 and 2600 m within the Cape Phillips Formation. In the Young Inlet D-21 well, there is a decline in extract yield to a depth of 800 m. Very little extract was obtained from the Thumb Mountain Formation but the transition from mature to overmature probably occurs below 1300 m. Low extract yields were obtained from all samples from the Russel E-82 and Cornwallis K-40 wells indicating that they are probably overmature.

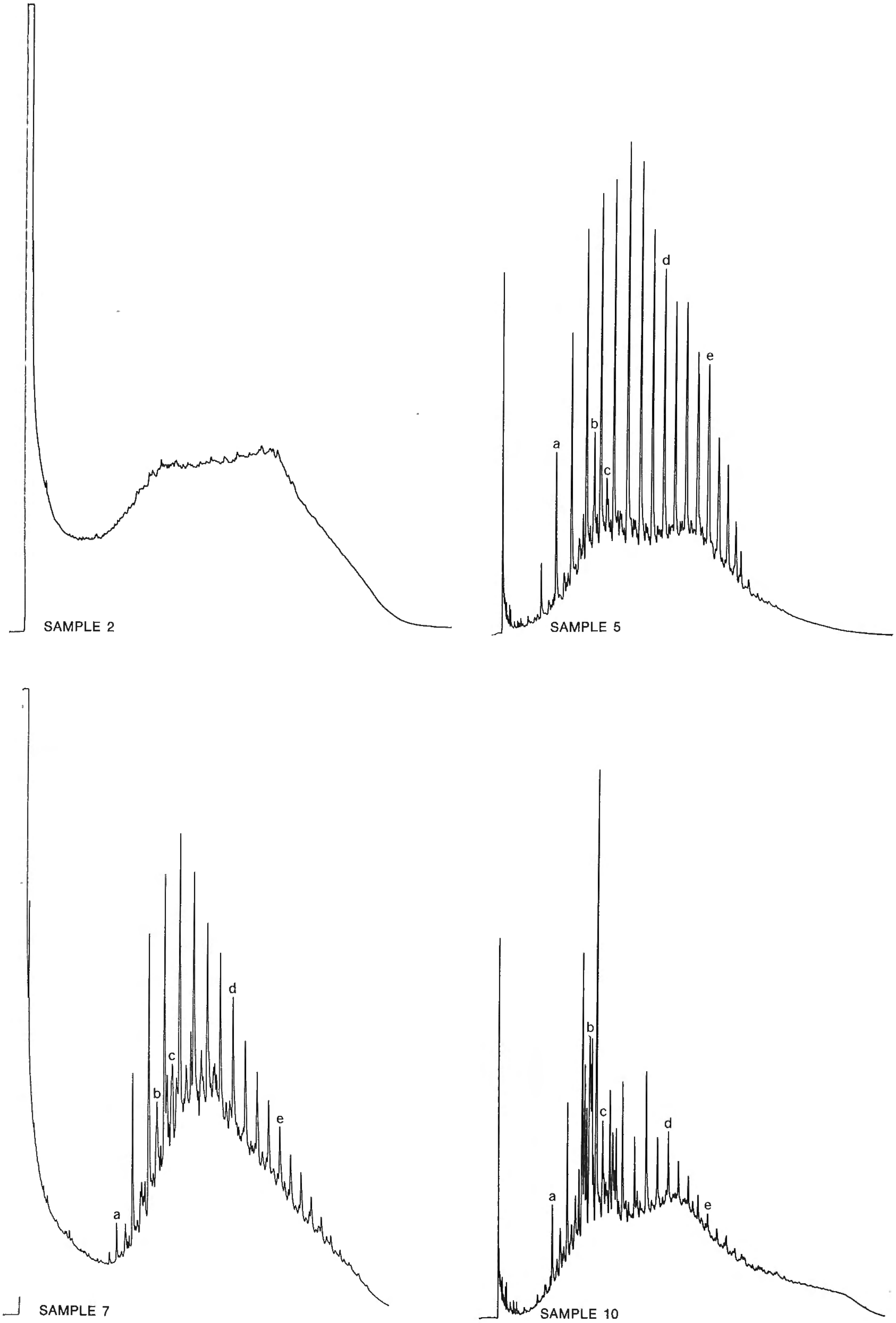
High wet gas contents were observed from the Cape Phillips and associated carbonates in the Victoria Island F-36 well. Despite a high organic carbon content little extract was obtained at 1372 and 1844 m whereas a good extract yield was obtained at 899 m. The mature to overmature transition probably occurs in the vicinity of 1800 m in this well. Relatively high wet gas contents (40-60%) were recorded from the Cape Phillips Formation in the Eids M-66 well. Very little extract was obtained below 600 m despite a relatively high organic carbon content. The mature to overmature transition probably occurs at the base of the Cape Phillips Formation.

MATURATION AND SOURCE ROCK POTENTIAL OF STRATIGRAPHIC UNITS

Hecla Bay and Griper Bay Supergroup

The Hecla Bay Formation consists mainly of fine- to medium-grained, well-sorted quartzose sandstone (*ca.* 75 m thick) with thin intervals (<5 m) of dark grey carbonaceous shale and siltstone and occasional thin coal seams. The Griper Bay Supergroup (Embry and Klovan, 1976) consists of at least 900 m of sandstone, siltstone and minor coal. These units have been encountered in the subsurface on Cameron and Vanier Islands. Apart from the occasional high value representing a coal seam, the organic carbon values are consistently low (0.2-0.5%) (Fig. 21). The cuttings gas is mainly methane and occurs in moderate to low yields (<20 000 ppm). Despite the preponderance of methane, these formations are considered to be in the mature zone on Cameron and Vanier Islands. Extract data (Table 14) commonly show relatively high proportions of hydrocarbons in the extract indicating that the sediments are mature to marginally mature. The hydrocarbon yields are variable. One sample (1600 m in Cape Fleetwood M-21) is stained. Further, the gas chromatogram of the saturated hydrocarbons from the sample shows that biodegradation has occurred (Fig. 23). With the exception of two samples, the hydrocarbon yields indicate either nil or only fair oil potential. The two exceptions (Cape Fleetwood L-21, 2088 m; West Bent Horn C-44,

FIGURE 23. Continued



2423 m) have higher yields indicating good oil source potential. However, the Cape Fleetwood sample shows a very high proportion of naphthenes in the gas chromatogram which is reminiscent of pipe grease (Fig. 23) whereas the sample from West Bent Horn shows a very unusual gas chromatogram. Several unidentified peaks occur which may be diterpenoid hydrocarbons. These compounds are common in Upper Cretaceous-Tertiary sediments of the Mackenzie Delta (Snowdon, 1977) in which organic matter of land plant origin is predominant. The dominance of land plant derived organic matter in the Hecla Bay and Griper Bay sequences is demonstrated by the low atomic hydrogen to carbon ratios and descriptions of the organic matter (Table 14).

TABLE 11. Extract and kerogen data, Degerböls, Assistance, Trold Fiord, Van Hauen, Belcher Channel, and Canyon Fiord Formations

WELL NAME	SAMPLE NO.	DEPTH in metres	FORMATION	LITHOFACIES	ORGANIC CARBON %	EXTRACT mg/g org. C	HYDROCARBONS mg/g org. C	HYDROCARBONS % in extract	KEROGEN Atomic H/C	KEROGEN % Coal Wood	KEROGEN % Herbaceous	KEROGEN % Amorphous
Andreason L-32 (2)	1	1817-1826	Degerböls-Assistance	Shale (calcareous)	0.50	44.3	8.9	20.2				
	2	1990-1999	Degerböls-Assistance	Sandstone	0.87	46.0	5.3	11.4				
Brock C-50 (5)	3	3155-3170	Assistance	Shale, siltstone	0.92	44.6	18.8	42.1				
	4	3231	Assistance	Shale	1.20	18.5	6.2	33.5				
Chads Creek B-64 (15)	5	3322	Trold Fiord-Van Hauen	Siltstone, chert, limestone	0.32	37.2	24.0	64.7				
	6	3810	Trold Fiord-Van Hauen	Shale	1.15	67.4	39.9	59.2				
	7	3993	Trold Fiord-Van Hauen	Shale, limestone	1.27	36.5	22.2	60.9				
	8	4176	Trold Fiord-Van Hauen	Shale	1.46	15.4	8.2	53.5				
	9	4420	Trold Fiord-Van Hauen	Shale	1.19	8.4	4.6	54.5				
	10	4724	Trold Fiord-Van Hauen	Shale, limestone	0.78	7.7	4.3	56.1				
	11	4846	Trold Fiord-Van Hauen	Shale, limestone	0.94	11.5	2.6	23.0				
	12	4968	Trold Fiord-Van Hauen	Shale, limestone	1.13	21.5	10.2	47.6				
	13	5029	Trold Fiord-Van Hauen	Shale	1.07	9.9	2.5	25.7				
Drake Point L-67A (16)	14	3134	Van Hauen	Shale	0.75	28.9	13.8	48.0				
	15	3135	Van Hauen	Siltstone	0.50	63.0	40.9	65.0				
	16	3235	Van Hauen	Shale (silty)	0.85	46.7	23.8	51.0				
	17	3249	Van Hauen	Shale (silty)	0.85	54.6	24.6	45.0				
Drake Point D-68 (17)	18	3078-3094	Trold Fiord	Siltstone, sandstone, shale	0.38	47.5	18.1	38.1	0.67			
	19	3383-3399	Van Hauen	Siltstone	0.72	77.4	36.1	46.6	0.59	60	40	
	20	3780-3795	Van Hauen	Siltstone	0.87	66.3	38.5	58.0	0.56			
	21	3917-3932	Van Hauen	Shale, siltstone	1.21	66.0	37.5	56.8				
	22	4069-4084	Van Hauen	Shale, calcitic veins	1.54	32.2	21.2	65.8	0.51	85	15	
	23	4191-4206	Van Hauen	Shale	1.62	22.7	11.7	51.4				
	24	4359-4374	Van Hauen	Marlstone, shale	1.68	5.4	2.1	38.8	0.38			
	25	4481-4496	Van Hauen	Marlstone, shale	1.41	7.0	2.4	34.4				
	26	4694-4709	Van Hauen	Igneous rock, shale	0.36	8.5	3.2	37.5	0.52			
	27	4877-4907	Van Hauen	Shale (metamorphosed)	1.26	10.5	6.1	58.6				
	28	5014-5029	Van Hauen	Shale, calcite veins	1.31	3.2	1.6	49.8	0.35			
	29	5105-5121	Van Hauen	Shale	0.92	6.7	2.5	37.8				
	30	5258-5273	Van Hauen	Limestone, shale	0.80	14.6	6.2	31.1				
Emerald K-33 (11)	31	3173	Trold Fiord	Siltstone	0.31	46.4	27.3	59.0				

Weatherall, Bird Fiord, Blackley, Cape de Bray and Eids Formations

The Weatherall Formation is characterized by repetitive coarsening-upward cycles of shale, siltstone and sandstone of the order of 3 to 30 m (Embry and Klovan, 1976). The Blackley and Cape de Bray Formations (Embry and Klovan, 1976) comprise rhythmically interbedded shale and siltstone and shale, respectively. They were formerly considered to be members of the Weatherall Formation. In the subsurface, units designated as the Eids Formation may correspond to either of these two formations. The Bird Fiord Formation superficially resembles the Weatherall Formation but contains a higher proportion of calcareous sediments. Sandy limestones are characteristic of the Bird Fiord Formation in the eastern part of the Parry Islands Fold Belt and give way to terrigenous clastic rocks of the Weatherall Formation to the west on Melville Island (Embry and Klovan, 1976). The section on Bathurst Island is transitional in character. These formations have been encountered in the subsurface on Bathurst Island, Vanier Island and western Melville Island.

The characteristic feature of these formations is a very uniform carbon content (0.45 ± 0.05% in the Bent Horn N-72 well) (Fig. 21). The cuttings gas shows a high proportion of wet gas although the yields are rather variable. The high gas yields recorded in the West Bent Horn C-44 and Sabine Bay A-07 wells probably reflect the true situation since both cuttings and can head space were analyzed from these wells whereas only the cuttings were analyzed from the remainder. Hydrocarbon yields indicate a fair to excellent source potential from oil (Table 15, Fig. 24). Some samples are stained (e.g. Bent Horn N-72, all samples; Cape Fleetwood M-21, 2576 m). The constancy of the excellent source rock characteristics throughout the area probably means that staining originated from local migration within the formation. These formations tend to be overmature in the following wells: Apollo C-73, Zeus F-11, below 1300 m in Dundas C-80, below 2300 m in Hotspur J-20, below 3000 m in West Bent Horn C-44. In these cases, gas condensate would be the hydrocarbon product. The atomic hydrogen to carbon ratios of the kerogen are low (0.55-0.74) considering the high hydrocarbon yields obtained. The kerogen descriptions

TABLE 11. Continued

WELL NAME	SAMPLE NO.	DEPTH in metres	FORMATION	LITHOFACIES	ORGANIC CARBON %	EXTRACT mg/g org. C	HYDROCARBONS		KEROGEN			
							mg/g org. C	% in extract	Atomic H/C	% Coal Wood	% Herbaceous	% Amorphous
Graham C-52 (42)	32	2237	Undifferentiated	Shale	0.93	4.6	nd	nd				
	33	2672	Belcher Channel(?)	Shale, siltstone	0.72	72.0	56.1	59.5				
	34	2743-2752	Belcher Channel	Siltstone, sandstone	0.32	85.5	57.9	67.7				
	35	3063	Belcher Channel	Limestone, shale	0.78	9.2	3.4	21.7				
Hecla J-60 (13)	36	2603	Degerböls	Limestone, shale	0.34	9.7	2.2	22.6				
	37	3353-3362	Van Hauen	Shale, siltstone	1.02	95.5	45.9	48.1				
	38	3496-3514	Van Hauen	Shale, siltstone	1.17	74.3	47.4	63.8				
	39	3611	Van Hauen	Shale, siltstone	1.02	31.1	7.4	23.8				
Pollux G-60 (32)	40	2423-2438	Degerböls	Limestone, shale	0.17	71.3	44.2	62.0				
	41	2774-2789	Assistance	Siltstone, shale	0.81	44.8	28.6	64.0				
	42	3231-3246	Canyon Fiord	Sandstone	0.36	107.6	74.6	69.3				
Robert Harbour K-07 (21)	43	1797-1800	Undifferentiated Permian	Siltstone	0.42	35.8	4.1	11.8				
	44	2194-2210	Undifferentiated Permian	Shale	2.06	43.5	8.0	18.3	0.84	50	40	10
	45	2438-2453	Undifferentiated Permian	Shale (calcareous)	1.87	46.5	8.5	18.3	1.11			
	46	2499-2514	Undifferentiated Permian	Shale (calcareous)	1.34	33.3	6.4	19.4	0.81			
	47	2714-2722	Undifferentiated Permian	Shale (calcareous)	0.81	40.3	8.2	20.3				
	48	3094-3109	Undifferentiated Permian	Siltstone, shale	0.73	51.1	9.5	18.6				
	49	3657-3673	Undifferentiated Pennsylvanian	Shale, siltstone	1.29	70.2	22.5	32.1				
	50	3779-3795	Undifferentiated Pennsylvanian	Shale, sandstone	1.16	63.0	20.5	32.5	0.78	50	50	
Sandy Point L-46 (9)	51	1792	Undifferentiated Permian	Conglomerate	0.30	17.2	4.1	23.0				
Satellite F-68 (3)	52	2172	Trold Fiord	Sandstone	0.28	21.3	10.9	51.0				
	53	2668	Hare Fiord	Shale (calcareous)	0.63	19.4	6.6	34.0				
	54	3356	Hare Fiord	Shale, siltstone	1.57	24.6	5.6	23.0				
Wilkins E-60 (6)	55	2664-2673	Undifferentiated Permian	Limestone (siliceous)	0.28	39.4	24.0	61.0				

Location of wells *see* Figure 3a, Table 1

Numbers in brackets *see* Figures 3a, 10

show a preponderance of herbaceous material with coaly organic matter forming the secondmost dominant component. The coaly organic matter may well represent amorphous organic matter which has become blackened during hydrocarbon generation.

Gas chromatograms of the saturated hydrocarbons show a very mature distribution peaking in the range C_{16} to C_{18} with no odd over even predominance in the n-alkanes (Fig. 24). Pristane and phytane are relatively minor components. The character of the gas chromatograms is extremely uniform throughout the area. The hydrocarbon yields in the mature zone indicate favourable source organic matter for oil generation although its concentration is rather low. Some oil potential therefore exists within this formation (*see* Henao-Londoño, 1977).

Blue Fiord Formation

The Blue Fiord Formation is characteristically developed as a resistant, microcrystalline and fossil fragmental limestone with lesser dolomite, shale and siltstone and is largely correlative with the Eids, Blackley and Cape de Bray Formations on Bathurst and Melville Islands (Thorsteinsson and Tozer, 1970). In the subsurface it is recognized on eastern Melville, Vanier and Cameron Islands and in the Victoria F-36 well. On Cameron Island it forms the reservoir for the Bent Horn oil pool. It generally has a low organic carbon content (*ca.* 0.1-0.2%, with a few higher values) (Fig. 21). Gas yields are low although they tend to be higher in those wells in which both head space and cuttings were analyzed (Fig. 21). High hydrocarbon yields were obtained from the Bent Horn N-72 well at 3267 m (staining?), Victoria Island at 899 m and Weatherall O-10 at 1372 m and 1600 m (Table 16, Fig. 24). The limited amount of kerogen data and the gas chromatograms strongly resemble those obtained from the Weatherall and equivalent formations (Figs. 24, 25, Tables 15, 16).

Bathurst Island and Stuart Bay Formations

The Bathurst Island Formation comprises fine-grained sandstone (variably argillaceous and calcareous), calcareous and silty mudstone, and minor dolomitic siltstone (Thorsteinsson and Tozer, 1970). The Stuart Bay Formation comprises calcareous, argillaceous, fine-grained sandstone with mudstone, siltstone and minor bioclastic limestone, and thin limestone with chert conglomerate beds at the base. These formations are

TABLE 12. Vitrinite reflectance data for the BP *et al.* Hotspur J-20 (62) and Panarctic Tenneco *et al.* Bent Horn N-72 (63) wells

HOTSPUR J-20		BENT HORN N-72	
Depth in metres	Reflectance %Ro max.	Depth in metres	Reflectance %Ro max.
601	0.84 ± 0.02	396	0.81 ± 0.03
980	0.90 ± 0.04	628	0.87 ± 0.03
986	1.01 ± 0.06	939	1.02 ± 0.03
1185	0.82 ± 0.05	1061	1.00 ± 0.03
1321	0.84	1286	1.07 ± 0.04
1608	0.91	1429	0.92 ± 0.04
1611	0.98	1667	0.89 ± 0.03
1967	1.33		

TABLE 13. Atomic hydrogen to carbon ratios of pyrobitumen from the Blue Fiord Formation on Cameron Island

Sample Well - number (Table 2)	Depth in metres	Atomic H/C
Bent Horn N-72 (63)	3153	0.58
Bent Horn N-72 (63)	3173	0.58
Bent Horn F-72 (64)	3136	0.99
Bent Horn F-72A (64)	3131	0.60
Bent Horn F-72A (64)	3132	0.61
West Bent Horn C-44 (65)	3184	0.57
West Bent Horn C-44 (65)	3190	0.58
West Bent Horn C-44 (65)	3195	0.56
Cape Fleetwood M-21 (66)	3335	0.56
Cape Fleetwood M-21 (66)	3343	0.56

TABLE 14. Extract and kerogen data for the Hecla Bay and Griper Bay Supergroup

WELL NAME	SAMPLE NO.	DEPTH in metres	FORMATION	LITHOFACIES	ORGANIC CARBON %	EXTRACT mg/g org. C	HYDROCARBONS mg/g org. C	HYDROCARBONS % in extract	KEROGEN Atomic H/C	KEROGEN % Coal Wood	KEROGEN % Herbaceous	KEROGEN % Amorphous
Bent Horn N-72 (63)	1	1585	Hecla	Sandstone, shale	0.50	108.7	45.5	41.8	0.76	5	90	5
Cape Fleetwood M-21 (66)	2	1600	Griper	Sandstone (stained)	0.32	417.7	360.3	86.2				
	3	1996	Hecla	Sandstone, shale	0.34	134.9	45.7	33.9				
	4	2088	Hecla	Shale, sandstone	0.52	103.5	59.7	57.7	0.67			
Hotspur J-20 (62)	5	980	Hecla	Shale	0.54	61.5	14.7	23.9				
West Bent Horn C-44 (65)	6	1798	Hecla	Sandstone, shale	0.32	82.9	31.0	37.3				
	7	1890	Hecla	Sandstone, shale, coal	0.42	92.6	27.8	30.1	0.68	30	60	10
	8	2012	Hecla	Sandstone, shale	0.32	99.7	20.2	20.3				
	9	2393	Hecla	Sandstone, siltstone	0.33	74.1	32.2	43.6				
	10	2423	Hecla	Sandstone, siltstone	0.72	167.1	73.3	43.8	0.67	30	60	10

of Early Devonian age and are equivalent to the upper part of the Cape Phillips Formation. The Bathurst Island Formation occurs in the Allison River N-12, Hotspur J-20 and Young Inlet D-21 wells, while the Stuart Bay Formation occurs only in the Hotspur J-20 well.

The organic carbon contents of these formations are variable, ranging from 0.5 to in excess of 2.0 per cent (Fig. 21). The proportion of wet gas in the cuttings gas is intermediate (40-60%) (Fig. 21), indicating possibly the onset of overmaturity. Extract data show that these formations are overmature in the Hotspur J-20 well and dry gas is the only anticipated hydrocarbon product. High yields were obtained from the Bathurst Island Formation in both the Allison River N-12 and Young Inlet D-21 wells (Table 16, Fig. 25). However, in both cases the lower parts of the formation are tending to overmature and the anticipated hydrocarbon product would be light oil tending to gas-condensate (Fig. 25). The gas chromatograms (Fig. 25) show a mature distribution with a high proportion of the acyclic isoprenoid alkanes, pristane and phytane.

The Russel E-82 well penetrated a section considered to be equivalent in age to the Peel Sound Formation which in turn is roughly equivalent to the Bathurst Island Formation. The hydrocarbon yields were low (10-12 mg per gram organic carbon). The gas chromatograms show a mature distribution in which the n-alkanes are dominant (Fig. 25). These samples appear still to be in the mature zone.

Read Bay, Allen Bay, Cape Phillips and Kitson River Formations

The Allen Bay (Upper Ordovician to Middle Silurian) and overlying Read Bay Formation (Middle Silurian to Lower Devonian) are carbonates that pass laterally into the graptolitic shale and siltstone of the Cape Phillips Formation (Upper Ordovician to Lower Silurian) (Thorsteinsson and Tozer, 1970). The Kitson River Formation is a 90 m thick graptolitic shale which overlies carbonate banks on Melville Island and is equivalent to the uppermost Cape Phillips Formation.

The shale facies is characterized by very high carbon values (3-5%) (Fig. 21) and is commonly accompanied by high gas yields (in excess of 50 000 ppm) particularly where the sequence is overmature (e.g. Apollo C-73, Zeus F-11, Dundas C-80). Where the shale facies falls within the mature zone, the hydrocarbon yields show good to excellent source potential for oil (e.g. Blue Fiord E-46, Eids M-66, upper part of Cape

TABLE 15. Extract and kerogen data for the Weatherall, Bird Fiord, Cape de Bray and Eids Formations

Apollo C-73 (57)	1	549-564	Weatherall	Siltstone	0.64	74.4	39.9	53.5				
	2	1509-1524	Cape de Bray	Shale, siltstone	0.52	23.2	12.8	55.2				
Bent Horn N-72 (63)	3	2377-2393	Bird Fiord	Sandstone	0.39	200.4	160.6	80.1				
	4	2530-2545	Bird Fiord	Shale, sandstone	0.42	181.5	156.3	86.1	0.66	20	70	10
	5	2667-2682	Bird Fiord	Shale, sandstone	0.39	222.6	194.2	87.2				
	6	2880-2896	Bird Fiord	Shale	0.39	195.9	153.4	78.3		30	60	10
Dundas C-80 (55)	7	671-686	Weatherall	Shale (micaceous)	0.74	88.7	55.9	63.1	0.74	20	80	
	8	975-991	Weatherall	Sandy siltstone	0.52	94.8	59.7	62.9				
	9	1311-1326	Weatherall	Shale (micaceous)	0.60	43.1	30.4	70.5	0.61	40	55	5
	10	1570-1600	Weatherall	Shale, sandstone stringers	0.51	24.2	10.6	43.7				
	11	2316-2332	Cape de Bray	Shale, silty stringers	0.64	7.4	nd	nd				
Cape Fleetwood M-21 (66)	12	2393	Bird Fiord-Cape de Bray	Sandstone, shale	0.44	104.3	35.2	33.8				
	13	2576	Bird Fiord-Cape de Bray	Shale, siltstone	0.40	315.9	253.0	80.1				
	14	2697	Bird Fiord-Cape de Bray	Siltstone, shale	0.47	139.1	107.5	77.2	0.60			
	15	2850	Bird Fiord-Cape de Bray	Siltstone, shale	0.51	113.2	90.2	79.7		30	55	15
	16	2972	Bird Fiord-Cape de Bray	Shale, siltstone	0.48	135.7	112.0	82.5	0.58	40	55	5
	17	3063	Bird Fiord-Cape de Bray	Siltstone, shale	0.41	127.7	96.5	75.5				
	18	3185	Bird Fiord-Cape de Bray	Siltstone, shale	0.39	98.7	75.0	76.0				
Eids M-66 (70)	19	37-46	Eids	Siltstone, shale	0.97	94.9	46.8	49.2				
Hotspur J-20 (62)	20	1291	Bird Fiord	Calcareous shale	0.49	46.1	15.6	33.8				
	21	1518-1536	Bird Fiord	Siltstone, sandstone, shale	1.04	77.0	57.0	73.9				
	22	1820-1838	Bird Fiord	Siltstone, sandstone	0.27	182.8	122.7	67.1				
	23	1973	Bird Fiord	Silty shale	0.27	21.3	6.0	28.5				
	24	2259-2277	Eids-Cape de Bray	Siltstone, sandstone, shale	0.27	143.7	101.9	70.9				
	25	2294	Eids-Cape de Bray	Siltstone	0.27	44.2	17.2	38.8				
Sabine Bay A-07 (58)	26	1250	Orksut (Cape de Bray) and Eids (undivided)	Shale, siltstone	0.43	44.2	19.4	44.0				
	27	1676	Orksut (Cape de Bray) and Eids (undivided)	Shale, siltstone	1.23	41.2	27.1	65.6				
	28	1219-1234	Cape de Bray		0.26	71.9	38.9	54.0				
West Bent Horn C-44 (65)	29	2637	Bird Fiord-Cape de Bray	Sandstone, shale	0.32	128.2	100.4	78.3		20	70	10
	30	2804	Bird Fiord-Cape de Bray	Siltstone, sandstone	0.35	85.2	60.6	71.2				
	31	2865	Bird Fiord-Cape de Bray	Shale, siltstone	0.49	113.9	89.3	78.3	0.60	20	70	10
	32	3109	Bird Fiord-Cape de Bray	Siltstone	0.29	35.7	17.2	48.1				
	33	3216	Bird Fiord-Cape de Bray	Limestone	0.30	38.8	27.8	71.8				
Zeus F-11 (56)	34	305-320	Cape de Bray	Shale	0.58	12.2	4.9	40.5				
	35	442-472	Cape de Bray	Shale, siltstone	0.60	5.7	2.2	38.6				

Location of wells *see* Figures 3a, b, Tables 2, 3

Numbers in brackets *see* Figures 3b, c, 21, 28

Phillips Formation in Eldridge Bay E-79, Weatherall O-10) (Fig. 26, Table 17). Elsewhere, these units are overmature and would be a source for only gas-condensate or dry gas (Allison River N-12, Apollo C-73, Zeus F-11, Sabine Bay A-07, Victoria Island F-36, Young Inlet D-21, Hotspur J-20, Dundas C-80). Gas chromatograms of the saturated hydrocarbons from the Cape Phillips Formation vary (Fig. 26). A most unusual distribution is seen in the samples from the Cape Phillips Formation in the Eldridge Bay E-79 well. The gas chromatograms are characterized by a pronounced hump of naphthenic components with few n-alkanes. In contrast, a gas chromatogram from the Cape Phillips Formation in the adjacent Weatherall O-10 well shows a higher proportion of n-alkanes as do the remainder of the Cape Phillips samples. The reason for the lack of n-alkanes in the Eldridge Bay samples is not readily apparent. The disappearance of n-alkanes is usually associated with biodegradation in crude oils. Biodegradation of n-alkanes in a source rock could occur only if extensive weathering of the rock had taken place.

The carbonates of the Allen Bay and Read Bay Formations generally have a low organic carbon content (<0.2% C) (e.g. Dundas C-80 well; Fig. 21), except where there is interfingering with the Cape Phillips Shale (e.g. Blue Fiord E-46). With the exception of the latter case, the hydrocarbon yields are low (Table 17).

TABLE 16. Extract and kerogen data for the Blue Fiord, Bathurst Island, Peel Sound and Stuart Bay Formations

WELL NAME	SAMPLE NO.	DEPTH in metres	FORMATION	LITHOFACIES	ORGANIC CARBON %	EXTRACT mg/g org. C	HYDROCARBONS mg/g org. C	HYDROCARBONS % in extract	KEROGEN Atomic H/C	KEROGEN % Coal Wood	KEROGEN % Herbaceous	KEROGEN % Amorphous
Bent Horn N-72 (63)	1	3267-3273	Blue Fiord	Argillaceous limestone	0.47	123.6	95.0	77.5				
	2	4313-4328	Blue Fiord	Shale, limestone	0.28	23.7	12.5	52.6				
Cape Fleetwood M-21 (66)	3	3368	Blue Fiord	Limestone	0.30	44.7	38.5	86.1				
	4	3459	Blue Fiord	Limestone	0.29	54.6	49.0	89.7				
Victoria Island F-36 (51)	5	899-914	Blue Fiord	Dolomite	0.45	113.7	95.5	74.0				
Weatherall O-10 (60)	6	1372-1387	Blue Fiord	Limestone, shale	0.56	158.0	106.4	67.3				
	7	1600-1615	Blue Fiord	Limestone	0.78	125.9	86.6	68.7	0.73	20	80	
West Bent Horn C-44 (65)	8	3338	Blue Fiord	Limestone (cryptocrystalline)	0.27	30.1	13.8	45.9		25	60	15
	9	3490	Blue Fiord	Limestone (cryptocrystalline)	0.25	29.6	14.3	48.1				
Allison River N-12 (68)	10	311-320	Bathurst Island	Bituminous, calcareous siltstone	2.43	114.8	73.9	54.3				
	11	1222-1231	Bathurst Island	Dolomitic siltstone	0.68	51.3	24.7	48.3				
Hotspur J-20 (62)	12	2654	Stuart Bay	Limestone, shale	4.75	2.0+	-	-	0.52			
	13	3089	Bathurst Island	Bituminous, calcareous shale	1.57	3.5+	0.8	22.8				
Russel E-82 (53)	14	305-314	Peel Sound (equivalent)	Dolomite, silty shale	0.46	29.8	11.6	40.0				
	15	917-927	Peel Sound (equivalent)	Dolomite	0.38	22.2+	12.0	54.1				
Young Inlet D-21 (67)	16	155-165	Bathurst Island	Shale, dolomitic siltstone	1.09	113.7	70.1	61.6				
	17	293-302	Bathurst Island	Dolomitic siltstone, shale	1.41	80.4	39.0	48.4				

+ Contaminated sample   Location of wells *see* Figure 3b, Table 2   Numbers in brackets *see* Figures 3b, 21

Thumb Mountain, Bay Fiord, Copes Bay and Parrish Glacier Formations

A limited amount of geochemical information has been obtained for Ordovician and Cambrian strata. These formations are largely carbonates and are of limited interest from a source rock standpoint. The Cornwallis Dome K-40 well penetrated the Copes Bay and Parrish Glacier Formations of Early Ordovician and Cambrian age, respectively. The gas yields from this well are extremely low (Fig. 21) and there is a decline in the proportion of wet gas with depth. Some extract was obtained from several cores throughout the well (Table 18). The yields were generally low, but even the hydrocarbons present could be attributed to contamination from waxed core boxes or pipe grease.

The Thumb Mountain Formation in the Allison River N-12, Dundas C-80 and Eids M-66 wells is overmature and yielded no extract. The Bay Fiord Formation in the Eldridge Bay E-79 and Sabine Bay A-07 wells is also overmature. Generally the source rock potential of these formations is nil. Where the organic carbon values are higher, there may be some prospects for dry gas but the association of these formations with evaporites means that the hydrogen sulphide content of any gas will be high.

SUMMARY OF SOURCE ROCK POTENTIAL AND OIL-SOURCE CORRELATION

It is evident from the foregoing discussion that the Weatherall, Bird Fiord, Blackley, Cape de Bray, Cape Phillips and Bathurst Island Formations can have excellent source potential for oil particularly on eastern Melville Island and Bathurst Island. The governing factor is the transformation from mature to overmature in which case the hydrocarbon product changes from oil to gas-condensate or dry gas. The Weatherall and Bird Fiord Formations have a uniformly low organic carbon content which downgrades their potential relative to the Cape Phillips Formation. However, the lithological nature of these formations (i.e. repetitive upward-coarsening cycles terminating in sandstone) means that drainage of oil should be highly effective. Any reservoir sandstones developed within them should therefore be highly prospective. The Bent Horn oil pool is located in the upper part of the Blue Fiord Formation and is overlain by the lower part of the Devonian clastic wedge which as mentioned above contains good source organic matter albeit in low quantities. The nearest reference point for older formations is the Hotspur J-20 well. In this well, the Stuart Bay, Bathurst Island and Cape Phillips Formations are all overmature. The most likely source for the Bent Horn oil is the fine-grained sediments of the Devonian clastic wedge (Blackley, Cape de Bray, Weatherall/Bird Fiord Formations).

Carbon isotopic data on the saturate and aromatic fractions of the Bent Horn oil and various rock extracts (Fig. 27) show that an extract from the Cape Phillips Formation is more similar to the Bent Horn oil than extracts of the Bird Fiord/Weatherall Formation. Both the Cape Phillips samples were from the Eldridge Bay well which, as noted above, contains a quite unusual distribution of hydrocarbons, different from that observed in the Bent Horn oil. However, gas

TABLE 17. Extract and kerogen data, Read Bay, Allen Bay, Cape Phillips and Kitson River Formations

WELL NAME	SAMPLE NO.	DEPTH in metres	FORMATION	LITHOFACIES	ORGANIC CARBON %	EXTRACT mg/g org. C	HYDROCARBONS		KEROGEN			
							mg/g org. C	% in extract	Atomic H/C	% Coal Wood	% Herbaceous	% Amorphous
Allison River N-12 (68)	1	2884	Cape Phillips	Shale	2.42	0	0	0				
Apollo C-73 (57)	2	2118-2134	Cape Phillips	Shale, black limestone	3.60	3.7	2.2	59.9				
	3	2362-2377	Cape Phillips	Shale (calcareous)	2.58	2.5	1.6	66.6				
	4	2606-2621	Cape Phillips	Shale	1.78	5.9	4.4	73.8				
	5	2728-2743	Cape Phillips	Limestone, shale	1.53	6.9	5.2	75.5				
Blue Fiord E-46 (71)	6	762	Allen Bay	Shale, argillaceous limestone	1.46	116.5	53.6	46.1				
	7	914	Allen Bay	Limestone, calcareous shale	1.65	171.0	85.4	50.0				
	8	1219	Cape Phillips	Dolomite	0.12	167.5	56.9	34.0				
	9	1646	Cape Phillips	Calcareous shale, limestone	1.77	85.4	53.9	63.1				
	10	1829	Cape Phillips	Argillaceous dolomite	1.74	58.5	35.6	60.9				
	11	1951	Allen Bay	Bituminous dolomite	0.74	77.3	55.7	72.1				
Dundas C-80 (55)	12	2682-2697	Kitson River	Shale, limestone stringers	3.12	0.8	-	-				
	13	2835	Kitson River	Shale, limestone stringers	2.28	1.9	-	-				
Eids M-66 (70)	14	210-219	Cape Phillips	Shale (calcareous)	2.72	95.0	60.7	63.9				
	15	292-301	Cape Phillips	Shale, calcite vein	4.68	72.4	47.3	65.3				
	16	521-530	Cape Phillips	Shale, limestone	2.24	94.7	67.7	71.5				
	17	704-713	Allen Bay	Limestone, shale	4.68	15.5	12.5	80.4				
Eldridge Bay E-79 (59)	18	1402	Cape Phillips	Shale, calcite veins	1.67	129.4	88.4	68.3	0.86	10	80	10
	19	1524	Cape Phillips	Shale	1.65	134.3	100.9	75.1				
	20	1598	Cape Phillips	Bituminous shale	4.55	79.4	54.6	68.7				
	21	1707	Cape Phillips	Bituminous shale	6.94	30.9	20.2	65.1	0.73		100	
	22	1868	Allen Bay	Dolomite	0.14	36.6	17.8	48.7				
	23	2316-2332	Allen Bay	Dolomite	0.13	36.8	-	-				
Hotspur J-20 (62)	24	3634	Cape Phillips	Shale	1.42	3.7	1.1	30.4	0.45			
Russel E-82 (53)	25	1704-1713	Read Bay	Dolomite, shale	0.55	22.0	15.6	71.1				
Sabine Bay A-07 (58)	26	1981	Cape Phillips	Shale, limestone	2.63	14.5	10.6	73.0				
Victoria Island F-36 (51)	27	1372	Cape Phillips-Read Bay	Bituminous shale, limestone	2.75	19.5	16.4	83.8				
	28	1844	Cape Phillips-Read Bay	Dolomite, pyrobitumen	4.28	0.3	-	-				
Weatherall O-10 (60)	29	1859-1875	Cape Phillips	Limestone, shale	1.72	80.9	47.9	59.2	0.96		20	80
	30	2012-2027	Cape Phillips	Bituminous limestone	0.56	157.8	135.1	85.6				
	31	2210-2225	Cape Phillips	Bituminous shale	1.52	192.5	150.2	78.0		10	80	10
Young Inlet D-21 (67)	32	610-619	Cape Phillips	Shale	2.87	56.8	30.6	54.0				
	33	765-774	Cape Phillips	Dolomitic shale	1.82	50.6	36.6	72.2				
Zeus F-11 (56)	34	594-610	Kitson River	Shale, siltstone	6.31	1.3	0.7	56.1				

Location of wells *see* Figure 3b, Table 2 — Numbers in brackets *see* Figures 3b, 21

chromatograms of the Weatherall extracts are quite similar to the Bent Horn oil (Fig. 27). In addition, within the Parry Islands Fold Belt, the Cape Phillips Formation is generally overmature except on central Melville Island (Eldridge Bay E-79 and Weatherall O-10 wells). A tentative conclusion is that the Bent Horn oil is derived from the Bird Fiord Formation.

BANKS ISLAND

MATURATION AND SOURCE ROCK POTENTIAL

Mesozoic and Tertiary strata

On Banks Island, a profound unconformity separates strata of Early Jurassic to Tertiary age from underlying Devonian rocks. Rocks of Triassic age have not been encountered on Banks Island (Miall, 1975). The maximum thickness of Mesozoic and Tertiary rocks encountered in the subsurface on Banks Island was 1977 m in the Castel Bay C-68 well. Of the wells studied, the Orksut I-44 well contained the greatest thickness of Mesozoic and Tertiary strata (1830 m).

Gas data from six wells on Banks Island show very low yields of dry gas for Mesozoic and Tertiary strata indicating the overall immaturity of this part of the section from the standpoint of hydrocarbon generation (Fig. 28). Extract data from two samples (Table 19) confirm this interpretation. No source rock potential can be expected from these Mesozoic and Tertiary strata.

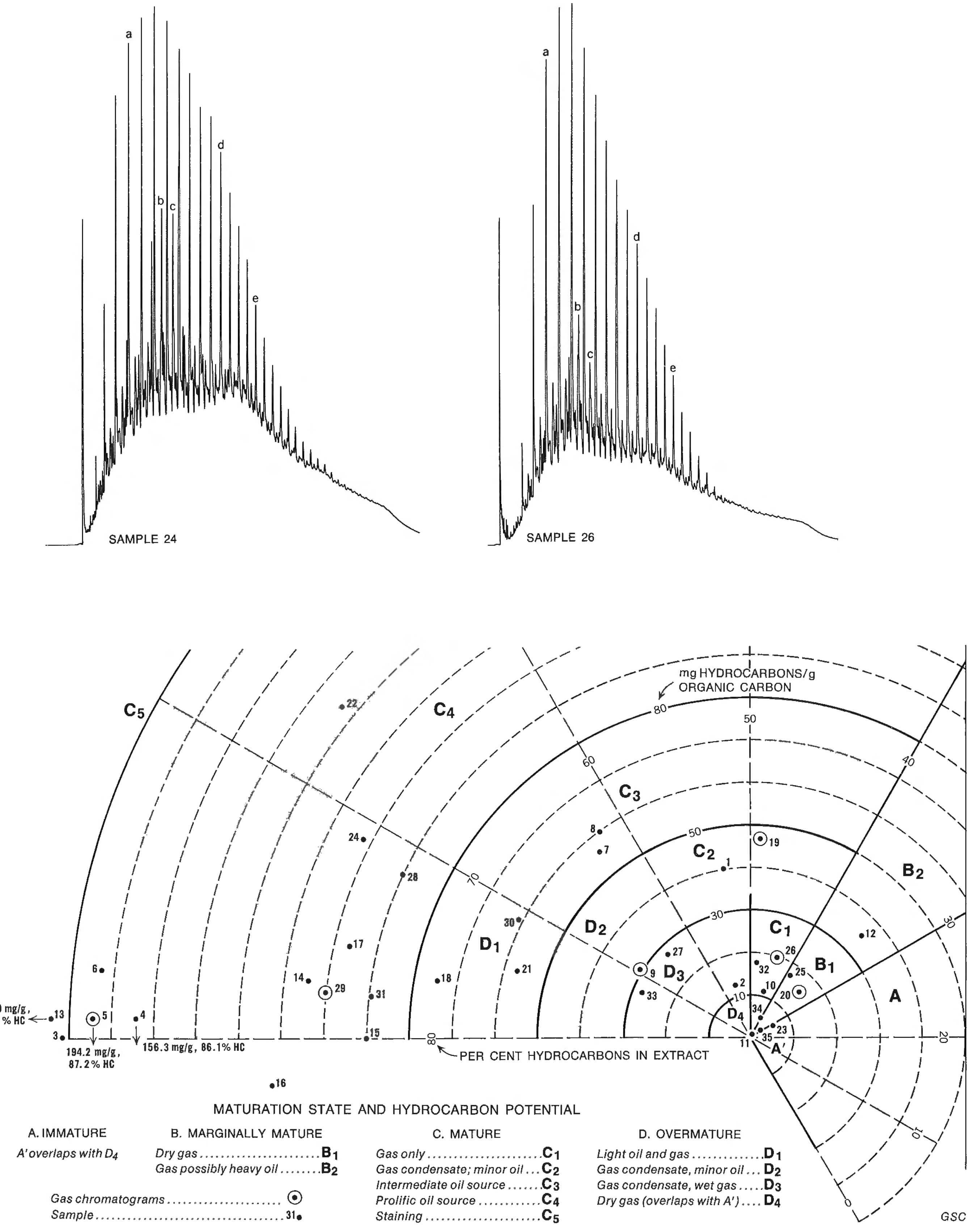
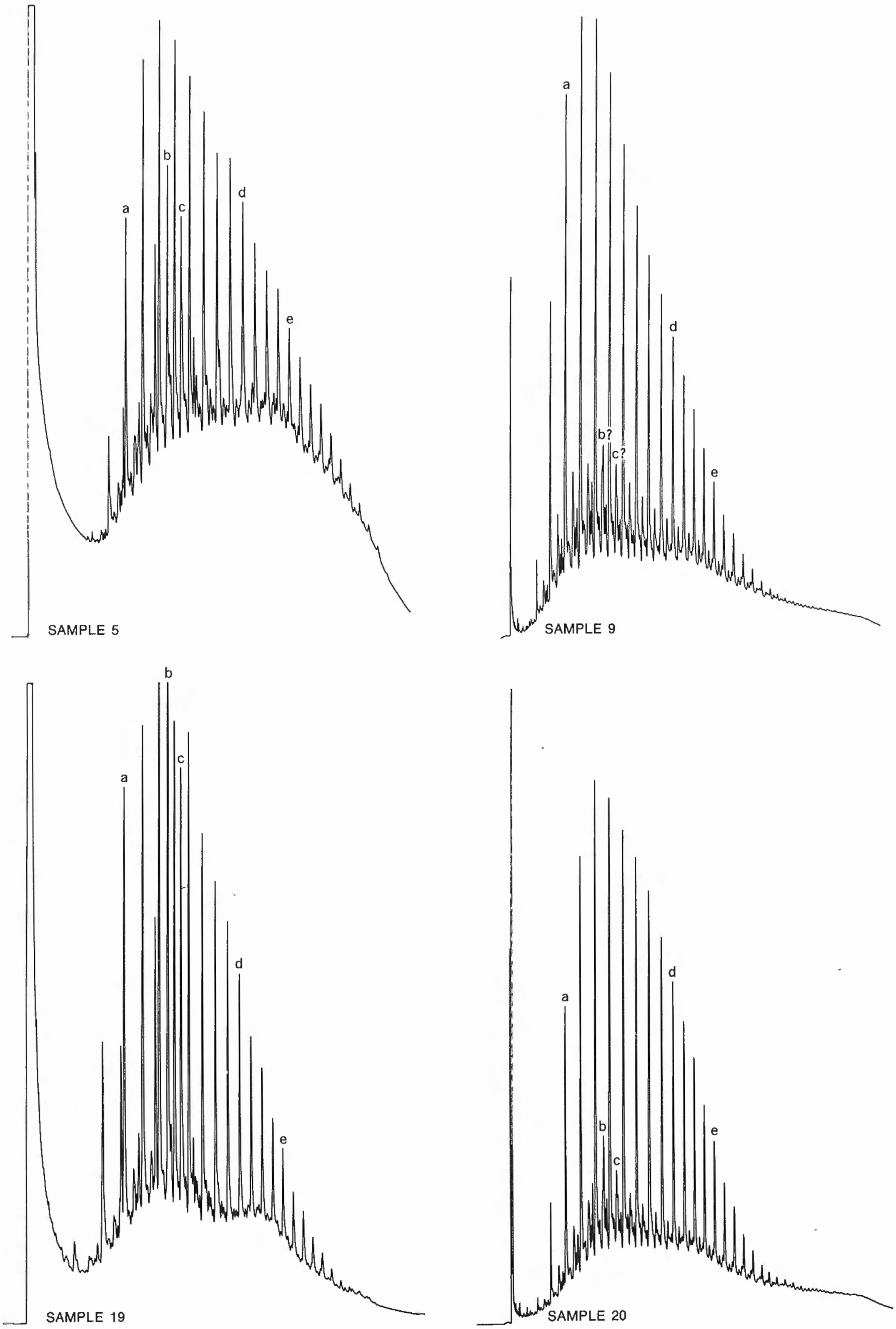


FIGURE 24. Source rock potential and gas chromatograms of the saturated hydrocarbons of the Weatherall, Bird Fiord, Cape de Bray and Eids Formations (*see* Table 15 for sample descriptions and Fig. 5 for key)

FIGURE 24. Continued



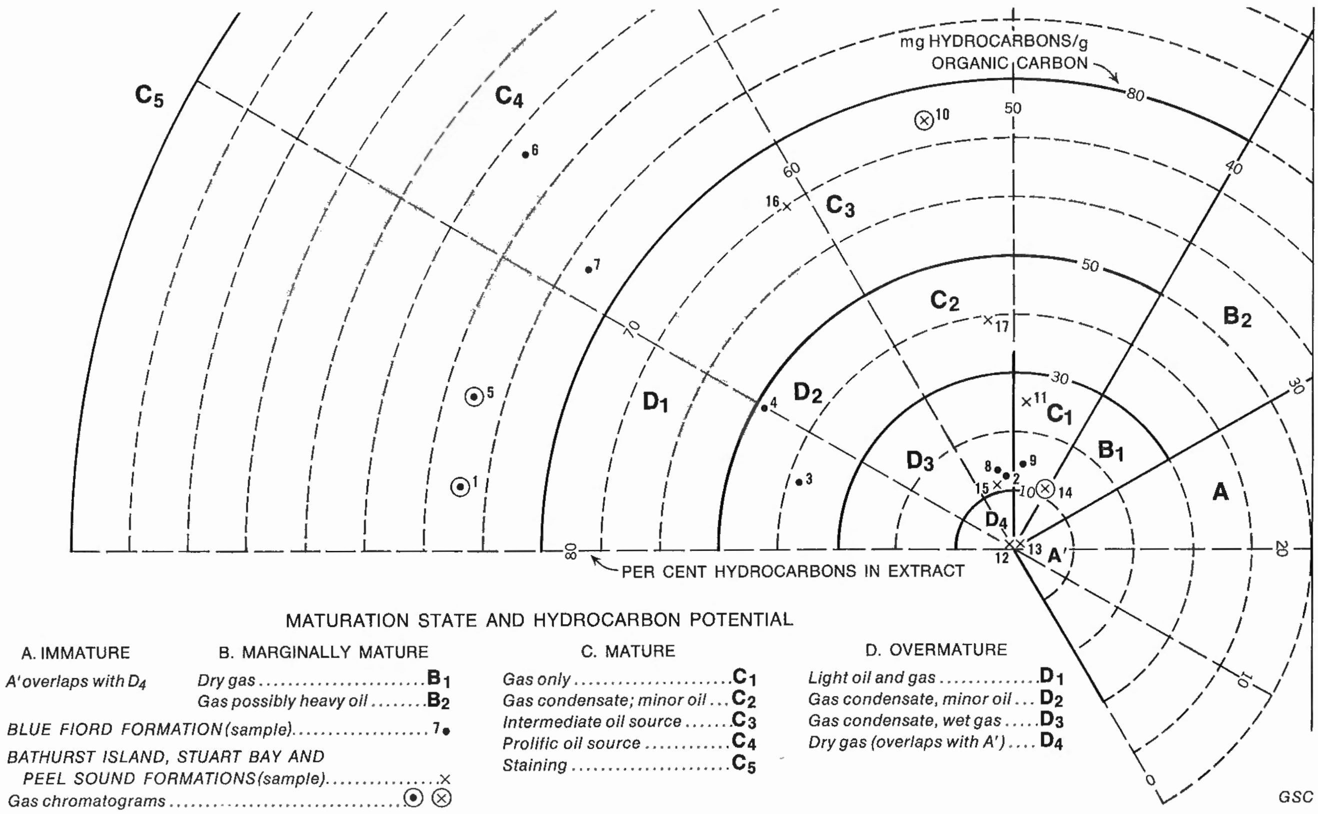


FIGURE 25. Source rock potential and gas chromatograms of the saturated hydrocarbons of the Blue Fiord, Bathurst Island, Peel Sound and Stuart Bay Formations (*see* Table 16 for sample descriptions and Fig. 5 for key)

Paleozoic strata

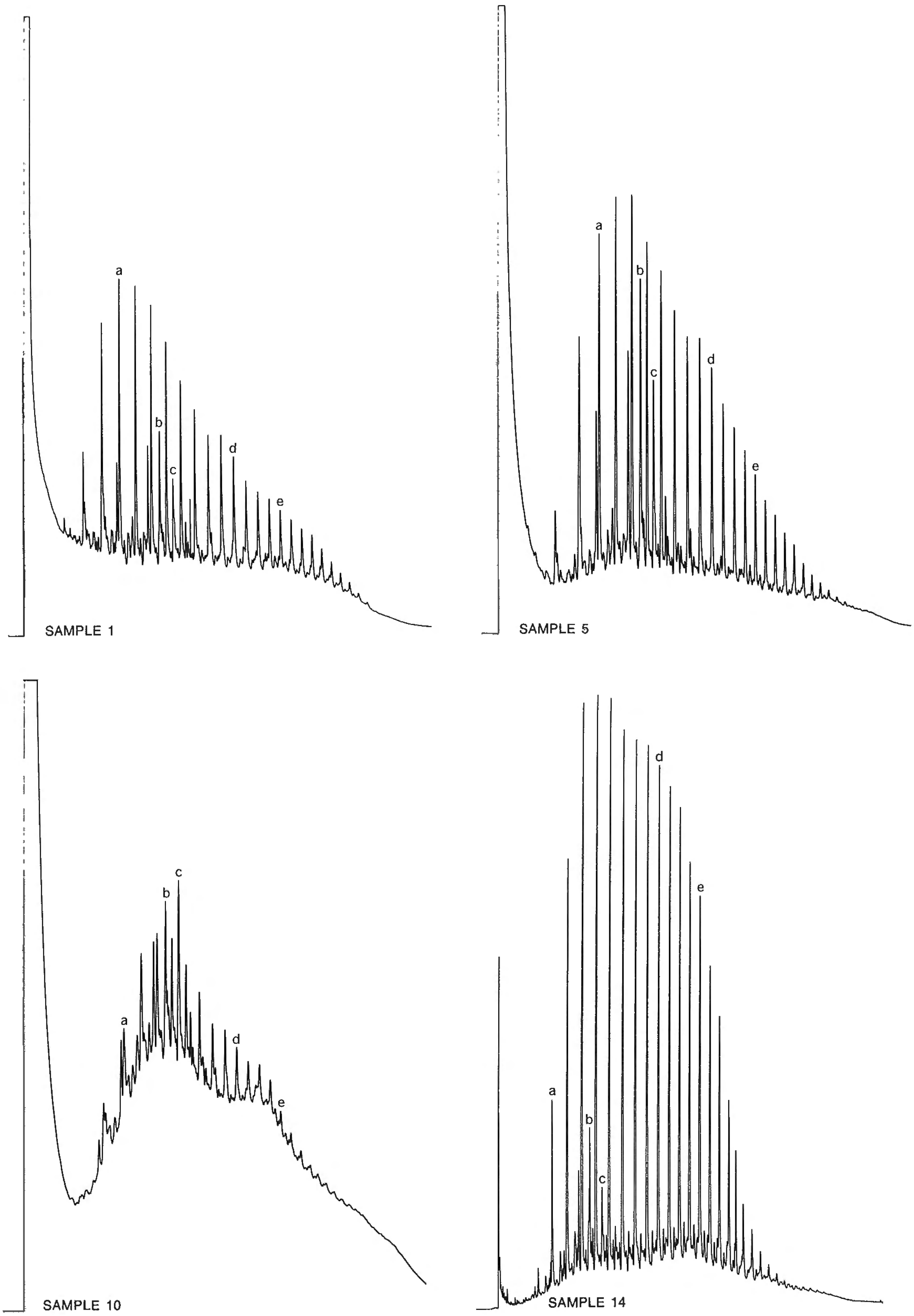
Wet gas was recorded in Paleozoic rocks in the Tiritchik M-48 and Orksut I-44 wells (Fig. 27). In both cases, the proportion of wet gas in the cuttings declined with depth. In the remaining four wells, the cuttings gas consisted entirely of methane. Spores from Paleozoic strata in the Storkerson Bay A-15, Nanuk D-76 and Uminmak H-07 wells were highly carbonized indicating the overmature zone from the standpoint of oil generation (Miall, 1976). A limited amount of extract data confirms this viewpoint (Table 19). The hydrocarbon yields are extremely low. The high proportion of wet gas in the cuttings gas in the Orksut and Tiritchik wells may indicate a potential for wet gas in the intervals 1830 to 2220 m and 910 to 1310 m, respectively. In the Orksut I-44 well, higher hydrocarbon yields were obtained from a sample from 1980 to 1993 m (Table 19) indicating that the lower part of the mature zone occurs at this depth. Miall (1976) reports that spores from 150 m above this interval are only moderately carbonized indicating that the sample came from within the mature zone. Some gas condensate could be generated between 1830 and 2150 m in this well. In contrast, the hydrocarbon yields from the Tiritchik well are low, indicating that wet gas would be the hydrocarbon product. Otherwise, only dry gas can be anticipated from the Paleozoic section in this area.

QUANTITATIVE ESTIMATES OF OIL YIELDS

SCHEI POINT FORMATION

The lateral consistency of the organic facies within the Schei Point Formation allows quantitative estimates to be made of the amount of oil that may have been generated within the Schei Point Formation. The area west of Ellef Ringnes was divided into a number of polygons (Fig. 29). The centre of each polygon was a well from which data had been obtained from the Schei Point Formation. The area of each polygon was determined using a planimeter and the thickness of the formation was determined. The mean organic carbon content for the Schei Point Formation in each well was determined from the organic carbon logs (Fig. 9). The yield of hydrocarbons per gram of organic carbon was averaged from the analyses of the Schei Point Formation in each well. A density of 0.8761 (30° API) was assumed for the hyrocarbon product; the rock density was assumed to be 2.3 and a factor of 1.3 was used to convert heavy extractable hydrocarbon to total oil yields (gasoline + heavy hydrocarbons). The total volume of oil in the Schei Point Formation was then calculated for each polygon in which the organic matter was considered to be mature or marginally mature (Table 20).

FIGURE 25. Continued



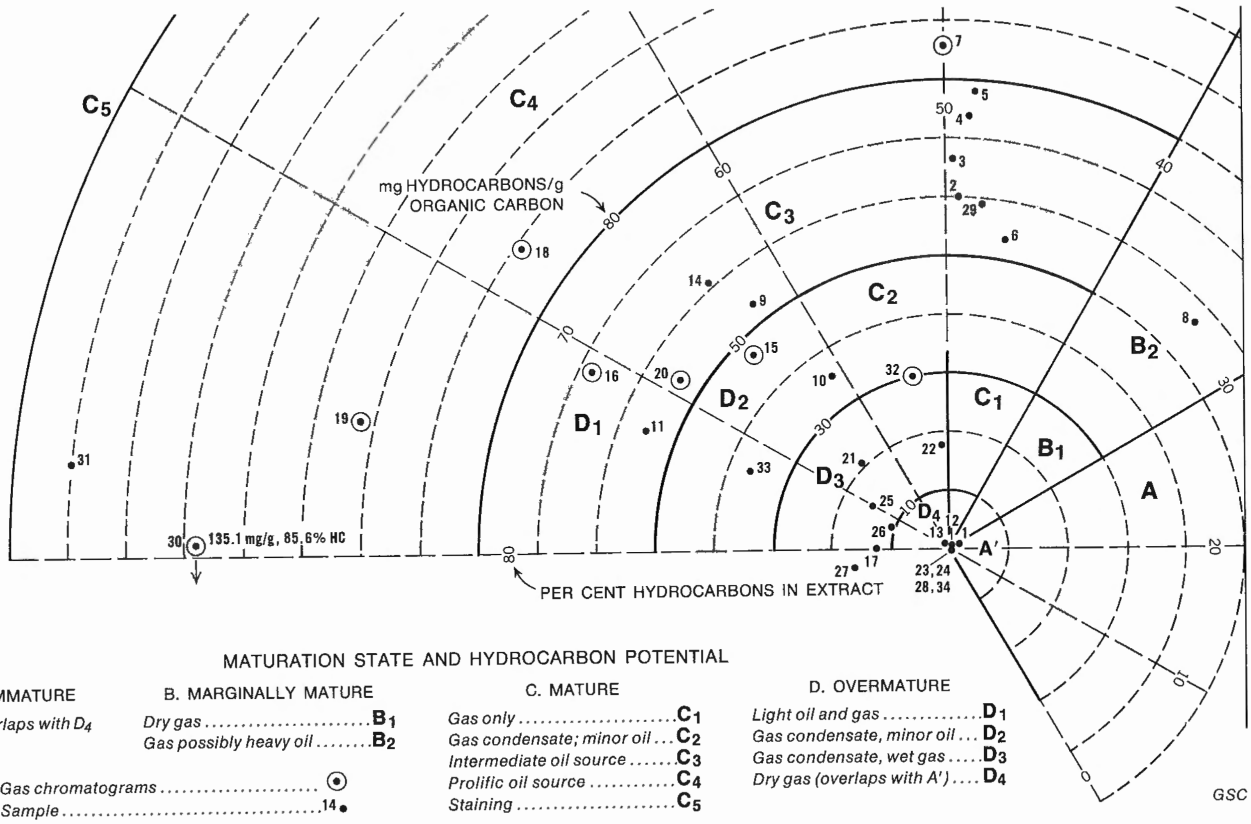


FIGURE 26. Source rock potential and gas chromatograms of the saturated hydrocarbons of the Cape Phillips, Kitson River, Read Bay and Allen Bay Formations (*see* Table 17 for sample descriptions and Fig. 5 for key)

The efficiency of migration is considered to be 8 per cent (i.e. 8% of the original in place hydrocarbons). McDowell (1975) has observed that drainage efficiencies range from 5 to 15 per cent. Similar values of 6 to 10 per cent have been obtained by Hunt (1977) for the Western Canadian Sedimentary Basin. A drainage factor of 8 per cent has been calculated for oil derived from the Phosphoria Formation (G.E. Claypool, pers. com., 1976). The amounts of oil that might have migrated out of the Schei Point Formation, assuming the total thickness of the formation was effective as a source, are given in Table 20. Since this is probably unrealistic, only 76.2 m of the formation were considered to constitute an effective source rock. As might be expected, there is a dramatic decrease in the amount of migrateable hydrocarbons (Table 20). Obviously the amount of effective source rock is a critical parameter. There are other assumptions in this procedure which can be questioned. The Schei Point Formation comprises shales, limestones and sandstones. The organic content of each of these lithofacies will vary and it is unrealistic to assume that the sandstones would be source rock. On the other hand, the organic content values were determined on samples which were collected every 15 or 9 m and the extract data were obtained on composite samples which may extend over 27 or 36 m and represent the average of the lithofacies in this interval. The drainage factors outlined above were obtained by consideration of the total section and the total volume of oil assumed to occur in reservoirs. Since oil is presumed to originate from specific source beds in a basin, the drainage factors in the effective source beds may be higher.

An alternate approach is to determine which parts of the Schei Point Formation are likely to have been source beds. Those shales or limestones which were in contact with clean sandstones were considered to be effective source rocks and data from these intervals were used in the calculations. Tissot, Espitalié, Deroo, Tempere and Jonathan (1974) have shown that the extract yield in a shale adjacent to a reservoir bed increases as a function of the distance from the reservoir bed. The depletion in the extract immediately adjacent to the reservoir bed was attributed to migration. Magara (1968) has demonstrated that shales adjacent to a reservoir rock undergo greater compaction (i.e. greater liquid loss) than shales remote from a permeable horizon. There is some evidence therefore that migration of hydrocarbons from a source rock is confined to that part of the source rock which is in communication with a permeable horizon. In the case documented by Tissot, Espitalié, Deroo, Tempere and Jonathan (1974), within 5 m of the reservoir the calculated hydrocarbon drainage efficiency is 36 per cent whereas over 20 m the drainage efficiency decreases to 13 per cent. An assumption in this calculation is that the recorded hydrocarbon yield at 14 m represents the original indigenous hydrocarbon yield of any part of the source rock prior to migration.

For the purposes of the Schei Point Formation, 18 m of shale adjacent to a sandstone are taken to represent an effective source rock. If a shale less than 36 m thick has sand both above and below, then the whole 36 m may constitute an effective source rock. A 10 per cent drainage factor was used in these cases.

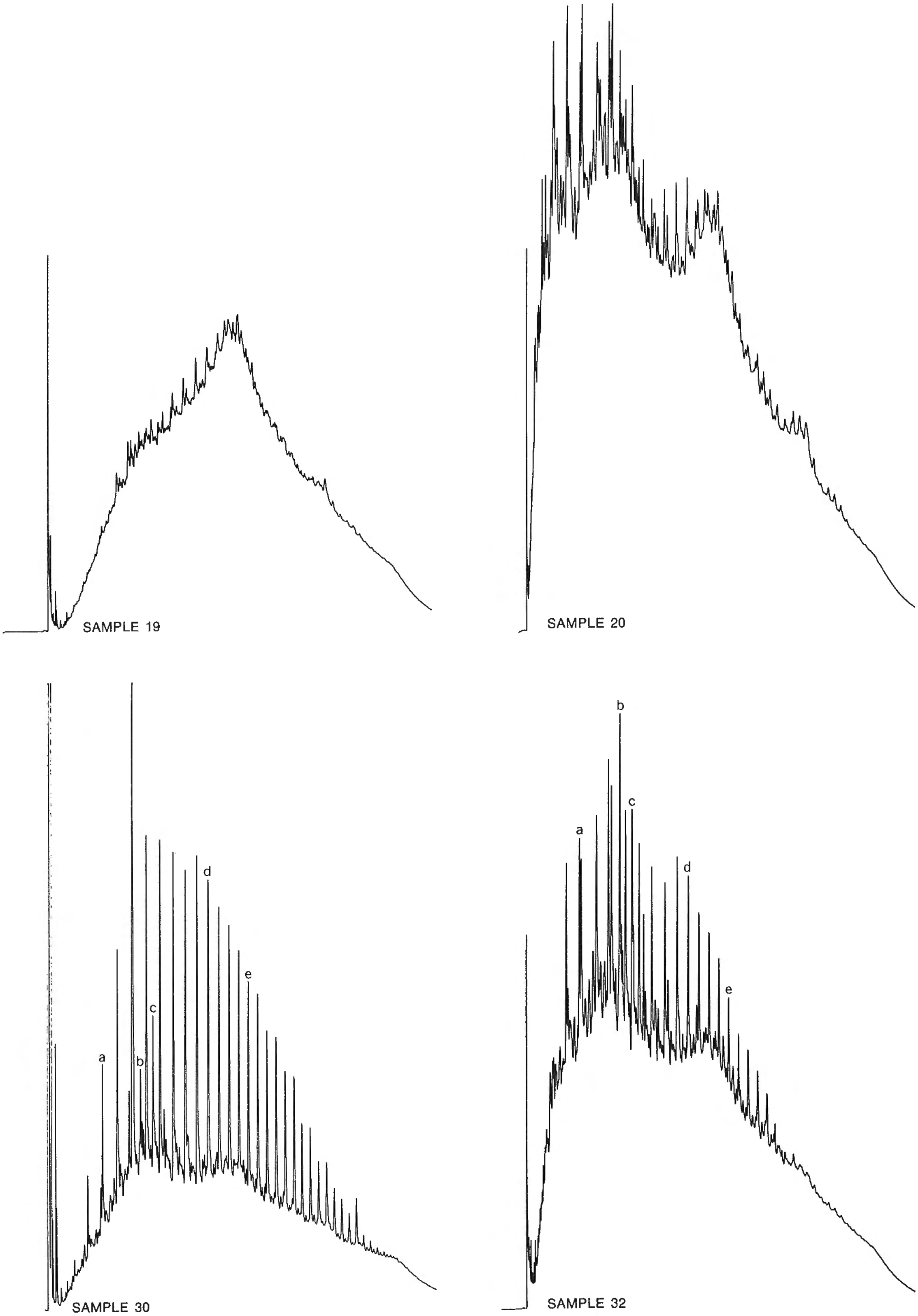


FIGURE 26. Continued

FIGURE 26. Continued

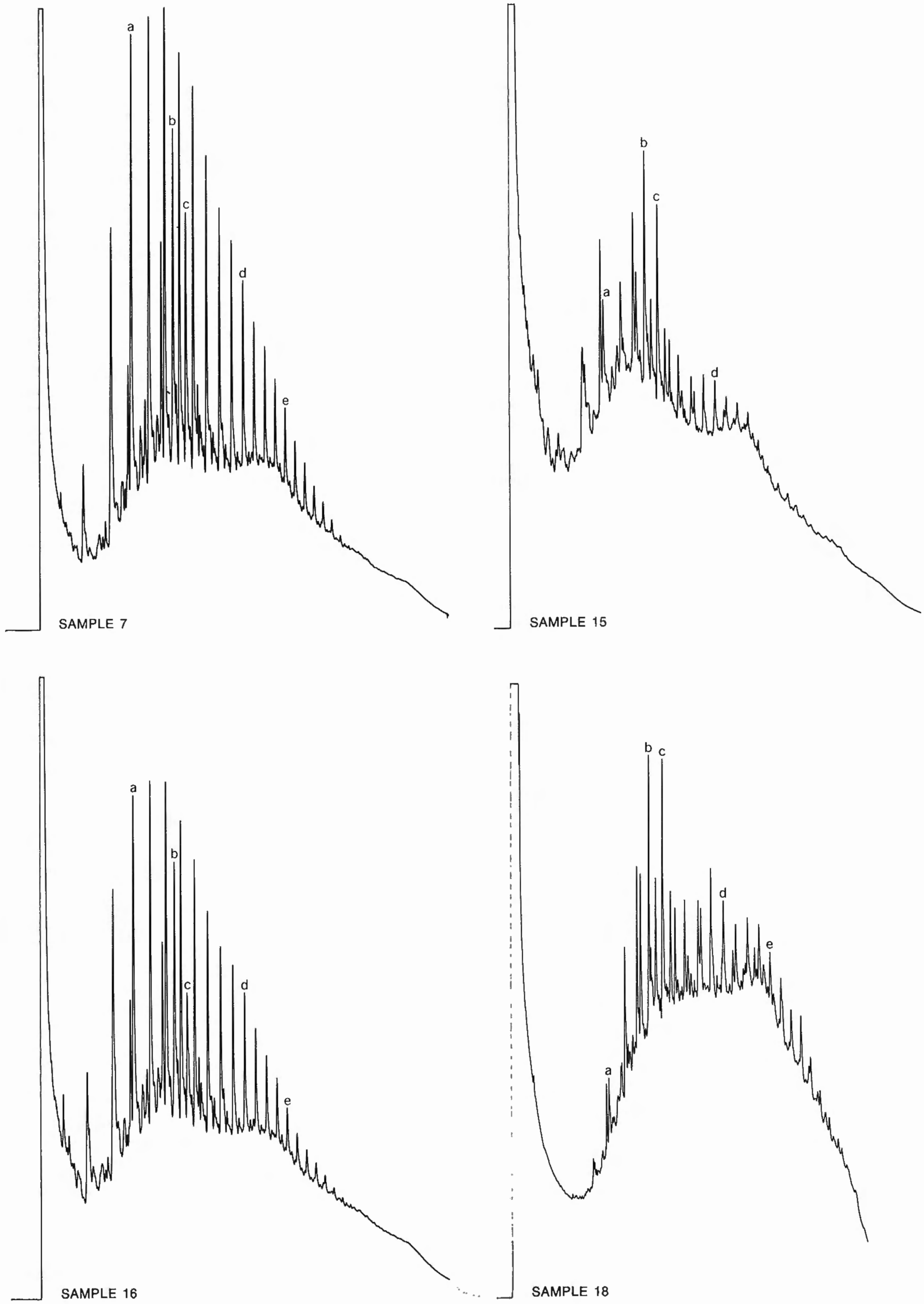


TABLE 18. Extract and kerogen data for Thumb Mountain, Bay Fiord, Copes Bay and Parrish Glacier Formations

WELL NAME	DEPTH in metres	FORMATION	LITHOFACIES	ORGANIC CARBON %	EXTRACT mg/g org. C	HYDROCARBONS mg/g org. C	HYDROCARBONS % in extract
Allison River N-12 (68)	3582	Thumb Mountain	Argillaceous limestone	0.10	-	-	
Cornwallis Central Dome K-40 (69)	860-869	Copes Bay	Limestone	0.19	127.0	86.0	54.6
	1170	Copes Bay	Limestone, sandstone	0.62	9.4	5.0	53.7
	1646-1655	Parish Glacier	Limestone, calcareous shale	0.38	25.8	13.3	51.6
	1932	Parish Glacier	Shale (calcareous)	0.10	20.3	11.1	54.7
	2250	Parish Glacier	Limestone	0.86	22.4	14.2	63.6
	2659	Parish Glacier	Limestone, shale	0.13	13.9	7.2	52.0
	3055	Parish Glacier	Shale (calcareous)	0.10	24.1	13.9	58.0
Dundas C-80 (55)	3886-3901	Thumb Mountain	Shale, calcite veins	1.75	1.7	-	-
Eids M-66 (70)	1106-1116	Thumb Mountain	Limestone, mudstone	1.36	3.0	-	-
Eldridge Bay E-79 (59)	2712-2728	Bay Fiord	Dolomite, anhydrite	0.22	44.8	30.2	67.2
	2785	Bay Fiord	Dolomite, shale	2.17	1.7	0.9	52.0
Sabine Bay A-07 (58)	2774	Bay Fiord		1.31	51.0	4.1	7.9

TABLE 19. Extract data, Banks Island

WELL NAME	DEPTH in metres	FORMATION	LITHOFACIES	ORGANIC CARBON %	EXTRACT mg/g org. C	HYDROCARBONS mg/g org. C	HYDROCARBONS % in extract
Orksut I-44	1673-1682	Wilkie Point	Shale, siltstone	2.10	34.5	9.6	27.7
	1984-1993	Orksut	Shale, trace dolomite	0.75	43.4	26.6	61.4
	2286-2295	Blue Fiord	Limestone, microcrystalline	7.27	1.5	0.8	55.0
Storkerson Bay A-15	1225-1234	Kanguk	Shale, carbonaceous	2.02	32.2	8.6	26.7
	1591-1600	Weatherall	Carbonaceous sandstone	0.89	7.0	0.8	11.3
	1819-1828	Nanuk	Shale	0.54	6.9+	3.9	56.8
Tiritchik M-48	1060-1070	Weatherall	Shale, siltstone	0.85	1.3	-	-
	1280-1289	Orksut	Bituminous shale	2.36	2.4+	1.2	49.1
	2075-2084	Blue Fiord	Dolomite	0.43	17.6+	4.0	22.7
Uminmak H-07	1353-1371	Weatherall	Carbonaceous shale	1.30	52.9	8.8	15.8

+ Contaminated sample   Location of wells *see* Figure 3b, Table 2   Numbers in brackets *see* Figures 3b, 21

If a shale unit is less than 18 m thick and has sands above and below, then a 40 per cent drainage factor was used. The volumes of migrateable oil determined by this method are also given in Table 20. The total amount of oil does not differ widely from that obtained by using an effective source rock thickness of 76.2 m and a drainage factor of 8 per cent. However, there is a significant redistribution of the amounts of migrateable oil in the different areas. Thus area C (Fig. 29) by this calculation contains most of the migrateable oil whereas in the first calculation it was area H. This change reflects the effectiveness of thin source beds which are both overlain and underlain by sandstones in the Brock C-50 well. It is evident that efficiency of migration is at a maximum where the source rock is interbedded with sandstones. It would be unrealistic to place too much value on the figures obtained by this exercise since there are many other factors which are unknown. The thickness of effective source beds is not known. Magara (1968, 1973) has suggested that mudstones adjacent to a reservoir bed may be drained of compaction fluids up to approximately 60 m from the reservoir bed. The thickness of this zone may be a function of the reservoir permeability as well as the characteristics of the source bed itself. In addition, there may be some restraint on the area of the formation which might be expected to be drained by a given reservoir unit because of constraints of permeability within the reservoir. Considerations of this type, however, do place limits on the amount of oil that might be expected to have migrated from a particular source rock.

Henao-Londoño (1977) gives values of 0.65 to 3.76 x 10^9 m^3 (4-24 billion barrels) of migrateable oil for the Schei Point/upper Blaa Mountain unit. In this study, only the Schei Point Formation has been used as a basis for calculation. If it is assumed that the Schei Point Formation represents half the area used by Henao-Londoño, then the volumes of migrateable oil obtained in this study are higher than the lower limit given by Henao-Londoño (0.5 x 10^9 m^3 versus 0.3 x 10^9 m^3) but are considerably lower than the upper limit (1.9 x 10^9 m^3).

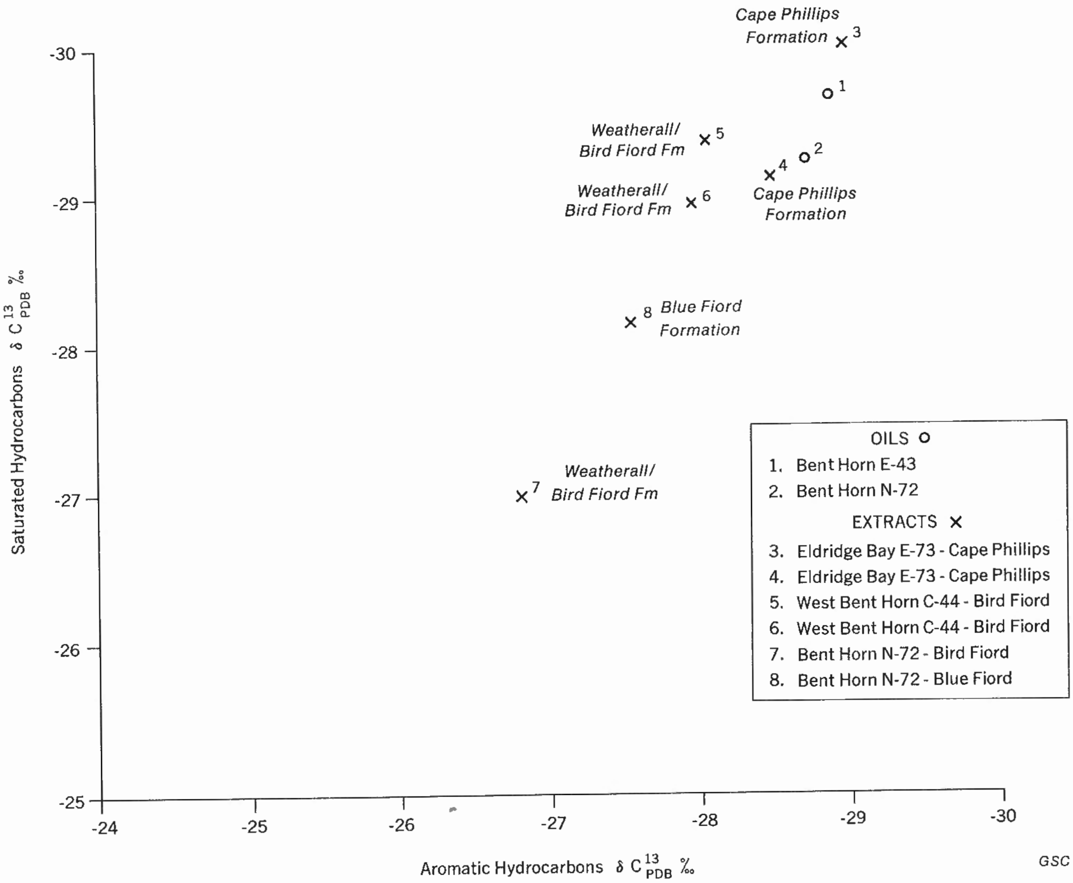


FIGURE 27. Correlation of Bent Horn oil with possible source rocks based on stable carbon isotope distribution

Weatherall and Bird Fiord Formations

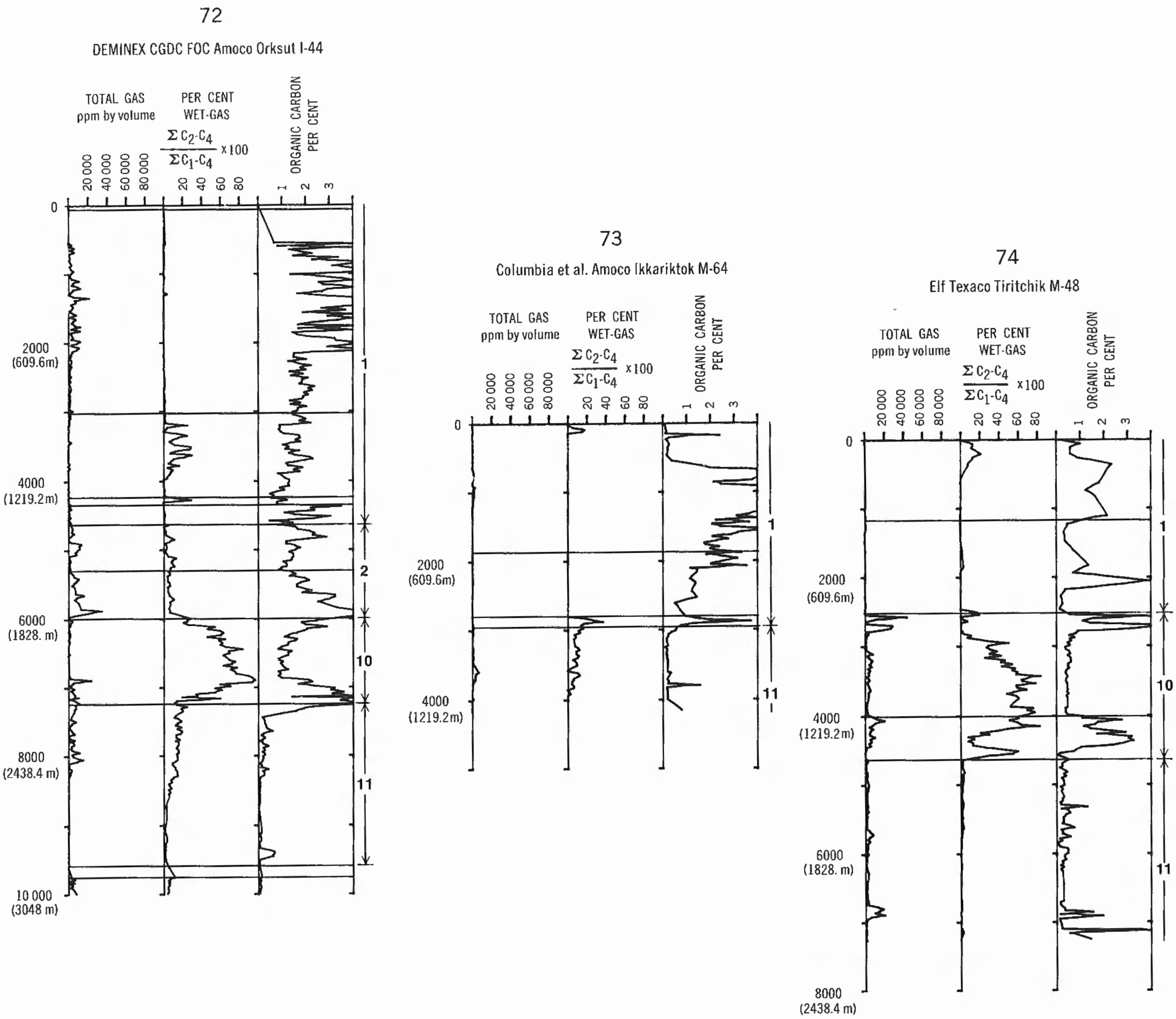
Embry and Klovan (1976) have demonstrated that the Weatherall and Bird Fiord Formations comprise repetitive upward-coarsening cycles that terminate in a thin fine-grained sandstone unit. It has already been noted that the organic matter in the Weatherall and Bird Fiord Formations contains organic matter suitable to provide a source for oil albeit in rather low concentration. If the sandstones are sufficiently permeable then the interfingering of sandstone with the source facies should provide optimum drainage of the oil. In the Bent Horn N-72 well, the Bird Fiord Formation is 790 m thick (Embry and Klovan, 1976) and consists of 83 repetitive cycles terminating in sandstones which vary in thickness from 1 to 15 m. The total sandstone thickness is over 275 m leaving a total thickness of effective source rock of 515 m. From a drainage area of 1000 km^2, 0.06 x 10^9 m^3 (0.57 billion barrels) of migrateable oil would be expected using a drainage factor of 40 per cent. The assumptions are the same as those used in the calculations for the Schei Point Formation. However, there is less uncertainty concerning the thickness of source rock to be drained because of the frequent occurrence of sandstones providing of course that each of the sandstones is an effective drainage unit. The hydrocarbon yield used was an average of all 23 analyses (Table 15) of the Bird Fiord Formation on Cameron and Vanier Islands. These include stained and non-stained samples so that the effect of prior migration has been minimized. The value of 0.06 x 10^9 m^3 of migrateable oil from a 1000 km^2 area is therefore an upper limit for the Bird Fiord Formation as found in the Bent Horn N-72 well. Farther to the west, the lower part of the Devonian clastic wedge enters the overmature zone so that gas would be the main hydrocarbon product.

TIMING OF HYDROCARBON GENERATION

SVERDRUP BASIN

Following the Ellesmerian Orogeny in Early Mississippian time, the northern part of the Franklinian Fold Belt subsided with initiation of deposition in the Sverdrup Basin. There was relatively little tectonic activity between the Ellesmerian Orogeny and the Eurekan Orogeny of Cenozoic age. The margins of the Sverdrup Basin were relatively resistant to subsidence and show incomplete sequences with many disconformities and gentle discordances for the Carboniferous to Upper Cretaceous interval. In the axial part of the basin, the sequence from Upper Carboniferous to Upper Cretaceous is essentially concordant.

In Figure 30, burial history curves are presented for the Schei Point and equivalent formations. Hydrocarbon maturity in the Schei Point Formation begins at a burial depth of 1800 m and reaches optimum levels below 3000 m. In respect of the western Sverdrup Basin, hydrocarbon generation is likely to have begun in the Early Cretaceous. The zone of maximum hydrocarbon generation would barely have been reached prior to the Eurekan Orogeny. Maximum hydrocarbon generation in the Schei Point in the deeper parts of the basin (e.g.



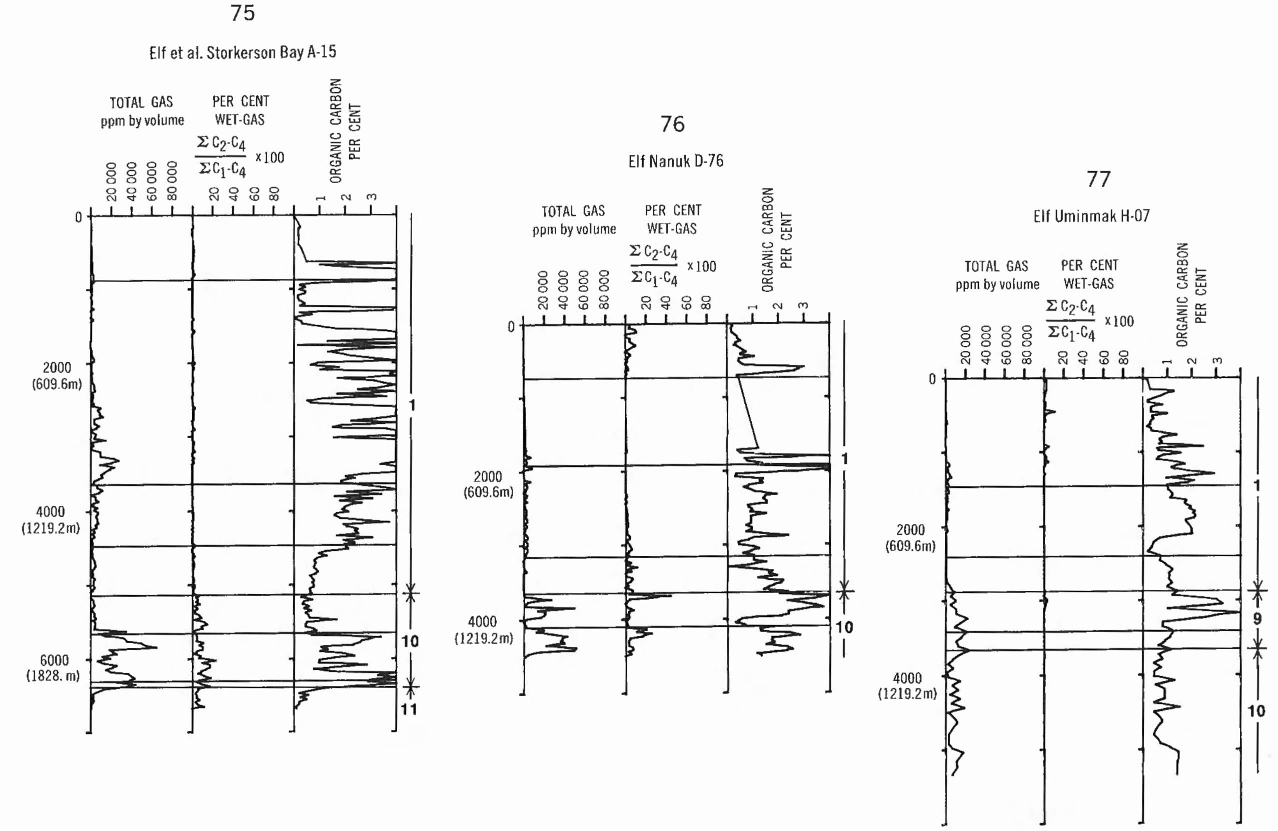
REFERENCE TO FORMATIONS

Beaufort, Eureka Sound, Kanguk, Hassel, Christoper, Isachsen 1
Deer Bay, Mould Bay, Awingak, Wilkie Point 2
Savik, Jaeger 3
Borden Island-Heiberg 4
Schei Point 5
Blaa Mountain 6
Bjorne and Blind Fiord 7
Degerbols, Trold Fiord, van Hausen, Assistance, Sabine Bay, Belcher Channel, Nansen, Hare Fiord, Canyon Fiord 8
Griper Bay, Hecla Bay 9
Bird Fiord, Weatherall, Cape de Bray, Blackley, Nanuk, Eids, Orksut 10
Blue Fiord 11
Stuart Bay, Bathurst Island, Peel Sound 12
Kitson River, Cape Phillips, Read Bay Allen Bay 13
Irene Bay, Thumb Mountain, Bay Fiord, Eleanor River, Baumann Fiord, Copes Bay 14
Parrish Glacier 15

Igneous intrusion ....

FIGURE 28. Relationship of gas and organic carbon logs to the major stratigraphic units on Banks Island (*see* Fig. 3c and Table 3 for well locations)

FIGURE 28. Continued



North Sabine area) is likely to have occurred just prior to the Eurekan Orogeny. Those structures which were being developed as a result of salt movement under loading during sedimentation are those which were ideally placed to receive migrating hydrocarbons. Structures which developed entirely during the Eurekan Orogeny would have been less favourably placed to receive hydrocarbons.

It is more difficult to determine the timing of gas generation and accumulation. The Drake and Hecla gas fields occur at relatively shallow depth and are within 600 m of the top of the marginally mature zone. Isotopic measurements of methane from the Hecla field gave a δC^{13} value of -42.5‰ P.D.B. Vitrinite reflectance levels are approximately 0.45% Ro max. In a purely marine environment, methane with isotopic values of δC^{13} -42‰ would be expected to have formed at higher maturation levels (reflectance level of ~1.0% Ro max) (Stahl and Carey, 1975). High maturation levels are found only in the Permian, some 3000 m below the level of the gas reservoirs. Methane derived from coal has a much higher isotopic value than that derived from purely marine organic matter even at low maturation levels (Stahl, 1974). Thus, the isotopic composition of the gas at Drake and Hecla is consistent with it being derived from mixed terrestrial and marine source organic matter at low levels of maturation. The immediate source would be the overlying Jurassic shale sequence and the underlying Triassic shales lying within the basin. It follows that the traps must have been formed relatively early in order to collect this relatively immature gas.

A similar carbon isotopic compostion (CH_4, δC^{13} -40.1‰ P.D.B.) was obtained for the King Christian Field. Since purely marine organic matter is not available to act as a source in the underlying formations, it follows that the source is probably mixed as in the case of the Hecla and Drake fields, although the lower carbon isotope value may indicate a higher contribution of terrestrial organic matter or a higher maturation level. The latter appears to be the case since the base of the Jurassic shale succession in the King Christian N-06 well is just fully mature (reflectance ~0.7% Ro max.). By analogy with the Drake-Hecla area, the gas in the King Christian field must have been generated and trapped at a depth of approximately 3000 m. Using Henao-Londoño's (1977) burial history curve (Fig. 30), the present author suggests that King Christian Island and the Borden Island/Heiberg reservoir (uppermost Triassic or lowermost Jurassic) could have received gas from immediately overlying and underlying shales in late Early Cretaceous time.

The carbon isotopic composition of gas from the Jackson Bay field is quite different from that in either the King Christian or Hecla fields. Two values have been obtained from differing levels within the reservoir δC^{13} -35.7‰ (DST2 Jackson Bay G-16A well) and -30.6‰ Jackson Bay G-16A well). The high δC^{13} values indicate that the gas is of late diagenetic origin (~2.0% Ro vitrinite reflectance; Stahl and Carey, 1975; Fuex, 1977). It has been noted in a previous section that the distribution of the overmature facies on Ellef Ringnes Island is governed by the distribution of sills and dykes. The occurrence of gas

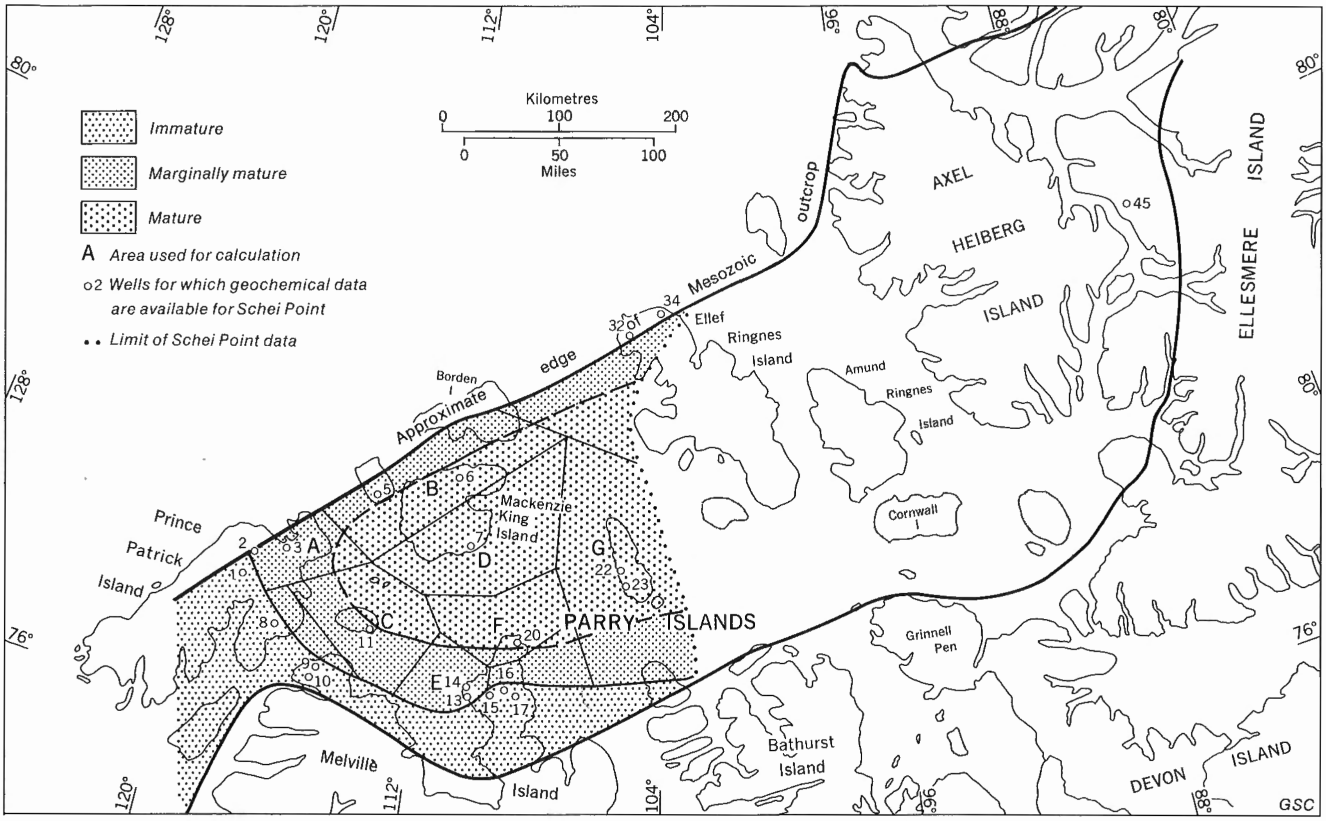


FIGURE 29. Organic metamorphic facies map for the Schei Point Formation in the western Sverdrup Basin showing areas used to calculate volumes of migratable oil (*see* Table 20). (*See* Table 1 for well names and locations)

TABLE 20. Volumes of oil in place and migrateable oil in the Schei Point source rock

Polygon (Fig. 29)	Area km^2	Schei Point Thickness m	Total Schei Point		250 feet effective source		Migrateable oil based on measured source rock and variable drainage*
			Oil in source*	Migrateable oil* 8% drainage	Oil in source*	Migrateable oil* 8% drainage	
A	3700	506	5.9	0.5	0.6	0.06	0.05
B	11 990	-493	7.7	0.6	1.2	0.10	0.20
C	8210	186	8.7	0.7	3.6	0.28	0.08
D	12 300	669	11.1	0.9	1.3	0.10	0.11
E	2800	143	0.3	0.01	0.2	0.01	0.02
F	7690	524	6.5	0.5	0.9	0.07	0.02

* Measured in billions of cubic metres

FRANKLINIAN GEOSYNCLINE

In the case of the Franklinian Geosyncline, the timing of hydrocarbon generation is more difficult to pinpoint. Since the sediments of the Devonian clastic wedge are either in the mature or overmature zone, it is reasonable to assume that maximum burial occurred in Middle to Late Devonian time. In the Parry Island Fold Belt, hydrocarbon generation in the Cape Phillips Formation probably occurred during this time. The major period of fold development was during the Ellesmerian Orogeny (Fammenian to Viséan) although some movement certainly preceded the deposition of Lower Devonian rocks (Thorsteinsson and Tozer, 1970). Hydrocarbon formation almost certainly preceded the main period of fold development. Stratigraphic traps (e.g. carbonate build-ups) are likely to be the preferred sites for hydrocarbon accumulation although subsequent epeirogenic movements may have caused secondary migration and loss of any accumulation. The timing of hydrocarbon generation in the Franklinian Geosyncline is in complete contrast to the Devonian of western Canada where hydrocarbon generation in Devonian rocks did not occur until Late Cretaceous or earliest Tertiary time (Deroo *et al.*, 1977).

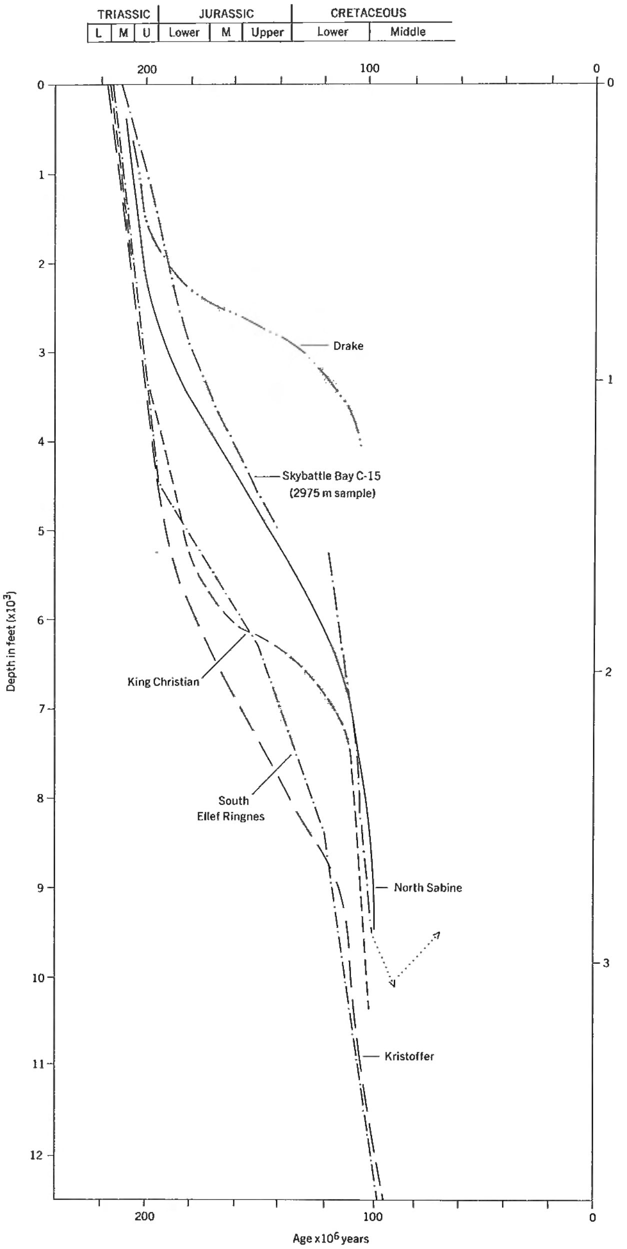


FIGURE 30. Burial history curves for the Schei Point Formation and equivalent formations. Curves from Drake, North Sabine, King Christian and Kristoffer after Henao-Londoño (1977). Curve from southern Ellef Ringnes after Sweeney (1977)

GENERAL CONCLUSIONS

Four facies of organic metamorphism have been recognized in the Sverdrup Basin; namely immature, marginally mature, mature and overmature. The onset of the marginally mature zone occurs at 1500 m maximum burial depth whereas the mature zone occurs below 3000 m maximum burial depth. Significant oil generation can be expected only below the latter depth in the Sverdrup Basin. The transition from mature to overmature occurs at approximately 4500 m maximum burial depth.

In the Sverdrup Basin, the Schei Point Formation is the only widespread source rock. It has been the source for the Melville Island tar sands and the oil shows in the vicinity of the Sabine Peninsula on Melville Island. However, it is unlikely to have been the source of large quantities of oil. A local source within the Heiberg Formation appears to have provided the oil on Thor Island. The Heiberg and Blaa Mountain Formations locally show good source rock potential. Strata of Jurassic and Cretaceous age are generally too immature for oil generation although parts of the Savik Formation can be considered as an immature potential source rock.

The gas in the Drake, Hecla and King Christian fields has been formed at low levels of maturation, probably in the marginally mature zone. The Mesozoic strata in the Sverdrup Basin are interpreted to have significant potential for gas. The gas in the Jackson Bay field is probably a product of local heating brought about by intrusion of igneous sills and dykes. The Permian strata on Melville Island have good potential for gas in the overmature facies. Migration probably occurred late in the basin history and just prior to the Eurekan Orogeny.

In the Franklinian Geosyncline, all the boreholes commence in either the mature or overmature facies. In the western part of Melville Island, the transition from mature to overmature occurs in the lower part of the Weatherall Formation. On Cameron Island, the transition lies within or below the Blue Fiord Formation. Throughout the remainder of the area, the transition occurs within the Cape Phillips or equivalent formations.

The Weatherall/Bird Fiord Formation is recognized as the source for the Bent Horn oil. However, the low organic carbon content means that its overall potential is relatively modest. Where mature, the lower Paleozoic graptolitic shale facies (Cape Phillips, Kitson River, Bathurst Island Formations) has excellent source potential for oil. Where overmature, this facies can have good gas potential. Maximum hydrocarbon generation in all prospective source rocks of the Franklinian Geosyncline probably occurred in Middle to Late Devonian time.

On Banks Island, Mesozoic and Tertiary strata are undermature, indicating no source potential. The Paleozoic rocks are generally overmature and may have some potential for dry gas.

REFERENCES

Allan, J.
1975: Natural and artificial diagenesis of macerals; Ph. D. Thesis, University of Newcastle upon Tyne, England.

Albrecht, P. and Ourisson, G.
1969: Diagenèse des hydrocarbures saturés dans une série sedimentaire épaisse (Douala Cameroun); Geochim. Cosmochim. Acta, v. 33, p. 138-142.

Albrecht, P., Vandenbroucke, M. and Mandengué, M.
1976: Geochemical studies on the organic matter from the Douala Basin (Cameroun) - I. Evolution of the extractable organic matter and the formation of petroleum; Geochim. Cosmochim. Acta, v. 40, p. 791-800.

Baker, D.A., Illich, H.A., Martin, S.J. and Landin, R.R.
1975: Hydrocarbon source potential of sediments in the Sverdrup Basin *in* Canda's Continental Margins; Can. Soc. Petrol. Geologists, Mem. 4, p. 545-556.

Balkwill, H.R.
in press: Evolution of Sverdrup Basin, Arctic Canada; Am. Assoc. Petrol. Geologist, Bull.

Blumer, M.
1957: Removal of elemental sulphur from hydrocarbon fractions; Anal. Chem., v. 29, p. 1039-1041.

Correia, M.
1971: Diagenesis of sporopollein and other comparable substances: application to hydrocarbon research *in* Sporopollein (J. Brooks, P.R. Grant, M.D. Muir, P. Van Gijzel and G. Shaw, eds); Academic Press, p. 569-620.

Deroo, G., Powell, T.G., Tissot, B. and McCrossan, R.G.
1977: The origin and migration of petroleum in the western Canadian sedimentary basin, Alberta; Geol. Surv. Can., Bull. 262.

Drummond, K.J.
1973: Canadian Arctic Island *in* Future Petroleum Provinces of Canada; Can. Soc. Petrol. Geologists, Mem. 1, p. 443-472.

Durand, B. and Espitalié, J.
1976: Geochemical studies on the organic matter from the Douala Basin (Cameroun) - II. Evolution of kerogen; Geochim. Cosmochim. Acta, v. 40, p. 801-808.

Embry, A. and Klovan, J.E.
1976: The Middle-Upper Devonian clastic wedge of the Franklin Geosyncline; Bull. Can. Soc. Petrol. Geologists, v. 24, p. 485-639.

Evans, C.R. and Staplin, F.L.
1971: Regional facies of organic metamorphism *in* Geochemical Exploration 1970 (R.W. Boyle and J.I. McGerrigle, eds); Can. Inst. Min. Metable., Spec. Vol. 11, p. 517-520.

Foscolos, A.E., Powell, T.G. and Gunther, P.R.
1976: The use of clay minerals and inorganic and organic geochemical indicators for evaluating the degree of diagenesis and oil generating potential of shales; Geochim. Cosmochim. Acta, v. 40, p. 953-966.

Fuex, N.
1977: The use of stable carbon isotope in hydrocarbon exploration; J. Geochem. Explor., v. 7, p. 155-188.

Gunther, P.R.
1976: A study employing optical methods to evaluate organic metamorphism and oil generating potential of sediments in the Mackenzie Delta area, District of Mackenzie; Geol. Surv. Can., Paper 76-IC, p. 143-152.

Heacock, R.L. and Hood, A.
1970: Process for measuring the live carbon content of organic samples; U.S. Patent 3,508,877, April 28, 1970.

Henao-Londoño, D.
1977: A preliminary geochemical evaluation of the Arctic Islands; Bull. Can. Petrol. Geol., v. 25, p. 1059-1084.

Hood, A. and Castaño, J.R.
1974: Organic metamorphism: its relationship to petroleum generation and application to studies of authigenic minerals; U.N. ESCAP, CCOP Tech. Bull. 8, p. 85-118.

Hunt, J.M.
1977: Ratio of petroleum to water during primary migration in Western Canada Basin; Bull. Am. Assoc. Petrol. Geologists, v. 61, p. 434.

Magara, K.
1978: Compaction and migration of fluids in Miocene mudstone, Nagaoka Plain; Bull. Am. Assoc. Petrol. Geologists, v. 52, p. 2466-2501.

1973: Compaction and fluid migration in Cretaceous shales of Western Canada; Geol. Surv. Can., Paper 72-18.

McDowell, A.N.
1975: What are the problems in estimating the oil potential of a basin?; Oil and Gas J., v. 73 (23), p. 85-90.

McIver, R.D.
1967: Composition of kerogen - clue to its role in the origin of petroleum; Proc. Seventh World Petrol. Congr., v. 2, p. 25-36.

Meneley, R.A., Henao, D. and Merritt, D.K.
1975: The northwest margin of the Sverdrup Basin *in* Canada's Continental Margins (C.J. Yorath, E.R. Parker and D.J. Glass, eds.); Can. Soc. Petrol. Geologists, Mem. 4, p. 531-544.

Miall, A.D.
1975: Post-Paleozoic geology of Banks, Prince Patrick and Eglinton Islands, Arctic Canada *in* Canada's Continental Margins (C.J. Yorath, E.R. Parker and D.J. Glass, eds.); Can. Soc. Petrol. Geologists, Mem. 4, p. 557-588.

1976: Proterozoic and Paleozoic geology of Banks Island, Arctic Canada; Geol. Surv. Can., Bull. 258.

Nixon, R.P.
1973: Oil source beds in Cretaceous Mowry Shale of the northwestern interior United States; Bull. Am. Assoc. Petrol. Geologists, v. 57, p. 136-161.

Philippi, G.T.
1958: Identification of oil source beds by chemical means; Proc. 20th Intern. Geol. Congr., Session III, Geology of Petroleum, p. 25-40.

1965: On the depth, time and mechanism of petroleum generation; Geochim. Cosmochim. Acta, v. 29, p. 1021-1049.

Powell, T.G., Cook, P.J. and McKirdy, D.M.
1975: Organic geochemistry of phosphorites relevance to petroleum genesis; Bull. Am. Assoc. Petrol. Geologists, v. 59, p. 618-632.

Powell, T.G., Foscolos, A.E., Gunther, P.R. and Snowdon, L.R.
in prep.: Diagenesis of organic matter and fine clay minerals: A comparative study.

Powell, T.G. and McKirdy, D.M.
1973: The effect of source material, rock type and diagenesis on the n-alkane content of sediments; Geochim. Cosmochim. Acta, v. 37, p. 623-633.

1975: Geological factors controlling crude oil composition in Australia and Papua New Guinea; Bull. Am. Assoc. Petrol. Geologists, v. 59, p. 1176-1197.

Rashid, M.A. and McAlary, J.D.
1977: Early maturation of organic matter and genesis of hydrocarbons as a result of heat from a shallow piercement salt dome; J. Geochem. Explor., v. 8, p. 549-569.

Rogers, M.A., McAlary, J.D. and Bailey, N.J.L.
1974: Significance of reservoir bitumens to thermal-maturation studies, Western Canada Basin; Bull. Am. Assoc. Petrol. Geologists, v. 58, p. 1806-1824.

Shibaoka, M., Bennet, A.J.R. and Gould, K.W.
1973: Diagenesis of organic matter and occurrence of hydrocarbons in some Australian sedimentary basins; J. Aust. Petrol. Explor. Assoc., v. 13, p. 73-80.

Snowdon, L.R.
1977: Organic geochemistry of the Upper Cretaceous/ Tertiary Delta Complexes of Beaufort-Mackenzie sedimentary basin, northern Canada; Ph. D. Thesis, Rice University, Houston, Texas.

Snowdon, L.R. and McCrossan, R.G.
1973: Identification of petroleum source rock using hydrocarbon gas and organic carbon content; Geol. Surv. Can., Paper 72-36.

Snowdon, L.R. and Peake, E.
in press: Gas chromatography of high molecular weight hydrocarbons with an inorganic salt eutectic column; Anal. Chem.

Snowdon, L.R. and Powell, T.G.
in press: N-alkane contamination of western Canadian drill cores; Bull. Can. Petrol. Geol.

Snowdon, L.R. and Roy, K.J.
1975: Regional organic metamorphism in the Mesozoic strata of the Sverdrup Basin; Bull. Can. Petrol. Geol., v. 23, p. 131-171.

Stahl, W.J.
1974: Carbon isotope fractionations in natural gases; Nature, v. 251 (5471), p. 134, 135.

Stahl, W.J. and Carey, B.D.
1975: Source rock identification by isotope analyses of natural gases from fields in the Val Verde and Delaware Basins, West Texas; Chem. Geol., v. 16, p. 257-267.

Staplin, F.L.
1969: Sedimentary organic matter, organic metamorphism and oil and gas occurrence; Bull. Can. Petrol Geol., v. 17, p. 47-66.

Stuart-Smith, J.H. and Wennekers, J.H.N.
1977: Geology and hydrocarbon discoveries of Canadian Arctic Islands; Bull. Am. Assoc. Petrol. Geologists, v. 61, p. 1-27.

Sweeney, J.F.
1977; Subsidence of the Sverdrup Basin, Canadian Arctic Islands; Bull. Geol. Soc. Am., v. 88, p. 41-48.

Teichmuller, M.
1971: Anwendung kohlenpetrographischer Methoden bei der Erdöl- und Erdgasprospektion; Erdol Kohle, v. 24, p. 69-76.

Thorsteinsson, R. and Tozer, E.T.
1970: Geology of the Arctic Archipelago *in* Geology and Economic Minerals of Canada (R.J.W. Douglas, ed.); Geol. Surv. Can., Econ. Geol. Rept. No. 1, p. 547-590.

Tissot, B., Califet-Debyser, Y., Deroo, G. and Oudin, J.L.
1971: Origin and evolution of hydrocarbons in early Toarcian shales, Paris Basin, France; Bull. Am. Assoc. Petrol. Geologists, v. 55, p. 2177-2193.

Tissot, B., Durand, B., Espitalié, J. and Combaz, A.
1974: Influence of nature and diagenesis of organic matter in formation of petroleum; Bull. Am. Assoc. Petrol. Geologists, v. 58, p. 499-506.

Tissot, B., Espitalié, J., Deroo, G., Tempere, C. and Jonathan, D.
1974: Origine et migration des hydrocarbures dans le Sahara oriental (Algerie) *in* Advances in Organic Geochemistry 1973 (B. Tissot and F. Benner, eds.); Editions Téchnip., Paris, p. 315-334.

Vandenbroucke, M., Albrecht, P. and Durand, B.
1976: Geochemical studies on the organic matter from the Douala Basin (Cameroun) - III. Comparison with the early Toarcian shales of the Paris Basin, France; Geochim. Cosmochim. Acta, v. 40, p. 1241-1250.

Vassoevich, N.G., Korchagina Yu I., Lopatin, N.V. and Chernyshev, V.V.
1969: Principal phase of oil formation; Intern. Geol. Rev., v. 12, p. 1276-1296.