Abstract
The oil sands deposits of Alberta represent a significant fraction of the world’s current reserves. The viscosity of these oils however requires special enhanced oil recovery techniques to be applied. Both capital and operational costs are significant for these methods. Remote monitoring of the production process holds substantial opportunity for the geophysical community. In this contribution, I describe the heavy oil deposits and the methods of enhanced production, discuss briefly some of the issues of rock physics that would contribute to monitoring of such a resource, and show some examples of seismic data obtained in such regions. Although geophysics shows promise for monitoring, there is a great deal of work that must be done to convince other geoscientists of its value.

Introduction
Canada’s bituminous oil sand deposits have likely been in place since the mid-Cretaceous, and were used by Canada’s First Nations to seal birch bark canoes. The deposits were first seen by Europeans in 1788, and have already been supplying upwards of 30% of Canada’s total petroleum production.

Despite this, it was only in 2003 that their size was officially noticed outside of Canada. At the end of that year, The Oil and Gas Journal revealed in its annual report on global petroleum supplies and consumption (Radler, 2003), a large ~20% jump over those of 2002 in overall global reserves by simply including the bituminous oil sands of Canada in its estimates.

This jump also lifted Canada’s reserve standing from near 5 Gbbl (772 x 10^6 m^3) to 180 Gbbl (28.6 x 10^9 m^3), a number exceeded only by the presumed 260 Gbbl (41.3 x 10^9) of Saudi Arabia and surpassing those of all the other Middle Eastern countries.

The size of these deposits had long been recognised (see, for example, Mossop, 1980) for additional background information and a review of the geological studies prior to that time) but had not been included prior to 2003, primarily because of the difficulties involved in producing such highly viscous oils.

The development of a variety of both surface mining and in situ recovery technologies however has reached the point of being economic, even before the rapid rise in the price of oil in the last year. Three other factors, the flattening of global conventional light oil reserves, the growth of consumption in Asia, and the political stability of Canada relative to other major producing areas are currently driving the startup of a large number of projects. Through the decade ending in 2004, CDN$29 billion has already been invested in oil sands projects with an estimated sum of $79.5 billion of direct- and $16.5 billion of sustaining-capital to be spent potentially in this coming decade (Alberta Economic Development, 2005).

Clearly, this is a large investment for Alberta, Canada and perhaps even the entire world. Here I give a brief background to the developments now taking place in Alberta, then shift the focus towards the role of geophysics in the development of this resource.

World hydrocarbon supplies
One simple characterisation of oils is based on its mass density. Generally, as mass density increases, the proportions of long-chain hydrocarbons (> C16 to C20) becomes larger in the oil. Different classifications exist but it is useful to compare those of the Canadian government (based on kg/m^3) to those of the American Petroleum Institute specific gravity (° API). In Canada, only the terms heavy (> 900 kg/m^3) and light (< 900 kg/m^3) are employed while the API provides four classifications from bitumen to light (Figure 1). Chemically, aside from the lengthening of hydrocarbons, bitumen is deficient in hydrogen, relative to lighter oils. Aside from the issues in production, this heavy material was economically undesirable as it must be upgraded by the addition of hydrogen to make a lighter and more valuable synthetic crude. Other problems arise due to relatively high sulphur
content of approximately 5% and small but not insignificant concentrations of metals such as titanium, tungsten, and iron. This bitumen and heavy oil is essentially the residue from a lighter oil that has lost its lighter fractions in part by bacterial degradation.

It is worthwhile to briefly look at some of the societal factors that are influencing the growth of the oil sands development. Including both light and intermediate oils that are produced by conventional techniques, the distribution of global reserves according to type shows that both heavy oil and bitumen account for approximately half of the established reserves\(^3\) of 2234 Gbbl\(^4\) (Figure 2a). An interesting pattern appears when the distribution of these various reserves is examined by region, (Figure 2b-d) revealing large inequalities. Essentially, the bulk of the conventional, heavy, and bitumen reserves are located in three regions, being respectively: the Middle East, South America (principally Venezuela), and North America (principally Canada).

Consumption patterns by region (Figure 3) also highlight important trends. After actually reaching a minimum in the early 1980s, consumption has generally increased in all areas and today is about 0.08 Gbbl/day (29.2 Gbbl/ year). The growth in consumption has not been rapid in the developed world generally. However, both China’s and India’s needs have nearly doubled in the decade ending in 2003 and this growth is expected to continue as the economies of these two large nations expand. This consumption growth is occurring in a situation in which it is becoming increasingly difficult to maintain and increase production of conventional light and intermediate oils, and is placing a strain on global supplies that, in part, have led to the rapid increase in the price of oil since 2003. Indeed, an oversimplified face value examination of the numbers above would suggest that the current global reserves would be depleted in less than a century.

**Geology of the Oil Sands**

There are three major oil sand accumulations in Alberta: the Peace River, the Cold Lake, and the Athabasca deposits; the locations of which are highlighted in Figure 4. The areas are distinguished primarily on the basis of differences in the geology, the geography, and the oil content. These areas cover upwards of 60,000 km\(^2\), an area roughly equivalent to that of Tasmania. The Athabasca (sometimes referred to the Athabasca-Wabiska deposits) are the largest. AEUB say established reserves are 177 Gbbl (28.1 x 10\(^9\) m\(^3\)) with the definition of established being those reserves that are producible given current technology. Estimates of the reserves that are but ultimately recoverable is 332 Gbbl (52.8 x 10\(^9\) m\(^3\)). The initial total oil in place, however is a staggering 1,700 Gbbl (270 x 10\(^9\) m\(^3\)) with some estimates of the ultimate oil in place (National Energy Board, 2004) even going as high as 2520 Gbbl (400 x 10\(^9\) m\(^3\)). It is currently unknown how much could eventually be obtained.

The geology of the three oil sand regions differs, but in many ways can be similarly summarised. It is useful to first briefly examine the overall geological structure of Alberta, (Figure 5) which begins in British Columbia in the Rocky Mountains. The tectonic history of the basin essentially consists of two parts (Price, 1994). First, from the later Proterozoic to the late Jurassic the western edge of North America essentially consisted of passive margin sedimentation, primarily sourced from the east. The second is characterised as the foreland basin stage that incorporated passively deposited supracrustal sediments that were detached from the metamorphic basement and thrust to the east from the late Jurassic to

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\(^3\) The careful reader will note some inconsistencies in the volumes given to the various reserves. These arise due to differences in the criteria employed by different reporting agencies in deriving their final statistics; in all cases the original source of the information used here is given. This author is not qualified nor prepared to defend any of these statistics, and indeed, as reserve devaluations continue to come to light in the media and in recent books, one may question actually who is able to do this difficult prognostication.

\(^4\) 1 BBO = Billion barrels of oil = 159 x 10\(^9\) m\(^3\) = 1 Gbbl = 10\(^9\) barrels.
Alberta is 660,000 km², for comparison New South Wales is 805,300 km². The total area of liquid bitumen in place in Alberta is estimated to be 800,000 km³. Summary map based on analysis of well log and other information. The total area of Alberta is 640,000 km², for comparison New South Wales has just over 800,000 km².

The early Eocene. The load of these thickened thrust sheets induced flexure of the lithosphere, bending the crust to produce a basin, which subsequently filled with Mesozoic siliciclastic sediments primarily of Cretaceous age. The first ranges of the Rocky Mountains are thrust sheets of a fold and a thrust belt, formed during the late Cretaceous and early Tertiary Laramide orogeny.

Within this overall framework, and using the Athabasca reservoir as representative, the host sands were deposited on top of a major angular unconformity that truncates Paleozoic limestones and calcareous shales. Valleys were subsequently filled with a series of earlier fluvial and estuarine deposits and crosscutting channel complexes (see Pemberton and James, 1997 for detailed discussions). This deposition occurred in the Lower Cretaceous of Aptian to Albian age (~120 to 100 Ma) in a formation regionally referred to as the Mannville Group. It must be noted that some of the resource may also be found in the older Paleozoic carbonates, particularly in the Peace River region.

The source rocks, the timing, and the migration mechanisms for the bitumen remains controversial. Such a large deposit will attract attention as well as unconventional explanations attempting to explain where the oil came from. For example, one theory maintains that both the sand and the oil resulted from a large terrestrial ‘gastrobleme’, which conveniently spewed forth the sands and then the oil5. More conventional theories are perhaps less dramatic but still retain a good deal of mystery. Generally, it is believed that the oil migrated to the east from the west across the basin (Figure 5) with a number of workers suggesting the generation and migration was roughly contemporaneous with the late Cretaceous – early Tertiary Laramide orogeny mentioned above. A variety of shales with ages from the Mesozoic to the Paleozoic have also been suggested (see Riediger et al., 2000 for a brief background to this discussion). However, recent geochemical studies using a new Re-Os dating technique on the bitumens (Selby and Creaser, 2005) have been carried out. The work suggests 112 ± 5.3 Ma as the date for the generation and migration of the oils, which is contemporaneous with the deposition of the final host sands. This early date precludes generation of the oil during the Laramide orogeny and points the source towards older and more voluminous Paleozoic source rocks. This scenario is consistent with both the unconsolidated nature of the oil sands (cementation being further hampered by the oil) and the large degree of biodegradation of the original oil, the residue of which is bitumen. It is also more consistent with numerical flow and hydrological studies (Adams et al., 2004).

Characteristics of the oil sand materials

The best sands have a number of favorable petrophysical characteristics (e.g. Mossop, 1980). The sand typically consists of moderately sorted, fine grained (62.5 to 250 μm) grains, of which 95% are quartz with less frequent feldspars, micas, and clays. As might be expected for such a material, the absolute permeability is high although the bitumen itself is essentially immobile due to its viscosity. Shale stringers however lie within the deposits and can restrict the flow of fluids. The sorting allows for high porosities from 25% to 35%. The high porosity is also the result insufficient mineral cementation indicative of the shallow burial depth and lack of diagenetic modification that these sands experienced. As such, the material is unconsolidated and defined as sand, not sandstone.

Workers have long been concerned about the microscopic distribution of the fluids within the pore space as this has direct implications on how the oil is produced. One longstanding model of this fluid distribution (Figure 7) suggests that the bitumen should be kept apart from the mineral grains by thin layers of water along surfaces and by pendicular menisci at grain contacts (Takamura, 1982; Ofouosiasiolu et al., 1992). Preferential wetting in smaller pore spaces keeps the matrix material water wet. There is some evidence however that...
this model may not be completely accurate. Zajic et al. (1981) examined a frozen oil sand using transmission electron microscopy with resolutions of 10 nm but saw no evidence at this scale for a thin layer of water. Czarnecki et al. (2005) has also questioned the water wetting assumptions, which can be traced to some early conjectures in the 1920s that suggest a lack of serious supporting evidence but have since been repeated in the literature. This may be an important consideration in future rock physics studies as the distribution of fluids controls the effective fluid properties, the complexity of the electrical conduction networks within the rock, and the cohesive surface forces between adjacent mineral grains.

Production technologies
To provide a background for geophysical discussions that will occur later, it is also important to reveal how these oils are produced. Essentially the very high viscosity of heavy oils and bitumens makes producing them difficult. Indeed the bitumen is immobile under conditions existing naturally within the earth and considerable production methodologies are required. The problem boils down to reducing the viscosity of the bitumen and heavy oils so that they flow through the porous rock. This may be done by injecting solvents but the most popular methods have lowered the viscosity by heating the formation. The viscosity of such liquids is highly sensitive to temperature (Figure 6) and changes by many orders of magnitude over a range from 0 to 300 °C. Natural in situ temperatures fall in a range of approximately 10 °C and the oils move very slowly.

This problem is overcome by a variety of strategies, principally by heating the reservoir. It is interesting to note that some of the first suggestions for heating the oils during the 1950s relied on the use of peaceful nuclear explosions. Fortunately, this suggestion was not implemented. Since then, production methods have essentially fallen into two categories: 1. Surface strip mining of oil sand ‘ore’ and processing for removal of the oil, and 2. In situ enhanced recovery techniques.

A large fraction of Canada’s total oil production is currently derived from the upgraded synthetic crude, which is produced at just two mines operated by Syncrude Canada Ltd. and Suncor Energy Inc. These mines straddle the Athabasca River north of Fort McMurray, Alberta. The oil sands are relatively shallow at these locations and allow for the economical removal of the overburden and extraction of ore. Typical daily production from these two mines and the associated upgrading facilities is approximately 380,000 bbl/day (~ 60,000 m³). It is estimated however that approximately 10% of the bitumen deposits could be accessed (20% of the bitumen deposits could be accessed). Production technologies

First, current exploration of the resource is conservatively carried out by drilling, which is expensive and provides relatively low resolution. Geophysical techniques can be used to assist by helping to locate the thickest and richest oil sand materials. Due to the shallow nature of the deposits, electromagnetic airborne techniques (e.g. Cristall et al., 2004) and electrical resistivity tomography (e.g., Kellett and Maris, 2005) have been applied to find the best deposits. High resolution seismic techniques (e.g. Siewert et al., 1998) have shown promise for delineating finer details of the complex fluvial and estuarine sedimentary structure (e.g. Langenberg et al., 2002).

There are a number of in situ technologies that have been developed to produce the heavy oils and bitumens that range from cold heavy oil production to steam assisted gravity drainage. A recent and more detailed review was recently provided by Butler and Yee (2002). However a few of the more popular methods are presented and some examples of geophysical observations related to monitoring such processes are given.
**Cold heavy oil production (CHOP)** is a method of producing heavy oils inexpensively without the addition of expensive enhanced recovery techniques although this method leaves more than 85% of the oil in the formation. In this method, vertical wellbores are drilled into the heavy oil sand reservoir and material is extracted with a special progressing cavity pump that consists of an auger screw (Figure 8). The screw or stator is the only moving part and is made of a tough synthetic elastomer that resists wear. The reason such wear resistance is desired is because cold production requires that sand also be produced with oil, water, and gas. Where exactly within the reservoir the sand comes from and how it assists the production of the oil is not completely understood. One model that appears to reasonably predict production histories is the creation of wormholes in the reservoir. These wormholes, which have been produced in laboratory situations, are essentially long cavities that progressively extend away from the producing wellbore while sand and fluids are removed. The wormholes are additionally valuable in that they produce a large effective surface area to the wellbore that allows for more effective production (e.g. Tremblay and Oldakowski, 2004).

Direct geophysical detection of the wormholes is unlikely as their dimensions are much smaller than seismic wavelengths (e.g. Chen et al., 2004). However, during production the pore fluid pressure (i.e. reservoir pressure) is drawn down by 50%, or more. The pressure drops below the bubble point and gas exsolves from the mixture to produce bubbles. The exsolution process maintains pressure within the reservoir and promotes the production of fluids and sand. Recent theoretical and experimental work by the Alberta Research Council (Lillico et al., 2001) suggests that initially large numbers of micron scale bubbles are nucleated. It is the reductions in the overall fluid compressibility, caused by nucleation of these bubbles that is likely to be responsible for strong changes in seismic amplitudes in the immediate vicinity of cold production wells (e.g. Lines et al., 2003), as shown in the seismic amplitude map (Figure 9) of Mayo (1996).

**Steam assisted gravity drainage (SAGD)** is a horizontal well steam injection technology developed in Canada in the past 20 years. This technique has become popular for in situ production in heavy oil and bitumen reservoirs. In SAGD, two parallel and horizontal wellbores are drilled one on top of the other, separated by approximately 2 m. The lower bore is near the bottom of the oil containing sands. At the beginning of this process, high quality steam is injected into both wellbores until the viscous oils between them are sufficiently mobile to enable good communication. At this point, injection continues only from the top well. Engineering models suggest that a steam chamber begins to grow both laterally away from the wellbore (at rates ~ 5 cm/day) and vertically within the oil sand. The growth of this steam zone occurs by the displacement of the now hot and lower viscosity oil which flows down along the sides of the chamber to its bottom (Figure 10). The pooled oil is then recovered through the lower wellbore with production rates of 100 m³/day and estimated recovery rates of 50%.

There are a number of variations on this theme (Butler and Yee, 2002). Methane gas may be injected in order to provide a region of low thermal conductivity at the top of the steam zone and reduce heat loss. This technique is referred to as steam and gas push (SAGP). In another technique that is now undergoing preliminary field trials and is referred to as vapor extraction (VAPEX), light hydrocarbon solvents such as ethane and propane are injected instead of steam. These solvents also reduce oil viscosity and allow it to flow in a manner similar to SAGD. This method is intended for reservoirs that are too thin for application of SAGD, which is inefficient in such situations due to the conductive heat losses. Another
process which has been employed on a large scale is cyclic steam stimulation (CSS). This process takes place from banks of deviated and vertical wells and involves injecting steam into the formation, at pressures approaching the lithostat. The heat from this injected steam and hot water is then allowed to diffuse into the formation, which heats the oil and lowers the viscosity. After a suitable period, the same wells are then turned onto production with the presumption that the heated oil will flow back to the well.

**Geophysical monitoring**

The *in situ* technologies for producing heavy oils and bitumens require large capital investments and have high ongoing operational costs. Despite the high economic input, there is often no guarantee that a given project will necessarily meet its initial expectations. A number of difficulties can arise in developing such a reservoir. A major problem can arise in well completion where the liquid access ports in the steel casings can collapse, restricting the flow of fluids both in and out of the wellbore. This can cause substantial sections of the reservoir to be bypassed. Nature herself is not always amenable to simplified models of the subsurface. There can be both barriers to permeability that deny the steam access to sections of the reservoir and other lean or barren zones of high permeability that can steal the costly steam by routing it away from where it was intended to go. These problems can be difficult to detect as the tools available to the production engineer typically remain limited to history-matching of the fluid injection and production history. Concerns are raised only if these fluid histories substantially miss the initial expectations.

Issues related to the common solutions of history-matching aside, there are few tools that allow technical problems within the wellbore to be located or even detected. Determining the consequences of geological complexity in the three dimensional world away from the wellbore can be even more difficult to understand. Geophysical techniques have the potential to provide additional information away from the wellbore that could highlight both technical and geological problems. This has been long recognised and the pioneering seismic monitoring projects began in the oil sands in the mid-1980s (see Schmitt, 2004 for a listing of this work). These early studies demonstrated that the changes induced by enhanced oil recovery methods were substantial and could be detected using geophysical methods. Typically, the seismic reflectivity of the disturbed zones is greatly enhanced for a variety of reasons.

Injection of steam and the formation of a steam chamber can dramatically affect physical properties, particularly at the low effective confining stress of the shallow Athabasca oil sands. There are many changes occurring in the reservoir during such types of production and have been reviewed previously (Schmitt, 2004). Briefly however, the conditions of temperature ($T$), confining stress ($P_c$), pore fluid pressure ($P_p$), gas saturation state ($S_g$), and geomechanical damage ($D$) (e.g. Chalaturnyk and Li, 2004) are continuously evolving spatially and temporally. These extrinsic variables will influence the intrinsic physical properties of P-wave and S-wave velocities ($V_P$ and $V_S$, respectively), the bulk density $\rho$, the porosity $\phi$, and the quality factor $Q$ (i.e. the inverse attenuation). The influence table (Figure 11), revised from Schmitt (2004), outlines the linkages between the extrinsic conditions and the intrinsic properties. This revised table also now includes the frequency $F$ at which observations are made as it is likely that oil sands materials behave anelastically (Solano, 2004). This table represents more
or less the behavior of the intrinsic properties due to changes in the extrinsic conditions. However, current understanding is far from being able to provide a reliable model for what the changes in such unconsolidated materials might be during production and further work is necessary.

Seismic monitoring over such production zones also differs from normal geophysical exploration in that the scales of the former are usually much smaller. Typical spacings between pairs of horizontal wellbores, for example, are less than 100 m and the wellbores extend for upwards of 1,000 m. As such, standard exploration seismic exploration techniques, while certainly useful, may not provide optimal spatial resolution.

My group has been involved with a series of 2D time lapse profiling for an Athabasca reservoir in the last few years. Figure 12 is an example of a profile acquired perpendicularly across three horizontal wellbore pairs (B1, B2, and B3), near the bottom of the reservoir at a depth of about 150 m (Schmitt, 1999). Large amplitude anomalies are associated with each of the three pairs and are presumably caused by the changes in the reservoir due to steaming. At the time the data was acquired, connection between the three different zones, as evidenced by temperature monitoring from observations wells, was just being established and the temperatures between the wells remained substantially cooler. This profile has been repeated 11 times since 1995 taking care to ensure that the source and receiver positions were unchanged between surveys. The results of this work will be forthcoming\(^6\). However, it is worth commenting that seismic response is not necessarily symmetrical with respect to the wellbores; suggesting that movement of fluids may not exactly occur in a uniform fashion. This should not be surprising given the complex nature of sedimentary structures within the reservoir (McGillivray et al., 2005); but such suggestions are not necessarily met with enthusiasm by reservoir simulators who prefer a simpler earth\(^7\).

**Directions for the future**

These are exciting times for the Alberta geophysical community; the oil sands provide an opportunity to carry out good science with a direct practical application. However, much work remains to be carried out. This work is not only directly technical, but in my humble opinion the community may need some shift in its operating paradigm from one of exploration, in which careful imaging of the geological structure has been paramount, to one that may be more quantitative such that the geophysical observations can be translated more precisely to the needs of production geologists and engineers. Only when this is done will we be able to convince them of the value of time-lapse monitoring in locating, for example, bypassed resources.

Aside from the production methodologies already mentioned, one future area of research that is now being discussed is that of ‘in situ upgrading’ in which some portion of the refining process is actually carried out as part of the production. This is currently only a concept, but it is likely that such processes will be substantially more complex than simply injecting steam. One could easily speculate that such production strategies would make seismic monitoring even more desirable. The client community, which will come more from the refining side of chemical engineering, understand the value of process monitoring and are likely to be receptive to any technology that can assist them towards these goals.

Finally, Alberta’s oil sand resource is large and as production from the heavy oils, and bitumens increase they will have an important impact. The subtitle to this paper: ‘Can Alberta Save the World’ suggested to me by David Denham must be put in context of the overall global demands. As mentioned earlier, global requirements in 2003 were closing in on 30 Gbbl (4.6 X 10\(^9\) m\(^3\)) per year. This means that even if we were able to squeeze every last drop of the highest estimate of the ultimate in-place hydrocarbons in the oil sands given above, the world-wide community would consume it in less than a decade. Clearly, we will soon have to seriously begin to seek additional supplementary sources of energy with conservation being one component of an overall strategy, as even our giant reserves cannot last forever.

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\(^6\) A ‘movie’ of these 11 seismic frames may be accessed from my webpage www.geo.phys. ulalberta.ca/~doug

\(^7\) The author has been informed that the seismic observations collected in the field must be in serious error as they did not agree with a particular computer generated reservoir simulation!
References


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Some other resources, recent short article in Wired magazine http://wired-vig.wired.com/wired/archive/12.07/oil.html, the Athabasca Regional Issues Working Group has a website (http://www.oilsands.cc/about_us/default.asp) that bring forth issues from the energy industries perspective related to the rapid development of the oil sands region. The Lloydminster Oilfield Technical Society has sponsored a highly informative website discussing numerous issues related to heavy oil production (http://www.lloydminsterheavyoil.com/).