Chapter 1

Heavy-oil Reservoirs: Their Characterization and Production

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Heavy Oil as an Important Resource for the Future

With more than 87 million barrels of oil being consumed worldwide every day, oil has come to be the lifeblood of modern civilization. It is cheap, relatively easy to procure and use, and has become addictive in terms of its flexibility in enhancing our lives in multiple applications. First and foremost, we are dependent on oil for transportation because more than 90% of transportation energy comes from oil. In addition, oil provides a feedstock for pharmaceuticals, agriculture, plastics, clothing, mining, electricity, and several other products that we use in our everyday lives. Almost all goods are connected to oil in one way or another; we are all dependent on oil and gas more than any other resource, yet not many of us think about this dependence.

Oil exploration and production has fueled world economic growth over the last century, and it has reached a stage where the economy of several nations is dependent on the exports of oil to the international market. Global demand for oil is now outstripping supply growth and the importance of this crucial commodity is such that companies engaged in oil exploration and production or transportation have dwarfed those in every other commodities sector. Some important aspects to keep in mind are that oil and gas are absolutely critical to the operation of today’s industrial society, essential for sustained economic growth in the industrialized world, and key to progress in nations working their way toward prosperity. This translates into a growing demand for oil and gas, much of it coming from developing nations with low levels of energy use per capita.

However, oil fields are not uniformly distributed in the world; some countries boast giant accumulations and others have none at all. Those that are not self-sufficient spend billions of dollars each year importing oil to satisfy their growing demand. The United States alone imports 65% of the oil it consumes. It is not possible for such countries to insulate themselves from the impact of global oil supply-and-demand imbalances. Also, oil is a finite resource bound to be exhausted one day. At year-end 2007, proven worldwide oil reserves were reported as 1238 billion barrels. In Figure 1, the proven reserves for some significant oil producers are shown, with Saudi Arabia topping the list. The production rate at the end of 2007 was 81.5 million barrels a day or 29.7 billion barrels per year. A simple calculation suggests that conventional crude oil supply could last for about 42 more years (at the 2007 production rate). Some energy experts argue that there is fallacy in using such numbers as reserves keep changing. Even if these figures are taken as conservative, or the reserves are taken as growing, the crude oil supply could last a little longer. But world oil demand is forecast to grow by 50% by 2025, and so the two could offset each other. Although these figures are based on assumptions that may not be strictly true (Campbell and Laherrère, 1998), this simple calculation forewarns us that conventional oil cannot last forever. Most would shudder to think of such a day, but it would be prudent to discuss and analyze a scenario wherein conventional crude oil supply does dwindle some day for us to evaluate what would be the next reliable resource.

Another significant reality to be considered is that many of the oil-producing nations have peaked their production and are on a decline. Figure 2 shows the production from the United States (which peaked in 1970), Mexico (production from the giant Cantarell Field is in decline), Venezuela, Norway, Russia, United Kingdom, and Egypt since 1985. The only exception seen on the graph is Russia, where production has increased since 2000 and continues to climb. North Sea crude oil production, not shown in

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Figure 1. Proven combined reserves of countries shown here add up to 1225 billion barrels, which is close to the world’s proven reserves of 1238 billion barrels at the end of 2007. Canada’s National Energy Board estimates that domestic conventional oil reserves stand at 5 billion barrels. The Oil and Gas Journal pegs Canadian oil-sands reserves at 174 billion barrels, for a combined estimate of 179 billion barrels of conventional and oil-sands reserves. Adding to this figure unofficial estimates of 111 billion barrels of recoverable reserves (at a 35% recovery factor) from Alberta’s Grosmont formation pushes Canadian oil reserves above Saudi Arabia’s. From BP Statistical Review of World Energy, 2008.

Figure 2. Daily oil production has been in decline for all countries listed except the Russian Federation. From BP Statistical Review of World Energy, 2008.

Figure 2, is also declining. Yet another important factor to note is that world oil discoveries have been steadily shrinking over the last few decades. In the last 25 years, no oil fields capable of producing more than 1 million barrels a day, such as Ghawar (discovered in 1948 in Saudi Arabia), Kirkuk (1938 in Iraq), Burgan Greater (1927 in Kuwait), or Cantarell (1976 in Mexico), have been discovered.

Since the early 1980s, world oil production has fallen short of the number of barrels consumed (Figure 3). As this shortfall increases so does the price per barrel. Higher prices in turn are taxing on the economy of developing countries. However, lately the demand of countries such as India and China has not diminished despite the spiking oil prices. At this writing, the 2008 global economic meltdown has dampened the demand for oil worldwide and prices have fallen. This could be a temporary phase followed by higher prices. Of course, we are talking about “conventional” oil.

Conventional oil consumption in the last three decades has increased in general and, as stated earlier, total world consumption stands at more than 87 million barrels per
day (b/d), despite the average price per barrel for 2008 being above $75 (Stonehouse, 2008). Oil demand has been projected to increase to 110 million b/d by 2015 and to 120 million b/d by 2025. As seen in Figure 4, after an initial lowering trend in the energy crisis of the early 1980s, there has been an overall increase of oil consumption in all regions of the world except Europe and Eurasia, with Asia Pacific showing significantly higher growth than others. If we analyze the data for some of the developed countries of the world, we again notice that oil consumption does not show significant growth over the last three decades (Figure 5a). However, two rapidly growing economies, China and India, have recorded a growth by a factor of 4 (Figure 5b) in the last three decades, and this growth has doubled in the last decade alone. This trend is expected to continue as these economies expand.

Production in China and India has not kept pace with consumption (Figure 6a and b). As with many other oil producing countries, Indonesia, which had been a net exporter of oil until recently, turned into a net importer of oil in 2005 (Figure 6c). This gap between production and consumption is widening, especially in developing countries. Figure 7 shows this gap as 10.5 million b/d for some developing nations, including China, India, Indonesia, Mexico, Pakistan, Philippines, Singapore, South Korea, and Taiwan. Two decades ago, the overall production in these countries as a whole matched their consumption.

Energy experts have suggested for some time that conventional oil production will peak this decade and decline thereafter never to rise again. Some say that world oil has already peaked, but others believe that Saudi oil supplies might decline earlier than expected (Simmons, 2005).
Either scenario acknowledges the fact that hydrocarbons are a finite resource. The sooner we accept it, the better we will handle the shortfall and avoid a crisis. Adding to our concerns is the geopolitical climate around the world that makes access to some oil-rich nations such as Russia, Venezuela, and others increasingly difficult. In such a global scenario, and with the price per barrel soaring past $140 as recently as 2008, it is natural to turn to alternative energy sources.

An assessment of the range of alternatives reveals that only unconventional hydrocarbon resources like oil sands, heavy oil, shale deposits (oil/gas), and coal liquids are sizeable enough to be considered. Globally, the recoverable reserves of heavy oil and natural bitumen are equal to the remaining reserves of conventional oil (Figure 8a). When the available data are analyzed, we find that although the Middle East dominates in terms of conventional oil (Figure 8b), South America, principally Venezuela, leads in heavy-oil reserves (Figure 8c), and bitumen reserves are abundant in North America, mainly in Canada (Figure 8d).

Conventional oil production in Canada has declined over the last few years, falling from 1.2 million b/d (including light and medium grades as well as heavy oil from Alberta and Saskatchewan) to 1 million b/d in 2006. This output could fall further to only 671,000 b/d by 2020. During the same five-year period, total production from mined oil sands and oil sands produced in situ by steam-assisted gravity drainage (SAGD) or other methods increased from 659,000 b/d in 2001 to 1.1 million b/d in 2006. This number is forecast to swell up to 4 million b/d in 2020 according to the Canadian Association of Petroleum Producers (CAPP). In 2008, total Canadian oil production including conventional and oil sands stood at 2.6 million b/d. This is expected to double by 2020 (Stell, 2008).

Russia has about 246.1 billion barrels of natural bitumen in place, of which only 33.7 billion barrels (approximately 14%) are recoverable. The remaining bitumen cannot
be realistically recovered as it exists either in remote areas or scattered in many small deposits. A large accumulation occurs in the Olenik Highland located in the Lena-Anabar Basin in eastern Siberia (Veazeay, 2006).

Forecasts vary because of the uncertainty associated with data sources and the level of optimism individuals may assign to their forecasts, which in turn is a function of their individual experience and interpretation of the data. Also, influencing such forecasts is the prevailing geopolitical climate. Yet the fact remains that for the foreseeable future, heavy oil could be contributing significantly to the world oil production.

**Oils and Rocks**

To be able to interpret the data collected during monitoring of heavy-oil production processes, we must have a thorough understanding of how the fluids and rocks behave under production conditions. Heavy oils are unique in the influence they have on the sands or consolidated rocks containing them.

- Heavy oils can act like a solid at low temperatures — they have a shear modulus.
- Heavy oils are strongly temperature dependent.
Heavy Oils: Reservoir Characterization and Production Monitoring

- Heavy oil properties are frequency dependent.
- Gas coming out of solution (even smallest amounts) can produce a large geophysical signature.
- Heavy oils often act as a cementing agent in unconsolidated sands.
- During production, the reservoir rock matrix is often structurally changed.
- The physical properties of rocks containing heavy oils are temperature dependent.
- The physical properties of rocks containing heavy oils are frequency dependent.

Simple Gassmann substitution will fail in heavy-oil reservoirs.

As a result of these complexities, we will elaborate on the characteristics of the oils themselves and the influence they have on reservoir rocks.

**Chemical properties of conventional crude oil**

Crude oil consists primarily of hydrocarbons or compounds comprising hydrogen and carbon only. Some elements such as sulfur, nitrogen, and oxygen are also present...
in small quantities and are generally combined with the carbon and hydrogen in complex molecules. As oils get heavier or more viscous, their composition becomes more complex and can contain chain and sheet structures with molecular weights in the thousands.

In fact, carbon and hydrogen can form hydrocarbons in several patterns depending on how the carbon and hydrogen atoms are attached to each other. The simplest pattern is the one that has a straight chain and represents the saturated hydrocarbons called normal paraffins. Examples are methane (CH₄, one carbon atom surrounded by four hydrogen atoms), ethane (C₂H₆, two carbon atoms surrounded by six hydrogen atoms), propane (C₃H₈), butane (C₄H₁₀), and so on.

Carbon atoms can also be attached to each other in a branched chain. Compounds with such a pattern are referred to as isoparaffins. If there are three carbon atoms they will form a straight chain compound, but four carbon atoms could also form a branched chain (Figure 9).

An additional pattern is when paraffins form a ring, referred to as cycloparaffins or naphtenes. An example of cyclohexane is shown in Figure 10.

Alternatively, multiple bonds between two carbon atoms are common. In the case of benzene, each carbon is bonded to a single hydrogen. The remaining bonds are shared among the other carbons. A common representation of benzene (Figure 11) is somewhat misleading because the carbon double bonds are not rigidly fixed between alternating carbons but are actually shared over all six carbons. Hence, the hexagon enclosing a circle is often used as a schematic representation. Numerous such rings can form together, growing into sheets. Such compounds are also called aromatics (because of their aromatic odor).

As oils become heavy and gain in molecular weight, the chains and sheets become larger, and identification of individual molecules becomes difficult. As a result, an alternative characterization is often used based on solubility.

SARA fractionation breaks the liquid into Saturates, Aromatics, Resins, and Asphaltenes. We have discussed saturates and aromatics. Resins are usually defined as the propane-insoluble but pentane-soluble fraction and asphaltenes as soluble in carbon disulfide but insoluble in petroleum ether or n-pentane. Notice that resins and asphaltenes are not defined as specific molecular structures. In practice, these molecules have molecular weights in the thousands, are polar, and contain elements such as sulfur, nitrogen, oxygen, and heavy metals. They have no definite melting point (decompose between 300°C and 400°C); exist in a dispersed state in crude oils, but can aggregate to form precipitates; and often are composed of condensed aromatic rings in the form of a nonhomogeneous flat sheet. Examples of asphaltene structures are shown in Figure 12a and 12b.

Sulfur is present in all crude oil samples. Its content can vary from almost negligible content to 5%–6%. It may occur not only as free sulfur, but also in combined form as hydrogen sulfide or as organic sulfur compounds (thiols, mercaptans, disulfides). Crude oil samples containing sulfur cause corrosion and have a bad odor.

Some crude oils contain large amounts of wax in solution. Waxes belong to the straight-chain paraffin series of compounds and have high molecular weights. Wax content in crudes is usually removed on lowering the temperature when it solidifies and settles down.

Density of a crude oil is related to the overall molecular weight, and, for lighter oils, density correlates well to oil properties. Although density is defined as the mass per unit volume of the substance, for crude oil the same physical property is often expressed in terms of specific gravity, which is the ratio of the weights of equal volumes of the substance in question and pure water. As volume changes
with temperature and pressure, these conditions should be specified. The American Petroleum Institute (API) has recommended the use of API gravity for crude oil, defined as the ratio of density of oil to the density of pure water both taken at 60°F and 1 atmosphere pressure.

\[
API = \frac{141.5}{\text{Specific gravity at } 60^\circ F} - 131.5 \quad (1)
\]

**Classification of crude oil**

Although API gravity has no units, it is expressed in degrees. API gravity is graduated on a special hydrometer designed for measuring specific gravities of petroleum liquids so that most values fall between 10° and 70°. This has become the standard used for comparing crude oil samples from different basins and countries.

The higher the API, the higher its commercial value. Interestingly, crude oil with API gravity greater than 10° floats in water; lower than 10°, it sinks. On the basis of its API gravity, crude oil is graded into light (>31.1°), medium (22.3°–31.1°), heavy (<22.3°), and extra heavy or bitumen (<10°).

This grading, recommended by the U. S. Department of Energy, is followed as a standard. Sometimes, heavy oil is so called because it is possible to recover it in its natural state by conventional production methods. However, some heavy oil less than 22.3° API may flow through wells very slowly with some form of stimulation in terms of heat or dilution. Oil that does not flow at all or cannot be pumped without some form of stimulation is called “bitumen.” Bitumen mined from oil sands in the Athabasca area of Alberta, Canada, is approximately 8° API. It is upgraded to a higher API gravity (31°–33°), which is known as synthetic oil. Figure 13 shows a sample of heavy oil, dark in color, and slow to flow.

**Figure 13.** In its raw state, bitumen is a black, asphalt-like oil. Image courtesy of Syncrude Canada, Ltd.

Oil sands are naturally occurring mixtures of sand, clay, water, and bitumen. Bitumen and synthetic oil extracted from oil sands are often referred to as “unconventional” to distinguish them from the free-flowing crude oil recovered from oil wells. Oil sands have recently been incorporated to the world’s oil reserves because the available technology can help in recovering oil and other useable products that are economically viable in current market conditions.

“Tar sands” was the term used for bituminous oil sands in the 19th and mid-20th century. However, tar...
also refers to the sticky viscous substance produced by destructive distillation of coal to pave roads. Petroleum product asphalt has come to replace tar and because naturally occurring bitumen is chemically more similar to asphalt than coal tar, the term “oil sands” is deemed more appropriate by the Alberta Energy Board. Figure 14 shows a sample of oil sands as they are mined in the Athabasca area looking like a crumpled mass of bitumen and sand together with some minerals and metals.

Oil sands and heavy oil are found in many countries including the United States, Mexico, Russia, China, and some in the Middle East (Figure 15). However, the largest deposits of oil sands are found in Canada and Venezuela and their combined reserves equal the world’s total reserves of conventional oil. In Canada, oil sands are found in the Athabasca, Peace River, and Cold Lake regions of Alberta, covering an area of nearly 141,000 km² (Figure 16). Heavy-oil deposits (8°–19° API) are also found in the Alberta/Saskatchewan border in the area of Lloydminster.

The Athabasca deposit is the only one in the world where oil sands are present shallow enough they can be mined on the surface. Approximately 10% of the Athabasca oil sands are covered by less than 75 m of overburden. Close to 3400 km² of mineable area lies to the north of Fort McMurray. The overburden consists of a very thin (<3 m) water-logged muskeg layer that overlies a 75-m column of clay and sand. The oil sands below are typically 40- to 60-m thick and reside on top of a limestone formation.

**Figure 14.** Oil sands are bitumen and sand blended with some minerals and metals. Image courtesy of Suncor Canada, Ltd.

**Figure 15.** Production of heavy oil worldwide in barrels of oil per day.
Mechanisms for the Formation of Heavy Oil

An interesting characteristic of reservoir oil observed worldwide is that the specific gravity of reservoir oil decreases with depth; that is, API gravity increases with depth. The maturation of oil takes place in source and reservoir rocks, kerogen producing lighter oil with depth in the latter (Hunt, 1979). As a result, the average trend observed worldwide is that higher API gravity oil is found at increasing depths, although less oil is produced with depth. It must be pointed out that these are general trends, but there are exceptions.

There are several processes that alter the original oil that occur during migration of oil and its subsequent accumulation. These processes include biodegradation, water washing, oxidation, deasphalting/evaporation, and preferential migration of lighter components (Deroo et al., 1977).

Biodegradation of crude oil over geologic timescales can change its composition and physical properties. Various microorganisms are present in sediments bearing petroleum reservoirs (Bastin, 1926) and utilize the hydrocarbons as a source of carbon for their metabolic processes. The process can be aerobic or anaerobic. Typically, the hydrocarbons are oxidized to alcohols and acids. Simple straight chains are preferred, but as biodegradation continues, more complex molecules are progressively consumed. Long-chain paraffins are oxidized to yield di-acids. Similarly, naphthenic aromatic rings are oxidized to di-alcohols. This biodegradation results in a loss of the saturated and aromatic hydrocarbon content, accumulating resins and asphaltenes, and leads to a decrease of API gravity (increase in density). It has been found that biodegradation can occur if reservoir temperatures do not exceed 80°C – 82°C (Hunt, 1979; Head et al., 2003).

Figure 17 shows gas chromatograms exhibiting the effect of biodegradation on a series of oil samples from the central part of the Western Canadian Sedimentary Basin (WCSB) toward the Athabasca oil sands. On the vertical axis is the relative amount of material exiting the “column” or filter material. On the horizontal axis is the time each compound takes to travel through the filter. Individual compounds, such as decane (C_{10}) will appear as sharp peaks. Other peaks are present, including biomarker isoprenoids (e.g., pristine and phytane). Figure 17a shows a conventional crude oil sample from Bellshill Lake pool. Numerous spikes are visible, primarily saturate or alkane chains. A similar analysis shown for the Edgerton sample in Figure 17b shows the depletion of normal alkanes and a relative enrichment of the pristine and phytane. At Flat Lake (Figure 17c), the normal alkanes have almost disappeared and pristine and phytane are quite prominent, although their absolute quantities have decreased. At Pelican (Figure 17d), which is adjacent to the McMurray area, even the isoprenoids have disappeared. Thus, this biodegradation results in an enrichment of the aromatic hydrocarbons, nonhydrocarbon resins, and asphaltenes. Hence, the vast Alberta heavy oils may represent only a small fraction of the original volume of lighter oil that migrated into the sands.

Water washing, oxidation, and deasphalting migration are processes that change crude oil within a reservoir. It is difficult to assess the impact of each of these effects separately.

Deasphalting and subsequent migration of lighter components depletes the residue in lighter hydrocarbons. In some situations, biodegradation can occur if oxygen, inorganic trace nutrients, and water are present; for instance, where there is an oil seep or if the oil accumulation is deeper but adjacent to an aquifer.

Asphalt seals can form at seep outcrops. Asphalt mats have also been formed at the oil-water interface of pools in contact with meteoric water (Hunt, 1996). All of these result from a combination of the above-mentioned processes and microbial alteration. In addition to the formation of asphalt seals, these processes can also cause a change in gravity of the trapped oil (Figure 18). In Lagunillas Field, in north-central Lake Maracaibo, circulating fresh water allows oil biodegradation, and this 5 to 10 km wide belt stretches from the outcrop to the shallowest oil with

![Figure 16. Alberta oil sand, carbonate triangle, and heavy-oil areas. Modified from Proctor et al., 1984.](image-url)
12° API. The oil becomes lighter downdip (20° API) at 1500 m and still lighter (36° API) at deeper levels.

Another mechanism that can lead to heavier oils is precipitation of asphaltene components. If a crude oil is saturated with heavy components, a change in pressure, temperature, or oil-type mix can cause the high-molecular-weight components to drop out of solution.

**General Phase Behavior of Hydrocarbons**

The existence of a substance in a solid, liquid, or gas state is determined by the pressure and temperature acting on the substance. Just as lowering the temperature can change steam into water, and water into ice, by lowering the temperature further, hydrocarbon compounds individually or in mixtures also change their state or phase. This can happen by not only changing temperature but also pressure. The change of state that is brought about is known as “phase behavior.” What type of fluid will be produced at the surface depends on the phase diagram of the reservoir fluid and the reservoir temperature and pressure. Hydrocarbon fluid-phase behavior is important in reservoir simulation, reserves evaluation, and forecasting. In addition, seismic velocity is very sensitive to even small amounts of gas that might develop as a phase boundary is crossed. Because heavy oil and bitumen in deep reservoirs cannot be produced naturally or in conventional ways, it is important to know the thermodynamic changes that these working fluids undergo. The phase behavior of
fluids is expressed on phase diagrams, which are graphs showing how fluids behave under different conditions.

**Single-component system**

To understand the phase behavior of hydrocarbons, let us first look at a simplistic case — a single pure component. Crude oil is a mixture of single hydrocarbons and phase behavior is strongly controlled by composition. For a single hydrocarbon component (e.g., propane or butane), the phase diagram is shown in Figure 19.

The first observation is, as expected, that the vapor pressure of a liquid increases as temperature increases. With the increase in temperature, more liquid molecules escape into the vapor phase, thus increasing the vapor pressure. This is called the vapor pressure curve or boiling point curve. This segment also represents what is known as the bubble point curve or the dew point curve, overlaying one another, representing the transition between the vapor and liquid states. The bubble point refers to the pressure and temperature condition at which the system is all liquid and in equilibrium with a bubble or a very small quantity of gas. Similarly, dew point is the pressure and temperature condition at which a droplet or very small quantity of liquid is in equilibrium with vapor. For a single-component system, a single curve represents all three conditions: vapor pressure, dew point, and bubble point.

When a liquid system is cooled, we would expect the solid state to be formed. The green segment in Figure 19 represents the liquid-solid transition or the melting curve (or solidification). When pressure is low, it is also possible to go from the solid to the vapor phase (sublimation) without going to the liquid phase (the red segment curve in Figure 19). Notice also the critical point, which represents the point at which the fluid is in a supercritical state, and the triple point, which represents that point at which all three phases (solid, liquid, and gas) coexist in equilibrium. These two points bound the boiling point curve. For single-component substances, at the critical point the liquid and vapor phase are indistinguishable. Above this temperature ($T_c$), the fluid is supercritical and no separate liquid and vapor phases exist.

“Multicomponent systems” are the norm in real reservoir situations (i.e., mixtures of different compounds) from chemically simple to chemically complex.

For a mixture of two compounds, there is no single line segment on the pressure-temperature phase diagram, where bubble and dew point curves overlap (Figure 20). Instead, the bubble point curve shifts to the upper left (higher pressures) and the dew point curve shifts to the lower right (lower pressures), both joining at the critical point. Interestingly, the critical point is not necessarily at the apex of the two-phase region; a supercritical fluid exists at $T > T_c$ and $P > P_c$. Also, if this were a mixture of two components with one more volatile than the other, then at a given temperature the pressure at which this mixture is condensed to total liquid is lower than the pressure at which the lighter of the two components in the mixture would condense individually. Similarly, the pressure at which the mixture of the two components is vaporized to total gas is higher than the pressure at which the heavy component would vaporize individually. In other words, for a mixture, the critical point
neither represents the maximum pressure nor maximum temperature for vapor-liquid coexistence.

**Hydrocarbon Mixtures, Terminology, and Phase Diagrams**

Crude oils typically contain gas in solution. As pressure is lowered and the bubble point line is crossed, gas will begin to come out of solution as a separate phase. During production, when crude oil is separated from the accompanying gas at the surface, the volume of gas evolved as oil reaches atmospheric pressure relative to the volume of remaining oil produced is the gas-oil ratio (GOR). It is usually measured in standard cubic feet (or meters) of gas per barrel (or cubic meter) of stock tank, or atmospheric oil ($1\text{ scf/bsto} = 0.1781 \text{ m}^3/\text{m}^3$).

If the volume of gas evolved is low (2000 scf/bsto), the oil is said to be low-shrinkage or black oil (because of its dark color). When GOR is greater than 2000 but less than 3300 scf/bsto, the oil is said to be high-shrinkage or volatile oil (usually brownish). For GOR greater than 3300 and below 50,000, the oil is usually called condensate reservoir gas. Above 50,000 GOR, reservoir gas condenses as a liquid at surface conditions and is called "wet gas." The term “dry gas” refers to natural gas, primarily methane (70–98%) and small quantities of ethane, propane, and butane. Such reservoirs produce no condensate. GOR values associated with dry gas exceed 10,000 scf/bsto. It is called “dry” because no liquid condenses as the gas travels from the reservoir to the surface.

The shape and position of the curve on the phase (P-T) diagram is determined by the chemical composition and the amount of each constituent present. Different types of reservoir fluids have unique phase diagrams and it is interesting to note how they vary. Let us examine the behavior of low-shrinkage crude oil on a phase diagram. A given volume of oil in the reservoir exists in a saturated state with gas. As it makes its way in a horizontal direction toward the well bore, the pressure drops and the temperature remains the same. Figure 21 shows the phase diagram for low-shrinkage oil. At point A (bubble point), the gas starts coming out of solution and the volume of oil shrinks. As fluids travel upward through the well bore, the shrinking continues at the same temperature but reduced pressure. The shrinkage in Figure 21 is 75% of its original volume at point B. Other quality lines indicated for lower pressures are closely spaced along the dew curve. When the fluids reach the separator, both temperature and pressure would decrease and this is indicated with a dotted line to the left. Oil usually accounts for approximately 85% at the condition of the separator.

The phase diagram for high-shrinkage or volatile oil is similar to that of black oil except the quality lines, if drawn, would be close together along the bubble point curve and widely spaced at lower pressures. Oil usually accounts for approximately 65% at the condition of the separator. The above two cases have been discussed for oil reservoirs.

For gas reservoirs, we will consider cases for retrograde gas condensate, wet gas, and dry gas.

**Retrograde gas condensate**

Some reservoirs may contain gaseous hydrocarbons (initial condition) that exist above their critical temperature and pressure. As these fluids move closer to the wellbore, they encounter reduced pressure and instead of expanding.
(for gas), they condense. In this sense, the term “retrograde” is used because normally gases liquefy when pressure is increased and not when pressure is decreased. So during gas production at the surface, condensate drops out in the separator. In such reservoirs, the fluids in place could be just gaseous or gaseous and liquid, depending on the pressure and temperature of the reservoir.

**Wet gas**

The temperature is above the critical condensing temperature of the gas mixture. At constant temperature, when there is a reduction of pressure, there is no condensation. However, when the gas from the reservoir reaches the separator, the temperature is lower and so liquid formation results.

**Dry gas**

The temperature is again above critical condensing temperature of the gas mixture and just as the wet gas, it does not condense with the reduction of pressure (at constant temperature). Also, when the gas reaches the separator, there is no condensation.

**Properties of Heavy Oil**

The bulk modulus \( K \) is a characteristic of pore fluids that strongly controls seismic properties. It is the inverse of the common engineering term compressibility \( C \). \( K \) relates the change in volume \( V \) for a given change in pressure \( P \).

\[
K = \frac{-1}{V} \frac{dV}{dP} = \frac{1}{C}
\]

For a mixture of two separate phases, A and B each with their own bulk modulus \( K_A \) and \( K_B \), the overall mixture modulus \( K_{mix} \) usually is described by Wood’s average.

\[
\frac{1}{K_{mix}} = \frac{V_A}{K_A} + \frac{V_B}{K_B} = \frac{V_A}{K_A} + \frac{(1 - V_A)}{K_B}
\]

where \( V_A \) and \( V_B \) represent the volume fraction of phase A and B, respectively. Because of the inverse dependence on component modulus, a very low modulus of soft fluid will dominate the mixture modulus. Such is the case when even insignificant amounts of very low modulus (very compressible) gases are present.

As shown in Figure 21, during the recovery process, pore pressure can cross the bubble point in either direction as the pressure or temperature changes. The calculated fluid bulk modulus (from Han and Batzle relations) of 7° API oil is plotted against pressure in Figure 22, in which sample the bubble point can be crossed at approximately 2 mPa. About this value, the bulk modulus of the homogeneous mixture is very high, 2600–2800 mPa, which is above the bulk modulus of water. However, once the bubble point is crossed, gas comes out of the solution and the modulus drops to near zero.

Similarly, the phase boundary can be crossed by changing temperature. As seen in Figure 23, the calculated bulk modulus is plotted as a function of temperature. Bubble point crossing occurs at approximately 120° C and the drop in bulk modulus value is of the same order as the pressure. Such appreciable changes in the
bulk modulus suggest that the heavy-oil properties and their phase behavior need to be well understood for seismic monitoring.

Density correlates to many other oil properties. At standard conditions, density is used to define API gravity. However, density is not constant with changing pressure or temperature. Figure 24 shows the variation for density with temperature for an 8.5°C API bitumen sample from Athabasca. Density decreases from 1.01 to 0.935 g/cm³. Similar density correlation is seen in Figure 25 between Cold Lake bitumen and temperature, where measurements were taken over a range of 20°–250°C and pressure range of 3.5–7 mPa.

Viscosity is one of the defining attributes of heavy oils. Generally it increases with a decrease in temperature and in API. As the temperature decreases, heavy oil changes its phase from the low-viscosity liquid phase to a drastically higher quasi-solid phase and eventually to the glass phase, where the viscosity is over the glass point (Han et al., 2006), defined as that temperature at which viscosity is equal to 10¹³ poise.

Because heavy oil consists of complex heavy compounds, the simple empirical trends developed for estimating light oil fluid properties such as viscosities, densities, GORs, and bubble points seldom apply. Although at higher temperatures some of these empirical trends may be obeyed, at lower temperatures the viscosity of heavy oils is high, exhibiting different properties that necessitate special consideration. The viscosity of heavy oils is especially important because production methods exploit this property.

High API, light oil viscosity depends on temperature and the amount of gas dissolved in it; that is, the higher the temperature or the more gas content in solution, the lower the viscosity. Also, viscosity changes slightly with pressure. Higher temperatures increase the molecular agitation, which in the absence of confining pressure increases the volume and so the intermolecular distances. This reduces molecular attraction and friction caused by colliding molecules.

The viscosity of heavy oils is mainly dependent on temperature and oil gravity. Figure 26 shows the variation of viscosity with temperature for 10.3°C API Cold Lake bitumen. The curve exhibits a double logarithmic relationship between viscosity and temperature.

Beggs and Robinson (1975) developed the following empirical relationship between the viscosity and temperature as well as density.

\[
\log_{10}(\eta^T + 1) = 0.505(17.8 + T)^{-1.163}. \tag{4}
\]

Figure 24. Temperature dependence of density for Athabasca bitumen. From Mochinaga et al., 2006.

Figure 25. Density of Cold Lake bitumen as a function of temperature on the basis of laboratory measurements. From Eastwood, 1993.

Figure 26. Viscosity of Cold Lake bitumen as a function of temperature on the basis of laboratory measurements. From Eastwood, 1993.
where

$$\log_{10}(y) = 0.5693 - 2.863 / \rho_o$$  \hspace{1cm} (5)$$

and $\eta$ is the viscosity in centipoises (cp), $T$ is the temperature in °C, and $\rho_o$ is the density at standard temperature and pressure (STP). The variation of viscosity with temperature is plotted in Figure 27 on the basis of the above equation. Note that the low temperature limit is fixed by the value 17.8, and so the equation is questionable for temperatures below 0°C.

The physical properties of heavy oil/bitumen must be understood to anticipate production performance and calculate reserves. These properties are determined from laboratory experiments on samples collected from formations of interest or from the surface. Empirical correlations derived from such experiments are applicable in a well-defined range of reservoir fluid characteristics; thus, when the laboratory pressure-volume-temperature (PVT) data become available, the required information can be derived from the empirical correlations.

Velocity is a crucial piece of information derived from seismic data. Velocities themselves depend on moduli of the material through which the seismic wave propagates. For example, velocity ($V_p$) for compressional waves is

$$V_p = [(K + 4/3G)/\rho]^{1/2},$$  \hspace{1cm} (6)$$

where $K$ is the bulk modulus, $G$ is the shear modulus, and $\rho$ is density. For most fluids, the shear modulus is zero, and the compression velocity reduces to

$$V_{\text{fluid}} = [K/\rho]^{1/2}.$$  \hspace{1cm} (7)$$

However, as we shall see, heavy oils do not act like most fluids.

Nur et al. (1984) studied the effect of temperature and pressure on P- and S-velocities and amplitude by making ultrasonic measurements on reservoir samples of heavy oil and tar sands from Kern River, California; Maracaibo, Venezuela; and Athabasca, Alberta. They found that in fully oil-saturated sands, velocities showed a 40% decline as temperature increased from 25° to 150°C at constant pressure. This strong dependence is reversed when brine replaces oil in the samples, with velocities showing a strong dependence on differential pressure but little dependence on temperature. Similarly, amplitude decreases significantly with increasing temperatures in samples with oil as compared with brine. This behavior is characteristic of heavy-oil and tar samples, and neither brine nor gas-saturated samples display it. This raises the possibility of using seismic methods to detect temperature anomalies in reservoirs. Tosaya et al. (1987) and Wang and Nur (1988) performed laboratory experiments to demonstrate the velocity and attenuation dependence on temperature for several heavy-oil/tar-sand samples.

Wang et al. (1990) measured acoustic velocities at ultrasonic frequency (800 kHz) in oil samples of different API as a function of temperature and pressure. They found that velocities in oils increase with increasing pressure and decrease with increasing temperature. Figure 28 shows the measured velocities plotted as a function of pressure for different temperatures in 5°, 7°, and 12° API heavy-oil samples. Apparently, the velocities vary linearly with increasing pressure. At higher temperatures, the velocities are slightly more sensitive to pressure changes. Also, velocities decrease nonlinearly as temperature increases and decreases faster at lower (20°C–45°C) temperature ranges. This is because solid or semisolid (asphaltene and wax) components of heavy oil, which could cause a decrease in velocity while melting. Once these materials have melted, velocities decrease linearly with the increase in temperature, which is typical behavior of light oils.

Eastwood (1993) performed several experiments to measure the effect of temperature on acoustic velocities in oil-sands samples from Cold Lake, Alberta, Canada. Figure 29 shows the temperature dependence of compressional velocities in two samples of bitumen (fluid only) over the temperature range 22°–127°C and at a constant pressure of 0.1 mPa. The velocity is seen to decrease by

![Figure 27. Variation of viscosity with temperature as computed from the empirical relationship given by Beggs and Robinson (1975), which produces a singularity at low temperatures. The data from Eastwood (1993) and Edgeworth et al. (1984) are also plotted. The heavy oil relationship from De Ghetto et al. (1995) is also indicated. From Batzle et al., 2006.](image-url)
approximately 30% relative to the velocity at 22°C, and this dependence exhibits a linear trend for temperatures 60°C and higher and a departure from this linear trend for temperatures lower than 60°C. This observation is similar to the conclusion by Wang et al. (1990).

As we have seen, velocity and density decrease when temperature for heavy oil, oil sands, or bitumen increases, with the magnitude of the decrease depending on the temperature and differential pressure, which is the difference between the confining pressure and pore pressure. This decrease in velocity and density results in a corresponding change in the amplitude, which can be determined from two or more successive seismic surveys acquired for monitoring changes in the reservoir. Thus, these property changes suggest the usefulness of time-lapse seismic surveys to monitor steam fronts during steam flooding or SAGD operations.

### Shear properties

As the viscosity of heavy oil becomes high, it effectively has a nonnegligible shear modulus. This transition can be tested in the laboratory by propagating a shear wave through the fluid sample. Batzle et al. (2006) noticed that for a very heavy oil sample (∼50 API), at low temperatures (∼12.5°C), a sharp shear-wave arrival is detected. At this temperature, the oil is almost a solid and so it has a shear modulus. As the temperature is increased, the shear velocity decreases and this also reduces the shear-wave amplitude (Figure 30). At such a stage, the oil is only marginally solid. Both the compressional and shear moduli decrease almost linearly with temperature, but the shear modulus approaches zero at approximately 80°C.

Because heavy oils act as a viscoelastic (semisolid) material, there is also frequency dependence. At room temperature, heavy oil supports a shear wave, but as the temperature increases, its shear modulus decreases rapidly, which in turn leads to a rapid drop in the shear modulus of the heavy-oil saturated rock (Figure 31a). At all temperatures, heavy oils would have a nonzero bulk modulus and the percentage change in bulk modulus would be smaller than the change in shear properties. This shear information can be more diagnostic than bulk modulus properties. Therefore, multicomponent seismic

![Figure 28](image)

**Figure 28.** Measured acoustic velocities in heavy-oil samples with (a) 5° API, (b) 7° API, and (c) 12° API. From Wang et al., 1990.

![Figure 29](image)

**Figure 29.** Experimentally measured compressional velocities (ultrasonic) in two Cold Lake bitumen (fluid only) samples as a function of temperature. The experiment was conducted at a pressure of 0.1 mPa. Velocities decrease almost 30% relative to the velocity at 22°C and exhibit a linear trend for temperatures above 60°C but not below. From Eastwood, 1993.
data should be able to help with the determination of $V_p/V_S$ and the derivation of bulk modulus properties.

However, notice that the modulus increases with increasing frequency. This frequency dependence, also referred to as “dispersion,” is directly related to the attenuation in the material. The typical measure of attenuation is the quality factor, and in Figure 31b, we show the quality factor plotted against the modulus for a heavy-oil saturated rock. At lower temperatures, the quality factor increases with frequency and initially decreases with temperature. However, at higher temperatures, $Q$ and the shear modulus increase with increasing temperatures. This behavior is most likely due to a loss of lighter components at elevated temperature.

**Figure 30.** Measured (ultrasonic) bulk and shear moduli in a heavy-oil sample of -5° API. From Batzle et al., 2006.

Rocks with Heavy Oil

Many various rock types are saturated with heavy oils. Because most heavy-oil reservoirs are near the surface, the rocks are often poorly consolidated. Figure 32a shows an example of Athabasca heavy-oil sand. Most of the grains are oil-coated and dark. These sands are fluvial and migrated into the pores early after deposition, preventing significant cementation. In fact, the heavy oil itself acts like cement, and removing it usually causes the matrix to collapse. Thus, one of the primary assumptions in a Gassmann substitution is violated — that the matrix remains unchanged under different saturation conditions. One issue that needs further investigation is the matter of grain surface wettability. Under normal conditions, the Athabasca sands are presumed to be water-wet. This may not be the case for all rocks.

Many heavy-oil reservoirs are not in clastics. The Grosmont formation contains a substantial quantity of Alberta’s heavy oil and, like most Middle East deposits, this formation is primarily composed of carbonates. Figure 32b shows a heavy-oil saturated carbonate from Texas. It is a quarry sample above the water table; therefore, in situ, this rock may be oil-wet. The matrix is made up of porous oolite grains. Note that the heavy oil is present only in the larger pore spaces.

In measurements of heavy-oil sands, Amos Nur and his coworkers noticed a dramatic temperature dependence of compressional velocity (Tosaya et al., 1987). This effect is most pronounced when the only pore fluid present is heavy oil (Figure 33). This observation led these researchers to first suggest that time-lapse seismic measurements would prove to be a useful reservoir monitoring tool.

![Figure 30](image)

**Figure 31.** (a) Shear storage modulus (the real part of the complex modulus), and (b) quality factor $Q$ of Uvalde heavy-oil rock. Measurements at temperature increments of 10°C and frequency increments of 0.1 on the log scale. Missing data points correspond to erroneous results (e.g., negative moduli) arising from noise and/or experimental errors and/or measurements lying outside of the sensitivity limit of the rheometer. From Behura et al., 2007.
The question arises, “How much of the temperature dependence is due to the rock frame, and how much is due to the oil?” Eastwood (1993) measured the effect of temperature on acoustic velocities in samples of the cleaned oil sands from Cold Lake. Figure 34 shows the temperature dependence of measured compressional velocity for a Cold Lake dry rock sample (no bitumen present) at different pressure values. The change in velocity with pressure is rather small, indicating that the dry rock matrix contributes little to the wave velocity for the temperature range at which measurements are made. Eastwood also found moderate temperature dependence for S-wave velocity for this sample. In contrast, Figure 35 shows velocity measurements made on a preserved Cold Lake oil-sands sample at different pressures. Notice the velocities decrease by approximately 12% relative to the initial velocities at 22°C and exhibit pressure dependence.
Another example of nonlinear dependence of velocity of heavy oil on temperature is shown in Figure 36. As the temperature is increased to 150°C, the velocity decreases by approximately 25%. Above 90°C, the velocity drops linearly with increasing temperature as is common with lighter oils. Below 70°C, the velocity departs from linearity, and in this particular case, the oil viscosity increases, approaching its glass point and beginning to act as a solid. When this happens, the change in the velocity is not only due to an increase in the bulk modulus, but also the appearance of a shear component, which is negligible when it is a liquid.

Dispersion in rocks (i.e., the variation of velocity with frequency) is important to be able to correlate laboratory acquired data with seismic or log data. Wang and Nur (1988) suggested that the velocity dispersion in rocks saturated with heavy oil is much larger than in the same rocks saturated with lighter fluids. Their results indicate that for heavy-oil saturated Berea sandstone, velocity dispersion could be as large as 10%. The authors try to explain the observed velocity dispersion in terms of the “local flow” mechanism (O’Connell and Budiansky, 1977; Mavko and Nur, 1979). This mechanism is probably not valid because of the high fluid viscosity.

Heavy oils themselves show strong frequency dependence (Figure 31). This fluid property is then directly imparted to the oil-saturated rock. Measurements on the Texas carbonate (Figure 32b) as a function of frequency are shown in Figure 37. Note the strong frequency dependence on compressional and shear waves. Dispersion becomes more pronounced as temperatures increase. Direct measurements indicate that observations made in the seismic band of 10–100 Hz often do not agree with standard acoustic log data (10,000 Hz) nor with ultrasonic (MHz) data.

Behura et al. (2007) measured in the laboratory the complex shear modulus and attenuation of a heavy-oil saturated rock sample at elevated temperatures within the seismic frequency band. As seen in Figure 38a, the modulus and quality factor (Q) of the heavy-oil saturated rock show a moderate dependence on frequency but are strongly influenced by temperature. These dependences are consistent with the measured properties of the extracted heavy oil as discussed before.
Schmitt (1999) also observed a significant difference between acoustic log and vertical seismic profile (VSP)-derived interval velocities in a heavy-oil sand reservoir (Figure 39). Thus, the viscoelastic (semisolid) behavior of the heavy-oil sands must be considered when applying data collected in one frequency band (logging or laboratory) with those collected in another band (seismic). Such discrepancies would result in differences in synthetic modeling in reservoirs because the reflection of heavy-oil sands based on acoustic logs would be different from the low-frequency seismic response.

**Geology of Two Major Heavy-oil/Oil-sands Areas**

Three-quarters of the world’s heavy-oil reserves are found in two areas: the Orinoco Belt in Venezuela and the Athabasca region in the northern Alberta and Saskatchewan provinces of Canada.

**Venezuela**

To the north of the Orinoco River, there is an extensive 54,000 km² (600 × 90 km) area, the Orinoco Heavy-Oil Belt, which contains an estimated 270 billion barrels of recoverable oil (Talwani, 2002) — the equivalent to the oil reserves of Saudi Arabia. This elongated region is divided into four sections: Machete, Zuata, Hamaca, and Cerro Negro (Figure 40). The Orinoco Belt contains an estimated 1.2 trillion barrels of heavy oil.
These giant deposits of extra-heavy crudes (<10° API), the largest in the world, come from Tertiary/Cretaceous reservoirs and contain large amounts of vanadium, nickel, and sulfur (Talwani, 2002). Because extra-heavy oil cannot be processed in conventional refineries, it is blended with lighter Venezuelan crudes and upgraded into synthetic oil, which is exported to the tune of 600,000 b/d (Christ, 2007).

During the Mesozoic era, the supercontinent Pangea started drifting and gradually split into a northern continent, Laurasia, and a southern continent, Gondwana. Eventually, Laurasia split into North America and Eurasia, and Gondwana split into South America, Africa, Australia, Antarctica, and the Indian subcontinent, which later collided with the Asian plate during the Cenozoic, leading to the formation of the Himalayas.

With this breakup, the northern passive margin (transition between basaltic oceanic plate and granitic continental plates) of South America was created. With subsequent deposition, this margin started subsiding. Sedimentation during the Middle Cretaceous was rich in organic content, leading to the source rock in the La Luna formation in the Maracaibo region and the equivalent Querequal and San Antonio formations in the Eastern Venezuela Basin (Figure 40). These source rocks have produced large quantities of oil and gas in Venezuela.

The passive margin sequence terminated during the Oligocene when the Caribbean Plate collided against the South American Plate. The passive margin changed to a foreland basin and this oblique collision gradually migrated eastward from the late Oligocene to early Miocene, causing the formation of thrust belts, which got uplifted and eventually eroded. The foredeeps located south of the thrust belt received abundant sedimentation (shale) that created the Eastern Venezuelan Basin. South of this, flexural and isostatic uplift led to the elevation and subsequent erosion of the ancient Guyana Shield. The eroded sediments were transported by the north-flowing rivers into the Eastern Venezuela Basin. The formation of sandstone deposits took place during the Oligocene-Miocene and are represented by the Oficina formation and its equivalents. These formations contain the bulk of the oil in the Orinoco Belt.

Gradual and continuous loading of sediments continued in the Eastern Venezuela Basin and the eventual compaction subjected the organic matter to increasingly higher temperatures with greater depths of burial. Thermal degradation (also called “cooking”) of organic-rich sediments took place from north to south, which is why the oil being formed migrated a few hundred kilometers updip to reach the southern part of the basin during the late Middle Miocene. During migration, the lighter oil fractions escaped or were acted upon by microbial activity, ending up as heavy-oil deposits.

Subsequent tectonic activity led to faulting, which cut off the supply of oil to the Orinoco Belt and so disrupted the migration pathways.

Figure 40. Orinoco Oil Belt in Venezuela comprises four production zones, each with distinct heavy-oil characteristics in terms of API gravity, viscosity, and metal and asphaltene content. The quality of the crude has been rated from highest A to lowest D. From Talwani, 2002.

Canada

The bulk of Canadian oil sands are concentrated in a 142,000 km² region encompassing the Athabasca-Wabiskaw, Cold Lake, and Peace River areas (Figure 16), which contain at least 175 billion barrels of recoverable crude bitumen. Athabasca oil sands are Canada’s largest deposits, holding 80% of the total.
In some areas with little overburden, deposits are so close to the surface that strip mining is the most efficient method of oil recovery. Athabasca oil sands are typically 40–60 m deep, lying above an almost flat limestone rock. The overburden consists of muskeg, a 1 to 3 m thick water-soaked layer of decaying plant matter over a layer of clay sand and gravel. Because of these conditions, Athabasca is the only region in the world where strip mining oil extraction is possible over roughly 3450 km² of its total territory. This represents 2.5% of the total oil sands in Alberta.

The regional geology of the Western Canadian Sedimentary Basin (Figure 41) is shown in cross section AA’ of Figure 42. The Alberta craton essentially consists of a simple monocline. A major unconformity separates the Paleozoic sediments from the gradually dipping Mesozoic strata (Deroo et al., 1977). The margins defining the basin are the Rocky Mountain Thrust Belt to the west and the boundary along which the sediments lap onto the Precambrian Shield to the northeast. To the southeast, the basin continues into Saskatchewan. The relatively deep sediments adjacent to the thrust belt thin out to the north and northeast because of depositional thinning and erosion.

During the period between Upper Devonian and Jurassic, the Alberta craton was dominated by deposition of marine carbonate and clastic sedimentary rock during a passive margin period. Marine sedimentation took place on a stable shelf including the deposition of Devonian reefs and associated off-reef facies. At the end of this period, orogenic movement to the west resulted in deposition of thick continental strata in the Alberta Foothills. This period ended in Tertiary time with the uplift of the land in the Canadian Cordillera, so that marine sedimentation made way for continental sedimentation. The continental sediments were derived and transported from the western uplift associated with the formation of the Western Canadian Cordillera to be deposited into the Inner Cretaceous Sea-way to the east. This later progressed from the southwest and eventually from south to north. The uplift of land during this period created a deep, broad foreland basin. During the early Cretaceous, a major drop in the base level set forth erosion of the sediments deposited during late Jurassic through Devonian. This created an unconformity in the east-west direction truncating the formations (Figure 42).

With the subsequent uplift of the Canadian Cordillera, deposition of thick sediments from late Cretaceous into the Tertiary overlaid the unconformity with a succession of sandstones, shales, and conglomerate filled channels. The permeable sediments are thought to have provided a conduit for updip migration of the hydrocarbons and basinal fluids from the source to the host rocks where bitumen is found today. As the uplift of the Canadian Cordillera continued, downward bending of the adjacent region referred to as the Western Plains was taking place. This formed the Alberta Syncline, which received large quantities of clastic sedimentation through erosion of the Rockies. The uplifting Canadian Cordillera continued through the Neogene, which resulted in the erosion of the Tertiary sediments (Figure 42).

The widespread Devonian limestones, dolomites of the Grosmont formation, and associated reefs cover a large part of east-central Alberta. These are overlain by the Upper Devonian Winterburn and Wabamun formations or their stratigraphic equivalents. The eroded updip edge of the Grosmont formation, which is approximately 130 km southwest of the oil sands found at Fort McMurray, is overlain by the stratigraphic equivalent formations of the upper beds of the McMurray formation. The subcropping carbonates mostly fall in the carbonate triangle marked in Figure 16. The oil in these carbonates has the same chemical characteristics of the oil from the oil sands above, which suggests that the carbonates were sourced from above.

The commonly accepted theory for the origin of the oil in sands is that the shales associated with the Lower Cretaceous in an oil migration pattern from west to east
Figure 42. Regional cross section of Alberta Syncline showing structural and stratigraphic relationships. Modified from Deroo et al., 1977.
(Demaision, 1977). Cretaceous shales are organically rich (Deroo et al., 1977) and thermally mature downdip of the Peace River accumulation (Hacquebard, 1975), suggestive of a long-distance migration (approximately 80 km for Peace River and approximately 380 km for Athabasca) for oil. In addition to Lower Cretaceous shales as source rocks, shales of other ages have also been postulated as contributing to oil accumulation (Riediger et al., 2000). The origin of such a colossal volume of hydrocarbons and its timing are still controversial. What is generally accepted is that whatever the source, these hydrocarbons were generated deep in the basin, migrated long distances updip, and accumulated in shallow stratigraphic traps near the basin’s eastern edge. Over time, under the action of water and bacteria, the light crude was transformed into bitumen. Degradation of the trapped oil has been found to be more severe at the edge of the basin (8° API at Athabasca), and this severity decreases basinward in steps from one deposit to another (26° API at Bellshill Lake, 250 miles southwest) (Deroo et al., 1974; Jardine, 1974).

Most of the exploitable bitumen resides in unconsolidated Lower Cretaceous sandstones in the Athabasca, Peace River, and Cold Lake areas. The Devonian and Mississippian carbonate reservoirs unconformably overlain by the Athabasca and Peace River oil sands also host bitumen but have not been exploited commercially. Figure 43 shows the initial volumes of crude bitumen by formation and area. The Athabasca with the in-place and mineable Wabiskaw McMurray formations followed by the Grosmont formation (Hein and Marsh, 2008) is by far the most significant deposit. Other formations like Grand Rapids, Clearwater, and Bluesky/Gething hold significant in-place volumes of bitumen.

Figure 44 is the bitumen-pay thickness map for the Athabasca area on the basis of a lower cutoff of 6% porosity and 1.5 m thickness. The general shape of the contours indicates that most of the bitumen resource occurs as a north-south trend along the eastern margin of the Athabasca oil-sands area (Hein and Cotterill, 2006).

**Heavy-oil Recovery**

Techniques in heavy-oil recovery can be divided into surface mining and in situ recovery (Figure 45).

### Surface mining

Two tons of oil sand mass render approximately one barrel of oil. Oil sands are mined by means of massive power shovels holding as much as 100 t of load (Figures 46 and 47). Dump trucks with a capacity of 400 t convey the mined oil sands to crushers where the bigger lumps are broken and other hard rocks are removed. The remaining sand is mixed with water and air at about 50°C, agitated in a cyclofeeder, and the slurry is then pipelined to the processing unit. The use of caustic soda and hot water has been discontinued to allow water recycling, thus reducing the volume of water that ends up in tailings ponds.

The slurry passes through vibrating screens that separate larger materials before it proceeds to the primary floatation separator. There, much of the bitumen content attaches to air bubbles, forming a froth layer while the coarse minerals and sand settle in the vessel. The middlings

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**Figure 43.** Original oil in place, Alberta bitumen. From Hein and Marsh, 2008.
part is removed from the vessel and passed into an aerated secondary floatation vessel. The resulting froth is combined with the primary froth. The water from this step is recycled, the sand is stripped of oil, and the polluted water goes to the tailings ponds. The bitumen is directed to storage tanks from where it is transported for upgrading.

Tailings ponds are usually built in old mine pits and contain a mixture of water, clay, sand, some residual bitumen, and some toxic chemicals. Figure 48 shows an open-air tailings pond where clay and sand particles are allowed to settle down — a slow process that can take up to a decade. After the settling process is complete, water is siphoned off into another area of operation and the pond is worked over for reclamation, ensuring proper drainage. Although no land has been posted for reclamation at the time of this writing, the plan is to return lands to the province under reclamation certification; this will involve topsoil restitution and planting of native flora.

**Figure 44.** Bitumen pay thickness of Athabasca Wabiskaw McMurray deposit for areas with >1.5-m bitumen. Contour interval is 10 m. Annotations showing surface mineable area (dashed line) and approved schemes including surface mining (squares), in situ thermal (circles), and primary and waterflood (triangles). Modified from Alberta Energy and Utilities Board, 2008; adapted from Hein and Cotterill, 2006.

**Figure 46.** Truck and power shovel in a strip mining operation. Image courtesy of Syncrude Canada Ltd.

**Figure 45.** Block diagram showing the classification of different heavy-oil recovery methods.
Because it is thicker than traditional oil, the combined bitumen froth is usually mixed with naphtha before going to a centrifugal separator where coarse and denser solids are removed. The separated bitumen is pipelined for upgrading into synthetic crude oil. New technology is being assimilated into the performance of tailings oil recovery (TOR) units, the diluent recovery units that recover naphtha, gas oils, and water from the froth and the inclined plate setters (IPS), all of which help recover close to 90% of the bitumen.

A process different from dilution centrifuging can separate heavy minerals (zirconium- and titanium-based compounds — rutile, ilmenite, and zircon) present in the bitumen during primary and secondary froth production (Kaminsky et al., 1979).

**In situ recovery**

Because only an estimated 20% of Alberta oil sands are close enough to the surface to be strip mined, heavy oils from most of Canada and all of Venezuela, the United States, Indonesia, and other countries are extracted mainly by means of in situ recovery techniques. These fall into two broad classes: thermal and nonthermal.

Thermal methods are most commonly applied because they supply heat to lower the viscosity of heavy oil and make it mobile so that it can be pumped to the surface.

In situ combustion (ISC) consists of burning a small amount of the oil in place to displace the rest closer to the producing wells. For this purpose, oxygen or an oxygen-rich gas mixture such as air (which may be preheated or otherwise) is injected into the reservoir, where the heavy crude oil is ignited. As combustion starts and the temperature rises, the lighter fractions of oil vaporize and, combined with the steam produced by vaporization of connate water, move forward in the reservoir matrix. As the surging combustion front comes in contact with cooler portions of the reservoir, the gases and vapors condense, transferring heat to the heavy oil and making it mobile to migrate. This process continues while the heavy residual coke left behind continues to burn, which produces hot gases provided that sufficient air supply is maintained. The different zones formed in the combustion process are shown in Figure 49.

Because air has a poor heat-carrying capacity, only 20% of the generated heat is carried forward ahead of the fire front. The rest of it is lost to the rock mass above and below. One of the efforts to utilize this lost heat is...
Figure 49. ISC zones forming the fire front as seen along a cross section of a formation. The temperature distribution along the formation ranges from 600°F to 1500°F. From Chattpoadhyay et al., 2005.

reverse combustion, in which once the fire is ignited, the initial injector well is made the producer and a different well is used for air injection. By reversing the direction of the air injection, oil is forced to move through the heated front to the producer, and in the process utilizes the heat in lowering its viscosity.

In another proposed technique, water is injected with air, which not only would reduce the air requirements but also help distribute the heat uniformly. As water reaches the combustion zone, it is converted into superheated steam, which passes through the flame and reaches the reservoir oil.

ISC is best suited for reservoirs that have a thickness greater than 3–4 m, contain 10–20° API (as heavier oils may deposit too much fuel), and permeability greater than 100 md to allow the flow of oil. ISC has been used for reservoirs 100–1200 m deep, but for greater depths compression costs are excessive, and ISC has lower sweep efficiency compared with other methods. Romania has the biggest ISC operation in the world, followed by India, and the United States (Louisiana).

Cyclic steam stimulation (CSS), also called steam soak or “huff-and-puff” method, uses steam injection to recover heavy oil. Steam is first injected into the well at high pressure and 300°C for several weeks, thereby heating the reservoir rock and the fluid and lowering the bitumen viscosity. After this, the well is shut in to allow heat to soak into the formation around the vertical well. Within the heavy-oil formation, there could be interfingering into high-permeability zones, but for simplicity one may assume that steam heats up the formation to a uniform temperature. Finally the well is put on production to pump out the mobile oil until the production rate declines several weeks later. The well is then put through another cycle of injection, soak, and production. This process may be repeated 20 or more times, as long as output justifies the cost of steam injection. For optimal results, this method requires a reservoir thickness of 15 m or more, a high well density (typically 1.5 hectare, or 15,000 square meters, per well), and the absence of base water aquifers that would vent away the injected heat. CSS has an average recovery factor of a little more than 20%.

High viscosity oil or bitumen (e.g., Cold Lake Field) may require larger quantities of steam than less viscous heavy oils (e.g., California and Venezuela). Also, for very deep targets, the effect of steam stimulation may be compromised by heat losses in the wellbore and problems arising due to high temperatures. One performance index for this process is the oil-to-steam ratio (OSR), which is defined as the volume of oil produced for unit volume of water injected as steam at standard conditions (Ali, 1994). The majority of the oil sands industry uses the reciprocal performance index, called steam-to-oil ratio (SOR) = 1/OSR. For CSS, while companies generally look to generate production at an SOR of less than 5, a typical break-even SOR is between 6 and 7 m³/m³, implying an OSR cutoff of roughly 0.14 to about 0.17 m³/m³. Historically, a value of 0.15 m³/m³ has been taken as a typical OSR cutoff value. The cutoff usually depends on the price of natural gas (used as a heat source) and bitumen and so can change with time.

SAGD has a much higher recovery factor, potentially more than 70% of the original oil in place, because it overcomes the inherent limitation of CSS — insufficient lateral drive available to move the hot oil to the producer well. Because vertical wells have limited contact with the reservoir, the lateral or radial flow requires considerable pressure, which is not there. The SAGD pioneered by Butler (1985) and Butler and Stephens (1981) makes use of two long horizontal wells and gravity drainage to move the oil (its viscosity temporarily altered) to the production well.

High-pressure steam injection in vertical wells has been used for some time. In steam flooding, as it is called, injection is usually carried out in a pattern, the most common being a five-point pattern, with the steam injector well at the center surrounded by producers. The steam injected at the center produces an expanding heat front into the formation. As it advances laterally, it forms a hot waterflood zone just ahead of the steam zone, which in turn tends to cool down to formation...
temperature. The gas drive effect that steam exerts outward from the injection point pushes the mobilized oil in the direction of the producers. This method works for heavy-oil formations but not for bitumen, which is difficult to push to start any adequate flow. Steam flooding has typical recovery factors greater than 50%.

SAGD improves on steam flooding principles. Two parallel horizontal wells are drilled into the formation in the same vertical plane (Figure 50). The upper well is used as a steam injector and the lower well as a producer. As steam is injected into the upper well, it rises to the top of the formation and sideways and forms a steam-saturated zone called a “chamber,” which has the almost uniform temperature and pressure of steam. This heat is conducted to the bitumen, reducing its viscosity and making it mobile. As the steam chamber expands with injection, it also condenses at the periphery of the chamber. The bitumen and the condensate drain under gravity to be collected by the producer. For this to happen, the vertical permeability in the reservoir needs to be high. Consequently, the placement of the horizontal wells has to be such that neither shale stringers nor vertical barriers interfere between them. Figure 51 shows a schematic of the steam chamber, and its creation and growth are necessary for oil production to occur. Notice that the energy transport within the steam chamber is by convection (indicated in Figure 51 with arrows) and hence its shape is convex.

Figure 50. SAGD heavy-oil recovery process. Image courtesy of The Pembina Institute.

Figure 51. Steam injection and drainage in a SAGD operation.

efficiency of the process increases at higher temperatures and higher steam pressures, although it depends on the viscosity of the bitumen or heavy oil and on the properties of the reservoir zone being drained. Usually SAGD wells are drilled in groups off central pads and their lateral reach in terms of horizontal sections is very large. The distance between two SAGD sections is dependent on the thickness of the reservoir zone, but a 5-m separation is common. For
thinner zones, the distance between wells is much shorter, 1 m or less for a 20-m pay.

Generally, SAGD is recommended for reservoir zones that have a thickness of at least 30–40 m. Several variations of the process aim to increase efficiency, surmount limitations, and improve economics. One which is being developed at this writing, steam and gas push (SAGP), calls for a noncondensable gas such as nitrogen or natural gas to be injected with steam to reduce its consumption and hence improve the economics. Another variation of SAGD is the nonthermal miscible technique, which will be discussed with nonthermal methods. In a process known as JAGD (J-well and gravity drainage) (Gates et al., 2008) the producing well has a J-shape, which is reported to have the advantage that production is less susceptible to the problems posed by permeability barriers such as shale layers.

Toe-to-Heel Air Injection™ (THAI) utilizes horizontal production wells paired with vertical air injection wells to recover heavy oil/bitumen (Figure 52). It represents a new approach to ISC (Greaves et al., 2004; Greaves and Xia, 2004). Traditional ISC operating between vertical wells has limited success in immobile bitumen reservoirs. THAI resolves some of the issues, which include long length of oil displacement as a consequence of using vertical producer wells; unpredictable burning surface and potential for spontaneous combustion at the surface, which is a direct result of air and oxygen injection at a significant distance from the producer wells; low air/oxygen flux; low-temperature oxidation; and difficult emulsions and gas override.

THAI is the first ISC process applicable to immobile bitumen reservoirs. Because it is less impacted by geologic variables found in oil sands than current steam-based technologies, it can be applied over a broader range of reservoirs (e.g., under 10-m thick, low pressure, previously steamved or depleted gas-over-bitumen, top or bottom water, and deeper reservoirs).

In the THAI process, horizontal production wells are drilled near the base of the reservoir with vertical air injection wells drilled near the toe of the production wells. A near-well steam preheat is conducted to establish communication between the injectors and the producers. Once the heavy oil/bitumen reaches the ignition temperature and mobility, air is injected, ignition occurs, and a combustion front develops. As air is injected into the formation, the combustion front moves from the toe to the heel of the horizontal well along its axis. The high temperatures within the combustion zone promote hydrocracking and result in partial upgrading of the in situ heavy oil/bitumen. The partially upgraded THAI oil along with vaporized water from the reservoir nitrogen and gases that form during combustion (primarily carbon dioxide) flow into the horizontal production well and are produced to surface facilities where the oil is treated and sent to market. An 8° API bitumen is produced as 12° API oil with a 1000-fold decrease in viscosity, greatly reducing diluent requirements to meet pipeline specifications.

The CAPRI technology uses a new horizontal well liner design. A catalyst is packed between an inner and outer slotted liner in the horizontal production well. THAI fluids flow from the reservoir into the outer liner and through the catalyst, further upgrading the oil before its entry into the inner liner of the well.

THAI and CAPRI processes require minimal surface facilities compared with other steam-based processes because of negligible natural gas consumption, steam generation, and water processing. This results in lower

Figure 52. THAI process. Image courtesy of Petrobank Energy.
greenhouse gas emissions and a smaller surface footprint. The resultant upgraded product and lower operating costs are expected to lead to higher netbacks. Both processes are patented and, at this writing, being field tested. A chapter on the development of this project is included in the book in a later section.

Nonthermal methods are typically suitable for light and moderately viscous (less than 200 cp) oils. They are also suited for thin formations of 10 m or less and for deeper formations at 1000 m and more. The two main objectives in nonthermal methods are to lower viscosity and interfacial tension. We have included the cold heavy-oil production with sand (CHOPS) method under this class although it does not require the use of any agent for production, unlike other methods. The vapor extraction (VAPEX) method has also been included in this class because it is a nonthermal counterpart of the SAGD method.

CHOPS enables oil production from unconsolidated oil sands by encouraging their influx in production wells and then maintaining it. This nonthermal method differs from other well completion and lifting practices in that there are no filter screens or gravel packs that prevent sand from entering the wells. Historically, sand production in wells is minimized to save on workover costs that arise when rod pumps cannot handle sand inflow. However, in heavy-oil reservoirs, keeping the sand out lowers oil production to uneconomic levels. CHOPS wells allow the unconsolidated oil sands to enter unimpeded, which are then lifted to the surface with progressive cavity pumps designed to manage material that consists of sand up to half its bulk. A cavity pump basically consists of a twisted steel pipe inside of a cylinder and attached to a motor. As the sandy material enters the well, the turning twisted pipe brings it to the surface. Simultaneous extraction of oil and sand generates high-porosity channels, or “wormholes,” that radiate away from the borehole (Figure 53b). Because wormholes have a permeability effect in heavy-oil reservoirs, the reservoir pressure falls below the bubble point, causing the dissolved gas to come out of solution to form foamy oil (Figure 53a). This gives rise to a partially saturated reservoir around the vertical borehole in the heavy-oil formation. The development of wormholes in the changing sand matrix also increases the porosity in the reservoir, lowering the seismic velocity in these zones.

Most cold-produced heavy-oil reservoirs do not have bottom water aquifers or top gas because these fluids could have detrimental effect on the production life of the wells (Mayo, 1996). CHOPS is a straightforward, cost-effective extraction method for a certain range of viscosities. It was pioneered in Canada where, in the mid-1990s, it became the primary heavy-oil production method (Wang et al., 2007). The method is also extensively used in Venezuela. The primary heavy-oil recovery factor with CHOPS is 5–10%.

The high volume of sand produced by CHOPS when a well is first put on production gradually decreases after some weeks. Excess sand is reinjected into the deep depleted formations by means of slurry fracture injection (SFI), which was developed in Canada. This environmentally friendly technology reduces the impact of waste on the surface.

VAPEX is similar to SAGD but uses light hydrocarbons instead of steam to reduce the viscosity of bitumen. Hydrocarbon gases such as ethane, propane, butane, or mixtures are injected in the upper horizontal well. These

![Figure 53. (a) Sand production and stress distribution around the borehole, and (b) single propagating wormhole in a sandstone formation as a result of cold heavy-oil production with sand. From Mayo, 1996.](image-url)
solvents dilute the bitumen around the wellbore, allowing it to flow into the lower production well. A solvent vapor chamber is formed around the upper horizontal well, which propagates away from the borehole. Because viscosity reduction takes place in cold conditions, VAPEX takes longer than thermal methods. To enhance its efficiency, one variation involves establishing communication between the two horizontal wells by circulating steam between them to reduce the viscosity of the bitumen around the boreholes; this quickens the process when the solvent is injected in the upper well. Similarly, mixing a small fraction of steam with the solvent has been suggested in the interest of enhancing efficiency.

Chemical flooding, although unsuitable for heavy-oil/bitumen recovery, is briefly discussed for the sake of completeness. In polymer flooding, water-soluble polymers are injected as a waterflood to help improve the sweep efficiency. Recovery is generally higher than just water flooding. Surfactant flooding lowers interfacial tension between oil and water, enhancing oil displacement efficiency, but the flooding becomes ineffective after a short distance because of surfactant adsorption and/or reaction with rock minerals. Alkaline flooding consists of an aqueous alkaline solution of sodium hydroxide or some other alkali. When injected into the light oil formation, the alkaline components react with the acidic components in the oil to form surfactants in situ, which reduce interfacial tension. Formation of emulsions also takes place and these help reduce water mobility and improve volumetric sweep efficiency. Emulsion flooding and carbon dioxide flooding have also been suggested.

Injected fluids are miscible or immiscible upon first contact with the resident oil. Ethane, propane, or butane are some of the fluids injected, sometimes followed by injection of natural gas or an inert gas such as nitrogen. Carbon dioxide has also been used as a fluid for displacement purposes.

In addition to the methods discussed above, there are evolving hybrid and proprietary technologies that hold promise. Imperial Oil has used proprietary liquid-assisted steam-enhanced recovery (LASER) in the Cold Lake area of Alberta. Essentially it adds a low concentration of diluents to the steam in mid-life steaming cycles, and these lead to improved recovery uplift.

Hybrid approaches combining production methods are evolving in the interest of higher outputs. Some of these are being tried and others are ideas to be experimented with. For instance, the SAGD-VAPEX approach, a mixture of steam and miscible solvents, should lead to reduced steam-to-oil ratios (SORs). Simultaneous CHOPS-SAGD — high permeability zones created by CHOPS in the horizontal well — followed by breakthrough of steam, should help SAGD recovery. Single or horizontal wells can be operated as moderate CSS wells in combination with a wide steam chamber, which will reduce the SOR by approximately 20%.

Pressure pulse technology (PPT) in combination with CHOPS and other methods is an economical and promising recovery approach. PPT is based on the premise that a low-frequency, high-amplitude pressure pulse acting on fluid-saturated porous media can enhance the flow of fluids. The mechanism involved is that the impinging wave generates a pore-scale dilation and contraction in the porous media through an elastic response so that the fluids flow in and out of the pores, overcoming capillary barriers, suppressing viscous fingering, and reducing pore throat blockage.

**Geophysical Characterization of Heavy-oil Formations**

Soon after Pickett (1963) showed on the basis of laboratory data that $V_p/V_S$ can be a lithology indicator and assigned values of 1.9 to limestone, 1.8 to dolomite, and 1.6–1.7 to sandstones, Tatham (1982) and Domenico (1984) followed up on this work and suggested correlations between the $V_p/V_S$ ratio, porosity, and lithology.

Tatham and Stoffa (1976), and McCormack et al. (1984) demonstrated the combined use of $V_p$ and $V_S$ from seismic data for identification of hydrocarbon anomalies and stratigraphic interpretation. This was followed by development of empirical relationships between $V_p$ and $V_S$ in clastics (Castagna et al., 1985; Han et al., 1986) and carbonates (Rafavich et al., 1984). As such applications were reported from time to time, it was also realized that a lowering of the $V_p/V_S$ ratio in response to one or more specific reservoir properties may not be unique or unambiguous (McCormack et al., 1985). This is because for a given rock type, there may be several parameters affecting the $V_p/V_S$ ratio, some of which McCormack et al. (1985) have listed as the number and distribution of mineral grain types that comprise the rock matrix, type of cement and degree of cementation, rock density, type of pore fluid and its density, effective stress, formation temperature, depth of burial, geological age of the formation, and porosity and pore aspect ratio, among others. Thus, for low-porosity rocks, the pore space may not have a significant effect and the $V_p/V_S$ ratio could be the determining factor; for rocks with higher porosity, the pore aspect ratio is generally important. The $V_p/V_S$ ratio can be used to distinguish sands, carbonates, and dolomites or for identification of sand-prone versus shale-prone environments (Brown et al., 1989). However, if the pore aspect ratios/porosities for different lithologies have an overlap in $V_p/V_S,$ then such a discrimination could be questionable.

The relationships between seismic data and lithology can also be determined at well control points by multivariate
analysis or neural networks, and then the lithology between the wells can be predicted from these determined relationships using linear or nonlinear methods. Such approaches are often resorted to if the correlation between lithology and chosen seismic attributes is weak.

Alternatively, rock physics analysis can help understand the relationship between lithology and related rock parameters and select those lithology-sensitive rock parameters that can be seismically derived. Once this is done, the chosen parameters can be derived from the available seismic data. Such elastic parameters can be estimated from conventional seismic data using amplitude variation with offset (AVO) analysis or from multicomponent seismic data.

For AVO analysis, the requirements include true amplitude processing, high signal-to-noise ratio, and long-offset data (for three-term AVO inversion), which require accurate moveout corrections and stretch compensation, among other things. The main advantage is that the available P-wave data can be used for this analysis.

Elastic parameters from AVO analysis

Because the $V_p/V_S$ ratio is a good indicator of lithology, attempts are made to derive this ratio by different methods. Dumitrescu and Lines (2007) compare this ratio derived by AVO analysis of conventional P-wave data and the ratio derived from multicomponent data. The seismic data are from a heavy-oil field (oil sands of the Devonian-Mississippian Bakken formation) near Plover Lake, Saskatchewan, Canada. Simultaneous inversion of prestack time-migrated PP gathers was performed to derive P- and S-impedance and $V_p/V_S$ volumes. This provides a significant improvement over performing separate inversions on P- and S-reflectivities. The result of this analysis is shown in Figure 54a in the form of a horizon slice at Bakken +2 ms from the $V_p/V_S$ volume.

Next, the joint inversion of PP and PS (registered in PP time) poststack data was performed using the method of Hirsche et al. (2005) described later. The $V_p/V_S$ ratio derived using this approach as equivalent to Figure 54a is shown in Figure 54b. Both of these displays compare well with a similar display (Figure 55a) derived using traveltimes. However, the $V_p/V_S$ volumes based on simultaneous and joint inversion produce values with a vertical resolution of a 2-ms sample interval, whereas the previous results from traveltimes were averaged over an interval of 60 ms (Figure 55). Thus inversion results offer sharper details for identification of sand or shale.

Xu and Chopra (2009) demonstrate a practical workflow for mapping heterogeneity facies within the bitumen-bearing

![Figure 54](image-url). Horizon slice at Bakken +2 ms on $V_p/V_S$ volume obtained from (a) simultaneous inversion on prestack PP data and from (b) joint inversion of poststack PP and PS data. From Dumitrescu et al., 2007.
McMurray reservoir in northeast Alberta, Canada. As stated earlier, determining density from three-term AVO analysis usually requires long-offset data. In this approach, the authors describe an improved inversion that relaxes the requirement for large angles and yields a more reliable output. As the first step, rock physics analysis is carried out by crossplotting different pairs of parameters for the McMurray formation reservoir, which is at a depth of approximately 100 m. One or more pairs of parameters that show good correlation are then selected with the objective to derive these from the seismic data. Density is seen to correlate with gamma ray, and so density is determined from the three-term improved AVO analysis. This density attribute can then be used to determine lithology. Figure 56a shows the density reflectivity extracted from seismic data; the equivalent inverted relative and absolute density sections are shown in Figure 56b and c. Notice the lateral variation of density.

Determination of density attribute from AVO analysis of P-wave seismic data requires long offsets. For seismic data recorded with less than 30° offset angle, determination of density is not possible by conventional AVO analysis. In such a situation, Dumitrescu et al. (2005) show the use of neural network analysis to determine density in the Long Lake oil-sands area near Fort McMurray. This area produces approximately 70,000 b/day of raw bitumen via SAGD from the McMurray formation. Three-dimensional three-component data were acquired over this 42-km² area in 2002–2003. Bin size was 10 × 10 m. The area has 38 wells with dipole sonics uniformly distributed, which were used for this analysis. After carrying out AVO analysis for the data, P- and S-reflectivity attributes were generated. This was followed by poststack inversion, which yielded P- and S-impedance. Probabilistic neural network analysis was conducted using migrated stack and the above AVO attributes. Figure 57 shows the derived density attribute along a line from the 3D volume, which provides useful variation of the attribute in the McMurray reservoir.

Tonn (2002) demonstrated an interesting application of neural network analysis for discrimination of shale heterogeneities in a sand-dominated heavy-oil reservoir. To achieve this objective, seismic attribute volumes were used to predict gamma-ray value distribution and so produce an equivalent gamma-ray volume.

This particular exercise began by establishing a relationship between gamma-ray and seismic attributes and using log data and the attribute volumes. Making use of simple options such as single attribute regression and then going to multiattribute correlation and neural networks forms a crucial testing phase in this exercise. It was found that neural network analysis using the migrated seismic; P- and S-impedance volumes as input volumes; and the energy, median frequency, and median gradient gave the best results. This exercise involves validation steps and blind well tests during the analysis. After this, the neural network was applied to the full 3D seismic volume and the 3D gamma-ray cube computed.

This exercise helped support the decision with regard to an optimal location for the horizontal SAGD wells for which clean sand bodies had to be delineated. Figure 58 shows two sections extracted from the predicted gamma-ray volume along the horizontal well pairs. Gamma-ray curves from the horizontal wells (logged later) and vertical wells are overlain. Good correlation between the predicted and measured gamma-ray values suggested that chances to encounter clean sand were high.

On drilling and subsequent logging, the horizontal wells encountered clean sand with a value less than 60° API. In one
well (Figure 58b), shale was encountered in a small 30-m portion (indicated with a blue curve) that was not predicted. Over this distance, measured gamma-ray values were 60° API whereas predicted values were 50° API. However, over the same interval just 5 m lower, the production well encountered clean sand with a gamma-ray value less than 30° API. Therefore, the upper injection well may have encountered a thin layer that was below seismic resolution. The exercise demonstrates that prediction of gamma-ray attributes from seismic data can be useful in delineating sand facies.

Bellman (2008) discusses a proprietary seismic transformation and classification (STAC) process, which involves using AVO, inversion, and multiattribute analysis to determine various rock physics attributes (Lambda*Rho, Mu*Rho, and density) from seismic data. These attributes are classified based on derived facies and fluid rock physics relationships from well logs and cores and translated back to the seismic facies to produce the top image shown in Figure 59. The bottom image is a conventional migrated stack display.
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Figure 58. Tracks of two different horizontal wells and projection lines with predicted gamma-ray values. Gamma-ray curves of upper injector well, lower producer, and three vertical test wells are included. From Tonn, 2002.

Figure 59. Comparison of conventional seismic profile (bottom) with derived facies profile (top). Nonreservoir shale or bottom water (black), bitumen reservoir (yellow), wet reservoir (blue), gas reservoir (green), and Devonian (purple). Gamma-ray logs with 0° to 70° (at baseline) API range are displayed on the profiles. Only well 13-15 was used in the derivation of facies shown above, the rest were drilled after the facies volume was completed. Numbers posted on the facies section represent the percentage of the well (within the McMurray interval) correctly predicted by the seismic facies and fluid estimates. All wells with a number below them were drilled after the facies volume was produced. From Bellman, 2008.
Multicomponent data for characterization of heavy-oil formations

Multicomponent data do not require long offsets because P- and S-wave modes are available at short offsets. Also, the P- and S-reflectivities are involved in better balanced conditions, allowing somewhat lower signal-to-noise ratios than for single wave mode (Garotta et al., 2000). Inversion outputs from multicomponent data (e.g., $V_p/V_S$ ratio) are more reliable than those derived from a single-wave mode.

Another advantage, although not strictly in the context of heavy-oil applications, is that P-wave AVO is sensitive to $V_p/V_S$, but these ratios are almost the same for low- and high-gas-saturated sands. P- to S-converted-wave amplitudes depend on shear-wave velocity and density changes. Of these, density is sensitive to low and high gas saturations and rock porosity variation. Consequently, converted-wave data are helpful. Also, because P-waves are attenuated in partially gas-saturated structures, converted waves in multicomponent data are used for imaging such structures.

Multicomponent data require the accurate association of P- and S-propagation times corresponding to the same time. In addition, the upfront cost of acquiring multicomponent data could be a deterrent. Kendall et al. (2005) propose a general workflow for using multicomponent data and other derived attributes for heavy-oil reservoir characterization (Figure 60).

The acquired multicomponent seismic data are processed in terms of PP and PS data volumes. Well log correlation is done on PP stack volume followed by horizon interpretation. AVO analysis on the prestack PP data is carried out. At the same time, PS data processing continues using the velocities and statics obtained from PP processing. Once the PS stack volume is processed, well log correlation is first done in PS time to pick similar geologic events as those picked on PP stack. Horizons so picked are used for registering the stacked PS data to PP time (Kendall et al., 2002) and used with the PP velocity model to perform PP-AVO and PS-AVO. Following the workflow in Figure 60, the 18 attributes listed in Table 1 were generated for a typical heavy-oil case study (Kendall et al., 2005).

Multiple attributes can be overwhelming for an interpreter and so it is advisable to integrate them into a few meaningful attributes to obtain an accurate reservoir model. To this end, various types of neural networks (Hampson et al., 2001; Leiphart and Hart, 2001) have been proposed. On the basis of the available well control, neural networks are used to derive relationships between the chosen attributes and the target log property. The choice of the probable attributes to be used in the analysis is done at what is known as the training phase. A probabilistic neural approach is typically preferred to other available techniques that include back-propagation and multilayer feed-forward neural networks. In the discussed case study, the goal is to characterize the bitumen-bearing McMurray formation. The petrophysical analysis indicated that density had the best correlation with the interpreted volume of shale, $V_{sh}$, or $V_{sh}$ estimate. $V_{sh}$ is a term frequently used by petrophysicists to establish a gamma-ray cutoff value, which can help to determine a shale from a clean sandstone in a clastic depositional setting. Consequently, a probabilistic neural network was used to first estimate density and this in turn was used to estimate $V_{sh}$. Figures 61 and 62 show these estimates along an arbitrary seismic line passing through four wells. Notice the

![Image of Figure 60. Workflow for multicomponent seismic reservoir characterization. From Kendall et al., 2005.](image-url)

**Table 1. Attributes generated for a typical heavy-oil case study.**

<table>
<thead>
<tr>
<th>PP-data</th>
<th>PS-data</th>
</tr>
</thead>
<tbody>
<tr>
<td>a. Stack</td>
<td>a. Common conversion point stack</td>
</tr>
<tr>
<td>b. P-wave reflectivity</td>
<td>b. S-wave reflectivity</td>
</tr>
<tr>
<td>c. Shear-wave reflectivity</td>
<td>c. Density reflectivity</td>
</tr>
<tr>
<td>d. Density reflectivity</td>
<td>d. Fluid factor</td>
</tr>
<tr>
<td>e. Acoustic impedance</td>
<td>e. Pseudo-shear impedance</td>
</tr>
<tr>
<td>f. P-wave impedance</td>
<td>f. S-wave impedance</td>
</tr>
<tr>
<td>g. S-wave impedance</td>
<td>g. Density (inversion)</td>
</tr>
<tr>
<td>h. Density (inversion)</td>
<td>h. $V_p/V_S$ ratio from event registration</td>
</tr>
<tr>
<td>i. Lambda*Rho</td>
<td></td>
</tr>
<tr>
<td>(incompressibility)</td>
<td></td>
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<tr>
<td>j. Mu*Rho (rigidity)</td>
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variation seen in these estimates in the formation of interest. These estimates have correlated well with drilling results after completion of this work. This type of analysis has been incorporated in the workflow to guide future SAGD well pairs to avoid drilling risks associated with shale plugs within the McMurray zone.

Peron (2004) describes a similar multicomponent data workflow, but instead of using neural networks on derived attributes, the determination of $V_P/V_S$ ratio was demonstrated by comparing P-wave and converted-wave 3D seismic data. Following the workflow in Figure 60 up to the point where log correlation is done, horizons are picked for top and bottom of the reservoir on the PP and PS sections. This is followed by trace-by-trace horizon matching of the events on the PP and PS sections. At well locations, horizons would match because they represent the same depth horizon. However, away from the well locations, differences would exist because of variations in the $V_P/V_S$ ratios. Thus, horizons are snapped together, which introduces time shifts and consequently their time-depth curves need to be corrected. In Figure 63, corrections required to align horizons were calculated at horizon times $T_0$ and $T_4$ from differences between P-wave horizon and PS-wave horizon times in the same PP time domain. Taking the corrections to be 0 ms at the surface, the corrections are then proportionally distributed between
the surface and the top horizon and then between the horizons. For simplicity, S-wave depth-time curves are recalculated separately for each trace, and this allows the determinations of the spatial variation of $V_P/V_S$.

Once the horizons for specific geologic interfaces are picked, the interval $V_P/V_S$ ratio is calculated from horizon times and displayed as a map. In the example for heavy-oil sands in northern Alberta (Figure 64), the map shows the distribution of $V_P/V_S$ in the interval between $T_0$ and $T_4$. Lower $V_P/V_S$ values corresponding to cleaner sands dominate the southern part of the survey, and higher $V_P/V_S$ ratios correspond to shaly areas in the northern part.

Hirsche et al. (2005) developed a new method for simultaneously inverting PP and PS seismic volumes. This approach honors the physical relationship between P- and S-wave velocities and provides a significant improvement over independent inversions of the two data volumes, especially for the $V_P/V_S$ ratio estimates. The method requires pre- or poststack PP and PS seismic traces as input along with an initial estimate of the background trend relationship between P- and S-impedance, obtained by crossplotting well log information. Also, a trend relationship between P-wave velocity and density is required. Simultaneous inversion is based on an extended conjugate gradient technique, which starts from an initial low-frequency model of P- and S-wave velocity, the fit between the recorded seismic traces, and the model-based synthetic traces are improved by locally modifying the

P-impedance model with local deviations of the relationship between P-impedance, S-impedance, and density.

Results from simultaneous inversion demonstrate that $V_P/V_S$ ratio estimates are significantly better than those independently obtained by PP and PS data sets and were subsequently used in a multivariate statistical technique to predict gamma-ray log over the entire 3D volume. The predicted gamma-ray log curves in Figure 65 show a very good fit to the recorded gamma-ray log curves. This exercise provides a significant insight into the distribution of sand and shale in the reservoir interval, which is otherwise difficult because of their similar impedances.
Lines et al. (2005) discuss a straightforward and robust method for creating $V_P/V_S$ maps from multicomponent data. Watson (2002) and Pengelly (2005) have also described this method. Flat events on vertical stacks are predominantly PP reflections but on radial stacks are mostly due to PS conversions. If the thickness between any two reflectors is $\Delta d$, then with reference to Figure 66 this thickness is given by

$$\Delta d = \frac{V_P \Delta t_{PP}}{2} = \frac{V_S \Delta t_{SS}}{2},$$

where $\Delta t_{SS}$ is the two-way S-wave traveltime. The converted-wave traveltime can be expressed as

$$\Delta t_{PS} = \frac{\Delta t_{PP}}{2} + \frac{\Delta t_{SS}}{2}.$$ 

Solving equations 8 and 9 we get

$$\frac{V_P}{V_S} = \frac{2\Delta t_{PS} - \Delta t_{PP}}{\Delta t_{PP}}.$$ 

So, traveltimes for reflection events above and below the interval of interest are picked on the PP and PS sections by first identifying the markers seeking guidance from the available logs or generated synthetic seismograms. Once the traveltimes are obtained, equation 10 above is used to compute $V_P/V_S$ for the entire data set.

This method has been successfully used for mapping oil sands in heavy-oil reservoirs. Figure 67 is a $V_P/V_S$ map for the producing sands at Bakken level in Plover Lake Field (Lines et al., 2005). The low $V_P/V_S$ values in the middle of the map indicate a thickening Bakken, while higher $V_P/V_S$ values to the lower right correspond to the eroded Bakken and thicker Lodgepole Formation. The $V_P/V_S$ map was an effective indicator of lithology.

Michelena et al. (2001) demonstrate the use of multicomponent seismic data for characterization of a heavy-oil formation in the Orinoco Oil Belt. The reservoir consists of closed interbedded heavy-oil bodies at very shallow depths. In this area there is little correlation between gamma-ray and acoustic impedance. There is poor correlation of velocities with lithology, although the S-wave correlation is better than the P-wave correlation. $V_P/V_S$ and gamma-ray correlation is also poor. However, the correlation between gamma-ray and density is high, which is suggestive of its use to help differentiate lithology. When the two parameters that show the highest correlation with gamma ray (S-wave and density) are crossplotted and the cluster points are colored with gamma-ray values (Figure 68), the sands and shales appear to be separated. This observation suggests that these elastic parameters can be estimated from seismic data and used to differentiate shales from sands.

An arbitrary line passing through three wells (with log curves available) was extracted from the PP and PS seismic volumes. These two lines were inverted for impedance
using commercial software and the results combined as per the method of Valenciano and Michelena (2000) to yield density of the medium. This method combines the PP and PS impedances into a single expression for density, which depends, in addition to the input impedances, on the product and ratio of the P- and S-wave velocities.

Figure 69 shows a segment of the density section with the overlaid density log. The target level is below 0.44 s and is seen in this figure as low density. In Figure 70, the lithology distribution along the arbitrary line is extracted from the 3D seismic volumes. Using the log curves for density and velocity available at the middle well and calibrating it with the derived elastic parameters at that location, a neural-net-based classification algorithm was used on the derived elastic parameters to yield distribution of lithology. Sands are seen in blue, shales in red, and transition zones are shown in yellow.

Within the formations, abrupt changes of clay content and porosity, in a lateral sense, give rise to reservoir heterogeneity. Similarly shale barriers interfere with the continuity of the reservoir sands and pose a problem for exploitation of the resource. It follows that an important exploration objective is to determine areas with clean sand within a given sequence.

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**Figure 67.** $V_p/V_S$ map for a 2.75- by 2.75-km area of the Plover Lake Field. Low $V_p/V_S$ values in the middle of the map correspond to thicker Bakken and Lodgepole, whereas higher $V_p/V_S$ values to the lower right of the map correspond to a zone where the Bakken sand and Lodgepole formation have been eroded, suggesting that $V_p/V_S$ is a good lithology discriminator. From Lines et al., 2005.

**Figure 68.** Crossplot for density versus S-wave velocity that is color-coded with gamma-ray values. Sands are seen clearly separated from shales. From Michelena et al., 2001.

**Figure 69.** Density section estimated after combining PP and PS inversions. There is good agreement between estimated and expected densities except between 0.2 and 0.4 s, where the seismic-derived density shows lateral variations around the well. From Michelena et al., 2001.

**Figure 70.** Lithology distribution after classifying the estimated elastic parameters using a neural-net-based algorithm. There is good agreement between seismic-based predictions and well logs, in particular below 0.44 s, where the target is located. The initial model was built using only information from well A. From Michelena et al., 2001.
Enhanced Oil Recovery, Time-lapse Monitoring, and Crosswell Imaging

Enhanced oil recovery (EOR) processes are methods adopted to extract oil from reservoirs after primary production or from reservoirs that contain heavy oil or bitumen that cannot be produced by conventional means. In other words, EOR methods are utilized for improving the efficiency of reservoir production. There are three different types of EOR processes used for different reservoirs: chemical flooding (which includes alkali and polymer flooding), miscible displacement (which includes CO₂ or hydrocarbon injection), and thermal recovery. In the context of heavy-oil production, thermal and chemical EOR processes are preferred.

Chemical methods involve injecting suitable solvents into heavy-oil formations to make oil less viscous and/or form an emulsifying solution that can be recovered more efficiently. These methods cut down on water and energy usage and pollution that some of the thermal methods entail.

As discussed in the section on heavy-oil recovery, thermal EOR processes comprise ISC (fireflood), SAGD, CSS, and THAI, all designed to reduce viscosity of the bitumen and induce petrophysical changes in the target reservoir formation in terms of velocity, density, conductivity, and other parameters. It is of interest to monitor such changes with geophysical methods.

High-resolution 3D surface seismic surveys for designing and monitoring EOR processes are carried out over specific time intervals, generating time-lapse seismic images of the reservoir and of the changes being induced in terms of seismic attributes that correlate with reservoir conditions and properties.

Thermal processes (ISC and steam injection) also lower the viscosity of heavy oil and bitumen to enable pumping the hydrocarbon to the surface. How fluids migrate away from the injection point will depend on permeability heterogeneities or other heterogeneities, or anisotropy induced by fracturing that exists or is induced in the reservoir during injection. Knowledge of some of these reservoir characteristics is helpful before any EOR process is started and, of course, determining the rate and movement of the thermal front, its shape, and overall areal extent of the heated zone provides valuable information for the management of the EOR project.

As steam is injected into the formation, it displaces the heavy oil from the pores of the medium. The rock frame and fluid compressibility increase, resulting in a decrease in the P-wave velocity and an increase in attenuation in the heated zone. Also, as the steamed zone reaches production stage, gas saturation increases. All of these changes result in time delays or pushdowns on seismic amplitudes of reflections from the steam-invaded zones. For example, in a typical sandstone reservoir sandwiched between shale configuration, the reflection from the top of the heated reservoir would have an increase or a brightening of the amplitude, whereas the reflection from the base of the heated reservoir would have a time-delayed reflection and a decrease or dimming of the amplitude reflection. Britton et al. (1983) used a conventional seismic survey over a steam-flooded area to demonstrate that traveltime delays could be seen around the steam injection well. Similarly, Macrides et al. (1988) concluded that seismic waves traveling through the steam-flooded zone get delayed in time and also undergo changes in amplitude.

Thus, time-lapse seismic images generated during EOR processes may exhibit amplitude anomalies corresponding to the changing conditions in the reservoir over time in terms of gas saturation, mobility, phase, temperature, and distribution of the reservoir fluids (Eastwood et al., 1994; Kalantzis, 1994; Kalantzis et al., 1996a, b).

In one of the earliest applications, Mummery (1985) demonstrated the use of seismic inversion to measure or detect the movement of the steam stimulation front within the Clearwater formation at Marguerite Lake, Cold Lake area. Oil sands in these deposits occur in four members of the Mannville Group (Mummery, 1985).

The McMurray formation rests unconformably upon Devonian Beaverhill Lake carbonates. It is composed mainly of nonmarine, well-sorted, mature quartose sandstones interpreted to be channel fill point bar deposits. The Clearwater formation was deposited during a transgressive period and is composed of marine salt-and-pepper sandstone containing some glauconite. Thick marine bar sands and interbar sands, silts, and shales make up the Clearwater formation in this region. The Lower Grand Rapids formation represents a period of northward propagation after the Clearwater deposition. Clastics in this formation represent a prograding deltaic sequence composed of delta plain and channel deposits. The Upper Grand Rapids formation represents a gradual return to transgressive conditions and contains beach deposits, shallow marine bar sands, and occasional thick channel sands.

Figure 71 shows a typical set of log curves from the Cold Lake area. Three-dimensional seismic data were acquired in 1980 and 1981 with identical field acquisition parameters and then processed following the same sequence of steps with care being taken that the data had enough high-frequency content.

The Clearwater formation is 35 m thick at a depth of 440 m and is subdivided into sand reservoir units C1, C2, and C3; the latter is the thickest and contains the most oil.
Seislog sections were generated for three lines and the sonic and density log curves from the two wells were overlaid on these sections to allow calibration. Comparison of the pre- and poststimulation data and the Seislog sections indicated that steam stimulation lowered impedance in the C3 zone and that this application could be used to monitor the movement of the steam front (Figure 72).

**Monitoring ISC fire front**

Greaves and Fulp (1987) utilized time-lapse 3D seismic data to monitor the propagation of ISC fire front in a small portion of the Holt Field in north central Texas, which is not impregnated with heavy oil. During a one-year period, three sets of 3D surveys were acquired at pre-, mid-, and postburn times. The objective was to detect the change in seismic character that could be attributed to the movement of the fire front. Because the combustion process changes gas saturation levels in the reservoir, reflections from the top and bottom of the reservoir will be more pronounced so that amplitude anomalies, both bright and dim, should be clearly seen. In this application, reflection strength, or envelope amplitude seismic attribute, was useful to detect anomalies.

The three processed seismic data volumes were transformed into envelope amplitude volumes. Difference volumes corresponding to midburn-preburn and postburn-preburn were then generated.

Figure 73 shows the comparison of a profile from pre-, mid-, and postburn attribute volumes. The reflection from the top of the reservoir is identified as a trough and on the preburn profile appears as one of enhanced amplitude, as indicated with arrows (Figure 73a). At the midburn display, this amplitude level increases in lateral extent and intensity (Figure 73b). At the postburn stage, there is further increase in intensity and lateral extent of these amplitudes (Figure 73c).

Time slices at the top of the reservoir through the difference in envelope amplitude for the midburn-preburn and postburn-preburn are shown in Figure 74. The bright amplitude is larger, covering most of the area in the lower half for the postburn difference volume.

This application demonstrated the use of seismic envelope attribute for detecting anomalous seismic responses attributable to reservoir processes.

Zadeh et al. (2007) discuss the seismic monitoring of ISC in the Balol heavy-oil field in Cambay Basin, India. The objective of this exercise was to test the ISC process to improve secondary recovery from a heavy-oil sandstone reservoir. The oil is 15° API at 72°C and a fluid pressure of 104 kg/cm². Because the primary recovery rate of the viscous heavy oil is only 10%–12%, it was decided to enhance production by means of ISC. The combustion front was expected to move by approximately 50 m a year, and acquiring time-lapse seismic data before and after ISC would monitor its advance.

With the increase in temperature in the reservoir, P-wave velocity and density decrease. Monitor seismic surveys will therefore exhibit pushdowns because of longer traveltimes. Also, reflection amplitudes in the zones that are affected by heating will exhibit lower impedance. Both of these changes can be determined by mapping changes in the seismic response before and after heating, which may be due to combustion or steam heating.

Synthetic seismic carried out as part of this exercise showed that P-wave velocity initially decreases rapidly with increasing gas saturation and, after reaching a
Figure 72. Seislog sections generated before (left) and after (right) steam injection indicated that steam stimulation lowered impedance in the C3 zone, and that this application could be used to monitor the movement of the steam front. From Mummary, 1985.

Figure 73. A profile from (a) preburn, (b) midburn, and (c) postburn 3D seismic data volumes. The reflection traces are overlain by a color scale of the computed envelope amplitude. A bright spot is created at the top of the reservoir by the midburn stage and this increases in lateral extent and intensity by postburn stage. From Greaves and Fulp, 1987.
minimum, it increases again (Figure 75). However, density decreases monotonically with an increase in gas saturation (Figure 75b). Fluid substitution effect from oil/water to gas is observed as a dimming of the top reservoir event and a brightening of the base reservoir event. This was actually seen on the monitor survey.

Two 3D seismic surveys were acquired for the purpose, the baseline data in 2003, and the monitor data in 2005. Because the monitor data had some repeatability issues, it was found that migrated near-offset (30–700 m) stack data were best suited for this analysis. After application of time-shift correction for overburden, the root mean square (RMS) of the difference in the baseline and monitor data sets was taken, and it showed good anomalies at the location of the injectors (Figure 76).

**Steam flood monitoring**

De Buyl (1989) demonstrated the monitoring of steam flooding in the Athabasca oil sands of Alberta. He showed that examining time differences and differences

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**Figure 74.** Time slices from the difference in envelope amplitude volumes at a level corresponding to the top of the reservoir. Bright amplitudes seen to the left have increased in their areal extent to the right. From Greaves and Fulp, 1987.

**Figure 75.** Variation of (a) P-velocity (m/s) and (b) density (kg/m³) with gas saturation. From Zadeh et al., 2007.

**Figure 76.** The RMS of the difference between the base and monitor surveys in the reservoir window after time shift correction. From Zadeh et al., 2007.
in pseudovelocity volumes between a baseline survey and a monitor survey can reveal the preferential direction of steam movement, and that this information can be used to optimize the EOR process deployed and maximize reservoir depletion. A 3D baseline survey was recorded before injecting steam into the 50-m oil-sands formation. This was done with a dense geometry wherein a 4-m common midpoint (CMP) geometry produced a 1-m depth resolution after processing. After this baseline survey, three monitor surveys were recorded at intervals.

In this analysis, time difference changes were mapped across the steamed reservoir. Seismic amplitudes were then inverted to pseudovelocity profiles. The inverted 3D profiles for the baseline survey were subtracted from similar profiles from subsequent monitor surveys, and vertical and horizontal displays were studied.

Figure 77 illustrates the enhanced spatial extent of the heat zone in the period between monitor 1 and monitor 2 surveys. Similarly, in Figure 78, the inverted velocity profile differences between the base survey and a particular monitor survey illustrate the complex pattern of steam propagation across the heterogeneous reservoir. Again, as part of this interpretation, the vertical and horizontal displays through the pseudovelocity difference volumes are shown in Figures 79 and 80. The increase in the size of these patterns indicates the rate of progress of steam injection during the period over which the steam was injected.

A pioneering seismic monitoring experiment was conducted from 1985 to 1987 at the Gregoire Lake In Situ Steam Pilot (GLISP) in northeastern Alberta, approximately 40 km south of Fort McMurray (Pullin et al., 1986; Pullin et al., 1987 a, b), which demonstrated the
use of high-resolution 3D seismic for delineating steam fronts in oil sands. At the time this site was selected by Amoco Canada along with partners Alberta Oil Sands Technology Research Authority (AOSTRA) and Petro-Canada, the first well drilled, H-3, had indicated the presence of a 50-m thick, relatively homogeneous McMurray formation, having approximately 30% porosity and 85% oil saturation (Hirsche et al., 2002). The McMurray oil sands are resting on a Devonian unconformity approximately 240 m below the surface. H-3 had also encountered a 4-m sand aquifer directly above the erosional surface. It was assumed that the basal wet zone shown in Figure 81 would be crucial to the success of the project in that it would allow the steam to be injected at a significant rate below the oil sand to mobilize the oil formation above. The second well, HO-7, indicated that the aquifer was absent. Thus, the proposed seismic survey was desirable for accurately mapping the area to help with the in situ design. Thorough planning of the seismic surveys began with sampling of cores, measuring velocities under in situ conditions as a function of temperature, and carrying out field tests for establishing seismic acquisition parameters (i.e., burying the seismometers, determining charge size for highest frequency content, offset, etc.).

An initial 3D survey was recorded as a baseline seismic response for the unheated reservoir and the surrounding lithologies. Three more monitoring surveys followed over the next two years (Figures 82–85).

As part of the seismic field tests, Figure 82 shows a shot-record comparison between the case in which surface seismometers were used for recording the data and later and when buried seismometers were used for the purpose. Also shown are the synthetic seismograms for

**Figure 79.** Difference of the inverted velocity profiles shown in Figure 78. Two horizontal anomalies correspond to high permeability thief zones. They are connected by a vertical pathway that may correspond to a fracture zone affecting encased lower permeability oil sands. From De Buyl, 1989.

**Figure 80.** Horizon slice at a depth of 200 m through the velocity difference profiles shown in Figure 79. From De Buyl, 1989.

**Figure 81.** GLISP geologic cross section showing the assumed distribution of the basal aquifer. From Pullin et al., 1987.
correlation with the shot records. Figure 83a shows a wedge model generated from computer modeling results done using sonic log and rock property data. The oil sand wedge model of 75°C increases in thickness from 0 to 20 m. Its seismic response (Figure 83b) shows that the boundaries between hot and cold oil sands produce reflections, and a 5-m thick oil sand layer can be detected with 175-Hz frequency seismic data. In addition, a pushdown directly below the heated oil sand on the Devonian reflection could help in estimating the areal extent of the heated zones and their thickness. Figure 84 shows a comparison of two seismic profiles, one from the baseline survey and the other from a follow-up monitor survey. Notice the pushdown of the Devonian reflection caused by the lowering of the velocity of heated oil sand and the character change observed between the two surveys at approximately 0.2 s on the monitor survey. Figure 85 shows the time delays for the three monitor surveys (Hirsche, 2006) and confirms that seismic data could track the progress of the steam flood in the reservoir.

Kalantzis et al. (1996a) discuss 3D seismic monitoring over Imperial Oil’s D3 pad undergoing CSS in the Cold Lake area of Alberta. Steam has been injected since 1985 into the 450-m deep Clearwater oil-sands formation at 310°C, 10 mPa, and a high rate of 240 m³/day for several weeks. After a desired volume of steam has been injected, the well is shut in for a soak period of approximately two weeks and the production begins from the same wellbore. The first survey was carried out in 1990 during the sixth production cycle, followed by another one in 1992 during the eighth steam injection cycle. Both of these surveys were centered on well D3-8 and included 15 of the 20 injector/producer wells on the pad and five observation wells (Figure 86). The well spacing in the east-west direction is 96 m and 167 m in the north-south direction.

Field acquisition geometry for both surveys was maintained identical. The energy source was dynamite and sample rate was 1 ms. There was no baseline survey available because the D3 pad has been undergoing CSS since 1985. Figure 87 shows inline 42 (depth profile) from the production (1990) and steam (1992) depth-migrated volumes. The Devonian marker (Figure 87b) is pushed down during the steam cycle as the velocity gets...
lowered in the steam-heated area above, between 450 and 480 m in the Clearwater formation. For observing lateral changes in the steam zone and to track the steam front, depth slices were summed over 5-m intervals (five samples per trace) so that the sum of amplitudes for the 470- to 475-m interval are shown in Figure 88. A small anomaly corresponding to each of the wells is seen in Figure 88a. For the steam injection volume, Figure 88b shows significant anomalies between the upper two rows of wells, indicating that this area of the reservoir was affected appreciably by the injected steam. Measurements made at OB1 and OB6 wells had shown significant increase in temperature, consistent with the large anomaly at OB1. The anomalies seen to the north of the first row are in agreement with the observation that there is communication between D3 and another pad to the north. Also seen on Figure 88b are the hyperbolic-shaped amplitude anomalies below wells D3-1 to D3-4. These are not due to processing artifacts but could be associated with movement of an expanding steam front. However, this hypothesis would need more field examples for validation.

Figure 89 shows the differenced isopach for the Devonian (below the reservoir) and Grand Rapids (above the reservoir) markers from production and steam versions, which represent the depth difference for the Devonian. It clearly shows the main depth pushdown to be located between the row of wells D3-1 to D3-4 and D3-6 to D3-9, which is the area affected by steam injection. Figure 90 shows the amplitude difference and amplitude ratio between the 1990 (production) and 1992 (steam) Devonian horizon interpreted from the two volumes. A large anomaly on both maps between the D3-1 to D3-4 and D3-6 to D3-9 row of wells indicates that the Devonian horizon is dimmed in this area because of the large steam-heated zone in the reservoir above.

In a similar analysis, Kalantzis et al. (1996b) show examples from another study performed in a Cold Lake area where at the time Mobil Canada had a 23 vertical-well pilot using steam stimulation for EOR. The reservoirs in this area are the Sparky and Waseca formations, which with the Colony, McLaren, General Petroleum, Clearwater, and McMurray formations constitute the Mannville Group. Sparky consists of Upper, Middle, and Lower high-viscosity (150,000 cp) bitumen-saturated sands separated by shales.
Although the reservoir has good lateral continuity, it is interrupted by discontinuous shale barriers, tight cemented siltstones, and calcified tight streaks that could affect vertical conformance of the steam stimulation.

Steam was injected into the three Sparky sands at a depth of 360 m at a constant rate of 200 m$^3$/d and wellhead pressures of 8–10 MPa (Kalantzis et al., 1996a,b).

A baseline 3D seismic survey was acquired in 1987 and a monitor survey in 1998, almost at the end of the second cycle of steam injection. After basic processing of the two volumes, the stacked data were examined. In Figure 91, an inline from the base and monitor volumes is shown. Bright amplitude anomalies associated with steam injection are seen clearly as indicated within the blue box. Furthermore, the reflectors below the Sparky sands (between 0.375 and 0.4 s) show time delays. The time delay (approximately 6 ms) is more obvious for the Devonian reflector as indicated with yellow arrows in Figure 91. Comparison of time slices from the two volumes at two different times (Figure 92) shows time delays at the Devonian level.

The two volumes are also processed through a one-pass 3D depth migration, and a comparison of the inline in Figure 91 is again compared in Figure 93. Notice that the amplitude of the reflections within the Sparky in the vicinity of the steaming wells has increased, and they are looking brighter. Also, the depth pushdown at the Devonian is evident. Isaac and Lawton (2006) revisited these same data arriving at similar conclusions.

**Monitoring SAGD steam flooding**

Li et al. (2001) discuss a case study from East Senlac, Saskatchewan, Canada in which the producing reservoir is unconsolidated fluvial channel sand of the Lower Cretaceous Dina formation. This sand directly overlies the erosional surface of Paleozoic carbonate, is 15-m thick, has an average porosity of 33%, a permeability of 5–10 darcies, and is highly saturated with viscous heavy oil. Oil is being produced using SAGD technology. Three pairs of horizontal wells A1–A3 were drilled first, followed by an infill horizontal well pair A4 to enhance production.

Three 3D surveys were acquired at different times to monitor the growth of the steam chamber, determine steam sweep efficiency, and examine how reservoir heterogeneity affects the heated reservoir zones. The first survey was shot in the winter of 1990 using vibrator as the source and yielded a bin size of 15 × 30 m. The second survey was shot in September 1997 after 18 months of continuous steam injection. This time the source was a truck-mounted weight drop to avoid damaging surface...
facilities surrounding the steam plant and wells. This survey yielded a bin size of $10 \times 20$ m. The third survey was acquired in the spring of 1998, when steam had continuously been injected for years. For this survey, Mega-Bin geometry was used in the interest of recording wider-band seismic signals containing higher signal-to-noise ratio and better offset and azimuth distributions. The dynamite charges used in 6-m drill holes remained safe. The bin size was $20 \times 40$ m, and the data had much higher folds than the previous two surveys.

Figure 88. Depth slices summed over a 5-m interval, 470–475 m, from (a) production (1990) and (b) steam (1992) depth-migrated data volumes. From Kalantzis et al., 1996a.
Evidently, the three surveys were not designed optimally for time-lapse monitoring, in which repeatability is the key so that differences between surveys can be attributed to changes in reservoir properties.

To extract meaningful information from the data sets, careful processing of the adopted sequence aimed at preserving relative amplitudes and intersurvey balancing is needed. Figure 94 shows a comparison of the three survey profiles with sections cut along the same line across the toes of the four SAGD horizontal wells. The steam chamber migration is clearly noticeable in Figure 94b and c. After two years of steam injection, the reflection from the top of the reservoir is strong and thickening compared with the other two profiles.

In a similar comparison (Figure 95), the profiles are taken along the horizontal trajectory of well A4. Again the significant influence of steam injection is clearly noticeable. The net changes in the reservoir over a period of time can be affected by taking different sections of these profiles. Figure 96 illustrates the difference of the profiles along horizontal trajectory A4, which demonstrates the length of the steam chamber around the wellbore and its vicinity. Production logging in this well confirmed the interpretation that after two years of steam injection, the full length of the horizontal well had been heated.

Theune et al. (2003) and Theune (2004) modeled the anticipated seismic responses due to steam injection into this reservoir that incorporated fluid substitution of steam and water for bitumen under expected in situ conditions. Because the Senlac reservoir is relatively thin (approximately 10 m), it was suggested that seismic monitoring of the reservoir would be difficult because traveltime attributes were not observable. However, in a subsequent analysis, Zhang (2006), while supporting Theune’s observation, showed that steamed reservoirs could be detected using variations in seismic amplitudes. Similar studies by Bianco and Schmitt appear later in this book.

**Frequency attenuation**

During steam injection, because of high temperature and pressure conditions, gas in the form of steam can exist only in a small, restricted zone at the wellbore. Consequently, gas saturation is close to zero. However, during production, the volume of free gas (carbon dioxide, methane, and steam) is considerably larger than during injection. Dilay and Eastwood (1995) report that based on the neutron logs, well pressure, temperature data, and reservoir stimulation, gas saturation around the wellbore (radius 20–30 m) is greater than 5% during oil production.

Such conditions could lead to higher attenuation of high frequencies in the heated zones near the wellbore than in the unheated reservoir away from the wells. Dilay and Eastwood (1995) demonstrated this by an interesting application of spectral analysis to seismic monitoring of CSS. Three seismic time windows were chosen for spectral analysis: one of length 110 ms above the reservoir, a second of 80 ms on the reservoir, and a third of 120 ms below the reservoir. The choice of the windows’ lengths was based on the criteria that they should ensure stable results, not intersect any seismic reflectors, and that neither the above nor the below window should sample the reservoir.

A signal power spectrum was estimated for each stacking bin of the three windows and for the injection and production cycles.
Figure 97 shows the results of the spectral analysis averaged over five traces about a well signal spectra (injection and production), which are similar (Figure 97a), and the spectra for the middle window, which is centered on the reservoir (Figure 97b). This time the two are quite different, particularly for higher frequencies, and the observed changes could be attributed to different phenomena such as velocity sag, changes in impedance contrasts, intrinsic attenuation of higher frequencies, geologic scattering, and degradation of stacking velocities. Figure 97c shows the spectra for the
window below the reservoir and the change in this could be due to intrinsic attenuation.

Dilay and Eastwood (1995) have further analyzed the power spectra by partitioning them into user-defined energy segments. A useful quantile frequency is the 85% energy segment that produces a spectral energy surface for injection and production surveys. Figure 98 shows these spectra across the entire 3D survey. In Figure 98a and b, the spectral tracking for the injection and production surveys are similar. In Figure 98c and d, a similar set for below the reservoir is quite different, deviating by as much as 30 Hz at some points. These show strong attenuation during the production cycle, which is attributed to partial gas saturation.

In the foregoing examples, the use of 3D seismic data for delineating steam fronts in oil sands, time maps, and time-difference maps for reflection data was demonstrated. Lines et al. (1989) utilize traveltime modeling of steam injection into oil sands to conclude that velocity models computed from seismic traveltimes indicate zones of oil sand heating. Three steps are followed in their approach. First, the tar sand layer thickness \( d(x,y) \) is estimated by computing depth maps before steam injection. This is done by converting the time-structure maps to depth maps by using the image-ray model described by Hubral (1977). Second, TOR successive monitor surveys after steam injection, differences in reflection traveltime \( \Delta t(x,y) \) caused by injection of steam are computed. Third, the change in slowness of the oil sand layer can then be computed by using

\[
\Delta s(x,y) = \frac{\Delta t(x,y)}{2d(x,y)},
\]

where \( \Delta t \) is the difference in reflection time because of steam injection, \( 2d \) is the two-way distance of the reflected raypaths in the oil sands, and \( \Delta s \) is the change in the slowness caused by steam injection.

Using the same data as described by Pullin (1987b), Lines et al. (1989) showed the velocity model (Figure 99a) for the first monitor survey, in which the velocity near the
steam injector wells (marked with dots) has been lowered by temperature increase.

Apart from using surface seismic data, seismic arrival times are also recorded by borehole seismometer at an observation well. When these values are included in the slowness calculation, the velocity model obtained (Figure 99b) is similar to the one obtained only from reflection data (Figure 99a).

Figure 92. Time slices from the stacked data volume (a) base and (b) steam monitor showing the time delay at the Devonian marker. From Kalantzis et al., 1996a.

Figure 93. Inline 12 from depth-migrated data (a) base and (b) steam monitor surveys. Notice the brightening of the amplitude at the Sparky level around the steaming wells and the depth pushdown at the Devonian. From Kalantzis et al., 1996a.
Seismic tomography methods

Just as reflection seismic is used for monitoring hydrocarbon reservoirs, crosswell seismic tomography produces images that determine changes therein. In a tomographic survey, a source of seismic energy is lowered to a suitable depth to span the zone of interest in one borehole, and a string of receivers is lowered to cover the same zone in another borehole. Sources and receivers will occupy many positions in the boreholes and are sampled at regular intervals covering the zone of interest. For each shot in one borehole, recording is done in the other borehole, providing coverage of the zone between the two boreholes with thousands of traces. Justice et al. (1993) review some of the applications of crosswell tomography for EOR monitoring. There are basically two types of measurements derived from seismic data and used for tomographic image reconstruction. One is based on traveltimes, which allow seismic velocity field (P or S) to be reconstructed, and the other is based on attenuation, which allows the Q-factor to be reconstructed in the reservoir. Most applications are based on traveltimes measurements and so they are more common.

Figure 94. Steam chamber developing across the pattern of four SAGD horizontal wells. The steam migration is clearly noticeable in (b) and (c). From Li et al., 2001.

Figure 95. Steam chamber developing along horizontal well pair A4. The steam migration is clearly noticeable in (b) and (c). From Li et al., 2001.

Figure 96. 4D seismic difference sections between (a) 1997 and 1990 surveys and (b) between 1998 and 1990 surveys. Highlighted sections show that the steam chamber has expanded along horizontal well pair A4. From Li et al., 2001.
Laine (1987) showed that crosswell methods could be used to construct tomographic images in a heavy-oil steam flood environment.

Bregman et al. (1989) discussed a crosswell seismic experiment for monitoring the fire front in a 17-m heavy-oil saturated sand between two wells 51 m apart at the target depth. The final velocity model obtained after an iterative procedure showed gross features that correlated with well logs. The application yielded encouraging results.

Paulsson et al. (1994) demonstrated successful application of crosswell tomography for monitoring steam injection in the McMurray formation at a location 60 km northeast of Fort McMurray, Alberta. The application defined geology and detected the movement of the thermal front. Figure 100 shows the P-wave velocity tomograms obtained by this method. The crosswell surveys were acquired in wells CH1–CH4 located at the corners of a square 75 m on a side. At the center of the square was an injection well IN1. CH1 and CH4 were the source wells, and CH2 and CH3 were the receiver wells. Two 80-level 3-C geophone arrays were cemented into CH2 and CH3 boreholes.

The velocity tomograms obtained after processing the data are shown in an unfolded form that traverses the four sides of the square. The upper set of tomograms are the pre-steam acquisition and the lower set for the survey acquisition done after 72 days of steam injection. Notice the effect of the steam injection is seen clearly in terms of the increase in red colors, signifying reduced velocity in the lower figure.

Eastwood et al. (1994) also report on the application of crosswell tomography in their CSS analysis at Cold Lake Alberta. The crosswell tomograms indicate the velocity structure in planes surrounding the central well D3-08 (marked with blue lines). The tomograms in Figure 101 show good correlation with sonic logs and good velocity correlation at common well locations. Data quality below 480 m (below the reservoir) is not reliable because of poor coverage at that level. In an attempt to test their hypothesis that calcified tight streaks were impeding vertical conformance of steam, the geologic model was overlain on the tomograms. Direct correlation between the location of the tight streaks and anomalous slow velocity in the reservoir were strong evidence that tight streaks were impeding vertical growth of the heated region.

Mathisen et al. (1995) describe the application of time-lapse crosswell seismic data processed as P- and S-wave tomograms for imaging heavy-oil lithofacies and changes as a result of steam injection. Baseline reservoir properties and conditions were established using P- and S-wave tomograms acquired before steam injection and then interpreted with timelapse and difference tomograms. Figure 102 shows a baseline S-wave tomogram that clearly differentiates the high-velocity channel facies in

![Figure 97](image-url)
yellow from the lower velocity, low-to-moderate flow levee facies (brown). Laterally continuous sequences of channels are seen extending in zone 3 and along the tops of zones 4b, 5, and 6. Velocity heterogeneity within each 300-ft/s (90 m/s) color-defined velocity unit is indicated in the display to the right with 150-ft/s (45 m/s) velocity contours. An anomalously high velocity unit (green-blue) is seen near the base.

The baseline P-wave tomogram exhibits the same reservoir lithology variations and structure as the S-wave tomogram (Figure 103). The low velocity zones seen are a result of the previous steam-heat injection and the formation of gas. A high velocity zone seen in green-blue near the base of the tomogram correlates with the S-wave tomogram.

Time-lapse tomograms were acquired and then processed to show the effects of additional steam injection.
Figure 99. Map of oil-sands velocity model for (a) first monitor survey (red dots indicate three injector wells for initial steam injection), and (b) cooperative inversion of reflection and borehole travel-times in first monitor survey. From Lines et al., 1989.

Figure 100. Four P-wave velocity tomograms. Overlain on (a) are gamma and resistivity logs from indicated wells; bitumen saturation and permeability from core measurements in T05, IN1, and T04; and the geologic model. In (b), the decrease in P-wave velocity indicated by reddening in section CH4CH2 shows the direction taken by the steam. The steam, injected near the center of the figure at approximately 250 m, appears to have risen approximately 20 m around the wellbore and then escaped to the east. Also shown are temperature logs from several wells. Two are shown for CH4. The one with the single spike was taken at the time of the second crosswell survey; the other, taken six weeks later, shows how the heat has expanded upward, which is also apparent on the tomogram. From Paulsson et al., 1994.
Challenges for Heavy-oil Production

Heavy-oil reservoirs, mostly on land, have been produced for decades around the world, but they entail extra...
Figure 103. Baseline heavy-oil sand P-wave tomogram with low-velocity zones (red) because of the presence of gas. It images the same structure and lithofacies variations (yellow and brown) as the S-wave tomogram (Figure 13). Temperature logs (black curve) document portions of the reservoir being heated by steam, whereas sonic logs (red curve) document zones with low-velocity anomalies at the wells (red) that are due to gas. The fact that the tomographic low-velocity zones coincide with high-temperature steam zones and the presence of gas suggests that low tomographic velocities displayed in red are imaging areas where gas has formed as a result of the steam process. From Mathisen et al., 1995.

Figure 104. Time-lapse P-wave tomograms that document progressive reductions in P-wave velocity (increase in red velocity field) due to cyclic and continuous steam injection. The red low-velocity field increases more because of the shallow inline injector than because of the deeper injector, which is projected into the line. Continuous injectors outside of the survey area also cause velocity reductions and growth of the red low-velocity fields. From Mathisen et al., 1995.
effort, investment, and operating challenges. The single most important factor behind many of the challenges is keeping the impact that bitumen or heavy-oil production has on the environment to a minimum. Some of the main concerns are discussed below.

Land surface disturbance and reclamation

Surface or open mining of oil sands in Athabasca involves first clearing large areas of the boreal forest of trees and of the upper muskeg-laden layer that comprises the wet swampy vegetation. Approximately 3500 km² of Alberta’s 381,000 km² total boreal forest are mineable, causing significant impact on the land surface and wildlife.

Mine tailings disposal

Mine tailings disposal is another major concern. Oil-sands production requires large quantities of hot water to separate bitumen from the sand and other material. Two to five barrels of water are used to produce a barrel of bitumen. Fresh water used for this purpose is currently being recycled 18 times, and the rest of it is released into the tailings ponds, which occupy 130 km² of boreal forest. Tailings are a sticky mass of clay and small quantities of sand, water, fine silts, and residual bitumen as well as some other contaminants. The sand and the heavier rock pieces settle down, but the fine clay remains in the water and takes more than 10 years to settle in the ponds.

Open tailings ponds not only emit foul odors but also are generally lethal to the birds and waterfowl they attract. This is particularly problematic in spring because migratory birds in northeastern Alberta find the warm water tailings ponds inviting for stopovers while other water bodies are still frozen. Inevitably, their plumes become oiled with the sticky bitumen, and they ingest polluted clay-laden water and die. Oil companies try to reduce bird killing using scarecrows and propane-fired canons, but birds eventually tend to become habituated to these deterrents. A more effective method relies on radar to detect approaching birds, simultaneously setting off in their path various deterrents such as propane canons, noise cannons, flashing lights, and robotic falcons powered by solar panels. This system is particularly effective at night, keeping ducks, geese, and shore birds, which are nocturnal and diurnal migrants, away from the lethal tailings ponds.

A mechanism patented in 1983 by Jan Kruyer (1988) recovers bitumen from oil-sands tailings, middlings, and sludge ponds. The process consists of passing the tailings mixture through an aperture cylindrical cage, which is in contact with an aperture oleophilic endless sieve. The sieve and the cage rotate continuously. As the tailings pass through the cage, the aqueous phase falls through the sieve apertures and is removed. The viscous oil phase is captured by the oleophilic sieve surface and is carried out of the separation zone into the recovery zone where it is removed.

Because the clay particles are not dispersed during the process, the resulting tailings consolidate easily. Kruyer’s patent holds promise, but it has not been implemented so far because of the high cost of replacing existing processes (Smith, 2009a).

Another major concern is that the contaminated water from the tailings ponds, laced with carcinogenic polycyclic aromatic hydrocarbons and trace metals, could seep into aquifers or underground water flows and end up in rivers. (Robinson and Eivemark, 1985). One way to control seeps is by means of a perimeter tailings beach and perimeter collector ditches of the free water pond. Plastic liners may also prevent contaminated water from escaping.

Recent research suggests that as dry tailings technology becomes commercially viable, sludge ponds may become a problem of the past. An article by Collison (2008) suggests that new bitumen mining techniques may be able to eliminate the sludge pond altogether.

Water consumption

In addition to contamination of fresh water resources, the large water demands represent an adverse effect of oil-sands mining. In Alberta, water availability fluctuates with climate changes and seasonal flows. More than 75% of the Athabasca River water allocation is being used by Suncor, Syncrude, and smaller players like Albion Sands and Canadian Natural Resources Limited, among others. The Alberta Energy and Utilities Board is still issuing more licenses for water usage as the oil-sands industry demands continue to grow. Environmentalists fear the potential irreversible cumulative effects this large increase in water consumption could have in the maintenance of a healthy ecosystem. Although the Canadian government is committed to not have oil-sands development adversely affect the environment, experts suggest that to maintain a healthy aquatic ecosystem a minimal water level must be maintained in the rivers, which can only be achieved by storing water during high flow times so that it is not depleted during low flow times. Encouraging water recycling is another suggestion that most, but not all, operators are already following.

Fuel consumption

Canadian oil-sands production entails the consumption of natural gas for heating treatment water, steam production, and for upgrading and refining heavy oil. Natural gas is already used for electricity generation,
heating, and chemical processing, and additional demand for heavy-oil refining is stretching the available supply thin. It also drives the price of natural gas higher, which in turn adds to production costs, putting the economy of heavy-oil extraction in question.

Natural gas consumption also affects the environment through carbon dioxide emissions. Donnelly and Pendergast (1999) concluded that deployment of nuclear-powered oil-sands projects would reduce a substantial fraction of Canada’s emissions. Predictably, any suggestion of nuclear power draws opposing arguments (Caldicott, 2007); for example, nuclear power plants release no carbon dioxide, but everything leading to their construction and operation does. The debate is sure to continue.

**Upgrading of heavy oil**

Canadian heavy-oil crude production in 2008 surpassed 1.2 million b/d, mostly from oil sands in Athabasca and extracted by Syncrude and Suncor. Overall production is likely to reach 2 million b/d by 2015. Bitumen production needs to be upgraded to synthetic oil of higher API gravity and reduced sulfur content to facilitate its transportation and to enhance its value to most refineries, which are designed to handle lighter crudes. Upgrading essentially involves the use of temperature, pressure, and catalysts to break long hydrocarbon chains into small ones. Because bitumen has more carbon and less hydrogen during upgrading, chemical processes that tend to add hydrogen and remove carbon are adopted.

The easiest way to reduce viscosity and increase mobility is to heat the bitumen so it can be pipelined to regional upgraders. Injection of steam in the subsurface is often used to lower the viscosity of the oil sufficiently to allow it to flow. An alternative is dilution (i.e., adding a light oil or natural gas condensate to further sufficiently reduce the viscosity of oil so that it can flow through pipelines with ease). But because large volumes of light oil are required, adequate capacity needs to be built in place for diluents to be recycled. To this end, a parallel pipeline must be laid to return the diluents to the upgrader.

Dilution of Athabasca bitumen in n-pentane or n-heptane yields a solid precipitate of asphaltenes, which consist of carbon, hydrogen, nitrogen, oxygen, and sulfur and have high molecular masses. Deasphalting itself yields crude oil with higher API gravity.

Because bitumen consists primarily of highly condensed polycyclic aromatic hydrocarbon molecules, these do not distill over when bitumen is heated; therefore, distillation typically yields low levels of distillates. Consequently, heavy oils must be cracked to get smaller molecules, a process referred to as “primary upgrading.” The cracked products are rich in sulfur and nitrogen, which are then reduced during secondary upgrading.

Coking is one of several cracking processes that has traditionally been used and is essentially the thermal cracking (above 45°C) of heavier fractions to produce gasoline and fuel gas. This process does not remove the metal content and carbon residue significantly; however, the coking liquids and residue have a high content of sulfur, olefins, and heavy aromatics. These require additional treatment before they can be used as transportation fuels or other fuels as such. An alternative to coking is visbreaking — a primary noncatalytic cracking process like coking but characterized by higher temperature and shorter residence time.

What this means is that the cracking reactions are terminated before the coke is formed as residue. By doing so, although the sulfur, nitrogen, metal, or asphaltenes content of the heavy oil is not changed significantly, the molecular weight is reduced, which results in a reduction in the boiling range and a lowering of viscosity. The presence of sulfur (a pollutant) and nitrogen causes problems in some downstream processes such as catalytic cracking.

There are some other variations of the cracking process (e.g., delayed and fluid coking) used for primary upgrading of heavy oils. In each case, the products are gases, distillates, oils, and coke as residue. In delayed coking the bitumen is heated before being fed into the coking chamber to allow sufficient time to undergo cracking reactions. The distillates from delayed cracking are usually passed through a chamber with cobalt molybdate catalyst; this process is called “hydrotreating,” in which the sulfur- and nitrogen-produced hydrogen sulfide and ammonia are removed.

Fluid coking allows preheated feed oil flow (bitumen) into the coking chamber in the form of a spray, where it gets thermally cracked above 500°C. The products are lower hydrocarbons, which are condensed with coke as deposit on fluidized coke particles. The yield from fluid coking is higher than that from delayed coking.

As stated above, coke has limited use as boiler fuel because of excessive emission of sulfur dioxide. However, if the bitumen is mixed with a small quantity of a reagent like calcium hydroxide and carbonized in a laboratory at 475°C, the resultant coke has significantly reduced sulfur dioxide emissions during combustion (George et al., 1982).

In “hydrocracking,” hydrogen is added, resulting in better distillate quality and lower levels of sulfur dioxide. However, because vanadium and nickel are present in bitumen, the catalysts gradually lose their properties and need to be replaced periodically. The outputs from the hydrocracker and the delayed or fluid cokers are hydro-treated and then pumped through pipelines to refineries.

Bitumen can also be upgraded by reforming, which involves splitting hydrogen atoms to transform the bitumen into a synthetic lighter crude.

In Venezuela, the heavy oil is warm enough so that it can flow. However, diluents still need to be added to pipeline it to the upgrading facility. Venezuela has
developed a process for marketing extra-heavy oil in the form of Orimulsion, which is essentially an emulsion of approximately 70% natural Cerro Negro bitumen (8.5° API) and 30% water with less than 1% alcohol-based emulsifiers to help bitumen droplets remain suspended in the emulsion. This emulsion serves as inexpensive feed for power stations. It has good combustion characteristics and lower carbon dioxide emissions than coal.

Aquaconversion is a thermal-catalytic steam conversion process that upgrades heavy or extra-heavy crudes (9° API) to 15° API syncrude that can be transported without the need for diluents and still be processed to final fuels in conventional refineries (Pereira et al., 2005). Aquaconversion does not produce any solid residue byproduct such as coke and does not require a hydrogen source or high-pressure equipment. The process can be set up in the production area, eliminating the need for external diluents and transport over long distances.

Heavy-oil upgrading is also achieved by means of sonic generators that make use of low-frequency sonic vibrations to generate resonant frequencies that create cavitation in the heavy-oil samples. When used effectively, cavitation (i.e., the formation of vapor bubbles in the flowing liquid) can accelerate physical and chemical processes. Sonic generators have been used to deasphalt heavy oil and upgrade it to 10° API or higher (Smith, 2009b).

Greenhouse gas emissions

The development of oil sands in Alberta, although generating significant revenue for the province, has also been the cause of controversy because of its effect on the environment, high rates of fossil energy use, and the associated greenhouse gas (GHG) emissions (Charpentier et al., 2009).

Canada produces 2% of the world’s GHG emissions. Oil-sands exploitation accounts for only 4% of the country’s GHG emissions, which is 8 times less than the Canadian emissions from transportation, 4.5 times less than electricity and heat generation, and less than half of the emissions from agriculture (Alberta Government Brochure, 2008).

It may be pointed out that although the GHG emissions produced per barrel have been gradually reduced (intensity of emissions per barrel of production reduced by 38% since 1990), overall GHG emissions are up as a result of enhanced production over the last few years. Therefore, the challenge is to reduce the overall GHG emissions to acceptable levels despite the projected increase in production.

Conscious attempts are being made by the Alberta government and by oil-sands operators to monitor GHG emissions because these could increase substantially with oil-sands production of syncrude, which is expected to reach 5 million b/d by 2030. The long-term plan by the government of Alberta is to reduce GHG emissions by 14% below the 2005 levels by 2050, and in the short-term, the emissions should be stabilized by 2020.

There are still many challenges ahead for the exploitation of heavy-oil sands, perhaps none more important than its environmental impact. Plans to come up with a solution to curb GHG emissions include carbon sequestration. It involves capturing carbon at the source and directing it into depleted reservoirs for storage or into producing reservoirs for enhanced recovery. This will come at a cost. A recent report (Hoberg and McCullough, 2009) by the Canadian Energy Research Institute (CERI) has suggested that it is possible to make oil sands environmentally sustainable. However, this will require the benchmark price for oil to be approximately $105/barrel(USS). Efforts are gradually under way to draw attention to the ways and means of reducing GHG emissions from oil sands below conventional oil so that technological advancements in this area help in producing “green” bitumen. Technology must be further improved to address critical thermal EOR processes such as CSS and SAGD, which are routinely used in deeper formations that cannot be mined. Two problems with these processes are cost and emissions. At the scale at which oil-sands operations are predicted to increase, they will use up the natural gas resources in Western Canada. Therefore, another cheap, clean, and efficient source of energy needs to be found.

There is a growing concern that in situ production can warm groundwater, thereby liberating arsenic and other heavy metals from deep sediments, posing risks to human health. More work is required to ascertain if there is truth in this and if in situ production needs to be avoided. On the other hand, in situ upgrading of heavy oil to obtain lower viscosity and higher API may also be a possibility in the future.

Ultimately, the main obstacle to oil-sands exploitation remains that the cost incurred to produce a barrel of synthetic oil is higher than the cost of producing conventional oil. Furthermore, only special refineries can handle synthetic oil with its various impurities. For this reason, synthetic oil generated from oil sands sells for a lower price than conventional crude, which is processed in regular refineries. During the industry’s cyclic downturns, this disparity widens and the result is that some of the new projects become uneconomic.

One of the ways to keep heavy-oil or bitumen production costs low is by enhancing production itself. Various ways and means have been suggested. In reservoirs where fluids occupy strata that are almost horizontal, drilling horizontal wells has become the preferred method of oil and gas recovery. Over the last many years, the cost of drilling such wells has come down, so that it costs only marginally more today. However, production from these wells is 15–20 times higher, which makes them an attractive choice for oil and gas producers.
Multilateral wells also justify their existence by allowing multiple wells to be drilled from a single main wellbore, eliminating the need to drill vertical stems for individual wells and thereby saving costly rig days. This arrangement also has the ability to tap several zones from branches emanating from a single wellbore.

Future outlook

As stated above, production from oil sands is energy intensive and causes concerns about their effect on the environment. The term "energy intensive" refers to the net energy available after accounting for the energy spent in producing the resource in a useable form. For oil sands, this value is much less than conventional oil. Coupled with this are concerns about the use of natural gas needed for generating steam to recover the bitumen, upgrading it to synthetic crude oil, its impact on the environment by emission of carbon dioxide, not to mention the risk of pollutant seepage from tailings ponds into freshwater aquifers. As many of the oil companies operating in the oil sands and heavy-oil areas around the world confront these issues, the reality is that production from oil sands and heavy-oil reservoirs is expensive compared with conventional oil. However, as much as we may not want to believe, the steady decline that is taking place in mature reservoirs and others that will fall in this category will need to be balanced out. Heavy-oil deposits with their worldwide distribution have large potential as major long-term oil sources. In recent years, the discoveries of heavy crude in deep waters of Brazil, in western Africa, and in the Gulf of Mexico have further encouraged efforts aimed at production of this unconventional resource.

Application of newer technologies in the last two decades has reduced operating costs for the production of heavy oil in different areas of the world. Going forward, the key to enhanced growth and improved economic viability lies in the development of new technologies to help sustain a continuous supply of environmentally responsible energy. As long as the price of conventional oil remains reasonable and the development of new technologies continues, the abundance of this resource and the stable political regimes in most areas around the world will encourage oil companies to decide on the high financial commitments required to become players in the future energy growth.

Advancements in geophysical characterization of heavy-oil reservoirs have a definite contribution to make. As seen over the last two decades, poststack seismic inversion has been used for detecting the movement of steam stimulation from within a heavy-oil reservoir. Seismic attributes have been used for differentiating heated from unheated parts of a reservoir and imaging the areas affected by steam injection. Prestack AVO attributes have been used for characterizing bitumen and heavy-oil formations in terms of their density. Time-lapse monitoring has been used to ascertain reservoir depletion. Multicomponent seismic offers the advantage of characterizing heavy-oil formations in terms of the $V_p/V_s$ ratio in addition to being able to correlate the $P$ and $S$ sections. All of these efforts have been ably supported by 3D visualization technology advancements. It is expected that advancements in all these areas will grow. We will see the application of sophisticated and accurate techniques in each of the areas mentioned above. Multicomponent seismic and neural network applications are two technologies likely to be favored in the near future for heavy-oil reservoir characterization.

References


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