Origin of the Lower Cretaceous Heavy Oils ("Tar Sands") of Alberta

By

Michael S. Stanton

Search and Discovery Article #10067 (2004)

Editorial Note: The importance of, and interest in, the “tar sands” of Alberta continues to increase—largely in response to the world’s energy demands in this time seemingly of continuous crisis. In an article about this massive energy resource in the July, 2004, issue of Wired (p. 102-104), entitled “The Trillion-Barrel Tar Pit,” it is noted that the cost of production is US$10/barrel. The author’s thesis in this Search and Discovery article, while controversial, is thought to be worthy of serious consideration and testing. If proved to be a reasonable interpretation, it has very wide application in exploration.

ABSTRACT

The source for Alberta's huge reserves in the oil sands ("tar sands") has been debated for more than five decades. Theories range from in situ deposition to breached Paleozoic reservoirs and even to an inorganic source. With one exception, almost all involve marine sediments. It is the purpose of this paper to argue that the source beds are primarily coal macerals from the organically rich Lower Cretaceous strata of western Alberta.

Other than (rare) sapropelic coals such as boghead and cannel, there has been a long-standing opinion that humic coals are gas-prone with little potential for major oil generation. In recent years this bias has been challenged by numerous researchers. Anthracite coal is an end product of maturation. It has already lost its oil during coalification.

During the coalification process the rank increases from peat to anthracite as a function of temperature (burial depth) and load pressure. It could be viewed as a conveyor belt where various products are generated and expelled en route to greater depths. These products include water, carbon dioxide, nitrogen, methane, and oil. Macerals are the microscopic components of kerogen. There are three main types: liptinite, vitrinite, and inertinite in order of decreasing oil proneness (based on atomic H/C vs O/C ratios) The degree of maturation is determined from the reflectivity of vitrinite. Coal macerals change chemically during coalification. At a vitrinite reflectance level (%Ro) of 0.5, the coal rank changes rather abruptly from sub-bituminous to high volatile bituminous. With increasing temperature the rank passes to low volatile bituminous at about 1.3% reflectivity. During this interval (between bituminization and debituminization) there is a major loss of volatiles (including oil). This stage of coalification corresponds exactly to the "oil window" maturation range for conventional (marine) source rocks. Coal is simply a nonmarine source rock with great oil-generating potential.

Estimates of original oil-in-place for the oil sands is almost 1.7 trillion barrels. The reserves are in sands of the Lower Cretaceous Mannville (McMurray) formation which
lies on the sub-Cretaceous unconformity. The unconformity bevels strata from Triassic to Devonian, and its permeable surface provides a pathway for migrating fluids, including oil, from mature source beds to reservoir (oil sands). Migration of fluids is a function of normal updip buoyancy, deep basin gas drive, and the tectonic squeeze of Laramide thrusts - a thermo-dynamic couplet.

Estimates of Upper Jurassic / Lower Cretaceous coal reserves of the mountains, foothills and basinal plains exceed 650 billion tonnes. This does not include disseminated carbonaceous material in shales. Vitrinite reflectivity studies show that maturity levels were reached and exceeded in the deep basin. High rank (overmature) Lower Cretaceous coal generated the deep basin gas of the Elmworth field (Masters, 1984).

Masters et al. (1984) concluded that source rocks for the oil sands were organic shales of Jurassic and Early Cretaceous age. I agree. However, there are many mature organic shales that have never produced such huge oil volumes. The apparent difference is the enormous tonnage of coal. TOC profiling shows unusually rich organic carbon content in Lower Cretaceous strata, implying a concentration far in excess of disseminated material. New research shows the oil potential of even humic macerals (such as vitrinite), previously considered gas-prone. Vitrinite is the dominant maceral of humic coal, but lipid types are also present (Welte, 1984). It is suggested here that coal is the source of oil-sands bitumen, released mainly during bituminization. Oils sourced from marine shales and carbonates are believed to be minor contributors.

Prevailing opinion still favors a marine source for the oil-sands bitumen. However, since the indicated volume of oil-sands bitumen is 100 times the total of all conventional oil in the province, marine sources are deemed to be inadequate.

There are two gigantic reserves in Alberta - huge tonnages of coal to the west, and immense oil-sands reserves in the east. Between them lie a mature basin and a permeable conduit. The coal-bearing beds and oil-sand reservoir are within the same stratigraphic interval. Marine sources appear inadequate. The non-conventional oil-sands bitumen requires a nonconventional source. These are the coal seams and carbonaceous shales of Late Jurassic to Early Cretaceous age.

A summation of the argument is given under "Conclusions".

**General Comments**

The problem of a source rock for the huge reserves of bitumen in Alberta's oil sands has been a contentious issue for geologists and geochemists for decades. Many theories have been proposed, and these are summarized in the following section.

There are about 1.67 trillion barrels of heavy crude in the oil sands. Unless one favors an in situ origin, the oil must have migrated from west to east along a pathway with adequate porosity/permeability characteristics, This is generally accepted to be the sub-Cretaceous unconformity. The bitumen could not have migrated far in its present
condition, so it has likely been altered by biodegradation, water-washing, oxidation, and reduced salinity of formation water. These concepts are accepted by most geoscientists. However, the question of source has remained a divisive issue.

The commonly accepted origin for the oil-sands bitumen are Triassic and Jurassic marine shales and/or carbonates of Devonian and Mississippian ages. These strata are beveled at the sub-Cretaceous unconformity. They are known sources of conventional crude; so the assumption that they sourced the oil sands is a logical one. However, as described later, conventional marine sources are inadequate to account for the huge volume of oil-sands crude. The probability of a continental source was proposed by Masters (1984). It is the purpose of this paper to suggest that the main source for the huge reserves of heavy oil is the equally immense coal deposits of the mountains and foreland basin. Arguments are presented in favor of this theory.

In 1974, I presented a paper to Chevron geologists in Calgary and to Chevron Oilfield Research Corporation geoscientists at La Habra, California. It was entitled "Origin of the Lower Cretaceous Heavy Oils of Alberta" (April, 1974). In it I suggested that that the Upper Jurassic Kootenay and Lower Cretaceous Luscar coals and carbonaceous shales were the main source of Alberta's oil-sands crude. It was well received by many of the geoscientists, but because of its speculative nature, it remained unpublished. Since then, new information about coal macerals and their relationship to oil generation tend to support my original suggestion.

**Theories of Origin**

The number of theories proposed for the source of oil-sands bitumen is indicative of the degree of controversy in the geological profession (Conybeare, 1966; Vigrass, 1968; and others). For the purpose of this section, I have used a modified tabulation of the theories listed by Vigrass for the first six on the list, with later additions from other sources. The main theories of origin for Alberta's oil sands are:

1. Oil escaped through fissures from Devonian reservoirs during or since Early Cretaceous (Link, 1951; Sproule, 1951).
2. Derived in situ from organic material deposited with the sand (Hume, 1951; Corbett, 1955).
3. Derived from shales of the Clearwater Formation, age equivalent to the McMurray Formation (McLean, 1917; Ball, 1935; Hitchon, 1963).
4. Originally, light oil that migrated from the deep basin and was later altered to heavy crude (Gussow, 1956).
5. Oil was derived from materials leached from soils into McMurray sandstones and subsequently converted to heavy hydrocarbons (Hodgson and Hitchon, 1965).
6. Hydrocarbons which moved out of the deep basin in micellar or colloidal solution in compaction waters and were “precipitated” on anticlinal structures or sand pinchouts perhaps due to a salinity change (Vigrass, 1968).
7. Sand and oil deposited together from a breached Paleozoic reservoir (Gallup, 1974).
8. The heavy oils were emplaced by upward migration of inorganic petroleum via deep faults which extended into the mantle (Porfir'ev, 1974). It is noted that this inorganic
theory has been tested by a well drilled into the Precambrian granite by C. Warren Hunt, with negative results.

9. Oil was sourced from Lower Cretaceous, Jurassic and Triassic carbonaceous shales (Masters, 1984).

10. Oil was likely sourced from basinal Jurassic and cratonic Devonian-Mississippian strata (Porter, 1992).

11. The theory presented here is that oil was generated from Upper Jurassic and Lower Cretaceous coals during the bituminization phase of the coalification process, mainly between high and low volatile bituminous rank. This temperature range is the same as the "oil window" for conventional marine source rocks. Coal is simply a nonmarine equivalent with huge oil-generating potential. It was source for the immense oil-sands reserves of Alberta.

Geologic Setting

This paper is concerned primarily with the Upper Jurassic / Lower Cretaceous strata of the mountains and foreland basin of central Alberta, and the eastern equivalent in the plains region (Mannville Group). The following is a brief overview of geological events as they relate to the current paper.

Figure 1 (from Porter, 1992) is a stratigraphic column showing the main post-Paleozoic units. Prominent is the sub-Cretaceous unconformity which beveled earlier strata. From Early Paleozoic to Jurassic, the Alberta craton had been dominated by marine carbonates and clastics, Devonian reefs and evaporites. This lengthy period of quiescent marine sedimentation ended in latest Jurassic time with the first signs of rising land in the Cordiller (Columbian orogeny). Transition from marine to continental sedimentation occurred first in southeastern British Columbia and southwestern Alberta, where Fernie marine clastics pass upwards into uppermost Jurassic and Lower Cretaceous nonmarine sequences. The transition progressed from south to north, reflecting a northward migration of orogenic activity. These nonmarine sequences include major coal-bearing intervals in the Upper Jurassic / Lower Cretaceous Kootenay Group of southwest Alberta and southeast British Columbia, the Luscar and Nikanassin (Blairmore) Group of west-central Alberta, and the Gething-Gates (Bullhead) Group of northwest Alberta.

Uplift during the Columbian orogeny created a narrow, deep, foreland basin of deposition. A major drop in base level in Early Cretaceous initiated a widespread erosional interval that truncated earlier formations from Late Jurassic through Devonian in age. This sub-Cretaceous (sub-Mannville) unconformity was overlain by sands and conglomerates of the Cadomin/Gething/Mannville formations. These relatively permeable beds provided a conduit for updip migration of basinal fluids and hydrocarbons from source to oil-sand host rocks. Deltaic, fluvial, and swampland deposits dominated much of Mannville sedimentation. Paleozoic carbonate highlands on the sub-Cretaceous unconformity influenced river drainage patterns and swampland vegetation.
Clastic input to the basin and plains regions came from both the Cordilleran uplift in the west and the Precambrian shield in the east. Nonmarine (lower and upper Mannville) sediments were separated by a shallow marine (brackish) interlude as shown in Figure 2 (from Cant, 1989). This figure also shows the Paleozoic highlands on the sub-Mannville unconformity, one of which trapped the Peace River heavy oil deposit. Pulses of uplift in the Cordillera supplied vast quantities of clastics to the rapidly subsiding foreland basin.

Following the dominant nonmarine sediments of the Mannville group, a merging of seaways from the Arctic and the Gulf formed a shallow epicontinental sea across Alberta. Increasing Cordilleran tectonism in Late Cretaceous and Tertiary times (Laramide orogeny) supplied huge quantities of sediments to the foreland basin; much of this section has since been lost to erosion. Overthrusting of Laramide tectonism deepened the foreland basin, supplied large quantities of sedimentary load, and applied eastward-directed dynamic pressure to basinal fluid systems.

Figure 1. Generalized Western Canada basin wedge, with principal oil and gas-reservoirs (from Porter, 1992).

Lower Cretaceous Oil Sands of Alberta

The main heavy oil areas of central Alberta are the Athabasca-Wabasca, Peace River, and Cold Lake fields with numerous smaller ones, as shown in Figure 3 (from Proctor et al., 1984). They cover an area of some 75,000 square km (29,000 square miles) in central Alberta (Porter, 1992). Also shown are the heavy oils of the Lloydminster fields which are chemically related to the oil-sand bitumen.

The estimated initial volume in-place of oil-sands bitumen is given as 269.8 billion cubic meters (1.698 trillion barrels) by the Alberta Energy and Utilities Board (1998). There are almost 450 billion barrels in subcropping Paleozoic carbonates (Carbonate Triangle). The carbonate oil has the same chemical characteristics as the overlying Mannville sand oil, suggesting it has soaked into the carbonates from above. Figure 4 (from Proctor et al., 1984) shows the oil sands and underlying carbonate oil. Instead of impregnation from above, it has also been interpreted as a breached Devonian reservoir (Gallup, 1974).

The Alberta Energy and Utilities Board (1998) lists the initial established reserves of conventional crude oil in Alberta as 2,490,100,000 cubic meters (15,662,700,000 barrels). By comparison, the same report lists the initial volume in place of crude bitumen in Alberta's heavy oil deposits as 269,800,000,000 cubic meters (1,698,000,000,000 barrels).
From EUB figures it is clear that the conventional oil reserves of western Canada comprise only about 1 percent of the total bitumen in the oil sands. This is more than 4 times the proven reserves of the Middle East, based on 1976 figures. Masters (1984) comments that the huge reserves of Lower Cretaceous oil and gas in the western Canada sedimentary basin make them the richest hydrocarbon province in the world. It should also be noted that large quantities of oil sands have been lost by erosion and degradation; these would have greatly increased the estimated initial in-place reserves. This enormous
The discrepancy between conventional and non-conventional oil reserves is of primary importance in the present discussion.

The gravity of oil-sands bitumen is low and ranges from 6 to 18 degrees API. The gravity is roughly related to depth and water salinity (Jardine, 1974). The oil sands are largely unconsolidated, with high porosity/permeability values. Distribution of sands on the sub-Cretaceous unconformity is related to fluvial-deltaic patterns and influenced by Paleozoic carbonate topography. Solution of underlying Devonian salt accounted for local areas of thicker oil-bearing sands, as shown in Figure 5 (from Page, 1974). Figure 6 (from Jardine, 1974) illustrates the intervals of heavy oil saturation in Mannville sands and the schematic relationship to pre-unconformity strata from Jurassic to Devonian.

In discussing the oil sands of Alberta, it is important not to overlook the heavy-oil fields of Saskatchewan (below 19 degrees API). The estimate of original oil in place is 2,294,929,000 barrels or 36,486,565 cubic meters (White, 1974). It is interesting that the bulk of these heavy oilfields are at the same stratigraphic horizon as Alberta's oil sands (the Mannville formation), suggesting the likelihood of a common source.

It is not the purpose of this paper to dwell on the geology of the oil sands. It is sufficient to emphasize that some two trillion barrels of heavy oil occur at or near surface in the oil-sands deposits of Alberta. This gigantic reserve requires an equally gigantic source. It is the aim of this paper to suggest that this source is primarily the Lower Cretaceous and Upper Jurassic coals of the foreland basin.

Figure 4. Schematic section showing oil trapped in sands and carbonates (from Proctor et al., 1983). Reproduced with the permission of the Minister of Public Works and government Services Canada, 2004, and Courtesy of Natural Resources Canada, Geological Survey of Canada.
Figure 5. Schematic diagram of regional groundwater flow and salt collapse (from Page, 1974). Reproduced with the permission of the Canadian Society of Petroleum Geologists.

Figure 6. Correlation chart of Lower Cretaceous heavy oil deposits (from Jardine, 1974). Reproduced with permission of the Canadian Society of Petroleum Geologists.
Lower Cretaceous / Upper Jurassic Coal of Alberta

This paper deals only with the Upper Jurassic and Lower Cretaceous coals of Alberta, and British Columbia, - the Kootenay group in the south, the Luscar group of central Alberta; and the Gething-Gates group in the north. They form a long linear series of exposures in the mountain and foothills regions of the disturbed belt. The coal is exposed in thrust sheets of the Laramide orogeny. Seams of up to 13 meters thick are reported (Cameron and Smith, 1991).

The Kootenay group of continental sediments overlie the Fernie group of marine shales and transitional (Passage) beds and are truncated by the Lower Cretaceous unconformity as shown in Figure 7 (from Poulton, 1989) which also emphasizes the coal-bearing character of the Mist Mountain formation of the Kootenay group. Huge coal deposits are also present in the central Luscar and northern Gething-Gates groups.

For the purpose of coal tonnage estimates, Alberta is divided into three regions - Mountains, Foothills, and Plains. The in-place resource estimated by the Energy Resources Conservation Board (1993) is as follows. Numbers are in gigatonnes (billions of tonnes).

<table>
<thead>
<tr>
<th>Region</th>
<th>Tonnage (Gt)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mountain region</td>
<td>24</td>
</tr>
<tr>
<td>Foothills region</td>
<td>14</td>
</tr>
<tr>
<td>Plains region</td>
<td>2000</td>
</tr>
</tbody>
</table>

Coals of the Mountain region are mainly low and medium-volatile bituminous; those of the Foothills region mainly high-volatile bituminous-, and those of the Plains mainly sub-bituminous (ERCB, 1993). In general, rank increases and volatiles decrease from basinal plains through foothills to mountains.

It is clear that by far the largest tonnage is in the Plains region. This estimate includes coals younger than Lower Cretaceous, but it is noted that of the 2000 gigatonnes of the Plains, at least 628 billion tonnes are within the Mannville Formation (Yurko, 1976) and that Mannville coalbeds range in depth from 1500 feet (457 in) in the northeast to 8000 feet (2438 in) along the margin of the Foothills. Thus there are more than 650 billion tonnes of estimated coal within the Upper Jurassic / Lower Cretaceous strata of the sedimentary basin, all correlatable with, or having access to, the host beds of the oil sands. Disseminated carbonaceous material within the sediments is unknown but must be huge. According to Hunt (1979) the vitrinite (coal) maceral may constitute up to 80% of clays and sands of sedimentary origin. If so, this makes the oil-generative potential of vitrinite of prime importance in the present discussion.
Coalification

Kerogen is the dominant organic matter in sedimentary rocks. It is insoluble in most acids, bases, and organic solvents. It does not include bitumen. Macerals are the microscopic constituents of kerogen. There are three main coal maceral groups:

- Liptinite or exinite (high content of algal or spore material, strongly sapropelic, fluorescent, boghead and cannel coals, relatively rare).
- Vitrinite or huminite (forms the major part of humic coals, angular to sub-angular, fluorescence weak or absent).
- Inertinite (angular, may show cell structure, high reflectance, no fluorescence, sometimes considered oxidation products of fires).

It should be noted that due to physical-chemical changes, this typing may be too rigid.

Fundamental to the subject of oil from coal is the process of coalification. Coalification is the natural maturation of coal in its passage from peat to anthracite. Organic matter matures progressively from peat through lignite, sub-bituminous, high-volatile bituminous, medium-volatile bituminous, low-volatile bituminous, semi-anthracite, and anthracite. The rank is measured microscopically by the reflectance--in-oil of the coal maceral vitrinite. Reflectance increases with increases in temperature (increasing burial depth) and is usually indicated as %Ro. Once the highest stage of reflectivity (Rmax) is reached, it cannot be reversed. It represents the highest temperature that rock was subjected to during its geological history and is the basis for estimating the thickness of strata that have been removed by erosion since its maximum burial depth.

Lignite is the first stage in coalification following its origin as peat. It is high in volatiles including water, carbon dioxide, certain acids, and nitrogen. A small amount of methane
and heavy bitumen may be formed in the first few hundred meters of burial (Hunt, 1979). In this regard it is interesting to note that the inertinite maceral (generally rejected as having any oil potential) may have been able to generate liquid hydrocarbon as early in the coalification stage as Ro% 0.2 to 0.5 (Smith and Cook, 1984). In other words, its "barren" reputation may be because inertinite had already expelled any bitumen it once contained.

During compaction and diagenesis, there is a rapid loss of water and other weakly-held volatiles (dehydration) and a slow build-up of hydrocarbons from lignite into the sub-bituminous rank. Maximum generation of volatiles occurs between the high- and low-volatile bituminous ranks (catagenesis). This occurs within a narrow temperature range between 80-100° and 120-150 °C. (Boreham and Powell, 1993). This correlates to vitrinite resistivities of about 0.5 to 1.3, the "oil window" of traditional (marine) source rocks. Above about 1.3%Ro (metagenesis), the coal progresses into the wet gas zone, and at about 2.0%Ro production is dry methane gas.

Figure 8, from Hacquebard and Cameron (1989), is an isoreflectance map of coals from the basal Bluesky-Gething Formation of NW Alberta / NE British Columbia as measured from drillhole recoveries. The values range from a reflectance of less than 1.1 to a maximum of more than 2.5, with the highest values in the deep foreland basin. Vitrinite reflectance is also used to evaluate the maturation stage of traditional source rocks. The optimum oil-generative capacity (the "oil window") lies between reflectivities of 0.5 to 1.3. It is, therefore, clear that during the coalification process, temperatures in the deep basin reached, and exceeded, the "oil window" range. Any oil generated from the coal would have been expelled prior to the metagenesis (overmature) phase.

The three main coal macerals - liptinite (exinite), vitrinite, and inertinite - are listed in decreasing order of oil-producing potential. The maceral character of a coal is commonly shown as a triangle with a maceral type at each comer. Figure 9, from Cameron and Smith (1991), is a triangle plot of maceral distribution for three of the subject coals (Jurassic Mist Mountain and Lower Cretaceous Gething and Gates). These show a high proportion of the vitrinite maceral trending towards inertinite - components commonly interpreted as gas-prone. This opinion has been questioned. Boreham and Powell (1993) list a number of recent workers who have observational evidence that oil has been generated and expelled even from low-potential (Type III) organic matter. Concerning generalizations about gas or oil potential of specific macerals, Boreham and Powell (1993) have this to say: "These generalizations, which have wide currency, have inhibited the development of an understanding of the source-rock potential in carbonaceous sequences. In fact, there is no clear relationship between petrographic type and petroleum potential in humic coals." To add to this quaddry, as they point out, is heterogeneity of macerals types in humic coals. Vitrinite changes chemically (colour and fluorescence) during higher stages of coalification owing to generated liquid hydrocarbons (Mukhopdhayy and Hatcher, 1993). Furthermore, beyond a reflectivity of about 1.1, vitrinite is difficult to distinguish from liptinite (Levine, 1993). It thus seems that assigning a gas-prone character to vitrinite is misleading. Littke and Leythauser (1993) conclude that "coal can be regarded as a moderate- to poor-quality oil source rock."
However, given the huge amount of vitrinite in sedimentary rocks, the overall contribution could be overwhelming, particularly for the organic-rich Jurassic / Lower Cretaceous coals in this study.

Oil-potential quality of coal is also commonly shown by plotting its maceral qualities on a van Krevelen diagram in which the atomic H/C ratio (vertical) is plotted against the atomic O/C ratio (horizontal). There are three main evolutionary or maturation paths for the parent kerogen, Type I, II, and III. It is perhaps unfortunate that these paths are often labeled for the dominant maceral: Type I (liptinite or exinite), Type II (vitrinite) and Type III (inertinite). It unjustly relegates a specific maceral to a pathway deemed oil or gas prone regardless of its thermal history. It also adds to confusion. Type I kerogen is the most oil-prone coal, such as boghead and cannel. Both are relatively rare. Type III is considered gas-prone or barren. Type II is somewhere in between - Figure 10 (from Mukhopadhyay and Hatcher, 1993) illustrates two representations of van Krevelen diagrams and the maturation (coalification) pathways of maceral types.

Figure 8. Isoreflectance contours of Bluesky-Gething coal of Alberta and British Columbia (Grande Cache to Pink Mountain) (from Hacquebard and Cameron, 1989). Reprinted from International Journal of Geology, v. 13, p. 207-260, with permission from Elsevier.
As mentioned, during the coalification process there is a stage in which volatiles rapidly increase then decrease. This was termed "bituminization" by Teichmuller (1982) and others. Although volatiles are expelled regularly during coalification, there is a pronounced increase at a reflectivity of about 0.5 (bituminization) and a significant decrease at about 1.3 (debituminization). This range corresponds approximately to the coal ranks of high- to low-volatile bituminous. There has clearly been a thermal-chemical generation and expulsion of volatiles within this reflectivity (temperature) range. Figure 11 (from Levine, 1993) shows the process as a significant phase in coalification from peat to anthracite.

It comes as no surprise that this bituminization range is almost identical to the "oil window" of conventional marine source rocks. This supports the statement mentioned earlier that coal is simply a nonmarine source rock with huge potential and obeying the same rules of thermal maturation. The correlation between the oil window is also clear in the composite illustration, shown in Figure 12 (from Boreham and Powell, 1993). The equivalence between oil generated from "normal" marine source rocks (at the right) and the coalification jump (at the left) is striking. A similar relationship is shown in tabular form by Robert (1979). Also of interest is the Thermal Alteration Index (TAI) showing the progressive color change of the vitrinite maceral from yellow to black. From 0.4 to 1.45 % reflectivity (yellow to light brown) the vitrinite exhibits light to dark brown fluorescence owing to generated liquid hydrocarbons (Mukhopadhyay and Hatcher, 1993). The evidence for vitrinite being a potential oil source seems conclusive. Despite its gas-prone reputation, vitrinite still retains significant oil-generative potential as shown in Figure 13 (from Tissot and Welte, 1978).

In this context, a statement by Forbes et al (1991), as discussed by Boreham and Powell (1993), is of interest. He commented that the amount of liquid petroleum expelled from Jurassic coals of the North Sea was more than enough to account for the reservoir oil of the Smorbukk Sor fields.

In recent years an increasing number of oil fields have been identified as having a nonmarine source. In most cases they are identified with some lipid-prone, sapropelic source, such as lacustrine shales or resinous and waxy macerals. However, as already stated, recent studies have shown that even humic coals (vitrinite-rich) are moderate oil generators.

Although the generation and expulsion of volatiles from coal within the "oil window" range are well-known, some researchers seem reticent to include liquid oil in the "volatiles", preferring noncommittal terms such as "occluded hydrocarbons". Without doubt, methane constitutes a large part of the expelled volatiles, but evidence indicates
that liquid hydrocarbons are also present. Gas would provide an excellent medium to aid in liquid expulsion.

Figure 11. Evolution of molecular fraction of a vitrinite-rich coal during coalification (from Levine, 1993).
Chemical Factors

Much of the foregoing has dealt with coal macerals, the microscopic components of kerogen, and the process of bituminization. That is all very well, but it overlooks the obvious. The production of tar and oil from coal has been known for centuries. Industrial distillation and coking procedures from coal are routine. Distillation of a ton of bituminous coal gave the following yields (Encyclopedia of Chemistry): tar, 8.78 gal; gas, 10,470 cu ft; light oil, 2.91 gal; ammonium sulphate (19.23 lbs); and other components. This distillation was done at 500 to 700°C, far higher than reservoir temperatures. But it clearly shows that a large volume of liquid hydrocarbons is present in a single ton of coal. It is a common belief of geochemists that time can compensate for temperature in many physico-chemical reactions. Swain (1970) commented that with "--substitution of the geologic time factor for elevated temperatures, all or nearly all known organic reactions might conceivably take place in sediments."

Hydrogenation is sometimes claimed as being a necessity for coal to become a significant producer of liquid hydrocarbons. Of interest is the Fischer-Tropsch synthesis, as reported by Freidel and Sharkey (1963). At a temperature of 170 to 330°C, at atmospheric or higher pressures, and in the presence of a metallic catalyst, they were able to synthesize a
complex mixture of hydrocarbons (from methane to waxes, including paraffins, olefins, and aromatics) from the simple components of water and carbon monoxide. Metallic catalysts like Fe, Ni, Co, and V are common in sediments (Ni and V are present in the oil-sands bitumen). Therefore, it seems possible for the natural synthesis of liquid hydrocarbons to occur in sedimentary strata - though exotic methods are not deemed necessary in the present argument.

Is there anything unusual about Upper Jurassic / Lower Cretaceous sediments of the western Canada basin? Yes, the extraordinarily high content of organic carbon. Figure 14, from Welte (1984), shows the organic carbon profile of a well from the Elmsworth field. The TOC of the Upper Jurassic / Lower Cretaceous interval between the 8000- and 10,000-foot depth is striking - with all of the section recording over 10% and in places reaching 80%. By contrast, the TOC of the overlying and underlying sections barely exceeds 1%. For observation, the logarithmic scale is visually misleading. On linear scale the discrepancy would be dramatic. The very high organic carbon content reflects the dense concentration of coal seams within carbonaceous sediments. If this well is typical of the region, it suggests that during the bituminization stage of coalification, there were gigantic tonnages of coal and coaly shale capable of producing huge volumes of liquid hydrocarbons - with a direct updip route to the oil sands.
Montgomery (1974) believes that the oil-sands bitumen is immature. He comments that the Ni/V ratio and the presence of porphyrins are consistent with a young immature oil. This view is disputed by Deroo et al. (1974), who claim the variations can be explained by exchanges with beds crossed during migration. (For the position taken in the present paper, long distance migration is mandatory). Coal and oil chemistry is a complex field. Processes such as gelification, aromatization, and structural organic chemistry are the realm of specialists - and best left there.

**Laramide Tectonism**

What part did tectonism play in oil generation and expulsion? A quiescent period of about 12 million years followed the Columbian orogeny. Laramide tectonism began about 75 Ma and resulted in the great thrust sheets of the Rocky Mountains (the combined result of western movement of the North American plate and eastward pressure of terrain impacts on the west coast). This had a double effect on the foreland basin. Throughout Late Cretaceous and Tertiary, it created tectonic downwarp and supplied vast new quantities of sediment. Much has since been removed by glacial and other erosional
processes, but vitrinite reflectance records the maximum temperature (burial depth) that was reached.

The eastward-directed thrust plates created a massive pressure regime in the foreland basin and its contained fluids. It is analogous to a wringer, squeezing out liquids and volatiles ahead of it. It was a significant force in the updip migration of water and hydrocarbons and a powerful addition to the normal buoyancy induced by sediment load.

Vitrinite reflectance shows that coals of the deep foreland basin had reached anthracite rank. Huge volumes of gas would have been generated and expelled from this overmature zone. Compaction and tectonic squeeze would force this overpressured gas into and through the mature zone, and act as a scrubbing agent for any liquid hydrocarbons and water still trapped in the sedimentary strata. Preferential ease of movement implies that gas would bypass pore-trapped or adsorbed water and act as an entrained propellant for liquid hydrocarbons en route to the oil sands.

Laramide overthrusts would have created fractures and open cleats in the coalbeds of the mountains and foothills. This would provide easier drainage for trapped methane and probably accounts for the vast gas reserves of the Elmworth field.

Summary

Discussions about the origin of Alberta's heavy oil deposits have divided geologists for over fifty years. A wide range of explanations have been proposed. Almost all of them involve conventional marine source rocks. Masters (1984) claimed that the oil-sands bitumen originated from nonmarine carboniferous shales. I agree and would suggest that, because of the dense concentration of organic matter in coal seams as against disseminated material, seams were the dominant contributors. It is argued that nonmarine coal beds and carbonaceous sediments are the main sources for the prodigious volume of bitumen in Alberta's oil sands. There is one problem - the bias that humic coal is gas-prone and that large oil fields are sourced from marine shales or carbonates.

Coalification is the temperature-pressure process where peat is changed to lignite and progressively to higher rank coal. There is an early release of water and loosely held volatiles. With increased temperature, lignite progresses to subbituminous rank. This maturation is accompanied by an increase in the atomic H/C ratio and a reduction in the O/C, and this is recorded on a van Krevelen diagram and assigned to one of three kerogen pathways (Types I, II, and III). Coal macerals (exinite, vitrinite, inertinite) are the microscopic components of kerogen. Exinite is oil-prone, Vitrinite is considered gas-prone, and inertinite is barren. This bias has recently been challenged.

Between high-volatile to low-volatile bituminous ranks, there is a rapid build-up of volatiles (bituminization) followed by a rapid decline (debituminization). This interval of optimum generation and loss of volatiles from coal macerals coincides exactly to the "oil window" of traditional marine source rocks. Vitrinite has been shown to be oil-generative, though probably inferior to marine sources. Distillation of a ton of humic coal
yields several gallons of liquid petroleum products (the stuff is there!). Coal is simply a nonmarine source rock with huge generative potential. Any unit deficiency of nonmarine versus marine source rocks will be outweighed by the volume of organic matter in coal-rich sediments.

Alberta has two gigantic natural resources - some two trillion barrels of oil-sands bitumen on the craton and at least 650 billion tonnes of coal in the mountains and adjacent regions. Both are at the same stratigraphic interval. There is a thermally mature basin between coal beds and oil, and there is a permeable horizon connecting the two. Laramide tectonics provided a massive pressure squeeze on migrating fluids and hydrocarbons (wringer effect). Vitrinite forms the major part of humic coal. Vitrinite has proven oil-generative potential. The implication seems clear - the oil was sourced from the time-equivalent coal-bearing, Lower Cretaceous sediments during the bituminization stage of coalification.

Government figures show that the amount of bitumen in the oil sands is 100 times the total of conventional oil in Alberta. Marine sources are inadequate. The non-conventional oil-sand bitumen has a non-conventional source - mainly the bituminization stage in the coalification process of Lower Cretaceous coals of western Alberta.

**Conclusions**

There are a few factors that emerge from the foregoing report:
1. Recent research has questioned the long-held bias that humic coal is gas-prone, incapable of large-scale generation of liquid hydrocarbons. Vitrinite is the dominant maceral of humic coal. Vitrinite has been shown capable of oil generation and expulsion. Vitrinite is present in up to 80% of sediments (Hunt, 1974). It is a potential oil source.
2. Coal is a dense concentration of vitrinite and other macerals, far exceeding disseminated material per volume. Anthracite coal of the mountains has long ago lost its oil during the bituminization stage in the coalification process.
3. During coalification from peat to anthracite there is a progressive physical and chemical change.
4. Bituminization of coal occurs between vitrinite reflectance levels of 0.5 and 1.3%, or approximately between high- and low-volatile bituminous rank. This interval is marked by generation and expulsion of "occluded hydrocarbons." These hydrocarbons include gas and oil - the suggested source of oil-sands bitumen.
5. The bituminization range for coal coincides exactly with the "oil window" of conventional (marine) source rocks.
6. Coal macerals (including vitrinite) constitute a nonmarine source rock with huge oil-generating potential.
7. Any per-unit mass deficiency in the generative capacity of coal macerals as compared to marine source rocks is overwhelmed by the sheer volume of organic matter in nonmarine strata of the geologic section. The potential of coal as an oil source has been grossly underestimated.
8. The Upper Jurassic/ Lower Cretaceous interval of Alberta is extremely rich in organic matter in the form of coal and carbonaceous shales. The coal macerals have passed
through the mature thermal stage and have expelled liquid hydrocarbons during bituminization. There is a permeable pathway from source to oil sands.

9. Fluid flow from the basin was intensified by deep basin gas drive and by the tectonic squeeze of Laramide thrusts.

10. Government estimates show that the volume of oil-sands bitumen is 100 times the total of conventional reserves. These statistics suggest that traditional marine source rocks are inadequate for the task.

11. The immense volume of oil-sands crude requires an equally gigantic source. These are the Lower Cretaceous coals and coaly sediments described above. No other known source can fulfill the role.

12. The deep-freeze and massive weight of Pleistocene glaciation may have affected degradation of the oil-sands bitumen and may even have induced a late-stage local migration of the oil. Aside from its erosional aspect, the effect of glacial ice on the chemistry and possible late movement of oil-sands bitumen seems to have been ignored.

Addendum

Oil-sands Bitumen

The oil-sands bitumen has low API gravities ranging from 6° to about 13°. Gas chromatography studies, such as illustrated in Figure 15 (from Jardine, 1974), have shown a progressive loss of aliphatic components from west to east (from deeper to shallower) leaving a bitumen enriched in naphthene-aromatics (the substrate envelope). This has been convincingly explained as due to a combination of biodegradation (aerobic bacteria prefer alkanes (paraffins) as a diet), by water-washing (removal of some more soluble components), oxidation, and salinity changes (entrance of fresh water from outcrops). Additionally, what about the deep-freeze effect of glaciation on the bitumen? Should it not be added to the list?
Glacial Ice

I have yet to see any reference to the possible effect that glacial ice might have had on oil-sands crude - both physically and chemically. What was its effect on degradation, or mobility?

For a million years all of Canada was covered by a thick sheet of glacial ice (Wisconsin phase). During its advance it stripped away much strata. In the oil-sands area, it resulted in the sands partly in contact to the glacial deep-freeze, with all sands exposed to the enormous weight of a thousand (?) meters of ice. This huge weight was suddenly removed (geologically speaking) 10,000 to 15,000 years ago. This Pleistocene addition of billions of tonnes of ice, the lengthy deep-freeze, and the sudden removal must have had an effect both on the chemical character of the bitumen, and perhaps even on late-stage (1 Ma) migration in the porous sands.

Much of the oil-sand deposit (perhaps billions of tonnes) has been removed by glacial bulldozing. Unless they have been widely spread or dispersed by drainage systems, one
might expect oil-rich sands to be present in morainal deposits. Is there any evidence of this?

**Botany**

Figure 14, from Welte, (1984), as described earlier, shows the total organic carbon (TOC) content of a well drilled in the Elmworth deep basin gas field. The Jurassic/Lower Cretaceous interval has a remarkably high percentage of organic matter. Which raises the question - is there something unique about the nature of these coals?

Figure 16, from Mukhopadhyay and Hatcher (1993), is a schematic profile of a Texas lignite. It shows microscopic floral components in environments from shallow delta lake to alluvial plain swamps. Of interest is the wide variety of sapropelic types (algae, spores, resins, and other lipid-rich constituents). It emphasizes the heterogeniety of maceral kinds that can occur within a lithotype. The authors also state that beyond medium-volatile bituminous rank, all liptinite macerals are converted to inertinite. In other words, the macerals have already lost their liquid hydrocarbons by that stage.

Is it a coincidence that the Jurassic/Lower Cretaceous contact is the same time that angiosperms (flowering plants) became the dominant form of plant life, displacing the gymnosperms (including conifers) from this position? Did this major revolution in plant ecology introduce some new sapropelic component to the soil or reflect some global atmospheric change affecting plant evolution? In this context, Figure 17, from Clayton (1993), is of interest. It shows a spectacular increase in waxy terrestrial-sourced oils at the Jurassic/Cretaceous boundary! Another coincidence? Or is it a fundamental change that is relevant to the current paper?

It is interesting how many of the major oil-producing regions of the world are also in foreland basins subject to overthrust pressures. These are not simply basinal sags, they are tectonically created basins in response to external pressure regimes, and in most cases are backed by a stable cratonic platform. Examples of oil-producing regions in the shadow of major overthrusts are: the western Candian basin, the Ouachita and Appalachian basins, the basins of South America in front of Andean thrusts, the oil fields of the Ural Mountains, the vast oil fields of the Middle East in front of the Zagros Crush Zone, to name a few. Are tectonically formed (overthrust) basins and the associated tectonic squeeze on fluid systems a major factor in the oil-producing success of these basins - a thermo-dynamic couplet?
Figure 16. Schematic profile, characteristics, and environment of a Texas lignite (from Mukhopadhyay and Hatcher, 1993).
Figure 17. Distribution of terrestrial (waxy) oil source with respect to geologic time (from Clayton, 1993).

References Cited

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