Geological Survey
of Canada

Commission géologique
du Canada

ORGANIC PETROGRAPHY AND KINETICS OF LIMESTONE AND SHALE SOURCE ROCKS IN WELLS ADJACENT TO SABLE ISLAND, NOVA SCOTIA AND THE INTERPRETATION ON OIL-OIL OR OIL-SOURCE ROCK CORRELATION AND BASIN MODELLING

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SSC FILE NO. OSC93-00336-(014)
CONTRACT NO. 23420-3-C056/01-OSC
FINANCIAL CODE:230 120 00000720104 04B9

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JANUARY 31, 1994

OPEN FILE NO. 3167

Natural Resources
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ABSTRACT

This report compared the hydrocarbon potential and maturity of fifty limestone (and calcareous shale) and fifty composite shale units based on organic facies, which uses maceral composition, fluorescence and oxidation criteria of macerals and minerals, hydrogen and oxygen indices (from Rock-Eval pyrolysis), and maturity (based on vitrinite reflectance).
Volumetrically, the comparable source rock potential of Limestone and calcareous shale are: 6% oil- and condensate-prone Kerogen Type IIA-IIB; 42% condensate- and gas-prone Kerogen Type IIB; 34% gas-prone Kerogen Type III; and 18% nonsource Kerogen Type IV. For Composite shale the potentials are: 20% oil- and condensate-prone Kerogen Type IIA-IIB; 40% condensate- and gas-prone Kerogen Type IIB; 40% gas-prone Kerogen Type III; and none of them are considered as nonsource for hydrocarbons.

The activation energy and Arrhenius Constant of Kerogen Type IIA-IIB source rock (N. Truimph B-52) suggest that 80% of the source rock is converted to oil and gas before a maturity of 0.8% R_o. On the other hand, Kerogen Type III source rock (Venture B-52) yields only 30-40% conversion at that maturity level. Activation energy distribution and Arrhenius Constant of two limestone source rocks indicate hydrocarbon generation at a late stage of maturity (0.9 to 1.1% R_o).

Based on aromatic GC-MS, the majority of petroleums and rock extracts in this study are at advanced levels of thermal maturity (middle to late oil window), as evidenced by the distribution of methylphenanthrene, dimethylphenanthrene, trimethylnaphthalene and tetramethylnaphthalene isomers. This is not surprising, given the great burial depth (4 to 6 km) of many of the samples.

Multiple linear regression and subsequent cluster analysis reveals a closely related family of oils ("Group A") including those from N. Triumph B-52, S. Venture O-59 (DST 10), Glenelg, Olympia, Thebaud, Penobscot, Bluenose, Arcadia, Venture H-22, Citnalta and Banquereau, all produced from Missisauga or Mic Mac reservoirs. The Cohasset oils form a second group and the Panuke oils do not seem to be related to each other or to any other oil. A group of rock extracts ("Cluster 1") from the lower and middle members of the Missisauga, along with the Penobscot Limestone and Cree Member samples, correlate well with each other, indicating similar organic facies. These samples also have reasonable affinities for the Group A oils, with

the Lower Missisauga samples from the Abenaki and S. Desbarres wells appearing to be the best candidate source rocks. A second cluster of extracts, including samples from the Verrill Canyon and Missisauga Formations are related to one another, but correlate neither with Group A oils nor Cluster 1 extracts.

To supplement the cluster analysis, a parameter related to the sulfur content of the samples (the ratio of the sum of C_2-alkyldibenzothiophenes to the sum of the C_2-alkylphenanthrenes) was established. It supports the statistical findings, further indicating that the oils and Cluster 1 extracts have a similarly low thiophenic sulfur content, in contrast to the relatively high sulfur Cluster 2 and unclassified extracts. Samples richer in sulfur derive from marine rocks, while the remainder are apparently of non-marine origin, a conclusion supported by the organic petrologic and stratigraphic data.

1-D basin modeling of two key wells (Abenaki J-56, carbonate-rich; W. Chebucto K-20, clastic-rich) showed that in W. Chebucto K-20 source rocks generated and migrated cummulative hydrocarbons five times more than Abenaki J-56 source rocks. Major hydrocarbons (both oil and gas) have been generated and expelled between 137 and 50 mybp from the Mississauga source rocks in the W. Chebucto K-20 well. Non-expelled oils in deeper source rocks have been cracked to gas and residue.

INTRODUCTION

Administrative Aspect

This research proposal was requested by Supply and Services Canada, Dartmouth, Nova Scotia at the initiation of the Basin Analysis Subdivision of the Atlantic Geoscience Centre, Geological Survey of Canada, Bedford Institute of Oceanography. Global Geoenergy Research Ltd. of Halifax, Nova Scotia, submitted a financial and work schedule for the research proposal The proposal was accepted and the research work was started July 8, 1993. Canada Nova Scotia Offshore Petroleum Board (CNSOPB), Halifax, Nova Scotia, on our request, permitted us to collect four crude oil and condensate samples and 100 unwashed cuttings samples from selected Scotian Shelf wells at the CNSOPB Repository, Dartmouth, Nova Scotia. According to the contract, Rock-Eval pyrolysis of the 100 samples was done at the ISPG Laboratory at Calgary, Alberta, and kerogen isolation, smear slide preparation, kerogen plug preparation were done at the palynology and coal laboratory at the AGC, Dartmouth, N. S. Bitumen extraction and liquid chromatography of 4 oil and 3 source rock samples was subcontracted to to Dr. Michael Kruge, Southern Illinois University, Carbondale, Illinois, USA who also did special aromatic GC-MS analyses. Kinetic analysis of four source rock samples were subcontracted to Dan Jarvie, Humble Geochemical Services, Humble, Texas.

Scientific Aspect

During the past twenty years, significant gas and associated condensate or light oil were discovered in the Jurassic-Cretaceous reservoirs around the Sable Subbasin of the Scotian Basin. The major issues on hydrocarbon generation, migration, and entrapment, which still remained unsolved included: (a) the source rock types in various stratigraphic intervals; (b) regional maturity variation for both source rocks and crude oils and condensates; (c) the relation between hydrocarbon generation and overpressuring; and (d) possible oil-oil and oil-condensate-source rock correlation.

Since 1988, Basin Analysis Subdivision of the Atlantic Geoscience Centre of the Geological Survey of Canada, Dartmouth, Nova Scotia initiated systematic research projects to characterize and resolve these problems. These studies (as done by Global Geoenergy Research Ltd.) characterized some of the source rocks in various stratigraphic intervals and characterized the geochemical properties of some selected oils and condensates, possible oil-oil or oil-source rock correlation, and quantified the timing and anount of hydrocarbon generation from various source rock intervals using BASIN-MOD program (Mukhopadhyay, 1989; Mukhopadhyay and Wade, 1990; Mukhopadhyay, 1990a; Mukhopadhyay, 1990b; Mukhopadhyay, 1991, Mukhopadhyay, 1993). Mukhopadhyay (1991) from from the extensive organic petrography and Rock-Eval analyses established the proportion of oil-, condensate-, and gas-prone source rocks in the various stratigraphic sequences. Mukhopadhyay (1991, 1990b, 1993) using the data from Kruge (1990, 1991, 1993) on the aromatic biomarkers and pyrolysis-gas chromatography of the asphaltene fractions of source rock extract or oils and isotope analyses indicated possible correlation of oil-oil and oil-source rock pairs. Accordingly, Mukhopadhyay (1991, 1993) indicated that the various crude oils or condensates may have been derived from three types of source rocks.

In the Scotian Basin, source rock studies during 1989-1993 were determined mainly in selected clastic rock intervals. Carbonates and evaporites may also be a source rock for liquid hydrocarbons as seen in the Gulf Coast and various basins of the Middle East (Palacas, 1984). The geochemically unique Cohasset/Panuke/Balmoral oil discoveries are in close proximity to the Abenaki carbonate bank. This stratigraphic unit was not studied earlier as a possible source rock for this oil. Moreover, kinetics analysis suggests a diversity in kinetics properties in various source rocks intervals (Mukhopadhyay, 1993). Another sysmatic study on kinetics analyses from more samples is extremely important to achieve a mass balance and timing of hydrocarbon generation and expulsion. In order to establish a mass balance between hydrocarbon generation, expelled oil and reservoired petroleum, it is pertinent to compile a source rock characterization on the composite shale and limestone units which have already been indicated as good sources for liquid and gaseous hydrocarbons. Basin modeling studies from some additional wells may contribute to the mass balance of oil and gas generation and migration within the Scotian Basin. Considering all those ansanswered questions, this research project was initiated by AGC.

The objectives of this study are: (a) to evaluate the Abenaki Formation limestone and calcareous shale as a source rock for the Cohasset - Panuke or any other oils; (b) to evaluate the kerogen type and hydrocarbon potential of composite shale sections from the Lower Cretaceous and Jurassic sequences of the Scotian Basin; (c) to determine the activation energies and frequency factors of some selected samples; (d) to use various aromatic biomarkers and their ratios from more petroleum and source rock samples to determine the level of maturity and oil-oil or oil-source rock correlation; and (e) to evaluate mass balance of hydrocarbon generation of source rocks and reservoired petroleum by using numerical basin modeling (by BASIN-MOD™ of Platt River Associates, 1992), similar to the work done by Mukhopadhyay (1993) and Mukhopadhyay et al., (in press).

SAMPLES AND ANALYTICAL PROCEDURES

Samples

Fifty limestone and calcareous shale samples from the Abenaki Formation were chosen for Rock-Eval pyrolysis, organic facies, and source rock potential. Those samples are selected from the following wells: Abenaki J-56 (10,700-14,450'), Cohasset D-42 (10,000-14,525'), Cohasset L-97 (3100-4900 m), Demoscota G-43 (11,400-15,300'), Penobscot L-30 (11,200-

14,000'), Uniacke G-72 (4200-5745 m).

Similarly, fifty composite shale samples from the Logan Canyon, Missisauga, Verrill Canyon and Mic Mac Formations were chosen from the following wells for Rock-Eval pyrolysis, maceral analysis, and vitrinite reflectance: Alma F-67 (3945-4890 m), Chebucto K-90 (2450-5090 m), Glenelg J-48 (2850-5025 m), N. Truimph B-52 (2660-3715 m), N. Truimph G-43 (2660-4755 m), S. Desbarres O-76 (2345-5705 m), Venture B-43 (5310-5475 m), Venture B-52 (2310-5960 m), Venture H-22 (3860-4710 m), and W. Chebucto K-20 (2770-5000 m).

Kinetics analysis by Rock-Eval pyrolysis methods using Rock-Eval 5 on two selected composite shale (N. Truimph B-52, 3560-3715 m and Venture B-52, 3680-3740 m) and two Abenaki Formation calcareous shale limestone (Abenaki J-56, 10090-10130' and Demoscota G-43, 11840-11880') were done using the methods as described by Mukhopadhyay (1993).

Four light oil/condensate samples (Balmoral M-32, DST 3, Panuke PP3 J-99, DST 1, Uniacke G-72, DST 6, Venture H-22, DST 7) and three limestone source rock sample (Abenaki J-56, 10090-10130'; Demoscota G-43, 11840-11880'; and Penobscot L-30, 13810-13840') were selected for maturity determination and oil-oil or oil-source rock correlation, using aromatic biomarkers in GC-MS.

Analytical Procedures

For the determination of kerogen type by organic petrography, three types of sample preparation were used: kerogen smear slide, whole rock polished pellet, and kerogen polished pellet. We used incident and transmitted white and blue light excitation. The terminologies used for maceral composition and kerogen type determination are from Stach et al. (1982), Mukhopadhyay et al., (1985), Senftle et al., (1987), Teichmuller (1986), Hutton, (1987), and Mukhopadhyay (1989). Details on source-rock characterization using organic facies are shown in Mukhopadhyay and Wade (1990).

Vitrinite reflectance was measured using both whole rock and kerogen pellets and Zeiss Axioskop with MPM 21 Controller for MPM 03 Photomultiplier. Except for samples from W. Chebucto K-20, vitrinite reflectance on other samples were measured by M. P. Avery of the Atlantic Geoscience Centre. Rock-Eval pyrolysis was carried out on selected washed cuttings, washed/hand-picked cuttings, and from the conventional cores using the Rock-Eval II equipment. For details of Rock-Eval instrumentation and evaluation of various parameters, see Espitalie et al. (1985).

Bitumen extraction was performed using Soxhlet for 24 hours with dichloromethane. Liquid chromatography was done using an open column packed with activated silica, eluting saturate, aromatic and two polar fractions with *n*-hexane, 9:1 *n*-hexane:CH_2Cl_2, CH_2Cl_2, and 1:1 methanol:CH_2Cl_2, respectively.

For analytical procedures for kinetic analysis, see Mukhopadhyay (1993). Basin modeling was done using the BASIN-MOD package provided at the AGC. For details on BASIN-MOD program, see Mukhopadhyay (1993).

For analytical methods using aromatic biomarker GC-MS, see the chapter on oil-oil or oil-source rock correlation chapter.

SOURCE ROCK CHARACTERIZATION

Rock-Eval Pyrolysis

Table 1A illustrates the data of various Rock-Eval pyrolysis parameters (S_1, S_2, S_1+S_2, S_3, PI, HI, OI, T_{max}, and TOC) for whole rock and isolated kerogens from 50 limestone and calcareous shale samples. The total organic carbon of the whole rock limestone and calcareous shale samples varies between 0.06 (Cohasset D-42) to 2.39% (Abenaki J-56). Some samples from Uniacke G-72 well which have >8% TOC, are considered as contaminated with drilling additives, which is based on organic petrographic study. Except for a few samples from both Cohasset wells, most samples have >0.3% TOC (minimum threshold for potential source rock for liquid hydrocarbons; Tissot and Welte, 1984). Abenaki J-56 and Penobscot L-30 samples, on an average, have more than 0.7% TOC. High TOC content of the isolated kerogens suggest better separation of mineral matter of limestone and calcareous shale to isolate kerogen. The total organic carbon content of all composite shales is >0.5% and most samples from Alma F-67, N. Truimph B-52/G-43 and S. Desbarres O-76 have TOC >1.0% (Table 1B).

Considering the depth and total organic carbon content of the samples, the amount of S_1 (thermal extraction below 300°C) fraction in most limestone samples, is considered as extremely high (Table 1A)(Tissot and Welte, 1984). Anomalously high S_1 content may be caused by: (a)contamination from drilling mud additives, especially hydrocarbons; (b) early generation of hydrocarbons; and (c) soaking of allochthonous bitumen or migrated petroleum. At this stage, it is difficult to predict the cause of this anomaly. The S_1 and PI of all composite shale samples were also found to be anomalously high (Table 1B).

Except for a few samples from Abenaki J-56 well, the S_2 fraction of most samples have <1 mg HC/g of rock suggesting extremely low potential for crude oil (Table 1A). The low S_2 can also be caused by the retention of liquid hydrocarbons (derived from cracking of kerogen) within the mineral matrix (Espitalie et al., 1985; Mukhopadhyay, 1989 and references therein). The high S_2 values of the isolated kerogens also support the idea. Samples from Alma F-67, N. Truimph B-52 and G-43, and S. Desbarres O-76 have significantly high S_2 content in the composite shale units suggesting presence of abundant potential oil-prone source rocks compared to limestone and calcareous shale samples.

Except in the Penobscot L-30 and Abenaki J-56 wells, T_{max} (maturation parameter) values in both limestone and composite shale samples do not show any increasing trend with increasing depth of the samples. The suppression of T_{max} may be caused by the anomalously high S_1 (free hydrocarbons) content of the samples.

Plots of HI vs. OI and HI vs. T_{max} (Tissot and Welte, 1984; Espitalie et al., 1985) show the maturation path of Kerogen Types I, II, III, and IV (Figs. 1A through 1C) and Kerogen Types I, II, and III (Figs. 2A through 2C). Figures 1A and 1B or 2A and 2B show comparable data for the whole rock and kerogen concentrate of the limestone and calcareous shale samples. Figures 1C and 2C show the plot of the composite shale whole rock samples. Comparing Fig. 1A and 1B, about 50% of the samples are falling within the Kerogen Types II and III, whereas a vast majority of kerogen concentrate samples lie on the Kerogen Type I and II path. The grouping of kerogen samples within Kerogen Type I and II are due to selective removal of oxygen-functional groups during the kerogen isolation procedure. Comparing Figs. 2A and 2B, a vast majority of whole rock samples are below Kerogen Type III, whereas most kerogen samples are within Kerogen Types II and III or close to Kerogen Type III suggesting a mineral matrix effect, Mukhopadhyay, 1989). A majority of the composite shale whole rock samples, however, lie within Kerogen Type II and III maturation path (Figs. 1C and 2C).

Maturation Based on Vitrinite Reflectance

Vitrinite reflectance data (Tables 1A and 1B) of limestone samples suggest that all samples are considered as mature (between 0.5 to 1.3% R_o) to overmature (>1.4% R_o). In most cases, vitrinite reflectance values increase with the depth of the sediment. The vitrinite reflectance values in the deeper sediments, in most cases, do not correlate with the T_{max} values which are possibly caused by bitumen absorption within the whole rock matrix. In Penobscot L-30, however, the increase in vitrinite reflectance (0.61 to 1.02% R_o) correlates well with T_{max} values (439 to 452°C). In the composite shale samples, the maturity follows the stratigraphic depth. The lowest maturity (0.44% R_o) is observed at N. Truimph B-52 at 2860-3115 m, whereas the highest maturity is in S. Desbarres O-76 at 5590-5715 m (1.78% R_o).

Organic Facies and Source Rock Potential

The overwhelming majority of the limestone and calcareous shale samples have abundant refractory macerals (fusinite, semifusinite, clustered micrinite, inertinitized algae, and inertodetrinite) indicating oxidation at the depositional interface (Table 2A). Those samples also contain other terrestrial macerals like vitrinite, exinite (resinite, sporinite etc.,) and AOM 3. This suggest a terrestrial influx within the Abenaki carbonate platform. However, there is also abundant algal derived organic matter (telalginite, lamalginite, exinite [algal spore], AOM 2). The algal organic matter is mostly oxidized and has lost its fluorescence. Within the exinite group, oxidized algal spore are common (example: Demoscota G-43, 11840'). As a result, most limestones and calcareous shale samples formed either Kerogen Types III or IIB. Based on organic facies, only a few samples from Abenaki J-56 well can be considered as Kerogen Type IIA-IIB having fluorescent lamalginite and AOM 2. On the other hand, composite shale samples from Alma F-67, N. Truimph B-52 or G-43, and W. Chebucto K-20 contain more marine macerals (lamalginite, telalginite, and AOM 2) which have higher fluorescence than most limestone samples (Table 2B).

Volumetrically, the comparable source rock potential between limestone and composite shale samples can be illustrated as follows:

<u>Limestone and calcareous shale</u>: 6% are oil- and condensate-prone Kerogen Type IIA-IIB; 42% are condensate- and gas-prone Kerogen Type IIB; 34% are gas-prone Kerogen Type III; and 18% are nonsource Kerogen Type IV.

<u>Composite shale</u>: 20% are oil- and condensate-prone Kerogen Type IIA-IIB; 40% condensate- and gas-prone Kerogen Type IIB; 40% are gas-prone Kerogen Type III. None of the shale samples are considered as nonsource for hydrocarbons.

KINETIC PROPERTIES OF SELECTED SOURCE ROCKS

Table 3 shows the activation energy distribution related to the percentages of hydrocarbon generated and their corresponding Arrhenius Constant from the selected four source rock samples. N. Truimph B-52 (Kerogen Type IIA-IIB) sample is similar to the N. Truimph G-43 sample which was analyzed in 1993 (Mukhopadhyay, 1993). The limestone samples from Abenaki and Demascota show extremely slow reaction rates. More than 80% of the hydrocarbons from those two samples are converted between 49 and 52 kcal/mole, whereas 80% of the hydrocarbons in the N. Truimph B-52 sample are converted below 47 kcal/mole. The kinetic data of the Kerogen Type III source rock from Venture B-52 are similar to the default values for Kerogen Type III in the BASIN-MOD program. The activation energies and Arrhenius Constant values of these samples are comparable to kinetics data of Monterrey, Phosphoria, Alum and Woodford shales determined by Hunt et al. (1991) using hydrous pyrolysis. Accordingly, the reaction rates for hydrocarbon generation from N. Truimph B-52 sample are considered as medium-fast (similar to Phosphoria Shale) and limestone samples are slow. These values are also different from the default values of Kerogen Type II used in the BASIN-MOD program.

Figures 3b, 3c, 3d and 3e show the distribution of activation energies when plotted against % HC conversion for Abenaki J-56, Demoscota G-43, N. Truimph B-52, and Venture B-52 wells, respectively. Figure 3d (N. Truimph B-52, Kerogen Type IIA-IIB) shows smooth peaks of activation energy around 44 and 48 kcal/mole. In contrast to that Venture B-52 (kerogen Type III) sample shows a sharp peak of activation energy between 46 and 50 kcal/mole (Fig. 3e). Neither of them are comparable to the standard Kerogen Type I Green River Shale (Fig. 3a). Both Abenaki J-56 and Demoscota G-43 limestone samples show sharp peaks of activation energies between 50 and 52 kcal/mole (Figs. 3b and 3c). They show some similarity of activation energy distributions of Green River Shale. This possibly suggests an algal affinity for those samples.

OIL-SOURCE ROCK CORRELATION AND MATURITY DETERMINATION USING AROMATIC MOLECULAR MARKERS

In the last two decades, great advances have been made in the application of biological marker compounds to the determination of maturation and organic facies of sedimentary organic matter.

However, these compounds, generally polycyclic alkanes, cannot always present a complete picture. For example, maturation indicators based on the saturate hydrocarbons are ineffective in samples at mid to late oil window maturity levels.

The aromatic fractions in fossil fuels provide many additional clues. A wide variety of polyaromatic compounds have been documented in fossil fuels (Later *et al.*, 1981; White and Lee, 1980; Whitehurst *et al.*, 1982; Radke *et al.*, 1984b; Villar *et al.*, 1988; Rowland *et al.*, 1984). Distributions of these compounds have been shown to be sensitive to maturation (Alexander *et al.*, 1983; 1986, Radke,1987; 1988; Radke *et al.*, 1980; 1982a; 1982b; 1984a; 1986, Garrigues *et al.*, 1988, Budzinski *et al.*, 1991; 1993a). In particular, the Methylphenanthrene Index (MPI) of Radke and Welte (1983) has been proven useful in maturity assessment, particularly in the middle to late oil window range. Recently, Kruge and others (1989; 1990a; 1990b, 1992) have documented the maturation and organofacies sensitivity of a series of polyaromatic molecular markers in marine shale extracts, coal extracts and coal pyrolyzates.

Aromatic fractions of 39 Scotian Shelf oils, condensates and rock extracts were analyzed by gas chromatography/mass spectrometry (GC/MS) to determine levels of thermal maturation and to correlate the petroleums with one another and with candidate source rocks.

Analytical Methods

Aromatic fractions of 17 petroleums (oils and condensates) and 15 extracts of candidate source rocks (Table 4) were analyzed by a Hewlett Packard 5890A gas chromatograph, coupled to an HP 5970B Mass Selective Detector. The GC was held initially at 100° C for 10 min., then raised to 300° at 3°/min., where it was held for 5 minutes. A 25 m OV-1 column with 0.2 mm inside diameter and 0.33 mm film thickness was employed. The mass spectrometer was run in selective ion monitoring mode, collecting data on the following ions: m/z 91, 156, 162, 168, 169, 170, 176, 182, 184, 192, 196, 198, 202, 206, 212, 216, 220, 228, 230, 231, 242, 252, 253, 256, 268, 282, 296 and 310, which are either the molecular ions of the most common polyaromatic compounds or are principal fragment ions of aromatized biomarkers, such as steroids. Two samples were rerun using full scan mode, to confirm that all principal aromatic peaks were being recorded. Quantitations were done on the molecular ions of the compounds of interest, using the selected ion monitoring data and the Hewlett Packard data system.

GC Peak Recognition

A total of 91 GC/MS peaks representing polyaromatic compounds (Fig. 4) were recognized and quantified in each of the 39 samples. The dimethylnaphthalenes, while dominant in the condensates, were often truncated in the rock extracts, due to the evaporation necessary in the sample preparation. The triaromatic steroids were extremely weak in many of the samples. Therefore these two compound groups were eliminated from further consideration. Table 6 lists the 80 remaining compounds, identified as far as possible by their mass spectral properties and by reference to the literature (Rowland et al., 1984; Wang and Simoneit, 1990; Budzinski et al., 1991; 1993b; 1993c). The chromatographic character of the peaks are more clearly illustrated on the individual mass chromatograms, exemplified by those of lower Missisauga rock extract from Migrant N-20 (Figs. 5-9). As the mass chromatograms show, the polyaromatic peaks are often clusters of isomers, some of which still cannot be specifically identified at the present time, due to the similarity of their mass spectra and the lack of commercially available authentic standards. However, most of the members of each cluster can be separated by GC and the variations in their relative peak distributions from sample to sample can provide much useful empirical information as to maturation levels and organic matter type. The individual GC peaks are labeled according to their mass spectrometric base peaks, which for all compounds under consideration are the molecular ions, and by their order of elution. For example, the eight C_3-alkylnaphthalene peaks, with a molecular ion of m/z 170, are designated peaks 170a through 170h (Fig. 5). Closely eluting peaks, such as the two which comprise peak 212g (Fig. 6), were not resolved in all samples and are summed as a single peak for consistency. There are several exceptions to the labeling system, designating 1) unsubstituted polyaromatics such as phenanthrene (PHN) or 2) heteroatomic aromatics which have molecular ions coincident with hydrocarbons, such as dibenzothiophene (DBT), sharing the m/z 184 trace with C_4-alkylnaphthalenes.

Data Handling

Due to the great number of chromatograms generated from this large data set, visual comparisons were not sufficiently thorough for petroleum-to-petroleum or petroleum-to-rock correlation. A multivariate statistical approach was chosen as the most effective. Once the raw integrated areas of the 80 peaks were transferred to a minicomputer spreadsheet, they could then be normalized. Condensates, such as the South Venture DST 5 (API gravity = 51°), show a much greater preponderance of lighter aromatic compounds than do relatively low maturity rock extracts, such as the extract from the Abenaki well (Fig. 10). To be able to better compare such samples for possible genetic relationships, the data were normalized within three groups according to retention time (Fig. 4). The first-eluting group includes the compounds with molecular ions at m/z 170, 184 and 182 (C_3- and C_4-alkylnaphthalenes, dibenzothiophene, dimethylbiphenyls and methyldibenzofurans). The second group includes compounds with molecular ions at m/z 178, 192, 206, 198, 212 and 202 (phenanthrene, methyl- and dimethylphenanthrenes, methyl- and dimethyldibenzothiophenes, pyrene and fluoranthene). The last-eluting group includes compounds with molecular ions at m/z 216, 230, 228, 242 and 252 (methyl- and dimethylpyrenes and their isomers, chrysene and benzo[a]anthracene, methylchrysene isomers, and pentaaromatic hydrocarbons including benzo[*a*]pyrene and its isomers.

Since the variation in peak intensities is so wide, the data must be scaled to avoid distortion during the correlation exercise. Scaling was performed by taking the base 10 logarithm of the normalized peak intensities, in which the tallest peaks (100%) now has a value of 2 and very small or missing peaks (with normalized areas of < 0.1%) are assigned values of -1.

The variations among the Scotian Shelf samples are functions of both maturation and organic matter type. To separate these two effects, methylphenanthrene indices (MPI, Radke and Welte, 1983) and several other maturity parameters using polyaromatic hydrocarbons were calculated for each sample, as presented in detail in the Results and Discussion section. The samples were arranged in order of increasing maturity as so determined and the 5 samples with the lowest and the 8 with the highest maturities were selected. The base 10 logarithms of the areas (normalized by retention time group) of each of the 80 peaks in the low maturity sample set were averaged, as were those with high maturity, forming composite low and high maturity data sets. Averages were employed to cancel differences associated with organic matter type. The low maturity averaged data were subtracted from the high and the differences reported as "Δm" in Table 6. Where Δm has a large positive value, the corresponding peak increases greatly with maturation, while a large negative value indicates that the peak decreases markedly in concentration as maturity increases.

Values of Δm range widely, from -1.61 to +0.80. A subset of data was extracted comprising those 39 peaks falling within a narrow window where $-0.22 \leq \Delta m \leq 0.17$, based on apparent boundaries in the data set, to dampen the effects of maturation. Next, average peak areas and their standard deviations were computed for all 80 peaks of all 39 samples ($\log_{10}$, normalized by retention time grouping). The standard deviations range from 0.07 to 0.89 (Table 6). To eliminate the peaks showing little variation (and thus little potential to aid in correlation), the subset of 39 maturation-insensitive peaks were further reduced to those 36 peaks with standard deviations > 0.15. To confirm that maturation effects were indeed dampened, each of the 36 peaks of the latest subset were averaged for the low and high maturity samples. When these two average sets were co-plotted, they matched closely, indicating that there is little residual maturity effect. These 36 peaks are marked (*) in Table 6 and will be termed the "correlation set".

Even with the original data set scaled logarithmically, normalized by retention time groupings, and reduced from 80 to 36 peaks, visual correlation among 39 samples is inefficient and merely qualitative. The degree of similarity between samples can also be expressed graphically by cross-plotting the correlation sets. For example, if the Chebucto and North Triumph oil samples are compared, a tight linear distribution is apparent. In contrast, if the Chebucto oil is compared with the Panuke J-99 oil, much greater scatter is apparent (Fig. 11). These results can be expressed quantitatively using coefficients of determination (r^2) from the linear regression of any two samples, where r^2 varies from 0 to 1, with a value of 1 indicating a perfect match. With the assistance of a computer, over 700 r^2 values were determined for all possible pairings of the 39 samples (Table 7).

To aid in the interpretation of these results for the oil-oil and oil-source correlation exercise, a cluster analysis was undertaken. The "unweighted average linkage" method (Massart and Kaufman, 1983) was applied to the similarity matrix of Table 7. Briefly, the clustering is begun by choosing the best match from the correlation matrix and linking those two samples on a dendrogram (Fig. 13), with the length of the connecting branches scaled to the r^2 value (the shorter the branch, the better the match). Then, the r^2 values of the two matched samples with all other samples are averaged, and this average replaces the original r^2 values for the two matched samples in the similarity matrix. The next closest match is plotted and matching continues until all samples are included. When a new sample is matched with a pre-existing cluster, a weighted average is computed. When two pre-existing clusters are linked, their r^2 values are averaged, with each weighted by the number of samples it contains. The term "unweighted average linkage" may thus at first appear to be a misnomer, but refers to the fact that the contributions of each sample are given equal importance.

Maturity Determination

Aromatic maturation parameters, including the methylphenanthrene index (MPI, Radke and Welte, 1983), the ratio of triaromatic to monoaromatic steroids, and the ratio of low to high molecular weight triaromatic steroids (Mackenzie *et al.*, 1983), are commonly applied in evaluating oils and source rock extracts. Since the present study was limited to the analysis of aromatic fractions, in part due to the lack of saturate biomarkers, it was expected at the outset, that maturation determinations could be successfully made. After analysis it became apparent that the monoaromatic steroids were not detectable in most cases and the high molecular weight (C_{26}-C_{28}) triaromatic steroids were weak or not present in the sample set. Thus the two parameters employing steroids were at their maximum values in many cases, suggesting that the overall maturity level for the sample set was rather high. This is not surprising, given the great burial depth of many of the samples (Table 4). Although the MPI was originally calibrated on terrestrial organic matter and the types of organic matter represented in this study were unknown at the outset, the author has observed that the MPI can be a useful relative indictor of high levels of maturity (mid to late oil window) for many types of organic matter. It was thus decided to begin maturation ranking of the samples by using the MPI:

$$\frac{1.5\ (3\text{-mPH} + 2\text{-mPH})}{(\text{Phenanthrene} + 9\text{-mPH} + 1\text{-mPH})}$$

converting to an estimated vitrinite reflectance equivalent (R_c) using the empirical relationship of Radke (1987), valid for $R_o < 1.35\%$:

$$R_c = 0.60\ \text{MPI} + 0.40$$

R_c values for the 39 Scotian Shelf samples range from 0.64 to 1.15, with the majority of samples (22) falling between 0.8 and 1.0 (Fig. 12). Not wishing to depend completely on a sole maturity parameter, it was expected that additional maturation indicators could be derived from other polyaromatic hydrocarbon groups. Only maturation variations among groups of isomers, i.e., the dimethylphenanthrenes, were considered for these purposes. Additional maturity parameters might also be created, by mixing peaks from different compound classes, but the possibility was not investigated here.

Individual isomers were chosen from among the trimethyl- and tetramethyl naphthalenes and dimethylphenanthrenes based on their observed response to natural and artificial maturation and on their computed thermodynamic stabilities (Radke, 1987; Kruge and Landais, 1992; Budzinski et al., 1993a; 1993b; Kruge and Bensley, 1993). To confirm that these peaks were responding to maturation changes in the Scotian Shelf samples, the samples unquestionably exhibiting the lowest and highest maturation levels (as determined by the MPI) were averaged within their maturity groups and subtracted. In all cases, the polyaromatic hydrocarbons used to create the supplemental maturity parameters behaved as predicted — the stable showed a relative increase and the labile, a decrease with increasing maturity. The resulting additional maturity ratios are defined as follows:

Trimethylnaphthalene (TrMN) Ratio

$$\frac{(1{,}3{,}6\text{-} + 2{,}3{,}6\text{-TrMN})}{(1{,}4{,}6\text{-} + 1{,}3{,}5\text{-} + 1{,}2{,}5\text{-} + 1{,}3{,}6\text{-} + 2{,}3{,}6\text{-TrMN})}$$

Tetramethylnaphthalene (TeMN) Ratio

$$\frac{(1{,}3{,}6{,}7\text{-} + 2{,}3{,}6{,}7\text{-TrMN})}{(1{,}2{,}4{,}7\text{-} + 1{,}2{,}5{,}6\text{-} + 1{,}3{,}6{,}7\text{-} + 2{,}3{,}6{,}7\text{-TrMN})}$$

Dimethylphenanthrene (DMP) Ratio

$$\frac{(2{,}6\text{-} + 2{,}7\text{-DMP})}{(1{,}7\text{-} + 2{,}6\text{-} + 2{,}7\text{-DMP})}$$

They are all expressed in the format:

$$\frac{\text{"stable compounds"}}{\text{"labile + stable"}}$$

so that the ratios increase with maturity and all can only vary between 0 and 1.

To determine a more solid maturity ranking than could be done with R_c alone, linear regressions were computed for the two phenanthrene ratios ($r^2 = 0.81$) and for the two naphthalene ratios ($r^2 = 0.79$), which indicated good correlations. The resulting best fit lines were rotated to form new "X" axes (X'_{phen} and X'_{naph}), the values for which were in turn also compared by linear regression ($r^2 = 0.64$). The best fit line for this regression was also rotated and the resulting X" values were used as the basis for an objective maturity ranking of the samples. Figure 12 displays the four maturity ratios in their original form, with the samples arrayed according to the X" ranking, along with vitrinite reflectance data for the rock samples. Although noise is present in each case, each curve progressively increases and thus the overall maturation ranking is clear.

Among rock samples, those with shallower burial depths (2-4 km, Cretaceous Logan Canyon and Missisauga Formations) are evidently the least mature according to the aromatic maturity parameters, placing them in the early stages of the oil window. Aromatic data indicate that the Logan Canyon sample from the N. Triumph G-43 well (3.7 km) and the Missisauga sample from the Thebaud well (3.9 km) have higher maturities than suggested by the vitrinite reflectances, which may be due to suppression of the latter. Phenanthrene ratios indicate a lower maturity than the naphthalene for two relatively shallow Jurassic rocks, the Baccaro Member sample from the Demascota well (3.6 km) and the Penobscot Limestone sample from the Penobscot well (4.2 km), probably due to facies effects. High maturity rocks (in the late oil window) include the deep (6.1 km) Mic Mac sample from the S. Venture well and the 5.1 km Missisauga sample from Venture B-52. The deep Missisauga samples from W. Chebucto (5.2 km) and N. Triumph G-43 (4.8 km) also exhibit relatively high maturities, although some facies effects may be operating on these marine samples.

The oil samples show considerable variation in maturity, according to the aromatic parameters, even though most of them have low specific gravities and are classified as condensates. Oils with maturities apparently in the early oil window include those from the Cohasset wells out of the shallow (1.9 km) Logan Canyon reservoir, the oils produced at shallow depths (1.9 to 2.6 km) by the Balmoral and Panuke wells, as well as the moderately deep oil (3.8 km) from the Missisauga in Citnalta. High maturity (late oil window) petroleums include those produced from deep (4.6 to 5.2 km) Mic Mac reservoirs in the Bluenose, Uniacke and Venture H-22 wells, as well as deep (5.0 to 5.2 km) reservoirs in the Missisauga from Arcadia J-16 and

S. Venture O-59. The remaining oil and rock samples are interpreted to have intermediate maturity levels (Fig. 12).

There is an overall trend indicating depth and stratigraphic control of the maturity of the rock extracts and the petroleums, with samples from deeper and/or older strata exhibiting higher levels of maturation.

Oil-Oil and Oil-Source Rock Correlation

A subset of 36 peaks from the aromatic GC/MS data was chosen for correlation purposes by the elimination of peaks strongly susceptible to maturation and of those peaks which showed little variation under any circumstances, as described in the Methods section. The data had been normalized according to retention time and scaled logarithmically prior to the filtering process. There may be some residual maturation effects in the correlation subset, but they should have been minimized.

Upon examination of the matrix of coefficients of determination (Table 7), it can be seen, for example, that in the column corresponding to the Chebucto oil sample, the quality of matches varies considerably. There are several very close matches ($r^2 > 0.95$), namely those with the N. Triumph B-52, S. Venture O-59 (DST 10) and Glenelg oils. It is extremely likely that these oils are genetically related. Further perusal of Table 6 leads to the recognition of close cross-matching among the oils listed above, as well as additional close relations with other oils and several rock extracts. Several additional smaller groupings also become apparent. Many other samples appear quite unrelated. To present this graphically in a concise and quantitative manner, a cluster analysis was performed (as described in the Methods section) and the results drawn as a dendrogram, scaled to r^2 values (Fig. 13).

The dendrogram confirms that the 4 oils just discussed form a tightly knit group, with all linkages above 0.95. Two other tight clusters, one comprised of the Olympia, Thebaud and Penobscot oils, the other of the Bluenose, Arcadia and two Venture H-22 oils, are also apparent. The latter group is characterized by higher maturity (Fig. 12), which may indicate that maturity effects on the correlation, while dampened considerably, were not entirely eliminated. All three groups are linked to each other with r^2 values > 0.9. The Citnalta and Banquereau oils are closely related to each other, but are linked somewhat more distantly by a branching at $r^2 = 0.85$ to the main group of oils, which is nevertheless still a reasonable match. All these oils, which can be collectively termed "Group A", are produced from Missisauga or Mic Mac reservoirs. The S. Venture (DST 5) and Uniacke petroleums show more a more limited similarity with the main group, perhaps in part the effect of their elevated maturity.

The Cohasset oils, produced out of the Cree Member of the Logan Canyon Formation, correlate well with one another, but poorly with the remaining samples. The one possible exception is the Sable Island oil from the Mamora Member of the same formation, with which the Cohasset oils have a limited affinity. The Panuke oils bear little resemblance to each other or to any of the other samples.

Among the rock extracts, a number of close correlations are also apparent. The Jurassic Abenaki Formation (Baccaro Member) sample from the Demascota well matches the Jurassic Penobscot Limestone sample (Mic Mac Formation, Penobscot L-30). These samples in turn show similarity in organic facies to the Lower Missisauga extracts of Abenaki J-56 and Migrant N-20 and the Logan Canyon samples of N. Triumph G-43 and Cohasset A-52 (Fig. 13). Lower and Middle Missisauga rocks from Venture B-52, Thebaud, S. Desbarres, and S. Sable exhibit a high degree of correlation to one another ($r^2 \leq 0.9$) and match the first cluster of rocks with a coefficient of determination of 0.86. This group of 10 extracts can be referred to as "Cluster 1". The second large cluster of rock samples has the Missisauga extracts from N. Triumph G-43 and W. Chebucto as its core, with the Missisauga extract from Whycocomagh and Verrill Canyon extracts from the Alma well as associated samples. This "Cluster 2" shows no affinity with the rocks of Cluster 1 (Fig. 13). The two remaining rock samples (Mic Mac from S. Venture and Misaine Member of the Abenaki Formation from Cohasset D-42) show no apparent relation to each other or to the other rock samples. As a whole, the rock extracts demonstrate that major differences in organic facies are represented in the Scotian Shelf samples.

The dendrogram shows a fair correlation ($r^2 = 0.75$) between the Group A petroleums and Cluster 1 rock extracts. The Cohasset oils correlate poorly with all rock samples. Cluster 2 rocks show no apparent similarity with any of the oils. Since the Group A oils show a high degree of genetic similarity to each other and account for the majority of oils analyzed for this study, it may be useful to consider them collectively, by taking the average of their correlation data sets. Then they may be correlated as a group to each rock sample, the results of which can be displayed in stratigraphic context (Fig. 14a). These results are in essential agreement with those displayed in the dendrogram, but offer a clearer assessment of the quality of the petroleum-to-rock correlation. The Group A oils are still shown in Fig. 14a to match reasonably with the Cluster 1 extracts, with the added refinement that the lower and middle members of the Missisauga appear to provide the best candidate source rocks, along with the Penobscot Limestone and Cree Member samples. Cluster 2 extracts, whether from the Verrill Canyon or Missisauga, continue to show no correlation with Group A oils.

Since the presence of organic sulfur in fossil fuel samples is strongly related to the depositional environment of the original organic matter, it is interesting to examine sulfur content in the samples. A relatively high sulfur content is one of the hallmarks of marine Type II organic matter, whereas lacustrine and terrestrially-derived kerogens (Types I and III) are characteristically low in sulfur. Several of the sulfur compounds (dimethyldibenzothiophenes, Table 6) were important in the cluster analysis, but they merit special consideration. A simple ratio ("Th/Ph") of the sum of the C_2-alkyldibenzothiophenes (m/z 212) to the sum of the C_2-alkylphenanthrenes (m/z 206) is effective in presenting a semi-quantitative view of the sulfur content for the aromatic fraction. If the values of this ratio for the extracts are displayed in stratigraphic order (Fig. 14b), it is apparent that the low sulfur extracts (Th/Ph = 0.06 to 0.25) are those which correlate most closely to Group A oils (Fig. 14a), which have a mean Th/Ph ratio of 0.08. The non-Group A oils in the Scotian Shelf sample set also have low sulfur contents, but they are distinguished by elevated concentrations of another aromatic heterocyclic species, methyldibenzofurans.

It is reasonable to ascribe the highly thiophenic extracts (Cluster 2 and unclassified rocks) to marine origins and the low sulfur Cluster 1 extracts (which provide acceptable matches to the Group A petroleums) to non-marine. By extension, Group A oils are also likely to have non-marine origins. These designations are in broad agreement with the organic petrologic and stratigraphic data.

BASIN MODELING

Similar to modeling of eight other wells (Mukhopadhyay, 1993), a rifting steady state heat flow with $\beta = 3.0$ and present day heat flow between 35 (Abenaki J-56) and 40 (W. Chebucto K-20) mW/m^2 were chosen as default values for modeling. The model maturity profiles correlate well with the measured maturity data for those two wells. However, use of rifting heat flow suggests that present day heat flow is the lowest.

Tables 8 and 9 show the following data used in modelling the Abenaki and Chebucto wells: formation name, beginning age, top depth, thickness, approximate lithology, kerogen type and aprroximate TOC (wt %). The lithologic mixing illustrates the proportions of sandstone/shale/limestone except for the Argo Formation where salt replaces limestone.

Figures 15a through 15j and 16a through 17l for the Abenaki J-56 and W. Chebucto K-20 wells, respectively, demonstrate the burial history, maturity and thermal conductivity through time, cummulative total HC and gas generation and migration through time and maturity or temperature or HC generation of individual source rocks through time.

The lithologic column within the burial history curves in Figures 15a and 16a does not include all formation names; the model names only those formations which are thickest. Figures 15a and 16a show that the maturation zones (example 0.4 to 0.7% R_o) cut across the stratigraphic boundaries between 200 and 87 my whereas, from 75-0 my, the zones run more or less parallel with the stratigraphic boundaries. Depressed maturation zones within the geohistory plots (15a and 16 a) can be seen when sediments were deposited in deeper paleowater depth. This downward shift of maturation zones are an artifact of the BASIN-MOD program.

Figures 15b and 16b show the maturation boundaries limiting the various formations and individual source rocks. The zones are divided into: (a) 0.4/0.5 to 0.7% R_o or early mature oil zone, (b) 0.7 to 1.0% R_o or mid mature oil zone, (c) 1.0 to 1.3% R_o which is either late mature oil zone or early mature gas zone, (d) 1.3 to 2.0/2,6% R_o or main gas generation zone. Depth for each maturity zone for those two wells are as follows:

TABLE A

Well No.	**Zone a**	**Zone b**	**Zone c**	**Zone d**
(m)	(m) (m)	(m)		
Abenaki J-56	2300-3750	3750-4650	4650-5300	5300-6450
W. Chebucto K-20	2000-4100	4100-5200	5200-5900	5900-7100

The cummulative HC generation throughout the sequence (up to 8000 m) varies with the nature and thickness of the source rocks. In comparison, W. Chebucto K-20 generated much higher HC's compared to Abenaki J-56 well. Comparable cummulative HC generation and expulsion efficiency from those two wells up to 8000m are as follows:

TABLE D

Well No.	Cumm. Oil (bbl HC/Ac.ft rock)	Cumm. Gas (bbl HC/ac.ft rock)	Depth (m)	Expulsion Efficiency (bbl HC/ac.ft rock)
Abenaki J-56 (Fig.15d)	100	250	4000-8000	50 oil, 250 gas
W. Chebucto K-20 (Fig. 16d)	400	1250	4000-8000	250 oil, 1000 gas

Cumm. oil = Cummulative oil; Cumm. Gas = Cummulative Gas

Comparing the history of maturation, temperature and transformation ratio through time and using the measured kinetics, the timing and amount of hydrocarbon generation and migration of seleceted rock intervals from those two wells were evaluated.

The Abenaki I unit (Kerogen Type IIL) from the Abenaki J-56 well, lies within the maturation zone ***a*** and is subjected to a maximum of 100°C temperature (Fig. 15f). A very low amount (<10bbl/acre foot) of liquid hydrocarbons were generated. The migration of hydrocarbons from the Abenaki unit is negligible (Fig. 15g). A lower Callovian source rock from the same well which lies within maturation zone ***b*** and is subjected to a maximum temperature of 110°C (Fig. 15h), has a low transformation ratio (0.4; Fig. 15i). This unit however, expelled about 50 bbl (equivalent) of gas per acre foot of rock (Fig. 15i). The next lower unit, Scatarie Member (Kerogen Type IIB), from Abenaki J-56 well, also generated mainly gas (Fig. 15j).

On the other hand, the Mississauga 2 source rock unit (kerogen Type IIA-IIB) in W. Chebucto K-20, which also lies within maturation zone ***b*** and is subjected to a maximum temperature of 120°C (Fig. 16f), has a transformatio ratio of 0.98 (Fig. 16g). This unit has generated and migrated abundant liquid hydrocarbons (500 bbl/acre foot) starting 125 mybp (Fig. 16h); it has a much lower gas generation. The next lower unit, Mississauga 3, which has Kerogen Type IIB and is subjected to a maximum temperature of 165°C (Fig. 16i), started HC generation 137 mybp. It generated and migrated more gas than liquid hydrocarbons (16j). The next lower unit, Top Jurassic, which has a higher proportion of shale than the other two, has mainly Kerogen

Type III and lies within maturation zone ***d***. It is subjected to a maximum temperature of 185°C (Fig. 16k) and has generated and migrated 900 bbl (equiv) of gas/acre foot since 137 mybp.

SUMMARY AND CONCLUSIONS

The report illustrated the results and significance of: (a) hydrocarbon potential and maturation of 50 selected limestone and calcareous shale samples (mainly from the Abenaki Formation) and 50 selected composite shale units from various stratigraphic intervals, (b) kinetics analyses of four selected source rocks, (c)maturation of liquid hydrocarbons, oil-oil and oil-source rock correlation of 39 selected oil, condensates, and source rock extracts by using aromatic biomarkers, and (d) 1-D basin modeling of two selected wells (carbonate-rich Abenaki J-56 and clastic-rich W. Chebucto K-20) using the BASIN-MOD program. The report added several aspects of importance towards the understanding of source rock types, their maturation, kinetic properties, oil-oil and oil-source rock correlation, and hydrocarbon generation and expulsion in the Scotian Basin which point toward the following summary and conclusions:

Source Rock Characterization

Based on organic facies, which uses maceral composition, fluorescence and oxidation criteria of macerals and minerals, hydrogen and oxygen indices (from Rock-Eval pyrolysis) and vitrinite reflectance, the hydrocarbon potential and maturity of selected limestone and composite shale source rocks was evaluated and compared. Volumetrically, the comparable source rock potential between limestone and composite shale samples can be illustrated as follows: Limestone and calcareous shale: 6% are oil- and condensate-prone Kerogen Type IIA-IIB; 42% are condensate- and gas-prone Kerogen Type IIB; 34% are gas-prone Kerogen Type III; and 18% are nonsource Kerogen Type IV. Composite shale: 20% are oil- and condensate-prone Kerogen Type IIA-IIB; 40% condensate- and gas-prone Kerogen Type IIB; 40% are gas-prone Kerogen Type III; and none of them are considered as nonsource for hydrocarbons.

Kinetics of Selected Source Rocks

The distribution of Activation Energies and Arrhenius Constant suggests that Kerogen Type IIA-IIB (peak at 44 to 48 kcal/mole) can generate and expel mainly oil (350 mg HC/g TOC) earlier in its maturation history (<0.8% R_o) than Kerogen Type IIB (peak around 50 and 55 kcal/mole) and III (46-50 kcal/mole). Kinetics of two limestone and calcareous shale source rocks show sharp peaks between 50-52 kcal/mole and the reaction rate is slower. The reaction rate of Kerogen Type IIA-IIB is considered as medium-fast and compared to Type IIC source rock of Hunt et al. (1991), whereas limestone source rocks can be compared to Kerogen Type I of the Green River Shale.

Maturation of Crude Oil/Condensate and Oil-Oil or Oil-Source Rock Correlation

The majority of petroleums and rock extracts in this study are at advanced levels of thermal maturity (middle to late oil window), as evidenced by the distribution of methylphenanthrene, dimethylphenanthrene, trimethylnaphthalene and tetramethylnaphthalene isomers. This is not surprising, given the great burial depth (4 to 6 km) of many of the samples.

Multiple linear regression and subsequent cluster analysis reveals a closely related family of oils ("Group A") including those from N. Triumph B-52, S. Venture O-59 (DST 10), Glenelg, Olympia, Thebaud, Penobscot, Bluenose, Arcadia, Venture H-22, Citnalta and Banquereau, all produced from Missisauga or Mic Mac reservoirs. The Cohasset oils form a second group and the Panuke oils do not seem to be related to each other or to any other oil.

A group of rock extracts ("Cluster 1") from the lower and middle members of the Missisauga, along with the Penobscot Limestone and Cree Member samples correlate well with each other, indicating similar organic facies. These samples also have reasonable affinities for the Group A oils, with the Lower Missisauga samples from the Abenaki and S. Desbarres wells appearing to be the best candidate source rocks. A second cluster of extracts, including samples from the Verrill Canyon and Missisauga Formations are related to one another, but correlate neither with Group A oils nor Cluster 1 extracts.

To supplement the cluster analysis, a parameter related to the sulfur content of the samples (the ratio of the sum of C_2-alkyldibenzothiophenes to the sum of the C_2-alkylphenanthrenes) was established. It supports the statistical findings, further indicating that the oils and Cluster 1 extracts have a similarly low thiophenic sulfur content, in contrast to the relatively high sulfur Cluster 2 and unclassified extracts. Samples richer in sulfur derive from marine rocks, while the remainder are apparently of non-marine origin, a conclusion supported by the organic petrologic and stratigraphic data.

Basin Modeling

Burial history curves of two selected wells (Abenaki J-56 and W. Chebucto K-20) suggest that the sedimentation rate between 200 and 75 mybp (syn- and early post-rift sediments) was relatively high and relatively low after that (late post-rift phase).

The best-fit maturation line correlating vitrinite reflectance and depth, is primarily controlled by small changes in present day heat flow (mW/m^2) values within a narrow range of lithopheric stretching factor, β.

Due to the presence of fewer oil-prone source rocks and slower reaction rates of the limestone source rock units, W. Chebucto K-20 source rocks (mainly clastic units) generated and migrated cummulative hydrocarbons five times more than Abenaki J-56 source rocks. Mississauga 2 unit (kerogen Type IIA-IIB) in W. Chebucto K-20 generated and migrated more oil (500 bbl/are foot) than gas, whereas Mississauga 3 (kerogen Type IIB) migrated major gas (900 bbl equiv/acre foot) between 125-50 mybp. Modelling suggests that major hydrocarbons (about 80%) were generated and expelled between 137 and 50 my before present. Most source rocks also reached their peak temperature during that time; temperature has decreased since then. This suggests that non-expelled oils within the source rocks have been cracked to gas and residue.

ACKNOWLEDGMENTS

The author acknowledges John A. Wade of Basin Analysis Subdivision, Atlantic Geoscience Centre, Bedford Institute of Oceanography, Dartmouth, Nova Scotia for various fruitful discussions during the period of this contract. The author acknowledges M. P. Avery and B. Crilley of Atlantic Geoscience Centre for kerogen isolation, kerogen smear slides, kerogen plugs, vitrinite reflectance data. The author acknowledges Steven Bigelow of CNSOPB for their permission to collect the samples and Karl Makrides of CNSOPB Core Storage Facility at Dartmouth, N. S. for his assistance during sample collection. The author acknowledges Dr. Michael A. Kruge of Southern Illinois University, Carbondale, Illinois and Dan Jarvie, Humble Geochemical Services, Humble, Texas, USA for the Liquid chromatography/aromatic gc-ms and kinetic data and report. The author acknowledges the help of M. G. Fowler of ISPG, Geological Survey of Canada, Calgary, Alberta and Ross Stewart of Calgary, Alberta for their Rock-Eval pyrolysis data.

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TABLE 1A : Rock–Eval pyrolysis data of limestone and calcareous shale samples

Borehole No.	Depth (ft/m)	Formation/ Member	R_o	T_{max} (°C)	TOC (wt%)	S_1	S_2	S_1+S_2	S_3	PI	HI	OI
Abenaki J-56	10090–10130'(w)	Baccaro	0.51	432	2.39	0.91	4.91	5.82	1.04	0.16	205	43
	(k)			429	74.15	23.7	206		20.6	0.10	282	27
	10800–10810'(w)	same	0.53	435	1.22	0.53	1.58	2.11	0.72	0.25	129	59
	(k)			431	78.9	45.3	174		25.1	0.21	220	31
	12040–12050'(w)	same	0.57	435	0.90	0.32	0.89	1.21	0.62	0.26	98	68
	(k)			431	65.78	28.1	146		8.70	0.16	222	13
	12360–12370'(w)	same	0.58	432	0.53	0.18	0.25	0.43	0.53	0.42	47	100
	(k)			432	90.62	40.7	262		16.0	0.13	288	17
	12890–12900'(w)	same	0.57	435	1.05	0.38	0.79	1.17	0.62	0.32	75	59
	13040–13050 (w)	same	0.60	433	0.63	0.47	0.45	0.92	0.57	0.51	71	90
	(k)			433	86.2	36.3	213		21.6	0.15	247	25
	13270–13280'(w)	Misaine	0.78	438	0.91	0.10	0.40	0.50	0.44	0.20	43	48
	(k)			432	67.1	21.1	116		17.9	0.15	172	26
	13790–13800'(w)	Scatarie	0.76	433	0.36	0.14	0.16	0.30	0.40	0.47	44	111
	(k)			441	83.04	32.0	179		34.0	0.15	215	40
	14080–14090'(w)	Mohican	0.82	437	0.60	0.32	0.40	0.72	0.32	0.44	66	53
	(k)			444	13.35	4.68	15.7		6.59	0.23	117	49
	14140–14150'(w)	same	0.89	440	0.65	0.48	0.43	0.91	0.43	0.53	66	66
	14220–14230'(w)	same	0.94	439	0.85	0.52	0.64	1.16	0.50	0.45	75	58
	(k)			443	45.1	14.2	66.8		11.1	0.18	148	24
	14350–14360'(w)	same	0.92	437	0.95	2.22	0.93	3.15	0.46	0.70	97	48
	14410–14435'(w)	Iroquois	0.91	439	0.80	1.84	0.62	2.46	0.69	0.75	77	86

R_o = mean random vitrinite reflectance; T_{max} = maturation parameter from Rock–Eval pyrolysis in °C. TOC = total organic carbon in weight %. S_1 and S_2 = in mg HC/g TOC; S_3 = mg CO_2/g TOC; PI = production index = S_1/S_1+S_2; HI = hydrogen index in mg HC/g TOC; OI = oxygen index = mg CO_2/gTOC. (w) = whole rock; (k) kerogen concentrate.

TABLE 1A : Rock–Eval pyrolysis data of limestone and calcareous shale samples

Borehole No.	Depth (ft/m)	Formation/ Member	R_o	T_{max} (°C)	TOC (wt%)	S_1	S_2	S_1+S_2	S_3	PI	HI	OI
Cohasset D–42	10000–10030'(w)	L.Mississauga	0.64	437	0.58	0.15	0.47	0.62	0.63	0.24	81	108
	10830–10850'(w)	Baccaro	0.71	431	0.23	0.13	0.10	0.23	0.34	0.57	43	147
	13430–13450'(w)	same	0.63		0.06							
	13740–13760'(w)	same	1.23		0.07							
	14160–14180'(w)	Misaine	1.23		0.17	0.03	0.07	0.10	0.15	0.30	41	88
	14370–14390'(w)	same	1.33		0.16	0.03	0.05	0.08	0.21	0.38	31	131
	14490–14520'(w)	same	1.34	457	0.25	0.02	0.04	0.06	0.49	0.33	16	196
Cohasset L–97	3100–3110 m (w) (k)	L. Mississauga	0.63	440	0.83 29.82	0.12 79.6	0.50 66.4	0.62	0.44 28.0	0.19 0.55	60 222	53 93
	3195–3205 m (w)	Baccaro	0.62	428	1.22	1.28	1.63	2.91	3.38	0.44	133	277
	3990–4000 m (w) (k)	same		 435	0.34 9.37	0.08 11.7	0.16 20.0	0.24	2.22 23.2	0.33 0.37	47 213	652 247
	4155–4165 m (w)	same			0.13							
	4470–4480 m (w)	Misaine	1.41	455	0.18	0.01	0.03	0.04	0.32	0.25	16	177
	4545–4555 m (w)	same	1.50		0.15							

R_o = mean random vitrinite reflectance; T_{max} = maturation parameter from Rock–Eval pyrolysis in °C. TOC = total organic carbon in weight %. S_1 and S_2 = in mg HC/g TOC; S_3 = mg CO_2/g TOC; PI = production index = S_1/S_1+S_2; HI = hydrogen index in mg HC/g TOC; OI = oxygen index = mg CO_2/gTOC.

TABLE 1A : Rock-Eval pyrolysis data of limestone and calcareous shale samples

Borehole No.	Depth (ft/m)	Formation/ Member	R_o	T_{max} (°C)	TOC (wt%)	S_1	S_2	S_1+S_2	S_3	PI	HI	OI
Cohasset L–97	4620–4630 m (w)	Scatarie	1.6		0.09							
	4855–4865 m (w)	Mohican	1.92		0.26							
	4870–4880 m (w)	same	1.82		0.18							
Demoscota G–43	11480–11510' (w) (k)	Verrill Canyon	0.73	438 440	1.00 74.02	0.39 33.8	0.77 145	1.17	0.73 7.02	0.34 0.19	77 195	73 9
	11840–11880' (w) (k)	Baccaro	0.72	440 423	0.94 74.1	0.38 18.2	0.76 85.3	1.14	0.59 49.1	0.33 0.18	80 115	62 66
	14550–14570' (w)	same		429	0.19	0.23	0.16	0.39	0.71	0.59	84	373
	14820–14840' (w)	same	0.75		0.10							
	15060–15080' (w)	Misaine	1.17		0.12							
	15250–15270' (w)	Scatarie	1.32		0.30							
Penobscot L–30	12280–12290' (w) (k)	Mic Mac	0.61	439 439	0.80 76.1	0.19 20.6	0.44 106	0.63	0.70 8.75	0.30 0.16	55 139	87 11
	12440–12450' (w) (k)	same	0.67	440 439	1.11 76.9	0.22 20.4	0.73 116	0.95	0.85 5.5	0.23 0.15	65 151	76 7
	12580–12600' (w) (k)	same	0.73	442 440	1.04 77.3	0.21 24.9	0.60 117	0.81	0.77 7.0	0.26 0.18	57 151	74 9
	12730–12740' (w) (k)	same	0.73	443 441	1.12 79.3	0.25 25.7	0.60 140	0.85	1.31 5.5	0.29 0.16	53 176	116 6

(w) = whole rock; (k) kerogen concentrate; R_o = mean random vitrinite reflectance; T_{max} = maturation parameter from Rock-Eval pyrolysis in °C. TOC = total organic carbon in weight %; S_1 and S_2 = in mg HC/g TOC; S_3 = mg CO_2/g TOC; PI = production index = S_1/S_1+S_2; HI = hydrogen index in mg HC/g TOC; OI = oxygen index = mg CO_2/gTOC.

TABLE 1A : Rock–Eval pyrolysis data of limestone and calcareous shale samples

Borehole No.	Depth (ft/m)	Formation/ Member	R_o	T_{max} (°C)	TOC (wt%)	S_1	S_2	S_1+S_2	S_3	PI	HI	OI
Penobscot L–30	12980–12990' (w) (k)	Mic Mac	0.77	441 439	1.13 77.9	0.23 20.0	0.83 129	1.06	0.74 5.9	0.22 0.13	73 165	65 7
	13320–13340' (w) (k)	same	0.85	444 443	1.00 76.2	0.22 21.9	0.64 106	0.86	0.71 4.9	0.26 0.17	64 139	71 7
	13690–13700' (w) (k)	same	0.84	444 443	0.71 76.5	0.15 20.6	0.37 111	0.52	0.66 6.5	0.29 0.16	52 145	92 8
	13810–13840' (w) (k)	same	0.95	451 446	0.89 75.6	0.17 20.6	0.44 101	0.61	0.98 5.4	0.28 0.17	40 133	110 7
	13970–14000' (w)	same	1.02	452	0.56	0.17	0.30	0.47	0.76	0.36	53	135
Uniacke G–72	4270–4280 m (w) (k)	Citnalta Limestone	0.71	436 431	1.74 72.5	0.40 13.6	0.94 81.9	1.34	1.74 34.1	0.30 0.	54	100
	4985–4990 m (w) (k)	Penobscot Limestone	1.03	430 418	8.64 60.9	0.38 6.3	3.58 62.0	3.96	13.6 41.7	0.10 0.09	41 101	157 68
	5020–5030 m (w) (k)	Mic Mac	1.18	439 423#	1.43 67.2	0.29 13.3	0.46 68,0	0.75	2.17 35.9	0.39 0.16	32 101	151 53
	5140–5150 m (w) (k)	same	1.28	427# 425#	10.8 60.3	1.00 12.1	7.39 53.8		20.5 35.6	0.12 0.15	68 89	190 65
	5665–5675 m (w)	same	1.52	428#	1.18	0.86	0.82	1.68	1.28	0.51	69	108
	5735–5745 m (w) (k)	same	1.57	430# 423#	1.73 71.7	0.59 20.4	0.84 79.3	1.43	1.80 36.2	0.41 0.20	48 110	104 50

(w) = whole rock; (k) kerogen concentrate; R_o = mean random vitrinite reflectance; T_{max} = maturation parameter from Rock–Eval pyrolysis in °C. TOC = total organic carbon in weight %; S_1 and S_2 = in mg HC/g TOC; S_3 = mg CO_2/g TOC; PI = production index = S_1/S_1+S_2; HI = hydrogen index in mg HC/g TOC; OI = oxygen index = mg CO_2/gTOC. # = possible contamination

TABLE 1B : Rock–Eval pyrolysis data of composite shale samples

Borehole No.	Depth (ft/m)	Formation/ Member	R_o	T_{max} (°C)	TOC (wt%)	S_1	S_2	S_1+S_2	S_3	PI	HI	OI
Alma F–67	3945 – 4130 m	Verrill Canyon	0.90	441	1.97	3.00	3.22	6.22	1.41	0.48	166	73
	4400 – 4595 m	same	1.15	433	1.47	2.62	5.81	8.43	1.70	0.31	399	117
	4700 – 4890 m	same	1.40	435	2.99	6.39	9.43	15.82	1.81	0.40	315	60
Chebucto K–90	2450 – 2650 m	Marmora	0.50	429	1.42	2.19	0.90	3.09	3.11	0.70	62	217
	3545 – 3620 m	Cree	0.68	435	2.76	2.22	1.36	3.58	3.18	0.62	49	115
	3730 – 3800 m	same	0.76	439	3.07	1.85	1.54	3.39	4.24	0.55	53	68
	3960 – 4115 m	Naskapi	0.80	443	2.50	2.05	1.34	3.39	1.70	0.63	49	69
	4335 – 4450 m	Mississauga	0.90	444	2.34	1.24	1.54	2.78	1.74	0.45	65	74
	4655 – 4885 m	same	1.25	432	2.39	1.12	1.55	2.67	2.42	0.42	64	101
	4975 – 5090 m	same	1.55	440	1.60	0.92	0.54	1.46	1.39	0.63	33	86
Glenelg J–48	2850 – 2970 m	Cree	0.60	433	2.93	1.38	1.83	3.21	3.12	0.43	62	106
	3540 – 3750 m	U. Mississauga	0.68	440	1.55	0.57	0.92	1.49	1.07	0.39	59	69
	3975 – 4150 m	same	0.90	444	1.74	0.39	1.06	1.45	0.89	0.27	61	51

R_o = mean random vitrinite reflectance; T_{max} = maturation parameter from Rock–Eval pyrolysis in °C. TOC = total organic carbon in weight %. S_1 and S_2 = in mg HC/g TOC; S_3 = mg CO_2/g TOC; PI = production index = S_1/S_1+S_2; HI = hydrogen index in mg HC/g TOC; OI = oxygen index = mg CO_2/gTOC.

TABLE 1B : Rock–Eval pyrolysis data of composite shale samples

Borehole No.	Depth (ft/m)	Formation/ Member	R_o	T_{max} (°C)	TOC (wt%)	S_1	S_2	S_1+S_2	S_3	PI	HI	OI
Glenelg J–48	4255 – 4400 m	U. Mississauga	1.02	431	4.59	1.26	1.46	2.72	5.03	0.46	31	109
	4570 – 4750 m	M. Mississauga	1.10	439	1.46	0.86	0.57	1.43	1.83	0.57	39	125
	4900 – 5025 m	Verrill Canyon	1.30	430	4.78	1.36	3.28	4.64	4.60	0.29	68	96
N.Truimph B–52	2660 – 2850 m	Cree		431	2.27	7.87	2.36	10.23	2.25	0.77	103	99
	2860 – 3115 m	same	0.44	433	3.46	10.41	4.06	14.47	2.15	0.72	117	62
	3210 – 3400 m	same	0.54	434	4.69	10.60	6.20	16.80	2.05	0.63	132	43
	3410 – 3560 m	Naskapi	0.57	435	3.52	10.04	5.75	15.79	2.25	0.64	163	63
	3560 – 3715 m	Naskapi	0.63	436	3.55	10.77	4.96	15.73	1.93	0.68	142	54
N.Truipmh G–43	2660 – 2750 m	Cree	0.58	426	2.08	5.06	3.86	8.92	1.41	0.57	185	67
	2840 – 2975 m	same	0.59	433	3.35	7.08	5.58	12.66	2.07	0.56	166	61
	3360 – 3550 m	same	0.65	427	3.01	6.30	5.39	11.69	1.53	0.54	179	50
	3600 – 3710 m	Naskapi	0.69	426	3.75	10.59	9.37	19.96	1.63	0.53	249	43
	4530 – 4600 m	Mississauga	0.83	426	2.83	6.74	11.6	18.34	1.97	0.37	410	69
	4680 – 4755 m	same	1.12	418	3.64	11.43	11.9	23.3	1.83	0.49	331	51
S.Desbarres O–76	2345 – 2425 m	Cree	0.52	428	2.86	5.08	3.52	8.60	1.63	0.59	123	56
	3150 – 3195 m	M. Mississauga	0.70	426	1.74	3.60	3.24	6.84	1.34	0.53	187	76
	3910 – 4075 m	Mic Mac	0.97	430	1.30	1.98	3.88	5.86	1.01	0.34	298	77
	4355 – 4515 m	same	1.14	422	2.24	4.45	6.06	10.51	1.59	0.42	270	70
	5025 – 5250 m	same	1.50	426	1.89	5.24	5.49	10.73	1.60	0.49	290	84
	5590 – 5705 m	same	1.78	431	2.55	5.73	10.4	16.13	2.23	0.36	408	87

R_o = mean random vitrinite reflectance; T_{max} = maturation parameter from Rock–Eval pyrolysis in °C. TOC = total organic carbon in weight %. S_1 and S_2 = in mg HC/g TOC; S_3 = mg CO_2/g TOC; PI = production index = S_1/S_1+S_2; HI = hydrogen index in mg HC/g TOC; OI = oxygen index = mg CO_2/gTOC.

TABLE 1B : Rock–Eval pyrolysis data of composite shale samples

Borehole No.	Depth (ft/m)	Formation/ Member	R_o	T_{max} (°C)	TOC (wt%)	S_1	S_2	S_1+S_2	S_3	PI	HI	OI
Venture B–43	5310 – 5475 m	Mic Mac	1.44	434#	4.14	1.66	1.11	2.77	4.69	0.60	27	116
Venture B–52	2310 – 2485 m	Cree	0.45	430	1.35	0.82	0.76	1.58	2.86	0.52	56	211
	2875 – 3045 m	Naskapi	0.57	436	1.64	1.31	0.71	2.02	1.84	0.65	43	112
	3680 – 3740 m	M. Mississauga	0.72	438	2.87	0.57	1.47	2.04	1.70	0.28	51	59
	5810 – 5960 m	Mic Mac	1.66	429#	5.31	1.00	1.40	2.40	5.72	0.42	27	110
Venture H–22	3860 – 3875 m	M. Mississauga	0.74	445	1.44	0.45	0.90	1.35	0.83	0.34	62	57
	4175 – 4385 m	same	0.77	445	1.10	0.41	0.68	1.09	0.75	0.38	61	68
	4410 – 4525 m	same		447	1.10	0.35	0.82	1.17	0.57	0.30	74	51
	4550 – 4710 m	same	0.86	448	1.19	0.48	0.61	1.09	0.75	0.44	51	63
W.ChebuctoK–20	2770 – 2930 m	Cree	0.43	432	2.22	6.62	4.19	10.8	1.49	0.61	188	67
	2950 – 3035 m	same	0.49	433	2.21	5.08	4.23	9.31	1.40	0.55	191	63
	3070 – 3170 m	same	0.55	434	2.87	8.80	5.67	14.47	1.42	0.61	197	49
	3340 – 3440 m	same	0.63	435	2.63	5.92	5.77	11.69	1.67	0.51	219	63
	3890 – 4010 m	Naskapi	0.65	438	3.15	6.48	6.30	12.78	1.50	0.51	200	47
	4165 – 4350 m	Mississauga	0.72	440	2.91	5.93	5.12	11.05	1.67	0.54	175	57
	4400 – 4570 m	same	0.75	439	3.06	8.97	6.57	15.54	1.49	0.58	214	48
	4825 – 5000 m	same	1.09	435#	2.99	7.61	5.92	13.53	1.85	0.56	197	61

R_o = mean random vitrinite reflectance; T_{max} = maturation parameter from Rock–Eval pyrolysis in °C. TOC = total organic carbon in weight %. S_1 and S_2 = in mg HC/g TOC; S_3 = mg CO_2/g TOC; PI = production index = S_1/S_1+S_2; HI = hydrogen index in mg HC/g TOC; OI = oxygen index = mg CO_2/gTOC. # = possible contamination.

TABLE 2A: Maceral Composition in volume percent (organic facies), R_o, kerogen type, and oil/gas potential of limestone and calcareous shale samples

Borehole No.	Depth (ft/m)	Fm/Mbr	R_o	Vit	Int	Exe	Res	Lam	Tel	Ltd	aom 1	aom 2	aom 3	Bit	Ra. Int	Kerog. Type	Oil/Gas Potent.
Abenaki J-56	10090'	Baccaro	0.51	34.5	7.5	27.0		8.0	0.5	2.5		19.0	0.5	0.5		IIA-IIBL	Oil/Cond
	10800'	same	0.53	38.5	15.0	25.5	0.5	2.0	2.5			8.0	7.0	1.0		IIB	Cond/Gas
	12040'	same	0.57	50.0	16.5	23.5		1.0	1.0	1.0		6.0		1.0		IIB	Cond/Gas
	12360'	same	0.58	33.5	20.5	20.5		3.5	2.0	3.0		15.0				IIA-IIBL	Oil/Cond
	12890'	same	0.57	50.5	21.5	17.0		1.0	1.0	1.0		8.0				IIB	Cond/Gas
	13040'	same	0.60	43.0	18.0	26.5	2.5	1.0		2.5		4.5		2.0		IIB	Cond/Gas
	13270'	Misaine	0.78	57.0	22.0	19.5		0.5				0.5		0.5		III	Gas
	13790'	Scatar.	0.76	61.5	15.5	22.0						1.0				IIB	Cond/Gas
	14080'	Mohican	0.82	64.0	13.5	13.0	2.0	1.0	1.0			1.5		1.0	3.0	IIB/III	Gas
	14140'	same	0.89	68.0	17.5	9.0	1.0	2.5	0.5			1.0				III	Gas
	14220'	same	0.94	63.5	18.0	7.0	0.5	0.5	0.5			1.0		0.5	8.5	IIB	Cond/Gas
	14350'	same	0.92	63.5	25.0	8.0		2.0				1.5				III	Gas
	14410'	Iroquo.	0.91	59.0	25.5	10.0	0.5		0.5			1.5		3.0		III	Gas
CohassetD-42	10000'	L.Miss.	0.64	58.0	19.5	17.0		1.5	1.0			2.5		0.5		IIB	Cond/Gas
	10830'	Baccaro	0.71	44.5	33.0	15.5	0.5	1.0		0.5		1.5		0.5	3.0	III	Gas
	13430'	same	0.63	55.5	14.5	12.5	1.0	2.0*	3.0*	0.5		7.5*		3.5		III/IV	Gas
	13740'	same	1.23	10.0	73.0	5.0*						5.5*	0.5	4.0	2.0	IV	Nonsour.
	14160'	Misaine	1.23	19.0	68.0	6.5*		0.5*	0.5*	0.5*		1.5*		1.0	2.0	IV	Nonsour.
	14370'	same	1.33	28.0	54.5	6.0*			0.5*	0.5*		0.5		4.0	5.5	IV	Nonsour.

LEGEND

Fm = Formation/Member; R_o = mean random vitrinite reflectance; Vit = vitrinite; Int = Inertinite; Exe = Exenite; Res = Resinite; Lam = Lamalginite; Tel = telalginite Ltd = liptodetrinite; aom 1 = amorphous organic matter 1 (oil); aom 2 = amorphous organic matter 2 (oil and condensate); aom 3 = amorphous organic matter 3 (gas); Bit = solid bitumen; Ra. Int = rank inertinite or oxidized liptinite; Kerog. Type = Kerogen Type; Oil/gas potent. = oil and gas potential.

* = oxidized phytoclasts; Nonsour. = nonsource rock. Baccaro = Baccaro Member; Misaine = Misaine Member; Scatar. = Scatarie Member; Mohican = Mohican Formation; Iroquo. = Iroquois Formation; L.Miss. = Lower Mississauga Formation; VerrCan = Verrill Canyon Formation.

TABLE 2A: Maceral Composition in volume percent (organic facies), R_o, kerogen type, and oil/gas potential of organic-rich limestone and calcareous shale samples

Borehole No.	Depth (ft/m)	Fm	R_o	Vit	Int	Exe	Res	Lam	Tel	Ltd	aom 1	aom 2	aom 3	Bit	Ra. Int	Kerog. Type	Oil/Gas Potent.
CohassetD-42	14500'	Misaine	1.34	32.0	50.5	5.5		1.0*	1.0*			0.5		1.0	8.5	III	Gas
CohassetL-97	3100 m	L.Miss.	0.63	47.0	23.0	26.0	0.5	0.5	0.5*			1.0*	1.0	0.5		IIB	Cond/Gas
	3195 m	Baccaro	0.62	34.5	41.0	16.5		0.5	1.5			1.5	4.5			III	Gas
	3990 m	same	-	50.0	25.0	10.0	15.0									IIB	Cond/Gas
	4155 m	Baccaro	-	55.0	35.0	5.0								5.0		III	Gas
	4470 m	Misaine	1.41	32.5	49.0				2.0					0.5	16.0	III-IV	Gas-nonsour.
	4545 m	same	1.50	30.5	51.0	0.5			0.5					0.5	17.0	IV	Nonsour.
	4620 m	Scatar.	1.6	29.0	55.5										15.5	IV	Nonsour.
	4855 m	Mohican	1.92	20.5	42.5				3.0			9.0		0.5	24.5	IIB	Cond/Gas
	4870 m	Same	1.82	20.0	34.0				0.5					0.5	45.0	IIA-IIB overmat.	Oil/Cond
Demoscota G-43	11480'	VerrCan	0.73	52.5	11.5	28.0	1.5	3.0				3.5				IIB	Cond/Gas
	11840'	Baccaro	0.72	54.5	23.0	17.0	1.0	2.0*	1.0	0.5		0.5		0.5		III	Gas
	14550'	Baccaro	-	53.0	25.0	17.0			4.0*			1.0				III	Gas
	14820'	Baccaro	0.75	46.0	51.0	9.0*				1.0		2.0*	1.0			III-IV	Nonsour.
	15060'	Misaine	1.17	38.5	48.5	12.0	*		0.5*			0.5*				IV	Nonsour.
	15250'	Scatar.	1.32	39.0	42.0	16.0		2.0	1.0							IIB	Cond/Gas

LEGEND

Fm = Formation/Member; R_o = mean random vitrinite reflectance; Vit = vitrinite; Int = Inertinite; Exe = Exenite; Res = Resinite; Lam = Lamalginite; Tel = telalginite

Ltd = liptodetrinite; aom 1 = amorphous organic matter 1 (oil); aom 2 = amorphous organic matter 2 (oil and condensate); aom 3 = amorphous organic matter 3 (gas);

Bit = solid bitumen; Ra. Int = rank inertinite or oxidized liptinite; Kerog. Type = Kerogen Type; Oil/gas potent. = oil and gas potential.

* = oxidized phytoclasts; Nonsour. = nonsource rock. Baccaro = Baccaro Member; Misaine = Misaine Member; Scatar. = Scatarie Member; Mohican = Mohican Formation; Iroquo. = Iroquois Formation; L.Miss. = Lower Mississauga Formation; VerrCan = Verrill Canyon Formation; MicMac = Mic Mac Formation; CitLs = Citnalta Limestone Member; PenLs = Penobscot Limestone Member.

TABLE 2A: Maceral Composition in volume percent (organic facies), R_o, kerogen type, and oil/gas potential of organic-rich limestone and calcareous shale samples

Borehole No.	Depth (ft/m)	Fm	R_o	Vit	Int	Exe	Res	Lam	Tel	Ltd	aom 1	aom 2	aom 3	Bit	Ra. Int	Kerog. Type	Oil/Gas Potent.
Penobscot L-30	12280’	MicMac	0.61	48.5	30.5	19.5		0.5	0.5			0.5				IIB	Cond/Gas
	12440’	same	0.67	49.0	28.0	21.5						1.5				IIB	Cond/Gas
	12580’	same	0.73	48.0	29.5	19.0		0.5	0.5			2.5				IIB	Cond/Gas
	12730’	same	0.73	51.5	27.0	19.5		1.0						1.0		IIB	Cond/Gas
	12980’	same	0.77	50.5	27.0	16.5		2.0	1.0	2.5		0.5				IIB	Cond/Gas
	13320’	same	0.85	29.0	48.0	19.0	2.0	0.5	0.5			1.0				III	Gas
	13690’	same	0.84	33.0	34.5	28.0	1.5	1.0	1.0			1.0				IIB	Cond/Gas
	13810’	same	0.95	30.0	42.5	19.0		1.0	1.0					1.5	5.0	III	Gas
	13970’	same	1.02	35.5	40.0	17.0	0.5	0.5	0.5					2.0	4.0	III	Gas
Uniacke G-72	4270 m	CitLs	0.71	43.5	37.0	15.5	2.5	0.5	0.5			0.5				IIB	Cond/Gas
	4985 m	PenLs	1.03	26.5	63.0	8.0	1.0		1.0*					0.5		III	Gas
	5020 m	MicMac	1.18	40.5	40.5	6.0			2.0					2.0	8.5	IIB	Cond/Gas
	5140 m	MicMac	1.28	30.0	46.5	8,0						1.0		2.0	12.5	IIB	Cond/Gas
	5665 m	MicMac	1.52	20.5	63.5	11.5									4.0	III	Gas
	5735 m	MicMac	1.57	29.0	55.0	11.0									3.0	III	Gas

LEGEND

Fm = Formation/Member; R_o = mean random vitrinite reflectance; Vit = vitrinite; Int = Inertinite; Exe = Exenite; Res = Resinite; Lam = Lamalginite; Tel = telalginite Ltd = liptodetrinite; aom 1 = amorphous organic matter 1 (oil); aom 2 = amorphous organic matter 2 (oil and condensate); aom 3 = amorphous organic matter 3 (gas); Bit = solid bitumen; Ra. Int = rank inertinite or oxidized liptinite; Kerog. Type = Kerogen Type; Oil/gas potent. = oil and gas potential.

* = oxidized phytoclasts; Nonsour. = nonsource rock. Baccaro = Baccaro Member; Misaine = Misaine Member; Scatar. = Scatarie Member; Mohican = Mohican Formation; Iroquo. = Iroquois Formation; L.Miss. = Lower Mississauga Formation; VerrCan = Verrill Canyon Formation; MicMac = Mic Mac Formation; CitLs = Citnalta Limestone Member; PenLs = Penobscot Limestone Member; MicMac = Mic Mac Formation.

TABLE 2B: Maceral Composition in volume percent (organic facies), R_o, kerogen type, and oil/gas potential of composite shale samples

Borehole No.	Depth (ft/m)	Fm/ Member	R_o	Vit	Int	Exe	Res	Lam	Tel	Ltd	aom 1	aom 2	aom 3	Bit	Ra. Int	Kerog. Type	Oil/Gas Potent.
Alma F-67	3945 m	VerrCan	0.90	53.0	12.0	27.0	2.0	3.0*	1.0			2.0				IIB	Cond/Gas
	4400	same	1.15	42.0	8.0	5.0		3.0				40.0		2.0		IIA-IIB	Oil/Cond
	4700	same	1.40	28.0	5.0	5.0		2.0	1.0			45.0	5.0	3.0	6.0	IIA-IIB	Oil/Cond
ChebuctoK-90	2450 m	Marmor.	0.50	60.0	25.5	9.0			0.5			3.0	2.0			III	Gas
	3545 m	Cree	0.68	64.0	24.5	8.0	0.5		0.5			2.0	0.5			III	Gas
	3730 m	Cree	0.76	62.0	28.0	5.0	2.0					2.0	1.0			III	Gas
	3960 m	Naskapi	0.80	58.0	28.0	8.0	1.0						5.0			III	Gas
	4335 m	Miss.	0.90	72.0	7.0	19.6							0.5			IIB	Gas
	4655 m	Miss.	1.25	68.0	20.0	10.0			1.0*				1.0			III	Gas
	4975 m	Miss.	1.55	71.0	16.0	10.0								2.0	1.0	III	Gas
Glenelg J-48	2850 m	Cree	0.60	54.0	29.0	15.0*			1.5					0.5		III	Gas
	3540 m	U.Miss.	0.68	48.0	31.5	19.5*			1.0*							III	Gas
	3975 m	same	0.90	63.5	19.0	16.0*	0.5		1.0*							III	Gas
	4255 m	same	1.02	38.0	50.0	9.5			1.0*				0.5	1.0		III	Gas
	4570 m	M.Miss.	1.10	46.0	35.0	15.5*		1.5*	2.0							III	Gas
	4900 m	VerrCan	1.30	36.0	41.0	11.0						10.0		2.0		IIB	Cond/Gas

LEGEND

Fm = Formation/Member; R_o = mean random vitrinite reflectance; Vit = vitrinite; Int = Inertinite; Exe = Exenite; Res = Resinite; Lam = Lamalginite; Tel = telalginite
Ltd = liptodetrinite; aom 1 = amorphous organic matter 1 (oil); aom 2 = amorphous organic matter 2 (oil and condensate); aom 3 = amorphous organic matter 3 (gas);
Bit = solid bitumen; Ra. Int = rank inertinite or oxidized liptinite; Kerog. Type = Kerogen Type; Oil/gas potent. = oil and gas potential.
* = oxidized phytoclasts; Nonsour. = nonsource rock. Marmor. = Marmora Member; Cree = Cree Member; U.Miss. = Upper Mississauga Formation; M.Miss. Middle Mississauga Formation;
VerrCan = Verrill Canyon Formation.

TABLE 2B: Maceral Composition in volume percent (organic facies), R_o, kerogen type, and oil/gas potential of composite shale samples

Borehole No.	Depth (ft/m)	Fm	R_o	Vit	Int	Exe	Res	Lam	Tel	Ltd	aom 1	aom 2	aom 3	Bit	Ra. Int	Kerog. Type	Oil/Gas Potent.
N.Truimph B-52	2660 m	Cree		27.0	46.0	22.0			2.0			2.0		1.0		IIB	Con/Gas
	2860 m	same	0.44	16.0	45.0	24.0	1.0					9.0		5.0		IIB	Cond/Gas
	3210 m	same	0.54	21.0	35.0	3.0						20.0	21.0			IIB	Cond/Gas
	3410 m	Naskapi	0.57	15.0	23.0	3.0						15.0	42.0			IIB	Cond/Gas
	3560 m	Naskapi	0.63	17.0	13.0	1.0		3.0				43.0	21.0	2.0		IIA-IIB	Oil/Cond
N.Truimph G-43	2660 m	Cree	0.58	31.0	31.0	5.0		5.0				25.0	2.0	1.0		IIB	Cond/Gas
	2840 m	same	0.59	27.0	35.0			4.0				24.0	6.0	4.0		IIB	Cond/Gas
	3360 m	same	0.65	21.0	32.0	26.0						5.0	13.0			IIB	Cond/Gas
	3600 m	Naskapi	0.69	12.0	20.0	1.0		1.0	1.0			43.0	17.0	5.0		IIA-IIB	Oil/Cond
	4530 m	Miss.	0.83	18.0	16.0			2.0				64.0				IIA-IIB	Oil/Cond
	4680 m	same	1.12	29.0	19.0	1.0						44.0	4.0	3.0		IIA-IIB	Oil/Cond
S.Desbarres O-76	2345 m	Cree	0.52	40.0	28.0	29.0			1.0			2.0				IIB	Cond/Gas
	3150 m	M.Miss.	0.70	42.0	17.0	40.0						1.0				IIB	Cond/Gas
	3910 m	MicMac	0.97	37.0	11.0	39.0		1.0	1.0			11.0				IIA-IIB	Oil/Cond
	4355 m	same	1.14	37.0	18.0	18.0			3.0			13.0		2.0	9.0	IIA-IIB	Oil/Cond
	5025 m	same	1.50	35.0	16.0	24.0			2.0		*	18.0			5.0	IIA-IIB	Oil/Cond

LEGEND

Fm = Formation/Member; R_o = mean random vitrinite reflectance; Vit = vitrinite; Int = Inertinite; Exe = Exenite; Res = Resinite; Lam = Lamalginite; Tel = telalginite
Ltd = liptodetrinite; aom 1 = amorphous organic matter 1 (oil); aom 2 = amorphous organic matter 2 (oil and condensate); aom 3 = amorphous organic matter 3 (gas);
Bit = solid bitumen; Ra. Int = rank inertinite or oxidized liptinite; Kerog. Type = Kerogen Type; Oil/gas potent. = oil and gas potential.
* = oxidized phytoclasts; Nonsour. = nonsource rock. Marmor. = Marmora Member; Cree = Cree Member; U.Miss. = Upper Mississauga Formation; Miss. = Mississauga Formation; M.Miss = Middle Missisaiga Formation; MicMac = Mic Mac Formation.

TABLE 2B: Maceral Composition in volume percent (organic facies), R_o, kerogen type, and oil/gas potential of composite shale samples

Borehole No.	Depth (ft/m)	Fm	R_o	Vit	Int	Exe	Res	Lam	Tel	Ltd	ao m 1	aom 2	aom 3	Bit	Ra. Int	Kerog. Type	Oil/Gas Potent.
S. Desbarres O-76	5590 m	MicMac	1.78	16.0	16.0							68.0				IIA–IIB	Oil/Cond
Venture B-43	5310 m	same	1.44	45.0	42.0	9.0								4,0		III	Gas
Venture B-52	2310 m	Cree	0.45	45.0	35.0	20.0*										III	Gas
	2875 m	Naskapi	0.57	33.0	47.0	19.0*								1.0		III	Gas
	3680 m	M.Miss.	0.72	32.0	49.0	19.0										III	Gas
	5810 m	Mic Mac	1.66	35.0	55.0	10.0										III	Gas
Venture H-22	3860 m	M.Miss.	0.74	21.0	60.0	18.0										III	Gas
	4175 m	same	0.77	14.0	65.0	19.0		1.0	1.0							III	Gas
	4410 m	same	-	18.0	54.0	27.0*	1.0									III	Gas
	4550 m	same	0.86	17.0	53.0	29.0*						1.0				III	Gas
W. Chebucto K-20	2770 m	Cree	0.43	59.5	12.5	16.5	0.5		2.5			8.0	0.5			IIB	Cond/Gas
	2950 m	same	0.49	55.5	20.5	14.5	1.5	1.5	0.5	0.5		5.0	0.5			IIB	Cond/Gas
	3070 m	same	0.55	53.5	19.0	14.0	0.5	1.5	1.5			9.0	0.5	0.5		IIB	Cond/Gas
	3340 m	same	0.63	58.5	13.0	21.0	0.5	2.5				4.5				IIB	Cond/Gas
	3890 m	Naskapi	0.65	53.0	15.0	20.0	1.5	0.5	2.0			8.0				IIB	Cond/Gas
	4165 m	Miss.	0.72	43.5	15.0	18.0*	1.0	0.5		0.5		21.0*	0.5			IIB	Cond/Gas
	4400 m	same	0.75	39.0	24.5	13.5		0.5	0.5			22.0*				IIB	Cond/Gas
	4825 m	same	1.09	41.5	15.0	6.5			1.0			25.5				IIB	Cond/Gas

LEGEND: Fm = Formation/Member; R_o = mean random vitrinite reflectance; Vit = vitrinite; Int = Inertinite; Exe = Exenite; Res = Resinite; Lam = Lamalginite; Tel = telalginite Ltd = liptodetrinite; aom 1 = amorphous organic matter 1 (oil); aom 2 = amorphous organic matter 2 (oil and condensate); aom 3 = amorphous organic matter 3 (gas); Bit = solid bitumen; Ra. Int = rank inertinite or oxidized liptinite; Kerog. Type = Kerogen Type; Oil/gas potent. = oil and gas potential.

* = oxidized phytoclasts; Nonsour. = nonsource rock. Naskapi = Naskapi Member; Cree = Cree Member; U.Miss. = Upper Mississauga Formation; Miss. = Mississauga Formation; M.Miss = Middle Mississaiga Formation; MicMac = Mic Mac Formation.

TABLE 3. ROCK-EVAL 5 DERIVED KINETIC PARAMETERS
Five heating rates: 1, 5, 15, 25, and 50 C/min

Sample Id.	Green River Shale (AP22)	Venture B-52 3680 m	N. Triumph B-52 3560 m	Demoscota G-43 11840-11880 ft	Abenaki J-56 10090-1013- ft
Kerogen Type	I	III	IIA-IIB	III	IIA-IIBL
Arrhenius factor (/my)	1.3844244E+27	3.8702914E+25	4.4367602E+24	9.6091408E+25	1.8258914E+26
	Percent of Reaction				
Activation Energy (kcal/mole)					
39			1.86		
40			0.94		
41			4.48		0.06
42		0.29			0.51
43		0.78			
44	0.23	1.06	22.33		
45		1.83	35.36		
46	1.70		19.20		
47	0.07	17.34	5.84		
48		38.20	3.87		
49	7.32	8.78		34.03	49.38
50	2.31	13.57		23.14	13.45
51		6.34	6.12	21.20	20.72
52		0.59		5.00	
53	84.50			6.82	9.97
54					2.68
55		11.22		5.77	
56	2.42			4.04	0.90
57	0.31				1.09
58					
59	1.14				1.24
60					
61					
62					
63					
64					
65					
66					
67					
68					
69					
70					
Standard Error (kcal/mole)	437	895	300	2805	581

Table 4--Scotian Shelf oil/condensates and source rock samples.

Well	SIU Sample No.	DST/ RFT	Depth (m)	Formation	Member
Petroleum Samples					
Arcadia J-16	NS9116	5	5156-5175	Missisauga	Lower
Balmoral M-32	NS9302	3	1954-1958	L.Canyon	Cree
Banquereau C-21	NS9113	1	3585-3596	Missisauga	Lower
Bluenose 2G-47	NS9115	8	4577-4590	Mic Mac	
Chebucto K-90	NS9001	4	4227-4238	Missisauga	Upper
CitnaltaI59	NS9112	3	3777-3781	Missisauga	Lower
Cohasset A-52	NS9004	5	1888-1891	Logan Canyon	Cree
Cohasset D-42	NS9002	7	1861-1865	Logan Canyon	Cree
Glenelg J-48	NS9010	8	3491-3495	Missisauga	Upper
N. Triumph B-52	NS9006	4	3771-3777	Missisauga	Upper
Olympia A-12	NS9007	5	4664-4678	Missisauga	Lower
Panuke B-90	NS9003	1	2293-2299	Missisauga	Upper
Panuke PP3 J-99	NS9301	1	2572-2580	L. Canyon	Cree
Penobscot L-30	NS9114	5	2642	Missisauga	Upper
S. Venture O-S9	NS9008	5	5035-5050	Missisauga	Lower
S. Venture O-S9	NS9009	10	4255-4267	Missisauga	Lower
Sable Island 3H-58	NS9005	5	1435-1436	Logan Canyon	Mamora
Thebaud C-74	NS9118	9	3865-3888	Missisauga	Lower
Uniacke G-72	NS9303	6	5191-5199	Mic Mac	
Venture H-22	NS9117	5	5021-5025	Mic Mac	
Venture H-22	NS9304	7	4957-4962	Mic Mac	
Extract Samples					
Abenaki J-56	NS9305		3080	Missisauga	Lower
Alma F-67	NS9013		4500	Verrill Canyon	
Alma F-67	NS9108		5045	Verrill Canyon	
Cohasset A-52	NS9011		2036	Logan Canyon	Cree
Cohasset D-42	NS9012		4426	Abenaki	Misaine
Demascota G-43	NS9306		3615	Abenaki	Baccaro
Migrant N-20	NS9101		3587	Missisauga	Lower
N. Triumph G-43	NS9103		4845	Missisauga	undif.
N. Triumph G-43	NS9109		3695	Logan Canyon	Naskapi
Penobscot L-30	NS9105		2118	Logan Canyon	undif.
Penobscot L-30	NS9307		4214	Mic Mac	Penobscot
S. Desberres 0-76	NS9107		3861	Missisauga	Lower
S. Sable B-44	NS9111		3938	Missisauga	Middle
S. Venture O-S9	NS9014		6115	Mic Mac	undif.
Thebaud C-74	NS9110		3911	Missisauga	Lower
Venture B-52	NS9102		5121	Missisauga	Lower
W. Chebucto K-20	NS9104		5210	Missisauga	undif.
Whycocomagh N-30	NS9106		3360	Missisauga	undif.

Liquid chromatographic data for 1993 Scotian Shelf samples (normalized %).

	Saturates	Aromatics	Polar 1	Polar 2
Petroleums				
Panuke PP3 J-99 (DST1)	68	26	5	1
Balmoral M-32 (DST3)	70	24	5	1
Uniacke G-72 (DST6)	46	47	6	1
Venture H-22 (DST7)	57	36	4	3
Rock Extracts				
Abenaki J-56 (3080m)	43	16	10	30
Demascota G-43 (3615m)	38	26	6	30
Penobscot L-30 (4214m)	51	32	2	15

Table 5

Table 6: GC/MS peak identification.

Peak	Compound (Isomers specifed if known)	Δm	Standard Deviation	*Used in correlation
m/z 170	**(C3–Alkylnaphthalenes)**			
170a	methylethylnaphthalene	0.06	0.23	*
170b	methylethylnaphthalene	0.02	0.22	*
170c	1,3,7–trimethylnaphthalene (TrMN)	0.25	0.22	
170d	1,3,6–TrMN	0.11	0.18	*
170e	1,4,6– & 1,3,5–TrMN	–0.04	0.17	*
170f	2,3,6–TrMN	0.12	0.17	*
170g	1,6,7– & 1,2,6–TrMN	–0.19	0.16	*
170h	1,2,5–TrMN	– 1.02	0.36	
m/z 184	**(C4–alkylnaphthalenes and dibenzothiophene)**			
184a	1,3,5,7–tetramethylnaphthalene (TeMN)	–0.02	0.18	*
184b	1,3,6,7–TeMN	–0.02	0.16	*
184c	1,2,4,7–TeMN	–0.55	0.29	
184d	1,2,5,7–TeMN	–0.78	0.33	
184e	2,3,6,7–TeMN	–0.03	0.17	*
184f	1,2,6,7–TeMN	–0.55	0.25	
184g	1,2,3,7–TeMN	–0.50	0.31	
184h	1,2,3,6–TeMN	–0.56	0.33	
184i	1,2,5,6–TeMN	–1.61	0.67	
DBT	dibenzothiophene	–0.50	0.89	
m/z 182	**(Dimethylbiphenyls and methyldibenzofurans)**			
182a		0.64	0.44	
182b	3,5–dimethylbiphenyl (DMBP)	0.52	0.28	
182c	3,3'–DMBP	0.39	0.24	
182d	3,4'–DMBP	0.40	0.23	
182e		0.80	0.40	
182f	3,4–DMBP	0.31	0.20	
mDBFa	methyldibenzofuran	–0.59	0.26	
mDBFb	methyldibenzofuran	–0.84	0.33	
mDBFc	methyldibenzofuran	–0.46	0.33	
m/z 198	**(Methyldibenzothiophenes)**			
198a	4–methyldibenzothiophene (MDBT)	0.32	0.30	
198b	3– & 2–MDBT	0.08	0.29	*
198c	1–MDBT	–0.85	0.76	

Table 6

Table 6: Continued

Peak	Compound asomers specifed if known)	Δm	Standard Deviation	*Used in correlation
m/z 212 (C2–Alkyldibenzothiophenes)				
212a	ethyldibenzothiophene	0.17	0.38	*
212b	4,6–dimethyldibenzothiophene (DMDBT	0.35	0.38	
212c	2,4–DMDBT	0.43	0.35	
212d	2,6– & 3,6–DMDBT	0.26	0.37	
212e	3,7–DMDBT	–0.03	0.38	*
212f	1,4– & 1,6– & 1,8–DMDBT	–0.07	0.46	*
212g	1,3–& 1,2– & 1,9–DMDBT	0.05	0.45	*
m/z 178 (Phenanthrene)				
PHN	phenanthrene	0.00	0.07	
m/z 192 (Methylphenanthrenes)				
192a	3–methylphenanthrene (MP)	0.38	0.15	
192b	2–MP	0.27	0.14	
192c	9–MP	0.10	0.12	
192d	1–MP	–0.04	0.09	
m/z 206 (C2–Alkylphenanthrenes)				
206a	3–ethylphenanthrene (ET)	0.16	0.28	*
206b	2–EP &9–EP& 3,6–DMP	–0.09	0.25	*
206c	1–EP	0.62	0.41	
206d	2,6–dimethylphenanthrene (DMP)	0.60	0.26	
206e	2,7–DMP	0.56	0.25	
206f	1,3– & 2,10– & 3,9– & 3,10–DMP	0.41	0.23	
206g	1,6– & 2,9–DMP	0.35	0.19	
206h	1,7–DMP	0.09	0.18	*
206i	2,3–DMP	0.40	0.20	
206j	1,9–DMP	–0.02	0.20	*
206k	1,8–DMP	0.05	0.19	*
2061		–0.80	0.41	
m/z 202 (Fluoranthene and pyrene)				
FLAN	fluoranthene	–0.64	0.28	
PYR	pyrene	–0.54	0.31	
m/z 216 (Methylpyrenes and isomers)				
216a		–0.22	0.16	*
216b	benzo[a]fluorene	–0.05	0.19	*
216c		–0.01	0.79	*
216d	2–methylpyrene	0.04	0.21	*
216e	4–methylpyrene	–0.17	0.17	*
216f	1–methylpyrene	–0.22	0.19	*

Table 6: Continued

Peak Compound (Isomers specifed if known)	Δm	Standard Deviation	*Used in correlation
m/z 230 (Dimethylpyrenes and isomers)			
230a	0.02	0.46	*
230b	0.32	0.32	
230c	−0.39	0.72	
230d	0.13	0.23	*
230e	−0.21	0.70	*
230f	0.04	0.36	*
230g	−0.12	0.16	*
230h	−0.17	0.18	*
230i	−0.41	0.32	
m/z 228 (Chrysene and benzo[a]anthracene)			
BAN benzo[a]anthracene	−0.78	0.36	
CHR chrysene	−0.04	0.30	*
m/z 242 (Methylchrysenes and isomers)			
242a methylchrysene	0.17	0.37	*
242b methylchrysene	0.04	0.40	*
242c methylbenzo[a]anthracene (?)	−0.22	0.29	*
242d methylchrysene	−0.13	0.37	*
m/z 252 (Benzo[a]pyrene and isomers)			
252a benzotj]fluoranthene	−0.53	0.42	
252b benzo[a]pyrene	−0.49	0.43	
252c benzo[e]pyrene	−1.54	0.85	

Table — Coefficients of determination from multiple linear regression of Scotian Shelf aromatic data. See text.

Sample	ARCADJ-5O	BALMOM-3O	BANQUC-1O	BLUENG-8O	CHEBUK-4O	CITNAI-3O	COHASA-5O	COHASD-7O	GLENEJ-8O	NTRIUB-4O	OLYMPA-5O	PANUKB-1O	PANUKJ-1O	PENOBL-5O	SABLEH-5O	SVENTO-1O	SVENTO-5O	THEBAC-9O	UNIACG-6O	VENTUH-5O	VENTUH-7O	ABENAJ-3R
ARCADJ-5O		0.69	0.75	0.95	0.89	0.74	0.63	0.62	0.81	0.88	0.91	0.41	0.46	0.87	0.59	0.90	0.84	0.92	0.71	0.97	0.96	0.89
BALMOM-3O	0.69		0.78	0.74	0.77	0.80	0.81	0.78	0.80	0.80	0.78	0.51	0.64	0.84	0.74	0.80	0.55	0.78	0.55	0.72	0.72	0.65
BANQUC-1O	0.75	0.78		0.77	0.93	0.97	0.80	0.82	0.94	0.93	0.86	0.53	0.67	0.86	0.83	0.89	0.60	0.86	0.65	0.77	0.77	0.75
BLUENG-8O	0.95	0.74	0.77		0.89	0.79	0.63	0.64	0.79	0.88	0.95	0.45	0.47	0.93	0.59	0.91	0.80	0.94	0.66	0.98	0.96	0.89
CHEBUK-4O	0.89	0.77	0.93	0.89		0.90	0.77	0.79	0.96	0.99	0.95	0.53	0.65	0.92	0.78	0.97	0.79	0.94	0.77	0.92	0.91	0.88
CITNAI-3O	0.74	0.80	0.97	0.79	0.90		0.79	0.81	0.90	0.91	0.86	0.56	0.63	0.90	0.80	0.87	0.59	0.87	0.60	0.78	0.75	0.72
COHASA-5O	0.63	0.81	0.80	0.63	0.77	0.79		0.90	0.86	0.81	0.75	0.59	0.56	0.79	0.90	0.77	0.49	0.73	0.51	0.63	0.61	0.57
COHASD-7O	0.62	0.78	0.82	0.64	0.79	0.81	0.90		0.86	0.81	0.78	0.66	0.58	0.81	0.88	0.81	0.56	0.77	0.53	0.66	0.61	0.58
GLENEJ-8O	0.81	0.80	0.94	0.79	0.96	0.90	0.86	0.86		0.98	0.89	0.52	0.62	0.89	0.87	0.93	0.67	0.88	0.69	0.81	0.82	0.77
NTRIUB-4O	0.88	0.80	0.93	0.88	0.99	0.91	0.81	0.81	0.98		0.94	0.53	0.64	0.93	0.81	0.96	0.74	0.94	0.74	0.90	0.90	0.86
OLYMPA-5O	0.91	0.78	0.86	0.95	0.95	0.86	0.75	0.78	0.89	0.94		0.56	0.54	0.95	0.74	0.97	0.79	0.96	0.68	0.95	0.92	0.85
PANUKB-1O	0.41	0.51	0.53	0.45	0.53	0.56	0.59	0.66	0.52	0.53	0.56		0.35	0.55	0.54	0.54	0.36	0.53	0.27	0.47	0.39	0.44
PANUKJ-1O	0.46	0.64	0.67	0.47	0.65	0.63	0.56	0.58	0.62	0.64	0.54	0.35		0.58	0.58	0.60	0.57	0.54	0.79	0.50	0.57	0.59
PENOBL-5O	0.87	0.84	0.86	0.93	0.92	0.90	0.79	0.81	0.89	0.93	0.95	0.55	0.58		0.76	0.93	0.75	0.95	0.66	0.91	0.89	0.83
SABLEH-5O	0.59	0.74	0.83	0.59	0.78	0.80	0.90	0.88	0.87	0.81	0.74	0.54	0.58	0.76		0.78	0.48	0.74	0.55	0.60	0.59	0.57
SVENTO-1O	0.90	0.80	0.89	0.91	0.97	0.87	0.77	0.81	0.93	0.96	0.97	0.54	0.60	0.93	0.78		0.80	0.96	0.73	0.92	0.90	0.85
SVENTO-5O	0.84	0.55	0.60	0.80	0.79	0.59	0.49	0.56	0.67	0.74	0.79	0.36	0.57	0.75	0.48	0.80		0.77	0.85	0.87	0.85	0.80
THEBAC-9O	0.92	0.78	0.86	0.94	0.94	0.87	0.73	0.77	0.88	0.94	0.96	0.53	0.54	0.95	0.74	0.96	0.77		0.67	0.94	0.90	0.87
UNIACG-6O	0.71	0.55	0.65	0.66	0.77	0.60	0.51	0.53	0.69	0.74	0.68	0.27	0.79	0.66	0.55	0.73	0.85	0.67		0.70	0.79	0.79
VENTUH-5O	0.97	0.72	0.77	0.98	0.92	0.78	0.63	0.66	0.81	0.90	0.95	0.47	0.50	0.91	0.60	0.92	0.87	0.94	0.70		0.96	0.89
VENTUH-7O	0.96	0.72	0.77	0.96	0.91	0.75	0.61	0.61	0.82	0.90	0.92	0.39	0.57	0.89	0.59	0.90	0.85	0.90	0.79	0.96		0.93
ABENAJ-3R	0.89	0.65	0.75	0.89	0.88	0.72	0.57	0.58	0.77	0.86	0.85	0.44	0.59	0.83	0.57	0.85	0.80	0.87	0.79	0.89	0.93	
ALMAF-4R	0.32	0.15	0.21	0.33	0.29	0.21	0.13	0.16	0.22	0.29	0.30	0.17	0.17	0.29	0.14	0.33	0.37	0.36	0.32	0.33	0.34	0.39
ALMAF-5R	0.20	0.06	0.11	0.16	0.19	0.09	0.06	0.11	0.12	0.16	0.17	0.10	0.29	0.14	0.08	0.21	0.47	0.20	0.45	0.21	0.21	0.28
COHASA-2R	0.82	0.63	0.74	0.80	0.86	0.71	0.61	0.63	0.77	0.84	0.80	0.46	0.60	0.79	0.61	0.83	0.77	0.83	0.78	0.83	0.85	0.93
COHASD-4R	0.16	0.02	0.03	0.09	0.09	0.02	0.04	0.06	0.05	0.08	0.09	0.11	0.05	0.06	0.04	0.10	0.24	0.10	0.17	0.13	0.12	0.19
DEMASG-3R	0.83	0.46	0.59	0.80	0.75	0.55	0.37	0.42	0.61	0.72	0.74	0.34	0.41	0.67	0.38	0.74	0.78	0.76	0.69	0.82	0.84	0.92
MIGRAN-3R	0.78	0.50	0.63	0.78	0.76	0.63	0.44	0.48	0.65	0.74	0.74	0.39	0.44	0.72	0.44	0.75	0.75	0.78	0.67	0.80	0.80	0.87
NTRIUG-3R	0.70	0.38	0.52	0.67	0.67	0.49	0.34	0.36	0.54	0.64	0.62	0.28	0.49	0.58	0.36	0.64	0.73	0.65	0.76	0.69	0.75	0.86
NTRIUG-4R	0.22	0.08	0.15	0.22	0.23	0.14	0.07	0.11	0.16	0.21	0.21	0.08	0.27	0.21	0.10	0.25	0.43	0.24	0.44	0.24	0.27	0.32
PENOBL-2R	0.64	0.53	0.68	0.64	0.76	0.66	0.57	0.68	0.71	0.75	0.72	0.54	0.54	0.70	0.59	0.75	0.67	0.76	0.62	0.70	0.65	0.73
PENOBL-4R	0.85	0.54	0.66	0.83	0.81	0.62	0.44	0.47	0.68	0.78	0.78	0.35	0.54	0.72	0.45	0.79	0.81	0.80	0.80	0.84	0.90	0.95
SDESBO-3R	0.89	0.66	0.72	0.92	0.84	0.75	0.54	0.52	0.73	0.83	0.85	0.40	0.55	0.87	0.50	0.83	0.80	0.85	0.73	0.91	0.94	0.93
SSABLB-3R	0.86	0.60	0.64	0.88	0.78	0.65	0.46	0.46	0.64	0.76	0.79	0.36	0.51	0.78	0.44	0.79	0.77	0.82	0.71	0.85	0.90	0.92
SVENTO-6R	0.07	0.01	0.05	0.05	0.06	0.04	0.02	0.02	0.04	0.06	0.05	0.13	0.02	0.04	0.02	0.06	0.06	0.07	0.06	0.05	0.06	0.13
THEBAC-3R	0.88	0.57	0.62	0.91	0.77	0.62	0.45	0.48	0.63	0.75	0.83	0.36	0.40	0.79	0.44	0.83	0.79	0.86	0.65	0.88	0.89	0.87
VENTUB-5R	0.87	0.52	0.55	0.87	0.73	0.56	0.40	0.43	0.59	0.71	0.78	0.32	0.39	0.75	0.38	0.77	0.85	0.81	0.66	0.88	0.88	0.84
WCHEBK-5R	0.11	0.02	0.05	0.11	0.10	0.05	0.01	0.03	0.04	0.08	0.09	0.03	0.16	0.09	0.01	0.11	0.31	0.11	0.29	0.13	0.15	0.19
WHYCON-3R	0.52	0.26	0.37	0.54	0.50	0.37	0.20	0.28	0.37	0.47	0.50	0.27	0.40	0.48	0.22	0.51	0.68	0.54	0.59	0.57	0.57	0.66

Table 7

Table — Continued																					
ALMAF-4R	ALMAF-5R	COHASA-2R	COHASD-4R	DEMASG-3R	MIGRAN-3R	NTRIUG-3R	NTRIUG-4R	PENOBL-2R	PENOBL-4R	SDESBO-3R	SSABLB-3R	SVENTO-6R	THEBAC-3R	VENTUB-5R	WCHEBK-5R	WHYCON-3R	Sample				
0.32	0.20	0.82	0.16	0.83	0.78	0.70	0.22	0.64	0.85	0.89	0.86	0.07	0.88	0.87	0.11	0.52	ARCADJ-5O				
0.15	0.06	0.63	0.02	0.46	0.50	0.38	0.08	0.53	0.54	0.66	0.60	0.01	0.57	0.52	0.02	0.26	BALMOM-3O				
0.21	0.11	0.74	0.03	0.59	0.63	0.52	0.15	0.68	0.66	0.72	0.64	0.05	0.62	0.55	0.05	0.37	BANQUC-1O				
0.33	0.16	0.80	0.09	0.80	0.78	0.67	0.22	0.64	0.83	0.92	0.88	0.05	0.91	0.87	0.11	0.54	BLUENG-8O				
0.29	0.19	0.86	0.09	0.75	0.76	0.67	0.23	0.76	0.81	0.84	0.78	0.06	0.77	0.73	0.10	0.50	CHEBUK-4O	("Chebucto K-90, DST 4, Oil")			
0.21	0.09	0.71	0.02	0.55	0.63	0.49	0.14	0.66	0.62	0.75	0.65	0.04	0.62	0.56	0.05	0.37	CITNAI-3O				
0.13	0.06	0.61	0.04	0.37	0.44	0.34	0.07	0.57	0.44	0.54	0.46	0.02	0.45	0.40	0.01	0.20	COHASA-5O				
0.16	0.11	0.63	0.06	0.42	0.48	0.36	0.11	0.68	0.47	0.52	0.46	0.02	0.48	0.43	0.03	0.28	COHASD-7O				
0.22	0.12	0.77	0.05	0.61	0.65	0.54	0.16	0.71	0.68	0.73	0.64	0.04	0.63	0.59	0.04	0.37	GLENEJ-8O				
0.29	0.16	0.84	0.08	0.72	0.74	0.64	0.21	0.75	0.78	0.83	0.76	0.06	0.75	0.71	0.08	0.47	NTRIUB-4O				
0.30	0.17	0.80	0.09	0.74	0.74	0.62	0.21	0.72	0.78	0.85	0.79	0.05	0.83	0.78	0.09	0.50	OLYMPA-5O				
0.17	0.10	0.46	0.11	0.34	0.39	0.28	0.08	0.54	0.35	0.40	0.36	0.13	0.36	0.32	0.03	0.27	PANUKB-1O				
0.17	0.29	0.60	0.05	0.41	0.44	0.49	0.27	0.54	0.54	0.55	0.51	0.02	0.40	0.39	0.16	0.40	PANUKJ-1O				
0.29	0.14	0.79	0.06	0.67	0.72	0.58	0.21	0.70	0.72	0.87	0.78	0.04	0.79	0.75	0.09	0.48	PENOBL-5O				
0.14	0.08	0.61	0.04	0.38	0.44	0.36	0.10	0.59	0.45	0.50	0.44	0.02	0.44	0.38	0.01	0.22	SABLEH-5O				
0.33	0.21	0.83	0.10	0.74	0.75	0.64	0.25	0.75	0.79	0.83	0.79	0.06	0.83	0.77	0.11	0.51	SVENTO-1O				
0.37	0.47	0.77	0.24	0.78	0.75	0.73	0.43	0.67	0.81	0.80	0.77	0.06	0.79	0.85	0.31	0.68	SVENTO-5O				
0.36	0.20	0.83	0.10	0.76	0.78	0.65	0.24	0.76	0.80	0.85	0.82	0.07	0.86	0.81	0.11	0.54	THEBAC-9O				
0.32	0.45	0.78	0.17	0.69	0.67	0.76	0.44	0.62	0.80	0.73	0.71	0.06	0.65	0.66	0.29	0.59	UNIACG-6O				
0.33	0.21	0.83	0.13	0.82	0.80	0.69	0.24	0.70	0.84	0.91	0.85	0.05	0.88	0.88	0.13	0.57	VENTUH-5O				
0.34	0.21	0.85	0.12	0.84	0.80	0.75	0.27	0.65	0.90	0.94	0.90	0.06	0.89	0.88	0.15	0.57	VENTUH-7O				
0.39	0.28	0.93	0.19	0.92	0.87	0.86	0.32	0.73	0.95	0.93	0.92	0.13	0.87	0.84	0.19	0.66	ABENAJ-3R				
	0.57	0.44	0.21	0.54	0.62	0.64	0.81	0.54	0.53	0.40	0.45	0.56	0.51	0.56	0.68	0.79	ALMAF-4R				
0.57		0.33	0.38	0.40	0.41	0.54	0.82	0.45	0.40	0.23	0.28	0.30	0.31	0.38	0.76	0.71	ALMAF-5R				
0.44	0.33		0.27	0.86	0.88	0.85	0.38	0.77	0.90	0.86	0.87	0.18	0.82	0.79	0.25	0.67	COHASA-2R	("Cohasset A-52, 2036 m, rock")			
0.21	0.38	0.27		0.26	0.26	0.31	0.25	0.14	0.22	0.12	0.20	0.26	0.20	0.21	0.29	0.26	COHASD-4R				
0.54	0.40	0.86	0.26		0.93	0.92	0.44	0.73	0.97	0.85	0.88	0.25	0.89	0.87	0.32	0.78	DEMASG-3R				
0.62	0.41	0.88	0.26	0.93		0.90	0.53	0.80	0.91	0.87	0.86	0.29	0.86	0.85	0.40	0.81	MIGRAN-3R				
0.64	0.54	0.85	0.31	0.92	0.90		0.61	0.70	0.93	0.79	0.83	0.34	0.79	0.79	0.47	0.84	NTRIUG-3R				
0.81	0.82	0.38	0.25	0.44	0.53	0.61		0.46	0.45	0.32	0.36	0.40	0.39	0.46	0.90	0.79	NTRIUG-4R				
0.54	0.45	0.77	0.14	0.73	0.80	0.70	0.46		0.73	0.65	0.59	0.20	0.64	0.65	0.28	0.73	PENOBL-2R				
0.53	0.40	0.90	0.22	0.97	0.91	0.93	0.45	0.73		0.89	0.91	0.21	0.89	0.88	0.31	0.77	PENOBL-4R				
0.40	0.23	0.86	0.12	0.85	0.87	0.79	0.32	0.65	0.89		0.95	0.12	0.90	0.88	0.22	0.65	SDESBO-3R				
0.45	0.28	0.87	0.20	0.88	0.86	0.83	0.36	0.59	0.91	0.95		0.16	0.94	0.89	0.27	0.68	SSABLB-3R				
0.56	0.30	0.18	0.26	0.25	0.29	0.34	0.40	0.20	0.21	0.12	0.16		0.15	0.14	0.43	0.35	SVENTO-6R				
0.51	0.31	0.82	0.20	0.89	0.86	0.79	0.39	0.64	0.89	0.90	0.94	0.15		0.95	0.26	0.69	THEBAC-3R				
0.56	0.38	0.79	0.21	0.87	0.85	0.79	0.46	0.65	0.88	0.88	0.89	0.14	0.95		0.33	0.76	VENTUB-5R				
0.68	0.76	0.25	0.29	0.32	0.40	0.47	0.90	0.28	0.31	0.22	0.27	0.43	0.26	0.33		0.69	WCHEBK-5R				
0.79	0.71	0.67	0.26	0.78	0.81	0.84	0.79	0.73	0.77	0.65	0.68	0.35	0.69	0.76	0.69		WHYCON-3R				

Table 7

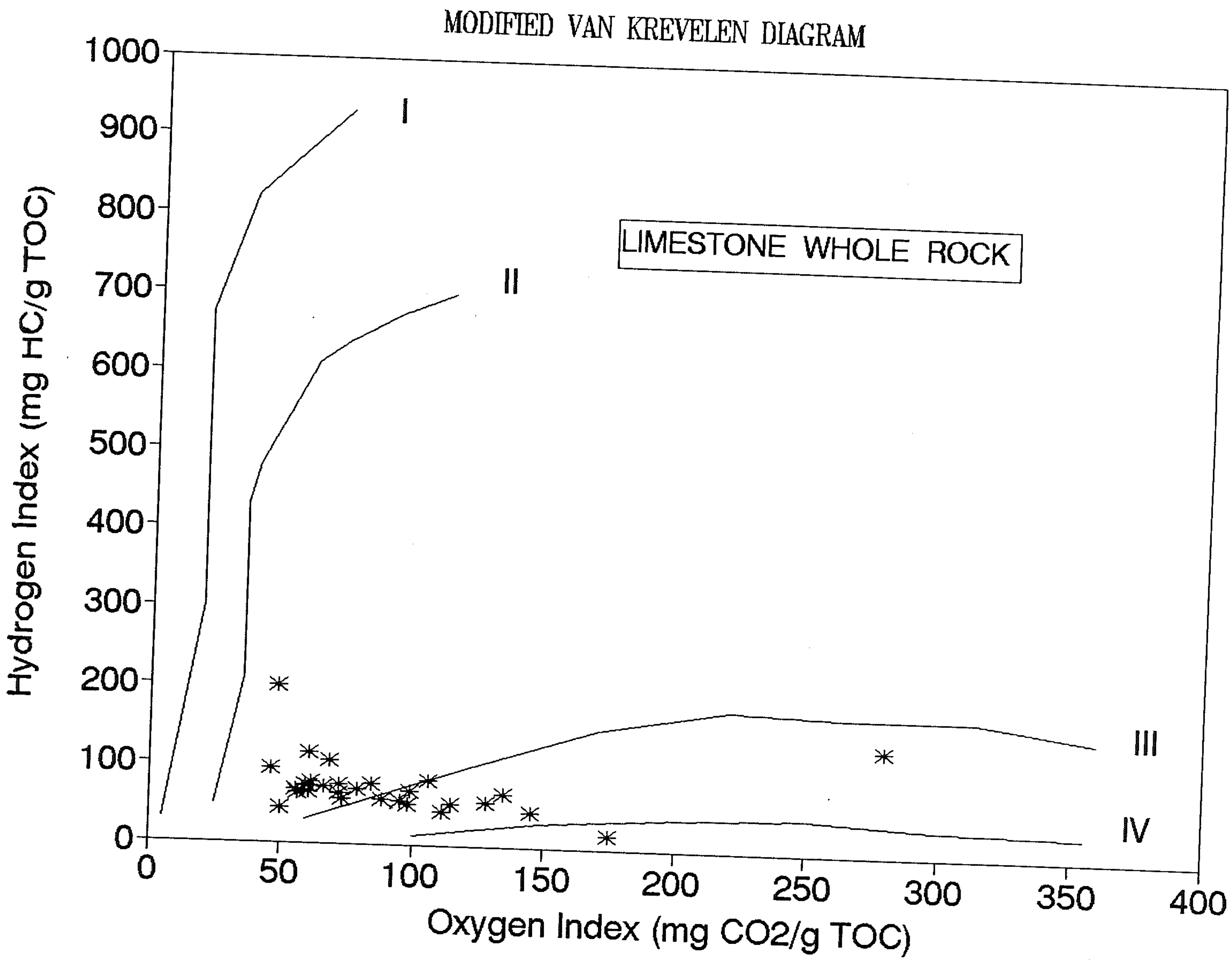

MODIFIED VAN KREVELEN DIAGRAM
LIMESTONE WHOLE ROCK
I
II
III
IV
Hydrogen Index (mg HC/g TOC)
1000
900
800
700
600
500
400
300
200
100
0
Oxygen Index (mg CO2/g TOC)
0
50
100
150
200
250
300
350
400

Figure 1A

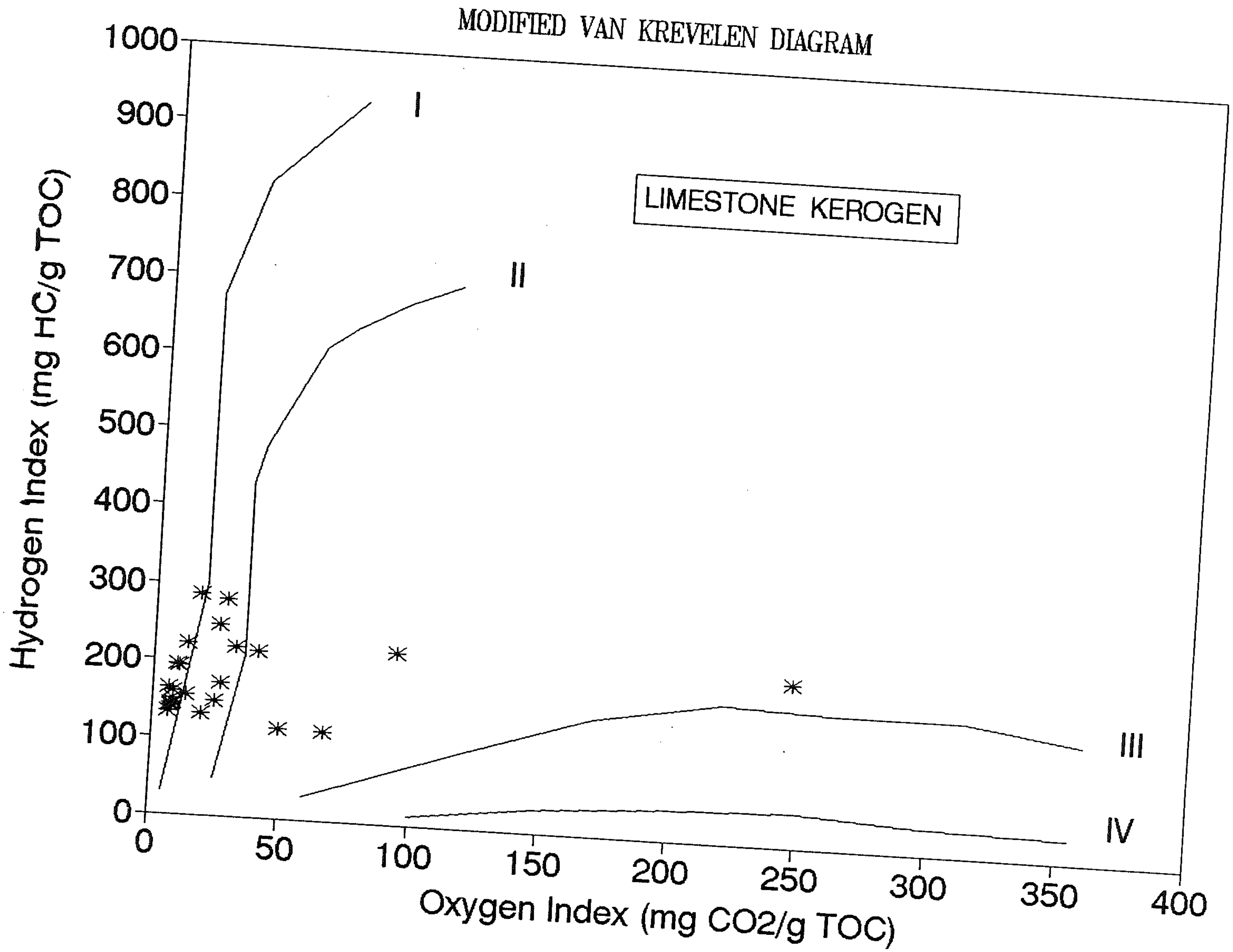

MODIFIED VAN KREVELEN DIAGRAM
LIMESTONE KEROGEN
I
II
III
IV
Hydrogen Index (mg HC/g TOC)
1000
900
800
700
600
500
400
300
200
100
0
Oxygen Index (mg CO2/g TOC)
0
50
100
150
200
250
300
350
400

Figure 1B

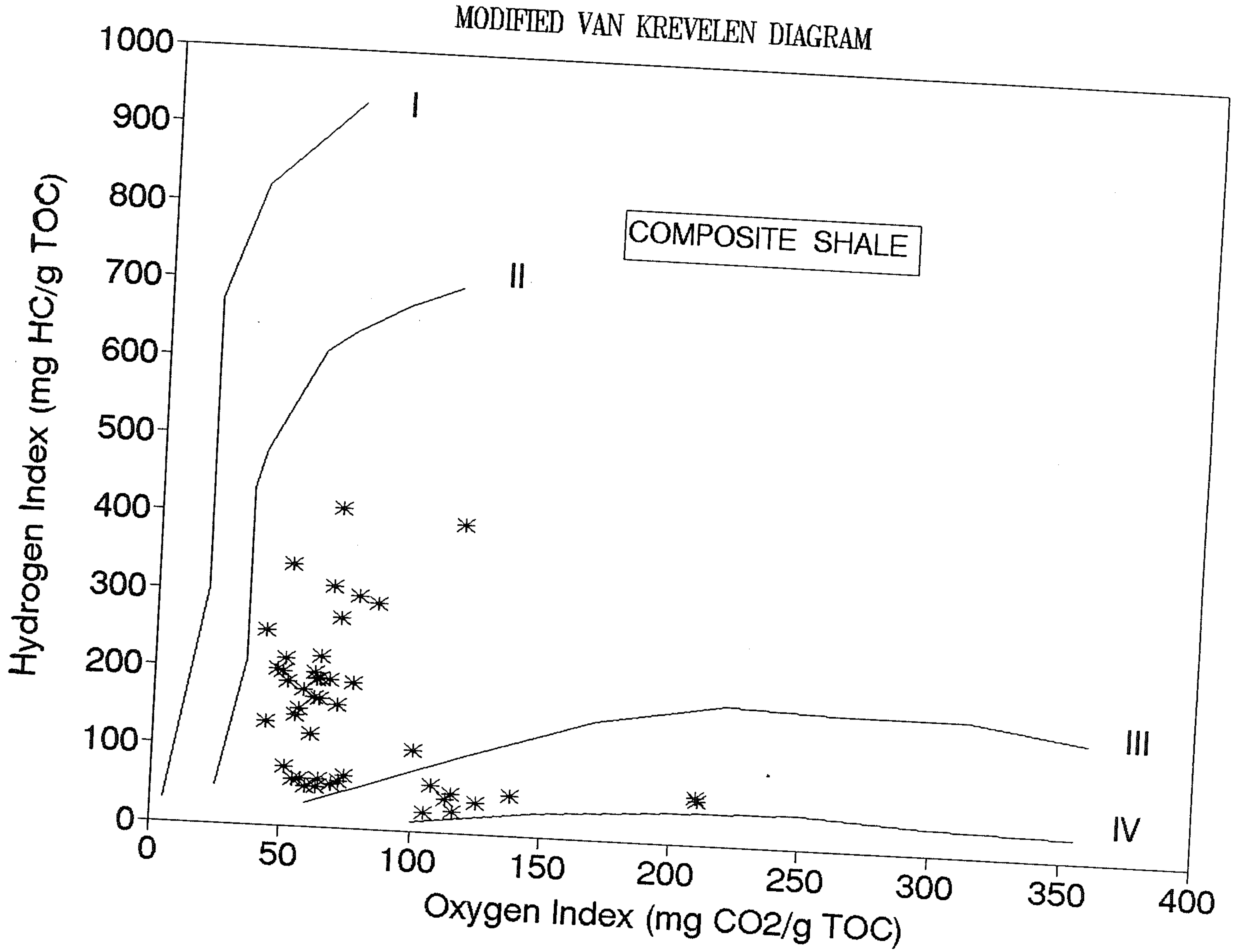

MODIFIED VAN KREVELEN DIAGRAM
COMPOSITE SHALE
I
II
III
IV
Hydrogen Index (mg HC/g TOC)
1000
900
800
700
600
500
400
300
200
100
0
Oxygen Index (mg CO2/g TOC)
0
50
100
150
200
250
300
350
400

Figure 1C

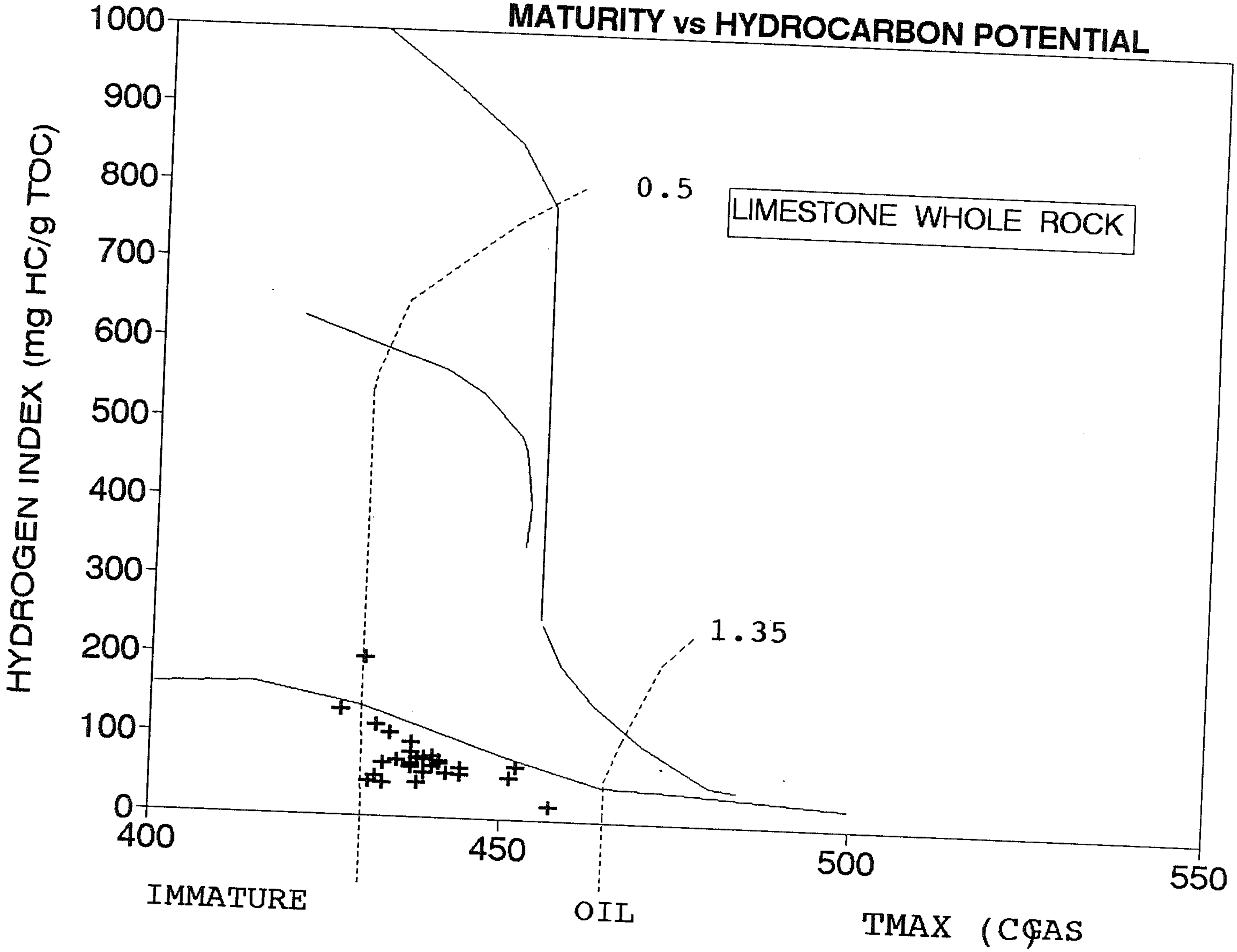

MATURITY vs HYDROCARBON POTENTIAL
LIMESTONE WHOLE ROCK
0.5
1.35
HYDROGEN INDEX (mg HC/g TOC)
1000
900
800
700
600
500
400
300
200
100
0
400
450
500
550
IMMATURE
OIL
TMAX (C)GAS

Figure 2A

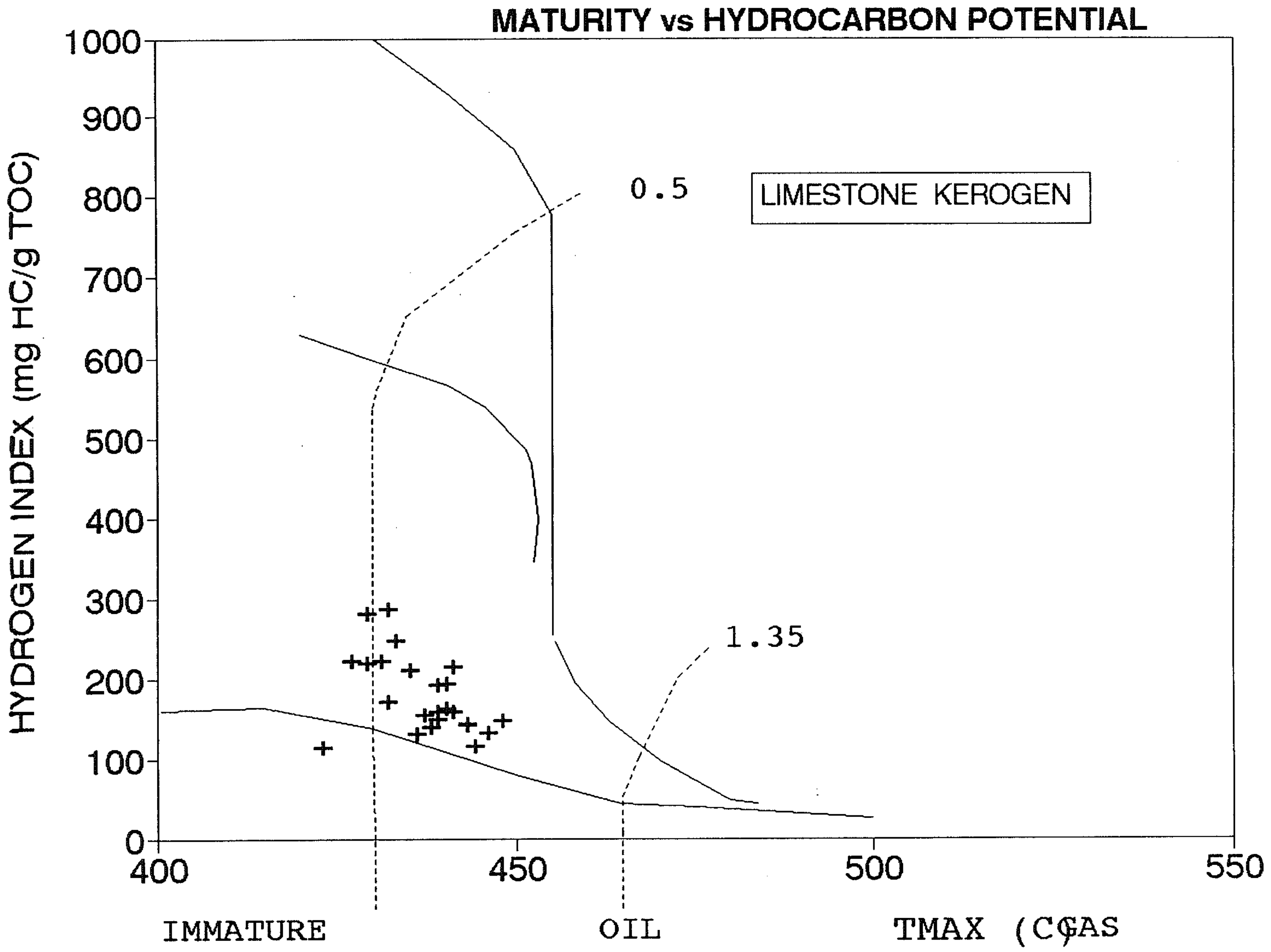

MATURITY vs HYDROCARBON POTENTIAL
LIMESTONE KEROGEN
HYDROGEN INDEX (mg HC/g TOC)
1000
900
800
700
600
500
400
300
200
100
0
400
450
500
550
0.5
1.35
IMMATURE
OIL
TMAX (C)
GAS

Figure 2B

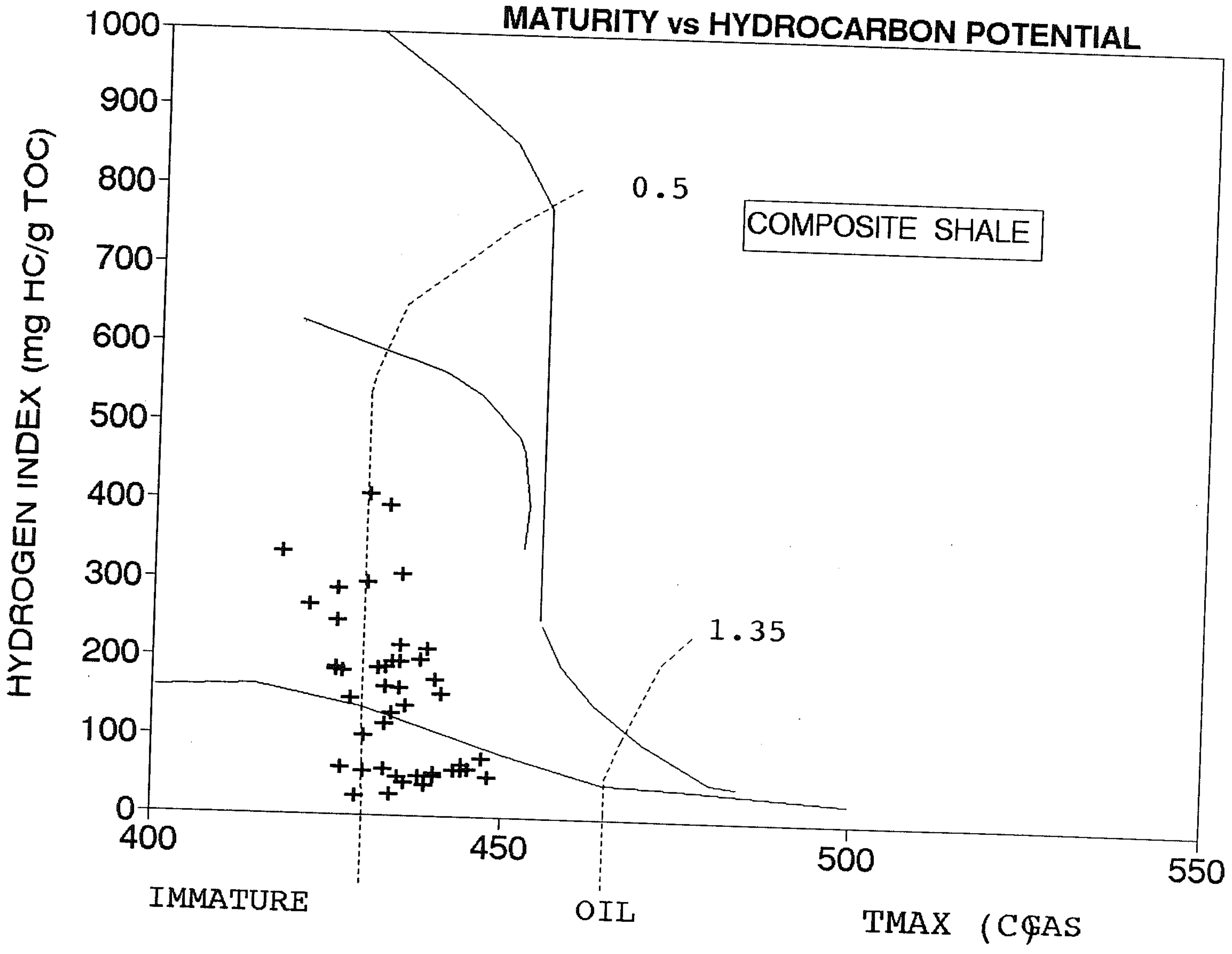

MATURITY vs HYDROCARBON POTENTIAL
COMPOSITE SHALE
HYDROGEN INDEX (mg HC/g TOC)
1000
900
800
700
600
500
400
300
200
100
0
400
450
500
550
0.5
1.35
IMMATURE
OIL
TMAX (C)GAS

Figure 2C

ROCK-EVAL DERIVED KINETIC PARAMETERS

GREEN RIVER SHALE (AP22)

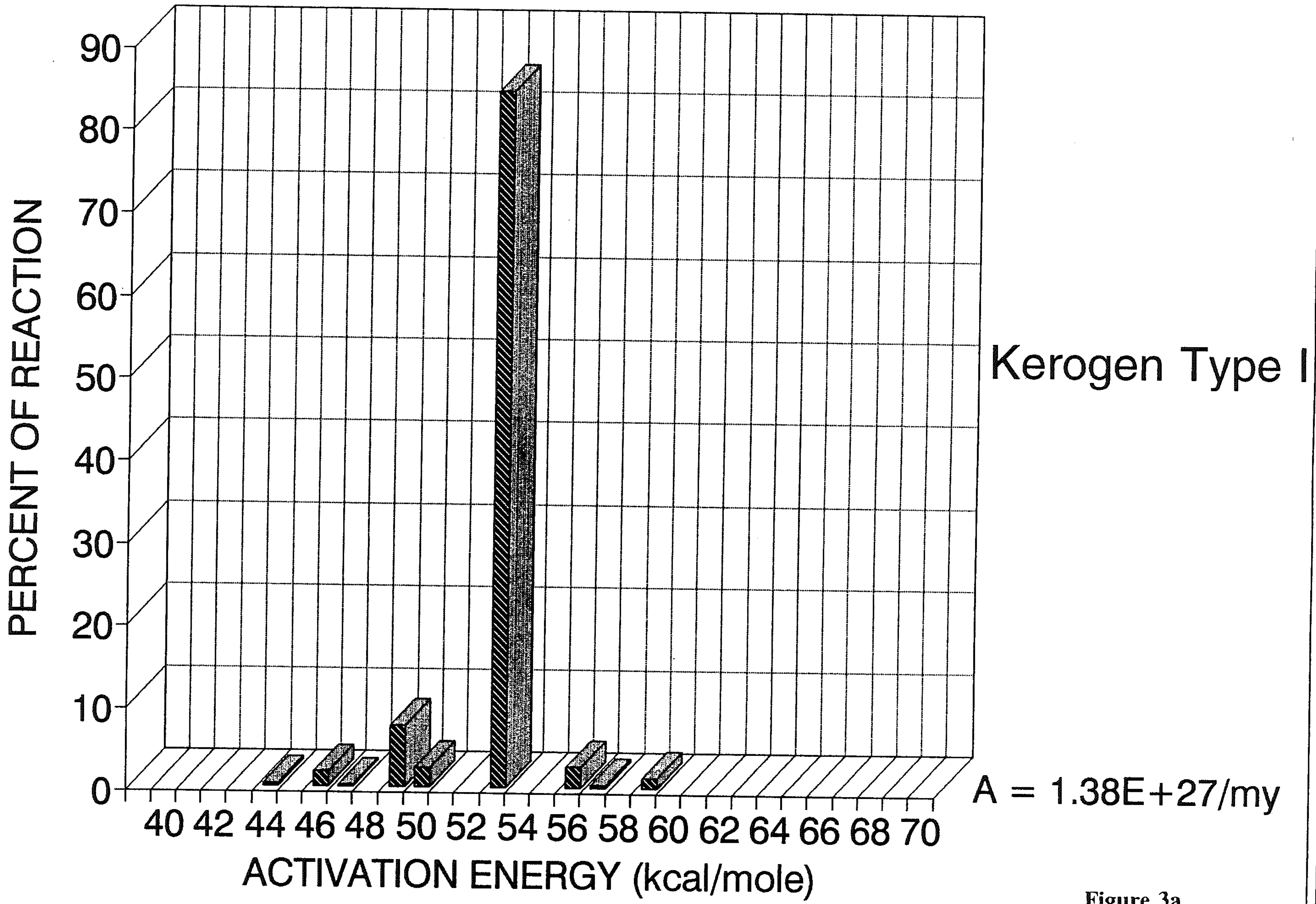
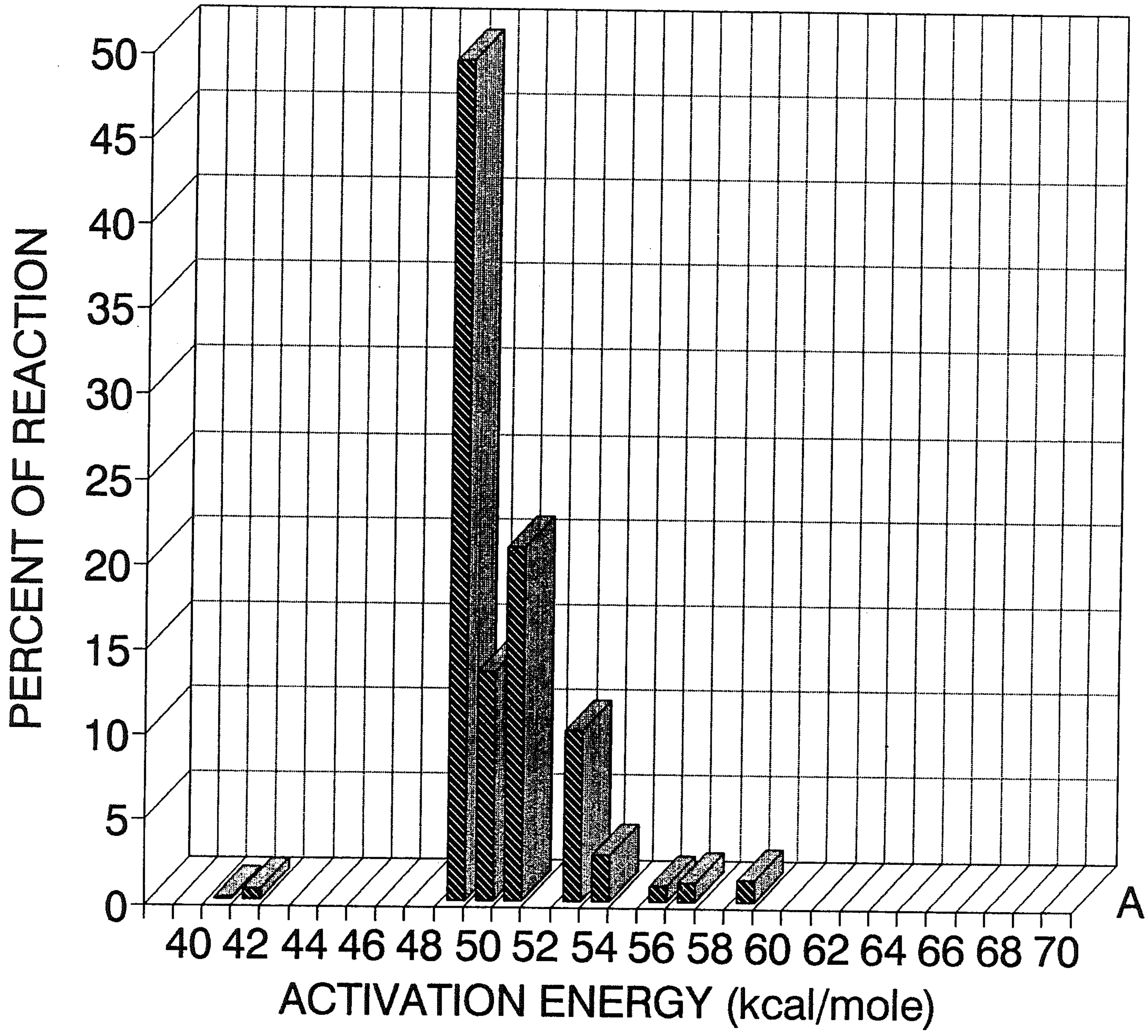


Figure 3a

ROCK-EVAL DERIVED KINETIC PARAMETERS

ABENAKI J-56 10090 - 10130 ft



Kerogen
Type IIA-IIBL

A = 1.83E+26/my

Figure 3b

ROCK-EVAL DERIVED KINETIC PARAMETERS

DEMOSCOTA G-43 11840 - 11880 ft

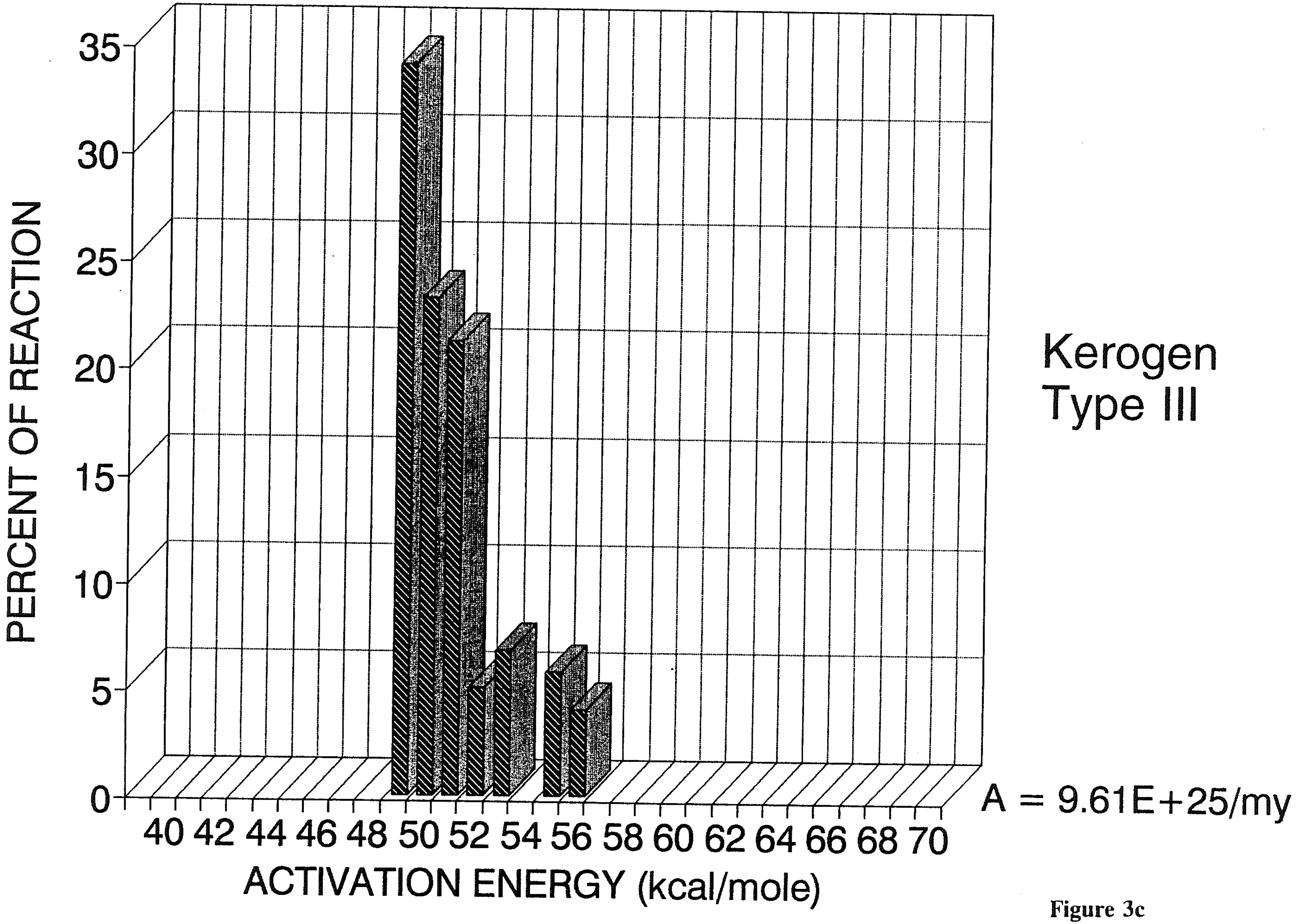
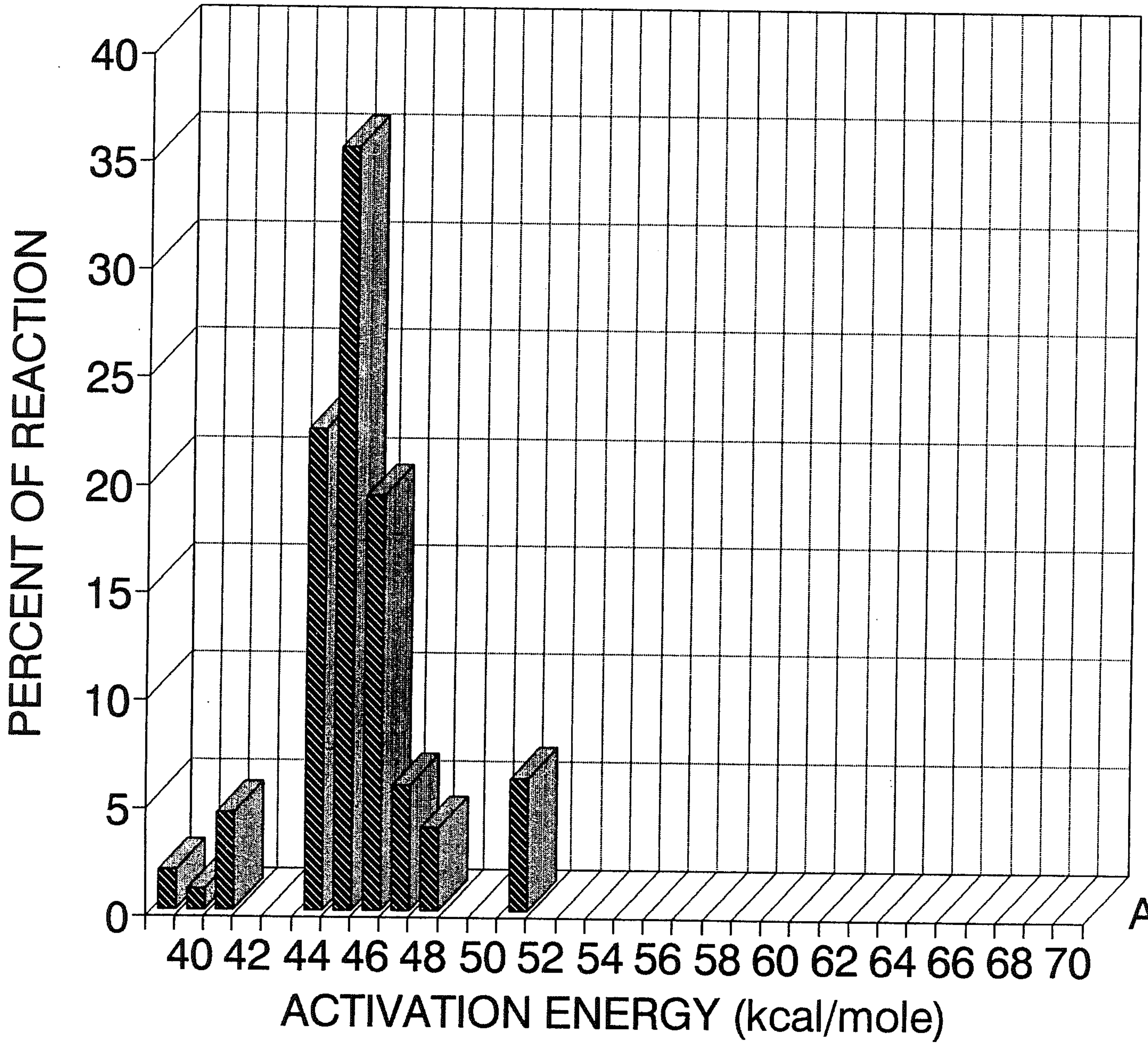


Figure 3c

ROCK-EVAL DERIVED KINETIC PARAMETERS

NORTH TRIUMPH B-52 3560 m



Kerogen
Type IIA-IIB

A = 4.44E+24/my

Figure 3d

ROCK-EVAL DERIVED KINETIC PARAMETERS

VENTURE B-52 3680 m

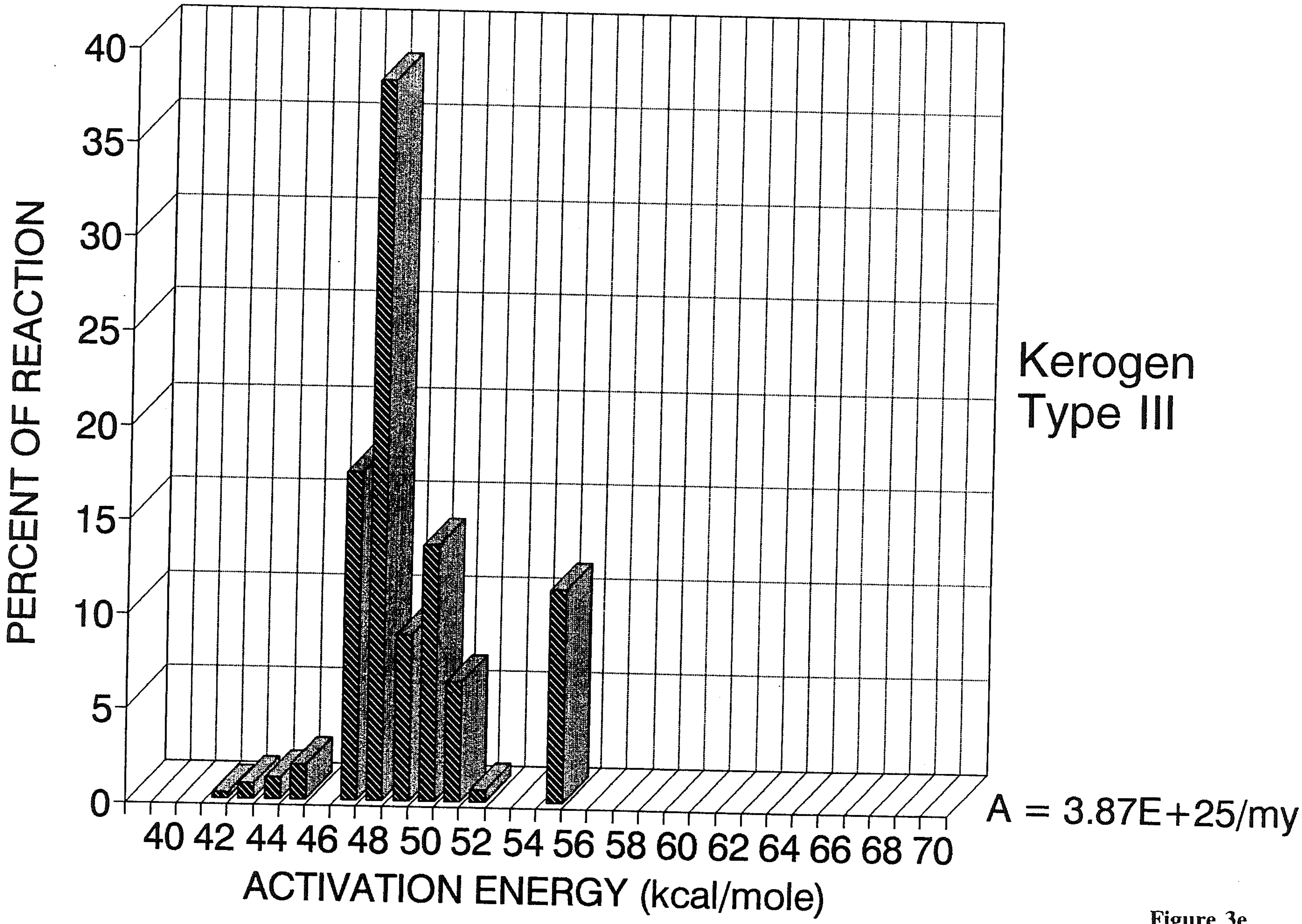


Figure 3e

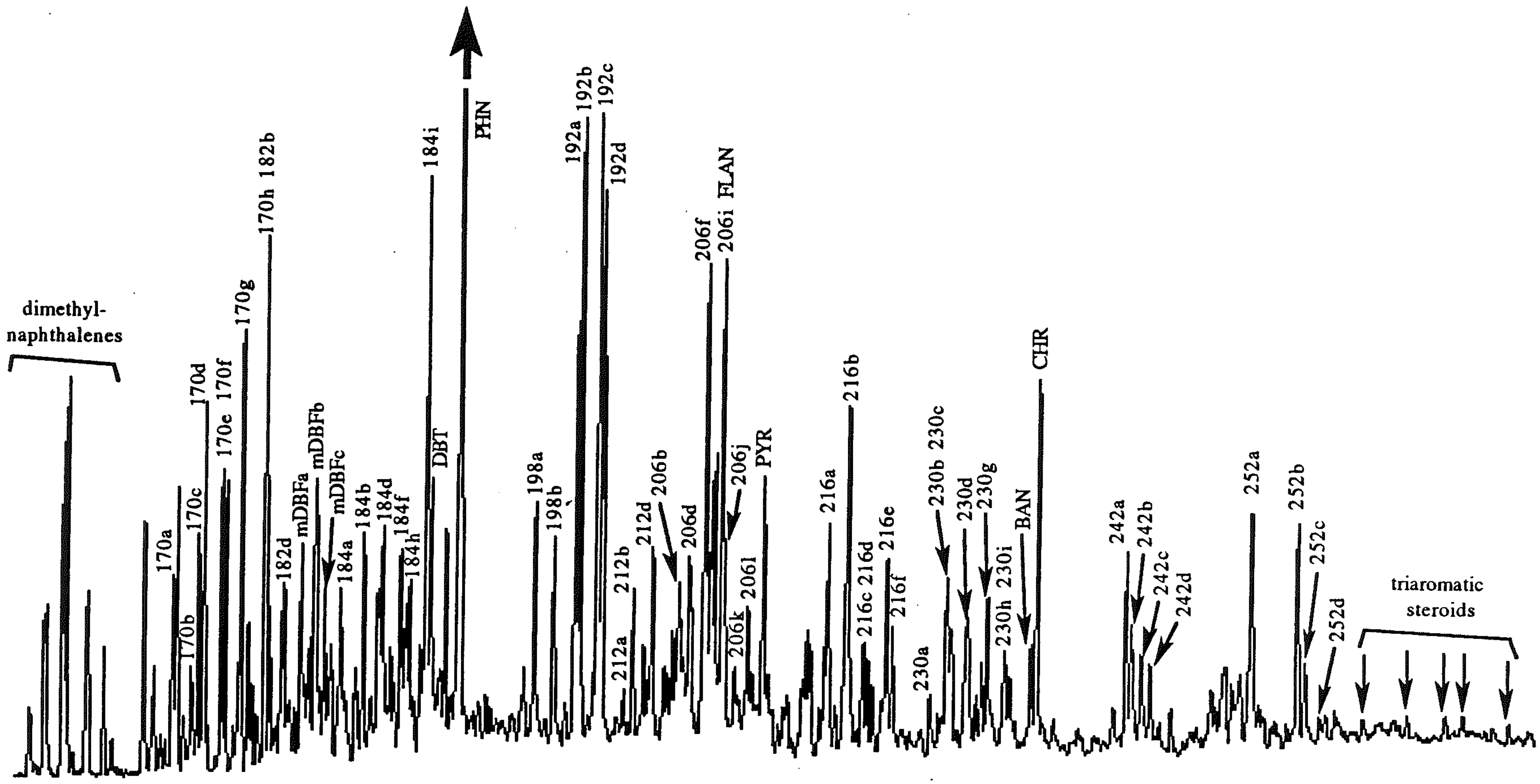

dimethyl-naphthalenes
170a
170b
170c
170d
170e 170f
170g
170h 182b
182d
mDBFa
mDBFb
mDBFc
184a
184b
184d
184f
184h
184i
DBT
PHN
198a
198b
192a
192b
192c
192d
212a
212b
212d
206b
206d
206f
206i FLAN
206j
206k
206l
PYR
216a
216b
216c 216d
216e
216f
230a
230b 230c
230d
230g
230h 230i
BAN
CHR
242a
242b
242c
242d
252a
252b
252c
252d
triaromatic steroids

Figure 4

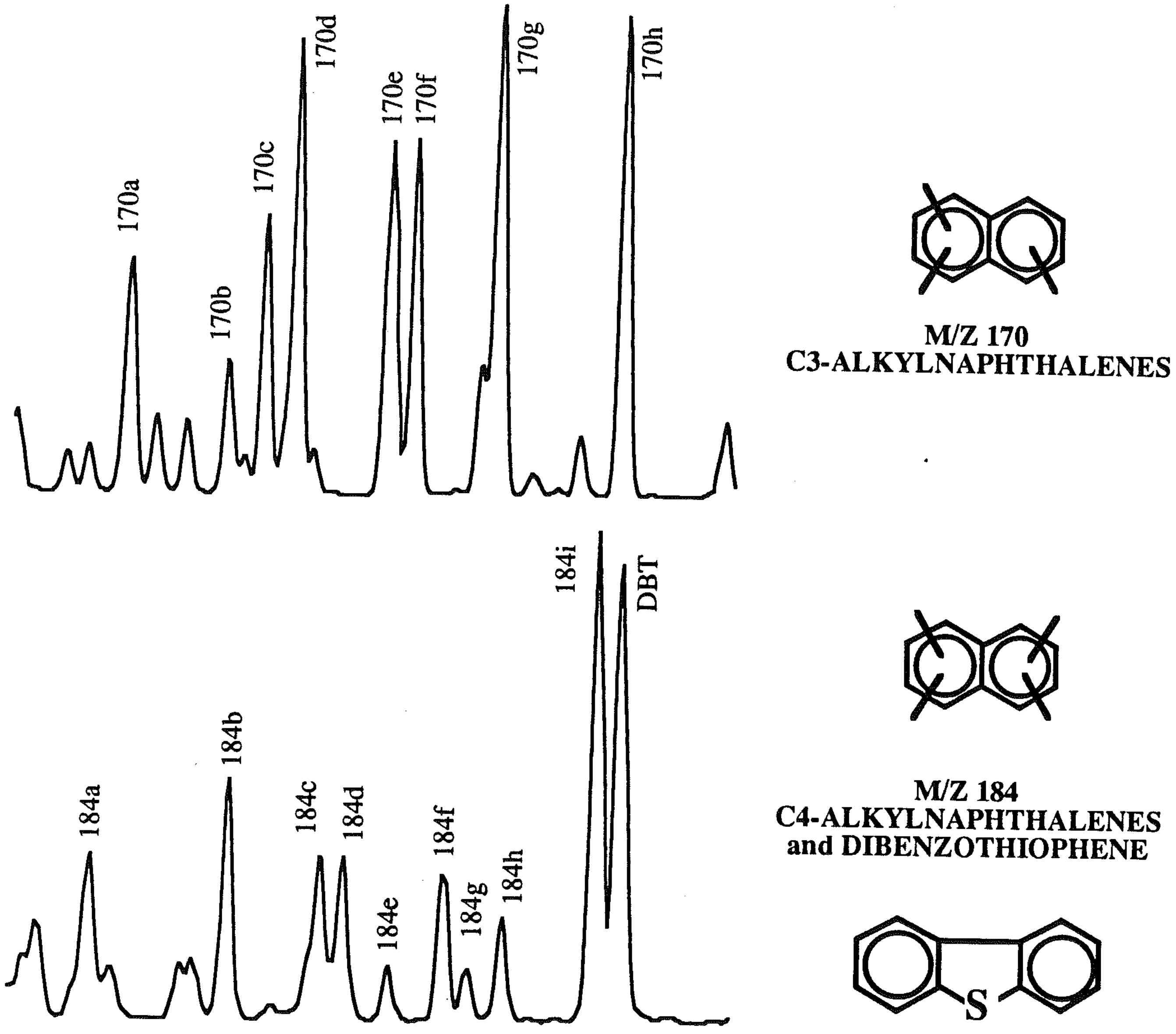
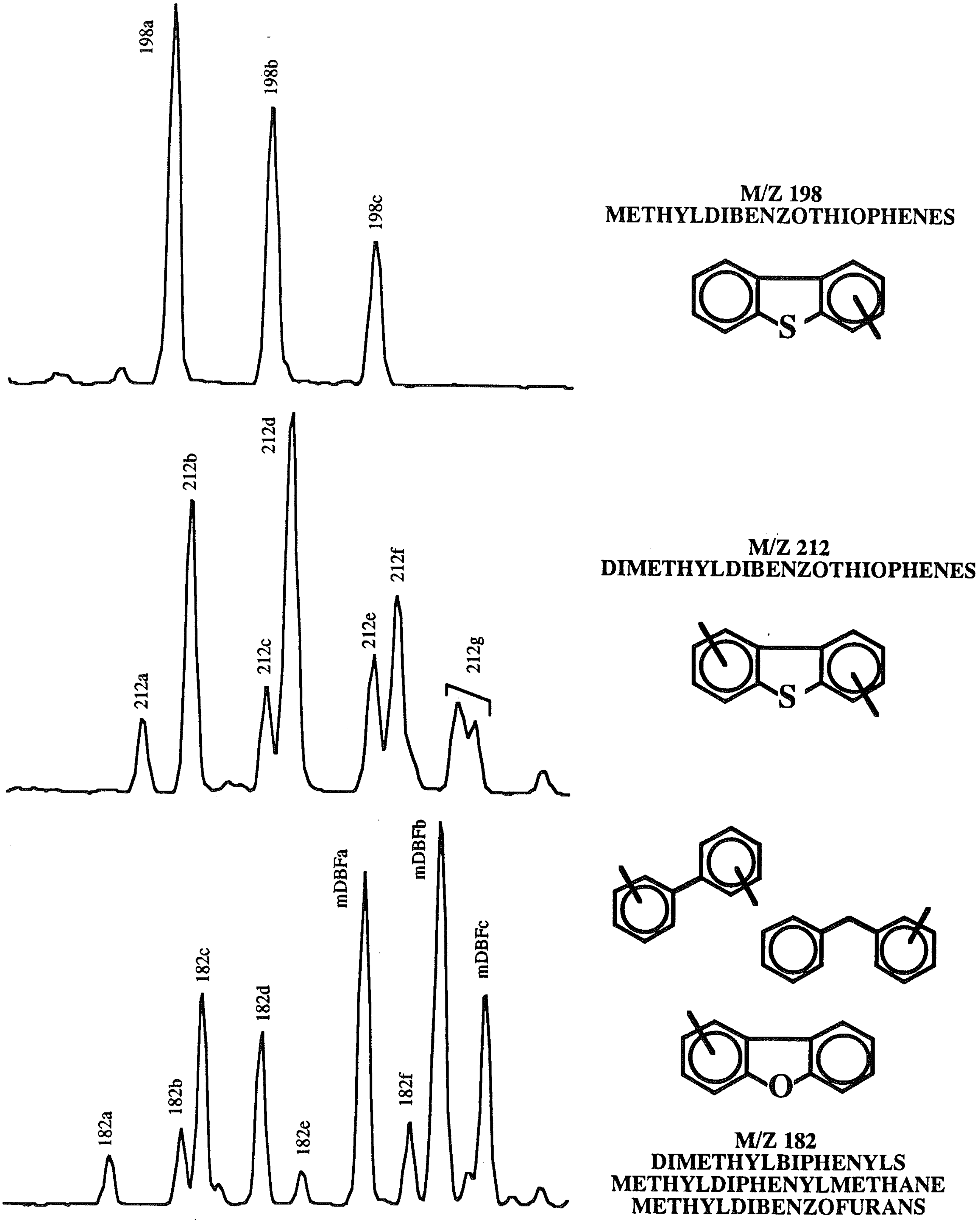

170a
170b
170c
170d
170e
170f
170g
170h
M/Z 170
C3-ALKYLNAPHTHALENES
184a
184b
184c
184d
184e
184f
184g
184h
184i
DBT
M/Z 184
C4-ALKYLNAPHTHALENES
and DIBENZOTHIOPHENE
S

Figure 5

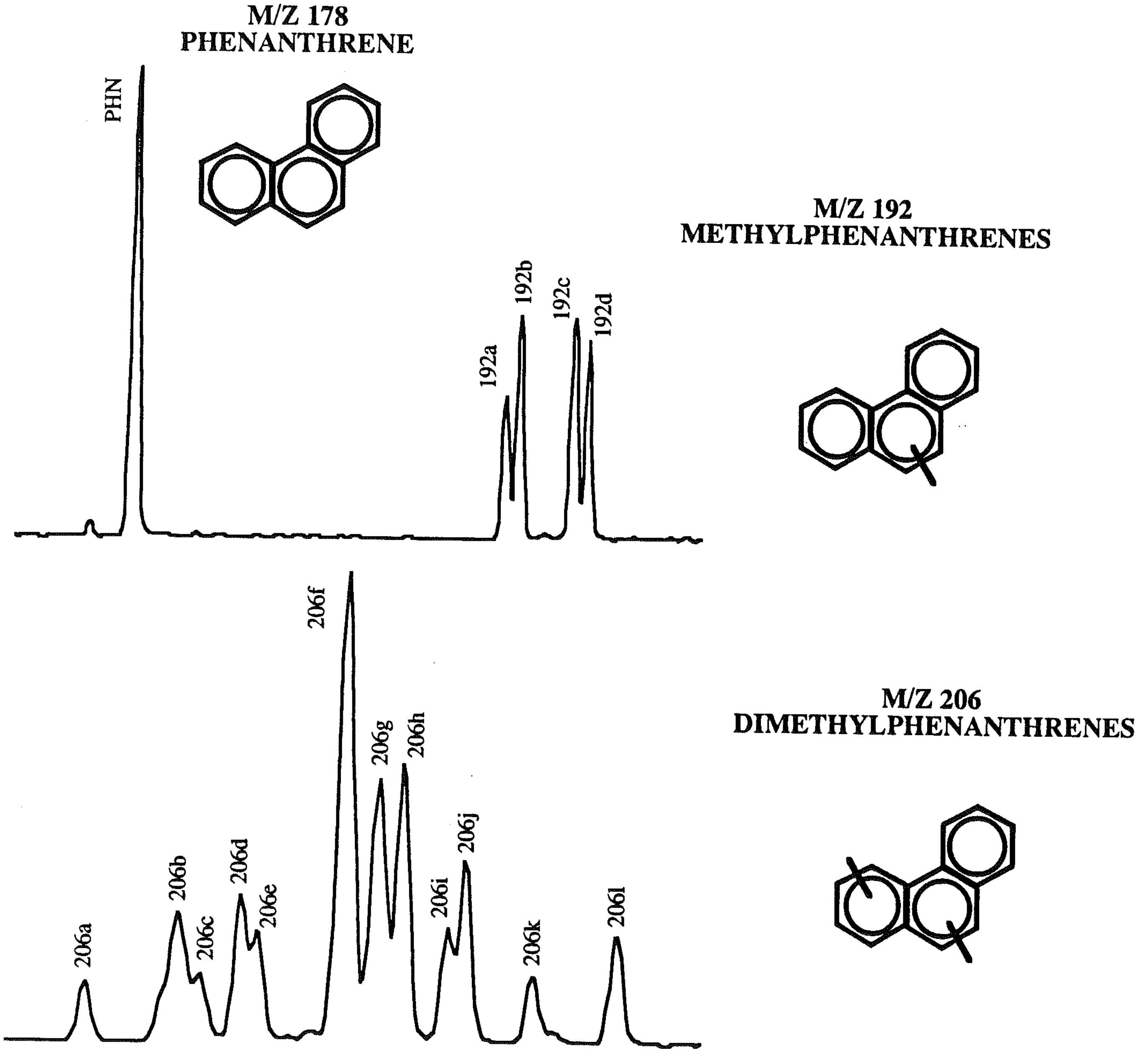


M/Z 198
METHYLDIBENZOTHIOPHENES

M/Z 212
DIMETHYLDIBENZOTHIOPHENES

M/Z 182
DIMETHYLBIPHENYLS
METHYLDIPHENYLMETHANE
METHYLDIBENZOFURANS

Figure 6

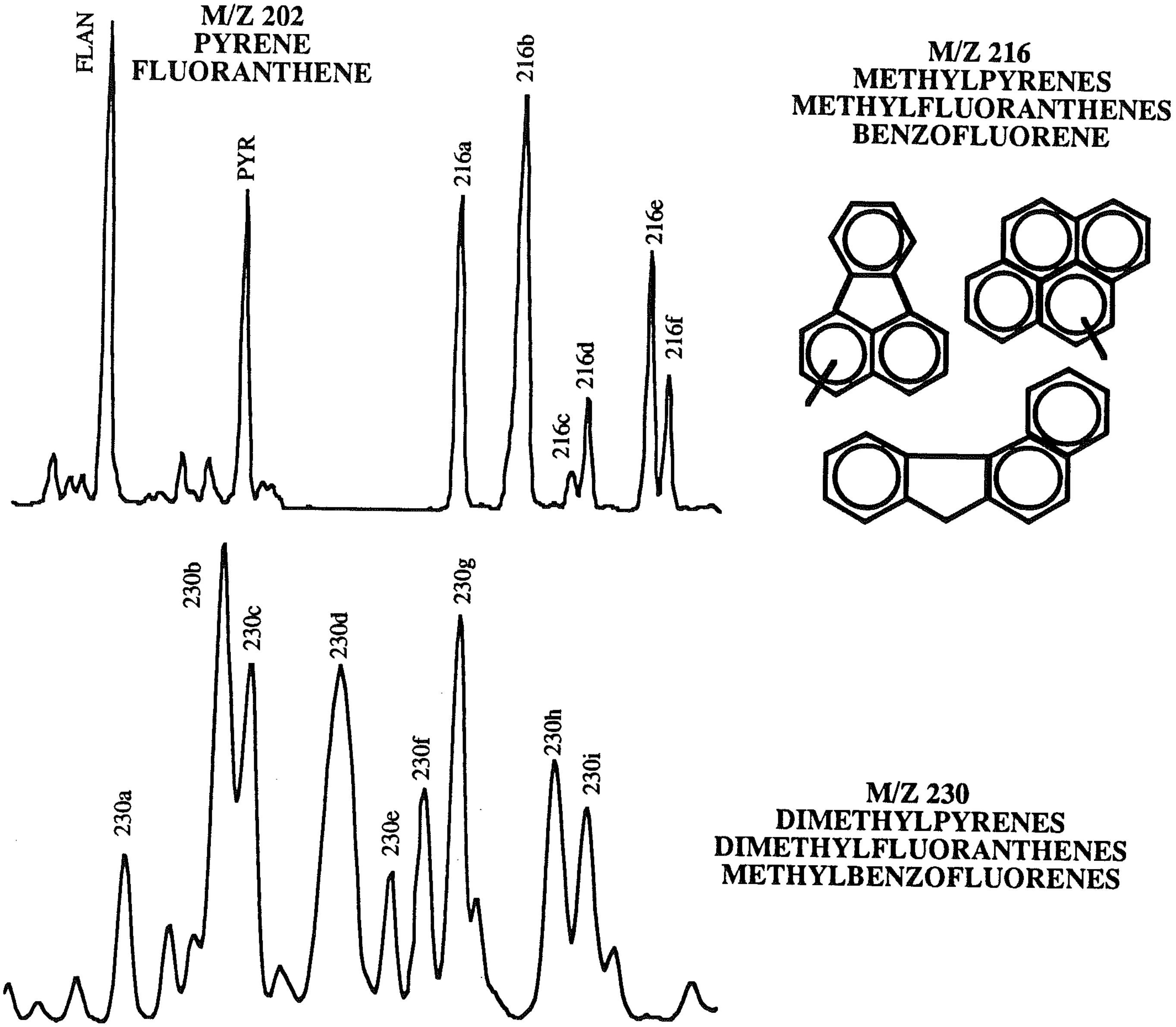


M/Z 178
PHENANTHRENE

M/Z 192
METHYLPHENANTHRENES

M/Z 206
DIMETHYLPHENANTHRENES

Figure 7



M/Z 202
PYRENE
FLUORANTHENE

M/Z 216
METHYLPYRENES
METHYLFLUORANTHENES
BENZOFLUORENE

M/Z 230
DIMETHYLPYRENES
DIMETHYLFLUORANTHENES
METHYLBENZOFLUORENES

Figure 8

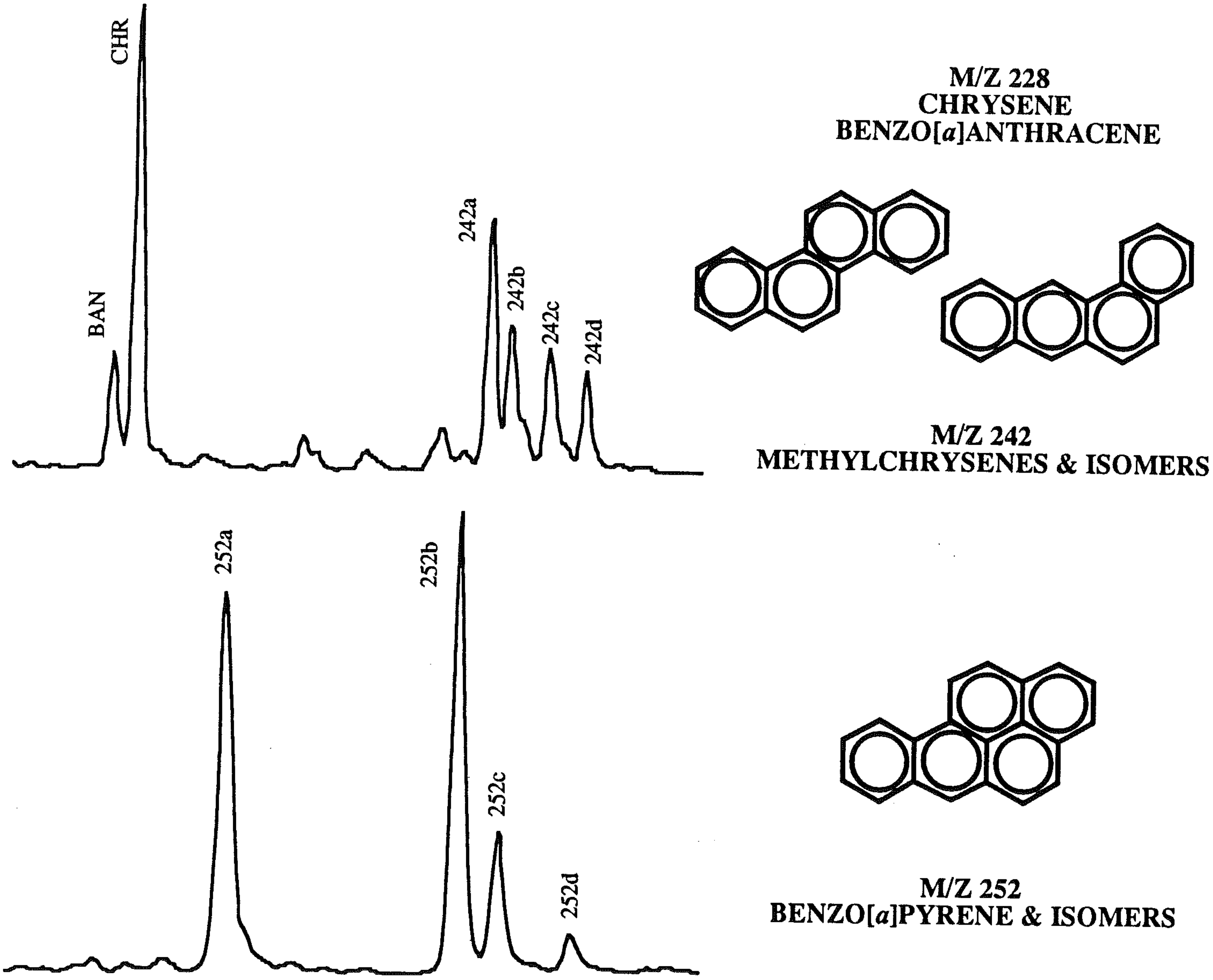

BAN
CHR
242a
242b
242c
242d
M/Z 228
CHRYSENE
BENZO[a]ANTHRACENE
M/Z 242
METHYLCHRYSENES & ISOMERS
252a
252b
252c
252d
M/Z 252
BENZO[a]PYRENE & ISOMERS

Figure 9

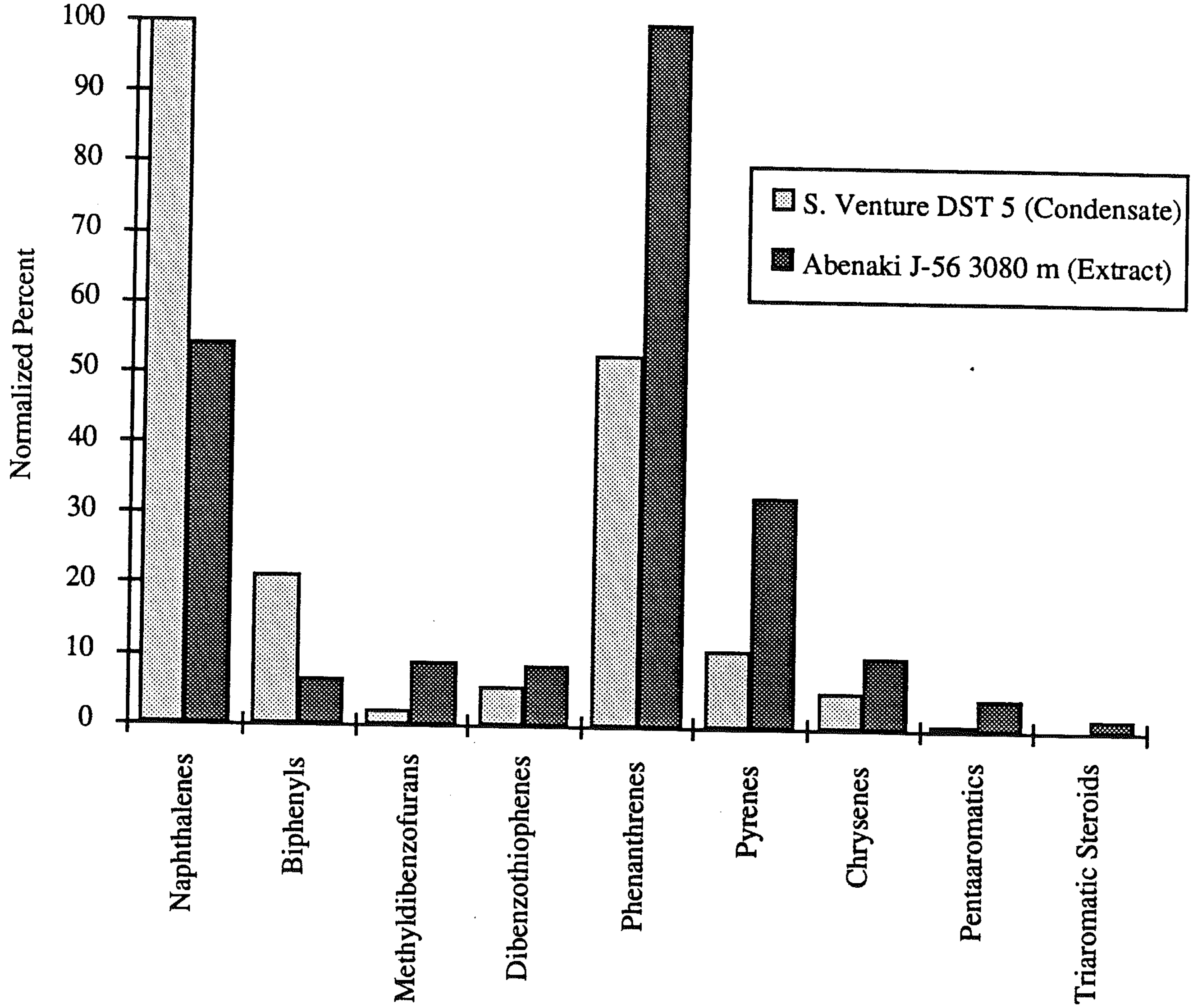

100
90
80
70
60
50
40
30
20
10
0
Normalized Percent
S. Venture DST 5 (Condensate)
Abenaki J-56 3080 m (Extract)
Naphthalenes
Biphenyls
Methyldibenzofurans
Dibenzothiophenes
Phenanthrenes
Pyrenes
Chrysenes
Pentaaromatics
Triaromatic Steroids

Figure 10

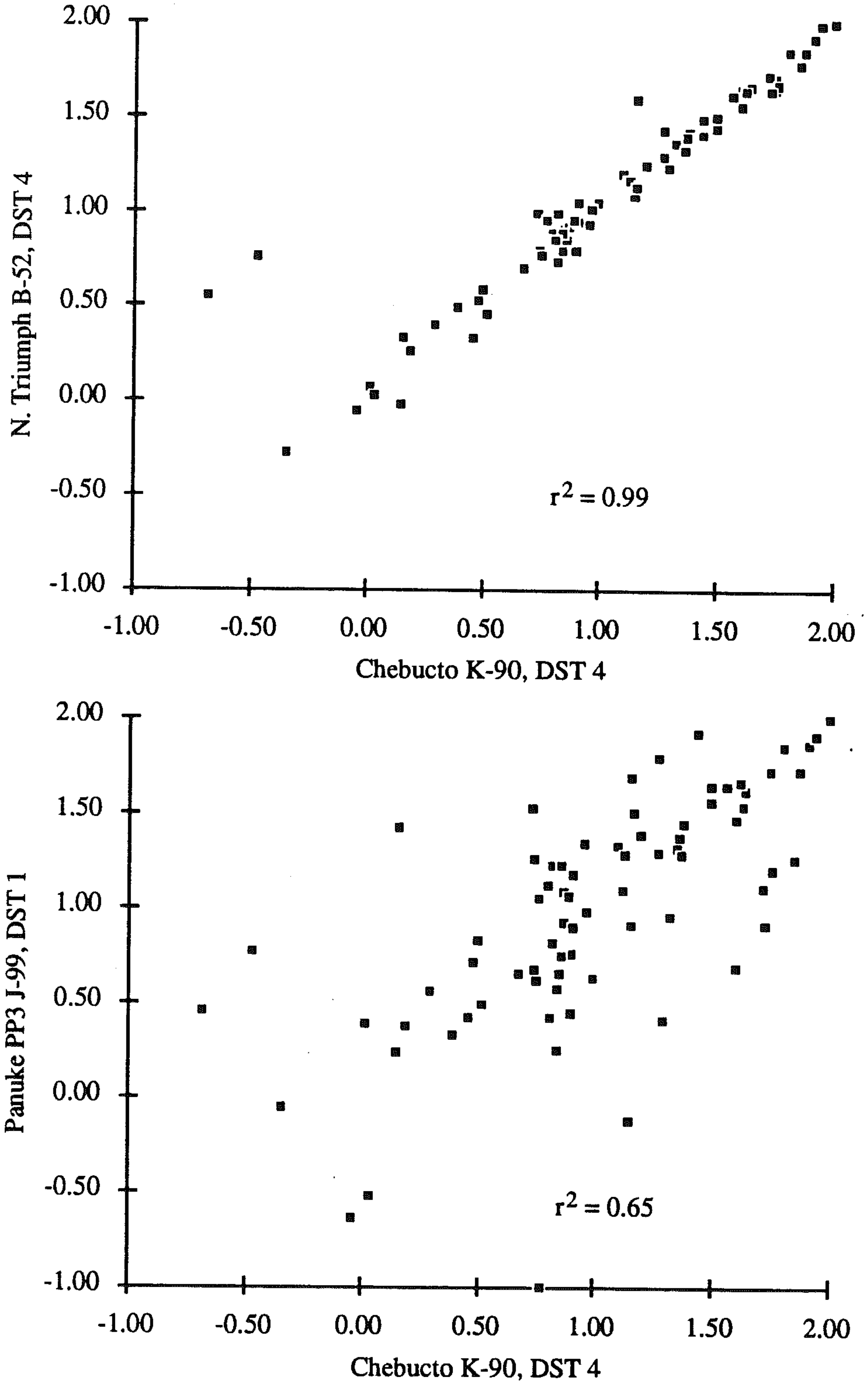

2.00
1.50
1.00
0.50
0.00
-0.50
-1.00
N. Triumph B-52, DST 4
$r^2 = 0.99$
-1.00
-0.50
0.00
0.50
1.00
1.50
2.00
Chebucto K-90, DST 4
2.00
1.50
1.00
0.50
0.00
-0.50
-1.00
Panuke PP3 J-99, DST 1
$r^2 = 0.65$
-1.00
-0.50
0.00
0.50
1.00
1.50
2.00
Chebucto K-90, DST 4

Figure 11

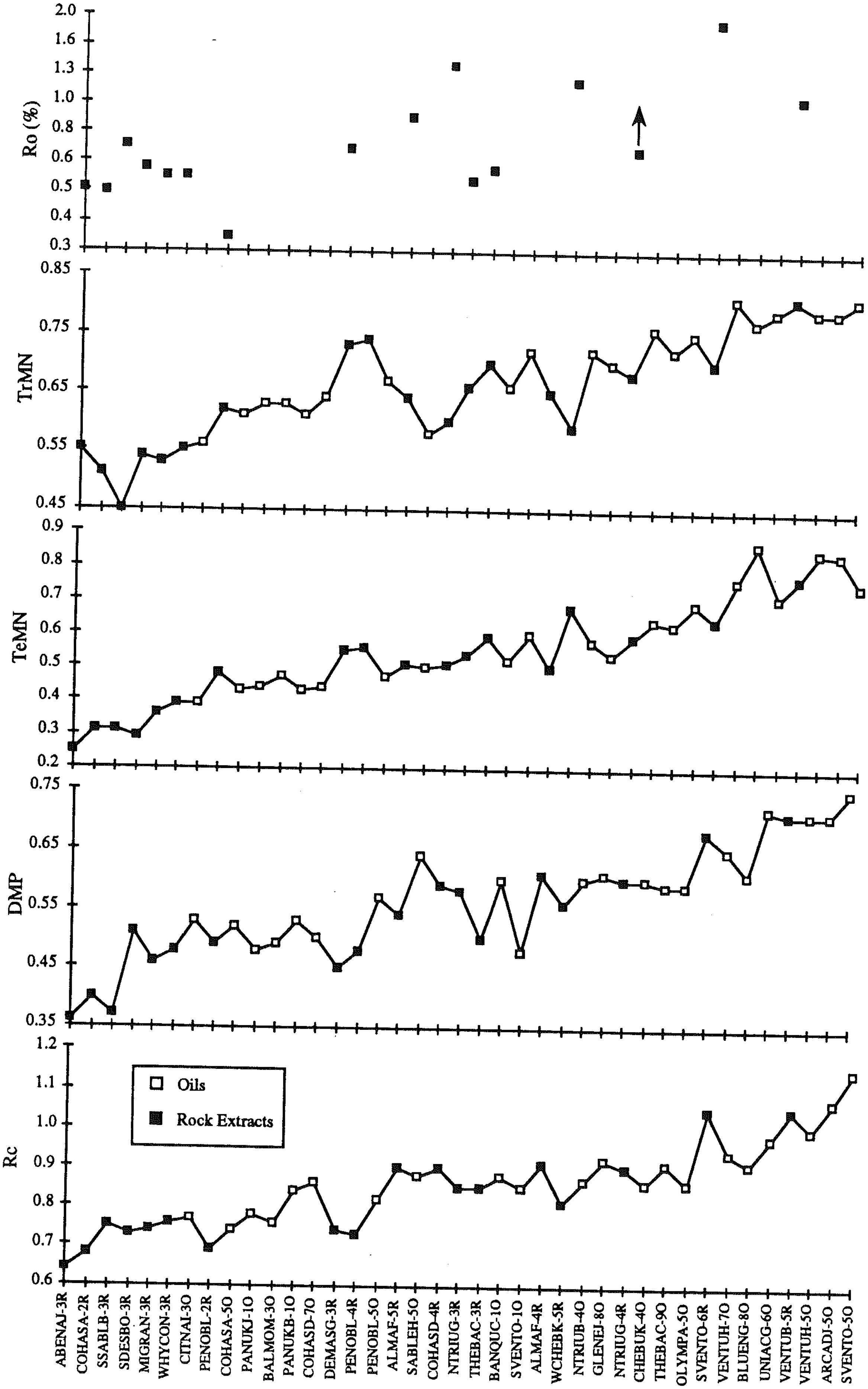

Ro (%)
2.0
1.6
1.3
1.0
0.8
0.6
0.5
0.4
0.3
TrMN
0.85
0.75
0.65
0.55
0.45
TeMN
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
DMP
0.75
0.65
0.55
0.45
0.35
Rc
1.2
1.1
1.0
0.9
0.8
0.7
0.6
□ Oils
■ Rock Extracts
ABENAJ-3R
COHASA-2R
SSABLB-3R
SDESBO-3R
MIGRAN-3R
WHYCON-3R
CITNAI-3O
PENOBL-2R
COHASA-5O
PANUKJ-1O
BALMOM-3O
PANUKB-1O
COHASD-7O
DEMASG-3R
PENOBL-4R
PENOBL-5O
ALMAF-5R
SABLEH-5O
COHASD-4R
NTRIUG-3R
THEBAC-3R
BANQUC-1O
SVENTO-1O
ALMAF-4R
WCHEBK-5R
NTRIUB-4O
GLENEJ-8O
NTRIUG-4R
CHEBUK-4O
THEBAC-9O
OLYMPA-5O
SVENTO-6R
VENTUH-7O
BLUENG-8O
UNIACG-6O
VENTUB-5R
VENTUH-5O
ARCADJ-5O
SVENTO-5O

Figure 12

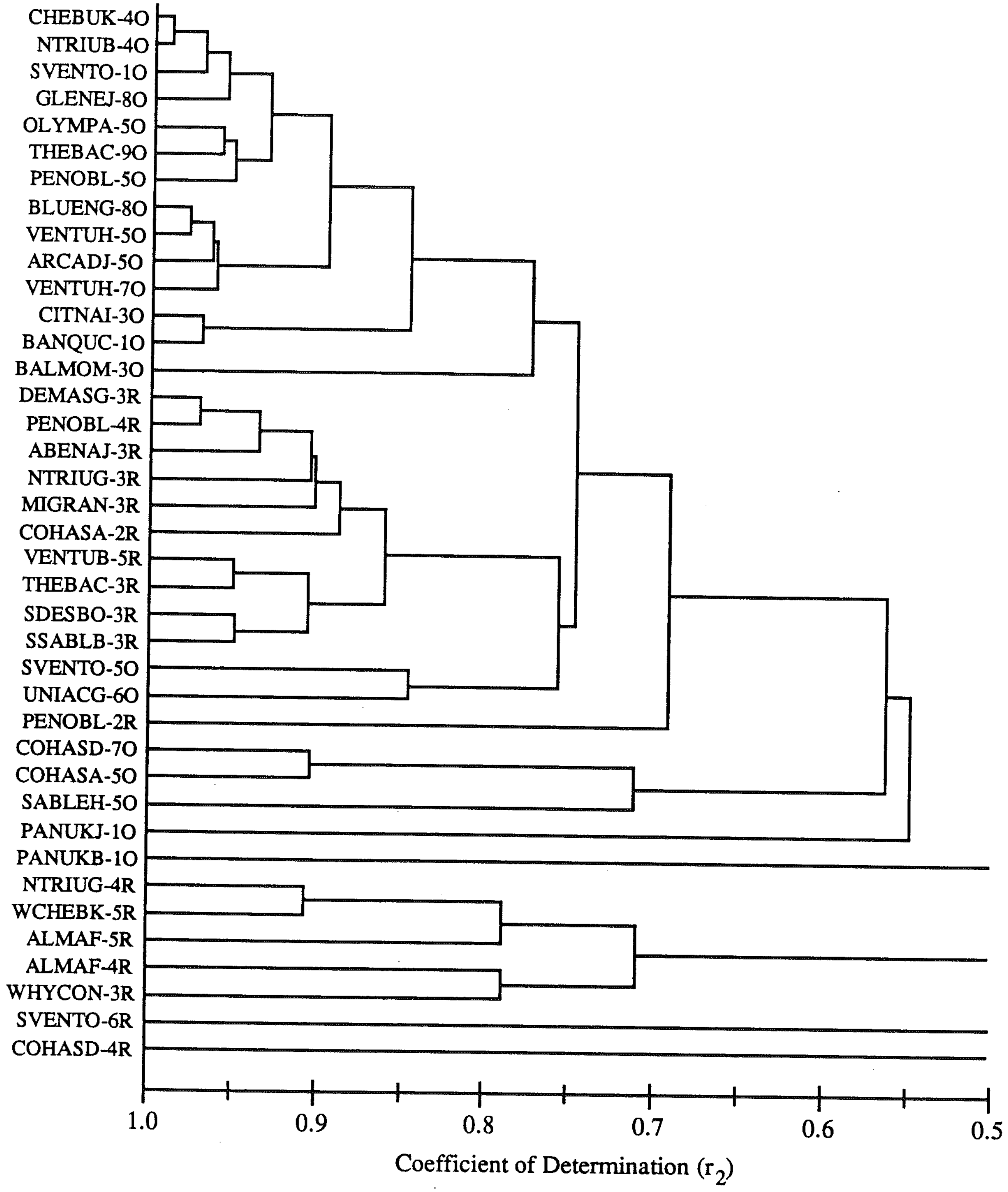
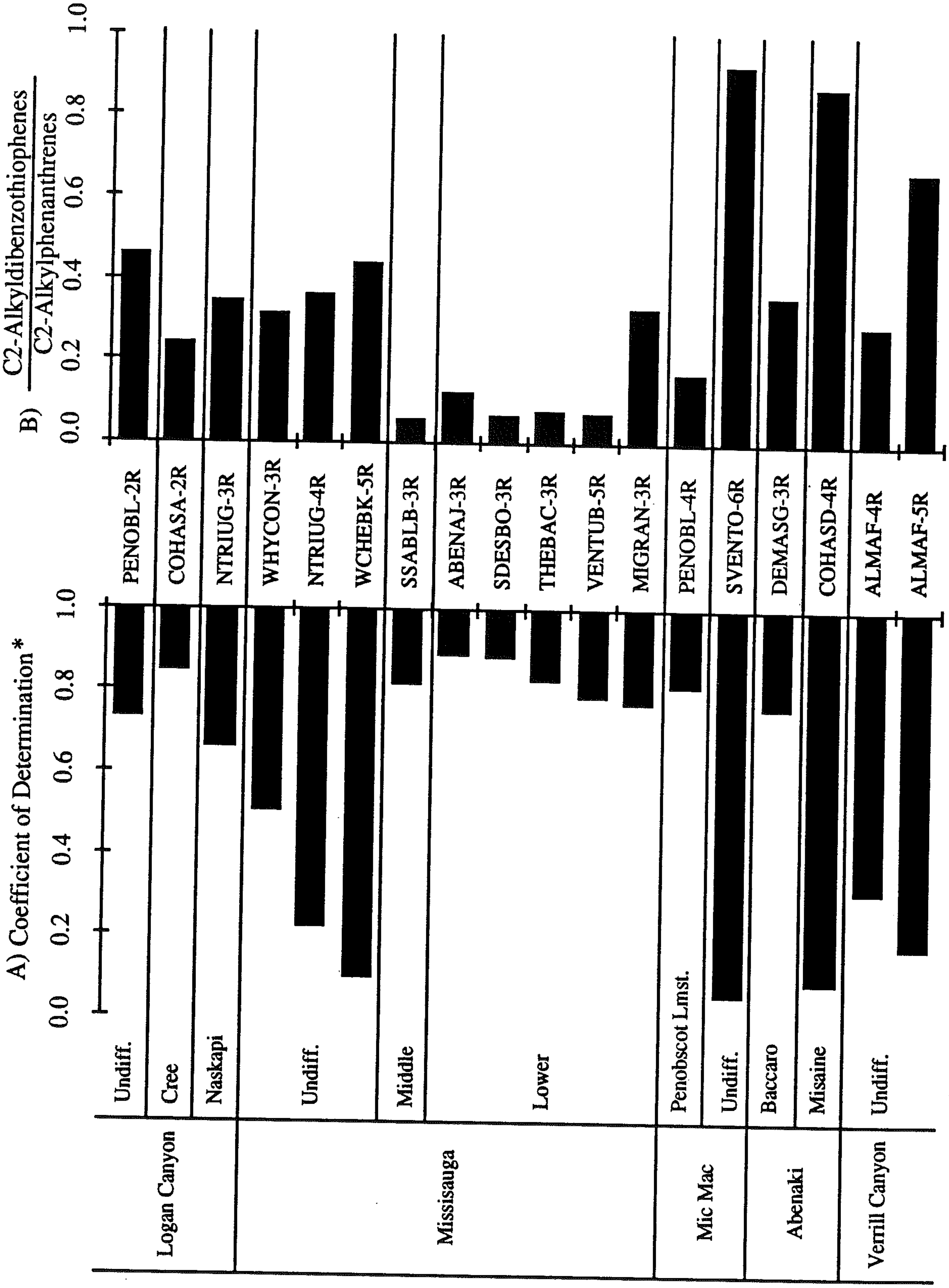

CHEBUK-4O
NTRIUB-4O
SVENTO-1O
GLENEJ-8O
OLYMPA-5O
THEBAC-9O
PENOBL-5O
BLUENG-8O
VENTUH-5O
ARCADJ-5O
VENTUH-7O
CITNAI-3O
BANQUC-1O
BALMOM-3O
DEMASG-3R
PENOBL-4R
ABENAJ-3R
NTRIUG-3R
MIGRAN-3R
COHASA-2R
VENTUB-5R
THEBAC-3R
SDESBO-3R
SSABLB-3R
SVENTO-5O
UNIACG-6O
PENOBL-2R
COHASD-7O
COHASA-5O
SABLEH-5O
PANUKJ-1O
PANUKB-1O
NTRIUG-4R
WCHEBK-5R
ALMAF-5R
ALMAF-4R
WHYCON-3R
SVENTO-6R
COHASD-4R
1.0
0.9
0.8
0.7
0.6
0.5
Coefficient of Determination (r_2)

Figure 13



* From comparison of rock extracts with Group A oils

Figure 14

Well: Abenaki J-56

FM_NAME	BEGIN_AGE	TOP_DEPTH	THICKNESS	LITHOLOGY	KEROGEN_NAME	TOC
Quarternary	1.6	~107	~93	90/10/0		
Unconformity1	15					
Miocene	25	~200	~200	30/70/0		
Unconformity2	52					
E..Eocene	58	~400	~42	90/10/0		
Unconformity3	64					
E. Paleocene	66.4	~442	~143	40/60/0		
Maaastrictian	70	~585	~287	Shale	Type III	1.5
Unconformity4	80					
Campanian	88.5	~872	~78	10/90/0	Type III	1.4
Turonian	90	~950	~36	Shale	IIB	1.75
Petrel	91	~986	~74	40/45/15	Type III	0.9
Cenoman	116	~1060	~915	55/45/0	Type III	1.5
Naskapi	119	~1975	~99	40/60/0	IIB	2.5
Barrem/Miss	124	~2074	~239	85/15/0	Type III	1.0
Haut/"O"	131	~2313	~242	50/40/10	Type III	0.5
Val/Berr	144	~2555	~666	65/35/0	Type III	1.0
Top Jura	144.5	~3221	~41	20/10/70	Type III	1.0
Abenaki 1	152	~3262	~298	20/10/70	IIL	1.75
Abenaki 2	163	~3560	~372	20/10/70	IIIL	0.75
L. Callovian	164	~3932	~57	0/10/90	Type III	0.3
Misaine	166	~3989	~124	10/90/0	IIB	0.5
Scatarie	168	~4113	~174	0/10/90	IIB	0.5
Mohican	200	~4287	~3713	30/30/40	Type III	0.5
BU	201					
Argo	204	~8000	~4000	0/5/95	Type III	0.2
Eurydice	220	~12000	~1500	40/50/10	Type III	10.0

Table 8

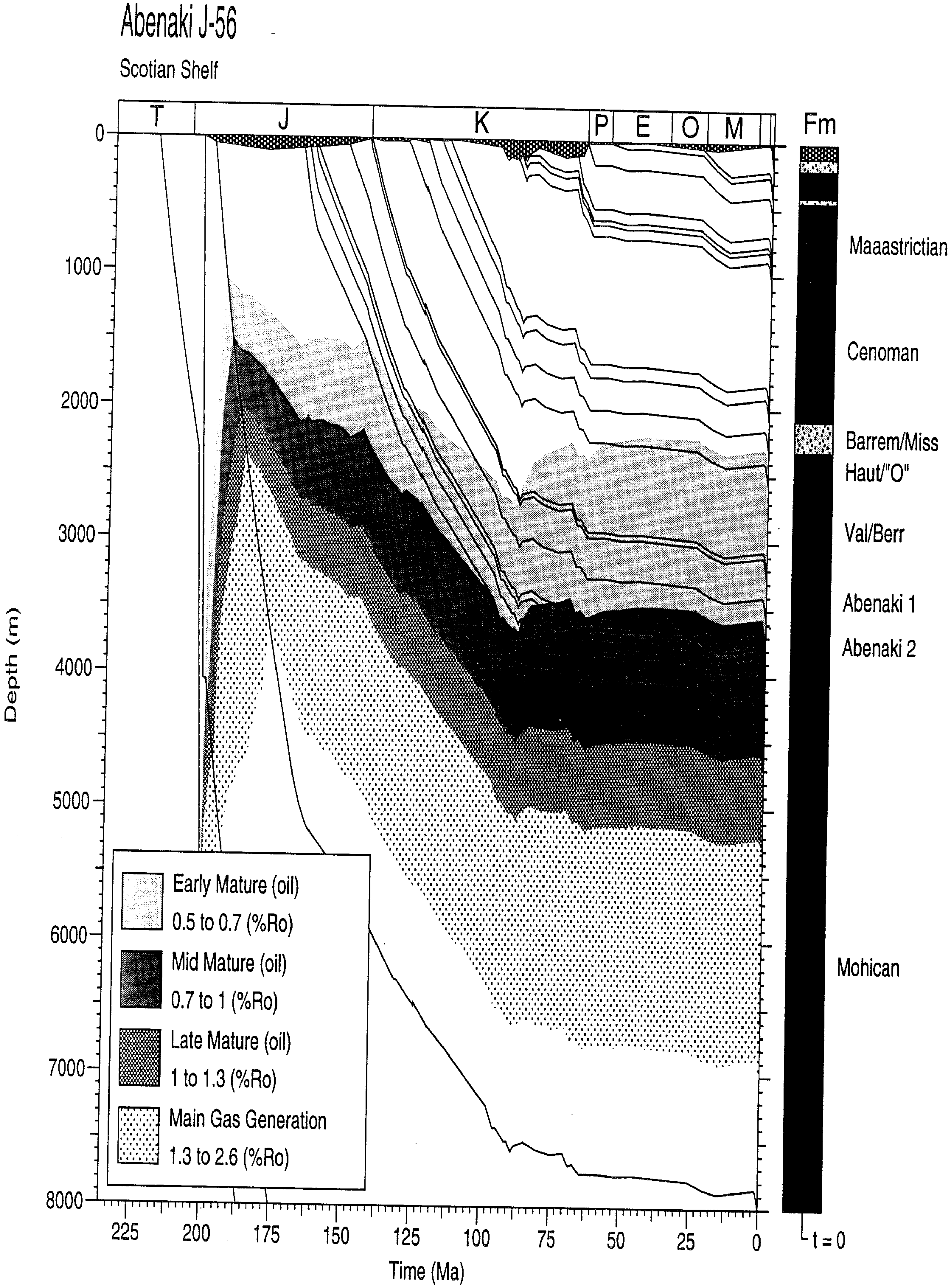

Abenaki J-56
Scotian Shelf
T
J
K
P
E
O
M
Fm
Maaastrictian
Cenoman
Barrem/Miss
Haut/"O"
Val/Berr
Abenaki 1
Abenaki 2
Mohican
Depth (m)
0
1000
2000
3000
4000
5000
6000
7000
8000
225
200
175
150
125
100
75
50
25
0
Time (Ma)
t = 0
Early Mature (oil)
0.5 to 0.7 (%Ro)
Mid Mature (oil)
0.7 to 1 (%Ro)
Late Mature (oil)
1 to 1.3 (%Ro)
Main Gas Generation
1.3 to 2.6 (%Ro)

Figure 15a

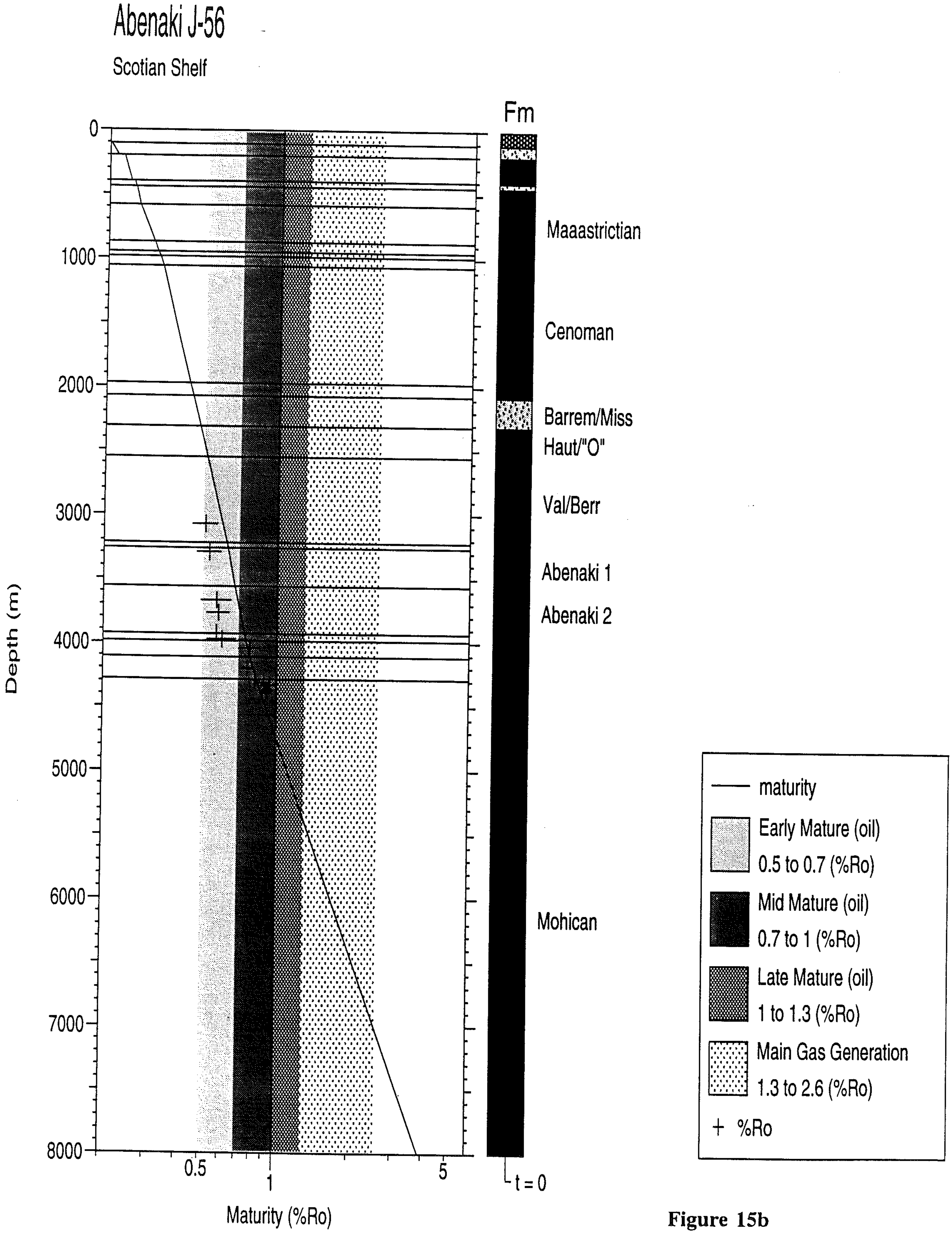

Abenaki J-56
Scotian Shelf
Fm
0
1000
2000
3000
4000
5000
6000
7000
8000
Depth (m)
0.5
1
5
Maturity (%Ro)
Maaastrictian
Cenoman
Barrem/Miss
Haut/"O"
Val/Berr
Abenaki 1
Abenaki 2
Mohican
t = 0
maturity
Early Mature (oil)
0.5 to 0.7 (%Ro)
Mid Mature (oil)
0.7 to 1 (%Ro)
Late Mature (oil)
1 to 1.3 (%Ro)
Main Gas Generation
1.3 to 2.6 (%Ro)
+ %Ro

Figure 15b

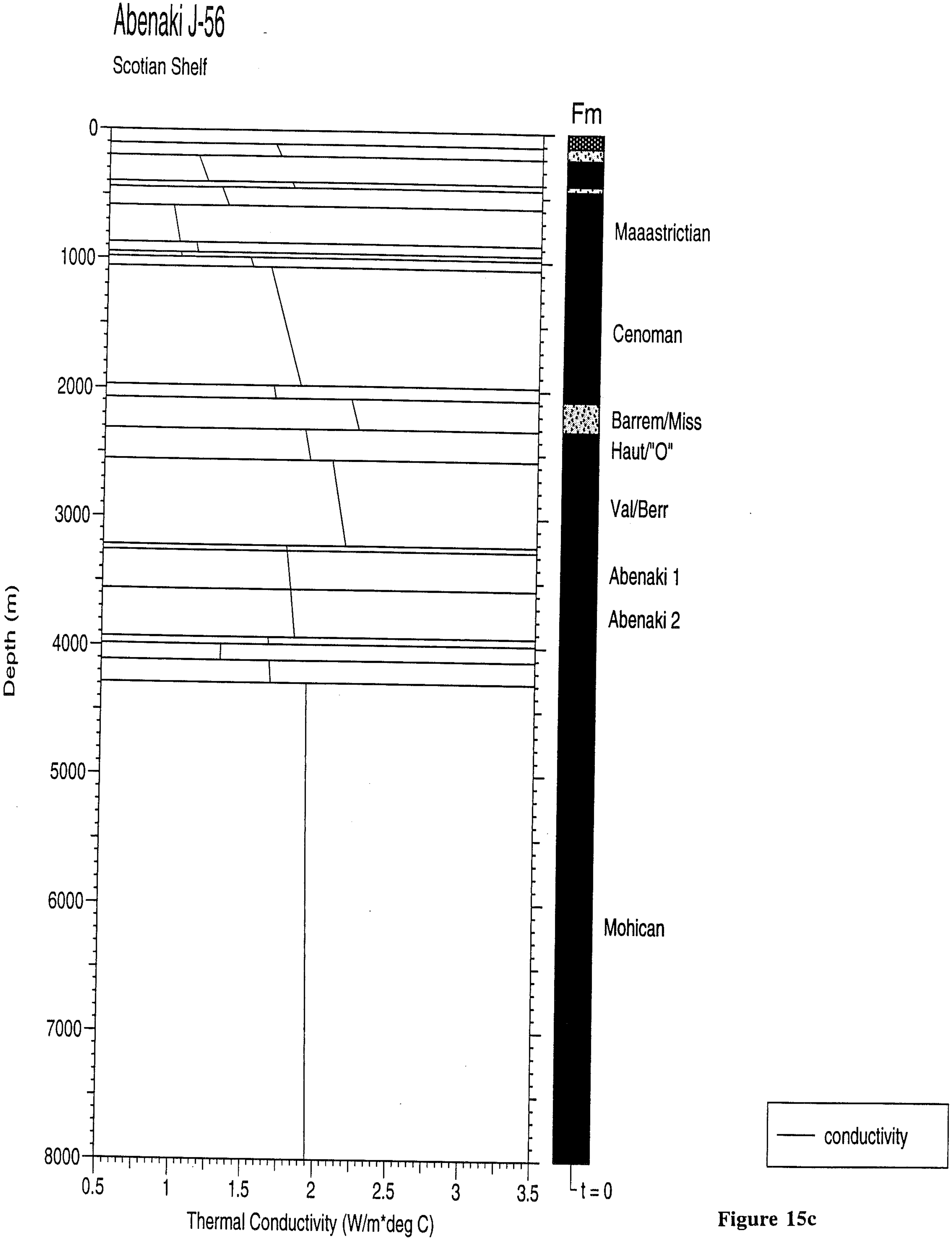
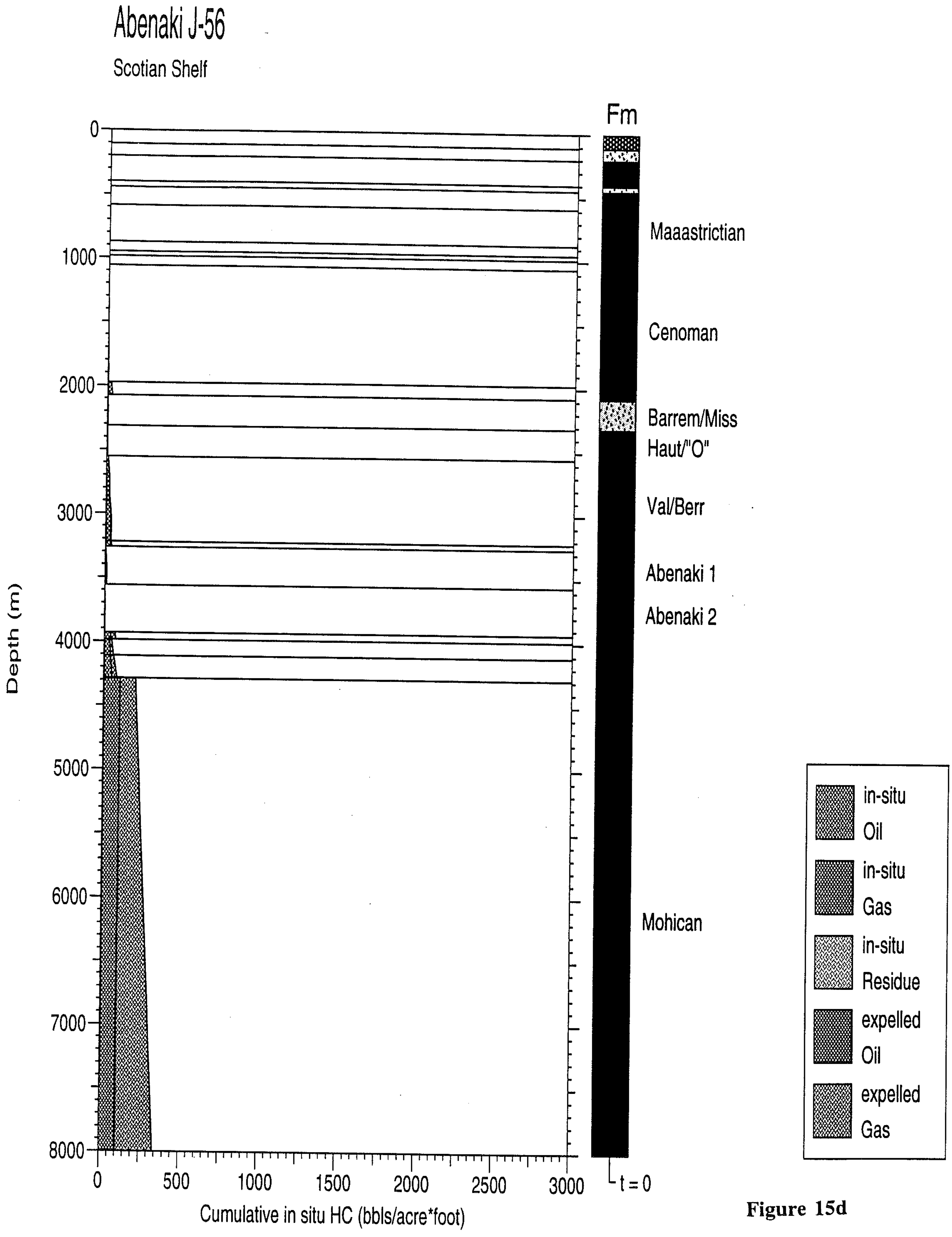

Abenaki J-56
Scotian Shelf
Fm
Depth (m)
0
1000
2000
3000
4000
5000
6000
7000
8000
0.5
1
1.5
2
2.5
3
3.5
Thermal Conductivity (W/m*deg C)
Maaastrictian
Cenoman
Barrem/Miss
Haut/"O"
Val/Berr
Abenaki 1
Abenaki 2
Mohican
t = 0
conductivity

Figure 15c



Abenaki J-56
Scotian Shelf
Fm
Maaastrictian
Cenoman
Barrem/Miss
Haut/"O"
Val/Berr
Abenaki 1
Abenaki 2
Mohican
t = 0
Depth (m)
0
1000
2000
3000
4000
5000
6000
7000
8000
0
500
1000
1500
2000
2500
3000
Cumulative in situ HC (bbls/acre*foot)
in-situ Oil
in-situ Gas
in-situ Residue
expelled Oil
expelled Gas

Figure 15d

Abenaki J-56

Scotian Shelf

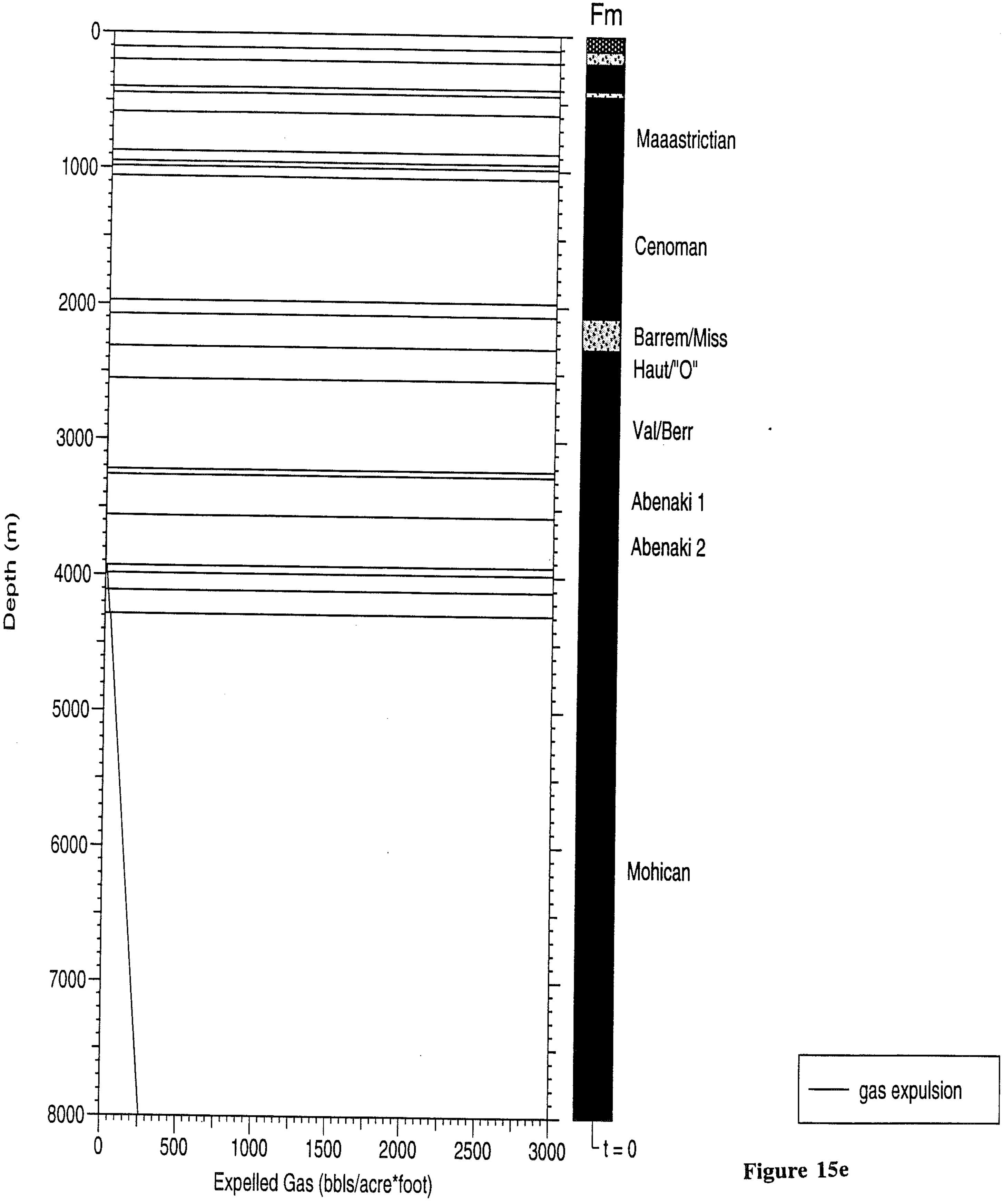


Figure 15e

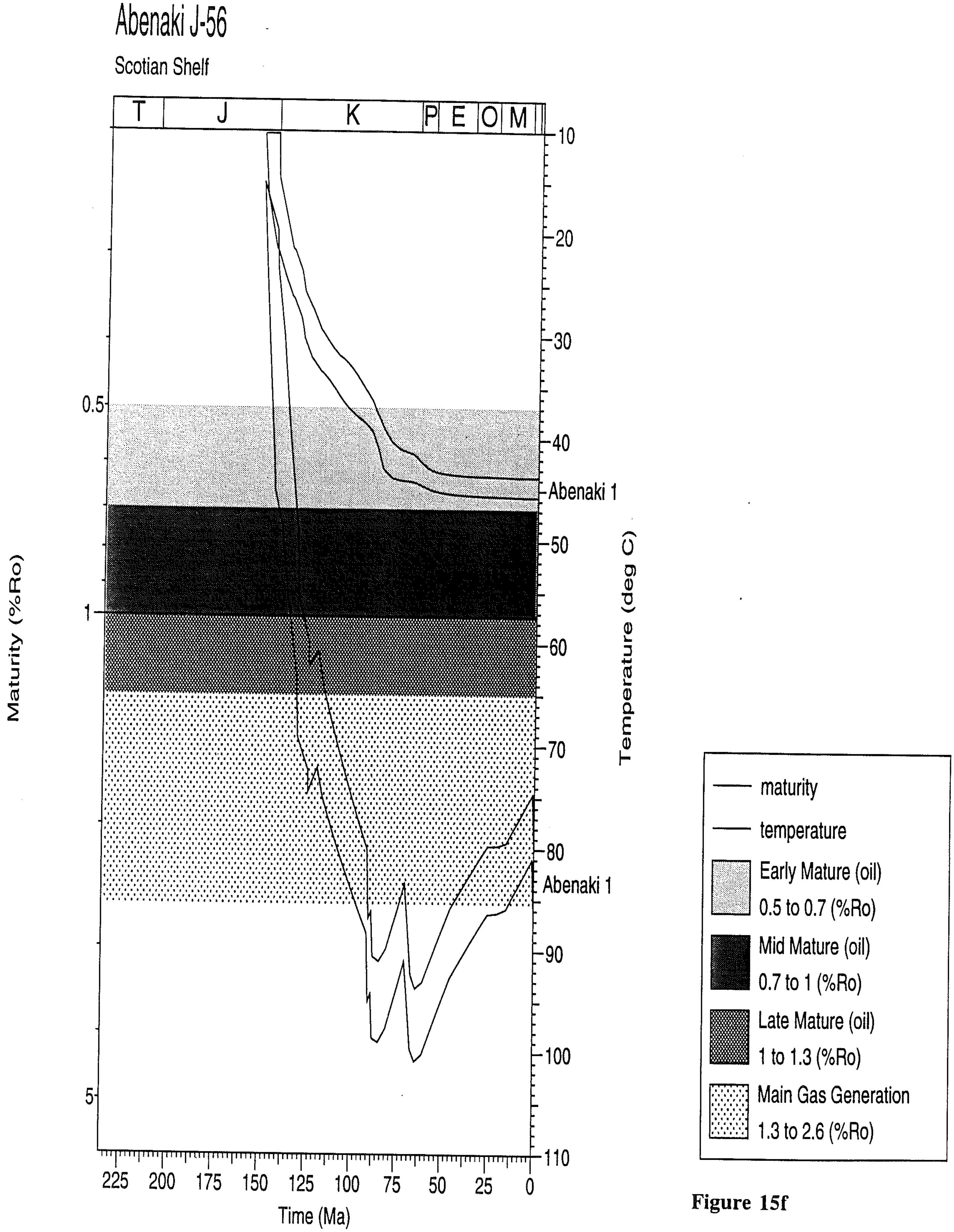

Abenaki J-56
Scotian Shelf
T
J
K
P
E
O
M
Maturity (%Ro)
0.5
1
5
Temperature (deg C)
10
20
30
40
50
60
70
80
90
100
110
Abenaki 1
Abenaki 1
225
200
175
150
125
100
75
50
25
0
Time (Ma)
maturity
temperature
Early Mature (oil)
0.5 to 0.7 (%Ro)
Mid Mature (oil)
0.7 to 1 (%Ro)
Late Mature (oil)
1 to 1.3 (%Ro)
Main Gas Generation
1.3 to 2.6 (%Ro)

Figure 15f

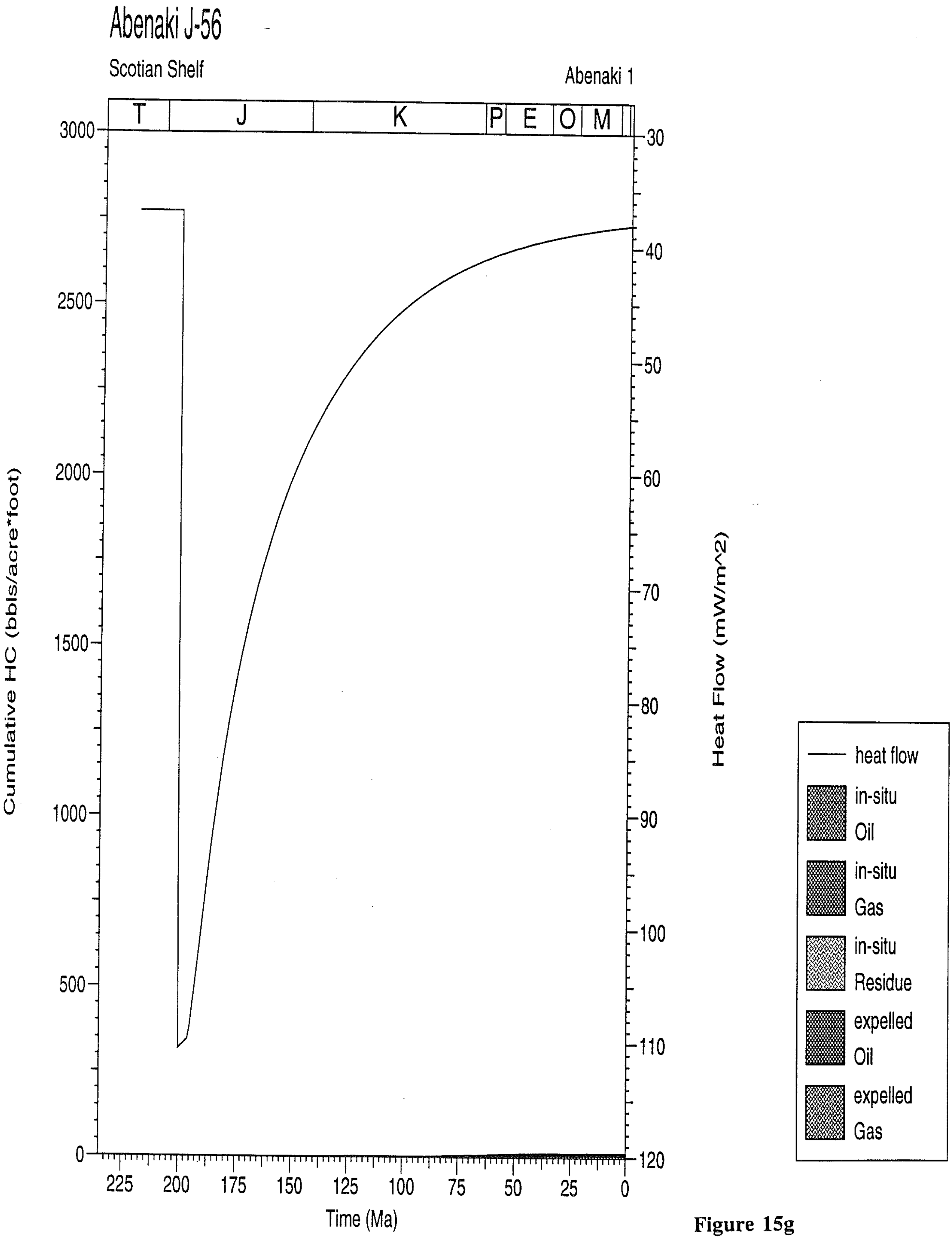

Abenaki J-56
Scotian Shelf
Abenaki 1
T
J
K
P
E
O
M
Cumulative HC (bbls/acre*foot)
3000
2500
2000
1500
1000
500
0
Heat Flow (mW/m^2)
30
40
50
60
70
80
90
100
110
120
225
200
175
150
125
100
75
50
25
0
Time (Ma)
heat flow
in-situ Oil
in-situ Gas
in-situ Residue
expelled Oil
expelled Gas

Figure 15g

Abenaki J-56

Scotian Shelf

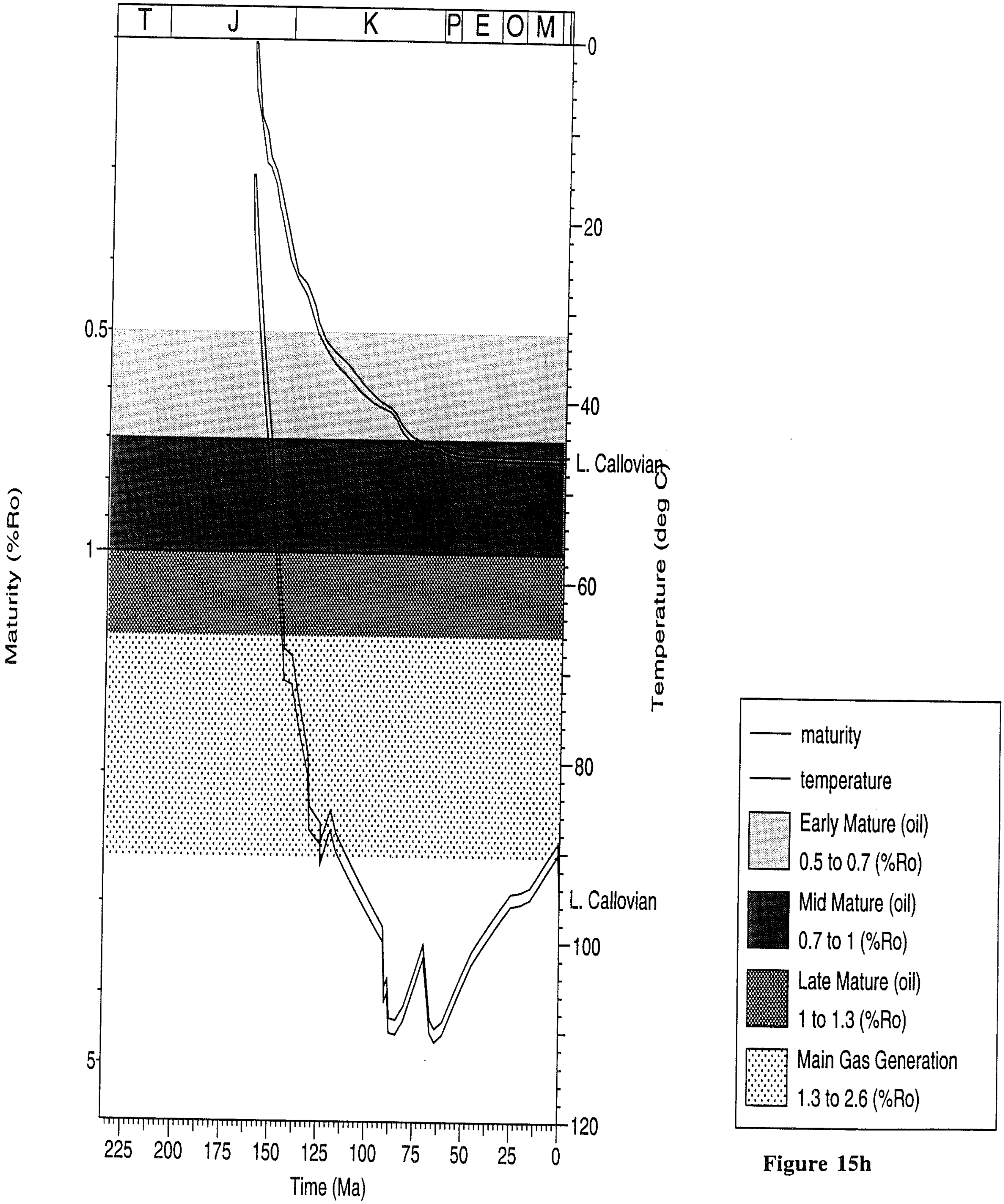


Figure 15h

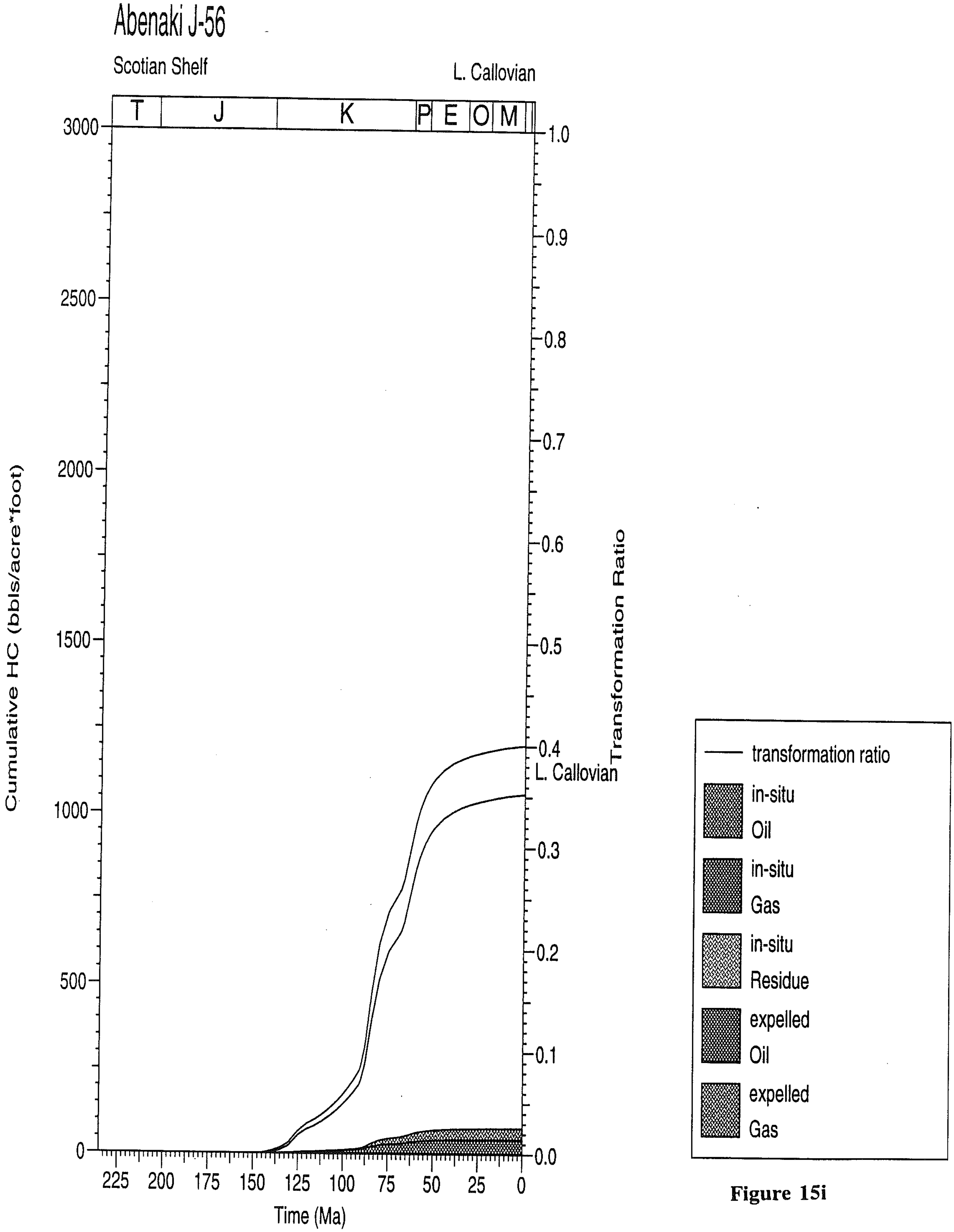

Abenaki J-56
Scotian Shelf
L. Callovian
T
J
K
P
E
O
M
3000
2500
2000
1500
1000
500
0
Cumulative HC (bbls/acre*foot)
1.0
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0.0
Transformation Ratio
L. Callovian
225
200
175
150
125
100
75
50
25
0
Time (Ma)
transformation ratio
in-situ Oil
in-situ Gas
in-situ Residue
expelled Oil
expelled Gas

Figure 15i

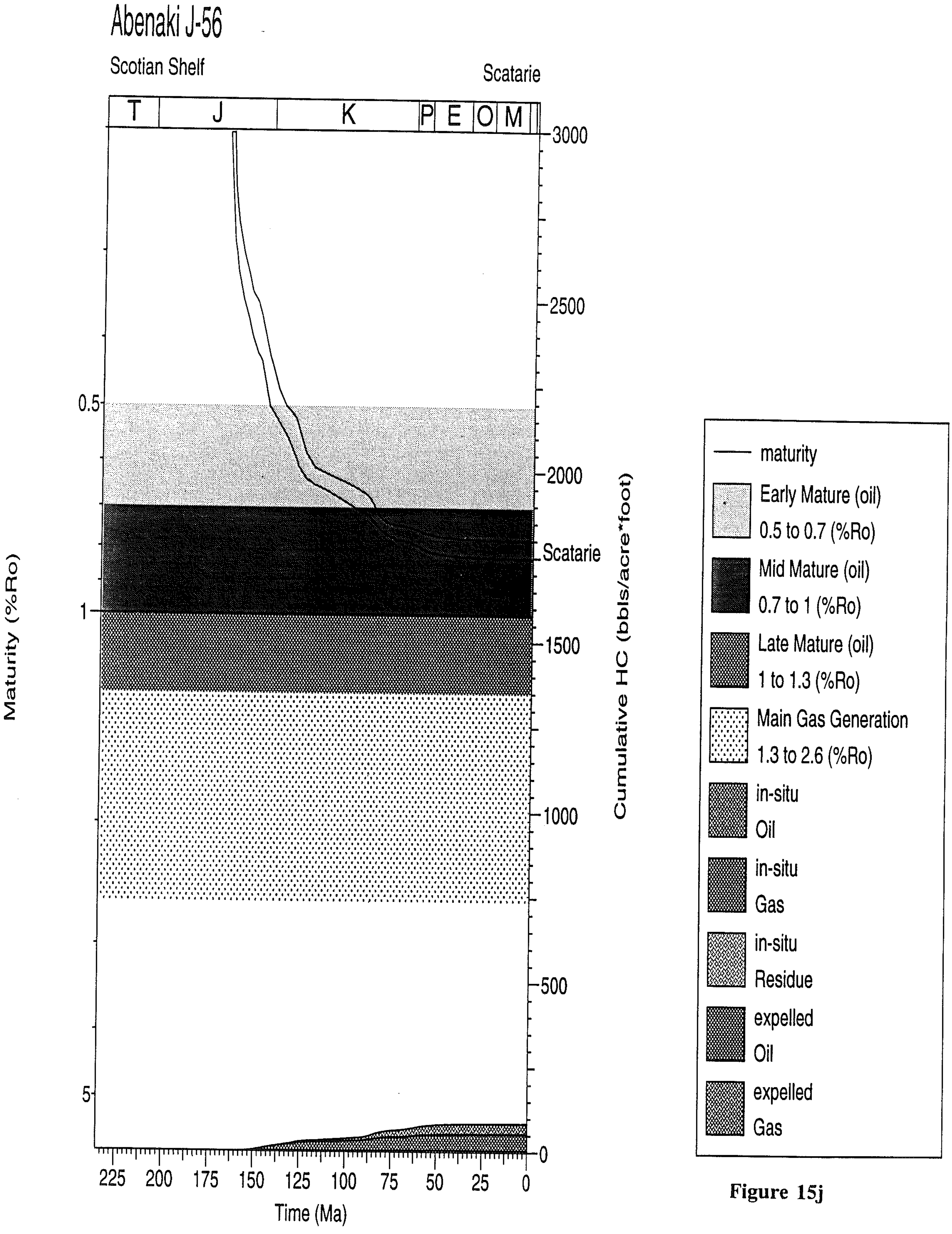

Abenaki J-56
Scotian Shelf
Scatarie
T
J
K
P
E
O
M
3000
2500
2000
Scatarie
1500
1000
500
0
0.5
1
5
Maturity (%Ro)
Cumulative HC (bbls/acre*foot)
225
200
175
150
125
100
75
50
25
0
Time (Ma)
maturity
Early Mature (oil) 0.5 to 0.7 (%Ro)
Mid Mature (oil) 0.7 to 1 (%Ro)
Late Mature (oil) 1 to 1.3 (%Ro)
Main Gas Generation 1.3 to 2.6 (%Ro)
in-situ Oil
in-situ Gas
in-situ Residue
expelled Oil
expelled Gas

Figure 15j

Well: W. Chebucto K-20

Stratigraphy Table

Formation or Event Name	Type	Begin Age (Ma)	Well Top (m)	Present Thick (m)	Lithology	Kerogen Name
Quarternary	F	1.6	74	176	90/10/0	
Unconformity1	H	3				
Pliocene	F	5	250	550	30/70/0	
Unconformity2	H	10.5				
Miocene	F	20	800	275	Shale	
Unconformity3	H	30				
E. Oligocene	F	49.5	1075	425	10/80/10	
Unconformity4	H	58.5				
L. Paleocene	F	62	1500	180	0/90/10	
Unconformity5	H	70				
E.Maaast	F	74.5	1680	29	0/60/40	Type III
Camp/Wyan	F	85	1709	94	0/90/10	IIA-IIB
Con/San/DC	F	92	1803	185	40/60/0	IIA-IIB
Log Can	F	98.5	1988	334	60/40/0	Type III
Sable	F	101	2322	168	50/50/0	IIB
Cree	F	117	2490	1241	60/40/0	IIB
Naskapi	F	120	3731	254	30/70/0	IIB
Miss 1	F	123.5	3985	415	60/40/0	Type III
Miss 2	F	127	4400	420	40/60/0	IIA-IIB
Miss 3	F	144	4820	1980	40/60/0	IIB
Top Jura	F	152	6800	500	20/80/0	Type III
MicMac/VC	F	181	7300	4300	20/70/10	Type III
Mohican	F	200	11600	3000	20/70/10	Type III
BU	H	201				
Argo	F	204	14600	2000	0/5/95	Type III
Eurydice	F	235	16600	1500	30/60/10	Type III

Table 9

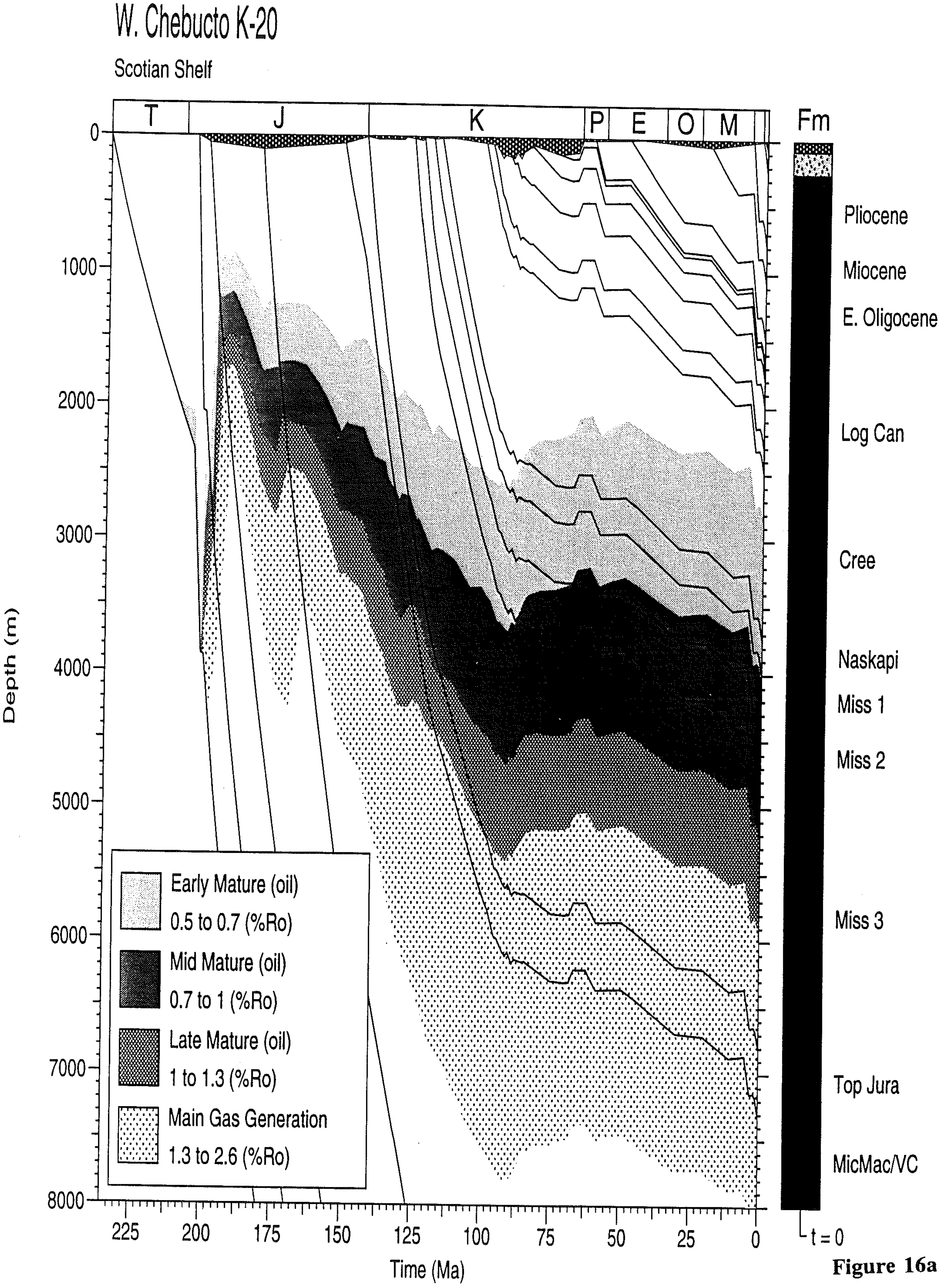

W. Chebucto K-20
Scotian Shelf
T
J
K
P
E
O
M
Fm
Pliocene
Miocene
E. Oligocene
Log Can
Cree
Naskapi
Miss 1
Miss 2
Miss 3
Top Jura
MicMac/VC
Depth (m)
0
1000
2000
3000
4000
5000
6000
7000
8000
225
200
175
150
125
100
75
50
25
0
Time (Ma)
t = 0
Early Mature (oil)
0.5 to 0.7 (%Ro)
Mid Mature (oil)
0.7 to 1 (%Ro)
Late Mature (oil)
1 to 1.3 (%Ro)
Main Gas Generation
1.3 to 2.6 (%Ro)

Figure 16a

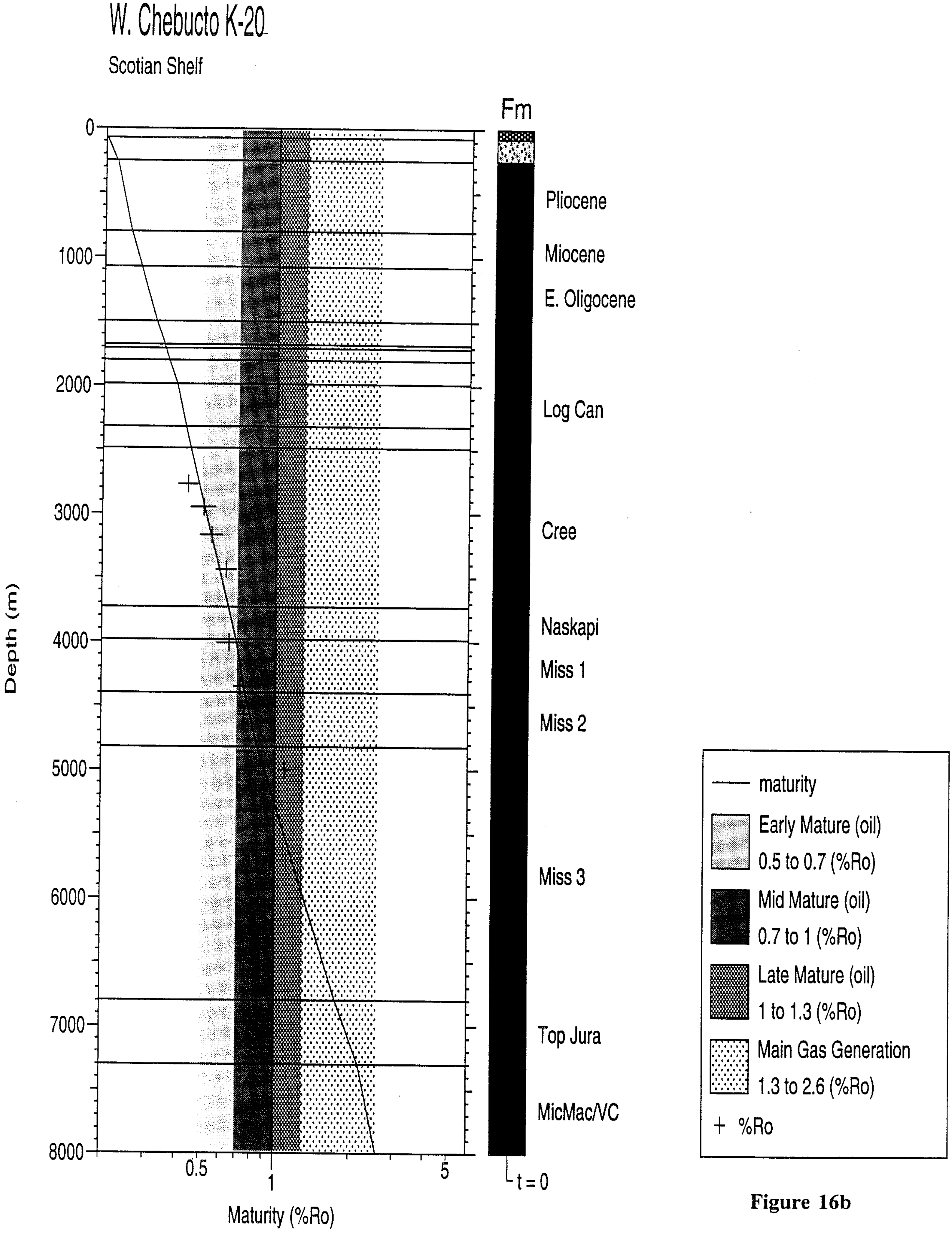

W. Chebucto K-20
Scotian Shelf
Fm
Depth (m)
0
1000
2000
3000
4000
5000
6000
7000
8000
0.5
1
5
Maturity (%Ro)
Pliocene
Miocene
E. Oligocene
Log Can
Cree
Naskapi
Miss 1
Miss 2
Miss 3
Top Jura
MicMac/VC
t = 0
maturity
Early Mature (oil) 0.5 to 0.7 (%Ro)
Mid Mature (oil) 0.7 to 1 (%Ro)
Late Mature (oil) 1 to 1.3 (%Ro)
Main Gas Generation 1.3 to 2.6 (%Ro)
+ %Ro

Figure 16b

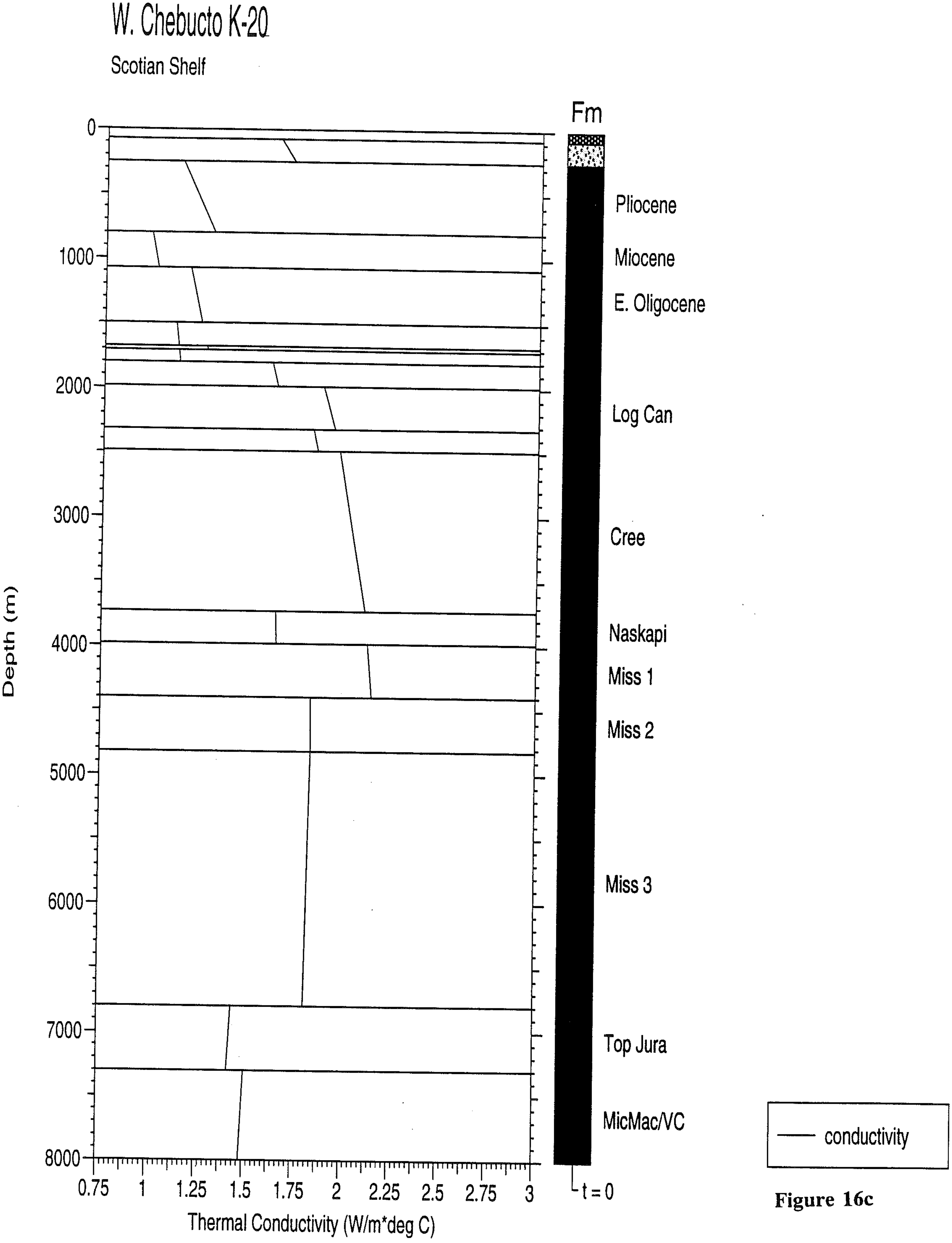

W. Chebucto K-20
Scotian Shelf
Depth (m)
0
1000
2000
3000
4000
5000
6000
7000
8000
0.75
1
1.25
1.5
1.75
2
2.25
2.5
2.75
3
Thermal Conductivity (W/m*deg C)
Fm
Pliocene
Miocene
E. Oligocene
Log Can
Cree
Naskapi
Miss 1
Miss 2
Miss 3
Top Jura
MicMac/VC
t = 0
conductivity

Figure 16c

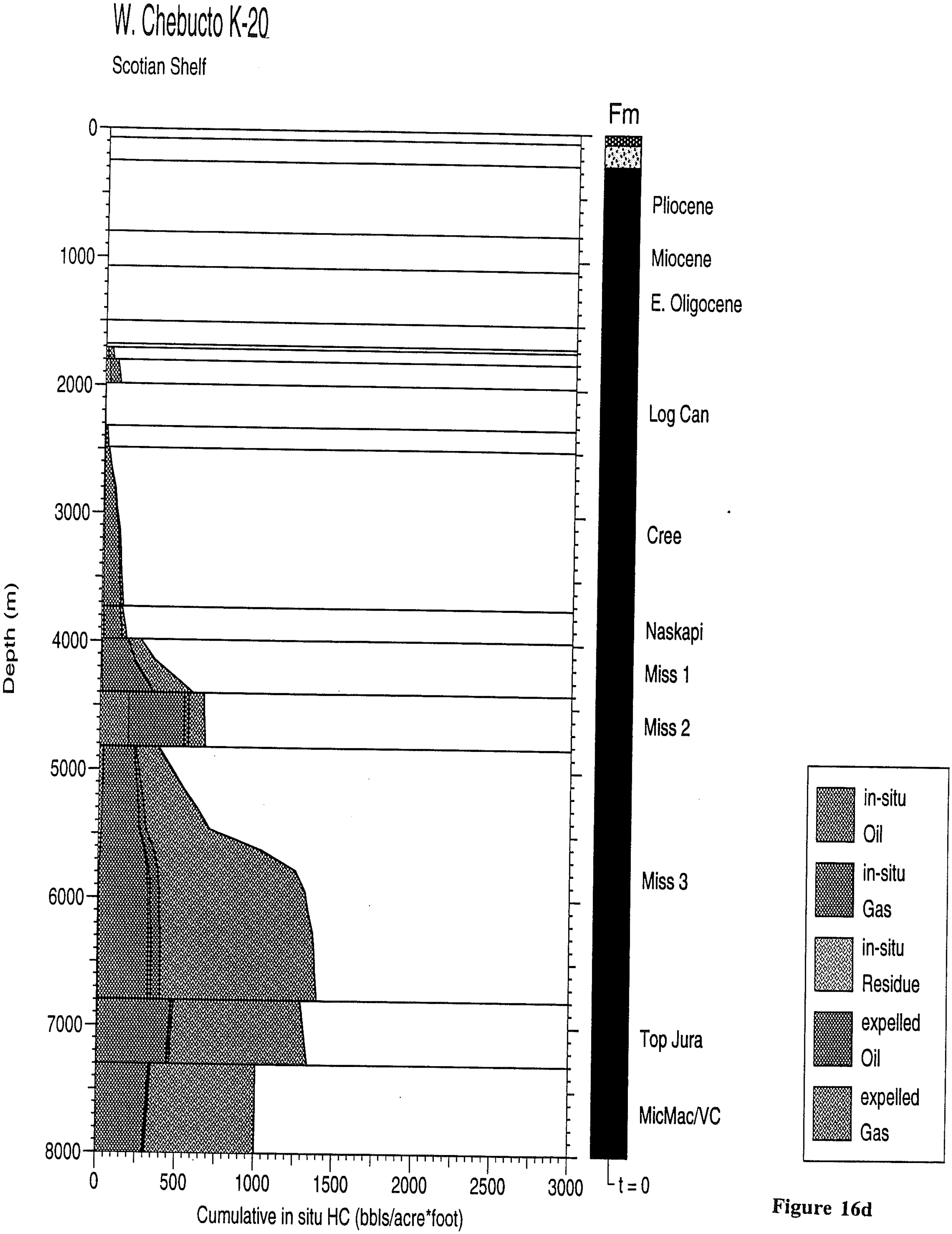
W. Chebucto K-20
Scotian Shelf
Fm
Depth (m)
0
1000
2000
3000
4000
5000
6000
7000
8000
0
500
1000
1500
2000
2500
3000
Cumulative in situ HC (bbls/acre*foot)
Pliocene
Miocene
E. Oligocene
Log Can
Cree
Naskapi
Miss 1
Miss 2
Miss 3
Top Jura
MicMac/VC
t = 0
in-situ Oil
in-situ Gas
in-situ Residue
expelled Oil
expelled Gas

Figure 16d

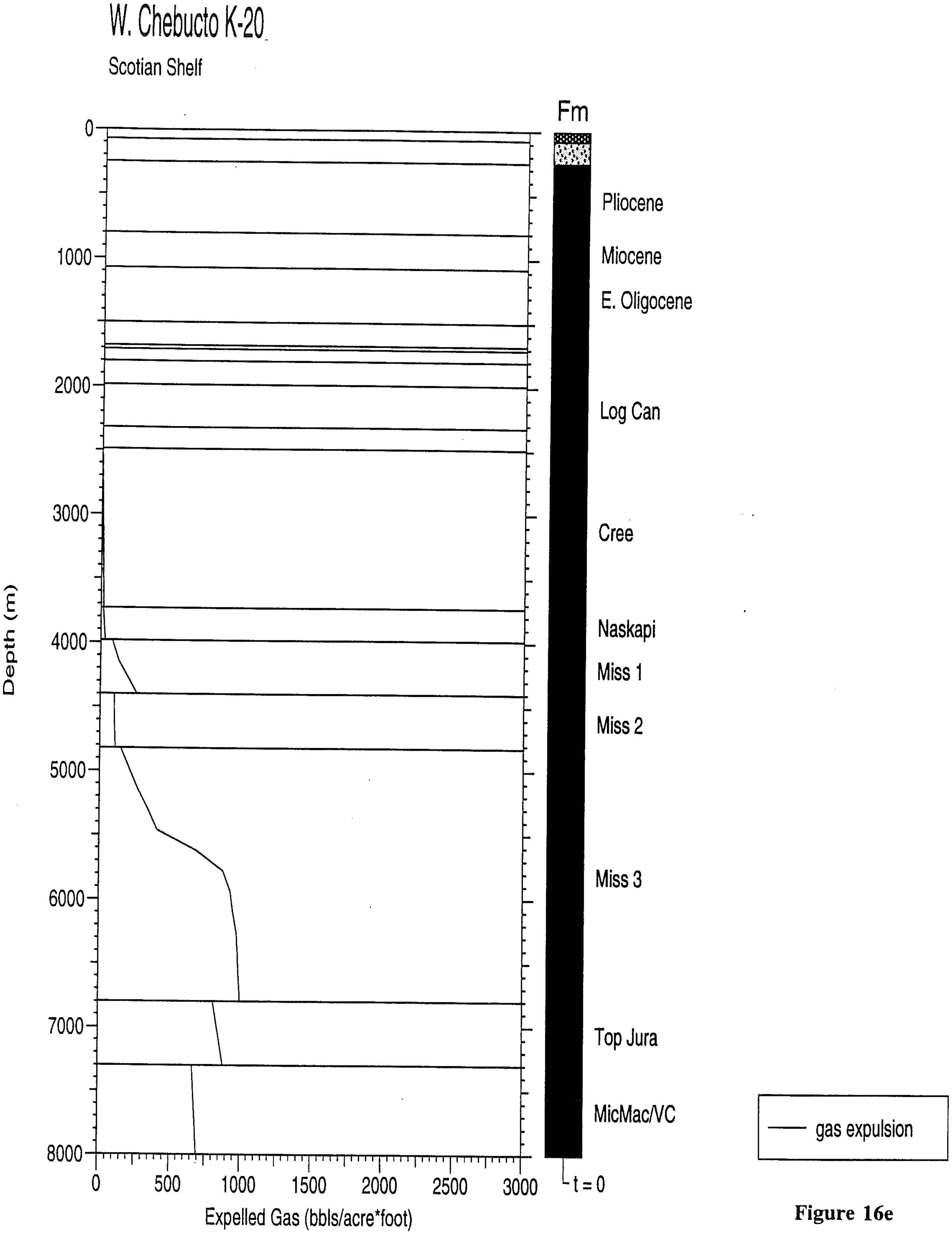

W. Chebucto K-20
Scotian Shelf
Fm
Depth (m)
0
1000
2000
3000
4000
5000
6000
7000
8000
Pliocene
Miocene
E. Oligocene
Log Can
Cree
Naskapi
Miss 1
Miss 2
Miss 3
Top Jura
MicMac/VC
gas expulsion
0
500
1000
1500
2000
2500
3000
t = 0
Expelled Gas (bbls/acre*foot)

Figure 16e

W. Chebucto K-20

Scotian Shelf

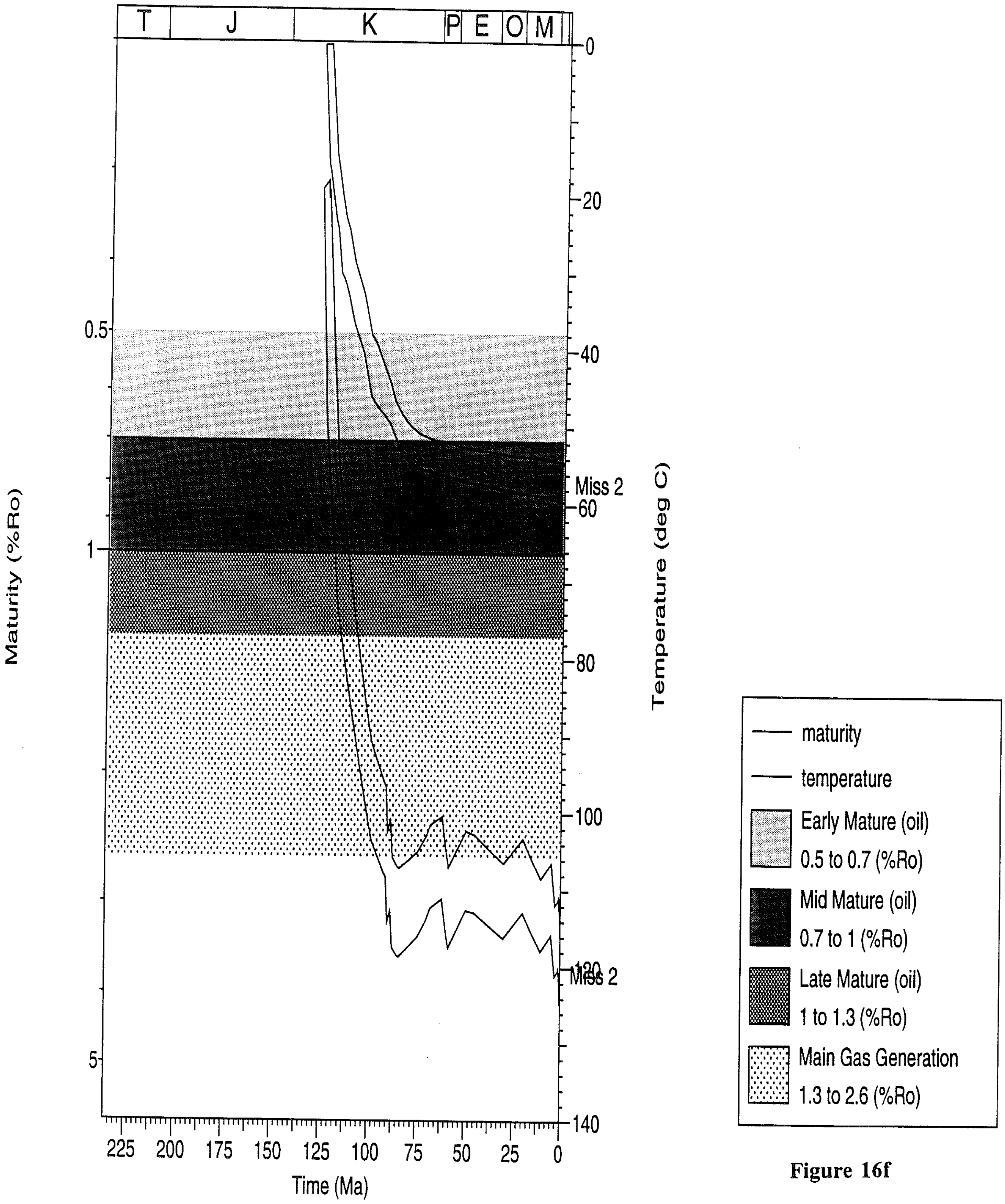


Figure 16f

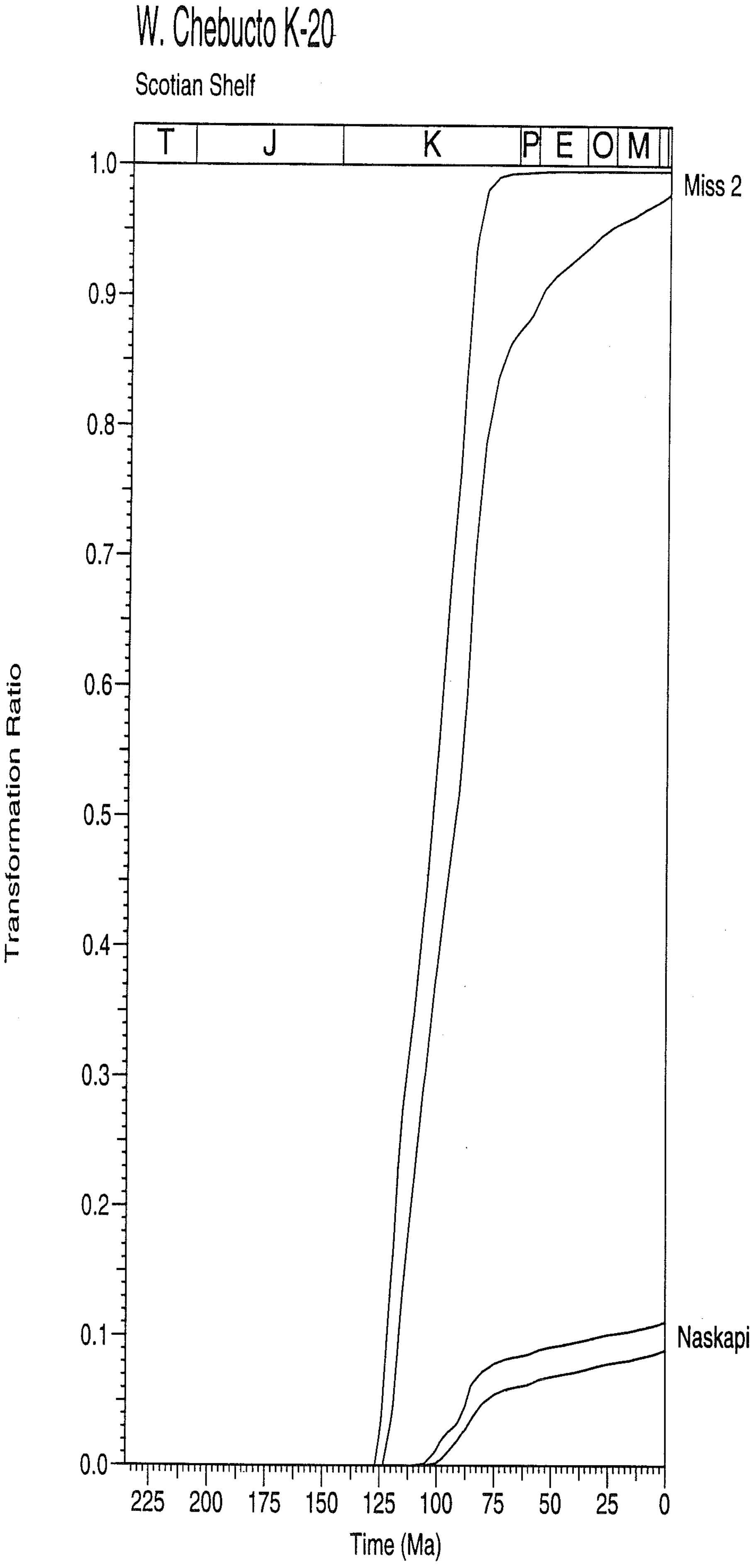

W. Chebucto K-20
Scotian Shelf
T
J
K
P
E
O
M
Transformation Ratio
1.0
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0.0
225
200
175
150
125
100
75
50
25
0
Time (Ma)
Miss 2
Naskapi
transformation ratio

Figure 16g

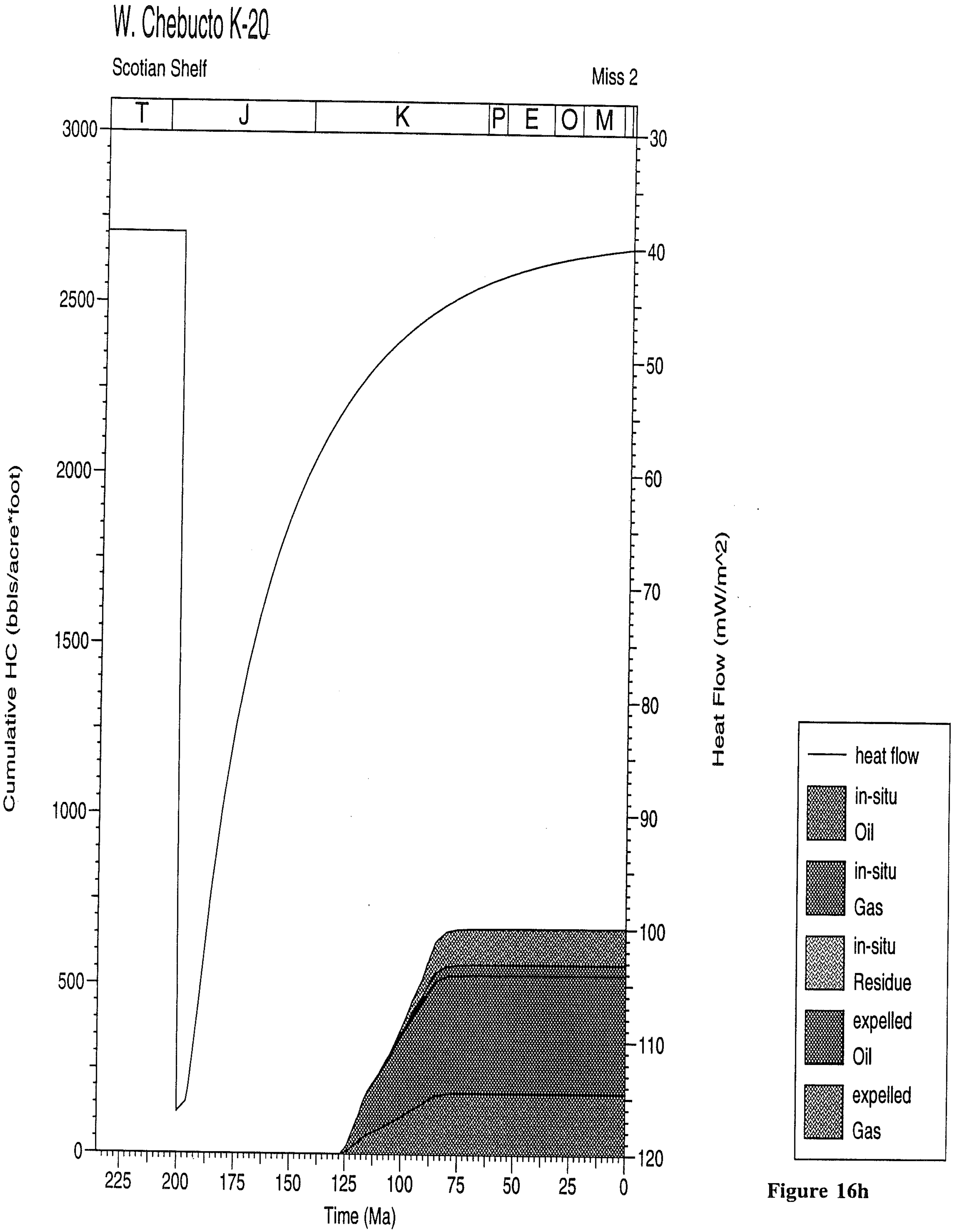

W. Chebucto K-20
Scotian Shelf
Miss 2
T
J
K
P
E
O
M
Cumulative HC (bbls/acre*foot)
3000
2500
2000
1500
1000
500
0
Heat Flow (mW/m^2)
30
40
50
60
70
80
90
100
110
120
225
200
175
150
125
100
75
50
25
0
Time (Ma)
heat flow
in-situ Oil
in-situ Gas
in-situ Residue
expelled Oil
expelled Gas

Figure 16h

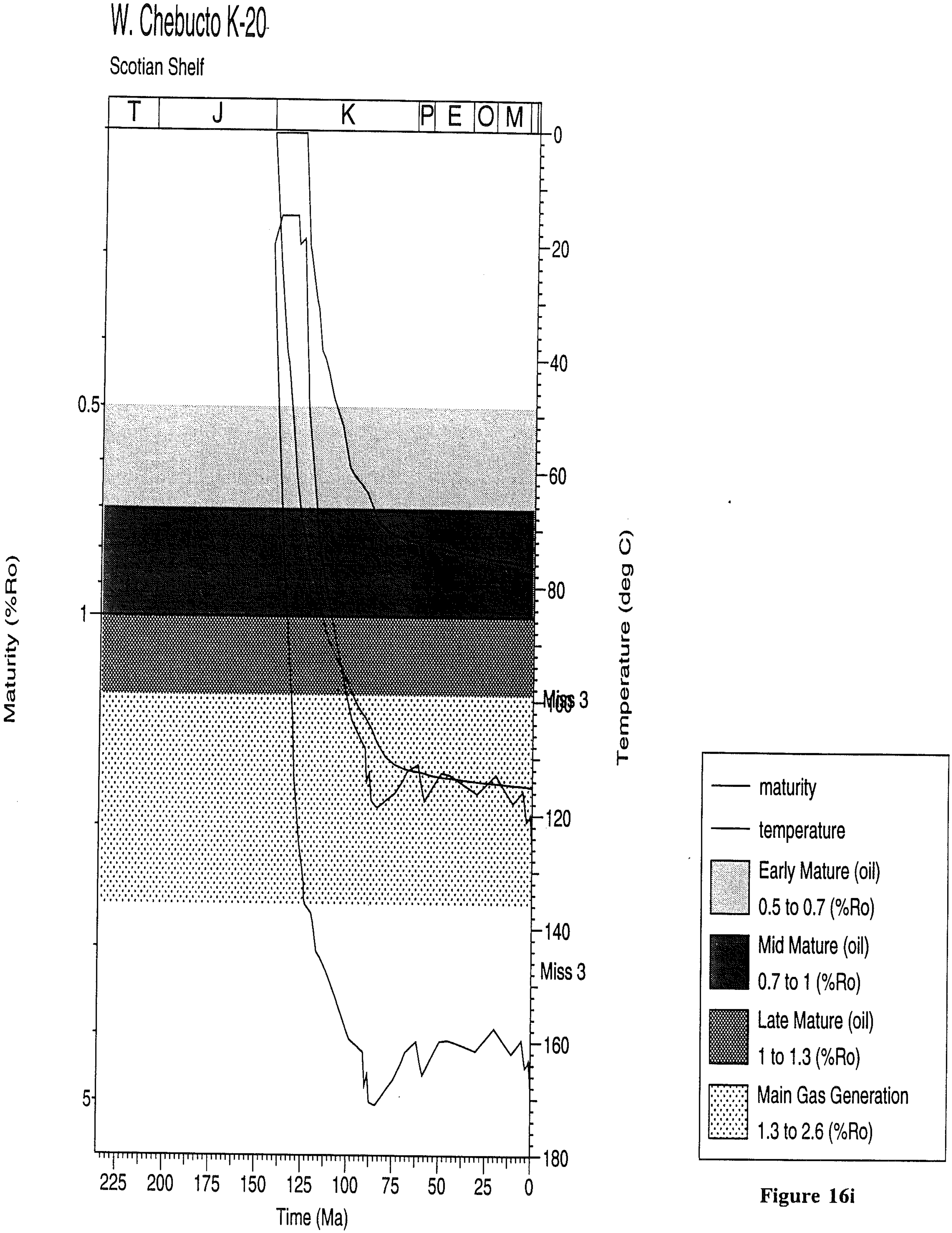

W. Chebucto K-20
Scotian Shelf
T
J
K
P
E
O
M
Maturity (%Ro)
0.5
1
5
Temperature (deg C)
0
20
40
60
80
100
Miss 3
120
140
Miss 3
160
180
225
200
175
150
125
100
75
50
25
0
Time (Ma)
maturity
temperature
Early Mature (oil)
0.5 to 0.7 (%Ro)
Mid Mature (oil)
0.7 to 1 (%Ro)
Late Mature (oil)
1 to 1.3 (%Ro)
Main Gas Generation
1.3 to 2.6 (%Ro)

Figure 16i

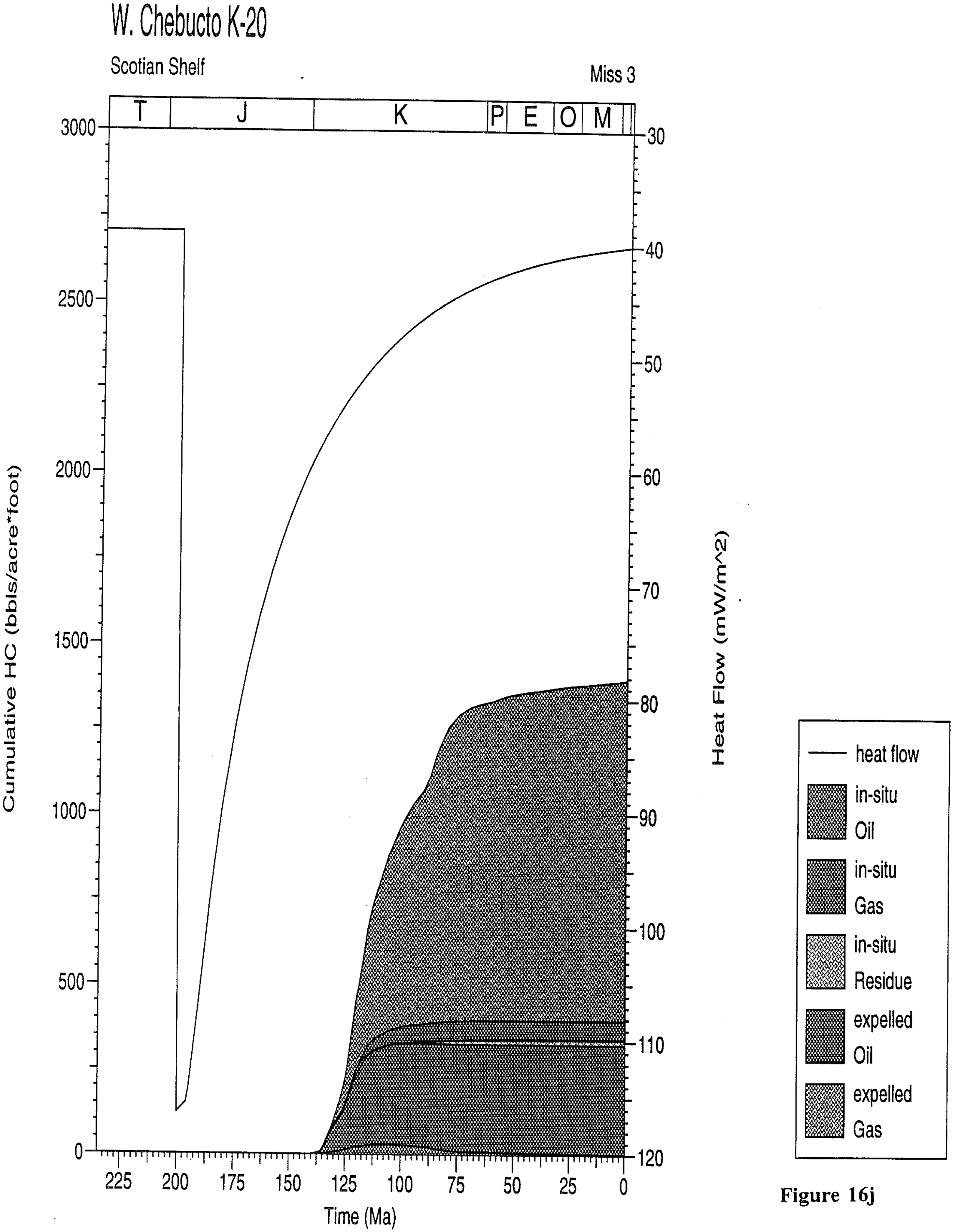

W. Chebucto K-20
Scotian Shelf
Miss 3
T
J
K
P
E
O
M
Cumulative HC (bbls/acre*foot)
3000
2500
2000
1500
1000
500
0
Heat Flow (mW/m^2)
30
40
50
60
70
80
90
100
110
120
225
200
175
150
125
100
75
50
25
0
Time (Ma)
heat flow
in-situ Oil
in-situ Gas
in-situ Residue
expelled Oil
expelled Gas

Figure 16j

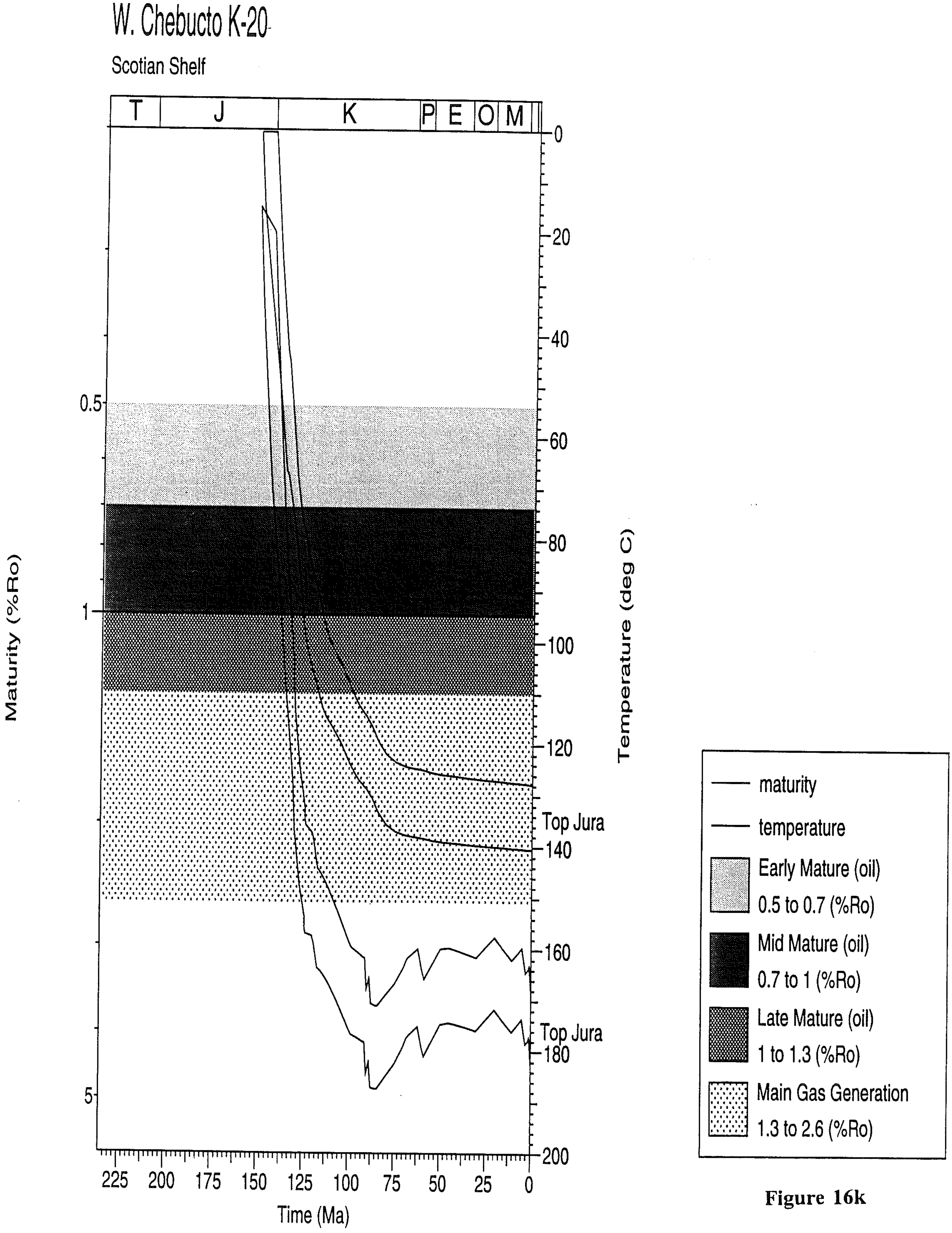
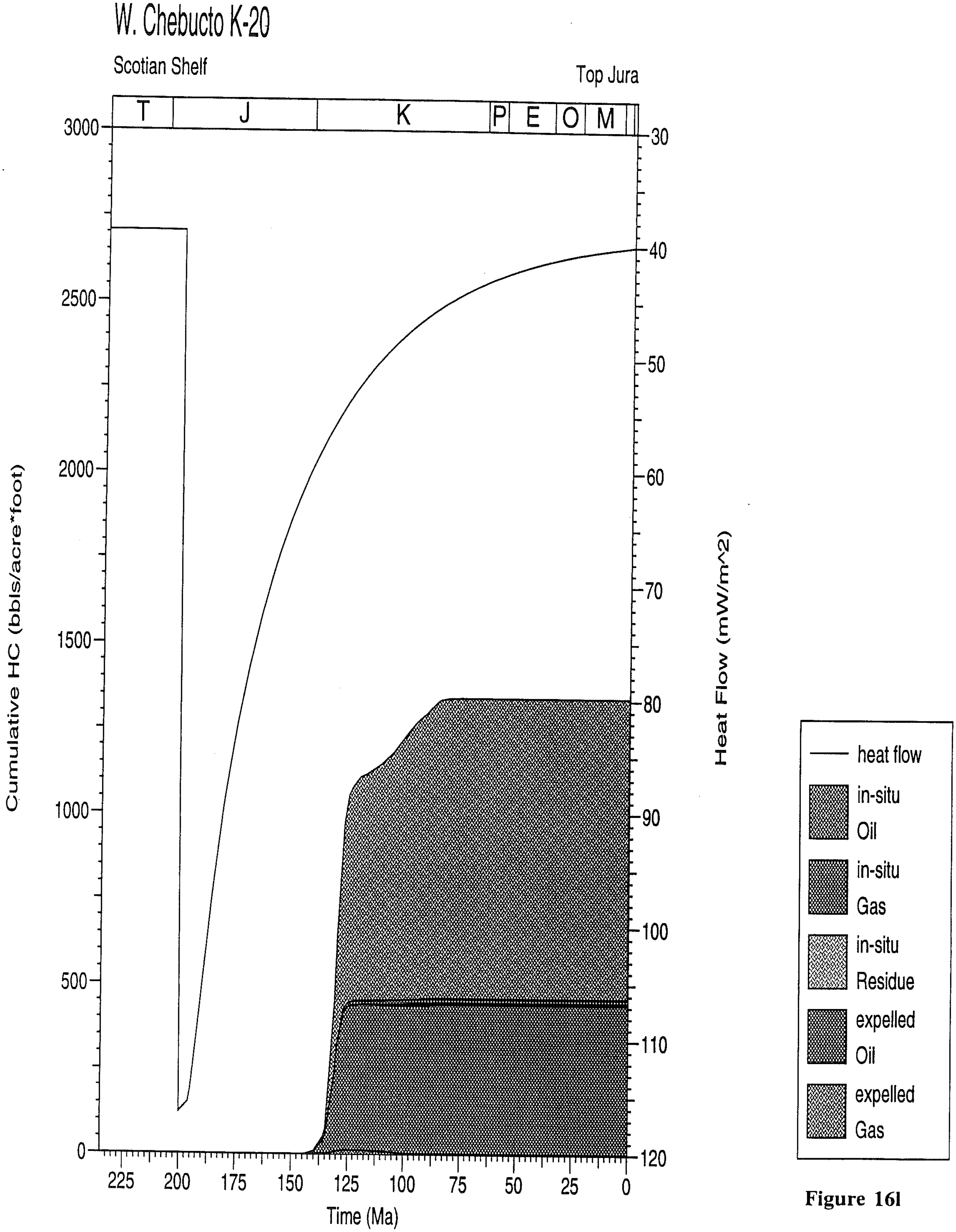

W. Chebucto K-20
Scotian Shelf
T
J
K
P
E
O
M
Maturity (%Ro)
0.5
1
5
Temperature (deg C)
0
20
40
60
80
100
120
140
160
180
200
Top Jura
Top Jura
225
200
175
150
125
100
75
50
25
0
Time (Ma)
maturity
temperature
Early Mature (oil) 0.5 to 0.7 (%Ro)
Mid Mature (oil) 0.7 to 1 (%Ro)
Late Mature (oil) 1 to 1.3 (%Ro)
Main Gas Generation 1.3 to 2.6 (%Ro)

Figure 16k



W. Chebucto K-20
Scotian Shelf
Top Jura
T
J
K
P
E
O
M
3000
2500
2000
1500
1000
500
0
Cumulative HC (bbls/acre*foot)
30
40
50
60
70
80
90
100
110
120
Heat Flow (mW/m^2)
225
200
175
150
125
100
75
50
25
0
Time (Ma)
heat flow
in-situ Oil
in-situ Gas
in-situ Residue
expelled Oil
expelled Gas

Figure 16l