

# Biodegradation and origin of oil sands in the Western Canada Sedimentary Basin

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**Abstract:** The oil sands deposits in the Western Canada Sedimentary Basin (WCSB) comprise of at least 85% of the total immobile bitumen in place in the world and are so concentrated as to be virtually the only such deposits that are economically recoverable for conversion to oil. The major deposits are in three geographic and geologic regions of Alberta: Athabasca, Cold Lake and Peace River. The bitumen reserves have oil gravities ranging from 8 to 12° API, and are hosted in the reservoirs of varying age, ranging from Devonian (Grosmont Formation) to Early Cretaceous (Mannville Group).

They were derived from light oils in the southern Alberta and migrated to the north and east for over 100 km during the Laramide Orogeny, which was responsible for the uplift of the Rocky Mountains. Biodegradation is the only process that transforms light oil into bitumen in such a dramatic way that overshadowed other alterations with minor contributions. The levels of biodegradation in the basin increasing from west (non-biodegraded) to east (extremely biodegraded) can be attributed to decreasing reservoir temperature, which played the primary role in controlling the biodegradation regime. Once the reservoir was heated to approximately 80 °C, it was pasteurized and no biodegradation would further occur. However, reservoir temperature could not alone predict the variations of the oil composition and physical properties. Compositional gradients and a wide range of biodegradation degree at single reservoir column indicate that the water-leg size or the volume ratio of oil to water is one of the critical local controls for the vertical variations of biodegradation degree and oil physical properties. Late charging and mixing of the fresh and degraded oils ultimately dictate the final distribution of compositions and physical properties found in the heavy oil and oil sand fields. Oil geochemistry can reveal precisely the processes and levels that control these variations in a given field, which opens the possibility of model-driven prediction of oil properties and sweet spots in reservoirs.

**Key words:** Western Canada Sedimentary Basin (WCSB), oil sands, biodegradation, mixing

## 1 Introduction

Once expelled from source rocks, the crude oil was subject to a complex series of subsequent compositional modifications that may occur during the migration and within the reservoirs (Tissot and Welte, 1984; Hunt, 1996). Thermal maturation and biodegradation are the most common ones, but other phenomena involving evaporative fractionation, water washing, gas washing, deasphalting, thermochemical sulfate reduction, gravity segregation, and dewaxing may all contribute to the alteration of crude oil either in the reservoirs or along the migration pathways (Larter and Aplin, 1995; Wenger et al, 2002). Most of these alteration processes in the reservoirs usually reduce the commercial value of the oil and complicate the development procedures.

Biodegradation impacts petroleum exploration and production by removing hydrocarbon compounds that are of most value and impacting the in-situ density and viscosity that determine well flow rate (Larter et al, 2006). There are

a number of conditions necessary for the biodegradation of petroleum: a) low reservoir temperature, < 100 °C usually 20-60 °C; b) the presence of water or other type of electron acceptor (Fe, SO<sub>4</sub>, N, Mn); c) an oil-water contact; d) the presence of microorganisms; e) nutrients (e.g. nitrate, phosphate) (Connan, 1984; Wenger et al, 2002; Head et al, 2003). Increasing levels of biodegradation generally cause a decline in oil quality, diminishing the producibility and value of oil. With increasing biodegradation, the oil becomes more viscous, richer in sulfur, resins, asphaltenes, and metals (e.g. Ni and V), has higher total acid number and lower API gravity (Connan, 1984; Peters and Moldowan, 1993; Wenger et al, 2002; Head et al, 2003; Jones et al, 2008). Once oil was severely biodegraded, light normal oil was transformed into heavy viscous oil or even oil sand. In fact, biodegradation seems to be the only process which can alter the chemical and physical properties of the oil in such a dramatic way as causing a decrease of API gravity from 40° to 5° and an increase of viscosity from less than 1 centipoises to over one million centipoises. Almost all commercial accumulated heavy oils and oil sands are originated from biodegradation.

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Among them the Western Canada Sedimentary Basin is the largest one in the world holding such kind of unconventional resources.

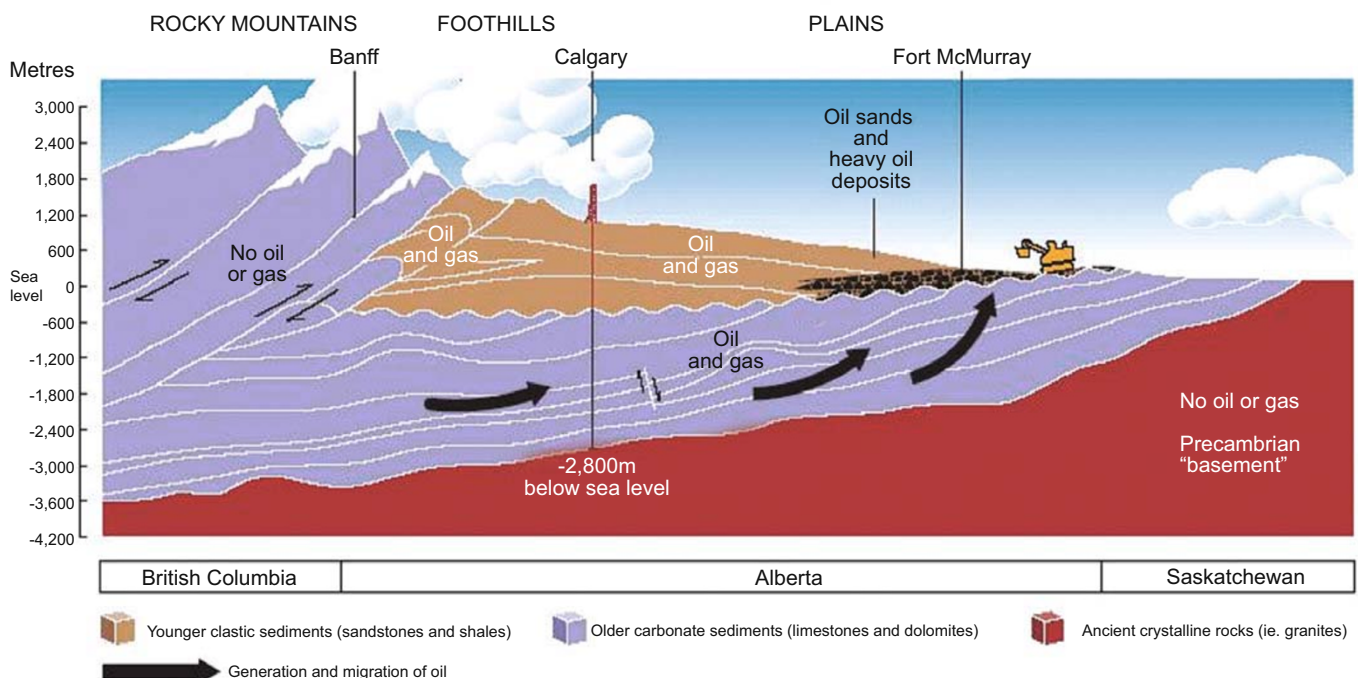
## 2 Geological background and oil sand distribution

The Western Canada Sedimentary Basin covers an area of 1,400,000 km<sup>2</sup> in the western part of North America. It contains a sedimentary section that ranges in age from Early Paleozoic to Early Tertiary. The basin developed in the Early Paleozoic and can be divided into two distinct parts, reflecting sedimentation in two profoundly different tectonic settings. The Paleozoic to Jurassic platformal succession, dominated by carbonate rocks, was deposited on the stable craton adjacent to the ancient (dominantly passive) margin of North America. The overlying mid-Jurassic to Paleocene foreland basin succession, dominated by clastic rocks, was formed during active margin orogenic evolution of the Canadian Cordillera. The Laramide Orogeny was responsible for the uplift of the Rocky Mountains (Wright et al, 1994). Concomitant with this uplift, the basin was tilted to the west and assumed the geometry of an asymmetrical foreland basin, with a gently dipping eastern margin and a thrust-bounded western margin. The foreland basin wedge is characterized by upward-coarsening progradational cycles capped by extensive non-marine deposits (Fig. 1).

During the Early Cretaceous, a major drop of sea level resulted in the significant erosion across the entire foreland trough (pre-Mannville unconformity). The earliest post-unconformity sediments include the alluvial fan and braided stream deposits of the Cadomin Formation and the fluvial deposits of the Lower Mannville Group. Mannville deposition took place over a profound unconformity surface

that truncated strata ranging from lowermost Cretaceous in the foothills to lower Paleozoic on the eastern margin of the basin. Regionally, the Devonian Prairie Evaporite has a wedge-shaped cross-section that tapers to the northeast. On the eastern side, over the edge of the salt collapse zone due to dissolution, anticlinal traps may develop within the Cretaceous section. The anticlinal development forms the structural component of the trapping mechanism that keeps the oil in the McMurray Formation. The seal of oil sand is formed by overlapping Clearwater shales of the Upper Mannville Group.

Identification of the source rocks of the WCSB oil sands remains controversial, however, the closest biomarker characteristic of these bitumens and oils is the Devonian-Mississippian Exshaw Formation (Fowler et al, 2001). This marine source rock is thin (10 m), but is commonly extremely organic-rich (TOC up to about 20%) and is composed largely of oil-prone type I kerogen and has hydrocarbon indices (HI) up to 600. Burial history models illustrate the time of hydrocarbon generation from the Exshaw Formation ranging from 110 and 80 Ma in the vicinity of the Alberta-British Columbia border to about 60-56 Ma in the Peace River area (Riediger et al, 1999; 2000). The uplift that occurred in the WCSB following the Laramide Orogeny in the Early Tertiary would have stopped hydrocarbon generation and brought the reservoirs nearer to the surface, thereby further facilitating biodegradation which continued until the present. The McMurray or equivalent sands were the primary collectors of the generated oil and provided the main conduit for migration. It is speculated that the migration path was at least 360 kilometres for the Athabasca deposit and at least 80 kilometres for the Peace River deposits (Anfort et al, 2001; Adams et al, 2004). The lighter oil was then subjected to the biodegradation transforming them into heavy oil and oil



**Fig. 1** Cross section of the Western Canada Sedimentary Basin indicating the distribution of oil and gas

sands.

There are three major oil sand deposits in the WCSB: Athabasca, Cold Lake and Peace River (Fig. 2a). The Athabasca Oil Sands, located in the northeastern of Alberta, cover an area of approximately 75,000 km<sup>2</sup> and hold the largest and most accessible reserves of bitumen with resources mainly in the McMurray Formation of the Lower Cretaceous Mannville Group. The reservoir bed is at the depth of 0-500 m below ground surface. Some of the oil sands near Fort McMurray close to the surface can be mined, but less than 20% of the total area can be developed in this way. In-situ techniques, which melt the bitumen and pump it from underground, are needed for deeper deposits. The Cold Lake Oil Sands extends for approximately 22,000 km<sup>2</sup> in the east-central of Alberta, occurring in multiple, vertically stacked reservoir beds in the Lower Cretaceous Mannville Group at the depth of 985-1970 m below ground surface. Southward from Athabasca, the Clearwater shales in the relatively deep-water change facies to a near-shore deltaic and foreshore/shoreface complex, which form the main reservoir beds of the Cold Lake Oil Sands. The Peace River Oil Sands are the smallest of Alberta's oil sands with an area of 8,000 km<sup>2</sup>, which are located along the axis of the Peace River Arch, a northeast-trending, basement-cored uplift that has a complex history of recurrent movements throughout the Phanerozoic. An in-place reserve of 155 billion barrels of bitumen is contained in Mississippian, Permian and Lower Cretaceous reservoir beds. Exploitable bitumen reserves in the Peace River area are mainly within the 15-20 m thick estuarine sands of the Bluesky Formation, time equivalent of the McMurray Formation at the depth of 550-700 m below ground surface (Strobl et al, 1997; Hubbard et al, 1999).

### 3 Biodegradation effects on oil compositions and physical properties

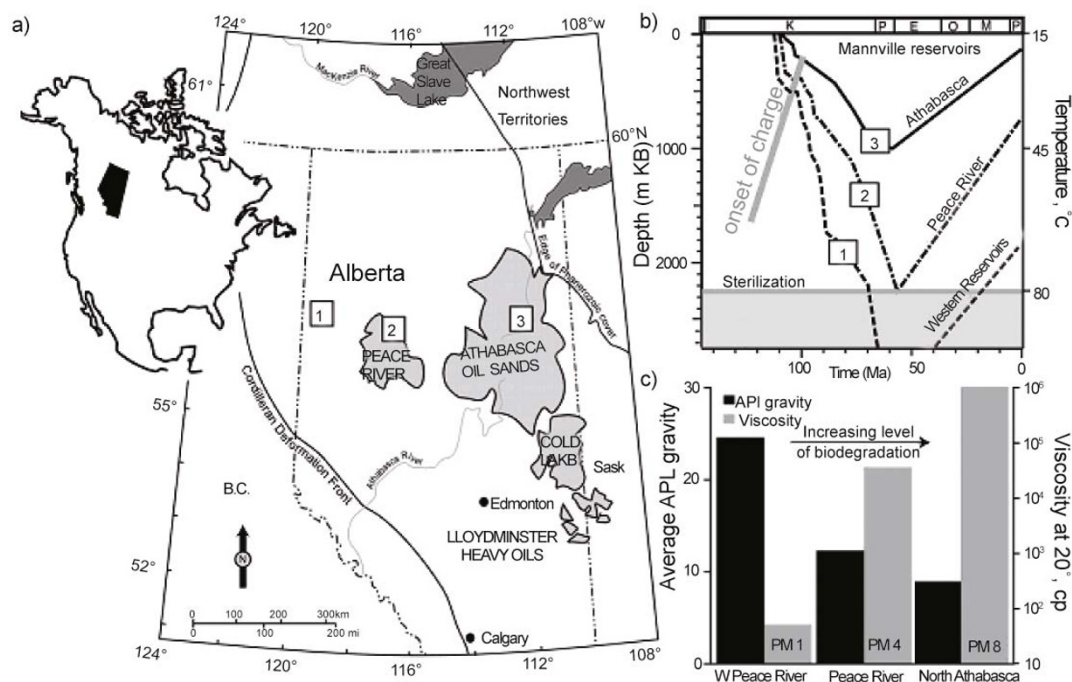
#### 3.1 Controls of lateral variations

During oil biodegradation, the oil fluid properties change because different classes of compounds in petroleum have different susceptibilities to biodegradation. The early stages of oil biodegradation are characterized by the loss of normal alkanes and subsequent loss of acyclic isoprenoid alkanes. Compared with those compound groups, other compound classes (e.g., highly branched and cyclic saturated hydrocarbons as well as aromatic compounds) are more resistant to biodegradation. However, even those more resistant compound classes are eventually destroyed as the biodegradation proceeds (Huang et al, 2003). Peters and Moldowan (1993) proposed a 1-10 scale on which the extent of oil biodegradation can be ranked based on the analysis of oil geochemistry (e.g., using the presence or absence of various biomarkers that have different susceptibilities to biodegradation, with "1" indicating very early degradation (partial loss of n-alkanes) and "10" indicating severely degraded oil). In this study all biodegradation level refers to Peters and Moldowan (1993) scales and abbreviated as PM level.

Biodegradation effects on oil compositions and physical properties in the WCSB have been investigated by various studies (Brooks et al, 1988; Riediger et al, 1999; Obermajer et al, 2004; Bennett et al, 2006; Larter et al, 2006), all illustrating a similar trend in that biodegradation levels intensify from west to east in the Cretaceous deposits. Once the effects of biodegradation are removed, the majority of heavy oils and oil sands in the Lower Cretaceous looked very similar. Empirically, it has been noted that biodegradation occurred in the reservoirs with a temperature lower than 80°C (Connan, 1984; Larter et al, 2003). Many microorganisms involved in subsurface oil biodegradation cannot survive at a temperature higher than 80°C. However, not all oil accumulations at temperatures lower than 80°C are biodegraded. Wilhelms et al (2001) noticed that if an oil reservoir had been heated to higher than 80 °C at any point since its deposition, the reservoir was paleopasteurized and not recolonized even after the basin was uplifted. Therefore, oil reservoirs that have experienced significant uplift may contain non-degraded oil, despite the currently shallow depth and low temperature of the reservoir. Such paleopasteurization processes are important in the Western Canada Sedimentary Basin, which can ideally interpret the occurrence of non-biodegraded oil to the west of the Peace River area.

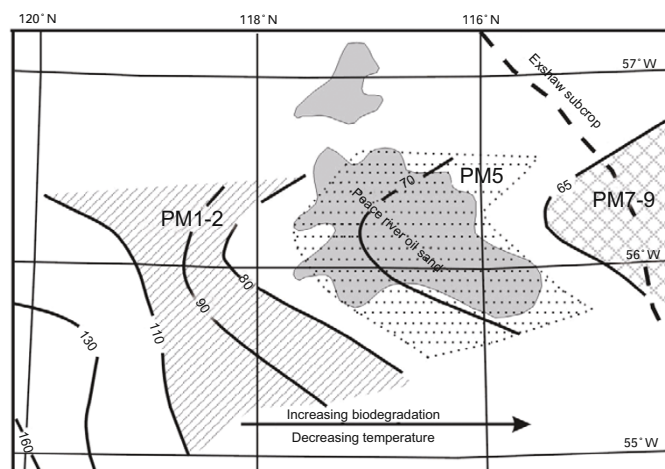
The trend of decreasing biodegradation from the Athabasca oil sands towards the west is a function of thermal history near maximum burial (Fig. 2b) rather than the current reservoir temperatures. Current reservoir temperature at the Athabasca is lower than 10 °C and that at the Peace River is 16-22 °C. The oil was heavily biodegraded due to lower reservoir temperature. However, non-biodegraded oil occurs at the western part of Peace River area where current reservoir temperature is around 40 °C. Such phenomena can be reasonably interpreted by burial history reconstruction. Recent burial history curves that cross the Peace River oil sands area established by Adams et al (2006) predicted the maximum burial temperatures of the Cretaceous reservoir beds in Peace River area ranging from 84 ± 4 °C in most of the western area to less than 65 ± 5 °C in the eastern area, suggesting that reservoir beds located at the western part of the Peace River reached pasteurization temperatures of over 80 °C in geological history (Fig. 3). Reservoir pasteurization terminated the biodegradation process and thus preserved oil quality. Therefore, non-biodegraded oil can be discovered even though the current reservoir temperature is far lower than 80 °C. In contrast, from the Peace River oil sands eastwards; the reservoirs have never reached pasteurization temperatures. These oils have undergone biodegradation to level 4 to 5 on the Peters and Moldowan (1993) scales in the Peace River area, while oils in the Athabasca area experienced biodegradation of level 7 to 9. This level of biodegradation also indicates that more than 50% of the initial petroleum has been lost. Biodegradations continuously occur and remain active today, where all oils are heavily biodegraded.

Representative gas chromatograms (GC) of hydrocarbon fractions from the WCSB are illustrated in Fig. 4. These oils are derived from a single source rock system (mainly from Exshaw Formation) and have similar maturities. The



**Fig. 2** (a) Locations of oil sand deposits in the WCSB (light gray areas), which have undergone varying degrees of biodegradation; (b) generalized burial and temperature history curves showing low reservoir temperatures for Athabasca reservoirs, moderate temperatures in the Peace River area and the pasterization of the western reservoirs shortly after oil charging; and (c) average API gravity and dead oil viscosity values for each study area, showing increasing degradation (PM = Peters & Moldowan biodegradation scale) and viscosity with decreasing API gravity to the east (After Larter et al, 2006)

differing hydrocarbon distribution pattern is due to varying levels of biodegradation. In the southwestern part of the basin, the oils are non-biodegraded, contain a complete suite of n-alkanes, and n-alkanes peaks are stronger than adjacent isoprenoid alkanes on the GC (pristane/n-C17 and phytane/n-C18 ratios are far less than 1.0, Fig. 4a). The unresolved complex mixture (UCM) of branched and cyclic compounds under the resolved peak envelope on the GC is small. Oils from west Peace River and southern Alberta are slightly biodegraded, where low molecular weight n-alkanes in the

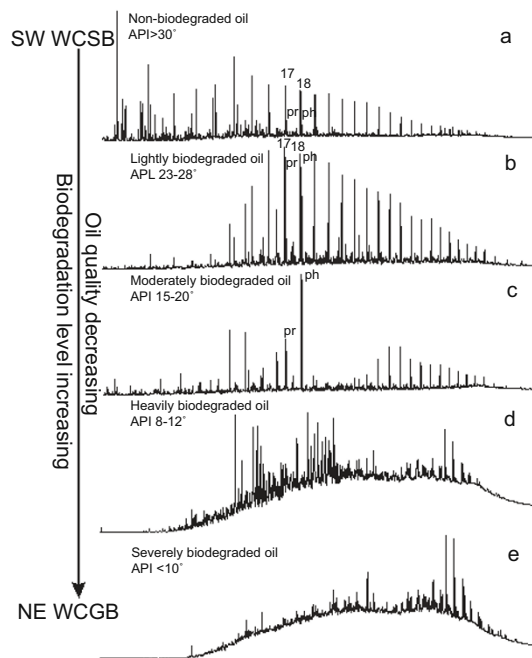


**Fig. 3** Map of mean maximum burial temperatures (°C) of the Bluesky Formation in Peace River area (after Adams et al, 2006)

C8–C15 range have been attacked (Fig. 4b). These oils have a similar amount of n-alkanes and isoprenoid alkanes (pristane/n-C17 and phytane/n-C18 ratios are close to 1.0). Moderately biodegraded oils are mainly distributed in the Lloydminster area, where oil becomes heavy but still producible with water flood. These oils contain almost no normal alkanes but the isoprenoid alkanes are present (Fig. 4c). The extent of biodegradation in the Peace River area are characterized by complete loss of the n-alkanes, acyclic isoprenoids, alkylbiphenyls and methylated naphthalenes, but terpane and sterane biomarkers do not appear to have been affected, indicating that most of the oils suffered a moderate level of biodegradation (Fig. 4d). The Athabasca oil sands are severely affected by biodegradation. All n-alkanes, isoprenoid alkanes, alkylated naphthalenes are completely removed. Most regular steranes are selectively removed with diasteranes being relatively concentrated or slightly attacked as well. Hopanes are in varying degrees converted to 25-norhopanes, which are often present in severely biodegraded oils and are generally considered to be the product of heavy biodegradation (Fig. 4e).

As the high-quality saturated hydrocarbons are removed, there is residual enhancement of the low-quality, high-molecular-weight multi-ring hydrocarbons and the non-hydrocarbon compounds, such as resins and asphaltenes (Wenger et al, 2002). These compositional changes lead to lower gravity, higher viscosity, and higher sulfur, nitrogen, and asphaltene contents. In the WCSB, oil physical properties clearly reflect the direct impact of biodegradation with API





**Fig. 4** Representative gas chromatograms from southwest to northeast of WCSB showing increasing level of biodegradation and decreasing oil quality. Pr: pristane; Ph: phytane; digital number refers carbon number of normal alkanes

gravities ranging from 6 to 10°API and with in-situ viscosities of up to  $2 \times 10^6$  cP in the Lower Cretaceous reservoir beds in the Athabasca area, while the same reservoir beds in the Peace River area contain oils of 8-12° API with a viscosity of  $0.1-8 \times 10^5$  cP at reservoir temperature. Equivalent reservoirs to the west of the Peace River oil sands area contain virtually normal light oils (API up to 38°) with very low to negligible levels of biodegradation (Adams et al 2006).

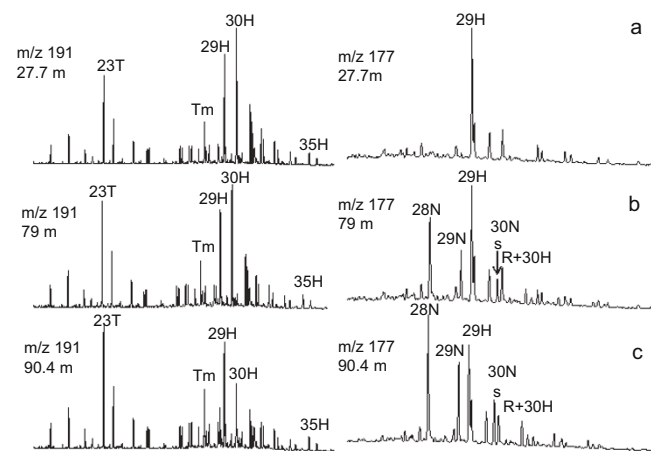
### 3.2 Vertical variations of degradation degree

While reservoir temperature history has overall control on lateral biodegradation level an east–west trend across the oil sand and heavy oil province in the WCSB, shows a wide range of variations at any given temperature (or depth), in oil properties such as API gravity or viscosity. Therefore it is difficult to predict the degree of biodegradation and oil physical properties based solely on the reservoir temperature history prior to drilling. Within reservoirs, field observations typically record a coincidence of the lowest oil quality and the strongest biodegradation at the oil water contact (OWC), suggesting that most petroleum degradation occurred at this interface (Head et al, 2003; Larter et al, 2003; Huang et al, 2004; 2008).

In the severely biodegraded oils of the Western Canadian oil sand reservoirs, chemical compositional gradients are common in both the Athabasca and the Peace River reservoir beds even though they are rarely documented. Early work carried out by Brooks et al (1988) reported that the diasterane/regular sterane ratios gradually increase downward in the Athabasca area. Diasteranes are less susceptible to biodegradation than steranes and their relative concentration is widely used to assess advanced levels of

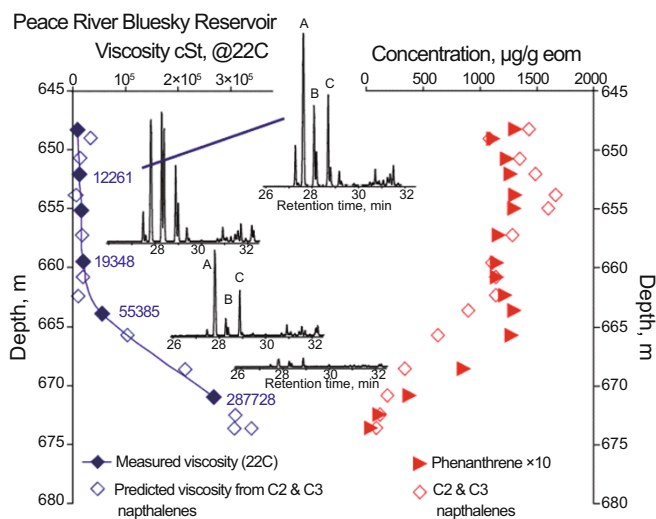
crude oil biodegradation. Recently publications by Bennett et al (2006) and Larter et al (2006) all illustrate that large scale vertical variations in chemical composition are driven by biodegradation processes at the OWC. Bitumens extracted from one of the Athabasca wells show a range of biodegradation from PM 5 in the main oil column increasing downward to PM 9 at the oil–water contact, where even diasteranes are attacked and 25-norhopanes are generated. 25-Norhopanes have always been regarded as being indicative of heavy biodegradation of oil, although they are not found in all heavily biodegraded oils. Representative GC-MS fragmentograms of 25-norhopanes (*m/z* 177) are illustrated in Fig. 5. At 27.7 m, a trace amount of 25-norhopanes may be discernable. With increasing burial depth the 25-norhopane concentrations increase dramatically. At 90.4 m (near OWC), the C28 25-norhopane is the dominant component. Quantitative measurements based on compositional changes at the molecular level indicate that the intrinsic level of biodegradation reaches a maximum at the bottom of the profile, near to the oil-water contact.

Fig. 6 illustrates the variations in naphthalene



**Fig. 5** Representative *m/z* 191 and *m/z* 177 mass fragmentograms of the saturated hydrocarbon fractions isolated from the Athabasca tar sand samples. (a) 27.7 m, (b) 79 m and (c) 90.4 m depth. Key to 191 mass fragmentograms: 23T, C<sub>23</sub> tricyclic terpane; Tm, C<sub>27</sub> 17a-22,29,30-trisnorhopane; 29H, C<sub>29</sub> 17 ahopane; 30H, C<sub>30</sub> 17ahopane; 35H, C<sub>35</sub> 17a(H) 22S and 22R homohopane. Key to *m/z* 177 mass fragmentograms: 28N, C<sub>28</sub> 17a25-norhopane; 29N, C<sub>29</sub> 17a25-norhopane; 30N, C<sub>30</sub> 17a 25-norhopane (After Bennett et al, 2006)

distributions and the corresponding viscosity data through an oil column from the Peace River oil sands area. The absolute concentrations of total C2- and C3-naphthalenes and of phenanthrene are shown varying systematically down hole in the bitumen. The concentrations of total C2- and C3-naphthalenes decrease gradually from about 1500 µg/g bitumen at the top part of the reservoir bed to less than 500 µg/g bitumen at the bottom. The concentrations of phenanthrene show a similar variation trend. Normalized *m/z* 156 mass chromatograms of C2-naphthalenes show the systematic variations which gradually depleted downward due to biodegradation. The molecular level variations in composition are proxies for overall bitumen composition



**Fig. 6** Variations in molecular geochemistry of solvent-extracted core-derived oil and the viscosity of equivalent separately spun oils from the Peace River oil sands (after Larter et al, 2008)

and thus viscosity. With decreasing vulnerable component concentrations, the viscosity increases from 12261 cP at the top to 287728 cP at the bottom. Interestingly, geochemically predicted viscosity profiles using principal component regression on C2- and C3-naphthalene distributions match well with actual measured data (Larter et al, 2008). Therefore, oil physical properties can be easily predicted with geochemical proxies derived from the analysis of solvent extracted bitumen from core samples using gas chromatography-mass spectrometry for heavy oils and oil sands where viscosity measurement is normally difficult. The actual compound suites are the most suitable to assess fluid properties which may vary with the level of degradation and oil type.

In summary, both the Peace River and the Athabasca oil sands bitumen accumulations show large scale vertical variations in chemical composition driven by the biodegradation processes at the OWC which translate them to large vertical variations in oil column viscosity with viscosities varying over an order of magnitude through the reservoir bed sections. This conclusion is sensible because at the OWC the environment is optimal (supplying both hydrocarbon food from the oil column and other nutrients from the water leg) for supporting microbial activity. Essential nutrients, such as nitrogen, potassium, and phosphorus are primarily derived from the mineral dissolution reactions from a suitable source. Large water leg size where nutrient enriched waters are readily available to microorganisms would be expected to promote biodegradation as nutrient supply by diffusion will be enhanced. Small water leg size limits the nutrient supply, which results in a reduction in the rate of petroleum biodegradation and thus the degree of biodegradation of a reservoir (Larter et al, 2003; Huang et al, 2004).

### 3.3 Multiple charging and mixing

Another process which will affect the distributions is

the in-reservoir mixing of crude oils coming from different origins. Oils coming from different source kitchens or different depositional facies are commonly charged into the same reservoir in nature. Reservoirs can be charged by multiple phases (or through continuous charging), and this will complicate fluid-quality distribution. Natural fluid mixing is a dynamic process that occurs over a long (geologic) time, with the late charged oils being more mature. When two oils are mixed in a reservoir, their maturity indicators conflict in different components. A more complicated filling/charging situation is where the first oil charge is subjected to biodegradation and later unbiodegraded charges result in a mixture of non-biodegraded and biodegraded oils within the same reservoir beds. The mixing of fresh and degraded oils dominates the composition and physical properties of the biodegraded oils (Masterson et al, 2001; Koopmans et al, 2002; Larter et al, 2003), which may be predicted within reservoir beds if the charging mixtures can be quantified accurately (Koopmans et al, 2002).

Biodegraded oils containing anomalously high concentrations of gasoline range compounds due to multiple charging are recognized in a number of oil fields globally (Masterson et al, 2001). The evidences of late charging and mixing in the WCSB were illustrated by Obermajer et al (2004) from the Lower Cretaceous Mannville reservoir beds in the west-central part of Saskatchewan. Heavy oils are characterized by complete removal of high molecular n-alkanes (> C15) and a large unresolved complex mixture (UCM) hump in their saturated fractions, clearly indicating the influences of biodegradation. In contrast, in mixed oils the gasoline range fraction of lower (C5-C8) molecular weight, n-alkane homologues and light aromatics such as benzene and toluene are still present. These characteristics show that the light hydrocarbon fractions are far less biodegraded than the heavier fractions. Such compositional characteristics may indicate that some of the reservoir beds containing biodegraded oil are subjected to a subsequent secondary charge of lighter, non-biodegraded crude oils. As a result, the effects of biodegradation of the initial charge of hydrocarbons might have been partially overprinted by the subsequent migration events as reservoirs already containing the biodegraded oil were augmented by non-biodegraded, lighter oil (Obermajer et al, 2004). The additional "pulse" of oil may not necessarily be from the same source rock since oil generation largely ceased after the Laramide Orogeny. The front end of migration fractionation from previous accumulations in deep reservoir beds may contribute to dilution of biodegraded oil with light hydrocarbons. Tilting of the bitumen-water interface in the eastern and southwestern parts of the Athabasca oil sands deposit which may have affected the distribution of the oils provides the supporting evidence for this interpretation. Although it is not possible to evaluate the extent of augmenting oil as the volume of this oil and the number of augmentations cannot be properly estimated, the oil physical properties can be dramatically improved since the light oil worked as a solvent in reservoir beds to dissolve the heavy components. It can be expected that the best oil quality in the field is situated at the place close to the late charge passage. Understanding the origins,

and the alteration of petroleum occurring in the heavily biodegraded fields is important for the efficient exploration and exploitation of heavy oil and oil sand resources. The recognition of this potential augmentation and its time relative to the biodegradation process may be especially important since the presence of lighter hydrocarbons affects the physical properties of oil and may have great significance for the design of programs of secondary and tertiary recovery. The recognition of these effects is also fundamentally important for understanding the time and mechanism of biodegradation of the original oil charging.

## 4 Conclusion

The heavy oil and oil sands in the Western Canada Sedimentary Basin which are mainly derived from the Devonian-Mississippian Exshaw Formation source rocks are distributed in the Cretaceous reservoir beds in the Athabasca, Cold Lake and Peace River areas. Current composition and physical properties were controlled by the level of biodegradation and mixing, which in turn were controlled by the reservoir temperature history and water leg size. Despite the highly variable level of biodegradation both regionally and locally, there is a general trend of increasing biodegradation from west to east for the heavy oils and oil sands with Athabasca oil sands degraded at PM level 6-9, Peace River oil sands degraded at PM level 4-5 and no degradation at the western part of the Peace River. The maximum temperature the reservoir ever experienced exerts the primary control for the large-scale lateral variations of biodegradation level, while the water leg size is a more critical control for the small-scale vertical variations. The latter is closely related to the nutrient supply for the organisms. Late charging and mixing of fresh and degraded oils ultimately dictates the final distribution of API gravity and viscosity found in heavy oil and oil sand fields.

The variations of oil compositions and physical properties can be easily predicted based on the model driven by the geological and geochemical investigations. Such techniques allow the mapping of viscosity sweet spots within a heavy oil accumulation which allows better definition of completion intervals and production strategies.

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