

## Cross-formational hydrocarbon fluid flows in the Tertiary deltaic system of the Beaufort–Mackenzie Basin

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### Abstract

Molecular and isotopic compositions of crude oils in the Beaufort–Mackenzie Basin confirm three genetic end-member oil groups and suggest extensive cross-formational hydrocarbon fluid flows in the Tertiary deltaic system. Inter- and intra-fractional variations in the geochemistry of the Tertiary-reservoired oils indicate that the oil source/maturity signatures were substantially masked by biomarkers that were picked up along migration pathways. Thus, many of the previously recognized “immature non-marine oils” are in fact thermally mature, probably derived from unpenetrated deeper marine source rocks. Although the effective source rock volumes have not been evaluated and their exact stratigraphic levels remain unknown, the relative timing of oil generation versus trap formation, rather than poor source quality, may be the cause of under-filled traps in the offshore area.

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### 1. Introduction

Petroleum geochemistry contributes to exploration successes by providing key constraints for geological models and critical input to exploration scenarios. One of the most important tasks in a typical exploration program is to identify the most effective source intervals or kitchens in a basin, through oil-source correlation. The results of correlation are valid only if the geochemical parameters used address adequately the genetic characteristics of the source rocks, as well as the mass transport and mixing processes of hydrocarbon fluids occurring in the carrier beds and reservoirs. This paper presents a case study of the Tertiary-reservoired oils in the Canadian Beaufort–Mackenzie Basin, where

over 200 drill-stem-test oils were systematically characterized. Compositional data were obtained from the gas chromatography (GC) of gasoline range hydrocarbons, and gas chromatography and gas chromatography–mass spectrometry (GC/MS) of C<sub>15+</sub> saturated and aromatic hydrocarbon fractions for all oils. The saturated and aromatic hydrocarbon fractions of 50 representative oil samples were also analyzed by gas chromatography–mass spectrometry–mass spectrometry (GC/MS/MS), for C<sub>26</sub>–C<sub>30</sub> steranes and C<sub>27</sub>–C<sub>35</sub> terpanes. Gas chromatography–isotopic ratio–mass spectrometry (GC-ir-MS) was also conducted on the *n*-alkanes isolated from these oils. Our results indicate that the previously proposed “immature oils derived from resinite-rich Tertiary coals” may actually represent normal to high maturity marine oils with contamination of non-marine bitumens from carrier beds or intra-reservoir shales. Thus, cross-formational hydrocarbon

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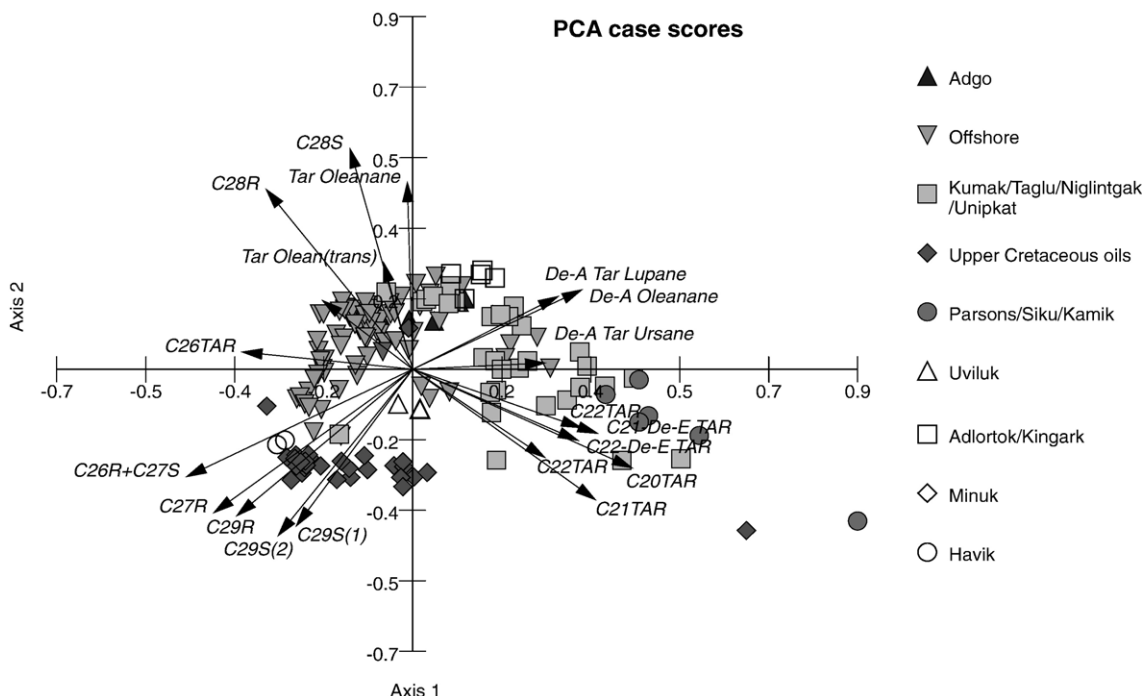


Fig. 1. Principal Component Analysis case scores based on standardized peak areas on the  $m/z$  231 mass fragmentograms of the aromatic hydrocarbon fractions for the studied oils.

fluid flows may complicate the true source and maturity signatures of a reservoir oil.

## 2. Results and analysis

Previous geochemical studies have suggested one or more of the Tertiary deltaic sequences as the source of the Tertiary-reservoired oils. Based on oil geochemistry, three genetic groups of Beaufort oils were initially suggested (Brooks, 1986a): two Cretaceous-derived groups in Cretaceous reservoirs (one marine and one terrestrial in character), and one Tertiary terrestrially derived group including all the Tertiary-reservoired oils. The thick deltaic Richards sequence was thought to be the source for the oils in the Tertiary group because of the presence of 24,28-bisnorlupanes and absence of 28,30-bisnorhopanes (Brooks, 1986b; Snowdon, 1988). Curiale (1991) also distinguished the Cretaceous-reservoired oils from the Tertiary-reservoired ones. However, he subdivided the Tertiary-reservoired oils into two subgroups, as lupanoids and noroleananes were recognized in the Kugmallit and Richards reservoir oils but not in the Reindeer and Moose Channel reservoir oils. The recent discovery of bisnorlupanes in coals of the lower Taglu sequence (Snowdon et al., 2004) suggests that the previous oil-source rock

correlations may not have been correct, thus this unit was proposed as the likely dominant source rocks for hydrocarbons in the Paleocene and early Eocene reservoirs in the southern Mackenzie Delta. A major problem associated with these earlier correlation studies is the underlying assumption of a uniform hydrocarbon source potential and biomarker distribution within each source rock. This led McCaffrey et al. (1994) to assess the lateral source facies variations from the variations in the sterane distributions in the oils, suggesting that the Tertiary deltaic source was substantially more oil-prone in the distal deltaic portions than in the region closer to the paleoshoreline.

As a follow-up to the recent work of Snowdon et al. (2004), over 170 potential Tertiary source rock samples were analyzed under the same conditions as for the oils. Our results confirm that bisnorlupanes and oleananes occur almost ubiquitously in the studied Tertiary source rocks and thus they are not unique to the Richards Formation. In an attempt to define more source-specific molecular markers, full scan GC/MS analyses were conducted on the aromatic hydrocarbons of all oils and rock extracts. This led to the identification of a number of partially aromatized triterpenoid hydrocarbons that are structurally related to  $\beta$ - and  $\alpha$ -amyrins in natural products. These compounds are present in much higher

abundance and wider structural diversity than the oleananes and bisnorlupanes identified in the saturated hydrocarbon fractions, thus adding new dimensions to biomarker analysis and reducing the uncertainty in oil-source correlation studies. For example, the  $m/z$  231 mass fragmentograms of the aromatic hydrocarbon fractions of the analyzed oils and rock extracts display reasonable separation of the samples into genetic groups. The application of Principal Component Analysis using peak areas on the  $m/z$  231 mass fragmentograms effectively reduces the number of parameters, with the first four eigenfunctions cumulatively representing 71% of the total variance within the data set. As shown in Fig. 1, it is relatively easy to identify three genetic end-members for the oils discovered in the Beaufort–Mackenzie Basin. However, many of the oils appear to show intermediate chemical compositions.

One question that has yet to be answered is whether the observed intermediate oil compositions indicate the source facies variations or, as we prefer, the contribution of liquid hydrocarbons in the Tertiary reservoirs from the underlying, but not penetrated, Mesozoic source rocks of the offshore region. Whereas the resinite-rich Tertiary humic coals show variable hydrocarbon potential and are gas or gas condensate prone, Upper Cretaceous marine source rocks in the Smoking Hills–Boundary Creek formations appear to have made significant contribution to the oils in the Tuktoyaktuk Peninsula–South Delta. Crude oils in the Kamik, Parsons and Siku discoveries also correlate well with Mesozoic nonmarine source rocks such as those in the Jurassic McGuire formations. The generally high gas/oil ratios for major Tertiary petroleum discoveries and the large variation observed in the absolute concentrations of many biomarker molecules in various source rocks suggest a highly possible scenario of fluid mixing and migration contamination when hydrocarbons generated in deeper source rocks migrate upward through faults and highly fractured coal seams. Thus, the possible presence of Mesozoic source rocks beyond the Tuktoyaktuk Peninsula–South Delta cannot be ruled out based on such data as shown in Fig. 1. The sterane distribution presented in this figure is typical of almost all Tertiary-reservoired oils in the southern Mackenzie Delta and Beaufort Sea, where the sterane component of the oils clearly consists of two disparate components, one mature and marine in character and another immature and dominantly terrestrial in origin.

Immature oils have been reported from many Cenozoic basins. Because of the large resource potential of such oils, several hydrocarbon generation models

have been proposed (e.g. Snowdon and Powell, 1982). The low maturity levels of some of the oils in the offshore parts of the Beaufort Mackenzie Basin, as indicated by  $C_{29}$  sterane isomerization ratios, appear to be supported by a zigzag pattern in the hydrogen isotope distributions of  $n$ -alkanes. However, almost all of these oils also show internally inconsistent maturity signatures from parameters in the same, and in different, oil fractions (gasoline-range hydrocarbons versus  $C_{15+}$  fractions). As indicated by the distributions of  $C_{27}$ ,  $C_{28}$  and  $C_{30}$  4-desmethylsteranes revealed by GC/MS/MS results, the marine component of the oil is clearly mature. This is in contrast to the higher plant-derived  $C_{29}$  steranes that are still immature! Aliphatic and aromatic biomarker concentrations in potential source rocks vary significantly with increasing maturity level. Thus, the oil maturity signatures determined from  $C_{15+}$  fractions may be potentially compromised by solubilization of generated but non-expelled hydrocarbons in fine-grained rocks on the migration pathway. To illustrate this point, a number of Upper Cretaceous marine sourced oils were artificially mixed in the laboratory with solvent extracts obtained from potential Tertiary source rocks with burial depth slightly greater than the Tertiary oil reservoirs. It is noted that addition of a mere 5% of a Tertiary rock extract into an Upper Cretaceous sourced oil (e.g. DST #12 from the Mayogiak P-17 well) would turn this mature marine oil into an apparent immature non-marine oil commonly observed in the Beaufort–Mackenzie Basin, based on biomarkers. We also note that variation in the level of oil biodegradation could also create uncertainties in the use of gross oil compositions as an indicator of oil maturity. Although the recent rapid subsidence of the basins along the southern Arctic Ocean favours oil generation at relatively low maturity levels, most of the economic oils discovered in the Beaufort–Mackenzie Basin appear to have been derived from conventionally mature source rocks, but contain lower maturity fluids pick up along the migration pathway or from intra-reservoir shales.

### 3. Discussion and conclusions

There are three possible models for the origin of the Tertiary-reservoired oils in the Beaufort–Mackenzie Basin. Based on our data, it is easy to exclude the possibility that thin, high quality but regionally uniform source rocks interbedded within one or more of the deltaic sequences sourced the oils. The unique carbon number distributions observed from the diasteranes in many of the Beaufort Sea oils show a high degree of match with those of an Upper Cretaceous source. This is

inconsistent with the suggestion of McCaffrey et al. (1994) that one or more of the deltaic sequences become substantially more oil prone in the distal parts of the delta, and that oil-prone source rocks in this distal portion generated most of the oils in the distal portion. In contrast, all available geochemical evidence appear to suggest that deeper pre-Tertiary sediments (Upper Cretaceous in the offshore and Lower Cretaceous/older strata in the southern Delta) generated the oils, which subsequently migrated into the Tertiary reservoirs and mixed with deltaic-sourced fluids of varying maturities, as well as in different proportions.

This study suggests caution should be applied when using conventional biomarker data for oil/oil and oil/source correlation in basins with extensive vertical, cross-formational hydrocarbon fluid flows, where the potential source rocks often contain biomarkers in drastically different concentrations. Because many of the commonly used  $C_{15+}$  molecular tracers for source facies and maturity show several orders of magnitude variation in petroleum systems, they do not reliably track facies or maturity signals in mixed oils. Light hydrocarbon and aromatic hydrocarbon parameters are valuable in this situation. As mixtures are the norm, the concept of the source/maturity of oils needs revision. An alternative approach for oil-source correlation is needed to track the relationships of source/maturity indices and petroleum mass fraction for accumulated oils.

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